UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning and Cost Management	)))	Docket No. AD22-8-000
Joint Federal-State Task Force on Electric Transmission	))	Docket No. AD21-15-000

COMMENTS OF
<u>NEW ENGLAND STATES COMMITTEE ON ELECTRICITY</u>

Pursuant to the Notice Inviting Post-Technical Conference Comments issued by the Federal Energy Regulatory Commission ("Commission" or "FERC") on December 23, 2023, the New England States Committee on Electricity ("NESCOE") submits these Comments to the Commission's above-referenced dockets on Transmission Planning and Cost Management and Joint Federal-State Task Force on Electric Transmission.

I. DESCRIPTION OF NESCOE

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

[1] *ISO New England Inc.*, 121 FERC ¶ 61,105 (2007).

II. INTRODUCTION

NESCOE appreciates the Commission's focus and close attention to transmission planning and cost management—two issues that are essential to the successful implementation of the New England states' energy and environmental policies and legal requirements. As NESCOE has detailed in recent filings with the Commission, New England states' laws and requirements are charting a steady path to transitioning the region's power mix to a clean energy system.[2] The transmission system is central to these plans to integrate renewable energy sources and support decarbonization efforts to meet state laws.

As the Commission has recognized, "[d]eveloping new transmission infrastructure implicates a host of different issues, including how to plan and pay for these facilities."[3] Federal and state regulators each have authority over certain transmission-related issues. As discussed herein, states have varying degrees of authority over transmission. Overarching the different state laws, however, is the Commission's statutory obligation to ensure the justness and reasonableness of transmission rates.[4] As the clean energy transition accelerates and investment in transmission grows, consumer protections are necessary to guard against imprudent investments, particularly where more cost-effective transmission or non-transmission options could have been pursued and when project costs are higher than projected.[5] The Commission's close scrutiny of costs and active engagement as the main arbiter of prudency are key to promoting public confidence in transmission planning and development, and the resulting transmission rates borne by customers.

---

[2] *See* Initial Comments of the New England States Committee on Electricity, Docket No. RM21-17-000 (filed Aug. 17, 2022) ("NESCOE Initial NOPR Comments"), at 15-16 (referencing Initial Comments of the New England States Committee on Electricity, Docket No. RM21-17-000 (filed Oct. 12, 2021) ("NESCOE Initial ANOPR Comments")).

[3] Joint Federal-State Task Force on Electric Transmission, 175 FERC ¶ 61,224, at P 2 (2021).

[4] *See* 16 U.S. § 824(d).

[5] *See* NESCOE Initial ANOPR Comments at 25.

NESCOE applauds the Commission's sustained efforts to focus on cost management practices in regional and local transmission planning, as exemplified by the Commission's October 6, 2022 Technical Conference, consideration of comments submitted in preparation for the Technical Conference, and the most recent Notice Inviting Post-Technical Conference Comments in these dockets. NESCOE strongly supports the Commission's continued examination of the potential cost monitoring and cost containment benefits expected by the creation of an Independent Transmission Monitor ("ITM"), transparency improvements to the Commission's use of formula rates and prudence practices, and interest in narrowing the regulatory gap existing for certain transmission facilities that receive no federal or state oversight.[6] NESCOE encourages the Commission to address each of these areas promptly to ensure that increased transmission investments giving rise to escalating transmission rates are prudently incurred and transmission development is planned to support reliability, resilience, and renewable generation integration. NESCOE's Comments are supported by testimony from Stephen J. Rourke and Marc D. Montalvo of Daymark Energy Advisors, contained in Attachment A to these Comments.

III. EXECUTIVE SUMMARY

NESCOE strongly supports the establishment of an ITM to monitor the planning and cost of transmission facilities in the region.[7] As transmission infrastructure continues to be built to replace aging facilities and to integrate cleaner resources, the Commission has the responsibility to ensure that rising transmission costs are thoroughly examined and that transmission planning

[6] *See* FERC's Notice Inviting Post-Technical Conference Comments at 7-12, Docket Nos. AD22-8-00, AD21-15-000 (Dec. 23, 2022).

[7] *See* NESCOE ANOPR Initial Comments at 32-35; Reply Comments of the New England States Committee on Electricity, Docket No. RM21-17-000 (filed Nov. 30, 2021) ("NESCOE ANOPR Reply Comments"), at 1-21; NESCOE Initial NOPR Comments at 4-5, 53, 80.

and operations are not unduly discriminatory or preferential.[8] The Commission has the ability to discharge its responsibilities by establishing an ITM with a clearly defined role and function. The Commission has the legal authority to establish an ITM without sub-delegating its own authority to set the just and reasonable transmission rate. Key to the validity of the ITM is carefully defining the ITM's functions to comprise active participation in the transmission planning process, review of transmission costs and inputs to rates, and issuance of reports and recommendations to the Commission.[9]

While an ITM with a well-defined role will support the efficacy and efficiency of transmission planning and cost transparency, an ITM should be considered among a suite of other necessary enhancements given the escalating amount of transmission investment associated with the clean energy transition. NESCOE continues to support the Commission undertaking additional and necessary oversight and process improvements, such as the Commission removing the presumption of prudence applicable to transmission formula rate updates and authorizing the Commission's Trial Staff to participate in the annual formula rate update processes. These additional steps would bolster public confidence that transmission rates are carefully scrutinized before being charged to customers.

Finally, NESCOE encourages the Commission to continue its practice of recognizing regional differences, needs, and public policies as it considers and develops appropriate cost containment solutions.

---

[8] *See* NESCOE ANOPR Reply Comments at 7-8.

[9] *See* Daymark Testimony at ¶ 6.

IV. COMMENTS

A. THE COMMISSION HAS THE LEGAL AUTHORITY TO REQUIRE THE CREATION OF AN ITM.

As previously discussed by NESCOE and more fully below, FERC has ample authority to direct the creation of an ITM.[10] Specifically, Sections 205 and 206 of the Federal Power Act ("FPA"), [11] FERC regulations, and orders provide the necessary authorization and means for the Commission to oversee and regulate transmission costs and, by extension, create an ITM to assist it with this responsibility.

1. FERC's Broad Authority over Transmission Services and Rates Extends to the Establishment of an ITM.

In examining the state-federal jurisdictional divide over the regulation of electric transmission in interstate commerce, the United States Supreme Court affirmed the FPA's "clear and specific grant of jurisdiction" to the Commission in *New York v. FERC*.[12] This statutory grant extends over the Commission's review of public utility transmission owners' tariffs filed under FPA Section 205,[13] as well as over the Commission's power to fix any rate, charge, or classification demanded, observed, charged or collected for transmission by such utilities, including the Commission's remedial authority over "any rule, regulation, practice, or contract affecting such rate, charge, or classification."[14]

Courts have upheld the Commission's interpretation of its remedial authority under FPA Section 206 to include the regulation of transmission planning and cost allocation practices, as

---

[10] *Id*. at 1-17.

[11] 16 U.S.C. §§ 824, *et seq*.

[12] *New York v. FERC*, 535 U.S. 1, 22 (2002).

[13] 16 U.S.C. § 834(d).

[14] 16 U.S.C. § 824e.

well as matters affecting transmission owners' rights of first refusal.[15] In fact, the Commission's landmark Orders 888, 890, and 1000, to name a few, are based on FERC's remedial authority over such practices.[16] FERC's broad authority over transmission costs and practices can be enhanced and exercised through the creation of an ITM that has monitoring and reporting responsibilities to the Commission, without ceding FERC's authority to set the just and reasonable rate. This principle is well established in the area of organized wholesale energy markets where Independent Market Monitors ("IMMs") function to assist the Commission in the exercise of its statutory responsibility over wholesale electricity markets under the FPA.

2. FERC Has Paved the Way for the Establishment of an ITM Function in Orders 2000 and 2000-A.

In Orders 2000 and 2000-A, FERC continued to fulfill its responsibilities under FPA Sections 205 and 206 to remedy undue discrimination in rates and identified anticompetitive effects and practices by advancing voluntary Regional Transmission Organization ("RTO") formation by public utility transmission owners.[17] The Commission determined that one of the essential functions for the proper operations of an RTO was the development of a market monitoring role that ensures the availability of objective information about the markets the RTO operates or administers and provides a vehicle to propose actions leading to improved efficiency,

---

[15] *S.C. Pub. Serv. Auth. v. FERC,* 762 F.3d 41, 56, 70, 75-76 (D.C. Cir. 2014) (affirming in connection with finding Order No. 1000 lawful in interpreting "practices" to include transmission planning and cost allocation processes, as well as the regulation of rights of first refusal). *See also Trans. Access Policy Grp. v. FERC,* 225 F.3d 667, 687 (D.C. Cir. 2000) (holding that the FPA's antidiscrimination provisions give FERC broad authority to remedy unduly discriminatory behavior).

[16] *See S.C. Pub. Serv. Auth. v. FERC,* 762 F.3d at 57, 75-77.

[17] *Regional Transmission Organizations,* Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999) (cross-referenced at 89 FERC ¶ 61,285, 65 Fed. Reg. 809, 904 (Jan. 6, 2000) (noting at 143 that the Commission has a statutory mandate under these sections to ensure that transmission in interstate commerce and rates, contracts, and practices affecting transmission services, do not reflect an undue preference or advantage (or undue prejudice or disadvantage) and are just, reasonable, and not unduly discriminatory or preferential), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000)("Order 2000-A") (cross-referenced at 90 FERC ¶ 61,201), 65 Fed. Reg. 12,088 (Mar. 8, 2000), aff'd sub nom. *Pub. Util. Dist. No. 1 of Snohomish Cnty., Wash. v. FERC,* 272 F.3d 607 (D.C. Cir. 2001) (emphasis added).

correction of market design flaws, or identification of existing market power.[18] Importantly, Order 2000 did not limit the market monitoring function to wholesale markets and expressly stated that "[t]he monitoring plan also must evaluate the behavior of market participants, *including transmission owners*, if any, in the region to determine whether their behavior adversely affects the ability of the RTO to provide reliable, efficient and nnondiscriminatory *transmission service*" (emphasis added).[19] The Commission was keenly aware that energy markets and transmission services are not neatly segregated into different areas and that the malfunctioning of one typically affects the other.[20] For that reason, the Commission left open the scope and design of the market monitoring function to the RTO's membership, provided certain minimum standards were met, including those of reviewing information, reporting on relevant developments, and recommending improvements to the status quo.[21]

While Order 2000 opened the door to market monitoring of transmission owners' operations to ensure that RTOs provide reliable, efficient, and non-discriminatory transmission services, it did not mandate the monitoring of transmission services and instead left the scope of the monitoring function to the RTOs:

> In developing its market monitoring plan, the RTO should identify the markets that will be monitored, i.e., *transmission*, ancillary services or any other market it may develop (e.g., congestion management).[22]

[18] Order 2000 at 463.

[19] *Id*. at 464.

[20] On that point, the Commission noted that it has an "obligation to ensure that rates for wholesale power sales are just and reasonable, and … that market-based rates can be just and reasonable only where transmission market power has been mitigated and there are no other barriers to entry." *Id*. at 145.

[21] *Id.* at 463-5.

[22] *Id*. at 463 (emphasis added).

Indeed, some IMMs have formal responsibilities relating to monitoring the services provided by independent transmission companies, reviewing information related to the operation of the transmission grid, reporting on the exercise of undue preference between transmission owners and their affiliates, calculating transmission congestion credits, and monitoring the potential of market participants[23] to exercise market power or violate any of the RTO or FERC Market Rules.[24] Similarly, Potomac Economics—the external Market Monitor for ISO-NE, Midcontinent ISO, New York ISO, and the Electric Reliability Council of Texas—has performed limited independent transmission monitoring of six utilities under FERC-approved market monitoring plans.[25] This monitoring, however, is limited to the provision of transmission service, such as its scheduling on a non-discriminatory basis, rather than the planning and cost recovery of transmission costs. Therefore, adequate monitoring of transmission planning and spending is not currently within the responsibilities of Potomac Economics.

While active review, reporting, and evaluation of the effectiveness of transmission services may not have been at the center of Order 2000, in its subsequently issued Order 2000-A on rehearing, the Commission recognized the evolving nature of electricity markets and services and agreed that "an important element of any market monitoring plan may be a process that provides for the periodic evaluation of the plan's design and effectiveness."[26] Thus, the Commission has

[23] For example, the term "Market Participant" in PJM's Open Access Transmission Tariff ("OATT") has a special definition applicable to Attachment M, PJM Market Monitoring Plan, that is distinctly broad and includes "an entity that generates, *transmits*, distributes, purchases, or sells *electricity*, ancillary services, *or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region*, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale." PJM's OATT, Part I, Common Service Provisions, Definitions (emphasis added).

[24] *See* PJM OATT, Attachment M at 6, 12, 15.

[25] A general description of Potomac Economics' transmission system monitoring operations and objectives is available at https://www.potomaceconomics.com/practice-areas/transmission-system-monitoring/ (last visited Mar. 20, 2023).

[26] Order 2000-A at 23.

recognized that as electricity markets and services change over time, so should market monitoring roles and responsibilities. As demonstrated in these comments and accompanying testimony, ample evidence exists to require the addition or establishment of specific transmission monitoring services, either as part of the existing external IMM structure or, preferably, in a separate ITM entity.

3. **Commission Regulations Already Require That Market Monitoring Ensure Reliable, Efficient, and Not Unduly Discriminatory Transmission Service**.

FERC's regulations on the creation of market monitoring functions in RTO/ISO regions established three standards that each RTO and ISO should satisfy to meet its obligations, or, alternatively, required RTOs/ISOs to propose an approach that is consistent with or superior to the standards.[27] The first standard relates directly to monitoring the behavior of transmission owners in providing reliable, efficient and not unduly discriminatory service and provides as follows:

> Market monitoring must include monitoring the behavior of market participants in the region, including transmission owners other than the Regional Transmission Organization, if any, to determine if their actions hinder the Regional Transmission Organization in providing reliable, efficient and not unduly discriminatory transmission service.[28]

While the regulations may have been driven by the need to ensure open and non-discriminatory transmission service, the efficiency of that service was expressly named as a necessary characteristic in the Commission's regulations. The efficiency of transmission service, however, can be measured not only by the current use of and delivery of service over the existing system, but also by the efficient planning and cost-effective expansion of the transmission system over time. Therefore, the Commission's existing regulations already provide sufficient grounds

[27] 18 C.F.R. § 35.34(k)(6).

[28] *Id.* § 35.34(k)(6)(i).

for active transmission monitoring, at least with respect to RTO and ISO regions. Consequently, the Commission would be acting within its authority to direct RTOs and ISOs to explain how they already comply with this requirement and use the record established in Docket No. RM21-17-000 and technical conferences at Docket Nos. AD22-8-000 and AD21-15-000 to determine what additional transmission monitoring standards and functions need to be established.

4. NESCOE Recommends the Commission Take Additional Actions To Ensure Robust Transmission Monitoring Services.

NESCOE respectfully urges the Commission to use the record developed through the significant stakeholder engagement in Docket Nos. RM21-17-000, AD22-8-000, and AD21-15-000 and build upon the existing regulatory framework for transmission cost oversight to fill in the identified gaps in a manner that allows for regional differences and State preferences. Regional transmission systems across the country vary in their topology and physical characteristics, regulatory approaches to cost oversight, stakeholder involvement, and public policies, among other things. As a result, the regulatory gaps will also differ from region to region.

Order 2000 already provides a significant amount of flexibility by allowing RTOs to propose a narrow or expansive scope of market monitoring functions, various levels of information sharing, reporting, and corrective tools, including penalty-levying authority, referral authority to FERC, or an advisory authority.[29] To the extent this flexibility has been exercised narrowly by RTOs in a manner to exclude transmission system monitoring on issues, such as regional and local transmission planning optimization, use of cost containment measures, and review of cost recovery processes, the Commission should require RTOs to promptly supplement their existing monitoring functions. This could be done through the establishment of a new ITM entity focused, among

[29] Order 2000 at 463-4.

other things, on the planning and operation of the transmission system and its interaction with wholesale markets, or through the express addition of specific transmission-related functions to existing external IMMs.

The Commission should not be deterred by calls to refrain from monitoring the transmission system, which, unlike the wholesale electricity markets, is characterized by traditional cost of service regulation. Such calls are a red herring that both ignore the complex interrelationship between the two areas and the regulatory gaps that enable recovery of certain transmission costs in some regions with little to no real review or oversight.

Wholesale electricity markets directly affect transmission costs and vice versa. For instance, in RTO markets, transmission congestion costs and line losses are both characteristics of the use of the transmission system but are costs that are, at least partially, recovered through the locational marginal pricing ("LMP") mechanism used to set the wholesale energy price. The level of LMP, in turn, is used to determine what transmission solutions can be offered in the form of transmission market efficiency projects that have the ability to ease transmission congestion and lower energy prices. Further, states may be able to achieve their public policy goals by investing in new transmission solutions that bring electricity with desired characteristics from remote areas, or by encouraging the build-out of specific in-state generation sources. Because of the potential for direct competition between generation and transmission resources, states need an independent source of information and cost evaluation to aid them in making consequential and far-reaching decisions about the energy infrastructure within their jurisdictions.

For the same reason, the Commission should continue to encourage the nascent transmission competition markets within RTOs that can optimize transmission solutions and financing options, while employing cost containment measures. In such cases, ITMs can fill the information gap by providing independent analysis and information on the costs of the proposed solutions over their useful life. Where projects are selected and put in service, the ITMs could track project costs (*e.g.*, estimated versus actual), verify that all benefits derived from a competitive solicitation process were properly accounted for, and suggest enhancements to the formula, protocols, or workpapers.[30]

Although the scope of the Commission's oversight over the proposed ITM functions will likely vary from region to region, the Commission should reiterate its commitment in Order 2000 that any new monitoring functions are not intended to supplant FERC's authority over the just and reasonable rate determination.[31]

5. Should FERC Determine that Order 2000 and Its Existing Regulations Are Not the Appropriate Vehicle To Usher Additional ITM Reforms, the Commission Should Use Its Statutory Authority Under Section 206 To Require Enhanced Review of Transmission Costs and Planning Processes.

While the Commission already has authority under Orders 2000 and 2000-A and its regulations at 18 C.F.R. § 35.34(k)(6) to require RTOs/ISOs to amend their market monitoring plans to include robust transmission monitoring functions or to direct the establishment of new ITM entities, the Commission may also use its remedial authority under Section 206 to institute a rulemaking proceeding that specifies in detail the particular ITM functions to be included in RTO/ISO tariffs. Should the Commission select this option, the record in the instant dockets and at Docket No. RM21-17-000 will provide ample support for the Commission's future actions.

To aid the Commission's determination specific to the ISO-NE region, NESCOE respectfully submits the testimony of Daymark Energy Advisors that recommends the creation of an external ITM for the purposes of engaging in the ISO-NE transmission planning process,

[30] *See* Daymark Testimony at ¶ 9.

[31] *See* Order 2000 at 465.

reviewing the ratemaking and cost recovery processes of ISO-NE transmission owners, and providing periodic reports to the Commission, states and stakeholders on the performance of those processes.[32]

6. The Commission Would Maintain Ultimate Authority Over Rate Setting and Penalty-Enforcement Actions.

Arguments that the Commission would unlawfully sub-delegate its ratemaking and enforcement authority to ITM entities are neither novel nor valid.[33] Similar arguments were raised in response to the Commission's establishment of market monitoring functions in Order 2000. FERC's determination there is instructive here, as well:

> In response to commenters' arguments that RTO market monitoring results in an impermissible shift of Commission authority to other entities, we emphasize that performance of market monitoring by RTOs is not intended to supplant Commission authority. Rather it will provide the Commission with an additional means of detecting market power abuses, market design flaws and opportunities for improvements in market efficiency. Further, because market monitoring plans will be required to be filed with and approved by the Commission as part of an RTO proposal, we will retain the ability to determine what, how and by whom activities will be performed in the first instance.[34]

Similarly, any reliance on the post-Order 2000 Court of Appeals decision in *U.S. Telecom Ass'n v. F.C.C.* is misplaced.[35] That case held that federal agency officials may not sub-delegate their *decision-making authority* to outside entities absent affirmative evidence of Congressional authorization to do so.[36] Such arguments miss the point: FERC would not be sub-delegating its decision-making authority to an ITM, just as it did not do so when it created the IMM function.

---

[32] *See* Daymark Testimony at ¶ 6.

[33] Statement of Larry Gasteiger, Executive Director, WIRES, Docket No. AD22-8-000 (filed Oct. 4, 2022) ("WIRES' Comments").

[34] Order 2000 at 465.

[35] *U.S. Telecom Ass'n v. F.C.C.*, 359 F.3d 554 (DC Cir. 2004).

[36] *Id*. at 566.

FERC would retain control over the scope, function, and authority of an ITM. Further, none of the proposed functions of reviewing information, reporting on findings, and providing recommendations contain attributes of a federal decision-making authority to set rates and practices affecting rates.

For example, in its *Policy Statement on Market Monitoring Units*, the Commission provided guidance on the role of IMMs in RTO and ISO markets and adopted protocols on IMM referrals to FERC's Office of Enforcement.[37] There, the Commission described the following four specific areas for IMM involvement in assisting FERC:

- To identify ineffective market rules and tariff provisions and recommend proposed rule and tariff changes to the ISO/RTO that promote wholesale competition and efficient market behavior.

- To review and report on the performance of wholesale markets in achieving customer benefits.

- To provide support to the ISO/RTO in the administration of Commission-approved tariff provisions related to markets administered by the ISO/RTO (e.g., day-ahead and real-time markets).

- To identify instances in which a market participant's behavior may require investigation and evaluation to determine whether a tariff violation has occurred, or may be a potential Market Behavior Rule violation, and immediately notify appropriate Commission staff for possible investigation.[38]

Certainly, the Commission was aware of the *U.S. Telecom Ass'n* decision issued the year before on the limits of federal sub-delegation powers when it limited its guidance on IMM functions to those of reviewing, reporting, and recommending on important market, tariff, and participant behavior matters. Notably, the Commission explicitly stated that "it is the responsibility of the

[37] *Policy Statement on Market Monitoring Units*, 111 FERC ¶ 61,267 (2005).

[38] *Id*. at 1-2.

ISO/RTO to make section 205 filings, rather than the [Market Monitoring Unit] MMU."[39] NESCOE is not proposing that an ITM have the authority to make Section 205 filings or to levy penalties. In the case of the former, such decisions would stay with the RTOs and transmission owners, subject to the Commission's remedial authority under Section 206, whereas in the case of the latter—they would remain with the Commission, acting as an impartial adjudicator to matters brought to it by Enforcement Staff.

B. REGULATORY GAPS REGARDING TRANSMISSION COST OVERSIGHT

Due to the dual federal-state regulatory regime involving electric transmission service and the restructuring of electric service in portions of the country, certain categories of transmission facilities have fallen in a gray area and are subject to very light or no scrutiny involving their planning, associated transmission drivers, and siting. NESCOE comments on each of those areas within the ISO-NE region.

1. Transmission Planning

Generally, in New England, regional transmission planning is conducted by ISO-NE and can include reliability, market efficiency, or public policy drivers.[40] ISO-NE's planning jurisdiction is typically invoked for network transmission facilities at 115 kV or above and starts with an independent Needs Assessment report.[41] After ISO-NE identifies the need for a transmission solution, incumbent and, in some circumstances, non-incumbent transmission owners may submit solutions to address the need. ISO-NE then makes the final determination, with input from its Planning Advisory Committee ("PAC"), which is open to interested persons with CEII

[39] *Id*. at 2.

[40] *See* Daymark Testimony at ¶ 29.

[41] *Id*.

clearance.[42] Reliability transmission upgrades in New England represent an investment of over $7 Billion since 2010 and are projected to increase to over $13 Billion by 2027.[43]

By contrast, local projects and asset condition projects in New England are planned by the incumbent transmission owners and do not require formal review or approval by ISO-NE.[44] The ISO does not perform an independent Needs Assessment for either of these categories of projects. The category of local projects usually involves radial expansion of a network or lower voltage level transmission facilities. Of particular interest is the recent growth in spending on a category of transmission projects known as "asset condition," also referred to as asset refurbishment. These projects are meant to replace or refurbish aging or failing transmission infrastructure and now account for $2.9 Billion in investment, with a projected increase to over $6 Billion by 2028.[45] The costs of these projects can be allocated on a regional or local basis.[46]

2. Transmission Siting

With few exceptions related to projects designated under the United States Department of Energy's National Interest Electric Transmission Corridor program, for which the Commission has backstop siting authority, the vast majority of transmission siting authority has remained with the states, to the extent they have chosen to exercise it. In New England, all six states have transmission siting laws that apply to new transmission lines over a certain voltage level, and only one state requires the siting review of existing transmission lines where they are replaced with in-kind assets of 10 miles of more.[47] With the exception of certain transmission lines in that state, *all*

---

[42] *Id*.

[43] *Id*. at ¶ 23.

[44] *Id*. at ¶ 29.

[45] *Id*. at ¶ 25.

[46] *Id*. at ¶ 29.

[47] *See* Table 1, *supra*, at 17.

other existing transmission lines in New England can undergo asset replacement or refurbishment without state siting approval, and without scrutiny by ISO-NE. Additionally, other existing transmission facilities, such as substations and buildings, need not seek siting authorization in any of the six New England states. This regulatory gap essentially allows transmission owners to plan, build, and recover through rates, without oversight beyond the annual formula rate updates, the vast majority of asset condition projects in New England currently totaling $2.9 Billion and projected to increase to $6 Billion in 2028.

Additionally, for the transmission facilities required to undergo siting review, the New England state siting laws do not assess prudency of costs. To the extent costs are reviewed, this is done in consideration of other factors, such as the public need for the facility weighed against the economic, reliability, and environmental impacts of the proposed project. Finally, only one state requires the reporting of actual transmission costs incurred until project completion. Below is a table summarizing the relevant transmission siting laws of the New England states.

Table 1. State Siting Review in New England

	Connecticut	**Maine**	**Massachusetts**	**New Hampshire**	**Rhode Island**	**Vermont**
Siting Authority	Connecticut Siting Council Chapter 277a of the CT General Statutes	Maine Public Utilities Commission (PUC) 35-A M.R.S.A. §3132	Energy Facilities Siting Board (EFSB) M.G.L. Ch 164, Sec. 69 J [a]	New Hampshire Site Evaluation Committee (SEC) RSA 162-H:3	Energy Facility Siting Board R.I. Gen. Laws § 42-98-4	Vermont PUC 30 V.S.A. § 248.
Types of Projects Reviewed	New transmission lines ≥ 69 kV	New transmission lines ≥ 69 kV New lines < 69 kV with a projected cost greater	New transmission lines ≥ 69 kV and longer than 1 mile Existing transmission lines ≥ 115 kV	New transmission lines ≥ 100 kV	New trans-mission lines ≥ 69 kV	Trans-mission lines ≥ 34.5 kV except for in-kind asset replacement

	Connecticut	Maine	Massachusetts	New Hampshire	Rhode Island	Vermont
		than $5 million	and longer than 10 miles, for in-kind asset replacement			
Transmission Cost Review	High level review of transmission costs and alternatives Review does not assess prudency of costs [b]	High level review of transmission costs and alternatives Review does not assess prudency of costs [b]	High level review of transmission costs and alternatives Review does not assess prudency of costs [b]	No	High level review of trans-mission costs and altern-atives Review does not assess prudency of costs [b]	High level review of trans-mission costs and alternatives Review does not assess prudency of costs [b]
Frequency of Cost Review	No formal requirement for continuing cost review or reporting [c]	No formal requirement for continuing cost review or reporting [d]	No formal requirement for continuing cost review or reporting	No formal requirement for continuing cost review or reporting [e]	No formal require-ment for continuing cost review or reporting	Costs are reported quarterly until construction complete If costs increase by 20%, reason for increase must be provided [f]

[a] Operating in parallel with EFSB jurisdiction is the Massachusetts Department of Public Utilities' (MA DPU") jurisdiction under M.G.L. Ch 164, Sec. 72, which long predates the creation of the EFSB. MA DPU jurisdiction applies for all transmission lines that are EFSB jurisdictional, typically in a consolidated proceeding under the EFSB to streamline the dual regulatory authorities. In addition, the MA DPU reviews non-EFSB jurisdictional transmission lines as stand-alone projects. However, in practice, the MA DPU has rarely exercised stand-alone Section 72 jurisdiction for new or modified transmission lines under 69 kV or less than a half mile in length.

[b] State siting authority review typically weighs cost with public need and economic, reliability, and environmental impacts. *See, e.g.*, C.G.S. § 16-50p; MPUC Commission Rule Chapter 330; R.I. Gen. Laws § 42-98-9(d); R.I. Gen. Laws § 42-6.2-8; V.S.A. § 248(b)(2).

[c] R.C.S.A. § 16-50j-41 provides that the Siting Council "may at any time initiate investigations and enforcement actions[.]" These investigations have a broad scope and can include the review of costs.

[d] Reporting requirements may be established as a condition of certificate issuance.

[e] The New Hampshire SEC may include specific reporting requirements in the certificate of site and facility issued for a particular project approved under its authority.

[f] Vermont PUC Commission Rule 5.409 requires costs to be monitored, updated, and reported until construction of the project has been completed. This is usually done on a quarterly basis. When the estimated capital costs of a project increase by 20 percent from the cost estimated at approval of the permit, the petitioner is required to notify the Commission and parties of the new capital cost estimates for the project and the reasons for the increase.

3. Transmission Rates

Today, all transmission owners in New England use formula transmission rates to recover their costs. As explained *supra*, the states' siting laws do not require a prudency review of the proposed transmission facilities before or after the facilities are put in service. States largely depend on the Commission's prudency review to ensure that once the project is selected by ISO-NE or the transmission owner, its costs are appropriately incurred, recorded, and recovered from ratepayers.

The review process for annual transmission formula updates is particularly troublesome, as parties challenging the prudency of expenditures bear a heavy burden to overcome the Commission's presumption that costs were properly incurred. Moreover, Commission Trial Staff does not participate in the annual update process, and the Commission does not generally review the updates unless a party files a challenge. Taken together, the process effectively leaves transmission costs unreviewed at both the state and federal levels. Also, such challenges are deeply resource intensive and require expertise that is not conflicted, which is exceptionally hard to come by. NESCOE urges the Commission to take the necessary steps to ensure that transmission formula rates undergo a robust cost review process, not just at the initial phase, but also during the annual updates.

C. THE COMMISSION SHOULD ESTABLISH AN ITM TO PROMOTE PUBLIC CONFIDENCE IN TRANSMISSION DEVELOPMENT AND ENSURE THAT CUSTOMERS ARE CHARGED JUST AND REASONABLE RATES.

NESCOE supports the establishment of an ITM for New England that provides neutral, independent, and expert review of proposed transmission projects and cost recovery. The focus of the ITM should be on active engagement in the transmission planning process, review of the ratemaking/cost recovery process, reporting on the performance of each of those processes, and providing recommendations for improvements.[48]

1. An ITM Would Promote Public Confidence in Transmission Development and Planning.

An ITM should be well-positioned to participate meaningfully in the ISO-NE transmission planning process, including the processes for local and asset condition/refurbishment. The ITM's role could include, without limitation, that of (1) monitoring and participating as an independent stakeholder in the PAC, Transmission Owner Planning Advisory Committee ("TOPAC"), and other relevant stakeholder meetings; (2) offering feedback on specific transmission plans in development; (3) assessing how well planning processes and assumptions are aligned with public policy objectives; (4) comparing and contrasting practices from ISOs/RTOs across the country and suggesting process enhancements; (5) recommending incorporation of new and emerging technologies; and (6) addressing changes in expected end user consumption patterns.[49]

With the anticipated significant investment in electric transmission for the remainder of this decade and beyond, the ITM could also play a meaningful role in supporting the "right-sized" approach to new projects.[50] Thinking of the power system as a portfolio of resources and devices,

---

[48] *See* Daymark Testimony at ¶ 6.

[49] *Id*. at ¶ 8.

[50] *Id*. at ¶ 37.

the ITM would evaluate proposed system upgrades holistically to assess the effect of the proposed solutions to the overall power system and its short- and long-term needs. In that vein, it could consider the effects of emerging conditions on the system and the opportunity for modular equipment, such as batteries, to resolve shorter-term needs in a cost-effective manner.[51] Similarly, the ITM could examine the risks of under building and recommend the efficient utilization of suitable rights-of-way and large parcels of land for major substations, as well as ways to optimize asset condition/refurbishment projects to facilitate future needs, such as interconnection and delivery of clean energy resources.

To be effective in this role, the ITM would need to have access to all relevant transmission planning information, including critical inputs, system needs, modeling assumptions, proposed alternatives, and cost estimates, as well as authority to engage with ISO-NE staff, transmission owners, and other relevant stakeholders on these planning issues. The ITM would devote a significant portion of its efforts early in the ISO-NE transmission planning process to achieve efficiencies by being a well-informed, regular, and active participant from the outset at the PAC and TOPAC sessions. This would be the optimal time for the ITM to access the necessary information for careful evaluation of the proposed solutions, ask questions, and gather input early in the regional planning process, thereby minimizing the risk of late identification of important issues that may derail the project at future stages. This would also be the time for the ITM to compare alternative transmission plans, their cost assumptions, and expected economic benefits. Further, to the extent that the existing ISO-NE tariff does not support evaluation of certain benefits

[51] *Id*.

for the purpose of project selection, the ITM would be able to recommend appropriate tariff revisions that would enhance the process going forward.[52]

In addition to its active engagement in and monitoring of the ISO-NE transmission planning processes and meetings, the ITM would prepare and present periodic reports to the Commission, representatives of the New England states, regional stakeholders, and ISO-NE that would comment on the performance of the planning process, identify any apparent deficiencies or gaps, and recommend enhancements to achieve efficiencies in regional, interregional and local planning.[53] Other opportunities for public involvement could include, but are not limited to, commenting at the public roll-out of the biennial ISO-NE Regional System Plan ("RSP") and addressing ISO-NE Board Members and the broader stakeholder community about its findings and proposed recommendations. Additionally, upon request by the Commission or New England states, the ITM could report on specific issues relating to transmission planning or costs affecting the respective jurisdictions.

2. An ITM Would Promote Public Confidence Through Its Review of and Reporting on Transmission Costs.

Currently, the Commission does not routinely monitor the cycle of existing transmission projects and their cost recovery, and its main involvement in cost prudency review is at the time the initial transmission formula rate is set. Given that all transmission owners in ISO-NE currently utilize formula rates, the costs of new and existing projects are only reviewed through the annual update process, which presents an abbreviated and limited period for input. As discussed *supra*, the ITM could provide an initial evaluation of projected transmission costs while in the planning process and before costs are recovered in rates. During the planning stage of economic projects,

---

[52] *Id*. at ¶ 38.

[53] *Id*. at ¶ 10.

for instance, the ITM could review the bidding process and the bid evaluation framework, compare costs to those of similar projects in other regions for benchmarking, ensure that the processes are run in a manner consistent with the established tariff, and make recommendations to the extent that the processes could be improved to reduce cost uncertainty or ensure a more comprehensive evaluation of benefits during project selection, consistent with public policy.[54]

Once projects are selected through the ISO-NE regional planning process or through the transmission owners' local or asset condition/refurbishment processes and costs can be incurred and recovered through rates, the ITM may review the formula rate updates to determine that project costs are properly reflected in the rate. The ITM can compare "as built" costs to cost estimates used in project selection and determine if the costs vary significantly from estimates, identify the causes, and assess reasonableness.[55] The ITM could prepare a post-mortem report after each formula rate update with its evaluation of the process, issues identified, and recommendations for improvements. Thus, the ITM's review of the effectiveness and appropriate recovery of costs would be independent from that of any interested parties or customers. Additionally, the ITM could track any formal challenges and Section 206 complaints to provide visibility of issues raised by stakeholders.

The ITM's review of the annual formula rate updates and any formal challenges would also provide an opportunity to assess what areas in the formula and protocols might benefit from enhanced transparency, ease of auditing, and engagement by the broadest set of stakeholders during annual rate updates. Such observations may form the basis for recommendations to the Commission, ISO-NE, transmission owners, and stakeholders. One area of interest to states and

[54] *Id*. at ¶ 33.

[55] *Id*. at ¶ 36.

customers would be the ITM's assessment of whether proposed cost containment provisions, such as return on equity ("ROE") caps and ROE incentives, are captured in rates and easily tracked.[56] Further, any ITM recommendations to transmission owners on transparency improvements and ease of use and review of existing formulas should be made publicly so that the Commission and stakeholders may benefit from that information.

The ITM's public dissemination of its independent analysis could help prevent unduly discriminatory rates by providing actionable information for the Commission's and stakeholders' future review and use in transmission rate cases. NESCOE agrees that an ITM should be viewed as an aide to the Commission in fulfilling its statutory duties to ensure that transmission rates are just and reasonable and not unduly discriminatory or burdensome. However, to unlock the full potential of the ITM concept, it is also important for the ITM to be able to act as a conduit for information and analysis to the states. This should include the ability to share information, evaluations, and analysis with relevant state agencies to facilitate each state's participation in existing Commission ratemaking processes. Enabling states to better participate in these Commission processes does not relieve the Commission of its statutory duty to ensure that rates are just and reasonable; it does help to inform the Commission's ultimate determination.

3. An ITM's Role Should Not Duplicate That of Other Stakeholders.

Just as it is important to define the scope of the ITM's functions, it is important to set certain limits that would prevent interfering with the efficient administration of the ISO-NE planning process. To that end, the ITM is not envisioned to duplicate ISO-NE's planning efforts nor substitute its judgment for ISO-NE determinations. The ITM would not represent any particular stakeholder in the transmission planning or rate-making processes but would function primarily as

[56] *Id*. at ¶ 34.

a source of independent information, by providing the Commission, states, and stakeholders greater insight into the New England region's transmission needs, planning processes, and cost issues.[57] In this way, the ITM could support the Commission's oversight function in validating the application of transmission planning models and cost inputs.

4. An ITM's Structure and Capabilities Should Allow It To Perform the Proposed Functions in a Nimble and Efficient Way.

The ITM's expertise must include areas of power system planning, transmission development, transmission rates, and FERC transmission policy. Knowledge of the competitive solicitation process in ISO-NE, as well as its planning and cost allocation methodologies that have implemented the Commission's Orders 1000 and 890 transmission planning principles is also needed to engage with and review regional transmission plans and the rate making/cost recovery process efficiently and meaningfully.[58] Resources should also be devoted to stay abreast of current and new state and federal energy policies, emerging technologies, and industry developments. As Daymark has observed, given the wide range of expertise required and the large volume of transmission development to be reviewed, the ITM would likely be composed of a small number of transmission engineering and rate making professionals.[59]

NESCOE recommends that the ITM be structured as a stand-alone entity that reports directly to the Commission. Such an arrangement would put the ITM in the best position to be independent from all stakeholders and have a direct line of communication with the Commission, thereby ensuring that the Commission's stated interest in closer oversight of the operations of and the investments made by its jurisdictional utilities is met.[60] As NESCOE's prior comments on this

[57] *Id*. at ¶ 7.

[58] *Id*. at ¶ 11.

[59] *Id*.

[60] *Id*. at ¶ 12.

issue noted, "oversight functions related to the planning process may not be appropriate to leave solely to the very entities running that process."[61] As noted above, however, it is also important for the ITM to be able to provide information and analysis to the states in order to facilitate state involvement in the existing FERC ratemaking process.

Importantly, the Commission would not be sub-delegating its authority to make ratemaking and public policy decisions on transmission issues, as the ITM's functions would be limited to those of participating in the transmission planning process, reviewing transmission costs and inputs to rates, and issuing reports and recommendations to the Commission. The ultimate ratemaking and rulemaking decisions would have the benefit of the ITM's informed analysis and recommendations, but they would remain with the Commission.

D. NESCOE SUPPORTS ADDITIONAL PROCESS IMPROVEMENTS.

1. The Commission Should End the Presumption of Prudence Applicable to Transmission Formula Rate Updates.

NESCOE continues to advocate for a change to the Commission's presumption of prudence applicable to transmission costs recovered through annual updates to transmission formula rates.[62] In particular, where entire categories of costs escape any state or federal review, such as the majority of the projected $6 Billion in asset condition/refurbishment costs through 2028 in the New England region, it is not appropriate to apply a presumption of prudence and allow only a brief challenge and review period that was designed for administrative efficiencies and regulatory certainty. Further, as NESCOE has demonstrated, even where transmission projects undergo state siting review, the Commission should not assume that such review involves a determination of prudency. In general, siting laws in New England direct state siting authorities to assess the need

[61] NESCOE ANOPR Reply Comments at 19.

[62] *Id*. at 23-24.

for the project, while weighing considerations, such as environmental, economic, and public policy objectives, availability of alternative routes, anticipated load growth, and state and federal reliability standards. To the extent costs may be considered, this is usually done in the context of an assessment of alternative routes and transmission solutions.[63] Simply, state siting laws do not direct state siting authorities to step into the Commission's transmission cost oversight role. Consumers paying the FERC-jurisdictional transmission rate rely on the Commission to conduct prudency review of the actual costs and to ensure that rates remain just and reasonable. For that reason, the Commission should end the nearly insurmountable presumption of prudence that effectively operates as a bar to successful challenges of costs incurred.[64]

2. The Commission Should Consider Allowing Its Trial Staff To Engage in the Transmission Formula Update Process.

The Commission has flexibility and optionality not only in establishing an ITM but also in providing for the engagement of Commission Trial Staff in the regular review of transmission costs through the annual update process. The Commission could use this opportunity to expand its in-house review of transmission formula rates to fill the regulatory gap that exists after transmission projects and initial formula rates are approved and transmission facilities are put in service. Currently, the Commission's Trial Staff is actively involved in the review of the transmission owners' initial formula rates. In such proceedings, state commissions, consumer advocates, and customers often rely on the legal experience, technical knowledge, and competence of Trial Staff in examining the formula rate inputs and applying Commission precedent to recommend a just and reasonable rate.

---

[63] *See* Daymark Testimony at ¶ 30.

[64] *See* NESCOE ANOPR Reply Comments at 11, discussing the asymmetry of information in transmission formula rate updates and the lack of resources plaguing the effective participation of state regulators, consumer advocates, and other transmission customers.

Unfortunately, Trial Staff's participation is limited to initial formula rate filings with the Commission, and the majority of transmission costs passed in rates thereafter remain unreviewed and unchallenged. Trial Staff's participation in the annual updates would be an important step to building confidence in the resulting transmission rates passed on to consumers.

3. The Commission Should Consider Transmission Planning Standard Reforms.

On March 22, 2023, the Maine Public Utilities Commission filed Post-Technical Conference Comments in this proceeding advocating for transmission planning standard reforms intended to establish a process for prioritizing transmission investments. NESCOE generally supports such reforms and encourages the Commission to consider methods by which future transmission investments could be prioritized in order to allow for more prudent and better-informed transmission investment decisions.

E. THE COMMISSION'S FUTURE ACTIONS WITH REGARDS TO COST OVERSIGHT AND CONTAINMENT SHOULD BE GUIDED BY A RECOGNITION OF REGIONAL DIFFERENCES, NEEDS AND POLICIES.

NESCOE recommends that, as the Commission considers appropriate reforms to bring much needed transparency and cost oversight to the various transmission planning and cost recovery processes under its jurisdiction, it builds on its long-standing practice in Orders 890 and 1000 that recognizes regional differences, needs, and policies across the nation. This same principle can guide the Commission in determining the appropriate solution for each region, such as the need, structure, and scope of an ITM, while allowing for input from states and other stakeholders in proposing variations that address regional or jurisdictional considerations.

V. CONCLUSION

For the reasons discussed above, NESCOE respectfully requests that the Commission afford due consideration to these Comments and move forward with the steps necessary to establish an ITM and adopt NESCOE's recommendations to ensure just and reasonable transmission rates.

Respectfully submitted,

/s/ Shannon Beale
Shannon Beale
Assistant General Counsel
New England States Committee on Electricity
P.O. Box 322
Osterville, MA 02655
Tel: (781) 400-9000
Email: shannonbeale@nescoe.com

McNEES WALLACE & NURICK LLC

By: */s/ Susan E. Bruce*
Susan E. Bruce
Aspassia V. Staevska
100 Pine St., P.O. Box 1166
Harrisburg, PA 17108
Phone: 717-237-5254
Fax: 717-260-1666
Email: sbruce@mcneeslaw.com
astaevska@mcneeslaw.com

Counsel to the New England States Committee on Electricity

Dated: March 23, 2023

CERTIFICATE OF SERVICE

I hereby certify that I have this day served via electronic transmission the foregoing upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Harrisburg, Pennsylvania, this 23rd day of March, 2023.

<u>/s/ Susan E. Bruce</u>

Susan E. Bruce
100 Pine St., P.O. Box 1166
Harrisburg, PA 17108
Phone: 717-237-5254
Fax: 717-260-1666
Email: sbruce@mcneeslaw.com

ATTACHMENT A

NESCOE Support
Independent Transmission Monitor (ITM) Concept
March 23, 2023

I. Purpose of Testimony

1. In support of NESCOE, these post technical conference comments on Dockets AD22-8-000 and AD21-15-000 provide a conceptual framework for the duties, responsibilities, structure, and benefits of an Independent Transmission Monitor (ITM). This conceptual framework is based on the New England regional transmission planning process and regional transmission rate making/cost recovery process, but may also be applicable to other regions of the country.

II. Professional background and relevant experience

2. *Stephen J. Rourke, Advisor, Daymark Energy Advisors:* Mr. Rourke advises asset owners, developers, investors, and utilities on bulk power system operations and planning and wholesale power market operations and administration. Formerly ISO New England's VP of System Planning, he is a strategic leader in regional and interregional planning policies and practices, new transmission and generation project analysis and interconnection, transmission cost allocation, regional economic planning studies, establishing resource adequacy requirements, and operation and administration of the Forward Capacity Market in New England.

3. As Vice President, System Planning, for ISO New England, Mr. Rourke held overall responsibility for the regional planning process, including transmission reliability and planning, resource reliability and planning, interregional coordination across the northeastern U.S., eastern Canada, and nationally, compliance with regional and national reliability standards established

by NERC and NPCC, development of the New England Regional System Plan, and representation of ISO New England at national and regional industry forums and in state and federal proceedings.

4. *Marc D. Montalvo, CEO and Principal Advisor, Daymark Energy Advisors:* Mr. Montalvo leads Daymark Energy Advisors, a consultancy that provides power system planning, and market and regulatory analysis and advisory services to industry and policymakers pursuing the efficient development and deployment of clean energy infrastructure. His principal practice areas are regulatory economics and power system planning. He has professional experience that includes FERC open access transmission policy and formula rates, wholesale market design, market monitoring, risk management, and capital planning. His consulting clients include utilities, generation and transmission project developers, regulators, and consumer protection agencies.

5. Prior to joining Daymark in 2014, Mr. Montalvo worked ten years for ISO New England as Director of Market Development, as Director of Market Monitoring, and as Director of Enterprise Risk Management. Prior to that he worked for La Capra Associates, an energy industry consultancy, as a managing consultant and director of wholesale market analytics. He started his career at New England Power (NEES). He also taught graduate-level courses in Finance and Business Analytics as an adjunct professor at Clark University from 2016 to 2019. Mr. Montalvo has submitted testimony numerous times to the Federal Energy regulatory Commission.

III. Summary of ITM Roles and Responsibilities

6. Based on our experience, we believe the ITM in New England should be structured to

focus in two main areas: (1) engagement in the transmission planning process and rate making/cost recovery process, and (2) providing periodic reports on the performance of each of those processes and, as necessary, recommending improvements.

7. At the outset, it is important to underscore what the ITM would *not* do. As discussed below, the ITM would not duplicate ISO-NE's planning efforts, nor seek to substitute its judgment for ISO-NE determinations. In general, it is not anticipated that the ITM would file pleadings in FERC rate proceedings. The ITM would not act on behalf of any particular stakeholder in the transmission planning or rate-making processes, but rather the ITM would function primarily as a source of information, providing the Commission, states, and stakeholders greater insight into the New England region's transmission needs, planning processes, and cost issues.

8. In New England, the ITM would monitor and participate as an independent stakeholder in the Planning Advisory Committee (PAC), a well-established public regional planning forum, and other relevant stakeholder meetings. Through the PAC, the ITM could offer feedback on specific transmission plans in development and, more broadly, on how well the planning process and assumptions aligned with public policy objectives, recommend incorporation of new and emerging technologies, and address changes in expected end user consumption patterns. Furthermore, through its engagement with the PAC and other stakeholder processes, the ITM ccould comment on the overall planning process, compare and contrast practices from ISO/RTOs across the country, and suggest process enhancements. Early and visible engagement through the PAC would maximize efficiency around the ITM's participation and feedback.

9. Much progress has been made in New England over the past decade on enhancing transmission rate and cost recovery transparency, e.g., development of the Regional Network

Service (RNS) formula rate. By participating in the regional transmission planning process the ITM ccould provide additional transparency. The ITM could track project costs (e.g., estimated versus actual), verifying that all benefits derived from a competitive solicitation process were properly accounted for (e.g., price caps, Return On Equity (ROE) limits), and suggest enhancements to the formula, protocols, or workpapers.

10. Finally, the ITM would prepare and present an annual (or perhaps more frequent periodic) report to regional stakeholders, representatives of the New England states, ISO-NE management and staff, and the Commission that would comment on the performance of the planning process, identify any apparent deficiencies or gaps, and recommend enhancements. Additionally, it might be beneficial to have the ITM publicly comment at the public roll-out of the biennial ISO-NE Regional System Plan (RSP), taking advantage of the opportunity to speak with ISO-NE Board Members as well as the broader stakeholder community and the public. Finally, upon the request by New England states or the Commission, the ITM might report on specific issues relating to transmission planning or costs impacting a state jurisdiction or FERC regulatory interest.

IV. Organizational Structure and Capabilities for an ITM

11. To be effective in carrying out its responsibilities, the ITM must be well-informed, and experienced in areas of power system planning, transmission development, transmission rates, and FERC transmission policy. This expertise should include knowledge of the competitive solicitation process, including, but not limited to FERC Order 1000 and Order 890 transmission planning principles. The ITM should stay abrest of current and new state and federal energy policies, and new and emerging technologies, evaluate their impact on planning processes and

recommend improvements, as appropriate. Such experience would allow the ITM to engage with and review regional transmission plans, the planning process, and the rate making/cost recovery process efficiently and meaningfully. Given the wide range of expertise required and the large volume of transmission development to be reviewed, it is likely that the ITM would be composed of a small team of transmission engineering and rate making professionals.

12. In New England, two entities perform the existing Commission required market monitoring functions. The Internal Market Monitor (IMM) performs all required functions, including market assessment, tariff compliance, and mitigation. The External Market Monitor (EMM) is focused mostly on the overall performance of the markets and does consult with the IMM on some investigations and mitigation matters. Both entities report to the ISO-NE Board. It is likely that the market monitor (the EMM may be best suited in the case of New England) may have the technical bandwidth to expand their capabilities and perform the expected role of the ITM. However, parties engaged in the transmission planning process extend beyond those participating in the ISO-NE administered wholesale power markets, and include the ISO itself as a central actor. For this reason, we do not propose that the ITM have any reporting relationship to the ISO Board, a committee of the states, or any other stakeholder group. Rather, we recommend that the ITM report directly to the Commission. This reporting relationship would ensure both unambiguous independence from all parties involved in the regional planning process and a clear line of communication between the ITM and the Commission. Such a reporting relationship is consistent with and would further the Commission's stated interest in closer oversight of the operations of and the investments made by its jurisdictional utilities.

13. In New England, the only way to gain a meaningful understanding of the development of transmission plans and the resultant cost recovery and rate impacts is through direct engagement

in the ISO-NE planning process. Beneficially, in New England, the regional planning process already provides for stakeholder access to much of this information, even if it often requires deep technical expertise to fully understand. The ITM will leverage existing planning forums to achieve efficiency, and will carry out its responsibilities in large part by participating in the PAC and by monitoring rate making processes.

14. The ISO/RTO, or any other entity acting as the regional Planning Authority, has an important function to carry out under the standards set forth by the North American Electric Reliability Corporation (NERC). Their work directly supports the continued reliable, safe, efficient operation of the bulk power system. The ITM is not intended to supplant this function. Rather, as an independent entity with no vested interest in the outcome, save the intelligent planning of the transmission system to meet the growing set of competing demands, the ITM will provide unbiased information and insight to FERC, state officials, and stakeholders concerned with reasonableness of the regional plans, the performance of the regional transmission planning process, and the cost of the projects being proposed and pursued.

15. The ITM should be an independent voice that asks critical questions regarding project needs and outcomes and the implications to the power system, today and in the future. The ITM would also independently review the formula rates, assess the ease with which parties are able to participate in the update process per the filed implementation protocols, examine the way new transmission project costs are reflected in the formula and then, as appropriate, suggest improvements to the clarity and transparency of the formula rates and supporting workpapers or process improvements in the protocols. As noted above, it is not expected that the ITM would file pleadings in a rate proceeding, but rather would issue reports of its analysis and findings. Based on this information ISO-NE or the TOs could, on their own accord, seek changes to their

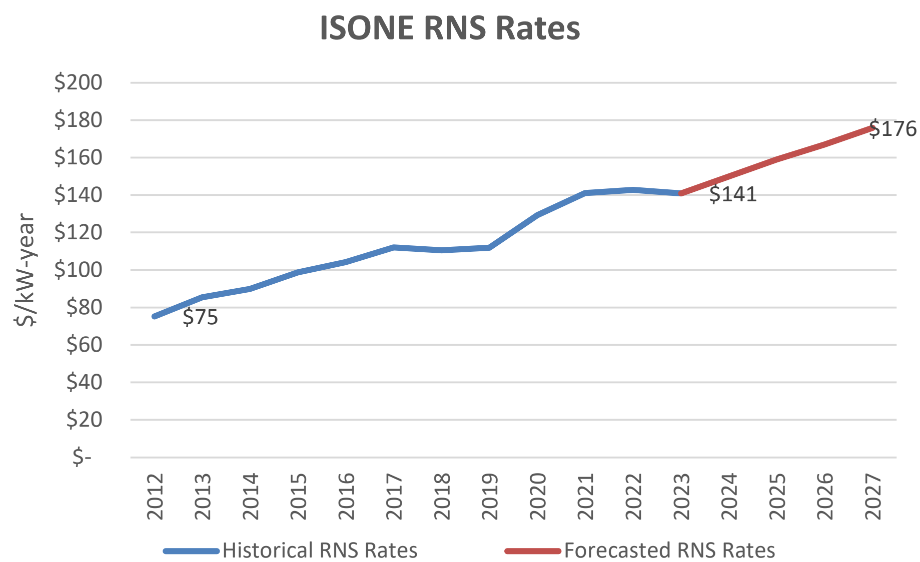
tariffs. The reports could also inform states and stakeholders to prompt them to request changes in subsequent annual filings or through established protocol processes. The Commission might also pursue changes based on an ITM's reports per Section 206 of the FPA.

V. Transmission development in New England and the Need for Enhanced Transmission Cost Oversight by an ITM

16. New England has seen a significant build out of the regional transmission system over the past 15 to 20 years. These projects were designed primarily to address reliability needs in major load centers within the region. Some examples of these include areas such as: Southwest Connecticut, Burlington, VT, Greater Boston MA, Southeastern MA and Cape Cod, Springfield, MA/Hartford, CT, Portland ME, New Hampshire Seacoast, and Providence, RI. Many of these upgrades not only have addressed reliability concerns on the transmission system, but also have allowed for the retirement of ageing fossil fuel resources and have reduced areas of chronic congestion in the wholesale power markets.

17. This investment in transmission has significantly increased the regional transmission rate in New England. The Regional Network Service (RNS) rate has continued to increase over the past ten years and is expected to continue to rise for the remainder of this decade. As can be seen in **Figure 1**, the RNS rate has almost doubled between 2012 and 2022.

Figure 1: Historical and Forecasted Regional Network Service Rates in New England: 2012-2027[1]



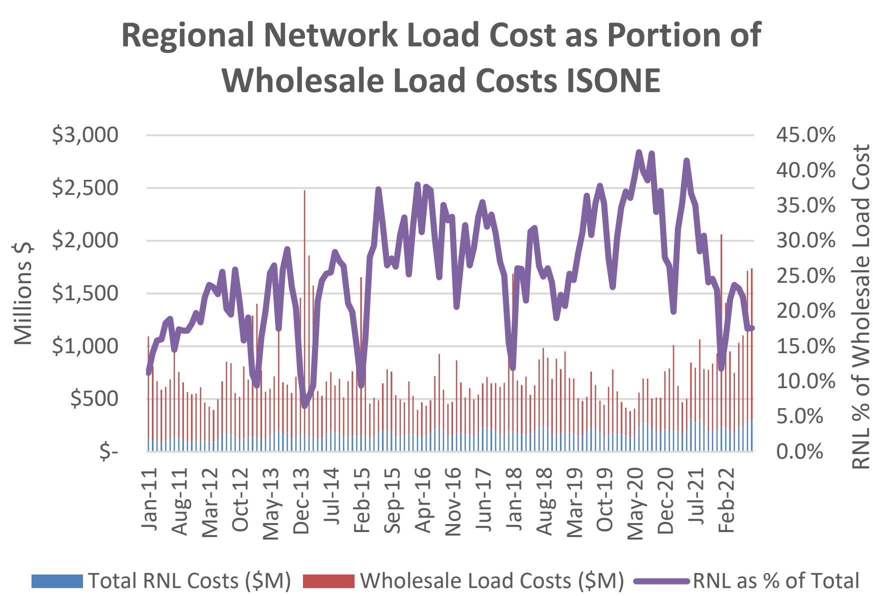
18. In New England, regional transmission costs have accounted for over 25% of the region's wholesale power costs in most years over the past decade. As more low variable cost, clean energy resources are brought online, further reducing overall fuel costs and average wholesale energy prices in the region, this percentage is likely to increase. Certainly, any component of overall charges to customers that reach or exceed 25% of the total bill is significant and warrants scrutiny.

19. The current transmission rate-making process relies almost entirely on the Commission as the regulatory authority to determine prudence. Beyond the siting review performed for certain projects (e.g., those requiring new rights-of-way or a new substation location), this is not a function generally carried out by the New England States. All New England Transmisison Owners employ formula rates to recover their transmission costs, which are updated on an annual basis through a filing with the Commisison, pursuant to the formula rate protocols. However, as

[1] Participating Transmission Owners Administrative Committee (PTO) AC Rates Working Group Presentations NEPOOL Transmission Committee

the Commission's formula rate policy generally places the principal burden of review on the transmission customer, the status quo cost review process is left wanting. The ITM would be in a position to understand the projects and costs as they are being developed and proposed through the planning process and then to review the formula rate updates to ensure that the costs are in fact consistent with expectations and that any variances are well understood. At a minimum, this role would provide regional stakeholders (and, critically, consumers) with confidence that the costs are being scrutinized by experts and are consistent with the plans. An ITM could also timely raise informal questions if costs do not look proper early in the formula rate update process—helping to increase efficiencies and reduce controversies and litigation later on. **Figure 2** below highlights the growing need of an ITM review of the regional transmission rate making/cost recovery process.

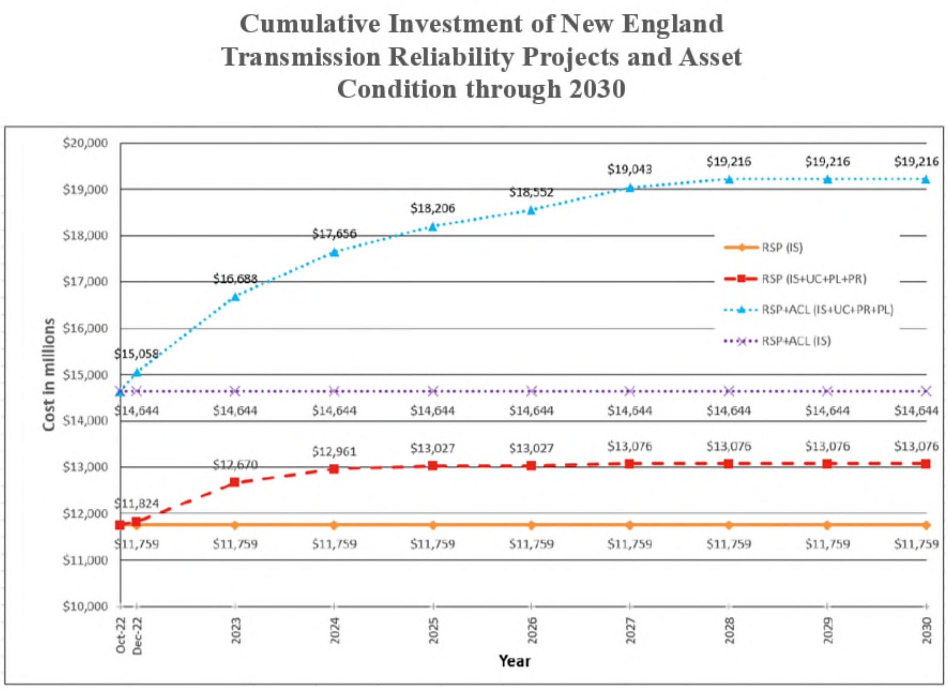
Figure 2: Regional Network Load Costs in New England: 2011-2022[2]



[2] Monthly Regional Network Load Cost Reports ISONE Section 3. RNL cost in this graph consists of infrastructure, reliability and administrative costs with more than 95% of the costs in the infrastructure category.

20. Moreover, known and expected Reliability Projects and Asset Condition/Refurbishment projects will likely accelerate this trend through the remainder of the decade. **Figure 3** shows the latest information from ISO-NE on the trend in transmission expenditures through 2030. These projects account for another approximately $4.6 Billion in transmission costs.

***Figure 3: Cumulative Investment of New England Transmission Reliability Projects and Asset Condition through 2030*[3]**



21. **Figure 3** above has a great deal of cost information about projects included in the ISO-NE developed Regional System Plan (RSP) and the Asset Condition (AC) projects brought forward by the regional Transmisison Owners. The yellow line labeled RSP (IS) represents the $11.759 B in transmission development that has been placed "In Service" (IS) as of October 2022. The purple line labeled RSP+AC (IS) represents the combined $14.644 billion ($B) in

[3] Regional System Plan Transmission Projects and Asset Condition October 2022 Update PAC Meeting

transmission development that has been placed “In-Service”. The difference between the two, $14.644B - $11.759B or $2.885B, is attributable to Asset Condition projects that are already in service. The terms UC – Under Construction, PL – Planned, and PR – Proposed, represent projects in various stages of the planning and development process. If all of these projects are placed in service as anticipated by 2028, the total costs are expected to reach $19.216 B.

22. Implementation of FERC Order 1000 in New England came after most of the reliability projects mentioned above had been identified and approved through the ISO-NE regional transmission planning process. As a result, these projects were carried out by the incumbent transmission owners in the region. Other reliability needs identified after implementation of Order 1000 were identified as time sensitive and defaulted to the incumbent Transmission Owners rather than going out for competitive solicitation. As competitive solicitation for transmission becomes more commonplace in New England, however, the ITM would review rates and cost recovery and would report on the extent to which bid components agreed to by the selected project developer, such as price containment provisions and ROE caps, are properly realized in the rate to benefit customers in the region.

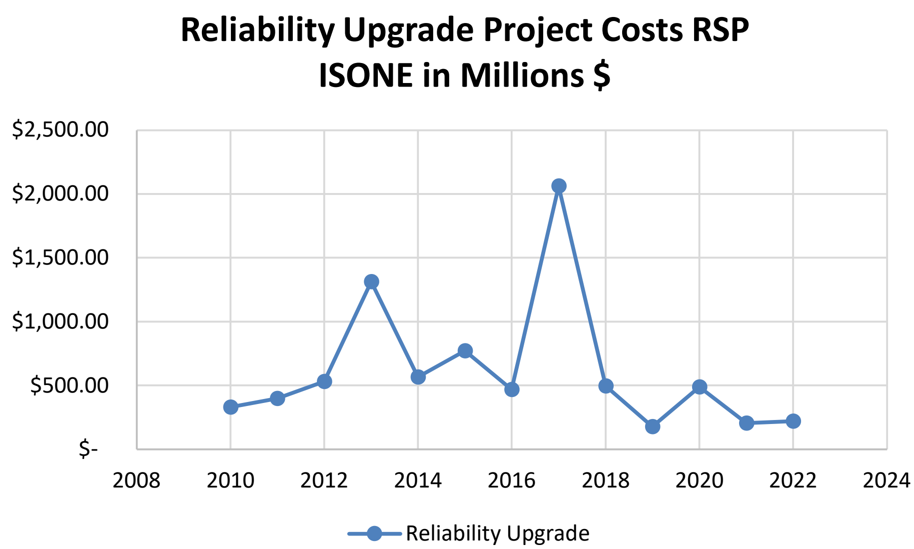
23. The ISO-NE led regional transmission planning process can result in three types of upgrades:

- Reliability Transmission Upgrades
- Public Policy Transmission Upgrades
- Market Efficiency Transmission Upgrades

To date, all the projects identified by ISO-NE in the regional transmission planning process have been Reliability Transmission Upgrades. **Figure 4** indicates the level of investment in Reliability Transmission Upgrades by year since 2010, with the total during this period being over $7

Billion. As shown above in **Figure 3**, this number is almost $12 Billion since 2002 and is expected to rise to $13.1 Billion by 2027.

Figure 4: Reliability Upgrade Project Costs: 2008-2024



24. With all these Reliability upgrades arising from the ISO-NE regional planning process in place or under construction, the region's Transmission Owners have been moving forward with significant upgrades under a separate category of projects that ISO-NE does not initiate as part of its planning function, Asset Condition/Refurbishment projects. Ageing or undersized substation equipment, technically obsolete equipment, and deteriorating wooden structures are examples of such Asset Condition/Refurbishment projects being undertaken across New England. Determinations for these Asset Condition/Refurbishment upgrades are undertaken solely by the Transmission Owners and presented as informational items within the regional transmission planning process; they are not part of the formal planning process led by ISO-NE with an associated Needs Assessment being performed by the ISO.

25. Asset Condition/Refurbishment projects now account for $2.9 Billion dollars of

transmission investment. As shown in Figure 3 above, ISO-NE expects all RSP projects to reach $13.076B by 2027. On top of that, Asset Condition/Refurbishment projects will total to approximately $6.1B by 2028, brining the total of all RSP plus AC projects to $19.216B.

26. A regional or national push for transmission to support the interconnection and delivery of large-scale clean energy resources will continue to drive additional transmission costs. These projects will likely be both regional and inter-regional in nature. Widescale electrification of transportation and heating sectors will likely cause a significant increase in system demand and also drive the need for more transmission. These transmission upgrades may be labeled as supporting public policy but may also address reliability issues driven by higher system demand. Similarly, rapid deployment of Distributed Energy Resources (DERs) highlights the implications of the impact that distribution level connected resources can have on the operability and reliability of the transmission system.

27. Given the above, transmission development in New England will continue to be on the rise for the foreseeable future. Such development will require several billion dollars of investment. The ITM will have an opportunity to engage early and efficiently with the transmission planning and rate making/cost recovery processes for this next stage of transmission evolution in New England and provide an important, independent, and unbiased voice for the region and visibility to FERC into whether rates are just and reasonable. Similarly, the ITM may provide useful transmission-level information as states plan to upgrade their distribution-level systems and reliability requirements to allow for accelerated DER deployment.

VI. Existing Regulatory Gaps in Transmission Planning, Cost Oversight and Monitoring

28. Regional or inter-regional projects developed through the ISO led transmission Planning process are always of a scale and voltage level to be included in the regional formula rate submitted to the FERC (non-radial facilities typically operating at 115 kV and above). In New England, all regionally planned projects over the past twenty years have addressed a reliability need identified through an ISO-NE Needs Assessment study and report. Although estimated project costs are a factor in ISO-NE's selection of preferred alternatives to address the stated needs, the entire process in New England ultimately relies on FERC as the regulatory authority to recover transmission-related costs, primarily reflected in the formula rates on file with FERC.

29. Process controls are in place at various stages of the ISO's transmission planning and development process in New England:

Regional Projects

- Project needs, scope, and alternative solutions are discussed at the ISO-NE led Planning Advisory Committee (PAC). The PAC is advisory only and has no formal governance structure. The PAC is open to all interested parties with CEII clearance. (Typically, ISO-NE planning jurisdiction is at 115 kV and above)
- ISO-NE-identified needs can be for reliability, market efficiency, or public policy. Projects selected by ISO-NE to meet these identified needs are automatically eligible for cost allocation through the Regional Network Service (RNS) rate, as outlined in the ISO-NE OATT.
- It is important to note that the Needs Assessment reports developed by ISO-NE for reliability projects provide an independent look at system needs, separate from the Transmission Owner(s). These Needs Assessment reports have been an

important part of any applicable state siting review regarding why a project is being proposed and the implications to the power system of the current or anticipated reliability needs. A similar report would be developed for Public Policy or Market Efficiency projects.

- Based on the type and timing of the system need, the project may be eligible for competitive solicitation under FERC Order 1000.
- Transmission Owners (incumbent and non-incumbent) drive the process of developing alternatives to satisfy an identified need. Whether an urgently needed reliability project that defaults to the incumbent Transmission Owner, or a competitive solicitation that has several proposals submitted for consideration, each Qualified Transmission Project Sponsor (QTPS) presents their alternative(s) to the PAC for review and comment. The ISO makes the final determination of the preferred alternative with input from the PAC.
- Project costs are always a major component of the ISO-NE selection criteria, although other qualitative and quantitative factors are considered. The cost comparisons are based on cost estimates provided for each alternative proposal. This process is an engineering assessment and not a formal rate review process.
- The resulting RNS rate impact is included in the formula rate informational filing with the Commission.

Local Projects

- System needs that are more local in nature (radial expansion of a network, lower voltage levels, etc.) are reported on in the Transmission Owner Planning

Advisory Committee (TOPAC) process. TOPAC meetings are typically held in conjunction with ISO-NE PAC meetings to facilitate meeting venue, technical support, etc. These sessions are led by the Transmission Owner(s) needing to present local planning issues vs. the regional planning issues presented by ISO-NE.

- The needs and proposed alternatives for these local issues are identified and presented by the incumbent Transmission Owner. Costs associated with these projects are typically included in the Transmission Owner's Local Network Service (LNS) rate and not the RNS rate.
- ISO-NE does not perform an independent Needs Assessment for these projects. Each Transmission Owner is responsible for identifying their own local system needs.
- The LNS rates are also formula rates filed with the Commission.

Asset Condition Projects

- New England has a large amount of aging transmission facilities across the region. In recent years, the regional Transmission Owners have been moving ahead with replacement or refurbishment of this equipment.
- The reasons for replacement or refurbishment are determined by and presented by the Transmission Owner(s) at the PAC for all projects that would impact the RNS rate, and some may impact the LNS rate. Typically, the PAC or TOPAC members are presented a set of power point slides that describe the problem identified by the Transmission Owner and lay out the solution proposed by the Transmission Owner.

- These projects are not brought forward based on an ISO-NE identified Needs Assessment with alternatives presented to address that need. These projects now account for over $6 billion of new transmission investment expected to be in the RNS rate by 2028. (See Figure 3 above)
- The resulting RNS or LNS rate impact is included in the respective formula rate filings with the Commission.

30. For projects needed for system reliability, any state siting process that may be required is typically focused on several things:

State Siting

- What are the reliability needs, i.e., what reliability standards/criteria would be violated absent a transmission build and how would the system be impacted? The ISO-NE Needs Assessment answers these questions for regionally planned projects.
- What were the key input assumptions? Load level, generation dispatch, contingencies analyzed, inclusion of state sponsored resources, such as Energy Efficiency and solar PV.
- A comparison of alternatives: Scope of each project, alternate routes, overall cost and environmental impacts, reliability enhancements.
- Is a Non-Transmission Alternative (NTA) a viable option? (Emphasis on NTA's can vary from state to state)
- In the state siting process, costs are looked at as a comparison between competing alternatives, not a deep dive into cost justification of all alternatives considered and not an ongoing review of estimated costs versus actual costs. These siting hearings

are not a full rate hearing in front of the DPU/PUC. There is a presumption by the states that this activity will take place as part of the rate filing with the FERC.

- Projects needed for Market Efficiency or Public Policy would undergo similar siting proceedings. The ISO-NE Needs Assessment would be focused on market or policy benefits and not reliability benefits judged against certain mandatory reliability standards.

31. Once identified by ISO-NE as the preferred alternative for the region, a transmission project is eligible for rate recovery through the RNS rate.

ISO-NE Stakeholder Process

- Each TO submits a transmission cost allocation application for the project to ISO-NE. This submission is reviewed by the ISO and is further reviewed by the Reliability Committee.
- For costs going into RNS rate, the Reliability Committee votes to provide advisory input to ISO-NE on cost allocation for Transmission Owner submitted project costs, with input from ISO-NE regarding what costs should be local v. regional. (This distinction is required for local action that has driven up project costs for reasons that are purely local in nature and have no regional benefit.) Total project costs are not approved or disallowed through this stakeholder process. This only determines if any of the costs associated with the project should be considered “local” rather than “regional”, in accordance with the ISO-NE OATT. Localized costs typically are included in the TO’s LNS rate.

32. As stated earlier, prudence review and final approval of the annual formula rate filing lies with FERC. FERC allows recovery of all prudently incurred costs; however, with the prevalence

of formula rates, FERC does not generally perform a prudence review in annual updates unless there is a 206 complaint by a customer initiating such a review..

VII. ITM Role in Transmisson Cost Review

33. The ITM would review the costs of projects at several steps. During the planning process, the ITM would be involved in evaluating the cost estimation and economic evaluation processes. To the extent that projects are competitively bid, the ITM would evaluate the bidding process and the bid evaluation framework. The ITM can also compare costs to those of similar projects in other regions for benchmarking. The ITM would look to ensure that the processes are run in a manner consistent with the established tariff and to the extent that the processes could be improved to reduce cost uncertainty or ensure more comprehensive evaluation of benefits during project selection consistent with public policy, it would make such recommendations.

34. The ITM would review the formula rate making process and report on the areas where the formula and protocols might be enhanced to increase transparency, ease of auditing, and engagement by the broadest set of stakeholders during annual rate updates. The ITM would review the proposed formula rates and make recommendations, as appropriate, to ensure that the components of a competitive bid, such as proposed cost containment provisions, ROE caps, ROE incentives, and any other special provisions, are captured and straightforwardly tracked. Moreover, the ITM could also recommend to the TOs ways to improve transparency and ease of use and review of existing formulas.

35. A recognized gap in the existing cost recovery and rate making process is the critical and timely review of the costs of projects as they are entered into the rate through the annual formula rate update process. The New England region moved from a stated rate to a formula rate for

regional and local network service. The formula rate offers the promise of improved transparency, but for it to serve that function requires the active and informed engagement of the transmission rate customer and other interested parties with some experience and expertise navigating FERC formula rates, the uniform system of accounts, and the FERC Form 1.

36. While not anticipated that the ITM will participate as a party to the formula rate annual update process or intervene in formula rate proceedings, the ITM will have the expertise needed to review the formula rate updates, to assess the update process, and, given access to the needed data, to determine that costs of projects are properly reflected in the rate. The ITM can compare "as built" costs to cost estimates used in project selection and determine if the costs vary significantly from estimates, identify the causes, and assess reasonableness. Additionally, the ITM would track any formal challenges and Section 206 complaints. The ITM would prepare a post-mortem report after each formula rate update with its evaluation of the process, issues identified, and recommendations for improvements.

VIII. An ITM would support getting "right-sized" transmission infrastructure.

37. A key component of any planning process should be how to determine *"right sized"* projects. Given the anticipated significant investment in transmission for the remainder of this decade and beyond, the ITM will play a meaningful role in supporting the "right-sized" approach to all new projects.

- An ITM should take an active part in the regional planning process, such as the Planning Advisory Committee (PAC) in New England. Input from PAC members is an important part of the planning process and provides helpful insight to ISO-NE as they consider how best to evaluate the "preferred alternative" for a transmission solution. Such participation provides:

- Access to all relevant transmission planning information – regional, local and asset condition/refurbishment projects
- Ability to directly engage with ISO-NE staff, Transmission Owner staffs, and other regional stakeholders active in the planning process
- Opportunity to look at critical inputs, system needs, proposed alternatives, cost estimates, and pros and cons of each approach at the early stages of the transmission planning process

• Thinking of the power system as a *portfolio of resources and devices*, the ITM has an opportunity to take a holistic look at proposed system upgrades and evaluate them from different perspectives:

  - Will the proposed solution be a meaningful and effective part of the overall power system?
  - Will it support system needs in the short and long term?
  - Will emerging conditions change the system to eliminate the need in the future? If so, can modular equipment (i.e., batteries) be utilized to resolve a shorter-term need? Could the battery be re-purposed later on?
  - Will the proposed solution support the wholesale power markets, public policies, enable access and delivery of clean energy sources, and address overall system costs?
  - Is there a risk of under building? Suitable Rights-of-Way (ROW) and large parcels of land for major sub-stations are in limited supply in New England and should be utilized effectively.

- Will a proposed Asset Condition/Refurbishment project make full use of land and ROW capabilities to facilitate future needs, such as the interconnection and delivery of clean energy resources?

- Given the scope, budget, and skill level of the ITM organization, the ITM could provide analytical capabilities for evaluation of the effectiveness of proposed solutions.

IX. An ITM would bring efficiency by engaging the existing processes and thereby avoid process delays or risks to reliability

38. ITM would work through existing PAC and TOPAC processes from its outset. There would be no need to create a new forum or process to accommodate the ITM input. The ITM would not duplicate ISO-NE's effort or seek to substitute judgment for ISO-NE determinations. The ITM would seek to function primarily as an informational resource and to provide greater visibility to the New England region and the Commission on transmission planning and cost issues. Communication with regional stakeholders on the overall planning process is on-going and there is ample opportunity for the ITM to engage ISO-NE, the ISO-NE Board, state agencies, regional Transmission Owners, the Commission and all others involved in the process.

Transmission Planning Process:

- As noted earlier, an ITM being a well-informed, regular, active, and early attendee at the PAC and TOPAC sessions to listen, learn, give feedback, and ask questions can only help the overall process. This also is the opportunity for the ITM to access the information necessary to most efficiently and properly review and comment on the overall planning process.

- Well informed questions, input and discussion early on in the regional planning process help to get out any information that may be missing to support the process, while developing and comparing alternatives. It may take little or no incremental time up front and can save time later in the process after significant amounts of work and analysis have already been expended and would be difficult or time consuming to have redone.

- Most major transmission line projects take several years from planning to completion and in-service. One or two more meetings, if any, on the front end of the transmission planning process to satisfy any input or concerns from the ITM could save time and avoid delays as projects move along to siting and development.
- The cost assumptions of alternative transmission plans would be vetted in the transmission planning process. The ITM would bring sufficient expertise that it could credibly ask questions about assumptions,, and the expected economic benefits of potential alternative approaches.
- To the extent that the existing tariff does not support evaluation of certain benefits for the purpose of project selection, the ITM will be able to recommend tariff revisions that would enhance the process going forward. Much of this activity currently happens within the context of the existing planning framework, save that issues often devolve into arguments between those who would pay and those that would be paid.

39. Establishing reliability standards and criteria at both the national and regional levels is a robust process involving feedback from all segments of the industry.

Planning Standards:

- At the federal level, standards are approved by NERC and then submitted to the Commission for final review and ultimate approval.
- At the regional level, new criteria are approved through each regional entity's governance structure. For New England, this is accomplished through the Northeast Power Coordinating Council (NPCC).
- An ITM could provide comments during the standard/criteria development and drafting stage, and their input would be considered at the front end like all other stakeholders.
- If informed by the ITM, states could choose to get more engaged at this stage of the standard/criteria development process.

End

Prepared by:

Stephen J. Rourke, Advisor
Marc Montalvo, President & CEO
Daymark Energy Advisors
370 Main Street, Suite 325
Worcester, MA 01608