NEPOOL
NEW ENGLAND POWER POOL
Sebastian Lombardi
Secretary

March 28, 2024

VIA E-MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of April 4, 2024 Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the April 2024 meeting of the Participants Committee will be held **in person on Thursday, April 4, 2024, at 10:00 am at the Renaissance Providence Downtown Hotel, located at 5 Avenue of the Arts, Providence, RI** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/.

For those who otherwise attend NEPOOL meetings but plan to participate in the April 4 meeting virtually, please use the following dial-in information: **866-803-2146; Passcode: 7169224.** To join WebEx, click this link and enter the event password **nepool**.

Please note that the NEPOOL room block for the night before the April 4 meeting has closed. However, if you are still in need of a room, please contact either Jaki Sloan (jsloan@daypitney.com) or Pat Gerity (pmgerity@daypitney.com) who may be able to assist with your overnight arrangements.

Looking Ahead -- 2024 NPC Summer Meeting**: The 2024 Participants Committee Summer Meeting will be held on **June 25-27, 2024** (with an opening coffee & dessert reception Monday evening, June 24) at The Omni Mount Washington in Bretton Woods, NH (https://www.omnihotels.com/hotels/bretton-woods-mount-washington). We encourage you to register early. You can make your Omni Mount Washington room reservation(s) through the Mount Washington Room Booking Link, via the NEPOOL 2024 Summer Meeting webpage, or by contacting the Omni Mount Washington (603-278-8406) and identifying yourself as part of NEPOOL. The NEPOOL group discounted room rate is **$299** per room, per night (single/double occupancy). The negotiated rate is available through ***June 7, after which rooms will only be available on a first-come, first-served basis at the Omni Mount Washington's rate available at that time. We kindly ask that all attendees please complete the 2024 NPC Summer Meeting Registration form available on the NEPOOL Summer Meeting website. We will provide and post on that page additional information related to the NPC Summer Meeting as it becomes available.

Respectfully yours,

/s/

Sebastian Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the March 7, 2024 Participants Committee meeting. A copy of the draft minutes, marked to show changes made to the draft circulated with the initial notice, is included and posted with this supplemental notice.

2. [There is no Consent Agenda for this meeting].

3. To receive an ISO Chief Executive Officer report. The April CEO report is included and posted with this supplemental notice.

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

5. To receive an ISO update on the 2024 Annual Work Plan. Materials regarding the updated 2024 Annual Work Plan are included and posted with this supplemental notice.

6. To consider and take action, as appropriate, on changes to Market Rule 1 to further delay FCA19 by an additional two years. Background materials and a draft resolution are included and posted with this supplemental notice.

7. To consider and take action, as appropriate, on Tariff changes to incorporate a process to move policy-related transmission investments forward and allocate the costs (Extended-Term/Longer-Term Transmission Planning Phase 2 Changes), including:

   a. the "***Core Process Proposal***" (revisions to Tariff Sections I.2.2 (Definitions), II.8 (Billing and Invoicing; Accounting), II.46 (General), II.49 (Definition of PTF), III.12.6.4 (Transmission Solutions Selected Through the Competitive Transmission Process), OATT Schedules 12 (Transmission Cost Allocation), 12C (Determination of Localized Costs), and new 14A (Recovery of Longer-Term Transmission Upgrade Costs by Non-Incumbent Transmission Developers), and Attachments K (RSP Process), N (Procedures for RSP Upgrades), O (Non-Incumbent Transmission Developer Operating Agreement), and P (Selected QTPS Agreement)); and

   b. the "***Supplemental Process Proposal***" (which includes all the elements of the *Core Process Proposal*, <u>plus</u> revisions bookmarked and highlighted in green, found in OATT Attachment K Sections 16.4(j) and 16.8, and Schedule 12 Section 10(b)).

   Background materials and draft resolutions are included and posted with this supplemental notice.

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

COVID-19 Considerations. To safeguard the well-being of yourself and others, please refrain from attending a NEPOOL meeting in person if you have confirmed that you have COVID-19. If you suspect that you might have COVID-19, or if you have been exposed to COVID-19, please take the precautions recommended by the CDC. In any case, all are encouraged to be respectful of others' personal space, and to respect individual choices with respect to wearing or not wearing masks.

8. To consider and, as appropriate, direct the balloting of changes to the Second Restated NEPOOL Agreement (and conforming changes to the Participants Agreement) to revise the allocation of any unused Provisional Member Group Seat Voting Share (to all six, rather than to five, Sectors). Background materials and a draft resolution are included and posted with this supplemental notice.

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

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

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

11. Administrative matters.

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

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PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Thursday, March 7, 2024, at the Seaport Hotel in Boston, MA. A quorum, determined in accordance with the Second Restated NEPOOL Agreement, was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the meeting, either in person or by telephone.

Ms.~~Committee Chair,~~ Sarah Bresolin, Chair, presided, and Mr. Sebastian Lombardi, Secretary, recorded. The Chair welcomed the members, alternates and invited guests who were present.

JOINT NOMINATING COMMITTEE

Continuing efforts begun at the previous meeting to provide information regarding the Joint Nominating Committee (JNC) process, Ms. Bresolin invited Ms. Cheryl LaFleur, Chair of the ISO New England Board of Directors, to provide additional context on, and to introduce the two incumbent Board members eligible for re-election who had not yet addressed the Committee as part of, the 2024 selection process (Ms. Caren Anders and Mr. Steve Corneli).

Ms. LaFleur, referencing materials circulated in advance of the meeting, reviewed the 2024 JNC process as well as the goals and factors that had been identified as central to a successful directorship. She emphasized the importance of a director being comfortable in a dynamic environment and possessing a wide range of critical skills and experience. Ms. LaFleur noted that each of the incumbents eligible for re-election possessed ~~the~~ skills and expertise that lined up with the JNC's critical skills matrix and the Participants Agreement requirements. She suggested that their capabilities would serve New England well as it faced major changes to its markets and transmission system, as well as other potential significant developments, in the coming years.

She pointed out that, both in 2024 and 2025, three incumbent directors would be eligible for re-election, with none hitting their term limit and no expected vacancies. She noted that, in benchmarking against Standard and Poor's (S&P) 500 companies, ISO Board members typically serve, on average, the same amount of time (nine years) as board members on S&P companies' boards. Ultimately, the ISO Board's Nominating and Governance Committee supported each of the three incumbents for re-election this year because of the critical skills and experience they bring to the ISO Board and a desire for continuity as the region faces complex challenges and undertakes major projects in the future.

Ms. LaFleur then turned to specific thoughts on each of the nominees who would be addressing the Committee at this meeting. Starting with Ms. Anders, she summarized Ms. Anders' work as the Chair of the ISO Board's System Planning and Reliability Committee (SPARC), and her membership in the Compensation and HR Committee and the Nominating and Governance Committee. Given ~~her~~ Ms. Anders' strong background in transmission planning and varied work experience, Ms. LaFleur noted that Ms. Anders has been a thoughtful, engaging director with good judgment and common sense. Ms. LaFleur also stated that Ms. Anders voluntarily pursued and obtained a certificate from the National Association of Corporate Directors.

Next, Ms. LaFleur turned to Mr. Corneli. She summarized his relevant experience and work on the Board's Audit and Finance, IT/Cyber Security, and Markets Committees. Ms. LaFleur noted Mr. Corneli's deep understanding of energy markets, in general, and the ISO-NE markets, in particular, as especially valuable to the ISO Board due to recent and potential upcoming changes to the region's wholesale markets. In light of the development and implementation of the Next Generation Markets (nGem) Real-Time Market Clearing Engine, Ms. LaFleur observed that Mr. Corneli's IT/Cyber Security Committee work paired well with his work on the Board's Markets Committee. Moreover, Ms. LaFleur commented that Mr. Corneli's previous experience and insight as a consumer advocate had been invaluable to the ISO Board. Concluding her introductory remarks, Ms. LaFleur reiterated the ISO Board's strong recommendation that all three nominees (Ms. Anders, Mr. Corneli and Mr. Mike Curran) be re-elected for an additional three-year term.

Ms. Anders then summarized her prior work experience, her service as the Chair of the Board's SPARC, and assignments to the Nominating and Governance Committee and Compensation and HR Committee. In response to a question from a member, Ms. Anders reviewed the process she employs as a director to review ISO-initiated ideas and offer feedback, as well as the level of interaction she has with the ISO's leadership team.

Mr. Corneli followed by summarizing his prior experiences as a consumer advocate, his involvement in federal energy policy development, and his work in the private sector. Mr. Corneli then identified the following critical challenges that he perceived as facing the ISO: (1) improving the tools that observe, monitor, and operate the power system, whose resource mix was changing; (2) identifying and improving reliability plans under a new resource mix; (3) adapting the wholesale markets to ensure that resources needed to meet the evolving reliability requirements are better identified and compensated; (4) providing greater transparency to Market Participants and to the States; (5) working closely with the States and stakeholders to understand jurisdictional issues; (6) anticipating and proactively addressing cyber security threats; and (7) attracting and retaining personnel to work on these challenges. He explained how his experience lends itself to helping the ISO Board confront those challenges. Mr. Corneli also summarized his Board Committee work.

Ms. Anders and Mr. Corneli then responded to members' questions. When asked how his service as an ISO Board member over the past three years may have changed or influenced his industry perspective, Mr. Corneli highlighted his surprise at just how much the stakeholder process had evolved since the early 2000s, noting in particular the increased collaboration and consensus building within the region, as well as the increased complexity required to address regional issues. Responding to a separate inquiry concerning how increased public focus and desire for information might be being addressed in Board discussions, Ms. Anders answered that the ISO Board reviews and offers guidance on the ISO's communication plans (including outreach and education) and strategy. She explained that the Board stays abreast of and listens to the issues raised that affect the region, stressing the importance of communicating on those issues that are within the ISO's purview and technical expertise. Mr. Corneli remarked that the ISO is working diligently to provide more information and analysis to regional stakeholders, including the general public, concerning issues related to the clean energy transition and added that the ISO Board supports and encourages ISO-NE management to think through the challenges and identify and make known feasible solution spaces.

APPROVAL OF FEBRUARY 1, 2024 MEETING MINUTES

The Chair referred the Committee to the preliminary minutes of the February 1, 2024 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated, with an abstention by Mr. Jon Lamson noted.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summary of ISO New England Board and Board Committee meetings that had occurred since the ~~December Annual M~~February 1 meeting, which had been circulated and posted in advance of this meeting. There were no questions or comments on the summaries.

In response to requests received prior to the meeting, Mr. van Welie provided some context for a paper, entitled "*Strategies for Enhanced Gas-Electric Coordination: A Blueprint for National Progress*" (Position Paper), that had been jointly published on February 20, 2024 by ISO-NE, MISO, PJM, and SPP (Multi-State RTOs). He explained that gas-electric coordination had become an issue of national concern. Prompted by NAESB's "*Gas Electric Harmonization Forum Report*", and focused attention by FERC Chairman Phillips and NERC CEO Jim Robb, the ISO/RTO Council (IRC), and ultimately the Multi-State RTOs, thought the time was ripe to identify issues and to suggest potential initiatives that state and federal regulators, working together with regional stakeholders, could pursue to achieve the goal of enhancing the coordination efforts among the gas and electric industries. Mr. van Welie explained that the initial target audience of the RTOs' Position Paper was the National Association of Regulatory Utility Commissioners (NARUC), and was released just a few days before NARUC's 2024 Winter Policy Summit. He further opined that action by Congress, and also by state regulatory commissions, would very likely be required to make significant progress in this area.

ISO COO REPORT

Operations Highlights

Dr. Chadalavada referred the Committee to his March operations report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through February 28, 2024, unless otherwise noted. He thanked with some wonder a member who had identified that the comparison of 2023 to 2024 Day-Ahead to Real-Time Location Marginal Prices (LMP) had initially included data for the extra day (February 29) in 2024, and had been revised to remove the inclusion of that day's data and the table subsequently re-circulated and re-posted. The March report highlighted: (i) that the Peak Hour for February, with~~or~~ 17,199 MW of Revenue Quality Metered Data (including settlement-only generation), occurred on February 14, 2024 during the hour ending at 7:00 pm; (ii) February averages for Day-Ahead Hub LMP ($36.91/MWh), Real-Time Hub LMP ($31.75/MWh), and natural gas prices ($3.52/MMBtu); (iii) Energy Market value was $364 million down from $750 million in February 2023; (iv) Ancillary Markets value ($6.1 million) was down from January 2023 ($6.8 million); (v) average Day-Ahead cleared physical energy during peak hours as a percentage of forecasted load was 98.9% during February (down from 101.7% reported for January, 2024); (vi) Daily Net Commitment Period Compensation (NCPC) payments for February totaled $1.4 million, and was comprised of $1.4 million in first contingency payments (down $1.9 million from January 2024) and included Dispatch Lost Opportunity Costs ($251,000), Rapid Response Pricing Opportunity Costs ($160,000), Day-Ahead External Transaction NCPC ($147,000) and distribution payments of $4,000. There were no second contingency or voltage NCPC payments in February; and (vii) Forward Capacity Market (FCM) value was $86.5 million. The FCM peak for 2024 remained to that point 17,993/MWh (having occurred on January 17 during the hour ending 6:00 p.m.).

Turning to slides addressing the projected April 8, 2024 solar eclipse, he provided additional detail to supplement information provided at the February meeting, including an expected reduction of 365 MW of commercial and 3,186 MW of behind-the-meter (BTM) solar generation during the eclipse maximum (roughly 3:30 p.m. Eastern Daylight Saving Time (EDT)), and an expected rebound of approximately 2,600 MW from both categories of solar generation in the hour following Totality End (roughly 4:40 p.m. EDT). For reference, Dr. Chadalavada said that, had the eclipse been expected to occur just a few weeks prior to April 8, over 5 GW of solar would have been impacted. He reported that peak BTM solar production for Winter 2023/24 was 5,027 MW (having occurred on February 22 during the hour ending 12:00 p.m.); the all-time BTM Solar peak was 5,200 MW, established in May 2023.

Dr. Chadalavada noted that the ISO would rely on the rest of the fleet during the eclipse to provide ramping capability to make up for the projected reductions in solar generation, and expected that need to be reflected and solved through Day-Ahead Energy Market activity. He again urged Participants to be prepared for the upcoming eclipse day.

Addressing upcoming planned transmission outages, Dr. Chadalavada noted two -- one in Quebec and one in New England. In Quebec, a transformer outage at Nicolet station would run from March 8 through April 1, 2024, and was expected for the duration of the outage to reduce transfer capability in both directions on the Phase II interface -- to 1,800 MW for imports and to 0 MW for exports. In New England, planned outages on Line 312 (Berkshire-Northfield) for March 27-28, all of April, and through the first 10 days in May, were expected to limit transfer capability from New York to New England to 1,100 MW during that outage period (transfer capability from New England to New York would not be impacted).

Winter 2023/24 Review

Dr. Chadalavada then turned to and summarized the Winter 2023/24 Review presentation circulated and posted with the meeting materials. He noted that Winter 2023/24 was mild, and that the System operated reliably. Temperatures, consistent with predictions by the National Oceanic and Atmospheric Administration (NOAA), were 5°F above normal (with 'normal' for NOAA reporting purposes reflecting a 30-year average and 'normal' for ISO purposes reflecting experience over the last five to seven years). Just one week, January 15-22, 2024, had been notably (5°F) below normal, with January 20, at 11°F below normal, the coldest day of the season. January 20 was also the only Inventoried Energy Program (IEP) Day. New England experienced above normal precipitation (5.7" overall), with Hartford setting a new winter precipitation record (7.8"). In contrast, ~~S~~snowfall amounts were below normal, with Boston and Hartford 28.4" and 15.1" below normal, respectively.

Dr. Chadalavada~~He~~ reported that the region experienced a fairly large decline in total winter energy demand (approximately 29.7 terrawatt hours (TWh), and 1.8 TWh below average winter energy demand since 2010), attributable to the mild weather and contributions of BTM solar generation. Fuel oil inventories were adequate and ended slightly higher than starting inventories. Liquefied Natural Gas (LNG) sendout to the pipelines, largely from St. John, was approximately 11.1 billion cubic feet (Bcf) (up approximately 4.2 Bcf from the Winter 2022/23), but was still the second lowest sendout since Winter 2008/09. There had been no reductions in any fuel source. Both December and February experienced the lowest loads for their respective months since Standard Market Design (SMD) was implemented in 2023.

Looking ahead, Dr. Chadalavada reported that the ISO planned to assess the region's winter energy shortfall risk in advance of Winter 2024/2025 using the Probabilistic Energy Adequacy Tool (PEAT). The Regional Energy Shortfall Threshold (REST) remained under development and was not expected to be finalized prior to the start of Winter 2024/25. He highlighted that winter weather forecasts continued to be a critical factor for the operational outlook and would be closely monitored. The ISO planned to continue communications similar to previous winters with the states, utilities, resource owners, and the general public.

In response to questions, Dr. Chadalavada confirmed that there would be input changes to PEAT, both on the supply and demand side. In addition, the ISO planned to seek in the May/June timeframe stakeholder input on the frequency of, and period to which, REST would apply. He confirmed that, with only one IEP Day triggered during the Winter 2023-24 period, it would be difficult to evaluate the benefits of that program and said that the ISO would wait to conduct a further evaluation of IEP until after Winter 2024/25. In response to members' opinions on the factors upon which to base such an evaluation, Dr. Chadalavada highlighted the multiple parameters -- reliability (REST metric), cost, environmental concerns, and performance/ efficiency of the markets -- to be balanced as part of that evaluation.

FERC ORDER 2023 REVISIONS

Ms. Emily Laine, Transmission Committee (TC) Chair, referred the Committee to the materials circulated in advance of the meeting regarding proposed revisions to the Tariff in response to the requirements of FERC Order 2023 (Order 2023 Revisions). She explained that the Order 2023 Revisions included significant reforms to the Tariff's generator interconnection procedures, shifting from a serial, first-come, first-served study process to a first-ready, first-served cluster study process, along with reforms to increase the speed of interconnection queue processing and to incorporate technological advancements into the interconnection process. She stated that the Order 2023 Revisions were considered within the NEPOOL process in two parts – one part, the majority of the Revisions subject to the purview of and voted by the TC (the OATT Revisions) and the other part, Revisions subject to the purview of and voted by the Markets Committee (MC) (the Market Rule Revisions).

Ms. Laine reviewed the history of the TC's and MC's review of the Revisions, including the six amendments (of over 26 Participant-proposed amendments/modifications introduced and discussed during the process) to the OATT Revisions that had been voted at the TC ~~ransmission Committee~~ (the Participant Amendments), none of which had garnered sufficient support to be recommended for Participants Committee support, and the Market Rule Revisions that had been recommended for Participants Committee support by the MC. She reported that, since the Technical Committees' votes on the Order 2023 Revisions, the ISO had engaged in further discussion on and consideration of the Participant Amendments, and had incorporated incremental changes to the package of Order 2023 Revisions proposed for Participants Committee action at this meeting. Ms. Laine explained that the incremental changes could be incorporated without adding to the overall timeframes or decreasing the efficiency of the new process. She identified the changes that had been incorporated, as described in the ISO's memo, and highlighted in the package of Tariff revisions, included with the meeting materials.

In response to clarifying questions, Ms. Laine confirmed that a Participant proposal to establish an interconnection reforms working group was not reflected in, and would not be offered as an amendment to, the Order 2023 Revisions being presented. However, the ISO had worked further with the Participant proponent after the last TC meeting and had committed to further stakeholder engagement on the issues and to reflect that commitment in the Order 2023 Revisions filing letter to be submitted ~~with~~ to the FERC.

Following an explanation by Mr. Lombardi of the forms of resolution provided with the meeting materials and the voting thresholds required to approve those resolutions, including a process recommendation given the developments following the Technical Committees' actions, the following motions were, without objection, together duly made and seconded for action by a single vote:

> RESOLVED, that the Participants Committee supports the Order 2023 OATT Revisions, as proposed by the ISO, and as reflected in the materials distributed to the Participants Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Transmission Committee.

> RESOLVED, that the Participants Committee supports the Order 2023 Market Rule Revisions, as recommended by the Markets Committee, and as reflected in the materials distributed to the Participants 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.

In comments, Participant and State representatives alike widely recognized with much appreciation and compliment the ISO's engagement, collaboration and compromise throughout the process, particularly the efforts and changes made following the votes at the TC. Participants specifically thanked the ISO's transmission, Participant Support and legal teams, not only for their responsiveness to Participant feedback and willingness to consider changes beyond those directly responsive to Order 2023, but also for their work synthesizing and proposing the required Tariff changes, as well as for facilitating streamlined consideration of the Order 2023 Revisions, particularly at this meeting. Overall, many opined that the collaborative process had culminated in a much improved compliance package.

Many of those who did not vote to recommend Participants Committee support at the TC explained the reasons why they now planned to support the package of Order 2023 Revisions. Proponents of some of the TC amendments explained that their support reflected the ISO's willingness to adopt/incorporate all or elements of the Participant proposals and its commitment to engage with stakeholders on future reforms to interconnection processes. Some were of the view that, while the Order 2023 Revisions reflect important changes to the status quo, more work remained. Those members encouraged the ISO, as well as Participants and the States, to be on the lookout for additional potential improvements and said~~expressed~~ that they looked forward to continued engagement on these issues.

Transmission Owner representatives, who similarly expressed their support for the Revisions, particularly those amendments that the ISO had agreed to after the TC meeting, noted for the record that their support was subject to the outcome of their pending requests for rehearing of Order 2023 and appeals to the District Court of Appeals for the D.C. Circuit related to the elimination of the "reasonable efforts" standard, which if reinstated, would presumably be addressed in subsequent Tariff changes.

On behalf of the ISO, Mr. Al McBride, Executive Director, Transmission Services & Resource Qualification, thanked Participants for their hard work and collaboration on the Order 2023 Revisions, and looked forward both to implementation and to ongoing partnership and cooperation on interconnection issues.

Without further discussion, the motions were unanimously approved, with abstentions by Harvard, Tenaska and Mr. Lamson~~'s representative~~ recorded.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the March 6, 2024 Litigation Report that had been circulated and posted before the meeting. He noted the link to the Multiple RTOs' Position Paper, discussed during the CEO Report, available in Section X of Litigation Report's Executive Summary. He highlighted that comments on the ISO's FCA18 Results Filing were due on or before April 8, 2024. Finally, he identified the three persons that the White House had recently announced as its nominees for FERC Commissioner (Judy Chang, David Rosner and Lindsay See), and committed to keep the Committee apprised of the progress on those nominations. He urged members to reach out to NEPOOL Counsel with any questions.

COMMITTEE REPORTS

Markets Committee. Ms. Mariah Winkler, the MC Chair, reported that the next MC meeting was scheduled for March 12-13 at the DoubleTree Hotel in Milford, MA. She reported that the MC was scheduled to act on Market Rule 1 revisions to further delay FCA19 by an additional two years, to consider further the Resource Capacity Accreditation (RCA) project and to discuss conforming Market Rule 1 changes associated with the Day-Ahead Ancillary Services Initiative (DASI). On behalf of the Participants, Ms. Bresolin thanked Ms. Winkler for her more than four years' service as MC Chair and looked forward to working Ms. Winkler as she moved into her role as Director of NEPOOL Relations.

Reliability Committee. Mr. Robert Stein, the RC Vice-Chair, reported that the next RC meeting was scheduled for March 19 at the Doubletree in Milford, MA, and would include a vote on conforming changes to the Tariff associated with Phase 2 of the extended-term/longer-term transmission planning project, a report on the results of FCA18, a discussion on Order 2023-related conforming changes to Planning Procedures (PP) 5-6 and PP-10, and continued consideration of the RCA project, with a focus on its impact on the Resource Adequacy Assessment (RAA) process. Mr. Stein thanked Ms. Emily Laine, RC Chair, for her efficiency and support as RC Chair, and wished her well as she moves over to become the MC Chair.

Transmission Committee. Mr. Dave Burnham, the TC Vice-Chair, reported that the next TC meeting was scheduled for March 27 at the Courtyard Hotel in Marlborough, MA. Key items would include voting on a set of Tariff changes to implement the Phase 2 extended-term/longer-term transmission planning project. He highlighted a planned March 26 webinar being provided by the ISO to inform stakeholders on the impact of the Order 2023 Revisions on Affected System Operator (ASO) Studies. Last, Mr. Burnham echoed the sentiments of Mr. Stein, and wished Ms. Laine well as she moves over to chair the MC.

Budget & Finance Subcommittee (B&F). Mr. Thomas Kaslow, B&F Chair, reported that the next B&F meeting was scheduled to meet by teleconference on March 26, 2024. Key discussion items would include three Financial Assurance (FA) Policy-related topics – Pay-for-Performance (PFP) delivery FA, DASI market impacts on FA, and FCA19 delay impacts on FA.

Membership Subcommittee. Mr. Bradley Swalwell, Subcommittee Chair, reported that the next Membership Subcommittee meeting was scheduled to be held the following Monday, March 11, by Zoom.

NPCC NORTHEASTERN REGIONAL GAS INFRASTRUCTURE STUDY UPDATE

Mr. Phil Fedora, NPCC Vice President, Reliability Services and Chief Engineer, provided an update on the northeastern regional gas infrastructure study launched by NPCC to evaluate fuel supply to the NPCC region's electric generation (Gas Study). For background, he explained that the Gas Study would consider the gas supply and pipeline constraints that may occur during extreme and protracted winter weather events during the winter peak heating season. A Steering Committee, comprised initially of representatives of NERC, the Northeast Gas Association, New York ISO, and ISO New England, would support evaluation of the modeling and simulations to be run, as well as the identification of risks associated with the ability of the natural gas system to serve gas-fired generation for the winter peak heating season, and ways to mitigate those risks going forward.

Mr. Fedora further reported that NPCC had licensed Gregg Engineering's Pipeline Hydraulic Simulation software, including Gregg's WinFlow model (a steady state daily simulation tool) and WinTran model (an hourly, transient simulation tool), which he compared to electric system load flow trends and stabilities software, to help build the integrated gas-electric infrastructure model. Non-disclosure agreements (NDAs) with pipelines and local distribution companies had just been finalized and efforts were underway to build, initialize and run the simulations. With contingencies and sensitivities developed with the help of the Steering Committee, results would be reviewed and finalized for near term (2024-2025), mid-term (2027-2028), and long term (2032-33) winter peak (December through February) heating seasons.

Mr. Fedora stated that NPCC had selected Levitan & Associates, Inc. to conduct the analysis. Plans called for the Gas Study to be completed by the end December, 2024. He committed to provide periodic reports to NEPOOL when and as requested. He emphasized that the bonus value of the Gas Study would be the development of the integrated gas-electric infrastructure model, which would be useful in providing simulations moving forward.

ADMINISTRATIVE MATTERS

Mr. George Twigg, NECPUC Executive Director, announced that registration for NECPUC's 2024 Annual Symposium, to be held May 19-21 at the Omni Mount Washington in Bretton Woods, NH, would open soon. He encouraged all those interested to register early. He also reported that the NECPUC working group focusing on retail demand response and load flexibility, which he had described at the February meeting, held its first meeting a few weeks earlier and would be meeting over the course of the next year to help explore what further potential might be extracted from demand-side resources to help address winter resource adequacy and peak demand growth. He thanked the ISO for its support and encouraged all those interested in the working group efforts to reach out to him directly to receive alerts on further working group meetings and efforts.

Looking ahead, Mr. Lombardi informed the Committee that the Participants Committee's next regularly-scheduled meeting would be held April 4 in person at the Renaissance Providence Downtown Hotel. Looking further ahead, he advised members that information about the 2024 Summer Meeting, which was scheduled for June 25-27 at the Omni Mount Washington Hotel in Bretton Woods, New Hampshire, would be provided soon. He encouraged members to register and make arrangements early, and strongly encouraged members to bring their families and significant others, whose presence enhanced the value and significance of the annual summer meeting.

FEEDBACK ON ISO BOARD MEMBER CANDIDATES (EXECUTIVE SESSION)

There being no other general business, after non-Participant representatives left the room and WebEx, the Committee went into executive session to afford Participants an opportunity to provide feedback confidentially on the three incumbent ISO Board Directors whose terms were scheduled to expire later this year, and had each been recommended by the ISO for an additional three-year term. Committee members provided that confidential feedback, and were encouraged to reach out to their Sector JNC representative with any remaining feedback. Committee members also provided feedback on the Board member selection process more generally, including expressions of a long-standing preference by some to move to individual votes on candidates, rather than voting by slate. Prior to concluding the executive session, Ms. Bresolin noted the proposed schedule for consideration and action on the recommended slate of candidates.

There being no further business, the meeting was then adjourned at 12:27 p.m.

Respectfully submitted,

____

Sebastian Lombardi, Secretary

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN MARCH 7, 2024 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User			Abby Krich (tel)
Advanced Energy United	Associate Non-Voting		Alex Lawton	
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
AVANGRID: CMP/UI	Transmission	Alan Trotta	Jason Rauch	Zach Teti (tel)
Avangrid Renewables	Transmission	Kevin Kilgallen (tel)		
Bath Iron Works Corporation	End User			Bill Short (tel)
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
BlueWave Public Benefit Corp.	AR-DG	Mike Berlinski (tel)		
Boylston Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
BP Energy Company (BP)	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield (tel)		
Clearway Power Marketing LLC	Supplier			Pete Fuller
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop. (CMEEC)	Publicly Owned Entity	Brian Forshaw (tel)		
Connecticut Office of Consumer Counsel (CT OCC)	End User		Jamie Talbert-Slagle	Jackie Litynski
Conservation Law Foundation (CLF)	End User	Phelps Turner (tel)		
Constellation Energy Generation	Supplier	Gretchen Fuhr (tel)		
Covanta Energy Marketing NA, Inc.	AR-RG			Josh Ghosh (tel)
CPV Towantic, LLC (CPV)	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
DTE Energy Trading, Inc. (DTE)	Supplier			José Rotger
Durgin and Crowell Lumber Co., Inc.	End User			Bill Short (tel)
Dynegy Marketing and Trade, LLC	Supplier	Ryan McCarthy		
ECP Companies Calpine Energy Services, LP (Calpine) New Leaf Energy	Generation	Andy Gillespie Liz Delaney	Brett Kruse (tel)	Alex Chaplin
Elektrisola, Inc.	End User			Bill Short (tel)
Enel X North America Inc.	AR-LR			Alex Chaplin
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission	James Daly	Dave Burnham	Vandan Divatia
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc. (Galt)	Supplier	José Rotger		
Garland Manufacturing Company	End User			Bill Short (tel)
Generation Bridge Companies	Generation			Dan Allegretti
Generation Group Member	Generation	Dennis Duffy (tel)	Abby Krich (tel)	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Companies	Generation			Bob Stein
Groton Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN FEBRUARY 1, 2024 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQ US)	AR-RG	Louis Guibault (tel)	Bob Stein	
Hammond Lumber Company	End User			Bill Short (tel)
Hanover, NH	End User			Bill Short (tel)
Harvard Dedicated Energy Limited (Harvard)	End User			Jackie Litynski
High Liner Foods (USA) Incorporated	End User		William P. Short III (tel)	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Icetec Energy Services, Inc. (Icetec)	AR-LR	Doug Hurley		
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths		
Jupiter Power	AR-RG		Ron Carrier (tel)	Jenny Liu
KCE Companies	AR-DG			Pete Fuller
Lamson, Jon	End User			John Cropley (tel)
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned Entity		Craig Kieney (tel)	
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar		
Maine Power LLC	Supplier	Jeff Jones (tel)		
Maine Public Advocate's Office (Maine OPA)	End User			Jackie Litynski; Chelsea Mattioda
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Marble River, LLC	Supplier		John Brodbeck (tel)	Abby Krich (tel)
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Mass. Attorney General's Office (MA AG)	End User	Jacquelyn Bihrle		Jamie Donovan
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Climate Action Network	End User			Abby Krich (tel)
Mass. Department of Capital Asset Management	End User		Paul Lopes (tel)	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide	Dan Murphy	
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Moore Company	End User			Bill Short (tel)
Narragansett Electric Co. (d/b/a RI Energy)	Transmission	Brian Thomson	Lindsay Orphanides (tel)	
Natural Resources Defense Council (NRDC)	End User	Claire Lang-Ree (tel)		
Nautilus Power, LLC	Generation			Dan Allegretti
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw (tel)
New Hampshire Office of Consumer Advocate (NHOCA)	End User	Matthew Fossum		
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson	Dan Dolan	Molly Connors (tel)
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Business Marketing, LLC	Supplier		Pete Fuller	
Nylon Corporation of America	End User			Bill Short (tel)

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN FEBRUARY 1, 2024 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Oxford Energy Center	Provisional Member	Compton Donoghue (tel)		
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Pawtucket Power Holding Company LLC	Generation	Dan Allegretti		
Paxton Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Peabody Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
PowerOptions, Inc.	End User			Jackie Litynski
Princeton Municipal Light Department	Publicly Owned Entity	Matt Ide		
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RI Division (DPUC)	End User	Paul Roberti		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity	Matt Ide		
Saint Anselm	End User			Bill Short (tel)
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User			Bill Short (tel)
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide	Dan Murphy
Sierra Club	End User	Casey Roberts (tel)		
South Hadley Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Pete Fuller
SYSO Inc.	AR-DG			Alex Chaplin
Tangent Energy Inc.	AR-LR	Brad Swalwell		
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity	Matt Ide		Dan Murphy
Tenaska Power Services Co. (Tenaska)	Supplier		Eric Stallings (tel)	
The Energy Consortium	End User		Mary Smith (tel)	Alex Chaplin
Union of Concerned Scientists	End User		Francis Pullaro (tel)	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieney (tel)		
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corporation	AR-LR		Jackie Litynski	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw (tel)
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Walden Renewables Development LLC	Generation			Abby Krich (tel)
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG			Dan Allegretti
ZTECH, LLC	End User			Bill Short (tel)

Summary of ISO New England Board and Committee Meetings
April 4, 2024 Participants Committee Meeting

Since the last update, the Board of Directors met on March 20 and 21. The Audit and Finance Committee, the Information Technology and Cyber Security Committee, the Markets Committee, the Nominating and Governance Committee, and the System Planning and Reliability Committee each met on March 20. All of the meetings were held in Holyoke.

The Audit and Finance Committee met with the Company's external auditors, KPMG, along with management, and reviewed the 2023 audited financial statements and discussed disclosure controls. The Committee voted to recommend the adoption of the audited financial statements by the Board of Directors. The Committee met further with KPMG to review the work plan for the 2024 System and Organization Controls Report. The Committee discussed the scope of the work, including objectives, audit team and methodology, and then held an executive session with KPMG. Next, the Committee received an update on current Internal Audit Department activities, together with a review of the risk assessment process and audit planning cycle. The Committee approved the Internal Audit Department's audit plan for 2024. Finally, the Committee received a report on the Company's financial performance against the 2024 budget, and approved management's proposal to engage KPMG as the paid preparer and reviewer of the Company's tax return to be filed with the Internal Revenue Service.

The Information Technology and Cyber Security Committee received an update on the Company's cyber security plan, along with a summary of the three-year work plan for cyber security projects that are currently underway. The Committee discussed the rolling three-year infrastructure plan, which is part of the Company's overall information technology strategic plan. The Committee was also provided with a summary of major information technology projects. Last, the Committee received a report on the Securities and Exchange Commission's final rule regarding cyber security risk management, strategy, governance, and incident disclosure. The Committee reviewed the rule and disclosures made pursuant to it and compared them to the Company's practices.

The Markets Committee received a description of market development activities, including ongoing work on capacity market reforms, and energy and ancillary services market projects. The Committee discussed the monitoring and reporting of financial transmission rights. The Committee then met with the System Planning and Reliability Committee to receive a report on the outcome of the 18th Forward Capacity Auction.

The Nominating and Governance Committee received an update on Joint Nominating Committee activities and the nomination process for 2024. The Committee then received a report from Russell Reynolds Associates regarding the Board search conducted in 2023, and best practices related to Board searches and diversity. The Committee also reviewed potential topics for discussion with FERC commissioners at the upcoming ISO/RTO Council (IRC) board conference in May, and considered plans for a markets-focused open Board meeting in November.

The System Planning and Reliability Committee was provided with a report on Regional System Plan projects. The Committee also received a summary of winter operations for the 2023/2024 season, and an update on economic study activities, which are progressing as planned. The Committee then met with the Markets Committee to discuss results of the 18th Forward Capacity Auction.

The Board of Directors prepared for its meeting with state regulators, and was provided with an update on the Resource Capacity Accreditation project. The Board received a report from the CEO, and discussed the President's nominations to the Federal Energy Regulatory Commission. The Board then reviewed the Company's annual communications plan for 2024, and received reports from the standing committees. During the Audit and Finance Committee report, the Board approved the audited financial statements for 2023. During the Compensation and Human Resources Committee report, the Board approved changing the Board director compensation structure from a meeting fee structure to a retainer-only structure. The change comports with current best practices and reduces administrative burdens. Following its meeting with state regulators, the Board was provided with an overview of the strategic planning process and timeline for 2024, and then discussed the Company's primary risks, as identified by management and the committees of the Board. The Board also reviewed mitigation strategies for those risks and their relation to strategic objectives and future initiatives.

NEPOOL Participants Committee Report

April 2024

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

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Regular Operations Report - Highlights

Highlights: March 2024

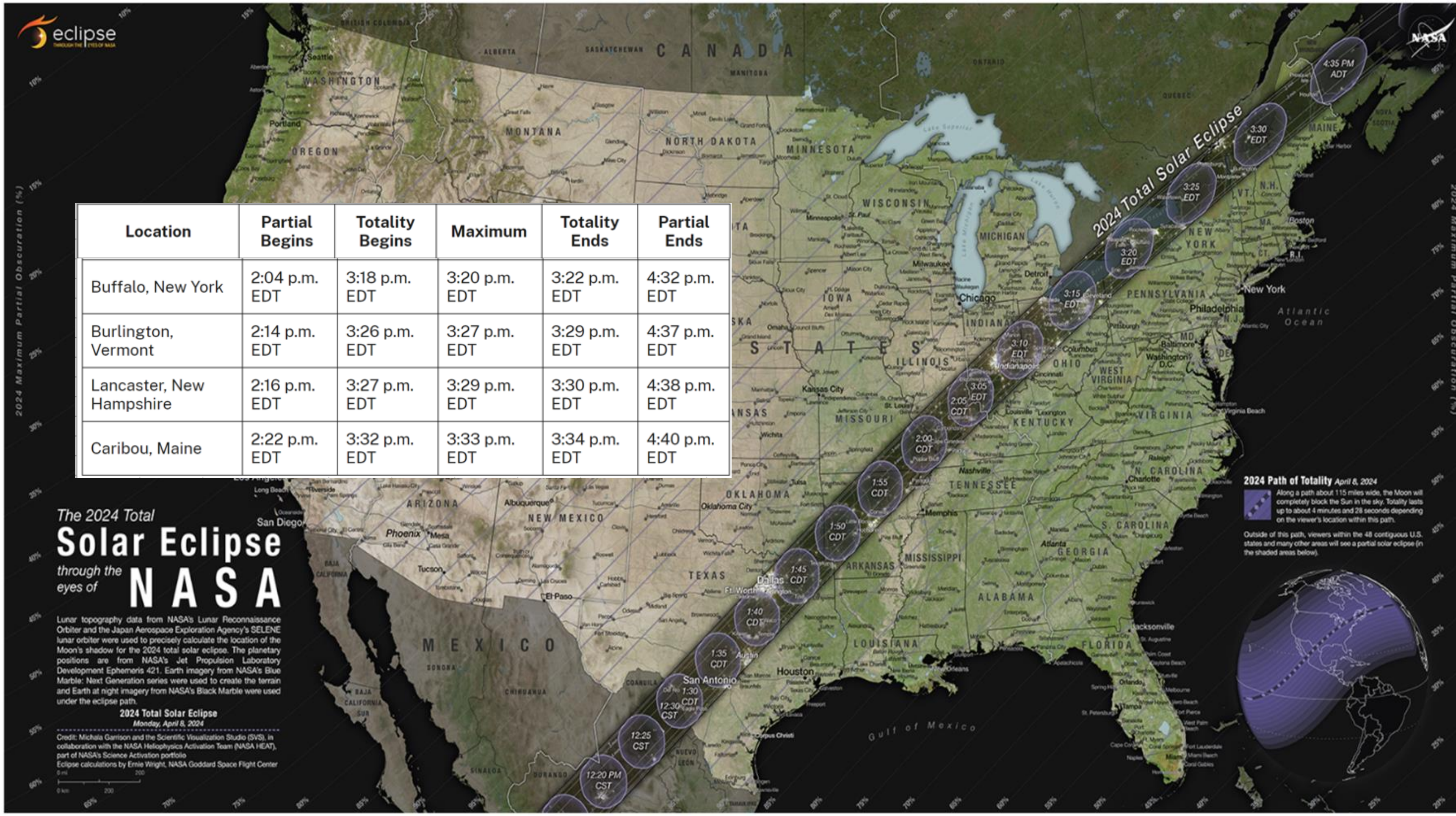
Data is through March 26th unless otherwise noted

- **Peak Hour** on March 21
  - 15,692 MW system peak (Revenue Quality Metered/RQM); hour ending 8:00 pm
- **Average Pricing**
  - Day Ahead (DA) Hub Locational Marginal Price (LMP): $24.31/MWh
  - Real Time (RT) Hub LMP: $23.33/MWh
  - Natural Gas: $1.64/Mmbtu (MA Natural Gas Average)
- **Energy Market** value $217.9M down from $389.0M in March 2023
  - Ancillary Markets* value $6.2M down from $6.3M in March 2023
  - Average DA cleared physical energy** during the peak hours as percent of forecasted load was 97.3% during March, down from 99.0% during February
  - Updated February Energy Market value: $374.7M
- **Net Commitment Period Compensation (NCPC)** total $1.1M
  - First Contingency $1.1M
    - Dispatch Lost Opportunity Cost (DLOC) - $207K; Rapid Response Pricing (RRP) Opportunity Cost - $140K; Posturing - $0K; Generator Performance Auditing (GPA) - $0K
    - $18K paid to resources at external locations, down $128K from February
      - $4K charged to DALO at external locations, $15K to RT Deviations
  - 2nd Contingency, Distribution and Voltage were zero.
- **Forward Capacity Market (FCM)** market value $86.5M

*Ancillaries = Reserves, Regulation, NCPC, less Marginal Loss Revenue Fund
**DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

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

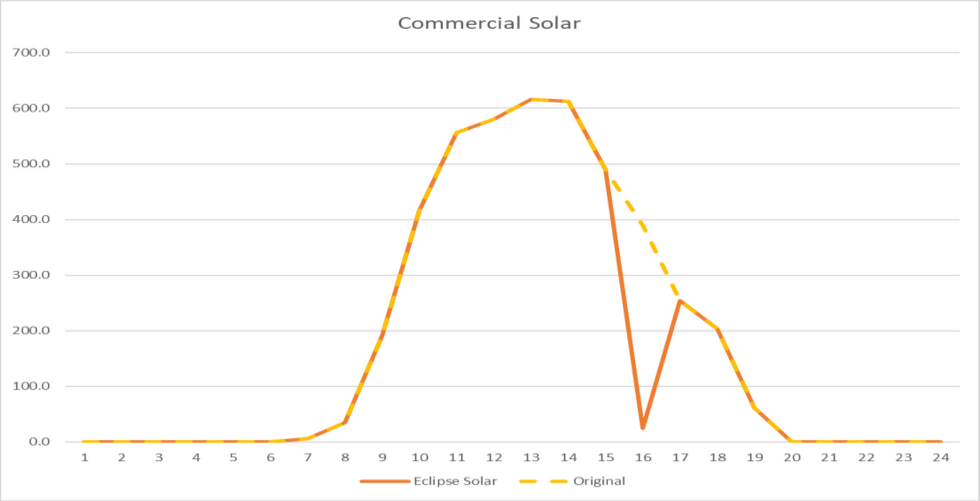
Highlights – Eclipse Timing



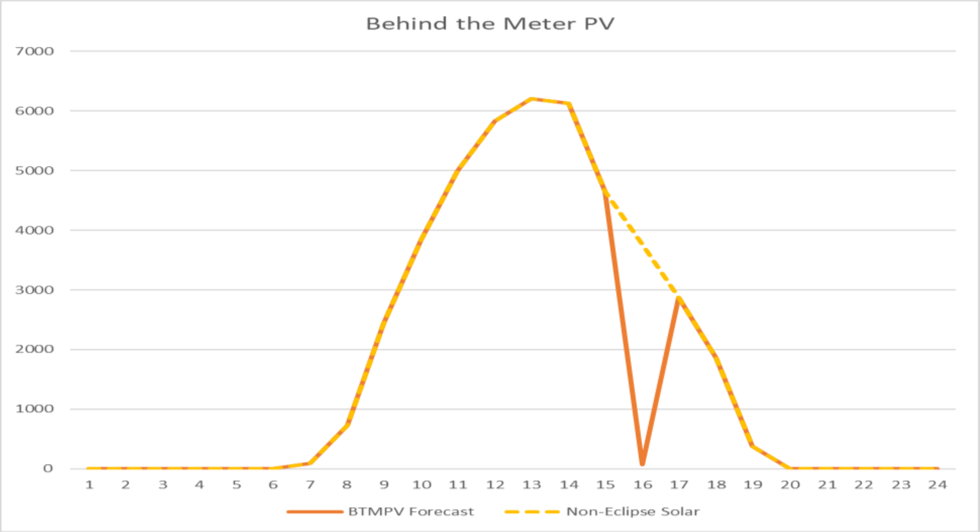
Location	Partial Begins	Totality Begins	Maximum	Totality Ends	Partial Ends
Buffalo, New York	2:04 p.m. EDT	3:18 p.m. EDT	3:20 p.m. EDT	3:22 p.m. EDT	4:32 p.m. EDT
Burlington, Vermont	2:14 p.m. EDT	3:26 p.m. EDT	3:27 p.m. EDT	3:29 p.m. EDT	4:37 p.m. EDT
Lancaster, New Hampshire	2:16 p.m. EDT	3:27 p.m. EDT	3:29 p.m. EDT	3:30 p.m. EDT	4:38 p.m. EDT
Caribou, Maine	2:22 p.m. EDT	3:32 p.m. EDT	3:33 p.m. EDT	3:34 p.m. EDT	4:40 p.m. EDT

At this time, the weather forecast for 4/8 is clear sunshine, which is estimated to reduce total PV output by ~3,600 MW, and as the eclipse passes, PV generation output is expected to reach ~2,500 MW

Highlights – Forecasted Solar Output during Eclipse



- ~365 MW loss of Commercial Solar during Eclipse Maximum
- 230 MW gain in Commercial Solar in hour following Totality End



- ~3200 MW loss of BTMPV during Eclipse Maximum
- 2260 MW gain in BTMPV in hour following Totality End

Highlights – Eclipse Preparations

- The ISO has simulated this event and our operators are ready
- NYISO will implement hourly scheduling on the CTS interface, starting one hour prior to the impact of the eclipse, to one hour after the impact
- The ISO regulation requirements for H/E 15 through H/E 17 will be raised up to 400 MW; NYISO and IESO are also raising their regulation requirements during the eclipse impact period
- The 312 line (Berkshire to Northfield) will be restored to service on 4/8 for the eclipse event, then will be removed from service on 4/9 to continue the planned work

Forward Capacity Market (FCM) Highlights

- CCP 15 (2024-2025)
  - The ISO held the third annual reconfiguration auction (ARA3) over March 1-5, 2024, and will post the results no later than April 3, 2024
- CCP 16 (2025-2026)
  - The ISO will hold the second annual reconfiguration auction (ARA2) over August 1-5, 2024, and will post the results no later than September 3, 2024
- CCP 17 (2026-2027)
  - The ISO will hold the first annual reconfiguration auction (ARA1) over June 3-5, 2024, and will post the results no later than July 5, 2024
  - ICR and related values for the ARAs to be conducted in 2024 were filed with FERC on November 30, 2023, and FERC issued an order accepting the results effective January 29, 2024

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 18 (2027-2028)
  - The ISO filed the auction results with FERC on February 21, 2024, and the filing is pending
    - Comments are due April 8, 2024, and ISO requested an effective date of June 20, 2024
- CCP 19 (2028-2029)
  - The ISO filed market rule changes to delay FCA 19 for one year with FERC on November 3, 2023; FERC issued an order accepting the delay to FCA 19 on January 2, 2024
  - The ISO will commence the interim reconfiguration auction qualification process resulting from the FCA 19 delay in April 2024

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (3.7°F) Max: 60°F, Min: 23°F Precipitation: 8.94” – Above Normal Normal: 4.17” Snow: 0.00”	Hartford	Temperature: Above Normal (6.7°F) Max: 72°F, Min: 22°F Precipitation: 7.99” - Above Normal Normal: 3.81” Snow: 0.00”

Peak Load:	15,503 MW	March 21, 2024	20:00 (ending)

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

Procedure	Declared	Cancelled	Note
None			

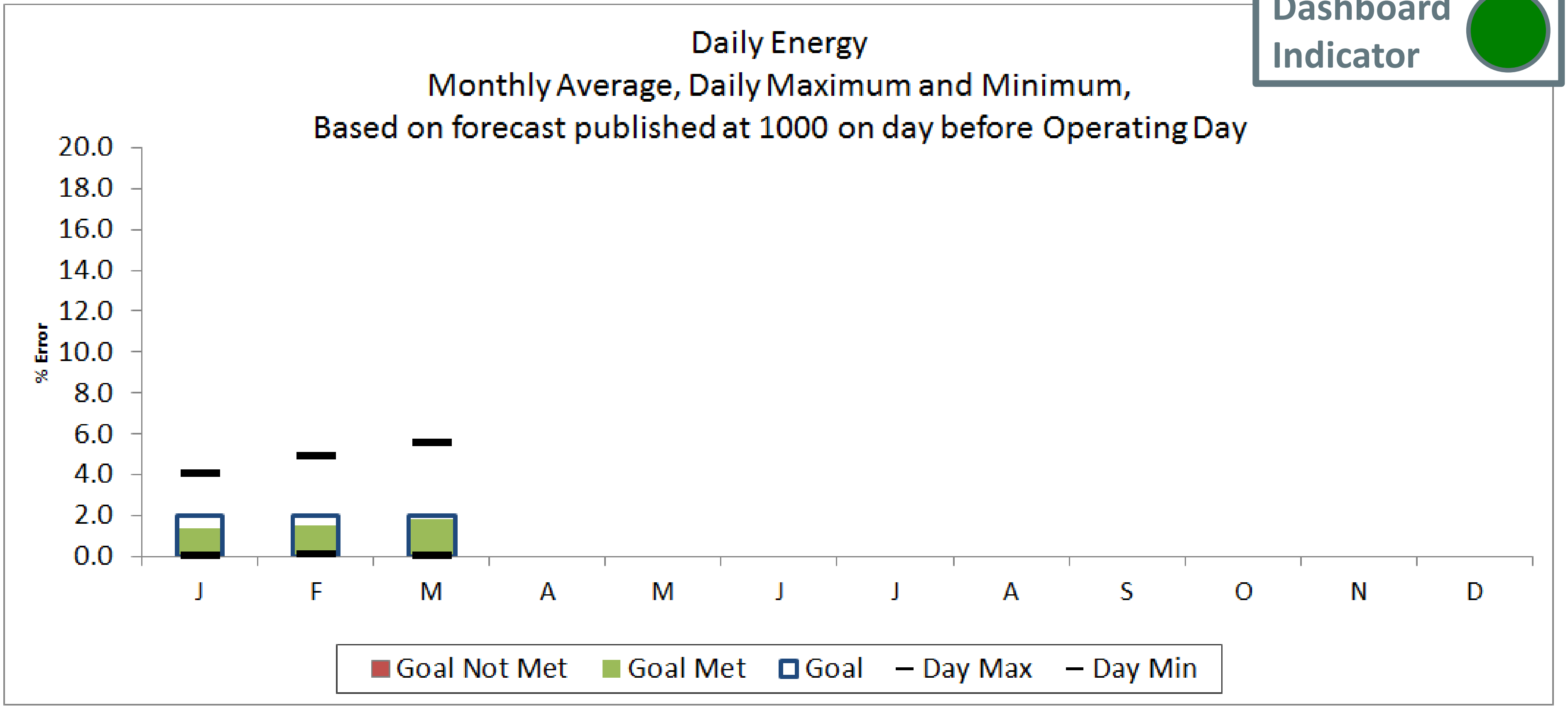
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
03/03/2024	NYISO	540
03/26/2024	IESO	860

2024 System Operations - Load Forecast Accuracy cont.

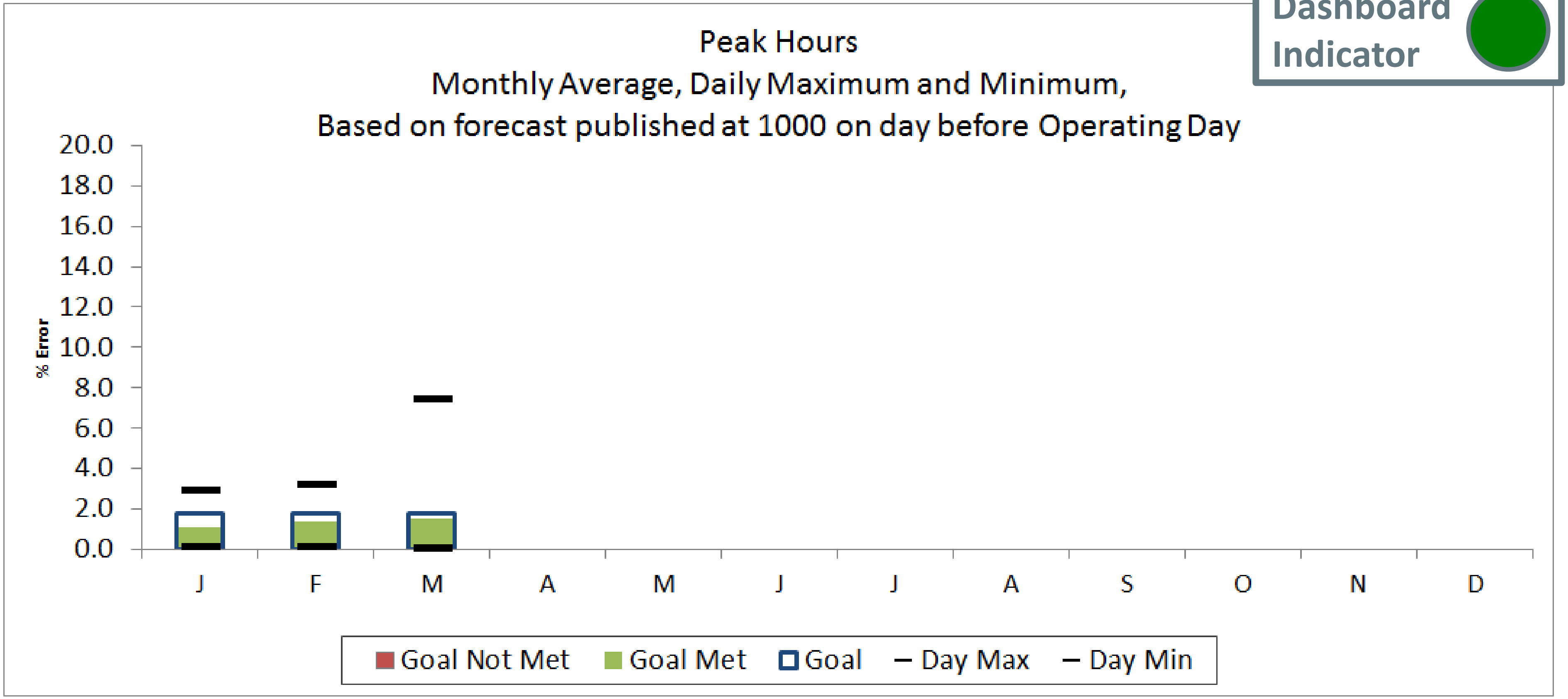
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.02	4.89	5.56										5.56
Day Min	0.00	0.12	0.02										0.00
MAPE	1.38	1.54	1.82										1.58
Goal	2.00	2.00	2.00										

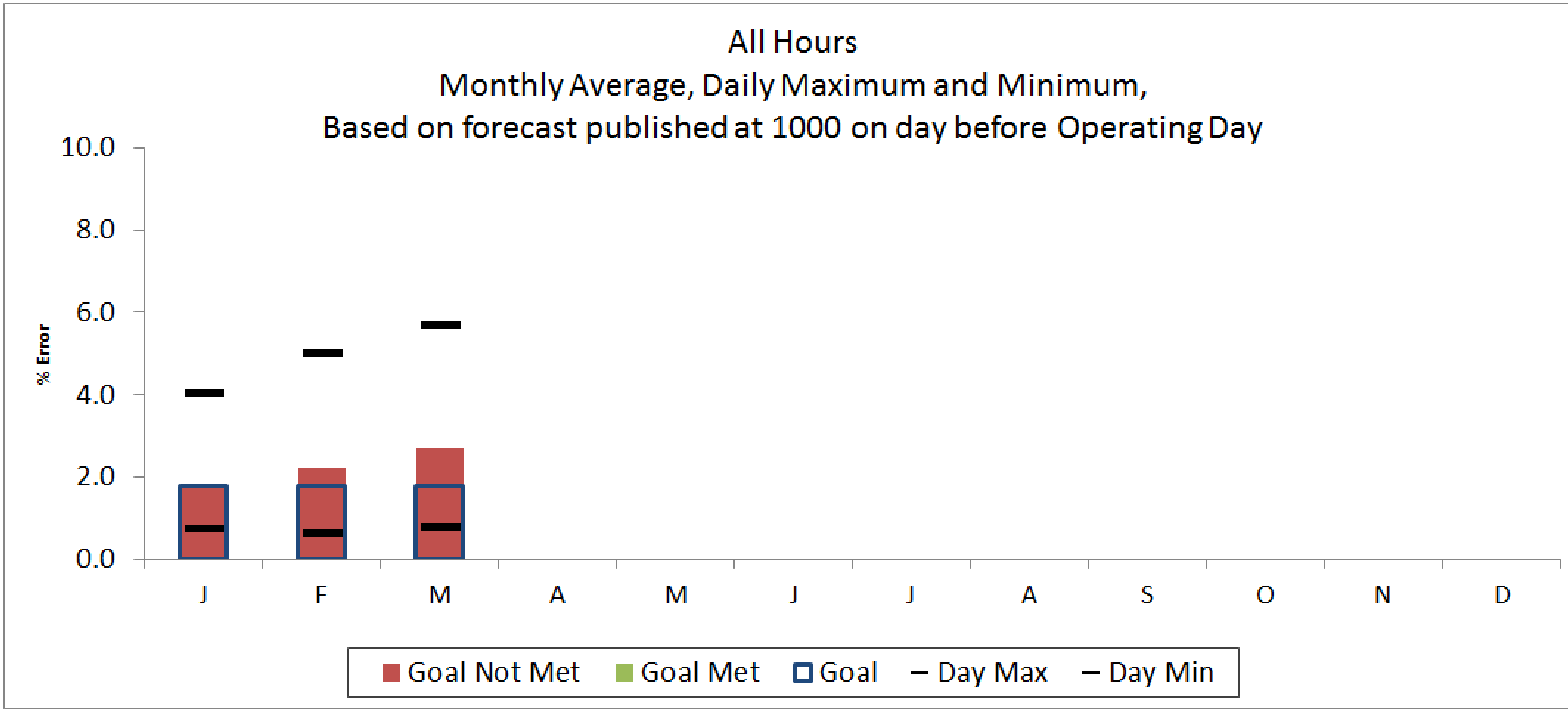
2024 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



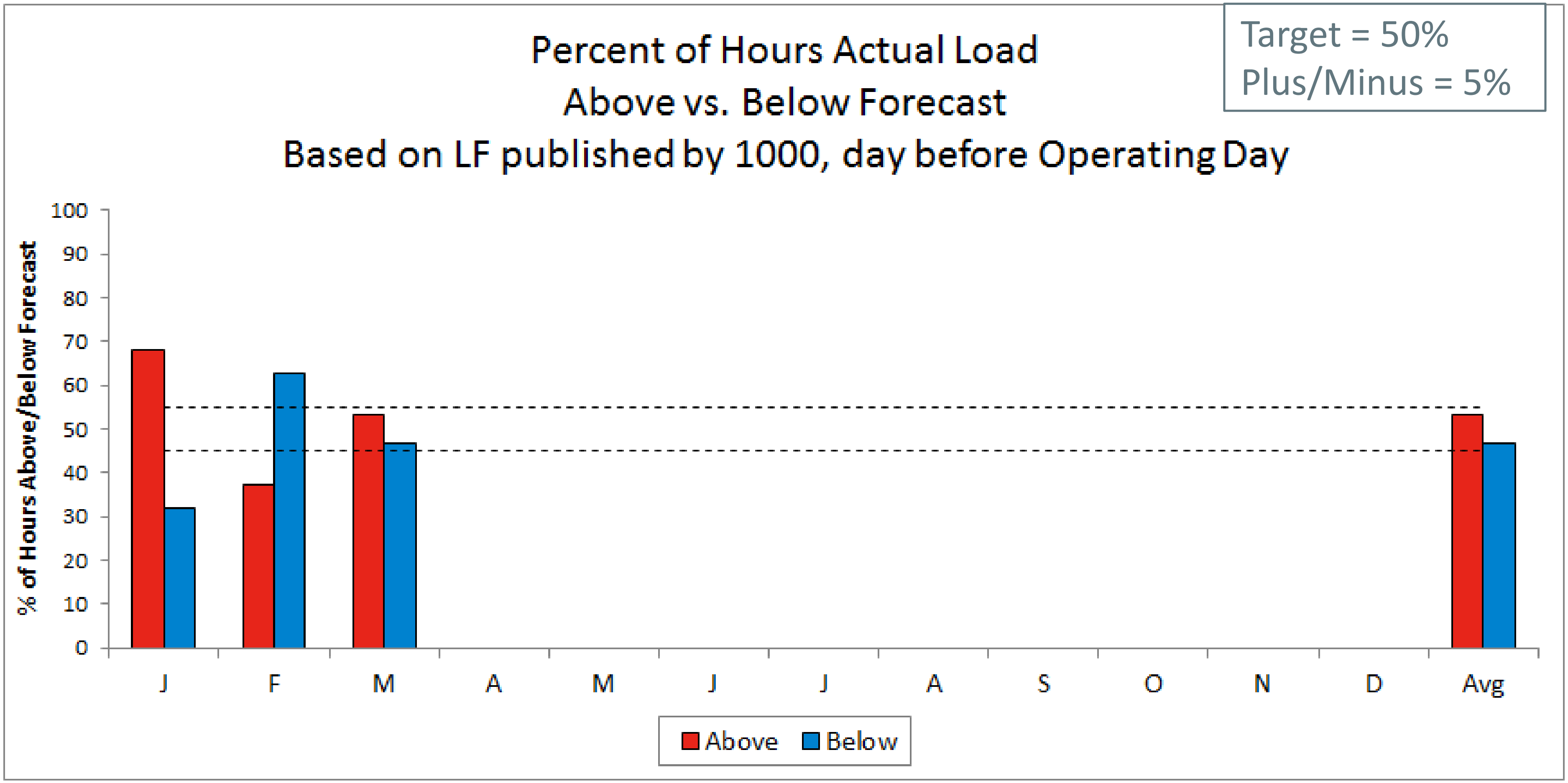
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	2.90	3.17	7.45										7.45
Day Min	0.08	0.10	0.02										0.02
MAPE	1.10	1.39	1.54										1.34
Goal	1.80	1.80	1.80										

2024 System Operations - Load Forecast Accuracy



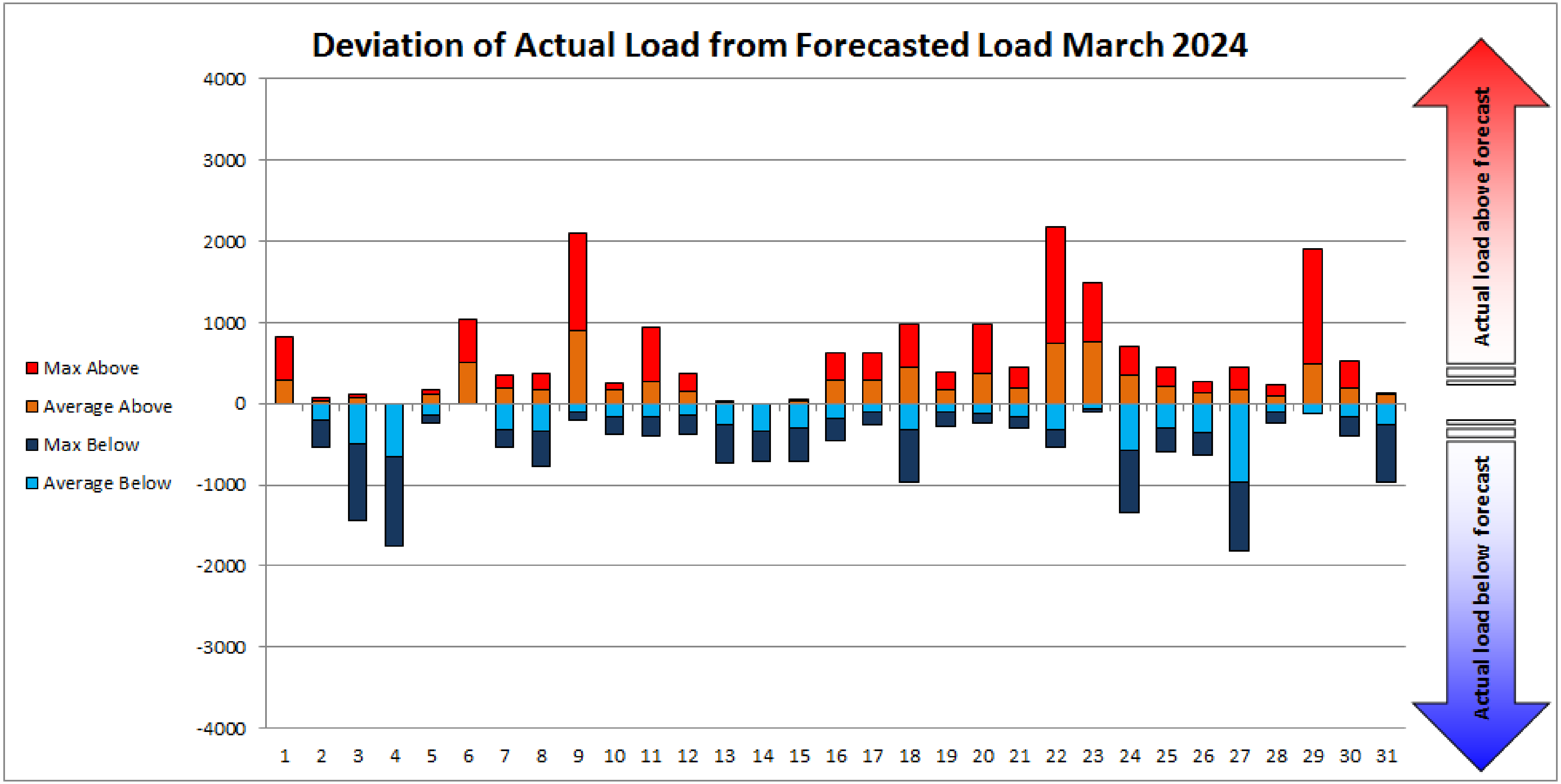
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.03	5.00	5.67										5.67
Day Min	0.73	0.64	0.76										0.64
MAPE	1.83	2.24	2.72										2.26
Goal	1.80	1.80	1.80										

2024 System Operations - Load Forecast Accuracy cont.



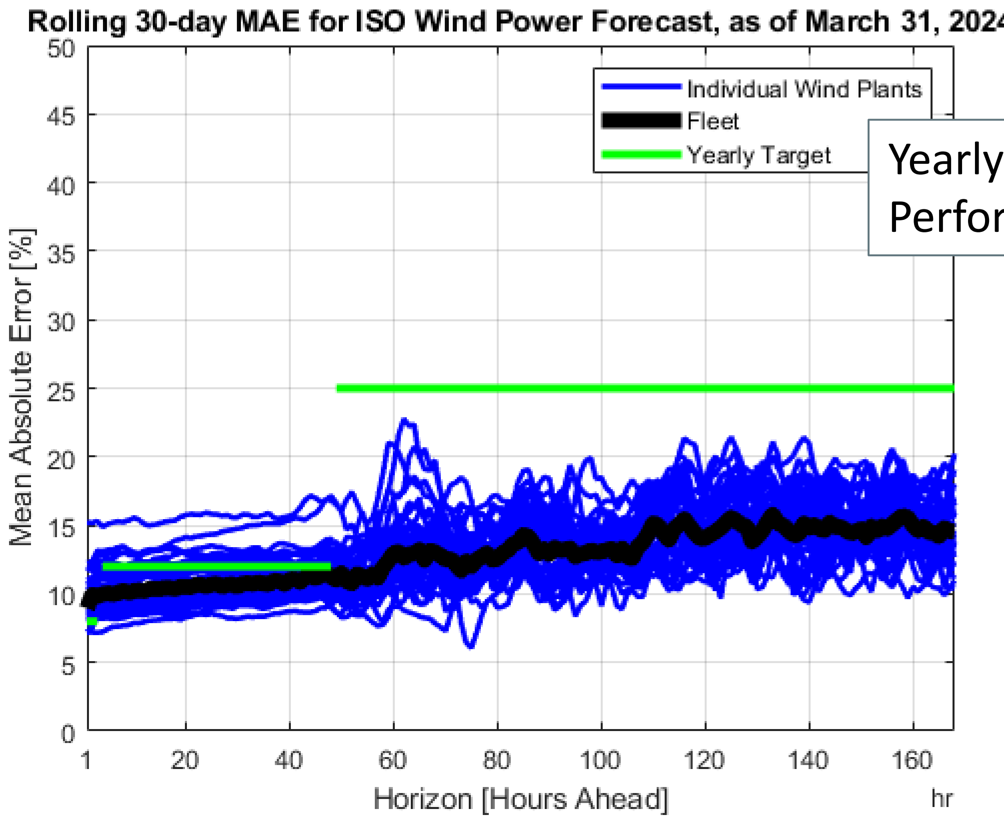
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	67.9	37.4	53.3										53
Below %	32.1	62.6	46.7										47
Avg Above	260.5	155.2	254.6										261
Avg Below	-155.5	-292.3	-253.5										-292
Avg All	132	-130	39										17

2024 System Operations - Load Forecast Accuracy cont.



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

Dashboard Indicator

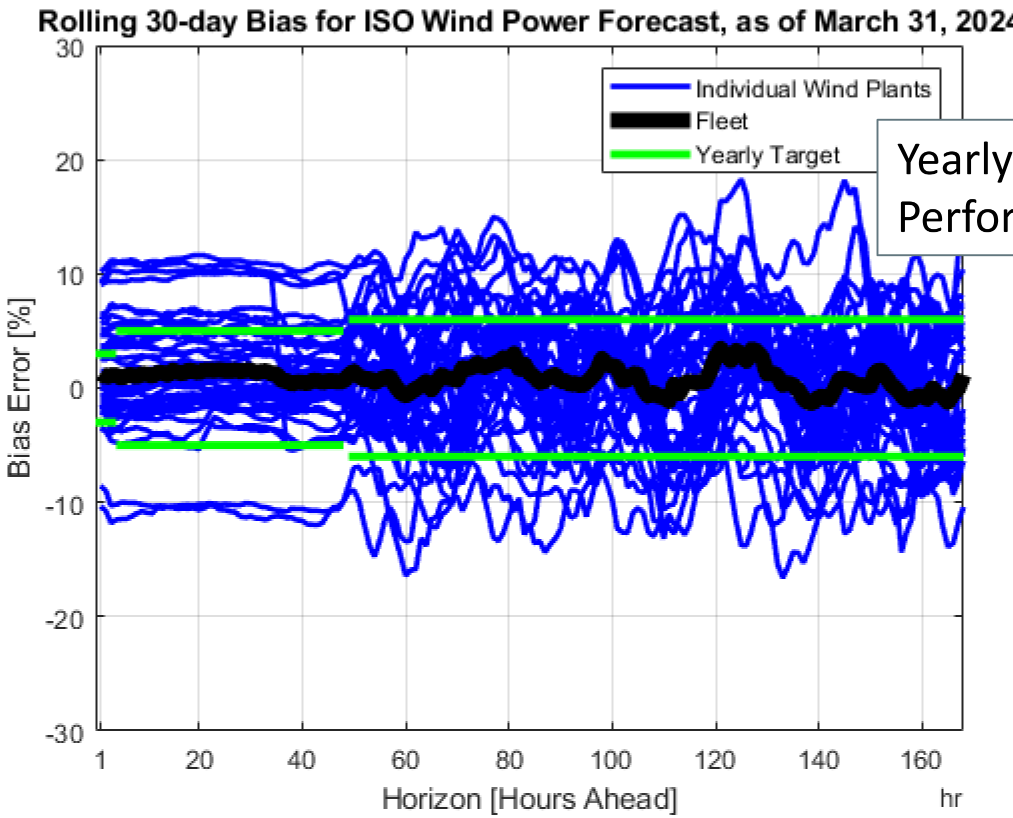


Yearly Fleet Performance targets

Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/DNV forecast is very good compared to industry standards; and except for lookahead horizon hour 1, monthly MAE is within the yearly performance targets.

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

Dashboard Indicator

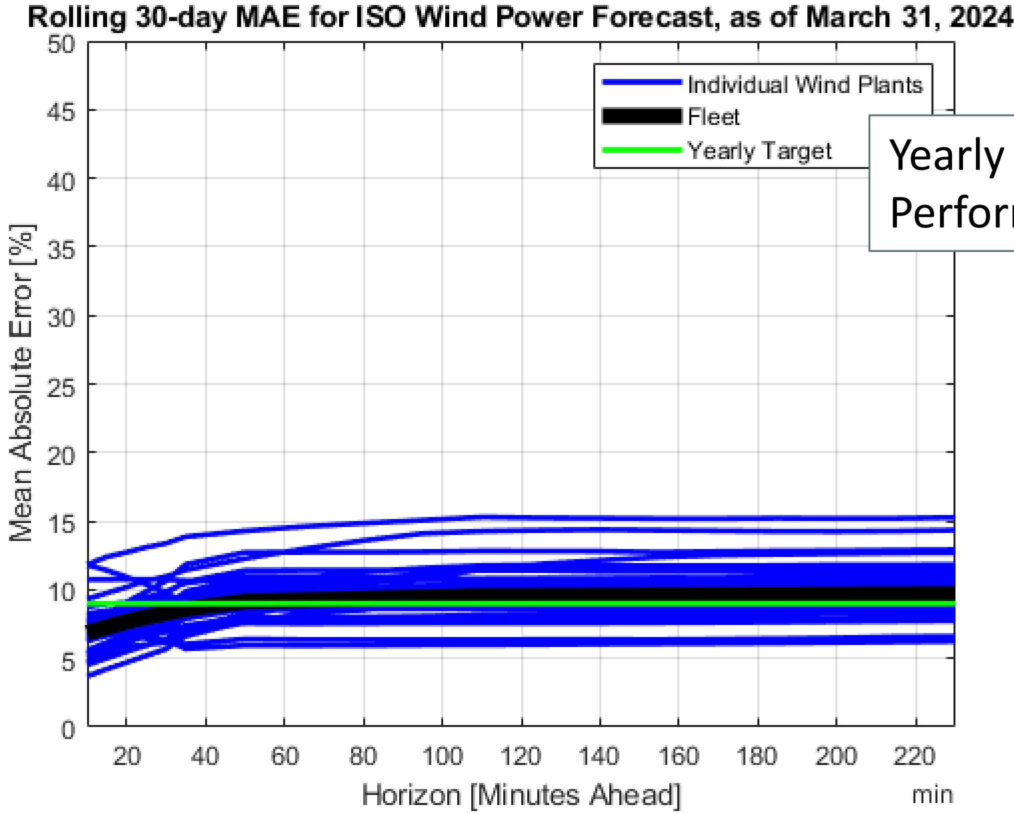


Yearly Fleet Performance targets

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

Wind Power Forecast Error Statistics: Short Term Forecast MAE

Dashboard Indicator

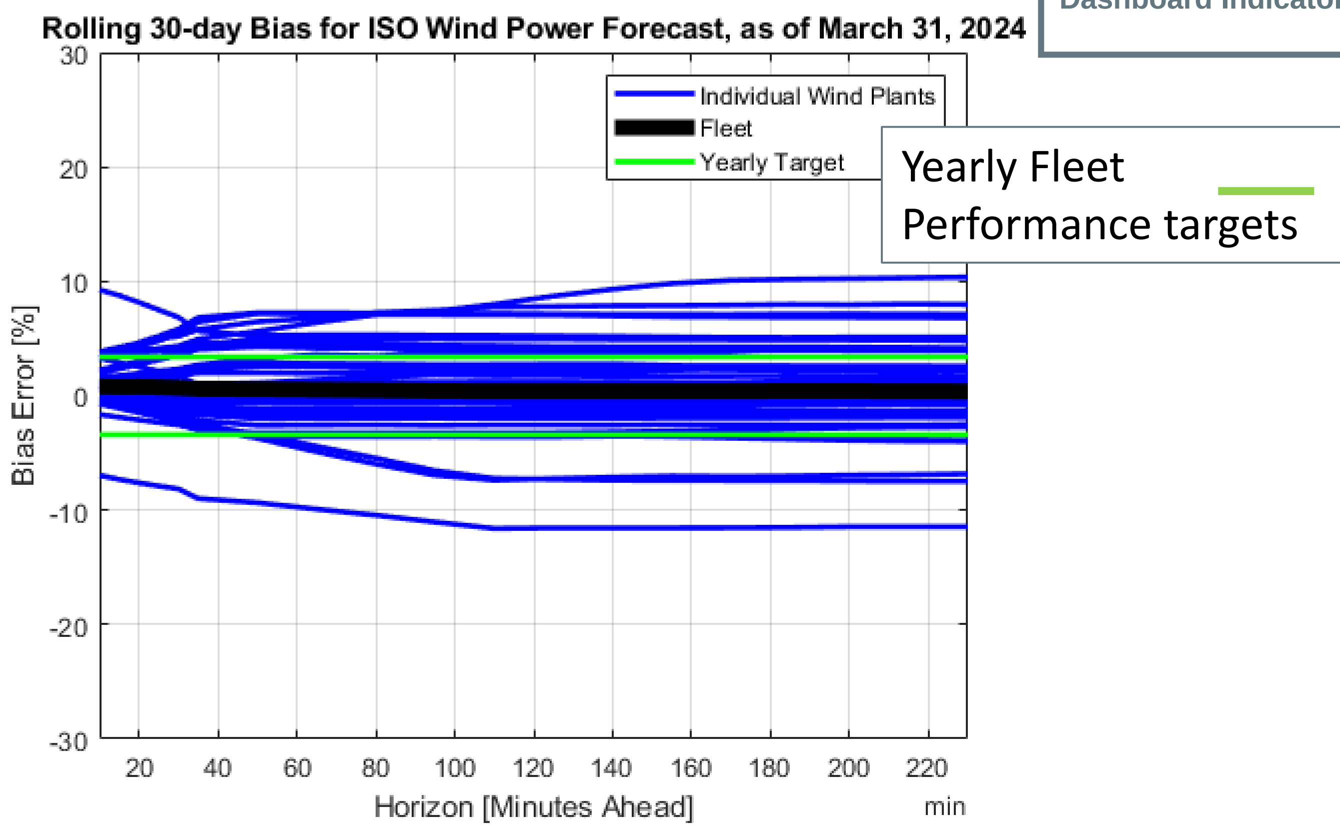


Yearly Fleet Performance targets

Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the forecast compares well with industry standards. After the 45 minute lookahead horizon, monthly MAE is just outside of yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator

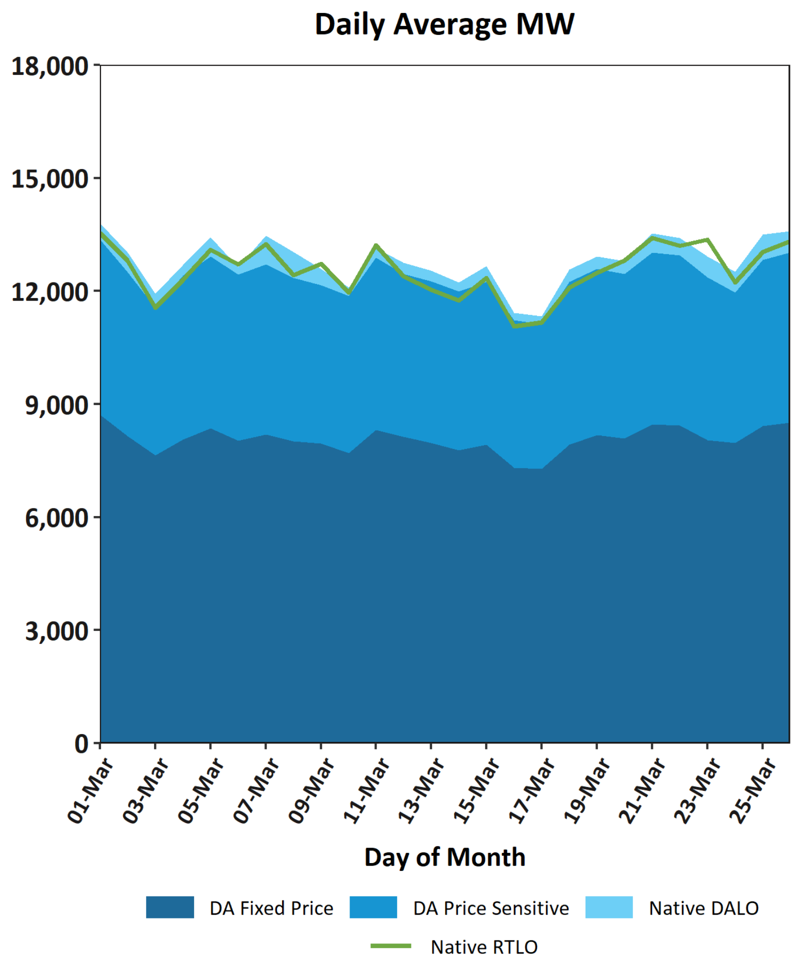


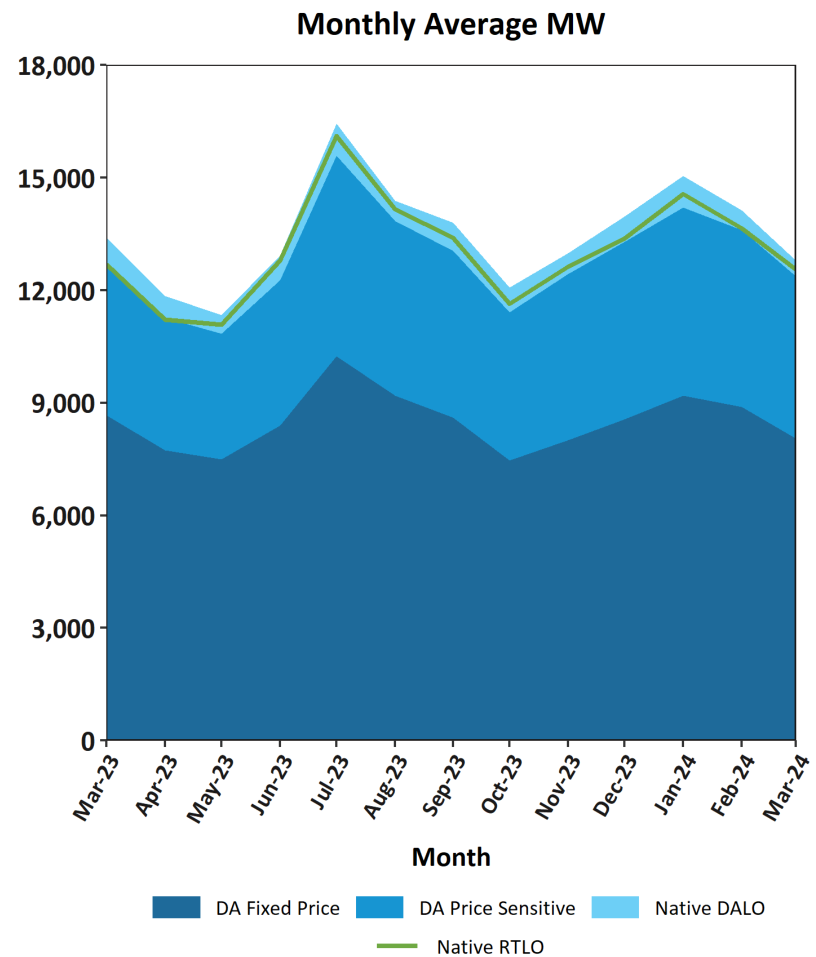
Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV forecast compares well with industry standards, and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

MARKET OPERATIONS

SUPPLY AND DEMAND VOLUMES

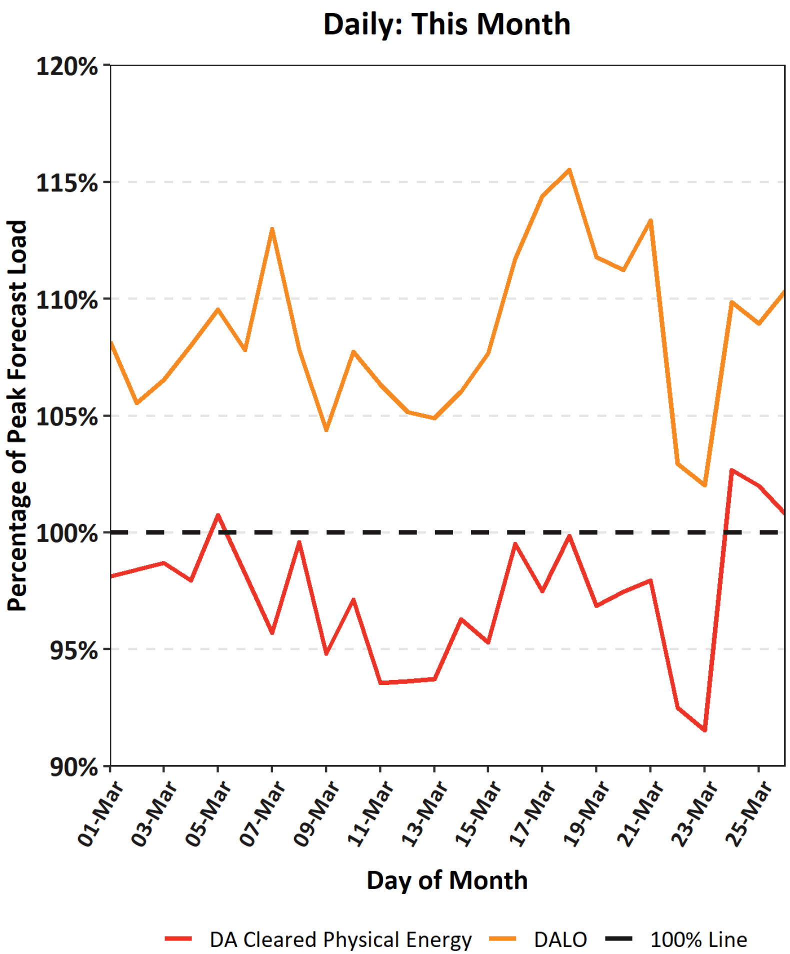
DA Cleared Native Load by Composition Compared to Native RT Load

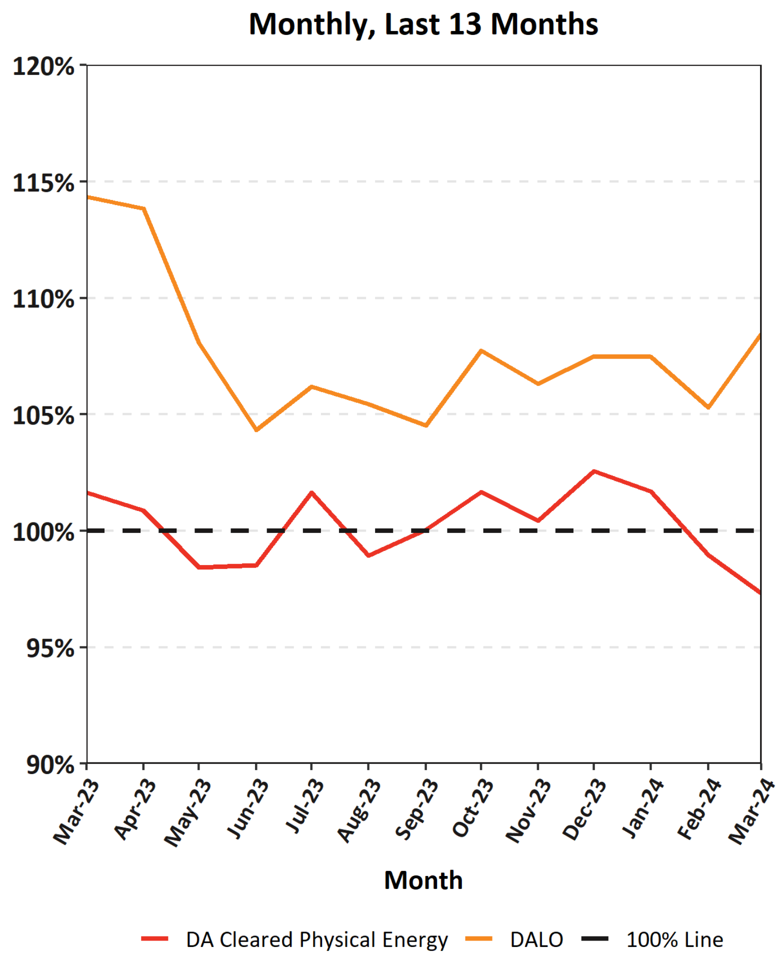




Native Day-Ahead Load Obligation (DALO) is the sum of all day-ahead cleared load, excluding modeled transmission losses and exports Native Real-Time Load Obligation (RTLO) is the sum of all real-time load, excluding exports

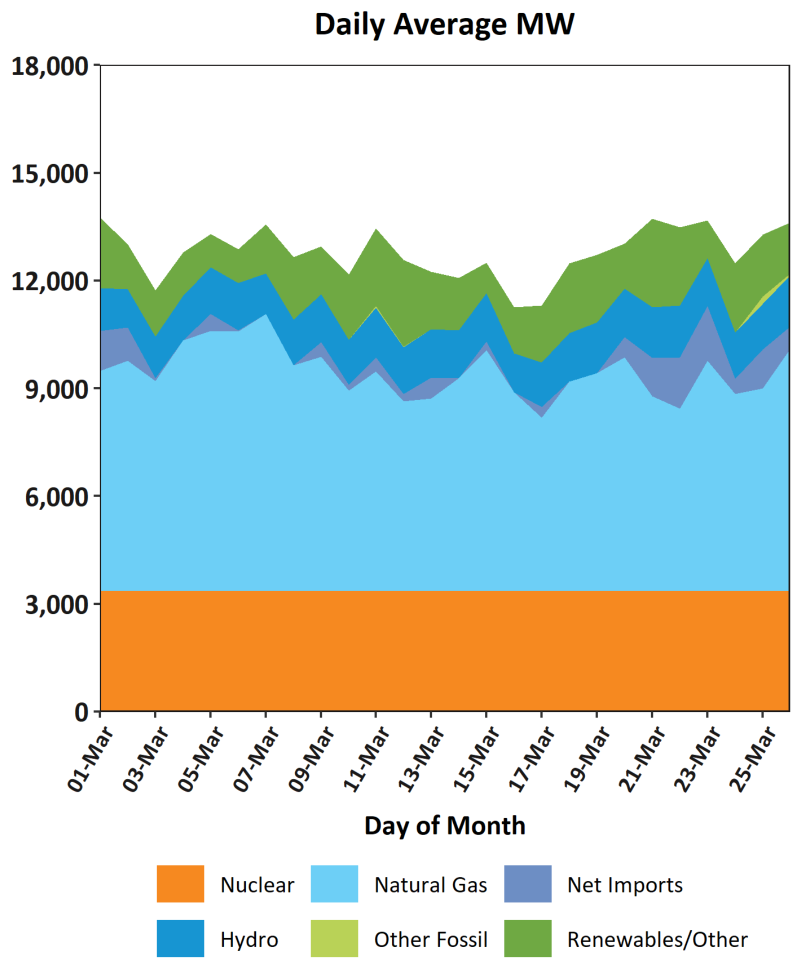
DA Volumes as % of Forecast in Peak Hour

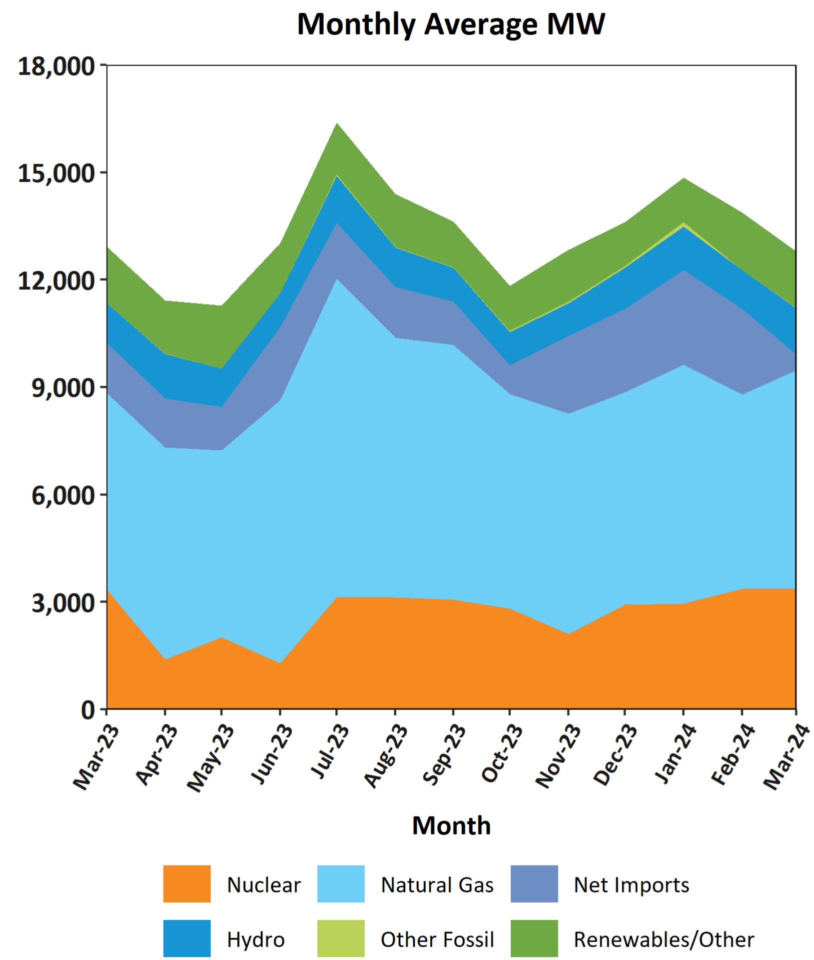




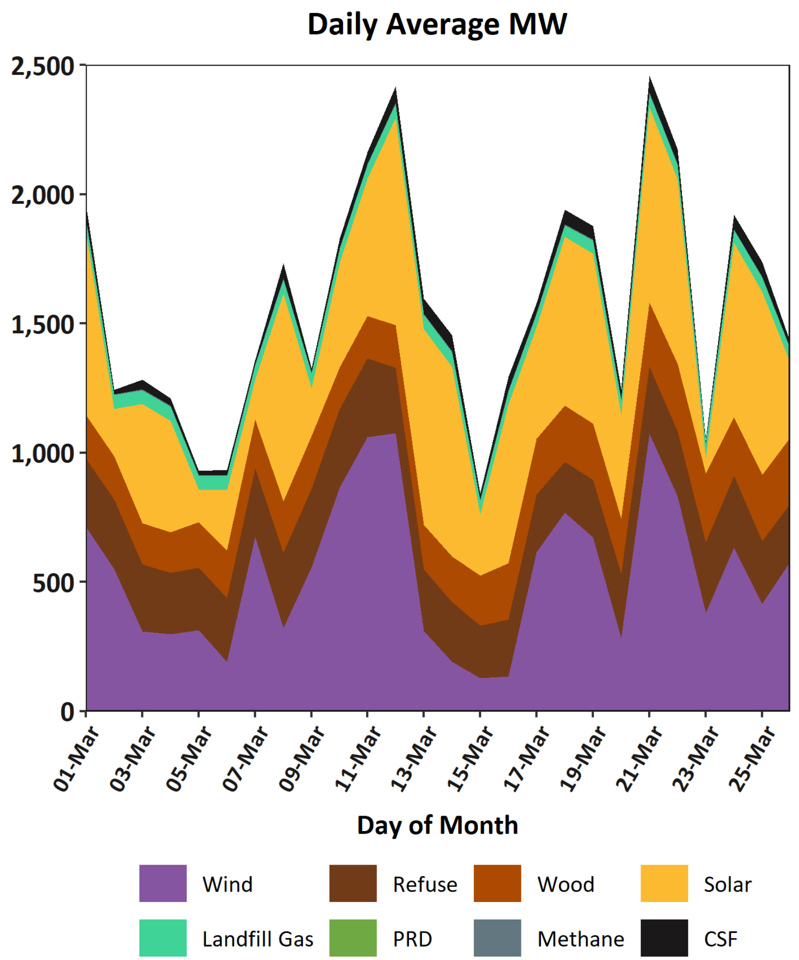
The number of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month was: none

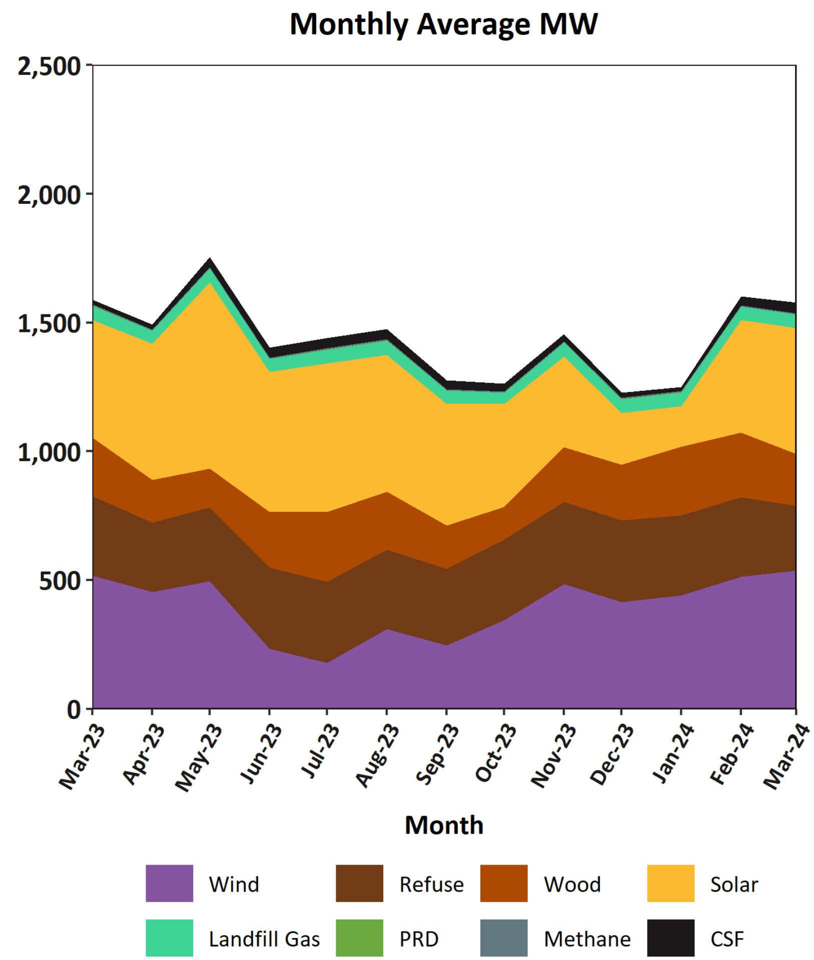
Resource Mix





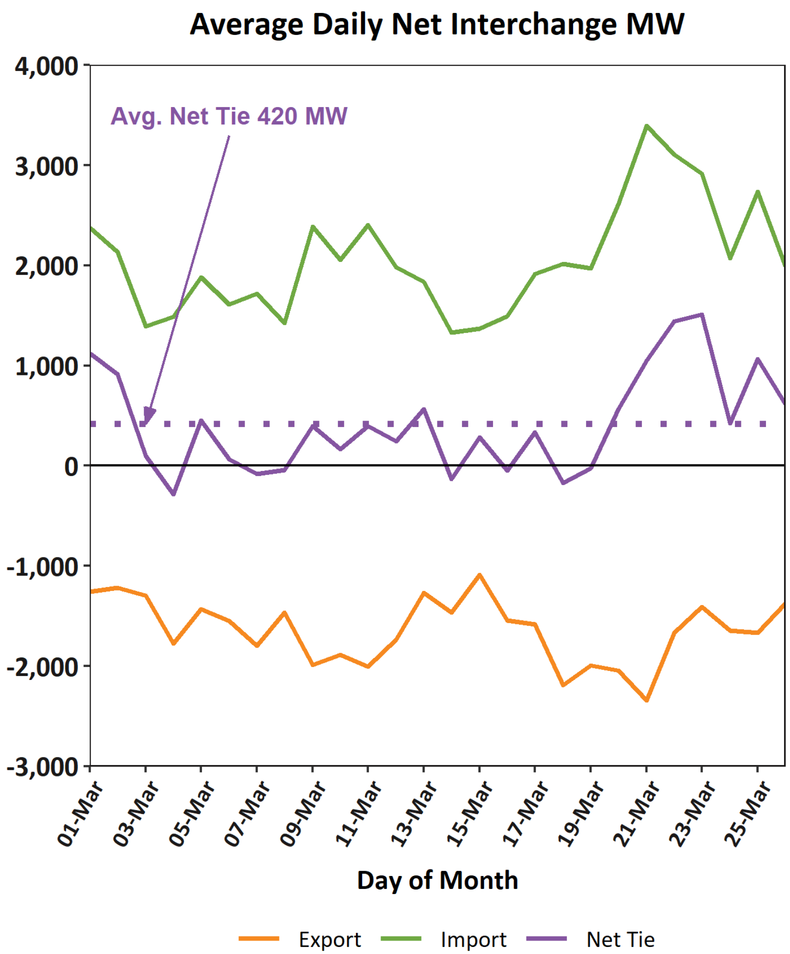
Renewable Generation by Fuel Type

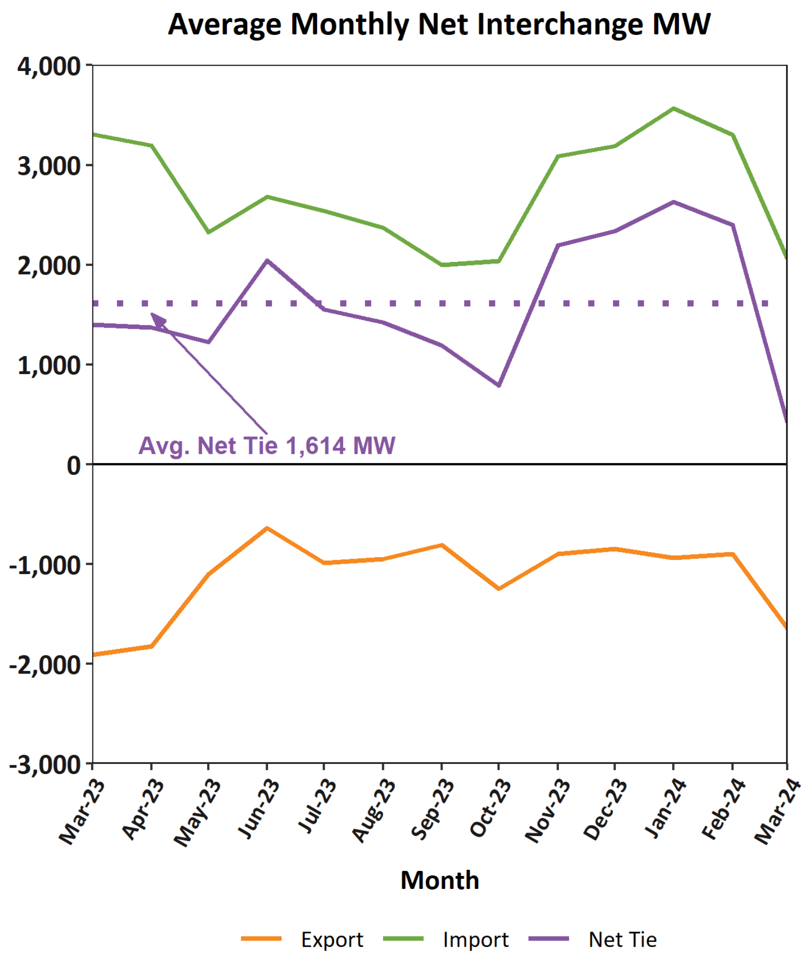




Note: CSF represents Continuous Storage Facilities (a.k.a. Batteries)

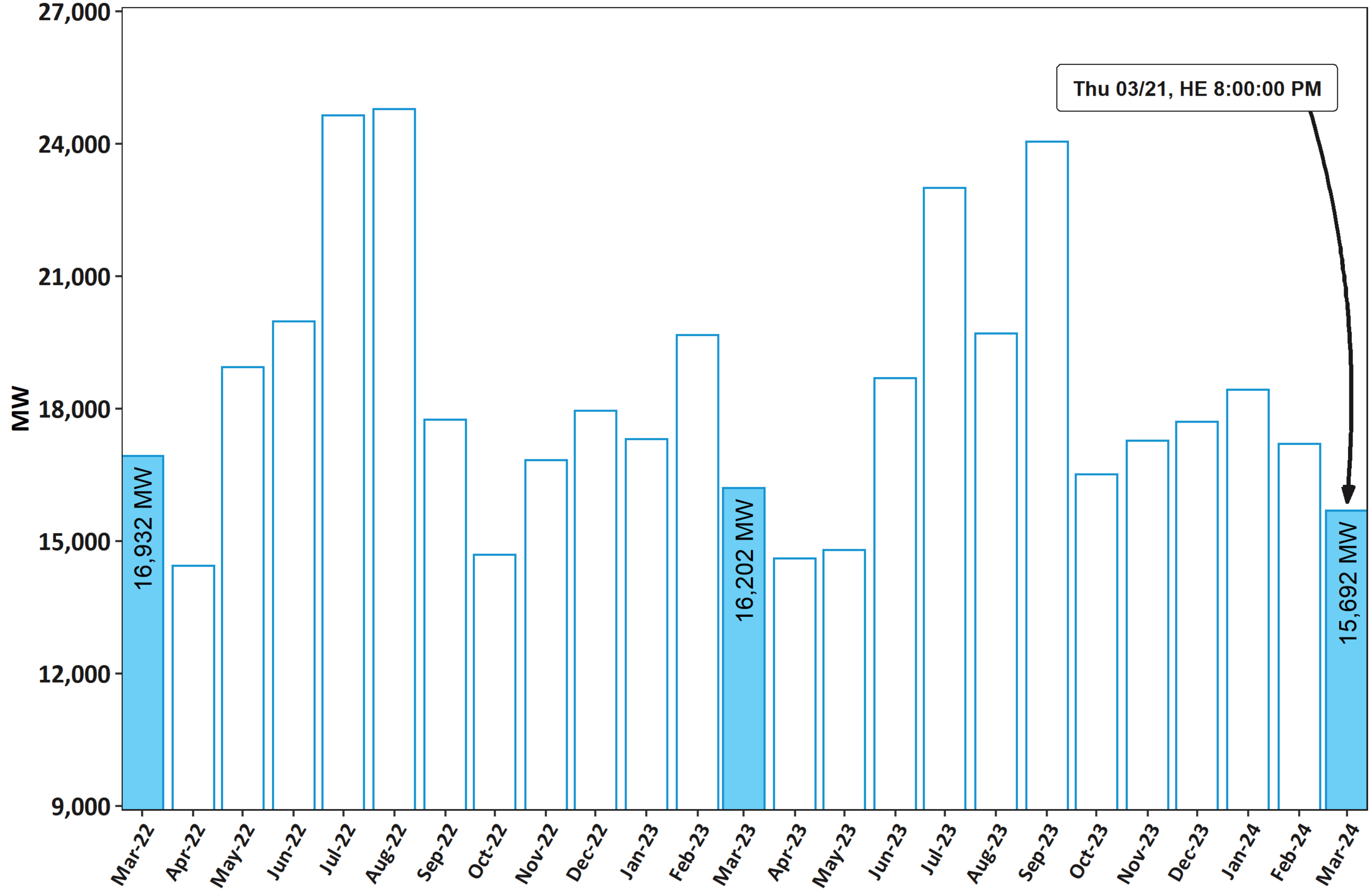
RT Net Interchange





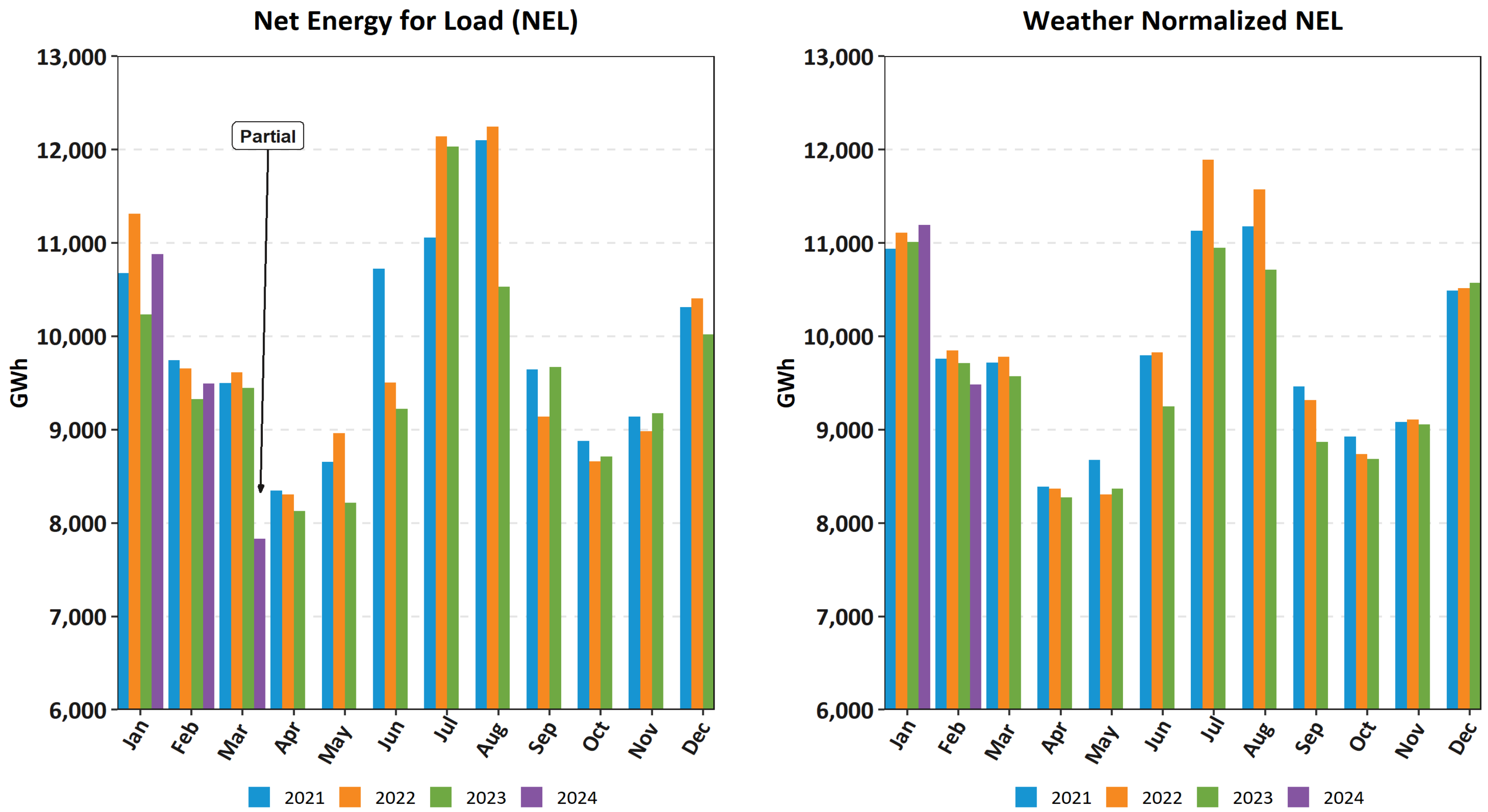
Net Interchange is the participant sum of daily imports minus the sum of daily exports; positive values are net imports

RQM System Peak Load MW by Month



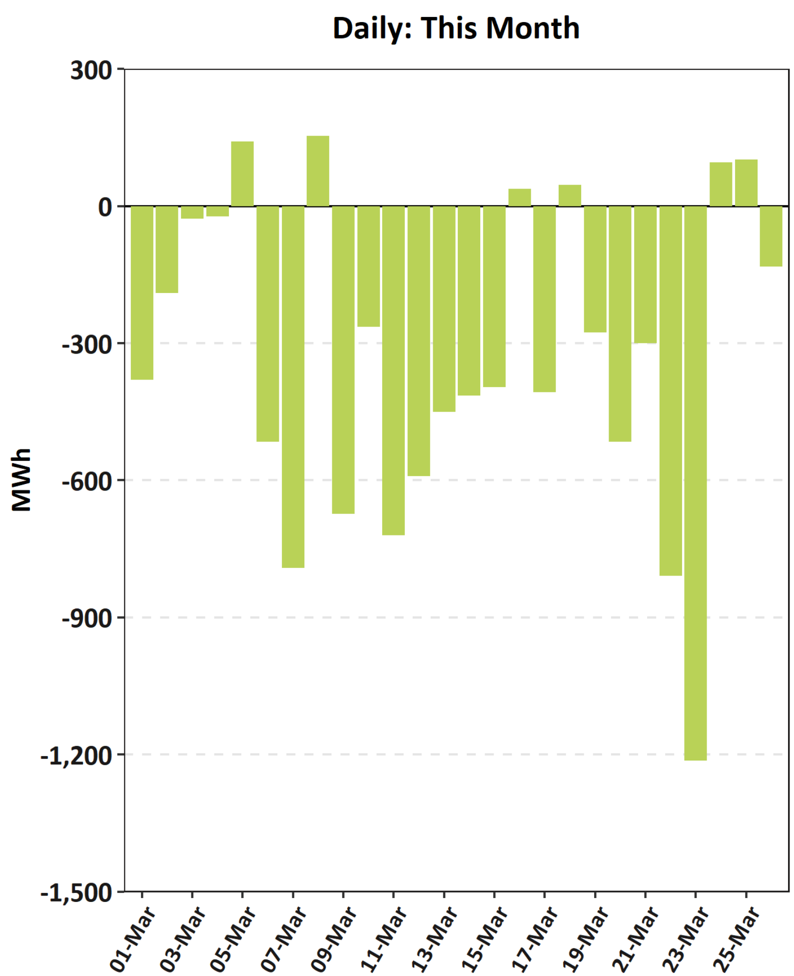
Shaded columns reflect current month and the same month the last 2 years

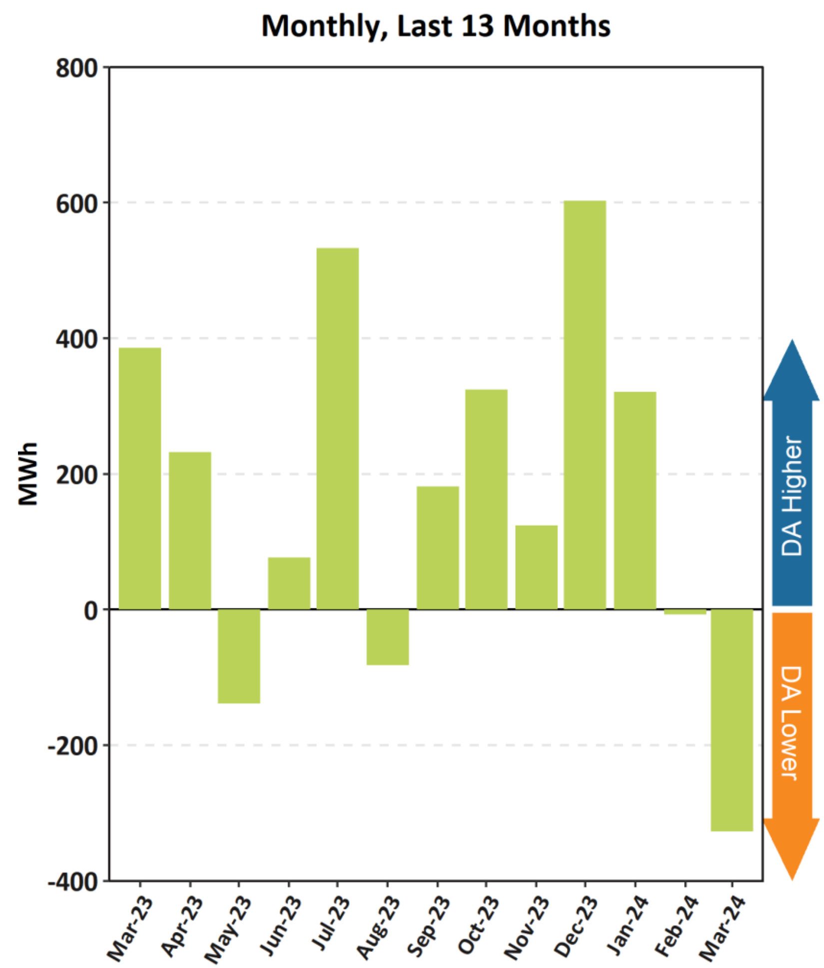
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL



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

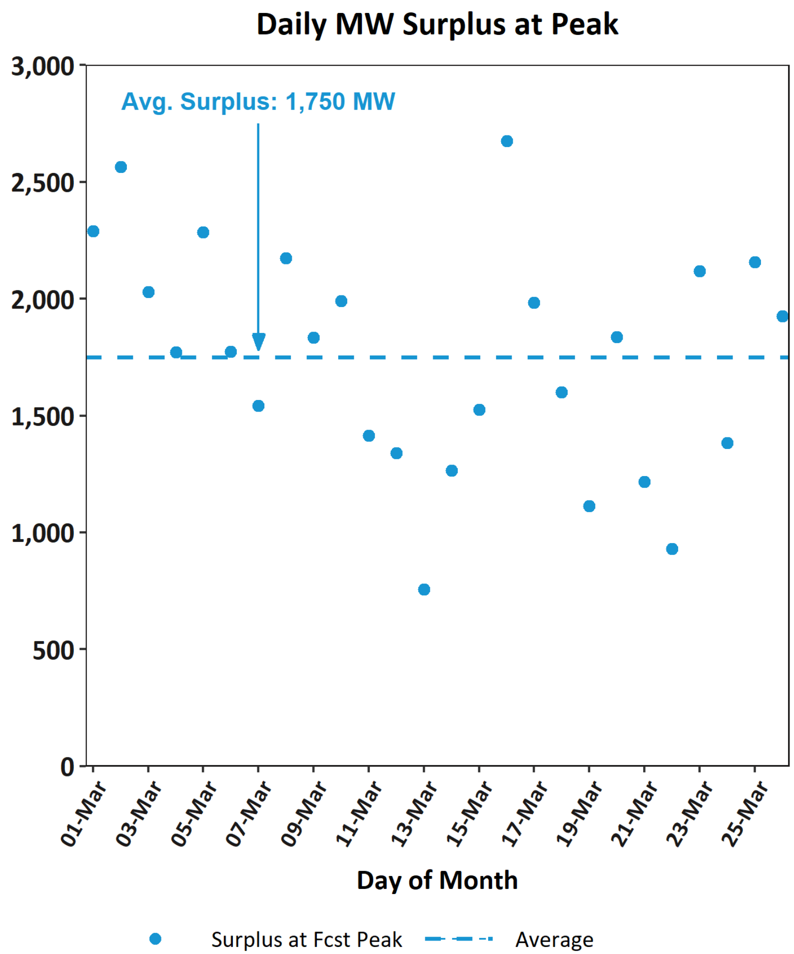
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour

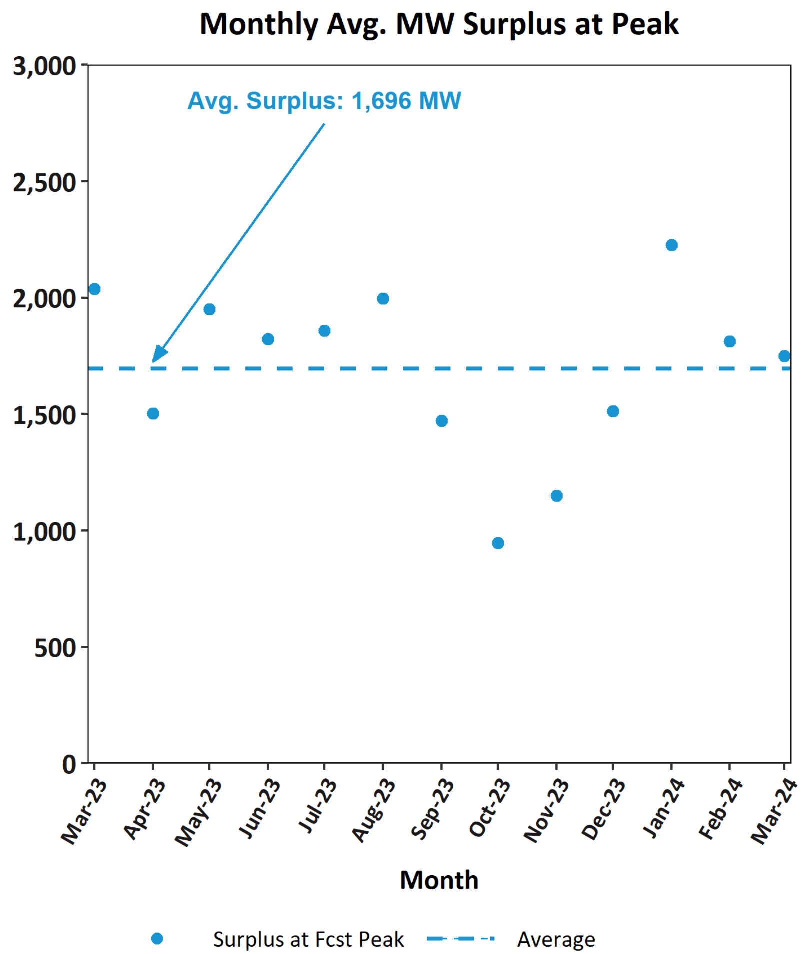




Negative values indicate DA Cleared Physical Energy value below its RT counterpart.

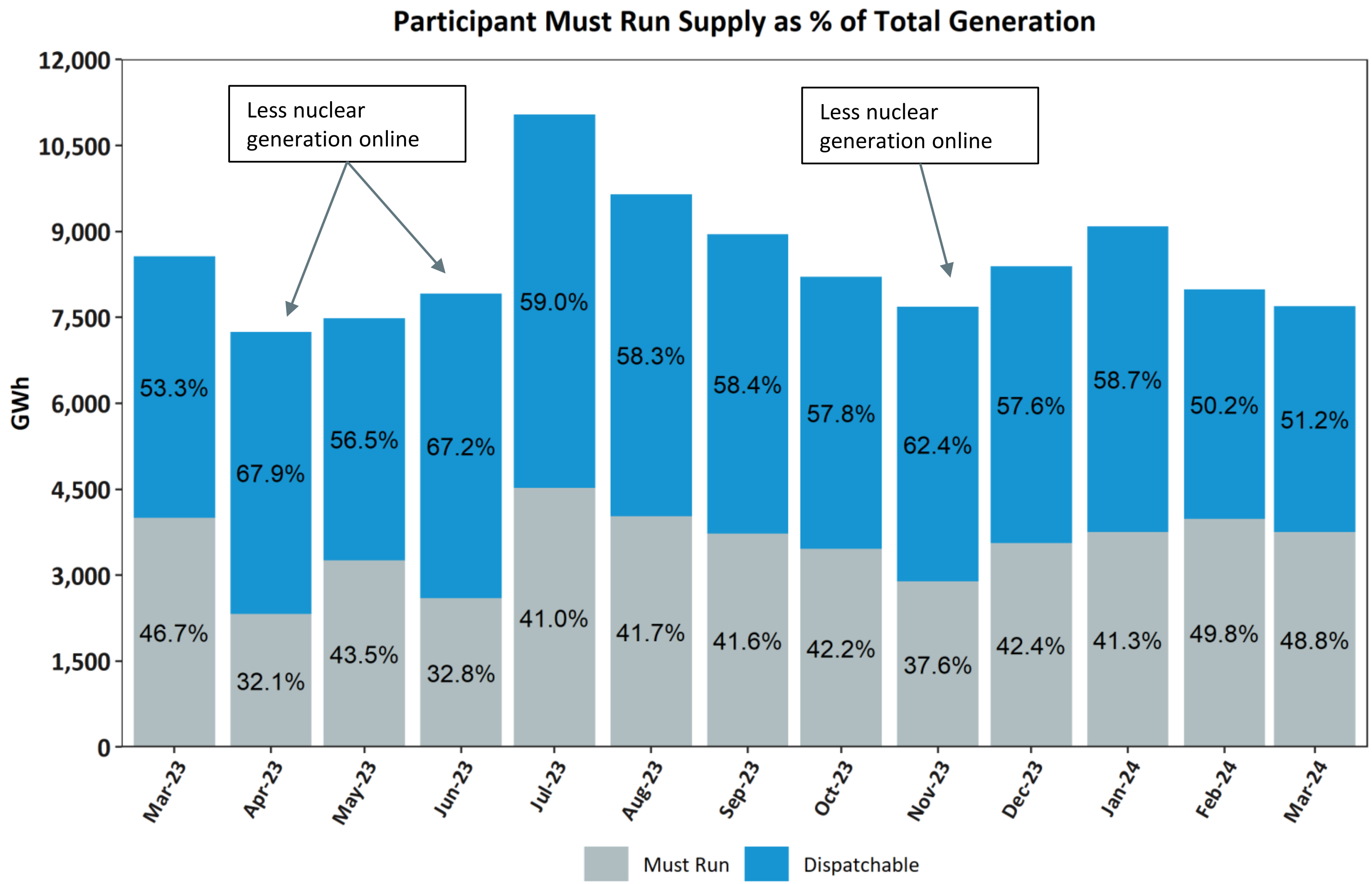
Capacity Surplus* Cleared in the DA Market Relative to Forecasted Peak-Hour Requirements





*DA capacity surplus includes DA offered ECO max above cleared amounts for cleared resources + offered reserves from available non-cleared resources + DA scheduled net interchange, reflected for the peak hour

RT Generation Output Offered as Must Run vs Dispatchable



Includes generation and DRR. Must Run (non-dispatchable) category reflects full output of settlement-only generation (SOG) as well as must run offers from modeled units

MARKET PRICING

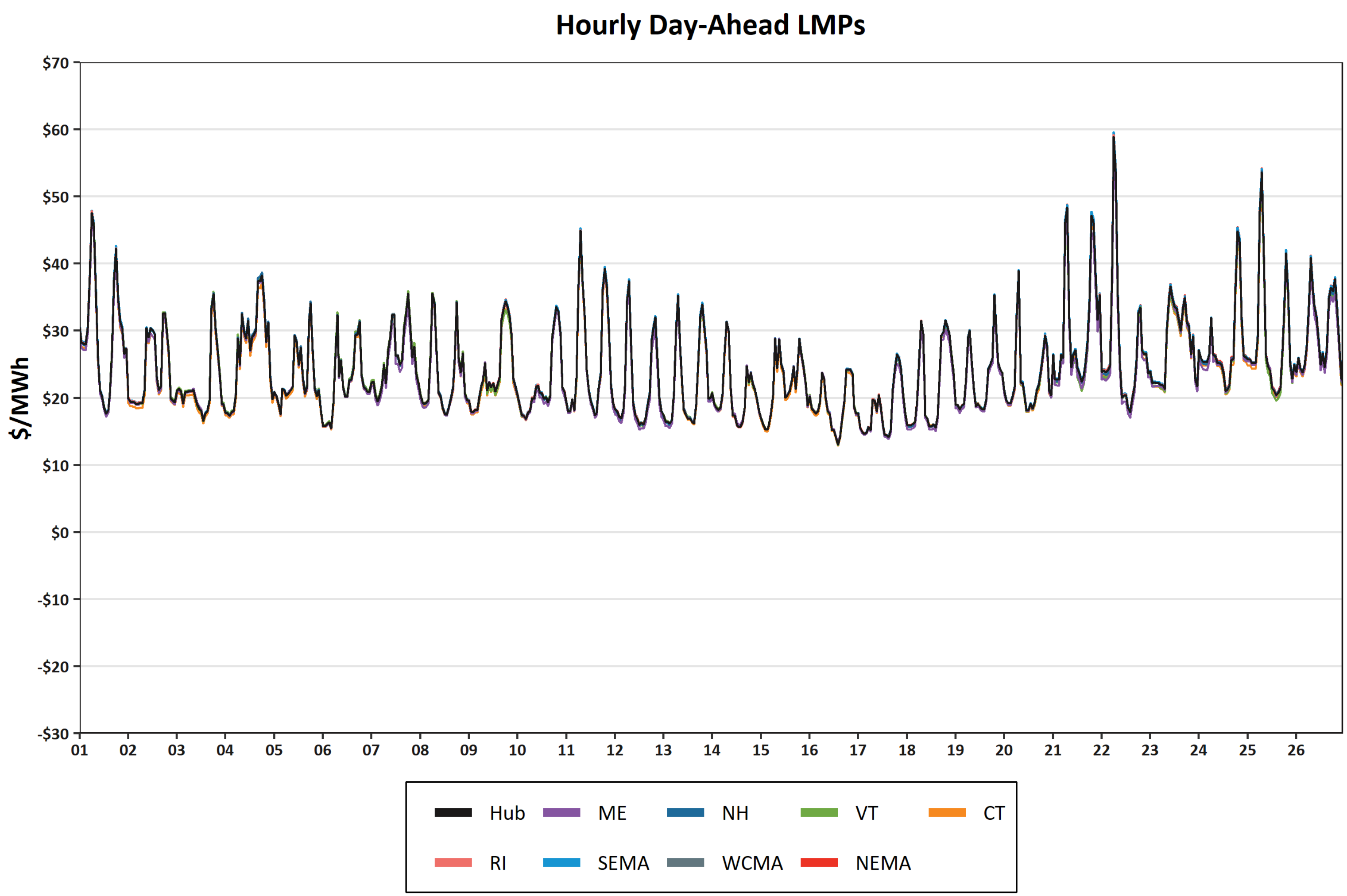
DA vs. RT LMPs ($/MWh)

Arithmetic Average

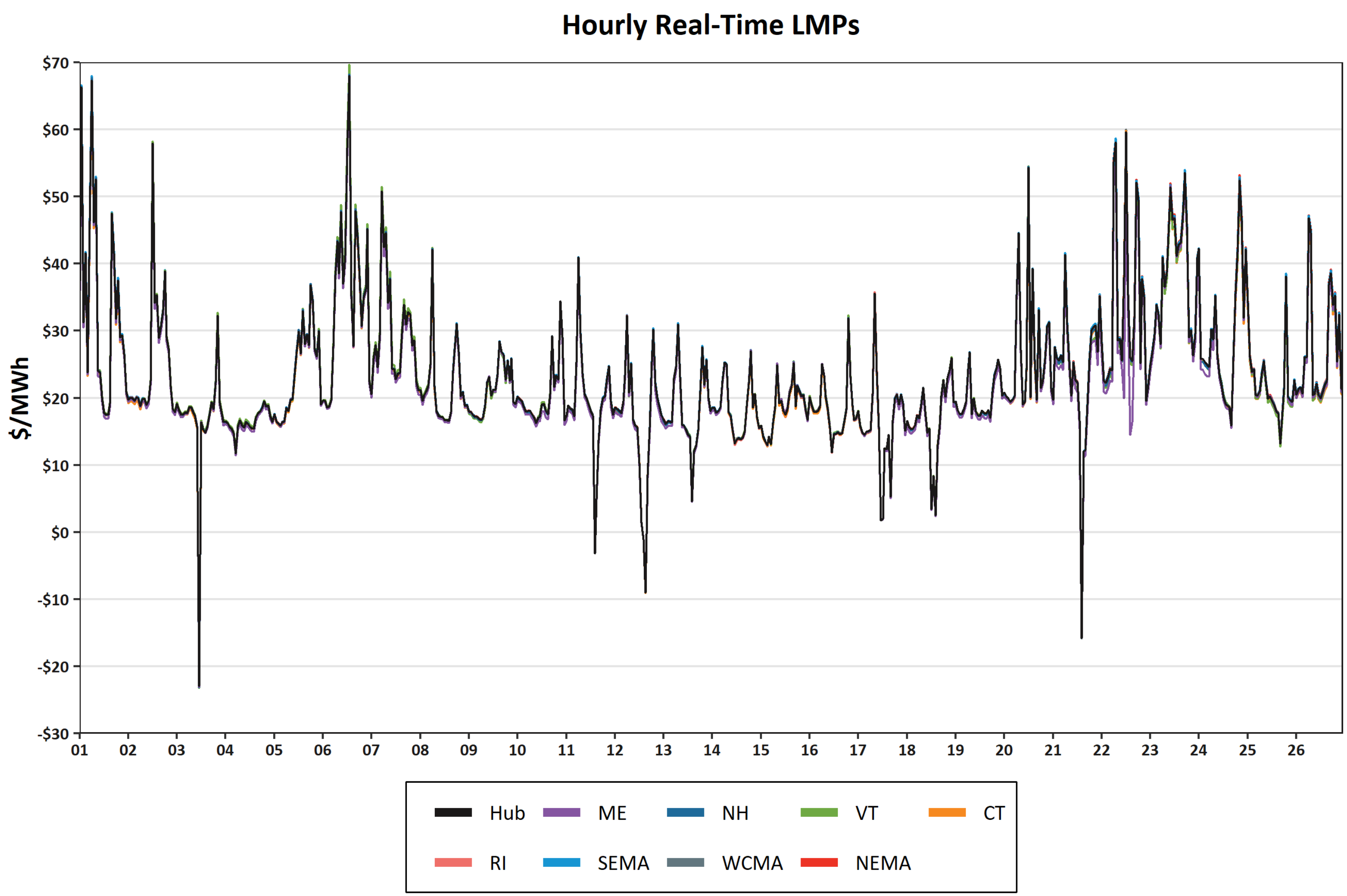
Year 2023	CT	Hub	ME	NEMA	NH	RI	SEMA	VT	WCMA
Day-Ahead	$84.07	$85.59	$84.20	$86.12	$85.77	$85.39	$86.05	$84.48	$85.69
Real-Time	$83.80	$84.89	$83.06	$85.40	$85.05	$84.69	$85.35	$83.64	$84.97
RT Delta %	-0.32%	-0.82%	-1.35%	-0.84%	-0.84%	-0.82%	-0.81%	-0.99%	-0.84%
Year 2022	**CT**	**Hub**	**ME**	**NEMA**	**NH**	**RI**	**SEMA**	**VT**	**WCMA**
Day-Ahead	$36.25	$37.04	$36.59	$37.35	$37.22	$36.89	$37.34	$36.78	$37.07
Real-Time	$35.26	$35.91	$35.36	$36.21	$36.05	$35.71	$36.17	$35.55	$35.92
RT Delta %	-0.32%	-0.82%	-1.35%	-0.84%	-0.84%	-0.82%	-0.81%	-0.99%	-0.84%

March-23	CT	Hub	ME	NEMA	NH	RI	SEMA	VT	WCMA
Day-Ahead	$34.27	$35.02	$34.86	$35.43	$35.47	$34.88	$35.38	$34.70	$35.06
Real-Time	$30.21	$30.77	$30.41	$31.08	$31.05	$30.58	$31.01	$30.36	$30.79
RT Delta %	-11.85%	-12.14%	-12.77%	-12.28%	-12.46%	-12.33%	-12.35%	-12.51%	-12.18%
March-24	**CT**	**Hub**	**ME**	**NEMA**	**NH**	**RI**	**SEMA**	**VT**	**WCMA**
Day-Ahead	$23.82	$24.31	$23.84	$24.36	$24.24	$24.22	$24.44	$24.13	$24.33
Real-Time	$22.98	$23.33	$22.72	$23.35	$23.25	$23.20	$23.42	$23.19	$23.36
RT Delta %	-3.53%	-4.03%	-4.70%	-4.15%	-4.08%	-4.21%	-4.17%	-3.90%	-3.99%
Annual Diff.	**CT**	**Hub**	**ME**	**NEMA**	**NH**	**RI**	**SEMA**	**VT**	**WCMA**
Yr over Yr DA	-30.49%	-30.58%	-31.61%	-31.24%	-31.66%	-30.56%	-30.92%	-30.46%	-30.6%
Yr over Yr RT	-23.93%	-24.18%	-25.29%	-24.87%	-25.12%	-24.13%	-24.48%	-23.62%	-24.13%

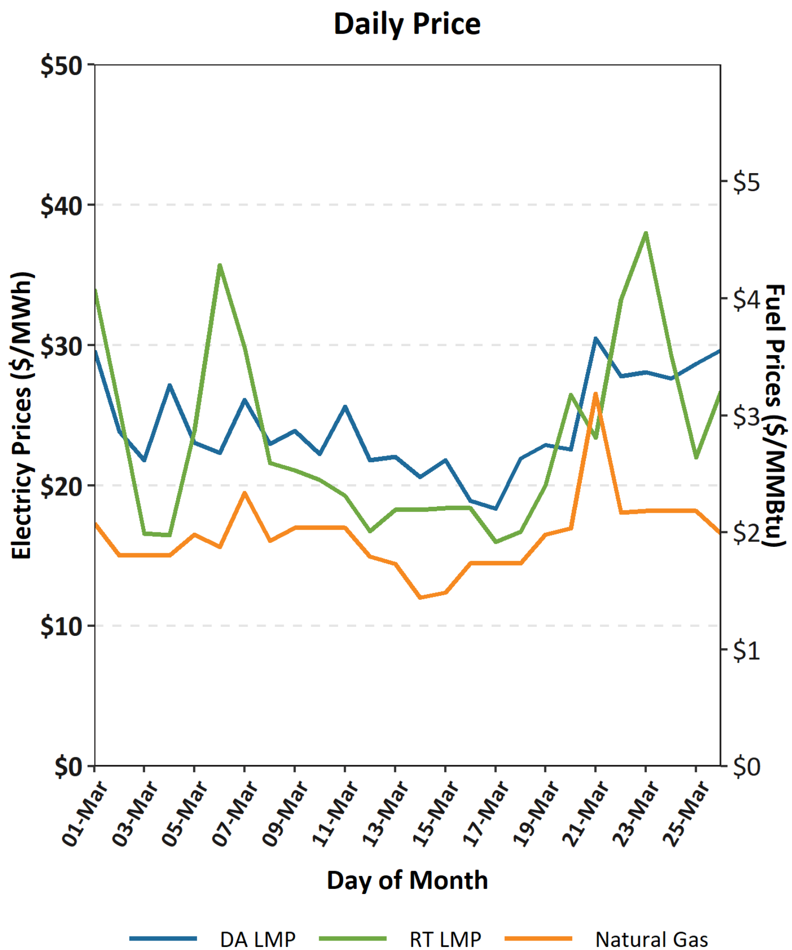
Hourly DA LMPs, March 1-26, 2024

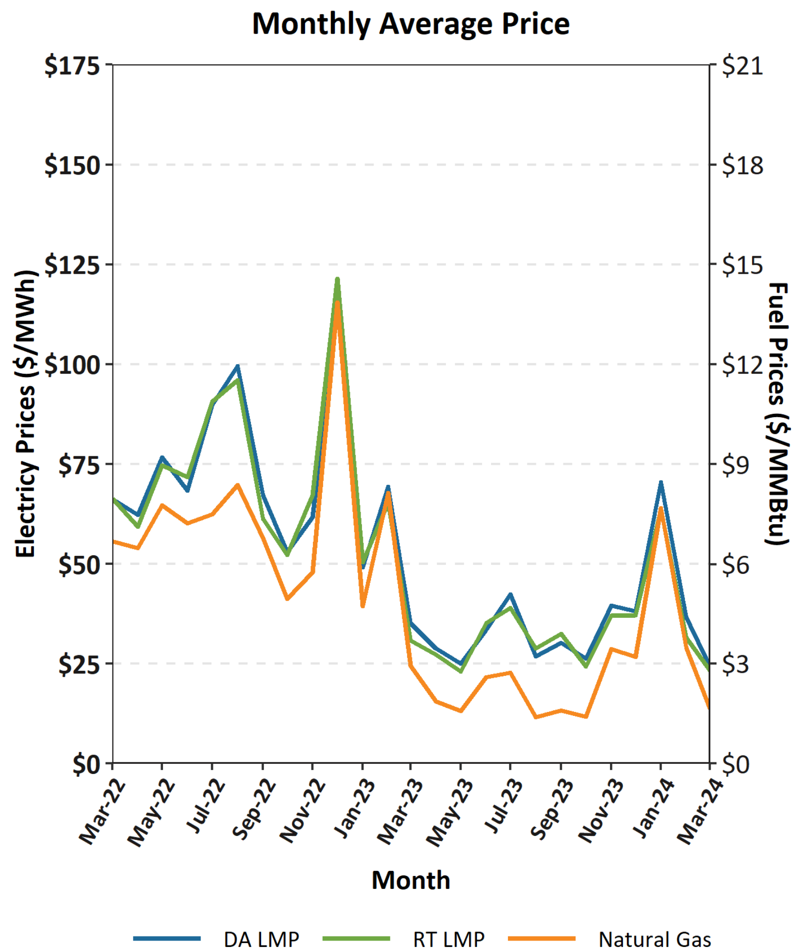


Hourly RT LMPs, March 1-26, 2024



Wholesale Electricity vs Natural Gas Prices by Month

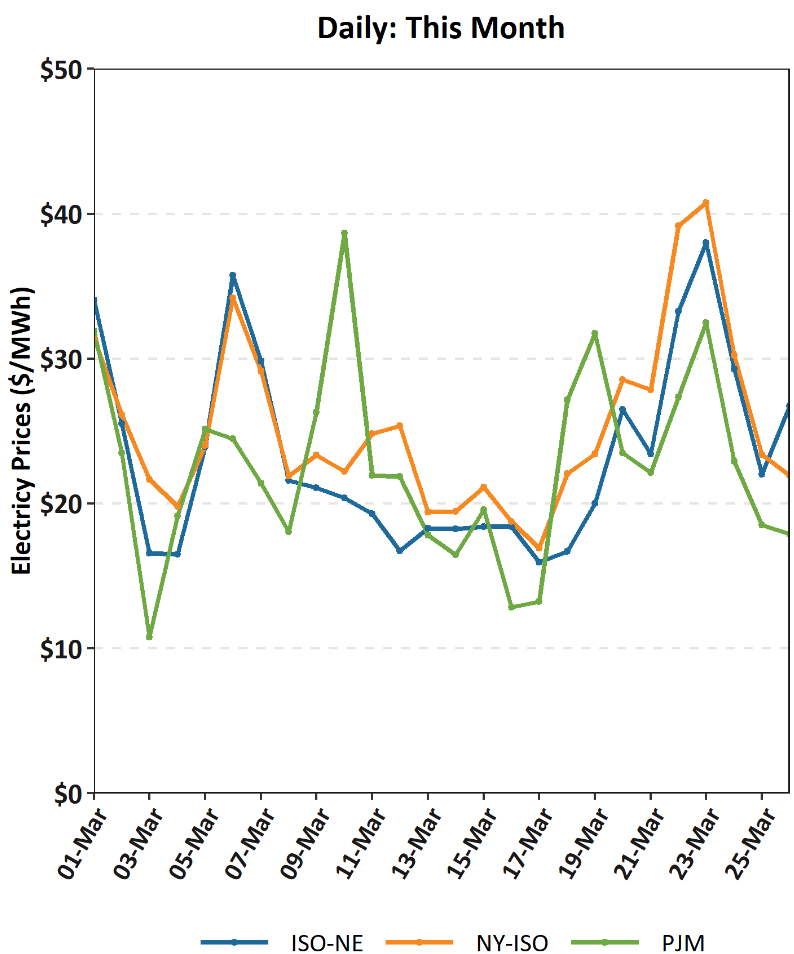


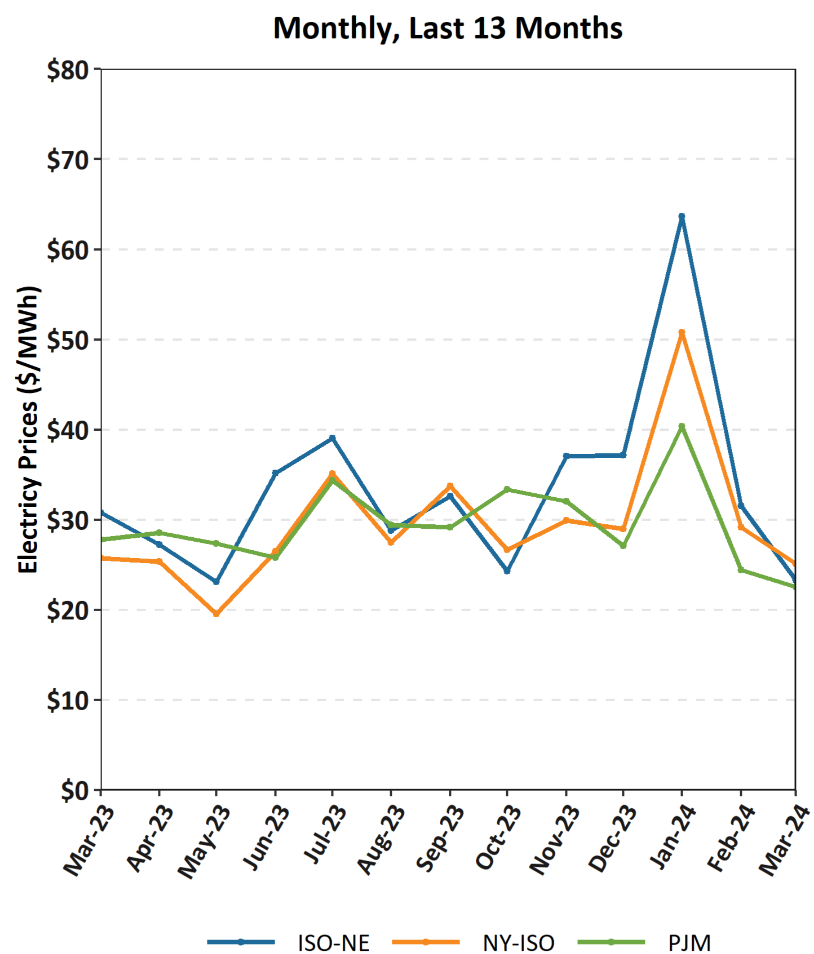


Underlying natural gas data furnished by: ICE Global markets in clear view

Gas price is average of Massachusetts delivery points

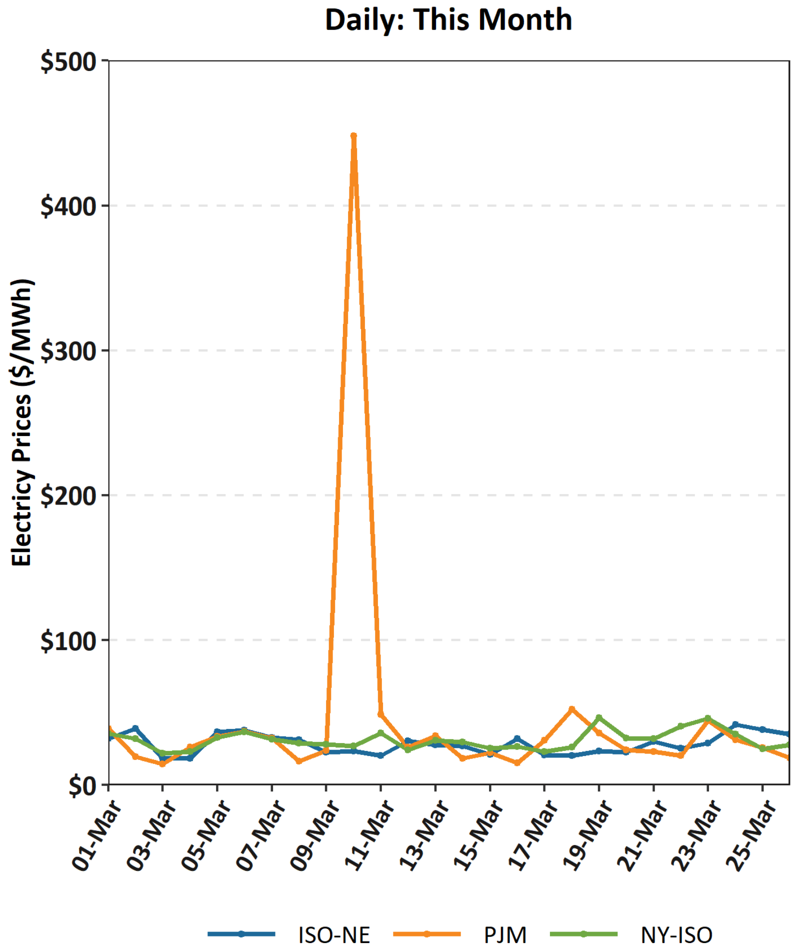
New England, NY, and PJM Hourly Average RT Prices by Month

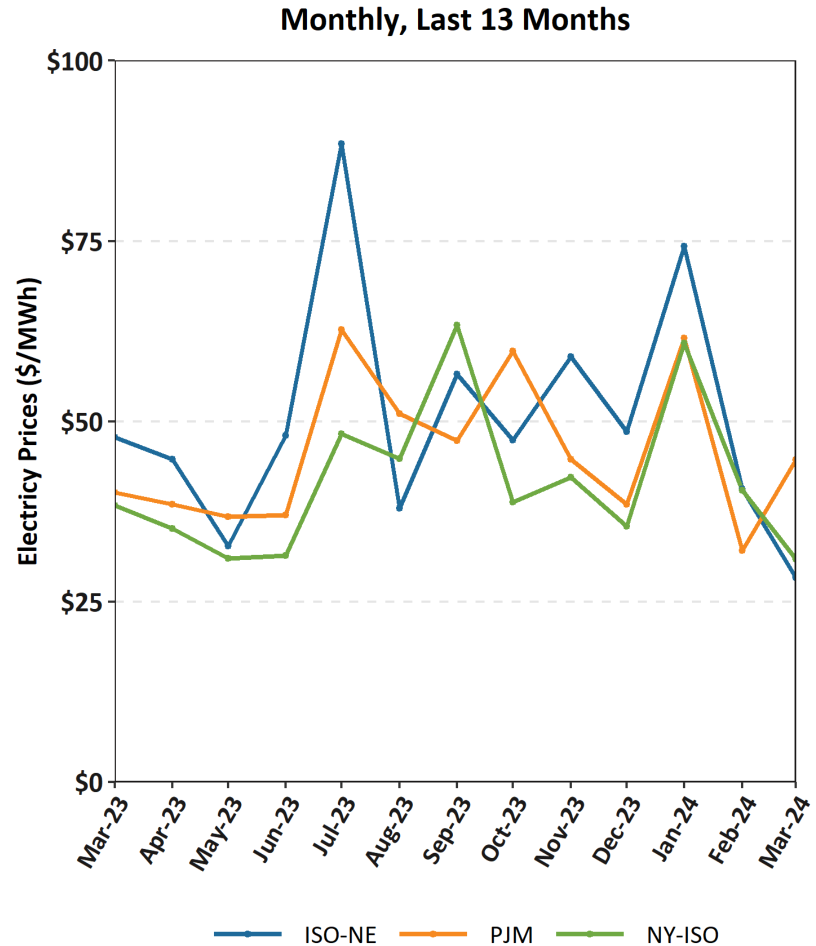




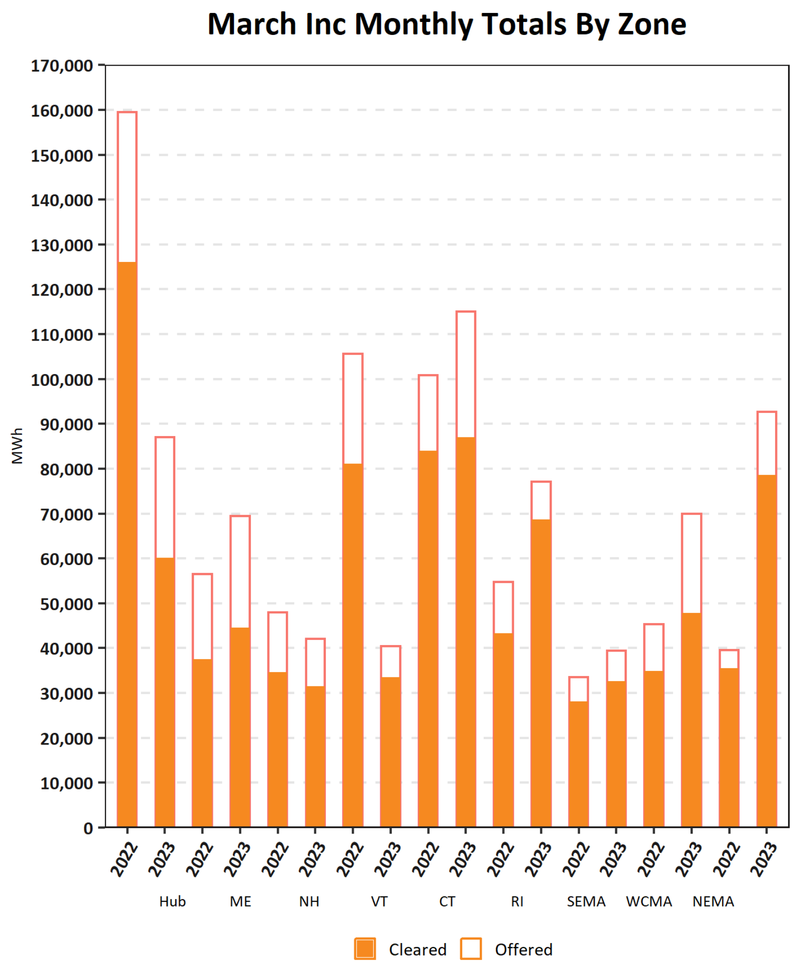
Hourly average prices are shown

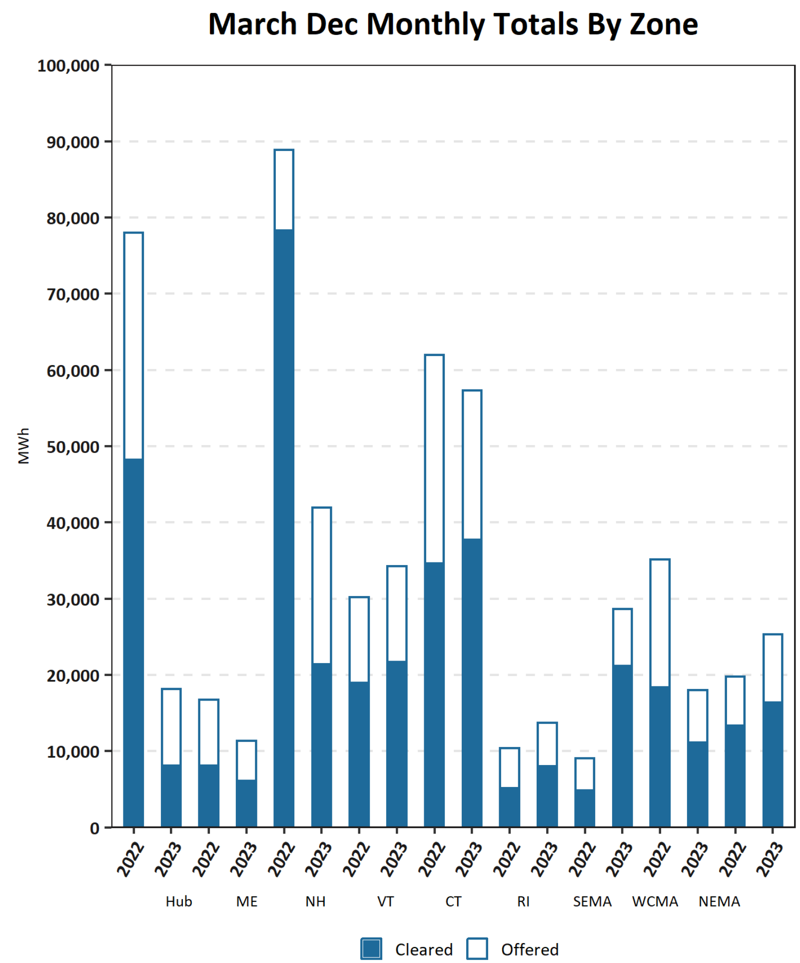
New England, NY, and PJM Average Forecasted Peak Hour RT Prices





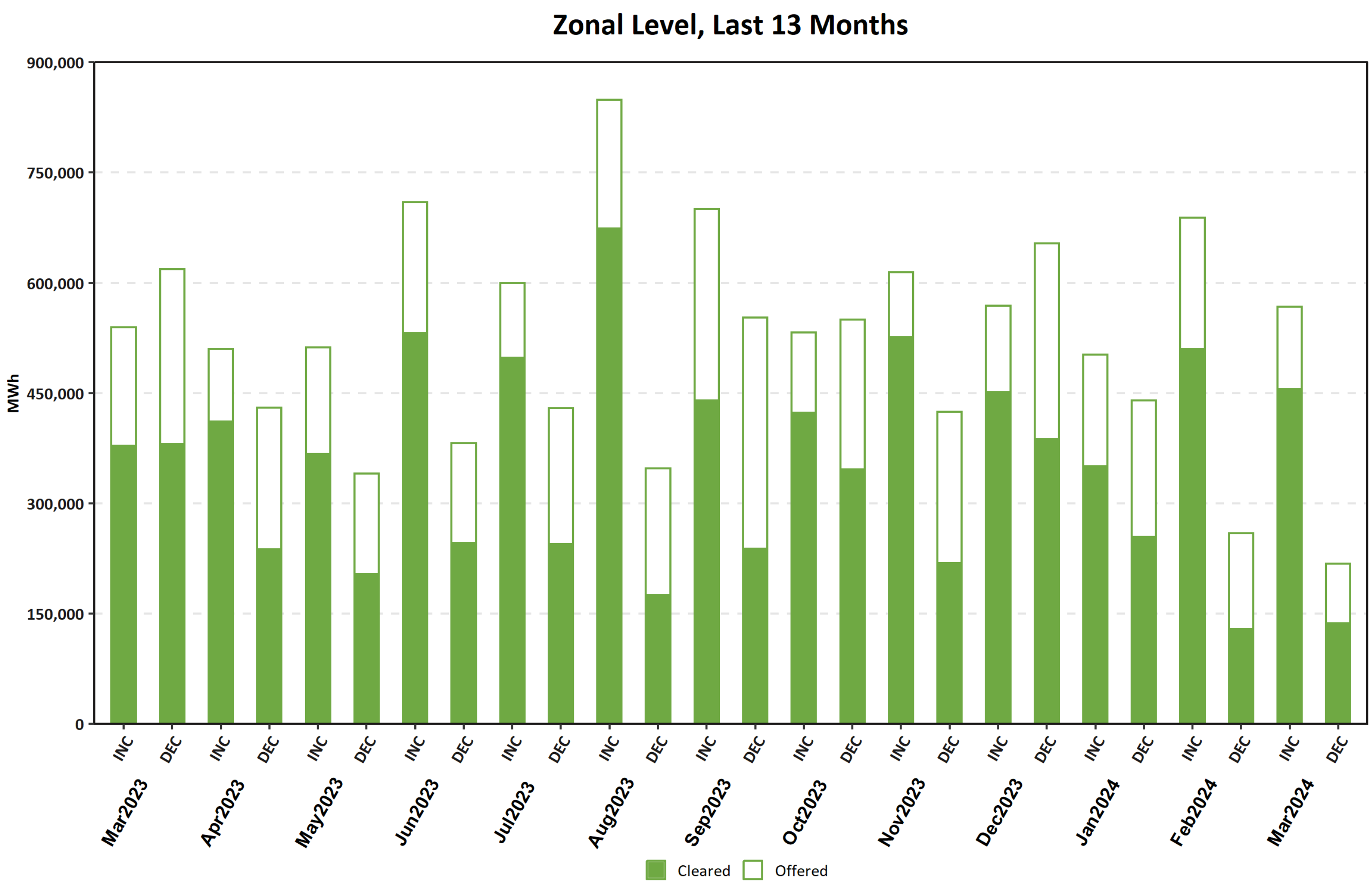
Zonal Increment Offers and Decrement Bid Amounts





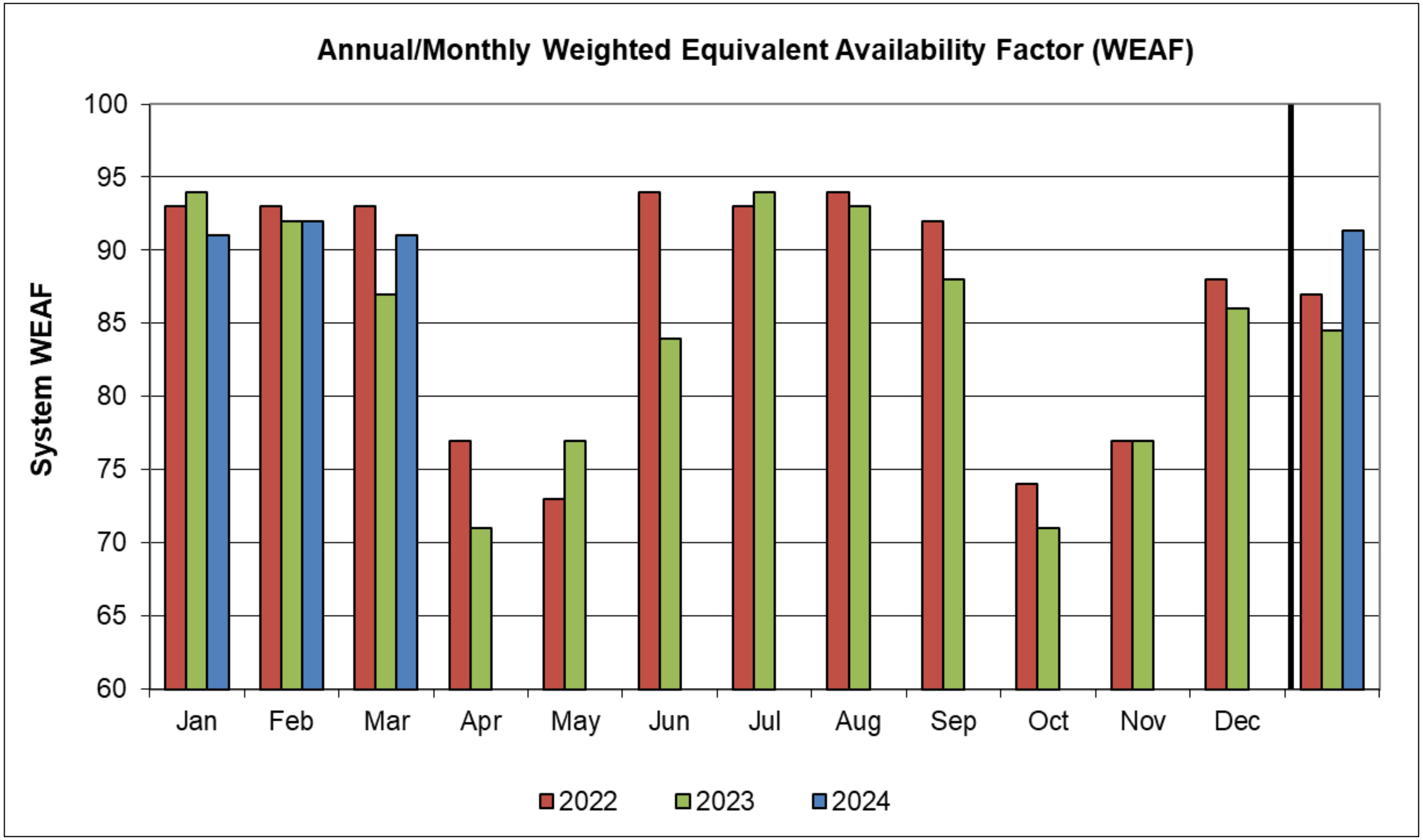
Includes nodal activity within the zone; excludes external nodes

Total Increment Offers and Decrement Bids



Includes nodal activity within the zone; excludes external nodes

System Unit Availability



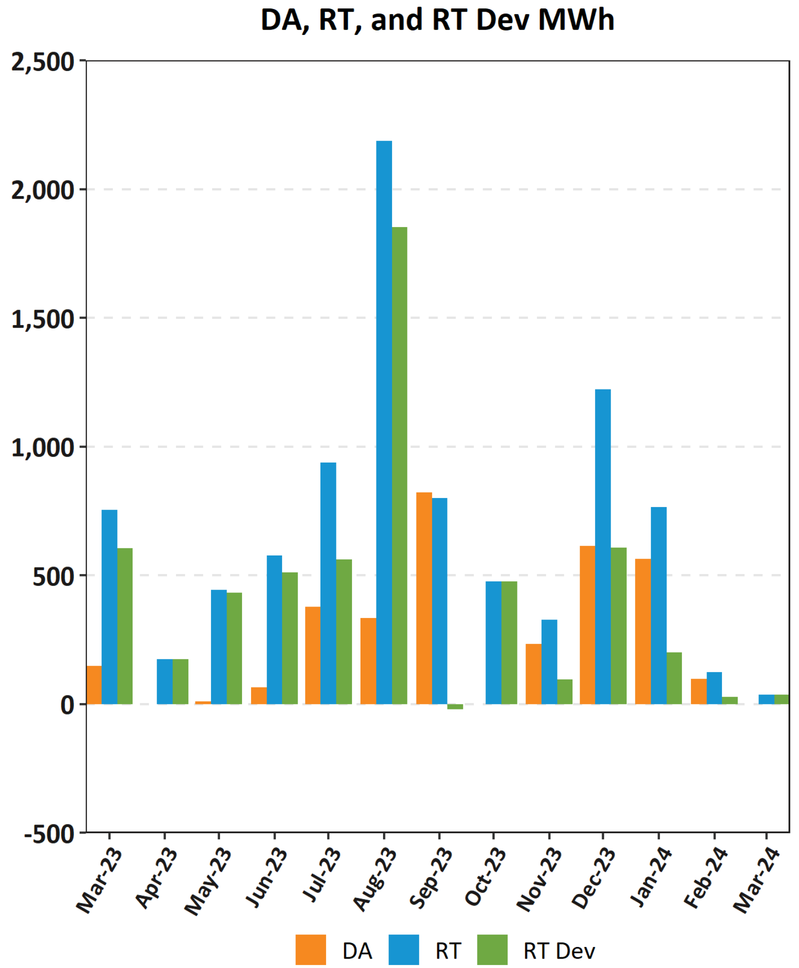
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2024	91	92	91										91
2023	94	92	87	71	77	84	94	93	88	71	77	86	85
2022	93	93	93	77	73	94	93	94	92	74	77	88	87

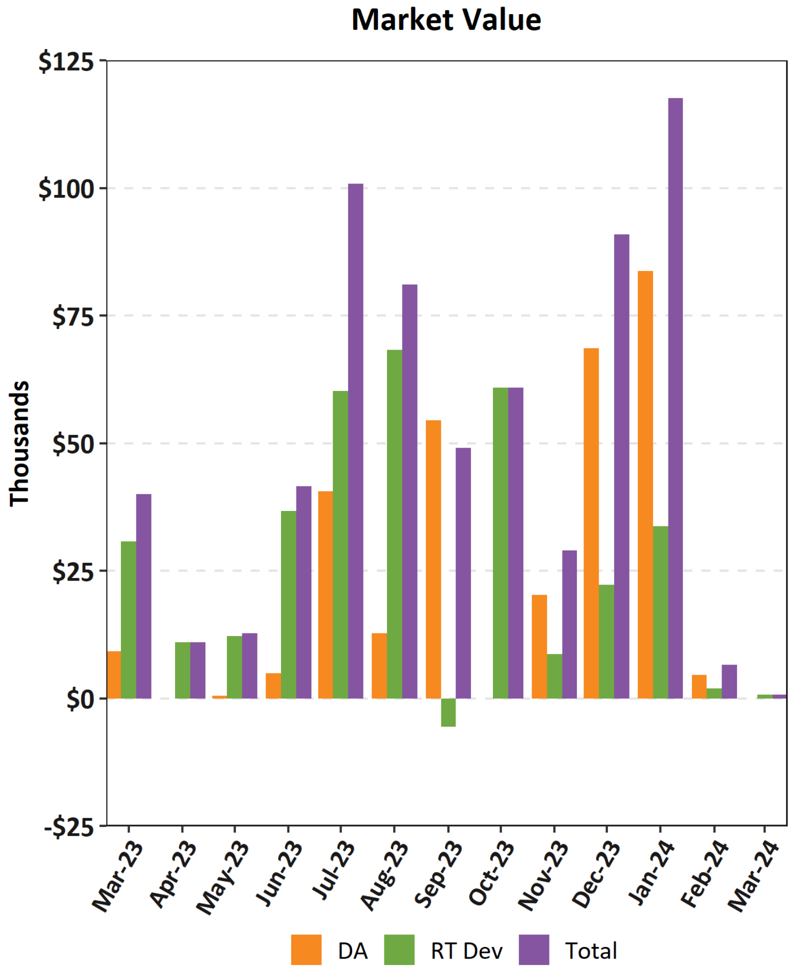
Data as of 3/25/24

BACK-UP DETAIL

DEMAND RESPONSE

Price Responsive Demand (PRD) Energy Market Activity by Month





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

NEW GENERATION

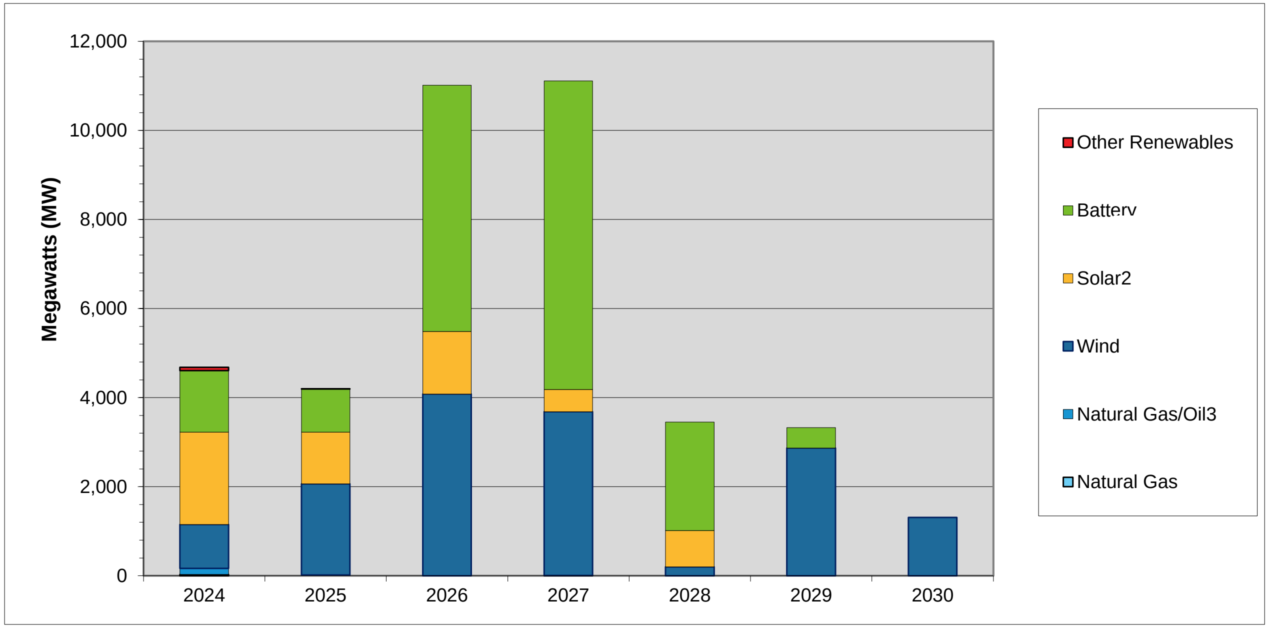
New Generation Update

Based on Queue as of 04/01/24

- Five projects totaling 1,319 MW were added to the interconnection queue since the last update
  - One solar, one battery and one wind project with in-service dates between 2026 and 2031
- In total, 406 generation projects are currently being tracked by the ISO, totaling approximately 42,760 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2024	2025	2026	2027	2028	2029	2030	Total MW	% of Total[1]
Other Renewables	72	2	0	0	0	0	0	74	0.2
Battery	1,384	965	5,532	6,927	2,437	454	0	17,699	45.3
Solar[2]	2,073	1,161	1,406	502	818	0	0	5,960	15.2
Wind	989	2,049	4,079	3,678	197	2,870	1,309	15,171	38.8
Natural Gas/Oil[3]	135	16	0	0	0	0	0	151	0.4
Natural Gas	26	0	0	4	0	0	0	30	0.1
Totals	4,679	4,193	11,017	11,111	3,452	3,324	1,309	39,085	100.0

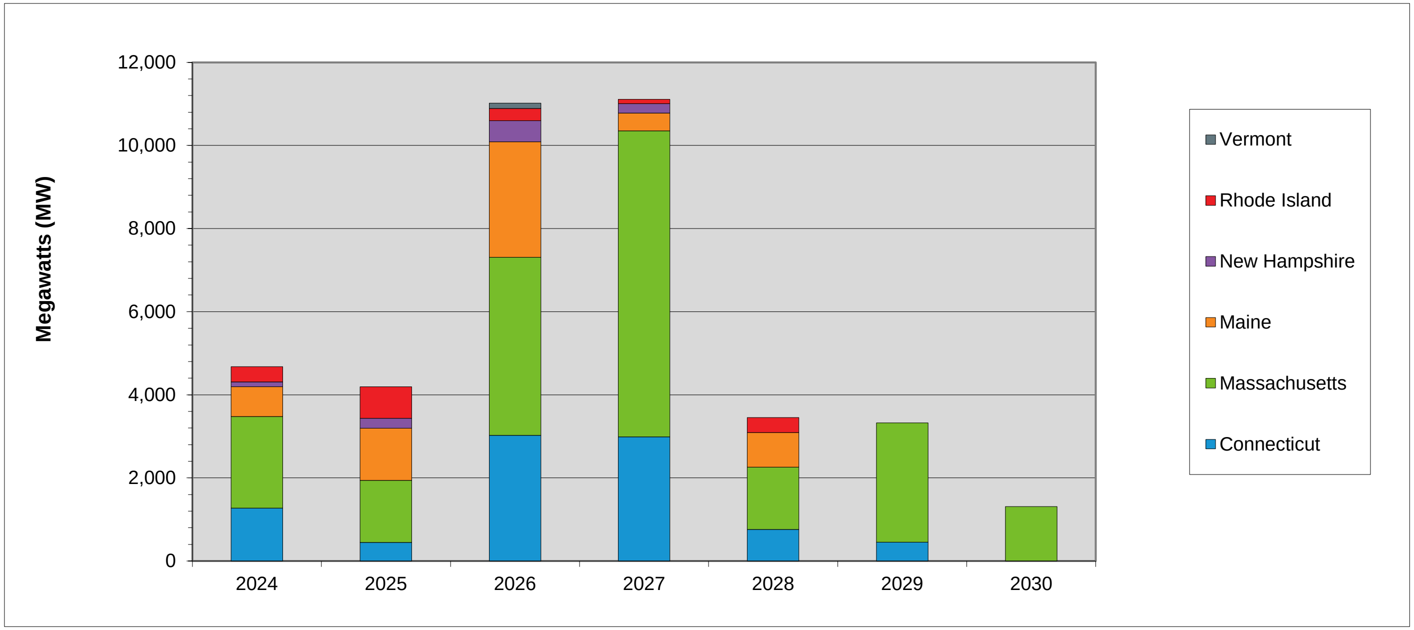
[1] Sum may not equal 100% due to rounding

[2] This category includes both solar-only, and co-located solar and battery projects

[3] The projects in this category are dual fuel, with either gas or oil as the primary fuel

Actual and Projected Annual Generator Capacity Additions

By State



	2024	2025	2026	2027	2028	2029	2030	Total MW	% of Total[1]
Vermont	0	0	128	0	0	0	0	128	0.3
Rhode Island	371	758	295	102	360	0	0	1,886	4.8
New Hampshire	114	239	504	226	0	0	0	1,083	2.8
Maine	720	1,256	2,779	433	832	0	0	6,020	15.4
Massachusetts	2,204	1,496	4,287	7,361	1,503	2,870	1,309	21,030	53.8
Connecticut	1,270	444	3,024	2,989	757	454	0	8,938	22.9
Totals	**4,679**	**4,193**	**11,017**	**11,111**	**3,452**	**3,324**	**1,309**	**39,085**	**100.0**

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

New Generation Projection

By Fuel Type

Unit Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	118	17,699	1	150	117	17,549
Fuel Cell	4	46	1	20	3	26
Hydro	1	28	1	28	0	0
Natural Gas	4	30	0	0	4	30
Natural Gas/Oil	3	151	1	62	2	89
Nuclear	0	0	0	0	0	0
Solar	248	5,960	15	343	233	5,617
Wind	28	18,846	2	926	26	17,920
Total	406	42,760	21	1,529	385	41,231

- Projects in the Natural Gas/Oil category may have either gas or oil as the primary fuel
- Green denotes projects with a high probability of going into service within the next 12 months
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	7	87	2	48	5	39
Intermediate	2	89	0	0	2	89
Peaker	369	23,738	17	555	352	23,183
Wind Turbine	28	18,846	2	926	26	17,920
Total	406	42,760	21	1,529	385	41,231

- Green denotes projects with a high probability of going into service within the next 12 months
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type and Fuel Type

Unit Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0	0	0	0	0
Battery Storage	118	17,699	0	0	0	0	118	17,699	0	0
Fuel Cell	4	46	4	46	0	0	0	0	0	0
Hydro	1	28	1	28	0	0	0	0	0	0
Natural Gas	4	30	2	13	0	0	2	17	0	0
Natural Gas/Oil	3	151	0	0	2	89	1	62	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	248	5,960	0	0	0	0	248	5,960	0	0
Wind	28	18,846	0	0	0	0	0	0	28	18,846
Total	406	42,760	7	87	2	89	369	23,738	28	18,846

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 14

Resource Type	Resource Type		FCA	ARA 1		ARA 2		ARA 3	
			CSO	CSO	Change	CSO	Change	CSO	Change
			MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*		592.043	688.07	96.027	659.671	-28.399	564.371	-95.3
	Passive Demand		3,327.071	3,327.932	0.861	3,315.207	-12.725	3,253.179	-62.028
Demand Total			**3,919.114**	**4,016.002**	**96.888**	**3,974.878**	**-41.124**	**3,817.550**	**-157.328**
Generator		*Non-Intermittent*	27,816.902	28,275.143	458.241	27,697.714	-577.429	27,684.252	-13.462
		Intermittent	1,160.916	1,128.446	-32.47	925.942	-202.504	893.444	-32.498
Generator Total			**28,977.818**	**29,403.589**	**425.771**	**28,623.656**	**-779.933**	**28,577.696**	**-45.96**
Import Total			**1,058.72**	**1,058.72**	**0**	**1,029.800**	**-28.92**	**958.380**	**-71.42**
Grand Total*			**33,955.652**	**34,478.311**	**522.661**	**33,628.334**	**-849.977**	**33,353.626**	**-274.708**
Net ICR (NICR)			**32,490**	**32,980**	**490**	**31,480**	**-1,500**	**31,690**	**210**

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2023-2027 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 15

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	677.673	673.401	-4.272	579.692	-93.709		
	Passive Demand	3,212.865	3,211.403	-1.462	3,134.652	-76.751		
Demand Total		**3,890.538**	**3,884.804**	**-5.734**	**3,714.344**	**-170.460**		
Generator	*Non-Intermittent*	28,154.203	27,714.778	-439.425	27,081.653	-633.125		
	Intermittent	1,089.265	1,073.794	-15.471	1,056.601	-17.193		
Generator Total		**29,243.468**	**28,788.572**	**-454.896**	**28,138.254**	**-650.318**		
Import Total		**1,487.059**	**1297.132**	**-189.927**	**1,249.545**	**-47.587**		
Grand Total*		**34,621.065**	**33,970.508**	**-650.557**	**33,102.143**	**-868.365**		
Net ICR (NICR)		**33,270**	**31,775**	**-1,495**	**31,545**	**-230**		

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2023-2027 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 16

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	765.35	589.882	-175.468				
Demand	*Passive Demand*	2,557.256	2,579.120	21.864				
Demand Total		**3,322.606**	**3,169.002**	**-153.604**				
Generator	*Non-Intermittent*	26,805.003	26,643.379	-161.624				
Generator	*Intermittent*	1,178.933	1,146.783	-32.15				
Generator Total		**27,983.936**	**27,790.162**	**-193.774**				
Import Total		**1,503.842**	**1,247.601**	**-256.241**				
Grand Total*		**32,810.384**	**32,206.765**	**-603.619**				
Net ICR (NICR)		**31,645**	**30,585**	**-1,060**				

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2023-2027 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 17

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	622.854						
	Passive Demand	2,316.815						
Demand Total		**2,939.669**						
Generator	*Non-Intermittent*	26,507.420						
	Intermittent	1,356.084						
Generator Total		**27,863.504**						
Import Total		**566.998**						
Grand Total*		**31,370.171**						
Net ICR (NICR)		**30,305**						

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2023-2027 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 18

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	543.580						
	Passive Demand	2,070.498						
Demand Total		**2,614.078**						
Generator	*Non-Intermittent*	27,026.635						
	Intermittent	1,450.872						
Generator Total		**28,477.507**						
Import Total		**464.835**						
Grand Total*		**31,556.420**						
Net ICR (NICR)		**30,550**						

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

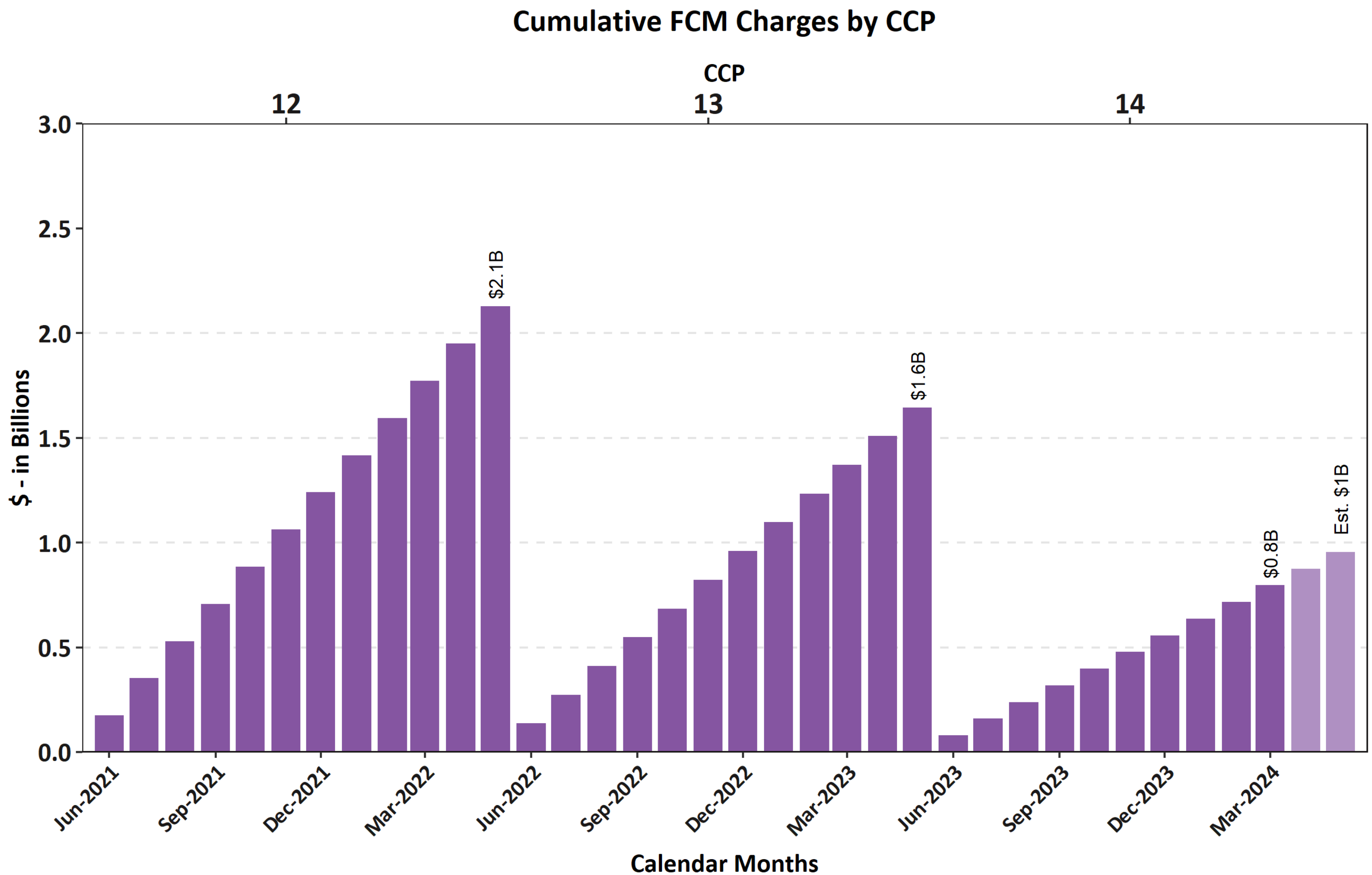
Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2023-2027 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/Passive	Existing	New	Grand Total
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	**3,085.734**	**514.072**	**3,599.806**
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	**3,386.703**	**653.541**	**4,040.244**
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	**3,596.056**	**323.058**	**3,919.114**
2024-25	Active	674.153	3.520	677.673
	Passive	3,046.064	166.801	3,212.865
	Grand Total	**3,720.217**	**170.321**	**3,890.538**
2025-26	Active	664.01	101.34	765.35
	Passive	2,428.638	128.618	2557.256
	Grand Total	**3,092.648**	**229.958**	**3,322.606**
2026-27	Active	615.369	7.485	622.854
	Passive	2,194.172	122.643	2,316.815
	Grand Total	**2,809.541**	**130.128**	**2,939.669**
2027-28	Active	543.58	0.0	543.58
	Passive	1,965.515	104.983	2070.498
	Grand Total	**2,509.095**	**104.983**	**2,614.498**

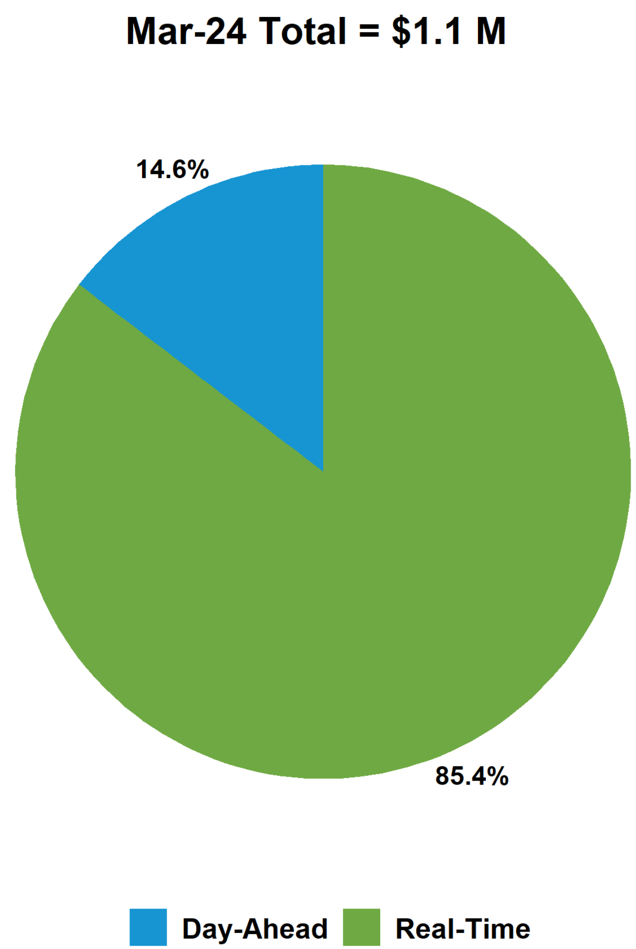
Forward Capacity Market Auctions

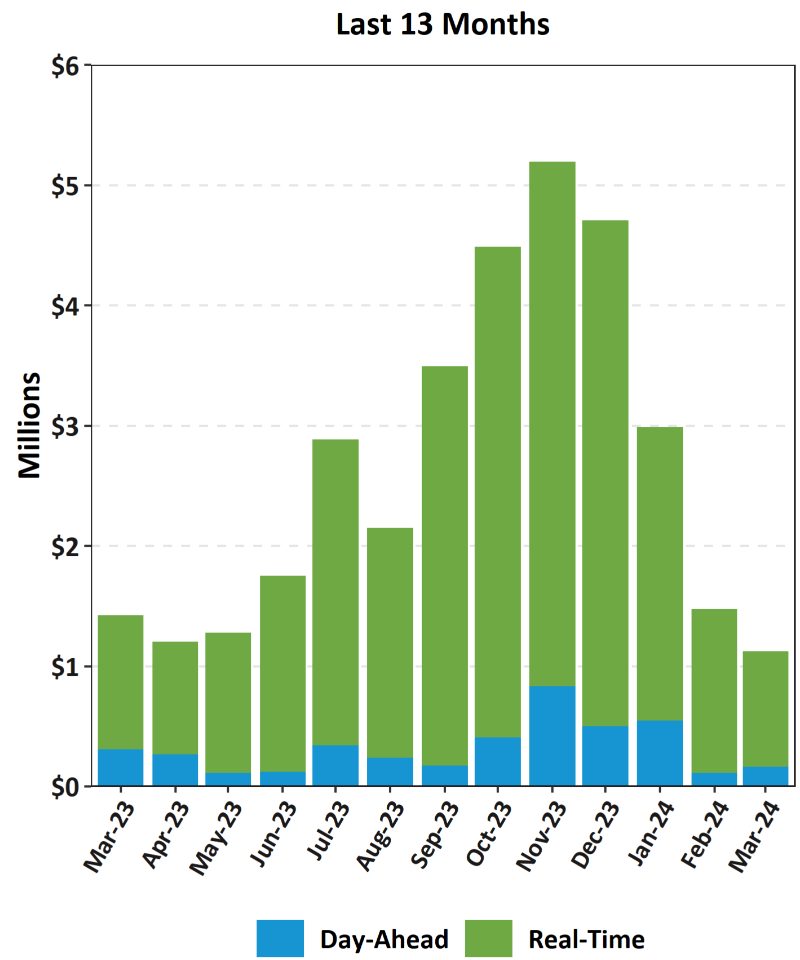


The items in the graph shaded in a lighter color represent the forecast for future months in the Capacity Commitment Period (CCP)

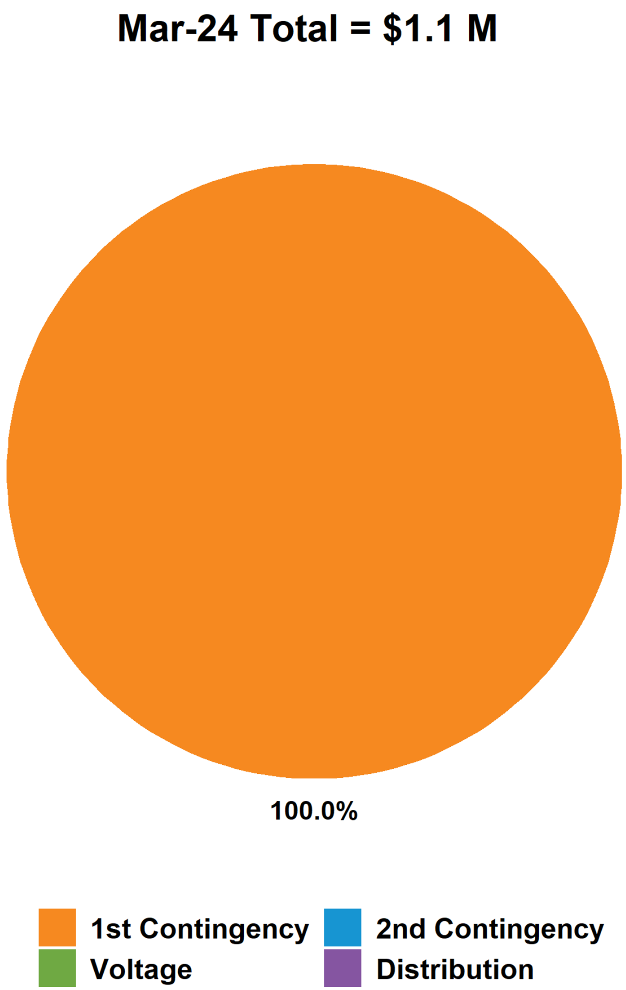
NET COMMITMENT PERIOD COMPENSATION

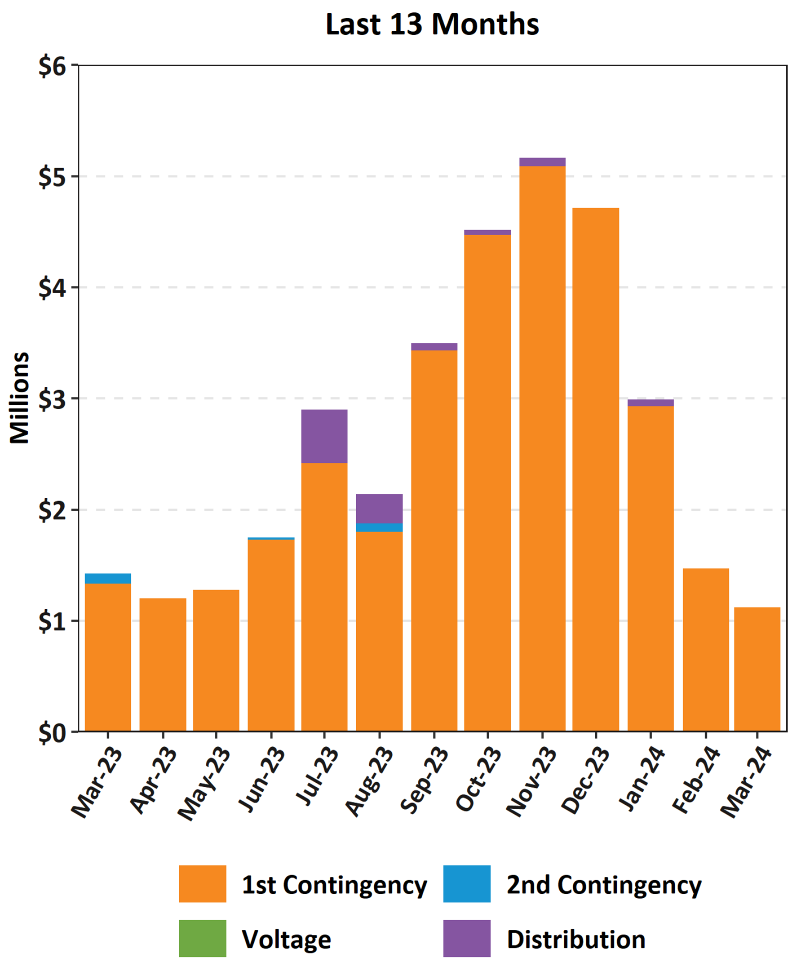
DA and RT NCPC Charges



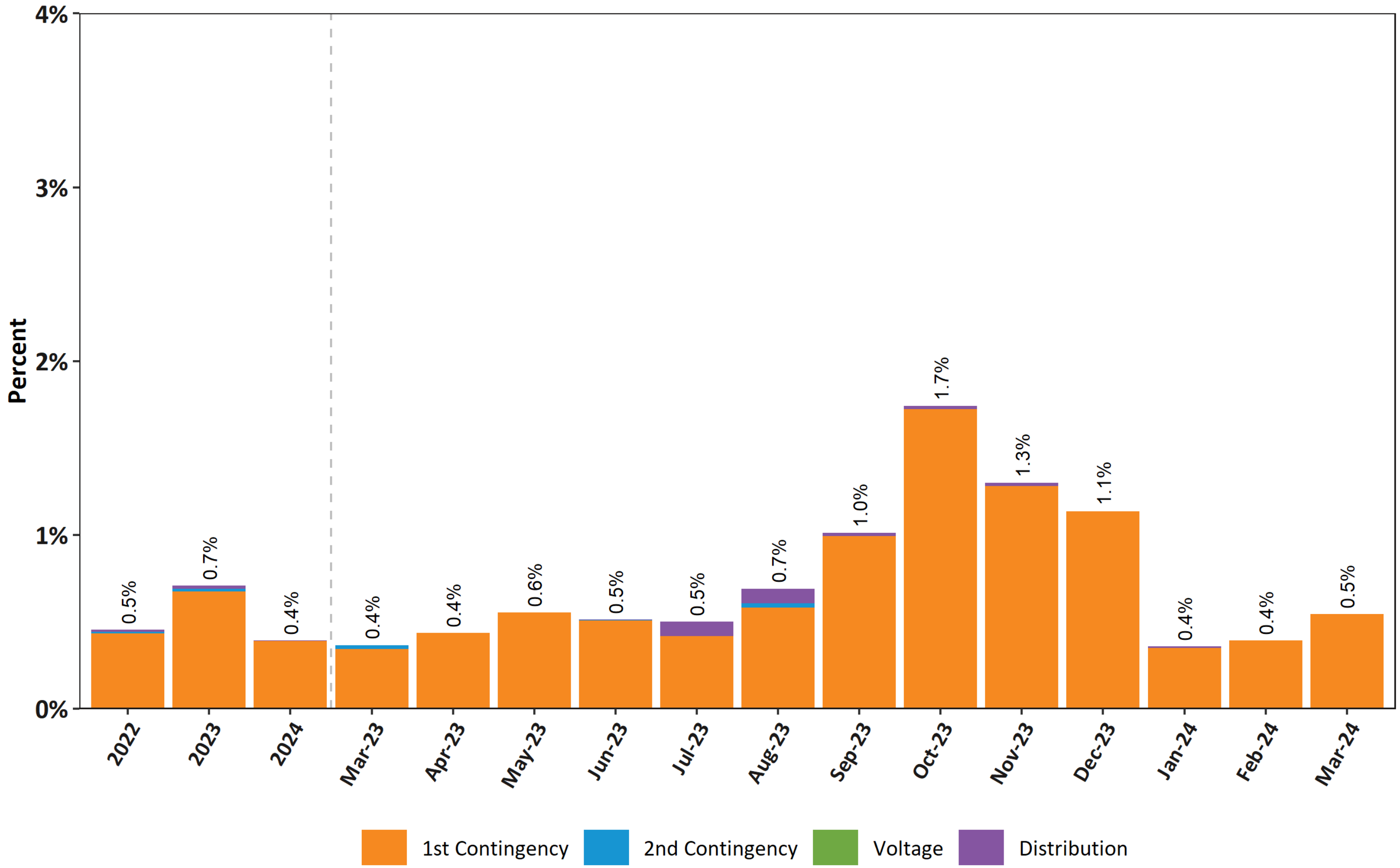


NCPC Charges by Type

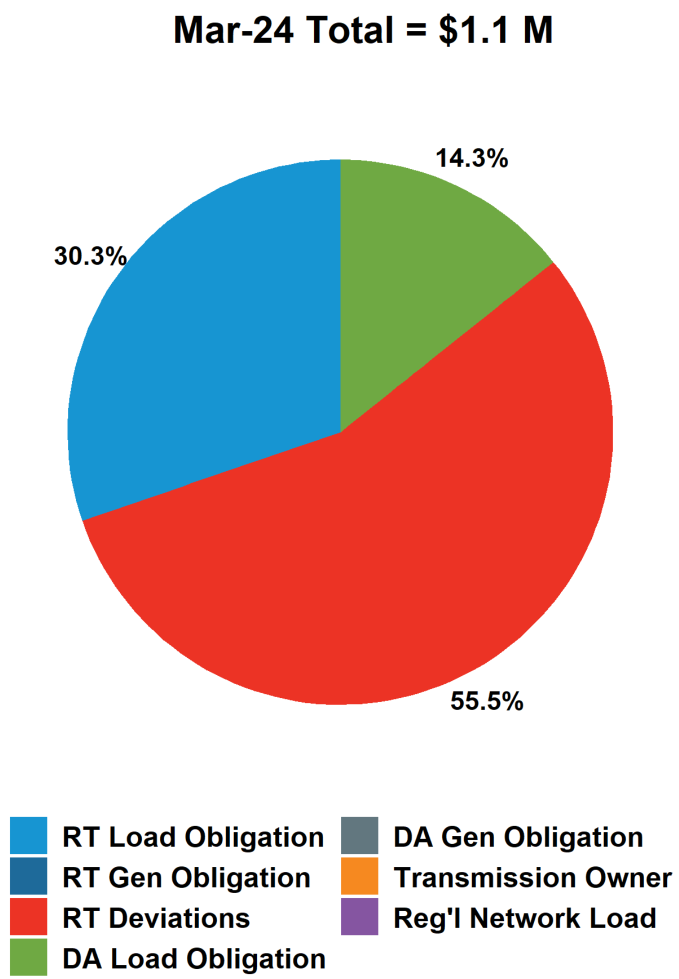


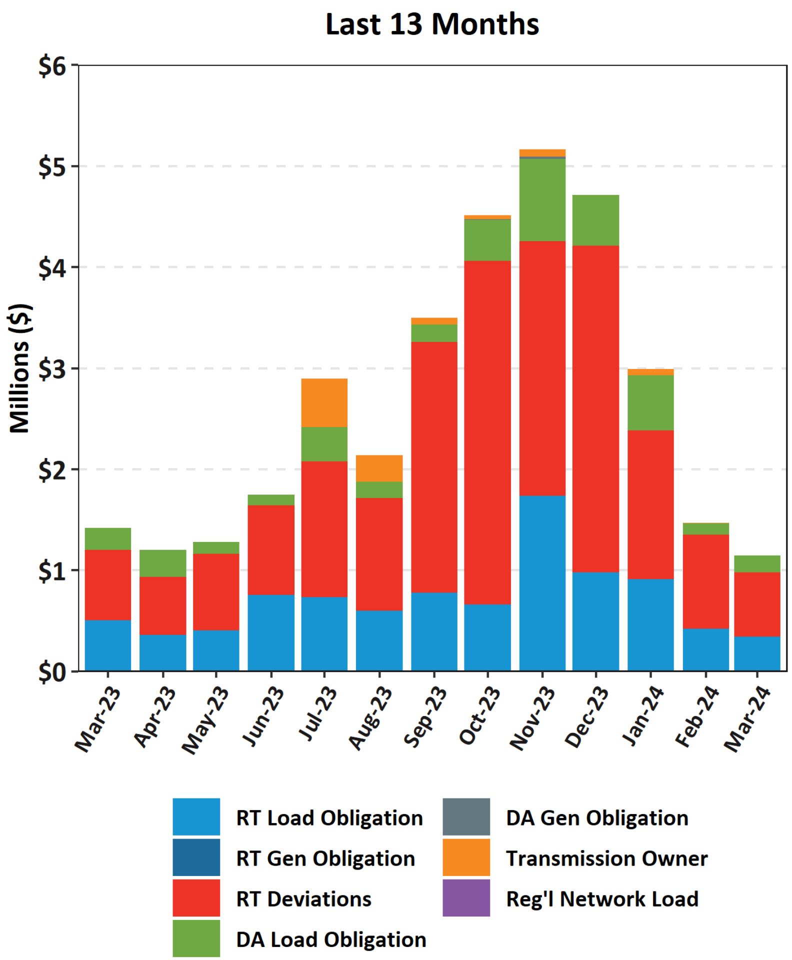


NCPC Charges by Type as Percent of Energy Market Value

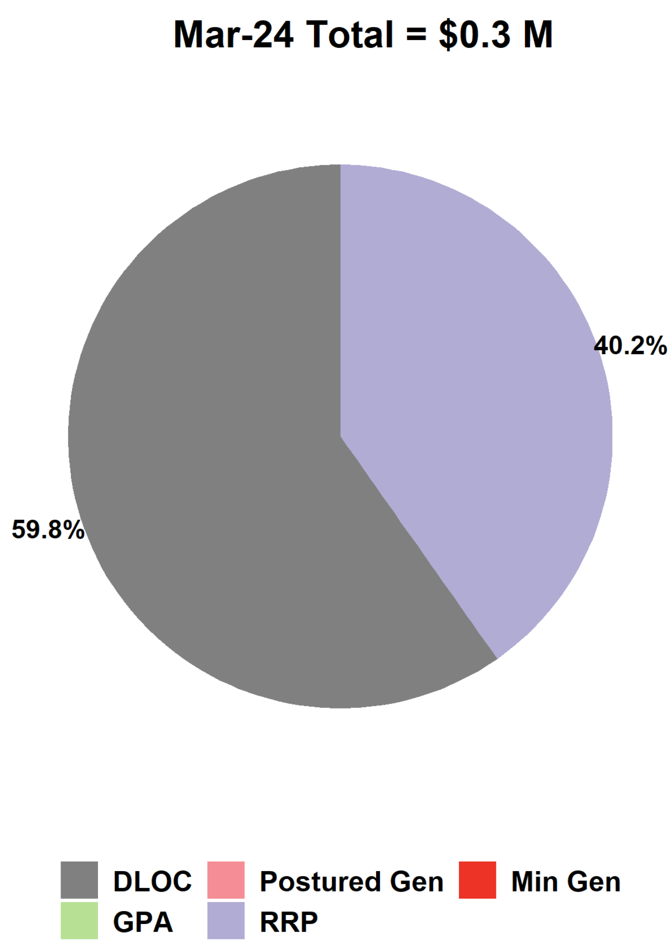


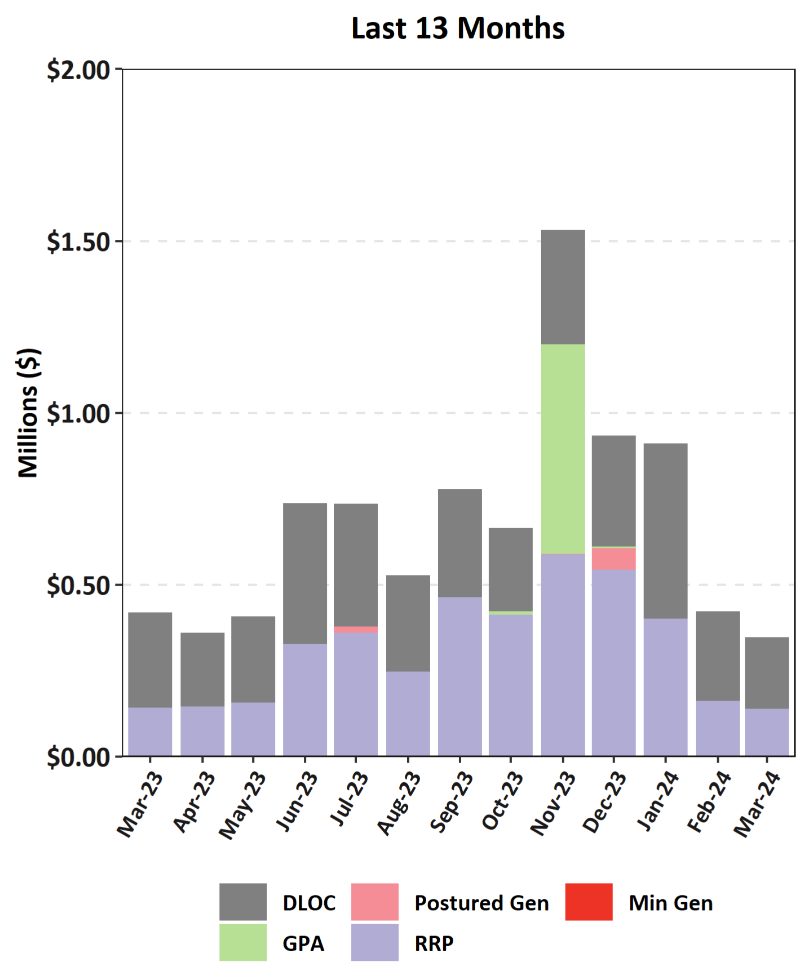
NCPC Charge Allocations





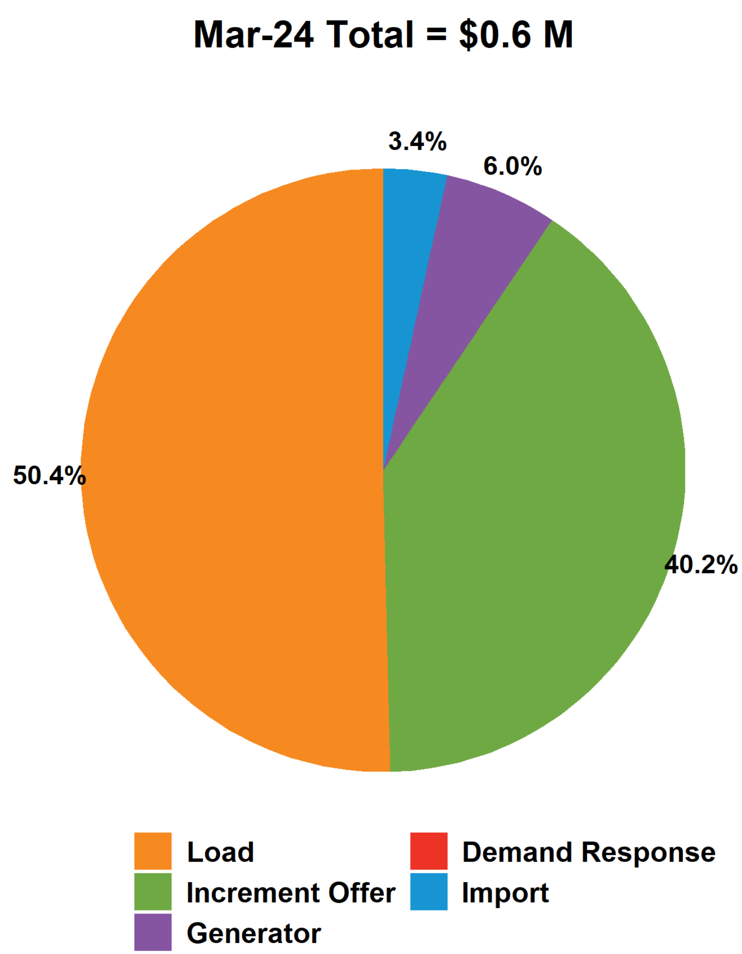
RT First Contingency NCPC paid to units and allocated to RTLO and/or RTGO

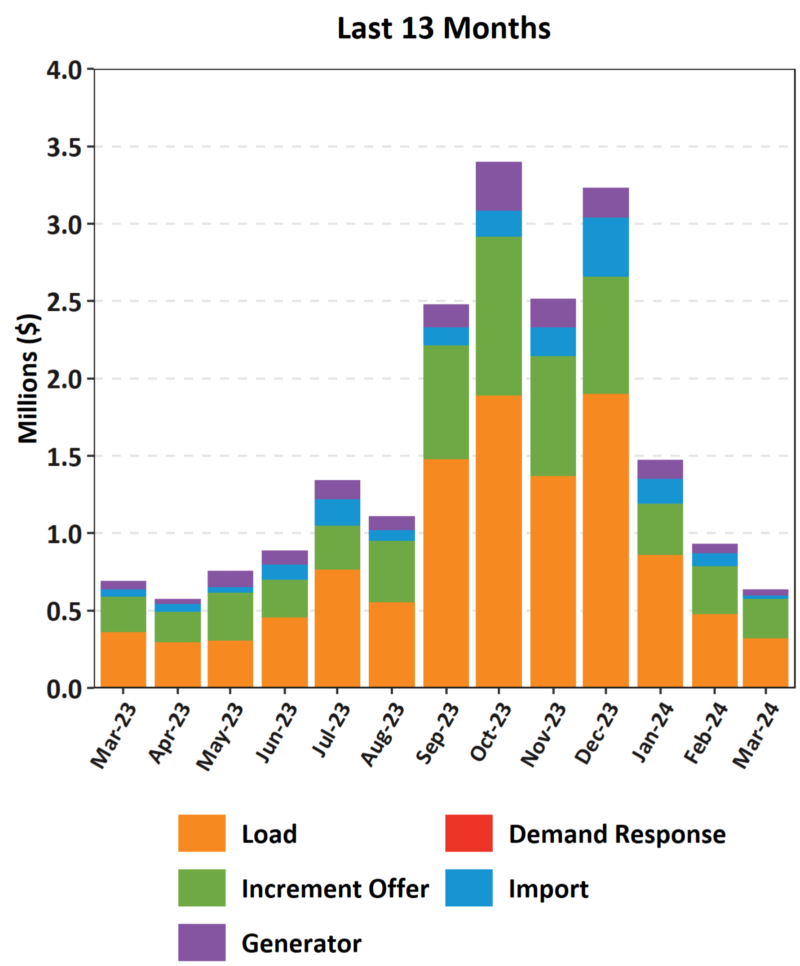




Note: The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report. The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.

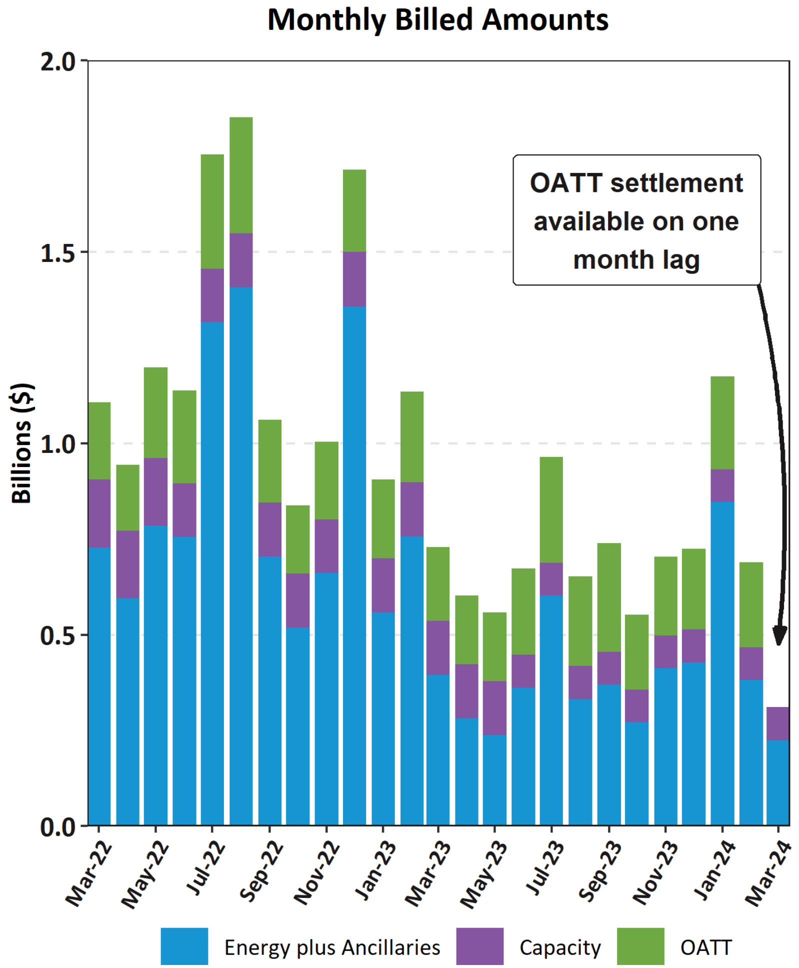
RT First Contingency Charges by Deviation Type

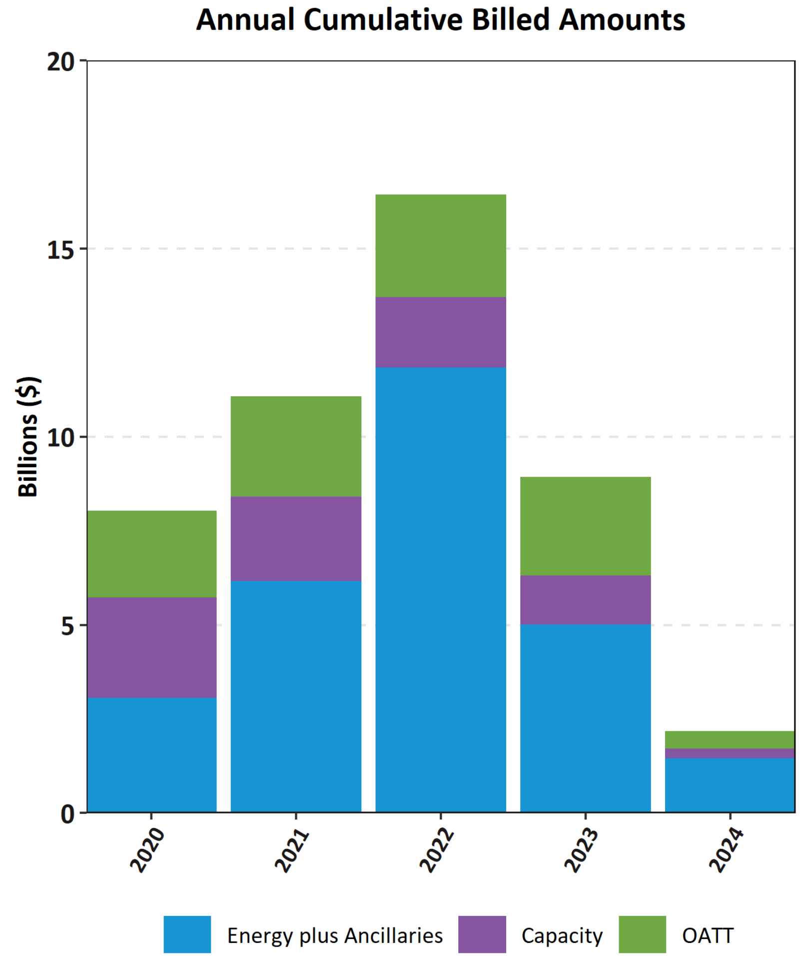




ISO BILLINGS

Total ISO Billings





Ancillaries = Reserves, Regulation, NCPC, minus Marginal Loss Revenue Fund. OATT = RNS, Through and Out, Schedule 9

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- April 18 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - MEPCO Sections 396 and 3001 End of Life Strategy – Avangrid
    - E-205E and E-205W 230kV Lines Asset Condition Refurbishment – National Grid
    - 339 and 349 345 kV Lines Asset Condition Project – National Grid
    - CT Lines 387 & 3252 Asset Condition Replacements & OPGW Installation – Eversource
    - Hurd State Park Corridor Rebuild Follow-up - Eversource
  - 2050 Transmission Study: Further Analysis on Offshore Wind POI Relocation
  - Economic Planning for the Clean Energy Transition (EPCET) – Discussion of Imports for Market Efficiency Needs Scenario (MENS)
  - Update on Legacy Distributed Energy Resource Assumptions in Needs Assessments
  - 2024 Final Draft Energy and Seasonal Peak Forecasts

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

2050 Transmission Study

- Final version of the study, technical appendix, responses to stakeholder feedback, and study fact sheet were published on 2/14/24
- Additional analysis to address stakeholder comments on offshore wind points of interconnection was presented to PAC on 3/20/24, and will continue through Q2 and Q3 2024

Economic Studies: EPCET

- Economic Planning for the Clean Energy Transition (EPCET) Pilot Study
  - An effort to review all assumptions in economic planning and perform a test study consistent with the changes to the Tariff
  - PAC presentations began in April 2022. To date, the ISO has presented results from the Benchmark, Market Efficiency Need, and Policy scenarios and is now in the process of finalizing the study
    - A report will be issued in Q2 2024

Economic Studies: 2024 Study

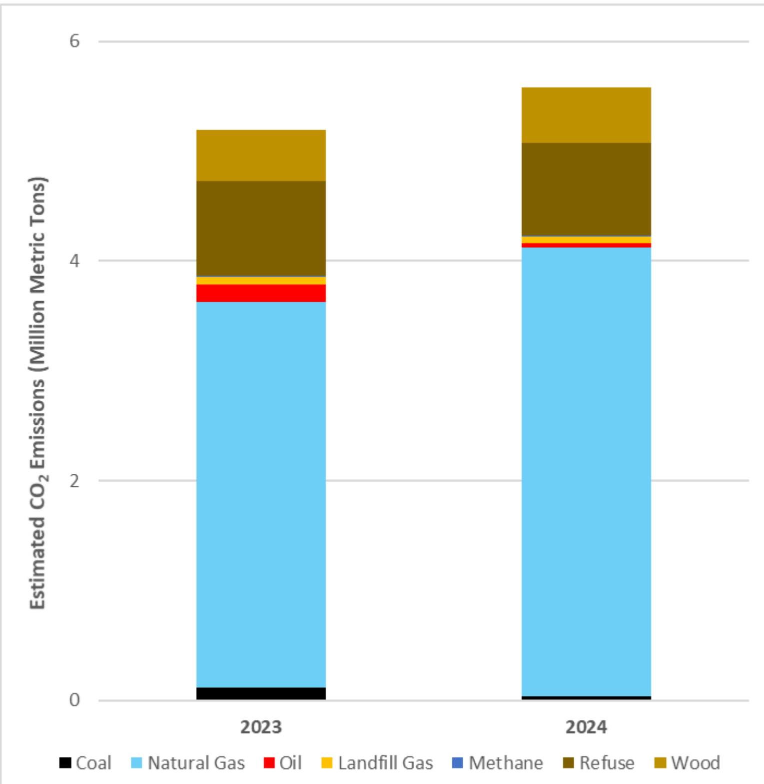
- 2024 Economic Study
  - First use of new Tariff language
    - Study was initiated at the January PAC meeting
  - Study will begin with Benchmark Scenario in Q1-Q2 2024, followed by Policy Scenario in Q3-Q4 2024
  - A Stakeholder-Requested Scenario can be submitted in Q2 2024 for consideration
  - Market Efficiency Needs Scenario will be studied in early 2025

ISO-NE Tie Benefits Evaluation

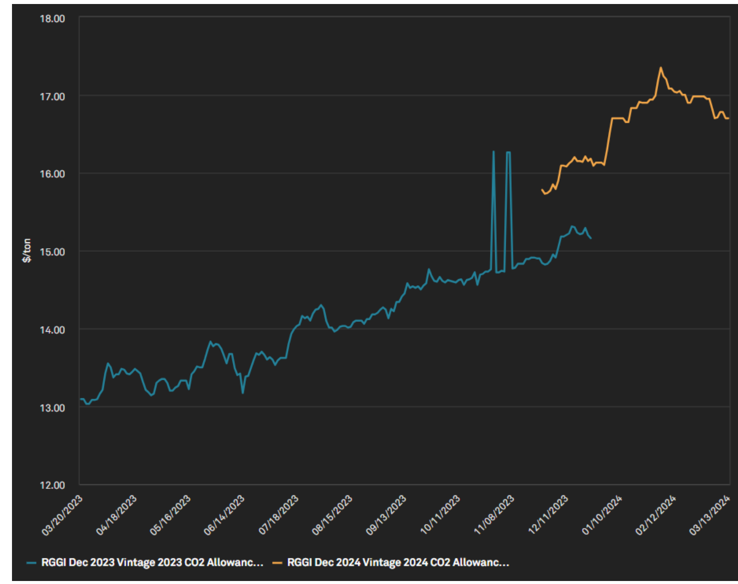
- The ISO started the tie benefits evaluation at the October 19 PSPC meeting. The third presentation was given at a special March 15 PSPC meeting and topics included:
  - Responses to stakeholder questions from January
  - A deeper dive into the MARS model methodology
  - Review of flows within MARS replications during tie benefits analyses
- The evaluation will extend through Q4 of 2024
  - Additional PSPC time will be dedicated for this topic
- The next PSPC meeting is scheduled for June 21
  - As a result of the FERC-approved FCA 19 delay, we will be altering this year’s PSPC schedule and will be canceling the May PSPC meeting
  - The ISO will review the 2024 PSPC cycle in greater detail at the May RC meeting

New England Power System Carbon Emissions

2023 vs. 2024 New England Power System Estimated Carbon Dioxide (CO_2) Emissions



RGGI Allowance Prices



- 3/13/24: RGGI allowance spot price - $16.70
- 63rd RGGI Auction Results:
  - 24,272,157 CO_2 allowances sold at clearing price $16.00
  - $388.4 million generated
  - 8.42 million Cost Containment Reserve (CCR) allowances sold after clearing price exceeded CCR threshold price $15.92
  - No more CCR allowances for the three remaining 2024 auctions

Data as of 3/10/24

RGGI – Regional Greenhouse Gas Initiative

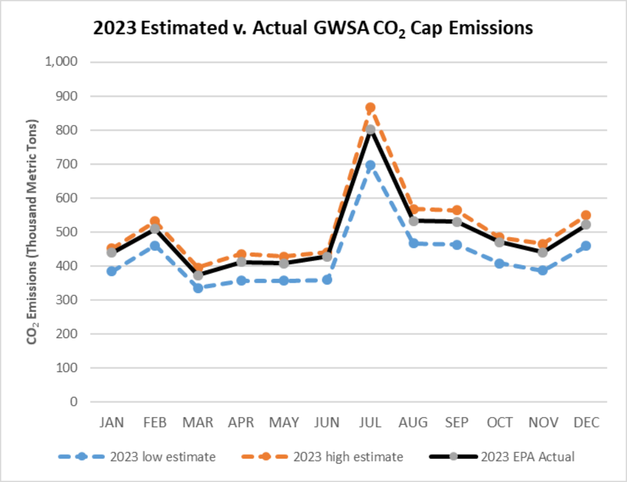
Massachusetts CO_2 Generator Emissions Cap

2024 Estimated Emissions Under CO_2 Cap

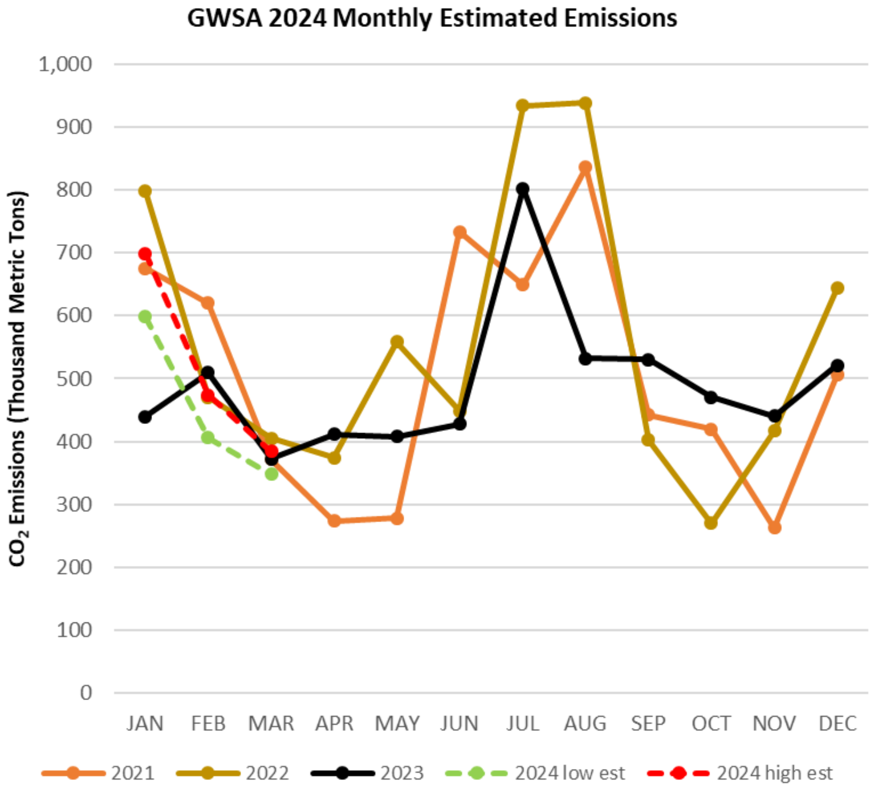
- As of 3/19/24, March estimated GWSA CO_2 emissions range between **347,712** and **383,909** metric tons
  - Year-to-date 2024 estimated emissions range between **17.8%** and **20.4%** of the 2024 cap of 7.61 MMT

2023 Estimated Emissions Under CO_2 Cap

- According to the EPA CAMPD, 2023 total GWSA CO_2 emissions were **5.86 MMT**, or **75%** of the 2023 cap of 7.84 MMT



2021-2024 Estimated Monthly Emissions (Thousand Metric Tons)



GWSA – Global Warming Solutions Act
MMT – Million Metric Tons

Source: ISO-NE (estimated emissions)

RSP Project Stage Descriptions

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

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

Greater Boston Projects

Status as of 3/25/2024

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

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

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

Greater Boston Projects, cont.

Status as of 3/25/2024

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1330	Separate X-24 and E-157W DCT	Dec-18	4
1363	Separate Q-169 and F-158N DCT	Dec-15	4
1637, 1640	Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
1516	Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-20	4
965	Install third 115 kV line from West Walpole to Holbrook	Sep-20	4
1558	Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
1199	Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	4
1335	Install a new 115 kV line from Sudbury to Hudson	Mar-25	3

Greater Boston Projects, cont.

Status as of 3/25/2024

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

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

Greater Boston Projects, cont.

Status as of 3/25/2024

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1356	Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	Apr-24	3
1357	Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	May-19	4
1518	Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	4
1519	Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 3/25/2024

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

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

SEMA/RI Reliability Projects

Status as of 3/25/2024

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

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

SEMA/RI Reliability Projects, cont.

Status as of 3/25/2024

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Mar-22	4
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	Mar-27	2
1721	Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	Aug-23	4
1722	Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation	Dec-25	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

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

SEMA/RI Reliability Projects, cont.

Status as of 3/25/2024

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1725	Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	May-24	3
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	4
1727	Retire the Barnstable SPS	Nov-21	4
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Aug-23	4
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Aug-23	4
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-25	2

SEMA/RI Reliability Projects, cont.

Status as of 3/25/2024

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1731	Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	4
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Dec-25	3
1733	Separate the 325/344 DCT lines from West Medway to West Walpole substations	Cancelled**	N/A
1734	Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
1736	Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
1737	Replace disconnect switches on 323 line at West Medway substation and replace 8 line structures	Aug-20	4

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

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

SEMA/RI Reliability Projects, cont.

Status as of 3/25/2024

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

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

Eastern CT Reliability Projects

Status as of 3/25/2024

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1815	Reconductor the L190-4 and L190-5 line sections	Dec-24	3
1850	Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Dec-22	4
1851	Upgrade Card 115 kV to BPS standards	Dec-22	4
1852	Install one 115 kV circuit breaker in series with Card substation 4T	Feb-23	4
1853	Convert Gales Ferry substation from 69 kV to 115 kV	Nov-23	4
1854	Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Jun-23	4

Eastern CT Reliability Projects, cont.

Status as of 3/25/2024

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1855	Re-terminate the 100 Line at Montville station and associated work. Energize the 100 Line at 115 kV	Jun-23	4
1856	Rebuild 400-1 Line section to allow operation at 115 kV (Tunnel to Ledyard Jct.)	Feb-23	4
1857	Add one 115 kV circuit breaker and re-terminate the 400-1 line section into Tunnel substation. Energize 400 Line at 115 kV	Feb-23	4
1858	Rebuild 400-2 Line section to allow operation at 115 kV (Ledyard Jct. to Border Bus with CMEEC)	Sept-22	4
1859	Rebuild the 400-3 Line Section to allow operation at 115 kV (Gales Ferry to Ledyard Jct.)	Feb-23	4
1860	Install a 25.2 MVAR 115 kV capacitor and one capacitor breaker at Killingly	Dec-21	4

Eastern CT Reliability Projects, cont.

Status as of 3/25/2024

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1861	Install one 345 kV series breaker with the Montville 1T	Nov-21	4
1862	Install a +55/-29 MVAR synchronous condenser with two 115 kV breakers at Shunock	Dec-23	4
1863	Install a 1% series reactor with bypass switch at Mystic, CT on the 1465 Line	Mar-22	4
1864	Convert the 400-2 Line Section to 115 kV (Border Bus to Buddington)	Feb-23	4
1904	Convert 69 kV equipment at Buddington to 115 kV to facilitate the conversion of the 400-2 line to 115 kV	Dec-23	4

New Hampshire Solution Projects

Status as of 3/25/2024

Project Benefit: Addresses system needs in the New Hampshire area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1878	Install a +55/-32.2 MVAR synchronous condenser at N. Keene 115 kV Substation with a 115 kV breaker	Sep-24	3
1879	Install a +55/-32.2 MVAR synchronous condenser at Huckins Hill 115 kV Substation with a 115 kV breaker	May-24	3
1880	Install a +127/-50 MVAR synchronous condenser at Amherst 345 kV Substation with two 345 kV breakers	Sep-24	3
1881	Install two 50 MVAR capacitors on Line 363 near Seabrook Station with three 345 kV breakers	Oct-23	4

Upper Maine Solution Projects

Status as of 3/25/2024

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1882	Rebuild 21.7 miles of the existing 115 kV line Section 80 Highland-Coopers Mills 115 kV line	Dec-24	3
1883	Convert the Highland 115 kV substation to an eight breaker, breaker-and-a-half configuration with a bus connected 115/34.5 kV transformer	Jul-28	1
1884	Install a 15 MVAR capacitor at Belfast 115 kV substation	Jul-28	1
1885	Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation	Jul-28	1
1886	Install +50/-25 MVAR synchronous condenser at Boggy Brook 115 kV substation, and install a new 115 kV breaker to separate Line 67 from the proposed solution elements	Jun-24	3

Upper Maine Solution Projects, cont.

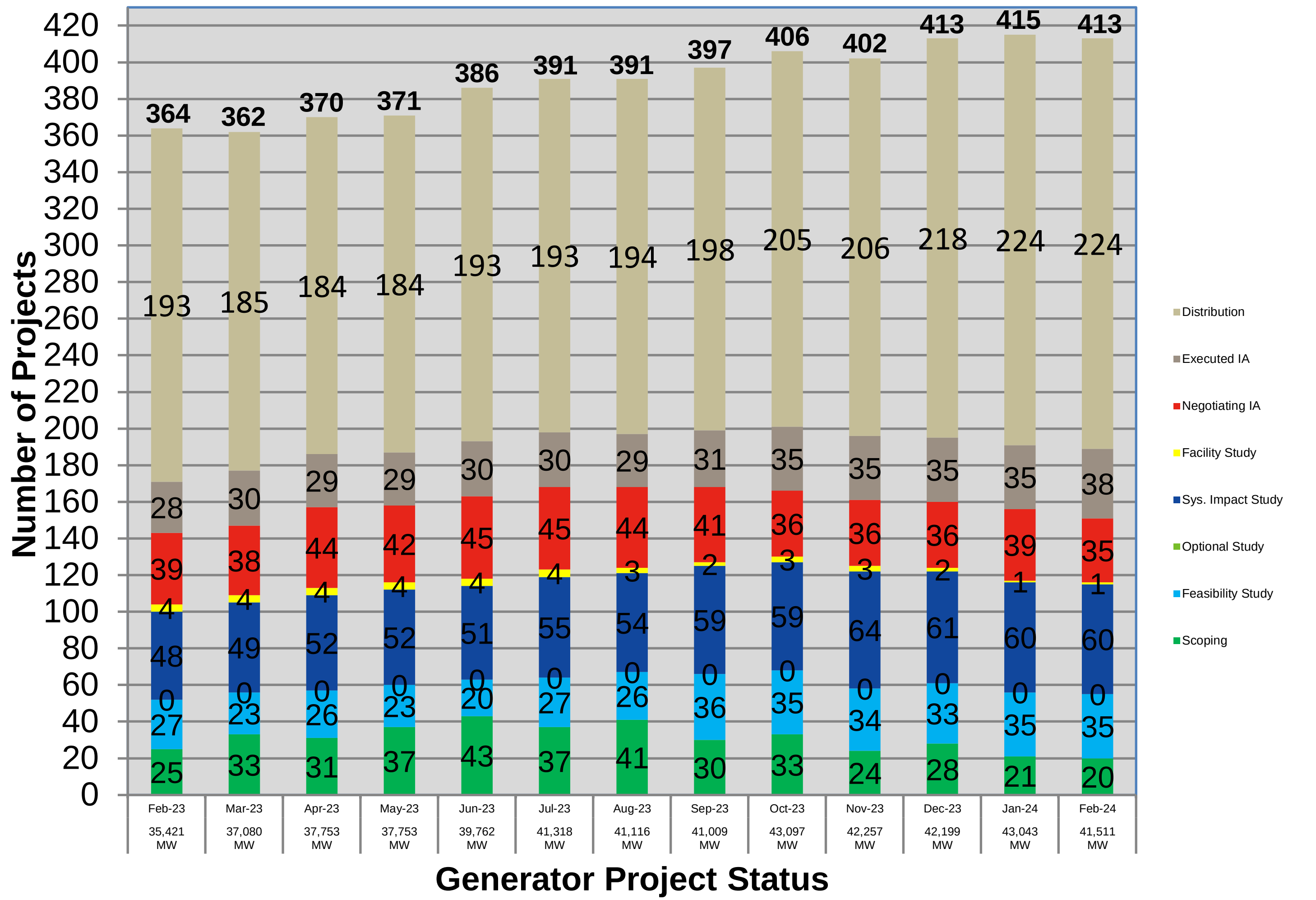
Status as of 3/25/2024

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1887	Install 25 MVAR reactor at Boggy Brook 115 kV substation	Jun-24	3
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Apr-24	3
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Cancelled *	N/A
1914	Install a new 80 MVAR reactor, reconfigure the existing two reactors at the 345 kV Orrington substation	Jun-25	2

* Cancelled per the Upper Maine Solutions Study Addendum that was published on January 11, 2024

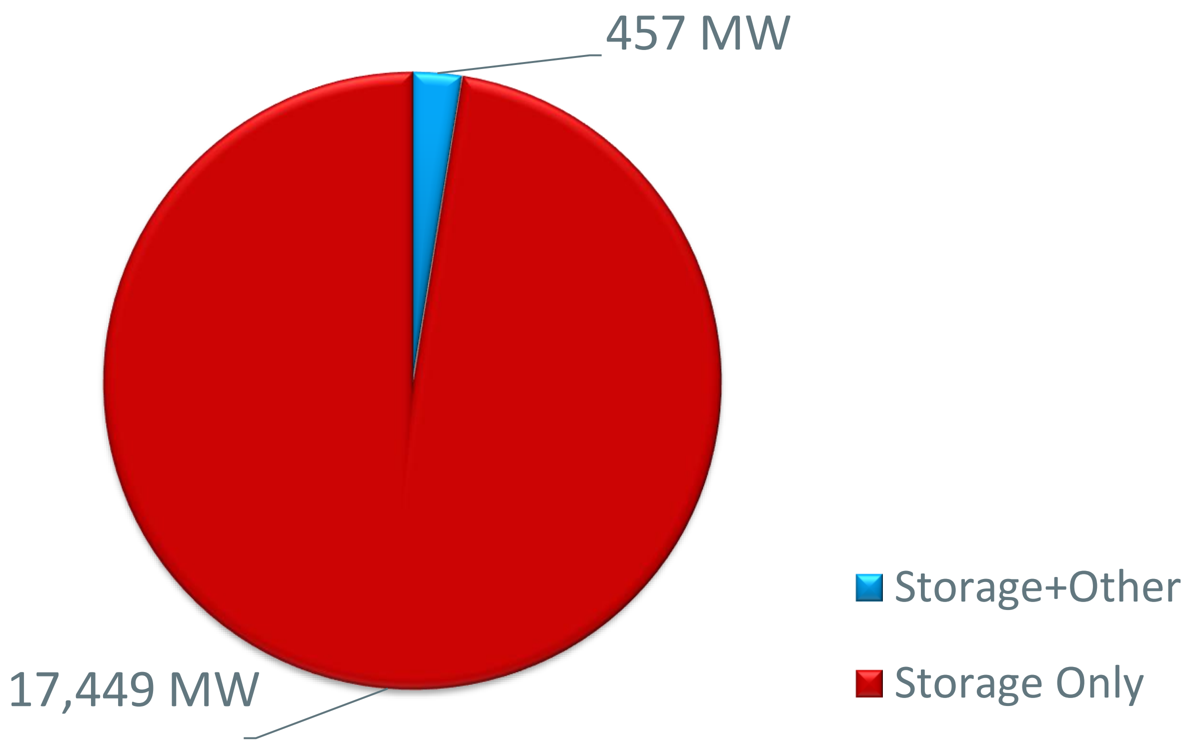
Status of Tariff Studies as of March 1, 2024



7 ETUs in Scoping, 4 in FS, 2 in SIS, 0 in OIS, 0 in FAC, 1 Negotiating IA, and 4 with Executed IA
Transmission Service Requests needing study: 1 in SIS
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of March 1, 2024)

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



OPERABLE CAPACITY ANALYSIS

Spring 2024 Analysis

Spring 2024 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May. - 2024[2] CSO (MW)	May. - 2024[2] SCC (MW)
Operable Capacity MW [1]	28,244	31,735
Active Demand Capacity Resource (+) [5]	512	346
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	894	894
Non Commercial Capacity (+)	198	198
Non Gas-fired Planned Outage MW (-)	3,043	3,765
Gas Generator Outages MW (-)	1,870	2,283
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	21,535	23,725
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,945	18,945
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,250	21,250
Operable Capacity Margin	285	2,475

[1]Operable Capacity is based on data as of **March 26, 2024** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **March 26, 2024.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 11, 2024.**

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

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

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

Spring 2024 Operable Capacity Analysis

90/10 Load Forecast	**May. - 2024[2] CSO (MW)**	**May. - 2024[2] SCC (MW)**
Operable Capacity MW [1]	28,244	31,735
Active Demand Capacity Resource (+) [5]	512	346
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	894	894
Non Commercial Capacity (+)	198	198
Non Gas-fired Planned Outage MW (-)	3,043	3,765
Gas Generator Outages MW (-)	1,870	2,283
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	21,535	23,725
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,388	20,388
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,693	22,693
Operable Capacity Margin	-1,158	1,032

[1] Operable Capacity is based on data as of **March 26, 2024** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **March 26, 2024.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 11, 2024.**

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

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

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

Spring 2024 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

March 26, 2024 - 50-50 FORECAST using CSO MW

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week in April & May.

Report created: 3/26/2024

Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
4/13/2024	28399	395	941	16	3835	3184	2700	0	20032	15625	2305	17930	2102	N	Spring 2024
4/20/2024	28399	395	877	16	3051	2898	2700	0	21038	15362	2305	17667	3371	N	Spring 2024
4/27/2024	28244	512	894	198	3679	1719	3400	0	21050	15336	2305	17641	3409	N	Spring 2024
5/4/2024	28244	512	894	198	2926	2848	3400	0	20674	17972	2305	20277	397	N	Spring 2024
5/11/2024	28244	512	894	198	3043	1870	3400	0	21535	18945	2305	21250	285	Y	Spring 2024
5/18/2024	28244	512	894	198	1608	987	3400	0	23853	19849	2305	22154	1699	N	Spring 2024
5/25/2024	28244	512	894	198	52	313	3400	0	26083	20841	2305	23146	2937	N	Spring 2024

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2023 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Spring 2024 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

March 26, 2024 - 90/10 FORECAST using CSO MW

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week in April & May.

Report created: 3/26/2024

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
4/13/2024	28399	395	941	16	3835	3184	2700	0	20032	16233	2305	18538	1494	N	Spring 2024
4/20/2024	28399	395	877	16	3051	2898	2700	0	21038	15962	2305	18267	2771	N	Spring 2024
4/27/2024	28244	512	894	198	3679	1719	3400	0	21050	15934	2305	18239	2811	N	Spring 2024
5/4/2024	28244	512	894	198	2926	2848	3400	0	20674	19351	2305	21656	-982	N	Spring 2024
5/11/2024	28244	512	894	198	3043	1870	3400	0	21535	20388	2305	22693	-1158	Y	Spring 2024
5/18/2024	28244	512	894	198	1608	987	3400	0	23853	21351	2305	23656	197	N	Spring 2024
5/25/2024	28244	512	894	198	52	313	3400	0	26083	22409	2305	24714	1369	N	Spring 2024

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2023 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

OPERABLE CAPACITY ANALYSIS

Summer Preliminary 2024 Analysis

Summer Preliminary 2024 Operable Capacity Analysis

50/50 Load Forecast (Reference)	June - 2024[2] CSO (MW)	June - 2024[2] SCC (MW)
Operable Capacity MW [1]	27,255	27,392
Active Demand Capacity Resource (+) [5]	518	380
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,190	1,190
Non Commercial Capacity (+)	198	198
Non Gas-fired Planned Outage MW (-)	2	13
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	26,359	26,347
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	24,633	24,633
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	26,938	26,938
Operable Capacity Margin	-579	-591

[1]Operable Capacity is based on data as of **March 26, 2024** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **March 26, 2024.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 1, 2024.**

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

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

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

Summer Preliminary 2024 Operable Capacity Analysis

90/10 Load Forecast	June - 2024[2] CSO (MW)	June - 2024[2] SCC (MW)
Operable Capacity MW [1]	27,255	27,392
Active Demand Capacity Resource (+) [5]	518	380
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,190	1,190
Non Commercial Capacity (+)	198	198
Non Gas-fired Planned Outage MW (-)	2	13
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	26,359	26,347
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	26,458	26,458
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	28,763	28,763
Operable Capacity Margin	-2,404	-2,416

[1]Operable Capacity is based on data as of **March 26, 2024** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **March 26, 2024.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 1, 2024.**

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

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

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

Summer Preliminary 2024 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

March 26, 2024 - 50-50 FORECAST using CSO MW

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

Report created: 3/26/2024

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
6/1/2024	27255	518	1190	198	2	0	2800	0	26359	24633	2305	26938	-579	Y	Summer 2024
6/8/2024	27255	518	1250	198	2	0	2800	0	26419	24633	2305	26938	-519	N	Summer 2024
6/15/2024	27255	518	1250	198	2	0	2800	0	26419	24633	2305	26938	-519	N	Summer 2024
6/22/2024	27255	518	1250	198	2	0	2800	0	26419	24633	2305	26938	-519	N	Summer 2024
6/29/2024	27255	518	1250	198	2	0	2100	0	27119	24633	2305	26938	181	N	Summer 2024
7/6/2024	27255	518	1250	198	156	0	2100	0	26965	24633	2305	26938	27	N	Summer 2024
7/13/2024	27255	518	1250	198	169	0	2100	0	26952	24633	2305	26938	14	N	Summer 2024
7/20/2024	27255	518	1250	198	186	0	2100	0	26935	24633	2305	26938	-3	N	Summer 2024
7/27/2024	27255	518	1250	198	69	0	2100	0	27052	24633	2305	26938	114	N	Summer 2024
8/3/2024	27255	518	1250	198	128	0	2100	0	26993	24633	2305	26938	55	N	Summer 2024
8/10/2024	27255	518	1250	198	105	0	2100	0	27016	24633	2305	26938	78	N	Summer 2024
8/17/2024	27255	518	1250	198	104	0	2100	0	27017	24633	2305	26938	79	N	Summer 2024
8/24/2024	27255	518	1250	198	112	0	2100	0	27009	24633	2305	26938	71	N	Summer 2024
8/31/2024	27255	518	1250	198	71	0	2100	0	27050	24633	2305	26938	112	N	Summer 2024
9/7/2024	27255	518	1250	198	110	10	2100	0	27001	24633	2305	26938	63	N	Summer 2024
9/14/2024	27255	518	1250	198	167	10	2100	0	26944	24633	2305	26938	6	N	Summer 2024

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).

2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.

3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.

4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.

5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.

6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.

7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.

8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.

9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)

10. Peak Load Forecast MW: Provided in the annual 2023 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).

11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.

12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)

13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)

14. Operable Capacity Season Label: Applicable season and year.

15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Summer Preliminary 2024 Operable Capacity Analysis 90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

March 26, 2024 - 90/10 FORECAST using CSO MW

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

Report created: 3/26/2024

Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
6/1/2024	27255	518	1190	198	2	0	2800	0	26359	26458	2305	28763	-2404	Y	Summer 2024
6/8/2024	27255	518	1250	198	2	0	2800	0	26419	26458	2305	28763	-2344	N	Summer 2024
6/15/2024	27255	518	1250	198	2	0	2800	0	26419	26458	2305	28763	-2344	N	Summer 2024
6/22/2024	27255	518	1250	198	2	0	2800	0	26419	26458	2305	28763	-2344	N	Summer 2024
6/29/2024	27255	518	1250	198	2	0	2100	0	27119	26458	2305	28763	-1644	N	Summer 2024
7/6/2024	27255	518	1250	198	156	0	2100	0	26965	26458	2305	28763	-1798	N	Summer 2024
7/13/2024	27255	518	1250	198	169	0	2100	0	26952	26458	2305	28763	-1811	N	Summer 2024
7/20/2024	27255	518	1250	198	186	0	2100	0	26935	26458	2305	28763	-1828	N	Summer 2024
7/27/2024	27255	518	1250	198	69	0	2100	0	27052	26458	2305	28763	-1711	N	Summer 2024
8/3/2024	27255	518	1250	198	128	0	2100	0	26993	26458	2305	28763	-1770	N	Summer 2024
8/10/2024	27255	518	1250	198	105	0	2100	0	27016	26458	2305	28763	-1747	N	Summer 2024
8/17/2024	27255	518	1250	198	104	0	2100	0	27017	26458	2305	28763	-1746	N	Summer 2024
8/24/2024	27255	518	1250	198	112	0	2100	0	27009	26458	2305	28763	-1754	N	Summer 2024
8/31/2024	27255	518	1250	198	71	0	2100	0	27050	26458	2305	28763	-1713	N	Summer 2024
9/7/2024	27255	518	1250	198	110	10	2100	0	27001	26458	2305	28763	-1762	N	Summer 2024
9/14/2024	27255	518	1250	198	167	10	2100	0	26944	26458	2305	28763	-1819	N	Summer 2024

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2023 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

Possible Relief Under OP4: Appendix A

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

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

Possible Relief Under OP4: Appendix A

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

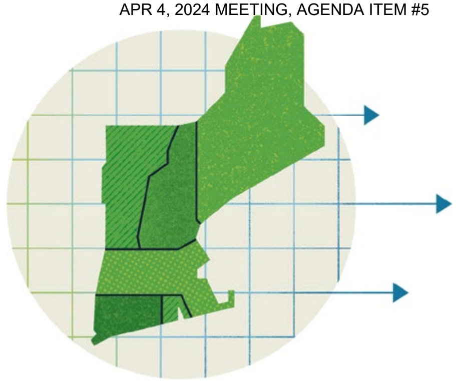
NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only resources <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values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

APRIL 4, 2024 | NEPOOL PARTICIPANTS COMMITTEE

Updated 2024 Annual Work Plan

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER



Objectives and Highlights

- This report reflects updates to the *2024 Annual Work Plan* (2024 AWP) since its publication in October 2023
  - The Update demonstrates the coordinated efforts by the ISO and stakeholders in adjusting schedules, resources, and priorities to accomplish projects of great significance to the region
- Potential impacts to this year's work plan may stem from FERC's Order on the further two-year FCA 19 delay in June and FERC's final rule on NOPR RM21-17 (*Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*) anticipated this spring
  - Also of note are the ISO's staffing challenges, having recently lost multiple members of teams working on key markets initiatives and the hiring of more entry-level staff
- Stakeholders can submit new requests for the ISO's 2025 AWP through the NEPOOL priorities process, which kicked off in March 2024
  - Over the following months, the requests are discussed, narrowed, and a final list is chosen for incorporation into the 2025 plan
  - The AWP focuses on larger initiatives and also does not represent the ISO's full workload, including project implementation work or the extensive day-to-day operations related to running the grid, the markets, and its organization

Anchor Projects on Track

- **Extended/Longer-Term Transmission Planning Phase 2:** Stakeholder discussions are now concluding from 2023; a FERC filing is expected in Q2 2024, with a Q3 effective date
- **Energy Adequacy Threshold Determination**: The ISO reported results from the Probabilistic Energy Adequacy Tool (PEAT) in 2023; stakeholder discussions to continue in Q2 2024 on establishing a Regional Energy Shortfall Threshold (REST), with a proposal presented by end of year
  - Analysis of scope, timing, and feasibility of regional solutions to maintain/achieve a REST would follow in 2025 as needed
- **Day-Ahead Ancillary Services Initiative (DASI) Implementation**: Development of software and implementation processes on track for Q1 2025
  - Stakeholder discussion began in Q1 2024 on DASI Conforming Changes, with a filing expected by end of Q2 2024
- **nGem Real-Time Market Clearing Engine**: Development of the new real-time market clearing engine software and infrastructure is on track for Q2 2025 implementation

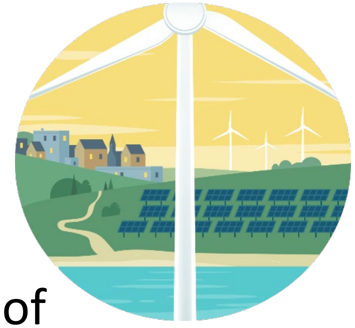
Anchor Projects on Track, cont’d

- **FERC Order No. 2023:** Compliance with the Order is on track to meet the FERC-mandated April 3 filing date, a May 1 eligibility date, and the ISO’s request for a May 31 effective date
  - NEPOOL work plan priority requests related to ISO Planning Procedures affected by Order No. 2023 are grouped together here:
  - **Assess Interconnection Standard for Charging of Electric Storage Resources (ESRs):** Updates made in Q1 2024 to PP5-6 (*Interconnection Planning Procedure for Generation and Elective Transmission Upgrades*) and proposed changes under Order No. 2023 Compliance address the stakeholder request to further describe modeling requirements for inverter-based resources and update load levels used in interconnection studies
  - **Improvements to the Proposed Plan Application (PPA) Process for TO-LED PPA Studies (including for Distributed Generation Interconnections)**: Coordination work kicked off in Q1 2024, with 1) an educational webinar on the ISO’s Order No. 2023 compliance proposal and the impact on Affected System Operator (ASO) Studies, and 2) stakeholder discussions of further updates to Planning Procedures to conform with Order No. 2023 changes and to incorporate the coordination process for ASO studies going forward

Notable Initiatives on Track

- **Day-Ahead and Real-Time Energy Shortage Pricing Assessment**: The ISO's evaluation continues, with potential for stakeholder discussions to begin as early as Q3 2024; timing may be impacted by outcomes and developments related to the two-year further delay of FCA 19
- **Flexible Response Services Assessment**: The ISO's evaluation continues, with stakeholder discussions targeted to begin in 2025
- **Evaluate Tie Benefits and HQICCs**: Stakeholder discussions targeted to continue into Q4 2024; study results will inform any potential initiatives that follow
- **Economic Planning for the Clean Energy Transition (EPCET) Pilot Study**: Stakeholder discussions are concluding; a summary report is planned for Q2
- **Evaluate Single Source Contingency Limit Increase**: Study scope is under development with PJM and NYISO; work continues in 2024 and potentially into 2025; study results will inform possible initiatives that follow

Notable Initiatives on Track, cont'd



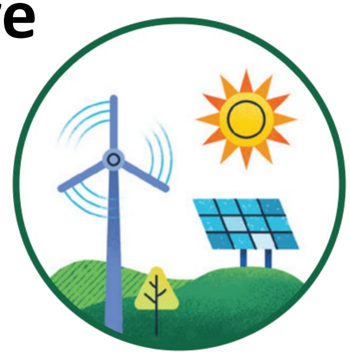
- **Inverter-Based Resource (IBR) Integration & Modeling:** In 2024, the ISO plans to establish guidelines for inclusion of IBR models into electromagnetic transient (EMT) modeling processes and associated model repositories
- **Cloud Computing and Cyber Security**: Projects are on track for 2024 implementation
- **Synchrophasor Enhancements for Future Grid**: Work is on track for 2024 and extending into 2025

Updated Anchor Projects: Resource Capacity Accreditation (RCA) and Alternative FCM Commitment Horizons

Scopes and schedules refined since 2024 AWP publication

- **RCA in the FCM**: Stakeholder discussions have continued from 2023 on capacity accreditation reforms for the 19th Forward Capacity Auction (FCA 19) for the 2028-2029 Capacity Commitment Period (CCP 19)
  - On Jan. 2, 2024, FERC accepted a one-year delay of the auction, from Feb. 2025 to 2026
- **Assessing Alternative FCM Commitment Horizons**: After an evaluation and discussion period, the ISO made the recommendation in Q1 2024 to develop a capacity auction that runs closer to the capacity commitment period (prompt) and restructuring the CCP from annual to sub-annual (seasonal) commitment periods, starting with FCA 19/CCP 19
  - Consistent with the above recommendation, the ISO proposed a further two-year delay of the capacity auction to provide maximum flexibility to 1) design a prompt and seasonal market for CCP 19, and 2) develop RCA reforms for CCP 19 in the context of a prompt and seasonal market
  - Stakeholder discussions of the further delay proposal are now concluding, with a filing expected in April 2024; FERC's Order is anticipated in June

Updated Anchor Projects: RCA and Alternative FCM Commitment Horizons, cont'd



- If FERC **accepts** the further delay, ISO will pause stakeholder discussions to evaluate scope and phasing of work, and develop a work plan for a combined accreditation design with a prompt/ seasonal capacity market to implement for CCP 19
  - With stakeholder support of a further delay, the ISO plans to design a market constraint approach for gas resources in the combined design
  - The ISO will also place early focus on developing the retirement components of the design and bring those designs to stakeholders early in the process
  - The timing of when the auction(s) would run to be determined as part of detailed design
- If FERC **rejects** the further delay, ISO would target implementing RCA under the forward market construct for FCA 19 in Feb. 2026 (the approved one-year delay), with a FERC filing in Q4 2024
  - To help ensure success, the proposal will focus solely on **three core components** of the accreditation reforms currently under discussion in the stakeholder process (these components remain applicable when pivoting from forward to prompt/seasonal):

    1) MRI-based accreditation, 2) RAA modeling/seasonal risk, 3) modeling limited energy resources
  - Beyond these core components, cannot add to scope in a Q4 2024 filing
  - Ongoing filings will be required to address details for FCA 19/CCP 19 and beyond

2024 Timelines of Possible Paths

Full RCA Design with Prompt/ Seasonal Capacity Market Construct

March, April, May Further discussion on RCA core design proposal

June Contingent on timing of FERC Order, may need to begin discussion of RCA core design Tariff language

July, August, September Pause and develop RCA-prompt/ seasonal work plan

October Discuss work plan with stakeholders

November Commence work plan

Complete stakeholder & regulatory process on further delay proposal

- *March MC vote*
- *April PC vote*
- *April FERC filing*
- *June FERC Order*

FERC Accepts Further Delay

FERC Denies Further Delay

Core RCA Design for FCA 19 in Feb. 2026 with Forward Capacity Market Construct

March, April, May Further discussion on RCA core design proposal

June Begin discussion of RCA core design Tariff language

July, August Continue discussion of Tariff language, amendments

September MC vote on RCA core design

October PC vote and file with FERC

If FERC does not accept RCA design, ISO would run FCA 19 without RCA in Feb. 2026

November-on Ongoing filings required to address details for FCA 19/CCP 19 and beyond

Updated Notable Initiatives

Scopes and schedules changed since 2024 AWP publication

- **Transmission Asset Condition Process Improvements and Sizing for the Clean Energy Transition**: Stakeholder discussion of Transmission Owner proposals on asset condition process improvements continue from 2023 and have extended further into 2024; FERC Order RM21-17 is expected to influence discussions on future-sizing
- **Work on FCM-Related Initiatives:** These stakeholder-requested initiatives are affected by FCM prompt/seasonal considerations and are therefore deferred pending a prompt/seasonal market design:
  - FCM Retirement Reforms: Return to Service
  - FCM Financial Assurance Policy/Entry-Related Improvement
- **Storage Modeling Market Enhancements Assessment:** The ISO continues to evaluate opportunities to more efficiently integrate energy storage resources into the energy and ancillary service markets, beyond FERC Order 841 (*Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*)
  - Timing of stakeholder discussions is no longer estimated to begin in 2024 and will be reassessed as part of the 2025 AWP

Potential New FERC Initiative

FERC actions are always accommodated but can impact AWP

- A final rule from FERC is anticipated in early 2024 on its Notice of Proposed Rulemaking RM21-17: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection
- ISO analysis of and action on the Order will depend on compliance timelines, but will likely require resources be directed to this initiative for the second half of 2024

Other Timely Effort: Implement New England Clean Energy Connect (NECEC) External Interface

- The ISO has started work across the company to incorporate the NECEC interface in December 2025
- Work involves potential changes to the ISO Tariff and schedules, agreements, dispatch instructions, transaction scheduling, EMS modeling, operation planning, resource adequacy, market rules and modeling, settlements, manuals and operating procedures, software and databases, and all references to interfaces in existing documentation and materials

2024 AWP Update	Q2	Q3	Q4
Markets Related	**RCA-Prompt/Seasonal**		
	Day-Ahead and Real-Time Energy Shortage Pricing Assessment		
	Flexible Response Services Assessment		
	Storage Modeling Market Enhancement Assessment		
Planning & Operations	**Regional Energy Shortfall Threshold (REST)**		
	Order No. 2023		
	LTTS Phase 2		
	EPCET		
	Tie Benefits & HQICCs Assessment		
	Transmission Asset Condition Process Improvement/Sizing Considerations		
	Single Source Contingency Limit Assessment		
	Other Initiatives & Continuing Business		
Capital Priorities	**DASI Implementation**		
	nGEM Real-Time Market Clearing Engine		
	Inverter-Based Resource Integration & Modeling		
	Synchrophasor Enhancements for Future Grid		
	Cloud Computing & Cyber Security		

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Rosendo Garza, NEPOOL Counsel

DATE: March 28, 2024

RE: ISO-NE's FCA19 2-Year Delay Proposal

At the April 4, 2024 Participants Committee meeting, you will be asked to vote on ISO-NE's proposed Market Rule 1 revisions to delay the nineteenth Forward Capacity Auction (FCA) by two years (FCA19 Delay Proposal), currently scheduled to take place in February 2026.[1] This memorandum provides an overview of the proposal and summarizes the stakeholder review process to date. Included with this memorandum are the following materials:

- Attachment A: Markets Committee-recommended Tariff revisions
- Attachment B: ISO-NE's March 12–13, 2024 Presentation
- Attachment C: ISO-NE's voting memorandum to the Markets Committee, dated March 6, 2024

BACKGROUND & OVERVIEW OF THE FCA19 DELAY PROPOSAL

Since the summer of 2023, Participants, ISO-NE, and the States have discussed and debated the potential of the region working toward the development of proposals for a new capacity market construct. To assist in the assessment, the ISO contracted with the Analysis Group (AG) to prepare a report evaluating prompt and seasonal market concepts for New England's capacity market.[2] The AG report concluded that the region should pursue a prompt/seasonal capacity market construct.

Based on AG's recommendation, ISO-NE developed a proposal to delay FCA19 by two years to allow time to develop a prompt and seasonal market designs in time for the 2028–2029 Capacity Commitment Period, i.e., CCP19. Moreover, as the ISO explained to the Markets Committee, a two-year delay would offer additional time to develop capacity accreditation changes for CCP19 in the context of a prompt and seasonal market, including a market constraint approach for gas resources.

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[1] Earlier this year, the FERC approved a joint proposal to delay FCA19, originally scheduled for February 2025, until 2026. Delegated Letter Order, 186 FERC ¶ 61,001 (Jan. 2, 2024).

[2] T. Schatzki, et al., Analysis Group, *Capacity Market Alternatives for a Decarbonized Grid: Prompt and Seasonal Markets* (Jan 2024), https://www.iso-ne.com/static-assets/documents/100007/a08b_mc_2024_01_09_11_agi_updated_report.pdf.

The FCA19 Delay Proposal consists of four components:

1. Revisions that delay FCA19 qualification and auction activities by two years (the ISO would run FCA19 in February 2028).
2. Suspension of certain annual reconfiguration auctions.
3. As detailed in Attachment A, a path to return to a forward auction construct should filings proposing a prompt/seasonal market design or accreditation reforms for CCP19 are unsuccessful at the FERC.
4. Provisions to allow New Capacity Resources with early in-service dates to submit qualification materials in 2025 and 2026.

STAKEHOLDER PROCESS TO DATE

The Markets Committee discussed and reviewed the FCA19 Delay Proposal. At its March 12–13 meeting, the Markets Committee considered the revisions to Market Rule 1 to implement ISO-NE's FCA19 Delay Proposal, and based on a show of hands vote, recommended that the Participants Committee support the proposal.[3]

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

> RESOLVED, that the Participants Committee supports the FCA19 Delay Proposal as reflected in revisions to Section III.13 of the Tariff, as recommended by the Markets Committee at its March 2024 meeting, and circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee, it being understood that a vote in favor of this resolution reflects support solely for the FCA19 Delay Proposal and is without prejudice to any future position that might be taken by a Participant(s) with respect to proposals (i) to reform the methodology to accredit resources' contribution to resource adequacy or (ii) to change the timing of the capacity auction relative to the capacity delivery period.

[3] Two oppositions in the Generator Sector and 15 abstentions (Generation Sector (1); Transmission Sector (1); Supplier Sector (6); AR Sector (3); and End User Sector (4)) were recorded.

III.13. Forward Capacity Market.

The ISO shall administer a forward market for capacity ("Forward Capacity Market") in accordance with the provisions of this Section III.13. For each one-year period from June 1 through May 31, starting with the period June 1, 2010 to May 31, 2011, for which Capacity Supply Obligations are assumed and payments are made in the Forward Capacity Market ("Capacity Commitment Period"), the ISO shall conduct a Forward Capacity Auction in accordance with the provisions of Section III.13.2 to procure the amount of capacity needed in the New England Control Area and in each modeled Capacity Zone during the Capacity Commitment Period, as determined in accordance with the provisions of Section III.12. To be eligible to assume a Capacity Supply Obligation for a Capacity Commitment Period through the Forward Capacity Auction, a resource must be accepted in the Forward Capacity Auction qualification process in accordance with the provisions of Section III.13.1.

III.13.A Forward Capacity Market Interim Provisions.

III.13.A.1 Interim Forward Capacity Auction Schedules.

Notwithstanding any other any dates, date ranges and/or deadlines for activities related to the Forward Capacity Auction established in or pursuant to any provision of the ISO New England Operating Documents, for the nineteenth~~, twentieth, twenty-first, twenty-second, twenty-third, twenty-fourth and, twenty-fifth~~ through thirty-seventh Forward Capacity Auctions (associated with the 2028-2029 through~~, 2029-2030, 2030-2031, 2031-2032, 2032-2033, 2033-2034, and 2034-2035~~ 2046-2047 Capacity Commitment Periods, respectively), the following provisions apply.

III.13.A.1.1 Nineteenth Forward Capacity Auction Delayed

For the nineteenth Forward Capacity Auction (associated with the 2028-2029 Capacity Commitment Period), the dates, date ranges and/or deadlines for activities related to the Forward Capacity Auction established in or pursuant to any provision of the ISO New England Operating Documents shall not apply and shall be delayed by three~~one~~ calendar years.

III.13.A.1.2 First Annual Reconfiguration Auction Suspension

For the nineteenth through thirty-sixth~~, twentieth, twenty-first, twenty-second, twenty-third and twenty-fourth~~ Forward Capacity Auctions (associated with the 2028-2029 through 2045-2046~~, 2029-2030, 2030-2031, 2031-2032, 2032-2033 and 2033-2034~~ Capacity Commitment Periods, respectively), the first annual reconfiguration auction as specified in Section III.13.4 that is typically held in the month of June, approximately 24 months before the start of the applicable Capacity Commitment Period, shall not be conducted.

III.13.A.1.3 Second Annual Reconfiguration Auction Suspension

For the nineteenth through twenty-seventh Forward Capacity Auctions (associated with the 2028-2029 through 2036-2037 Capacity Commitment Periods, respectively), the second annual reconfiguration auction as specified in Section III.13.4 that is typically held in the month of August, approximately 10 months before the start of the applicable Capacity Commitment Period, shall not be conducted.

III.13.A.1.4 Third Annual Reconfiguration Auction Suspension

For the nineteenth through twenty-first Forward Capacity Auctions (associated with the 2028-2029 through 2030-2031 Capacity Commitment Periods, respectively), the third annual reconfiguration auction as specified in Section III.13.4 that is typically held in the month of March, approximately three months before the start of the applicable Capacity Commitment Period, shall not be conducted.

III.13.A.1.5 Accelerated Qualification Period and Auctions

For the twentieth~~, twenty-first, twenty-second, twenty-third, twenty-fourth and twenty-fifth,~~ through thirty-seventh ~~-~~Forward Capacity Auctions (associated with the 2029-2030 through~~, 2030-2031, 2031-2032, 2032-2033, 2033-2034, and 2034-2035~~ 2046-2047 Capacity Commitment Periods, respectively), the Forward Capacity Auction, and the qualification process for each such auction, shall be conducted under a 10-month timeline in accordance with the key dates set forth in the schedule below. For each Forward Capacity Auction specified in the table below, the ISO shall publish the dates, date ranges and deadlines for activities related to the respective Forward Capacity Auction no later than six months before the applicable notification to Lead Market Participants of their Existing Capacity Resource's summer Qualified Capacity and winter Qualified Capacity values as specified in Section III.13.1.2.3(a).

Capacity Commitment Period	Forward Capacity Auction Date	Revised annual reconfiguration auction Dates (as applicable)
2028-2029	February 2028	No reconfiguration auctions
2029-2030	December 2028~~6~~	~~Second annual reconfiguration auction August 2028; third~~ No reconfiguration auctions ~~annual reconfiguration auction March 2029~~
2030-2031	October 2029~~7~~	~~Second annual reconfiguration auction August 2029;~~ ~~t~~No reconfiguration auctions~~hird annual reconfiguration auction March 2030~~
2031-2032	August 2030~~28~~	~~Second annual reconfiguration auction August 2030; third~~ Third annual reconfiguration auction March 2031
2032-2033	June 2031~~29~~	~~Second annual reconfiguration auction August 2031;~~ ~~t~~Third annual reconfiguration auction March 2032
2033-2034	April 2032~~0~~	~~Second annual reconfiguration auction August 2032;~~ T~~t~~hird annual reconfiguration auction March 2033
2034-2035	February 2033	Third annual reconfiguration auction March 2034
2035-2036	December 2033	Third annual reconfiguration auction March 2035
2036-2037	October 2034	Third annual reconfiguration auction March 2036
2037-2038	August 2035	Second annual reconfiguration auction August 2036; Third annual reconfiguration auction March 2037
2038-2039	June 2036	Second annual reconfiguration auction August 2037; Third annual reconfiguration auction March 2038
2039-2040	April 2037	Second annual reconfiguration auction August 2038; Third annual reconfiguration auction March 2039
2040-2041	February 2038	Second annual reconfiguration auction August 2039; Third annual reconfiguration auction March 2040
2041-2042	December 2038	Second annual reconfiguration auction August 2040; Third annual reconfiguration auction March 2041
2042-2043	October 2039	Second annual reconfiguration auction August 2041; Third annual reconfiguration auction March 2042
2043-2044	August 2040	Second annual reconfiguration auction August 2042; Third annual reconfiguration auction March 2043

2044-2045	June 2041	Second annual reconfiguration auction August 2043; Third annual reconfiguration auction March 2044
2045-2046	April 2042	Second annual reconfiguration auction August 2044; Third annual reconfiguration auction March 2045
2046~~34~~-2047~~35~~	February 204~~3~~3~~1~~	Regular annual reconfiguration auction schedule applies~~.~~

The ISO may adjust any published date, date range and/or deadline for Forward Capacity Auction activities by 10 Business Days if needed, and shall publish a revised date, date range and/or deadline no later than 30 days in advance of such adjustment.

III.13.A.2. Interim Reconfiguration Auction Qualification.

(a) Notwithstanding any other provision of the ISO New England Operating Documents, a New Capacity Resource that has not already acquired a Capacity Supply Obligation and intends to achieve Commercial Operation as defined in Section III.13.1.1.2.2.2(h) before June 1, 2026, may qualify for the annual reconfiguration auction, monthly reconfiguration auction and bilateral activities described in Section III.13.4 and Section III.13.5 under this section providing the following conditions are met:

(1) The Project Sponsor submits qualification materials as described in Section III.13.1, including a New Capacity Show of Interest Form in April 2024 and a New Capacity Qualification Package in June 2024. The ISO shall post a list of the required materials on its website and a complete schedule for their submittal at least 60 days in advance; and

(2) The Project Sponsor requests that the ISO monitor the New Capacity Resource's compliance with its critical path schedule as described in Section III.13.3.1.1 by November 1, 2024.

(b) Notwithstanding any other provision of the ISO New England Operating Documents, a New Capacity Resource that has not already acquired a Capacity Supply Obligation, and intends to achieve Commercial Operation as defined in Section III.13.1.1.2.2.2(h) before June 1, 2028, may qualify for the annual reconfiguration auction, monthly reconfiguration auction and bilateral activities described in Section III.13.4 and Section III.13.5 occurring in 2026, 2027, and 2028 for the 2025-2026 Capacity Commitment Period associated with the sixteenth Forward Capacity Auction, the 2026-2027 Capacity Commitment Period associated with the seventeenth Forward

Capacity Auction, and the 2027-2028 Capacity Commitment Period associated with the eighteenth Forward Capacity Auction, as applicable, under this section providing the following conditions are met:

(1) The Project Sponsor submits qualification materials as described in Section III.13.1, including a New Capacity Show of Interest Form in April 2025 and a New Capacity Qualification Package in June 2025. The ISO shall post a list of the required materials on its website and a complete schedule for their submittal at least 60 days in advance; and

(2) The Project Sponsor requests that the ISO monitor the New Capacity Resource's compliance with its critical path schedule as described in Section III.13.3.1.1 by the first Business Day occurring in November 2025.

(c) Notwithstanding any other provision of the ISO New England Operating Documents, a New Capacity Resource that has not already acquired a Capacity Supply Obligation and intends to achieve Commercial Operation as defined in Section III.13.1.1.2.2.2(h) before June 1, 2028, may qualify for the annual reconfiguration auction, monthly reconfiguration auction and bilateral activities described in Section III.13.4 and Section III.13.5 occurring in 2027 and 2028 for the 2026-2027 Capacity Commitment Period associated with the seventeenth Forward Capacity Auction, and the 2027-2028 Capacity Commitment Period associated with the eighteenth Forward Capacity Auction, as applicable, under this section providing the following conditions are met:

(1) The Project Sponsor submits qualification materials as described in Section III.13.1, including a New Capacity Show of Interest Form in April 2026 and a New Capacity Qualification Package in June 2026. The ISO shall post a list of the required materials on its website and a complete schedule for their submittal at least 60 days in advance; and

(2) The Project Sponsor requests that the ISO monitor the New Capacity Resource's compliance with its critical path schedule as described in Section III.13.3.1.1 by the first Business Day occurring in November 2026.

Alternative FCM Commitment Horizons – ISO Proposal to Delay FCA 19 to Facilitate Prompt/Seasonal Design

Chris Geissler
DIRECTOR
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Alternative FCM Commitment Horizons – Delay FCA 19 to Facilitate Prompt/Seasonal Design

WMPP ID: 178

Proposed Effective Date: June 2024

- Since August 2023, ISO and Analysis Group have discussed considerations and tradeoffs associated with the potential development of a prompt and/or seasonal capacity market with stakeholders
  - Culminated in an Analysis Group recommendation for the ISO to develop a prompt and seasonal capacity market
- Consistent with Analysis Group's recommendation, the ISO is proposing a further delay to FCA 19 to allow for time to design a prompt and seasonal capacity market with capacity accreditation
- This presentation (1) reviews the ISO's consideration to move to a prompt and seasonal capacity market, (2) concludes the proposal for an additional delay to the FCA 19 processes to incorporate time to develop a prompt and seasonal capacity market design, and (3) addresses follow up questions from the February MC meeting

Background: Summary of Discussions to Date

- ISO, Analysis Group, and stakeholders have discussed the tradeoffs associated with prompt and/or seasonal capacity market concepts across several Markets Committee meetings
- Discussions have covered a range of topics including:
  - Potential market and reliability impacts
  - Possible interactions with capacity accreditation
  - Anticipated impacts under a future decarbonized grid
  - Key outstanding design questions and details
- Culminated in an Analysis Group report recommending the development of a prompt and seasonal capacity market

ISO Proposal

- Consistent with this recommendation, ISO is proposing a further two-year delay to FCA 19 to allow time to design a prompt and seasonal market for CCP 19
  - Allows time for ISO to develop capacity accreditation reforms for CCP 19 in the context of a prompt and seasonal market
  - Timing of when auction(s) for CCP 19 would be run under prompt and seasonal framework would be determined as part of detailed design
- Under the proposal, FCA 19 would be run in February 2028 in the event that the redesign of the capacity market is not completed or accepted by FERC

Assessment of Gas Market Constraint

- As part of the Resource Capacity Accreditation effort, ISO has discussed numerous approaches to accrediting natural gas resources for the winter months
- As explained in its January memo to the Markets Committee, ISO's preferred approach is the market constraint approach, but this approach is not feasible for FCA 19 under a one year delay
- Several stakeholders noted a similar preference for a market constraint approach

ISO will Develop a Market Constraint for Gas Resources Under Prompt/Seasonal Design

- At the February MC, stakeholders asked if the ISO could develop and implement a market constraint for gas under a prompt and seasonal capacity market
- After stakeholders and FERC approve the ISO's further delay proposal, the ISO will begin developing a market constraint for gas resources as part of a prompt and seasonal capacity market design for CCP 19
- Will prioritize this design item, along with several others (*next*)

ISO Plans to Prioritize Key Design Areas in Prompt, Seasonal, Accreditation Effort

- These design areas include:
  - Development of a gas market constraint
  - Determination of new retirement process
  - New auction schedule and timing
- ISO looks forward to working with stakeholders to develop these key areas as part of its detailed design work

Transition Back to Forward Auction: Overview

- If later proposed filing on prompt, seasonal, accreditation for CCP 19 is not successful, this path could reestablish the status quo for forward annual auctions
- Shifts all FCA 19 activities back by another two years (three years total)
  - No Annual Reconfiguration Auctions for CCPs 19, 20, and 21
- Employs a 10 month schedule over many auction cycles to return to three-year forward schedule
  - Reduced number of Annual Reconfiguration Auctions during ‘back to forward’ transition period
- Includes language allowing resources with early in-service dates to submit qualification materials in 2025 and 2026

Summary of Additional Tariff Changes Since February MC

Tariff Section	Tariff Change	Reason for Change
III.13.A.2	Revised key date for CPS monitoring activity from November 1 to first Business Day in November	November 1 is not a Business Day

Conclusion

- ISO is proposing a further two-year delay to FCA 19 to allow time to design a prompt and seasonal market for CCP 19, consistent with Analysis Group's recommendation
  - A two-year delay will provide time to develop capacity accreditation reforms for CCP 19 in the context of a prompt and seasonal market
- Under the proposed delay, FCA 19 would be run in February 2028 in the event that the redesign of the capacity market is not completed or accepted by FERC
- The ISO will prioritize development of several key aspects of the design (e.g., gas market constraint, retirement processes, auction schedule and timing)

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Markets Committee, July 11, 2023, Aug 8-10, 2023, Sept 12-13, 2023	ISO reviews alternative FCM commitment period horizon key considerations
Markets Committee, Oct 11-12, 2023	ISO overview of scope of AGI's work
Markets Committee, Nov 7-8, 2023	AGI outlines methodology, gathers stakeholder feedback
Markets Committee, Dec 12-14, 2023	AGI publishes draft report and presents key findings, gathers stakeholder feedback
Markets Committee, Jan 9-11, 2024	AGI reviews final report; gathers stakeholder feedback
Markets Committee, Feb 6-7, 2024	ISO recommendation develop a prompt/seasonal proposal. Introduce FCA 19 additional delay
Markets Committee, Mar 12-13, 2024	Vote on FCA 19 additional delay
Participants Committee, Apr 4, 2024	Vote on FCA 19 additional delay

2024 Timelines of Possible Paths

- If FERC **accepts** the further delay, ISO will pause stakeholder discussions to evaluate scope and phasing of work, and develop a work plan for a combined accreditation design with a prompt/seasonal capacity market to implement for CCP 19
  - With stakeholder support of a further delay, the ISO plans to design a market constraint approach for gas resources in the combined design
  - The ISO will also place early focus on developing the retirement components of the design and bring those designs to stakeholders early in the process
  - The timing of when the auction(s) would run to be determined as part of detailed design
- If FERC **rejects** the further delay, ISO would target implementing RCA under the forward market construct for FCA 19 in Feb. 2026 (the approved one-year delay), with a FERC filing in Q4 2024
  - To help ensure success, the proposal will focus solely on **three core components** of the accreditation reforms currently under discussion in the stakeholder process (these components remain applicable when pivoting from forward to prompt/seasonal):

    1) MRI-based accreditation, 2) RAA modeling/seasonal risk, 3) modeling limited energy resources
  - Beyond these core components, cannot add to scope in a Q4 2024 filing
  - Ongoing filings will be required to address details for FCA 19/CCP 19 and beyond

2024 Timelines of Possible Paths, cont.

Full RCA Design with Prompt/ Seasonal Capacity Market Construct

March, April, May Further discussion on RCA core design proposal

June Contingent on timing of FERC Order, may need to begin discussion of RCA core design Tariff language

July, August, September Pause and develop RCA-prompt/ seasonal work plan

October Discuss work plan with stakeholders

November Commence work plan

Complete stakeholder & regulatory process on further delay proposal
- *March MC vote*
- *April PC vote*
- *April FERC filing*
- *June FERC Order*

FERC Accepts Further Delay

FERC Denies Further Delay

Core RCA Design for FCA 19 in Feb. 2026 with Forward Capacity Market Construct

March, April, May Further discussion on RCA core design proposal

June Begin discussion of RCA core design Tariff language

July, August Continue discussion of Tariff language, amendments

September MC vote on RCA core design

October PC vote and file with FERC

If FERC does not accept RCA design, ISO would run FCA 19 without RCA in Feb. 2026

November-on Ongoing filings required to address details for FCA 19/CCP 19 and beyond

Questions

Chris Geissler
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ISO new england

memo

To: NEPOOL Markets Committee

From: Chris Geissler, Director – Economic Analysis

Date: March 6, 2024

Subject: Alternative Forward Capacity Market (FCM) Commitment Horizons (WMPP ID: 178) – Delay Forward Capacity Auction 19 (FCA 19) to Facilitate Prompt/Seasonal Design

The ISO is requesting a vote on proposed revisions to Section III.13 of Market Rule 1 to further delay FCA 19 by an additional two years to allow time to design a prompt and seasonal capacity market along with capacity accreditation reforms.

By way of background, starting in July 2023, the ISO and Analysis Group discussed considerations and tradeoffs associated with the potential development of a prompt and/or seasonal capacity market. This culminated in an Analysis Group report recommending the development of a prompt and seasonal capacity market for the region.

Consistent with this recommendation, the ISO is proposing a further two-year delay to FCA 19 to allow time to design a prompt and seasonal market for CCP 19. This further delay will also allow the ISO to develop the capacity accreditation reforms for CCP 19 in the context of a prompt and seasonal market. In addition, once the further delay to FCA 19 has been approved by stakeholders and the Commission, the ISO will begin developing a market constraint for gas resources as part of a prompt and seasonal capacity market design for CCP 19.

The proposed Market Rule 1 revisions delay the FCA 19 qualification and auction activities by another two years, provide for two additional interim auction qualification periods, and incorporate a path to reestablish the status quo for forward annual auctions as needed.

The proposal for the committee's consideration at its March 12-13, 2024 meeting has been presented previously to the Markets Committee at the meeting dates outlined below.

- July 11, 2023, agenda item 9A
- August 8-10, 2023, agenda item 3A
- September 12-13, 2023, agenda item 5C
- October 11-12, 2023, agenda item 11
- November 7-8, 2023, agenda item 3B
- December 12-14, 2023, agenda item 3B
- January 9-11, 2024, agenda items 8B
- February 6-7, 2024, agenda item 6A

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MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: March 28, 2024

RE: Vote on Tariff Revisions to Support Longer-Term Transmission Planning

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Introduction

At the April 4, 2024 Participants Committee meeting, you will be asked to support the ISO's proposed revisions to its Transmission, Markets and Services Tariff ("Tariff") to help enable the New England states to achieve their public policy requirements through the development of transmission solutions to address identified system needs and provision for their cost allocation ("Longer-Term Transmission Planning Revisions").[1] The Longer-Term Planning Revisions were developed by ISO-NE in response to NESCOE requests and NEPOOL input. They have been recommended unanimously by both the Transmission Committee, which voted on the bulk of the revisions in Sections I and II of the Tariff,[2] and by the Reliability Committee, which voted on one minor conforming change to Section III.12.6.4 of the Tariff.[3] The proposed Tariff revisions and related materials have been included with this memo.

Overview of Longer-Term Transmission Planning Revisions

The Longer-Term Transmission Planning Revisions have been separated into two proposals. The first is the "Core Process Proposal", which contains most of the Longer-Term Planning Revisions, including the conforming change recommended by the Reliability Committee. The second is the "Supplemental Process Proposal", which contains incremental additions to the Core Process Proposal to address a contingency, as described further below. Both the Core Process Proposal and the Supplemental Process Proposal are based on the process for longer-term

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[1] An ISO-NE presentation from November 2023 provides some conceptual framework for the Longer-Term Transmission Planning Revisions Core Process Proposal (discussed below): https://www.iso-ne.com/static-assets/documents/100005/a02_2023_11_21_tc_ltts_presentation.pdf. In January NESCOE provided this presentation on the Supplemental Process Proposal (discussed below): https://www.iso-ne.com/static-assets/documents/100007/a04.2_2024_01_23_tc_nescoe_supplemetnal_process_ltts.pdf.

[2] Section I includes the general terms and conditions of the Tariff and the definitions used in it. The Section I changes are to the definitions. Section II of the Tariff is the Open Access Transmission Tariff ("OATT"). The Section II revisions include revisions to: Sections II.8, II.46, II.49, Attachment K, Attachment N, Attachment O, Attachment P, Schedule 12, and Schedule 12C, along with new Schedule 14A to the OATT.

[3] Section III of the Tariff contains the Market Rules. The Reliability Committee has purview over Section III.12.6.4 to which the conforming change was made.

transmission planning studies that identify transmission needs, taking into account State-identified Requirements, which were included in the Tariff as part of Phase 1 of this project.[4]

At a high-level, the Core Process Proposal contains the following elements: (i) transmission needs based on State-identified Requirements will be determined by NESCOE; (ii) ISO-NE will conduct competitive solicitations for solutions from Qualified Transmission Project Sponsors to address NESCOE determined needs, and potentially other needs, such as reliability needs; (iii) ISO-NE will evaluate solutions based on a set of evaluation criteria, including a benefit-to-cost analysis that shows a benefit-to-cost ratio ("BCR") of greater than 1.0 ("BCR Threshold"); (iv) ISO-NE will select a preliminary preferred solution with a BCR of greater than 1.0; (v) NESCOE may then (a) terminate the competitive solicitation, or (b) move forward with the ISO-NE preferred solution; and (vi) the preferred solution that moves forward will be subject to a default regionalized cost allocation (spread across the six New England states according to load share), or an alternative default cost allocation if and as provided by NESCOE. Much of this process and its results would be informed by consultation with and input from the Planning Advisory Committee ("PAC"). In the event that non-time-sensitive reliability or market efficiency needs are not addressed through the longer-term process, they will be addressed through the existing Tariff processes.

The Supplemental Process Proposal includes the elements of the Core Process Proposal, except that it adds provisions to address the case where there is a transmission solution desirable to one or more states that does not meet the BCR Threshold.[5] In such cases, the Supplemental Process Proposal allows the states to advance the transmission solution by treating its costs up to the BCR similar to Regional Benefit Upgrades (i.e., regionalize the costs), and then having one or more states agree to fund the incremental costs above the BCR Threshold for the solution. The Supplemental Process Proposal includes extensive interaction with the PAC.

<u>Stakeholder Review Process to Date</u>

The Transmission Committee reviewed, provided input and voted on this matter over the course of six meetings.[6] At the March 27 Transmission Committee meeting, there was one Participant amendment put forward for vote by Avangrid to codify in the Tariff the requirement for ISO-NE to do independent capital cost estimates of proposed transmission solutions ("Avangrid Amendment"). The Avangrid Amendment passed with 66.8% in favor[7] and was

[4] Tariff revisions for Phase 1 of the Longer-Term Transmission Planning project were accepted by the Commission effective February 25, 2022 in FERC Docket No. ER22-727. As part of those revisions, "State-identified Requirements" are defined in Section I.2 of the Tariff as "a legal requirement, mandate or policy of a New England state or local government that forms the basis for a Longer-Term Transmission Study request submitted to the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT."

[5] These Supplemental Process Proposal provisions are found in Attachment K of the OATT, Sections 16.4(j) and 16.8, and in in Section 10(b) to Schedule 12 of the OATT.

[6] The Transmission Committee meetings were on October 17, 2023, November 21, 2023, December 21, 2023, January 23, 2024, February 29, 2024 and March 27, 2024.

[7] The following 4 Sectors were all in favor: (Transmission, Supplier, Publicly Owned Entity, and End User); 2 Sectors were all opposed (Generation and AR). No Participant from the Provisional Member

adopted by ISO-NE into its Core Process Proposal, and is also reflected in the Supplemental Process Proposal. Ultimately, the Transmission Committee voted separately on the Core Process Proposal (as amended) and the Supplemental Process Proposal, with each passing unanimously (with two abstentions noted).

Separately, the Reliability Committee reviewed a proposed conforming change for inclusion in the larger package of Revisions, and at its March 19 meeting, the Reliability Committee, based on a voice vote, unanimously recommended Participants Committee support for that conforming change.

<u>Resolutions for Participants Committee Action</u>

> RESOLVED, that the Participants Committee supports the Longer-Term Planning Revisions ***Core Process Proposal***, as recommended by the Transmission Committee and the Reliability Committee, and as reflected in the materials distributed to the Participants Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Transmission Committee.
>
> RESOLVED, that the Participants Committee supports the Longer-Term Planning Revisions ***Supplemental Process Proposal***, as recommended by the Transmission Committee, and as reflected in the materials distributed to the Participants Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Transmission Committee.

Group Seat voted. 20 abstentions were also recorded (Generation (5), Supplier (5), AR (4), and End User (6)).

memo

To: NEPOOL Transmission Committee and NEPOOL Reliability Committee

From: Brent Oberlin, Executive Director, Transmission Planning

Date: March 21, 2024

Subject: Extended-term/Longer-term Transmission Planning Phase 2

The ISO is requesting a vote on the Extended-term/Longer-term Transmission Planning Phase 2 proposal. The proposal creates a competitive request for proposal (RFP) process in connection with the findings from the Longer-Term Transmission Studies (LTTS). This project responds to the New England States' Vision for a Clean, Affordable and Reliable 21st Century Regional Electric Grid by creating an optional process for the states to enable the development of transmission to address anticipated system concerns and documents the associated cost allocation.

The Transmission Committee (TC) will take action on Section I.2 of the Transmission Markets, and Services Tariff, as well as revisions to Sections II.8, II.46, II.49, Attachment K, Attachment N, Attachment O, Attachment P, Schedule 12, and Schedule 12C of the Open Access Transmission Tariff (OATT), along with new Schedule 14A to the OATT.

The Reliability Committee will take action on a conforming change to Section III.12.6.4 of Market Rule 1, to pull through a cross reference to the OATT's Attachment K Section 16 added so that Longer-Term Transmission Upgrades can be included in FCM modeling.

At the TC, the proposal will be voted under two constructs, the core proposal and the core plus a supplemental proposal. At the RC, the conforming change relates to the core proposals and therefore applies to both.

The proposal for the committees' consideration at their March meetings have been presented on the meeting dates outlined below:

Transmission Committee

- October 17, 2023; agenda item #2
- November 21, 2023; agenda item #2
- December 21, 2023; agenda item #4
- January 23, 2024; agenda item 4
- February 29, 2024; agenda item #4 and agenda item 5
- March 27, 2024; agenda item #3 and agenda item #4

Reliability Committee

- February 13-14; agenda item #6
- March 19, 2024; agenda item #8

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I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

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

(b) words denoting a gender include all genders;

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

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

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

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

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

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

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

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

Capacity Rationing Rule addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

~~**Capacity Scarcity Condition** is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.~~

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 of Market Rule 1.

Capacity Transfer Rights (CTRs) are calculated in accordance with Section III.13.7.5.4.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Zone is a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of Market Rule 1.

Capacity Zone Demand Curves are the demand curves used in the Forward Capacity Market for a Capacity Zone as specified in Sections III.13.2.2.2 and III.13.2.2.3.

Capital Funding Charge (CFC) is defined in Section IV.B.2 of the Tariff.

Incremental ARR Holder is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

Incremental Cost of Reliability Service is described in Section III.13.2.5.2.5.2 of Market Rule 1.

Independent Transmission Company (ITC) is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

Information Request is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Requirement means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

Interchange Transactions are transactions deemed to be effected under Market Rule 1.

Interconnecting Transmission Owner has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Agreement is the "Large Generator Interconnection Agreement", ~~–~~the "Small Generator Interconnection Agreement", or the "Elective Transmission Upgrade Interconnection Agreement" pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

Interconnection Customer has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Procedure is the "Large Generator Interconnection Procedures", the "Small Generator Interconnection Procedures", or the "Elective Transmission Upgrade Interconnection Procedures" pursuant to Schedules 22, 23, and 25 of the ISO OATT.

Interconnection Reliability Operating Limit (IROL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

Interconnection Request has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Interface Bid is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

Intermittent Power Resource is a wind, solar, run of river hydro or other renewable resource that does not have control over its net power output.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local Longer-Term Transmission Upgrade is any addition, modification, and/or upgrade to the New England Transmission System with a voltage level below 115 kV that is required in connection with the construction of a Longer-Term Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Section 16 of Attachment K to the OATT.

Local Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115 kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is a value calculated as described in Section III.12.2.1 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are costs that the ISO, with advisory input from the Reliability Committee, determines in accordance with Schedule 12C of the OATT shall not be included in the Pool-Supported PTF costs recoverable under this OATT, or in costs allocated to Regional Network Load according to Section 6 and Section 10 of Schedule 12. If there are any Localized Costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

Long Lead Time Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 and Schedule 25 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Longer-Term Proposal is a proposal submitted by a Qualified Transmission Project Sponsor pursuant to Section 16.4(b) of Attachment K to the OATT.

Longer-Term Transmission Solution is the Longer-Term Proposal identified as the preferred solution pursuant to Section 16 of Attachment K to the OATT.

Longer-Term Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT. The 2050 Transmission Study shall be the first Longer-Term Transmission Study.

Longer-Term Transmission Upgrade is an addition, modification, and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Longer-Term Transmission Upgrade PTF classification specified in the OATT and has been included in the Regional System Plan and RSP Project List as a Longer-Term Transmission Upgrade pursuant to the procedures described in Section 16 of Attachment K of the OATT.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset, or the consumption of a Dispatchable Asset Related Demand, is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Selected Qualified Transmission Project Sponsor is the Qualified Transmission Project Sponsor that proposed the Phase Two Solution, ~~or~~ Stage Two Solution, or Longer-Term Proposal that has been identified by the ISO as the preferred Phase Two Solution, ~~or~~ Stage Two Solution, or Longer-Term Transmission Solution.

Selected Qualified Transmission Project Sponsor Agreement is the agreement between the ISO and a Selected Qualified Transmission Project Sponsor. The Selected Qualified Transmission Project Sponsor Agreement is provided in Attachment P to the OATT.

Self-Schedule is the action of a Market Participant in committing its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Generator Asset or DARD would have been committed by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of the LMP. Demand Response Resources are not permitted to Self-Schedule.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that officer.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Sponsored Policy Resource is a New Capacity Resource that: receives a revenue source, other than revenues from ISO-administered markets, that is supported by a government-regulated rate, charge, or other regulated cost recovery mechanism, and; qualifies as a renewable, clean, zero carbon, or alternative energy resource under a renewable energy portfolio standard, clean energy standard, decarbonization or net-zero carbon standard, alternative energy portfolio standard, renewable energy goal, clean energy goal, or decarbonization or net-zero carbon goal enacted by federal or New England state statute, regulation, or executive or administrative order and as a result of which the resource receives the revenue source.

Stage One Proposal is a first round submission, as defined in ~~Sections~~ Section- 4A.~~5~~ 6 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.~~5~~ 8 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stakeholder-Requested Scenario is an Economic Study reference scenario that is described in Section 17.2(d) of Attachment K to the OATT.

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated

II.8 Billing and Invoicing; Accounting

II.8.1 Billing Procedure: Billings to Transmission Customers shall be made in accordance with this Section II.8, Schedules 18, 20 and 21 and the ISO New England Billing Policy, as applicable, and as may be supplemented by other billing procedures established pursuant to the TOA, a MTOA or an OTOA, as applicable.

II.8.2 Invoicing: Invoicing and payments are addressed in Attachments L1, L2, L3 and L4 to Section II of the Transmission, Markets and Services Tariff.

II.8.3 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) will be calculated in accordance with the methodology specified for interest on refunds in 18 C.F.R. §35.19a(a)(2)(iii) of the Commission's regulations. Interest on delinquent amounts will be calculated from the due date of the bill to the date of payment. Payments must be made by Electronic Funds Transfer or in immediately available funds.

II.8.4 Customer Default: In the event a Transmission Customer fails to make payment to the ISO for services under this OATT, other than under Schedules 18, 20 and 21 of this OATT, on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the ISO notifies the Transmission Customer to cure such failure, a default by the Transmission Customer will be deemed to exist under this OATT. Additional default provisions may apply as stated under the ISO New England Billing Policy, Exhibit ID to Section I of the Transmission, Markets and Services Tariff. Upon the occurrence of a default under this OATT, the ISO may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission approves such termination. In the event of a billing dispute between the ISO and the Transmission Customer, service will continue to be provided under a Service Agreement, and service termination proceedings will not be initiated as long as the Transmission Customer continues to make all payments invoiced by the ISO, including any disputed amounts, subject to resolution of such dispute in favor of such Transmission Customer. If the Transmission Customer fails to meet this requirement for continuation of service, then the ISO may provide notice to the Transmission Customer of the ISO's intention to suspend service in sixty days, in accordance with applicable Commission rules and regulations, and may proceed with such suspension.

II.8.5 Study Costs and Revenues: Transmission Owners shall (i) include in a separate operating revenue account or sub-account the revenues, if any, it receives from transmission service when making Third-Party Sales under Section II of the Tariff, and (ii) include in a separate transmission operating expense account or sub-account, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies which the Transmission Owner conducts or is subcontracted to conduct to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including Third-Party Sales, if any, under this OATT; and include in a separate operating revenue account or sub-account the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in a billing under the OATT.

II.8.6 Billing and Invoicing For Other Services and Transactions: Billings and invoicing for MTF Service, OTF Service, Local Service, Excepted Transactions, Grandfathered Intertie Agreements and MEPCO Grandfathered Transmission Service Agreements will be made pursuant to the terms and conditions of Schedules 18, 20 and 21 of this OATT, Excepted Transactions, Grandfathered Intertie Agreements or MEPCO Grandfathered Transmission Service Agreements under which service is provided.

II.8.7 Study Costs and Revenues of a Non-Incumbent Transmission Developer: Non-Incumbent Transmission Developers that are not otherwise party to the TOA shall include in a separate transmission operating expense account or sub-account, costs properly chargeable to expenses that are incurred to perform studies for Phase One Proposals and Phase Two Solutions, and Stage One Proposals and Stage Two Solutions pursuant to Attachment K of this OATT; and include in a separate operating revenue account or sub-account the revenues received for such studies when such amounts are separately stated and identified in a billing under the OATT.

II.8.8 Refund Obligations and Surcharge Rights Associated With Adjustments to Regional and Local Rates: The ISO, PTOs and Non-Incumbent Transmission Developers shall (consistent with Attachment L4 to this OATT) calculate refunds from the PTOs or Non-Incumbent Transmission Developers to the ISO and/or surcharges by the PTOs or Non-Incumbent Transmission Developers to the ISO, which will be passed through by the ISO to its Customers, attributable to adjustments associated with charges under Attachment F and Schedules 1, 8, 9, 13, ~~and~~ 14, and 14A of this OATT resulting from: (i) an audit of the regional rates; (ii) a Commission order, including, without limitation, orders approving settlements and letter orders or (iii) a billing correction. Any recalculations shall be made as though any such adjustments had been in effect as of the effective date of the required change(s), with interest to the extent required by applicable order or contract. The affected PTO(s) or Non-Incumbent Transmission Developer(s) shall individually calculate any refunds and/or surcharges associated with any changes in the rates under their respective Local Service Schedules or other rate recovery mechanisms, as appropriate. The ISO, PTOs and Non-Incumbent Transmission Developers shall, to the extent necessary, reasonably cooperate with each other in performing such recalculations. The refund obligations to the ISO associated with such adjustments to rates under Schedules 1, 8, 9 and 21 shall be several, and not joint, obligations and rights of the PTOs; the refund obligations to the ISO associated with such adjustments to rates under Schedules 13, ~~and~~ 14, and 14A shall be several, and not joint, obligations and rights of the Non-Incumbent Transmission Developers.

II.8.9 Creditworthiness: The creditworthiness procedures are specified in Attachments L1 through L4 to this OATT.

II.46 General

Additions to or modifications of the PTF may be required or permitted under this OATT, and be subject to related rights, obligations and procedures, in any of the following circumstances:

(a) An addition or modification may be required under Part II.B or Part II.C of the OATT in order to meet a new request for Regional Network Service or Through or Out Service. Where such an addition or modification is to be effected, the rights and obligations of the ISO, the PTOs and Transmission Customers shall be determined in accordance with the applicable provisions of Parts II.B and II.C of this OATT.

(b) An addition or modification may be required to permit the interconnection of a new or modified generating unit or the interconnection of an Elective Transmission Upgrade. Where such an addition or modification is to be effected, the rights and obligations of the ISO, the PTOs, and the Generator Owner or applicant for an Elective Transmission Upgrade, shall be determined in accordance with Section II.47 of this OATT and Schedules 11, 12, 22, 23, and 25 to this OATT.

(c) A Reliability Transmission Upgrade, Market Efficiency Transmission Upgrade, NEMA Upgrade, ~~or~~ Public Policy Transmission Upgrade, or Longer-Term Transmission Upgrade may be required or proposed pursuant to a Regional System Plan and Attachment K of this OATT. Where a Reliability Transmission Upgrade, Market Efficiency Transmission Upgrade, NEMA Upgrade, ~~or~~ Public Policy Transmission Upgrade or Longer-Term Transmission Upgrade is to be effected, the rights and obligations of the ISO, the PTOs, Non-Incumbent Transmission Developers, and Transmission Customers shall be determined in accordance with the TOA, the NTDOA, Schedule 12 and Attachment K, as applicable.

(d) Consistent with reliability and safety standards, Transmission Owners, and operators of affected Local Control Centers in New England Control Area and the ISO will coordinate scheduled generation and transmission facility outages so as to minimize, to the extent practicable, Congestion Costs and Local Second Contingency Protection Resource NCPC Charges (as calculated pursuant to Market Rule 1) in accordance with the TOA, MTOA and applicable ISO New England Operating Procedures. The ISO shall provide Transmission

Owners and the operators of the affected Local Control Centers with such information as is necessary to enable them to perform this function. Any information provided to Transmission Owners and the operators of the affected Local Control Centers pursuant to this provision will be subject to all the applicable requirements of the Commission's Order 889.

These provisions for PTF additions and modifications are not intended to be exclusive.
Nothing in this OATT is intended to preclude any entity from identifying and constructing Elective Transmission Upgrades on a merchant or other basis, so long as it obtains all required legal rights and approvals and satisfies applicable ISO and affected Transmission Owner requirements relating to such facilities.

An addition or modification under the TOA which constitutes PTF under the OATT shall become part of the PTF and shall be fully subject to this OATT, whether or not all or any part of the costs of the addition or modification are included in Pool Supported PTF costs. The transmission priorities, if any, with respect to the use of the addition or modification as among the owner and supporters of the addition or modification and other Transmission Customers shall be determined under Parts II.A to II.D, inclusive, of this OATT.

To the extent that a Generator Owner is responsible for the costs of a Generator Interconnection Related Upgrade or Elective Transmission Upgrade, or an entity other than a Generator Owner is responsible for costs of any other system upgrade, the Generator Owner or entity which supports part or all of the costs of the addition or modification shall be entitled to a share of any associated Incremental ARRs equivalent to the share of the total costs of such upgrade which it supports, as assigned and allocated in accordance with Appendix C of Market Rule 1. Any incremental FTRs resulting from Generator Interconnection Related Upgrades or other upgrades shall be auctioned along with other FTRs in accordance with Section 7 of Market Rule 1.

If issues of cost allocation arise with respect to the recovery of any of the costs provided for in this Part II.G of this OATT, or in Schedules 9, 11, 12, 13, ~~or~~ 14, or 14A to this OATT, such issues shall be subject to determination by the Commission in the appropriate proceeding.

II.49 Definition of PTF

PTF or Pool Transmission Facilities are the transmission facilities owned by PTOs, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the TOA, rated 69 kV or above required to allow energy from significant power sources to move freely on the New England Transmission System, and include:

1. All transmission lines and associated facilities owned by PTOs rated 69 kV and above, except for lines and associated facilities that (i) were not built as Public Policy Transmission Upgrades or Longer-Term Transmission Upgrades and (ii) contribute little or no parallel capability to the PTF. The following do not constitute PTF:

   (a) Unless they were built as part of a Public Policy Transmission Upgrade or a Longer-Term Transmission Upgrade,

      i. Those lines and associated facilities which are required to serve local load only,

      ii. Generator leads, which are defined as radial transmission from a generation bus to the nearest point on the PTF; or

      iii. Lines that are normally operated open.

   (b) Lines and associated facilities that are classified as MTF or OTF.

2. All Public Policy Transmission Upgrades and Longer-Term Transmission Upgrades that comprise transmission lines rated 115 kV or above, and associated facilities rated 115 kV or above, owned by PTOs, and identified pursuant to Attachment K to the OATT shall constitute PTF.

3. Parallel linkages in network stations owned by PTOs (including substation facilities such as transformers, circuit breakers and associated equipment) interconnecting the lines which constitute PTF.

4. If a PTOs with significant generation in its transmission and distribution system (initially 25 MW) is connected to the New England Transmission System and none of the transmission

facilities owned by the PTO qualify to be included in PTF as defined in (1), (2) and (3) above, then such PTO's connection to PTF will constitute PTF if both of the following requirements are met for this connection:

(a) The connection is rated 69 kV or above.

(b) The connection is the principal transmission link between the PTO and the remainder of the PTF network.

5. Rights of way and land owned by PTOs required for the installation of facilities that constitute PTF under (1), (2), (3) or (4) above.

The ISO shall review at least annually the status of transmission lines and associated facilities and determine whether such facilities constitute PTF and shall prepare and keep current a schedule or catalogue of PTF facilities.

The following examples indicate the intent of the above definitions:

Unless they were built as part of a Public Policy Transmission Upgrade or Longer-Term Transmission Upgrade, radial tap lines to local load are excluded.

Lines which loop, from two geographically separate points on the PTF, the supply to a load bus from the PTF are included.

Lines which loop, from two geographically separate points on the PTF, the connections between a generator bus and the PTF are included.

Radial connections or connections from a generating station to a single substation or switching station on the PTF are excluded, unless the requirements of paragraph (2) or (4) above are met.

Transmission facilities owned or supported by a Related Person of a PTO which are rated 69 kV or above and are required to allow Energy from significant power sources to move freely on the New England Transmission System shall also constitute PTF provided (i) such Related Person files with the ISO its consent to such treatment; and (ii) the ISO determines that treatment of the facilities as PTF will facilitate accomplishment of the ISO's objectives. If such facilities constitute PTF pursuant to this paragraph, they shall be treated as "owned" or "supported," as applicable, by a PTO for purposes of this OATT and the other provisions of the TOA, including the ability to include the cost associated with such PTF and any Transmission Support Expenses for support of PTF made by its Related Person in that PTO's Annual Transmission Revenue Requirements, pursuant to Attachment F of the OATT.

Of those transmission facilities that are upgrades, modifications or additions, on and after January 1, 2004, to the transmission system administered by the ISO under the Interim Independent System Operator Agreement, or to the New England Transmission System on or after the Operations Date, only those that: (i) are rated 115kV or above, and (ii) otherwise meet the non-voltage criteria specified in Section II.49 shall be classified as PTF. Those transmission facilities that were PTF pursuant to the Restated NEPOOL Agreement on December 31, 2003, and any upgrades to such facilities that meet the criteria specified in Section II.49, shall remain classified as PTF for all purposes under this Tariff.

SCHEDULE 14A

RECOVERY OF LONGER-TERM TRANSMISSION UPGRADE COSTS BY NON-INCUMBENT TRANSMISSION DEVELOPERS

1. Applicability

1.1 Use by Non-Incumbent Transmission Developers

This schedule is to be utilized by Non-Incumbent Transmission Developers that: (i) are not also Participating Transmission Owners, and (ii) are Qualified Transmission Project Sponsors. This schedule is designed to enable the recovery of all prudently incurred costs following the execution of the Selected Qualified Transmission Sponsor Agreement, to the extent permitted in Section 16 of Attachment K to this OATT, for Longer-Term Transmission Upgrades, and the recovery of "construction work in progress" costs stemming from a Longer-Term Transmission Upgrade.

1.2 Costs Recovered Under Schedule 14A May Not Also Be Recovered Through Another Schedule

Any costs recovered by the Non-Incumbent Transmission Developer under this Schedule 14A cannot also be recovered under another Schedule to this OATT.

1.3 Transfer of Unrecovered Costs Upon Execution of the Transmission Operating Agreement

Following the execution of the Transmission Operating Agreement by the Non-Incumbent Transmission Developer, any costs that are not already recovered under this Schedule 14A may be recovered under the appropriate cost recovery mechanism set forth in this OATT, as appropriate.

2. Section 205 Rate Filing; Invoicing

2.1 Section 205 Rate Filing

Prior to recovering any Longer-Term Transmission Upgrade costs and in accordance with Section 16 of Attachment K to this OATT, a Non-Incumbent Transmission Developer shall submit a filing with the Commission pursuant to Section 205 of the Federal Power Act requesting approval of the actual Longer-Term Transmission Upgrade costs and the period of time over which the costs are to be recovered. Upon approval by the Commission, such terms of recovery shall be included in discrete schedules to this Schedule 14A. The Non-Incumbent Transmission

Developer shall notify the ISO of the Commission-approved Longer-Term Transmission Upgrade costs and the applicable recovery period recognized in the Commission Order.

2.2 Invoicing and Collection by ISO

The ISO acts as counterparty for the billing and collection agent for Non-Incumbent Transmission Developers for recovery of their Commission-approved Longer-Term Transmission Upgrade costs, in accordance with Section 16 of Attachment K to this OATT. Upon notification from a Non-Incumbent Transmission Developer of the Commission Order approving costs for recovery, the ISO shall allocate and invoice costs consistent with the applicable cost allocation established in accordance with Section 16 of Attachment K to this OATT. The ISO shall disburse the monthly collected amounts to the Non-Incumbent Transmission Developer, as appropriate.

3. Construction Work in Progress Costs

3.1 Section 205 Rate Filing

In accordance with the terms of the Non-Incumbent Transmission Developer Operating Agreement, a Non-Incumbent Transmission Developer may submit filings to the Commission pursuant to Section 205 of the Federal Power Act for recovery of its “construction work in progress” costs associated with a Longer-Term Transmission Upgrade. Upon approval by the Commission, such terms of recovery shall be included in discrete schedules to this Schedule 14A.

ATTACHMENT K
REGIONAL SYSTEM PLANNING PROCESS

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APPENDIX 1 – ATTACHMENT K – LOCAL: LOCAL SYSTEM PLANNING PROCESS

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1. Overview

This Attachment describes the regional system planning process conducted by the ISO, as well as the coordination with transmission-owning entities in, or other entities interconnected to, the New England Transmission System and neighboring systems to ensure the reliability of the New England Transmission System and compliance with national and regional planning standards, criteria and procedures, while accounting for market performance, economic, environmental, and other considerations, as may be agreed upon from time to time. The New England Transmission System is comprised of PTF, Non-PTF, OTF and MTF within the New England Control Area that is under the ISO's operational authority or control pursuant to the ISO Tariff and/or various transmission operating agreements. This Attachment describes the regional system planning process for the PTF conducted by the ISO, and local system planning process conducted by the PTOs, pursuant to their responsibilities defined in the Tariff, the various transmission operating agreements and this Attachment. Additional details regarding the regional system planning process are also provided in the ISO New England Planning Procedures and ISO New England Operating Procedures, which are available on the ISO's website.

The ISO shall conduct the regional system planning process for the PTF in coordination with the transmission-owning entities in, or other entities interconnected to, the New England Transmission System and neighboring systems, consistent with the rights and obligations defined in the Tariff, applicable transmission operating agreements and this Attachment. As described in this Attachment's Section 6 and Appendix 1, entitled "Attachment K -Local System Planning Process", the PTOs are responsible for the Local System Planning ("LSP") process for the Non-PTF in the New England Transmission System. As also described in Section 6, and pursuant to the Tariff and/or transmission operating agreements, the OTOs and MTOs are required to participate in the ISO's regional system planning process for reliability purposes and to perform and/or support studies of the impact of regional system planning projects on their respective OTF and MTF.

The regional system planning process described in this Attachment provides for the ISO to undertake assessments of the needs of the PTF system on a systemwide or specific area basis. These assessments shall be referred to as Needs Assessments, as described in Section 4.1 of this Attachment. The ISO shall incorporate market responses that have met the criteria specified in Sections 4.1(f) and 4A.3(b) of this Attachment into the Needs Assessments, Public Policy Transmission Studies or the Regional System Plan ("RSP"), described below. Where market responses incorporated into the Needs Assessments or Public

Policy Transmission Studies do not eliminate or address the needs identified by the ISO in Needs Assessments, Public Policy Transmission Studies or the RSP, the ISO shall develop or evaluate, pursuant to Sections 4.2(b), 4.3, or 4A of this Attachment, as applicable, regulated transmission solutions proposed in response to the needs identified by the ISO.

Pursuant to Sections 3 and 7 of this Attachment, the ISO shall develop the RSP for approval by the ISO Board of Directors following stakeholder input through the Planning Advisory Committee established pursuant to Section 2 of this Attachment. The RSP is a compilation of the regional system planning process activities conducted by the ISO. The RSP shall address needs of the PTF system determined by the ISO through Needs Assessments initiated and updated on an ongoing basis by the ISO to: (i) account for changes in the PTF system conditions; (ii) ensure reliability of the PTF system; (iii) comply with national and regional planning standards, criteria and procedures; and (iv) account for market performance, economic, environmental and other considerations as may be agreed upon from time to time.

As more fully described in Section 3 of this Attachment, the RSP shall identify:

(i) PTF system reliability and market efficiency needs,

(ii) the requirements and characteristics of the types of resources that may satisfy PTF system reliability and market efficiency needs to provide stakeholders an opportunity to develop and propose efficient market responses to meet the needs identified in Needs Assessments;

(iii) regulated transmission solutions to meet the needs identified in Needs Assessments where market responses do not address such needs or additional transmission infrastructure may be required to comply with national and regional planning standards, criteria and procedures or provide market efficiency benefits in accordance with Attachment N of this OATT; ~~and~~

(iv) those projects identified through the Public Policy procedures described in Section 4A of this Attachment K; and

(v) those projects identified through the longer-term transmission planning procedures described in Section 16 of this Attachment K.

In addition, the RSP shall also provide information on a broad variety of power system requirements that serves as input for reviewing the design of the markets and the overall economic performance of the system. The RSP shall also describe the coordination of the ISO's regional system plans with regional, local and inter-area planning activities.

Pursuant to Section 3.6 of this Attachment, the ISO shall also develop, maintain and post on its website a cumulative list reflecting the regulated transmission solutions proposed in response to Needs Assessments (the "RSP Project List"). The RSP Project List shall be a cumulative representation of the regional transmission planning expansion efforts ongoing in New England.

1.1 Enrollment

For purposes of participating as a transmission provider in the New England transmission planning region pursuant to this Attachment K, and distinct from Transmission Providers as defined in Section I of this Tariff, an entity chooses to enroll by executing (or having already executed) a: (i) transmission operating agreement with the ISO, or (ii) a Market Participant Service Agreement coupled with a written notification to the ISO that the entity desires to be a transmission provider in the New England region. Such enrollment in the transmission planning region is not necessary to participate in the Planning Advisory Committee, which is open to any entity as described in Section 2.3 of this Attachment K.

1.2 A List of Entities Enrolled in the Planning Region

A list of entities enrolled in the transmission planning region as transmission providers as described in Section 1.1. above, is included as Appendix 2 of this Attachment K.

2. Planning Advisory Committee

2.1 Establishment

A Planning Advisory Committee shall be established by the ISO to perform the functions set forth in Section 2.2 of this Attachment. It shall have a Chair and Secretary, who shall be appointed by the chief executive officer of the ISO or his or her designee. Before appointing an individual to the position of the Chair or Secretary, the ISO shall notify the Planning Advisory Committee of the proposed assignment and, consistent with its personnel practices, provide any other information about the individual reasonably requested by the Planning Advisory Committee. The chief executive officer of the ISO or his or her designee shall consider the input of the members of the Planning Advisory Committee in selecting, removing or replacing such officers. The Planning Advisory Committee shall be advisory only and shall have no formal voting protocol.

The ISO may form subcommittees that, at the discretion of the ISO, may report to the Planning Advisory Committee.

2.2 Role of Planning Advisory Committee

The Planning Advisory Committee may provide input and feedback to the ISO concerning the regional system planning process, including the development of and review of Needs Assessments, the conduct of Solutions Studies, the development of the RSP, and updates to the RSP Project List. Specifically, the Planning Advisory Committee serves to review and provide input and comment on: (i) the development of the RSP, (ii) assumptions for studies, (iii) the results of Needs Assessments, Solutions Studies, and competitive solutions developed pursuant to Section 4.3 of this Attachment, (iv) potential market responses to the needs identified by the ISO in a Needs Assessment or the RSP, (v) Cluster Enabling Transmission Upgrades Regional Planning Studies, (vi) the results of Public Policy Transmission Studies and competitive solutions developed pursuant to Section 4A of this Attachment, and (vii) Longer-Term Transmission Studies and competitive solutions developed pursuant to Section 16 of this Attachment. The Planning Advisory Committee, with the assistance of and in coordination with the ISO, serves also to identify and prioritize the Stakeholder-Requested Scenario and stakeholder-requested scenario sensitivities for Economic Studies to be performed by the ISO, and provides input and feedback to the ISO concerning the conduct of Economic Studies~~, and Public Policy Transmission Studies,~~ including the criteria and assumptions~~ for such studies~~. Based on input and feedback related to the regional system planning process provided by the Planning Advisory Committee to the ISO, the ISO shall consult with the appropriate NEPOOL technical committees, including but not limited to, the Markets, Reliability and Transmission Committees, on issues and concerns identified by the Planning Advisory Committee as requiring further investigation and consideration of potential changes to ISO New England Operating Documents.

2.3 Membership

There are no membership requirements to become part of the Planning Advisory Committee. Meetings are open to members of any entity, including State regulators or agencies and NESCOE, subject to the Critical Energy Infrastructure Information ("CEII") policy as further described in Section 2.4(d) of this Attachment. To be added to the Planning Advisory Committee email distribution list, an email address shall be provided to the Secretary of the Committee. Throughout this Attachment K, a member of the Planning Advisory Committee refers to any individual, whether they attend Planning Advisory Committee meetings or are included on the email distribution list.

2.4 Procedures

(a) Notice of Meetings

Prior to the beginning of each year, the ISO shall list on the ISO Calendar, which is available on the ISO's website, the proposed meeting dates for the Planning Advisory Committee for each month of the year. Prior to a Planning Advisory Committee meeting, the ISO shall provide notice to the Planning Advisory Committee by electronic email with the date, time, format for the meeting (i.e., in person or teleconference), and the purpose for the meeting.

(b) Frequency of Meetings

Meetings of the Planning Advisory Committee shall be held as frequently as necessary to serve the purposes stated in Section 2.2 of this Attachment and as further specified elsewhere in this Attachment, generally expected to be no less than four (4) times per year.

(c) Availability of Meeting Materials

The ISO shall post materials for Planning Advisory Committee meetings on the Planning Advisory Committee section on the ISO's website prior to meetings. The materials for the Planning Advisory Committee meetings shall be made available to the members of the Planning Advisory Committee subject to protections warranted by confidentiality requirements of the ISO New England Information Policy set forth in Attachment D of the ISO Tariff and Critical Energy Infrastructure Information ("CEII") policy as further described in Section 2.4(d) of this Attachment.

(d) Access to Planning-Related Materials that Contain CEII

CEII is defined as specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure (physical or virtual) that:

(i) Relates details about the production, generation, transportation, transmission, or distribution of energy;

(ii) Could be useful to a person in planning an attack on critical infrastructure;

(iii) Is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552; and

(iv) Does not simply give the location of critical infrastructure.

CEII pertains to existing and proposed system and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters. CEII does not include information that is otherwise publicly available. Simplified maps and general information on engineering, vulnerability, or design that relate to production, generation, transportation, transmission or distribution of energy shall not constitute CEII.

Planning-related materials determined to be CEII will be posted on the ISO's password-protected website. To obtain access to planning-related materials determined to be CEII, the entity seeking to obtain such access must contact the ISO's Customer Service department. Authorized Market Participants or their representatives, such as consultants, are bound by the ISO New England Information Policy and will be able to access CEII materials through the ISO's password-protected website. State and federal governmental agency employees and their consultants will be able to access such materials through the ISO's password-protected website upon submittal of a signed non-disclosure agreement, which is available on the ISO's website. Personnel of the ERO, NPCC, other regional transmission organizations or independent system operators, and transmission owners from neighboring regions will be able to access CEII materials pursuant to governing agreements, rules and protocols. All external requests by other persons for planning-related materials determined to be CEII shall be recorded and tracked by ISO's Customer Services staff. Such requestors will be able to obtain access to CEII documents filed with the Commission pursuant to the Commission's regulations governing access to CEII. To the extent a requestor seeks access to planning-related material that is not filed with the Commission, such requestor shall comply with the requirements provided in the CEII procedures of the ISO, available on the ISO's website, prior to receiving access to CEII information. Upon compliance with the ISO's CEII procedures, the ISO shall grant the requestor access to the planning-related CEII document through direct distribution or access to the ISO password-protected website.

2.5 Local System Planning Process

The LSP process described in Appendix 1 to this Attachment applies to the transmission system planning for the Non-PTF in the New England Transmission System. The PTOs will utilize interested members of the Planning Advisory Committee for advisory stakeholder input in the LSP process that will meet, as needed, at the conclusion of, or independent of, scheduled Planning Advisory Committee meetings. The LSP meeting agenda and meeting materials will be developed by representatives of the pertinent PTOs and PTO representatives will chair the LSP meeting. The ISO will post the LSP agenda and materials for LSP.

3. RSP: Principles, Scope, and Contents

3.1 Description of RSP

The ISO shall develop the RSP based on periodic comprehensive assessments (conducted not less than every third year) of the PTF systemwide needs to maintain the reliability of the New England Transmission System while accounting for market efficiency, economic, environmental, and other considerations, as agreed upon from time to time. The ISO shall update the RSP to reflect the results of ongoing Needs Assessments conducted pursuant to Section 4.1 of this Attachment. The RSP shall also account for projected improvements to the PTF that are needed to maintain system reliability in accordance with national and regional standards and the operation of efficient markets under a set of planning assumptions.

The RSP shall, among other things:

(i) describe, in a consolidated manner, the assessment of the PTF system needs, the results of such assessments, and the projected improvements;

(ii) provide the projected annual and peak demands for electric energy for a five-to ten-year horizon, the needs for resources over this period and how such resources are expected to be provided;

(iii) specify the physical characteristics of the physical solutions that can meet the needs defined in the Needs Assessments and include information on market responses that can address them; and

(iv) provide sufficient information to allow Market Participants to assess the quantity, general locations, operating characteristics and required availability criteria of the type of incremental supply or demand-side resources, or merchant transmission projects, that would satisfy the identified needs or that may serve to modify, offset or defer proposed regulated transmission upgrades.

The RSP shall also include a description of proposed regulated transmission solutions that, based on the Solutions Studies described in Section 4.2 of this Attachment and the competitive solution process described in Sections 4.3 and 16 of this Attachment, meets the needs identified in the Needs Assessments. To this end, as further described in Section 3.6 below, the ISO shall develop and maintain a RSP Project List, a cumulative listing of proposed regulated transmission solutions classified, to the extent known, as Reliability Transmission Upgrades, Market Efficiency Transmission Upgrades, Longer-Term Transmission Upgrades, and Public Policy Transmission Upgrades (which, for the foregoing types of upgrades, –may include the portions of Interregional Transmission Projects located within the New England Control Area) and of External Transmission Projects. The RSP shall also provide reasons for any new regulated transmission solutions or Transmission Upgrades included in the RSP Project List, any change in status of a regulated transmission solution or Transmission Upgrade in the RSP Project List, or for any removal of regulated transmission solutions or Transmission Upgrades from the RSP Project List that are known as of that time.

Each RSP shall be built upon the previous RSP.

3.2 Baseline of RSP

The RSP shall account for: (i) all projects that have met milestones, including market responses and regulated transmission solutions (e.g., planned demand-side projects, generation and transmission projects and Elective Transmission Upgrades) as determined by the ISO, in collaboration with the Planning Advisory Committee, pursuant to Sections 4.1, 4.2, 4.3, ~~and~~ 4A, and 16 of this Attachment; and (ii) the requirements for system operation and restoration services, not including the development of a system operations or restoration plan, which is outside the scope of the regional system planning process.

3.3 RSP Planning Horizon and Parameters

The RSP shall be based on a five-to ten-year planning horizon, and reflect five-to ten-year capacity and load forecasts.

The RSP shall conform to: Good Utility Practice; applicable Commission compliance requirements related to the regional system planning process; applicable reliability principles, guidelines, criteria, rules, procedures and standards of the ERO, NPCC, and any of their successors; planning criteria adopted and/or developed by the ISO; Transmission Owner criteria, rules, standards, guides and policies developed by the Transmission Owner for its facilities consistent with the ISO planning criteria, the applicable criteria of the ERO and NPCC; local transmission planning criteria; and the ISO New England Planning Procedures and ISO New England Operating Procedures, as they may be amended from time to time (collectively, the “Planning and Reliability Criteria”).

The revisions to this Attachment K submitted to comply with FERC’s Order No. 1000 shall not apply to any Proposed or Planned project included in an RSP approved by the ISO Board of Directors (or in an RSP Project List update) prior to the May 18, 2015 effective date of the Order No. 1000 compliance filing of the ISO and the PTOs, unless the ISO is re-evaluating the solution design for such project as of that effective date, or subsequently determines that the solution design for such project requires re-evaluation.

3.4 Other RSP Principles

The RSP shall be designed and implemented to: (i) avoid unnecessary duplication of facilities; (ii) identify facilities that are necessary to meet Planning and Reliability Criteria; (iii) avoid the imposition of unreasonable costs upon any Transmission Owner, Transmission Customer or other user of a transmission facility; (iv) take into account the legal and contractual rights and obligations of the Transmission Owners and the transmission-related legal and contractual rights and obligations of any other entity; (v) provide for coordination with existing transmission systems and with appropriate inter-area and local expansion plans; and (vi) properly coordinate with market responses, including, but not limited to generation, merchant transmission and demand-side responses.

3.5 Market Responses in RSP

Market responses shall include investments in resources (e.g., demand-side projects, generation and distributed generation) and Elective Transmission Upgrades and shall be evaluated by the ISO, in consultation with the Planning Advisory Committee, pursuant to Sections 4.1(f), 4A.3(b), and 7 of this Attachment.

In developing the RSP, the ISO shall account for market responses: (i) proposed by Market Participants as addressing needs (and any critical time constraints for addressing such needs) identified in an RSP, Needs Assessment, or Public Policy Transmission Study; and (ii) that have proved to be viable by meeting the criteria specified in Section 4.1(f) or 4A.3(b) of this Attachment, as applicable.

Specifically, market responses that are identified to the ISO and are determined by the ISO, in consultation with the Planning Advisory Committee, to be sufficient to alleviate the need for a particular regulated transmission solution or Transmission Upgrade, based on the criteria specified in the pertinent Needs Assessment or RSP, and are judged by the ISO to be achievable within the required time period, shall be reflected in the next RSP and/or in a new or updated Needs Assessment. That particular regulated transmission solution or Transmission Upgrade may continue to be included in the appropriate category on the RSP Project List (as described in Section 3.6 below), subject to the ISO having the flexibility to indicate that the project should proceed at a later date or it may be removed if it is determined to be no longer needed. If the market response does not fully address the defined needs, or if additional transmission infrastructure is required to facilitate the efficient operation of the market, the RSP shall also include that particular regulated transmission solution or Transmission Upgrade, subject to the ISO having the flexibility to indicate that the Transmission Upgrade or regulated transmission solution should proceed at a later date and be modified, if necessary.

3.6 The RSP Project List

(a) Elements of the RSP Project List

The RSP Project List shall identify regulated transmission solutions proposed in response to the needs identified in a RSP or Needs Assessments conducted pursuant to Section 4.1 of this Attachment, ~~and shall identify~~ Public Policy Transmission Upgrades identified pursuant to Section 4A of this Attachment, and Longer-Term Transmission Upgrades identified pursuant to Section 16 of this Attachment. The RSP Project List shall identify the proposed regulated transmission solutions separately as a Reliability Transmission Upgrade, a Market Efficiency Transmission Upgrade, ~~or~~ a Public Policy Transmission Upgrade, or a Longer-Term Transmission Upgrade.

With regard to Reliability Transmission Upgrades, ~~and~~ Market Efficiency Transmission Upgrades, Public Policy Transmission Upgrades, and Longer-Term Transmission Upgrades, the following subcategories will be utilized to indicate the status of each proposed regulated transmission solution in the evaluation process. These subcategories include: (i) Proposed; (ii) Planned; (iii) Under Construction; and (iv) In-Service. ~~A Public Policy Transmission Upgrade will be identified in the RSP Project List as (i) Proposed; (ii) Planned: (iii) Under Construction; or (iv) In-Service.~~

The regulated transmission solution subcategories are defined as follows:

(i) For purposes of Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades, “Proposed” shall include a regulated transmission solution that (a) has been proposed in response to a specific need identified by the ISO in a Needs Assessment or the RSP and (b) has been evaluated or further defined and developed in a Solutions Study, as specified in Section 4.2(a) of this Attachment, or in the competitive solutions process specified in Section 4.3 of this Attachment, such that there is significant analysis that supports a determination by the ISO, as communicated to the Planning Advisory Committee, that the proposed regulated transmission solution would likely meet the need identified by the ISO in a Needs Assessment or the RSP, but has not received approval by the ISO under Section I.3.9 of the Tariff.

For purposes of Public Policy Transmission Upgrades and Longer-Term Transmission Upgrades, “Proposed” means that the ISO has included the project in the RSP Project

List pursuant to the procedures described in Section 4A or 16 of this Attachment K, but that the project has not yet been approved by the ISO under Section I.3.9 of the Tariff.

(ii) "Planned" shall include a Transmission Upgrade that has met the requirements for a Proposed project and has been approved by the ISO under Section I.3.9 of the Tariff.

(iii) "Under Construction" shall include a Transmission Upgrade that has received the approvals required under the Tariff and engineering and construction is underway.

(iv) "In Service" shall include a Transmission Upgrade that has been placed in commercial operation.

The RSP Project List shall also list External Transmission Projects for which cost allocation and, if applicable, operating agreements have been accepted by the Commission, and indicate whether such External Transmission Projects are proposed, under construction or in service.

Each Reliability Transmission Upgrade and Market Efficiency Transmission Upgrade shall be cross-referenced to the specific systemwide or area needs identified in a Needs Assessment or RSP. Each proposed Public Policy Transmission Upgrade shall be cross-referenced in the RSP Project List to a specific Public Policy Transmission Study. Each proposed Longer-Term Transmission Upgrade shall be cross-referenced in the RSP Project List to a specific Longer-Term Transmission Study.

For completeness, the RSP Project List shall also include Elective Transmission Upgrades and transmission facilities (as determined under the ISO interconnection process specified in this OATT) to be built to accommodate new generation, and Elective Transmission Upgrades that have satisfied the requirements of this OATT.

An Interregional Transmission Project developed pursuant to Section 6.3 of this Attachment K may displace a regional Reliability Transmission Upgrade or Market

Efficiency Transmission Upgrade on the RSP Project List where the ISO has determined that the Interregional Transmission Project is a more efficient or cost-effective solution. In the case of an Interregional Transmission Project that could meet the needs met by a Public Policy Transmission Upgrade, the associated Public Policy Transmission Upgrade may be removed from the RSP Project List in the circumstances described, and using the procedures specified, in Section 4A of Attachment K.

(b) Periodic Updating of RSP Project List

The RSP Project List will be updated by the ISO periodically by adding, removing or revising regulated transmission solutions or Transmission Upgrades in consultation with the Planning Advisory Committee and, as appropriate, the Reliability Committee.

Updating of the RSP Project List shall be considered an update of the RSP to be reflected in the next RSP, as appropriate, pursuant to Section 3.1 of this Attachment.

(c) RSP Project List Updating Procedures and Criteria

As part of the periodic updating of the RSP Project List, the ISO: (i) shall modify (in accordance with the provisions of this Attachment) regulated transmission solutions or Transmission Upgrades to reflect changes to the PTF system configurations, including ongoing investments by Market Participants or other stakeholders; (ii) may add to and classify accordingly, regulated transmission solutions; (iii) may remove from the RSP Project List regulated transmission solutions or Transmission Upgrades previously identified in the RSP Project List if the ISO determines that the need for the proposed regulated transmission solution or the approved Transmission Upgrade no longer exists or is no longer feasible; and (iv) may remove from the RSP Project List regulated transmission solutions or Transmission Upgrades that have been displaced by an Interregional Transmission Project in the circumstances described in Section 3.6(a) of this Attachment. With regard to (iii) above, this may include ~~a~~the removal of a regulated transmission solution or Transmission Upgrade because a market response meeting the need reaches the maturity specified in Sections 4.1(f) or 4A.3(b) of this Attachment and has been determined, pursuant to Sections 4.1(f) or 4A.3(b) of this Attachment, to meet the need described in the pertinent Needs Assessment, Public Policy Transmission Study or RSP, as applicable. In doing so, the ISO shall consult with and consider the input from the Planning Advisory Committee and, as appropriate, the Reliability Committee. In addition, the ISO shall remove from the RSP Project List any Public Policy Transmission Upgrade if the ISO determines, with input from the Planning Advisory Committee, that the need to which the Public Policy Transmission Upgrade responds no longer exists. Furthermore, the ISO shall remove from the RSP Project List any Longer-Term Transmission Upgrade if requested to do so in a written NESCOE communication.

If a regulated transmission solution or Transmission Upgrade is removed from the RSP Project List by the ISO, the entity responsible for the construction of the regulated transmission solution or Transmission Upgrade shall be reimbursed for any costs prudently incurred or prudently committed to be incurred (plus a reasonable return on investment at existing Commission-approved ROE levels) in connection with the planning, designing, engineering, siting, permitting, procuring and other preparation for construction, and/or construction of the regulated transmission solution or Transmission Upgrade proposed for removal from the RSP Project List. The provisions of Schedule 12, Schedule 13, ~~and~~ Schedule 14, and Schedule 14A of this OATT shall apply to any cost reimbursement under this Section. Prior to finalizing the RSP, the ISO shall provide the Planning Advisory Committee with written information explaining the reasons for any removal under this Section.

(d) Posting of LSP Project Status

Each PTO will be individually responsible for publicly posting and updating the status of its respective LSP and the transmission projects arising therefrom on its company website. The ISO's posting of the RSP Project Lists will include links to each PTO's specific LSP posting to be provided to the ISO by the PTOs.

4. Procedures for the Conduct of Needs Assessments, Treatment of Market Responses and Evaluation of Regulated Transmission Solutions

4.1 Needs Assessments

The regional system planning process established in this Attachment K has ~~three~~ four different processes. Except as otherwise provided in Section 16 of this Attachment, ~~T~~the reliability planning process established in this Attachment K shall apply to all transmission solutions adopted to resolve a reliability need, ~~.~~ and ~~T~~the market efficiency planning process established in this Attachment K shall apply to all transmission solutions adopted to resolve a market efficiency need. The public policy planning process established in this Attachment K shall apply to all transmission solutions adopted to resolve a public policy need. The longer-term transmission planning procedures established in this Attachment K shall apply to all transmission solutions adopted to resolve a longer-term need, and may apply to a non-time-sensitive reliability or market-efficiency need to the extent identified by the ISO and combined with longer-term needs in a request for proposal(s) requested by NESCOE in accordance with Section 16.4(a) of this Attachment K.

As described further in Section 4.1(a) below, the planning process in Section 17 of this Attachment K shall be used to identify market efficiency issues and, along with Section 4.1(a), trigger market efficiency Needs Assessments. Market efficiency Needs Assessments shall be conducted pursuant to this Section 4.

For needs identified initially as reliability, market efficiency or public policy needs, the collateral benefits of potential solutions to those needs shall not change the planning process applicable to those identified needs; notwithstanding the foregoing, the ISO shall report its views as to whether a project or preferred solution may also satisfy identified reliability needs of the system as described in Section 4A.8 of this Attachment K.

Sections 4.1 through 4.3 of this Attachment are not applicable to the planning of Public Policy Transmission Upgrades, which is governed instead by Section 4A of this Attachment. Sections 4.1 through 4A of this Attachment are not applicable to the planning of Longer-Term Transmission Upgrades, which is governed instead by Section 16 of this Attachment.

On a regular and ongoing basis, the ISO, in coordination with the PTOs and the Planning Advisory Committee, shall conduct assessments (i.e., Needs Assessments) of the adequacy of the PTF system, as a whole or in part, to maintain the reliability of such facilities (i.e., reliability Needs Assessment) and the operation of efficient wholesale electric markets in New England (i.e., market efficiency Needs Assessment). A Needs Assessment shall analyze whether the PTF in the New England Transmission System: (i) meet applicable reliability standards; (ii) have adequate transfer capability to support local, regional, and inter-regional reliability; (iii) support the efficient operation of the wholesale electric markets; (iv) are sufficient to integrate new resources and loads on an aggregate or regional basis; or (v) otherwise examine various aspects of its performance and capability. A Needs Assessment shall also identify: (i) the location and nature of any potential problems with respect to the PTF and (ii) situations that significantly affect the reliable and efficient operation of the PTF along with any critical time constraints for addressing the needs of the PTF to facilitate the development of market responses and to initiate the pursuit of regulated transmission solutions.

(a) Triggers for Needs Assessments

The ISO, in coordination with the PTOs and the Planning Advisory Committee, shall perform Needs Assessments, inter alia, as needed to:

- Assess compliance with reliability standards and criteria (including those established by the ISO, NERC, and NPCC) consistent with the long term needs of the system.
- Assess the adequacy of the transmission system capability, such as transfer capability, to support local, regional and interregional reliability.
- Assess the efficient operation of the wholesale electric market. (See Attachment N regarding the identification of market efficiency upgrades).
- Assess sufficiency of the system to integrate new resources and loads on an aggregate or regional basis as needed for the reliable and efficient operation of the system.
- Analyze various aspects of system performance. (Including but not limited to, transient network analysis, small signal analysis, electromagnetic transients program analysis, or delta P analysis).
- Examine short circuit performance of the system.
- Assess the ability to efficiently operate and maintain the transmission system.
- Address market efficiency issues.

- Address system performance in consideration of de-list bids and cleared demand bids consistent with sections 4.1(c) and 4.1(f) of Attachment K.

- Address system performance as otherwise deemed appropriate by the ISO.

(b) [RESERVED]

(c) Conduct of a Needs Assessment for Rejected De-List Bids

(i) In the case of a rejected Static De-List Bid or Dynamic De-List Bid, the ISO may as warranted, with advisory input from the Reliability Committee, examine the unavailability of the resource(s) with the rejected bid as a sensitivity in a Needs Assessment, or examine the unavailability of the resource(s) in the base representation in a Needs Assessment. The ISO may as warranted, with advisory input from the Reliability Committee, initiate a Needs Assessment for the purpose of modeling rejected Static De-List Bids or Dynamic De-List Bids where the ISO believes that the initiation of such a study is warranted.

(ii) Prior to the start of each New Capacity Show of Interest Submission Window, the ISO shall present to the Reliability Committee the status of any prior rejected Dynamic De-List Bids, Static De-List Bids, Permanent De-List Bids or Retirement De-List Bids being studied in the regional system planning process.

(d) Notice of Initiation of Needs Assessments

Prior to its commencement, the ISO shall provide notice of the initiation of a Needs Assessment to the Planning Advisory Committee consistent with Section 2 of this Attachment.

(e) Preparation of Needs Assessment

Needs Assessments may examine resource adequacy, transmission adequacy, projected congestion levels and other relevant factors as may be agreed upon from time to time. Needs Assessments shall also consider the views, if any, of the Planning Advisory Committee, State regulators or agencies, NESCOE, the Market Advisor to the ISO Board of Directors, and the ISO Board of Directors. A corresponding assessment shall be performed by the PTOs to identify any needs relating to the Non-PTF transmission facilities (of whatever voltage) that could affect the provision of Regional Transmission Service over the PTF.

(f) Treatment of Market Responses in Needs Assessments

The ISO shall reflect proposed market responses in the regional system planning process. Market responses may include, but are not limited to, resources (e.g., demand-side projects and distributed generation), and Elective Transmission Upgrades.

In performing Needs Assessments, the ISO shall rely on certain resources to prevent the identification of system needs. Specifically, the ISO shall incorporate or update information regarding future resources, with the exception of imports across external tie lines, in Needs Assessments that have been proposed and (i) have cleared in a Forward Capacity Auction pursuant to Market Rule 1 of the ISO Tariff, (ii) have been selected in, and are contractually bound by, a state-sponsored request for proposals, (iii) have a financially binding obligation pursuant to a contract, or (iv) have been forecast in the ISO's Forecast Report of Capacity, Energy, Loads and Transmission. The ISO shall also incorporate or update information regarding all existing resources, with the exception of imports across external tie lines, in Needs Assessments. Imports across future or existing external tie lines will not be relied upon unless such imports (i) have a Capacity Supply Obligation corresponding to the year of study, (ii) have been selected in, and are contractually bound by, a state-sponsored request for proposals, (iii) have a financially binding obligation pursuant to a contract, or (iv) may be represented by a minimum flow based on HQ Interconnection Capability Credits. The ISO will model out-of-service all submitted Retirement De-List Bids, submitted Permanent De-List Bids, and demand bids that have cleared in a substitution auction, and may model out-of-service rejected-for-reliability Static De-List Bids and rejected-for-reliability Dynamic De-List Bids from the most recent Forward Capacity Auction. With respect to having been selected in, and being contractually bound by a state-sponsored request for proposals, or having a financially binding obligation pursuant to a contract, demonstration of such contracts is accomplished through submittal for ISO review of an order or other similar authorization from the appropriate state regulatory agency, along with a copy of the contract, that together demonstrate the contractual requirements. These documents may be submitted by: the Project Sponsor; the state regulatory agency authorizing the contract; a transmission company that is a counterparty to the contract; or by a third-party organization representing the interests of the New England states regarding energy related issues, such as NESCOE. The ISO shall incorporate or update information regarding a proposed Elective Transmission Upgrade in a Needs Assessment at a time after the studies corresponding to the Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), a commercial operation date has been ascertained, and for which the certification has been accepted in accordance with Section III.12 of the Tariff. In the case where the Elective Transmission Upgrades are proposed in conjunction with the interconnection of a resource, these Elective Transmission Upgrades shall be considered at the same time as the proposed resource is considered in the Needs Assessment provided that the studies corresponding to the Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), a commercial operation date has been ascertained, and for which the certification has been accepted in accordance with Section III.12 of the Tariff.

(g) Needs Assessment Support

For the development of the Needs Assessments, the ISO will coordinate with the PTOs and the Planning Advisory Committee to support the ISO's performance of Needs Assessments. To facilitate this support, the ISO will post on its website the models, files, cases, contingencies, assumptions and other information used to perform Needs Assessments. The ISO may establish requirements that any PTO or member of the Planning Advisory Committee must satisfy in order to access certain information used to perform Needs Assessments, due to ISO New England Information Policy and CEII constraints. The ISO may ask PTOs or Planning Advisory Committee members with special expertise to provide technical support or perform studies required to assess one or more potential needs that will be considered in the Needs Assessments process. These entities will provide, and the ISO will post on its website, the models, files, cases, contingencies, assumptions and other information used by those entities to perform studies. The ISO will post the draft results of any such Needs Assessment studies on its website. The ISO will convene meetings open to any representative of an entity that is a member of the Planning Advisory Committee to facilitate input on draft Needs Assessments studies and the inputs to those studies prior to the ISO's completion of a draft Needs Assessment report to be reviewed by the entire Planning Advisory Committee pursuant to Section 4.1(i) of this Attachment. All provisions of this subsection (g) relating to the provision and sharing of information shall be subject to the ISO-NE Information Policy.

(h) Input from the Planning Advisory Committee

Meetings of the Planning Advisory Committee shall be convened to identify additional considerations relating to a Needs Assessment that were not identified in support of initiating the assessment, and to provide input on the Needs Assessment's scope, assumptions and procedures, consistent with the responsibilities of the Planning Advisory Committee as set forth in Section 2.2 of this Attachment.

(i) Publication of Needs Assessment and Response Thereto

The ISO shall report the results of Needs Assessments to the Planning Advisory Committee, subject to CEII constraints. Needs Assessments containing CEII will be posted on the ISO's password-protected website consistent with Section 2.4(d) of this Attachment. Needs Assessments will identify high-level functional requirements and characteristics for regulated transmission solutions and market responses that can meet the needs described in the assessment. Where the ISO forecasts that a solution is needed to solve reliability criteria violations in three years or less from the completion of a Needs Assessment (unless the solution to the Needs Assessment will likely be a Market Efficiency Transmission Upgrade), and the requirements of Section 4.1(j) of this Attachment have been met or where there is only one Phase One Proposal submitted in response to a request for proposal issued under Sections 4.3(a) of this Attachment or only one proposed solution that is selected to move on as a Phase Two Solution, the ISO will evaluate the adequacy of proposed regulated solutions by performing Solutions Studies, as described in Section 4.2 of this Attachment. Where the solution to a Needs Assessment will likely be a Market Efficiency Transmission Upgrade, or where the forecast year of need for a solution that is likely to be a Reliability Transmission Upgrade is more than three years from the completion of a Needs Assessment, the ISO will conduct a solution process based on a two-stage competitive solution process, as described in Section 4.3 of this Attachment.

(j) Requirements for Use of Solutions Studies Rather than Competitive Solution Process for Projects Based on Year of Need

The following requirements must be met in order for the ISO to use Solutions Studies in the circumstances described in Section 4.1(i) based on the solution's year of need:

(i) The ISO shall separately identify and post on its website an explanation of the reliability criteria violations and system conditions that the region has a time-sensitive need to solve within three years of the completion of the relevant Needs Assessment. The explanation shall be in sufficient detail to allow stakeholders to understand the need and why it is time-sensitive.

(ii) In deciding whether to utilize Solutions Studies, such that the regulated transmission solution will be developed through a process led by the ISO and built by the PTO(s), the ISO shall:

(A) Provide to the Planning Advisory Committee and post on its website a full and supported written description explaining the decision to designate a PTO as the entity responsible for construction and ownership of the reliability project, including an explanation of other transmission or non-transmission options that the region considered but concluded would not sufficiently address the immediate reliability need, and the circumstances that generated the reliability need and an explanation of why that reliability need was not identified earlier.

(B) Provide a 15-day period during which comments from stakeholders on the posted description may be sent to the ISO, which comments will be posted on the website, as well.

(iii) The ISO shall maintain and post on its website a list of prior year designations of all projects in the limited category of transmission projects for which the PTO(s) was designated as the entity responsible for construction and ownership of the project following the performance of Solutions Studies. The list must include the project's need-by date and the date the PTO(s) actually energized the project, i.e., placed the project into service. The ISO shall file such list with the Commission as an informational filing in January of each calendar year covering the designations of the prior calendar year, when applicable.

4.2 Evaluation of Regulated Transmission Solutions in Solutions Studies, Where Competitive Solution Process of Section 4.3 Is Not Applicable

The procedures described in this Section 4.2 shall be utilized for the evaluation of regulated transmission solutions for reliability and market efficiency needs where the requirements of Sections 4.1(i) and/or (j) of this Attachment are satisfied. Otherwise, the procedures of Section 4.3 shall be utilized for that purpose.

(a) Evaluation and Development of Regulated Transmission Solutions in Solutions Studies for Market Efficiency Transmission Upgrades and Reliability Transmission Upgrades

In the case of Market Efficiency Transmission Upgrades and Reliability Transmission Upgrades, the ISO, in coordination with the proponents of regulated transmission solutions and other interested or affected stakeholders, shall conduct or participate in studies ("Solutions Studies") to evaluate whether proposed regulated transmission solutions meet the PTF system needs identified in Needs Assessments. The ISO, in coordination with affected stakeholders shall also identify regulated transmission projects for addressing the needs identified in Needs Assessments.

The ISO may form ISO-led targeted study groups to conduct Solutions Studies. Such study groups will include representatives of the proponents of regulated transmission solutions and other interested or affected stakeholders. Through this process, the ISO may identify the solutions for the region that offer the best combination of electrical performance, cost, future system expandability, and feasibility to meet a need identified in a Needs Assessment in the required time frame. These solutions may differ from a transmission solution proposed by a transmission owner.

Proponents of regulated transmission proposals in response to Needs Assessments shall also identify any LSP plans that require coordination with their regulated transmission proposals addressing the PTF system needs.

(b) Notice of Initiation of a Solutions Study

The ISO shall provide notice of the initiation and scope of a Solutions Study to the Planning Advisory Committee.

(c) Classification of Regulated Transmission Solutions as Market Efficiency Transmission Upgrades or Reliability Transmission Upgrades

As described in Section 3.1 and 3.6(a) of this Attachment, proposed regulated transmission solutions determined by the ISO, in consultation with the Planning Advisory Committee, to address needs identified in Needs Assessments shall be classified as a Reliability Transmission Upgrade and/or a Market Efficiency Transmission Upgrade pursuant to the standards set forth in Attachment N of this OATT.

(d) Evaluation Factors Used for Identification of the Preferred Solution

Factors to be considered during the evaluation process for identification of the preferred solution may include, but are not limited to, the following which are listed in no particular order:

- Installed cost;
- Life-cycle cost, including all costs associated with right of way acquisition, easements, and associated real estate;
- System performance;
- Cost cap or cost containment provisions;
- In-service date of the project or portion(s) thereof;
- Project constructability;
- Generation and transmission facility outages required during construction;
- Extreme contingency performance;
- Operational impacts;
- Incremental costs for potential resource retirements;
- Interface impacts;
- Future expandability;
- Consistency with Good Utility Practice;
- Potential siting/permitting issues or delays;
- Loss savings;
- Replacement of aging infrastructure;
- Environmental impact;
- Design standards; and
- Impact on NPCC Bulk Power System classification.

(e) Identification of the Preferred Solution and Inclusion of Results of Solutions Studies for Market Efficiency Transmission Upgrades and Reliability Transmission Upgrades in the RSP

The results of Solutions Studies related to Market Efficiency Transmission Upgrades and Reliability Transmission Upgrades will be reported to the Planning Advisory Committee. After receiving feedback from the Planning Advisory Committee, the ISO will identify the preferred solution. The ISO will inform the appropriate Transmission Owners in writing regarding the identification of the preferred solution.

Once identified, the preferred solution, as appropriate, will be reflected (with an overview of why the solution is preferred) in the RSP and/or its Project List, as it is updated from time to time in accordance with this Attachment. Where external impacts of regional projects are identified through coordination by the ISO with neighboring entities, those impacts will be identified in the RSP. Costs associated with such impacts will be addressed as set forth in Schedule 15.

(f) Cancellation of a Solutions Study

The ISO may cancel a Solutions Study at any time. Such cancellation may be due to new or different assumptions which may change or eliminate the identified needs. Any costs associated with Solutions Study development shall be recovered pursuant to Section 3.6(c) of this Attachment.

4.3 Competitive Solution Process for Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades

(a) Initiating the Competitive Solution Process

The ISO will publicly issue a request for proposal for which, pursuant to Section 4.1(i) of this Attachment, a competitive solution process will be utilized. The request for proposal will indicate that a Qualified Transmission Project Sponsor may submit an individual or joint Phase One Proposal(s) offering a solution that addresses the identified needs or address a subset of those needs. In the case where a joint Phase One Proposal is submitted, all parties must be Qualified Transmission Project Sponsors. A Qualified Transmission Project Sponsor may propose a comprehensive solution to address the identified needs, or a subset thereof, that includes an upgrade(s) located on or connected to a PTO's existing transmission system where the Qualified Transmission Project Sponsor is not the PTO for the existing system element(s). In such cases, the Qualified Transmission Project Sponsor's proposed solution relating to the upgrade(s) of an existing transmission system element(s) must provide all data available to the Qualified Transmission Project Sponsor as part of its response to the request for proposal. The Qualified Transmission Project Sponsor is not required to procure agreements with the PTO for implementation of such upgrades as the PTO is required to implement the upgrade(s) in accordance with Schedule 3.09(a) of the Transmission Operating Agreement if the proposed solution is selected through the competitive process.

A PTO or PTOs identified by the ISO as the Backstop Transmission Solution provider(s) shall submit an individual or joint Phase One Proposal (if more than one PTO is identified) as a Backstop Transmission Solution to comprehensively address all of the needs identified in the request for proposal that would be solved by a project located within or connected to its/their existing electric system, and which it/they would therefore have an obligation to build under Schedule 3.09(a) of the TOA. Such PTOs may recover the costs of preparing the Backstop Transmission Solution in accordance with the mechanisms reflected in the OATT and the terms of the TOA.

A member of the Planning Advisory Committee that is not a Qualified Transmission Project Sponsor but would like the ISO to consider a Phase One Proposal reflecting its concept for a project in response to a request for proposal (that is, a project that is "unsponsored") must, before the deadline for the submission of Phase One Proposals, identify a Qualified Transmission Project Sponsor willing to submit a corresponding Phase One Proposal and Phase Two Solution (and to develop and construct the project, if selected in the competitive solution process) in order for the unsponsored project to be submitted in response to an ISO solicitation in Phase One. Upon request by the pertinent Planning Advisory Committee member for assistance in identifying a sponsor, the ISO shall post on its website and distribute to the Planning Advisory Committee a notice that solicits expressions of interest by Qualified Transmission Project Sponsors for sponsorship of the member's conceptual project. All expressions of interest shall include a detailed explanation of why the Qualified Transmission Project Sponsor is best qualified to construct, own and operate the unsponsored project. If only one Qualified Transmission Project

Sponsor expresses interest, the ISO shall designate it as the Qualified Transmission Project Sponsor. If more than one Qualified Transmission Project Sponsor expresses interest, the Planning Advisory Committee member shall select the Qualified Transmission Project Sponsor. In either case, the designated Qualified Transmission Project Sponsor shall thereafter comply with the requirements of this Attachment K and the ISO Tariff with respect to the project. If no Qualified Transmission Project Sponsor expresses interest, the unsponsored project may not be submitted as a Phase One Proposal.

(b) Use and Control of Right of Way

Neither the submission of a project by a Qualified Transmission Project Sponsor nor the selection by the ISO of a project submitted by a Qualified Transmission Project Sponsor for inclusion in the RSP Project List shall alter a PTO's use and control of an existing right of way, the retention, modification, or transfer of which remain subject to the relevant law or regulation, including property or contractual rights, that granted the right-of-way. Nothing in the processes described in this Attachment K requires a PTO to relinquish any of its rights-of-way in order to permit a Qualified Transmission Project Sponsor to develop, construct or own a project.

(c) Information Required for Phase One Proposals; Study Deposit; Timing

Phase One Proposals shall provide the following information:

(i) a detailed description of the proposed solution, in the manner specified by the ISO, including an identification of the proposed route for the solution and technical details of the project, such as interconnection into the existing transmission system;

(ii) a detailed explanation of the identified needs that are addressed, how the proposed solution addresses those identified needs, a description of those needs which have not been addressed, and a description of the impact of the Phase One Proposal on those needs which have not been addressed;

(iii) the proposed schedule, including key high-level milestones, for development, siting, procurement of real estate rights, permitting, construction and completion of the proposed solution;

(iv) right, title, and interest in rights of way, substations, and other property or facilities, if any, that would contribute to the proposed solution or the means and timeframe by which such would be obtained; and

(v) the estimated installed costs of the proposed solution, including a high-level itemization of the components of the cost estimate and any cost containment or cost cap measures.

With each proposal, the submitting Qualified Transmission Project Sponsor must include payment of a $100,000 study deposit per submitted Phase One Proposal to support the cost of Phase One Proposal and Phase Two Solution study work by the ISO. The study deposit of $100,000 shall be applied towards the costs incurred by the ISO associated with the study of the Phase One Proposal and Phase Two Solution.

Phase One Proposals must be submitted by the deadline specified in the public posting by the ISO of the request for proposal described in Section 4.3(a) of this Attachment, which shall not be less than 60 days from the posting date of the request for proposal. The ISO may reject submittals which are insufficient or not adequately supported.

(d) LSP Coordination

Qualified Transmission Project Sponsors of Phase One Proposals shall also identify any LSP plans that require coordination with their Phase One Proposals.

(e) Review of Phase One Proposals by ISO

If any identified need is only solved by the Backstop Transmission Solution, the ISO shall proceed under Section 4.2 of this Attachment, rather than pursuant to the procedures set forth in the remainder of this Section 4.3.

If all of the identified needs are solved by more than one Phase One Proposal, the ISO shall perform a review of each proposal to determine whether the proposed solution:

(i) provides sufficient data and that the data is of sufficient quality to satisfy Section 4.3(c) of this Attachment;

(ii) satisfies one or more of the needs as identified in Section 4.3(c)(ii);

(iii) is technically practicable and indicates possession of, or an approach to acquiring, the necessary rights of way, property and facilities that will make the proposal reasonably feasible in the required timeframe; and

(iv) is eligible to be constructed only by an existing PTO in accordance with Schedule 3.09(a) of the TOA because the proposed solution is an upgrade to existing PTO facilities, or because the costs of the proposed solution are not eligible for regional cost allocation under the OATT and will be allocated only to the local customers of a PTO.

(f) Proposal Deficiencies; Further Information

If the ISO identifies any minor deficiencies in meeting the requirements of Section 4.3(e) in the information provided in connection with a proposed Phase One Proposal, the ISO will notify the submitting Phase One Proposal Qualified Transmission Project Sponsor and provide an opportunity for the sponsor to cure the deficiencies within the timeframe specified by the ISO. Upon request, Qualified Transmission Project Sponsors of Phase One Proposals shall provide the ISO with additional information reasonably necessary for the ISO's evaluation of the proposed Phase One Proposals. This identification and notification will occur prior to the publication by the ISO of any Phase One Proposals. In providing information under this subsection (f), or in Phase Two Solutions, the Qualified Transmission Project Sponsor may not modify its project materially or submit a new project, but instead may clarify its Phase One Proposal. Phase Two Solutions reflecting a material modification to a Phase One Proposal or representing a new project will be rejected.

(g) Listing of Qualifying Phase One Proposals or Groups of Phase One Proposals

The ISO will provide the Planning Advisory Committee with, and post on the ISO's website, a listing of Phase One Proposals that meet the criteria of Section 4.3(e). The listing will contain Phase One Proposals, either individually or as a group, that solve all of the identified needs. A meeting of the Planning Advisory Committee will be held thereafter in order to solicit stakeholder input on the listing, and the listed proposals. The ISO with input from the Planning Advisory Committee may exclude Phase One Proposals, from the list, and from consideration in Phase Two Solutions, based on a determination that the Phase One Proposal is not competitive with other Phase One Proposals, that have been submitted in terms of cost, electrical performance, future system expandability, or feasibility. Information on Phase One Proposals containing CEII will be posted on the ISO's protected website consistent with Section 2.4(d) of this Attachment. The ISO may amend its listing based on stakeholder input. The ISO shall post on its website an explanation of why it has determined to exclude a Phase One Proposal from consideration in the Phase Two Solution process.

(h) Information Required for Phase Two Solutions; Identification and Reporting of Preliminary Preferred Phase Two Solution

Qualified Transmission Project Sponsors of Phase One Proposals reflected on the final listing developed pursuant to Section 4.3(g) of this Attachment shall provide the following information in their proposed Phase Two Solutions:

(i) updates of the information provided in Phase One Proposals, or a certification that the information remains current and correct;

(ii) list of required major Federal, State and local permits;

(iii) description of construction sequencing, a conceptual plan for the anticipated transmission and generation outages necessary to construct the Phase Two Solution and their respective durations, and possible constraints;

(iv) project schedule, with additional detail compared with Phase One Proposals, as specified by the ISO;

(v) detailed cost component itemization and life-cycle cost including any clarifications to cost containment or cost cap measures that were not included as part of the Phase One Proposal;

(vi) description of the financing being used;

(vii) design and equipment standards to be used;

(viii) description of the authority the Qualified Transmission Project Sponsor(s) has to acquire necessary rights of way;

(ix) experience of the Qualified Transmission Project Sponsor(s) in acquiring rights of way;

(x) status of acquisition of right, title, and interest in rights of way, substations, and other property or facilities, if any, that are necessary for the proposed Phase Two Solution;

(xi) detailed explanation of project feasibility and potential constraints and challenges;

(xii) description of the means by which the Qualified Transmission Project Sponsor(s) proposes to satisfy legal or regulatory requirements for siting, constructing, owning and operating transmission projects; and

(xiii) detailed explanation of potential future expandability.

Phase Two Solutions must be submitted to the ISO by the deadline specified in the posting of the final listing (following stakeholder input) of Phase One Proposals described in Section 4.3(g). The deadline for submittal of Phase Two Solutions shall not be less than 60 days from the posting date of the final listing. The ISO may reject Phase Two Solution submittals which are insufficient or not adequately supported.

The ISO will identify the Phase Two Solution, individually or as a group, that offers the best combination of electrical performance, cost, future system expandability and feasibility to comprehensively address all of the needs in the required timeframe as the preliminary preferred Phase Two Solution in response to each request for proposal. The ISO will report the preliminary preferred Phase Two Solution, together with explanatory materials, to the Planning

Advisory Committee and seek stakeholder input on the preliminary preferred Phase Two Solution.

The ISO will consider several factors during the evaluation process for identification of the preliminar~~il~~y preferred Phase Two Solution. These factors may include, but are not limited to, the following which are listed in no particular order:

- Life-cycle cost, including all costs associated with right of way acquisition, easements, and associated real estate;
- System performance;
- Cost cap or cost containment provisions;
- In-service date of the project or portion(s) thereof;
- Project constructability;
- Generation and transmission facility outages required during construction;
- Extreme contingency performance;
- Operational impacts;
- Incremental costs for potential resource retirements;
- Interface impacts;
- Future expandability;
- Consistency with Good Utility Practice;
- Potential siting/permitting issues or delays;
- Loss savings;
- Replacement of aging infrastructure;
- Environmental impact;
- Design standards;
- Impact on NPCC Bulk Power System classification; and
- Qualified Transmission Project Sponsor(s) capabilities.

(i) Reimbursement of Phase Two Solution Costs; Collection and Refund of ISO Study Costs

Qualified Transmission Project Sponsors whose Phase One Proposals are listed pursuant to Section 4.3(g) for review as Phase Two Solutions shall be entitled to recover, pursuant to rates and appropriate financial arrangements set forth in the Tariff (and, as applicable, the TOA and NTDOA), all prudently incurred costs associated with developing a Phase Two Solution. PTOs shall be entitled to recover, pursuant to rates and appropriate financial arrangements set forth in the Tariff, all prudently incurred study costs and costs associated with developing any upgrades or modifications to such PTOs' existing facilities necessary to facilitate the development of a listed Phase One Proposal proposed by any other Qualified Transmission Project Sponsor.

Any difference between a Qualified Transmission Project Sponsor's study deposit and the actual cost of the Phase One Proposal and Phase Two Solution studies shall be paid by or refunded to the Qualified Transmission Project Sponsor, as appropriate, with interest calculated in accordance with Section 35.19a(a)(2) of the FERC regulations. Any refund payment shall be accompanied by a detailed and itemized accounting of the actual study costs incurred. Any invoice to collect funds in addition to the deposit shall be accompanied by a detailed and itemized accounting of the actual study costs incurred. Any disputes arising from the study process shall be addressed under the dispute resolution process specified in Section I.6 of the ISO Tariff.

(j) Selection of the Preferred Phase Two Solution

Following receipt of stakeholder input, the ISO will identify the preferred Phase Two Solution, individually or as a group, (with an overview of why the solution is preferred) by a posting on its website. The ISO's identification will select the project that offers the best combination of electrical performance, cost, future system expandability and feasibility to meet the need in the required timeframe. The ISO will also notify the Qualified Transmission Project Sponsor(s) that proposed the preferred Phase Two Solution that its project has been selected for development. The preferred Phase Two Solution may include an upgrade(s) located on or connected to a PTO's existing transmission system where the Qualified Transmission Project Sponsor is not the PTO for the existing system element(s). In such cases the ISO will notify the PTO that have upgrades required by the preferred Phase Two Solution to proceed in accordance with Schedule 3.09(a) of the Transmission Operating Agreement. Once the ISO has identified the preferred Phase Two Solution, any remaining Phase Two Solutions, along with the Backstop Transmission Solution, must stop all development. The ISO will include the project as a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, as appropriate, in the RSP and/or its Project List, as it is updated from time to time in accordance with this Attachment. Where external impacts of regional projects are identified through coordination by the ISO with neighboring entities, those impacts will be identified in the RSP. Costs associated with such impacts will be addressed as set forth in Schedule 15.

(k) Execution of Selected Qualified Transmission Project Sponsor Agreement

Within 30 days of receiving notification pursuant to Section 4.3(j) of this Attachment, the Qualified Transmission Project Sponsor shall submit to the ISO its acceptance of responsibility to proceed with the preferred Phase Two Solution by execution of a Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT). Within 30 days of receiving notification pursuant to Section 4.3(j) of this Attachment, each Qualified Transmission Project Sponsor that is part of the joint proposal shall submit to the ISO its acceptance of responsibility to proceed with the preferred Phase Two Solution by execution of a Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT). Any cost cap or cost containment provisions shall be included in each Selected Qualified Transmission Project Sponsor Agreement.

(l) Failure to Proceed

If the ISO finds, after consultation with a PTO Qualified Transmission Project Sponsor(s), that one or more of the Qualified Transmission Project Sponsors is failing to pursue approvals or construction in a reasonably diligent fashion, the ISO will notify all Qualified Transmission Project Sponsors that one or more of the Qualified Transmission Project Sponsors is failing to pursue approvals or construction in a reasonably diligent fashion. The Qualified Transmission Project Sponsor(s) that is failing to pursue approvals or construction in a reasonably diligent fashion will have 60 days from the ISO's notification to reassign a portion or all of the preferred Phase Two Solution to another Qualified Transmission Project Sponsor in accordance with Section 8 of the Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT). In the event that such reassignment does not occur within 60 days, the ISO shall require the applicable PTO(s) to execute the Selected Qualified Transmission Project Sponsor Agreement and implement the Backstop Transmission Solution pursuant to Schedule 3.09(a) of the Transmission Operating Agreement. In such cases the ISO shall prepare a report explaining why it has reassigned the project. If the Qualified Transmission Project Sponsor that is failing or unable to proceed is a PTO, the report shall be consistent with the provisions of Section 1.1(e) of

Schedule 3.09(a) of the Transmission Operating Agreement, including the ISO's proposed course of action. If prepared with respect to a Qualified Transmission Project Sponsor that is not a PTO, the report shall include a report from that sponsor. The ISO shall file its report (whether with respect to a PTO or non-PTO Qualified Transmission Project Sponsor) with the Commission.

(m) Cancellation of a Request for Proposal

The ISO may cancel a request for proposal at any time. Such cancellation may be due to new or different assumptions which may change or eliminate the identified needs. Any costs associated with solution development shall be recovered pursuant to Sections 3.6(c), 4.3(a) and 4.3(i) of this Attachment.

4A. Public Policy Transmission Studies; Public Policy Transmission Upgrades

4A.1 NESCOE Requests for Public Policy Transmission Studies

No less often than every three years, by January 15 of that year, the ISO will post a notice indicating that members of the Planning Advisory Committee may, no later than 45 days after the posting of the notice: (i) provide NESCOE, via the process described below, with input regarding state and federal Public Policy Requirements identified as driving transmission needs relating to the New England Transmission System, and regarding particular transmission needs driven by those Public Policy Requirements, and (ii) provide the ISO with input regarding local (e.g., municipal and county) Public Policy Requirements identified as driving transmission needs relating to the New England Transmission System, and regarding particular transmission needs driven by those Public Policy Requirements. A meeting of the Planning Advisory Committee may be held for this purpose. Members of the Planning Advisory Committee shall direct all such input related to state, federal, and local Public Policy Requirements that drive transmission needs to the ISO and the ISO will post such input on the ISO's website. By no later than May 1 of that year, NESCOE may submit to the ISO in writing a request for a new Public Policy Transmission Study, or an update of a previously conducted study. The request will identify the Public Policy Requirements identified as driving transmission needs relating to the New England Transmission System, and may identify particular NESCOE-identified public policy-related transmission needs as well. Along with any such request, NESCOE will provide the ISO with a written explanation of which transmission needs driven by state or federal Public Policy Requirements the ISO will evaluate for potential solutions in the regional planning process, including why other suggested transmission needs will not be evaluated. The ISO will post the NESCOE request and explanation on the ISO's website. If NESCOE does not provide that listing of identified transmission needs (which may consist of a NESCOE statement of its determination that no transmission needs are driven by state or federal Public Policy Requirements identified during the stakeholder process) and that explanation (which may consist of a NESCOE explanation of why no transmission needs are driven by state or federal Public Policy Requirements identified during the stakeholder process), the ISO will note on its website that a NESCOE listing and explanation have not been provided. In that circumstance, the ISO will determine subsequently (after opportunity for Planning Advisory Committee input), and post on its website an explanation of, which transmission needs driven by state or federal Public Policy Requirements the ISO will evaluate in the regional planning process, including why other suggested transmission needs will not be evaluated.

4A.1.1 Study of Federal Public Policy Requirements Not Identified by NESCOE; Local Public Policy Requirements

If a stakeholder believes that a federal Public Policy Requirement that may drive transmission needs relating to the New England Transmission System has not been appropriately addressed by NESCOE, it may file with the ISO, no later than 15 days after the posting of NESCOE's explanation as described in Section 4A.1 of this Attachment, a written request that explains the stakeholder's reasoning and that seeks reconsideration by the ISO of NESCOE's position regarding that requirement. The ISO will post the stakeholder's written request on the ISO's website. Where the ISO agrees with a stated stakeholder position, or on its own finding, the ISO may perform an evaluation under Sections 4A.2 through 4A.4 of this Attachment of a federal Public Policy Requirement not otherwise identified by NESCOE. The ISO will post on its website an explanation of those transmission needs driven by federal Public Policy Requirements not identified by NESCOE that will be evaluated for potential transmission solutions in the regional system planning process, and why other suggested transmission needs driven by federal Public Policy Requirements not identified by NESCOE will not be evaluated. In addition, the ISO will post on its website an explanation of those transmission needs driven by local Public Policy Requirements that will be evaluated for potential transmission solutions in the regional system planning process, and why other suggested transmission needs driven by local Public Policy Requirements will not be evaluated.

4A.2 Preparation for Conduct of Public Policy Transmission Studies; Stakeholder Input

Upon receipt of the NESCOE request, or as the result of the ISO's consideration of a federal or local Public Policy Requirement pursuant to Section 4A.1.1, the ISO will prepare and post on its website a proposed scope for the Public Policy Transmission Study, and associated parameters and assumptions (including resource assumptions), and provide the foregoing to the Planning Advisory Committee by no later than September 1 of the request year. A meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit stakeholder input for consideration by the ISO on the study's scope, parameters and assumptions.

4A.3 Public Policy Transmission Studies

(a) Conduct of Public Policy Transmission Studies; Stakeholder Input

With input from Planning Advisory Committee and potentially impacted PTOs, the ISO will perform the initial phase of the Public Policy Transmission Study to develop a rough estimate of the costs and benefits of high-level concepts that could meet transmission needs driven by Public Policy Requirements. The study's results will be posted on the ISO's website, and a meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit input on the results of the initial phase of the study, and the scope, parameters and assumptions (including resource assumptions) for any follow-on phase of the study. The ISO may − as a follow-on phase of the Public Policy Transmission Study − perform more detailed analysis and engineering work on the high-level concepts.

(b) Treatment of Market Solutions in Public Policy Transmission Studies

The ISO shall reflect proposed market responses in the Public Policy Transmission Study. Market responses may include, but are not limited to, resources (e.g., demand-side projects and distributed generation), Merchant Transmission Facilities and Elective Transmission Upgrades.

In performing Public Policy Transmission Studies, the ISO shall rely on certain resources to prevent the identification of transmission needs driven by Public Policy Requirements. Specifically, the ISO shall incorporate in the Public Policy Transmission Study information regarding future resources, with the exception of imports across external tie lines, that have been proposed and (i) have cleared in a Forward Capacity Auction pursuant to Market Rule 1 of the ISO Tariff, (ii) have been selected in, and are contractually bound by, a state-sponsored request for proposals, (iii) have a financially binding obligation pursuant to a contract, or (iv) have been forecast in the ISO's Forecast Report of Capacity, Energy, Loads and Transmission. The ISO shall also incorporate or update information regarding all existing resources, with the exception of imports across external tie lines, in Public Policy Transmission Studies. Imports across future or existing external tie lines will not be relied upon unless such imports (i) have a Capacity Supply Obligation corresponding to the year of study, (ii) have been selected in, and are contractually bound by, a state-sponsored request for proposals, (iii) have a financially binding obligation pursuant to a contract, or (iv) may be represented by a minimum flow based on HQ Interconnection Capability Credits. The ISO will model out-of-service all submitted Retirement De-List Bids, submitted Permanent De-List Bids, and demand bids that have cleared in a substitution auction, and may model out-of-service rejected-for-reliability Static De-List Bids and rejected-for-reliability Dynamic De-List Bids from the most recent Forward Capacity Auction. With respect to having been selected in, and being contractually bound by a state-sponsored request for proposals, or having a financially binding obligation pursuant to a contract, demonstration of such contracts is accomplished through submittal for ISO review of an order or other similar authorization from the appropriate state regulatory agency, along with a copy of the contract, that together demonstrate the contractual requirements. These documents may be submitted by: the Project Sponsor; the state regulatory agency authorizing the contract; a transmission company that is a counterparty to the contract; or by a third-party organization representing the interests of the New England states regarding energy related issues, such as NESCOE. The ISO shall incorporate information regarding a proposed Merchant Transmission Facility or Elective Transmission Upgrade in a Public Policy Transmission Study at a time after the studies corresponding to the Merchant Transmission Facility or Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), and a commercial operation date has been ascertained, with the exception of Elective Transmission Upgrades that are proposed in conjunction with the interconnection of a resource, which shall be considered at the same time as the proposed resource is considered in the Public Policy Transmission Study.

4A.4 Response to Public Policy Transmission Studies

The results of the Public Policy Transmission Study will be provided to the Planning Advisory Committee and posted on the ISO's website, and a meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit input for the ISO on those results, including any updates from the states on any methods by which they are satisfying their respective Public Policy Requirements included in the Public Policy Transmission Study. The ISO's costs of performing the Public Policy Transmission Study described in Section 4A.3 will be collected by the ISO pursuant to Schedule 1 of Section IV.A of the Tariff. Any prudently incurred PTO costs for assistance requested by the ISO to support the Public Policy Transmission Study will be recovered by the applicable PTO(s) in accordance with Attachment F and Schedule 21 of the Tariff.

The ISO will evaluate the input from the Planning Advisory Committee and provide the results of the Public Policy Transmission Study to Qualified Transmission Project Sponsors for their use in preparing Stage One Proposals to develop, build and operate one or more projects consistent with the general design requirements identified by the ISO in the study.

4A.5 Use and Control of Right of Way

Neither the submission of a project by a Qualified Transmission Project Sponsor nor the selection by the ISO of a project submitted by a Qualified Transmission Project Sponsor for inclusion in the RSP Project List shall alter a PTO's use and control of an existing right of way, the retention, modification, or transfer of which remain subject to the relevant law or regulation, including property or contractual rights, that granted the right-of-way. Nothing in the processes described in this Attachment K requires a PTO to relinquish any of its rights-of-way in order to permit a Qualified Transmission Project Sponsor to develop, construct or own a project.

4A.6 Stage One Proposals

(a) Information Required for Stage One Proposals

The ISO will publicly post on its website a request for proposal inviting, for each high-level general project concept identified by the ISO pursuant to Section 4A.3(a) above, Qualified Transmission Project Sponsors to submit (by the deadline specified in the request for proposal, which shall be not less than 60 days from the date of posting the request for proposal) an individual or joint Stage One Proposal. In the case where a joint Stage One Proposal is submitted, all parties must be Qualified Transmission Project Sponsors. The following information must be provided as part of the Stage one Proposal:

(i) a detailed description of the proposed solution, in the manner specified by the ISO, including an identification of the proposed route for the solution and technical details of the project, such as interconnection into the existing transmission system;

(ii) a detailed explanation of how the proposed solution addresses the identified need;

(iii) the proposed schedule, including key high-level milestones, for development, siting, procurement of real estate rights, permitting, construction and completion of the proposed solution;

(iv) right, title, and interest in rights of way, substations, and other property or facilities, if any, that would contribute to the proposed solution or the means and timeframe by which such would be obtained; and

(v) the estimated installed costs of the proposed solution, including a high-level itemization of the components of the cost estimate, and any cost containment or cost cap measures.

A Qualified Transmission Project Sponsor may submit a proposed solution that includes an upgrade(s) located on or connected to a PTO's existing transmission system where the Qualified Transmission Project Sponsor is not the PTO for the existing system element(s). In such cases, the Qualified Transmission Project Sponsor's proposed solution relating to the upgrade(s) of an existing transmission system element(s) must provide all data available to the Qualified Transmission Project Sponsor as part of its response to the request for proposal. The Qualified Transmission Project Sponsor is not required to procure agreements with the PTO for implementation of such upgrades as the PTO is required to implement the upgrade(s) in accordance with Schedule 3.09(a) of the Transmission Operating Agreement if the proposed solution is selected through the competitive process.

A member of the Planning Advisory Committee that is not a Qualified Transmission Project Sponsor but would like the ISO to consider a Stage One Proposal reflecting its concept for a project in response to a request for proposal (that is, a project that is "unsponsored") must identify a Qualified Transmission Project Sponsor willing to submit a corresponding Stage One Proposal and Stage Two Solution (and to develop and construct the project, if selected in the competitive solution process) in order for the unsponsored project to be submitted in response to an ISO solicitation in Stage One Proposal. Upon request of the pertinent Planning Advisory Committee member for assistance in identifying a sponsor, the ISO shall post on its website and distribute to the Planning Advisory Committee a notice that solicits expressions of interest by Qualified Transmission Project Sponsors for sponsorship of the member's conceptual project. All expressions of interest shall include a detailed explanation of why the Qualified Transmission Project Sponsor is best qualified to construct, own and operate the unsponsored project. If only one Qualified Transmission Project Sponsor expresses interest, the ISO shall designate it as the Qualified Transmission Project Sponsor. If more than one Qualified Transmission Project Sponsor expresses interest, the Planning Advisory Committee member shall select the Qualified Transmission Project Sponsor. In either case, the designated Qualified Transmission Project Sponsor shall thereafter comply with the requirements of this Attachment K and the ISO Tariff with respect to the project. If no Qualified Transmission Project Sponsor expresses interest, the unsponsored project may not be submitted as a Stage One Proposal.

With each proposal, the submitting Qualified Transmission Project Sponsor must include payment of a $100,000 study deposit per submitted project to support the cost of Stage One Proposal and Stage Two Solution study work by the ISO. The study deposit of $100,000 shall be applied towards the costs incurred by the ISO associated with the study of the Stage One Proposal and Stage Two Solution.

(b) LSP Coordination

Qualified Transmission Project Sponsors of Stage One Proposals shall also identify any LSP plans that require coordination with their Stage One Proposals.

(c) Review of Stage One Proposals by ISO

Upon receipt of Stage One Proposals, the ISO shall perform a review of each proposal to determine whether the proposed solution:

(i) provides sufficient data and that the data is of sufficient quality to satisfy Section 4A.6(a);

(ii) satisfies the needs driven by Public Policy Requirements identified in the request for proposal, as reflected in the Public Policy Transmission Study;

(iii) is technically practicable and indicates possession of, or an approach to acquiring, the necessary rights of way, property and facilities that will make the proposal reasonably feasible in the required timeframe; and;

(iv) is eligible to be constructed only by an existing PTO in accordance with Schedule 3.09(a) of the TOA because the proposed solution is an upgrade to existing PTO facilities or because the costs of the proposed solution are not eligible for regional cost allocation under the OATT and will be allocated only to the local customers of a PTO.

(d) Proposal Deficiencies; Further Information

If the ISO identifies any deficiencies (compared with the requirements of Section 4A.6(a)) in the information provided in connection with a proposed Stage One Proposal, the ISO will notify the Stage One Proposal Qualified Transmission Project Sponsor and provide an opportunity for the Qualified Transmission Project Sponsor to cure the deficiencies within the timeframe specified by the ISO. Upon request, Qualified Transmission Project Sponsors of Stage One Proposals shall provide the ISO with additional information reasonably necessary for the ISO's evaluation of the proposed solutions. This identification and notification will occur prior to the publication by the ISO of any Stage One Proposals. In providing information under this subsection (d), or in Stage Two Solutions, the Qualified Transmission Project Sponsor may not modify its project materially or submit a new project, but instead may clarify its project. Stage Two Solutions reflecting a material modification to a Stage One Proposal or representing a new project will be rejected.

(e) List of Qualifying Stage One Proposals

The ISO will provide the Planning Advisory Committee with, and post on the ISO's website, a list of Stage One Proposals that meet the criteria of Section 4A.6(c). A meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit input for the ISO on that list. The ISO shall also indicate whether any of the Stage One Proposals may also satisfy identified reliability needs of the system. The ISO with input from the Planning Advisory Committee may exclude Stage One Proposals from the list, and from consideration in Stage Two Solutions, based on a determination that the Stage One Proposal is not competitive with other Stage One Proposals that have been submitted in terms of cost, electrical performance, future system expandability, or feasibility. Information on Stage One Proposals containing CEII will be posted on the ISO's protected website consistent with Section 2.4(d) of this Attachment. The ISO may amend its listing based on stakeholder input.

4A.7 Reimbursement of Stage One Proposal and Stage Two Solution Costs; Collection and Refund of ISO Study Costs

Qualified Transmission Project Sponsors that are requested by NESCOE in writing or by one or more states' governors or regulatory authorities directly to submit a Stage One Proposal shall be entitled to recover, pursuant to rates and appropriate financial arrangements set forth in the Tariff and the TOA, their prudently incurred costs from the Regional Network Load of the states identified by NESCOE in the written communication as having made the request or from the Regional Network Load of the states that made the request directly. Stage One Proposal costs shall otherwise not be subject to recovery under the ISO Tariff.

Qualified Transmission Project Sponsors whose projects are listed by the ISO pursuant to Section 4A.6(e) shall be entitled to recover, pursuant to rates and appropriate financial arrangements set forth in the Tariff and, as applicable, the TOA and NTDOA, all prudently incurred costs associated with developing a Stage Two Solution. PTOs shall be entitled to recover, pursuant to rates and appropriate financial arrangements set forth in the Tariff, all prudently incurred study costs and costs associated with developing any upgrades or modifications to such PTOs' existing facilities necessary to facilitate the development of a listed Stage Two Solution proposed by any other Qualified Transmission Project Sponsor.

Any difference between a Qualified Transmission Project Sponsor's study deposit and the actual cost of the Stage One Proposal and Stage Two Solutions studies shall be paid by or refunded to the Qualified Transmission Project Sponsor, as appropriate, with interest calculated in accordance with Section 35.19a(a)(2) of the FERC regulations. Any refund payment shall be accompanied by a detailed and itemized accounting of the actual study costs incurred. Any invoice to collect funds in addition to the deposit shall be accompanied by a detailed and itemized accounting of the actual study costs incurred. Any disputes arising from the study process shall be addressed under the dispute resolution process specified in Section I.6 of the Tariff.

4A.8 Information Required for Stage Two Solutions; Identification and Reporting of Preliminary Preferred Stage Two Solution

Qualified Transmission Project Sponsors of Stage One Proposals listed pursuant to Section 4A.6(e) of this Attachment shall provide the following information in their proposed Stage Two Solutions:

(i) updates of the information provided in Stage One Proposals, or a certification that the information remains current and correct;

(ii) list of required major Federal, State and local permits;

(iii) description of construction sequencing, a conceptual plan for the anticipated transmission and generation outages necessary to construct the Stage Two Solution and their respective durations, and possible constraints;

(iv) project schedule, with additional detail compared with Stage One Proposals, as specified by the ISO;

(v) detailed cost component itemization and life-cycle cost including any clarifications to cost containment or cost cap measures that were not included as part of the Stage One Proposal;

(vi) description of the financing being used;

(vii) design and equipment standards to be used;

(viii) description of the authority the Qualified Transmission Project Sponsor(s) has to acquire necessary rights of way;

(ix) experience of the Qualified Transmission Project Sponsor(s) in acquiring rights of way;

(x) status of acquisition of right, title, and interest in rights of way, substations, and other property or facilities, if any, that are necessary for the proposed Stage Two Solution;

(xi) detailed explanation of project feasibility and potential constraints and challenges;

(xii) description of the means by which the Qualified Transmission Project Sponsor(s) proposes to satisfy legal or regulatory requirements for siting, constructing, owning and operating transmission projects; and

(xiii) detailed explanation of potential future expandability.

Stage Two Solutions must be submitted to the ISO by the deadline specified in the posting of the final listing (following stakeholder input) of Stage One Proposals described in Section 4A.6(e). The deadline for submittal of Stage Two Solutions shall not be less than 60 days from the posting date of the final listing. The ISO may reject Stage Two Solution submittals which are insufficient or not adequately supported.

The ISO will consider several factors during the evaluation process for identification of the preliminar~~il~~y preferred Stage Two Solution. These factors may include, but are not limited to, the following which are listed in no particular order:

- Life-cycle cost, including all costs associated with right of way acquisition, easements, and associated real estate;
- System performance;
- Cost cap or cost containment provisions;
- In-service date of the project or portion(s) thereof;
- Project constructability;
- Generation and transmission facility outages required during construction;
- Extreme contingency performance;
- Operational impacts;
- Incremental costs for potential resource retirements;
- Interface impacts;
- Future expandability;

- Consistency with Good Utility Practice;
- Potential siting/permitting issues or delays;
- Loss savings;
- Replacement of aging infrastructure;
- Environmental impact;
- Design standards;
- Impact on NPCC Bulk Power System classification; and
- Qualified Transmission Project Sponsor(s) capabilities

The ISO will report the preliminary preferred Stage Two Solution(s), along with its views as to whether the preliminary preferred solution(s) also satisfies identified reliability needs of the system, to the Planning Advisory Committee and seek stakeholder input on the preliminary preferred Stage Two Solution(s).

4A.9 Inclusion of Public Policy Transmission Upgrades in the Regional System Plan and RSP Project List; Milestone Schedules; Removal from RSP Project List

(a) Inclusion of Public Policy Transmission Upgrades in the Regional System Plan and RSP Project List

Following receipt of stakeholder input, the ISO will identify the preferred Stage Two Solution (with an overview of why the solution is preferred) by a posting on its website. The ISO's identification will select the Stage Two Solution that best addresses the identified Public Policy Requirement while utilizing the best combination of electrical performance, cost, future system expandability and feasibility to meet the need in the required timeframe. The ISO will also notify the Qualified Transmission Project Sponsor that proposed the preferred Stage Two Solution that its project has been selected for development, and include the project as a Public Policy Transmission Upgrade in the Regional System Plan and RSP Project List, as it is updated from time to time in accordance with this Attachment. The preferred Stage Two Solution may include an upgrade(s) located on or connected to a PTO's existing transmission system where the Qualified Transmission Project Sponsor is not the PTO for the existing system element(s). In such cases the ISO will notify the PTO that have upgrades required by the preferred Stage Two Solution to proceed in accordance with Schedule 3.09(a) of the Transmission Operating Agreement. Once the ISO has identified the preferred Stage Two Solution, any remaining Stage Two Solutions must stop all development. Where external impacts of regional Public Policy Transmission Upgrades are identified through coordination by the ISO with neighboring entities, those impacts will be identified in the RSP. Costs associated with such impacts will be addressed as set forth in Schedule 15.

(b) Execution of Selected Qualified Transmission Project Sponsor Agreement

Within 30 days of its receiving notification pursuant to Section 4A.9(a) of this Attachment, the Qualified Transmission Project Sponsor shall submit to the ISO its acceptance of responsibility to proceed with the preferred Stage Two Solution by execution of the Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT). Within 30 days of receiving notification pursuant to Section 4A.9(a) of this Attachment, each Qualified Transmission Project Sponsor that is part of the joint proposal shall submit to the ISO its acceptance of responsibility to proceed with the preferred Stage Two Solution by execution of a Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT). Any cost cap or cost containment provisions shall be included each Selected Qualified Transmission Project Sponsor Agreement.

(c) Failure to Proceed

If the ISO finds, after consultation with a Qualified Transmission Project Sponsor, that the sponsor is failing to pursue approvals or construction in a reasonably diligent fashion, or that one or more of the Qualified Transmission Project Sponsors is unable to proceed with the project due to forces beyond its reasonable control, the ISO shall, after consultation with the Planning Advisory Committee, prepare a report, including a proposed course of action. If the Qualified Transmission Project Sponsor that is failing or unable to proceed is a PTO, the ISO shall, after consultation with the Planning Advisory Committee, prepare a report consistent with the provisions of Section 1.1(e) of Schedule 3.09(a) of the Transmission Operating Agreement, including the ISO's proposed course of action. The proposed course of action may include, for example, a consideration and selection of another Stage Two Proposal relating to the pertinent Public

Policy Requirement, or the re-solicitation of Stage One Proposals to meet the pertinent Public Policy Requirement. If prepared with respect to a Qualified Transmission Project Sponsor that is not a PTO, the report shall include a report from that sponsor. The ISO shall file its report (whether with respect to a PTO or a non-PTO Qualified Transmission Project Sponsor) with the Commission.

4A.10 Cancellation of a Request for Proposal

The ISO may cancel a request for proposal at any time. Such cancellation may be due to new or different assumptions which may change or eliminate the identified needs. Any costs associated with solutions development shall be recovered pursuant to Sections 3.6(c) and 4A.7 of this Attachment.

4A.11 Local Public Policy Transmission Upgrades

The costs of Local Public Policy Transmission Upgrade(s) that are required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan in accordance with Section 4A.9 shall be allocated in accordance with Schedule 21 of the ISO OATT.

4B. Qualified Transmission Project Sponsors

4B.1 Evaluation of Applications

The ISO will evaluate applications submitted by an entity that seeks to qualify as a sponsor of a proposed Reliability Transmission Upgrade, Market Efficiency Transmission Upgrade, ~~or~~ Public Policy Transmission Upgrade, or Longer-Term Transmission Upgrade.

4B.2 Information To Be Submitted

The application to be submitted to the ISO by an entity desiring to be a Qualified Transmission Project Sponsor will include the following information:

(i) the current and expected capabilities of the applicant to finance and construct a Reliability Transmission Upgrade, Market Efficiency Transmission Upgrade, ~~or~~ Public Policy Transmission Upgrade, or Longer-Term Transmission Upgrade, and operate and maintain it for the life of the project;

(ii) the financial resources of the applicant;

(iii) the technical and engineering qualifications and experience of the applicant;

(iv) if applicable, the previous record of the applicant regarding construction and maintenance of transmission facilities;

(v) demonstrated capability of the applicant to adhere to construction, maintenance and operating Good Utility Practices, including the capability to respond to outages;

(vi) the ability of the applicant to comply with all applicable reliability standards; and

(vii) demonstrated ability of the applicant to meet development and completion schedules.

4B.3 Review of Qualifications

The ISO shall review each application for completeness. The ISO will notify each applicant within 30 calendar days of receipt of such application whether the application is complete, or identify any deficiencies in provision of the information required by Section 4B.2 of this Attachment. An applicant notified of deficiencies must provide any remedial information within 30 calendar days of the receipt of such notice. Thereafter, the ISO will determine whether the applicant is physically, technically, legally, and financially capable of constructing a Reliability Transmission Upgrade, Market Efficiency Transmission Upgrade, ~~or~~ Public Policy Transmission Upgrade, or Longer-Term Transmission Upgrade in a timely and competent manner, and operating and maintaining the facilities consistent with Good Utility Practice and applicable reliability criteria for the life of the project, and use its best efforts to inform the applicant within 90 days from the date on which it has a completed application on file with the ISO whether it has met all of these criteria. A PTO determined by the ISO to meet all of these criteria will be deemed a Qualified Transmission Project Sponsor. A non-PTO entity determined by the ISO to meet all of these criteria will, upon its execution of the Non-incumbent Transmission Developer Operating Agreement (in the form specified in Attachment O of the OATT) and the Market Participant Service Agreement, be deemed a Qualified Transmission Project Sponsor.

4B.4 List of Qualified Transmission Project Sponsors

Qualified Transmission Project Sponsors are listed in Appendix 3 of this Attachment K.

4B.5 Annual Certification

Each Qualified Transmission Project Sponsor shall submit to the ISO annually a certification that the information initially submitted in response to Section 4B.2 of this Attachment K has not changed adversely in a material fashion, or (if a material adverse change has occurred in the intervening year) submit instead a new application for qualification as a project sponsor. In the latter case, the entity shall not be a Qualified Transmission Project Sponsor unless and until the ISO approves its new application.

5. Supply of Information and Data Required for Regional System Planning

The Transmission Owners, Generator Owners, Transmission Customers, Market Participants and other entities requesting transmission or interconnection service or proposing the integration of facilities to PTF in the New England Transmission System or alternatives to such facilities, and stakeholders requesting a Needs Assessment pursuant to Section 4.1 of this Attachment, shall supply, as required by the Tariff, the Participants Agreement, MPSAs, applicable transmission operating agreements, and/or other existing agreements, protocols and procedures, or upon request by the ISO, and subject to required CEII and confidentiality protections as specified in Section 2.4 of this Attachment, any information (including cost estimates) and data that is reasonably required to prepare an RSP or perform a Needs Assessment, Solutions Study, or any other study performed under this Attachment K.

6. Regional, Local and Interregional Coordination

6.1 Regional Coordination

The ISO shall conduct the regional system planning process for the PTF in coordination with the transmission-owning entities in, or other entities interconnected to, the New England Transmission System consistent with the rights and obligations defined in the ISO OATT, applicable transmission operating agreements or protocols, and/or this Attachment. Pursuant to Section II.49 of this OATT and Sections 3.02, 3.05 and 3.09 of the TOA, the ISO has Operating Authority or control over all PTF and Non-PTF within the New England Control Area, which are utilized for the provision of transmission service under this OATT. The ISO also has Operating Authority or control over the United States portions of the HVDC ties to Quebec and over Merchant Transmission Facilities and Other Transmission Facilities, pursuant to this OATT or applicable transmission operating agreements or protocols. The ISO, however, is not responsible for the planning of the Non-PTF, OTF and MTF. As provided in Section 6.2 and Appendix 1 of this Attachment, the PTOs are responsible for the planning of the Non-PTF and coordinating such planning efforts with the ISO. Pursuant to the OATT and/or applicable transmission operating agreements or protocols, the transmission owners of OTF and MTF are required to participate in the ISO's regional system planning process and perform and/or support studies of the impacts of regional system projects on their respective facilities.

6.2 Local Coordination

The regional system planning process shall be conducted and the RSP shall be developed in coordination with the local system plans of the PTOs. In accordance with the TOA and OATT provisions identified in Section 6.1 of this Attachment, the PTOs have responsibility for planning Non-PTF. The PTOs conduct planning of Non-PTF using the LSP process outlined in Section 2.5 and Appendix 1 of this Attachment, in coordination with the ISO, other entities interconnected with the New England Transmission System, Transmission Customers and stakeholders, and in accordance with the provisions in the TOA, the OATT and the Planning and Reliability Criteria. The openness and transparency of the LSP process is intended to be consistent with the regional system planning process.

6.3 Interregional Coordination

The regional system planning process shall be conducted and the RSP shall be developed in coordination with the similar plans of the surrounding ISOs/RTOs and Control Areas pursuant to the Northeastern Planning Protocol and other agreements with neighboring systems (including entities that are not Parties to the Northeastern Planning Protocol) and NPCC.

(a) **Interregional Coordination and Cost Allocation Among ISO, New York Independent System Operator, Inc. ("NYISO") and PJM Interconnection, L.L.C. ("PJM") Under Order No. 1000**

Pursuant to Section 7 of the Northeastern Planning Protocol (which is posted on the web at www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc, the Joint ISO/RTO Planning Committee ("JIPC") reviews regional needs and solutions identified in the regional planning processes of the ISO, NYISO and PJM in order to identify, with input from the Interregional Planning Stakeholder Advisory Committee ("IPSAC"), the potential for Interregional Transmission Projects that could meet regional needs more efficiently or cost-effectively than regional transmission projects. All members of the Planning Advisory Committee shall be considered IPSAC members. The JIPC will coordinate studies deemed necessary to allow the effective consideration by the regions, in the same general timeframe, of a proposed Interregional Transmission Project in comparison to regional transmission solutions. Any stakeholder may propose in the New England planning process, for evaluation under Section 4.2, 4.3, or 4A (as applicable) of Attachment K, an Interregional Transmission Project (or project concept) that may be more efficient or cost-effective than a regional transmission solution. If a proposed Interregional Transmission Project is approved in each region in which the project is located, the corresponding New England regional transmission project(s) will be displaced in the circumstances described in Section 3.6(a) of this Attachment, and the costs of the Interregional Transmission Project will be allocated among the regions based on the formula provided in Schedule 15 of this OATT, or in accordance with another funding arrangement filed with and accepted by the Commission. The amount of the costs of an Interregional Transmission Project allocated as the responsibility of New England pursuant to the methodology referenced in Section 6.3(a) of this Attachment shall be allocated within New England as specified in Schedule 15 of the ISO OATT.

(b) Other Interregional Assessments and Other Interregional Transmission Projects
Interregional system assessments and/or interregional system expansion planning studies may be performed periodically by the ISO with Planning Authorities who are not parties to the Northeastern Planning Protocol, or with the JIPC pursuant to Section 6 of the Northeastern Planning Protocol, or both. The ISO shall convene periodic meetings of the Planning Advisory Committee (which may be combined with meetings of the IPSAC), to provide input and feedback to the ISO concerning such assessments and studies. To the extent that an Interregional Transmission Project is agreed to by ISO and by another region (not a Party to the Northeastern Planning Protocol) in which a portion of the project is located, the related cost allocation and operating agreements will be filed with the Commission (and, as applicable, with Canadian jurisdictional agencies) in accordance with existing filing rights.

7. Procedures for Development and Approval of the RSP

7.1 Initiation of RSP

No less often than once every three years, the ISO shall initiate an effort to develop its RSP and solicit input on regional system needs for the RSP from the Planning Advisory Committee. The Planning Advisory Committee shall meet to perform its respective functions in connection with the preparation of the RSP, as specified in Section 2 of this Attachment. The ISO shall issue the periodic planning reports that support the RSP, such as Needs Assessments, as those reports are completed.

7.2 Draft RSP; Public Meeting

The ISO shall provide a draft of the RSP to the Planning Advisory Committee and input from that Committee shall be received and considered in preparing and revising subsequent drafts. The ISO shall post the draft RSP and provide notice to the Planning Advisory Committee of a meeting to review the draft RSP as specified in Section 2.2 of this Attachment.

After the ISO has provided a draft of the RSP to the Planning Advisory Committee, the ISO shall issue a second draft of the RSP to be presented by the ISO staff to the ISO Board of Directors for approval. The draft RSP shall incorporate the results of any Needs Assessment, and corresponding Solutions Studies, performed since the last RSP was approved. A subcommittee of that Board shall hold a public meeting, at their discretion, to receive input directly and to discuss any proposed revisions to the RSP. The final recommended RSP shall be presented to the ISO Board of Directors and shall be acted on by the ISO Board of Directors within 60 days of receipt. The foregoing timeframes are subject to adjustment as determined by the ISO in coordination with the Planning Advisory Committee.

7.3 Action by the ISO Board of Directors on RSP; Request for Alternative Proposals

(a) Action by ISO Board of Directors on RSP

The ISO Board of Directors may approve the recommended draft RSP as submitted, modify the RSP or remand all or any portion of it back with guidance for development of a revised recommendation. The Board of Directors may consider the RSP in executive session, and shall consider in its deliberations the views of the subcommittee of the Board of Directors reflecting the public meeting held pursuant to Section 7.2 of this Attachment. In considering whether to approve the draft RSP, the Board of Directors may, if it finds a proposed Reliability Benefit Upgrade not to be viable, or if no Reliability Benefit Upgrade has been proposed, direct the ISO staff to meet with the affected load serving entities and State entities in order to develop an interim solution. Should that effort fail, and as a last resort, the Board of Directors may direct the ISO to issue a Request For Alternative Proposal (“RFAP”), subject to the procedures described below, and may withhold approval of the draft RSP, or portions thereof, pending the results of that RFAP and any Commission action on any resulting jurisdictional contract or funding mechanism. The ISO shall provide a written explanation as to any subsequent changes or modification made in the final version of the RSP.

(b) Requests For Alternative Proposals

(i) The RFAP shall seek generation, demand-side and merchant transmission alternatives that can be implemented rapidly and provide substantial reliability benefits over the period solicited in the RFAP, and normally will focus on an interim ("gap") solution until an identified Reliability Transmission Upgrade has been placed in-service. The ISO will file a proposed RFAP with the Commission for approval at least 60 days prior to its issuance. The filing shall explain why the issuance of an RFAP is necessary.

(ii) The ISO staff shall provide the Board of Directors and subject to confidentiality requirements, the Planning Advisory Committee with an analysis of the alternatives offered in response to the RFAP, and provide a recommendation together with a funding mechanism reflecting input from the Planning Advisory Committee.

(iii) The ISO may enter into contracts awarded pursuant to an RFAP process, and/or propose a funding mechanism. Bidders that are awarded contracts through the RFAP process shall file those contracts with the Commission for approval of the rates to be charged thereunder to the extent that such contracts are for services that are jurisdictional to the Commission. The ISO shall file related or separate funding mechanisms with the Commission as well. All other contracts entered into pursuant to an RFAP shall be filed with the Commission for informational purposes.

(iv) The Board of Directors will reflect the results of the RFAP process in the approved RSP.

8. Obligations of PTOs to Build; PTOs' Obligations, Conditions and Rights

In accordance with the TOA, PTOs designated by the ISO as the appropriate entities to construct and own or finance Transmission Upgrades included in the RSP shall construct and own or finance such facilities or enter into appropriate contracts to fulfill such obligations. In the event that a PTO: (i) does not construct or indicates in writing that it does not intend to construct a Transmission Upgrade included in the RSP; or (ii) demonstrates that it has failed (after making a good faith effort) to obtain necessary approvals or property rights under applicable law, the ISO shall promptly file with the Commission a report on the results of the planning process, which report shall include a report from the PTO responsible for the planning, design or construction of such Open Access Transmission Tariff Section II – Attachment K – Regional System Planning Process Transmission Upgrade, in order to permit the Commission to determine what action, if any, it should take.

In connection with regional system planning, the ISO will not propose to impose on any PTO obligations or conditions that are inconsistent with the explicit provisions of the TOA or deprive any PTO of any of the rights set forth in the TOA.

Subject to necessary approvals and compliance with Section 2.06 of the TOA, nothing in this OATT shall affect the right of any PTO to expand or modify its transmission facilities in the New England Transmission System on its own initiative or in response to an order of an appropriate regulatory authority. Such expansions or modifications shall conform with: (a) Good Utility Practice; (b) applicable reliability principles, guidelines, criteria, rules, procedures and standards of national, regional, and local reliability councils that may be in existence; and (c) the ISO and relevant PTO criteria, rules, standards, guides and policies. The ISO reserves its right to challenge the permitting of such expansions or modifications.

9. Merchant Transmission Facilities

9.1 General

Subject to compliance with the requirements of the Tariff and any other applicable requirements with respect to the interconnection of bulk power facilities with the New England Transmission System, any entity shall have the right to propose and construct the addition of transmission facilities ("Merchant Transmission Facilities"), none of the costs of which shall be covered under the cost allocation provisions of this OATT. Any such Merchant Transmission Facilities shall be subject to the requirements of Section 9.2 of this Attachment. In performing studies in connection with the RSP, the prospect that proposed Merchant Transmission Facilities will be completed shall be accounted for as will the prospect that proposed generating units will be completed.

9.2 Operation and Integration

All Merchant Transmission Facilities shall be subject to: (i) an agreement to transfer to the ISO operational control authority over any facilities which constitute part of the Merchant Transmission Facilities that are to be integrated with, or that will affect, the New England Transmission System; and (ii) taking such other action as may be required to make the facility available for use as part of the New England Transmission System.

9.3 Control and Coordination

Until such time as a Merchant Transmission Owner has transferred operational control over its Merchant Transmission Facilities to the ISO pursuant to Section 9.2(i), all such Merchant Transmission Facilities shall be subject to the operational control, scheduling and maintenance coordination of the System Operator in accordance with the Tariff.

10. Cost Responsibility for Transmission Upgrades

The cost responsibility for each upgrade, modification or addition to the transmission system in New England that is included with the status of “Planned” in the RSP Project List as defined in Section 3.6 of this Attachment shall be determined in accordance with Schedule 12 of this OATT.

11. Allocation of ARRs

The allocation of ARRs in connection with Transmission Upgrades is addressed in Section III.C.8 of the Tariff.

12. Dispute Resolution Procedures

12.1 Objective

Section 12 of this Attachment sets forth a dispute resolution process (the “Regional Planning Dispute Resolution Process”) through which regional transmission planning-related disputes may be resolved as expeditiously as possible.

12.2 Confidential Information and CEII Protections

All information disclosed in the course of the Regional Planning Dispute Resolution Process shall be subject to the protection of confidential information and CEII consistent with the ISO New England Information Policy and CEII policy.

12.3 Eligible Parties

Any member of the Planning Advisory Committee that has been adversely affected by a Reviewable Determination, defined in Section 12.4(a) of this Attachment, with respect to the regional system planning process described in this Attachment is eligible to raise its dispute, as appropriate, under this Dispute Resolution Process ("Disputing Party").

12.4 Scope

In order to ensure that the regional transmission planning process set forth under this Attachment moves expeditiously forward, the scope of issues that may be subject to the Regional Planning Dispute Resolution Process under this Section 12 shall be limited to certain key procedural and substantive decisions made by the ISO within its authority as specified in documents on file with the Commission. That is, decisions not subject to resolution within the jurisdiction of the Commission are not within the scope of the Regional Planning Dispute Resolution Process. Examples of matters not within the scope of the Regional Planning Dispute Resolution Process include planning to serve retail native load or state siting issues. Additionally, the Tariff already explicitly provides specific dispute resolution procedures for various matters. To this end, any matter regarding the review and approval of applications pursuant to Section I.3.9 of the Tariff, which is subject to the dispute resolution process under Section I.6 of the Tariff, shall not be within the scope of this Regional Planning Dispute Resolution Process. Similarly, any matter regarding Transmission Cost Allocation shall be governed by the dispute resolution process under Schedule 12 of the OATT, and shall be outside the scope of this Regional Planning Dispute Resolution Process.

(a) Reviewable Determinations

The determinations that may be subject to the Regional Planning Dispute Resolution Process under this Section 12 that include certain procedural and substantive challenges that may arise at limited designated key decision points in the regional transmission planning process for PTF. Procedural challenges will be limited to whether or not the steps taken up to a designated key decision point conform to the requirements set forth in this Attachment. Substantive challenges will be limited to whether or not a determination or conclusion rendered at a designated key decision point was supported by adequate basis in fact.

The designated key decision points for Reviewable Determinations shall be limited to the following:

(i) Results of a Needs Assessment conducted and communicated by the ISO to the Planning Advisory Committee as specified in Section 4.1 of this Attachment;

(ii) Updates to the RSP Project List, including adding, removing or revising regulated transmission solutions included thereunder, as presented at the Planning Advisory Committee and as specified in Section 3.6 of this Attachment;

(iii) –Results of Solutions Studies conducted and communicated by the ISO to the Planning Advisory Committee as specified in Section 4.2 of this Attachment;

(iv) Consideration of market responses in Needs Assessments as specified in Section 4.1(f) of this Attachment;

(v) Prioritization and substance of Stakeholder-Requested Scenarios to be conducted by the ISO in a given Economic Study cycle as specified in Section 17.2(d) of this Attachment; and

(vi) Prioritization of Economic Study scenario sensitivities to be performed in a given Economic Study cycle where the Planning Advisory Committee is not able to prioritize them as specified in Section –17.4 of this Attachment.

(b) Material Adverse Impact

In order to prevail in a challenge to a procedural-based Reviewable Determination, the Disputing Party must show that the alleged procedural error had a material adverse impact on the determination or conclusion. In order to prevail in a challenge to a substantive-based Reviewable Determination, the Disputing Party must show that either (i) the determination is based on incorrect data or assumptions or (ii) incorrect analysis was performed by the ISO, and (iii) as a result the ISO made an incorrect decision or determination.

12.5 Notice and Comment

A Disputing Party aggrieved by a Reviewable Determination shall have fifteen (15) calendar days upon learning of the Reviewable Determination following the ISO's presentation of such Reviewable Determination at the Planning Advisory Committee to request dispute resolution by giving notice to the ISO ("Request for Dispute Resolution"). A Request for Dispute Resolution shall be in writing and shall be addressed to the ISO's Chair of the Planning Advisory Committee and, as appropriate, the affected Transmission Owner. Within three (3) Business Days of the receipt by the ISO of a Request for Dispute Resolution, the ISO shall prepare and distribute to all members of the Planning Advisory Committee a notice of the Request for Dispute Resolution including, subject to the protection of Confidential Information and CEII, the specifics of the Request for Dispute Resolution and providing the name of an ISO representative to whom any comments may be sent. Any member of the Planning Advisory Committee may submit to the ISO's designated representative, on or before the tenth (10th) Business Day following the date the ISO distributes the notice of the Request for Dispute Resolution, written comments to the ISO with respect to the Request for Dispute Resolution. The party filing the Request for Dispute Resolution may respond to any such comments by submitting a written response to the ISO's designated representative and to the commenting party on or before the fifteenth (15th) Business Day following the date the ISO distributes the notice of the Request for Dispute Resolution. The ISO may, but is not required to, consider any written comments.

12.6 Dispute Resolution Procedures

(a) Resolution Through the Planning Advisory Committee

The Planning Advisory Committee shall discuss and resolve any dispute arising under this Attachment involving a Reviewable Determination, as defined in Section 12.4 of this Attachment, between and among the ISO, the Disputing Party, and, as appropriate, the affected Transmission Owner (collectively, "Parties") (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution).

(b) Resolution Through Informal Negotiations

To the extent that the Planning Advisory Committee is not able to resolve a dispute arising under this Attachment involving a Reviewable Determination, as defined in Section 12.4 of this Attachment, between and among the ISO, the Disputing Party, and, as appropriate, the affected

Transmission Owner, such dispute shall be the subject of good-faith negotiations among the Parties. Each Party shall designate a fully authorized senior representative for resolution on an informal basis as promptly as practicable.

(c) Resolution Through Alternative Dispute Resolution

In the event the designated representatives are unable to resolve the dispute through informal negotiation within thirty (30) days, or such other period as the Parties may agree upon, by mutual agreement of the Parties, such dispute may be submitted to mediation or any other form of alternative dispute resolution upon the agreement of all Parties to participate in such mediation or other alternative dispute resolution process. Such form of alternative dispute resolution shall not include binding arbitration.

If a Party identifies exigent circumstances reasonably requiring expedited resolution of the dispute, such Party may file a Complaint with the Commission or seek other appropriate redress before a court of competent jurisdiction.

12.7 Notice of Dispute Resolution Process Results

Within three (3) Business Days following the resolution of a dispute pursuant to either Section 12.6(b) or Section 12.6(c) of this Attachment, the ISO shall distribute to the Planning Advisory Committee a document reflecting the resolution.

13. Rights Under The Federal Power Act

Nothing in this Attachment shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

14. Annual Assessment of Transmission Transfer Capability

Each year, the ISO shall issue the results of the annual assessment of transmission transfer capability, conducted pursuant to applicable NERC, NPCC and ISO New England standards and criteria and the identification of potential future transmission system weaknesses and limiting facilities that could impact the transmission system's ability to reliably transfer energy in the planning horizon. Each annual assessment will identify those portions of the New England system, along with the associated interface boundaries, that should be considered in the assessment of Capacity Zones to be modeled in the Forward Capacity Market pursuant to ISO Tariff Section III.12. This report will be posted on the ISO website.

Each annual assessment will model out-of-service resources associated with the following bids, if the ISO determines the removal of the resource is likely to have an impact on the transmission transfer limits for the relevant period: Retirement De-List Bids, Permanent De-List Bids, demand bids submitted for the upcoming substitution auction, and rejected for reliability Static De-List Bids and rejected for reliability Dynamic De-List Bids from the most recent Forward Capacity Auction.

15. Procedures for the Conduct of Cluster Enabling Transmission Upgrades Regional Planning Study

The purpose of this Section 15 is to support the conduct of Interconnection Studies under the Interconnection Procedures set forth in Schedules 22, 23 and 25 of Section II of the Tariff. Other than Section 2 of this Attachment K regarding the responsibilities of the Planning Advisory Committee and this Section 15, none of the other provisions in this Attachment K apply to the conduct of the Cluster Enabling Transmission Upgrade Regional Planning Study or the results of the study.

15.1 Notice of Initiation of Cluster Enabling Transmission Upgrade Regional Planning Study in Support of Cluster Studies under the Interconnection Procedures.

Pursuant to Section 4.2.2 of Schedule 22, Section 1.5.3.2 of Schedule 23, and Section 4.2.2 of Schedule 25 of Section II of this Tariff, the ISO shall provide notice to the Planning Advisory Committee of the initiation of a cluster for studying certain Interconnection Requests. The cluster study process, known as Clustering, shall consist of two phases. This notice shall trigger the first phase of Clustering, during which the ISO shall conduct a Cluster Enabling Transmission Upgrade (“CETU”) Regional Planning Study (“CRPS”) (the cost of which will be recovered by the ISO pursuant to Schedule 1 of Section IV.A of the Tariff). In the second phase of Clustering, the ISO shall conduct Interconnection System Impact Studies and Interconnection Facilities Studies in clusters pursuant to Schedules 22, 23 and 25 of Section II of the Tariff.

15.2 Preparation for Conduct of CRPS; Stakeholder Input

The purpose of the CRPS shall be to identify the new transmission infrastructure and any associated system upgrades to enable the interconnection of potentially all of the resources proposed in the Interconnection Requests for which the conditions identified in Section 4.2.1 of Schedule 22, Section 1.5.3.1 of Schedule 23, and Section 4.2.1 of Schedule 25 of Section II of the Tariff have been triggered. The ISO will prepare and post on its website, consistent with Section 2.4(d) of this Attachment K, a proposed scope of the CRPS and associated parameters and assumptions, and provide the foregoing to the Planning Advisory Committee. A meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit stakeholder input for consideration by the ISO on the CRPS's scope, parameters and assumptions, consistent with the responsibilities of the Planning Advisory Committee as set forth in Section 2.2 of this Attachment. As part of the CRPS's scope, the ISO will describe the circumstances that triggered the conditions in Section 4.2.1 of Schedule 22, Section 1.5.3.1 of Schedule 23, and Section 4.2.1 of Schedule 25 of Section II of the Tariff. In addition, the ISO will identify: (i) the Interconnection Requests, to be referenced by Queue Position, that are expected to be eligible to participate in the Cluster Interconnection System Impact Study, and (ii) the preliminary transmission upgrade concepts proposed to be considered in the CRPS. The preliminary transmission upgrade concepts may account for previously conducted transmission reinforcement studies and previously identified concepts for transmission upgrades in the relevant electrical area, including Elective Transmission Upgrades with Interconnection Requests pending in the interconnection queue prior to the initiation of the CRPS.

A member of the Planning Advisory Committee or an Interconnection Customer may make a written submission to the ISO, requesting that Clustering be considered for specific Interconnection Requests in the ISO New England interconnection queue. In response to such a request, the ISO will either develop a notice of initiation of a cluster pursuant to Section 15.1 of this Attachment K, or identify, in writing, to the Planning Advisory Committee why the conditions in Section 4.2.1 of Schedule 22, Section 1.5.3.1 of Schedule 23, and Section 4.2.1 of Schedule 25 of Section II of the Tariff have not been triggered.

15.3 Conduct of the CRPS

The CRPS will consist of analyses performed under the conditions used in the conduct of an Interconnection System Impact Study under the Interconnection Procedures. The CRPS will consist of steady state thermal analysis, voltage and transient stability analysis, and, as appropriate, other analysis, such as weak-grid-related analyses. The ISO will use Reasonable Efforts to complete the CRPS within twelve (12) months from the notice of the cluster initiation to the Planning Advisory Committee. If less than two (2) Interconnection Requests identified pursuant to Section 4.2.1 of Schedule 22, Section 1.5.3.1 of Schedule 23, and Section 4.2.1 of Schedule 25 of Section II of the Tariff remain in the interconnection queue prior to the completion of the CRPS, the ISO will terminate the CRPS.

15.4 Publication of the CRPS

The ISO shall post a draft report of the CRPS to the Planning Advisory Committee, consistent with Section 2.4(d) of this Attachment K, and a meeting of the Planning Advisory Committee will be held promptly thereafter in order to discuss the results of the CRPS. A comment period will follow the Planning Advisory Committee meeting. The ISO will post on its website any comments received and the ISO's responses to those comments.

The CRPS report will provide:

(i) a planning level description of the CETU(s) and a non-binding good faith order-of-magnitude estimate, developed by the applicable Transmission Owner(s), of the costs for the CETU(s);

(ii) a list of other facilities that may be needed in addition to the CETU(s) and a non-binding good faith order-of-magnitude estimate, developed by the applicable Transmission Owner(s), of the costs for those facilities (the CRPS will not provide descriptions of expected Interconnection Facilities for specific Interconnection Requests in the cases where the Interconnection Facilities cannot be finalized until the actual Interconnection Requests that will be moving forward in the cluster are known);

(iii) the approximate megawatt quantity (or quantities if more than one level of megawatt injection was studied in the CRPS) of resources that could be interconnected in a manner that meets the Network Capability Interconnection Standard and the Capacity Capability Interconnection Standard in accordance with Schedules 22, 23 and 25 of Section II of the Tariff; and,

(iv) a list of the Interconnection Requests, to be referenced by Queue Position, that at the sole discretion of the ISO are identified as eligible to participate in the Cluster Interconnection System Impact Study that will be conducted by the ISO in accordance with Section 4.2.3 of Schedule 22, Section 1.5.3.3 of Schedule 23, and Section 4.2.3 of Schedule 25 of Section II of the Tariff. The list shall include the expected cost allocation for the eligible

Interconnection Requests, calculated in accordance with Schedule 11 of Section II of the Tariff.

The non-binding good faith order-of-magnitude estimates under Section 15.4(i)-(ii) of this Attachment will be developed by the applicable Transmission Owner(s), and the costs of developing such estimates shall be recovered as specified in Sections 3.3.1, 6.1 and 7.2 of Schedule 22, Section 3.3.1, 3.4.2, and Attachment 1 of Schedule 23, and Section 3.3.1, 6.1 and 7.2 of Schedule 25.

The posting, consistent with Section 2.4 (d) of this Attachment K, of the final CRPS report on the ISO website will trigger the Cluster Interconnection System Impact Study Entry Deadline specified in Section 4.2.3.1 of Schedule 22, Section 1.5.3.3.1 of Schedule 23, and Section 4.2.3.1 of Schedule 25 of Section II of the Tariff. The Cluster Interconnection System Impact Study Entry Deadline shall be 30 days from the posting of the final CRPS report.

Notwithstanding any other provision in this Section 15, the final Maine Resource Integration Study shall be the first CRPS and will form the basis for the first Cluster Interconnection System Impact Study to be conducted in accordance with Section 4.2.3 of Schedule 22, Section 1.5.3.3 of Schedule 23, and Section 4.2.3 of Schedule 25 of Section II of the Tariff.

16. Procedures for the Conduct of Longer-Term Transmission Studies and Evaluation of Longer-Term Transmission Upgrades

This Section 16 sets forth the procedures for the ISO's conduct of Longer-Term Transmission Studies and evaluation of Longer-Term Transmission Upgrades. ~~Other than Section 2, regarding the responsibilities of the Planning Advisory Committee, Section 5, regarding the supply of information, and this Section 16 of this Attachment K, none of the other provisions in this Attachment K apply to the conduct of the Longer-Term Transmission Studies.~~ These procedures supplement, and are not intended to replace, other study processes provided in this Attachment K. The costs incurred by the ISO in consulting or providing technical support, performing the Longer-Term Transmission Study and any follow-on study, and conducting the solicitation process for Longer-Term Transmission Upgrades (excluding any costs incurred by the ISO associated with the evaluation of Longer-Term Proposals) shall be recovered pursuant to Schedule 1 of Section IV.A of the Tariff.

16.1 Request for Longer-Term Transmission Studies

The ISO, at its sole discretion, may collaborate with and provide technical support to NESCOE or the New England states in connection with the states' procurements, and efforts to secure federal funding for transmission investments. In addition, NESCOE may submit a written request for the ISO to conduct a Longer-Term Transmission Study to identify high-level concepts of transmission infrastructure and, if requested, high-level cost estimates that could meet State-identified Requirements specified in the request based on state-identified scenarios and timeframes, which may extend beyond the five-to-ten year planning horizon. A request for a Longer-Term Transmission Study may be submitted to the ISO no earlier than six months from conclusion of the prior cycle, which includes Longer-Term Transmission Studies, follow-on studies, and any associated competitive solicitation. The Longer-Term Transmission Study request shall identify the State-identified Requirements that serve as the basis of the request; the proposed objectives of the study; and the scenarios and timeframe(s) proposed for use in the study.

16.2 Preparation for Conduct of the Longer-Term Transmission Studies; Stakeholder Input

Upon receipt of a request for a Longer-Term Transmission Study from NESCOE, the ISO will post the request on the ISO's website. A meeting of the Planning Advisory Committee will be held promptly thereafter for NESCOE to present the Longer-Term Transmission Study request. NESCOE will then provide the ISO written confirmation of the specific scenarios to be analyzed in the study, together with the specific information to facilitate the conduct of the study, including, but not limited to: assumptions, types and location of new resource development, location of new loads and load serving stations, and injection points or geographic zones. The ISO will then develop a scope of work that may be performed, and post on the ISO's website the Longer-Term Transmission Study's proposed scope of work, associated parameters, and assumptions. A meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit stakeholder input on the study's scope, parameters, and assumptions. Members of the Planning Advisory Committee shall direct all such input related to the Longer-Term Transmission Study's scope, parameters, and assumptions to the ISO for consideration by the ISO and NESCOE, as applicable. Depending on the scope and objectives of a Longer-Term Transmission Study request, the ISO may request information to support consideration of new loads in the study. The ISO will provide the final scope of work for the Longer-Term Transmission Study to NESCOE for confirmation, and once written confirmation is received, will post the final scope of work on the ISO's website.

16.3 Conduct of the Longer-Term Transmission Study; Follow-on Studies; Stakeholder Input

The ISO, in consultation with NESCOE, will perform the Longer-Term Transmission Study, supplemented by third-party consultants as necessary. The ISO may ask Participating Transmission Owners or Planning Advisory Committee members with special expertise to provide technical support or assist in the performance of the study. The study will consist of transmission system analysis to be performed under the conditions specified in the confirmed scope of work. If the ISO identifies a need to deviate from the final scope of work, the ISO will consult with NESCOE prior to incorporating the change. Once NESCOE provides written confirmation, the ISO will notify the Planning Advisory Committee of any changes. The study will assess the ability of the PTF to meet applicable planning criteria under the provided conditions.

~~The costs of the performance of the Longer-Term Transmission Study will be recovered pursuant to Schedule 1 of Section IV.A of the Tariff.~~

The ISO will post on the ISO's website the results of the Longer-Term Transmission Study. A meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit input on the study results. Members of the Planning Advisory Committee shall direct all such input related to the Longer-Term Transmission Study results to the ISO for consideration by the ISO and NESCOE, as applicable.

The ISO, in consultation with NESCOE, will prepare a Longer-Term Transmission Study report and post it on the ISO's website. The report will identify the overview of transmission system limitations and the high-level concepts of transmission infrastructure and, if requested, associated cost estimates, required to solve the longer-term issues identified in the study based on the state-identified scenarios and timeframe. Members of the Planning Advisory Committee shall direct all such input related to the Longer-Term Transmission Study report to the ISO for consideration by the ISO and NESCOE, as applicable.

NESCOE may submit a written request for the ISO to perform follow-on studies based on the results of the Longer-Term Transmission Study. In its request, NESCOE will provide the ISO specific scenarios to be analyzed in the follow-on study, together with specific information to facilitate the conduct of the study, including, but not limited to scope, parameters and assumptions. Upon receipt of the request for a follow-on study, the ISO will post the request for a follow-on study on the ISO's website and a meeting of the Planning Advisory Committee will be held promptly thereafter for NESCOE to present the follow-on study request. NESCOE will then provide the ISO written confirmation of the specific scenarios to be analyzed in the follow-on study, together with the specific information to facilitate the conduct of the study, including, but not limited to scope, parameters and assumptions. The ISO will then develop a scope of work that may be performed and post on the ISO's website the follow-on study's proposed scope of work, associated parameters, and assumptions. A meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit stakeholder input on the study's scope, parameters, and assumptions. Members of the Planning Advisory Committee shall direct all such input related to the follow-on study's scope, parameters, and assumptions to the ISO for consideration by the ISO and NESCOE, as applicable. The ISO will provide the final scope of work for the follow-on study to NESCOE for confirmation, and once written confirmation is received, will post the final scope of work on the ISO's website and proceed with performing the follow-on study.

The results of the follow-on study will be posted on the ISO's website and a meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit input on the results. Such input shall be directed to the ISO for consideration by NESCOE and the ISO, as applicable. The ISO will prepare a follow-on study report, as needed, and post it on the ISO's website.

16.4 Competitive Solution Process for Longer-Term Transmission Upgrades

(a) Identification of Longer-Term Needs; Request for Proposal Determination

At the request of NESCOE, the ISO will consult with and provide technical support to NESCOE on possible longer-term needs that may be addressed through one or more request for proposal(s) ~~based on results of~~in connection with a Longer-Term Transmission Study or a follow-on study. During this consultation, the ISO, at its sole discretion, may also identify for NESCOE's consideration known non-time-sensitive reliability or market efficiency needs that could be combined with longer-term needs in a request for proposal(s). NESCOE determines which potential needs will be included in a request for proposal(s) and whether to move forward with such a request(s). If the ISO receives from NESCOE a written list identifying the specific needs that NESCOE may be interested in including in one or more potential request for proposal(s), the ISO will post the list on the ISO's website. A meeting of the Planning Advisory Committee will be held promptly thereafter for NESCOE to present the needs. Members of the Planning

Advisory Committee shall direct all comments related to the NESCOE-identified needs to the ISO for consideration by NESCOE.

Any time following NESCOE's receipt and consideration of Planning Advisory Committee input but prior to NESCOE submitting a request to initiate a subsequent Longer-Term Transmission Study, NESCOE may submit a written request for the ISO to publicly issue, via a posting on the ISO's website, a request for proposal(s) inviting Qualified Transmission Project Sponsors to submit proposals offering a comprehensive solution that addresses the needs specified in NESCOE's request for the ISO to initiate a request for proposal(s).

Notwithstanding any other provision to the contrary, if a non-time-sensitive reliability or market efficiency need that the ISO identified for NESCOE's consideration under this Section 16.4(a) is combined with longer-term needs included in a request for proposal(s), then the reliability or market efficiency need and the development of regulated transmission solutions for that need shall be subject to the procedures for longer-term transmission planning in Section 16. If any non-time-sensitive reliability or market efficiency needs are not included in the needs selected by NESCOE to be addressed in a request for proposal(s), then those non-time-sensitive reliability or market efficiency needs shall be addressed pursuant to Section 4.3 of this Attachment K. If the longer-term process is terminated pursuant to Section 16.6 of this Attachment K or corresponding Longer-Term Transmission Upgrade is removed from the RSP Project List pursuant to Section 3.6(c), then: (1) in the case of a market efficiency need, the ISO shall initiate the process under Section 4.3 of this Attachment K, and (2), in the case of a reliability need, notwithstanding any other provisions to the contrary, the ISO shall: (i) assess the reliability need and its time-sensitivity, as appropriate; (ii) determine whether a solution is needed to solve the reliability need in three years or less from the completion of the assessment in this Section 16.4(a); and (iii) initiate the applicable process pursuant to Sections 4.1-4.3 of this Attachment K.

(b) Issuance of Request for Proposal

The ISO will publicly post on its website a request for proposal(s) inviting Qualified Transmission Project Sponsors to submit (by the deadline specified in the request for proposal, which shall not be less than 60 days from the date of posting the request for proposal) a Longer-Term Proposal offering a comprehensive solution that addresses all the needs identified in the request. The request for proposal will indicate that a Qualified Transmission Project Sponsor may submit an individual or joint Longer-Term Proposal(s). In the case where a joint proposal is submitted, all parties must be Qualified Transmission Project Sponsors.

(c) Use and Control of Right of Way

Neither the submission of a project by a Qualified Transmission Project Sponsor nor the selection by the ISO of a project submitted by a Qualified Transmission Project Sponsor for inclusion in the RSP Project List shall alter a PTO's use and control of an existing right of way, the retention, modification, or transfer of which remain subject to the relevant law or regulation, including property or contractual rights, that granted the right-of-way. Nothing in the processes described in this Attachment K requires a PTO to relinquish any of its rights-of-way in order to permit a Qualified Transmission Project Sponsor to develop, construct or own a project.

(d) Information Required for Longer-Term Proposals; Study Deposit; Timing

The following information must be provided as part of the Longer-Term Proposal:

(i) detailed description of the proposed solution, in the manner specified by the ISO, including an identification of the proposed route for the solution and technical details of the project, such as interconnection into the existing transmission system;

(ii) detailed explanation of how the proposed solution addresses the identified need(s);

(iii) list of required major Federal, State and local permits

(iv) proposed schedule, including key high-level milestones, for development, siting, procurement of real estate rights, permitting, construction and completion of the proposed solution;

(v) right, title, and interest in rights of way, substations, and other property or facilities, if any, that would contribute to the proposed solution or the means and timeframe by which such would be obtained;

(vi) description of the authority the Qualified Transmission Project Sponsor(s) has to acquire necessary rights of way;

(vii) experience of the Qualified Transmission Project Sponsor(s) in acquiring rights of way;

(viii) description of construction sequencing, a conceptual plan for the anticipated transmission and generation outages necessary to construct the proposed solution and their respective duration, and possible constraints;

(ix) detailed cost component itemization and life-cycle cost, including cost containment or cost cap measures;

(x) description of the financing being used;

(xi) design and equipment standards to be used;

(xii) detailed explanation of project feasibility and potential constraints and challenges;

(xiii) description of the means by which the Qualified Transmission Project Sponsor(s) proposes to satisfy legal or regulatory requirements for siting, constructing, owning and operating transmission projects; and

(xiv) detailed explanation of potential future expandability.

A Qualified Transmission Project Sponsor may submit a proposed solution that includes an upgrade(s) located on or connected to a PTO's existing transmission system where the Qualified Transmission Project Sponsor is not the PTO for the existing system element(s). In such cases, the Qualified Transmission Project Sponsor's proposed solution relating to the upgrade(s) of an existing transmission system element(s) must provide all data available to the Qualified Transmission Project Sponsor as part of its response to the request for proposal. The Qualified Transmission Project Sponsor is not required to procure agreements with the PTO for implementation of such upgrades as the PTO is required to implement the upgrade(s) in accordance with Schedule 3.09(a) of the Transmission Operating Agreement if the proposed solution is selected through the competitive process.

With each proposal, the submitting Qualified Transmission Project Sponsor must include payment of a $100,000 study deposit per submitted Longer-Term Proposal to support the cost of Longer-Term Proposal evaluation by the ISO. The study deposit of $100,000 shall be applied toward the costs incurred by the ISO associated with the evaluation of the Longer-Term Proposal. Any difference between a Qualified Transmission Project Sponsor's study deposit and the actual cost of the evaluation of a Longer-Term Proposal shall be paid by or refunded to the Qualified Transmission Project Sponsor, as appropriate, with interest calculated in accordance with Section 35.19a(a)(2) of the FERC regulations. Any refund payment shall be accompanied by a detailed and itemized accounting of the actual study costs incurred. Any invoice to collect funds in addition to the deposit shall be accompanied by a detailed and itemized accounting of the actual study costs incurred. Any disputes arising from the study process shall be addressed under the dispute resolution process specified in Section I.6 of the ISO Tariff.

Longer-Term Proposals must be submitted by the deadline specified in the public posting by the ISO of the request for proposal. The ISO may reject submittals which are insufficient or not adequately supported.

(e) LSP Coordination

Qualified Transmission Project Sponsors of Longer-Term Proposals shall also identify any LSP plans that require coordination with their Longer-Term Proposals.

(f) Review of Longer-Term Proposals

Upon receipt of Longer-Term Proposals, the ISO shall perform a review of each proposal to determine whether the proposal:

(i) provides sufficient data and that the data is of sufficient quality to satisfy Section 16.4(d);
(ii) satisfies the needs identified in the request for proposal;
(iii) is technically practicable and indicates possession of, or an approach to acquiring, the necessary rights of way, property and facilities that will make the proposal reasonably feasible in the required timeframe; and;
(iv) is eligible to be constructed only by an existing PTO in accordance with Schedule 3.09(a) of the TOA because the proposed solution is an upgrade to existing PTO facilities or because the costs of the proposed solution are not eligible for regional cost allocation under the OATT and will be allocated only to the local customers of a PTO.

F[A2]or each Longer-Term Proposal that satisfies the criteria specified in this Section 16.4(f), the ISO shall also perform an independent capital cost estimate, using a consistent capital cost estimating methodology, to ensure consistency in its review of the Longer-Term Proposals and their cost estimates.

(g) Proposal Deficiencies; Further Information

If the ISO identifies any minor deficiencies (compared with the requirements of Section 16.4(d)) in the information provided in connection with a Longer-Term Proposal, the ISO will notify the Qualified Transmission Project Sponsor that submitted the Longer-Term Proposal and provide an opportunity for the Qualified Transmission Project Sponsor to cure the deficiencies within the timeframe specified by the ISO. Upon request, Qualified Transmission Project Sponsors of Longer-Term Proposals shall provide the ISO with additional information reasonably necessary for the ISO's evaluation of the proposed solutions. In providing information under this subsection (g), the Qualified Transmission Project Sponsor may not modify its project materially or submit a new project, but instead may clarify its Longer-Term Proposal.

(h) Identification and Reporting of Preliminary Preferred Longer-Term Transmission Solution; Stakeholder Input

The ISO will identify the Longer-Term Transmission Solution that offers the best combination of electrical performance, cost, future system expandability and feasibility to comprehensively address all of the needs in the timeframes specified in the request for proposal(s) as the preliminary preferred Longer-Term Transmission Solution in response to each request for proposal.

The ISO will consider several factors during the evaluation process for identification of the preliminary preferred Longer-Term Transmission Solution. These factors may include, but are not limited to, the following which are listed in no particular order:

- Life-cycle cost, including all costs associated with right of way acquisition, easements, and associated real estate;
- System performance;
- Cost cap or cost containment provisions;
- In-service date of the project or portion(s) thereof;
- Project constructability;
- Generation and transmission facility outages required during construction;
- Extreme contingency performance;
- Operational impacts;

- Incremental costs for potential resource retirements;
- Interface impacts;
- Future expandability;
- Consistency with Good Utility Practice;
- Potential siting/permitting issues or delays;
- Environmental impact;
- Design standards;
- Impact on NPCC Bulk Power System classification; and
- Qualified Transmission Project Sponsor(s) capabilities

The ISO will determine the financial benefits associated with Longer-Term Proposals that meet the needs identified in the request for proposal(s) and are competitive in terms of electrical performance, cost, future system expandability and feasibility. These financial benefits will consider factors that include, but are not limited to, the following which are listed in no particular order:

- Production cost and congestion savings;
- Avoided capital cost of local resources needed to serve demand;
- Avoided transmission investment;
- Reduction in losses; and
- Reduction in expected unserved energy

To be eligible for consideration as the preliminary preferred Longer-Term Transmission Solution, the Longer-Term Proposal must provide a benefit-to-cost ratio of greater than 1.0. Longer-Term Proposals with a benefit-to-cost ratio of 1.0 or less shall not be eligible for consideration as the preliminary preferred Longer-Term Transmission Solution. The benefit-to-cost ratio shall equal financial benefits divided by project costs. For the purpose of this calculation, financial benefits will be set equal to the present value of all financially quantifiable benefits provided by the project projected for the first 20 years of the project's life and project costs will be set equal to the present value of the annual revenue requirements projected for the first 20 years of the project's life.

The ISO will report the preliminary preferred Longer-Term Transmission Solution to the Planning Advisory Committee and seek input on the preliminary preferred Longer-Term Transmission Solution. Members of the Planning Advisory Committee may provide comments to the ISO on the preliminary preferred Longer-Term Transmission Solution.

(i) ISO Selection of Preferred Longer-Term Transmission Solution; NESCOE Response

Following receipt of stakeholder input, the ISO will identify the preferred Longer-Term Transmission Solution, together with an overview of why the solution is preferred, in a report and post that report on the ISO's website. The ISO will select the project that meets the conditions specified in Section 16.4(h) of this Attachment K. Within 30 days of the ISO's posting of the report identifying the preferred Longer-Term Transmission Solution, NESCOE may submit to the ISO a written communication: (a) requesting that the ISO terminate the process, or (b) requesting that the ISO continue the process, but specifying an alternative allocation for the recovery of the incremental costs to address longer-term needs beyond those necessary to address any reliability or economic needs included in the longer-term request for proposal(s). If the ISO does not receive a written communication requesting that the ISO terminate the process, the ISO will proceed in accordance with Section 16.5 of this Attachment K, which shall apply solely to Longer-Term Proposals that meet the greater than 1.0 benefit-to-cost ratio threshold. The ISO shall terminate the process if requested to do so in the written NESCOE communication pursuant to Section 16.6 of this Attachment.

(j) ISO Reporting Where No Longer-Term Proposal Meets the Greater than 1.0 Benefit-to-Cost Ratio Threshold; NESCOE Response

In the event that no Longer-Term Proposal meets the benefit-to-cost ratio threshold, the ISO will present its findings to the Planning Advisory Committee. In the absence of a Longer-Term Proposal that meets the benefit-to-cost ratio threshold, the ISO will not identify a preliminary preferred Longer-Term Transmission Solution, but will make a recommendation on a Longer-

Term Proposal. Members of the Planning Advisory Committee may provide comments to the ISO on its findings, and the ISO will provide and post on its website responses to written comments. If, after considering stakeholder input, the ISO determines that no Longer-Term Proposal meets the benefit-to-cost ratio threshold, the ISO will cancel the request for proposal in accordance with Section 16.6 of this Attachment K after the 15th day from the posting of the ISO's responses on the website.

16.5 Where the Greater than 1.0 Benefit-to-Cost Ratio Threshold has Been Met: Inclusion of Longer-Term Transmission Upgrade in the Regional System Plan and RSP Project List; Milestone Schedule; Removal from RSP Project List

(a) Inclusion of Longer-Term Transmission Upgrade in the Regional System Plan and RSP Project List

If the ISO does not receive a written NESCOE communication requesting that the ISO terminate the process or providing an alternative cost allocation within the 30 day period specified in Section 16.4(i) of this Attachment, the ISO will notify the Qualified Transmission Project Sponsor that proposed the preferred Longer-Term Transmission Solution that its project has been selected for development, and include the project as a Longer-Term Transmission Upgrade in the Regional System Plan or RSP Project List, as it is updated from time to time in accordance with this Attachment. The preferred Longer-Term Transmission Solution may include an upgrade(s) located on or connected to a PTO's existing transmission system where the Qualified Transmission Project Sponsor is not the PTO for the existing system element(s). In such cases, the ISO will notify the PTO that has upgrades required by the preferred Longer-Term Transmission Solution to proceed in accordance with Schedule 3.09(a) of the TOA.

If the ISO receives a written NESCOE communication providing an alternative cost allocation pursuant to Section 16.4(i) of this Attachment, the ISO will notify the Qualified Transmission Project Sponsor that proposed the preferred Longer-Term Transmission Solution that its project has been selected for development and the PTO that has upgrades required by the preferred Longer-Term Transmission Solution, and provide them the written NESCOE communication reflecting the requested alternative cost allocation. In the case where the ISO notifies the PTO that has upgrades required by the preferred Longer-Term Transmission Solution to proceed in accordance with Schedule 3.09(a) of the TOA, any prudently incurred PTO costs associated with a filing to implement the cost allocation requested by NESCOE will be recovered by the applicable PTO in accordance with Attachment F of this OATT.

Within 30 days of the Commission's order addressing the alternative cost allocation, NESCOE will provide the ISO a communication specifying whether the process should proceed in accordance with Section 16.5(b) or terminate in accordance with Section 16.6 of this Attachment K. If the written NESCOE communication provides for the process to proceed, then the ISO will notify the Qualified Transmission Project Sponsor and PTO and include the project as a Longer-Term Transmission Upgrade in the Regional System Plan or RSP Project List, as it is updated from time to time in accordance with this Attachment. If the written NESCOE communication requests termination of the process, the ISO shall terminate the process pursuant to Section 16.6 of this Attachment.

Costs for the Longer-Term Transmission Upgrade included in the Regional System Plan or RSP Project List shall be allocated in accordance with Section 10 of Schedule 12 to this OATT.

(b) Execution of Selected Qualified Transmission Project Sponsor Agreement

If the ISO does not receive a written NESCOE communication requesting that the ISO terminate the process or providing an alternative cost allocation pursuant to Section 16.4(i) of this Attachment, within 30 days of ~~its~~ receiving notification pursuant to Section 16.5(a) of this Attachment, the Qualified Transmission Project Sponsor shall submit to the ISO its acceptance of responsibility to proceed with the preferred Longer-Term Transmission Solution by execution of the Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT). Within 30 days of receiving notification pursuant to Section 16.5(a) of this Attachment, each Qualified Transmission Project Sponsor that is part of the joint proposal shall submit to the ISO its acceptance of responsibility to proceed with the preferred Longer-Term Transmission Solution by execution of a Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT). Any cost cap or cost containment provisions shall be included in each Selected Qualified Transmission Project Sponsor Agreement.

If the ISO receives a written NESCOE communication providing an alternative cost allocation pursuant to Section 16.4(i) of this Attachment, within 30 days of the ISO's notification to the Qualified Transmission Project Sponsor that NESCOE has elected to proceed, the Qualified Transmission Project Sponsor shall submit to the ISO its acceptance of responsibility to proceed with the preferred Longer-Term Transmission Solution by execution of the Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT). Within 30 days of the ISO's notification to the Qualified Transmission Project Sponsor that NESCOE has elected to proceed~~inclusion of the project in the Regional System Plan or RSP Project List~~, each Qualified Transmission Project Sponsor that is part of the joint proposal shall submit to the ISO its acceptance of responsibility to proceed with the preferred Longer-Term Transmission Solution by execution of a Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT). Any cost cap or cost containment provisions shall be included in each Selected Qualified Transmission Project Sponsor Agreement.

Qualified Transmission Project Sponsors whose projects are listed on the RSP Project List and have executed the Selected Qualified Transmission Project Sponsor Agreement shall be entitled to recover, pursuant to the rates and appropriate financial arrangements set forth in the Tariff and, as applicable, the TOA and NTDOA, all prudently incurred cost associated with developing the Longer-Term Transmission Upgrade subsequent to executing the Selected Qualified Transmission Project Sponsor Agreement.

PTOs shall be entitled to recover, pursuant to rates and appropriate financial arrangements set forth in the Tariff, all prudently incurred study costs and costs associated with developing any upgrades or modifications to such PTOs' existing facilities necessary to facilitate the development of a Longer-Term Transmission Solution proposed by any other Qualified Transmission Project Sponsor.

Notwithstanding the foregoing, a PTO is not precluded from recovering, pursuant to the applicable rates and appropriate financial arrangements set forth in the Tariff and the TOA, all prudently incurred costs associated with meeting its obligations to plan and maintain its Transmission Facilities as defined in Section 2.01 of the TOA.

(c) Failure to Proceed

If the ISO finds, after consultation with a Qualified Transmission Project Sponsor, that the sponsor is failing to pursue approvals or construction in a reasonably diligent fashion, or that one or more of the Qualified Transmission Project Sponsors is unable to proceed with the project due to forces beyond its reasonable control, the ISO shall, after consultation with the Planning Advisory Committee, prepare a report, including a proposed course of action. If the Qualified Transmission Project Sponsor that is failing or unable to proceed is a PTO, the ISO shall, after consultation with the Planning Advisory Committee, prepare a report consistent with the provisions of Section 1.1(e) of Schedule 3.09(a) of the Transmission Operating Agreement, including the ISO's proposed course of action. The proposed course of action may include, for example, a consideration and selection of another Longer-Term Proposal, or the re-solicitation of Longer-Term Proposals. If prepared with respect to a Qualified Transmission Project Sponsor that is not a PTO, the report shall include a report from that sponsor. The ISO shall file its report (whether with respect to a PTO or a non-PTO Qualified Transmission Project Sponsor) with the Commission.

16.6 Cancellation of a Longer-Term Transmission Study; Cancellation of a Request for Proposal

The ISO may cancel a Longer-Term Transmission Study process or a request for proposal at any time. Such cancellation may be due, but is not limited to, new or different assumptions which may change or eliminate the identified needs. The ISO shall cancel a Longer-Term Transmission Study process or a request for proposal if requested to do so in a written NESCOE communication.

16.7 Local Longer-Term Transmission Upgrades

The costs of Local Longer-Term Transmission Upgrade(s) that are required in connection with the construction of a Longer-Term Transmission Upgrade approved for inclusion in the Regional System

Plan in accordance with Section 16.5(a) of this Attachment K shall be allocated in accordance with Schedule 21 of the OATT.

17. Procedures for the Conduct of Economic Studies

This Section 17 sets forth the procedures for the ISO's conduct of Economic Studies.

17.1 Overview

The Economic Study process shall be used to identify market efficiency issues on the PTF portion of the New England Transmission System and, as applicable, evaluate competitive solutions to alleviate identified market efficiency needs. The process will also provide information to facilitate the evaluation of economic and environmental impacts of New England regional policies, federal policies, and various resource technologies on satisfying future resource needs in the region.

17.2 Economic Study Reference Scenarios

The ISO shall develop and study the following four reference scenarios. The ISO shall consult with, and consider the input from, the Planning Advisory Committee on the scope, parameters, and assumptions used in modeling the scenarios described in this Section 17.2.

(a) Benchmark Scenario

The purpose and scope of the Benchmark Scenario is to improve the economic planning model and associated assumptions and criteria used in the other scenarios by comparing it against historical performance of the system in the previous year and adjusting the assumptions and model accordingly. This scenario will help identify any modeling issues in the base set of input data.

The initial economic planning model will use the existing base case model and data and may be adjusted based on historical performance and observations. Historical performance of the system includes recorded observations from the prior year to the beginning of the study cycle.

The study year shall be year N-1 and the simulation length shall be one year for the Benchmark Scenario.

Any identified market efficiency issues resulting from a Benchmark Scenario shall not be evaluated as a market efficiency need against the factors and metrics in Attachment N.

(b) Market Efficiency Needs Scenario

The purpose and scope of the Market Efficiency Needs Scenario is to identify market efficiency issues on the PTF portion of the New England Transmission System at the end of the ten-year planning horizon pursuant to Section 17.5 of this Attachment. Pursuant to Section 4.1 of this Attachment, the ISO shall conduct a market efficiency Needs Assessment to evaluate and determine whether market efficiency issues identified in a Market Efficiency Needs Scenario are market efficiency needs.

The model used for the Market Efficiency Needs Scenario shall be the updated base case from the Benchmark Scenario and forecasted out to the ten-year planning horizon year using assumptions and criteria in Section 4.1(f) of this Attachment.

The study year shall be year N+10 and the simulation length shall be one year for the Market Efficiency Needs Scenario.

(c) Policy Scenario

The purpose and scope of the Policy Scenario is to identify any potential market efficiency issues resulting from the New England states' energy policies and goals, among others (e.g., federal legislation, state legislation, or utility renewable portfolio standard targets). The policies and goals selected for the Policy Scenario shall be selected by the ISO and Planning Advisory Committee pursuant to Section 17.4 of this Attachment.

The model used for the Policy Scenario shall be the base case model resulting from the Benchmark Scenario and forecasted out to a year when relevant New England and other applicable energy policies and goals are in full effect.

The study year for the Policy Scenario shall be dependent on deadlines for achieving the New England region and other energy policies and goals. However, the study year will be at least ten years into the future and cover the deadlines for achieving all applicable goals and policies. The study simulation length shall be one year.

The results from studying a Policy Scenario shall be used for informational purposes only. Any identified market efficiency issues resulting from a Policy Scenario shall not be evaluated as a market efficiency need against the factors and metrics in Attachment N.

(d) Stakeholder-Requested Scenario

The purpose of the Stakeholder-Requested Scenario is to study a scenario with a region-wide scope that is requested by stakeholders and not covered by the other scenarios described in this Section 17.

The model used for the Stakeholder-Requested Scenario shall be the base case model resulting from the Benchmark Scenario and then forecasted out to a year with assumptions requested by the stakeholders and agreed upon by the ISO.

The study year shall be dependent on the requested scenario and the simulation length shall be one year.

The results from studying a Stakeholder-Requested Scenario shall be used for informational purposes only. Any identified market efficiency issues resulting from a Stakeholder-Requested Scenario shall not be evaluated as a market efficiency need against the factors and metrics in Attachment N.

17.3 Frequency, Initiation, and Schedule

The Economic Study process shall be conducted at least once every three years and at most once every two years. The process shall be initiated for the first time under this Section 17 in January 2024.

Each Economic Study cycle shall be initiated by the ISO providing the Planning Advisory Committee with notice that the ISO will be initiating the process for the Economic Study cycle. The ISO shall provide to the Planning Advisory Committee the schedule for the Economic Study cycle within three months of initiating the process. The schedule shall include dates for the ISO's collection, and stakeholders' submission, of data to be used in the studies, the preparation of models, the completion of studies, and the issuance of study results. The schedule shall include a one-month period for stakeholders to submit proposals for the Stakeholder-Requested Scenario. If the Economic Study cycle and potential resulting competitive request for proposals process cannot be completed within the initial schedule, the ISO shall notify stakeholders of such, provide a revised estimated completion date, and provide an explanation of the reason or reasons why the additional time is required.

17.4 Preparation of the Economic Study Reference Scenarios and Stakeholder Sensitivity Requests

The ISO shall prepare and post on its website a proposed scope for the scenarios described in Section 17.2, and the associated parameters and assumptions. The ISO shall either provide the Planning Advisory Committee with notice that the ISO posted the information or send the information itself to the Planning Advisory Committee after it is posted. A Planning Advisory Committee meeting will be held thereafter to solicit stakeholder input for consideration by the ISO on the study's scope, parameters, and assumptions.

Following the analyses, runs, and presentation of the results of the Economic Study reference scenarios described in Section 17.2, stakeholders may request, and the ISO may propose, additional sensitivities to test the effect of a specific change to input assumptions. The sensitivities shall be limited to a single theme or category of changes to allow for better understanding of the causal effect of the change to the results. The ISO shall prioritize and list the sensitivities that can be completed during the Economic Study cycle taking into consideration the impact of the additional efforts on the ISO resources and other priorities.

Results from studies conducted with stakeholder-requested scenario sensitivities shall be used for information purposes only. Any identified market efficiency issues resulting from a study with a stakeholder-requested scenario sensitivity shall not be evaluated as a market efficiency need against the factors and metrics in Attachment N.

17.5 Market Efficiency Needs Assessment

The ISO shall use the Market Efficiency Needs Scenario and criteria in Attachment N to identify market efficiency issues on the PTF portion of the New England Transmission System and, as applicable, identify market efficiency needs on the PTF portion of the New England Transmission System.

All of the market efficiency issues and associated benefits of relieving those issues will be documented in a market efficiency Needs Assessment conducted pursuant to Section 4.1 of this Attachment.

Any market efficiency issues that meet the criteria in Attachment N will be identified as market efficiency needs, and a request for proposal or multiple requests for proposals will be issued to initiate the competitive solution process for Market Efficiency Transmission Upgrades to address the identified market efficiency need or needs pursuant to Section 4.3 of this Attachment.

17.6 Evaluation of Regulated Transmission Solutions for Market Efficiency Transmission Upgrades

The process in Section 4.3 of this Attachment shall be used to solicit and evaluate competitive solutions for identified market efficiency needs.

17.7 Stakeholder Input on Study Results

After the results from the Economic Study reference scenarios described in Section 17.2 and stakeholder-requested scenario sensitivities described in Section 17.4 are available, the ISO shall provide such results to stakeholders at Planning Advisory Committee meetings and solicit feedback based on the results.

17.8 Economic Studies Requested by Individual Stakeholders

An individual stakeholder may request that the ISO conduct Economic Studies at the stakeholder's own expense to examine situations where potential regulated transmission solutions, market responses, or investments could result in (i) a net reduction in total production cost to supply system load based on the factors specified in Attachment N of this OATT, (ii) reduced congestion, or (iii) the integration of new resources or loads, or both, on an aggregate or regional basis. The scope, assumptions, and deliverables shall be agreed to by the ISO and the stakeholder requesting the study. The notice and schedule initiating the Economic Study process described in Section 17.3 shall include the dates for submitting requests for studies under this Section 17.8.

The ISO may hire a consultant to conduct the analysis, and the entity requesting the study shall be responsible for the ISO's costs for study administration, study analysis, and consultants used to perform the study.

The ISO shall provide an estimated cost and duration to each stakeholder that requests an Economic Study. Each stakeholder that requests a study under this Section 17.8 shall provide written confirmation with the ISO that the stakeholder would like the ISO to proceed with conducting the study after receiving the estimated cost and duration for the study it requested.

The results from studies conducted pursuant to this Section 17.8 shall be used for informational purposes only. Any identified market efficiency issues resulting from studies conducted pursuant to this Section 17.8 shall not be evaluated as a market efficiency need against the factors and metrics in Attachment N.

17.9 Cost Recovery

The costs of the Economic Study process described in Sections 17.1 through 17.7 shall be recovered by the ISO pursuant to Schedule 1 of Section IV.A of the Tariff. The costs of Economic Studies performed by the ISO under Section 17.8 of this Attachment shall be paid for by the stakeholder requesting the study.

17.10 Coordination with PTOs

The PTOs shall coordinate with the ISO in the performance of the Economic Study process pursuant to and as described in Section 5 of this Attachment.

ATTACHMENT K APPENDIX 1

ATTACHMENT K -LOCAL

LOCAL SYSTEM PLANNING PROCESS

APPENDIX 1
ATTACHMENT K -LOCAL
LOCAL SYSTEM PLANNING PROCESS

1. Local System Planning Process

1.1 General

In circumstances where transmission system planning for Non-Pool Transmission Facilities ("Non-PTF")[1], including Local Public Policy Transmission Upgrades, is taking place in New England that is not incorporated into the RSP planning process, the following Local System Plan ("LSP") process will be utilized for transmission planning purposes. The purpose of the LSP is to enable formal stakeholder input to planning for Non-PTF that is not incorporated into the RSP. The LSP shall ensure the opportunity for Planning Advisory Committee participation in the LSP process. The LSP will not be subject to approval by the ISO or the ISO Board under the RSP.

1.2 Planning Advisory Committee Review

The Planning Advisory Committee shall periodically provide input and feedback to the PTOs concerning the development of the LSP and the conduct of associated system enhancement and expansion studies. It is contemplated that LSP issues for identified local areas will be periodically addressed at the end of regularly scheduled Planning Advisory Committee meetings. Regular meetings of the Planning Advisory Committee shall be extended as necessary to serve the purposes of this section. Each PTO contemplating the addition of new Non-PTF will present its respective LSP to the Planning Advisory Committee not less than once per year. Not less than every three years, each PTO will post a notice as part of its LSP process indicating that members of the Planning Advisory Committee, NESCOE, or any state may provide the PTO with input regarding state and federal Public Policy Requirements identified as driving transmission needs relating to Non-PTF and regarding particular local transmission needs driven by Public Policy Requirements. The PTO will provide a written explanation, to be posted on the ISO website, of why suggested transmission needs driven by Public Policy Requirements will or will not be evaluated for potential solutions in the LSP planning process.

1.3 Role of the PTOs

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[1] For absence of doubt, the PTOs clarify that Non-PTF is meant to include Category B and Local Area Facilities as defined by the TOA.

Each PTO will be responsible for administering the LSP process pertaining to its own Non-PTF, including Local Public Policy Transmission Upgrades, by presenting LSP information to the Planning Advisory Committee, developing an appropriate needs analysis and addressing LSP needs within its local area. In developing its LSP, each PTO will ensure comparable treatment of similarly situated customers or potential customers and will take into consideration data, comments and specific requests supplied by the Planning Advisory Committee, Transmission Customers and other stakeholders. To the extent that generation and/or demand resources are identified that could impact planning for Non-PTF, each PTO will take such resources into account when developing the LSP for its facilities, consistent with Good Utility Practice. Each PTO will also be responsible for addressing issues or concerns arising out of Planning Advisory Committee review of its proposed LSP and posting its LSP and the LSP Project List.

1.4 Description of LSP

The LSP shall describe the projected improvements to Non-PTF that are needed to maintain system reliability or as Local Public Policy Transmission Upgrades, and shall reflect the results of such reviews within the limited geographical areas that pertain to the LSP, as determined by each PTO ("LSP Needs Assessments"), and corresponding system planning and expansion studies. The LSP Needs Assessments will be coordinated with the RSP and include the information that the ISO-NE incorporates into the RSP plans, as applicable. The proponents of regulated transmission proposals in response to LSP Needs Assessments shall also identify any RSP plans that require coordination with their regulated transmission proposals addressing the Non-PTF system needs.

The LSP shall identify the planning process, criteria, data, and assumptions used to develop the LSP. To the extent the current LSP utilizes data, assumptions or criteria used by the ISO in the RSP, any such data, assumptions or criteria will also be identified in the LSP.

Each PTO shall consult with NESCOE and applicable states, local authorities and stakeholders to consider their views prior to including a Local Public Transmission Upgrade in its LSP, as described in Section 1.6.

Each PTO's LSP will be made available on a website for review by the Planning Advisory Committee, Transmission Customers and other stakeholders, subject to the ISO New England Information Policy and

CEII restrictions or requirements. The ISO's posting of the RSP and the RSP Project List will include links to each PTO's specific LSP posting.

The LSP of a particular PTO shall be posted not less than 3 business days prior to its presentation by the PTO to the Planning Advisory Committee. The Planning Advisory Committee, Transmission Customers, and other stakeholders will have 30 days from the date of the PTO's presentation to the Planning Advisory Committee to provide any written comments for consideration by the PTO. The LSP shall specify the physical characteristics of the solutions that can meet the needs identified in the LSP. The LSP shall provide sufficient information to allow Market Participants to assess the quantity, general locations and operating characteristics of the type of incremental supply or demand-side resources, or merchant transmission projects, that would satisfy the identified needs or that may serve to modify, offset or defer proposed regulated transmission upgrades.

Each year's LSP shall be based upon the LSP completed in the prior year by either recertifying the results of the prior LSP or providing specific updates.

1.5 Economic Studies

To the extent that the ISO selects any Economic Studies pursuant to Section 4.1(b) of Attachment K or otherwise performs Economic Studies that will impact Non-PTF, the PTOs will coordinate with the ISO in the performance of such Economic Studies.

1.6 Public Policy Studies

As part of the LSP process, each PTO will evaluate potential transmission solutions on its Non-PTF system that are likely to be both efficient and cost-effective for meeting Public Policy Requirements.

1.6A Process to Identify Public Policy Requirements Driving Non-PTF Transmission Needs

Within six months of publication, each PTO will review the Public Policy Requirements posted by the ISO to determine and evaluate at a high level any public policy needs potentially driving transmission needs on their respective Non-PTF systems. Such evaluations will also include potential public policy needs suggested by third parties. Each PTO will review NESCOE's written explanation of which transmission needs driven by state or federal Public Policy Requirements will be evaluated by the ISO and why other suggested transmission needs will not be evaluated. If NESCOE does not provide a listing of identified transmission needs and explanation, each PTO will review the ISO's explanations of which transmission needs driven by state or federal Public Policy Requirements will be evaluated by the ISO and why other suggested transmission needs will not be evaluated. In addition, each PTO will review the ISO's explanation of which transmission needs driven by local Public Policy Requirements will be evaluated in the regional system planning process and why other suggested transmission needs driven by local Public Policy requirements will not be evaluated. Each PTO will then determine if any of the posted state, federal or local Public Policy Requirements are driving a need on its Non-PTF transmission system and will include the non-PTF needs in its local planning process.

As part of the local planning process, each PTO will list the identified transmission needs on its non-PTF transmission system driven by state, federal, or local Public Policy Requirements that will be evaluated, and provide an explanation of why any identified transmission needs will not be evaluated as part of its LSP. The list will be posted in the PTO's LSP and presented at the annual PAC meeting. The PTO will seek input at the PAC meeting from stakeholders about whether further study is warranted to identify solutions for local transmission system needs and seek recommendations about whether to proceed with such studies. A stakeholder may provide written input on the list within 30 days from the date of presentation for consideration by the PTO. Each PTO will then confirm, or modify if appropriate, its determination of which identified transmission needs on its non-PTF transmission system driven by state, federal, or local Public Policy Requirements will be evaluated and which will not be evaluated, and revise its annual LSP accordingly. If the potential Non-PTF transmission needs identified would affect the Non-PTF facilities of more than one PTO, the affected PTOs will coordinate their efforts with other affected PTOs, as necessary.

1.6B Procedure for Evaluating Potential Public Policy Solutions on the Non-PTF

Once it has been determined that a non-PTF need driven by state, federal or local Public Policy Requirements will be evaluated, each PTO will prepare a scope and associated assumptions as part of a Public Policy Local Transmission Study. For those needs where a scope is available, a PTO may present the proposed scope for the Public Policy Local Transmission Study within its LSP and as part of its LSP presentation described in Section 1.6A. A stakeholder may provide written input to the scope within 30 days after the LSP presentation for the PTO to consider.

Each PTO will schedule a follow-up PAC meeting presentation for additional stakeholder input within 4 months after the PTO's LSP presentation as described in Section 1.6A if the proposed scope for a Public Policy Local Transmission Study was not included in its annual LSP presentation. Within 30 days after the follow-up meeting, a stakeholder may provide written input to the scope for the PTO to consider. Subsequently, the PTO will determine the study scope for the Public Policy Local Transmission Study and revise its annual LSP.

In preparation of a Public Policy Local Transmission Study that will be presented to the PAC as part of the LSP for the following year, the PTO will undertake the following: First, the PTO will perform the initial phase of the Public Policy Local Transmission Study to develop an estimate of costs and benefits and post its preliminary results on a website. Second, the PTO will use good faith efforts to contact stakeholders and the appropriate state and/or local authorities informing them of the posting, requesting input on whether further study is warranted to identify solutions for local transmission system needs, and seeking recommendations about whether to proceed with further planning and construction of a Local Public Policy Transmission Upgrade. Each PTO will then make a determination of whether further study is warranted to identify solutions for local transmission system needs, or will select its final solution, and revise its annual LSP accordingly. If the potential Non-PTF transmission needs identified would affect the Non-PTF facilities of more than one PTO, the affected PTOs will coordinate their efforts with other affected PTOs, as necessary. Results of a Public Policy Local Transmission Study will be provided to the PAC as part of the LSP for the following year.

2. Posting of LSP Project List

Each PTO shall develop, maintain and make available on a website, a cumulative listing of proposed regulated transmission solutions that may meet LSP needs (the "LSP Project List"). The LSP Project List will be updated at least annually. The LSP Project List shall also provide reasons for any new Non-PTF, including Local Public Policy Transmission Upgrades, any change in status of proposed Non-PTF, including Local Public Policy Transmission Upgrades, or any removal of proposed Non-PTF, including Local Public Policy Transmission Upgrades, from the LSP Project List. Each PTO will be individually responsible for publicly posting and updating the status of its respective LSP and the transmission projects arising therefrom on a website in a format comparable to the manner in which RSP plans and projects are posted on the RSP Project List. The ISO's posting of the RSP and RSP Project List will include links to each PTO's specific LSP Project List.

3. Posting of Assumptions and Criteria

Each PTO will make available on a website the planning criteria and assumptions used in its current LSP. A link to each PTO's planning criteria and assumptions will be posted on the ISO website.

4. Cost Responsibility for Transmission Upgrades

The cost responsibility for each upgrade, modification or addition to the transmission system in New England that is included in the LSP Project List of this Appendix 1 shall be determined in accordance with Schedule 21 of this OATT.

5. LSP Dispute Resolution Procedures

5.1 Objective

Section 5 of this Appendix 1 sets forth an LSP dispute resolution process (the "LSP Dispute Resolution Process") through which LSP-related transmission planning-related disputes may be resolved as expeditiously as possible.

5.2 Confidential Information and CEII Protections

All information disclosed in the course of the LSP Dispute Resolution Process shall be subject to the protection of confidential information and CEII consistent with the ISO New England Information Policy and CEII policy.

5.3 Eligible Parties

Any member of the Planning Advisory Committee that has been adversely affected by a PTO's Reviewable Determination with respect to the LSP transmission planning process described in this Appendix 1 is eligible to raise its dispute, as appropriate, under this LSP Dispute Resolution Process ("Disputing Party").

5.4 Scope

In order to ensure that the LSP transmission planning process set forth under this Appendix 1 moves expeditiously forward, the scope of issues that may be subject to the LSP Dispute Resolution Process under this Section 5 shall be limited to certain key procedural and substantive decisions made by the applicable PTO within its authority as specified in documents on file with the Commission. That is, decisions not subject to resolution within the jurisdiction of the Commission are not within the scope of this LSP Dispute Resolution Process. Examples of matters not within the scope of the LSP Dispute Resolution Process include planning to serve retail native load or state siting issues. Additionally, the

Tariff already explicitly provides specific dispute resolution procedures for various matters. To this end, any matter regarding the review and approval of applications pursuant to Section I.3.9 of the Tariff, which is subject to the dispute resolution process under Section I.6 of the Tariff, shall not be within the scope of this LSP Dispute Resolution Process. Similarly, any matter regarding Transmission Cost Allocation shall be governed by the dispute resolution process under Schedule 12 of the OATT, and shall be outside the scope of this LSP Dispute Resolution Process.

(a) Reviewable Determinations:

The LSP determinations made by the applicable PTO that may be subject to the LSP Dispute Resolution Process under this Section 5 ("Reviewable LSP Determination") shall include certain procedural and substantive challenges at designated key decision points during the LSP transmission planning process for Non-PTF, including Local Public Policy Transmission Upgrades ("Key LSP Decision Points"). Procedural challenges will be limited to whether or not the steps taken up to a Key LSP Decision Point conform to the requirements set forth in this Appendix 1. Substantive challenges will be limited to whether or not a determination or conclusion rendered at a Key LSP Decision Point was supported by adequate basis in fact. The Key LSP Decision Points shall be limited to the following:

(i) Results of an LSP Needs Assessment conducted and communicated by a PTO to the Planning Advisory Committee as specified in this Appendix 1;

(ii) Updates to the LSP Project List, including adding, removing or revising regulated Non-PTF transmission solutions included thereunder, as presented at the Planning Advisory Committee and as specified in this Appendix 1;

(iii) Results of Non-PTF transmission solutions studies, including any Local Public Policy Transmission Upgrade studies, conducted and communicated by the PTO to the Planning Advisory Committee as specified in this Appendix 1; and

(iv) Consideration of market responses in LSP Needs Assessments as specified in this Appendix 1.

(b) Material Adverse Impact

In order to prevail in a challenge to a procedural-based Reviewable LSP Determination, the Disputing Party must show that the alleged procedural error had a material adverse impact on the determination or conclusion made by the applicable PTO. In order to prevail in a challenge to a substantive-based Reviewable LSP Determination, the Disputing Party must show that either (i) the determination is based on incorrect data or assumptions or (ii) incorrect analysis was performed by the PTO, and (iii) as a result thereof, the PTO made an incorrect decision or determination.

5.5 Notice and Comment

A Disputing Party aggrieved by a PTO's Reviewable LSP Determination shall have fifteen (15) calendar days upon learning of the Reviewable LSP Determination following the PTO's presentation of such LSP Reviewable Determination at the Planning Advisory Committee to request dispute resolution by giving notice to the Applicable PTO ("Request for LSP Dispute Resolution").

A Request for LSP Dispute Resolution shall be in writing and shall be provided to the applicable PTO and, as appropriate, other affected Transmission Owners. Within three (3) Business Days of the receipt by a PTO of a Request for Dispute Resolution, the PTO, in coordination with the ISO, shall prepare and distribute to all members of the Planning Advisory Committee a notice of the Request for Dispute Resolution including, subject to the protection of Confidential Information and CEII, the specifics of the Request for Dispute Resolution and providing the name of a PTO representative to whom any comments may be sent. Any member of the Planning Advisory Committee may submit to the PTO's designated representative, on or before the tenth (10th) Business Day following the date the PTO distributes the notice of the Request for Dispute Resolution, written comments to the PTO with respect to the Request for Dispute Resolution. The Disputing Party filing the Request for Dispute Resolution may respond to any such comments by submitting a written response to the PTO's designated representative and to the commenting party on or before the fifteenth (15th) Business Day following the date the PTO distributes the notice of the Request for Dispute Resolution. The PTO may, but is not required to, consider any written comments.

5.6 Dispute Resolution Procedure

(a) Resolution Through the Planning Advisory Committee

The Planning Advisory Committee shall discuss and resolve any LSP related dispute arising under this Appendix 1 involving a Reviewable LSP Determination, as defined in Section 5.4 of this Appendix 1, between and among the applicable PTO, the Disputing Party, and, as appropriate, other affected Transmission Owners and the ISO (collectively, “Parties”) (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution).

(b) Resolution Through Informal Negotiation

To the extent that the Planning Advisory Committee is not able to resolve a dispute arising under this Appendix 1 involving a Reviewable LSP Determination, as defined in Section 5.4 of this Appendix 1, between and among the Parties, such dispute shall be the subject of good-faith negotiations among the Parties. Each Party shall designate a fully authorized senior representative for resolution on an informal basis as promptly as practicable.

(c) Resolution Through Alternative Dispute Resolution

In the event the designated representatives are unable to resolve the dispute through informal negotiations within thirty (30) days, or such other period as the Parties may agree upon, by mutual agreement of the Parties, such LSP related dispute may be submitted to mediation or any other form of alternative dispute resolution upon the agreement of all Parties to participate in such mediation or other alternative dispute resolution process. Such form of alternative dispute resolution shall not include binding arbitration.

If a Party identifies exigent circumstances reasonably requiring expedited resolution of the LSP related dispute, such Party may file a Complaint with the Commission or seek other appropriate redress before a court of competent jurisdiction

5.7 Notice of Results of Dispute Resolution

Within three (3) Business Days following the resolution of a dispute pursuant to either Section 5.6(b) or 5.6(c) of this Appendix 1, the PTO shall distribute to members of the Planning Advisory Committee a document reflecting the resolution.

5.8 Rights under the Federal Power Act:

Nothing in this Appendix 1 shall restrict the rights of any party to file a complaint with the Commission under relevant provisions of the Federal Power Act.

ATTACHMENT K APPENDIX 2

LIST OF ENTITIES ENROLLED IN THE TRANSMISSION PLANNING REGION ENTITIES

APPENDIX 2

ATTACHMENT K

LIST OF ENTITIES ENROLLED IN THE TRANSMISSION PLANNING REGION

The entities listed in this Appendix 2 are those enrolled for the purpose of participating as a transmission provider in the New England transmission planning region pursuant to Attachment K as of the date the revisions to this Appendix 2 were filed with the Commission. The most current list of entities enrolled for the purpose of participating as a transmission provider in the New England transmission planning region pursuant to Attachment K is available on the ISO-NE website. This Appendix 2 will be updated to reflect any subsequent enrollments as part of unrelated OATT filings at the time ISO-NE undertakes such unrelated filings.

Town of Braintree Electric Light Department

Central Maine Power Company

~~The City of~~ Chicopee Municipal Lighting ~~Department~~Plant

~~The City of Holyoke Gas and Electric Department~~

The Connecticut Light and Power Company

Connecticut Municipal Electric Energy Cooperative

Connecticut Transmission Municipal Electric Energy Cooperative

Cross-Sound Cable Company, LLC

~~Emera Maine~~

Fitchburg Gas and Electric Light Company

Green Mountain Power Corporation

The City of Holyoke Gas and Electric Department

Town of Hudson Light & Power Department

Maine Electric Power Company

Massachusetts Municipal Wholesale Electric Company

Town of ~~Maine Electric Power Company~~

Middleborough Gas ~~and~~ & Electric Department

The Narragansett Electric Company d/b/a Rhode Island Energy

New England Electric Transmission Corporation

New England Energy Connection, LLC

New England Hydro-Transmission Corporation

New England Hydro-Transmission Electric Company Inc.

New England Power Company d/b/a National Grid

New Hampshire Electric Cooperative, Inc.

New Hampshire Transmission, LLC

Town of Norwood Municipal Light Department

~~Eversource Energy Service Company as agent for: The Connecticut Light and Power Company, NSTAR Electric Company, Public Service Company of New Hampshire, and Western Massachusetts Electric Company~~

~~Norwood Municipal Light Department~~

NSTAR Electric Company

Public Service Company of New Hampshire

Town of Reading Municipal Light Department

Shrewsbury Electric & Cable Operations

Town of Stowe Electric Department

Taunton Municipal Lighting Plant

~~Town of Reading Municipal Light Department~~

The United Illuminating Company

Unitil Energy Systems, Inc.

Vermont Electric Cooperative, Inc.

Vermont Electric Power Company, Inc.

Vermont Electric Transmission Company

Vermont Public Power Supply Authority

Vermont Transco LLC

Versant Power

Town of Wallingford, CT, Department of Public Utilities, —Electric Division

~~Western Massachusetts Electric Company~~

ATTACHMENT K APPENDIX 3

LIST OF QUALIFIED TRANSMISSION PROJECT SPONSORS

The entities listed in this Appendix 3 are those approved by ISO-NE as Qualified Transmission Project Sponsors as of the date the revisions to this Appendix 3 were filed with the Commission. The most current list of entities approved as Qualified Transmission Project Sponsors is available on the ISO-NE website. This Appendix 3 will be updated to reflect any subsequent enrollments as part of unrelated OATT filings at the time ISO-NE undertakes such unrelated filings.

Anbaric Development Partners, LLC

Avangrid Networks, Inc.

~~Braintree Electric Light Department~~

Central Maine Power Company

~~City of Holyoke Gas and Electric Department~~

~~The Connecticut Light and Power Company~~

~~The~~ Connecticut Transmission Municipal Electric Cooperative

Versant Power ~~Emera Maine~~

Eversource Energy Transmission Ventures, Inc.

NGV US Transmission~~Grid America Holdings~~, Inc.

Hudson Light and Power Department

Maine Electric Power Company

Massachusetts Municipal Wholesale Electric Company

Middleboro Gas & Electric Department

Narragansett Electric Company d/b/a Rhode Island Energy

New England Energy Connection, LLC

New England Power Company

New Hampshire Transmission, LLC

Norwood Municipal Light Department

NSTAR Electric Company

PPL Translink, Inc.

Public Service Company of New Hampshire

SP Transmission, LLC

Taunton Municipal Light Plant

The City of Holyoke Gas and Electric Department

The Connecticut Light and Power Company

Town of Braintree Electric Light Department

Transource New England, LLC

United Illuminating Company

Vermont Transco, LLC

~~Western Massachusetts Electric Company~~

ATTACHMENT P

SELECTED QUALIFIED TRANSMISSION PROJECT SPONSOR AGREEMENT

Between

ISO NEW ENGLAND~~,~~ INC.

And

____

This Selected Qualified Transmission Project Sponsor Agreement, including the Schedules attached hereto and incorporated herein (collectively, "Agreement") is made and entered into as of the Effective Date between ISO New England~~,~~ Inc. ("ISO-NE" or "the ISO"), and ___________________ ("Selected QTPS"), referred to herein individually as "Party" and collectively as "the Parties."

RECITALS

WHEREAS, in accordance with FERC Order No. 1000 or ~~and~~ Attachment K of the ISO-NE Open Access Transmission Tariff ("OATT"), ISO-NE selects the preferred Phase or Stage Two Solution or Longer-Term Transmission Solution for inclusion in the in the Regional System Plan ("RSP") and/or its Project List;

WHEREAS, the Selected QTPS is a Qualified Transmission Project Sponsor pursuant to Section 4B of Attachment K of the OATT;

WHEREAS, the Selected QTPS has executed the [Transmission Operating Agreement] [Non-Incumbent Developer Transmission Operating Agreement];

WHEREAS, pursuant to Sections 4.3(j), ~~or~~ 4A.9(a), or 16 of Attachment K of the OATT, ISO-NE notified the Selected QTPS that its project has been selected for development;

WHEREAS, pursuant to Sections 4.3(k), ~~or~~ 4A.9(b), or 16 of Attachment K of the OATT, by executing this Agreement the Selected QTPS accepts responsibility to proceed with the Project, and therefore has the obligation to construct the Project; and

NOW, THEREFORE, in consideration of the promises, and the mutual representations, warranties, covenants and agreements hereinafter set forth, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound, Selected QTPS and the ISO-NE agree as follows:

1.0 Defined Terms

All capitalized terms used in this Agreement shall have the meanings ascribed to them in the Tariff or in definitions either in the body of this Agreement or its attached Schedules. In the event of any conflict between defined terms set forth in Section I of the Tariff or defined terms in this Agreement, including the Schedules, such conflict will be resolved in favor of the terms as defined in this Agreement.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Selected Qualified Transmission Project Sponsor Agreement.

Breaching Party shall mean a Party that is in Breach of the Selected Qualified Transmission Project Sponsor Agreement.

Commercially Reasonable Efforts shall mean a level of effort which, in the exercise of prudent judgment in the light of facts or circumstances known or which should reasonably be known at the time a decision is made, can be expected by a reasonable person to accomplish the desired result in a manner consistent with Good Utility Practice and which takes the performing party's interests into consideration.

Component In-Service shall mean that a portion (component) of the Project has been placed in commercial operation.

Component In-Service Date shall mean the date that a portion (component) of the Project is placed In-Service.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 8 of the Selected Qualified Transmission Project Sponsor Agreement.

Governmental Authority shall mean the government of any nation, state or other political subdivision thereof, including any entity exercising executive, military, legislative, judicial, regulatory, or administrative functions of or pertaining to a government.

In-Service shall mean that the Project has been placed in commercial operation.

In-Service Date shall mean the date the Project is placed In-Service.

Project shall mean the Market Efficiency Transmission Upgrade, Reliability Transmission, ~~or~~ Public Policy Upgrade, or Longer-Term Transmission Upgrade included in the Regional System Plan and/or the ISO-NE Project List described in Schedule A of this Agreement.

Required Project In-Service Date is the date the Project is required to: (i) be completed in accordance with the Scope of Work in Schedule A of this Agreement, (ii) is placed In-Service; and; (iii) be under ISO-NE operational dispatch.

Tariff consists of the ISO New England~~,~~ Inc. Transmission, Markets, and Services Tariff.

Article 2 - Effective Date and Term

2.0 Effective Date

This Agreement shall become effective on the date the Agreement has been executed by all Parties, or if this Agreement is required to be filed with FERC for acceptance, upon the date specified by FERC.

2.1 Term

This Agreement shall continue in full force and effect from the Effective Date until: (i) the Selected QTPS has executed the TOA; and (ii) the Project (a) has been completed in accordance with the terms and conditions of this Agreement and (b) meets all relevant required planning criteria, or (iii) the Agreement is terminated pursuant to Article 6 of this Agreement.

Article 3 - Project Construction

3.0 Construction of Project by Selected QTPS

Selected QTPS shall design, engineer, procure, install and construct the Project, including any modifications thereto, in accordance with: (i) the terms of this Agreement, including but not limited to the Scope of Work in Schedule A and the Development Schedule in Schedule B; (ii) applicable reliability principles, guidelines, and standards of the Northeast Power Coordinating Council and the North American Electric Reliability Corporation; (iii) the ISO New England Operating Documents; and (iv) Good Utility Practice. Nothing contained herein shall modify PTOs' rights under the TOA to construct and own upgrades to its existing and affected substation or facilities.

3.1 Milestones

3.1.0 Milestone Dates

Selected QTPS shall meet the milestone dates set forth in the Development Schedule in Schedule B of this Agreement. Milestone dates set forth in Schedule B only may be extended by ISO-NE in writing. ISO-NE reasonably may extend any such milestone date, in the event of delays not caused by the Selected QTPS that could not be remedied by the Selected QTPS through the exercise of due diligence if a corporate officer of the Selected QTPS submits a revised Development Schedule containing revised milestones and showing the Project in full operation no later than the Required Project In-Service Date specified in Schedule B of this Agreement.

3.2 Applicable Technical Requirements and Standards

At the point of interconnection, the applicable technical requirements and standards of the Participating Transmission Owner(s) ("PTO")) to whose facilities the Project will interconnect shall apply to the design, engineering, procurement, construction and installation of the Project. The remaining portion of the Project shall meet applicable industry standards and Good Utility Practice. At a minimum, all new facilities should comply with the current National Electric Safety Code.

3.3 Project Modification

3.3.0 Project Modification

The Scope of Work and Development Schedules (Schedules A and B, respectively), including the milestones therein, may be revised, as required through written consent by the parties. Such modifications may include alterations as necessary and directed by ISO-NE such as modifications resulting from the I.3.9 process or to meet the system condition for which the Project was included in the Regional System Plan.

3.3.1 Consent of ISO-NE to Project Modifications

Selected QTPS may not modify the Project without prior written consent of ISO-NE.

3.4 Project Status Reports

Selected QTPS shall submit to ISO-NE quarterly construction status reports in writing. The reports shall contain, but not be limited to, updates and information related to: (i) current engineering and construction status of the Project; (ii) Project completion percentage, including milestone completion; (iii) current target Project or phase completion date(s); (iv) applicable outage information; and (v) cost expenditures to date and revised projected cost estimates for completion of the Project.

3.5 Exclusive Responsibility of Selected QTPS

Selected QTPS shall be solely responsible for all planning, design, engineering, procurement, construction, installation, management, operations, safety, and compliance with Applicable Laws and Regulations associated with the Project. ISO-NE shall have no responsibility to manage, supervise, or ensure compliance or adequacy of same.

Article 4 – Subcontractor Insurance

4.0 Subcontractor Insurance

In accordance with Good Utility Practice, Selected QTPS shall require each of its subcontractors to maintain and, upon request, provide Selected QTPS evidence of insurance coverage of types, and in amounts, commensurate with the risks associated with the services provided by the subcontractor. Bonding and hiring of contractors or subcontractors shall be the Selected QTPS's discretion, but regardless of bonding or the existence or non-existence of insurance, the Selected QTPS shall be responsible for the performance or non-performance of any contractor or subcontractor it hires.

Article 5 – Default and Force Majeure

5.0 Events of Default

(a) Subject to the terms and conditions of this Section 5.0, the occurrence of any of the following events shall constitute an event of default of a Party under this Agreement:

(i) Failure by a Party to perform any material obligation set forth in this Agreement, and continuation of such failure for longer than thirty (30) days after the receipt by the non-breaching Party of written notice of such failure; provided, however, that if the breaching Party is diligently pursuing a remedy during such thirty (30) day period, said cure period shall be extended for an additional thirty (30) days or as otherwise agreed by the Parties, provided that such extension ensures that the Project meets the Required Project In-Service Date.

(ii) Failure to perform a material obligation set forth in this Agreement shall include but not be limited to:

a. Any breach of a representation, warranty, or covenant made in this Agreement;
b. Failure to meet a milestone or milestone date set forth in the Development Schedule in Schedule B of this Agreement, or as extended in writing as described in Sections 3.1.0 and 3.3.0 of this Agreement;
c. Assignment of this Agreement in a manner inconsistent with the terms of this Agreement; or
d. Failure of any Party to provide information or data required to be provided to another Party under this Agreement for such other Party to satisfy its obligations under this Agreement.
e. If there is a dispute between the Parties as to whether a Party has failed to perform a material obligation, the cure period(s) provided in Section 5.0(a)(i) above shall run from the point at which a finding of failure to perform has been made by a Governmental Authority.
f. With respect to either Party, (A) the filing of any petition in bankruptcy or insolvency, or for reorganization or arrangement under any bankruptcy or insolvency laws, or voluntarily

taking advantage of any such laws by answer or otherwise or the commencement of involuntary proceedings under any such laws, (B) assignment by either Party for the benefit of creditors; or (C) allowance by either Party of the appointment of a receiver or trustee of all or a material part of its property if such receiver or trustee is not discharged within thirty (30) days after such appointment.

5.1 Remedies

Upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to: (i) commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof; (ii) suspend performance hereunder; and (iii) exercise such other rights and remedies as it may have in equity or at law. Nothing in this Section 5.1 is intended in any way to affect the rights of a third-party to seek any remedy it may have in equity or at law from the Selected QTPS resulting from Selected QTPS's Default of this Agreement.

5.2 Waiver

The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement, or to exercise its rights with respect to a Breach or Default under this Agreement or with regard to any other matters arising in connection with this Agreement will not be deemed a waiver or continuing waiver with respect to any other failure to comply with any other obligation, right, or duty of this Agreement. Any waiver of any obligation, right, or duty under this Agreement must be in writing.

5.3 Force Majeure

A Party shall not be considered to be in Default or Breach under this Agreement, and shall be excused from performance or liability for damages to any other party, if and to the extent it shall be delayed in or prevented from performing or carrying out any of the provisions of this Agreement, except the obligation to pay any amount when due, in consequence of any act of God, labor disturbance, failure of contractors or suppliers of materials (not including as a result of non-payment), act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm, flood, ice, explosion, breakage or accident to machinery or equipment or by any other cause or causes (not including a lack of funds or other financial causes) beyond such Party's reasonable control, including any order, regulation, or restriction imposed by governmental, military or lawfully established civilian authorities. A Party claiming a force majeure event shall use reasonable diligence to remove the condition that prevents performance, except that the settlement of any labor disturbance shall be in the sole judgment of the affected Party.

Article 6 - Termination

6.0 Termination by ISO-NE

In the event that: (i) ISO-NE determines to remove the Project from the RSP; (ii) ISO-NE otherwise determines that the identified need has changed or been eliminated therefore the Project is no longer required to address the specific need for which the Project was included in the RSP; or (iii) a force majeure or other event outside of the Selected QTPS's control that, with the exercise of reasonable efforts, Selected QTPS cannot alleviate and which prevents the Selected QTPS from satisfying its obligations under this Agreement; or (iv) the Parties fail to agree to modifications under Section 3.3.0; or (v) one or more of the Selected QTPSs for the Project is failing to pursue approvals or construction in a reasonably diligent fashion, or that one or more of the Selected QTPSs is unable to proceed with the project due to forces beyond its reasonable control, ISO-NE may terminate this Agreement by providing written notice of termination to Selected QTPS. The termination shall become effective upon the date the Selected QTPS receives such notice, except as otherwise provided in Section 6.2.

ISO-NE shall also terminate this Agreement following written communication from NESCOE requesting that ISO-NE remove a Longer-Term Transmission Upgrade from the RSP.

6.1 Termination by Default

This Agreement shall terminate in the event a Party is in Default of this Agreement in accordance with Section 5.0 of this Agreement and the ISO shall take action in accordance with Sections 4.3(l), ~~or~~ 4A.9(c), or 16 of Attachment K.

6.2 Filing at FERC

If, pursuant to FERC regulations, the termination of this agreement is required to be filed with FERC, such termination shall be effective upon the date established by FERC. ISO-NE shall report any termination of this Agreement in its Electric Quarterly Report.

Article 7 – Indemnity and Limitation of Liability

7.0 Hold Harmless

Each Selected QTPS will indemnify and hold harmless all other Selected QTPSs, affected PTOs and ISO-NE and its directors, managers, members, shareholders, officers and employees from any and all liability (except for that stemming from the other Selected QTPS(s), the ISO-NE or an affected PTO's negligence, gross negligence or willful misconduct), resulting from the Selected QTPS's failure to timely complete the Project. As used herein, the "other Selected QTPS" is a Selected QTPS whose Phase Two Solution is part of the group that solves all needs identified in the request for proposal and an "affected PTO" is one that would be subject to penalties assessed by NERC or FERC or adverse regulatory orders or monetary claims or damages due to the Selected QTPS's failure to timely complete the Project.

7.1 Liability

(a) Neither Party shall be liable to the other Party for any incidental, indirect, special, exemplary, punitive or consequential damages, including lost revenues or profits, even if such damages are foreseeable or the damaged Party has advised such Party of the possibility of such damages and regardless of whether any such damages are deemed to result from the failure or inadequacy of any exclusive or other remedy.

(b) Nothing in this Agreement shall be deemed to affect the right of ISO-NE to recover its costs due to liability under this Article 7 through the NEPOOL Participants Agreement or ISO-NE Tariff.

Article 8 – Assignment

8.0 Assignment

A Party may assign all of its rights, duties, and obligations under this Agreement in accordance with this Section 8.0. No Party may assign any of its rights or delegate any of its duties or obligations under this Agreement without prior written consent of the other Party, which consent shall not be unreasonably withheld, conditioned, or delayed. Any such assignment or delegation made without such written consent shall be null and void. Assignment by the Selected QTPS shall be contingent upon, prior to the effective date of the assignment: (i) the Selected QTPS or the assignee demonstrating to the satisfaction of ISO-NE that the assignee has the technical competence and financial ability: (a) to comply with the requirements of this Agreement, (b) to construct the Project consistent with the assignor's cost estimates for the Project and in accordance with any cost cap or cost containment commitments, and (c) to operate and maintain the Project once constructed; and (ii) the assignee is a Qualified Transmission Project Sponsor pursuant to Section 4B of Attachment K of the OATT. For all assignments by any Party, the assignee must assume in writing, to be provided to the other Party, all rights, duties, and obligations of the assignor arising under this Agreement. Any assignment described herein shall not relieve or discharge the assignor from any of its obligations hereunder absent the written consent of the other Party. In no circumstance, shall an assignment of this Agreement or any of the rights, duties, and obligations under this Agreement diminish the rights of the ISO-NE under this Agreement or the ISO New England Operating Documents. Any assignees that will construct, maintain, or operate the Project shall be subject to, and comply with the terms of this Agreement, and the ISO New England Operating Documents.

Article 9 - Information Exchange

9.0 Information Access

Subject to the ISO Information Policy, each Party shall make available to the other Party information necessary to carry out each Party's obligations and responsibilities under this Agreement and the ISO New England Operating Documents. Such information shall include but not be limited to, information reasonably requested by ISO-NE to prepare the Regional System Plan. The Parties shall not use such information for purposes other than to carry out their obligations or enforce their rights under this Agreement and the ISO New England Operating Documents.

Article 10 - Confidentiality

10.0 Confidential Information and CEII

Confidential Information and CEII shall be treated in accordance with the ISO Information Policy.

Article 11 – Dispute Resolution

11.0 Dispute Resolution Procedures

The Parties agree that any dispute arising under this Agreement shall be the subject of good-faith negotiations among the Parties. Each Party shall designate one or more representatives with the authority to negotiate the matter in dispute to participate in such negotiations. The Parties shall engage in such good-faith negotiations for a period of not less than sixty (60) calendar days. Notwithstanding the foregoing, any dispute arising under this Agreement may be submitted to arbitration or any other form of alternative dispute resolution upon the agreement of the Parties to participate in such an alternative dispute resolution process. Nothing in this Agreement shall, however, restrict a Party's right to file a complaint with FERC under the relevant provisions of the Federal Power Act.

Article 12 - Regulatory Requirements

12.0 Regulatory Approvals

Selected QTPS shall seek and obtain all required authorizations or approvals as soon as reasonably practicable, and by the milestone dates set forth in the Development Schedule of Schedule B of this Agreement, as applicable.

Article 13 - Representations and Warranties

13.0 General

Selected QTPS hereby represents, warrants and covenants as follows, with these representations, warranties, and covenants effective as to the Selected QTPS during the full time this Agreement is effective:

13.0.1 Organization

Selected QTPS is duly organized, validly existing and in good standing under the laws of the state of its organization.

13.0.2 Authority

Selected QTPS has all requisite power and authority to execute, deliver and perform this Agreement; the execution, delivery and performance by Selected QTPS of this Agreement have been duly authorized by all necessary and appropriate action on the part of Selected QTPS; and this Agreement has been duly and validly executed and delivered by Selected QTPS and constitutes the legal, valid and binding obligations of Selected QTPS, enforceable against Selected QTPS in accordance with the terms of this Agreement.

13.0.3 No Breach

The execution, delivery and performance by Selected QTPS of this Agreement will not result in a breach of any terms, provisions or conditions of any agreement to which Selected QTPS is a party which breach has a reasonable likelihood of materially and adversely affecting Selected QTPS's performance under this Agreement.

Article 14 - Operation of Project

14.0 In-Service

The following requirements shall be satisfied prior to the date the Project goes In-Service:

14.0.1 Execution of the Transmission Operating Agreement

Selected QTPS is able to meet all requirements of the Transmission Operating Agreement and has authority to execute that agreement.

14.0.2 Operational Requirements

The Project must meet all applicable operational requirements described in the ISO New England Operating Documents.

14.0.3 Synchronization

Selected QTPS shall have received any necessary authorizations or permissions from ISO-NE and the owners of the facilities to which the Project will interconnect to synchronize with the New England Transmission System or to energize, as applicable, the Project.

14.1 Partial Operation

If the Project is to be completed in phases, the completed part of the Project may operate prior to completion and Required Project In-Service Date set forth in Schedule B of this Agreement, provided that: (i) Selected QTPS has notified ISO-NE in writing of the successful completion of the Project phase; (ii) ISO-NE has determined that partial operation of the Project will not negatively impact the reliability of the New England Transmission System; (iii) Selected QTPS has demonstrated that the requirements for going In-Service set forth in Section 14.0 of this Agreement have been met for partial operation of the Project; and (iv) partial operation of the Project is consistent with Applicable Laws and Regulations, applicable reliability standards, and Good Utility Practice.

Article 15 - Survival

15.0 Survival of Rights

The rights and obligations of the Parties in this Agreement shall survive the termination, expiration, or cancellation of this Agreement to the extent necessary to provide for the determination and enforcement of said obligations arising from acts or events that occurred while this Agreement was in effect. The Indemnity and Limitation of Liability provisions in Article 7 and the Binding Cost Cap or Cost Containment Measures referenced in Article 16 and set forth in Schedule C of this Agreement also shall survive termination, expiration, or cancellation of this Agreement.

Article 16 - Binding Cost Cap or Cost Containment Measures

16.0 Binding Cost Cap or Cost Containment Measures

Any binding cost cap or cost containment measures, or commitment to forego any kind of rate incentives or rate recovery submitted by the Selected QTPS as part of its Project shall be detailed in Schedule C of this Agreement.

Article 17 - Non-Standard Terms and Conditions

17.0 Schedule D - Non-Standard Terms and Conditions

Subject to FERC acceptance or approval, the Parties agree that the terms and conditions set forth in the attached Schedule D are hereby incorporated by reference, and made a part of, this Agreement. In the event of any conflict between a provision of Schedule D that FERC has accepted and any provision of the standard terms and conditions set forth in this Agreement that relates to the same subject matter, the pertinent provision of Schedule D shall control.

Article 18 - Miscellaneous

18.0 Notices

Unless otherwise expressly specified or permitted by the terms hereof, all communications and notices provided for herein shall be in writing and any such communication or notice shall become effective (a) upon personal delivery thereof, including by overnight mail or courier service, (b) in the case of notice by United States mail, certified or registered, postage prepaid, return receipt requested, upon receipt thereof, or (c) in the case of notice by e-mail, upon receipt thereof; provided that such transmission is promptly confirmed by either of the methods set forth in clauses (a) or (b) above, in each case addressed to the relevant party and copy party hereto at its address set forth below in this section 18.0 or at such other address as such party or copy party may from time to time designate by written notice to the other party hereto; further provided that a notice given in connection with this Section 18.0 but received on a day other than a Business Day, or after business hours in the situs of receipt, will be deemed to be received on the next Business Day.

Addresses:

ISO-NE:
ISO New England~~,~~ Inc.
1 Sullivan Road
Holyoke, MA 01040
Attention:
e-mail:

Selected QTPS:
____
____
____
____
Attention:
e-mail address ______________________

18.1 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Parties.

18.2 Incorporation of Other Documents

The ISO New England Operating Documents, as they may be amended from time to time, are incorporated by reference herein and made a part hereof and Selected QTPS is subject to, and must comply with the terms and conditions of those documents.

18.3 Headings

The headings of the sections of this Agreement are inserted for purposes of convenience only and shall not be construed to affect the meaning or construction of any of the provisions hereof.

18.4 Interpretation

Wherever the context may require, any noun or pronoun used herein shall include the corresponding masculine, feminine or neuter forms. The singular form of nouns, pronouns and verbs shall include the plural and vice versa.

18.5 Amendment; Limitations on Modifications of Agreement

(a) This Agreement shall only be subject to modification or amendment by agreement of the Parties in writing and the acceptance of any such amendment by FERC, if required to be filed at FERC.

(b) In light of the foregoing, the Parties agree that they shall not rely to their detriment on any purported amendment, waiver or other modification of any rights under this Agreement unless the requirements of this Section 18.5 are satisfied and further agree not to assert equitable estoppel or any other equitable theory to prevent enforcement of this provision in any court of law or equity, arbitration or other proceeding.

18.6 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

18.7 Further Assurances

Each Party agrees, upon the other Party's request, to make Commercially Reasonable Efforts to execute and deliver such additional documents and instruments, provide information, and to perform such additional acts as may be necessary or appropriate to effectuate, carry out and perform all of the terms, provisions, and conditions of this Agreement.

18.8 Counterparts

This Agreement may be executed in any number of counterparts, each of which shall be deemed an original, but all of which together shall constitute but one and the same instrument. The parties hereto agree that any document or signature delivered by facsimile transmission shall be deemed an original executed document for all purposes hereof.

18.9 Governing Law

This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware including all matters of construction, validity and performance without regard to the conflicts-of-laws provisions thereof and the Federal Power Act, as applicable.

18.10 Entire Agreement

Except for the ISO New England Operating Documents, applicable reliability standards, or successor documents, this Agreement, including all Schedules, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. Except for the ISO New England Operating Documents, applicable reliability standards, or successor documents, there are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

18.11 No Third Party Beneficiaries

It is not the intention of this Agreement or of the Parties to confer a third party beneficiary status or rights of action upon any person or entity whatsoever other than the Parties and nothing contained herein, either express or implied, shall be construed to confer upon any person or entity other than the Parties any rights of action or remedies either under this Agreement or in any manner whatsoever.

[Signature Page Follows]

IN WITNESS WHEREOF, this Agreement has been duly executed and delivered by the duly authorized officer of each Party as of the date written below.

For ISO New England Inc.

Name: ______________________________________

Title: _______________________________________

Date: _______________________________________

For Selected QTPS

Name: ______________________________________

Title: _______________________________________

Date: ____

SCHEDULE A

Description of Project and Scope of Work

SCHEDULE B

Development Schedule

Selected QTPS shall ensure and demonstrate to the ISO-NE that it timely has met the following milestones and milestone dates and that the milestones remain in good standing:

[As appropriate include the following standard Milestones, with any revisions, and additional milestones necessary for the Project]:

Milestones and Milestone Dates
Demonstrate adequate Project financing. On or before ______, Selected QTPS must demonstrate that adequate project financing has been secured. Project financing must be maintained for the term of this Agreement [add detail if necessary].
Acquisition of all necessary federal, state, county, and local site permits. On or before ______, Selected QTPS must demonstrate that all required federal, state, county and local site permits have been acquired. [add detail if necessary]. Provide separate dates for each permit]
Substantial Site Work Completed: On or before _______, Selected QTPS must demonstrate that at least 20% of Project site construction is completed. Additionally, the Selected QTPS must submit updated ratings and the final project drawings to the ISO-NE.
Delivery of major electrical equipment. On or before ______, Selected QTPS must demonstrate that all major electrical equipment has been delivered to the project site. [add detail if necessary].
Demonstrate required ratings. On or before ______, Selected QTPS must demonstrate that the project meets all required electrical ratings. [add detail if necessary].
Required Project In-Service Date. On or before ______, Selected QTPS must: (i) demonstrate that the Project is completed in accordance with the Scope of Work in Schedules A of this Agreement; (ii) meets the criteria outlined in Schedule B of this Agreement; (iii) is placed In-Service; and (iv) is under ISO-NE operational dispatch.
[Add additional Milestones]

SCHEDULE C

Binding Cost Cap or Cost Containment Measures

[Insert binding cost cap or cost containment terms and conditions, if any contained in the Selected QTPS selected proposal. If no such binding cost cap or cost containment measures state “None”.]

SCHEDULE D

Non-Standard Terms and Conditions

[Insert non-standard terms and conditions, if any. If no such non-standard terms and conditions, state “None”.]

SCHEDULE 12

TRANSMISSION COST ALLOCATION ON AND AFTER JANUARY 1, 2004

This Schedule 12 describes the cost allocation treatment of upgrades, modifications or additions to the transmission system in New England on and after January 1, 2004. Nothing in this Schedule 12 shall eliminate the PTF status of transmission facilities that were PTF on December 31, 2003; and any upgrades to such facilities that continue to meet the definition of PTF specified in this OATT shall be classified as PTF for all purposes under this OATT. The costs of all upgrades to the Highgate Transmission Facilities will be treated as HTF and allocated according to this schedule, as may be amended from time to time, provided that such HTF upgrades shall not be limited by Appendix B to Attachment F Implementation Rule under this OATT if classified as Regional Benefit Upgrades.

A. Process for Categorizing Upgrades for Cost Allocation:

Upgrades, modifications or additions to the New England Transmission System shall be categorized by the ISO, with advisory input from the Reliability Committee and the Planning Advisory Committee, as appropriate. A list of categorized Transmission Upgrades shall be made part of each annual and interim RSP, subject to the provisions of Attachment K of this OATT.

B. Transmission Cost Allocation by Category:

1. Generator Interconnection Related Upgrades:

The cost for all Generator Interconnection Related Upgrades shall be allocated pursuant to Schedule 11 of this OATT.

2. Elective Transmission Upgrades:

The cost for all Elective Transmission Upgrades shall not be included in the Pool-Supported PTF costs recoverable under this OATT, but shall be allocated solely to the entity or entities volunteering to make and pay for such Elective Transmission Upgrades.

3. NEMA Upgrades:

The cost for all NEMA Upgrades shall be included in the Pool-Supported PTF costs recoverable under this Tariff for so long as such Transmission Upgrades continue to meet the definition of PTF under this OATT and allocated to Transmission Customers taking service under this OATT.

4. RTEP02 Upgrades:

The costs for all RTEP02 Upgrades placed in service on or before December 20, 2007, shall be included in the Pool-Supported PTF costs recoverable under this OATT for so long as such Transmission Upgrades continue to meet the definition of PTF under this OATT and allocated to Transmission Customers taking service under this OATT.

5. Regional Benefit Upgrades:

The cost for all Regional Benefit Upgrades, as well as all transmission facilities that were PTF as of December 31, 2003 and upgrades to such facilities that meet the definition of PTF under this OATT, shall be included in the Pool-Supported PTF costs recoverable under this OATT for so long as such Transmission Upgrades and such existing PTF continue to meet the definition of PTF under this OATT and allocated to Transmission Customers taking service under this OATT. Market Efficiency Transmission Upgrades that are not RBUs shall not be included in the Pool-Supported PTF Costs recoverable under this OATT.

6. Public Policy Transmission Upgrade Costs:

(a) Seventy percent of the costs of each Public Policy Transmission Upgrade shall be allocated to Transmission Customers taking service under this OATT in the same manner as Regional Benefit Upgrades.

(b) The remaining thirty percent of the costs of each Public Policy Transmission Upgrade shall be allocated to the Regional Network Load of each state in direct proportion to the state's share of the public policy planning need that gives rise to the Public Policy Transmission Upgrade ("Planning Need"). Each state's share of the Planning Need shall be: (i) as shown in a Planning Need identified by NESCOE in a request for a Public Policy Transmission Study pursuant to Section 4A.1 of Attachment K, based on its estimate of the MWhs of electric energy (or MWs of capacity, if applicable) needed over the requested study period to satisfy the state and federal Public Policy Requirements it identified for evaluation and how such needs are allocated among the states, which shall take into account the MWhs (or MWs of capacity, if applicable) associated with contracts and other mechanisms that are available and capable to satisfy the Public Policy Requirements for the year or years of need considered in the requested Public Policy Transmission Study; or (ii) if NESCOE does not provide a Planning Need in such a request, the load-ratio share of the Regional Network Load of each state that has been identified pursuant to the procedures set forth in Sections 4A.1 and 4A.1.1 of Attachment K as having one or more Public Policy Requirements that will be evaluated in the corresponding Public Policy Transmission Study. Nothing in this Schedule 12 shall prevent the applicable PTOs from filing with the Commission an alternative cost allocation for a Public Policy Transmission Upgrade in accordance with the TOA or a Qualified Transmission Project Sponsor that is not a PTO from filing with the Commission an alternative cost allocation for a Public Policy Transmission Upgrade. The revenue requirements for such Public Policy Transmission Upgrades shall be separately determined in accordance with the provisions of Attachment F to this OATT, subject to separate incentives or other modifications specifically approved by the Commission for such upgrades under Section 205 of the Federal Power Act.

Notwithstanding anything else in this Section 6, the costs of Public Policy Transmission Upgrades to address the Public Policy Requirement of a local government shall not be allocated under Schedule 12 and shall be allocated under a separate local schedule or cost recovery mechanism.

7. Local Benefit Upgrades:

The cost for Local Benefit Upgrades shall not be included in the Pool-Supported PTF costs recoverable under this OATT.

8. Localized Costs:

Localized Costs shall not be included in the Pool-Supported PTF costs recoverable under this OATT, or in costs allocated to Regional Network Load according to Section 6 of this Schedule 12, but instead the responsibility for such Localized Costs shall be the responsibility of the entity or entities causing or subject to such Localized Costs. The System Operator, in accordance with Schedule 12C of this OATT, shall review RTEP02 Upgrades, Regional Benefit Upgrades, reconstructions/replacements of all or part of Pool Transmission Facilities, and Public Policy Transmission Upgrades and identify any Localized Costs associated with them.

9. Merchant Transmission Facilities Cost Allocation

The cost of all Merchant Transmission Facilities, including the cost of Transmission Upgrades required to interconnect the Merchant Transmission Facilities to the PTF, shall be the responsibility of the developer of the Merchant Transmission Facilities, and shall not be included in the Pool-Supported PTF costs recoverable under this OATT.

10. Longer-Term Transmission Upgrades:

(a) Longer-Term Transmission Upgrades that meet a greater than 1.0 benefit-to-cost ratio threshold:

The cost of Longer-Term Transmission Upgrades shall be allocated in the same manner as Regional Benefit Upgrades, unless the applicable PTOs in accordance with the TOA or a Qualified Transmission Project Sponsor that is not a PTO in accordance with the NTDOA files with the Commission an alternative cost allocation for a Longer-Term Transmission Upgrade that implements the cost allocation requested by NESCOE in a written communication to the ISO pursuant to Section 16.4(i) of Attachment K to this OATT and the Commission approves such alternative cost allocation, in which case: (a) only the portion of the costs associated with addressing any combined reliability and/or market efficiency needs identified in the request for proposal(s) issued pursuant to Section 16.4(a) of Attachment K to this OATT, as calculated by the ISO, shall be allocated in the same manner as Regional Benefit Upgrades; and (b) the incremental costs associated with addressing the longer-term needs identified in a request for proposal(s) issued pursuant to Section 16.4(a) of Attachment K to this OATT shall be allocated under the alternative cost allocation filed with and accepted by the Commission by the applicable PTO in accordance with the TOA or by a Qualified Transmission Project Sponsor that is not a PTO in accordance with the NTDOA.

SCHEDULE 12C

DETERMINATION OF LOCALIZED COSTS ON AND AFTER JANUARY 1, 2004

Introduction

The purpose of this Schedule 12C is to describe procedures that the ISO will use in determining Localized Costs for eligible Transmission Upgrades as specified below on or after January 1, 2004.

Review and Approval

These Schedule 12C review and approval procedures are separate and distinct from any other approval procedures within the Transmission, Markets and Services Tariff and are not a condition for receiving approval under any other section of the Transmission, Markets and Services Tariff. If submission of a proposed plan for a Transmission Upgrade by a Market Participant or Transmission Owner for review pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff is required, then the approval for Transmission Upgrade cost allocations as described under this Schedule 12C of this OATT cannot occur sooner than after that review has been completed and it has been determined, pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff, that the Market Participant or Transmission Owner is free to proceed with implementation of the proposed Transmission Upgrade.

Entities conducting transmission system studies shall review and discuss transmission design and construction alternatives as they are developed under a System Impact Study ("SIS") or as part of the Regional System Plan with the System Operator, Reliability Committee and the Planning Advisory Committee, as deemed appropriate by the ISO.

1. Review Procedures For Determining Localized Costs

All (1) RTEP02 Upgrades; (2) Regional Benefit Upgrades developed pursuant to Section 4.2 of Attachment K of the OATT; (3) reconstructions/replacements of all or part of Pool Transmission Facilities; and (4) Regional Benefit Upgrades, ~~and~~ Public Policy Transmission Upgrades, and Longer-Term Transmission Upgrades developed pursuant to Sections 4.3, ~~and~~ 4A, and 16 (respectively) of Attachment K of the OATT shall be reviewed by the ISO with advisory input from the Reliability Committee to determine if any of the costs associated with such upgrades are Localized Costs, except that a proposed Transmission Upgrade which costs less than $500,000 may be exempted from this review by the ISO. The ISO, with advisory input from the Reliability Committee, will review and update, as appropriate, the $500,000 threshold on an annual basis.

The Market Participant or Transmission Owner seeking cost recovery for a proposed Transmission Upgrade, including reconstruction or replacement, shall submit to the ISO and the Reliability Committee the following information as deemed appropriate by the ISO:

(a) A description of (i) the proposed Transmission Upgrade and any feasible and practical transmission alternatives that were considered, and (ii) the most currently available study grade or better estimates of the construction, including the potential impact on the bulk power system during the construction of such upgrade, and (iii) the operating costs of the proposed Transmission Upgrade and any feasible and practical transmission alternatives that were considered.

(b) A summary of the technical analysis performed for the Transmission Upgrade and the identified transmission alternatives.

(c) A review and discussion of the need for the proposed Transmission Upgrade.

(d) A discussion of why the requested Transmission Upgrade was selected over other transmission alternatives, with a description of the benefits of the proposed Transmission Upgrade over other transmission alternatives from an operational, timing of implementation, cost and reliability perspective.

If in reviewing the application and associated information, the ISO, with advisory input from the Reliability Committee, decides that additional information, review, or study is required prior to acting on the application, the ISO, with advisory input from the Reliability Committee, may elect to defer action and solicit supplementary information, review, or study as required. Sources for such additional information may be, but are not limited to, the entity sponsoring the application, Transmission Owners, or the Reliability Committee.

In making its determination of whether Localized Costs exist for the Transmission Upgrades identified in (1), (2) and (3) above, the ISO will consider the reasonableness of the proposed engineering design and construction method with respect to (i) Good Utility Practice, (ii) the current engineering design and construction practices in the area in which the Transmission Upgrade is built, (iii) alternate feasible and practical Transmission Upgrades and (iv) the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrades.

In making its determination of whether Localized Costs exist for the Transmission Upgrades identified in (4) above, the ISO will consider incremental costs resulting from changes to the Transmission Upgrade described in the Transmission Cost Allocation application (or any revisions thereto) for regional rate recovery compared to the description of the Transmission Upgrade in Schedule A to the Selected Qualified Transmission Project Sponsor Agreement. Localized Costs for the Transmission Upgrades identified in (4) above that are located on a PTO's existing transmission system, where the Selected Qualified Transmission Project Sponsor is not the PTO for the existing system element(s), will be determined in a manner consistent with the process described for the Transmission Upgrades identified in (1), (2) and (3) above.

Local siting requirements for transmission facilities shall not be dispositive of whether or not Localized Costs exist with respect to any particular Transmission Upgrade.

The ISO will develop detailed procedures to fulfill the objectives and requirements of this Schedule 12C.

2. Additional Transmission Upgrade Costs or Design Changes Subsequent to the ISO's Determination of Localized Costs

If the costs associated with a Transmission Upgrade exceed the estimated Pool-Supported PTF costs determined in the original Localized Costs review by ten percent, or the design associated with the construction of a Transmission Upgrade is materially changed subsequent to the ISO's determination of Localized Costs, then the applicant for Pool-Supported PTF costs shall be required to submit its Transmission Upgrade again to a review by the ISO to determine if any of the incremental costs or costs associated with the change in design are Localized Costs.

3. Dispute Resolution Regarding Determination of Localized Costs

The ISO's determination of Localized Costs under this OATT shall take effect on the date on which the ISO issues its written findings and determination. The applicant for cost recovery (the "Applicant") whose project is deemed to include Localized Costs may dispute such decision by the ISO by submitting within 60 days of such decision formal written notice of the dispute to the ISO, describing in detail the basis for its challenge of the ISO's determination. The Applicant and the ISO shall then enter into good faith negotiations for a period not to exceed 60 days from the date of the Applicant's written notice to try to resolve the dispute.

If there is no satisfactory resolution of the dispute at the end of the negotiation period, the Applicant shall then have the right to file a Section 206 complaint with the Commission.

ATTACHMENT N
PROCEDURES FOR REGIONAL SYSTEM PLAN UPGRADES

I. INTRODUCTION

Pursuant to Part II.G of the ISO New England Open Access Transmission Tariff (Sections II.46 – II.47), Attachment K and this Attachment, the ISO shall classify upgrades as Reliability Transmission Upgrades, Market Efficiency Transmission Upgrades, ~~or~~ Public Policy Transmission Upgrades or Longer-Term Transmission Upgrades during the Regional System Plan ("RSP") process. Pursuant to established standards, that process is designed to collect and reflect broad input from all stakeholders through the Planning Advisory Committee ("PAC"). The PAC is composed of a wide variety of regional stakeholders, including Governance Participants (such as generator owners, marketers, load serving entities, merchant transmission owners and participating transmission owners), governmental representatives, public interest groups, state agencies (including those participating in the New England Conference of Public Utilities Commissioners), retail customers, representatives of local communities, and consultants. The PAC meets regularly throughout the year.

This procedure describes the standards used by the ISO to identify Reliability Transmission Upgrades, Market Efficiency Transmission Upgrades, ~~and~~ Public Policy Transmission Upgrades and Longer-Term Transmission Upgrades and the process for making such identifications pursuant to Part II.G and Attachment K of the OATT.

The ISO may amend these standards and procedures from time to time, as appropriate, with input from the Reliability Committee and PAC.

II. STANDARDS FOR IDENTIFYING RELIABILITY TRANSMISSION UPGRADES, MARKET EFFICIENCY TRANSMISSION UPGRADES, ~~AND~~ PUBLIC POLICY TRANSMISSION UPGRADES AND LONGER-TERM TRANSMISSION UPGRADES

A. Identification of Reliability Transmission Upgrades

Reliability Transmission Upgrades are those upgrades necessary to ensure the continued reliability of the New England Transmission System based on applicable reliability standards. In applying the applicable reliability standards, some of the considerations that will be taken into account are as follows:

- available supply and transmission (i.e., known resource changes, which includes anticipated transmission enhancements (considering Elective Transmission Upgrades and Merchant Transmission Facilities), demand side resources, and new, retired or unavailable generators);
- load growth;
- acceptable stability response;
- acceptable short circuit capability;
- acceptable voltage levels;
- adequate thermal capability; and
- acceptable system operability and responses (e.g. automatic operations, voltage changes).

To identify the transmission system facilities required to maintain reliability and system performance consistent with the applicable reliability standards, the ISO shall:

- determine whether the above factors are met using reasonable assumptions for certain amounts of forecasted load growth, and generation and transmission facility availability (due to maintenance, forced outages, or other unavailability); and
- rely on Good Utility Practice, applicable reliability standards, and the ISO System Rules.

A Reliability Transmission Upgrade is not an upgrade required by the interconnection of a generator except to the extent determined under the terms of Schedule 11 of the OATT. A Reliability Transmission Upgrade may also provide market efficiency benefits.

B. Identification of Market Efficiency Transmission Upgrades

Market Efficiency Transmission Upgrades are upgrades designed primarily to provide a net reduction in total production cost to supply the system load. Proposed Market Efficiency Transmission Upgrades shall be identified by the ISO where the net present value of the net reduction in total cost to supply the system load, as determined by the ISO, exceeds the net present value of the carrying cost of the identified transmission upgrade.

An upgrade identified as a Reliability Transmission Upgrade may qualify for interim treatment as a Market Efficiency Transmission Upgrade if market efficiency is used to influence the schedule for the implementation of the upgrade. Such opportunities shall be identified by the ISO when the net present value of the reduction to total production cost to supply the system load, as determined by the ISO, exceeds the net present value of the Reliability Transmission Upgrade after it is advanced less the net present value of the upgrade for when it is projected to be needed for reliability.

1. **Base Economic Evaluation Model**

In making a determination of the net present value of bulk power system resource costs, the ISO shall take into account applicable economic factors that shall include the following projected factors:

- energy costs;
- Capacity Costs;
- cost of supplying total operating reserve;
- system losses;
- available supply and transmission (i.e., known resource changes, which includes anticipated transmission enhancements (considering Elective Transmission Upgrades and Merchant Transmission Facilities), demand side resources and new, retired or unavailable generators);
- load growth;
- fuel costs;
- fuel availability;
- generator availability;
- release of bottled generating resources;
- present worth factors for each project specific to the owner of the project;
- present worth period not to exceed ten years; and
- cost of the project.

Analysis may include utilization of historical information such as may be included in market reports as well as special studies and should report cumulative net present value annually over the study period.

2. **Other Data Provided to Stakeholders**

Although not used to evaluate the net economic benefit of the system upgrade, analysis may be provided to illustrate the net cost to load with and without the transmission upgrade – considering additional factors such as locational installed capacity, congestion costs, and impacts on bilateral prices for electricity.

Summary

Based on information provided through such analysis and pursuant to the factors listed in (1) above, the ISO, in consultation with the PAC, will identify Market Efficiency Transmission Upgrades to be included in the RSP. If however, during the course of their analysis, the ISO determines that without the project the applicable reliability standards will not be met, then the project will be designated as a Reliability Transmission Upgrade and included in the RSP as such.

C. Identification of Public Policy Transmission Upgrades

Public Policy Transmission Upgrades are upgrades designed to meet ~~–~~transmission needs driven by public policy requirements, including such needs identified by NESCOE. Proposed Public Policy Transmission Upgrades shall be assessed and identified by the ISO in accordance with Section 4A of Attachment K to the OATT.

D. Identification of Longer-Term Transmission Upgrades

Longer-Term Transmission Upgrades are upgrades designed to meet transmission needs identified by NESCOE in accordance with Section 16 of Attachment K. Proposed Longer-Term Transmission Upgrades shall be assessed and identified by the ISO in accordance with Section 16 of Attachment K to the OATT.

III. PROCEDURES FOR IDENTIFYING RELIABILITY TRANSMISSION UPGRADES, MARKET EFFICIENCY TRANSMISSION UPGRADES, ~~AND~~ PUBLIC POLICY TRANSMISSION UPGRADES AND LONGER-TERM TRANSMISSION UPGRADES

A. ~~ISO~~ Identification of Needs for Reliability Transmission Upgrades, Market Efficiency Transmission Upgrade, ~~and~~ Public Policy Transmission Upgrades and Longer-Term Transmission Upgrades

1. An assessment of the adequacy of the region's electric system.

On a regular and on-going basis, the ISO shall conduct studies to identify the location and nature of any potential problems on the New England Transmission System. These assessments shall be conducted to identify those factors relevant to the standards for identifying needs which might be solved or mitigated by Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades, as specified in Section II of this Attachment.

The ISO will publish its identification of such relevant factors on the New England Transmission System on its website and to the PAC, thereby providing market signals for generation, merchant transmission and load responses to develop and implement market-based solutions for the relief of actual and projected system reliability concerns, transmission constraints and market inefficiencies. The ISO will also present the results of its assessments in appropriate market forums to facilitate market responses to those needs. Market responses having met appropriate milestones pursuant to Attachment K to the OATT will be included in studies to assess the effects of such market responses on the identified problems with reliability and market inefficiencies.

Based on input and feedback provided by the PAC, the ISO shall refer to the Markets Committee and Reliability Committee issues and concerns identified by the PAC for further investigations and consideration of potential changes to rules and procedures.

2. Conduct of Public Policy Transmission Studies

The ISO will conduct the public policy transmission planning process pursuant to the timelines and procedures set out in Section 4A of Attachment K to this OATT.

3. Conduct of Longer-Term Transmission Studies

The ISO will conduct the longer-term transmission planning process pursuant to the timelines and procedures set out in Section 16 of Attachment K to this OATT.

B. Adequacy of the market responses, and as necessary, adequacy of Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades

The ISO shall assess the adequacy of proposed market responses in addressing identified system needs. The ISO shall also ensure that there are no significant adverse effects associated with such market responses, pursuant to Section I.3.9 of the Tariff and Planning Procedure 5-3, “Guidelines for Conducting and Evaluating Proposed Plan Application Analysis”.

If the market does not respond with adequate solutions to address the system needs identified by the ISO, the ISO shall present a coordinated transmission plan in the RSP that identifies appropriate projects for addressing both reliability, and market efficiency needs.

This coordinated plan is updated by the ISO as market responses to identified problems are developed. Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades are implemented only after market solutions have been given first consideration.

C. Periodic Updates to the RSP

A Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade may be added to the RSP at any time in a given year, ~~and~~ a Public Policy Transmission Upgrade project may be added to the RSP in accordance with Sections 3.6 and 4A of Attachment K to the OATT, and a Longer-Term Transmission Upgrade project may be added to the RSP in accordance with Sections 3.6 and 16 of Attachment K to the OATT. In doing so, the ISO shall consult with and consider input from the PAC and the Reliability Committee, within the scope of their respective functions.

The time required to implement transmission projects, however, is often longer than that needed for market-based solutions. Thus, the RSP process recognizes that a new market response could result in a deferral or a significant change in the proposed timing and/or configuration of a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrades. Also, a needed Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade may become delayed due to other factors.

As a result, the ISO may remove or defer a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade project from the RSP at any time in a given year, if the market responds by developing credible market-based solutions, or other circumstances arise that impact the need for the Transmission Upgrade. If market-based solutions have not met appropriate milestones prior to significant sunk transmission expense being made to provide the Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, then the ISO will assess the risks and costs associated with adding or advancing a transmission project from the RSP. The ISO may remove a Public Policy Transmission Upgrade project from the RSP in accordance with Sections 3.6 and 4A of Attachment K to the OATT. The ISO may remove a Longer-Term Transmission Upgrade project from the RSP in accordance with Sections 3.6 and 16 of Attachment K to the OATT. The ISO shall consult with and consider input from the PAC and the Reliability Committee with regard to such changes in the RSP. In the event that a transmission project is removed, deferred, added or advanced, the ISO shall promptly notify the affected Participating Transmission Owners and Non-Incumbent Transmission Developers.

IV. COST-EFFECTIVENESS AND COST ALLOCATION DETERMINATION OF RELIABILITY TRANSMISSION UPGRADES AND MARKET EFFICIENCY TRANSMISSION UPGRADES

The cost-effectiveness and cost allocation of identified Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades will be determined pursuant to the Tariff, Attachment K; Schedule 12; and Planning Procedure 4. The level of detail needed to fulfill the requirements of the RSP process and Planning Procedure 4 will ensure that, in addition to a determination of Pool-supported PTF costs and Localized Costs, the planning and stakeholder review processes will include a comprehensive examination of all Transmission Upgrade construction alternatives and their associated costs and will thus evaluate the cost-effectiveness of each Transmission Upgrade and its potential alternatives.

ATTACHMENT O

NON-INCUMBENT TRANSMISSION DEVELOPER OPERATING AGREEMENT

NON-INCUMBENT TRANSMISSION DEVELOPER OPERATING AGREEMENT

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NON-INCUMBENT TRANSMISSION DEVELOPER OPERATING AGREEMENT

This Operating Agreement (this "Agreement"), dated as of [date], is made and entered into by ___________________________, a [STATE] [TYPE OF ENTITY] ("NTD"), and ISO New England Inc. ("ISO"), a Delaware corporation (NTD and the ISO are collectively referred to herein as the "Parties").

WHEREAS, the ISO is a regional transmission organization ("RTO") authorized by the Federal Energy Regulatory Commission ("FERC") to exercise the functions required of RTOs pursuant to FERC's Order No. 2000 ("Order 2000") and FERC's RTO regulations;

WHEREAS, NTD has been approved as a "Qualified Transmission Project Sponsor" pursuant to the ISO Open Access Transmission Tariff (the "ISO OATT"), which is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff (the "ISO Tariff");

WHEREAS, in accordance with the requirements of Order 2000, the ISO will be the transmission provider under the ISO OATT of non-discriminatory, open access transmission services over the transmission facilities of NTD, once placed in service, that become part of the New England Transmission System ("Transmission Service");

WHEREAS, the ISO OATT will be designed to provide for the payment by transmission customers for Transmission Service at rates designed to recover the revenue requirements of NTD in supporting the provision of such transmission service by the ISO under the ISO OATT;

WHEREAS, the ISO will be responsible for system planning within the ISO region subject to certain rights and obligations of NTD, all as set forth in this Agreement;

WHEREAS, the functions to be performed by the ISO and Order 2000 require that the ISO have the requisite operational authority over NTD's transmission facilities;

WHEREAS, in accordance with the terms set forth herein, NTD desires for the ISO to exercise, and the ISO desires to exercise, Operating Authority (as defined in Section 3.02 of this Agreement) over the NTD Transmission Facilities (as defined in this Agreement) consistent with the requirements of Order 2000, once those facilities are placed in service;

WHEREAS, NTD will among other things, continue to own, physically operate, and maintain its transmission facilities; and

WHEREAS, references to the PTOs in this Agreement are not intended to impose additional requirements or obligations on the PTOs in addition to those in the TOA;

NOW, THEREFORE, in consideration of the promises, and the mutual representations, warranties, covenants and agreements hereinafter set forth, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound, NTD and the ISO agree as follows:

ARTICLE I
DEFINITIONS; INTERPRETATIONS

1.01 **Definitions; Interpretations.** Each of the capitalized terms and phrases used in this Agreement (including the foregoing recitals) and not otherwise defined herein shall have the meaning specified in Schedule 1.01. In this Agreement, unless otherwise provided herein:

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

(b) words denoting a gender include all genders;

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

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

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

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

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

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

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

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

(k) words such as "hereunder", "hereto", "hereof" and "herein" and other words of similar import shall, unless the context requires otherwise, refer to this Agreement as a whole and not to any particular article, section, subsection, paragraph or clause hereof;

(l) a reference to "include" or "including" means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of ejusdem generis shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned; and

(m) neither this Agreement nor any other agreement, document or instrument referred to herein or executed and delivered in connection herewith shall be construed against any Person as the principal draftsperson hereof or thereof.

ARTICLE II
TRANSMISSION FACILITIES

2.01 **Transmission Facilities.** As to NTD, the transmission facilities over which the ISO shall exercise Operating Authority (as of the date the facilities are placed in service) in accordance with the terms set forth herein shall be:

(a) those facilities of NTD listed in Schedule 2.01(a) (hereinafter "NTD Category A Facilities"), as such list of facilities may be added to or deleted from in accordance with Sections 2.01(d) and 2.02 below;

(b) those facilities of NTD listed in Schedule 2.01(b) (hereinafter "NTD Category B Facilities"), as such list of facilities may be added to or deleted from, in accordance with Sections 2.01(d) and 2.02 below; and

(c) those transmission facilities of NTD within the New England Transmission System with a voltage level of less than 69 kV and all transformers that have no NTD Category A Facilities or NTD Category B Facilities connected to the lower voltage side of the transformer that are not listed on Schedule 2.01(a) and Schedule 2.01(b) (hereinafter "NTD Local Area Facilities"), provided that any excluded facilities of NTD listed on Schedule 4.01(d) shall not be NTD Local Area Facilities.

(d) The transmission facilities included on any of the lists of the NTD Category A Facilities or the NTD Category B Facilities contained in Schedule 2.01(a) and Schedule 2.01(b), respectively, may be redesignated on another of those two lists, deleted from such list, or redesignated as a NTD Local Area Facility without the necessity of an amendment to this Agreement, but only in the following manner:

(i) at the direction of a Governmental Authority with jurisdiction over the Transmission Facilities in question, provided that the ISO and NTD shall be provided prior written notice of such changes;

(ii) as agreed between the ISO and NTD; or

(iii) where the operational characteristics of a transmission facility have been materially modified (including a change from a radial transmission facility to a looped transmission facility that contributes to the parallel carrying capability of the New England Transmission System) in accordance with Section 2.01(e); provided that any such changes shall also be subject to ISO review consistent with Section 2.06.

(e) All transmission facilities to be redesignated as NTD Category A Facilities, NTD Category B Facilities, or Local Area Facilities or deleted from the lists in Schedule 2.01(a) and Schedule 2.01(b) in accordance with Section 2.01(d)(iii), and all transmission facilities to be added to the lists in Schedule 2.01(a) and Schedule 2.01(b) in accordance with Section 2.02 shall be classified in accordance with the following standards:

(i) NTD Category A Facilities shall consist of: all transmission lines with a voltage level of 115 kV and above, except for those 115 kV transmission facilities specifically designated as NTD Category B Facilities in accordance with Section 2.01(e)(ii); all transmission interties between Control Areas; all transformers that have NTD Category A Facilities connected to the lower voltage side of the transformer; all transformers that require an NTD Category A Facility to be taken out of service when the transformer is taken out of service; and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such transmission lines, interties, and transformers.

(ii) NTD Category B Facilities shall consist of: all 115 kV radial transmission lines and all 69 kV transmission lines that are not interties between Control Areas; all transformers that have any NTD Category B Facilities and no NTD Category A Facilities connected to the lower voltage side of the transformer except to the extent such transformers are designated as NTD Category A Facilities in accordance with Section 2.01(e)(i); and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such NTD Category B Facilities.

(iii) NTD Local Area Facilities shall consist of all transmission facilities with a voltage level of less than 69 kV and all transformers that have no NTD Category A

Facilities or NTD Category B Facilities connected to the lower voltage side of the transformer.

(iv) To the extent there is any dispute between the ISO and NTD as owner of a transmission facility concerning classification of such transmission facility under these standards, such disagreement shall be subject to the dispute resolution provisions of this Agreement, provided that the ISO's classification of a transmission facility under the standards shall govern pending resolution of the dispute.

Collectively, all NTD Category A Facilities, NTD Category B Facilities, and NTD Local Area Facilities shall hereinafter be referred to as the "Transmission Facilities," provided that "Transmission Facilities" shall not include Excluded Assets as defined in Section 2.04 of this Agreement or Merchant Facilities. The ISO shall maintain on its OASIS a posting of the current versions of Schedule 2.01(a) and Schedule 2.01(b), in each instance, reflecting each such change promptly after such change is made.

(f) The classifications set forth in this Section 2.01 are for operational purposes. Rate treatment of Transmission Facilities shall be governed by the ISO OATT, provided that filings for rate treatment under the ISO OATT shall be subject to Section 3.04 of this Agreement.

2.02 **New and Acquired Transmission Facilities and Transmission Upgrades.**

(a) Any New Transmission Facility or Transmission Upgrade shall be considered a "Transmission Facility" under this Agreement once it is included as "Proposed" in the RSP Project List and, unless otherwise agreed by the ISO and NTD, shall thereafter be added to Schedule 2.01(a) and/or (b), as applicable.

(b) Any Merchant Facility interconnected to or within the New England Transmission System shall not be the subject of this Agreement. Any Merchant Facility interconnected to or within the New England Transmission System constructed and placed in commercial operation after the Operations Date shall be subject to the authority of the ISO under a separate agreement in accordance with Section 2.03 and any applicable provisions of the ISO OATT.

2.03 **Merchant Facilities.** The terms and conditions under which NTD, an Affiliate of NTD or any other entity grants authority over any Merchant Facilities to the ISO shall not be governed by this

Agreement, it being understood that NTD shall enter into operating agreements relating to its Merchant Facilities directly with the ISO in accordance with applicable provisions of the ISO OATT. Nothing in this Agreement is intended to limit or expand the right of NTD, the Affiliate of NTD, or any other entity to propose, construct, or own Merchant Facilities interconnected to the New England Transmission System. No Merchant Facility may become an Acquired Transmission Facility.

2.04 **Excluded Assets.** The "Excluded Assets" of NTD shall consist of those assets and/or facilities of NTD set forth in Section 2.04(a) and (b). These Excluded Assets are expressly excluded from the definition of Transmission Facilities under this Agreement, and the ISO shall not have Operating Authority over NTD's Excluded Assets. Nothing in this Section 2.04 is intended to address the rate treatment of the Transmission Facilities or any other asset of NTD. Rate treatment of Transmission Facilities shall be governed by the ISO OATT, provided that filings for rate treatment under the ISO OATT shall be subject to Section 3.04 of this Agreement:

(a) Excluded Assets are any assets, facilities, and/or portions of facilities owned by NTD that are connected with or associated with Transmission Facilities to the extent specifically excluded pursuant to the following items (i) through (vii) of this Section 2.04(a):

(i) proceeds from the use or disposition of Transmission Facilities;

(ii) any payment, refund or credit (1) relating to Taxes in respect of the Transmission Facilities, (2) arising under any contracts or tariffs of NTD and relating to services provided prior to the beginning of the Term, or (3) arising under any contract or tariff that provides for rates that are subject to regulation by an agency other than FERC.

(iii) any rights, ownership, title or interest NTD may have with respect to telecommunications assets and equipment, provided that the ISO shall continue to have the right to use such telecommunication assets and equipment attached to or associated with Transmission Facilities solely to the extent needed for the exercise of the ISO's Operating Authority and further provided that such use right shall not be assignable by the ISO;

(iv) any existing contracts or contract rights of NTD related in any manner to Transmission Facilities unless NTD agrees to assign or transfer such contracts to the ISO;

(v) any assets, property rights, licenses, permits or facilities that are used for or in (1) the distribution, generation, trading or marketing of electricity (except for facilities specifically defined as Transmission Facilities that are used for such activities), (2) gas transportation, gas, water, petroleum, chemical, real estate development, or cable business, or (3) any other activity unrelated to the transmission of electricity located on, or making use of, the Transmission Facilities;

(vi) any causes of action or claims related to Transmission Facilities, provided, that, upon the written agreement of NTD and the ISO to the assumption by the ISO of the management of such claims under mutually agreed terms and conditions, the ISO may manage NTD's causes of action or claims against a third party relating to such Transmission Facilities, and provided further that the ISO shall have the right to pursue causes of action or claims against third parties to the extent necessary for the ISO to fulfill its responsibilities for invoicing, collection and disbursement of customer payments in accordance with Section 3.10; and

(vii) any asset or facility for which Operating Authority may not be lawfully transferred or assigned.

(b) Excluded assets are any assets or facilities of NTD that are not specifically defined as Transmission Facilities, including without limitation the facilities or portions of facilities described in items (i) through (xii) of this Section 2.04(b):

(i) all cash, cash equivalents, bank deposits, accounts receivable, and any income, sales, payroll, property or other Tax receivables;

(ii) proceeds from the use or disposition of any facilities or assets owned by NTD;

(iii) certificates of deposit, shares of stock, securities, bonds, debentures, and evidences of indebtedness;

(iv) any rights or interest in trade names, trademarks, service marks, patents, copyrights, domain names or logos;

(v) any payment, refund or credit (1) relating to Taxes, (2) arising under any contracts or tariffs of NTD and relating to services provided prior to the beginning of the Term, or (3) arising under any contract or tariff that provides for rates that are subject to regulation by an agency other than FERC;

(vi) any facilities, including transmission facilities, located outside the New England Transmission System;

(vii) any rights, ownership, title or interest NTD may have with respect to telecommunications assets and equipment;

(viii) any existing contracts or contract rights of NTD unless NTD agrees to assign or transfer such contracts to the ISO;

(ix) any assets, property rights, licenses, permits or facilities that are used for or in (1) the distribution, generation, trading or marketing of electricity or (2) gas transportation, gas, water, petroleum, chemical, real estate development, or cable business, or (3) any other activity unrelated to the transmission of electricity whether or not located on, or making use of, the Transmission Facilities;

(x) any causes of action or claims;

(xi) any asset or facility for which Operating Authority may not be lawfully transferred or assigned; and

(xii) any interests of any kind in NTD's real property, provided that nothing in this Section 2.04 shall restrict NTD from conveying interests in real property in any future written agreement into which the ISO and NTD may, in their sole discretion, enter.

2.05 **Connection with Non-Parties.**

(a) NTD shall connect its Transmission Facilities (once placed in service) with the facilities of any entity that is not a Party, including the facilities of a current or proposed Transmission Customer, and shall install (or cause to be installed) and construct (or cause to be constructed) any transmission facilities required to connect the facilities of a non-Party to the Transmission Facilities to the extent such connection or construction is required by applicable law, including the Federal Power Act and any applicable regulations issued by FERC and provided that the construction of any such transmission facilities shall be subject to the conditions associated with NTD's obligation to build set forth in Schedule 3.09(a). Any such connection shall be subject further to: (1) the receipt of any necessary regulatory approvals, (2) compliance with the procedures set forth in the ISO OATT for review of the reliability and operational impacts of a proposed interconnection (including the procedures for interconnection of a Generating Unit under the Interconnection Standard); and (3) execution of an Interconnection Agreement with such entity containing provisions for the safe and reliable operation of each interconnection with respect to such entity's facilities in accordance with Good Utility Practice, applicable NERC/NPCC Requirements, and applicable Law (including the Federal Power Act); provided that

(i) Except as provided in 2.05(a)(ii) below, NTD shall engage in good faith negotiations as to the terms and conditions of such Interconnection Agreement with any such non-Party, but, except as may be required pursuant to regulations issued by FERC, NTD shall not be required to enter into any Interconnection Agreement containing terms and conditions unacceptable to NTD and shall reserve the right to resolve any disputes, and/or make any filings with FERC, with respect thereto.

(ii) With respect to the interconnection of a Large Generating Facility or a Small Generating Facility to any Transmission Facility, the Interconnection Agreement shall be a three-party agreement among NTD, the ISO, and the interconnecting non-Party based on the Schedule 22 Large Generator Interconnection Agreement or Schedule 23 Small Generator Interconnection Agreement, respectively, in the ISO OATT. With respect to the interconnection of other Generating Units to any Transmission Facility of NTD, the ISO shall be a party to Interconnection Agreements if and to the extent that FERC regulations require the ISO to be a party. Either the ISO or the PTOs (working with NTD as a party to the Disbursement Agreement), may propose amendments to the Schedule 22 Large Generator Interconnection Agreement or Schedule 23 Small Generator Interconnection Agreement under Section 205 of the Federal Power Act and shall include in such proposal the views of the ISO and NTD and PTOs, as applicable, provided that the standard applicable under Section 205 of the Federal Power Act shall apply only to the NTD and/or PTOs' position on any financial obligations of the PTOs and/or NTD (as applicable) or the interconnecting non-Party, and any provisions related to physical impacts of the interconnection on the Transmission Facilities or other assets. If NTD, the ISO and the interconnecting non-Party agree to the terms and conditions of a specific Large Generator Interconnection Agreement or Small Generator Interconnection Agreement, as applicable, or any amendments to such an Interconnection Agreement, then NTD and the ISO shall jointly file the executed Interconnection Agreement, or amendment thereto, with FERC under Section 205 of the Federal Power Act. To the extent NTD, the ISO and such interconnecting non-Party cannot agree to proposed variations from the Schedule 22 or 23 Interconnection Agreement applicable to a Large Generating Facility or Small Generating Facility, respectively, or cannot otherwise agree to the terms and conditions of the Interconnection Agreement, or any amendments to such an Interconnection Agreement, then NTD and the ISO shall jointly file an unexecuted Interconnection Agreement, or amendment thereto, with FERC under Section 205 of the Federal Power Act and shall identify the areas of disagreement in such filing, provided that, in the event of disagreement on terms and conditions of the Interconnection Agreement related to the costs of upgrades to the Transmission Facilities, the anticipated schedule for the construction of such upgrades, any financial obligations of NTD, and any provisions related to physical impacts of the interconnection on the Transmission Facilities or other assets, then the standard applicable under Section 205 of the Federal Power Act shall apply only to NTD's position on such terms and conditions.

The costs of interconnection facilities shall be allocated in the manner specified in the ISO OATT.

(b) NTD shall also connect its Transmission Facilities (once placed in service) with the facilities of any entity that is not a Party upon satisfaction of the "Elective Transmission Upgrade" provisions of the ISO OATT, provided that NTD shall only connect the facilities of such entity (the "Elective Transmission Upgrade Applicant") upon satisfaction of the following conditions:

(i) The Elective Transmission Upgrade Applicant shall enter into an Interconnection Agreement with the affected PTO(s) and NTD and, to the extent necessary and appropriate, enter into support agreements with the affected PTO(s) and NTD, provided that the Elective Transmission Upgrade Applicant may request, upon providing the security, credit assurances, and/or deposits required by the affected PTO, the filing with the Commission by NTD and/or affected PTOs of unexecuted Interconnection Agreements and support agreements.

(ii) The Elective Transmission Upgrade Applicant shall obtain all necessary legal rights and approvals for the construction and maintenance of the upgrade and shall cooperate with NTD in obtaining all necessary legal rights and approvals for the construction and maintenance of additions or modifications, if any, required in conjunction with the upgrade.

(iii) The Elective Transmission Upgrade Applicant shall be responsible for 100% of all of the costs of said upgrade and of any additions to or modifications of the Transmission Facilities that are required to accommodate the Elective Transmission Upgrade. A request for rate treatment of an Elective Transmission Upgrade, if any, shall be determined by FERC in the appropriate proceeding.

2.06 **Review of Transmission Plans.** NTD shall submit to the ISO in such form, manner and detail as the ISO may reasonably prescribe: (i) any new or materially changed plans for retirements of or changes in the capacity of such Transmission Facilities rated 69 kV or above or plans for construction of New Transmission Facilities or Transmission Upgrades rated 69 kV or above; and (ii) any new or materially changed plan for any other action to be taken by NTD which may have a significant effect on the stability, reliability or operating characteristics of the Transmission Facilities, the facilities of any Transmission Owner, or the system of a Participant. The ISO shall provide notification of any such NTD submissions to the appropriate Technical Committee(s). Unless prior to the expiration of ninety (90) days, the ISO notifies NTD in writing that it has determined that implementation of the plan will have a significant adverse effect upon the reliability or operating characteristics of the Transmission Facilities, the facilities of any Transmission Owner, or the system of a Participant, NTD shall be free to proceed. If the ISO notifies NTD that implementation of such plan has been determined to have a significant adverse effect upon the reliability or operating characteristics of the Transmission Facilities, the facilities of any Transmission Owner, or the system of a Participant, NTD shall not proceed to implement such plan unless NTD takes such action or constructs such facilities as the ISO determines to be reasonably necessary to avoid such adverse effect.

2.07 **Condemnation.** If, at any time, any Governmental Authority commences any process to acquire any Transmission Facilities or any other interest in Transmission Facilities then held by NTD through condemnation or otherwise through the power of eminent domain, (i) NTD shall provide the ISO with written notice of such process, (ii) NTD shall, at its cost, direct any litigation or proceeding regarding such condemnation or eminent domain matter, (iii) NTD shall have the right to settle any such proceeding without the consent of the ISO, and (iv) any award in condemnation or eminent domain shall be paid to NTD without any claim to such award by the ISO.

ARTICLE III

OPERATING AUTHORITY

3.01 **Grant of Operating Authority.** Subject to the terms set forth in this Agreement, including Article III and Article X hereof, NTD hereby authorizes the ISO, through its officers, employees, consultants, independent contractors and other personnel, to exercise Operating Authority over the Transmission Facilities once they are placed in service, including provision of Transmission Service over the Transmission Facilities under the TOA and ISO OATT, and the ISO hereby agrees to assume and exercise Operating Authority over the Transmission Facilities in accordance with the TOA once they are placed in service. Coincident with the NTD's Transmission Facilities being placed in service or the acquisition of operational Transmission Facilities, the NTD shall execute the TOA pursuant to Section 10.05 hereof, list such Transmission Facilities under the TOA and, by doing so, authorize the ISO to exercise Operating Authority over such Transmission Facilities via the TOA.

3.02 **[reserved]**

3.03 **Transmission Services and OATT Administration.**

(a) The ISO shall administer the ISO OATT in the manner specified in this Section 3.03. The ISO's OATT administration responsibilities shall include those enumerated below:

(i) The ISO shall receive, post on OASIS as required by Commission regulations, and respond to requests by Large Generating Facilities and Small Generating Facilities to be interconnected under the ISO OATT, and all Transmission Service. Except as provided in Section 3.03(a)(ii), the ISO shall perform the system impact studies and facilities studies (and execute and administer agreements for such studies) in connection with such requests to the Administered Transmission System. Notwithstanding the foregoing, (A) the ISO shall consult with NTD prior to completion of system impact studies and facilities studies in connection with requests that affect the Transmission Facilities and distribution facilities and shall include in any such studies NTD's reasonable estimates of the costs of upgrades to the Transmission Facilities needed to implement the conclusions of such studies and NTD's reasonable anticipated schedule for the construction of such upgrades; (B) nothing in this Agreement shall preclude the ISO from entering into a separate agreement(s) with NTD for such studies, pursuant to the ISO's supervision and the ISO's authority to require modifications to such studies, to perform system impact studies and facilities studies; (C) except as provided in Section 3.03(a)(ii) with respect to interconnection of Generating Units that would not have an impact on facilities used for the provision of regional transmission service, nothing in this Agreement shall preclude the performance of studies related to the interconnection of Generating Units by a third party consultant to the extent permitted by applicable procedures in the ISO OATT (including procedures governing the treatment of confidential information) and provided that such studies performed by any third party consultant must include NTD's reasonable estimates of the costs of upgrades to such Transmission Facilities needed to implement the conclusions of such studies and NTD's reasonable anticipated schedule for the construction of such upgrades; and (D) NTD shall, upon request by the ISO, conduct any necessary studies related to the Transmission Facilities, including system impact studies and facilities studies, and shall assist in the performance of any such studies, including the provision of information and data in accordance with Section 11.07 of this Agreement.

(ii) The ISO shall review applications for Transmission Service or requests for the interconnection of Large Generating Facilities and Small Generating Facilities to be interconnected to a Transmission Facility to determine whether the service or interconnection would have an impact on facilities used for the provision of regional transmission service. If so, and the interconnection is to a Transmission Facility, the ISO will perform a system impact study and facilities study, as necessary to address the impacts on facilities used for the provision of regional transmission service.

(iii) The ISO shall operate and maintain the OASIS (or a successor system) as required by FERC. NTD shall provide updates to the NTD-specific pages on the OASIS site, subject to the ISO's review of such updates. The ISO shall have the authority to direct any changes to such NTD-specific pages that it deems appropriate to conform to FERC requirements and the terms and conditions of the ISO OATT.

(b) Notwithstanding Section 3.03(a), retail load customers requesting to interconnect with the Transmission Facilities of NTD shall submit service requests to NTD. Such service requests submitted to the ISO shall be forwarded to NTD. NTD shall execute and administer the agreements, and shall be responsible for billing, collections, dispute resolution and the performance of system impact studies and facilities studies, in coordination with the ISO as necessary, in connection with such requests.

(c) Transmission Service Agreements. The ISO and NTD shall enter into all agreements for Transmission Service over the Transmission Facilities; provided that:

(i) A pro forma regional transmission service agreement (or service agreements) shall be attached to the ISO OATT and such pro forma service agreement(s) shall set forth the respective rights and responsibilities of the Transmission Customer, the ISO, the PTOs and NTD. The ISO shall have the authority, pursuant to Section 205 of the Federal Power Act, to amend the pro forma service agreement(s) or the Market Participant Service Agreement ("MPSA") or executed service agreements related to the terms and conditions of regional Transmission Service.

(ii) The ISO shall be responsible for filing with the FERC, or electronically reporting to the FERC as applicable, all new agreements for Transmission Service over the Transmission Facilities. In the event of any dispute between the ISO or NTD and a Transmission Customer concerning the terms and conditions of such service agreements, the ISO shall file an unexecuted copy of the pro forma service agreement set forth in the ISO OATT and shall include in such filing any statement provided by NTD, affected PTO(s) and the Transmission Customers concerning their respective positions on any proposed changes or additions to the pro forma service agreement.

3.04 **Application Authority.**

(a) NTD shall have the authority to submit filings under Section 205 of the Federal Power Act to establish and to revise (pursuant to an NTD rate schedule filed under Schedules 13, ~~or~~ 14, or 14A, as applicable, of the ISO OATT):

(i) charges for costs permitted to be recovered under Sections 4.3, ~~and~~ 4A, and 16 of Attachment K to the ISO OATT;

(ii) once its project is listed as "Proposed" in the RSP Project List, charges for the costs of Commission-approved construction work in process; and

(iii) once its project is listed as "Proposed" in the RSP Project List, any rates, charges, terms or conditions for transmission services that are based solely on the revenue requirements of the Transmission Facilities (including Transmission Facilities leased to NTD or to which NTD has contractual entitlements).

NTD shall not have the authority to revise such rates, terms and conditions in a manner that would abridge the rights granted to the ISO in Section 3.04(b). NTD shall provide written notification to the ISO and stakeholders of any filing described in sub-paragraph (i) through (iv), above, which notification shall include a detailed description of the filing, at least 30 days in advance of a filing. NTD shall consult with interested stakeholders upon request. NTD shall retain the right to modify aspects of any filing authorized by this Section 3.04(a) after it provides written notification to the ISO and stakeholders, and shall provide notification to the ISO and stakeholders of any material modification to such filings.

With respect to any filing described in sub-paragraph (iii) above, NTD shall include in any filing a statement that, in the good faith judgment of NTD, the proposal will not be inconsistent with the design of the New England Markets, as accepted or approved by FERC. In the event the ISO believes that a proposed filing described in sub-paragraph (iii) above, would have such an inconsistency, it shall so advise NTD and NTD and the ISO shall consult in good faith to resolve any ISO concerns, but, if such disagreement cannot be resolved, NTD may submit a filing under Section 205, provided that NTD's filing (including the transmittal letter for such filing) to FERC shall include any written statement provided by the ISO setting forth the basis for the ISO's concerns.

NTD shall consult with the ISO to determine whether the ISO will need to make any software modifications in order to implement any filing authorized by this Section 3.04(a) and when any needed software modifications could reasonably be expected to be implemented. NTD's filing to FERC (and the transmittal letter for such a filing) shall include any written statement provided by the ISO setting forth the basis for any software-related implementation concerns raised by the ISO. The ISO shall make Commercially Reasonable Efforts to implement any needed software modifications by the effective date accepted by the FERC for a filing authorized by this Section 3.04(a), provided that, if the ISO has exercised such Commercially Reasonable Efforts, a failure to implement needed software modifications by the FERC-accepted effective date shall not constitute an event of default by the ISO under this Agreement or subject the ISO to financial damages, and further provided that the ISO shall run retroactive settlements consistent with the FERC-accepted effective date for a filing authorized by this Section 3.04(a) once such software modifications have been implemented.

(b) The ISO has the authority to submit filings under Section 205 of the Federal Power Act as set forth in the TOA.

(c) NTD shall have no authority to submit a filing under Section 205 of the Federal Power Act to modify any provision of the ISO OATT that implements any of the items listed in Section 3.04(b) of the TOA.

3.05 **<u>The ISO's Responsibilities</u>.**

(a) In addition to its other obligations under this Agreement, in performing its obligations and responsibilities hereunder, and in accordance with Good Utility Practice, the ISO shall:

(i) maintain system reliability; and

(ii) in all material respects, act in accordance with applicable Laws and conform to, and implement, all applicable reliability criteria, policies, standards, rules, regulations, orders, license requirements and all other applicable NERC/NPCC Requirements, and other applicable reliability organizations' reliability rules, and all applicable requirements of federal or state laws or regulatory authorities.

(b) The ISO shall obtain and retain all necessary authorizations of FERC and other regulatory authorities to function as the New England RTO and shall possess the characteristics and perform the functions required for that purpose.

3.06 **<u>NTD's Responsibilities</u>.**

(a) NTD shall, in accordance with Good Utility Practice:

(i) collaborate with the ISO with respect to:

(A) the development of Rating Procedures,

(B) the establishment of ratings for New Transmission Facilities;

(C) the establishment of ratings for Acquired Transmission Facilities that do not have an existing rating; and

(D) the establishment of any changes to existing ratings for Transmission Facilities in effect as of the Operations Date.

To the extent there is any disagreement between the ISO and NTD concerning Rating Procedures or the rating of a Transmission Facility, such disagreement shall be the subject of good faith negotiations between NTD and the ISO, provided that (x) NTD's position concerning such Rating Procedures or Transmission Facility ratings shall govern until NTD and the ISO agree on a resolution to such disagreement; and (y) nothing in this Section 3.06(a)(iv) shall limit the rights of the ISO or of NTD to submit a filing under Section 206 of the Federal Power Act with respect to Transmission Facility ratings or Rating Procedures. During any collaboration or discussions concerning Transmission Facility ratings, NTD shall continue to provide the ISO with up-to-date ratings information in accordance with the applicable Rating Procedures.

(ii) cooperate with actions taken by PTOs' Local Control Centers with respect to the Transmission Facilities; and

(iii) in all material respects, comply with all applicable laws, regulations, orders and license requirements, and with all applicable requirements, and with all applicable NERC/NPCC Requirements, other applicable reliability organizations' local reliability rules, and all applicable requirements of federal or state laws or regulatory authorities.

3.07 **Reserved Rights of NTD.**

(a) Notwithstanding any other provision of this Agreement to the contrary, NTD shall retain all of the rights set forth in this Section 3.07; provided, however, that such rights shall be exercised in a manner consistent with applicable NERC/NPCC Requirements and applicable regulatory standards. This Section 3.07 is not intended to reduce or limit any other rights of NTD as a signatory to this Agreement or under the ISO OATT.

(i) Nothing in this Agreement shall restrict any rights: (A) of NTD if it is a party to a merger, acquisition or other restructuring transaction to make filings under Section 205 of the Federal Power Act with respect to NTD's reallocation or redistribution of revenues or the assignment of such NTD's rights or obligations, to the extent the Federal Power Act requires such filings; or (B) of NTD to terminate its participation in this Agreement pursuant to Article X of this Agreement.

(ii) Except as expressly provided in the grant of Operating Authority to the ISO, NTD retains all rights that it otherwise has incident to its ownership of, and legal and equitable title to, its assets, including its Transmission Facilities and all land and land rights, including the right to build, acquire, sell, lease, merge, dispose of, retire, use as security, or otherwise transfer or convey all or any part of its assets, subject to NTD's compliance with Section 2.06 of this Agreement. Subject to Article X, NTD may, directly or indirectly, by merger, sale, conveyance, consolidation, recapitalization, operation of law, or otherwise, transfer all or any portion of the Transmission Facilities subject to this Agreement but only if such transferee or successors shall agree in writing to be bound by terms of this Agreement.

(iii) NTD shall have the right to adopt and implement, consistent with Good Utility Practice, procedures and to take such actions it deems necessary to protect its facilities from physical damage or to prevent injury or damage to persons or property.

(iv) NTD retains the right to take whatever actions, consistent with Good Utility Practice, it deems necessary to fulfill its obligations under applicable Law.

(v) Nothing in this Agreement shall be construed as limiting in any way the rights of NTD to make any filing with any applicable state or local regulatory authority.

(vi) NTD shall have the right to retain one or more subcontractors to perform any or all of its obligations under this Agreement. The retention of a subcontractor pursuant to the terms of this Section 3.07 shall not relieve NTD of its primary liability for the performance of any of its obligations under this Agreement.

(b) Any and all other rights and responsibilities of NTD related to the ownership or operation of its Transmission Facilities not expressly assigned to the ISO under this Agreement will remain with NTD.

(c) Nothing in this Agreement shall be deemed to impair or infringe on any rights or obligations of NTD under the Federal Power Act and FERC's rules and regulations thereunder, provided that any such rights are not inconsistent with the express terms of this Agreement. Nothing contained in this Agreement shall be construed to limit in any way the right of NTD to take any position, including opposing positions, in any administrative or judicial proceeding or filing by NTD or the ISO, notwithstanding that such proceeding or filing may be undertaken or made, explicitly or implicitly, pursuant to this Agreement.

3.08 **[reserved]**

3.09 **[reserved]**

3.10 **<u>Invoicing, Collection and Disbursement of Payments</u>.**

(a) <u>Invoicing</u>. Except as provided in Section 3.10(a)(ii), the ISO will administer its current net settlement system, including invoicing of charges to Transmission Customers for Transmission Services on the Transmission Facilities as follows:

(i) The charges invoiced by the ISO on behalf of NTD shall include the following (each, an "<u>Invoiced Amount</u>"):

(A) all charges listed in NTD's Commission-accepted rate schedule under Schedules 13, ~~and~~ 14, and 14A of the ISO OATT; and

(B) any and all rates, charges, fees and/or penalties under interconnection agreements which have been filed with and accepted by FERC, other than amounts billed directly by NTD pursuant to Section 3.10(a)(ii) below.

(ii) Payments relating to all services provided by NTD outside of Schedules 13, ~~and~~ 14, and 14A that provide for payment to NTD, and any other payments shall be invoiced by NTD and shall not be invoiced by the ISO; provided that, notwithstanding the foregoing, NTD and the ISO may enter into separate agreements such that the ISO provides invoicing services for such payments.

(iii) The ISO shall remit or credit to NTD, consistent with the ISO Tariff and the net settlement system, any and all payments received or collected from Transmission Customers for Invoiced Amounts in accordance with this Agreement. NTD shall designate (and notify the ISO of the identity of) a single authorized individual to provide such directions to the ISO. This individual shall also respond to any ISO questions or requests for clarification concerning such directions; provided that the ISO shall be able to rely upon the direction of the designated individual unless and until it receives notification from NTD or from a Governmental Authority of reversal of such direction by any Governmental Authority with jurisdiction over this Agreement.

(b) The ISO's Collection Obligations and Application of Financial Assurances Policies. If a Transmission Customer defaults on any payment of any Invoiced Amount (the "Owed Amounts"), the ISO shall take all necessary actions to execute or call upon any Financial Assurances held by the ISO attributable to such Transmission Customer.

(c) No Pledge of Invoiced Amounts. The ISO shall not create, incur, assume or suffer to exist any lien, pledge, security interest or other change or encumbrance, or any other type of preferential arrangement (including a banker's right of set off) against any Invoiced Amounts, any accounts receivables representing Invoiced Amounts, the settlement account maintained by the ISO into which payments on Invoiced Amounts are made and from which remittances are made to NTD or any Financial Assurances.

3.11 **Subcontractors.** NTD acknowledges and agrees that, subject to the terms set forth herein, the ISO has the right to retain one or more subcontractors to perform any or all of its obligations under this Agreement. The retention of a subcontractor pursuant to the terms of this Section 3.11 shall not relieve the ISO of its primary liability for the performance of any of its obligations under this Agreement.

3.12 **No Impairment of the ISO's Other Legal Rights and Obligations.** Nothing in this Agreement shall be deemed to impair or infringe on any rights or obligations of the ISO under the Federal Power Act and FERC's rules and regulations thereunder, including the ISO's rights and obligations to submit filings to recover its administrative, capital, and other costs.

ARTICLE IV
REPRESENTATIONS AND WARRANTIES OF THE PARTIES

4.01 **Representations and Warranties of NTD.** NTD represents and warrants to the ISO as follows:

(a) Organization. It is duly organized, validly existing and in good standing under the laws of the state of its organization.

(b) Authorization. It has all requisite power and authority to execute, deliver and perform this Agreement; the execution, delivery and performance by NTD of this Agreement have been duly authorized by all necessary and appropriate action on the part of NTD; and this Agreement has been duly and validly executed and delivered by NTD and constitutes the legal, valid and binding obligations of NTD, enforceable against NTD in accordance with its terms.

(c) No Breach. The execution, delivery and performance by NTD of this Agreement will not result in a breach of any terms, provisions or conditions of any agreement to which NTD is a party which breach has a reasonable likelihood of materially and adversely affecting NTD's performance under this Agreement.

4.02 **Representations and Warranties of the ISO.** The ISO represents and warrants to NTD as follows:

(a) Organization. It is duly organized, validly existing and in good standing under the laws of the state of its organization.

(b) Authorization. It has all requisite power and authority to execute, deliver and perform this Agreement; the execution, delivery and performance by the ISO of this Agreement have been duly authorized by all necessary and appropriate action on the part of the ISO; and this Agreement has been duly and validly executed and delivered by the ISO and constitutes the legal, valid and binding obligation of the ISO, enforceable against the ISO in accordance with its terms.

(c) No Breach. The execution, delivery and performance by the ISO of this Agreement will not result in a breach of any of the terms, provisions or conditions of any agreement to which the ISO is a party which breach has a reasonable likelihood of materially and adversely affecting the ISO's performance under this Agreement.

ARTICLE V
COVENANTS OF NTD

5.01 **Covenants of NTD.** NTD covenants and agrees that during (i) the Term, or (ii) the period expressly specified herein, as applicable, NTD shall comply with all covenants and provisions of this Article V, except to the extent the ISO waives such covenants or performance is excused pursuant to Section 11.11(b).

5.02 **[reserved]**

5.03 **Expenses.** Except to the extent specifically provided herein, all costs and expenses incurred by NTD in connection with the negotiation of this Agreement shall be borne by NTD; provided that nothing herein shall prevent NTD from recovering such expenses in accordance with applicable law.

5.04 **Consents and Approvals.**

(a) NTD shall exercise Commercially Reasonable Efforts to promptly prepare and file all necessary documentation to effect all necessary applications, notices, petitions, filings and other documents, and shall exercise Commercially Reasonable Efforts to obtain (and will cooperate with each other in obtaining) any consent, acquiescence, authorization, order or approval of, or any exemption or nonopposition by, any Governmental Authority required to be obtained or made by NTD in connection with this Agreement or the taking of any action contemplated by this Agreement.

(b) NTD shall exercise Commercially Reasonable Efforts to obtain consents of all other third parties necessary to the performance of this Agreement by NTD. NTD shall promptly notify the ISO of any failure to obtain any such consents and, if requested by the ISO, shall provide copies of all such consents obtained by NTD.

(c) Nothing in this Section 5.04 shall require NTD to pay any sums to a third party, including any Governmental Authority, excluding filing fees paid to any Governmental Authority in connection with a filing necessary or appropriate to further action.

5.05 **Notice and Cure.** NTD shall notify the ISO in writing of, and contemporaneously provide the ISO with true and complete copies of any and all information or documents relating to, any event, transaction or circumstance, as soon as practicable after it becomes Known to NTD, that causes or shall cause any covenant or agreement of NTD under this Agreement to be breached or that renders or shall render untrue any representation or warranty of NTD contained in this Agreement as if the same were made on or as of the date of such event, transaction or circumstance. NTD shall use all Commercially Reasonable Efforts to cure such event, transaction or circumstance as soon as practicable after it becomes Known to NTD. No notice given pursuant to this Section 5.05 shall have any effect on the representations, warranties, covenants or agreements contained in this Agreement for purposes of determining satisfaction of any condition contained herein or shall in any way limit the ISO's right to seek indemnity under Article IX.

ARTICLE VI
COVENANTS OF THE ISO

6.01 **Covenants of the ISO.** The ISO covenants and agrees that during (i) the Term, or (ii) the period expressly specified herein, as applicable, the ISO shall comply with all covenants and provisions of this Article VI, except to the extent the Parties consent in writing to a waiver of such covenants or performance is excused pursuant to Section 11.11(b).

6.02 **[reserved]**

6.03 **Expenses.** Except to the extent specifically provided herein, all costs and expenses incurred by the ISO in connection with the negotiation of this Agreement shall be borne by the ISO; provided that nothing herein shall prevent the ISO from recovering such expenses in accordance with applicable law.

6.04 **[reserved]**

6.05 **Notice and Cure.** The ISO shall notify NTD in writing of, and contemporaneously shall provide NTD with true and complete copies of any and all information or documents relating to, any event, transaction or circumstance, as soon as practicable after it becomes Known to the ISO, that causes or shall cause any covenant or agreement of the ISO under this Agreement to be breached or that renders or shall render untrue any representation or warranty of the ISO contained in this Agreement as if the same were made on or as of the date of such event, transaction or circumstance. The ISO shall use all Commercially Reasonable Efforts to cure such event, transaction or circumstance as soon as practicable after it becomes Known to the ISO. No notice given pursuant to this Section 6.05 shall have any effect on the representations, warranties, covenants or agreements contained in this Agreement for purposes of determining satisfaction of any condition contained herein or shall in any way limit any right of NTD to seek indemnity under Article IX.

ARTICLE VII
TAX MATTERS

7.01 **Responsibility for NTD Taxes.** NTD shall prepare and file all Tax Returns and other filings related to its Transmission Business and Transmission Facilities and pay any Tax liabilities related to its Transmission Business and Transmission Facilities. The ISO shall not be responsible for, or required to file, any Tax Returns or other reports for NTD and shall have no liability for any Taxes related to NTD's Transmission Business or Transmission Facilities. The ISO and NTD hereby agree that, for tax purposes, the Transmission Facilities shall be deemed to be owned by NTD.

7.02 **Responsibility for ISO Taxes.** The ISO shall prepare and file all Tax Returns and other filings related to its operations and pay any Tax liabilities related to its operations. NTD shall not be responsible for, or required to, file any Tax Returns or other reports for the ISO and shall have no liability for any Taxes related to the ISO's operations.

ARTICLE VIII
RELIANCE; SURVIVAL OF AGREEMENTS

8.01 **Reliance; Survival of Agreements.** Notwithstanding any right of any Party (whether or not exercised) to investigate the accuracy of any of the matters subject to indemnification by any other Party contained in this Agreement, each of the Parties has the right to rely fully upon the representations, warranties, covenants and agreements of the other Party contained in this Agreement. The provisions of Sections 11.01, 11.07, 11.11 and 11.15 and Articles VII and IX shall survive the termination of this

Agreement. With regard to Section 3.10 of this Agreement, the ISO will perform final billing consistent with Section 3.10 of this Agreement for all services provided until the Termination Date.

ARTICLE IX
INSURANCE; LIMITATION OF LIABILITIES

9.01 **Hold Harmless**. NTD will indemnify and hold harmless all affected PTOs from any and all liability (except for that stemming from an affected PTO's negligence, gross negligence or willful misconduct), resulting from the NTD's failure to timely complete (based on the milestone provisions contained in the ISO OATT) a Reliability Transmission Upgrade (as defined in the ISO OATT) that the NTD was chosen in the Regional System Plan to construct. As used herein, an "affected PTO" is one that would be subject to penalties assessed by NERC or FERC or adverse regulatory orders or monetary claims or damages due to the NTD's failure to timely complete the Reliability Transmission Upgrade.

9.02 – 9.04 **[Reserved]**

9.05 **Insurance.**

(a) NTD will maintain property insurance on its Transmission Facilities and liability insurance in accordance with good utility practice.

(b) All insurance required under this Section 9.05 by outside insurers shall be maintained with insurers qualified to insure the obligations or liabilities under this Agreement and having a Best's rating of at least B+ VIII (or an equivalent Best's rating from time to time of B+ VIII), or in the event that from time to time Best's ratings are no longer issued with respect to insurers, a comparable rating by a nationally recognized rating service or such other insurers as may be agreed upon by the Parties.

(c) Upon execution of this Agreement, and when requested thereafter, NTD shall furnish the ISO with certificates of all such insurance policies setting forth the amounts of coverage, policy numbers, and date of expiration for such insurance in conformity with the requirements of this Agreement.

9.06 **Liability.**

(a) Neither Party shall be liable to the other Party for any incidental, indirect, special, exemplary, punitive or consequential damages, including lost revenues or profits, even if such damages are foreseeable or the damaged Party has advised such Party of the possibility of such damages and regardless of whether any such damages are deemed to result from the failure or inadequacy of any exclusive or other remedy.

(b) Nothing in this Agreement shall be deemed to affect the right of the ISO to recover its costs due to liability under this Article IX through the ISO Participants Agreement or the ISO Administrative Tariff.

ARTICLE X
TERM; DEFAULT AND TERMINATION

10.01 **Term; Termination Date.**

(a) **Term.** Subject to the terms set forth in this Section 10.01, the term of this Agreement (the "Term") shall commence on the Effective Date and shall continue in force until terminated pursuant to Article X hereof. The date of such termination shall be referred to herein as the "Termination Date."

(b) **Termination by NTD.** NTD may terminate this Agreement:

(i) upon no less than 180 day's prior notice to the ISO; or

(ii) upon an ISO event of default in accordance with Section 10.03(a), provided that NTD shall exercise this right in accordance with Section 10.03(b)(i).

(c) **Termination By the ISO.** By notice to NTD, the ISO may terminate its obligations under this Agreement:

(i) upon the withdrawal of one or more PTOs from the Transmission Operating Agreement and the ISO has given notice to the PTOs that it is terminating the Transmission Operating Agreement pursuant to Section 10.01(c)(i) thereof;

(ii) if FERC issues an order putting into effect material changes in the liability and indemnification protections afforded to the ISO under this Agreement or the ISO Tariff;

(iii) if FERC issues an order putting into effect an amendment or modification of this Agreement that materially adversely affects the ISO's ability to carry out its responsibilities under this Agreement, unless the ISO has agreed to such changes in accordance with Section 11.04;

(iv) upon a NTD event of default in accordance with Section 10.04(a), provided that the ISO shall exercise this right in accordance with Section 10.04(b)(i); or

(v) if, within the period of ten years from the Effective Date, no NTD project has been listed by the ISO on the RSP Project List as "Proposed."

(d) Continuing Obligations. The withdrawing or terminating Party shall have the following continuing obligations following withdrawal from this Agreement: All financial obligations incurred and payments applicable to the time period prior to the Termination Date shall be honored by the terminating or withdrawing Party and the other Party in accordance with the terms of this Agreement, and each Party shall remain liable for all obligations arising hereunder prior to the Termination Date.

10.03 **[reserved]**

10.03 **Events of Default of the ISO.**

(a) Events of Default of the ISO. Subject to the terms and conditions of this Section 10.03, the occurrence of any of the following events shall constitute an event of default of the ISO under this Agreement:

(i) Failure by the ISO to perform any material obligation set forth in this Agreement and continuation of such failure for longer than thirty (30) days after the receipt by the ISO of written notice of such failure from NTD; provided, however, that if the ISO is diligently pursuing a remedy during such thirty (30) day period, said cure period shall be extended for an additional thirty (30) days or as otherwise agreed by NTD;

(ii) If there is a dispute between the ISO and NTD as to whether the ISO has failed to perform a material obligation, the cure period(s) provided in Section 10.03(a)(i) above shall run from the point at which a finding of failure to perform has been made by a Governmental Authority;

(iii) Any attempt (not including consideration of strategic options or entering into exploratory discussions) by the ISO to transfer an interest in, or assign its obligations under, this Agreement, except as otherwise permitted hereunder;

(iv) Failure of the ISO (if it has received the necessary corresponding funds from ISO customers) to pay when due any and all amounts payable to NTD by the ISO as part of the settlement process pursuant to Section 3.10 within three (3) Business Days;

(v) With respect to the ISO, (A) the filing of any petition in bankruptcy or insolvency, or for reorganization or arrangement under any bankruptcy or insolvency laws, or voluntarily taking advantage of any such laws by answer or otherwise or the commencement of involuntary proceedings under any such laws, (B) assignment by the ISO for the benefit of creditors; or (C) allowance by the ISO of the appointment of a receiver or trustee of all or a material part of its property if such receiver or trustee is not discharged within thirty (30) days after such appointment.

(b) Remedies for Default. If an event of default by the ISO occurs, NTD shall have the right to avail itself of any or all of the following remedies, all of which shall be cumulative and not exclusive:

(i) To terminate this Agreement in accordance with Section 10.01(b)(ii); provided that if the ISO contests such allegation of an ISO event of default, this Agreement shall remain in effect pending resolution of the dispute, but any applicable notice period shall run during the pendency of the dispute;

(ii) To demand that the ISO shall terminate any right of the ISO, immediately make arrangements for the orderly transfer of the ISO's invoicing and collection functions with respect to NTD and assist NTD or NTD's designee in resuming performance of the functions the later of 20 days from the date of making such demand or the start of the next billing cycle.

10.04 **Events of Default of NTD.**

(a) Events of Default of NTD. Subject to the terms and conditions of this Section 10.04, the occurrence of any of the events listed below shall constitute an event of default of NTD under this Agreement (in each instance, a "NTD Default"):

(i) Failure by NTD to perform any material obligation set forth in this Agreement and continuation of such failure for longer than thirty (30) days after the receipt by NTD of written notice of such failure from the ISO, provided, however, that if NTD is diligently pursuing a remedy during such thirty (30) day period, said cure period shall be extended for an additional thirty (30) days or as otherwise agreed by the ISO and NTD;

(ii) If there is a dispute between NTD and the ISO as to whether NTD has failed to perform a material obligation, the cure period(s) provided in Section 10.04(a)(i) above shall run from the point at which a finding of failure to perform has been made by a Governmental Authority; or

(iii) With respect to NTD, (A) the filing of any petition in bankruptcy or insolvency, or for reorganization or arrangement under any bankruptcy or insolvency laws, or voluntarily taking advantage of any such laws by answer or otherwise or the commencement of involuntary proceedings under any such laws, (B) assignment by NTD for the benefit of creditors; or (C) allowance by NTD of the appointment of a receiver or trustee of all or a material part of its property if such receiver or trustee is not discharged within thirty (30) days after such appointment.

(b) Remedies for Default. If an event of default by NTD occurs, the ISO shall have the following remedy: to terminate this Agreement in accordance with Section 10.01(c)(iv); provided that if NTD contests such allegation of an NTD event of default, this Agreement shall remain in effect pending resolution of the dispute, but any applicable notice period shall run during the pendency of the dispute.

10.05 **Transmission Operating Agreement and Disbursement Agreement; Registration.** On the date on which (1) any of the Transmission Facilities or a New Transmission Facility is placed into service or (2) NTD's acquisition of Acquired Transmission Facilities is consummated, whichever occurs earlier:

(a) NTD shall execute and deliver to the ISO a counterpart of the Transmission Operating Agreement as an Additional PTO (as defined therein). Upon such execution and delivery, this Agreement shall terminate automatically.

(b) NTD shall promptly execute a signature page for the Disbursement Agreement and deliver it to the parties thereto and shall become a party to the Disbursement Agreement.

(c) NTD shall register with NPCC as a Transmission Owner [and Transmission Service Provider][under discussion].

ARTICLE XI
MISCELLANEOUS

11.01 **Notices.** Unless otherwise expressly specified or permitted by the terms hereof, all communications and notices provided for herein shall be in writing and any such communication or notice shall become effective (a) upon personal delivery thereof, including by overnight mail or courier service, (b) in the case of notice by United States mail, certified or registered, postage prepaid, return receipt requested, upon receipt thereof, or (c) in the case of notice by facsimile, upon receipt thereof; provided that such transmission is promptly confirmed by either of the methods set forth in clauses (a) or (b) above, in each case addressed to the relevant party and copy party hereto at its address set forth in Schedule 11.01 or at such other address as such party or copy party may from time to time designate by written notice to the other party hereto; further provided that a notice given in connection with this Section 11.01 but received on a day other than a Business Day, or after business hours in the situs of receipt, will be deemed to be received on the next Business Day.

11.02 **Supersession of Prior Agreements.** With respect to the subject matter hereof, this Agreement (together with all schedules and exhibits attached hereto) constitutes the entire agreement and understanding among the Parties with respect to all subjects covered by this Agreement and supersedes all prior discussions, agreements and understandings among the Parties with respect to such matters.

11.03 **<u>Waiver</u>.** Any term or condition of this Agreement may be waived at any time by the Party that is entitled to the benefit thereof, but no such waiver shall be effective unless set forth in a written instrument duly executed by or on behalf of the Party waiving such term or condition. No waiver by a Party of any term or condition of this Agreement, in any one or more instances, shall be deemed to be or construed as a waiver of the same or any other term or condition of this Agreement on any future occasion. All remedies, either under this Agreement or by Law or otherwise afforded, shall be cumulative and not alternative.

11.04 **<u>Amendment; Limitations on Modifications of Agreement</u>.**

(a) This Agreement shall only be subject to modification or amendment by agreement of the Parties and the acceptance of any such amendment by FERC.

(b) In light of the foregoing, the Parties agree that they shall not rely to their detriment on any purported amendment, waiver or other modification of any rights under this Agreement unless the requirements of this Section 11.04 are satisfied and further agree not to assert equitable estoppel or any other equitable theory to prevent enforcement of this provision in any court of law or equity, arbitration or other proceeding.

11.05 **<u>No Third Party Beneficiaries</u>.** Except as provided in Article IX, it is not the intention of this Agreement or of the Parties to confer a third party beneficiary status or rights of action upon any Person or entity whatsoever other than the Parties and nothing contained herein, either express or implied, shall be construed to confer upon any Person or entity other than the Parties any rights of action or remedies either under this Agreement or in any manner whatsoever.

11.06 **<u>No Assignment; Binding Effect</u>.** Neither this Agreement nor any right, interest or obligation hereunder may be assigned by a Party, (including by operation of law) law (an "Assignment")-, without the prior written consent of the other Party in its sole discretion and any attempt at Assignment in contravention of this Section 11.06 shall be void, provided, however, that NTD may assign its rights and interests hereunder as security in connection with any financing for the construction or operation of NTD's Transmission Facilities (a "Collateral Assignment") without prior written consents or approvals. NTD may assign or transfer any or all of its rights, interests and obligations hereunder upon the transfer of its assets through sale, reorganization, or other transfer, provided that:

(a) NTD's successors and assigns shall agree to be bound by the terms of this Agreement except that NTD's successors and assigns shall not be required to be bound by any obligations hereunder to the extent that NTD has agreed to retain such obligations; and

(b) notwithstanding (a), NTD shall assign or transfer to any new owner of Transmission Facilities subject to this Agreement all of the rights, responsibilities and obligations associated with the physical operation of such Transmission Facilities as well as all of the rights, responsibilities and obligations associated with the ISO's Operating Authority with respect to such Transmission Facilities, further provided that the new owner shall have the right to retain one or more subcontractors to perform any or all of its responsibilities or obligations under this Agreement.

Subject to the foregoing, this Agreement is binding upon, inures to the benefit of and is enforceable by the Parties and their respective permitted successors and assigns. No Assignment shall be effective until NTD receives all required regulatory approvals for such Assignment.

11.07 **<u>Further Assurances; Information Policy; Access to Records</u>.**

(a) Each Party agrees, upon the other Party's request, to make Commercially Reasonable Efforts to execute and deliver such additional documents and instruments, provide information, and to perform such additional acts as may be necessary or appropriate to effectuate, carry out and perform all of the terms, provisions, and conditions of this Agreement and of the transactions contemplated hereby.

(b) The ISO shall, upon NTD's request, make available to NTD any and all information within the ISO's custody or control that is necessary for NTD to perform its responsibilities and obligations or enforce its rights under this Agreement, provided that such information shall be made available to NTD only to the extent permitted under the ISO Information Policy and subject to any applicable restrictions in the ISO Information Policy, including provisions of the ISO Information Policy governing the confidential treatment of non-public information, and provided further that any NTD employee or employee of NTD's Local Control Center shall comply with such ISO Information Policy and any applicable standards of conduct to prevent the disclosure of such information to any unauthorized Person. Any dispute concerning what information is necessary for NTD to perform its responsibilities and obligations or enforce its right under this Agreement shall be subject to dispute resolution under Section 11.12 of this Agreement.

(c) NTD shall, upon the ISO's request, make available to the ISO any and all information within NTD's custody or control that is necessary for the ISO to perform its responsibilities and obligations or enforce its rights under this Agreement, provided that such information shall be shall be made available to the ISO only to the extent permitted under the ISO Information Policy and subject to any applicable restrictions in the ISO Information Policy, including provisions of the ISO Information Policy governing the confidential treatment of non-public information, and provided further that any ISO employee shall comply with such ISO Information Policy and any applicable standards of conduct to prevent the disclosure of such information to any unauthorized Person. Any dispute concerning what information is necessary for the ISO to perform its responsibilities and obligations or enforce its right under this Agreement shall be subject to dispute resolution under Section 11.12 of this Agreement.

(d) If, in order to properly prepare its Tax Returns, other documents or reports required to be filed with Governmental Authorities or its financial statements or to fulfill its obligations hereunder, it is necessary that the ISO or NTD be furnished with additional information, documents or records not referred to specifically in this Agreement, and such information, documents or records are in the possession or control of the other Party, the other Party shall use its best efforts to furnish or make available such information, documents or records (or copies thereof) at the ISO's or NTD's request, cost and expense. Any information obtained by the ISO or NTD in accordance with this paragraph shall be subject to any applicable provisions of the ISO Information Policy

(e) Notwithstanding anything to the contrary contained in this Section 11.07:

(i) no Party shall be obligated by this Section 11.07 to undertake studies or analyses that such Party would not otherwise be required to undertake or to incur costs outside the normal course of business to obtain information that is not in such Party's custody or control at the time a request for information is made pursuant to this Section 11.07;

(ii) if NTD and the ISO are in an adversarial relationship in litigation or arbitration (other than with respect to litigation or arbitration to enforce this Section 11.07), the furnishing of information, documents or records by the ISO or NTD in accordance with this Section 11.07 shall be subject to applicable rules relating to discovery;

(iii) no Party shall be compelled to provide any privileged and/or confidential documents or information that are attorney work product or subject to the attorney/client privilege; and

(iv) no Party shall be required to take any action that impairs or diminishes its rights under this Agreement or otherwise lessens the value of this Agreement to such Party.

11.08 **Business Day.** Notwithstanding anything herein to the contrary, if the date on which any payment is to be made pursuant to this Agreement is not a Business Day, the payment otherwise payable on such date shall be payable on the next succeeding Business Day with the same force and effect as if made on such scheduled date and, provided such payment is made on such succeeding Business Day, no interest shall accrue on the amount of such payment from and after such scheduled date to the time of such payment on such next succeeding Business Day.

11.09 **Governing Law.** This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware including all matters of construction, validity and performance without regard to the conflicts-of-laws provisions thereof.

11.10 **Consent to Service of Process.** Each of the Parties hereby consents to service of process by registered mail, Federal Express or similar courier at the address to which notices to it are to be given, it being agreed that service in such manner shall constitute valid service upon such Party or its successors or assigns in connection with any such action or proceeding; provided, however, that nothing in this Section 11.10 shall affect the right of any Party or its successors and permitted assigns to serve legal process in any other manner permitted by applicable Law or affect the right of any such Party or its successors and assigns to bring any action or proceeding against the other Party or its property in the courts of other jurisdictions.

11.11 **Force Majeure.** A Party shall not be considered to be in default or breach under this Agreement, and shall be excused from performance or liability for damages to any other party, if and to the extent it shall be delayed in or prevented from performing or carrying out any of the provisions of this Agreement, except the obligation to pay any amount when due, in consequence of any act of God, labor disturbance, failure of contractors or suppliers of materials (not including as a result of non-payment), act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm, flood, ice, explosion, breakage or accident to machinery or equipment or by any other cause or causes (not including a lack of funds or other financial causes) beyond such Party's reasonable control, including any order, regulation, or restriction imposed by governmental, military or lawfully established civilian authorities. A Party claiming a force majeure event shall use reasonable diligence to remove the condition that prevents performance, except that the settlement of any labor disturbance shall be in the sole judgment of the affected Party.

11.12 **Dispute Resolution.** The Parties agree that any dispute arising under this Agreement shall be the subject of good-faith negotiations among the Parties and affected market participants, if any. Each Party and each affected market participant shall designate one or more representatives with the authority to negotiate the matter in dispute to participate in such negotiations. The Parties and affected market participants shall engage in such good-faith negotiations for a period of not less than 60 calendar days. Notwithstanding the foregoing, any dispute arising under this Agreement may be submitted to arbitration or any other form of alternative dispute resolution upon the agreement of the Parties and all affected market participants to participate in such an alternative dispute resolution process. Nothing in this Agreement shall, however, restrict a Party's right to file a complaint with FERC under the relevant provisions of the Federal Power Act.

11.13 **Invalid Provisions.** If any provision of this Agreement is held to be illegal, invalid or unenforceable under any present or future Law, and if the rights or obligations of any Party under this Agreement shall not be materially and adversely affected thereby, (a) such provision shall be fully severable, (b) this Agreement shall be construed and enforced as if such illegal, invalid or unenforceable provision had never comprised a part hereof, (c) the remaining provisions of this Agreement shall remain in full force and effect and shall not be affected by the illegal, invalid or unenforceable provision or by its severance herefrom, and (d) the court holding such provision to be illegal, invalid or unenforceable may in lieu of such provision add as a part of this Agreement a legal, valid and enforceable provision as similar in terms to such illegal, invalid or unenforceable provision as it deems appropriate.

11.14 **Headings and Table of Contents.** The headings of the sections of this Agreement and the Table of Contents are inserted for purposes of convenience only and shall not be construed to affect the meaning or construction of any of the provisions hereof.

11.15 **Liabilities; No Joint Venture.**

(a) The obligations and liabilities of the ISO and NTD arising out of or in connection with this Agreement shall be several, and not joint, and each Party shall be responsible for its own debts, including Taxes. No Party shall have the right or power to bind any other Party to any agreement without the prior written consent of such other Party. The Parties do not intend by this Agreement to create nor does this Agreement constitute a joint venture, association, partnership, corporation or an entity taxable as a corporation or otherwise. No express or implied term, provision or condition of this Agreement shall be deemed to constitute the parties as partners or joint venturers.

(b) To the extent any Party has claims against the other Party, such Party may only look to the assets of the other Party for the enforcement of such claims and may not seek to enforce any claims against the directors, members, officers, employees, affiliates, or agents of such other Party who, each Party acknowledges and agrees, have no liability, personal or otherwise, by reason of their status as directors, members, officers, employees, affiliates, or agents of that Party, with the exception of fraud or willful misconduct.

11.16 **Counterparts.** This Agreement may be executed in any number of counterparts, each of which shall be deemed an original, but all of which together shall constitute but one and the same instrument. The parties hereto agree that any document or signature delivered by facsimile transmission shall be deemed an original executed document for all purposes hereof.

11.17 **Effective Date.**

This Agreement shall become effective on the date of execution (the “Effective Date”).

IN WITNESS WHEREOF, this Agreement has been duly executed and delivered by the duly authorized officer of each Party as of the date written below.

For ISO New England Inc.

Name:______________________________________

Title:_______________________________________

Date:_______________________________________

For [NTD]

Name:______________________________________

Title:_______________________________________

Date:_______________________________________

Schedule 1.01

Schedule of Definitions

Acquired Transmission Facilities. Any transmission facility acquired within the New England Control Area by NTD after the Operations Date that meets the classification standards set forth in Section 2.02(a).

Additional Term. "Additional Term" shall have the meaning ascribed thereto in Section 10.01(a) of this Agreement.

Affiliate. Any person or entity which controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" shall mean the possession, directly or indirectly and whether acting alone or in conjunction with others, of the authority to direct the management or policies of a person or entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

Agreement. This Operating Agreement between the ISO and NTD, as it may be amended from time to time.

Ancillary Service. Those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the transmission system in accordance with Good Utility Practice.

Approved Outages. "Approved Outages" shall have the meaning ascribed thereto in Market Rule 1 of the ISO Tariff.

Best's. The A.M. Best Company.

Business Day. Any day other than a Saturday or Sunday or an ISO holiday, as posted by the ISO on its website.

Commercially Reasonable Efforts. A level of effort which, in the exercise of prudent judgment in the light of facts or circumstances known or which should reasonably be known at the time a decision is made, can be expected by a reasonable person to accomplish the desired result in a manner consistent with Good Utility Practice and which takes the performing party's interests into consideration.

"Commercially Reasonable Efforts" will not be deemed to require a Person to undertake unreasonable measures or measures that have a significant adverse economic affect on such Person, including the payment of sums in excess of amounts that would be expended in the ordinary course of business for the accomplishment of the stated purpose.

Commission. The Federal Energy Regulatory Commission.

Control Area. An electric power system or combination of electric power systems, bounded by metering, to which a common automatic generation control scheme is applied in order to:

(a) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and applicable NERC/NPCC Requirements; and

(d) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Coordination Agreement. An agreement between the ISO and the operator(s) of one or more neighboring Control Areas addressing issues including interchange scheduling, operational arrangements, emergency procedures, energy for emergency and reliability needs, the exchange of information among Control Areas, and other aspects of the coordinated operation of the Control Areas.

Disbursement Agreement. The Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Effective Date. “Effective Date” shall have the meaning ascribed thereto in Section 11.18(a) of this Agreement.

Elective Transmission Upgrade. A Transmission Upgrade constructed by any Person which is not required to be constructed pursuant to any applicable requirement of this Agreement, but which may be subject to applicable requirements set forth in the ISO OATT and this Agreement.

Elective Transmission Upgrade Applicant. "Elective Transmission Upgrade Applicant" shall have the meaning ascribed thereto in Section 2.05 of this Agreement.

Environment. Soil, land surface or subsurface strata, surface waters (including navigable waters, ocean waters, streams, ponds, drainage basins, and wetlands), groundwaters, drinking water supply, stream sediments, ambient air (including indoor air), plant and animal life, and any other environmental medium or natural resource.

Environmental Damages. "Environmental Damages" shall mean any cost, damages, expense, liability, obligation or other responsibility arising from or under Environmental Law consisting of or relating to:

(a) any environmental matters or conditions (including on-site or off-site contamination, occupational safety and health, and regulation of chemical substances or products);

(b) fines, penalties, judgments, awards, settlements, legal or administrative proceedings, damages, losses, claims, demands and response, investigative, remedial or inspection costs and expenses arising under Environmental Law;

(c) financial responsibility under Environmental Law for cleanup costs or corrective action, including any investigation, cleanup, removal, containment or other remediation or response actions ("Cleanup") required by applicable Environmental Law (whether or not such Cleanup has been required or requested by any Governmental Authority or any other Person) and for any natural resource damages; or

(d) any other compliance, corrective, investigative, or remedial measures required under Environmental Law.

Environmental Laws. Any Law now or hereafter in effect and as amended, and any judicial or administrative interpretation thereof, including any judicial or administrative order, consent decree or judgment, relating to pollution or protection of the Environment, health or safety or to the use, handling, transportation, treatment, storage, disposal, release or discharge of Hazardous Materials.

Excluded Assets. "Excluded Assets" shall have the meaning ascribed thereto in Section 2.04 of this Agreement.

Existing Operating Procedures. "Existing Operating Procedures" shall have the meaning ascribed thereto in Section 3.02(d) of this Agreement.

External Transactions. Interchange transactions between the New England Transmission System and neighboring Control Areas.

FACTS. Flexible AC Transmission Systems.

FERC. The Federal Energy Regulatory Commission.

Final Order. An order issued by a Governmental Authority in a proceeding after all opportunities for rehearing are exhausted (whether or not any appeal thereof is pending) that has not been revised, stayed, enjoined, set aside, annulled or suspended, with respect to which any required waiting period has expired, and as to which all conditions to effectiveness prescribed therein or otherwise by law, regulation or order have been satisfied.

Financial Assurances. "Financial Assurances" shall have the meaning ascribed thereto in Section 3.10(b) of this Agreement.

FPA. The Federal Power Act.

FTR. A Financial Transmission Right, as defined in the ISO OATT.

Generally Accepted Accounting Principles. The widely accepted set of rules, conventions, standards, and procedures for reporting financial information, as established by the Financial Accounting Standards Board.

Generating Unit. A device for the production of electricity.

Good Utility Practice. Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority. The government of any nation, state or other political subdivision thereof, including any entity exercising executive, military, legislative, judicial, regulatory, or administrative functions of or pertaining to a government, not including NTD or the ISO.

Hazardous Materials. Any waste or other substance that is listed, defined, designated, or classified as, or otherwise determined to be, hazardous, radioactive, or toxic or a pollutant or a contaminant under or pursuant to any Environmental Law, including any admixture or solution thereof, and specifically including petroleum and all derivatives thereof or synthetic substitutes therefor and asbestos or asbestos-containing materials.

Indemnifiable Loss. "Indemnifiable Loss" shall have the meaning ascribed thereto in Section 9.01(a)(i) of this Agreement.

Indemnifying Party. "Indemnifying Party" shall have the meaning ascribed thereto in Section 9.02 of this Agreement.

Indemnitee. "Indemnitee" shall have the meaning ascribed thereto in Section 9.02 of this Agreement.

Interconnection Agreement. An agreement or agreements for the interconnection of any entity to the Transmission Facilities of NTD.

Interconnection Standard. The applicable interconnection standards set forth in the ISO OATT.

Invoiced Amount. "Invoiced Amount" shall have the meaning ascribed thereto in Section 3.10(a)(i) of the Agreement.

ISO. ISO New England Inc., the RTO for New England authorized by the Federal Energy Regulatory Commission to exercise the functions required pursuant to FERC's Order No. 2000 and FERC's corresponding regulations.

ISO Control Center. The primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO Information Policy. The information policy set forth in the ISO OATT.

ISO-NE. ISO New England Inc.

ISO OATT. The ISO Open Access Transmission Tariff, as in effect from time to time.

ISO Participants Agreement. The agreement among the ISO and stakeholder participants addressing, inter alia, the stakeholder process for the ISO.

ISO Planning Process. The process set forth in the ISO OATT, for the coordinated planning and expansion of the New England Transmission System with provision for the participation of all state regulatory authorities with jurisdiction over retail rates in the ISO region acceptable to those authorities, which process shall be subject to certain terms and conditions set forth in Schedule 3.09(a).

ISO System Plan. The "Regional System Plan" as defined in the ISO OATT.

ISO Tariff. The ISO Transmission, Markets and Services Tariff, as amended from time to time, on file with FERC.

Large Generating Facility. "Large Generating Facility" shall have the meaning ascribed thereto in the ISO OATT.

Law. Any federal, state, local or foreign statute, law, ordinance, regulation, rule, code, order, other requirement or rule of law.

Load Shedding. The systematic reduction of system demand by temporarily decreasing load.

Market Monitoring Unit. Any market monitoring unit established by the ISO, including any internal market monitoring unit of the ISO and any independent market monitoring unit of the ISO.

Market Participant Service Agreement. The agreement among the ISO and market participants addressing, inter alia, the requirements for participating in the New England Markets.

Market Rules. The rules describing how the New England Markets are administered.

Merchant Facility. A transmission facility constructed by an entity that assumes all market risks associated with the recovery of costs for the facility and whose costs are not recovered through traditional cost-of-service based rates, but instead are recovered either through negotiated agreements with customers or through market revenues.

NTD Category A Facilities. Those transmission facilities listed in Schedule 2.01(a) of the Agreement, as that list may be modified from time to time in accordance with the terms of this Agreement.

NTD Category B Facilities. Those transmission facilities listed in Schedule 2.01(b) of the Agreement, as that list may be modified from time to time in accordance with the terms of this Agreement.

NTD Local Area Facilities. "Local Area Facilities" shall have the meaning ascribed thereto in Section 2.01 of this Agreement.

NTD Local Restoration Plan. The restoration plan developed by NTD with respect to the Transmission Facilities.

NERC. The North American Electric Reliability Corporation.

NERC/NPCC Requirements. NPCC criteria, guides, and procedures, NERC reliability standards, and NERC operating policies and planning standards (until such time as they are replaced by NERC reliability standards) and any successor documents.

New England Control Area. The Control Area consisting of the interconnected electric power system or combination of electric power systems in the geographic region consisting of Vermont, New Hampshire, Maine, Massachusetts, Connecticut and Rhode Island.

New England Markets. Markets or programs (including congestion pricing and design and implementation of FTRs) for the purchase of energy, capacity, ancillary services, demand response services or other related products or services that are offered in the New England Control Area and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Commission.

New England Transmission System. The system comprised of the transmission facilities over which the ISO has operational jurisdiction, including the Transmission Facilities of NTD and the PTOs and the transmission system of any ITC formed pursuant to Attachment M to the ISO OATT.

New Transmission Facility. Any new transmission facility constructed within the New England Transmission System that is owned by NTD and that goes into commercial operation after the Effective Date. For the avoidance of doubt, in the case of a high-voltage, direct-current system, a New Transmission Facility shall include the transmission cable and the AC/DC converter stations as a single project.

Non-PTF. "Non-PTF" shall have the meaning ascribed thereto in the ISO OATT.

NPCC. The Northeast Power Coordinating Council.

OASIS. The Open Access Same-Time Information System of the ISO.

Operating Authority. "Operating Authority" shall have the meaning ascribed thereto in the TOA.

Operating Limits. The transfer limits for a transmission interface or generation facility.

Operating Procedures. The operating manuals, procedures, and protocols relating to the exercise of Operating Authority over the Transmission Facilities, as such manuals, procedures, and protocols may be modified from time to time in accordance with this Agreement.

Order 2000. FERC's Order No. 2000, *i.e.*, *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs. ¶31,089 (1999), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Stats. & Regs. ¶31,092 (2000), *petitions for review dismissed sub nom.*, Public Utility District No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 . (D.C. Cir. 2001).

Owed Amounts. "Owed Amounts" shall have the meaning ascribed thereto in Section 3.10(c) of this Agreement.

PARS. Phase angle regulators.

Participant. A participant in the New England Markets, Transmission Customer, or other entity that has entered into the ISO Participants Agreement.

Participants Committee. "Participants Committee" shall mean the stakeholder participants committee established pursuant to the ISO Participants Agreement.

Party or Parties. A "Party" shall mean the ISO or NTD, as the context requires. "Parties" shall mean NTD and the ISO.

Person. An individual, partnership, joint venture, corporation, business trust, limited liability company, trust, unincorporated organization, government or any department or agency thereof, or any other entity.

Planned Outages. "Planned Outages" shall have the meaning ascribed thereto in Market Rule 1 of the ISO Tariff.

Planning Procedures. The manuals, procedures and protocols for planning and expansion of the New England Transmission System, as such manuals, procedures, and protocols may be modified from time to time in accordance with this Agreement.

Prime Rate. The interest rate that commercial banks charge their most creditworthy borrowers, as published in the most recent Wall Street Journal in its "Monday Rates" column.

PTF. "PTF" shall have the meaning ascribed thereto in the ISO OATT.

PTO or Participating Transmission Owner. "PTO" shall have the meaning ascribed thereto in the opening paragraph of the TOA. "Participating Transmission Owner" shall have the same meaning as "PTO."

Rating Procedures. "Rating Procedures" shall have the meaning ascribed thereto in Section 3.02(d) of this Agreement.

Regulation and Frequency Response Service. An Ancillary Service as defined in the ISO OATT.

Reliability Authority. "Reliability Authority" shall have the meaning established by NERC, as such definition may change from time to time, provided such definition of Reliability Authority shall not be inconsistent with the specific rights and responsibilities of the ISO and the PTOs under this Agreement.

Restoration Plans. The System Restoration Plan, all PTO Local Restoration Plans and the NTD Local Restoration Plan.

RSP Project List. "RSP Project List" shall have the meaning ascribed thereto in the ISO OATT.

RTO. An independent entity that complies with Order No. 2000 and FERC's corresponding regulations (or an entity that complies with all such requirements except for the scope and regional configuration requirements), as determined by the FERC.

Schedule 22 Large Generator Interconnection Agreement. The interconnection agreement included in Schedule 22 of the ISO OATT.

Schedule 23 Small Generator Interconnection Agreement. The interconnection agreement included in Schedule 23 of the ISO OATT.

Scheduled Outages. "Scheduled Outages" shall have the meaning ascribed thereto in Market Rule 1 of the ISO Tariff.

Small Generating Facility. "Small Generating Facility" shall have the meaning ascribed thereto in the ISO OATT.

System Failure. Widespread telecommunication, hardware or software failure or systemic the ISO hardware or software failures that makes it impossible to receive or process bid information, dispatch resources, or exercise Operating Authority over the Transmission Facilities.

Tax or Taxes. All taxes, charges, fees, levies, penalties or other assessments imposed by any United States federal, state or local or foreign taxing authority, including, but not limited to, income, excise, property, sales, transfer, franchise, payroll, withholding, social security or other taxes, including any interest, penalties or additions attributable thereto.

Tax Return. Any return, report, information return, or other document (including any related or supporting information) required to be supplied to any authority with respect to Taxes.

Technical Committees. "Technical Committee" shall mean the stakeholder technical committees established pursuant to the ISO Participants Agreement.

Term. "Term" shall have the meaning ascribed thereto in Section 10.01 of this Agreement.

Third Party. "Third Party" shall have the meaning ascribed thereto in Section 9.01(a) of this Agreement.

Termination Date. "Termination Date" shall have the meaning ascribed thereto in Section 10.01(a) of this Agreement.

TOA. The Transmission Operating Agreement entered into by the ISO and the PTOs, effective February 1, 2005, as it may be amended from time to time.

Transmission Business. The business activities of each PTO related to the ownership, operation and maintenance of its Transmission Facilities.

Transmission Customer. Any entity taking Transmission Service under the ISO OATT.

Transmission Facilities. "Transmission Facilities" shall have the meaning ascribed thereto in Sections 2.01 and 2.02 of this Agreement.

Transmission Owner. "Transmission Owner" shall have the meaning ascribed thereto in the ISO OATT.

Transmission Provider. The ISO, in its capacity as the provider of transmission services over the Transmission Facilities of the PTOs in accordance with FERC's Order No. 2000 and FERC's RTO regulations.

Transmission Service. The non-discriminatory, open access, wholesale transmission services provided to customers by the ISO in accordance with the ISO OATT.

Transmission Upgrade. Any upgrade to an existing Transmission Facility owned by NTD that goes into commercial operation after the Effective Date.

VAR. Volt-Amps Reactive.

Schedule 2.01(a)

Schedule 2.01(b)

Schedule 11.01

NOTICES

ISO New England Inc.

President and Chief Executive Officer
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040
Telephone: (413) 535-4000
Facsimile: 413-535-4379

General Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040
Telephone: (413) 535-4000
Facsimile: (413) 535-4379

[NTD]

[Name
Address
Phone:
Fax:]

(d) Easements, if required, have been obtained or are on schedule consistent with the critical path schedule. Needed land purchases, if required, have been made or are on schedule consistent with the critical path schedule.

(e) Any contracts required to procure or construct a transmission project are in place consistent with the critical path schedule. The ISO's analysis may also take into account whether such contracts contain incentive and/or penalty clauses to encourage third parties to advance the delivery of material services to conform with the critical path schedule.

(f) Physical site work is on schedule consistent with the critical path schedule.

(g) The transmission project is in a designated National Interest Electric Transmission Corridor in accordance with Section 216 of the Federal Power Act, 16 U.S.C. §§ 824p.

III.12.6.4. Transmission Solutions Selected Through the Competitive Transmission Process.

For a transmission solution, which may consist of single or multiple proposals, selected through the competitive transmission process pursuant to Sections 4.3, ~~and~~ 4A, or Section 16 of Attachment K, such transmission solution, or relevant portion thereof, shall be considered in-service on the in-service date provided in the executed Selected Qualified Transmission Project Sponsor Agreement(s). The ISO shall use the in-service date in the executed Selected Qualified Transmission Project Sponsor Agreement(s) to determine whether to include the transmission solution, or relevant portion thereof, in the network model for the relevant Capacity Commitment Period. In the event that the selected transmission solution includes an upgrade(s) located on a PTO's existing transmission system where the Selected Qualified Transmission Project Sponsor is not the PTO for the existing system element(s) being upgraded, the process for establishing the in-service date and determining whether to include the upgrade(s) on the existing transmission system, or relevant portion thereof, in the network model for the Capacity Commitment Period shall be as described in Section III.12.6.1.

III.12.7. Resource Modeling Assumptions.

III.12.7.1. Proxy Units.

When the available resources are insufficient for the unconstrained New England Control Area to meet the resource adequacy planning criterion specified in Section III.12.1, proxy units shall be used as

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

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

(b) words denoting a gender include all genders;

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

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

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

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

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

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

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

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

Capacity Rationing Rule addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

~~**Capacity Scarcity Condition** is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.~~

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 of Market Rule 1.

Capacity Transfer Rights (CTRs) are calculated in accordance with Section III.13.7.5.4.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Zone is a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of Market Rule 1.

Capacity Zone Demand Curves are the demand curves used in the Forward Capacity Market for a Capacity Zone as specified in Sections III.13.2.2.2 and III.13.2.2.3.

Capital Funding Charge (CFC) is defined in Section IV.B.2 of the Tariff.

Incremental ARR Holder is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

Incremental Cost of Reliability Service is described in Section III.13.2.5.2.5.2 of Market Rule 1.

Independent Transmission Company (ITC) is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

Information Request is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Requirement means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

Interchange Transactions are transactions deemed to be effected under Market Rule 1.

Interconnecting Transmission Owner has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Agreement is the “Large Generator Interconnection Agreement”, the “Small Generator Interconnection Agreement”, or the “Elective Transmission Upgrade Interconnection Agreement” pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

Interconnection Customer has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Procedure is the “Large Generator Interconnection Procedures”, the “Small Generator Interconnection Procedures”, or the “Elective Transmission Upgrade Interconnection Procedures” pursuant to Schedules 22, 23, and 25 of the ISO OATT.

Interconnection Reliability Operating Limit (IROL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

Interconnection Request has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Interface Bid is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

Intermittent Power Resource is a wind, solar, run of river hydro or other renewable resource that does not have control over its net power output.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local Longer-Term Transmission Upgrade is any addition, modification, and/or upgrade to the New England Transmission System with a voltage level below 115 kV that is required in connection with the construction of a Longer-Term Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Section 16 of Attachment K to the OATT.

Local Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115 kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is a value calculated as described in Section III.12.2.1 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are costs that the ISO, with advisory input from the Reliability Committee, determines in accordance with Schedule 12C of the OATT shall not be included in the Pool-Supported PTF costs recoverable under this OATT, or in costs allocated to Regional Network Load according to Section 6 and Section 10 of Schedule 12. If there are any Localized Costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

Long Lead Time Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 and Schedule 25 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Longer-Term Proposal is a proposal submitted by a Qualified Transmission Project Sponsor pursuant to Section 16.4(b) of Attachment K to the OATT.

Longer-Term Transmission Solution is the Longer-Term Proposal identified as the preferred solution pursuant to Section 16 of Attachment K to the OATT.

Longer-Term Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT. The 2050 Transmission Study shall be the first Longer-Term Transmission Study.

Longer-Term Transmission Upgrade is an addition, modification, and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Longer-Term Transmission Upgrade PTF classification specified in the OATT and has been included in the Regional System Plan and RSP Project List as a Longer-Term Transmission Upgrade pursuant to the procedures described in Section 16 of Attachment K of the OATT.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset, or the consumption of a Dispatchable Asset Related Demand, is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Selected Qualified Transmission Project Sponsor is the Qualified Transmission Project Sponsor that proposed the Phase Two Solution, ~~or~~ Stage Two Solution, or Longer-Term Proposal that has been identified by the ISO as the preferred Phase Two Solution, ~~or~~ Stage Two Solution, or Longer-Term Transmission Solution.

Selected Qualified Transmission Project Sponsor Agreement is the agreement between the ISO and a Selected Qualified Transmission Project Sponsor. The Selected Qualified Transmission Project Sponsor Agreement is provided in Attachment P to the OATT.

Self-Schedule is the action of a Market Participant in committing its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Generator Asset or DARD would have been committed by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of the LMP. Demand Response Resources are not permitted to Self-Schedule.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that officer.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Sponsored Policy Resource is a New Capacity Resource that: receives a revenue source, other than revenues from ISO-administered markets, that is supported by a government-regulated rate, charge, or other regulated cost recovery mechanism, and; qualifies as a renewable, clean, zero carbon, or alternative energy resource under a renewable energy portfolio standard, clean energy standard, decarbonization or net-zero carbon standard, alternative energy portfolio standard, renewable energy goal, clean energy goal, or decarbonization or net-zero carbon goal enacted by federal or New England state statute, regulation, or executive or administrative order and as a result of which the resource receives the revenue source.

Stage One Proposal is a first round submission, as defined in ~~Sections~~ Section- 4A.~~5~~ 6 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.~~5~~ 8 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stakeholder-Requested Scenario is an Economic Study reference scenario that is described in Section 17.2(d) of Attachment K to the OATT.

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated

II.8 Billing and Invoicing; Accounting

II.8.1 Billing Procedure: Billings to Transmission Customers shall be made in accordance with this Section II.8, Schedules 18, 20 and 21 and the ISO New England Billing Policy, as applicable, and as may be supplemented by other billing procedures established pursuant to the TOA, a MTOA or an OTOA, as applicable.

II.8.2 Invoicing: Invoicing and payments are addressed in Attachments L1, L2, L3 and L4 to Section II of the Transmission, Markets and Services Tariff.

II.8.3 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) will be calculated in accordance with the methodology specified for interest on refunds in 18 C.F.R. §35.19a(a)(2)(iii) of the Commission's regulations. Interest on delinquent amounts will be calculated from the due date of the bill to the date of payment. Payments must be made by Electronic Funds Transfer or in immediately available funds.

II.8.4 Customer Default: In the event a Transmission Customer fails to make payment to the ISO for services under this OATT, other than under Schedules 18, 20 and 21 of this OATT, on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the ISO notifies the Transmission Customer to cure such failure, a default by the Transmission Customer will be deemed to exist under this OATT. Additional default provisions may apply as stated under the ISO New England Billing Policy, Exhibit ID to Section I of the Transmission, Markets and Services Tariff. Upon the occurrence of a default under this OATT, the ISO may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission approves such termination. In the event of a billing dispute between the ISO and the Transmission Customer, service will continue to be provided under a Service Agreement, and service termination proceedings will not be initiated as long as the Transmission Customer continues to make all payments invoiced by the ISO, including any disputed amounts, subject to resolution of such dispute in favor of such Transmission Customer. If the Transmission Customer fails to meet this requirement for continuation of service, then the ISO may provide notice to the Transmission Customer of the ISO's intention to suspend service in sixty days, in accordance with applicable Commission rules and regulations, and may proceed with such suspension.

II.8.5 Study Costs and Revenues: Transmission Owners shall (i) include in a separate operating revenue account or sub-account the revenues, if any, it receives from transmission service when making Third-Party Sales under Section II of the Tariff, and (ii) include in a separate transmission operating expense account or sub-account, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies which the Transmission Owner conducts or is subcontracted to conduct to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including Third-Party Sales, if any, under this OATT; and include in a separate operating revenue account or sub-account the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in a billing under the OATT.

II.8.6 Billing and Invoicing For Other Services and Transactions: Billings and invoicing for MTF Service, OTF Service, Local Service, Excepted Transactions, Grandfathered Intertie Agreements and MEPCO Grandfathered Transmission Service Agreements will be made pursuant to the terms and conditions of Schedules 18, 20 and 21 of this OATT, Excepted Transactions, Grandfathered Intertie Agreements or MEPCO Grandfathered Transmission Service Agreements under which service is provided.

II.8.7 Study Costs and Revenues of a Non-Incumbent Transmission Developer: Non-Incumbent Transmission Developers that are not otherwise party to the TOA shall include in a separate transmission operating expense account or sub-account, costs properly chargeable to expenses that are incurred to perform studies for Phase One Proposals and Phase Two Solutions, and Stage One Proposals and Stage Two Solutions pursuant to Attachment K of this OATT; and include in a separate operating revenue account or sub-account the revenues received for such studies when such amounts are separately stated and identified in a billing under the OATT.

II.8.8 Refund Obligations and Surcharge Rights Associated With Adjustments to Regional and Local Rates: The ISO, PTOs and Non-Incumbent Transmission Developers shall (consistent with Attachment L4 to this OATT) calculate refunds from the PTOs or Non-Incumbent Transmission Developers to the ISO and/or surcharges by the PTOs or Non-Incumbent Transmission Developers to the ISO, which will be passed through by the ISO to its Customers, attributable to adjustments associated with charges under Attachment F and Schedules 1, 8, 9, 13, ~~and~~ 14, and 14A of this OATT resulting from: (i) an audit of the regional rates; (ii) a Commission order, including, without limitation, orders approving settlements and letter orders or (iii) a billing correction. Any recalculations shall be made as though any such adjustments had been in effect as of the effective date of the required change(s), with interest to the extent required by applicable order or contract. The affected PTO(s) or Non-Incumbent Transmission Developer(s) shall individually calculate any refunds and/or surcharges associated with any changes in the rates under their respective Local Service Schedules or other rate recovery mechanisms, as appropriate. The ISO, PTOs and Non-Incumbent Transmission Developers shall, to the extent necessary, reasonably cooperate with each other in performing such recalculations. The refund obligations to the ISO associated with such adjustments to rates under Schedules 1, 8, 9 and 21 shall be several, and not joint, obligations and rights of the PTOs; the refund obligations to the ISO associated with such adjustments to rates under Schedules 13, ~~and~~ 14, and 14A shall be several, and not joint, obligations and rights of the Non-Incumbent Transmission Developers.

II.8.9 Creditworthiness: The creditworthiness procedures are specified in Attachments L1 through L4 to this OATT.

II.46 General

Additions to or modifications of the PTF may be required or permitted under this OATT, and be subject to related rights, obligations and procedures, in any of the following circumstances:

(a) An addition or modification may be required under Part II.B or Part II.C of the OATT in order to meet a new request for Regional Network Service or Through or Out Service. Where such an addition or modification is to be effected, the rights and obligations of the ISO, the PTOs and Transmission Customers shall be determined in accordance with the applicable provisions of Parts II.B and II.C of this OATT.

(b) An addition or modification may be required to permit the interconnection of a new or modified generating unit or the interconnection of an Elective Transmission Upgrade. Where such an addition or modification is to be effected, the rights and obligations of the ISO, the PTOs, and the Generator Owner or applicant for an Elective Transmission Upgrade, shall be determined in accordance with Section II.47 of this OATT and Schedules 11, 12, 22, 23, and 25 to this OATT.

(c) A Reliability Transmission Upgrade, Market Efficiency Transmission Upgrade, NEMA Upgrade, ~~or~~ Public Policy Transmission Upgrade, or Longer-Term Transmission Upgrade may be required or proposed pursuant to a Regional System Plan and Attachment K of this OATT. Where a Reliability Transmission Upgrade, Market Efficiency Transmission Upgrade, NEMA Upgrade, ~~or~~ Public Policy Transmission Upgrade or Longer-Term Transmission Upgrade is to be effected, the rights and obligations of the ISO, the PTOs, Non-Incumbent Transmission Developers, and Transmission Customers shall be determined in accordance with the TOA, the NTDOA, Schedule 12 and Attachment K, as applicable.

(d) Consistent with reliability and safety standards, Transmission Owners, and operators of affected Local Control Centers in New England Control Area and the ISO will coordinate scheduled generation and transmission facility outages so as to minimize, to the extent practicable, Congestion Costs and Local Second Contingency Protection Resource NCPC Charges (as calculated pursuant to Market Rule 1) in accordance with the TOA, MTOA and applicable ISO New England Operating Procedures. The ISO shall provide Transmission

Owners and the operators of the affected Local Control Centers with such information as is necessary to enable them to perform this function. Any information provided to Transmission Owners and the operators of the affected Local Control Centers pursuant to this provision will be subject to all the applicable requirements of the Commission's Order 889.

These provisions for PTF additions and modifications are not intended to be exclusive. Nothing in this OATT is intended to preclude any entity from identifying and constructing Elective Transmission Upgrades on a merchant or other basis, so long as it obtains all required legal rights and approvals and satisfies applicable ISO and affected Transmission Owner requirements relating to such facilities.

An addition or modification under the TOA which constitutes PTF under the OATT shall become part of the PTF and shall be fully subject to this OATT, whether or not all or any part of the costs of the addition or modification are included in Pool Supported PTF costs. The transmission priorities, if any, with respect to the use of the addition or modification as among the owner and supporters of the addition or modification and other Transmission Customers shall be determined under Parts II.A to II.D, inclusive, of this OATT.

To the extent that a Generator Owner is responsible for the costs of a Generator Interconnection Related Upgrade or Elective Transmission Upgrade, or an entity other than a Generator Owner is responsible for costs of any other system upgrade, the Generator Owner or entity which supports part or all of the costs of the addition or modification shall be entitled to a share of any associated Incremental ARRs equivalent to the share of the total costs of such upgrade which it supports, as assigned and allocated in accordance with Appendix C of Market Rule 1. Any incremental FTRs resulting from Generator Interconnection Related Upgrades or other upgrades shall be auctioned along with other FTRs in accordance with Section 7 of Market Rule 1.

If issues of cost allocation arise with respect to the recovery of any of the costs provided for in this Part II.G of this OATT, or in Schedules 9, 11, 12, 13, ~~or~~ 14, or 14A to this OATT, such issues shall be subject to determination by the Commission in the appropriate proceeding.

II.49 Definition of PTF

PTF or Pool Transmission Facilities are the transmission facilities owned by PTOs, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the TOA, rated 69 kV or above required to allow energy from significant power sources to move freely on the New England Transmission System, and include:

1. All transmission lines and associated facilities owned by PTOs rated 69 kV and above, except for lines and associated facilities that (i) were not built as Public Policy Transmission Upgrades or Longer-Term Transmission Upgrades and (ii) contribute little or no parallel capability to the PTF. The following do not constitute PTF:

   (a) Unless they were built as part of a Public Policy Transmission Upgrade or a Longer-Term Transmission Upgrade,

      i. Those lines and associated facilities which are required to serve local load only,

      ii. Generator leads, which are defined as radial transmission from a generation bus to the nearest point on the PTF; or

      iii. Lines that are normally operated open.

   (b) Lines and associated facilities that are classified as MTF or OTF.

2. All Public Policy Transmission Upgrades and Longer-Term Transmission Upgrades that comprise transmission lines rated 115 kV or above, and associated facilities rated 115 kV or above, owned by PTOs, and identified pursuant to Attachment K to the OATT shall constitute PTF.

3. Parallel linkages in network stations owned by PTOs (including substation facilities such as transformers, circuit breakers and associated equipment) interconnecting the lines which constitute PTF.

4. If a PTOs with significant generation in its transmission and distribution system (initially 25 MW) is connected to the New England Transmission System and none of the transmission

facilities owned by the PTO qualify to be included in PTF as defined in (1), (2) and (3) above, then such PTO's connection to PTF will constitute PTF if both of the following requirements are met for this connection:

(a) The connection is rated 69 kV or above.

(b) The connection is the principal transmission link between the PTO and the remainder of the PTF network.

5. Rights of way and land owned by PTOs required for the installation of facilities that constitute PTF under (1), (2), (3) or (4) above.

The ISO shall review at least annually the status of transmission lines and associated facilities and determine whether such facilities constitute PTF and shall prepare and keep current a schedule or catalogue of PTF facilities.

The following examples indicate the intent of the above definitions:

Unless they were built as part of a Public Policy Transmission Upgrade or Longer-Term Transmission Upgrade, radial tap lines to local load are excluded.

Lines which loop, from two geographically separate points on the PTF, the supply to a load bus from the PTF are included.

Lines which loop, from two geographically separate points on the PTF, the connections between a generator bus and the PTF are included.

Radial connections or connections from a generating station to a single substation or switching station on the PTF are excluded, unless the requirements of paragraph (2) or (4) above are met.

Transmission facilities owned or supported by a Related Person of a PTO which are rated 69 kV or above and are required to allow Energy from significant power sources to move freely on the New England Transmission System shall also constitute PTF provided (i) such Related Person files with the ISO its consent to such treatment; and (ii) the ISO determines that treatment of the facilities as PTF will facilitate accomplishment of the ISO's objectives. If such facilities constitute PTF pursuant to this paragraph, they shall be treated as "owned" or "supported," as applicable, by a PTO for purposes of this OATT and the other provisions of the TOA, including the ability to include the cost associated with such PTF and any Transmission Support Expenses for support of PTF made by its Related Person in that PTO's Annual Transmission Revenue Requirements, pursuant to Attachment F of the OATT.

Of those transmission facilities that are upgrades, modifications or additions, on and after January 1, 2004, to the transmission system administered by the ISO under the Interim Independent System Operator Agreement, or to the New England Transmission System on or after the Operations Date, only those that: (i) are rated 115kV or above, and (ii) otherwise meet the non-voltage criteria specified in Section II.49 shall be classified as PTF. Those transmission facilities that were PTF pursuant to the Restated NEPOOL Agreement on December 31, 2003, and any upgrades to such facilities that meet the criteria specified in Section II.49, shall remain classified as PTF for all purposes under this Tariff.

SCHEDULE 14A

RECOVERY OF LONGER-TERM TRANSMISSION UPGRADE COSTS BY NON-INCUMBENT TRANSMISSION DEVELOPERS

1. Applicability

1.1 Use by Non-Incumbent Transmission Developers

This schedule is to be utilized by Non-Incumbent Transmission Developers that: (i) are not also Participating Transmission Owners, and (ii) are Qualified Transmission Project Sponsors. This schedule is designed to enable the recovery of all prudently incurred costs following the execution of the Selected Qualified Transmission Sponsor Agreement, to the extent permitted in Section 16 of Attachment K to this OATT, for Longer-Term Transmission Upgrades, and the recovery of "construction work in progress" costs stemming from a Longer-Term Transmission Upgrade.

1.2 Costs Recovered Under Schedule 14A May Not Also Be Recovered Through Another Schedule

Any costs recovered by the Non-Incumbent Transmission Developer under this Schedule 14A cannot also be recovered under another Schedule to this OATT.

1.3 Transfer of Unrecovered Costs Upon Execution of the Transmission Operating Agreement

Following the execution of the Transmission Operating Agreement by the Non-Incumbent Transmission Developer, any costs that are not already recovered under this Schedule 14A may be recovered under the appropriate cost recovery mechanism set forth in this OATT, as appropriate.

2. Section 205 Rate Filing; Invoicing

2.1 Section 205 Rate Filing

Prior to recovering any Longer-Term Transmission Upgrade costs and in accordance with Section 16 of Attachment K to this OATT, a Non-Incumbent Transmission Developer shall submit a filing with the Commission pursuant to Section 205 of the Federal Power Act requesting approval of the actual Longer-Term Transmission Upgrade costs and the period of time over which the costs are to be recovered. Upon approval by the Commission, such terms of recovery shall be included in discrete schedules to this Schedule 14A. The Non-Incumbent Transmission

Developer shall notify the ISO of the Commission-approved Longer-Term Transmission Upgrade costs and the applicable recovery period recognized in the Commission Order.

2.2 Invoicing and Collection by ISO

The ISO acts as counterparty for the billing and collection agent for Non-Incumbent Transmission Developers for recovery of their Commission-approved Longer-Term Transmission Upgrade costs, in accordance with Section 16 of Attachment K to this OATT. Upon notification from a Non-Incumbent Transmission Developer of the Commission Order approving costs for recovery, the ISO shall allocate and invoice costs consistent with the applicable cost allocation established in accordance with Section 16 of Attachment K to this OATT. The ISO shall disburse the monthly collected amounts to the Non-Incumbent Transmission Developer, as appropriate.

3. Construction Work in Progress Costs

3.1 Section 205 Rate Filing

In accordance with the terms of the Non-Incumbent Transmission Developer Operating Agreement, a Non-Incumbent Transmission Developer may submit filings to the Commission pursuant to Section 205 of the Federal Power Act for recovery of its “construction work in progress” costs associated with a Longer-Term Transmission Upgrade. Upon approval by the Commission, such terms of recovery shall be included in discrete schedules to this Schedule 14A.

ATTACHMENT K
REGIONAL SYSTEM PLANNING PROCESS

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APPENDIX 1 – ATTACHMENT K – LOCAL: LOCAL SYSTEM PLANNING PROCESS

APPENDIX 2 – LIST OF ENTITIES ENROLLED IN THE TRANSMISSION PLANNING REGION

APPENDIX 3 – LIST OF QUALIFIED TRANSMISSION PROJECT SPONSORS

1. Overview

This Attachment describes the regional system planning process conducted by the ISO, as well as the coordination with transmission-owning entities in, or other entities interconnected to, the New England Transmission System and neighboring systems to ensure the reliability of the New England Transmission System and compliance with national and regional planning standards, criteria and procedures, while accounting for market performance, economic, environmental, and other considerations, as may be agreed upon from time to time. The New England Transmission System is comprised of PTF, Non-PTF, OTF and MTF within the New England Control Area that is under the ISO's operational authority or control pursuant to the ISO Tariff and/or various transmission operating agreements. This Attachment describes the regional system planning process for the PTF conducted by the ISO, and local system planning process conducted by the PTOs, pursuant to their responsibilities defined in the Tariff, the various transmission operating agreements and this Attachment. Additional details regarding the regional system planning process are also provided in the ISO New England Planning Procedures and ISO New England Operating Procedures, which are available on the ISO's website.

The ISO shall conduct the regional system planning process for the PTF in coordination with the transmission-owning entities in, or other entities interconnected to, the New England Transmission System and neighboring systems, consistent with the rights and obligations defined in the Tariff, applicable transmission operating agreements and this Attachment. As described in this Attachment's Section 6 and Appendix 1, entitled "Attachment K -Local System Planning Process", the PTOs are responsible for the Local System Planning ("LSP") process for the Non-PTF in the New England Transmission System. As also described in Section 6, and pursuant to the Tariff and/or transmission operating agreements, the OTOs and MTOs are required to participate in the ISO's regional system planning process for reliability purposes and to perform and/or support studies of the impact of regional system planning projects on their respective OTF and MTF.

The regional system planning process described in this Attachment provides for the ISO to undertake assessments of the needs of the PTF system on a systemwide or specific area basis. These assessments shall be referred to as Needs Assessments, as described in Section 4.1 of this Attachment. The ISO shall incorporate market responses that have met the criteria specified in Sections 4.1(f) and 4A.3(b) of this Attachment into the Needs Assessments, Public Policy Transmission Studies or the Regional System Plan ("RSP"), described below. Where market responses incorporated into the Needs Assessments or Public

Policy Transmission Studies do not eliminate or address the needs identified by the ISO in Needs Assessments, Public Policy Transmission Studies or the RSP, the ISO shall develop or evaluate, pursuant to Sections 4.2(b), 4.3, or 4A of this Attachment, as applicable, regulated transmission solutions proposed in response to the needs identified by the ISO.

Pursuant to Sections 3 and 7 of this Attachment, the ISO shall develop the RSP for approval by the ISO Board of Directors following stakeholder input through the Planning Advisory Committee established pursuant to Section 2 of this Attachment. The RSP is a compilation of the regional system planning process activities conducted by the ISO. The RSP shall address needs of the PTF system determined by the ISO through Needs Assessments initiated and updated on an ongoing basis by the ISO to: (i) account for changes in the PTF system conditions; (ii) ensure reliability of the PTF system; (iii) comply with national and regional planning standards, criteria and procedures; and (iv) account for market performance, economic, environmental and other considerations as may be agreed upon from time to time.

As more fully described in Section 3 of this Attachment, the RSP shall identify:

(i) PTF system reliability and market efficiency needs,

(ii) the requirements and characteristics of the types of resources that may satisfy PTF system reliability and market efficiency needs to provide stakeholders an opportunity to develop and propose efficient market responses to meet the needs identified in Needs Assessments;

(iii) regulated transmission solutions to meet the needs identified in Needs Assessments where market responses do not address such needs or additional transmission infrastructure may be required to comply with national and regional planning standards, criteria and procedures or provide market efficiency benefits in accordance with Attachment N of this OATT; ~~and~~

(iv) those projects identified through the Public Policy procedures described in Section 4A of this Attachment K; and

(v) those projects identified through the longer-term transmission planning procedures described in Section 16 of this Attachment K.

In addition, the RSP shall also provide information on a broad variety of power system requirements that serves as input for reviewing the design of the markets and the overall economic performance of the system. The RSP shall also describe the coordination of the ISO's regional system plans with regional, local and inter-area planning activities.

Pursuant to Section 3.6 of this Attachment, the ISO shall also develop, maintain and post on its website a cumulative list reflecting the regulated transmission solutions proposed in response to Needs Assessments (the "RSP Project List"). The RSP Project List shall be a cumulative representation of the regional transmission planning expansion efforts ongoing in New England.

1.1 Enrollment

For purposes of participating as a transmission provider in the New England transmission planning region pursuant to this Attachment K, and distinct from Transmission Providers as defined in Section I of this Tariff, an entity chooses to enroll by executing (or having already executed) a: (i) transmission operating agreement with the ISO, or (ii) a Market Participant Service Agreement coupled with a written notification to the ISO that the entity desires to be a transmission provider in the New England region. Such enrollment in the transmission planning region is not necessary to participate in the Planning Advisory Committee, which is open to any entity as described in Section 2.3 of this Attachment K.

1.2 A List of Entities Enrolled in the Planning Region

A list of entities enrolled in the transmission planning region as transmission providers as described in Section 1.1. above, is included as Appendix 2 of this Attachment K.

2. Planning Advisory Committee

2.1 Establishment

A Planning Advisory Committee shall be established by the ISO to perform the functions set forth in Section 2.2 of this Attachment. It shall have a Chair and Secretary, who shall be appointed by the chief executive officer of the ISO or his or her designee. Before appointing an individual to the position of the Chair or Secretary, the ISO shall notify the Planning Advisory Committee of the proposed assignment and, consistent with its personnel practices, provide any other information about the individual reasonably requested by the Planning Advisory Committee. The chief executive officer of the ISO or his or her designee shall consider the input of the members of the Planning Advisory Committee in selecting, removing or replacing such officers. The Planning Advisory Committee shall be advisory only and shall have no formal voting protocol.

The ISO may form subcommittees that, at the discretion of the ISO, may report to the Planning Advisory Committee.

2.2 Role of Planning Advisory Committee

The Planning Advisory Committee may provide input and feedback to the ISO concerning the regional system planning process, including the development of and review of Needs Assessments, the conduct of Solutions Studies, the development of the RSP, and updates to the RSP Project List. Specifically, the Planning Advisory Committee serves to review and provide input and comment on: (i) the development of the RSP, (ii) assumptions for studies, (iii) the results of Needs Assessments, Solutions Studies, and competitive solutions developed pursuant to Section 4.3 of this Attachment, (iv) potential market responses to the needs identified by the ISO in a Needs Assessment or the RSP, (v) Cluster Enabling Transmission Upgrades Regional Planning Studies, (vi) the results of Public Policy Transmission Studies and competitive solutions developed pursuant to Section 4A of this Attachment, and (vii) Longer-Term Transmission Studies and competitive solutions developed pursuant to Section 16 of this Attachment. The Planning Advisory Committee, with the assistance of and in coordination with the ISO, serves also to identify and prioritize the Stakeholder-Requested Scenario and stakeholder-requested scenario sensitivities for Economic Studies to be performed by the ISO, and provides input and feedback to the ISO concerning the conduct of Economic Studies~~, and Public Policy Transmission Studies,~~ including the criteria and assumptions~~ for such studies~~. Based on input and feedback related to the regional system planning process provided by the Planning Advisory Committee to the ISO, the ISO shall consult with the appropriate NEPOOL technical committees, including but not limited to, the Markets, Reliability and Transmission Committees, on issues and concerns identified by the Planning Advisory Committee as requiring further investigation and consideration of potential changes to ISO New England Operating Documents.

2.3 Membership

There are no membership requirements to become part of the Planning Advisory Committee. Meetings are open to members of any entity, including State regulators or agencies and NESCOE, subject to the Critical Energy Infrastructure Information ("CEII") policy as further described in Section 2.4(d) of this Attachment. To be added to the Planning Advisory Committee email distribution list, an email address shall be provided to the Secretary of the Committee. Throughout this Attachment K, a member of the Planning Advisory Committee refers to any individual, whether they attend Planning Advisory Committee meetings or are included on the email distribution list.

2.4 Procedures

(a) Notice of Meetings

Prior to the beginning of each year, the ISO shall list on the ISO Calendar, which is available on the ISO's website, the proposed meeting dates for the Planning Advisory Committee for each month of the year. Prior to a Planning Advisory Committee meeting, the ISO shall provide notice to the Planning Advisory Committee by electronic email with the date, time, format for the meeting (i.e., in person or teleconference), and the purpose for the meeting.

(b) Frequency of Meetings

Meetings of the Planning Advisory Committee shall be held as frequently as necessary to serve the purposes stated in Section 2.2 of this Attachment and as further specified elsewhere in this Attachment, generally expected to be no less than four (4) times per year.

(c) Availability of Meeting Materials

The ISO shall post materials for Planning Advisory Committee meetings on the Planning Advisory Committee section on the ISO's website prior to meetings. The materials for the Planning Advisory Committee meetings shall be made available to the members of the Planning Advisory Committee subject to protections warranted by confidentiality requirements of the ISO New England Information Policy set forth in Attachment D of the ISO Tariff and Critical Energy Infrastructure Information ("CEII") policy as further described in Section 2.4(d) of this Attachment.

(d) Access to Planning-Related Materials that Contain CEII

CEII is defined as specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure (physical or virtual) that:

(i) Relates details about the production, generation, transportation, transmission, or distribution of energy;

(ii) Could be useful to a person in planning an attack on critical infrastructure;

(iii) Is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552; and

(iv) Does not simply give the location of critical infrastructure.

CEII pertains to existing and proposed system and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters. CEII does not include information that is otherwise publicly available. Simplified maps and general information on engineering, vulnerability, or design that relate to production, generation, transportation, transmission or distribution of energy shall not constitute CEII.

Planning-related materials determined to be CEII will be posted on the ISO's password-protected website. To obtain access to planning-related materials determined to be CEII, the entity seeking to obtain such access must contact the ISO's Customer Service department. Authorized Market Participants or their representatives, such as consultants, are bound by the ISO New England Information Policy and will be able to access CEII materials through the ISO's password-protected website. State and federal governmental agency employees and their consultants will be able to access such materials through the ISO's password-protected website upon submittal of a signed non-disclosure agreement, which is available on the ISO's website. Personnel of the ERO, NPCC, other regional transmission organizations or independent system operators, and transmission owners from neighboring regions will be able to access CEII materials pursuant to governing agreements, rules and protocols. All external requests by other persons for planning-related materials determined to be CEII shall be recorded and tracked by ISO's Customer Services staff. Such requestors will be able to obtain access to CEII documents filed with the Commission pursuant to the Commission's regulations governing access to CEII. To the extent a requestor seeks access to planning-related material that is not filed with the Commission, such requestor shall comply with the requirements provided in the CEII procedures of the ISO, available on the ISO's website, prior to receiving access to CEII information. Upon compliance with the ISO's CEII procedures, the ISO shall grant the requestor access to the planning-related CEII document through direct distribution or access to the ISO password-protected website.

2.5 Local System Planning Process

The LSP process described in Appendix 1 to this Attachment applies to the transmission system planning for the Non-PTF in the New England Transmission System. The PTOs will utilize interested members of the Planning Advisory Committee for advisory stakeholder input in the LSP process that will meet, as needed, at the conclusion of, or independent of, scheduled Planning Advisory Committee meetings. The LSP meeting agenda and meeting materials will be developed by representatives of the pertinent PTOs and PTO representatives will chair the LSP meeting. The ISO will post the LSP agenda and materials for LSP.

3. RSP: Principles, Scope, and Contents

3.1 Description of RSP

The ISO shall develop the RSP based on periodic comprehensive assessments (conducted not less than every third year) of the PTF systemwide needs to maintain the reliability of the New England Transmission System while accounting for market efficiency, economic, environmental, and other considerations, as agreed upon from time to time. The ISO shall update the RSP to reflect the results of ongoing Needs Assessments conducted pursuant to Section 4.1 of this Attachment. The RSP shall also account for projected improvements to the PTF that are needed to maintain system reliability in accordance with national and regional standards and the operation of efficient markets under a set of planning assumptions.

The RSP shall, among other things:

(i) describe, in a consolidated manner, the assessment of the PTF system needs, the results of such assessments, and the projected improvements;

(ii) provide the projected annual and peak demands for electric energy for a five-to ten-year horizon, the needs for resources over this period and how such resources are expected to be provided;

(iii) specify the physical characteristics of the physical solutions that can meet the needs defined in the Needs Assessments and include information on market responses that can address them; and

(iv) provide sufficient information to allow Market Participants to assess the quantity, general locations, operating characteristics and required availability criteria of the type of incremental supply or demand-side resources, or merchant transmission projects, that would satisfy the identified needs or that may serve to modify, offset or defer proposed regulated transmission upgrades.

The RSP shall also include a description of proposed regulated transmission solutions that, based on the Solutions Studies described in Section 4.2 of this Attachment and the competitive solution process described in Sections 4.3 and 16 of this Attachment, meets the needs identified in the Needs Assessments. To this end, as further described in Section 3.6 below, the ISO shall develop and maintain a RSP Project List, a cumulative listing of proposed regulated transmission solutions classified, to the extent known, as Reliability Transmission Upgrades, Market Efficiency Transmission Upgrades, Longer-Term Transmission Upgrades, and Public Policy Transmission Upgrades (which, for the foregoing types of upgrades, –may include the portions of Interregional Transmission Projects located within the New England Control Area) and of External Transmission Projects. The RSP shall also provide reasons for any new regulated transmission solutions or Transmission Upgrades included in the RSP Project List, any change in status of a regulated transmission solution or Transmission Upgrade in the RSP Project List, or for any removal of regulated transmission solutions or Transmission Upgrades from the RSP Project List that are known as of that time.

Each RSP shall be built upon the previous RSP.

3.2 Baseline of RSP

The RSP shall account for: (i) all projects that have met milestones, including market responses and regulated transmission solutions (e.g., planned demand-side projects, generation and transmission projects and Elective Transmission Upgrades) as determined by the ISO, in collaboration with the Planning Advisory Committee, pursuant to Sections 4.1, 4.2, 4.3, ~~and~~ 4A, and 16 of this Attachment; and (ii) the requirements for system operation and restoration services, not including the development of a system operations or restoration plan, which is outside the scope of the regional system planning process.

3.3 RSP Planning Horizon and Parameters

The RSP shall be based on a five-to ten-year planning horizon, and reflect five-to ten-year capacity and load forecasts.

The RSP shall conform to: Good Utility Practice; applicable Commission compliance requirements related to the regional system planning process; applicable reliability principles, guidelines, criteria, rules, procedures and standards of the ERO, NPCC, and any of their successors; planning criteria adopted and/or developed by the ISO; Transmission Owner criteria, rules, standards, guides and policies developed by the Transmission Owner for its facilities consistent with the ISO planning criteria, the applicable criteria of the ERO and NPCC; local transmission planning criteria; and the ISO New England Planning Procedures and ISO New England Operating Procedures, as they may be amended from time to time (collectively, the "Planning and Reliability Criteria").

The revisions to this Attachment K submitted to comply with FERC's Order No. 1000 shall not apply to any Proposed or Planned project included in an RSP approved by the ISO Board of Directors (or in an RSP Project List update) prior to the May 18, 2015 effective date of the Order No. 1000 compliance filing of the ISO and the PTOs, unless the ISO is re-evaluating the solution design for such project as of that effective date, or subsequently determines that the solution design for such project requires re-evaluation.

3.4 Other RSP Principles

The RSP shall be designed and implemented to: (i) avoid unnecessary duplication of facilities; (ii) identify facilities that are necessary to meet Planning and Reliability Criteria; (iii) avoid the imposition of unreasonable costs upon any Transmission Owner, Transmission Customer or other user of a transmission facility; (iv) take into account the legal and contractual rights and obligations of the Transmission Owners and the transmission-related legal and contractual rights and obligations of any other entity; (v) provide for coordination with existing transmission systems and with appropriate inter-area and local expansion plans; and (vi) properly coordinate with market responses, including, but not limited to generation, merchant transmission and demand-side responses.

3.5 Market Responses in RSP

Market responses shall include investments in resources (e.g., demand-side projects, generation and distributed generation) and Elective Transmission Upgrades and shall be evaluated by the ISO, in consultation with the Planning Advisory Committee, pursuant to Sections 4.1(f), 4A.3(b), and 7 of this Attachment.

In developing the RSP, the ISO shall account for market responses: (i) proposed by Market Participants as addressing needs (and any critical time constraints for addressing such needs) identified in an RSP, Needs Assessment, or Public Policy Transmission Study; and (ii) that have proved to be viable by meeting the criteria specified in Section 4.1(f) or 4A.3(b) of this Attachment, as applicable.

Specifically, market responses that are identified to the ISO and are determined by the ISO, in consultation with the Planning Advisory Committee, to be sufficient to alleviate the need for a particular regulated transmission solution or Transmission Upgrade, based on the criteria specified in the pertinent Needs Assessment or RSP, and are judged by the ISO to be achievable within the required time period, shall be reflected in the next RSP and/or in a new or updated Needs Assessment. That particular regulated transmission solution or Transmission Upgrade may continue to be included in the appropriate category on the RSP Project List (as described in Section 3.6 below), subject to the ISO having the flexibility to indicate that the project should proceed at a later date or it may be removed if it is determined to be no longer needed. If the market response does not fully address the defined needs, or if additional transmission infrastructure is required to facilitate the efficient operation of the market, the RSP shall also include that particular regulated transmission solution or Transmission Upgrade, subject to the ISO having the flexibility to indicate that the Transmission Upgrade or regulated transmission solution should proceed at a later date and be modified, if necessary.

3.6 The RSP Project List

(a) Elements of the RSP Project List

The RSP Project List shall identify regulated transmission solutions proposed in response to the needs identified in a RSP or Needs Assessments conducted pursuant to Section 4.1 of this Attachment, ~~and shall identify~~ Public Policy Transmission Upgrades identified pursuant to Section 4A of this Attachment, and Longer-Term Transmission Upgrades identified pursuant to Section 16 of this Attachment. The RSP Project List shall identify the proposed regulated transmission solutions separately as a Reliability Transmission Upgrade, a Market Efficiency Transmission Upgrade, ~~or~~ a Public Policy Transmission Upgrade, or a Longer-Term Transmission Upgrade.

With regard to Reliability Transmission Upgrades, ~~and~~ Market Efficiency Transmission Upgrades, Public Policy Transmission Upgrades, and Longer-Term Transmission Upgrades, the following subcategories will be utilized to indicate the status of each proposed regulated transmission solution in the evaluation process. These subcategories include: (i) Proposed; (ii) Planned; (iii) Under Construction; and (iv) In-Service. ~~A Public Policy Transmission Upgrade will be identified in the RSP Project List as (i) Proposed; (ii) Planned: (iii) Under Construction; or (iv) In-Service.~~

The regulated transmission solution subcategories are defined as follows:

(i) For purposes of Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades, "Proposed" shall include a regulated transmission solution that (a) has been proposed in response to a specific need identified by the ISO in a Needs Assessment or the RSP and (b) has been evaluated or further defined and developed in a Solutions Study, as specified in Section 4.2(a) of this Attachment, or in the competitive solutions process specified in Section 4.3 of this Attachment, such that there is significant analysis that supports a determination by the ISO, as communicated to the Planning Advisory Committee, that the proposed regulated transmission solution would likely meet the need identified by the ISO in a Needs Assessment or the RSP, but has not received approval by the ISO under Section I.3.9 of the Tariff.

For purposes of Public Policy Transmission Upgrades and Longer-Term Transmission Upgrades, "Proposed" means that the ISO has included the project in the RSP Project

List pursuant to the procedures described in Section 4A or 16 of this Attachment K, but that the project has not yet been approved by the ISO under Section I.3.9 of the Tariff.

(ii) "Planned" shall include a Transmission Upgrade that has met the requirements for a Proposed project and has been approved by the ISO under Section I.3.9 of the Tariff.

(iii) "Under Construction" shall include a Transmission Upgrade that has received the approvals required under the Tariff and engineering and construction is underway.

(iv) "In Service" shall include a Transmission Upgrade that has been placed in commercial operation.

The RSP Project List shall also list External Transmission Projects for which cost allocation and, if applicable, operating agreements have been accepted by the Commission, and indicate whether such External Transmission Projects are proposed, under construction or in service.

Each Reliability Transmission Upgrade and Market Efficiency Transmission Upgrade shall be cross-referenced to the specific systemwide or area needs identified in a Needs Assessment or RSP. Each proposed Public Policy Transmission Upgrade shall be cross-referenced in the RSP Project List to a specific Public Policy Transmission Study. Each proposed Longer-Term Transmission Upgrade shall be cross-referenced in the RSP Project List to a specific Longer-Term Transmission Study.

For completeness, the RSP Project List shall also include Elective Transmission Upgrades and transmission facilities (as determined under the ISO interconnection process specified in this OATT) to be built to accommodate new generation, and Elective Transmission Upgrades that have satisfied the requirements of this OATT.

An Interregional Transmission Project developed pursuant to Section 6.3 of this Attachment K may displace a regional Reliability Transmission Upgrade or Market

Efficiency Transmission Upgrade on the RSP Project List where the ISO has determined that the Interregional Transmission Project is a more efficient or cost-effective solution. In the case of an Interregional Transmission Project that could meet the needs met by a Public Policy Transmission Upgrade, the associated Public Policy Transmission Upgrade may be removed from the RSP Project List in the circumstances described, and using the procedures specified, in Section 4A of Attachment K.

(b) Periodic Updating of RSP Project List

The RSP Project List will be updated by the ISO periodically by adding, removing or revising regulated transmission solutions or Transmission Upgrades in consultation with the Planning Advisory Committee and, as appropriate, the Reliability Committee.

Updating of the RSP Project List shall be considered an update of the RSP to be reflected in the next RSP, as appropriate, pursuant to Section 3.1 of this Attachment.

(c) RSP Project List Updating Procedures and Criteria

As part of the periodic updating of the RSP Project List, the ISO: (i) shall modify (in accordance with the provisions of this Attachment) regulated transmission solutions or Transmission Upgrades to reflect changes to the PTF system configurations, including ongoing investments by Market Participants or other stakeholders; (ii) may add to and classify accordingly, regulated transmission solutions; (iii) may remove from the RSP Project List regulated transmission solutions or Transmission Upgrades previously identified in the RSP Project List if the ISO determines that the need for the proposed regulated transmission solution or the approved Transmission Upgrade no longer exists or is no longer feasible; and (iv) may remove from the RSP Project List regulated transmission solutions or Transmission Upgrades that have been displaced by an Interregional Transmission Project in the circumstances described in Section 3.6(a) of this Attachment. With regard to (iii) above, this may include ~~a~~the removal of a regulated transmission solution or Transmission Upgrade because a market response meeting the need reaches the maturity specified in Sections 4.1(f) or 4A.3(b) of this Attachment and has been determined, pursuant to Sections 4.1(f) or 4A.3(b) of this Attachment, to meet the need described in the pertinent Needs Assessment, Public Policy Transmission Study or RSP, as applicable. In doing so, the ISO shall consult with and consider the input from the Planning Advisory Committee and, as appropriate, the Reliability Committee. In addition, the ISO shall remove from the RSP Project List any Public Policy Transmission Upgrade if the ISO determines, with input from the Planning Advisory Committee, that the need to which the Public Policy Transmission Upgrade responds no longer exists. Furthermore, the ISO shall remove from the RSP Project List any Longer-Term Transmission Upgrade if requested to do so in a written NESCOE communication.

If a regulated transmission solution or Transmission Upgrade is removed from the RSP Project List by the ISO, the entity responsible for the construction of the regulated transmission solution or Transmission Upgrade shall be reimbursed for any costs prudently incurred or prudently committed to be incurred (plus a reasonable return on investment at existing Commission-approved ROE levels) in connection with the planning, designing, engineering, siting, permitting, procuring and other preparation for construction, and/or construction of the regulated transmission solution or Transmission Upgrade proposed for removal from the RSP Project List. The provisions of Schedule 12, Schedule 13, ~~and~~ Schedule 14, and Schedule 14A of this OATT shall apply to any cost reimbursement under this Section. Prior to finalizing the RSP, the ISO shall provide the Planning Advisory Committee with written information explaining the reasons for any removal under this Section.

(d) Posting of LSP Project Status

Each PTO will be individually responsible for publicly posting and updating the status of its respective LSP and the transmission projects arising therefrom on its company website. The ISO's posting of the RSP Project Lists will include links to each PTO's specific LSP posting to be provided to the ISO by the PTOs.

4. Procedures for the Conduct of Needs Assessments, Treatment of Market Responses and Evaluation of Regulated Transmission Solutions

4.1 Needs Assessments

The regional system planning process established in this Attachment K has ~~three~~ four different processes. Except as otherwise provided in Section 16 of this Attachment, ~~T~~the reliability planning process established in this Attachment K shall apply to all transmission solutions adopted to resolve a reliability need, ~~.~~ and ~~T~~the market efficiency planning process established in this Attachment K shall apply to all transmission solutions adopted to resolve a market efficiency need. The public policy planning process established in this Attachment K shall apply to all transmission solutions adopted to resolve a public policy need. The longer-term transmission planning procedures established in this Attachment K shall apply to all transmission solutions adopted to resolve a longer-term need, and may apply to a non-time-sensitive reliability or market-efficiency need to the extent identified by the ISO and combined with longer-term needs in a request for proposal(s) requested by NESCOE in accordance with Section 16.4(a) of this Attachment K.

As described further in Section 4.1(a) below, the planning process in Section 17 of this Attachment K shall be used to identify market efficiency issues and, along with Section 4.1(a), trigger market efficiency Needs Assessments. Market efficiency Needs Assessments shall be conducted pursuant to this Section 4.

For needs identified initially as reliability, market efficiency or public policy needs, the collateral benefits of potential solutions to those needs shall not change the planning process applicable to those identified needs; notwithstanding the foregoing, the ISO shall report its views as to whether a project or preferred solution may also satisfy identified reliability needs of the system as described in Section 4A.8 of this Attachment K.

Sections 4.1 through 4.3 of this Attachment are not applicable to the planning of Public Policy Transmission Upgrades, which is governed instead by Section 4A of this Attachment. Sections 4.1 through 4A of this Attachment are not applicable to the planning of Longer-Term Transmission Upgrades, which is governed instead by Section 16 of this Attachment.

On a regular and ongoing basis, the ISO, in coordination with the PTOs and the Planning Advisory Committee, shall conduct assessments (i.e., Needs Assessments) of the adequacy of the PTF system, as a whole or in part, to maintain the reliability of such facilities (i.e., reliability Needs Assessment) and the operation of efficient wholesale electric markets in New England (i.e., market efficiency Needs Assessment). A Needs Assessment shall analyze whether the PTF in the New England Transmission System: (i) meet applicable reliability standards; (ii) have adequate transfer capability to support local, regional, and inter-regional reliability; (iii) support the efficient operation of the wholesale electric markets; (iv) are sufficient to integrate new resources and loads on an aggregate or regional basis; or (v) otherwise examine various aspects of its performance and capability. A Needs Assessment shall also identify: (i) the location and nature of any potential problems with respect to the PTF and (ii) situations that significantly affect the reliable and efficient operation of the PTF along with any critical time constraints for addressing the needs of the PTF to facilitate the development of market responses and to initiate the pursuit of regulated transmission solutions.

(a) Triggers for Needs Assessments

The ISO, in coordination with the PTOs and the Planning Advisory Committee, shall perform Needs Assessments, inter alia, as needed to:

- Assess compliance with reliability standards and criteria (including those established by the ISO, NERC, and NPCC) consistent with the long term needs of the system.
- Assess the adequacy of the transmission system capability, such as transfer capability, to support local, regional and interregional reliability.
- Assess the efficient operation of the wholesale electric market. (See Attachment N regarding the identification of market efficiency upgrades).
- Assess sufficiency of the system to integrate new resources and loads on an aggregate or regional basis as needed for the reliable and efficient operation of the system.
- Analyze various aspects of system performance. (Including but not limited to, transient network analysis, small signal analysis, electromagnetic transients program analysis, or delta P analysis).
- Examine short circuit performance of the system.
- Assess the ability to efficiently operate and maintain the transmission system.
- Address market efficiency issues.

- Address system performance in consideration of de-list bids and cleared demand bids consistent with sections 4.1(c) and 4.1(f) of Attachment K.

- Address system performance as otherwise deemed appropriate by the ISO.

(b) [RESERVED]

(c) Conduct of a Needs Assessment for Rejected De-List Bids

(i) In the case of a rejected Static De-List Bid or Dynamic De-List Bid, the ISO may as warranted, with advisory input from the Reliability Committee, examine the unavailability of the resource(s) with the rejected bid as a sensitivity in a Needs Assessment, or examine the unavailability of the resource(s) in the base representation in a Needs Assessment. The ISO may as warranted, with advisory input from the Reliability Committee, initiate a Needs Assessment for the purpose of modeling rejected Static De-List Bids or Dynamic De-List Bids where the ISO believes that the initiation of such a study is warranted.

(ii) Prior to the start of each New Capacity Show of Interest Submission Window, the ISO shall present to the Reliability Committee the status of any prior rejected Dynamic De-List Bids, Static De-List Bids, Permanent De-List Bids or Retirement De-List Bids being studied in the regional system planning process.

(d) Notice of Initiation of Needs Assessments

Prior to its commencement, the ISO shall provide notice of the initiation of a Needs Assessment to the Planning Advisory Committee consistent with Section 2 of this Attachment.

(e) Preparation of Needs Assessment

Needs Assessments may examine resource adequacy, transmission adequacy, projected congestion levels and other relevant factors as may be agreed upon from time to time. Needs Assessments shall also consider the views, if any, of the Planning Advisory Committee, State regulators or agencies, NESCOE, the Market Advisor to the ISO Board of Directors, and the ISO Board of Directors. A corresponding assessment shall be performed by the PTOs to identify any needs relating to the Non-PTF transmission facilities (of whatever voltage) that could affect the provision of Regional Transmission Service over the PTF.

(f) Treatment of Market Responses in Needs Assessments

The ISO shall reflect proposed market responses in the regional system planning process. Market responses may include, but are not limited to, resources (e.g., demand-side projects and distributed generation), and Elective Transmission Upgrades.

In performing Needs Assessments, the ISO shall rely on certain resources to prevent the identification of system needs. Specifically, the ISO shall incorporate or update information regarding future resources, with the exception of imports across external tie lines, in Needs Assessments that have been proposed and (i) have cleared in a Forward Capacity Auction pursuant to Market Rule 1 of the ISO Tariff, (ii) have been selected in, and are contractually bound by, a state-sponsored request for proposals, (iii) have a financially binding obligation pursuant to a contract, or (iv) have been forecast in the ISO's Forecast Report of Capacity, Energy, Loads and Transmission. The ISO shall also incorporate or update information regarding all existing resources, with the exception of imports across external tie lines, in Needs Assessments. Imports across future or existing external tie lines will not be relied upon unless such imports (i) have a Capacity Supply Obligation corresponding to the year of study, (ii) have been selected in, and are contractually bound by, a state-sponsored request for proposals, (iii) have a financially binding obligation pursuant to a contract, or (iv) may be represented by a minimum flow based on HQ Interconnection Capability Credits. The ISO will model out-of-service all submitted Retirement De-List Bids, submitted Permanent De-List Bids, and demand bids that have cleared in a substitution auction, and may model out-of-service rejected-for-reliability Static De-List Bids and rejected-for-reliability Dynamic De-List Bids from the most recent Forward Capacity Auction. With respect to having been selected in, and being contractually bound by a state-sponsored request for proposals, or having a financially binding obligation pursuant to a contract, demonstration of such contracts is accomplished through submittal for ISO review of an order or other similar authorization from the appropriate state regulatory agency, along with a copy of the contract, that together demonstrate the contractual requirements. These documents may be submitted by: the Project Sponsor; the state regulatory agency authorizing the contract; a transmission company that is a counterparty to the contract; or by a third-party organization representing the interests of the New England states regarding energy related issues, such as NESCOE. The ISO shall incorporate or update information regarding a proposed Elective Transmission Upgrade in a Needs Assessment at a time after the studies corresponding to the Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), a commercial operation date has been ascertained, and for which the certification has been accepted in accordance with Section III.12 of the Tariff. In the case where the Elective Transmission Upgrades are proposed in conjunction with the interconnection of a resource, these Elective Transmission Upgrades shall be considered at the same time as the proposed resource is considered in the Needs Assessment provided that the studies corresponding to the Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), a commercial operation date has been ascertained, and for which the certification has been accepted in accordance with Section III.12 of the Tariff.

(g) Needs Assessment Support

For the development of the Needs Assessments, the ISO will coordinate with the PTOs and the Planning Advisory Committee to support the ISO's performance of Needs Assessments. To facilitate this support, the ISO will post on its website the models, files, cases, contingencies, assumptions and other information used to perform Needs Assessments. The ISO may establish requirements that any PTO or member of the Planning Advisory Committee must satisfy in order to access certain information used to perform Needs Assessments, due to ISO New England Information Policy and CEII constraints. The ISO may ask PTOs or Planning Advisory Committee members with special expertise to provide technical support or perform studies required to assess one or more potential needs that will be considered in the Needs Assessments process. These entities will provide, and the ISO will post on its website, the models, files, cases, contingencies, assumptions and other information used by those entities to perform studies. The ISO will post the draft results of any such Needs Assessment studies on its website. The ISO will convene meetings open to any representative of an entity that is a member of the Planning Advisory Committee to facilitate input on draft Needs Assessments studies and the inputs to those studies prior to the ISO's completion of a draft Needs Assessment report to be reviewed by the entire Planning Advisory Committee pursuant to Section 4.1(i) of this Attachment. All provisions of this subsection (g) relating to the provision and sharing of information shall be subject to the ISO-NE Information Policy.

(h) Input from the Planning Advisory Committee

Meetings of the Planning Advisory Committee shall be convened to identify additional considerations relating to a Needs Assessment that were not identified in support of initiating the assessment, and to provide input on the Needs Assessment's scope, assumptions and procedures, consistent with the responsibilities of the Planning Advisory Committee as set forth in Section 2.2 of this Attachment.

(i) Publication of Needs Assessment and Response Thereto

The ISO shall report the results of Needs Assessments to the Planning Advisory Committee, subject to CEII constraints. Needs Assessments containing CEII will be posted on the ISO's password-protected website consistent with Section 2.4(d) of this Attachment. Needs Assessments will identify high-level functional requirements and characteristics for regulated transmission solutions and market responses that can meet the needs described in the assessment. Where the ISO forecasts that a solution is needed to solve reliability criteria violations in three years or less from the completion of a Needs Assessment (unless the solution to the Needs Assessment will likely be a Market Efficiency Transmission Upgrade), and the requirements of Section 4.1(j) of this Attachment have been met or where there is only one Phase One Proposal submitted in response to a request for proposal issued under Sections 4.3(a) of this Attachment or only one proposed solution that is selected to move on as a Phase Two Solution, the ISO will evaluate the adequacy of proposed regulated solutions by performing Solutions Studies, as described in Section 4.2 of this Attachment. Where the solution to a Needs Assessment will likely be a Market Efficiency Transmission Upgrade, or where the forecast year of need for a solution that is likely to be a Reliability Transmission Upgrade is more than three years from the completion of a Needs Assessment, the ISO will conduct a solution process based on a two-stage competitive solution process, as described in Section 4.3 of this Attachment.

(j) Requirements for Use of Solutions Studies Rather than Competitive Solution Process for Projects Based on Year of Need

The following requirements must be met in order for the ISO to use Solutions Studies in the circumstances described in Section 4.1(i) based on the solution's year of need:

(i) The ISO shall separately identify and post on its website an explanation of the reliability criteria violations and system conditions that the region has a time-sensitive need to solve within three years of the completion of the relevant Needs Assessment. The explanation shall be in sufficient detail to allow stakeholders to understand the need and why it is time-sensitive.

(ii) In deciding whether to utilize Solutions Studies, such that the regulated transmission solution will be developed through a process led by the ISO and built by the PTO(s), the ISO shall:

(A) Provide to the Planning Advisory Committee and post on its website a full and supported written description explaining the decision to designate a PTO as the entity responsible for construction and ownership of the reliability project, including an explanation of other transmission or non-transmission options that the region considered but concluded would not sufficiently address the immediate reliability need, and the circumstances that generated the reliability need and an explanation of why that reliability need was not identified earlier.

(B) Provide a 15-day period during which comments from stakeholders on the posted description may be sent to the ISO, which comments will be posted on the website, as well.

(iii) The ISO shall maintain and post on its website a list of prior year designations of all projects in the limited category of transmission projects for which the PTO(s) was designated as the entity responsible for construction and ownership of the project following the performance of Solutions Studies. The list must include the project's need-by date and the date the PTO(s) actually energized the project, i.e., placed the project into service. The ISO shall file such list with the Commission as an informational filing in January of each calendar year covering the designations of the prior calendar year, when applicable.

4.2 Evaluation of Regulated Transmission Solutions in Solutions Studies, Where Competitive Solution Process of Section 4.3 Is Not Applicable

The procedures described in this Section 4.2 shall be utilized for the evaluation of regulated transmission solutions for reliability and market efficiency needs where the requirements of Sections 4.1(i) and/or (j) of this Attachment are satisfied. Otherwise, the procedures of Section 4.3 shall be utilized for that purpose.

(a) Evaluation and Development of Regulated Transmission Solutions in Solutions Studies for Market Efficiency Transmission Upgrades and Reliability Transmission Upgrades

In the case of Market Efficiency Transmission Upgrades and Reliability Transmission Upgrades, the ISO, in coordination with the proponents of regulated transmission solutions and other interested or affected stakeholders, shall conduct or participate in studies ("Solutions Studies") to evaluate whether proposed regulated transmission solutions meet the PTF system needs identified in Needs Assessments. The ISO, in coordination with affected stakeholders shall also identify regulated transmission projects for addressing the needs identified in Needs Assessments.

The ISO may form ISO-led targeted study groups to conduct Solutions Studies. Such study groups will include representatives of the proponents of regulated transmission solutions and other interested or affected stakeholders. Through this process, the ISO may identify the solutions for the region that offer the best combination of electrical performance, cost, future system expandability, and feasibility to meet a need identified in a Needs Assessment in the required time frame. These solutions may differ from a transmission solution proposed by a transmission owner.

Proponents of regulated transmission proposals in response to Needs Assessments shall also identify any LSP plans that require coordination with their regulated transmission proposals addressing the PTF system needs.

(b) Notice of Initiation of a Solutions Study

The ISO shall provide notice of the initiation and scope of a Solutions Study to the Planning Advisory Committee.

(c) Classification of Regulated Transmission Solutions as Market Efficiency Transmission Upgrades or Reliability Transmission Upgrades

As described in Section 3.1 and 3.6(a) of this Attachment, proposed regulated transmission solutions determined by the ISO, in consultation with the Planning Advisory Committee, to address needs identified in Needs Assessments shall be classified as a Reliability Transmission Upgrade and/or a Market Efficiency Transmission Upgrade pursuant to the standards set forth in Attachment N of this OATT.

(d) Evaluation Factors Used for Identification of the Preferred Solution

Factors to be considered during the evaluation process for identification of the preferred solution may include, but are not limited to, the following which are listed in no particular order:

- Installed cost;
- Life-cycle cost, including all costs associated with right of way acquisition, easements, and associated real estate;
- System performance;
- Cost cap or cost containment provisions;
- In-service date of the project or portion(s) thereof;
- Project constructability;
- Generation and transmission facility outages required during construction;
- Extreme contingency performance;
- Operational impacts;
- Incremental costs for potential resource retirements;
- Interface impacts;
- Future expandability;
- Consistency with Good Utility Practice;
- Potential siting/permitting issues or delays;
- Loss savings;
- Replacement of aging infrastructure;
- Environmental impact;
- Design standards; and
- Impact on NPCC Bulk Power System classification.

(e) Identification of the Preferred Solution and Inclusion of Results of Solutions Studies for Market Efficiency Transmission Upgrades and Reliability Transmission Upgrades in the RSP

The results of Solutions Studies related to Market Efficiency Transmission Upgrades and Reliability Transmission Upgrades will be reported to the Planning Advisory Committee. After receiving feedback from the Planning Advisory Committee, the ISO will identify the preferred solution. The ISO will inform the appropriate Transmission Owners in writing regarding the identification of the preferred solution.

Once identified, the preferred solution, as appropriate, will be reflected (with an overview of why the solution is preferred) in the RSP and/or its Project List, as it is updated from time to time in accordance with this Attachment. Where external impacts of regional projects are identified through coordination by the ISO with neighboring entities, those impacts will be identified in the RSP. Costs associated with such impacts will be addressed as set forth in Schedule 15.

(f) Cancellation of a Solutions Study

The ISO may cancel a Solutions Study at any time. Such cancellation may be due to new or different assumptions which may change or eliminate the identified needs. Any costs associated with Solutions Study development shall be recovered pursuant to Section 3.6(c) of this Attachment.

4.3 Competitive Solution Process for Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades

(a) Initiating the Competitive Solution Process

The ISO will publicly issue a request for proposal for which, pursuant to Section 4.1(i) of this Attachment, a competitive solution process will be utilized. The request for proposal will indicate that a Qualified Transmission Project Sponsor may submit an individual or joint Phase One Proposal(s) offering a solution that addresses the identified needs or address a subset of those needs. In the case where a joint Phase One Proposal is submitted, all parties must be Qualified Transmission Project Sponsors. A Qualified Transmission Project Sponsor may propose a comprehensive solution to address the identified needs, or a subset thereof, that includes an upgrade(s) located on or connected to a PTO's existing transmission system where the Qualified Transmission Project Sponsor is not the PTO for the existing system element(s). In such cases, the Qualified Transmission Project Sponsor's proposed solution relating to the upgrade(s) of an existing transmission system element(s) must provide all data available to the Qualified Transmission Project Sponsor as part of its response to the request for proposal. The Qualified Transmission Project Sponsor is not required to procure agreements with the PTO for implementation of such upgrades as the PTO is required to implement the upgrade(s) in accordance with Schedule 3.09(a) of the Transmission Operating Agreement if the proposed solution is selected through the competitive process.

A PTO or PTOs identified by the ISO as the Backstop Transmission Solution provider(s) shall submit an individual or joint Phase One Proposal (if more than one PTO is identified) as a Backstop Transmission Solution to comprehensively address all of the needs identified in the request for proposal that would be solved by a project located within or connected to its/their existing electric system, and which it/they would therefore have an obligation to build under Schedule 3.09(a) of the TOA. Such PTOs may recover the costs of preparing the Backstop Transmission Solution in accordance with the mechanisms reflected in the OATT and the terms of the TOA.

A member of the Planning Advisory Committee that is not a Qualified Transmission Project Sponsor but would like the ISO to consider a Phase One Proposal reflecting its concept for a project in response to a request for proposal (that is, a project that is "unsponsored") must, before the deadline for the submission of Phase One Proposals, identify a Qualified Transmission Project Sponsor willing to submit a corresponding Phase One Proposal and Phase Two Solution (and to develop and construct the project, if selected in the competitive solution process) in order for the unsponsored project to be submitted in response to an ISO solicitation in Phase One. Upon request by the pertinent Planning Advisory Committee member for assistance in identifying a sponsor, the ISO shall post on its website and distribute to the Planning Advisory Committee a notice that solicits expressions of interest by Qualified Transmission Project Sponsors for sponsorship of the member's conceptual project. All expressions of interest shall include a detailed explanation of why the Qualified Transmission Project Sponsor is best qualified to construct, own and operate the unsponsored project. If only one Qualified Transmission Project

Sponsor expresses interest, the ISO shall designate it as the Qualified Transmission Project Sponsor. If more than one Qualified Transmission Project Sponsor expresses interest, the Planning Advisory Committee member shall select the Qualified Transmission Project Sponsor. In either case, the designated Qualified Transmission Project Sponsor shall thereafter comply with the requirements of this Attachment K and the ISO Tariff with respect to the project. If no Qualified Transmission Project Sponsor expresses interest, the unsponsored project may not be submitted as a Phase One Proposal.

(b) Use and Control of Right of Way

Neither the submission of a project by a Qualified Transmission Project Sponsor nor the selection by the ISO of a project submitted by a Qualified Transmission Project Sponsor for inclusion in the RSP Project List shall alter a PTO's use and control of an existing right of way, the retention, modification, or transfer of which remain subject to the relevant law or regulation, including property or contractual rights, that granted the right-of-way. Nothing in the processes described in this Attachment K requires a PTO to relinquish any of its rights-of-way in order to permit a Qualified Transmission Project Sponsor to develop, construct or own a project.

(c) Information Required for Phase One Proposals; Study Deposit; Timing

Phase One Proposals shall provide the following information:

(i) a detailed description of the proposed solution, in the manner specified by the ISO, including an identification of the proposed route for the solution and technical details of the project, such as interconnection into the existing transmission system;

(ii) a detailed explanation of the identified needs that are addressed, how the proposed solution addresses those identified needs, a description of those needs which have not been addressed, and a description of the impact of the Phase One Proposal on those needs which have not been addressed;

(iii) the proposed schedule, including key high-level milestones, for development, siting, procurement of real estate rights, permitting, construction and completion of the proposed solution;

(iv) right, title, and interest in rights of way, substations, and other property or facilities, if any, that would contribute to the proposed solution or the means and timeframe by which such would be obtained; and

(v) the estimated installed costs of the proposed solution, including a high-level itemization of the components of the cost estimate and any cost containment or cost cap measures.

With each proposal, the submitting Qualified Transmission Project Sponsor must include payment of a $100,000 study deposit per submitted Phase One Proposal to support the cost of Phase One Proposal and Phase Two Solution study work by the ISO. The study deposit of $100,000 shall be applied towards the costs incurred by the ISO associated with the study of the Phase One Proposal and Phase Two Solution.

Phase One Proposals must be submitted by the deadline specified in the public posting by the ISO of the request for proposal described in Section 4.3(a) of this Attachment, which shall not be less than 60 days from the posting date of the request for proposal. The ISO may reject submittals which are insufficient or not adequately supported.

(d) LSP Coordination

Qualified Transmission Project Sponsors of Phase One Proposals shall also identify any LSP plans that require coordination with their Phase One Proposals.

(e) Review of Phase One Proposals by ISO

If any identified need is only solved by the Backstop Transmission Solution, the ISO shall proceed under Section 4.2 of this Attachment, rather than pursuant to the procedures set forth in the remainder of this Section 4.3.

If all of the identified needs are solved by more than one Phase One Proposal, the ISO shall perform a review of each proposal to determine whether the proposed solution:

(i) provides sufficient data and that the data is of sufficient quality to satisfy Section 4.3(c) of this Attachment;

(ii) satisfies one or more of the needs as identified in Section 4.3(c)(ii);

(iii) is technically practicable and indicates possession of, or an approach to acquiring, the necessary rights of way, property and facilities that will make the proposal reasonably feasible in the required timeframe; and

(iv) is eligible to be constructed only by an existing PTO in accordance with Schedule 3.09(a) of the TOA because the proposed solution is an upgrade to existing PTO facilities, or because the costs of the proposed solution are not eligible for regional cost allocation under the OATT and will be allocated only to the local customers of a PTO.

(f) Proposal Deficiencies; Further Information

If the ISO identifies any minor deficiencies in meeting the requirements of Section 4.3(e) in the information provided in connection with a proposed Phase One Proposal, the ISO will notify the submitting Phase One Proposal Qualified Transmission Project Sponsor and provide an opportunity for the sponsor to cure the deficiencies within the timeframe specified by the ISO. Upon request, Qualified Transmission Project Sponsors of Phase One Proposals shall provide the ISO with additional information reasonably necessary for the ISO's evaluation of the proposed Phase One Proposals. This identification and notification will occur prior to the publication by the ISO of any Phase One Proposals. In providing information under this subsection (f), or in Phase Two Solutions, the Qualified Transmission Project Sponsor may not modify its project materially or submit a new project, but instead may clarify its Phase One Proposal. Phase Two Solutions reflecting a material modification to a Phase One Proposal or representing a new project will be rejected.

(g) Listing of Qualifying Phase One Proposals or Groups of Phase One Proposals

The ISO will provide the Planning Advisory Committee with, and post on the ISO's website, a listing of Phase One Proposals that meet the criteria of Section 4.3(e). The listing will contain Phase One Proposals, either individually or as a group, that solve all of the identified needs. A meeting of the Planning Advisory Committee will be held thereafter in order to solicit stakeholder input on the listing, and the listed proposals. The ISO with input from the Planning Advisory Committee may exclude Phase One Proposals, from the list, and from consideration in Phase Two Solutions, based on a determination that the Phase One Proposal is not competitive with other Phase One Proposals, that have been submitted in terms of cost, electrical performance, future system expandability, or feasibility. Information on Phase One Proposals containing CEII will be posted on the ISO's protected website consistent with Section 2.4(d) of this Attachment. The ISO may amend its listing based on stakeholder input. The ISO shall post on its website an explanation of why it has determined to exclude a Phase One Proposal from consideration in the Phase Two Solution process.

(h) Information Required for Phase Two Solutions; Identification and Reporting of Preliminary Preferred Phase Two Solution

Qualified Transmission Project Sponsors of Phase One Proposals reflected on the final listing developed pursuant to Section 4.3(g) of this Attachment shall provide the following information in their proposed Phase Two Solutions:

(i) updates of the information provided in Phase One Proposals, or a certification that the information remains current and correct;

(ii) list of required major Federal, State and local permits;

(iii) description of construction sequencing, a conceptual plan for the anticipated transmission and generation outages necessary to construct the Phase Two Solution and their respective durations, and possible constraints;

(iv) project schedule, with additional detail compared with Phase One Proposals, as specified by the ISO;

(v) detailed cost component itemization and life-cycle cost including any clarifications to cost containment or cost cap measures that were not included as part of the Phase One Proposal;

(vi) description of the financing being used;

(vii) design and equipment standards to be used;

(viii) description of the authority the Qualified Transmission Project Sponsor(s) has to acquire necessary rights of way;

(ix) experience of the Qualified Transmission Project Sponsor(s) in acquiring rights of way;

(x) status of acquisition of right, title, and interest in rights of way, substations, and other property or facilities, if any, that are necessary for the proposed Phase Two Solution;

(xi) detailed explanation of project feasibility and potential constraints and challenges;

(xii) description of the means by which the Qualified Transmission Project Sponsor(s) proposes to satisfy legal or regulatory requirements for siting, constructing, owning and operating transmission projects; and

(xiii) detailed explanation of potential future expandability.

Phase Two Solutions must be submitted to the ISO by the deadline specified in the posting of the final listing (following stakeholder input) of Phase One Proposals described in Section 4.3(g). The deadline for submittal of Phase Two Solutions shall not be less than 60 days from the posting date of the final listing. The ISO may reject Phase Two Solution submittals which are insufficient or not adequately supported.

The ISO will identify the Phase Two Solution, individually or as a group, that offers the best combination of electrical performance, cost, future system expandability and feasibility to comprehensively address all of the needs in the required timeframe as the preliminary preferred Phase Two Solution in response to each request for proposal. The ISO will report the preliminary preferred Phase Two Solution, together with explanatory materials, to the Planning

Advisory Committee and seek stakeholder input on the preliminary preferred Phase Two Solution.

The ISO will consider several factors during the evaluation process for identification of the preliminar~~il~~y preferred Phase Two Solution. These factors may include, but are not limited to, the following which are listed in no particular order:

- Life-cycle cost, including all costs associated with right of way acquisition, easements, and associated real estate;
- System performance;
- Cost cap or cost containment provisions;
- In-service date of the project or portion(s) thereof;
- Project constructability;
- Generation and transmission facility outages required during construction;
- Extreme contingency performance;
- Operational impacts;
- Incremental costs for potential resource retirements;
- Interface impacts;
- Future expandability;
- Consistency with Good Utility Practice;
- Potential siting/permitting issues or delays;
- Loss savings;
- Replacement of aging infrastructure;
- Environmental impact;
- Design standards;
- Impact on NPCC Bulk Power System classification; and
- Qualified Transmission Project Sponsor(s) capabilities.

(i) Reimbursement of Phase Two Solution Costs; Collection and Refund of ISO Study Costs

Qualified Transmission Project Sponsors whose Phase One Proposals are listed pursuant to Section 4.3(g) for review as Phase Two Solutions shall be entitled to recover, pursuant to rates and appropriate financial arrangements set forth in the Tariff (and, as applicable, the TOA and NTDOA), all prudently incurred costs associated with developing a Phase Two Solution. PTOs shall be entitled to recover, pursuant to rates and appropriate financial arrangements set forth in the Tariff, all prudently incurred study costs and costs associated with developing any upgrades or modifications to such PTOs' existing facilities necessary to facilitate the development of a listed Phase One Proposal proposed by any other Qualified Transmission Project Sponsor.

Any difference between a Qualified Transmission Project Sponsor's study deposit and the actual cost of the Phase One Proposal and Phase Two Solution studies shall be paid by or refunded to the Qualified Transmission Project Sponsor, as appropriate, with interest calculated in accordance with Section 35.19a(a)(2) of the FERC regulations. Any refund payment shall be accompanied by a detailed and itemized accounting of the actual study costs incurred. Any invoice to collect funds in addition to the deposit shall be accompanied by a detailed and itemized accounting of the actual study costs incurred. Any disputes arising from the study process shall be addressed under the dispute resolution process specified in Section I.6 of the ISO Tariff.

(j) Selection of the Preferred Phase Two Solution

Following receipt of stakeholder input, the ISO will identify the preferred Phase Two Solution, individually or as a group, (with an overview of why the solution is preferred) by a posting on its website. The ISO's identification will select the project that offers the best combination of electrical performance, cost, future system expandability and feasibility to meet the need in the required timeframe. The ISO will also notify the Qualified Transmission Project Sponsor(s) that proposed the preferred Phase Two Solution that its project has been selected for development. The preferred Phase Two Solution may include an upgrade(s) located on or connected to a PTO's existing transmission system where the Qualified Transmission Project Sponsor is not the PTO for the existing system element(s). In such cases the ISO will notify the PTO that have upgrades required by the preferred Phase Two Solution to proceed in accordance with Schedule 3.09(a) of the Transmission Operating Agreement. Once the ISO has identified the preferred Phase Two Solution, any remaining Phase Two Solutions, along with the Backstop Transmission Solution, must stop all development. The ISO will include the project as a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, as appropriate, in the RSP and/or its Project List, as it is updated from time to time in accordance with this Attachment. Where external impacts of regional projects are identified through coordination by the ISO with neighboring entities, those impacts will be identified in the RSP. Costs associated with such impacts will be addressed as set forth in Schedule 15.

(k) Execution of Selected Qualified Transmission Project Sponsor Agreement

Within 30 days of receiving notification pursuant to Section 4.3(j) of this Attachment, the Qualified Transmission Project Sponsor shall submit to the ISO its acceptance of responsibility to proceed with the preferred Phase Two Solution by execution of a Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT). Within 30 days of receiving notification pursuant to Section 4.3(j) of this Attachment, each Qualified Transmission Project Sponsor that is part of the joint proposal shall submit to the ISO its acceptance of responsibility to proceed with the preferred Phase Two Solution by execution of a Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT). Any cost cap or cost containment provisions shall be included in each Selected Qualified Transmission Project Sponsor Agreement.

(l) Failure to Proceed

If the ISO finds, after consultation with a PTO Qualified Transmission Project Sponsor(s), that one or more of the Qualified Transmission Project Sponsors is failing to pursue approvals or construction in a reasonably diligent fashion, the ISO will notify all Qualified Transmission Project Sponsors that one or more of the Qualified Transmission Project Sponsors is failing to pursue approvals or construction in a reasonably diligent fashion. The Qualified Transmission Project Sponsor(s) that is failing to pursue approvals or construction in a reasonably diligent fashion will have 60 days from the ISO's notification to reassign a portion or all of the preferred Phase Two Solution to another Qualified Transmission Project Sponsor in accordance with Section 8 of the Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT). In the event that such reassignment does not occur within 60 days, the ISO shall require the applicable PTO(s) to execute the Selected Qualified Transmission Project Sponsor Agreement and implement the Backstop Transmission Solution pursuant to Schedule 3.09(a) of the Transmission Operating Agreement. In such cases the ISO shall prepare a report explaining why it has reassigned the project. If the Qualified Transmission Project Sponsor that is failing or unable to proceed is a PTO, the report shall be consistent with the provisions of Section 1.1(e) of

Schedule 3.09(a) of the Transmission Operating Agreement, including the ISO's proposed course of action. If prepared with respect to a Qualified Transmission Project Sponsor that is not a PTO, the report shall include a report from that sponsor. The ISO shall file its report (whether with respect to a PTO or non-PTO Qualified Transmission Project Sponsor) with the Commission.

(m) Cancellation of a Request for Proposal

The ISO may cancel a request for proposal at any time. Such cancellation may be due to new or different assumptions which may change or eliminate the identified needs. Any costs associated with solution development shall be recovered pursuant to Sections 3.6(c), 4.3(a) and 4.3(i) of this Attachment.

4A. Public Policy Transmission Studies; Public Policy Transmission Upgrades

4A.1 NESCOE Requests for Public Policy Transmission Studies

No less often than every three years, by January 15 of that year, the ISO will post a notice indicating that members of the Planning Advisory Committee may, no later than 45 days after the posting of the notice: (i) provide NESCOE, via the process described below, with input regarding state and federal Public Policy Requirements identified as driving transmission needs relating to the New England Transmission System, and regarding particular transmission needs driven by those Public Policy Requirements, and (ii) provide the ISO with input regarding local (e.g., municipal and county) Public Policy Requirements identified as driving transmission needs relating to the New England Transmission System, and regarding particular transmission needs driven by those Public Policy Requirements. A meeting of the Planning Advisory Committee may be held for this purpose. Members of the Planning Advisory Committee shall direct all such input related to state, federal, and local Public Policy Requirements that drive transmission needs to the ISO and the ISO will post such input on the ISO's website. By no later than May 1 of that year, NESCOE may submit to the ISO in writing a request for a new Public Policy Transmission Study, or an update of a previously conducted study. The request will identify the Public Policy Requirements identified as driving transmission needs relating to the New England Transmission System, and may identify particular NESCOE-identified public policy-related transmission needs as well. Along with any such request, NESCOE will provide the ISO with a written explanation of which transmission needs driven by state or federal Public Policy Requirements the ISO will evaluate for potential solutions in the regional planning process, including why other suggested transmission needs will not be evaluated. The ISO will post the NESCOE request and explanation on the ISO's website. If NESCOE does not provide that listing of identified transmission needs (which may consist of a NESCOE statement of its determination that no transmission needs are driven by state or federal Public Policy Requirements identified during the stakeholder process) and that explanation (which may consist of a NESCOE explanation of why no transmission needs are driven by state or federal Public Policy Requirements identified during the stakeholder process), the ISO will note on its website that a NESCOE listing and explanation have not been provided. In that circumstance, the ISO will determine subsequently (after opportunity for Planning Advisory Committee input), and post on its website an explanation of, which transmission needs driven by state or federal Public Policy Requirements the ISO will evaluate in the regional planning process, including why other suggested transmission needs will not be evaluated.

4A.1.1 Study of Federal Public Policy Requirements Not Identified by NESCOE; Local Public Policy Requirements

If a stakeholder believes that a federal Public Policy Requirement that may drive transmission needs relating to the New England Transmission System has not been appropriately addressed by NESCOE, it may file with the ISO, no later than 15 days after the posting of NESCOE's explanation as described in Section 4A.1 of this Attachment, a written request that explains the stakeholder's reasoning and that seeks reconsideration by the ISO of NESCOE's position regarding that requirement. The ISO will post the stakeholder's written request on the ISO's website. Where the ISO agrees with a stated stakeholder position, or on its own finding, the ISO may perform an evaluation under Sections 4A.2 through 4A.4 of this Attachment of a federal Public Policy Requirement not otherwise identified by NESCOE. The ISO will post on its website an explanation of those transmission needs driven by federal Public Policy Requirements not identified by NESCOE that will be evaluated for potential transmission solutions in the regional system planning process, and why other suggested transmission needs driven by federal Public Policy Requirements not identified by NESCOE will not be evaluated. In addition, the ISO will post on its website an explanation of those transmission needs driven by local Public Policy Requirements that will be evaluated for potential transmission solutions in the regional system planning process, and why other suggested transmission needs driven by local Public Policy Requirements will not be evaluated.

4A.2 Preparation for Conduct of Public Policy Transmission Studies; Stakeholder Input

Upon receipt of the NESCOE request, or as the result of the ISO's consideration of a federal or local Public Policy Requirement pursuant to Section 4A.1.1, the ISO will prepare and post on its website a proposed scope for the Public Policy Transmission Study, and associated parameters and assumptions (including resource assumptions), and provide the foregoing to the Planning Advisory Committee by no later than September 1 of the request year. A meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit stakeholder input for consideration by the ISO on the study's scope, parameters and assumptions.

4A.3 Public Policy Transmission Studies

(a) Conduct of Public Policy Transmission Studies; Stakeholder Input

With input from Planning Advisory Committee and potentially impacted PTOs, the ISO will perform the initial phase of the Public Policy Transmission Study to develop a rough estimate of the costs and benefits of high-level concepts that could meet transmission needs driven by Public Policy Requirements. The study's results will be posted on the ISO's website, and a meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit input on the results of the initial phase of the study, and the scope, parameters and assumptions (including resource assumptions) for any follow-on phase of the study. The ISO may − as a follow-on phase of the Public Policy Transmission Study − perform more detailed analysis and engineering work on the high-level concepts.

(b) Treatment of Market Solutions in Public Policy Transmission Studies

The ISO shall reflect proposed market responses in the Public Policy Transmission Study. Market responses may include, but are not limited to, resources (e.g., demand-side projects and distributed generation), Merchant Transmission Facilities and Elective Transmission Upgrades.

In performing Public Policy Transmission Studies, the ISO shall rely on certain resources to prevent the identification of transmission needs driven by Public Policy Requirements. Specifically, the ISO shall incorporate in the Public Policy Transmission Study information regarding future resources, with the exception of imports across external tie lines, that have been proposed and (i) have cleared in a Forward Capacity Auction pursuant to Market Rule 1 of the ISO Tariff, (ii) have been selected in, and are contractually bound by, a state-sponsored request for proposals, (iii) have a financially binding obligation pursuant to a contract, or (iv) have been forecast in the ISO's Forecast Report of Capacity, Energy, Loads and Transmission. The ISO shall also incorporate or update information regarding all existing resources, with the exception of imports across external tie lines, in Public Policy Transmission Studies. Imports across future or existing external tie lines will not be relied upon unless such imports (i) have a Capacity Supply Obligation corresponding to the year of study, (ii) have been selected in, and are contractually bound by, a state-sponsored request for proposals, (iii) have a financially binding obligation pursuant to a contract, or (iv) may be represented by a minimum flow based on HQ Interconnection Capability Credits. The ISO will model out-of-service all submitted Retirement De-List Bids, submitted Permanent De-List Bids, and demand bids that have cleared in a substitution auction, and may model out-of-service rejected-for-reliability Static De-List Bids and rejected-for-reliability Dynamic De-List Bids from the most recent Forward Capacity Auction. With respect to having been selected in, and being contractually bound by a state-sponsored request for proposals, or having a financially binding obligation pursuant to a contract, demonstration of such contracts is accomplished through submittal for ISO review of an order or other similar authorization from the appropriate state regulatory agency, along with a copy of the contract, that together demonstrate the contractual requirements. These documents may be submitted by: the Project Sponsor; the state regulatory agency authorizing the contract; a transmission company that is a counterparty to the contract; or by a third-party organization representing the interests of the New England states regarding energy related issues, such as NESCOE. The ISO shall incorporate information regarding a proposed Merchant Transmission Facility or Elective Transmission Upgrade in a Public Policy Transmission Study at a time after the studies corresponding to the Merchant Transmission Facility or Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), and a commercial operation date has been ascertained, with the exception of Elective Transmission Upgrades that are proposed in conjunction with the interconnection of a resource, which shall be considered at the same time as the proposed resource is considered in the Public Policy Transmission Study.

4A.4 Response to Public Policy Transmission Studies

The results of the Public Policy Transmission Study will be provided to the Planning Advisory Committee and posted on the ISO's website, and a meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit input for the ISO on those results, including any updates from the states on any methods by which they are satisfying their respective Public Policy Requirements included in the Public Policy Transmission Study. The ISO's costs of performing the Public Policy Transmission Study described in Section 4A.3 will be collected by the ISO pursuant to Schedule 1 of Section IV.A of the Tariff. Any prudently incurred PTO costs for assistance requested by the ISO to support the Public Policy Transmission Study will be recovered by the applicable PTO(s) in accordance with Attachment F and Schedule 21 of the Tariff.

The ISO will evaluate the input from the Planning Advisory Committee and provide the results of the Public Policy Transmission Study to Qualified Transmission Project Sponsors for their use in preparing Stage One Proposals to develop, build and operate one or more projects consistent with the general design requirements identified by the ISO in the study.

4A.5 Use and Control of Right of Way

Neither the submission of a project by a Qualified Transmission Project Sponsor nor the selection by the ISO of a project submitted by a Qualified Transmission Project Sponsor for inclusion in the RSP Project List shall alter a PTO's use and control of an existing right of way, the retention, modification, or transfer of which remain subject to the relevant law or regulation, including property or contractual rights, that granted the right-of-way. Nothing in the processes described in this Attachment K requires a PTO to relinquish any of its rights-of-way in order to permit a Qualified Transmission Project Sponsor to develop, construct or own a project.

4A.6 Stage One Proposals

(a) Information Required for Stage One Proposals

The ISO will publicly post on its website a request for proposal inviting, for each high-level general project concept identified by the ISO pursuant to Section 4A.3(a) above, Qualified Transmission Project Sponsors to submit (by the deadline specified in the request for proposal, which shall be not less than 60 days from the date of posting the request for proposal) an individual or joint Stage One Proposal. In the case where a joint Stage One Proposal is submitted, all parties must be Qualified Transmission Project Sponsors. The following information must be provided as part of the Stage one Proposal:

(i) a detailed description of the proposed solution, in the manner specified by the ISO, including an identification of the proposed route for the solution and technical details of the project, such as interconnection into the existing transmission system;

(ii) a detailed explanation of how the proposed solution addresses the identified need;

(iii) the proposed schedule, including key high-level milestones, for development, siting, procurement of real estate rights, permitting, construction and completion of the proposed solution;

(iv) right, title, and interest in rights of way, substations, and other property or facilities, if any, that would contribute to the proposed solution or the means and timeframe by which such would be obtained; and

(v) the estimated installed costs of the proposed solution, including a high-level itemization of the components of the cost estimate, and any cost containment or cost cap measures.

A Qualified Transmission Project Sponsor may submit a proposed solution that includes an upgrade(s) located on or connected to a PTO's existing transmission system where the Qualified Transmission Project Sponsor is not the PTO for the existing system element(s). In such cases, the Qualified Transmission Project Sponsor's proposed solution relating to the upgrade(s) of an existing transmission system element(s) must provide all data available to the Qualified Transmission Project Sponsor as part of its response to the request for proposal. The Qualified Transmission Project Sponsor is not required to procure agreements with the PTO for implementation of such upgrades as the PTO is required to implement the upgrade(s) in accordance with Schedule 3.09(a) of the Transmission Operating Agreement if the proposed solution is selected through the competitive process.

A member of the Planning Advisory Committee that is not a Qualified Transmission Project Sponsor but would like the ISO to consider a Stage One Proposal reflecting its concept for a project in response to a request for proposal (that is, a project that is "unsponsored") must identify a Qualified Transmission Project Sponsor willing to submit a corresponding Stage One Proposal and Stage Two Solution (and to develop and construct the project, if selected in the competitive solution process) in order for the unsponsored project to be submitted in response to an ISO solicitation in Stage One Proposal. Upon request of the pertinent Planning Advisory Committee member for assistance in identifying a sponsor, the ISO shall post on its website and distribute to the Planning Advisory Committee a notice that solicits expressions of interest by Qualified Transmission Project Sponsors for sponsorship of the member's conceptual project. All expressions of interest shall include a detailed explanation of why the Qualified Transmission Project Sponsor is best qualified to construct, own and operate the unsponsored project. If only one Qualified Transmission Project Sponsor expresses interest, the ISO shall designate it as the Qualified Transmission Project Sponsor. If more than one Qualified Transmission Project Sponsor expresses interest, the Planning Advisory Committee member shall select the Qualified Transmission Project Sponsor. In either case, the designated Qualified Transmission Project Sponsor shall thereafter comply with the requirements of this Attachment K and the ISO Tariff with respect to the project. If no Qualified Transmission Project Sponsor expresses interest, the unsponsored project may not be submitted as a Stage One Proposal.

With each proposal, the submitting Qualified Transmission Project Sponsor must include payment of a $100,000 study deposit per submitted project to support the cost of Stage One Proposal and Stage Two Solution study work by the ISO. The study deposit of $100,000 shall be applied towards the costs incurred by the ISO associated with the study of the Stage One Proposal and Stage Two Solution.

(b) LSP Coordination

Qualified Transmission Project Sponsors of Stage One Proposals shall also identify any LSP plans that require coordination with their Stage One Proposals.

(c) Review of Stage One Proposals by ISO

Upon receipt of Stage One Proposals, the ISO shall perform a review of each proposal to determine whether the proposed solution:

(i) provides sufficient data and that the data is of sufficient quality to satisfy Section 4A.6(a);

(ii) satisfies the needs driven by Public Policy Requirements identified in the request for proposal, as reflected in the Public Policy Transmission Study;

(iii) is technically practicable and indicates possession of, or an approach to acquiring, the necessary rights of way, property and facilities that will make the proposal reasonably feasible in the required timeframe; and;

(iv) is eligible to be constructed only by an existing PTO in accordance with Schedule 3.09(a) of the TOA because the proposed solution is an upgrade to existing PTO facilities or because the costs of the proposed solution are not eligible for regional cost allocation under the OATT and will be allocated only to the local customers of a PTO.

(d) Proposal Deficiencies; Further Information

If the ISO identifies any deficiencies (compared with the requirements of Section 4A.6(a)) in the information provided in connection with a proposed Stage One Proposal, the ISO will notify the Stage One Proposal Qualified Transmission Project Sponsor and provide an opportunity for the Qualified Transmission Project Sponsor to cure the deficiencies within the timeframe specified by the ISO. Upon request, Qualified Transmission Project Sponsors of Stage One Proposals shall provide the ISO with additional information reasonably necessary for the ISO's evaluation of the proposed solutions. This identification and notification will occur prior to the publication by the ISO of any Stage One Proposals. In providing information under this subsection (d), or in Stage Two Solutions, the Qualified Transmission Project Sponsor may not modify its project materially or submit a new project, but instead may clarify its project. Stage Two Solutions reflecting a material modification to a Stage One Proposal or representing a new project will be rejected.

(e) List of Qualifying Stage One Proposals

The ISO will provide the Planning Advisory Committee with, and post on the ISO's website, a list of Stage One Proposals that meet the criteria of Section 4A.6(c). A meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit input for the ISO on that list. The ISO shall also indicate whether any of the Stage One Proposals may also satisfy identified reliability needs of the system. The ISO with input from the Planning Advisory Committee may exclude Stage One Proposals from the list, and from consideration in Stage Two Solutions, based on a determination that the Stage One Proposal is not competitive with other Stage One Proposals that have been submitted in terms of cost, electrical performance, future system expandability, or feasibility. Information on Stage One Proposals containing CEII will be posted on the ISO's protected website consistent with Section 2.4(d) of this Attachment. The ISO may amend its listing based on stakeholder input.

4A.7 Reimbursement of Stage One Proposal and Stage Two Solution Costs; Collection and Refund of ISO Study Costs

Qualified Transmission Project Sponsors that are requested by NESCOE in writing or by one or more states' governors or regulatory authorities directly to submit a Stage One Proposal shall be entitled to recover, pursuant to rates and appropriate financial arrangements set forth in the Tariff and the TOA, their prudently incurred costs from the Regional Network Load of the states identified by NESCOE in the written communication as having made the request or from the Regional Network Load of the states that made the request directly. Stage One Proposal costs shall otherwise not be subject to recovery under the ISO Tariff.

Qualified Transmission Project Sponsors whose projects are listed by the ISO pursuant to Section 4A.6(e) shall be entitled to recover, pursuant to rates and appropriate financial arrangements set forth in the Tariff and, as applicable, the TOA and NTDOA, all prudently incurred costs associated with developing a Stage Two Solution. PTOs shall be entitled to recover, pursuant to rates and appropriate financial arrangements set forth in the Tariff, all prudently incurred study costs and costs associated with developing any upgrades or modifications to such PTOs' existing facilities necessary to facilitate the development of a listed Stage Two Solution proposed by any other Qualified Transmission Project Sponsor.

Any difference between a Qualified Transmission Project Sponsor's study deposit and the actual cost of the Stage One Proposal and Stage Two Solutions studies shall be paid by or refunded to the Qualified Transmission Project Sponsor, as appropriate, with interest calculated in accordance with Section 35.19a(a)(2) of the FERC regulations. Any refund payment shall be accompanied by a detailed and itemized accounting of the actual study costs incurred. Any invoice to collect funds in addition to the deposit shall be accompanied by a detailed and itemized accounting of the actual study costs incurred. Any disputes arising from the study process shall be addressed under the dispute resolution process specified in Section I.6 of the Tariff.

4A.8 Information Required for Stage Two Solutions; Identification and Reporting of Preliminary Preferred Stage Two Solution

Qualified Transmission Project Sponsors of Stage One Proposals listed pursuant to Section 4A.6(e) of this Attachment shall provide the following information in their proposed Stage Two Solutions:

(i) updates of the information provided in Stage One Proposals, or a certification that the information remains current and correct;

(ii) list of required major Federal, State and local permits;

(iii) description of construction sequencing, a conceptual plan for the anticipated transmission and generation outages necessary to construct the Stage Two Solution and their respective durations, and possible constraints;

(iv) project schedule, with additional detail compared with Stage One Proposals, as specified by the ISO;

(v) detailed cost component itemization and life-cycle cost including any clarifications to cost containment or cost cap measures that were not included as part of the Stage One Proposal;

(vi) description of the financing being used;

(vii) design and equipment standards to be used;

(viii) description of the authority the Qualified Transmission Project Sponsor(s) has to acquire necessary rights of way;

(ix) experience of the Qualified Transmission Project Sponsor(s) in acquiring rights of way;

(x) status of acquisition of right, title, and interest in rights of way, substations, and other property or facilities, if any, that are necessary for the proposed Stage Two Solution;

(xi) detailed explanation of project feasibility and potential constraints and challenges;

(xii) description of the means by which the Qualified Transmission Project Sponsor(s) proposes to satisfy legal or regulatory requirements for siting, constructing, owning and operating transmission projects; and

(xiii) detailed explanation of potential future expandability.

Stage Two Solutions must be submitted to the ISO by the deadline specified in the posting of the final listing (following stakeholder input) of Stage One Proposals described in Section 4A.6(e). The deadline for submittal of Stage Two Solutions shall not be less than 60 days from the posting date of the final listing. The ISO may reject Stage Two Solution submittals which are insufficient or not adequately supported.

The ISO will consider several factors during the evaluation process for identification of the preliminar~~il~~y preferred Stage Two Solution. These factors may include, but are not limited to, the following which are listed in no particular order:

- Life-cycle cost, including all costs associated with right of way acquisition, easements, and associated real estate;
- System performance;
- Cost cap or cost containment provisions;
- In-service date of the project or portion(s) thereof;
- Project constructability;
- Generation and transmission facility outages required during construction;
- Extreme contingency performance;
- Operational impacts;
- Incremental costs for potential resource retirements;
- Interface impacts;
- Future expandability;

- Consistency with Good Utility Practice;
- Potential siting/permitting issues or delays;
- Loss savings;
- Replacement of aging infrastructure;
- Environmental impact;
- Design standards;
- Impact on NPCC Bulk Power System classification; and
- Qualified Transmission Project Sponsor(s) capabilities

The ISO will report the preliminary preferred Stage Two Solution(s), along with its views as to whether the preliminary preferred solution(s) also satisfies identified reliability needs of the system, to the Planning Advisory Committee and seek stakeholder input on the preliminary preferred Stage Two Solution(s).

4A.9 Inclusion of Public Policy Transmission Upgrades in the Regional System Plan and RSP Project List; Milestone Schedules; Removal from RSP Project List

(a) Inclusion of Public Policy Transmission Upgrades in the Regional System Plan and RSP Project List

Following receipt of stakeholder input, the ISO will identify the preferred Stage Two Solution (with an overview of why the solution is preferred) by a posting on its website. The ISO's identification will select the Stage Two Solution that best addresses the identified Public Policy Requirement while utilizing the best combination of electrical performance, cost, future system expandability and feasibility to meet the need in the required timeframe. The ISO will also notify the Qualified Transmission Project Sponsor that proposed the preferred Stage Two Solution that its project has been selected for development, and include the project as a Public Policy Transmission Upgrade in the Regional System Plan and RSP Project List, as it is updated from time to time in accordance with this Attachment. The preferred Stage Two Solution may include an upgrade(s) located on or connected to a PTO's existing transmission system where the Qualified Transmission Project Sponsor is not the PTO for the existing system element(s). In such cases the ISO will notify the PTO that have upgrades required by the preferred Stage Two Solution to proceed in accordance with Schedule 3.09(a) of the Transmission Operating Agreement. Once the ISO has identified the preferred Stage Two Solution, any remaining Stage Two Solutions must stop all development. Where external impacts of regional Public Policy Transmission Upgrades are identified through coordination by the ISO with neighboring entities, those impacts will be identified in the RSP. Costs associated with such impacts will be addressed as set forth in Schedule 15.

(b) Execution of Selected Qualified Transmission Project Sponsor Agreement

Within 30 days of its receiving notification pursuant to Section 4A.9(a) of this Attachment, the Qualified Transmission Project Sponsor shall submit to the ISO its acceptance of responsibility to proceed with the preferred Stage Two Solution by execution of the Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT). Within 30 days of receiving notification pursuant to Section 4A.9(a) of this Attachment, each Qualified Transmission Project Sponsor that is part of the joint proposal shall submit to the ISO its acceptance of responsibility to proceed with the preferred Stage Two Solution by execution of a Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT). Any cost cap or cost containment provisions shall be included each Selected Qualified Transmission Project Sponsor Agreement.

(c) Failure to Proceed

If the ISO finds, after consultation with a Qualified Transmission Project Sponsor, that the sponsor is failing to pursue approvals or construction in a reasonably diligent fashion, or that one or more of the Qualified Transmission Project Sponsors is unable to proceed with the project due to forces beyond its reasonable control, the ISO shall, after consultation with the Planning Advisory Committee, prepare a report, including a proposed course of action. If the Qualified Transmission Project Sponsor that is failing or unable to proceed is a PTO, the ISO shall, after consultation with the Planning Advisory Committee, prepare a report consistent with the provisions of Section 1.1(e) of Schedule 3.09(a) of the Transmission Operating Agreement, including the ISO’s proposed course of action. The proposed course of action may include, for example, a consideration and selection of another Stage Two Proposal relating to the pertinent Public

Policy Requirement, or the re-solicitation of Stage One Proposals to meet the pertinent Public Policy Requirement. If prepared with respect to a Qualified Transmission Project Sponsor that is not a PTO, the report shall include a report from that sponsor. The ISO shall file its report (whether with respect to a PTO or a non-PTO Qualified Transmission Project Sponsor) with the Commission.

4A.10 Cancellation of a Request for Proposal

The ISO may cancel a request for proposal at any time. Such cancellation may be due to new or different assumptions which may change or eliminate the identified needs. Any costs associated with solutions development shall be recovered pursuant to Sections 3.6(c) and 4A.7 of this Attachment.

4A.11 Local Public Policy Transmission Upgrades

The costs of Local Public Policy Transmission Upgrade(s) that are required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan in accordance with Section 4A.9 shall be allocated in accordance with Schedule 21 of the ISO OATT.

4B. Qualified Transmission Project Sponsors

4B.1 Evaluation of Applications

The ISO will evaluate applications submitted by an entity that seeks to qualify as a sponsor of a proposed Reliability Transmission Upgrade, Market Efficiency Transmission Upgrade, ~~or~~ Public Policy Transmission Upgrade, or Longer-Term Transmission Upgrade.

4B.2 Information To Be Submitted

The application to be submitted to the ISO by an entity desiring to be a Qualified Transmission Project Sponsor will include the following information:

(i) the current and expected capabilities of the applicant to finance and construct a Reliability Transmission Upgrade, Market Efficiency Transmission Upgrade, ~~or~~ Public Policy Transmission Upgrade, or Longer-Term Transmission Upgrade, and operate and maintain it for the life of the project;

(ii) the financial resources of the applicant;

(iii) the technical and engineering qualifications and experience of the applicant;

(iv) if applicable, the previous record of the applicant regarding construction and maintenance of transmission facilities;

(v) demonstrated capability of the applicant to adhere to construction, maintenance and operating Good Utility Practices, including the capability to respond to outages;

(vi) the ability of the applicant to comply with all applicable reliability standards; and

(vii) demonstrated ability of the applicant to meet development and completion schedules.

4B.3 Review of Qualifications

The ISO shall review each application for completeness. The ISO will notify each applicant within 30 calendar days of receipt of such application whether the application is complete, or identify any deficiencies in provision of the information required by Section 4B.2 of this Attachment. An applicant notified of deficiencies must provide any remedial information within 30 calendar days of the receipt of such notice. Thereafter, the ISO will determine whether the applicant is physically, technically, legally, and financially capable of constructing a Reliability Transmission Upgrade, Market Efficiency Transmission Upgrade, ~~or~~ Public Policy Transmission Upgrade, or Longer-Term Transmission Upgrade in a timely and competent manner, and operating and maintaining the facilities consistent with Good Utility Practice and applicable reliability criteria for the life of the project, and use its best efforts to inform the applicant within 90 days from the date on which it has a completed application on file with the ISO whether it has met all of these criteria. A PTO determined by the ISO to meet all of these criteria will be deemed a Qualified Transmission Project Sponsor. A non-PTO entity determined by the ISO to meet all of these criteria will, upon its execution of the Non-incumbent Transmission Developer Operating Agreement (in the form specified in Attachment O of the OATT) and the Market Participant Service Agreement, be deemed a Qualified Transmission Project Sponsor.

4B.4 List of Qualified Transmission Project Sponsors

Qualified Transmission Project Sponsors are listed in Appendix 3 of this Attachment K.

4B.5 Annual Certification

Each Qualified Transmission Project Sponsor shall submit to the ISO annually a certification that the information initially submitted in response to Section 4B.2 of this Attachment K has not changed adversely in a material fashion, or (if a material adverse change has occurred in the intervening year) submit instead a new application for qualification as a project sponsor. In the latter case, the entity shall not be a Qualified Transmission Project Sponsor unless and until the ISO approves its new application.

5. Supply of Information and Data Required for Regional System Planning

The Transmission Owners, Generator Owners, Transmission Customers, Market Participants and other entities requesting transmission or interconnection service or proposing the integration of facilities to PTF in the New England Transmission System or alternatives to such facilities, and stakeholders requesting a Needs Assessment pursuant to Section 4.1 of this Attachment, shall supply, as required by the Tariff, the Participants Agreement, MPSAs, applicable transmission operating agreements, and/or other existing agreements, protocols and procedures, or upon request by the ISO, and subject to required CEII and confidentiality protections as specified in Section 2.4 of this Attachment, any information (including cost estimates) and data that is reasonably required to prepare an RSP or perform a Needs Assessment, Solutions Study, or any other study performed under this Attachment K.

6. Regional, Local and Interregional Coordination

6.1 Regional Coordination

The ISO shall conduct the regional system planning process for the PTF in coordination with the transmission-owning entities in, or other entities interconnected to, the New England Transmission System consistent with the rights and obligations defined in the ISO OATT, applicable transmission operating agreements or protocols, and/or this Attachment. Pursuant to Section II.49 of this OATT and Sections 3.02, 3.05 and 3.09 of the TOA, the ISO has Operating Authority or control over all PTF and Non-PTF within the New England Control Area, which are utilized for the provision of transmission service under this OATT. The ISO also has Operating Authority or control over the United States portions of the HVDC ties to Quebec and over Merchant Transmission Facilities and Other Transmission Facilities, pursuant to this OATT or applicable transmission operating agreements or protocols. The ISO, however, is not responsible for the planning of the Non-PTF, OTF and MTF. As provided in Section 6.2 and Appendix 1 of this Attachment, the PTOs are responsible for the planning of the Non-PTF and coordinating such planning efforts with the ISO. Pursuant to the OATT and/or applicable transmission operating agreements or protocols, the transmission owners of OTF and MTF are required to participate in the ISO's regional system planning process and perform and/or support studies of the impacts of regional system projects on their respective facilities.

6.2 Local Coordination

The regional system planning process shall be conducted and the RSP shall be developed in coordination with the local system plans of the PTOs. In accordance with the TOA and OATT provisions identified in Section 6.1 of this Attachment, the PTOs have responsibility for planning Non-PTF. The PTOs conduct planning of Non-PTF using the LSP process outlined in Section 2.5 and Appendix 1 of this Attachment, in coordination with the ISO, other entities interconnected with the New England Transmission System, Transmission Customers and stakeholders, and in accordance with the provisions in the TOA, the OATT and the Planning and Reliability Criteria. The openness and transparency of the LSP process is intended to be consistent with the regional system planning process.

6.3 Interregional Coordination

The regional system planning process shall be conducted and the RSP shall be developed in coordination with the similar plans of the surrounding ISOs/RTOs and Control Areas pursuant to the Northeastern Planning Protocol and other agreements with neighboring systems (including entities that are not Parties to the Northeastern Planning Protocol) and NPCC.

(a) **Interregional Coordination and Cost Allocation Among ISO, New York Independent System Operator, Inc. ("NYISO") and PJM Interconnection, L.L.C. ("PJM") Under Order No. 1000**

Pursuant to Section 7 of the Northeastern Planning Protocol (which is posted on the web at www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc, the Joint ISO/RTO Planning Committee ("JIPC") reviews regional needs and solutions identified in the regional planning processes of the ISO, NYISO and PJM in order to identify, with input from the Interregional Planning Stakeholder Advisory Committee ("IPSAC"), the potential for Interregional Transmission Projects that could meet regional needs more efficiently or cost-effectively than regional transmission projects. All members of the Planning Advisory Committee shall be considered IPSAC members. The JIPC will coordinate studies deemed necessary to allow the effective consideration by the regions, in the same general timeframe, of a proposed Interregional Transmission Project in comparison to regional transmission solutions. Any stakeholder may propose in the New England planning process, for evaluation under Section 4.2, 4.3, or 4A (as applicable) of Attachment K, an Interregional Transmission Project (or project concept) that may be more efficient or cost-effective than a regional transmission solution. If a proposed Interregional Transmission Project is approved in each region in which the project is located, the corresponding New England regional transmission project(s) will be displaced in the circumstances described in Section 3.6(a) of this Attachment, and the costs of the Interregional Transmission Project will be allocated among the regions based on the formula provided in Schedule 15 of this OATT, or in accordance with another funding arrangement filed with and accepted by the Commission. The amount of the costs of an Interregional Transmission Project allocated as the responsibility of New England pursuant to the methodology referenced in Section 6.3(a) of this Attachment shall be allocated within New England as specified in Schedule 15 of the ISO OATT.

(b) Other Interregional Assessments and Other Interregional Transmission Projects
Interregional system assessments and/or interregional system expansion planning studies may be performed periodically by the ISO with Planning Authorities who are not parties to the Northeastern Planning Protocol, or with the JIPC pursuant to Section 6 of the Northeastern Planning Protocol, or both. The ISO shall convene periodic meetings of the Planning Advisory Committee (which may be combined with meetings of the IPSAC), to provide input and feedback to the ISO concerning such assessments and studies. To the extent that an Interregional Transmission Project is agreed to by ISO and by another region (not a Party to the Northeastern Planning Protocol) in which a portion of the project is located, the related cost allocation and operating agreements will be filed with the Commission (and, as applicable, with Canadian jurisdictional agencies) in accordance with existing filing rights.

7. Procedures for Development and Approval of the RSP

7.1 Initiation of RSP

No less often than once every three years, the ISO shall initiate an effort to develop its RSP and solicit input on regional system needs for the RSP from the Planning Advisory Committee. The Planning Advisory Committee shall meet to perform its respective functions in connection with the preparation of the RSP, as specified in Section 2 of this Attachment. The ISO shall issue the periodic planning reports that support the RSP, such as Needs Assessments, as those reports are completed.

7.2 Draft RSP; Public Meeting

The ISO shall provide a draft of the RSP to the Planning Advisory Committee and input from that Committee shall be received and considered in preparing and revising subsequent drafts. The ISO shall post the draft RSP and provide notice to the Planning Advisory Committee of a meeting to review the draft RSP as specified in Section 2.2 of this Attachment.

After the ISO has provided a draft of the RSP to the Planning Advisory Committee, the ISO shall issue a second draft of the RSP to be presented by the ISO staff to the ISO Board of Directors for approval. The draft RSP shall incorporate the results of any Needs Assessment, and corresponding Solutions Studies, performed since the last RSP was approved. A subcommittee of that Board shall hold a public meeting, at their discretion, to receive input directly and to discuss any proposed revisions to the RSP. The final recommended RSP shall be presented to the ISO Board of Directors and shall be acted on by the ISO Board of Directors within 60 days of receipt. The foregoing timeframes are subject to adjustment as determined by the ISO in coordination with the Planning Advisory Committee.

7.3 Action by the ISO Board of Directors on RSP; Request for Alternative Proposals

(a) Action by ISO Board of Directors on RSP

The ISO Board of Directors may approve the recommended draft RSP as submitted, modify the RSP or remand all or any portion of it back with guidance for development of a revised recommendation. The Board of Directors may consider the RSP in executive session, and shall consider in its deliberations the views of the subcommittee of the Board of Directors reflecting the public meeting held pursuant to Section 7.2 of this Attachment. In considering whether to approve the draft RSP, the Board of Directors may, if it finds a proposed Reliability Benefit Upgrade not to be viable, or if no Reliability Benefit Upgrade has been proposed, direct the ISO staff to meet with the affected load serving entities and State entities in order to develop an interim solution. Should that effort fail, and as a last resort, the Board of Directors may direct the ISO to issue a Request For Alternative Proposal (“RFAP”), subject to the procedures described below, and may withhold approval of the draft RSP, or portions thereof, pending the results of that RFAP and any Commission action on any resulting jurisdictional contract or funding mechanism. The ISO shall provide a written explanation as to any subsequent changes or modification made in the final version of the RSP.

(b) Requests For Alternative Proposals

(i) The RFAP shall seek generation, demand-side and merchant transmission alternatives that can be implemented rapidly and provide substantial reliability benefits over the period solicited in the RFAP, and normally will focus on an interim ("gap") solution until an identified Reliability Transmission Upgrade has been placed in-service. The ISO will file a proposed RFAP with the Commission for approval at least 60 days prior to its issuance. The filing shall explain why the issuance of an RFAP is necessary.

(ii) The ISO staff shall provide the Board of Directors and subject to confidentiality requirements, the Planning Advisory Committee with an analysis of the alternatives offered in response to the RFAP, and provide a recommendation together with a funding mechanism reflecting input from the Planning Advisory Committee.

(iii) The ISO may enter into contracts awarded pursuant to an RFAP process, and/or propose a funding mechanism. Bidders that are awarded contracts through the RFAP process shall file those contracts with the Commission for approval of the rates to be charged thereunder to the extent that such contracts are for services that are jurisdictional to the Commission. The ISO shall file related or separate funding mechanisms with the Commission as well. All other contracts entered into pursuant to an RFAP shall be filed with the Commission for informational purposes.

(iv) The Board of Directors will reflect the results of the RFAP process in the approved RSP.

8. Obligations of PTOs to Build; PTOs' Obligations, Conditions and Rights

In accordance with the TOA, PTOs designated by the ISO as the appropriate entities to construct and own or finance Transmission Upgrades included in the RSP shall construct and own or finance such facilities or enter into appropriate contracts to fulfill such obligations. In the event that a PTO: (i) does not construct or indicates in writing that it does not intend to construct a Transmission Upgrade included in the RSP; or (ii) demonstrates that it has failed (after making a good faith effort) to obtain necessary approvals or property rights under applicable law, the ISO shall promptly file with the Commission a report on the results of the planning process, which report shall include a report from the PTO responsible for the planning, design or construction of such Open Access Transmission Tariff Section II – Attachment K – Regional System Planning Process Transmission Upgrade, in order to permit the Commission to determine what action, if any, it should take.

In connection with regional system planning, the ISO will not propose to impose on any PTO obligations or conditions that are inconsistent with the explicit provisions of the TOA or deprive any PTO of any of the rights set forth in the TOA.

Subject to necessary approvals and compliance with Section 2.06 of the TOA, nothing in this OATT shall affect the right of any PTO to expand or modify its transmission facilities in the New England Transmission System on its own initiative or in response to an order of an appropriate regulatory authority. Such expansions or modifications shall conform with: (a) Good Utility Practice; (b) applicable reliability principles, guidelines, criteria, rules, procedures and standards of national, regional, and local reliability councils that may be in existence; and (c) the ISO and relevant PTO criteria, rules, standards, guides and policies. The ISO reserves its right to challenge the permitting of such expansions or modifications.

9. Merchant Transmission Facilities

9.1 General

Subject to compliance with the requirements of the Tariff and any other applicable requirements with respect to the interconnection of bulk power facilities with the New England Transmission System, any entity shall have the right to propose and construct the addition of transmission facilities (“Merchant Transmission Facilities”), none of the costs of which shall be covered under the cost allocation provisions of this OATT. Any such Merchant Transmission Facilities shall be subject to the requirements of Section 9.2 of this Attachment. In performing studies in connection with the RSP, the prospect that proposed Merchant Transmission Facilities will be completed shall be accounted for as will the prospect that proposed generating units will be completed.

9.2 Operation and Integration

All Merchant Transmission Facilities shall be subject to: (i) an agreement to transfer to the ISO operational control authority over any facilities which constitute part of the Merchant Transmission Facilities that are to be integrated with, or that will affect, the New England Transmission System; and (ii) taking such other action as may be required to make the facility available for use as part of the New England Transmission System.

9.3 Control and Coordination

Until such time as a Merchant Transmission Owner has transferred operational control over its Merchant Transmission Facilities to the ISO pursuant to Section 9.2(i), all such Merchant Transmission Facilities shall be subject to the operational control, scheduling and maintenance coordination of the System Operator in accordance with the Tariff.

10. Cost Responsibility for Transmission Upgrades

The cost responsibility for each upgrade, modification or addition to the transmission system in New England that is included with the status of "Planned" in the RSP Project List as defined in Section 3.6 of this Attachment shall be determined in accordance with Schedule 12 of this OATT.

11. Allocation of ARRs

The allocation of ARRs in connection with Transmission Upgrades is addressed in Section III.C.8 of the Tariff.

12. Dispute Resolution Procedures

12.1 Objective

Section 12 of this Attachment sets forth a dispute resolution process (the "Regional Planning Dispute Resolution Process") through which regional transmission planning-related disputes may be resolved as expeditiously as possible.

12.2 Confidential Information and CEII Protections

All information disclosed in the course of the Regional Planning Dispute Resolution Process shall be subject to the protection of confidential information and CEII consistent with the ISO New England Information Policy and CEII policy.

12.3 Eligible Parties

Any member of the Planning Advisory Committee that has been adversely affected by a Reviewable Determination, defined in Section 12.4(a) of this Attachment, with respect to the regional system planning process described in this Attachment is eligible to raise its dispute, as appropriate, under this Dispute Resolution Process ("Disputing Party").

12.4 Scope

In order to ensure that the regional transmission planning process set forth under this Attachment moves expeditiously forward, the scope of issues that may be subject to the Regional Planning Dispute Resolution Process under this Section 12 shall be limited to certain key procedural and substantive decisions made by the ISO within its authority as specified in documents on file with the Commission. That is, decisions not subject to resolution within the jurisdiction of the Commission are not within the scope of the Regional Planning Dispute Resolution Process. Examples of matters not within the scope of the Regional Planning Dispute Resolution Process include planning to serve retail native load or state siting issues. Additionally, the Tariff already explicitly provides specific dispute resolution procedures for various matters. To this end, any matter regarding the review and approval of applications pursuant to Section I.3.9 of the Tariff, which is subject to the dispute resolution process under Section I.6 of the Tariff, shall not be within the scope of this Regional Planning Dispute Resolution Process. Similarly, any matter regarding Transmission Cost Allocation shall be governed by the dispute resolution process under Schedule 12 of the OATT, and shall be outside the scope of this Regional Planning Dispute Resolution Process.

(a) Reviewable Determinations

The determinations that may be subject to the Regional Planning Dispute Resolution Process under this Section 12 that include certain procedural and substantive challenges that may arise at limited designated key decision points in the regional transmission planning process for PTF. Procedural challenges will be limited to whether or not the steps taken up to a designated key decision point conform to the requirements set forth in this Attachment. Substantive challenges will be limited to whether or not a determination or conclusion rendered at a designated key decision point was supported by adequate basis in fact.

The designated key decision points for Reviewable Determinations shall be limited to the following:

(i) Results of a Needs Assessment conducted and communicated by the ISO to the Planning Advisory Committee as specified in Section 4.1 of this Attachment;

(ii) Updates to the RSP Project List, including adding, removing or revising regulated transmission solutions included thereunder, as presented at the Planning Advisory Committee and as specified in Section 3.6 of this Attachment;

(iii) Results of Solutions Studies conducted and communicated by the ISO to the Planning Advisory Committee as specified in Section 4.2 of this Attachment;

(iv) Consideration of market responses in Needs Assessments as specified in Section 4.1(f) of this Attachment;

(v) Prioritization and substance of Stakeholder-Requested Scenarios to be conducted by the ISO in a given Economic Study cycle as specified in Section 17.2(d) of this Attachment; and

(vi) Prioritization of Economic Study scenario sensitivities to be performed in a given Economic Study cycle where the Planning Advisory Committee is not able to prioritize them as specified in Section 17.4 of this Attachment.

(b) Material Adverse Impact

In order to prevail in a challenge to a procedural-based Reviewable Determination, the Disputing Party must show that the alleged procedural error had a material adverse impact on the determination or conclusion. In order to prevail in a challenge to a substantive-based Reviewable Determination, the Disputing Party must show that either (i) the determination is based on incorrect data or assumptions or (ii) incorrect analysis was performed by the ISO, and (iii) as a result the ISO made an incorrect decision or determination.

12.5 Notice and Comment

A Disputing Party aggrieved by a Reviewable Determination shall have fifteen (15) calendar days upon learning of the Reviewable Determination following the ISO's presentation of such Reviewable Determination at the Planning Advisory Committee to request dispute resolution by giving notice to the ISO ("Request for Dispute Resolution"). A Request for Dispute Resolution shall be in writing and shall be addressed to the ISO's Chair of the Planning Advisory Committee and, as appropriate, the affected Transmission Owner. Within three (3) Business Days of the receipt by the ISO of a Request for Dispute Resolution, the ISO shall prepare and distribute to all members of the Planning Advisory Committee a notice of the Request for Dispute Resolution including, subject to the protection of Confidential Information and CEII, the specifics of the Request for Dispute Resolution and providing the name of an ISO representative to whom any comments may be sent. Any member of the Planning Advisory Committee may submit to the ISO's designated representative, on or before the tenth (10th) Business Day following the date the ISO distributes the notice of the Request for Dispute Resolution, written comments to the ISO with respect to the Request for Dispute Resolution. The party filing the Request for Dispute Resolution may respond to any such comments by submitting a written response to the ISO's designated representative and to the commenting party on or before the fifteenth (15th) Business Day following the date the ISO distributes the notice of the Request for Dispute Resolution. The ISO may, but is not required to, consider any written comments.

12.6 Dispute Resolution Procedures

(a) Resolution Through the Planning Advisory Committee

The Planning Advisory Committee shall discuss and resolve any dispute arising under this Attachment involving a Reviewable Determination, as defined in Section 12.4 of this Attachment, between and among the ISO, the Disputing Party, and, as appropriate, the affected Transmission Owner (collectively, "Parties") (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution).

(b) Resolution Through Informal Negotiations

To the extent that the Planning Advisory Committee is not able to resolve a dispute arising under this Attachment involving a Reviewable Determination, as defined in Section 12.4 of this Attachment, between and among the ISO, the Disputing Party, and, as appropriate, the affected

Transmission Owner, such dispute shall be the subject of good-faith negotiations among the Parties. Each Party shall designate a fully authorized senior representative for resolution on an informal basis as promptly as practicable.

(c) Resolution Through Alternative Dispute Resolution

In the event the designated representatives are unable to resolve the dispute through informal negotiation within thirty (30) days, or such other period as the Parties may agree upon, by mutual agreement of the Parties, such dispute may be submitted to mediation or any other form of alternative dispute resolution upon the agreement of all Parties to participate in such mediation or other alternative dispute resolution process. Such form of alternative dispute resolution shall not include binding arbitration.

If a Party identifies exigent circumstances reasonably requiring expedited resolution of the dispute, such Party may file a Complaint with the Commission or seek other appropriate redress before a court of competent jurisdiction.

12.7 Notice of Dispute Resolution Process Results

Within three (3) Business Days following the resolution of a dispute pursuant to either Section 12.6(b) or Section 12.6(c) of this Attachment, the ISO shall distribute to the Planning Advisory Committee a document reflecting the resolution.

13. Rights Under The Federal Power Act

Nothing in this Attachment shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

14. Annual Assessment of Transmission Transfer Capability

Each year, the ISO shall issue the results of the annual assessment of transmission transfer capability, conducted pursuant to applicable NERC, NPCC and ISO New England standards and criteria and the identification of potential future transmission system weaknesses and limiting facilities that could impact the transmission system's ability to reliably transfer energy in the planning horizon. Each annual assessment will identify those portions of the New England system, along with the associated interface boundaries, that should be considered in the assessment of Capacity Zones to be modeled in the Forward Capacity Market pursuant to ISO Tariff Section III.12. This report will be posted on the ISO website.

Each annual assessment will model out-of-service resources associated with the following bids, if the ISO determines the removal of the resource is likely to have an impact on the transmission transfer limits for the relevant period: Retirement De-List Bids, Permanent De-List Bids, demand bids submitted for the upcoming substitution auction, and rejected for reliability Static De-List Bids and rejected for reliability Dynamic De-List Bids from the most recent Forward Capacity Auction.

15. Procedures for the Conduct of Cluster Enabling Transmission Upgrades Regional Planning Study

The purpose of this Section 15 is to support the conduct of Interconnection Studies under the Interconnection Procedures set forth in Schedules 22, 23 and 25 of Section II of the Tariff. Other than Section 2 of this Attachment K regarding the responsibilities of the Planning Advisory Committee and this Section 15, none of the other provisions in this Attachment K apply to the conduct of the Cluster Enabling Transmission Upgrade Regional Planning Study or the results of the study.

15.1 Notice of Initiation of Cluster Enabling Transmission Upgrade Regional Planning Study in Support of Cluster Studies under the Interconnection Procedures.

Pursuant to Section 4.2.2 of Schedule 22, Section 1.5.3.2 of Schedule 23, and Section 4.2.2 of Schedule 25 of Section II of this Tariff, the ISO shall provide notice to the Planning Advisory Committee of the initiation of a cluster for studying certain Interconnection Requests. The cluster study process, known as Clustering, shall consist of two phases. This notice shall trigger the first phase of Clustering, during which the ISO shall conduct a Cluster Enabling Transmission Upgrade (“CETU”) Regional Planning Study (“CRPS”) (the cost of which will be recovered by the ISO pursuant to Schedule 1 of Section IV.A of the Tariff). In the second phase of Clustering, the ISO shall conduct Interconnection System Impact Studies and Interconnection Facilities Studies in clusters pursuant to Schedules 22, 23 and 25 of Section II of the Tariff.

15.2 Preparation for Conduct of CRPS; Stakeholder Input

The purpose of the CRPS shall be to identify the new transmission infrastructure and any associated system upgrades to enable the interconnection of potentially all of the resources proposed in the Interconnection Requests for which the conditions identified in Section 4.2.1 of Schedule 22, Section 1.5.3.1 of Schedule 23, and Section 4.2.1 of Schedule 25 of Section II of the Tariff have been triggered. The ISO will prepare and post on its website, consistent with Section 2.4(d) of this Attachment K, a proposed scope of the CRPS and associated parameters and assumptions, and provide the foregoing to the Planning Advisory Committee. A meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit stakeholder input for consideration by the ISO on the CRPS's scope, parameters and assumptions, consistent with the responsibilities of the Planning Advisory Committee as set forth in Section 2.2 of this Attachment. As part of the CRPS's scope, the ISO will describe the circumstances that triggered the conditions in Section 4.2.1 of Schedule 22, Section 1.5.3.1 of Schedule 23, and Section 4.2.1 of Schedule 25 of Section II of the Tariff. In addition, the ISO will identify: (i) the Interconnection Requests, to be referenced by Queue Position, that are expected to be eligible to participate in the Cluster Interconnection System Impact Study, and (ii) the preliminary transmission upgrade concepts proposed to be considered in the CRPS. The preliminary transmission upgrade concepts may account for previously conducted transmission reinforcement studies and previously identified concepts for transmission upgrades in the relevant electrical area, including Elective Transmission Upgrades with Interconnection Requests pending in the interconnection queue prior to the initiation of the CRPS.

A member of the Planning Advisory Committee or an Interconnection Customer may make a written submission to the ISO, requesting that Clustering be considered for specific Interconnection Requests in the ISO New England interconnection queue. In response to such a request, the ISO will either develop a notice of initiation of a cluster pursuant to Section 15.1 of this Attachment K, or identify, in writing, to the Planning Advisory Committee why the conditions in Section 4.2.1 of Schedule 22, Section 1.5.3.1 of Schedule 23, and Section 4.2.1 of Schedule 25 of Section II of the Tariff have not been triggered.

15.3 Conduct of the CRPS

The CRPS will consist of analyses performed under the conditions used in the conduct of an Interconnection System Impact Study under the Interconnection Procedures. The CRPS will consist of steady state thermal analysis, voltage and transient stability analysis, and, as appropriate, other analysis, such as weak-grid-related analyses. The ISO will use Reasonable Efforts to complete the CRPS within twelve (12) months from the notice of the cluster initiation to the Planning Advisory Committee. If less than two (2) Interconnection Requests identified pursuant to Section 4.2.1 of Schedule 22, Section 1.5.3.1 of Schedule 23, and Section 4.2.1 of Schedule 25 of Section II of the Tariff remain in the interconnection queue prior to the completion of the CRPS, the ISO will terminate the CRPS.

15.4 Publication of the CRPS

The ISO shall post a draft report of the CRPS to the Planning Advisory Committee, consistent with Section 2.4(d) of this Attachment K, and a meeting of the Planning Advisory Committee will be held promptly thereafter in order to discuss the results of the CRPS. A comment period will follow the Planning Advisory Committee meeting. The ISO will post on its website any comments received and the ISO's responses to those comments.

The CRPS report will provide:

(i) a planning level description of the CETU(s) and a non-binding good faith order-of-magnitude estimate, developed by the applicable Transmission Owner(s), of the costs for the CETU(s);

(ii) a list of other facilities that may be needed in addition to the CETU(s) and a non-binding good faith order-of-magnitude estimate, developed by the applicable Transmission Owner(s), of the costs for those facilities (the CRPS will not provide descriptions of expected Interconnection Facilities for specific Interconnection Requests in the cases where the Interconnection Facilities cannot be finalized until the actual Interconnection Requests that will be moving forward in the cluster are known);

(iii) the approximate megawatt quantity (or quantities if more than one level of megawatt injection was studied in the CRPS) of resources that could be interconnected in a manner that meets the Network Capability Interconnection Standard and the Capacity Capability Interconnection Standard in accordance with Schedules 22, 23 and 25 of Section II of the Tariff; and,

(iv) a list of the Interconnection Requests, to be referenced by Queue Position, that at the sole discretion of the ISO are identified as eligible to participate in the Cluster Interconnection System Impact Study that will be conducted by the ISO in accordance with Section 4.2.3 of Schedule 22, Section 1.5.3.3 of Schedule 23, and Section 4.2.3 of Schedule 25 of Section II of the Tariff. The list shall include the expected cost allocation for the eligible

Interconnection Requests, calculated in accordance with Schedule 11 of Section II of the Tariff.

The non-binding good faith order-of-magnitude estimates under Section 15.4(i)-(ii) of this Attachment will be developed by the applicable Transmission Owner(s), and the costs of developing such estimates shall be recovered as specified in Sections 3.3.1, 6.1 and 7.2 of Schedule 22, Section 3.3.1, 3.4.2, and Attachment 1 of Schedule 23, and Section 3.3.1, 6.1 and 7.2 of Schedule 25.

The posting, consistent with Section 2.4 (d) of this Attachment K, of the final CRPS report on the ISO website will trigger the Cluster Interconnection System Impact Study Entry Deadline specified in Section 4.2.3.1 of Schedule 22, Section 1.5.3.3.1 of Schedule 23, and Section 4.2.3.1 of Schedule 25 of Section II of the Tariff. The Cluster Interconnection System Impact Study Entry Deadline shall be 30 days from the posting of the final CRPS report.

Notwithstanding any other provision in this Section 15, the final Maine Resource Integration Study shall be the first CRPS and will form the basis for the first Cluster Interconnection System Impact Study to be conducted in accordance with Section 4.2.3 of Schedule 22, Section 1.5.3.3 of Schedule 23, and Section 4.2.3 of Schedule 25 of Section II of the Tariff.

16. Procedures for the Conduct of Longer-Term Transmission Studies and Evaluation of Longer-Term Transmission Upgrades

This Section 16 sets forth the procedures for the ISO's conduct of Longer-Term Transmission Studies and evaluation of Longer-Term Transmission Upgrades. ~~Other than Section 2, regarding the responsibilities of the Planning Advisory Committee, Section 5, regarding the supply of information, and this Section 16 of this Attachment K, none of the other provisions in this Attachment K apply to the conduct of the Longer-Term Transmission Studies.~~ These procedures supplement, and are not intended to replace, other study processes provided in this Attachment K. The costs incurred by the ISO in consulting or providing technical support, performing the Longer-Term Transmission Study and any follow-on study, and conducting the solicitation process for Longer-Term Transmission Upgrades (excluding any costs incurred by the ISO associated with the evaluation of Longer-Term Proposals) shall be recovered pursuant to Schedule 1 of Section IV.A of the Tariff.

16.1 Request for Longer-Term Transmission Studies

The ISO, at its sole discretion, may collaborate with and provide technical support to NESCOE or the New England states in connection with the states' procurements, and efforts to secure federal funding for transmission investments. In addition, NESCOE may submit a written request for the ISO to conduct a Longer-Term Transmission Study to identify high-level concepts of transmission infrastructure and, if requested, high-level cost estimates that could meet State-identified Requirements specified in the request based on state-identified scenarios and timeframes, which may extend beyond the five-to-ten year planning horizon. A request for a Longer-Term Transmission Study may be submitted to the ISO no earlier than six months from conclusion of the prior cycle, which includes Longer-Term Transmission Studies, follow-on studies, and any associated competitive solicitation. The Longer-Term Transmission Study request shall identify the State-identified Requirements that serve as the basis of the request; the proposed objectives of the study; and the scenarios and timeframe(s) proposed for use in the study.

16.2 Preparation for Conduct of the Longer-Term Transmission Studies; Stakeholder Input

Upon receipt of a request for a Longer-Term Transmission Study from NESCOE, the ISO will post the request on the ISO's website. A meeting of the Planning Advisory Committee will be held promptly thereafter for NESCOE to present the Longer-Term Transmission Study request. NESCOE will then provide the ISO written confirmation of the specific scenarios to be analyzed in the study, together with the specific information to facilitate the conduct of the study, including, but not limited to: assumptions, types and location of new resource development, location of new loads and load serving stations, and injection points or geographic zones. The ISO will then develop a scope of work that may be performed, and post on the ISO's website the Longer-Term Transmission Study's proposed scope of work, associated parameters, and assumptions. A meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit stakeholder input on the study's scope, parameters, and assumptions. Members of the Planning Advisory Committee shall direct all such input related to the Longer-Term Transmission Study's scope, parameters, and assumptions to the ISO for consideration by the ISO and NESCOE, as applicable. Depending on the scope and objectives of a Longer-Term Transmission Study request, the ISO may request information to support consideration of new loads in the study. The ISO will provide the final scope of work for the Longer-Term Transmission Study to NESCOE for confirmation, and once written confirmation is received, will post the final scope of work on the ISO's website.

16.3 Conduct of the Longer-Term Transmission Study; Follow-on Studies; Stakeholder Input

The ISO, in consultation with NESCOE, will perform the Longer-Term Transmission Study, supplemented by third-party consultants as necessary. The ISO may ask Participating Transmission Owners or Planning Advisory Committee members with special expertise to provide technical support or assist in the performance of the study. The study will consist of transmission system analysis to be performed under the conditions specified in the confirmed scope of work. If the ISO identifies a need to deviate from the final scope of work, the ISO will consult with NESCOE prior to incorporating the change. Once NESCOE provides written confirmation, the ISO will notify the Planning Advisory Committee of any changes. The study will assess the ability of the PTF to meet applicable planning criteria under the provided conditions.

~~The costs of the performance of the Longer-Term Transmission Study will be recovered pursuant to Schedule 1 of Section IV.A of the Tariff.~~

The ISO will post on the ISO's website the results of the Longer-Term Transmission Study. A meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit input on the study results. Members of the Planning Advisory Committee shall direct all such input related to the Longer-Term Transmission Study results to the ISO for consideration by the ISO and NESCOE, as applicable.

The ISO, in consultation with NESCOE, will prepare a Longer-Term Transmission Study report and post it on the ISO's website. The report will identify the overview of transmission system limitations and the high-level concepts of transmission infrastructure and, if requested, associated cost estimates, required to solve the longer-term issues identified in the study based on the state-identified scenarios and timeframe. Members of the Planning Advisory Committee shall direct all such input related to the Longer-Term Transmission Study report to the ISO for consideration by the ISO and NESCOE, as applicable.

NESCOE may submit a written request for the ISO to perform follow-on studies based on the results of the Longer-Term Transmission Study. In its request, NESCOE will provide the ISO specific scenarios to be analyzed in the follow-on study, together with specific information to facilitate the conduct of the study, including, but not limited to scope, parameters and assumptions. Upon receipt of the request for a follow-on study, the ISO will post the request for a follow-on study on the ISO's website and a meeting of the Planning Advisory Committee will be held promptly thereafter for NESCOE to present the follow-on study request. NESCOE will then provide the ISO written confirmation of the specific scenarios to be analyzed in the follow-on study, together with the specific information to facilitate the conduct of the study, including, but not limited to scope, parameters and assumptions. The ISO will then develop a scope of work that may be performed and post on the ISO's website the follow-on study's proposed scope of work, associated parameters, and assumptions. A meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit stakeholder input on the study's scope, parameters, and assumptions. Members of the Planning Advisory Committee shall direct all such input related to the follow-on study's scope, parameters, and assumptions to the ISO for consideration by the ISO and NESCOE, as applicable. The ISO will provide the final scope of work for the follow-on study to NESCOE for confirmation, and once written confirmation is received, will post the final scope of work on the ISO's website and proceed with performing the follow-on study.

The results of the follow-on study will be posted on the ISO's website and a meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit input on the results. Such input shall be directed to the ISO for consideration by NESCOE and the ISO, as applicable. The ISO will prepare a follow-on study report, as needed, and post it on the ISO's website.

16.4 Competitive Solution Process for Longer-Term Transmission Upgrades

(a) Identification of Longer-Term Needs; Request for Proposal Determination

At the request of NESCOE, the ISO will consult with and provide technical support to NESCOE on possible longer-term needs that may be addressed through one or more request for proposal(s) ~~based on results of~~in connection with a Longer-Term Transmission Study or a follow-on study. During this consultation, the ISO, at its sole discretion, may also identify for NESCOE's consideration known non-time-sensitive reliability or market efficiency needs that could be combined with longer-term needs in a request for proposal(s). NESCOE determines which potential needs will be included in a request for proposal(s) and whether to move forward with such a request(s). If the ISO receives from NESCOE a written list identifying the specific needs that NESCOE may be interested in including in one or more potential request for proposal(s), the ISO will post the list on the ISO's website. A meeting of the Planning Advisory Committee will be held promptly thereafter for NESCOE to present the needs. Members of the Planning

Advisory Committee shall direct all comments related to the NESCOE-identified needs to the ISO for consideration by NESCOE.

Any time following NESCOE's receipt and consideration of Planning Advisory Committee input but prior to NESCOE submitting a request to initiate a subsequent Longer-Term Transmission Study, NESCOE may submit a written request for the ISO to publicly issue, via a posting on the ISO's website, a request for proposal(s) inviting Qualified Transmission Project Sponsors to submit proposals offering a comprehensive solution that addresses the needs specified in NESCOE's request for the ISO to initiate a request for proposal(s).

Notwithstanding any other provision to the contrary, if a non-time-sensitive reliability or market efficiency need that the ISO identified for NESCOE's consideration under this Section 16.4(a) is combined with longer-term needs included in a request for proposal(s), then the reliability or market efficiency need and the development of regulated transmission solutions for that need shall be subject to the procedures for longer-term transmission planning in Section 16. If any non-time-sensitive reliability or market efficiency needs are not included in the needs selected by NESCOE to be addressed in a request for proposal(s), then those non-time-sensitive reliability or market efficiency needs shall be addressed pursuant to Section 4.3 of this Attachment K. If the longer-term process is terminated pursuant to Section 16.6 of this Attachment K or corresponding Longer-Term Transmission Upgrade is removed from the RSP Project List pursuant to Section 3.6(c), then: (1) in the case of a market efficiency need, the ISO shall initiate the process under Section 4.3 of this Attachment K, and (2), in the case of a reliability need, notwithstanding any other provisions to the contrary, the ISO shall: (i) assess the reliability need and its time-sensitivity, as appropriate; (ii) determine whether a solution is needed to solve the reliability need in three years or less from the completion of the assessment in this Section 16.4(a); and (iii) initiate the applicable process pursuant to Sections 4.1-4.3 of this Attachment K.

(b) Issuance of Request for Proposal

The ISO will publicly post on its website a request for proposal(s) inviting Qualified Transmission Project Sponsors to submit (by the deadline specified in the request for proposal, which shall not be less than 60 days from the date of posting the request for proposal) a Longer-Term Proposal offering a comprehensive solution that addresses all the needs identified in the request. The request for proposal will indicate that a Qualified Transmission Project Sponsor may submit an individual or joint Longer-Term Proposal(s). In the case where a joint proposal is submitted, all parties must be Qualified Transmission Project Sponsors.

(c) Use and Control of Right of Way

Neither the submission of a project by a Qualified Transmission Project Sponsor nor the selection by the ISO of a project submitted by a Qualified Transmission Project Sponsor for inclusion in the RSP Project List shall alter a PTO's use and control of an existing right of way, the retention, modification, or transfer of which remain subject to the relevant law or regulation, including property or contractual rights, that granted the right-of-way. Nothing in the processes described in this Attachment K requires a PTO to relinquish any of its rights-of-way in order to permit a Qualified Transmission Project Sponsor to develop, construct or own a project.

(d) Information Required for Longer-Term Proposals; Study Deposit; Timing

The following information must be provided as part of the Longer-Term Proposal:

(i) detailed description of the proposed solution, in the manner specified by the ISO, including an identification of the proposed route for the solution and technical details of the project, such as interconnection into the existing transmission system;

(ii) detailed explanation of how the proposed solution addresses the identified need(s);

(iii) list of required major Federal, State and local permits

(iv) proposed schedule, including key high-level milestones, for development, siting, procurement of real estate rights, permitting, construction and completion of the proposed solution;

(v) right, title, and interest in rights of way, substations, and other property or facilities, if any, that would contribute to the proposed solution or the means and timeframe by which such would be obtained;

(vi) description of the authority the Qualified Transmission Project Sponsor(s) has to acquire necessary rights of way;

(vii) experience of the Qualified Transmission Project Sponsor(s) in acquiring rights of way;

(viii) description of construction sequencing, a conceptual plan for the anticipated transmission and generation outages necessary to construct the proposed solution and their respective duration, and possible constraints;

(ix) detailed cost component itemization and life-cycle cost, including cost containment or cost cap measures;

(x) description of the financing being used;

(xi) design and equipment standards to be used;

(xii) detailed explanation of project feasibility and potential constraints and challenges;

(xiii) description of the means by which the Qualified Transmission Project Sponsor(s) proposes to satisfy legal or regulatory requirements for siting, constructing, owning and operating transmission projects; and

(xiv) detailed explanation of potential future expandability.

A Qualified Transmission Project Sponsor may submit a proposed solution that includes an upgrade(s) located on or connected to a PTO's existing transmission system where the Qualified Transmission Project Sponsor is not the PTO for the existing system element(s). In such cases, the Qualified Transmission Project Sponsor's proposed solution relating to the upgrade(s) of an existing transmission system element(s) must provide all data available to the Qualified Transmission Project Sponsor as part of its response to the request for proposal. The Qualified Transmission Project Sponsor is not required to procure agreements with the PTO for implementation of such upgrades as the PTO is required to implement the upgrade(s) in accordance with Schedule 3.09(a) of the Transmission Operating Agreement if the proposed solution is selected through the competitive process.

With each proposal, the submitting Qualified Transmission Project Sponsor must include payment of a $100,000 study deposit per submitted Longer-Term Proposal to support the cost of Longer-Term Proposal evaluation by the ISO. The study deposit of $100,000 shall be applied toward the costs incurred by the ISO associated with the evaluation of the Longer-Term Proposal. Any difference between a Qualified Transmission Project Sponsor's study deposit and the actual cost of the evaluation of a Longer-Term Proposal shall be paid by or refunded to the Qualified Transmission Project Sponsor, as appropriate, with interest calculated in accordance with Section 35.19a(a)(2) of the FERC regulations. Any refund payment shall be accompanied by a detailed and itemized accounting of the actual study costs incurred. Any invoice to collect funds in addition to the deposit shall be accompanied by a detailed and itemized accounting of the actual study costs incurred. Any disputes arising from the study process shall be addressed under the dispute resolution process specified in Section I.6 of the ISO Tariff.

Longer-Term Proposals must be submitted by the deadline specified in the public posting by the ISO of the request for proposal. The ISO may reject submittals which are insufficient or not adequately supported.

(e) LSP Coordination

Qualified Transmission Project Sponsors of Longer-Term Proposals shall also identify any LSP plans that require coordination with their Longer-Term Proposals.

(f) Review of Longer-Term Proposals

Upon receipt of Longer-Term Proposals, the ISO shall perform a review of each proposal to determine whether the proposal:

(i) provides sufficient data and that the data is of sufficient quality to satisfy Section 16.4(d);
(ii) satisfies the needs identified in the request for proposal;
(iii) is technically practicable and indicates possession of, or an approach to acquiring, the necessary rights of way, property and facilities that will make the proposal reasonably feasible in the required timeframe; and;
(iv) is eligible to be constructed only by an existing PTO in accordance with Schedule 3.09(a) of the TOA because the proposed solution is an upgrade to existing PTO facilities or because the costs of the proposed solution are not eligible for regional cost allocation under the OATT and will be allocated only to the local customers of a PTO.

F[A2]or each Longer-Term Proposal that satisfies the criteria specified in this Section 16.4(f), the ISO shall also perform an independent capital cost estimate, using a consistent capital cost estimating methodology, to ensure consistency in its review of the Longer-Term Proposals and their cost estimates.

(g) Proposal Deficiencies; Further Information

If the ISO identifies any minor deficiencies (compared with the requirements of Section 16.4(d)) in the information provided in connection with a Longer-Term Proposal, the ISO will notify the Qualified Transmission Project Sponsor that submitted the Longer-Term Proposal and provide an opportunity for the Qualified Transmission Project Sponsor to cure the deficiencies within the timeframe specified by the ISO. Upon request, Qualified Transmission Project Sponsors of Longer-Term Proposals shall provide the ISO with additional information reasonably necessary for the ISO's evaluation of the proposed solutions. In providing information under this subsection (g), the Qualified Transmission Project Sponsor may not modify its project materially or submit a new project, but instead may clarify its Longer-Term Proposal.

(h) Identification and Reporting of Preliminary Preferred Longer-Term Transmission Solution; Stakeholder Input

The ISO will identify the Longer-Term Transmission Solution that offers the best combination of electrical performance, cost, future system expandability and feasibility to comprehensively address all of the needs in the timeframes specified in the request for proposal(s) as the preliminary preferred Longer-Term Transmission Solution in response to each request for proposal.

The ISO will consider several factors during the evaluation process for identification of the preliminary preferred Longer-Term Transmission Solution. These factors may include, but are not limited to, the following which are listed in no particular order:

- Life-cycle cost, including all costs associated with right of way acquisition, easements, and associated real estate;
- System performance;
- Cost cap or cost containment provisions;
- In-service date of the project or portion(s) thereof;
- Project constructability;
- Generation and transmission facility outages required during construction;
- Extreme contingency performance;
- Operational impacts;

- Incremental costs for potential resource retirements;
- Interface impacts;
- Future expandability;
- Consistency with Good Utility Practice;
- Potential siting/permitting issues or delays;
- Environmental impact;
- Design standards;
- Impact on NPCC Bulk Power System classification; and
- Qualified Transmission Project Sponsor(s) capabilities

The ISO will determine the financial benefits associated with Longer-Term Proposals that meet the needs identified in the request for proposal(s) and are competitive in terms of electrical performance, cost, future system expandability and feasibility. These financial benefits will consider factors that include, but are not limited to, the following which are listed in no particular order:

- Production cost and congestion savings;
- Avoided capital cost of local resources needed to serve demand;
- Avoided transmission investment;
- Reduction in losses; and
- Reduction in expected unserved energy

To be eligible for consideration as the preliminary preferred Longer-Term Transmission Solution, the Longer-Term Proposal must provide a benefit-to-cost ratio of greater than 1.0. Longer-Term Proposals with a benefit-to-cost ratio of 1.0 or less shall not be eligible for consideration as the preliminary preferred Longer-Term Transmission Solution. The benefit-to-cost ratio shall equal financial benefits divided by project costs. For the purpose of this calculation, financial benefits will be set equal to the present value of all financially quantifiable benefits provided by the project projected for the first 20 years of the project’s life and project costs will be set equal to the present value of the annual revenue requirements projected for the first 20 years of the project’s life.

The ISO will report the preliminary preferred Longer-Term Transmission Solution to the Planning Advisory Committee and seek input on the preliminary preferred Longer-Term Transmission Solution. Members of the Planning Advisory Committee may provide comments to the ISO on the preliminary preferred Longer-Term Transmission Solution.

(i) ISO Selection of Preferred Longer-Term Transmission Solution; NESCOE Response

Following receipt of stakeholder input, the ISO will identify the preferred Longer-Term Transmission Solution, together with an overview of why the solution is preferred, in a report and post that report on the ISO's website. The ISO will select the project that meets the conditions specified in Section 16.4(h) of this Attachment K. Within 30 days of the ISO's posting of the report identifying the preferred Longer-Term Transmission Solution, NESCOE may submit to the ISO a written communication: (a) requesting that the ISO terminate the process, or (b) requesting that the ISO continue the process, but specifying an alternative allocation for the recovery of the incremental costs to address longer-term needs beyond those necessary to address any reliability or economic needs included in the longer-term request for proposal(s). If the ISO does not receive a written communication requesting that the ISO terminate the process, the ISO will proceed in accordance with Section 16.5 of this Attachment K, which shall apply solely to Longer-Term Proposals that meet the greater than 1.0 benefit-to-cost ratio threshold. The ISO shall terminate the process if requested to do so in the written NESCOE communication pursuant to Section 16.6 of this Attachment.

(j) ISO Reporting Where No Longer-Term Proposal Meets the Greater than 1.0 Benefit-to-Cost Ratio Threshold; NESCOE Response

In the event that no Longer-Term Proposal meets the benefit-to-cost ratio threshold, the ISO will present its findings to the Planning Advisory Committee. In the absence of a Longer-Term Proposal that meets the benefit-to-cost ratio threshold, the ISO will not identify a preliminary preferred Longer-Term Transmission Solution, but will make a recommendation on a Longer-Term Proposal. Members of the Planning Advisory Committee may provide comments to the ISO on its findings, and the ISO will provide and post on its website responses to written comments. If, after considering stakeholder input, the ISO determines that no Longer-Term Proposal meets the benefit-to-cost ratio threshold, the ISO will cancel the request for proposal in accordance with Section 16.6 of this Attachment K after the 15th day from the posting of the ISO's responses on the website. Notwithstanding any other provision of this Attachment K, the ISO will not cancel the request for proposal in accordance with Section 16.6 of this Attachment K if, by the 15th day from the posting of the ISO's responses on the website, the ISO receives a written communication from NESCOE: (a) accepting the ISO recommended Longer-Term Proposal, identifying the New England states, individually or jointly, that have agreed to voluntarily fund the costs of that Longer-Term Proposal in excess of those eligible for treatment as Regional Benefit Upgrades pursuant to Schedule 12 of the OATT, and identifying the manner in which those excess costs shall be allocated among the states identified in the communication, or (b) identifying up to three Longer-Term Proposals for which NESCOE seeks further analysis. If the communication from NESCOE accepts the ISO-recommended Longer-Term Proposal, this proposal becomes the preferred Longer-Term Proposal and the ISO will proceed in accordance with Section 16.8 of this Attachment K, which shall apply solely to Longer-Term Proposals that do not meet the greater than 1.0 benefit-to-cost ratio threshold. If NESCOE identifies Longer-Term Proposals for further analysis, the ISO will perform further analysis of these proposals, present its findings to the Planning Advisory Committee for input, and post that input on its website. A Longer-Term Proposal is eligible for NESCOE's identification as a preferred Longer-Term Proposal if the ISO, at its sole discretion, has determined that it addresses all the needs in the timeframes specified in the request for proposal(s) and is viable. The ISO will cancel the request for proposal in accordance with Section 16.6 of this Attachment K after 15 days from posting the Planning Advisory Committee's input, unless the ISO receives a written communication from NESCOE identifying a preferred Longer-Term Proposal, the New England states, individually or jointly, that have agreed to voluntarily fund the costs of that Longer-Term Proposal in excess of those eligible for treatment as Regional Benefit Upgrades pursuant to Schedule 12 of the OATT, and identifying the manner in which those excess costs shall be allocated among the states identified in the communication, in which case, the ISO will proceed in accordance with Section 16.8 of this Attachment K.

16.5 Where the Greater than 1.0 Benefit-to-Cost Ratio Threshold has Been Met: Inclusion of Longer-Term Transmission Upgrade in the Regional System Plan and RSP Project List; Milestone Schedule; Removal from RSP Project List

(a) Inclusion of Longer-Term Transmission Upgrade in the Regional System Plan and RSP Project List

If the ISO does not receive a written NESCOE communication requesting that the ISO terminate the process or providing an alternative cost allocation within the 30 day period specified in Section 16.4(i) of this Attachment, the ISO will notify the Qualified Transmission Project Sponsor that proposed the preferred Longer-Term Transmission Solution that its project has been selected for development, and include the project as a Longer-Term Transmission Upgrade in the Regional System Plan or RSP Project List, as it is updated from time to time in accordance with this Attachment. The preferred Longer-Term Transmission Solution may include an upgrade(s) located on or connected to a PTO's existing transmission system where the Qualified Transmission Project Sponsor is not the PTO for the existing system element(s). In such cases, the ISO will notify the PTO that has upgrades required by the preferred Longer-Term Transmission Solution to proceed in accordance with Schedule 3.09(a) of the TOA.

If the ISO receives a written NESCOE communication providing an alternative cost allocation pursuant to Section 16.4(i) of this Attachment, the ISO will notify the Qualified Transmission Project Sponsor that proposed the preferred Longer-Term Transmission Solution that its project has been selected for development and the PTO that has upgrades required by the preferred Longer-Term Transmission Solution, and provide them the written NESCOE communication reflecting the requested alternative cost allocation. In the case where the ISO notifies the PTO that has upgrades required by the preferred Longer-Term Transmission Solution to proceed in accordance with Schedule 3.09(a) of the TOA, any prudently incurred PTO costs associated with a filing to implement the cost allocation requested by NESCOE will be recovered by the applicable PTO in accordance with Attachment F of this OATT.

Within 30 days of the Commission's order addressing the alternative cost allocation, NESCOE will provide the ISO a communication specifying whether the process should proceed in accordance with Section 16.5(b) or terminate in accordance with Section 16.6 of this Attachment K. If the written NESCOE communication provides for the process to proceed, then the ISO will notify the Qualified Transmission Project Sponsor and PTO and include the project as a Longer-Term Transmission Upgrade in the Regional System Plan or RSP Project List, as it is updated from time to time in accordance with this Attachment. If the written NESCOE communication requests termination of the process, the ISO shall terminate the process pursuant to Section 16.6 of this Attachment.

Costs for the Longer-Term Transmission Upgrade included in the Regional System Plan or RSP Project List shall be allocated in accordance with Section 10 of Schedule 12 to this OATT.

(b) Execution of Selected Qualified Transmission Project Sponsor Agreement

If the ISO does not receive a written NESCOE communication requesting that the ISO terminate the process or providing an alternative cost allocation pursuant to Section 16.4(i) of this Attachment, within 30 days of ~~its~~ receiving notification pursuant to Section 16.5(a) of this Attachment, the Qualified Transmission Project Sponsor shall submit to the ISO its acceptance of responsibility to proceed with the preferred Longer-Term Transmission Solution by execution of the Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT). Within 30 days of receiving notification pursuant to Section 16.5(a) of this Attachment, each Qualified Transmission Project Sponsor that is part of the joint proposal shall submit to the ISO its acceptance of responsibility to proceed with the preferred Longer-Term Transmission Solution by execution of a Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT). Any cost cap or cost containment provisions shall be included in each Selected Qualified Transmission Project Sponsor Agreement.

If the ISO receives a written NESCOE communication providing an alternative cost allocation pursuant to Section 16.4(i) of this Attachment, within 30 days of the ISO's notification to the Qualified Transmission Project Sponsor that NESCOE has elected to proceed, the Qualified Transmission Project Sponsor shall submit to the ISO its acceptance of responsibility to proceed with the preferred Longer-Term Transmission Solution by execution of the Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT). Within 30 days of the ISO's notification to the Qualified Transmission Project Sponsor that NESCOE has elected to proceed~~inclusion of the project in the Regional System Plan or RSP Project List~~, each Qualified Transmission Project Sponsor that is part of the joint proposal shall submit to the ISO its acceptance of responsibility to proceed with the preferred Longer-Term Transmission Solution by execution of a Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT). Any cost cap or cost containment provisions shall be included in each Selected Qualified Transmission Project Sponsor Agreement.

Qualified Transmission Project Sponsors whose projects are listed on the RSP Project List and have executed the Selected Qualified Transmission Project Sponsor Agreement shall be entitled to recover, pursuant to the rates and appropriate financial arrangements set forth in the Tariff and, as applicable, the TOA and NTDOA, all prudently incurred cost associated with developing the Longer-Term Transmission Upgrade subsequent to executing the Selected Qualified Transmission Project Sponsor Agreement.

PTOs shall be entitled to recover, pursuant to rates and appropriate financial arrangements set forth in the Tariff, all prudently incurred study costs and costs associated with developing any upgrades or modifications to such PTOs' existing facilities necessary to facilitate the development of a Longer-Term Transmission Solution proposed by any other Qualified Transmission Project Sponsor.

Notwithstanding the foregoing, a PTO is not precluded from recovering, pursuant to the applicable rates and appropriate financial arrangements set forth in the Tariff and the TOA, all prudently incurred costs associated with meeting its obligations to plan and maintain its Transmission Facilities as defined in Section 2.01 of the TOA.

(c) Failure to Proceed

If the ISO finds, after consultation with a Qualified Transmission Project Sponsor, that the sponsor is failing to pursue approvals or construction in a reasonably diligent fashion, or that one or more of the Qualified Transmission Project Sponsors is unable to proceed with the project due to forces beyond its reasonable control, the ISO shall, after consultation with the Planning Advisory Committee, prepare a report, including a proposed course of action. If the Qualified Transmission Project Sponsor that is failing or unable to proceed is a PTO, the ISO shall, after consultation with the Planning Advisory Committee, prepare a report consistent with the provisions of Section 1.1(e) of Schedule 3.09(a) of the Transmission Operating Agreement, including the ISO's proposed course of action. The proposed course of action may include, for example, a consideration and selection of another Longer-Term Proposal, or the re-solicitation of Longer-Term Proposals. If prepared with respect to a Qualified Transmission Project Sponsor that is not a PTO, the report shall include a report from that sponsor. The ISO shall file its report (whether with respect to a PTO or a non-PTO Qualified Transmission Project Sponsor) with the Commission.

16.6 Cancellation of a Longer-Term Transmission Study; Cancellation of a Request for Proposal

The ISO may cancel a Longer-Term Transmission Study process or a request for proposal at any time. Such cancellation may be due, but is not limited to, new or different assumptions which may change or eliminate the identified needs. The ISO shall cancel a Longer-Term Transmission Study process or a request for proposal if requested to do so in a written NESCOE communication.

16.7 Local Longer-Term Transmission Upgrades

The costs of Local Longer-Term Transmission Upgrade(s) that are required in connection with the construction of a Longer-Term Transmission Upgrade approved for inclusion in the Regional System Plan in accordance with Section 16.5(a) of this Attachment K shall be allocated in accordance with Schedule 21 of the OATT.

16.8 Where the Greater than 1.0 Benefit-to-Cost Ratio Threshold has not been Met: Inclusion of Longer-Term Transmission Upgrade in the Regional System Plan and RSP Project List; Milestone Schedule; Removal from RSP Project List

(a) Inclusion of Longer-Term Transmission Upgrade in the Regional System Plan and RSP Project List

Upon receipt of a written NESCOE communication identifying a preferred Longer-Term Proposal pursuant to Section 16.4(j) of this Attachment K, the ISO will notify the Qualified Transmission Project Sponsor that proposed the Longer-Term Proposal that its project has been selected for development as the preferred Longer-Term Transmission Solution and the PTO that has upgrades required by the preferred Longer-Term Transmission Solution, and provide them the written NESCOE communication identifying the New England states that have voluntarily agreed to fund costs in excess of those eligible for treatment as Regional Benefit Upgrades pursuant to Schedule 12 of this OATT and the agreed-to allocation for the excess costs. In the case where the ISO notifies the PTO that has upgrades required by the preferred Longer-Term Transmission Solution to proceed in accordance with Schedule 3.09(a) of the TOA, any prudently incurred PTO costs associated with a filing to implement the cost allocation requested by NESCOE will be recovered by the applicable PTO in accordance with Attachment F of this OATT.

Within 30 days of the Commission's order addressing the cost allocation, NESCOE will provide the ISO a communication specifying whether the process should proceed in accordance with Section 16.8(b) or terminate in accordance with Section 16.6 of this Attachment K. If the written NESCOE communication provides for the process to proceed, then the ISO will notify the Qualified Transmission Project Sponsor and PTO and include the project as a Longer-Term Transmission Upgrade in the Regional System Plan or RSP Project List, as it is updated from time to time in accordance with this Attachment. If the written NESCOE communication requests termination of the process, the ISO shall terminate the process pursuant to Section 16.6 of this Attachment.

Costs for the Longer-Term Transmission Upgrade included in the Regional System Plan or RSP Project List shall be allocated in accordance with Section 10 of Schedule 12 to this OATT.

(b) Execution of Selected Qualified Transmission Project Sponsor Agreement

Within 30 days of the ISO's notification to the Qualified Transmission Project Sponsor that NESCOE has elected to proceed under Section 16.8(a) of this Attachment K, the Qualified Transmission Project Sponsor shall submit to the ISO its acceptance of responsibility to proceed with the preferred Longer-Term Transmission Solution by execution of the Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT). Within 30 days of the ISO's notification to the Qualified Transmission Project Sponsor that NESCOE has elected to proceed under Section 16.8(a) of this Attachment K~~inclusion of the project in the Regional System Plan or RSP Project List~~, each Qualified Transmission Project Sponsor that is part of the joint proposal shall submit to the ISO its acceptance of responsibility to proceed with the preferred Longer-Term Transmission Solution by execution of a Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT). Any cost cap or cost containment provisions shall be included in each Selected Qualified Transmission Project Sponsor Agreement.

Qualified Transmission Project Sponsors whose projects are listed on the RSP Project List and have executed the Selected Qualified Transmission Project Sponsor Agreement shall be entitled to recover, pursuant to the rates and appropriate financial arrangements set forth in the Tariff and, as applicable, the TOA and NTDOA, all prudently incurred cost associated with developing the Longer-Term Transmission Upgrade subsequent to executing the Selected Qualified Transmission Project Sponsor Agreement.

PTOs shall be entitled to recover, pursuant to rates and appropriate financial arrangements set forth in the Tariff, all prudently incurred study costs and costs associated with developing any upgrades or modifications to such PTOs' existing facilities necessary to facilitate the development of a Longer-Term Transmission Solution proposed by any other Qualified Transmission Project Sponsor.

Notwithstanding the foregoing, a PTO is not precluded from recovering, pursuant to the applicable rates and appropriate financial arrangements set forth in the Tariff and the TOA, all prudently incurred costs associated with meeting its obligations to plan and maintain its Transmission Facilities as defined in Section 2.01 of the TOA.

(c) Failure to Proceed

If the ISO finds, after consultation with a Qualified Transmission Project Sponsor, that the sponsor is failing to pursue approvals or construction in a reasonably diligent fashion, or that one or more of the Qualified Transmission Project Sponsors is unable to proceed with the project due to forces beyond its reasonable control, the ISO shall, after consultation with the Planning Advisory Committee, prepare a report, including a proposed course of action. If the Qualified Transmission Project Sponsor that is failing or unable to proceed is a PTO, the ISO shall, after consultation with the Planning Advisory Committee, prepare a report consistent with the provisions of Section 1.1(e) of Schedule 3.09(a) of the Transmission Operating Agreement, including the ISO's proposed course of action. The proposed course of action may include, for example, a consideration and selection of another Longer-Term Proposal, or the re-solicitation of Longer-Term Proposals. If prepared with respect to a Qualified Transmission Project Sponsor that is not a PTO, the report shall include a report from that sponsor. The ISO shall file its report (whether with respect to a PTO or a non-PTO Qualified Transmission Project Sponsor) with the Commission.

17. Procedures for the Conduct of Economic Studies

This Section 17 sets forth the procedures for the ISO's conduct of Economic Studies.

17.1 Overview

The Economic Study process shall be used to identify market efficiency issues on the PTF portion of the New England Transmission System and, as applicable, evaluate competitive solutions to alleviate identified market efficiency needs. The process will also provide information to facilitate the evaluation of economic and environmental impacts of New England regional policies, federal policies, and various resource technologies on satisfying future resource needs in the region.

17.2 Economic Study Reference Scenarios

The ISO shall develop and study the following four reference scenarios. The ISO shall consult with, and consider the input from, the Planning Advisory Committee on the scope, parameters, and assumptions used in modeling the scenarios described in this Section 17.2.

(a) Benchmark Scenario

The purpose and scope of the Benchmark Scenario is to improve the economic planning model and associated assumptions and criteria used in the other scenarios by comparing it against historical performance of the system in the previous year and adjusting the assumptions and model accordingly. This scenario will help identify any modeling issues in the base set of input data.

The initial economic planning model will use the existing base case model and data and may be adjusted based on historical performance and observations. Historical performance of the system includes recorded observations from the prior year to the beginning of the study cycle.

The study year shall be year N-1 and the simulation length shall be one year for the Benchmark Scenario.

Any identified market efficiency issues resulting from a Benchmark Scenario shall not be evaluated as a market efficiency need against the factors and metrics in Attachment N.

(b) Market Efficiency Needs Scenario

The purpose and scope of the Market Efficiency Needs Scenario is to identify market efficiency issues on the PTF portion of the New England Transmission System at the end of the ten-year planning horizon pursuant to Section 17.5 of this Attachment. Pursuant to Section 4.1 of this Attachment, the ISO shall conduct a market efficiency Needs

Assessment to evaluate and determine whether market efficiency issues identified in a Market Efficiency Needs Scenario are market efficiency needs.

The model used for the Market Efficiency Needs Scenario shall be the updated base case from the Benchmark Scenario and forecasted out to the ten-year planning horizon year using assumptions and criteria in Section 4.1(f) of this Attachment.

The study year shall be year N+10 and the simulation length shall be one year for the Market Efficiency Needs Scenario.

(c) Policy Scenario

The purpose and scope of the Policy Scenario is to identify any potential market efficiency issues resulting from the New England states' energy policies and goals, among others (e.g., federal legislation, state legislation, or utility renewable portfolio standard targets). The policies and goals selected for the Policy Scenario shall be selected by the ISO and Planning Advisory Committee pursuant to Section 17.4 of this Attachment.

The model used for the Policy Scenario shall be the base case model resulting from the Benchmark Scenario and forecasted out to a year when relevant New England and other applicable energy policies and goals are in full effect.

The study year for the Policy Scenario shall be dependent on deadlines for achieving the New England region and other energy policies and goals. However, the study year will be at least ten years into the future and cover the deadlines for achieving all applicable goals and policies. The study simulation length shall be one year.

The results from studying a Policy Scenario shall be used for informational purposes only. Any identified market efficiency issues resulting from a Policy Scenario shall not be evaluated as a market efficiency need against the factors and metrics in Attachment N.

(d) Stakeholder-Requested Scenario

The purpose of the Stakeholder-Requested Scenario is to study a scenario with a region-wide scope that is requested by stakeholders and not covered by the other scenarios described in this Section 17.

The model used for the Stakeholder-Requested Scenario shall be the base case model resulting from the Benchmark Scenario and then forecasted out to a year with assumptions requested by the stakeholders and agreed upon by the ISO.

The study year shall be dependent on the requested scenario and the simulation length shall be one year.

The results from studying a Stakeholder-Requested Scenario shall be used for informational purposes only. Any identified market efficiency issues resulting from a Stakeholder-Requested Scenario shall not be evaluated as a market efficiency need against the factors and metrics in Attachment N.

17.3 Frequency, Initiation, and Schedule

The Economic Study process shall be conducted at least once every three years and at most once every two years. The process shall be initiated for the first time under this Section 17 in January 2024.

Each Economic Study cycle shall be initiated by the ISO providing the Planning Advisory Committee with notice that the ISO will be initiating the process for the Economic Study cycle. The ISO shall provide to the Planning Advisory Committee the schedule for the Economic Study cycle within three months of initiating the process. The schedule shall include dates for the ISO’s collection, and stakeholders’ submission, of data to be used in the studies, the preparation of models, the completion of studies, and the issuance of study results. The schedule shall include a one-month period for stakeholders to submit proposals for the Stakeholder-Requested Scenario. If the Economic Study cycle and potential resulting competitive request for proposals process cannot be completed within the initial schedule, the ISO shall notify stakeholders of such, provide a revised estimated completion date, and provide an explanation of the reason or reasons why the additional time is required.

17.4 Preparation of the Economic Study Reference Scenarios and Stakeholder Sensitivity Requests

The ISO shall prepare and post on its website a proposed scope for the scenarios described in Section 17.2, and the associated parameters and assumptions. The ISO shall either provide the Planning Advisory Committee with notice that the ISO posted the information or send the information itself to the Planning Advisory Committee after it is posted. A Planning Advisory Committee meeting will be held thereafter to solicit stakeholder input for consideration by the ISO on the study's scope, parameters, and assumptions.

Following the analyses, runs, and presentation of the results of the Economic Study reference scenarios described in Section 17.2, stakeholders may request, and the ISO may propose, additional sensitivities to test the effect of a specific change to input assumptions. The sensitivities shall be limited to a single theme or category of changes to allow for better understanding of the causal effect of the change to the results. The ISO shall prioritize and list the sensitivities that can be completed during the Economic Study cycle taking into consideration the impact of the additional efforts on the ISO resources and other priorities.

Results from studies conducted with stakeholder-requested scenario sensitivities shall be used for information purposes only. Any identified market efficiency issues resulting from a study with a stakeholder-requested scenario sensitivity shall not be evaluated as a market efficiency need against the factors and metrics in Attachment N.

17.5 Market Efficiency Needs Assessment

The ISO shall use the Market Efficiency Needs Scenario and criteria in Attachment N to identify market efficiency issues on the PTF portion of the New England Transmission System and, as applicable, identify market efficiency needs on the PTF portion of the New England Transmission System.

All of the market efficiency issues and associated benefits of relieving those issues will be documented in a market efficiency Needs Assessment conducted pursuant to Section 4.1 of this Attachment.

Any market efficiency issues that meet the criteria in Attachment N will be identified as market efficiency needs, and a request for proposal or multiple requests for proposals will be issued to initiate the competitive solution process for Market Efficiency Transmission Upgrades to address the identified market efficiency need or needs pursuant to Section 4.3 of this Attachment.

17.6 Evaluation of Regulated Transmission Solutions for Market Efficiency Transmission Upgrades

The process in Section 4.3 of this Attachment shall be used to solicit and evaluate competitive solutions for identified market efficiency needs.

17.7 Stakeholder Input on Study Results

After the results from the Economic Study reference scenarios described in Section 17.2 and stakeholder-requested scenario sensitivities described in Section 17.4 are available, the ISO shall provide such results to stakeholders at Planning Advisory Committee meetings and solicit feedback based on the results.

17.8 Economic Studies Requested by Individual Stakeholders

An individual stakeholder may request that the ISO conduct Economic Studies at the stakeholder's own expense to examine situations where potential regulated transmission solutions, market responses, or investments could result in (i) a net reduction in total production cost to supply system load based on the factors specified in Attachment N of this OATT, (ii) reduced congestion, or (iii) the integration of new resources or loads, or both, on an aggregate or regional basis. The scope, assumptions, and deliverables shall be agreed to by the ISO and the stakeholder requesting the study. The notice and schedule initiating the Economic Study process described in Section 17.3 shall include the dates for submitting requests for studies under this Section 17.8.

The ISO may hire a consultant to conduct the analysis, and the entity requesting the study shall be responsible for the ISO's costs for study administration, study analysis, and consultants used to perform the study.

The ISO shall provide an estimated cost and duration to each stakeholder that requests an Economic Study. Each stakeholder that requests a study under this Section 17.8 shall provide written confirmation with the ISO that the stakeholder would like the ISO to proceed with conducting the study after receiving the estimated cost and duration for the study it requested.

The results from studies conducted pursuant to this Section 17.8 shall be used for informational purposes only. Any identified market efficiency issues resulting from studies conducted pursuant to this Section 17.8 shall not be evaluated as a market efficiency need against the factors and metrics in Attachment N.

17.9 Cost Recovery

The costs of the Economic Study process described in Sections 17.1 through 17.7 shall be recovered by the ISO pursuant to Schedule 1 of Section IV.A of the Tariff. The costs of Economic Studies performed by the ISO under Section 17.8 of this Attachment shall be paid for by the stakeholder requesting the study.

17.10 Coordination with PTOs

The PTOs shall coordinate with the ISO in the performance of the Economic Study process pursuant to and as described in Section 5 of this Attachment.

ATTACHMENT K APPENDIX 1

ATTACHMENT K -LOCAL

LOCAL SYSTEM PLANNING PROCESS

APPENDIX 1

ATTACHMENT K -LOCAL

LOCAL SYSTEM PLANNING PROCESS

1. Local System Planning Process

1.1 General

In circumstances where transmission system planning for Non-Pool Transmission Facilities ("Non-PTF")[1], including Local Public Policy Transmission Upgrades, is taking place in New England that is not incorporated into the RSP planning process, the following Local System Plan ("LSP") process will be utilized for transmission planning purposes. The purpose of the LSP is to enable formal stakeholder input to planning for Non-PTF that is not incorporated into the RSP. The LSP shall ensure the opportunity for Planning Advisory Committee participation in the LSP process. The LSP will not be subject to approval by the ISO or the ISO Board under the RSP.

1.2 Planning Advisory Committee Review

The Planning Advisory Committee shall periodically provide input and feedback to the PTOs concerning the development of the LSP and the conduct of associated system enhancement and expansion studies. It is contemplated that LSP issues for identified local areas will be periodically addressed at the end of regularly scheduled Planning Advisory Committee meetings. Regular meetings of the Planning Advisory Committee shall be extended as necessary to serve the purposes of this section. Each PTO contemplating the addition of new Non-PTF will present its respective LSP to the Planning Advisory Committee not less than once per year. Not less than every three years, each PTO will post a notice as part of its LSP process indicating that members of the Planning Advisory Committee, NESCOE, or any state may provide the PTO with input regarding state and federal Public Policy Requirements identified as driving transmission needs relating to Non-PTF and regarding particular local transmission needs driven by Public Policy Requirements. The PTO will provide a written explanation, to be posted on the ISO website, of why suggested transmission needs driven by Public Policy Requirements will or will not be evaluated for potential solutions in the LSP planning process.

1.3 Role of the PTOs

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[1] For absence of doubt, the PTOs clarify that Non-PTF is meant to include Category B and Local Area Facilities as defined by the TOA.

Each PTO will be responsible for administering the LSP process pertaining to its own Non-PTF, including Local Public Policy Transmission Upgrades, by presenting LSP information to the Planning Advisory Committee, developing an appropriate needs analysis and addressing LSP needs within its local area. In developing its LSP, each PTO will ensure comparable treatment of similarly situated customers or potential customers and will take into consideration data, comments and specific requests supplied by the Planning Advisory Committee, Transmission Customers and other stakeholders. To the extent that generation and/or demand resources are identified that could impact planning for Non-PTF, each PTO will take such resources into account when developing the LSP for its facilities, consistent with Good Utility Practice. Each PTO will also be responsible for addressing issues or concerns arising out of Planning Advisory Committee review of its proposed LSP and posting its LSP and the LSP Project List.

1.4 Description of LSP

The LSP shall describe the projected improvements to Non-PTF that are needed to maintain system reliability or as Local Public Policy Transmission Upgrades, and shall reflect the results of such reviews within the limited geographical areas that pertain to the LSP, as determined by each PTO ("LSP Needs Assessments"), and corresponding system planning and expansion studies. The LSP Needs Assessments will be coordinated with the RSP and include the information that the ISO-NE incorporates into the RSP plans, as applicable. The proponents of regulated transmission proposals in response to LSP Needs Assessments shall also identify any RSP plans that require coordination with their regulated transmission proposals addressing the Non-PTF system needs.

The LSP shall identify the planning process, criteria, data, and assumptions used to develop the LSP. To the extent the current LSP utilizes data, assumptions or criteria used by the ISO in the RSP, any such data, assumptions or criteria will also be identified in the LSP.

Each PTO shall consult with NESCOE and applicable states, local authorities and stakeholders to consider their views prior to including a Local Public Transmission Upgrade in its LSP, as described in Section 1.6.

Each PTO's LSP will be made available on a website for review by the Planning Advisory Committee, Transmission Customers and other stakeholders, subject to the ISO New England Information Policy and

CEII restrictions or requirements. The ISO's posting of the RSP and the RSP Project List will include links to each PTO's specific LSP posting.

The LSP of a particular PTO shall be posted not less than 3 business days prior to its presentation by the PTO to the Planning Advisory Committee. The Planning Advisory Committee, Transmission Customers, and other stakeholders will have 30 days from the date of the PTO's presentation to the Planning Advisory Committee to provide any written comments for consideration by the PTO. The LSP shall specify the physical characteristics of the solutions that can meet the needs identified in the LSP. The LSP shall provide sufficient information to allow Market Participants to assess the quantity, general locations and operating characteristics of the type of incremental supply or demand-side resources, or merchant transmission projects, that would satisfy the identified needs or that may serve to modify, offset or defer proposed regulated transmission upgrades.

Each year's LSP shall be based upon the LSP completed in the prior year by either recertifying the results of the prior LSP or providing specific updates.

1.5 Economic Studies

To the extent that the ISO selects any Economic Studies pursuant to Section 4.1(b) of Attachment K or otherwise performs Economic Studies that will impact Non-PTF, the PTOs will coordinate with the ISO in the performance of such Economic Studies.

1.6 Public Policy Studies

As part of the LSP process, each PTO will evaluate potential transmission solutions on its Non-PTF system that are likely to be both efficient and cost-effective for meeting Public Policy Requirements.

1.6A Process to Identify Public Policy Requirements Driving Non-PTF Transmission Needs

Within six months of publication, each PTO will review the Public Policy Requirements posted by the ISO to determine and evaluate at a high level any public policy needs potentially driving transmission needs on their respective Non-PTF systems. Such evaluations will also include potential public policy needs suggested by third parties. Each PTO will review NESCOE's written explanation of which transmission needs driven by state or federal Public Policy Requirements will be evaluated by the ISO and why other suggested transmission needs will not be evaluated. If NESCOE does not provide a listing of identified transmission needs and explanation, each PTO will review the ISO's explanations of which transmission needs driven by state or federal Public Policy Requirements will be evaluated by the ISO and why other suggested transmission needs will not be evaluated. In addition, each PTO will review the ISO's explanation of which transmission needs driven by local Public Policy Requirements will be evaluated in the regional system planning process and why other suggested transmission needs driven by local Public Policy requirements will not be evaluated. Each PTO will then determine if any of the posted state, federal or local Public Policy Requirements are driving a need on its Non-PTF transmission system and will include the non-PTF needs in its local planning process.

As part of the local planning process, each PTO will list the identified transmission needs on its non-PTF transmission system driven by state, federal, or local Public Policy Requirements that will be evaluated, and provide an explanation of why any identified transmission needs will not be evaluated as part of its LSP. The list will be posted in the PTO's LSP and presented at the annual PAC meeting. The PTO will seek input at the PAC meeting from stakeholders about whether further study is warranted to identify solutions for local transmission system needs and seek recommendations about whether to proceed with such studies. A stakeholder may provide written input on the list within 30 days from the date of presentation for consideration by the PTO. Each PTO will then confirm, or modify if appropriate, its determination of which identified transmission needs on its non-PTF transmission system driven by state, federal, or local Public Policy Requirements will be evaluated and which will not be evaluated, and revise its annual LSP accordingly. If the potential Non-PTF transmission needs identified would affect the Non-PTF facilities of more than one PTO, the affected PTOs will coordinate their efforts with other affected PTOs, as necessary.

1.6B Procedure for Evaluating Potential Public Policy Solutions on the Non-PTF

Once it has been determined that a non-PTF need driven by state, federal or local Public Policy Requirements will be evaluated, each PTO will prepare a scope and associated assumptions as part of a Public Policy Local Transmission Study. For those needs where a scope is available, a PTO may present the proposed scope for the Public Policy Local Transmission Study within its LSP and as part of its LSP presentation described in Section 1.6A. A stakeholder may provide written input to the scope within 30 days after the LSP presentation for the PTO to consider.

Each PTO will schedule a follow-up PAC meeting presentation for additional stakeholder input within 4 months after the PTO's LSP presentation as described in Section 1.6A if the proposed scope for a Public Policy Local Transmission Study was not included in its annual LSP presentation. Within 30 days after the follow-up meeting, a stakeholder may provide written input to the scope for the PTO to consider. Subsequently, the PTO will determine the study scope for the Public Policy Local Transmission Study and revise its annual LSP.

In preparation of a Public Policy Local Transmission Study that will be presented to the PAC as part of the LSP for the following year, the PTO will undertake the following: First, the PTO will perform the initial phase of the Public Policy Local Transmission Study to develop an estimate of costs and benefits and post its preliminary results on a website. Second, the PTO will use good faith efforts to contact stakeholders and the appropriate state and/or local authorities informing them of the posting, requesting input on whether further study is warranted to identify solutions for local transmission system needs, and seeking recommendations about whether to proceed with further planning and construction of a Local Public Policy Transmission Upgrade. Each PTO will then make a determination of whether further study is warranted to identify solutions for local transmission system needs, or will select its final solution, and revise its annual LSP accordingly. If the potential Non-PTF transmission needs identified would affect the Non-PTF facilities of more than one PTO, the affected PTOs will coordinate their efforts with other affected PTOs, as necessary. Results of a Public Policy Local Transmission Study will be provided to the PAC as part of the LSP for the following year.

2. Posting of LSP Project List

Each PTO shall develop, maintain and make available on a website, a cumulative listing of proposed regulated transmission solutions that may meet LSP needs (the "LSP Project List"). The LSP Project List will be updated at least annually. The LSP Project List shall also provide reasons for any new Non-PTF, including Local Public Policy Transmission Upgrades, any change in status of proposed Non-PTF, including Local Public Policy Transmission Upgrades, or any removal of proposed Non-PTF, including Local Public Policy Transmission Upgrades, from the LSP Project List. Each PTO will be individually responsible for publicly posting and updating the status of its respective LSP and the transmission projects arising therefrom on a website in a format comparable to the manner in which RSP plans and projects are posted on the RSP Project List. The ISO's posting of the RSP and RSP Project List will include links to each PTO's specific LSP Project List.

3. Posting of Assumptions and Criteria

Each PTO will make available on a website the planning criteria and assumptions used in its current LSP. A link to each PTO's planning criteria and assumptions will be posted on the ISO website.

4. Cost Responsibility for Transmission Upgrades

The cost responsibility for each upgrade, modification or addition to the transmission system in New England that is included in the LSP Project List of this Appendix 1 shall be determined in accordance with Schedule 21 of this OATT.

5. LSP Dispute Resolution Procedures

5.1 Objective

Section 5 of this Appendix 1 sets forth an LSP dispute resolution process (the "LSP Dispute Resolution Process") through which LSP-related transmission planning-related disputes may be resolved as expeditiously as possible.

5.2 Confidential Information and CEII Protections

All information disclosed in the course of the LSP Dispute Resolution Process shall be subject to the protection of confidential information and CEII consistent with the ISO New England Information Policy and CEII policy.

5.3 Eligible Parties

Any member of the Planning Advisory Committee that has been adversely affected by a PTO's Reviewable Determination with respect to the LSP transmission planning process described in this Appendix 1 is eligible to raise its dispute, as appropriate, under this LSP Dispute Resolution Process ("Disputing Party").

5.4 Scope

In order to ensure that the LSP transmission planning process set forth under this Appendix 1 moves expeditiously forward, the scope of issues that may be subject to the LSP Dispute Resolution Process under this Section 5 shall be limited to certain key procedural and substantive decisions made by the applicable PTO within its authority as specified in documents on file with the Commission. That is, decisions not subject to resolution within the jurisdiction of the Commission are not within the scope of this LSP Dispute Resolution Process. Examples of matters not within the scope of the LSP Dispute Resolution Process include planning to serve retail native load or state siting issues. Additionally, the

Tariff already explicitly provides specific dispute resolution procedures for various matters. To this end, any matter regarding the review and approval of applications pursuant to Section I.3.9 of the Tariff, which is subject to the dispute resolution process under Section I.6 of the Tariff, shall not be within the scope of this LSP Dispute Resolution Process. Similarly, any matter regarding Transmission Cost Allocation shall be governed by the dispute resolution process under Schedule 12 of the OATT, and shall be outside the scope of this LSP Dispute Resolution Process.

(a) Reviewable Determinations:

The LSP determinations made by the applicable PTO that may be subject to the LSP Dispute Resolution Process under this Section 5 ("Reviewable LSP Determination") shall include certain procedural and substantive challenges at designated key decision points during the LSP transmission planning process for Non-PTF, including Local Public Policy Transmission Upgrades ("Key LSP Decision Points"). Procedural challenges will be limited to whether or not the steps taken up to a Key LSP Decision Point conform to the requirements set forth in this Appendix 1. Substantive challenges will be limited to whether or not a determination or conclusion rendered at a Key LSP Decision Point was supported by adequate basis in fact. The Key LSP Decision Points shall be limited to the following:

(i) Results of an LSP Needs Assessment conducted and communicated by a PTO to the Planning Advisory Committee as specified in this Appendix 1;

(ii) Updates to the LSP Project List, including adding, removing or revising regulated Non-PTF transmission solutions included thereunder, as presented at the Planning Advisory Committee and as specified in this Appendix 1;

(iii) Results of Non-PTF transmission solutions studies, including any Local Public Policy Transmission Upgrade studies, conducted and communicated by the PTO to the Planning Advisory Committee as specified in this Appendix 1; and

(iv) Consideration of market responses in LSP Needs Assessments as specified in this Appendix 1.

(b) Material Adverse Impact

In order to prevail in a challenge to a procedural-based Reviewable LSP Determination, the Disputing Party must show that the alleged procedural error had a material adverse impact on the determination or conclusion made by the applicable PTO. In order to prevail in a challenge to a substantive-based Reviewable LSP Determination, the Disputing Party must show that either (i) the determination is based on incorrect data or assumptions or (ii) incorrect analysis was performed by the PTO, and (iii) as a result thereof, the PTO made an incorrect decision or determination.

5.5 Notice and Comment

A Disputing Party aggrieved by a PTO's Reviewable LSP Determination shall have fifteen (15) calendar days upon learning of the Reviewable LSP Determination following the PTO's presentation of such LSP Reviewable Determination at the Planning Advisory Committee to request dispute resolution by giving notice to the Applicable PTO ("Request for LSP Dispute Resolution").

A Request for LSP Dispute Resolution shall be in writing and shall be provided to the applicable PTO and, as appropriate, other affected Transmission Owners. Within three (3) Business Days of the receipt by a PTO of a Request for Dispute Resolution, the PTO, in coordination with the ISO, shall prepare and distribute to all members of the Planning Advisory Committee a notice of the Request for Dispute Resolution including, subject to the protection of Confidential Information and CEII, the specifics of the Request for Dispute Resolution and providing the name of a PTO representative to whom any comments may be sent. Any member of the Planning Advisory Committee may submit to the PTO's designated representative, on or before the tenth (10th) Business Day following the date the PTO distributes the notice of the Request for Dispute Resolution, written comments to the PTO with respect to the Request for Dispute Resolution. The Disputing Party filing the Request for Dispute Resolution may respond to any such comments by submitting a written response to the PTO's designated representative and to the commenting party on or before the fifteenth (15th) Business Day following the date the PTO distributes the notice of the Request for Dispute Resolution. The PTO may, but is not required to, consider any written comments.

5.6 Dispute Resolution Procedure

(a) Resolution Through the Planning Advisory Committee

The Planning Advisory Committee shall discuss and resolve any LSP related dispute arising under this Appendix 1 involving a Reviewable LSP Determination, as defined in Section 5.4 of this Appendix 1, between and among the applicable PTO, the Disputing Party, and, as appropriate, other affected Transmission Owners and the ISO (collectively, "Parties") (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution).

(b) Resolution Through Informal Negotiation

To the extent that the Planning Advisory Committee is not able to resolve a dispute arising under this Appendix 1 involving a Reviewable LSP Determination, as defined in Section 5.4 of this Appendix 1, between and among the Parties, such dispute shall be the subject of good-faith negotiations among the Parties. Each Party shall designate a fully authorized senior representative for resolution on an informal basis as promptly as practicable.

(c) Resolution Through Alternative Dispute Resolution

In the event the designated representatives are unable to resolve the dispute through informal negotiations within thirty (30) days, or such other period as the Parties may agree upon, by mutual agreement of the Parties, such LSP related dispute may be submitted to mediation or any other form of alternative dispute resolution upon the agreement of all Parties to participate in such mediation or other alternative dispute resolution process. Such form of alternative dispute resolution shall not include binding arbitration.

If a Party identifies exigent circumstances reasonably requiring expedited resolution of the LSP related dispute, such Party may file a Complaint with the Commission or seek other appropriate redress before a court of competent jurisdiction

5.7 Notice of Results of Dispute Resolution

Within three (3) Business Days following the resolution of a dispute pursuant to either Section 5.6(b) or 5.6(c) of this Appendix 1, the PTO shall distribute to members of the Planning Advisory Committee a document reflecting the resolution.

5.8 Rights under the Federal Power Act:

Nothing in this Appendix 1 shall restrict the rights of any party to file a complaint with the Commission under relevant provisions of the Federal Power Act.

ATTACHMENT K APPENDIX 2

LIST OF ENTITIES ENROLLED IN THE TRANSMISSION PLANNING REGION ENTITIES

APPENDIX 2

ATTACHMENT K

LIST OF ENTITIES ENROLLED IN THE TRANSMISSION PLANNING REGION

The entities listed in this Appendix 2 are those enrolled for the purpose of participating as a transmission provider in the New England transmission planning region pursuant to Attachment K as of the date the revisions to this Appendix 2 were filed with the Commission. The most current list of entities enrolled for the purpose of participating as a transmission provider in the New England transmission planning region pursuant to Attachment K is available on the ISO-NE website. This Appendix 2 will be updated to reflect any subsequent enrollments as part of unrelated OATT filings at the time ISO-NE undertakes such unrelated filings.

Town of Braintree Electric Light Department

Central Maine Power Company

~~The City of~~ Chicopee Municipal Lighting ~~Department~~Plant

~~The City of Holyoke Gas and Electric Department~~

The Connecticut Light and Power Company

Connecticut Municipal Electric Energy Cooperative

Connecticut Transmission Municipal Electric Energy Cooperative

Cross-Sound Cable Company, LLC

~~Emera Maine~~

Fitchburg Gas and Electric Light Company

Green Mountain Power Corporation

The City of Holyoke Gas and Electric Department

Town of Hudson Light & Power Department

Maine Electric Power Company

Massachusetts Municipal Wholesale Electric Company

~~Maine Electric Power Company~~

Town of Middleborough Gas ~~and~~ & Electric Department

The Narragansett Electric Company d/b/a Rhode Island Energy

New England Electric Transmission Corporation

New England Energy Connection, LLC

New England Hydro-Transmission Corporation

New England Hydro-Transmission Electric Company Inc.

New England Power Company d/b/a National Grid

New Hampshire Electric Cooperative, Inc.

New Hampshire Transmission, LLC

Town of Norwood Municipal Light Department

~~Eversource Energy Service Company as agent for: The Connecticut Light and Power Company, NSTAR Electric Company, Public Service Company of New Hampshire, and Western Massachusetts Electric Company~~

~~Norwood Municipal Light Department~~

NSTAR Electric Company

Public Service Company of New Hampshire

Town of Reading Municipal Light Department

Shrewsbury Electric & Cable Operations

Town of Stowe Electric Department

Taunton Municipal Lighting Plant

~~Town of Reading Municipal Light Department~~

The United Illuminating Company

Unitil Energy Systems, Inc.

Vermont Electric Cooperative, Inc.

Vermont Electric Power Company, Inc.

Vermont Electric Transmission Company

Vermont Public Power Supply Authority

Vermont Transco LLC

Versant Power

Town of Wallingford, CT, Department of Public Utilities, ~~–~~Electric Division

~~Western Massachusetts Electric Company~~

ATTACHMENT K APPENDIX 3

LIST OF QUALIFIED TRANSMISSION PROJECT SPONSORS

The entities listed in this Appendix 3 are those approved by ISO-NE as Qualified Transmission Project Sponsors as of the date the revisions to this Appendix 3 were filed with the Commission. The most current list of entities approved as Qualified Transmission Project Sponsors is available on the ISO-NE website. This Appendix 3 will be updated to reflect any subsequent enrollments as part of unrelated OATT filings at the time ISO-NE undertakes such unrelated filings.

Anbaric Development Partners, LLC

Avangrid Networks, Inc.

~~Braintree Electric Light Department~~

Central Maine Power Company

~~City of Holyoke Gas and Electric Department~~

~~The Connecticut Light and Power Company~~

~~The~~ Connecticut Transmission Municipal Electric Cooperative

Versant Power ~~Emera Maine~~

Eversource Energy Transmission Ventures, Inc.

NGV US Transmission~~Grid America Holdings~~, Inc.

Hudson Light and Power Department

Maine Electric Power Company

Massachusetts Municipal Wholesale Electric Company

Middleboro Gas & Electric Department

Narragansett Electric Company d/b/a Rhode Island Energy

New England Energy Connection, LLC

New England Power Company

New Hampshire Transmission, LLC

Norwood Municipal Light Department

NSTAR Electric Company

PPL Translink, Inc.

Public Service Company of New Hampshire

SP Transmission, LLC

Taunton Municipal Light Plant

The City of Holyoke Gas and Electric Department

The Connecticut Light and Power Company

Town of Braintree Electric Light Department

Transource New England, LLC

United Illuminating Company

Vermont Transco, LLC

~~Western Massachusetts Electric Company~~

ATTACHMENT P
SELECTED QUALIFIED TRANSMISSION PROJECT SPONSOR AGREEMENT

Between

ISO NEW ENGLAND~~,~~ INC.

And

____

This Selected Qualified Transmission Project Sponsor Agreement, including the Schedules attached hereto and incorporated herein (collectively, "Agreement") is made and entered into as of the Effective Date between ISO New England~~,~~ Inc. ("ISO-NE" or "the ISO"), and ___________________ ("Selected QTPS"), referred to herein individually as "Party" and collectively as "the Parties."

RECITALS

WHEREAS, in accordance with FERC Order No. 1000 or ~~and~~ Attachment K of the ISO-NE Open Access Transmission Tariff ("OATT"), ISO-NE selects the preferred Phase or Stage Two Solution or Longer-Term Transmission Solution ~~–~~for inclusion in the in the Regional System Plan ("RSP") and/or its Project List;

WHEREAS, the Selected QTPS is a Qualified Transmission Project Sponsor pursuant to Section 4B of Attachment K of the OATT;

WHEREAS, the Selected QTPS has executed the [Transmission Operating Agreement] [Non-Incumbent Developer Transmission Operating Agreement];

WHEREAS, pursuant to Sections 4.3(j), ~~or~~ 4A.9(a), or 16 of Attachment K of the OATT, ISO-NE notified the Selected QTPS that its project has been selected for development;

WHEREAS, pursuant to Sections 4.3(k), ~~or~~ 4A.9(b), or 16 of Attachment K of the OATT, by executing this Agreement the Selected QTPS accepts responsibility to proceed with the Project, and therefore has the obligation to construct the Project; and

NOW, THEREFORE, in consideration of the promises, and the mutual representations, warranties, covenants and agreements hereinafter set forth, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound, Selected QTPS and the ISO-NE agree as follows:

1.0 Defined Terms

All capitalized terms used in this Agreement shall have the meanings ascribed to them in the Tariff or in definitions either in the body of this Agreement or its attached Schedules. In the event of any conflict between defined terms set forth in Section I of the Tariff or defined terms in this Agreement, including the Schedules, such conflict will be resolved in favor of the terms as defined in this Agreement.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Selected Qualified Transmission Project Sponsor Agreement.

Breaching Party shall mean a Party that is in Breach of the Selected Qualified Transmission Project Sponsor Agreement.

Commercially Reasonable Efforts shall mean a level of effort which, in the exercise of prudent judgment in the light of facts or circumstances known or which should reasonably be known at the time a decision is made, can be expected by a reasonable person to accomplish the desired result in a manner consistent with Good Utility Practice and which takes the performing party's interests into consideration.

Component In-Service shall mean that a portion (component) of the Project has been placed in commercial operation.

Component In-Service Date shall mean the date that a portion (component) of the Project is placed In-Service.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 8 of the Selected Qualified Transmission Project Sponsor Agreement.

Governmental Authority shall mean the government of any nation, state or other political subdivision thereof, including any entity exercising executive, military, legislative, judicial, regulatory, or administrative functions of or pertaining to a government.

In-Service shall mean that the Project has been placed in commercial operation.

In-Service Date shall mean the date the Project is placed In-Service.

Project shall mean the Market Efficiency Transmission Upgrade, Reliability Transmission, ~~or~~ Public Policy Upgrade, or Longer-Term Transmission Upgrade ~~-~~included in the Regional System Plan and/or the ISO-NE Project List described in Schedule A of this Agreement.

Required Project In-Service Date is the date the Project is required to: (i) be completed in accordance with the Scope of Work in Schedule A of this Agreement, (ii) is placed In-Service; and; (iii) be under ISO-NE operational dispatch.

Tariff consists of the ISO New England~~,~~ Inc. Transmission, Markets, and Services Tariff.

Article 2 - Effective Date and Term

2.0 Effective Date

This Agreement shall become effective on the date the Agreement has been executed by all Parties, or if this Agreement is required to be filed with FERC for acceptance, upon the date specified by FERC.

2.1 Term

This Agreement shall continue in full force and effect from the Effective Date until: (i) the Selected QTPS has executed the TOA; and (ii) the Project (a) has been completed in accordance with the terms and conditions of this Agreement and (b) meets all relevant required planning criteria, or (iii) the Agreement is terminated pursuant to Article 6 of this Agreement.

Article 3 - Project Construction

3.0 Construction of Project by Selected QTPS

Selected QTPS shall design, engineer, procure, install and construct the Project, including any modifications thereto, in accordance with: (i) the terms of this Agreement, including but not limited to the Scope of Work in Schedule A and the Development Schedule in Schedule B; (ii) applicable reliability principles, guidelines, and standards of the Northeast Power Coordinating Council and the North American Electric Reliability Corporation; (iii) the ISO New England Operating Documents; and (iv) Good Utility Practice. Nothing contained herein shall modify PTOs' rights under the TOA to construct and own upgrades to its existing and affected substation or facilities.

3.1 Milestones

3.1.0 Milestone Dates

Selected QTPS shall meet the milestone dates set forth in the Development Schedule in Schedule B of this Agreement. Milestone dates set forth in Schedule B only may be extended by ISO-NE in writing. ISO-NE reasonably may extend any such milestone date, in the event of delays not caused by the Selected QTPS that could not be remedied by the Selected QTPS through the exercise of due diligence if a corporate officer of the Selected QTPS submits a revised Development Schedule containing revised milestones and showing the Project in full operation no later than the Required Project In-Service Date specified in Schedule B of this Agreement.

3.2 Applicable Technical Requirements and Standards

At the point of interconnection, the applicable technical requirements and standards of the Participating Transmission Owner(s) ("PTO")) to whose facilities the Project will interconnect shall apply to the design, engineering, procurement, construction and installation of the Project. The remaining portion of the Project shall meet applicable industry standards and Good Utility Practice. At a minimum, all new facilities should comply with the current National Electric Safety Code.

3.3 Project Modification

3.3.0 Project Modification

The Scope of Work and Development Schedules (Schedules A and B, respectively), including the milestones therein, may be revised, as required through written consent by the parties. Such modifications may include alterations as necessary and directed by ISO-NE such as modifications resulting from the I.3.9 process or to meet the system condition for which the Project was included in the Regional System Plan.

3.3.1 Consent of ISO-NE to Project Modifications

Selected QTPS may not modify the Project without prior written consent of ISO-NE.

3.4 Project Status Reports

Selected QTPS shall submit to ISO-NE quarterly construction status reports in writing. The reports shall contain, but not be limited to, updates and information related to: (i) current engineering and construction status of the Project; (ii) Project completion percentage, including milestone completion; (iii) current target Project or phase completion date(s); (iv) applicable outage information; and (v) cost expenditures to date and revised projected cost estimates for completion of the Project.

3.5 Exclusive Responsibility of Selected QTPS

Selected QTPS shall be solely responsible for all planning, design, engineering, procurement, construction, installation, management, operations, safety, and compliance with Applicable Laws and Regulations associated with the Project. ISO-NE shall have no responsibility to manage, supervise, or ensure compliance or adequacy of same.

Article 4 – Subcontractor Insurance

4.0 Subcontractor Insurance

In accordance with Good Utility Practice, Selected QTPS shall require each of its subcontractors to maintain and, upon request, provide Selected QTPS evidence of insurance coverage of types, and in amounts, commensurate with the risks associated with the services provided by the subcontractor. Bonding and hiring of contractors or subcontractors shall be the Selected QTPS's discretion, but regardless of bonding or the existence or non-existence of insurance, the Selected QTPS shall be responsible for the performance or non-performance of any contractor or subcontractor it hires.

Article 5 – Default and Force Majeure

5.0 Events of Default

(a) Subject to the terms and conditions of this Section 5.0, the occurrence of any of the following events shall constitute an event of default of a Party under this Agreement:

(i) Failure by a Party to perform any material obligation set forth in this Agreement, and continuation of such failure for longer than thirty (30) days after the receipt by the non-breaching Party of written notice of such failure; provided, however, that if the breaching Party is diligently pursuing a remedy during such thirty (30) day period, said cure period shall be extended for an additional thirty (30) days or as otherwise agreed by the Parties, provided that such extension ensures that the Project meets the Required Project In-Service Date.

(ii) Failure to perform a material obligation set forth in this Agreement shall include but not be limited to:

a. Any breach of a representation, warranty, or covenant made in this Agreement;
b. Failure to meet a milestone or milestone date set forth in the Development Schedule in Schedule B of this Agreement, or as extended in writing as described in Sections 3.1.0 and 3.3.0 of this Agreement;
c. Assignment of this Agreement in a manner inconsistent with the terms of this Agreement; or
d. Failure of any Party to provide information or data required to be provided to another Party under this Agreement for such other Party to satisfy its obligations under this Agreement.
e. If there is a dispute between the Parties as to whether a Party has failed to perform a material obligation, the cure period(s) provided in Section 5.0(a)(i) above shall run from the point at which a finding of failure to perform has been made by a Governmental Authority.
f. With respect to either Party, (A) the filing of any petition in bankruptcy or insolvency, or for reorganization or arrangement under any bankruptcy or insolvency laws, or voluntarily

taking advantage of any such laws by answer or otherwise or the commencement of involuntary proceedings under any such laws, (B) assignment by either Party for the benefit of creditors; or (C) allowance by either Party of the appointment of a receiver or trustee of all or a material part of its property if such receiver or trustee is not discharged within thirty (30) days after such appointment.

5.1 Remedies

Upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to: (i) commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof; (ii) suspend performance hereunder; and (iii) exercise such other rights and remedies as it may have in equity or at law. Nothing in this Section 5.1 is intended in any way to affect the rights of a third-party to seek any remedy it may have in equity or at law from the Selected QTPS resulting from Selected QTPS's Default of this Agreement.

5.2 Waiver

The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement, or to exercise its rights with respect to a Breach or Default under this Agreement or with regard to any other matters arising in connection with this Agreement will not be deemed a waiver or continuing waiver with respect to any other failure to comply with any other obligation, right, or duty of this Agreement. Any waiver of any obligation, right, or duty under this Agreement must be in writing.

5.3 Force Majeure

A Party shall not be considered to be in Default or Breach under this Agreement, and shall be excused from performance or liability for damages to any other party, if and to the extent it shall be delayed in or prevented from performing or carrying out any of the provisions of this Agreement, except the obligation to pay any amount when due, in consequence of any act of God, labor disturbance, failure of contractors or suppliers of materials (not including as a result of non-payment), act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm, flood, ice, explosion, breakage or accident to machinery or equipment or by any other cause or causes (not including a lack of funds or other financial causes) beyond such Party's reasonable control, including any order, regulation, or restriction imposed by governmental, military or lawfully established civilian authorities. A Party claiming a force majeure event shall use reasonable diligence to remove the condition that prevents performance, except that the settlement of any labor disturbance shall be in the sole judgment of the affected Party.

Article 6 - Termination

6.0 Termination by ISO-NE

In the event that: (i) ISO-NE determines to remove the Project from the RSP; (ii) ISO-NE otherwise determines that the identified need has changed or been eliminated therefore the Project is no longer required to address the specific need for which the Project was included in the RSP; or (iii) a force majeure or other event outside of the Selected QTPS's control that, with the exercise of reasonable efforts, Selected QTPS cannot alleviate and which prevents the Selected QTPS from satisfying its obligations under this Agreement; or (iv) the Parties fail to agree to modifications under Section 3.3.0; or (v) one or more of the Selected QTPSs for the Project is failing to pursue approvals or construction in a reasonably diligent fashion, or that one or more of the Selected QTPSs is unable to proceed with the project due to forces beyond its reasonable control, ISO-NE may terminate this Agreement by providing written notice of termination to Selected QTPS. The termination shall become effective upon the date the Selected QTPS receives such notice, except as otherwise provided in Section 6.2.

ISO-NE shall also terminate this Agreement following written communication from NESCOE requesting that ISO-NE remove a Longer-Term Transmission Upgrade from the RSP.

6.1 Termination by Default

This Agreement shall terminate in the event a Party is in Default of this Agreement in accordance with Section 5.0 of this Agreement and the ISO shall take action in accordance with Sections 4.3(l), ~~or~~ 4A.9(c), or 16 of Attachment K.

6.2 Filing at FERC

If, pursuant to FERC regulations, the termination of this agreement is required to be filed with FERC, such termination shall be effective upon the date established by FERC. ISO-NE shall report any termination of this Agreement in its Electric Quarterly Report.

Article 7 – Indemnity and Limitation of Liability

7.0 Hold Harmless

Each Selected QTPS will indemnify and hold harmless all other Selected QTPSs, affected PTOs and ISO-NE and its directors, managers, members, shareholders, officers and employees from any and all liability (except for that stemming from the other Selected QTPS(s), the ISO-NE or an affected PTO's negligence, gross negligence or willful misconduct), resulting from the Selected QTPS's failure to timely complete the Project. As used herein, the "other Selected QTPS" is a Selected QTPS whose Phase Two Solution is part of the group that solves all needs identified in the request for proposal and an "affected PTO" is one that would be subject to penalties assessed by NERC or FERC or adverse regulatory orders or monetary claims or damages due to the Selected QTPS's failure to timely complete the Project.

7.1 Liability

(a) Neither Party shall be liable to the other Party for any incidental, indirect, special, exemplary, punitive or consequential damages, including lost revenues or profits, even if such damages are foreseeable or the damaged Party has advised such Party of the possibility of such damages and regardless of whether any such damages are deemed to result from the failure or inadequacy of any exclusive or other remedy.

(b) Nothing in this Agreement shall be deemed to affect the right of ISO-NE to recover its costs due to liability under this Article 7 through the NEPOOL Participants Agreement or ISO-NE Tariff.

Article 8 – Assignment

8.0 Assignment

A Party may assign all of its rights, duties, and obligations under this Agreement in accordance with this Section 8.0. No Party may assign any of its rights or delegate any of its duties or obligations under this Agreement without prior written consent of the other Party, which consent shall not be unreasonably withheld, conditioned, or delayed. Any such assignment or delegation made without such written consent shall be null and void. Assignment by the Selected QTPS shall be contingent upon, prior to the effective date of the assignment: (i) the Selected QTPS or the assignee demonstrating to the satisfaction of ISO-NE that the assignee has the technical competence and financial ability: (a) to comply with the requirements of this Agreement, (b) to construct the Project consistent with the assignor's cost estimates for the Project and in accordance with any cost cap or cost containment commitments, and (c) to operate and maintain the Project once constructed; and (ii) the assignee is a Qualified Transmission Project Sponsor pursuant to Section 4B of Attachment K of the OATT. For all assignments by any Party, the assignee must assume in writing, to be provided to the other Party, all rights, duties, and obligations of the assignor arising under this Agreement. Any assignment described herein shall not relieve or discharge the assignor from any of its obligations hereunder absent the written consent of the other Party. In no circumstance, shall an assignment of this Agreement or any of the rights, duties, and obligations under this Agreement diminish the rights of the ISO-NE under this Agreement or the ISO New England Operating Documents. Any assignees that will construct, maintain, or operate the Project shall be subject to, and comply with the terms of this Agreement, and the ISO New England Operating Documents.

Article 9 - Information Exchange

9.0 Information Access

Subject to the ISO Information Policy, each Party shall make available to the other Party information necessary to carry out each Party's obligations and responsibilities under this Agreement and the ISO New England Operating Documents. Such information shall include but not be limited to, information reasonably requested by ISO-NE to prepare the Regional System Plan. The Parties shall not use such information for purposes other than to carry out their obligations or enforce their rights under this Agreement and the ISO New England Operating Documents.

Article 10 - Confidentiality

10.0 Confidential Information and CEII

Confidential Information and CEII shall be treated in accordance with the ISO Information Policy.

Article 11 – Dispute Resolution

11.0 Dispute Resolution Procedures

The Parties agree that any dispute arising under this Agreement shall be the subject of good-faith negotiations among the Parties. Each Party shall designate one or more representatives with the authority to negotiate the matter in dispute to participate in such negotiations. The Parties shall engage in such good-faith negotiations for a period of not less than sixty (60) calendar days. Notwithstanding the foregoing, any dispute arising under this Agreement may be submitted to arbitration or any other form of alternative dispute resolution upon the agreement of the Parties to participate in such an alternative dispute resolution process. Nothing in this Agreement shall, however, restrict a Party's right to file a complaint with FERC under the relevant provisions of the Federal Power Act.

Article 12 - Regulatory Requirements

12.0 Regulatory Approvals

Selected QTPS shall seek and obtain all required authorizations or approvals as soon as reasonably practicable, and by the milestone dates set forth in the Development Schedule of Schedule B of this Agreement, as applicable.

Article 13 - Representations and Warranties

13.0 General

Selected QTPS hereby represents, warrants and covenants as follows, with these representations, warranties, and covenants effective as to the Selected QTPS during the full time this Agreement is effective:

13.0.1 Organization

Selected QTPS is duly organized, validly existing and in good standing under the laws of the state of its organization.

13.0.2 Authority

Selected QTPS has all requisite power and authority to execute, deliver and perform this Agreement; the execution, delivery and performance by Selected QTPS of this Agreement have been duly authorized by all necessary and appropriate action on the part of Selected QTPS; and this Agreement has been duly and validly executed and delivered by Selected QTPS and constitutes the legal, valid and binding obligations of Selected QTPS, enforceable against Selected QTPS in accordance with the terms of this Agreement.

13.0.3 No Breach

The execution, delivery and performance by Selected QTPS of this Agreement will not result in a breach of any terms, provisions or conditions of any agreement to which Selected QTPS is a party which breach has a reasonable likelihood of materially and adversely affecting Selected QTPS's performance under this Agreement.

Article 14 - Operation of Project

14.0 In-Service

The following requirements shall be satisfied prior to the date the Project goes In-Service:

14.0.1 Execution of the Transmission Operating Agreement

Selected QTPS is able to meet all requirements of the Transmission Operating Agreement and has authority to execute that agreement.

14.0.2 Operational Requirements

The Project must meet all applicable operational requirements described in the ISO New England Operating Documents.

14.0.3 Synchronization

Selected QTPS shall have received any necessary authorizations or permissions from ISO-NE and the owners of the facilities to which the Project will interconnect to synchronize with the New England Transmission System or to energize, as applicable, the Project.

14.1 Partial Operation

If the Project is to be completed in phases, the completed part of the Project may operate prior to completion and Required Project In-Service Date set forth in Schedule B of this Agreement, provided that: (i) Selected QTPS has notified ISO-NE in writing of the successful completion of the Project phase; (ii) ISO-NE has determined that partial operation of the Project will not negatively impact the reliability of the New England Transmission System; (iii) Selected QTPS has demonstrated that the requirements for going In-Service set forth in Section 14.0 of this Agreement have been met for partial operation of the Project; and (iv) partial operation of the Project is consistent with Applicable Laws and Regulations, applicable reliability standards, and Good Utility Practice.

Article 15 - Survival

15.0 Survival of Rights

The rights and obligations of the Parties in this Agreement shall survive the termination, expiration, or cancellation of this Agreement to the extent necessary to provide for the determination and enforcement of said obligations arising from acts or events that occurred while this Agreement was in effect. The Indemnity and Limitation of Liability provisions in Article 7 and the Binding Cost Cap or Cost Containment Measures referenced in Article 16 and set forth in Schedule C of this Agreement also shall survive termination, expiration, or cancellation of this Agreement.

Article 16 - Binding Cost Cap or Cost Containment Measures

16.0 Binding Cost Cap or Cost Containment Measures

Any binding cost cap or cost containment measures, or commitment to forego any kind of rate incentives or rate recovery submitted by the Selected QTPS as part of its Project shall be detailed in Schedule C of this Agreement.

Article 17 - Non-Standard Terms and Conditions

17.0 Schedule D - Non-Standard Terms and Conditions

Subject to FERC acceptance or approval, the Parties agree that the terms and conditions set forth in the attached Schedule D are hereby incorporated by reference, and made a part of, this Agreement. In the event of any conflict between a provision of Schedule D that FERC has accepted and any provision of the standard terms and conditions set forth in this Agreement that relates to the same subject matter, the pertinent provision of Schedule D shall control.

Article 18 - Miscellaneous

18.0 Notices

Unless otherwise expressly specified or permitted by the terms hereof, all communications and notices provided for herein shall be in writing and any such communication or notice shall become effective (a) upon personal delivery thereof, including by overnight mail or courier service, (b) in the case of notice by United States mail, certified or registered, postage prepaid, return receipt requested, upon receipt thereof, or (c) in the case of notice by e-mail, upon receipt thereof; provided that such transmission is promptly confirmed by either of the methods set forth in clauses (a) or (b) above, in each case addressed to the relevant party and copy party hereto at its address set forth below in this section 18.0 or at such other address as such party or copy party may from time to time designate by written notice to the other party hereto; further provided that a notice given in connection with this Section 18.0 but received on a day other than a Business Day, or after business hours in the situs of receipt, will be deemed to be received on the next Business Day.

Addresses:

ISO-NE:

ISO New England~~,~~ Inc.

1 Sullivan Road

Holyoke, MA 01040

Attention:

e-mail:

Selected QTPS:

____

____

____

____

Attention:

e-mail address ______________________

18.1 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Parties.

18.2 Incorporation of Other Documents

The ISO New England Operating Documents, as they may be amended from time to time, are incorporated by reference herein and made a part hereof and Selected QTPS is subject to, and must comply with the terms and conditions of those documents.

18.3 Headings

The headings of the sections of this Agreement are inserted for purposes of convenience only and shall not be construed to affect the meaning or construction of any of the provisions hereof.

18.4 Interpretation

Wherever the context may require, any noun or pronoun used herein shall include the corresponding masculine, feminine or neuter forms. The singular form of nouns, pronouns and verbs shall include the plural and vice versa.

18.5 Amendment; Limitations on Modifications of Agreement

(a) This Agreement shall only be subject to modification or amendment by agreement of the Parties in writing and the acceptance of any such amendment by FERC, if required to be filed at FERC.

(b) In light of the foregoing, the Parties agree that they shall not rely to their detriment on any purported amendment, waiver or other modification of any rights under this Agreement unless the requirements of this Section 18.5 are satisfied and further agree not to assert equitable estoppel or any other equitable theory to prevent enforcement of this provision in any court of law or equity, arbitration or other proceeding.

18.6 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

18.7 Further Assurances

Each Party agrees, upon the other Party's request, to make Commercially Reasonable Efforts to execute and deliver such additional documents and instruments, provide information, and to perform such additional acts as may be necessary or appropriate to effectuate, carry out and perform all of the terms, provisions, and conditions of this Agreement.

18.8 Counterparts

This Agreement may be executed in any number of counterparts, each of which shall be deemed an original, but all of which together shall constitute but one and the same instrument. The parties hereto agree that any document or signature delivered by facsimile transmission shall be deemed an original executed document for all purposes hereof.

18.9 Governing Law

This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware including all matters of construction, validity and performance without regard to the conflicts-of-laws provisions thereof and the Federal Power Act, as applicable.

18.10 Entire Agreement

Except for the ISO New England Operating Documents, applicable reliability standards, or successor documents, this Agreement, including all Schedules, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. Except for the ISO New England Operating Documents, applicable reliability standards, or successor documents, there are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

18.11 No Third Party Beneficiaries

It is not the intention of this Agreement or of the Parties to confer a third party beneficiary status or rights of action upon any person or entity whatsoever other than the Parties and nothing contained herein, either express or implied, shall be construed to confer upon any person or entity other than the Parties any rights of action or remedies either under this Agreement or in any manner whatsoever.

[Signature Page Follows]

IN WITNESS WHEREOF, this Agreement has been duly executed and delivered by the duly authorized officer of each Party as of the date written below.

For ISO New England Inc.

Name: ______________________________________

Title: ____

Date: ____

For Selected QTPS

Name: ______________________________________

Title: ____

Date: ____

SCHEDULE A

Description of Project and Scope of Work

SCHEDULE B

Development Schedule

Selected QTPS shall ensure and demonstrate to the ISO-NE that it timely has met the following milestones and milestone dates and that the milestones remain in good standing:

[As appropriate include the following standard Milestones, with any revisions, and additional milestones necessary for the Project]:

Milestones and Milestone Dates
Demonstrate adequate Project financing. On or before ______, Selected QTPS must demonstrate that adequate project financing has been secured. Project financing must be maintained for the term of this Agreement [add detail if necessary].
Acquisition of all necessary federal, state, county, and local site permits. On or before ______, Selected QTPS must demonstrate that all required federal, state, county and local site permits have been acquired. [add detail if necessary]. Provide separate dates for each permit]
Substantial Site Work Completed: On or before _______, Selected QTPS must demonstrate that at least 20% of Project site construction is completed. Additionally, the Selected QTPS must submit updated ratings and the final project drawings to the ISO-NE.
Delivery of major electrical equipment. On or before ______, Selected QTPS must demonstrate that all major electrical equipment has been delivered to the project site. [add detail if necessary].
Demonstrate required ratings. On or before ______, Selected QTPS must demonstrate that the project meets all required electrical ratings. [add detail if necessary].
Required Project In-Service Date. On or before ______, Selected QTPS must: (i) demonstrate that the Project is completed in accordance with the Scope of Work in Schedules A of this Agreement; (ii) meets the criteria outlined in Schedule B of this Agreement; (iii) is placed In-Service; and (iv) is under ISO-NE operational dispatch.
[Add additional Milestones]

SCHEDULE C

Binding Cost Cap or Cost Containment Measures

[Insert binding cost cap or cost containment terms and conditions, if any contained in the Selected QTPS selected proposal.   If no such binding cost cap or cost containment measures state "None".]

SCHEDULE D

Non-Standard Terms and Conditions

[Insert non-standard terms and conditions, if any. If no such non-standard terms and conditions, state “None”.]

SCHEDULE 12

TRANSMISSION COST ALLOCATION ON AND AFTER JANUARY 1, 2004

This Schedule 12 describes the cost allocation treatment of upgrades, modifications or additions to the transmission system in New England on and after January 1, 2004. Nothing in this Schedule 12 shall eliminate the PTF status of transmission facilities that were PTF on December 31, 2003; and any upgrades to such facilities that continue to meet the definition of PTF specified in this OATT shall be classified as PTF for all purposes under this OATT. The costs of all upgrades to the Highgate Transmission Facilities will be treated as HTF and allocated according to this schedule, as may be amended from time to time, provided that such HTF upgrades shall not be limited by Appendix B to Attachment F Implementation Rule under this OATT if classified as Regional Benefit Upgrades.

A. Process for Categorizing Upgrades for Cost Allocation:

Upgrades, modifications or additions to the New England Transmission System shall be categorized by the ISO, with advisory input from the Reliability Committee and the Planning Advisory Committee, as appropriate. A list of categorized Transmission Upgrades shall be made part of each annual and interim RSP, subject to the provisions of Attachment K of this OATT.

B. Transmission Cost Allocation by Category:

1. Generator Interconnection Related Upgrades:

The cost for all Generator Interconnection Related Upgrades shall be allocated pursuant to Schedule 11 of this OATT.

2. Elective Transmission Upgrades:

The cost for all Elective Transmission Upgrades shall not be included in the Pool-Supported PTF costs recoverable under this OATT, but shall be allocated solely to the entity or entities volunteering to make and pay for such Elective Transmission Upgrades.

3. NEMA Upgrades:

The cost for all NEMA Upgrades shall be included in the Pool-Supported PTF costs recoverable under this Tariff for so long as such Transmission Upgrades continue to meet the definition of PTF under this OATT and allocated to Transmission Customers taking service under this OATT.

4. RTEP02 Upgrades:

The costs for all RTEP02 Upgrades placed in service on or before December 20, 2007, shall be included in the Pool-Supported PTF costs recoverable under this OATT for so long as such Transmission Upgrades continue to meet the definition of PTF under this OATT and allocated to Transmission Customers taking service under this OATT.

5. Regional Benefit Upgrades:

The cost for all Regional Benefit Upgrades, as well as all transmission facilities that were PTF as of December 31, 2003 and upgrades to such facilities that meet the definition of PTF under this OATT, shall be included in the Pool-Supported PTF costs recoverable under this OATT for so long as such Transmission Upgrades and such existing PTF continue to meet the definition of PTF under this OATT and allocated to Transmission Customers taking service under this OATT. Market Efficiency Transmission Upgrades that are not RBUs shall not be included in the Pool-Supported PTF Costs recoverable under this OATT.

6. Public Policy Transmission Upgrade Costs:

(a) Seventy percent of the costs of each Public Policy Transmission Upgrade shall be allocated to Transmission Customers taking service under this OATT in the same manner as Regional Benefit Upgrades.

(b) The remaining thirty percent of the costs of each Public Policy Transmission Upgrade shall be allocated to the Regional Network Load of each state in direct proportion to the state's share of the public policy planning need that gives rise to the Public Policy Transmission Upgrade ("Planning Need"). Each state's share of the Planning Need shall be: (i) as shown in a Planning Need identified by NESCOE in a request for a Public Policy Transmission Study pursuant to Section 4A.1 of Attachment K, based on its estimate of the MWhs of electric energy (or MWs of capacity, if applicable) needed over the requested study period to satisfy the state and federal Public Policy Requirements it identified for evaluation and how such needs are allocated among the states, which shall take into account the MWhs (or MWs of capacity, if applicable) associated with contracts and other mechanisms that are available and capable to satisfy the Public Policy Requirements for the year or years of need considered in the requested Public Policy Transmission Study; or (ii) if NESCOE does not provide a Planning Need in such a request, the load-ratio share of the Regional Network Load of each state that has been identified pursuant to the procedures set forth in Sections 4A.1 and 4A.1.1 of Attachment K as having one or more Public Policy Requirements that will be evaluated in the corresponding Public Policy Transmission Study. Nothing in this Schedule 12 shall prevent the applicable PTOs from filing with the Commission an alternative cost allocation for a Public Policy Transmission Upgrade in accordance with the TOA or a Qualified Transmission Project Sponsor that is not a PTO from filing with the Commission an alternative cost allocation for a Public Policy Transmission Upgrade. The revenue requirements for such Public Policy Transmission Upgrades shall be separately determined in accordance with the provisions of Attachment F to this OATT, subject to separate incentives or other modifications specifically approved by the Commission for such upgrades under Section 205 of the Federal Power Act.

Notwithstanding anything else in this Section 6, the costs of Public Policy Transmission Upgrades to address the Public Policy Requirement of a local government shall not be allocated under Schedule 12 and shall be allocated under a separate local schedule or cost recovery mechanism.

7. Local Benefit Upgrades:

The cost for Local Benefit Upgrades shall not be included in the Pool-Supported PTF costs recoverable under this OATT.

8. Localized Costs:

Localized Costs shall not be included in the Pool-Supported PTF costs recoverable under this OATT, or in costs allocated to Regional Network Load according to Section 6 of this Schedule 12, but instead the responsibility for such Localized Costs shall be the responsibility of the entity or entities causing or subject to such Localized Costs. The System Operator, in accordance with Schedule 12C of this OATT, shall review RTEP02 Upgrades, Regional Benefit Upgrades, reconstructions/replacements of all or part of Pool Transmission Facilities, and Public Policy Transmission Upgrades and identify any Localized Costs associated with them.

9. Merchant Transmission Facilities Cost Allocation

The cost of all Merchant Transmission Facilities, including the cost of Transmission Upgrades required to interconnect the Merchant Transmission Facilities to the PTF, shall be the responsibility of the developer of the Merchant Transmission Facilities, and shall not be included in the Pool-Supported PTF costs recoverable under this OATT.

10. L[A1]onger-Term Transmission Upgrades:

(a) L[A2]onger-Term Transmission Upgrades that meet a greater than 1.0 benefit-to-cost ratio threshold: The cost of Longer-Term Transmission Upgrades shall be allocated in the same manner as Regional Benefit Upgrades, unless the applicable PTOs in accordance with the TOA or a Qualified Transmission Project Sponsor that is not a PTO in accordance with the NTDOA files with the Commission an alternative cost allocation for a Longer-Term Transmission Upgrade that implements the cost allocation requested by NESCOE in a written communication to the ISO pursuant to Section 16.4(i) of Attachment K to this OATT and the Commission approves such alternative cost allocation, in which case: (a) only the portion of the costs associated with addressing any combined reliability and/or market efficiency needs identified in the request for proposal(s) issued pursuant to Section 16.4(a) of Attachment K to this OATT, as calculated by the ISO, shall be allocated in the same manner as Regional Benefit Upgrades; and (b) the incremental costs associated with addressing the longer-term needs identified in a request for proposal(s) issued pursuant to Section 16.4(a) of Attachment K to this OATT shall be allocated under the alternative cost allocation filed with and accepted by the Commission by the applicable PTO in accordance with the TOA or by a Qualified Transmission Project Sponsor that is not a PTO in accordance with the NTDOA.

(b) L[A3]onger-Term Transmission Upgrades that do not meet the greater than 1.0 benefit-to-cost ratio threshold: A portion of the cost of the Longer-Term Transmission Upgrades determined by multiplying the benefit-to-cost ratio, as calculated pursuant to Section 16.4(h) of Attachment K to this OATT, by the total cost of the Longer-Term Transmission Upgrades shall be allocated in the same manner as Regional Benefit Upgrades. The remaining portion of the cost of the Longer-Term Transmission Upgrades shall be allocated to Regional Network Load in each of the New England states that voluntarily agree to fund the remaining portion of the cost in accordance with the cost allocation that may be filed by the applicable PTO pursuant to the TOA or a Qualified Transmission Project Sponsor that is not a PTO pursuant to the NTDOA that implements the cost allocation requested by NESCOE in a written communication to the ISO pursuant to Section 16.4(j) of Attachment K to this OATT and is approved by the Commission.

SCHEDULE 12C

DETERMINATION OF LOCALIZED COSTS ON AND AFTER JANUARY 1, 2004

Introduction

The purpose of this Schedule 12C is to describe procedures that the ISO will use in determining Localized Costs for eligible Transmission Upgrades as specified below on or after January 1, 2004.

Review and Approval

These Schedule 12C review and approval procedures are separate and distinct from any other approval procedures within the Transmission, Markets and Services Tariff and are not a condition for receiving approval under any other section of the Transmission, Markets and Services Tariff. If submission of a proposed plan for a Transmission Upgrade by a Market Participant or Transmission Owner for review pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff is required, then the approval for Transmission Upgrade cost allocations as described under this Schedule 12C of this OATT cannot occur sooner than after that review has been completed and it has been determined, pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff, that the Market Participant or Transmission Owner is free to proceed with implementation of the proposed Transmission Upgrade.

Entities conducting transmission system studies shall review and discuss transmission design and construction alternatives as they are developed under a System Impact Study ("SIS") or as part of the Regional System Plan with the System Operator, Reliability Committee and the Planning Advisory Committee, as deemed appropriate by the ISO.

1. Review Procedures For Determining Localized Costs

All (1) RTEP02 Upgrades; (2) Regional Benefit Upgrades developed pursuant to Section 4.2 of Attachment K of the OATT; (3) reconstructions/replacements of all or part of Pool Transmission Facilities; and (4) Regional Benefit Upgrades, Public Policy Transmission Upgrades, and Longer-Term Transmission Upgrades developed pursuant to Sections 4.3, 4A, and 16 (respectively) of Attachment K of the OATT shall be reviewed by the ISO with advisory input from the Reliability Committee to determine if any of the costs associated with such upgrades are Localized Costs, except that a proposed Transmission Upgrade which costs less than $500,000 may be exempted from this review by the ISO.

The ISO, with advisory input from the Reliability Committee, will review and update, as appropriate, the $500,000 threshold on an annual basis.

The Market Participant or Transmission Owner seeking cost recovery for a proposed Transmission Upgrade, including reconstruction or replacement, shall submit to the ISO and the Reliability Committee the following information as deemed appropriate by the ISO:

(a) A description of (i) the proposed Transmission Upgrade and any feasible and practical transmission alternatives that were considered, and (ii) the most currently available study grade or better estimates of the construction, including the potential impact on the bulk power system during the construction of such upgrade, and (iii) the operating costs of the proposed Transmission Upgrade and any feasible and practical transmission alternatives that were considered.

(b) A summary of the technical analysis performed for the Transmission Upgrade and the identified transmission alternatives.

(c) A review and discussion of the need for the proposed Transmission Upgrade.

(d) A discussion of why the requested Transmission Upgrade was selected over other transmission alternatives, with a description of the benefits of the proposed Transmission Upgrade over other transmission alternatives from an operational, timing of implementation, cost and reliability perspective.

If in reviewing the application and associated information, the ISO, with advisory input from the Reliability Committee, decides that additional information, review, or study is required prior to acting on the application, the ISO, with advisory input from the Reliability Committee, may elect to defer action and solicit supplementary information, review, or study as required. Sources for such additional information may be, but are not limited to, the entity sponsoring the application, Transmission Owners, or the Reliability Committee.

In making its determination of whether Localized Costs exist for the Transmission Upgrades identified in (1), (2) and (3) above, the ISO will consider the reasonableness of the proposed engineering design and construction method with respect to (i) Good Utility Practice, (ii) the current engineering design and construction practices in the area in which the Transmission Upgrade is built, (iii) alternate feasible and practical Transmission Upgrades and (iv) the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrades.

In making its determination of whether Localized Costs exist for the Transmission Upgrades identified in (4) above, the ISO will consider incremental costs resulting from changes to the Transmission Upgrade described in the Transmission Cost Allocation application (or any revisions thereto) for regional rate recovery compared to the description of the Transmission Upgrade in Schedule A to the Selected Qualified Transmission Project Sponsor Agreement. Localized Costs for the Transmission Upgrades identified in (4) above that are located on a PTO's existing transmission system, where the Selected Qualified Transmission Project Sponsor is not the PTO for the existing system element(s), will be determined in a manner consistent with the process described for the Transmission Upgrades identified in (1), (2) and (3) above.

Local siting requirements for transmission facilities shall not be dispositive of whether or not Localized Costs exist with respect to any particular Transmission Upgrade.

The ISO will develop detailed procedures to fulfill the objectives and requirements of this Schedule 12C.

2. Additional Transmission Upgrade Costs or Design Changes Subsequent to the ISO's Determination of Localized Costs

If the costs associated with a Transmission Upgrade exceed the estimated Pool-Supported PTF costs determined in the original Localized Costs review by ten percent, or the design associated with the construction of a Transmission Upgrade is materially changed subsequent to the ISO's determination of Localized Costs, then the applicant for Pool-Supported PTF costs shall be required to submit its Transmission Upgrade again to a review by the ISO to determine if any of the incremental costs or costs associated with the change in design are Localized Costs.

3. Dispute Resolution Regarding Determination of Localized Costs

The ISO's determination of Localized Costs under this OATT shall take effect on the date on which the ISO issues its written findings and determination. The applicant for cost recovery (the "Applicant") whose project is deemed to include Localized Costs may dispute such decision by the ISO by submitting within 60 days of such decision formal written notice of the dispute to the ISO, describing in detail the basis for its challenge of the ISO's determination. The Applicant and the ISO shall then enter into good faith negotiations for a period not to exceed 60 days from the date of the Applicant's written notice to try to resolve the dispute.

If there is no satisfactory resolution of the dispute at the end of the negotiation period, the Applicant shall then have the right to file a Section 206 complaint with the Commission.

ATTACHMENT N
PROCEDURES FOR REGIONAL SYSTEM PLAN UPGRADES

I. INTRODUCTION

Pursuant to Part II.G of the ISO New England Open Access Transmission Tariff (Sections II.46 – II.47), Attachment K and this Attachment, the ISO shall classify upgrades as Reliability Transmission Upgrades, Market Efficiency Transmission Upgrades, ~~or~~ Public Policy Transmission Upgrades or Longer-Term Transmission Upgrades during the Regional System Plan ("RSP") process. Pursuant to established standards, that process is designed to collect and reflect broad input from all stakeholders through the Planning Advisory Committee ("PAC"). The PAC is composed of a wide variety of regional stakeholders, including Governance Participants (such as generator owners, marketers, load serving entities, merchant transmission owners and participating transmission owners), governmental representatives, public interest groups, state agencies (including those participating in the New England Conference of Public Utilities Commissioners), retail customers, representatives of local communities, and consultants. The PAC meets regularly throughout the year.

This procedure describes the standards used by the ISO to identify Reliability Transmission Upgrades, Market Efficiency Transmission Upgrades, ~~and~~ Public Policy Transmission Upgrades and Longer-Term Transmission Upgrades and the process for making such identifications pursuant to Part II.G and Attachment K of the OATT.

The ISO may amend these standards and procedures from time to time, as appropriate, with input from the Reliability Committee and PAC.

II. STANDARDS FOR IDENTIFYING RELIABILITY TRANSMISSION UPGRADES, MARKET EFFICIENCY TRANSMISSION UPGRADES, ~~AND~~ PUBLIC POLICY TRANSMISSION UPGRADES AND LONGER-TERM TRANSMISSION UPGRADES

A. Identification of Reliability Transmission Upgrades

Reliability Transmission Upgrades are those upgrades necessary to ensure the continued reliability of the New England Transmission System based on applicable reliability standards. In applying the applicable reliability standards, some of the considerations that will be taken into account are as follows:

- available supply and transmission (i.e., known resource changes, which includes anticipated transmission enhancements (considering Elective Transmission Upgrades and Merchant Transmission Facilities), demand side resources, and new, retired or unavailable generators);
- load growth;
- acceptable stability response;
- acceptable short circuit capability;
- acceptable voltage levels;
- adequate thermal capability; and
- acceptable system operability and responses (e.g. automatic operations, voltage changes).

To identify the transmission system facilities required to maintain reliability and system performance consistent with the applicable reliability standards, the ISO shall:

- determine whether the above factors are met using reasonable assumptions for certain amounts of forecasted load growth, and generation and transmission facility availability (due to maintenance, forced outages, or other unavailability); and
- rely on Good Utility Practice, applicable reliability standards, and the ISO System Rules.

A Reliability Transmission Upgrade is not an upgrade required by the interconnection of a generator except to the extent determined under the terms of Schedule 11 of the OATT. A Reliability Transmission Upgrade may also provide market efficiency benefits.

B. Identification of Market Efficiency Transmission Upgrades

Market Efficiency Transmission Upgrades are upgrades designed primarily to provide a net reduction in total production cost to supply the system load. Proposed Market Efficiency Transmission Upgrades shall be identified by the ISO where the net present value of the net reduction in total cost to supply the system load, as determined by the ISO, exceeds the net present value of the carrying cost of the identified transmission upgrade.

An upgrade identified as a Reliability Transmission Upgrade may qualify for interim treatment as a Market Efficiency Transmission Upgrade if market efficiency is used to influence the schedule for the implementation of the upgrade. Such opportunities shall be identified by the ISO when the net present value of the reduction to total production cost to supply the system load, as determined by the ISO, exceeds the net present value of the Reliability Transmission Upgrade after it is advanced less the net present value of the upgrade for when it is projected to be needed for reliability.

1. **Base Economic Evaluation Model**

In making a determination of the net present value of bulk power system resource costs, the ISO shall take into account applicable economic factors that shall include the following projected factors:

- energy costs;
- Capacity Costs;
- cost of supplying total operating reserve;
- system losses;
- available supply and transmission (i.e., known resource changes, which includes anticipated transmission enhancements (considering Elective Transmission Upgrades and Merchant Transmission Facilities), demand side resources and new, retired or unavailable generators);
- load growth;
- fuel costs;
- fuel availability;
- generator availability;
- release of bottled generating resources;
- present worth factors for each project specific to the owner of the project;
- present worth period not to exceed ten years; and
- cost of the project.

Analysis may include utilization of historical information such as may be included in market reports as well as special studies and should report cumulative net present value annually over the study period.

2. **Other Data Provided to Stakeholders**

Although not used to evaluate the net economic benefit of the system upgrade, analysis may be provided to illustrate the net cost to load with and without the transmission upgrade – considering additional factors such as locational installed capacity, congestion costs, and impacts on bilateral prices for electricity.

Summary

Based on information provided through such analysis and pursuant to the factors listed in (1) above, the ISO, in consultation with the PAC, will identify Market Efficiency Transmission Upgrades to be included in the RSP. If however, during the course of their analysis, the ISO determines that without the project the applicable reliability standards will not be met, then the project will be designated as a Reliability Transmission Upgrade and included in the RSP as such.

C. Identification of Public Policy Transmission Upgrades

Public Policy Transmission Upgrades are upgrades designed to meet ~~-~~transmission needs driven by public policy requirements, including such needs identified by NESCOE. Proposed Public Policy Transmission Upgrades shall be assessed and identified by the ISO in accordance with Section 4A of Attachment K to the OATT.

D. Identification of Longer-Term Transmission Upgrades

Longer-Term Transmission Upgrades are upgrades designed to meet transmission needs identified by NESCOE in accordance with Section 16 of Attachment K. Proposed Longer-Term Transmission Upgrades shall be assessed and identified by the ISO in accordance with Section 16 of Attachment K to the OATT.

III. PROCEDURES FOR IDENTIFYING RELIABILITY TRANSMISSION UPGRADES, MARKET EFFICIENCY TRANSMISSION UPGRADES, ~~AND~~ PUBLIC POLICY TRANSMISSION UPGRADES AND LONGER-TERM TRANSMISSION UPGRADES

A. ~~ISO~~ Identification of Needs for Reliability Transmission Upgrades, Market Efficiency Transmission Upgrade, ~~and~~ Public Policy Transmission Upgrades and Longer-Term Transmission Upgrades

1. An assessment of the adequacy of the region's electric system.

On a regular and on-going basis, the ISO shall conduct studies to identify the location and nature of any potential problems on the New England Transmission System. These assessments shall be conducted to identify those factors relevant to the standards for identifying needs which might be solved or mitigated by Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades, as specified in Section II of this Attachment.

The ISO will publish its identification of such relevant factors on the New England Transmission System on its website and to the PAC, thereby providing market signals for generation, merchant transmission and load responses to develop and implement market-based solutions for the relief of actual and projected system reliability concerns, transmission constraints and market inefficiencies. The ISO will also present the results of its assessments in appropriate market forums to facilitate market responses to those needs. Market responses having met appropriate milestones pursuant to Attachment K to the OATT will be included in studies to assess the effects of such market responses on the identified problems with reliability and market inefficiencies.

Based on input and feedback provided by the PAC, the ISO shall refer to the Markets Committee and Reliability Committee issues and concerns identified by the PAC for further investigations and consideration of potential changes to rules and procedures.

2. Conduct of Public Policy Transmission Studies

The ISO will conduct the public policy transmission planning process pursuant to the timelines and procedures set out in Section 4A of Attachment K to this OATT.

3. Conduct of Longer-Term Transmission Studies

The ISO will conduct the longer-term transmission planning process pursuant to the timelines and procedures set out in Section 16 of Attachment K to this OATT.

B. Adequacy of the market responses, and as necessary, adequacy of Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades

The ISO shall assess the adequacy of proposed market responses in addressing identified system needs. The ISO shall also ensure that there are no significant adverse effects associated with such market responses, pursuant to Section I.3.9 of the Tariff and Planning Procedure 5-3, “Guidelines for Conducting and Evaluating Proposed Plan Application Analysis”.

If the market does not respond with adequate solutions to address the system needs identified by the ISO, the ISO shall present a coordinated transmission plan in the RSP that identifies appropriate projects for addressing both reliability, and market efficiency needs.

This coordinated plan is updated by the ISO as market responses to identified problems are developed. Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades are implemented only after market solutions have been given first consideration.

C. Periodic Updates to the RSP

A Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade may be added to the RSP at any time in a given year, ~~and~~ a Public Policy Transmission Upgrade project may be added to the RSP in accordance with Sections 3.6 and 4A of Attachment K to the OATT, and a Longer-Term Transmission Upgrade project may be added to the RSP in accordance with Sections 3.6 and 16 of Attachment K to the OATT. In doing so, the ISO shall consult with and consider input from the PAC and the Reliability Committee, within the scope of their respective functions.

The time required to implement transmission projects, however, is often longer than that needed for market-based solutions. Thus, the RSP process recognizes that a new market response could result in a deferral or a significant change in the proposed timing and/or configuration of a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrades. Also, a needed Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade may become delayed due to other factors.

As a result, the ISO may remove or defer a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade project from the RSP at any time in a given year, if the market responds by developing credible market-based solutions, or other circumstances arise that impact the need for the Transmission Upgrade. If market-based solutions have not met appropriate milestones prior to significant sunk transmission expense being made to provide the Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, then the ISO will assess the risks and costs associated with adding or advancing a transmission project from the RSP. The ISO may remove a Public Policy Transmission Upgrade project from the RSP in accordance with Sections 3.6 and 4A of Attachment K to the OATT. The ISO may remove a Longer-Term Transmission Upgrade project from the RSP in accordance with Sections 3.6 and 16 of Attachment K to the OATT. The ISO shall consult with and consider input from the PAC and the Reliability Committee with regard to such changes in the RSP. In the event that a transmission project is removed, deferred, added or advanced, the ISO shall promptly notify the affected Participating Transmission Owners and Non-Incumbent Transmission Developers.

IV. COST-EFFECTIVENESS AND COST ALLOCATION DETERMINATION OF RELIABILITY TRANSMISSION UPGRADES AND MARKET EFFICIENCY TRANSMISSION UPGRADES

The cost-effectiveness and cost allocation of identified Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades will be determined pursuant to the Tariff, Attachment K; Schedule 12; and Planning Procedure 4. The level of detail needed to fulfill the requirements of the RSP process and Planning Procedure 4 will ensure that, in addition to a determination of Pool-supported PTF costs and Localized Costs, the planning and stakeholder review processes will include a comprehensive examination of all Transmission Upgrade construction alternatives and their associated costs and will thus evaluate the cost-effectiveness of each Transmission Upgrade and its potential alternatives.

ATTACHMENT O

NON-INCUMBENT TRANSMISSION DEVELOPER OPERATING AGREEMENT

NON-INCUMBENT TRANSMISSION DEVELOPER OPERATING AGREEMENT

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NON-INCUMBENT TRANSMISSION DEVELOPER OPERATING AGREEMENT

This Operating Agreement (this "Agreement"), dated as of [date], is made and entered into by ___________________________, a [STATE] [TYPE OF ENTITY] ("NTD"), and ISO New England Inc. ("ISO"), a Delaware corporation (NTD and the ISO are collectively referred to herein as the "Parties").

WHEREAS, the ISO is a regional transmission organization ("RTO") authorized by the Federal Energy Regulatory Commission ("FERC") to exercise the functions required of RTOs pursuant to FERC's Order No. 2000 ("Order 2000") and FERC's RTO regulations;

WHEREAS, NTD has been approved as a "Qualified Transmission Project Sponsor" pursuant to the ISO Open Access Transmission Tariff (the "ISO OATT"), which is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff (the "ISO Tariff");

WHEREAS, in accordance with the requirements of Order 2000, the ISO will be the transmission provider under the ISO OATT of non-discriminatory, open access transmission services over the transmission facilities of NTD, once placed in service, that become part of the New England Transmission System ("Transmission Service");

WHEREAS, the ISO OATT will be designed to provide for the payment by transmission customers for Transmission Service at rates designed to recover the revenue requirements of NTD in supporting the provision of such transmission service by the ISO under the ISO OATT;

WHEREAS, the ISO will be responsible for system planning within the ISO region subject to certain rights and obligations of NTD, all as set forth in this Agreement;

WHEREAS, the functions to be performed by the ISO and Order 2000 require that the ISO have the requisite operational authority over NTD's transmission facilities;

WHEREAS, in accordance with the terms set forth herein, NTD desires for the ISO to exercise, and the ISO desires to exercise, Operating Authority (as defined in Section 3.02 of this Agreement) over the NTD Transmission Facilities (as defined in this Agreement) consistent with the requirements of Order 2000, once those facilities are placed in service;

WHEREAS, NTD will among other things, continue to own, physically operate, and maintain its transmission facilities; and

WHEREAS, references to the PTOs in this Agreement are not intended to impose additional requirements or obligations on the PTOs in addition to those in the TOA;

NOW, THEREFORE, in consideration of the promises, and the mutual representations, warranties, covenants and agreements hereinafter set forth, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound, NTD and the ISO agree as follows:

ARTICLE I
DEFINITIONS; INTERPRETATIONS

1.01 **Definitions; Interpretations.** Each of the capitalized terms and phrases used in this Agreement (including the foregoing recitals) and not otherwise defined herein shall have the meaning specified in Schedule 1.01. In this Agreement, unless otherwise provided herein:

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

(b) words denoting a gender include all genders;

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

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

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

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

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

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

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

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

(k) words such as "hereunder", "hereto", "hereof" and "herein" and other words of similar import shall, unless the context requires otherwise, refer to this Agreement as a whole and not to any particular article, section, subsection, paragraph or clause hereof;

(l) a reference to "include" or "including" means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of ejusdem generis shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned; and

(m) neither this Agreement nor any other agreement, document or instrument referred to herein or executed and delivered in connection herewith shall be construed against any Person as the principal draftsperson hereof or thereof.

ARTICLE II
TRANSMISSION FACILITIES

2.01 **Transmission Facilities.** As to NTD, the transmission facilities over which the ISO shall exercise Operating Authority (as of the date the facilities are placed in service) in accordance with the terms set forth herein shall be:

(a) those facilities of NTD listed in Schedule 2.01(a) (hereinafter "NTD Category A Facilities"), as such list of facilities may be added to or deleted from in accordance with Sections 2.01(d) and 2.02 below;

(b) those facilities of NTD listed in Schedule 2.01(b) (hereinafter "NTD Category B Facilities"), as such list of facilities may be added to or deleted from, in accordance with Sections 2.01(d) and 2.02 below; and

(c) those transmission facilities of NTD within the New England Transmission System with a voltage level of less than 69 kV and all transformers that have no NTD Category A Facilities or NTD Category B Facilities connected to the lower voltage side of the transformer that are not listed on Schedule 2.01(a) and Schedule 2.01(b) (hereinafter "NTD Local Area Facilities"), provided that any excluded facilities of NTD listed on Schedule 4.01(d) shall not be NTD Local Area Facilities.

(d) The transmission facilities included on any of the lists of the NTD Category A Facilities or the NTD Category B Facilities contained in Schedule 2.01(a) and Schedule 2.01(b), respectively, may be redesignated on another of those two lists, deleted from such list, or redesignated as a NTD Local Area Facility without the necessity of an amendment to this Agreement, but only in the following manner:

(i) at the direction of a Governmental Authority with jurisdiction over the Transmission Facilities in question, provided that the ISO and NTD shall be provided prior written notice of such changes;

(ii) as agreed between the ISO and NTD; or

(iii) where the operational characteristics of a transmission facility have been materially modified (including a change from a radial transmission facility to a looped transmission facility that contributes to the parallel carrying capability of the New England Transmission System) in accordance with Section 2.01(e); provided that any such changes shall also be subject to ISO review consistent with Section 2.06.

(e) All transmission facilities to be redesignated as NTD Category A Facilities, NTD Category B Facilities, or Local Area Facilities or deleted from the lists in Schedule 2.01(a) and Schedule 2.01(b) in accordance with Section 2.01(d)(iii), and all transmission facilities to be added to the lists in Schedule 2.01(a) and Schedule 2.01(b) in accordance with Section 2.02 shall be classified in accordance with the following standards:

(i) NTD Category A Facilities shall consist of: all transmission lines with a voltage level of 115 kV and above, except for those 115 kV transmission facilities specifically designated as NTD Category B Facilities in accordance with Section 2.01(e)(ii); all transmission interties between Control Areas; all transformers that have NTD Category A Facilities connected to the lower voltage side of the transformer; all transformers that require an NTD Category A Facility to be taken out of service when the transformer is taken out of service; and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such transmission lines, interties, and transformers.

(ii) NTD Category B Facilities shall consist of: all 115 kV radial transmission lines and all 69 kV transmission lines that are not interties between Control Areas; all transformers that have any NTD Category B Facilities and no NTD Category A Facilities connected to the lower voltage side of the transformer except to the extent such transformers are designated as NTD Category A Facilities in accordance with Section 2.01(e)(i); and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such NTD Category B Facilities.

(iii) NTD Local Area Facilities shall consist of all transmission facilities with a voltage level of less than 69 kV and all transformers that have no NTD Category A

Facilities or NTD Category B Facilities connected to the lower voltage side of the transformer.

(iv) To the extent there is any dispute between the ISO and NTD as owner of a transmission facility concerning classification of such transmission facility under these standards, such disagreement shall be subject to the dispute resolution provisions of this Agreement, provided that the ISO's classification of a transmission facility under the standards shall govern pending resolution of the dispute.

Collectively, all NTD Category A Facilities, NTD Category B Facilities, and NTD Local Area Facilities shall hereinafter be referred to as the "Transmission Facilities," provided that "Transmission Facilities" shall not include Excluded Assets as defined in Section 2.04 of this Agreement or Merchant Facilities. The ISO shall maintain on its OASIS a posting of the current versions of Schedule 2.01(a) and Schedule 2.01(b), in each instance, reflecting each such change promptly after such change is made.

(f) The classifications set forth in this Section 2.01 are for operational purposes. Rate treatment of Transmission Facilities shall be governed by the ISO OATT, provided that filings for rate treatment under the ISO OATT shall be subject to Section 3.04 of this Agreement.

2.02 **New and Acquired Transmission Facilities and Transmission Upgrades.**

(a) Any New Transmission Facility or Transmission Upgrade shall be considered a "Transmission Facility" under this Agreement once it is included as "Proposed" in the RSP Project List and, unless otherwise agreed by the ISO and NTD, shall thereafter be added to Schedule 2.01(a) and/or (b), as applicable.

(b) Any Merchant Facility interconnected to or within the New England Transmission System shall not be the subject of this Agreement. Any Merchant Facility interconnected to or within the New England Transmission System constructed and placed in commercial operation after the Operations Date shall be subject to the authority of the ISO under a separate agreement in accordance with Section 2.03 and any applicable provisions of the ISO OATT.

2.03 **Merchant Facilities.** The terms and conditions under which NTD, an Affiliate of NTD or any other entity grants authority over any Merchant Facilities to the ISO shall not be governed by this

Agreement, it being understood that NTD shall enter into operating agreements relating to its Merchant Facilities directly with the ISO in accordance with applicable provisions of the ISO OATT. Nothing in this Agreement is intended to limit or expand the right of NTD, the Affiliate of NTD, or any other entity to propose, construct, or own Merchant Facilities interconnected to the New England Transmission System. No Merchant Facility may become an Acquired Transmission Facility.

2.04 **Excluded Assets.** The "Excluded Assets" of NTD shall consist of those assets and/or facilities of NTD set forth in Section 2.04(a) and (b). These Excluded Assets are expressly excluded from the definition of Transmission Facilities under this Agreement, and the ISO shall not have Operating Authority over NTD's Excluded Assets. Nothing in this Section 2.04 is intended to address the rate treatment of the Transmission Facilities or any other asset of NTD. Rate treatment of Transmission Facilities shall be governed by the ISO OATT, provided that filings for rate treatment under the ISO OATT shall be subject to Section 3.04 of this Agreement:

(a) Excluded Assets are any assets, facilities, and/or portions of facilities owned by NTD that are connected with or associated with Transmission Facilities to the extent specifically excluded pursuant to the following items (i) through (vii) of this Section 2.04(a):

(i) proceeds from the use or disposition of Transmission Facilities;

(ii) any payment, refund or credit (1) relating to Taxes in respect of the Transmission Facilities, (2) arising under any contracts or tariffs of NTD and relating to services provided prior to the beginning of the Term, or (3) arising under any contract or tariff that provides for rates that are subject to regulation by an agency other than FERC.

(iii) any rights, ownership, title or interest NTD may have with respect to telecommunications assets and equipment, provided that the ISO shall continue to have the right to use such telecommunication assets and equipment attached to or associated with Transmission Facilities solely to the extent needed for the exercise of the ISO's Operating Authority and further provided that such use right shall not be assignable by the ISO;

(iv) any existing contracts or contract rights of NTD related in any manner to Transmission Facilities unless NTD agrees to assign or transfer such contracts to the ISO;

(v) any assets, property rights, licenses, permits or facilities that are used for or in (1) the distribution, generation, trading or marketing of electricity (except for facilities specifically defined as Transmission Facilities that are used for such activities), (2) gas transportation, gas, water, petroleum, chemical, real estate development, or cable business, or (3) any other activity unrelated to the transmission of electricity located on, or making use of, the Transmission Facilities;

(vi) any causes of action or claims related to Transmission Facilities, provided, that, upon the written agreement of NTD and the ISO to the assumption by the ISO of the management of such claims under mutually agreed terms and conditions, the ISO may manage NTD's causes of action or claims against a third party relating to such Transmission Facilities, and provided further that the ISO shall have the right to pursue causes of action or claims against third parties to the extent necessary for the ISO to fulfill its responsibilities for invoicing, collection and disbursement of customer payments in accordance with Section 3.10; and

(vii) any asset or facility for which Operating Authority may not be lawfully transferred or assigned.

(b) Excluded assets are any assets or facilities of NTD that are not specifically defined as Transmission Facilities, including without limitation the facilities or portions of facilities described in items (i) through (xii) of this Section 2.04(b):

(i) all cash, cash equivalents, bank deposits, accounts receivable, and any income, sales, payroll, property or other Tax receivables;

(ii) proceeds from the use or disposition of any facilities or assets owned by NTD;

(iii) certificates of deposit, shares of stock, securities, bonds, debentures, and evidences of indebtedness;

(iv) any rights or interest in trade names, trademarks, service marks, patents, copyrights, domain names or logos;

(v) any payment, refund or credit (1) relating to Taxes, (2) arising under any contracts or tariffs of NTD and relating to services provided prior to the beginning of the Term, or (3) arising under any contract or tariff that provides for rates that are subject to regulation by an agency other than FERC;

(vi) any facilities, including transmission facilities, located outside the New England Transmission System;

(vii) any rights, ownership, title or interest NTD may have with respect to telecommunications assets and equipment;

(viii) any existing contracts or contract rights of NTD unless NTD agrees to assign or transfer such contracts to the ISO;

(ix) any assets, property rights, licenses, permits or facilities that are used for or in (1) the distribution, generation, trading or marketing of electricity or (2) gas transportation, gas, water, petroleum, chemical, real estate development, or cable business, or (3) any other activity unrelated to the transmission of electricity whether or not located on, or making use of, the Transmission Facilities;

(x) any causes of action or claims;

(xi) any asset or facility for which Operating Authority may not be lawfully transferred or assigned; and

(xii) any interests of any kind in NTD’s real property, provided that nothing in this Section 2.04 shall restrict NTD from conveying interests in real property in any future written agreement into which the ISO and NTD may, in their sole discretion, enter.

2.05 **Connection with Non-Parties.**

(a) NTD shall connect its Transmission Facilities (once placed in service) with the facilities of any entity that is not a Party, including the facilities of a current or proposed Transmission Customer, and shall install (or cause to be installed) and construct (or cause to be constructed) any transmission facilities required to connect the facilities of a non-Party to the Transmission Facilities to the extent such connection or construction is required by applicable law, including the Federal Power Act and any applicable regulations issued by FERC and provided that the construction of any such transmission facilities shall be subject to the conditions associated with NTD's obligation to build set forth in Schedule 3.09(a). Any such connection shall be subject further to: (1) the receipt of any necessary regulatory approvals, (2) compliance with the procedures set forth in the ISO OATT for review of the reliability and operational impacts of a proposed interconnection (including the procedures for interconnection of a Generating Unit under the Interconnection Standard); and (3) execution of an Interconnection Agreement with such entity containing provisions for the safe and reliable operation of each interconnection with respect to such entity's facilities in accordance with Good Utility Practice, applicable NERC/NPCC Requirements, and applicable Law (including the Federal Power Act); provided that

(i) Except as provided in 2.05(a)(ii) below, NTD shall engage in good faith negotiations as to the terms and conditions of such Interconnection Agreement with any such non-Party, but, except as may be required pursuant to regulations issued by FERC, NTD shall not be required to enter into any Interconnection Agreement containing terms and conditions unacceptable to NTD and shall reserve the right to resolve any disputes, and/or make any filings with FERC, with respect thereto.

(ii) With respect to the interconnection of a Large Generating Facility or a Small Generating Facility to any Transmission Facility, the Interconnection Agreement shall be a three-party agreement among NTD, the ISO, and the interconnecting non-Party based on the Schedule 22 Large Generator Interconnection Agreement or Schedule 23 Small Generator Interconnection Agreement, respectively, in the ISO OATT. With respect to the interconnection of other Generating Units to any Transmission Facility of NTD, the ISO shall be a party to Interconnection Agreements if and to the extent that FERC regulations require the ISO to be a party. Either the ISO or the PTOs (working with NTD as a party to the Disbursement Agreement), may propose amendments to the Schedule 22 Large Generator Interconnection Agreement or Schedule 23 Small Generator Interconnection Agreement under Section 205 of the Federal Power Act and shall include in such proposal the views of the ISO and NTD and PTOs, as applicable, provided that the standard applicable under Section 205 of the Federal Power Act shall apply only to the NTD and/or PTOs' position on any financial obligations of the PTOs and/or NTD (as applicable) or the interconnecting non-Party, and any provisions related to physical impacts of the interconnection on the Transmission Facilities or other assets. If NTD, the ISO and the interconnecting non-Party agree to the terms and conditions of a specific Large Generator Interconnection Agreement or Small Generator Interconnection Agreement, as applicable, or any amendments to such an Interconnection Agreement, then NTD and the ISO shall jointly file the executed Interconnection Agreement, or amendment thereto, with FERC under Section 205 of the Federal Power Act. To the extent NTD, the ISO and such interconnecting non-Party cannot agree to proposed variations from the Schedule 22 or 23 Interconnection Agreement applicable to a Large Generating Facility or Small Generating Facility, respectively, or cannot otherwise agree to the terms and conditions of the Interconnection Agreement, or any amendments to such an Interconnection Agreement, then NTD and the ISO shall jointly file an unexecuted Interconnection Agreement, or amendment thereto, with FERC under Section 205 of the Federal Power Act and shall identify the areas of disagreement in such filing, provided that, in the event of disagreement on terms and conditions of the Interconnection Agreement related to the costs of upgrades to the Transmission Facilities, the anticipated schedule for the construction of such upgrades, any financial obligations of NTD, and any provisions related to physical impacts of the interconnection on the Transmission Facilities or other assets, then the standard applicable under Section 205 of the Federal Power Act shall apply only to NTD's position on such terms and conditions.

The costs of interconnection facilities shall be allocated in the manner specified in the ISO OATT.

(b) NTD shall also connect its Transmission Facilities (once placed in service) with the facilities of any entity that is not a Party upon satisfaction of the "Elective Transmission Upgrade" provisions of the ISO OATT, provided that NTD shall only connect the facilities of such entity (the "Elective Transmission Upgrade Applicant") upon satisfaction of the following conditions:

(i) The Elective Transmission Upgrade Applicant shall enter into an Interconnection Agreement with the affected PTO(s) and NTD and, to the extent necessary and appropriate, enter into support agreements with the affected PTO(s) and NTD, provided that the Elective Transmission Upgrade Applicant may request, upon providing the security, credit assurances, and/or deposits required by the affected PTO, the filing with the Commission by NTD and/or affected PTOs of unexecuted Interconnection Agreements and support agreements.

(ii) The Elective Transmission Upgrade Applicant shall obtain all necessary legal rights and approvals for the construction and maintenance of the upgrade and shall cooperate with NTD in obtaining all necessary legal rights and approvals for the construction and maintenance of additions or modifications, if any, required in conjunction with the upgrade.

(iii) The Elective Transmission Upgrade Applicant shall be responsible for 100% of all of the costs of said upgrade and of any additions to or modifications of the Transmission Facilities that are required to accommodate the Elective Transmission Upgrade. A request for rate treatment of an Elective Transmission Upgrade, if any, shall be determined by FERC in the appropriate proceeding.

2.06 **Review of Transmission Plans.** NTD shall submit to the ISO in such form, manner and detail as the ISO may reasonably prescribe: (i) any new or materially changed plans for retirements of or changes in the capacity of such Transmission Facilities rated 69 kV or above or plans for construction of New Transmission Facilities or Transmission Upgrades rated 69 kV or above; and (ii) any new or materially changed plan for any other action to be taken by NTD which may have a significant effect on the stability, reliability or operating characteristics of the Transmission Facilities, the facilities of any Transmission Owner, or the system of a Participant. The ISO shall provide notification of any such NTD submissions to the appropriate Technical Committee(s). Unless prior to the expiration of ninety (90) days, the ISO notifies NTD in writing that it has determined that implementation of the plan will have a significant adverse effect upon the reliability or operating characteristics of the Transmission Facilities, the facilities of any Transmission Owner, or the system of a Participant, NTD shall be free to proceed. If the ISO notifies NTD that implementation of such plan has been determined to have a significant adverse effect upon the reliability or operating characteristics of the Transmission Facilities, the facilities of any Transmission Owner, or the system of a Participant, NTD shall not proceed to implement such plan unless NTD takes such action or constructs such facilities as the ISO determines to be reasonably necessary to avoid such adverse effect.

2.07 **Condemnation.** If, at any time, any Governmental Authority commences any process to acquire any Transmission Facilities or any other interest in Transmission Facilities then held by NTD through condemnation or otherwise through the power of eminent domain, (i) NTD shall provide the ISO with written notice of such process, (ii) NTD shall, at its cost, direct any litigation or proceeding regarding such condemnation or eminent domain matter, (iii) NTD shall have the right to settle any such proceeding without the consent of the ISO, and (iv) any award in condemnation or eminent domain shall be paid to NTD without any claim to such award by the ISO.

ARTICLE III
OPERATING AUTHORITY

3.01 **Grant of Operating Authority.** Subject to the terms set forth in this Agreement, including Article III and Article X hereof, NTD hereby authorizes the ISO, through its officers, employees, consultants, independent contractors and other personnel, to exercise Operating Authority over the Transmission Facilities once they are placed in service, including provision of Transmission Service over the Transmission Facilities under the TOA and ISO OATT, and the ISO hereby agrees to assume and exercise Operating Authority over the Transmission Facilities in accordance with the TOA once they are placed in service. Coincident with the NTD's Transmission Facilities being placed in service or the acquisition of operational Transmission Facilities, the NTD shall execute the TOA pursuant to Section 10.05 hereof, list such Transmission Facilities under the TOA and, by doing so, authorize the ISO to exercise Operating Authority over such Transmission Facilities via the TOA.

3.02 **[reserved]**

3.03 **Transmission Services and OATT Administration.**

(a) The ISO shall administer the ISO OATT in the manner specified in this Section 3.03. The ISO's OATT administration responsibilities shall include those enumerated below:

(i) The ISO shall receive, post on OASIS as required by Commission regulations, and respond to requests by Large Generating Facilities and Small Generating Facilities to be interconnected under the ISO OATT, and all Transmission Service. Except as provided in Section 3.03(a)(ii), the ISO shall perform the system impact studies and facilities studies (and execute and administer agreements for such studies) in connection with such requests to the Administered Transmission System. Notwithstanding the foregoing, (A) the ISO shall consult with NTD prior to completion of system impact studies and facilities studies in connection with requests that affect the Transmission Facilities and distribution facilities and shall include in any such studies NTD's reasonable estimates of the costs of upgrades to the Transmission Facilities needed to implement the conclusions of such studies and NTD's reasonable anticipated schedule for the construction of such upgrades; (B) nothing in this Agreement shall preclude the ISO from entering into a separate agreement(s) with NTD for such studies, pursuant to the ISO's supervision and the ISO's authority to require modifications to such studies, to perform system impact studies and facilities studies; (C) except as provided in Section 3.03(a)(ii) with respect to interconnection of Generating Units that would not have an impact on facilities used for the provision of regional transmission service, nothing in this Agreement shall preclude the performance of studies related to the interconnection of Generating Units by a third party consultant to the extent permitted by applicable procedures in the ISO OATT (including procedures governing the treatment of confidential information) and provided that such studies performed by any third party consultant must include NTD's reasonable estimates of the costs of upgrades to such Transmission Facilities needed to implement the conclusions of such studies and NTD's reasonable anticipated schedule for the construction of such upgrades; and (D) NTD shall, upon request by the ISO, conduct any necessary studies related to the Transmission Facilities, including system impact studies and facilities studies, and shall assist in the performance of any such studies, including the provision of information and data in accordance with Section 11.07 of this Agreement.

(ii) The ISO shall review applications for Transmission Service or requests for the interconnection of Large Generating Facilities and Small Generating Facilities to be interconnected to a Transmission Facility to determine whether the service or interconnection would have an impact on facilities used for the provision of regional transmission service. If so, and the interconnection is to a Transmission Facility, the ISO will perform a system impact study and facilities study, as necessary to address the impacts on facilities used for the provision of regional transmission service.

(iii) The ISO shall operate and maintain the OASIS (or a successor system) as required by FERC. NTD shall provide updates to the NTD-specific pages on the OASIS site, subject to the ISO's review of such updates. The ISO shall have the authority to direct any changes to such NTD-specific pages that it deems appropriate to conform to FERC requirements and the terms and conditions of the ISO OATT.

(b) Notwithstanding Section 3.03(a), retail load customers requesting to interconnect with the Transmission Facilities of NTD shall submit service requests to NTD. Such service requests submitted to the ISO shall be forwarded to NTD. NTD shall execute and administer the agreements, and shall be responsible for billing, collections, dispute resolution and the performance of system impact studies and facilities studies, in coordination with the ISO as necessary, in connection with such requests.

(c) Transmission Service Agreements. The ISO and NTD shall enter into all agreements for Transmission Service over the Transmission Facilities; provided that:

(i) A pro forma regional transmission service agreement (or service agreements) shall be attached to the ISO OATT and such pro forma service agreement(s) shall set forth the respective rights and responsibilities of the Transmission Customer, the ISO, the PTOs and NTD. The ISO shall have the authority, pursuant to Section 205 of the Federal Power Act, to amend the pro forma service agreement(s) or the Market Participant Service Agreement ("MPSA") or executed service agreements related to the terms and conditions of regional Transmission Service.

(ii) The ISO shall be responsible for filing with the FERC, or electronically reporting to the FERC as applicable, all new agreements for Transmission Service over the Transmission Facilities. In the event of any dispute between the ISO or NTD and a Transmission Customer concerning the terms and conditions of such service agreements, the ISO shall file an unexecuted copy of the pro forma service agreement set forth in the ISO OATT and shall include in such filing any statement provided by NTD, affected PTO(s) and the Transmission Customers concerning their respective positions on any proposed changes or additions to the pro forma service agreement.

3.04 **Application Authority.**

(a) NTD shall have the authority to submit filings under Section 205 of the Federal Power Act to establish and to revise (pursuant to an NTD rate schedule filed under Schedules 13, ~~or~~ 14, or 14A, as applicable, of the ISO OATT):

(i) charges for costs permitted to be recovered under Sections 4.3, ~~and~~ 4A, and 16 of Attachment K to the ISO OATT;

(ii) once its project is listed as "Proposed" in the RSP Project List, charges for the costs of Commission-approved construction work in process; and

(iii) once its project is listed as "Proposed" in the RSP Project List, any rates, charges, terms or conditions for transmission services that are based solely on the revenue requirements of the Transmission Facilities (including Transmission Facilities leased to NTD or to which NTD has contractual entitlements).

NTD shall not have the authority to revise such rates, terms and conditions in a manner that would abridge the rights granted to the ISO in Section 3.04(b). NTD shall provide written notification to the ISO and stakeholders of any filing described in sub-paragraph (i) through (iv), above, which notification shall include a detailed description of the filing, at least 30 days in advance of a filing. NTD shall consult with interested stakeholders upon request. NTD shall retain the right to modify aspects of any filing authorized by this Section 3.04(a) after it provides written notification to the ISO and stakeholders, and shall provide notification to the ISO and stakeholders of any material modification to such filings.

With respect to any filing described in sub-paragraph (iii) above, NTD shall include in any filing a statement that, in the good faith judgment of NTD, the proposal will not be inconsistent with the design of the New England Markets, as accepted or approved by FERC. In the event the ISO believes that a proposed filing described in sub-paragraph (iii) above, would have such an inconsistency, it shall so advise NTD and NTD and the ISO shall consult in good faith to resolve any ISO concerns, but, if such disagreement cannot be resolved, NTD may submit a filing under Section 205, provided that NTD's filing (including the transmittal letter for such filing) to FERC shall include any written statement provided by the ISO setting forth the basis for the ISO's concerns.

NTD shall consult with the ISO to determine whether the ISO will need to make any software modifications in order to implement any filing authorized by this Section 3.04(a) and when any needed software modifications could reasonably be expected to be implemented. NTD's filing to FERC (and the transmittal letter for such a filing) shall include any written statement provided by the ISO setting forth the basis for any software-related implementation concerns raised by the ISO. The ISO shall make Commercially Reasonable Efforts to implement any needed software modifications by the effective date accepted by the FERC for a filing authorized by this Section 3.04(a), provided that, if the ISO has exercised such Commercially Reasonable Efforts, a failure to implement needed software modifications by the FERC-accepted effective date shall not constitute an event of default by the ISO under this Agreement or subject the ISO to financial damages, and further provided that the ISO shall run retroactive settlements consistent with the FERC-accepted effective date for a filing authorized by this Section 3.04(a) once such software modifications have been implemented.

(b) The ISO has the authority to submit filings under Section 205 of the Federal Power Act as set forth in the TOA.

(c) NTD shall have no authority to submit a filing under Section 205 of the Federal Power Act to modify any provision of the ISO OATT that implements any of the items listed in Section 3.04(b) of the TOA.

3.05 **<u>The ISO's Responsibilities</u>.**

(a) In addition to its other obligations under this Agreement, in performing its obligations and responsibilities hereunder, and in accordance with Good Utility Practice, the ISO shall:

(i) maintain system reliability; and

(ii) in all material respects, act in accordance with applicable Laws and conform to, and implement, all applicable reliability criteria, policies, standards, rules, regulations, orders, license requirements and all other applicable NERC/NPCC Requirements, and other applicable reliability organizations' reliability rules, and all applicable requirements of federal or state laws or regulatory authorities.

(b) The ISO shall obtain and retain all necessary authorizations of FERC and other regulatory authorities to function as the New England RTO and shall possess the characteristics and perform the functions required for that purpose.

3.06 **<u>NTD's Responsibilities</u>.**

(a) NTD shall, in accordance with Good Utility Practice:

(i) collaborate with the ISO with respect to:

(A) the development of Rating Procedures,

(B) the establishment of ratings for New Transmission Facilities;

(C) the establishment of ratings for Acquired Transmission Facilities that do not have an existing rating; and

(D) the establishment of any changes to existing ratings for Transmission Facilities in effect as of the Operations Date.

To the extent there is any disagreement between the ISO and NTD concerning Rating Procedures or the rating of a Transmission Facility, such disagreement shall be the subject of good faith negotiations between NTD and the ISO, provided that (x) NTD's position concerning such Rating Procedures or Transmission Facility ratings shall govern until NTD and the ISO agree on a resolution to such disagreement; and (y) nothing in this Section 3.06(a)(iv) shall limit the rights of the ISO or of NTD to submit a filing under Section 206 of the Federal Power Act with respect to Transmission Facility ratings or Rating Procedures. During any collaboration or discussions concerning Transmission Facility ratings, NTD shall continue to provide the ISO with up-to-date ratings information in accordance with the applicable Rating Procedures.

(ii) cooperate with actions taken by PTOs' Local Control Centers with respect to the Transmission Facilities; and

(iii) in all material respects, comply with all applicable laws, regulations, orders and license requirements, and with all applicable requirements, and with all applicable NERC/NPCC Requirements, other applicable reliability organizations' local reliability rules, and all applicable requirements of federal or state laws or regulatory authorities.

3.07 **<u>Reserved Rights of NTD</u>.**

(a) Notwithstanding any other provision of this Agreement to the contrary, NTD shall retain all of the rights set forth in this Section 3.07; provided, however, that such rights shall be exercised in a manner consistent with applicable NERC/NPCC Requirements and applicable regulatory standards. This Section 3.07 is not intended to reduce or limit any other rights of NTD as a signatory to this Agreement or under the ISO OATT.

(i) Nothing in this Agreement shall restrict any rights: (A) of NTD if it is a party to a merger, acquisition or other restructuring transaction to make filings under Section 205 of the Federal Power Act with respect to NTD's reallocation or redistribution of revenues or the assignment of such NTD's rights or obligations, to the extent the Federal Power Act requires such filings; or (B) of NTD to terminate its participation in this Agreement pursuant to Article X of this Agreement.

(ii) Except as expressly provided in the grant of Operating Authority to the ISO, NTD retains all rights that it otherwise has incident to its ownership of, and legal and equitable title to, its assets, including its Transmission Facilities and all land and land rights, including the right to build, acquire, sell, lease, merge, dispose of, retire, use as security, or otherwise transfer or convey all or any part of its assets, subject to NTD's compliance with Section 2.06 of this Agreement. Subject to Article X, NTD may, directly or indirectly, by merger, sale, conveyance, consolidation, recapitalization, operation of law, or otherwise, transfer all or any portion of the Transmission Facilities subject to this Agreement but only if such transferee or successors shall agree in writing to be bound by terms of this Agreement.

(iii) NTD shall have the right to adopt and implement, consistent with Good Utility Practice, procedures and to take such actions it deems necessary to protect its facilities from physical damage or to prevent injury or damage to persons or property.

(iv) NTD retains the right to take whatever actions, consistent with Good Utility Practice, it deems necessary to fulfill its obligations under applicable Law.

(v) Nothing in this Agreement shall be construed as limiting in any way the rights of NTD to make any filing with any applicable state or local regulatory authority.

(vi) NTD shall have the right to retain one or more subcontractors to perform any or all of its obligations under this Agreement. The retention of a subcontractor pursuant to the terms of this Section 3.07 shall not relieve NTD of its primary liability for the performance of any of its obligations under this Agreement.

(b) Any and all other rights and responsibilities of NTD related to the ownership or operation of its Transmission Facilities not expressly assigned to the ISO under this Agreement will remain with NTD.

(c) Nothing in this Agreement shall be deemed to impair or infringe on any rights or obligations of NTD under the Federal Power Act and FERC's rules and regulations thereunder, provided that any such rights are not inconsistent with the express terms of this Agreement. Nothing contained in this Agreement shall be construed to limit in any way the right of NTD to take any position, including opposing positions, in any administrative or judicial proceeding or filing by NTD or the ISO, notwithstanding that such proceeding or filing may be undertaken or made, explicitly or implicitly, pursuant to this Agreement.

3.08 **[reserved]**

3.09 **[reserved]**

3.10 **<u>Invoicing, Collection and Disbursement of Payments</u>.**

(a) <u>Invoicing</u>. Except as provided in Section 3.10(a)(ii), the ISO will administer its current net settlement system, including invoicing of charges to Transmission Customers for Transmission Services on the Transmission Facilities as follows:

(i) The charges invoiced by the ISO on behalf of NTD shall include the following (each, an "<u>Invoiced Amount</u>"):

(A) all charges listed in NTD's Commission-accepted rate schedule under Schedules 13<u>, </u>~~and~~ 14<u>, and 14A </u>of the ISO OATT; and

(B) any and all rates, charges, fees and/or penalties under interconnection agreements which have been filed with and accepted by FERC, other than amounts billed directly by NTD pursuant to Section 3.10(a)(ii) below.

(ii) Payments relating to all services provided by NTD outside of Schedules 13, ~~and~~ 14, and 14A that provide for payment to NTD, and any other payments shall be invoiced by NTD and shall not be invoiced by the ISO; provided that, notwithstanding the foregoing, NTD and the ISO may enter into separate agreements such that the ISO provides invoicing services for such payments.

(iii) The ISO shall remit or credit to NTD, consistent with the ISO Tariff and the net settlement system, any and all payments received or collected from Transmission Customers for Invoiced Amounts in accordance with this Agreement. NTD shall designate (and notify the ISO of the identity of) a single authorized individual to provide such directions to the ISO. This individual shall also respond to any ISO questions or requests for clarification concerning such directions; provided that the ISO shall be able to rely upon the direction of the designated individual unless and until it receives notification from NTD or from a Governmental Authority of reversal of such direction by any Governmental Authority with jurisdiction over this Agreement.

(b) The ISO's Collection Obligations and Application of Financial Assurances Policies. If a Transmission Customer defaults on any payment of any Invoiced Amount (the "Owed Amounts"), the ISO shall take all necessary actions to execute or call upon any Financial Assurances held by the ISO attributable to such Transmission Customer.

(c) No Pledge of Invoiced Amounts. The ISO shall not create, incur, assume or suffer to exist any lien, pledge, security interest or other change or encumbrance, or any other type of preferential arrangement (including a banker's right of set off) against any Invoiced Amounts, any accounts receivables representing Invoiced Amounts, the settlement account maintained by the ISO into which payments on Invoiced Amounts are made and from which remittances are made to NTD or any Financial Assurances.

3.11 **Subcontractors.** NTD acknowledges and agrees that, subject to the terms set forth herein, the ISO has the right to retain one or more subcontractors to perform any or all of its obligations under this Agreement. The retention of a subcontractor pursuant to the terms of this Section 3.11 shall not relieve the ISO of its primary liability for the performance of any of its obligations under this Agreement.

3.12 **No Impairment of the ISO's Other Legal Rights and Obligations.** Nothing in this Agreement shall be deemed to impair or infringe on any rights or obligations of the ISO under the Federal Power Act and FERC's rules and regulations thereunder, including the ISO's rights and obligations to submit filings to recover its administrative, capital, and other costs.

ARTICLE IV
REPRESENTATIONS AND WARRANTIES OF THE PARTIES

4.01 **Representations and Warranties of NTD.** NTD represents and warrants to the ISO as follows:

(a) Organization. It is duly organized, validly existing and in good standing under the laws of the state of its organization.

(b) Authorization. It has all requisite power and authority to execute, deliver and perform this Agreement; the execution, delivery and performance by NTD of this Agreement have been duly authorized by all necessary and appropriate action on the part of NTD; and this Agreement has been duly and validly executed and delivered by NTD and constitutes the legal, valid and binding obligations of NTD, enforceable against NTD in accordance with its terms.

(c) No Breach. The execution, delivery and performance by NTD of this Agreement will not result in a breach of any terms, provisions or conditions of any agreement to which NTD is a party which breach has a reasonable likelihood of materially and adversely affecting NTD's performance under this Agreement.

4.02 **Representations and Warranties of the ISO.** The ISO represents and warrants to NTD as follows:

(a) Organization. It is duly organized, validly existing and in good standing under the laws of the state of its organization.

(b) Authorization. It has all requisite power and authority to execute, deliver and perform this Agreement; the execution, delivery and performance by the ISO of this Agreement have been duly authorized by all necessary and appropriate action on the part of the ISO; and this Agreement has been duly and validly executed and delivered by the ISO and constitutes the legal, valid and binding obligation of the ISO, enforceable against the ISO in accordance with its terms.

(c) No Breach. The execution, delivery and performance by the ISO of this Agreement will not result in a breach of any of the terms, provisions or conditions of any agreement to which the ISO is a party which breach has a reasonable likelihood of materially and adversely affecting the ISO's performance under this Agreement.

ARTICLE V
COVENANTS OF NTD

5.01 **Covenants of NTD.** NTD covenants and agrees that during (i) the Term, or (ii) the period expressly specified herein, as applicable, NTD shall comply with all covenants and provisions of this Article V, except to the extent the ISO waives such covenants or performance is excused pursuant to Section 11.11(b).

5.02 **[reserved]**

5.03 **Expenses.** Except to the extent specifically provided herein, all costs and expenses incurred by NTD in connection with the negotiation of this Agreement shall be borne by NTD; provided that nothing herein shall prevent NTD from recovering such expenses in accordance with applicable law.

5.04 **Consents and Approvals.**

(a) NTD shall exercise Commercially Reasonable Efforts to promptly prepare and file all necessary documentation to effect all necessary applications, notices, petitions, filings and other documents, and shall exercise Commercially Reasonable Efforts to obtain (and will cooperate with each other in obtaining) any consent, acquiescence, authorization, order or approval of, or any exemption or nonopposition by, any Governmental Authority required to be obtained or made by NTD in connection with this Agreement or the taking of any action contemplated by this Agreement.

(b) NTD shall exercise Commercially Reasonable Efforts to obtain consents of all other third parties necessary to the performance of this Agreement by NTD. NTD shall promptly notify the ISO of any failure to obtain any such consents and, if requested by the ISO, shall provide copies of all such consents obtained by NTD.

(c) Nothing in this Section 5.04 shall require NTD to pay any sums to a third party, including any Governmental Authority, excluding filing fees paid to any Governmental Authority in connection with a filing necessary or appropriate to further action.

5.05 **Notice and Cure.** NTD shall notify the ISO in writing of, and contemporaneously provide the ISO with true and complete copies of any and all information or documents relating to, any event, transaction or circumstance, as soon as practicable after it becomes Known to NTD, that causes or shall cause any covenant or agreement of NTD under this Agreement to be breached or that renders or shall render untrue any representation or warranty of NTD contained in this Agreement as if the same were made on or as of the date of such event, transaction or circumstance. NTD shall use all Commercially Reasonable Efforts to cure such event, transaction or circumstance as soon as practicable after it becomes Known to NTD. No notice given pursuant to this Section 5.05 shall have any effect on the representations, warranties, covenants or agreements contained in this Agreement for purposes of determining satisfaction of any condition contained herein or shall in any way limit the ISO's right to seek indemnity under Article IX.

ARTICLE VI
COVENANTS OF THE ISO

6.01 **Covenants of the ISO.** The ISO covenants and agrees that during (i) the Term, or (ii) the period expressly specified herein, as applicable, the ISO shall comply with all covenants and provisions of this Article VI, except to the extent the Parties consent in writing to a waiver of such covenants or performance is excused pursuant to Section 11.11(b).

6.02 **[reserved]**

6.03 **Expenses.** Except to the extent specifically provided herein, all costs and expenses incurred by the ISO in connection with the negotiation of this Agreement shall be borne by the ISO; provided that nothing herein shall prevent the ISO from recovering such expenses in accordance with applicable law.

6.04 **[reserved]**

6.05 **Notice and Cure.** The ISO shall notify NTD in writing of, and contemporaneously shall provide NTD with true and complete copies of any and all information or documents relating to, any event, transaction or circumstance, as soon as practicable after it becomes Known to the ISO, that causes or shall cause any covenant or agreement of the ISO under this Agreement to be breached or that renders or shall render untrue any representation or warranty of the ISO contained in this Agreement as if the same were made on or as of the date of such event, transaction or circumstance. The ISO shall use all Commercially Reasonable Efforts to cure such event, transaction or circumstance as soon as practicable after it becomes Known to the ISO. No notice given pursuant to this Section 6.05 shall have any effect on the representations, warranties, covenants or agreements contained in this Agreement for purposes of determining satisfaction of any condition contained herein or shall in any way limit any right of NTD to seek indemnity under Article IX.

ARTICLE VII
TAX MATTERS

7.01 **Responsibility for NTD Taxes.** NTD shall prepare and file all Tax Returns and other filings related to its Transmission Business and Transmission Facilities and pay any Tax liabilities related to its Transmission Business and Transmission Facilities. The ISO shall not be responsible for, or required to file, any Tax Returns or other reports for NTD and shall have no liability for any Taxes related to NTD's Transmission Business or Transmission Facilities. The ISO and NTD hereby agree that, for tax purposes, the Transmission Facilities shall be deemed to be owned by NTD.

7.02 **Responsibility for ISO Taxes.** The ISO shall prepare and file all Tax Returns and other filings related to its operations and pay any Tax liabilities related to its operations. NTD shall not be responsible for, or required to, file any Tax Returns or other reports for the ISO and shall have no liability for any Taxes related to the ISO's operations.

ARTICLE VIII
RELIANCE; SURVIVAL OF AGREEMENTS

8.01 **Reliance; Survival of Agreements.** Notwithstanding any right of any Party (whether or not exercised) to investigate the accuracy of any of the matters subject to indemnification by any other Party contained in this Agreement, each of the Parties has the right to rely fully upon the representations, warranties, covenants and agreements of the other Party contained in this Agreement. The provisions of Sections 11.01, 11.07, 11.11 and 11.15 and Articles VII and IX shall survive the termination of this

Agreement. With regard to Section 3.10 of this Agreement, the ISO will perform final billing consistent with Section 3.10 of this Agreement for all services provided until the Termination Date.

ARTICLE IX
INSURANCE; LIMITATION OF LIABILITIES

9.01 **Hold Harmless**. NTD will indemnify and hold harmless all affected PTOs from any and all liability (except for that stemming from an affected PTO's negligence, gross negligence or willful misconduct), resulting from the NTD's failure to timely complete (based on the milestone provisions contained in the ISO OATT) a Reliability Transmission Upgrade (as defined in the ISO OATT) that the NTD was chosen in the Regional System Plan to construct. As used herein, an "affected PTO" is one that would be subject to penalties assessed by NERC or FERC or adverse regulatory orders or monetary claims or damages due to the NTD's failure to timely complete the Reliability Transmission Upgrade.

9.02 – 9.04 **[Reserved]**

9.05 **Insurance.**

(a) NTD will maintain property insurance on its Transmission Facilities and liability insurance in accordance with good utility practice.

(b) All insurance required under this Section 9.05 by outside insurers shall be maintained with insurers qualified to insure the obligations or liabilities under this Agreement and having a Best's rating of at least B+ VIII (or an equivalent Best's rating from time to time of B+ VIII), or in the event that from time to time Best's ratings are no longer issued with respect to insurers, a comparable rating by a nationally recognized rating service or such other insurers as may be agreed upon by the Parties.

(c) Upon execution of this Agreement, and when requested thereafter, NTD shall furnish the ISO with certificates of all such insurance policies setting forth the amounts of coverage, policy numbers, and date of expiration for such insurance in conformity with the requirements of this Agreement.

9.06 **Liability.**

(a) Neither Party shall be liable to the other Party for any incidental, indirect, special, exemplary, punitive or consequential damages, including lost revenues or profits, even if such damages are foreseeable or the damaged Party has advised such Party of the possibility of such damages and regardless of whether any such damages are deemed to result from the failure or inadequacy of any exclusive or other remedy.

(b) Nothing in this Agreement shall be deemed to affect the right of the ISO to recover its costs due to liability under this Article IX through the ISO Participants Agreement or the ISO Administrative Tariff.

ARTICLE X
TERM; DEFAULT AND TERMINATION

10.01 **Term; Termination Date.**

(a) **Term.** Subject to the terms set forth in this Section 10.01, the term of this Agreement (the "Term") shall commence on the Effective Date and shall continue in force until terminated pursuant to Article X hereof. The date of such termination shall be referred to herein as the "Termination Date."

(b) **Termination by NTD.** NTD may terminate this Agreement:

(i) upon no less than 180 day's prior notice to the ISO; or

(ii) upon an ISO event of default in accordance with Section 10.03(a), provided that NTD shall exercise this right in accordance with Section 10.03(b)(i).

(c) **Termination By the ISO.** By notice to NTD, the ISO may terminate its obligations under this Agreement:

(i) upon the withdrawal of one or more PTOs from the Transmission Operating Agreement and the ISO has given notice to the PTOs that it is terminating the Transmission Operating Agreement pursuant to Section 10.01(c)(i) thereof;

(ii) if FERC issues an order putting into effect material changes in the liability and indemnification protections afforded to the ISO under this Agreement or the ISO Tariff;

(iii) if FERC issues an order putting into effect an amendment or modification of this Agreement that materially adversely affects the ISO's ability to carry out its responsibilities under this Agreement, unless the ISO has agreed to such changes in accordance with Section 11.04;

(iv) upon a NTD event of default in accordance with Section 10.04(a), provided that the ISO shall exercise this right in accordance with Section 10.04(b)(i); or

(v) if, within the period of ten years from the Effective Date, no NTD project has been listed by the ISO on the RSP Project List as "Proposed."

(d) Continuing Obligations. The withdrawing or terminating Party shall have the following continuing obligations following withdrawal from this Agreement: All financial obligations incurred and payments applicable to the time period prior to the Termination Date shall be honored by the terminating or withdrawing Party and the other Party in accordance with the terms of this Agreement, and each Party shall remain liable for all obligations arising hereunder prior to the Termination Date.

10.03 **[reserved]**

10.03 **Events of Default of the ISO.**

(a) Events of Default of the ISO. Subject to the terms and conditions of this Section 10.03, the occurrence of any of the following events shall constitute an event of default of the ISO under this Agreement:

(i) Failure by the ISO to perform any material obligation set forth in this Agreement and continuation of such failure for longer than thirty (30) days after the receipt by the ISO of written notice of such failure from NTD; provided, however, that if the ISO is diligently pursuing a remedy during such thirty (30) day period, said cure period shall be extended for an additional thirty (30) days or as otherwise agreed by NTD;

(ii) If there is a dispute between the ISO and NTD as to whether the ISO has failed to perform a material obligation, the cure period(s) provided in Section 10.03(a)(i) above shall run from the point at which a finding of failure to perform has been made by a Governmental Authority;

(iii) Any attempt (not including consideration of strategic options or entering into exploratory discussions) by the ISO to transfer an interest in, or assign its obligations under, this Agreement, except as otherwise permitted hereunder;

(iv) Failure of the ISO (if it has received the necessary corresponding funds from ISO customers) to pay when due any and all amounts payable to NTD by the ISO as part of the settlement process pursuant to Section 3.10 within three (3) Business Days;

(v) With respect to the ISO, (A) the filing of any petition in bankruptcy or insolvency, or for reorganization or arrangement under any bankruptcy or insolvency laws, or voluntarily taking advantage of any such laws by answer or otherwise or the commencement of involuntary proceedings under any such laws, (B) assignment by the ISO for the benefit of creditors; or (C) allowance by the ISO of the appointment of a receiver or trustee of all or a material part of its property if such receiver or trustee is not discharged within thirty (30) days after such appointment.

(b) Remedies for Default. If an event of default by the ISO occurs, NTD shall have the right to avail itself of any or all of the following remedies, all of which shall be cumulative and not exclusive:

(i) To terminate this Agreement in accordance with Section 10.01(b)(ii); provided that if the ISO contests such allegation of an ISO event of default, this Agreement shall remain in effect pending resolution of the dispute, but any applicable notice period shall run during the pendency of the dispute;

(ii) To demand that the ISO shall terminate any right of the ISO, immediately make arrangements for the orderly transfer of the ISO's invoicing and collection functions with respect to NTD and assist NTD or NTD's designee in resuming performance of the functions the later of 20 days from the date of making such demand or the start of the next billing cycle.

10.04 **Events of Default of NTD.**

(a) Events of Default of NTD. Subject to the terms and conditions of this Section 10.04, the occurrence of any of the events listed below shall constitute an event of default of NTD under this Agreement (in each instance, a "NTD Default"):

(i) Failure by NTD to perform any material obligation set forth in this Agreement and continuation of such failure for longer than thirty (30) days after the receipt by NTD of written notice of such failure from the ISO, provided, however, that if NTD is diligently pursuing a remedy during such thirty (30) day period, said cure period shall be extended for an additional thirty (30) days or as otherwise agreed by the ISO and NTD;

(ii) If there is a dispute between NTD and the ISO as to whether NTD has failed to perform a material obligation, the cure period(s) provided in Section 10.04(a)(i) above shall run from the point at which a finding of failure to perform has been made by a Governmental Authority; or

(iii) With respect to NTD, (A) the filing of any petition in bankruptcy or insolvency, or for reorganization or arrangement under any bankruptcy or insolvency laws, or voluntarily taking advantage of any such laws by answer or otherwise or the commencement of involuntary proceedings under any such laws, (B) assignment by NTD for the benefit of creditors; or (C) allowance by NTD of the appointment of a receiver or trustee of all or a material part of its property if such receiver or trustee is not discharged within thirty (30) days after such appointment.

(b) Remedies for Default. If an event of default by NTD occurs, the ISO shall have the following remedy: to terminate this Agreement in accordance with Section 10.01(c)(iv); provided that if NTD contests such allegation of an NTD event of default, this Agreement shall remain in effect pending resolution of the dispute, but any applicable notice period shall run during the pendency of the dispute.

10.05 **<u>Transmission Operating Agreement and Disbursement Agreement; Registration.</u>** On the date on which (1) any of the Transmission Facilities or a New Transmission Facility is placed into service or (2) NTD's acquisition of Acquired Transmission Facilities is consummated, whichever occurs earlier:

(a) NTD shall execute and deliver to the ISO a counterpart of the Transmission Operating Agreement as an Additional PTO (as defined therein). Upon such execution and delivery, this Agreement shall terminate automatically.

(b) NTD shall promptly execute a signature page for the Disbursement Agreement and deliver it to the parties thereto and shall become a party to the Disbursement Agreement.

(c) NTD shall register with NPCC as a Transmission Owner [and Transmission Service Provider][under discussion].

ARTICLE XI
<u>MISCELLANEOUS</u>

11.01 **<u>Notices</u>.** Unless otherwise expressly specified or permitted by the terms hereof, all communications and notices provided for herein shall be in writing and any such communication or notice shall become effective (a) upon personal delivery thereof, including by overnight mail or courier service, (b) in the case of notice by United States mail, certified or registered, postage prepaid, return receipt requested, upon receipt thereof, or (c) in the case of notice by facsimile, upon receipt thereof; <u>provided that</u> such transmission is promptly confirmed by either of the methods set forth in clauses (a) or (b) above, in each case addressed to the relevant party and copy party hereto at its address set forth in <u>Schedule 11.01</u> or at such other address as such party or copy party may from time to time designate by written notice to the other party hereto; <u>further provided</u> that a notice given in connection with this Section 11.01 but received on a day other than a Business Day, or after business hours in the situs of receipt, will be deemed to be received on the next Business Day.

11.02 **<u>Supersession of Prior Agreements</u>.** With respect to the subject matter hereof, this Agreement (together with all schedules and exhibits attached hereto) constitutes the entire agreement and understanding among the Parties with respect to all subjects covered by this Agreement and supersedes all prior discussions, agreements and understandings among the Parties with respect to such matters.

11.03 **Waiver.** Any term or condition of this Agreement may be waived at any time by the Party that is entitled to the benefit thereof, but no such waiver shall be effective unless set forth in a written instrument duly executed by or on behalf of the Party waiving such term or condition. No waiver by a Party of any term or condition of this Agreement, in any one or more instances, shall be deemed to be or construed as a waiver of the same or any other term or condition of this Agreement on any future occasion. All remedies, either under this Agreement or by Law or otherwise afforded, shall be cumulative and not alternative.

11.04 **Amendment; Limitations on Modifications of Agreement.**

(a) This Agreement shall only be subject to modification or amendment by agreement of the Parties and the acceptance of any such amendment by FERC.

(b) In light of the foregoing, the Parties agree that they shall not rely to their detriment on any purported amendment, waiver or other modification of any rights under this Agreement unless the requirements of this Section 11.04 are satisfied and further agree not to assert equitable estoppel or any other equitable theory to prevent enforcement of this provision in any court of law or equity, arbitration or other proceeding.

11.05 **No Third Party Beneficiaries.** Except as provided in Article IX, it is not the intention of this Agreement or of the Parties to confer a third party beneficiary status or rights of action upon any Person or entity whatsoever other than the Parties and nothing contained herein, either express or implied, shall be construed to confer upon any Person or entity other than the Parties any rights of action or remedies either under this Agreement or in any manner whatsoever.

11.06 **No Assignment; Binding Effect.** Neither this Agreement nor any right, interest or obligation hereunder may be assigned by a Party, (including by operation of law) law (an "Assignment")-, without the prior written consent of the other Party in its sole discretion and any attempt at Assignment in contravention of this Section 11.06 shall be void, provided, however, that NTD may assign its rights and interests hereunder as security in connection with any financing for the construction or operation of NTD's Transmission Facilities (a "Collateral Assignment") without prior written consents or approvals. NTD may assign or transfer any or all of its rights, interests and obligations hereunder upon the transfer of its assets through sale, reorganization, or other transfer, provided that:

(a) NTD's successors and assigns shall agree to be bound by the terms of this Agreement except that NTD's successors and assigns shall not be required to be bound by any obligations hereunder to the extent that NTD has agreed to retain such obligations; and

(b) notwithstanding (a), NTD shall assign or transfer to any new owner of Transmission Facilities subject to this Agreement all of the rights, responsibilities and obligations associated with the physical operation of such Transmission Facilities as well as all of the rights, responsibilities and obligations associated with the ISO's Operating Authority with respect to such Transmission Facilities, further provided that the new owner shall have the right to retain one or more subcontractors to perform any or all of its responsibilities or obligations under this Agreement.

Subject to the foregoing, this Agreement is binding upon, inures to the benefit of and is enforceable by the Parties and their respective permitted successors and assigns. No Assignment shall be effective until NTD receives all required regulatory approvals for such Assignment.

11.07 **<u>Further Assurances; Information Policy; Access to Records</u>.**

(a) Each Party agrees, upon the other Party's request, to make Commercially Reasonable Efforts to execute and deliver such additional documents and instruments, provide information, and to perform such additional acts as may be necessary or appropriate to effectuate, carry out and perform all of the terms, provisions, and conditions of this Agreement and of the transactions contemplated hereby.

(b) The ISO shall, upon NTD's request, make available to NTD any and all information within the ISO's custody or control that is necessary for NTD to perform its responsibilities and obligations or enforce its rights under this Agreement, provided that such information shall be made available to NTD only to the extent permitted under the ISO Information Policy and subject to any applicable restrictions in the ISO Information Policy, including provisions of the ISO Information Policy governing the confidential treatment of non-public information, and provided further that any NTD employee or employee of NTD's Local Control Center shall comply with such ISO Information Policy and any applicable standards of conduct to prevent the disclosure of such information to any unauthorized Person. Any dispute concerning what information is necessary for NTD to perform its responsibilities and obligations or enforce its right under this Agreement shall be subject to dispute resolution under Section 11.12 of this Agreement.

(c) NTD shall, upon the ISO's request, make available to the ISO any and all information within NTD's custody or control that is necessary for the ISO to perform its responsibilities and obligations or enforce its rights under this Agreement, provided that such information shall be shall be made available to the ISO only to the extent permitted under the ISO Information Policy and subject to any applicable restrictions in the ISO Information Policy, including provisions of the ISO Information Policy governing the confidential treatment of non-public information, and provided further that any ISO employee shall comply with such ISO Information Policy and any applicable standards of conduct to prevent the disclosure of such information to any unauthorized Person. Any dispute concerning what information is necessary for the ISO to perform its responsibilities and obligations or enforce its right under this Agreement shall be subject to dispute resolution under Section 11.12 of this Agreement.

(d) If, in order to properly prepare its Tax Returns, other documents or reports required to be filed with Governmental Authorities or its financial statements or to fulfill its obligations hereunder, it is necessary that the ISO or NTD be furnished with additional information, documents or records not referred to specifically in this Agreement, and such information, documents or records are in the possession or control of the other Party, the other Party shall use its best efforts to furnish or make available such information, documents or records (or copies thereof) at the ISO's or NTD's request, cost and expense. Any information obtained by the ISO or NTD in accordance with this paragraph shall be subject to any applicable provisions of the ISO Information Policy

(e) Notwithstanding anything to the contrary contained in this Section 11.07:

(i) no Party shall be obligated by this Section 11.07 to undertake studies or analyses that such Party would not otherwise be required to undertake or to incur costs outside the normal course of business to obtain information that is not in such Party's custody or control at the time a request for information is made pursuant to this Section 11.07;

(ii) if NTD and the ISO are in an adversarial relationship in litigation or arbitration (other than with respect to litigation or arbitration to enforce this Section 11.07), the furnishing of information, documents or records by the ISO or NTD in accordance with this Section 11.07 shall be subject to applicable rules relating to discovery;

(iii) no Party shall be compelled to provide any privileged and/or confidential documents or information that are attorney work product or subject to the attorney/client privilege; and

(iv) no Party shall be required to take any action that impairs or diminishes its rights under this Agreement or otherwise lessens the value of this Agreement to such Party.

11.08 **Business Day.** Notwithstanding anything herein to the contrary, if the date on which any payment is to be made pursuant to this Agreement is not a Business Day, the payment otherwise payable on such date shall be payable on the next succeeding Business Day with the same force and effect as if made on such scheduled date and, provided such payment is made on such succeeding Business Day, no interest shall accrue on the amount of such payment from and after such scheduled date to the time of such payment on such next succeeding Business Day.

11.09 **Governing Law.** This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware including all matters of construction, validity and performance without regard to the conflicts-of-laws provisions thereof.

11.10 **Consent to Service of Process.** Each of the Parties hereby consents to service of process by registered mail, Federal Express or similar courier at the address to which notices to it are to be given, it being agreed that service in such manner shall constitute valid service upon such Party or its successors or assigns in connection with any such action or proceeding; provided, however, that nothing in this Section 11.10 shall affect the right of any Party or its successors and permitted assigns to serve legal process in any other manner permitted by applicable Law or affect the right of any such Party or its successors and assigns to bring any action or proceeding against the other Party or its property in the courts of other jurisdictions.

11.11 **Force Majeure.** A Party shall not be considered to be in default or breach under this Agreement, and shall be excused from performance or liability for damages to any other party, if and to the extent it shall be delayed in or prevented from performing or carrying out any of the provisions of this Agreement, except the obligation to pay any amount when due, in consequence of any act of God, labor disturbance, failure of contractors or suppliers of materials (not including as a result of non-payment), act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm, flood, ice, explosion, breakage or accident to machinery or equipment or by any other cause or causes (not including a lack of funds or other financial causes) beyond such Party's reasonable control, including any order, regulation, or restriction imposed by governmental, military or lawfully established civilian authorities. A Party claiming a force majeure event shall use reasonable diligence to remove the condition that prevents performance, except that the settlement of any labor disturbance shall be in the sole judgment of the affected Party.

11.12 **Dispute Resolution.** The Parties agree that any dispute arising under this Agreement shall be the subject of good-faith negotiations among the Parties and affected market participants, if any. Each Party and each affected market participant shall designate one or more representatives with the authority to negotiate the matter in dispute to participate in such negotiations. The Parties and affected market participants shall engage in such good-faith negotiations for a period of not less than 60 calendar days. Notwithstanding the foregoing, any dispute arising under this Agreement may be submitted to arbitration or any other form of alternative dispute resolution upon the agreement of the Parties and all affected market participants to participate in such an alternative dispute resolution process. Nothing in this Agreement shall, however, restrict a Party's right to file a complaint with FERC under the relevant provisions of the Federal Power Act.

11.13 **Invalid Provisions.** If any provision of this Agreement is held to be illegal, invalid or unenforceable under any present or future Law, and if the rights or obligations of any Party under this Agreement shall not be materially and adversely affected thereby, (a) such provision shall be fully severable, (b) this Agreement shall be construed and enforced as if such illegal, invalid or unenforceable provision had never comprised a part hereof, (c) the remaining provisions of this Agreement shall remain in full force and effect and shall not be affected by the illegal, invalid or unenforceable provision or by its severance herefrom, and (d) the court holding such provision to be illegal, invalid or unenforceable may in lieu of such provision add as a part of this Agreement a legal, valid and enforceable provision as similar in terms to such illegal, invalid or unenforceable provision as it deems appropriate.

11.14 **Headings and Table of Contents.** The headings of the sections of this Agreement and the Table of Contents are inserted for purposes of convenience only and shall not be construed to affect the meaning or construction of any of the provisions hereof.

11.15 **Liabilities; No Joint Venture.**

(a) The obligations and liabilities of the ISO and NTD arising out of or in connection with this Agreement shall be several, and not joint, and each Party shall be responsible for its own debts, including Taxes. No Party shall have the right or power to bind any other Party to any agreement without the prior written consent of such other Party. The Parties do not intend by this Agreement to create nor does this Agreement constitute a joint venture, association, partnership, corporation or an entity taxable as a corporation or otherwise. No express or implied term, provision or condition of this Agreement shall be deemed to constitute the parties as partners or joint venturers.

(b) To the extent any Party has claims against the other Party, such Party may only look to the assets of the other Party for the enforcement of such claims and may not seek to enforce any claims against the directors, members, officers, employees, affiliates, or agents of such other Party who, each Party acknowledges and agrees, have no liability, personal or otherwise, by reason of their status as directors, members, officers, employees, affiliates, or agents of that Party, with the exception of fraud or willful misconduct.

11.16 **Counterparts.** This Agreement may be executed in any number of counterparts, each of which shall be deemed an original, but all of which together shall constitute but one and the same instrument. The parties hereto agree that any document or signature delivered by facsimile transmission shall be deemed an original executed document for all purposes hereof.

11.17 **Effective Date.**

This Agreement shall become effective on the date of execution (the "Effective Date").

IN WITNESS WHEREOF, this Agreement has been duly executed and delivered by the duly authorized officer of each Party as of the date written below.

For ISO New England Inc.

Name:______________________________________

Title:_______________________________________

Date:_______________________________________

For [NTD]

Name:______________________________________

Title:_______________________________________

Date:_______________________________________

Schedule 1.01

Schedule of Definitions

Acquired Transmission Facilities. Any transmission facility acquired within the New England Control Area by NTD after the Operations Date that meets the classification standards set forth in Section 2.02(a).

Additional Term. "Additional Term" shall have the meaning ascribed thereto in Section 10.01(a) of this Agreement.

Affiliate. Any person or entity which controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" shall mean the possession, directly or indirectly and whether acting alone or in conjunction with others, of the authority to direct the management or policies of a person or entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

Agreement. This Operating Agreement between the ISO and NTD, as it may be amended from time to time.

Ancillary Service. Those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the transmission system in accordance with Good Utility Practice.

Approved Outages. "Approved Outages" shall have the meaning ascribed thereto in Market Rule 1 of the ISO Tariff.

Best's. The A.M. Best Company.

Business Day. Any day other than a Saturday or Sunday or an ISO holiday, as posted by the ISO on its website.

Commercially Reasonable Efforts. A level of effort which, in the exercise of prudent judgment in the light of facts or circumstances known or which should reasonably be known at the time a decision is made, can be expected by a reasonable person to accomplish the desired result in a manner consistent with Good Utility Practice and which takes the performing party's interests into consideration.

"Commercially Reasonable Efforts" will not be deemed to require a Person to undertake unreasonable measures or measures that have a significant adverse economic affect on such Person, including the payment of sums in excess of amounts that would be expended in the ordinary course of business for the accomplishment of the stated purpose.

Commission. The Federal Energy Regulatory Commission.

Control Area. An electric power system or combination of electric power systems, bounded by metering, to which a common automatic generation control scheme is applied in order to:

(a) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and applicable NERC/NPCC Requirements; and

(d) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Coordination Agreement. An agreement between the ISO and the operator(s) of one or more neighboring Control Areas addressing issues including interchange scheduling, operational arrangements, emergency procedures, energy for emergency and reliability needs, the exchange of information among Control Areas, and other aspects of the coordinated operation of the Control Areas.

Disbursement Agreement. The Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Effective Date. “Effective Date” shall have the meaning ascribed thereto in Section 11.18(a) of this Agreement.

Elective Transmission Upgrade. A Transmission Upgrade constructed by any Person which is not required to be constructed pursuant to any applicable requirement of this Agreement, but which may be subject to applicable requirements set forth in the ISO OATT and this Agreement.

Elective Transmission Upgrade Applicant. "Elective Transmission Upgrade Applicant" shall have the meaning ascribed thereto in Section 2.05 of this Agreement.

Environment. Soil, land surface or subsurface strata, surface waters (including navigable waters, ocean waters, streams, ponds, drainage basins, and wetlands), groundwaters, drinking water supply, stream sediments, ambient air (including indoor air), plant and animal life, and any other environmental medium or natural resource.

Environmental Damages. "Environmental Damages" shall mean any cost, damages, expense, liability, obligation or other responsibility arising from or under Environmental Law consisting of or relating to:

(a) any environmental matters or conditions (including on-site or off-site contamination, occupational safety and health, and regulation of chemical substances or products);

(b) fines, penalties, judgments, awards, settlements, legal or administrative proceedings, damages, losses, claims, demands and response, investigative, remedial or inspection costs and expenses arising under Environmental Law;

(c) financial responsibility under Environmental Law for cleanup costs or corrective action, including any investigation, cleanup, removal, containment or other remediation or response actions ("Cleanup") required by applicable Environmental Law (whether or not such Cleanup has been required or requested by any Governmental Authority or any other Person) and for any natural resource damages; or

(d) any other compliance, corrective, investigative, or remedial measures required under Environmental Law.

Environmental Laws. Any Law now or hereafter in effect and as amended, and any judicial or administrative interpretation thereof, including any judicial or administrative order, consent decree or judgment, relating to pollution or protection of the Environment, health or safety or to the use, handling, transportation, treatment, storage, disposal, release or discharge of Hazardous Materials.

Excluded Assets. "Excluded Assets" shall have the meaning ascribed thereto in Section 2.04 of this Agreement.

Existing Operating Procedures. "Existing Operating Procedures" shall have the meaning ascribed thereto in Section 3.02(d) of this Agreement.

External Transactions. Interchange transactions between the New England Transmission System and neighboring Control Areas.

FACTS. Flexible AC Transmission Systems.

FERC. The Federal Energy Regulatory Commission.

Final Order. An order issued by a Governmental Authority in a proceeding after all opportunities for rehearing are exhausted (whether or not any appeal thereof is pending) that has not been revised, stayed, enjoined, set aside, annulled or suspended, with respect to which any required waiting period has expired, and as to which all conditions to effectiveness prescribed therein or otherwise by law, regulation or order have been satisfied.

Financial Assurances. "Financial Assurances" shall have the meaning ascribed thereto in Section 3.10(b) of this Agreement.

FPA. The Federal Power Act.

FTR. A Financial Transmission Right, as defined in the ISO OATT.

Generally Accepted Accounting Principles. The widely accepted set of rules, conventions, standards, and procedures for reporting financial information, as established by the Financial Accounting Standards Board.

Generating Unit. A device for the production of electricity.

Good Utility Practice. Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority. The government of any nation, state or other political subdivision thereof, including any entity exercising executive, military, legislative, judicial, regulatory, or administrative functions of or pertaining to a government, not including NTD or the ISO.

Hazardous Materials. Any waste or other substance that is listed, defined, designated, or classified as, or otherwise determined to be, hazardous, radioactive, or toxic or a pollutant or a contaminant under or pursuant to any Environmental Law, including any admixture or solution thereof, and specifically including petroleum and all derivatives thereof or synthetic substitutes therefor and asbestos or asbestos-containing materials.

Indemnifiable Loss. "Indemnifiable Loss" shall have the meaning ascribed thereto in Section 9.01(a)(i) of this Agreement.

Indemnifying Party. "Indemnifying Party" shall have the meaning ascribed thereto in Section 9.02 of this Agreement.

Indemnitee. "Indemnitee" shall have the meaning ascribed thereto in Section 9.02 of this Agreement.

Interconnection Agreement. An agreement or agreements for the interconnection of any entity to the Transmission Facilities of NTD.

Interconnection Standard. The applicable interconnection standards set forth in the ISO OATT.

Invoiced Amount. "Invoiced Amount" shall have the meaning ascribed thereto in Section 3.10(a)(i) of the Agreement.

ISO. ISO New England Inc., the RTO for New England authorized by the Federal Energy Regulatory Commission to exercise the functions required pursuant to FERC's Order No. 2000 and FERC's corresponding regulations.

ISO Control Center. The primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO Information Policy. The information policy set forth in the ISO OATT.

ISO-NE. ISO New England Inc.

ISO OATT. The ISO Open Access Transmission Tariff, as in effect from time to time.

ISO Participants Agreement. The agreement among the ISO and stakeholder participants addressing, inter alia, the stakeholder process for the ISO.

ISO Planning Process. The process set forth in the ISO OATT, for the coordinated planning and expansion of the New England Transmission System with provision for the participation of all state regulatory authorities with jurisdiction over retail rates in the ISO region acceptable to those authorities, which process shall be subject to certain terms and conditions set forth in Schedule 3.09(a).

ISO System Plan. The “Regional System Plan” as defined in the ISO OATT.

ISO Tariff. The ISO Transmission, Markets and Services Tariff, as amended from time to time, on file with FERC.

Large Generating Facility. “Large Generating Facility” shall have the meaning ascribed thereto in the ISO OATT.

Law. Any federal, state, local or foreign statute, law, ordinance, regulation, rule, code, order, other requirement or rule of law.

Load Shedding. The systematic reduction of system demand by temporarily decreasing load.

Market Monitoring Unit. Any market monitoring unit established by the ISO, including any internal market monitoring unit of the ISO and any independent market monitoring unit of the ISO.

Market Participant Service Agreement. The agreement among the ISO and market participants addressing, inter alia, the requirements for participating in the New England Markets.

Market Rules. The rules describing how the New England Markets are administered.

Merchant Facility. A transmission facility constructed by an entity that assumes all market risks associated with the recovery of costs for the facility and whose costs are not recovered through traditional cost-of-service based rates, but instead are recovered either through negotiated agreements with customers or through market revenues.

NTD Category A Facilities. Those transmission facilities listed in Schedule 2.01(a) of the Agreement, as that list may be modified from time to time in accordance with the terms of this Agreement.

NTD Category B Facilities. Those transmission facilities listed in Schedule 2.01(b) of the Agreement, as that list may be modified from time to time in accordance with the terms of this Agreement.

NTD Local Area Facilities. "Local Area Facilities" shall have the meaning ascribed thereto in Section 2.01 of this Agreement.

NTD Local Restoration Plan. The restoration plan developed by NTD with respect to the Transmission Facilities.

NERC. The North American Electric Reliability Corporation.

NERC/NPCC Requirements. NPCC criteria, guides, and procedures, NERC reliability standards, and NERC operating policies and planning standards (until such time as they are replaced by NERC reliability standards) and any successor documents.

New England Control Area. The Control Area consisting of the interconnected electric power system or combination of electric power systems in the geographic region consisting of Vermont, New Hampshire, Maine, Massachusetts, Connecticut and Rhode Island.

New England Markets. Markets or programs (including congestion pricing and design and implementation of FTRs) for the purchase of energy, capacity, ancillary services, demand response services or other related products or services that are offered in the New England Control Area and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Commission.

New England Transmission System. The system comprised of the transmission facilities over which the ISO has operational jurisdiction, including the Transmission Facilities of NTD and the PTOs and the transmission system of any ITC formed pursuant to Attachment M to the ISO OATT.

New Transmission Facility. Any new transmission facility constructed within the New England Transmission System that is owned by NTD and that goes into commercial operation after the Effective Date. For the avoidance of doubt, in the case of a high-voltage, direct-current system, a New Transmission Facility shall include the transmission cable and the AC/DC converter stations as a single project.

Non-PTF. "Non-PTF" shall have the meaning ascribed thereto in the ISO OATT.

NPCC. The Northeast Power Coordinating Council.

OASIS. The Open Access Same-Time Information System of the ISO.

Operating Authority. "Operating Authority" shall have the meaning ascribed thereto in the TOA.

Operating Limits. The transfer limits for a transmission interface or generation facility.

Operating Procedures. The operating manuals, procedures, and protocols relating to the exercise of Operating Authority over the Transmission Facilities, as such manuals, procedures, and protocols may be modified from time to time in accordance with this Agreement.

Order 2000. FERC's Order No. 2000, *i.e.*, *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs. ¶31,089 (1999), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Stats. & Regs. ¶31,092 (2000), *petitions for review dismissed sub nom.*, Public Utility District No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 . (D.C. Cir. 2001).

Owed Amounts. "Owed Amounts" shall have the meaning ascribed thereto in Section 3.10(c) of this Agreement.

PARS. Phase angle regulators.

Participant. A participant in the New England Markets, Transmission Customer, or other entity that has entered into the ISO Participants Agreement.

Participants Committee. "Participants Committee" shall mean the stakeholder participants committee established pursuant to the ISO Participants Agreement.

Party or Parties. A "Party" shall mean the ISO or NTD, as the context requires. "Parties" shall mean NTD and the ISO.

Person. An individual, partnership, joint venture, corporation, business trust, limited liability company, trust, unincorporated organization, government or any department or agency thereof, or any other entity.

Planned Outages. "Planned Outages" shall have the meaning ascribed thereto in Market Rule 1 of the ISO Tariff.

Planning Procedures. The manuals, procedures and protocols for planning and expansion of the New England Transmission System, as such manuals, procedures, and protocols may be modified from time to time in accordance with this Agreement.

Prime Rate. The interest rate that commercial banks charge their most creditworthy borrowers, as published in the most recent Wall Street Journal in its "Monday Rates" column.

PTF. "PTF" shall have the meaning ascribed thereto in the ISO OATT.

PTO or Participating Transmission Owner. "PTO" shall have the meaning ascribed thereto in the opening paragraph of the TOA. "Participating Transmission Owner" shall have the same meaning as "PTO."

Rating Procedures. "Rating Procedures" shall have the meaning ascribed thereto in Section 3.02(d) of this Agreement.

Regulation and Frequency Response Service. An Ancillary Service as defined in the ISO OATT.

Reliability Authority. "Reliability Authority" shall have the meaning established by NERC, as such definition may change from time to time, provided such definition of Reliability Authority shall not be inconsistent with the specific rights and responsibilities of the ISO and the PTOs under this Agreement.

Restoration Plans. The System Restoration Plan, all PTO Local Restoration Plans and the NTD Local Restoration Plan.

RSP Project List. "RSP Project List" shall have the meaning ascribed thereto in the ISO OATT.

RTO. An independent entity that complies with Order No. 2000 and FERC's corresponding regulations (or an entity that complies with all such requirements except for the scope and regional configuration requirements), as determined by the FERC.

Schedule 22 Large Generator Interconnection Agreement. The interconnection agreement included in Schedule 22 of the ISO OATT.

Schedule 23 Small Generator Interconnection Agreement. The interconnection agreement included in Schedule 23 of the ISO OATT.

Scheduled Outages. "Scheduled Outages" shall have the meaning ascribed thereto in Market Rule 1 of the ISO Tariff.

Small Generating Facility. "Small Generating Facility" shall have the meaning ascribed thereto in the ISO OATT.

System Failure. Widespread telecommunication, hardware or software failure or systemic the ISO hardware or software failures that makes it impossible to receive or process bid information, dispatch resources, or exercise Operating Authority over the Transmission Facilities.

Tax or Taxes. All taxes, charges, fees, levies, penalties or other assessments imposed by any United States federal, state or local or foreign taxing authority, including, but not limited to, income, excise, property, sales, transfer, franchise, payroll, withholding, social security or other taxes, including any interest, penalties or additions attributable thereto.

Tax Return. Any return, report, information return, or other document (including any related or supporting information) required to be supplied to any authority with respect to Taxes.

Technical Committees. "Technical Committee" shall mean the stakeholder technical committees established pursuant to the ISO Participants Agreement.

Term. "Term" shall have the meaning ascribed thereto in Section 10.01 of this Agreement.

Third Party. "Third Party" shall have the meaning ascribed thereto in Section 9.01(a) of this Agreement.

Termination Date. "Termination Date" shall have the meaning ascribed thereto in Section 10.01(a) of this Agreement.

TOA. The Transmission Operating Agreement entered into by the ISO and the PTOs, effective February 1, 2005, as it may be amended from time to time.

Transmission Business. The business activities of each PTO related to the ownership, operation and maintenance of its Transmission Facilities.

Transmission Customer. Any entity taking Transmission Service under the ISO OATT.

Transmission Facilities. "Transmission Facilities" shall have the meaning ascribed thereto in Sections 2.01 and 2.02 of this Agreement.

Transmission Owner. "Transmission Owner" shall have the meaning ascribed thereto in the ISO OATT.

Transmission Provider. The ISO, in its capacity as the provider of transmission services over the Transmission Facilities of the PTOs in accordance with FERC's Order No. 2000 and FERC's RTO regulations.

Transmission Service. The non-discriminatory, open access, wholesale transmission services provided to customers by the ISO in accordance with the ISO OATT.

Transmission Upgrade. Any upgrade to an existing Transmission Facility owned by NTD that goes into commercial operation after the Effective Date.

VAR. Volt-Amps Reactive.

Schedule 2.01(a)

Schedule 2.01(b)

Schedule 11.01

NOTICES

ISO New England Inc.

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[NTD]

[Name
Address
Phone:
Fax:]

(d) Easements, if required, have been obtained or are on schedule consistent with the critical path schedule. Needed land purchases, if required, have been made or are on schedule consistent with the critical path schedule.

(e) Any contracts required to procure or construct a transmission project are in place consistent with the critical path schedule. The ISO's analysis may also take into account whether such contracts contain incentive and/or penalty clauses to encourage third parties to advance the delivery of material services to conform with the critical path schedule.

(f) Physical site work is on schedule consistent with the critical path schedule.

(g) The transmission project is in a designated National Interest Electric Transmission Corridor in accordance with Section 216 of the Federal Power Act, 16 U.S.C. §§ 824p.

III.12.6.4. Transmission Solutions Selected Through the Competitive Transmission Process.

For a transmission solution, which may consist of single or multiple proposals, selected through the competitive transmission process pursuant to Sections 4.3, ~~and~~ 4A, or Section 16 of Attachment K, such transmission solution, or relevant portion thereof, shall be considered in-service on the in-service date provided in the executed Selected Qualified Transmission Project Sponsor Agreement(s). The ISO shall use the in-service date in the executed Selected Qualified Transmission Project Sponsor Agreement(s) to determine whether to include the transmission solution, or relevant portion thereof, in the network model for the relevant Capacity Commitment Period. In the event that the selected transmission solution includes an upgrade(s) located on a PTO's existing transmission system where the Selected Qualified Transmission Project Sponsor is not the PTO for the existing system element(s) being upgraded, the process for establishing the in-service date and determining whether to include the upgrade(s) on the existing transmission system, or relevant portion thereof, in the network model for the Capacity Commitment Period shall be as described in Section III.12.6.1.

III.12.7. Resource Modeling Assumptions.

III.12.7.1. Proxy Units.

When the available resources are insufficient for the unconstrained New England Control Area to meet the resource adequacy planning criterion specified in Section III.12.1, proxy units shall be used as

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity and Sebastian Lombardi, NEPOOL Counsel

DATE: March 28, 2024

RE: Proposal to Amend the Allocation of Any Unused Provisional Member Voting Share

You will be asked at the April 4 meeting to consider, and potentially to approve the balloting of, limited revisions to the Second Restated NEPOOL Agreement ("2d RNA") in the form of a One Hundred Thirty-Fifth Agreement Amending the RNA ("135th Agreement") (as well as conforming changes to the Participants Agreement ("PA") in the form of Amendment No. 12 to the PA ("PAA 12")) to modify the allocation of any unused Provisional Member Group Seat voting share to all six Sectors, rather than to all but the AR Sector. These limited revisions are proposed to ensure that, consistent with the allocation of Sector Voting Share (currently shared equally), any unused Provisional Member Group Seat voting share is allocated equivalently amongst *all* of the six Sectors.[1]

Background: Current Provisional Member Group Arrangements[2]

Provisional Members that are not Related Persons of one or more Participants in one of NEPOOL's six Sectors participate as part of a single group seat – the Provisional Member Group Seat. The Provisional Member Group Seat is currently allocated 1% of the NEPOOL Vote[3] (the six Sectors currently share equally the remaining 99% (or 16.5% each)). While the Provisional Member Group Seat is allocated 1%, only the Fixed Voting Share of the Provisional Members casting an affirmative or negative vote on a proposed action or amendment is included in the aggregate Member Adjusted Voting Shares.[4] Thus, to maintain an aggregate Member Adjusted Voting Share of 100%, any unused portion of the Provisional Member Group Seat Voting Share is reallocated consistent with subsection (a) of the definition of Member Adjusted Voting Share, which currently applies to voting members of "each active Sector (other than the AR Sector)".[5] As such, under current 2d RNA language, the AR Sector is not allocated any of the unused portion of the Provisional Member Group Seat Voting Share.[6] A recent vote

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[1] Each Sector would be allocated a *pro rata* share of the unused Provisional Member Group Seat voting share, such that if all Sectors have an equal Sector Voting Share, each Sector would be allocated an equal share of unused Provisional Member Group Seat voting share. If, for example, one Sector had a lesser aggregate Sector Voting Share, its allocation would be lesser, or the same percentage that its Sector Voting Share represents in relation to the aggregate Sector Voting Shares.

[2] The current Provisional Member arrangements were implemented in late 2014 by way of the 126th Agreement Amending the 2d RNA. *See* Revised Provisional Member Arrangements, *New England Power Pool*, Docket No. ER15-238-000 (filed Oct. 30, 2014); *New England Power Pool*, Docket No. ER15-238-000 (Dec. 12, 2014) (unpublished letter order accepting revised Provisional Member arrangements).

[3] 2d RNA § 1.68D (Provisional Member Group Seat Voting Share). There are currently 8 Provisional Members in the Provisional Member Group Seat.

[4] 2d RNA § 1.50(c) (Member Adjusted Voting Share).

[5] 2d RNA § 1.50(a).

[6] 2d RNA §§ 1.50(b); 1.2 (Adjusted Sub-Sector Voting Share).

outcome at the Transmission Committee focused attention on the impact of unequal Sector Voting Shares under the application of the current reallocation methodology.[7]

Suggested Revision to Reallocation of Unused Provisional Member Group Seat Voting Share

To ensure equivalent sharing of any unused portion of the Provisional Member Group Seat Voting Share amongst all six Sectors, similar to the equivalent sharing of the aggregate Sector Voting Shares, three targeted revisions are proposed as marked in the draft 135th Agreement (with conforming changes reflected in PAA 12):[8]

1. The addition of a defined term "Unused Provisional Member Voting Share Sector Allocation";
2. Use of the new defined term in the calculation of the NPC Sector Voting Share or Technical Committee Adjusted Sector Voting Share for all but the AR Sector; and
3. Use of the new defined term in the calculation of Adjusted Sub-Sector Voting Share.[9]

Attachment 1 to this memorandum illustrates, using two (2) hypothetical voting examples, the mathematical impact of the proposed revisions.

Participants Committee Action

A motion to approve balloting of the 135th Agreement and PAA 12 requires a two-thirds (66.67%) NEPOOL Vote by the Participants Committee. When the Committee is ready to take action on this matter, the following form of resolution may be used:

> RESOLVED that the Participants Committee authorizes and directs the Balloting Agent (as defined in the Second Restated NEPOOL Agreement) to circulate ballots for the approval of agreements amending the Second Restated New England Power Pool Agreement and the Participants Agreement to reflect the allocation of any unused Provisional Member Group Voting Share to all Sectors as presented at this meeting, together with [such changes as were discussed and agreed to by the Committee and]

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[7] *See* Notice of Transmission Committee Feb. 15, 2024 Actions, Vote 6, New Leaf's Amendment #1, which was not supported with a NEPOOL Vote of exactly 66.66% in favor ("New Leaf Vote"). Under the current provisions of the 2d RNA, for the New Vote, the AR Sector Voting Share was 16.5% (no portion of the reallocation), while each of the remaining 5 Sectors' Voting Share was 16.7% (splitting 5 ways, or 0.02% each, the unused Provisional Member Group Seat Voting Share). With 4 Sectors (including the AR Sector) unanimously in favor, 2 Sectors unanimously opposed, and no Provisional Members present or voting in favor or opposed, the motion failed to achieve NEPOOL support with exactly 66.66% in favor. Had the reallocation been equally shared by all six Sectors, the motion would have instead passed with exactly 67.67% in favor. The February 15th TC outcome was not consistent with an equivalent sharing of Sector Voting Share. The New Leaf Vote is the first and only vote whose outcome would have changed with the revised methodology proposed herein.

[8] PAA 12 adds the definition of "Unused Provisional Member Voting Share Sector Allocation" and the identical revisions to the definition of "Member Adjusted Voting Share" to the Participants Agreement.

[9] The last paragraph of §1.2 (Adjusted Sub-Sector Voting Share) is also a clean-up, because it is not always true. The Adjusted Sub-Sector Voting Share ***will*** exceed the sum of the Member Fixed Voting Shares of the AR Sub-Sector voting members for a Technical Committee vote in certain, specific circumstances. That scenario will occur only for a Technical Committee vote where one or two non-AR Sectors have not achieved a Sector Quorum. For example, if 2 non-AR Sectors are completely absent, each of the remaining 4 Sectors would cast 25% of the vote. A 25% Vote by the AR Sector (the sum of its adjusted Sub-Sector Voting Shares) would clearly exceed the sum of its Member Fixed Voting Shares (16.5%).

such non-substantive changes as may be agreed to after the meeting by the Chair or any Vice-Chair of the Participants Committee, to each Participant for execution by its voting member or alternate on this Committee or such Participant's duly authorized officer.

If approved, ballots will be circulated for signature. To be approved in balloting, the 135th Agreement must be approved by a two-thirds Vote, and PAA 12 by a 70% Vote, from a sufficient number of members to satisfy the Minimum Response Requirement.

Attachment 1

Example Vote 1: No Provisional Members Voting, 4 Sectors (including AR) all in favor, 2 Sectors all opposed

Scenario 1 (TC Feb New Leaf Vote)				
Sector/Group	Current Allocation		Proposed Allocation	
Generation	16.700		16.667	
Transmission	16.700		16.667	
Supplier	16.700		16.667	
Alternative Resources	16.500		16.667	
Publicly Owned Entity		16.700		16.667
End User		16.700		16.667
Provisional Members	0.000	0.000	0.000	0.000
	66.60	33.14	66.67	33.33
	In Favor	**Opposed**	**In Favor**	**Opposed**

Example Vote 2: No Provisional Members Voting, 4 Sectors (all non-AR) all in favor, 2 Sectors all opposed (1 is AR)

Example 2 (Hypothetical)				
Sector/Group	Current Allocation		Proposed Allocation	
Generation	16.700		16.667	
Transmission	16.700		16.667	
Supplier	16.700		16.667	
Alternative Resources		16.500		16.667
Publicly Owned Entity		16.700		16.667
End User	16.700		16.667	
Provisional Members	0.000	0.000	0.000	0.000
	66.80	33.20	66.67	33.33
	In Favor	**Opposed**	**In Favor**	**Opposed**

**ONE HUNDRED THIRTY-FIFTH AGREEMENT AMENDING
NEW ENGLAND POWER POOL AGREEMENT
(Unused Provisional Member Voting Share Allocation Changes)**

THIS ONE HUNDRED THIRTY-FIFTH AGREEMENT AMENDING NEW ENGLAND POWER POOL AGREEMENT, dated as of April 4, 2024 ("135th Agreement"), amends the New England Power Pool Agreement (the "NEPOOL Agreement").

WHEREAS, effective February 1, 2005 the NEPOOL Agreement was amended by the One Hundred Seventh Agreement Amending New England Power Pool Agreement and restated as the Second Restated NEPOOL Agreement, and has subsequently been amended numerous times; and

WHEREAS, the Participants desire to amend further the Second Restated NEPOOL Agreement to reflect the revision detailed herein.

NOW, THEREFORE, upon approval of this 135th Agreement by the NEPOOL Participants Committee in accordance with the procedures set forth in the Second Restated NEPOOL Agreement, the Participants agree as follows:

**SECTION 1
AMENDMENTS**

1.1 Addition of Definition. The following definition is added to Section 1 of the Second Restated NEPOOL Agreement and inserted in the appropriate alphabetical order:

Unused Provisional Member Voting Share Sector Allocation is the product of (a) the difference between the Provisional Member Group Seat Voting Share and the aggregate Member Adjusted Voting Shares of the members of the Provisional Member Group Seat which cast affirmative or negative votes on the matter and (b) the quotient obtained by dividing the Sector Voting Share by the aggregate Sector Voting Shares.

1.2 Amendment to Section 1.2. Section (1.2) (Adjusted Sub-Sector Voting Share) is amended so that it reads as follows:

Adjusted Sub-Sector Voting Share shall be determined for each Principal Committee vote in accordance with the following formula:

AVS = T + UPMVSA + (T * [(AR Sector Voting Share %-Q)/Q])

Where:

AVS is an AR Sub-Sector's Adjusted Voting Share.

T is (i) for each Sub-Sector which has not satisfied its AR Sub-Sector Quorum Requirement, the sum of the Member Fixed Voting Shares of the Sub-Sector members who vote on the proposed action, or on whose behalf a vote is properly cast, and (ii) for each Sub-Sector which has satisfied its AR Sub-Sector Quorum Requirement, that Sub-Sector's Sub-Sector Voting Share.

UPMVSA is the product of (A) the Unused Provisional Member Voting Share Sector Allocation and (B) the quotient obtained by dividing T by the AR Sector Voting Share.

Q is the sum of (A) for each Sub-Sector which has not satisfied its AR Sub-Sector Quorum Requirement, the Member Fixed Voting Shares of the Sub-Sector members who voted on the proposed action or on whose behalf a vote is properly cast and (B) the Sub-Sector Voting Shares of the AR Sub-Sectors which have satisfied their AR Sub-Sector Quorum Requirement.

~~The aggregate Adjusted Sub-Sector Voting Share for each vote shall equal the sum of the Member Fixed Voting Shares of the AR Sub-Sector voting members.~~

1.3 Amendment to Section 1.50(a). Sub-section (a) of Section 1.50 (Member Adjusted Voting Share) is amended so that it reads as follows:

(a) for a voting member of each active Sector (other than the AR Sector) which casts an affirmative or negative vote on a proposed action or amendment and which has been appointed by a Participant or group of Participants which are members of a Sector satisfying its Sector Quorum requirement for the proposed action or amendment, is the quotient obtained by dividing (i) the Sector Voting Share of that Sector for the Participants Committee or the Adjusted Sector Voting Share of that Sector for the Technical Committees, in each case plus the Unused Provisional Member Voting Share Sector Allocation~~minus the aggregate Member Adjusted Voting Shares of the members of the Provisional Member Group Seat which cast affirmative or negative votes on the matter~~, by (ii) the number of voting members appointed by members of that Sector which cast affirmative or negative votes on the matter, adjusted, if necessary, for End User Participants and group voting members as provided in the definition of "Member Fixed Voting Share"; and

SECTION 2
MISCELLANEOUS

2.1 This 135th Agreement shall become effective May 1, 2024, or on such other date as the Commission shall provide that the amendment reflected herein shall become effective.

2.2 Capitalized terms used in this 135th Agreement that are not defined herein shall have the meanings ascribed to them in the Second Restated NEPOOL Agreement.

AMENDMENT NO. 12 TO PARTICIPANTS AGREEMENT (Unused Provisional Member Voting Share Allocation Changes)

THIS AMENDMENT NO. 12 TO PARTICIPANTS AGREEMENT ("Amendment No. 12") is made and entered into as of the 1st day of May, 2024 by and between ISO New England Inc. (the "ISO") and the New England Power Pool, an unincorporated association created pursuant to the New England Power Agreement dated as of September 1, 1971, as amended and restated, acting herein by and through the NEPOOL Participants Committee ("NEPOOL").

WHEREAS, the Participants Agreement by and among the ISO and NEPOOL became effective as of February 1, 2005 and has subsequently been amended nine times.

WHEREAS, the ISO and NEPOOL desire to amend the Participants Agreement to reflect the revisions detailed herein.

NOW, THEREFORE, upon approval of this Amendment No. 12 by the ISO and by the NEPOOL Participants Committee in accordance with the procedures set forth in the Participants Agreement, the ISO and NEPOOL agree as follows:

1. Amendments to Section 1.1 (Defined Terms).

1.1 Addition of Definition. The following definition is added to Section 1.1 of the Participants Agreement:

"Unused Provisional Member Voting Share Sector Allocation" shall have the meaning given it in the RNA.

1.2 Amendment to Definition of "Member Adjusted Voting Share". Sub-section (a) to the definition of Member Adjusted Voting Share is amended so that it reads as follows:

(a) for a voting member of each active Sector (other than the AR Sector) which casts an affirmative or negative vote on a proposed action or amendment and which has been appointed by a Participant or group of Participants which are members of a Sector satisfying its Sector Quorum requirement for the proposed action or amendment, is the quotient obtained by dividing (i) the Sector Voting Share of that Sector for the Participants Committee or the Adjusted Sector Voting Share of that Sector for the Technical Committees, in each case plus the Unused Provisional Member Voting Share Sector Allocation~~minus the aggregate Member Adjusted Voting Shares of the members of the Provisional Member Group Seat which cast affirmative or negative votes on the matter~~, by (ii) the number of voting members appointed by members of that Sector which cast affirmative or negative votes on the matter, adjusted, if necessary, for End User Participants and group voting members as provided in the definition of "Member Fixed Voting Share"; and

2. Effective Date. This Amendment No. 10 shall become effective on May 1, 2024 or on such other date as the Commission shall provide that the amendments reflected herein shall become effective.

3. Counterparts. Counterparts of this Amendment No. 12 may be signed by the parties, each of which shall be an original but both of which together shall constitute one and the same instrument.

4. Governing Law. This Amendment No. 12 shall be governed by and enforced in accordance with the laws of the State of Delaware.

5. Miscellaneous. Terms used in this Amendment No. 12 that are not defined herein shall have the meanings ascribed to them in the Participants Agreement, the Second Restated NEPOOL Agreement, or the ISO's Transmission, Markets and Services Tariff.

[The next page is the signature page.]

IN WITNESS WHEREOF, the ISO and NEPOOL have caused this Amendment No. 12 to be executed by their duly authorized representatives as of the date first written above.

ISO NEW ENGLAND INC.	NEW ENGLAND POWER POOL acting through the NEPOOL Participants Committee
By:______________________________	By:________________________________
Name: Gordon van Welie	Name: Sarah Bresolin
Title: President and Chief Executive Officer	Title: Chair, NEPOOL Participants Committee

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of April 3, 2024

The following activity, as more fully described in the attached Litigation Report, has occurred since the report dated March 6, 2024 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

FERC Administrative Developments

	FERC Commissioner Nominee Congressional Hearings	Mar 21	US Senate Comm. on Energy and Natural Resources holds full committee hearing questioning FERC Commissioner nominees ***Judy W. Chang*** (former MA Undersecretary of Energy and Climate Solutions; Adjunct Lecturer at Harvard), ***David Rosner*** (FERC Energy Industry Analyst; since 2022 a detailee to the Senate Committee on Energy and Natural Resources), and ***Lindsay S. See*** (currently serving as the Solicitor General for West Virginia)

I. Complaints/Section 206 Proceedings

No Activities to Report

II. Rate, ICR, FCA, Cost Recovery Filings

5	FCA18 Results Filing (ER24-1290)	Mar 11, 26 Apr 2	National Grid, No Coal No Gas intervene 2 private citizens file comments protesting FCA18 (though filed in FCA17's Results Filing docket (ER23-1435))
5	**Mystic 8/9 COSA (ER18-1639)**		
7	(-027) Second CapEx Info Filing Settlement Proceedings	Mar 20 Mar 22	2nd settlement conference held Settlement Judge French schedules 3rd settlement conference for ***Apr 19, 2024***
9	Transmission Rate Annual (2023-24) Update/Informational Filing (ER20-2054)	Mar 15	Identified TOs answer MOPA's Mar 4 response

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

10	Waiver Request: Withdrawal from IEP and Return of IEP Net Revenues Received) (Canal Marketing/Canal 3) (ER24-1407)	Mar 25 Mar 22, 28	IMM submits comments supporting repayment of IEP revenue National Grid, NEPOOL (out-of-time) intervene
11	Waiver Request: Interconnection Request Deposit Refund Deadline) (Moscow Dev. Co.) (ER24-1295)	Mar 6	NEPOOL intervenes

IV. OATT Amendments / TOAs / Coordination Agreements

No Activities to Report

V. Financial Assurance/Billing Policy Amendments

No Activities to Report

VI. Schedule 20/21/22/23 Changes & Agreements

No Activities to Report

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activities to Report

VIII. Regional Reports

*	16	ISO-NE FERC Form 715 (not docketed)	Mar 27	ISO-NE submits 2023 annual report of total MWh of transmission service

IX. Membership Filings

*	16	Apr 2024 Membership Filing (ER24-1650)	Mar 29	***New Members:*** Eagle Creek Madison Hydro and Vineyard Offshore and ***Termination of Participant status:*** Power Supply Services and Green Choice Energy; comment deadline ***Apr 19, 2024***
	16	Feb 2024 Membership Filing (ER24-1062)	Mar 28	FERC accepts: (i) the memberships of Agile Energy Trading; Command Power; Eagle Creek Renewable Energy Holdings LLC; and Ocean State Power and (ii) the termination of the Participant status of Community Eco Power; MPower Energy LLC; Pixelle Energy Services; Power Ledger Pty Ltd; Union Atlantic Electricity; and Utility Services of Vermont

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

*	17	Revised Glossary Terms (RD24-6)	Mar 8	NERC files proposed revisions to its Glossary of Terms; comment deadline ***Apr 10, 2024***
			Mar 15	Ameren intervenes
	17	Revised Reliability Standard: EOP-012-2 (RD24-5)	Mar 21	IRC protests and NEGPA files comments regarding the Freeze Protection Standards
			Mar 26-Apr 2	Avangrid Renewables, Calpine, PA PUC, TAPS intervene doc-lessly (each out-of-time)
			Apr 1	EPSA files comments supporting NEPGA's comments, urging the FERC to remedy prospectively any cost recovery issues
	18	CIP Standards Development: Info. Filings on Virtualization and Cloud Computing Srvcs Projects (RD20-2)	Mar 13	NERC files required quarterly report with revised schedule for Project 2016-02 (projected filing of revised standards remains ***Jun 2024***)
*	18	NERC 2024 Standards Report (RR09-6)	Mar 22	NERC files 2024 Standards Report

XI. Misc. - of Regional Interest

*	19	203 Application: Eversource / GIP IV (EC24-59)	Mar 13	GIP IV seeks FERC authorization to acquire Eversource's interests in North East Offshore, Revolution Wind and South Fork Wind
			Mar 28	Public Citizen intervenes
*	19	203 Application: GIM / BlackRock (EC24-58)	Mar 12	GIM and BlackRock seek FERC authorization for BlackRock's indirect acquisition of GIM (and its public utility subsidiaries, including Clearway Power Mktg and GenConn Energy); comment deadline ***May 13, 2024***
			Mar 18-29	PJM, PJM IMM, Private Equity Stakeholder Project, Public Citizen intervene

	20	203 Application: Energy Harbor / Vistra (EC23-74)	Mar 7	Energy Harbor/Vistra notify the FERC that the authorized transaction was consummated on Mar 1, 2024 (making Energy Harbor and Dynegy Marketing and Trade Related Persons)
*	20	PURPA Enforcement Petition – Allco Finance Ltd (EL24-95)	Mar 27	Allco requests the FERC initiate an enforcement action against CT DEEP for improper implementation of PURPA; comment deadline ***Apr 17, 2024***
*	20	EPC Cancellation – CMP/FPL Wyman (ER24-1510)	Mar 15	CMP files cancellation notice; comment deadline ***Apr 5, 2024***
*	20	LGIA – ISO-NE/CMP/Andro Hydro (ER24-1477)	Mar 14	ISO-NE, CMP file non-conforming LGIA to govern the interconnection of Andro Hydro's 27 MW facility
			Mar 28	Andro Hydro intervenes
	21	CMP ESF Service Rate (ER24-1177)	Mar 8	CMP answers EMI, and Rumford ESS / ME REA protests
			Mar 22	Rumford ESS, NECEC and ME REA respond to CMP's Mar 8 answer
			Mar 29	CMP answers Rumford ESS' Mar 22 answer
			Apr 1	FERC accepts, subject to refund and settlement judge procedures, CMP's ESF Rate, *eff. Apr 2, 2024*
	21	Facilities Support Agreement – NSTAR/Hingham (ER24-1175)	Mar 29	FERC accepts agreement, *eff. Feb 9, 2024*
	22	Viridon Incentive Rate Treatment (ER24-771)	Mar 21	FERC approves Viridon's requests for (i) a regulatory asset incentive, (ii) a hypothetical capital structure of 60% equity and 40% debt, (iii) 50 basis point RTO adder, and (iv) authorization for future affiliates formed to operate in New England to utilize the incentive rate treatments granted in this docket

XII. Misc. - Administrative & Rulemaking Proceedings

*	23	Joint Federal-State Current Issues Collaborative (AD24-7)	Mar 21	FERC establishes the Collaborative; successor to JFSTF; first meeting expected in ***Fall 2024***
	23	Joint Federal-State Task Force on Electric Transmission (AD21-15)	Mar 21	FERC, notes that JFSTF will expire on ***Nov 10, 2024***, and Feb 28, 2024 was its last meeting
	24	*Order 2023-A*: Interconnection Reforms (RM22-14)	Mar 21	FERC issues order on rehearing (*Order 2023-A*), setting aside, in part, and clarifying, in part, *Order 2023*
*	27	NOPR: Compensation for Reactive Power Within the Standard Power Factor Range (RM22-2)	Mar 21	FERC issues NOPR; comment deadline ***May 27, 2024***; reply comment deadline ***Jul 26, 2024***
	28	Transmission NOPR (RM21-17)	Mar 6-21	Ceres, AMP, Bekaert, Freeport-McMoRan, US Climate Alliance file comments
			Mar 20	NESCOE asks that the FERC reject late-filed comments or, alternatively, accept its supplemental comments

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

*	30	Smart One Energy, LLC (IN23-13)	Mar 12	FERC approves Stipulation and Consent Agreement that resolves investigation into whether Smart One violated NYISO's Tariff by failing to timely inform NYISO, in its Apr 2020 and Apr 2021 credit questionnaire submissions, of sanctions imposed upon it by the MD PSC and VA SCC; Smart One agrees to pay a ***$5,000 civil penalty***

XIV. Natural Gas Proceedings

No Activity to Report

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

35	CASPR (20-1333, 21-1031) (consolidated)**	Mar 12	Court grants 4th abeyance request (until ***Mar 1, 2026***)
35	Northern Access Project (22-1233)	Mar 29	Court denies Petitions for Review

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity and Teresa Chen, NEPOOL Counsel

DATE: April 3, 2024

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

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"),[1] state regulatory commissions, and the Federal Courts and legislatures through April 3, 2024. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

- **206 Proceeding: ISO Market Power Mitigation Rules (EL23-62)**

This Section 206 proceeding is being held in abeyance. As previously reported, this proceeding was instituted by the FERC on May 5, 2023, pursuant to its finding that the existing ISO-NE Tariff provisions related to the mechanics of its market power mitigation and the consideration of any proposed fuel price adjustment, may be unjust and unreasonable.[2] Changes in response to some of the requirements of the *Dynegy Mitigation Order* ("Upward Mitigation Revisions") were supported by the Participants Committee, jointly filed with ISO-NE, accepted by the FERC,[3] and became effective as of *December 12, 2023*. On January 29, 2024, ISO-NE requested that this proceeding continue to be held in abeyance,[4] through ***August 30, 2024***, "pending completion of the stakeholder process through which further revisions to [the Tariff] are being proposed and vetted.[5] The FERC granted ISO-NE's motion on February 7, 2024, stating that it would not take any action on this 206 proceeding before ***August 30, 2024***. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **RENEW Network Upgrades O&M Cost Allocation Complaint (EL23-16)**

The December 13, 2022 complaint by RENEW Northeast, Inc. ("RENEW") against ISO-NE and the Participating Transmission Owners ("PTOs"), which seeks changes to the ISO-NE Tariff (Schedules 11 and 21) that would eliminate the direct assignment of Network Upgrade Operations and Maintenance ("O&M") costs to

[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 Ne w England Inc. ("ISO" or "ISO-NE") Transmission, Markets and Services Tariff (the "Tariff").

[2] *Dynegy Marketing and Trade, LLC and ISO New England, Inc.*, 183 FERC ¶ 61,091 (May 5, 2023) ("*Dynegy Mitigation Order*"). In the Dynegy Mitigation Order, ISO-NE was directed to either: (1) show cause as to why the Tariff remains just and reasonable and not unduly discriminatory or preferential; or (2) explain what changes to the Tariff it believes would remedy the identified concerns if the FERC were to determine that the Tariff has in fact become unjust and unreasonable or unduly discriminatory. The refund effective date for this proceeding is May 12, 2023.

[3] *ISO New England Inc.*, Docket No. ER24-324-000 (Dec. 12, 2023) (unpublished letter order).

[4] On July 14, 2023, the FERC granted ISO-NE's June 28, 2023 motion, supported by NEPOOL on July 5, 2023, requesting that the FERC hold this proceeding in abeyance to allow potential ISO-NE Tariff design changes to be vetted through the Participant Processes. The FERC stated that it would not take any action on this 206 proceeding before Feb. 1, 2024.

[5] ISO-NE identified as additional topics not fully addressed by the Upward Mitigation Revisions the following: (1) whether the duration of general threshold energy mitigation is appropriate; and (2) whether a Resource should be permitted to submit multiple fuel price adjustments that reflect the cost of fuel for segments of its Supply Offer that exceed a Resource's Day-Ahead Energy Market awards.

Interconnection Customers,[6] remains pending before the FERC. As previously reported, the proposed revisions to Schedule 11 of the Tariff were voted by the Transmission Committee at its October 26, 2021 meeting, and were discussed at the Participants Committee's November 3, 2021 meeting. RENEW asked the FERC to issue an order granting the Complaint by April 14, 2023 (approximately 60 days prior to the June 15, 2023 deadline for the NE PTOs to publish a draft of the Annual Update to the data used in the transmission formula rate). Both of those dates have long since passed.

Responses, comments and protests were filed in late January 2023 by ISO-NE (which alternatively moved to dismiss itself as a party ("ISO-NE Jan 19 Motion")), the PTO AC, NEPOOL, AEU/Clean Energy Council, CPV Towantic, Glenvale, MA AG, NECOS, NEPGA, and NESCOE. Doc-less interventions only were filed by Calpine, CMMEC, EMI, Eversource, Narragansett ("RI Energy"), National Grid, New Leaf Energy, NextEra, NRG, Versant, CT DEEP, MA DPU, the American Clean Power Association ("ACPA"), Solar Energy Industries Association ("SEIA"), and Public Citizen. In additional rounds of briefing, RENEW answered ISO-NE's Jan 19 Motion; RENEW, the PTO AC, and National Grid filed answers to the January 23 protests/comments; ISO-NE answered RENEW's February 7 answer; and CPV Towantic, Glenvale, and the MA AG filed answers to the February 7 answers. There was again no activity since the last Report. As noted, this matter remains pending before the FERC. If you have questions on this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

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

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

- ***Base ROE Complaint I (EL11-66)***. In the first Base ROE Complaint proceeding, the FERC concluded that the TOs' ROE had become unjust and unreasonable,[7] set the TOs' Base ROE at 10.57% (reduced from 11.14%), capped the TOs' total ROE (Base ROE *plus* transmission incentive adders) at 11.74%, and required implementation effective as of October 16, 2014 (the date of *Opinion 531-A*).[8] However, the FERC's orders were challenged, and in *Emera Maine,*[9] the U.S. Court of Appeals for the D.C. Circuit ("DC Circuit") vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.

[6] RENEW also requested (i) that it be considered an Interested Party or afforded adequate opportunity to participate and access transmission rate information under the PTOs' Formula Rate Protocols and (ii) the PTOs be directed to provide greater transparency regarding O&M costs in the interconnection process.

[7] The TOs' 11.14% pre-existing Base ROE was established in *Opinion 489*. *Bangor Hydro-Elec. Co.*, Opinion No. 489, 117 FERC ¶ 61,129 (2006), *order on reh'g*, 122 FERC ¶ 61,265 (2008), *order granting clarif.*, 124 FERC ¶ 61,136 (2008), *aff'd sub nom.*, Conn. Dep't of Pub. Util. Control v. FERC, 593 F.3d 30 (D.C. Cir. 2010) ("*Opinion 489*")).

[8] *Coakley Mass. Att'y Gen. v. Bangor Hydro-Elec. Co.*, 147 FERC ¶ 61,234 (2014) ("*Opinion 531*"), *order on paper hearing*, 149 FERC ¶ 61,032 (2014) ("*Opinion 531-A*"), *order on reh'g*, 150 FERC ¶ 61,165 (2015) ("*Opinion 531-B*").

[9] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*"). *Emera Maine* vacated the FERC's prior orders in the Base ROE Complaint I proceeding, and remanded the case for further proceedings consistent with its order. The Court agreed with both the TOs (that the FERC did not meet the Section 206 obligation to first find the existing rate unlawful before setting the new rate) and "Customers" (that the 10.57% ROE was not based on reasoned decision-making, and was a departure from past precedent of setting the ROE at the midpoint of the zone of reasonableness).

- ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[10] and third (EL14-86)[11] ROE complaint proceedings were consolidated for purposes of hearing and decision, though the parties were permitted to litigate a separate ROE for each refund period. After hearings were completed, ALJ Sterner issued a 939-paragraph, 371-page *Initial Decision*, which lowered the base ROEs for the EL13-33 and EL14-86 refund periods from 11.14% to 9.59% and 10.90%, respectively.[12] The *Initial Decision* also lowered the ROE ceilings. Parties to these proceedings filed briefs on exception to the FERC, which has not yet issued an opinion on the ALJ's *Initial Decision*.

- ***Base ROE Complaint IV (EL16-64)***. The fourth and final ROE proceeding[13] also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March 27, 2017.[14] The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%, which may reach a maximum ROE of 11.74% with incentive adders, was ***not*** unjust and unreasonable for the Complaint IV period, and hence was not unlawful under Section 206 of the FPA.[15] Parties in this proceeding filed briefs on exception to the FERC, which has not yet issued an opinion on the *Base ROE IV Initial Decision*.

October 16, 2018 Order Proposing Methodology for Addressing ROE Issues Remanded in Emera Maine and Directing Briefs. On October 16, 2018, the FERC, addressing the issues that were remanded in *Emera Maine,* proposed a new methodology for determining whether an existing ROE remains just and reasonable.[16] The FERC indicated its intention that the methodology be its policy going forward, including in the four currently pending New England proceedings (*see*, however, *Opinion 569-A*[17] (EL14-12; EL15-45) in

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[10] The 2012 Base ROE Complaint, filed by Environment Northeast (now known as Acadia Center), Greater Boston Real Estate Board, National Consumer Law Center, and the NEPOOL Industrial Customer Coalition ("NICC", and together, the "2012 Complainants"), challenged the TOs' 11.14% ROE, and seeks a reduction of the Base ROE to 8.7%.

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

[12] *Environment Northeast v. Bangor Hydro-Elec. Co. and Mass. Att'y Gen. v. Bangor Hydro-Elec. Co,* 154 FERC ¶ 63,024 (Mar. 22, 2016) ("*2012/14 ROE Initial Decision*").

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

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

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

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

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

Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[18]

At highest level, the new methodology will determine whether (1) an existing ROE is unjust and unreasonable under the first prong of FPA Section 206 and (2) if so, what the replacement ROE should be under the second prong of FPA Section 206. In determining whether an existing ROE is unjust and under the first prong of Section 206, the FERC stated that it will determine a "composite" zone of reasonableness based on the results of three models: the Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"), and Expected Earnings models. Within that composite zone, a smaller, "presumptively reasonable" zone will be established. Absent additional evidence to the contrary, if the utility's existing ROE falls within the presumptively reasonable zone, it is not unjust and unreasonable. Changes in capital market conditions since the existing ROE was established may be considered in assessing whether the ROE is unjust and unreasonable.

If the FERC finds an existing ROE unjust and unreasonable, it will then determine the new just and reasonable ROE using an averaging process. For a diverse group of average risk utilities, FERC will average four values: the midpoints of the DCF, CAPM and Expected Earnings models, and the results of the Risk Premium model. For a single utility of average risk, the FERC will average the medians rather than the midpoints. The FERC said that it would continue to use the same proxy group criteria it established in *Opinion 531* to run the ROE models, but it made a significant change to the manner in which it will apply the high-end outlier test.

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[19] The new ROE would be effective as of the date of *Opinion 531-A*, or October 16, 2014. Accordingly, the issue to be addressed in the Base ROE Complaint II proceeding is whether the ROE established on remand in the first complaint proceeding remained just and reasonable based on financial data for the six-month period September 2013 through February 2014 addressed by the evidence presented by the participants in the second proceeding. Similarly, briefing in the third and fourth complaints will have to address whether whatever ROE is in effect as a result of the immediately preceding complaint proceeding continues to be just and reasonable.

The FERC directed participants in the four proceedings to submit briefs regarding the proposed approaches to the FPA section 206 inquiry and how to apply them to the complaints (separate briefs for each proceeding). Additional financial data or evidence concerning economic conditions in any proceeding must relate to periods before the conclusion of the hearings in the relevant complaint proceeding. Following a FERC notice granting a request by the TOs and Customers[20] for an extension of time to submit briefs, the latest date for filing initial and reply briefs was extended to January 11 and March 8, 2019, respectively. On January 11, initial briefs were filed by EMCOS, Complainant-Aligned Parties, TOs, Edison Electric Institute ("EEI"), Louisiana PSC, Southern California Edison, and AEP. As part of their initial briefs, each of the Louisiana PSC, SEC and AEP also moved to intervene out-of-time. Those interventions were opposed by the TOs on January 24, 2019. The Louisiana PSC answered the TOs' January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, and FERC Trial Staff.

Opinion 569; and (iv) calculating the zone of reasonableness in equal thirds, instead of using the quartile approach that was applied in *Opinion 569*.

[18] *Id.* at P 19.

[19] *Id.* at P 59.

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

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

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

II. Rate, ICR, FCA, Cost Recovery Filings

- **FCA18 Results Filing (ER24-1290)**

On February 21, 2024, ISO-NE filed the results of the eighteenth Forward Capacity Auction ("FCA18") held February 5, 2024 for the June 1, 2027 - May 31, 2028 Capacity Commitment Period ("CCP"). ISO-NE reported the following highlights:

- FCA18 Capacity Zones were the Northern New England ("NNE") Capacity Zone (the Maine, New Hampshire and Vermont Load Zones), the Maine Capacity Zone (the Maine Load Zone) and the Rest-of-Pool ("ROP") Capacity Zone (the Southeastern Massachusetts, Rhode Island, Northeastern Massachusetts/Boston, Connecticut and Western/Central Massachusetts Load Zones). NNE was modeled as an export-constrained Capacity Zone. The Maine Load Zone was modeled as a separate nested export-constrained Capacity Zone within NNE.
- FCA18 commenced with a starting price of $14.52/kW-mo. and concluded for all Capacity Zones after four rounds.
- Capacity Clearing Prices were the same, $3.58/kw-mo, for all Capacity Zones and imports over the external interfaces.[22]
- There were no active demand bids for the substitution auction and, accordingly, the substitution auction was not conducted.
- No resources cleared as Conditional Qualified New Generating Capacity Resources.
- No Long Lead Time Generating Facilities secured a Queue Position to participate as a New Generating Capacity Resource.
- No De-List Bids were rejected for reliability reasons.

ISO-NE asked the FERC to accept the FCA18 rates and results, effective June 20, 2024. Comments on this filing are due on or before ***April 8, 2024***. On April 2, 2024, 2 private citizens filed comments protesting the FCA18 results, though in the docket for FCA17 (ER23-1435) and not on the basis of an incorrect application of the Tariff rules. Doc-less interventions have thus far been filed by NEPOOL, Calpine, National Grid, NEPGA, Public Citizen, and No Coal No Gas ("NCNG"). If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

Mystic I Remand. As previously reported, the DC Circuit issued a decision on August 23, 2022[23] that, among other things: (i) granted State Petitioners' petitions for review on the cost allocation issue; (ii) vacated

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

[22] 123 MW over the NY AC Ties, 70 MW over the New Brunswick external interface, 18.17 MW over the HQ Highgate external interface, and 253.78 MW over the Phase I/II HQ Excess external interface.

[23] *Constellation Mystic Power, LLC v. FERC*, 45 F.4th 1028 (D.C. Cir. 2022) ("*Mystic I Remand Order*").

the clawback portions excluding Everett costs and the challenged delay provision of the orders under review; and (iii) remanded the cases to the FERC to address NESCOE's request for clarification about revenue credits and for clarification of the apparent contradictions in the FERC's *December 2020 Rehearing Order*.

(-000) Third CapEx Info Filing. On September 15, 2023, Mystic submitted, as required by orders in this proceeding and Sections I.B.1.i. and II.6.of Schedule 3A of the COS Agreement ("Protocols") its "Third CapEx Info Filing" to provide support for the capital expenditures and related costs that Mystic projects will be collected as an expense between January 1, 2024 to May 31, 2024 ("2024 CapEx Projects"). This filing was not noticed for public comment by the FERC.

***(-018) Second CapEx Info Filing*.** On December 5, 2023, the FERC issued an order[24] on the formal challenges to Mystic's September 15, 2022 "Second CapEx Info Filing".[25] As previously reported, formal challenges to the Second CapEx Info Filing were submitted by NESCOE and ENECOS[26] (with ENECOS challenges supported separately by MMWEC/NHEC). Several rounds of answers, described in previous reports, followed. In February 2023, Mystic asked that the Formal Challenges to the Second CapEx Info Filing be held in abeyance pending submission of a settlement agreement to resolve challenges to the First CapEx Info Filing. ENECOS protested that request, identifying issues in their challenges to the Second CapEx Info Filing that would not be resolved by a First CapEx Settlement Agreement. The First CapEx Settlement Agreement was filed and approved, leaving for resolution certain of ENECOS' challenges.

In the *Second CapEx Info Filing Order*, the FERC granted in part, subject to hearing and settlement judge procedures, and dismissed in part, ENECOS' Formal Challenges. Specifically, the FERC found that, issues of material fact, that could not be resolved on the record before it, continued with respect to a number of ENECOS' Formal Challenges. Accordingly, the FERC set for hearing and settlement judge procedures issues raised, in whole or in part, in ENECOS Formal Challenges 1, 2, 6, and 7. The FERC summarily dismissed ENECOS' Formal Challenges 3-5 and 8 (as outside the scope of the proceeding).

***(-026) Allegheny Order Addressing ENECOS' Request for Rehearing of Order on Remand Modification Order*.** On November 6, 2023, ENECOS requested rehearing of the *Mystic I Order on Remand Modification Order*.[27]

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[24] *Constellation Mystic Power, LLC*, 185 FERC ¶ 61,170 (Dec. 5, 2023) ("*Second CapEx Info Filing Order*").

[25] The "Second CapEx Info Filing" provides support for the capital expenditures and related costs that Mystic projects will be collected as an expense between January 1, 2023 to December 31, 2023 ("2023 CapEx Projects").

[26] ENECOS Formal Challenges included failures by Mystic: (1) to adequately support its July 1, 2004 – Dec. 31, 2017 Rate Base on Attachment B to Mystic 8&9 Schedule D (with the majority of the cost appearing to O&M expenses that should have been expensed prior to the term); (2) to adequately support its Jan. 1, 2018 – May 31, 2022 Rate Base in line with the requirements of Schedule 3A and the Methodology of the Mystic COSA; (3-5) to prove that certain costs under Mystic's 2022 CapEx Projects - specifically, its Campus Segregation Project and comprehensive rotor inspections - are necessary to meet the reliability need of the Mystic COSA and the least-cost commercially reasonable option consistent with Good Utility Practice; (6) to sufficiently support Everett's Nov. 1, 2018 – May 31, 2022 Rate Base in Attachment B; (7) to properly classify certain of Everett's 2022 and 2023 CapEx Projects costs (some of which should have been characterized as maintenance expenses charged before the term of the Mystic COSA); and (8) to include costs of firm interstate and intrastate pipeline transportation reservations in Everett Schedule B of the populated template.

[27] *Constellation Mystic Power, LLC*, 185 FERC ¶ 61,016 (Oct. 6, 2023) ("*Mystic I Order on Remand Modification Order*"). The *Mystic I Order on Remand Modification Order* set aside the FERC determinations in the *Mystic I Order on Remand* that: (i) interested parties may review and challenge revenues and Revenue Credits during the true-up process; (ii) interested parties may review and challenge Tank Congestion Charges during the true-up process; and (iii) the revenues from the sliding scale revenue sharing mechanism for third-party vapor sales should be included within the true-up. As previously reported, the FERC concluded in the *Mystic I Order on Remand* that "the language of the true-up and Protocol provisions of the [COS] Agreement, Schedule 3A, does not include these three items within the scope of the true-up, nor is calculation of these items consistent with purpose for the true-up mechanism in the [COS] Agreement because none of them are projected in advance, but rather they are each settled and audited on a monthly basis. The FERC found that "existing cos t review and audit processes, … facilitated by ISO-NE, its auditors, and the Internal Market Monitor, are sufficient to ensure that Mystic adheres to its filed rate with respect to these items and continues to appropriately balance customers' interest in transparency of the formula rate with Mystic's interests in protecting commercially-sensitive information, reducing security risks, and avoiding burdensome audit obligations".

Specifically, ENECOS requested that the FERC both (i) reinstate its conclusions as to the scope of customer scrutiny of formula rate inputs under the COSA set forth in its March 28, 2023 *Mystic I Order on Remand*[28] and (ii) grant Public Systems' motion for additional disclosure to facilitate customer review of the extraordinary costs incurred during the first 18 months of the COSA's operation. On December 7, 2023, the FERC issued an "Allegheny Notice", noting that ENECOS request for rehearing may be deemed to have been denied by operation of law, but noting that ENECOS' request will be addressed in a future order.[29] On February 15, 2024, the FERC issued that order, modifying the discussion in the *Mystic I Order on Remand Modification Order* but reaching the same result.[30] On February 29, 2024, ENECOS amended their petition for review before the DC Circuit (Case No. 24-1018) to include the *Mystic I Order on Remand Modification Order Allegheny Order* (*see* Section XVI below),

Recall that, as previously reported with respect to this aspect of the Mystic proceeding, Mystic requested rehearing and/or clarification of the March 28, 2023 *Mystic I Order on Remand (-*024*)*. Mystic asserted that (a) the FERC should have considered and rejected NESCOE's arguments about "truing up" and challenging the Revenue Credit; (b) the Tank Congestion Charge and the calculation of the Forward Sales Margin credited to Mystic and its ratepayers should not be included in the true-up process; and (c) if the FERC does not grant rehearing on (a) or (b), in the alternative, it should clarify that the scope of review during the true-up for Revenue Credits and the Forward Sale Margin Shared with Mystic is not a prudence review and does not require disclosure of granular, unmasked transaction data. On May 30, 2023, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[31] The FERC then issued the *Mystic I Order on Remand Modification Order* which modified the discussion in the *Mystic I Order on Remand* and set aside that *Order* in part.[32] In addition, the *Order* also denied Public Systems[33] May 19, 2023 request that the FERC direct ISO-NE to release additional information concerning ISO-NE's audit of performance under Mystic COSA ("Audit Information Request").[34]

(-027) Second CapEx Info Filing Settlement Proceedings. While the FERC set several aspects of ENECOS Formal Challenges for a trial-type evidentiary hearing, the FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and to that end, is holding the hearing in abeyance pending the completion of settlement judge procedures. As directed, the Chief ALJ appointed a settlement judge, Judge Patricia M. French, to assist participants in settling the issues in this proceeding, and deemed the settlement proceedings continued without further action. Judge French convened a first settlement conference on January 4, 2024, a second settlement conference on March 20, 2024, and scheduled a third settlement conference for ***April 19, 2024***.

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[28] *Constellation Mystic Power, LLC*, 182 FERC ¶ 61,200 (Mar. 28, 2023) ("*Mystic I Order on Remand*"), *reh'g denied by operation of law,* 183 FERC ¶ 62,115 (May 30, 2023) ("*Mystic I Order on Remand Allegheny Notice*"); *Mystic I Order on Remand Modification Order* (addressing arguments raised on reh'g and setting aside the *Mystic I Order on Remand*, in part, granting Constellation motion to lodge and denying Public Systems' Request for Disclosure of Audit Information).

[29] *Constellation Mystic Power, LLC*, 185 FERC ¶ 62,120 (Dec. 7, 2023) ("*Mystic I Order on Remand Modification Order Allegheny Notice*").

[30] *Constellation Mystic Power, LLC*, 186 FERC ¶ 61,103 (Feb. 15, 2024) ("*Mystic I Order on Remand Modification Order Allegheny Order*").

[31] *Mystic I Order on Remand Allegheny Notice*.

[32] *Constellation Mystic Power, LLC*, 185 FERC ¶ 61,016 (Oct. 6, 2023) ("*Mystic I Order on Remand Modification Order*").

[33] "Public Systems" for these purposes are: MMWEC, CMEEC, NHEC, VPPSA, the Eastern New England Consumer-Owned Systems ("ENECOS"), and Energy New England, LLC ("ENE").

[34] In the *Mystic I Order on Remand Modification Order*, the FERC found that the additional audit information requested was "not supported by the Mystic [COSA] and unnecessary, given the attention that ISO-NE, its auditors, and the Market Monitor give these items on a regular basis". Nevertheless, the FERC accepted "ISO-NE's offer to provide additional transparency measures for the remainder of the Mystic Agreement as soon as practicable, starting no later than [Dec. 5, 2023]." (P 13).

(-028) Second CapEx Info Filing Order - Mystic's Request for Rehearing Deemed Denied by Operation of Law. On January 4, 2024, Mystic requested clarification, and in the alternative rehearing, of the *Second CapEx Info Filing Order*.[35] Specifically, Mystic requested clarification and/or rehearing of (i) the FERC's ruling on ENECOS's Formal Challenge No. 7 related to Everett's projected 2023 capital expenditures, (ii) that the FERC denied the accounting argument that ENECOS included in their Formal Challenge No. 1; and (iii) the FERC's rulings related to capital costs incurred prior to the start of the term of the COS Agreement (its grant in part of ENECOS's Formal Challenge No. 1 on the basis that Mystic did not adequately "support" Mystic 8&9 capital costs between July 2004 and December 31, 2017 ("Pre-2018 Rate Base"), and its grant of ENECOS's Formal Challenges Nos. 2 and 6). On January 19, 2024, ENECOS answered Mystic's request. On February 5, 2024, the FERC issued an "Allegheny Notice",[36] noting that ENECOS request for rehearing may be deemed to have been denied by operation of law, but noting that ENECOS' request will be addressed in a future order.[37]

(-014) Revised ROE (Sixth) Compliance Filing. Also still pending is Mystic's December 20, 2021 filing in response to the requirements of the *Mystic ROE Allegheny Order*.[38] The sixth compliance filing revised (i) the Cost of Common Equity figures from 9.33% to 9.19%, for both Mystic 8&9 and Everett Marine Terminal ("Everett"), and (ii) the stated Annual Fixed Revenue Requirements for both the 2022/23 and 2023/24 Capacity Commitment Periods. Comments on the sixth compliance filing were due on or before January 10, 2022; none were filed. The Sixth Compliance Filing remains pending before the FERC.

30-Day Compliance Filing per Order on ENECOS Mystic COSA Complaint (ER23-1735). On April 27, 2023, Mystic filed, as directed by the FERC's March 28, 2023 *Order on ENECOS Mystic COSA Complaint*,[39] changes to the Mystic COSA to include pipeline-related crediting as an explicit provision in the COSA. Mystic also provided additional information/COSA changes to (i) describe the crediting process; (ii) differentiate, through both an explanation in its compliance filing and creation of two new line items in Schedule 3A, the credits and charges included as part of the Fixed Pipeline Costs; (iii) address how and whether the pipeline-related crediting procedure interacts or should interact with the true-up procedure already included in the COSA and revise the true-up as necessary; and (iv) differentiate in the COSA the Pipeline Transportation Costs as Fixed O&M/Return on Investment Costs from the Pipeline Transportation Agreement Costs. Comments on the 30-day compliance filing were due on or before May 18, 2023. ISO-NE and Monitoring Analytics, LLC filed doc-less motions to intervene.

On July 10, 2023, ENECOS submitted comments (out-of-time) asserting that Mystic's compliance filing did not provide information sufficient to show that Mystic's after-the-fact pipeline-related crediting ensures that Mystic customers do not pay for pipeline costs that do not benefit them ("Crediting Issue"), the Schedule 3A true-up process does not provide the opportunity for an adequate verification process, and ISO-NE's COSA-related

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[35] *Constellation Mystic Power, LLC*, 185 FERC ¶ 61,170 (Dec. 5, 2023) ("*Second CapEx Info Filing Order*").

[36] The FERC issues an "Allegheny Notice" when it does not act within 30 days after receiving a challenge (a request for clarification and/or rehearing) to a FERC order. An Allegheny Notice confirms that the request is deemed denied by operation of law (*see Allegheny Def. Project v. FERC*, 964 F.3d 1, 2020 WL 3525547 (D.C. Cir. June 30, 2020)) and the FERC order is final and ripe for appeal. The FERC has the right, up to the point when the record in a proceeding is filed with the court of appeals, to modify or set aside, in whole or in part, any finding or order made or issued by it. The FERC's intention to avail itself of its right and to issue a further order addressing the issues raised in the request (a "merits order") is signaled by the phrase "and providing for Further Consideration"; the absence of that phrase signals that the FERC does not intend to issue a merits order in response to the rehearing request.

[37] *Constellation Mystic Power, LLC*, 186 FERC ¶ 62,048 (Feb. 5, 2024) ("*Second CapEx Info Filing Order Allegheny Notice*").

[38] An "Allegheny Order" is a merits rehearing order issued on or after the 31st day after receipt of a rehearing request, reflecting the FERC's authority to "modify or set aside, in whole or in part," its order until it files the record on appeal with a reviewing federal court. An Allegheny Order will use "modifying the discussion" if the FERC is providing a further explanation, but is not changing the outcome, of the underlying order; or "set aside" if the FERC is changing the outcome of the underlying order. Aggrieved parties have 60 days after a deemed denial to file a review petition, even if FERC has announced its intention to issue a further merits order.

[39] *Belmont Municipal Light Dept., et al. v. Constellation Mystic Power, LLC and ISO New England, Inc.*, 182 FERC ¶ 61,199 (Mar. 28, 2023) ("*Order on ENECOS Mystic COSA Complaint*", which denied in part, and accepted in part, ENECOS' Complaint against Mystic and ISO-NE challenging the pass-through of firm pipeline transportation costs under the 2nd Amended and Restated Mystic COSA).

filings to date have similarly not addressed the Crediting Issue. ENECOS requested that the FERC direct Mystic to provide a work paper to "verify its assertion that it has always applied a full credit for third-party pipeline transportation costs to Constellation LNG's billings to Mystic". On July 20, 2023, Mystic protested ENECOS' comments. This 30-day compliance filing remains pending before the FERC.

If you have questions on any aspect of these proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

- **Transmission Rate Annual (2023-24) Update/Informational Filing (ER20-2054-003)**

Formal Challenge by MOPA. On January 31, 2024, the Maine OPA ("MOPA") filed a formal challenge ("MOPA Formal Challenge") to the 2023-24 Annual Update.[40] MOPA asserted that, with respect to the cost of asset condition projects placed into service in 2022, the NETOs have refused to answer questions regarding investment policies and practices related to prudence of these investments and asserts that the NETOs' decision not to respond to these questions violates their obligation under the OATT's Protocols. Comments on the MOPA Formal Challenge were due on or before February 21, 2024 and were filed by Consumer Advocates[41] (who supported MOPA's attempt to discover the information requested in its September 15, 2023 requests and agreed that policies, processes, and procedures related to ACP costs are discoverable pursuant to the Protocols) and Identified TOs[42] (who urged the FERC to reject the MOPA Formal Challenge as baseless and misguided). On March 4, 2024, MOPA answered Identified TOs' comments. Identified TOs answered MOPA's March 4 answer on March 15 (as corrected on March 18, 2024). This matter is pending before the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Versant MPD OATT 2023 Annual Update Settlement Agreement (ER20-1977-006)**

On January 5, 2024, Versant submitted a Joint Offer of Settlement ("Versant MPD OATT 2023 Annual Update Settlement Agreement") between itself and the Eastern Maine Electric Cooperative, Inc. ("EMEC") and the Maine Public Utilities Commission (together, the "Maine Parties") which, if approved, would resolve all issues raised by the Maine Parties with regards to Versant's 2023 annual update to the transmission charges under the MPD OATT. Comments on the Versant MPD OATT 2023 Annual Update Settlement Agreement were due on or before January 26, 2024; none were filed. The Versant MPD OATT 2023 Annual Update Settlement Agreement is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Versant MPD OATT 2022 Annual Update Settlement Agreement (ER20-1977-005)**

On August 30, 2023, Versant submitted a Joint Offer of Settlement ("Versant MPD OATT 2022 Annual Update Settlement Agreement") between itself and the Maine Wholesale Customer Group, the Aroostook Energy Association, MOPA, and the Maine Public Utilities Commission (together, the "Maine Parties") which, if approved, would resolve all issues raised by the Maine Parties with regards to Versant's 2022 annual update

[40] On July 31, 2023, the PTO AC submitted its annual filing identifying adjustments to Regional Transmission Service charges, Local Service charges, and Schedule 12C Costs under Section II of the Tariff for 2024 (the "2023-24 Annual Update"). The filing reflected the charges to be assessed under annual transmission and settlement formula rates, reflecting actual 2022 cost data, plus forecasted revenue requirements associated with projected PTF, Local Service and Schedule 12C capital additions for 2023 and 2024, as well as the Annual True-up including associated interest. The PTO AC stated that the annual updates result in a Pool "postage stamp" RNS Rate of $154.35/kW-year effective Jan. 1, 2024, an increase of $12.71 /kW-year from the charges that went into effect on Jan. 1, 2023. In addition, the filing included updates to the revenue requirements for Scheduling, System Control and Dispatch Services (the Schedule 1 formula rate), which result in a Schedule 1 charge of $1.95 kW-year (effective June 1, 2023 through May 31, 2024), a $0.20/kW-year increase from the Schedule 1 charge that last went into effect on June 1, 2023.

[41] For purposes of this proceeding, "Consumer Advocates" are the MA AG, CT OCC, NH OCA and RI Division.

[42] "Identified TOs" are the New England Transmission Owners with asset condition projects that are the focus of the MOPA Formal Challenge: CL&P, Maine Electric Power Company ("MEPCO"), NSTAR (East & West), National Grid, Public Service Company of New Hampshire ("PSNH"), Rhode Island Energy ("RI Energy"), and Vermont Transco LLC ("VTransco").

to the transmission charges under the MPD OATT. Comments on the Versant MPD OATT 2022 Annual Update Settlement Agreement were due on or before September 20, 2023; none were filed. The Versant MPD OATT 2022 Annual Update Settlement Agreement remains pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Transmission Rate Annual (2022-23) Update/Informational Filing (ER09-1532)**

RENEW Formal Challenge. RENEW's January 31, 2023 formal challenge ("Challenge") to the 2022/23 Update/Informational Filing[43] remains pending before the FERC. In the Challenge, RENEW asserted that (i) the TOs failed to provide adequate rate input information in the Annual Informational Filing and in the Information Exchange Period under the Interim Formula Rate Protocols regarding inclusion or exclusion of "O&M costs" on Network Upgrades that the TOs directly assign to Interconnection Customers (and thereby failing to demonstrate that such O&M costs are not being double counted in transmission rates); and (ii) the TO's Interpretation of "Interested Party" to exclude RENEW violated the Interim Formula Rate Protocols. RENEW thus asked that the FERC (a) require the TOs to show the calculation of the annual O&M charges with sources of data inputs and show how such O&M charges are not being double recovered in transmission rates, and (b) determine that an entity such as RENEW is an Interested Party under the Interim Formula Rate Protocols and that its Information Requests seeking rate inputs and support for the O&M charges on Network Upgrades are within the scope of the Interim Formula Rate Protocols process. Comments on RENEW's Challenge were due on or before March 16, 2023. Comments and protests were filed by: Avangrid, Eversource, National Grid, Public Systems, RI Energy, Unitil, Versant Power, VTransco/GMP. On March 31, 2023, RENEW answered the comments and protests to its Challenge. Subsequently, on April 14, 2023, Eversource answered RENEW's March 31 answer. There has been no activity in this proceeding since Eversource's answer. This matter remains pending before the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

- **Waiver Request: Withdrawal from IEP and Return of IEP Net Revenues Received (Canal Marketing / Canal 3) (ER24-1407)**

On March 4, 2024 (as amended and supplemented on March 8 and March 22, 2024), Canal Marketing LLC (f/k/a Stonepeak Kestrel Energy Marketing LLC) ("CM") requested a one-time waiver of the provisions of Appendix K to Market Rule 1 (Inventoried Energy Program (the "IEP")) so as to permit CM to (i) withdraw CM's participation in the IEP on behalf of Canal 3 Generating LLC ("Canal 3")[44] for Winter 2023-24 and (ii) to return to ISO-NE the net revenues, with applicable interest, that CM received on behalf of Canal 3 for Canal 3's participation in the IEP for Winter 2023-2024 because Canal 3's return from a forced outage was delayed beyond the end of the IEP's Winter 2023-24 period.[45] CM explained that, when it elected to participate in the IEP on behalf of Canal 3 on September 21, 2023, CM anticipated that the Canal 3 Facility would be back in service by December 18, 2023, and would be

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[43] The 2022/23 annual filing reflected the charges to be assessed under annual transmission and settlement formula rates, reflecting actual 2021 cost data, plus forecasted revenue requirements associated with projected PTF, Local Service and Schedule 12C capital additions for 2022 and 2023, as well as the Annual True-up including associated interest. The formula rates in effect for 2023 included a billing true up of seven months of 2021 (June-Dec.). The Pool "postage stamp" RNS Rate, effective Jan. 1, 2023, was $140.94 /kW-year, a decrease of $1.84 /kW-year from the charges that went into effect the year prior. The updates to the revenue requirements for Scheduling, System Control and Dispatch Services (the Schedule 1 formula rate) resulted in a Schedule 1 charge of $1.75 kW-year (eff. June 1, 2022 through May 31, 2023), a $0.12/kW-year decrease from the Schedule 1 charge that last went into effect on June 1, 2022.

[44] Canal 3 is an approximately 333 MW (summer rating) gas- and oil-fired generation facility. Canal 3 has been on forced outage since Feb. 3, 2023, when a blade on the turbine wheel broke off and caused catastrophic damage to the gas turbine, which significantly impacted the compressor blades and bearings. As a result, the full train was disassembled and shipped to General Electric ("GE"), its manufacturer, for repair. GE initially provided a repair schedule that contemplated Canal 3's return to service by Dec. 15, 2023.

[45] At the time CM made its IEP election submission, CM anticipated that, based on information provided by GE, Canal 3 would be back on line by Dec. 18, 2023. CM informed ISO-NE in mid-December that forced outage of Canal 3 would continue until near the end of the IEP's Winter 2023-24 period, but no mechanism for a withdrawal from the IEP or the return of IEP payments received was identified.

available for the remainder of the IEP's Winter 2023-24 period. However, the actual return-to-service date for the Canal 3 Facility was delayed beyond the end of the IEP's Winter 2023-24 period and Canal 3 was not able to perform during the Winter 2023-24 period. CM seeks the requested waiver because no provision in Appendix K nor any other provision of the Tariff was identified as providing a mechanism for a Participant to withdraw from the IEP or to return IEP revenues to ISO-NE. Comments on the CM Waiver Request were due on or before March 25, 2024. The IMM submitted comments supporting the CM Waiver Request insofar as it requests the prompt repayment of the revenues received on behalf of Canal 3 under the IEP and, if determined to be warranted by the FERC, net of Program charges. NEPOOL (out-of-time) and National Grid intervened doc-lessly. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Waiver Request: OATT Schedule 22 § 3.4.1 (Interconnection Request Deposit Refund Deadline) (Moscow Dev. Co.) (ER24-1295)**

On February 14, 2024, Moscow Development Company, LLC ("MDC")[46] requested a one-time waiver of the 10-Business Day deadline in OATT Schedule 22 §3.4 (Valid Interconnection Request) to withdraw an Interconnection Request following its Scoping Meeting with ISO-NE (and then be entitled to the return of any remaining balance of the initial $50,000 deposit provided). MDC explained, and ISO-NE confirmed, that MDC did not receive complete information at the Scoping Meeting (specifically that development of its project would depend upon completion of the Third Maine Resource Integration Study ("3rd ME Cluster Study"), a condition that would lead to MDC withdrawing the interconnection request). Instead, ISO-NE provide MDC with the 3rd ME Cluster Study information 6 weeks after the Scoping Meeting. Upon receipt of the information, MDC withdrew its Interconnection Request, but after the deadlines set forth in Schedule 22 for the return of the deposit. MDC asserted that, had it received complete information at the Scoping Meeting, MDC would have withdrawn the project within the 10-Business Day deadline, and asks for a waiver of § 3.4 to permit it to receive the remainder of its interconnection request deposit. Comments on the Waiver were due on or before March 6, 2024. ISO-NE submitted comments on March 5, 2023 confirming the underlying facts and supporting the requested Waiver. NEPOOL intervened doc-lessly on March 6, 2024. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FRM Offer Cap and Data Publication Timeline Changes (ER24-1245)**

On February 14, ISO-NE and NEPOOL jointly filed changes to Market Rule 1 (i) to update the Forward Reserve Offer Cap ("FRM Offer Cap") to $7,100/MW-mo. and (ii) to delay FRM Offer Data publication for one year after each procurement period begins (to eliminate the potential for the previous year's Offer Data to influence current year offer formulations in an anti-competitive manner) (together, the "FRM Revisions"). Both Revisions are consistent with the IMM's recommendations in its 2023 Spring Quarterly Markets Report. The FRM Revisions were unanimously supported by the Participants Committee at its February 1, 2024 meeting (Agenda Item 6). ISO-NE requested an effective date of April 15, 2024, which will permit the FRM Revisions to take effect prior to the summer 2024 Forward Reserve Auction, which will open on April 17, 2024. Comments on this filing were due on or before March 6, 2024. Both the IMM and EMM submitted comments supporting the FRM Revisions. Calpine, Constellation, LS Power, National Grid, NEPGA, and the MA DPU filed doc-less interventions only. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **ISO/RTO Credit-Related Information Sharing (ER24-138)**

As previously reported, in response to the requirements of *Order 895*, ISO-NE and NEPOOL jointly filed, on October 18, 2023, changes to the Information Policy to (i) permit ISO-NE to share Market Participant, Transmission Customer and Applicant (collectively, "Participants") credit-related information with other ISO/RTOs; (ii) permit ISO-NE to use credit-related information received from other ISO/RTOs to the same extent and for the same

[46] MDC is a partnership between Cianbro Development Co., LLC and Patriot Renewables, LLC. MDC is developing its Radar Solar project on property owned by affiliated company Moscow Land Holdings, LLC.

purposes as ISO-NE is permitted under the Tariff with respect to its Participants; and (iii) require ISO-NE to keep such received credit-related information confidential in accordance with the Tariff, in each case for the purpose of credit risk management and mitigation (the "Credit Info Sharing Changes"). The Credit Info Sharing Changes were supported by the Participants Committee by way of the October 5, 2023 Consent Agenda (Item # 6). Comments on the Credit Info Sharing Changes were due on or before November 8, 2023; none were filed. National Grid intervened doc-lessly. There were no developments in this proceeding since the last Report and this matter remains pending before the FERC. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

In a lengthy compliance Order[47] issued March 1, 2023, the FERC approved in part, and rejected in part, ISO-NE, NEPOOL and the PTO AC's ("Filing Parties") *Order 2222* compliance filing[48] ("*Order 2222 Compliance Order*").[49] In the *Order 2222 Compliance Order*, the FERC directed a number of revisions and additional compliance and informational filings to be filed within 30, 60 or 180 days of the *Order 2222 Compliance Order.* As previously reported, the FERC accepted the 30-, 60- and 180-day compliance filings.[50] In the order conditionally accepting the 60-day compliance filing,[51] the FERC directed ISO-NE to submit a further compliance filing, on or before January 31, 2024, to comply with the directives of the *First Compliance Order* regarding the submission of DERA meter data.[52] The FERC also granted in part ISO-NE's request for an extension of time to address directives in the *First Order 2222 Compliance Order*.[53]

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[47] Commissioners Danly and Clements each provided separate concurrences with, and Commissioner Christie provided a separate dissent from, the *Compliance Order*. Commissioners Danly and Christie, despite their opposing positions on the Compliance Order, both reiterated their reasons for dissenting from *Order 2222* and concern for FERC overreach and difficulty with complying with *Order 2222*. In her separate concurrence, Commissioner Clements urged the ISO on compliance to "modify its proposal to address undue barriers and make participation more workable" and "to pursue steps that genuinely open [the New England Markets] to DERs like behind-the-meter resources."

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

[49] *ISO New England Inc. and New England Power Pool Participants Comm.*, 182 FERC ¶ 61,137 (Mar. 1, 2023) ("*First Order 2222 Compliance Order*").

[50] *ISO New England Inc.*, Docket Nos. ER22-983-003 and ER22-983-005 (Oct. 25, 2023) (unpublished letter order) ("*30/180-Day Order 2222 Compliance Order*"). The 30-Day compliance filings explained how current Tariff capacity market mitigation rules would apply to DECRs participating in FCA18 and provided an update on implementation timeline milestones associated with DECR participation in FCA18 and the other markets. The 180-Day compliance filing explained how the current Tariff capacity market mitigation rules would apply to DECRs participating in FCA19 and beyond and the Mar. 1, 2024 effective date for the rules allowing DECRs to participate in the FCM).

[51] *ISO New England Inc.*, 185 FERC ¶ 61,095 (Nov. 2, 2023) ("*Order 2222 60-Day Compliance Filing Order*").

[52] Specifically, the FERC directed ISO-NE to revise the Tariff to designate the DER Aggregator as the entity responsible for providing any required metering information to ISO-NE, and to require that each DER Aggregator maintain and submit aggregate settlement data for the DERA, so that ISO-NE can regularly settle with the DER Aggregator for its market participation. To the extent that ISO-NE proposes in that further compliance filing that metering data come from or flow through distribution utilities, the FERC directed ISO-NE to coordinate with distribution utilities and relevant electric retail regulatory authorities to establish protocols for sharing such metering data, and explain how such protocols minimize costs and other burdens and address concerns raised with respect to privacy and cybersecurity. *Id.* at P 34.

[53] The FERC ordered ISO-NE in its 60-day compliance filing to revise the Tariff to: (1) have RERRA make the determination of whether to allow customers of small utilities to participate in ISO-NE's markets through aggregation; (2) require that each DER Aggregator maintain and submit aggregate settlement data for the DERA; (3) designate the DER Aggregator as the entity responsible for providing any required metering information to ISO-NE, and if necessary, establish protocols for sharing meter data that minimize costs and other burdens and address concerns raised with respect to privacy and cybersecurity; (4) designate the DER Aggregator as the entity responsible

Request for Rehearing of Order 2222 60-Day Compliance Filing Order Deemed Denied By Operation of Law (-006). On December 4, 2023, AEU requested rehearing of the *Order 2222 60-Day Compliance Filing Order*. AEU asserted that the *Order 2222 60-Day Compliance Filing Order* is arbitrary and capricious because (i) it concludes, contrary to substantial record evidence, that ISO-NE's metering configurations do not pose an undue barrier to participation for most behind-the-meter DERs, and as such, are consistent with Order No. 2222; (ii) it fails to respond meaningfully to the arguments and record evidence submitted by AEU; (iii) it concludes that "ISO-NE satisfactorily discusses the steps that it contemplated and the less burdensome alternative approaches it considered" in connection with its metering proposal; (iv) it concludes that ISO-NE's description of submetering requirements for DERAs participating as Alternative Technology Regulation Resources ("ATRR") conforms to the FERC's orders; and (v) it concludes that ISO-NE's proposal to extend its existing requirements for Binary Storage Facilities ("BSF") and Continuous Storage Facilities ("CSF") to DERAs seeking to provide withdrawal service are consistent with *Order 2222*. On January 4, 2024, the FERC issued an Allegheny Notice, noting that AEU's request for rehearing may be deemed to have been denied by operation of law, but noting that AEU's request will be addressed in a future order.[54]

Federal Court (DC Circuit) Appeals. As previously reported, CMP and UI, National Grid, Eversource, and ISO-NE filed separate appeals of the *Order 2222 Compliance Order*. Those appeals have been consolidated (Case No. 23-1167) and are reported on in Section XVI below.

Further Compliance Changes (-007). As directed, on January 31, 2024, ISO-NE filed further compliance changes, which were related to the responsibilities for the provision of metering data and metering data submission deadlines for DERAs participating in New England Markets ("Further Compliance Changes"). The Further Compliance Changes were supported by the Participants Committee at its February 1, 2024 meeting. Comments on the Further Compliance Changes were due on or before February 21, 2024. On February 14, 2024, NEPOOL filed comments supporting the Further Compliance Changes. No other comments or protests were filed. The Further Compliance Changes are pending before the FERC.

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

IV. OATT Amendments / TOAs / Coordination Agreements

No Activities to Report

V. Financial Assurance/Billing Policy Amendments

No Activities to Report

for providing any required metering information to ISO-NE; and (5) add specificity regarding existing resource non-performance penalties that would apply to a DERA when a Host Utility overrides ISO-NE dispatch instructions. ISO-NE was also directed to: (1) identify the existing rules requiring a Market Participant that provides energy withdrawal service to be a load serving entity that is billed for energy withdrawal ("LSE Requirement") and explain whether the LSE Requirement is required of all resources seeking to provide wholesale energy withdrawal service in the energy market; (2) explain why its proposed metering and telemetry requirements were just and reasonable and did not pose an unnecessary and undue barrier to individual DERs joining a DERA; (3) establish protocols for sharing metering data that minimize costs and other burdens and address privacy and cybersecurity concerns; and (4) address how ISO-NE will resolve disputes that are within its authority and subject to its Tariff, regardless of whether there is an available dispute resolution process established by the RERRA.

[54] *ISO New England Inc.*, 186 FERC ¶ 62,002 (Jan. 4, 2023) ("*Order 2222 60-Day Compliance Filing Order Allegheny Notice*").

VI. Schedule 20/21/22/23 Changes & Agreements

- **Schedule 21-VP: Versant/Jonesboro LSA (ER24-24)**

As previously reported, the FERC accepted for filing a Local Service Agreement ("LSA") by and among Versant, ISO-NE, NE Renewable Power, and Jonesboro, LLC ("Jonesboro"), effective *December 4, 2023*, but denied waiver of the FERC's 60-day prior notice requirement for the filing.[55] The FERC found that the Filing Parties did not make the required showing of extraordinary circumstances to warrant waiver of the prior filing requirement. Accordingly, the FERC directed the Filing Parties (i) to refund the time value of revenues collected for the time period the rate was collected without FERC authorization, with refunds limited so as not to cause Filing Parties to operate at a loss ("Time Value Refunds"); and (ii) to file a refund report, including information supporting calculation of the Time Value Refunds.

Time Value Refunds Report. On December 18, 2023, Versant Power filed a refund report ("Report") detailing the Time Value Refunds it paid to NE Renewable Power and Jonesboro on December 15, 2023. Comments on the Report were due on or before January 8, 2024; none were filed. The Report remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-GMP: National Grid/Green Mountain Power LSA (ER23-2804)**

As previously reported, ISO-NE and New England Power ("National Grid", and together with ISO-NE, the "Filing Parties") filed on September 11, 2023, a 20-year LSA by and among National Grid, ISO-NE and Green Mountain Power ("GMP").[56] The Filing Parties stated that the LSA conformed to the *pro forma* LSA contained in the ISO-NE Tariff and superseded and replaced another conforming LSA among ISO-NE, National Grid, and GMP that listed an expiration date of September 30, 2022 (TSA-NEP-25). The Parties requested that the FERC grant waiver of its notice requirement[57] to the extent necessary to permit a requested October 21, 2022 effective date. The LSA was filed separately given that requested effective date.

LSA Accepted; Waiver of Prior Filing Requirement Denied; Time Value Refunds Ordered. Similar to the Versant/Jonesboro proceeding (*see* ER24-24 above), the FERC accepted the National Grid/GMP LSA for filing, effective *November 11, 2023*, but denied waiver of the FERC's 60-day prior notice requirement for the filing.[58] The FERC found that the Filing Parties did not make the required showing of extraordinary circumstances to warrant waiver of the prior filing requirement. Accordingly, the FERC directed the Filing Parties to make Time Value Refunds. On December 4, 2023, Filing Parties requested, and on December 6, 2023 the FERC granted, a 45-day extension of time (to January 22, 2024) to make the Time Value Refunds, with the corresponding refund report to be filed no later than February 21, 2024.

Time Value Refunds Report. On February 21, 2024, National Grid filed a refund report ("Report") detailing the Time Value Refunds National Grid paid to GMP on January 22, 2024. Comments on the Report were due on or before March 13, 2024; none were filed. The Report is pending before the FERC.

[55] *ISO New England Inc.*, Docket No. ER24-24-000 (Nov. 30, 2023) (unpublished letter order).

[56] The LSA was designated as Service Agreement No. TSA-NEP-114 under the ISO-NE OATT.

[57] 18 CFR § 35.11 (which permits, upon application and for good cause shown, the FERC to allow a rate schedule, tariff, service agreement, or a part thereof, to become effective as of a date prior to the date of filing or the date such change would otherwise become effective in accordance with the FERC's rules (e.g. 60 days after filing)). FERC policy is to deny waiver of the prior notice requirement when an agreement for new service is filed on or after the date that services commence, absent a showing of extraordinary circumstances.

[58] *ISO New England Inc.*, Docket No. ER23-2804-000 (Nov. 7, 2023) (unpublished letter order).

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

- **Schedule 21-VP: Versant/Black Bear LSAs (ER23-2035)**

On July 28, 2023, the FERC accepted seven fully executed, non-conforming LSAs by and among Versant Power, ISO-NE and Black Bear Hydro Partners, LLC or Black Bear SO, LLC (together with Black Bear Hydro Partners, "Black Bear").[59] The service agreements are based on the Form of Local Service Agreement contained in Schedule 21-Common under the ISO-NE OATT, but were filed because they are non-conforming insofar as they reflect different rates from those set forth in Schedule 21-VP. The LSAs were accepted for filing effective *August 1, 2023*, rather than January 1, 2021 as requested, triggering a Time Value Refund requirement.[60] On August 29, 2023, Versant Power submitted a Refund Report detailing the Time Value Refunds it paid to Black Bear Hydro Partners, LLC and Black Bear SO, LLC on August 18, 2023. Comments on the Refund Report were due on or before September 19, 2023; none were filed. The Refund Report remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-VP: 2022 Annual Update Settlement Agreement (ER20-2054-003)**

On August 29, 2023, Versant submitted a Joint Offer of Settlement ("Versant 2022 Annual Update Settlement Agreement") between itself and the MPUC. Versant stated that, if approved, the 2022 Annual Update Settlement Agreement would resolve all issues raised by the MPUC with respect to the 2022 Annual Update. Comments on the Versant 2022 Annual Update Settlement Agreement were due on or before September 19, 2023; none were filed. MPUC intervened doc-lessly on September 15, 2023. This matter remains pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activities to Report

VIII. Regional Reports[61]

- **Capital Projects Report - 2023 Q4 (ER24-1229)**

On February 9, 2024, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the fourth quarter ("Q4") of calendar year 2023 (the "Report"). ISO-NE is required to file the Report under section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights include the following new projects: (i) nGEM Real-Time Market Clearing Engine Implementation Phase I ($14.8 million); (ii) Managing Transmission Line Ratings ($7.7 million); (iii) CIP Electronic Security Perimeter Redesign Phase II ($5.2 million); and (iv) FCM Delivery Financial Assurance ($270,000). Two projects were reported to have significant changes (reductions in funds): IMM Data Analysis Phase IV (reduced by $288,800) and Settlement of Technology Improvements (reduced by $119,400). Comments on this filing were due on or before March 1, 2024. NEPOOL filed comments on February 13, 2024 supporting the 2023 Q4 Report. National Grid intervened doc-lessly. This matter is pending before the FERC. If

[59] *ISO New England Inc.*, Docket No. ER23-2035-000 (July 28, 2023) ("*Versant Black Bear LSAs Order*").

[60] The FERC denied the requested waiver of its 60-day prior notice requirement (18 C.F.R. § 35.11), finding that the Filing Parties did not make an adequate showing of extraordinary circumstances. Accordingly, Versant was required to refund the time value of revenues collected for the time period the rate was collected without FERC authorization (with refunds limited so as not to cause Vers ant to operate at a loss) and file a refund report with the FERC.

[61] Reporting on the *Opinion 531* Refund Reports (EL11-66) has been suspended and will be continued if and when there is new activity to report.

you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **ISO-NE FERC Form 715 (not docketed)**

On March 27, 2024, ISO-NE submitted its 2023 Annual Transmission Planning and Evaluation Report. These filings are not noticed for public comment.

IX. Membership Filings

- **April 2024 Membership Filing (ER24-1650)**

On March 29, 2024, NEPOOL requested that the FERC accept: (i) the following Applicants' membership in NEPOOL as of April 1, 2024: Eagle Creek Madison Hydro LLC [Related Person to Ontario Power Generation Inc.; Ontario Power Generation Energy Trading, Inc.; Brown Bear II Hydro, Inc., and Eagle Creek Renewable Energy Holdings LLC (Supplier Sector)] and Vineyard Offshore LLC (Generation Sector) and (ii) the termination as of March 1, 2024 of the Participant status of: Power Supply Services, LLC (AR Sector) and RPA Energy Inc. d/b/a Green Choice Energy (Supplier Sector). Comments on this filing, if any, are due on or before ***April 19, 2024***.

- **March 2024 Membership Filing (ER24-1369)**

On February 29, 2024, NEPOOL requested that the FERC accept: (i) the following Applicants' membership in NEPOOL as of March 1, 2024: DRW Energy Trading LLC [Related Person to Ebsen and Umber (Supplier Sector)]; Innovo Markets Inc. (GIS-Only Participant); OW North America LLC [Related Person to ENGIE (AR Sector) and Marble River (the EDP companies) (Supplier Sector)]; and Trailstone Renewables, LLC [Related Person to Talen Energy Marketing et al. (Supplier Sector)]; (ii) the Termination as of March 1, 2024 of the Participant status of: Transource New England, LLC (Provisional Group Member); and (iii) the name change of the following Participants: Canal Marketing LLC (f/k/a Stonepeak Kestrel Energy Marketing LLC); Excelsior Billerica, LLC (f/k/a Syncarpha Billerica, LLC); Excelsior Bondsville, LLC (f/k/a Syncarpha Bondsville, LLC); Excelsior Lexington, LLC (f/k/a Syncarpha Lexington, LLC). Comments on this filing were due on or before March 21, 2024; none were filed. This matter is pending before the FERC.

- **February 2024 Membership Filing (ER24-1062)**

On March 28, 2024, the FERC accepted: (i) the following Applicants' membership in NEPOOL: Agile Energy Trading LLC (Supplier Sector); Command Power Corp. (Supplier Sector); Eagle Creek Renewable Energy Holdings LLC [Related Person to Ontario Power Generation Inc.; Ontario Power Generation Energy Trading, Inc.; and Brown Bear II Hydro, Inc. (Supplier Sector)]; and Ocean State Power, LLC [Related Person to Jericho Power *et al.* (AR Sector, RG Sub-Sector)] and (ii) the termination of the Participant status of Community Eco Power, LLC (AR Sector, RG Sub-Sector, Small RG Group Seat); MPower Energy LLC (Supplier Sector); Pixelle Energy Services LLC (Generation Sector); Power Ledger Pty Ltd (GIS-Only Member); Union Atlantic Electricity (Supplier Sector); and Utility Services of Vermont LLC [Related Person to ENE (Publicly Owned Entity Sector)].[62] Unless the March 28 order is challenged, this proceeding will be concluded.

[62] *New England Power Pool Participants Comm.*, Docket No. ER24-1062-000 (Mar. 28, 2024).

X. Misc. - ERO Rules, Filings; Reliability Standards[63]

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).

- **NERC Glossary of Terms Revisions (RD24-6)**

On March 8, 2024, NERC filed proposed revisions to definitions in its Glossary of Terms[64] used in the NERC Reliability Standards. The revisions (2 new, 30 modified, and 4 retired terms)[65] define, or are related to, the components of Reporting Area Control Error ("ACE"). NERC requested the changes to be effective on the first day of the first calendar quarter that is twelve (12) months after approval. Comments on this filing are due on or before ***April 10, 2024***. Thus far, Ameren Services Company has intervened doc-lessly.

- **Revised Reliability Standard: EOP-012-2 (RD24-5)**

On February 16, 2024, NERC filed proposed Reliability Standard EOP-012-2 (Extreme Cold Weather Preparedness and Operations) to provide a comprehensive framework of requirements addressing cold weather planning and operations ("Freeze Protection Standards"). NERC stated that EOP-012-2 would improve upon the approved, but not yet effective, EOP-012-1 by clarifying the applicability of standard's requirements for generator cold weather preparedness, further defining the circumstances under which a Generator Owner may declare that constraints preclude them from implementing one or more corrective actions to address freezing issues, and shorting the implementation timeline so cold weather reliability risks would be addressed more quickly. EOP-012-2 also reflects additional improvements that would address the recommendations of the FERC, NERC, and Regional Entity Staff Joint Inquiry into the causes of the February 2021 cold weather event affecting Texas and the south-central United States. Comments on EOP-012-2 were due on or before March 21, 2024. The ISO/RTO Council ("IRC"), including ISO-NE, protested the proposed Standard citing various issues and concerns regarding the effectiveness of the Freeze Protection Standards as a winterization standard.[66] NEPGA submitted comments supporting the goals of the Freeze Protection Standards, and while it did not specifically protest or challenge the proposed Freeze Protection Standards, submitted comments requesting that the FERC encourage ISO-NE to work with affected Generator Owners to ensure that the Tariff allows for cost recovery of compliance costs (which, absent changes, it doubted could be achieved currently). On April 2, 2024, EPSA submitted comments supporting NEPGA's comments, urging the FERC to "survey the markets within its jurisdiction to determine whether there are

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[63] Reporting on the following ERO Reliability Standards or related rule-making proceedings has been suspended since the last Report and will be continued if and when there is new activity to report: NERC Report on Evaluation of Physical Reliability Standard (CIP-014) (RD23-2); *Order 901*: IBR Reliability Standards (RM22-12); and 2024 Reliability Standards Development Plan (RM05-17 *et al.*).

[64] The "Glossary" is a comprehensive list that reflects all of the defined terms used in Reliability Standards that have been adopted by the NERC Board of Trustees. The Glossary is updated through the Reliability Standards development process, and changes to the Glossary are sometimes proposed independent of proposed changes to Reliability Standards, as is the case in this proceeding. The Glossary is available on NERC's website.

[65] ***New Glossary Terms***: ACE Diversity Interchange and Inadvertent Interchange Management; ***Modified Glossary Terms***: Actual Net Interchange; ACE; Automatic Generation Control; Automatic Time Error Correction; Balancing Authority Area; Balancing Contingency Event; Control Performance Standard; Disturbance; Dynamic Interchange Schedule or Dynamic Schedule; Frequency Bias Setting; Frequency Error; Implemented Interchange; Inadvertent Interchange; Interchange Meter Error; Operating Reserve – Spinning; Operating Reserve – Supplemental; Overlap Regulation Service; Pseudo-Tie; Ramp Rate or Ramp; Regulation Service; Reportable Balancing Contingency Event; Reporting Area Control Error; Reserve Sharing Group; Reserve Sharing Group Reporting ACE; Scheduled Frequency; Scheduled Net Interchange; Supplemental Regulation Service; Tie Line Bias; Time Error; and Time Error Correction; ***Retired Glossary Terms***: Disturbance Control Standard; Net Interchange Schedule; Net Scheduled Interchange; and Reportable Disturbance.

[66] The IRC urged the FERC to direct NERC to revise the standard to: exclude cost-based constraint criteria from the standard itself, recognizing that the issue needs to be addressed through other avenues in the regulatory process; use effective facility performance as a benchmark instead of relying on vague references to "general industry practice"; eliminate language that is vague, unauditable, and susceptible to multiple interpretations by different Generator Owners; narrow the proposed exemptions for existing generating units; shorten and clarify the periods allotted for implementation of freeze protection measures; eliminate grandfathering provisions so that the same enhanced winterization standard applies to all affected generating units regardless of commercial operation date; require annual reviews of declared Generator Cold Weather Constraints; and add timing specificity for required inspections and maintenance.

sufficient vehicles for cost recovery should NERC's Freeze Protection Standards be approved. If there is a determination that any market does not have sufficient cost recovery pathways in place, the Commission should take action to remedy these issues ahead of the time generators would need to take action in order to meet the effective date of the proposed standard. Doc-less interventions have been filed by Dominion (timely) and out-of-time by Avangrid Renewables, Calpine, PA PUC, and TAPS. This matter is pending before the FERC.

- **Revised Reliability Standard: CIP-012-2 (RD24-3)**

On January 31, 2024, NERC filed proposed Reliability Standard CIP-012-2 (Cyber Security – Communications between Control Centers) to improve upon and expand the protections required by Reliability Standard CIP-012-1 by requiring Responsible Entities to mitigate the risk posed by loss of availability of communication links and Real-time Assessment and Real-time monitoring data transmitted between Control Centers. Proposed Reliability Standard CIP-012-2 modifies CIP-012-1 by adding two new Parts to Requirement R1 to address availability: Part 1.2, which requires protections for the availability of data in transit; and Part 1.3, which requires protections to initiate recovery of lost (i.e., unavailable) communication links. Comments on CIP-012-2 were due on or before February 21, 2024; none were filed. This matter is pending before the FERC.

- **NERC Cold Weather Data Collection Plan (RD23-1-002)**

Also on February 16, 2024, NERC filed, in response to the requirements of the *Cold Weather Standards Order*,[67] its plan to gather and analyze certain data related to generator owner declared constraints and the performance of freeze protection measures during future extreme cold weather events ("NERC Cold Weather Data Collection Plan") to be included in each October 1 annual information filing, the first of which will be submitted on October 1, 2025. Comments on the Cold Weather Data Collection Plan were due on or before March 12, 2024; none were filed. This matter is pending before the FERC.

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

As previously reported, NERC is required to file on an informational basis quarterly status updates regarding the development of new or modified Reliability Standards pertaining to virtualization and cloud computing services. NERC submitted its most recent informational filing regarding one active CIP standard development project (Project 2016-02 – Modifications to CIP Standards ("Project 2016-02"))[68] on March 13, 2024. Project 2016-02 focuses on modifications to the CIP Reliability Standards to incorporate applicable protections for virtualized environments. In the March 13 report, NERC reported that the schedule for Project 2016-02 has been further revised slightly and now calls for final balloting of revised standards in April (rather than March) 2024; NERC Board of Trustees Adoption is still scheduled for May 2024 and filing of the revised standards with the FERC in **June 2024**.

- **NERC 2024 Standards Report (RR09-6)**

On March 22, 2024, NERC filed its 2024 Standards Report, Status and Timetable for Addressing Regulatory Directives summarizing the progress made and plans for addressing the reliability standard-related directives issued by the FERC. NERC reported that since March 27, 2023, the date of NERC's last annual report, (i) the FERC issued eight new directives, (ii) it filed petitions with the FERC addressing six directives, and that (iii) currently, there are 13 outstanding directives, 7 of which NERC is addressing through standards development projects. These filings are not noticed for public comment.

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[67] *N. Am. Elec. Rel. Corp.*, 182 FERC ¶ 61,094 (Feb. 16, 2023) ("*Cold Weather Standards Order*"), *reh'g denied*, 183 FERC ¶ 62,034 (Apr. 20, 2023), *order addressing arguments raised on reh'g*, 183 FERC ¶ 61,222 (June 29, 2023).

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

- **RTO Recommendations for Gas-Electric Coordination**

On February 21, 2024, ISO-NE, MISO, PJM, and SPP ("Joint RTOs") released "*Strategies for Enhanced Gas Electric Coordination: A Blueprint for National Progress*," a paper recommending potential initiatives that could help enhance the reliability of gas-electric coordination. Joint RTOs put forth a range of immediate- and near-term initiatives aimed at enhancements to the gas market, RTO operations, and coordination between state and federal regulators. The Joint RTOs identify specific recommendations along with suggested specific action steps to be undertaken respectively by the RTOs; gas producers, marketers, and pipelines; and/or federal and state regulators corresponding to each recommendation.

XI. Misc. - of Regional Interest

- **203 Application: Eversource/ GIP IV (EC24-59)**

On March 13, 2024, North East Offshore, LLC, Revolution Wind, LLC, South Fork Wind, LLC (together with North East Offshore and Revolution Wind, the "Companies"), and GIP IV Whale Fund Holdings, L.P. ("GIP Whale") requested FERC authorization for a proposed transaction pursuant to which GIP Whale and/or one more of its affiliates would acquire Eversource Investment, LLC's interests in the Companies (the "Proposed Transaction"). After the Proposed Transaction, GIP Whale will acquire: (1) Eversource Investment's 50 percent interest in North East Offshore and will thereby also indirectly acquire a 50 percent interest in Revolution Wind; and (2) Eversource Investment's 50 percent Class B interest in South Fork Class B and will thereby also indirectly acquire an indirect interest in South Fork Wind. Comments on this 203 application were due on or before April 3, 2024; none were filed. Public Citizen filed a doc-less motion to intervene. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: GIP/BlackRock (EC24-58)**

On March 12, 2024, Global Infrastructure Management, LLC ("GIM") d/b/a Global Infrastructure Partners, on behalf of investment funds sponsored by GIM that own public utility subsidiaries, and BlackRock, Inc. requested authorization for a transaction pursuant to which BlackRock Funding Inc. will acquire 100% of the LLC interests in GIM and thereby an indirect controlling interest in the GIM public utility subsidiaries, including, among others, Clearway Power Marketing and GennConn Energy. Following an errata notice, comments on this 203 application are due on or before ***May 13, 2024***. Thus far, interventions have been filed by PJM, the PJM IMM, the Private Equity Stakeholder Project,[69] and Public Citizen. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Three Corners Solar/Three Corners Prime Tenant (EC23-90)**

On July 28, 2023, the FERC authorized[70] the disposition and consolidation of jurisdictional facilities and the lease of an existing generation facility that will result from the commencement of a master lease agreement ("Lease") between Three Corners Solar, LLC ("Lessor") and Three Corners Prime Tenant, LLC ("Lessee") pursuant to which Lessee will lease, operate, and control an approximately 112 MWac solar photovoltaic ("PV") electric generation facility owned by Lessor in Kennebec County, Maine (the "Transaction"). Pursuant to the July 28 order, Lessor and Lessee must file a notice within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

[69] The Private Equity Stakeholder Project states that it supports stakeholders impacted by private equity firms and similar private asset managers. *See* https://pestakeholder.org/.

[70] *Three Corners Solar, LLC and Three Corners Prime Tenant, LLC*, 184 FERC ¶ 62,060 (Jul. 28, 2023).

- **203 Application: Energy Harbor / Vistra (EC23-74)**

On February 16, 2024, nearly 10 months after it was first asked, the FERC conditionally authorized[71] a proposed transaction pursuant to which Energy Harbor, LLC and Energy Harbor Nuclear Generation LLC (collectively, the "Energy Harbor Public Utilities") and certain Vistra subsidiaries that are public utilities[72] (together with the Energy Harbor Public Utilities, "Applicants") will become indirectly owned by a newly-formed subsidiary holding company of Vistra – Vistra Vision, subject to Vistra's commitment to divest its Richland and Stryker generating facilities ("Divestiture Transaction") and Applicants' commitment to implement interim mitigation until the proposed divestiture is completed, including the use of cost-based offers and offer caps for sales from Richland-Stryker, and the engagement of an independent entity to oversee compliance and to prepare quarterly reports that Applicants will file with the FERC. Applicants were directed, among other things, to submit an informational filing in this docket to notify parties to this proceeding when the Divestiture Transaction is consummated, as well as the usual notice within 10 days of consummation of the transaction authorized in this proceeding. On March 7, 2024, Applicants notified the FERC that the transaction authorized in this proceeding was consummated on March 1, 2024. As a result, Energy Harbor LLC became a Related Person to Dynegy Marketing and Trade, LLC (Supplier Sector). Reporting on this transaction is now complete. If you have any remaining questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **PURPA Enforcement Petition – Allco Finance Ltd/CT DEEP (EL24-95)**

On March 27, 2024, Allco Finance Limited ("Allco") petitioned the FERC to initiate an enforcement action against the Connecticut Department of Energy and Environmental Protection ("CT DEEP") to remedy what it asserts is CT DEEP's improper implementation of section 210 of PURPA. Allco asked the FERC to (i) invalidate and permanently enjoin the Shared Clean Energy Facility program's 50 MW volumetric cap, (ii) invalidate and permanently enjoin the CT DEEP from implementing Conn. Gen. Stat. §§ 16a-3f, 16a-3g, 16a-3j, and 16a-3m, which compel CL&P and UI to procure energy from zero carbon resources that have a 5 MW or greater nameplate capacity rating and participate in the New England Markets, (iii) invalidate and permanently enjoin the CT DEEP from implementing solicitations for off-shore wind facilities and/or nuclear facilities, and (iv) to permanently enjoin the CT DEEP from regulating wholesale sales except as permitted by PURPA. Comments on the filing are due on or before ***April 17, 2024***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **EPC Cancelation – CMP/FPL Wyman (ER24-1510)**

On March 15, 2024, CMP filed a Notice of Termination of its Engineering and Procurement Agreement with FPL Energy Wyman, LLC ("FPL Wyman"). CMP reported that the notice was being filed because it had completed the services set forth in the Agreement. CMP requested a March 15, 2024 effective date for the termination notice. Comments on the filing are due on or before ***April 5, 2024***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA – ISO-NE/CMP/Andro Hydro (ER24-1477)**

On March 13, 2024, ISO-NE and CMP filed a non-conforming LGIA to govern the interconnection of Andro Hydro, LLC's 27.57 MW hydro facility, which interconnects to the Jay Substation. The LGIA is non-conforming in that it contains limited deviations from the Schedule 22 *pro forma* LGIA that are necessary to reflect unique characteristics of Andro Hydro's proposed interconnection, including the interconnection of its facility through shared facilities co-owned, and used by, JGT2 Redevelopment LLC to serve its own load. A February 12, 2024 effective date was requested. Comments on the LGIA filing were due on or before April 3, 2024; none were filed.

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[71] *Energy Harbor Corp. and Vistra Corp.*, 186 FERC ¶ 61,129 (Feb. 16, 2024).

[72] The following Vistra subsidiaries were identified as public utilities: Ambit Northeast; Conn. Gas & Elec.; Dynegy Energy Services; Dynegy Energy Services (East); Energy Rewards; Energy Services Providers; Everyday Energy; Mass. Gas & Elec.; Public Power; Public Power (PA); Public Power & Utility of NY; Public Power & Utility of Maryland; Everyday Energy NJ; TriEagle Energy; Viridian Energy; Viridian Energy NY; Viridian Energy PA; Viridian Energy Ohio; Moss Landing Energy Storage 1; Moss Landing Energy Storage 2; and Moss Landing Energy Storage.

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

- **LGIA – ISO-NE/NSTAR/MMWEC (ER24-1238)**

On February 12, 2024, ISO-NE and NSTAR filed a non-conforming LGIA to govern the interconnection of MMWEC's existing Large Generating Facility and the Surplus Interconnection of MMWEC's new 6.9 MW solar generating facility, both of which are located in Ludlow, MA. The LGIA is non-conforming in that it includes a fourth party, the Surplus Interconnection Customer, and also contains non-conforming changes that are necessary in light of MMWEC's representations regarding its ability to meet the indemnification requirement. A January 10, 2024 effective date was requested. Comments on the LGIA filing were due on or before March 4, 2024; 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).

- **RFA – PSNH/NECEC (ER24-1210)**

On February 8, 2024, PSNH filed a Related Facilities Agreement ("RFA") to set forth the terms and conditions under which it will construct Related Facilities in its New Hampshire service territory to allow the reliable interconnection of NECEC Transmission's Project. A February 9, 2024 effective date was requested. Comments on the RFA filing were due on or before March 1, 2024; none were filed. National Grid filed a doc-less motion to intervene. 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).

- **CMP ESF Rate (ER24-1177)**

On April 1, 2024, the FERC accepted, subject to refund and settlement judge procedures, CMP's rate schedule for distribution services for electric storage facilities ("ESFs") seeking to participate in the ISO-NE Market ("ESF Rate").[73] As previously reported, CMP filed the ESF Rate following re-consideration by the MPUC of the jurisdictional applicability of the ESF rate (which, while it recovers costs associated with the use of local the distribution network, the MPUC found upon re-consideration to include charges related to a FERC-jurisdictional wholesale transaction per *Order 841*). CMP sought in this proceeding to obtain FERC approval of a modified version of the MPUC Rate, with the primary difference between the MPUC Rate and the ESF Rate being the removal of state benefit charges. In the *CMP ESF Rate Order*, the FERC found that CMP's filing had not been shown to be just and reasonable, and raised issues of material fact that could not be resolved based on the record and would be more appropriately addressed in hearing and settlement judge procedures.[74] Accordingly, the FERC accepted the filing, subject to refund, and established hearing and settlement judge procedures. The FERC denied CMP's request for waiver of the FERC's 60-day prior notice requirement, and accepted the ESF Rate effective April 2, 2024, though, as noted, subject to refund and hearing and settlement judge procedures.[75] The FERC encouraged efforts to reach settlement before hearing procedures commence and will hold the hearing in abeyance pending the outcome of settlement judge procedures. The FERC directed that a settlement judge be appointed.[76] If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Facilities Support Agreement – NSTAR/Hingham (ER24-1175)**

On March 29, 2024, the FERC accepted a Facilities Support Agreement filed by NSTAR to cover the design, engineering, construction, ownership, operation, and maintenance, at Hingham's expense, of a new switching station on land owned by NSTAR in Weymouth, MA and new connections to NSTAR's 115 kilovolt Line #478-502,

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[73] *Central Maine Power Co.,* 187 FERC ¶ 61,002 (Apr. 1, 2024) ("*CMP ESF Rate Order*").

[74] *Id.* at P 29.

[75] *Id*.

[76] *Id.* at P 30.

part of a solution designed to address a reliability concern identified in Hingham's service territory.[77] The Facilities Support Agreement was accepted effective as of February 9, 2024, as requested. Unless the March 29 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).

- **IA Cancellation Versant / PERC (ER24-965)**

On January 22, 2024, Versant filed a notice of cancellation of an Interconnection Agreement ("IA") between itself and Penobscot Energy Recovery Company ("PERC"). Versant reported that PERC discontinued operations of an approximately 25 MW solid waste-fired generating facility that interconnected to its Orrington Substation. The facility was later sold to C&M Faith Holdings LLC, and is no longer connected or operating. Comments on the notice of cancellation are due on or before February 12, 2024; none were filed. On February 12, PERC intervened doc-lessly. On February 29, 2024, Versant Power asked that the FERC take no action on the filed notice of cancellation prior to ***May 1, 2024***, in order to allow Versant and the new owner of the PERC facility, which may wish to reenergize the facility and assume the IA, to agree to a course of action. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Viridon Incentive Rate Treatments (ER24-771)**

On March 21, 2024, the FERC granted the request by Viridon New England LLC,[78] an affiliate of Blackstone Inc., to utilize three incentive rate treatments – (i) a regulatory asset incentive, (ii) a hypothetical capital structure of 60% equity and 40% debt until the first transmission project awarded to Viridon is placed into service, and at that time, VNE will begin to use its actual capital structure, and (iii) an RTO participation incentive[79] – for the development of transmission projects within the New England region. The FERC also authorized future Viridon subsidiaries created to own or develop specific transmission assets in New England to use the same rate incentives without re-litigation. Unless the *Viridon Incentive Rate Treatment 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).

- **E&P Agreement 2d Amendment: Seabrook/NECEC Transmission (ER24-508)**

On March 22, 2024, the FERC accepted a second amendment to the Engineering and Procurement ("E&P") Agreement between Seabrook and NECEC Transmission LLC ("NECEC") (the "A&R E&P Agreement").[80] As previously reported, the A&R E&P Agreement covers the final engineering drawings through the procurement and delivery of the 24.5 kV generator circuit breaker and ancillary equipment to Seabrook Station in advance of the Fall 2024 outage, and the second amendment seeks approximately $2 million in additional funding to cover higher engineering costs as well as changes to the scope of work related to a hydraulic controller, the generator breaker monitoring system, and other items. Unless the March 22 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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[77] *NSTAR Elec. Co.*, Docket No. ER24-1175-000 (Mar. 29, 2024) (unpublished letter order).

[78] *Viridon New England LLC*, 186 FERC ¶ 61,205 (Mar. 21, 2024) ("*Viridon Incentive Rate Treatment Order*").

[79] Specifically, the incentive rate treatments for which authorization is sought are (i) recovery of all prudently incurred pre-commercial, start-up and formation costs, and establishment of a regulatory asset that will include all expenses that are incurred prior to the rate year in which Viridon's costs are first flowed through to customers under the Tariff, including authorization to accrue carrying charges and to amortize the regulatory asset over five years for cost recovery purposes ("Regulatory Asset Incentive"); (ii) use of a hypothetical capital structure of 40% debt and 60% equity until the first transmission project awarded to Viridon achieves commercial operation ("Hypothetical Capital Structure Incentive"); and (iii) inclusion of a 50 basis-point return on equity ("ROE") adder to the base ROE ("RTO Participation Incentive") in recognition that Viridon has committed to turn over functional control of all transmission assets it develops and owns to ISO-NE. Viridon states that it will become a transmission-owning member of ISO-NE at the earliest possible date permitted under the Tariff and governing documents and will transfer functional control of any transmission project to ISO-NE once such project is placed in service.

[80] *NextEra Energy Seabrook, LLC*, Docket No. ER24-508-001 (Mar. 22, 2024) (unpublished letter order).

XII. Misc. - Administrative & Rulemaking Proceedings[81]

- **Joint Federal- State Current Issues Collaborative (AD24-7)**

On March 21, 2024, the FERC issued an order establishing a Federal and State Current Issues Collaborative ("Collaborative").[82] The Collaborative will be the successor to the Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force" or "JFSTF"),[83] which by design will expire on November 10, 2024 (3 years from its first public meeting). The FERC stated that the Collaborative will provide a venue for federal and state regulators to share perspectives, increase understanding, and, where appropriate, identify potential solutions regarding challenges and coordination on matters that impact specific state and federal regulatory jurisdiction, including (but not limited to) the following: electric reliability and resource adequacy; natural gas-electric coordination; wholesale and retail markets; new technologies and innovations; and infrastructure. The Collaborative will similarly be comprised of all FERC Commissioners as well as representatives from 10 state commissions, who will be nominated for and serve one-year terms from the date of appointment by the FERC. The FERC will issue notices announcing the time, place and agenda for each meeting of the Collaborative, after consulting with members of the Collaborative and considering suggestions from state commissions. Collaborative meetings will be on the record, and open to the public for listening and observing. The FERC expects that the first public meeting of the Collaborative will be held in the Fall of 2024. The Collaborative will expire 3 years after its first public meeting, but may be extended for an additional period of time prior to its expiration by agreement of both FERC and NARUC.

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

Since the last Report, in the *Order Establishing Collaborative* summarized immediately above, the FERC noted that JFSTF will expire on ***November 10, 2024***, and February 28, 2024 was its last meeting.[84] Absent further activity, reporting on AD21-15 is now concluded.

- **NOPR: EQR Filing Process and Data Collection (RM23-9)**

On October 19, 2023, the FERC issued a NOPR[85] proposing various changes to current Electric Quarterly Report ("EQR") filing requirements, including both the method of collection and the data being collected. The proposed changes are designed to update the data collection, improve data quality, increase market transparency, decrease costs, over time, of preparing the necessary data for submission, and streamline compliance with any future filing requirements. Among other things, the FERC proposes to implement a new collection method for EQR reporting based on the eXtensible Business Reporting Language ("XBRL")-Comma-Separated Values standard; amend its regulations to require ISO/RTOs to produce reports containing market participant transaction data; and

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[81] Reporting on the following Administrative proceedings have been suspended since the last Report and will be continued if and when there is new activity to report: ACPA Petition for Capacity Accreditation Technical Conference (AD23-10); and Reliability Technical Conference (AD23-9).

[82] *Joint Federal-State Task Force on Elec. Transmission and Federal and State Current Issues Collaborative*, 186 FERC ¶ 61,189 (Mar. 21, 2024) ("*Order Establishing Collaborative*").

[83] *Joint Federal-State Task Force on Electric Transmission*, 175 FERC ¶ 61,224 (June 18, 2021). The Transmission Task Force is comprised of all FERC Commissioners as well as representatives from 10 state commissions (two from each NARUC region). State commission representatives will serve one-year terms from the date of appointment by FERC and in no event will serve on the Task Force for more than three consecutive terms. The Transmission Task Force will convene multiple formal meetings annually, with FERC issuing orders fixing the time and place and agenda for each meeting, and the meetings will be open to the public for listening and observing and on the record. The Transmission Task Force will focus on "topics related to efficiently and fairly planning and paying for transmission, including transmission to facilitate generator interconnection, that provides benefits from a federal and state perspective." New England is represented by Commissioners Riley Allen (VT PUC) and Marissa Gillett (Chair, CT PURA). *See* Order on Nominations, *Joint Federal-State Task Force on Elec. Trans.*, 180 FERC ¶ 61,030 (July 15, 2022).

[84] *Order Establishing Collaborative* at P 3.

[85] *Revisions to the Filing Process and Data Collection for the Electric Quarterly Report*, 185 FERC ¶ 61,043 (Oct. 19, 2023) ("*EQR NOPR*").

modify or clarify EQR reporting requirements. Requests for additional time to comment on the *EQR NOPR* were filed by EEI/EPSA, the IRC and the Bonneville Power Administration ("BPA"). On December 7, 2023, the FERC extended the deadline for submitting comments to and including February 26, 2024. Comments on the NOPR were filed by ISO-NE, CAISO, MISO, NYISO, PJM, BPA, EEI, Energy Compliance Consulting, EPSA, Interstate Gas Supply, Macquarie, PG&E, Systrends, Tri-State, XBRL US. This matter is pending before the FERC.

- ***Orders 2023 and 2023-A*: Interconnection Reforms (RM22-14)**

Order 2023. On July 28, 2023, the FERC issued *Order 2023*,[86] its final rule on proposed reforms to the *pro forma* Large Generator Interconnection Procedures ("LGIP"), *pro forma* Small Generator Interconnection Procedures ("SGIP"), *pro forma* Large Generator Interconnection Agreement ("LGIA"), and *pro forma* SGIA to address interconnection queue backlogs, improve certainty, and prevent undue discrimination for new technologies. *Order 2023* adopts reforms to: (i) implement a first-ready, first-served cluster study process;[87] (ii) increase the speed of interconnection queue processing;[88] and (iii) incorporate technological advancements into the interconnection process.[89] Many of the reforms adopted in *Order 2023* closely track the reforms set out in the

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[86] *Improvements to Generator Interconnection Procedures and Agreements*, Order No. 2023, 184 FERC ¶ 61,054 (July 28, 2023) ("*Order 2023*").

[87] A first-ready, first-served cluster study process improves efficiency in the interconnection study process by including the following elements: increased access to information prior to entering the queue; a mechanism to study interconnection requests in groups where all interconnection requests in the group are equally queued and of equal study priority; and increased financial commitments and readiness requirements to enter and proceed through the queue. In contrast, the existing first-come, first-served serial study process in the *pro forma* LGIA and LGIP provides limited information to interconnection customers prior to entering the queue, assigns interconnection requests an individual queue position based solely on the date of entry into the queue, and contains limited financial and readiness requirements.

In order to implement a first-ready, first-served cluster study process, *Order 2023* requires: (1) transmission providers to publicly post available information pertaining to generator interconnection; (2) transmission providers to use cluster studies as the interconnection study method; (3) transmission providers to allocate cluster study costs on a pro rata and per capita basis; (4) transmission providers to allocate network upgrade costs based on a proportional impact method; (5) interconnection customers to pay study and commercial readiness deposits as part of the cluster study process; (6) interconnection customers to demonstrate site control at the time of submission of the interconnection request; and (7) transmission providers to impose withdrawal penalties on interconnection customers for withdrawing from the interconnection queue, with certain exceptions. We also require transmission providers to adopt a transition process to move from the existing serial interconnection process to the new cluster study process.

[88] In order to increase the speed of interconnection queue processing, *Order 2023*: (1) eliminates the reasonable efforts standard for conducting interconnection studies and imposes a financial penalty on transmission providers that fail to meet interconnection study deadlines; and (2) establishes an affected system study process and associated *pro forma* affected system agreements.

[89] In order to incorporate technological advancements into the interconnection process, *Order 2023* requires transmission providers to: (1) allow more than one generating facility to co-locate on a shared site behind a single point of interconnection and share a single interconnection request; (2) evaluate the proposed addition of a generating facility at the same point of interconnection prior to deeming such an addition a material modification if the addition does not change the originally requested interconnection service level; (3) allow interconnection customers to access the surplus interconnection service process once the original interconnection customer has an executed LGIA or requests the filing of an unexecuted LGIA; (4) use operating assumptions in interconnection studies that reflect the proposed charging behavior of an electric storage resource; and (5) evaluate the list of alternative transmission technologies enumerated in this final rule during the generator interconnection study process.

FERC's Notice of Proposed Rulemaking.[90] However, the FERC did revise aspects of the reforms.[91] *Order 2023* became effective November 6, 2023[92] (60 days from its publication in the *Federal Register* ("Publication Date")).

A more detailed summary of, and a presentation on, *Order 2023* was provided to, and discussed with, the Transmission Committee. Compliance will require changes to the Tariff's *pro forma* LGIA, LGIP, SGIA and SGIP. Absent further changes to the compliance schedule, there will be much to accomplish in a relatively short amount of time.

Requests for Clarification and/or Rehearing. Requests for rehearing, clarification and/or an extension of time were filed by 35 parties. Those parties raised, among other issues, the following:

- The FERC erred in removing the Reasonable Efforts standard and imposing penalties for late studies;
- The FERC must clarify aspects of the transition process and use of Transitional Cluster Studies and Transitional Serial Studies;
- Transmission Providers need additional details on the FERC's requirement for Transmission Provider's to publish heatmaps;
- The FERC must provide insight on the process of performing cluster studies as well as the cost allocation methodology; and
- Transmission Providers require further clarity regarding the alternative transmission technologies that they are required to review.

Requests for Clarification and/or Rehearing Denied by Operation of Law. On September 28, 2023, the FERC issued a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration".[93] The *Order 2023 Allegheny Notice* confirmed that the 60-day period during which a petition for review of *Order 2023* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing and/or clarification of *Order 2023* within the required 30-day period. The Notice also indicated that the FERC would address, as is its right, the rehearing request in a future order, and may modify or set aside its order, in whole or in part, "in such manner as it shall deem proper." The FERC issued that order, *Order 2023-A*, on March 21, 2024 (*see* immediately below). Several parties submitted petitions in Federal Court challenging *Order 2023*. Developments in those federal court proceedings will be summarized in Section XVI below.

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[90] *Order 2023* also requires: (i) interconnection customers requesting to interconnect a non-synchronous generating facility to: (a) provide the transmission provider with the models needed for accurate interconnection studies; and (b) have the ability to maintain power production at pre-disturbance levels and provide dynamic reactive power to maintain system voltage during transmission system disturbances and within physical limits; (ii) all newly interconnecting large generating facilities provide ride through capability consistent with any standards and guidelines that are applied to other generating facilities in the balancing authority area on a comparable basis; and (iii) with respect to the *pro forma* SGIP and *pro forma* SGIA, the incorporation of enumerated alternative transmission technologies into the interconnection process, and the provision of modeling and ride through requirements for non-synchronous generating facilities.

[91] Reforms revised in *Order 2023* pertain to the cluster study process, allocation of cluster study and network upgrade costs, increased financial commitments and readiness requirements, financial penalties for delayed interconnection studies, the affected system study process, pro forma affected system agreements, the material modification process, operating assumptions for interconnection studies, incorporating the enumerated alternative transmission technologies, and ride through requirements. In addition, the FERC declined to adopt the NOPR proposals pertaining to informational interconnection studies, shared network upgrades, the optional resource solicitation study, and the alternative transmission technologies annual report.

[92] *Order 2023* was published in the Fed. Reg. on Sep. 6, 2023 (Vol. 88, No. 171) pp. 61,041-61,349.

[93] *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 62,163 (Sep 28, 2023) ("*Order 2023 Allegheny Notice*").

Order 2023-A. On March 21, 2024, the FERC issued *Order 2023-A*[94] addressing arguments raised on rehearing of *Order 2023*. *Order 2023-A* set aside, in part, and clarified *Order 2023*. Among other things, in *Order 2023-A* the FERC:

- upheld its prior determination that eliminating the Reasonable Efforts Standard with firm steady deadlines was "warranted as part of a package of comprehensive reforms to address interconnection queue delays and backlogs;"[95]

- denied several requests for rehearing or clarification regarding the transition process, including requests to revise the deposit amounts and withdrawal penalty amounts for the transitional process;[96]

- declined to revise the eligibility date for participation in a transitional cluster study or set a size threshold for the transitional cluster study;[97]

- declined to clarify whether transmission providers may use Energy Resource Interconnection Service ("ERIS") or Network Resource Interconnection Service ("NRIS") assumptions for public heatmaps, rather than just NRIS, but provided that a transmission provider may propose on compliance an option for heatmap users to view results using ERIS assumptions in addition to NRIS assumptions;[98]

- declined requests to revisit the requirement that transmission providers evaluate the list of alternative transmission technologies and noted that as long as a transmission provider has evaluated the list, it has complied with Order 2023 and affirmed its prior decision not to include dynamic line ratings or storage-as-a-transmission-asset on the list of alternative transmission technologies.[99]

Due to breadth of the issues addressed in *Order 2023-A*, the FERC extended the *Order 2023* compliance filing deadline until 30 days after the date *Order 2023-A* is published in the *Federal Register* which, as of the date of this Report, has not yet occurred. A more fulsome summary from NEPOOL Counsel of the Order was distributed to, and was reviewed with, the Transmission Committee at the March 27, 2024 TC Meeting. ISO-NE's Order 2023 Revisions were unanimously supported at the March 7 Participants Committee meeting, but are not to be filed until closer to the as-yet-to-be-determined updated compliance filing deadline.

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

- **NOPR: Transmission Siting (RM22-7)**

On December 15, 2022, the FERC issued a NOPR[100] proposing to revise its regulations governing applications for permits to site electric transmission facilities under section 216 of the FPA, as amended by the

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[94] *Improvements to Generator Interconnection Procedures and Agreements*, 186 FERC ¶ 61,199 (Mar. 21, 2024) ("*Order 2023-A*").

[95] *Id.* at P 280.

[96] *Id.* at P 257.

[97] *Id.*

[98] *Id*. at P 95.

[99] *Id*. at P 615.

[100] *Applications for Permits to Site Interstate Elec. Transmission Facilities*, 181 FERC ¶ 61,205 (Dec. 15, 2022) ("*Transmission Siting NOPR*").

Infrastructure and Jobs Act. The *Transmission Siting NOPR* is intended to ensure consistency with the Infrastructure and Jobs Act's amendments to FPA section 216, to modernize certain regulatory requirements, and to incorporate other updates and clarifications to provide for the efficient and timely review of permit applications. Following a NARUC request for an extension of time granted by the FERC, comments on the *Transmission Siting NOPR* were due on or before May 17, 2023. Comments were filed by CLF, AL PSC, National Wildlife Federation Action Fund, National Wild Life Federation and State-Affiliated Organizations, AEU, CLF (May 16), NESCOE, ACPA, ACRE, Clean Energy Buyers Assoc., EDF, EEI/WIRES, Joint Consumer Advocates, Public Interest Organizations, SEIA, and US Chamber of Commerce. Commissioner Phillips' and each of the Commissioners' responses to Senator Schumer's and Senator Barrasso's letters have been posted to eLibrary. This matter is pending before the FERC.

- **NOPR: Compensation for Reactive Power Within the Standard Power Factor Range (RM22-2)**

On March 21, 2024, the FERC issued a NOPR[101] proposing revisions to Schedule 2 of the *pro forma* OATT, § 9.6.3 of the *pro form* LGIA, and § 1.8.2 of the *pro forma* SGIA to prohibit separate compensation to generators for the provision of reactive power within the standard power factor range or "deadband."[102] The proposed change may affect revenues received by reactive power resources in New England.[103] The NOPR seeks comments on, among other issues, the following:

(i) The reliability impact of prohibiting transmission providers from including in their transmission rates any charges associated with the supply of reactive power within the standard power factor range from a generating facility in regions where generating facilities currently receive such compensation;

(ii) Whether, and if so how, the elimination of separate reactive power payments will affect generating facilities' ability to recover their costs in the markets that currently provide reactive power compensation within the standard power factor range;

(iii) Whether, and if so how, eliminating separate reactive power compensation within the standard power factor range may affect investment decisions to build, or finish building, generation facilities, and whether, and if so how, the elimination could otherwise affect generators' business decisions in those markets; and

(iv) If the FERC allows existing generation resources that have previously received compensation for reactive power supply to continue to receive compensation for a limited period while prohibiting new generation resources from receiving reactive power compensation, how should it determine eligibility for continued compensation in a manner that is just and reasonable and not unduly discriminatory or preferential.[104]

Initial comments on the *Reactive Power NOPR* are due ***May 27, 2024***; reply comments, ***June 26, 2024***.[105] NEPOOL Counsel prepared a summary of the NOPR which was distributed to, and was reviewed with, the Transmission Committee at the March 27, 2024 TC Meeting.

[101] *Compensation for Reactive Power Within the Standard Power Factor Range*, 186 FERC ¶ 61,203 (Mar. 21, 2024) ("*Reactive Power NOPR*").

[102] *Reactive Power NOPR* PP 51-53.

[103] Generating facilities in New England are compensated for reactive power under a flat, inflation-adjusted rate design.

[104] *Id.* at PP 47, 49, 56.

[105] The *Reactive Power NOPR* was published in the Fed. Reg. on Mar. 28, 2024 (Vol. 89, No. 61) pp. 21,454-21,468.

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

Following its ANOPR process,[106] the FERC issued on April 21, 2022 a NOPR[107] that would require public utility transmission providers to:

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

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

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

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

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

In addition, the *Transmission NOPR* would not permit public utility transmission providers to take advantage of the construction-work-in-progress ("CWIP") incentive for regional transmission facilities selected for purposes of cost allocation through long-term regional transmission planning and would permit the exercise of federal rights of first refusal ("ROFR") for transmission facilities selected in a regional transmission plan for purposes of cost allocation, conditioned on the incumbent transmission provider with the federal ROFR for such regional transmission facilities establishing joint ownership of the transmission facilities. While the ANOPR sought comment on reforms related to cost allocation for interconnection-related network upgrades, interconnection queue processes, interregional transmission coordination and planning, and oversight of transmission planning and costs, the *Transmission NOPR* does not propose broad or comprehensive reforms directly related to these topics. The FERC indicated that it would continue to review the record developed to date and expects to address possible inadequacies through subsequent proceedings that propose reforms, as warranted, related to these topics.

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

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[106] *See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 176 FERC ¶ 61,024 (July 15, 2021) ("*Transmission Planning & Allocation/Generation Interconnection ANOPR*"). The FERC convened a tech. conf. on Nov. 15, 2021, to examine in detail the issues and potential reforms described in the *ANOPR*. Speaker materials and a transcript of the tech. conf. are posted in FERC's eLibrary. Pre-technical conference comments were submitted by over 175 parties, including by: NEPOOL, ISO-NE, AEU, Anbaric, Avangrid, BP, CPV, Dominion, EDF, EDP, Enel, EPSA, Eversource, Exelon, LS Power, MA AG, MMWEC, National Grid, NECOS, NESCOE, NextEra, NRDC, Orsted, Shell, UCS, VELCO, Vistra, Potomac Economics, ACORE, ACPA/ESA, APPA, EEI, ELCON, Industrial Customer Orgs, LPPC, MA DOER, NARUC, NASUCA, NASEO, NERC, NRECA, SEIA, State Agencies, TAPS, WIRES, Harvard Electric Law Initiative; NYU Institute for Policy Integrity, New England for Offshore Wind Coalition, and the R Street Institute. *ANOPR* reply comments and post-technical conference comments were filed by over 100 parties, including: by: CT AG, Acadia Center/CLF, CT AG, Dominion, Enel, Eversource, LS Power, MA AG, MMWEC, NESCOE, NextEra, Shell, UCS, Vistra, ACPA/ESA, AEU, APPA, EEI, ELCON, Environmental and Renewable Energy Advocates, EPSA, Harvard ELI, NRECA, Potomac Economics, and SEIA. Supplemental reply comments were filed by WIRES, a group of former military leaders and former Department of Defense officials, and ACPA/AEU/SEIA.

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

Comments. Following a number of requests for extensions of time, comments on the *Transmission NOPR* were due August 17, 2022.[108] Nearly 200 sets of comments were filed, including comments by NEPOOL, ISO-NE, Acadia/CLF, Anbaric, AEU, Avangrid, BP, Dominion, Enel, Engie, Eversource, Invenergy, LSP Power, MOPA, MMWEC/CMEEC/NHEC/VPPSA, National Grid, NECOES, NESCOE, NextEra, NRG, Onward Energy, Orsted, PPL, Shell, Transource, VELCO, Vistra, ISO/RTO Council, NERC, US DOJ/FTC, MA AG, State Agencies, VT PUC/DPS, Potomac Economics, ACPA, ACRE, APPA, EEI, EPSA, Industrial Customer Organizations, LPPC, NASUCA, NRECA, Public Interest Organizations, SEIA, TAPS, WIRES, Harvard Electricity Law Initiative, New England for Offshore Wind, and the R Street Institute.

Reply Comments. Reply comments were due September 19, 2022. Nearly 100 sets of reply comments were filed, including by: ISO-NE, AEU, Anbaric, Avangrid, CT DEEP, Cypress Creek, Dominion, ENGIE, Eversource, Invenergy, LS Power, MA AG, NECOS, NESCOE, NextEra, Shell, Transource, UCS, ACPA, ACRE, APPA, EEI, Industrial Customer Organizations, LPPA, NRECA, Public Interest Organizations, R Street, and SEIA. On November 28, 2022, the New Jersey BPU moved to lodge its recently issued Board Order selecting transmission projects to be built pursuant to PJM's State Agreement Approach ("SAA") for the purpose of supporting New Jersey's offshore wind ("OSW") goals, the Brattle Group's SAA Evaluation Report, and PJM's SAA Economic Analysis Report, which it stated demonstrates that competitive transmission solicitations can provide significant value to consumers. In December 2022, the Harvard Electricity Law Initiative, and P. Alaama submitted further comments.

LS Power and NRG filed comments in this proceeding, as well as in (Transmission Planning and Cost Management Joint Federal-State Task Force on Electric Transmission) (AD22-8) and JFSTF proceeding (AD21-15). They asserted that the FERC "cannot sufficiently address the transmission planning issues raised in its Transmission NOPR without addressing the intertwined cost management issues raised in AD22-8-000 and during the October 6, 2022 Technical Conference in AD22-8." Additional comments were filed by ACRE, Breakthrough Energy, Clean Energy Buyers Association, the Cross Sector Coalition, Developers Advocating Transmission Advancements, Environmental Advocates,[109] Institute for Policy Integrity at NYU, Rocky Mountain Institute, EEI, ELCON, Niskanen Center, WIRES, and a number of individuals and organizations urging the FERC to finalize the *Transmission NOPR*. The Harvard Electricity Law Initiative responded to WIRES' comments.

Since the Last Report, NESCOE filed a motion requesting that the FERC reject late-filed comments. In the alternative, if the FERC accepts those comments, NESCOE asked that the FERC accept its supplemental comments that were also included with their March 20 motion.

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

[108] A July 27, 2022, request by the Georgia Public Service Commission ("GA PUC") for an additional 30 days of time to submit comments and reply comments was denied on Aug. 9, 2022.

[109] The "Environmental Advocates" included: AEU, ACPA, Clean Air Task Force, Earthjustice, Environmental Defense Fund, Evergreen Action, Fresh Energy, Interwest Energy Alliance, League of Conservation Voters, National Wildlife Federation, NRDC, Northwest Energy Coalition, Rewiring America, Sierra Club, Southern Environmental Law Center, The Environmental Law & Policy Center, UCS, WE ACT for Environmental Justice, and Western Resource Advocates.

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- **Smart One Energy, LLC (IN23-13)**

On March 12, 2024, the FERC approved a Stipulated and Consent Agreement[110] with Smart One Energy, LLC ("Smart One"). The Agreement resolves a non-public investigation into whether Smart One violated NYISO's Tariff by failing to timely inform NYISO, in its April 2020 and April 2021 credit questionnaire submission, of material changes its financial status, including sanctions imposed upon it by the Maryland Public Service Commission and Virginia State Corporation Council in 2019 and 2020 (answering "N/A" where prompted to list any sanctions "involving the Applicant/Customer, guarantor (if applicable), Principals, or traders of Applicant/ Customer imposed by the SEC, FERC, CFTC, any state or provincial entity responsible for regulating activity in energy markets… where such sanctions were … imposed in the past seven years"). (Smart One exited the NYISO markets in August 2021). Under the Agreement, in which Smart One neither admits nor denies the alleged violations, Smart One agreed to pay a ***civil penalty of $5,000*** to the US Treasury. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

Natural Gas-Related Enforcement Actions

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

Procedural Schedule Suspended. As previously reported, on May 24, 2022, the Honorable Judge Karen Gren Scholer of the U.S. District Court for the Northern District of Texas ("Northern District") issued an order staying this proceeding. Consistent with that order and out of an abundance of caution, ALJ Joel DeJesus, who will be the presiding judge for hearings in this matter,[111] suspended the procedural schedule until such time as the Court's stay is lifted and the parties provide jointly a proposed amended procedural schedule.

On June 14, 2023, the Commission issued an Order on Presiding Officer Reassignment,[112] which (i) directed the Chief ALJ to reassign this proceeding to another ALJ not previously involved in the proceeding (i.e., designate a new presiding officer) once the *June 14 Order* takes effect; (ii) held that the *June 14 Order* will take effect once the Northern District clarifies or lifts its stay for the limited purpose of allowing the *June 14 Order* to take effect or the stay is lifted or dissolved such that hearing procedures may resume; and (iii) stated that this proceeding otherwise remains suspended until the Northern District's stay is lifted or dissolved such that hearing procedures may resume.

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

On December 16, 2021, the FERC issued a show cause order[113] in which it directed Rover and ETP (together, "Respondents") to show cause why they should not be found to have violated NGA section 7(e), FERC Regulations (18 C.F.R. § 157.20); and the FERC's Certificate Order,[114] by: (i) intentionally including diesel fuel and other toxic substances and unapproved additives in the drilling mud during its horizontal directional drilling

[110] *Smart One Energy, LLC,* 186 FERC ¶ 61,181 (Mar. 12, 2024).

[111] See *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.*, 178 FERC ¶ 61,028 (Jan. 20, 2022) ("*Rover/ETP Hearings Order*"). The hearings will be to determine whether Rover Pipeline, LLC ("Rover") and its parent company Energy Transfer Partners, L.P. ("ETP" and collectively with Rover, "Respondents") violated section 157.5 of the FERC's regulations and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.

[112] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 183 FERC ¶ 61,190 (June 14, 2023) ("*June 14 Order*").

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

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

("HDD") operations under the Tuscarawas River in Stark County, Ohio, in connection with the Rover Pipeline Project;[115] (ii) failing to adequately monitor the right-of-way at the site of the Tuscarawas River HDD operation; and (iii) improperly disposing of inadvertently released drilling mud that was contaminated with diesel fuel and hydraulic oil. The FERC directed Respondents to show why they should not be assessed civil penalties in the amount of ***$40 million***.

On March 21, 2022, Respondents answered and denied the allegations in the *Rover/ETP CPCN Show Cause Order*. On April 20, 2022, OE Staff answered Respondents' March 21 answer. On May 13, Respondents submitted a surreply, reinforcing their position that "there is no factual or legal basis to hold either [Respondent] liable for the intentional wrongdoing of others that is alleged in the Staff Report." The FERC denied Respondents' request for rehearing of the FERC's January 21, 2022 designation notice.[116] This matter is pending before the FERC.

- **Total Gas & Power North America, Inc. et al. (IN12-17)**

On April 28, 2016, the FERC issued a show cause order[117] 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.[118]

The FERC also directed TGPNA to show cause why it should not be required to disgorge unjust profits of ***$9.18 million***, plus interest; TGPNA, Tran and Hall to show cause why they should not be assessed civil penalties (TGPNA - ***$213.6 million***; Hall - ***$1 million*** (jointly and severally with TGPNA); and Tran - ***$2 million*** (jointly and severally with TGPNA)). In addition, the FERC directed TGPNA's parent company, Total, S.A. ("Total"), and TGPNA's affiliate, Total Gas & Power, Ltd. ("TGPL"), to show cause why they should not be held liable for TGPNA's, Hall's, and Tran's conduct, and be held jointly and severally liable for their disgorgement and civil penalties based on Total's and TGPL's significant control and authority over TGPNA's daily operations. Respondents filed their answer on July 12, 2016. OE Staff replied to Respondents' answer on September 23, 2016. Respondents answered OE's September 23 answer on January 17, 2017, and OE Staff responded to that answer on January 27, 2017.

Hearing Procedures. On July 15, 2021, the FERC issued and order establishing hearing procedures to determine whether Respondents violated the FERC's Anti-Manipulation Rule, and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.[119] On July 27, 2021, Chief Judge Cintron designated Judge Suzanne Krolikowski as the Presiding ALJ and established an extended Track III Schedule for the proceeding.

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

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

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

[118] The allegations giving rise to the Total Show Cause Order were laid out in a September 21, 2015 FERC Staff Notice of Alleged Violations which summarized OE's case against the Respondents. Staff determined that the Respondents violated NGA section 4A and the Commission's Anti-Manipulation Rule by devising and executing a scheme to manipulate the price of natural gas in the southwest United States between June 2009 and June 2012. Specifically, Staff alleged that the scheme involved making largely uneconomic trades for physical natural gas during bid-week designed to move indexed market prices in a way that benefited the company's related positions. Staff alleged that the West Desk implemented the bid-week scheme on at least 38 occasions during the period of interest, and that Tran and Hall each implemented the scheme and supervised and directed other traders in implementing the scheme.

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

Discovery in this case closed on December 2, 2022. On December 16, 2022, Respondents filed for a preliminary injunction in the US District Court for the Southern District of Texas ("Southern District"). In order to allow for briefing and a decision on that motion, the FERC placed this proceeding in abeyance.[120]

On June 14, 2023, the Commission issued an Order on Presiding Officer Reassignment,[121] which (i) directed the Chief ALJ to reassign this proceeding to another ALJ not previously involved in the proceeding (i.e., designate a new presiding officer) once the *TGPNA Presiding Officer Reassignment Order* takes effect; (ii) held that the *TGPNA Presiding Officer Reassignment Order* will take effect once the Southern District clarifies or lifts its stay for the limited purpose of allowing the *TGPNA Presiding Officer Reassignment Order* to take effect or the stay is lifted or dissolved such that hearing procedures may resume; (iii) stated that this proceeding otherwise remains suspended until the Southern District's stay is lifted or dissolved such that hearing procedures may resume; and (iv) provided procedural guidance to the new presiding officer. On July 18, Judge Patricia M. French was substituted as Presiding Judge (relieving Judge Krolikowski of all of her duties with respect to this proceeding).

XIV. Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com).

New England Pipeline Proceedings

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

- **Iroquois ExC Project (CP20-48)**
  - 125,000 Dth/d of incremental firm transportation service to ConEd and KeySpan by building and operating new natural gas compression and cooling facilities at the sites of four existing Iroquois compressor stations in Connecticut (Brookfield and Milford) and New York (Athens and Dover).
  - Three-year construction project; service request by November 1, 2023.
  - On March 25, 2022, after procedural developments summarized in previous Reports, the FERC issued to Iroquois a certificate of public convenience and necessity, authorizing it to construct and operate the proposed facilities.[122] The certificate was conditioned on: (i) Iroquois' completion of construction of the proposed facilities and making them available for service within ***three years*** of the date of the; (ii) Iroquois' compliance with all applicable FERC regulations under the NGA; (iii) Iroquois' compliance with the environmental conditions listed in the appendix to the order; and (iv) Iroquois' filing written statements affirming that it has executed firm service agreements for volumes and service terms equivalent to those in its precedent agreements, prior to commencing construction. The March 25, 2022 order also approved, as modified, Iroquois' proposed incremental recourse rate and incremental fuel retention percentages as the initial rates for transportation on the Enhancement by Compression Project.
  - On April 18, 2022, Iroquois accepted the certificate issued in the *Iroquois Certificate Order*.
  - On June 17, 2022, in accordance with the *Iroquois Certificate Order,* Iroquois submitted its Implementation Plan, documenting how it will comply with the FERC's Certificate conditions.
    - In its March 8, 2024 monthly status report, Iroquois indicated that it is still awaiting issuance of air permits from the New York State Department of Environmental Conservation ("NYDEC") and the CT DEEP. Iroquois noted that the public comment period on the NY DPS reliability and

[120] *Total Gas & Power North America, Inc., Total, S.A., Total Gas & Power, Ltd., Aaron Hall, and Therese Tran f/k/a Nguyen*, 181 FERC ¶ 61,252 (Dec. 21, 2022).

[121] *Total Gas & Power North America, Inc., Total, S.A., Total Gas & Power, Ltd., Aaron Hall, and Therese Tran f/k/a Nguyen*, 183 FERC ¶ 61,189 (June 14, 2023) ("*TGPNA Presiding Officer Reassignment Order*").

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

needs determination, noticed by NYDEC was open until March 29, 2024. Iroquois has still not yet requested or received authorization to commence construction; accordingly, no construction activities were undertaken in February 2024 and no construction was planned for March 2024.

XV. State Proceedings & Federal Legislative Proceedings

No activities to report.

XVI. Federal Courts

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

- **Order 2023 (23-1282 (AEU); 23-1284 (MISO); 23-1289 (PacificCorp); 23-1293 (FPL); 23-1297 (SPP); 23-1299 (PJM); 23-1305 (FirstEnergy); 23-1310 (NYISO); 23-1312 (Dominion); 23-1313 (Exelon); 23-1320 (MISO TOs); 23-1327 (Avangrid); 23-1330 (Central Hudson); 23-1346 (PacifiCorp)) (consolidated)**
  Underlying FERC Proceeding: RM22-14[123]
  Petitioners: AEU et al.
  Status: Being Held In Abeyance; Motions to Govern Future Proceedings Due Apr 16, 2024

Several Petitioners have challenged *Order 2023*. Those challenges have now been consolidated, with the AEU docket (23-1282) as the lead docket. Most recently, on February 15, 2024, the FERC asked that the consolidated cases continue to be held in abeyance pending further order of the court. In response, on February 20, 2024, the Court granted the request for continued abeyance, directing the parties to file motions to govern future proceedings in these consolidated proceedings by ***April 16, 2024***.

- ***Order 2222*** **Compliance Orders (23-1167, 23-1168, 23-1169, 23-1170, 23-1335)(consolidated)**
  Underlying FERC Proceeding: ER22-983[124]
  Petitioners: Eversource, ISO-NE, National Grid, and CMP/UI
  Status: Being Held In Abeyance

On June 30, 2023, ISO-NE (23-1168), CMP/UI (23-1170), Eversource (23-1167), and National Grid (23-1169) petitioned the DC Circuit Court of Appeals for review of the FERC's orders related to the FERC's *Order 2222 Compliance Orders*.[125] On July 3, 2023, the Court consolidated the cases, with Case No. 23-1667 as the lead case.

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[123] *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,054 (July 28, 2023) ("*Order 2023*"); 184 FERC ¶ 62,163 (Sep. 28, 2023) (Notice of Denial of Rehearing by Operation of Law).

[124] *ISO New England Inc. and New England Power Pool Participants Comm.*, 182 FERC ¶ 61,137 (Mar. 1, 2023) ("*Order 2222 Compliance Order*"); *ISO New England Inc. and New England Power Pool Participants Comm.*, 183 FERC ¶ 62,050 (May 1, 2023) ("*Order 2222 Compliance Allegheny Notice*", and together with the *Order 2222 Compliance Order*, the "*Order 2222 Compliance Orders*").

[125] In response to the region's *Order 2222 Changes*, the FERC directed a number of revisions and additional compliance and informational filings to be filed within 30, 60 or 180 days of the *Order 2222 Compliance Order*, as described in previous Reports. When filed, the Filing Parties stated that the *Order 2222 Changes* create a pathway for Distributed Energy Resource Aggregations ("DERAs") to participate in the New England Markets by: creating new, and modifying existing, market participation models for DERA use; establishing eligibility requirements for DERA participation (including size, location, information and data requirements); setting bidding parameters for DERAs; requiring metering and telemetry arrangements for DERAs and individual Distributed Energy Resources ("DERs"); and providing for coordination with distribution utilities and relevant electric retail regulatory authorities ("RERRAs") for DERA/DER registration, operations, and dispute resolution purposes.

On July 24, 2023, the FERC moved to have the consolidated cases held in abeyance pending the issuance of the Commission's further order on rehearing. The Court granted that motion on July 27, 2023, with the case to be held in abeyance pending further order of the Court. Since the last Report, the Court granted the FERC's latest motion to continue to hold cases in abeyance, directing (i) the FERC to file status reports at 60-day intervals beginning on ***April 8, 2024***; and (ii) the parties to file motions to govern future proceedings within 14 days of the expiration of the period for filing a petition for review of the FERC's forthcoming order on reh'g of its November 2023 order in ER22-983.

- **Seabrook Dispute Order (23-1094, 23-1215) (consolidated)**
  Underlying FERC Proceeding: EL21-6, EL 23-3[126]
  Petitioner: NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC
  Status: Oral Argument Held Feb 6, 2024; Case Pending Before the Court

On April 4, 2023, NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC (collectively, "NextEra") petitioned the DC Circuit Court of Appeals for review of the FERC's orders related to the Seabrook Dispute.[127] NextEra subsequently petitioned the Court for review of the June 15, 2023 *Seabrook Dispute Allegheny Order*, which was consolidated with Case No. 23-1094. Briefing is completed. Oral argument was heard on February 6, 2024 by Judges Millett, Katsas and Rao. This matter is pending before the Court.

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[126] *NextEra Energy Seabrook, LLC and NECEC Transmission LLC and Avangrid, Inc. v. NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC*, 182 FERC ¶ 61,044 (Feb. 1, 2023) *("Seabrook Dispute Order")*, *reh'g denied by operation of law*, *NextEra Energy Seabrook, LLC et al.*, 183 FERC ¶ 62,001 (Apr. 3, 2023) ("*Seabrook Dispute Allegheny Notice*"); *NextEra Energy Seabrook, LLC et al.*, 183 FERC ¶ 61,196 (June 15, 2023) ("*Seabrook Dispute Allegheny Order*").

[127] In the Seabrook Dispute Order, the FERC (i) both denied and granted in part the Seabrook Complaint; (ii) dismissed the Seabrook Declaratory Order Petition; and (iii) directed Seabrook to replace the Seabrook Station breaker pursuant to its obligations under the Seabrook LGIA and Good Utility Practice. Specifically, the FERC denied the Seabrook Complaint in part because it found that Avangrid had "not shown that Seabrook is obligated to replace the breaker due to Seabrook failing to meet certain open access obligations or because Seabrook has failed to comply with Schedule 25 of the ISO-NE Tariff". However, the FERC found that, "under Seabrook's LGIA, Seabrook may not refuse to replace the breaker because it is needed for reliable operation of Seabrook Station and required by Good Utility Practice" and thus, given the specific facts and circumstances in the record, granted the Seabrook Complaint in part. With respect to cost issues, the FERC agreed with Avangrid that, in this case, Seabrook should not recover opportunity costs (e.g. lost profits, lost revenues, and foregone Pay for Performance ("PFP") bonuses) or legal costs. In dismissing the Declaratory Order Petition, the FERC noted that the issues raised in the Petition were addressed in the Seabrook Dispute Order, that additional findings were unnecessary, and thus exercised its discretion to not take action on, and to dismiss, the Petition. The breaker replacement is currently expected to take place during the Fall 2024 refueling outage and the commercial operation date for the NECEC Project is December 2024. Seabrook plans to file an agreement governing installation at the earlier of 30 days prior to delivery of the breaker or 120 days prior to the start of the Fall 2024 outage. The FERC noted its expectation that such an agreement would resolve whatever remaining issues exist between the parties to allow replacement of the breaker to move forward during the 2024 outage, or if not, an unexecuted agreement would be filed.

- **Mystic II (ROE & *True*-Up)**
  (21-1198; 21-1222, 21-1223, 21-1224, 22-1001, 22-1008, 22-1026) (consolidated)
  Underlying FERC Proceeding: EL18-1639-010, -011,[128] -013[129] -017[130]
  Petitioners: Mystic, CT Parties,[131] MA AG, ENECOS
  Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due Apr 24, 2024

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

As previously reported, on July 8, 2022, Connecticut Parties and ENECOS jointly moved to hold these proceedings in abeyance until 30 days after the DC Circuit issued an opinion in *MISO Transmission Owners v. FERC*, 16-1325 ("*MISO TOs"*). They requested abeyance on the basis that the consolidated petitions in this proceeding and *MISO TOs* both involve challenges to the FERC's ROE methodology (the FERC set the ROE used in calculating Constellation's rates using the methodology challenged in *MISO TOs*). Although Constellation opposed the abeyance request, the Court granted the abeyance request on July 27, 2022, directing the Parties to file motions to govern future proceedings within 30 days of the court's disposition of *MISO TOs*. The Court has since decided *MISO TOs*. However, the parties continue to agree that this case should remain in abeyance pending further proceedings related to MISO TOs, now on remand at the FERC. Most recently, on January 24, 2024, Constellation reported that all parties agree and asked the Court that this case should remain in abeyance for an additional 90 days pending FERC action on remand in the *MISO TOs* case. On January 25, 2024, the Court issued an order that these cases remain in abeyance and that the parties file motions to govern future proceedings by ***April 24, 2024***.

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Underlying FERC Proceeding: ER18-619[132]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
  Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due Mar 2, 2026

As previously reported, the Sierra Club, NRDC, RENEW Northeast, and CLF petitioned the DC Circuit Court of Appeals on August 31, 2020 for review of the FERC's order accepting ISO-NE's CASPR revisions and the FERC's subsequent *CASPR Allegheny Order*. Appearances, docketing statements, a statement of issues to be raised, and a statement of intent to utilize deferred joint appendix were filed. A motion by the FERC to dismiss the case was

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

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

[130] *Constellation Mystic Power, LLC*, 179 FERC ¶ 61,011 (Apr. 28, 2022) ("*Mystic First CapEx Info. Filing Order*"); *Constellation Mystic Power, LLC*, 179 FERC ¶ 62,179 (June 27, 2022) ("*June 27 Notice*") (Notice of Denial By Operation of Law of Rehearings of *Mystic First CapEx Info. Filing Order*).

[131] In this appeal, "CT Parties" are the CT PURA CT PURA, CT DEEP, and the CT OCC.

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

dismissed as moot by the Court, referred to the merits panel (Judges Pillard, Katsas and Walker), and is to be addressed by the parties in their briefs.

Petitioners have moved to hold this matter in abeyance now four times. In the most recent request (filed March 1, 2024) (fourth abeyance request), Petitioners asked the Court to hold this matter in abeyance until March 1, 2026 "in light of the continued delay of the revisions to its capacity market that ISO New England previously asserted were a predicate to eliminating the market impediment that is the subject of the underlying claims before the Court". The Court granted the request on May 12, 2024, ordering the parties to file motions to govern future proceedings by ***March 2, 2026***.

- ***Opinion 531-A*** **Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[133]
  Petitioners: TOs (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[134] petitioned the DC Circuit Court of Appeals for review of the FERC's October 6, 2017 order rejecting the TOs' filing that sought to reinstate their transmission rates to those in place prior to the FERC's orders later vacated by the DC Circuit's *Emera Maine*[135] decision. On September 22, 2020, the FERC submitted an unopposed motion to hold this proceeding in abeyance for four months to allow for the Commission to "a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the Court granted the FERC's motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021. On January 25, 2021, the FERC requested that the Court continue to hold this petition for review in abeyance for an additional three months, with parties to file motions to govern future proceedings at the end of that period. The FERC requested continued abeyance because of its intention to issue a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the FERC. Petitioners consented to the requested abeyance. On February 11, 2021, the Court issued an order that that this case remain in abeyance pending further order of the court. On April 21, 2021, the FERC filed an unopposed motion for continued abeyance of this case *because* the Commission intends to issue a future order on Petitioners' request for rehearing of the challenged *Order Rejecting Compliance Filing*, and because the remand proceeding in which the challenged order was issued remains ongoing.

On May 4, 2021, the Court ordered that this case remain in abeyance pending further order of the Court, directing the FERC to file a status report by September 1, 2021 and at 120-day intervals thereafter. The parties were directed to file motions to govern future proceedings in this case within 30 days of the completion of agency proceedings. The FERC's last status report, indicating that the proceedings before the Commission remain ongoing and that this appeal should continue to remain in abeyance, was filed on November 28, 2023.

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

[134] The "TOs" are CMP; Eversource Energy Service Co., on behalf of its affiliates CL&P, NSTAR and PSNH; National Grid; New Hampshire Transmission; UI; Unitil and Fitchburg; VTransco; and Versant Power.

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

Other Federal Court Activity of Interest

- ***Northern* Access *Project* (22-1233)**
  (consolidated with orders on improvements to a Texas LNG facility - 12-1235, 22-1267)
  Underlying FERC Proceeding: *CP15-115*[136]
  Petitioner: Sierra Club
  Status: Petition Denied March 29, 2024

On September 6, 2022, the Sierra Club petitioned the DC Circuit for review of *Northern Access Project Add'l Extension Order*, challenging the FERC's grant of further extensions of time to obtain the necessary permits for and to complete construction of the Northern Access Project. As previously reported, briefing was completed and oral argument before Judges Henderson, Pan and Rogers was held on September 18, 2023. On March 29, 2024, the Court denied Sierra Club's Petition,[137] finding the "FERC acted well within its discretion."

[136] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 179 FERC ¶ 61,226 (June 29, 2022) ("*Northern Access Project Add'l Extension Order*").

[137] *Sierra Club v. FERC*, No. 22-1233 (D.C. Cir. 2024).

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