Billions on the line:

Delivering on the federal-Alberta MOU to unlock interprovincial transmission in Western Canada

JANUARY 2026 | **Joel Krupa**
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About us

Clean Prosperity is a Canadian climate policy organization that advocates for pragmatic solutions to grow the low-carbon economy.

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Abbreviations

AESO	Alberta Electric System Operator
CER	Canada Energy Regulator
CIB	Canada Infrastructure Bank
FERC	U.S. Federal Energy Regulatory Commission
ITC	investment tax credit
LTO	AESO’s Long Term Outlook
LTP	AESO Long-term Transmission Plan
MOU	memorandum of understanding
NRCAN	Natural Resources Canada
OTP	optimal transmission planning
REM	Restructured Energy Market
SREPs	Smart Renewables and Electrification Pathways program

Executive summary

In November 2025, the federal and Alberta governments signed a memorandum of understanding (MOU) that could be a breakthrough for decarbonization. It is a major energy policy rethink, touching on every aspect of the energy transition.

In the MOU, the governments commit to build a strong and integrated interprovincial transmission grid. Specifically, Alberta agreed to work with Ottawa "to significantly increase the intertie transfer capability between the western provinces." The MOU explicitly calls for the "construction of large transmission interties with British Columbia and Saskatchewan."

These provisions of the agreement build on recent political momentum. Both the federal and Alberta governments have identified building an integrated east-west power grid as an opportunity for Canada and Alberta to strengthen the economy and meet rising energy needs in a reliable, affordable, and sustainable manner. The MOU may represent the strongest political alignment on interties in decades.

This is a unique moment of opportunity for Canada's electricity future. Alberta — like other provinces — faces rising electricity demand from residential and industrial consumers, a growing and electrifying economy, and affordability pressures. At the same time, Alberta — like other provinces — has an electricity system that is largely siloed, with limited connectivity to other provincial power grids. In fact, Canadian provinces are better connected with the U.S. markets than neighbouring provinces. Strengthening interprovincial connectivity is important for enhancing reliability, lowering costs for consumers, and anchoring decarbonization efforts.

> Both the federal and Alberta governments have identified building an integrated east-west power grid as an opportunity for Canada and Alberta to strengthen the economy and meet rising energy needs in a reliable, affordable, and sustainable manner.

But the MOU stops short of outlining a specific plan to get there. Intertie projects require the participation of British Columbia and Saskatchewan and other stakeholders (i.e. system operators) that were not signatories to the MOU. This limited the ability to include binding implementation details. But the agreement could have set out a clear process or timeline for engaging the other provinces and assigned transmission-related outcomes to the implementation committee mandated by the MOU. Other focus areas in the agreement outline policy measures, cooperation agreements, funding arrangements, and next steps for their respective priorities; no such detail is provided for interprovincial transmission.

This report aims to help fill that gap by providing an Alberta-focused case study for expanded interprovincial transmission. We build on the work of others[1] to discuss the benefits of a more integrated grid and the barriers to expanding transmission, as well as lay out the important first steps needed to turn the MOU's commitments on interties into reality. Alberta and the federal government need to outline an implementation plan and this report sets out what that plan should contain. We recommend:

1. COMMIT TO A PLAN

The **Alberta and federal governments, in partnership with British Columbia and Saskatchewan, should develop a clear implementation plan** for expanding interprovincial transmission by April 1, 2026.

A strong implementation plan should include the following three components:

2. COLLABORATION

The **federal government and Western Canadian provincial governments should establish formal transmission-specific working groups** that begin with dialogue aimed at improving collaboration and harmonizing planning efforts. The working groups should include system operators, utilities, and Indigenous communities.

a) While provinces should lead planning and coordination for interprovincial transmission projects, **a limited federal role is warranted where there is an absence of effective provincial coordination** to advance the goals in the MOU. If such circumstances arise, the federal government should request that the Canada Energy Regulator (CER):

- work with the provinces to identify interprovincial transmission opportunities;
- clarify the jurisdictional demarcations of interprovincial provincial transmission lines; and
- once this jurisdictional clarity is established, consider exercising its permitting authority, while not seeking to regulate operations.

[1] Refer to recent work by Madeleine McPherson, Blake Shaffer and Philippe Dunsky, the Canadian Climate Institute, Corporate Knights, and a joint Indigenous/non-Indigenous contribution co-written by the lead author of this work.

3. QUANTIFICATION OF THE BENEFITS

The **Alberta Electric System Operator (AESO) should quantify the full range of costs and benefits from expanded interprovincial transmission.** This would be a new approach to transmission planning in Alberta — which currently uses a narrow scope when considering the benefits of new transmission infrastructure.

This is work that could be advanced by sharing data within the working groups described in recommendation two. The federal and Alberta governments should help fund this work and require that the results be made publicly available.

4. FUNDING MOBILIZATION

The federal government should accelerate interprovincial transmission projects by:

i. **Deploying the Canada Infrastructure Bank's newly expanded $45 billion capital envelope** to offer concessional financing for intertie projects, and
ii. **Considering increasing the Clean Electricity Investment Tax Credit's 15% credit for intertie projects**, as proposed by the Canada Electricity Advisory Council.

The convergence of affordability concerns, electrification-driven demand, and a commitment to east-west electricity trade makes this a pivotal moment. Seizing the opportunity could position Alberta — and Canada — for greater economic resilience, cleaner energy, and stronger interprovincial ties.

Introduction

Alberta has always understood the importance of getting its energy to market. For decades, the province has advocated relentlessly to ensure the requisite pipelines, infrastructure, and policies are in place to move its traditional energy resources, oil and gas, to where they are needed. The November 2025 memorandum of understanding (MOU) between the federal and Alberta governments recognizes the strategic importance of Alberta's energy resources. The MOU also points to the construction of new electricity transmission interties as an important part of Alberta and Canada's energy future. This signals that governments are ready to work on a long-discussed energy market opportunity: interprovincial electricity transmission.

Canada generally, and Alberta specifically, have underdeveloped interprovincial transmission infrastructure.[2] Maintaining this status quo will inflict significant negative economic consequences. Over the coming decades, Alberta generators and ratepayers could miss out on billions in savings on electricity system costs, as well as billions of dollars in foregone reliability benefits.[3] In an era of expanding international protectionism, the costs of inadequate transmission interconnection could

[2] Alberta is among the least connected electricity systems in North America, and the least interconnected province as a percentage of electrical load.

[3] Among other concerns, the lack of robust interties hampers Alberta's ability to reliably import electricity — even in unstable times when the province is at risk of blackouts. The rotating outages across Alberta in April 2024 show that this gap needs to be addressed urgently.

escalate further as provinces are hindered in their ability to trade clean electricity through leveraging natural interregional complementarities.[4]

Expanding interprovincial transmission is even more urgent as Alberta's economy, like other provincial economies, grows and electrifies. Residential consumers are increasingly installing air conditioners, adopting heat pumps, and driving electric vehicles. Industrial consumers are exploring electrification opportunities to reduce emissions, and emerging sectors such as data centres and direct air capture require substantial amounts of electricity to power their operations.

Reliable, affordable, and low-carbon electricity will be critical not only to Alberta's economic growth and stability, but also to its reputation as a jurisdiction that gets things done. The Alberta Electric System Operator's (AESO) 2024 Long-Term Outlook (LTO) now projects electricity demand growth of 1.2% annually — triple the 0.4% forecast in its 2021 LTO. Similarly, BC Hydro is forecasting a 15% increase in electricity demand between 2024 and 2030, prompting that utility to issue calls for power in 2024 and 2025. Meeting this increasing demand for electricity will require a multifaceted approach (including net new generation), and interprovincial transmission is a vital component in building the electricity system of the future.

Now more than ever, expanding interprovincial transmission presents an important opportunity to create important benefits for diverse stakeholder and rightsholder groups:

For Canada: In the wake of U.S. tariffs and threats to Canadian sovereignty, expanding transmission between the provinces can help accelerate our electricity autonomy by reducing U.S. regulatory influence in our electricity markets. In exchange for access to the U.S. market, the U.S. Federal Energy Regulatory Commission (FERC) exerts significant influence on Canadian soil. Saunders (2001) argues[5] that FERC acts as the de facto regulator of many Canadian electricity markets. It's time for policy and regulatory approaches that pave the way for greater east-west connectivity, rather than focusing on north-south connections.

For Alberta: The province stands to realize billions in net financial savings over the next few decades, as well as additional billions worth of benefits from greater reliability and security. Expanding interprovincial transmission will help attract investment, promote the acceleration of grid modernization, maximize the efficient use of existing power generation reserves, create greater economic diversification and export opportunities, and diversify the generation supply mix.

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[4] Across the West, for example, Alberta benefits from substantial wind and solar resources, Saskatchewan has excellent solar resources, and British Columbia has abundant hydropower. On windy days, Alberta could send excess power to Saskatchewan and British Columbia. In hours when there is no wind or sun, British Columbia could sell hydropower to Alberta.

[5] The link directs readers to a short memo summarizing some of the core arguments in Saunders, J. Owen (2001), "North American Deregulation of Electricity: Sharing Regulatory Sovereignty," Texas International Law Journal 36, no. 1: 167–173.

For consumers: Access to more diverse electricity sources will not only improve grid reliability (thereby minimizing the risk of outages for residential, commercial, and industrial consumers), but it also has the potential to lower electricity costs. Curtailment of Alberta's existing interties with B.C. and Montana is estimated to cost Alberta electricity consumers an additional $300 to $500 million annually by meeting demand with higher-cost local generation instead of lower-cost imports.[6]

For Indigenous governments: Many Indigenous organizations and governments want to partner with public and private sector counterparts on sustainability-focused economic reconciliation.[7] The First Nations Major Projects Coalition's 2024 National Indigenous Electrification Strategy explicitly calls for "the rapid build-out of interjurisdictional transmission lines and interties."

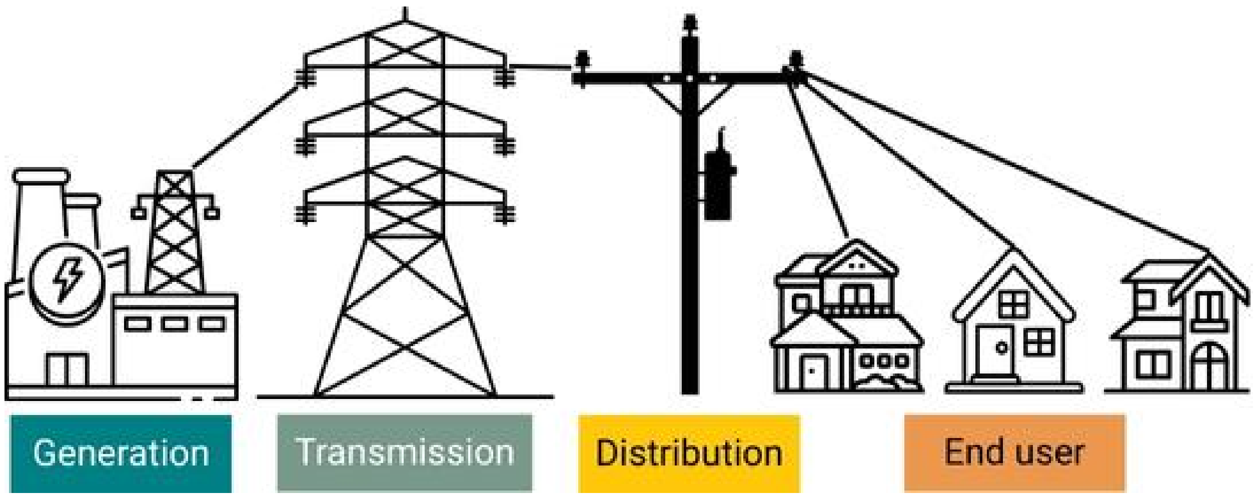
In sum, Canada is in a unique moment where expanding interprovincial transmission is widely recognized as beneficial and there is political consensus and momentum behind expanding transmission infrastructure. Still, the path forward is not entirely clear. While the federal-Alberta MOU commits to "significantly increase the intertie transfer capability between the western provinces" and "[construct] large transmission interties with British Columbia and Saskatchewan," the details of how to do so are yet to be defined. Furthermore, to realize the MOU commitment to expand interties, persistent barriers to building transmission infrastructure must be addressed — provincial silos, cost-sharing disputes, limited national coordination, and entrenched north-south trade patterns with the U.S.

This paper is organized into four sections. First, we provide a brief overview of Alberta's electricity transmission grid and the current state of the province's interties. Next we outline the benefits of expanding interties — particularly between Alberta and British Columbia — as well as the broad alignment of stakeholder interests that make it possible. The following section discusses key barriers and challenges that have historically hindered interprovincial transmission expansion and continue to do so today. Finally we end with our recommendations to policymakers and electricity system stakeholders. We call on the federal and Alberta governments to turn the MOU commitments into a concrete implementation plan, and we outline what should be included in that plan.

[6] According to the Market Surveillance Administrator's Wholesale Market Report for Q1 2025, when Alberta was import constrained, wholesale electricity prices were higher than they otherwise would have been. When Alberta was export constrained, wholesale prices were lower, but generators lost the opportunity to sell excess power to other provinces.
[7] In recent years, Indigenous groups have grown increasingly sophisticated as transmission proponents, and are in many cases able to take equity, construction, and/or other roles that can propel a project rapidly forward.

Current state of Alberta's interprovincial transmission network

Figure 1: Components of the electricity supply chain



A transmission network carries electricity from the point of generation to end consumers over high-voltage transmission lines. The electricity then moves to lower-voltage distribution lines that bring electricity into homes or businesses for use.

Transmission can move electricity across a province or to neighbouring provinces and states. However, Canada's transmission systems are planned and managed at the provincial level, with little to no coordination or cooperation between provinces. This has led to limited interprovincial interties, as the systems were designed to serve local needs rather than support a larger, more integrated grid.

Provinces have prioritized north-south electricity trade with the U.S., rather than east-west trade between provinces.[8] Greater economic opportunities in highly populated U.S. regions or cities, disagreements about cost and benefit allocation for provincial interties, and a lack of national coordination have all contributed to the underdevelopment of interprovincial connectivity.

[8] Canada trades twice as much electricity to the U.S. as we do between the provinces.

The AESO has acknowledged that “Alberta is one of the least interconnected systems in North America.” While the province is connected to neighbouring B.C., Saskatchewan, and Montana through three interties, net imports only covered about 1% of the province's electricity usage in 2024.[9] In contrast, California is among the most interconnected jurisdictions in North America, typically importing around 30% of its electricity supply from outside the state.[10]

Figure 2: Transfer capabilities are higher between Canada and the United States than between provinces[11]

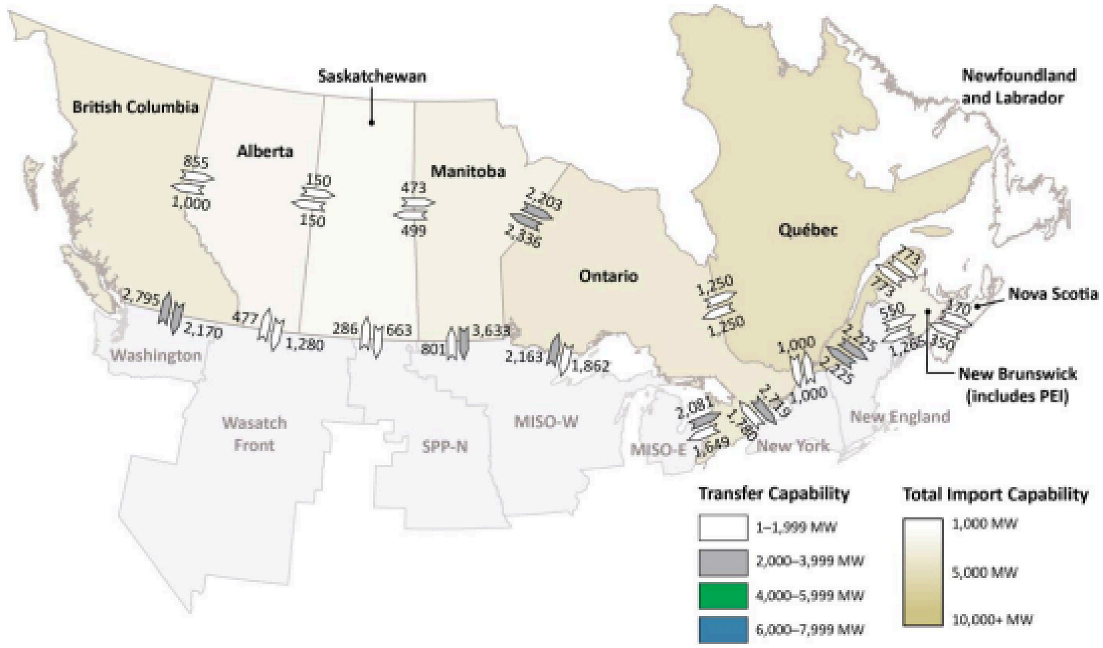


Figure ES.2: Transfer Capabilities (Winter)

Source: North American Electric Reliability Corporation – Interregional Transfer Capability Study Canadian Analysis Strengthening Reliability Through the Energy Transformation – April 2025.

[9] Authors' own calculation based on average imports of 132 MW and average load of 10,112 MW in 2024.
[10] In 2023, California supplied two-thirds of its retail electricity sales from clean energy sources (including renewables, hydro, and nuclear), an achievement made possible in part by the state's high level of interconnection with neighbouring grids.
[11] Transfer capability is a modelled measure of how much electricity can practically and reliably move between regions, and it can vary by season and operating conditions. It is distinct from an individual intertie's path rating, which reflects the line's engineering limits and represents the maximum flow that can be reliably attained. For example, the path rating of the Alberta-Montana intertie is 325 MW north-to-south and 300 MW south-to-north.

Management of Alberta's interties

Alberta's interties are often underutilized relative to their full rated capacities due to planned maintenance, unplanned outages, and/or derating (i.e. reducing the capacity of the line below its rated limit). We focus predominantly on the Alberta-B.C. relationship in this paper.

Alberta-B.C. intertie

Typically, the majority (e.g. 80-90%) of the transfer capacity on interties is used for commercial transfer of electricity (i.e. imports and exports). Although the Alberta-B.C. intertie is rated for 1,200 MW of imports into Alberta, the AESO has long operated the intertie well below its rating — usually 40-60% of its rating over the past two decades. The remainder of the transmission capacity is set aside for contingency management and transmission reliability margins. More recently, in March 2023, the AESO further reduced import capacity to about 25% of the intertie's rated import capacity. In contrast, flows from Alberta to B.C. are typically permitted at 90% of the intertie's rated capacity (1,000 MW).

The AESO maintains that limiting imports from B.C. is necessary to safeguard grid reliability. Alberta's grid operates in relative isolation, with limited interties connecting the province to neighbouring systems. If the AB-B.C. intertie tripped while Alberta was relying heavily on those imports to meet a large share of total provincial demand, the province could see large frequency drops and experience blackouts. And because Alberta cannot rely heavily on external support to stabilize the system, the province chooses to maintain larger reliability margins on its interties. B.C.'s grid, on the other hand, is connected to several U.S. states through a strong network of interties, which means the impact of a tripped intertie is absorbed by a much larger, well interconnected system.

There are a number of ways that Alberta could improve its grid to support increased imports without compromising reliability. Ancillary services, such as Fast Frequency Response technologies and Load Shed Service for imports are tools that make sure the grid can withstand a sudden loss of imports. And a second intertie could provide redundancy, making it easier to use existing capacity without fear of losing a significant electricity supply source.

There has been a policy directive to restore capacity on the Alberta-B.C. intertie since 2003 (per the Transmission Development Policy), and a legislative obligation for the AESO to restore the intertie capacity since 2007 (s.16 2007 Transmission Regulation). Since then, the AESO completed multiple studies and workshops on the intertie restoration; but while minor upgrades were completed, Alberta has yet to restore the intertie to its full rated capacity. Restoration efforts proved difficult to implement because of continued concerns with reliability and contingency events, as well as a disagreement about who (e.g. consumers or importers/exporters) should pay for upgrades and required ancillary services.

In April and July 2024, B.C. asked Alberta to restore the intertie to its full capacity. In December 2024 the Alberta government directed the AESO to restore the intertie to 950 MW, and to procure the necessary ancillary services to support full import flows. The government directed the AESO to submit a plan to the Alberta Utilities Commission (AUC), the regulator, by the end of 2026.

Alberta-Saskatchewan intertie

The Alberta-Saskatchewan intertie has a smaller role in Alberta's system as it is one-eighth of the size of the Alberta-B.C. intertie, with a rated capacity of 150 MW in both eastward and westward directions. The Alberta-Saskatchewan intertie went out of service in late 2024, following an equipment failure. The intertie returned to normal service as of October 30, 2025.

In December 2024 the Alberta government directed the AESO to increase the path rating of the Alberta-Saskatchewan intertie as part of the equipment replacement project, without specifying the new path rating.

Benefits of expanded interprovincial transmission

The benefits of expanding interprovincial transmission in Canada have been well documented. Not only does increased transmission provide climate benefits, but research suggests that interprovincial transmission could result in substantial economic benefits for Albertans too.[12] In this section, we summarize these benefits.

Economic and reliability benefits for Albertans

Greater grid resiliency

Provide back-up during major disruptions, such as extreme weather
During extremely cold periods when the wind isn't blowing and gas power plants risk outages, Alberta could rely on electricity imports from neighbouring jurisdictions that may not be facing the same weather conditions.

Balance swings in variable supply
Alberta's mix of wind, solar, and gas-fired power could complement B.C.'s hydroelectricity by helping to balance out hourly and seasonal electricity supply variability in both provinces. For example, if the wind in Alberta is unexpectedly low in a particular hour, B.C.'s hydropower system could respond quickly to help meet demand. Seasonally, Alberta's wind power generation peaks in the winter when hydro reserves are lowest and B.C.'s hydropower peaks in the summer when wind levels are low, creating a natural seasonal complementarity.

Ease grid bottlenecks
Renewables can create the equivalent of traffic jams on an electricity grid when there is more electricity being generated than can be carried on existing transmission lines. This is called congestion and causes renewable generation to be curtailed (disconnected from the grid).[13] More interties can ease this congestion, ensuring that clean power is not wasted (and is ultimately carried to where it is needed).

[12] Researchers have noted that when reliability benefits are included, relatively unconstrained transmission expansion provides cost-benefit ratios several times higher than those using more traditional cost-benefit evaluations (limited to production cost savings, capital cost savings, and emissions cost savings).
[13] The Government of Alberta is undergoing a review of its transmission policy and replacing its zero-congestion policy (although congestion still occurs) with a new framework that allows congestion if it proves to be more cost-efficient.

Adapt to climate-related challenges
Climate change is making droughts more common and severe, which (among other things) negatively impacts the hydropower that British Columbia heavily relies on. Interties allow provinces to access diverse generation sources, creating a hedge against the impacts of the changing climate on certain types of generation.

Reduce risk of unexpected shutdowns
Strong interconnections with other provinces improve the overall reliability of the system. If a large generator were to unexpectedly go offline, interties can immediately fill this electricity supply gap and help keep the system stable. Many industrial consumers face significant losses if they lose power and operations cease unexpectedly; even a single minute of downtime can result in a facility spending hours resuming operations.

Enhanced competitiveness

Lower electricity costs
Interties can enable greater competition in Alberta's electricity market by providing greater market access to generators in other provinces. This has the potential to reduce electricity prices for business and industrial consumers, helping them be more competitive. Furthermore, interties reduce the need to build additional generation to meet a few hours of peak demand by leveraging resources in regions with different peaking hours. This reduces overall system costs.

Create new revenue opportunities
Interties support Alberta's ability to export excess electricity (primarily excess wind and solar power) to other jurisdictions — generation that would otherwise be curtailed, with a resulting negative impact on generator revenues.

Support economic growth and diversification
Economic growth, electrification of Alberta's economy, and growth in new industries will require access to more electricity. Interties can help meet this need by supporting clean energy integration and providing access to reliable power. This is particularly important for attracting new electricity-intensive industries such as data centres, whose proponents need reliable and, increasingly, low-carbon electricity.[14]

[14] For example, Microsoft's data centres are committed to "100% of electricity consumption, 100% of the time, matched by zero-carbon energy purchases by 2030."

Indigenous participation and ownership opportunities

For more remote communities generally, and remote Indigenous communities specifically, experience suggests that properly structured transmission deployment can bring new economic development opportunities (such as in the successful East-West Tie project along the northern shore of Lake Superior or the Indigenous-led Watay Power project) that can support economic reconciliation. Opportunities could include equity ownership, construction opportunities (such as jobs or ownership in associated corporations), and operational management roles, among other benefits.

Decreased reliance on U.S. oversight

Alberta (along with many other provinces) currently cedes some regulatory authority to the U.S. Federal Energy Regulatory Commission (FERC) by virtue of allowing open access trading rules that govern cross-border trade. These rules mean that if Alberta wants to sell electricity to the U.S., it must provide American entities with reciprocal access to its electricity market. In practice, this entails FERC providing regulatory guidance on market rules even on Canadian soil. More transmission interconnecting Alberta with neighbouring provinces would reduce reliance on U.S. trading relationships, providing the province with a stronger negotiating position if and when cross-border disputes arise.

Climate benefits

Enabling clean energy deployment

Unlock new clean energy opportunities from mature and emerging technologies
Clean energy needs a pathway from generation sites to urban and industrial load centres. Increased transmission can support this expansion, which research in other Canadian jurisdictions shows could allow technologies like wind and reservoir hydroelectric power to grow their share of electricity generation. There are also opportunities to connect new kinds of renewable generation in Alberta, for example by converting oil and gas fields to geothermal energy projects.

Enable greater use of intermittent renewable electricity
As already highlighted, enhanced interprovincial transmission would allow British Columbia and Saskatchewan to purchase low-cost renewable power from windy Alberta, which otherwise might have been curtailed.[15] The Northwest Territories could also benefit from renewable power exports from Alberta. Similarly, new hydroelectric and other renewable facilities in the territories could be incrementally improved by greater interconnection with Alberta and other neighbouring jurisdictions.

[15] Similarly, sunny Saskatchewan could also take advantage of the natural complementarity between new solar generation and the firm capacity of Manitoba Hydro's immense hydroelectric capacity.

Minimizing the need for substantial new carbon-intensive power plants

New interprovincial transmission may help avoid the development of expensive, carbon-intensive greenfield generation facilities. Modelling shows that new interprovincial transmission can reduce the cost of a Canadian net-zero grid by 26% (in contrast to scenarios involving no new interprovincial transmission). Transmission deployment may also secure environmental benefits for the future by locking in long-term infrastructure that allows clean power deployment to be accelerated.

Barriers to interprovincial transmission expansion and the cost of inaction

Expanding interprovincial transmission would deliver important economic and climate benefits. Despite the long-standing recognition of the benefits (see above), governments and system operators must overcome persistent barriers to make progress.

Key barriers to greater interprovincial transmission

The factors hindering greater interprovincial transmission have been well documented over the decades, and include the following:

Quantifying and allocating costs and benefits

Interprovincial transmission infrastructure is expensive to build, but it offers cost savings and other significant economic and reliability benefits once built. Determining who pays for those costs and who captures the resulting benefits is a complex and challenging task, and difficulties in negotiating fair cost-sharing and benefit-allocation agreements are a key barrier to projects moving forward.

In Alberta, the AESO is responsible for transmission planning. The AESO's current transmission planning process focuses on meeting Alberta's internal energy demand and providing reliable and efficient grid operation, with limited consideration of the capabilities, plans, or needs of neighbouring jurisdictions.[16] This siloed approach means that Alberta views capabilities outside the province as less dependable than internal resources. As a result, AESO's planning does not fully assess or seek to leverage the broader benefits of interprovincial transmission, including reliability, resiliency, and economic efficiencies.

By recognizing and quantifying the full value of increased interconnection, the AESO could better align transmission planning to capture these benefits. This exercise would also provide valuable information to policymakers, demonstrating that interties are a critical tool for enhancing Alberta's

[16] System operators and utilities in other provinces, such as BC Hydro and SaskPower, also focus their transmission planning largely within their own provincial boundaries.

electricity grid. Making the information publicly available could enable cross-jurisdictional comparison, supporting incentive alignment and transparent, collaborative decision-making.[17]

Jurisdiction fragmentation

Canada's electricity system, including transmission, is largely planned, operated, and governed within provincial siloes, with little involvement from the federal government outside of permitting international connections. Provincial system operators and regulators do not have a mandate to identify opportunities or efficiencies with their provincial neighbours. Without a formal mandate or direction from provincial governments — or some other coordinating entity like those we see in other countries — there is little incentive or structure to support provincial collaboration.

This province-centric approach stands in contrast to models in the U.S. and Europe, which enjoy much greater electricity connection between regions. In the U.S., there is a greater role for the federal government in interregional transmission.[18] For example, the Federal Energy Regulatory Commission (FERC) mandates regional transmission planning (FERC Order 1000), which has led to the formation of large regional transmission organizations and independent system operators that generally manage multi-state electricity grids. In the European Union, transnational bodies like the European Network of Transmission System Operators for Electricity and the EU Agency for the Cooperation of Energy Regulators bring together system operators and regulators to collaborate on cross-border projects.

Here in Canada, despite having the constitutional ability to do so,[19] the federal government has not historically exercised its jurisdiction over interprovincial transmission, leaving the matter to the

[17] Key AESO documents, such as the AESO's 2023 Reliability Requirements Roadmap, could be leveraged to clearly quantify the benefits of interconnection for policymakers.

[18] The U.S. grid also has a degree of jurisdictional fragmentation, with "hundreds of different owners…divided into multiple planning regions."

[19] Section 92(10)a of the Constitution Act, 1867, gives the federal government jurisdiction over transportation projects that connect provinces with each other.

provinces.[20] If the federal government were to assume its jurisdiction over interprovincial transmission, the Canada Energy Regulator (CER) could take an active role in regulating and permitting interprovincial transmission projects.[21] The CER has a permitting process for international lines — it adopts the relevant provincial permitting process — but would need to develop a permitting process applicable to interprovincial lines.

Importantly, once an interprovincial line is approved and built, provincial system operators (e.g. AESO, BC Hydro) would still retain authority and autonomy over their provincial electricity grids, controlling the management and operation of their own electricity and transmission systems. With that in mind, the success of a new intertie project would not only be contingent on federal permitting and regulation, but also mutual provincial buy-in and commitment to utilizing the transmission line. In Alberta, transmission lines are built and owned by private companies, and they would need assurance that they would be able to recover their costs.

Beyond regulating and permitting, a federal entity like the CER could facilitate collaboration among provinces on interprovincial lines. If provinces run into challenges that block regional planning efforts, the federal government is well-suited to provide leadership and facilitate collaboration. As an example, the federal government could host working groups that bring together system operators, utilities, provincial governments, and Indigenous communities with a mandate to identify and advance intertie opportunities. Past initiatives, such as the Canada Electricity Advisory Council and the Regional Electricity Cooperation and Strategic Infrastructure Initiative, noted support for a stronger federal role in facilitating collaborative conversations.

The CER is well-placed to facilitate greater provincial collaboration on transmission. The CER could assume a neutral position when projects have uneven costs and benefits, support broader public policy priorities (e.g. connecting remote Indigenous communities to reliable power or supporting better assessment of overall project benefits), and offer a unified response to potential FERC overreach.[22]

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[20] Despite abstaining from regulating interprovincial electricity transmission, the federal government, through the Canada Energy Regulator (CER), has been active in regulating interprovincial oil and gas pipelines. For example, the federal government asserted its jurisdiction to approve a pipeline carrying oil (TMX) from Alberta through British Columbia, despite attempts by B.C. to pass legislation to limit such activity. In short, the CER has long focused on shaping interprovincial oil and gas flows while building a well-established and integrated oversight position in coordination with provincial entities.

[21] The Canadian Energy Regulator Act s.261 provides the Governor-in-Council with the ability to designate an interprovincial power line for CER oversight and s.262(1)c includes interprovincial lines in the CER's certificate authority; however, there is no specific permitting or certificate process set out for interprovincial power lines. Therefore, should an interprovincial transmission line be designated a project of national interest under the Building Canada Act, the CER does not presently have a permitting process to speed up.

[22] All benefits outlined in legal scholarship by Blue, Gillis, and van de Biezenbos (see Appendix A.3.).

Cost

As already outlined, transmission infrastructure is expensive. For example, Manitoba's Bipole III 1,300 km transmission line, completed in 2018, cost nearly $4 million per kilometre, following significant cost overruns. The final cost was approximately $5 billion, compared to the original estimate of $2.2 billion in 2007. And Nova Scotia's proposed offshore wind transmission line is estimated to cost between $5 billion and $10 billion. Transmission lines typically traverse long distances to reach load centres — often across difficult terrain, which adds to the cost. Furthermore, waiting times and prices for key inputs, such as cables and transformers, have almost doubled post-COVID.

This costliness can lead to political hurdles and challenges with cost allocation that prevent projects from being built, even if the upfront costs result in long-term savings. Funding or financing support from the federal government could help alleviate key pain points and incentivize provinces to come to the table and advance new projects. For example, the Canada Infrastructure Bank (CIB) contributed $217 million in equity financing to a new transmission line between Nova Scotia and New Brunswick, a contribution that will help that project get built.

Other barriers

Diverse market structures: the presence of both monopoly and competitive electricity markets, alongside public and private ownership models, makes it challenging to facilitate interprovincial trade and allocate costs and benefits fairly (see Appendix A.2.).

Increased competition: increased interprovincial electricity trade exposes generators to more competition, which can drive down wholesale prices. While this means lower electricity prices for consumers, private sector generators in a market like Alberta may see competition with Crown corporations in neighbouring provinces (i.e. BC Hydro and SaskPower) as unfair.

Risk aversion: provinces are reluctant to integrate their electricity systems more closely with neighbouring jurisdictions because it increases reliance on out-of-province resources and can be perceived as a loss of control over their grid. Given voters' sensitivity to price spikes and supply shortages, governments are averse to the risks associated with becoming more interconnected and dependent on other electricity systems.

Historical friction: the existing Alberta-B.C. intertie has been a source of tension between the two provinces. For example, the AESO has long limited the import capacity of the intertie to protect Alberta's grid reliability (by preventing overreliance on imports), reducing B.C.'s ability to export into the province. As mentioned above, the Government of Alberta recently directed the AESO to restore the intertie.

NIMBYism: local communities are often inclined to resist new transmission infrastructure for reasons including visual impact, lack of perceived benefits, impact on property values, and other concerns.[23]

Legacy infrastructure and economic orientation towards the United States: Canadian provinces have long histories of bilateral cooperation and electricity market coordination with the U.S., rather than with each other. There are approximately 35 active major international transmission corridors linking the U.S. and Canada, while Canada has only 33 interprovincial transmission lines. As a result, Canadian generators can more easily sell power to the U.S. than to neighbouring provinces and territories.

Representative case studies

Recent incidents in Alberta underscore the importance of stronger electricity connections with provincial neighbours.

Lack of imports during supply shortages

Alberta experienced grid alert events in January and April 2024, during which times the electricity grid struggled to supply enough power to meet demand. In January 2024, the province experienced record demand due to extremely low temperatures. The high demand coincided with outages at seven natural gas generators (both planned and unplanned), low wind generation, and limited power imports, creating a perfect storm. Import support was limited as higher electricity prices in the U.S. pulled power south instead of into Alberta. Fortunately, the AESO was still able to secure some emergency imports from B.C. and Saskatchewan that prevented rotating outages.

The April 2024 grid alert event followed insufficient supply resulting from low wind generation and high numbers of natural gas generator outages. Alberta's import capacity was fully utilized (and the capacity of the Alberta-Saskatchewan intertie was additionally increased to respond to this emergency), but was inadequate to prevent rotating outages.

Ultimately, lacking robust interregional interconnections, Alberta's grid was forced to rely heavily on local resources — making it more vulnerable to supply and demand fluctuations and other issues.

Inability to export excess capacity

Alberta has the ability to generate significant amounts of renewable electricity, particularly wind-powered generation. However, Alberta frequently experiences transmission congestion, meaning that there is insufficient transmission capacity to transmit the electricity from where it is generated to where it is needed. In these instances, renewable generators are directed to reduce or cease

[23] While these barriers are significant, NIMBYism affects all Canadian infrastructure projects.

generation, limiting Alberta's ability to fully utilize already-operational resources. This congestion happens regularly; in 2024, renewable energy was constrained in 45% of all hours, adding up to 508 GWh of constrained output in 2024. Using the average wholesale price of electricity ($62.78/MWh in 2024), that represents an estimated $32 million in foregone value.[24]

While more transmission within Alberta or introducing more energy storage (e.g. batteries) are potential solutions to this issue, increasing transmission capacity between provinces could unlock broader benefits. For example, during certain periods when hydroelectric power generators face drought in B.C., Alberta could buy power from Alberta-based sources at lower prices and sell it at a premium to B.C. buyers. Similarly, with the increasing number of extremely hot B.C. summer days, Alberta could sell cheap renewable power to support increased air conditioning use by B.C. industrial or residential customers.

[24] Not all constrained generation would have necessarily received the average price. Constrained hours tend to occur when there is excess supply, which would lead to lower prices.

Recommendations

Alberta has been discussing the benefits of expanding interprovincial electricity transmission for years, but progress has been limited. There are good reasons for this; experts agree that scoping the economics of transmission in Alberta is difficult. Building long linear infrastructure is also a practical and technical challenge, and new lines can face local opposition.

However, much has changed on the ground. Old narratives of political gridlock and planning incompatibility are fading. Now many key stakeholders are more aligned, as the country pursues nation-building infrastructure projects and faces rapid demand growth.[25] This alignment is reflected most strongly in the recent federal-Alberta MOU where the governments commit to advancing interprovincial transmission in Western Canada. Despite this political momentum, the MOU does not provide an implementation pathway for interties.

Beyond the MOU, there are other positive signs for momentum on interprovincial transmission. In January 2025, the AESO released its Long-Term Transmission Plan (LTP), which outlined plans to restore the Alberta-B.C. and Alberta-Saskatchewan interties to their full capacity, following recent ministerial direction. The LTP also noted new intertie opportunities between Alberta and both B.C. and Saskatchewan under ambitious decarbonization scenarios. Committing to restoring the capacity of existing interties should remain a top priority for Alberta. At the same time, there are clear, no-regrets steps that Alberta and other Western provinces can take to advance greater interconnection.

In this paper, we put forward recommendations that would accelerate momentum and lay the groundwork for an implementation plan able to turn political alignment into real projects.
Governments should solidify the MOU by establishing an implementation plan for expanding interprovincial transmission. This implementation plan should include the following three components:

- **pursuit of collaborative regional planning;**
- **an understanding and quantification of the benefits; and**
- **mobilization of funding supports.**

Commit to a plan

The federal and Western provincial governments should seize the opportunity to expand interprovincial electricity transmission as laid out in the federal-Alberta MOU.

[25] Of course, we are not arguing that all stakeholders will be supportive. Some stakeholders who may be benefiting from the status quo — such as some incumbent generators — may not be enthusiastic.

The MOU includes big, important objectives that can grow the low-carbon economies of Canada, Alberta, and the other Western provinces, calling for the "construction of large transmission interties with British Columbia and Saskatchewan to strengthen the ability of the western power markets to supply low carbon power to oil, LNG, critical minerals, agricultural, data centres and CCUS industries in support of their sustainability goals." Alberta commits to "collaborate with Canada to significantly increase the inter-tie transfer capability between the western provinces (with consideration to the northern regions) to build the low carbon generation and transmission grid that supports the growth of low intensity heavy oil, LNG, critical minerals, agriculture, data centres and CCUS industries for export growth and domestic use."

What is now needed is an implementation workplan. This implementation plan for expanding interprovincial transmission should be as detailed as the plans for other priority areas in the MOU.

Recommendation 1: **The Alberta and federal governments, in partnership with British Columbia and Saskatchewan, should develop a clear implementation plan for expanding interprovincial transmission by April 1, 2026.**

Pursue collaborative regional planning

Transmission planning largely occurs within provinces, resulting in comparatively little collaboration between provinces. This approach leaves opportunities (and money) on the table. The AESO, as well as other key stakeholders in the Alberta electricity system, should embrace best-in-class regional planning and coordination practices. This should start with the lowest of the low-hanging fruit — increasing dialogue among the western provinces, ideally with organized discussions involving the transmission operators (i.e. the AESO, BC Hydro, and SaskPower), transmission owners, and policymakers.

Voluntary working groups focused on expanding interprovincial transmission would provide a neutral platform for convening stakeholders to share ideas, facilitate data sharing, and proactively shape plans while preserving provincial autonomy. Importantly, this level of coordination would not require participants to cede operational or planning control. As conversations mature, a formal organization could be established with a mandate to identify and pursue opportunities for interprovincial transmission projects.

Recommendation 2: The federal government and Western Canadian provincial governments should establish formal transmission-specific working groups that begin with dialogue aimed at improving collaboration and harmonizing planning efforts. The working groups should include system operators, utilities, and Indigenous communities.

Electricity policy and regulation fall under provincial jurisdiction, so provinces should lead regional planning and interprovincial transmission expansion.

That said, provincial systems and planning have long been siloed, and federal leadership may help to facilitate greater provincial collaboration on transmission. The federal government already assumes this role with interprovincial pipelines; the CER is active in regulating and approving pipeline infrastructure that crosses provincial boundaries. The Alberta government has acknowledged the federal government's important role in permitting pipelines. This precedent could support the case for a federal role in transmission interconnection.

Importantly, while the federal government could take a role in facilitating coordination, and regulating and permitting interprovincial transmission lines, provincial electricity grids would remain under the operation and control of their respective provinces.

Recommendation 2a: While provinces should lead planning and coordination for interprovincial transmission projects, a limited federal role is warranted where there is an absence of effective provincial coordination to advance the goals in the MOU. If such circumstances arise, the federal government should request that the Canada Energy Regulator:

- work with the provinces to identify interprovincial transmission opportunities;
- clarify the jurisdictional demarcations of interprovincial provincial transmission lines; and
- once this jurisdictional clarity is established, consider exercising its permitting authority, while not seeking to regulate operations.

Understand and quantify benefits

A key challenge in advancing interprovincial transmission is fairly allocating the costs between those that benefit, as well as distributing the benefits between provinces. It is comparatively easy to quantify the financial flows as electricity is sold from one province to another, but the broader advantages — including reliability, security, and climate benefits — should likewise be quantified.

While allocating these benefits (as well as the costs) between participating provinces remains a sticky challenge, establishing the total value proposition through modelling is a necessary first step. We cannot distribute benefits without first understanding them.[26] The AESO is presently establishing whether, and how, to calculate the wider economic benefits of transmission. It should include a clear and transparent methodology that measures the wider benefits of transmission, including interprovincial transmission.

[26] Previous work from Navius Research and the University of Victoria have quantified the value of expanded interprovincial transmission expansion, but additional granular and updated modelling is required.

Recommendation 3: The Alberta Electric System Operator should quantify the full range of costs and benefits from expanded interprovincial transmission. This would be a new approach to transmission planning in Alberta, which currently uses a narrow scope when considering the benefits of new transmission infrastructure.

This is work that could be advanced by sharing data within the working groups described in recommendation 2. The federal and Alberta governments should help fund this work and require that the results be made publicly available.

Mobilize funding supports

Expanding interprovincial transmission infrastructure will not only enable growth in electricity trade, but it is also required for achieving Canada's emissions reduction targets. Given these national priorities, the federal government should actively support provincial efforts — not only through coordination and facilitation, but also by providing meaningful financial support to help bring projects to fruition.

The Clean Electricity Investment Tax Credit (ITC) is the most important funding support available to interprovincial transmission projects. The ITC provides a refundable 15% tax credit for eligible capital investments in interprovincial transmission equipment, along with various other clean electricity projects, such as solar, hydro, and nuclear. Importantly, the Clean Electricity ITC is one of the few ITCs that can be claimed by Crown corporations, such as provincial utilities (e.g. BC Hydro and SaskPower). In Budget 2025, the federal government committed to soon introducing legislation to finalize the Clean Electricity ITC.

Federal funding for interprovincial transmission could also come from the Canada Infrastructure Bank (CIB), Natural Resources Canada (NRCan), and the Indigenous Loan Guarantee Program. The CIB provides low-cost loans, equity, and loan guarantees to projects across five priority sectors, among them clean power, which includes interties. Canada's Clean Electricity Strategy noted that the

CIB would invest at least $10 billion in clean power projects. Earlier this year, the CIB committed $217 million in equity financing to a new transmission line between Nova Scotia and New Brunswick. In Budget 2025, the federal government announced its intention to increase the CIB's capital envelope from $35 billion to $45 billion, and to enable the CIB to invest in projects referred to the Major Projects Office.

NRCan's Smart Renewables and Electrification Pathways (SREPs) Program is a $4.5 billion fund for renewables and grid modernization, which could include upgrades or expansion to transmission systems, particularly if they facilitate the integration of clean electricity. This program has not yet provided funding to any interprovincial transmission projects, but it did provide about $700,000 to a study for upgrading a transmission line in Newfoundland and Labrador. The SREPs program is not currently accepting proposals.

The Canada Indigenous Loan Guarantee Program is a $10 billion program that supports Indigenous groups in acquiring equity in major projects across all sectors of the economy. This program has been operational for less than a year and has only issued one loan guarantee at the time of writing, for a stake in a pipeline.

To date, these programs have played a very limited role in advancing both inter- and intra-provincial transmission projects. However, with the expansion of the CIB's capital envelope and the Major Projects Office's mandate to accelerate nation-building projects, concessional financing tools (including loans and equity investments) could play a large role in supporting interprovincial transmission development.

At the same time, the federal government should consider increasing the Clean Electricity ITC for interprovincial transmission projects specifically. Interprovincial transmission infrastructure is capital-intensive (more so than most of the other projects eligible under the ITC). Moreover, interprovincial transmission provides system-wide benefits that impact other clean electricity investments. In providing a strong incentive for these projects, the federal government could encourage provinces to participate in regional planning and help get projects built.

Recommendation 4: The federal government should mobilize federal support to accelerate interprovincial transmission projects by:

i. deploying the CIB's newly expanded $45 billion capital envelope to offer concessional financing for intertie projects; and
ii. considering increasing the ITC for intertie projects, as proposed by the Canada Electricity Advisory Council.

Appendix: Further electricity market background and context

A.1. Alberta electricity policy developments

Alberta's electricity system is undergoing significant policy and regulatory changes, largely driven by the rapid growth of renewable electricity generation and the need to address emerging challenges in the system.

Alberta has experienced considerable growth in its renewable electricity generation, and this shift in the province's generation profile has raised challenges and concerns with respect to reliability, affordability, transmission congestion, and long-term investment incentives, among other things. It's not that renewables are inherently problematic; indeed, they have a number of desirable characteristics, including being low-cost and non-emitting. However, they are intermittent resources, available only when the sun shines and the wind blows. Alberta's system was originally designed for traditional, dispatchable generation technologies such as gas and coal, and is not optimized for the unique attributes of today's grid with increasing generation from renewable sources.

In 2022, the Alberta Electric System Operator (AESO) identified a need to review the electricity market structure to address the above challenges. Following the AESO's stakeholder engagement and recommendations to the Government of Alberta, in March 2024 the province directed the AESO to redesign Alberta's electricity market. The redesigned system is called the Restructured Energy Market (REM), and is intended to strengthen reliability, improve affordability, and ensure sufficient investment to meet energy needs. In August 2025, the AESO released the final design for the REM, with implementation beginning in mid-2027.

In parallel with the REM, the province is also reviewing and updating Alberta's transmission policy. In July 2024, the Minister of Affordability and Utilities directed the AESO to move away from zero-congestion transmission planning to an optimal transmission planning (OTP) approach. Under the old approach, the AESO had to build transmission such that there was no congestion in the system. The new planning approach will require the AESO to complete a cost-benefit analysis on potential projects, proposing projects only if they provide net benefits. The objective of the OTP is to be more economically efficient — reducing costs while still maintaining a reliable system.

A.2. Comparison of provincial electricity market structures

In Canada, jurisdiction over electricity systems primarily lies with the provinces. Each province builds, operates, and regulates its grid independently, with a focus on meeting its own power needs. As a result, there are diverse electricity market structures across the provinces, ranging from vertically integrated, government-owned utilities (Crown corporations) such as SaskPower and BC Hydro, to fully deregulated, market-based systems, such as in Alberta.

These structural differences lead to different pricing mechanisms, varying incentives, and different operating rules that can make it challenging to trade electricity between grids. This, in part, explains why there has been limited market integration to date, and why building more interprovincial transmission lines remains tricky despite the opportunities.

Province	Vertical integration	Ownership	Level of competition
Alberta	Unbundled	Mixed (private and municipal)	Open wholesale market, retail competition
British Columbia	Vertically integrated	Crown corporation (BC Hydro)	Low
Saskatchewan	Vertically integrated	Crown corporation (SaskPower)	Low
Manitoba	Vertically integrated	Crown corporation (Manitoba Hydro)	Low
Quebec	Vertically integrated	Crown corporation (Hydro-Québec)	Low
Ontario	Unbundled	Mixed (Crown corporation, municipal, and private)	Open wholesale market, some retail competition
Prince Edward Island	Mostly vertically integrated	Mixed (Crown corporation and private)	Low
New Brunswick	Vertically integrated	Crown corporation	Low
Nova Scotia	Vertically integrated	Private company	Low
Newfoundland and Labrador	Vertically integrated	Crown corporation (Newfoundland and Labrador Hydro)	Low

Source: Authors, with information adapted from Pineau.

A.3. A select summary of notable early U.S. actions with implications for Canadian electricity market regulatory and policy sovereignty

Year	Activity	Market/regulatory/policy outcome for Canada
1978	U.S. Congress enacts Public Utilities Regulatory Policies Act (PURPA).	Requirement for purchase of non-self-generated electricity creates transmission access issues.
1986	Issuance of FERC Opinion No. 256.	Created uncertainty for the ability of Canadian energy tribunals to regulate terms of trade for one energy source — natural gas.
1992	U.S. Congress passes Energy Policy Act, with Title VII adding Section 211.	Section 211 applies to Canadian utilities seeking access on interstate transmission lines, eventually creating reciprocity rights concerns from the perspective of FERC employees (in 1994, according to footnote 18 in Blue).
1995	Energy Alliance Partnership, otherwise known as 73 FERC 61019.	FERC was acting as determiner of what constituted fair trade, rather than adhering to legislative and executive branch international agreements on free trade. Blue notes that "FERC thereby applied domestic United States law to a Canadian utility because of the way it was organized in Canada!".
1996	FERC issues Order No. 888. Six weeks after Order No. 888, FERC undertook additional actions pertaining to Alberta.	Created an organizational framework which made decisions against Canadian-owned companies, based on the way they were organized in Canada.

Source: Authors, with information adapted and synthesized from Blue and Saunders[27].

[27] The link directs readers to a short memo summarizing some of the core arguments in Saunders, J. Owen (2001), "North American Deregulation of Electricity: Sharing Regulatory Sovereignty," Texas International Law Journal 36, no. 1: 167–173.