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

| | |
|---|---|
| Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection | Docket No. RM21-17-000 |

# COMMENTS OF ACADIA CENTER AND CONSERVATION LAW FOUNDATION

**August 17, 2022**

## Table of Contents

Pursuant to the Notice of Proposed Rulemaking ("NOPR") issued by the Federal Energy Regulatory Commission ("Commission") on April 21, 2022, Acadia Center and Conservation Law Foundation ("CLF") submit these joint initial comments in the above-captioned rulemaking.[1, 2] Acadia Center and CLF strongly support the Commission's efforts to modernize regional transmission planning and cost allocation processes. As organizations focused on the northeast region, these comments will highlight the ways that updated transmission planning and cost allocation processes can better meet the needs of New England's electric grid and its communities and consumers.[3]

## I. Comments

The need for transmission planning and cost allocation reform is clear. As the Commission states in the NOPR, the status quo of transmission planning and cost allocation is resulting in a "disproportionate share of transmission facilities to meet transmission needs driven by changes in the resource mix and demand being developed outside regional transmission planning and cost allocation processes, resulting in less efficient and cost-effective transmission development."[4] While Commission Order No. 1000 was an important first step towards improved regional transmission planning and cost allocation, further reforms are necessary[5] because Order No. 1000 has failed to require public utility transmission providers to align their transmission planning and funding processes with state policies and objectives.[6] In New

---

[1] By its May 25, 2022 Notice on Requests for Extension of Time, the Commission extended the deadline to submit initial comments in response to the NOPR to August 17, 2022.
[2] Acadia Center and CLF hereby incorporate by reference their reply comments on the Advanced Notice of Proposed Rulemaking ("ANOPR") in this docket. November 30, 2021, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20211130-5219.
[3] Acadia Center and CLF are also filing joint comments in this rulemaking with other partners on additional subjects, such as issues of national importance or matters relating specifically to offshore wind.
[4] NOPR at P 36.
[5] *Id.* at P 44.
[6] Regulatory Assistance Project, "FERC Transmission: The Highest-Yield Reforms," July 2022, https://www.raponline.org/wp-content/uploads/2022/07/rap-littell-prause-weston-FERC-transmission-highest-yield-reforms-2022-july.pdf, at 4.

England, the states recently called for transmission planning reform, stating that the region "cannot effectively plan for integrating clean energy resources and decarbonization of the electricity system required by certain states' laws without having a clear understanding of the investments needed in regional transmission infrastructure."[7] For these reasons, and as outlined below, Acadia Center and CLF strongly support the Commission's aim to ensure that public utility transmission providers engage in regional transmission planning and cost allocation on a sufficiently long-term, forward-looking basis to meet transmission needs driven by changes in the resource mix and demand.[8]

### A. The Commission Must Direct the RTOs/ISOs to Conduct Portfolio-Based Long-Term Scenario Planning that Evaluates a Minimum Set of Benefits, Considers State Law and Policy, and Includes Base Selection Criteria.

The Commission appropriately concludes that existing regional transmission planning processes often miss the big picture by failing to look sufficiently forward in time and by failing to adequately address key factors such as state law. In New England, as in other regions, this outdated approach leads to piecemeal and inefficient transmission development, driving up the costs to achieve long-term goals. This piecemeal approach also misses opportunities to reduce impacts on communities and the environment and to align with state policies.

Acadia Center and CLF strongly support the Commission's adoption of rules that will help ensure each region is conducting forward-looking planning of transmission needs and infrastructure on a sufficiently long-term time horizon, employing scenario-based analysis, and addressing relevant laws and policies.  Such rules will help ensure just and reasonable rates and maintain the fairness, relevance, and competitiveness of the wholesale electricity markets.

---

[7] New England States Committee on Electricity, "New England States' Vision for a Clean, Affordable, and Reliable 21st Century Regional Electric Grid," October 16, 2020, https://yq5v214uei4489eww27gbgsu-wpengine.netdna-ssl.com/wp-content/uploads/2020/10/NESCOE_Vision_Statement_Oct2020.pdf, at 3-4.
[8] NOPR at P 44.

### 1. Mandatory Long-Term Regional Transmission Planning is Essential to Ensure that Electric Transmission Systems Like New England's Remain Reliable and Safe, with Just and Reasonable Planning Outcomes and Rates.

Acadia Center and CLF strongly support the Commission's proposal to require that transmission planners assess grid needs through long-term scenario assessments that incorporate assumptions about future generation and demand over a forward-looking planning horizon. Some regions are already employing a 20-year planning horizon, as the Commission proposes here.[9] ISO-New England ("ISO-NE") generally employs a 5-to-10-year planning horizon, but recently requested and received permission to amend Attachment K to its tariff to allow the New England States Committee on Electricity ("NESCOE") to submit periodic requests for "high-level" longer-term transmission studies, along with "high-level" cost estimates.[10] In addition, ISO-NE recently agreed to undertake an inaugural long-term planning effort called the 2050 Transmission Study. Analysis of this study is still underway, but this study and related processes have the potential to assist the region substantially with regard to efforts to efficiently and transparently plan for anticipated grid needs. Setting a requirement of regional transmission planning on a 20-year horizon, with the option of longer (*e.g.*, 30 years) and/or interim milestone planning, is consistent with the needs of New England as well as other regions.

The Commission correctly aims in the NOPR to solve the problem of inefficient, non-transparent transmission planning largely driven by interconnection queues and behind-the-curtains transmission-owner one-off processes by proposing transparent, long-term transmission planning. Generator interconnection queues, local, and non-transparent planning are not an adequate way to plan electric transmission systems that are evolving in response to the adoption

---

[9] NOPR at P 94.

[10] *See* ISO-NE Attachment K Longer-Term Planning Changes, Docket ER22-727 (December 27, 2021), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20211227-5049; Order 178 FERC ¶ 61,137 (Feb. 25, 2022) (approving proposed amendments to Attachment K).

of new and cost-effective renewable technologies, customer-side resources, and new types of customer demand, such as transportation and building electrification. In New England and other regions, many of these changes are happening on a foreseeable—and sometimes legally mandated—timeline in line with state law and policy, and grid planners should be planning over long-term horizons to factor in such major and predictable trends. Improving and consolidating these planning processes in the ways proposed by the Commission is also in the public interest because it can strengthen transparency and perceived accountability.

### 2. Long-Term Regional Transmission Planning Must Be Undertaken on an Integrated Portfolio Basis that Avoids Artificial Siloing.

Unfortunately, the NOPR does not require long-term transmission planning to be undertaken on an integrated portfolio basis with reliability and economic planning. Therefore, the Commission's final rule must require portfolio-based planning that assesses economic, reliability, and other needs at the same time. This will ensure transmission planning that meets grid needs in an efficient and cost-effective manner. Portfolio-based planning avoids the trap of falsely viewing "reliability" as somehow isolated and separate from a changing energy mix, changing economics, and other factors that affect grid needs. In reality, these factors involve interrelated considerations within the same electric system that affect each other and therefore must be considered as pieces of the same puzzle by grid planners. In its comments on the ANOPR, NESCOE correctly finds that, "[l]ike wholesale power markets, transmission and 'public policy … are inextricably intertwined.'"[11] Similarly, the Massachusetts Department of Energy Resources concludes that, "[a]ll future transmission projects should be considered and planned with an eye toward the region's overall need to simultaneously ensure reliability while

[11] NESCOE Comments on ANOPR, October 12, 2021, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20211012-5597, at 21, *citing ISO New England Inc.*, 173 FERC ¶ 61,161 (2020) (Glick, Comm'r, dissenting at ¶ 7).

electrification takes effect, maintain low system congestion, and integrate significant amounts of clean energy resources."[12] Because overall needs cannot be identified without a broad and integrated lens, grid planners should be required to conduct portfolio-based planning that assesses overall grid needs and multiple benefits.

As the Office of the Massachusetts Attorney General explained in response to the ANOPR, Commission Order Nos. 1000 and 2003 "encouraged the development of siloed regional planning processes that separately evaluate transmission projects for reliability, economic efficiency, and public policy objectives, and thereby are unable [to] consider the full range of potential project benefits and costs."[13] Instead, "regional planners should look holistically at maximizing overall efficiency of the power system rather than segregating projects into artificial silos."[14] The NOPR fails to rectify this deficiency because it does not mandate a portfolio-based planning approach that integrates not just so-called "public policy" but rather all relevant factors into Long-Term Regional Transmission Planning including reliability and economics. The final rule must correct this by requiring integrated planning to ensure reliable, just and reasonable solutions that can meet more than a single type of grid need at a time.

Grid planners are well-equipped to walk and chew gum at the same time and should be required to adopt an integrated approach. The Office of the Massachusetts Attorney General has provided an important example of the need for this integrated planning. The Boston 2028 RFP conducted by ISO-NE in 2020 is an example of a solicitation where "[i]n focusing on cost-effectively solving reliability needs alone, ISO-NE rejected all but one of thirty-six proposals."[15]

---

[12] Massachusetts Department of Energy Resources ("Mass. DOER") Comments on ANOPR, October 12, 2021, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20211012-5379, at 17.
[13] Massachusetts Attorney General Comments on ANOPR, October 12, 2021, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20211012-5586, at 21.
[14] *Id.* at 13.
[15] *Id.* at 22 (citation omitted).

In rejecting all but the cheapest, most narrowly focused proposal, ISO-NE lost the opportunity to solve multiple system needs in a single project that would have been more cost-effective than multiple transmission projects.[16] Siloed planning is contrary to commonsense and must be ended so that grid planners are required to look at the whole picture at once. Only then can grid needs be met in a timely, cost-effective, and holistic manner.

Despite not requiring portfolio transmission planning, the Commission correctly concludes that, "more comprehensive regional transmission planning and cost allocation processes—like the process used to plan the MISO MVP" can ensure greater and more distributed benefits, improve the engagement of states and communities, and result in more efficient outcomes.[17] This can be particularly important in multi-state RTOs/ISOs such as New England, where population densities are not uniform and resource availability varies.

ISO-NE's recent 2050 Transmission Study also provides support for updated Commission rules requiring broad and integrated planning. That study is the first effort in New England to carry out a long-term transmission needs assessment consistent with some of the concepts in the NOPR, including the need to plan for changes to the resource mix based on state law and policy. Among other things, the study finds that substantial north-south transmission lines may be needed to unlock renewable resources in the northern part of New England to help serve demand in southern parts of New England. Employing a portfolio-based assessment of transmission needs would help to reduce the total number of such north-south lines. While the 2050 Transmission Study helps demonstrate the demand for these kinds of studies, it falls short of meeting all the criteria and objectives set out in the NOPR and lacks key elements that can make it more clearly actionable, such as resolution of cost-allocation questions and clarity on the

[16] *Id*. at 22-23.
[17] *See, e.g*., NOPR at PP 28, 33, 54.

relationship between different types of transmission projects and their respective planners (*e.g.*, local, public policy, reliability, economic). Updated transmission planning rules will assist ISO-NE and other RTOs/ISOs to strengthen all their long-term planning efforts.

A portfolio approach could also broaden the scope of options for non-wires solutions to avoid the need for costly infrastructure investments. This would be particularly helpful in New England, where the 2050 Transmission Study finds that demand management or other non-wires solutions could alleviate the need to invest in additional transmission lines to meet grid needs that are anticipated to occur over just a handful of days each year. Non-wires solutions could alleviate the impacts of transmission infrastructure on communities and landscapes, while reducing costs for the region as a whole. Evaluating both transmission and non-wires solutions with a broader lens can increase the number of tools in the grid planner's toolbox as well as the diversity of those tools, so that New England does not have to use a hammer when a screwdriver would be better suited to the job.

**3. To Ensure Grid Reliability and Just and Reasonable Rates, Changes in Energy Mix and Customer Demand Due to Factors Like Applicable Law and Prevailing Trends Must be Considered Carefully in All Regional Grid Planning.**

The Commission appropriately proposes to require regional transmission planners to incorporate a minimum set of factors into the development of long-term scenarios. ISO-NE has indicated that it recognizes the need to better integrate state policy into its planning and has taken limited preliminary steps to explore what that would look like in practice.[18] In his comments at the Commission's November 15, 2021 Technical Conference, Dr. Ethier, Vice President for System Planning at ISO-NE, acknowledged the need to "figure out how to go forward" so that

[18] *See, e.g.*, Comments of Robert Ethier (ISO-NE Vice President for System Planning), FERC Technical Conference in RM21-17, Nov. 15, 2021, at 20:25, 21:1-21.

the transmission grid can "meet the needs of the future."[19] The guidance the Commission proposes here will benefit ISO-NE and other transmission planners who are navigating similar novel challenges and should be adopted in the final rule.

The seven minimum factors that the Commission proposes in the NOPR are each reasonable and necessary, spanning from federal, state, and local legal requirements governing resource mix, decarbonization, and/or electrification to utility integrated resource plans and anticipated resource retirements.[20] These factors are consistent with the types of factors increasingly incorporated by state public utilities commissions into utility distribution system planning requirements.[21] These minimum factors are also consistent with certain factors, such as state law and expected retirements, that ISO-NE recently considered in the 2050 Transmission Study that was just carried out[22] and which is still being analyzed by ISO-NE and stakeholders.

The Commission's proposed factors, including state legal requirements, are clearly tied to future grid needs. As the Commission notes in the NOPR, "five of the six New England states are statutorily required to reduce economy-wide greenhouse gas emissions by at least 80% below 1990 levels by 2050."[23] State laws are therefore essential considerations in planning transmission to serve New England's needs, as state laws drive substantial procurements of energy resources along with the concomitant need for additional transmission, as well as repurposed transmission and non-transmission grid solutions. Regulator-approved utility integrated resource plans are

---

[19] *Id.* at 21:8-9, 19-20.
[20] NOPR at P 104.
[21] *See, e.g.*, Code of Colorado Regulations, 4 CCR 723-3 §§ 3625-3627 (transmission planning rules requiring long-range scenario planning that considers public policy, emerging technologies, load growth), §§ 3525-3542 (distribution system planning rules requiring long-range scenario planning that considers public policy, load growth); Maine 35-A M.R.S.A. § 3147 (requiring 10-year grid plans that consider reliability, resilience, cost-effectiveness, and the achievement of public policy goals).
[22] *See* ISO-NE 2050 Transmission Study, https://www.iso-ne.com/system-planning/transmission-planning/longer-term-transmission-studies/.
[23] NOPR at P 104 n.190.

also important indicators in New England, along with each of the other factors the Commission enumerates, including electrification trends and generator interconnection requests. Although in New England, state laws are currently the primary drivers of change to the resource mix, Acadia Center and CLF further support the approaches recommended by the Public Interest Organizations regarding how transmission planning can best address non-binding utility corporate goals. Because each of these factors impacts the need for transmission, they must be required considerations in long-term transmission planning efforts.

The Commission's final rule should additionally clarify that the requirement to consider state law and changes to the energy resource mix means that grid planners should not only consider state law and policy related to decarbonization, generation procurement, and electrification, but also demand management such as energy efficiency, distributed generation, flexible load, and demand response. Many of the New England states are already ranked at the top of the list nationally for energy efficiency and are pursuing a range of demand management goals that will be increasingly important as electrification proceeds and grid needs evolve. Laws and initiatives in this area will also deeply impact grid needs while providing grid solutions.

The Commission's proposal to allow transmission planners the opportunity to incorporate additional factors beyond these minimum factors is also reasonable. The Commission states that planners may consider additional factors if they demonstrate that the incorporation of such additional factors is "consistent with or superior to" the Commission's final rule.[24] This permits flexibility for input from the states and interested or affected parties in a specific region, and allows the opportunity to address any new factors that may become relevant in the future.

[24] *Id.* at P 105.

4. **The Commission Must Direct Regional Grid Planners to Evaluate a Minimum Set of Benefits to Ensure Transparent, Just and Reasonable Outcomes and Enable Multi-Regional Cooperation.**

Acadia Center and CLF urge the Commission to adopt a required set of minimum benefits that must be considered in long-term regional planning. While additional benefits and other factors relevant to cost-allocation may be left to regional variation, it is important for the success and cost-effectiveness of transmission planning efforts, and for minimum planning consistency across regions, to require the evaluation of a base set of benefits. The list of benefits the Commission enumerates in the NOPR[25] are commonsense minimum expectations and must be required considerations in all cases in order to ensure the successful development of reliable and just and reasonable transmission infrastructure.

As discussed in detail below, the Commission must also require consideration of a minimum set of benefits in regional cost allocation to ensure that costs are allocated roughly commensurate with benefits and that rates are just and reasonable.[26]

5. **The Commission Must Promulgate Additional Selection Criteria Guidance for Regional Grid Planners, such as a Base Set of Selection Criteria or Considerations, in Order to Ensure the Success of Grid Modernization Efforts.**

The Commission's proposal regarding selection criteria moves in the right direction but should take an additional step forward by establishing a core set of selection criteria, or selection considerations, that can be further built upon by each specific region. Acadia Center and CLF applaud the Commission for its proposal to require public utility transmission providers to consult with and seek support from state entities on the criteria for selecting transmission

[25] *Id.* at P 185.

[26] Further, Acadia Center and CLF are both signatories to the joint comments of Public Interest Organizations ("PIOs") in this proceeding and therefore hereby cross-reference those PIO comments which address the need for mandated consideration of a minimum set of required benefits in regional transmission planning and cost allocation.

projects.[27] However, a core or minimum set of criteria must be provided *ex ante* in order to ensure success in practice in regions like New England. This additional guidance will provide critical information to grid planners that rely on the Commission to help circumscribe the scope of their authority and to identify the considerations that they are allowed to weigh in on for transmission planning.

RTOs/ISOs such as ISO-NE need to receive clear guidance as to their authority to weigh factors such as environmental justice or the availability of a non-transmission alternative that could reduce community and environmental impacts. Guidance from the Commission as to such minimum considerations in selecting among alternatives would help RTOs/ISOs like ISO-NE to have confidence that they are acting within the scope of their authority when they evaluate these factors. This can facilitate more productive conversations at the regional level as to the full scope of selection criteria that will be applicable. Without required minimum criteria, RTOs/ISOs like ISO-NE may continue to resist integrating principles like environmental justice into decision-making due to a lack of concrete guidance and concerns over lack of authority and jurisdiction. Although the Commission should mandate a minimum set of benefits to be considered, the states can and should play a key role in identifying additional benefits to be prioritized, in accordance with state law and regional needs.

For these reasons, Acadia Center and CLF urge the Commission to adopt a core set of selection criteria, or selection considerations, that at a minimum include the following principles:

1. Avoid, minimize, and mitigate environmental impacts;
2. Avoid, minimize, and mitigate impacts on environmental justice communities;
3. Optimize grid benefits across affected parties such as states in the region;
4. Prioritize the use of existing transmission infrastructure where feasible; and
5. Prioritize non-transmission alternatives such as demand management solutions that avoid, defer, or reduce the need for or cost of transmission investments.

[27] NOPR at P 244.

These core selection criteria are general and basic principles that are consistent with NEPA and the Federal Power Act, as well as state law. These factors are complementary to the criteria applied by state siting boards, but with a greater focus on transmission-level benefits and alternatives than on matters more narrowly within the jurisdiction of states. Adopting these federal criteria would not preempt state selection criteria but would ensure that grid planners consider key factors at an early stage. This will help to ensure that core benefits are optimized at the grid planning stage and that poison pills are eliminated while alternatives are still available. It may reduce the frequency of failure at state siting boards because these core considerations will already have been addressed in the planning stages. This will be critical to help ensure that New England and other regions are able to build the transmission necessary to deliver needed energy resources, because it can ensure that the projects that reach a state siting board have already been at least partially optimized.

The Commission can make clear in its final rule that these criteria are not intended to preempt state law but are intended as guideposts to grid planners as to the scope of considerations they can and should weigh in decision-making regarding project selection.

### B. The Commission Should Clarify the Final Rule's Provisions on the Identification of Geographic Zones and Should Mandate the Identification of Zones in Regions with Legally Binding Decarbonization Mandates.

The NOPR, appropriately, gives stakeholders a role in the development of geographic zones by (1) requiring public utility transmission providers to solicit input from stakeholders on draft geographic zones, and (2) requiring public utility transmission providers to incorporate this feedback into the final list of designated geographic zones.[28] Despite the enhanced role given to stakeholders in the development of geographic zones, the NOPR gives public utility transmission

[28] *Id.* at PP 148-149.

providers, like ISO-NE, too much control over the initial decision to identify specific geographic zones for renewable energy. In particular, the NOPR only requires public utility transmission providers to "consider" whether to identify geographic zones.[29] It is unclear whether stakeholders will be given the opportunity to provide input into the public utility transmission provider's "consideration" of whether to identify geographic zones in the first instance. For example, the NOPR states that prior to any potential identification of geographic zones, the public utility transmission provider will first "consider" whether geographic zones are warranted, but does not indicate whether stakeholders will be involved in this initial consideration phase.

Without stakeholder input, independent system operators like ISO-NE may unilaterally decline to identify geographic zones. Accordingly, at a minimum, the final rule should mandate that stakeholders be involved in the initial "consideration" of whether geographic zones are warranted.

More importantly, however, under the final rule, the Commission should mandate the creation of geographic zones in regions where the majority of states have binding greenhouse gas ("GHG") emission reductions or renewables mandates, like New England. The NOPR only makes the identification of geographic zones optional. Without mandatory identification and establishment of geographic zones for renewable energy development, there is a significant risk that sufficient transmission will not be built to accommodate states' GHG emissions reduction and/or renewables mandates in an efficient and cost-effective manner.

ISO-NE largely advocated in the ANOPR for a status quo approach, alleging that its clustering rules already provide the means for identifying geographic areas with potential for

[29] *Id*. at P 145.

high amounts of renewable energy.[30] While clustering provides some value by reducing the unpredictability of the interconnection process through spreading costs among multiple interconnecting customers, to date, ISO-NE's clustering methodology has been unsuccessful in facilitating the transmission upgrades needed to integrate large amounts of offshore wind into the ISO-NE grid. Therefore, a more proactive approach for transmission planning is needed.

Geographic zones afford an opportunity to integrate significant new renewable generation into the grid. However, despite providing avenues for stakeholder involvement in the development of geographic zones, the NOPR is overly discretionary regarding their establishment, which creates a significant risk of inaction by RTOs/ISOs like ISO-NE. Rather than merely require public utility transmission providers to "consider" geographic zones, the final rule should mandate the establishment of geographic zones in RTO/ISO regions where the majority of states in the region have instituted binding GHG emission reductions. For example, under such an approach, in a region like New England where five of the six states have mandatory GHG emissions reductions,[31] ISO-NE would be required to establish geographic zones. A mandatory rule establishing geographic zones could prevent a situation where ISO-NE's existing excess capacity is depleted by the early offshore wind projects and subsequent offshore wind projects are abandoned because of the high costs of transmission upgrades needed to increase capacity on the grid.[32] The mandatory establishment of geographic zones could also result in the construction of fewer transmission corridors, which could significantly reduce costs, reduce siting challenges, and reduce impacts to the benthic environment.[33]

---

[30] ISO-NE Comments on ANOPR, October 12, 2021, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20211012-5581, at 24.
[31] NOPR at P 104 n.190.
[32] Anbaric Development Partners, LLC ("Anbaric") Comments on ANOPR, October 12, 2021, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20211012-5692, at 6-8.
[33] Anbaric notes that proactive transmission planning for offshore wind could yield 49 percent less transmission

ISO-NE's development of capacity zones provides a useful model for the establishment of geographic zones. ISO-NE designates both export-constrained capacity zones and import-constrained capacity zones. In import-constrained capacity zones, internal constraints limit the amount of energy that can be brought into the zone. Conversely, in export-constrained capacity zones, internal constraints limit the amount of energy that can be taken out of the zone. Export-constrained zones are modeled when the maximum capacity limit is less than the total of existing and proposed new resources in the zone. ISO-NE reviews transmission transfer capabilities to identify potential zonal boundaries and transfer limits.[34]

If the final rule were to require the mandatory establishment of geographic zones in areas with binding emissions reduction requirements, zones could be established using similar criteria as are used by ISO-NE to establish export-constrained capacity zones. Specifically, RTOs/ISOs could set up geographic zones based on areas where constraints limit the ability of new resources connecting to the grid from being exported to other areas of the grid. In other words, geographic zones could be established based on areas where generators are attempting to connect to the grid, but constraints on the grid prevent or impede the integration of these resources. In ISO-NE, this could mean geographic zones in northern Maine and both onshore and offshore zones in southeastern New England, as grid constraints are preventing the integration of onshore wind from northern Maine and offshore wind in southeastern New England. RTOs/ISOs could prioritize the establishment of geographic zones in areas where the difference between the maximum capacity limit and new resources attempting to integrate to the grid is greatest. This

cables than the gen-tie alternative and reduce onshore upgrade transmission costs by 65 percent, or $1 billion. *Id.* at Att. A at 12, 15.

[34] Capacity Zone Development, ISO-NE, https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/capacity-zone-development; Capacity Zones Formation and Demand Curves, ISO-NE, October 2021, https://www.iso-ne.com/static-assets/documents/2021/11/20211018-fcm101-lesson-4-capacity-zones-demand-curves_PRINT.pdf.

approach would be both objective and technologically neutral and prevent RTOs/ISOs from picking winners and losers.[35]

### C. The Proposed Cost Allocation Reforms are Warranted and Long Overdue, But Must be Strengthened to Ensure Just and Reasonable Rates.

The Commission correctly observes that identifying a cost allocation method that is perceived as fair remains challenging, especially in transmission planning regions that encompass several states, such as New England.[36] That regional consensus on cost allocation methods continues to be elusive stems in large part from cost allocation approaches that, like transmission planning, are often separated by type—economic, reliability and public policy projects.[37] In New England and other regions, this siloed approach to transmission planning and cost allocation has resulted in a paradigm that fails to consider the full suite of benefits and beneficiaries of regional transmission facilities, and thus fails to allocate the costs of such facilities roughly commensurate with the benefits, resulting in rates that are unjust and unreasonable and unduly discriminatory and preferential.

In the NOPR, the Commission seeks to remove some of the barriers to cost-effective transmission cost allocation, many of which have persisted since the Commission's last attempt to reform cost allocation under Order No. 1000.[38] As the Commission correctly points out, reform is necessary not only to ensure that rates are just and reasonable, but also because existing

---

[35] In conjunction with the above recommendation, RTOs/ISOs could employ similar criteria to identify geographic zones as used by the Electric Reliability Council of Texas ("ERCOT") and the Public Utility Commission of Texas ("PUCT") to establish the Texas Competitive Renewable Energy Zones ("CREZs"). ERCOT and the PUCT established CREZs based on the following criteria: (1) adequate (and preferably abundant) renewables potential; (2) sufficient land for renewable energy development; (3) feasible transmission routes; and (4) expressed interest from renewables developers. *See* John Cohn & Olivera Jankovska, Texas CREZ Lines: How Stakeholders Shape Major Energy Infrastructure Projects, Center for Energy Studies: Rice University's Baker Institute for Public Policy, at 10 (November 2020), https://www.bakerinstitute.org/files/16576/.
[36] NOPR at P 297.
[37] *Id.* at P 284.
[38] *Id.* at PP 297-299.

challenges with cost allocation will only be exacerbated by the additional complexity resulting from the Commission's proposed Long-Term Regional Transmission Planning.[39] The Commission proposes increased state involvement in cost allocation for Long-Term Regional Transmission Facilities and proposes requiring an explanation of benefits that public utility transmission providers will use in any *ex ante* cost allocation method associated with Long-Term Regional Transmission Planning.[40]

While the Commission's proposals are important steps in the right direction, they fall well short of the changes needed to ensure meaningful cost allocation reform that results in just and reasonable rates, especially in multi-state regions. More important than what the Commission proposes in the NOPR concerning cost allocation, is what the Commission does not propose. It does not propose to alter the requirements in Order No. 1000 with respect to existing reliability and economic planning requirements.[41] Nor does it propose to define benefits, or to require public utility transmission providers to assess a minimum set of transmission benefits.[42] It also does not propose a definition of agreement under the proposed State Agreement Process.[43]

In this rulemaking, the Commission should revise its proposals and: (1) *require* public utility transmission providers to perform holistic, multi-value transmission planning and cost allocation that assess reliability, economic and public policy needs, and that assess a minimum set of benefits; and (2) expand upon its proposals concerning cost allocation with respect to interregional planning and generator interconnection processes. By doing so, the Commission will help ensure the development of just and reasonable cost allocation methods.

---

[39] *Id.* at PP 278, 298.
[40] *Id*. at PP 302-318, 325-327.
[41] *Id*. at P 3.
[42] *Id.* at PP 183-185, 326.
[43] *Id*. at P 306.

### 1. Mandatory Holistic, Multi-Value Cost Allocation that Considers a Minimum Set of Benefits of Transmission Facilities is Necessary to Ensure Just and Reasonable Rates.

For too long and in too many regions, including New England, public utility transmission providers have conducted transmission planning and cost allocation in a siloed fashion, and have thus failed to accurately account for many of the benefits of regional transmission facilities, resulting in unnecessarily high transmission costs.[44] Indeed, as The Brattle Group and Grid Strategies noted in a report prepared for and submitted in the ANOPR process:

> [M]ost existing planning processes do not take advantage of the available experience or consider the multiple values proposed transmission investment can provide beyond addressing specific drivers and needs. If a project is driven by reliability needs, the broader economic and public policy benefits provided by the project are usually not quantified and considered. If a project is categorized as an economic or public policy project, but simultaneously provides reliability benefits without addressing a specific reliability violation, that reliability benefit usually is not considered either. This particular "compartmentalized" or "siloed" planning approach leads to an understatement of transmission related system benefits and a significant under-appreciation of the costs and risks imposed on customers by an insufficiently robust and flexible transmission infrastructure.[45]

As the Commission stated in Order No. 1000, if cost allocation methods do not appropriately account for the benefits associated with transmission facilities, they can result in rates that are not just and reasonable or are unduly discriminatory or preferential.[46]

There are several examples of positive experiences with multi-value planning and cost allocation,[47] and conversely, there are examples of how the failure to account for multiple benefits resulted in negative outcomes, such as the failure to select projects that would have

[44] The Brattle Group and Grid Strategies, "Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs," (Oct. 2021), https://gridprogress.files.wordpress.com/2021/10/transmission-planning-for-the-21st-century-proven-practices-that-increase-value-and-reduce-costs-7.pdf, at 3-4, 16-17, 30-33.
[45] *Id.* at 31.
[46] ANOPR at P 69; Order 1000 at P 487.
[47] The Brattle Group and Grid Strategies, "Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs," (Oct. 2021), at 53-58.

benefitted customers.[48] For instance, in the Boston 2028 RFP conducted by ISO-NE in 2020, ISO-NE missed the opportunity to solve multiple system needs in a single project that would have been more cost-effective than multiple transmission projects.[49] Because New England's siloed approach to planning and cost allocation inhibits identification of multi-value solutions, a more integrated and holistic process is needed for projects identified through the regional transmission planning process.[50]

The ISO-NE Boston 2028 RFP was ISO-NE's first and only procurement under Order No. 1000, and sought bids for upgrades to compensate for the closure of the Mystic generating station in Massachusetts, which was located at an important transmission node. Multiple bidders in the process took the opportunity to innovate and submitted bids that solved the reliability issue in a manner that solved for future renewable interconnections, and in doing so aimed to meet current and future needs. These bids offered multi-value solutions to address short-term reliability needs and state-mandated clean energy goals, but ISO-NE did not consider these mandates. As the Regulatory Assistance Project points out, ISO-NE has used its own "immediate need reliability" exception to effectively avoid the competitive procurement mandate in Order No. 1000.[51] The Boston 2028 RFP episode demonstrates that "if best practice from [the Commission] is not made mandatory for an RTO, it does not matter in practice."[52]

As a threshold matter, the Commission makes clear in the NOPR that it is not seeking to

---

[48] Commissioner Clements, https://twitter.com/ClementsFERC/status/1554146769902215171 (August 1, 2022) ("If you think we should adopt a minimum set of benefits, I am interested in examples of how the failure to evaluate these benefits has led to negative outcomes, such as the failure to select projects that would have benefitted customers.").
[49] Massachusetts Attorney General Comments on ANOPR, October 12, 2021, at 22-23.
[50] *Id.* at 22, 25-26.
[51] Regulatory Assistance Project, "FERC Transmission: The Highest-Yield Reforms," July 2022, https://www.raponline.org/wp-content/uploads/2022/07/rap-littell-prause-weston-FERC-transmission-highest-yield-reforms-2022-july.pdf, at 15.
[52] *Id.*

modify the Order No. 1000 requirements for public utility transmission providers with respect to reliability and economic planning requirements, and the Commission is not seeking to apply the proposed reforms to the cost allocation methods associated with regional transmission facilities that address needs driven by reliability and/or economic considerations.[53] This is a fundamental flaw in the NOPR that, if finalized, will prevent providers from developing cost-effective cost allocation methods. Like transmission planning, regional cost allocation must be holistic and include reliability, economic and public policy considerations.

In the NOPR, the Commission correctly voices concerns that existing regional transmission planning and cost allocation requirements may result in public utility transmission providers undervaluing the benefits of Long-Term Regional Transmission Facilities, and that the current approach of considering "only a subset of categories of benefits" may result in inaccurate valuation of a facility's benefits and may contribute to the risk of free rider problems that impede development of cost-effective regional transmission facilities.[54]

To begin addressing these concerns, the Commission proposes a list of Long-Term Transmission Benefits that public utility transmission providers may consider in Long-Term Regional Transmission Planning and cost allocation processes.[55] The Commission further proposes to require public utility transmission providers to identify in compliance filings the benefits they will use, how they will calculate the benefits, and how the benefits will reflect the benefits of regional transmission facilities.[56] Additionally, the Commission clarifies that the list of benefits is not exhaustive, leaving room for providers to consider other benefits.[57]

[53] NOPR at PP 3, 314.
[54] *Id.* at P 325.
[55] *Id.* at PP 183-185, 326.
[56] *Id.* at P 183.
[57] *Id.* at P 184.

While the Commission's proposals are important steps toward more fully accounting for the benefits of transmission facilities, and for moving toward allocating costs in a manner that is roughly commensurate with benefits, the proposals fall short of what is needed to ensure a full accounting of benefits and beneficiaries and ensure just and reasonable rates. Indeed, the Commission declines to propose to prescribe any particular definition of "benefits" or "beneficiaries" or to require use of any specific benefits.[58] By failing to require consideration of even a minimum set of benefits, the Commission risks perpetuating the status quo in planning regions, including New England.[59] Indeed, experience in the years since Order No. 1000 has shown that public utility transmission providers have generally declined to consider anything close to the full suite of transmission benefits. As the Brattle Group-Grid Strategies report indicates, many quantifiable transmission benefits are not typically accounted for in most transmission planning processes due to perceived limitations in quantifying those benefits.[60] Overlooking benefits because traditional tools and processes do not automatically capture these benefits "leads to the premature rejection of valuable projects and underinvestment in transmission infrastructure."[61]

The Commission must require public utility transmission providers to consider a minimum set of transmission benefits. The minimum set of benefits that public utility transmission providers should be required to assess include the Long-Term Regional Transmission Benefits identified in the NOPR.[62] Evaluation of the Long-Term Regional

---

[58] *Id.* at P 183.
[59] NESCOE suggests that cost allocation reforms should not unintentionally disrupt settled methods. *See* NOPR at P 293, fn.488, *citing* NESCOE Comments on ANOPR, October 12, 2021, at 50.
[60] Regulatory Assistance Project, "FERC Transmission: The Highest-Yield Reforms," July 2022, https://www.raponline.org/wp-content/uploads/2022/07/rap-littell-prause-weston-FERC-transmission-highest-yield-reforms-2022-july.pdf, at .
[61] *Id*. at 30-32.
[62] NOPR at P 185.

Transmission Benefits proposed by the Commission would provide a more accurate cost-benefit analysis and would provide additional cost allocation tools. For instance, as the Commission states, the benefit of avoided or delayed reliability transmission investment allocates costs among public utility transmission providers whose facilities the new facilities would displace in proportion to their share of the total benefits (*i.e.,* the total avoided costs).[63] In addition to the Long-Term Regional Transmission Benefits identified in the NOPR, the minimum set of benefits that public utility transmission providers should be required to assess should also include those benefits listed in the Brattle Group-Grid Strategies report that are not already identified in the list of Long-Term Regional Transmission Benefits.

As the Department of Energy pointed out during the ANOPR process, the Commission has determined, and the D.C. Circuit has recognized, that it is "undisputed" that "high-voltage power lines produce significant regional benefits" and a cost sharing mechanism that ignores the regional benefits of a project would be inconsistent with Section 206.[64] Further, given the broad array of potential benefits of regional transmission, "it should be no surprise that investments in more efficient or cost-effective transmission infrastructure can yield substantial benefits to consumers."[65]

Consideration of regional benefits in a multi-state region with divergent state policy goals will not negatively impact consumers. For instance, even in regions like New England, where not every state has equally ambitious public policies supporting decarbonization, public utility transmission providers must account for all the benefits of transmission facilities, and a multi-

[63] *Id.* at P 190.
[64] U.S. Department of Energy ("DOE") Comments on ANOPR, October 12, 2021, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20211012-5498, at 15, *citing Old Dom. Elec. Coop. v. FERC*, 898 F.3d 1254, 1260 (D.C. Cir. 2018).
[65] NOPR at P 30.

value analysis based on minimum cost allocation standards and a minimum set of benefits allows for such an accounting. Indeed, as the U.S. Department of Energy correctly points out, just because one state in a region has a certain policy does not necessarily prevent citizens in the other states in the region with different policies from receiving benefits.[66] As a result, allocating the costs of transmission used to meet a certain state's policy to only ratepayers in that state violates beneficiary-pays principles.[67]

While the Commission seeks to provide public utility transmission providers flexibility by allowing them to continue using some or all aspects of existing transmission planning and cost allocation,[68] this flexibility will prevent meaningful cost allocation reform from occurring in New England. Indeed, based on comments filed during the ANOPR process, it is likely that ISO-NE will opt to continue the existing approach to regional cost allocation. But that approach is clearly broken.[69] If the final rule includes this flexibility, then the Commission must include the requirement proposed in the NOPR that regions opting for this approach demonstrate that continued use does not interfere with or otherwise undermine the Long-Term Regional Transmission Planning proposed in the NOPR.

**2. Additional Cost Allocation Reforms Are Needed to Promote Coordination of Interregional Transmission Planning and Generator Interconnection Processes.**

Interconnection and interregional planning are not the focus of the NOPR, but the Commission makes proposals concerning cost allocation in these areas that should help ensure just and reasonable rates. The Commission proposes to require public utility transmission

[66] DOE Comments on ANOPR, October 12, 2021, at 41.
[67] *Id*. at 41-42.
[68] NOPR at P 74.
[69] As ISO-NE has indicated, despite facilitating $12 billion in investment in transmission since 2002 to meet reliability needs, the regional planning process has not yet identified any need for public policy transmission projects. *See* ISO-NE Comments on ANOPR, October 12, 2021 at 7, fn.16. Further, as discussed above, ISO-NE's one competitive procurement under Order No. 1000 failed to consider multi-value projects.

providers in neighboring regions to revise coordination procedures to allow an entity to propose an interregional transmission facility in the regional transmission planning process, which would allow needs driven by changes in the resource mix and demand to be considering in interregional transmission coordination and cost allocation.[70] Because this proposal should help identify facilities that could more efficiently or cost-effectively meet the needs identified through Long-Term Regional Transmission Planning, and should thereby help ensure just and reasonable rates, it should be pursued.

The Commission also finds that there is a need for better coordination between the regional transmission planning and cost allocation and generator interconnection processes and proposes to require that public utility transmission providers consider in their Long-Term Regional Transmission Planning certain interconnection upgrades that have been identified multiple times in the generator interconnection process but that have never been built.[71] Specifically, the Commission proposes that public utility transmission providers evaluate for selection in the regional transmission plan interconnection related network upgrades for cost allocation purposes where: (1) the interconnection related network upgrade has been identified in at least two interconnection queue cycles during the preceding five years; (2) the interconnection-related network upgrade has a voltage of at least 200 kV and/or an estimated cost of $30 million; (3) the interconnection related upgrade has not been developed because it has been withdrawn; and (4) the interconnection related network upgrade has not been included in a generator interconnection agreement.[72]

---

[70] NOPR at PP 167-168.
[71] *Id.* at PP 130, 166.
[72] *Id.*

Acadia Center and CLF agree with the Commission that the proposed requirement would address "potential barrier[s] to integrating new sources of generation that may otherwise continue to exist absent such requirements" and "provide an avenue to allocate these regional transmission facilities' costs more broadly in recognition of their widespread benefits."[73] Although Acadia Center and CLF support the proposed rule change, the reform would address a relatively limited subset of interconnection needs for cost allocation purposes as part of Long-Term Regional Transmission Planning. Given the need for significant network upgrades to connect the large amount of renewable generation—and particularly offshore wind—to the ISO-NE grid over the next decade, the Commission should adopt more substantial modifications to cost allocation processes relating to interconnection including in its rulemaking under Docket No. RM22-14, Improvements to Generator Interconnection Procedures and Agreements, ("Interconnection NOPR").

The transmission upgrades needed for connecting renewable generation in New England can provide substantial regional benefits.[74] The Commission correctly recognizes that these types of interconnection-related network upgrades can provide widespread transmission benefits that extend beyond the interconnection customer and that "planning these transmission upgrades exclusively through the generator interconnection process may result in a mismatch between the beneficiaries of the transmission upgrade and those to whom the costs are allocated."[75] However, neither the proposed reform in this rulemaking nor the recently issued Interconnection NOPR fully address the major shortfalls with the current cost allocation process that precludes all

[73] *Id.* at P 168.
[74] Mass. DOER Comments on ANOPR, October 12, 2021 at 19; Anbaric Comments on ANOPR, October 12, 2021, at 3, Attachment A at 18-19, 23; LS Power Comments on ANOPR, October 12, 2021, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20211012-5696, at 45-46.
[75] NOPR at P 165.

beneficiaries from better contributing to the costs of such upgrades. Unless additional changes are adopted that better allocate the costs of interconnection upgrades to regional beneficiaries, there is a significant risk that the spiraling cost of transmission for offshore wind generation results in the abandonment of certain offshore wind projects and prevents the New England states from meeting their decarbonization targets.[76] Accordingly, the Commission should issue a new rulemaking that goes beyond the reforms contemplated in this NOPR and the Interconnection NOPR and propose additional solutions for allocating interconnection costs.

### D. The Commission's Proposals for Increasing State Involvement in Transmission Planning and Cost Allocation Are Positive Changes but Further Elaboration is Needed.

The NOPR contains a number of proposals that, if adopted, would appropriately increase the states' role in transmission development and cost allocation, and in New England would appropriately increase NESCOE's (or another state led entity's) role in transmission planning. While the reforms proposed in the NOPR are necessary, they are not sufficient and the final rule should include several modifications.

#### 1. The Final Rule Should Allow the Majority of States in a Region to Veto an RTO's/ISO's Proposed Transmission Development Selection Criteria and to Propose Their Own Selection Criteria.

With regard to transmission planning, the NOPR states that "public utility transmission providers *must* consult with and seek support from the relevant state entities . . . within their transmission planning region's footprint to develop the selection criteria" for regional transmission facilities.[77] The NOPR also requires public utility transmission providers to consult with stakeholders when proposing the selection criteria that will be used to "ensure that more efficient or cost-effective regional transmission facilities to address the region's transmission

---

[76] Anbaric Comments on ANOPR, October 12, 2021, at 6-8.
[77] NOPR at P 244 (emphasis added).

needs driven by changes in the resource mix and demand ultimately are selected in the regional transmission plan."[78] The NOPR notes that the evaluation process "must result in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission project was selected or not selected."[79]

Although the Commission's proposed requirements regarding consultation with state entities and other stakeholders for transmission project selection are important and necessary, further elaboration in the final rule is needed to ensure that states' interests are adequately incorporated into the transmission planning process. A criticism by the states that comprise ISO-NE' s footprint is that ISO-NE does not adequately consider the New England states' goals regarding decarbonization and the integration of clean energy resources when conducting Long-Term Regional Transmission Planning.[80] Therefore, to provide states with ample opportunity to participate in developing transmission project selection criteria, the final rule should clarify that states have the authority to propose specific transmission development selection criteria. Providing states with the authority to propose their own criteria will ensure that RTOs/ISOs like ISO-NE do not refuse to consider states' interests and goals regarding the transmission needs driven by changes affecting future resource mix and demand.

Moreover, in certain instances, states should be given veto authority over public utility transmission providers' development of the selection criteria that is used to evaluate transmission facilities in Long-Term Regional Transmission Planning. More specifically, in situations where a majority of states in a region have binding decarbonization targets, states should be given the option to veto an RTO's/ISO's development of selection criteria where they disagree with the

---

[78] *Id.* at P 242.
[79] *Id.*
[80] *See, e.g.*, NESCOE, "New England States' Vision for a Clean, Affordable, and Reliable 21st Century Regional Electric Grid," at 3-5.

RTO/ISO and choose to exercise their veto authority. For example, in New England there has often been conflict between ISO-NE's business-as-usual transmission facility selection criteria, which prioritize reliability and economic considerations, and state policy, where five of the six New England states have enacted binding decarbonization targets. Therefore, if a majority of the New England states disagree with ISO-NE's development of selection criteria, then they should have the ability to veto ISO-NE's proposal if they choose to exercise such authority.

The NOPR recognizes that public utility transmission providers should have the flexibility to develop transmission project selection criteria "that could sufficiently balance state interests within each transmission planning region" and that "providing an opportunity for state involvement in regional transmission planning processes is becoming more important as states take a more active role in shaping the resource mix and demand, which, in turn, means those actions are increasingly affecting the long-term transmission needs."[81] Veto authority in certain circumstances, as well as explicit authority to propose their own selection criteria, would guarantee that states are given a real and substantial role in developing selection criteria for transmission planning.

**2. The Final Rule Should Provide Further Clarity on the Commission's Proposed Requirements for Increased State Involvement in Cost Allocation Processes.**

The NOPR also contains several positive reforms that would increase state involvement in cost allocation processes. The Commission proposes to increase state involvement by (1) requiring public utility transmission providers in each transmission planning region to "seek agreement from the relevant state entities regarding the approach to cost allocation for Long-Term Regional Transmission" facilities; and/or (2) permit relevant state entities to "voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or portfolio

[81] NOPR at P 244.

of facilities) after it is selected in the regional transmission plan."[82] As described in the NOPR, the Long-Term Regional Transmission Cost Allocation method would be an "*ex ante* regional cost allocation method that would be included in each public utility transmission provider's OATT as part of Long-Term Regional Transmission Planning," whereas the State Agreement Process would be an "*ex post* allocation process" that would occur "[a]fter a Long-Term Regional Transmission Facility is selected in the regional transmission plan . . . that would be followed to establish a cost allocation method that results from the State Agreement Process.

### a. Although Agreements by Relevant State Entities have Significant Potential to Help Facilitate Transmission Development, Further Clarification is Needed in the Final Rule.

Regarding the Commission's proposed requirement that public utility transmission providers seek agreement from relevant state entities for cost allocation of transmission projects, the NOPR would require each state to designate a single entity as its voting representative.[83] The Commission proposes to give public utility transmission providers flexibility with regard to defining what constitutes "agreement" on cost allocation among the relevant state entities, and would allow state entities to forgo a role in determining the cost allocation approach for Long-Term Regional Transmission facilities.[84] The Commission notes that in determining what constitutes agreement among the states, "the states may choose to apply the existing provisions for engaging with the relevant state entities" and that for ISO-NE, it may consider NESCOE's by-laws in defining the thresholds of agreement among relevant state entities.[85]

Acadia Center and CLF strongly support requiring public utility transmission providers to seek agreement from relevant state entities—like NESCOE in the case of ISO-NE—for cost

[82] NOPR at PP 305, 311.
[83] *Id.* at P 304.
[84] *Id*. at PP 306-307.
[85] *Id.* at P 306 & n.513.

allocation of transmission projects. We note that in its initial comments on the ANOPR, NESCOE agreed that states should occupy a central role in transmission planning and cost allocation and that the key to any rules on cost allocation "is a sufficiently robust role for state participation in the regional planning process."[86] In the case of New England, requiring ISO-NE to seek agreement from relevant state entities regarding cost allocation would provide the New England states with a more robust role in transmission planning, which "could help increase stakeholder—and state—support for facilities, which in turn may increase the likelihood that those facilities are sited and ultimately developed."[87] It would also allow states to "coordinate to advance their policy goals through needed transmission development and may minimize delays and additional costs that can be associated with siting proceedings."[88]

The Commission invites commenters to provide suggestions on what constitutes an agreement "among relevant state entities." While Acadia Center and CLF generally agree that the states should be afforded flexibility to define agreement among relevant state entities, the Commission should provide some guidelines in the final rule in terms of what constitutes agreement. In particular, the final rule should clarify that states in a region need not unanimously agree on a cost allocation approach and can define agreement among relevant state entities as occurring when a majority of states in a region approve the cost allocation methodology for transmission projects. Such a rule clarification is especially pertinent to New England, where five of the six states have binding decarbonization mandates; requiring unanimity could enable one of the New England states to refuse an agreement on cost allocation, which in turn could prevent the construction of needed transmission projects. Only requiring a majority of states to

[86] NESCOE Comments on ANOPR, October 12, 2021, at 21, 49.
[87] NOPR at P 299.
[88] NOPR at P 301.

approve an agreement on cost allocation would be consistent with NESCOE's memorandum of understanding ("MOU") with ISO-NE, which requires that policy determinations "be made only by a majority of the six New England states, both in number and weighted to reflect relative electric load of each state within the New England region's overall load."[89]

In anticipation of circumstances where the relevant state entities fail to agree on a cost allocation method for all or a portion of Long-Term Regional Transmission Facilities, the Commission should have the responsibility to establish a Long-Term Regional Transmission Cost Allocation Method.[90] If the work of establishing a Long-Term Regional Transmission Cost Allocation Method is left to public utility transmission providers, it is possible the method will not reflect the interests of any states and will repeat the pattern of ineffective regional compliance filings enabled by Order No. 1000.

**b. The Voluntary State Agreement Process Has Significant Potential to Facilitate Transmission Upgrades Needed to Integrate Large Renewable Projects into the Grid.**

Regarding the "State Agreement Process," this process would allow "one or more relevant state entities [to] voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or portfolio) of facilities *after* it is selected in the regional transmission plan for purposes of cost allocation."[91] The Commission proposes requiring that public utility transmission providers provide states a time period to negotiate alternative cost allocation methods, and suggests a 90-day time period for negotiation.[92]

---

[89] MOU Among ISO-NE, NEPOOL, and NESCOE, November 21, 2007, https://www.iso-ne.com/static-assets/documents/regulatory/part_agree/mou_final.pdf., at 3, 9.
[90] NOPR at P 310.
[91] *Id.* at P 311 (emphasis added).
[92] *Id.* at PP 319-320.

Acadia Center and CLF agree that voluntary state agreements on transmission cost allocation could provide an important tool for Long-Term Regional Transmission Planning. In the context of New England, given that five of the six states in the region have binding decarbonization mandates, voluntary agreements among the states have significant potential to better socialize the costs of Long-Term Regional Transmission Facilities, including the costs of transmission investments needed to connect large renewable projects to the grid, such as the dozen or so offshore wind projects currently seeking to connect to the ISO-NE grid in southeastern New England.[93] In New England, voluntary agreements on cost allocation for transmission investments relating to offshore wind could "help to ensure just and reasonable Commission-jurisdictional rates by increasing the likelihood that more efficient or cost-effective regional transmission facilities to address transmission needs driven by changes in the resource mix and demand are developed."[94] Further, where voluntary agreements are reached, they are "likely to decrease the controversy over development of such facilities, by, for example, making the relevant state entities more confident that ratepayers in the state are receiving benefits at least roughly commensurate with their share of the cost of such facilities."[95]

The Commission finds that providing states with a time period to "propose alternate cost allocation methods could help facilitate the timely development of more efficient or cost-effective regional transmission facilities," and suggests a time period of 90 days.[96] To avoid

[93] Although such voluntary agreements were allowed under Order 1000, there was uncertainty about the legality of such agreements, which necessitated the Commission's issuance of a policy statement in 2021 that explicitly recognized the legality of state voluntary agreements. *See State Voluntary Agreements to Plan and Pay for Transmission Facilities*, 175 FERC ¶ 61,225 (2021). Acadia Center and CLF support the Commission providing additional clarity on such agreements in a formal rule, and believe that this clarity can assist the New England states in better realizing the potential for these agreements to allocate the costs of the transmission upgrades needed to connect renewable projects to the grid.
[94] *Id.* at P 314.
[95] *Id.*
[96] *Id.* at PP 320-321.

unnecessarily delaying transmission development, a 90-day time period is appropriate.

## II. Conclusion

Acadia Center and CLF applaud the Commission's important proposal to promulgate rules that will modernize transmission planning and cost allocation to meet current and future grid needs. We urge the Commission to adopt the proposed rules with the modifications recommended herein and those included in the comments of the Public Interest Organizations, to which Acadia Center and CLF are also signatories, and which we hereby incorporate by reference. Regional transmission planners including ISO-NE need guidance such as minimum requirements for long-term transmission planning, including minimum factors for incorporation in the development of scenarios and minimum benefits to be considered when evaluating alternatives and allocating costs. It is furthermore common sense to incorporate state laws like the mandatory decarbonization laws adopted by five states in New England into transmission planning, because those laws are already affecting the energy resource mix, along with grid needs, and will continue to impact energy system needs.

Respectfully submitted,

*/s/ Melissa E. Birchard*
Melissa E. Birchard
Director, Clean Energy & Grid Reform
Acadia Center
198 Tremont Street, Suite 415
Boston, MA 02111
mbirchard@acadiacenter.org

*/s/ Nick Krakoff*
Nick Krakoff
Staff Attorney
Conservation Law Foundation
27 North Main Street
Concord, NH 03301
nkrakoff@clf.org

*/s/ Phelps Turner*
Phelps Turner
Senior Attorney
Conservation Law Foundation
53 Exchange Street, Suite 200
Portland, ME 04101
pturner@clf.org