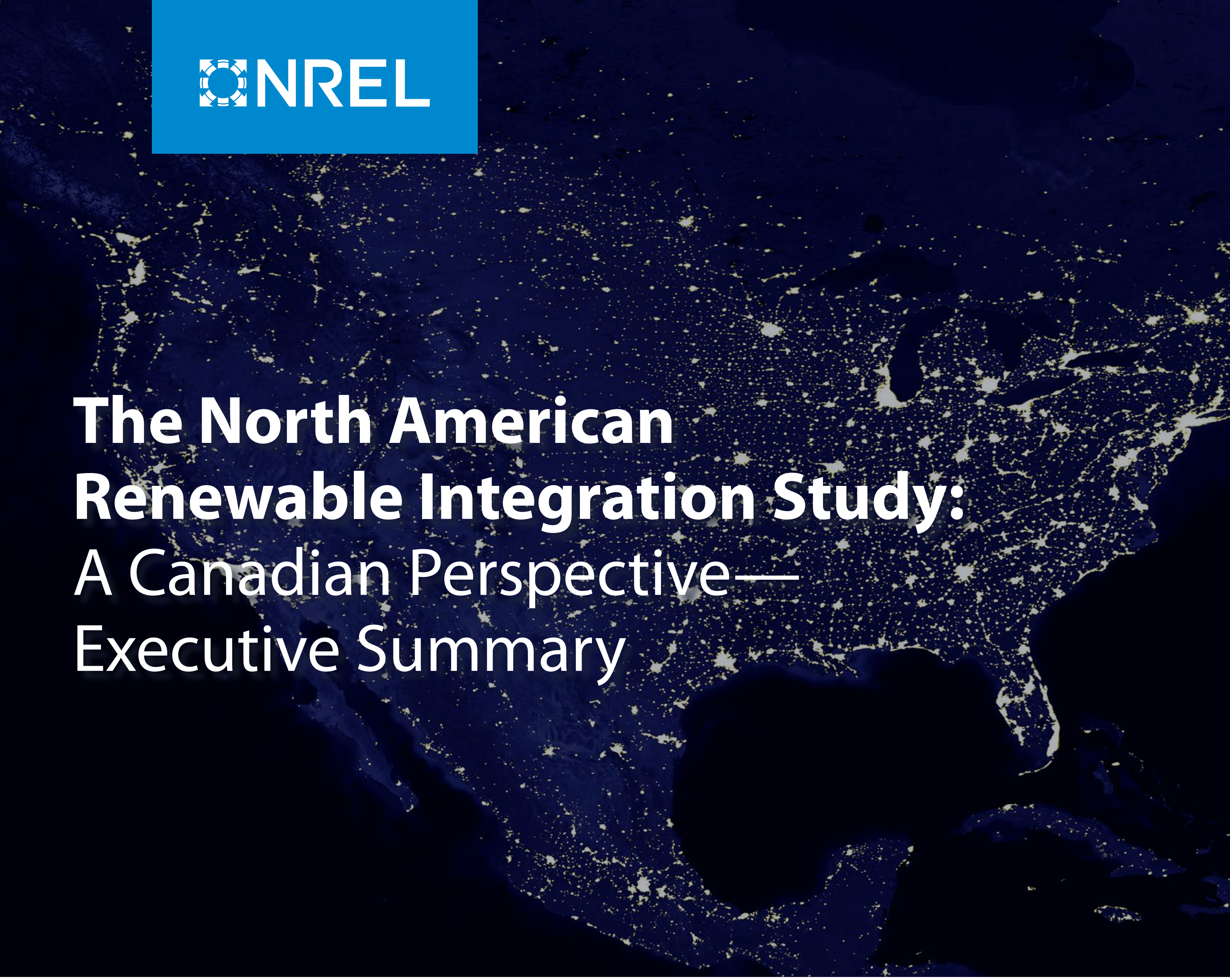

The North American Renewable Integration Study: A Canadian Perspective—Executive Summary

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Suggested Citation

Brinkman, Gregory, Dominique Bain, Grant Buster, Caroline Draxl, Paritosh Das, Jonathan Ho, Eduardo Ibanez, et al. 2021. *The North American Renewable Integration Study: A Canadian Perspective—Executive Summary*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-79225-ES. https://www.nrel.gov/docs/fy21osti/79225-ES.pdf

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Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-6A20-79225-ES
June 2021

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The North American electric power system is undergoing significant change, with renewable resources now contributing more generation than ever before. This transformation is poised to continue given decreasing technology costs and ambitious decarbonization goals at the federal, state, province, local, corporate, and consumer levels. The North American Renewable Integration Study (NARIS) aims to inform grid planners, utilities, industry, policymakers, and other stakeholders about challenges and opportunities for continental system integration of large amounts of wind, solar, and hydropower to support a low-carbon future grid.

The National Renewable Energy Laboratory (NREL) conducted a detailed, continent-wide analysis with planning scenarios of transmission, generation, and demand to reach 80%–92% carbon reductions (from 2005) for the Canadian electric power system, and up to 80% reductions continent-wide. We used a suite of models to study future scenarios and gain insights, including potential impacts on costs, emissions, resource adequacy, and the specific technologies that help enable the transition to a low-carbon grid. Our analysis had a particular focus on the potential role of cooperation among the three North American countries and between regions within each country, and how transmission can support sharing of supply and demand diversity.

The NARIS project began in 2016. This summary and a separate full report describe a Canadian perspective in coordination with the Natural Resources Canada, and a companion report describes a U.S. perspective in coordination with the U.S. Department of Energy. NARIS was an extension of a previous body of work, including the Western Wind and Solar Integration Study, the Eastern Renewable Generation Integration Study, Interconnections Seam Study, and the Pan Canadian Wind Integration Study. NARIS analyzed the entire continent in detail while studying higher renewable generation than previous studies. The scenarios in NARIS were informed by the goals in the Mid-Century Strategies (MCS) for the Paris Agreement in each country.

With input from the NARIS Technical Review Committee, NREL developed and evaluated a set of four core scenarios (see Table 1, page 2) to understand the impacts of renewable technology cost trajectories, emission constraints, and demand growth levels on the key outcomes. We also assessed 38 additional sensitivity scenarios to help understand the value of transmission and cooperation between regions and countries, the impact of technology cost assumptions for storage and distributed generation, and the impacts of natural gas prices and generator retirements. We also performed analysis to understand the potential benefits of hydropower flexibility in the future grid. The scenario assumptions were finalized at the end of 2018, using cost trajectories from the NREL Annual Technology Baseline (ATB) and existing mandatory state and federal policies enacted as of that time. The scenarios are discussed in detail in the full *The North American Renewable Integration Study (NARIS): A Canadian Perspective* report.

Compared to the updated 2020 ATB cost trajectories, the NARIS Business as Usual scenario represents the Conservative trajectory, while Low-Cost Variable Generation represents a trajectory between Advanced and Moderate. The resulting infrastructure and operational patterns for each scenario are the result of cost-minimizing optimizations. Existing and evolving market structures may or may not support these development and operational patterns. The NARIS analysis provides insights into the feasibility of possible pathways, and the technologies and strategies that can minimize the costs.

Table 1. Description of the Core Scenarios

Scenario	Key Assumptions	Renewable Contribution[a]
Business as Usual (BAU)	The North American grid continues to evolve with expected trajectories for all technology costs, and there are no major changes to carbon legislation across the continent (assumes 80% carbon reduction for Canada, informed by economy-wide reductions in Paris Agreement MCS).	90% (93% total carbon-free)
Low-Cost Variable Generation (Low-Cost VG)	VG, including wind and solar, follows a low-cost trajectory based on NREL's 2018 Annual Technology Baseline (ATB). Otherwise, the scenario is the same as the BAU scenario.	91% (94% total carbon-free)
Carbon Constrained (CO2 Constrained)	Carbon emissions from the electricity sector are reduced throughout North America, including an 80% reduction from 2005 levels in the United States and Mexico and a 92% reduction in Canada, also from 2005 levels (informed by MCS for electric sector).	95% (97% total carbon-free)
Electrification	New end-use energy demands, including heating and transportation are electrified. And 2050 loads are nearly double the 2020 loads. Otherwise, the scenario is the same as Carbon Constrained scenario.	95% (97% total carbon-free)

[a] Renewable Contribution is the modeled share of annual generation in 2050 from all renewable technologies. Canadian generation was 82% carbon-free in 2020.

Figure 1 shows the modeled generation by fuel type in 2050 for the core scenarios (compared to the near-term 2024 model year). Annual renewable energy contributions in the scenarios studied vary from 90% (BAU) to 95% (Electrification). Because of the challenge in finding consistent, site-specific hydropower expansion costs, hydropower expansion was not considered in the core scenarios. The full report has an analysis of generic hydropower representation throughout Canada and finds that new hydropower would provide the most value to the Electrification scenarios. This is likely due to the contribution of hydropower to both energy and planning reserves, which are very important in the Electrification scenario. The thermal generation is mostly gas, with some nuclear generation. Distributed rooftop solar photovoltaic (PV) adoption is approximately half of the solar in most of the scenarios, and ranges from 7 GW to 32 GW DC for a variety of scenarios (depending on costs and billing structures).

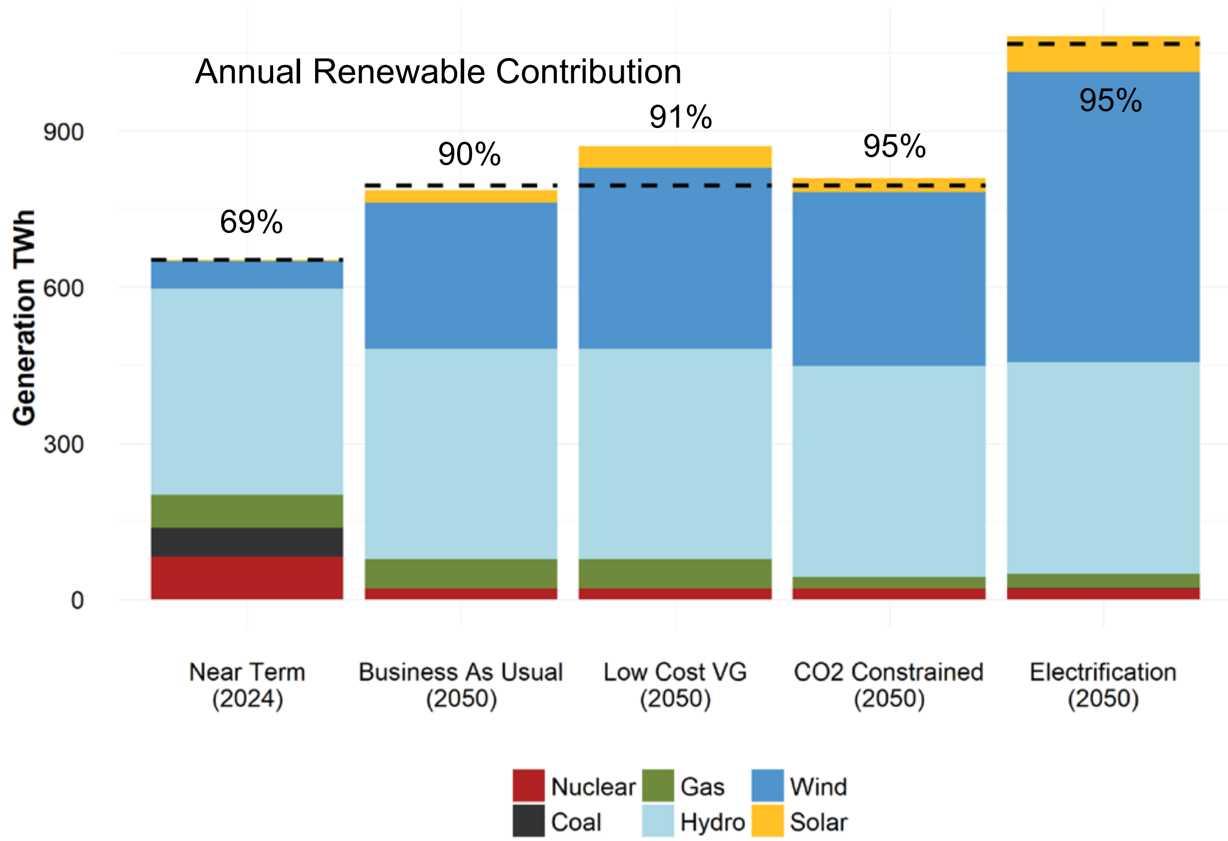

Figure 1. Projected Canadian generation in 2024 and 2050 in the NARIS core scenarios

Total Canadian demand is represented with the dashed line. These results are from the ReEDS model. When the bars are above the load lines, net exports to the US are happening. The 2024 Near Term scenario is the from the BAU trajectory, but it is nearly identical for all scenarios. Hydropower expansion was not considered in the core scenarios, but a sensitivity was performed with generic cost assumptions and is described in detail in the full report. We also explored scenarios with higher Canadian exports to the U.S., as described in the full report.

All scenarios were designed using a utility-scale co-optimization of generation and transmission (NREL Regional Energy Deployment System [ReEDS] model), minimizing the total system cost for utility-scale generation and transmission. The behind-the-meter solar PV market was projected with an agent-based model (NREL Distributed Generation Market Demand [dGen]) to simulate customer adoption. Several scenarios were evaluated for resource adequacy (NREL Probabilistic Resource Adequacy Suite) and simulation of 5-minute operations with nodal transmission resolution (Energy Exemplar PLEXOS model) in 2050. All modeling was performed using consistent data sets through the NREL Renewable Energy Potential (reV) model, National Solar Radiation Database, and the Wind Integration National Dataset Toolkit. The range of conditions studied includes wind, load, and solar profiles based on 2007–2013 meteorology, and hydrological conditions that include typical, wet, dry, and inflexible (representing typical hydrology with inflexible operational rules).

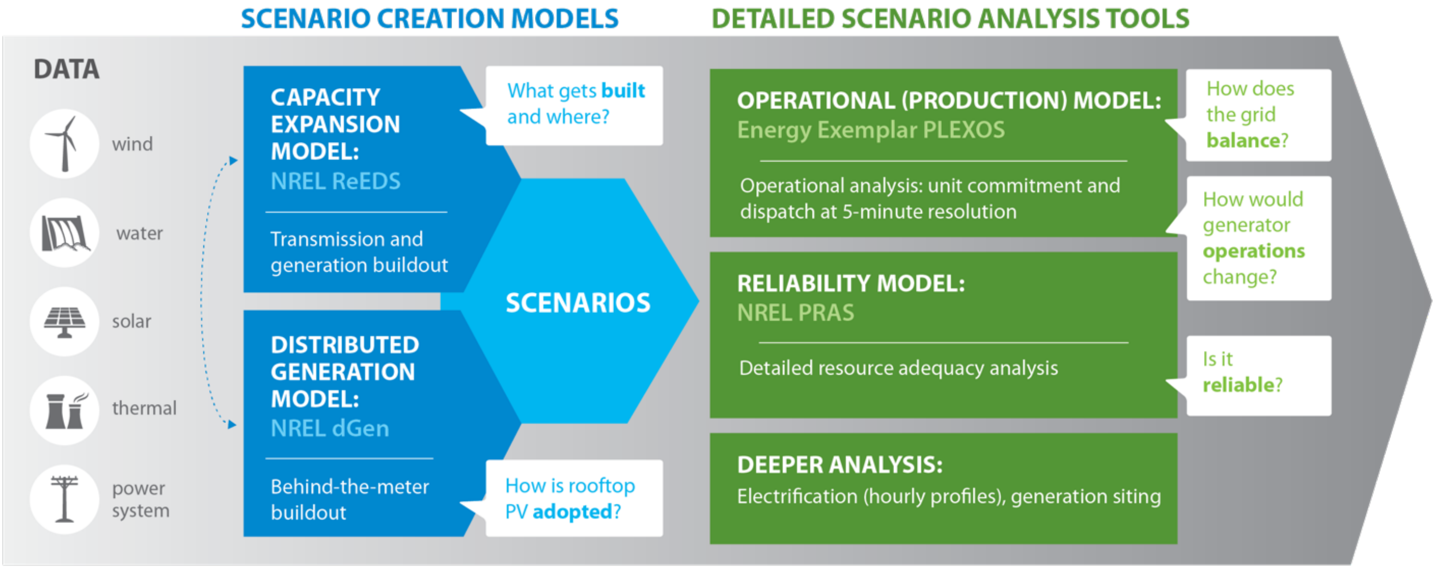

Figure 2. Overview of the different models used in NARIS, including key questions each model can help answer

This Executive Summary provides high-level insights from a Canadian perspective of the NARIS analysis, which is presented in full in the report, *The North American Renewable Integration Study (NARIS): A Canadian Perspective*.

Multiple pathways can lead to decarbonization of 93% to 97% of Canadian generation by 2050.

Steeper cost reduction of wind and solar can lead to a faster transition.

NARIS shows that carbon emissions from the grid can be reduced significantly (more than 80% continent-wide, 92% in Canada) while maintaining the ability to balance supply and demand in a variety of scenarios. Figure 3 shows the emissions trajectory of the scenarios through 2050 as modeled in the core scenarios. The Low-Cost VG scenario achieves almost all of its carbon reductions by the year 2030, when the majority of coal in Canada must be retired. Eliminating the last few percentage points of CO_2-emitting generation may be the hardest (see Denholm et al., 2021), although this study does not demonstrate that it is impossible to achieve.

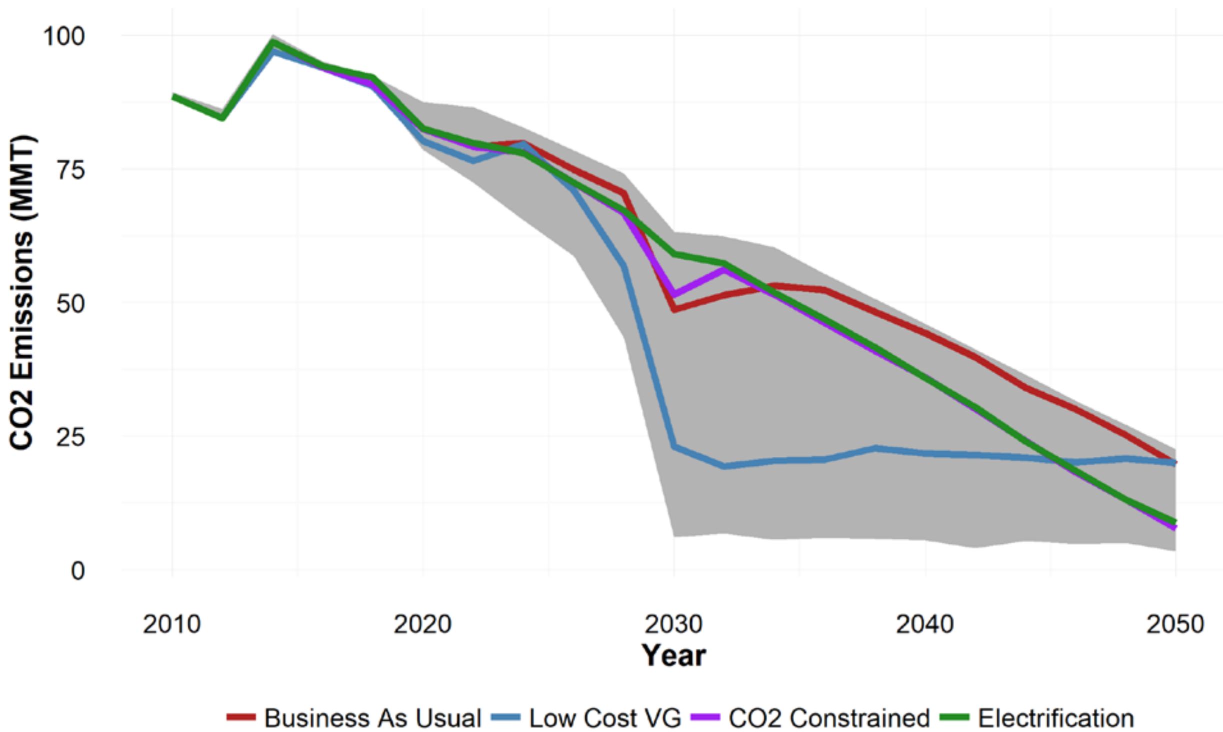

Figure 3. Projected Canadian power sector annual CO_2 emissions trajectory through 2050 in the core scenarios

Note that the emissions reductions resulting from the electrification of energy end-uses (e.g., transportation, heating) in the Electrification scenario are not considered in this power sector analysis. The gray area represents the bounds of all NARIS scenarios. The CO_2 Constrained and Electrification scenarios follow an almost identical trajectory after 2028 due to the binding carbon constraints. All carbon quantification in this report is direct emissions only and does not consider life-cycle emissions (which includes indirect emissions from production).

Assuming conservative technology cost assumptions for wind and solar, the Carbon Constrained scenario has total system costs 5% higher than the BAU to achieve an 92% CO_2 reduction in Canada (cost impacts are similar in the U.S.). Wind and solar cost trajectories have a more significant impact on costs compared to the carbon policy assumptions. The Low-Cost VG scenario is very similar to the Carbon Constrained scenario in 2050 buildout and even lower in total emissions through 2050, but the total costs are 11% lower than the BAU. In the Electrification scenario, the electric system costs are $200 billion higher for building and operating infrastructure to the higher demand, but there are non-electricity energy cost reductions that are not considered in the analysis.

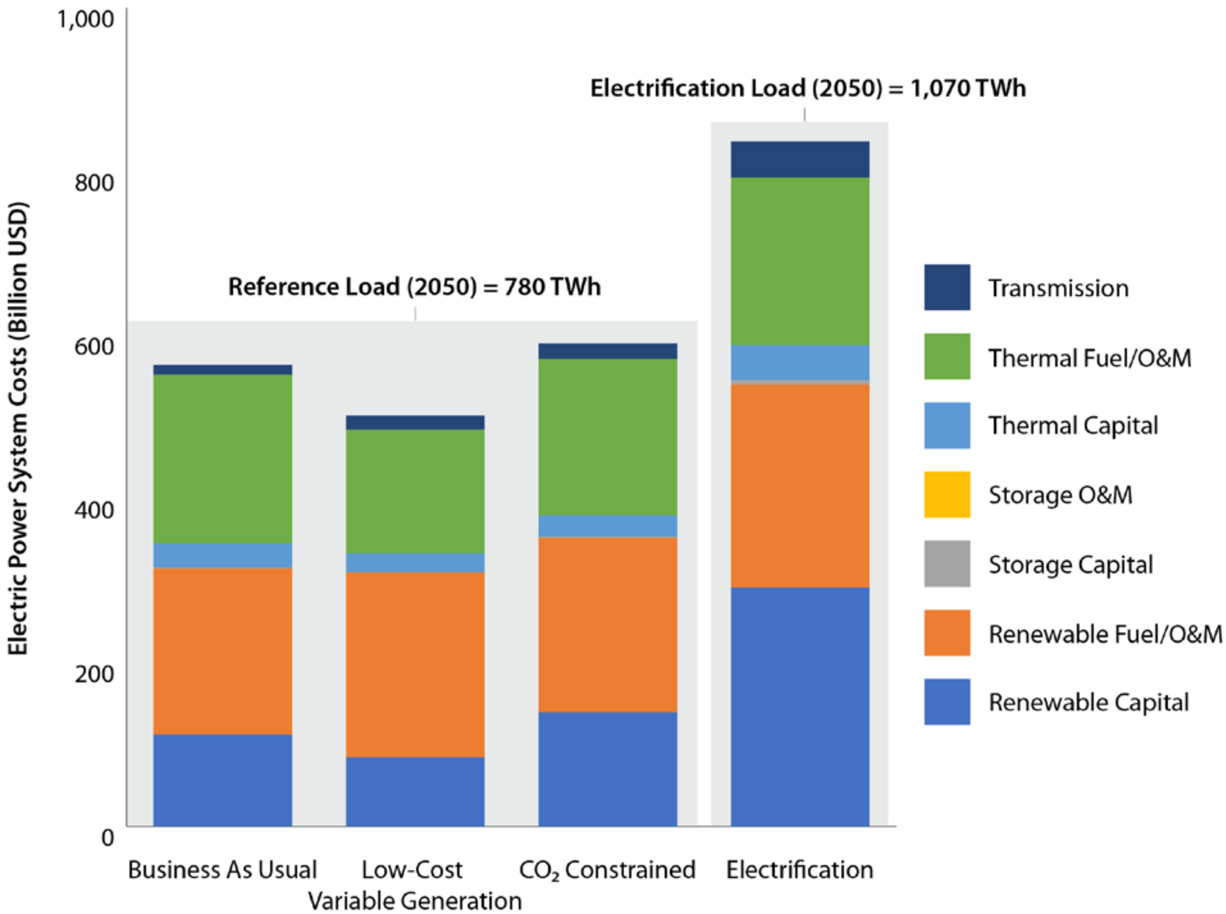

Figure 4. Projected total 2020-2050 Canadian system costs for the core scenarios (2018 $USD)

The Electrification scenario costs include only electric sector costs and represent a large difference in 2050 demand (2050 demand is noted on figure); this does not consider the savings from reducing energy use in other sectors.

The future low-carbon system can balance supply and demand in a wide range of future conditions with hydropower, gas, and wind contributing most to resource adequacy.

Using 7 years of meteorological information (2007–2013) to represent wind, solar, and load profiles and 10,000 random draws of generator outages, we estimated loss-of-load hours, which measures the regional expected number of hours where supply cannot meet demand in a year, and expected unserved energy, which measures the expected amount of energy demand that cannot be met due to reasonably foreseeable outages. The expected unserved energy and loss-of-load hours both compare favorably with the North American Energy Reliability Corporation *2020 Long-Term Reliability Assessment*.

Figure 5 shows the planning reserve requirement and contribution by resource type through time for three scenarios. Thermal generation provides 5%–10% of energy in all of the scenarios in

2050, but still contributes more than one-fourth of winter planning reserves in most scenarios. Some of this contribution from thermal generation could be replaced by new hydropower or storage (as seen in the Low-Cost VG + Storage scenario, which is a sensitivity analysis that assumes more advanced technology innovation in wind, solar, and storage cost trajectories leading to 14 GW of storage). Hydropower continues to provide approximately half of planning reserve needs in the model by 2050, and hydropower expansion (not considered in these core scenarios) could potentially contribute more, especially in a higher-demand future.

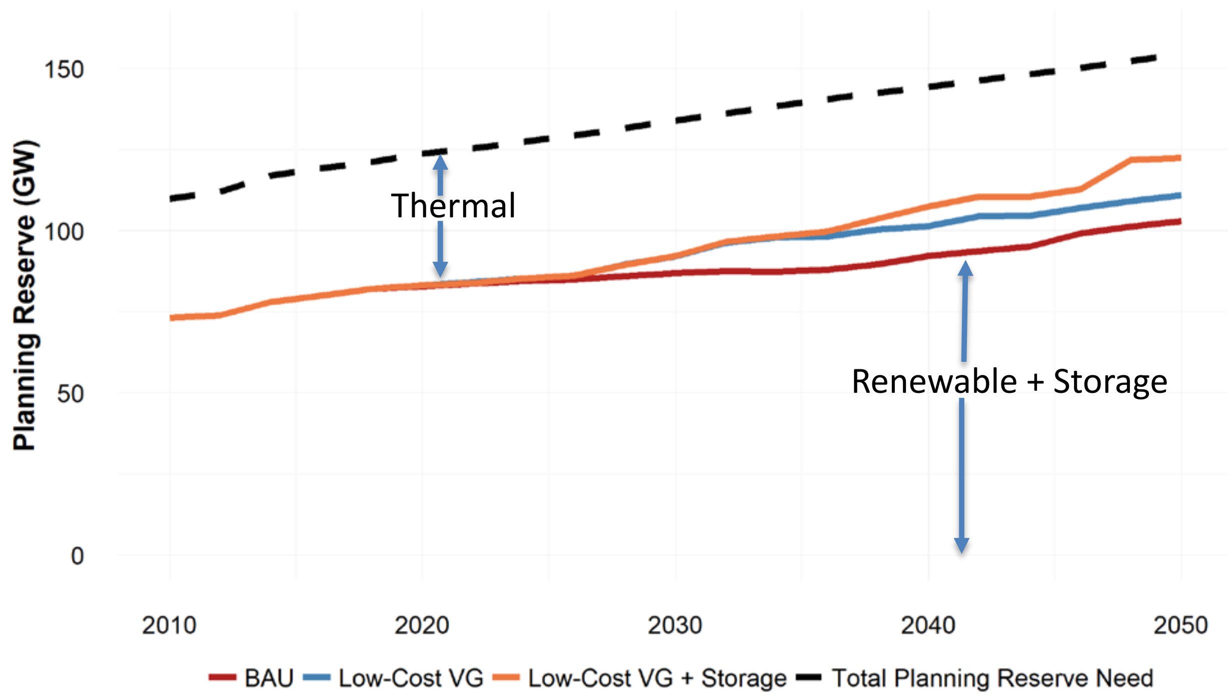

Figure 5. Winter planning reserve contribution of renewables plus storage in three scenarios

The dashed line shows the winter planning reserve need for Canada, while the color lines show the contribution of renewables plus storage in three scenarios. Hydropower contributes approximately half of the total planning reserve need in 2050. Wind and thermal generators provide most of the rest. Solar provides summer planning reserve, but very little during the winter. See full report for detailed breakdowns. These results are from the ReEDS model.

Regional and international cooperation can provide significant net system benefits through 2050.

Increasing electricity trade between countries can provide $10 billion–$30 billion of net value to the system. Interregional transmission expansion achieves up to $180 billion in net benefits.

Figure 6 shows the net system benefits of expanding transmission in the future scenarios. The net values are estimated by comparing the total system cost in each core scenario in model runs with and without allowing additional transmission expansion (either interregional or international). Allowing international transmission expansion provides $10 billion–$30 billion (2018 USD) of net value to the continental system in total between 2020 and 2050 in all the scenarios except BAU; this demonstrates some of the potential benefits of international collaboration. Interregional transmission expansion provides \$60 billion–\$180 billion in net system benefits as modeled; this is true for a predesigned, high-voltage direct current, macrogrid overlay or model-optimized interregional transmission lines. Although the net system value of the macrogrid is slightly less than the value of the model-optimized transmission build, some benefits of the macrogrid overlay are not quantified in the model (including self-contingency and controllability). These findings are consistent with the NREL Interconnections Seam Study.

Although these values are less than 4% of the total \$5 trillion–\$8 trillion total system costs (which include all capital and operating generation and transmission system costs), transmission plays an important role in minimizing costs. Transmission expansion benefits are higher with more electrification and higher wind and solar contribution, a trend that could continue in lower-carbon scenarios or longer-term futures. Transmission can also provide reliability benefits and enable exchanging load and renewable generation diversity between regions, both under normal conditions and in extreme events.

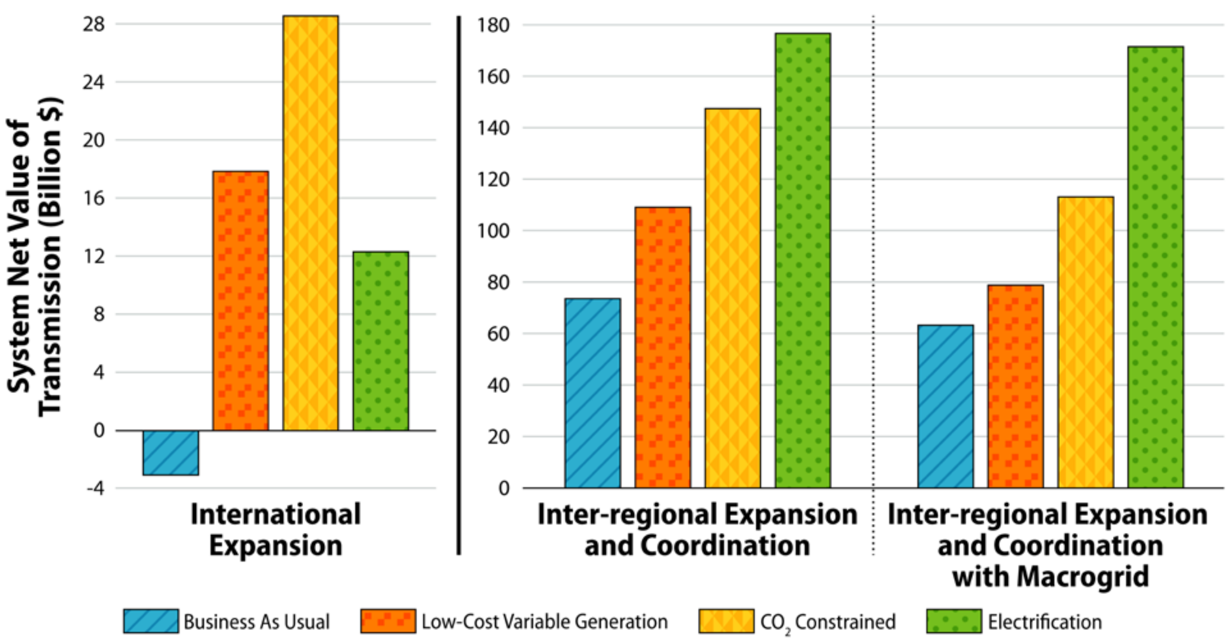

Figure 6. Net value of transmission in the core scenarios.

Each net value estimate is calculated by comparing a scenario that allows transmission builds to a version of the scenario with restricted transmission builds. The continental net system benefits are shared throughout the system; assigning benefits to regions would depend on markets and agreements. These results are from the ReEDS model.

Operational flexibility comes from transmission and flexible operation of all generator types, including hydropower, wind, solar, and thermal generation.

For the Low-Cost VG scenarios with 2050 infrastructure, we analyzed nodal unit commitment and dispatch modeling (using PLEXOS) at 5-minute time resolution for a single year of meteorological data. Figure 7 shows the 5-minute nationwide dispatch during the last week of January, including some of the highest load hours of the year in Canada. Various forms of flexibility are evident in this plot. The gas and hydropower exhibit morning and evening peaks to follow load in Canada and the United States. For most of the days on January 16 and 17 (with low Canadian wind output but high load), Canada imports from the U.S. (seen where the black load line is higher than the stacked area of generation). High-load days on January 18 and 19 have higher wind output, and the Canadian grid exports to the U.S. even during the evening load peak. Curtailment of wind and solar generation is almost non-existent during this high-load week, although curtailment can provide flexibility during other times of the year. There is very little storage installed in Canada in this scenario, so it is not visible in the dispatch.

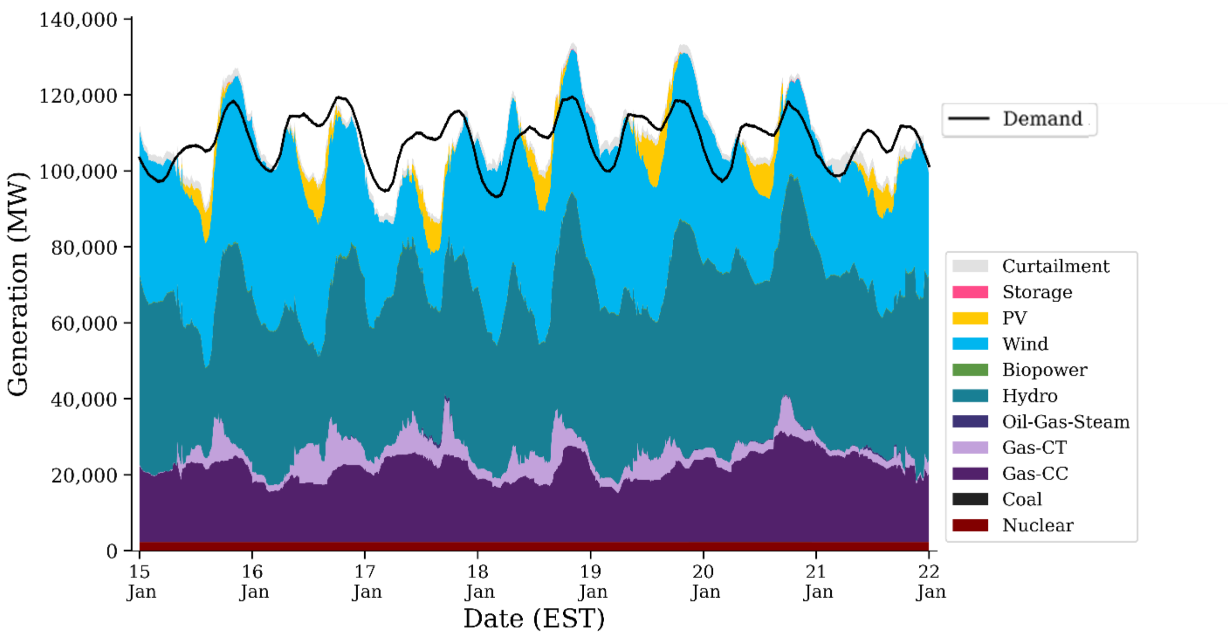

Figure 7. Canada-wide 5-minute dispatch stack for January.

These results are from the PLEXOS model, using load, wind, and solar data from 2012 meteorological patterns.

Hydropower provides a zero-carbon source of energy, capacity, and flexibility to the grid. To understand the benefits of hydropower flexibility in the future grid, we modeled the operations in the Low-Cost VG 2050 scenario assuming no ability to adjust power output from U.S. and Canadian hydropower generators and compared it to results with a level of flexibility intended to represent that of today. Table 2 shows the results, indicating that annual system costs are $2.3 billion higher without this flexibility.

Table 2. Benefits of Hydropower Flexibility as Modeled in 2050

Metric	Impact
Cost	Today's level of hydropower flexibility reduced annual operating costs by $2.3 billion, representing 3.0% of the system production costs.
Curtailment	The flexibility of hydropower to turn down during periods of curtailment and generate more during periods of need reduced curtailment from 9.9% to 9.2%.
Emissions	Increased flexibility reduces carbon emissions in this scenario by 1.3%.

These values are based on comparing the 5-minute dispatch model runs from the Low-Cost VG scenario with runs from an identical scenario with all hydropower flexibility disabled (dispatchable hydropower generators are assumed to have flat output levels for each month). U.S. and Canadian hydropower resources were included in the sensitivity and results presented are aggregated for the continent. Canadian hydropower is similar to the U.S. in total capacity. Note that flexibility constraints could also affect the ability of hydropower to provide adequacy; this adequacy value of flexibility has not been addressed here.

Future Work

In addition to highlighting several opportunities for a coordinated, continental low-carbon grid, NARIS created open-source data and methods on which future studies can build. Next steps for future work include (but are not limited to):

- **Reliability:** NARIS addressed the adequacy portion of reliability in detail, but the stability portion of reliability was not studied. Future studies could continue to study wider ranges of meteorological conditions and extreme events, and also address frequency and voltage stability for high-renewable scenarios, building on existing work (e.g., the Western Wind and Solar Integration Study).
- **Evolving Technologies and Goals:** Government and private-sector CO_2 emission reduction goals, as well as technology costs (especially storage), have changed since the NARIS assumptions were finalized. Studying scenarios requiring additional emission reductions could increase the importance of some of the findings or illuminate new findings. These scenarios provide a useful basis for studying impacts of technologies and operating practices (including wind and solar providing essential reliability services beyond reserves), but they are not a projection of the expected future.
- **Markets:** The NARIS scenarios were created by co-optimization of generation and transmission. Current market structures may or may not support the transmission infrastructures and generation fleets projected in the study; future work could help us understand potential implications for U.S. wholesale markets and retail rate impacts.
- **Demand:** The uncertainty of electricity demand patterns in the long-term future is significant because of climate change and electrification of other sectors. Building on recent work in the United States and Canada (e.g., the Electrification Futures Study), electrification-focused studies could also help refine and quantify the benefits of electrification to other sectors and could help us understand the potential flexibility of new demands.

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