Clean Energy Transmission Working Group

Report to the Legislature

December 2023

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Letter From the Chairs

Massachusetts Secretary of Energy and Environmental Affairs (EEA) Rebecca Tepper would like to acknowledge the following people for their volunteer service on the Clean Energy Transmission Working Group (CETWG) and assistance in preparing this report.

[Thank you to non-members who contributed, e.g., Jenner & Block]

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Acroynms

AC	alternating current
AI	artificial intelligence
AMI	advanced metering infrastructure
ANOPR	advanced notice of proposed rulemaking
ARI	active resource integration
ASO	affected system operator
BIL	Bipartisan Infrastructure Law
CCRIS	Cape Cod Resource Integration Study
CECP	Clean Energy and Climate Plan
CEISP	Commission on Energy Infrastructure Siting and Permitting
CETWG	Clean Energy Transmission Working Group
CIP	Capital Investment Project
DC	direct current
DER	distributed energy resources
DERMS	Distributed Energy Resource Management Systems
DG	distributed generation
DLR	dynamic line rating
DOE	Department of Energy
DOER	Department of Energy Resources
DPU	Department of Public Utilities
EDC	electric distribution companies
EEA	Energy and Environmental Affairs
EFSB	Energy Facilities Siting Board
EFSC	Energy Facilities Siting Council
EOED	Executive Office of Economic Development
EPS	electric power system
ESMP	Electric Sector Modernization Plans
ETU	Elective Transmission Upgrades
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GDO	Grid Deployment Office
GET	Grid Enhancing Technologies
GHG	greenhouse gas
GRIP	Grid Resilience and Innovation Partnerships
HVDC	high voltage direct current
IIJA	Infrastructure Investment and Jobs Act
IRA	Inflation Reduction Act

ISO-NE	Independent Service Operator New England
kV	kilovolt
LRTP	long-range transmission plan
MassCEC	Massachusetts Clean Energy Center
MassDEP	Massachusetts Department of Environmental Protection
MEPA	Massachusetts Environmental Policy Act
MISO	Midcontinent Independent System Operator
MIT	Massachusetts Institute of Technology
MMBtu	million British thermal units
MOWIP	Modular Offshore Wind Integration Plan
MVP	multi-value planning
MW	megawatts
NECEC	New England Clean Energy Connect
NERC	North American Electricity Reliability Corporation
NESCOE	New England States Committee on Electricity
NIETC	national interest electric transmission corridor
NJ BPU	New Jersey Bureau of Public Utilities
NOPR	Notice of Proposed Rulemaking
NPCC	Northeast Power Coordinating Council
NPCC	Northeast Power Coordinating Council
NYES	New York Energy Solution
OATT	open access transmission tariff
PFC	power flow controllers
PNNL	Pacific Northwest National Laboratory
POI	point of interconnection
PV	photovoltaic
QW	gigawatt
RTOs	Regional Transmission Operators
SEMA	Southeast Massachusetts
SPP	Southwest Power Pool
TFP	Transmission Facilitation Program
TO	transmission operator
TSED	Transmission Siting and Economic Development
VSC	voltage source converters
WPI	Worcester Polytechnic Institute
ZBA	Zoning Board of Appeal

Executive Summary

The Clean Energy Transmission Working Group (CETWG) was established as part of the requirements of Chapter 179, §71 of the Acts of 2022, "An Act Driving Clean Energy and Offshore Wind" (the Climate Law) to assess and report to the general court on any necessary transmission infrastructure upgrades that may be required to support the deployment of clean energy projects, including offshore wind projects. The Climate Law designates 17 members to serve on the CETWG and requires the CETWG submit a final report, along with recommendations for legislative and regulatory actions at the state, regional, and federal level, no later than December 31, 2023, to the clerks of the House of Representatives and Senate and the chairs of the Joint Committee on Telecommunications, Utilities and Energy. In carrying out its mandate the CETWG met nine times from July through December 2023 to receive presentations, review materials, and discuss the following topics:

- Jurisdictional Authority
- Transmission System Planning
- Distribution System Planning
- Cost Allocation
- Offshore Wind Transmission
- Interconnection
- Grid Enhancing Technologies
- Siting and Permitting

Jurisdictional Authority

The Federal Powers Act (FPA) of 1935 provides FERC exclusive jurisdiction over sales of electricity that cross state lines and the transmission of electricity across state lines through the regional high voltage bulk power transmission system. States and local governments have authority over the siting and construction of transmission lines. They also have authority over the electric distribution system, including rate regulation, siting and construction of distribution facilities, and interconnection of facilities to the distribution system. The legislature directs statutory and regulatory changes that drive the need for transmission, such as decarbonization requirements leading to greater electrification that, in turn, increases load and potential need for new transmission.

Transmission System Planning

Transmission facilities in the Commonwealth are owned and operated primarily by National Grid and Eversource Energy, and to a lesser extent other utilities and municipal light plants. These facilities operate at voltages levels between 69 kV and 345 kV and are part of a larger interconnected electric grid extending from the Canadian Maritime Provinces to the Midwest United States. Transmission owners design, operate, and maintain the grid to ensure compliance with mandatory reliability standards and design criteria and ensure reliability of the transmission system.

ISO New England (ISO-NE) is an independent entity regulated by FERC that plans and operates the region's bulk power system. ISO-NE conducts regional transmission planning in New England pursuant to its tariff, considering projects based on reliability, market efficiency, or public policy needs. The ISO-NE planning process for reliability needs begins with a reliability assessment study of a particular sub-area of the New England transmission system, called a "Needs Assessment" that identifies system needs, considering forecasted loads and known changes to the generation fleet over a ten-year horizon. When ISO-NE identifies a system reliability problem from a needs assessment, it works with transmission owners to develop transmission upgrades to resolve reliability needs or uses a competitive transmission development process to solicit transmission solutions from qualified transmission developers. ISO-NE's tariff also includes planning processes that transmission planners can use to identify transmission upgrades that provide economic benefits or meet one or more New England state's public policy requirements or goals.

Transmission owners also have obligations to maintain or replace their existing facilities. Because of this, the transmission owners frequently engage in asset condition-related upgrades. Asset condition projects are not subject to the regional planning process, but transmission owners generally allocate the costs of these projects on a pro rata basis across the region. In response to a request by NESCOE, transmission owners are in the process of implementing reforms to these procedures.

The electric grid nation-wide is confronting ongoing challenges stemming from aging infrastructure, insufficient transmission capacity and growing variable generation sources. In response to these challenges, DOE recently completed a National Transmission Needs Study designed to identify and quantify interregional needs under different clean energy policy scenarios. The Needs Study showed an urgent demand for additional electric transmission infrastructure in and between nearly all transmission regions across the United States to enhance reliability and resilience.

The Needs Study identified New England as one region having a significant need to increase its interregional transfer capacity, specifically between New England and New York. Transmission planners are making progress in exploring expanded ties between regions in the Northeast. Earlier this year, Massachusetts led a bipartisan request to DOE from the New England states, New York, and New Jersey to form a multi-state collaborative to work with our federal partners on opportunities to develop electric transmission infrastructure to enhance our interregional connections, including the potential build-out of an offshore wind network.

In 2020, the New England states through the New England States Committee on Electricity (NESCOE) asked ISO-NE to implement a longer-term, repeatable regional transmission planning effort that would provide a high-level transmission system plan to meet the needs of the New England states' energy transition with participation and input by State officials. In 2021, ISO-NE began work on the 2050 Transmission Study, the first such longer-term study. The 2050 Transmission Study is designed to inform states, stakeholders, and the region of possible future transmission needs and provide directional results to inform decisions around future investment to meet the region's clean energy needs. The Study resulted in several high-level observations around transmission-related challenges the future grid may face during the clean energy transition:

- Reducing peak load significantly reduces transmission costs. Limiting load growth could be achieved through more aggressive demand response, energy efficiency, and peak shaving programs. Limiting load growth could also be achieved by using some stored fuel for heating on the coldest days.

- Targeting and prioritizing areas of the transmission system with the highest likelihood of future system constraint are likely to bring the greatest benefit for a wide range of possible future conditions as the clean energy transition accelerates.
- Incremental upgrades can be made as opportunities arise. Many of the transmission concerns found can be addressed by rebuilding existing transmission lines rather than building new lines in new locations.
- Generator locations matter. The specific location of generators can have a significant impact on the needed transmission upgrades. In general, locating generation close to large load centers, such as cities, can reduce the strain on the transmission system.
- Transformer capacity is crucial. Transformers "step down" power from higher to lower voltages. The Study found that as load increases, higher voltage lines become more important. In turn, the power transferred on the higher voltage lines must eventually be stepped down to lower voltages on the way to the distribution system. The region will need a significant number of additional transformers to support load growth.

As part of the study, ISO-NE developed conceptual transmission infrastructure solutions for all identified concerns and corresponding cost estimates. Generally, the solutions comprised both new transmission lines as well as the rebuilding of existing transmission lines. Total cost to serve a 51 GW winter peak load in 2050 would be $16-17 Billion, approximately $.62 to $.65 Billion per year between now and 2050. Total cost to serve a 57 GW winter peak load in a high-electrification scenario would be approximately $23- $26 Billion, approximately $.88 Billion to $1 Billion per year to 2050. For context, total transmission spending between 2002 and 2023 totaled $15.3 billion, or an average of approximately $0.73 billion per year. The investments would be spread out between now and 2050 and are useful for providing an order-of-magnitude estimate of future transmission system costs inherent in maintaining reliable transmission service through the clean energy transition. ISO-NE is now working to establish a process by which states can operationalize the 2050 Study results. Stakeholder discussions on this second phase of the longer-term transmission study process began in October 2023.

Distribution System Planning

The distribution electric network encompasses the intricate network of power lines, utility poles, substations, and associated equipment that acts as the final link in the journey of supplying electrical energy from the transmission system to end-users. The distribution system within the Commonwealth has been experiencing a systematic change in recent years with the adoption of distributed solar power and the increased deployment of energy storage solutions. This growth can be attributed to proactive state policies and initiatives that have resulted in the distribution networks within Massachusetts becoming some of the most densely connected systems for distributed energy resources in the country.

As part of the growing electrification, the future distribution system will need to accommodate substantial new load from several sources, including transportation and heating. The Commonwealth's electric distribution companies (EDCs) have raised concerns that infrastructure is approaching a critical juncture, with existing networks close to becoming fully utilized and a pressing need for investment to enhance capacity and flexibility for customers. In response, the EDCs have prepared Electric Sector Modernization Plans (ESMPs) containing forecasts of future distribution grid reliability needs, and the EDCs' proposed investments in the electric grid to address these needs, The EDCs recently submitted their ESMPs to the DPU for review and approval.

The 2050 Transmission Study and ESMPs highlight that the clean energy transition likely will require significant electric transmission and distribution infrastructure investments. The costs of future grid investments will flow into regional transmission service and local distribution rates. By way of context, the regional transmission rate has nearly doubled between 2012 and 2023 and is projected to increase over the next four years approximately another 38 percent. According to ISO-NE, transmission rates for residential retail consumers in CT, ME, MA, NH, and RI in effect on January 1, 2022, shows that transmission costs represent approximately 7.9% to 15.3% of total residential retail electricity rates. This has contributed to New England consumers paying some of the highest electricity rates in the country.

Cost Allocation

FERC mandates the adoption of cost allocation methods in planning regions and has a long-standing cost allocation policy that aligns costs with benefits by identifying the beneficiaries of proposed regional transmission facilities and imposing those costs on them. However, FERC did not adopt a universal or comprehensive definition of "benefits" and "beneficiaries," allowing regional planning entities flexibility if they complied with six regional cost allocation principles. In 2022 FERC issued a NOPR to reform regional transmission planning and cost allocation while providing regions and states flexibility in developing appropriate methods for allocating the costs of meeting long-term transmission needs. The NOPR proposed greater state involvement in determining cost allocation, while preserving cost allocation principles. The NOPR remains pending at FERC.

At present, ISO-NE Regional Benefit Upgrades to address grid reliability and economic needs are allocated on a load-ratio basis based on the amount of electricity demand in each state. Under a default cost allocation method, costs of public policy projects planned by ISO-NE would be shared 70 percent by consumers throughout the region on a load-ratio basis and 30 percent by consumers of those states whose public policies drive the need for these projects. Elective transmission projects are 100 percent funded by the project developer and local transmission projects are funded locally by customers causing the need for the project.

Offshore Wind Transmission

The current approach to offshore wind transmission planning involves offshore wind developers taking interconnection and delivery risk by making informed approximations on where they can import the most amount of clean energy at the lowest cost and least disruption to surrounding communities. However, as each subsequent state RFP is released, low-cost options for onshore interconnection sites for individual offshore wind farms dwindle, and onshore interconnection and grid upgrade costs and associated uncertainties are rapidly increasing. Optimizing points of interconnection for offshore wind is critical.

Targeted upgrades of the onshore network to facilitate delivery of offshore wind from proactively planned points of interconnections can provide substantial benefits. Points of interconnection need to be maximized for imported power capacity, dependability, and resilience, considering environmental and community impacts. A more collaborative and proactive planning process considering how to integrate future clean energy resources onshore and offshore will allow the region to evaluate the most cost-effective and flexible options for the region and its electricity customers. Realizing the benefit of an offshore wind network requires that individual offshore wind transmission solutions are standardized so they can be integrated in the future. In addition, HVDC equipment needs for offshore wind will require continued work and assessment, notably to improve what equipment is currently available, diversifying supplier options in the market, and building out a HVDC supply chain that can lower costs.

Interconnection

Backlogs of projects in the interconnection queue waiting to be studied and high volumes of projects dropping out of studies at various stages of the process are driving calls for interconnection process reform. ISO-NE's interconnection queue has seen significant delays in the time necessary to complete studies, with over 30,000 MW of proposed projects in its queue. As interest in developing clean energy has grown so has the need for more studies that are also more complex. Studies are time intensive, complicated, and rely on a limited workforce challenged by a shortage in engineering expertise to accomplish this work.

ISO-NE has primarily studied interconnection projects serially, or one after another. Under FERC regulations project developers bear the costs of the upgrades needed to connect to the grid, including upgrades at the point of interconnection and upgrades elsewhere on the system, called network upgrades. If a single project seeking interconnection triggers costly upgrades beyond the normal costs of building interconnection facilities the project may become nonviable, and the developer may cancel the interconnection request. Because the issue on the grid has not been resolved, it will likely remain for the next project that ISO-NE studies, causing that project to cancel its interconnection request.

FERC's recent Order 2023 mandates a variety of changes to the interconnection process, with the expectation these will speed up interconnection queues and improve the timeliness of interconnection projects. The changes include requirements that studies be conducted in groups or clusters to share network upgrade costs among projects, fixed timelines for studies to be competed, higher barriers to enter the project queue, and penalties for TOs and RTO/ISOs if deadlines are not achieved. ISO-NE is in the process of developing its compliance rules, which are required for submission to FERC in April 2024.

Grid Enhancing Technologies

Grid Enhancing Technologies (GETs) are hardware and software tools that increase the capacity, efficiency, and/or safety of the electric transmission system. Transmission operators utilize these optimization technologies, including dynamic line ratings (DLRs), advanced power flow controllers (PFCs), and topology optimization on existing and new transmission infrastructure to provide greater situational awareness, flexibility, and control over the grid. As the grid becomes increasingly congested and capacity constrained, GETs can reduce congestion costs and increase reliability and resilience by providing several system benefits. These include improved situational awareness to enable safer real-time operations, asset health monitoring information to support asset replacement deferral while longer-term solutions are implemented, and increased grid resilience. Considering it may take years to construct new transmission lines, the deployment of GETs may provide the system greater operational flexibility until additional transmission capacity can be added and can materially increase the capacity of existing transmission assets and aid in deploying new clean energy resources.

Siting and Permitting

Federal, state, and local authorities all play a role in siting and permitting electric transmission facilities. Electric transmission facility siting and permitting largely rests with the states. The Commonwealth has two state agencies with responsibilities in energy facilities siting: the Department of Public Utilities (DPU) and the Energy Facilities Sitting Board (EFSB). The DPU has authority over new electric transmission line construction or significant alteration of existing lines. For these projects, electric companies must show a proposed project is needed, serves the public convenience, and is consistent with the public interest. The DPU also has authority over eminent domain, local zoning exemptions, and grants of location for transmission line. The EFSB is an independent board, whose statutory purpose is to review and approve proposed energy facilities to ensure a reliable energy supply, with minimum impact on the environment, at the lowest possible cost. There are numerous other state and local agencies that have specified areas of permit and approval authority and oversight for proposed electric transmission facilities.

Recommendations

The CETWG report makes several recommendations designed to enhance the process of planning, developing, siting, and operating existing and new transmission facilities to support the transition to a clean energy future. Recommendations are broken out into several areas: transmission planning, interconnection, offshore wind transmission, workforce development, and siting and permitting. The list of recommendations is extensive and includes:

- Support efforts to create more ~~holistic,~~ proactive, and forward-looking transmission planning processes that address all transmission needs and benefits in an integrated fashion.
- Encourage the co-location of needed new onshore transmission infrastructure within state-owned or state-controlled properties and corridors, such as highway and railroad rights-of-way.
- Consider collaborating with TOs and ISO-NE to develop guidance for identifying and procuring key pieces of transmission-related equipment.
- Support a regional analysis of GETs, informed by experience to-date with the implementation of FERC Order 881.
- ~~Consider directing~~ EDCs and TOs should~~to~~ work with ISO-NE to identify and execute local transmission upgrades ~~necessary to meet statewide climate goals, including upgrades~~ necessary to implement the electric sector grid modernization plans consistent with DPU direction.
- Amend Section 70 of Chapter 179 of the Acts of 2022 to enable DOER to competitively solicit and select proposals for transmission to deliver clean energy generation to help achieve the Commonwealth's clean energy requirements, beyond existing authority to solicit and select transmission related solely to offshore wind.
- In partnership with other New England states, t~~T~~he Commonwealth should continue to develop enhancements to and creation of programs to limit peak load growth (e.g., demand response, time of use rates, rate design, load management, and energy efficiency programs) which, in turn, would reduce the intensity of needed transmission.
- Work with regional partners to e~~E~~stablish a forum to explore interconnection process improvements beyond Order 2023 compliance.
- Evaluate the offshore wind procurement process as part of a strategic offshore wind plan, considering recent procurement experiences along the east coast.
- Work with other New England states, ISO-NE, and transmission-owning companies to initiate a regional analysis to determine the optimal locations for the interconnection of offshore wind.
- Support continued workforce development efforts to increase the number of engineers and technical staff ~~within relevant agencies to ensure review of state and local siting and permitting applications in a prudent and expeditious manner~~.
- Recommend the CEISP consider the conclusions regarding siting and permitting challenges to electric transmission infrastructure addressed in this report.

1. Background

Massachusetts is moving aggressively to meet statutory requirements to reduce carbon emissions from the electric, heating, and transportation sectors by 2050 and to increase renewable energy resources.[1] Other New England states have similar requirements and goals.[2] These requirements are prompting an historic transition to the electric power grid, prioritizing clean resources such as wind and solar photovoltaic (PV) generation and leading to increased electrification of the heating and transportation sectors. Over the next several decades, electrification is expected to increase overall consumer demand for electricity, drive changes in usage patterns,[3] and increase the need for transmission to move electricity from new generation resources to the consumer. As the electric grid evolves toward renewable and variable or intermittent resources, and consumers rely more on electricity for generation, transportation and heating and cooling, ensuring a reliable and efficient transmission system to meet these new demands will be increasingly important.[4]

Legislative Mandate for the Clean Energy Transmission Working Group

1.1.1. Section 71 of the 2022 Climate Act Requirements

The Clean Energy Transmission Working Group (CETWG) was established as part of the requirements of Chapter 179, §71 of the Acts of 2022, "An Act Driving Clean Energy and Offshore Wind" (the Climate Law) to assess and report to the general court on any necessary transmission infrastructure upgrades that may be required to support the deployment of clean energy projects that may interconnect into the Commonwealth for the benefit of residents of the Commonwealth and the region, including but not limited to offshore wind projects.

The CETWG's scope includes the following:

- Consider both in-state transmission upgrades as well as regional transmission upgrades that may be necessary to accommodate the Commonwealth's clean energy requirements.
- Provide recommendations on actions or initiatives that may be undertaken by Independent Service Operator of New England (ISO-NE), the Federal Energy Regulatory Commission (FERC), and other regional and state-level entities that may be helpful or necessary to funding, securing, or approving such upgrades.
- Include a cost-benefit analysis to identify regulatory and legal challenges associated with obtaining and streamlining tariff approvals to accommodate increased clean energy penetration across New England.

[1] In December 2022, the Executive Office of Energy and Environmental Affairs (EOEEA) released the 2050 Clean Energy and Climate Plan (CECP), detailing how the state plans to meet its statutory requirements to achieve Net Zero greenhouse gas emissions by 2050. The plan sets sector-specific emissions limits which equal the required gross greenhouse gas emissions reductions of at least 85 percent below 1990 levels and proposes carbon sequestration goals to supplement reductions and meet the 2050 net-zero requirement.

[2] The five New England states with emission reduction requirements or goals are Connecticut, Maine, Massachusetts, Rhode Island, and Vermont.

3 To include changes in seasonal and daily shifts in peak demand.

4 The ISO-New England 2023 Regional System Plan, page 15, "the power grid of the future looks radically different from the power grid of the past, and immense resource and transmission buildouts, along with flexible loads and modifications to our grid planning processes, are required to meet the changed needs."

- Assess and review cost-allocation measures adopted in other jurisdictions that aim to spread transmission upgrade costs equitably among ratepayers and developers across the states and regions.
- Give special attention to the need to equitably allocate costs to, and share costs with, benefitted populations outside the Commonwealth, and include policy recommendations that may be needed to equitably recover such costs.

The Climate Law requires the CETWG to submit a final report, along with any recommendations for legislative and regulatory actions at the state, regional, and federal level, no later than December 31, 2023, to the clerks of the House of Representatives and the Senate and the chairs of the Joint Committee on Telecommunications, Utilities and Energy.

1.1.2. Clean Energy Transmission Working Group Membership

CETWG membership is specified in the Climate Law and comprises seventeen (17) members, or their designees, appointed by the Governor and representing a wide array of organizations and interests. The Chairman of the Department of Public Utilities (DPU) and the Commissioner of Department of Energy Resources (DOER) chair the CETWG, supported by DPU and DOER staff. Members do not receive compensation for their services and serve until completion of the final report with recommendations is issued. The members include the following representatives:

- Chair of the Department of Public Utilities
- Commissioner of the Department of Energy Resources
- Attorney General
- 2 co-chairs of the Joint Committee on Telecommunications, Utilities, and Energy
- 6 appointees of the Governor from the following organizations and associations:
    - American Society of Civil Engineers
    - Associated Industries of Massachusetts, Inc.
    - Massachusetts Taxpayers Foundation, Inc.
    - National Consumer Law Center
    - The Acadia Center
    - Northeast Clean Energy Council, Inc.
- 6 additional appointees of the Governor, representing:
    - Representative or consultant to the offshore wind industry
    - Representative or consultant to the solar energy industry
    - Economist with knowledge of the electricity transmission, distribution, generation, and power supply
    - Representative of municipal interests or a regional public entity
    - 2 representatives of investor-owned utilities in the Commonwealth

Public Meetings

1.1.3. Schedule

The CETWG conducted a total of nine public meetings between July and December 2023. The CETWG held meetings virtually via Zoom and provided advance notice to the public. The CETWG added two additional meetings in December to provide additional time for members to consider the draft report to the legislature and allow additional opportunities for public comment.

Meeting Dates and Presentations

- July 28th: Introduction to ISO-New England System Planning
- August 25th: ISO-NE's 2050 Transmission Study
- September 22nd: Offshore Wind Transmission
- October 13th: Distribution System Planning and Operations
- November 3rd: Jurisdictional Authority and Cost Allocation
- November 17th: Interconnection and FERC Order 2023, Clean Energy Siting and Permitting, and Review Draft CETWG Report Conclusions and Recommendations
- December 6th: Review of Draft CETWG Report
- December 15th: Review of 2nd Draft CETWG Report
- December 21st: Final Report Vote

1.1.4. Public comments and participation

Meetings of the CETWG provided an opportunity for public comment and written comments were accepted throughout the process of meeting and developing this report. Written public comments are summarized in a brief appendix and posted to the CETWG website. In addition, interested parties were encouraged to register for notifications of meetings via a CETWG list service and meeting materials and presentations were made available via the CETWG website for review.

1.1.5. Access to information

The CETWG website is available to the public and provides an overview of the 2022 Climate Law in regard to the reporting requirements and meeting details, to include the reporting requirements of the CETWG, appointed members and organizational affiliation, and meeting schedule. For each meeting an agenda, presentation materials, previous meeting minutes, and other relevant information were posted in advance. A Notice of Public Meeting was also submitted to the Secretary of State in advance as required. Draft report conclusions and recommendation were posted to the website on November 16th, 2023, a first draft of the CETWG report posted on November 25th, 2023, and a second draft report was posted on December 12~~3~~th, 2023. A public meeting and vote to approve report recommendations was held on December 21st, 2023. Public comment was accepted throughout the process.

2. Jurisdiction Authority

Federal/FERC

FERC is an independent federal agency within the Department of Energy (DOE) that regulates the interstate transmission of electricity, natural gas, and oil. The Department of Energy Organization Act created FERC ~~was created~~ in 1977 ~~by the Department of Energy Organization Act~~ and replaced its predecessor agency known as the Federal Power Commission. ~~As an independent agency,~~ DOE may not review FERC's decisions ~~are not reviewable by the DOE~~, although they are subject to judicial review in the U.S. courts of appeals.

Below is an overview of FERC's jurisdiction over electricity transmission, particularly with respect to the setting of rates, system planning and interconnection, siting of facilities, and maintaining reliability.

2.1.1. Transmission rates

The Federal Power Act of 1935 (FPA) gave FERC's predecessor, the Federal Power Commission, jurisdiction over the transmission of electricity, and the sale of electric energy at wholesale, in interstate commerce. In short, FERC has exclusive authority over sales for resale of electricity that cross state lines, as well the transmission of electricity across state lines.

In *New York v. FERC*, the Supreme Court affirmed the FPA's "clear and specific grant of jurisdiction" to FERC over the regulation of electric transmission in interstate commerce. 535 U.S. 1, 22 (2002). This statutory grant extends to FERC's review of public utility transmission owners' tariffs filed under FPA Section 205, as well as over FERC's power under FPA Section 206 to fix any rate, charge, or classification demanded, observed, charged, or collected for transmission by such utilities (including the FERC's remedial authority over "any rule, regulation, practice, or contract affecting such rate, charge, or classification"). FERC plays an essentially passive and reactive role under Section 205, as those filings are driven by the filing utility. By contrast, FERC can take on a proactive role under Section 206, which empowers it to modify existing rates either upon a complaint or upon its own initiative.

FERC's actions in these areas may impact consumer bills, but it is the state public utility commissions that determines retail rates (*i.e.*, the rates individual consumers pay each month on their electricity bills). States have authority over sales of electricity to consumers within their state, as well as intra-state transmission (also called distribution) of electricity.

2.1.2. Transmission planning and interconnection

FERC affirmed and clarified its jurisdiction over transmission planning and interconnection of facilities to the bulk transmission system through a series of orders dating back to 1990s. In 1996, FERC issued its historic Order No. 888, which restructured interstate transmission of electricity from a contract-based service to a common carrier-type service and provided for open access. In 1999, FERC issued Order No. 2000, which promoted the creation of regional transmission organizations (RTOs) to provide nondiscriminatory open access to transmission. Order No. 2000 defined the minimum characteristics of an RTO as: (1) independence from market participants; (2) appropriate scope and regional configuration; (3) possession of operational authority for all transmission facilities under RTO control; and (4) exclusive authority to maintain short-term reliability of the grid. ISO-NE is the RTO for the New England region.

Then, in 2005, Congress amended the FPA to specifically authorize FERC to act "in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities." In 2007, FERC issued Order No. 890, requiring all public utility transmission providers' local transmission planning processes to satisfy nine transmission planning principles: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; (7) regional participation; (8) economic planning studies; and (9) cost allocation for new projects.

Building on this, in 2011, FERC issued another transmission planning order (Order No. 1000) requiring each transmission owning and operating public utility to participate in regional transmission planning that satisfies specific planning principles designed to prevent undue discrimination and preference in transmission service, and that produces a regional transmission plan. Each planning process must have a method for allocating *ex ante* among beneficiaries the costs of new transmission facilities in the regional transmission plan, and the method must satisfy six regional cost allocation principles—including "cost causation," under which "[t]he cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits."

In 2022, FERC issued a Notice of Proposed Rulemaking (NOPR) to reform regional transmission planning,~~ and~~ cost allocation, and generator interconnection[5]~~which is still pending at FERC~~. One goal of this Proposed Rule is to ensure more proactive and forward-looking planning of future transmission needs while also affording regions and states sufficient flexibility in developing appropriate methods for allocating the costs of meeting those transmission needs. On July 28, 2023, FERC issued its order on "Improvements to Generator Interconnection Procedures and Agreements" (Order 2023) to speed up the processes RTOs are using to study and approve the interconnection of new generation resources, including solar and offshore wind generators. RTOs will adjust their existing processes by early 2024 to comply with the new order.

2.1.3. Federal role in transmission siting

The Energy Policy Act of 2005 established a limited federal role for the siting of transmission facilities by adding Section 216 to the FPA, authorizing the Commission to issue permits to construct transmission facilities, under certain circumstances, including when a state denies or fails to act on a siting application within one year. See section 8.1 for more information about FERC's limited transmission siting authority.

2.1.4. Transmission reliability

After the 2003 Northeast Blackout, Congress gave FERC broad authority over the reliability of the high voltage (99 kilovolt (kV)+) transmission system, also called the bulk power system. FPA Section 215 directs FERC to adopt and enforce mandatory reliability standards. Under this regime, the North American Electricity Reliability Corporation (NERC) develops the standards and proposes them to FERC; FERC then gets to review and approve. NERC, in turn, delegates authority to eight regional entities to monitor and enforce compliance of those reliability standards. The entity that covers New England, the Northeast Power Coordinating Council (NPCC), is thus authorized within its region to enhance reliability by, among other things, engaging in assessments of reliability, creating region-specific standards, and monitoring the compliance of users, owners, and operators within the region.

State Authorities

States and local governments have authority over the siting and construction of transmission lines. They also have authority over the electric distribution system, including rate regulation, siting and construction of distribution facilities, and interconnection of facilities to the distribution system. The legislature directs statutory and regulatory changes, including to the distribution system, siting, and electric generation procurement. The legislature also drives the need for transmission through legislative changes, such as decarbonization requirements leading to greater electrification that, in turn, increases

[5] In 2023 FERC issued Order 2023 proposing reforms to existing generator interconnection rules and policies (see chapter 6 of this report). The remaining NOPR transmission planning and cost allocation reforms remain pending at FERC.

load and potential need for new transmission. In addition, state-initiated and led procurements for renewable generating resources can have implications for transmission needs and reliability impacts.

In Massachusetts, the DPU is the state's regulatory agency that can promulgate policies, including clean energy policies, that impact the grid. The Siting Division of the DPU has authority to, among other things, issue licenses to construct and operate transmission lines and permit the taking of land (or issuance of easements) for necessary energy facilities. Separately, the Energy Facilities Siting Board (EFSB), an independent state board, reviews proposed large energy facilities, including electric transmission lines. EFSB approval is required prior to the commencement of construction of any EFSB-jurisdictional facility in the Commonwealth, and no State agency may issue a construction permit for any such facility unless EFSB has approved the petition to construct the facility.

The Massachusetts DOER develops and implements policies that include maximizing procurement and deployment of clean energy resources and improving the cost of such resources relative to fossil fuel generation. For example, DOER plays a key role in supporting Massachusetts' procurement of offshore wind generation. Massachusetts' current procurement goals target a total of 5,600 megawatts (MW) from clean energy and offshore wind. The original legislation, the 2016 Energy Diversity Act, required a total of 1,600 MW of offshore wind by 2027. The legislature increased t~~T~~hat target~~ was increased~~ several times in ensuing years. Recent legislation (H. 5060, enacted Aug. 2022) provides that DOER may competitively solicit and procure proposals for offshore wind energy transmission to support wind energy generation projects. Under the Act, DOER may coordinate with other state agencies and other New England states to develop a solicitation to best meet the needs of the growing offshore wind industry while maintaining reliability. DOER must consider the total amount of transmission needed to maintain reliability, avoid unnecessary costs to upgrade the existing transmission grid, achieve the Commonwealth's offshore wind and decarbonization goals, and benefit consumers and the environment. Proposals can include upgrades to the existing grid, extending the grid closer to offshore wind locations, and interconnecting offshore substations. The Act also directed DOER to prepare a study on the benefits and costs of requiring electric distribution companies to conduct additional solicitations and procurements for up to 1,600 megawatts (MW) of additional offshore wind. DOER published its Offshore Wind Study in May 2019, recommending that Massachusetts distribution companies proceed with solicitations to secure an additional 1,600 MW of offshore wind generation.

3. Transmission Planning

Bulk Power System

3.1.1. ISO-NE transmission planning

Transmission owners have carefully maintained and expanded ~~T~~the New England transmission system ~~has been carefully maintained and expanded~~ for decades to move power efficiently from various sources to the region's load centers. To manage the varying amounts and sources of generation to serve the load needed for New England customers, the transmission system requires thoughtful and in-depth short- and long-term planning. With the growing amount of new, clean energy generation across the Commonwealth and region, it is essential that all stakeholders involved work together to ensure system reliability and expand the grid to meet rapidly evolving needs.

Transmission facilities across the Commonwealth are owned and operated primarily by National Grid and Eversource Energy, and to a lesser extent by several other utilities, including many of the Commonwealth's municipal light plants. These facilities operate at voltages levels between 69 kV and

345 kV. They are part of a much larger interconnected electric grid which extends from the Canadian Maritime Provinces to the Midwest United States. Transmission owners design, operate and maintain tThe entire grid is designed, operated, and maintained to ensure compliance with mandatory NERC reliability standards. Within New England, transmission owners mustthe grid is also designed to comply with mandatory standards and criteria from the NPCC, ISO-NE, as well as transmission planning and design criteria specific to individual transmission owners. These standards and criteria continue to evolve to ensure that the transmission system can continue to operate reliably in the face of growing load, changing generation sources, and increasing severe weather.

ISO-NE conducts regional transmission planning in New England pursuant to Attachment K of its open access transmission tariff (OATT) and generally considers projects based on reliability, market efficiency, or public policy needs. The ISO-NE planning process for reliability needs begins with a reliability assessment study of a particular sub-area of the New England transmission system, called a "Needs Assessment." These studies identify system needs (i.e. potential overloads, instability, etc.), considering forecasted loads and known changes to the generation fleet over a ten-year horizon. When ISO-NE identifies a system reliability problem is identified from a needs assessment, itISO-NE works with transmission owners to develop a portfolio of transmission upgrades to resolve the transmission reliability needs or, in some cases, uses the competitive transmission development process to solicit transmission solutions from qualified transmission developers. Since ISO-NE implemented changes to its OATT to comply with the directives of Order No. 1000 in 2015, ISO-NE has conducted one competitive solicitation. [Pfeifenberger: mention in this chapter transmission upgrades planned to address the reliability needs identified through studies undertaken in response to generation interconnection requests?]

ISO-NE then further evaluates tThe transmission system solution options are then further evaluated to determine, among other things, their feasibility of construction, potential for environmental impacts, estimated costs, longevity, and operational differences. When analysis of the options is complete, ISO-NE recommends a proposed transmission solution.

ISO-NE's tariff also includes planning processes that transmission planners can use to identify transmission upgrades that provide primarily economic benefits (i.e. lower wholesale power costs) or meet one or more New England state's public policy requirements or goals:

- Longer-Term Transmission Planning Process: Under a new process that FERC approved last year, the ISO-NE's regional system planning process authorizes ISO-NE to conduct longer-term transmission studies that may extend beyond a ten-year planning horizon. While the ISO conducts the longer-term transmission studies, it relies on the states to determine the range of scenarios, including drivers, inputs, assumptions, and timeframes to be used in these studies. ISO-NE is currently in the process of developing tariff language for the longer-term transmission planning process that would allow states to operationalize study results through an ISO-NE led procurement.

- Order 1000 Process: Since 2017, ISO-NE has initiated a process every three-years required under its tariff that provides an opportunity for regional study and potential evaluation and selection of public policy-driven transmission. This process, which covers the ten-year planning horizon, includes a role for the states in confirming that public policy requirements drive transmission needs and a role for ISO-NE is analyzing transmission needs and determining whether to select solutions.

- Elective Transmission Upgrades (ETU): An ETU offers the opportunity to submit a request for ISO-NE to study a proposed transmission upgrade. 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 built, the ETU transmission project becomes part of the New England transmission network. This process is nearly identical to the interconnection process for new generation in ISO-NE. The New England Clean Energy Connect (NECEC) project is an example of a public policy project that ISO-NE studied as an ETU.

To date, ISO-NE has used these processes infrequently.

The transmission owners use similar approaches to periodically assess their portions of the bulk power transmission system for compliance with reliability planning standards and criteria. These assessments overlap, to some extent, with the assessments that ISO-NE performs and also extend to radial portions of the transmission system that are not studied by ISO-NE. They ~~also~~ include additional planning criteria specific to each transmission owner, and assessments of transmission needs arising from upgrades or changes on the distribution system. For example, load growth or the addition of generation connected to the distribution system may require expansion of existing substations or the addition of new substations, both of which often require upgrades to the transmission system. The transmission owners identify t~~T~~hese projects via their Local System Plans ~~would be identified by the transmission owners~~ and coordinate themd with regional planning processes that ISO-NE oversees.

~~Incumbent transmission owners plan local projects in New England, typically radial expansion of a network or lower voltage level transmission facilities. These do not require ISO-NE formal review or approval.~~

The transmission owners also have ongoing obligations to maintain or replace their existing facilities – many of which are at least 50 years old and in some cases over 100 years old. Because of this, the transmission owners frequently engage in asset condition-related upgrades[6]. These projects can range

[6] Transmission owners develop asset condition projects and they are not subject to ISO-NE's regional planning process. Now, spending on asset condition projects far outpaces the spending on ISO-NE identified reliability transmission upgrades. Through June 2023, there has been $3.4 billion cumulative investment in New England on asset condition projects. Projected spend on asset condition projects through 2030 equals $4.3 billion.

from targeted replacements of individual components of a transmission facility – such as transmission line structures – to the complete reconstruction of a particular facility. The costs of these projects are generally recovered via regional transmission rates and allocated on a pro rata basis across the region. As a result, ~~many of the~~ transparency and stakeholder meeting requirements that apply to other regional reliability projects must also apply to asset condition projects. ~~For projects with estimated costs greater than $5 million, the transmission owners provide notice~~ These include~~through~~ presentations to the IS~~C~~O-NE's Planning Advisory Committee (PAC), NEPOOL's Reliability Committee, and the listing of the projects on ISO-NE's Asset Condition List. ~~ISO-NE's Planning Advisory Committee~~. In response to a request by the New England States Committee on Electricity's (NESCOE)[7], ~~T~~transmission owners are in the process of implementing reforms to these procedures ~~in response o a NESCOE request~~. ~~Asset condition projects are not subject to the regional planning process, but costs are generally allocated on a pro rata basis across the region.~~ In many cases, asset condition projects add capacity to the transmission system as an ancillary benefit, which can help integrate new clean energy resources.

~~ISO-NE's tariff also includes planning processes that can be used to identify transmission upgrades that provide primarily economic benefits (i.e. lower wholesale power costs) or meet public policy requirements or goals identified by one or more New England states. For transmission planning driven by public policy-related needs, there are several mechanisms that ISO-NE can employ:~~

- ~~Longer-Term Transmission Planning Process: Under a new process that FERC approved last year, the ISO-NE's regional system planning process authorizes ISO-NE to conduct longer-term transmission studies that may extend beyond a ten-year planning horizon. While the ISO conducts the longer-term transmission studies, it relies on the states to determine the range of scenarios, including drivers, inputs, assumptions, and timeframes to be used in these studies.~~

- ~~Order 1000 Process: Since 2017, ISO-NE has initiated a process every three-years required under its tariff that provides an opportunity for regional study and potential evaluation and selection of public policy-driven transmission. This process, which covers the ten-year planning horizon, includes a role for the states in confirming that public policy requirements drive transmission needs and a role for ISO-NE is analyzing transmission needs and determining whether to select solutions.~~

- ~~Elective Transmission Upgrades (ETU) offers the opportunity to submit a request for ISO-NE to study a proposed transmission upgrade. 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. This process is nearly identical to the interconnection process for new generation in ISO-NE. The New England Clean Energy Connect (NECEC) project is an example of a public policy project that ISO-NE studied as an ETU.~~

~~To date, these processes have been used infrequently and have not resulted in any regional transmission upgrades, although ISO-NE is currently in the process of developing tariff language for the longer-term transmission planning process that would allow states to operationalize study results through an ISO-NE led procurement.~~

[7] See: https://www.iso-ne.com/static-assets/documents/2023/02/2023_02_08_nescoe_asset_conditions_letter.pdf

3.1.2. ~~Interregional~~ Transmission needs in New England

3.1.2.1. Need for greater network connectivity

The transmission system is an essential component of the transition to a clean energy future and a resilient transmission network is of increasing importance to the nation's economic, energy security, and overall well-being. The nation's electric grid is confronting ongoing challenges stemming from aging infrastructure, insufficient transmission capacity, and a growing population of variable generation sources. As such, in response to the President's Bipartisan Infrastructure Law (BIL) also known as IIJA, DOE recently completed a National Transmission Needs Study[8] (Needs Study) ~~was recently completed by the DOE,~~ to better understand these challenges at a national level by identifying and quantifying interregional needs under different levels of clean energy policy achievement. The Needs Study delved into publicly available data and more than 50 other industry reports from the past five years that assess existing and anticipated needs given varying factors such as electricity demand, public policy, and market conditions. Additionally, the DOE (in collaboration with Pacific Northwest National Laboratory (PNNL)) is currently conducting a National Transmission Planning Study[9] to understand the value of building interregional transmission to meet these identified needs.

~~Independent of regional differences to how areas are operated, the Needs Study delved into publicly available data and more than 50 other industry reports from the past five years that assess existing and anticipated needs given varying factors such as electricity demand, public policy, and market conditions.~~

~~3.1.2.2. Economic indicators for more flexible interregional connections~~

~~There are regional differences in electricity prices. Extraordinary conditions and high-value periods significantly influence the value of transmission, with 50% of the transmission congestion value originating from just 5% of the hours. An examination of new generation and energy storage resources awaiting interconnection agreements across various regions suggests a shift towards greater use of wind, solar, and battery storage technologies in the generation mix. A review of recent power systems studies underscores the historical and expected drivers, advantages, and obstacles associated with expanding the nation's electric transmission network. Collectively, these studies underscore an urgent need to expand electric transmission, driven by the imperatives of enhancing grid reliability, resilience, and resource adequacy, facilitating the integration of renewable resources and access to clean energy, reducing the energy burden, supporting electrification efforts, and alleviating congestion and curtailment.~~

~~3.1.2.3.~~ 3.1.2.2. Benefits of interregional transmission

Interregional transmission investments will bolster system resilience by granting access to diverse generation resources in different climatic zones, a crucial factor as climate change leads to more frequent extreme weather events that can disrupt the power system. Equitable investments in areas with higher cumulative burdens may also mitigate existing disadvantages and enhance the benefits for communities that face elevated energy burdens, prolonged outages, and heightened environmental risks. Additionally, alongside shifts in electricity supply, regional objectives and legislative actions pertaining to heating and transportation are poised to reshape the way the country consumes electricity ~~is consumed across the country~~ in the coming decade and beyond. The electrification of heating and transportation will

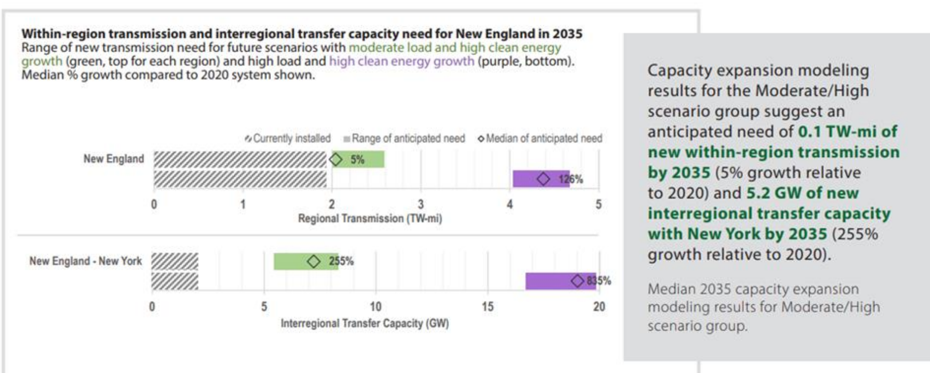
8 National Transmission Needs Study (energy.gov)
9 National Transmission Planning Study | Department of Energy

substantially increase total demand on the national grid and reshape daily electrical system demand patterns.

The Needs Study assessed anticipated future transmission and transfer capacity needs for various scenarios within the power sector across three different future years. According to the results of capacity expansion models, the most substantial growth in transmission capacity will be required in the Texas, Mountain, Southeast, Midwest, and Plains regions, but New England is also identified as having needs. However, the most significant increase in interregional transfer capacity will need to occur between the Plains and Midwest, between the Midwest and the Mid-Atlantic, and between New York and New England, with notable growth in connections between these three interconnections. For the towns and communities in Massachusetts, this study output is a strong signal that action needs to occur now, to position the Commonwealth to achieve this enhanced transfer capacity when it is most needed.

~~3.1.2.4.~~3.1.2.3. Key findings in DOE Needs study

The ~~DOE~~ Needs Study shows an urgent demand exists for additional electric transmission infrastructure in nearly all regions across the United States to enhance reliability and resilience. ~~In New England, the ISO-NE 2023 Energy Shortfall Study supports this concern. Specifically, more hydro power imports into the region by existing and new circuits could reinforce the overall resiliency of the region.~~ The ~~DOE~~ Needs Study found interregional needs between New York and New England grow significantly under all examined scenarios. (see image below from the Needs Study results)[10]. It is worth emphasizing the timing of the need, considering an interregional transmission solution could take upwards of 10 years to implement, meaning New England, working with New York, should consider upgrades in the near term to keep pace with needs.



Substantial transmission expansion is imperative by 2030 in many regions across the US, and the needed expansions occur both within system ("intraregional") and between systems ("interregional). Historically, the most substantial advantages in augmenting interregional transfer capacity have been observed along the interconnection boundaries. With specific mentions in the Needs Study of the future benefit of enhanced New York to New England transfers, the starting point to prudently act upon the goal of interregional transmission expansion is to assess the existing circuits that make up this transfer. This may provide the region and states with the ability to integrate capacity additions into the scope of planned upgrades in the region. ~~The same approach could be taken for transfers coming in and out of Boston from the North and South~~~~The most significant advantages stem from increasing interregional transmission. Historically, the most substantial advantages in augmenting interregional transfer capacity have been observed along the interconnection boundaries, but the needs both continue to grow and evolve. With~~

[10] Source: Needs Study at 198.

~~specific mentions in the Study on the future benefit of enhanced New York to New England transfers, the starting point to prudently act upon this goal is to assess all of the existing circuits that make up this transfer. This may allow the region and states the visibility to see what circuits making up these transfers may need to be rebuilt in the future, and if capacity could be significantly increased through an insignificant scope addition to these projects. The same approach could be taken for transfers coming in and out of Boston from the North and South~~.

~~It is worth noting that over time these needs will evolve along with the significant change in power demand and generation profiles. The transformation toward cleaner energy sources, evolving regional demands, and the escalating frequency of extreme weather events all necessitate adjustments in the future power grid. Substantial transmission expansion is imperative by 2030 in many regions across the US. The same applies to interregional transmission expansion, with a significant demand for new interregional transmission between nearly all regions by 2040.~~

Transmission planners are making p~~P~~rogress in~~is being made to~~ exploring~~e~~ expanded~~ing~~ ties between regions in the Northeast. Earlier this year, Massachusetts led a bipartisan request to DOE from all six New England states, New York, and New Jersey to form a multi-state collaborative to work with our federal partners on opportunities to develop electric transmission infrastructure to enhance our interregional connections, including the potential build-out of an offshore wind network.[11] This is the first example of~~time~~ this kind of federal-multi state collaboration~~ has been implemented~~. Since the initial request, two additional states in the Mid-Atlantic, Maryland and Delaware, joined this effort. DOE convened the first in person meeting of the collaborative in November 2023. The collaborative is working to develop an actionable scope of work covering short, medium, and long-term activities.

Transmission system expansion within New England, or "intraregional" transmission, will also be critical to ensure that new electricity coming from offshore wind and onshore renewables as well as electricity from existing generation resources can travel to meet demand. Massachusetts is particularly reliant on community solar for meeting its clean energy and emission reduction targets, as these relatively smaller projects (usually 5 MWac) have historically had better success in being sited, permitted and built in state. At the same time that Massachusetts must accelerate the pace at which solar is deployed within its borders, community solar in particular is facing increasing challenges. Interconnection capacity on the distribution system has been absorbed and the high levels of solar penetration are causing impacts on the bulk power system. Because of these transmission-scale impacts, ~~ISO-NE and the transmission owners have established lengthy group studies, called~~ Affected System Operator (ASO) studies have been established. Some developers have expressed concerns~~,~~ that the ASO study process is slowing down the pace of deployment and ~~-~~resulting in extremely high costs to interconnect. some have expressed concern that they do not resolve the short-term bottlenecks, as even the Capital Investment Projects (CIPs) authorized by the Provisional Program will not be online until 2028 or later. The nearly 700 MW of solar projects in the CIPs have interconnection applications dating back to 2017, and still have 4 years to wait until energization. Some developers have also expressed that c~~C~~ommunity solar deployment is likely to continue at a greatly reduced pace until the end of the decade when the upgrades proposed in the CIPs and ESMPs, all of which beyond one CIP have yet to be authorized, are completed.

[11] https://www.mass.gov/doc/interregional-transmission-letter/download.

Distribution System

3.1.3. Defining the distribution system

The distribution electric network encompasses the intricate network of power lines, utility poles, substations, and associated equipment that acts as the final link in the journey of supplying electrical energy from the transmission system to end-users. Traditionally, the system bridged the gap between the high voltage transmission system and end users, by efficiently conveying power to homes, businesses, and other establishments.

In contrast to the high-voltage transmission system, the distribution system operates at lower voltages and is responsible for transporting electricity from transmission substations over shorter distances to a multitude of endpoints within a designated geographic area, be it a neighborhood or a city. Substations are crucial elements in the distribution system; they house transformers that allow power to be stepped down from a transmission voltage to a lower distribution voltage so it can safely serve the residents in a particular locality. Transformers also allow voltage to step up from low to higher voltage if there is a surplus of DERs in an area that results in exports to the transmission system. ~~To enable the smooth bidirectional flow of power between transmission and distribution, the transformers and accompanying primary electrical equipment within substations must possess sufficient capacity, which is why the electric distribution companies' (EDCs) current Electric Sector Modernization Plans (ESMPs) consider many expanded or new substations. These substation buildouts will play a pivotal role in enhancing network capability, ensuring that customers continue to get their evolving power needs served safely and reliably.~~

3.1.4. Current state of the distribution system

The distribution system within the Commonwealth has been experiencing a systematic change in recent years in how it operates. While in the past load growth has been more predictable, and generation was primarily large, centralized, and fossil-fueled, the landscape is rapidly changing. This includes the successful adoption of distributed solar power, and the increased deployment of energy storage solutions, which have both contributed to the positive, and drastic shift in generation profiles throughout the State. Over the past decade, DERs have proliferated in Massachusetts, resulting in the distribution networks within Massachusetts becoming some of the most densely connected systems for distributed energy resources (DER) in the entire country and increasing the need for distribution system exports. To enable the smooth bidirectional flow of power between transmission and distribution, the transformers and accompanying primary electrical equipment within substations must possess sufficient capacity, which is why the electric distribution companies' (EDCs) current Electric Sector Modernization Plans (ESMPs)[12] consider many expanded or new substations. These substation buildouts will play a pivotal role in enhancing network capability, ensuring that customers continue to get their evolving power needs served safely and reliably. ~~This growth can be attributed to proactive State policies and initiatives, resulting in the~~

[12] ESMPs are comprehensive documents that describe the current state of the distribution grid, the EDCs' current and proposed investments in the electric grid, projections regarding future reliability needs of the grid, a forecast of the Commonwealth's future power needs, strategies to support renewable energy resources, electric vehicles, and electrified buildings, and more. The EDCs (Eversource, National Grid and Unitil) each submitted an ESMP to the DPU utilizing a standardized outline jointly developed by the EDCs and the Grid Modernization Advisory Council (GMAC). See the GMAC website for more information on ESMPs: https://.mass.gov/info-details/grid-modernization-advisory-council-gmac www

~~distribution networks within Massachusetts becoming some of the most densely connected systems for distributed energy resources (DER) in the entire country.~~

3.1.5. Comprehensive planning approach

Moving to a more proactive and comprehensive, longer term distribution planning approach is key to achieving our clean energy transition. Such a process should ensure that infrastructure is robust enough for future generation interconnection needs and the more complex load profiles of the future. In recognition of this need~~ese changes~~, the distribution companies have had~~it has been necessary~~ to re-examine what it means to effectively plan for the distribution system of the future. ~~With this considered, the distribution companies~~ They have implemented more rigorous processes aimed at better comprehending the localized conditions within the diverse regions in the Commonwealth and~~, concurrently~~ assessing the projected continued DER adoptions and electrification needs well into the future. ~~This approach is focused on better encompassing asset condition needs, tracking significant DER adoption trends, anticipating demand growth, and addressing the specific, evolving needs of customers.~~ While the distribution networks have made significant strides in optimizing the value derived from current assets through asset management and planning practices, the distribution companies have raised concerns that infrastructure is now approaching a critical juncture. They have concluded that the existing network's capacity is coming close to becoming fully utilized, and in response to the demands of the clean energy transition, there is a pressing need for investment to enhance capacity, and flexibility for customers.

3.1.6. Future focus for system optimization and flexibility

As ~~part of the growing~~ electrification proceeds~~of the State~~, the distribution system will be driven by the need to accommodate substantial new load ~~from a number of sources~~, including transportation and heating. An essential element in fostering an affordable transition to clean energy is promoting the efficient utilization of the network, in conjunction with the creation of more capacity in the appropriate areas. Enhanced flexibility minimizes the need for excess system capacity and, in turn, lessens costs for customers. Technologies like Distributed Energy Resource Management Systems (DERMS), including active resource integration (ARI), could help facilitate the efficient expansion of the system. The integration of technologies such as advanced metering infrastructure (AMI), combined with dynamic price signals, would actively engage customers in managing their demand and encouraging the efficient use of the system infrastructure.

~~Moving to a more comprehensive, longer term distribution planning approach is key to achieving our clean energy transition. Such a process should ensure that infrastructure is robust enough for the more complex load profiles of the future.~~

ISO-NE 2050 Transmission Study[13]

In 2020, the New England states through the New England States Committee on Electricity (NESCOE), released a Vision Statement for a clean reliable and affordable power grid.[14] The Vision Statement calls for changes in three key areas of the regional energy system: wholesale market design, transmission planning, and governance. With respect to transmission planning, the states asked ISO New

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[13] ISO-NE presented an overview of its 2050 Transmission Study at the CETWG's 2nd public meeting. The presentation may be found at the CETWG website: Clean Energy Transmission Working Group (CETWG) | Mass.gov

[14] https://nescoe.com/resource-center/vision-stmt-oct2020/#:~:text=October%202020%20–%20The%20New%20England,system%3A%20Wholesale%20Electricity%20Market%20Design

England (ISO-NE) to implement a longer-term, repeatable regional transmission planning effort that would provide a high-level transmission system plan to meet the needs of the New England states' energy transition with participation and input by State officials. In addition, NESCOE asked ISO-NE to develop a process whereby states can operationalize study results (e.g., competitive solicitations).

In 2021, ISO-NE began work on the 2050 Transmission Study, the first such longer-term study.[15] The 2050 Transmission Study is designed to inform states, stakeholders, and the region of possible future transmission needs. It is important to note that the study is a high-level transmission analysis and not an exhaustive analysis of the transmission needs that may need to be addressed in the future. Rather, the 2050 Transmission Study provides directional results that can help inform plans for and decisions around future investment needed to meet the region's clean energy needs.

3.1.7. Scope, assumptions, state input

The 2050 Transmission Study is a high-level transmission study that considers both summer and winter peaks for the years 2035, 2040, and 2050. The objective of the study is to identify the amount, type, and high-level cost estimates of transmission infrastructure that would be needed to meet state energy policies while satisfying reliability criteria. The assumptions for the study were provided by NESCOE and represent a scenario that is compliant with greenhouse gas (GHG) emission limits ~~scenario that~~ established~~reflects~~ by the region's energy and environmental laws. The demand (load) forecast and expected resource mix are based on the All Options Pathway in Massachusetts' Deep Decarbonization Roadmap report, published in December 2020.[16]

The assumed loads in the 2050 Transmission Study are significantly higher than any loads seen to date in New England, driven by the electrification of the heating and transportation sectors (see Figure 1~~Figure 1~~). The highest load modeled was the 2050 winter evening peak of approximately 57 gigawatts (GW). For comparison, the highest load observed to date on the New England system was the 2006 summer peak of just over 28 GW, and the highest winter load observed to date was the January 2004 peak of just below 23 GW.[17]

[15] ISO-NE also revised its tariff to establish this process. These changes were approved by FERC in 2022.
[16] https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download
[17] Draft 2050 Transmission Report at 11.

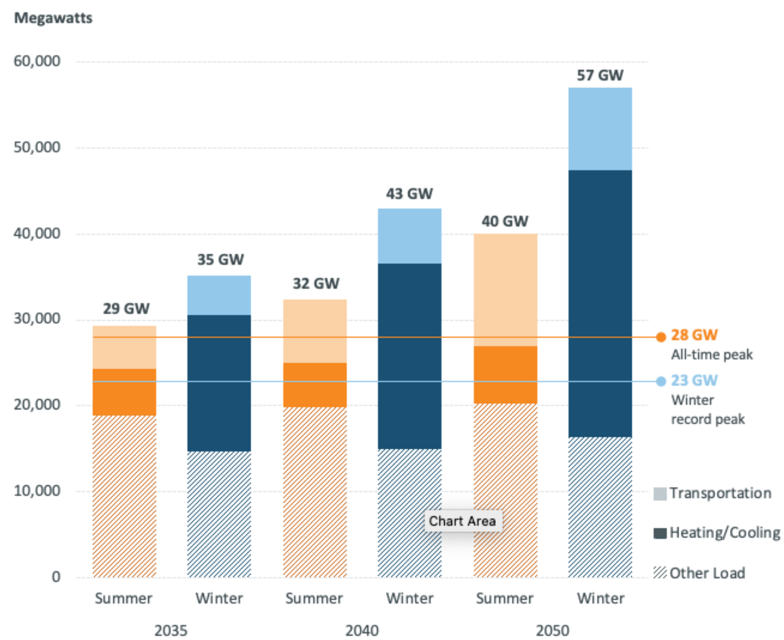

Figure 1: ISO-NE 2050 Transmission Study Peak Load Forecast

The 2050 Transmission Study assumes ~~these loads are served by~~ a generation fleet that differs significantly from today's resource mix. It assumes a~~A~~ll coal, oil, diesel, and municipal solid waste-fueled generation, as well as a portion of today's natural-gas-fueled generation, ~~was assumed~~ retire~~d~~ by 2035. It further assumes t~~T~~he remainder of today's natural-gas-fueled generation, as well as biomass, nuclear, hydroelectric, and renewable generators, ~~were assumed to~~ remain operational through 2050. New clean resources, such as wind, solar, battery storage, and increased imports from neighboring power systems in New York and Québec replace the retired generation and serve the increases in load. Figure 2 from the Study shown below highlight the very significant forecast growth in regional clean energy resources, particularly solar and offshore wind[18]. The solar energy needs are particularly significant in comparison to current installed capacity. Solar PV can be installed behind the meter, at the distribution system level (often in the form of community solar) and at the transmission system level. All three forms of solar PV will be necessary, and Massachusetts will need to rely on a combination of in-state and regional renewable resources to meet its goals.

[18] In addition, the Massachusetts Clean Energy and Climate Plan (CECP) for 2025 and 2030 projects 4.5 GW of solar by 2025, and 8.4 GW of solar by 2030.

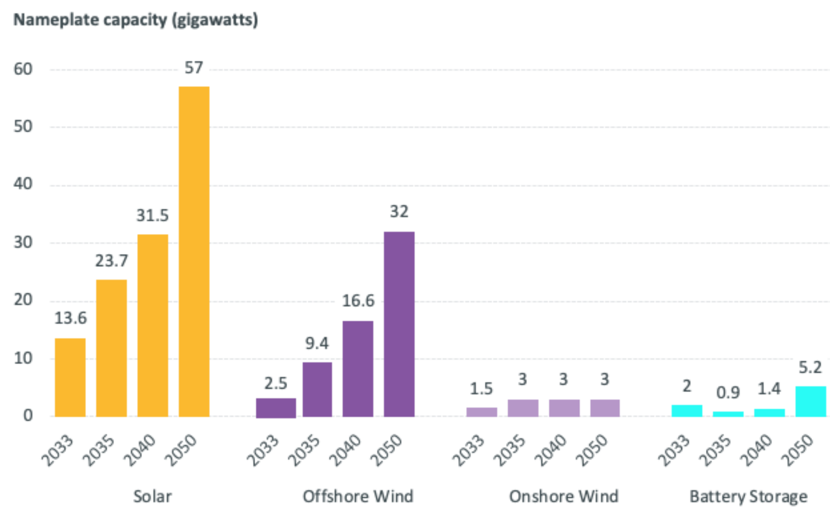

Figure 2: ISO-NE 2050 Transmission Study Resource Mix

3.1.8. Findings

The 2050 Transmission Study identified a series of transmission concerns that would need to be addressed to reliably serve the forecast load in 2050. In response to feedback from NESCOE and other stakeholders, ISO-NE identified the most commonly observed, or "high likelihood," transmission concerns. The high-likelihood concerns ~~identified by ISO-NE~~ are those that are relatively insensitive to specific study assumptions; that is, they are likely to occur even if the assumptions ~~used in the study~~ do not unfold exactly as predicted. Where possible, ISO-NE grouped the high-likelihood concerns when they occurred in a similar region and could be resolved by a common solution set. ISO-NE identified 4 such groupings:

- **North-South:** a variety of overloads occurred at the transmission interfaces that connect Maine and New Hampshire to northeastern Massachusetts.
- **Boston Import:** In most scenarios, the current paths to import power into Boston were unable to support increasing load due to high load and low assumed generation in the area.
- **Northwestern Vermont Import:** in the winter, the current paths to import power into northwestern Vermont (Burlington area) were unable to support the increasing load with assumed low generation.
- **Southwest Connecticut Import:** there are currently two high voltage paths connecting Southwest Connecticut to the rest of the New England system, which were unable to support the needed power flow as the load increased.

In addition to the groupings above, ISO-NE identified numerous other isolated high-likelihood concerns as well as many concerns that were not considered high-likelihood. The latter are mainly related to serving the highest load level considered in the study (57 GW winter peak).

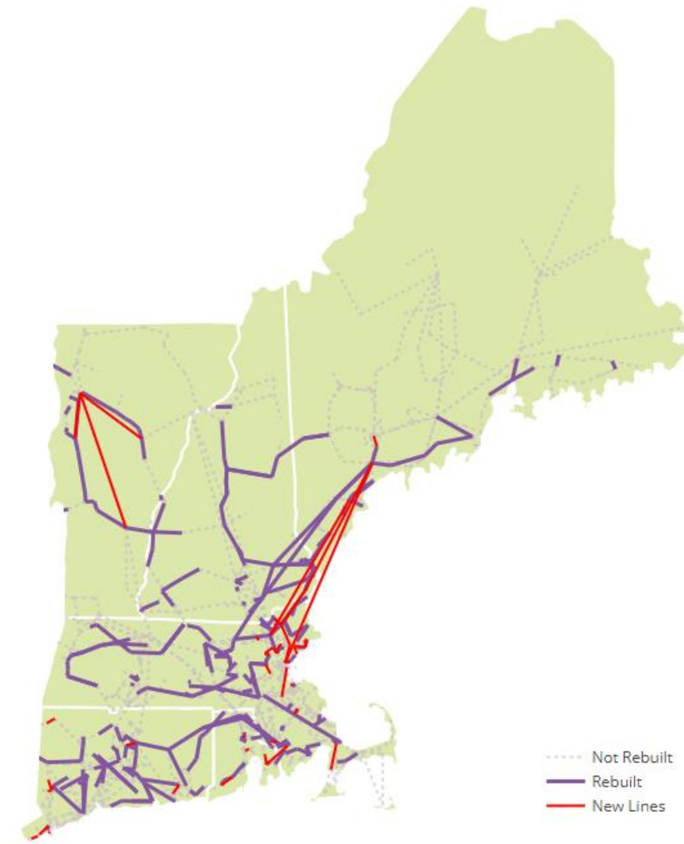

Figure 3: ISO-NE 2050 Transmission Study Solutions Map

As part of the study, ISO-NE developed conceptual solutions for all identified concerns and corresponding cost estimates. Generally, the solutions comprised both new transmission lines as well as the rebuilding of existing transmission lines (see Figure 3). For the key groupings of high-likelihood concerns, ISO-NE explored one or more conceptual approaches to resolve the identified concerns and noted tradeoffs between the various approaches. For example, ISO-NE identified four possible approaches, or roadmaps, to resolve the North-South/Boston Imports (which were grouped together since solutions were heavily dependent on one another). ISO-NE developed t~~T~~hese roadmaps ~~were developed~~ to provide a variety of examples of how these concerns might be mitigated. The 2050 Transmission Study does not recommend any particular roadmap over another; each includes advantages and disadvantages.

3.1.9. Next steps

3.1.9.1. Cost estimates and key findings

The identified upgrades are useful for providing an order-of-magnitude estimate of future transmission system costs. These estimated costs are intended to inform consumers, industry stakeholders, and policy makers of the costs inherent in maintaining reliable transmission service through the clean energy transition (see Table 2).

Table 12: ISO-NE 2050 Transmission Study Cost Estimates

Year/Load Level	Maximum Load Served (MW)	Total Cost Range
2035	35,000	$6-9 Billion
2040	43,000	$11-13 Billion
2050 (51 GW winter peak)	51,000	$16-17 Billion
2050 (57 GW winter peak)	57,000	$23-26 Billion

ISO-NE estimates that it could cost up to $26 billion to resolve the transmission concerns identified in the 2050 Transmission Study. It is important to note that this estimate reflects costs to solve the high-level concerns identified in the 2050 Transmission Study, which are only part of the total required investment. More detailed transmission analysis may uncover additional needed investments. In addition, the 2050 Transmission Study does not consider potential distribution system upgrades. ISO-NE notes that significant upgrades to the distribution system will be needed to accommodate the 2050 peak load studied.

The investment will be spread out between now and 2050, so the total cost of $16-$17 billion to serve a 51 GW winter peak load is approximately $0.62-$0.65 billion per year. Similarly, the total cost of $23-$26 billion to serve a 57 GW winter peak load results in average spending of approximately $0.88-$1.00 billion per year. For context, total transmission spending between 2002 and 2023 totaled $15.3 billion, or an average of approximately $0.73 billion per year.

The 2050 Transmission Study resulted in several high-level observations around transmission-related challenges the future grid may face as a result of the clean energy transition.

- **Reducing peak load significantly reduces transmission cost.** NESCOE'sThe assumptions initially provided by NESCOE included an assumed 2050 winter peak load of 57 GW. The study explored how a lower peak load in 2050 might impact transmission needs and costs by also studying at 51 GW 2050 winter peak load. The 2050 Transmission Study found that increases in load result in significantly higher transmission costs as load levels increase. The cost to serve 51 GW of load is $16-$17 billion, while the cost to serve 57 GW of load is $23-$26 billion. Limiting load growth could be achieved through more aggressive demand response, energy efficiency, and peak shaving programs. Limiting load growth could also be achieved by using some stored fuel for heating on the coldest days. For example, moving from 57 GW to 51 GW of peak load could represent ~80% heating electrification while still maintaining 100% transportation electrification.
- **Targeting and prioritizing high likelihood concerns is highly effective.** While the 2050 Transmission Study is a high-level analysis, the results can be used to identify which areas of the transmission system are most likely to be constrained in the future. The 2050 Transmission Study found that "projects that address these high-likelihood concerns are likely to bring the greatest benefit for a wide range of possible future conditions as the clean energy transition accelerates."[19]

[19] Draft 2050 Transmission Report at 17.

- **Incremental upgrades can be made as opportunities arise.** Many of the transmission concerns found in the 2050 Transmission Study can be addressed by rebuilding existing transmission lines rather than building new lines in new locations. Taking advantage of line rebuilds could minimize costs as well as be less environmentally disruptive. Rebuilds can generally be achieved in a shorter timeframe than new transmission lines, which would allow the region to postpone investment decisions until more information is available. The 2050 Transmission Study found that upgrading the capacity of lines as the opportunity arises, or "right-sizing" asset condition projects[20] when they occur, could be a financially prudent way for New England to reliably serve increased peak loads. Discussion on how to "right-size" transmission investment will occur at ISO-NE's public stakeholder forum, the Planning Advisory Committee. NESCOE has requested that the region first make progress on reforms to improve the transparency, predictability, and cost discipline of asset condition projects as a prerequisite to a right-sizing approach. [21]

- **Generator locations matter.** The specific location of generators can have a significant impact on the needed transmission upgrades. In general, locating onshore generation and connecting offshore wind generation at points close to large load centers, such as cities, can reduce the strain on the transmission system.

- **Transformer capacity is crucial.** Transformers "step down" power from higher to lower voltages. The 2050 Transmission Study found that as load increases, higher voltage lines become more important. In turn, the power transferred on the higher voltage lines must be stepped up and eventually be stepped down to lower voltages on the way to the distribution system. The region will need aA significant number of additional transformers ~~will be needed~~ to support load growth. Transformers typically are expensive, however, and require a long lead time (1-2 years). The 2050 Transmission Study found that "due to the long lead times and the large number of transformers needed, it may be prudent to start ordering transformers ahead of time and determining their exact locations later on."[22] [Pfeifenberger: Note: the supply-chain challenges for HVDC equipment, a critical technology for delivering larger-scale offshore wind generation to shore, are even worse (could cite to our Sept 2023 HVDC report)]

3.1.9.2. Final report

ISO-NE published tThe draft 2050 Transmission Study ~~was published~~ on November 1, 2023, with a 30-day public comment period. ISO-NE will finalize the study after reviewing the comments received and updating the report as needed.

3.1.9.3. Phase 2 tariff change

As noted above, in 2020, the New England states, through NESCOE, requested that in addition to a longer-term, repeatable transmission planning process, ISO-NE establish a process by which the states can operationalize the study results. ISO-NE began stakeholder discussions on this second-phase of the longer-term transmission study process in October 2023. The proposed process, which reflects NESCOE input, would allow NESCOE to identify transmission concerns to address, followed by a solicitation that

[20] In New England, asset condition projects are identified by transmission owners when equipment exceeds its useful life. Draft 2050 Transmission Report at 17.
[21] https://nescoe.com/resource-center/asset-condition-process-improvements-next-steps/
[22] Draft 2050 Transmission Report at 20

ISO-NE would administer. The proposal contemplates that ISO-NE will allocate costs for projects selected through the solicitation would be allocated across the region on a load ratio share basis (*i.e.*, based on the amount of electricity demand in each state), although states, through NESCOE, will have the opportunity to propose an alternative cost allocation methodology. Discussions on this proposal will continue into 2024, and couldare expected to become effective in mid-2024, depending on FERC approval.

Grid Investments for the Clean Energy Transition

This section highlights that New England has a need for significant new transmission and distribution system facilities to accommodate the clean energy transition and satisfying these needs will involve large infrastructure investments:

- As shown above, the 2050 Transmission Study estimates total regional transmission system expenditures of up to $26 billion from now until 2050 to serve forecast peak winter energy demand. This estimate excludes additional infrastructure costs related to generator interconnection and distribution system upgrades.

- At the distribution level, the Commonwealth's EDCs have prepared ESMPs containing forecast of distribution system investments in the range of $15 billion. [ES: $12.1 billion ten-year investment plan; NGrid: >$2 billion over the next five years; Unitil ~$45 million over next five years].

It is important to recognize that these estimates result from distinct analyses each with its own set of assumptions, study methodologies, and forecast horizons and should not be viewed as providing an integrated, comprehensive outlook on future grid investments. Further, these values represent very high-level forecasts of future energy needs and infrastructure build outs and are subject to significant change as the clean energy transition plays out. Nonetheless, it is directionally clear that the transition underway will require significant electric transmission and distribution infrastructure investments, the costs of which will flow into regional transmission service and local distribution rates. By way of reference, the estimated investment in New England to maintain reliability has been $11.9 billion from 2002 to June 2023 with another $1.5 billion of investment anticipated through 2027. New England's Regional Network Service rate has nearly doubled between 2012 ($75.25/kW-yr) and 2023 ($141.64/kW-yr) and is projected to increase over the next four years to $196/kW-yr in 2028 – an approximately 38 percent increase. According to ISO-NE's Regional System Plan, transmission rates for residential retail consumers in CT, ME, MA, NH, and RI in effect on January 1, 2022, shows that transmission costs represent approximately 7.9% to 15.3% of total residential retail electricity rates. This has contributed to New England consumers paying some of the highest electricity rates in the country.

4. Cost Allocation

Overview of Transmission Costs and Benefits

In Order No. 1000, FERC mandated the adoption of cost allocation methods in planning regions. It also directed that cost allocation methods focus on aligning costs with benefits by identifying the beneficiaries of proposed regional transmission facilities and imposing those costs on them. However, FERC did not adopt a universal or comprehensive definition of "benefits" and "beneficiaries." Recognizing inherent difficulty and controversy of cost allocation decisions, FERC allowed regional planning entities flexibility if they complied with six regional cost allocation principles identified by

FERC. Among other principles, FERC required that entities allocate costs are to be allocated in a manner *at least roughly commensurate* with estimated benefits (Principle 1), and a planning region may choose to use a different cost allocation method for different types of transmission facilities in the regional plan (Principle 6).

After FERC's Order No. 1000, public utility transmission providers in each planning region adopted varying cost allocation methods to comply with that Order's cost allocation principles. The most common methods to allocate costs have treated reliability needs, economic needs, and public policy requirements separately. But some transmission system operators in other regions[transmission providers?] have identified benefits across a portfolio of transmission facilities and have allocated costs on a portfolio basis rather than on a facility-by-facility basis.

In 2021, FERC issued an Advanced Notice of Proposed Rulemaking (ANOPR) presenting potential reforms to improve the regional transmission planning and cost allocation processes, among other things. In the ANOPR, FERC expressed a concern that regional transmission planning and cost allocation processes may not be sufficiently forward-looking to meet transmission needs driven by changes in the resource mix and demand. FERC was concerned that planners and policy makers may not be considering the full range of benefits that transmission investments can provide, understating the expected value of such projects and how these values change over time.

Following the ANOPR, as referenced earlier, in 2022 FERC issued its NOPR to reform regional transmission planning and cost allocation. One goal of the NOPR was to encourage system operators to consider a broader set of transmission-related benefits in their planning efforts and afford regions and states sufficient flexibility in developing appropriate methods for allocating the costs of meeting long-term transmission needs. The NOPR proposed greater state involvement in determining cost allocation, while also preserving the Order No. 1000 cost allocation principles. The cost allocation would either be negotiated in advance and applied to all or some set of transmission facilities that are (1) identified as part of long-term regional transmission planning, (2) negotiated on a case-by-case basis after transmission facilities are identified (the State Agreement approach), or (3) a combination of these methods. Under a State Agreement approach, the relevant state entities must voluntarily agree to a cost allocation method. The NOPR remains pending at FERC.

ISO-NE Cost Allocation

4.1.1. Reliability projects and economic projects

Pursuant to Schedule 12 of ISO-NE's tariff, consumers across the region share costs for Regional Benefit Upgrades (which includes Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades) are shared by consumers across the region, on the principle that all consumers benefit when the reliability and efficiency of the regional network is improvesd. More specifically, the tariff allocates costs for Regional Benefit Upgrades are allocated on a load-ratio basis— *i.e.*, based on the amount of electricity demand in each state.

4.1.2. Public policy projects

The default cost allocation methodology for public policy projects is that consumers throughout the region pay 70% of the costs are shared by consumers throughout the region on a load-ratio basis, and each state pays 30% of the costs are allocated to each state in direct proportion of the state's share of the public policy planning need that gives rise to the projects. This process has unfortunately not resulted in any public policy transmission upgrades. Elective Transmission Projects, where the project developer funds~~ed~~ 100% of the costs~~by the project developer~~, provide another means for pursuing state policy goals. For example, the NECEC project was developed as a result of the Commonwealth's 2016 Energy Diversity Act and recovers most of its costs from ratepayers of the Massachusetts utilities holding long-term contracts for transmission service on the NECEC line.

4.1.3. Local transmission projects

As noted above, the~~incumbent~~ transmission owners plan so-called local projects in New England, typically radial expansion of a network,~~ or~~ lower voltage level transmission facilities, or upgrades to the transmission system that are associated with studies or modification of the distribution system. These do not require formal review or approval by ISO-NE, aside from a technical review to confirm that the projects will not cause an adverse impact to the regional transmission system. Costs of these projects are allocated locally, to customers within a single transmission owner's service territory~~the transmission customer causing the need for the project~~.

Review of cost allocation measures in other jurisdictions

Several RTOs use other cost sharing models, such as portfolio-based allocation methods instead of a project-by-project approach.

4.1.3.1. SPP Highway-Byway

Under the Southwest Power Pool's (SPP) Highway-Byway approach, the SPP allocates costs of facilities ~~are allocated~~ differently based on the voltage level. SPP allocates 100 percent of t~~T~~he costs of those facilities operating at 300 kV and above ~~will be allocated 100 percent~~ across the SPP region on a postage stamp basis. For facilities operating above 100 kV and below 300 kV SPP allocates t~~T~~he costs ~~of facilities operating above 100 kV and below 300 kV will be allocated~~ one-third on a regional postage stamp basis and two-thirds to the zone in which the facilities are located. SPP allocates 100 percent of t~~T~~he costs of facilities operating at or below 100 kV ~~will be allocated 100 percent~~ to the zone in which the facilities are located.

For 100-300kV facilities, SPP recently proposed to establish a process to allocate 100 percent of the costs of these facilities on a regionwide basis. While FERC initially accepted the proposal, on rehearing it reversed that conclusion and found that SPP had not met its burden under Section 205 of the FPA to show that the proposed process will result in just and reasonable, and not unduly discriminatory or preferential, outcomes. FERC found that SPP's proposal, even as modified on compliance, gave the SPP board too much discretion in allocating the costs of Byway facilities.

4.1.3.2. MISO MVP

Through a ~~m~~Multi-~~v~~Value ~~p~~Planning (MVP) approach, the Midcontinent Independent System Operator (MISO) evaluates a wider range of multiple possible benefits from portfolios of regional transmission solutions, rather than more narrow standard approaches of placing projects into reliability, economic, or public policy siloes. Through this portfolio-based multi-value approach, MISO has collectively—with its stakeholders, including the Organization of MISO States—assessed multiple benefits of proposed facilities together and compared those benefits to the costs. MISO considers a broad range of transmission-related benefits, including fuel and congestion cost savings, avoided local transmission investments, decarbonization benefits, and avoided risk of blackouts. And it compares these benefits to the costs on a portfolio-wide basis to determine net benefits to the region, and to broadly allocate the costs of the transmission to those that benefit.

Building on the MVP approach, MISO has undertaken a new approach—the Long-Term Regional Transmission Plan—which initially focused only~~s~~ on the MISO Midwest region. This portfolio-based approach, evaluating networked facilities that can provide benefits across the MISO Midwest footprint, has helped secure broad political support from all states. That support was critical for securing buy-in from each state to broadly allocate the cost of such transmission projects across the region. As a result of this work, the first tranche of long-range transmission plan (LRTP) projects approved by the MISO board consists of a portfolio of 18 different regional transmission facilities, spanning nine states in MISO Midwest. These projects are designed to facilitate an expected retirement of 58 GW of existing generation resources (including 39 GW of aging coal generation) and support the integration of 90 GW of new generation, including 56 GW of wind and solar generation. MISO estimates that the $10.3 billion cost of the LRTP portfolio will generate between $37 billion and $69 billion in total benefits for the region, primarily through reduced fuel costs, reduced transmission congestion (which forces dispatch of higher cost generators), avoided investment in less efficient local facilities, and decarbonization.

4.1.3.3. PJM State Agreement Approach

FERC has approved PJM's State Agreement Approach (SAA) to transmission planning. Under this approach, states may jointly or individually agree voluntarily to share in the allocation of costs of a proposed transmission expansion or enhancement that addresses state public policy requirements identified or accepted by the state(s) in the region—so long as they agree to pay all the costs of the project. 174 FERC ¶ 61,090. The expansion or enhancement project would be reflected in the PJM Regional Transmission Expansion Plan as either a supplemental project or a state public policy project.

New Jersey was the first state in the PJM region to use the S~~tate ~~A~~greement ~~A~~pproach~~ when the New Jersey Bureau of Public Utilities (NJ BPU) issued an order requesting PJM to open a competitive proposal window to solicit proposals to expand the PJM transmission system to provide for the deliverability and interconnection of 7,500 MW of offshore wind into the state by 2035. PJM explained in its proposal that, because the State Agreement Approach is a flexible mechanism, as opposed to a prescriptive process, there is no pro forma service agreement that a state must use to identify and develop a project that will effectuate its public policy requirements. Under PJM's proposal, as accepted by FERC, PJM would develop recommendations for project proposals and New Jersey would subsequently file with FERC identifying the public policy projects, the chosen developers, and the cost allocation method for the projects. Through this SAA approach, New Jersey was able to initiate transmission investments that delivered the necessary additional points of interconnection for its 2035 goal of 7,500 MW offshore wind generation at cost savings of over $900 million, lower project development risks, and significantly reduced environmental and community impacts [Pfeifenberger: cite to my CETWG presentation or I can provide a direct citation to NJ SAA order].

5. Offshore Wind Transmission

Offshore Wind Opportunities in Massachusetts

The current approach to offshore wind transmission planning involves offshore wind developers taking interconnection and delivery risk by making informed approximations on where they can import the most amount of clean energy at the lowest cost and least disruption to the surrounding communities. The cost to connect the submarine cables of an offshore wind farm to an onshore substation is only one contributor to the overall cost of the project, however. ~~s.~~The availability of land near a coastal landing point to expand a substation, constructing a converter station, or siting~~e~~ a new transmission circuit leading out of the area has proven to be very challenging and can lead to high costs for onshore facilities. The offshore wind developers may not have information on a lot of these factors, and the utilities owning the facilities with which they will connect may be unable to offer any meaningful help until a potential interconnection customer has selected a desired point of interconnection and entered the interconnection queue. As each subsequent state RFP is released, the low-cost options for onshore interconnection sites for individual offshore wind farms are quickly dwindling, and onshore interconnection and grid upgrade costs and associated uncertainties are rapidly increasing.

For these reasons, Massachusetts and the New England region are at a critical juncture, where the experiences of the past may successfully inform a better way of achieving the interconnection of the region's approximately 9 GW of ~~existing~~ offshore wind procurement authority ~~commitments~~. Targeted upgrades of the onshore network to facilitate delivery of offshore wind from proactively planned points of interconnections can provide substantial benefits, regardless of whether future offshore wind developers use radial lines or connect to multi-plant collector lines. In any scenario, the points of interconnection need to be maximized for imported power capacity, dependability, and resilience, considering environmental and community impacts. A more collaborative and proactive planning process considering how to integrate future clean energy resources onshore and offshore will allow the region to evaluate the most cost-effective and flexible options for the region and its electricity customers—ones that can also be expanded readily as the energy transition progresses. In addition, this planning effort and the resulting implementation plans could be effectively coordinated with ongoing transmission work in these areas so efficiencies can be gained where appropriate.

Massachusetts customers and the broader New England region have made large investments in the transmission network over the last decade and should expect not just a safe and reliable system, but a network that can cost-effectively integrate large volumes of clean power in a timely fashion. Now is the time to identify, and reinforce or enhance, the existing onshore grid infrastructure to make that possible. In doing so, the Commonwealth has an opportunity to leverage the existing capability of the transmission network in the State and help de-risk offshore wind projects looking to connect.

A recent report issued by the Brattle Group outlines that w~~W~~ith an ever-changing set of circumstances, offshore wind developers must consider the right delivery approaches for their projects~~, as outlined in a recent report issued by the Brattle Group~~[23] Below is a list of some of the prevailing approaches, based on an assumption of four offshore wind farms.

- Radial Tie Lines: This would be where all four wind farms connect into different and respective substations onshore and are not connected offshore.
- Backbone Offshore Grid: This where all four offshore windfarms are connected with each other, but only two of them (e.g., the most northern and most southern windfarm) are connected to onshore substations.
- Meshed Generation Ties: A combination of the radial line and backbone approach, with each wind farm connected to an individual substation on land, but all of the wind farms connected with each other. It is possible to connect radial tie lines into a meshed offshore grid at some point in the future, if developers build the radial tie lines ~~are built~~ with "mesh ready" (or "network ready") offshore substations (as New York and New Jersey have mandated in their recent OSW procurements).

[23] U.S. Offshore Wind Transmission: Holistic Planning and Challenges

- Offshore Collector Station. This is where some entity builds a large offshore platform, or energy island, ~~is built~~ and all four wind farms connect into the "collector" substation at that offshore platform. Only one set of submarine cables then go from this platform to a single beachhead, connecting to one or more existing onshore substations.
- Onshore Collector Station: Same as the radial tie line approach, except all of the windfarms connect directly into a single collector substation on shore.

Of the above examples, the radial tie line approach is the more prevalent approach today, as it has appeared to present the lowest level of risk and complexity for developers to date. It should also be noted that while a meshed and backbone approach may offer more system flexibility and reduced congestion, it is more challenging to define these benefits at this point, and these approaches also increase the costs of the offshore transmission facilities. The fact that facilities and benefits would be shared between multiple projects and multiple states also adds complexity to such meshed, backbone, and collector station solutions. However, because the creating an "meshed" offshore network by linking individual generation ties in the future is expected to be very valuable, both New York and New Jersey have mandated in their recent offshore wind generation procurement that wind plants are constructed with HVDC generation ties and "mesh-ready" (or "network ready") offshore HVDC converter stations [Pfeifenberger: cite to my CETWG presentation].

Offshore Wind Industry Assessments

There have been several studies of offshore wind grid interconnections for New England and the east coast of the U.S. These studies have yielded some prevailing principles as they approach the challenge in the context of offshore wind goals of up to 85 GW along the U.S. Atlantic coast, connected together and tied into the mainland at preferred points of interconnection. There is some common logic to the core initial steps that need to be taken, to best position for the targeted magnitude of successful integration ~~that is targeted~~.

5.1.1. Central strategic themes

5.1.1.1. Benefits of an offshore backbone:

Efficiently integrating 85 GW of offshore wind would require an ultra-high capacity offshore transmission network that could also efficiently reinforce the onshore grid by enabling long-distance, interregional energy transfer. Consistent with a modelling project the National Offshore Wind Research and Development Consortium (NOWRDC) has sponsored, a team of experts from Tufts University, Iowa State, and Clemson University have developed three separate models to evaluate and illustrate this future state. The coordinated expansion models varied in size, including a 93,520-bus model, a 722-bus model, and 176-bus grid model[24]. The team developed all three models specifically to evaluate East Coast offshore wind, and together they serve a full suite of capabilities from detailed evaluation of points of interconnection ("POIs") to expansion planning horizons out to 2050.

5.1.1.2. Design standards

To ensure future models for high levels of connectivity and benefit, it is critical to design the early offshore wind transmission system ~~be designed~~ as modular and expandable with clear standards. For these reasons, the need for standardization is apparent:

[24] EDCs to provide a cite for this study.

- Voltage: Should the offshore grid be planned for 525 kV or 325 kV?
- Direct current (DC) versus alternating current (AC): While DC transmission solutions for offshore wind can be more costly, the control and quality achievable far outweighs AC. This is especially the case over longer distances and where planners desire fewer cables and narrower rights of way~~ are desired~~. There is also discussion regarding whether a bi-pole high-voltage DC (HVDC) line design is a better approach than a monopole HVDC design.
- Offshore platform capacity: A standard design—likely HVDC—is important to optimize for feasible offshore platforms and submarine cables.
- Converter Type: Should Voltage Source Converters (VSC), as a more modern HVDC technology, be the preferred choice for all developers?
- Market Flexibility and Interregional Connections: With a backbone or meshed offshore transmission network, there would be the capability for delivering offshore wind generation to different power markets and transferring power between the markets. This interregional sharing of electricity and grid services allows for a least-cost, reliable, and resilient decarbonization of the nation's electric systems.

Areas of Immediate Focus

5.1.2. Interconnection points

~~Common to a~~All studies, irrespective of ~~despite~~ the offshore configuration employed, suggest that optimizing points of interconnection (POIs) is as critical as, if not more critical than, all other offshore wind transmission considerations. If there is an uninformed developer landscape or communities that have not been consulted (or do not want offshore wind), this can become a key impediment to any otherwise strong offshore wind project. The location of offshore wind generation connections to the onshore grid will also determine how expensive the necessary onshore upgrades will be. Some POIs may be more distant from offshore wind plants (and thus require longer, more expensive offshore cables to reach the POIs), but require substantially fewer and less expensive onshore upgrades. The objective should be to determine which POIs offer solutions with the lowest total costs and the least environmental and community impacts.

5.1.3. Technology standardization and advances

Realizing the benefit of an offshore wind network requires that individual offshore wind transmission solutions are standardized so they can be integrated in the future. There is also HVDC equipment that needs further~~continued~~ work and assessment. For example, a networked HVDC transmission solutions will require DC circuit breakers that are not yet fully available commercially. More work needs to be performed to improve what is currently available, diversifying supplier options in the market, and building out a United States HVDC supply chain that can bring down costs.

5.1.4. Supply chain and services

With so much interest in HVDC as it relates to offshore wind, the supply of HVDC equipment is significantly backlogged worldwide. If the "right" plan comes along too late, all the manufacturing slots will be taken for the rest of the decade. Additionally, services such as the availability of specialized ships needed to install equipment are an issue, as New York experienced earlier in 2023.

Review of Industry Studies and Offshore Wind Activities in Massachusetts

ISO-NE has performed several assessments of the capability of the existing transmission system to interconnect and deliver increasing quantities of offshore wind. The first was the Offshore Wind Integration component of the 2019 economic studies, which ISO-NE ~~was~~ finalized in early 2020 (ISO-NE 2019 Economic Study: Offshore Wind Integration- June 30, 2020). ISO-NE undertook t~~T~~his study ~~was undertaken by ISO-NE~~ at NESCOE's~~the~~ request~~ of NESCOE~~. It sought to examine the potential wholesale market and transmission impacts of adding up to 8,000 MW of offshore wind resources to the New England transmission system by 2030. It found that 5,800 MW of offshore wind could be added to points across southern New England (Pilgrim & Brayton Point-MA, Kent County-RI, & Montville-CT) without significant upgrades to the onshore transmission network.

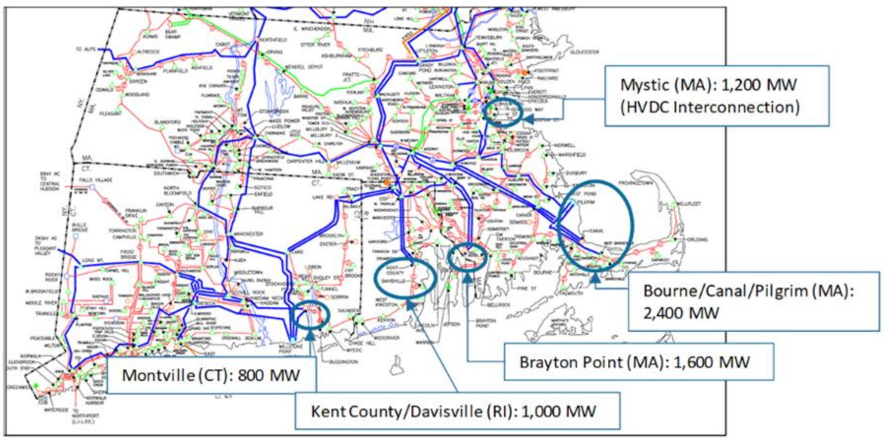

Figure 6-13: Anticipated injection capabilities without major transmission reinforcements.

Figure 4: Anticipated injection capabilities with major transmission reinforcements. Source: ??

Beyond the 5,800 MWs identified as "Low Hanging Fruit," ISO-NE studied two alternative transmissions approaches ~~were studied~~ to reach the 8,000 MWs NESCOE requested~~ by NESCOE~~. These approaches were:

- Continued interconnection of offshore wind on the southern coast of New England combined with onshore upgrades, or
- HVDC submarine cables that would travel further offshore to collection centers, then inject more directly into large load centers like Boston (Mystic-MA).

The study highlighted that beyond ~5,800 MW, there is a tradeoff regarding larger investments to either the onshore transmission network or additional offshore transmission, with each potential approach worthy of further consideration. It estimated the incremental transmission costs to be approximately $1B or more for the incremental 1,200 MWs of offshore wind under either configuration and actual AC upgrade costs were highly location specific. The study was high-level, and further analysis of potential onshore points of interconnection would be needed to determine the potential costs more precisely.

The second study is the multi-phase Cape Cod Resource Integration Study (CCRIS), which ISO-NE is ~~being~~ conducting~~ed by ISO-NE~~ to identify potential transmission and associated system upgrades required for the interconnection of certain proposed offshore wind projects~~farms~~ to Cape Cod. The Phase 1 study results, completed in July 2021, showed that a new 345 kV line between West Barnstable and

Bourne substations would be required to interconnect 1,200 MWs in either the Falmouth or West Barnstable areas. ISO-NE provided aAn initial estimate of ~$335 M was provided for the identified transmission and associated upgrades. Phase 2 of the study is ongoing. At this time, it is not clear what impact the changes to ISO-NE interconnection process required by FERC Order No. 2023 will have on the completion of the study.

Two other studies have examined different configurations for the interconnection of offshore wind along the New England coastline.

After the Massachusetts DOER-Offshore Wind Study in May 2019, the Massachusetts DOER considered whether a separate solicitation should occur for independent transmission, prior to the Commonwealth conducting additional solicitations for offshore wind generation[25]. If the DOER had elected to proceed with an independent solicitation for transmission, the solicitation would have likely occurred in 2020 or 2021. After receiving comments from utilities, offshore wind developers, independent transmission developers, and other parties, the DOER elected not to conduct a separate solicitation for independent transmission. DOER based itsThe decision was based, in part, on the additional risk that?n a separate solicitation would add to the Commonwealth's offshore wind procurements.

Finally, Anbaric, an independent transmission developer, commissioned the Brattle Group and General Electric to performThe final relevant the study, Offshore Wind in New England: The Benefits of a Better Planned Grid -May 2020, was commissioned by Anbaric, an independent transmission developer, and performed by the Brattle Group[26]. Brattle quantitatively and qualitatively evaluated tTwo different approaches were evaluated both quantitatively and qualitatively in this study:

- Current Approach- Offshore wind developers include project specific transmission as part of their bid(s)
- "Planned" Approach Alternative- Transmission is developed independently, and in advance of, future offshore wind generation.

The study concluded that a planned approach, which relies on HVDC technology for generation ties to reach points of interconnection near major load centers in Boston and western Connecticut, would offer lower total costs by significantly reducing will likely lower onshore upgrade costs and risk for both offshore transmission and generation. It would require that offshore wind procurements take into account the benefits of reaching more distant but more attractive points of interconnections and, if offshore transmission were to be procured separately, significant coordination between the New England states and ISO-NE.

Federal Funding Opportunities

The 2021 IIJA, passed by Congress in 2021, and the 2022 Inflation Reduction Act (IRA), passed by Congress in 2022, include billions of dollars in loans, grants, and other forms of financial assistance to support transmission infrastructure.

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[25] See https://www.mass.gov/doc/offshore-wind-transmission-letter-07-28-20/download. There is more info near the bottom of this page: https://www.mass.gov/info-details/offshore-wind-study

[26] Available at: Webinar – New England Anbaric

5.1.5. Infrastructure Investment and Jobs Act

Through the IIJA, the DOE's Grid Deployment Office (GDO) is administering a $10.5 billion Grid Resilience and Innovation Partnerships (GRIP) Program[27] to enhance grid flexibility and improve the resilience of the power system against growing threats of extreme weather and climate change. The GRIP Program includes three funding mechanisms:

- **Grid Resilience Utility and Industry Grants ($2.5 billion)**: Support the modernization of the electric grid to reduce impacts due to extreme weather and natural disasters. Electric grid operators, electricity storage operators, electricity generators, transmission owners and operators, distribution providers and fuel suppliers are eligible to apply.
- **Smart Grid Grants ($3 billion)**: ~~Aim to i~~Increase the flexibility, efficiency, and reliability of the electric power system, with particular focus on increasing capacity of the transmission system, preventing faults that may lead to wildfires or other system disturbances, integrating renewable energy at the transmission and distribution levels, and facilitating the integration of increasing electrified vehicles, buildings, and other grid-edge devices. Eligible applicants include institutions of higher education, for-profit entities, non-profit entities, and state and local governmental entities, and tribal nations.
- **Grid Innovation Program ($5 billion)**: Supports projects that use innovative approaches to transmission, storage, and distribution infrastructure to enhance grid resilience and reliability. Projects selected under this program can include interregional transmission projects, investments that accelerate interconnection of clean energy generation, and utilization of distribution grid assets to provide backup power and reduce transmission requirements. Eligible entities include states (individual or combined), tribes and territories, local governments, and public utility commissions.

In addition to the GRIP Program, DOE's GDO has developed a $2.5 billion **Transmission Facilitation Program**[28] (TFP) that will help build out new interregional transmission lines across the country. The TFP, administered through the Building a Better Grid Initiative, is a revolving fund program that will provide federal support to overcome the financial hurdles in the development of large-scale new transmission lines and upgrading existing transmission. TFP authorizes DOE to borrow up to $2.5 billion through three financing tools:

- Capacity contracts with eligible projects where DOE would serve as an "anchor customer" to buy up to 50% of planned line rating for up to 40 years and to sell the contract to recover costs
- Loans from DOE
- DOE participation in public-private partnerships within a national interest electric transmission corridor (NIETC) and necessary to accommodate an increase in electricity demand across more than one state or transmission planning region.

[27] [1] https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program

[28] https://www.energy.gov/gdo/transmission-facilitation-program

5.1.6. Inflation Reduction Act[29]

Through the IRA, ~~DOE's~~ GDO has approximately $3 billion in financing and facilitation tools to support the buildout of transmission lines across the country. The G~~rid~~ D~~eployment~~ O~~ffice~~ is administering the following IRA financing and facilitation programs.

- **Transmission Facility Financing**: Provides $2 billion in direct loan authority for facility financing. This program is currently under development and more information will be available in the coming months.
- **Grants to Facilitate the Siting of Interstate Electricity Transmission Lines -**Transmission Siting and Economic Development (TSED) Grants: Provide $760 million in grants to siting authorities to facilitate the siting and permitting of interstate and offshore electricity transmission lines and provide economic development grants to communities affected by interstate and offshore transmission lines.
- **Interregional and Offshore Wind Electricity Transmission Planning, Modeling and Analysis**: Provides $100 million in funding for offshore wind and interregional transmission analyses and convenings.

In May 2023, the Massachusetts DOER -submitted an application to DOE seeking up to $250 million in funding through the Grid Innovation Program for a project focused on onshore transmission upgrades and infrastructure, including key POIs to integrate offshore wind.[30] While DOE did not select the project for funding through the first round of the program, the identification of regionally beneficial POIs highlighted the potential for proactively planned onshore transmission upgrades to lower consumer costs by reducing uncertainties for developers and accelerating the integration of offshore wind resources through grid-ready interconnections.

DOER is already preparing for the second round of Grid Innovation Program funding by working with other New England states to solicit innovative project design concepts for possible submission to DOE.[31] Full applications by states, tribes and territories, local governments, and public utility commissions are due by April 17, 2024.[32]

Policy and Regulatory Initiatives and Coordination

The last several years have seen a great deal of collaboration among the New England states in pursuit of innovative and proactive approaches to transmission planning. As penetration of renewable energy and long-term load forecasts continues to grow, a clear need arose to optimize the integration of renewable energy resources, and offshore wind in particular.

In the fall of 2022, the New England States began the Regional Transmission Initiative to seek comments on how to best integrate further onshore and offshore renewable energy into the New England grid in a reliable, efficient and cost-effective manner. This included requesting specific feedback on the feasibility of a Modular Offshore Wind Integration Plan (MOWIP) and a solicitation for project concept papers from utilities and independent transmission developers for submission to the US DOE for funding

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[29] https://www.energy.gov/gdo/inflation-reduction-act
30 https://www.mass.gov/news/healey-driscoll-administration-to-compete-for-up-to-250-million-in-federal-grants-for-clean-energy-infrastructure
31 https://newenglandenergyvision.com/new-england-states-transmission-initiative/
32 https://www.grants.gov/search-results-detail/350971

in early 2023. DOE responded favorably to several of the concept papers, and several states submitted full applications for grants to DOE in May 2023 (including Massachusetts, as discussed above).

In October 2023, Massachusetts, Rhode Island, and Connecticut agreed to coordinate their combined offshore wind RFPs for up to 6,800 MWs of new resources. It is hoped that these efforts could lead to multi-state proposals which provide greater cost savings and regional benefits than the individual states might receive in their individual procurements.

Other State & Regional Planning and Policy Documents

5.1.7. Massachusetts Clean Energy and Climate Plan for 2025 and 2030

Massachusetts has ambitious clean energy requirements, and offshore wind development is an anchor resource in achieving our clean energy transition. According to the Massachusetts Clean Energy and Climate Plan (CECP) for 2025 and 2030, the Commonwealth expects offshore wind ~~is expected~~ to be the primary source of electricity for a decarbonized energy system. Offshore wind buildout will require regional and interregional collaboration to successfully integrate generation facilities to the electric grid.

The CECP identifies a pathway for the electric sector to achieve decarbonization goals, which require the electric sector to decrease its GHG emissions by more than 53% by 2025 and 70% by 2030. Many other Northeast states have published plans or roadmaps to achieve their climate goals.

5.1.8. Maine Offshore Wind Roadmap

Maine's Offshore Wind Roadmap is a strategic economic development plan for the offshore wind industry in Maine that maximizes benefits to Maine citizens, ensures compatibility with the Maine coastal heritage, and minimizes the impacts on ocean-based industries and environment.

New England will need an estimated 3 GW to 11 GW of offshore wind capacity by 2050 in the Gulf of Maine to meet both climate goals and projected demand for clean energy. In 2019, Maine passed legislation to require 80% of electricity consumed in Maine to be generated from renewable sources by 2030, with a goal of 100% by 2050 and GHG emission reduction requirements of 45% below 1990 levels by 2030 and 80% by 2050.

Transmission planning is an essential piece of the puzzle when discussing offshore wind~~OSW~~ build out. Planning and coordination are necessary to ensure the efficient~~that future~~ development of offshore wind~~OSW~~ resources ~~is done efficiently~~ while balancing other factors. This includes long-term planning strategies and identifying POIs considering existing capacity, distance to future offshore wind~~OSW~~ leases, and environmental impacts. Maine has proposed actions such as coordination among stakeholders to meet state policy goals, continuing engagement with ISO-NE to discuss market administration and regional planning, prioritizing existing POIs with robust transmission infrastructure, and continuing efforts such as the New England Regional Transmission Initiative.

5.1.9. ·Rhode Island Road to 100% Renewable Electricity

In January 2020, Rhode Island Governor Gina Raimondo signed Executive Order 20-01, setting a first-in-the-nation goal to meet 100% decarbonization in the State by 2030. In December 2020 the state issued "Rhode Island Road to 100% Renewable Electricity" to detail an approach to achieve 100% decarbonization by the end of this decade, with offshore wind one of the resources outlined as a significant contributor in meeting this goal. The report also described two areas of potential exploration when considering integrated grid~~n~~ planning in the state - analyzing transmission and distribution system needs for multiple scenarios with 100% renewable electricity to identify potential grid challenges and development opportunities and exploring how to enhance grid visibility and forecasting. Rhode Island also emphasizes the importance of regional collaboration throughout the report, indicating that this is necessary to remove barriers to distributed energy resource deployment with competing policy interests.

6. Interconnection and Order 2023

Because adding new resources to the grid, including energy storage facilities, can affect the performance of the electric system, grid operators must study them~~they must be studied~~ prior to interconnection to avoid adverse impacts on the reliability of the grid, such as an overload, voltage deviation outside of an acceptable range, or potential instability. If these studies identify an adverse impact to reliability, the affected transmission and/or distribution system owners must perform system upgrades or modifications before the generator can interconnect. The specific study process depends on whether a generator is seeking to interconnect to the transmission system under the FERC-jurisdictional interconnection process administered by ISO-NE, or state-jurisdictional interconnection processes administered by the transmission and distribution utilities.

ISO-NE Process

Interconnection process reform has become a focus for FERC, ISO-NE, and RTOs across the country because of large backlogs of projects in the interconnection queue waiting to be studied and high volumes of projects are dropping out of studies at various stages of the process. The diagram below, from a recent DOE presentation, shows a summary of the current interconnection study process.

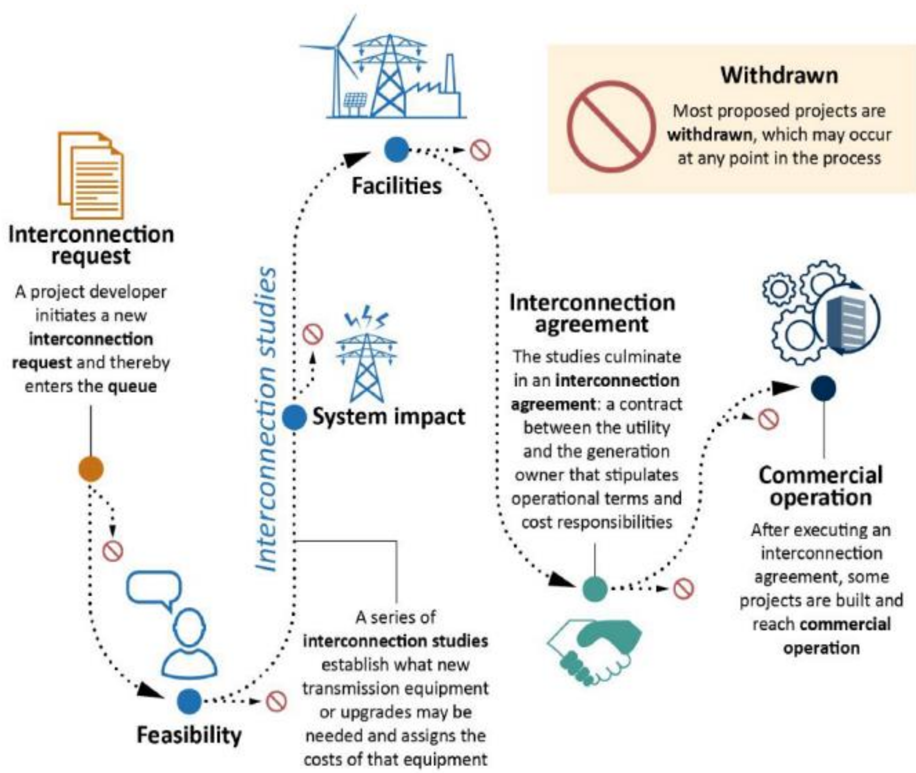

Figure 5: Department of Energy: Interconnection Study Process

While ISO-NE's interconnection queue is not as long as many others in the country, it too has seen significant delays in the time necessary to complete studies. With over 30,000 MW of proposed projects in its queue, ISO-NE shares the same challenge that many other RTOs face. Indeed, it is not just that studies take years to complete. The interest in developing clean energy has grown over the years, creating the need for many more studies, and more complex studies, than have historically been conducted. Studies are labor intensive, complicated, and rely on a workforce challenged by engineering shortages.

~~In~~ Until now, ISO-NE has~~, projects have~~ primarily ~~been~~ studied projects “serially,” meaning one after another, though limited group studies can and do occur. Under FERC regulations established two decades ago, project developers bear the costs of the upgrades needed to connect to the grid, including upgrades at the point of interconnection and more distant upgrades elsewhere on the system, called network upgrades. For most generation interconnection requests, such upgrades are needed ~~This is~~ because spare injection headroom has been exhausted and transmission owners have not planned and constructed new, regional headroom ~~has not been planned and constructed~~. If a single project seeking interconnection triggers costly upgrades - beyond the normal costs of building interconnection facilities, which already cost millions of dollars - the project may become nonviable and ~~be~~ cancel its interconnection request~~ed~~. Because the issue on the grid has not been resolved, it is likely that the identified overloads~~it~~ will appear again for the next project that ISO-NE studies~~is studied~~, causing that project to ~~be~~ cancel its interconnection request~~ed~~, and the cycle continues. This requires frequent re-studies of interconnection requests, which increases the time required to complete the process. ~~is often referred to as queue collapse~~.

FERC Commissioner Alison Clements recently highlighted the impact of the broken study process:

> *“Ultimately, the dysfunction of the interconnection process harms consumers. It prevents low-cost generation from coming online that could have reduced the cost of electricity, and it harms reliability. Several of the nation’s largest grid operators have stated that they could face resource adequacy problems if new resource entry does not occur rapidly enough to match the pace of resource retirements.”*

At the core of this issue is a misalignment of need with process. The country needs proactive transmission planning processes in order to integrate cost-effectively the headroom needed for interconnecting the thousands of ~~needed~~ new projects to~~on~~ the grid and maintain reliability. Currently, these transmission planning processes largely do not exist (see report section 3.3.2 for a description of the transmission planning processes in New England). This relegates identifying and funding many major network upgrades through the incremental generation~~to~~ the interconnection process, which is not designed for this. Broad network upgrade costs are often too substantial for any individual project to fund and cost-effective solutions cannot be identified incrementally through the exiting process. Many liken it to charging the first car on the onramp the entire cost of widening the highway. It is also inefficient, as one-by-one upgrades in unanticipated locations are not as cost-effective as holistic expansion plans that simultaneously consider all grid-related needs.

However, while transmission planning reform gets to the root cause of the interconnection challenge, there are certainly necessary improvements to the generation interconnection framework to ~~process improvements that can~~ speed up study processes and timelines. Those are~~will be~~ discussed in section 4.4.

Distribution System Process

Similar to the transmission interconnection process, distribution utilities within the Commonwealth have historically used a first-in, first-out (queued) approach to processing interconnection requests from DERs. The costs of system upgrades necessary to interconnect a particular distributed generation (DG) system would be assigned to the applicant. Queue backlogs have emerged in recent years due to a large influx of applications, many of them queued for the same substations.

Under several dockets[33], the Department of Public Utilities developed a framework to perform group studies at saturated substations to develop more comprehensive solutions and allow distribution utilities to propose and obtain approval for alternative cost allocation proposals. As a result of these dockets, Eversource and National Grid have performed numerous of group studies involving multiple substations and project owners and proposed cost allocation methodologies to share the costs for common system modifications between beneficiaries. Several group studies and associated cost allocation mechanisms are currently pending before the DPU~~epartment~~.

In Massachusetts, because of significant DG deployment, additional studies are~~have been~~ required for the interconnection of most projects 1 MW or greater~~ since 2019~~. When the interconnection of a DG facility to a distribution electric power system (EPS) has the potential to adversely affect a neighboring EPS (distribution or transmission), ISO-NE requires a study of potential adverse impacts on that neighboring system~~ is required by ISO-NE~~.[34] These Affected System Operator (ASO) studies can take 12-18 months (sequentially or concurrently with a distribution impact study) and the necessity of these studies is~~are~~ likely to continue indefinitely as all substations have reached DG "saturation."[35] As these studies are joint studies; the ASO and ISO-NE determine the procedural details and timing, including whether and when an ASO study is necessary. The Distribution Companies are responsible for coordinating with the ASO and ISO-NE and communicating with interconnecting customers and the DPU~~state public utility commission~~.

To ensure efficient processing of DG and utility scale interconnections, it is necessary to align infrastructure upgrades at the distribution and transmission level. In light of FERC Order 2023, ISO-NE is in the process of providing clarification on the interaction between the DG ASO and ISO-NE interconnection queues. Following ISO-NE's implementation of Order 2023, an opportunity should be provided for regional stakeholder engagement on ASO study best practices.

Interconnection Improvements

As described in section 3.1, FERC has jurisdiction over interconnection applications in the ISO-NE queue~~ and recently initiated a NOPR focused on making improvements to the transmission planning,~~

[33] Massachusetts DPU dockets 17-164, 19-55, 20-75, and 20-75-B

[34] Pursuant to the Section I.3.9 Process outlined in the ISO-NE Tariff ("Affected System Operator ("ASO") Study"). Under ISO-NE Planning Procedure No. 5-1 regarding ISO-NE's review of such changes, a Proposed Plan Application is required for new or increased generation greater than five MW; ISO-NE reserves the right to require a Proposed Plan Application for new or increased generation greater than one MW and less than five MW.

[35] The Massachusetts Department of Public Utilities set rules concerning ASO studies in Order on Affected Operating Studies, D.P.U. 19-55-C (2020).

~~cost allocation and interconnection processes~~. FERC Order 2023[36] mandates a variety of changes to the interconnection process, with the expectation these will speed up interconnection queues across regional RTOs and improve the timeliness of interconnection projects.

~~.~~The most important changes included in Order 2023 are as follows:

- Studies conducted in groups, called clusters, and shared network upgrade costs amongst projects.
- Fixed, predictable and (hopefully) faster timelines.
- Higher thresholds to entry into the interconnection queue, like site control requirements~~barriers to entry like site control~~ and deposits to reduce volumes of "speculative" projects.
- Penalties for Transmission Owners and RTO/ISOs if they don't meet study deadlines.
- Evaluations of alternative technologies that could avoid costly upgrades.
- Flexibility for projects that add storage.
- Study methodology improvements for battery storage.

ISO-NE is in the process of developing its Order 2023 compliance rules and ~~, which~~ will ~~be~~ submitted them to FERC in 2024. The ISO-NE Transmission Committee website contains ISO-NE's plans for these changes, as well as amendments and proposals from stakeholders~~, can primarily be found on the ISO-NE Transmission Committee website~~. [37]

The changes mandated by Order 2023, while beneficial to the overall interconnection process, leave certain challenges partially or completely unresolved. This provides an opportunity for ISO-NE to go beyond compliance with the basic rules outlined in Order 2023. Advanced Energy United recently published a whitepaper that articulated priorities for ISO-NE~~ New England~~'s Order 2023 compliance as well as reforms beyond the order. [38]

For example, it is important to note that entering the generation interconnection study process continues to be the only way for a project to determine its costs to interconnect. Order 2023 requires the use of heat maps that show available headroom on the grid and provide certain other~~and certain~~ levels of data disclosure for interconnection customers, but because of the opaque nature of the studies and the unpredictability of costs, high volumes of "speculative" projects may continue to enter the queue, essentially on fact-finding missions, which in turn creates more work for RTOs and transmission operators (TOs). Improvements to data transparency and cost certainty for interconnection customers remain areas in need of more attention.

In addition, study processes remain slow and laborious. Even with improvements, ISO-NE estimates its queue entry and initial study phase (not including necessary re-studies) will take almost a

[36] See: https://www.ferc.gov/media/e-1-order-2023-rm22-14-000. Although the mechanics of the interconnection process will be substantially different after Order No. 2023 is implemented, many aspects of the process will remain the same. Complex technical studies will still need to be performed by ISO-NE and the transmission owners, and the transmission owners will still need to design, permit, and construct transmission upgrades as needed to ensure that reliability of the transmission system is maintained.
[37] https://www.iso-ne.com/committees/transmission/transmission-committee
Insert cite to AEU

year.[39] Process automation, Artificial Intelligence (AI), improved and streamlined models, staff additions, and other innovations to improve timelines and accuracy are areas for additional process improvements to assist in speeding study times.

Costly and delayed construction timelines will also be a challenge. Assuming the region is able to process many more studies, and interconnection customers accept the associated costs, transmission owners need to build network upgrades associated with those generation interconnection requestsprojects need to be built in an efficient and timely manner. Across the country multi-year backlogs for network upgrade construction projects and escalating costs due to inflationary pressures are emerging issues. ISO-NE, with its smaller market and less crowded queue, has an opportunity to lead on this issue before these issues become further entrenched.

Finally, to ensure efficient processing of DG and utility scale interconnections, it is necessary to align infrastructure upgrades at the distribution and transmission level. In light of Order 2023, ISO-NE is in the process of providing clarification on the interaction between the DG ASO and ISO-NE interconnection queues, but next steps will require significant coordination between the many involved stakeholders.

In addition to FERC Order 2023, the Department of Energy has released a draft roadmap[40] to improve interconnection processes, focusing on increasing data access and transparency, improving process and timing, promoting economic efficiency, and maintaining a reliable grid.

To address these issues, many RTOs around the country have established forums to discuss and implement needed interconnection improvements on an ongoing basis (i.e., a continuous improvement approach). For example, the California ISO (CAISO) has combined proactive transmission planning for future generation interconnection and other transmission needs with clear identification of available headroom at various interconnection points. (See *Briefing on Resources available for near term interconnection*, http://www.caiso.com/Documents/Briefing-ResourcesAvailable-NearTermInterconnection.pdf). Unlike ISO-NE, CAISO also utilizes remedial action schemes (RAS) to significantly increase the headroom on the existing grid. In addition, CAISO also proposed *2023 Interconnection Process Enhancements* (see https://www.caiso.com/InitiativeDocuments/Straw-Proposal-Interconnecton-Process-Enhancements-2023-Sep212023.pdf) that would speed up interconnection requests at grid locations with sufficient headroom. Similarly, Midcontinent ISO (MISO) and Southwest Power Pool (SPP) offer greatly accelerated interconnection processes for new resources that share headroom with existing plants or are able to utilize the headroom at retired plants (see https://www.pjm.com/-/media/committees-groups/subcommittees/ips/2023/20230731/20230731-item-11---pjm-ips-transfer-of-cirs-education---miso_spp_pacificorp_pjm-ver-7-31-2023.ashx).

7. Grid Enhancing Technologies

Introduction and Definition

This Report emphasizes the need for expanded transmission capacity to integrate the renewable energy resources that are necessary for the Commonwealth to meet its 2050 net zero greenhouse gas emissions goal. Considering that it may take five to ten years to construct new transmission lines, the

[39] https://www.iso-ne.com/static-assets/documents/100004/a03b_2023_10_17_tc_order2023_proposed_compliance_overview.pdf
[40] https://www.energy.gov/eere/articles/doe-releases-draft-roadmap-improve-interconnection-clean-energy-resources-nations

need for expanded transmission capacity represents a source of significant delay to progress on the Commonwealth's energy and climate goals. Grid Enhancing Technologies (GETs) are a suite of technologies that could be deployed today on the existing transmission system and offer the potential to materially increase the capacity of existing transmission assets and an opportunity to bootstrap the Commonwealth's progress deploying new clean energy resources.

~~Grid Enhancing Technologies (~~GETs~~)~~ are hardware and software tools that increase the capacity, efficiency, and/or reliability~~safety~~ of the electric transmission system. Transmision operators utilize t~~T~~hese optimization technologies, including dynamic line ratings (DLRs), advanced power flow controllers (PFCs), and topology optimization ~~are utilized~~ on existing and new transmission infrastructure to give them~~operators~~ more situational awareness, flexibility, and control over the grid. As the nation's grid becomes increasingly congested and capacity constrained, GETs can reduce congestion costs and increase reliability and resilience by providing several system benefits, including situational awareness and alerting capability to enable safer real-time operations, asset health monitoring information to support asset replacement deferral while longer-term solutions are implemented, and increased grid resilience.

Transmission operators can utilize GETs ~~can be utilized~~ in a transmission loading order approach in which RAS could be used first to create additional interconnection headroom (as CAISO is already doing), GETs would be used next to increase interconnection headroom through optimization of the grid, this would be followed by increasing the capacity of existing lines and existing rights of way, before grid expansion through new transmission line is considered to first consider~~where optimization of the grid (via the utilization of low-cost tools such as GETs) is considered first, then grid reinforcement, and then grid expansion~~. This is a sequential way to create an expanded, flexible, dynamic grid with customer affordability as a guiding principle. Such transmission planning loading order principles have been used internationally: for example, Germany's NOVA principle emphasizes "grid optimization first, then grid strengthening before any further grid expansion."[41]

7.1.1. Dynamic line ratings

Transmission operators generally rely on two types of line ratings to measure the amount of power a transmission line can safely conduct: Static Ratings, which are based on conservative assumptions regarding weather, and are unvarying or change only seasonally; and Ambient Adjusted Ratings (AAR), which use ambient temperature, and potentially additional factors, to rate transmission line capacity each day. DLRs, by contrast, ~~DLRs~~ use sensing devices and algorithms to collect ambient weather data and information about ~~the~~ overhead conductors to calculate the maximum amount of capacity a transmission line can safely carry (the "ampacity" of the line) as conditions change dynamically even within each hour~~, also called ampacity~~. More accurate consideration of ambient conditions allows operators to utilize the true, varying thermal limits of ~~the~~ transmission lines more safely. Use of real time and forecasted DLRs often yields transmission line capacity ratings significantly higher than either Static Ratings or Ambient Adjusted Ratings, and thus provide an opportunity to safely and optimally utilize existing transmission system capacity that had previously gone unused.~~Use of real time and forecasted DLRs often yields greater capacity than using static line ratings, which do not account for real-time ambient conditions and rely on very conservative assumptions, and thus provides an opportunity to safely use the existing transmission system more efficiently.~~

An example here in Massachusetts of DLRs increasing transmission line~~creating critical grid~~ capacity ~~in Massachusetts~~ is ~~came from a two-year pilot conducted by~~ National Grid's two-year pilot that

[41] https://www.transnetbw.com/en/world-of-energy/nova-principle

aimed to verify ~~the~~ DLR ~~system's~~ performance and its ability to accurately and safely maximize the utilization of existing transmission line capacity, and the extent to which it ~~for~~ optimized operations and further enabled the delivery of clean and affordable energy ~~delivery~~ to customers.[42] Recorded DLR data from the National Grid pilot yielded~~showed~~ the following results:

- DLR exceeded~~s~~ ~~the~~ Static Rating ~~for~~ 94% to 97% of the time.
- DLRs yielded a mean (average) increase of 47% in line capacity above Static Ratings overall.
- DLRs yielded a mean (average) increase of 31% in transmission~~Mean (average) increase of 31% in~~ line capacity above Ambient-Adjusted Ratings (AARs).
- Similarly, a recent implementation of DLR by Pennsylvania Power and Light confirmed the effectiveness of DLR. Instead of rebuilding or reconductoring two 230-kV lines, PPL spent less than $300,000 installing sensors on the lines. The utility saved about $50 million in costs and immediately started saving about $20 million in annual congestion costs. Average capacity ratings on one line increased about 18% and 19% on the other line, while "emergency" ratings on the first line increased about 9% and on by 17% on the second line. Congestion costs in the 2021/22 and 2022/23 winters on one line fell from more than $60 million to about $1.6 million. (See https://www.energypa.org/wp-content/uploads/2023/04/Dynamic-Line-Ratings-H-Lehmann-E-Rosenberger.pdf) ~~Mean (average) increase of 47% in line's capacity above Static Rating.~~

7.1.2. Power Flow Control

Power flow control technologies actively balance the flow on transmission lines by transferring—pushing or pulling —power from one line to another. The hardware can intelligently raise or lower the impedance (~~, or~~ the opposition to electrical current) on transmission lines~~,~~ in real time to ensure that power is delivered on lines that have the capacity to carry it. Advanced power flow control expands on this function with enhancements such as faster and more flexible deployment options, easy scaling to meet the size of the need, and the ability to relocate hardware when needed elsewhere on the grid.[43] Consider, for example, three transmission lines with the same maximum design capacity: one operating at 28% of capacity, a second operating at 40% of capacity, and a third operating above its rated capacity at 105%. Power Flow Control could be used redistribute power across all three lines so that each is operating close to its design capacity. The result is a material increase in the amount of power carried by the first two lines, and a slight reduction in the overloaded capacity of the third line which keeps it in service and maintains the reliability of the transmission system.

7.1.3. Topology optimization

Transmission topology optimization software models the grid's network and power flow conditions to identify ways to reroute power flow around congested or overloaded transmission elements. Transmission operators implement t~~T~~hese "reconfigurations" ~~are implemented~~ by switching on or off existing high voltage circuit breakers. By more evenly distributing flow over the network, topology optimization increases the transfer capacity of the grid, and decreases the need to curtail power generating resources..[44] Applications of topology optimization in Great Britain, MISO, and SPP have

[42] https://cigre-usnc.org/wp-content/uploads/2021/11/An-Empirical-Analysis-of-the-Operational-Efficiencies-and-Risks-Associated-with-Line-Rating-Methodologies.pdf
[43] https://watt-transmission.org/
[44] https://watt-transmission.org/

shown that the technology can substantially reduce grid congestion and the curtailment of renewable generation (see https://www.brattle.com/experts/pablo-ruiz/?full#insights-events-publications)

Use and Sequence of GETs

Historically, utilities, system operators, and regulators assumed the transmission grid was essentially "fixed" in capacity and configuration by Static Rating assumptions. However, the deployment use of GETs challenges this assumption as the capabilities of the grid varies based on variablesthings like ambient weather conditions, wind speed, and overall utilization of the network. The evolution of transmission planning practices to include GETs is critical as transmission related costs riseare expected to rise considerably in the next several decades. As noted in the ISO-NE 2050 transmission study, transmission costs could rise to as high as $23-$26 billion in a fully decarbonized future[45] as the state and region plans for scenarios with higher electrification, offshore wind integration, and renewable energy deployment. As the Commonwealth and region continue to develop transmission expansion strategies to address decarbonization goals, optimizing the use of GETs will be a critical tool in rightsizing transmission and reducing impacts to the consumer.

GETrid enhancing technologies have been broadly deployed in Europe[46] to increase grid infrastructure by unlocking additional capacity on the existing transmission system. These technologies also complement transmission build outs by enhancing the utility of transmission infrastructure instead of eliminating or replacing it.

The operational flexibility provided by GETs is also valuable in the context of addressing extreme weather events and enhancing grid resilience. The value of DLR was demonstrated during the 2018 "bomb cyclone", when a 13-day cold snap (December 25, 2017 to January 8, 2018) constrained a large portion of the Northeast U.S. grid, demonstrated the value of DLR. [47] During this extreme event, which featured higher loads triggered by colder weather, ISO-NE issued an abnormal conditions alert to address both the weather and supply concerns. ISO-NE also increased their transmission line ratings (made possible by the cold conditions, which helped to improve thermal transfer capability), including the scheduling limits on the AC ties into New York (from 1,400 MW to 1,600 MW), which helped avoid significantlarge congestion costs and maintained system reliability.

A recent DOE report highlighting the ratepayer impact of GETs identified six key indicators for GETs value[48]:

1. Wind and Solar Share The variable nature of renewable generation may operate more efficiently with GETs.

2. Renewable Curtailment Indicates stress on the transmission system and the need to increase power flow out of renewable generation pockets.

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45 https://www.iso-ne.com/system-planning/transmission-planning/longer-term-transmission-studies
46 See ENTSO-E Technopedia pages for DLR and APFC, and IRENA Innovation Landscape Brief on DLR for examples of worldwide deployments.
47 See ISO-NE, https://www.iso-ne.com/static-assets/documents/2018/01/20180112_cold_weather_ops_npc.pdf, Jan 16, 2018 This appears to be a broken link
48 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

3. Transmission Congestion An indicator of transmission system limitations that, if relieved, could facilitate the development of more renewable generation.

4. Price Differentials An economic (price signal) indicator that can help isolate localized transmission issues and their magnitude,

5. Proposed Transmission Indicates regions where there may be existing congestion or new resources that could be supported by GETs.

6. Proposed Renewables Regions where additional infrastructure may be necessary to bring new renewable resources online.

Within that context, aA recent study highlighted three locations within ISO-NE as potentially well-suited for GETs based on the interconnection queue and 2030 Resource Plan, including a key offshore wind interconnection point in Southeast Massachusetts (SEMA).[49] The study identified DLRs and Advanced Power Flow Control deployments in the SEMA region to support reliability and to reduce production costs under a modeled 2030 resource mix with over 50% renewable energy. Optimal deployment of the two technologies reduced renewable curtailment at the interconnection point by more than half, with the technologies paying for themselves in less than one year.

The Brattle Group also conducted a GETs study which modeled an optimal deployment of GETs using the Southwest Power Pool system in Kansas and Oklahoma and projects in the interconnection queue with signed interconnection agreements. Brattle investigated how much new generation could economically interconnect if GETs unlocked additional capacity on the grid. Without GETs, 2,580 MW of wind and solar generation could interconnect in the next five years. With GETs, twice as much new generation (5,250 MW) could interconnect. In this study. GETs deployments would have one-time installation costs of $90 million, with annual production cost savings of $175 million.[50]

As noted in these studies, GETs play a key role in the integration of clean energy to the grid and at various stages of transmission expansion as highlighted in a 2023 white paper by The Brattle Group, "Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts."[51]

Before:

- -Before construction, GETs can reduce congestion by 40% or more.

The benefits of GETs start before traditional transmission projects are developed. Planning for and building new transmission typically takes five to ten years or longer. Many GETs can be installed in under a year to alleviate congestion and help integrate more resources before the new transmission projects are put in place. GETs are scalable and their deployments are reversible—unlike other capital heavy investments, they can be removed (and relocated) if the original need is no longer there. The portability, scalability, reversibility, and comparatively smaller investment size of GETs provides flexibility to address transmission issues before new transmission is built. This option is particularly effective when there is uncertainty about the future, for example with the pace of load growth, or possible

[49] Assessing the Value of Grid Enhancing Technologies: Modeling, Analysis, and Business Justification; Idaho National Laboratory – Jake Gentle, Alex Abboud, Megan Culler, Chris Sticht; Telos Energy - Sean Morash, Andrew Siler, Leonard Kapiloff, Derek Stenclik, Matthew Richwine. June 1, 2023. INL/MIS-23-71254

[50] https://watt-transmission.org/unlocking-the-queue/

[51] https://watt-transmission.org/wp-content/uploads/2023/04/Building-a-Better-Grid-How-Grid-Enhancing-Technologies-Complement-Transmission-Buildouts.pdf

changes in power flow patterns. In addition, GETs that provide immediate solutions to existing grid issues could allow more time to develop traditional transmission solutions, and simultaneously delay capital investments.

During:

- -During construction, outages can be avoided or ameliorated, with similar reductions in congestion costs of 40% or more.

The complementary benefits of GETs continue during the construction of traditional transmission solutions by reducing the impact of outages or avoiding outages entirely. Installing GETs ~~as the solution~~ (in particular, DLR and Topology Control) often does not require transmission outages, or ~~only~~ requires only ~~a~~ shorter outages. When the preferred solution is to build new (or reconductor existing) transmission, GETs could help alleviate the impact of transmission outages needed for upgrading existing lines and interconnecting the new line(s) into the existing grid.

After:

- -A~~nd a~~fter construction, GETs can increase utilization on new lines ~~can increase~~ by 16%, or more improving the Benefit to Cost ratio of the new lines.

GETs can further help increase the value of new traditional transmission projects after they are put in service. For example, GETs can increase the utilization of the existing system(-[which will include the newly added line(s))], ~~hence~~ increasing the Benefit to Cost ratio of any given transmission project. This could allow for more transmission projects to pass the selection threshold (the Benefit to Cost ratio is one of the key metrics used), potentially increasing the number of validated transmission projects. Previous analysis of the Southwest Power Pool ("SPP") system has shown that GETs will increase the utilization level of existing 345 kV lines by 16%. GETs can also be deployed after the fact to mitigate unanticipated consequences triggered by the new line(s). For example, if energizing the new line(s) results in unintended congestion, such as those on the underlying lower voltage lines, GETs could be quickly deployed to address it. Finally, GETs can contribute to system resiliency under extreme conditions as they provide means for situational awareness and operational remedies.

Furthermore, monitoring newly constructed transmission lines provides value for multiple aspects of the asset across its lifecycle. DLR provider LineVision offers an advanced non-contact overhead line monitoring system. The LineVision installed its DLR measure~~and it was installed~~ on NY Transco's recently energized New York Energy Solution (NYES) electric transmission project, a 54-mile modernization of a 1930's-era transmission corridor with new modern, storm-resilient monopoles and several new and improved electric substations to relieve congestion and facilitate the flow of clean energy to homes and businesses in furtherance of New York State's carbon reduction goals. The use of this technology uniquely allows the operators monitoring NYES to track all phases of power with a single monitoring system that accomplishes dynamic line ratings and greater visibility into transmission~~of the~~ asset~~'s~~ behavior.[52]

8. Siting and Permitting

Federal, state, and local authorities all play a role in siting and permitting electric transmission facilities. This section provides an overview of existing transmission siting and permitting authorities and processes.

[52] https://www.linevisioninc.com/news/linevision-new-york-transco-collaborate-on-efficiency-resilience-health-of-new-clean-energy-transmission-line-in-the-hudson-valley

Federal

As noted in Section 2.1, the Federal Power Act grants FERC jurisdiction over rates and terms of service for transmission of electric energy in interstate commerce but does not grant FERC authority over siting of transmission facilities, except for the limited backstop siting authority in Section 216. Thus, electric transmission facility siting and permitting largely rests with the states.

The Energy Policy Act of 2005 added section 216 to the FPA that provides for a limited federal role in transmission siting. Section 216 authorizes FERC to issue permits to construct transmission facilities under certain limited circumstances (i.e., FERC's "backstop" siting authority):

- FERC's authority is limited to facilities sited in DOE-designated NIETCs. NIETCs are geographic areas DOE determines have a need for transmission facilities to resolve electric transmission capacity constraints or congestion that adversely affects consumers.
- FERC may issue permits if: (1) a state lacks the authority to approve the siting of the proposed facilities or consider the interstate benefits; (2) the applicant does not qualify to apply in a state because the applicant does not serve end-use customers in the state; or (3) a state that has authority withheld its approval for more than one year or has conditioned its approval such that the proposed project will not significantly reduce congestion or is not economically feasible.
- FERC must find that the proposed facilities: (1) will be used for the transmission of electricity in interstate commerce; (2) are consistent with the public interest; (3) will significantly reduce transmission congestion in interstate commerce and benefit consumers; (4) are consistent with sound national energy policy and will enhance energy independence; and (5) will maximize, to the extent reasonable and economical, the transmission capabilities of existing towers or structures.[53]

Since section 216's enactment, federal court decisions have hindered DOE's ability to designate NIETCs and there have been no backstop siting applications filed with FERC. In 2021 Congress amended section 216 through the Infrastructure Investment and Jobs Act to address the court decisions. As amended, section 216 expanded the circumstances under which DOE may designate a NIETC to include geographic areas expected to experience transmission capacity constraints or congestion that adversely affects consumers. Section 216 as amended further clarifies that FERC has authority to issue permits in circumstances where a state has denied approval of an application.

In response to this amendment, in December 2022, FERC issued a Notice of Proposed Rulemaking (NOPR) in to revise its existing backstop siting regulations.[54] A final rule on FERC's backstop siting NOPR is pending.

In addition to FERC's backstop siting authority, the U.S. Environmental Protection Agency, Bureau of Ocean Energy Management (off-shore wind facilities beyond 3-mile state nautical boundary), Army Corps of Engineers, U.S. Fish and Wildlife Service, and Federal Aviation Administration have specific authorities applicable to permitting electric transmission facilities.

53 Section 216 authorizes a permit holder, if unable to reach agreement with a property owner, to use eminent domain to acquire the necessary right-of-way for the construction of the permitted transmission facilities.
54 Federal Register :: Applications for Permits To Site Interstate Electric Transmission Facilities.

State

This section explores the role of energy facilities siting, in general, and for transmission facilities in particular, by the Massachusetts DPU and the Massachusetts EFSB.

8.1.1. Dual siting responsibilities of the DPU and EFSB

The Commonwealth has two state agencies involved in energy facilities siting: the DPU and the EFSB. As described below, siting complexities and challenges exist within each agency's own siting processes, as well as in coordination between these two agencies. For the general public, the dual nature of siting jurisdiction at the DPU and the EFSB (and other aspects of siting proceedings) can make it challenging to understand and participate fully in the process.

A brief history of energy facilities siting in Massachusetts may help explain the respective roles of DPU siting functions and the EFSB. For much of the past century, and until the creation of the EFSB, the DPU led the Commonwealth's involvement with siting-related functions for energy facilities including: (1) the grant of zoning exemptions to "public service corporations" for the construction and operation of energy facilities; (2) eminent domain and survey authority for electric transmission and natural gas pipelines; (3) approval for construction and operation of electric transmission lines; and (4) grants of location for electric transmission lines. The DPU continues to have primary jurisdictional authority in these areas.

Amid rising environmental concerns in the late 1960s and early 1970s regarding the development of new power plants and other large energy infrastructure – and increasing difficulties of then-vertically integrated utilities in securing permits for such facilities, the Legislature convened the Massachusetts Electric Power Plant Siting Commission to explore potential solutions. This led to the creation of the Energy Facilities Siting Council in 1974 ("EFSC," now EFSB) with responsibilities to review and approve not only the siting of electric power plants, but also natural gas and oil pipelines, large oil and natural gas storage facilities, and electric transmission facilities. The legislature also provided the Siting Council with extraordinary authority to issue or modify other state and local permits, if previously EFSC-approved facilities were unreasonably denied or delayed necessary state or local permits, or subject to onerous permit conditions. The legislature also exempted the Siting Council from most aspects of the Massachusetts Environmental Policy Act (MEPA) to avoid duplication of review and potential delay.

A state government reorganization in 1992 relocated the EFSB staff to the DPU in the newly established Siting Division and rebranded the EFSC as the EFSB. As part of the legislative reorganization, the EFSB shed some of its functions to other divisions of the DPU (such as natural gas long-range supply planning) and the DPU Chair assumed~~was given~~ the authority to assign DPU siting matters to the Siting Board for adjudication if a project encompassed both agencies' siting jurisdictions. Other than these and other administrative changes, the EFSB and DPU siting authorities remained largely intact and were not consolidated. In 2008, pursuant to the Green Communities Act, the DPU and EFSB, were relocated to a new Secretariat, the Executive Office of Energy and Environmental Affairs (EEA). As EEA agencies, both the EFSB and the DPU became subject to the EEA Environmental Justice Policy.[55]

8.1.2. What is the EFSB?

The EFSB is an independent nine-member board chaired by the Secretary of EEA, which includes the following officials (or designees): commissioners of the DPU (two), Massachusetts

55 Confirmed in the Brockton Power Company SJC decision, 469 Mass. 196 (2014).

Department of Environmental Protection (MassDEP), and DOER; the Secretary of the Executive Office of Economic Development (EOED); and three public members (with energy, environmental, and labor expertise, respectively). The Siting Board's statutory purpose is to review proposed energy facilities to ensure a reliable energy supply, with a minimum impact on the environment, at the lowest possible cost. Statutory authority of the Siting Board is specified in G.L. c. 164, §§ 69G – 69S; Regulatory authority in 980 CMR 1.00 - 12.00. The DPU Siting Division is staff to the EFSB and the DPU Commission. Staff adjudicates cases and prepares tentative decisions and orders for review by the EFSB and DPU Commission.

Table 2~~1~~: EFSB Siting Actions

EFSB Siting Actions

Approval to Construct (12-month proceeding) – this is the central adjudicatory function of the EFSB sought by applicants seeking to build and operate jurisdictional energy facilities. EFSB approval is required before any other state construction permits may be issued. G.L. c. 164, §§ 69J-69J$^1/_2$.

Action by Consent (ABC) – a mechanism to issue an EFSB decision, except a final decision in an adjudicatory matter. To become effective, an ABC must be signed by all Board members. 980 CMR 2.07.

Determination of Jurisdiction (four-month proceeding) – upon request, a proceeding to determine if the EFSB has jurisdiction over a particular facility. 980 CMR 2.09.

Advisory Rulings (60 days to accept request for Advisory Ruling) – written non-binding ruling regarding the applicability of an EFSB statute or regulation. 980 CMR 2.08.

Certificate of Environmental Impact and Public Interest (six-month proceeding) – Pursuant to G.L. c. 164, § 69K-69O½, the Siting Board may also issue a Certificate of Environmental Impact and Public Interest to any applicant that proposes to construct or operate a generation facility or to any electric, gas, or oil company that proposes to construct or operate jurisdictional facilities in Massachusetts. Such a Certificate, if granted, has the legal effect of providing all state and local permits that are required for construction and operation of the facility, as requested by the applicant.

8.1.3. EFSB jurisdictional facilities

G.L. c. 164, § 69G gives the Siting Board jurisdiction over the following types of proposed new energy facilities, which the Siting Board may approve, approve with conditions, or deny:

Electric generating facilities - any generating unit designed for or capable of operating at a gross capacity of 100 megawatts or more, including associated buildings, ancillary facilities, and transmission and pipeline interconnections that are not otherwise subject to the Siting Board's jurisdiction.

Electric transmission lines - new lines that have either: (1) a design rating of 69 kV or more and which is one mile or more in length on a new transmission corridor; or (2) a design rating of 115 kV or more which is 10 miles or more in length on an existing transmission corridor, except reconductoring (i.e., replacing the cables that carry or "conduct" the electric current) or rebuilding at the same voltage; (3) an ancillary structure (such as a new or modified substation), which is an integral part of the operation of any transmission line subject to the Siting Board's jurisdiction.

Gas manufacture or storage - a unit, including associated buildings and structures, designed for or capable of the manufacture or storage of gas, except: (1) a unit with a total gas storage capacity of less than 25,000 gallons and also with a manufacturing capability of less than 2,000 million British thermal units (MMBtu) per day; (2) a unit whose primary purpose is research, development or demonstration of technology and whose sale of gas, if any, is incidental to that primary purpose; or (3) a landfill or sewage treatment plant.

Gas transmission pipeline – a new pipeline with a normal operating pressure in excess of 100 pounds per square inch gauge, which is greater than one mile in length, except restructuring, rebuilding, or relaying of existing gas pipelines of the same capacity.

Oil storage facility - a new unit exceeding 500,000 barrels (21 million gallons) or an oil pipeline greater than one mile in length, except restructuring, rebuilding, or relaying of existing pipelines of the same capacity.

8.1.4. DPU jurisdictional facility siting and related functions

Electric Transmission Lines – The DPU has no jurisdictional thresholds for voltage or line length specified in statute or regulations. (G.L. c. 164, § 72). G.L. c. 164, § 72 requires electric companies to obtain Department approval prior to the construction or significant alteration of existing lines (e.g., increased voltage or increased structure heights) but not reconductoring and equivalent pole replacements. To receive such approval, the electric company must show that the proposed project is needed and that it serves "the public convenience and is consistent with the public interest." Each transmission facility submitted for Siting Board approval under c. 164, § 69J also requires G.L. c. 164, § 72 approval by the Department, administered by the Siting Board in consolidated proceedings. Given the lack of clearly defined physical thresholds for § 72 transmission facilities, the DPU is frequently asked for informal determinations of whether proposed transmission projects, particularly refurbishments of existing lines, require such reviews.

Eminent Domain (G.L. c. 164, §§ 72 & 75C) and Survey Authorization (G.L. c. 164, §§ 72A & 75D) for electric and gas companies, respectively. The Siting Division adjudicates petitions by electric and natural gas companies for the right to exercise the power of eminent domain to meet their public service obligations. To grant eminent domain, the DPU must determine that the project is necessary for the purpose alleged, will serve the public convenience, and is consistent with the public interest.

Zoning Exemptions for "Land and Structures" – The DPU may grant exemptions from local zoning ordinances or by-laws. G.L. c. 40A, § 3 applies to "public service corporations." DPU must find that "exemptions are required" and the "present or proposed use of the land or structure is reasonably necessary for the convenience or welfare of the public."

Grant of Location for transmission lines – Where a grant of location has been refused, the DPU~~epartment~~ may provide grant a location for the transmission line if it deems the location necessary for the public convenience and in the public interest. G.L. c. 166, § 28.

The DPU exercises its jurisdictional authority through Orders issued by its three-member commission. In some cases, Siting Division staff may determine informally that proposed reconstruction/rebuilding of existing transmission lines does not trigger Section 72 jurisdiction (or EFSB jurisdiction).

8.1.5. EFSB/DPU adjudicatory process

The Siting Board's regulations detail how its review of jurisdictional facilities is conducted. See 980 CMR 1.00-12.00. The Siting Board conducts its review of jurisdictional facilities in adjudicatory proceedings under G.L. c. 30A. 980 CMR 2.02(3). Siting Board review commences with Notice and a public comment hearing in one or more of the affected cities or towns. 980 CMR 1.04. The purpose of the public comment hearing is to provide information on a proposed project and to afford members of the general public an opportunity to comment on a proposed facility. 980 CMR 1.04. The Siting Board accepts both oral and written comment on a proposed project and allows intervention and limited participation in a proceeding. 980 CMR 1.04, 1.05. The Siting Board establishes an evidentiary record relating to a proposed project through review of an applicant's petition, pre-filed testimony from the parties, discovery, and cross examination at evidentiary hearings. 980 CMR 1.06.

The Siting Board makes its decisions in a public meeting consistent with Open Meeting Law. 980 CMR 1.08, 2.04, 2.06. After the record is complete and parties submit briefing, Siting Board staff draft a Tentative Decision and issue it to the parties for written comment. The Tentative Decision is also made available to the public. 980 CMR 1.08, 2.06. The Siting Board accepts oral comment, deliberates, and votes at a public meeting. 980 CMR 2.04. After voting, the Siting Board directs staff to issue a Final Decision approving, rejecting, or approving with conditions the proposed project. 980 CMR 1.08, 2.04. The Siting Board's adjudicatory decisions are subject to judicial review at the Supreme Judicial Court. G.L. c. 164, § 69P; G.L. c. 25, § 5.

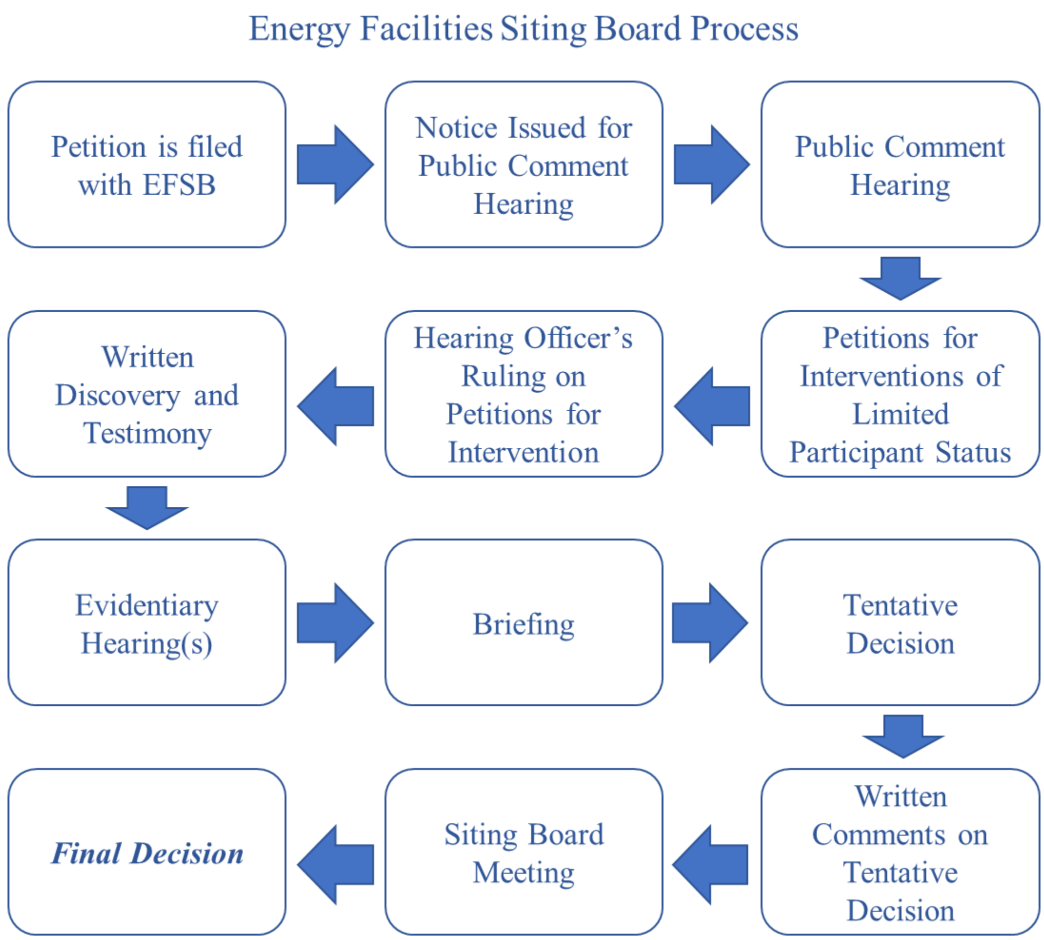

Figure 6: EFSP Process

8.1.6. Areas of EFSB/DPU review for electric transmission projects

Petitions seeking EFSB's approval of electric transmission line proposals must have the following elements by statute (G.L. c. 164, § 69J):

1. A description of the facility, site and surrounding areas;
2. An analysis of the need for the facility, within and/or outside the Commonwealth;
3. A description of alternatives to the facility, such as other methods of transmitting or storing energy, other site locations, other sources of electrical power, or a reduction of requirements through load management;
4. A description of the environmental impacts of the facility, such as land use impact, water resource impact, air quality impact, solid waste impact, radiation impact, and noise impact.

G.L. c. 164, § 69J requires the Siting Board to approve a petition to construct if it determines that:

1. All information relating to current activities, environmental impacts, facilities agreements and energy policies as adopted by the commonwealth is substantially accurate and complete;
2. Projections of the demand for electric power, or gas requirements and of the capacities for existing and proposed facilities are based on substantially accurate historical information and reasonable statistical projection methods and include an adequate consideration of conservation and load management;
3. Plans for expansion and construction of the applicant's new facilities are consistent with current health, environmental protection, and resource use and development policies as adopted by the commonwealth and are consistent with the policies to provide a necessary energy supply for the commonwealth with a minimum impact on the environment at lowest possible cost.

The Siting Board does not have regulations specific to its review of petitions to construct electric transmission lines, although the statute makes this option available.[56] Based on statutory requirements and case precedent, the Siting Board has included the following key topics in its review of electric transmission lines:

- Need (in statute)
- Site and routing alternatives (in statute)
- Non-transmission alternatives (such as distributed generation, storage, and energy efficiency) (in statute)
- Cost of proposed project, alternative routes, and non-transmission alternatives
- Land use impact (in statute)
- Water resource impact (in statute)

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56 "The board shall be empowered to issue and revise filing guidelines after public notice and a period for comment. A minimum of data shall be required by these guidelines from the applicant for review concerning land use impact, water resource impact, air quality impact, solid waste impact, radiation impact and noise impact." G.L. c. 164, § 69J

- Air quality impact (in statute)
- Solid waste impacts (in statute)
- Magnetic field impacts (called "radiation impact" in statute)
- Noise impact (in statute)
- Visual impacts
- Historical/cultural resource
- Flora/fauna/habitat impacts
- Traffic impacts
- Safety
- Hazardous waste
- Environmental Justice (pursuant to 2021 EEA Environmental Justice Policy and An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy. St. 2021, c. 8 ("Roadmap Act"), and when applicable, MEPA EJ Protocols)
- Public convenience and welfare (where zoning exemptions are requested pursuant to G.L. c. 40A, §3)
- Potential property value impacts57

In cases involving a Certificate (pursuant to G.L. c. 164, §§ 69K - 69O and 980 CMR §§ 6.00) in which an applicant requests that the Siting Board issue all necessary state and local permits for a previously EFSB-approved project, the applicant must also demonstrate:

- It meets at least one of six grounds (such as undue delay or burdensome conditions imposed by other state and local permit agencies)
- Need for the facility
- Compatibility of the facility with environmental protection, public health, and public safety
- The extent to which construction and operation of the facility will fail to conform with existing state and local laws, ordinances, bylaws, rules and regulations and reasonableness of exemptions thereunder, if any, consistent with the implementation of the energy policies contained in the Siting statute to provide a reliable energy supply for the commonwealth with a minimum impact on the environment at the lowest possible cost
- The public interest, convenience and necessity requiring construction and operation of the facility

8.1.7. Other permitting agencies

In addition to the siting jurisdiction by the EFSB and DPU, there are numerous other state and local agencies that may have specified areas of permit and approval authority and oversight for proposed electric transmission facilities. These include:

Massachusetts Environmental Policy Act - Disclosure of environmental impacts and consideration of feasible measures to minimize or avoid them. The Siting Board is exempt from the

57 Property values impacts fall outside the scope of the Siting Board's review of transmission lines under G.L. c. 164, § 69J, but may be relevant to DPU review authority under G.L. c. 164, §72 and G.L. c. 40A, §3. See Eversource Energy, EFSB 17-02/D.P.U. 17-82/17-83, at 221 (2019).

requirements of MEPA by statute. G.L. c. 164, § 69I.[58] However, DPU-jurisdictional siting matters (such as transmission lines under G.L. c. 164, § 72, and zoning exemptions under G.L. c. 40A, § 3) have no such exemption, and, when referred by the DPU to the Siting Board for consolidated review with related Siting Board petitions, remain subject to MEPA.

Massachusetts Dept. of Environmental Protection - Air Plan Review – use of best available technology to reduce emissions; Water-related permits – discharge; stormwater; water withdrawal; tidelands (chap. 91); Hazardous wastes and spill prevention plans

Local Agencies - Conservation Commission; Zoning Board and Zoning Board of Appeal (ZBA); Building Department; Planning Board; Department of Public Works; Electrical Inspector; Health Department, others. The following table highlights some of the local permitting issues that can affect transmission-related projects:

Local Agency/Department/Body	Permit/Approval	Description
Conservation Commission	Massachusetts Wetlands Protection Act (G.L. c. 131 § 40) Order of Conditions; additional Local Wetlands Bylaws and Ordinances (if any)	The Massachusetts Wetlands Protection Act (G.L. c. 131 § 40) and implementing regulations (310 CMR 10.00) is a state statute administered locally by Conservation Commissions. In addition to administering the WPA, certain communities also administer a Wetlands Ordinance. The WPA and Wetlands Ordinances require the preparation of a Notice of Intent ("NOI") for certain activities within a wetland resource area and/or work within 100 feet of certain wetland resource areas (i.e., the 100-foot Buffer Zone). The general performance standards for work or activities occurring within wetland resource areas are identified in the WPA
Select Board/City Council	Grant of Location	Grants of Locations are required when a petitioner wishes to locate infrastructure upon, along, under or across that public way.
Tree Wardens	Public Shade Trees (G.L. c. 87)	According to G.L. c. 87, § 1, public shade trees are defined as "all trees within a public way or on the boundaries thereof." An applicant would obtain a permit from the municipal Tree Warden (or MassDOT, as applicable) and work to identify appropriate mitigation.
Zoning Board	Zoning Approvals	Various zoning ordinance areas relating to buildings, land use, construction, health and safety
Planning Board	Scenic Roads (G.L. c. 40 § 15C)	After a road has been designated as a scenic road, any repair, maintenance, reconstruction,

58 Despite this statutory exemption, MEPA review is typically conducted in parallel with, and broadly informs the Siting Board's proceedings, which is a fundamental purpose of MEPA with respect to state permitting agencies. See 301 CMR 11.00 et seq.

		or paving work done with respect thereto shall not involve or include the cutting or removal of trees, or the tearing down or destruction of stone walls, or portions thereof, except with the prior written consent of the planning board, or if there is no planning board, the selectmen of a town, or the city council of a city.
Department of Public Works	Street Opening Permit	Street Opening Permits are required for construction activities located on or under the public right of way, either sidewalk and/or roadway. Often includes provisions for ongoing coordination with police and fire departments; work schedule and duration of closures/detours; routing of traffic
	Earth Removal Permit	Method of removal; type and location of temporary structures, hours of operation, route for transporting material; area and depth of excavation
	Stormwater and Sewer Connection Permits (for manholes, construction sites, etc.)	Approval for connection to public sewer and stormwater systems

Other - Massachusetts Historical Commission; Natural Heritage and Endangered Species Program; Coastal Zone Management; State Fire Marshal (fuel/ammonia storage); Massachusetts Legislature (Article 97 public lands)

Growing Portfolio of Clean Energy Projects

There are several discernable trends that point toward a sustained increase in workloads for DPU/EFSB Siting activity in the foreseeable future.

- Offshore wind development requires long, high-voltage transmission lines that run beneath federal and state waters and onshore to points of interconnection on the New England grid as well as new or modified substations and switching stations. In addition, new or upgraded transmission lines elsewhere on the grid will be needed to enable offshore wind power to flow freely on the grid, without congestion or bottlenecks;

- Battery energy storage systems or other energy storage technologies may require new or modified substations, switching stations, and transmission lines to interconnect to the New England grid;

- ~~DPU Capital Investment Project (CIP) Provisional Program: The DPU is investigating how to improve distributed energy resource planning to further the Commonwealth's progress towards achieving net-zero greenhouse gas emissions. Currently, a distributed generation facility whose interconnection triggers an upgrade of the electric power system must pay for the full cost of that upgrade. These upgrades can be expensive and require extensive system planning and time to construct. The DPU is reviewing significant customer-funded upgrades~~

~~to transmission and distribution systems to facilitate interconnection of distributed generation resources;~~

- ESMP~~lectric Sector Modernization Plan~~s (established by "An Act Driving Clean Energy and Offshore Wind" – 2022) will include both distribution and transmission system investments, such as substations and transmission lines that may be needed for electrification and resiliency;
- Asset Condition Replacements. Replacement of many old, oil-filled underground cables, and related work may trigger DPU/EFSB siting jurisdiction in some cases;
- ISO-NE recommended reliability-based transmission investments.

Challenges for Solar Development

Community solar deployment in Massachusetts faces significant siting challenges. Increasing local opposition and competing policy priorities for preservation of natural and working lands combine to increase project costs and timelines and decrease project sizes. While policymakers may accept a higher ratepayer impact as a tradeoff for focusing future solar deployment in the built environment, the pace of deployment will fall even further behind as project sizes shrink.

Identifying good places for transmission system expansion will need to take into consideration siting and permitting limitations. More so than in other areas of the country, siting utility-scale solar in New England is extremely challenging. Wetlands are extensive, increasing the required acreage per MW and rendering many areas undevelopable entirely. Much of the landscape is hilly or mountainous, reducing the overall area that gets good solar exposure and putting many other areas off-limits due to stormwater runoff regulations. At the same time, the sizes of both parcels and municipalities are smaller than other parts of the country; assembling enough acreage for a utility-scale project typically necessitates cobbling together numerous parcels owned by multiple landowners and dealing with multiple local jurisdictions for permitting. In northern New England, where more land is available, transmission constraints render huge areas uneconomic for solar development. At the same time, southern New England states are densely populated, reducing the opportunity for utility-scale projects and bringing any projects that are possible into closer contact with residents, who have a significant ability to delay and derail projects. Finally, effectively all of the land in New England that is potentially developable for utility scale solar is either farmland or forest, in contrast with other areas of the country that have more open landscapes. Both farmland and forest are highly valued, and conversion of these land use types elicits strong opposition from not just residents but also environmental organizations and even policymakers who otherwise are strongly supportive of solar deployment.

9. Recommendations

This CETWG offers the following recommendations designed to enhance the process of planning, developing, siting, and operating existing and new transmission facilities to support the Commonwealth's transition to a clean energy future.

9.1. Transmission Planning

- The Commonwealth should support regional and interregional efforts to create more proactive and forward-looking transmission planning processes that address all transmission needs and benefits (i.e., reliability, economic, and public policy) in an integrated fashion. Such planning should prioritize high-likelihood needs and protect consumers from paying for transmission investments to address needs that are unlikely to materialize while protecting consumers from inefficient or unneeded transmission investment. This includes:
    - (i) continuing to work with ISO-NE, transmission-owning utilities (TOs), and other New England states to develop and implement a new longer-term transmission planning process with a state-led option to operationalize study results, develop appropriate regional transmission projects including through regional competitive procurements, more cost-effectively create headroom for interconnecting clean energy resources, and allocate costs equitably to beneficiaries across the region,
    - (ii) advocating to FERC to support transmission planning and cost allocation reforms reflecting such a holistic, proactive, and forward-looking transmission planning process to address both regional and interregional transmission needs,
    - (iii) continuing to pursue reforms with TOs and regional partners such as ISO-NE and NESCOE to establish procedures to improve the transparency, predictability, and cost discipline related tofor identifying cost effective upgrades to already existing infrastructure (including upsizing of aging infrastructure that would need to be reconditioned) as solutions to near- and longer-term transmission needs,
    - (iv) implementing mechanisms to optimize the grid, such as deploying grid enhancing technologies (GETs) to reduce costs and prioritizing multi-value transmission in New England and in ties to neighboring regions,
    - (v) continuing to advocate for cost discipline and transparency in connection with transmission development,
    - (vi) explore implementing a transmission "loading order" approach before grid expansion through new transmission line is considered (as discussed in Section 7.1.1), in which RAS could be used first to create additional interconnection headroom (as CAISO is already doing), GETs would be used next to increase interconnection headroom through optimization of the grid, this would be followed by increasing the capacity of existing lines and existing rights of way, before grid expansion through new transmission line is considered and
    - (vi) working with ISO-NE and advocating to FERC for improved interconnection processes that are streamlined and integrated with regional and interregional planning efforts and provide more transparency about grid locations with headroom for new resources.
- To the extent new onshore transmission lines are needed outside of existing electric transmission corridors, the Commonwealth should encourage the co-location of transmission infrastructure within state-owned or state-controlled properties and corridors, such as

highway and railroad rights-of-way. The legislature should consult with relevant agencies (such as Massachusetts Department of Transportation and the Massachusetts Bay Transit Authority) and consider allocating additional resources to these agencies or granting additional statutory authority to support the Commonwealth's clean energy transition. This aligns with federal guidance on leveraging alternative uses of highway rights-of-way.[59]

- Consistent with any direction from the DPU, support the inclusion of local transmission upgrades necessary to meet statewide climate goals in the TOs' Local System Plans and, if necessary, the development of associated cost allocation mechanisms. Any progress reports and actions taken in response to the progress reports should be made publicly available.

- The procurement of long-lead time bulk power system equipment risks delaying the Commonwealth's and the region's progress on constructing beneficial transmission. The Commonwealth should consider collaborating with the TOs and ISO-NE to develop guidance for identifying and procuring key pieces of transmission-related equipment.

- The Commonwealth should support a regional analysis of GETs, informed by experience to-date with the implementation of FERC Order 881. If after appropriate analysis planners determine that GETs offer a more cost-effective strategy to achieve the Commonwealth's transmission goals, they should be any needed tariff rules should be devleoped to facilitate the deploymented of GETs. GETs should also be considered in planning to reduce costs while transmission lines are under construction. If regional transmission planning processes identify the need for increased capacity, GETs should be considered to mitigate the costs of constraints while larger projects are built to address them.

- Amend Section 70 of Chapter 179 of the Acts of 2022 to enable DOER to competitively solicit and select proposals for transmission to deliver clean energy generation to help achieve the Commonwealth's clean energy requirements, beyond existing authority to solicit and select transmission related solely to offshore wind.

- Consider directing EDCs and TOs shouldto work with ISO-NE to identify and execute local transmission upgrades necessary to meet statewide climate goals, including upgrades necessary to implement the electric sector grid modernization plans, consistent with DPU direction. Such efforts should seek to promote coordinated, transparent, and cost-effective planning of local transmission upgrades and equitable allocation of costs. EDCs and TOs should complete this task by a specific date, ensuring alignment with distribution upgrades and expeditious interconnection of clean energy resources. A progress report should be submitted to ISO-NE, EEA, DOER and DPU. Progress reports and actions taken in response to the progress reports should be made publicly available.

- Support the development of local transmission upgrades necessary to proactively create points of interconnections and the necessary headroom on the transmission grid to meet statewide climate goals and expeditiously interconnect new clean energy resources in a cost-effective fashion while minimizing environmental and community impacts, including upgrades necessary to implement the electric distribution companies' Electric Sector Modernization Plans and listed on the transmission owners' Local System Plans. Request that

[59] See 2021 Memorandum from the US DOT Federal Highway Administration available at https://www.fhwa.dot.gov/real_estate/right-of-way/corridor_management/alternative_uses_guidance.cfm.

the transmission owners clearly identify such upgrades on their Local System Plans. Consider the development of new cost allocation mechanisms to ensure equitable allocation of costs.

- ISO-NE's draft 2050 Transmission Study found that reducing peak load significantly reduces transmission cost. Initiatives that reduce the need for infrastructure build are critical to reducing cost pressures on consumers associated with the build out of transmission and distribution systems. In partnership with other New England states, tThe Commonwealth should continue to develop enhancements to/creation of programs to limit peak load growth (e.g., demand response, time of use rates, rate design, load management, and energy efficiency programs) which, in turn, would reduce the intensity of needed transmission. The Commonwealth should also consider whether coordination with other New England states in this area would enhance the benefits of such programs.

- Work with ISO-NE and neighboring regions to better utilize the existing interregional transmission capability (e.g., through intertie optimization and GETs, including DLR, which would likely significantlycould be options for increasinge interregional transmission capability during winter cold snaps that tend to strain the New England grid)

- Continue the effort with other New England states, New York, and mid-Atlantic states New Jersey to determine explore interregional transmission needs and identify the most cost-effective upgrades and new transmission projects (onshore and/or offshore); work with these other states and regions to (i) implement offshore transmission standards in the states' offshore wind procurements (such as HVDC standards and network-ready offshore substations) that will allow the creationing of regional and interregional transmission links if and when valuable in the future, and (ii) consider new interregional planning procedures.

9.2. Interconnection

- Work with regional partners to eEstablish a forum to (i) continuously explore interconnection process improvements beyond initial Order 2023 compliance, including by taking advantage of experience gained in other regions, such as MISO, SPP, and CAISO, and (ii) facilitate stakeholder collaboration on regional best practices for Distributed Generation (DG) Affected System Operator (ASO) studies. Such a forum should promote broad participation, including from ISO-NE, state officials, utilities, developers of transmission-interconnected and distributed generation, consumer advocates, and the public.

- Encourage ISO-NE to explore ways that the interconnection process can be better integrated into the transmission planning process.

- ISO-NE should consider going beyond what FERC established in Order 2023 and take steps to integrate GETs in interconnection processes, including by taking the following actions: [Pfeifenberger: Note, the rest of this (including the bullets) should apply not just to generation interconnection, but also to transmission planning]
    - ISO-NE should consider providing renewable developers with opportunities to identify GETs solutions during the interconnection process and as a means to address transmission system constraints that may be resulting in the curtailments of existing projects.

- ISO-NESO-NE and the Commonwealth's utilities should consider GETs, including DLR, as a valid mitigation alternative in interconnection studies.
- They should dDevelop procedures to document GETs and include them in business practice manuals.
- There should be detailed reporting on the evaluation of GETs in interconnection studies (including the basis for rejection.)
- ISO-NE and the Commonwealth's utilities should work with GETs vendors to develop the models to be used in interconnection studies.
- ISO-NE and the Commonwealth's utilities should update their software to include the GETs models.

9.3. Offshore Wind Transmission

- The Commonwealth should evaluate the offshore wind procurement process as part of a strategic offshore wind plan, considering the recent procurement experiences along the east coast. This should target lowering total customer costs and de-risking offshore wind procurement events by reducing the cost of entry for developers. This could include separating land-based transmission upgrades from offshore wind development, and considering standards for offshore transmission projects that would support future development of an expandable multi-terminal HVDC offshore grid.
- The Commonwealth should work with other New England states, ISO-NE, and transmission-owning companies to initiate a regional analysis to determine the optimal locations for the interconnection of offshore wind. The analysis should include options to interconnect offshore wind resources that: (i) minimizes costs and needed upgrades to deliver power to load centers and meet future load growth, (ii) enables the ability to interconnect other new clean energy resources, and (iii) minimizes environmental and community impact.

9.4. Workforce Development

- Currently, power system engineers are in high demand across the country, as well as other economic and technical specialties. To expedite the interconnection of clean energy resources, and the development of the necessary transmission infrastructure, the Commonwealth should continue to support workforce development efforts to increase the number of engineers and technical staff, both within relevant state agencies and in the broader industry to ensure review of state and local siting and permitting applications in a prudent and expeditious manner. This could include Massachusetts state agencies and the Massachusetts Clean Energy Center (MassCEC) could work with universities that have existing engineering programs, such as Worcester Polytechnic Institute, to creating, expanding, and or enhancinge those programs at universities providing engineering training and linking them to internships and onsite training at ISO-NE and local clean energy companies. Additional collaborations between Worcester Polytechnic Institute (WPI), Massachusetts Institute of Technology (MIT) and other universities could be considered to pilot the use of AI and automation for study models and process management. The Massachusetts legislature should consider directing the Massachusetts Clean Energy Center CEC to explore the possibility of such a programs and allocate funding to ensure its success. Additional collaborations between Worcester

~~Polytechnic Institute (WPI), Massachusetts Institute of Technology (MIT) and other universities could be established to pilot the use of AI and automation for study models and process management.~~

9.5. Siting and Permitting

- Existing authorities and processes applicable to siting and permitting of electric transmission in the Commonwealth pose multiple challenges to the timely development of new or upgraded transmission infrastructure. Some of the key areas of concern with the DPU/EFSB siting process include:
  - The time required to obtain final orders and decisions, which can greatly exceed the 12-month timeline described in the EFSB's statute (G.L. c. 164, § 69J);[60]
  - The cost and complexity involved in siting cases for both applicants and other parties;
  - Frequent appeals of DPU/EFSB orders and decisions and the cost and delay this may entail;
  - Outdated statutes and regulations, and other areas where regulations would be helpful, but do not exist;
  - Concerns by environmental and community groups about barriers to participation in the adjudicatory process, and whether their concerns are adequately addressed in final orders and decisions;
  - Environmental Justice (and language access) as both a procedural and substantive issue;
  - Staffing of the DPU/EFSB Siting Division, and whether it is adequate;
  - Areas of duplication in permitting and siting review among multiple agencies;
  - Concerns regarding insufficient outreach, community engagement, and consultation with stakeholders and residents prior to development of project proposals and submission for siting approval;
  - The dual role of the DPU and the EFSB as siting agencies and the additional procedural and substantive complexities that result; and
  - The composition of the EFSB Board, and whether new members are necessary to reflect additional stakeholder interests.

- Pursuant to Executive Order 620, Governor Healey established the Commission on Energy Infrastructure Siting and Permitting (CEISP). The CEISP's mandate is to advise the Governor on: (1) accelerating the responsible deployment of clean energy infrastructure through siting and permitting reform in a manner consistent with applicable legal requirements and the Clean Energy and Climate Plan; (2) facilitating community input into the siting and permitting of clean energy infrastructure; and (3) ensuring that the benefits of

[60] The Supreme Judicial Court has construed such language to be directory in nature. Box Pond Ass'n v. EFSB, 435 Mass 408, 415, n.7 (2001).

the clean energy transition are shared equitably among all residents of the Commonwealth. Executive Order 620 specifically tasks the CEISP with developing recommendations for reform of electric transmission facilities siting and permitting: "The CEISP shall review and assess existing statutes, regulations, and administrative processes and make recommendations to the Governor concerning the reform of state and local permitting and siting processes for energy related infrastructure, including, for example, options to accelerate the deployment of clean energy generation and electric distribution and transmission infrastructure while ensuring that communities have adequate input into the siting and permitting processes for said infrastructure."61 The CEISP must produce a report conveying its recommendations to the Governor by March 31, 2024. The CETWG acknowledges the CEISP's mandate to advise the Governor on energy siting and permitting reforms to support the Commonwealth's need for clean energy infrastructure, including reforms specifically addressing siting and permitting of electric transmission. In carrying out this mandate, the CETWG recommends that the CEISP consider the conclusions regarding siting and permitting challenges to electric transmission infrastructure addressed in this report.

9.6. Other

- The 2050 Transmission Study resulted in several high-level observations around transmission-related challenges the future grid may face as a result of the clean energy transition. The CETWG acknowledges these key takeaways and supports the Commonwealth's continued engagement with regional partners on these issues, some of which are captured in the recommendations above.
    - **Reducing peak load significantly reduces transmission cost.** The assumptions initially provided by NESCOE included an assumed 2050 winter peak load of 57 GW. The study explored how a lower peak load in 2050 might impact transmission needs and costs by also studying at 51 GW 2050 winter peak load. The 2050 Transmission Study found that increases in load result in significantly higher transmission costs as load levels increase. The cost to serve 51 GW of load is $16-$17 billion, while the cost to serve 57 GW of load is $23-$26 billion. Limiting load growth could be achieved through more aggressive demand response, energy efficiency, and peak shaving programs. Limiting load growth could also be achieved by using some stored fuel for heating on the coldest days. For example, moving from 57 GW to 51 GW of peak load could represent ~80% heating electrification while still maintaining 100% transportation electrification.
    - **Targeting and prioritizing high likelihood concerns is highly effective.** While the 2050 Transmission Study is a high-level analysis, the results can be used to identify which areas of the transmission system are most likely to be constrained in the future. The 2050 Transmission Study found that "projects that address these high-likelihood concerns are likely to bring the greatest benefit for a wide range of possible future conditions as the clean energy transition accelerates."[62]

[61] Recommendations may include suggestions for administrative, regulatory, and legislative changes to existing laws and procedures.

[62] Draft 2050 Transmission Report at 17.

- **Incremental upgrades can be made as opportunities arise.** Many of the transmission concerns found in the 2050 Transmission Study can be addressed by rebuilding existing transmission lines rather than building new lines in new locations. Taking advantage of line rebuilds could minimize costs as well as be less environmentally disruptive. Rebuilds can generally be achieved in a shorter timeframe than new transmission lines, which would allow the region to hold off on investment decisions until more information is available. The 2050 Transmission Study found that upgrading the capacity of lines as the opportunity arises, or "right-sizing" aging asset condition projects[63] when they occur, could be a financially prudent way for New England to reliably serve increased peak loads. Discussion on how to "right-size" transmission investment will occur at ISO-NE's public stakeholder forum, the Planning Advisory Committee. Because reconditioning an aging transmission asset without evaluating upsizing opportunities can result in lost opportunities, NESCOE has requested that the region first make progress on reforms to improve the transparency, predictability, and cost discipline of aging asset condition projects as a prerequisite to a right-sizing approach.[64]

- Generator interconnection locations matter. The specific location of where generators interconnect to the gridgenerators can have a significant impact on the needed transmission upgrades. In general, locating generation close or interconnecting them to grid points close to large load centers, such as cities, can reduce the strain on the transmission system.

- **Transformer capacity is crucial.** Transformers "step up" and "step down" power between higher andfrom higher to lower voltages. The 2050 Transmission Study found that as load increases, higher voltage lines become more important. In turn, the power "stepped up" and transferred on the higher voltage lines must eventually "step down" to lower voltages on the way to the distribution system. A significant number of additional transformers will be needed to support load growth. However, transformers typically are expensive and require a long lead time (1-2 years). The 2050 Transmission Study found that "due to the long lead times and the large number of transformers needed, it may be prudent to start ordering transformers ahead of time and determining their exact locations later on."[65]

[63] In New England, asset condition projects are identified by transmission owners when equipment exceeds its useful life. Draft 2050 Transmission Report at 17.
[64] https://nescoe.com/resource-center/asset-condition-process-improvements-next-steps/
[65] Draft 2050 Transmission Report at 20