Eastern Canada - Northeast U.S. Interregional Transmission Planning Roadmap

Prepared for:

Northeast Grid Planning Forum (NGPF)

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POWER ADVISORY

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Prepared by Power Advisory

Peter Shattuck

John Dalton

Andrew Bracken

Brendan Callery

Brady Yauch

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GLOSSARY

ACER	European Union Agency for Cooperation of Energy Regulators
BCR	Benefit-Cost Ratio
CBCA	Cross-Border Cost Allocation utilized for PCIs and PMIs
CEF	Connecting Europe Facility
CIB	Canada Infrastructure Bank
DOE	United States Department of Energy
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
FERC	Federal Energy Regulatory Commission
HLC	High Likelihood Concern from an LTTS
IESO	Ontario Independent Electricity System Operator
IOU	Investor-Owned Utility
IPSAC	Interregional Planning Stakeholder Advisory Committee
ISO	Independent System Operator, including ISO-NE and NYISO
ISO-NE	Independent System Operator-New England
JIPC	Joint ISO/RTO Planning Council including ISO-NE, NYISO and PJM
JTIQ	MISO Joint Targeted Interconnection Queue project portfolio
kV	kilovolt
LIPA	Long Island Power Authority
LTRP	MISO Long Range Transmission Plan
LTTP	ISO-NE Longer-Term Transmission Planning
LTTS	ISO-NE Longer-Term Transmission Study
MISO	Midwest Independent System Operator
MMTP	Minnesota-Manitoba Transmission Project
MOU	Memorandum of Understanding
MTEP	MISP Transmission Expansion Plan
MVP	MISO Multi-Value Project
MW	Megawatt
MWh	Megawatt Hour
NB	New Brunswick
NEB	Canada National Energy Board
NEG-ECP	New England Governors and Eastern Canadian Premiers
NERC	North American Electric Reliability Corporation
NESCOE	New England States Committee on Electricity
NFAT	Needs For and Alternatives To review process of the Manitoba PUB
NICE	The NEG-ECP-formed Northeast International Committee on Electricity
NL	Newfoundland and Labrador
NPCC	Northeast Power Coordinating Council
NRA	National Regulatory Authority
NRCAN	Natural Resources Canada

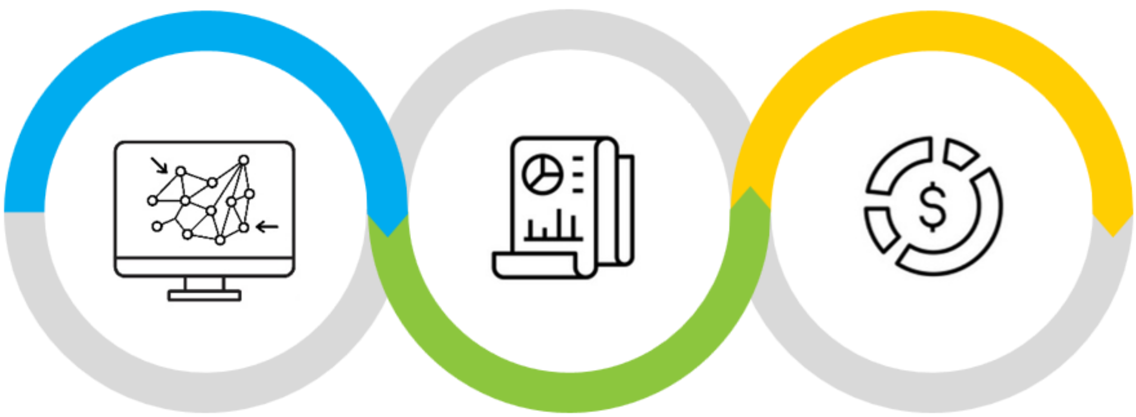
NS	Nova Scotia
NS-IESO	Nova Scotia Independent Energy System Operator
NY	New York
NYISO	New York Independent System Operator
ON	Ontario
PCI	Project of Common Interest
PEI	Prince Edward Island
PMI	Project of Mutual Interest
POINTS	Planning Offshore Interregional Network Standardization Consortium
PPTN	NYISO Public Policy Transmission Need
PPTPP	NYISO Public Policy Transmission Planning Process
PSC	NY Public Service Commission
PUB	Manitoba Public Utilities Board
QC	Québec
RECSI	Regional Electricity Cooperation and Infrastructure
ROFR	Right of First Refusal
RTE	Réseau de Transport d'Électricité, the French TSO
TO	Transmission Owner
TSF	IESO Transmitter Selection Framework
TSO	Transmission System Operator
TW	Terawatt
TWh	Terawatt Hour
TYNDP	ENTSO-E Ten Year Network Development Plan

EXECUTIVE SUMMARY

Eastern Canadian provinces and U.S. Northeast states have ambitious climate goals, complementary energy resources, and a history of collaboration across shared borders. Integrated energy system planning and transmission development could enable provinces and states to make best use of the region's diverse and complementary energy resources, improve reliability and achieve energy and climate objectives at lowest cost and least impact.

A number of interregional transmission projects have been developed between states and provinces and new initiatives hold the promise of moving the continental northeast toward shared grid planning functions. However, more work is needed to enable coordination across distinct regulatory regimes, and to ensure mechanisms for stakeholder participation and feedback that will strengthen collaboration and improve project outcomes. At a pivotal moment, this Roadmap builds on existing efforts, recent momentum, and models from other jurisdictions to chart the pathway toward transmission planning across, between, and amongst the northeast states and eastern-Canadian provinces.

Creating a framework for identifying and developing solutions to interregional energy system needs rests on three core pillars that underpin effective processes:



Need Identification

Creating a process to analyze and identify long-term transmission needs that accounts for policy goals, public interest values, and evolution of the power system over time.

Stakeholder-Informed Project Design/Selection

Establishing an inclusive mechanism to design (in vertically integrated markets) or procure (in restructured markets) solutions to address identified needs.

Cost Allocation

Agreeing on a methodology to apportion costs based on energy system benefits and achievement of broader public policy goals, including economic development.

The Roadmap described in this report proposes to build the foundation of an integrated Eastern Canada and the U.S. Northeast transmission planning and solution development process by focusing on three action areas:

Trust-Building and Coordination

Establishing forums for coordination among participating jurisdictions and their respective stakeholders and communities.

Open Information Sharing & Analysis

Sharing information on energy system configurations and future requirements and conducting analysis to identify needs transparently.

Policy Reforms

Revising existing or creating new mechanisms to enable planning and solution development between provinces and states.

INTRODUCTION

Decarbonization goals, increasing demand for electricity, and a recognition of the benefits of collaboration have increased support for bilateral and regional and transmission development across Eastern Canada (Ontario, Québec, New Brunswick, Nova Scotia, Prince Edward Island and Newfoundland and Labrador) and the Northeast U.S. (the New England states of Maine, New Hampshire, Vermont, Massachusetts, Rhode Island and Connecticut, and New York.)

The cost-savings, reliability and other benefits of Interregional transmission development could be significant: the North American Electric Reliability Corporation (NERC) Interregional Transfer Capability Study found the need for 12.4 GW of new transfer capability across Eastern Canada and 4.4 GW between New York and New England to strengthen energy adequacy and reliability.[i] Analysis by the Massachusetts Institute of Technology study found that adding 4 GW of transmission between Québec, New England and New York could lower the cost of a zero-emission power system by 17-28%, providing $2.4 billion in annual savings.[ii]

While a number of transmission projects have been developed to connect jurisdictions within and between Eastern Canada and the U.S. Northeast, broader benefits of enhanced coordination have yet to be realized due to fragmented planning processes and challenges presented by differences in regulatory structures.

The Northeast Grid Planning Forum (NGPF) has been convened to focus discussions on the benefits of interregional system planning supported by robust stakeholder input. This *Eastern Canada – Northeast U.S. Interregional Transmission Development Roadmap* presents policy pathways to build on those discussions and establish new mechanisms to move Eastern Canada and the Northeast U.S. toward more coordinated planning and transmission project development.

- Section I describes electric sector regulatory structures and transmission planning and development practices within the region, highlighting implications for joint action.
- Section II reviews multi-jurisdictional transmission initiatives within the region.
- Section III profiles models from other regions that accommodate distinct market constructs and transmission development authorities.
- Section IV presents options to navigate identification of needs, selection of projects and allocation of costs.
- The Roadmap in Section V proposes subsequent work streams to address barriers and facilitate broad coordination.

*Successful regional collaboration hinges on **stakeholder engagement** and fulsome **consideration of both supply and demand side resources**. Meaningful engagement of stakeholders and affected communities in processes to plan for, design and construct transmission projects is critical to instill confidence in the need for transmission, and to ensure development of projects with the least adverse impact.*

I. EXISTING REGULATORY STRUCTURES & TRANSMISSION PLANNING IMPLICATIONS

Success in establishing an improved process to plan interregional transmission will require incorporating and harmonizing current planning approaches that govern transmission development in provinces and states. As shown in Table 1, below, the transmission planner, planning horizon, transmission owner, and prevalence of competitive procurement mechanisms vary among jurisdictions in Eastern Canada and the Northeast U.S. Transmission is planned by a provincially owned Crown Corporation, private utility or independent system operator. Planning horizons range from 10 to 25 years, and transmission is owned by Crown Corporations or private utilities, who in some markets win the right to develop and own transmission projects.

Table 1: Regulatory Structures for Transmission in Eastern Canada and the Northeast U.S.

	Transmission Planner	Planning Horizon	Transmission Owner	Competitive Procurement
New Brunswick	Crown Corp.	10-20 years	Crown Corp.	No
New England	ISO-NE	To 2050	Multiple utilities	Yes
New York	NYISO	20 years	Multiple utilities	Yes
Newfoundland & Labrador	Crown Corp	10 years	Crown Corp.	No
Nova Scotia	NS-IESO	10-20 years	Nova Scotia Power	No
Ontario	IESO	10-20 years	Hydro One	Yes[iii]
Prince Edward Island	Maritime Electric	10 years	Maritime Electric	No
Québec	Crown Corp	10-15 years	Crown Corp.	No

These different regulatory and planning structures create implications that must be accounted for in relation to identifying needs and designing or selecting project solutions and allocating costs.

- Need Identification: Transparency and stakeholder engagement in transmission planning processes vary across jurisdictions. A collaborative planning framework will require new approaches to sharing information and will require harmonizing planning processes to meet the requirements and planning horizons of each jurisdiction. Transparency and engagement will provide confidence in identified needs among jurisdictions and stakeholders.

- Project Design / Selection: Competitive solicitation is utilized in some but not all jurisdictions to select transmission projects (or non-transmission solutions) to meet identified needs. Competitive processes in place in the Northeast states and in development Ontario will have to be aligned with and accommodate the designation of a single utility to develop, build, own and operate transmission in Eastern Canadian provinces other than Ontario. Alternatively, new mechanisms would be required to select projects in the U.S. Northeast.

- Cost Allocation: Formal mechanisms do not exist to allocate costs of interregional projects between provinces and states. For projects within New England, costs are apportioned among states. Separately, a limited, heretofore unutilized mechanism exists to share costs of certain transmission projects between ISO-NE and the New York Independent System Operator (NYISO). Otherwise, costs for projects built to-date have been apportioned on an ad-hoc basis between provinces and states. New formal and durable mechanisms will be needed to enable allocation of costs that benefit provinces and/or states.

The following Section II describes budding coordination processes that provide forums to begin harmonizing transmission planning and build toward broader regional collaboration.

II. BUILDING ON MOMENTUM FOR MULTI-JURISDICTION TRANSMISSION PLANNING

Several recent transmission policy and planning initiatives provide learnings, momentum, and opportunities to advance interregional collaboration. These initiatives are beginning to coalesce multiple northeast jurisdictions around common goals and processes, and present opportunities to advance coordination across the broader Eastern Canada and Northeast U.S. region.

Northeast International Committee on Energy (NICE): In September 2024 the New England Governors and Eastern Canadian Premiers (NEG-ECP) issued a *Resolution Concerning the Committee on Energy and Regional Collaboration*. The resolution notes that “bidirectional transmission across borders and boundaries provides opportunities to increase resilience and reliability and reduce prices for consumers.” The resolution additionally reconvenes the Northeast International Committee on Energy (NICE) to pursue interregional collaboration and transmission planning. NICE brings together senior leadership from across the region and includes a working group dedicated to transmission planning. Given the geographic scope of NEG-ECP – which includes Québec, New Brunswick, Nova Scotia, Prince Edward Island and Newfoundland and Labrador, and the New England states – NICE presents a unique opportunity to advance cooperation among the states and provinces. This existing binational forum can promote collaboration around better utilization of existing generation resources, coordination of demand-side management, building of new bidirectional transmission to enable development of new generation resources, and using hydroelectric resources to store and balance intermittent renewable energy[iv]. Including Ontario and New York, two key energy producers and consumers within the NPCC footprint, could further expand the impact of NICE.

Northeast States Collaborative on Interregional Transmission: The Northeast U.S. states of Maine, Vermont, Massachusetts, Rhode Island, Connecticut, and New York established the Northeast States Collaborative on Interregional Transmission (the “Collaborative”) in alongside the mid-Atlantic states of New Jersey, Delaware, and Maryland. The Collaborative came together in 2023 to coordinate transmission grid expansion efforts in conjunction with the U.S. Department of Energy (DOE). On July 9, 2024, the ten states established a Memorandum of Understanding (MOU) to formalize collaboration and accelerate the development, siting and permitting of regional and interregional transmission. On April 28, 2025, the Collaborative issued a Strategic Action Plan on State-Led Interregional Transmission Priorities. The Action Plan establishes shared goals, identifies policy reforms needed to advance interregional transmission, and committed states to issue a Request for Information (RFI) to identify interregional transmission projects that could be advanced through transmission planning and cost allocation processes. The RFI[v] was issued June 23, 2025, and project proposals are due October 23, 2025.

Key Takeaway #1: Efforts underway through the Collaborative evidence that states have recognized a new system is needed and states have taken the first steps to spur improvements in transmission project selection with public interest review criteria. The reconvening of NICE shows that states and provinces in the leading cross-border entity (NEG-ECP) have prioritized coordinated cross border transmission planning. Taken together, both indicate recognition by the key jurisdictions that current transmission planning approaches are constrained and insufficient, and need to change to realize the benefits of broader regional energy system integration. External stakeholder support in helping to shape these promising developments will be essential to success

Increased Canadian Inter-provincial Collaboration: In Eastern Canada, and Canada more broadly, several initiatives demonstrate the increasing interest in strengthening East-West ties between provinces. Premiers from Eastern Canadian provinces are promoting the Eastern Energy Partnership to send wind and hydroelectric power from Atlantic Canada and QC to Western Canada and New England.[vi] Additionally, NS Premier Tim Houston's Wind West concept includes developing 40 GW or more of offshore wind for export to demand centers in central Canada and New England.[vii] Interprovincial transmission has been a focus since the 2010s, when the Atlantic Loop was proposed to integrate QC and Atlantic Canadian provinces and displace fossil-fueled electricity with hydroelectricity. Though the full Atlantic Loop has not progressed, two projects consistent with the concept have been constructed. The Labrador-Island Transmission Link connects Churchill Falls and Muskrat Falls hydroelectric facilities in mainland Labrador with the island of Newfoundland and the Maritime Transmission Link connects Newfoundland and NS. A third inter-provincial transmission project – the Wasoqonatl Reliability Intertie between NS and NB – is under construction, with financial support from the Canada Infrastructure Bank (CIB).[viii]

Additional inter-provincial collaboration has included QC and its neighbors. Transmission between Labrador and QC will be developed pursuant to the recent MOU between QC and NL revising the terms under which Hydro Québec purchases output from Churchill Falls and providing for the development of 3,900 MW of new hydroelectric capacity and associated transmission.[ix] IESO and Hydro Québec have agreed to a capacity swap covering the next ten years under which ON will provide up to 600 MW of capacity in winter months, while Hydro Québec will provide the same amount to ON in the summer months.

Key Takeaway #2: Eastern Canadian provinces have a history of collaboration that has resulted in development of a number of inter-provincial projects. Current interest in strengthening East-West ties within Canada and development of wind energy in Atlantic Canada, new hydroelectric resources in NL, and nuclear generation in ON provide a timely opportunity for energy system planning within Eastern Canada and alignment with interregional planning through NICE and the Collaborative. These developments provide a major opportunity to better coordinate energy markets and plan for well sited and designed transmission.

III. COLLABORATIVE MODELS FROM OTHER JURISDICTIONS

Transmission planning and development approaches from other regions provide models from which Eastern Canada and the Northeast U.S can draw. This section focuses on two regional transmission development approaches that span broad regions and enable centralized planning while preserving the authority and autonomy of participating jurisdictions. The Midcontinent Independent System Operator (MISO) Long-Range Transmission Plan and the European Network of Transmission System Operators for Electricity (ENSTO-E) Ten Year Network Development Plan are described across need identification, project design/selection, and cost allocation, as summarized in Table 2.

Table 2: Key Design Elements of MISO and ENTSO-E Transmission Planning Processes

	Planning Horizon	Need Identification	Project Selection	Cost allocation	Supplemental funding
MISO LRTP	20+ years	Top-down based on scenario analysis	Procurement & assignment	Local, subregional and regional, based on accrual of benefits	No
ENTSO-E TYNDP	20 years	Top-down based on TSO plans and scenario analysis	Voluntary project nomination by TSOs	To nominating TSOs and other TSOs determined to accrue significant benefit	Yes, from Connecting Europe Facility

A. Midcontinent Independent System Operator (MISO)

MISO operates the electricity market across 15 states in the U.S. Midwest and the Canadian province of Manitoba. MISO conducts transmission planning processes on behalf of participating utilities in the U.S. (Manitoba plans transmission independently) to identify and select projects needed to meet near-term and long-term needs.

Need Identification

MISO's LRTP results from top-down scenario analysis to determine needs over 20-40 years based on energy system modeling. Need identification accounts for projected load, anticipated system conditions, and utility and state policies. Based on needs, MISO identifies portfolios of conceptual Multi-Value Projects (MVPs) that would enhance the reliability and efficiency of the grid and are not dependent on any one generation project or specific reliability violation.

Project Design/Selection

Projects are designed by utilities or selected through competitive processes depending on the size and location of projects. MVPs that include facilities above 100 kV and cost over $20 million[x] are competitively solicited by MISO, while projects below these thresholds are directly assigned to utilities in whose service territories the projects are located. Competitive solicitation is not used for projects located in states that grant incumbent transmission owners the Right of First Refusal (ROFR) to construct and own transmission.[xi]

The latest ***MVP Tranche 2.1*** *portfolio of $22 billion (USD) of investment across 24 projects expanding and strengthening 345kV and 765kV transmission in the MISO Midwest subregion, is summarized in Appendix B, which also describes the process to identify, design, approve and pay for the cross-border* ***Minnesota-Manitoba Transmission Project****.*

Cost Allocation

Costs of projects selected through LRTP are allocated depending on the distribution of benefits. Costs can be allocated to local utilities, within a MISO subregion, and across MISO depending on the extent of benefits that a project provides.

Key Takeaways: The LRTP provides an effective model for: 1) identifying region-wide needs based on plans of member utilities, 2) accommodating transmission ownership structures that vary across states and provinces, and 3) allocating costs based on benefits. However, long-term cross-border transmission planning is limited by Manitoba's utilization of a separate process to plan transmission. The LRTP process has had limited success in advancing projects connecting to neighboring grid regions and in advancing MVP projects in the MISO South subregion, as described in the transmission planning Report Card from Americans for a Clean Energy Grid.

B. The European Network of Transmission System Operators for Electricity (ENTSO-E)

ENTSO-E coordinates planning among European nations to identify regional and pan-European needs and to determine priority projects eligible for funding from the European Union (EU). ENTSO-E consists of a membership Assembly of 40 Transmission System Operators (TSOs) in 36 countries. A 12-member Board of Directors elected from the Assembly oversees the ENTSO-E Secretariate and operations.[xii]

Need Identification

Building on grid development plans from TSO members, ENTSO-E identifies Europe-wide energy infrastructure requirements over a 20-year period. Planning begins with a System Needs Study that accounts for EU Member States' energy and climate plans and other long-term national strategies in energy system modeling. The System Needs Study identifies where cross-border projects could facilitate decarbonization, support security of electricity supply, and minimize costs.

Project Design/Selection

Projects consistent with the opportunities identified in System Needs Studies can be voluntarily proposed by one or more TSOs for inclusion in TYNDPs developed annually by ENTSO-E. TYNDPs include optimal transfer capabilities between EU Member States, and identify projects nominated to meet these needs as Projects of Common Interest (PCIs) benefiting two or more EU Member States or Projects of Mutual Interest (PMIs) benefiting one or more EU Member States and non-EU nations.

TSOs are not required to propose projects to meet identified needs, and planning authority for projects within EU Member States remains at the national level. Projects that are proposed for inclusion in the TYNDP are evaluated across common benefit and cost categories that account for energy system benefits, greenhouse gas reductions, energy security, and integration of renewable energy.

*The **Celtic Interconnector** is a 700 MW bidirectional high voltage direct current project between Ireland and France that advanced through the ENTSO-E planning process from concept to cost allocation agreement and funding from the EU. The project enables wind development in Ireland and provides system benefits to both countries. Further detail is provided in Appendix C.*

Cost Allocation

Benefit-cost analysis is utilized by TSOs promoting PMIs/PCIs to allocate costs among themselves, and to determine if other TSOs accrue sufficient benefits to merit allocation of project costs.[xiii] TSOs can request support from the European Union Agency for the Cooperation of Energy Regulators (ACER) to develop mutually acceptable cost allocation approaches, which can then be used to develop business cases and apply for funding from the European Commission's Connecting Europe Facility (CEF). The CEF is critical to driving collaboration and enabling development of projects that might otherwise struggle to secure necessary funding.

Key Takeaways: The TYNDP is an effective process to: 1) identify Europe-wide transmission needs based on plans of individual members, 2) enable voluntary development of projects consistent with regional needs, and 3) allocate costs based on a common cost-benefit analysis framework, with funding support from the EU. The TYNDP does not include mechanisms to competitively procure projects, limiting potential project innovation and cost control.

IV. OPTIONS TO ADVANCE INTERREGIONAL TRANSMISSION PLANNING IN THE NORTHEAST

Advancing interregional transmission planning in Eastern Canada and the Northeast U.S. requires establishing a well-structured, stakeholder-inclusive process to share information, set goals, and identify needs. Once needs are identified, existing mechanisms can be utilized to advance beneficial projects. Cost allocation can be matched to delivered benefits, building on best practices from MISO, ENTSO-E, and existing mechanisms in the region.

A. Need Identification

Identifying needs across Eastern Canada and the Northeast U.S. or within a targeted subregion will require provinces and states to agree to common goals, establish protocols for sharing energy system data, and designated an entity to conduct energy system modeling to identify and prioritize needs.

The recently established ISO-NE Longer-Term Transmission Planning (LTTP) process provides an instructive model for need identification across a multi-jurisdiction region, and surfaces issues that would have to be addressed in broader regional need identification. The LTTP identifies needs through a Longer-Term Transmission Study (LTTS), the first of which was the 2050 Transmission Study. The 2050 Transmission Study was conducted by the RTO to examine the policy goal of achieving net-zero greenhouse gas emissions in New England by 2050, requiring a 98%+ reduction in the carbon intensity of generation from 2020.[xiv] Additional key assumptions, informed by the states and previous modeling, included 2050 interim load projections, available generation sources and energy storage by state, resource capabilities, and import capacity from neighboring jurisdictions.

Based on these state-specified goals and assumptions, ISO-NE determined transmission needs in 2035, 2040 and 2050 across three seasonal peak "snapshot" scenarios. For each scenario, ISO-NE identified High-Likelihood Concerns (HLC) that occurred across a range of time horizons and load levels. The analysis further identified conceptual transmission solution roadmaps for addressing HLCs. Based on these roadmaps, New England states (through the New England States Committee on Electricity, NESCOE) then requested ISO-NE to initiate the current LTTP procurement for transmission projects to address the North-South HLC and build transmission to enable development of renewable energy in Maine.

Importance of demand management: ISO-NE's 2050 Transmission Study found that reducing peak demand by 10% reduces the cost of new transmission by 33%, saving $10 billion. Analysis for NYSERDA and the NY PSC determined that 8.5 GW of flexible demand would be available by 2040 from electric vehicles, heat pumps, energy storage and demand response, yielding $2.4 billion in potential annual savings.

Conducting similar analysis across Eastern Canada and the Northeast U.S. or a subregion would require:

1. Establishing **goals** based on shared values and policy mandates;
2. Agreeing on **key assumptions** related to load, availability and characteristics of energy resources (including demand-side resources), and necessary modeling inputs (e.g., weather profiles, existing interregional transmission capability, etc.);
3. Determining **target years** for analysis;
4. Identifying key **sensitivities** to evaluate (e.g., fuel prices, technology costs, resource limitations, etc.), and;
5. **Sharing data** and information needed to conduct modeling.

Once goals and assumptions are established by provinces and states, with stakeholder input, an entity would have to be designated to conduct or oversee modeling. The Northeast Power Coordinating Council (NPCC) could be considered to conduct or at least inform modeling, with direction and oversight from provinces and states, or a new entity could be established. If the initial focus is on a subregion (e.g. jurisdictions represented in NEG-ECP), modeling could be conducted by NPCC, a provincial utility, or a third party. If other existing processes are considered for this modeling function, such as the ISO-NE LTTP, NYISO Public Policy Transmission Planning Process (PPTPP, described in Appendix A), IESO's bulk transmission planning process, or Integrated Resource Planning processes in other provinces, these processes would likely require modifications to currently delineated scope and timelines. These options and potential modifications are further discussed in Section V.

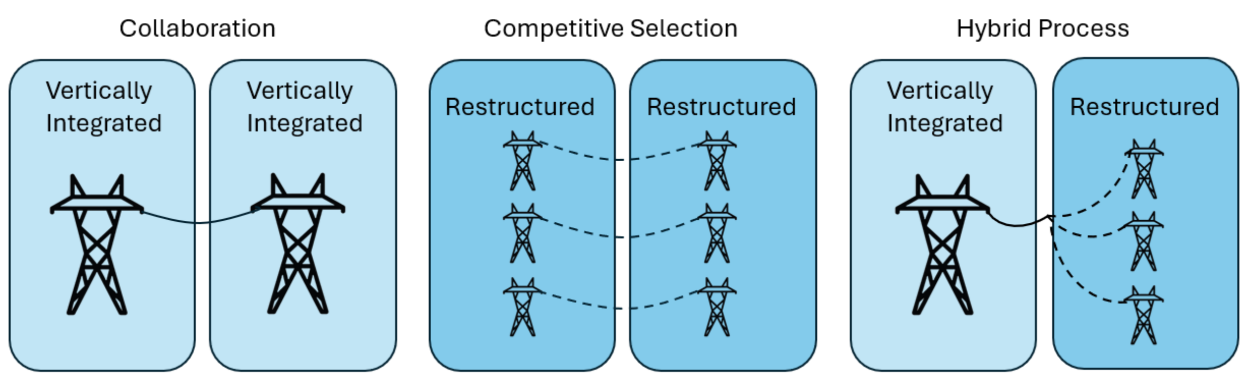
In the near-term, independent third-party modeling of the full region and/or subregions could help identify illustrative benefits and help build support for a more formal collaborative planning process. While regulatory grade modeling directed by provinces, states or ISOs would ultimately be required to solicit solutions to solve identified needs, independent modeling could provide a strong rationale for stakeholders to invest time and effort needed to implement interregional transmission planning. This independent modeling approach could account for staffing and resource constraints that could limit near-term engagement by ISOs, states and provinces. Independent modeling processes would also support early engagement with stakeholders, raise awareness of the benefits of collaboration, and surface key considerations that would need to be addressed in formal processes. Modeling processes should include meaningful stakeholder engagement to enhance transparency and build understanding of the need for and benefits of projects that will ultimately impact stakeholders and local communities.

B. Project Selection/Design

After determining needs, the process of selecting solutions should first include a screening step to consider non-transmission solutions such as targeted energy efficiency and demand response, as well as grid enhancing technologies and advanced transmission technologies. Evaluating non-transmission solutions first will ensure that the most efficient and cost-effective options are considered and will increase confidence among stakeholders in the need for transmission in cases when non-transmission solutions are unable to solve identified needs cost-effectively.

The approach to selecting solutions will be determined by the regulatory and transmission development mechanisms in jurisdictions where projects are located, as illustrated in Figure 1 and described below. Additionally, an improved process should create both region-wide and jurisdiction-specific mechanisms to directly solicit and incorporate stakeholder participation and feedback in the project design, screening, and selection process.

Figure 1: Project Selection Frameworks as Determined by Regulatory Structures



Where projects resulting from the Need Identification process are located within **two or more vertically integrated jurisdictions**, Crown Corporations and/or utilities would **collaborate** to design, build, own and operate projects. In NS, the newly created NS-IESO could serve a similar function to a vertically integrated utility in designing transmission project components within the province. These elements would then be built, owned, and operated by Nova Scotia Power. In ON, the IESO could design project components within the province through the bulk transmission planning process. These project components could then be built, owned, and operated by Hydro One or be procured through the Transmitter Selection Framework (TSF) under development.

Projects connecting **two or more restructured markets** (i.e., ISO-NE, NYISO and IESO for eligible projects) would be developed through a **competitive selection process**. For ISO-NE and NYISO there is a proposed process outlined in the Collaborative Strategic Action Plan, wherein states issue a Request for Information to identify candidate interregional projects. Candidate projects would be evaluated in conjunction with ISOs, including through the existing Joint ISO/RTO Planning Committee (JIPC) process. ISOs, in conjunction with states and stakeholders, would then pursue tariff reforms needed to advance projects through detailed evaluation and selection in ISO planning processes.[xv]

Where projects span **vertically integrated jurisdictions and restructured markets** (i.e., between provinces and New England states within NEG-ECP, or between NY and ON or QC) a **hybrid project design and selection process** could be utilized. Following need identification, the vertically integrated utility could design one or more project configurations. These configurations would include new transmission within the vertically integrated jurisdiction, point(s) of interconnection, border crossing location(s), and cable landing location(s), as appropriate. NS-IESO could serve a similar role to a vertically integrated utility by designing transmission within NS. In ON the IESO could either design the project or utilize the competitive TSF, depending on whether the project is subject to competitive procurement.

In the restructured markets the grid operator could procure projects proposing to integrate with one or more of the design options identified by provincial utilities. In ISO-NE, the LTTP process could be utilized, beginning with NESCOE identifying the need for interregional transmission as a public policy objective in an LTTS.[xvi] The current LTTP procurement for transmission to enable integration of onshore wind from Northern Maine could provide a model for defining needs to integrate external resources. In NY, NYISO could procure the project through the PPTPP, following identification of the need for interregional transmission by the NY Public Service Commission (PSC).

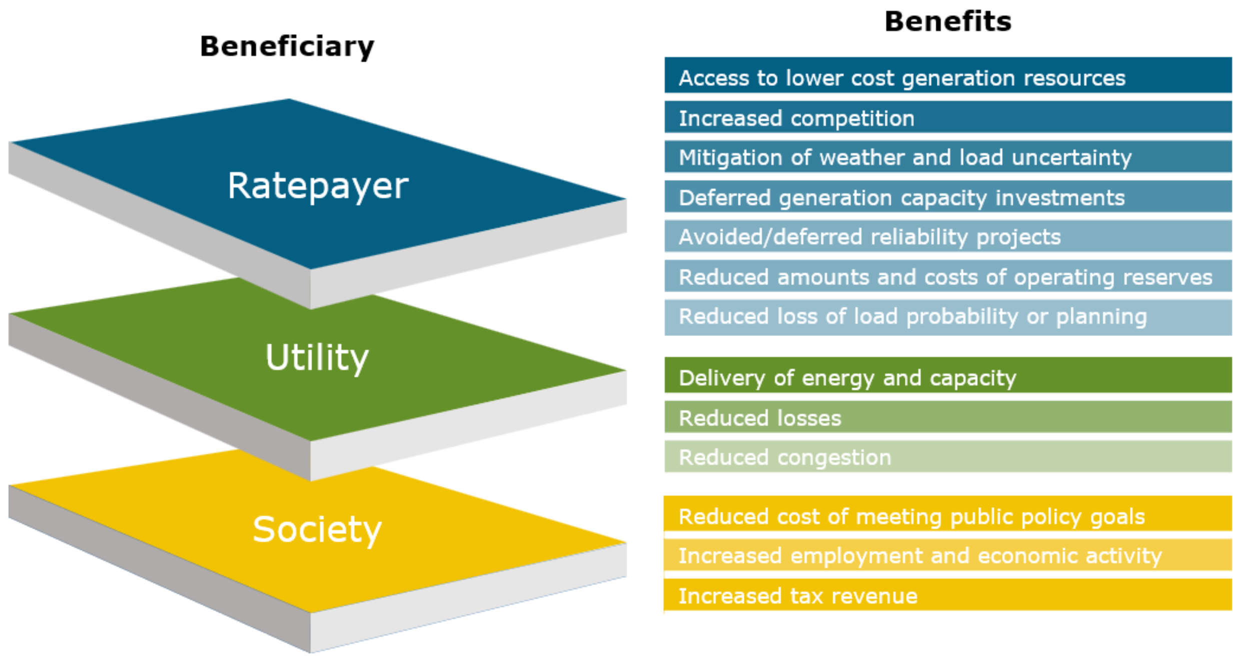
Alternatively, New England states and New York could identify projects to integrate with provincially designed projects through another mechanism such as the Request for Information (RFI) process launched by the Northeast States Collaborative. Projects selected through such a process could then be advanced through voluntary agreement among states. In 2021 the U.S. Federal Energy Regulatory Commission (FERC) issued a Policy Statement establishing that such State Voluntary Agreements to Plan and Pay for Transmission were not inconsistent with federal law and precedent. Such a voluntary agreement was contemplated in relation to the Clean Resilience Link project, a 1,000 MW transmission expansion between ISO-NE and NYISO that was proposed by New England states and New York to the DOE Grid Innovation Program in 2024. As a third option, state-specific authorizations could be utilized to procure transmission.[xvii]

Project selection options in restructured markets:

1. Existing competitive transmission procurement mechanisms (PPTPP, LTTP and IESO TSF)
2. Voluntary State Agreements
3. State-specific procurement authority

C. Cost Allocation

Once projects have been identified, costs could be allocated based on energy system benefits and additional public policy benefits enabled by solutions to identified transmission needs. Energy system benefits should include quantifiable savings such as reduced production costs, avoided capacity costs, avoidance of alternative transmission investments, improved transmission system efficiency, reliability, and other benefits.[xviii] The figure below illustrates the multiple types of benefits that accrue to different beneficiaries, with darker shading indicating a greater degree of quantifiability.



In addition to energy system benefits, economic development and public policy benefits could be considered to inform cost allocation. Examples of such benefits in Eastern Canada and the Northeast U.S. could include:

- Enabling development of wind energy in Atlantic Canada to enhance resource diversity;
- Utilization of hydroelectric resources for long-duration storage as a tool to increase reliability and resource adequacy during peaks;
- Avoided curtailment of surplus wind and solar energy in the Northeast U.S. and/or Atlantic Canada, and;
- Trade of surplus seasonal energy and capacity.

Cost allocation frameworks should ensure full consideration of all benefits evaluated in each participating jurisdiction and should establish consistent approaches to analyze benefits. The Cross-Border Cost Allocation (CBCA) methodology utilized in Europe for PCIs provides an example framework for allocating costs of transmission projects across international borders. Existing interregional transmission development frameworks in the Northeast U.S. will need to be revised to enable consideration of a broader range of benefits, as the existing JIPC protocol only accounts for avoided transmission investment.[xix] Cost allocation under this approach would be filed with FERC as a Voluntary State Agreement in the U.S., and for approval by provincial regulators in provinces.

Under the CBCA process, the jurisdictions (promoters) developing a transmission project use the cost benefit analysis methodology from the most-recent TYNDP to inform project-specific cost allocation. The project promoters agree on approaches to determine and allocate quantifiable benefits identified through the TYNDP, acknowledge other benefits and externalities, and submit a joint cost allocation proposal to their regulators for approval. Additional revenue-sharing mechanisms are proposed, including plans for distributing revenue raised by charging tariffs on electricity transmitted via transmission projects.

Federal funding could facilitate cost allocation by covering shortfalls between quantified benefits and costs, and by motivating collaboration. In the ENTSO-E process, funding from the Connecting Europe Facility is utilized to advance projects that are aligned with European policy goals, and where project revenues and benefits fall short of costs. In the U.S., transmission funding authorized under the Infrastructure Investment and Jobs Act and Inflation Reduction Act was made available to states and other eligible applicants through competitive processes, which encouraged multi-state, and multi-stakeholder collaboration. In Canada, equity financing through CIB is reducing ratepayer costs of the Wasoqonatl Reliability Tie.[xx] Funding through the CIB or another mechanism could support beneficial multi-jurisdiction projects in Eastern Canada, including projects that connect to the Northeast U.S.

V. THE ROADMAP

Policymakers and grid operators can advance interregional transmission development by establishing mechanisms and forums to enhance coordination and joint planning, by sharing information, and by reforming policies that inhibit coordination.

A. Establish Trust Building and Coordination Mechanisms

Establishing a joint coordination agreement will facilitate collaboration and development of tools and processes needed to advance interregional transmission. Provinces and states could enter into an MOU that formalizes collaboration and provides a clear mandate for agency staff regarding the scope of future work. The MOU between members of the Northeast States' Collaborative provides a model on which to build, as it establishes shared goals, delineates the scope of coordination, defines roles and responsibilities and creates information sharing protocols. An MOU could be established among members of NEG-ECP, with NY and ON invited to join.

Coordination with parallel or overlapping planning initiatives in the northeast should be pursued to facilitate shared learnings, advance mutually beneficial actions and avoid duplication of efforts. Specifically, efforts should be coordinated with the Northeast States Collaborative which includes New England states and NY and has a priority focus on facilitating development of interregional transmission. Additionally, Canadian provinces pursuing offshore wind deployment could benefit from engagement with the US *Planning Offshore Interregional Network Standardization ("POINTS") Consortium* that is working to establish standards for offshore transmission equipment to facilitate shared transmission solutions and interoperability.[xxi]

An effective and durable transmission planning process requires opportunities for ***stakeholder input and participation****, including equity participation from First Nations. Processes established to advance interregional transmission should promote transparency, outreach to affected groups, and mechanisms to provide meaningful input.*

Coordination among provinces and states should be accompanied by participation from grid operators and utilities to ensure technical feasibility and alignment with operation of the transmission system. However, provinces and states should retain ultimate decision-making authority in order to overcome siloed planning processes and incentive structures that encourage development of local transmission over interregional projects.[xxii]

B. Establish Protocols for Information Sharing & Analysis

Identifying the benefits of interregional transmission, defining needs, and advancing beneficial projects depends on information sharing between provinces, states, and grid operators. Consistent or compatible data on electricity supply and demand across time periods, and information on grid configurations and operations will be needed to create accurate models that span grid planning regions. To address this need, an MOU between provinces and states could set information sharing guidelines, including confidentiality provisions to protect sensitive information. Non-confidential or anonymized information could be published for use by the public and interested parties. The ENTSO-E process provides a model of transparency, wherein summary data on load, generation, transmission, system operations and more and is published on the Transparency Platform. The Regional Electricity Cooperation and Infrastructure (RECSI) Initiative conducted by Natural Resources Canada helped to identify transmission needs in Eastern and Western Canada, and learnings from the process could be utilized going forward, with a focus on the need for increased transparency.

Building on shared information, provinces and states could consider a range of entities to conduct necessary analyses, and analysis could be conducted by different entities over time to meet evolving needs. In the near-term, independent analysis to demonstrate the value of coordinated transmission planning across the region could be conducted by external entities. External analysis to demonstrate the benefits of interregional transmission development would help build support for formal analysis and for provinces, states and grid operators to dedicated the time and effort needed to advance collaboration. This analysis would not necessarily require financial commitments from provinces and states but could benefit from expressions of support for external entities to secure necessary resources. The value and accuracy of external modeling would benefit from – but is not dependent on – access to official data.

Formal modeling could be pursued through a number of different mechanisms:

- NPCC – NPCC spans the Northeast U.S. and Eastern Canada (with the exception of NL), enforces North American transmission reliability standards and determines and enforces additional regionally-specific reliability criteria. These functions provide established information-sharing mechanisms and organizational infrastructure on which to build. With revisions to its mandate and bylaws, and subject to approval by NERC and FERC, NPCC could serve a similar role as ENTSO-E in Europe, amalgamating plans from provinces, states, and grid operators and developing comprehensive, region-wide analysis. Analysis would identify illustrative projects that provide energy system benefits and facilitate achievement of goals agreed upon by provinces and states. NPCC could also focus on a subregion composed of two or more jurisdictions or grid planning regions.
- Utility/IESO-ISO joint modeling – Provincial utilities and IESO/NS-IESO could conduct joint analysis with ISO-NE and/or NYISO. Protocols could be established within participants' respective transmission tariffs and governance structures to designate a lead entity and mechanisms for input and oversight by other parties.
- 3rd party modeling – An independent 3rd party could be commissioned to conduct analysis on behalf of participating provinces and states to identify needs, with

appropriate input and participation from grid operators and utilities. Needs advanced to project development would then proceed through project evaluation and design processes of the utility(ies) and/or grid operators in which the project(s) would be located.

Each of these options should be further analyzed to assess fitness for purpose, administrative efficiency, and replicability over time.

C. Adapt Existing Processes to Enable Interregional Transmission Development

Existing processes provide a foundation for collaborative planning but will need to be adapted or supplemented to enable durable interregional transmission planning and development. Key strengths and limitations of existing processes and market constructs are presented below; further analysis and collaboration between provinces, states and grid operators is needed to determine the suitability of these processes and any necessary reforms. Additional mechanisms to optimize interregional transmission are additionally noted.

Existing Processes

ISO-NE Long-Term Transmission Planning Process (LTTP)

The recently established LTTP is enabling collaborative transmission development by six New England states and could be utilized to procure interregional transmission. A limitation of the existing LTTP process is that a new transmission needs study (the Longer-Term Transmission Study) cannot be initiated until six months after the prior LTTP process is completed. ISO-NE has indicated a target completion date for the current LTTP of Q3, 2026,[xxiii] meaning that the next LTTS could not be initiated until Q1 2027 at the earliest. Assuming two years to complete the LTTS, a procurement for interregional transmission could be conducted no earlier than 2029. Depending on the timeline of preceding steps to formalize collaboration and identify needs, New England states could consider tariff revisions to enable initiation of the next LTTS before 2027, or state could establish a separate mechanism to procure interregional transmission. A separate mechanism would have to account for interaction with the current LTTP, and uncertainty related to the solution selected through the current LTTP.

Costs for projects selected through an LTTP procurement that exceed a 1.0 benefit-cost ratio (BCR) are allocated by default to New England states on a load-share basis unless NESCOE proposes an alternative cost allocation. If no projects exceed a 1.0 BCR, one or more states can agree to cover the shortfall in benefits to achieve a 1.0 BCR. Both cost allocation approaches appear applicable to interregional projects, and the flexibility to establish alternative cost allocation methodologies could facilitate allocating costs of interregional projects that provide greater benefits to one or more New England states, including benefits associated with achievement of public policy objectives.

Pros	Con
✓ States identify goals and assumptions ✓ Default cost allocation & ability to propose alternative approaches	• Timing – next LTTP cannot begin until 2027

NYISO Public Policy Transmission Planning Process (PPTPP)

The PPTPP is a proven mechanism that provides the New York State Public Service Commission (PSC) broad authority to define a need for which the NYISO procures solutions. To date the PPTPP has not been used to procure interregional transmission, though the Western New York PPTPP was intended, in part, to increase the ability to import renewable energy from ON. If the PSC is convinced of the need for interregional transmission, a future PPTPP could be utilized for planning and procurement. While the objective of the PPTPP is to achieve public policy objectives, the PSC can identify additional benefit categories and metrics for the NYISO to utilize in a PPTPP procurement. This flexibility could enable the PSC to establish benefit categories in alignment with other jurisdictions participating in developing an interregional transmission planning process. However, it is noted that the PPTPP is not presently designed to address reliability or market efficiency needs, nor to avoid the need for alternative projects to meet such needs.

Pros	Con
✓ Broad authority to identify goals ✓ Proven mechanism	• Not designed for reliability or market efficiency

Voluntary State Agreement

Utilizing a voluntary state agreement pursuant to FERC's 2021 Policy Statement could allow states to advance projects outside of established planning processes, providing potential timing benefits in aligning action with other jurisdictions. A voluntary state agreement could incorporate an open or competitive process to identify preferred projects, such as the RFI proposed in the Collaborative Strategic Action Plan or the RFI-like process that New England states utilized in 2023 to identify projects to submit to DOE's Grid Innovation Program (this process led to identification of the Clean Resilience Link connecting ISO-NE and NYISO). However, utilization of a voluntary agreement outside of established tariff-based planning and procurement processes could be subject to legal challenge.

Pro	Con
✓ Not bound by existing processes or timelines	• Potential legal exposure

Order 1920A Compliance

In May 2024 FERC issued Order 1920[xxiv] to identify and assess projects to meet needs driven by multiple overlapping drivers over the long term (20 years). The subsequent Order 1920-A established that regions must jointly evaluate proposed interregional projects that address regional needs. As noted in the Northeast States Collaborative Strategic Action Plan, the Order 1920-A compliance process could provide an opportunity to develop transmission planning principles through which states could propose interregional projects to meet needs more efficiently.[xxv] However, with an extension granted,[xxvi] ISO-NE will not submit a compliance filing until 2027, and implementation is anticipated no earlier than 2029. As such, New England states could benefit from pursuing interim solutions.

Pro	Con
✓ Durable mechanism enshrined in tariff	• Long lead time (2029+) to implementation

Additional Mechanisms to Optimize Interregional Transmission

Optimizing Intertie Utilization

Market reforms to optimize intertie utilization could enhance the value of interregional transmission. As noted in multiple analyses,[xxvii] current market rules governing interties can result in the inefficient utilization of interregional transmission capacity, increasing costs for consumers and devaluing interties in transmission planning. ISO-NE and NYISO have taken steps to optimize intertie utilization,[xxviii] and states and provinces could pursue similar optimization of cross-border transmission, accounting for differences in regulatory structures between provinces and states.

Pricing Structures to Optimize “Hydro-Banking”

Hydroelectric resources in QC and NL could be used to “bank” renewable energy and avoid the need for alterative energy storage or balancing resources. Realizing the potential for “hydro-banking” depends on developing pricing structures that maximize cross-border benefits. Bidirectional interregional transmission could enable surplus energy from New England, NY, Atlantic Canada and ON to be exported and displace hydroelectric generation in QC and Labrador, with hydroelectric generation exported during a later period of reduced wind and solar energy production. Using hydroelectric resources to bank clean energy could reduce the need for alternative energy storage resources and minimize the overall capacity buildout across the region. Avoided costs of energy storage and avoided curtailment could reduce consumer costs in jurisdictions planning to develop large quantities of wind and solar. Displacing hydroelectric generation during periods of high wind and solar output would enable conservation of hydroelectric capacity for use during periods of high demand and thus increase energy security.

Establishing a pricing or crediting structure for export of surplus wind and solar and reimport of hydroelectricity would maximize benefits of hydro banking and thus increase the value of bidirectional interregional transmission. A price collar could be established, setting a floor price for wind and solar export and a ceiling for hydroelectric imports. The price floor could be informed by the value of avoided hydroelectric production and the ceiling informed by the cost of alternative energy storage options. Alternatively, an energy crediting mechanism could be established, akin to the capacity swap in place between ON and QC.

CONCLUSION

The first electric grids in North America were developed in NY and ON almost a century and a half ago. Since then, the grid has expanded across Eastern Canada and the Northeast U.S., delivering benefits and reducing costs through economies of scale. The grid must now evolve to supply increasing demand and facilitate achievement of decarbonization goals. Provinces and states could benefit through enhanced coordination and transmission project development that optimizes utilization of existing resources and enables development of new clean energy sources. Prior collaboration within the region and other multi-jurisdictional transmission development models highlight the steps needed to identify, select and pay for beneficial projects. Formalizing collaboration, sharing information, and adapting existing process as described in this Roadmap can enable provinces and states to realize the benefits interregional transmission development.

APPENDIX A: CURRENT REGULATORY STRUCTURES AND TRANSMISSION PLANNING AND DEVELOPMENT PRACTICES ACROSS THE REGION

Eastern Canada

In Eastern Canada, the QC, NB, and NL electric systems are managed by province-owned vertically integrated Crown Corporations that plan, develop, own, and operate transmission, with the provinces providing regulatory oversight. New Brunswick Power has Balancing Authority responsibilities that extend beyond NB to include PEI and Northern Maine. In PEI, the transmission system is managed by the privately owned, vertically integrated Maritime Electric, which has similar functions as province-owned Crown Corporations. In these provinces, integrated transmission planning accounts for reliability, economic, and public policy objectives, with project development carried out by the vertically integrated utility. Connections between these provinces are jointly developed, constructed and paid for by the vertically integrated utilities.

In NS, the 2024 Energy Reform Act created an Independent Energy System Operator (NS-IESO), which will assume transmission planning responsibilities previously carried out by Nova Scotia Power. Nova Scotia Power will continue to develop, own and operate transmission in the province. Notably, the Nova Scotia and Canadian federal governments have acted recently to begin leasing of offshore wind energy areas off the coast of Nova Scotia, establishing a goal of leasing 5 GW by 2030. This capacity outstrips current generation and demand in the province, prompting consideration of transmission exports to enable development of the resource.[xxix]

In Ontario, IESO works with Hydro One, the principal transmission owner in the province, to plan transmission needs within 21 regions, including evaluation of non-wires solutions across a 20-year timeframe. Bulk transmission spanning multiple regions within the province is planned by IESO, taking account of needs extending 20 years into the future. Projects are approved by the regulator, the Ontario Energy Board, and Hydro One builds, owns and operates almost all[xxx] transmission in the province. Interties with neighboring jurisdictions are evaluated on an ad hoc basis in conjunction with neighbouring transmission companies or system operators, including evaluation of interregional transmission to address regional and bulk system needs.[xxxi] The IESO and Hydro One are currently undertaking or considering a number of end-of-life investments at existing interties with neighboring jurisdictions, including at the Michigan/Ontario border and the Ontario/Manitoba Intertie.[xxxii] Additionally, the IESO is currently establishing a TSF to competitively solicit projects to meet identified needs for select projects expected to be in-service in the 2030s.[xxxiii]

Interprovincially, despite some highlights coming from specific provinces, eastern Canada lacks a comprehensive framework for interregional transmission planning and procurement. This “east-west” transmission planning gap has recently received increased attention and scrutiny by Canadian officials at the federal and provincial level.

Northeast U.S.

In the U.S. Northeast, electricity markets are restructured and transmission is planned and operated independently by regional independent system operators ISO-NE and NYISO (the "ISOs"). Under existing rules, ISOs plan transmission over 5–10-year horizons to ensure reliability at the local level and improve market efficiency, and over multiple decades to achieve public policy objectives. US Federal Energy Regulatory Commission Order 1920, adopted in May 2024, is intended to promote more integrated long-term planning to address multiple needs within, and to a limited extent between, ISO regions. For market efficiency and public policy projects, and in cases where a reliability project is not deemed time-sensitive, the ISOs run competitive solicitations to select projects that meet identified needs. Reliability projects that are deemed time-sensitive are built by incumbent utilities – such as investor-owned utilities (IOUs) and other transmission owners (TOs) in whose service territories such projects are located.

In New England public policy transmission is developed through the LTTP process that ISO-NE recently established at the request of New England states.[xxxiv] The LTTP planning process is initiated upon request of the New England States Committee on Electricity (NESCOE) for ISO-NE to run a Longer-Term Transmission Study (LTTS) identifying high-level concepts of transmission infrastructure needed to meet public policy goals identified by NESCOE. This new process creates a framework for multiple states to coordinate with each other and the ISO to develop transmission projects essential to the region. Upon completion of the LTTS, NESCOE may request that ISO-NE competitively solicit projects to address one or more identified needs. ISO-NE then solicits solutions to identified needs, and with NESCOE's approval selects an independent developer or incumbent transmission owner to build the project. Project costs are recovered from utilities across New England based on their share of regional load unless NESCOE establishes an alternative cost allocation. The first Longer-Term Transmission study – the 2050 Transmission Study – was conducted from 2021 to 2024. Based on the study's findings, NESCOE requested that ISO-NE solicit transmission solutions to enable integration of new onshore wind[xxxv] from Northern Maine. The LTTP RFP was launched in March 2025, and ISO-NE anticipates selecting a project for NESCOE approval in the third quarter of 2026.[xxxvi]

NYISO conducts a Comprehensive System Planning Process to reliably serve forecasted New York demand over a 20-year time horizon, address transmission needs driven by public policies, and identify economic opportunities under an array of possible future system conditions.[xxxvii] NYISO's PPTPP[xxxviii] was established pursuant to FERC Order 1000 and is conducted every two years to support achievement of state and federal policy requirements. A PPTPP may be run out-of-cycle upon request of the PSC. NYISO initiates the PPTPP process by soliciting input from stakeholders on needs driven by public policy requirements. The PSC then identifies needs to be addressed through competitive procurement, in consultation with the Long Island Power Authority (LIPA) for needs on Long Island. NYISO conducts the competitive solicitation and selects a winning project. Three PPTPP procurements have been conducted, and a fourth is underway for transmission to interconnect offshore wind to New York City.[xxxix]

Both New England and NY developed interregional transmission projects connecting to neighboring jurisdictions before restructuring of their electricity markets in the early 2000s, and three additional interconnections have subsequently been developed through state or utility-led procurements. The 330 MW Cross Sound Cable[xl] connecting Connecticut and Long Island was developed in 2002 in response to a LIPA procurement for energy capacity. More recently, state-directed procurements outside of ISO-led public policy processes have led to the development of two projects connecting to QC: the Champlain Hudson Power Express[xli] delivering 1,250 MW of hydroelectricity to New York City via underground and submarine transmission, and the 1,200 MW New England Clean Energy Connect[xlii] connecting to the ISO-NE grid through Maine.

APPENDIX B: MISO TRANSMISSION PLANNING PROCESSES

MISO plans transmission through an integrated bottom-up process to identify transmission needs over the next 10-20 years in the Transmission Expansion Plan (MTEP) and the top-down process to identify projected needed over 20-40 years through the Long-Range Transmission Plan (LRTP). This appendix describes both processes, summarizes the latest projects advanced through MISO transmission planning, and profiles the Minnesota-Manitoba Transmission project as an example of a cross-border project advanced through coordinated planning and distinct approval processes on each side of the Canada-U.S. border.

MISO Transmission Expansion Plan

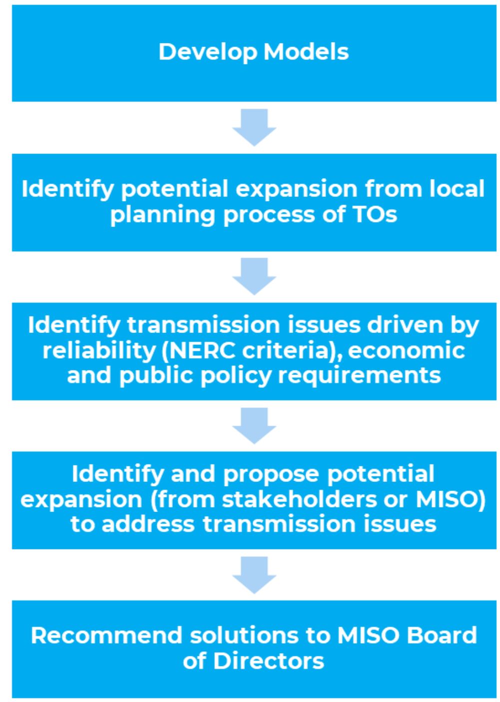
MISO utilizes the MTEP to identify and support the development of transmission infrastructure across its system to ensure reliability, enable a competitive energy market, support policy goals and allow for competition among transmission developers. MISO has established six guiding principles that inform the ISO's approach to transmission planning:

- Market access
- Planning criteria
- Policy alignment
- Cost allocation
- Information exchange
- Regional coordination

These guiding principles are enacted through MISO's Value-Based Planning Approach, a planning process that spans short- to long-term horizons depending on study objectives and need drivers. The MISO Value-Based Planning Approach includes:

- Local Planning – review needs of member transmission owners; evaluate system against reliability standards
- Regional Planning – long-term regional planning based on future scenarios
- Policy Assessment – analyze the impact of changes in state or federal policy and determine transmission required to support policy achievement
- Resource Integration – based on interconnection queue requests
- Interregional Planning – collaborate with neighboring grid operators.

As a result of this planning approach, the MTEP process and final report is structured into three main planning areas: local, regional and interregional.



MISO publishes MTEPs annually following an 18-month planning process. Each planning process moves through a cycle as outlined in the figure at right. MISO starts with a planning analysis through which it tests the transmission system under a wide variety of conditions, collaborating with TOs and other stakeholders to develop appropriate planning models. The local reliability planning process relies on known and committed (i.e., short term) inputs into the process, while the regional/interregional planning process considers projected (i.e., long-term) inputs. Inputs include expected load (size, location, peak demand by season), existing and planned generation resources, and transmission infrastructure in-service by horizon year. Short-term inputs rely heavily on MISO member inputs (utilities, TOs, states) and generation requests in the MISO interconnection queue, while long-term inputs are determined through projections based on utility IRPs, state targets, economic factors, and previous MTEP portfolios. The developed models are made available to stakeholders under confidentiality and non-disclosure protection.

MISO considers stakeholder input throughout the cycle, including from Subregional Planning Meetings, and input from the Planning Subcommittee and the Planning Advisory Committee. Considering stakeholder input, MISO identifies transmission solutions and determines project types by criteria established in MISO’s tariff. Project types include but are not limited to: Baseline Reliability Project, Generator Interconnection Project, Market Efficiency Project and Multi-Value Project (MVP).

MISO staff formally recommends a set of projects to the MISO Board of Directors for review and approval. The approved projects are posted in Appendix A of the MTEP report and represent the preferred solutions to the identified transmission needs.

Long Range Transmission Planning

LRTP Process Overview

The Long-Range Transmission Planning (LRTP) process is conducted periodically to address significant changes to future conditions. It serves to identify regional transmission needs over a 20+ year horizon and results in projects that are regional backbone facilities to move power between geographically dispersed areas within MISO. The LRTP occurs over several MTEP annual cycles.

1. **Develop Future Scenarios** – develop scenario-based futures with resource forecast and siting
2. **Develop Resource Plan and Site Future Resource** – development of planning models utilizing future scenarios
3. **Identify Transmission Issues** – identify potential transmission issues
4. **Integrated Transmission Development** – proposals for solutions to issues
5. **Transmission Solution Evaluation** – evaluate the effectiveness of various solutions
6. **Project Recommendation and Justification** – recommend preferred solutions for MTEP implementation
7. **Project Cost Allocation** – apply appropriate cost allocation

LRTP follows a seven-step value-based planning process, similar to the approach used for MTEP. The planning inputs to the LRTP include projected load growth resulting from economic expansion and electrification, and MISO member plans including utility IRPs and announced state or utility goals. LRTP portfolios are “least-regrets” solutions that plan for an uncertain future based on system, economic and policy factors known at the time the LRTP is developed. The LRTP focuses on broad regional issues that are not sensitive to changes in input assumptions and proposes long lead solutions that reduce long-term costs and require advanced planning to implement.

Project recommendations selected from the LRTP process are presented to the MISO Board of Directors for review and approval. The LRTP solutions are categorized as Multi-Value Projects (MVPs) which are defined as regional transmission solutions eligible for cost allocation across the MISO region or a subregion on the basis of supporting one or more of the following three goals:

1. Reliably and economically enable achievement of regional public policy goals,
2. Provide multiple types of regional economic value, and
3. Provide a combination of regional reliability and economic value.

In addition, MVPs must:

- cost $20 million or more,
- involve facilities with voltages of 100 kV or higher, and
- have financially quantifiable benefits exceeding costs.

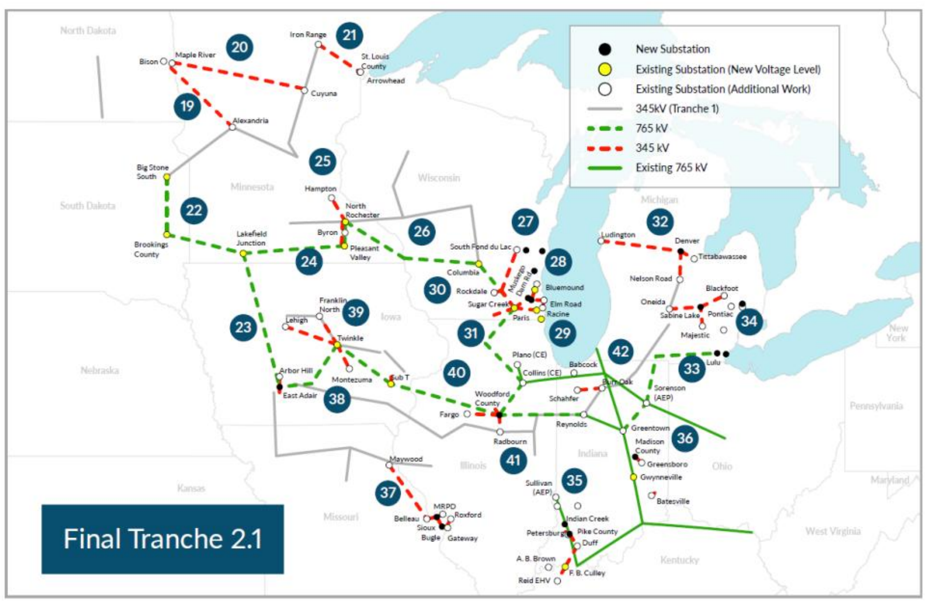
There have been three MVP portfolios developed and approved by MISO to date: 2011 MVP Portfolio, LRTP Tranche 1 and LRTP Tranche 2.1. MISO plans to develop additional LRTP portfolios, as described below. Each tranche will address transmission needs and challenges of different subregions in MISO.

According to MISO tariff rules, MVP cost allocation methodology is applied to LRTP portfolios. The costs of transmission projects that are selected and approved as MVPs are spread MISO-wide on a load-ratio share basis or spread across a MISO-subregion if benefits are primarily provided to that single subregion. MISO's tariff states that MVP portfolios with benefits that spread broadly across either the Midwest or South subregion, and not the other subregion, are to have 100% of the costs allocated in the benefitting subregion.[xliii] The exact threshold of benefits is not clearly defined.

LRTP Tranche 2.1 Overview

The 2024 MTEP resulted in the approval of the Tranche 2.1 portfolio consisting of $22 billion of investment across 24 projects to expand and strengthen the 345 kV and 765 kV transmission system in the MISO Midwest subregion.[xliv] Tranche 2.1 is primarily a reliability-based portfolio and was developed over several years including more than 300 meetings and feedback on the process and solutions.

Tranche 2.1 meets all planning requirements by addressing multiple reliability issues and providing a benefit-cost ratio ranging from 1.8 to 3.5 as well as other benefits, such as economic development.



Source: MTEP24 Transmission Portfolio

LRTP and Tranche 2.1 Timeline

Currently, MISO is in the middle of a larger LRTP initiative. Tranche 2.1 was the most recent portfolio selected under the LRTP.

Formation of LRTP and Tranche 1:

In 2019-2020, MISO began to formulate a strategy for long-range planning as states, utilities and corporations within its territory began setting aggressive renewable and decarbonization goals. MISO members requested that MISO develop the LRTP process to address transmission needs and enable the most cost-effective regional investments. Given the magnitude of future needs, MISO created a conceptual, indicative roadmap as a basis to consider transmission solutions. The roadmap includes multiple tranches with different subregional focus areas.

Tranches 1, 2.1 and 2.2 – Midwest

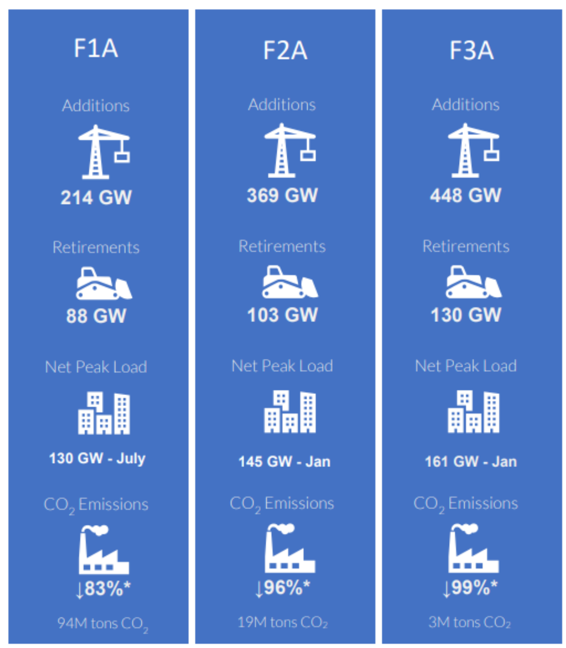
Tranche 3 – South

Tranche 4 – Midwest-South connection

The Tranche 1 portfolio was approved in July 2022 as part of MTEP21.[xlv] The portfolio totals $10.3 billion of investment and consists of 18 projects spread across the MISO Midwest. The full portfolio has a benefit-to-cost ratio of 2.6 - 3.8 and maximizes use of existing rights-of-way. The projects are now into regulatory approval processes.

Establish Futures and Siting

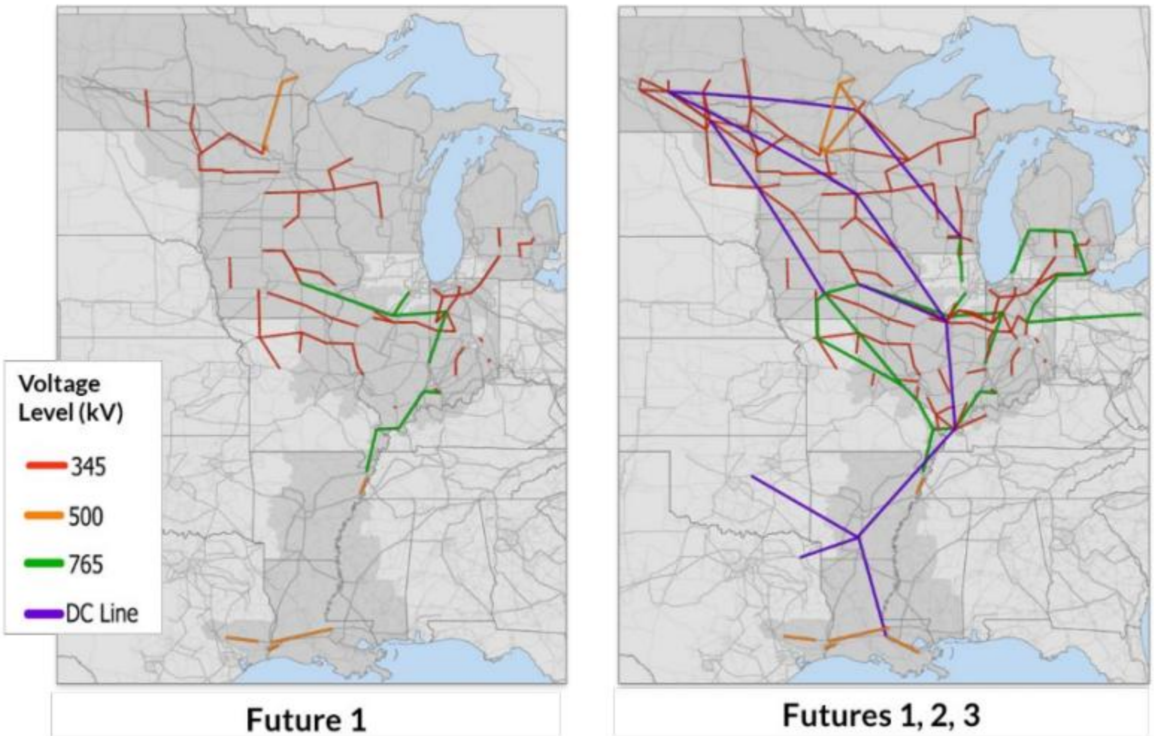
MISO began the LRTP Tranche 2.1 process in early 2023 by developing forward-looking planning scenarios called "Futures", which capture a range of economic, policy, and technological variables over a 20-year period, provide potential resource mixes, and consider future uncertainty. MISO formed several Futures that incorporate different levels of decarbonization, achievement of utility and states goals, generation retirements, and demand and energy growth (see image to the right).



Source: MTEP24 Chapter 2 Regional Long Range Transmission Planning

The second step is siting analysis, in which MISO analyzed where future generation would likely be located based on locational need, resource availability, and stakeholder feedback. Based on these inputs conceptual transmission solutions were developed for the Futures (see image on following page.) The Futures and siting process was informed by 500+ stakeholder revisions impacting the inputs.

For Tranche 2.1, MISO determined that Future 2A is the most aligned with a least-cost expansion that meets member goals.[xlvi] MISO builds on the Futures and siting process by developing reliability and economic models over 10-, 15- and 20-year horizons.



Source: MTEP24 Chapter 2 Regional Long Range Transmission Planning

Identify Transmission Needs

MISO performed reliability and economic analysis to identify transmission needs. The reliability analysis assesses whether the MISO transmission system can deliver energy from future resources to future loads. The analysis assesses a range of projected load and dispatch patterns associated with the Future 2A scenario in the 10- and 20-year time horizons. Economic analysis identifies congestion, generation curtailment, regional price separation and overall costs to serve load.

The studies identified severe congestion driven by high renewable energy penetration and increased load that lacked the adequate high-voltage transmission to be supported reliably. Overall, the analysis pointed to the need for a high-voltage transmission backbone that would eliminate congestion and price separation between West and East/Central regions (of the greater MISO Midwest subregion).[xlvii]

Propose Solutions

Based on the Futures, siting analysis and transmission needs determined, MISO identified potential transmission solutions to solve those needs. When considering what solutions to propose for Tranche 2.1, MISO assessed the differences between building a 765 kV versus a 345 kV backbone. The main considerations included:

- Transmission limits including safe loading limit and absolute limits,
- Cost per MW-Mile, and
- Land-Use per MW-Mile.

This step also included refining the projects part of Tranche 2.1 by removing, modifying and adding projects to optimize impacts. As part of the refinement, MISO conducted robustness testing, which refers to a process for reviewing the impact of system changes, specifically key projects. For the Tranche 2.1 process, the key projects included selected MTEP23 and MTEP24 projects, the MISO-SPP Joint Targeted Interconnection Queue (JTIQ) projects, and the Grain Belt Express Merchant HVDC project.

Finally, MISO performed an analysis of alternative transmission projects, which considers solutions received from stakeholders. MISO received 97 projects representing 47 transmission solutions. MISO includes mechanisms to assess non-transmission alternatives,[xlviii] though none were selected for inclusion in Tranche 2.1. Based on the alternative analysis, MISO made additions to the project portfolio in Minnesota, Iowa, Indiana, North Dakota, South Dakota, Michigan and a replacement in Missouri.[xlix] MISO published an initial draft portfolio of Tranche 2.1 in March 2024.

Evaluate and Justify Solutions

MISO used twelve reliability models representing various system conditions and dispatch patterns to fully assess system performance with and without the proposed LRTP portfolio of projects. The main considerations studied were the impact and severity of overloads and voltage violations. Across four different scenarios, MISO found that the LRTP Tranche 2.1 Portfolio would solve 50% to 72% of all 200 kV and above constraint violations.[l]

MISO also analyzed the full portfolio economically. It found that the Tranche 2.1 portfolio:

- Reduces economic congestion on existing transmission across the MISO Midwest subregion by 29.5%;
- Reduces curtailment in the MISO Midwest subregion by 27.1 TWh (11.2%);
- Reduces price separation across the subregions and decreases system cost to serve load;
- Facilitates a more economical dispatch for MISO Midwest resulting in $8.1 billion in Adjusted Production Cost savings; and
- Provides a robust regional backbone supporting 115.7 GW of Future 2A generation resource development.[li]

MISO developed a business case analysis to demonstrate financially quantifiable benefits of the portfolio exceed costs, as required by MVP eligibility criteria. MISO used methodologies to quantity benefits for nine metrics which can be grouped into four categories of benefits:

reliability, avoided investment, production costs and environmental. Benefits were calculated over a 20- and 40-year period starting from the assumed in-service date of 2032. The full details of the benefit metrics and methodologies can be found in the LRTP Tranche 2 Business Case Metrics Methodology Whitepaper.

The cost-benefit analysis found that the Tranche 2.1 portfolio delivers benefits totaling $51.7-$101 billion over a 20-year period with an overall portfolio-wide benefit-to-cost ratio ranging from 1.8 to 3.5.[lii]

Recommend Preferred Solutions

Following determination that the portfolio meets the cost-benefit ratio requirements, MISO finalized and recommended the project list to the Board of Directors for approval in October of 2024. The final Tranche 2.1 portfolio includes 24 projects and 323 facilities across the MISO Midwest subregion estimated to cost $21.8 billion, with target in-service dates from 2032 to 2034.

Cost Allocation

The final step under the LRTP process is to determine benefits and apportion portfolio costs across the MISO system, or Midwest subregion in the case of Tranche 2.1. MISO's analysis of nine benefit metrics identified the distribution of each benefit across the Cost Allocation Zones (CAZ) in the Midwest subregion. The cost allocation methods for each benefit metric vary:

- Based on location of reliability issues addressed by new transmission,
- Based on load ratio share in the subregion/region,
- Based on the zonal location of upgrade, and
- Based on economic benefits identified through modeling.[liii]

The MISO Midwest is formed of seven CAZ's. Ranges of benefit/cost ratios were applied to each CAZ based on the Future 2A scenario outcomes with a 20-year present value and 7.1% discount rate. According to cost recovery rules for MVPs, the costs of Tranche 2.1 projects are to be recovered from MISO load and exports associated with the MISO Midwest subregion through the energy-based MVP Usage Rate ($/MWh).

Competitive Selection Process

MISO evaluates which MVPs are eligible for competitive selection per MISO Tariff rules[liv] leading to Competitive Transmission Administrations (CTA) for the eligible projects.[lv] MISO determined that seven projects encompassing 24 of the Tranche 2.1 facilities are eligible for competitive selection and posted a schedule of the RFPs in February 2025. As a result, MISO plans to release seven Requests for Proposals (RFPs) for the competitive transmission projects over 2025 and 2026.[lvi]

For MVPs (or segments of projects) that are located in states with Right of First Refusal (ROFR) clauses for utilities to construct and own transmission, MISO directly assigns the projects to local TOs. In the case of Tranche 2.1, the states with a ROFR include Indiana, Michigan, Minnesota, North Dakota, and South Dakota. MISO has yet to release the full list of projects and assignment to TOs under the Tranche 2.1 portfolio.

After MISO selects developers for transmission projects under the competitive selection process or assigns TOs projects, the respective developers and owners are responsible for final routing, permitting and construction of the transmission facilities. This will include moving through the appropriate approval processes of state regulatory bodies. MISO monitors and reviews the projects selected through its status reports and dashboard under the MTEP webpage and MVP Triennial Reviews.[lvii,lviii]

MISO expects that the Tranche 2.1 portfolio projects will be constructed and in-service by 2032-2034. Assuming these dates are met, the LRTP Tranche 2.1 process will have taken 10-12 years to complete.

Minnesota-Manitoba Transmission Project

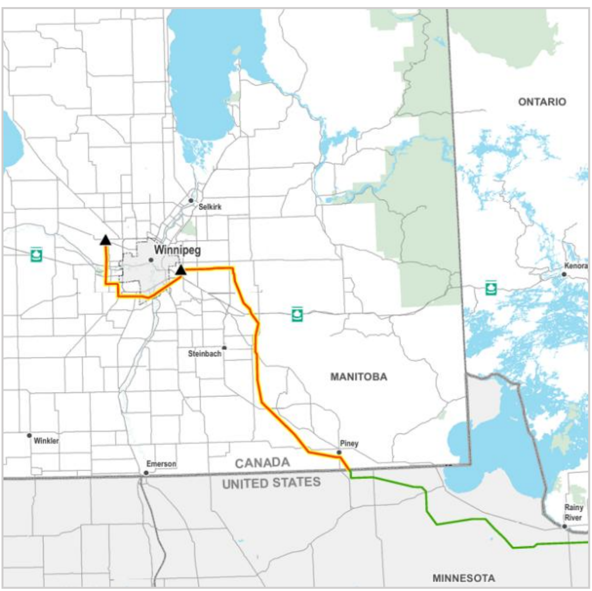
The Minnesota-Manitoba Transmission Project (the “MMTP”) is a 500 kV single circuit AC transmission system that connects Minnesota and Manitoba across the U.S.-Canada border. The MMTP was commissioned in 2020 and has been serving as an integral link between Minnesota and Manitoba. It serves as an informative example of how a large-scale transmission project crossing the U.S.-Canada international border was developed and approved.

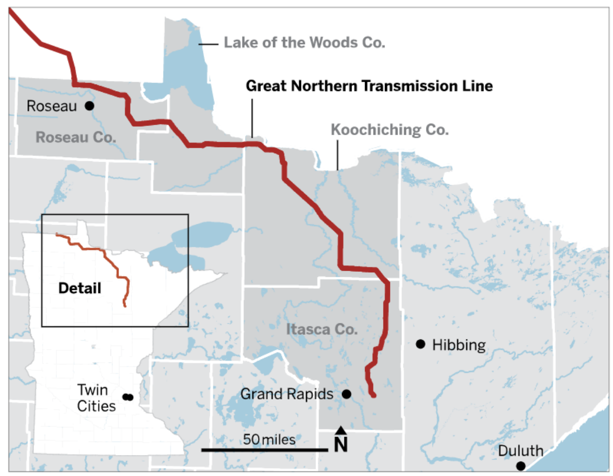
Overview of the MMTP

The MMTP consists of two segments: the Great Northern Transmission Line constructed by Minnesota Power in Minnesota and the Dorsey International Power Line (IPL) constructed by Manitoba Hydro in Manitoba. The MMTP traverses 437 miles, provides 883 MW of transmission capacity and cost $1.05 billion (USD).

The Great Northern Transmission Line runs from the Canada-US border in Roseau County to a substation in Grand Rapids, MN. The Dorsey IPL runs from Manitoba Hydro's Dorsey Converter Station to the international border. The project was first conceived in 2011-2012 by the two utilities who proceeded to work through the necessary regulatory and environmental approvals. MISO included both segments of the MMTP in its MTEP14 for planning purposes after submission by two utilities. Project construction was completed in June 2020.

Great Northern Transmission Line	Dorsey IPL
• $560M (USD) • 224 miles / 361 km • Minnesota Power • Cost recovery through MISO tariffs	• $490M (USD) • 213 miles / 213 km • Manitoba Hydro • Cost recovery through ratepayers and export revenue





Source: Canada Energy Regulator & Minnesota Power

Justification for the MMTP

The MMTP provides significant value for Minnesota, Manitoba and the greater MISO Midwest region. System benefits include clean energy resource supply, increased reliability across the MISO system and decreased price differentials. The project enables:

- Manitoba Power to export hydro power to the U.S and increases the opportunity for new power sales;
- Minnesota to access emission-free and lower-cost hydropower to serve baseload demand;
- Both Manitoba and Minnesota to improve reliability of power supply during emergency conditions or drought situations;
- Minnesota Power to balance the variability of its growing wind energy resources, allowing the utility and MISO to export excess wind to Manitoba for hydropower storage.

Manitoba Hydro and Minnesota Power executed contracts totaling 383 MW for the long-term sale of electricity to Minnesota Power. This includes a 250 MW agreement for a term of 15 years (signed in 2012 to start 2020) and a 133 MW Agreement for 20 years (signed in 2014 to start with completion of MMTP).[lix, lx] Manitoba Hydro's previous revenues from exporting power to Minnesota had reduced electricity rates in Manitoba and supported the ultimate decision to build the project in Manitoba.[lxi]

Minnesota Power's Bison Wind Energy Center is a combination of wind projects totalling nearly 500 MW in capacity in North Dakota. The wind center was cited as a major resource that would benefit of the MMTP as the project enables Minnesota Power to export wind energy to Manitoba for storage as hydropower and avoid curtailment of excess generation.[lxii] In addition, Minnesota at the time forecasted increased industrial load growth on Minnesota's Iron Range, the area in which the transmission line terminates.

MMTP reduces transmission losses and congestion between the pricing nodes on the U.S.-Canada border and MISO's pricing node for the Minneapolis area.[lxiii] This enables access to lower cost energy for Manitoba, Minnesota and MISO Midwest in day-ahead and real-time markets.

Cost Recovery

While both projects were included in the MISO's transmission planning, only the Great Northern Transmission Line was included in the MISO's 2014 MTEP for cost recovery through MISO tariffs.[lxiv] Manitoba participates in MISO's capacity and energy markets but does not provide full planning and operation of its transmission system to MISO.

Minnesota Power submitted the Great Northern Transmission Line to the MTEP14 process to be included in the planning and for cost recovery under MISO tariffs. MISO evaluated the project according to its MTEP cost-benefit framework. Because of project's features, it was classified as an MVP and was required to demonstrate financially quantifiable benefits exceeding costs. MISO concluded that the project met these requirements and included it in the MTEP14.[lxv] Given its status as an MVP, MISO applied a system-wide cost allocation on load-ratio share basis and Minnesota Power recovered its portion of costs via MISO's regional transmission charges through the assigned CAZs.

Manitoba Hydro, as a Crown Corporation serving the province, is required to receive approval from the Manitoba Public Utilities Board (PUB) to recover capital costs through its rate base. Manitoba Hydro applied for approval of the project under a Preferred Development Plan, which included the Dorsey IPL and other generation projects. Manitoba Hydro submitted that a significant portion of the plan's cost would be paid for by export revenues to the U.S., which would lower the overall impact on domestic ratepayers.[lxvi]

The Government of Manitoba advised Manitoba Hydro that it intended to have an independent body conduct a Needs For and Alternatives To (NFAT) review to inform whether the projects should be approved. In 2014, the Manitoba PUB released its report on the NFAT and recommended that the Dorsey IPL proceed.[lxvii] In December 2014, the Minister of

Manitoba responsible for the PUB released an Order in Council in response to the NFAT report approving the construction and operation of the Dorsey IPL.[lxviii]

Timeline and Regulatory Approvals

The MMTP involved a significant regulatory undertaking. In addition to receiving the inclusion by MISO in its MTEP14 and approval for cost recovery by the Manitoba PUB, the two segments required permitting and regulatory approvals from the U.S. and Canadian governments, as well as Minnesota and Manitoba. The MMTP was required to obtain the following approvals from their respective regulatory bodies, agencies, and organizations.[lxix]

Great Northern Transmission Line:

- MISO – MTEP Approval (2014)
- Federal Energy Regulatory Commission – Construction Agreement (2015)
- Minnesota Public Utilities Commission – Certificate of Need (2015) & Route Permit (2016)
- Minnesota Department of Commerce – Certificate of Need (2016)
- U.S. Department of Energy – Environmental Impact Statement (2015) & Presidential Permit (2016)
- US Army Corps of Engineers – Section 404 Permit (2016)
- US Fish and Wildlife Service – ROW Permit (2017)[lxx]

Dorsey IPL:

- Manitoba PUC – NAFT Review (2014)
- Canada National Energy Board (NEB)[lxxi] – Environmental Assessment and International Project Approval (2018)
- Manitoba Conservation and Climate – Environmental Impact Statement (2019)[lxxii]

APPENDIX C: THE CELTIC INTERCONNECTOR

Overview of the Project

The Celtic Interconnector (the "Project") is a transmission project to link the electricity grids of Ireland and France, facilitating the exchange of 700 MW between the two countries. The Project, designated a Project of Common Interest (PCI) in the TYNDP process, is under construction and expected to be commissioned by 2027.

The 575 km high voltage direct current subsea cable will improve energy security, support the transition to renewable energy, and enhance the flexibility of the European energy market.

The Project Capex is €1.6 billion, with €531 million in funding provided by the EU.

Justification for the Project

The Celtic Interconnector will improve security of supply in Ireland and France, facilitate electricity trading, and increase competition resulting in downward pressure on electricity prices. The Project will also support the development of renewable energy in both countries.

- The average marginal price difference would be higher than 10€/MWh between France and Ireland in future scenarios without the Project, and only between 5€ and 10€/MWh with the addition of the Project.[lxxiii]
- The project facilitates better access (for France) to renewable energy generation, specifically onshore wind in Ireland, and avoids curtailment of wind energy in Ireland. Curtailment of wind in Ireland decreases by half (3 TWh) in 2030 with the addition of the Project.[lxxiv]
- The project enables Ireland to receive benefits from the more stable continental grid, increasing the security of supply and enhancing management of reactive power and frequency.

Process to Identify Need, Select the Project and Determine Cost Allocation

The following sections describe the need identification process and project development sequence for interregional projects in Europe. The need for a project connecting Ireland and France was first identified in Europe-wide energy planning, and the Project then progressed through a six-step development process: 1) cost-benefit analysis; 2) early development funded in part by the EU; 3) application for EU funding to support construction, 4) receipt of EU funding; 5) cost allocation agreement, and 6) inclusion in national development plans, permitting, and construction.

Need Identification in the Ten-Year National Development Plan (TYNDP)

The TYNDP is the EU's central planning process for electricity infrastructure. The plan, released in multiple documents, is published every two years and maps out Europe's electricity transmission infrastructure needs over the next decade to support the EU's energy policy objectives.

The main objectives of the TYNDP are:

- Integration of renewable energy;
- Cross-border electricity market efficiency;
- Security of supply; and
- Decarbonization and climate neutrality goals.

The TYNDP includes:

- Pan-European grid expansion scenarios;
- Identification of infrastructure gaps that require attention;
- Cost-benefit analyses (CBAs) of proposed projects; and
- Evaluation of projects for eligibility as a Project of Common Interest or Project of Mutual Interest

The TYNDP includes a System Needs Study identifying where the flow of electricity could be improved across Europe to reach decarbonization targets and increase reliability. Designing solutions to address identified needs is the responsibility of project promoters, who may propose projects for assessment in the TYNDP.[lxxv] Project promoters are primarily TSOs in ENTSO-E participating countries, and entities other than TSOs can promote projects.[lxxvi] In order to submit a project into the TYNDP, the project must demonstrate:

- A cross-border impact;
- A contribution to EU energy goals; and
- Technical and economic maturity.

ENTSO-E performs a cost-benefit analysis (CBA) for the project, assessing multiple indicators, including how the project impacts socio-economic welfare, security of supply, CO_2 emissions, integration of renewable energy sources, and frequency stability. Inclusion in the TYNDP is mandatory for a project to be considered for PCI/PMI status under the EU's TEN-E Regulation. The TYNDP CBA process is the first major filter and planning stage for any large-scale cross-border European transmission project.[lxxvii]

Below is an outline of the steps carried out by the Project as it moved from a concept in the TYNDP to inclusion in transmission plans of EirGrid (Ireland's TSO) and RTE (the French TSO).

Step 1: Inclusion in the TYNDP (Concept Phase)

Projects can enter the TYNDP based on high-level feasibility demonstration, potential to meet EU energy goals (market integration, security of supply, sustainability), and interest from TSOs or developers.

The Celtic Interconnector was submitted by EirGrid and RTE and included in early TYNDPs (2012) due to its potential to:

- Improve energy security for Ireland (then largely isolated from EU markets);
- Enable renewable energy exports from Ireland; and
- Strengthen EU market integration.

The TDYNP found investment needs between Ireland and France due to new renewable energy generation in southern Ireland and northwest France, a market integration bottleneck between the two countries causing price differences, and security of supply in northwest France.

The Project was assessed for its costs and benefits according to the CBA Guidelines of Grid Development Projects and the 2012 TYNDP found that the conceptual Project was of pan-European significance in the long term (2017-2022).

The TYNDP CBA evaluates the following:

Cost-Benefit Category	Description
Socio-Economic Welfare	Measures overall system cost reduction (e.g. cheaper electricity prices, reduced congestion).
Security of Supply	Evaluates resilience and backup capacity – especially relevant for island systems like Ireland.
RES Integration	Quantifies ability to integrate more renewable energy by improving grid flexibility.
CO_2 Emissions	Projects that reduce reliance on fossil generation get higher scores.
Losses Reduction	Assesses decrease in transmission losses (i.e., energy efficiency gains).
Flexibility & Curtailment	Quantifies renewable energy that would otherwise be curtailed due to lack of grid access.
Technical Resilience	Improves grid stability and operational security, especially across borders.
Market Integration	Reduces market isolation and price volatility across regions

The Celtic Interconnector scored strongly in the CBA because it:

- Reduces Ireland's energy isolation;

- Enables integration of Ireland's vast wind resources;
- Improves price convergence between Ireland and continental Europe;
- Enhances energy security in both countries; and
- Allows for mutual emergency support.

Step 2: National and Regional Support including Feasibility Studies

Based on the above TYNDP findings, both TSOs must agree to jointly develop the Project and adopt it as a potential transmission solution in their national development plans. Both EirGrid and RTE decided to jointly move forward with the Project and advance development through:

- Feasibility studies on route, technical design, and grid integration, funded in part with €3.5 million from the EU, as further described below.
- Additional cost-benefit analysis by EirGrid and RTE (using the ENTSO-E's cost benefit methodology);
- Public consultations and environmental assessments; and
- Coordination between regulators – Commission for Regulation of Utilities in Ireland and Commission de Régulation de l'Énergie in France – to assess the economic viability and stakeholder support.

Step 3: Application for Designation as a Project of Common Interest (PCI)

Following the additional development steps noted above EirGrid and RTS applied for designation as PCI in order to receive financial, regulatory and permitting support.

To be designated as a PCI, a project must:

- Be included in the latest TYNDP;
- Produce significant cross-border benefits;
- Enhance market integration, competition, and system flexibility;
- Enhance energy security; and
- Contribute to EU energy and climate targets.[lxxviii]

The Celtic Interconnector met all these criteria and was therefore included on the PCI list in 2013.

Step 4: Access to EU Funding and PCI Benefits

As a PCI, the Celtic Interconnector became eligible for EU financial support through the Connecting Europe Facility (CEF) for Energy. The CEF is a key EU funding instrument designed to enhance infrastructure across the EU in the areas of transport, energy and digital services. Its primary goal is to foster economic growth, job creation and competitiveness.

The support / benefits obtained by the Project included:

- Grants for studies and works. The Project received funding for both preparatory studies and construction.
- Accelerated permitting processes through streamlined rules and environmental assessments. As a PCI, the Project falls under a single national authority for obtaining permits with a maximum timeline of 3.5 years.
- Support from the Innovation and Networks Executive Agency (INEA) and later European Climate, Infrastructure and Environment Executive Agency (CINEA), which manage CEF funds.

The Celtic Interconnector received:

- €3.5 million for feasibility and permitting stages (2013-2016);
- €4 million for regulatory and cost allocation stages (2017-2019); and
- €531 million in CEF grants to support construction. This funding was secured in Q4 2019.

Step 5: Regulatory Approval and Cost Allocation

While a PCI falls under one authority for major permitting in the EU, the project promoters must receive approval from the national regulatory authorities (NRAs) and other environmental and social bodies of their respective countries. For the Celtic Interconnector, the NRAs were the CRU in Ireland and the CRE in France.

- In 2018, EirGrid and RTE submitted a Joint Investment Request to the CRU and CRE for approval to include the Project's cost in the country's tariffs and a decision on Cross-Border Cost Allocation (CBCA). See below for detail on the CBCA process and outcome.
- In 2019 both regulatory bodies approved funding the Project.
- A Cross-Border Cost Allocation (CBCA) decision was made to split costs fairly between countries based on projected benefits.
- The Agency for the Cooperation of Energy Regulators (ACER) helped mediate and approve the CBCA. (ACER is an EU agency whose primary responsibility is to coordinate and support national energy regulators in the EU).
- Following approvals in 2019 EirGrid and RTE both filed Environmental Impact Assessments (EIA) and other applications to the appropriate authorities in their countries and the United Kingdom (for crossing UK managed waters).

Cross-Border Cost Allocation

EirGrid and RTE submitted a Joint Investment Request to CRU of Ireland and CRE of France for approval to recover the costs of the Project and establish cost allocation. The filing provided a full review of the Project, including application of the most-recent CBA framework used in the 2018 TYNDP. In addition, other externalities of the Project that are not captured within the CBA were considered such as the positive externalities of solidarity, market integration and sustainability. The Investment Request additionally proposed EirGrid and RTE's proposal for CBCA.

Cost-benefit analysis found benefit accrual of ~35% to France and ~65% to Ireland[lxxix] as a consequence of the Project's two primary benefits: facilitating increased renewable energy generation in Ireland and providing Ireland with access to lower cost power in France. Overall, the CBA demonstrated that the Project delivers significant benefit to Europe and a positive NPV.

The benefits analysis in the Investment Request also evaluated whether additional countries would receive benefits sufficient to merit allocating costs such countries. ACER CBCA guidelines recommend that only countries with a net-positive impact exceeding 10% of the sum of impacts should be consulted to share costs. EirGrid and RTE found that no other EU country met this significance threshold; this confirmed there was no need to consult TSOs of other countries and confirmed that Ireland and France would fund the Project.[lxxx]

Given the net benefit disparity between Ireland and France, EirGrid and RTE agreed on the need for a CBCA decision and provided a proposal to both NRAs according to ACER guidelines. The joint CBCA decision set out the following:

- Assume that about 60% of the Project's costs would be covered by CEF funding.
- For the remainder of the Project's cost, 65% would be allocated to EirGrid and 35% to RTE.[lxxxi]
- Revenue would be shared 50:50 up to a yearly cumulative threshold. Revenue in excess of this threshold would be provided to EirGrid until any difference in net investment is met; the additional revenue returns to 50:50.

Step 6: Integration into National Development Plans, Final Development Construction

After securing the CBCA decision and CEF funding:

- The Project was formally included in the grid development plans of both EirGrid and RTE (2019).[lxxxii,lxxxiii] As a result, in subsequent national grid development plans and TYNDPs, the interconnector is assumed to be in service.
- EirGrid, RTE and the NRAs finalized regulatory frameworks. This includes updating the CBCA as Project costs, benefits, and funding are finalized. In addition, these parties conducted proceedings to determine cost recovery models for their portion of costs in each country. EriGrid and RTE are both recovering costs from their respective rate bases through a regulated asset base mechanism using a Weighted Average Cost of Capital.[lxxxiv ,lxxxv]
- Final public consultations, permitting and design were completed from 2019 to 2023.
- Final Investment Decision was made in 2022. Project financing of €800 million was agreed with the European Investment Bank, Danske Bank, BNP and Barclays.
- Construction planning and contracting phases began in 2023, with a target operational date of late 2026 or early 2027.

ENDNOTES:

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[i] NERC, 2025, *Interregional Transfer Capability Study*

[ii] MIT Center for Energy and Environmental Policy Research, 2020, *Two-Way Trade in Green Electrons: Deep Decarbonization of the Northeastern U.S. and the Role of Canadian Hydropower*

[iii] The scope of IESO's Transmitter Selection Framework is under development and may lead to an increase in transmission owned by entities other than Hydro One.

[iv] Québec and Newfoundland and Labrador have 210 TWh of energy potential in hydroelectric reservoirs, equivalent to about 23,000 times the total capacity of battery energy storage facilities in operation across Eastern Canada and the Northeast U.S. "Hydro banking" is further discussed in Section V. Hydro Québec states that it has combined storage capacity of over 176 TWh and NL Hydro reports on average Churchill Falls generates over 34 TWh of energy annually.

[v] RFI available at: https://energyinstitute.jhu.edu/wp-content/uploads/2025/06/Northeast-States-Collaborative_RFI_FINAL-6_20_25.pdf

[vi] See: First ministers' meeting: Moving energy from Eastern Canada a priority

[vii] See: https://www.facebook.com/nsgov/videos/nova-scotia-proudly-supports-the-eastern-energy-partnership-an-ambitious-move-to/726910363125547/

[viii] On March 5, 2025, the Canada Infrastructure Bank committed $217 million (CAD) to support the Wasoqonatl Reliability Intertie, see: https://cib-bic.ca/en/medias/articles/cib-commits-217-million-to-nova-scotia-to-new-brunswick-wasoqonatl-reliability-intertie/

[ix] New hydroelectric capacity includes expansion of the existing Churchill Falls facility (1,650 MW) and construction of the new Gull Island facility (2,250 MW). MOU available at: https://www.ourchapter.ca/files/NewfoundlandLabrador-Québec-MOU-English-Dec12-2024.pdf.

[x] MVPs eligible or competitive procurement must provide regional or subregional public policy, economic and/or reliability benefits, have a project cost of $20 million or more, involve facilities with voltages of 100 kV or higher, and are required to demonstrate that financially quantifiable benefits exceed costs.

[xi] States in MISO footprint with ROFR in effect: Indiana, Michigan, Minnesota, Mississippi, North Dakota, and South Dakota

[xii] See: https://www.entsoe.eu/about/

[xiii] The EU Agency for the Cooperation of Energy Regulators (ACER) Cross-Border Cost Allocation guidelines recommend that TSOs for which net-positive impacts exceeding 10% of the sum of impacts should be consulted to share costs. See Appendix A for additional detail.

[xiv] The goal is based on the findings of the "All Options" pathway in the Energy Pathways to Deep Decarbonization report published by the Massachusetts Department of Energy Resources in December 2020.

[xv] See Collaborative Strategic Action Plan at 5.

[xvi] ISO-NE could then identify in-region HLCs associated with new interregional transmission through an LTTS. Based results of the LTTS NESCOE could request that ISO-NE procure solutions to address one or more HLCs associated with developing new interregional transmission.

[xvii] These authorizations, by state, include: MA: MGL §179 Sec. 82, CT: §16a-3n, RI: §39-31-5, ME: 35-A M.R.S §3210-H, VT: 30 V.S.A. §218c

[xviii] See the Brattle Group's 2021 Report A Roadmap to Improved Interregional Transmission Planning for discussion of the full range of transmission system benefits and best practices for allocating transmission costs based on benefits.

[xix] 2023 Northeast Coordinated System Plan, page 2

[xx] See: https://cib-bic.ca/en/medias/articles/cib-commits-217-million-to-nova-scotia-to-new-brunswick-wasoqonatl-reliability-intertie/

[xxi] See: https://www.energy.gov/gdo/standardization-interregional-offshore-wind-transmission

[xxii] DOE, 2024, Barriers and Opportunities to Realize the System Value of Interregional Transmission.

[xxiii] Materials related to the LTTP RFP are available at: https://www.iso-ne.com/system-planning/transmission-planning/competitive-transmission

[xxiv] Order 1920, (2024)

[xxv] Section D of the Strategic Action Plan discusses the opportunity to advance interregional projects through the Order 1920 compliance process in detail.

[xxvi] See: https://www.iso-ne.com/static-assets/documents/100020/rm21-17-000.pdf

[xxvii] E3 for NARUC, 2024, *Collaborative Enhancements to Unlock Interregional Transmission*, ACORE, 2023, *The Need for Intertie Optimization: Reducing Customer Costs, Improving Grid Resilience, and Encouraging Interregional Transmission*, Brattle Group, 2024 *Intertie Optimization: Efficient Use of Interregional Transmission (Update)*,

[xxviii] Supra xvii at 11.

[xxix] See Net Zero Atlantic's June 2025 report Market Opportunities for Offshore Wind in Atlantic Canada, available at: Atlantic Canada Offshore Wind Grid Integration and Transmission Study | Net Zero Atlantic

[xxx] In terms of MWs of demand, Hydro One's transmission network accounts for more than 98% of demand. See the OEB's Uniform Transmission Rates (UTR) for the amount of MWs and revenue requirement for the different transmitters in Ontario. See: https://www.rds.oeb.ca/CMWebDrawer/Record/880955/File/document

[xxxi] Per the 2025 Annual Planning Outlook the Integrated Regional Resource Plan in the Niagara region will "consider opportunities for Ontario's intertie with New York in the Niagara area when developing options for reinforcing the bulk system in the area." Similarly, in Eastern Ontario, the IESO's bulk plan will "examine the potential for new and/or expanded interties with neighbouring jurisdictions."

[xxxii] See the 2025 Annual Planning Outlook (APO): https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/2025/2025-Annual-Planning-Outlook.pdf, page 41 and 57.

[xxxiii] Supra, iii.

[xxxiv] The LTTP process is governed by Section 16 of Attachment K to the ISO-NE Open Access Transmission Tariff.

[xxxv] The NESCOE-requested scope of the LTTP includes interconnection of at least 1,200 MW of onshore wind, increasing the Maine-New Hampshire and Suroweic-South Interface to 3,000 MW and 3,200 MW, respectively. This could enable additional development of solar or other new projects in Maine in addition to onshore wind. See: https://www.iso-ne.com/static-assets/documents/100018/a05_2024_12_18_pac_transmission_needs_for_a_longer-term_transmission_planning_rfp_final.pdf

[xxxvi] Supra, xvi.

[xxxvii] See: https://www.nyiso.com/planning

[xxxviii] The PPTN process is governed by Section 31.4 of Attachment Y to the New York Open Access Transmission Tariff, available at: Tariffs, FERC Filings & Orders - NYISO

[xxxix] See: https://www.nyiso.com/documents/20142/40894368/New-York-City-Offshore-Wind-Public-Policy-Transmission-Need-Project-Solicitation.pdf

[xl] See: https://www.crosssoundcable.com

[xli] See: https://chpexpress.com/

[xlii] See: https://www.necleanenergyconnect.org/

[xliii] MISO Tariff, Attachment FF - Transmission Expansion Planning Protocol

[xliv] MISO, MTEP24 Transmission Portfolio

[xlv] MISO, MISO Transmission Expansion Plan (MTEP), See Previous MTEP Reports MTEP21.zip

[xlvi] MISO, MTEP24 Chapter 2 - Regional Long Range Transmission Planning

[xlvii] *Id.*

[xlviii] MISO, https://www.misoenergy.org/engage/MISO-Dashboard/mtep-selection-of-non-transmission-alternatives/

[xlix] *Id, see pages 41-62 for alternative analysis.*

[l] *Id.*

[li] *Id.*

[lii] *Id.*

[liii] MISO uses PROMOD for its economic modeling which is a production cost modeling tool providing hourly (annual) chronological security-constrained unit commitment and economic dispatch.

[liv] *Supra, xliii.*

[lv] MISO, Business Practices Manuals. See MISO BPM-020, Section 7.5

[lvi] MISO, LRTP Tranche 2.1 RFP Release Schedule

[lvii] MISO, MISO Transmission Expansion Plan (MTEP)

[lviii] MISO, Multi-Value Projects (MVPs)

[lix] The Manitoba Hydro-Electric Board & Minnesota Power, 250 MW System Power Sale Agreement

[lx] The Manitoba Hydro-Electric Board & Minnesota Power, 133 MW System Power Sale Agreement

[lxi] National Energy Board, Reasons for Decision Manitoba Hydro EH-001-2017, 2018, November

[lxii] Minnesota Power, Great Northern Transmission Line

[lxiii] *Supra, lxi.*

[lxiv] MISO, MTEP14

[lxv] *Supra, lxiv.*

[lxvi] Manitoba PUB, Report on the Needs For and Alternatives To (NFAT)

[lxvii] *Supra, lxvi.*

[lxviii] Manitoba Minister, Order in Council 00545 / 2014

[lxix] The list of regulatory approvals is not comprehensive but offers the major regulatory approvals and permits required.

[lxx] Great Northern Transmission Line, About the Project

[lxxi] The NEB now operates as the Canada Energy Regulator (CER).

[lxxii] Manitoba Hydro, Completed major projects

[lxxiii] ENTSO-E, TYNDP 2022 System Needs Study, Opportunities for a more efficient European power system in 2030 and 2040

[lxxiv] ENTSO-E, TYNDP 2020 System Needs Study, Completing the map Power system needs in 2030 and 2040

[lxxv] ENTSO-E, TYNDP Promoter Corner

[lxxvi]To be an eligible project promoter, an entity must hold a transmission operating license in a regulated environment (either ENTSO-E represented country or other country if the project is located in an EU country) or is promoting a project that is eligible to be considered under the interconnector exemption pursuant to Article 63 of Regulation EU 2019/943. The latter allows non-TSO entities to submit interconnector projects. The projects themselves must either be a result of a prior TYNDP system needs study, featured in the most recent PCI/PMI list, be part of a county's most recent national development plan, have a letter of support from a member state, have a signed agreement by all concerned TSOs, or have applied for (or received) the interconnector exemption. National Grid Ventures, Xlinks Ltd, and Zhero (Medlink) are examples of non-TSO project promoters. ENTSO-E, TYNDP 2022 Guidance for applicants – Transmission and storage projects promoters

[lxxvii] Promoters may submit projects that are not cross-border (wholly within one member state) to move through the TYNDP CBA process in order to gain funding or regulatory benefits.

[lxxviii] European Commission, PCI and PMI selection process

[lxxix] The CBA results demonstrated that if costs were shared equally between the Project promoters and benefits accrue as predicted, France would be subject to net negative impacts.

[lxxx] The evaluation determined across all four scenarios studied that Ireland and France were the only countries with net benefits over 10%, with the two countries' net benefits totalling near 70%-80% across three scenarios. In one scenario, almost 50% of the benefits were split across 15 countries but no country reached the significance threshold.

[lxxxi] EirGrid, RTE and the NRAs agreed to review the CBCA if significant changes to benefits resulted from various economic factors and when the final CEF funding amount was granted.

[lxxxii] EirGrid, Transmission Development Plan 2021-2030

[lxxxiii] RTE, French transmission network development plan 2019

[lxxxiv] Ireland CRU, Celtic Electricity Interconnector "EirGrid – Regulatory Framework Request

[lxxxv] RTE, A stable and sustainable business model