UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Inquiry Regarding the Commission's Electric Transmission Incentives Policy	))))	Docket No. PL19-3-000

COMMENTS OF THE
NEW ENGLAND STATES COMMITTEE ON ELECTRICITY

The New England States Committee on Electricity ("NESCOE") submits these comments pursuant to the Federal Energy Regulatory Commission's ("FERC" or "Commission") March 21, 2019 Notice of Inquiry in the above-referenced proceeding ("NOI").[1] The NOI requests comment on the "scope and implementation" of the Commission's "electric transmission incentives regulations and policy" and how to consider transmission incentive requests for future projects.[2] NESCOE greatly appreciates the Commission's initiation of this proceeding and its attention to transmission investments and their rate implications.

I. DESCRIPTION OF COMMENTER

NESCOE is the Regional State Committee for New England. It is governed by a board of managers appointed by the Governors of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont and is funded through a regional tariff that ISO New England Inc. ("ISO-NE") administers.[3] NESCOE's mission is to represent the interests of the citizens of the New England region by advancing policies that will provide electricity at the lowest possible price over the long term, consistent with maintaining reliable service and

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1 *Inquiry Regarding the Commission's Electric Transmission Incentives Policy*, 166 FERC ¶ 61,208 (2019).

2 *Id.* at PP 1-2.

3 *ISO New England Inc.*, 121 FERC ¶ 61,105 (2007).

environmental quality.[4] These comments represent the collective view of the six New England states.

II. BACKGROUND

A. FERC's Implementation of Section 219

In 2006, the Commission issued Order No. 679[5] in response to the directives contained in Section 219 of the Federal Power Act ("FPA").[6] Order 679 sets forth the Commission's current framework for granting incentives. It is intended to "benefit customers by providing real incentives to encourage new infrastructure, not simply increasing rates in a manner that has no correlation to encouraging new investment."[7] Order 679 requires an applicant seeking incentives to "demonstrate that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion consistent with the requirements of section 219, that there is a nexus between the incentive sought and the investment being made, and that the resulting rates are just and reasonable."[8] Order 679 described the incentives applicants would be permitted to request, which included financial incentives such as bonus return-on-equity ("ROE") and incentives that reduce investment risks.[9]

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4 *See* Sept. 8, 2006 NESCOE Term Sheet ("Term Sheet") that was filed for information as Exhibit A to the Memorandum of Understanding among ISO-NE, the New England Power Pool ("NEPOOL"), and NESCOE (the "NESCOE MOU"). Informational Filing of the New England States Committee on Electricity, Docket No. ER07-1324-000 (filed Nov. 21, 2007). Pursuant to the NESCOE MOU, the Term Sheet is the binding obligation of ISO-NE, NEPOOL and NESCOE.

5 *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057 (2006) ("Order 679"), *order on reh'g*, Order No. 679-A, 117 FERC ¶ 61,345 (2006) ("Order 679"), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

6 16 U.S.C. § 824s (2012).

7 Order 679 at P 6.

8 *Id.* at P 76. *See id.* at PP 2, 28; NOI at P 6.

9 NOI at P 7. The list of potential incentives is non-exhaustive. *See* Order 679 at P 55.

Order 679 provided two avenues for Commission review of an applicant's request for incentives: "(1) through a combination of a petition for a declaratory order and a subsequent section 205 filing or (2) by filing only a section 205 filing."[10] In either case, the applicant must show "that there is a nexus between the incentives sought and the investment being made, in addition to satisfying the section 219 requirement of ensuring reliability and/or reducing the cost of delivered power by reducing congestion."[11] An applicant has met this nexus test when it "demonstrates that the total package of incentives requested is 'tailored to address the demonstrable risks or challenges faced by the applicant.'"[12] This is a fact-specific inquiry, with the applicant required to "provide sufficient support to allow the Commission to evaluate each element of the package and the interrelationship of all elements of the package."[13] The Commission makes its determination on a case-by-case basis.[14]

Regarding the threshold requirement in Section 219 that the project must ensure reliability or reduce congestion, the Commission found in Order 679 that applicants can demonstrate that it has met this requirement "through reliance on a Commission accepted regional planning process."[15] The Commission established a rebuttal presumption that projects selected through "a fair and open regional planning process" qualify for incentives.[16]

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10 Order 679 at P 76.

11 *United Illuminating Co.*, 167 FERC ¶ 61,126 at P 24 (2019) ("*United Illuminating*"), citing Order 679 at P 48.

12 *United Illuminating* at P 24, quoting Order 679-A at P 40. *See* 18 C.F.R. § 35.35(d) (2018).

13 *LS Power Grid New York, LLC*, 167 FERC ¶ 61,139 at P 19 (2019) (footnote omitted).

14 *Id.*

15 Order 679 at P 82.

16 *Id.* at P 58 (footnote omitted). *See id.* at P 57 ("we are . . . required to make findings that a particular investment falls within the scope of section 219. . . . Other applicants not meeting these criteria may nonetheless demonstrate that their project is needed to maintain reliability or reduce congestion by presenting us a factual record that would support such findings. Once we determine that the project is eligible for incentives, we would

The Commission's 2012 Policy Statement on transmission incentives provided further guidance.[17] The Commission summarized this guidance in a recent order, underscoring that applicants face a high hurdle when requesting ROE adders:

> In the 2012 Policy Statement, the Commission announced its expectation that an applicant seeking an ROE incentive based on a project's risks and challenges would demonstrate that: (1) the proposed project faces risks and challenges that are not either already accounted for in the applicant's base ROE or addressed through risk-reducing incentives; (2) the applicant is taking appropriate steps and using appropriate mechanisms to minimize its risk during project development; (3) alternatives to the project have been, or will be, considered in either a relevant transmission planning process or another appropriate forum; and (4) the applicant will commit to limiting the application of the ROE incentive to a cost estimate.[[18]]

The NOI seeks information to assist the Commission "in evaluating [its] transmission incentive policy and ensuring that the policy continues to satisfy [its] obligations under section 219 of the FPA."[19] The NOI notes that the Commission issued Order 679 almost 13 years ago and that "the landscape for planning, developing, operating, and maintaining transmission infrastructure has changed considerably."[20] This includes the implementation of Order No. 1000,[21] which became effective in regional transmission organization (RTO)/independent system

. . . consider whether the particular incentives being proposed are appropriate for the particular investments being made.").

17 *Promoting Transmission Investment Through Pricing Reform*, 141 FERC ¶ 61,129 (2012) ("2012 Policy Statement").

18 *United Illuminating* at P 43, citing 2012 Policy Statement at PP 20, 24-30.

19 NOI at P 13.

20 *Id.*

21 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011) ("Order 1000"), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

operator (ISO) tariffs between 2013 and 2015 and has "significant implications for how transmission facilities are planned and developed."[22]

B. Transmission Investments in New England

ISO-NE has identified New England's significant investments in electric transmission over the last twenty years as leading to "reduced risk of blackouts, lower wholesale energy costs, and less air pollution," while positioning the system "to become greener and more flexible."[23] Since 2002, New England consumers have funded more than $10 billion in transmission to promote electric system reliability.[24] Another $1.6 billion in transmission investments is planned through 2022.[25] For most New England residential retail electric customers, transmission costs account for between 11% to 18% of total retail rates.[26] Over the last decade, transmission charges have risen dramatically, increasing almost every year since 2008 and growing from roughly $869 million that year to $2.25 billion in 2018.[27]

ISO-NE began its implementation of Order 1000 changes in 2015.[28] Under the regional planning process that ISO-NE developed to comply with Order 1000, ISO-NE is generally required to use a competitive solicitation process to meet new regional transmission needs.[29]

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22 NOI at PP 12-13.

23 ISO-NE, 2019 Regional Electricity Outlook, March 2019 ("2019 REO"), at 28, available at https://www.iso-ne.com/static-assets/documents/2019/03/2019_reo.pdf.

24 *Id.*

25 *Id.*

26 Joint Report of the Consumer Liaison Group Coordinating Committee and ISO New England, 2018 Report of the Consumer Liaison Group, Mar. 12, 2019, at 32, available at https://www.iso-ne.com/static-assets/documents/2019/03/2018_report_of_the_consumer_liaison_group_final.pdf.

27 *Id.* at 34.

28 *See* ISO-NE, 2017 Regional System Plan, at 68.

29 *See* ISO-NE, Transmission, Markets and Services Tariff, Section II (Open Access Transmission Tariff ("ISO-OATT")), Attachment K, § 4.3 (Competitive Solution Process for Reliability Transmission Upgrades and

The Commission allowed for an exception to this process "to be used in certain limited circumstances" in the case of reliability needs within three years ("Time-Sensitive Needs").[30] ISO-NE assigns the solutions to Time-Sensitive Needs to the incumbent transmission owner(s) whose service territory or territories encompass the solution.[31] To date, ISO-NE has not issued a competitive solicitation for transmission and, in the case of reliability needs, ISO-NE has determined that all needs are either Time-Sensitive Needs or that the solutions to those Time-Sensitive Needs also solve non-time sensitive needs.[32]

Market Efficiency Transmission Upgrades) and § 4A.5-4A.8 (solicitation process to meet identified Public Policy Requirements through Public Policy Transmission Upgrades).

30 *ISO New England Inc.*, 143 FERC ¶ 61,150 at PP 236-241 (2013).

31 *See id.* at P 236.

32 ISO-NE recently announced the potential commencement of a competitive solicitation later this year. *See* Memorandum from Vamsi Chadalavada, Executive Vice President and Chief Operating Officer, ISO-NE, to NEPOOL Participants Committee, Re-entry of retired resources and Order 1000, April 30, 2019, available at https://www.iso-ne.com/static-assets/documents/2019/05/20190430_re-entryretiredresources_order1000_memo.pdf. This potential solicitation arises from a unique set of facts involving the retirement of a large generating resource in Greater Boston. While this step toward competition is encouraging, NESCOE expects that, in implementing the current tariff, ISO-NE will continue to determine that the vast majority of reliability needs are Time-Sensitive Needs, with the competitive process remaining the exception rather than the rule in New England. NESCOE has previously expressed to the Commission its concern that the routine use of the solution study process to solve Time-Sensitive Needs will prevent New England consumers from realizing the benefits of competition, including opportunities for cost discipline. Comments of the New England States Committee on Electricity, Docket No. AD16-18-000 (filed May 31, 2016), at 9. *See* Post-Technical Conference Comments of the New England States Committee on Electricity, Docket No. AD16-18-000 (filed Oct. 3, 2016), at 6 (requesting that the Commission closely monitor stakeholder discussions "to determine whether, depending on the outcome, further action is prudent to ensure that (i) the appropriate balance has been struck between solving for time-sensitive reliability needs and achieving consumer benefits through competition, and (ii) there are opportunities for cost discipline to the greatest extent practicable, whether a project is exempt from competition or not."). While the NOI is focused on the Commission's transmission incentives policy, as discussed below in response to Question 1, competitive processes may be uniquely positioned to serve as an alternative, or complement, to the Commission's current nexus framework. The Commission should evaluate factors that are limiting the implementation of competitive processes for transmission and consider how to promote competition where it does not place reliability at risk and is in the interest of consumers. *See, e.g., Time to open 'time-sensitive' transmission projects to Order 1000 competition*, Utility Dive, May 9, 2019 (discussing the exception for Time-Sensitive Needs and one potential approach to increasing competition while accounting for reliability concerns), available at https://www.utilitydive.com/news/time-to-open-time-sensitive-transmission-projects-to-order-1000-competiti/554397/.

III. COMMENTS

New England consumers have long valued the benefits of electric transmission. Over the last two decades, they have invested billions of dollars in transmission infrastructure to meet emerging regional reliability needs. These costs have steadily grown and compose an increasing percentage of the charges reflected in electric retail bills.

In December 2018, NESCOE expressed to the Commission its concern about escalating transmission costs and supported an Organization of MISO States' request that the Commission initiate a process to review its incentive policies.[33] NESCOE stated:

> It is in our view appropriate for FERC to assess on a periodic basis whether Order No. 679's economic incentives remain just and reasonable, whether they are today necessary to provide incentives for specific actions that would not otherwise happen, and whether, as designed, they deliver recognizable value for electricity customers and further Congressional objectives in the Energy Policy Act of 2005.[[34]]

NESCOE further stated that "[l]ike any economic incentive, ROE adders and other transmission incentives should not be assumed to be necessary in perpetuity. Consistent with its statutory obligation to ensure a just and reasonable rate, it is appropriate for FERC to assess from time to time which if any incentives are required to deliver tangible consumer benefits."[35]

NESCOE agrees with the Commission that a reevaluation of its transmission incentives policy is timely,[36] particularly given the advent of competitive processes for selecting and constructing new transmission projects under Order 1000. NESCOE supports reforms to the

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33 NESCOE Letter to the Commission, New England States' Comments on Transmission Incentive Rates, Dec. 20, 2018, at 1-2, available at http://nescoe.com/wp-content/uploads/2018/12/NESCOE_IncentiveRatesLetter_20Dec2018.pdf.

34 *Id.* at 2 (footnote omitted).

35 *Id.*

36 NOI at P 2.

Commission's regulations and policy, discussed below, that are appropriate based on fundamental changes to the transmission planning process since Order 679 and the Commission's obligation to ensure just and reasonable rates.

The responses below are organized consistent with the NOI. Pursuant to the NOI's guidance,[37] NESCOE does not provide a response to every question but may provide additional perspectives through reply comments.

A. Approach to Incentives Policy

Q 1) Should the Commission retain the risks and challenges framework for evaluating incentive applications?

Response: The NOI's initial set of questions focus on the nexus test set forth in Order 679 where applicants "must demonstrate that there is a nexus between the incentive sought and the risks and challenges of investment being made."[38] The NOI poses two potential alternatives to the current "risks and challenges" framework for meeting this nexus.[39]

The NOI does not explicitly seek input on whether an Order 1000 competitive process could also serve as an alternative, or complement, to the current framework.[40] This competitive process may be well positioned to play such a role provided, as discussed below, that competitive processes are realized and are appropriately robust. The Commission should consider how best to use the competitive process as a mechanism for applicants to establish a nexus between incentives and investments.

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[37] *Id.* at P 13.

[38] *Id.* at P 15. *See id.* at PP 16-18.

[39] *Id.* at PP 16-18.

[40] The NOI poses a number of questions in a subsequent section regarding the relationship between Order 1000 and transmission incentives policies, *id.* at PP 30, 33-34, 40, which NESCOE addresses later in these comments.

In regions like New England, where competitive processes have been established to meet new transmission needs,[41] competing transmission developers have the opportunity to provide the revenue requirements, financial incentives, and risk mitigation measures that they need to invest in new transmission facilities. Transmission developers that "gold-plate" a bid, seeking financial returns or conditions beyond what is necessary to make the investment, place their project at a disadvantage in the evaluation process. Provided that there is robust participation in response to a solicitation—a threshold issue that would require definition—competition should drive developers to include in their bids only those revenue requirements and attendant transmission incentives that they view as a precondition to making an investment. Developers participating in this process are thus incented to "bid down the prices at which they will build new facilities in order to remain competitive." *MISO Trans. Owners v. FERC*, 819 F.3d 329, 333 (7th Cir. 2016). "[C]utting prices in order to increase business often is the very essence of competition." *Matsushita Elec. Industrial Co., Ltd., et al. v. Zenith Radio Corp., et al.*, 475 U.S. 574, 594 (1986), *cert. denied*, 481 U.S. 1029 (1986). To enhance a bid's attractiveness, developers may further seek to minimize the conditions, such as non-ROE risk mitigation incentives, that they include for a proposed project.[42]

The competitive processes that RTOs/ISOs have established pursuant to Order 1000 may be uniquely situated to promote Congress' directive, reflected in Section 219, that the Commission establish incentive-based rates that are just and reasonable. A truly competitive process aligns with Order 679's objective of ensuring that incentives are granted only if there is a correlation to the proposed new investment.[43] A robust competitive process would also allow

[41] ISO-NE OATT, Attachment K, §§ 4.3 and 4A.5-4A.8.

[42] Ideally, developers would also include cost containment mechanisms that limit the risks placed on consumers.

[43] Order 679 at PP 6 and 48.

RTOs/ISOs and interested parties to evaluate the reasonableness of incentive requests and compare them to the revenue requirements reflected in other bids. Consistent with the Commission's current policies, this would be a fact-specific inquiry, with the burden on the applicant to demonstrate the "nexus between the requested incentives and the risks and challenges of the project."[44] Incentives that are not tailored to the project can, and should, draw scrutiny and place the project at risk of not being selected as the solution to an identified regional need. Moreover, as discussed further below in response to Question 4, developers seeking incentives must show how a project's special risks and challenges distinguish it from routine investments in infrastructure to comply with existing reliability and planning standards.

Importantly, while the Commission can leverage the competitive process to consider requests for incentives, it should not automatically award incentives to every project selected in a regional plan for purposes of cost allocation. There is a risk that the process may not be sufficiently competitive. For example, under the Order 1000 process that ISO-NE has implemented, there is no experience with competitive processes to date and thus no basis to assume meaningful competition will emerge in early efforts to solicit projects. The ISO-NE process also contemplates the possibility that only one proposed solution will come forward in response to a competitive solicitation and establishes a separate process to evaluate such a proposal.[45] To address the potential that a solicitation may attract insufficient interest to be meaningfully competitive, the Commission could establish a rebuttable presumption that a project selected pursuant to an Order 1000 competitive process meets the nexus test while providing a process for review and comment to ensure that the project emerged through a fair

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[44] *United Illuminating* at P 24, citing 18 C.F.R. § 35.35(d) (2018).

[45] *See* ISO-NE OATT, Attachment K, §§ 4.1(i) and 4.2.

and open competitive process with meaningful levels of participation. This is similar to the rebuttal presumption that the Commission adopted in Order 679 regarding projects selected through the regional planning process.[46] Like the current framework, the project proponent would need to make a Section 205 filing and request authorization from the Commission for the incentives sought.[47]

To the extent the Commission pursues an approach to transmission incentives that seeks to leverage the Order 1000 competitive process, the development of this framework would benefit from additional input and discussion. This includes consideration of what constitutes "meaningful" or "robust" competition for purposes of applying a rebuttable presumption.

Q 2) Is providing incentives to address risks and challenges an appropriate proxy for the expected benefits brought by transmission and identified in section 219 (i.e., ensuring reliability or reducing the cost of delivered power by reducing transmission congestion)? If risks and challenges are not a useful proxy for benefits, is it an appropriate approach for other reasons?

Response: See response to Question 1. With the implementation of Order 1000, provided there is meaningful competition as discussed above, there is no need to rely on a proxy. Under an Order 1000 competitive process, an RTO/ISO's process will identify a regional need for a project, such as for reliability or market efficiency. A project developer's bid represents a direct and tangible correlation between the incentives sought and the developer's determination of the risks and challenges in connection with the project.

Q 3) The Commission currently considers risks both in calculating a public utility's base ROE and in assessing the availability and level of any ROE adder for risks and challenges. Is this approach still appropriate? If so, which risks are relevant to each inquiry, and, if they differ, how should the Commission distinguish between risks and challenges examined in each inquiry?

Response: See response to Question 1.

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[46] *See supra* notes 15 and 16.

[47] *See supra* notes 10-14 and accompanying text.

Q 4) Would directly examining a transmission project's expected benefits improve the Commission's transmission incentives policy, consistent with the goals of section 219? Are there drawbacks to this approach, particularly relative to the current risks and challenges framework?

Response: No, the Commission should not modify its transmission incentives policy to focus on expected project benefits. Examining a project's expected benefits is unnecessary for the reasons set forth in responses to Questions 1 and 2. In addition, a project's expected benefits are established through the identification of the project need (e.g., through a regional reliability needs assessment process).

A focus on expected project benefits, rather than special risks and challenges, also does not appear to accord with the Section 219 requirement that the Commission establish infrastructure incentives within the confines of a just and reasonable rate. The possibility that a project can benefit consumers does not establish the need for consumers to fund incentivized investments through regulatory recovery beyond what is provided through the base ROE and cost-of-service ratemaking. The Commission has provided a similar perspective, finding "that the most compelling case for incentives are new projects that present special risks or challenges, not routine investments made in the ordinary course of expanding the system to provide safe and reliable transmission service."[48]

The NOI recognizes that transmission owners are, for example, obligated to comply with North American Electric Reliability Corporation ("NERC") standards and regional planning criteria.[49] The Commission has drawn a contrast between reliability projects developed to comply with these standards and those presenting special risks and challenges: "[R]outine investments made to comply with existing reliability standards may not always qualify for an

[48] Order 679-A at P 23. *See* Order 679 at P 94. *Accord* United Illuminating at P 62.

[49] NOI at P 22.

incentive-based ROE. These are the types of investments that have, as a general matter, been adequately addressed through traditional ratemaking because there is an obligation to construct them and high assurance of recovery of the related costs."[50] In addition, as the Commission has stated, most risks and challenges can and should be addressed in the first instance through risk reducing incentives.[51]

A framework focusing on how a project's special risks and challenges distinguish that project from "routine investments made in the ordinary course of expanding the system" provides a greater assurance that consumers are not paying more for transmission than is needed to make those investments. This framework appropriately places emphasis on an inquiry into why consumers should bear additional costs for a project and the need for developers to justify those costs.

The ISO-NE planning process illustrates the need for continued focus on special risks and challenges. Under this process, ISO-NE conducts transmission system planning in accordance with NERC standards and potentially more stringent Northeast Power Coordinating Council ("NPCC") and ISO-NE reliability standards and criteria.[52] ISO-NE identifies violations of standards and criteria for system reliability and evaluates solutions to those system needs, with selected reliability projects placed in its regional system plan. These projects do not necessarily present special risks or challenges. For example, asset condition upgrades are an emerging

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[50] Order 679 at P 94. *See* Order 679-A at P 23 ("The Commission reaffirms that the most compelling case for incentives are projects that present special risks or challenges, not routine investments made in the ordinary course of expanding the system to provide safe and reliable transmission service.") and P 60 (same). *Accord United Illuminating* at P 62 (rejecting ROE incentive adder request where the applicant did not demonstrate that the project "faces risks and challenges either not already accounted for in [the applicant's] base ROE or addressed through risk-reducing incentives.").

[51] 2012 Policy Statement at P 11.

[52] *See, e.g.,* ISO-NE, Transmission Planning Process Guide, available at https://www.iso-ne.com/static-assets/documents/2018/05/transmission_planning_process_guide_1_30_2018.pdf.

category of transmission investment in New England.[53] These projects replace or refurbish existing facilities due to damage or deterioration. In assessing the need for an asset condition project, transmission owners will inspect structures for a range of issues including woodpecker and insect damage, pole top rot, and common hardware failures.[54] Special incentives should not be necessary to spur the replacement of current assets that continue to be needed to serve consumers in the normal course of business. Providing incentives for reliability projects that are required—and that qualify for the base ROE and cost-of-service rate recovery—risks imposing excessive costs on consumers.

Q 5) If the Commission adopts a benefits approach, should it lay out general principles and/or bright line criteria for evaluating the potential benefits of a proposed transmission project? If so, how should the Commission establish the principles or criteria?

Response: No, the Commission should not adopt a benefits approach for the reasons set forth in response to Question 4.

Q 6) How would a direct evaluation of expected benefits, instead of using risks and challenges as a proxy, impact certainty for project developers?

Response: The Commission should not adopt a benefits approach for the reasons set forth in response to Question 4.

Q 7) Should transmission projects with a demonstrated likelihood of benefits be awarded incentives automatically? How could the Commission administer such an approach?

Response: No, the Commission should not award incentives automatically. Any change in Commission policy to grant incentives automatically would undermine the Section 219 requirement of promoting transmission infrastructure within the confines of a just and reasonable

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53 *See* ISO-NE, New England Asset Management Key Study Area, available at https://www.iso-ne.com/system-planning/key-study-areas/new-england-asset-management/.

54 *See, e.g.,* Eversource Energy, Eversource 345-kV Structure Replacement Projects, ISO-NE Planning Advisory Committee, Dec. 2017, at Slides 10-14, available at https://www.iso-ne.com/static-assets/documents/2017/12/a9_eversource_345kv_structure_replacement_projects.pdf.

rate. An automatic incentive would significantly tip the balance against customers' interests and risk imposing excessive costs. It would shift the burden onto consumers to police the nexus between incentives and investments. Moreover, as discussed in response to Question 4, there are many projects that are routine and required to solve violations of NERC and regional reliability criteria. Those projects warrant heightened scrutiny in demonstrating that Section 219 incentives are needed. Eligibility for incentives should continue to be determined on a case-by-case basis, taking into account, *inter alia*, the special risks and challenges of a project and whether the base ROE and risk-reducing incentives address any such risks and challenges.[55] At minimum, if the Commission were to make incentives automatic based on studies projecting a certain amount of benefits, the assumptions underlying those studies would require rigorous review.

Q 8) If the Commission grants incentives based on expected benefits, should the level of the incentive vary based on the level of the expected benefits relative to transmission project costs? If so, how should the Commission determine how to vary incentives based on the size of benefits?

Response: The Commission should not adopt a benefits approach for the reasons set forth in response to Question 4.

Q 9) Should incentives be conditioned upon meeting benefit-to-cost benchmarks, such as a benefit-cost ratio? If so, what benefit-to-cost ratios should be used?

Response: No, the Commission should not adopt a benefits approach for the reasons set forth in response to Question 4.

Q 10) Should incentives be based only on benefit-to-cost estimates or should the Commission condition the incentives on evidence that that those benefit-to-cost estimates were realized?

Response: NESCOE does not support either approach for the reasons provided in response to Question 4. To the extent the Commission pursues a benefits approach and approves incentives based on benefit-to-cost estimates, it should condition the incentives on an applicant's

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[55] *See* 2012 Policy Statement at PP 20, 24-30. *Accord United Illuminating* at P 62.

demonstration that those benefit-to-cost estimates are realized. There should also be the opportunity for the recovery of refunds, as appropriate. Without these protections, consumers could incur the costs of incentives without receiving the corresponding benefit, an outcome that is not just and reasonable.

Q 11) If an incentive is conditioned upon a transmission developer meeting benefit-to-cost benchmarks, what types of benefits and costs should a transmission developer include, and the Commission consider to support requests for such incentives? Should there be measurement and verification, and if so, over what time period? If expected benefits do not accrue, should the incentive be revoked?

Response: See response to Question 4. If the Commission pursues such an approach and incentives are conditioned upon benefit-to-cost benchmarks, the developer should be held accountable for attaining those benchmarks. Otherwise, consumers could incur the costs of incentives without receiving the corresponding benefit. Measurement and verification should therefore be required if the Commission adopts this approach, and the incentive should remain in place only as long as the benchmarks are attained. There should also be the opportunity for the recovery of refunds, as appropriate.

Q 12) How, if at all, would examining transmission projects' characteristics in evaluations of transmission incentives applications improve the Commission's transmission incentives policy and achieve the goals of section 219? Are there drawbacks to this approach, particularly relative to the current risks and challenges framework? Would this approach result in different outcomes, as compared to the current risks and challenges approach for granting incentives?

Response: The question appears to view project characteristics as separate from the risks and challenges of a project. As a threshold matter, further detail is required to understand why a project's characteristics do not include risks and challenges.

To the extent the Commission intends to use project characteristics as an approach to awarding incentives based on expected benefits, it would not achieve the goals of Section 219 for the reasons set forth in response to Question 4. Moreover, projects with similar characteristics can present different risks and challenges. For example, projects that unlock constrained resources can present different risks and challenges depending on whether they are overhead or underground, or whether they are on new or existing rights of way.

Q 13) If the Commission adopts an approach based on project characteristics, should it lay out general principles and/or bright line criteria for identifying or evaluating those characteristics?

Response: The Commission should not adopt an approach based on project characteristics for the reasons provided in response to Question 12.

Q 14) If so, how should applicable criteria be established, and, in cases where more than one criterion applies, how should they be evaluated in combination?

Response: The Commission should not adopt an approach based on project characteristics for the reasons provided in response to Question 12.

Q 15) How would an approach based on project characteristics impact certainty for project developers, particularly relative to the current risks and challenges framework?

Response: The Commission should not adopt an approach based on project characteristics for the reasons provided in response to Question 12.

Q 16) Should transmission projects with certain characteristics be awarded incentives automatically? How could the Commission administer such an approach?

Response: No, the Commission should not award incentives automatically for project characteristics for the reasons set forth in responses to Questions 7 and 12.

B. Incentive Objectives

Q 17) Should the Commission tailor incentives to promote these types of projects based on their expected reliability benefits? If so, how should the Commission differentiate these projects from others required to meet reliability standards?

Response: No, the Commission should not tailor incentives for projects based on expected reliability benefits for the reasons set forth in response to Question 4.

Q 18) Are there specific reliability benefits or project characteristics that could merit such an approach?

Response: No, for the reasons set forth in responses to Questions 4 and 12.

Q 19) If the Commission tailored incentives for reliability benefits, how should the Commission measure the expected enhancement to transmission reliability? Should there be a threshold or bright line test applied? If so, how?

Response: See response to Question 4. Subject to the qualifications discussed above, using the Order 1000 competitive process as a vehicle for awarding incentives obviates the need for the Commission to tailor incentives to project types: a project's bid into a robust competitive solicitation process should include all of the financial and risk-mitigation requirements that a developer needs to make the investment.

Q 20) Should the Commission incentivize transmission facilities that expand access to essential reliability services, such as frequency support, ramping capability, and voltage support?

Response: No, for the reasons set forth in responses to Questions 4 and 12.

Q 22) Should the Commission tailor incentives to promote projects that accomplish the outcomes of reducing congestion or facilitating access to additional generation?

Response: No, for the reasons set forth in responses to Questions 1, 4, and 12. In addition, "facilitating access to additional generation" is a broad category that is not reflected in Section 219.

Q 23) Should the Commission establish bright line metrics, such as a specified level of reduction in average production costs, to determine whether a transmission project merits incentives?

Response: No, for the reasons set forth in responses to Questions 1, 4, and 12. Moreover, Section 219 directs the Commission to establish a transmission incentives policy that benefits consumers by reducing the cost of delivered power: if the Commission were to establish a bright line metric, it should be based on a measurable reduction in the cost of delivered power to consumers, not average production costs.

Q 26) Should the Commission utilize an incentives approach that is based on targeting certain geographic areas where transmission projects would enhance reliability and/or have particular economic efficiency benefits? If so, how should the relevant geographic areas be identified and defined? What entity (e.g., the Commission, RTOs/ISOs, state regulators, other stakeholders) should designate such areas?

Response: No, the Commission should not develop a new incentives approach focusing on geographic areas to enhance reliability or economic efficiency benefits. In RTO/ISO regions, there are already processes in place to identify the need for reliability and economic efficiency transmission projects.[56] To the extent the Commission is considering a process separate from those that RTOs/ISOs employ in regional transmission planning, NESCOE cannot meaningfully respond to such a proposal without additional information, such as the threshold need for a separate process, the specific objective it would seek to satisfy, and how it would function alongside the established RTO/ISO process.

If the Commission were to establish an incentive approach based on targeting certain geographic areas, state officials must be accorded a primary role in that process.

Q 27) What criteria should be used to define such geographic areas? Procedurally, how should such geographic areas be determined, monitored, and updated?

Response: The Commission should not define geographic areas for the reasons set forth in response to Question 26.

Q 28) Should the relevant geographic areas be defined on an ex ante basis and/or should the transmission developer have the burden of demonstrating that the relevant transmission project falls within a geographic region that has an acute need for transmission?

Response: The Commission should not adopt either approach for the reasons set forth in response to Question 26.

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56 *See, e.g.,* ISO-NE OATT, Attachment K, § 4.1.

Q 29)   How can flexibility characteristics improve the operation of the transmission system?

Response: See response to Question 12. Moreover, to the extent the Commission determines that it is appropriate to incent particular characteristics, those characteristics must be objectively defined in advance of program implementation. The term "flexibility," for example, would need to be defined as a transmission attribute.

Q 30)   Should the Commission incentivize flexibility characteristics and, if so, how should it do so?

Response: See response to Question 29.

Q 31)   How could the Commission define "flexibility" in this context?

Response: See responses to Questions 4 and 12.

Q 32)   Should the Commission incentivize physical and cyber-security enhancements at transmission facilities? If so, what types of security investments should qualify for transmission incentives? What type of incentive(s) would be appropriate?

Response: See responses to Questions 4 and 12. In addition, physical and cyber-security enhancements to transmission facilities are required under NERC and NPCC standards and, at least where New England is concerned, NESCOE understands that these investments are already being made.

Q 33)   How should the Commission define "security" in the context of determining eligibility for incentive treatment? For example, should the Commission define security based on specific investments or based on performance of delivering increased security of the transmission system?

Response: See responses to Questions 4, 12, and 32.

Q 34)   Should transmission projects that enhance resilience be eligible for incentives based upon their reliability-enhancing attributes?

Response: See responses to Questions 1, 4, 12, and 29. Similar to "flexibility," there has been no definition adopted for "resilience" and that term would, as a threshold matter, need to be defined with specificity as a transmission attribute. In addition, as stated above, RTO/ISO regions already employ processes to identify the need for reliability projects. NESCOE cannot meaningfully respond to the approach proposed in this question without additional information, such as the threshold need for a separate process, the specific objective it would seek to satisfy, and how it would function alongside the established RTO/ISO process.

Q 37) How should the Commission incentivize the deployment of technologies and other measures to enhance the capacity, efficiency, and operation of the transmission grid? How can the Commission identify and quantify how a technology or other measure contributes to those goals? Please provide examples.

Response: See responses to Questions 1, 4, and 12. In addition, as a general matter, a prudent utility would seek to adopt new technologies as appropriate. The Commission has recognized that only technology that is truly novel or innovative should be eligible for incentives related to the deployment of advanced technology.[57]

Q 38) Can the Commission distinguish between incremental improvements that merit an incentive and those maintenance-related expenses that a transmission owner would make in its ordinary course of business?

Response: See responses to Questions 1, 4, and 52.

Q 45) If the Commission should use incentives to encourage interregional transmission projects, should all interregional projects be eligible or should it be based on some other criteria? How should the Commission consider the benefits of an individual interregional transmission project?

Response: The Commission should not modify its incentives policy to target interregional transmission projects. Many regions already have in place processes to consider the need for interregional projects. For example, ISO-NE, PJM Interconnection LLC ("PJM"), and New York ISO ("NY-ISO") coordinate transmission planning activities primarily through the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol ("Protocol").

[57] *See United Illuminating* at P 63, citing *NSTAR Elec. Co.*, 125 FERC ¶ 61,313 at P 77 (2008), *order on reh'g*, 127 FERC ¶ 61,052 (2009).

The Commission accepted the Protocol as compliant with Order 1000 directives regarding interregional transmission coordination and cost allocation.[58] ISO-NE, PJM, and NY-ISO also jointly administer the Interregional Planning Stakeholder Advisory Committee ("IPSAC"), which provides input into the development of a Northeast Coordinated System Plan ("NCSP").[59] The most recent NCSP describes how ISO-NE, PJM, and NY-ISO work together to "identify and resolve planning issues with potential interregional impacts, consistent with [NERC] reliability requirements and other applicable state and local reliability criteria."[60] In addition, the NCSP notes that the three regions collaborate through entities such as NPCC and the Eastern Interconnection Planning Collaborative "to enhance the widespread reliability and efficiency of the interregional electric power system."[61] These existing planning processes are more appropriate venues for discussion of interregional needs than a developer-initiated proceeding to request incentives.

In addition, whether a project is regional or spans multiple regions, eligibility for incentives should continue to be determined on a case-by-case basis, taking into account, *inter alia*, the special risks and challenges of a project and whether the base ROE and risk-reducing incentives address any such risks and challenges.[62]

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[58] *ISO New England Inc. et al.*, 151 FERC ¶ 61,133 (2015); *ISO New England Inc. et al.*, Delegated Letter Order, Docket Nos. ER13-1957-001 et al. (Nov. 19, 2015).

[59] IPSAC materials are available at https://www.iso-ne.com/committees/planning/ipsac/.

[60] ISO-NE, NY-ISO, and PJM, 2017 Northeastern Coordinated System Plan, April 30, 2018, at 1, available at https://www.iso-ne.com/committees/planning/ipsac/.

[61] *Id.* at 2.

[62] *See* 2012 Policy Statement at PP 20, 24-30. *Accord United Illuminating* at P 62.

Q 47) Should the Commission use incentives to encourage the development of transmission projects that will facilitate the interconnection of large amounts of resources?

Response: No, the Commission should not modify its incentives policy to encourage the interconnection of large amounts of resources. Regional resource adequacy needs and state laws are driving resource interconnections. ISO-NE and some other RTOs/ISOs have established a competitive wholesale capacity market to procure the megawatts ("MWs") needed for regional resource adequacy. For example, the last five ISO-NE capacity auctions have secured thousands of MWs of new generating capacity, including a 650 MW facility that cleared in the most recent auction.[63] In the case of some states' laws, individual New England states are implementing legal requirements to encourage the substantial development of new resources, particularly the increased integration of clean energy.[64]

For these reasons, it is unclear what consumer benefits would be achieved by modifying incentive regulations to encourage the interconnection of large amounts of resources. At the same time, consumers would incur potentially significant costs in connection with these incentives without a clear correlation to project risks and challenges.

Q 51) Should the Commission consider granting incentives to promote joint ownership arrangements with non-public utilities and, if so, how?

Response: NESCOE cannot meaningfully respond to such a proposal without additional information, such as the how granting incentives for these joint ownership arrangements is consistent with Section 219 and how joint ownerships benefit consumers.

63 ISO-NE, Finalized Auction Results Confirm Sufficient Capacity Resources for 2022–2023, available at https://www.iso-ne.com/static-assets/documents/2019/02/20190228_pr_fca13_final_results.pdf.

64 *See, e.g.,* 2019 REO, at 21 (listing states' recent clean energy procurements).

Q 52) Should these or other incentives be granted automatically for transmission projects selected in a regional transmission plan for purposes of cost allocation?

Response: No. Incentives should not be granted automatically for projects selected in a regional transmission plan for purposes of cost allocation. See the response to Question 1 regarding leveraging the Order 1000 competitive process to reform the Commission's transmission incentive policies and the response to Question 7 opposing the award of automatic incentives.

In addition, as NESCOE explained in response to Question 4, the Commission has appropriately distinguished between incentives for "new projects that present special risks or challenges" and "routine investments made in the ordinary course of expanding the system to provide safe and reliable transmission service."[65] At least in New England, most projects selected in a regional transmission plan for the purposes of cost allocation are these types of routine investments. The Commission should continue to closely scrutinize, on a case-by-case basis, requests for incentives rather than apply incentives automatically.

This project-specific inquiry is particularly needed in New England in light of the ISO-NE's reliance on projects to meet Time-Sensitive Needs[66] and the contractual arrangements in connection with these projects. In New England, transmission owners contracted with ISO-NE through a Transmission Operating Agreement ("TOA") for the right and obligation to construct projects needed to meet Time-Sensitive Needs.[67] Through the TOA, transmission owners had the opportunity to negotiate revenue and risk-reducing mechanisms and, in fact, secured the

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[65] Order 679-A at P 23.

[66] *See supra* p. 6 and accompanying notes.

[67] *See* TOA, Schedule 3.09(a), available at https://www.iso-ne.com/static-assets/documents/regulatory/toa/v1_er07_1289_000_toa_composite.pdf.

ability to recover abandonment costs as part of this arms-length bargain. The TOA provides transmission owners with abandoned plant recovery if the project does not proceed, "notwithstanding any contrary FERC policy or rule relating generally to the recovery of the costs of abandoned plant."[68] The TOA thus provided transmission owners with the opportunity to address the risks and challenges they identified in constructing new projects for which they negotiated for the right and obligation to build.

NESCOE agrees with the Commission that an obligation to build, while not dispositive of eligibility for incentives, may affect the Commission's consideration of incentive requests.[69] Applicants seeking incentives related to solutions to Time-Sensitive Needs should face a heavy burden in establishing the need for mechanisms beyond what they negotiated at arms-length in the TOA and what is already provided in the base ROE and cost-of-service rate recovery.[70]

Q 54) Should the Commission continue to use certain incentives to seek to place non-incumbent transmission developers on a level playing field with incumbent transmission owners in Order No. 1000 regional transmission planning processes? If so, should the Commission consider requests for such incentives under section 205, or should the Commission consider requests for such incentives for non-incumbent transmission owners under section 219?

Response: See response to Question 1.

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68 TOA, Schedule 3.09(a), Section 1.1(d).

69 *Northeast Utilities Service Co. and National Grid USA*, 125 FERC ¶ 61,183 at P 60 (2008), quoting *Northeast Utilities Service Co.*, 124 FERC ¶ 61,044 at P 89 (2008).

70 *See* Order 679 at P 94 ("[R]outine investments made to comply with existing reliability standards may not always qualify for an incentive-based ROE. These are the types of investments that have, as a general matter, been adequately addressed through traditional ratemaking because there is an obligation to construct them and high assurance of recovery of the related costs. For these and other reasons, traditional ROE determinations may continue to be appropriate for these investments."). *Accord United Illuminating* at P 62.

C. Existing Incentives

Q 61) Should the Commission revise the RTO-participation incentive?

Response: Yes. Section 219(c) requires the Commission to "provide for incentives to each transmitting utility or electric utility that joins an" RTO/ISO. In Order 679-A, the Commission found that "an inducement for utilities to join, and remain in" ISOs/RTOs promoted Section 219's objectives of providing consumer benefits "by ensuring reliability and reducing the cost of delivered power."[71] The Commission stated that "the best way to ensure those benefits are spread to as many consumers as possible is to provide an incentive that is widely available to member utilities of [ISOs/RTOs] and is effective for the entire duration of a utility's membership in the" ISO/RTO.[72] The NOI notes that the Commission did not "make a finding on the appropriate size or duration of the" RTO adder incentive.[73] The Commission also declined in Order 679 to include a "generic adder" for membership in an ISO or RTO.[74]

The Commission should reevaluate the reasonableness of awarding an ROE adder in perpetuity to transmission owners that are members of an ISO/RTO. While the Commission has found that it would only award an RTO participation incentive adder "when justified,"[75] in practice, the Commission has "typically has awarded a 50 basis-point ROE adder to utilities that either join or are already members of an RTO or ISO."[76] In New England, the Commission approved in 2004 a 50 basis point adder for RTO membership and this adder is included as part

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71 Order 679-A at P 86.

72 *Id.*

73 NOI at P 38, citing Order 679 at P 331.

74 Order 679 at P 326.

75 Order 679-A at P 79.

76 *Promoting Transmission Investment Through Pricing Reform*, 135 FERC ¶ 61,146 at P 34 (2011).

of the stated base ROE rate.[77] It is not clear, 15 years after this Commission order, that a 50 basis-point adder is a necessary and appropriate inducement to join or continue participating in ISO-NE and that inclusion of this adder remains just and reasonable.

The Commission should reaffirm the burden it placed on utilities in Order 679 to demonstrate, on a case-by-case basis, that the level of RTO participation adder is appropriate. It should also underscore that, in the case of a utility with a longstanding relationship as member of an RTO/ISO, that the utility demonstrate why a continued RTO participation adder is warranted.

Q 62) Should the Commission consider providing incentives other than ROE adders for utilities that join RTO/ISOs, such as the automatic provision of CWIP in rate base or the abandoned plant incentive for all transmission-owning members of an RTO/ISO? If so, what other types of incentives would be appropriate?

Response: No. Incentives should continue to be determined on a case-by-case basis, taking into account, *inter alia*, the special risks and challenges of a project and whether the base ROE and risk-reducing incentives address any such risks and challenges.[78] See responses to Questions 4, 70, and 77.

Q 63) If the Commission continues to provide ROE adders for RTO/ISO participation, what is an appropriate level for an ROE adder?

Response: See responses to Questions 61 and 62.

Q 64) Should the RTO-participation incentive be awarded for a fixed period of time after a transmission owner joins an RTO or ISO?

Response: See responses to Question 61 and 62.

Q 65) Should the RTO-participation adder be awarded on a project-specific basis?

Response: See responses to Questions 61 and 62.

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[77] *Bangor Hydro-Elec. Co., et al.*, 206 FERC ¶ 61,280 at P 245 (2004). *See* ISO-OATT, Attachment F Implementation Rule, Section II.A.2.(a)(iii).

[78] *See* 2012 Policy Statement at PP 20, 24-30. *Accord United Illuminating* at P 62.

Q 68) Do NERC reliability standards affect the willingness of transmission developers to enhance existing transmission facilities by deploying new technologies because of concerns these technologies may increase the risk of standards violations?

Response: NESCOE is not aware of the challenge underlying the premise of this question and would need more information to respond meaningfully. One threshold question is whether the reliability standard, rather than the Commission's incentives policy, should be modified.

Q 69) Are there any types of transmission incentives that could better encourage deployment of new technologies? If so, please describe them.

Response: See response to Question 1. In addition, as a general matter, a prudent utility would seek to adopt new technologies as appropriate.

Q 70) Should the Commission continue to provide regulatory asset treatment and CWIP as incentives? Should these incentives be granted automatically to certain types of transmission projects? If so, how would the Commission determine what types of transmission projects?

Response: The Commission should not automatically grant regulatory asset treatment and CWIP. Eligibility for incentives should continue to be determined on a case-by-case basis, taking into account, *inter alia*, the special risks and challenges of a project and whether the base ROE and risk-reducing incentives address any such risks and challenges.[79] See responses to Questions 1, 4, and 7.

Q 71) Should the costs of unsuccessful Order No. 1000 proposals be recoverable through regulatory asset and deferred pre-commercial cost recovery incentives? If so, what costs are appropriate for recovery?

Response: No. The Commission has approved tariff provisions in various regions providing for competitive solicitation processes to comply with Order 1000. In New England, there are established rules for cost recovery in connection with the development of project proposals.[80] The Commission should not alter these rules—which were the subject of extensive regional

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79 *See* 2012 Policy Statement at PP 20, 24-30. *Accord United Illuminating* at P 62.

80 *See* ISO-NE OATT, Attachment K, §§ 4.3(i) and 4A.6.

stakeholder discussions and trade-offs among interested parties—through a subsequent generic proceeding on transmission incentives.

Q 77) Should the Commission grant the abandoned plant incentive automatically, rather than on a case-by-case basis? Under what circumstances might an automatic award of the abandoned plant incentive be appropriate?

Response: No, the Commission should not grant abandoned plant as an automatic incentive. Eligibility for incentives should continue to be determined on a case-by-case basis, taking into account, *inter alia*, the special risks and challenges of a project and whether the base ROE and risk-reducing incentives address any such risks and challenges.[81] See responses to Questions 1,4, and 7. Contractual arrangements in New England also underscore the need for scrutiny in considering applications for incentives as discussed in response to Question 52.

Q 79) How should the Commission evaluate whether the costs of an abandoned facility were prudently incurred?

Response: This should be a case-by-case determination, with the burden on the transmission owner to justify that costs were prudently incurred consistent with Commission precedent.

D. Mechanics and Implementation

Q 83) Should the Commission limit the duration of a granted transmission incentive? If so, should this limit be based on the type of incentive granted?

Response: See response to Question 1. Subject to the qualifications discussed above, using the Order 1000 competitive process as a vehicle for awarding incentives obviates the need for the Commission to make this determination: a project's bid into a robust competitive process should include all of the financial and risk-mitigation requirements that a developer needs to make the investment and terms regarding the duration of cost recovery.

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[81] *See* 2012 Policy Statement at PP 20, 24-30. *Accord United Illuminating* at P 62.

Q 84) How should the Commission structure a durational component to its incentives? For example, should the Commission provide that transmission incentives automatically sunset after a certain period?

Response: See response to Question 83.

Q 85) Should the Commission provide that a transmission incentive can be eliminated or modified upon a material change to the transmission project? How would such an elimination or modification be implemented? What should constitute such a material change? How would the Commission and interested parties be informed of such a material change?

Response: See response to Question 1. In general, the terms and conditions of a competitive solicitation for transmission under Order 1000 should address how a material change to a project selected as part of that solicitation will impact the project's cost recovery. To encourage participation in competitive solicitations, RTOs/ISOs should provide full transparency regarding a developer's ability to recover costs and meet the revenue requirements for a project that is selected in a regional plan for purposes of cost allocation.

To the extent a project is not selected pursuant to a competitive process (for example, a project to meet a Time-Sensitive Need), the Commission should provide that a transmission incentive can be eliminated or modified based upon a material change to the transmission project. This is consistent with Section 219's directive that incentive-based rates shall be established "for the purpose of benefitting consumers" and must be just and reasonable. As a condition of approving requested incentives, the Commission could require the applicant to report periodically on whether there has been a material change to the project. The report should contain sufficient information for the Commission and third parties to assess whether a change warrants the elimination or modification of incentives.

Q 86) Should there be a process of measurement and verification (or audit) to determine if the expected benefits accrued to consumers?

Response: See response to Question 85 and its discussion of a reporting requirement. See also the response to Question 4 discussing why transmission incentives should continue to focus on special risks and challenges. To the extent the Commission adopts an approach focusing on expected benefits, the party requesting incentives should bear the burden of demonstrating the achievement of these benefits.

Q 88) Should the Commission consider eliminating an incentive if the project fails to realize its anticipated benefits?

Response: See responses to Questions 85 and 86.

Q 89) Should there be reporting on projects' expected benefits compared to results, and over what time period?

Response: See responses to Questions 85 and 86.

Q 90) What are the benefits and drawbacks of granting incentives on a case-by-case basis, as compared to being granted automatically, with or without related threshold criteria? Would an automatic approach based on established threshold criteria provide additional certainty? If so, how?

Response: See response to Question 7. Incentives should not be granted automatically. The Commission should assess the facts associated with each project for which incentives are requested in order to decide whether, based on those facts, incentive costs in rates would be just and reasonable. As discussed in the response to Question 1, provided certain conditions are met, the Commission could establish a rebuttable presumption regarding the nexus between incentives and investments in the case of a project selected under an Order 1000 competitive solicitation process.

E. Metrics for Evaluating the Effectiveness of Incentives

Q 98) What metrics should the Commission use in measuring the effectiveness of incentives, e.g., if certain milestones are reached or only if a transmission project is built and energized?

Response: This question underscores the risk in automatically granting incentives. A milestone, for example, does not establish the effectiveness of an incentive unless there is a demonstration that the milestone would not have been achieved but for the incentive. In general, the Commission should focus any metrics on the placing of a project into service. As discussed above, leveraging an Order 1000 competitive process—where bidders request the incentives they need to move forward with a project—can help measure the effectiveness of the particular incentives a developer has identified as necessary to build a project.

Q 100) Should the Commission require that incentive recipients provide additional data through Form FERC-730? If so, what additional information should be provided?

Response: Form FERC-730 currently contains information about costs only. As reflected in responses to Questions 4 and 7, the Commission should continue to apply an approach to incentives that focuses on the special risks and challenges of a project and make that determination on a case-by-case basis. However, should the Commission adopt an approach that evaluates project benefits, it should require that recipients of incentives provide additional data through Form FERC-730 for each incentivized project to enable the Commission and third parties to assess whether the expected level of consumer benefits are actually being achieved. Form FERC-730 does not currently include information that would enable the Commission to assess whether the consumer benefits that were expected when incentives were approved are being achieved in a measurable way. Should the Commission seek to adopt a benefits-based approach, it could solicit views as part of any further action in a related proceeding on how benefits could be measured and input into Form FERC-730.

IV. CONCLUSION

NESCOE appreciates the Commission's initiation of this proceeding and its assessment of transmission incentives policies. NESCOE respectfully requests that the Commission consider these comments in evaluating reforms to its transmission incentives regulations and policies.

Respectfully submitted,

/s/ Jason Marshall

Jason Marshall
General Counsel
New England States Committee
on Electricity
655 Longmeadow Street
Longmeadow, MA 01106
Tel: (617) 913-0342
jasonmarshall@nescoe.com

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