This draft Maine Transmission Infrastructure Study has been prepared by E3 and released by the Maine Department of Energy Resources for public comment.

All public comments received in response to the draft report will be included as an additional appendix to the final Maine Transmission Infrastructure Study when it is submitted to the Joint Standing Committee on Energy, Utilities and Technology in accordance with Resolves 2025 Chapter 57.

Written comments are due no later than August 17, 2026, and must be submitted by email to DOER@maine.gov.

MAINE TRANSMISSION INFRASTRUCTURE STUDY

Landscape Review of Transmission Processes, Needs, and Emerging Opportunities in the State of Maine

July 31, 2026

Energy+Environmental Economics

Energy and Environmental Economics (E3) is an analytically driven consulting firm focused on the transition to clean energy resources with offices in San Francisco, Boston, New York, Calgary, and Denver. Founded in 1989, E3 delivers analysis that is widely utilized by governments, utilities, regulators, and developers across North America. E3 completes roughly 350 projects per year, all exclusively related to the clean energy transition, across our four practice areas: Transmission, Pricing, and Risk (TPR), Energy Planning and Policy (EPP), Market Advisory and Valuation (MAV), and Distribution Technology and Planning (DTP). The diversity of our clients – in their questions, perspectives, and concerns – has provided us with the breadth of experience needed to understand all facets of the energy industry. We have leveraged this experience and garnered a reputation for rigorous, unbiased technical analysis and strong, actionable strategic advice.

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1 Executive Summary

Maine's electric transmission system is entering a period of significant transition. For decades, transmission planning focused primarily on maintaining system reliability and replacing aging infrastructure. That role has since expanded to also support growing electricity demand, enable the development of new energy resources, strengthen resilience to evolving system conditions, and facilitate the efficient movement of power throughout New England and neighboring regions. At the same time, new transmission projects must be developed in a manner that reflects Maine's environmental values and provides meaningful opportunities for public participation.

Pursuant to Resolves 2025 Ch. 57 (L.D. 197), this study provides a comprehensive review of Maine's transmission landscape. To assist Maine policymakers and members of the public in understanding and navigating the myriad processes that influence where, when, why, and how transmission infrastructure is deployed, it documents the existing planning, siting, permitting, and stakeholder engagement processes; synthesizes existing studies of future transmission needs; examines considerations to utilize transportation rights-of-way; reviews emerging transmission technologies and construction methods; and identifies best practices from Maine and other jurisdictions. Collectively, these findings provide a common foundation for policymakers, agencies, utilities, developers, communities, and other stakeholders as the transmission system in Maine and neighboring jurisdictions continues to evolve. This report does not substitute for existing planning processes by recommending or evaluating specific transmission proposals or projects.

The review demonstrates that many of the transmission investments likely to occur over the next decade will be driven primarily by reliability and asset replacement needs. Beyond these near-term investments, a variety of needs emerge, including transmission necessary for integrating new in-state resources, and infrastructure designed to increase transfer capability between Maine and the rest of New England. While the precise scale and timing of many future investments remain dependent on factors such as electricity demand, regional resource options and development, and federal policy changes, transmission planning will increasingly require flexible, long-term approaches capable of evaluating multiple future scenarios. Additionally, this report reflects transmission investment needs as of the time of publication. As grid conditions evolve and additional transmission planning studies are completed, transmission needs in Maine and across the region are likely to continue to develop.

This study also highlights that successful transmission development depends on more than engineering solutions. Effective planning relies on transparent decision-making, meaningful stakeholder engagement, coordinated permitting, careful consideration of community impacts, and evaluation of a broad portfolio of potential solutions. Emerging technologies, including advanced transmission technologies and strategic undergrounding in appropriate circumstances, expand the range of available options and can complement, although not entirely replace, conventional transmission infrastructure. Effective utilization of existing rights-of-way, including potential co-location with transportation infrastructure, could help meet growing supply and transmission needs while minimizing land-use and community impacts. Consistently evaluating each alternative and development option alongside traditional solutions can help identify investments that maximize benefits while minimizing costs and impacts, although tradeoffs between various impacts are fundamental and must be evaluated in the context of specific goals and options at hand.

Key Takeaways

1. **Transmission investment is becoming increasingly important to Maine's energy future.** Growing electric demand, aging infrastructure, new resource development, and evolving regional power flows are collectively increasing the need for transmission planning and investment.

2. **Maine already has a comprehensive but complex planning and permitting framework.** Transmission development involves coordinated review across regional, state, federal, and local entities, with multiple opportunities for public participation throughout planning, permitting, and approval processes.

3. **Near-term transmission needs will likely be driven by reliability and asset replacement.** Existing utility plans and ISO New England assessments identify substantial investments needed to maintain safe, reliable operation of the existing transmission system, independent of longer-term planning objectives.

4. **Existing rights-of-way can reduce, but not eliminate, siting challenges.** Effective utilization of existing transmission corridors, and co-location with transportation and rail corridors may reduce environmental impacts and permitting complexity in some locations, although technical, operational, and property constraints can also limit where these opportunities are feasible.

5. **Advanced transmission technologies should become part of the standard planning toolkit.** Technologies such as dynamic line ratings, advanced conductors, power flow controls, topology optimization, and strategically deployed storage can improve system performance and, in some cases, defer or reduce traditional infrastructure investments. Each present distinct benefits and limitations; their application should be based on comprehensive cost-benefit analysis and integrated with conventional planning practices.

6. **Strategic undergrounding may be appropriate in select circumstances but is not a universal solution.** Underground transmission can provide meaningful benefits where visual impacts, environmental sensitivities, resilience considerations, or right-of-way constraints are particularly significant. However, substantially higher construction and maintenance costs as well as different environmental impacts mean undergrounding is generally best evaluated on a project-specific basis rather than applied broadly.

7. **Successful transmission planning depends on evaluating all reasonable solutions.** Long-term planning processes should consistently compare traditional transmission investments, advanced technologies, non-traditional approaches, and portfolio solutions using transparent analytical methods that account for uncertainty and a broad range of benefits. Federal Energy Regulatory Commission (FERC) Order No. 1920 supports many of

these best practices, requiring ISO-NE update its planning processes by June, 2027 to better support long-term, comprehensive evaluation of transmission needs and solutions.

8. **Stakeholder and community engagement is fundamental to durable transmission decisions.** Early, transparent, and sustained engagement improves understanding of transmission needs, helps identify community concerns before projects advance, and supports more informed decision-making while reducing the potential for siting and permitting delays by proactively raising and addressing stakeholder concerns. Stakeholder engagement should include opportunities for input from industry stakeholders and agencies, local residents, landowners, and communities affected by planned transmission development.

Ultimately, Maine's transmission system will continue to evolve in response to changing reliability needs, economic conditions, and energy policy objectives. By improving understanding of existing processes, synthesizing current knowledge of future transmission needs, and identifying emerging technologies and best practices, this study establishes a foundation for future planning and informed stakeholder participation. As transmission investments are evaluated in the years ahead, maintaining transparent planning processes, rigorously assessing available solutions, and balancing statewide, regional, and community interests will be essential to ensuring that future transmission development delivers lasting value to Maine and its residents.

2 Introduction and Legislative Context

On June 10, 2025, Gov. Janet Mills approved L.D. 197, a legislative resolve "directing the Governor's Energy Office to Conduct a Study Regarding the Future of Electric Transmission Infrastructure in the State."[1] Shortly thereafter, the Maine Department of Energy Resources (DOER – formerly the Governor's Energy Office), launched the Maine Transmission Infrastructure Study,[2] and convened a stakeholder group comprising diverse perspectives on transmission infrastructure to help advise and guide this study, pursuant to L.D. 197. L.D. 197 (also frequently referred to as the Resolve) laid out the following requirements for the study to review:

1. Existing processes for the siting and permitting of new and upgraded electric transmission infrastructure in the State, including opportunities for public engagement and methods for efficiently meeting permitting or regulatory requirements;
2. Best practices related to electric transmission planning, siting, permitting and community engagement from other states or regions, including consideration of different types of state siting authorities and consideration of the potential for the sharing of electric transmission infrastructure costs with other states;
3. Existing analyses of future electric transmission needs in the State necessary to integrate new renewable resources as well as to ensure reliability, improve market efficiency or support the achievement of the State's policy goals, including the goals established pursuant to the Maine Revised Statutes, Title 35-A, section 3210, subsection 1-A; Title 35-A, section 3404; Title 35-A, chapter 38; and Title 38, section 576-A;
4. Types of existing rights-of-way and opportunities for potential use of those rights-of-way for siting of electric transmission infrastructure in the State, including colocation with transportation, electric transmission and railway rights-of-way; and 5. Existing and emerging technology and construction methods, such as grid-enhancing technologies, advanced conductors and so-called strategic undergrounding, including a cost-benefit analysis comparing buried high-voltage direct current lines with aerial high-voltage alternating current lines and aerial high-voltage direct current lines.

Accordingly, each of these topics are addressed in the major sections of this report:

5. An evaluation of **Existing Processes for Transmission Siting, Permitting, Planning, and Stakeholder Engagement.** This seeks to lay out, in a clear and accessible way, the processes through which new transmission is identified and ultimately approved and built

[1] **Maine Legislature**, Resolves 2025, Chapter 57. https://mainelegislature.org/legis/bills/getPDF.asp?paper=SP0084&item=5&snum=132

[2] Details on this study, including a link to the Resolve itself, an archive of public meetings and related resources, and a list of stakeholder group members, are available via the study website here: https://www.maine.gov/energy/current-studies/transmission-infrastructure-study

in the New England region, and specifically in Maine. Additionally, it works to identify major avenues for stakeholder involvement throughout that planning and development process.

6. An assessment of **Existing Analyses of Future Electric Transmission Needs**. This summarizes recent studies that have evaluated transmission needs in Maine, and discusses a number of the most prominent proposed and in-development projects in the state.
7. A discussion of **Rights-of-Way and Electric Transmission** throughout Maine, and the potential for roadway and railway **colocation**. This section further considers the challenges and opportunities of transmission siting, focusing on potential colocation with other infrastructure types.
8. A review of **Existing and Emerging Transmission Technologies and Construction Methods**. This includes discussion of advanced transmission technologies and their potential applications in Maine, as well as a qualitative evaluation of the costs and benefits associated with strategic underground of transmission infrastructure.
9. Finally, the study concludes with discussion of **Best Practices from other Jurisdictions** across each of these transmission topics.

Altogether, this represents a thorough lay-of-the-land assessment of transmission processes, identified needs, and emerging opportunities in the state of Maine, as well as the ways in which stakeholders can engage in these processes going forward. Development of this report has followed a series of public stakeholder sessions in which the project team presented on these same five core topics, and sought input and feedback from both the designated stakeholder group and the broader public.[3]

The project team worked to integrate feedback received into this report, with the objective of making this a practical resource that both addresses the topics laid out in the Resolve, while also reflecting key interests and perspectives from stakeholder group members. The report is intended to provide a snapshot of the transmission landscape at the time of publication; as grid conditions evolve and additional transmission planning studies are completed, the needs, opportunities, and considerations discussed throughout this report are expected to continue developing. The Maine Department of Energy Resources (DOER) commissioned Energy and Environmental Economics, Inc. ("E3") to develop this study, with additional support from The Ray on topics related to Rights-of-Way colocation, and from the Consensus Building Institute ("CBI") for stakeholder engagement support and best practices related to stakeholder engagement.

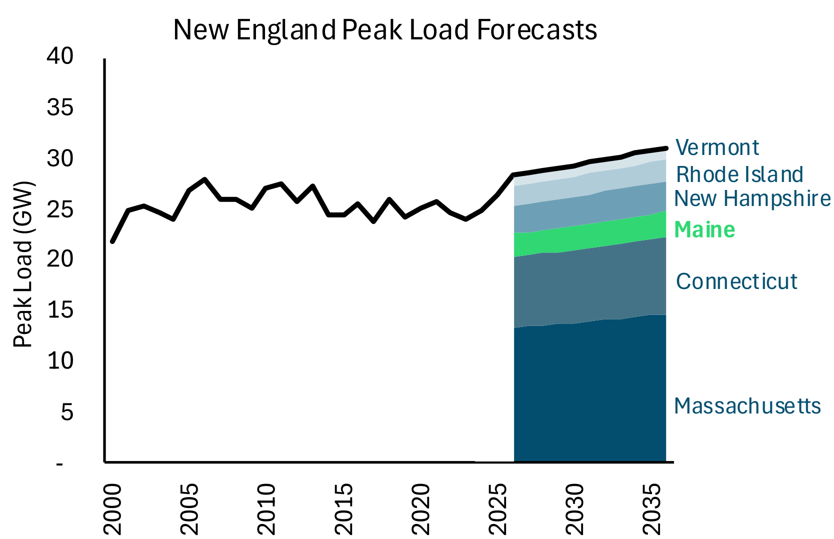
Importantly, this study is being conducted during a time when transmission is becoming an increasingly vital component of long-term energy planning in Maine and in the broader New England region. Transmission investment is critical for maintaining reliability and mitigating growing power sector costs, while also ensuring the grid remains safe and operationally efficient. As the grid

[3] Slide decks and meeting notes from each of those stakeholder meetings are included in the DOER Meeting Archive, accessible at https://www.maine.gov/energy/opportunities/public-meeting-archive

continues to evolve, this role will only grow more important. Three major drivers of new transmission need include load growth, aging transmission assets, and an evolving energy mix.

+ **Load Growth:** Over the past two decades, peak loads have been largely flat, as efficiency improvements and behind-the-meter load reduction offset population growth and some incremental end-use electrification. Across the coming decade, load forecasts[4] are expected to grow steadily, driven jointly by large load developments and continued increases in electric heating, cooling, and transportation loads. Growing loads will require new transmission to serve them, in addition to new generation resources to ensure both sufficient energy and reliable capacity.

Figure 1. 2026 CELT Peak Load Forecasts

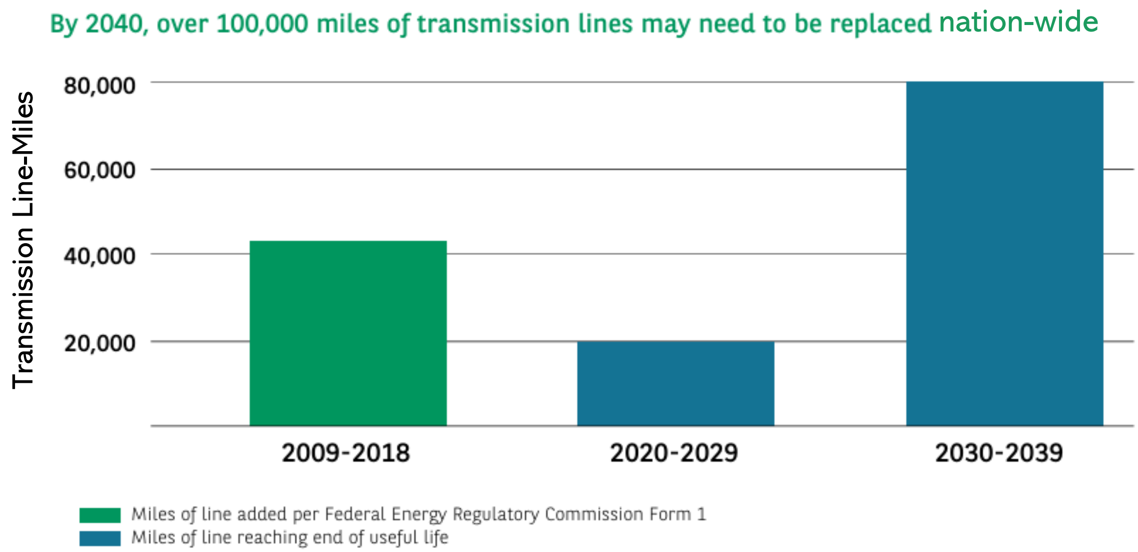


+ **Aging Transmission Assets:** Much of the oldest components of the existing transmission network nationwide are approaching end-of-useful life, with a report from the Lawrence Berkely National Lab finding that as much as 100,000 miles of transmission lines may need to be fully replaced by 2040 nationwide. This represents about 16% of all in-service transmission lines in the country. New England is no exception; over $5 billion in so-called asset condition projects have been identified as requiring near-term replacement, and that amount is based on just the 2026-2030 asset condition and reliability need assessments. Of that, ~$500 million is identified in Maine. Additional replacement needs will be identified when the next window is evaluated; between now and 2050 a substantial portion of the New England transmission network is likely to require some investment to ensure continued safe and reliable operation; these needs must be closely scrutinized, but

[4] As projected by ISO-NE in the 2026 CELT report, accessible at https://www.iso-ne.com/system-planning/system-plans-studies/celt

coupled with load growth can present opportunities to right-size infrastructure investments to meet growing current and future needs.

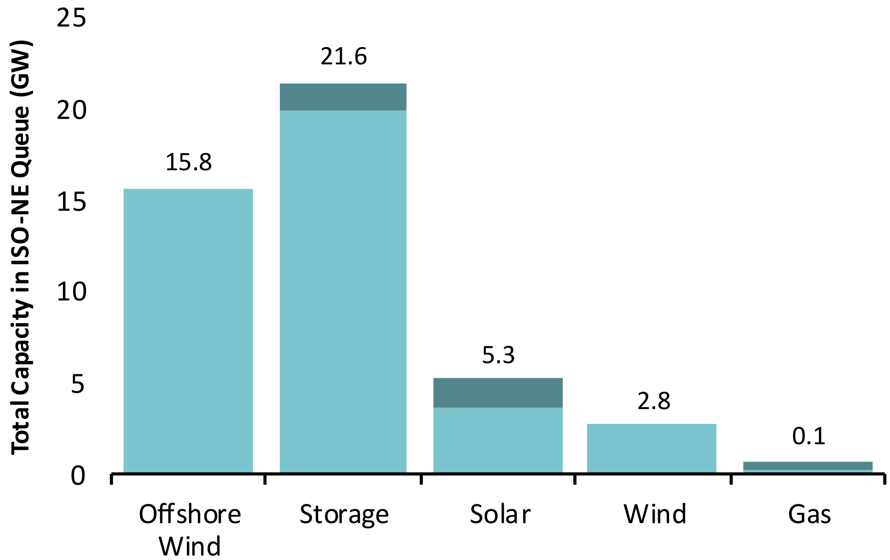
Figure 2. Aging Asset Replacement Needs through 2040[5]



+ **Evolving Grid Mix:** In addition to the above pressures, we are at a point where affordability is paramount, but new low cost generation options are limited. Fuel prices are volatile with geopolitical conflicts driving further scarcity, and national demand driven largely by data center load growth has outstripped the pace of production for new generation technologies—including combustion turbines (CTs) and combined cycle gas turbines (CCGTs)—in addition to some non-emitting resources. This supply-demand imbalance has further driven up costs for these technologies, creating a challenging environment to both serve growing demand and mitigate rate changes. As the grid mix continues to evolve and grow more diverse to meet these overlapping needs, optimal resource locations will shift, requiring new transmission to deliver to load areas.

[5] Data and chart originally from the Oliver Wyman "Modernizing Aging Transmission" report. Now accessible via the 2025 BPN Paribas Asset Management "Listed Environmental Infrastructure: An analytical assessment of the investment case and structural growth drivers" report, available at https://docfinder.bnpparibas-am.com/api/files/f585500b-0b9d-4465-9340-7706fbed2773

Figure 3. Current Capacity in the ISO-NE Interconnection Queue



With these overlapping pressures driving renewed focus on the role of transmission in long-term power sector planning, it is critical that stakeholders in Maine have a clear understanding of the processes governing planning, siting, and permitting as they work today, in addition to insights into methods that have been effective in other jurisdictions, and emerging technologies and development considerations that could be beneficial. As a state renowned for its natural beauty, large infrastructure decisions of all types must be carefully considered; their need clearly demonstrated and all options for addressing that need fairly and thoroughly evaluated. This report aims to lay the building blocks by which stakeholders can effectively engage in these processes, and help shape the direction of future investment decisions to ensure the solutions that yield the most benefits to Mainers are identified and advanced.

3 Existing Processes for Transmission Siting, Permitting, Planning, and Stakeholder Engagement

This chapter describes the key regulatory and legislative processes through which electric transmission projects in Maine are identified, selected, reviewed, and approved for construction. These processes are distributed across local, regional, state, and federal authorities, and the specific processes projects are subject to depend on how the project is initiated, where it is located, and what impacts it may have. In general, FERC has jurisdiction over interstate transmission planning, wholesale electricity markets, and transmission rates, while states retain primary authority over transmission siting and permitting, with local governments also playing important roles through municipal approvals.

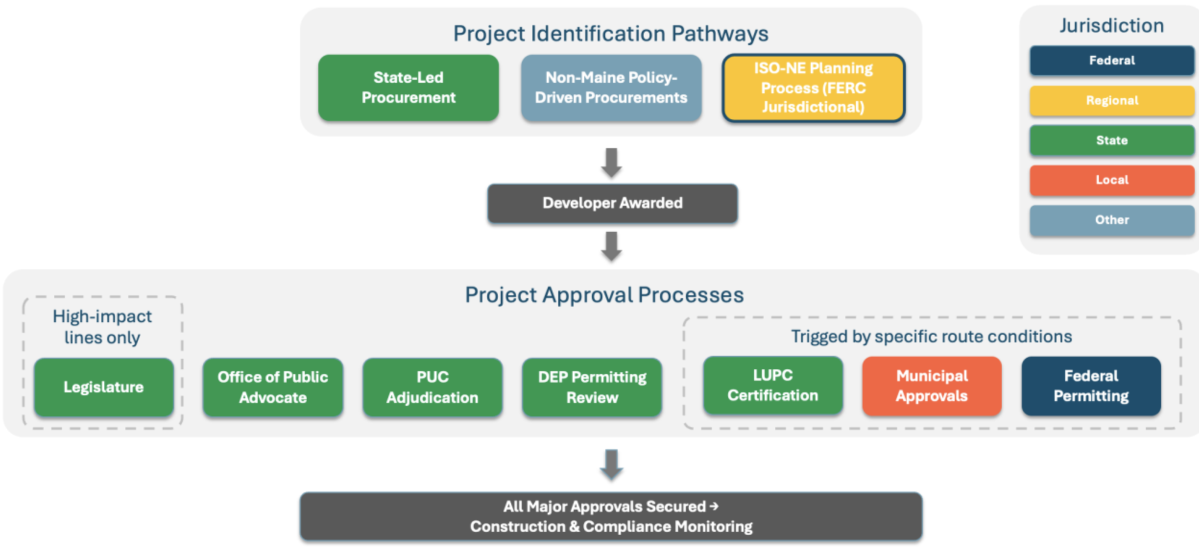
Throughout this report, the review of existing processes focuses on transmission infrastructure, defined as lines ranging from 69 kV to 765 kV. Lower voltage distribution lines are planned through separate local utility processes and are not addressed in this report.

This chapter is organized into two main sections: 1) project identification pathways; and 2) project approval processes. The project identification pathways section focuses on the processes through which transmission needs are identified and potential projects are proposed, assessed, selected, or procured. In Maine, these pathways include ISO-NE's regional transmission planning process, from which most new transmission projects in the region originate; Maine-led legislative or procurement processes, such as the Northern Maine Renewable Energy Development Program; and policy-driven procurements initiated by other states or entities that may result in transmission infrastructure located in Maine.

The second section of this chapter describes project approval processes which are the siting, permitting, zoning and regulatory approvals that a selected transmission project must secure before construction can begin. Specific approval processes may vary by project. Maine's approval processes for transmission lines include legislative approval for high-impact transmission lines, Maine Public Utilities Commission (MPUC) review through the Certificate of Public Convenience and Necessity (CPCN) process, and Office of Public Advocate review of non-wires alternatives (NWA). Several other permitting processes may be triggered depending on project location or size. These processes include Department of Environmental Protection (DEP) and Board of Environmental Protection (BEP) permitting review, Land Use Planning Commission (LUPC) certification, federal permitting, and municipal approvals. These processes are meant to evaluate projects based on public need, costs, alternatives, environmental impacts, land use compatibility, public health and safety, reliability, and consistency with Maine's state energy goals.

Figure 4 illustrates how transmission projects originate from project identification pathways, are awarded to a developer, and seek siting and permitting reviews in project approval processes before they are legally able to begin construction. Each of the processes shown in Figure 4 are discussed in detail throughout this chapter.

Figure 4. Transmission Project Development Milestones



Stakeholder engagement opportunities are discussed and highlighted in callout boxes throughout this chapter for each project identification pathway and approval process. There are a variety of opportunities for stakeholders to engage in both identification pathways and approval processes. These opportunities include legislative hearings, public comment periods, agency proceedings, public witness hearings, and municipal meetings, as well as stakeholder advocacy committee meetings, and formal intervention in adjudicatory proceedings. These opportunities vary in timing, formality, and accessibility, with some being open to the general public and others requiring formal invitation or committee membership. Together, these engagement opportunities provide multiple points at which communities, landowners, residents, municipalities, state agencies, utilities, developers, advocates, and other interested parties may participate in transmission decision-making.

Project Identification Pathways

There are several main pathways through which transmission projects can be identified, analyzed, and selected for development. These include:

- ISO-NE Transmission Planning
- Maine-Led Procurement
- Non-Maine Policy Driven Procurement

These pathways represent the most prominent mechanisms through which major transmission projects affecting Maine have historically been identified. Other project development pathways, including privately sponsored merchant transmission projects, also exist but are not a primary focus of this report.

ISO-NE Transmission Planning

The Independent System Operator of New England (ISO-NE) is the regional grid operator and transmission planning entity for most of Maine and the broader New England region, including Connecticut, Massachusetts, New Hampshire, Rhode Island, and Vermont. While the majority of Maine's electrical grid is operated by ISO-NE, a portion of the northern region of Maine is instead administered by the Northern Maine Independent System Administrator (NMISA). ISO-NE's regional transmission system includes approximately 9,000 miles of high-voltage transmission lines rated 115 kV and above, and 14 interconnections with neighboring systems to allow power to move between New England and neighboring regions, supporting reliability, economic exchange, and access to external resources.[6] These interregional ties include:

1. **New York ISO (NYISO):** connected via nine transmission interconnection ties
2. **Hydro Quebec:** connected via three DC transmission interconnection ties
3. **New Brunswick Power (NBP):** connected via two transmission interconnection ties

Figure 5. ISO-NE Regional Map[7]

ISO-NE is federally regulated by the FERC and has three major regional responsibilities: operating the high-voltage grid, administering wholesale electricity markets, and conducting regional system planning. This section focuses solely on the ISO-NE regional transmission planning process as a pathway for identifying transmission projects. Transmission planning is the process of identifying transmission needs, evaluating potential solutions to meet those needs, soliciting transmission

[6] ISO New England, Transmission: https://www.iso-ne.com/about/key-stats/transmission
[7] Federal Energy Regulatory Commission, ISO New England: https://www.ferc.gov/industries-data/electric/electric-power-markets/iso-ne

solutions and awarding development rights, and regionally allocating costs of the transmission projects.

Process Description

ISO-NE's transmission planning process begins with modeling the transmission system to identify needs on the regional grid. Transmission planning models are engineering, economic, and power flow tools that test whether the grid can reliably and efficiently deliver electricity under a set of forecasted or assumed conditions. These models incorporate assumptions about future electricity demand, generation and storage resource costs and development trajectories, resource retirements, transmission constraints, fuel prices, and more.

ISO-NE's transmission planning process and modeling efforts identify three key categories of need that arise across the region's grid:

- **Reliability:** Needs identified to ensure that the transmission system can continue to serve load and meet applicable reliability standards under forecasted system conditions
- **Market efficiency:** Economic needs identified where new projects or transmission upgrades may reduce congestion, lower costs of producing and delivering power, and improve operational efficiencies of the regional power system
- **Public policy:** Needs identified to support federal, state, or local public policy requirements or state-identified energy goals

ISO New England's transmission planning framework consists of several interconnected planning processes that evaluate transmission needs over different geographic scales and planning horizons. At the local level, transmission owners develop Local System Plans (LSPs) to identify reliability, asset condition, load growth, and interconnection needs within their service territories. These local planning efforts provide important inputs to ISO-NE's regional planning activities, where identified needs are evaluated alongside broader regional considerations.

At the regional level, ISO-NE uses several complementary planning processes to address different categories of transmission needs. The Regional System Plan (RSP) serves as the region's primary near-term planning process, addressing reliability, resource adequacy, transmission system efficiency, and asset condition needs over a ten-year planning horizon. ISO-NE also conducts Long-Term Transmission Planning (LTTP) to identify and address transmission needs that may emerge as the region's resource mix, electricity demand, and public policy objectives evolve through mid-century. The studies and analyses produced through recent RSP and LTTP planning cycles are discussed in greater detail in Chapter 4 Existing Analyses of Future Electric Transmission Needs. Because the RSP and LTTP represent ISO-NE's primary regional transmission planning processes, the planning steps described in this section focus on the processes generally used across those two planning frameworks.

1. Input Development

ISO-NE begins its transmission planning process by developing a set of study inputs to its planning models. Key inputs include load forecasts, generation and storage build trajectories, resource retirements assumptions, transmission system data, and utility LSPs and asset condition information. These inputs are used in several complementary models that evaluate different aspects of future electric system performance and needs.

Capacity expansion models estimate the mix of generation, storage, and potentially transmission resources needed to meet projected electricity demand and reliability requirements under planning assumptions. Production cost modeling simulates detailed operation of the electric system, including generator dispatch, transmission utilization, fuel consumption, emissions, and electricity market outcomes. Power flow modeling evaluates how electricity moves across the transmission system and is used to identify specific lines, transformers, and other electrical equipment that can become congested, hit rated thermal constraints, or experience voltage imbalance under modeled grid conditions.

Stakeholder Engagement Opportunities

The Planning Advisory Committee (PAC) is the primary forum for public stakeholder engagement in ISO New England's transmission planning process. ISO-NE regularly convenes PAC meetings throughout planning studies to share information, present inputs, assumptions, and results, and solicit feedback from stakeholders on planning needs and proposed solutions. PAC meetings are open to the public and provide an opportunity for utilities, developers, state agencies, consumer advocates, environmental organizations, and other interested parties to participate in discussions and provide input throughout each step of the planning process.

The New England Power Pool (NEPOOL) is the primary stakeholder governance organization in New England's wholesale electricity markets and transmission planning processes. NEPOOL is composed of a broad range of stakeholders, including transmission owners, generators, suppliers, public power entities, end users, and alternative resource providers. Membership is open to organizations that satisfy NEPOOL's membership requirements, providing opportunities for a broad range of interested entities to participate in committee discussions and governance activities. Through its committee structure, NEPOOL provides stakeholders with opportunities to review and provide input on planning assumptions, study methodologies, and other inputs used by ISO New England during the development of transmission planning studies.

The New England States Committee on Electricity (NESCOE) is the regional organization that represents the collective interests of the six New England states in matters related to the electric grid and wholesale electricity markets. In the transmission planning process, NESCOE helps identify and communicate state energy policies and priorities to ISO-NE, which inform the development of planning assumptions, scenarios, and other policy-driven inputs used in regional transmission studies. NESCOE also requested that ISO-NE initiate the Long-Term Transmission Planning (LTTP) process to study longer-term transmission needs associated with reliably operating the grid in a future that reflects the achievement of state policy objectives. Through this role, NESCOE helps ensure that inputs to long-term planning analyses reflect state objectives related to reliability, affordability, and clean energy development.

2. Need Identification

The next step of the ISO-NE transmission planning process is using the transmission planning models to identify transmission needs. A transmission need is identified when the study shows that the transmission system may not be able to reliably, efficiently, or cost-effectively serve expected future electric system conditions. Different planning models identify different types of need. Capacity expansion and production cost models identify opportunities where transmission investments could reduce overall system costs, improve access to lower-cost generation resources, or better accommodate future resource development. Power flow models identify physical limitations of the transmission system, including overloaded transmission facilities, voltage violations, or other conditions that may prevent the system from reliably serving future demand or meeting applicable reliability criteria.

For example, a need may be identified if a transmission line is projected to overload during peak demand, if voltage levels fall outside acceptable ranges following the loss of a transmission line or generator, if congestion prevents lower-cost generation from serving customers, or if existing transmission capacity is insufficient to accommodate planned resource development. Depending on the type of need identified, subsequent studies may evaluate potential transmission or non-transmission solutions.

Not every identified need results in a competitive solicitation. Some needs may be addressed through local utility planning, asset condition replacement, or a solutions study, depending on the nature, size, and timing of the need. Competitive solicitations are generally used for larger regional transmission needs that span multiple utilities or states and can be addressed through alternative transmission solutions proposed by competing developers.

Identified transmission needs are published in ISO-NE's Needs Assessment Report, the Regional System Plan, and other economic, reliability, and policy-driven studies.[8] These needs are also presented and discussed through ISO-NE's stakeholder planning process.

Stakeholder Engagement Opportunities

The PAC holds regular meetings where the ISO-NE presents study assumptions, methodologies, and results during need identification, providing stakeholders with opportunities to review analyses, ask questions, and provide feedback on emerging transmission needs.

3. Solution Development and Solicitation

Once a transmission need is identified, ISO-NE determines the appropriate pathway for developing a solution. For regional needs that span multiple utility service territories, ISO-NE uses a competitive

[8] These studies include the Longer-Term Transmission Planning (LTTP) studies, Future Grid Reliability Study (FGRS) and Economic Planning for the Clean Energy Transition (EPCET) study, System Efficiency Needs Scenario (SENS), formally called the market Efficiency Needs Scenario (MENS), and ISO-NE Regional System Plan (RSP). These studies and the resulting identified needs also account for needs identified from the Asset Condition List (ACL), state-driven policy goals and needs, and local utility's asset condition and reliability upgrades. These studies are discussed in further detail in Chapter 4: Existing Analyses of Future Electric Transmission Needs.

Request for Proposals (RFP) process to solicit transmission solutions from Qualified Transmission Project Sponsors (QTPS). Qualified sponsors may include incumbent transmission owners and non-incumbent transmission developers. Qualified sponsors develop solutions to finance, engineer, construct, and own new transmission solutions that meet the identified needs of the competitive proposal. Solutions may be any transmission project that will meet the identified transmission needs, and vary in scope, size, and cost.

For high-priority, time-sensitive reliability needs, ISO-NE may instead conduct a solutions study and work with incumbent transmission owners and stakeholders to identify a solution that can be implemented within the required timeframe. Similarly, many local transmission needs and asset condition projects are addressed directly by the incumbent transmission owner through ISO-NE's regional planning process rather than through a competitive solicitation.

Stakeholder Engagement Opportunities

The PAC serves as a forum for ISO-NE to provide updates on proposal development, solicitation activities, and proposal evaluations, allowing stakeholders to review and discuss potential transmission solutions as they are developed and assessed.

4. Project Selection

ISO-NE evaluates proposals to determine which combination of project design, cost, and project team best meets the system needs. Factors that ISO-NE considers in making its determination include whether the proposed solution's modeled performance address the identified need, project cost and financial strength of the project team, feasibility of project design, ability to meet the required timeframe, and compatibility with the transmission system. ISO-NE may remove proposals from consideration if they are not competitive on these criteria.

Once ISO-NE makes its final decision and selects the transmission solution, the bidder of the selected transmission solution is awarded development rights for the project and must execute a Selected Qualified Transmission Project Sponsor Agreement (SQTPSA) within 30 days. The SQTPSA is a legal agreement between ISO-NE and the selected STPS that formalizes the project sponsor's development rights and their responsibility to develop the selected transmission solution.

Stakeholder Engagement Opportunities

The PAC provides stakeholders with an opportunity to review and discuss ISO-NE updates on proposal evaluations and project selection decisions.

5. Cost Allocation

ISO-NE determines whether transmission project costs are eligible for regional cost allocation under its tariff, and how the eligible costs are allocated. Transmission facilities designated as Pooled Transmission Facilities (PTFs), generally because they provide reliability or economic benefits to the broader region, are eligible for regional cost allocation. Economic and reliability-based PTF costs are generally allocated across New England based on the share of regional electricity demand served by each transmission owner, resulting in costs that are broadly proportional to each state's electricity demand. Public policy projects use a different approach, with 70% of costs allocated regionally on a load-ratio basis, and 30% of costs allocated among states whose policies drive the need on a load-ratio basis. Some project costs, such as incremental costs associated with measures to reduce local visual or other impacts, may remain local if they do not provide regional benefits, and merchant or state-procured projects may use different cost recovery structures.[9]

For interregional transmission facilities (projects spanning regional grid systems, e.g. ISO-NE and NYISO), costs are allocated to each region using an avoided-cost method. Under this approach, each region's share of project costs is generally based on the value of transmission investments that would be avoided within that region relative to the total avoided costs across both regions.

Stakeholder Engagement Opportunities

NEPOOL provides a formal stakeholder governance role in cost allocation through its committee structure and Participants Committee voting process. Stakeholders review and vote on proposed tariff changes, including transmission planning and cost allocation frameworks, allowing stakeholder positions to be formally communicated to FERC.

The PAC receives updates from ISO-NE on proposed cost allocation approaches and related planning activities, providing stakeholders with an opportunity to review, discuss, and provide feedback on how transmission project costs may be assigned across the region.

Maine-Led Procurement

Another pathway for identifying transmission projects in Maine is through Maine-led procurements. Maine's legislature may create a special procurement authority to identify and contract for projects that advance its state energy priorities. These procurements are distinct from ISO-NE's regional transmission planning process, and are generally used when the Legislature determines a specific type of energy or transmission infrastructure is needed to advance Maine's policy goals, but may be unlikely to be identified through ISO-NE's planning process or other channels.

The Northern Maine Renewable Energy Development Program (NMREDP) is a key example of Maine-led procurement. Through that program, the Maine Public Utilities Commission (MPUC) is authorized to procure renewable energy generation projects in northern Maine and the transmission infrastructure needed to deliver the resource to load centers. The program is designed to support at

[9] ISO New England, Transmission Cost Allocation: https://www.iso-ne.com/system-planning/transmission-planning/transmission-cost-allocation

least 1,200 MW of renewable energy resources in northern Maine, while also considering cost, deliverability, economic benefits, ratepayer impacts, and regional participation.[10]

While the NMREDP is administered by the MPUC, the Maine DOER also has authority under Title 35-A, §10313 to initiate and conduct competitive solicitations for renewable and clean resources, including related transmission, when determined to be necessary under the State Energy Plan.

Stakeholders can participate in Maine-led procurement during the legislative phase and during the MPUC-led implementation of the Maine-led procurement by responding to RFIs and providing comments to the draft RFP. Early engagement with stakeholders is particularly important for transmission procurements because selected projects must still complete all applicable siting, permitting, and approval processes before construction can begin.

Process Description

There is no prescribed process for Maine-led procurement. Each process is often established by the legislation and implemented by a responsible procurement agency to meet the specific project need. The process described in this section follows the NMREDP as an example.

1. Legislation

The Maine Legislature authorizes a bill granting authority to the MPUC to procure a targeted generation and transmission-based solution to help achieve state goals. The bill defines the purpose, grants the MPUC responsibility for the procurement, and outlines the evaluation criteria for the procurement.

Stakeholder Engagement Opportunities

Stakeholders may provide written or oral testimony to legislative committees considering the authorizing legislation. Maine's testimony portal allows members of the public to testify by Zoom or submit written testimony for public hearings. Participants may include the MPUC, Maine DOER, Office of the Public Advocate, Office of the Attorney General, Maine utilities, transmission and energy developers, and local advocacy groups or members of the public, including affected communities, landowners, and residents. Legislative testimony commonly addresses the purpose of the proposal, anticipated costs and benefits, implementation considerations, and potential community impacts.

2. Coordination with ISO-NE

Maine coordinates with the regional transmission system operator to ensure it's intended solutions may electrically interconnect with the ISO-NE system, aligns with ongoing ISO-NE transmission planning processes, and avoids conflicts with other planned transmission upgrades. Coordination efforts with ISO-NE may also help identify whether the procurement can be structured to

[10] Maine Public Utilities Commission, Northern Maine Renewable Energy Development Program: https://www.maine.gov/mpuc/regulated-utilities/electricity/rfp-awarded-contracts/northernmainerfp

complement regional needs, such as the ISO-NE LTTP process, and whether other New England states may have an interest in participating by sharing costs and benefits.

3. Request for Information (RFI) and Request for Proposals (RFP)

The MPUC often releases an RFI before issuing a final RFP. An RFI allows the MPUC to gather market intelligence, understand available technologies and delivery approaches, assess and garner developer interest, identify cost and schedule considerations, and receive stakeholder feedback before finalizing the requirements of the procurement. This step reduces ambiguity and improves the likelihood that the final RFP attracts high-quality, competitive proposals that align with the program goals.

After reviewing RFI responses, the MPUC may also issue a draft RFP for comment. This step is to request feedback on procurement requirements, evaluation criteria, contract structures, cost-containment provisions, and to further refine the RFP. The MPUC then issues a final RFP seeking formal proposals that meet the stated need.

Stakeholder Engagement Opportunities

During MPUC implementation, stakeholders may provide input through RFI responses, comments on draft Requests for Proposals (RFPs), and participation in relevant Commission proceedings. RFIs and draft RFP comments help inform procurement structure, technical requirements, evaluation criteria, and contract terms. The Northern Maine RFP includes a public questions-and-answers log that provides clarifications to bidders and other interested parties regarding procurement requirements.

4. Procurement and Project Selection

The MPUC evaluates proposals based on the criteria established by statute and the RFP. Relevant considerations include cost, economic benefit to northern Maine, bidder qualifications, project viability, contribution to Maine's renewable energy goals, ratepayer impacts, and the ability to successfully interconnect with the ISO-NE system. The procurement may include both a generation component and a transmission component to deliver the resource to load centers.

Selected generation resources are procured through long-term Power Purchase Agreements (PPAs). Selected transmission projects may require separate contractual agreements to support project development, cost recovery, and coordination with participating states or utilities.

5. Cost Allocation

Project costs are recovered from Maine ratepayers unless neighboring states voluntarily participate Unless one or more neighboring states voluntarily participate in the procurement, the costs of the Northern Maine Renewable Energy Development Program are borne by Maine ratepayers. If neighboring states elect to participate, project costs may be shared in accordance with participation agreements negotiated by the Commission. The MPUC determines the mechanisms by which these costs are recovered from Maine customers. Generation costs are generally recovered through power purchase agreements (PPAs), under which payments are made for delivered energy and renewable energy credits, while transmission costs are recovered through a FERC-approved cost-based formula rate established under a voluntary agreement with the selected transmission developer.[11]

If other states decide to participate in the program, costs are shared among the participating states. The MPUC's current RFP requires developers to offer the same bid with identical commercial terms and prices to any coordinating state or entity that wishes to participate. Participating states evaluate the proposal under its own authority, and the final cost allocation is established through a Voluntary Agreement and associated FERC filing.

Non-Maine Policy Driven Procurements

Other states may also pursue transmission and generation procurement processes to advance their own policy goals in a similar manner to Maine's Northern Maine Renewable Energy Development Program. In some cases, projects selected through these procurements may affect Maine's electric system or be physically located in the state.

One example is the New England Clean Energy Connect (NECEC), a high-voltage transmission line developed in response to a Massachusetts-led procurement soliciting long-term contracts for clean energy.[12] The project was designed to deliver up to 1,200 MW of hydroelectric power from Hydro Quebec to Massachusetts utilities.[13] Although driven by Massachusetts policy objectives, NECEC is located primarily within Maine and includes approximately 145 miles of new transmission infrastructure extending from the Beattie Township to Lewiston.

There is no single prescribed process for procurements led by states outside of Maine. However, processes are likely to follow a similar framework described in the Maine-Led Procurement section.

Project Approval Processes

Once a transmission project has been identified and selected through one of the project identification pathways described in the previous section, it must obtain the necessary siting, permitting, zoning, and other regulatory approvals before construction can begin. Collectively, these are referred to in this report as Project Approval Processes.

The Project Approval Processes required may vary by project and involve multiple state agencies and potentially local and federal authorities. Processes differ in both scope and duration, with timelines ranging from relatively short administrative reviews to multi-year proceedings. These processes provide opportunities for stakeholder engagement, including public meetings, comment periods, consultations with affected parties, and participation in formal review proceedings.

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[11] Federal Power Act, Section 205: https://www.ferc.gov/sites/default/files/2021-04/federal_power_act.pdf
[12] Greater Boston Chamber of Commerce, The Importance of Delivering Clean Energy to Massachusetts: https://bostonchamber.com/thought-leadership/the-importance-of-delivering-clean-energy-to-massachusetts/
[13] New England Clean Energy Connect: https://www.necleanenergyconnect.org/

This section summarizes the seven primary Project Approval Processes relevant to transmission projects in Maine, including their purpose, governing authority, stakeholder engagement opportunities, and typical timelines. While these represent the principal approval processes, additional permits, approvals, or agency coordination may be required depending on a project's location and characteristics. For example, the Maine Department of Transportation may require its own approvals for projects crossing or affecting state highways, transportation rights-of-way, or other department-managed property. Opportunities and evaluation of permitting methodologies for collocated transmission in transportation rights-of-way is discussed in further detail in Chapter 5: Existing Rights-of-Way and Electric Transmission.

Legislative Approval

Legislative approval is required before construction of projects that qualify as a "high-impact electric transmission line," meaning most lines greater than 50 miles in length operating at 345 kV or higher.[14] When evaluating a permit for high-impact lines, the MPUC must follow Title 35-A §3132(6-D), which requires majority approval by legislature by vote. If the project is deemed to substantially impact public lands, a two-thirds approval is necessary by the legislature. This legislative approval requirement is not an adjudicatory permitting process, and therefore this report does not outline project approval steps. Instead, it is a legislative vote by elected members of each house of the Legislature.

High-impact lines approved for contract through a competitive procurement conducted by the MPUC or another state agency under statutory authority, as discussed in the Maine-Led Procurement section, are deemed to have received the required majority legislative approval. Separately, Title 35-A §3132(6-D) also prohibits construction of high-impact lines in the Upper Kennebec Region.[15]

Maine Public Utilities Commission (MPUC)

The MPUC regulates public utilities in Maine, including electric and gas utilities. Its mission includes ensuring safe and reliable utility service, maintaining just and reasonable rates, minimizing energy costs, and reducing greenhouse gas emissions.[16] The Commission is led by three Commissioners who are appointed by the Governor, confirmed by the Senate, and serve staggered six-year terms. The Commissioners make final decisions for the MPUC by a public vote or majority action and are supported by professional staff, including engineers, lawyers, consumer specialists and financial analysts.

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[14] Maine Public Utilities Commission Rules, 65 ME Code R. Ch. 330: https://www.maine.gov/sos/rulemaking/agency-rules/public-utilities-commission-rules

[15] Maine Legislature, 35-A M.R.S. § 3132: https://legislature.maine.gov/statutes/35-A/title35-Asec3132.html

[16] Maine Public Utilities Commission: https://www.maine.gov/mpuc/

Process Description

The MPUC reviews transmission projects through the Certificate of Public Convenience and Necessity (CPCN) process.[17] The CPCN is an adjudicatory proceeding that evaluates whether a project is the public interest and should be permitted to begin construction. As part of its review, the MPUC considers factors including ratepayer costs, reasonable alternatives, environmental impacts, economic benefits, reliability, and stakeholder feedback.

Approval of the CPCN signifies that proceeding with the project is prudent and meets a public need, and authorizes the developer to begin construction. Detailed steps of the CPCN adjudication process and opportunities for stakeholder engagement are outlined below.

Stakeholder engagement opportunities related to the MPUC CPCN approval process are available once the application for a CPCN has been filed, during the review process, hearings, and submitting public comments. Stakeholders that want to formally participate in the CPCN review and hearing process must obtain intervenor status, which requires stakeholders to be government agencies, have a direct interest in the outcome, or demonstrate ability to contribute materially to the record. The MPUC also administers an intervenor and participant funding program that may cover qualified costs associated with participation, including hiring expert witness support.[18] These opportunities are discussed in further detail within each step of the CPCN approval process.

1. CPCN Filing

A developer begins the process of MPUC review by submitting a petition for a CPCN to the MPUC. The petition must include a description of need for the project, the effect of the proposed transmission line on the public, proximity to inhabited dwellings, and justification of the proposed route. A non-wires alternatives (NWA) report must also be completed, compliant with Title 35-A §3132-C as discussed in the next Project Approval Process section.[19]

2. Notice and Intervention

After filing the petition for a CPCN, the MPUC reviews the petition for completeness before publishing notice of the proceeding.

Stakeholder Engagement Opportunities

Members of the public may follow the docket and submit written comments through the MPUC's Case Management System (CMS).

3. Evidentiary Hearings and Public Witness Hearings

[17] Maine Legislature, 35-A M.R.S. § 3133-A: https://legislature.maine.gov/statutes/35-a/title35-Asec3133-A.html
[18] Maine Public Utilities Commission, Intervenor Funding: https://www.maine.gov/mpuc/about/intervenor-funding
[19] Maine Legislature, 35-A M.R.S. § 3132-C: https://legislature.maine.gov/statutes/35-A/title35-Asec3132-C.html

The MPUC may hold evidentiary hearings and public witness hearings as part of a CPCN proceeding. Evidentiary hearings are formal proceedings in which parties may submit testimony, introduce evidence, respond to data requests, cross-examine witnesses, and develop the factual record that the Commission will use to make its decision. Public witness hearings provide a separate opportunity for members of the public to speak under oath and share concerns, support, or information about the project. The MPUC describes public witness hearings as formal, quasi-judicial proceedings that operate similarly to a court process, with a Hearing Examiner taking testimony from members of the public.

Stakeholder Engagement Opportunities

Members of the public can provide sworn testimony during public witness hearings. These opportunities allow residents, municipalities, landowners, businesses, advocacy organizations, and other interested stakeholders to raise concerns or provide information about project need, cost, routing, community impacts, environmental impacts, alternatives, and other issues relevant to the MPUC's review.

A person, organization, or government agency that wants to participate as a formal party must file a formal **Petition to Intervene** in the CPCN docket. A Petition to Intervene is a formal legal request to become an active party in the CPCN process and participate in evidentiary hearings. Mandatory intervention is granted to government agencies and to persons or groups that may be substantially and directly affected by the proceeding. The MPUC may also allow discretionary intervention for other interested persons or groups. Once intervenor status is granted, the intervenor becomes a formal party to the case and may receive filings, participate in discovery, submit testimony or evidence, and take part in hearings.

Intervenors can provide sworn testimony, formal evidence, and conduct discovery for evidentiary hearings.

4. Review of Petition

The MPUC determines public need and whether a proposed project meets the statutory standard for public need. This review includes assessing whether the project is needed for reliability, economic, and policy purposes, whether the project's costs are reasonable in light of the benefits it provides, whether less costly or less impactful alternatives are available, and whether non-wires alternatives could meet the identified need over the effective life of the project. The Commission must also consider findings from the Department of Environmental Protection's (DEP) permitting review determining whether the project can be constructed in a manner consistent with applicable environmental, land, and water resource standards.

5. Final Order

The MPUC concludes the CPCN proceeding by issuing a final order granting, denying, or conditionally approving the petition. If the CPCN is granted, the MPUC provides notice of the order to each affected municipality clarifying that issuance of the CPCN does not override or supersede municipal authority.

If the petition is denied or if a party disagrees with the final order, any party to the CPCN proceeding may petition to reconsider, rehear, reopen, clarify, modify, rescind, or vacate the order by filing a petition with the Commission within 20 days.[20] If the Commission does not grant the petition within 20 days after filing, the petition is deemed denied. A party that participated in the Commission proceeding and is adversely affected by the final decision may then appeal the MPUC's final decision directly to the Maine Supreme Judicial Court. The Maine Supreme Judicial Court has exclusive jurisdiction over appeals and requests for judicial review of MPUC final decisions, except for Superior Court review of Commission rules under Title 5 §8058. An appeal generally does not stay or suspend the MPUC's order unless the Commission or the court grants a stay under the applicable statutory standard.

Stakeholder Engagement Opportunities

Stakeholder parties that participated in the CPCN proceeding may appeal the MPUC's final decision, and parties that participated in the proceeding and are adversely affected by the final decision can petition directly to the Maine Supreme Judicial Court.

Office of Public Advocate

The Office of Public Advocate participates in Maine transmission review in part through its statutory role in evaluating whether a proposed transmission investment can be avoided, deferred, or reduced through cost-effective non-wires alternatives (NWA). Under Maine law, NWAs are infrastructure, technology, or application that address an identified reliability need while deferring or reducing the need for traditional transmission or distribution capital investments. Examples of NWAs include energy efficiency, conservation, energy storage, load management, demand response, and distributed generation. The Office of Public Advocate contracts with a "non-wires alternative coordinator" to investigate and make recommendations regarding NWAs for proposed capital investments in transmission and distribution projects being considered by the MPUC.

The investigation must be conducted in coordination with Efficiency Maine Trust.[21] The investigation compares the net present value (NPV) of the proposed project to those of NWAs. Utilities must provide data requested by the Office of Public Advocate or Efficiency Maine Trust to aid the NWA analysis, subject to MPUC enforcement.

After completing its investigation, the Public Advocate then provides a recommendation to the MPUC regarding the effectiveness of NWAs and the proposed plan of procurement. If the coordinator recommends an NWA, the recommendation must include a proposed procurement plan for the recommended alternative. The Public Advocate's role ensures that, before Maine ratepayers bear

[20] Maine Public Utilities Commission, Chapter 110, Section 11(D)
[21] Efficiency Maine Trust: https://www.efficiencymaine.com/

the cost of significant new transmission infrastructure, the MPUC has a record on whether lower-cost, non-wires solutions could meet the same reliability need.

This section does not outline a separate step-by-step approval process because the Office of Public Advocate does not independently approve or deny transmission projects. Instead, its NWA review is an analytical input into the MPUC's review, and ultimate CPCN proceeding decision as described in the previous section.

Department of Environmental Protection (DEP)

The Maine DEP is the state environmental permitting agency for projects with environmental, land, natural resource, and water related impacts, including transmission projects. DEP review most commonly occurs under the Site Location of Development Act (Site Law)[22], the Natural Resources Protection Act (NRPA),[23] or both.

The Site Location of Development Act (Site Law) is Maine's primary environmental permitting program for large developments with the potential for substantial environmental impacts. Large developments are defined as projects occupying 20 or more acres or creating three or more acres of impervious surface are generally subject to Site Law review.[24] The review evaluates whether a proposed project has been designed and sited to avoid or minimize unreasonable adverse impacts on natural resources and to protect public health, safety, and welfare.

The NRPA requires DEP approval for projects that would alter, construct in, or otherwise affect protected natural resources, including wetlands, rivers, streams, great ponds, coastal wetlands, significant wildlife habitat, fragile mountain areas, and coastal sand dune systems. Its purpose is to protect these resources by ensuring that projects avoid or minimize unreasonable impacts to scenic, recreational, navigational, habitat, fisheries, and other natural resource values. Depending on the type and scale of the proposed activity, NRPA authorization may take the form of an individual permit or a Permit-by-Rule notification for certain lower-impact activities.

Other permits may be required based on project location and environmental impact, including but not limited to stormwater permits, water quality certification, air emissions and waste discharge licenses, air licenses, and borrow pit permits. For transmission lines, the DEP's review may also include specific consideration of route, line character, width, appearance, public health and safety risks, and whether alternatives could lessen environmental impacts without unreasonably increasing project cost.

Stakeholders have multiple opportunities to engage with the DEP permitting review throughout the process. The public may provide written or oral comments to the DEP, attend monthly BEP meetings, and request a hearing. Stakeholders who wish to formally participate in the process by presenting

[22] Maine Legislature, Title 38, Chapter 3, §§ 481-490
[23] Maine Legislature, Title 38, Chapter 3, §§ 480-A to 480-Z
[24] Maine Department of Environmental Protection, Site Location of Development Law: https://www.maine.gov/dep/land/sitelaw/Site-Law.pdf

formal evidence and cross-examining witnesses during a hearing must obtain intervenor status. After a decision, aggrieved stakeholders may appeal a DEP Commissioner or BEP decision. These opportunities are highlighted in the process steps below.

Process Description

The DEP permitting review process begins with the formal submission of permit applications by the developer. The process includes a technical review, public comment and hearing opportunities, a final permit decision, and opportunities to appeal a decision. Depending on the project scope and impact, either the Board of Environmental Protection (BEP) or the DEP Commissioner will have authority over reviewing and approving permits.

+ **Board of Environmental Protection (BEP):** The BEP has jurisdiction over high-impact transmission projects. High-impact transmission lines are defined under the same statutory criteria for whether a project requires legislative approval: most lines over 50 miles operating at 345 kV and above or Direct Current (DC). The BEP consists of seven members on the board, appointed by the Governor and confirmed by the Legislature. Board members are selected to represent the broad interests of Maine ratepayers and the subject matter expertise required to understand the environmental impacts of transmission infrastructure. At least three members must have scientific backgrounds in environmental science and protection, and the board must represent four geographic regions of Maine.[25]
+ **Department of Environmental Protection (DEP):** The DEP has jurisdiction over projects that do not meet the high impact standard. The DEP Commissioner may refer projects within its jurisdiction to the BEP if the developer and DEP Commissioner jointly decide to refer to the BEP, or if a DEP decision is appealed.

1. Formal Submission of Permit Applications

A developer must file formal applications for all DEP permits and approvals required for the project. After an application is submitted, the DEP determines whether the application is complete for processing and may request additional information as needed. Acceptance of an application as complete allows for review to begin, but it does not prevent the DEP staff, DEP Commissioner, or the BEP from requesting additional technical information during review.[26]

2. Technical Review Process

The DEP Commissioner or BEP evaluates the statutory criteria for all applicable permits under Site Law, NRPA, and any other relevant permits necessary for environmental, land, and water related impacts. The DEP and BEP may request additional analysis and technical studies during this process and are aided by the DEP staff. Under Site Law, technical review may include assessing whether the developer has the financial and technical capacity to develop the project consistent with state environmental standards and whether the project has made adequate provision to exist in the

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[25] Maine Department of Environmental Protection, Board of Environmental Protection Purpose: https://www.maine.gov/dep/bep/info/is-purpose.html
[26] Maine Legislature, 38 M.R.S. § 344

natural environment without adversely affecting existing uses, scenic character, air quality, water quality, or other natural resources. Under NRPA, the DEP evaluates whether the proposed activity would unreasonably interfere with existing scenic, aesthetic, recreational, or navigational uses, cause unreasonable erosion, or unreasonably harm significant wildlife habitat, freshwater wetlands, fisheries, aquatic life, or related resources.[27]

For transmission lines subject to Site Law, the technical reviewers also receive evidence regarding the location, character, and environmental impacts of the proposed line. Alternatives may be considered that would lessen environmental impacts or public health and safety risks without unreasonably increasing project cost. The DEP Commissioner or BEP may approve or disapprove all or portions of the proposed transmission line and may impose conditions related to the line's location, character, width, and appearance.[28]

Stakeholder Engagement Opportunities

DEP permitting often involves consultation with other Maine agencies that provide technical expertise or separate approvals. The **Maine Department of Inland Fisheries and Wildlife (IFW) and Department of Marine Resources (DMR)** are often consulted for technical expertise regarding wildlife, fisheries, habitat, and aquatic resource impacts in DEP decisions and hearings.

3. Public Comment and Hearing Opportunities

DEP accepts public comments during the permit review. Public comment occurs through written comments submitted to the DEP project manager or through comments on a draft permit decision. For applications decided by the BEP, the DEP Commissioner must provide a summary of the application to the BEP, governmental agencies, and interested parties, and the process must provide time for comments before a draft permit or license is prepared.

During the permit review process, the DEP Commissioner or BEP may decide to hold a hearing as part of the permitting review process. Hearings are a discretionary step in the DEP permitting process, and are usually held for large and high-impact transmission projects. For projects where Site Law is applicable, a public hearing is required.

[27] Maine Legislature, 38 M.R.S. §§ 480-D, 484
[28] Maine Legislature, 38 M.R.S. § 487-A

Stakeholder Engagement Opportunities

The DEP accepts **public comments** throughout the permitting application period. Stakeholders may also submit written comments via email or mail to the DEP project manager and can request a hearing.

BEP meetings are open to the public during which limited opportunities are available for the public to address the BEP.

Stakeholders that wish to present formal evidence, conduct discovery, or cross-examine witnesses during a hearing must be granted **intervenor status**. During a public hearing, experts and stakeholders provide sworn oral and written testimony and evidence on scenic, property, wildlife, land use, public health and safety, and climate related impacts.

4. Final Decision

For projects within BEP's jurisdiction, the seven-seat board holds a vote on whether to approve, approve with conditions, or deny permits. For projects within the DEP's jurisdiction, the DEP Commissioner has executive discretion to approve, provide conditional approval, or deny permits based on statutory compliance with environmental standards. Both the DEP Commissioner and BEP have the power to deny permits they review that do not meet the statutory standards, and the DEP can enforce compliance with the statutory laws once permits are granted.

Once permits are granted, the developer may proceed with the permitted construction activities only after satisfying permit conditions and obtaining any other required state, local, regional, or federal approvals. DEP permits do not replace the need for MPUC CPCN approval, LUPC certification, municipal approvals, or federal permits. If a permit is denied, the project cannot proceed under that permit unless the denial is reversed or modified through the available appeal process, or if the developer submits and obtains approval for a revised proposal.

Stakeholder Engagement Opportunities

Stakeholders who are **aggrieved persons**, meaning persons who may suffer a particularized injury as a result of a DEP Commissioner license decision, may appeal a DEP Commissioner's decision to the BEP or make a judicial appeal to the Maine Superior Court. Appealable DEP Commissioner decisions include final decisions to approve, approve with conditions, or deny DEP permits. Other DEP Commissioner actions are also subject to appeal to the BEP, including acceptances of permit-by-rule notifications, minor revisions, and public benefit determinations. Filing an administrative appeal of DEP Commissioner decisions with the BEP is not required before filing a judicial appeal. If the BEP made the original permit licensing decision, appeals are generally made to the Maine Superior Court.

Engagement from Other Maine Agencies

The **Maine Department of Transportation (MaineDOT)** has permitting authority for transmission lines within or affecting public rights-of-way (ROW) limits and grants applicable permits for transmission projects including utility location permits and highway opening and excavation permits. Further information on utilizing ROW for transmission projects is discussed in Chapter 5 Existing Rights-of-Way and Electric Transmission.

The **Maine Bureau of Parks and Lands (BPL)**, within the **Maine Department of Agriculture, Conservation, and Forestry (DACF)**, has the power to enter into leases for certain public lands. Before doing so, the BPL must determine if the project will result in a "reduction" or "substantial alteration" of the use of those public lands.[29] The BPL Director has the power to make these determinations. These decisions do not supersede LUPC authority for siting in UT zones.

Land Use Planning Commission (LUPC)

The Maine LUPC is the state planning and zoning authority for Maine's Unorganized and Deorganized Territories (UT), including townships, most plantations, and several towns. The LUPC service area is expansive, including the largest contiguous undeveloped area in the northeast and some coastal islands. The LUPC serves a role similar to that of a municipal planning board or zoning authority for land-use decisions in these areas. Figure 6 shows the LUPC service area, which comprises over half of Maine's total land area, consists of 460 towns, plantations, and townships, and over 200 coastal islands, and has approximately 12,000 year-round residents.[30]

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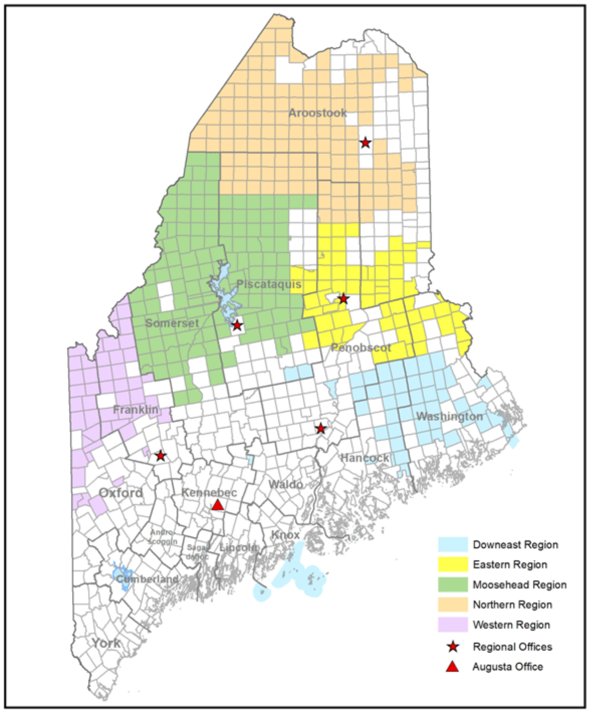
[29] Maine Legislature Article IX, § 23

[30] Maine Land Use Planning Commission, Unorganized and Deorganized Territories Overview: https://www.maine.gov/dacf/lupc/about/index.shtml

Figure 6. Maine Unorganized and Deorganized Territories



The LUPC (formerly the Land Use Regulation Commission) is a state commission created in the early 1970s and located within the Maine Department of Agriculture, Conservation, and Forestry (DACF). The Commission consists of eleven members: two members appointed by the Governor, including a Tribal representative, one member appointed by the Legislature, and the other eight members appointed by each of the eight counties with the most acreage in the LUPC service area. All appointees are reviewed by the Legislature and confirmed by the Senate.[31]

Maine law requires the LUPC to prepare an official comprehensive land use plan and use it as a guide for land use standards, district boundaries, and development decisions. The LUPC is responsible for implementing its land use statute and the Comprehensive Land Use Plan (CLUP).[32] The CLUP is a long-term planning document that sets the LUPC's vision, goals, and policy objectives for its service area. It guides the LUPC's zoning framework, rulemaking, permitting, and broader land-use decisions, and provides the policy basis for the zoning districts, subdistricts, and the uses allowed in each subdistrict.

All LUPC meetings are open to the public and the LUPC maintains meeting materials, hearing information, zoning maps, application forms, and permitting materials on its website.[33]

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[31] Maine Land Use Planning Commission, Statute: https://www.maine.gov/dacf/lupc/laws_rules/rule_chapters/Statute_2025-09-24.pdf
[32] Maine Land Use Planning Commission, Comprehensive Land Use Plan: https://www.maine.gov/dacf/lupc/plans_maps_data/clup/2010_CLUP.pdf
[33] Maine Land Use Planning Commission: https://www.maine.gov/dacf/lupc

Process Description

The LUPC service area is divided into three broad zoning districts: management, protection, and development. Within these districts are 32 subdistricts that establish more specific land use and environmental standards based on the characteristics of the land and natural resources present. Each subdistrict has allowed land uses and may have specific development standards and permitting requirements. The 32 subdistricts include 14 protection subdistricts, three management subdistricts, and 15 development subdistricts.[34]

1. **Protection Subdistricts** are areas with significant natural, recreational, cultural, or historic resources where development could create substantial impacts. Development in these areas is more limited and subject to protective standards.
2. **Management Subdistricts** apply to working lands and resource-based uses, including commercial forestry, agriculture, and mineral extraction, while also allowing certain compatible development activities subject to applicable standards.
3. **Development Subdistricts** generally apply to areas where residential, recreational, commercial, or industrial development is appropriate, subject to standards that apply to the specific subdistrict and proposed activity.

For transmission projects, LUPC review focuses on land use compatibility. The LUPC determines whether the proposed route and related facilities are allowed uses in each affected subdistrict and whether the project complies with applicable zoning standards. The LUPC zoning review process is outlined below.

This review is separate from, but may be coordinated with, the DEP environmental permitting review process. The DEP has permitting authority in the LUPC's service area for projects that qualify for review under the Site Location of Development Law (Site Law). However, projects in the LUPC service area must obtain a Site Law Certification (SLC) from the LUPC for ultimate permit approval from the DEP.

1. Pre-Application Meeting and Application Submission

Applicants are encouraged to meet with LUPC staff early in project development through a pre-application meeting. These meetings provide an opportunity to discuss the proposed project, identify the applicable zoning subdistricts and regulatory requirements, determine whether the project is an allowed use or requires a permit, special exception, or zoning amendment, and understand the expected review process, timelines, fees, and application requirements.

Once an application has been prepared, applicants may also participate in a pre-submission meeting with LUPC staff. Unlike a pre-application meeting, which focuses on identifying the applicable review process, a pre-submission meeting provides an opportunity to review the completed application at a high level before it is formally filed to help ensure that required information has been included. Pre-submission meetings are required for applications proposing to

[34] Maine Land Use Planning Commission, Chapter 10 Land Use Districts and Standards: https://www.maine.gov/dacf/lupc/laws_rules/ch10.html

create or modify planned development, prospectively zoned development, or resource plan protection subdistricts, and are recommended for other large or complex transmission projects.

Although these meetings are not required for every transmission project, early coordination with LUPC staff is considered a best practice. By clarifying permitting pathways and application requirements before filing, these meetings can reduce the likelihood of incomplete applications, identify potential zoning or routing issues early in project development, and support a more efficient permitting process.

2. Zoning Amendment

If a proposed transmission project is not an allowed development activity in one or more of the affected subdistricts crossed by the proposed route, the developer may need to seek a zoning amendment before the project can proceed. If the project is listed as a use allowed by special exception, the applicant must submit a permit application that addresses the additional special exception criteria. LUPC staff process zoning and permit applications, but the Commission retains decision-making authority for zoning amendments.

Stakeholder Engagement Opportunities

In response to a public notice of a project seeking rezoning, permit approval, or SLC from the LUPC, the **public may submit written comments** about the proposal and request a public hearing. Whether to hold a public hearing for a permit application or SLC request is at the discretion of the LUPC. When deciding whether to hold a public hearing, the LUPC considers a number of factors, including the level of public interest and is the likelihood of credible conflicting technical information.

For rezonings, a public hearing is required if five or more commentors request a public hearing.

3. Site Law Certification (SLC)

When a project in the LUPC's service area requires a DEP permit under Site Law, DEP may not issue a Site Law permit until it receives a Site Law Certification (SLC) from the LUPC. Applicants may apply for SLC from the LUPC prior to filing a permit with the DEP, or concurrently with their DEP permit application.

By granting an SLC, the LUPC certifies to the DEP that the project is an allowed use in the zoning subdistricts involved, complies with all zoning requirements, and meets applicable LUPC land use standards that are not considered under DEP review. The LUPC must provide the SLC to the DEP within 90 days after accepting the request as complete, or within 60 days after the closure of a hearing if one was held.

Stakeholder Engagement Opportunities

Any person aggrieved by a LUPC decision, meaning a person who may suffer a direct and adverse injury as a result of the LUPC's decision, may request review within 30 days of the decision.

Federal Processes

Federal approval is required if a transmission project crosses federal land, affects federally regulated resources such as wetlands, navigable waters, or protected species, or receives federal funding. The specific federal agencies involved depend on the nature and location of the impacts. Commonly involved agencies include the Bureau of Land Management, U.S. Forest Service, and U.S. Army Corps of Engineers.

Separately, projects may also be subject to National Environmental Protection Act (NEPA) review.[35] NEPA requires federal agencies to evaluate the environmental effects of proposed major federal actions before making decisions. Major federal actions most commonly include projects requiring a federal permit or approval, receiving federal funding, or located on federal land. The U.S. Environmental Protection Agency (EPA) administers the public-facing aspects of the NEPA process, including Environmental Impact Statement (EIS) filing, public notice, and review of EIS documents. The Council on Environmental Quality (CEQ) oversees NEPA implementation across federal agencies.[36] Depending on the expected level of impact, the lead federal agency may determine that the project qualifies for a categorical exclusion, requires an Environmental Assessment (EA), or requires a more detailed EIS.

For transmission projects with multiple federal approvals, the federal review process can involve coordination among several agencies. The U.S. Department of Energy's Coordinated Interagency Transmission Authorizations and Permits (CITAP) Program is intended to coordinate federal environmental reviews and permitting for qualifying interstate electric transmission facilities, with DOE serving as the lead agency for coordinating federal authorizations.[37] These federal processes do not replace state or local approvals, but they may proceed in parallel with Maine's CPCN, DEP, LUPC, municipal, and other applicable approval processes.

Stakeholder Engagement Opportunities

When federal permitting triggers NEPA review requiring an EA or EIS, the process generally includes opportunities for public review and comment that are open to any interested party.

[35] U.S. Environmental Protection Agency, National Environmental Policy Act Review Process: https://www.epa.gov/nepa/national-environmental-policy-act-review-process
[36] Council on Environmental Quality: https://ceq.doe.gov
[37] U.S. Department of Energy, Coordinated Interagency Transmission Authorizations and Permits Program: https://www.energy.gov/oe/coordinated-interagency-transmission-authorizations-and-permits-program

Municipal and County Processes

Municipal land use permits may be required based on the project's route. These permits may include building, electrical, road opening, and erosion control permits. In these instances, developers engage with municipal officers to determine whether existing zoning ordinances apply to their projects, and the relevant local authorities determine compliance, if applicable. Municipal zoning may not override the state-led CPCN process.

If a project is located within a public way, the developer must also receive a locational permit from the municipal or county licensing authority. The developer's application is typically evaluated based on impacts to public safety and avoidance of unreasonable interference with travel.

Stakeholder Engagement Opportunities

Stakeholder engagement in municipal land use permitting processes varies by location. Some municipalities require public hearings with the option for public testimony, while others are strictly administrative. Only abutters or owners of facilities in the public way may file objections to locational permits. Public hearings are typically only required if such objections are submitted.

4 Existing Analyses of Future Electric Transmission Needs

A wide range of studies have been conducted in recent years to assess electric transmission needs affecting Maine. These studies vary considerably in geographic scope, planning horizon, purpose, and methodology. Some focus on near-term reliability needs within specific utility service territories, while others evaluate long-term reliability and economic needs at regional and interregional scales driven by projected load growth and resource development trends.

Collectively, these studies provide important insights into the transmission infrastructure that may be required to maintain reliability, accommodate load growth, integrate new generation resources, and support evolving state and regional energy policy goals. They also illustrate that transmission planning occurs through multiple overlapping processes, including utility local planning, regional reliability planning, long-term transmission planning, interconnection studies, state energy planning efforts, and federal transmission assessments.

This section is divided into two subsections. The first summarizes a selection of studies and planning processes spanning the range of planning horizons, geographic scales, and transmission need categories affecting Maine. The second identifies common findings across these analyses and summarizes the major categories of transmission need identified in multiple studies. It describes the primary drivers of each category and the types of transmission investments that may be needed. Together, these subsections provide an overview of existing transmission planning work and the transmission needs likely to impact Maine.

Existing Analyses Reviewed

A review of existing transmission planning studies, utility planning documents, and policy analyses was conducted to identify transmission needs affecting Maine and the surrounding region. This section summarizes six representative studies that provide an overview of major transmission needs identified over both the short and long term. These studies include:

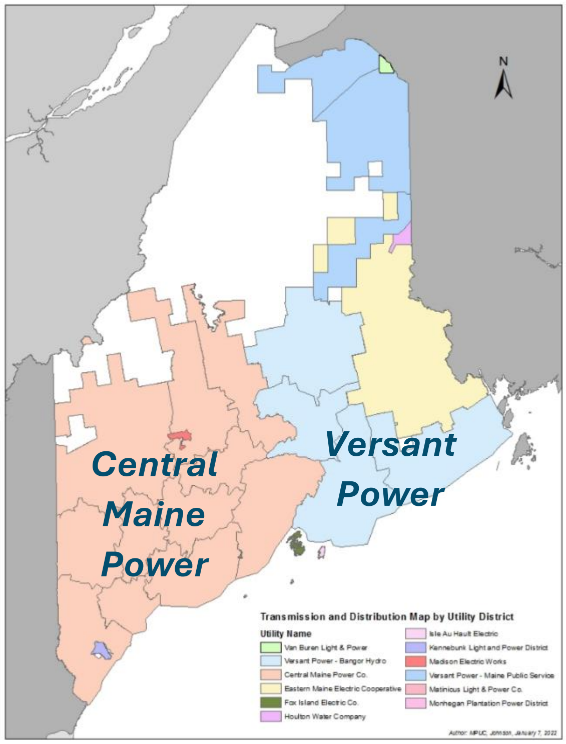
1. Maine Utility Local System Plans
2. Maine Energy Plan
3. Northern Maine Independent System Operator (NMISA) 7-Year Outlook
4. ISO-NE Regional System Plan
5. ISO-NE 2050 Transmission Study
6. DOE National Transmission Study

Brief summaries of additional studies reviewed as part of this assessment are provided in the Appendix.

Maine Utility Local System Plans

Local System Plans (LSPs) are utility-led transmission planning studies conducted within the ISO New England (ISO-NE) planning framework. These plans identify and evaluate transmission projects needed to address local system requirements. Compared to longer-term regional planning studies conducted by ISO-NE, LSPs generally focus on shorter 5- to 10-year planning horizons and transmission facilities within utility service territories. In Maine, LSPs are prepared by Central Maine Power (CMP) and Versant Power's Bangor Hydro District (BHD), as shown in Figure 7.

Figure 7. Map of Maine Utility Service Territories[38]



Both CMP and Versant develop their Local System Plans using ISO-NE load forecasts and planning assumptions, supplemented by utility-specific information regarding local system conditions and expected changes in electricity demand and generation. The plans rely on detailed transmission system modeling, including power flow, contingency, and other transmission planning analyses, to evaluate system performance under a range of forecasted operating conditions and identify potential thermal and voltage violations, reliability deficiencies, and associated transmission upgrade needs.

The projects identified through LSPs generally fall into several categories, including asset condition replacements, reliability upgrades, load-serving improvements, and customer or generator interconnections. Many of the projects involve facilities operating at voltages between 34.5 kV and 115 kV, although the studies assess needs within broader transmission networks that include higher-voltage facilities.

CMP's 2025 Local System Plan identified 50 transmission projects planned between 2026 and 2028,[39] while Versant Power's Bangor Hydro District 2025 Local System Plan identified 48 projects

[38] Maine Office of the Public Advocate: https://www.maine.gov/meopa/sites/maine.gov.meopa/files/inline-files/2022_Electric_Service_Area.pdf

[39] Avangrid (parent company of CMP), Local System Plan Presentation (2025): https://www.cmpco.com/documents/40117/115962868/Avangrid_2024_LSP_TOPAC-Presentation_Final.pdf/f07dc9bf-98f3-eaa0-8ac6-922ae63c4f4a?t=1749835806314&utm_source=chatgpt.com

planned between 2025 and 2029.[40] Table 1 summarizes the projects identified in the two Local System Plans by project status.

Table 1. Project Identified by Maine Utility LSPs

Project Status	CMP	Versant BHD
Concept	6	14
Planned	33	19
Proposed	8	7
Under Construction	3	8
Total	**50**	**48**

LSPs are a key input to ISO-NE's transmission planning processes. ISO-NE reviews needs and proposed solutions identified in Local System Plans to ensure they satisfy applicable reliability and planning criteria and to determine whether a regional transmission solution could more efficiently or effectively address those needs. In some cases, ISO-NE may identify a regional project that supersedes or modifies a proposed local solution. Projects selected through the regional planning process may be designated as Pooled Transmission Facilities (PTF) and become eligible for regional cost allocation, while other projects remain local transmission investments funded through utility rates.

The LSP process serves as an important mechanism for identifying transmission needs at the utility level while maintaining coordination with ISO-NE's broader transmission planning framework.

Maine Energy Plan

The Maine Energy Plan is the State's strategic roadmap for advancing an affordable, reliable, and clean energy system that supports Maine's residents, businesses, and economy. Published by the Governor's Energy Office (now called the Department of Energy and Resources) in 2025,[41] the plan evaluates the actions and infrastructure needed to achieve the State's energy, economic development, and climate objectives. The plan is supported by a technical analysis, Maine Pathways to 2040,[42] which evaluates potential future energy system conditions and identifies infrastructure needs associated with different pathways to achieving Maine's energy goals.

The Maine Energy Plan identifies transmission infrastructure as a critical enabler of Maine's energy future and highlights several areas where transmission investment may be needed including:

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[40] Versant Power, Local System Plan Bangor Hydro District: https://www.versantpower.com/docs/default-source/oasis/versant-power-lsp-2025-r0-251021.pdf?sfvrsn=67f9fe8c_1&utm_source=chatgpt.com

[41] Maine Governor's Energy Office, Maine Energy Plan (2025): https://www.maine.gov/energy/sites/maine.gov.energy/files/2025-01/Maine%20Energy%20Plan%20January%202025.pdf

[42] Maine Governor's Energy Office, Maine Pathways to 2040 (2024): https://www.maine.gov/energy/sites/maine.gov.energy/files/2024-10/Maine%20Pathways%20Report%20Draft%20for%20Comment.pdf

- Building new transmission to connect **new generation resources**
- Upgrading **transmission between Maine and New England** to serve demand in both regions with diverse and cost-effective clean resources
- Upgrading **local transmission** to meet rising peak load due to electrification
- Consideration of expanding transmission ties to **Canadian provinces**

One priority is the development of new transmission infrastructure to connect new generation resources, particularly renewable energy resources located in northern Maine. The plan references the Northern Maine Renewable Energy Development Program, which was established by the Legislature and is currently pursuing transmission infrastructure capable of integrating at least 1,200 MW of renewable generation, while noting that additional transmission capacity may ultimately be required as resource development expands.

The plan also identifies the need to strengthen transmission connections between Maine and the rest of New England. Increased transfer capability would enable greater sharing of diverse and cost-effective energy resources across the region while supporting reliability and economic objectives. Examples include upgrades to the Maine–New Hampshire and North-South transmission interfaces that have been identified through ISO New England's Long-Term Transmission Planning process.

In addition to large-scale regional transmission investments, the plan recognizes the need for continued investments in local transmission systems to address aging existing infrastructure and accommodate increasing electricity demand.

Finally, the Maine Energy Plan highlights the potential value of expanding transmission ties with neighboring Canadian provinces. Increased interregional transfer capability could improve access to clean energy resources, enhance system reliability, and provide additional flexibility as Maine's energy system continues to evolve.

Overall, the Maine Energy Plan presents transmission infrastructure as one of several foundational components of Maine's long-term energy strategy and identifies transmission investment as necessary to support critical resource development, load growth, economical regional energy exchange, and system reliability. The Maine Department of Energy Resources is required by law to update the Maine Energy Plan every two years. Development of the 2027 Maine Energy Plan is underway, will be informed by in-depth technical analyses and robust stakeholder input, and will offer objectives, strategies, and actions to ensure affordable, reliable, and increasingly clean energy for Maine people and businesses.

Northern Maine Independent System Operator (NMISA) 7-Year Outlook

The Northern Maine Independent System Administrator (NMISA) publishes a Seven-Year Outlook each year to assess planned development within the Northern Maine Transmission System (NMTS).[43] The study evaluates projected electricity demand, generation resources, resource adequacy,

[43] Northern Maine Independent System Administrator, Seven-Year Outlook: https://www.nmisa.com/wp-content/uploads/2025/06/2025-Seven-Year-Outlook.pdf

transmission system conditions, and planned infrastructure investments. It also summarizes system impact studies conducted by transmission owners and provides an assessment of future system needs within northern Maine.

The Northern Maine Transmission System consists primarily of Versant Power's Maine Public District (MPD) and the Eastern Maine Electric Cooperative (EMEC) service territory. Unlike the rest of Maine, which is electrically interconnected with the ISO New England system, northern Maine is interconnected through the New Brunswick Power (NBP) transmission system. MPD is interconnected with New Brunswick Power through three transmission lines and has a total transfer capability of approximately 134 MW and EMEC is interconnected with New Brunswick Power through a single 69 kV transmission line with a transfer capability of approximately 32 MW.

Projected load growth within the Northern Maine Transmission System is modest. Peak demand is forecast to increase from approximately 153 MW in 2025 to 158 MW in 2031, representing an average annual increase of less than 1 MW per year. Annual energy consumption is similarly projected to increase from approximately 854 GWh to 880 GWh over the same period. Existing generation resources include approximately 32 MW of hydroelectric generation, 42 MW of wind generation, 20 MW of biomass generation, and more than 100 MW of distributed generation resources. The NMISA territory is depicted in Figure 8.

Figure 8. NMISA Territory[44]

[44] U.S. Energy Information Administration: https://www.eia.gov/todayinenergy/detail.php?id=19671

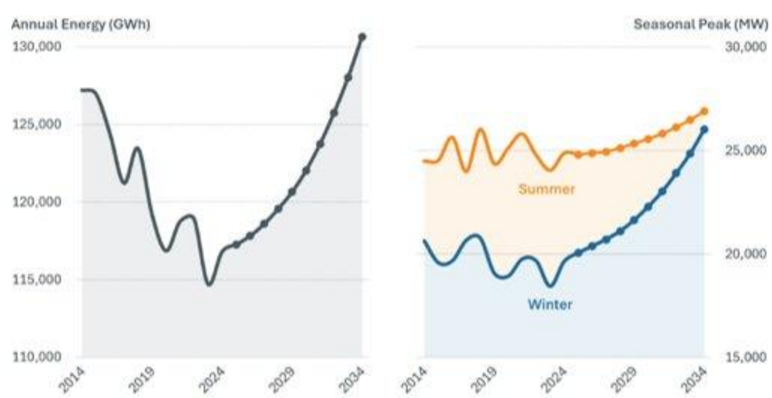
The 2025 Outlook identifies several planned capital projects intended to improve system reliability and reduce operation and maintenance costs. However, these projects are not expected to materially increase the transfer capability of the MPD transmission system.

The 2025 Seven-Year Outlook indicates that the Northern Maine Transmission System is expected to maintain adequate generating resources to satisfy reliability requirements through 2031. NMISA projects a reserve margin of approximately 37 percent over the study period, significantly exceeding the system's Planning Reserve Margin requirement of 20 percent. As a result, the study concludes that no additional generation or transmission resources are required to maintain resource adequacy under expected system conditions during the planning horizon.

ISO-NE Regional System Plan

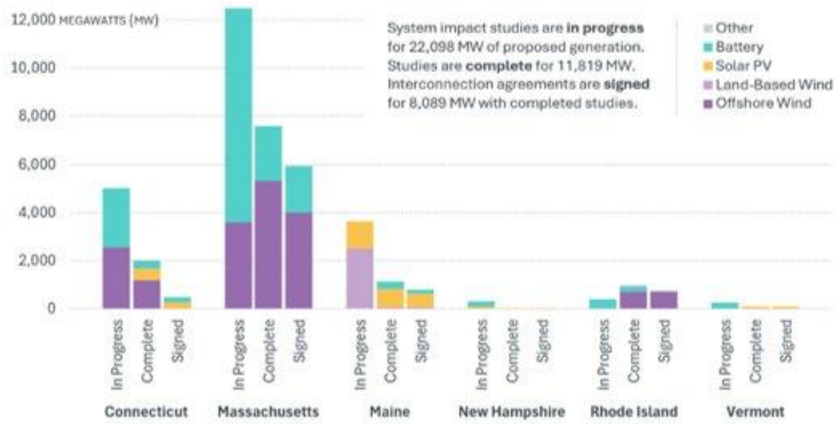
The ISO New England Regional System Plan (RSP) is the region's primary transmission planning document and provides a biennial assessment of the reliability, resource adequacy, and transmission needs of the New England power system.[45] The RSP evaluates system needs over a **ten-year planning horizon** and serves as the foundation for ISO-NE's regional transmission planning activities. The plan incorporates a range of inputs, including ISO-NE's Capacity, Energy, Loads, and Transmission (CELT) Forecast, proposed generator and energy storage interconnection requests, resource retirement assumptions, utility Local System Plans, asset condition assessments submitted by transmission owners, and planning studies conducted through ISO-NE's reliability, economic, and long-term transmission planning processes. Key inputs related to projected load growth and proposed generation and energy storage resources are summarized in Figure 9 and Figure 10. The RSP also summarizes findings from broader planning initiatives, including resource adequacy assessments and studies such as Economic Planning for the Clean Energy Transition (EPCET).

Figure 9. Annual Net Energy and Peak Demand



[45] ISO-NE, 2025 Regional System Plan: https://www.iso-ne.com/static-assets/documents/100030/final_2025_rsp.pdf

Figure 10. Interconnection Queue as of July 1, 2025



The RSP identifies transmission needs through three primary categories of transmission investment: Reliability Transmission Upgrades (RTUs), System Efficiency Transmission Upgrades (SETUs), and Asset Condition Projects. Together, these categories provide a comprehensive view of the drivers of transmission investment across New England.

Reliability Transmission Upgrades are designed to address reliability deficiencies identified through ISO-NE's transmission planning process. These projects are developed to ensure compliance with applicable reliability standards and maintain secure system operation under forecasted system conditions. As of June 2025, ISO-NE identified approximately 20 reliability project components that were proposed, planned, or under construction across New England, with an estimated total cost of approximately $450 million through the end of 2028.

System Efficiency Transmission Upgrades are intended to reduce transmission congestion and lower overall electricity production costs. Unlike reliability projects, SETUs are justified based on their economic benefits to the regional power system. The current Regional System Plan does not identify any active SETU projects. ISO-NE attributes this outcome in part to the economic benefits provided by existing reliability projects and the ability of competitive wholesale electricity markets to encourage development of generation resources that alleviate congestion without requiring transmission upgrades.

The largest category of transmission investment identified in the Regional System Plan is **Asset Condition Projects**. These projects involve the replacement, refurbishment, or upgrade of transmission infrastructure that is approaching the end of its useful life or is at elevated risk of failure. The October 2025 Asset Condition List identifies approximately $5.8 billion in planned transmission infrastructure investments through 2032, substantially exceeding the investment levels associated with either Reliability Transmission Upgrades or System Efficiency Transmission Upgrades.

The Regional System Plan highlights the growing importance of maintaining and replacing aging transmission infrastructure throughout New England. While reliability-driven transmission investments remain an important component of regional planning, the scale of planned asset condition investments indicates that infrastructure replacement is expected to be one of the primary drivers of transmission spending over the coming decade

ISO-NE 2050 Transmission Study

The ISO New England 2050 Transmission Study was initiated at the request of the New England States Committee on Electricity (NESCOE) to identify long-term transmission needs associated with a clean electric system and represents the first phase of ISO-NE's Long-Term Transmission Planning (LTTP) process.46 Unlike traditional ISO-NE transmission planning studies, which typically evaluate reliability needs over a three- to ten-year planning horizon, the 2050 Transmission Study examined potential transmission requirements through mid-century. The study serves as the foundation for subsequent phases of the LTTP process, in which transmission solutions are developed, evaluated, and may be selected through competitive transmission solicitations.

The study had two primary objectives. First, it sought to identify the transmission infrastructure needed to reliably serve future electric demand while satisfying applicable NERC, NPCC, and ISO-NE reliability criteria. Second, it developed conceptual transmission roadmaps designed to address those needs while considering the feasibility and cost of transmission development. These roadmaps were not intended to represent specific project recommendations, but rather high-level pathways illustrating how future transmission needs could potentially be addressed under different system conditions.

The 2050 Transmission Study relied on load forecasts and future resource portfolios derived from the Massachusetts Deep Decarbonization Roadmap's "All Options Pathway," published in 2020. ISO-NE evaluated transmission system conditions using snapshots of the 2035, 2040, and 2050 electric system under a range of summer and winter peak load conditions. These scenarios incorporated assumptions regarding future generation development, resource retirements, electrification-driven load growth, and changing patterns of electricity consumption. The highest-demand scenario modeled an extreme winter peak load of approximately 57 GW in 2050, while the lowest-demand scenario modeled a normal winter peak load of approximately 51 GW. The key load growth and resource adoption assumptions used in the study are shown in Figure 11 and Figure 12. The analysis focused primarily on thermal and contingency-based transmission performance and did not include detailed voltage, short-circuit, or transient stability assessments.

[46] ISO-NE, 2050 Transmission Study: https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf

Figure 11. 2050 Transmission Study Load Assumptions

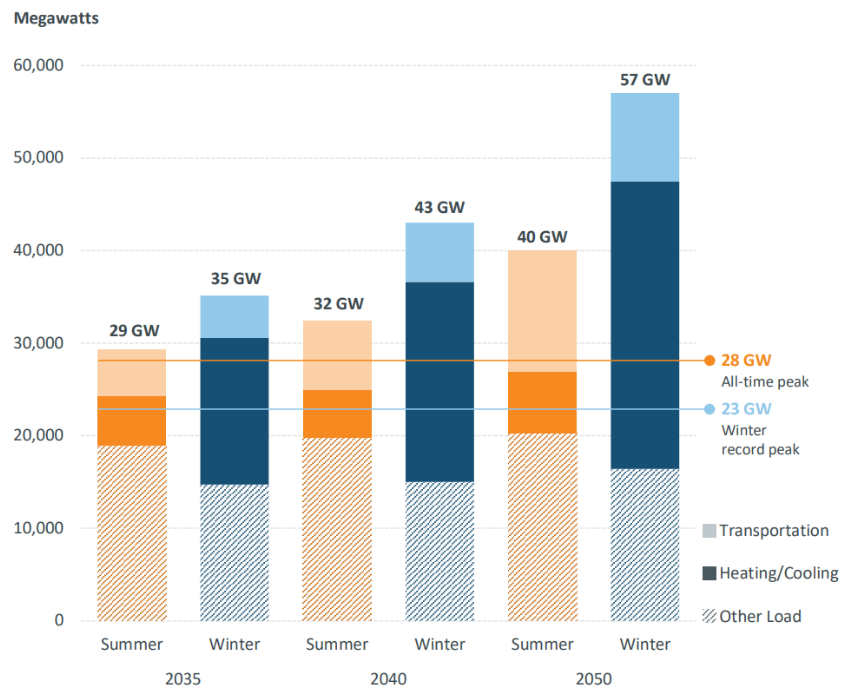
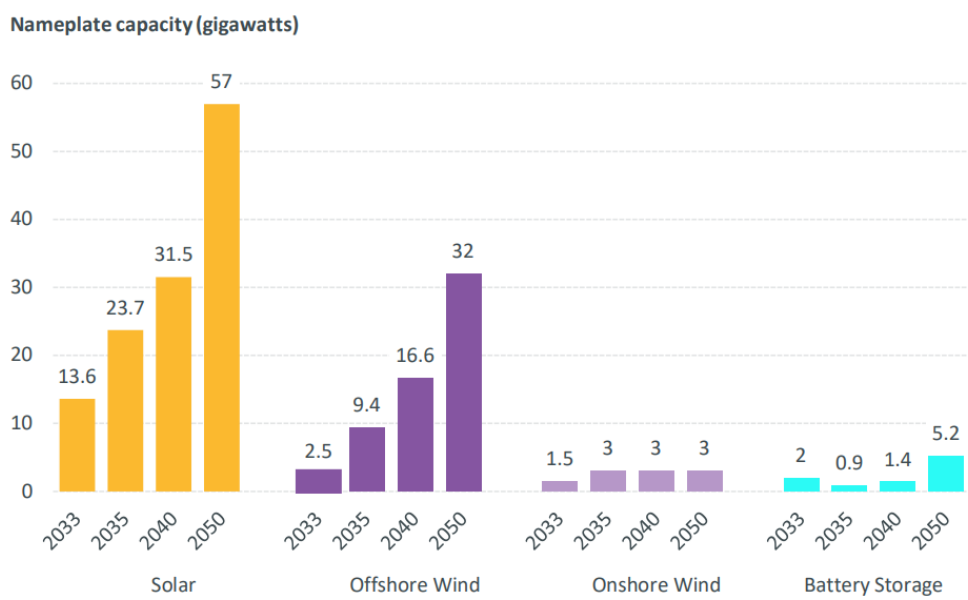


Figure 12. 2050 Transmission Study Renewable Generation and Energy Storage Input Assumptions



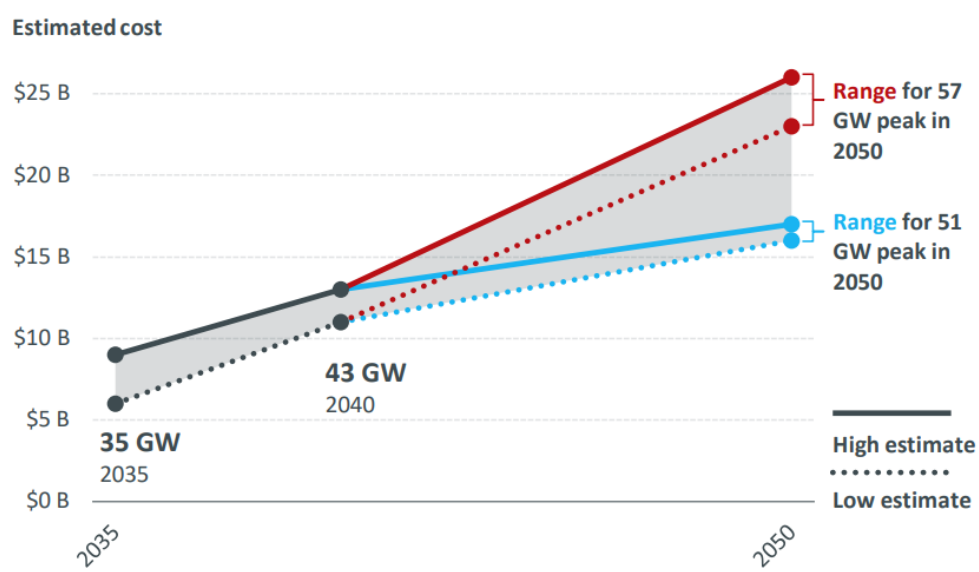
Several findings from the study have direct relevance to Maine:

+ Peak load growth is a major driver of future transmission investment requirements, with transmission costs increasing significantly under the highest electrification scenarios.

- Incremental transmission upgrades, such as reconductoring existing lines, increasing conductor capacity, and upgrading existing facilities, may provide cost-effective opportunities to address emerging needs over time.
- The geographic relationship between generation resources and load centers affects transmission constraints, particularly in import-constrained areas such as Greater Boston.
- Transformer capacity may become a significant constraint as reliance on high-voltage transmission infrastructure increases, particularly at 345 kV and 115 kV substations.

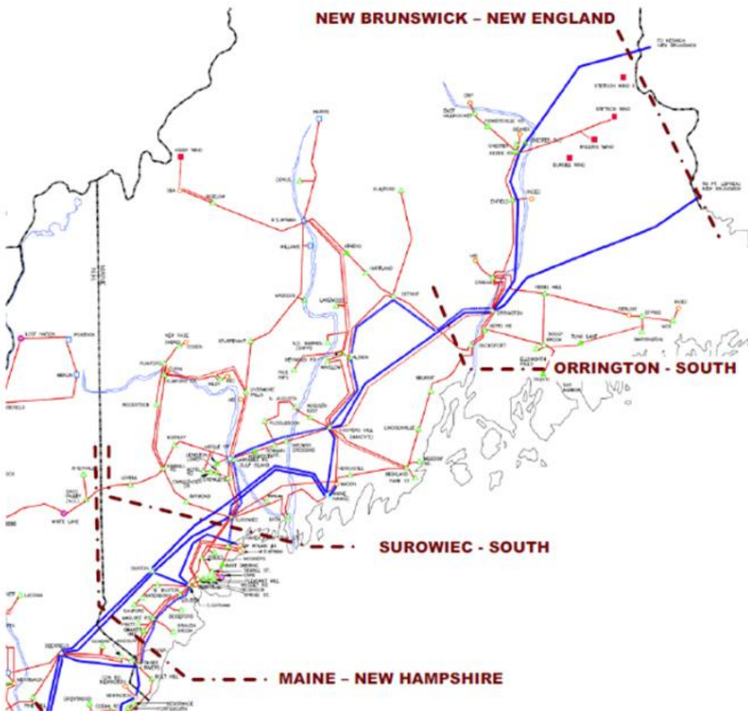
Figure 13 illustrates the estimated transmission investment costs associated with addressing the needs identified in the study. Estimated transmission investment requirements ranged from approximately $16 billion to more than $26 billion across the scenarios evaluated, with costs increasing substantially under higher-load futures. The results reinforce the study's conclusion that peak demand growth is a major determinant of long-term transmission investment requirements.

Figure 13. Estimated Cost Required for Transmission Expansion to Meet Studied Needs



Of particular relevance to Maine, the study identified recurring transmission constraints on the Maine–New Hampshire and North-South interfaces shown in Figure 14 that connect Maine and New Hampshire to major load centers in southern New England. These interfaces were identified as high-likelihood concerns across multiple future scenarios, indicating that they are likely to require transmission upgrades under a wide range of future resource and load conditions. The study's findings informed subsequent long-term transmission planning efforts, including the development of ISO-NE's first Long-Term Transmission Planning solicitation. Building on the needs identified in the 2050 Transmission Study and additional technical analyses, the solicitation established transfer capability objectives at the Maine–New Hampshire and Surowiec–South interfaces while supporting the interconnection of approximately 1,200 MW of renewable generation in central Maine.

Figure 14. Key Transmission Interfaces within Maine and between Maine and the Rest of New England[47]



These upgrades are intended to facilitate the cost-effective integration of new generation resources needed to serve growing electricity demand across New England while also increasing Maine's ability to import and export power when economically beneficial, improving access to regional energy markets and enhancing system flexibility.

DOE National Transmission Study

The U.S. Department of Energy (DOE) published the National Transmission Needs Study in 2023 to identify transmission infrastructure needs across the United States and establish a common reference point for evaluating regional and interregional transmission expansion opportunities. Rather than conducting new transmission planning analyses, the study synthesized the results of numerous existing transmission, resource adequacy, and decarbonization studies that evaluated future electricity system needs through approximately 2035. The results were intended to inform federal transmission planning efforts and help identify transmission corridors where additional investment may provide significant reliability, economic, or public policy benefits.

To facilitate comparison across studies, DOE grouped the analyzed scenarios according to their underlying assumptions regarding electricity demand growth and clean energy deployment. The main groupings were moderate load with high clean energy and high load with high clean energy as shown in Table 2. This approach allowed DOE to assess how differing assumptions about

[47] RTO Insider: https://www.rtoinsider.com/116826-iso-ne-reveals-details-long-term-tx-proposals/

electrification, economic growth, and resource development influence future transmission requirements.

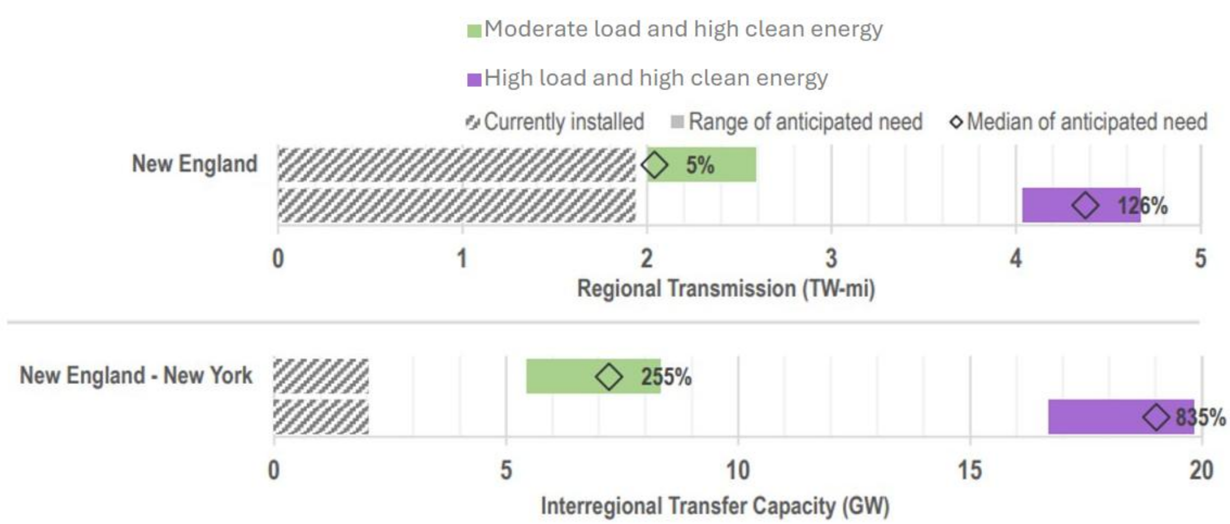
Table 2. DOE National Transmission Study Groupings of Reviewed Transmission Expansion Studies by Input Assumptions

	Load Growth	Clean Energy Penetration
Moderate	3,974-7,000 TWh	38.6%-80% by 2040
High	>7,000 TWh	>80% by 2040

The National Transmission Needs Study is fundamentally an economic assessment that identifies transmission expansions that would be cost-effective under a range of future load growth and clean energy deployment scenarios.

As shown in Figure 15, the study identified substantial differences in economically justified transmission expansion between scenarios with similar clean energy assumptions but different levels of load growth. For New England intraregional transmission, the moderate-load, high-clean-energy scenario supported approximately 0.2 to 0.6 TW-miles of transmission expansion, while the high-load, high-clean-energy scenario supported approximately 2.0 to 2.5 TW-miles of expansion. Similar trends were observed for interregional transmission between New England and New York. Under the moderate-load, high-clean-energy scenario, the study found that approximately 3.5 to 5 GW of additional transfer capability would be economically justified, whereas the high-load, high-clean-energy scenario supported approximately 15 to 18 GW of additional transfer capability.

Figure 15. Range of Cost-Effective Transmission Expansion Findings



For Maine and New England, these findings highlight the importance of considering transmission planning within both regional and interregional contexts and illustrate the potential scale of future transmission investment needs. The wide range of outcomes across the studies also underscores the extent to which transmission requirements are sensitive to key uncertainties, particularly assumptions regarding future load growth.

Summary of Identified Transmission Needs

The studies reviewed in the previous section identify a broad range of transmission needs affecting Maine and the surrounding region. While these studies differ in scope, planning horizon, methodology, and underlying assumptions, several common themes emerge. Collectively, they indicate that future transmission investment needs are driven by a combination of aging infrastructure, reliability requirements, load growth, generation development, and increasing opportunities for regional and interregional energy exchange.

Table 3 summarizes the major categories of transmission need identified across the reviewed studies. For each need category, the table identifies the primary drivers of the need, the studies in which the need was identified, the estimated magnitude of the need where available, associated cost estimates, and anticipated delivery timeframes. The table is intended to provide a consolidated view of the transmission needs identified across the literature and to facilitate comparison of needs that arise from different planning processes and planning horizons.

Table 3. Transmission Needs Identified

	Type of Need	Driver(s)	Study	Magnitude of Need (MW)	Cost ($M)	Delivery Year
Asset Condition List	Asset condition	Triggered by aging infrastructure or equipment failure	Asset Condition List (October 2025)	CMP: 10 projects MEPCO: 1 project	CMP: $96.8M MEPCO: $7.2M	List currently extends through 2028, but ongoing process
Reliability Transmission Upgrades (RTUs)	Reliability needs	Increasing loads and integration of new resources	RSP Project List (October 2025)	Upper Maine (UME) 2029 solutions vary in nature	Est. total cost of $151M for UME solutions	Currently planned for 2024-2028
Maine Interface Transfer Upgrades (pursuant to 2025 LTTP RFP)	Combination of reliability, economic, and policy-driven needs	Triggered by LTTP process but addresses medium-term reliability need in southern New England	2050 Transmission Study (2024) LTTP RFP (2025)	Increase Maine-New Hampshire interface limit to 3,000 MW and Surowiec-South to 3,200 MW; facilitate interconnection of 1,200 MW of renewable generation at Pittsfield	Current proposals range from $2.1-2.2B, based on preliminary results of LTTP procurement	Est. in-service Q4 of 2032 based on RFP responses
Northern Maine Renewable Integration	Combination of economic and policy-driven	Renewable energy integration in Northern Maine	Third Maine Resource Integration Study (2024)	At least 1,200 MW of renewables	TBD	Expected to coincide roughly with LTTP upgrades (see below)
Interregional Transmission Expansion	Combination of reliability, economic, and policy-driven needs	Likely necessary to achieve clean energy targets while maintaining reliability	Maine Energy Plan: Pathways to 2040 (2025), DOE Transmission Needs Study (2023)	5 GW between Canada and Maine by 2050 (up from 1,200 MW from NECEC currently), ~7 GW between New England and New York under moderate load by 2035 (up from ~2 GW)	TBD	New England <> New York needs identified in 2035, increase in Canadian hydro imports grows through 2050
Gulf of Maine Offshore Wind Integration	Combination of economic and policy-driven	Offshore wind integration in the Gulf of Maine	Offshore Wind Roadmap, Wind Energy Needs Assessment (2022)	Up to 2,776 MW of offshore wind by 2050	TBD	Depends on technological advancement and onshore infrastructure buildout

The transmission needs summarized in Table 3, and the subsections that follow, are organized from the nearest-term to the longest-term needs and, generally, from the highest-certainty to the greatest uncertainties. For example, asset condition and reliability-driven projects identified through established planning processes, such as ISO New England's Asset Condition List, are based on known equipment replacement needs and planned investments through 2028 and beyond, making them relatively certain. In contrast, transmission needs associated with offshore wind development in the Gulf of Maine depend on the future resource development, which faces economic, policy, and market uncertainties. As a result, the timing, scale, and ultimate necessity of the associated transmission investments are less certain.

The sections that follow discuss each identified transmission need in greater detail, beginning with near-term asset condition and reliability investments and progressing toward longer-term generation integration, interregional transmission expansion, and offshore wind-related transmission needs.

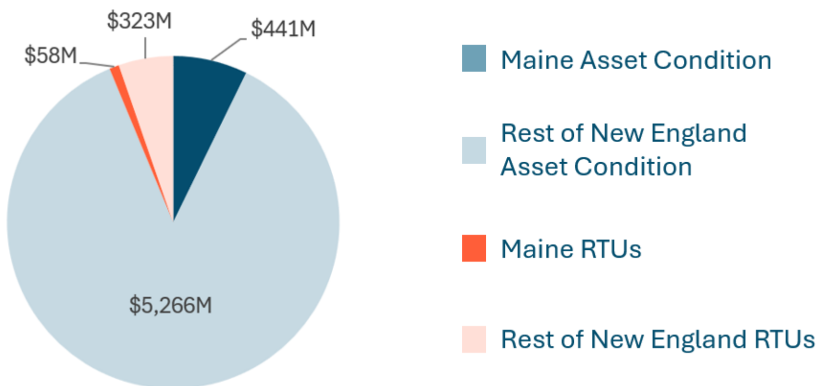
Asset Condition and Reliability Upgrades

Asset condition and reliability upgrades represent the most immediate transmission needs identified through the literature review. Unlike many of the needs discussed later in this section, these projects are driven by existing infrastructure conditions and established reliability requirements, making them among the highest-certainty transmission investments expected over the near term.

Asset condition projects address transmission infrastructure that is approaching the end of its useful life or is at elevated risk of failure. As of October 2025, ISO New England's Asset Condition List identified eleven projects in Maine representing approximately $443 million in planned investment. These projects include major ongoing efforts to replace aging 345 kV transmission structures along key transmission corridors. Across the remainder of New England, ISO-NE identified an additional 109 asset condition projects representing approximately $5.3 billion in planned investment through 2032.

Reliability upgrades address transmission system deficiencies identified through ISO-NE's reliability planning process. These needs may arise from projected load growth, changes in generation resources, evolving power flow patterns, or other system conditions that could result in violations of applicable reliability criteria. As of October 2025, five reliability-driven transmission projects had been identified in Maine with an estimated cost of approximately $58 million. The largest of these is the Upper Maine 2029 Project, a multi-year transmission upgrade designed to address voltage stability concerns and improve reliability across portions of both the Versant and CMP service territories.

Figure 16. Forecasted Investment in Asset Condition and Reliability Upgrades in Maine and ISO-NE (2026-2030)



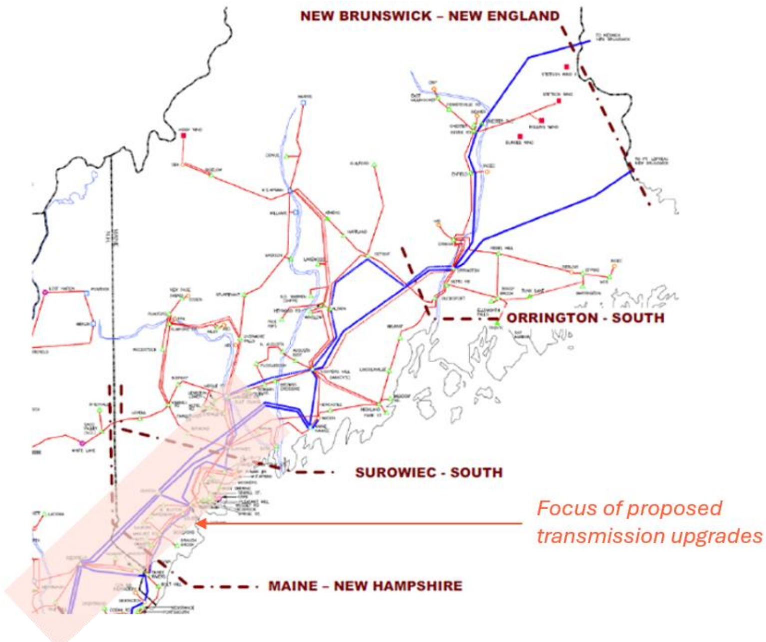
Together, these projects form the foundation of New England's transmission system and are necessary to maintain safe and reliable electric service. The costs of most regional asset condition and reliability upgrades are allocated across New England transmission customers based on each state's share of regional electricity demand, commonly referred to as load-ratio share. Given the state's relatively small share of regional demand, Maine customers are generally responsible for a proportionate share of the costs of these regional investments, regardless of where within New England the projects are physically located.

Maine Interface Transfer Upgrades

Transmission interfaces are defined locations on the transmission system where power flows between regions are monitored and, in some cases, constrained to maintain reliable, economically efficient system operation. Several studies reviewed as part of this assessment, including ISO New England's 2050 Transmission Study and subsequent Long-Term Transmission Planning (LTTP) analyses, identified constraints on the transmission interfaces connecting Maine to the rest of New England. These constraints are primarily driven by increasing power transfers during periods of high demand, particularly during winter peak conditions. Identified upgrades could facilitate both increased imports to Maine during periods of critical need, and enable the efficient development of lower-cost generation resources located in Maine that could help serve load both in-state and farther south.

Of particular importance are the Maine–New Hampshire and Surowiec–South interfaces shown in Figure 17. Building on the findings of the 2050 Transmission Study, ISO-NE's first LTTP solicitation established transfer capability objectives intended to increase the amount of power that can be transferred across these interfaces by up to just over 3 GW while also enabling the interconnection of approximately 1,200 MW of renewable generation at Pittsfield in central Maine. Two transmission solutions with estimated costs of approximately $2.2 billion remain under evaluation by ISO-NE. Both proposals rely heavily on upgrades within existing transmission rights-of-way and are expected to have commercial operation dates in the early 2030s if selected pending economic screening.

Figure 17. Maine Transmission Interfaces and Proposed LTTP Upgrade Areas[48]



The identified interface constraints represent one of the most significant medium-term transmission needs affecting Maine. Unlike asset condition and reliability projects, which primarily maintain the existing transmission system, these upgrades are intended to increase transfer capability and support the evolving needs of the regional electric system. They would facilitate greater movement of electricity between Maine and southern New England, support the integration of new generation resources, and improve overall system efficiency.

Northern Maine Renewable Integration

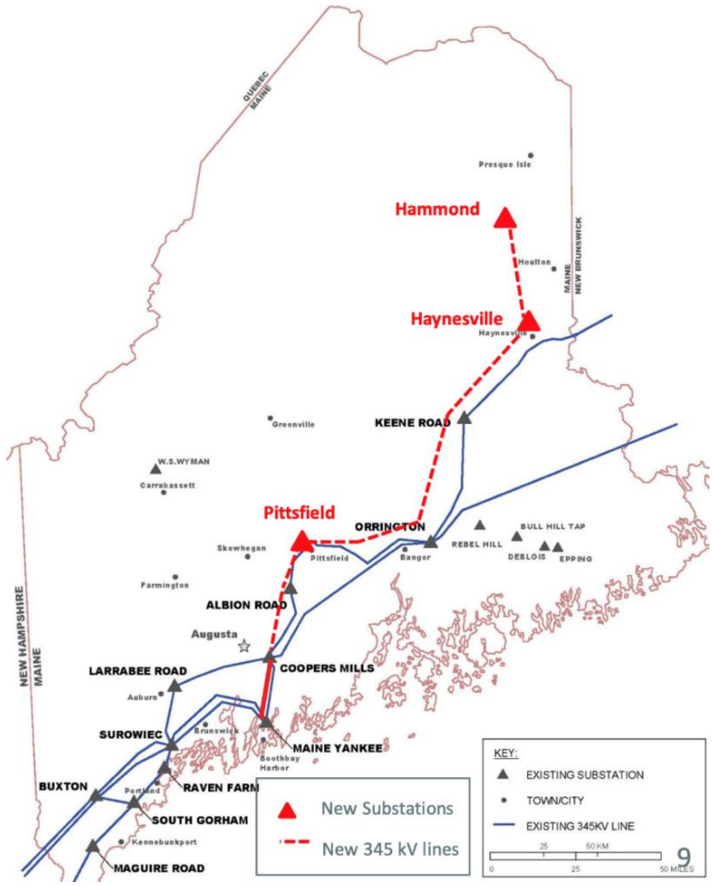
Northern Maine contains some of the highest-quality onshore wind resources in New England, but the region's existing transmission system was not designed to accommodate large-scale export of renewable energy to load centers in southern Maine and the broader New England region. As a result, multiple studies have identified the need for new transmission infrastructure to enable development of these resources and deliver their output to customers throughout the region.

The need was directly evaluated through ISO New England's Third Maine Resource Integration Study (MRIS), which examined the transmission requirements associated with approximately 1,500 MW of proposed renewable generation located primarily in Aroostook and Penobscot Counties. The study concluded that the existing transmission system lacks sufficient capability to reliably interconnect and deliver this quantity of generation under a range of operating conditions. To address this need, the study identified a preferred transmission solution consisting of a new 345 kV transmission line

[48] ISO-NE, 2050 Transmission Study: https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf

connecting northern Maine to the existing Orrington–Albion Road 345 kV corridor and the construction of a new substation in the Pittsfield area.

***Figure 18. Northern Maine Renewable Integration Concept*[49]**



The identified transmission need is currently being advanced through the Northern Maine Renewable Energy Development Program, a competitive procurement process administered by the Maine Public Utilities Commission. The procurement seeks transmission infrastructure capable of supporting at least 1,200 MW of renewable generation while creating opportunities for regional participation and cost sharing. Depending on the outcome of the procurement, neighboring states may elect to contract for a portion of the associated renewable energy and participate in the allocation of transmission costs.

Northern Maine renewable integration represents one of the most significant generation-driven transmission needs identified through this assessment. Together with the Maine Interface Transfer Upgrades discussed previously, these investments would establish a pathway for delivering northern Maine renewable resources to load centers throughout Maine and New England. More broadly, they illustrate the close relationship between transmission and generation development,

[49] ISO-NE, Third Maine Resource Integration Study Results: https://www.iso-ne.com/static-assets/documents/100012/a02_third_maine_resource_integration_study_june2024_non_ceii.pdf

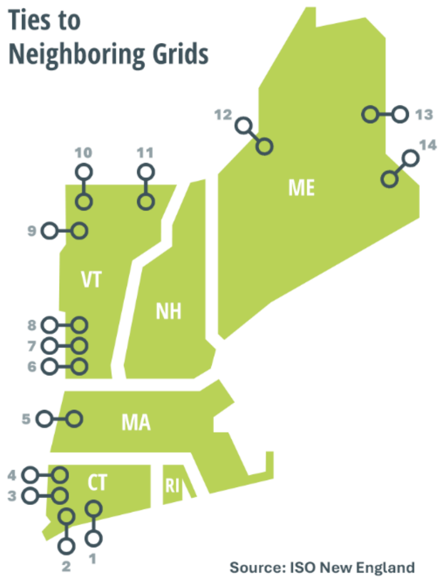
as neither investment can achieve its full value without the other. They also highlight the potential importance of regional resource sharing, as efficiently integrating northern Maine generation at lower cost to Maine may depend on transmission investments and cost-sharing arrangements that enable neighboring states to access and share benefits from these resources.

Interregional Transfer Capacity Expansion

Several studies reviewed as part of this assessment identified a potential need to expand transmission capacity between New England and neighboring regions, including New York, Québec, and the Canadian Maritimes. Unlike the transmission needs discussed previously, which are tied to specific reliability concerns or identified generation development opportunities, interregional transmission expansion is driven by broader trends including load growth, changing energy mix, and the benefits of sharing generation and transmission resources across larger geographic areas.

The U.S. Department of Energy's National Transmission Needs Study identified economic benefits from expanding interregional transmission interties between ISO-NE and New York under higher load growth scenarios. The study found that the interregional interface between ISO-NE and New York could increase by several gigawatts by 2035 and would be beneficial, with the magnitude of the need strongly influenced by assumptions regarding future electricity demand. The Maine Energy Plan generally identified expanded transmission ties with neighboring Canadian provinces as a potential opportunity to improve reliability, grid flexibility, access to diverse resources like Quebec hydroelectric power and emerging renewable generation resources in Atlantic Canada, and support economic energy exchange.

Figure 19. ISO-NE Interregional Transmission Interfaces[50]



New York Interfaces: 1-9
Hydro Quebec Interfaces: 10-12
New Brunswick Power Interfaces: 13-14
Note: Four ties between NMISA and New Brunswick not shown in this map

Compared to the transmission needs discussed previously, interregional transmission expansion is associated with greater uncertainty. The timing, scale, and location of future interregional investments depend heavily on future load growth, energy market conditions, public policy decisions, economic and grid stability needs associated with resource development patterns, and coordination among multiple jurisdictions.

Gulf of Maine Offshore Wind Integration

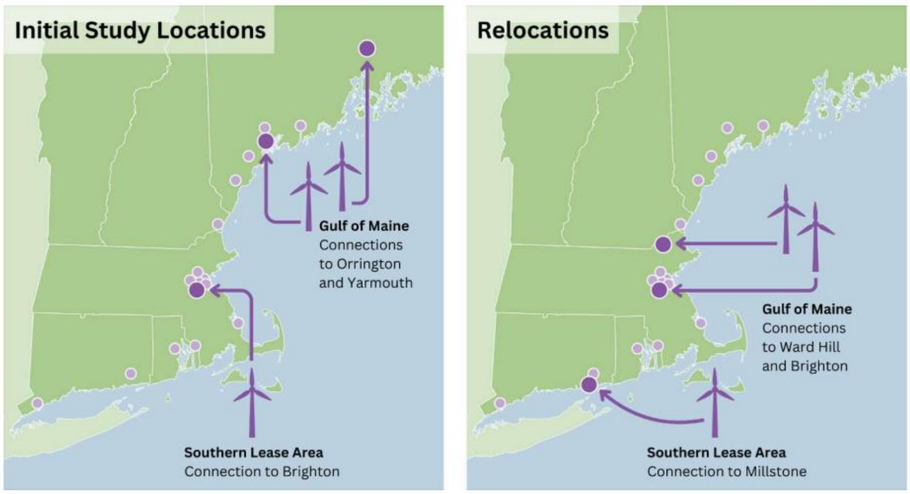
Several studies reviewed as part of this assessment identified the potential need for significant transmission investments to support future offshore wind development in the Gulf of Maine. Unlike the transmission needs discussed previously, which are linked to identified reliability concerns, ongoing procurements, or known generation development opportunities, offshore wind-related transmission needs depend on the future scale, timing, and location of offshore wind development.

ISO New England's Offshore Wind Analysis evaluated scenarios in which large quantities of Gulf of Maine offshore wind generation are interconnected to the regional transmission system. The study found that significant transmission upgrades would likely be required if offshore wind projects interconnect in Maine and significant generation is exported to load centers elsewhere in New England. In particular, the analysis identified the Maine–New Hampshire and North-South transmission interfaces as potential constraints under several offshore wind development scenarios. Upgrades to these interfaces would increase the ability of the transmission system to deliver offshore wind generation to regional load centers while also providing broader reliability and

[50] ISO New England, Maps and Diagrams: https://www.iso-ne.com/about/key-stats/maps-and-diagrams#system-diagram

economic benefits. The analysis also considered scenarios in which Gulf of Maine offshore wind projects interconnect at points of interconnection in Massachusetts or New Hampshire rather than Maine. By locating the point of interconnection closer to major load centers, these approaches could reduce power flows across constrained Maine transmission interfaces and potentially lessen the need for some onshore transmission upgrades within Maine.

Figure 20. Offshore Wind Interconnection Locations Studied in ISO-NE's Offshore Wind Analysis[51]



In addition to transmission interface constraints, the integration of large offshore wind projects may be influenced by regional reliability considerations associated with the loss of large generation sources. Historically, ISO New England has maintained a 1,200 MW loss-of-source limit to protect the reliability of interconnected systems in New York and PJM. As offshore wind project sizes continue to increase, ISO New England, NYISO, and PJM have been evaluating whether the existing system can support a higher minimum loss-of-source limit and what upgrades may be required to do so.[52] Preliminary results indicate that an increase may be possible, although additional operational and reliability considerations require further investigation. The three participating RTOs suspended evaluation indefinitely.

Offshore wind integration remains the most uncertain transmission need identified in this assessment. Future transmission requirements will depend on the pace and scale of offshore wind development, interconnection locations, and evolving reliability requirements. While studies have identified transmission upgrades that may be needed under large-scale Gulf of Maine offshore wind deployment scenarios, the timing and scope of these investments remain less certain than the near- and medium-term transmission needs discussed in the preceding sections.

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[51] ISO-NE, 2050 Transmission Study: Offshore Wind Analysis: https://www.iso-ne.com/static-assets/documents/100021/2050_osw_report_final.pdf

[52] ISO-NE, 2025 Regional System Plan: https://www.iso-ne.com/static-assets/documents/100030/final_2025_rsp.pdf

5 Existing Rights-of-Way and Electric Transmission

LD 197 Sec 1.4. Types of existing rights-of-way and opportunities for potential use of those rights of-way for siting of electric transmission infrastructure in the State, including colocation with transportation, electric transmission and railway rights-of-way

Overview of Transportation Right-of-Way Colocation

Transportation right-of-way (ROW) colocation is the siting of transmission lines by utilities or transmission developers within roadway or railway ROW. This approach specifically focuses on utilizing highway and railway corridors where possible to minimize developing new transmission ROW. Siting in these corridors makes use of previously disturbed land, minimizing the need to procure new land, develop undisturbed greenfield land, or disturb scenic views. This strategy also provides a structured method for connecting rural and urban energy networks and can simplify environmental permitting processes and lessen local community concerns compared to developing entirely new transmission routes. However, successful colocation of transmission requires navigating a variety of factors, such as complex operational and financial trade-offs, particularly if the corridors are planned for future transportation capacity expansions.

The first part of this section, Cost and Benefit Tradeoffs of ROW Colocation, examines the planning, financial, and non-monetary factors of ROW colocation. Next, national precedent in the current landscape of colocated transmission is reviewed, followed by a localized analysis in opportunity for Maine. The core findings of the literature review are then presented in the next section, analyzing federal, Maine, and out-of-state regulations regarding safety, design, and relocation costs, first for roadways and then for railways. Finally, the Opportunities for Future Consideration section highlights state-level best practices and opportunities for future consideration.

Cost and Benefit Tradeoffs of ROW Colocation

Integrating transmission infrastructure into existing ROW serves as a high-value opportunity, yet practical implementation involves intricate regulatory, technical, and collaborative challenges. Each corridor demands a bespoke evaluation of its specific operational, environmental, and legal constraints. The following section analyzes the multifaceted tradeoffs and stakeholder dynamics central to this process.

Planning Considerations

As both transmission and transportation corridors are planned, each must carefully consider interactions with the other to avoid potential conflicts. During the transmission planning process, all existing transportation assets posing potential conflicts with transmission infrastructure must be considered. The approach taken for colocation in one corridor may not be suitable for another corridor. The specific geography, dimensions, environmental factors, safety requirements, drainage, and other factors must be taken into account to determine the optimal transmission route. This includes evaluating the technical decisions related to underground versus overhead infrastructure, each of which carries different cost, maintenance, resilience, and operational implications. Strategic undergrounding is also discussed in the chapter called Existing and Emerging Technology and Construction Methods.

At the DOT and railroad level, future transportation plans must be consulted to determine where expansion has been proposed that might conflict with transmission routes. These long-term transportation corridor preservation needs are especially important because agencies must ensure present infrastructure decisions do not limit future roadway expansion, transit investments, freight mobility, or safety improvements. Existing DOT and railroad lighting and traffic control devices, survey monuments, wetlands, pollinator habitats, emergency vehicle pull-offs, snow storage, and other ROW uses need to be mapped or considered alongside all other utility (fiber optic lines, gas pipelines, etc.) conflicts.

Ultimately, developers and agencies must navigate the overlapping and complex public and private interests surrounding their respective transmission and transportation projects. Transportation agencies, utilities, regulators, local governments, private landowners, environmental stakeholders, and the general public may all have different priorities, timelines, and risk tolerances. This complexity creates a critical need for strong coordination, policy alignment, and long-term planning to successfully advance projects.

Financial Considerations

From a utility or transmission developer perspective, the economics of colocation differ from those of traditional land acquisition. Colocation of transmission within existing transportation corridors often requires occupancy fees paid to the hosting transportation agency. Despite these costs, colocation can reduce land acquisition costs, limit the need for negotiations with numerous private landowners, and potentially accelerate project delivery. These efficiencies can make transportation corridors an attractive alternative to greenfield routes. Countervailing considerations include incremental costs associated with collocating complex infrastructure, including both financial costs as well as other risks and associated mitigations driven by safety and other considerations.

For transportation agencies and railroads, the decision to enable colocation with transmission must balance the value of exclusive ROW control with the benefits of shared use. Colocation can create new revenue opportunities through occupancy agreements while helping offset maintenance expenses through coordinated corridor management and infrastructure investments. When structured effectively, these arrangements can provide financial and operational benefits for both parties.

Non-monetary Considerations

Considerations for the impact to the environment and aesthetic quality factor into the transmission colocation decision process, highlighting important non-monetary outcomes. Siting transmission within previously disturbed ROW corridors may present a smaller environmental impact as compared to siting along greenfield land, helping to concentrate infrastructure within already developed corridors rather than opening entirely new areas for development. This strategy can help avoid or minimize impacts to environmentally sensitive areas and viewsheds by reducing new greenfield corridors, and considering the strategic undergrounding of transmission in certain locations.

Ultimately, successful transportation ROW colocation requires balancing infrastructure needs, financial realities, environmental stewardship, and public interest considerations within a highly coordinated and evolving policy landscape.

National Precedent

As of June 2025, there are approximately 1,400 miles of proposed, planned, or completed colocated transmission nationally, utilizing both roadway and railway ROW. This section discusses the current compilation of existing colocation projects and research conducted to identify barriers to future colocation projects.

Despite the national precedent for transmission colocation within transportation ROW, there continue to be obstacles that limit additional colocation.[53] To address this, the Joint Office of Energy and Transportation is currently assessing the feasibility of transmission colocation within Interstate System ROW.

Through the Joint Office of Energy and Transportation, the Pacific Northwest National Laboratory (PNNL) partnered with the U.S. Department of Transportation's Volpe Center (Volpe Center) to produce the Electric Transmission in Transportation Rights-of-Way Gaps Analysis. This research focuses on policy, technical, and institutional barriers to transmission colocation that arise from the state and federal level.[54] Specifically, Data Appendix A of the PNNL analysis aggregates voltage, construction, and ROW type, along with status and length, of colocated transmission projects between 2000 and 2025, and is shown in Figure 21.[55]

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[53] Pacific Northwest National Laboratory, Electric Transmission in Transportation Rights of Way: https://www.pnnl.gov/projects/electric-transmission-transportation-rights-way

[54] Ibid.

[55] Pacific Northwest National Laboratory, Data Appendices to the Electric Transmission in Transportation Rights-of-Way Gaps Analysis: https://www.pnnl.gov/projects/electric-transmission-transportation-rights-way/data-appendices

Figure 21. Transmission Projects Located in Transportation Rights-of-Way

		Voltage Type		Construction Type			ROW Type			Status as of June 2025			Length
Project Name	State(s)	AC	HVDC	Over	Under	Both	Road	Rail	Both	Commissioned	NEPA Approved	Proposed	Miles
AV Solar Ranch One Project	CA	X			X		X			X			4
Lacombe to Barket	CO	X			X		X					X	1
SOO Green HVDC Link	IA-IL		X		X		X				X		350
Dodge County Wind Project Transmission Line	MN	X		X			X					X	27
Mankato-Mississippi River Transmission Project	MN	X		X			X					X	140
Williston to Stateline Transmission Line Project	ND	X		X			X					X	16
Champlain Hudson Power Express	NY		X		X			X			X		336
South Fork Wind	NY	X			X				X	X			4
Amtrak Zoo to Paoli Electric Transmission Line	PA	X		X				X			X		18
Big Cottonwood Canyon Wildfire Mitigation	UT				X		X			X			35
Haymarket Transmission Project	VA	X				X	X					X	5
New England Clean Power Link	VT		X		X		X				X		154
Badger Coulee 345 kV Transmission Line Project	WI	X		X			X			X			180
Dodge County Distribution Interconnection Project	WI	X		X			X					X	15
Rockdale to West Middleton Transmission Project	WI	X		X			X			X			32
Cardinal-Hickory Creek 345-kV Transmission Line	WI-IA	X		X					X	X			102
	Total	10	3	8	7	1	12	2	2	6	4	6	1419

Opportunity in Maine

There are 1,315 miles of National Highway System corridors in Maine.[56] Class I and Class III[57] railroads in Maine constitute 732 and 231 miles, respectively, totaling over 2,300 miles of transportation corridors throughout the state.[58] Existing National Highway System (NHS) roadway and railway ROW in Maine are shown in Figure 22.

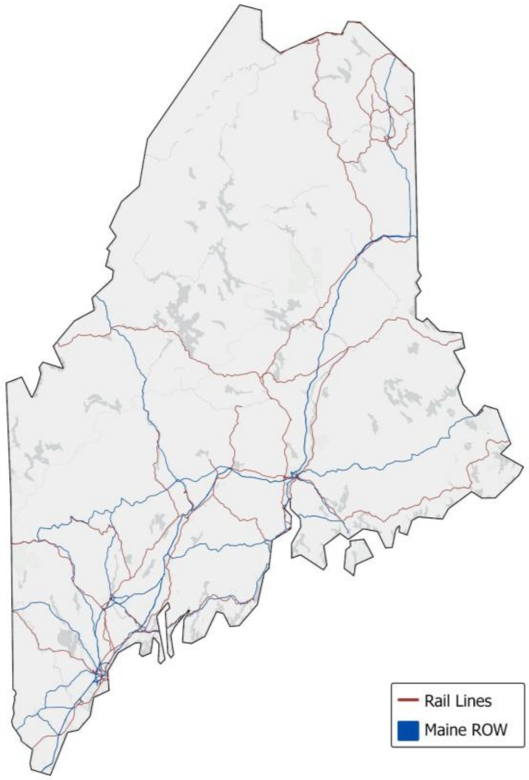
While these figures highlight a substantial potential for transmission colocation within existing transportation ROW, colocating transmission with transportation corridors requires aligning state statutory frameworks with transmission and DOT policies and further analysis to identify where opportunities would be suitable across the existing transportation corridors. Evaluating this potential involves weighing efficiency gains against the technical complexities and safety protocols inherent to shared corridors.

[56] Federal Highway Administration, Highway Statistics Series: https://www.fhwa.dot.gov/policyinformation/statistics/2024/hm30.cfm

[57] Class I and Class III railroads refer to railroad carriers within the classification thresholds for annual operating revenues as determined by the Surface Transportation Board under section 1201.1–1 of title 49, Code of Federal Regulations. 49 U.S. Code § 20102: https://www.govinfo.gov/content/pkg/USCODE-2024-title49/pdf/USCODE-2024-title49-subtitleV-partA-chap201-subchapI-sec20102.pdf

[58] MaineDOT, Maine State Rail Plan: https://www.maine.gov/dot/sites/maine.gov.dot/files/docs/ofps/docs/railplan/MaineStateRailPlan.pdf

Figure 22. Maine NHS Roadway and Railway ROW Map



Existing Federal and Maine Procedures and Out-of-State Precedent

To explore colocation in Maine, a literature review of laws, regulations, policy, and guidance was conducted to identify existing precedents and best practices. This section provides an overview of the necessary processes for planning and deploying transmission and transportation colocation projects. These processes include regulatory procedures, technical design considerations, permitting methodologies, safety considerations, and utility relocation costs. Discussion of each process addresses Federal and Maine-specific processes detailing activities within the state, while providing alternative or innovative approaches to transportation colocation established in other states. Together, this section provides an overview of how processes are conducted within Maine today while highlighting best practices and lessons learned from other states.

Roadway Procedures and Precedent

The following sections discuss existing federal and Maine procedures and out-of-state precedent relating to transmission colocation within roadway corridors.

Evaluation of Applicable Regulatory Processes

Statutory and regulatory frameworks exist at the Federal and State level which permit or prohibit transportation colocation, specify the special circumstances that affect them, and otherwise provide general guidance. For roadway ROW, regulatory and policy frameworks exist for transmission colocation in transportation ROWs on a case-by-case basis.

Federal

Current Federal regulations outlined in 23 CFR Part 645.205 hold that transmission colocation within Federal-aid highway ROW is in the public interest so long as their occupancy is consistent with specific safety and aesthetic requirements. Specifically, transmission lines may be colocated if the occupancy does not negatively impact the safety and visual quality of the highway, and is not in conflict with other Federal, state, or local laws and regulations.[59]

The Federal Highway Administration's (FHWA) 2021 "State DOTs Leveraging Alternative Uses of the Highway Right-of-Way Guidance" Memorandum provided additional clarification for states to allow transmission accommodation in the highway ROW. The 2021 FHWA Memo outlines two methods for siting transmission in the ROW. First is to site transmission as utility (under 23 CFR Part 645). The second is to seek designation as an authorized, alternative use of the ROW under 23 CFR Part 710. If state law or policy categorizes electric transmission as a utility, then accommodation as a utility can be used.

There is no overarching Federal legislation or guidance specifically governing the colocation of transmission lines within railroad ROW as there is for roadway ROW. Such installations are typically managed at the private level. As a result, project requirements and restrictions are determined by individual railroads.

Maine

Maine regulations recognize that it can be in the public interest to colocate utilities within state-owned ROW under the condition that highway functionality cannot be compromised. Further, utilities that site facilities within the ROW are responsible for all costs and risks; MaineDOT accepts no liability.[60]

While transmission colocation is generally permitted within standard highway ROW, Maine regulations generally prohibit longitudinal transmission installations within Freeway Controlled Access Highways (COA). However, MaineDOT may issue a permit for longitudinal installations under restricted conditions.[61] Applicants for a proposed colocated transmission facility must demonstrate that a) the accommodation of the facility will not negatively affect freeway and traffic safety, b) there were no suitable alternate locations or alternate locations were cost prohibitive, c) the accommodation will not impact the operation, maintenance, and other critical activities; d) access

[59] 23 CFR 645.205, Policy: https://www.ecfr.gov/current/title-23/chapter-I/subchapter-G/part-645/subpart-B/section-645.205

[60] MaineDOT, Utility Accommodation Rules: https://www.maine.gov/dot/sites/maine.gov.dot/files/docs/utilities/locopen/2021/FINAL2021UtilAcmdnRules4-22-21.pdf

[61] 23 CFR 645.205, Policy: https://www.ecfr.gov/current/title-23/chapter-I/subchapter-G/part-645/subpart-B/section-645.205

to the facility does not require the use of roadways or connecting ramps; and e) that the accommodation will be in Maine's public interest.[62]

Other States

Similar to MaineDOT's Rules, Minnesota's Utility Accommodation Policy generally prohibits longitudinal transmission within freeway ROW with an exception reserved for special circumstances. To secure a permit for installation, utilities and transmission must provide a technical justification for colocation. This justification must prove that a) the proposed transmission accommodation will not negatively impact the safety, design, or any other critical roadway functions, b) all other alternative routes are not feasible or are cost prohibitive, c) future expansion of the freeway will not be impaired by the accommodation, d) siting the transmission line outside of the freeway ROW would result in less productive agricultural land, and, e) access to the transmission facility for construction and maintenance will not negatively impact safety or traffic operations.[63]

Wisconsin requires colocation to be considered by integrating it into the planning process for new transmission. Wisconsin statutes dictate a priority order for siting new transmission facilities. The first consideration must be given to existing utility corridors. If new transmission lines cannot be sited in existing utility corridors, highway and railroad corridors must be considered second, followed by recreational trails third.[64]

Evaluation of Select Technical Design Considerations

Technical design requirements outline the clearances, dimensions, locations, and other key guidelines for the colocation of transmission within transportation ROW. Technical design requirements for colocating within roadway ROW vary widely but can be adjusted to meet specific colocation requirements such as future relocation, impacts to scenic areas, safety, and roadway operations.

Federal

23 CFR Part 645 prohibits new utility installations on highway ROW that have used Federal-aid or direct Federal highway funds which present aesthetic implications for areas of designated scenic quality or natural beauty. These areas include public recreational areas, wildlife areas, overlooks, and rest areas. This regulation gives state Departments of Transportation the authority to make exceptions in the following circumstances. Both new underground and aboveground installations may be permitted if their installation does not require significant impacts to trees or natural features that are visible from the highway. New aboveground installations may be allowed if a) alternate locations are unavailable or cost prohibitive, b) undergrounding is not technically feasible or is cost

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[62] Ibid.
[63] Ibid.
[64] 2023-2024 Wisconsin Statutes & Annotations 1.12, State energy policy: https://docs.legis.wisconsin.gov/statutes/statutes/1/12

prohibitive, and c) the installation will use design features and materials most conducive to the aesthetic quality of the scenic area.[65]

Maine

Pursuant to 23 CFR § 645.209, new installations are prohibited in scenic areas unless they meet certain exemption criteria set by MaineDOT.[66]

MaineDOT's Utility Accommodation Rules govern the technical requirements for colocated transmission facilities in MaineDOT's ROW. MaineDOT emphasizes that the materials and construction of all facilities in the ROW must ensure a long operational lifespan and minimal required maintenance. Facilities must be located to interfere with the function of the highway and other adjacent facilities as minimally as possible. Longitudinal installations must be as uniformly aligned within the ROW to reduce possible conflicts and allow for undergrounding additional future facilities.[67]

For underground facilities in MaineDOT ROW, the minimum depth of cover is 36 inches. MaineDOT requires casing under bridge approach slabs and when located close to structural footings. Additionally, MaineDOT requires all underground electric lines to be in Rigid Metal Conduit (RMC) or in PVC Conduit. For aboveground facilities, poles should maintain a uniform clearance from other longitudinal facilities. The preferred corridor for pole lines is as close to the ROW line as practical.[68]

Other States

Given that impacts to the traveling public and roadway function are a primary consideration for transmission colocation, DOT design manuals can specify detailed requirements to mitigate indirect effects. Wisconsin Department of Transportation's (WisDOT) Highway Maintenance Manual specifies technical design requirements aimed at reducing the impact to the adjacent roadway and facilities. The Manual requires that colocated utilities, including transmission, are located in such a way that reduces the need for any future relocation of facilities in order to a) allow for future highway expansion or improvements b) minimize the impact to traffic during maintenance; c) allow sufficient clearance from existing utilities and highway structures, and; d) be located away from the 45-degree cone of support.[69]

WisDOT allows all points of access for underground longitudinal installations within the ROW of a controlled access highway so long as they are placed outside of the traffic lane clear zones. However, underground installations themselves may not be placed within the clear zone. The Manual also

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[65] 23 CFR 645.209: https://www.ecfr.gov/current/title-23/section-645.209

[66] MaineDOT, Utility Accommodation Rules: https://www.maine.gov/dot/sites/maine.gov.dot/files/docs/utilities/locopen/2021/FINAL2021UtilAcmdnRules4-22-21.pdf

[67] Ibid.

[68] MaineDOT, Utility Accommodation Rules: https://www.maine.gov/dot/sites/maine.gov.dot/files/docs/utilities/locopen/2021/FINAL2021UtilAcmdnRules4-22-21.pdf

[69] WisDOT, Highway Maintenance Manual, Chapter 9, Section 15: https://wisconsindot.gov/Documents/doing-bus/real-estate/permits/09-15-00.pdf

dictates that the minimum depth of bury for underground transmission is 24 inches, which is measured from the ground surface to the top of the facility when the facility is installed. While WisDOT does not require casing of underground facilities, it recommends casing to protect facilities, allow for future expansion, and avoid potential boring costs in the future. [70] Additionally, all appurtenant facilities associated with underground facilities must be located outside of the clear zone and as close to the ROW line as possible.

The Manual prohibits aboveground and underground installations within the clear zone, and requires them to be as close to the ROW line as possible so long as geodetic control monuments are not impacted. However, WisDOT may make exceptions in cases where no alternate locations are feasible or where the ROW boundary coincides with the edge of the clear zone.[71]

Similarly, Iowa's Utility Accommodation Policy outlines technical design considerations with the adjacent roadway's function and integrity in mind. The preferred location for underground longitudinal installations, which is generally permitted in freeway ROW, is within eight feet of the ROW boundary. On rural-type non-freeway roadways, underground installations must be located beyond the road foreslope and ditch bottom. If adequate ROW room is available, the installation should be beyond the end of any culverts at a minimum depth of 10 feet beneath the flow line. If adequate ROW room is not available, the installation should be installed at a minimum depth of 10 feet and installed using trenchless methods. On urban-type non-Freeway roadways, underground installations should be located as close to the ROW as possible.[72]

The minimum depth for underground colocated transmission within both Iowa DOT freeway and non-freeway ROW is 48 inches, though exceptions may be made for rocky terrain. No installation less than 24 inches deep will be authorized, however.[73]

Iowa DOT requires that aboveground installations be as close to the ROW line as possible and must not impact traffic safety and operations or future road or utility improvements. On rural-type non-Freeway roadways, aboveground obstructions must be as close to the ROW line as possible and outside of the clear zone. On urban-type non-Freeway roadways, aboveground obstructions must be located at least 10 feet from the back of the curb.[74]

Evaluation of Permitting Methodologies

Permitting structures at the Federal and state level dictate the process for approval, including environmental and other needed reviews. Several layers of permitting structures affect Maine. In other states, alternative permitting frameworks are associated with compressed project timelines for colocated transmission in roadway ROW. For colocated transmission in railway ROW, permitting for railway colocation is dependent on individual railroads.

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[70] Ibid.
[71] Ibid.
[72] Iowa DOT, Utility Accommodation Policy: https://iowadot.gov/media/140/download?inline
[73] Ibid.
[74] Ibid.

Federal

Federal regulations make certain exemptions for transmission projects colocated in roadway ROW for environmental review. 23 CFR § 771.117(c)(2) allows utility colocations in transportation ROW as meeting the criteria for Categorical Exclusion (CE) by the FHWA; utility colocation within transportation ROW do not typically warrant additional FHWA National Environmental Policy Act (NEPA) approvals.[75] 23 CFR § 771.118(c)(1) provides more discrete examples of what may qualify as a Federal Transit Administration (FTA) Categorical Exclusion, such as the installation of new utility facilities in the ROW including cables, utility poles, and power substations do not typically require additional FTA NEPA approvals.[76] 10 CFR Part 1021, Appendix B, B4.13 further establishes a CE for upgrades or repairs to existing powerlines.[77]

Maine

Maine's current permitting framework applies to new transmission colocation in highway ROW much like it applies to new transmission within greenfield sites, offering no expedited review of colocated lines under the Maine Public Utilities Commission (MPUC), Maine Department of Environmental Protection (DEP), or MaineDOT processes.

The permitting process outlined in Title 35-A of Maine Revised Statutes for MPUC does not allow for colocated transmission projects to be considered differently from any other transmission project. While siting transmission in transportation ROW does not automatically trigger higher approval requirements, there is no specific exemption for colocated transmission projects.

Like the permitting process for MPUC, two statutory schemes administered by DEP- Site Location of Development (Site Law) and Natural Resources Protection Act (NRPA)- do not outline exemptions for colocated transmission. Site Law governs projects that substantially impact the local environment to ensure minimal negative impact.[78] NRPA protects resources of scenic significance, recreational value, and cultural or historical significance, such as rivers and streams, mountains, wetlands, and other natural areas. Colocated transmission occupying previously disturbed ROW is not excluded or subject to different environmental reviews.

MaineDOT manages utility installations through two permits: a Location Permit to establish the physical site and a Highway Opening Permit for construction. These are issued under a framework that treats transmission equivalently to standard distribution or communication lines.[79]

Other States

[75] 23 CFR 771.117(c)(2): https://www.ecfr.gov/current/title-23/part-771/section-771.117#p-771.117(c)(2)
[76] 23 CFR 771.118(c)(1): https://www.ecfr.gov/current/title-23/part-771/section-771.118#p-771.118(c)(1)
[77] 10 CFR Part 1021, Appendix B, B4.13: https://www.ecfr.gov/current/title-10/chapter-X/part-1021/appendix-Appendix%20B%20to%20Part%201021
[78] 38 Maine Revised Statutes §481, Findings and purpose: https://www.mainelegislature.org/legis/statutes/38/title38sec481.html
[79] MaineDOT, Utility Accommodation Rules: https://www.maine.gov/dot/sites/maine.gov.dot/files/docs/utilities/locopen/2021/FINAL2021UtilAcmdnRules4-22-21.pdf

Minnesota has implemented a concurrent, rather than sequential, review process. For new transmission lines in Minnesota, a Certificate of Need, Route Permit, and Environmental Review are needed. Minnesota's permitting structure allows the process to obtain an Environmental Review to run concurrently with the Certificate of Need process. Further, a public meeting held for an environmental review can also fulfill the public comment requirement for a Certificate and Route permit. By avoiding a fully sequential review process, Minnesota's permitting structure allows for a shorter permitting timeline and helps minimize burden on state agencies and developers.[80]

Evaluation of Safety Considerations

Colocating transmission within transportation corridors can introduce adverse safety impacts if not carefully assessed and mitigated. Safety requirements for roadway transmission colocation can be made as stringent as desired. Where facilities are located and what existing safety infrastructure is in place matter. Use of specific technologies and mitigation strategies can minimize safety impacts within roadway and railway corridors.

Federal

At the Federal level, highway corridors are treated as shared corridors where utilities may be accommodated where the safety of the traveling public comes first. The safety of the traveling public is critical, but should not be the sole consideration when colocating utilities, as utilities provide an essential public good.[81] In the decision to colocate transmission within roadway corridors, 23 USC § 109 dictates that the impact to safety must first be considered, and in no situation should a project continue that demonstrates an adverse effect on safety.[82]

On Federal-aid or direct Federal highway projects, Federal regulations require new aboveground installations to be sited as far away from the roadway as possible, or along the ROW boundary if feasible. No installations should be placed within the clear zone of a highway unless there are no alternative locations or if it is not technically feasible or cost prohibitive to underground the line in that location. If a correlation is found between an existing installation and adverse safety conditions, corrective action must be taken to address safety concerns.[83]

Federal railroad safety standards do not direct the placement of utility facilities. Because of a lack of robust federal guidance, railroad colocation projects must follow the safety requirements outlined by specific railroads.

Maine

[80] Northeast-Midwest Institute, State Permitting Policies & Best Practices for Electrical Transmission in the Northeast-Midwest Region (2024): https://www.nemw.org/wp-content/uploads/2024/06/State-Permitting-Policies-for-Electrical-Transmission-NEMWI.pdf

[81] 23 CFR 645.209, General requirements: https://www.ecfr.gov/current/title-23/section-645.209

[82] 23 U.S. Code §109, Standards: https://www.govinfo.gov/content/pkg/USCODE-2024-title23/html/USCODE-2024-title23-chap1-sec109.htm

[83] 23 CFR 645.209, General requirements: https://www.ecfr.gov/current/title-23/section-645.209

MaineDOT's Utility Accommodation Rules outline safety requirements for the construction of and safety design considerations for colocated transmission within roadway ROW. During construction, as well as during maintenance or adjustment, traffic control methods as outlined by the current version of the Manual on Uniform Traffic Control Devices for Streets and Highways to reduce safety risks to and delay time for the traveling public. Additional requirements exist for construction and maintenance work occurring on freeways. A utility or developer must designate a Traffic Control Supervisor and submit a Traffic Control Plan.[84]

MaineDOT's Utility Accommodations Rules specify a minimum depth of cover of 36 inches for underground facilities. MaineDOT also states that the owner of colocated facilities is responsible for maintaining its facilities so as not to degrade the safety and function of the adjacent roadway. Owners are responsible for promptly addressing safety concerns posed by their facilities at their own expense. For all facilities in the ROW, MaineDOT emphasizes that designs should provide larger setbacks whenever possible, as these promote increased safety for the traveling public. Additionally, larger setbacks reduce the risk of conflicts with future highway expansion or projects.[85]

Other States

Like Maine and other states, Wisconsin details safety requirements for transmission colocation with a focus on mitigation of negative safety impacts. WisDOT's Highway Maintenance Manual matches the Federal safety framework for roadway colocation. WisDOT requires colocated aboveground utilities to be outside of the clear zone and as close to the ROW boundary as possible. In cases where an aboveground facility is located within the clear zone or in an area that has an accident potential higher than other areas, WisDOT may require that the facility owner install protective barriers like a crash cushion.[86]

Evaluation of Utility Relocation Costs

The discussion of utility relocation costs involves identifying which party is responsible for the costs incurred when a utility facility must be relocated from a transportation ROW, and in which circumstances. Early coordination and planning to colocate transmission away from areas where future roadway projects are planned reduces financial costs and risks for DOTs and transmission developers. Determining the party responsible for utility relocation costs depends on individual agreements with Railroads.

Federal

Under 23 U.S.C. § 123 and 23 CFR Part 645, federal funds may reimburse utility relocation costs necessitated by transportation projects, provided specific eligibility criteria are met. A utility-owned transmission facility is an eligible facility. Under 23 USC §123, when a state covers the cost of

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[84] MaineDOT, Utility Accommodation Rules: https://www.maine.gov/dot/sites/maine.gov.dot/files/docs/utilities/locopen/2021/FINAL2021UtilAcmdnRules4-22-21.pdf

[85] Ibid.

[86] WisDOT, Highway Maintenance Manual, Chapter 9, Section 15: https://wisconsindot.gov/Documents/doing-bus/real-estate/permits/09-15-00.pdf

relocating a utility facility required by a transportation project, the state may receive federal funds in the same proportion as federal funds are used on the transportation project.[87]

23 CFR Part 645.107 expands on 23 USC §123 to define eligibility, conditions for utility relocation reimbursement, and exclusions. 23 CFR Part 645.107 governs the reimbursement sought by a state DOT for expenses arising from an approved and executed DOT agreement with a utility. It also governs reimbursement for costs incurred by state DOTs that arise from agreements between FHWA and utilities.[88]

Federal guidance from FHWA stresses that states should avoid relocations whenever possible, whether reimbursable or not, to minimize the burden on taxpayers, as they will ultimately be responsible for relocation costs whether the DOT or utility is responsible. When a state reimburses a utility relocation, the taxpayer funds it; when a utility bears the cost, the ratepayer funds it. Thus, state agencies and utilities should take proper caution and planning to avoid future relocations.[89]

Maine

Under the Maine Constitution and state policy, transportation funds are strictly prohibited from being used for utility relocation.[90] The MaineDOT Utility Accommodation Rules state that transmission facility owners are responsible for the relocation or any other activity necessitated by a MaineDOT project. Further, if, to avoid relocation or reconstruction during the design phase, MaineDOT must spend its own funds for additional design efforts, the utility will be responsible for those costs. Utilities are also responsible for design change costs incurred by MaineDOT during the construction phase.[91]

Other States

Some states have shifted cost responsibility from utilities to DOTs, minimizing the financial risk for utilities to colocate transmission in transportation corridors. Minnesota Statutes Section 161.45 requires the Commissioner of Transportation, under the terms of a Constructability Report, to provide a four year notice for relocation. If less than four years is given, the commissioner must pay for 75% of the relocation costs.[92] Similar language has been introduced in other states, such as in

[87] 23 U.S. Code §123, Relocation of utility facilities: https://www.govinfo.gov/content/pkg/USCODE-2011-title23/html/USCODE-2011-title23-chap1-sec123.htm
[88] 23 CFR 645.107, Eligibility: https://www.ecfr.gov/current/title-23/section-645.107
[89] Federal Highway Administration, Avoiding Utility Relocations: https://www.fhwa.dot.gov/utilities/utilityrelo/2.cfm
[90] MaineDOT, Utility Accommodation Rules: https://www.maine.gov/dot/sites/maine.gov.dot/files/docs/utilities/locopen/2021/FINAL2021UtilAcmdnRules4-22-21.pdf
[91] Ibid.
[92] 2025 Minnesota Statutes §161.45, Utility on Highway Right-Of-Way; Relocation: https://www.revisor.mn.gov/statutes/cite/161.45#stat.161.45

Illinois.[93,94,95] These statutes create an additional financial burden to the DOT, but derisks colocated transmission projects for utilities.

Railroad Procedures and Precedent

The following sections discuss existing federal and Maine procedures and out-of-state precedent relating to transmission colocation within railroad corridors.

Evaluation of Applicable Regulatory Processes

For railroad ROW, while Maine statutes permit railroad colocation, specific requirements for colocation are left to the discretion of the individual railroads. There is no overarching Federal legislation or guidance specifically governing the colocation of transmission lines within railroad ROW as there is for roadway ROW. Such installations are typically managed at the private level.

Maine

Maine Revised Statutes authorizes transmission colocation, stating that any party seeking to colocate an electric line must secure a permit from the railroad company. In the event of a disagreement between a railroad and an entity seeking to colocate within the railroad ROW, this section vests ultimate decision-making authority with the Maine Public Utilities Commission, empowering it to intervene and formally grant the colocation permit.[96]

Two Class I railroads operating in Maine, Canadian Pacific Kansas City (CPKC) and CSX, both use similar language to state that while transmission colocation is permitted within their ROW, the primary purpose of the ROW is to operate a railroad. Any utility occupancy must not interfere with, interrupt, or endanger rail operations.[97] The St. Lawrence & Atlantic Railroad (through their parent company Genesee & Wyoming Inc.), outlines the steps for utilities to obtain a Utility Occupancy License,[98] as does Amtrak.[99] Other railroads in the state did not make readily accessible information online about transmission colocation, however it is assumed that others have similar policies and requirements.

Other States

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93 Illinois Senate Bill 2808 (2025-2026): https://www.ilga.gov/Legislation/BillStatus?DocNum=2808&GAID=18&DocTypeID=SB&SessionID=114&GA=104

94 Illinois House Bill 4995 (2025-2026): https://www.ilga.gov/Legislation/BillStatus?DocNum=4995&GAID=18&DocTypeID=HB&SessionID=114&GA=104

95 Illinois House Bill 4803 (2025-2026): https://www.ilga.gov/Legislation/BillStatus?DocNum=4803&GAID=18&DocTypeID=HB&SessionID=114&GA=104

96 35-A Maine Revised Statutes §2311, Lines along railroads; application to Public Utilities Commission when disagreement: https://legislature.maine.gov/statutes/35-a/title35-Asec2311.html

97 Canadian Pacific Railway, Utility Specifications and Application Process - US: https://www.cpkcr.com/content/dam/cpkc/community/public-works-and-utilities/CP-Utility-Specs-and-Application-Process.pdf

98 Genesee & Wyoming, Utility Occupancies: https://www.gwrr.com/services/real-estate/utility-occupancies

99 Amtrak, Utility Installations: https://www.amtrak.com/utility-installations

Wisconsin requires highway and railroad corridors to be considered second in the siting of new transmission. This is discussed in more detail above; see the Other States subsection under Evaluation of Applicable Regulatory Processes for colocation within roadway ROW.

Evaluation of Select Technical Design Considerations

Technical design requirements for railroads ensure that colocation will not negatively impact railroad functions. There is no Federal guidance for technical design requirements for railroad colocation. Similarly, in Maine, there are no state-level statutory or regulatory technical design requirements. While railroads follow industry-standard engineering guidelines, the specific technical requirements for colocation are set by individual railroads to protect their structural and operational needs of their railways. Utilities must consult the design manuals for each specific railroad to confirm technical requirements.

Other States

Technical design requirements can be left to railroads to outline or they can be outlined by the state. California and Texas are two states that have implemented technical design requirements for transmission colocation in railroad ROW at the state level, each taking two different pathways. California's Public Utilities Commission (PUC) has issued formal orders while Texas has codified standards into their Administrative Code. In addition to following these state standards, utilities must still secure private occupancy agreements and follow all the railroad's technical requirements.

Through California PUC General Order Number 95, "Rules For Overhead Electric Line Construction," horizontal clearance to rail tracks to proximate utility structures must be eight feet and six inches, though this distance may be increased or decreased depending on the specific circumstance.[100]

For aboveground installations adjacent to railroad ROW in Texas, a 10-foot horizontal clearance is required for industry track, while a 50-foot horizontal clearance is required for other track types. Unguyed poles must have a horizontal clearance of the pole height plus ten feet. Underground colocated installations within state railroad ROW must be sited as far from tracks or railroad structures as is feasible. Casing is required if the installation is within 40 feet of the centerline of the track. The minimum depth for underground transmission lines is dependent on voltage. Lines operating at 750 volts or less must be buried at least three feet below natural grade. Lines operating at greater than 750 volts must be buried at least four feet below natural grade.[101]

Evaluation of Permitting Methodologies

There are no specific Federal permitting methodologies that apply to railroad colocation, and no other states appear to serve as clear best practices in this area.

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[100] California Public Utilities Commission, General Order No. 95: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M550/K438/550438485.pdf

[101] 43 Texas Administrative Code §21.909, Utilities Paralleling Railroad Property: https://texas-sos.appianportalsgov.com/rules-and-meetings?$locale=en_US&interface=VIEW_TAC_SUMMARY&queryAsDate=01%2F16%2F2026&recordId=124363

Maine

Maine's general permitting process detailed in the roadway section for Evaluation of Permitting Methodologies likely apply to colocated projects in railroad ROW. Refer to that section above for more detail on Maine's framework.

When proposing a project, a utility or transmission developer must work with individual railroads and consult each carrier's specific permitting structure. CSX offers Longitudinal Occupancy Permits, for utilities that run parallel to the railroad or railroad property.[102] CSX outlines at a high-level their permitting process, which includes a feasibility study and full review. CPKC issues Utility License Agreements for activities such as the installation, relocation, or removal of utilities within railroad property. For underground installations at a depth of 12 inches or greater, applicants must prepare a geotechnical report and a plan for track monitoring.[103] The St. Lawrence & Atlantic Railroad requires a utility occupancy license prior to construction, followed by a Right of Entry or contractor access agreement to legally enter the railroad ROW.[104] Amtrak requires engineering and design entry permits as well as utility occupancy license agreements for all colocated installations.[105,106] Eastern Maine Railroad and Maine Northern Railway Company have no readily accessible information online about the permitting process for transmission colocation, however it is assumed that they have similar policies and requirements.

Evaluation of Safety Considerations

Similar to roadway corridors, colocation within railroad corridors must achieve mitigation of negative safety impacts to railroad operations. Federal railroad safety standards do not direct the placement of utility facilities. Because of a lack of robust federal guidance, railroad colocation projects must follow the safety requirements outlined by specific railroads.

Maine

While safety guidelines and requirements are specified by each individual railroad, both as considerations for construction activities and the location of projects, they generally align on avoiding adverse effects on the function of the railway. CSX states that all utility activities should not impact or endanger trains, tracks, or railroad facilities.[107] Similarly, The St. Lawrence & Atlantic

[102] CSX, Permitting Information Packet: https://www.csx.com/index.cfm/library/files/customers/property-real-estate/permitting/utility-permits/permit-information-packet/
[103] Canadian Pacific Railway, Utility Specifications and Application Process - US: https://www.cpkcr.com/content/dam/cpkc/community/public-works-and-utilities/CP-Utility-Specs-and-Application-Process.pdf
[104] Genesee & Wyoming, Utility Occupancies: https://www.gwrr.com/services/real-estate/utility-occupancies
[105] Amtrak, National Railroad Passenger Corporation Electrified Territory Specification for Wire, Conduit and Cable Occupations: https://www.amtrak.com/content/dam/projects/dotcom/english/public/documents/corporate/engineering-practices/engineering-specs/ce-4-specification-for-wire-conduit-cable-occupations-in-electrified-territory.pdf
[106] Amtrak, Utility Installations: https://www.amtrak.com/utility-installations
[107] CSX, Design & Construction Standard Specifications (Wireline Occupancies): https://www.csx.com/index.cfm/library/files/customers/property-real-estate/permitting/wireline-design-construction-specifications/

Railroad states that utility construction must never interfere with railroad operations.[108] Amtrak states that the primary interest of the railroad is the safety and integrity of their operations. Amtrak reviews each project independently to determine the need for the oversight of Amtrak personnel.[109] Amtrak also requires power and communication lines be constructed in accordance with Amtrak's Electrification Standards and "Safety Rules for the Installation and Maintenance of Electric Supply and Communications Lines, National Electrical Safety Code Handbook."[110] CSX requires an inductive interference coordination study for all longitudinal aerial transmission lines.[111]

Other States

Ensuring minimal interference from colocated transmission on railroad operation can be made a requirement. Under Texas Administrative Code, the Texas Department of Transportation may require the utility to pay for an inductive inference study for a proposed transmission line colocated longitudinally in railroad ROW.[112]

The SOO Green HVDC Link, a high-voltage transmission project currently under construction running between Iowa and Illinois, will utilize undergrounded bi-directional DC technology. SOO Green's HVDC Link uses direct current instead of alternating current, avoiding induced currents that can impact people and objects within the electric field. The magnetic field remaining above ground would be weaker than levels typically generated by household appliances.[113] This significantly reduces electrical and magnetic interference within rail and roadway corridors.

Evaluation of Utility Relocation Costs

Utility relocation costs are costs incurred when a transmission facility must be relocated to accommodate railroad expansion or other projects. There is no overarching Federal guidance on utility relocation costs in the case of railroad colocation as there is for roadway colocation.

Maine

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[108] Genesee & Wyoming, General Specifications for Sub-grade and Above Grade Utility Crossings of Railroad's Right-of-Way: https://www.gwrr.com/wp-content/uploads/2023/03/GWI-Utility-Specifications-rev-03072013.pdf

[109] Amtrak, Utility & Right-of-Way Occupations: https://www.amtrak.com/content/dam/projects/dotcom/english/public/documents/real-estate/Amtrak-Utility-ROW-Occupations-Policies-Procedures-093020.pdf

[110] Amtrak, National Railroad Passenger Corporation Electrified Territory Specification For Wire, Conduit And Cable Occupations: https://www.amtrak.com/content/dam/projects/dotcom/english/public/documents/corporate/engineering-practices/engineering-specs/ce-4-specification-for-wire-conduit-cable-occupations-in-electrified-territory.pdf

[111] CSX, Design & Construction Standard Specifications (Wireline Occupancies): https://www.csx.com/index.cfm/library/files/customers/property-real-estate/permitting/wireline-design-construction-specifications/

[112] 43 Texas Administrative Code §21.909, Utilities Paralleling Railroad Property: https://texas-sos.appianportalsgov.com/rules-and-meetings?$locale=en_US&interface=VIEW_TAC_SUMMARY&queryAsDate=01%2F16%2F2026&recordId=124363

[113] Pacific Northwest National Laboratory, Appendix F: Transmission in ROW Case Studies: https://www.pnnl.gov/sites/default/files/media/file/Appendix%20F%20-%20Transmission%20in%20ROW%20Case%20Studies.pdf

There is no explicit Maine statute governing utility relocation costs if a transmission line must be relocated from railroad ROW. While 35-A Maine Revised Statutes §2311 gives MPUC authority to resolve disputes between utilities and railroads, the section does not dictate which party must pay utility relocation costs. Instead, utility relocation cost responsibility is outlined in individual agreements between Railroads and utilities, or within individual railroad's policies. For example, CPKC's policy states that occupancy of CPKC ROW does not constitute a permanent easement or right to the ROW and thus any utility adjustment or relocation necessitated by CPKC will be the sole responsibility of the utility.[114]

Other States

In the absence of state guidance, utility relocation cost responsibility can be decided in conversations between transmission developers and railroads. SOO Green agreed to be responsible for the costs associated with relocating the SOO Green HVSC Link. SOO Green decided to pay a fee to occupy both rail and road rights-of-way instead of seeking an easement. Additionally, if transmission developers are responsible for relocation costs, they may be incentivized to choose corridors that are less likely to require relocation. To mitigate the possibility of relocation, SOO Green pursued segments of ROW that have a lower likelihood of expansion.[115]

Opportunities for Future Consideration

The processes reviewed from states across the country provide strategies and implementation approaches that could inform future considerations in Maine for streamlining decision-making and promoting the colocation of transmission infrastructure within transportation ROWs. Ultimately, the review of federal, state and railroad statutes, regulations, and policies, suggest that considering transportation ROW colocation requires outlining a structured and rigorous framework for approval. Such a framework would entail case-specific technical criteria, clear permitting processes, informed relocation cost responsibility, and clear design standards up front in order to effectively manage road safety, design standards, operational integrity, and other considerations.

The following potential opportunities for future consideration build upon these key takeaways to translate the lessons learned from other states and proposed solutions from review literature into a framework of actionable best practices for transportation ROW colocation.

Utilize and Partner with Existing Infrastructure

Reviewed literature suggests that utilities and transmission developers could coordinate with fiber companies to identify highly suitable transportation ROW corridors where fiber infrastructure exists.

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[114] Canadian Pacific Railway, Utility Specifications and Application Process - US: https://www.cpkcr.com/content/dam/cpkc/community/public-works-and-utilities/CP-Utility-Specs-and-Application-Process.pdf

[115] Pacific Northwest National Laboratory, Appendix F: Transmission in ROW Case Studies: https://www.pnnl.gov/sites/default/files/media/file/Appendix%20F%20-%20Transmission%20in%20ROW%20Case%20Studies.pdf

Colocated transmission could then be installed within these existing colocated fiber corridors. As a potential next step following the "NextGen Highways Feasibility Study for the Minnesota Department of Transportation," NextGen Highways identified as an action item to evaluate the feasibility for MNIT and MnDOT to colocate new fiber facilities with buried transmission in transportation ROW.[116]

Utilizing existing infrastructure to site transmission can reduce costs for utilities and transmission developers and minimize impacts to roadway and railway ROW. However, by involving fiber companies in pre-planning discussions and as colocation corridors themselves, fiber companies could expect additional complexity and time costs.

ROW Occupancy Fees

Existing FHWA guidance does not require state DOTs to charge fair market rent for ROW use, but encourages state DOTs to use any fees collected for transportation uses.[117]

Some states have implemented occupancy fees to act as an additional revenue stream for DOTs and help offset the non-monetary cost associated with a loss of exclusive ROW use. They present an additional cost to utilities. However, a utility or developer must compare this with the cost or procuring private land for transmission.

Iowa DOT outlines a fee structure for longitudinal colocation within freeway ROW based on the number of cables and total mileage. For installations where a multiduct system is required, IDOT charges $13,094.31 per mile of cable or $26,188.61 per cable installation, whichever is greater. For all other installations, IDOT charges $4,252.25 per mile of cable or $21,673.33 per cable installation, whichever is greater. All fees increase 3% annually after the 2024 base year.[118]

WisDOT outlines a fee structure for longitudinal colocation occupations on controlled-access highways based on annual average daily traffic (AADT). For routes with 100,000 AADT or less, WisDOT charges $10,000 per mile. For routes with greater than 100,000 AADT, WisDOT charges $12,000 per mile. On top of both these charges, WisDOT adds $20 per duct per mile.[119]

Safety Infrastructure

Some DOTs require guardrails or other barriers to be installed when transmission poles or other infrastructure within the ROW are installed. DOTs can secure additional safety installations at no cost to them if a proposed transmission facility necessitates additional safety infrastructure by having the poles installed behind this infrastructure. Safety barriers may additionally serve as a benefit to the transmission facility, protecting equipment and installations in the ROW. However,

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[116] NextGen Highways, NextGen Highways Feasibility Study for the Minnesota Department of Transportation: https://nextgenhighways.org/wp-content/uploads/2023/01/NextGen-Highways-Feasibility-Study-Minnesota-DOT.pdf

[117] Federal Highway Administration, State DOTs Leveraging Alternative Uses of the Highway Right-of-Way Guidance (2021 Memorandum). *Not currently accessible online*.

[118] Iowa DOT, Utility Accommodation Policy: https://iowadot.gov/media/140/download?inline

[119] WisDOT, Highway Maintenance Manual, Chapter 9, Section 15: https://wisconsindot.gov/Documents/doing-bus/real-estate/permits/09-15-00.pdf

this presents an added cost to transmission facility owners. This strategy should only be pursued when it is appropriate to do so, when it is in accordance with relevant sections of an updated Utility Accommodations Policy, and in such cases when additional safety infrastructure would benefit the traveling public. However, in some cases, a DOT seeks to avoid adding a safety barrier such as a guardrail, as adding an additional physical object in the ROW can instead present a safety risk.

Geospatial Analysis of ROW for Colocation

Several states have analyzed their transportation corridors for transmission colocation suitability. Maine has 1,315 miles of National Highway System (NHS) roadway and almost 1,000 miles of combined Class I and Class III railway. Additional roadway ROW outside of the NHS may also be analyzed. A geospatial analysis of the ROW for transmission incorporates inclusion and exclusion criteria, buffer distances, and state-specific data layers that identify if a corridor is suitable for transmission colocation. This allows DOTs and railroads to identify highly suitable areas for transmission deployment as well as optimal routes between two points.

A state-wide or corridor-specific geospatial analysis of transportation ROW for transmission colocation serves as a reference for future colocation requests and early coordination and streamlines the pre-planning process for colocation projects. DOTs and railroads can quickly identify the suitability of a given ROW corridor upon request by a utility or transmission developer. However, geospatial analyses may run into data availability challenges if particular data layers are unavailable or incomplete. This issue, as well as ROW analyses themselves, represent time and cost commitments.

The Washington state legislature directed Washington state DOT to, among other activities, identify DOT-owned highway ROW sections suitable for siting transmission or distribution.[120] This subsection of work is currently underway as of June 2025. The analysis will identify optimal colocated transmission corridors and their associated installation costs, such as vaults, trenching, and boring costs. The analysis will include cost calculations for installation, which factor in geological, environmental, and other constraints that reduce a corridor's overall feasibility for transmission colocation.[121]

Vegetation Management

DOTs and railroads can require transmission utilities to submit a Vegetation Management Schedule, which outlines the respective maintenance responsibilities and schedules for both the facility owner and the agency within the occupied ROW. By offsetting the cost and labor responsibility to the transmission facility owner, the DOT and railroads are able to share their vegetation management costs. This poses an additional cost to transmission facility owners. However, vegetation

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[120] Washington Engrossed Substitute House Bill 2134 (2024): https://lawfilesext.leg.wa.gov/biennium/2023-24/Pdf/Bills/Session%20Laws/House/2134-S.SL.pdf

[121] Washington DOT, Alternative Use of the Highway Rights-of-Way Legislative Report, January 2025: https://wsdot.wa.gov/sites/default/files/2025-01/Alternative-Use-of-Highway-Rights-of-Way-Report-January2025.pdf

management costs are likely already factored into cost decisions regardless of colocated or greenfield corridor costs.

Georgia DOT requires that all utilities colocated within their ROW submit an annual Vegetation Management Schedule for sites within DOT-owned ROW for activities including mowing and tree pruning. Georgia DOT requires utilities to submit a Vegetation Management Schedule each year to perform any vegetation maintenance activities within the bounds of a utility easement on the state highway system. Georgia DOT is responsible for mowing all ROW areas that are in good condition, have continuous turf growth, are contiguous to turf in non-occupied areas of the ROW, and are on slopes of 3:1 or less. Utilities are responsible for occupied areas that contain vegetation other than turf grass and with slopes greater than 3:1.[122]

Colocation Planning Working Groups

States can convene a working group to develop colocation planning satisfactory to various public agencies, private companies, and the general public. These groups bring together a diverse collection of stakeholders to explore changes to policy and siting. Working Groups can help mitigate conflicts between different groups and sectors, develop a consensus, and reduce risks for all parties. However, they are labor intensive and require dedicated stakeholder time.

Arizona Executive Order 2025-13, "Removing Barriers to Delivering Affordable Energy for Arizona," instructed the Governor's Office of Resiliency, Residential Utility Consumer Office, and Department of Economic Security to internally coordinate to deliver a report. One of the goals of the Task Force was to propose how to eliminate obstacles impacting the use of public lands for transmission and generation projects. The Task Force convened stakeholders from government agencies, utilities and cooperatives, state councils and commissions, private companies, universities, non-profit organizations, laboratories, and other relevant groups. In March 2026, the Task Force released their report with recommendations that included discussion of transmission colocation.[123]

In Minnesota, a working group led by MnDOT has been convened with multiple state agencies including MNIT (Minnesota IT Services), MNGEO (Minnesota Geospatial Information Office), Minnesota PUC, and Minnesota Department of Commerce. The working group plans to convene utilities and developers at a later date. As of June 2026, work is continuing. If implemented in Maine, a broad range of Maine-specific stakeholders representing the grid, roadway, and railway would need to be selected.

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[122] Georgia DOT, Vegetation Management: https://www.dot.ga.gov/PartnerSmart/utilities/Documents/VegetationMgtPolicyFinalEffective1-1-2002.pdf

[123] Arizona Governor's Office of Resiliency, Arizona Energy Promise Taskforce Report to Governor Katie Hobbs: https://resilient.az.gov/sites/default/files/2026-04/arizona-energy-promise-taskforce-report.pdf

Horizontal Blowout Accommodation

Highway and railroad ROW could be used to accommodate the blowout distance from adjacent overhead transmission facilities. WisDOT permits transmission facilities that are located on private easements to overhang DOT-owned ROW with a permit.[124] For example, highway ROW could be used to provide the horizontal clearance needed for wind-induced blowout of overhead transmission lines, rather than siting the lines within the ROW. Siting transmission lines on private land adjacent to DOT-owned ROW would utilize the highway ROW to accommodate sway, reducing the required horizontal setback of the transmission line by half.

An occupancy fee structure could also be developed for this type of accommodation as well, even without full occupancy of the ROW.

Permitting Exemptions

Drawing on the FHWA's Categorical Exclusion framework, state agencies could accelerate project timelines by carving out explicit permitting exemptions for colocation within transportation ROWs, to the extent these projects utilize previously disturbed corridors that have already undergone extensive environmental and regulatory reviews.

Constructability Reports

The DOT could require a utility or developer to submit a Constructability Report before it issues a permit. Constructability Reports, authored by a utility or transmission developer in consultation with a DOT, outline coordination terms and conditions, aligning both before a project begins. These reports allow agreement to terms early in the process and streamline the project. However, they require time to develop and coordination to address concerns from both parties.

Minnesota Statutes require MnDOT and a utility or transmission developer to develop and agree to a constructability report before MnDOT may issue a permit for transmission co-location. A Minnesota constructability report must outline the terms and conditions for a colocated facility. Additionally, in Minnesota, Constructability Reports must specify the amount of notice required for utility relocation. The DOT is responsible for 75% of the relocation costs if insufficient notice is given.[125]

Colorado Revised Statutes dictate that a transmission developer in Colorado must submit a constructability, access, and maintenance report to Colorado DOT prior to the approval of colocated projects. The report must include mitigation strategies for the impacts the proposed line may have on wildlife habitat and wildlife crossings, as well as impacts to disproportionately impacted

[124] WisDOT, Highway Maintenance Manual, Chapter 9, Section 15: https://wisconsindot.gov/Documents/doing-bus/real-estate/permits/09-15-00.pdf

[125] 2025 Minnesota Statutes §161.45, Utility on Highway Right-Of-Way; Relocation: https://www.revisor.mn.gov/statutes/cite/161.45#stat.161.45

communities. The mitigation strategy for impacts to disproportionately impacted communities must include community engagement activities.[126]

Hire expert employees from other industries

The DOT, other state agencies, railroads, or utilities could hire former industry employees to expertly guide the colocation planning discussions. For example, a utility could hire a former MaineDOT employee, or a transmission developer could hire a former employee of a railroad to help them navigate the complex requirements and policies of working with these agencies. Having a staff member with specific industry experience allows agencies and developers alike to communicate effectively across industry sectors. However, hiring and employing an additional staff member may introduce an additional cost.

SOO Green, the transmission developer for the SOO Green HVDC Link transmission project, hired a former employee of CPKC to ensure that SOO Green had the required expertise for technical conversations with CPKC regarding mitigating the project's impact on their railroad.[127]

State Agency Cooperative Agreements

An agreement between state agencies could formalize a working relationship. Cooperative Agreements ensure coordination and alignment of priorities. They allow for streamlined pre-planning processes, as alignment has already been achieved prior to new projects. The framework for coordination has also been agreed upon. However, a Cooperative Agreement requires time and effort to develop and implement.

Wisconsin DOT (WisDOT) and the Public Service Commission of Wisconsin (PSCW) entered into a Cooperative Agreement in 2009 to formally ensure that coordination between the two agencies occur to site new and upgraded transmission in transportation ROW where feasible. Through the Agreement, PSCW and WisDOT agree to promptly communicate and cooperate to ensure mutual goals are met. Through Liaison Procedures, WisDOT and PSCW agree to coordinate to provide applicants with necessary information and data, outline points of contact at each agency, and review all applications with their respective agency goals while recognizing public needs. WisDOT also agrees to integrate consideration of transmission colocation projects into its planning process.[128]

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[126] Colorado Revised Statutes 43-1-228, High voltage lines in state highway right-of-way - development projects and priorities - surcharge - study - reports - rules - definitions: https://advance.lexis.com/container?config=0345494EJAA5ZjE0MDIyYy1kNzZkLTRkNzktYTkxMS04YmJhNjBlNWUwYzYKAFBvZENhdGFsb2e4CaPI4cak6laXLCWyLBO9&crid=3c828b80-4bd3-4133-bc58-abfcd76678b8

[127] Pacific Northwest National Laboratory, Appendix F: Transmission in ROW Case Studies: https://www.pnnl.gov/sites/default/files/media/file/Appendix%20F%20-%20Transmission%20in%20ROW%20Case%20Studies.pdf

[128] NextGen Highways, Cooperative Agreement Between The Wisconsin Department of Transportation and the Public Service Commission of Wisconsin Regarding New Electric Transmission Lines: https://nextgenhighways.org/wp-content/uploads/2025/12/Final-DOT-PSC-MOU-1109.pdf

6 Existing and Emerging Technology and Construction Methods

The transmission landscape is ever evolving; emerging technologies have meaningfully broadened the toolset planners have to help address reliability, operational, and economic challenges, and a range of construction methods and approaches have been effectively deployed to strategically help navigate development barriers. On the technology side, modern advances have allowed planners to optimize the system in a way that was previously impossible; "Advanced Transmission Technologies" or "ATTs"—a catchall term for new hardware and software solutions—variously allow for greater system fine-tuning, enable higher throughput in a given right-of-way, or help reduce losses over long-distances routes. Deployed alongside more "conventional" transmission upgrades, these technologies provide a larger set of tools with which to improve reliability and address congestion.

On the construction side, transmission routes can frequently intersect areas that are environmentally sensitive, or impractical for overhead lines. This can include areas with particularly high scenic or recreational value, or development in dense urban areas where overhead space is at a premium. In these instances, strategic undergrounding of transmission solutions can provide benefits; however they also come at higher costs compared to overhead alternatives, so must be prudently explored and deployed strategically for segments facing meaningful barriers.

This section explores both emerging technologies options and their potential role within the system planning framework, as well as the costs and benefits of strategic undergrounding, and considerations for potential deployment.

Advanced Transmission Technologies (ATTs)

The suite of ATTs considered includes both hardware and software solutions that can:

+ Increase utilization of existing transmission infrastructure
+ Improve grid flexibility and resiliency
+ Support integration of renewable energy resources
+ Reduce or defer the need for certain new transmission builds

Deploying ATTs can allow planners to realize these benefits at lower cost and with less lead time than traditional transmission solutions. Currently, the grid is comprised of high-voltage AC transmission lines that connect generators (supply) to load (demand). These lines form the backbone of the bulk power grid and their development and reinforcement will continue to play an important part in delivering power across the region. However, power flows over these lines could be further optimized: currently they follow physics (impedance) and not operator intent, which can lead to instances where constraints on one line can be binding even if other lines may be underutilized. This can be exacerbated by static line ratings that reflect the most limiting environmental conditions.

Upgrading conventional transmission facilities is costly and generally takes a long time. Therefore, planners may be restricted in how quickly and cost-effectively they can manage reliability and congestion issues on the system. This is where ATTs come in: they allow for a more rapid and cost-effective response to these issues, giving planners greater flexibility at lower cost to ratepayers. They are not a panacea, however, and will not replace the "wires and poles" that make up the current grid; rather, they are a supplement that provide the opportunity to optimize the existing network and potentially defer or avoid some amount of build-out on the margin.

The best way to think about ATTs is as part of a portfolio that should be co-optimized along with the existing planning tools. That means evaluating them along with, rather than instead of, traditional wires-and-poles solutions as part of a comprehensive planning process that considers both near- and long-term needs. Otherwise, planners risk deploying ATTs in a siloed fashion that might appear efficient through a narrow lens but actually result in sub-optimal outcomes over the long-term. As a rule, planners should follow all standards of Good Utility Practice to ensure ATTs are deployed responsibly and efficiently to maximize their value within the broader grid. Jurisdictions around the world are quickly growing their experience with these technologies and so opportunities for knowledge sharing of best practices continue to grow.

Specific Types of ATTs

Dynamic Line Ratings

Planners have traditionally set static line ratings to reflect the most limiting environmental conditions, meaning that power flows are limited to accommodate the worst-case scenario. Dynamic line ratings, on the other hand, allow line ratings to be set "intelligently" in close-to real-time, allowing for greater flows that maintain reliability given actual, observed environmental conditions. This is accomplished using either *direct* or *indirect* monitoring: the former uses sensors installed on the lines themselves that monitor conditions such as temperate and sag, whereas the latter infers line conditions using environmental data like ambient temperature. ISO-NE is already planning to incorporate indirect monitoring to set dynamic ratings (which it calls "Ambient Adjusted Ratings") by the end of this year.[129]

The primary benefits of DLRs are their low cost and expedient deployment. They can easily yield near-term benefits that exceed costs. However, their effectiveness depends on local weather conditions and broader system topology: they can only resolve constraints to the extent there are not other downstream bottlenecks. So, despite their low cost, planners should still exercise care when considering DLRs as a solution. Furthermore, planners should recognize DLRs for what they are –

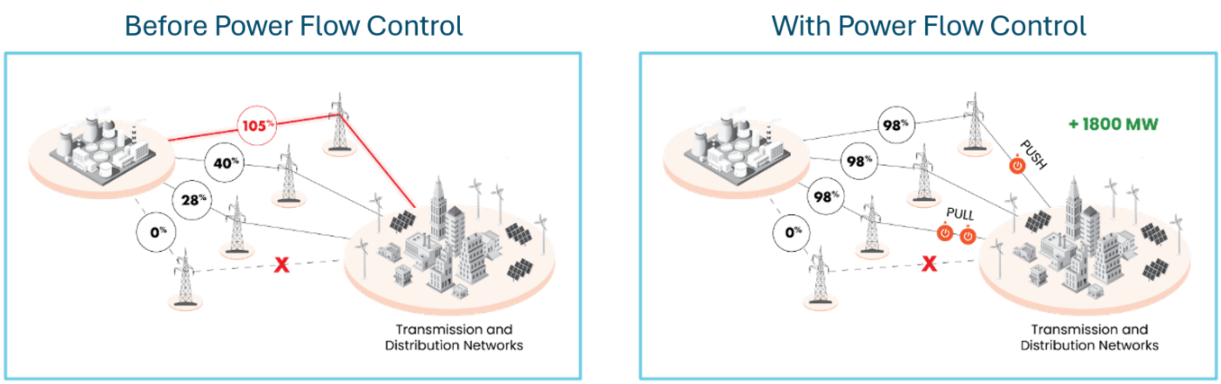
[129] ISO-NE FERC Order No. 881: Managing Transmission Line Ratings: https://www.iso-ne.com/participate/support/participant-readiness-outlook/ferc-order-no-881-mtlr

one tool that should be co-optimized with the rest, like traditional hardware upgrades, as part of a comprehensive transmission plan.

Advanced Power Flow Control

Advanced Power Flow Control or "APFCs" is a technique to direct power flows using electronic devices that dynamically adjust transmission line reactance. Unlike traditional AC system, AFPCs give operators the ability to intentionally direct power flows across the grid, rather than leaving it to physics. This allows loading across lines to be optimized, thereby reducing congestion. Like DLRs, the benefits of APFCs are their low cost and expedient deployment, however they are subject to the same considerations of co-optimization with other solutions and recognition of their limitations. Their effectiveness depends on the availability of parallel transmission pathways that can accommodate additional loading, and consequently less effective in radial-dominated portions of the grid.

Figure 23. Illustration of Power Flow Control Impact



Topology Optimization

While APFCs use hardware upgrades along individual lines to redirect power flow throughout the grid, Topology Optimization (TOs) employs software models to achieve a similar effect, identifying and deploying optimal reconfigurations to flexibly and efficiently route the flow of electricity around congested elements. TOs can be complemented by the ability of PFCs to modulate the power flow patterns across particular lines, when installed together, and are also best deployed in meshed networks.

Live topology optimization and control can also allow reconfigurations to alleviate congestion during extreme weather events. One use case is showcased by SPP's 2018 study that analyzed the opportunities of increasing power flow through lines to heat them and reduce icing which can cause line failure during severe winter conditions.[130] Given the integrated need to install power flow controls on the hardware side to maximize the benefits of topology optimization on the software side,

[130] Ruiz, P. et al., Transmission Topology Optimization: Pilot Study to Support Congestion Management and Ice Buildup Mitigation, SPP Technology Expo, Nov 2018.

implementation can be challenging, as grid operators need to understand how to utilize both the PFCs and the TO software in tandem to promote optimal power flow across the network.

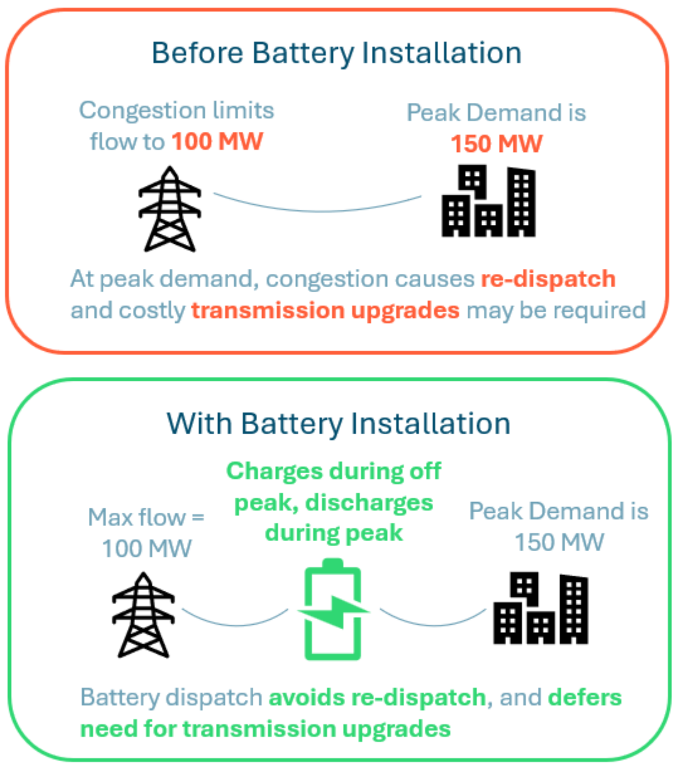
Figure 24. Illustration of Topology Optimization Impact

Storage as a Transmission Asset

Grid operators could use energy storage to avoid or defer costly transmission upgrades in cases of congestion or local reliability issues. For example, if there is a load pocket experiencing re-dispatch because of congestion, a battery could help resolve that congestion at lower cost than a strictly "wires-and-poles" solution.

The same is true in the case of addressing localized reliability needs like frequency response, inertia, and/or voltage support. In addition to generally being lower cost, storage is a mature technology that is extremely modular and can be deployed faster than traditional transmission solutions, especially in geographically isolated area. Finally, storage will remains eligible for the full investment tax credit (ITC) through 2033, and a partial credit through 2036, which can help defray its upfront cost.

Figure 25. Storage as a Transmission Asset (SATA) Illustration



Advanced Conductors

Advanced conductors are next-generation overhead transmission wires built around a composite core rather than the conventional steel core used in standard Aluminum Conductor Steel-Reinforced (ACSR) lines. The most widely deployed design is the Aluminum Conductor Composite Core (ACCC), which pairs a stronger, lighter carbon-and-glass-fiber composite core with trapezoidal-shaped aluminum strands. Because the composite core has a much lower thermal expansion rate than steel, these conductors can run at higher operating temperatures without the excessive sag that limits conventional lines, allowing them to carry significantly more power. In practice, advanced conductors can move roughly twice the current of an equivalent conventional conductor while cutting line losses by approximately 30%, which is why they have become a centerpiece of reconductoring strategies that upgrade existing lines without building new corridors.

Beyond raw capacity, advanced conductors deliver a cluster of secondary benefits: reduced line sag, superior corrosion resistance, lower energy losses, and the option to embed a fiber-optic cable within the core for monitoring and communications. Because reconductoring typically reuses existing towers and rights-of-way, it sidesteps much of the permitting, land-acquisition, and environmental review that slow new-build transmission. A 2024 study from UC Berkeley and GridLab concluded that replacing existing lines with advanced conductors could roughly double transmission capacity within existing right-of-way and help enable a 90% clean grid.[131]

The principal trade-off is cost: advanced conductors carry a per-unit price premium over conventional conductors, since the composite core and specialized manufacturing are more expensive than commodity ACSR. That premium, however, is frequently offset on a total-project and lifecycle basis, because the energy saved through lower losses, the avoided cost of new structures and rights-of-way, and the faster path to service often make reconductoring cheaper than greenfield alternatives. Several conductor types beyond ACCC exist (collectively termed High-Temperature Low-Sag, or HTLS, conductors), and the right choice depends on the line's voltage, span, and capacity requirements.

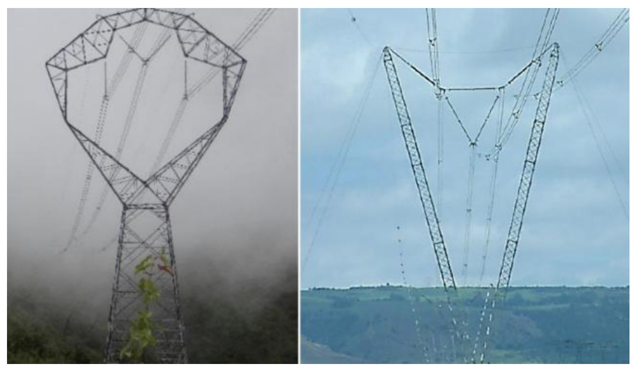
Advanced Line Design

Advanced line design refers to optimized transmission tower and structure geometries that extract more capacity, efficiency, and power quality from a given line without resorting to specialized compensation equipment. One advanced line design method uses curved steel arms and compact, optimized conductor phase spacing to reshape the electromagnetic profile of the line. Other advanced line design methods optimize conductor arrangements, materials, and monitoring systems, including compact monopoles, multi-circuit structures, low-profile aesthetic structures, composite poles and crossarms, and expanded conductor bundles. Compact structures and monopoles may reduce the physical footprint of each structure and make it easier to co-locate transmission within existing ROW. Multi-circuit structures can carry more than one circuit or voltage level on the same structure, potentially increasing transfer capability without requiring separate towers and separate ROW corridors. Phase-compacted or high-surge impedance designs improve electrical performance by lowering impedance and increasing power transfer capability. Depending on the specific design, these structures can deliver capacity increases of roughly 5-60% and efficiency (line-loss) improvements of up to 33% at native voltages, meaning utilities gain throughput without the harmonic-distortion risks that series capacitors can introduce.

[131] Accelerating Transmission Expansion by Using Advanced Conductors in Existing Right-of-Way, Energy Institute at Haas WP343R, Chojkiewicz et al., https://haas.berkeley.edu/wp-content/uploads/archive/WP343.pdf.

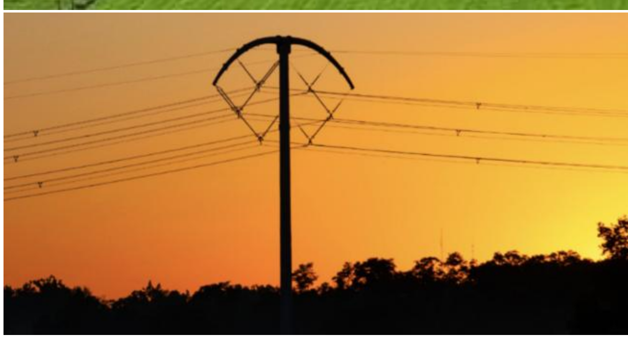
A potential advantage is easier permitting and smaller environmental footprint. Reduced structure heights, as much as 30% lower than conventional towers, can help mitigate visual impact, ease siting challenges, and reduce avian collision risk, while EMF mitigation can further smooth the permitting path. The optimized geometry typically requires new structures rather than retrofitting old ones, which lowers its savings in pure replacement scenarios. This means that deploying advanced line designs often requires a full line rebuild or new build, making these designs more costly relative to solutions that avoid tower rebuilds. Advanced line design projects are more comparable to major brownfield rebuilds or greenfield transmission builds, and in these cases, reported project costs run about 8-18% cheaper than traditional line designs. For long lines (50+ miles), advanced designs can also eliminate Sub-Synchronous Resonance (SSR) issues that can otherwise damage nearby rotating generation. There are a range of potential vendors for these advanced line design structures and components and they vary by project type. Figure 26 below shows some of the multi-circuit and multi-use transmission structures currently on the market, while Figure 27 shows T-Pylon and Curved Steel structures. .

Figure 26. (Left) Multi-circuit and multi-use configurations; (Right) Transmission Structures with Compacted Phases[132]



[132] EPRI, Advanced Transmission Line Designs for High ROW Utilization: https://www.epri.com/research/products/000000003002023331

Figure 27: (Left) T-Pylon structures[133]; (Right) Curved steel structures[134]



High-Voltage Direct Current (HVDC) Transmission

High Voltage Direct Current (HVDC) systems transmit power as direct rather than alternating current, and they can yield substantial benefits in the right applications, though high development costs mean they are best reserved for specific use cases. Compared with conventional AC lines, HVDC can increase line capacity by roughly 40-200%, with the largest advantages emerging over long distances or across water, such as subsea routes. Additionally, HVDC solutions can connect two separate asynchronous AC networks and provide precise real and reactive power controls, giving them some operational benefits in addition to the long-distance transfer capability.

The defining cost driver is that HVDC requires expensive converter stations at each end to interface direct current with the surrounding AC grid. These stations impose a meaningful upfront premium,

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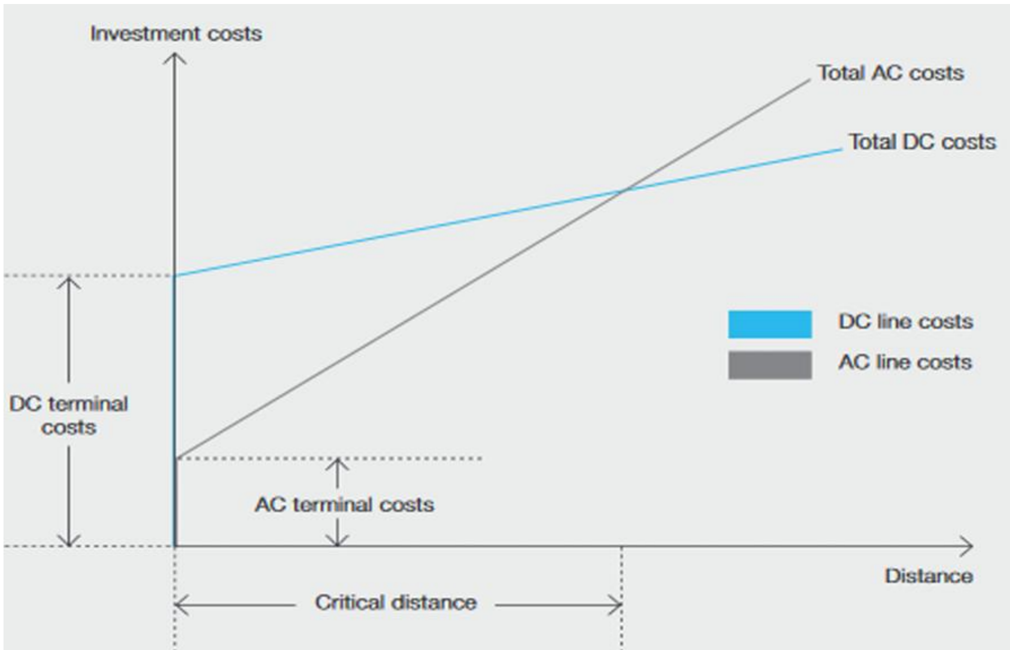
[133] National Grid: https://www.nationalgrid.com/stories/energy-explained/what-is-a-T-pylon
[134] EPRI, Advanced Transmission Line Designs for High ROW Utilization: https://www.epri.com/research/products/000000003002023331

which is why HVDC economics hinge on amortizing that fixed cost over a long, high-capacity line: there is a break-even distance beyond which HVDC's lower per-mile line cost outweighs the converter expense. As a rule of thumb, HVDC tends to become economic when more than roughly a 60% capacity increase is needed and the right-of-way cannot be expanded, or where long subsea or underground routes rule out AC entirely.

Figure 28. AV and HVDC Breakeven Cost Illustration[135]



HVDC is therefore best suited to a defined set of enabling conditions: high-capacity feeds into dense city centers, long-distance high-capacity corridors, underground or subsea lines, grids with high penetrations of inverter-based resources, and interconnections between separate (asynchronous) grids. The takeaway is that HVDC is a powerful but situational tool: transformative where its specific advantages apply, but difficult to justify for shorter, lower-capacity, or easily-sited routes.

Additional Technology Reviewed:

In addition to the above advanced transmission technologies, our team also reviewed virtual power plants for their potential to help alleviate transmission needs in select transmissions constrained areas. Though not traditionally viewed as an ATT, these can provide similar benefits as some of the ATTs discussed above.

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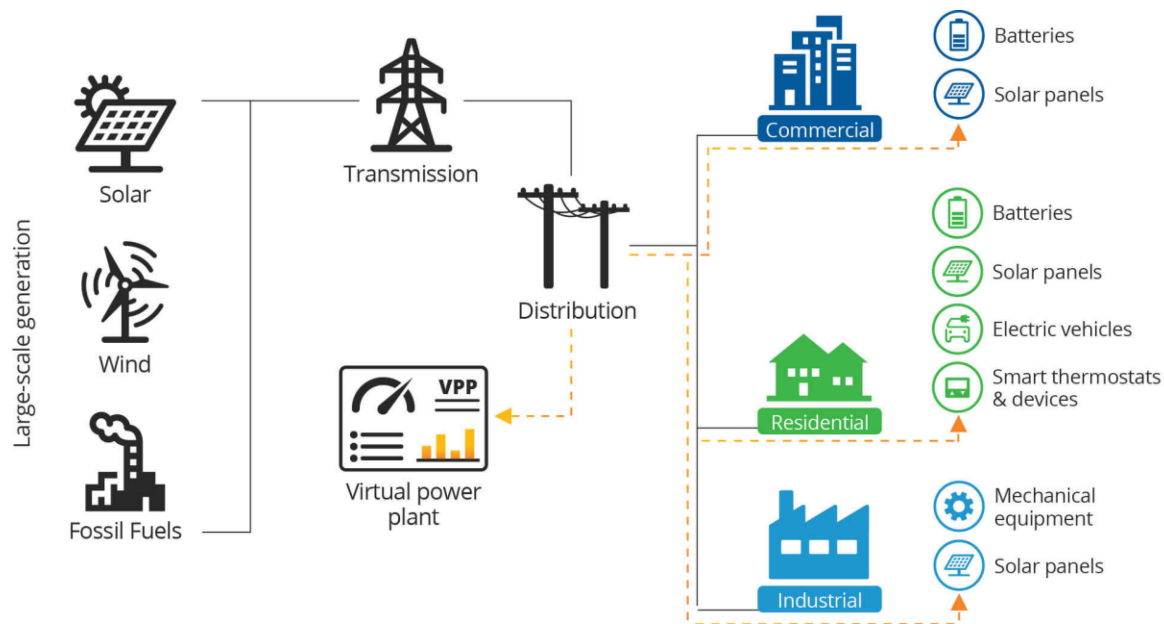
135 Graphic sourced from the Department of Energy "Advanced Transmission Technologies" report, December 2020. Accessible at https://www.energy.gov/sites/prod/files/2021/02/f82/Advanced%20Transmission%20Technologies%20Report%20-%20final%20as%20of%2012.3%20-%20FOR%20PUBLIC.pdf

Virtual Power Plants

Virtual Power Plants (VPPs) are software platforms that aggregate distributed energy resources to mimic dispatchable resources. This allows these resources, which individually may be too small to engage in market activities, to have significant impacts on grid operations. VPPs can be used to reduce grid stress by reducing load or discharging power in certain parts of the grid by using resources such as rooftop solar with batteries, EVs and chargers, and commercial and industrial loads. This can, in turn, defer or avoid investment in transmission infrastructure.

Figure 29. Virtual Power Plant Illustration



Most deployed VPPs are concentrated in states that have favorable market structures or regulatory mechanisms such as California, Texas, and New York, reflecting the importance of supportive policy, regulatory, and market design frameworks. The primary barriers to implementing VPPs are regulatory restrictions on aggregation and market participation of distributed resources, along with the necessary investments in both the hardware and software to manage them.

ATT Summary and Applications in Maine

Advanced transmission technologies such as those profiled in this section offer significant potential benefits and should be proactively considered as part of transmission planning. However, as noted throughout this section their adoption should be guided by comprehensive cost-benefit analyses to ensure they represent the most economically efficient solution for addressing identified system needs. When selected, ATT deployment should follow Good Utility Practice to maintain system reliability and maximize the performance and value of the technology. Planning processes should also remain flexible, enabling planners to evaluate an expanding range of conventional and emerging technologies over time. Ultimately, transmission planning should consistently assess all viable solutions to identify the most cost-effective portfolio for meeting system needs, while sharing implementation experiences and industry best practices to support broader and more effective adoption of ATTs.

Table 4 below provides an indication of the types of use-cases where these technologies could provide benefits in Maine, as well as some pros and cons planners should consider when evaluating these as transmission solutions. While there are no "silver bullets" when it comes to solving real-world transmission challenges, this expanded toolkit is a major step-forward, providing modern planners with many more ways to solve critical system needs than were available even a couple decades back.

Table 4. Potential ATT Applications in Maine

Technology	Description	Potential Applications in Maine	Pros	Cons
Dynamic Line Rating	Adjusting line and transformer ratings in near-real time in response to environmental conditions	May be used to increase line ratings and reduce congestion, especially during winter months	• Low cost to deploy • Does not require line rebuild. • Can yield near term benefits that more than offset costs	• Relatively small transfer impacts compared to hardware upgrades options • Depending on scale of future need this may not be "right sized"
Advanced Power Flow Controls	Changing reactance in line to change power flow direction and increase line capacity	May redirect power from congested lines to alternate circuits, reducing congestion costs. Less beneficial in radial portions of Maine's grid	• Low cost to deploy • Quick deployment • Improves reliability	• Better for mesh-networked and long-distance lines • Requires installation of hardware devices
Topology Optimization	Software models automatically reconfigure power flow routes around congested elements	May more efficiently utilize spare grid capacity to bypass congestion	• Low cost to deploy • Quick deployment • Improves reliability	• Better for mesh-networked and long-distance lines • Requires installation of sensors

Energy Storage as Transmission Asset	Energy storage to inject reactive power for voltage control and real power for N-1-1 contingency response	Strategically placed storge resources to prevent load shedding	• Can support reliability and grid resilience • Can defer need for higher cost upgrades	• Hardware deployment and complex studies • Limited to N-1-1 contingency support
Advanced Conductors	Using advanced materials in lines with enhanced performance in conducting lines	Reconductor high-usage or long lines to increase capacity. Utilize advanced conductors in new builds to gain throughput advantages	• Reconductoring is ~1/3 the cost of a full rebuild but can double line capacity.	• Cost savings are greatest where towers can get reutilized; less beneficial where towers are old. • Limited cost savings if need to rebuild towers, though throughput advantages remain
Advanced Line Design	Optimized tower designs allow for increased capacity, efficiency, and power quality	Option when rebuilding existing lines or constructing new lines	• Reported capacity increase of up to 60%, • Height reduction relative to conventional towers	• Requires full line rebuild or new build
HVDC	High-voltage direct-current transmission lines used in-place of standard alternating-current lines	Dedicated DC line from high-capacity generation region to high demand center, bypassing system limits	• Minimizes losses over long distances • Requires smaller right-of-way than comparable AC solutions	• Requires full line rebuild or new build • May be oversized depending on scale of future need

Costs and Benefits of Strategic Undergrounding vs Aerial Transmission

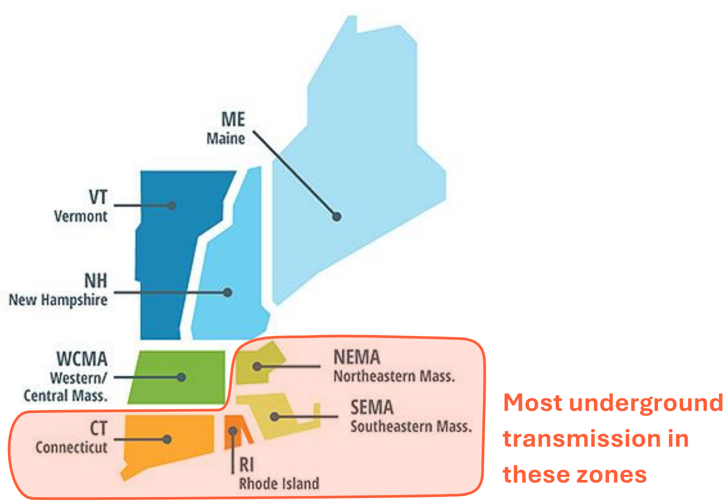
Most transmission lines in New England are constructed overhead, with underground transmission historically limited to locations where overhead construction is impractical. As interest in new transmission development grows, so too does interest in whether underground transmission may provide benefits such as avoiding aesthetic and environmental impacts or improving protection from extreme weather. But the benefits provided by undergrounding comes at a cost premium.

This section reviews the historical use of underground transmission, summarizes its primary benefits and costs, and discusses how to identify conditions under which the benefits of undergrounding justify the additional costs relative to conventional overhead transmission.

Historical Underground Transmission in New England

Underground transmission is not a new concept in New England. Many existing underground transmission facilities were constructed more than 30 years ago in dense urban areas where overhead transmission was impractical due to existing buildings, transportation infrastructure, and limited right-of-way availability. These facilities are concentrated primarily in southern New England, particularly around major population centers in Massachusetts, Connecticut, and Rhode Island.

Figure 30. Existing Underground Transmission in New England[136]



Historically, underground transmission was used primarily where physical constraints made overhead construction impractical. Most of the regional transmission system was built overhead due to its lower cost and simpler maintenance.

Recent Undergrounding Precedent

More recent transmission projects demonstrate that undergrounding has been proposed primarily to address significant community concerns regarding the visual, environmental, or land use impacts of overhead transmission infrastructure.

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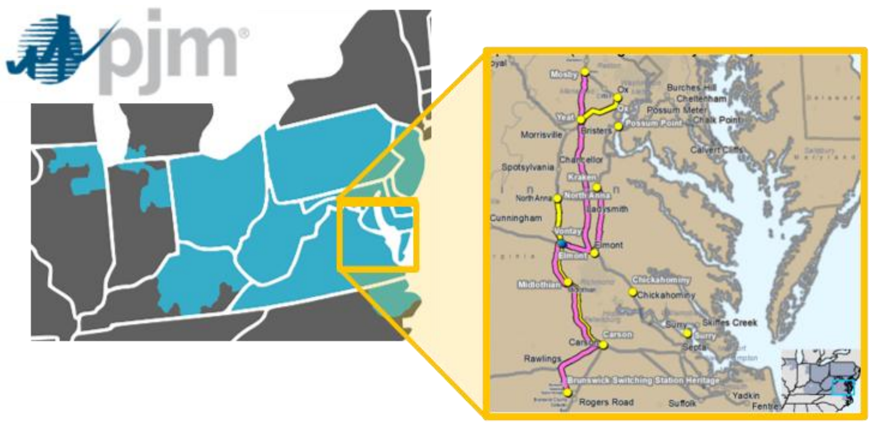
[136] ISO-NE, Maps and Diagrams: https://www.iso-ne.com/about/key-stats/maps-and-diagrams

One example is the Heritage–Mosby transmission project which was recently approved by PJM as part of their 2025 Regional Transmission Plan.[137] This project is an approximately 185-mile underground high-voltage direct current (HVDC) transmission line intended to support growing electricity demand in northern Virginia's dense Washington-area suburbs, driven in part by the rapid development of data centers. Local support for undergrounding the project, despite estimates that it would roughly double capital costs relative to overhead alternatives, was demonstrated by a letter from the Loudoun County Board of Supervisors to PJM advocating for the underground design due to its avoidance of the visual and environmental impacts associated with overhead transmission.

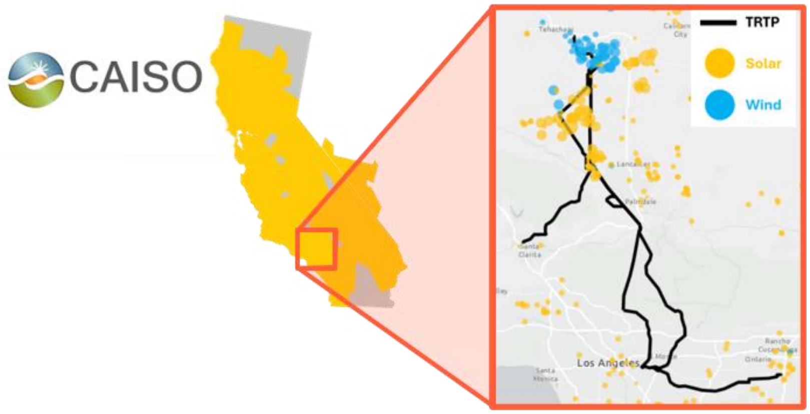
Figure 31. Heritage-Mosby Transmission Project



Another example is the Tehachapi Renewable Transmission Project in California, a 173-mile transmission project completed in 2016 designed to deliver large quantities of renewable energy from the Tehachapi region to load centers in Southern California. The project included approximately 3.5 miles of underground transmission in response to local concerns about impacts to nearby residential and recreational areas. The underground segment cost approximately $224 million, compared to an estimated $4 million for the same segment if constructed as an overhead line.

[137] PJM, Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board: https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2026/20260203/20260203-pjm-board-whitepaper-february-2026.pdf

Figure 32. Tehachapi Renewable Transmission Project



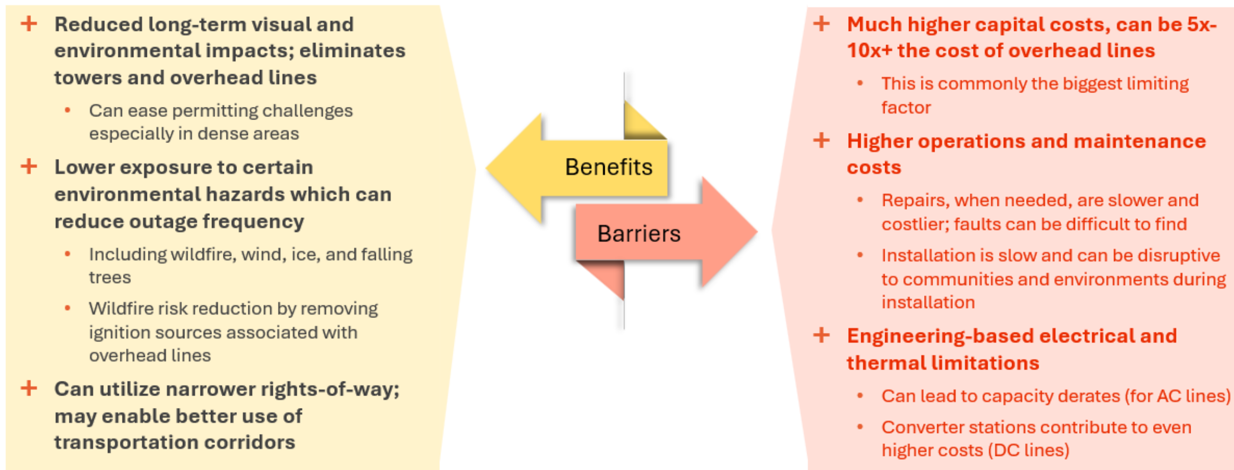
Together, these examples illustrate how undergrounding has increasingly been considered as a tool for addressing stakeholder concerns related to visual, environmental, and community impacts. They also demonstrate that in these conditions, undergrounding may be pursued despite significant cost premiums.

Benefits and Barriers of Strategic Undergrounding

The historical examples described above illustrate how underground transmission has been used in specific circumstances to address stakeholder concerns related to aesthetic and environmental impacts. As the need for new transmission infrastructure grows, there may be opportunities to deploy underground transmission in locations where it can provide meaningful benefits. However, studies evaluating underground transmission have generally found that widespread undergrounding of the transmission system would be prohibitively expensive relative to conventional overhead construction. At the same time, these studies suggest that targeted applications of underground transmission may provide benefits that justify their additional costs.

This report refers to this systematic, targeted application of buried transmission as **strategic undergrounding**. Identifying opportunities for strategic undergrounding requires consideration of both the benefits that undergrounding may provide and the barriers that may limit its applicability. This section examines these benefits and barriers (summarized in Figure 33) and discusses considerations for quantifying the costs and benefits associated with underground transmission.

Figure 33. Benefits and Barriers for Strategic Undergrounding



Benefit: Reduced Visual Impacts

The elimination of transmission towers and overhead conductors from the landscape is one of the most commonly cited benefits of underground transmission. Burying transmission infrastructure can reduce visual impacts on residential areas, scenic resources, recreational areas, and other locations where overhead transmission facilities may be perceived as undesirable. Avoiding visual impacts may also improve public acceptance of transmission projects, reducing stakeholder opposition and facilitating project siting and permitting in some cases. These considerations have influenced several recent underground transmission proposals including the PJM Heritage-Mosby line and the CAISO Tehachapi Renewable Transmission Project.

Quantifying visual benefits can be challenging because many impacts are subjective and vary by location. Several approaches have been used to estimate their value, including studies evaluating the impact of transmission infrastructure on property values, willingness-to-pay surveys that estimate how individuals value scenic preservation, and assessments of impacts to tourism and recreation. For example, studies conducted by Lawrence Berkeley National Laboratory found that transmission towers and overhead transmission lines can reduce nearby property values by approximately 5% to upwards of 20%, although the magnitude of impacts varies depending on project characteristics, proximity to the infrastructure, and local conditions. [138] In rural areas, overhead line impacts on property values can be much higher, up to 45%.[139]

Benefit: Lower Exposure to Certain Environmental Hazards

Underground transmission infrastructure may be less vulnerable than overhead lines to certain hazards, including high winds, heavy snow and ice, falling trees, and, in some regions, wildfire. As a

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[138] Lawrence Berkeley National Laboratory, A Method to Estimate the Costs and Benefits of Undergrounding Electricity Transmission and Distribution lines: https://eta-publications.lbl.gov/sites/default/files/lbnl-1006394_pre-publication.pdf

[139] Journal of Real Estate Research, The Pricing of Power Lines: A Geospatial Approach to Measuring Residential Property Values, David M. Wyman & Chris C. Mothorpe (2018): https://ideas.repec.org/a/taf/rjerxx/v40y2018i1p121-154.html

result, undergrounding may improve system resilience and reduce the frequency of outages associated with these events. While underground transmission is not immune to all impacts from environmental hazards (the impacts of flooding are discussed below), it generally avoids many of the failure mechanisms that affect overhead infrastructure during severe weather events.

The benefits associated with improved resilience can be quantified using reliability, production cost, and power flow studies that evaluate system performance under extreme weather conditions. Potential benefits include reductions in customer outages and unserved energy, avoided transmission congestion during outage events, reduced emergency repair costs, and improved reliability for critical facilities and infrastructure. The magnitude of these benefits depends on the frequency and severity of environmental hazards, the importance of the loads being served, and the physical characteristics of the transmission system being evaluated.

Benefit: Utilization of Narrow Right-of-Way

Underground transmission typically requires a narrower permanent right-of-way than an equivalent overhead transmission line because it does not require transmission towers, conductor clearances, or the same extent of vegetation management buffers. For example, a typical 345 kV overhead transmission line may require a right-of-way easement of approximately 120 to 200 feet, while an equivalent underground transmission line may require a permanent easement of approximately 40 to 60 feet. As a result, undergrounding may reduce land disturbance and provide additional routing flexibility in locations where obtaining a new overhead right-of-way is difficult. This can be particularly beneficial in developed areas, environmentally sensitive areas, or locations where physical constraints make overhead construction challenging, potentially reducing costs associated with avoiding or mitigating those constraints. However, undergrounding may also introduce different environmental impacts associated with trenching, ledge blasting, and backfilling.

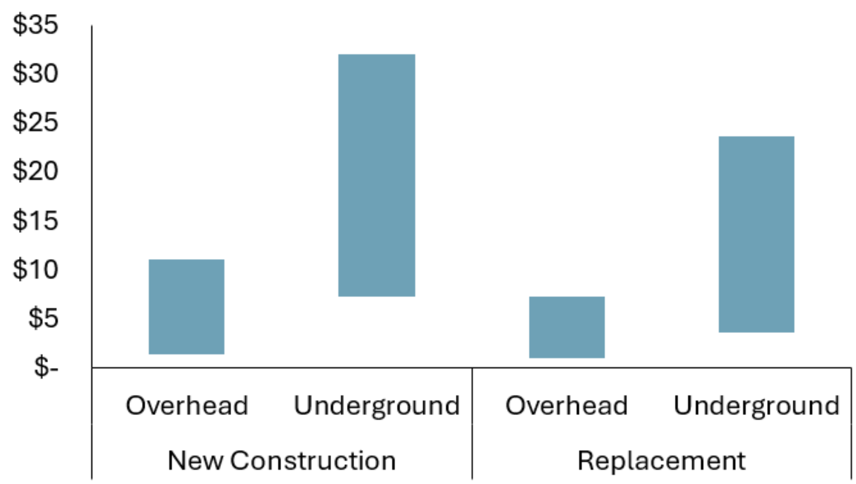
The benefits associated with reduced right-of-way requirements can be quantified through avoided land acquisition costs, reduced vegetation management expenses, and improved siting flexibility. In some cases, undergrounding may also enable routes that would be infeasible for overhead transmission due to clearance requirements, land use conflicts, or community concerns. The magnitude of these benefits depends on local land values, environmental conditions, permitting requirements, and the availability of alternative routes.

Barrier: High Capital Costs

The most significant barrier to underground transmission is its substantially higher capital cost relative to conventional overhead construction. Underground transmission requires excavation, trenching, cable installation, thermal management systems, specialized materials, and more complex construction techniques, all of which increase project costs. As a result, underground transmission projects often cost several times more than comparable overhead facilities.

The cost of underground transmission depends on several factors including voltage level, transmission technology (HVAC or HVDC), route length, geologic conditions, land use characteristics, and whether the project is new construction or a retrofit of an existing line. Costs are generally highest in locations with challenging geology, extensive utility conflicts, or dense development. Figure 34 illustrates the range of capital costs reported in a 2023 New York study for overhead and underground transmission under both new construction and transmission replacement scenarios.[140] The study found that underground transmission can generally cost more than twice as much as comparable overhead facilities. The example of the underground segment of the Tehachapi Renewable Transmission Project illustrates that in certain cases, cost premiums can be much greater.

Figure 34. Range of Underground and Overhead Transmission Capital Costs for New Construction and Replacement Projects ($ Millions per Mile)



Barrier: Higher Operations and Maintenance Costs

While underground transmission may reduce certain routine maintenance activities such as vegetation management, it introduces new operational and maintenance challenges. Underground cables operate in a complex subsurface environment and require specialized equipment and expertise to inspect, monitor, and repair. As a result, failures on underground transmission lines can be significantly more difficult and costly to address than failures on comparable overhead facilities.

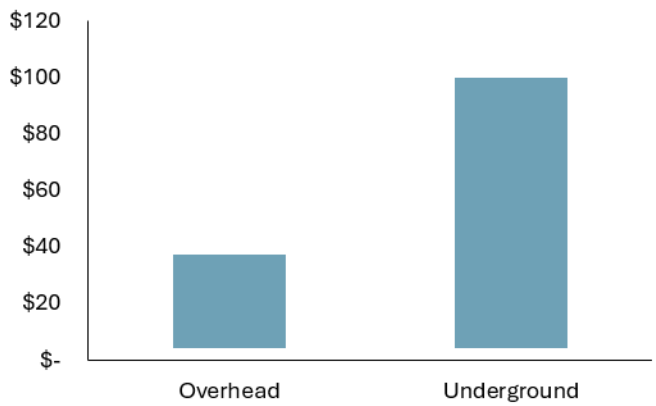
A primary challenge is fault detection and repair. When an overhead transmission line experiences a failure, the damaged equipment is often visible and accessible. In contrast, locating and repairing faults on underground transmission lines may require extensive testing, excavation, and restoration activities. Ratepayers may experience prolonged outages as repair times can range from several weeks to months depending on the nature and location of the failure, compared to hours or days for many overhead line outages. Underground transmission may also be susceptible to issues such as moisture intrusion, cable degradation, and damage associated with surrounding soil and

[140] Industrial Economics, Incorporated (Prepared for the New York State Department of Public Service), The Benefits, Costs, and Economic Impacts of Undergrounding New York's Electric Grid: https://dps.ny.gov/system/files/documents/2023/09/final-report-ny-undergrounding-2023-06-27.pdf

groundwater conditions. In areas prone to flooding or high groundwater levels, these conditions can complicate maintenance activities and increase the risk of equipment damage or failure.

The operational and maintenance implications of underground transmission can be evaluated through lifecycle cost analyses that account for inspection, maintenance, repair, and replacement costs over the life of the asset. As illustrated in Figure 35, estimates of transmission operations and maintenance costs vary widely, with reported costs ranging from approximately $4,000 to $100,000 per mile depending on the transmission technology, voltage level, environmental conditions, and maintenance activities considered. Although costs vary substantially across projects, underground transmission operations and maintenance costs can be many multiples higher than those of comparable overhead facilities.

Figure 35. Operations and Maintenance Costs of Overhead and Underground Transmission ($ Thousands per Mile)[141]



Barrier: Electrical and Thermal Limitations

Underground transmission introduces electrical and thermal challenges that are generally less significant for overhead transmission. In particular, underground alternating current (AC) cables produce substantially more capacitance than overhead lines, which can limit the practical distance over which AC transmission can be deployed. As a result, underground transmission projects longer than 50-100 miles often require high-voltage direct current (HVDC) technology, which can increase project complexity and cost.

Underground transmission cables also dissipate heat through the surrounding soil rather than directly to the atmosphere. In areas with poor thermal conditions, cables may require thermal backfill, specialized installation methods, or reduced operating capacity to avoid overheating.

[141] Industrial Economics, Incorporated (Prepared for the New York State Department of Public Service), The Benefits, Costs, and Economic Impacts of Undergrounding New York's Electric Grid: https://dps.ny.gov/system/files/documents/2023/09/final-report-ny-undergrounding-2023-06-27.pdf

The severity and cost impacts of these technical constraints depends on factors including line length, voltage level, transmission technology, soil composition, thermal conductivity, and moisture conditions.

Considerations for Identifying Future Opportunities for Strategic Undergrounding

Understanding the benefits and barriers associated with underground transmission can help identify conditions under which strategic undergrounding may warrant further consideration. This section discusses those conditions and highlights potential future applications for evaluating underground transmission projects.

The conditions described in Table 5 below are not intended to represent a prescriptive set of criteria or minimum requirements for undergrounding, nor do they all need to be present for undergrounding to provide significant benefits. Rather, they illustrate circumstances that may increase the potential for strategic undergrounding to provide significant benefits and warrant further consideration as a transmission development option:

Table 5. Favorable Conditions for Strategic Undergrounding

High aesthetic values	Areas where visual impacts from overhead transmission could affect property values, tourism, recreation, scenic resources, or community character.
Favorable right-of-way	Locations where obtaining a new overhead right-of-way is difficult, where underground routing could reduce land disturbance, or where underground routes could be significantly shorter than overhead
Higher density areas	Locations where a larger number of customers, businesses, or community assets may benefit from reduced visual impacts or improved resilience.
Favorable geology	Areas with subsurface conditions that facilitate trenching, installation, and maintenance of underground transmission infrastructure.
Adequate thermal conditions	Locations with soil and environmental conditions that support effective heat dissipation from underground cables and minimize the need for specialized thermal management measures.
High environmental hazard	Areas that experience elevated risks from severe weather, heavy snow and ice, falling trees, wildfire, or other hazards that disproportionately affect overhead transmission infrastructure.
Costly outage consequences	Locations serving critical facilities or customers for which outages may result in significant economic, public safety, or reliability impacts.

Together, these conditions provide a framework for identifying potential opportunities for strategic undergrounding. However, they are not meant to all be present for an opportunity to exist. Some may be more difficult to satisfy than others. For example, favorable geologic conditions can reduce installation costs, but Maine's extensive granite bedrock may make trenching more challenging in many areas. As a result, opportunities for strategic undergrounding are likely to vary considerably across the state and may be concentrated in locations where multiple benefits can be realized simultaneously or where one or more benefits are particularly significant.

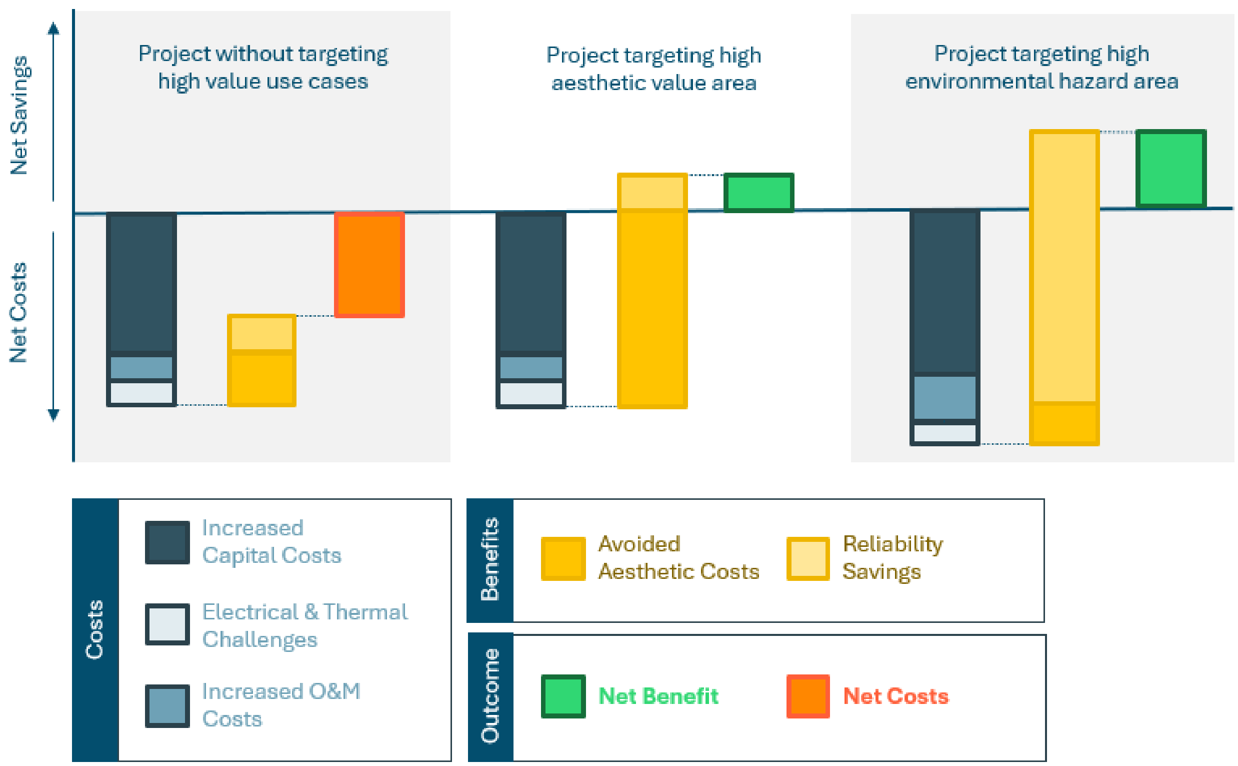
Once potential opportunities have been identified, evaluations may quantify and compare project-specific lifecycle costs and benefits across underground and overhead alternatives to assess whether underground transmission represents an appropriate solution. One approach for conducting such an evaluation is summarized below:

- Identify potential opportunities for undergrounding based on project characteristics and local conditions relevant to the list above.
- Estimate the lifecycle costs of underground transmission and comparable overhead alternatives.

+ Establish which potential undergrounding benefits and quantification methods are relevant to the community, environmental, and physical context affected by the project.
+ Quantify potential benefits.
+ Compare the estimated costs and benefits of undergrounding to determine whether net benefits may be realized.
+ Compare the results with the overhead alternative to assess whether undergrounding or traditional transmission construction may be the more appropriate solution for the specific context.

Figure 36 provides a theoretical illustrative example of how such evaluations may be represented. The figure presents three hypothetical cost-benefit comparisons using stacked bar charts that display estimated costs, benefits, and net results. The first panel illustrates a project that does not apply the strategic undergrounding approach targeting the beneficial conditions described above and the costs of undergrounding exceed the associated benefits. The second panel illustrates a project located in a high-aesthetic-value area, where visual and community benefits outweigh the additional costs of undergrounding. The third panel illustrates a project located in an area with high environmental hazard exposure, where resilience-related benefits exceed the additional costs of undergrounding. These examples are intended to demonstrate how project-specific conditions can influence the outcome of a cost-benefit evaluation and whether undergrounding may warrant further consideration relative to an overhead alternative.

Figure 36. Illustrative Cost-Benefit Analysis of Strategic Undergrounding



7 Best Practices for the Transmission Planning, Siting, Permitting, and Community Engagement

The preceding sections of this report examined Maine's transmission planning processes, project approval pathways, future transmission needs, rights-of-way utilization and considerations related to ATTs and strategic undergrounding. Together, these topics highlight the complexity of developing transmission infrastructure and the challenges associated with balancing reliability, affordability, environmental stewardship, and community interests. To identify opportunities for future improvement, these findings were considered alongside a review of literature, regulatory proceedings, and stakeholder discussions addressing transmission development challenges across Maine and other jurisdictions.

This section begins by identifying key challenges associated with transmission planning, siting, permitting, and community engagement. It then defines success criteria that reflect what effective outcomes would look like if these challenges were addressed. Finally, it summarizes best practices identified through the literature and stakeholder input that may help advance these outcomes by improving decision-making, reducing project delays, and supporting more effective development of transmission infrastructure.

Transmission Planning

Transmission planning is the process of identifying future transmission needs and evaluating potential solutions to meet those needs. Effective planning is critical to ensuring that transmission infrastructure can reliably and cost-effectively support future electricity demand, resource development, and public policy objectives.

Key Challenges

There are several recurring challenges associated with transmission planning. These challenges generally center around three fundamental questions that shape planning outcomes:

- Who pays and who decides?
- What counts as need?
- What solutions are considered?

Each of these questions encompasses a set of related barriers that can influence how transmission needs are identified, evaluated, and ultimately addressed. The challenges associated with each question are described in the sections below.

Who Pays and Who Decides?

Transmission projects often provide benefits across multiple utilities, states, and customer groups. As a result, disagreements over how project costs should be allocated can delay project development even after a need has been identified. Stakeholders also noted that meaningful participation in planning processes can be difficult due to resource limitations, technical complexity, and the significant time commitment required to engage effectively.

Cost allocation disputes. Disagreements regarding how project costs should be distributed among states, utilities, and ratepayers can delay projects during the final stages of the planning process when cost allocation approvals are required. Cost allocation concerns may also contribute to stakeholder or state opposition during permitting, particularly when parties perceive that project costs and benefits are not equitably aligned. Stakeholders may differ in their views regarding who benefits from a project and therefore who should bear its costs.

Participation barriers. Effective participation in transmission planning requires significant technical expertise, time, and resources. Limited staff capacity, resource constraints, and the complexity of planning processes can make it difficult for state agencies, local governments, consumer advocates, community organizations, and other stakeholders to engage meaningfully in planning decisions. When stakeholders are unable to effectively participate, they may have fewer opportunities to ensure that their interests are reflected in planning outcomes. This can contribute to increased opposition later in the development process, particularly during state and local siting, permitting, and approval proceedings.

What Counts as Need?

Transmission planning outcomes are heavily influenced by assumptions regarding future system conditions and the methods used to evaluate project benefits. Stakeholders may disagree on both the nature of future transmission needs and the appropriate framework for assessing them.

Selecting and quantifying benefit metrics. Planning outcomes can vary depending on which benefits are considered, how those benefits are measured, and the time horizon over which they are evaluated. There is no single standardized approach for evaluating transmission benefits, and planning regions often use different methodologies and a potential limited subset of the potential available benefit categories. For example, FERC Order No. 1920 identified 11 potential benefit metrics that may be used to evaluate transmission projects but did not require the use of any specific metric or set of metrics. As a result, differences in how reliability, resilience, economic, environmental, and public policy benefits are quantified can materially affect project selection.

Model uncertainty. Long-term forecasts for electricity demand, generation development, resource costs, technology adoption, fuel prices, and public policy are inherently uncertain. Because transmission infrastructure is typically planned and operated over several decades, often 40 years or more, planning decisions must be made despite uncertainty regarding how the electric system will evolve over time. While longer planning horizons may better capture the full benefits and costs of long-lived transmission investments, they also introduce greater uncertainty regarding future conditions. Conversely, shorter planning horizons may reduce uncertainty but risk overlooking longer-term system needs and benefits. Small differences in assumptions can produce materially different projections of future system needs, project benefits, and preferred solutions. As a result, stakeholders may disagree about key modeling inputs and assumptions or be reluctant to make decisions based on long-term modeling results, making it challenging to establish consensus around long-term infrastructure investments and their anticipated outcomes.

What Solutions are Considered?

Once a need has been identified, planning processes must determine which solutions should be evaluated and compared. Existing planning frameworks may not always be structured to consistently assess the full range of available options.

Incorporating non-traditional technologies. Traditional planning processes have historically been regionally focused and centered on conventional transmission infrastructure. As a result, non-traditional solutions, including advanced transmission technologies (ATTs), strategic undergrounding opportunities, and interregional transmission projects, may not always be evaluated consistently alongside traditional transmission investments.

Interregional collaboration. Planning processes are generally designed to identify and evaluate solutions within a single planning region. Advancing interregional transmission projects often requires coordination across multiple regions with different planning frameworks, priorities, timelines, and decision-making processes. These differences can make it challenging to align planning activities, evaluate benefits consistently, identify mutually beneficial projects, and reach agreement on cost allocation for projects that span multiple jurisdictions.

Success Criteria

To help evaluate potential best practices, it is first useful to define what constitutes a successful transmission planning process. The success criteria described below are derived from the challenges identified above and are not intended to prescribe specific outcomes or planning approaches. Rather, they identify characteristics that are commonly associated with effective planning processes in the literature and stakeholder discussions and provide a framework for assessing whether planning processes are effectively addressing those challenges and achieving their intended objectives.

Transmission planning is successful when:

- Transmission needs are identified through transparent, long-term, and scenario-based analyses that states, utilities, and stakeholders view as credible.
- Processes resolve key issues such as cost allocation, benefit assessment, and technology selection early enough to avoid repeated disputes over fundamental planning assumptions.

- Projects advance from need identification to project selection without prolonged delays caused by uncertainty regarding the need, benefits, or preferred solution.

Best Practices

Three broad categories of best practices may help address these challenges and success criteria and support more effective planning processes. These categories are described below, along with examples of potential approaches to address them.

Closing Information Gaps

Early engagement among planners, states, developers, and stakeholders can improve understanding of system needs, align expectations, and identify potential concerns before they become barriers later in the planning process. Increasing transparency and improving access to information can also help build confidence in planning outcomes.

Examples of potential solutions for closing information gaps include:

- **Active and structured engagement of states and stakeholders** throughout the planning process can improve transparency, incorporate local and regional perspectives, and build confidence in planning outcomes. Providing clear opportunities for participation and establishing defined processes for stakeholder input can help identify concerns before major decisions are made, reduce the likelihood of disputes later in the process, and support the identification of transmission solutions that better align with the needs, priorities, and interests of states and other stakeholders.
- **Early state involvement in cost allocation discussions** can help address questions regarding who pays for transmission investments and how benefits are distributed. Engaging states before major planning decisions are finalized can improve understanding of cost allocation approaches, facilitate consensus around cost allocation outcomes, and reduce the potential for disagreements that delay project advancement.

Assessing All Available Solutions

Planning processes can benefit from evaluating a comprehensive range of potential solutions alongside traditional transmission infrastructure to select the technology and project design that best meets the needs of the grid and its ratepayers. Many non-traditional solutions involve tradeoffs and may present higher costs, technical challenges, or regulatory complexities relative to conventional approaches. However, under the right conditions and in appropriate applications, these solutions may provide benefits that justify their consideration. Consistent evaluation of alternative solutions helps ensure that identified needs are addressed using the most cost-efficient and responsive approach for affected communities and the broader electric system.

Examples identified in the literature include:

- **Right-sizing transmission infrastructure** to accommodate future needs means designing transmission facilities to meet not only current system requirements but also reasonably anticipated future needs. This may involve evaluating whether projects undertaken to replace aging infrastructure could also cost-effectively expand system capability or address other identified transmission needs. Right-sizing considerations may include expected load growth, future generation development, electrification trends, evolving public policy objectives, and the selection of transmission technologies and facility designs that are appropriate for future system conditions. Incorporating these considerations during project development can reduce the likelihood of costly upgrades or replacements later in the asset's life.

+ **Consistent evaluation of advanced transmission technologies (ATTs)** alongside traditional infrastructure solutions can help increase the utilization of existing transmission infrastructure and, in some cases, defer or reduce the need for more capital-intensive investments.
+ **Consideration of strategic undergrounding opportunities** could provide net value in locations where multiple advantages can be realized simultaneously or where specific local conditions make undergrounding particularly advantageous. Incorporating strategic undergrounding into planning evaluations can help ensure that underground transmission is considered alongside other potential solutions where it may warrant further analysis.
+ **Co-location with existing road and rail ROW** may represent a potential approach for assessing all available solutions, as it can help streamline siting and permitting processes, reduce site acquisition costs, and provide aesthetic and environmental benefits, while also recognizing that such approaches may introduce their own regulatory and coordination challenges.
+ **Assessment of interregional transmission solutions** can help identify opportunities where collaborative projects spanning multiple planning regions may provide greater overall benefits than regionally contained alternatives. Evaluating interregional solutions alongside regional projects can help ensure that transmission needs are addressed using the most effective and beneficial approach across a broader geographic area.

Comprehensive Modeling

Robust planning processes rely on analytical approaches that account for uncertainty and evaluate transmission needs across a range of possible futures. Such modeling frameworks consider a broad set of benefits that reflect the needs of the grid and its ratepayers, helping to identify projects that provide value under multiple scenarios rather than relying on a single forecast. By doing so, these approaches can facilitate low-regrets investment decisions, a tool for mitigating forecast risk by making investments that are expected to deliver benefits across a wide range of potential future conditions, even if specific assumptions about the future do not materialize.

Examples of potential solutions for comprehensive modeling include:

+ **Scenario-based planning** approaches evaluate transmission needs across multiple plausible futures, including variations in load growth, resource mix, policy outcomes, and technology adoption, to better understand how different assumptions influence planning outcomes and to enable least, or low-regrets investment decisions by identifying solutions that remain valuable under a range of conditions.

+ **Long-term planning horizons** extend beyond near-term reliability needs to better evaluate benefits over timeframes that align more closely with project lifetimes and to capture how those benefits may evolve as system conditions adapt to future trends, including electrification, renewable integration, and changing demand patterns.
+ **A broad set of benefit metrics** refers to the inclusion of multiple categories of system and customer impacts in planning evaluations, including reliability, resilience, public policy objectives, congestion reduction, energy loss reductions, and investment deferral, as well as potential community-based benefits such as workforce development and funding for critical infrastructure, to ensure that planning decisions reflect the full range of potential impacts.
+ **Portfolio-based solutions** allow planners to evaluate combinations of investments rather than individual projects in isolation, enabling assessment of how multiple projects may work together to meet system needs more effectively and provide greater overall value. In addition, portfolios of projects may provide more widespread transmission benefits than individual projects, which can help facilitate cost allocation decisions compared to single projects that may primarily benefit specific sub-regions.

Current Initiatives Supporting Transmission Planning Best Practices

Several initiatives currently underway in Maine and the ISO New England region are advancing many of the planning best practices described above.

Closing information gaps. This Department of Energy Resources-led study is intended to support informed transmission planning by convening stakeholders, documenting Maine's current transmission planning, siting, and permitting landscape, and identifying opportunities for future improvement.

Assessing all available solutions. FERC Order No. 1920 requires ISO New England to evaluate advanced transmission technologies (ATTs) and consider right-sizing transmission facilities for future needs, with ISO New England required to submit its compliance filing by June 2027. In addition, Maine agencies have undertaken their own evaluations of advanced transmission technologies, including the Maine Public Utilities Commission's 2025 report on Grid Enhancing Technologies (GETs).

Comprehensive modeling. FERC Order No. 1920 also requires long-term, scenario-based transmission planning over a 20-year planning horizon. The Order recommends consideration of a broader range of benefits during planning, without requiring their use, and provides methods for quantifying these benefits.

Supporting stakeholder participation. FERC's Office of Public Participation (OPP) provides assistance and resources to help members of the public, community organizations, Tribal Nations, and other non-governmental stakeholders participate in FERC proceedings. This includes proceedings related to ISO New England's transmission planning processes and implementation of FERC policies and regulations.

Transmission Siting and Permitting

Transmission siting and permitting is the process through which proposed transmission projects obtain the approvals necessary to construct and operate new infrastructure. Effective siting and permitting processes help balance the need for timely infrastructure development with protection of environmental resources, community interests, and property rights.

Key Challenges

There are several recurring challenges associated with transmission siting and permitting. These challenges generally center around three fundamental questions that shape project outcomes:

- Who decides?
- How to engage?
- How are impacts felt?

Each of these questions encompasses a set of related barriers that can influence how transmission projects move from planning to construction.

Who decides?

Transmission projects frequently require approvals from multiple agencies operating at the local, state, regional, and federal levels. Coordinating these approvals can be challenging, particularly for projects that span multiple jurisdictions.

Fragmentation of authority. Transmission projects often must navigate multiple permitting processes administered by agencies with different regulatory responsibilities, timelines, documentation requirements, and decision-making criteria. These overlapping reviews can increase project complexity and contribute to longer development timelines.

Multi-jurisdictional benefit requirements. Many transmission projects provide benefits that extend beyond the communities or states in which they are located. As a result, projects may be required to demonstrate benefits across multiple jurisdictions, and if there is a perceived imbalance or overburdening of specific stakeholders, it can lead to resistance and increased friction in permitting processes.

How to engage?

Siting and permitting processes rely on meaningful participation from agencies, stakeholders, and the public. However, the complexity of transmission projects can make effective engagement challenging.

Lengthy and costly environmental review. Environmental review is a critical component of project development but can significantly extend project timelines and increase development costs, particularly for projects requiring multiple federal and state approvals.

Limited agency capacity. Staffing and resource constraints within permitting agencies can make it difficult to conduct timely technical, environmental, and economic reviews of increasingly complex transmission proposals. Limited capacity may also reduce opportunities for proactive coordination among agencies, planners, and project developers to ensure that the needs of the ratepayers they represent are reflected in projects seeking permits, which can help support smoother and more collaborative permitting processes.

Limited community participation. Communities most directly affected by transmission development may face practical challenges to participating in complex planning, siting, and permitting processes, particularly where resources or technical expertise are limited.

How are impacts felt?

Transmission infrastructure often produces regional benefits while concentrating many project impacts within host communities. This dynamic can create an imbalance between the distribution of benefits and burdens, which may contribute to local concerns or resistance during permitting proceedings.

Community benefits and impacts. Communities hosting transmission infrastructure may perceive limited local benefits relative to visual, land use, environmental, or construction impacts. These perceptions can contribute to vocal localized project opposition.

Revenue-impact alignment. Financial benefits such as lower electricity costs, improved reliability, or regional economic benefits may accrue across a broad geographic area, while, as previously mentioned, local communities more acutely experience project impacts. Misalignment between the perceived intensity of local impacts and more diffuse regional benefits can make it more difficult to build durable community support.

Success Criteria

To help evaluate potential best practices, it is first useful to define what constitutes a successful transmission siting and permitting process. The success criteria described below are derived from the challenges identified above and are not intended to prescribe specific outcomes or permitting approaches. Rather, they identify characteristics that are commonly associated with effective siting and permitting processes in the literature and stakeholder discussions and provide a framework for assessing whether these processes are effectively addressing those challenges and achieving their intended objectives.

Transmission siting and permitting processes are successful when:

- Projects move through coordinated, transparent, and predictable review processes
- Projects receive timely decisions while maintaining rigorous environmental and technical review
- Host communities understand how project benefits relate to local impacts and have meaningful opportunities to participate throughout the approval process
- Projects receive durable support that minimizes legal or political challenges after approvals are issued

Best Practices

Three broad categories of best practices may help address these challenges and support more effective siting and permitting processes. These categories are described below, along with examples of potential approaches to address them.

Strengthening Capacity and Effective Participation

Providing agencies, states, and stakeholders with the resources, information, and opportunities needed to participate effectively in both planning and permitting processes can improve decision-making and reduce downstream conflicts.

Examples of potential approaches include:

- **Building state, stakeholder, and community capacity** through technical assistance, dedicated staffing, and access to planning information, which enables more informed participation in technical discussions, improves the quality of feedback provided during planning and permitting processes, and helps reduce delays caused by information gaps or misunderstandings.
- **Early and sustained stakeholder and community engagement** throughout project development to identify concerns before key decisions are finalized, allowing project developers and agencies to incorporate feedback into project design, address potential conflicts proactively, and build trust with affected communities, landowners, and residents over time.
- **Structured stakeholder governance** that provides clear, recurring opportunities for participation and coordination, such as NEPOOL committees and working groups, which create predictable forums for dialogue, support transparency in decision-making, and facilitate coordination among diverse stakeholders across jurisdictions.

Clear Signals around Transmission Needs

Clearly identifying transmission needs before project development begins can provide greater certainty for developers, regulators, and stakeholders while helping to streamline subsequent siting and permitting decisions.

Examples of potential approaches include:

- **Publishing transmission priority signals** provides early guidance to developers, agencies, and stakeholders by clearly communicating anticipated infrastructure needs. By signaling where infrastructure is likely to be needed, these efforts help align expectations, reduce uncertainty, and avoid known siting barriers, whether physical, environmental, or community-based, by directing project development toward areas with demonstrated system value and fewer constraints. This approach can reduce speculative proposals and support more efficient use of agency and stakeholder resources during subsequent siting and permitting processes.
- **Streamlined determination of need** establishes a clear and well-supported project justification before detailed permitting activities begin, reducing duplication of effort and

limiting re-litigation of fundamental assumptions during later stages. By resolving core questions about need early in the process, permitting reviews can focus more directly on environmental, community, and design considerations, improving process efficiency and helping projects move through approval stages more predictably.

- **Use of regional planning studies** grounds siting and permitting decisions in a documented technical basis for identified transmission needs. Leveraging these studies ensures that decisions reflect comprehensive, scenario-based analysis of broader system conditions, providing a transparent and credible foundation for demonstrating project benefits. This approach can facilitate coordination across jurisdictions and support more consistent and informed decision-making throughout the permitting process. In some cases, it may also require regional planning processes to isolate and clearly identify both costs and benefits at the state level to support decision-making across jurisdictions.

Delivering Community Value

Projects may be more likely to receive durable support when host communities experience benefits that are more closely aligned with project impacts.

Examples of potential approaches include:

- **Community benefit-sharing mechanisms** that provide direct value to host communities by aligning project outcomes with local priorities, such as funding for infrastructure, workforce development, social programming, or environmental improvements, thereby helping to balance perceived impacts and build local support.
- **Payment-in-lieu-of-taxes (PILOT) structures** that provide stable local revenues by offering predictable, long-term financial contributions to municipalities. PILOT agreements are negotiated payments made by project developers to local governments as an alternative to traditional property taxes, often establishing fixed or formula-based payments over time. Unlike standard property tax arrangements, which may fluctuate based on assessed value and may be distributed across a broader tax base, PILOTs can provide greater certainty and allow for more direct allocation of financial benefits to the specific communities that host infrastructure and experience project impacts.
- **Consideration of community benefits during procurement** to encourage developers to incorporate local value into project proposals by making community benefits a factor in project selection, incentivizing developers to proactively design projects that respond to local needs and concerns.
- **Organized community engagement** that provides clear opportunities for ongoing dialogue throughout project development by establishing structured, transparent processes for communication, feedback, and responsiveness, helping to build trust and reduce the likelihood of conflict later in the permitting process.
- **Establish a minimum community benefit package** for transmission projects, similar to Maine's land-based wind statute. Maine's existing wind statute requires expedited wind energy developments to provide community benefits, including payments to host communities, measures to reduce energy costs for local residents, and contributions

toward land or natural resource conservation.[142] It also establishes a minimum community benefits package valued **at** $4,000 per wind turbine per year**, averaged over 20 years,** separate from the project's property tax obligations. A similar framework could be considered for major transmission projects to provide predictable, consistent benefits to host communities.

8 Conclusion

Maine stands at an inflection point in the planning of its electric transmission system, with a variety of pressures driving the need for new transmission investment in the coming years. These include growing electricity demand, aging existing assets, the development of new in-state generation resources, and the prospect of mutually beneficial power exchange improvements with the rest of New England and neighboring Canadian provinces. At the same time, emerging transmission technologies, evolving construction approaches, and new planning methodologies are expanding the range of tools available to meet these needs, creating new opportunities to balance reliability, affordability, environmental stewardship, and community interests. These collectively are placing new and different demands on a system that must simultaneously modernize and expand.

This study seeks to build a shared and accessible foundation for understanding the transmission system in Maine, providing: A) a clear description of how transmission is identified, sited, permitted, and approved in Maine today; B) a synthesis of the many independent studies that have examined the state's future transmission needs; C) an assessment of the opportunities and limitations associated with colocating transmission within existing roadway and railway corridors; D) a review of the advanced technologies and construction methods that are reshaping what is technically and economically possible; and E) a survey of best practices, in Maine and elsewhere, for planning, siting, and engaging communities on these projects. Taken together, these chapters are intended to give policymakers, agencies, utilities, developers, and the public a common set of facts and a common vocabulary as processes and specific investments unfold in the years ahead.

Several themes recur throughout this report and are worth restating as this study concludes. First, no single tool or process will meet Maine's future transmission needs on its own. Conventional overhead transmission will remain the backbone of the system, but advanced transmission technologies, strategic undergrounding, storage, and non-wires alternatives each have a role to play under the right conditions, and planning processes that fail to evaluate the full menu of options risk locking in higher costs or missed opportunities. Second, existing infrastructure, particularly transportation rights-of-way, represents a meaningful but bounded resource. Colocation may reduce land-use conflicts and ease some permitting burdens, but it is not a complete substitute for careful, corridor-specific analysis, and likely will not eliminate the need for some new greenfield routes in the future. Third, uncertainty is a permanent feature of long-term transmission planning, not a temporary condition to be resolved before decisions are made. Load growth, generation

[142] Maine Legislature, Title 35-A, § 3454

development, federal policy, and technology costs will all continue to evolve, and the planning approaches most likely to serve Maine well are those built for flexibility: scenario-based analysis, portfolio thinking, and periodic reassessment rather than reliance on a single forecast.

Finally, this study reinforces that the technical and financial dimensions of transmission planning cannot be separated from questions of process and trust. Maine already has a comparatively rich set of avenues for public participation, spanning legislative review, MPUC proceedings, DEP and LUPC permitting, and municipal processes, among others. Continuing to foster engagement through these avenues—through earlier engagement, clearer signals about anticipated needs, and closer attention to how project benefits and burdens are distributed—will do as much to determine whether future transmission projects are built efficiently as any single piece of technology or financing mechanism.

The findings compiled here are necessarily a snapshot. New studies will be published, new projects will be launched, and new technologies will mature in the years following this report's release. What should endure is the underlying approach this study has tried to model: transparent evaluation of the full range of available solutions, honest treatment of uncertainty, and sustained engagement with the communities and stakeholders who have a stake in the outcome. Applied consistently, that approach offers Maine the best chance of building the transmission system its residents and businesses will need, in a manner that reflects the state's values and secures lasting benefit for its people.

Appendix

Matrix of Reviewed Existing Analyses of Future Electric Transmission Needs

Resource (Year Published)	Analytical Approach	Future Scenarios	Need Findings
Central Maine Power (CMP) LSP (2025)	Transmission planning process that analyzes Tx infrastructure based on NERC reliability and NPCC standards, ISONE OATT, and MPUC local Tx planning criteria/Safe Harbor Stipulation document. Analyzes local Tx system (34.5-115 kV).	Uses ISO-NE's CELT load forecast (10 year planning horizon). Models generation of intermittent resources based on historical output in territory.	CMP has >500 mi of 345 kV Tx lines, >1250 mi of 115 kV Tx lines, and over 1000 mi of 34.5 kV Tx lines (non PTF). CMP's LSP identified the following projects for 2026-2028: • 6 Conceptual, 14 Planned, and 2 Proposed Reliability projects • 5 Planned and 3 Under Construction Asset Condition projects • 14 Planned and 6 Proposed Generator Interconnection projects
Versant Power's Bangor Hydro District LSP (2025)	Summary of needs assessment results, criteria, data, and study assumptions, proposed alternatives, and solution study results. Identifies Tx system criteria of system needs (34.5kV+) that are not under ISONE planning (non-PTF).***	Power flow analysis of Tx system needs using Transmission 2000**. Conducts Stability Assessment, Steady State Assessment, Fault Current Assessment, and Economic Assessment. Loads are based on ISONE MOD Case, Versant Power refine this. Use latest assumptions of Tx, Generation, and demand from ISONE's RSP.	BHD's LSP identified the following projects (2025-2029): • 8 Under Construction • 19 Planned • 7 Proposed • 14 Conceptual

Maine Won't Wait (2024)	Four-year climate action plan that includes strategies and goals to emit less carbon, increase renewable production, and address impacts of climate change	N/A	Explicitly calls out procurement of at least 1,200 MW of renewable energy in northern Maine and associated transmission
Maine Energy Plan and Maine Pathways to 2040 (2025)	Pathways analysis of how Maine might meet its clean energy and climate goals using Evolved Energy Research's (EER) EnergyPATHWAYS stock rollover tool and the Regional Investment and Operations (RIO) optimization model RIO captures the buildout of interzonal & intrazonal transmission lines, local distribution lines, and generator spur lines (but assumes no existing headroom); assumes Aroostook Renewable Gateway or similar project is built	1. Core 2. 100% Renewable Generation 3. Hybrid Heat 4. High Flexible Load 5. No Flexible Load High DER + High Flex	Buildout of T&D system required to accommodate increasing loads and facilitate balance between New England and Eastern Canada (esp. hydro): • Lower T&D upgrades required in scenarios with flexible load and hybrid heating technologies • New resource integration drives upgrade need (e.g., Aroostook County and Gulf of Maine) • 3 GW of transmission upgrades by 2040, esp. in southern ME • 4.6 GW of regional upgrades connecting to rest of New England required by 2040 • Increase HQ transfer capacity from 1.2 GW from NECEC to 5 GW by 2050 • Overall transfer capacity with Canada increases from 2 GW to 12.3 GW by 2050 under Core and 16.5 GW under 100% Renewable Generation EER specifically calls attention to the following needs: 1. Regional upgrades between Maine and Boston (or "North-South/Boston Import upgrades") 2. Upgrades to access 1.2–2.4 GW of onshore wind from northern Maine

			Upgrades to interconnect up to 3 GW of offshore wind in the Gulf of Maine.
Maine Offshore Wind Roadmap (2023)	Broad-reaching, strategic development plan for the offshore wind industry in Maine plus several technical reports, including Offshore Wind Transmission Technical Review (August 2022) and Wind Energy Needs Assessment (November 2022)	N/A	Identifies regional transmission as a strategic priority, incl. engagement with the New England Regional Transmission Initiative, ISO-NE, and FERC; Request for Interest on transmission with MA, NH, CT, & RI; developer access to project financing; support for HVDC technology advancement Highlights importance of offshore transmission "backbones" to minimize ecosystem impacts; co-location of onshore transmission cables with existing linear development (e.g., existing roads or transmission corridors)
Wind Energy Needs Assessment (2022)	Scenario analysis of offshore wind development in the Gulf of Maine under range of potential future electricity supply and demand conditions	Includes three supply scenarios that vary the amount of land-based transmission and renewable energy development costs: 1. Constrained Onshore Development (COD): Northern Maine line build (1,200 MW), but no incremental onshore transmission in Maine beyond ~800 MW of projects in pipeline 2. Unconstrained Onshore Development (UOD): no constraints on resource	COD scenario effectively increases competitiveness of OSW; under UOD scenario, no incremental OSW is built beyond research array and Monhegan due to high cost of floating turbines; additional ~1 GW of onshore transmission assumed under DP scenario still constrains onshore wind, so offshore wind remains economic Key takeaway is that additional onshore transmission capacity unlocks lower cost onshore wind, avoiding need for floating turbines; this finding should likely be investigated further using resource adequacy model to ensure sole reliance on onshore resources remains reliable

		selection or transmission development; aggressive offshore wind cost reduction 3. Diverse Portfolio (DP): constrained offshore development plus additional onshore transmission (~3,000 MW of total capacity)	
Greater Portland Certificate of Public Convenience and Necessity (2025)	CMP states the project is "necessary to resolve anticipated reliability criteria violations and ensure reliability for the Greater Portland area…The needs identified by CMP are driven by forecasted load growth in the area and asset condition." Petition was filed in Docket 2025-00276.		Phase 1 includes: • A new 115kV Tx line from Raven Farm Substation in Cumberland to Bayside Substation (12.2 miles total) • A new 115/12.47kV substation (East End of Downtown Portland) • Expansion of two existing substations in Cumberland and Portland • One substation demolition in Yarmouth • Rebuild of three 34.5kV transmission line sections (20 mi) Total cost: $546.97 M (-25/+50%) Phase 2 anticipates: • A new 115 kV connection between Bayside Substation and the South Portland Loop • A new 115 kV transmission line between Old Orchard Beach and Scarborough • Other upgrades and asset renewal in South Portland Loop

Northern Maine Independent System Administrator (NMISA) 7-Year Outlook (2025)	NMISA conducts annual outlook for planned development of Northern Maine Transmission System (NMTS) with seven-year horizon: 1. Load forecast 2. Generation resources 3. Resource adequacy 4. Transmission planning Includes overview of any system impact studies performed by Transmission Owners (TOs), including steady state, stability, and short circuit analyses.	A single Base Case designed to inform market participants of any forecasted long-term deficiency in resource adequacy or transmission capability.	Routine annual capital projects projected for planning period include a series of capitalized maintenance projects by Versant Power Maine Public District (MPD) that are likely to increase system reliability and decrease transmission O&M expenses. These projects are not expected to increase the Total Transfer Capacity (TTC) of the MPD system, which currently sits at 134 MW for both imports from and exports to New Brunswick.
Northeast States Collaborative's Strategic Action Plan Whitepaper (2025)	Multi-state, interregional transmission planning framework based on a synthesis of existing national and regional studies: • DOE 2023 Tx Needs Study, DOE NTPS, GE-NRDC study, MA Decarbonization Pathways study, LBNL IREZ study, NERC ITCS study Includes a qualitative analysis of gaps in current ISO/RTO processes and identifies "low-regrets" projects through RFIs and coordinated state-led evaluations.	1. No Decarbonization 2. High decarbonization, moderate load 3. High decarbonization, high load	Identifies consistent and low-regrets needs for interregional Tx, including: • 2 GW between NY and PJM by 2035, and 4 GW by 2040 (up to 6 GW for high decarbonization, high load scenarios) • 1.7 GW between NY and ISO-NE by 2035, and 3 GW by 2040 (up to 7 GW for high decarbonization, high load scenarios) • 0.4 GW by 2033 and 5 GW by 2050 between Quebec and ISO-NE • 1.9 GW by 2033 and 5 GW by 2050 between Quebec and NY
ISO-NE Regional System Plan (2025)	Summarizes updated load forecasts, new supply resources, and resource adequacy. Includes overview of reliability, economic, and public policy transmission studies performed by ISO-NE.	N/A	Reliability Transmission Upgrades (RTUs) • For June 2025 through end of 2028, estimated cost of RTUs currently under construction is ~$0.45B • 20 project components currently proposed, planned, or under construction System Efficiency Transmission Upgrades (SETUs) • No solutions identified to date due to RTU-driven benefits and development of economic resources in response to wholesale markets Asset Condition Projects

			• Estimated $5.8B in spending through 2032
Economic Planning for the Clean Energy Transition (2024)	Study of potential economic challenges to clean energy transition that includes 33 scenarios and over 2,800 simulations.	Three core scenarios: • Benchmark • Market Efficiency Needs • Policy	Designing power system requires balance of reliability, economic efficiency, and carbon-neutrality. • Most paths to low-carbon grid involve high variability in supply and demand • Increased variability will require vastly different supply levels from year to year • Emissions reductions are seasonal • Renewable-only build-outs may be vast, with later additions seeing diminishing economic and environmental returns • Higher variability increase value of dispatchable resources • Current revenue structures may not adequately compensate resources for their value to the grid • Firm, dispatchable, zero-carbon generation could help • Difficult minimum load conditions, energy adequacy challenges, and potential system congestion may appear in 2030s

Future Grid Reliability Study (FGRS) Phase 1: 2021 Economic Study (2022)	Hourly production cost simulation of security-constrained unit commitment and economic dispatch model, ancillary services analysis via an augmented production cost model, RA screen, and probabilistic resource availability analysis	32 future scenarios/alternatives of varying resource mixes and load profiles for 2040, with 4 main scenarios: • Low Decarbonization • Moderate decarbonization • Import-Supported Decarbonization • Deep Decarbonization	• All FGRS Scenarios found the need for multiple 345 kV AC Tx lines • Increase Tx limits in Northern NE and SEMA/RI area • Electrification of heating/transportation will drive up to 33 GW of new demand by 2040 (Scenario 3) and require transmission upgrades • Future studies should use nodal modeling of Tx system instead of 13 zone 'pipe and bubble' model, and share with NYISO • FGRS Phase 1 (2022) did not include cost of Tx upgrades)
ISONE's 2050 Transmission Study (2024)	Regional transmission needs assessment based on load forecasts and future portfolios from Massachusetts' "All Options Pathway" from the Deep Decarbonization Roadmap, published in December 2020. Contingency analysis of snapshot years restricted to thermal steady-state analysis, not voltage, short-circuit, or transient stability. Tested peak load boundary conditions (i.e., most extreme cases of combined load and renewable resource outputs), which typically occur during cold winter peak hours when weather conditions result in low renewable production.	Single scenario ("All Options Pathway") with three snapshot years (2035, 2040, and 2050), combination of winter and summer load forecasts, and potential resource mixes for 13 "snapshots" in total: • Highest load modeled was 2050 winter evening peak snapshot at approximately 57 GW	Key takeaways related to transmission include: • Reducing peak load significantly reduces transmission cost (esp. above ~51 GW, after which upgrades are roughly double in cost) • Incremental upgrades can be made as opportunities arise (e.g., reconductoring, bundling multiple conductors per phase on 115 kV lines, or upgrading existing lines) • Location of generators vis-à-vis load centers affects overloads (esp. in import-constrained areas like Boston) • Transformer capacity is crucial as reliance on high-voltage transmission increases (esp. 345/115 kV transformers that were not designed to handle large loads assumed in study) High-likelihood concerns flagged by ISO-NE that are relevant to Maine: • Maine-New Hampshire and North-South transmission interfaces connecting Maine and New Hampshire to northeastern Massachusetts

Offshore Wind Analysis (2025)	In response to feedback on initial study, ISO-NE conducted N-1 and N-1-1 DC thermal steady-state analysis to address following topics: 1. Offshore wind relocation: connecting further south to reduce overloads on North-South interface 2. High-level offshore wind interconnection screening: examine potential POIs for viability	Examines subset of high-likelihood concerns and roadmaps from initial study • Relocates Gulf of Maine wind farm POIs from Yarmouth, ME to Brighton, MA and Orrington, ME to Ward Hill, MA • Relocates MA/RI lease area POI from Brighton, MA to Millstone, CT	Connecting some of initial study's hypothetical future offshore wind further south could reduce necessary upgrades: • Relocating offshore wind POIs from Maine to Boston area may lead to significant transmission cost savings • System still needs upgrades on North-South and Maine-New Hampshire interface Around 9,600 MW of additional onshore wind may be able to interconnect in New England without new transmission infrastructure: • Up to 86% of existing major coastal substations may be able to interconnect 1,200 MW of offshore wind without new transmission infrastructure; up to 38% may be able to do so without any upgrades to existing transmission infrastructure either • A small subset of these substations may be able to interconnect 2,000 MW without any new transmission infrastructure • Depending on location, up to 9,600 MW of wind farms may be able to operate simultaneously at full output without new transmission infrastructure or significant curtailment

Increasing New England Loss of Source Limit (2025)	Joint interregional study by ISO-NE, NYISO, and PJM evaluating the feasibility of increasing New England's maximum allowable single-source contingency above the current 1,200 MW limit. The study included transfer analysis, N-1 steady-state analysis, and stability analysis to assess impacts on the interconnected system and identify transmission reinforcements that may be required.	Evaluated the planned future transmission system under a potential increase in the New England Loss of Source limit from 1,200 MW to 2,000 MW, including sensitivity analyses of large resource contingencies in New England and neighboring systems.	Findings: • The current 1,200 MW Loss of Source limit should remain in place under the planned system. • Increasing the limit to 2,000 MW would require transmission reinforcements, including upgrades on the New York–New England interface, and potentially additional upgrades on NYISO's Central East interface and the PJM–NYISO interface. • Additional work is needed to resolve operational and implementation issues, including identifying future 2,000 MW resource locations and developing operating procedures before any increase could be implemented.
NYISO 2023-2042 System & Resource Outlook (2024)	Summary of NYISO's Comprehensive System Planning Process (CSPP), including potential resource and transmission development driven by economic or public policy needs. • Potential resource mixes that achieve New York's public policy mandates, while maintaining reserve margins, and capacity requirements • Regions of New York where renewable or other resources may be unable to generate at their full capability due to transmission constraints; • Extent to which these transmission constraints limit delivery of renewable energy to consumers • Opportunities for transmission investment that may provide	Five potential futures in which New York achieves its climate change policy requirements: • Base Case: similar to status quo • Contract Case: evaluates impact of ~16 GW of additional renewable capacity procured by state • (3) Policy Case: State Scenario, Higher Demand, Lower Demand	Transmission findings: 1. Historic levels of investment in the transmission system are happening, but more will be needed. 2. Additional dynamic reactive power support must be added to the grid in upstate New York to alleviate congestion and fully utilize the transmission capability of the Central East interface. 3. Opportunities for further transmission investment in Western and Northern New York should be monitored as resources are developed in those regions. 4. Planning energy exchange with neighboring systems is becoming more complex and will be increasingly so in the future as each system transitions to more decarbonized systems.

	economic, policy, and/or operational benefits.		
Hydro-Québec Action Plan 2035 (2023)	Establishes priorities and long-term strategic approach for Hydro-Québec over the next ten years.	N/A	Calls for $45-50B of investment by 2035 to increase capacity of transmission system and maximize access to new generation resources. Three lines are currently under development: 1. Côte-Nord 2. Vallée-du-Saint-Laurent 3. Appalaches-Bas-Saint-Laurent
New Brunswick Power Energizing Our Future: Strategic Plan 2023-2035 (2023)	Strategic plan designed to help New Brunswick achieve its climate and clean energy goals.	N/A	In response to growing load and aging assets, NB Power must invest in new clean energy and the transmission grid. • Adopt smart metering and advanced distribution management systems • Upgrade grid to handle increased demand, two-way power flows, etc. • Develop smart grid technologies for monitoring and outage response

New Brunswick Power 2023 Integrated Resource Plan (2023)	Long-term picture of New Brunswick's energy supply and demand, with focus on reducing GHGs and achieving net-zero electricity system by 2035. Typical IRP process in which input assumptions developed, technical and policy constraints defined, and least-cost portfolio identified via capacity expansion and production cost modeling.	Scenario matrix with two dimensions (electrification and technological development): 1. Scenario A: high electrification, rapid technological development 2. Scenario B: high electrification, moderate technological development 3. Scenario C: low electrification, moderate technological development 4. Scenario D: low electrification, rapid technological development	Alleviate transmission constraints through new infrastructure, targeted demand reductions, and strategically located generation. Integration of new wind drives need for transmission, but operational studies required. Decisions around two plants, Belledune and Mactaquac, have significant impacts on transmission requirements to maintain system reliability. NB Power also identified opportunities to expand interregional transmission capacity with Québec and Nova Scotia. • Active participant in the federal government's Atlantic Loop initiative, which seeks to define transmission upgrades required to deliver clean power from Québec or Newfoundland and Labrador to the Maritimes. • A sensitivity exploring Atlantic Loop, which includes an additional 1,150 MW of transmission between Québec and New Brunswick, found the project helped the region achieve decarbonization but increased costs for residents by 7-9% during the 2040s. • A lower cost solution would be to simply build carbon-free resources in New Brunswick.
New Brunswick Power Renewable Integration and Grid Security Project (2025)	N/A	N/A	New 500 MW generator in Westmorland County and >$300 million in transmission upgrades to facilitate integration of intermittent renewables.

DOE's National Transmission Needs Study (2023)	Aggregating and synthesizing results from multiple prominent national transmission modeling efforts, providing ranges of findings	The studies were grouped into categories based on their underlying assumptions on load growth and clean energy penetration. Moderate load growth is defined as being between a 2021 baseline of 3,974 TWh and 7,000 TWh. High load growth exceeds 7,000 TWh. Moderate clean energy penetration ranges between the 2021 baseline of 38.6 percent and 80 percent by 2040. High clean energy penetration exceeds 80 percent by 2040. Interregional transmission capacity expansion results in these studies are reported as the percent increase by category groupings and by year (2030, 2035, and 2040).	Significant intra- and inter-regional transmission investments necessary by 2035, esp. under high load and clean energy growth scenario: • New England transmission need expected to increase by 126% relative to 2020 system under high load and high clean energy growth • Inter-regional transfer capacity between New England and New York expected to increase by 255% under moderate load and high clean energy growth, 835% under high load and high clean energy growth
DOE Atlantic Offshore Wind Transmission Study (2024)	Compares varying Tx planning and topology to unlock 85 GW of OSW by 2050.	Models OSW buildout to 85 GW by 2050. Load scenarios include: 1. Reference/Moderate electrification 2. High electrification 3. Deep decarbonization/net-zero Generation scenarios include OSW buildout, high renewables mix, reduced fossil gen, storage deployment, and imports/interregional flows	• Tx costs range from \$96B-\$116B, with radial being the base case (cheapest), and costs increasing from intra- to inter- to inter-intra regional, and finally a backbone being the most expensive • Tx upgrades would add 27 GW of OSW to ISO-NE

DOE Grid Resilience and Innovation Partnership (2023 & 2024)	Funding allocated for grid modernization and resilience	N/A	Maine-specific Projects: 1. Georgia Tx Corporation: Smart Technology for Advanced Resilient Transmission (START) Project ($92.9M Grid Resilience Utility and Industry Grant) 2. Central Maine Power: $30.3M Smart Grid Grant 3. Maine Governor's Energy Office: $65.4M Smart Grid Grant 4. MA Dep. Of Energy Resources: $389.3M Grid Innovation Grant