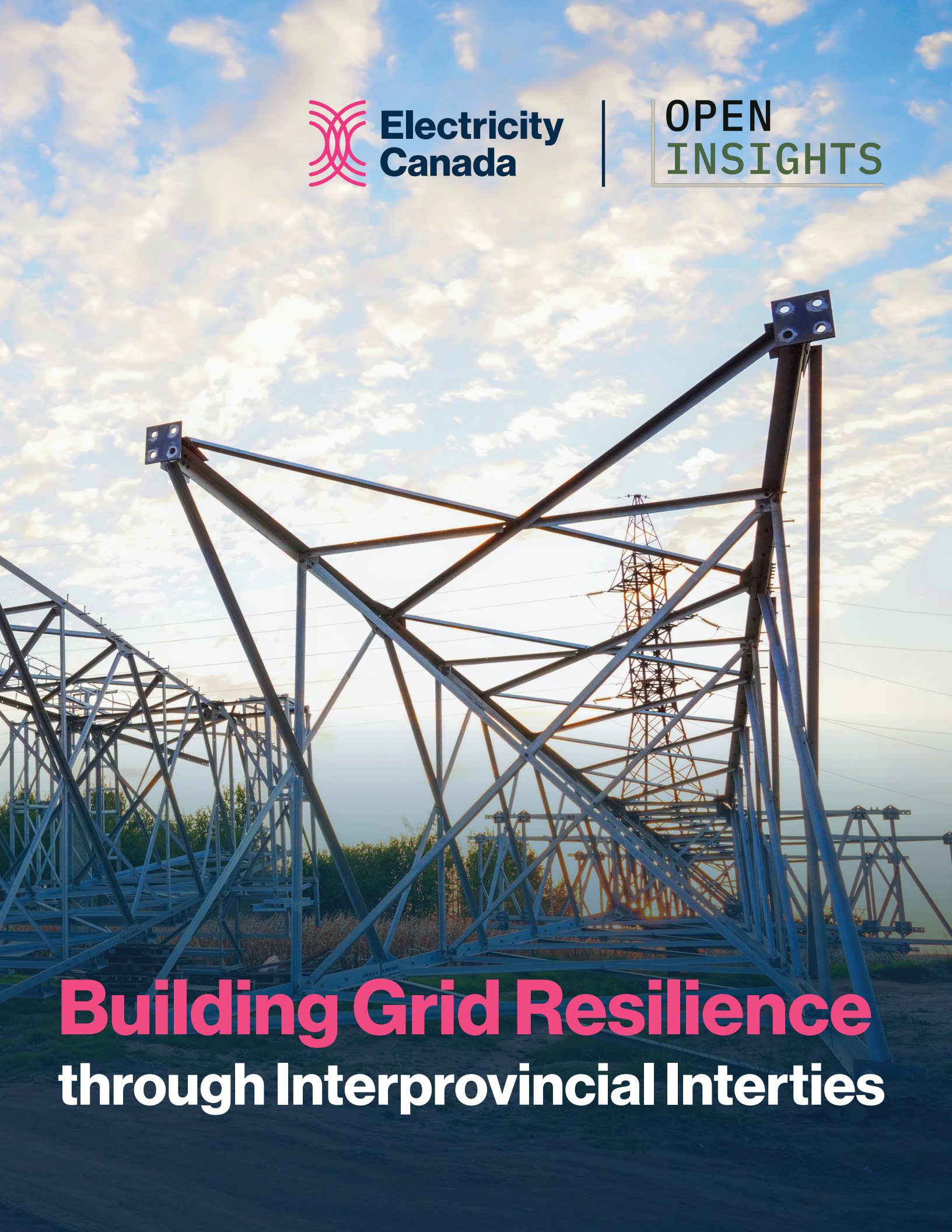




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Building Grid Resilience through Interprovincial Interties

Acknowledgements

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Suggested Citation

Electricity Canada & Open Insights (2026). *Building Grid Resilience through Interprovincial Interties*. Available at:

https://issuu.com/canadianelectricityassociation/docs/building_grid_resilience_through_interprovincial_i

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Disclaimer

Utilities carry a broad mandate spanning safety, reliability, affordability, environmental performance, and regulatory compliance. This report addresses only one aspect of that mandate: reliability, specifically system resilience to extreme weather events.

The findings presented in this report should not be interpreted as a comprehensive assessment of utility performance, priorities, or overall effectiveness.

Executive summary: Building grid resilience through interprovincial interties

Climate vulnerability and the case for interties

Canada's electricity infrastructure is experiencing increasing pressure from climate change, marked by a growing frequency and severity of extreme weather events, such as heatwaves, cold snaps, droughts, floods and wildfires. These weather anomalies expose the grid to significant risks, caused by fluctuations in available generation capacity, transmission lines capacity and spikes in demand. As the power sector is preparing for the future, the inherent vulnerability of largely provincial grids to localized shocks presents a critical challenge for utilities, system operators, and generators. Provinces are already interconnected and at times lean on those ties for reliability and operational flexibility but planning and operation remain largely province-by-province. This relative independence carries its own risk when a shock is large or geographically widespread.

One response to this challenge stands out: expanding interprovincial transmission lines. Canada's electricity system is planned and operated province by province, leaving each region largely on its own when an extreme weather event hits. Interprovincial transmission lines allow provinces to share electricity across borders, allowing neighboring provinces to provide aid in times of stress. There is also growing interest in interties at the policy level, as evidenced by the federal government's recent National Electricity Strategy. This, combined with growing evidence that expanded connections build a more reliable grid, makes interties a crucial area where provincial and federal coordination can have a direct and meaningful role to play.

In short, localized weather shocks are turning into a systemic planning problem that can pose local challenges at provincial level and interties are a direct tool to mitigate that risk across the entire country.

The central question guiding this analysis is: Can expanding interprovincial intertie capacity help build a more resilient, stable, and cost-effective national grid for 2050, one that is better insulated from the effects of extreme weather?

A shift to systemic resilience

This report investigates the vulnerability of the Canadian grid to extreme weather shocks and interties' potential to build resilience. Using an established power system and reliability model, we analyzed how grid reliability changes under two futures: one without any additional interprovincial transmission lines, and one where intertie capacity is expanded. Both scenarios account for a wide range of extreme weather events (see Table 1) and cover four key corridors: British Columbia–Alberta, Manitoba–Saskatchewan, Ontario–Quebec, and Atlantic Canada.

Our analysis suggests that while more frequent extreme weather events could significantly harm grid reliability, expanded interties are a key tool for combating this impact and can also bring important secondary economic benefits.

Our analysis points to three important benefits of expanding interties:

1. Improved reliability

Expanded interties significantly reduce the risk of power outages¹ across Canada. When one province faces a shortfall, whether from a sudden spike in peak demand, an unexpected loss of generation, or supply being stretched during extreme weather, connected neighbors can step in to cover the gap. Our analysis shows that nationally, building out interties reduces the expected frequency of outages by 69% under extreme weather conditions.

Our analysis finds this effect consistently across all corridors studied. In the British Columbia-Alberta corridor alone, expanded interties cut the expected frequency of power outages by **92%**, as British Columbia can draw on Alberta's electricity instead of relying solely on its own generation (see Figure 1).

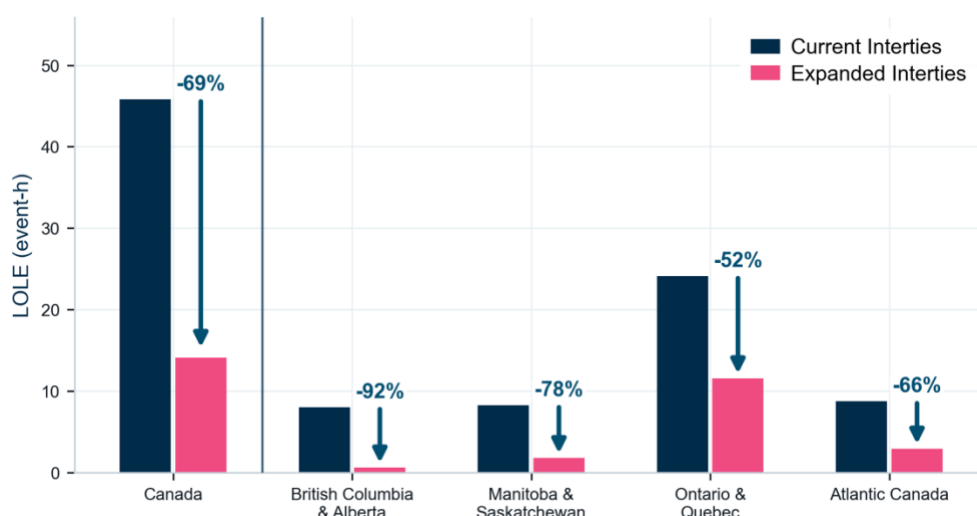


Figure 1: Impact of intertie expansion on loss of load expectation (LOLE) across Canada and by regions, 2050

2. Weather resilience

Beyond reducing outages, interties make the grid less vulnerable to extreme weather shocks. Provinces have different generation mixes and weather impacts are often localized, so what affects one region may leave another unaffected. Connections between them allow the system to automatically draw on the most resilient supply available at any given time. A recent example: a January 2026 cold snap pushed the Nova Scotia grid to the brink of

¹ In this report, 'power outages' refers to bulk, grid-level supply shortfalls, where available generation and transmission cannot meet demand, rather than local distribution failures affecting individual customers.

overload, prompting a public appeal to conserve power to avoid wider outages (CBC News, 2026).

No single province has a generation mix that is immune to every type of extreme weather, but provinces have different strengths (hydro, wind, nuclear) and interties let them complement each other. When a heat wave reduces thermal output in one region, a neighboring province with unaffected resources can fill the gap. As shown in Figure 2, expanded interties substantially narrow the difference in reliability between normal and extreme weather conditions.

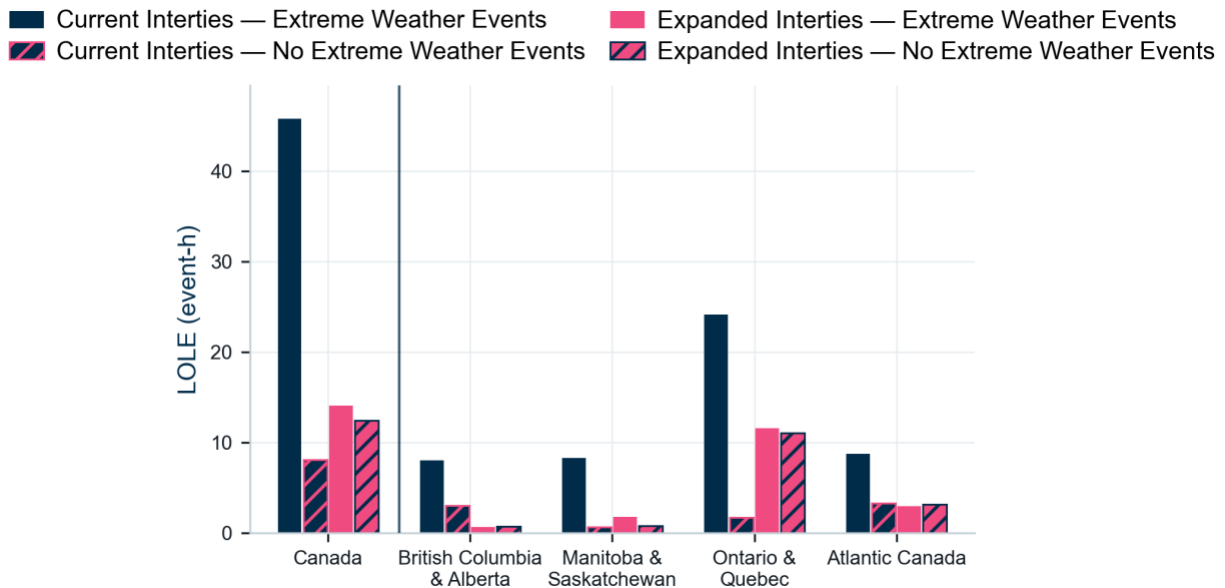


Figure 2: LOLE under extreme vs. no acute weather conditions – Current vs. Expanded Interties, 2050

3. Economic opportunities and cost-effective planning

Expanded interties also offer significant economic advantages and enable cost-effective long-term planning. Provinces can reduce their overall electricity costs, access new export revenue, and shift investment toward a cleaner and more efficient national grid.

When provinces can share electricity rather than each building their own surplus capacity, the overall cost of the grid falls. Our analysis shows total cost reductions of 19% for British Columbia and 7% for Ontario at the individual-province level (see Tables 5 and 7). These savings come from investing in cleaner, lower-cost generation, while maintaining and in many cases improving reliability.

Provinces with abundant wind or hydro resources can invest in building surplus generation. Expanding interties lets them sell that surplus to neighbors, turning previously unused energy into a new revenue stream. Provinces like Alberta and Quebec could effectively act as “clean energy banks” for the rest of the country, with export revenues helping to offset the cost of building out their generation capacity.

Interties also let provinces rely less on building their own large-scale generation and instead tap into renewables available next door. For example, Ontario could draw on Quebec's wind, reducing its need for nuclear or gas capacity expansions beyond current plans. This points to a broader shift: away from expensive, province-by-province capacity planning and toward a shared national system that unlocks lower costs while accelerating the clean energy transition.

Key conclusions

The evidence suggests that **interprovincial grid interconnection is a useful lever for planning a reliable, lower-carbon, and economically competitive electricity grid in the face of intensifying climate risks.**

1. Extreme weather events are becoming more frequent and severe, increasing risks to the electricity grid.
2. By increasing intertie capacities, the grid can draw on a more diverse generation mix across regions, insulating against localized outage risks while reducing investment costs.
3. When building out interprovincial transmission, provinces with more renewable energy potential (e.g. Alberta, Manitoba and Quebec) can act like a battery, supplementing regional supplies, reducing overall investment costs and creating a new revenue stream for these 'battery' provinces.

Taking these findings into consideration, greater grid integration is a concrete step toward a resilient, low-cost energy future for all Canadians.

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Abstract

Canada's electricity grid is largely planned and operated province by province, exposing regions to localized extreme weather shocks that are growing in frequency and severity. While provinces can mitigate these risks through other means, such as creating a fallback fleet of firm capacity within their own borders, we investigate whether expanded interprovincial intertie capacity offers a cost-effective mitigation strategy for extreme weather events, highlighting the benefits of cross-province collaboration. We link a peer-reviewed national capacity expansion model (**COPPER**), populated with the publicly accessible **CODERS** database, to a probabilistic resource adequacy model (**PRAS**), incorporating weather-dependent outage rates, capacity deratings and demand impacts derived from climate reanalysis data and published environmental sensitivity functions. For this report, we compared two 2050 scenarios/futures: one where we restrict the model such that no new transmission is built, and a second in which the model finds the cost-optimal expansion of interties across specific corridors (British Columbia-Alberta, Manitoba-Saskatchewan, Ontario-Quebec, and Atlantic Canada). Our findings show that interties consistently improve reliability while also insulating the grid from weather impacts, narrowing the reliability gap between normal and extreme weather conditions. Additionally, we see potential for lower net system costs across the board and new revenue streams for select provinces. These findings align with prior international research on the benefits of interregional transmission and support the focus on interties evident in the National Electricity Strategy. This suggests that interprovincial interties are a robust lever for provincial and federal policymakers planning a reliable, lower-carbon 2050 grid.

1. Introduction

When exploring the future of the Canadian energy grid, we need to consider the reliability of the expanded system. One impact on reliability that utilities need to consider is weather. Weather impacts both the availability of generation capacity and interties and leads to fluctuations in user demand. Uncertainty around demand and available energy is usually captured in reserve margins, which require the grid to carry surplus capacity to reduce the likelihood of unmet demand. However, reserve margins are not designed to account for extreme changes in demand or supply. This would lead to drastically increased costs requiring a build out of mostly unused capacity.

Standard reliability planning focuses on single-element contingencies, often described as N-1 planning, where the system is sized to withstand the loss of any one component. These approaches are well suited to isolated equipment failures. However, they are not designed to capture the correlated, system-wide stresses that an extreme weather event can place on supply and demand simultaneously, even as such events grow in frequency and intensity. This is not hypothetical: a January 2026 cold snap pushed the Nova Scotia grid to the brink of overload, forcing a public appeal to conserve power to avoid wider outages (CBC News, 2026).

A comparable event occurred in Alberta during the January 2024 polar vortex: record cold pushed demand to an all-time provincial peak at the same time as two large natural gas units were forced offline and wind output was near zero. This prompted four grid alerts and the first province-wide emergency alert asking Albertans to curtail load. Rotating outages were only avoided because that appeal cut demand by roughly 200 MW within minutes (Market Surveillance Administrator, 2024).

While utilities, system operators, and generators can each expand their own assets, interprovincial transmission is one area where no single party can act alone. This report illustrates the impacts of expanded interprovincial interties – how they can mitigate reliability risks, reduce grid costs and create additional revenue – to answer the research question:

Can expanding interprovincial intertie capacity help build a more resilient, stable, and cost-effective national grid for 2050, one that is better insulated from the effects of extreme weather?

This is particularly timely as the federal government's National Electricity Strategy, announced in May 2026, explicitly targets barriers to interprovincial interties.

2. Methodology

2.1 Models and data

This analysis is built on the M3 Modelling Platform, an open-source, integrated suite of Canadian energy-system data, models, and visualization tools built by the SESIT group at the University of Victoria, and maintained by the Energy Modelling Hub (M3, 2026). Input data is drawn from CODERS, an annually updated public database of Canadian electricity system data, and grid buildouts are determined with the COPPER capacity-expansion model, which represents a cost-optimal grid configuration based on as of the time of writing. Resource adequacy is then assessed with the Probabilistic Resource Adequacy Suite (PRAS), an open-source toolkit developed by the National Renewable Energy Laboratory (Stephen, 2021), which stress-tests each modelled grid against parameterized weather conditions. A full description of the data sources, models, and weather parameterization is provided in the Technical Appendix. All three components are openly available: CODERS at <https://coders.cme-emh.ca/>, COPPER at <https://gitlab.com/sesit/copper> (documentation at <https://sesit-copper.readthedocs.io/>), and PRAS at <https://github.com/NREL/PRAS>. The corresponding model documentation and peer-reviewed descriptions are given in CODERS (2026), COPPER (2026), Arjmand and McPherson (2022), National Renewable Energy Laboratory (2026), and Stephen (2021).

2.2 Scenarios

To explore how expanded interties affect the grid buildout, we compare two grid buildouts in 2050, based on the following scenarios:

- A Current Interties scenario, representing a future in which provinces do not coordinate on new interprovincial transmission, so each province must meet its demand plus reserve margins using only its 2025 transmission capacity and an updated generation mix; and
- An Expanded Interties scenario, representing a future in which provinces successfully coordinate to build interties along specific corridors (British Columbia-Alberta, Manitoba-Saskatchewan, Ontario-Quebec, and Atlantic Canada), with new transmission built wherever it is cost-effective to meet demand plus reserve margins.

This study also included the following set of policies, assumed to take effect based on current political commitments:

- *Clean Electricity Regulations*, coming into effect in 2035 and excluding Alberta due to its MOU;
- Province-specific industrial carbon pricing, continue pricing standards past 2030 without further tightening; and
- *CleanBC*, which included no new gas or nuclear plants being built in British Columbia.

2.3 Weather and reliability

Each modelled grid is then stress-tested for resource adequacy using PRAS. Weather affects the grid through three linked channels: generator and transmission outage rates, capacity

deratings, and electricity demand. We represent these channels with literature-derived sensitivity and fragility functions applied to a 2050 weather time series that combines common seasonal (chronic) conditions with synthetic extreme (acute) events such as heatwaves, cold snaps, droughts, wildfires, high winds, and ice storms. Each acute event is applied to all provinces within the same time frame. A given shock (heatwave, cold snap, wind storm or ice storm) is assumed to occur simultaneously across regions, rather than assuming that neighbours enjoy normal conditions; this is a deliberately conservative, spatially correlated stress assumption. Chronic seasonal conditions and wildfire likelihood, by contrast, vary by region according to historical weather patterns. The full parameterization, including the generator sensitivity coefficients and event definitions, is provided in the Technical Appendix.

The weather representation used here is a reimplementaion and consolidation of approaches developed for other jurisdictions rather than a new method: temperature-driven capacity deratings and weather-based outage rates follow Allen-Dumas et al. (2019), Kabre and Weimar (2022), van Vliet et al. (2016), Henry and Pratson (2016) and Sergio and Colelli (2025), and temperature-dependent demand follows Behm et al. (2020). This report's contribution is to collate these functions, adapt them to Canadian generation mixes, climates and provincial system boundaries, and apply them consistently across the national grid.

Table 1: Extreme weather events and their impacts on the grid

Weather Event	Grid Impacts
Heat waves	Reduces the output of thermal and nuclear generation; increases electricity demand for cooling.
Cold snaps	Increases available thermal capacity, due to reduced cooling limitations; drives up electricity demand for heating.
Drought	Reduces hydro generation capacity by up to 50%, significantly affecting provinces that depend heavily on hydroelectricity.
Wildfires	Damages transmission lines; disrupts flow in affected regions.
High winds	Disrupts transmission lines and affects wind generator availability across the network.
Ice storms	Overloads and damages transmission lines; disrupts flow in affected regions.

3. Results

3.1 Reliability metrics

Reliability is reported using two standard resource adequacy metrics.

Loss of Load Expectation (LOLE): the expected number of hours per year for which available supply is insufficient to meet demand.

Expected Unserved Energy (EUE): the expected amount of demand (MWh) that cannot be served per year.

Lower values in both these metrics indicate a more reliable system.

3.2 Overview

Four system-level findings emerge consistently across the corridors studied:

1. **Transmission improves reliability:** Transmission buildout consistently lowers LOLE and EUE through greater redundancy and expanded cross-border trade opportunities.

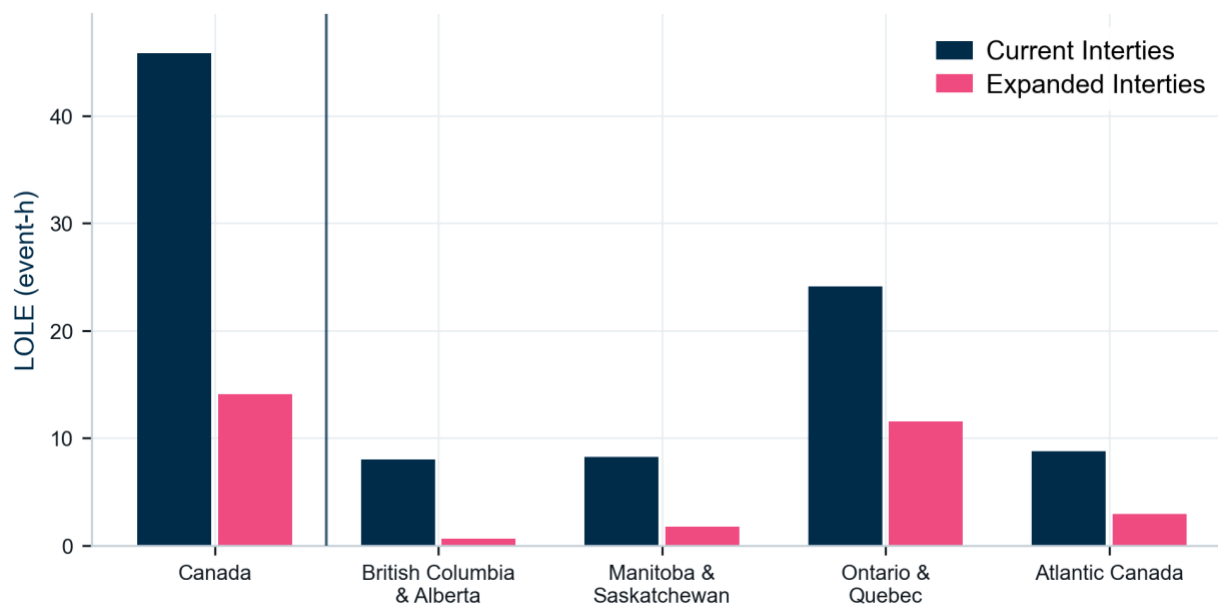


Figure 3: Loss of load expectation (LOLE) under extreme weather, Current vs. Expanded Interties, nationally and by region, 2050. Expanded interties reduce the national expected outage frequency by 69%.

2. **A weather-resilient grid:** Interties enable access to less heat-affected generation during the summer, while leveraging cold-weather capacity gains to meet elevated winter demand, insulating the grid from weather shocks.

Building Grid Resilience through Interprovincial Interties

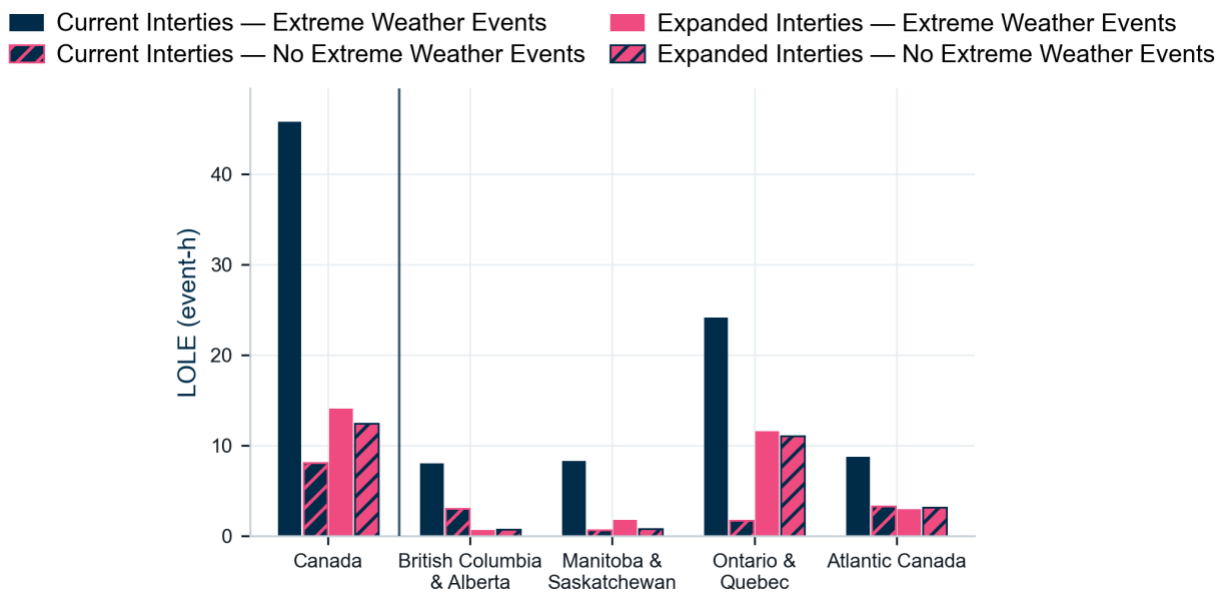


Figure 4: Reliability under extreme vs. no-acute weather conditions, Current vs. Expanded Interties, 2050. Expanded interties narrow the reliability gap between normal and extreme conditions.

3. Lower costs: Building generation and transmission together achieves cost savings while boosting system reliability.

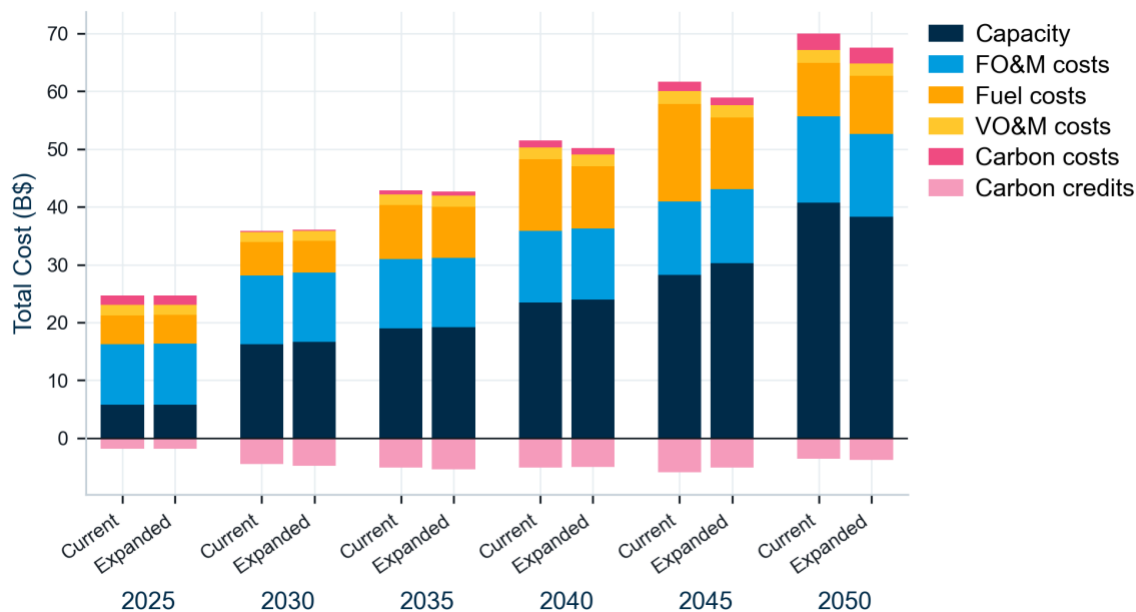


Figure 5: System cost composition by year, Current vs. Expanded Interties. Building generation and transmission together lowers total system cost.

Expanding interties lowers net system costs in every corridor. Figure 6 breaks the difference in each corridor's annual cost into five components: generation capital, generation operating cost (fixed and variable O&M, fuel and carbon), transmission,

import costs and export revenue. All values are annual costs in 2024 Canadian dollars relative to the no-new-interties baseline.

The pattern holds across corridors: coordinated buildout displaces generation capital and raises export revenue, and together these outweigh the added transmission and import costs. Every corridor's total system cost ends up below the baseline by 2050, with savings widening over time. Export revenue is plotted with a positive sign, so a value above zero means the corridor earns more export revenue under expanded interties than under the baseline.

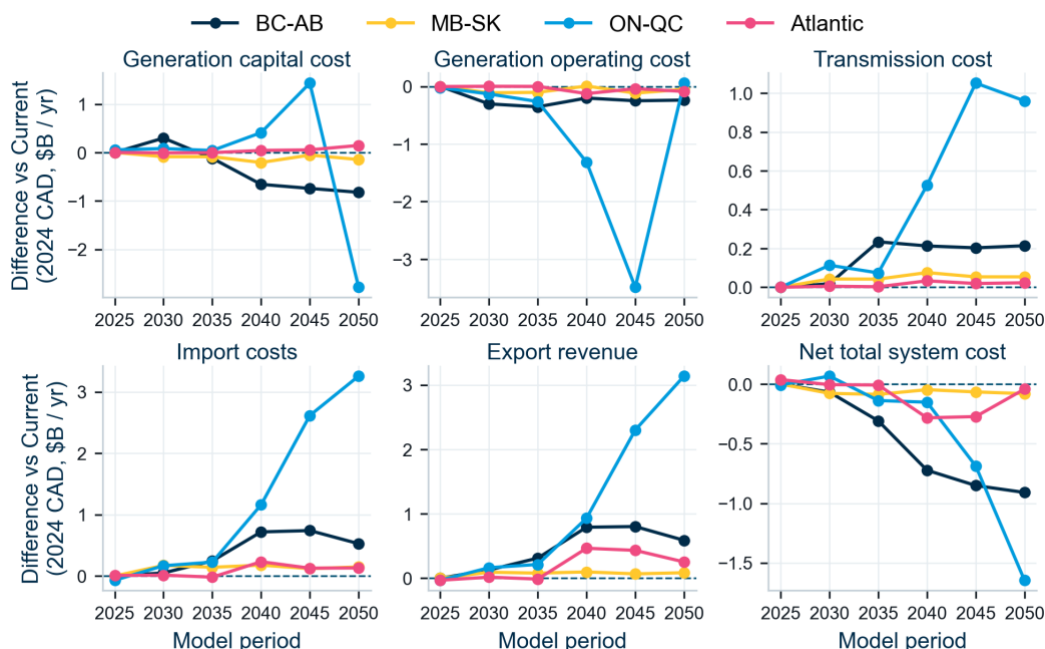


Figure 6: Difference in each corridor's annual cost under the Expanded interties scenario, by component, 2025-2050 (2024 CAD, \$B per year). Values below zero mean the expanded-intertie grid costs less than the baseline. Lower generation capital and higher export revenue drive the net saving in every corridor, partly offset by added transmission and import costs. Export revenue is shown with a positive sign, so values above zero indicate additional export revenue.

- Lessons for nuclear-dominated grids:** While thermal capacity is usually considered more reliable, sustained heat reduces the capacity available from thermal-reliant grids because of cooling requirements and environmental restrictions. Interties reduce that exposure by giving a heat-affected province access to resources whose output is not correlated with its own air temperature. In Ontario, a large share of the nuclear fleet draws cooling water from the Great Lakes, which moderates the impact of air-temperature changes. But the plants are restricted by the permitted temperature rise at the discharge, which is referenced to ambient lake conditions and so tightens as the lake warms (CNSC, 2012). That limit applies unevenly across the fleet. Section 3.3.3 sets out the mechanism and explores the extreme bounds.

The corridor-level results that follow show how these four findings play out in each region, and where local circumstances depart from the general pattern.

Across all four corridors, expanded interties consistently improve reliability while lowering net system costs. Nationally, building out interties reduces the expected frequency of outages under extreme weather by 69%. The improvement is largest where a province can lean on a neighbour with a complementary generation mix. The expected outage frequency falls by 92% in British Columbia (drawing on Alberta's thermal and wind resources), by 78% in Saskatchewan, and by 90% in Ontario (drawing on Quebec's wind and hydro). At the corridor level, region-wide LOLE falls by 52% in Ontario-Quebec and by 66% across the Atlantic provinces. Interties also make the grid more weather-resilient because weather shocks are localized and provincial generation mixes differ. Connections allow the system to draw on whichever supply is least affected at any moment, narrowing the reliability gap between normal and extreme conditions (Figure 3 & Figure 4).

These reliability gains come with a net cost saving. In every corridor, total system costs fall as generation and transmission are planned together. These costs are reduced by roughly 19% in British Columbia and 7% in Ontario, with smaller but still favourable changes in the Manitoba-Saskatchewan and Atlantic corridors.

The mechanism is twofold: first, provinces that can import firm capacity avoid overbuilding their own generation; second, resource-rich provinces build surplus capacity (mostly wind) and earn new export revenue, effectively acting as “clean energy banks” for their neighbours. The result is a shift away from costly province-by-province self-sufficiency toward a shared system that lowers cost while accelerating the clean-energy transition.

Nevertheless, the benefits are not uniform across provinces. Quebec's own LOLE and EUE worsen in the Expanded Interties scenario, as the model builds out additional wind farms, which are susceptible to greater spring variability. The Ontario-Quebec heatwave result also shows that thermal-reliant grids (particularly high nuclear grids) retain an edge under normal conditions, but are exposed under concentrated heat extremes depending on the heat resiliency of specific plants. Section 3.3.3 explores the effects through bounds rather than a single estimate (Figure 12 & Figure 13, Table 5).

In the Atlantic corridor, expected unserved energy can rise even where total outage hours fall, as clustered new wind plants produce correlated spring outages. This illustrates a tension between the two metrics that is worth highlighting: a lower LOLE alongside a higher EUE means outages become less frequent but more severe. It is important to consider both metrics when planning the future grid.

3.3 Provincial breakdown

3.3.1 British Columbia - Alberta (+2 GW AB→BC)

The British Columbia-Alberta corridor illustrates the benefits of increased interties most clearly: expanded intertie capacity allows Alberta to export more energy to British Columbia, improving British Columbia's reliability while creating potential additional revenue for Alberta. British Columbia's self-sufficiency policy is not imposed in the model; net flows are left unconstrained so that the benefits of interprovincial trade can be isolated.

Grid configuration

Under the Expanded Interties scenario, the model builds 2 GW of new export capacity from Alberta into British Columbia. With firm imports available, British Columbia builds substantially less of its own capacity, specifically solar capacity, cutting its capacity investment. The province instead relies on imports from Alberta, which builds additional wind capacity alongside the expanded transmission, positioning itself as an electricity exporter.²

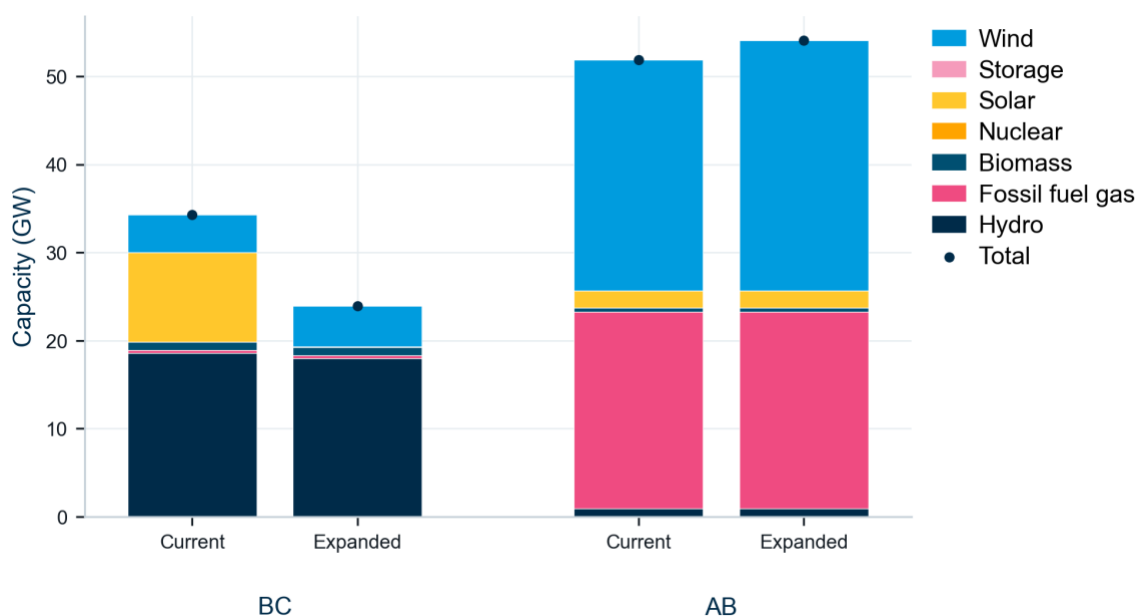


Figure 7: Impact of interties on the 2050 grid configuration, British Columbia-Alberta. With firm imports available, British Columbia builds substantially less of its own (largely solar) capacity while Alberta expands wind.

² It should be acknowledged that of the 14 Electricity Purchase Agreements (EPAs) issued over the 2024 and 2025 BC Hydro Calls for Power, only one EPA has been awarded to a solar generator and the rest have gone to wind generators (BC Hydro, 2024, 2025). However, by 2050, our model sees solar capital costs as having decreased at a faster rate than wind capital costs (as seen in Table 8). As a result, the large amount of solar expansion in the Current Interties scenario, though counter to historical grid expansion choices, is still consistent with the projected techno-economic inputs used for this modelling work.

Reliability

British Columbia sees improvements in both LOLE and EUE, which can be attributed to using imports from Alberta instead of solar energy to meet its demand. As solar generators are more susceptible to extreme weather impacts than wind generators, the expected frequency of outages falls by 92%, while Alberta sees no material change.

FUTURE STUDY

Single line expansion vs multi-line redundancy

We model intertie expansion as added capacity on a single connection, which leaves both provinces exposed to separation from a single line failure. Building the same capacity through multiple lines would add redundancy at higher cost. Quantifying this trade-off would require further studies, and should be considered prior to planning the intertie connections.

Costs

British Columbia’s system costs decrease while its import costs increase, resulting in a net decrease in total costs. Alberta’s system costs increase (with added wind and transmission costs), though this is offset by increased export revenue, resulting in only a marginal change in its total costs. Corridor-wide, net total costs fall by roughly \$0.91B/yr (-7%) by 2050 (all figures are annual costs in 2024 Canadian dollars). The change in Alberta’s export revenue (+\$637.7M/yr) is not simply the mirror image of British Columbia’s export revenue (-\$49.6M/yr). The counterpart to Alberta’s new export earnings is British Columbia’s higher import cost (+\$576.2M/yr), not British Columbia’s export revenue. British Columbia’s export revenue reflects its own separate sales to other regions (including to Alberta at other times of the year), which fall as it builds less surplus generation; the two provinces’ export-revenue figures therefore move independently.

Table 2: Impact of intertie expansion on reliability, British Columbia–Alberta corridor, 2050.

Metric	Overall	BC	AB
Reliability Metrics (2050)			
LOLE (event-h)	-7.41 (-92%)	-7.41 (-92%)	-
EUE (MWh)	-3,285.23 (-49%)	-3,285.23 (-49%)	-

Building Grid Resilience through Interprovincial Interties

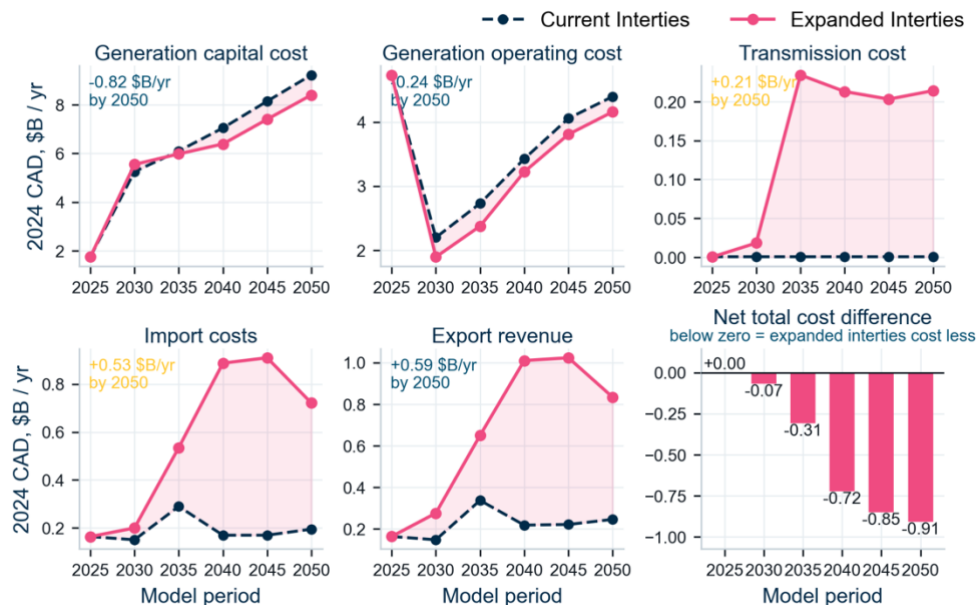


Figure 8: British Columbia-Alberta corridor: annual cost by component, Current vs. Expanded Interties (2024 CAD, \$B per year). By 2050 generation capital falls \$0.82B/yr and operating cost \$0.24B/yr, against \$0.21B/yr of added transmission. Export revenue rises \$0.59B/yr and import costs \$0.53B/yr, for a net reduction of \$0.91B/yr.

In sum, the British Columbia-Alberta intertie delivers the largest reliability improvement in the study while lowering net costs. British Columbia buys weather-proof firm capacity for less than it would cost to build in-province, while Alberta converts surplus generation into a new revenue stream.

3.3.2 Manitoba - Saskatchewan (450 MW SK→MB, 290 MW MB→SK)

Grid configuration

With expanded interties in place, we see less wind capacity being built in Manitoba, with a 13% difference between scenarios. Saskatchewan makes small additions to its own fleet, and the two provinces build out bidirectional interties.³

³ We did not enforce nuclear buildout in Saskatchewan, and the model saw benefit in building it out in Manitoba instead. This shows that additional nuclear is favourable in this corridor, but that because of model dynamics it appears more cost-optimal to site it in Manitoba.

Building Grid Resilience through Interprovincial Interties

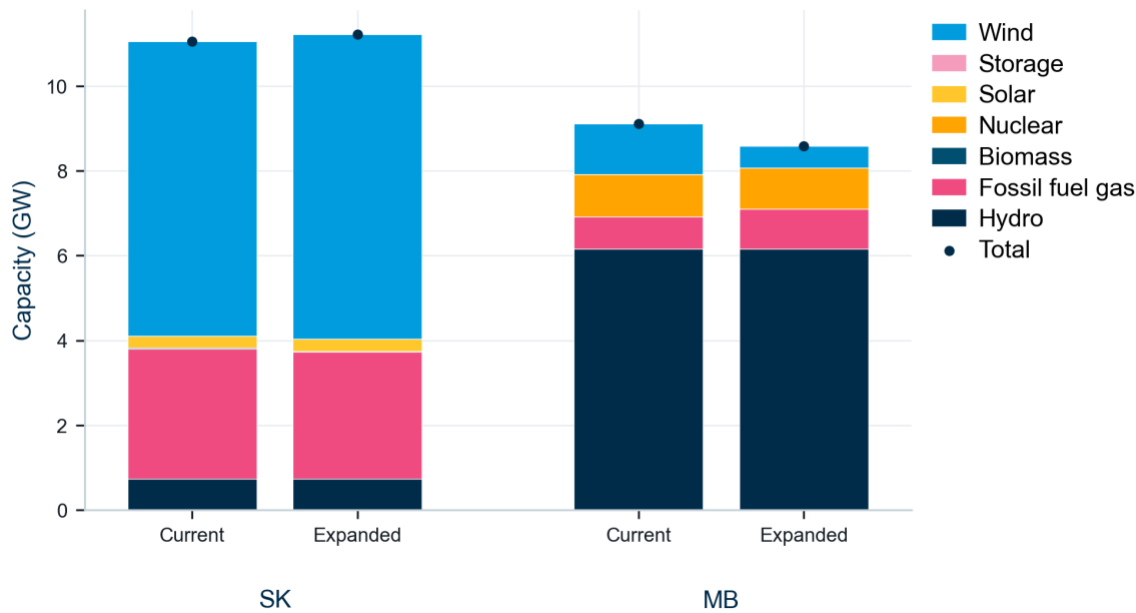


Figure 9: Impact of interties on the 2050 grid configuration, Manitoba-Saskatchewan. Required wind capacity in Manitoba drops as it can import more from Saskatchewan.

Reliability

Saskatchewan sees improvements in LOLE and EUE; Manitoba sees no change in LOLE and a marginal increase in EUE⁴. This bidirectional design allows power to flow east when Manitoba's wind capacity underperforms and west when Saskatchewan's system is stressed, so each province serves as the other's backstop at different times.

Costs

System cost changes are marginal in both provinces. Saskatchewan gains export revenue; Manitoba's import costs increase, leading to marginal net corridor savings of about \$0.08B/yr (-1%) by 2050. Export revenue is valued at a flat \$25/MWh across all corridors, representing a hurdle rate rather than a modelled market-clearing price.

Table 3: Impact of intertie expansion on reliability, Manitoba-Saskatchewan corridor, 2050.

Metric	Overall	SK	MB
Reliability Metrics (2050)			
LOLE (event-h)	-6.49 (-78%)	-6.49 (-78%)	-
EUE (MWh)	-138.45 (-87%)	-138.53 (-87%)	0.02 (+inf%)

⁴ Marginal enough to be considered a modelling artifact.

Building Grid Resilience through Interprovincial Interties

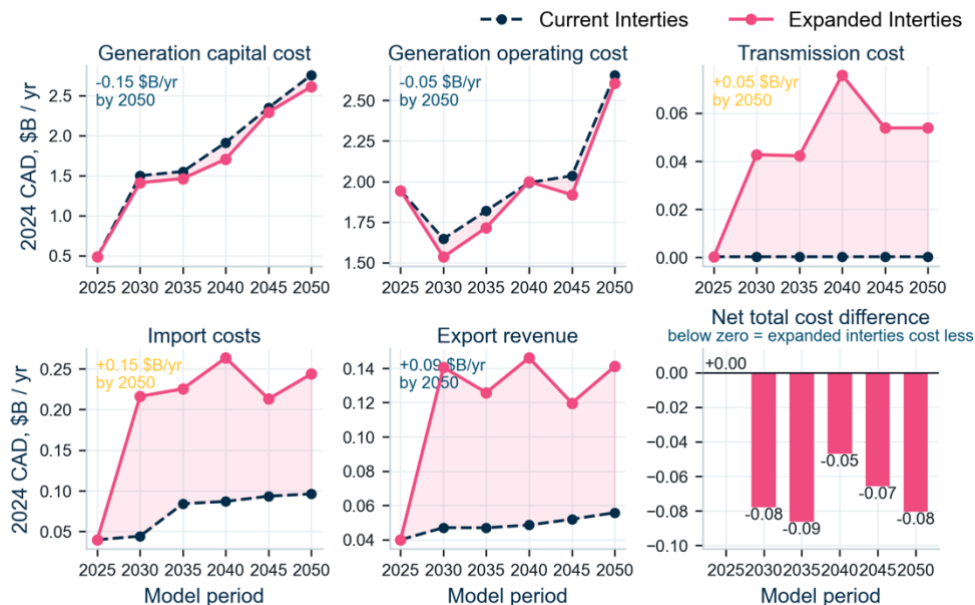


Figure 10: Manitoba-Saskatchewan corridor: annual cost by component, Current vs. Expanded Interties (2024 CAD, \$B per year). No component moves by more than \$0.16B/yr. Lower generation capital (\$0.15B/yr) and higher export revenue (\$0.09B/yr) roughly offset added transmission (\$0.05B/yr) and import costs (\$0.15B/yr), for a net reduction of \$0.08B/yr.

3.3.3 Ontario - Quebec (7.45 GW QC→ON)

Grid configuration

Under the Expanded Interties scenario, the model builds a major transmission expansion between Quebec and Ontario (7.45 GW). The resulting increase in exports from Quebec substantially reduces the amount of new nuclear capacity that must be built in Ontario.

In turn, Quebec builds out significantly more wind capacity. This implies that Ontario can meet its demand by utilizing Quebec as a clean energy bank, supplementing Ontario's supply when the grid is stressed and creating a revenue source for Quebec.

Ontario's existing nuclear capacity is the same in both scenarios, but under the Expanded Interties scenario, Ontario adds 5.4 GW of new nuclear by 2050, compared with 11.7 GW under Current Interties. In both scenarios, no new gas capacity is built, but in the Expanded Interties scenario roughly 6.6 GW of existing gas capacity is retained rather than retired in Ontario. This, combined with greater access to imports from Quebec, covers the demand that the additional 6.3 GW of nuclear would otherwise have served. Keeping those units available is the cost-optimal way to meet the reserve-margin requirement in the hours when imports and Quebec's wind fall short. While the Expanded Interties case retains more gas in Ontario, corridor-wide, the gas fleet barely changes. The net effect is largely a relocation of firm capacity to where it is needed rather than an expansion of it.

The 7.45 GW corridor is a cost-optimal, technically feasible transfer capability, not a construction plan. An interconnection of this size would be staged in practice and would face routing,

permitting and inter-jurisdictional coordination challenges, none of which we model. The figure shows what interties could deliver; establishing what is practical requires further work.

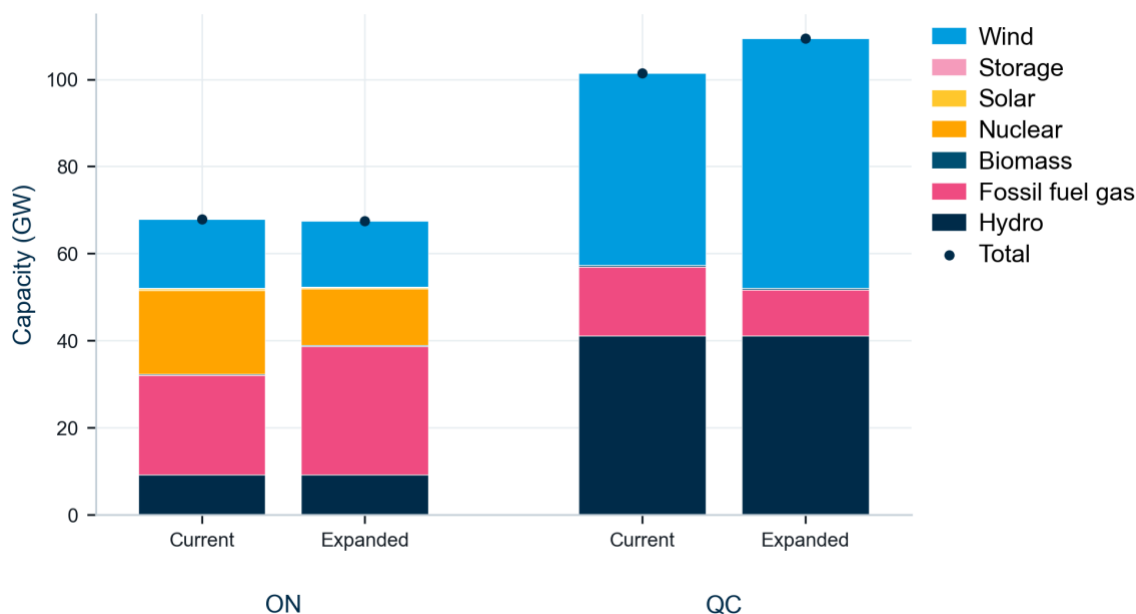


Figure 11: Impact of interties on the 2050 grid configuration, Ontario–Quebec. Cross-border imports from Quebec mean less new nuclear is built in Ontario, while Quebec builds out wind for export.

Reliability

Across both Ontario and Quebec, expected outage frequency region-wide under extreme weather still falls by 52% (Figure 1). However, Ontario sees improvements in both LOLE and EUE, while Quebec sees worsening of both metrics. Two seasonal dynamics explain the asymmetry (Figure 12). In spring, the Expanded Interties scenario has more dropped energy in Quebec, as the additional wind capacity is more susceptible to outages from spring storms or fluctuations in predicted available capacity. In summer, the Current Interties scenario has more outages caused by heatwave impacts on thermal-reliant grids. This dynamic is not seen in the Expanded Interties scenario, as the additional intertie capacity allows energy to be imported from Quebec when heat derates Ontario's nuclear and natural gas capacity. Because the additional Quebec–Ontario tie is modelled as a one-directional (Quebec-to-Ontario) connection, these results reflect conservative expansion-cost and usage assumptions. A bidirectional tie – the more likely real-world design – would also let Ontario support Quebec during its spring wind shortfalls, which would be expected to reduce Quebec's dropped energy in the Expanded Interties scenario.

FUTURE STUDY

Practicality study of the Quebec-Ontario tie

The Quebec-Ontario tie is modelled as one-directional, Quebec to Ontario, with no upper limit on how much capacity the model may build. A future study should test whether a bidirectional tie improves Ontario's winter and spring reliability and should sweep a range of intertie capacities to show stakeholders at what scale the dynamics reported here emerge.

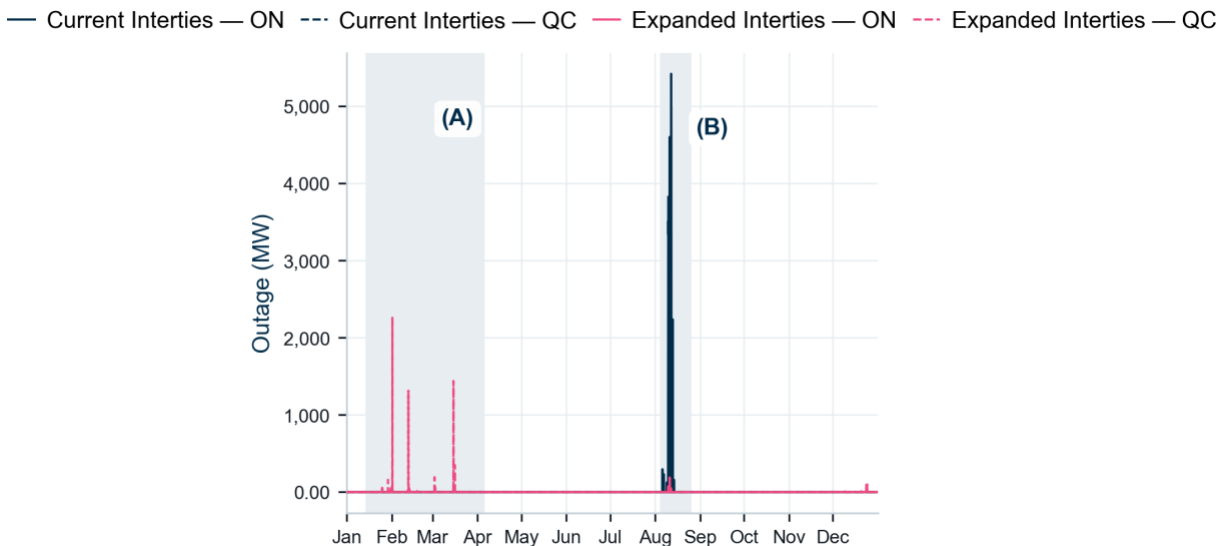


Figure 12: Outages by scenario over the year for Ontario and Quebec in 2050. The Expanded Interties scenario shows risk of outages in spring due to wind shortfalls in Quebec (A), while the Current Interties scenario shows large summer outages on Ontario's thermal-reliant grid during a heatwave event (B).

DEEP DIVE

Isolating the reliability contribution of the Quebec-Ontario tie

Both core scenarios plan the generation mix and the interties together. To separate the effect of the interties from the fleet they enable, we also ran an asynchronous scenario placing the Current Interties generation buildout on the Expanded Interties transmission network. In this asynchronous scenario, Ontario keeps the larger nuclear and gas fleet, and the corridor gains the extra Quebec-to-Ontario intertie.

Under the full extreme-weather year, the asynchronous case has the lowest outage frequency of the three scenarios and far less unserved energy than Current Interties. As visible in Figure A, the added trade capacity relieves the summer heat derating of Ontario's nuclear and gas capacity without bringing the spring wind exposure that comes with Quebec's export-driven wind buildout. We do still see more dropped energy in the summer, compared to the Expanded Interties case, showing that while the interties improve reliability, the grid remains sensitive to heat waves.

Hence, while expanding interties has a net positive impact on reliability, the generation mix shapes the remaining dynamics. A different fleet – one combining firm supply in spring with heat-resistant supply in summer. This is an area for future research to explore further.

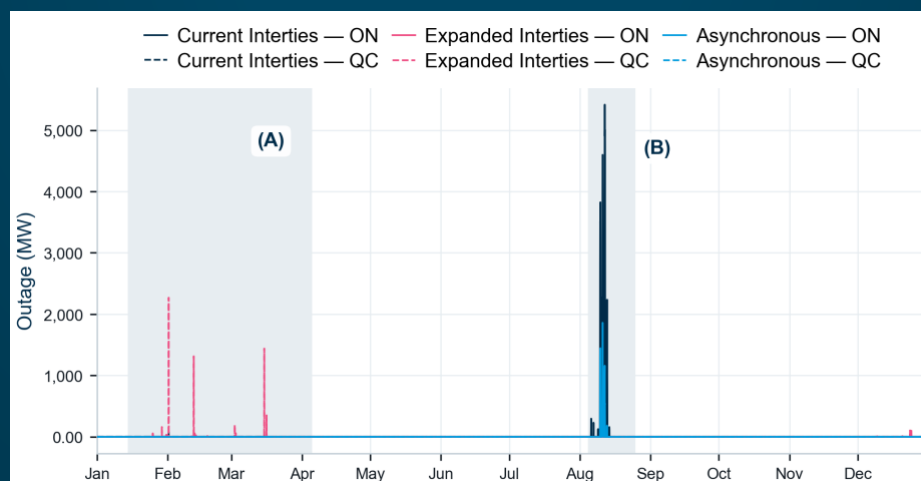


Figure A: Energy dropped throughout the year, in MW. Section (A) highlights spring wind-based outages and (B) summer heat-related outages.

Heatwave dynamic and the heat-resilient nuclear case

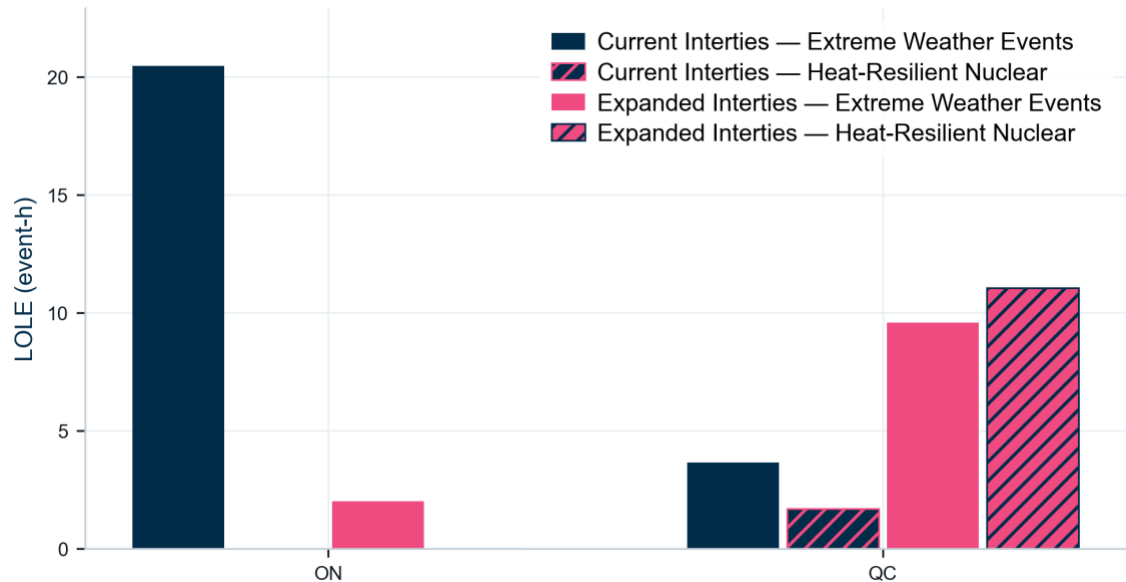
While the above results show a reliability risk during summer, Ontario's heat dynamic requires further review, given the variety of intake mechanisms across the nuclear fleet and the environmental regulations that apply. Darlington draws its condenser cooling water through a submerged offshore intake tunnel roughly 800 m from shore, which moderates intake

temperature relative to a shoreline draw (CNSC, 2012). Pickering draws through a shoreline intake channel fed from a forebay, and its refurbishment covers the reactors rather than the intake works (CNSC, 2023; OPG, 2025). Hence, the above dynamics could change depending on the resilience of the nuclear generators to environmental impacts, as well as on changes to regulatory measures that enforce a hard cap based on the lake’s ambient water temperature. To account for this uncertainty, we re-ran the corridor with the heat event removed, as a heat-resilient nuclear bound we re-ran the corridor with the heat event removed, as a heat-resilient nuclear bound that assumes no heat-driven derate anywhere in Ontario’s thermal and nuclear fleet

Table 4: Ontario nuclear capacity and cooling-water intake by station, 2026. Net ratings; Pickering units 1 and 4 were retired in 2024. Intake descriptions: Darlington (CNSC, 2012); Pickering (CNSC, 2023); refurbishment schedule (OPG, 2025).

Station (cooling-water body)	Units	Net capacity (MW)	Share of fleet	Intake
Darlington (Lake Ontario)	4	3,512	29%	Offshore tunnel, ~800 m out, ~10 m depth
Pickering B, units 5–8 (Lake Ontario)	4	2,060	17%	Shoreline intake channel fed from a forebay

Under that assumption the comparison reverses, with both EUE and LOLE lower in the Current Interties scenario. This highlights that there is potential to avoid the reliability risks by employing more heat-resistant technologies. The real dynamic likely falls between the two bounds, as Ontario's limit is set by provincial approval rather than by reactor physics. Each station is required not to impact its surrounding environment, which limits changes in lake water temperature (Ontario Ministry of the Environment, 2006, as reported in CNSC, 2012, Bruce Power, 2026). Nevertheless, additional interties act as an insulating measure, reducing the effect of the applied shock regardless of how strongly heat is expected to affect Ontario’s nuclear fleet.



Building Grid Resilience through Interprovincial Interties

Figure 13: Ontario-Quebec LOLE, 2050, under the modelled heat event and under the heat-resilient nuclear case in which that event is removed. Removing the derate reverses the comparison, leaving the Current Interties scenario more reliable. The two are deliberate opposite bounds; the fleet's actual response falls between them.

Table 5: Effect of intertie expansion on Ontario-Quebec reliability, under the modelled heat event and under the heat-resilient nuclear case (heat event removed), 2050. The two bound the fleet's plausible heat response rather than predicting it. Values are the change from Current to Expanded Interties; positive numbers indicate the Expanded scenario is less reliable.

Metric	Overall	ON	QC
All Extreme Weather Impacts (2050)			
LOLE (event-h)	-12.54 (-52%)	-18.46 (-90%)	5.93 (+162%)
EUE (MWh)	-82,284.46 (-91%)	-90,147.07 (-99%)	7,864.61 (++++%)
Heat-Resilient Nuclear – heat event removed (2050)			
LOLE (event-h)	9.38 (+558%)	-	9.38 (+558%)
EUE (MWh)	7,871.7 (++++%)	-	7,871.7 (++++%)

Costs

Ontario's system costs decrease, while import costs rise, leading to a 7% decrease in total system costs. Quebec's system costs increase (added wind and transmission costs), offset by increased export revenue, for a marginal change in total costs. Corridor-wide, net total costs fall by roughly \$1.65B/yr (-4%) by 2050.

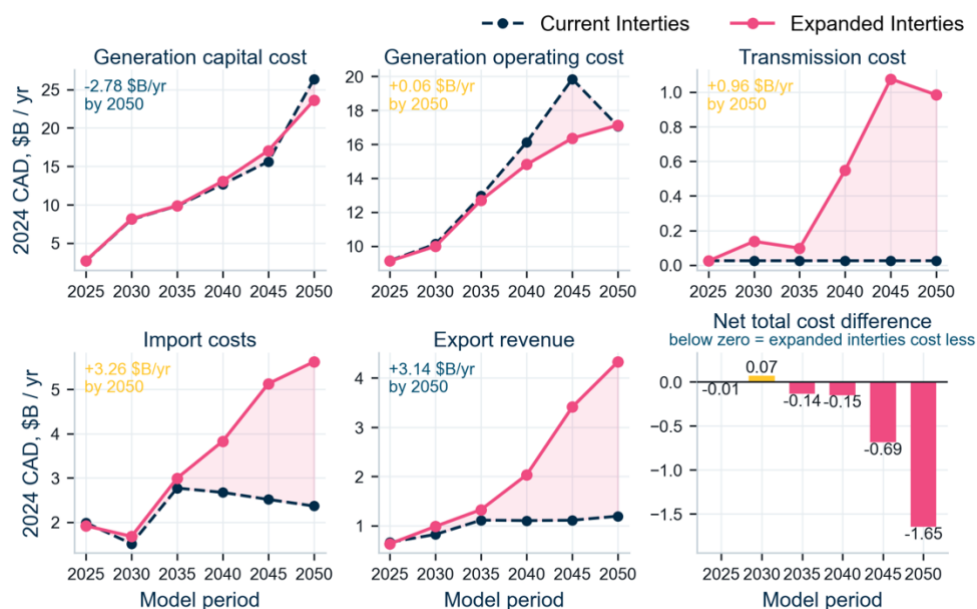


Figure 14: Ontario-Quebec corridor: annual cost by component, Current vs. Expanded Interties (2024 CAD, \$B per year). Generation capital falls \$2.78B/yr by 2050 as less new nuclear is built in Ontario, against \$0.96B/yr of added transmission. Export revenue rises \$3.14B/yr and import costs \$3.26B/yr, for a net reduction of \$1.65B/yr. Operating cost is unchanged.

3.3.4 Atlantic Canada

Grid configuration

With expanded interconnection, the region's capacity mix replaces storage with additional wind capacity and transmission; the export potential this creates removes the need to store excess wind energy locally.

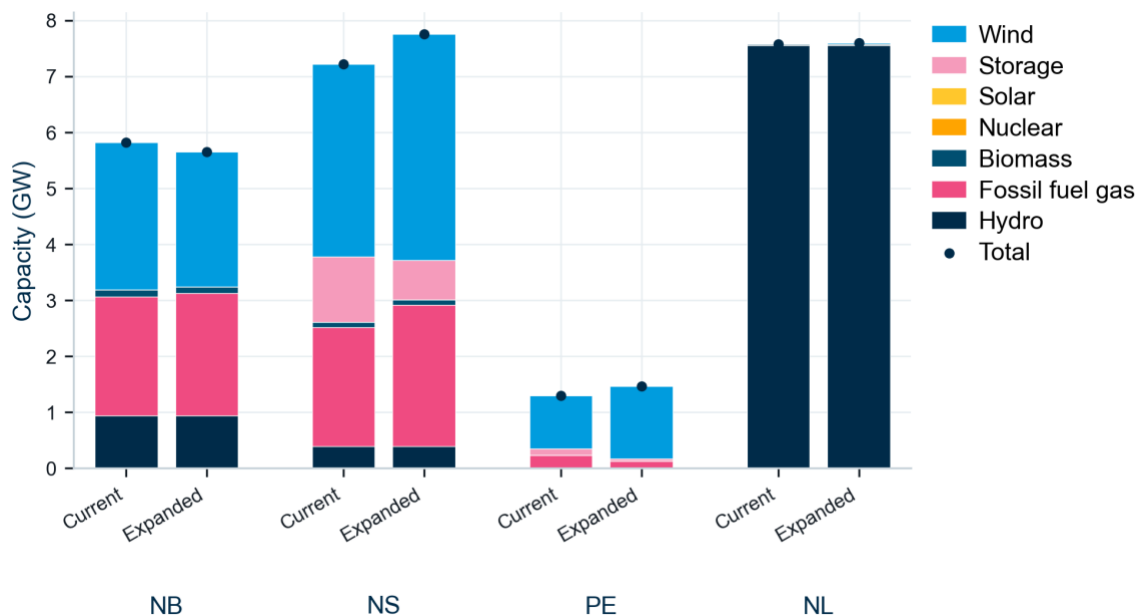


Figure 15: Impact of interties on the 2050 grid configuration, Atlantic Canada. Transmission and export potential substitute for local storage, with Nova Scotia, Prince Edward Island and Newfoundland and Labrador adding wind.

Reliability

New Brunswick and Newfoundland and Labrador see no change. Nova Scotia sees worsening in LOLE and EUE (Figure 16), while Prince Edward Island sees improvement in LOLE but worsening in EUE (Figure 17). This is due to the Expanded Interties scenario building more wind capacity, which has higher outage rates in spring. Additionally, locating wind plants close together may lead to simultaneous outages and a higher amount of undelivered energy, even when total outages are lower.

Building Grid Resilience through Interprovincial Interties

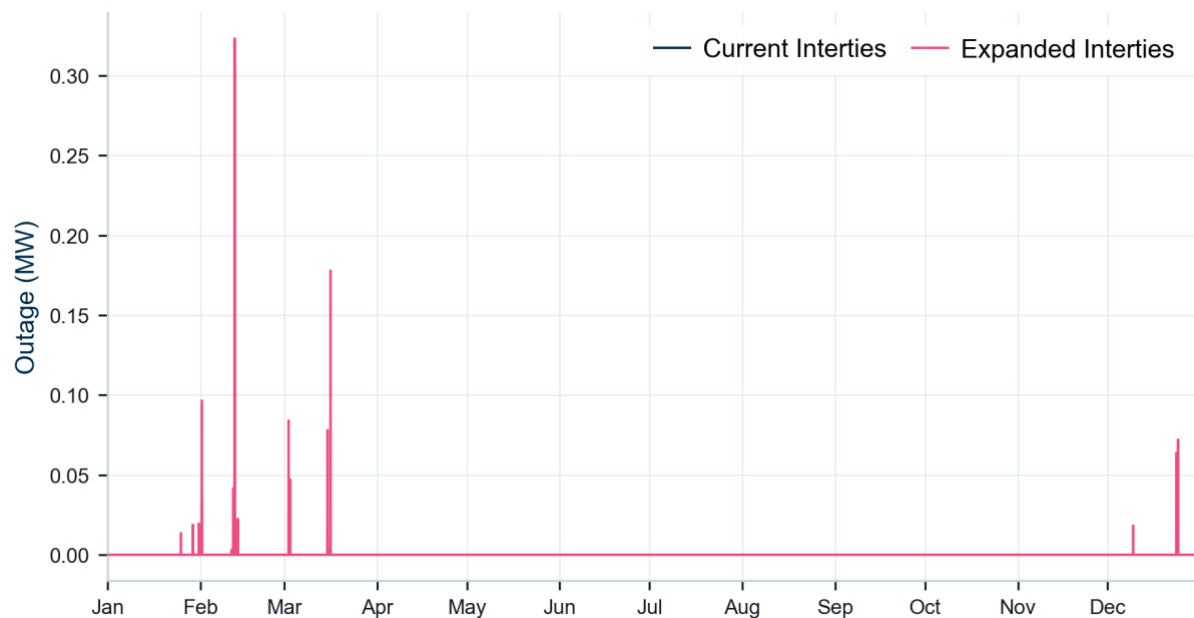


Figure 16: Outages by scenario over the year, Nova Scotia, extreme weather, 2050. Clustered new wind raises spring outage energy even where total outage hours fall.

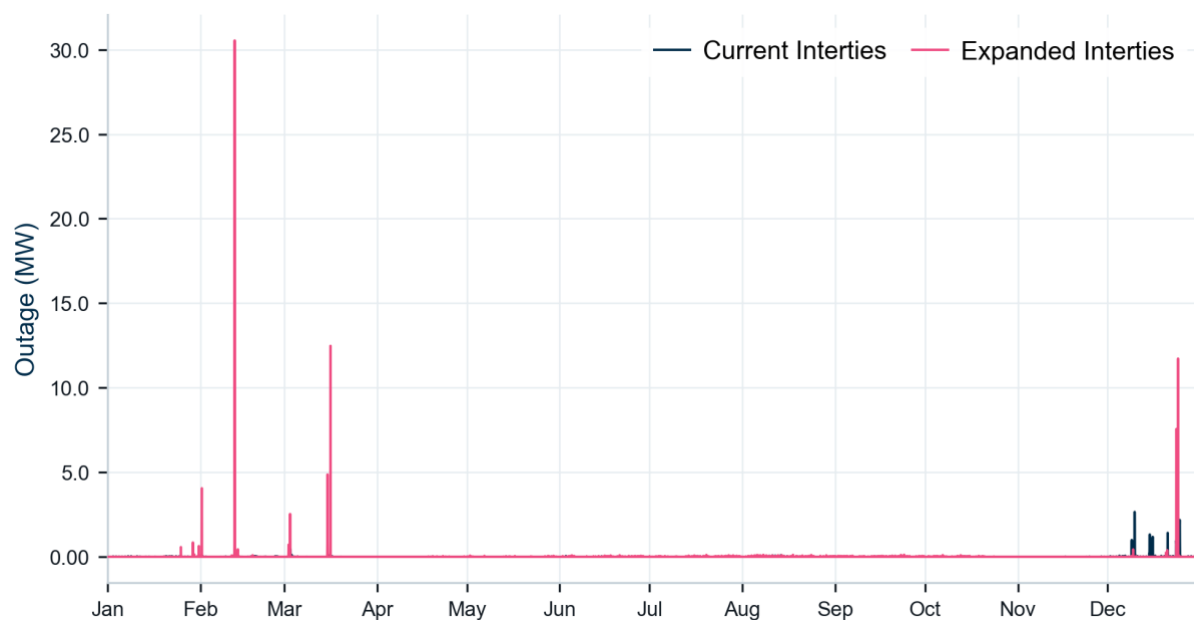


Figure 17: Outages by scenario over the year, Prince Edward Island, extreme weather, 2050.

Costs

New Brunswick's costs are roughly unchanged, as higher import costs are offset elsewhere. Nova Scotia, Prince Edward Island, and Newfoundland and Labrador all see system cost increases from added wind and transmission, offset partly or fully by export revenue; Prince Edward Island's total costs fall overall. Corridor-wide, net total costs fall slightly (about \$0.04B/yr, -2%) by 2050.

Building Grid Resilience through Interprovincial Interties

Table 6: Impact of intertie expansion on reliability, Atlantic Canada (New Brunswick, Nova Scotia, Prince Edward Island, Newfoundland and Labrador), 2050.

Metric	Overall	NB	NS	PEI	NL
Reliability Metrics (2050)					
LOLE (event-h)	-5.82 (-66%)	—	0.21 (+inf%)	-5.79 (-66%)	—
EUE (MWh)	75.51 (+125%)	—	1.66 (+++%)	73.63 (+137%)	—

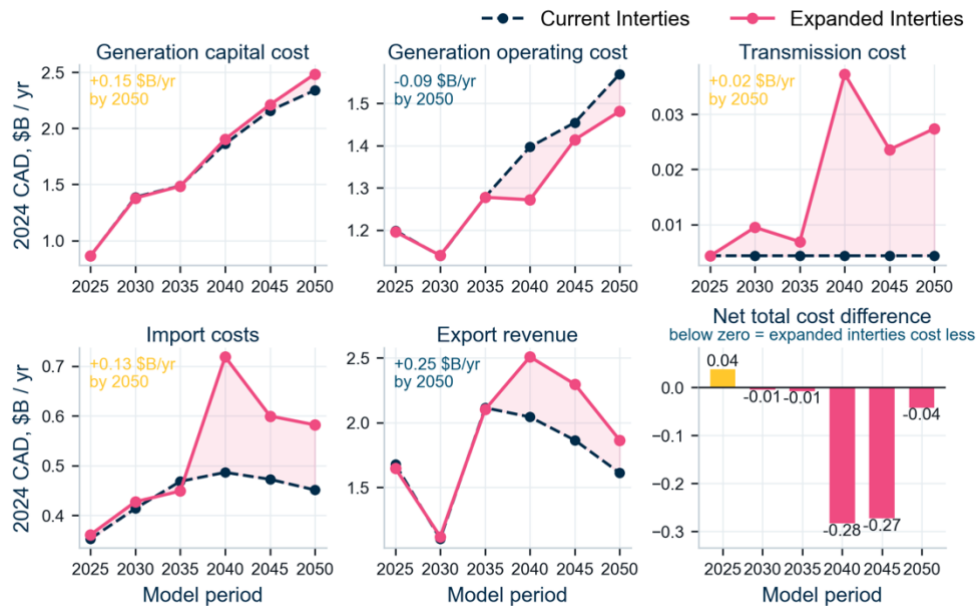


Figure 18: Atlantic Canada corridor: annual cost by component, Current vs. Expanded Interties (2024 CAD, \$B per year). Generation capital rises \$0.15B/yr as the region adds wind, offset by \$0.09B/yr lower operating cost and \$0.25B/yr more export revenue, for a net reduction of \$0.04B/yr.

4. Discussion & Conclusion

Our results align with international literature on the value of interregional transmission for resilience. Analyses by Grid Strategies and ACORE find that transmission moves power to where it is scarce during extreme events, including the 2022 Winter Storm Elliott, materially reducing shortfall risk (Goggin, 2021; ACORE, 2023). The NREL Interconnections Seam Study similarly finds that increased interregional capacity delivers both reliability and economic value across the U.S. grid (Bloom et al., 2020). Our corridor-level results extend this evidence to the Canadian interprovincial context, where the literature has long argued that province-by-province planning is costly and that greater integration and coordination would yield system-wide gains (Pineau, 2021). Studies of Canadian decarbonization costs point in the same direction (Dolter & Rivers, 2018; Arjmand & McPherson, 2022). The international literature also points to economic benefits beyond cost and reliability, such as lower and more stable energy prices, which invites further research in the Canadian context.

The heatwave dynamic we observe is consistent with the climate-vulnerability literature on thermal and nuclear generation. Higher temperatures and constrained cooling water derate thermoelectric and nuclear plants (van Vliet et al., 2016), and the frequency of climate-linked nuclear outages is rising (Ahmad, 2021), even though historical curtailments have been modest and partly manageable through cooling retrofits and operational adaptation (Tadrous & Calic, 2025). In Ontario, the binding mechanism is the permitted limit on heat rejection rather than a shortage of cooling water, and it is documented for only a minority of the fleet. We therefore report the Ontario-Quebec summer result as a range bounded by full exposure and full resilience rather than as a single estimate (Section 3.3.3).

Additionally, empirical evidence from European hydro and thermal generators shows that extreme weather significantly raises power-plant outage risk, with strong technology-specific patterns (Sergio & Colelli, 2025). Our analysis complements these plant-level findings with a system-level remedy. Interties let unaffected resources in a neighbouring province cover correlated thermal deratings during heat extremes. The direction of our findings supports the federal National Electricity Strategy announced in May 2026, which explicitly targets barriers to interprovincial interties (Government of Canada, 2026).

The evidence indicates that interprovincial grid interconnection is a robust lever for planning a reliable, lower-carbon and economically competitive electricity grid in the face of intensifying climate risks. Three conclusions follow.

First, extreme weather events are becoming more frequent and severe, raising risks for the grid that conventional reserve-margin planning does not capture.

Second, by raising intertie capacities the grid can draw on a more diverse generation mix across regions, insulating against localized outage risk while reducing investment costs.

Third, provinces with greater renewable potential can act as clean-energy banks that supplement regional supply, lowering overall investment costs while opening a new revenue stream for themselves. Variable renewables still carry reliability risk. While planning can account

for their expected output, interties deliver the most value when the supply they carry is relatively firm – backed by storage or a diverse resource mix – rather than intermittent generation alone.

FUTURE STUDY

Firm-backed interties vs. additional firm generation

The corridor cost reductions reported here, roughly 1-7% per year and most below 4%, are modest against the scale of building new tie-lines and relying on largely intermittent supply. A dedicated risk study should compare interties paired with firm backup, such as wind plus battery storage, against building additional firm generation, weighing residual reliability risk against the added cost and emissions of each. Ontario-Quebec, where wind variability is high and hydro support limited, is the strongest candidate.

The principal open questions are distributional rather than technical: who pays for new lines, and how are the reliability and cost benefits shared between exporting and importing provinces? Addressing these will require a collaborative interprovincial transmission framework enabled by provincial and federal regulation. With that governance in place, expanded interties offer a concrete, evidence-based step toward a resilient, low-cost and low-carbon energy future for all Canadians.

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Technical Appendix

This appendix collects the detailed methodology supporting the analysis: the underlying data sources, the capacity-expansion and reliability models, the weather parameterization, the notes on interpreting the results, and the study's methodological limitations.

Interpreting the results and limitations

Please note that the findings presented here are based on CODERS, a database of public electricity grid data; COPPER, an open-source cost-optimization model structured from the perspective of a single, universal system operator; and PRAS, a probabilistic resource adequacy model developed by NREL.

While this means that the data and models applied here differ from those used by Canada's utilities and system operators, both CODERS, COPPER and PRAS have undergone continuous validation by experts at leading institutions. For COPPER, this includes a yearly comparison workshop with models developed and used by groups, including Environment and Climate Change Canada (ECCC), Natural Resources Canada (NRCan), HEC, ESMIA, and Sutubra, ensuring a rigorous methodological approach. Furthermore, the data present in the CODERS database is a collection of primary and secondary sources, which have been validated in collaboration with sectoral experts and can be interrogated on a by-value bases through its website and sources.

Regarding the economic projections presented here, while the results demonstrate potential cost reductions and revenue increases, the model uses a simplified market structure. Therefore, additional analysis is likely needed to draw robust conclusions regarding exact localized profit and cost impacts.

The capacity-expansion model finds the cost-optimal grid configuration (the grid that minimizes system-wide costs) while enforcing policies and requirements such as emission limits and reserve margins, and it does so from the perspective of a single, universal system operator. The resulting grid is therefore an illustration of what could be built under the stated assumptions, not a forecast of what each utility will build. The findings are best used to assess the potential benefits of different grid evolutions and to weigh them against further factors such as sectoral and industry interests and trends.

Costs warrant particular care. Transmission is implemented unidirectionally in the model, with the exporting province paying the transmission price, so costs are broken into system costs, transmission costs, import costs, and export revenue. The market structure is simplified, and the allocation of costs and benefits between provinces is uncertain. In practice, the importing province that gains reliability would likely share these costs: for example, if Alberta builds extra transmission and generation to supplement British Columbia, some of that cost would likely be shared, since British Columbia benefits from both lower system costs and added reliability. This cost allocation is outside the scope of this study, and the economic figures in particular warrant further analysis before being read as precise provincial profit or cost impacts. All cost figures in

this report are annualized and expressed in 2024 Canadian dollars: each figure is an annual cost for the modelled period, not a one-time capital outlay or a discounted lifetime total. For example, the British Columbia-Alberta intertie appears as roughly \$214M per year by 2050, the annualized cost of the line (its capital cost spread over the asset's service life, plus fixed operating costs), so the equivalent undiscounted build-and-operate cost accumulated across the modelling horizon is several times larger. Costs are therefore shown as annual trajectories over time rather than as a single headline number, to make this annualization transparent.

Finally, the weather representation relies on literature-derived sensitivity and fragility functions (Table 7) and on synthetic acute events parameterized for a single 2050 weather year (

Table 8), with drought modelled at the lower bound of its sensitivity range. The results are therefore conditional on these parameter choices.

Data sources

Input data was drawn from ODERS compiles primary and secondary sources – generator inventories, transmission topology, costs and demand – that have been validated in collaboration with sectoral experts and can be interrogated on a by-value basis through its public interface.

Modelling approach

The core of the methodology is a two-stage linkage: a capacity expansion model determines what grid gets built under each intertie scenario, and a probabilistic reliability model then stress-tests that grid against parameterized weather conditions.

Capacity expansion

Long-term grid evolution is modelled with COPPER (Canadian Opportunities for Planning and Production of Electricity Resources), a peer-reviewed, open-source, multi-period capacity expansion model developed by the SESIT group (Arjmand & McPherson, 2022). COPPER co-optimizes investments in generation, storage, and transmission alongside hourly dispatch, finding the federally cost-optimal solution from the perspective of a single grid operator. The model is compared and verified against multiple models at a yearly model-comparison workshop, including those of ECCC, NRCan, HEC, ESMIA and Sutubra.

The optimization minimizes total system cost subject to five sets of constraints:

- Hourly demand must be met in every zone.
- Each region must hold a planning reserve margin. This is a capacity target, not a reliability target such as 0.1 days per year of loss of load.
- Policy constraints apply: the Clean Electricity Regulations from 2035, province-specific industrial carbon pricing, Alberta's CER exemption, and CleanBC's restriction on new gas and nuclear in British Columbia.
- Technology build limits and existing-asset retirement schedules constrain what can be added and when.
- Transmission is limited by each corridor's available capacity.

The second constraint shapes how the results should be read. Because the build step sizes the grid to a reserve margin rather than to a reliability metric, two scenarios with similar reserve margins can still show materially different LOLE and EUE once weather-dependent outages are applied. That gap is the effect this study isolates, and it is why reliability is assessed independently in PRAS rather than inferred from the build. The full formulation is documented in the COPPER model documentation (Arjmand & McPherson, 2022).

Reliability modelling

Resource adequacy is assessed with the Probabilistic Resource Adequacy Suite (PRAS), an open-source toolkit developed by NREL that performs a Monte Carlo simulation of multi-region power systems over hundreds of thousands of sample years of unplanned outages to quantify shortfall risk (Stephen, 2021). Each province is represented by 5 to 10 zones⁶.

Weather-based outage and capacity impacts

Generators and transmission infrastructure are impacted by the weather, affecting both outage probabilities and capacity deratings. These impacts were quantified as sensitivity and fragility functions, which allow us to simulate how the climate impacts our grid. This report bases its implementation of the effects on the Oak Ridge National Laboratory review of environmental sensitivity quantification (Allen-Dumas et al., 2019), which collected a variety of impacts across hazards, such as thermal power plant capacity decreasing by roughly 0.3–0.5% for each 1°C increase in ambient temperature above a 15°C reference, alongside temperature-dependent deratings for transmission and the effects of wind, flood, wildfire and ice on grid components. Additional resources were the PNNL fragility functions resource report (Kabre & Weimar, 2022), as well as more detailed historical records of temperature- and runoff-linked curtailments and outages (Tadrous & Calic, 2025; Sergio & Colelli, 2025). A detailed breakdown of weather impact on different generation types can be seen in

Technology	Ref. temp (°C)	Cold-side slope (%/°C)	Hot-side slope (%/°C)	Modelling notes
Solar PV	25	+0.40	-0.40	Cell-temperature coefficient relative to 25°C STC ($T_{\text{cell}} \approx T_{\text{air}} + 20^{\circ}\text{C}$), within the typical -0.3 to -0.5%/°C P_{max} range (industry module specifications).
Wind	15	+0.30	-0.30	Air-density effect only.
Gas	15	+0.50	-0.50	Output relative to 15°C ambient; 0.5%/°C is a conservative central value, with some units up to ~1%/°C (González-Díaz et al., 2017).
Oil	15	+0.30	-0.40	Frame/aeroderivative oil turbines share gas-turbine thermodynamics, so the same ambient-temperature derating applies.

⁶ The number of zones depends on the size of the province.

Coal	20	+0.15	-0.35	Parameterized against cooling-water temperature; ~3–5% net-output loss per 10°C of cooling-water warming (Henry & Pratson, 2016)
Nuclear	20	0.00	-2.00	Flat below ~25°C, then -2%/°C above the cooling-water discharge threshold down to a floor, reflecting environmental limits (Tadrous & Calic, 2025). The constraint represented is the permitted temperature rise at the discharge, not intake-water availability. The slope is applied uniformly across the nuclear fleet, which is conservative for stations with submerged offshore intakes and permissive for those without (Section 3.3.3).

Table 7.

Table 7: Generator temperature-sensitivity coefficients used to derive capacity. Positive cold-side slopes denote capacity gains as temperature falls below the reference; negative hot-side slopes denote losses as temperature rises above it.

Technology	Ref. temp (°C)	Cold-side slope (%/°C)	Hot-side slope (%/°C)	Modelling notes
Solar PV	25	+0.40	-0.40	Cell-temperature coefficient relative to 25°C STC ($T_{\text{cell}} \approx T_{\text{air}} + 20^\circ\text{C}$), within the typical -0.3 to -0.5%/°C P_{max} range (industry module specifications).
Wind	15	+0.30	-0.30	Air-density effect only.
Gas	15	+0.50	-0.50	Output relative to 15°C ambient; 0.5%/°C is a conservative central value, with some units up to ~1%/°C (González-Díaz et al., 2017).
Oil	15	+0.30	-0.40	Frame/aeroderivative oil turbines share gas-turbine thermodynamics, so the same ambient-temperature derating applies.
Coal	20	+0.15	-0.35	Parameterized against cooling-water temperature; ~3–5% net-output loss per 10°C of cooling-water warming (Henry & Pratson, 2016)
Nuclear	20	0.00	-2.00	Flat below ~25°C, then -2%/°C above the cooling-water discharge threshold down to a floor, reflecting environmental limits (Tadrous & Calic, 2025). The constraint represented is the permitted temperature rise at the discharge, not intake-water availability. The slope is applied uniformly across the nuclear fleet, which is conservative for stations with submerged offshore intakes and permissive for those without (Section 3.3.3).

Weather parameterization

To integrate these effects into our resource adequacy assessment, we created a weather time series to calculate the per generator outage probabilities and capacity impacts. High-resolution estimates of temperature, rainfall, wind speeds, wildfire and drought were created by combining ERA5 daily reanalysis data for 2025 with historical NBAC (National Burned Area Composite) wildfire data from 2000-2025. Using this information, we created “chronic” weather conditions, which represent common seasonal trends throughout the year. Additionally, we implemented

“acute” events – synthetic shocks to the system that capture edge-case events of the kind that have happened in the past. They are parameterized as follows:

- Extreme heat, where the mean temperature was set to the 98th percentile of maximum temperature for the region;
- Extreme cold, where the mean temperature was set to the 2nd percentile of minimum temperature for the region;
- Drought, which was implemented as a sensitivity analysis, applying a 10–50% capacity reduction to hydro capacities and a runoff index set to -3;
- Wildfires, where the regional likelihood of fire presence was calculated from historical wildfire data. Outage likelihood given fire presence was calculated from fire-weather information based on slope, ground fuel (aridity index), Fire Weather Index (FWI) and Buildup Index (BUI);
- High wind, where wind speeds were set to 41 m/s; and
- Ice storms, where wind speeds were set to 15 m/s and ice accumulation to 38 mm, representing a high Sperry-Piltz Ice Accumulation Index.

Outage rates and capacity deratings supplied to PRAS were calculated by applying the weather-based sensitivity and fragility functions above to the parameterized weather conditions for each region and event. These acute weather events are detailed further in

Table 8.

Table 8: Extreme weather event parameterization. Dates and lengths define the synthetic shock window applied on top of the chronic seasonal weather series.

Acute event	Onset (2050)	Duration	Exact parameterization
Drought	12 Aug	31 days	Hydro capacity scaled by drought factor 10-50% and the runoff index set to -3
Heatwave	1 Aug	14 days	Hourly air temperature scaled so that the mean daily temperature is the 98th percentile of regional maximum
Flood	7 Nov	14 days	Streamflow at the 100th percentile
Ice storm	14 Jan	7 days	T = -0.1°C; wind 15 m/s; ice accretion 38 mm (high Sperry-Piltz Ice Accumulation Index).
Wind storm	1 Nov	2 days	Sustained wind speed 41 m/s.
Wildfire	FWI-driven	Fire season	Outage likelihood computed from ESCER Fire Weather Index fields (FWI/BUI), slope and ground-fuel aridity rather than a fixed date.
Spatial scope	—	—	Events clustered within a 500 km radius

Demand impacts

Electricity demand is itself weather-sensitive, so each region's load is temperature-adjusted before the reliability simulation. This temperature-dependent representation follows established load-modelling practice for European systems, where weather variables are among the

strongest predictors of daily and hourly demand (Behm et al., 2020). The resulting demand series were applied on top of the chronic and acute weather conditions, so that heatwaves and cold snaps raise cooling and heating load in step with the supply-side deratings described above.

Together, these components form a closed chain from weather to reliability. Parameterized chronic and acute weather conditions drive outage rates, capacity deratings and demand, which PRAS then simulates against the COPPER-built grid under each intertie scenario.

Cost assumptions

The capacity-expansion model is driven by technology and transmission cost assumptions compiled from CODERS.

Table 9 lists the capital and operating cost assumptions for the generation and storage technologies, Table 10 lists provincial natural gas costs, Table 11 lists other fuel costs, and Table 12 lists the transmission pricing parameters. Capital costs decline over the modelling horizon as technologies mature, so both the 2025 and 2050 values are shown, while fixed and variable operating costs and most fuel costs are held constant. Capital and fixed operating costs are expressed per MW of capacity, variable operating costs per MWh generated, and fuel costs per GJ of fuel input. All costs are given in 2024\$.

Table 9: Technology cost assumptions (capital, fixed and variable operating costs).

Technology	2025 Capital Cost (\$/W)	2050 Capital Cost (\$/W)	Fixed O&M (\$/MW/yr)	Variable O&M (\$/MWh)
Onshore wind ⁷	3.115	2.261	38,532	0
Offshore wind ⁷	9.428	7.414	160,953	0
Solar PV ⁷	2.1939	1.1121	22,308	0
Nuclear (conventional) ⁷	11.4378	9.4089	177,983	3.47
Nuclear (SMR) ⁷	12.4785	10.2746	138,996	4.39
Hydro (run-of-river) ⁸	3.629	3.1643	52,028	0
Hydro (small reservoir) ⁸	9.5811	8.3541	148,246	6.88
Hydro (large reservoir) ⁸	11.0112	9.6011	19,926	1.97
Gas combined cycle ⁷	1.8572	1.4758	17,849	2.73
Gas combined cycle (refurbish) ⁷	0.1683	0.1337		
Gas combined cycle + CCS (new) ⁷	4.7083	3.135	40,378	8.54
Gas combined cycle + CCS (retrofit) ⁷	2.1893	1.4578		
Gas simple cycle ⁷	2.186	1.7436	23,855	6.88
Gas simple cycle (refurbish) ⁷	0.7935	0.6329		
Battery storage (Li-ion) ⁷	1.7469	0.9766	59,488	0
Pumped hydro storage ⁸	5.7347	5.7347	16,722	1
Coal ⁷	7.2063	5.8284	59,384	6.58
Coal + CCS (new) ⁷	11.3817	8.3432	87,126	16.06
Coal + CCS (retrofit) ⁷	3.8698	2.8367		
Diesel ⁷	3.4761	3.4761	49,288	8.32
Biomass ⁷	6.1213	5.0327	145,841	7.73

⁷ EIA (2023). Annual Energy Outlook 2023, Table 1: Cost and Performance Characteristics of New Central Station Electricity Generating Technologies. U.S. Energy Information Administration. https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf

⁸ BC Hydro (2021). BC Hydro's 2021 Integrated Resource Plan Application, Appendix J-1 RODAT. British Columbia Utilities Commission. <https://www.bcuc.com/OurWork/ViewProceeding?applicationid=965>

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Table 10: Provincial natural gas cost assumptions. Based on 2021 industrial natural gas prices from the Canada Energy Regulator's Canada's Energy Future 2023.

Province	Cost (\$/GJ)
British Columbia	3.52
Alberta	3.78
Saskatchewan	5.67
Manitoba	5.61
Ontario	6.70
Quebec	5.07
New Brunswick	6.48
Nova Scotia	5.61
Prince Edward Island	5.70
Newfoundland and Labrador	3.91

Table 11: Other fuel cost assumptions, national, all time periods.

Fuel	Cost (\$/GJ)
Uranium ⁹	0.80
Coal ⁹	3.28
Diesel ⁹	25.68
Biodiesel ⁹	34.72
Renewable gas ¹⁰	22.00
Hydrogen (green) ⁹	61.83
Hydrogen (blue) ⁹	17.10
Waste ¹⁰	3.50

Table 12: Transmission pricing parameters.

Transmission parameter	Value	Unit
Inter-regional transmission (capital) ¹¹	243.55	\$/MW/km
Transmission fixed O&M	0.61	\$/MW

⁹ EIA (2021). Short-Term Energy Outlook. U.S. Energy Information Administration.

<https://www.eia.gov/outlooks/steo/data/browser/#/?v=8>

¹⁰ EIA (2022). State Energy Data System (SEDS). U.S. Energy Information Administration.

https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep_sum/html/sum_pr_eu.html&sid=US

¹¹ MISO (2024). Transmission Cost Estimation Guide. Midcontinent Independent System Operator.

<https://cdn.misoenergy.org/MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24337433.pdf>

About Electricity Canada

Electricity Canada is the national voice for electricity in Canada. Our members generate, transmit, and distribute power to homes and businesses across Canada. We represent integrated electric utilities, independent power producers, transmission and distribution companies, power marketers, and system operators. Our members deliver electricity to all Canadians, in every province and territory.

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Open Insights contributes to the Canadian climate and energy transition dialogue by enabling reliable, transparent modelling that improves the rigour and quality of policy outcomes. We are a collaborative effort between SESIT at the University of Victoria, Energy Modelling Hub, the Energy & Materials Research Group at Simon Fraser University, and Macrocosm Group, each committed to building a more transparent and accessible Canadian modelling ecosystem.

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