



December 28, 2021

VIA ELECTRONIC FILING

Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

**Re: ISO New England Inc. and New England Power Pool,
Docket No. ER22- -000; Transmission Planning Improvements**

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act,¹ ISO New England Inc. (the “ISO”) joined by the New England Power Pool (“NEPOOL”) Participants Committee² (together, the “Filing Parties”), hereby jointly³ submit proposed Tariff revisions to improve the competitive transmission planning process in New England (“Transmission Planning Improvements”). The Tariff changes proposed in this filing are supported by the testimony of Brent Oberlin (the “Oberlin Testimony”).⁴

The ISO conducted the region’s first competitively developed transmission solicitation process from December 2019 to July 2020 (“Boston RFP”). As discussed further below, shortly after the conclusion of the Boston RFP, the ISO engaged in a “lessons learned” discussion with stakeholders to seek potential improvements to the competitive transmission solicitation process. As a result of that process, the Filing Parties have developed Tariff improvements related to the competitive solicitation process. These enhancements, which are more fully described in Mr. Oberlin’s testimony, consist of:

¹ 16 U.S.C. § 824d (2006 and Supp. II 2009).

² Capitalized terms used but not defined in this filing are intended to have the meaning given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff (the “Tariff”). Section II of the Tariff is the Open Access Transmission Tariff (“OATT”).

³ Under New England's RTO arrangements and, except as noted below, the rights to make this filing of changes to the OATT under Section 205 of the Federal Power Act are the ISO's. NEPOOL, which pursuant to the Participants Agreement provides the sole market participant stakeholder process for advisory voting on ISO matters, supported the changes reflected in this filing and accordingly, joins in this Section 205 filing.

⁴ The Oberlin Testimony is Attachment 3 to this filing letter and is sponsored solely by the ISO.

- Revisions to Sections 4.3 (Competitive Solution Process for Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades) and 4A (Public Policy Transmission Studies; Public Policy Transmission Upgrades) of Attachment K to the ISO OATT;
- Revisions to Sections 6 (Termination by ISO-NE) and 7 (Hold Harmless) of the *pro forma* Selected Qualified Transmission Project Sponsor Agreement, which is Attachment P to the ISO OATT; and
- Revisions to Section III.12.6.4 (Transmission Projects Selected Through The Competitive Transmission Process) of the Tariff.

I. DESCRIPTION OF THE FILING PARTIES AND COMMUNICATIONS

The ISO is the independent, private, non-profit entity that serves as the Regional Transmission Organization (“RTO”) for New England. The ISO operates the New England bulk power system and administers New England’s organized wholesale electricity market pursuant to the ISO New England Transmission, Markets and Services Tariff and the Transmission Operating Agreement with the New England Participating Transmission Owners. In its capacity as an RTO, the ISO has the responsibility to protect the short-term reliability of the New England Control Area and to plan and operate the system according to reliability standards established by the ISO, the Northeast Power Coordinating Council, Inc. (“NPCC”) and the North American Electric Reliability Corporation (“NERC”).

NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include more than 520 members. The participants include all of the electric utilities rendering or receiving service under the ISO Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, end users, developers, demand resource providers, and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Federal Energy Regulatory Commission (“FERC” or “Commission”),⁵ the participants act through the NEPOOL Participants Committee. The Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. Pursuant to Section 2.2 of the Participants Agreement, “NEPOOL provide[s] the sole Participant Processes for advisory voting on ISO matters and the selection of ISO Board members, except for input from state regulatory authorities and as otherwise may be provided in the Tariff, TOA and the Market Participant Services Agreement included in the Tariff.”⁶

Correspondence and communications in this proceeding should be addressed to:

⁵ *ISO New England Inc.*, 109 FERC ¶ 61,147 (2004).

⁶ The TOA is the Transmission Operating Agreement.

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I. STANDARD OF REVIEW

The Transmission Planning Improvements are submitted pursuant to Section 205 of the Federal Power Act, which “gives a utility the right to file rates and terms for services rendered

⁷ Due to the joint nature of this filing, the Filing Parties respectfully request a waiver of Section 385.203(b)(3) of the Commission’s regulations to allow the inclusion of more than two persons on the service list in this proceeding.

with its assets.”⁸ Under Section 205, the Commission “plays ‘an essentially passive and reactive’ role”⁹ whereby it “can reject [a filing] only if it finds that the changes proposed by the public utility are not ‘just and reasonable.’”¹⁰ The Commission limits this inquiry “into whether the rates proposed by a utility are reasonable – and [this inquiry does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs.”¹¹ The Transmission Planning Improvements filed herein “need not be the only reasonable methodology, or even the most accurate.”¹² As a result, even if an intervenor or the Commission develops an alternate proposal, the Commission must accept the Tariff revisions proposed in this Section 205 filing if the revisions are just and reasonable.¹³

II. DESCRIPTION AND RATIONALE FOR PROPOSED TARIFF CHANGES

A. Competitive Transmission Solution Enhancements - Attachment K.

The Filing Parties propose a number of Tariff enhancements to improve the competitive transmission process under Attachment K. Section 4.3 of Attachment K sets forth the competitive transmission process for Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades. Section 4A of Attachment K provides the competitive transmission process for Public Policy Transmission Upgrades. Many of the proposed enhancements in Section 4.3 correspond to the changes made in Section 4A.

The specifics of the proposed enhancements are detailed in Mr. Oberlin’s testimony. Generally, the Filing Parties propose to improve the competitive transmission process by allowing a subset of needs identified in the competitive process to be solved by a Qualified Transmission Project Sponsor (“QTPS”) and allowing for joint proposals other than the Backstop Transmission Solution to be proposed. The joint proposals may solve all or a subset of the identified needs.

1. Solving A Subset of Needs

Specifically, the Filing Parties propose to revise Section 4.3(a) (Initiating the Competitive Solution Process) to allow QTPS to solve all or some of the needs identified in the request for proposal (“RFP”). Currently, the process requires a Phase One Proposal to solve all the needs

⁸ *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002).

⁹ *Id.* at 10 (quoting *City of Winnfield v. FERC*, 744 F.2d 871, 876 (D.C. Cir. 1984)).

¹⁰ *Id.* at 9.

¹¹ *Cities of Bethany, Bushnell et al. v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir.), *cert. denied*, 469 U.S. 917 (1984) (“*Cities of Bethany*”); *see also ISO New England Inc.*, 114 FERC ¶ 61,315 at P 33 and n.35 (2005), *citing Pub. Serv. Co. of New Mexico v. FERC*, 832 F.2d 1201, 1211 (10th Cir. 1987) and *Cities of Bethany* at 1136.

¹² *Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995) (citing *Cities of Bethany* at 1136).

¹³ *Cf. Southern California Edison Co., et al.*, 73 FERC ¶ 61,219 at 61,608 n.73 (1995) (“Having found the Plan to be just and reasonable, there is no need to consider in any detail the alternative plans proposed by the Joint Protesters.”) (citing *Cities of Bethany* at 1136).

identified in the RFP. Requiring a QTPS to comprehensively solve all the identified needs could limit the number of QTPSs that are able to participate in an RFP. Accordingly, the Transmission Planning Improvements propose to revise Section 4.3(a) to allow a QTPS to submit a Phase One Proposal that solves a subset of identified needs. The proposed revisions to Section 4.3(a) state that a QTPS may submit a Phase One Proposal(s) offering solutions that “addresses the identified needs or a subset of those needs.” In other words, a QTPS may submit a Phase One Proposal with a solution that does not solve all the needs identified in the RFP. Allowing a QTPS to solve a subset of the needs will allow more QTPSs to participate, which will make the transmission solicitation process more competitive.

Corresponding changes are necessary to other sections in 4.3 of Attachment K in order to accommodate allowing a QTPS to solve a subset of identified needs. For example, the proposed revisions add new language to Section 4.3(c)(ii) requiring that Phase One Proposals that do not solve all the identified needs must include an explanation of the needs that are being addressed, a description of the needs that have not been addressed, and the impact of the Phase One Proposal on those needs that have not been addressed. The proposed revisions also require a change to Section 4.3(e)(ii) (Preliminary Review by ISO) to accommodate solving of a subset of identified needs by stating that the Phase One Proposal must address “one or more of the needs identified in Section 4.3(c)(ii).”

2. Joint Proposals

The Transmission Planning Improvements also revise the solicitation process to allow for the submission of joint proposals. Pursuant to the existing language in Section 4.3(a), joint proposals are already permitted for the Backstop Transmission Solution if more than one PTO is identified by the ISO. The proposed revisions revise Section 4.3(a) by adding that a QTPS may submit “an individual or joint” Phase One Proposal(s). Under the proposed revisions, to Section 4.3(a) allowing joint proposals, all the parties to a joint proposal must be approved QTPSs. A joint proposal can solve all of the needs or a subset of the needs identified in the RFP. If a joint proposal is selected as the Preferred Phase Two Solution, each QTPS must execute a separate Selected Qualified Transmission Project Sponsor Agreement (“SQTPSA”) and would have their portion of the project added to the Regional System Plan Project List. If one of the parties to the joint proposal defaults, and does not reassign its upgrades to another QTPS under Section 8 (Assignment) of the SQTPSA, the entire solution, or group of solutions, will be cancelled and the Backstop Transmission Solution would be implemented. Similar revisions are proposed in Section 4A.6(a) allowing QTPSs to submit individual or joint Stage One Proposals and requiring where a joint Stage One Proposal is submitted, all parties must be QTPS.

The Filing Parties propose corresponding changes to other sections in 4.3 and 4A of Attachment K to accommodate the submission of joint proposals. Specifically, modifications are proposed for:

- Section 4.3(c) (Information Required for Phase One Proposals, Study Deposit; Timing Phase One Proposals shall provide the following information) to provide that for a joint proposal, a single study deposit is necessary since the joint

proposal is submitted by only one QTPS. To accomplish this, the word “submitting” is added to Section 4.3(c). A corresponding change is proposed in Section 4A.6(a).

- Section 4.3(f) (Proposed Deficiencies; Further Information) to reflect that if the ISO identifies minor deficiencies a joint Phase One Proposal, the ISO will notify QTPS that submitted the joint Phase One Proposal of the deficiency. To effectuate this, the proposal adds the word “submitting” to Section 4.3(f).
- Section 4.3(h) (Information Required for Phase Two Solutions; Identification and Reporting of Preliminary Preferred Phase Two Solution) to reflect that a group of Phase Two Solution submittals could be chosen to address the identified need.
- Section 4.3(h) to make Qualified Transmission Project Sponsor plural to reflect that there could be joint proposals. Similar changes to the term Qualified Transmission Project Sponsor are proposed for Section 4A.8 (Information Required for Stage Two Solutions; Identification and Reporting of Preliminary Stage Two Solutions).
- Section 4.3(j) to reflect that there could be multiple Phase Two Solutions combined into a group that address the identified need.
- Section 4.3(k) to reflect that, each QTPS that is part of the joint proposal that is selected as the preferred Phase Two Solution must execute a SQTSA. A corresponding change is proposed in Section 4A.9(b).
- Section 4.3(l) (Failure to Proceed) to address, that with joint proposals, there will be more than one QTPS. A corresponding change is also proposed to Section 4A.9(c).

B. Other Competitive Transmission Solution Tariff Changes

1. Life-Cycle Costs

The proposed revisions remove the requirement for life-cycle costs to be provided as part of the Phase One Proposals. Life-cycle costs do not provide significant value when submitted in the Phase One Proposal because submitted life-cycle cost do not include costs associated with an upgrade(s) located on or connected to a PTO’s existing transmission system where the QTPS is not the PTO for the existing system element(s). Since the total life-cycle costs are not known for each Phase One Proposal, life-cycle costs cannot be compared and any analysis performed on Phase One Proposals must be done utilizing the provided installed costs. Life-cycle costs are required for Phase Two Solutions where more detailed information on the proposed project is available for evaluation. To effectuate this revision, the Transmission Planning Improvements modify Section 4.3(c)(v) by deleting “life-cycle and” and deleting “a description of the financing being used.” A corresponding change is proposed for Section 4A.6(a)(v). Under the proposed revisions, the description of financing being used is relocated from Section 4.3(c)(v) to Section

4.3(h)(vi). The proposed revisions also change the numbering for Section 4.3(h) to accommodate the relocation. Corresponding changes are also proposed to relocate the “description of financing being used” from Section 4A.6(v) to Section 4A.8(vi).

2. Attachment K Clarification Changes

The Filing Parties propose the following clarification changes to Attachment K.

- Under Section 4.3(a) “Phase One Proposals” is replaced with “Backstop Transmission Solution” to clarify that PTOs may only recover Phase One Proposal costs associated with the Backstop Transmission Solution. Changes to Section 4.3(a) are also proposed to clarify that the response is to “request for proposal” not a “Needs Assessment.”
- Under Sections 4.3(l) and 4A.9(c), the proposed revisions delete “non PTO” as the term is not necessary to the provisions in those sections and it unnecessarily limits how the ISO may learn that a QTPS is failing to proceed.
- Under Section 4.3(h) to reflect that the Phase Two Solution must comprehensively address all of the needs.
- Under Section 4.3(h) remove the incorrect reference to “Needs Assessment” and replaces it with “request for proposal.” A similar revision is proposed for Section 4A.6(a) that replaces “Public Policy Transmission Study” with “request for proposal.”
- Under Section 4.3(h)(xi) replace word “sponsor” with “Qualified Transmission Project Sponsor” and remove “state” because necessary permits may not be limited to state permits. A corresponding change is also proposed for Section 4A.8(xi).
- Under Section 4A.3(b), replace “Needs Assessment” with “Public Policy Transmission Study.” Since Section 4A.3 relates to public policy transmission planning, the replacement of “Needs Assessment” with “Public Policy Transmission Study” corrects a clerical error.

3. Pro Forma Selected Qualified Transmission Project Sponsor Agreement

The SQTPSA is an agreement entered into by the ISO and the Selected QTPS (whether a PTO or non-incumbent developer) following the QTPS’s selection to develop a project through the competitive process. The purpose of the SQTPSA is to state the terms and conditions

relating to development and construction of the selected project, including, among other things, project milestones, status reports, modifications, assignment, termination, and any cost containment. The SQTPSA is Attachment P to the ISO OATT.

The Transmission Planning Improvements modify Section 6 (Termination by ISO-NE) of the SQTPSA to reflect termination under a joint proposal. Under a joint proposal, if one of the Selected QTPSs is failing to move forward with the project, all QTPSs will have their portion of the project terminated. In such a situation, however, the assignment provisions under Section 8 (Assignment) of the SQTPSA may be applicable. Under Section 8 of the SQTPSA, in order to utilize the assignment provisions, the Selected QTPSs must coordinate any reassignment and the assignee must be a QTPS; the Selected QTPS or the assignee must demonstrate to the ISO that assignee has the technical competence and financial ability to: (a) comply with the requirements of the SQTPSA (including the milestone schedule); (b) 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) operate and maintain the project once constructed.

Additionally, the Transmission Planning Improvements modify Section 7 (Hold Harmless) of the SQTPSA. The modifications are necessary to accommodate the changes discussed earlier that allow for a project to have multiple Selected QTPSs.

In order to allow additional time for the assignment under Section 8 of the SQTPSA, the Transmission Planning Improvements propose to modify Section 4.3(l) of Attachment K. Specifically, the proposed modifications provide that the QTPS that is failing to proceed has 60 days after notification from the ISO to reassign a portion or all of the project to another QTPS in accordance with Section 8 of the SQTPSA. Additional changes are also proposed to Section 4.3(l) to delete "Attachment P to the OATT" and insert "pursuant to Schedule 3.09(a) of the Transmission Operating Agreement."

4. *Other Tariff Changes*

The Transmission Planning Improvements include corresponding changes to Section III.12.6.4 of the Tariff. The proposed changes to Section III.12.6.4 replace the word "project" with "solution" in several places to more accurately align the terminology with the language in Attachment K. Additionally, as discussed above, the Transmission Planning Improvements allow for a subset of needs identified in an RFP to be solved by a QTPS and for QTPSs to submit joint proposals. As a result, there may be multiple SQTPSAs. For this reason, the Transmission Planning Improvements include a corresponding change to Section III.12.6.4 to reflect that a complete transmission solution may have multiple SQTPSAs.

IV. STAKEHOLDER PROCESS

The ISO presented the revisions to Attachment K to the NEPOOL Transmission Committee on July 14, 2021, August 24, 2021, and September 28, 2021. At the September 28, 2021 meeting, the NEPOOL Transmission Committee voted to approve the revisions with no opposition and two abstentions. The NEPOOL Participants Committee voted at its November 4, 2021 meeting to approve the revisions to Attachment K as part of its consent agenda. The ISO

presented revisions to Section III.12.6.4 of the Tariff to the NEPOOL Reliability Committee on September 21, 2021 and October 19, 2021. At the October meeting, the NEPOOL Reliability Committee approved the revisions with no opposition. The NEPOOL Participants Committee approved the revisions as part of the consent agenda at its November 4, 2021 meeting.

V. REQUESTED EFFECTIVE DATE

The Filing Parties request an effective date of Monday February 28, 2022 for the Transmission Planning Improvements.

VI. ADDITIONAL SUPPORTING INFORMATION

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates.¹⁴ However, the Transmission Planning Improvements are not a traditional "rate," and the Filing Parties are not traditional investor-owned utilities. In light of these circumstances, the Filing Parties submit the following additional information in substantial compliance with relevant provisions of Section 35.13, and request a waiver of Section 35.13 of the Commission's regulations to the extent the content or form deviates from the specific technical requirements of the regulations.

35.13(b)(1) - Materials included herewith are as follows:

- ♦ this transmittal letter;
- ♦ blacklined sections of the ISO Tariff reflecting the Transmission Planning Improvements filing (Attachment 1);
- ♦ clean sections of the ISO Tariff reflecting the Transmission Planning Improvements (Attachment 2);
- ♦ the Oberlin Testimony (Attachment 3);
- ♦ a list of the governors, utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont, and other entities, to which a copy of this filing has been sent (Attachment 4).

35.13(b)(2) - The Filing Parties, request that the Transmission Planning Improvements become effective on February 28, 2022.

35.13(b)(3) - Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are posted on the ISO's website at <https://www.iso->

¹⁴ 18 C.F.R. § 35.13 (2022).

ne.com/participate/participant-asset-listings/directory?id=1&type=committee. An electronic copy of this transmittal letter and the accompanying materials has also been sent to the governors and electric utility regulatory agencies for the six New England states which comprise the New England Control Area, and to the New England Conference of Public Utility Commissioners, Inc.. Their names and addresses are shown in the attached listing. In accordance with Commission rules and practice, there is no need for the Governance Participants or the entities identified in the listing to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

35.13(b)(4) - A description of the materials submitted pursuant to this filing is contained in Section VI of this transmittal letter.

35.13(b)(5) - The reasons for this filing are discussed in the introduction of this transmittal letter and in the Oberlin Testimony.

35.13(b)(6) - The ISO's approval of the Transmission Planning Improvements is evidenced by this filing. With respect to NEPOOL's support, as noted in Section IV of this transmittal letter, the Transmission Planning Improvements reflect the outcome of the Participant Processes required by the Participants Agreement, and is supported by the NEPOOL Participants Committee.

35.13(b)(7) - The Filing Parties have no knowledge of any relevant expenses or costs of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

VII. CONCLUSION

For the reasons stated herein, the Filing Parties respectfully request that the Commission accept the Transmission Planning Improvements as filed, without condition, suspension, or hearing, to be effective February 28, 2022.

Respectfully submitted,

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ATTACHMENT K
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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.

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, and (vi) Longer-Term Transmission Studies. The Planning Advisory Committee, with the assistance of and in coordination with the ISO, serves also to identify and prioritize requests 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 Section 4.3 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, 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 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. 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.

With regard to Reliability Transmission Upgrades and Market Efficiency 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, “Proposed” means that the ISO has included the project in the RSP Project List pursuant to the procedures described in Section 4A 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.

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 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.

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 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 reliability planning process established in this Attachment K shall apply to all transmission solutions adopted to resolve a reliability need. 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. 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.

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 while promoting the operation of efficient wholesale electric markets in New England. 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 requests for an economic study consistent with section 4.1.b of Attachment K.
- 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) Requests by Stakeholders for Needs Assessments for Economic Considerations

The ISO's stakeholders may request the ISO to initiate a Needs Assessment to examine situations where potential regulated transmission solutions or 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 and/or loads on an aggregate or regional basis (an "Economic Study").

Requests for Economic Studies shall be submitted, considered and prioritized as follows:

- (i) By no later than April 1 of each year, any stakeholder may submit to the ISO for public posting on the ISO's website a request for an Economic Study.
- (ii) The ISO shall thereafter add any of its own proposals for Economic Studies. The ISO shall also develop a rough work scope and cost estimate for all requested Economic Studies, and develop preliminary prioritization based on the ISO's perceived regional and/or, as coordinated with the applicable neighboring system, inter-area benefits to assist stakeholders in the prioritization of Economic Studies.
- (iii) By no later than May 1 of each year, the ISO shall provide the foregoing information to the Planning Advisory Committee, and a Planning Advisory Committee meeting shall be held at which Economic Study proponents will provide an explanation of their request.
- (iv) By no later than June 1 of each year, the ISO shall hold a meeting of the Planning Advisory Committee for the members of the Planning Advisory Committee to discuss,

identify and prioritize, as further facilitated by the ISO's preparation of a straw priority list to be further discussed at such meeting, up to two (2) Economic Studies (the costs of which will be recovered by the ISO pursuant to Schedule 1 of Section IV.A of the Tariff) to be performed by the ISO in a given year taking into consideration their impact on the ISO budget and other priorities. The ISO may consider performing up to three (3) Economic Studies if a Public Policy Transmission Study will not be concurrently performed.

- (v) The ISO and the Planning Advisory Committee may agree to hold additional meetings to further discuss and resolve any issue concerning the substance of the Economic Studies themselves and/or their prioritization.
- (vi) If the Planning Advisory Committee, after discussions between the Planning Advisory Committee and ISO management, is not able to prioritize the Economic Studies to be performed by the ISO in a given year, any member of the Planning Advisory Committee must submit a request for Regional Planning Dispute Resolution Process pursuant to Section 12 of this Attachment, such request to be submitted no later than August 30, to resolve the issues concerning the substance of the Economic Studies themselves and/or their prioritization.
- (vii) The ISO will issue a notice to the Planning Advisory Committee detailing the prioritization of the Economic Studies as identified by the Planning Advisory Committee or, if a request for Regional Planning Dispute Resolution Process is submitted pursuant to Section 4.1.(b)(vi), as determined through that Process.

The foregoing timelines are subject to adjustment as determined by the ISO in coordination with the Planning Advisory Committee. The ISO will provide periodic updates on the status of Economic Studies to the Planning Advisory Committee.

Economic Study requests not within the three studies identified in Section 4.1(b)(iv) to be performed in a given year may be requested and paid for by the study proponent.

(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 ~~with respect to each Needs Assessment~~ 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 Sponsors may submit an individual or joint Phase One Proposal(s) offering a solutions that ~~comprehensively address~~es 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 ~~for any~~ 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 ~~Phase One Proposals~~ 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 ~~Needs Assessment~~ (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 ~~life-cycle and~~ installed costs of the proposed solution, including a high-level itemization of the components of the cost estimate, ~~a description of the financing being used,~~ 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) ~~Preliminary~~ Review of Phase One Proposals by ISO

~~If the sole Phase One Proposal in response to a given Needs Assessment is 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 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 ~~has been submitted in response to the request for proposal described in Section 4.3(a) of this Attachment K,~~ the ISO

shall perform a ~~preliminary feasibility~~ 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) ~~appears to satisfy~~ one or more of the needs ~~described in the Needs Assessment 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

~~For each Needs Assessment, the~~ 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 ~~projects-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 ~~projects-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;

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

~~(ix)~~ 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)~~sponsor~~ proposes to satisfy ~~state~~-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 ~~meet the~~ needs in the required timeframe as the preliminary preferred Phase Two Solution in response to each request for proposal~~Needs Assessment~~. 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 preliminarily 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 ~~its~~ 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 ~~the 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 ~~the each~~ Selected Qualified Transmission Project Sponsor Agreement.

(l) Failure to Proceed

If the ISO finds, after consultation with a ~~non~~-PTO Qualified Transmission Project Sponsor(s), that ~~the one or more of the Qualified Transmission Project Sponsorsponsor~~ is failing to pursue approvals or construction in a reasonably diligent fashion, ~~or that the sponsor is unable to proceed with the project due to forces beyond its reasonable control,~~ 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

~~request-require~~ the applicable PTO(s) to execute the Selected Qualified Transmission Project Sponsor Agreement (~~Attachment P to the OATT~~) 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 ~~Needs Assessment~~ 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, providing the following information: 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 ~~life cycle and~~ installed costs of the proposed solution, including a high-level itemization of the components of the cost estimate, ~~a description of the financing being used,~~ 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 ~~Public Policy Transmission Study 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) **Preliminary Review of Stage One Proposals by ISO**

Upon receipt of Stage One Proposals, the ISO shall perform a ~~preliminary feasibility~~ 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) ~~appears to satisfy~~ 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 state-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 preliminarily 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 ~~in the each~~ Selected Qualified Transmission Project Sponsor Agreement.

(c) Failure to Proceed

If the ISO finds, after consultation with a ~~non-PTO~~ 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.

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 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 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) Substance of Economic Studies to be conducted by the ISO in a given year as specified in Section 4.1(b) of this Attachment; and
- (vi) Prioritization of Economic Studies to be performed in a given year where the Planning Advisory Committee is not able to prioritize them as specified in Section 4.1(b) 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

This Section 16 sets forth the procedures for the ISO's conduct of Longer-Term Transmission Studies. 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.

16.1 Request for Longer-Term Transmission Studies

NESCOE may submit a 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 study. 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; 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 Study report. 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.

ATTACHMENT K APPENDIX 1
ATTACHMENT K -LOCAL
LOCAL SYSTEM PLANNING PROCESS

APPENDIX 1
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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

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

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

Hudson Light & Power Department

Massachusetts Municipal Wholesale Electric Company

Maine Electric Power Company

Middleborough Gas and Electric Department

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

New Hampshire Electric Cooperative, Inc.

New Hampshire Transmission, LLC

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

Shrewsbury Electric & Cable Operations

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

Town of Wallingford CT Dept 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.

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

Emera Maine

Eversource Energy Transmission Ventures, Inc.

Grid America Holdings, Inc.

Hudson Light and Power Department

Maine Electric Power Company

Middleboro Gas & Electric Department

New England Energy Connection, LLC

New England Power Company

New Hampshire Transmission, LLC

Norwood Municipal Light Department

NSTAR Electric Company

Public Service Company of New Hampshire

Taunton Municipal Light Plant

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 and Attachment K of the ISO-NE Open Access Transmission Tariff (“OATT”), ISO-NE selects the preferred Phase or Stage Two 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 Section 4.3(j) or 4A.9(a) of Attachment K of the OATT, ISO-NE notified the Selected QTPS that its project has been selected for development;

WHEREAS, pursuant to Section 4.3(k) or 4A.9(b) 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 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.

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 Section 4.3(l) or 4A.9(c) 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: sqtspa@iso-ne.com

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”.]

III.12. Calculation of Capacity Requirements.

III.12.1. Installed Capacity Requirement.

Prior to each Forward Capacity Auction, the ISO shall calculate the Installed Capacity Requirement for the New England Control Area for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction in accordance with this Section III.12.1.

The ISO shall determine the Installed Capacity Requirement such that the probability of disconnecting non-interruptible customers due to resource deficiency, on average, will be no more than once in ten years. Compliance with this resource adequacy planning criterion shall be evaluated probabilistically, such that the Loss of Load Expectation (“LOLE”) of disconnecting non-interruptible customers due to resource deficiencies shall be no more than 0.1 day each year. The forecast Installed Capacity Requirement shall meet this resource adequacy planning criterion for each Capacity Commitment Period. The Installed Capacity Requirement shall be determined assuming all resources pursuant to Sections III.12.7 and III.12.9 will be deliverable to meet the forecasted demand determined pursuant to Section III.12.8.

If the Installed Capacity Requirement shows a consistent bias over time, either high or low, the ISO shall make adjustments to the modeling assumptions and/or methodology through the stakeholder process to eliminate the bias in the Installed Capacity Requirement. The modeling assumptions used in determining the Installed Capacity Requirement are specified in Sections III.12.7, III.12.8 and III.12.9. For the purpose of this Section III.12, a “resource” shall include generating resources, demand resources, and import capacity resources eligible to receive capacity payments in the Forward Capacity Market.

III.12.1.1. System-Wide Marginal Reliability Impact Values.

Prior to each Forward Capacity Auction, the ISO shall determine the system-wide Marginal Reliability Impact of incremental capacity at various capacity levels for the New England Control Area. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used in determining the Installed Capacity Requirement.

III.12.2. Local Sourcing Requirements and Maximum Capacity Limits.

Prior to each Forward Capacity Auction, the ISO shall calculate the capacity requirements and limitations, accounting for relevant transmission interface limits which shall be determined pursuant to Section

III.12.5, for each modeled Capacity Zone (as described in Section III.12.4) for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction.

The ISO shall use consistent assumptions and standards to establish a resource's electrical location for purposes of qualifying a resource for the Forward Capacity Market and for purposes of calculating Local Sourcing Requirements and Maximum Capacity Limits. The methodology used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.2.1 and III.12.2.2, respectively. The modeling assumptions used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.5, III.12.6, III.12.7, III.12.8 and III.12.9.

III.12.2.1. Calculation of Local Sourcing Requirements for Import-Constrained Capacity Zones.

For each import-constrained Capacity Zone, the Local Sourcing Requirement shall be the amount needed to satisfy the higher of: (i) the Local Resource Adequacy Requirement as determined pursuant to Section III.12.2.1.1; or (ii) the Transmission Security Analysis Requirement as determined pursuant to Section III.12.2.1.2.

III.12.2.1.1. Local Resource Adequacy Requirement.

The Local Resource Adequacy Requirement shall be calculated as follows:

- (a) Two areas shall be modeled: (i) the Capacity Zone under study which includes all load and all resources electrically located within the Capacity Zone, including external Control Area support from tie benefits on the import-constrained side of the interface, if any; and (ii) the rest of the New England Control Area which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits on the unconstrained side of the interface, if any.
- (b) The only transmission constraint to be modeled shall be the transmission interface limit between the Capacity Zone under study and the rest of the New England Control Area as identified pursuant to Section III.12.5.
- (c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area

meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

(d) The Local Resource Adequacy Requirement for the import-constrained Capacity Zone Z shall be determined in accordance with the following formula:

$$LRA_Z = Resources_Z + Proxy Units_Z - (Proxy Units Adjustment_Z(1-FOR_Z)) - (Firm Load Adjustment_Z(1-FOR_Z))$$

In which:

$$LRA_Z = \text{MW of Local Resource Adequacy Requirement for Capacity Zone Z;}$$

$$Resources_Z = \text{MW of resources electrically located within Capacity Zone Z, including import Capacity Resources on the import-constrained side of the interface, if any;}$$

$$Proxy Units_Z = \text{MW of proxy unit additions in Load Zone Z;}$$

$$\begin{aligned} &\text{Firm Load} \\ &Adjustment_Z = \text{MW of firm load added (or subtracted) within Capacity Zone Z to make the LOLE of the New England Control Area equal to 0.105 days per year; and} \end{aligned}$$

$$FOR_Z = \text{Capacity weighted average of the forced outage rate modeled for all resources within Capacity Zone Z, including and proxy unit additions to Capacity Zone Z.}$$

$$\begin{aligned} &\text{Proxy Units} \\ &Adjustment = \text{MW of firm load added to (or unforced capacity subtracted from) Capacity Zone Z until the system LOLE equals 0.1} \end{aligned}$$

days/year.

To determine the Local Resource Adequacy Requirement, the firm load is adjusted within Capacity Zone Z until the LOLE of the New England Control Area reaches 0.105 days per year. The LOLE of 0.105 days per year includes an allowance for transmission related LOLE of 0.005 days per year associated with each interface. As firm load is added to (or subtracted from) Capacity Zone Z, an equal amount of firm load is removed from (or added to) the rest of New England Control Area.

III.12.2.1.2. Transmission Security Analysis Requirement.

A Transmission Security Analysis shall be used to determine the requirement of the zone being studied, and shall include the following features:

- (a) The ISO shall perform a series of transmission load flow studies and/or a deterministic operable capacity analysis targeted at determining the performance of the system under stressed conditions, and at developing a resource requirement sufficient to allow the system to operate through those stressed conditions.
- (b) The Transmission Security Analysis Requirement shall be set at a level sufficient to cover most reasonably anticipated events, but will not guarantee that every combination of obligated resources within the zone will meet system needs.
- (c) In performing the Transmission Security Analysis, the ISO may establish static transmission interface transfer limits, as identified pursuant to Section III.12.5, as a reasonable representation of the transmission system's capability to serve load with available existing resources.
- (d) The Transmission Security Analysis may model the entire New England system and individual zones, for both the first contingency (N-1) and second contingency (N-1-1) conditions. First contingency conditions (N-1) shall include the loss of the most critical generator or most critical transmission element with respect to the zone. Second contingency conditions (N-1-1) shall include both: (i) the loss of the most critical generator with respect to the zone followed by the loss of the most critical transmission element ("Line-Gen"); and (ii) the loss of the most critical transmission element followed by the loss of the next most critical transmission element ("Line-Line") with respect to the zone.

III.12.2.1.3. Marginal Reliability Impact Values for Import-Constrained Capacity Zones.

Prior to each Forward Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for each import-constrained Capacity Zone. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used to determine the Local Resource Adequacy Requirement pursuant to Section III.12.2.1.1, except that the capacity transfer capability between the Capacity Zone under study and the rest of the New England Control Area determined pursuant to Section III.12.2.1.1(b) shall be reduced by the greater of: (i) the Transmission Security Analysis Requirement minus the Local Resource Adequacy Requirement, and; (ii) zero.

III.12.2.2. Calculation of Maximum Capacity Limit for Export-Constrained Capacity Zones.

For each export-constrained Capacity Zone, the Maximum Capacity Limit shall be calculated using the following method:

- (a) Two areas shall be modeled: (i) the Capacity Zone under study which includes all load and all resources electrically located within the Capacity Zone, including external Control Area support from tie benefits on the export-constrained side of the interface, if any; and (ii) the rest of the New England Control Area, which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits to the rest of the New England Control Area, if any.
- (b) The only transmission constraint to be modeled shall be the transmission interface limit between the Capacity Zone under study and the rest of the New England Control Area as identified pursuant to Section III.12.5.
- (c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.
- (d) The Maximum Capacity Limit for the export-constrained Capacity Zone Y shall be determined in accordance with the following formula:

$$\text{Maximum Capacity Limit}_Y = \text{ICR} - \text{LRA}_{\text{Rest of New England}}$$

In which:

Maximum Capacity Limit_Y = Maximum MW amount of resources , including Import Capacity Resources on the export-constrained side of the interface, if any, that can be procured in the export-constrained Capacity Zone Y to meet the Installed Capacity Requirement;

ICR = MW of Installed Capacity Requirement for the New England Control Area, determined in accordance with Section III.12.1; and

LRA_{Rest of New England} = MW of Local Sourcing Requirement for the rest of the New England Control Area, which for the purposes of this calculation is treated as an import-constrained region, determined in accordance with Section III.12.2.1.

III.12.2.2.1. Marginal Reliability Impact Values for Export-Constrained Capacity Zones.

Prior to each Forward Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for each export-constrained Capacity Zone. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used to determine the export-constrained Capacity Zone's Maximum Capacity Limit.

III.12.3 Consultation and Filing of Capacity Requirements.

At least two months prior to filing the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission, the ISO shall review the modeling assumptions and resulting Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves with the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. Following consultation with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO shall file the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves

for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission pursuant to Section 205 of the Federal Power Act 90 days prior to the Forward Capacity Auction for the Capacity Commitment Period. The ISO shall file with the Commission pursuant to Section 205 of the Federal Power Act, the proposed identification of a potential new Capacity Zone when the boundary of the potential new Capacity Zone differs from the boundaries of existing Load Zones or Capacity Zones. In order to be used in a given FCA, any new Capacity Zone must have received approval from the Commission prior to the Existing Capacity Qualification Deadline of the applicable FCA.

III.12.4. Capacity Zones.

For each Forward Capacity Auction, the ISO shall, using the results of the most recent annual assessment of transmission transfer capability conducted pursuant to ISO Tariff Section II, Attachment K, determine the Capacity Zones to model as described below, and will include such designations in its filing with the Commission pursuant to Section III.13.8.1(c):

- (a) The ISO shall model in the Forward Capacity Auction, as separate export-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the Maximum Capacity Limit is less than the sum of the existing Qualified Capacity and proposed new capacity that could qualify to be procured in the export constrained Capacity Zone, including existing and proposed new Import Capacity Resources on the export-constrained side of the interface.

- (b) The ISO shall model in the Forward Capacity Auction, as separate import-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the second contingency transmission capability results in a line-line Transmission Security Analysis Requirement, calculated pursuant to Section III.12.2.1.2 and pursuant to ISO New England Planning Procedures, that is greater than the existing Qualified Capacity in the zone, with the largest generating station in the zone modeled as out-of-service. Each assessment will model out-of-service all Retirement De-List Bids and Permanent De-List Bids (including any received for the current Forward Capacity Auction at the time of this calculation), substitution auction demand bids submitted for the current Forward Capacity Auction, rejected for reliability Static De-List Bids from the most recent previous Forward Capacity Auction, and rejected for reliability Dynamic De-List Bids from the most recent previous Forward Capacity Auction.

(c) Adjacent Load Zones that are neither export-constrained nor import-constrained shall be modeled together as the Rest of Pool Capacity Zone in the Forward Capacity Auction.

III.12.4A. Dispatch Zones.

The ISO shall establish Dispatch Zones that reflect potential transmission constraints within a Load Zone that are expected to exist during each Capacity Commitment Period. Dispatch Zones shall be used to establish the geographic location of Active Demand Capacity Resources. For each Capacity Commitment Period, the ISO shall establish and publish Dispatch Zones by the beginning of the New Capacity Show of Interest Submission Window of the applicable Forward Capacity Auction, and those Dispatch Zones shall remain in place through the end of the Capacity Commitment Period for which they were established. The ISO will review proposed Dispatch Zones with Market Participants prior to establishing and publishing final Dispatch Zones.

III.12.5. Transmission Interface Limits.

Transmission interface limits, used in the determination of Local Sourcing Requirements, shall be determined pursuant to ISO Tariff Section II, Attachment K using network models that include all resources, existing transmission lines and proposed transmission lines that the ISO determines, in accordance with Section III.12.6, will be in service no later than the first day of the relevant Capacity Commitment Period. The transmission interface limits shall be established, using deterministic analyses, at levels that provide acceptable thermal, voltage and stability performance of the system both with all lines in service and after any criteria contingency occurs as specified in ISO New England Manuals and ISO New England Administrative Procedures.

III.12.6. Modeling Assumptions for Determining the Network Model.

The ISO shall determine, in accordance with this Section III.12.6, the generating units and transmission infrastructure to include in the network model that: (i) are expected to be in service no later than the first day of the relevant Capacity Commitment Period; and (ii) may have a material impact on the network model, a potential interface constraint, or on one or more Local Sourcing Requirements. The network model shall be used, among other purposes, (i) for the Forward Capacity Market qualification process and (ii) to calculate transmission interface limits in order to forecast the Local Sourcing Requirements. The network model shall include:

(a) For the relevant Capacity Commitment Period, the network model shall include:

- (i) all existing resources, along with any associated interconnection facilities and/or Elective Transmission Upgrades that have not been approved to be retired for the relevant Capacity Commitment Period, as described in Sections III.13.2.5.2.5.3 and III.13.2.8.3;
 - (ii) all new resources with Qualified Capacity for the relevant Capacity Commitment Period, along with any associated interconnection facilities and/or Elective Transmission Upgrades; and
 - (iii) in the case of an initial interconnection analysis that is conducted consistent with the Network Capability Interconnection Standard, any generating unit or External Elective Transmission Upgrade that has a valid Interconnection Request and is reasonably expected to declare commercial operation no later than the first day of the relevant Capacity Commitment Period.
- (b) Prior to each Forward Capacity Auction and each annual reconfiguration auction, the ISO shall determine and publish a list of the transmission projects and elements of transmission projects that will be included in the network model. During the process of making the transmission infrastructure determinations, as described in Section III.12.6.1, the ISO shall consult with the Governance Participants, the Transmission Owners, any transmission project proponents, the state utility regulatory agencies in New England and, as appropriate, other state agencies.

III.12.6.1. Process for Establishing the Network Model.

- (a) The ISO shall establish an initial network model prior to the Forward Capacity Auction that only includes transmission infrastructure, including Internal Elective Transmission Upgrades, that is already in service at the time that the initial network model is developed.
- (b) After establishing the initial network model, the ISO shall compile a preliminary list of the transmission projects or elements of transmission projects in the RSP Project List, individually or in combination with each other, as appropriate, to identify transmission projects that may achieve an in-service date no later than the first day of the relevant Capacity Commitment Period and that will have a material impact on the network model, on a potential interface constraint or one or more Local Sourcing Requirements.
- (c) For the transmission projects or elements of transmission projects in the RSP Project List that are included in the preliminary list developed pursuant to subsection (b), the ISO shall determine whether the

transmission projects or elements of transmission projects meet all of the initial threshold milestones specified in Section III.12.6.2 and will be considered for further evaluation pursuant to subsection (d).

(d) For those transmission projects or elements of transmission projects that meet the initial threshold milestones in subsection (c), the ISO shall use the evaluation criteria specified in Section III.12.6.3, and any other relevant information, to determine whether to include a transmission project or element of a transmission project in the final network model.

(e) If after completing its evaluation pursuant to Sections III.12.6.1 through III.12.6.3 and conferring with the transmission project proponents, the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO determines that the transmission project or a portion of the transmission project is reasonably expected to be in service no later than the first day for the relevant Capacity Commitment Period, then such transmission project or portion of transmission project shall be considered in service in the finalized network model to calculate the transmission interface limits pursuant to Section III.12.5.

III.12.6.2. Initial Threshold to be Considered In-Service.

The ISO shall determine whether transmission projects or elements of transmission projects meet all of the following initial threshold milestones:

(a) A critical path schedule for the transmission project has been furnished to ISO showing that the transmission project or the element of the transmission project will be in-service no later than the first day of the relevant Capacity Commitment Period. The critical path schedule must be sufficiently detailed to allow the ISO to evaluate the feasibility of the schedule.

(b) At the time of the milestone review, siting and permitting processes, if required, are on schedule as shown on the critical path schedule.

(c) At the time of the milestone review, engineering is on schedule as shown on the critical path schedule.

(d) At the time of the milestone review, land acquisition, if required, is on schedule as shown on the critical path schedule.

(e) Corporate intent to build the transmission project has been furnished to the ISO. An officer of the host Transmission Owner or Elective Transmission Upgrade Interconnection Customer has submitted to the ISO a statement verifying that the officer has reviewed the proposal and critical path schedule submitted to the ISO, and the Transmission Owner or Elective Transmission Upgrade Interconnection Customer concurs that the schedule is achievable, and it is the intent of the Transmission Owner or Elective Transmission Upgrade Interconnection Customer to build the proposed transmission project in accordance with that schedule. The Transmission Owner or Elective Transmission Upgrade Interconnection Customer may develop alternatives or modifications to the transmission project during the course of design of the transmission project that accomplish at least the same transfer capability. Such alternatives or modifications are acceptable, so long as the ISO determines that the alternative or modification is reasonably expected to achieve an in-service date no later than the first day of the relevant Capacity Commitment Period. The provision of an officer's statement shall be with the understanding that the statement shall not create any liability on the officer and that any liability with respect to the Transmission Owner's obligations shall be as set forth in the Transmission Operating Agreement and shall not be affected by such officer's statement.

III.12.6.3. Evaluation Criteria.

For a transmission project or element of a transmission project that meets the initial threshold milestones specified in Section III.12.6.2, the ISO shall consider the following factors and any other relevant information to determine whether to include the transmission project or element of the transmission project in the network model for the relevant Capacity Commitment Period.

(a) Sufficient engineering to initiate construction is on schedule as shown on the critical path schedule.

(b) Approval under Section I.3.9 of the Transmission, Markets and Services Tariff, if required, has been obtained or is on schedule to be obtained as shown on the critical path schedule.

(c) Significant permits, including local permits, if required to initiate construction have been obtained or are on schedule consistent with the critical path schedule.

(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 ~~Projects~~ Solutions Selected Through the Competitive Transmission Process.

For a transmission project-solution, which may consist of single or multiple proposals, selected through the competitive transmission process pursuant to Sections 4.3 and 4A of Attachment K, such transmission project-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 project-solution, or relevant portion thereof, in the network model for the relevant Capacity Commitment Period. In the event that the selected transmission project-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 additional capacity to determine the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values. The proxy units shall reflect resource capacity and outage characteristics such that when the proxy units are used in place of all

other resources in the New England Control Area, the reliability, or LOLE, of the New England Control Area does not change. The outage characteristics are the summer capacity weighted average availability of the resources in the New England Control Area as determined in accordance with Section III.12.7.3. The capacity of the proxy unit is determined by adjusting the capacity of the proxy unit until the LOLE of the New England Control Area is equal to the LOLE calculated while using the capacity assumptions described in Section III.12.7.2.

When modeling transmission constraints for the determination of Local Resource Adequacy Requirements, the same proxy units may be added to the import-constrained zone or elsewhere in the rest of the New England Control Area depending on where system constraints exist.

III.12.7.2. Capacity.

The resources included in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall include:

- (a) all Existing Generating Capacity Resources,
- (b) resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period,
- (c) all Existing Import Capacity Resources backed by a multiyear contract to provide capacity in the New England Control Area, where that multiyear contract requires delivery of capacity for the Commitment Period for which the Installed Capacity Requirement is being calculated, and
- (d) Existing Demand Capacity Resources that are qualified to participate in the Forward Capacity Market and New Demand Capacity Resources that have cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period,

but shall exclude:

- (e) capacity associated with Export Bids cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period,

(f) capacity de-listed or retired as a result of Permanent De-List Bids, Retirement De-List Bids, or substitution auction demand bids that cleared in previous Forward Capacity Auctions, and

(g) capacity retired pursuant to Section III.13.1.2.4.1(a), unless the Lead Market Participant has opted to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1.

The rating of Existing Generating Capacity Resources and Existing Import Capacity Resources used in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be the summer Qualified Capacity value of such resources for the relevant zone. The rating of Demand Capacity Resources shall be the summer Qualified Capacity value reduced by any reserve margin adjustment factor that is otherwise included in the summer Qualified Capacity value. The rating of resources, except for Demand Capacity Resources, cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period shall be based on the amount of Qualified Capacity that cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period. Resources are located within the Capacity Zones in which they are electrically connected as determined during the qualification process.

III.12.7.2.1. [Reserved.]

III.12.7.3. Resource Availability.

The Installed Capacity Requirement, Local Resource Adequacy Requirements, Transmission Security Analysis Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated taking resource availability into account and shall be determined as follows:

For Existing Generating Capacity Resources:

(a) The most recent five-year moving average of EFORD shall be used as the measure of resource availability used in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Transmission Security Analysis Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

(b) [Reserved.]

For resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period that do not have sufficient data to calculate an availability metric as defined in subsection (a) above, class average data for similar resource types shall be used.

For existing Active Demand Capacity Resources:

Historical performance data for those resources will be used to develop an availability metric for use in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

III.12.7.4. Load and Capacity Relief.

Load and capacity relief expected from system-wide implementation of the following actions specified in ISO New England Operating Procedure No. 4. Action During a Capacity Deficiency, shall be included in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values:

- (a) **Implement voltage reduction.** The MW value of the load relief shall be equal to 1% of (the 90/10 forecasted seasonal net peak loads minus all Existing Demand Capacity Resources).
- (b) **Arrange for available Emergency energy from Market Participants or neighboring Control Areas.** These actions are included in the calculation through the use of tie benefits to meet system needs. The MW value of tie benefits is calculated in accordance with Section III.12.9.
- (c) **Maintain an adequate amount of ten-minute synchronized reserves.** The amount of system reserves included in the determination of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be consistent with those needed for reliable system operations during Emergency Conditions. When modeling transmission constraints, the reserve requirement for a zone shall be the zone's pro rata share of the forecasted system peak load multiplied by the system reserves needed for reliable system operations during Emergency Conditions.

III.12.8. Load Modeling Assumptions.

The ISO shall forecast load for the New England Control Area and for each Load Zone within the New England Control Area. The load forecasts shall be based on appropriate models and data inputs. Each year, the load forecasts and underlying methodologies, inputs and assumptions shall be reviewed with

Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. If the load forecast shows a consistent bias over time, either high or low, the ISO shall propose adjustments to the load modeling methodology to the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies to eliminate the bias. To ensure that Demand Response Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources are not reflected as reductions in the load forecast, the ISO shall reflect them in historical loads as specified below.

(a) The ISO shall add back into historical loads the metered MW demand reduction of Demand Response Resources dispatched by the ISO.

(b) [Reserved.]

(c) [Reserved.]

(d) The ISO shall add back into historical loads summer and winter MW values to account for On-Peak Demand Resources and Seasonal Peak Demand Resources as follows:

The ISO shall develop a trend line between (i) the point when summer MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are assumed to be zero (June 1, 2006) and (ii) the point when summer MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are reflected by the Capacity Supply Obligations that those resources acquired in the most recent Forward Capacity Auction for June 1 of the associated Capacity Commitment Period. To determine the summer MW values to be added back into historical loads, the ISO shall apply the resulting trend to the summer months (April through November) in all the historical years covered by the trend line.

The ISO shall develop a trend line between (i) the point when winter MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are assumed to be zero (December 1, 2006) and (ii) the point when winter MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are reflected by the Capacity Supply Obligations that those resources acquired in the most recent Forward Capacity Auction for December 1 of the associated Capacity Commitment Period. To determine the winter MW values to be added back into historical loads, the ISO shall apply the resulting trend to the winter months (December through March) in all the historical years covered by the trend line.

The ISO shall make adjustments to forecasted loads to account for any differences between the most recently available MW values reflective of the Capacity Supply Obligations that On-Peak Demand Resources and Seasonal Peak Demand Resources acquired in each of the annual reconfiguration auctions and the MW values reflective of the Capacity Supply Obligations that those resources acquired in the corresponding Forward Capacity Auctions.

III.12.9. Tie Benefits.

The Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated assuming appropriate tie benefits, if any, available from interconnections with neighboring Control Areas. Tie benefits shall be calculated only for interconnections (1) without Capacity Network Import Interconnection Service or Network Import Interconnection Service or (2) that have not requested Capacity Network Import Interconnection Service or Network Import Interconnection Service with directly interconnected neighboring Control Areas with which the ISO has in effect agreements providing for emergency support to New England, including but not limited to inter-Control Area coordination agreements, emergency aid agreements and the NPCC Regional Reliability Plan.

Tie benefits shall be calculated using a probabilistic multi-area reliability model, by comparing the LOLE for the New England system before and after interconnecting the system to the neighboring Control Areas. To quantify tie benefits, firm capacity equivalents shall be added until the LOLE of the isolated New England Control Area is equal to the LOLE of the interconnected New England Control Area.

III.12.9.1. Overview of Tie Benefits Calculation Procedure.

III.12.9.1.1. Tie Benefits Calculation for the Forward Capacity Auction and Annual Reconfiguration Auctions; Modeling Assumptions and Simulation Program.

For each Capacity Commitment Period, tie benefits shall be calculated for the Forward Capacity Auction and the third annual reconfiguration auction using the calculation methodology in this Section III.12.9.

For the first and second annual reconfiguration auctions for a Capacity Commitment Period, the tie benefits calculated for the associated Forward Capacity Auction shall be utilized in determining the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values as adjusted to account for any changes in import capability of interconnections with neighboring Control Areas and changes in import capacity resources using the methodologies in Section III.12.9.6.

Tie benefits shall be calculated using the modeling assumptions developed in accordance with Section III.12.9.2 and using the General Electric Multi-area Reliability Simulation (MARS) program.

III.12.9.1.2. Tie Benefits Calculation.

The total tie benefits to New England from all directly interconnected neighboring Control Areas are calculated first using the methodology in Section III.12.9.3. Following the calculation of total tie benefits, individual tie benefits from each qualifying neighboring Control Area are calculated using the methodology in Section III.12.9.4.1. If the sum of the tie benefits from each Control Area does not equal the total tie benefits to New England, then each Control Area's tie benefits are adjusted based on the ratio of the individual Control Area tie benefits to the sum of the tie benefits calculated for each Control Area using the methodology in Section III.12.9.4.2. Following this calculation, tie benefits are calculated for each qualifying individual interconnection or group of interconnections using the methodology in Section III.12.9.5.1. If the sum of the tie benefits from individual interconnections or groups of interconnections does not equal their associated Control Area's tie benefits, then the tie benefits of each individual interconnection or group of interconnections is adjusted based on the ratio of the tie benefits of the individual interconnection or group of interconnections to the sum of the tie benefits within the Control Area using the methodology in Section III.12.9.5.2.

III.12.9.1.3. Adjustments to Account for Transmission Import Capability and Capacity Imports.

Once the initial calculation of tie benefits is performed, the tie benefits for each individual interconnection or group of interconnections is adjusted to account for capacity imports and any changes in the import capability of interconnections with neighboring Control Areas, using the methodologies in Section III.12.9.6. Once the import capability and capacity import adjustments are completed, the sum of the tie benefits of all individual interconnections and groups of interconnections for a Control Area, with the import capability and capacity import adjustments, represents the tie benefits associated with that Control Area, and the sum of the tie benefits from all Control Areas, with the import capability and capacity import adjustments, represents the total tie benefits available to New England.

III.12.9.2. Modeling Assumptions and Procedures for the Tie Benefits Calculation.

III.12.9.2.1. Assumptions Regarding System Conditions.

In calculating tie benefits, “at criterion” system conditions shall be used to model the New England Control Area and all interconnected Control Areas.

III.12.9.2.2. Modeling Internal Transmission Constraints in New England.

In calculating tie benefits, all New England internal transmission constraints that (i) are modeled in the most recent Regional System Plan resource adequacy studies and assessments and (ii) are not addressed by either a Local Sourcing Requirement or a Maximum Capacity Limit calculation shall be modeled, using the procedures in Section III.12.9.2.5.

III.12.9.2.3. Modeling Transmission Constraints in Neighboring Control Areas.

The ISO will review annually NPCC’s assumptions regarding transmission constraints in all directly interconnected neighboring Control Areas that are modeled for the tie benefits calculations. In the event that NPCC models a transmission constraint in one of the modeled neighboring Control Areas, the ISO will perform an evaluation to determine which interfaces are most critical to the ability of the neighboring Control Area to reliably provide tie benefits to New England from both operational and planning perspectives, and will model those transmission constraints in the tie benefits calculation, using the procedures in Section III.12.9.2.5.

III.12.9.2.4. Other Modeling Assumptions.

- A.** External transfer capability determinations. The transfer capability of all external interconnections with New England will be determined using studies that take account of the load, resource and other electrical system conditions that are consistent with those expected during the Capacity Commitment Period for which the calculation is being performed. Transfer capability studies will be performed using simulations that consider the contingencies enumerated in sub-section (iii) below.

- (i) The transmission system will be modeled using the following conditions:
 - 1. The forecast 90/10 peak load conditions for the Capacity Commitment Period;
 - 2. Qualified Existing Generating Capacity Resources reflecting their output at their Capacity Network Resource level;
 - 3. Qualified Existing Demand Capacity Resources reflecting their Capacity Supply Obligation received in the most recent Forward Capacity Auction;
 - 4. Transfers on the transmission system that impact the transfer capability of the interconnection under study.

- (ii) The system will be modeled in a manner that reflects the design of the interconnection. If an interconnection and its supporting system upgrades were designed to provide incremental capacity into the New England Control Area, simulations will assume imports up to the level that the interconnection was designed to support. If the interconnection was not designed to be so comparably integrated, simulations will determine the amount of power that can be delivered into New England over the interconnection.
- (iii) The simulations will take into account contingencies that address a fault on a generator or transmission facility, loss of an element without a fault, and circuit breaker failure following the loss of an element or an association with the operation of a special protection system.

- B.** In calculating tie benefits, New England capacity exports are removed from the internal capacity resources and are modeled as a resource in the receiving Control Area. The transfer capability of external interconnections is not adjusted to account for capacity exports.

III.12.9.2.5. Procedures for Adding or Removing Capacity from Control Areas to Meet the 0.1 Days Per Year LOLE Standard.

In calculating tie benefits, capacity shall be added or removed from the interconnected system of New England and its neighboring Control Areas, until the LOLE of New England and the LOLE of each Control Area of the interconnected system equals 0.1 days per year simultaneously. The following procedures shall be used to add or remove capacity within New England and the interconnected Control Areas to achieve that goal.

- A. Adding Proxy Units within New England when the New England system is short of capacity.** In modeling New England as part of the interconnected system, if New England is short of capacity to meet the 0.1 days per year LOLE, proxy units (with the characteristics identified in Section III.12.7.1) will be added to the sub-areas that are created by any modeled internal transmission constraints within New England, beginning with the sub-area with the highest LOLE. If there are no modeled internal transmission constraints in the New England Control Area, then proxy units will be added to the entire Control Area. If, as a result of the addition of one or more proxy units, the system is surplus of capacity, then the methodology in Section III.12.9.2.5(b) will be used to remove the surplus capacity.
- B. Removing capacity from New England when the New England system is surplus of capacity.** In modeling New England as part of the interconnected system, if New England is

surplus of capacity to meet the 0.1 days per year LOLE, the surplus capacity will be removed from the sub-areas as follows. Resources will be removed from sub-areas with capacity surplus based on the ratio of capacity surplus in the sub-area to the total capacity surplus in these surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the existing Qualified Capacity, and any amount of proxy units added in that sub-area that is above its 50-50 peak load forecast. Notwithstanding the foregoing, if removing resources will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas using the same ratios described above for the removal of capacity surplus. If there are no modeled internal transmission constraints in the New England Control Area, then the surplus capacity shall be removed from the entire Control Area.

C. Adding capacity within neighboring Control Areas when the neighboring Control Area is short of capacity. In modeling neighboring Control Areas as part of the interconnected system, if the neighboring Control Area is short of capacity to meet the 0.1 days per year LOLE, additional capacity will be added to the neighboring Control Area's sub-areas that are created by any modeled internal transmissions constraints, beginning with the sub-area with the highest LOLE. If there are no modeled internal transmission constraints in the Control Area, then capacity will be added to the entire Control Area. The process that the neighboring Control Area utilizes in its resource adequacy study to meet its resource adequacy criterion will be utilized to add capacity to that Control Area. In filing the Installed Capacity Requirement values pursuant to Section III.12.3, the ISO will provide citations to any resource adequacy studies relied upon for these purposes. If, as a result of the capacity addition, the system is surplus of capacity, then the methodology in Section III.12.9.2.5(d) shall be used to remove the surplus capacity.

D. Removing capacity from neighboring Control Areas when the neighboring Control Area is surplus of capacity. In modeling neighboring Control Areas as part of the interconnected system, if the neighboring Control Area is surplus of capacity to meet the 0.1 days per year LOLE, the surplus capacity will be removed from the neighboring Control Area's sub-areas as follows. Resources will be removed from sub-areas with capacity surplus based on the ratio of capacity surplus in the sub-area to the total capacity surplus in the surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the installed capacity in the sub-area above its 50/50 peak load forecast. For a sub-area that has a minimum locational resource requirement above its 50/50 peak load forecast, the amount of capacity surplus is the amount of the installed capacity in the sub-area above its minimum

locational resource requirement. Notwithstanding the foregoing, if removing resources from a sub-area will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas using the same ratio of capacity surplus in the sub-area to the total capacity surplus in the those remaining surplus sub-areas. If there are no modeled internal transmission constraints in the neighboring Control Area, then the surplus capacity will be removed from the entire Control Area.

- E. Maintaining the neighboring Control Area's locational resource requirements.** In modeling a neighboring Control Area with internal transmission constraints, all minimum locational resource requirements in the Control Area's sub-areas as established by the neighboring Control Area's installed capacity requirement calculations shall be observed.

III.12.9.3. Calculating Total Tie Benefits.

The total tie benefits with all qualifying directly interconnected neighboring Control Areas shall be calculated by comparing the interconnection state of the New England system with all interconnections to neighboring Control Areas connected with the interconnection state of the New England system with all interconnections with neighboring Control Areas disconnected. To calculate total tie benefits:

- A.** The New England system shall be interconnected with all directly interconnected neighboring Control Areas and the New England Control Area, and each neighboring Control Area shall be brought to 0.1 days per year LOLE simultaneously by adjusting the capacity of each Control Area, utilizing the methods for adding or removing capacity in Section III.12.9.2.5.
- B.** Once the interconnected system is brought to 0.1 days per year LOLE, the LOLE of the New England Control Area shall be calculated a second time, with the New England system isolated from the rest of the interconnected system that was brought to 0.1 days per year LOLE.
- C.** Total tie benefits shall be the sum of the amounts of firm capacity that needs to be added to the isolated New England Control Area at the point at which each interconnection with neighboring Control Areas interconnects in New England to bring the New England LOLE back to 0.1 days per year. This value is subject to adjustment in accordance with Section III.12.9.6.

III.12.9.4. Calculating Each Control Area's Tie Benefits.

III.12.9.4.1. Initial Calculation of a Control Area's Tie Benefits.

Tie benefits from each neighboring Control Area shall be determined by calculating the tie benefits for every possible interconnection state that has an impact on the tie benefit value between the New England system and the target neighboring Control Area. If two or more interconnections between New England and the target neighboring Control Area exist, then all interconnections grouped together will be used to represent the state of interconnection between New England and the target neighboring Control Area. The tie benefits from the target neighboring Control Area shall be equal to the simple average of the tie benefits calculated from all possible interconnection states, subject to adjustment in accordance with Section III.12.9.4.2.

III.12.9.4.2. Pro Ration Based on Total Tie Benefits.

If the sum of the individual Control Area tie benefits calculated in accordance with Section III.12.9.4.1 is different than the total tie benefits from all Control Areas calculated in accordance with Section III.12.9.3, then each Control Area's tie benefits shall be increased or decreased based on the ratio of the individual Control Area tie benefits to the sum of the tie benefits for each individual Control Area, so that the sum of each Control Area's tie benefits, after the pro-ration, is equal to the total tie benefits calculated in accordance with Section III.12.9.3. The pro-rated Control Area tie benefits are subject to further adjustment in accordance with Section III.12.9.6.

III.12.9.5. Calculating Tie Benefits for Individual Ties.

Tie benefits shall be calculated for an individual interconnection or group of interconnections to the extent that a discrete and material transfer capability can be identified for the interconnection or group of interconnections. All interconnections or groups of interconnections shall have equal rights in calculating individual tie benefits, with no grandfathering or incremental tie capability treatment.

For purposes of calculating tie benefits, a group of interconnections refers to two or more AC lines that operate in parallel to form a transmission interface in which there are significant overlapping contributions of each line toward establishing the transfer limit, such that the individual lines in a group of interconnections cannot be assigned individual contributions.

III.12.9.5.1. Initial Calculation of Tie Benefits for an Individual Interconnection or Group of Interconnections.

Tie benefits for an individual interconnection or group of interconnections shall be calculated by calculating tie benefits for each possible interconnection state between the New England system and the individual interconnection or group of interconnections. The tie benefits from that interconnection or

group of interconnections shall be equal to the simple average of the tie benefits calculated from all possible interconnection states, subject to adjustment in accordance with Section III.12.9.5.2.

III.12.9.5.2. Pro Ration Based on Total Tie Benefits.

If the sum of the individual interconnection's or group of interconnection's tie benefits calculated in accordance with Section III.12.9.5.1 is different than the associated Control Area's tie benefits calculated in accordance with Section III.12.9.4, then the tie benefits of the individual interconnection or group of interconnections shall be adjusted based on the ratio of the tie benefits of the individual interconnection or group of interconnections to the sum of the tie benefits for each interconnection or group of interconnections in that Control Area, so that the sum of the tie benefits for each interconnection or group of interconnections in the Control Area, after the pro-ration, is equal to the total tie benefits for the Control Area calculated in accordance with Section III.12.9.4. The pro-rated tie benefits for each interconnection or group of interconnections is subject to further adjustment in accordance with Section III.12.9.6.

III.12.9.6. Accounting for Capacity Imports and Changes in External Transmission Facility Import Capability.

III.12.9.6.1. Accounting for Capacity Imports.

In the initial tie benefits calculations, capacity imports are modeled as internal resources in New England, and the import capability of the interconnections with neighboring Control Areas is not reduced to reflect the impact of capacity imports. After the initial tie benefits calculations, total tie benefits, tie benefits for each Control Area, and tie benefits from each individual interconnection or group of interconnections shall be adjusted to account for capacity imports using the methodology contained in this Section III.12.9.6.1. For the Forward Capacity Auction and third annual reconfiguration auction, this adjustment shall be applied to the tie benefit values calculated in accordance with Sections III.12.9.3, III.12.9.4 and III.12.9.5 respectively. For the first and second annual reconfiguration auctions, this adjustment shall be applied to the tie benefits values calculated for the Forward Capacity Auction.

- A.** Capacity imports shall be deducted from the import capability of each individual interconnection or group of interconnections to determine the available import capability of the interconnection or group of interconnections prior to accounting for tie benefits from those interconnections. The transfer capability of an interconnection or group of interconnections shall be determined using the procedures in Section III.12.9.2.4.A.

- B.** If the tie benefits value of an individual interconnection or group of interconnections, as determined in accordance with Section III.12.9.5, is greater than the remaining transmission import capability of the interconnection or group of interconnections after accounting for capacity imports, the tie benefit value of the individual interconnection or group of interconnections shall be equal to the remaining transmission import capability (taking into account any further adjustments to transmission import capability in accordance with Section III.12.9.6.2). If the tie benefits value of an individual interconnection or group of interconnections is not greater than the remaining transmission import capability after accounting for capacity imports, then the tie benefit value of the individual interconnection or group of interconnections shall be equal to the value determined in accordance with Section III.12.9.5 (taking into account any further adjustments to transmission import capability in accordance with Section III.12.9.6.2).
- C.** The tie benefits for each Control Area shall be the sum of the tie benefits from the individual interconnections or groups of interconnections with that Control Area, after accounting for any adjustment for capacity imports and any further adjustments to transmission import capability in accordance with Section III.12.9.6.2.
- D.** The total tie benefits from all qualifying neighboring Control Areas shall be the sum of the Control Area tie benefits, after accounting for any adjustment for capacity imports and any further adjustments to transmission import capability in accordance with Section III.12.9.6.2.
- E.** For purposes of determining the adjustment to tie benefits to account for capacity imports under this Section III.12.9.6.1, the capacity imports applicable for determining tie benefits for the Forward Capacity Auction shall be the Qualified Existing Import Capacity Resources for the relevant Capacity Commitment Period, and the capacity imports applicable for determining tie benefits for the annual reconfiguration auctions are those Import Capacity Resources that hold Capacity Supply Obligations for the relevant Capacity Commitment Period as of the time the tie benefits calculation is being performed for the annual reconfiguration auction.

III.12.9.6.2. Changes in the Import Capability of Interconnections with Neighboring Control Areas.

For purposes of calculating tie benefits for the Forward Capacity Auction and third annual reconfiguration auction, the most recent import capability values for an interconnection or group of interconnections with a neighboring Control Area shall be reflected in the modeling of system conditions for the tie benefits calculation. In addition, for the first and second annual reconfiguration auctions, any changes to the

import capability of an interconnection or group of interconnections with a neighboring Control Area shall be reflected in the adjustment to tie benefits to account for capacity imports under Section III.12.9.6.1.

III.12.9.7. Tie Benefits Over the HQ Phase I/II HVDC-TF.

The tie benefits from the Quebec Control Area over the HQ Phase I/II HVDC-TF calculated in accordance with Section III.12.9.1 shall be allocated to the Interconnection Rights Holders or their designees in proportion to their respective percentage shares of the HQ Phase I and the HQ Phase II facilities, in accordance with Section I of the Transmission, Markets and Services Tariff.

III.12.10. Calculating the Maximum Amount of Import Capacity Resources that May be Cleared Over External Interfaces in the Forward Capacity Auction and Reconfiguration Auctions.

For external interfaces, Import Capacity Resources shall be allowed in the Forward Capacity Auction and reconfiguration auctions up to the interface limit minus the tie benefits, calculated pursuant to Section III.12.9.1 or 12.9.2 over the applicable interface.

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.

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, and (vi) Longer-Term Transmission Studies. The Planning Advisory Committee, with the assistance of and in coordination with the ISO, serves also to identify and prioritize requests 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 Section 4.3 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, 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 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. 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.

With regard to Reliability Transmission Upgrades and Market Efficiency 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, “Proposed” means that the ISO has included the project in the RSP Project List pursuant to the procedures described in Section 4A 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.

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 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.

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 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 reliability planning process established in this Attachment K shall apply to all transmission solutions adopted to resolve a reliability need. 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. 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.

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 while promoting the operation of efficient wholesale electric markets in New England. 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 requests for an economic study consistent with section 4.1.b of Attachment K.
- 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) Requests by Stakeholders for Needs Assessments for Economic Considerations

The ISO's stakeholders may request the ISO to initiate a Needs Assessment to examine situations where potential regulated transmission solutions or 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 and/or loads on an aggregate or regional basis (an "Economic Study").

Requests for Economic Studies shall be submitted, considered and prioritized as follows:

- (i) By no later than April 1 of each year, any stakeholder may submit to the ISO for public posting on the ISO's website a request for an Economic Study.
- (ii) The ISO shall thereafter add any of its own proposals for Economic Studies. The ISO shall also develop a rough work scope and cost estimate for all requested Economic Studies, and develop preliminary prioritization based on the ISO's perceived regional and/or, as coordinated with the applicable neighboring system, inter-area benefits to assist stakeholders in the prioritization of Economic Studies.
- (iii) By no later than May 1 of each year, the ISO shall provide the foregoing information to the Planning Advisory Committee, and a Planning Advisory Committee meeting shall be held at which Economic Study proponents will provide an explanation of their request.
- (iv) By no later than June 1 of each year, the ISO shall hold a meeting of the Planning Advisory Committee for the members of the Planning Advisory Committee to discuss,

identify and prioritize, as further facilitated by the ISO's preparation of a straw priority list to be further discussed at such meeting, up to two (2) Economic Studies (the costs of which will be recovered by the ISO pursuant to Schedule 1 of Section IV.A of the Tariff) to be performed by the ISO in a given year taking into consideration their impact on the ISO budget and other priorities. The ISO may consider performing up to three (3) Economic Studies if a Public Policy Transmission Study will not be concurrently performed.

- (v) The ISO and the Planning Advisory Committee may agree to hold additional meetings to further discuss and resolve any issue concerning the substance of the Economic Studies themselves and/or their prioritization.
- (vi) If the Planning Advisory Committee, after discussions between the Planning Advisory Committee and ISO management, is not able to prioritize the Economic Studies to be performed by the ISO in a given year, any member of the Planning Advisory Committee must submit a request for Regional Planning Dispute Resolution Process pursuant to Section 12 of this Attachment, such request to be submitted no later than August 30, to resolve the issues concerning the substance of the Economic Studies themselves and/or their prioritization.
- (vii) The ISO will issue a notice to the Planning Advisory Committee detailing the prioritization of the Economic Studies as identified by the Planning Advisory Committee or, if a request for Regional Planning Dispute Resolution Process is submitted pursuant to Section 4.1.(b)(vi), as determined through that Process.

The foregoing timelines are subject to adjustment as determined by the ISO in coordination with the Planning Advisory Committee. The ISO will provide periodic updates on the status of Economic Studies to the Planning Advisory Committee.

Economic Study requests not within the three studies identified in Section 4.1(b)(iv) to be performed in a given year may be requested and paid for by the study proponent.

(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 preliminarily 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.

(I) 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 preliminarily 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.

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 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 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) Substance of Economic Studies to be conducted by the ISO in a given year as specified in Section 4.1(b) of this Attachment; and
- (vi) Prioritization of Economic Studies to be performed in a given year where the Planning Advisory Committee is not able to prioritize them as specified in Section 4.1(b) 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

This Section 16 sets forth the procedures for the ISO's conduct of Longer-Term Transmission Studies. 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.

16.1 Request for Longer-Term Transmission Studies

NESCOE may submit a 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 study. 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; 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 Study report. 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.

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

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

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

Hudson Light & Power Department

Massachusetts Municipal Wholesale Electric Company

Maine Electric Power Company

Middleborough Gas and Electric Department

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

New Hampshire Electric Cooperative, Inc.

New Hampshire Transmission, LLC

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

Shrewsbury Electric & Cable Operations

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

Town of Wallingford CT Dept 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.

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

Emera Maine

Eversource Energy Transmission Ventures, Inc.

Grid America Holdings, Inc.

Hudson Light and Power Department

Maine Electric Power Company

Middleboro Gas & Electric Department

New England Energy Connection, LLC

New England Power Company

New Hampshire Transmission, LLC

Norwood Municipal Light Department

NSTAR Electric Company

Public Service Company of New Hampshire

Taunton Municipal Light Plant

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 and Attachment K of the ISO-NE Open Access Transmission Tariff (“OATT”), ISO-NE selects the preferred Phase or Stage Two 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 Section 4.3(j) or 4A.9(a) of Attachment K of the OATT, ISO-NE notified the Selected QTPS that its project has been selected for development;

WHEREAS, pursuant to Section 4.3(k) or 4A.9(b) 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 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.

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 Section 4.3(l) or 4A.9(c) 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: sqtspa@iso-ne.com

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”.]

III.12. Calculation of Capacity Requirements.

III.12.1. Installed Capacity Requirement.

Prior to each Forward Capacity Auction, the ISO shall calculate the Installed Capacity Requirement for the New England Control Area for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction in accordance with this Section III.12.1.

The ISO shall determine the Installed Capacity Requirement such that the probability of disconnecting non-interruptible customers due to resource deficiency, on average, will be no more than once in ten years. Compliance with this resource adequacy planning criterion shall be evaluated probabilistically, such that the Loss of Load Expectation (“LOLE”) of disconnecting non-interruptible customers due to resource deficiencies shall be no more than 0.1 day each year. The forecast Installed Capacity Requirement shall meet this resource adequacy planning criterion for each Capacity Commitment Period. The Installed Capacity Requirement shall be determined assuming all resources pursuant to Sections III.12.7 and III.12.9 will be deliverable to meet the forecasted demand determined pursuant to Section III.12.8.

If the Installed Capacity Requirement shows a consistent bias over time, either high or low, the ISO shall make adjustments to the modeling assumptions and/or methodology through the stakeholder process to eliminate the bias in the Installed Capacity Requirement. The modeling assumptions used in determining the Installed Capacity Requirement are specified in Sections III.12.7, III.12.8 and III.12.9. For the purpose of this Section III.12, a “resource” shall include generating resources, demand resources, and import capacity resources eligible to receive capacity payments in the Forward Capacity Market.

III.12.1.1. System-Wide Marginal Reliability Impact Values.

Prior to each Forward Capacity Auction, the ISO shall determine the system-wide Marginal Reliability Impact of incremental capacity at various capacity levels for the New England Control Area. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used in determining the Installed Capacity Requirement.

III.12.2. Local Sourcing Requirements and Maximum Capacity Limits.

Prior to each Forward Capacity Auction, the ISO shall calculate the capacity requirements and limitations, accounting for relevant transmission interface limits which shall be determined pursuant to Section

III.12.5, for each modeled Capacity Zone (as described in Section III.12.4) for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction.

The ISO shall use consistent assumptions and standards to establish a resource's electrical location for purposes of qualifying a resource for the Forward Capacity Market and for purposes of calculating Local Sourcing Requirements and Maximum Capacity Limits. The methodology used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.2.1 and III.12.2.2, respectively. The modeling assumptions used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.5, III.12.6, III.12.7, III.12.8 and III.12.9.

III.12.2.1. Calculation of Local Sourcing Requirements for Import-Constrained Capacity Zones.

For each import-constrained Capacity Zone, the Local Sourcing Requirement shall be the amount needed to satisfy the higher of: (i) the Local Resource Adequacy Requirement as determined pursuant to Section III.12.2.1.1; or (ii) the Transmission Security Analysis Requirement as determined pursuant to Section III.12.2.1.2.

III.12.2.1.1. Local Resource Adequacy Requirement.

The Local Resource Adequacy Requirement shall be calculated as follows:

- (a) Two areas shall be modeled: (i) the Capacity Zone under study which includes all load and all resources electrically located within the Capacity Zone, including external Control Area support from tie benefits on the import-constrained side of the interface, if any; and (ii) the rest of the New England Control Area which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits on the unconstrained side of the interface, if any.
- (b) The only transmission constraint to be modeled shall be the transmission interface limit between the Capacity Zone under study and the rest of the New England Control Area as identified pursuant to Section III.12.5.
- (c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area

meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

(d) The Local Resource Adequacy Requirement for the import-constrained Capacity Zone Z shall be determined in accordance with the following formula:

$$LRA_Z = Resources_Z + Proxy Units_Z - (Proxy Units Adjustment_Z(1-FOR_Z)) - (Firm Load Adjustment_Z(1-FOR_Z))$$

In which:

$$LRA_Z = \text{MW of Local Resource Adequacy Requirement for Capacity Zone Z;}$$

$$Resources_Z = \text{MW of resources electrically located within Capacity Zone Z, including import Capacity Resources on the import-constrained side of the interface, if any;}$$

$$Proxy Units_Z = \text{MW of proxy unit additions in Load Zone Z;}$$

$$\begin{aligned} &\text{Firm Load} \\ &Adjustment_Z = \text{MW of firm load added (or subtracted) within Capacity Zone Z to make the LOLE of the New England Control Area equal to 0.105 days per year; and} \end{aligned}$$

$$FOR_Z = \text{Capacity weighted average of the forced outage rate modeled for all resources within Capacity Zone Z, including and proxy unit additions to Capacity Zone Z.}$$

$$\begin{aligned} &\text{Proxy Units} \\ &Adjustment = \text{MW of firm load added to (or unforced capacity subtracted from) Capacity Zone Z until the system LOLE equals 0.1} \end{aligned}$$

days/year.

To determine the Local Resource Adequacy Requirement, the firm load is adjusted within Capacity Zone Z until the LOLE of the New England Control Area reaches 0.105 days per year. The LOLE of 0.105 days per year includes an allowance for transmission related LOLE of 0.005 days per year associated with each interface. As firm load is added to (or subtracted from) Capacity Zone Z, an equal amount of firm load is removed from (or added to) the rest of New England Control Area.

III.12.2.1.2. Transmission Security Analysis Requirement.

A Transmission Security Analysis shall be used to determine the requirement of the zone being studied, and shall include the following features:

- (a) The ISO shall perform a series of transmission load flow studies and/or a deterministic operable capacity analysis targeted at determining the performance of the system under stressed conditions, and at developing a resource requirement sufficient to allow the system to operate through those stressed conditions.
- (b) The Transmission Security Analysis Requirement shall be set at a level sufficient to cover most reasonably anticipated events, but will not guarantee that every combination of obligated resources within the zone will meet system needs.
- (c) In performing the Transmission Security Analysis, the ISO may establish static transmission interface transfer limits, as identified pursuant to Section III.12.5, as a reasonable representation of the transmission system's capability to serve load with available existing resources.
- (d) The Transmission Security Analysis may model the entire New England system and individual zones, for both the first contingency (N-1) and second contingency (N-1-1) conditions. First contingency conditions (N-1) shall include the loss of the most critical generator or most critical transmission element with respect to the zone. Second contingency conditions (N-1-1) shall include both: (i) the loss of the most critical generator with respect to the zone followed by the loss of the most critical transmission element ("Line-Gen"); and (ii) the loss of the most critical transmission element followed by the loss of the next most critical transmission element ("Line-Line") with respect to the zone.

III.12.2.1.3. Marginal Reliability Impact Values for Import-Constrained Capacity Zones.

Prior to each Forward Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for each import-constrained Capacity Zone. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used to determine the Local Resource Adequacy Requirement pursuant to Section III.12.2.1.1, except that the capacity transfer capability between the Capacity Zone under study and the rest of the New England Control Area determined pursuant to Section III.12.2.1.1(b) shall be reduced by the greater of: (i) the Transmission Security Analysis Requirement minus the Local Resource Adequacy Requirement, and; (ii) zero.

III.12.2.2. Calculation of Maximum Capacity Limit for Export-Constrained Capacity Zones.

For each export-constrained Capacity Zone, the Maximum Capacity Limit shall be calculated using the following method:

- (a) Two areas shall be modeled: (i) the Capacity Zone under study which includes all load and all resources electrically located within the Capacity Zone, including external Control Area support from tie benefits on the export-constrained side of the interface, if any; and (ii) the rest of the New England Control Area, which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits to the rest of the New England Control Area, if any.
- (b) The only transmission constraint to be modeled shall be the transmission interface limit between the Capacity Zone under study and the rest of the New England Control Area as identified pursuant to Section III.12.5.
- (c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.
- (d) The Maximum Capacity Limit for the export-constrained Capacity Zone Y shall be determined in accordance with the following formula:

$$\text{Maximum Capacity Limit}_Y = \text{ICR} - \text{LRA}_{\text{Rest of New England}}$$

In which:

Maximum Capacity Limit_Y = Maximum MW amount of resources , including Import Capacity Resources on the export-constrained side of the interface, if any, that can be procured in the export-constrained Capacity Zone Y to meet the Installed Capacity Requirement;

ICR = MW of Installed Capacity Requirement for the New England Control Area, determined in accordance with Section III.12.1; and

LRA_{Rest of New England} = MW of Local Sourcing Requirement for the rest of the New England Control Area, which for the purposes of this calculation is treated as an import-constrained region, determined in accordance with Section III.12.2.1.

III.12.2.2.1. Marginal Reliability Impact Values for Export-Constrained Capacity Zones.

Prior to each Forward Capacity Auction, the ISO shall determine the Marginal Reliability Impact of incremental capacity, at various capacity levels, for each export-constrained Capacity Zone. For purposes of calculating these Marginal Reliability Impact values, the ISO shall apply the same modeling assumptions and methodology used to determine the export-constrained Capacity Zone's Maximum Capacity Limit.

III.12.3 Consultation and Filing of Capacity Requirements.

At least two months prior to filing the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission, the ISO shall review the modeling assumptions and resulting Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves with the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. Following consultation with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO shall file the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits, System-Wide Capacity Demand Curve and Capacity Zone Demand Curves

for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission pursuant to Section 205 of the Federal Power Act 90 days prior to the Forward Capacity Auction for the Capacity Commitment Period. The ISO shall file with the Commission pursuant to Section 205 of the Federal Power Act, the proposed identification of a potential new Capacity Zone when the boundary of the potential new Capacity Zone differs from the boundaries of existing Load Zones or Capacity Zones. In order to be used in a given FCA, any new Capacity Zone must have received approval from the Commission prior to the Existing Capacity Qualification Deadline of the applicable FCA.

III.12.4. Capacity Zones.

For each Forward Capacity Auction, the ISO shall, using the results of the most recent annual assessment of transmission transfer capability conducted pursuant to ISO Tariff Section II, Attachment K, determine the Capacity Zones to model as described below, and will include such designations in its filing with the Commission pursuant to Section III.13.8.1(c):

- (a) The ISO shall model in the Forward Capacity Auction, as separate export-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the Maximum Capacity Limit is less than the sum of the existing Qualified Capacity and proposed new capacity that could qualify to be procured in the export constrained Capacity Zone, including existing and proposed new Import Capacity Resources on the export-constrained side of the interface.
- (b) The ISO shall model in the Forward Capacity Auction, as separate import-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the second contingency transmission capability results in a line-line Transmission Security Analysis Requirement, calculated pursuant to Section III.12.2.1.2 and pursuant to ISO New England Planning Procedures, that is greater than the existing Qualified Capacity in the zone, with the largest generating station in the zone modeled as out-of-service. Each assessment will model out-of-service all Retirement De-List Bids and Permanent De-List Bids (including any received for the current Forward Capacity Auction at the time of this calculation), substitution auction demand bids submitted for the current Forward Capacity Auction, rejected for reliability Static De-List Bids from the most recent previous Forward Capacity Auction, and rejected for reliability Dynamic De-List Bids from the most recent previous Forward Capacity Auction.

(c) Adjacent Load Zones that are neither export-constrained nor import-constrained shall be modeled together as the Rest of Pool Capacity Zone in the Forward Capacity Auction.

III.12.4A. Dispatch Zones.

The ISO shall establish Dispatch Zones that reflect potential transmission constraints within a Load Zone that are expected to exist during each Capacity Commitment Period. Dispatch Zones shall be used to establish the geographic location of Active Demand Capacity Resources. For each Capacity Commitment Period, the ISO shall establish and publish Dispatch Zones by the beginning of the New Capacity Show of Interest Submission Window of the applicable Forward Capacity Auction, and those Dispatch Zones shall remain in place through the end of the Capacity Commitment Period for which they were established. The ISO will review proposed Dispatch Zones with Market Participants prior to establishing and publishing final Dispatch Zones.

III.12.5. Transmission Interface Limits.

Transmission interface limits, used in the determination of Local Sourcing Requirements, shall be determined pursuant to ISO Tariff Section II, Attachment K using network models that include all resources, existing transmission lines and proposed transmission lines that the ISO determines, in accordance with Section III.12.6, will be in service no later than the first day of the relevant Capacity Commitment Period. The transmission interface limits shall be established, using deterministic analyses, at levels that provide acceptable thermal, voltage and stability performance of the system both with all lines in service and after any criteria contingency occurs as specified in ISO New England Manuals and ISO New England Administrative Procedures.

III.12.6. Modeling Assumptions for Determining the Network Model.

The ISO shall determine, in accordance with this Section III.12.6, the generating units and transmission infrastructure to include in the network model that: (i) are expected to be in service no later than the first day of the relevant Capacity Commitment Period; and (ii) may have a material impact on the network model, a potential interface constraint, or on one or more Local Sourcing Requirements. The network model shall be used, among other purposes, (i) for the Forward Capacity Market qualification process and (ii) to calculate transmission interface limits in order to forecast the Local Sourcing Requirements. The network model shall include:

(a) For the relevant Capacity Commitment Period, the network model shall include:

- (i) all existing resources, along with any associated interconnection facilities and/or Elective Transmission Upgrades that have not been approved to be retired for the relevant Capacity Commitment Period, as described in Sections III.13.2.5.2.5.3 and III.13.2.8.3;
 - (ii) all new resources with Qualified Capacity for the relevant Capacity Commitment Period, along with any associated interconnection facilities and/or Elective Transmission Upgrades; and
 - (iii) in the case of an initial interconnection analysis that is conducted consistent with the Network Capability Interconnection Standard, any generating unit or External Elective Transmission Upgrade that has a valid Interconnection Request and is reasonably expected to declare commercial operation no later than the first day of the relevant Capacity Commitment Period.
- (b) Prior to each Forward Capacity Auction and each annual reconfiguration auction, the ISO shall determine and publish a list of the transmission projects and elements of transmission projects that will be included in the network model. During the process of making the transmission infrastructure determinations, as described in Section III.12.6.1, the ISO shall consult with the Governance Participants, the Transmission Owners, any transmission project proponents, the state utility regulatory agencies in New England and, as appropriate, other state agencies.

III.12.6.1. Process for Establishing the Network Model.

- (a) The ISO shall establish an initial network model prior to the Forward Capacity Auction that only includes transmission infrastructure, including Internal Elective Transmission Upgrades, that is already in service at the time that the initial network model is developed.
- (b) After establishing the initial network model, the ISO shall compile a preliminary list of the transmission projects or elements of transmission projects in the RSP Project List, individually or in combination with each other, as appropriate, to identify transmission projects that may achieve an in-service date no later than the first day of the relevant Capacity Commitment Period and that will have a material impact on the network model, on a potential interface constraint or one or more Local Sourcing Requirements.
- (c) For the transmission projects or elements of transmission projects in the RSP Project List that are included in the preliminary list developed pursuant to subsection (b), the ISO shall determine whether the

transmission projects or elements of transmission projects meet all of the initial threshold milestones specified in Section III.12.6.2 and will be considered for further evaluation pursuant to subsection (d).

(d) For those transmission projects or elements of transmission projects that meet the initial threshold milestones in subsection (c), the ISO shall use the evaluation criteria specified in Section III.12.6.3, and any other relevant information, to determine whether to include a transmission project or element of a transmission project in the final network model.

(e) If after completing its evaluation pursuant to Sections III.12.6.1 through III.12.6.3 and conferring with the transmission project proponents, the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO determines that the transmission project or a portion of the transmission project is reasonably expected to be in service no later than the first day for the relevant Capacity Commitment Period, then such transmission project or portion of transmission project shall be considered in service in the finalized network model to calculate the transmission interface limits pursuant to Section III.12.5.

III.12.6.2. Initial Threshold to be Considered In-Service.

The ISO shall determine whether transmission projects or elements of transmission projects meet all of the following initial threshold milestones:

(a) A critical path schedule for the transmission project has been furnished to ISO showing that the transmission project or the element of the transmission project will be in-service no later than the first day of the relevant Capacity Commitment Period. The critical path schedule must be sufficiently detailed to allow the ISO to evaluate the feasibility of the schedule.

(b) At the time of the milestone review, siting and permitting processes, if required, are on schedule as shown on the critical path schedule.

(c) At the time of the milestone review, engineering is on schedule as shown on the critical path schedule.

(d) At the time of the milestone review, land acquisition, if required, is on schedule as shown on the critical path schedule.

(e) Corporate intent to build the transmission project has been furnished to the ISO. An officer of the host Transmission Owner or Elective Transmission Upgrade Interconnection Customer has submitted to the ISO a statement verifying that the officer has reviewed the proposal and critical path schedule submitted to the ISO, and the Transmission Owner or Elective Transmission Upgrade Interconnection Customer concurs that the schedule is achievable, and it is the intent of the Transmission Owner or Elective Transmission Upgrade Interconnection Customer to build the proposed transmission project in accordance with that schedule. The Transmission Owner or Elective Transmission Upgrade Interconnection Customer may develop alternatives or modifications to the transmission project during the course of design of the transmission project that accomplish at least the same transfer capability. Such alternatives or modifications are acceptable, so long as the ISO determines that the alternative or modification is reasonably expected to achieve an in-service date no later than the first day of the relevant Capacity Commitment Period. The provision of an officer's statement shall be with the understanding that the statement shall not create any liability on the officer and that any liability with respect to the Transmission Owner's obligations shall be as set forth in the Transmission Operating Agreement and shall not be affected by such officer's statement.

III.12.6.3. Evaluation Criteria.

For a transmission project or element of a transmission project that meets the initial threshold milestones specified in Section III.12.6.2, the ISO shall consider the following factors and any other relevant information to determine whether to include the transmission project or element of the transmission project in the network model for the relevant Capacity Commitment Period.

(a) Sufficient engineering to initiate construction is on schedule as shown on the critical path schedule.

(b) Approval under Section I.3.9 of the Transmission, Markets and Services Tariff, if required, has been obtained or is on schedule to be obtained as shown on the critical path schedule.

(c) Significant permits, including local permits, if required to initiate construction have been obtained or are on schedule consistent with the critical path schedule.

(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 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 additional capacity to determine the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values. The proxy units shall reflect resource capacity and outage characteristics such that when the proxy units are used in place of all

other resources in the New England Control Area, the reliability, or LOLE, of the New England Control Area does not change. The outage characteristics are the summer capacity weighted average availability of the resources in the New England Control Area as determined in accordance with Section III.12.7.3. The capacity of the proxy unit is determined by adjusting the capacity of the proxy unit until the LOLE of the New England Control Area is equal to the LOLE calculated while using the capacity assumptions described in Section III.12.7.2.

When modeling transmission constraints for the determination of Local Resource Adequacy Requirements, the same proxy units may be added to the import-constrained zone or elsewhere in the rest of the New England Control Area depending on where system constraints exist.

III.12.7.2. Capacity.

The resources included in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall include:

- (a) all Existing Generating Capacity Resources,
- (b) resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period,
- (c) all Existing Import Capacity Resources backed by a multiyear contract to provide capacity in the New England Control Area, where that multiyear contract requires delivery of capacity for the Commitment Period for which the Installed Capacity Requirement is being calculated, and
- (d) Existing Demand Capacity Resources that are qualified to participate in the Forward Capacity Market and New Demand Capacity Resources that have cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period,

but shall exclude:

- (e) capacity associated with Export Bids cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period,

(f) capacity de-listed or retired as a result of Permanent De-List Bids, Retirement De-List Bids, or substitution auction demand bids that cleared in previous Forward Capacity Auctions, and

(g) capacity retired pursuant to Section III.13.1.2.4.1(a), unless the Lead Market Participant has opted to have the resource reviewed for reliability pursuant to Section III.13.1.2.3.1.5.1.

The rating of Existing Generating Capacity Resources and Existing Import Capacity Resources used in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be the summer Qualified Capacity value of such resources for the relevant zone. The rating of Demand Capacity Resources shall be the summer Qualified Capacity value reduced by any reserve margin adjustment factor that is otherwise included in the summer Qualified Capacity value. The rating of resources, except for Demand Capacity Resources, cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period shall be based on the amount of Qualified Capacity that cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period. Resources are located within the Capacity Zones in which they are electrically connected as determined during the qualification process.

III.12.7.2.1. [Reserved.]

III.12.7.3. Resource Availability.

The Installed Capacity Requirement, Local Resource Adequacy Requirements, Transmission Security Analysis Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated taking resource availability into account and shall be determined as follows:

For Existing Generating Capacity Resources:

(a) The most recent five-year moving average of EFORD shall be used as the measure of resource availability used in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Transmission Security Analysis Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

(b) [Reserved.]

For resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period that do not have sufficient data to calculate an availability metric as defined in subsection (a) above, class average data for similar resource types shall be used.

For existing Active Demand Capacity Resources:

Historical performance data for those resources will be used to develop an availability metric for use in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values.

III.12.7.4. Load and Capacity Relief.

Load and capacity relief expected from system-wide implementation of the following actions specified in ISO New England Operating Procedure No. 4. Action During a Capacity Deficiency, shall be included in the calculation of the Installed Capacity Requirement, Local Resource Adequacy Requirements, Maximum Capacity Limits and Marginal Reliability Impact values:

- (a) **Implement voltage reduction.** The MW value of the load relief shall be equal to 1% of (the 90/10 forecasted seasonal net peak loads minus all Existing Demand Capacity Resources).
- (b) **Arrange for available Emergency energy from Market Participants or neighboring Control Areas.** These actions are included in the calculation through the use of tie benefits to meet system needs. The MW value of tie benefits is calculated in accordance with Section III.12.9.
- (c) **Maintain an adequate amount of ten-minute synchronized reserves.** The amount of system reserves included in the determination of the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be consistent with those needed for reliable system operations during Emergency Conditions. When modeling transmission constraints, the reserve requirement for a zone shall be the zone's pro rata share of the forecasted system peak load multiplied by the system reserves needed for reliable system operations during Emergency Conditions.

III.12.8. Load Modeling Assumptions.

The ISO shall forecast load for the New England Control Area and for each Load Zone within the New England Control Area. The load forecasts shall be based on appropriate models and data inputs. Each year, the load forecasts and underlying methodologies, inputs and assumptions shall be reviewed with

Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. If the load forecast shows a consistent bias over time, either high or low, the ISO shall propose adjustments to the load modeling methodology to the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies to eliminate the bias. To ensure that Demand Response Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources are not reflected as reductions in the load forecast, the ISO shall reflect them in historical loads as specified below.

(a) The ISO shall add back into historical loads the metered MW demand reduction of Demand Response Resources dispatched by the ISO.

(b) [Reserved.]

(c) [Reserved.]

(d) The ISO shall add back into historical loads summer and winter MW values to account for On-Peak Demand Resources and Seasonal Peak Demand Resources as follows:

The ISO shall develop a trend line between (i) the point when summer MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are assumed to be zero (June 1, 2006) and (ii) the point when summer MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are reflected by the Capacity Supply Obligations that those resources acquired in the most recent Forward Capacity Auction for June 1 of the associated Capacity Commitment Period. To determine the summer MW values to be added back into historical loads, the ISO shall apply the resulting trend to the summer months (April through November) in all the historical years covered by the trend line.

The ISO shall develop a trend line between (i) the point when winter MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are assumed to be zero (December 1, 2006) and (ii) the point when winter MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are reflected by the Capacity Supply Obligations that those resources acquired in the most recent Forward Capacity Auction for December 1 of the associated Capacity Commitment Period. To determine the winter MW values to be added back into historical loads, the ISO shall apply the resulting trend to the winter months (December through March) in all the historical years covered by the trend line.

The ISO shall make adjustments to forecasted loads to account for any differences between the most recently available MW values reflective of the Capacity Supply Obligations that On-Peak Demand Resources and Seasonal Peak Demand Resources acquired in each of the annual reconfiguration auctions and the MW values reflective of the Capacity Supply Obligations that those resources acquired in the corresponding Forward Capacity Auctions.

III.12.9. Tie Benefits.

The Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values shall be calculated assuming appropriate tie benefits, if any, available from interconnections with neighboring Control Areas. Tie benefits shall be calculated only for interconnections (1) without Capacity Network Import Interconnection Service or Network Import Interconnection Service or (2) that have not requested Capacity Network Import Interconnection Service or Network Import Interconnection Service with directly interconnected neighboring Control Areas with which the ISO has in effect agreements providing for emergency support to New England, including but not limited to inter-Control Area coordination agreements, emergency aid agreements and the NPCC Regional Reliability Plan.

Tie benefits shall be calculated using a probabilistic multi-area reliability model, by comparing the LOLE for the New England system before and after interconnecting the system to the neighboring Control Areas. To quantify tie benefits, firm capacity equivalents shall be added until the LOLE of the isolated New England Control Area is equal to the LOLE of the interconnected New England Control Area.

III.12.9.1. Overview of Tie Benefits Calculation Procedure.

III.12.9.1.1. Tie Benefits Calculation for the Forward Capacity Auction and Annual Reconfiguration Auctions; Modeling Assumptions and Simulation Program.

For each Capacity Commitment Period, tie benefits shall be calculated for the Forward Capacity Auction and the third annual reconfiguration auction using the calculation methodology in this Section III.12.9.

For the first and second annual reconfiguration auctions for a Capacity Commitment Period, the tie benefits calculated for the associated Forward Capacity Auction shall be utilized in determining the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values as adjusted to account for any changes in import capability of interconnections with neighboring Control Areas and changes in import capacity resources using the methodologies in Section III.12.9.6.

Tie benefits shall be calculated using the modeling assumptions developed in accordance with Section III.12.9.2 and using the General Electric Multi-area Reliability Simulation (MARS) program.

III.12.9.1.2. Tie Benefits Calculation.

The total tie benefits to New England from all directly interconnected neighboring Control Areas are calculated first using the methodology in Section III.12.9.3. Following the calculation of total tie benefits, individual tie benefits from each qualifying neighboring Control Area are calculated using the methodology in Section III.12.9.4.1. If the sum of the tie benefits from each Control Area does not equal the total tie benefits to New England, then each Control Area's tie benefits are adjusted based on the ratio of the individual Control Area tie benefits to the sum of the tie benefits calculated for each Control Area using the methodology in Section III.12.9.4.2. Following this calculation, tie benefits are calculated for each qualifying individual interconnection or group of interconnections using the methodology in Section III.12.9.5.1. If the sum of the tie benefits from individual interconnections or groups of interconnections does not equal their associated Control Area's tie benefits, then the tie benefits of each individual interconnection or group of interconnections is adjusted based on the ratio of the tie benefits of the individual interconnection or group of interconnections to the sum of the tie benefits within the Control Area using the methodology in Section III.12.9.5.2.

III.12.9.1.3. Adjustments to Account for Transmission Import Capability and Capacity Imports.

Once the initial calculation of tie benefits is performed, the tie benefits for each individual interconnection or group of interconnections is adjusted to account for capacity imports and any changes in the import capability of interconnections with neighboring Control Areas, using the methodologies in Section III.12.9.6. Once the import capability and capacity import adjustments are completed, the sum of the tie benefits of all individual interconnections and groups of interconnections for a Control Area, with the import capability and capacity import adjustments, represents the tie benefits associated with that Control Area, and the sum of the tie benefits from all Control Areas, with the import capability and capacity import adjustments, represents the total tie benefits available to New England.

III.12.9.2. Modeling Assumptions and Procedures for the Tie Benefits Calculation.

III.12.9.2.1. Assumptions Regarding System Conditions.

In calculating tie benefits, “at criterion” system conditions shall be used to model the New England Control Area and all interconnected Control Areas.

III.12.9.2.2. Modeling Internal Transmission Constraints in New England.

In calculating tie benefits, all New England internal transmission constraints that (i) are modeled in the most recent Regional System Plan resource adequacy studies and assessments and (ii) are not addressed by either a Local Sourcing Requirement or a Maximum Capacity Limit calculation shall be modeled, using the procedures in Section III.12.9.2.5.

III.12.9.2.3. Modeling Transmission Constraints in Neighboring Control Areas.

The ISO will review annually NPCC’s assumptions regarding transmission constraints in all directly interconnected neighboring Control Areas that are modeled for the tie benefits calculations. In the event that NPCC models a transmission constraint in one of the modeled neighboring Control Areas, the ISO will perform an evaluation to determine which interfaces are most critical to the ability of the neighboring Control Area to reliably provide tie benefits to New England from both operational and planning perspectives, and will model those transmission constraints in the tie benefits calculation, using the procedures in Section III.12.9.2.5.

III.12.9.2.4. Other Modeling Assumptions.

- A. External transfer capability determinations. The transfer capability of all external interconnections with New England will be determined using studies that take account of the load, resource and other electrical system conditions that are consistent with those expected during the Capacity Commitment Period for which the calculation is being performed. Transfer capability studies will be performed using simulations that consider the contingencies enumerated in sub-section (iii) below.

- (i) The transmission system will be modeled using the following conditions:
 - 1. The forecast 90/10 peak load conditions for the Capacity Commitment Period;
 - 2. Qualified Existing Generating Capacity Resources reflecting their output at their Capacity Network Resource level;
 - 3. Qualified Existing Demand Capacity Resources reflecting their Capacity Supply Obligation received in the most recent Forward Capacity Auction;
 - 4. Transfers on the transmission system that impact the transfer capability of the interconnection under study.

- (ii) The system will be modeled in a manner that reflects the design of the interconnection. If an interconnection and its supporting system upgrades were designed to provide incremental capacity into the New England Control Area, simulations will assume imports up to the level that the interconnection was designed to support. If the interconnection was not designed to be so comparably integrated, simulations will determine the amount of power that can be delivered into New England over the interconnection.
- (iii) The simulations will take into account contingencies that address a fault on a generator or transmission facility, loss of an element without a fault, and circuit breaker failure following the loss of an element or an association with the operation of a special protection system.

- B.** In calculating tie benefits, New England capacity exports are removed from the internal capacity resources and are modeled as a resource in the receiving Control Area. The transfer capability of external interconnections is not adjusted to account for capacity exports.

III.12.9.2.5. Procedures for Adding or Removing Capacity from Control Areas to Meet the 0.1 Days Per Year LOLE Standard.

In calculating tie benefits, capacity shall be added or removed from the interconnected system of New England and its neighboring Control Areas, until the LOLE of New England and the LOLE of each Control Area of the interconnected system equals 0.1 days per year simultaneously. The following procedures shall be used to add or remove capacity within New England and the interconnected Control Areas to achieve that goal.

- A. Adding Proxy Units within New England when the New England system is short of capacity.** In modeling New England as part of the interconnected system, if New England is short of capacity to meet the 0.1 days per year LOLE, proxy units (with the characteristics identified in Section III.12.7.1) will be added to the sub-areas that are created by any modeled internal transmission constraints within New England, beginning with the sub-area with the highest LOLE. If there are no modeled internal transmission constraints in the New England Control Area, then proxy units will be added to the entire Control Area. If, as a result of the addition of one or more proxy units, the system is surplus of capacity, then the methodology in Section III.12.9.2.5(b) will be used to remove the surplus capacity.
- B. Removing capacity from New England when the New England system is surplus of capacity.** In modeling New England as part of the interconnected system, if New England is

surplus of capacity to meet the 0.1 days per year LOLE, the surplus capacity will be removed from the sub-areas as follows. Resources will be removed from sub-areas with capacity surplus based on the ratio of capacity surplus in the sub-area to the total capacity surplus in these surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the existing Qualified Capacity, and any amount of proxy units added in that sub-area that is above its 50/50 peak load forecast. Notwithstanding the foregoing, if removing resources will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas using the same ratios described above for the removal of capacity surplus. If there are no modeled internal transmission constraints in the New England Control Area, then the surplus capacity shall be removed from the entire Control Area.

C. Adding capacity within neighboring Control Areas when the neighboring Control Area is short of capacity. In modeling neighboring Control Areas as part of the interconnected system, if the neighboring Control Area is short of capacity to meet the 0.1 days per year LOLE, additional capacity will be added to the neighboring Control Area's sub-areas that are created by any modeled internal transmissions constraints, beginning with the sub-area with the highest LOLE. If there are no modeled internal transmission constraints in the Control Area, then capacity will be added to the entire Control Area. The process that the neighboring Control Area utilizes in its resource adequacy study to meet its resource adequacy criterion will be utilized to add capacity to that Control Area. In filing the Installed Capacity Requirement values pursuant to Section III.12.3, the ISO will provide citations to any resource adequacy studies relied upon for these purposes. If, as a result of the capacity addition, the system is surplus of capacity, then the methodology in Section III.12.9.2.5(d) shall be used to remove the surplus capacity.

D. Removing capacity from neighboring Control Areas when the neighboring Control Area is surplus of capacity. In modeling neighboring Control Areas as part of the interconnected system, if the neighboring Control Area is surplus of capacity to meet the 0.1 days per year LOLE, the surplus capacity will be removed from the neighboring Control Area's sub-areas as follows. Resources will be removed from sub-areas with capacity surplus based on the ratio of capacity surplus in the sub-area to the total capacity surplus in the surplus sub-areas. The amount of capacity surplus for a sub-area is the amount of the installed capacity in the sub-area above its 50/50 peak load forecast. For a sub-area that has a minimum locational resource requirement above its 50/50 peak load forecast, the amount of capacity surplus is the amount of the installed capacity in the sub-area above its minimum

locational resource requirement. Notwithstanding the foregoing, if removing resources from a sub-area will exacerbate a binding transmission constraint, then capacity will not be removed from that sub-area and will instead be removed from the remaining sub-areas using the same ratio of capacity surplus in the sub-area to the total capacity surplus in the those remaining surplus sub-areas. If there are no modeled internal transmission constraints in the neighboring Control Area, then the surplus capacity will be removed from the entire Control Area.

- E. Maintaining the neighboring Control Area's locational resource requirements.** In modeling a neighboring Control Area with internal transmission constraints, all minimum locational resource requirements in the Control Area's sub-areas as established by the neighboring Control Area's installed capacity requirement calculations shall be observed.

III.12.9.3. Calculating Total Tie Benefits.

The total tie benefits with all qualifying directly interconnected neighboring Control Areas shall be calculated by comparing the interconnection state of the New England system with all interconnections to neighboring Control Areas connected with the interconnection state of the New England system with all interconnections with neighboring Control Areas disconnected. To calculate total tie benefits:

- A.** The New England system shall be interconnected with all directly interconnected neighboring Control Areas and the New England Control Area, and each neighboring Control Area shall be brought to 0.1 days per year LOLE simultaneously by adjusting the capacity of each Control Area, utilizing the methods for adding or removing capacity in Section III.12.9.2.5.
- B.** Once the interconnected system is brought to 0.1 days per year LOLE, the LOLE of the New England Control Area shall be calculated a second time, with the New England system isolated from the rest of the interconnected system that was brought to 0.1 days per year LOLE.
- C.** Total tie benefits shall be the sum of the amounts of firm capacity that needs to be added to the isolated New England Control Area at the point at which each interconnection with neighboring Control Areas interconnects in New England to bring the New England LOLE back to 0.1 days per year. This value is subject to adjustment in accordance with Section III.12.9.6.

III.12.9.4. Calculating Each Control Area's Tie Benefits.

III.12.9.4.1. Initial Calculation of a Control Area's Tie Benefits.

Tie benefits from each neighboring Control Area shall be determined by calculating the tie benefits for every possible interconnection state that has an impact on the tie benefit value between the New England system and the target neighboring Control Area. If two or more interconnections between New England and the target neighboring Control Area exist, then all interconnections grouped together will be used to represent the state of interconnection between New England and the target neighboring Control Area. The tie benefits from the target neighboring Control Area shall be equal to the simple average of the tie benefits calculated from all possible interconnection states, subject to adjustment in accordance with Section III.12.9.4.2.

III.12.9.4.2. Pro Ration Based on Total Tie Benefits.

If the sum of the individual Control Area tie benefits calculated in accordance with Section III.12.9.4.1 is different than the total tie benefits from all Control Areas calculated in accordance with Section III.12.9.3, then each Control Area's tie benefits shall be increased or decreased based on the ratio of the individual Control Area tie benefits to the sum of the tie benefits for each individual Control Area, so that the sum of each Control Area's tie benefits, after the pro-ration, is equal to the total tie benefits calculated in accordance with Section III.12.9.3. The pro-rated Control Area tie benefits are subject to further adjustment in accordance with Section III.12.9.6.

III.12.9.5. Calculating Tie Benefits for Individual Ties.

Tie benefits shall be calculated for an individual interconnection or group of interconnections to the extent that a discrete and material transfer capability can be identified for the interconnection or group of interconnections. All interconnections or groups of interconnections shall have equal rights in calculating individual tie benefits, with no grandfathering or incremental tie capability treatment.

For purposes of calculating tie benefits, a group of interconnections refers to two or more AC lines that operate in parallel to form a transmission interface in which there are significant overlapping contributions of each line toward establishing the transfer limit, such that the individual lines in a group of interconnections cannot be assigned individual contributions.

III.12.9.5.1. Initial Calculation of Tie Benefits for an Individual Interconnection or Group of Interconnections.

Tie benefits for an individual interconnection or group of interconnections shall be calculated by calculating tie benefits for each possible interconnection state between the New England system and the individual interconnection or group of interconnections. The tie benefits from that interconnection or

group of interconnections shall be equal to the simple average of the tie benefits calculated from all possible interconnection states, subject to adjustment in accordance with Section III.12.9.5.2.

III.12.9.5.2. Pro Ration Based on Total Tie Benefits.

If the sum of the individual interconnection's or group of interconnection's tie benefits calculated in accordance with Section III.12.9.5.1 is different than the associated Control Area's tie benefits calculated in accordance with Section III.12.9.4, then the tie benefits of the individual interconnection or group of interconnections shall be adjusted based on the ratio of the tie benefits of the individual interconnection or group of interconnections to the sum of the tie benefits for each interconnection or group of interconnections in that Control Area, so that the sum of the tie benefits for each interconnection or group of interconnections in the Control Area, after the pro-ration, is equal to the total tie benefits for the Control Area calculated in accordance with Section III.12.9.4. The pro-rated tie benefits for each interconnection or group of interconnections is subject to further adjustment in accordance with Section III.12.9.6.

III.12.9.6. Accounting for Capacity Imports and Changes in External Transmission Facility Import Capability.

III.12.9.6.1. Accounting for Capacity Imports.

In the initial tie benefits calculations, capacity imports are modeled as internal resources in New England, and the import capability of the interconnections with neighboring Control Areas is not reduced to reflect the impact of capacity imports. After the initial tie benefits calculations, total tie benefits, tie benefits for each Control Area, and tie benefits from each individual interconnection or group of interconnections shall be adjusted to account for capacity imports using the methodology contained in this Section III.12.9.6.1. For the Forward Capacity Auction and third annual reconfiguration auction, this adjustment shall be applied to the tie benefit values calculated in accordance with Sections III.12.9.3, III.12.9.4 and III.12.9.5 respectively. For the first and second annual reconfiguration auctions, this adjustment shall be applied to the tie benefits values calculated for the Forward Capacity Auction.

- A.** Capacity imports shall be deducted from the import capability of each individual interconnection or group of interconnections to determine the available import capability of the interconnection or group of interconnections prior to accounting for tie benefits from those interconnections. The transfer capability of an interconnection or group of interconnections shall be determined using the procedures in Section III.12.9.2.4.A.

- B.** If the tie benefits value of an individual interconnection or group of interconnections, as determined in accordance with Section III.12.9.5, is greater than the remaining transmission import capability of the interconnection or group of interconnections after accounting for capacity imports, the tie benefit value of the individual interconnection or group of interconnections shall be equal to the remaining transmission import capability (taking into account any further adjustments to transmission import capability in accordance with Section III.12.9.6.2). If the tie benefits value of an individual interconnection or group of interconnections is not greater than the remaining transmission import capability after accounting for capacity imports, then the tie benefit value of the individual interconnection or group of interconnections shall be equal to the value determined in accordance with Section III.12.9.5 (taking into account any further adjustments to transmission import capability in accordance with Section III.12.9.6.2).
- C.** The tie benefits for each Control Area shall be the sum of the tie benefits from the individual interconnections or groups of interconnections with that Control Area, after accounting for any adjustment for capacity imports and any further adjustments to transmission import capability in accordance with Section III.12.9.6.2.
- D.** The total tie benefits from all qualifying neighboring Control Areas shall be the sum of the Control Area tie benefits, after accounting for any adjustment for capacity imports and any further adjustments to transmission import capability in accordance with Section III.12.9.6.2.
- E.** For purposes of determining the adjustment to tie benefits to account for capacity imports under this Section III.12.9.6.1, the capacity imports applicable for determining tie benefits for the Forward Capacity Auction shall be the Qualified Existing Import Capacity Resources for the relevant Capacity Commitment Period, and the capacity imports applicable for determining tie benefits for the annual reconfiguration auctions are those Import Capacity Resources that hold Capacity Supply Obligations for the relevant Capacity Commitment Period as of the time the tie benefits calculation is being performed for the annual reconfiguration auction.

III.12.9.6.2. Changes in the Import Capability of Interconnections with Neighboring Control Areas.

For purposes of calculating tie benefits for the Forward Capacity Auction and third annual reconfiguration auction, the most recent import capability values for an interconnection or group of interconnections with a neighboring Control Area shall be reflected in the modeling of system conditions for the tie benefits calculation. In addition, for the first and second annual reconfiguration auctions, any changes to the

import capability of an interconnection or group of interconnections with a neighboring Control Area shall be reflected in the adjustment to tie benefits to account for capacity imports under Section III.12.9.6.1.

III.12.9.7. Tie Benefits Over the HQ Phase I/II HVDC-TF.

The tie benefits from the Quebec Control Area over the HQ Phase I/II HVDC-TF calculated in accordance with Section III.12.9.1 shall be allocated to the Interconnection Rights Holders or their designees in proportion to their respective percentage shares of the HQ Phase I and the HQ Phase II facilities, in accordance with Section I of the Transmission, Markets and Services Tariff.

III.12.10. Calculating the Maximum Amount of Import Capacity Resources that May be Cleared Over External Interfaces in the Forward Capacity Auction and Reconfiguration Auctions.

For external interfaces, Import Capacity Resources shall be allowed in the Forward Capacity Auction and reconfiguration auctions up to the interface limit minus the tie benefits, calculated pursuant to Section III.12.9.1 or 12.9.2 over the applicable interface.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

ISO New England Inc.
New England Power Pool

)

Docket No. ER22-____-000

**PREPARED TESTIMONY OF MR. BRENT K. OBERLIN
ON BEHALF OF ISO NEW ENGLAND INC.**

Q: PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A: My name is Brent K. Oberlin. I am Director of Transmission Planning with ISO New England Inc. (the “ISO”). My business address is One Sullivan Road, Holyoke, Massachusetts 01040-2841.

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A: I have a Bachelor of Science degree from Rensselaer Polytechnic Institute and I am a Licensed Professional Engineer in the State of Connecticut. In my current position of Director, Transmission Planning, which I have held since 2010, I oversee regional bulk electric power system planning, including the implementation of the Regional System Planning Process under Attachment K of the ISO Open Access Transmission Tariff (“OATT”).¹ I originally joined the ISO in 2006 and served as a Principal Engineer, and then as Manager, Area Transmission Planning for Northern New England.

¹ Capitalized terms used but not otherwise defined in this testimony have the meanings ascribed thereto in the ISO's Transmission, Markets and Services Tariff (the "Tariff"). The OATT is contained in Section II of the Tariff.

1 Prior to joining the ISO in 2006, I was a Project Manager in the Transmission Planning
2 Department at Northeast Utilities. Before that, I was an engineer with the Northeast
3 Nuclear Energy Company at the Millstone nuclear plant. I have over 25 years of
4 experience regarding the operation and planning of the New England bulk power system.
5

6 **Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

7 **A:** The purpose of my testimony is to explain the following proposed Tariff improvements
8 to the ISO's competitive transmission process:

- 9 • Revisions to Sections 4.3 (Competitive Solution Process for Reliability
10 Transmission Upgrades and Market Efficiency Transmission Upgrades) and 4A
11 (Public Policy Transmission Studies; Public Policy Transmission Upgrades) of
12 Attachment K to the ISO OATT;
- 13 • Revisions to Sections 6 (Termination by ISO-NE) and 7 (Hold Harmless) of the
14 pro forma Selected Qualified Transmission Project Sponsor Agreement, which is
15 Attachment P to the ISO OATT; and
- 16 • Revisions to Section III.12.6.4 (Transmission Projects Selected Through The
17 Competitive Transmission Process).

18 These Tariff changes collectively are referred to as the "Transmission Planning
19 Improvements" in my testimony.
20

21 **Q: PLEASE DESCRIBE THE PROCESS TO DEVELOP THE LESSONS LEARNED**
22 **REVISIONS.**

23 **A:** Many of the Transmission Planning Improvements were initially proposed by
24 stakeholders. The ISO conducted the region's first competitively developed transmission
25 solicitation process from December 2019 to July 2020 ("Boston RFP"). Shortly after the
26 conclusion of the Boston RFP, the ISO held individual meetings with the Qualified
27 Transmission Project Sponsors ("QTPSs") that participated in the Boston RFP. The ISO

1 also solicited feedback and discussed potential improvements to the competitive
2 transmission solicitation process with the Planning Advisory Committee (“PAC”). PAC
3 meetings were held on October 21, 2020; December 16, 2020; February 17, 2021; and
4 April 14, 2021. The purpose of the meetings was to discuss potential improvements to
5 the competitive solution process identified by stakeholders following the Boston RFP.
6 As a result of the PAC discussions, the ISO developed proposed Tariff revisions to
7 improve the competitive transmission solicitation process. The ISO presented the
8 revisions to Attachment K to the New England Power Pool (“NEPOOL”) Transmission
9 Committee on July 14, 2021, August 24, 2021, and September 28, 2021. At the
10 September 28, 2021 meeting, the NEPOOL Transmission Committee voted to approve
11 the revisions with no opposition and two abstentions. The NEPOOL Participants
12 Committee voted at its November 4, 2021 meeting to approve the revisions to
13 Attachment K as part of its consent agenda. The ISO presented revisions to Section
14 III.12.6.4 of the Tariff to the NEPOOL Reliability Committee on September 21, 2021 and
15 October 19, 2021. At the October meeting, the NEPOOL Reliability Committee
16 approved the revisions with no opposition. The NEPOOL Participants Committee
17 approved the revisions as part of the consent agenda at its November 4, 2021 meeting.

18
19 **Q: PLEASE PROVIDE A GENERAL OVERVIEW OF THE COMPETITIVE**
20 **TRANSMISSION SOLUTION PROCESS IN NEW ENGLAND?**

21 **A:** Attachment K of the OATT sets forth the procedures for transmission infrastructure to be
22 developed under a competitive transmission solution process. First, any entity that
23 intends to submit a response to an ISO RFP for a Reliability Transmission Upgrade

1 (“RTU”), Market Efficiency Transmission Upgrade (“METU”) or Public Policy
2 Transmission Upgrade (“PPTU”) must be qualified by the ISO as a QTPS in accordance
3 with Section 4B of Attachment K. Once an entity is qualified by the ISO as a QTPS (and
4 maintains QTPS status), the entity may participate in the competitive transmission
5 process under Sections 4.3 and 4A of Attachment K.
6

7 The competitive transmission solution process is two-step process where QTPSs submit
8 varying information in both steps. Under Sections 4.3 and 4A of Attachment K, the ISO
9 issues a request for proposal (“RFP”) indicating that QTPSs may submit Phase One
10 Proposals (for RTUs and METUs under Section 4.3) or Stage One Proposals (for PPTUs
11 under Section 4A) that must comprehensively address the identified transmission needs.
12 In accordance with Section 4.3, the Participating Transmission Owner(s) (“PTO”) must
13 also submit a Phase One Backstop Transmission Solution to address the identified
14 reliability or market efficiency need. Phase One and Stage One Proposals need to be
15 detailed enough to demonstrate they can solve the needs identified in the RFP and
16 provide sufficient information on the project costs and logistics.
17

18 The ISO reviews the Phase One and Stage One Proposals to ensure that they address all
19 identified transmission needs, are cost competitive, and are feasible. With advisory input
20 from the PAC, the ISO determines the Phase One or Stage One Proposals that will be
21 considered in the Phase Two or Stage Two Solutions process.
22

1 Phase Two (for RTUs and METUs under Section 4.3) and Stage Two (for PPTUs under
2 Section 4A) Solutions must include more detailed and particularized supplemental
3 information than the Phase One or Stage One Proposal. Specifically, QTPSs with Phase
4 One or Stage One Proposals that move onto the Phase Two or Stage Two Solutions
5 process must provide the additional detail required by Sections 4.3(h) (Information
6 Required for Phase Two Solutions; Identification and Reporting of Preliminary Preferred
7 Phase Two Solution) or 4A.8 (Information Required for Stage Two Solutions;
8 Identification and Reporting of Preliminary Preferred Stage Two Solution). This detailed
9 information is necessary in order to support the analyses that the ISO will undertake to
10 differentiate between all of the solutions that are selected to move onto Phase Two or
11 Stage Two Solutions and ultimately are selected as the preferred solution. Under
12 Sections 4.3(j) (Selection of the Preferred Phase Two Solution) and 4A.9(a) (Inclusion of
13 Public Policy Transmission Upgrades in the Regional System Plan and the RSP Project
14 List), the ISO notifies the QTPS that its project has been selected as the preferred Phase
15 Two or Stage Two Solution for development and the developer accepts responsibility by
16 execution of the Selected Qualified Transmission Project Sponsor Agreement
17 (“SQTPSA”), in accordance with existing Sections 4.3(k) (Execution of Selected
18 Qualified Transmission Project Sponsor Agreement) and 4A.9(b) (Execution of Selected
19 Qualified Transmission Project Sponsor Agreement).

20
21 **Q: PLEASE DESCRIBE GENERALLY THE TRANSMISSION PLANNING**
22 **IMPROVEMENTS.**

1 **A:** The Transmission Planning Improvements include a number of proposed enhancements
2 to the competitive transmission process set forth in Attachment K to the OATT. The
3 majority of the enhancements are made in Section 4.3, which sets forth the competitive
4 transmission solution process for RTUs and METUs. Tariff changes are also proposed in
5 Section 4A, which sets forth the process for PPTUs. Many of the proposed changes to
6 Section 4A correspond to changes made in Section 4.3.

7
8 Revisions corresponding to the Attachment K changes are proposed in Section 6.0 of the
9 SQTPSA (Termination by ISO-NE) and Section 7.0 (Hold Harmless).

10
11 The Transmission Planning Improvements also include corresponding changes to Section
12 III.12.6.4 of the Tariff (Transmission Projects Selected Through The Competitive
13 Transmission Process).

14
15 **Q. PLEASE DESCRIBE THE SPECIFIC PROPOSED REVISIONS TO**
16 **ATTACHMENT K.**

17 **A:** The proposed enhancements modify the competitive transmission solution process to
18 allow a QTPS to solve all or some of the needs identified in an RFP. Currently, the
19 process requires a Phase One Proposal to comprehensively solve all the needs identified
20 in the RFP. Requiring a QTPS to comprehensively solve all the identified needs could
21 limit the number of QTPSs that are able to participate in an RFP.

1 Accordingly, the Transmission Planning Improvements revise Section 4.3(a) (Initiating
2 the Competitive Solution Process) to allow a QTPS in a Phase One Proposal to solve a
3 subset of identified needs. Specifically, the proposed revisions to Section 4.3(a) state that
4 a QTPS may submit a Phase One Proposal(s) offering solutions that “addresses the
5 identified needs or a subset of those needs.” In other words, under the proposed
6 revisions, a QTPS may submit a Phase One Proposal with a solution that does not solve
7 all the needs identified in the RFP. Allowing a QTPS to solve a subset of the needs will
8 allow more QTPSs to participate, which will make the transmission solicitation process
9 more competitive.

10
11 **Q: IF A PHASE ONE PROPOSAL INCLUDES A SOLUTION THAT ONLY**
12 **ADDRESSES PART OF THE IDENTIFIED NEED, HOW WILL THE ISO**
13 **ENSURE THAT THE PROEJCT THAT IS ULITIMATELY SELECTED SOLVES**
14 **ALL OF THE IDENTIFIED NEEDS?**

15 **A:** If possible, the ISO will combine individual Phase One Proposals that do not solve all the
16 needs together to create a solution that solves all the needs. If the individual proposals
17 considered collectively do not solve all the needs, the proposals will not move forward.
18 Further, submitting a Phase One Proposal that does not solve all the needs may prevent
19 the proposal from moving forward to Phase Two Solutions if it is not feasible to combine
20 the proposal with another Phase One Proposal(s) to solve all the needs identified in the
21 RFP. Additionally, Phase One Proposals that do solve all the needs will not be combined
22 with other Phase One Proposals that address all the identified needs because this would
23 be inefficient and lead to unnecessary costs.

1 If multiple QTPSs are selected (combining proposals) to comprehensively solve the
2 identified needs, each QTPS must execute a separate SQTPSA. If a QTPS defaults, and
3 does not reassign its upgrades to another QTPS under Section 8 (Assignment) of the
4 SQTPSA, the entire project will be in default, and the ISO will move to the Backstop
5 Transmission Solution.

6
7 **Q: WHAT OTHER ATTACHMENT K REVISIONS BESIDES CHANGES TO**
8 **SECTION 4.3(A) ARE NECESSARY TO ACCOMMODATE THE CHANGES**
9 **THAT ALLOW A QTPS TO SOLVE A SUBSET OF IDENTIFIED NEEDS?**

10 **A:** In addition to the revisions to Section 4.3(a) described above, the proposed revisions
11 modify Section 4.3(c)(ii) to accommodate solving a subset of the identified needs. The
12 proposed revisions add new language to Section 4.3(c)(ii) that Phase One Proposals that
13 do not solve all the identified needs must include an explanation of the needs that are
14 being addressed, a description of the needs that have not been addressed, and the impact
15 of the Phase One Proposal on those needs that have not been addressed.

16
17 The proposed revisions also require a change to Section 4.3(e)(ii) (Preliminary Review
18 by ISO) to accommodate solving a subset of identified needs by stating that the Phase
19 One Proposal must address “one or more of the needs identified in Section 4.3(c)(ii).”

20
21 The revisions modify Section 4.3(g) (List of Qualified Phase One Proposals) to
22 accommodate the possibility that the ISO will combine subsets of Phase One Proposals
23 that collectively comprehensively address the identified. The revisions to Section 4.3(g)

1 state that the listing under that section will “contain Phase One Proposals, either
2 individually or as group that solve all of the identified needs.” The title to Section 4.3(g)
3 is also proposed to be changed by adding “or Groups of Phase One Proposals” to reflect
4 the previous revisions to the body of the section. Other proposed changes to Section
5 4.3(g) include removing “for each Needs Assessment” and replacing the word “projects”
6 with “Phase One Proposals.”
7

8 **Q: CAN THE BACKSTOP TRANSMISSION SOLUTION SOLVE A SUBSET OF**
9 **NEEDS?**

10 **A.** No. The Backstop Transmission Solution must solve all the identified needs. To clarify
11 this point, the proposed changes revise Section 4.3(a) to state that the Backstop
12 Transmission Solution must “comprehensively address all of the needs identified in the
13 request for proposal....” Additionally, the Transmission Planning Improvements revise
14 Section 4.3(e) to provide that if there are identified needs that are only solved by the
15 Backstop Transmission Solution and no other Phase One Proposals, the ISO will move
16 forward with the Backstop Transmission Solution.
17

18 **Q: CAN A QTPS SUBMIT A STAGE ONE PROPOSAL FOR A PUBLIC POLICY**
19 **TRANSMISSION UPGRADE UNDER SECTION 4A THAT ONLY SOLVES A**
20 **SUBSET OF THE IDENTIFIED NEED?**

21 **A:** No. A QTPS must solve all the identified needs. This is because the Public Policy
22 process does not require submittal of a Backstop Transmission Solution. As such, there

1 is no guarantee that any proposal or combination of proposals will solve all the identified
2 needs.

3
4 **Q: PLEASE DESCRIBE OTHER ENHANCEMENTS TO THE COMPETITIVE**
5 **TRANSMISSION SOLICITATION PROCESS.**

6 **A:** The Transmission Planning Improvements revise the solicitation process to allow for the
7 submission of joint proposals. Pursuant to existing Section 4.3(a), joint proposals are
8 already permitted for the Backstop Transmission Solution if more than one PTO is
9 identified by the ISO. The proposed changes revise Section 4.3(a) by adding that a QTPS
10 may submit an “individual or joint” Phase One Proposal(s). Under the proposed
11 revisions, all the parties to a joint proposal must be approved QTPSs. A joint proposal
12 can solve all of the needs or a subset of the needs identified in the RFP. If a joint
13 proposal is selected, each QTPS needs to execute a separate SQTPSA and would have
14 their portion of the project added to the Regional System Plan Project List. If one of the
15 parties to the joint proposal defaults, and does not reassign its upgrades to another QTPS
16 under Section 8 of the SQTPSA, the entire project would be cancelled and the Backstop
17 Transmission Solution would be implemented.

18
19 Similar revisions are proposed in Section 4A.6(a) allowing QTPSs to submit individual
20 or joint Stage One Proposals and requiring that where a joint Stage One Proposal is
21 submitted, all parties must be QTPS. There is no Backstop Transmission Solution for
22 PPTUs.

1 **Q: PLEASE DESCRIBE THE CORRESPONDING TARIFF REVISIONS THAT ARE**
2 **NECESSARY TO ACCOMMODATE THE SUBMISSION OF JOINT**
3 **PROPOSALS.**

4 **A:** The Transmission Planning Improvements modify Section 4.3(c) (Information Required
5 for Phase One Proposals, Study Deposit; Timing Phase One Proposals shall provide the
6 following information) to provide that for a joint proposal, a single study deposit is
7 necessary since the joint proposal is submit by only one QTPS. To accomplish this, the
8 word “submitting” is added to Section 4.3(c). A corresponding change is proposed in
9 Section 4A.6(a).

10
11 The proposed revisions to Section 4.3(f) (Proposed Deficiencies; Further Information)
12 provide that if the ISO identifies minor deficiencies a joint Phase One Proposal, the ISO
13 will notify QTPS that submitted the joint Phase One Proposal of the deficiency. To
14 effectuate this, the proposal adds the word “submitting” to Section 4.3(f).

15
16 The Transmission Planning Improvements modify Section 4.3(h) (Information Required
17 for Phase Two Solutions; Identification and Reporting of Preliminary Preferred Phase
18 Two Solution) to reflect that a group of Phase Two Solution submittals could be chosen
19 to address the identified need.

20
21 Further, Section 4.3(h) is revised to make Qualified Transmission Project Sponsor plural
22 to reflect that there could be joint proposals. Similar changes to the term Qualified

Transmission Project Sponsor are proposed for Section 4A.8 (Information Required for Stage Two Solutions; Identification and Reporting of Preliminary Stage Two Solutions).

The Transmission Planning Improvements modify Section 4.3(j) to reflect that there could be multiple Phase Two Solutions combined into a group that address the identified need.

The Transmission Planning Improvements also modify Section 4.3(k) to reflect that, each QTPS that is part of the joint proposal that is selected as the preferred Phase Two Solution must execute a SQTPSA. A corresponding change is proposed in Section 4A.9(b).

Modifications are also proposed for Section 4.3(l) (Failure to Proceed) to address, that with joint proposals, there will be more than one QTPS. A corresponding change is also proposed to Section 4A.9(c).

Q: WHAT OTHER CHANGES ARE PROPOSED TO THE COMPETITIVE TRANSMISSION SOLICITATION PROCESS?

A: The proposed revisions remove the requirement for life-cycle costs to be provided as part of the Phase One Proposals. The ISO does not believe that life-cycle costs provide significant value when submitted in the Phase One Proposal because submitted life-cycle cost do not include costs associated with an upgrade(s) located on or connected to a PTO's existing transmission system where the QTPS is not the PTO for the existing

1 system element(s). Since the total life-cycle costs are not known for each Phase One
2 Proposal, life-cycle costs cannot be compared and any analysis performed on Phase One
3 Proposals must be done utilizing the provided installed costs. Life-cycle costs are
4 required for Phase Two Solutions where more detailed information on the proposed
5 project is available for evaluation. To effectuate this revision, the Transmission Planning
6 Improvements modify Section 4.3(c)(v) by deleting “life-cycle and” and deleting “a
7 description of the financing being used.” A corresponding change is proposed for
8 Section 4A.6(a)(v). Under the proposed revisions, the description of financing being
9 used is relocated from Section 4.3(c)(v) to Sections 4.3(h)(vi). The proposed revisions
10 also change the numbering for Section 4.3(h) to accommodate the relocation.
11 Corresponding changes are also proposed to relocate the “description of financing being
12 used” from Section 4A.6(v) to Section 4A.8(vi).

13
14 **Q: WHAT IS THE SELECTED QUALIFIED TRANSMISSION PROJECT**
15 **SPONSOR AGREEMENT?**

16 **A:** The SQTPSA is an agreement entered into by the ISO and the Selected QTPS (whether a
17 PTO or non-incumbent developer) following the QTPS’s selection to develop a project
18 through the competitive process. The purpose of the SQTPSA is to state the terms and
19 conditions relating to development and construction of the selected project, including,
20 among other things, project milestones, status reports, modifications, assignment,
21 termination, and any cost containment. The SQTPSA is Attachment P to the ISO OATT.

22
23 **Q: PLEASE DESCRIBE THE PROPOSED CHANGES TO THE SQTPSA.**

1 **A:** The Transmission Planning Improvements modify Section 6 of the SQTPSA to reflect
2 termination under a joint proposal. Under a joint proposal, if one of the Selected QTPSs
3 is failing to move forward with the project, all QTPSs will have their portion of the
4 project terminated. In such a situation, however, the assignment provisions under Section
5 8 of the SQTPSA may be applicable. In order to utilize the assignment provisions, the
6 existing language under Section 8 requires that the Selected QTPSs must coordinate any
7 reassignment and the assignee must be a QTPS; the Selected QTPS or the assignee must
8 demonstrate to the ISO that assignee has the technical competence and financial ability
9 to: (a) comply with the requirements of the SQTPSA (including the milestone schedule);
10 (b) construct the project consistent with the assignor's cost estimates for the project and
11 in accordance with any cost cap or cost containment commitments; and (c) operate and
12 maintain the project once constructed. The Transmission Planning Improvements do not
13 modify any of the provisions under Section 8. To allow additional time for assignment of
14 responsibilities under Section 8 of the SQTPSA, however, the Transmission Planning
15 Improvements propose to modify Section 4.3(1) of Attachment K. Specifically, the
16 proposed modifications provide that the QTPS that is failing to proceed has 60 days after
17 notification from the ISO to reassign a portion or all of the project to another QTPS in
18 accordance with Section 8 of the SQTPSA.

19
20 The Transmission Planning Improvements modify Section 7 of the SQTPSA to
21 accommodate the changes discussed earlier that allow for a project to have multiple
22 Select QTPSs.

1 Additional changes are also proposed to Section 4.3(l) of Attachment K to delete
2 “Attachment P to the OATT” and insert “pursuant to Schedule 3.09(a) of the
3 Transmission Operating Agreement.”
4

5 **Q: ARE THERE OTHER ATTACHMENT K CLARIFIATION CHANGES?**

6 **A:** Yes. The Transmission Planning Improvements include several proposed clarification
7 changes to Attachment K. “Phase One Proposals” is replaced with “Backstop
8 Transmission Solution” under Section 4.3(a) to clarify that PTOs may only recover Phase
9 One Proposal costs associated with the Backstop Transmission Solution. Changes to
10 Section 4.3(a) are also proposed to clarify that the response is to “request for proposal”
11 not a “Needs Assessment.”
12

13 The proposed revisions also remove “preliminary feasibility” in Section 4.3(e) and
14 “Preliminary” in the title of Section 4.3(e). These changes more accurately reflect the
15 review conducted by ISO under Section 4.3(e). A similar change is proposed for Section
16 4A.6(c) (Preliminary Review of Stage One Proposals by ISO).
17

18 The Transmission Planning Improvements also add “all of the identified needs are
19 solved” to Section 4.3(e) to clarify that the Phase One Proposal, or group of proposals,
20 must address all of the identified needs to continue with the process. The proposed
21 revisions also replace “appears to” with “satisfies one or more of” in Section 4.3(e)(ii) to
22 remove any ambiguity that a Phase One Proposal must solve one or more of the identified

1 needs. In the corresponding Section 4A.6(c)(ii), the proposed revisions replace “appears
2 to satisfy” with “satisfies” and adds “identified in the request for proposal.”

3
4 Under Sections 4.3(l) and 4A.9(c), the proposed revisions delete “non PTO” as the term
5 is not necessary to the provisions in those sections and it unnecessarily limits how the
6 ISO may learn that a QTPS is failing to proceed.

7
8 The Transmission Planning Improvements modify Section 4.3(h) to reflect that a group
9 of proposals can be selected as the Phase Two Solution and that the Phase Two Solution
10 must comprehensively address all of the needs.

11
12 The proposed changes to Section 4.3(h) also remove the incorrect reference to “Needs
13 Assessment” and replaces it with “request for proposal.” A similar revision is proposed
14 for Section 4A.6(a) that replaces “Public Policy Transmission Study” with “request for
15 proposal.”

16
17 Clarification changes are also proposed to Section 4.3(h)(xi) (by replacing the word
18 “sponsor” with Qualified Transmission Project Sponsor(s)” and removing “state” because
19 necessary permits may not be limited to state permits. A corresponding change is also
20 proposed for Section 4A.8(xi).

21
22 In Section 4A.3(b), the proposed changes replace “Needs Assessment” with “Public
23 Policy Transmission Study.” Since Section 4A.3 relates to public policy transmission

1 planning, the replacement of “Needs Assessment” with “Public Policy Transmission
2 Study” corrects a clerical error.

3
4 **Q: ARE THERE NON ATTACHMENT K TRANSMISSION PLANNING**
5 **IMPROVEMENT CHANGES?**

6 **A:** Yes. The Transmission Planning Improvements include corresponding changes to
7 Section III.12.6.4 of the Tariff. The proposed changes replace the word “project” with
8 “solution” in several places in Section III. 12.6.4 to more accurately align the
9 terminology with the language in Attachment K. Additionally, as discussed above, the
10 Transmission Planning Improvements allow for a subset of needs identified in an RFP to
11 be solved by a QTPS and for QTPSs to submit joint proposals. As a result, there may be
12 multiple SQTPSAs. For this reason, the Transmission Planning Improvements include a
13 corresponding change to Section III.12.6.4 to reflect that a complete transmission
14 solution may have multiple SQTPSAs.

1 Q: DOES THIS CONCLUDE YOUR TESTIMONY?

2 A: Yes.

3

4

5 I declare that the foregoing is true and correct.

6

7 Executed on 12/23/21

8

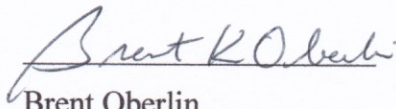
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Brent Oberlin

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