Comments of the American Clean Power Association[1] and RENEW-Northeast[2] on Changes and Upgrades to the Regional Electric Transmission System Needed to Integrate Renewable Energy Resources

I. INTRODUCTION

For the New England States to meet their climate and clean energy goals, they must begin procuring new transmission by 2023. Transmission is required to access grid-scale renewable energy located far from population centers, and grid enhancements are required to accommodate new sources of distributed energy like solar and battery energy storage. The New England States must site transmission lines to minimize impacts on the environment and protect communities overburdened by pollution and prior infrastructure development. And projects must be procured competitively to reduce consumer costs.

The need for expanded transmission has never been clearer, and a decade's worth of studies tell us how to prepare the power system for renewable energy. Procuring the first round of necessary transmission projects in the near term will enable States to access new federal funds and address grid constraints that threaten to impede the transition to a clean energy future.

In May of 2022, RENEW issued a Transmission Blueprint for New England, which is attached to these comments.[3] The Blueprint provides a path for the States to procure new transmission for future generation projects yet to be awarded contracts, and an approach for allocating the costs according to the benefits each state receives.

1. <u>There is No Time to Wait</u>

The New England States must commence transmission procurements by early 2023 to access federal infrastructure funds and jump-start projects that will take years to build. Major transmission projects typically take longer to complete than generation projects, and proactive development of transmission projects must start now if growth of renewable energy is to continue. Moving quickly will position the New England States to access transmission funding provided in the 2021 Infrastructure Investment and Jobs Act and the 2022 Inflation Reduction

[1] American Clean Power is the voice of the clean power industry that is powering America's future, providing cost-effective solutions to the climate crisis while creating jobs, spurring massive investment in the U.S. economy and driving high-tech innovation across the nation. ACP is uniting the power of America's renewable energy industry to advance our shared goals and to transform the U.S. power grid to a low-cost, reliable and renewable power system. The views and opinions expressed in this filing do not necessarily reflect the official position of each individual member of American Clean Power.

[2] RENEW Northeast unites environmental advocates with developers and operators of the region's largest clean energy projects to coordinate their ideas and resources with the goal of increasing environmentally sustainable power generation in New England from the region's abundant renewable energy resources.

[3] *See generally* https://renewne.org/transmission-blueprint-for-new-england.

Act. These funds could help to reduce customer costs and reduce risks of "transmission-first" development.

New England's current process of connecting each generator, or small group of generators, sequentially is slow, incremental, and expensive, and cannot successfully support long-term regional or national clean energy goals. Unless the States undertake prompt efforts to address transmission needs, clean energy deployment – particularly for offshore wind– risks slowing, and States will struggle to meet climate and economic development goals. Implementing a transmission procurement process can help to overcome these challenges and cost-effectively accelerate clean energy deployment.

2. New England Has a Transmission Deficit

Analyses by New England States have identified significant transmission investments needed to achieve existing clean energy goals. For instance, the June 2021 New England Energy Vision Report to Governors found that "the resource mix in New England is rapidly shifting toward more clean energy, including onshore and offshore wind; hydroelectric resources; solar [photovoltaics]; and battery storage. These resource shifts are expected to have major implications for the region's transmission system."[4] Massachusetts' Decarbonization Roadmap found that the region needs new intra-zonal and intra-regional transmission with an aggregate rating of 10,000 to 37,000 MW (MW) to achieve 2050 targets.[5]

Inadequate and antiquated transmission is already threatening renewable energy development and undermining clean energy sources across the region. The first 2,800 MW of offshore wind projects seeking to connect to Cape Cod are facing over $500 million in onshore transmission upgrades, increasing from under $10,000/MW of interconnection costs for the first of these projects, to over $275,000/MW for the most recent.[6] Further connections to Southeast New England are projected to require new on-shore high-voltage transmission of well over $1 billion.[7] Similarly, abundant onshore wind and solar energy potential in Northern Maine is constrained by

[4] New England States Committee on Electricity, *New England Energy Vision Statement* 11 (June 2021), https://newenglandenergyvision.files.wordpress.com/2021/06/advancing-the-vision-report-to-governors-2.pdf

[5] Evolved Energy Research, *Massachusetts Decarbonization Roadmap: Energy Pathways to Deep Decarbonization* 64 (December 2020) (prepared for the Massachusetts Executive Office of Energy and Environmental Affairs) [hereinafter Roadmap], https://www.mass.gov/doc/energy-pathways-for-deep-decarbonization-report/download

[6] Interconnection costs of $7.7 million for QP624 (Vineyard Wind 1), $195.5 million for QP 700 (Park City Wind) and $335 million for the next 1200 MWs in the first Cape Cod interconnection cluster. ISO-NE, QP 624 Wind System Impact Study Report (January 21, 2019), https://smd.iso-ne.com/planning/ceii/studies/ma/qp624_wind-sis-report_jan212019.pdf; and ISO-NE, *QP 700 Offshore Wind System Impact Study Report* (December 14, 2020), https://smd.iso-ne.com/planning/ceii/studies/ma/qp700-offshore-wind-sis_report.zip (both CEII); ISO-NE, *First Cape Cod Resource Integration Study* (July 30, 2021), https://www.iso-ne.com/static-assets/documents/2021/07/cape-cod-resource-integration-study-report-non-ceii-final.pdf

[7] New 345kV overhead and underground transmission from West Barnstable to K Street in Boston has been estimated to cost $1.4 billion. The Brattle Group, *Offshore Transmission in New England: The Benefits of a Better Planned Grid* 17 (May 2020), https://newengland.anbaric.com/wp-content/uploads/2020/07/Brattle_Group_Offshore_Tranmission_in_New-England_5.13.20-FULL-REPORT.pdf

lack of transmission,[8] and limitations in Northern Vermont and New Hampshire are stifling renewable energy development as well.[9] State climate plans call for additional grid connections to New York and Quebec, and for strengthening connections between Northern and Southern New England.[10] Addressing these grid constraints is necessary to achieve state renewable energy requirements, and will enable more efficient use of existing power sources.[11] Additionally, building transmission to access low-cost renewable energy will allow buyers (such as corporations, large institutions, and municipalities) to purchase regional wind and solar and drive deployment without ratepayer contracts.[12]

3. The New England States Should Prepare a Transmission RFP as Soon as Possible

ISO New England ("ISO-NE") and others have performed a long list of studies over the past decade identifying current and anticipated transmission constraints and in many cases identifying solutions.[13] By drawing on existing state authorities, current ISO-NE rules, and precedents from

[8] ISO-NE, *2016-2017 Maine Resource Integration Study* (March 12, 2018), https://www.iso-ne.com/static-assets/documents/2018/03/final_maine_resource_integration_study_report_non_ceii.pdf; and ISO-NE, *Final Second Maine Resource Integration Study* (October 30, 2020), https://www.iso-ne.com/static-assets/documents/2021/01/second-maine-resource-integration-study-report-non-ceii-final.pdf

[9] *See* ISO-NE, *Wind Development in Constrained Areas* (March 21, 2013) https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2013/mar212013/a5_wind_development_in_constrained_areas_new.pdf; ISO-NE, *Strategic Transmission Analysis: Wind Integration Study* (May 22, 2013), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2013/may222013/a3_wind_integration_study_052213_rev1.pdf; and ISO-NE, *Strategic Transmission Analysis: Wind Integration Study – Vermont* (June 17, 2015), https://smd.iso-ne.com/operations-services/ceii/pac/2015/06/a4_strategic_transmission_analysis_wind_integration_study_vermont.pdf, (all CEII)

[10] One analysis found the need for 8.4 GWs to 13.9 GWs of transmission to Quebec and 0.5 GWs to 4.5 GWs of transmission to New York, all across eight decarbonization pathways. Evolved Energy Research, *Massachusetts Decarbonization Roadmap: Energy Pathways to Deep Decarbonization* 64 (December 2020) (prepared for the Massachusetts Executive Office of Energy and Environmental Affairs) [hereinafter Roadmap], https://www.mass.gov/doc/energy-pathways-for-deep-decarbonization-report/download

[11] ISO-NE Internal Market Monitor, *2021 Annual Markets Report* 118 (May 26, 2022), https://www.iso-ne.com/static-assets/documents/2022/05/2021-annual-markets-report.pdf

[12] Transmission can enable third-party purchases of renewable energy through PPAs. In Texas, transmission to access onshore wind through the Competitive Renewable Energy Zone (CREZ) program has enabled over 2,000 MWs of onshore wind energy PPAs from 22 corporate buyers, https://windsolaralliance.org/wp-content/uploads/2018/10/Corporates-Renewable-Procurement-and-Transmission-Report-FINAL.pdf. Independent transmission has enabled corporate PPAs for offshore wind in the Netherlands, https://cleantechnica.com/2019/05/28/microsoft-announces-new-offshore-wind-energy-agreement-in-the-netherlands/, and Belgium, https://www.rechargenews.com/wind/google-buys-first-ever-offshore-wind-power-as-part-of-record-deal/2-1-675522

[13] The most recent studies include: ISO-NE, *2015 Economic Study Evaluation of Increasing the Keene Road Export Limit* (September 2, 2016), https://www.iso-ne.com/static-assets/documents/2016/09/2015_economic_study_keene_road_increased_export_limits_fina.docx

other jurisdictions for state-run transmission procurements, the New England States can conduct transmission solicitations that will provide reliable and competitive solutions delivering the greatest consumer, environmental, and social equity benefits over the life of projects. The New England States can begin procuring this needed transmission today.

The New England States have extensive experience with running successful and competitive solicitations for clean generation projects. Transmission procurement could follow the same general principles and process where the State (or States), which have identified the needs for transmission, issue a Request for Proposals ("RFP") for transmission solutions. Bidders would be responsible for developing responses to these needs and demonstrating that proposed solutions meet desired outcomes. Bidders would be responsible for the interconnection process and bear the risk of obtaining approvals from ISO-NE, just like generators today.

Transmission developers can include studies with their bids to identify constraints or potential constraints to provide an understanding of general transmission issues. Bidders can demonstrate that their proposed point of delivery into ISO-NE, along with their proposed interconnection and

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ISO-NE, *2015 Economic Study Strategic Transmission Analysis—Onshore Wind Integration* September 2, 2016), https://www.iso-ne.com/static-assets/documents/2016/09/2015_economic_study_onshore_wind_integration_final.docx
ISO-NE, *2016 Economic Study: NEPOOL Scenario Analysis* (November 17, 2017), https://www.iso-ne.com/static-assets/documents/2017/11/final_2016_phase1_nepool_scenario_analysis_economic_study.docx
ISO-NE, *2019 Economic Study: Economic Impacts of Increases in Operating Limits of the Orrington-South Interface* (October 30, 2020), https://www.iso-ne.com/static-assets/documents/2020/10/2019-renew-es-report-final.docx
ISO-NE, *2016/2017 Maine Resource Integration Study* (March 12, 2018), https://smd.iso-ne.com/operations-services/ceii/cluster-studies/final_maine_resource_integration_study_report.pdf (requires access to Critical Energy Infrastructure Information)
ISO-NE, *Final Second Maine Resource Integration Study* (October 30, 2020), https://www.iso-ne.com/static-assets/documents/2021/01/second-maine-resource-integration-study-report-non-ceii-final.pdf
RLC Engineering, *QP639 Elective Transmission upgrade Interconnection System Impact Study Final Report* (May 7, 2020))(prepared for ISO-NE), https://smd.iso-ne.com/planning/ceii/studies/me/qp639-etu-1200-mw-hvdc-sis-report_may072020.pdf and associated *QP889 Elective Transmission Upgrade Interconnection System Impact Study Final Report* (September 24, 2021), https://smd.iso-ne.com/planning/ceii/studies/me/qp889-etu-sis-report.pdf
ABB Inc., *QP506 Internal HVDC North to South Flow System Impact Study Report* (July 28, 2017)(prepared for ISO-NE), https://smd.iso-ne.com/planning/ceii/studies/ma/qp506-internal-hvdc-north-to-south-flow-sis-report_jul282017.pdf (requires access to Critical Energy Infrastructure Information)
ISO-NE, *2019 Economic Study: Offshore Wind Integration* (June 30, 2020), https://www.iso-ne.com/static-assets/documents/2020/06/2019_nescoe_economic_study_final.docx
ISO-NE, 2019 *Economic Study: Significant Offshore Wind Integration* (October 5, 2020), https://www.iso-ne.com/static-assets/documents/2020/10/2019-anbaric-economic-study-final.docx
ISO-NE, *First Cape Cod Resource Integration Study Redacted Non-CEII Version* (July 30, 2021), https://www.iso-ne.com/static-assets/documents/2021/07/cape-cod-resource-integration-study-report-non-ceii-final.pdf
ISO-NE, *Second Cape Cod Resource Integration Study Preliminary Results* (April 28, 2022), https://smd.iso-ne.com/operations-services/ceii/pac/2022/04/a6_second_cape_cod_resource_integration_study_preliminary_results_ceii.pdf
ISO-NE, *New Generation Curtailment Analysis—Pilot Study Preliminary Results* (April 28, 2022), https://www.iso-ne.com/static-assets/documents/2022/04/a5_new_generation_curtailment_analysis_pilot_study_preliminary_results.pdf

transmission or distribution system upgrades, is sufficient to ensure full delivery consistent with the desired level of renewable energy to be interconnected.

The New England States take the lead in identifying, selecting, and approving projects to create the needed transmission capability. For illustrative purposes, RENEW's Blueprint assumes 6,100 MWs of transmission capability to address known needs. Current studies already provide information about optimal interconnection locations,[14] which would be confirmed in the development of the transmission solicitation.

As a precursor to a multi-state transmission procurement, interested States may benefit from executing and seeking approval of a Voluntary State Agreement ("VSA") that defines the process and details of the solicitation. The VSA would include agreement on the scope of procurement and enable feasible and collaborative multi-state project evaluations. The Federal Energy Regulatory Commission ("FERC") has approved similar Transmission Study Agreements,[15] memorializing features such as project selection detail and authority, evaluation process, responsibilities, and milestones associated with New Jersey's State Agreement Approach ("SAA") process with PJM Interconnection ("PJM").[16] While voluntary approaches cannot replace the need for a holistic transmission planning process that simultaneously addresses multiple needs, they could provide a significant improvement over transmission upgrades driven by generators' willingness to pay on an individual basis, or state-by-state policy-driven upgrades.

For example, to address known grid constraints and achieve existing state targets and expected third-party needs that would allow for a more cost-effective scale of transmission project development, the illustrative procurement of 6,100 MWs of transmission would include:

- 4,800 MWs of transmission needs to reflect offshore wind goals of the Southern New England States and potential third parties, including:
  - 2,400 MW to reflect the current offshore wind goal for Massachusetts

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[14] *See* ISO-NE, *2019 Economic Study Offshore Wind Transmission Interconnection Analysis* 4 (June 17, 2020), https://www.iso-ne.com/static-assets/documents/2020/06/a4_2019_economic_study_offshore_wind_transmission_interconnection_analysis.pdf; and ISO-NE, *2050 Transmission Study: Preliminary Assumptions and Methodology for the 2050 Transmission Study Scope of Work - Revision 2* (November 17, 2021) [hereinafter 2050 Study Preliminary Assumptions], https://www.iso-ne.com/static-assets/documents/2021/12/draft_2050_transmission_planning_study_scope_of_work_for_pac_rev2_clean.pdf. For offshore wind, this includes ISO-NE having modeled injection of 31,954 MW of fixed bottom and floating offshore wind to POIs, predominantly in Massachusetts and Maine. 2050 Study Preliminary Assumptions at 4. ISO-NE subsequently modeled a sensitivity with offshore wind injections weighted toward Connecticut, resulting in a 400-mile reduction in overloaded transmission lines. ISO-NE, *2050 Transmission Study: Sensitivity Results and Solution Development Plans* (April 28, 2022) [hereinafter 2050 Study Sensitivity Results], https://www.iso-ne.com/static-assets/documents/2022/04/a14_2050_transmission_study_sensitivity_results_and_solution_development_plans.pdf.

[15] *See e.g. PJM Interconnection, L.L.C.*, 174 FERC ¶ 61,090 (2021) (order approving executed State Agreement Approach Study Agreement between PJM and the New Jersey Board of Public Utilities implementing the State Agreement Approach process).

[16] *Id.*

- 1,200 MW to reflect the current offshore wind goal for Connecticut
- 600 MW in offshore wind procurement as proposed in Rhode Island legislation;

- 600 MW in offshore wind capacity for other States and third parties;

- 1,200-MW HVDC or HVAC from Northern Maine to the ISO-NE grid
  - 600 MW to support the current Northern Maine Renewable Energy procurement[17]
  - 600 MW for other States and third parties;

- 100-MW transmission capacity to address the Sheffield-Highgate Export Interface[18] (SHEI)
  - 50 MW for Vermont to reduce SHEI backlog and curtailments
  - 50 MW on SHEI for other States and third parties.

Additional transmission capacity from Canada and/or increased transfer capability between Massachusetts and New Hampshire could also be procured to integrate these resources.

II. Responses to RFI

1. **Comment on how individual states, Participating States, or the region can best position themselves to access U.S. DOE funding or other DOE project participation options relating to transmission, including but not limited to funding, financing, technical support, and other opportunities available through the federal Infrastructure and Investment Jobs Act.**

Since 2021, the U.S. Department of Energy ("DOE") has received expanded authority and funding that could assist New England in transmission expansion. Both the Infrastructure Investment and Jobs Act of 2021 (also termed the Bipartisan Infrastructure Law, ("BIL") and the Inflation Reduction Act of 2022 ("IRA") contain new substantive provisions that could support

[17] 35-A MRSA §3210-H authorizes procurement of renewable energy or renewable energy credits equivalent to 18 percent of Maine's 2019 retail electric load. A procurement is pending. Public Utilities Commission, Request for Renewable Energy Generation and Transmission Projects Pursuant to the Northern Maine Renewable Energy Development Program, No. 2021-00369, Order (Me. P.U.C. November 29, 2021). Maine's 2019 retail electric load was 11,732,040 megawatt-hours of which 18 percent is 2,111,767 megawatt-hours, which is equivalent to 653 MWs of land-based wind operating at a 37 percent capacity factor. U.S. Energy Information Administration, Maine Electricity Profile 2019 (last visited May 20, 2022), https://www.eia.gov/electricity/state/archive/2019/maine/

[18] Upgrades to VELCO's K42 transmission line are designed replace aging equipment, reduce resistance and reactance, and benefit future interconnections. ISO-NE, *VELCO's Asset Condition Project: K42 Transmission Line Replacement* (January 26, 2022) (ISO memo supporting upgrade), https://www.iso-ne.com/static-assets/documents/2022/01/velco_asset_condition_project_k42_transmission_line_replacement.pdf. Discussion at ISO-NE's Planning Advisory Committee indicated that additional solutions to transmission constraints could further alleviate curtailment and facilitate interconnection.

planning, permitting, local community impacts, and financing major transmission in New England that would support reliable integration of clean energy. These include:

- **BIL § 40106 – Transmission facilitation program ("TFP"):** Authorizes $2.5 billion in permanent borrowing authority to loans from Treasury Department, for a DOE program to support construction of nonfederal electric transmission lines and other facilities by entering into capacity contracts and offering loans to developers. DOE could also participate in the design, operation, and ownership of projects. The section provides for public-private partnerships that would enable DOE to partner with private developers and assist with planning and permitting challenges. DOE has issued an initial RFI suggesting that the first opportunity for TFP funding will come later in 2022, for federal capacity contracts.

- **BIL § § 40101, 40103, 40107 - GRIP Grants for Resilience, Smart Grid, and R&D spending:** Provides $5 billion through 2026 for various grid hardening activities, which can include resilience improvements for transmission, available to states, tribes, and grid operators among others; $6 billion through 2026 for grid resilience RD&D, which can include transmission projects; and expands DOE's existing § 1306 grants to include advanced transmission technologies that increase transfer capability, with $3 billion available through 2026. DOE has requested comments on a combined RFI and FOA for these three programs.

- **BIL § 40109 – State Energy Program:** $500 million through 2026 to support state energy activities, including transmission planning.

- **IRA § 50101 - Transmission Facility Financing:** Provides $2 billion in direct loan authority for transmission projects, which DOE has indicated can be extended significantly as loan guarantees.

- **IRA § 50152 - Grants to Facilitate the Siting of Interstate Electricity Transmission Lines –** Provides $760 million in grant authority for states to help site transmission lines, including direct grants to affected communities.

- **IRA § 50153 - Interregional and Offshore Wind Electricity Transmission Planning, Modeling, and Analysis –** Provides $100 million to DOE through September 30, 2031, for convening stakeholder groups to conduct planning and modeling for interregional and offshore transmission.

DOE also has substantial expanded funding available for its loan program office, as well as more general funds for retooling infrastructure – which could include transmission. ACP and RENEW recommend that New England States jointly take advantage of as many programs as possible, including seeking full funding through the State Energy Program and funding of offshore transmission planning and analysis. As potential transmission corridors become clearer, the New England states should also consider applying to DOE for §50152 grants for affected communities. In addition, if it can be done quickly, the States should encourage potential owners and operators of offshore transmission to seek federal funding (such as direct grants or loan guarantees) to reduce ratepayer impacts – particularly where transmission development may precede or parallel offshore wind development. Programs such as the TFP could help to ensure that early transmission development can be financed, enabling future offshore wind projects to take advantage of coordinated, open access transmission infrastructure.

Finally, a key component of increased reliability and resilience is ensuring that renewable resources are able to interconnect with the transmission system in a timely manner. In the near term, States should consider using funds to help defray interconnection costs associated with interconnecting offshore wind generation to help ensure that shovel ready projects get built. Interconnection facilities for offshore wind are also typically eligible for the 30 percent Investment Tax Credit under § 48 of the Internal Revenue Code, which now has certainty for the next decade through the IRA.

2. **Comment on ways to minimize adverse impacts to ratepayers including, but not limited to, risk sharing, ownership and/or contracting structures including cost caps, modular designs, cost sharing, etc.**

Development of transmission and renewable energy generation should be aligned to mitigate risks for ratepayers and project developers. Procuring transmission with awareness of future planned generation can reduce risks of unpredictable costs and timelines to upgrade the existing grid that result from relying upon generators to fund individual upgrades. Risk can be mitigated further through transmission procurements that include cost-control mechanisms to ensure timely project completion and synchronization with generation project schedules to avoid building a "bridge to nowhere". The New England States should adopt a forward looking, proactive approach to construct high-quality transmission resources *in advance of the construction of specific generation projects utilizing such transmission resources*, with a particular focus on offshore wind. Past examples include (1) ERCOT's CREZ approach,[19] (2) the Tehachapi Renewable Transmission Project,[20] (3) SPP's Highway-Byway/Priority Projects,[21] and (4) MISO's MVP projects.[22] Each of these proactive efforts have ultimately provided substantial benefits to customers.

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[19] *Transmission & CREZ Fact Sheet*, Powering Texas (last visited Sept. 28, 2021), *available at*: https://poweringtexas.com/wp-content/uploads/2018/12/Transmission-and-CREZ-Fact-Sheet.pdf.

[20] *See* Southern California Edison, *Tehachapi Renewable Transmission Project* (last visited Sept. 28, 2021), available at: https://www.sce.com/about-us/reliability/upgrading-transmission/TRTP-4-11.

[21] *See* T. Wilner, *FERC Approves SPP's 'Highway/Byway' Cost Allocation*, Windpower Monthly (June 28, 2010), available at: https://www.windpowermonthly.com/article/1012826/ferc-approves-spps-highway-byway-cost-allocation.

[22] *See e.g.* Midcontinent Independent System Operator, *MTEP14 MVP Triennial Review*, (Sept. 2014) available at https://cdn.misoenergy.org/MTEP14%20MVP%20Triennial%20Review%20Report117061.pdf , and *MTEP17MVP Triennial Review*, (Sep. 2017), available at https://cdn.misoenergy.org/MTEP14%20MVP%20Triennial%20Review%20Report117061.pdf.

The New England States have extensive experience with running successful and competitive solicitations for clean generation projects. Future transmission procurement could follow the same general principles and process, whereby the State (or States), which have identified the need for transmission, issue an RFP for transmission solutions. Bidders would be responsible for developing responses to these needs and demonstrating that proposed solutions meet desired outcomes. They would be responsible for the interconnection process and bear the risk of obtaining approvals from ISO-NE, just like generators today. Transmission developers would enter into a Transmission Service Agreement with electric distribution companies ("EDCs") that would be approved by FERC.

In turn, the EDCs would recover the cost of the new transmission through non-bypassable state-approved charges collected from their end use customers. Several New England States have laws specific to EDC recovery of upgrades necessary to support clean energy procurement programs. The States, through a competitive solicitation, could require developers commit to significant and effective cost containment requirements that protect consumers from cost overruns and other risks. As the region looks towards making major transmission investments, it is in ratepayers' interest to ensure that the network is built as cost effectively as possible, which competition can help do.

Recent New England offshore wind RFPs allow EDCs to reduce the amount paid for any energy and/or renewable energy credits ("RECs") under the Power Purchase Agreement ("PPA") to reflect any costs related to network upgrades and/or the interconnection of the project to the transmission system of the interconnecting utility that are collected under the ISO-NE Tariff or ISO-NE rules.

For example, the upcoming Rhode Island RFP for offshore wind contemplates that transmission could be procured to support multiple future projects. Even if the Rhode Island RFP results in the selection of project using a long generator lead line, that project will have flexibility built into its PPA that could accommodate or utilize state procured transmission.[23]

[23] The Narragansett Electric Company, Draft Request for Proposals for Long-Term Contracts for Offshore Wind Energy Pursuant to the Affordable Clean Energy Security Act R.I. Gen. Laws Chapter 39-31, Rhode Island Public Utilities Commission Docket No. 22-22-EL (September 6, 2022) (RFP Section 2.2.3.4, requires amount paid for any energy and/or RECs under the PPA to be reduced to reflect any costs related to network upgrades and/or the interconnection of the project to the transmission system of the interconnecting utility that are collected under the ISO-NE Tariff or ISO-NE rules; and RFP Section 2.2.4.4. requires, in the event future third-party offshore wind developers request interconnection service on the bidder's Interconnection Customer Interconnection Facilities, the bidder will negotiate in good faith and use commercially reasonable best efforts to enter into a voluntary agreement with such third-party offshore wind developers).

3. **Identify the advantages and disadvantages of utilizing different types of transmission lines, like alternating current (AC) and direct current (DC) options for transmission lines and transmission solutions. Should 1200MW/525kV HVDC lines be a preferred standard in any potential procurement involving offshore transmission lines?**

Establishing a preferred regional standard for high-capacity HVDC transmission will maintain consistency with current transmission system operations while enabling future expansion to realize economies of scale. HVDC transmission cables with capacities of 400kV and 525kV are currently being deployed in Europe and can transmit 2,000 MW or more. Utilizing these high-capacity cables will enable optimal use of limited cable routes, will facilitate efficient utilization of accessible points of interconnection ("POI") and will minimize overall marine cabling requirements.

Planning and operating procedures used by ISO-NE limit the ability to fully utilize the capability of these higher capacity transmission lines at present, but application of established operational practices to offshore wind, minor modifications to planning and operating procedures, targeted system upgrades, and new technologies for networking HVDC lines could each facilitate greater utilization of these higher-capacity HVDC transmission lines going forward, making it beneficial to select a regional standard today that keeps this future use in mind.

The New England States should consider working with ISO-NE to reevaluate and update their single contingency loss of source limit placed on new interconnections. ISO-NE restricts new interconnections to a 1,200-MW single contingency loss of source limit to protect neighboring control areas from the impact of losing too much supply at once.[24] Given the scale at which new clean energy development will be taking place, the region should explore all options to enable building fewer, larger transmission facilities to improve cost effectiveness while reducing environmental impacts. So long as offshore wind continues to interconnect using radial cables, the existing 1,200-MW limit would, for example, require at least seven separate undersea circuits to interconnect 8,000 MW of offshore wind to southeast New England.[25] If the 1,200-MW limit on new interconnections were raised to 1,600 MW, five undersea circuits could be sufficient to interconnect 8,000 MW. Allowing for these larger interconnections could allow offshore wind projects to capture further economies of scale, reduce total costs to consumers, and reduce

[24] ISO New England Planning Procedure No. 5-6 Interconnection Planning Procedure for Generation And Elective Transmission Upgrades, Appendix A "Interconnection Design – Loss-of-Source: The interconnection shall be designed such that, with all lines initially in service, there is no normal design contingency or common mode transmission system, station, or internal plant failure which could result in a net loss of more than 1,200 MW of resources, except in the case of an increase of no more than 2% above the maximum capability, in place at the time of the original incorporation of this provision into PP5-6 in June 2016, of an existing facility that already corresponded to a loss of more than 1,200 MW of resource for a normal design contingency."

[25] For example, when ISO performed the first cluster study for interconnecting Northern Maine wind generation, the cluster size was limited to 1,200 MW despite approximately 2,000 MW of wind being in the queue in that area at the time. When ISO evaluated the transmission needs for interconnecting offshore wind as part of the NESCOE 2019 offshore wind economic study, each undersea circuit bringing power to shore was limited to a maximum of 1,200 MW.

environmental impact to the region.[26] And, as discussed below, given typical offshore wind capacity factors, a line capable of delivering 1,600 MW would likely not be doing so in many market intervals.

Despite the restriction placed on new interconnections, ISO-New England operates its system with three existing resources that exceed the 1,200 MW single contingency source loss limit. Two of these are generators slightly larger than 1,200 MW; the other is the Phase I/II tie line between ISO-NE and Hydro Quebec, which is rated at 2,000 MW.[27] These three resources are regularly allowed to supply more than 1,200 MW of energy to New England. Phase I/II, in particular, is frequently allowed to supply well over 1,200 MW. ISO coordinates its operating plan with NYISO and PJM to maximize the use of Phase I/II while ensuring reliability is not compromised.[28] The following chart shows the hourly scheduled import on Phase I/II for the month of August 2022.[29] Phase I/II was scheduled to import more than 1,200 MWh in every hour of this particular month. In just over sixty percent of hours Phase I/II was scheduled to import 1,600 MWh or more, and in over ninety six percent of hours it was scheduled to import 1,400 MWh or more.

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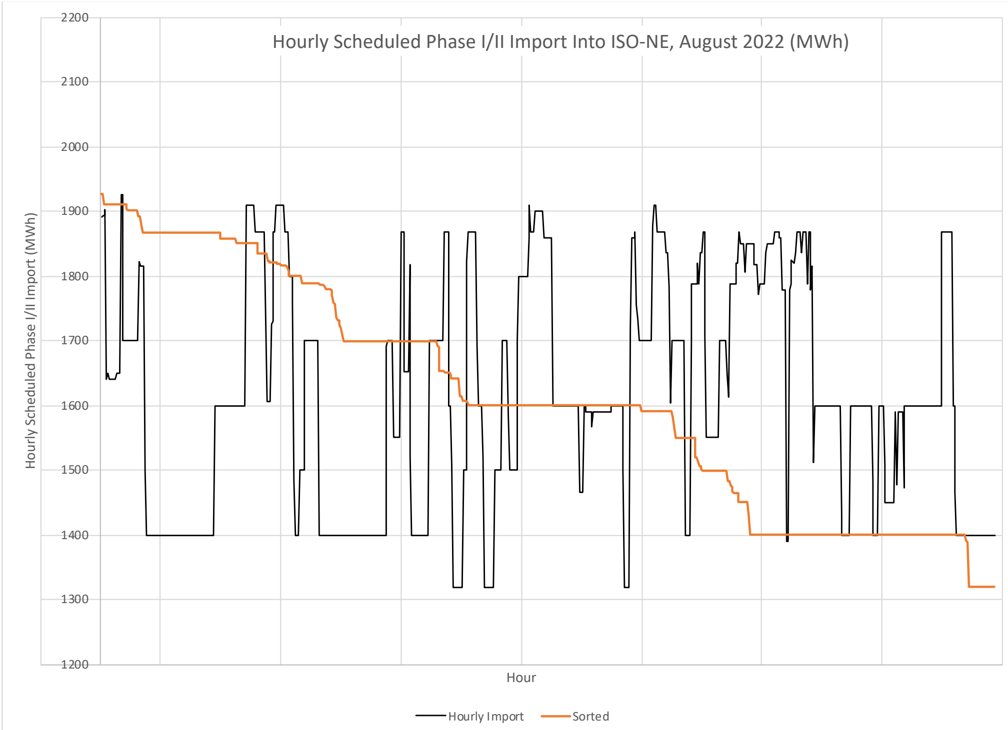
[26] *See e.g.,* Dr. Biljana Stojkovska, presentation to New England Energy Vision Transmission Planning Technical Forum (February 2, 2021), https://newenglandenergyvision.com/transmission-planning). (Optimized transmission planning in the United Kingdom would in some cases utilize 1,500 to 1,800-MW HVDC cables to interconnect offshore wind. Utilizing these larger circuits resulted in lower costs and reduced environmental impact by reducing the number of circuits needed).

[27] According to section 2.1 of the ISO New England 2022-2031 Forecast Report of Capacity, Energy, Loads, and Transmission ("CELT"), Millstone 3 has a nameplate rating of 1,253 MW while Seabrook has a nameplate rating of 1,309 MW. PP5-6 was even revised in 2020 to allow existing resources over 1,200 MW to increase their capability by no more than 2% in order to allow Millstone 3 to increase its interconnection capability from 1245 MW to 1262 MW.*See* ISO-NE, Reliability Committee agenda item 9.1 (March 17, 2020), https://www.iso-ne.com/static-assets/documents/2020/03/a09.1_rc_2020_03_17_PP5_6_revs.zip and the associated Queue Position 930).

[28] ISO New England Inc. Transmission, Markets, and Services Tariff, Attachment G Procedure to Protect for the Loss of Phase II Imports, describes the process used by ISO New England, New York ISO, and PJM to monitor their respective systems and provide the data required by ISO New England to calculate import limits on the Phase I/II high-voltage direct-current interconnection between it and Hydro-Québec. The import limit placed on Phase I/II in operations is, according to this procedure, based upon real time and forecasted NYISO and PJM reactive conditions.

[29] Real-Time Actual Scheduled Interchange data for October 24, 2022, available at https://www.iso-ne.com/isoexpress/web/reports/grid/-/tree/interchange.



Based on the annual reports ISO publishes on external interface metered data, Phase I/II operated above 1,200 MW in approximately 93 percent of hours in 2021.[30] Clearly, the region and its neighboring systems are regularly able to manage a loss of source in New England that exceeds 1,200 MW, even if this is not possible in all hours.

In the near term, given the increasing frequency with which ISO-NE has been able to reliably allow existing resources to operate above 1,200 MW, the region should revisit the need to restrict new interconnections to 1,200 MW. Any new resource over 1,200 MW could be subjected to the same operational limitations placed on existing resources over 1,200 MW to maintain system reliability. Even with such operational restrictions, it may still be financially and environmentally advantageous to the region to be able to interconnect new resources using fewer radial transmission lines.

On a longer-term basis, New England should work with its neighbors to determine what upgrades or operating procedures would be required to raise the 1,200-MW limit under all normal conditions. If more cost-effective development of new offshore wind, imports, and onshore wind and solar resources can be achieved by raising this limit, resulting transmission investments in New England or neighboring regions may lower overall costs and environmental impact for the region in the years ahead. Indeed, planning for larger offshore wind infrastructure (and fewer cable landing points and POIs) today, on the assumption that this limit can safely be

[30] External Interface Metered Data available at https://www.iso-ne.com/isoexpress/web/reports/grid/-/tree/external-interface-metered-data.

raised in the future, would be the most advantageous approach for the region, even if the infrastructure might begin with limited operations at first. The time and expense of developing additional offshore transmission infrastructure – which includes years-ahead procurement of components, and contracting for highly specialized cable-laying vessels – means that the New England States should not merely take current system rules as they find them, but should explore future enhancements.

Regardless of what single contingency source loss limit is planned for, the States should also explore with ISO-NE changes to its planning and operating procedures that would allow more generation to be connected to new radial transmission lines than the source loss limit itself. Connecting more MW of nameplate variable generation and storage to a radial transmission line than the source loss limit can better utilize the line's capability, and result in improved overall economics and operability. For example, if 1,200 MW of onshore wind with a 45 percent capacity factor connects to a radial transmission line, the line will be loaded on average at just 540 MW, forty five percent of the current source loss limit. By connecting a combination of onshore wind, solar, and batteries with aggregate nameplate capability in excess of 1,200 MW to that same line, the line can be loaded on average at a significantly higher level - even if each individual technology operates at no more than a forty five percent capacity factor and the aggregate injection from these resources never exceeds 1,200 MW. This improves the economics by spreading the cost of the transmission infrastructure over more megawatt-hours, and providing the system with a smoother, more stable source of energy. However, ISO-NE identified at its September 21, 2022, meeting of the Planning Advisory Committee that it would not currently allow more than 1,200 MW of generation (e.g., wind, solar, and storage) to interconnect to a radial line. The reasoning was that the transmission line itself might have a thermal rating in excess of 1,200 MW, and since the 1,200 MW loss of source limit would not be reflected as an operational limit on the radial transmission line, the ISO would have no way to limit the generators' combined output to 1,200 MW in operations. The possible benefits in terms of improved economics, rapid deployment of clean energy resources, and reduced environmental impact, appear to make this current operational limitation one that would be worth revisiting and developing an operational solution that would enable this type of optimized operation.

Utilizing networked HVDC transmission with advanced HVDC controls, rather than using solely radial connections, would enable the interconnection of larger offshore wind resources. In a networked system, no single contingency would result in the loss of all generation. Modern HVDC solutions planned for European offshore wind farms can reroute power instantaneously in the event of a fault, just as the current AC transmission network does, enabling offshore wind power to be redirected to other networked HVDC transmission lines in the event of a cable failure. When a cable to shore is lost, the network is reconfigured instantaneously to redirect power in a matter of milliseconds, sending power to shore at other injection points and avoiding loss of power that had been carried by the failed cable.

Due to the variable nature of offshore wind generation, most of the time the remaining networked cables would be capable of picking up all of the offshore wind previously injected by the failed cable. For example, in windy conditions with offshore wind producing 75 percent of its rated capability, three 2,000 MW networked cables used to interconnect 6 GW of offshore wind generation would each be injecting 1,500 MW onto the grid. If one cable was lost, the 1,500 MW carried by the failed cable would be instantaneously re-routed to utilize 1,000 MW of available capacity on the remaining two cables, which would then each deliver 2,000 MW to the grid. The cable loss would thus result in an instantaneous loss of only 500 MWs to the grid – well under 1,200 MW. During the limited set of hours when all wind farms served by the network were capable of operating at full or near-full output, they could be dispatched down to ensure no single contingency would result in the source loss limit being exceeded.

Thus, HVDC cables with capacities in excess of 1,200 MW could be utilized in conjunction with networked HVDC interlinks between offshore converter stations and HVDC circuit breakers. Until offshore HVDC interlinks are built, higher capacity, better-coordinated radial cables to shore could be limited to carrying no more than the loss of source limit. Once offshore HVDC interlinks are installed, the additional capacity of higher voltage HVDC cables to shore could be utilized.

Market development of HVDC switchgear technology is currently focused on 525kV. Thus, thus setting a standard for 2,000 MW/525kV HVDC transmission cables now, to be initially operated at 1,200 MW/525kV, would enable New England to create a future-proof foundation for development of a networked ocean grid while remaining within current operational parameters.

4. **Comment on whether certain projects should be prioritized and why. For example, should a HVDC offshore project that eliminates the need for major land-based upgrades be prioritized over another HVDC offshore project that does not eliminate such upgrades.**

Given the RFI's offshore wind focus, the onshore upgrade needs should certainly be a factor in considering projects. Overall cost, environmental impact, likelihood of siting approval, ability to acquire all required rights-of-way ("ROW"), and efficient use of ROW to ensure one transmission project is not blocking future transmission project needs should all be included in the evaluation of projects. In short, projects that are consistent with future needs and which preserve optionality should be prioritized.

5. **Identify any regional or interregional benefits or challenges presented by the possibility of using HVDC lines to assist in transmission system restoration following a load shedding or other emergency event and particularly from using the black start capabilities of HVDC lines in the event of a blackout.**

HVDC is an appropriate option to consider for moving large amounts of power long distances and circumvent congestion (i.e., from Northern Maine to Boston) but the specific situation will dictate when this is more cost effective than AC system upgrades. AC upgrades are likely more cost effective initially, but as offshore wind penetration increases, HVDC is likely to make sense in many cases.[31] HVDC is good for getting power from Point A to Point B, but generation cannot be added or withdrawn at multiple locations along the way.

However, HVDC, particularly using advanced converters, can provide black start capability to the alternating current grid.[32] This capability is not typically accounted for in transmission planning or cost allocation. The New England states should consider non-traditional (but quantifiable) transmission benefits such as black start capability in evaluating how to expand the regional grid to maximize net benefits.

6. **Identify the benefits and/or challenges presented by using land based HVDC lines or other infrastructure to increase the integration of renewable energy (other than offshore wind) in New England to balance injections of offshore wind.**

The States should pursue an all-of-the-above transmission strategy. Adopting a range of transmission solutions will ensure that enough clean energy resources can be developed to meet regional needs; additionally, diversity in terms of technology and geography among those resources will provide a dependable supply of clean energy to the region.

Even at today's level of renewable energy development in Northern New England, limited transmission capacity from New Hampshire and Vermont to Massachusetts has created separation between zones and limited development of new resources in Northern New England. HVDC transmission between New Hampshire and Massachusetts could be one approach to alleviate these constraints.

7. **Comment on the region's ability to use offshore HVDC transmission lines to facilitate interregional transmission in the future.**

It will likely prove challenging (or, at a minimum, extremely expensive) to mesh or otherwise integrate offshore transmission facilities if they are developed separately and use differing technologies and voltage levels. To the extent possible, the New England States should attempt to standardize their requirements for offshore transmission and interconnection facilities so that facilities will be as interoperable as possible. Additionally, as New York is moving towards a "mesh-ready" approach, the New England states should coordinate with New York and consider adoption of similar technology standards to support future interregional transfers. Given the proximity of many of the Southern New England and New York Bight lease areas, coordination on transmission could prove highly beneficial to both regions – but this requires up-front collaboration.

[31] *See* NEPOOL scenario analysis study, *supra* note 13.

[32] *See e.g.* Garciarivas et al, VSC-HVDC and its Applications for Black Start Restoration Processes, Applied Sciences 11(12):5648 (2022), https://www.researchgate.net/publication/352520426_VSC-HVDC_and_its_Applications_for_Black_Start_Restoration_Processes ; Jiang-Hafner et al, HVDC with Voltage Source Converters: A Powerful Standby Black Start Facility (2008), https://library.e.abb.com/public/c1f12e6192fdee7ac1257450005cb8b1/08TD0083.pdf

8. **Comment on any just-transition, environmental justice, equity, and workforce development considerations or opportunities presented by the transmission system buildout and how these policy priorities are centered in decisions to develop future infrastructure.**

The New England states should evaluate whether cost-effective integration of offshore wind could enable more rapid closure of existing fossil fueled power plants (or reduced usage, in the case of peaker plants). This can help to reduce local emissions impacts, which are often concentrated in historically affected communities.

9. **Comment on how to develop transmission solutions that maximize the reliability and economic benefits of regional clean energy resources.**

Maximizing value of New England's transmission system: The scale of investment needed to meet the region's decarbonization goals is enormous, as is the scale of the transmission facilities needed to deliver clean energy consistent with those goals. While significant attention is given to the (in)efficiency of regional markets in the NEPOOL stakeholder process, somewhat less attention is given to the efficient use of the region's investment in its transmission facilities. Opportunities exist to maximize the benefits of the region's transmission system.

First, New England should generally consider planning for a larger number of high-voltage transmission facilities. The backbone of New England's AC transmission system is operated at 345 kV, a lower voltage than in many other parts of the country. Higher voltage lines can move more power over longer distances. Consequently, New England is able to move less power over long distances than if a higher voltage were used. Though higher voltages have in the past raised concerns over siting impacts due to taller structures and higher up-front costs, the options before us to achieve the States' goals are either going to a higher voltage or significantly increasing the number of new transmission lines needed which also raises visual impact concerns. For lower overall cost and siting impact, a higher voltage may now be the least cost and lowest-impact option and should be fully considered.

Second, New England should proactively plan transmission. New England's failure over a decade ago to plan and develop onshore transmission upgrades that would have allowed for the interconnection of Maine land-based wind, in addition to meeting system reliability needs, through the Maine Power Reliability Project (MPRP) has significantly curbed development of that low-cost renewable resource for the entire region and serves as a cautionary tale.[33] Future

[33] As part of the MPRP, two new transmission lines were built between the Orrington substation in Northern Maine and the Coopers Mills substation in central Maine (previously known as Maxcys). One was a 345 kV transmission line (with a connection mid-way at Albion). The second was a 115 kV transmission line (Section 254). The *CMP Maine Power Reliability Program Proposed Application Analysis Final Draft Report* presented to the NEPOOL Reliability Committee on June 17, 2008, noted that the 115 kV line would be constructed to 345 kV standards and initially operated at 115 kV. However, the incremental cost of 345 kV construction for this line was ultimately determined to be unnecessary for maintaining reliability, and the line was built to 115 kV standards, precluding the

transmission development, whether planned for reliability, public policy, economic, or interconnection needs, should be future-proofed to a reasonable extent, by sizing the infrastructure in recognition of expected future needs and designing the infrastructure in a way that maximizes the ability of future construction to use the same rights of way or make connections to the planned facilities.

Third, siloed transmission processes often fail to identify "right-sizing" opportunities to meet future needs and near term needs simultaneously. When upgrades to address aging infrastructure and reliability upgrades to address specific reliability needs are planned, the current process is focused on resolving only the identified needs from that specific planning process. Often it would be possible to modify the planned upgrades slightly, at a relatively modest increased initial cost, to improve system operability and long-term cost effectiveness. This increased initial cost is frequently far less than the cost of achieving those same benefits through a subsequent standalone system upgrade. Examples include utilizing a larger conductor, utilizing bundled conductors, building a line to a higher voltage standard, or installing a synchronous condenser rather than a STATCOM. Benefits could include increasing transfer limits on the system, reducing congestion and curtailment, reducing the cost of future generator interconnections, reducing land-use impacts by minimizing the number of transmission facilities needed, and reducing long-term operations and maintenance costs.

Fourth, the New England States should deploy Grid-Enhancing Technologies ("GET") where appropriate. GETs, also referred to as advanced transmission technologies, are hardware and software solutions that increase the capacity, efficiency, and reliability of the transmission grid. These tools are already used in countries in Europe and South America and in Australia, where regulatory regimes reward efficiency in the bulk power system. In the US, adoption has been slower due to a lack of incentives for deployment. GETs include Advanced Power Flow Controls ("APFC") which are power electronics-based Flexible AC Transmission System ("FACTS") devices that actively balance flows on transmission lines by pushing power off overloaded lines or pulling it onto under-utilized lines; Dynamic Line Ratings, software and hardware which identifies the real-time capacity of transmission lines; and Topology Optimization, software that identifies ways to reroute power flow around congested areas while maintaining reliability.

ability to operate the line at a higher voltage in the future. In its October 2, 2009, Transmission Cost Allocation letter regarding this line, ISO noted that operating the line at the higher voltage would improve system performance, but with the projected system conditions over the ten-year planning horizon there was not strictly a reliability need for this given "current planning criteria", which ignored the impact of generators in the interconnection queue. Since that time, the Orrington-South constraint has become one of the most frequently congested interfaces in New England. 2021 Annual Markets Report, 120, *supra* note 11. The cost of adding a new 345 kV line from Orrington to Coopers Mills now would eclipse the incremental cost that would have been incurred had the MPRP line originally been built to 345 kV standards. Further, the valuable and limited right of way used for the construction of the 115 kV line is no longer available for locating a new 345 kV transmission line, making siting such a new line challenging, regardless of the costs.

GETs can increase the operational capacity and utilization of the onshore grid while minimizing adverse impacts to ratepayers. There is a growing body of literature showing that GETs help increase grid reliability and reduce overall grid costs, and improve grid utilization.[34] For example, in Texas in 2006 AEP avoided a $20 million upgrade by installing real-time line ratings on a 138 kV transmission line, avoiding a stranded asset.[35] Other case studies show that GETs could cut congestion costs by 23-43% on their own, even before "traditional" wires upgrades are considered.[36] However, transmission planners often focus exclusively on reliability needs with traditional line construction solutions, deprioritizing evaluation of alternatives and incorporation of economic benefits from congestion reduction with GETs. When accounted for properly in planning, GETs can ensure that the highest value transmission infrastructure is built by resolving constraints that do not require new infrastructure. New England's transmission needs require both better utilization of existing infrastructure as well as new lines, and the region should address both needs.

Additionally, GETs can provide a bridge solution while new infrastructure is built, allowing new offshore generators to connect and deliver before major new transmission infrastructure is complete. GETs offer additional value because they are scalable to address evolving grid needs. GETs, after being installed, can be scaled up or also be redeployed elsewhere on the grid given updated information and changing contexts. For example, APFC devices are modular deployments of multiple devices that can be installed in phases to address immediate, then medium, and ultimately long-term needs. Similarly, many DLR sensors and systems can be redeployed as grid needs change.

<u>Regional deployment of energy storage:</u> The inclusion of energy storage resources could significantly increase the benefits to New England ratepayers. Specifically, energy storage can provide complementary and additive benefits to a larger procurement and can be done in a cost-effective way.

Storage can provide many benefits in the context of an investment in transmission infrastructure:

a) Avoids curtailment of variable renewable generation by charging when renewable output is greater than the line capacity and discharging when line capacity is available. This curtailment avoidance provides greater utilization of the transmission line and allows for the oversizing of renewable energy generation relative to the size of the line, allowing for the delivery of more renewable energy with greater consistency.

[34] *See* Working for Advanced Transmission Technologies Coalition Resource Library, https://watt-transmission.org/resources-2/
[35] *See* WATT PUCT filing at 5 (Dec. 30, 2021), https://watt-transmission.org/wp-content/uploads/2022/04/WATT-Coalition-PUCT-Comments.pdf.
[36] U.S. Department of Energy, Grid-Enhancing Technologies (February 2022), https://www.energy.gov/sites/default/files/2022-04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf

b) Facilitates the delivery of renewable power during the most valuable hours. By charging when renewable energy is plentiful and discharging during hours of high-cost and high-emissions power (e.g. summer evening peaks), energy storage can help the transmission investment deliver the most ratepayer benefits and carbon reductions.

c) Provides the opportunity for cost savings in N-1 contingency planning by allowing greater utilization of the transmission infrastructure. N-1 contingency planning requires adequate headroom in transmission line capacity to ensure reliability if a single asset comes offline, and transmission investments must be sized accordingly. Energy storage systems can reduce the amount of unused headroom to increase the effective utilization of the line.[37]

Energy storage resources do not need to be paired directly with renewable energy generation facilities or sited at the point of interconnection to provide these benefits. Standalone and co-located storage can compete to provide the best outcomes for ratepayers. For example, while some co-located storage can be competitive because it has a reduced interconnection cost, stand-alone energy storage projects can optimize energy delivery from multiple renewable energy facilities and can be sited in locations that maximize locational value due to its small footprint. Allowing all types and configurations of energy projects to bid into this procurement will provide evaluators more options to compare and select the highest value combination of projects. Energy storage is increasingly cost-competitive, particularly because of the recent passage of the Inflation Reduction Act, which provides significant federal investment in energy storage through the Investment Tax Credit. Providing a process for energy storage developers to participate in this procurement would allow the New England states to leverage this federal investment and further reduce the cost of the procurement to ratepayers.

[37] *See* Ralph Masiello, *Market Design for Congestion Relief With Energy Storag*e, https://quanta-technology.com/wp-content/uploads/2020/05/Emerging-Technologies-White-Paper-Energy-Storage_final3.pdf.

<u>Comments on the Draft MOWIP:</u>

10. **Identify potential Points of Interconnection (POIs) in the ISO-NE control area for renewable energy resources, including offshore wind. What are the benefits and weaknesses associated with each identified POI? To the extent your comments rely on any published ISO-NE study, please cite accordingly.**

An RFP for transmission solutions should not limit developers to predetermined POIs. Participants should have the ability to develop solutions to possible congestion, including using market-based solutions like storage or demand response, as well as transmission solutions that might proceed through the Elective Transmission Upgrade (ETU) process.

Developers have access to ISO-NE's long list of studies from the past decade-plus identifying current and anticipated transmission constraints. These studies also give the States the information they need to decide whether to issue an RFP for transmission to meet the objectives proposed by ISO-NE of reducing or eliminating congestion related to offshore wind resources. The States could also sponsor an ETU request that describes a specific transmission facility or an "objective" upgrade where ISO-NE would identify the facilities needed to achieve the objective. During the development of the interconnection procedure revisions in 2016-2017 that resulted in the creation of the cluster study procedures, RENEW encouraged ISO-NE to provide information on the effectiveness of ETU solutions for how many MW could be interconnected, be made deliverable, and what additional supporting upgrades would be required. In this context, the additional information provided by ISO-NE is helpful, as it can potentially encourage one of more States to pursue a transmission solicitation to achieve policy requirements.

In the economic studies of offshore wind integration performed at the request of NESCOE and Anbaric in 2019/2020, ISO-NE identified that the following quantities of offshore wind could be interconnected at certain points along the southeast coast without the need for major onshore transmission infrastructure upgrades:[38]

- Cape Cod (Bourne/Barnstable) (MA): 2,400 MW
- Brayton Point (MA): 1,600 MW
- Montville (CT): 800 MW
- Kent County/Davisville (RI): 1,000 MW
- Mystic (MA): 1,200 MW

Adding much more than this quantity of new generation at these locations (absent significant new onshore transmission upgrades or other congestion mitigation solutions) would result in considerable congestion and curtailment for the new offshore wind resources.

[38] *See* ISO-NE, *2019 Economic Study: Offshore Wind Integration* 6, *supra* note 13.

As ISO-NE has performed the first and second cluster interconnection studies for offshore wind generation on Cape Cod, it has identified the system upgrades that would be required in order to allow *all* 4 GWs of offshore wind proposing to interconnect to the Cape area to operate at full output simultaneously, under all conditions.[39] ISO's decision to study all 4 GWs running at full output is not in accordance with the currently effective interconnection procedures which allow for generators to dispatch against (i.e., compete with) each other.[40] Requiring current and future interconnection customers to meet a higher burden that has never been required of prior interconnection customers can place added transmission upgrade costs on these projects.

There are legitimate concerns related to congestion and possible curtailment of offshore wind resources. These issues could arise if the current interconnection procedures were followed and offshore wind projects interconnected without further congestion-relieving upgrades to ensure deliverability. However, it would be inappropriate and ineffective to attempt to resolve these systemic issues solely through the generator interconnection process. Requiring interconnection customers to resolve these congestion concerns – many of which reflect preexisting system conditions – does not provide space for other solutions. These could include market-based solutions such as storage or demand response, as well as transmission solutions that might proceed through the ETU, Market Efficiency Transmission Upgrade, or Public Policy Transmission Upgrade processes. Solutions could also include the contemplated Longer Term Transmission Planning process that is on the ISO's Annual Work Plan, or (in the longer run) adoption of a New England process for Long-Term Regional Transmission Planning as described in FERC's Notice of Proposed Rulemaking in Docket RM21-17.

11. **Similarly, comment on whether there are benefits to integrating offshore wind deeper into the region's transmission system rather than simply interconnecting at the nearest landfall (*e.g.*, using rivers to run HVDC lines further into the interior of New England). If there are enough benefits to make this approach feasible, please comment on any obstacles, barriers, or issues that Participating States should be aware of regarding such an approach.**

As noted in response to Question 10, *supra*, there are challenges with connecting too much offshore wind at coastal POIs with current grid topology. Some projects will likely either need to find other POIs, or more network upgrades will be needed. The New England States and ISO-NE must strike an appropriate balance.

[39] 1600 MW studied under the serial interconnection process, 1200 MW studied under the first Cape Cod cluster study, and 1200 MW in the second Cape Cod Cluster Study.
[40] *See* ISO New England, OATT Schedule 22 and PP5-6 Section 1.1 (Network Capability Interconnection Standard definition).

Past ISO-NE studies and state procurements[41] provide a clear picture of the most pressing transmission bottlenecks and potential solutions, which can be used as the foundation for an initial competitive procurement.

States' selection criteria should consider how proposals meet transmission needs at the lowest lifecycle cost (and lowest net delivered cost of energy) while upholding reliability, increasing resilience, maximizing future renewable energy development, and minimizing environmental and environmental justice impacts. Criteria should include the benefits the selected transmission projects will have on existing generation, particularly generation that helps meet climate goals, and its capability to provide for future transmission expansion that might be needed. Transmission project selection could be coordinated with generation procurement processes to maximize the efficiency and use of the transmission facility.

12. **Identify likely offshore corridor options for transmission lines. Please comment on the potential for such corridor options, include size of the corridor footprint and potential number of cables that can be accommodated, to minimize the number of lines and associated siting and environmental disturbance needed to integrate offshore wind resource. For any offshore corridor identified, please indicate how the corridor avoids or minimizes disturbances to marine resources identified in the applicable plan, including the Connecticut Blue Plan and the Massachusetts Ocean Management Plan;**

The requested information is best provided by developers in response to an RFP. Developers will be competing on environmental benefits in a competitive solicitation. States' selection criteria should consider how proposals meet transmission needs at the lowest lifecycle cost while upholding reliability, increasing resilience, maximizing future renewable energy development, and minimizing environmental impacts.

13. **Identify strategies to optimize for future interconnection between offshore converters, either AC or DC, to permit power flow between converters to facilitate the transmission of power from offshore to multiple POIs as needed. Similarly, comment on the ability of offshore converters from competing manufacturers to communicate with one another in this future case;**

As noted above, early coordination is essential. Adoption of a regional or inter-regional technology and voltage standard will assist in ensuring future interoperability.

14. **Comment on the benefits and/or weaknesses of different ownership structures, such as a consortia of developers with transmission owners or use of U.S. DOE participation as**

[41] State renewable energy procurements have required bidders to identify project-related transmission upgrades. *See e.g.*, Massachusetts Department of Energy Resources, *Request for Proposals for Long-Term Contracts for Offshore Wind Energy Projects* Appendix I (May 7, 2021) (bidders required to submit a Deliverability Constraint Analysis), https://macleanenergy.files.wordpress.com/2021/05/83c3-rfp-and-appendices-final.pdf

an anchor tenant through its authorizations in the federal Infrastructure and Investment Jobs Act, for new offshore transmission lines;

As noted above, DOE funding through the Transmission Facilitation Program (TFP) or other recently-adopted authorities could be valuable in reducing the up-front costs of transmission, and enabling coordinated transmission development to precede offshore wind project completion in some cases. The principal concern, given the need for rapid planning, siting, and permitting, is whether Federal involvement creates the risk of additional complication or delay. DOE has indicated that it does not view a federal capacity contract through the TFP as requiring an Environmental Impact Statement under the National Environmental Policy Act; if any DOE funding requires an ("EIS"), it should be as closely integrated as possible with environmental reviews by the Bureau of Ocean Energy Management – including coordination through the Federal Permitting Improvement Steering Council where possible.

15. **Comment on cost allocation mechanisms that would prevent cost-shifting between the states based on their policy goals and ensure that local and regional benefits remain quantifiably distinct. How should any future potential procurement identify and distinguish local, regional, and state-specific benefits (e.g., reliability) such that ratepayers only pay for services that they benefit from?**

RENEW's Blueprint includes a framework in which the States would remain in control over cost allocation. It provides a process including the determination of the transmission need, the criteria for evaluating and selecting the proposed projects, and the establishment of cost allocation between parties if multiple States participate in the solicitation. The transmission developers would have the burden of demonstrating that their proposed solutions meet the States' identified needs, and would bear the risks associated with the ISO-NE interconnection process.[42]

The New England States can utilize existing regulatory pathways to conduct an efficient regional public policy transmission solicitation. In return, they would receive dedicated transmission capability, providing certainty in the interconnection of the required public policy resources and enabling third party purchases of renewable energy.

Cost allocation is also an essential aspect of getting transmission built. Workable cost allocation methodologies rely on simple "beneficiary pays" principles, ensuring the costs are allocated roughly commensurate with the benefits received. Customers' transmission costs should reflect the benefits received. The recommended cost allocation approach described below and elaborated in the RENEW Blueprint (attached) applies cost responsibility in proportion to transmission capability created in support of State policy needs, accounting for avoided costs,

[42] ISO-NE study results are not required for states to select a transmission solution. As with generator interconnections, ISO-NE will determine the upgrades required, if necessary, to interconnect the transmission solution while maintaining a reliable grid. Transmission developers submitting proposals before these results are known bear the risk that additional interconnection upgrades are identified and would be responsible for these costs.

enabling third party transactions, and preventing excessive cost-shifting to any State that does not request creation of new transmission capability.

As a first step, existing allocation methods could be applied to apportion avoided costs. If any of the identified public-policy transmission solutions were also to resolve, avoid, or defer any existing or planned reliability or aging-infrastructure transmission upgrades, a portion of the total public-policy project costs could be allocated in the same manner as the avoided reliability or aging-infrastructure project. This portion could equal the avoided cost of any upgrades that otherwise would have been needed to meet regional reliability or aging infrastructure needs, and would address multiple needs simultaneously while "right-sizing" to avoid duplicative projects.

The Blueprint's recommended approach allocates the remaining costs to each State in proportion to the capability requested and received from the transmission procurement. In addition, should other States or third parties subscribe to any excess transmission capability, they would be assigned a similar per-megawatt cost responsibility as that of the participating States. As a result, the costs for participating States would decrease, and the participating States would be fully compensated for pre-funding the initially unsubscribed capability. States that chose not to participate would not be expected to bear any additional cost responsibility. Cost allocations to non-participating States would be limited to only avoided reliability or asset replacement costs. Aligning cost responsibilities with requested transmission capability facilitates the process of identifying, preserving, and assigning newly-created transmission capacity. Ideally, the terms of the VSA or enabling tariff would allow a wide range of potential applicants for this available capability, including allocations to other States, generators, or third-party buyers.[43]

[43] All buyers of transmission capability would be subject to the terms of the capability reservation set out in the VSA or subsequent procurement agreements.

Assuming the third-party capability of the line was fully subscribed, allocating costs in proportion to the megawatt transmission capability created would result in the cost responsibilities summarized in Table 1.

TABLE 1: COST ALLOCATIONS WITH THIRD-PARTY MW FULLY SUBSCRIBED

	OSW (4,800 megawatts)	N. ME RE (1,200 megawatts)	SHEI (100 megawatts)	Percentage (6,100 megawatts)
MA	2400			39.34%
CT	1200			19.67%
RI	600			9.84%
Other States & Third Parties	600			9.84%
ME		600		9.84%
Other States & Third Parties		600		9.84%
VT			50	0.82%
Other States & Third Parties			50	0.82%

Other States & Third Parties Total	20.49%

Because the full transmission capability may not be reserved at the outset, an allocation method is also required to apportion the costs associated with the remaining capability in the interim. RENEW and ACP also propose to allocate these costs in proportion to the megawatt transmission capability requested and procured by each participating state. Table 2 shows how, as the subscriptions increase for the open season capability through additional state and third-party reservations, the appropriate portion of the initial project costs (possibly including carrying charges) will be allocated to the additional subscribers. As a result, the costs for participating States will decrease and the participating States will be fully compensated for pre-funding the initially unsubscribed capability.

TABLE 2: COST ALLOCATIONS WITH DIFFERENT SUBSCRIPTION LEVELS

	Megawatt Quantity	Allocation with Fully Subscribed Capability (6,100 megawatt)	Allocation with Initially-Unsubscribed Capability (4,850 megawatt)	Incremental Responsibility from Lack of Subscriptions
Calculation	*(a)*	*(b)*	*(c)*	*(d)*
		(a)/6,100	*(a)/4,850*	*(c)*20.49%*
MA	2400	39.34%	49.48%	10.14%
CT	1200	19.67%	24.74%	5.07%
RI	600	9.84%	12.37%	2.54%
ME	600	9.84%	12.37%	2.54%
VT	50	0.82%	1.03%	0.21%
Other States & Third Parties Total	1250	20.49%	--	--

As an alternative, the initially unsubscribed portion of the created transmission capability could be recovered from all ISO-NE transmission users in proportion to load (postage stamp), utilizing the ISO-NE's existing postage stamp cost recovery for pool transmission facilities. FERC approved pre-funding of public policy transmission projects in late 2007 for the California Independent System Operator's Location-Constrained Renewable Interconnection (LCRI) tariff provision to support the development of an at-scale transmission solution for over 4,000 MWs of renewable generation in California's Tehachapi resource area.[44]

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[44] California Independent System Operator Corporation, *California ISO okays first location-constrained transmission project* (May 18, 2009), https://www.caiso.com/Documents/CaliforniaISOOkaysFirstLocation-ConstrainedTransmissionProject.pdf.

Assuming the unsubscribed capability was initially allocated on a postage stamp basis, it would result in the cost responsibilities summarized in Table 3. As interested third parties subscribe to this capability, this initial cost responsibility would be refunded.

TABLE 3: POSTAGE STAMP COST ALLOCATIONS WITH DIFFERENT SUBSCRIPTION LEVELS

	Megawatt Quantity	Allocation with Fully Subscribed Capability (6,100 megawatt)	Allocation of Initially-Unsubscribed Capability (1,250 megawatt)	Responsibility from Lack of Subscriptions (6,100 megawatt)
	(a)	*(b)*	*(c)*	*(d)*
Calculation		*(a)/6,100*	*ISO-NE 2020 Load Ratio Share*	*(c)*20.49%*
MA	2400	39.34%	45.36%	9.29%
CT	1200	19.67%	23.95%	4.91%
RI	600	9.84%	6.64%	1.36%
ME	600	9.84%	9.86%	2.02%
VT	50	0.82%	4.37%	0.90%
NH	0	0%	9.82%	2.01%
Other States & Third Parties Total	1250	20.49%	--	--

The feasibility of this cost allocation approach would rely on its adoption by participating States as a key element of the VSA negotiation and execution process. Under the recommended approach, States that choose not to participate would not be expected to bear any additional cost responsibility. Allocating costs to non-participating States would be limited to only avoided reliability or asset replacement costs, and to cover capability subscriptions pursued by non-participating States. In an alternative approach, while States would initially fund any unsubscribed capability that may exist on a postage stamp basis, this cost responsibility would be refunded by subsequent subscriptions under the terms of the approved VSA or enabling tariff.

In addition to complexities surrounding cost allocation, stronger rules might be needed to provide more durable rights for States to identify, preserve, and assign created transmission capability to the States funding the project and other interested third parties. Under recent FERC precedent,[45] New Jersey's SAA Agreement provides a template for the critical task of reserving

[45] *PJM Interconnection, L.L.C,* 179 FERC ¶ 61,024 (2022).

rights in the regional planning model for future use by state-selected generators.[46] In ISO-NE, future reservations by non-participating States or third parties might require similar rules. "Anchor" States- those sponsoring and paying for the transmission upgrades- might be content with their rights under the existing ISO-NE Tariff or might choose to submit to FERC for its approval a proposal for modifications to ensure appropriate capacity reservations, if needed.[47]

By seeking a procurement of a transmission solution at an efficient scale needed, instead of incrementally through individual generation interconnection requests, participating States and their ratepayers would benefit from the more optimal planning and the lower costs offered by economies of scale.

16. **Comment on the benefits and/or weaknesses of using a public-private partnership that might include one or more states or U.S. DOE as part owners with private developers or other sources.**

As noted above, the potential benefit of a public-private partnership – allowable under the TFP, although DOE has not issued guidance on this approach yet – is that federal funding can defray consumer costs and allow for necessary up-front transmission expansion before transmission customers are ready to procure service. The greatest potential drawback is the increase in complexity and risk of delay.

17. **Comment on the co-benefits of landfalling offshore transmission lines, such as improvements to reliability and/or resilience (*i.e.*, through the use of HVDC converters or otherwise), economic development (*e.g.*, port development, hydrogen production, *etc.*) and any local system benefits. Identify ways to measure and maximize these co-benefits when evaluating transmission buildout.**

As noted above, advanced HVDC converters can provide significant reliability enhancements through black start capability. Although it does not distinguish the specific economic development benefits of transmission landfall locations, a 2020 report[48] identifies that total project development and onsite activity from offshore wind could add over 12,000 jobs

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[46] PJM Interconnection, Rate Schedule FERC No. 49, State Agreement Approach Agreement between PJM and NJ BPU.

[47] ISO-NE has a provision for Late Comer Projects involving ETUs that can allow States to claw back costs from subsequently interconnecting generators. The late-comer provision will refund each State's share of the line, reducing its risk of initially overbuilding the line compared to the amount of generation that is initially procured. ISO-NE, ISO New England Inc. Open Access Transmission Tariff, sched. 11 (5). If this model is not acceptable to the States, they should approach FERC for alternatives. *See State Voluntary Agreements to Plan and Pay for Transmission Facilities*, 175 FERC ¶ 61,225 (2021) (encouraging states to identify barriers to VSA and, as necessary, consider making filings before FERC to address those barriers).

[48] American Wind Energy Association, *U.S. Offshore Wind Power Economic Impact Assessment* (2020), https://supportoffshorewind.org/wp-content/uploads/sites/6/2020/03/AWEA_Offshore-Wind-Economic-ImpactsV3.pdf

nationally by 2030,[49] and over $1.3 billion in economic output by 2035.[50] The New England States should account for the opportunities for Community Benefit Agreements as well as co-located loads (such as hydrogen electrolysis plants) taking advantage of inexpensive power. ACP, RENEW, and their members are fully prepared to support the New England States in their efforts to quantify the specific economic benefits associated with landfall of transmission from offshore wind.

Respectfully submitted,

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October 28, 2022

[49] *Id.* at Table 5.
[50] *Id.* at Table 6.

A TRANSMISSION BLUEPRINT FOR NEW ENGLAND:
DELIVERING ON RENEWABLE ENERGY

MAY 23, 2022

BOARD OF DIRECTOR LEVEL MEMBERS

THE MEMBERS OF RENEW

The comments expressed herein represent the views of RENEW and not necessarily those of any particular member.

ABOUT US

ABOUT RENEW

RENEW Northeast (RENEW) is a non-profit association uniting the renewable energy industry and environmental interest groups whose mission involves coordinating the ideas and resources of its members with the goal of promoting and increasing renewable energy in New England.

RENEW works to create and strengthen the public policies that will lead to the development and integration of high levels of renewable energy production for the benefit of the region. Modeled after successful organizations in other parts of the country, RENEW was initially a collaborative project of the wind industry and public interest environmental organizations. RENEW's goal is to recruit as members other renewable energy companies, suppliers, utilities and manufacturers that share a common vision of clean, renewable and environmentally responsible power development. RENEW strives to be a single, coherent voice for its membership to achieve renewable energy and greenhouse gas reduction goals by sharing resources and aligning messages. RENEW takes a leadership role in policy development on renewable energy issues before ISO New England, state legislatures, governors, and utility commissions.

ABOUT BOREAS

Boreas Renewables, LLC is a consulting practice serving renewable energy resource developers, owners, operators, and advocates including RENEW Northeast. Founded in 2008, Boreas specializes in helping developers navigate their way through the ISO New England interconnection process, participate in the Forward Capacity Market, and register to sell into the New England wholesale electricity markets. Boreas works with clean energy resource owners and operators to understand how existing and upcoming market rules and compliance requirements factor into their day-to-day operations. In addition to following the evolving markets, Boreas actively advocates within the NEPOOL and ISO New England stakeholder process for electricity market rules and system planning improvements that will allow for the development and integration of high levels of renewable energy.

ABOUT THE BRATTLE GROUP

Johannes Pfeifenberger and Joseph DeLosa of The Brattle Group contributed to the cost-allocation section of this report. The Brattle Group is an economic, regulatory, and electricity industry consulting firm headquartered in Boston, MA.

EXECUTIVE SUMMARY

New England's electric transmission must be expanded and modernized to enable the transition to renewable energy. Investing in transmission will enable offshore wind to continue scaling, expanding, unlock Northern New England's clean energy potential and alleviate bottlenecks that undermine existing renewable energy projects. New transmission must be planned and constructed to minimize impacts on the environment, local communities and businesses.

Transmission Need

The existing transmission system is unable to accommodate the large quantities of renewable energy required by New England States' climate and clean energy policies. The problem is growing at an alarming rate. Offshore wind farms proposing to connect to Cape Cod and Southeast Massachusetts are facing hundreds of millions of dollars in costs to upgrade undersized power lines, and inadequate transmission has halted development of Northern Maine's abundant land-based wind and solar energy potential. Existing wind and solar plants are increasingly required to turn off due to inadequate transmission, which squanders clean energy and increases costs. Numerous studies over the past decade from grid operator ISO-New England (ISO-NE) and the States have identified these problems and suggested solutions.

Benefits

Investing in transmission will enable renewable energy to be developed at low cost, and better planning will reduce the costs of the transmission itself. As described in Section 2, building transmission to facilitate the next round of offshore wind projects will enable new clean energy to displace more expensive power plants, reducing prices by over $600 million each year. Closing expensive, outdated power plants will reduce emissions of carbon dioxide and hazardous pollutants. Investing in the grid proactively will avoid piecemeal upgrades that could require the same transmission lines to be rebuilt multiple times or necessitate expensive and disruptive projects that can be avoided through better planning.

Regional Collaboration

The New England States must work together to build needed transmission projects by running competitive solicitations that maximize competition, minimize costs, and ensure state control over planning and project selection. As elaborated in Section 3, the wealth of existing analyses from the past decade can be used to define the scope and objectives of transmission solutions. State laws, existing ISO-NE rules, and precedents from other jurisdictions create a pathway for procurement of needed transmission that can be accomplished within the next 12 months. Moving quickly will position New England to access billions of dollars in transmission funding included in the federal infrastructure bill.

Equitable approaches for allocating costs among New England States are described in Section 4. Cost allocation can be rooted in targets for deployment of specific resources – such as offshore wind targets for Massachusetts, Connecticut and Rhode Island – or targets to enable renewable energy development in a specific region – such as Northern Maine and Northern Vermont. States can additionally support transmission that will enable large institutions, business, municipalities and other third parties to purchase renewable energy, with the up-front cost of transmission paid back to States as the capacity is utilized. The scope of the transmission solicitation and the cost allocation approach can be tailored to States' resource needs and appetites for participation. A solicitation could include all six New England States or a subset of States.

Without new transmission States will struggle to achieve climate and economic development goals desired from renewable energy.

› The solutions are known, the benefits are clear, and the time to act is now.

SECTION 1

THE NEED FOR TRANSMISSION

By next year, New England must begin procuring new transmission to remain on a trajectory to meet its climate and clean energy goals. Transmission is required to access grid-scale renewable energy located far from population centers, and grid enhancements are required to accommodate new sources of distributed energy like solar and battery energy storage. New power lines must be sited to minimize impacts on the environment and protect communities overburdened by pollution and prior infrastructure development. And projects must be procured competitively to reduce consumer costs.

The need for transmission has never been clearer and a decade's worth of studies tell us how to prepare the power system for renewable energy. Procuring the first round of necessary transmission projects in the near term will enable States to access new federal funds and address grid constraints that threaten to impede the transition to a clean energy future.

Transmission Deficit

Analyses by New England States identify significant transmission investments that are needed to achieve existing clean energy goals. The June 2021 New England Energy Vision Report to Governors found that "the resource mix in New England is rapidly shifting toward more clean energy, including onshore and offshore wind; hydroelectric resources; solar [photovoltaics]; and battery storage. These resource shifts are expected to have major implications for the region's transmission system."[1] Massachusetts' Decarbonization Roadmap found that the region needs 10,000 to 37,000 megawatts (MW) of new transmission to achieve 2050 targets[2] – that, at the upper end, is the equivalent to the capacity of all existing power sources in New England.[3]

Inadequate transmission is already threatening renewable energy development and undermining clean energy sources across the region. Offshore wind projects seeking to connect to Cape Cod are facing over $500 million in on-shore transmission upgrades,[4] and further connections to Southeast New England are projected to require new on-shore high-voltage transmission of well over $1 billion.[5] Abundant onshore wind and solar energy potential in Northern Maine is constrained by lack of transmission,[6] and limitations in Northern Vermont and New Hampshire are stifling renewable energy development. State climate plans call for additional grid connections to New York and Quebec, and for strengthening connections between Northern and Southern New England.[7] Addressing these grid constraints is required to achieve state renewable energy requirements, and will enable more efficient use of existing power sources. Additionally, building transmission to access low-cost renewable energy will enable corporations, large institutions, and municipalities to purchase regional wind and solar and drive deployment without ratepayer contracts.[8]

No Time to Wait

The New England States must conduct transmission procurements by early 2023 if they are to access federal infrastructure funds and jump-start projects that will take years to build. Major transmission projects typically take longer to complete than generation projects, and proactive development of the near-term transmission projects must start now if growth of renewable energy is to continue. Moving quickly will position the New England States to access a portion of the $2.5 billion of transmission funding provided in the 2021 Infrastructure Investment and Jobs Act for the Transmission Facilitation Program.[9] Tax credits proposed for transmission in the Congressional budget reconciliation bill could further reduce costs for New England ratepayers by hundreds of millions of dollars.[10]

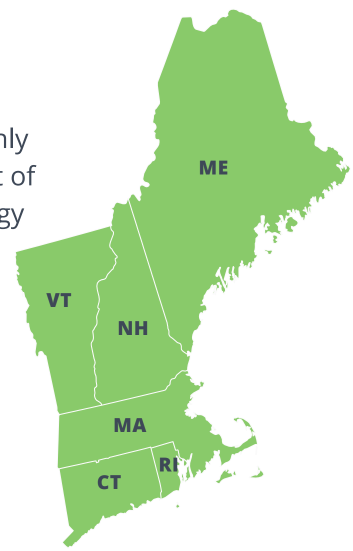
The current process of connecting each generator sequentially is slow, incremental, and expensive. Unless efforts are undertaken swiftly to address near-term transmission needs, clean energy deployment will slow, and States will struggle to meet climate and economic development goals. Implementing a state-driven transmission procurement process will overcome these challenges and accelerate clean energy deployment.

SECTION 2

BENEFITS OF TRANSMISSION

Strengthening New England's transmission will reduce electricity generation costs and greenhouse gas emissions, enhance reliability, and decrease the need for conventional fossil-fueled power plants. Addressing land-use concerns arising from transmission development from the outset will minimize harms on host communities and the environment and increase public support. Energy storage and other non-transmission alternatives (NTAs) can be considered in the transmission planning to minimize the footprint of new infrastructure. Some quantity of electric transmission capability held in support of obsolete fossil generation resource interconnections could also be made available by improving ISO-NE market rules to send the right signals to those generators to retire and release space on the transmission system.

Near Term Projects



The benefits of transmission can be realized by solving for the thoroughly documented grid constraints that today are hindering the development of new wind and solar and curtailing the operations of existing clean energy resources. Transmission upgrades must account for both new and existing renewable energy resources otherwise market conditions could force renewable generation to compete against itself instead of growing the region's output of renewable energy.

A first round of transmission is needed as follows to achieve the New England States' offshore wind deployment legal requirements, unlock low-cost land-based wind and solar in Northern New England and enhance electricity flows into and within the region.

- **Offshore Wind** – four modular 1,200-MW transmission links from offshore lease areas to demand centers and reinforcements of the onshore grid to achieve existing offshore wind targets for **Massachusetts** (2,400 MWs), **Connecticut** (1,200 MWs), **Rhode Island** (600 MWs) and to provide 600 MWs for purchases by other States and third parties. These transmission links could be interconnected offshore to enhance resiliency and create a meshed ocean grid.[11]
- **Northern Maine Renewable Energy** – 1,200 MWs of transmission to integrate abundant land-based wind and solar to achieve Maine's renewable energy goals and enable purchases by other States and third parties.
- **New Hampshire and Vermont** – Strengthened connections between New Hampshire and Massachusetts[12] to address grid constraints between Northern and Southern New England and between Vermont and Quebec[13] to access carbon-free resources. Transmission upgrades or non-transmission alternatives such as energy storage could enable additional renewable energy development in Northern Vermont and Northern New Hampshire.

If transmission is not built before generation is procured, renewable energy development will be more expensive, or may not happen at all. Northern Maine presents a cautionary example, as the buildout of land-based wind stalled after accessible, low-cost connections were utilized. A similar challenge now confronts offshore wind. With the grid in Southeast New England becoming more saturated with renewable energy resources, it will require larger, longer-distance and more expensive transmission to demand centers or major onshore transmission upgrades.[14] Spreading the costs of these major projects among multiple projects and multiple beneficiary States will avoid overburdening the economics of any single project.

Consumer and Environmental Benefits

The massive volume of renewable energy that can be realized by near-term transmission investment by the States will produce hundreds of millions of dollars in consumer savings and reduce greenhouse gas emissions by millions of tons. Massachusetts, Connecticut, and Rhode Island have contracted for 4,700 MWs of offshore wind, and ISO-NE has determined that integrating additional offshore wind will require long-distance HVDC transmission to demand centers or new onshore high-voltage transmission in new rights of way.[15] Building four of these transmission solutions will enable development of the next 4,800 MWs of offshore wind, bringing the offshore wind total to 9,500 MWs. Economic Studies conducted by ISO-NE found the scaling of offshore wind from 5,000 MWs to 8,000 MWs produces $620 to $650 million in annual wholesale electricity cost savings,[16] and avoids 1.1 to 1.2 million tons of CO_2 emissions per year.[17] Additionally, new transmission will alleviate grid constraints and reduce instances when local demand is less than supply and wind and solar are turned off or 'curtailed.' Analysis from Connecticut found that eliminating these curtailments would reduce costs of decarbonizing the state's grid by $400 million to $700 million dollars.[18]

Reliability, Resiliency and Operational Flexibility

Increasing pathways for electricity to reach consumers will reduce risks of outages due to severe weather and grid failures. This stronger and more resilient transmission system will enable faster recovery when grid outages do occur. A regional offshore and onshore grid built for renewables will increase flexibility, enabling grid operators to adjust to the variability of wind and solar in different locations across the entire Northeast. Strengthening transmission across New England will enable old and inefficient fossil-fuel power plants to retire while maintaining grid reliability. ISO-NE recently procured $49 million in transmission upgrades to enable retirement of oil- and gas-fired Mystic Generating Station in Boston,[19] ending hundreds of millions of dollars in annual ratepayer subsidies to support the aging power plant.[20] While that procurement was focused on ensuring reliability, strategic development of transmission for public policy resources could expedite retirement of additional outdated power plants.

TRANSMISSION PROCUREMENT

ISO-NE and others have performed a long list of studies over the past decade identifying current and anticipated transmission constraints and in many cases identifying solutions.[21] By drawing on existing state authorities, current ISO-NE rules, and precedents from other jurisdictions for state-run transmission procurements, the New England States can conduct transmission solicitations that will provide reliable and competitive solutions delivering the greatest consumer, environmental, and social equity benefits over the life of projects. The New England States can begin procuring this needed transmission today.

Project Identification

State climate and energy policies require a fundamental transformation in the mix of resources that produce the region's electricity, the quantity of electricity needed, and the locations where this energy is generated. New clean energy generation in northern and central Maine[22], off the southern coast[23], and northern Vermont and New Hampshire[24] are already seeing significant transmission limitations. Additionally, the need for transmission from Canada and between Maine, New Hampshire, and Massachusetts has been identified in state and regional climate plans.[25] Past ISO-NE studies and state procurements[26], provide a clear picture of the most pressing transmission bottlenecks and potential solutions, which can be used as the foundation for an initial competitive procurement.

Competitive Solicitation

Drawing on existing legal authorities and public policy objectives, the States can run competitive solicitations and select preferred projects that meet their identified needs. Connecticut[27], Rhode Island[28] , and Maine[29] have existing statutory authority to procure transmission, and a bill[30] progressing through the Massachusetts legislature would require the Commonwealth to exercise existing transmission procurement authority.[31] Vermont's System Planning Committee requires development of a 20-year transmission plan every 3 years and assigns responsibility for implementation.[32] New Hampshire's Renewable Portfolio Standard[33] provides a basis for using procurements of certificates to meet its requirements.[34] By running a procurement themselves, the States have the ability to control this process and work collectively with each other.[35] If multiple States desire to work cooperatively, solicitations could be issued jointly, through parallel state-level solicitations or a voluntary agreement designed to ensure consistency and allocate costs according to the preferences of the States.[36] Meanwhile, projects submitting responses to theses solicitations would be responsible for achieving the appropriate ISO-NE interconnection approval, as discussed below.

ISO-NE Process for Reviewing Transmission Upgrades

Any transmission project within New England needs to be studied and approved by ISO-NE to ensure it meets reliability criteria. ISO-NE's Elective Transmission Upgrade (ETU) interconnection process allows anyone to submit a request for ISO-NE to study a proposed transmission upgrade.[37] The ETU request may describe a specific transmission facility or an "objective" upgrade where ISO-NE would identify the facilities needed to achieve the objective. The study identifies whether any additional transmission system improvements are needed, beyond those proposed, to maintain reliability. The requestor pays for the ISO-NE study and is ultimately responsible for the cost of building the project and any identified system upgrades. Once the ETU transmission project is built, it becomes part of the New England transmission network. The ETU process is nearly identical to the interconnection process that new generators go through with ISO-NE. This makes the ETU process the best available option for coordination with state procurements as it follows the same general procurement process that the States have successfully used for years to procure new clean generation under long term contracts.[38]

Other Approaches for Transmission Upgrades Are Not Yet Compatible with State Procurements

ISO-NE's existing processes for identification of transmission needs, selection of solutions, and allocation of costs in a centralized and repeatable manner are not currently viable paths for solving transmission needs driven by state policy requirements. The reliability and asset condition upgrade processes does not consider public policy needs; the market efficiency upgrade process has never been successfully used; and the public policy upgrade process does not provide States control over project selection and cost allocation.[39] The States and ISO-NE are working to develop new processes to address longer-term transmission needs driven by climate policy and comply with new transmission planning requirements set by the Federal Energy Regulatory Commission (FERC).[40] These processes should help New England build necessary transmission over the mid- to long-term. While the prospect of these new processes leading to an efficient way to procure future transmission that has the blessing of the States is promising, the need for new transmission in the near-term to avoid lengthy delays for the renewable energy build-out is clear. Until this new preferable process is developed, States should utilize existing state laws and ISO-NE rules to issue solicitations without delay. New England does not have the luxury of time before upgrades to the transmission system are needed.

Project Selection

States' selection criteria should consider how proposals meet transmission needs at the lowest lifecycle cost while upholding reliability, increasing resilience, maximizing future renewable energy development, and minimizing environmental and environmental justice impacts. Criteria should include the benefits the selected transmission projects will have on existing generation, particularly generation that helps meet climate goals, and its capability to provide for future transmission expansion that might be needed. Transmission project selection could be coordinated with generation procurement processes to maximize the efficiency and use of the transmission facility.

Risk Mitigation

Development of transmission and renewable energy generation must be aligned to mitigate risks for ratepayers and project developers. Procuring transmission separately from generation can reduce risks of unpredictable costs and timelines to upgrade the existing grid. Risk can be mitigated further through transmission procurements that include cost-control mechanisms to ensure timely project completion and synchronization with generation project schedules to avoid building a "bridge to nowhere".

Competitive Solicitation Framework

The New England States have extensive experience with running successful and competitive solicitations for clean generation projects. Transmission procurement could follow the same general principles and process where the State (or States), which have identified the need for transmission, issue a Request for Proposals for transmission solutions. Bidders would be responsible for developing responses to these needs and demonstrating that proposed solutions meet desired outcomes. Bidders would be responsible for the interconnection process and bear the risk of obtaining approvals from ISO-NE, just like generators today. Table 1 lays out the basic framework by which this process could work, where each entity involved (the State, the transmission developer, and ISO-NE) is responsible for different aspects of the process.

Table 1: *Framework for the competitive solicitation of transmission projects*

Step	State(s)	Transmission Developer(s)	ISO-NE
1	Determine Need/Scope of Solicitation and Evaluation Criteria		
2	Notice Intent to Issue Request for Proposal	Submit Interconnection Requests to ISO-NE for Elective Transmission Upgrade	
3	Issue Request for Proposal		
4		Develop Responses to RFP	Study Interconnection Request and Assess Reliability Impacts
5		Submit Responses to RFP	
6	Review RFP Responses		
7	Select winner based on Criteria		Issue I.3.9 Approval
8	Execute Transmission Services Agreement	Execute Transmission Service and Operating Agreements and Interconnection Agreement	Execute Interconnection Agreement and Transmission Operating Agreement[41]
9	Payment to Transmission Developer	Construct Project	
10		Project in Service	Operation and Dispatch

Under this framework, the States remain in control over key aspects of the process including the determination of the transmission need, the criteria for evaluating and selecting the proposed projects, and the establishment of cost allocation between parties if multiple States participate in the solicitation. The transmission developers have the burden of demonstrating that their proposed solutions meet the States' identified needs and bear the risks associated with the ISO-NE interconnection process.[42]

SECTION 4

COST ALLOCATION

The New England States can utilize existing regulatory pathways to hold an efficient regional public policy transmission solicitation. In return, they receive dedicated transmission capability providing certainty in the interconnection of the required public policy resources and can enable third party purchases of renewable energy.

Workable cost allocation methodologies rely on simple beneficiary pays principles for ensuring the costs are allocated roughly commensurate with the benefits received and customers are not compelled to pay for services they do not need. The recommended cost allocation approach described below and elaborated in the appendix applies cost responsibility in proportion to transmission capability created in support of the States' policy needs, accounting for avoided costs, enabling third party transactions, and excusing any State that does not request creation of new transmission capability.

Recommended Approach

As a first step, existing allocation methods could be applied to apportion avoided costs. If any of the identified public-policy transmission solutions were also to resolve, avoid, or defer any existing or planned reliability or aging-infrastructure transmission upgrades, a portion of the total public-policy project costs could be cost allocated in the same manner as the avoided reliability or aging-infrastructure project. This portion could equal the avoided cost of any upgrades that otherwise would have been needed to meet regional reliability or aging infrastructure needs.

The recommended approach allocates the remaining costs to each State in proportion to the capability requested and received from the transmission procurement. In addition, should other States or third parties subscribe to any excess transmission capability, they would be assigned a similar per-megawatt cost responsibility as that of the participating States. As a result, the costs for participating States will decrease as they will be fully compensated for pre-funding the initially unsubscribed capability. States that choose not to participate would not be expected to bear any additional cost responsibility. Cost allocations to non-participating States would be limited to only avoided reliability or asset replacement costs, which would be assigned in any event. Aligning cost responsibilities with requested transmission capability facilitates the process of identifying, preserving, and assigning created transmission capability.

Alternative Approaches

Alternative cost allocation paradigms could be based on the estimated economic benefits provided by the transmission projects. Under this approach, the States would rely on ISO-NE to estimate overall cost savings (i.e., the long-term value of multiple transmission benefits) provided by the proposed transmission solutions for each State and allocate some (or all) of the transmission costs based on projected benefits. While technically feasible, this approach can be difficult to implement as ongoing benefit evaluations may introduce challenges for the States to estimate their cost responsibility on an ongoing basis. Additional challenges may be encountered in justifying transmission capability reservations not roughly commensurate with economic benefit outcomes.

A third option would rely on allocating costs based on each State's total unmet public-policy goals. This option may encounter feasibility challenges in determining with specificity the "amount" of unmet policy goals, which vary widely across design features and are difficult to translate into common units. The evolving nature of unmet renewable goals also presents challenges in justifying reservation of a requested amount of transmission capability for public policy use.

APPENDIX

COST ALLOCATION

Overcoming cost allocation challenges has proved to be a significant hurdle for many ambitious and critical transmission development efforts in the United States. Using the recommended process below, States will lead an efficient regional public-policy transmission solicitation that will furnish them with dedicated transmission capability providing certainty in the interconnection of the clean energy resources needed to meet public-policy requirements.

ILLUSTRATIVE SCOPE, CONSIDERATIONS FOR PROCUREMENT STRUCTURE

Pursuant to the procurement process described above, the New England States take the lead in identifying, selecting, and approving projects to create the needed transmission capability. For illustrative purposes, this study assumes 6,100 MWs of transmission capability to address known needs. Current studies already provide information about optimal interconnection locations,[43] which would be confirmed in the development of the transmission solicitation.

As a precursor to a multi-state transmission procurement, interested States may benefit from executing and seeking approval of a Voluntary State Agreement (VSA) that defines the process and details of the solicitation. The VSA would include agreement on the scope of procurement and enable feasible and collaborative multi-state project evaluations. FERC has approved similar Transmission Study Agreements, [44] memorializing features such as project selection detail and authority, evaluation process, responsibilities, and milestones associated with New Jersey's State Agreement Approach (SAA) process with PJM.[45]

To address known grid constraints and achieve existing state targets and expected third-party needs that will allow for a more cost-effective scale of transmission project development, the illustrative procurement of 6,100 MWs of transmission would include:

- **4,800 MWs of transmission** needs to reflect offshore wind (OSW) goals of Southern New England States and potential third parties, including:
  - 2,400 MWs to reflect the current OSW goal for Massachusetts
  - 1,200 MWs to reflect the current OSW goal for Connecticut
  - 600 MWs in OSW procurement as proposed in Rhode Island legislation
  - 600 MWs in OSW capacity for other States and third parties'
- **1,200 MWs HVDC or HVAC** from Northern Maine to ISO-NE grid
  - 600 MWs to support the current Northern Maine Renewable Energy Program[46]
  - 600 MWs for other States and third parties
- **100-MW transmission capacity** to address the Sheffield-Highgate Export Interface [47] (SHEI)
  - 50 MWs for VT to reduce SHEI backlog and curtailments
  - 50 MWs on SHEI for other States and third parties

Additional transmission capacity from Canada and/or increased transfer capability between Massachusetts and New Hampshire could also be procured.

APPENDIX

COST ALLOCATION OPTIONS

OPTION 1 (RECOMMENDED):

Workable cost allocation methodologies rely on simple beneficiary-pays principles, ensuring that costs allocated are roughly commensurate with benefits received, and that customers are not compelled to pay for services they do not need.[48] To that end, the recommended cost allocation approach applies cost responsibility in proportion to incremental transmission capability each State requests be created in support of its state policy needs, accounting for avoided costs, and excluding any state that does not request creation of incremental transmission capability.

As a first step, cost allocation for the planned public-policy transmission projects would consider other avoided transmission costs.[49] That is, if any of the identified public-policy transmission solutions were also to resolve, avoid, or defer any existing or planned reliability or aging-infrastructure transmission upgrades, that portion of the total public-policy project costs would be cost allocated in the same manner as the avoided reliability or aging-infrastructure project. This portion should equal the avoided cost of the upgrades that would otherwise be needed to meet the reliability or aging infrastructure needs. Existing planning procedures provide a framework for identifying facilities to be allocated in this manner.[50] Specifically, in the generator interconnection process, ISO-NE identifies upgrades that are the same, or similar to, system benefits as projects simultaneously included in the Regional System Plan (RSP).[51] Processes exist to allocate regionally these portions of costs providing regional benefit.[52]

The remaining costs of the public policy projects would be allocated to each participating State in proportion to the transmission capability requested and received from the transmission procurement. Cost associated with remaining transmission capability created for future state use or third-party buyers must also be addressed. This additional capability would remain available for future subscriptions at a similar per-megawatt cost responsibility as that of the participating States. Ideally, the terms of the VSA or enabling tariff would allow a wide range of potential applicants for this available capability, including allocations to other States, generators, or third-party buyers.[53]

Assuming the third-party capability of the line was fully subscribed, allocating costs in proportion to the megawatt transmission capability created would result in the cost responsibilities summarized in Table 1.

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Table 1: *Cost Allocations With Third-Party Megawatts Fully Subscribed*

	OSW (4,800 megawatts)	N. ME RE (1,200 megawatt)	SHEI (100 megawatts)	Percentage (6,100 megawatts)
MA	2400			39.34%
CT	1200			19.67%
RI	600			9.84%
Other States & Third Party	600			**9.84%**
ME		600		9.84%
Other States & Third Party		600		**9.84%**
VT			50	0.82%
Other States & Third Party			50	**0.82%**

Other States & Third Party Total	20.49%

Because the full transmission capability may not be reserved at the outset, an allocation method is also required to apportion the costs associated with the remaining capability in the interim. We also propose to allocate these costs in proportion to the megawatt transmission capability requested and procured by each participating state. Table 2 shows how, as the subscriptions increase for the open season capability through additional state and third-party reservations, the appropriate portion of the initial project costs (possibly including carrying charges) will be allocated to the additional subscribers. As a result, the costs for participating States will decrease and the participating States will be fully compensated for pre-funding the initially unsubscribed capability.

Table 2: *Cost Allocations With Different Subscription Levels*

	Megawatt Quantitiy	Allocation with Fully Subscribed Capability (6,100 megawatt)	Allocation with Initially Unsubscribed Capability (4,850 megawatt)	Incremental Responsibility from Lack of Subscriptions
Calculations	(a)	(b)	(c)	(d)
		(a)/6,100	(a)/4,850	(c)*20.49%
MA	2400	39.34%	49.48%	10.14%
CT	1200	19.67%	24.74%	5.07%
RI	600	9.84%	12.37%	2.54%
ME	600	9.84%	12.37%	2.54%
VT	50	0.82%	1.03%	0.21%
Other States & Third Party	1250	20.49%		

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As an alternative, the initially unsubscribed portion of the created transmission capability could be recovered from all ISO-NE transmission users in proportion to load (postage stamp), utilizing the ISO-NE's existing postage stamp cost recovery for pool transmission facilities. FERC approved pre-funding of public policy transmission projects in late 2007 for the California Independent System Operator's Location-Constrained Renewable Interconnection (LCRI) tariff provision to support the development of an at-scale transmission solution for over 4,000 MWs of renewable generation in California's Tehachapi resource area.[54]

Assuming the unsubscribed capability was initially allocated on a postage stamp basis, it would result in the cost responsibilities summarized in Table 3. As interested third parties subscribe to this capability, this initial cost responsibility would be refunded.

Table 3: *Postage Stamp Cost Allocations With Different Subscription Levels*

	Megawatt Quantitiy	Allocation with Fully Subscribed Capability (6,100 megawatt)	Allocation of Initially Unsubscribed Capability (1,250 megawatt)	Responsibility from Lack of Subscriptions (6,100 megawatt)
Calculations	(a)	(b)	(c)	(d)
		(a)/6,100	ISO-NE 2020 Load Ratio Share	(c)*20.49%
MA	2400	39.34%	45.36%	9.29%
CT	1200	19.67%	23.95%	4.91%
RI	600	9.84%	6.64%	1.36%
ME	600	9.84%	9.86%	2.02%
VT	50	0.82%	4.37%	0.90%
NH	0	0%	9.82%	2.01%
Other States & Third Party	1250	20.49%		

COST ALLOCATION OPTIONS

1. Feasibility and Implementation of Approach:

The feasibility of the above cost allocation approach would rely on its adoption by participating States as a key element of the VSA negotiation and execution process. Under the recommended approach, States that choose not to participate would not be expected to bear any additional cost responsibility. Cost allocations to non-participating States would be limited to only avoided reliability or asset replacement costs, which would be assigned in any event, and to cover capability subscriptions pursued by non-participating States. In the alternative approach, while States would initially fund any unsubscribed capability that may exist on a postage stamp basis, this cost responsibility would be refunded by subsequent subscriptions under the terms of the approved VSA and/or ETU rules.

In addition to complexities surrounding cost allocation, stronger rules might be needed that could provide more durable rights for States to identify, preserve, and assign created transmission capability to the States funding the project and other interested third parties. Under recent FERC guidance,[55] New Jersey's SAA Agreement provides a template for the critical task of reserving rights in the regional planning model for future use by state-selected generators.[56] In ISO-NE, future reservations by non-participating States or third parties might also require similar rules. Anchor States might be content with their rights under the existing ISO-NE Tariff for ETUs or might choose to submit to FERC for its approval a proposal for modifications to enable a VSA.[57]

2. Discussion:

By seeking a procurement of a transmission solution instead of incrementally through individual generation interconnection requests, participating States and their ratepayers would benefit from the more optimal planning and the lower costs offered by economies of scale. If the solicitation proposals also solve existing reliability/aging infrastructure needs, this procurement has additional benefits including:

- "Right-sizing" the replacement facility to incorporate public policy needs.
- Sharing in the benefits:
  - For States that would have had to fund a reliability upgrade, the public policy funding is defraying their contributions to that cost.
  - For States that would have had to fund a public policy upgrade, the reliability funding is defraying their contribution to that cost.
- Maximizing allocations to willing buyers of capacity and main beneficiaries is likely to minimize cost allocation disputes.

COST ALLOCATION OPTIONS

OPTION 2: ALLOCATION BASED ON ESTIMATED ECONOMIC BENEFITS

An alternative cost allocation paradigm could be based on the estimated economic benefits[58] provided by the transmission projects.[59] Under this approach, States would rely on ISO-NE to estimate overall cost savings (i.e., the long-term value of multiple transmission benefits) provided by the proposed transmission solutions for each State.

Under this framework, ISO-NE would then utilize the estimated benefits to allocate some or all of the transmission costs. To ensure accuracy, ISO-NE estimates of production costs savings as well as estimates of additional economic benefits not captured in production cost simulations (including public-policy-related cost savings) could be used.[60] Ideally, several scenarios of plausible future market conditions would be simulated to understand the variance of benefits given the large degree of long-term uncertainty.

On the basis of these estimated long-term benefits, costs would be allocated such that each State is expected to obtain benefits in excess of allocated costs, thereby meeting the requirement that costs allocations be roughly commensurate with benefits received.

1. Feasibility and Implementation of Approach:

The estimation of transmission related cost savings (economic benefits) is widely used, particularly for public-policy and multi-value transmission projects as pointed out by FERC in its recent Notice of Proposed Rulemaking (NOPR) and noted earlier for the country's other grid operators at NYISO, MISO, SPP and CAISO. ISO-NE already utilizes models to estimate production cost savings from increased transmission capability and renewable integration. While ISO-NE still has very limited experience with quantifying other benefits for such a multi-value assessment, the experience of other ISOs is readily available to serve as a model for a multi-benefit framework for New England—which would also become a FERC requirement if the proposed rulemaking is implemented as proposed in the NOPR.

2. Discussion:

While technically feasible, this approach can be difficult to implement and modeling benefit estimations are prone to disagreements as estimated benefits greatly depend on study assumptions, metrics used, and study time horizons. While NYISO, SPP, MISO and CAISO have successfully implemented such multi-benefit frameworks, other regions have encountered difficulties, with parties disputing study assumptions, assumed benefit categories, and the quality of analysis used as the basis for allocating costs.[61]

In addition, the reliance on benefits for cost allocation can lead to additional challenges for multi-state project selections as changing benefits estimates may make it difficult for States to estimate their cost responsibility on an ongoing basis as benefits change. An additional challenge will likely be reflected in the potentially disparate benefits to each state from various submitted transmission proposals, misaligning incentives within the multi-state selection process.

Finally, allocating costs based on estimated benefits may lead to additional potential challenges justifying the reservation of transmission capability. If transmission upgrades are funded through system-wide cost allocations based on estimated benefits, it may be challenging for individual States to "reserve" or "subscribe" transmission capability for renewable generation projects under this option, unless the megawatt magnitude of such subscription is also based on estimated benefits—which may differ from renewable generation integration needs.

OPTION 3: IN PROPORTION TO UNMET RENEWABLE GOALS;

A third option would rely on allocating costs on the basis of each state's total unmet public-policy goals.[62] In theory, this approach would align well with cost allocation principles, attempting to align cost with the proximate cause of the new renewable generation development needed to achieve state policies.

1. Feasibility and Implementation of Approach:

There may be challenges in determining, with any specificity, the "amount" of unmet public policy goals. This challenge is compounded by making these determinations of future policy goals the basis for allocations of substantial costs to ratepayers.

Unmet renewable goals vary widely across States not only in quantity, but also across design features. An additional challenge would arise translating identified unmet renewable goals into common units (e.g., megawatts or megawatt-hours of additional clean-energy generation needed) to allocate costs of transmission capability. Further, any method based on unmet renewable goals would need to specify the stringency of policy requirements that would suffice as the basis for cost sharing. For instance, it remains unclear whether procurement laws would be needed as the basis for allocations, or whether stated *policy goals* would suffice.

2. Discussion:

A key advantage of allocating costs on the basis of unmet public policy goals is avoiding allocations to States with no desire for public-policy resource development.[63] This benefit may be outweighed by the challenges of this approach. For instance, there may be a tenuous relationship between the total unmet policy goals of a state and the outcome of any particular transmission project. In seeking to justify state-specific reservations of transmission capability associated with these transmission procurements, any mismatch between costs incurred and benefits received may lead to disputes and regulatory challenges.

Finally, this allocation paradigm may not prove to be durable as unmet public policy goals will change (potentially even drastically) over time as legislatures continue to increase renewable procurement targets. This ongoing uncertainty may challenge the complex multi-state selection process and the confidence of participating States in reliably achieving interconnection opportunities that are commensurate with allocated costs. Revising or updating cost allocation on the basis of updated renewable goals is unlikely to lead to the durable and sustainable cost allocation methodology required for States to advance the ground-breaking transmission procurements envisioned herein.

Conclusion

The recommended process provides a means for States to develop transmission needed to achieve near-term policy goals with a cost allocation approach that only requires States to pay for desired transmission. As transmission planning and procurement processes evolve, States can build on and adapt this approach based on experience with the first round of procurement, new requirements from FERC, and ongoing efforts to reform New England’s transmission development processes.

Endnotes

1 New England States Committee on Electricity, *New England Energy Vision Statement* 11 (June 2021), https://newenglandenergyvision.files.wordpress.com/2021/06/advancing-the-vision-report-to-governors-2.pdf

2 Evolved Energy Research, *Massachusetts Decarbonization Roadmap: Energy Pathways to Deep Decarbonization* 64 (December 2020) (prepared for the Massachusetts Executive Office of Energy and Environmental Affairs) [hereinafter Roadmap], https://www.mass.gov/doc/energy-pathways-for-deep-decarbonization-report/download

3 The combined capacity of all energy sources in ISO-NE's latest capacity auction totaled 32,810 MWs. ISO-NE, *New England's Forward Capacity Auction Closes with Adequate Power System Resources for 2025-2026* (March 9, 2022), https://www.iso-ne.com/static-assets/documents/2022/03/20220309_pr_fca16_initial_results.pdf

4 Interconnection costs of $7.7 million for QP624 (Vineyard Wind 1), $195.5 million for QP 700 (Park City Wind) and $335 million for the next 1200 MWs. ISO-NE, *First Cape Cod Resource Integration Study* (July 30, 2021), https://www.iso-ne.com/static-assets/documents/2021/07/cape-cod-resource-integration-study-report-non-ceii-final.pdf

5 New 345kV overhead and underground transmission from West Barnstable to K Street in Boston estimated to cost $1.4 billion. The Brattle Group, *Offshore Transmission in New England: The Benefits of a Better Planned Grid* 17 (May 2020), https://newengland.anbaric.com/wp-content/uploads/2020/07/Brattle_Group_Offshore_Tranmission_in_New-England_5.13.20-FULL-REPORT.pdf

6 ISO-NE, 2016-2017 *Maine Resource Integration Study* (March 12, 2018), (https://www.iso-ne.com/static-assets/documents/2018/03/final_maine_resource_integration_study_report_non_ceii.pdf) and ISO-NE, *Final Second Maine Resource Integration Study* (October 30, 2020), (https://www.iso-ne.com/static-assets/documents/2021/01/second-maine-resource-integration-study-report-non-ceii-final.pdf)

7 The Roadmap, *supra* note 2, finds the need for 8.4 GWs to 13.9 GWs of transmission to Quebec and 0.5 GWs to 4.5 GWs of transmission to New York, all across eight decarbonization pathways.

8 Transmission can enable third-party purchases of renewable energy through power purchase agreements (PPAs). In Texas, transmission to access onshore wind through the Competitive Renewable Energy Zone (CREZ) program has enabled over 2,000 MWs of onshore wind energy PPAs from 22 corporate buyers, https://windsolaralliance.org/wp-content/uploads/2018/10/Corporates-Renewable-Procurement-and-Transmission-Report-FINAL.pdf. Independent transmission has enabled corporate PPAs for offshore wind In the Netherlands, https://cleantechnica.com/2019/05/28/microsoft-announces-new-offshore-wind-energy-agreement-in-the-netherlands/ and Belgium, https://www.rechargenews.com/wind/google-buys-first-ever-offshore-wind-power-as-part-of-record-deal/2-1-675522

9 The Department of Energy's (DOE) programs include the $2.5 billion Transmission Facilitation Program (TFP), $5 billion Enhancing Grid Resilience Program, and $5 billion for Ensuring Resiliency and Reliability. Under the TFP proposal now subject to public comment, DOE is authorized to borrow up to $2.5 billion to assist in the construction of new and upgraded high-capacity transmission lines through three financing tools: loans from DOE; DOE participation in public-private partnerships; and capacity contracts with eligible projects in which DOE would serve as an "anchor customer." More details are available in DOE's Notice of Intent, https://www.energy.gov/sites/default/files/2022-01/Transmission%20NOI%20final%20for%20web_1.pdf

10 The applicability of the federal Investment Tax Credit (ITC) to transmission associated with specific generating resources remains uncertain in the absence of Treasury Department guidance, and States can account for treatment of the ITC when additional clarity emerges.

11 New Jersey's procurement of transmission for offshore wind includes a "backbone" option consisting of links between offshore collector platforms, https://www.nj.gov/bpu/pdf/boardorders/2020/20201118/8D%20-%20ORDER%20Offshore%20Wind%20Transmission.pdf and New York has proposed that the next offshore wind projects should be developed with mesh-ready capability, https://www.nyserda.ny.gov/-/media/Files/Programs/offshore-wind/2022-03-30-presentation-slides.pdf

12 Limited transmission capacity from New Hampshire and Vermont to Massachusetts has created separation between zones and limited development of new resources in Northern New England. The Massachusetts Roadmap, *supra* note 2, at 70, finds need for up to 3.7 GWs of new transmission between New Hampshire and Massachusetts to alleviate these constraints.

13 The Roadmap, *supra* note 2, states a need for 0.7 GW to 0.8 GW of new transmission between Quebec and Vermont, and 2.7 GW to 4.8 GW of new transmission from Quebec to Massachusetts, which could include transmission through Vermont. In Connecticut Department of Energy and Environmental Protection, Integrated Resources Plan Appendix A3 3 (October 2021) [hereinafter CT IRP], https://portal.ct.gov/-/media/DEEP/energy/IRP/2020-IRP/Appendix-A3--Modeling-Results.pdf, the agency determined that for achieving a carbon-free power sector by 2040, it would need 1.2 GW to 2.2 GW of imports from Quebec across five decarbonization scenarios.

14 Only 1,200 MWs of the 2,800 MWs proposed to interconnect to Southeast Massachusetts could feasibly interconnect, requiring either 1,200 MWs of HVDC transmission to the Boston area, or major new transmission between Cape Cod and Boston. ISO-NE, *Second Cape Cod Resource Integration Study Preliminary Results* (April 28, 2022), https://smd.iso-ne.com/operations-services/ceii/pac/2022/04/a6_second_cape_cod_resource_integration_study_preliminary_results_ceii.pdf (requires access to Critical Energy Infrastructure Information).

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15 ISO-NE, *2019 Economic Study Offshore Wind Transmission Interconnection Analysis* 4 (June 17, 2020), https://www.iso-ne.com/static-assets/documents/2020/06/a4_2019_economic_study_offshore_wind_transmission_interconnection_analysis.pdf

16 ISO-NE, *2019 Economic Study: Offshore Wind Integration* 19 (June 30, 2020), https://www.iso-ne.com/static-assets/documents/2020/06/2019_nescoe_economic_study_final.docx. Showing $4.157 billion in total Load-Serving Entity Energy Expenses and Uplift Costs with 5,000 MWs of offshore wind online and unconstrained transmission, and $3.502 billion to $3.538 billion in total LSE expense with 8,000 MWs of offshore wind online, with the variation determined by points of interconnection.

17 *Id.* at 21.

18 CT IRP, *supra* note 13. The CT IRP determined a Balanced Blend scenario selecting the lowest cost resources to meet the state's 100 percent carbon free target by 2040 without alleviating grid constraints. This Balanced Blend scenario was compared with a No Transmission Constraints scenario for wherein power could flow freely across New England without constraints. The No Transmission Constraints scenario produced $400 million in present value cumulative financial benefit with Base Load assumptions (64), and $699 million in present value benefit with the Electrification Load reflecting increased demand from electric vehicles and heat pumps (67).

19 ISO-NE, *ISO-NE makes selection in first Order 1000 transmission RFP* (July 24, 2020), https://isonewswire.com/2020/07/24/iso-ne-makes-selection-in-first-order-1000-transmission-rfp/

20 *See generally, Constellation Mystic Power, LLC,* 165 FERC ¶ 61,267 (2018).

21 The most recent studies are:

ISO-NE, *2015 Economic Study Evaluation of Increasing the Keene Road Export Limit* (September 2, 2016), https://www.iso-ne.com/static-assets/documents/2016/09/2015_economic_study_keene_road_increased_export_limits_fina.docx

ISO-NE, *2015 Economic Study Strategic Transmission Analysis—Onshore Wind Integration* (September 2, 2016), https://www.iso-ne.com/static-assets/documents/2016/09/2015_economic_study_onshore_wind_integration_final.docx

ISO-NE, *2016 Economic Study: NEPOOL Scenario Analysis* (November 17, 2017), https://www.iso-ne.com/static-assets/documents/2017/11/final_2016_phase1_nepool_scenario_analysis_economic_study.docx

ISO-NE, *2019 Economic Study: Economic Impacts of Increases in Operating Limits of the Orrington-South Interface* (October 30, 2020), , https://www.iso-ne.com/static-assets/documents/2020/10/2019-renew-es-report-final.docx

ISO-NE, *2016/2017 Maine Resource Integration Study* (March 12, 2018), https://smd.iso-ne.com/operations-services/ceii/cluster-studies/final_maine_resource_integration_study_report.pdf (requires access to Critical Energy Infrastructure Information)

ISO-NE, *Final Second Maine Resource Integration Study* (October 30, 2020), https://www.iso-ne.com/static-assets/documents/2021/01/second-maine-resource-integration-study-report-non-ceii-final.pdf

RLC Engineering, *QP639 Elective Transmission upgrade Interconnection System Impact Study Final Report* (May 7, 2020))(prepared for ISO-NE), https://smd.iso-ne.com/planning/ceii/studies/me/qp639-etu-1200-mw-hvdc-sis-report_may072020.pdf and associated *QP889 Elective Transmission Upgrade Interconnection System Impact Study Final Report* (September 24, 2021), https://smd.iso-ne.com/planning/ceii/studies/me/qp889-etu-sis-report.pdf

ABB Inc., *QP506 Internal HVDC North to South Flow System Impact Study Report* (July 28, 2017)(prepared for ISO-NE), https://smd.iso-ne.com/planning/ceii/studies/ma/qp506-internal-hvdc-north-to-south-flow-sis-report_jul282017.pdf (requires access to Critical Energy Infrastructure Information)

ISO-NE, *2019 Economic Study: Offshore Wind Integration* (June 30, 2020), https://www.iso-ne.com/static-assets/documents/2020/06/2019_nescoe_economic_study_final.docx

ISO-NE, *2019 Economic Study: Significant Offshore Wind Integration* (October 5, 2020), https://www.iso-ne.com/static-assets/documents/2020/10/2019-anbaric-economic-study-final.docx

ISO-NE, *First Cape Cod Resource Integration Study Redacted Non-CEII Version* (July 30, 2021), https://www.iso-ne.com/static-assets/documents/2021/07/cape-cod-resource-integration-study-report-non-ceii-final.pdf

ISO-NE, *Second Cape Cod Resource Integration Study Preliminary Results* (April 28, 2022), https://smd.iso-ne.com/operations-services/ceii/pac/2022/04/a6_second_cape_cod_resource_integration_study_preliminary_results_ceii.pdf

ISO-NE, *New Generation Curtailment Analysis—Pilot Study Preliminary Results* (April 28, 2022), https://www.iso-ne.com/static-assets/documents/2022/04/a5_new_generation_curtailment_analysis_pilot_study_preliminary_results.pdf

22 ISO *New England, Inc.*, Docket No. ER22-391-000, Informational Filing for Qualification in FCA 16 16-17 (filed November 9, 2021) (Orrington South Limitations at 16-17 and Surowiec South Limitations at 17).

23 Mitsubishi Electric Power Products, Inc., System Impact Study (SIS) QP700 iv (December 2020) (project required to convert

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already planned 115kV line into a new 345kV line), https://smd.iso-ne.com/planning/ceii/studies/ma/qp700-offshore-wind-sis_report.zip

24 Studies and other documents concerning Northern New England needs include:

ISO-NE, *Wind Forecast Accuracy and Undelivered Energy Update* 23 (March 24, 2022) (Orrington South, Whitefield South, and Sheffield Highgate continue to be the most congested areas with much less Undelivered Energy in the rest of the system.), https://www.iso-ne.com/static-assets/documents/2022/03/a02_vrwg_2022_03_24_wind_forecast_and_undelivered_energy_update.pptx

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VELCO, *K-42 Transmission Line Replacement* (September 21, 2021), https://www.iso-ne.com/static-assets/documents/2021/09/a7_k42_line_refurbishment_project.pdf

New England States Committee on Electricity, Right Sizing Transmission Projects (April 11, 2022) (Memo to ISO-NE Planning Advisory Committee supporting VELCO K42 proposal), https://www.iso-ne.com/static-assets/documents/2022/04/nescoe_memo_right_sizing_transmission_projects.pdf

Eversource, *Proposed Plan Application Study Report* (June 28, 2021), https://smd.iso-ne.com/operations-services/ceii/rc/2021/07/a5_2_eversource_new_hampshire_transmission_lines_rebuild_project_lvl3_ppas_es_21_t40_thru_es_21_t45.zip

25 See e.g., Roadmap, *supra* note 2 (need for up to 3 GW of new transmission between Maine and New Hampshire and 3.7 GW between New Hampshire and Massachusetts to alleviate constraints).

26 State renewable energy procurements have required bidders to identify project-related transmission upgrades. *See e.g.*, Massachusetts Department of Energy Resources, *Request for Proposals for Long-Term Contracts for Offshore Wind Energy Projects* Appendix I (May 7, 2021) (bidders required to submit a Deliverability Constraint Analysis), https://macleanenergy.files.wordpress.com/2021/05/83c3-rfp-and-appendices-final.pdf

27 Conn. Gen. Stat. §16a-3n.

28 R.I. Gen. Laws §39-31-5.

29 35-A M.R.S §3210-H.

30 An Act Advancing Offshore Wind and Clean Energy, H.4515, 192nd General Court of Massachusetts (2021-2022).

31 An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, St. 2021, c. 188, §95 (authorizes the Department of Energy Resources to require utilities to procure transmission for offshore wind).

32 30 V.S.A. § 218c.

33 RSA 362-F:9.

34 *State Voluntary Agreements to Plan and Pay for Transmission Facilities*, 175 FERC ¶ 61,225 (2021) [hereinafter Policy Statement] (voluntary agreements among States are not precluded by federal law, and provide them a way to prioritize, plan, and pay for transmission facilities as an alternative to Order No. 1000).

35 See Pullman & Comley, LLC, Three Is Not a Crowd: A Tri-State Approach to Producing More Clean Energy" (December 28, 2015), https://www.jdsupra.com/legalnews/three-is-not-a-crowd-a-tri-state-46846/?

36 *See Id.*

37 ISO-NE, ISO New England Inc. Open Access Transmission Tariff, sched. 25 (Standard Elective Transmission Upgrade Interconnection Procedures) [hereinafter ISO-NE Schedule 25].

38 *See e.g.,* Massachusetts D.P.U. 18-64, D.P.U. 18-65, D.P.U. 18-66, Order (June 25, 2019), approving three PPAs pursuant to Section 83D of An Act Relative to Green Communities, St. 2008, c. 169 and 220 CMR 24.00, et seq. in which energy purchased under the PPAs would be delivered into New England over new transmission infrastructure interconnecting as an EUT under ISO-NE Schedule 25 and in accordance with FERC-approved Transmission Service Agreements.

39 ISO-NE, ISO New England Inc. Open Access Transmission Tariff, att. K (Regional System Planning Process).

40 ISO-NE, *Extended Term Transmission Planning Tariff Changes Key Project* (last visited May 20, 2022), https://www.iso-ne.com/

committees/key-projects/extended-term-transmission-planning-key-project/; ISO-NE, *2050 Transmission Study: Preliminary N-1 and N-1-1 Thermal Results* (March 16, 2022), https://www.iso-ne.com/static-assets/documents/2022/03/a4_2050_transmission_study_preliminary_n_1_and_n_1_1_thermal_results_presentation.pdf; and ISO-NE, *2050 Transmission Study: Sensitivity Results* and *Solution Development Plans* (April 28, 2022) [hereinafter 2050 Study Sensitivity Results], https://www.iso-ne.com/static-assets/documents/2022/04/a14_2050_transmission_study_sensitivity_results_and_solution_development_plans.pdf

41 ISO-NE, *Transmission Operating Agreements* (last visited May 20, 2022), https://www.iso-ne.com/participate/governing-agreements/transmission-operating-agreements

42 ISO-NE study results are not required for states to select a transmission solution. As with generator interconnections, ISO-NE will determine the upgrades required, if necessary, to interconnect the transmission solution while maintaining a reliable grid. Transmission developers submitting proposals before these results are known bear the risk that additional interconnection upgrades are identified and would be responsible for these costs.

43 *See* ISO-NE, *supra note 15;* and ISO-NE, *2050 Transmission Study: Preliminary Assumptions and Methodology for the 2050 Transmission Study Scope of Work - Revision 2* (November 17, 2021) () [hereinafter 2050 Study Preliminary Assumptions], https://www.iso-ne.com/static-assets/documents/2021/12/draft_2050_transmission_planning_study_scope_of_work_for_pac_rev2_clean.pdf. For offshore wind, this includes ISO-NE having modeled injection of 31,954 MW of fixed bottom and floating offshore wind to points of interconnection (POIs), predominantly in Massachusetts and Maine. 2050 Study Preliminary Assumptions at 4. ISO-NE subsequently modeled a sensitivity with offshore wind injections weighted toward Connecticut, resulting in a 400-mile reduction in overloaded transmission lines. 2050 Study Sensitivity Results, *supra* note 40.

44 *PJM Interconnection,* L.L.C., 174 FERC ¶ 61,090 (2021) (order approving executed State Agreement Approach Study Agreement between PJM and the New Jersey Board of Public Utilities implementing the State Agreement Approach process).

45 *Id.*

46 35-A MRSA §3210-H authorizes procurement of renewable energy or renewable energy credits equivalent to 18 percent of Maine's 2019 retail electric load. A procurement is pending. Public Utilities Commission, Request for Renewable Energy Generation and Transmission Projects Pursuant to the Northern Maine Renewable Energy Development Program, No. 2021-00369, Order (Me. P.U.C. November 29, 2021). Maine's 2019 retail electric load was 11,732,040 megawatt-hours of which 18 percent is 2,111,767 megawatt-hours, which is equivalent to 653 MWs of land-based wind operating at a 37 percent capacity factor. U.S. Energy Information Administration, Maine Electricity Profile 2019 (last visited May 20, 2022), https://www.eia.gov/electricity/state/archive/2019/maine/

47 Upgrades to VELCO's K42 transmission line are designed to replace aging equipment, reduce resistance and reactance, and benefit future interconnections. ISO-NE, *VELCO's Asset Condition Project: K42 Transmission Line Replacement* (January 26, 2022) (ISO memo supporting upgrade), https://www.iso-ne.com/static-assets/documents/2022/01/velco_asset_condition_project_k42_transmission_line_replacement.pdf. Discussion at ISO-NE's Planning Advisory Committee indicated that additional solutions to transmission constraints could further alleviate curtailment and facilitate interconnection.

48 See *South Carolina Pub. Serv. Auth. v. FERC,* 762 F.3d 41, 84-85 (D.C. Cir. 2014) (costs of transmission projects must be "allocated to those who cause the costs to be incurred and reap the resulting benefits.")(internal citations omitted); 57 FERC ¶ 61,140 (1991)("…customers should not be compelled to pay for services they have not requested and do not want.")..

49 This initial step could also be utilized in advance of allocating costs under Options 2 and 3.

50 ISO-NE, ISO New England Planning Procedure No. 4-1 §1, states that the "Generator Owner shall be obligated to pay all of the cost of such upgrade, including all Direct Interconnection Transmission Costs and any applicable tax gross-up amounts, **to the extent such costs would not have been incurred "but for" the interconnection;** provided that, **if ISO determines that a particular Generator Interconnection Related Upgrade provides benefits to the system as a whole** as well as to particular parties, **then the cost of such Upgrade shall be allocated in the same way as Reliability Transmission Upgrades.**" [emphasis added]

51 Most projects included in the RSP are subject to regional cost allocation. ISO-NE, *2021 Regional System Plan 109* (Nov. 2, 2021), https://www.iso-ne.com/static-assets/documents/2021/11/rsp21_final.docx.

52 *See* ISO-NE, *supra* note 50, at §2.

53 All buyers of transmission capability would be subject to the terms of the capability reservation set out in the VSA or subsequent procurement agreements.

54 California Independent System Operator Corporation, *California ISO okays first location-constrained transmission project* (May 18, 2009), https://www.caiso.com/Documents/CaliforniaISOOkaysFirstLocation-ConstrainedTransmissionProject.pdf.

55 *PJM Interconnection,* L.L.C, 179 FERC ¶ 61,024 (2022).

Endnotes

56 PJM Interconnection, Rate Schedule FERC No. 49, State Agreement Approach Agreement between PJM and NJ BPU.

57 ISO-NE has a provision for Late Comer Projects involving ETUs that can allow States to claw back costs from subsequently interconnecting generators. The late-comer provision will refund each State's share of the line, reducing its risk of initially overbuilding the line compared to the amount of generation that is initially procured. ISO-NE, ISO New England Inc. Open Access Transmission Tariff, sched. 11 (5). If this model is not acceptable to the States, they should approach FERC for alternatives. *See* Policy Statement, supra note 34, at P 6 (encouraging states to identify barriers to VSA and, as necessary, consider making filings before FERC to address those barriers).

58 Economic benefits of transmission can include production cost savings, reduced congestion, dispatch costs, and losses, increased reliability and operational flexibility, lower capacity needs and generation costs, increased competition and market liquidity, renewables integration and environmental benefits, insurance and risk-mitigation benefits, diversification benefits, economic development from transmission investments, and other metrics. Pfeifenberger, Johannes, Transmission Cost Allocation: Principles, Methodologies and Recommendations (2020), https://www.brattle.com/wp-content/uploads/2021/05/20508_transmission_cost_allocation_-_principles_methodologies_and_recommendations.pdf

59 This paradigm could serve either as the sole method to allocate procurement costs or a method to allocate costs remaining after avoided costs are apportioned.

60 *See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Notice of Proposed Rulemaking,* 179 FERC ¶ 61,028 at PP 185-225 (2022); and Pfeifenberger, Johannes, *21st Century Transmission Planning: Benefits Quantification and Cost Allocation* (2021), (providing examples of similar multi-value approaches by NYISO, SPP, MISO, and CAISO), https://www.brattle.com/wp-content/uploads/2022/01/21st-Century-Transmission-Planning-Benefits-Quantification-and-Cost-Allocation.pdf.

61 *See, e.g.,* Monitoring Analytics, *2021 Quarterly State of the Market Report, Jan. through Sep. 676-679,* https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021q3-som-pjm-sec12.pdf

62 Similar to Option 2, this paradigm could serve either as the sole method to allocate procurement costs or a method to allocate costs remaining after avoided costs are apportioned.

63 This advantage is shared by the recommended option, with only committed States responsible for cost allocations.