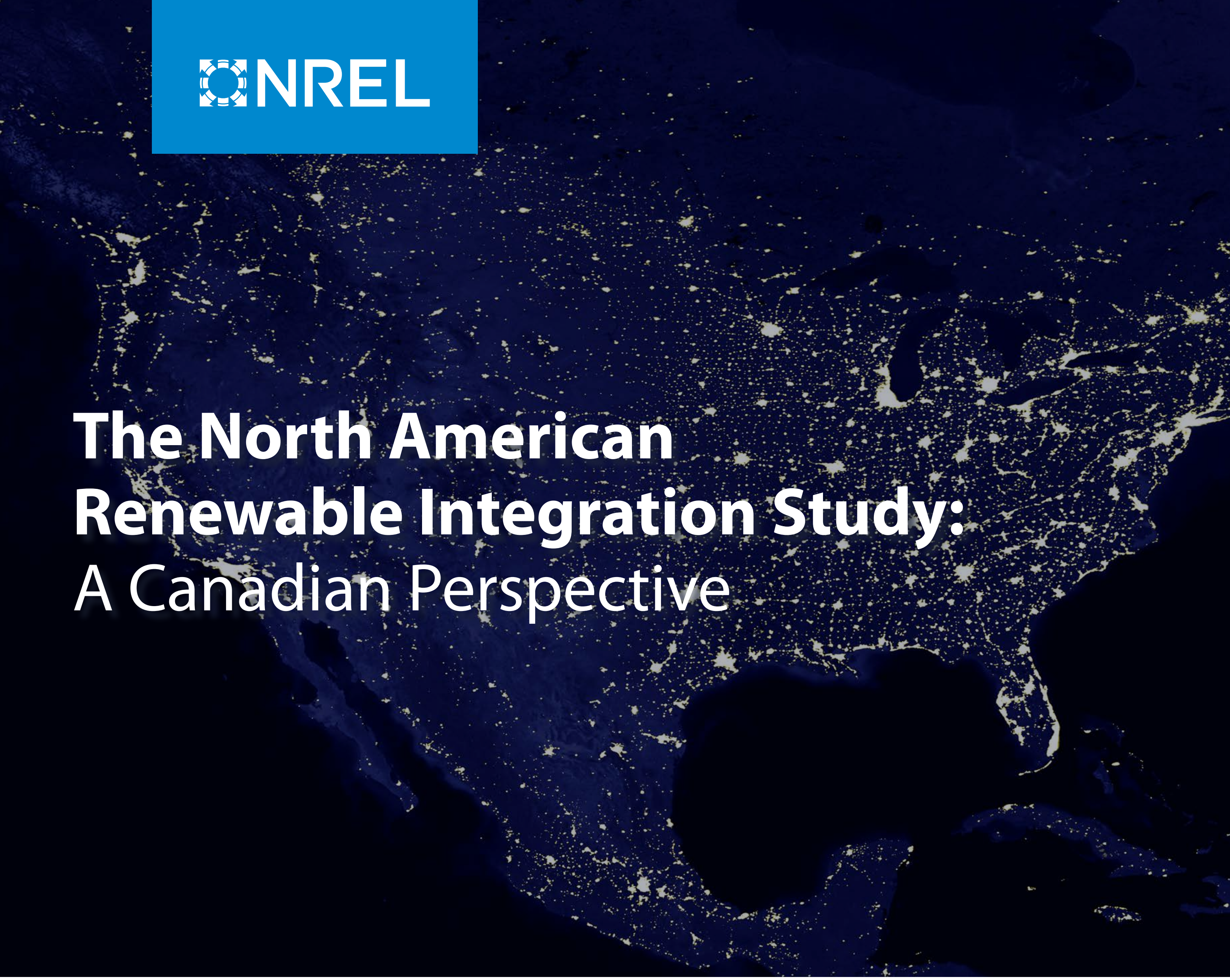


The North American Renewable Integration Study: A Canadian Perspective

Gregory Brinkman,[1] Dominique Bain,[1] Grant Buster,[1] Caroline Draxl,[1] Paritosh Das,[1] Jonathan Ho,[1] Eduardo Ibanez,[2] Ryan Jones,[3] Sam Koebrich,[1] Sinnott Murphy,[1] Vinayak Narwade,[1] Joshua Novacheck,[1] Avi Purkayastha,[1] Michael Rossol,[1] Ben Sigrin,[1] Gord Stephen,[1] and Jiazi Zhang[1]

[1] National Renewable Energy Laboratory
[2] GE Energy
[3] Evolved Energy Research

The North American Renewable Integration Study:

A Canadian Perspective

Authors

Gregory Brinkman,[1] Dominique Bain,[1] Grant Buster,[1] Caroline Draxl,[1] Paritosh Das,[1] Jonathan Ho,[1] Eduardo Ibanez,[2] Ryan Jones,[3] Sam Koebrich,[1] Sinnott Murphy,[1] Vinayak Narwade,[1] Joshua Novacheck,[1] Avi Purkayastha,[1] Michael Rossol,[1] Ben Sigrin,[1] Gord Stephen,[1] and Jiazi Zhang[1]

[1] National Renewable Energy Laboratory
[2] GE Energy
[3] Evolved Energy Research

June 2021

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.* Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-79225. https://www.nrel.gov/docs/fy21osti/79225.pdf

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency and Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Contract No. DE-AC36-08GO28308

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

National Renewable Energy Laboratory
15013 Denver West Parkway, Golden, CO 80401
303-275-3000 • www.nrel.gov

NOTICE
This work was authored in part by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36- 08GO28308. The views expressed in the article do not necessarily represent the views of the DOE or the U.S. Government. Primary funding for the U.S. and Canadian reports was provided by Natural Resources Canada and the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy's Wind Energy Technologies Office, Water Power Technologies Office, and Solar Energy Technologies Office. The Government of Mexico also provided funding for the NARIS project.

Cover photos from iStock, clockwise starting at top: 1162086622, 1205564390, 1214915940
NREL prints on paper that contains recycled content.

Preface

This report is one of four reports published as part of the North American Renewable Integration Study, or NARIS:

- *The North American Renewable Integration Study: A U.S. Perspective*
- *The North American Renewable Integration Study: A U.S. Perspective—Executive Summary*
- *The North American Renewable Integration Study: A Canadian Perspective* (this report)
- *The North American Renewable Integration Study: A Canadian Perspective—Executive Summary*

For more information about NARIS, see www.nrel.gov/analysis/naris.html.

Acknowledgements

The North American Renewable Integration Study (NARIS) was a multiyear, international effort on which many institutions collaborated and to which many individuals contributed. We would like to thank everyone who was involved in the study.

Members of the NARIS Technical Review Committee—which included experts representing approximately 50 utilities, grid system operators, and industry organizations throughout North America—helped guide the study assumptions, data, and methodologies to address relevant questions. Although the committee members helped review the report, it might not reflect the specific views or interpretations of any member of the committee or their institution. We would like to thank everyone who attended committee meetings (in person and virtual) or provided guidance during the study process, including those who provided specific comments on this report.

Natural Resources Canada organized a NARIS Stakeholder Committee of interested parties from industry groups, academia, and nonprofits. These stakeholders also helped review and guide the study throughout the project, and they provided a valuable and different perspective. Thanks to all who participated on this committee or provided specific comments on this report.

The authors would like to extend a special thanks for serving on the NARIS management team to Charlton Clark, Guohui Yuan, Sam Bockenhauer, Jian Fu, Tracey Kutney, Tom Levy, and Bronwyn Lazowski, and to Aaron Bloom for inspiration and support.

We would like to thank Jimmy Royer, Marcia Blanchette, Leonardo Beltrán Rodríguez, Efraín Villanueva Arcos, Fidel Carrasco, Riccardo Bracho, and Carlo Brancucci for helping develop the vision for NARIS and providing support. Thanks to Devonie McCamey, Mike Meshek, Madeline Schroeder, and Liz Craig for communications support.

Wes Jones, Harry Sorensen, and Tim Kaiser helped provide resources on computational science, which was invaluable for such a computationally intensive study. Thanks to Jo Ann Ranola, Robert Spencer, Ana Dyreson, and Billy Roberts for visualization of the inputs and results.

The authors of the report would also like to acknowledge the reviewers at Natural Resources Canada and the CanmetENERGY Research Centers, and Environment and Climate Change Canada for their review and feedback in the development of the report. In addition to those already mentioned, we would like to thank Doug Arent, Gian Porro, Jennie Jorgenson, Kathryn Jackson, Hill Balliet, and Cynthia Bothwell for their reviews of the NARIS reports. Any omissions or errors are the responsibility of the authors.

Primary funding for the U.S. and Canadian reports was provided by Natural Resources Canada and the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy's Wind Energy Technologies Office, Water Power Technologies Office, and Solar Energy Technologies Office. The Government of Mexico also provided funding for the NARIS project.

List of Acronyms and Abbreviations

AB	Alberta
AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
BAU	business as usual
BC	British Columbia
CAISO	California Independent System Operator
CAMX	California and Mexico
dGen	Distributed Generation Market Demand
DPV	distributed photovoltaics
ECMWF	European Centre for Medium-Range Weather Forecasts
EIA	Energy Information Administration (United States)
ERCOT	Electricity Reliability Council of Texas
EUE	expected unserved energy
FRCC	Florida Reliability Coordinating Council
HQ	Hydro Québec
HVDC	high-voltage direct current
IESO	Independent Electricity System Operator
ISO	independent system operator
LCOE	levelized cost of electricity
LOLE	loss-of-load expectation
LOLH	loss-of-load hours
LTRA	Long-Term Reliability Assessment
MAE	mean absolute error
MH	Manitoba Hydro
MISO	Midcontinent Independent System Operator
MWh	megawatt-hours
NARIS	North American Renewable Integration Study
NEB	National Energy Board (Canada)
NEM	net energy metering
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NWPP	Northwest Power Pool
NYISO	New York Independent System Operator
PCM	production cost model
PRAS	Probabilistic Resource Adequacy Suite
PRODESEN	Programa de Desarrollo del Sistema Eléctrico Nacional
PV	photovoltaics
ReEDS	Regional Energy Deployment System Model
reV	Renewable Energy Potential Model
RMRG	Rocky Mountain Reserve Group
RTO	regional transmission organization
SENER	Secretaría de Energía de México
SPP	Southwest Power Pool
SRSG	Southwest Reserve Sharing Group
TEPPC	Transmission Expansion Planning Policy Committee

TWh	terawatt-hours
TW-mi	terawatt-miles
USD	U.S. dollars
VG	variable generation
WECC	Western Electricity Coordinating Council
WIND	Wind Integration National Dataset
WRF	Weather Research and Forecasting

Table of Contents

List of Figures

List of Tables

1 Introduction

The North American Renewable Integration Study (NARIS) is the first detailed power system integration study for the entire North American continent. NARIS aims to inform grid planners, operators, policymakers, and other stakeholders about the potential opportunities for system integration of large amounts of wind, solar, and hydropower to create a low-carbon grid in the future. The NARIS project began in 2016. This report describes a Canadian perspective in coordination with the Natural Resources Canada, and a companion report describes a United States perspective in coordination with the U.S. Department of Energy.

The North American electric power grids are evolving toward higher contributions of variable generation (VG) resources (i.e., wind and solar) for several reasons, including lower costs and lower emissions. NARIS analyzes the entire North American continent, which is composed of five asynchronous interconnections that overlap the three countries. The analysis and conclusions of the study can help guide stakeholders to understand how the components of the power system can help work together to create a reliable, cost-effective, low-carbon grid in North America. This includes understanding the benefits of different technologies and operating practices to the future system.

The key analysis goals of NARIS were to evaluate a set of possible pathways for North American grid evolution through 2050 and to leverage production cost and Monte Carlo modeling tools to understand key questions about grid flexibility and resource adequacy.

NARIS extends and complements grid integration studies from the past, including the Pan Canadian Wind Integration Study (GE Energy Consulting 2016), Western Wind and Solar Integration Study (GE Energy 2010), and Eastern Renewable Generation Integration Study (Bloom et al. 2016). However, there are a few key differences between NARIS and most of these large, stakeholder-driven studies:

- NARIS studies all the grid-connected portions of Canada, the United States, and Mexico and applies consistent methods and data throughout. This includes the Eastern Interconnection, the Western Interconnection, the Texas Interconnection, the Québec Interconnection, and the Sistema Eléctrico Nacional (Mexico).
- Partly because of its longer study horizon, NARIS studies higher deployment of renewable generation, especially VG resources such as wind and solar photovoltaics, throughout North America.
- NARIS optimizes the entire generation fleet and transmission infrastructure evolution through 2050, which makes each scenario specifically designed to key assumptions (Section 1.2). Many previous integration studies started with a planned system and added wind and solar to that system, without additional retirements or changes to the rest of the generating fleet.

Some of the key accomplishments of NARIS include:

- Analysis
    - Performed the most comprehensive long-term analysis of power system evolution to date on the North American grid using models and data sets described in Section 2
    - Analyzed the feasibility and adequacy of high-renewable scenarios
    - Analyzed the value of technologies, including transmission, hydropower flexibility, and storage in the future power system
- Tools and Methods
    - Created continental capacity expansion planning tool (Regional Energy Deployment System Model, or ReEDS) based on expansion of the existing U.S. tool. The ReEDS model and data for the United States is open-sourced, with extensibility for Canada and Mexico pending public data. Aggregated results from the ReEDS modeling in NARIS are available on the NARIS website.[1]
    - Created open-sourced the Probabilistic Resource Adequacy Suite (PRAS)[2] modeling framework to assess multiregional system reliability metrics.
    - Improved methods for representing resource adequacy in capacity expansion models to produce reliable scenarios. This method has been open-sourced as part of ReEDS.
    - Created open-sourced, consistent, continent-wide wind resource data with 5-minute time resolution representing 2007–2014 (expanding the existing U.S. data set for wind). Solar 5-minute data were downscaled from existing the 30-minute National Solar Radiation Database data set.[3]
    - Created 5-minute resolution data sets for wind power, solar power, and load for a variety of scenarios
    - Created the open-source Renewable Energy Potential Model (reV)[4] model for geospatial analysis and data preparation for consistent use between modeling platforms.

---

[1] "North American Renewable Integration Study," NREL, https://www.nrel.gov/analysis/naris.html.
[2] "Probabilistic Resource Adequacy Suite," GitHub, https://github.com/NREL/PRAS.
[3] Data are available at "NREL Wind Integration National Dataset," Amazon Web Services, https://registry.opendata.aws/nrel-pds-wtk/. Usage examples are available at "NREL Highly Scalable Data Service (HSDS) Examples," GitHub, https://github.com/nrel/hsds-examples. Solar data are available at "NSRDB: National Solar Radiation Database," NREL, https://nsrdb.nrel.gov/.
[4] "reV: The Renewable Energy Potential Model," NREL, https://www.nrel.gov/gis/renewable-energy-potential.html.

- Created dGen (Distributed Generation Market Demand)[5] distributed photovoltaics (DPV) adoption models for Canada and Mexico by extending the existing U.S. model, with as much data consistency with the U.S. model as the data sources allow
- Refined hydropower flexibility assumptions in the models, enabling sensitivities to understand the value of flexibility.

The primary technologies considered in NARIS were wind, solar PV, and hydropower, with a focus on the flexibility benefits of existing hydropower. To consider additional hydropower expansion, we analyzed a set of sensitivities considering generic hydropower expansion costs because we did not have consistent, Canada-wide site-specific cost estimates. Transmission and storage were examined with a variety of modeling runs. Other renewable generation technologies that might contribute to the system in 2050 but were not a key focus in the study include concentrating solar power, geothermal, and biomass; for these resources (and also nuclear generation), existing assumptions in the models and data sets were used (for costs and performance of new and existing assets), but no additional scenario analysis was done to understand the potential pathways for these resources.

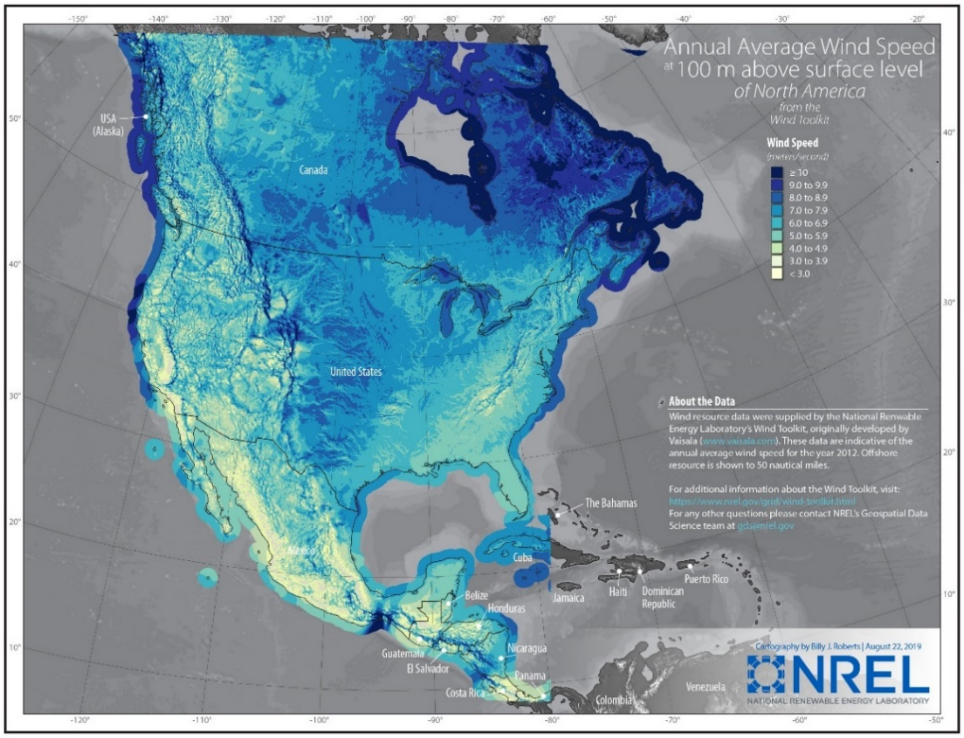
The methods and analysis for this study were guided by the NARIS Technical Review Committee, which helped ensure the methods and data were rigorous, and that we were addressing important questions.

1.1 Motivation

North America has abundant and diverse energy resources (Figure 1 shows wind and solar resource, while Figure 2 shows hydropower installations and transmission infrastructure). With significant growth in wind and solar generation in the past decade, the electric grid is becoming more meteorologically dependent than ever before. NARIS endeavors to study the challenges and opportunities associated with this increased dependence.

Existing and new generation technologies like reservoir, run-of-river, and pumped-storage hydropower, battery storage, and thermal generation all play a role in the future grid. The study findings, like much previous work, verify that transmission infrastructure with coordinated operation can help North America take advantage of the diversity of resources to produce affordable and reliable electricity. NARIS aims to analyze some of the ways these technologies can work together in a variety of future scenarios.

[5] "Distributed Generation Market Demand," NREL, https://www.nrel.gov/analysis/dgen/.



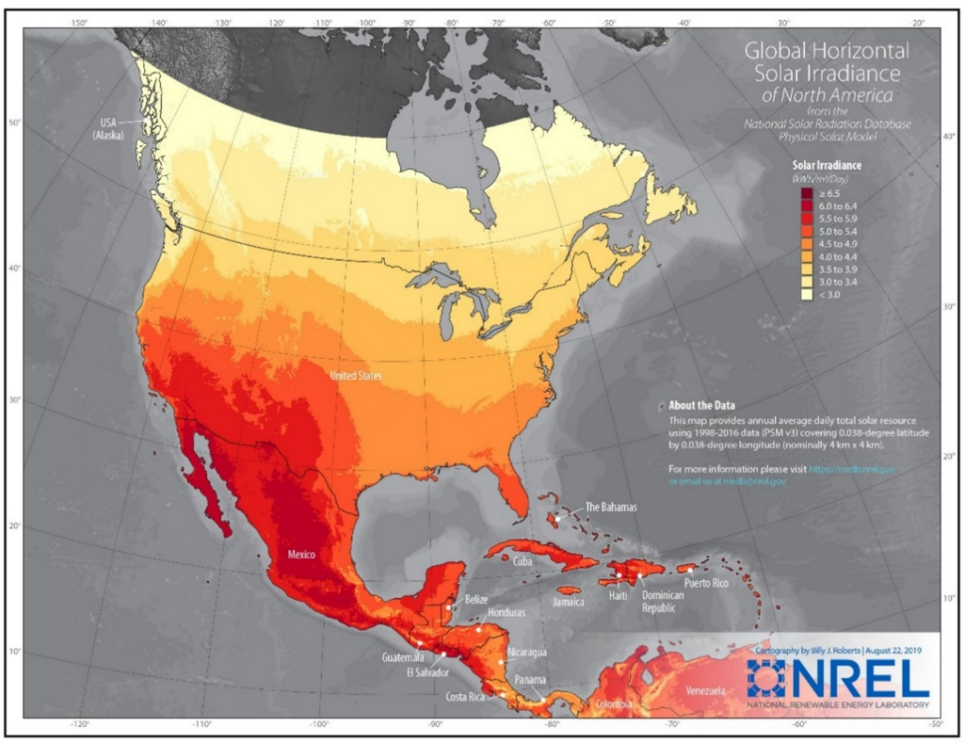


Figure 1. North American wind (top) and solar (bottom) resource

North America has some of the best wind and solar resources in the world, and all regions have excellent wind or solar resources nearby. Many regions have good resources for both wind and solar. These maps show the resource potential; siting and other constraints will limit deployment in some areas, and other inputs like temperature and air density will impact the translation of this resource to power.

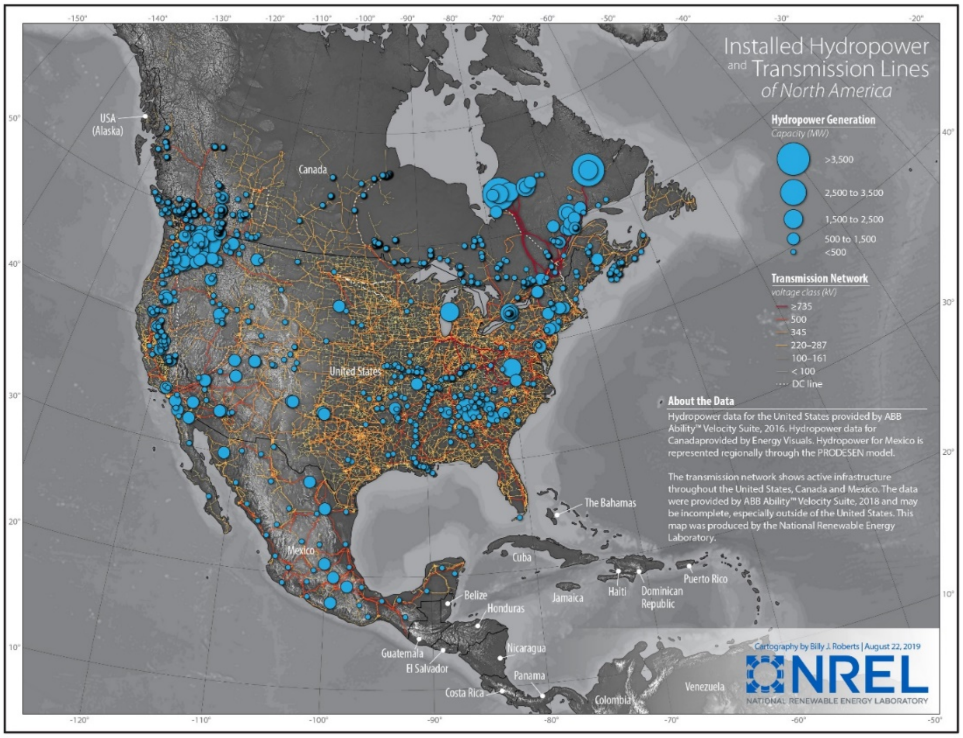


Figure 2. Installed hydropower and transmission lines of North America

North America also has hydropower resources concentrated in several regions throughout the continent. It is evident that many high-voltage transmission lines have been built to connect hydropower with load centers (e.g., west coast, northeast). Transmission helps enable geographic diversity among all generating resources and load, hydropower generation can also contribute to the flexibility. Although the NARIS scenarios do not model extensive hydropower expansion, the value provided by hydropower is examined in Section 3.4.

1.2 Scenario Overview

The scenarios in NARIS are designed to study a range of future possible grid evolution; many of them share assumptions with the National Renewable Energy Laboratory's (NREL's) annual Standard Scenarios work.[6] The four "core scenarios" shown in Table 1 indicate four potential pathways of North American grid evolution through 2050. Figure 3 shows the key assumptions for the core scenarios; detailed assumptions are available in Table 2 (page 8) and Section 2 (page 11).

Table 1. Key Assumptions in the Core Scenarios through 2050

Scenario	Key Assumptions
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 (assuming 80% carbon reduction from 2050 for the electric sector only in Canada, compared with 80% economy-wide reductions in Paris Agreement Mid Century Strategy).

[6] https://www.nrel.gov/analysis/standard-scenarios.html

Scenario	Key Assumptions
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).[b] Otherwise, the scenario is the same as the BAU scenario.
Carbon Constrained (CO_2 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.[a] Otherwise, the scenario is the same as the BAU scenario.
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.

[a] The starting points for the carbon assumptions, especially in the Carbon Constrained scenarios, were the Paris Agreement Mid-Century Strategy documents in all three countries (Government of Canada 2016; SEMARNAT-INECC 2016; White House 2016), with the BAU being based on legislation in Canada

[b] "Annual Technology Baseline: 2018 ATB," NREL, https://atb.nrel.gov/electricity/2018/.

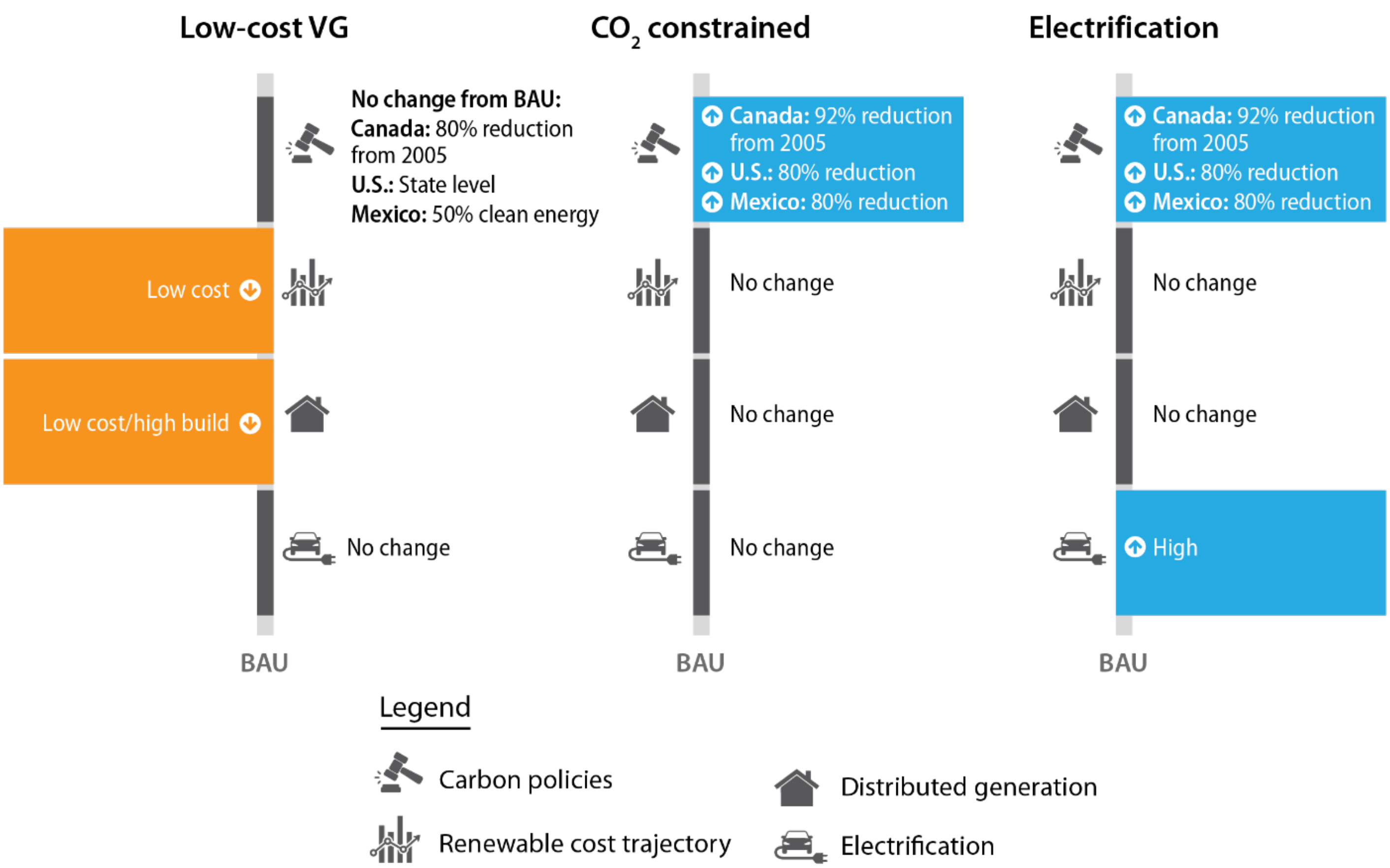


Figure 3. Comparison of core scenarios in NARIS and BAU

Each scenario shows the differences from the BAU. The "high build" of distributed generation (more installed capacity) in the Low-Cost VG scenario is due to the lower assumed costs.

We also studied a variety of sensitivities to these core scenarios, typically by varying one assumption at a time. These changes include gas prices, transmission build assumptions, storage costs, and other variables. Each of these sensitivities describes the entire evolution of the grid through 2050 and is referred to as a "scenario" throughout the report. This report focuses primarily on the core scenarios, especially the Business as Usual (BAU) and Low-Cost VG scenarios. The sensitivities help us understand uncertainty and help us quantify the impacts of key assumptions or technologies. Where the additional scenarios are important for conclusions, they are described and presented in the appropriate section. Detailed results for all scenarios are available are available on the NARIS website.[7]

[7] "North American Renewable Integration Study," NREL, https://www.nrel.gov/analysis/naris.html.

Table 2. Key Assumptions in All Scenarios through 2050[a]

Scenario (+ Sensitivity Tag)	Canada Carbon Policy[b]	U.S. Carbon Policy[b]	Mexico Carbon Policy[b]	Cost Trajectories	Transmission[c]	Retirements[d]	Electrification[e]	Gas Price
Business as Usual (BAU)	**80% Reduction**	**State-Level**	**50% clean**	**BAU**	**Coordinated**	**BAU**	**BAU**	**BAU**
BAU Early Retire	—	—	—	—	—	Early	—	—
BAU High Cost Gas	—	—	—	—	—	—	—	High
BAU Low Cost Gas	—	—	—	—	—	—	—	Low
BAU Low Cost Storage	—	—	—	Low-cost storage	—	—	—	—
BAU Macro Grid	—	—	—	—	+ Macrogrid	—	—	—
BAU No Cross-Border Expansion	—	—	—	—	+ No new cross-border lines allowed	—	—	—
BAU No Cross-Border Expansion Uncoordinated	—	—	—	—	Uncoordinated, no new cross-border lines	—	—	—
BAU Uncoordinated	—	—	—	—	Uncoordinated	—	—	—
Low-Cost Variable Generation (VG)	**80% Reduction**	**State-Level**	**50% Clean Energy**	**Low-Cost RE**	**Coordinated**	**BAU**	**BAU**	**BAU**
Low Cost VG Early Retire	—	—	—	—	—	Early	—	—
Low Cost VG High Cost Gas	—	—	—	—	—	—	—	High
Low Cost VG Low Cost Gas	—	—	—	—	—	—	—	Low
Low Cost VG and Storage	—	—	—	Low-cost storage + VG	—	—	—	—
Low Cost VG Macro Grid	—	—	—	—	+ Macrogrid	—	—	—
Low Cost VG No Cross-Border Expansion	—	—	—	—	+ No new cross-border lines allowed	—	—	—
Low Cost VG No Cross-Border Expansion Uncoordinated	—	—	—	—	Uncoordinated, no new cross-border lines	–	—	—
Low Cost VG Uncoordinated	—	—	—	—	Uncoordinated	—	—	—
Carbon Constrained	**92% Reduction**	**80% Reduction**	**80% Reduction**	**BAU**	**Coordinated**	**BAU**	**BAU**	**BAU**
CO2 Constrained Early Retire	—	—	—	—	—	Early	—	—
CO2 Constrained High Cost Gas	—	—	—	—	—	—	—	High
CO2 Constrained Low Cost Gas	—	—	—	—	—	—	—	Low
CO2 Constrained Low Cost Storage	—	—	—	Low-cost storage	—	—	—	—
CO2 Constrained Macro Grid	—	—	—	—	+ Macrogrid	—	—	—
CO2 Constrained No Cross-Border Expansion	—	—	—	—	+ No new cross-border lines allowed	—	—	—
CO2 Constrained No Cross-Border Expansion Uncoordinated	—	—	—	—	Uncoordinated, no new cross-border lines	—	—	—
CO2 Constrained Uncoordinated	—	—	—	—	Uncoordinated	—	—	—
CO2 Constrained Low Cost VG	—	—	—	Low-cost VG	—	—	—	—
CO2 Constrained Low Cost VG High Gas	—	—	—	Low-cost VG	—	—	—	High
CO2 Constrained Low Cost VG and Low Cost Storage	—	—	—	Low-cost VG and storage	—	—	—	—
Electrification	**92% Reduction**	**80% Reduction**	**80% Reduction**	**BAU**	**Coordinated**	**BAU**	**High**	**BAU**
Electrification Early Retire	—	—	—	—	—	Early	—	—
Electrification High Cost Gas	—	—	—	—	—	—	—	High
Electrification Low Cost Gas	—	—	—	—	—	—	—	Low
Electrification and Storage	—	—	—	Low-cost storage	—	—	—	—
Electrification Macro Grid	—	—	—	—	+ Macrogrid	—	—	—
Electrification No Cross-Border Expansion	—	—	—	—	+ No new cross-border lines allowed	—	—	—
Electrification No Cross-Border Expansion Uncoordinated	—	—	—	—	Uncoordinated, no new cross-border lines	—	—	—
Electrification Uncoordinated	—	—	—	—	Uncoordinated	—	—	—
Electrification Low Cost VG	—	—	—	Low-cost VG	—	—	—	—
Electrification Low Cost VG High Gas	—	—	—	Low-cost VG	—	—	—	High
Electrification Low Cost VG and Low Cost Storage	—	—	—	Low-cost VG and storage	—	—	—	—

The table does not include hydropower sensitivities (flexibility, wet/dry, or Canadian supply sensitivities), described later in the report

[a] — Indicates no change from core case for the scenario

[b] **Carbon**

- Canada: Assumes BAU is an 80% CO_2 reduction and Carbon Constrained is a 92% reduction, which is more in line with Mid-Century Strategy, and is 80% economy-wide
- United States: Assumes BAU is state-level policies only and Carbon Constrained is a 80% reduction (in line with Mid-Century Strategy)
- Mexico: Assumes BAU is 50% clean energy standard and Carbon Constrained is a 80% reduction

[c] **Transmission**

- Coordinated: The model builds and operates transmission in an optimal way.
- Uncoordinated: The model sees hurdle rates (cost to flow power) between regions and only builds lines that have a benefit-cost ratio above 3.
- No cross-border: The model runs the same as coordinated but without any new cross-border transmission allowed (to help understand the benefit of new cross-border lines).
- Macrogrid: The model runs as coordinated, with an HVDC (high-voltage direct current) macrogrid. Some potential benefits of this grid might not be well captured in standard modeling frameworks. The macrogrid is based on the grid for the U.S. Interconnections Seam study, with an extension into Canada.

[d] **Retirements**

- This scenario represents potential concerns for early thermal unit retirement.
- Coal: In the Early Retirements scenario, coal is assumed to retire early based on whether the ReEDS model continues to operate with more than 75% capacity factor. This could be driven by lack of cost recovery or carbon or other pollutant policies. In BAU, only announced retirements are included.
- Nuclear: In the Early Retirements scenario, all nuclear is assumed to not be relicensed (but operates until relicensing), based on ongoing retirement concerns. In the BAU assumption, 50% of nuclear is relicensed and still operating in 2050 (based on commission date)

[e] **Electrification and Load Growth**

- Canada: BAU (nonelectrification) cases assume 2050 load of 780 terawatt-hours (TWh) (based on Canada's National Energy Board extrapolated). Electrification cases assume 1,070 TWh (based on EnergyPATHWAYS modeling for NARIS). 2016 load is 600 TWh.
- United States: BAU (nonelectrification) cases assume 2050 load of 5,100 TWh (based on U.S. Energy Information Administration [EIA] extrapolated). Electrification cases assume 7,100 TWh (based on NREL's Electrification Futures Study). 2016 load is 3,950 TWh.
- Mexico: Because the Programa de Desarrollo del Sistema Eléctrico Nacional (PRODESEN) and the Mid-Century Strategy have similar assumptions for load growth, both scenarios are identical in load. 2016 load is 310 TWh. 2050 load is 790 TWh.
- In current runs, no hourly profile changes are considered for electrification, except optimal vehicle charging. Reference the Electrification Futures Study[8] for more work on this topic

[8] "Electrification Futures Study," NREL, https://www.nrel.gov/analysis/electrification-futures.html.

1.3 Assumptions and Limitations

This section describes the key assumptions and limitations of the study, so stakeholders can understand the context for interpreting the study results.

- NARIS is not a forecast or official plan for any given region or state. The scenarios were produced through specific optimization methods, so infrastructure decisions may differ from what decision-making organizations choose to do. The study analyzes a suite of scenarios to understand ways the grid could evolve and operate to help inform planners. In many cases, the optimization is shallow and there are alternative infrastructure builds with similar costs.
- The study is not an attempt at a 100% renewable energy or 100% carbon reduction study. More study is necessary to understand the full implications of reaching 100% renewable electricity in Canada or all of North America. Eliminating the last few percentage points of CO_2-emitting generation may be the hardest (see Denholm et al. 2021), although the study does not demonstrate that it is impossible to achieve.
- We did not have consistent, site-specific cost estimates for hydropower generation expansion; to consider the value of hydropower expansion to the system, we ran several model sensitivities with generic hydropower cost assumptions.
- NARIS considers enacted legislation with binding targets for renewable or clean energy portfolios that cover electricity generation at the federal or state/province level by October 2018; it does not attempt to extrapolate local or corporate targets and understand how they could impact infrastructure builds.
- More study is needed to understand dynamic concerns, including frequency stability. NARIS did not perform any AC or dynamic power flow modeling. It is assumed for the study that interconnection-wide frequency support can be provided by technologies like nuclear, hydropower, synchronous condensers, and/or advanced inverters; if additional generation is required for frequency support, this would increase curtailment.
- Operational practices will continue to change between today and 2050, including the way balancing authorities interact with each other. Aside from several scenarios, NARIS assumes that regions have the ability to efficiently trade electricity or build infrastructure if it is optimal.
- NARIS is not a detailed analysis of electricity markets. Specific market rules and participant behavior will impact the evolution and operation of the grid; the study is based mostly on optimization models and assumes overall cost-optimal resources will be developed and operated (as described in Section 2.1). The study does not attempt to determine whether generation resources will receive sufficient revenue in existing or future market structures.
- The study does not consider the impact of climate change on demand patterns, wind, solar, hydropower, or thermal generation.
- In addition to climate change, electrification may cause significant changes to demand flexibility and timing which are not addressed in detail here. Future work can help analyze the implications, particularly for adequacy (which could benefit from demand flexibility).
- No policy recommendations are made in this report or study.
- All costs are in 2018 USD for consistency with U.S. report.

2 Data and Methods

This section provides an overview of the data, models, and methods used in NARIS; many of the models and data are documented elsewhere or are open-sourced.

2.1 Methods and Models

Figure 4 provides an overview of the modeling process used in the NARIS. Four primary modeling types underpin the analysis:

- **Generation and Transmission Capacity Expansion:** The NREL ReEDS model co-optimizes the build-out of generation and transmission infrastructure, subject to the assumptions in each scenario.
- **Distributed Generation Market Adoption:** The NREL dGen model is an agent-based consumer adoption model that projects different pathways of distributed PV deployment for the residential, commercial, and industrial sectors.
- **Production Cost (Unit Commitment and Dispatch):** The Energy Exemplar PLEXOS model simulates the operation of the power system at hourly and 5-minute timescales.
- **Reliability (Resource Adequacy) Model:** The NREL PRAS model simulates simplified system operation for every hour for 7 years of meteorological conditions (wind, solar, load), and thousands of random draws of outages of thermal generators. Variability of hydropower inflows (and impacts on adequacy) was not considered in PRAS.

The same data were used throughout NARIS. The distributed generation and capacity expansion models were used to explore the uncertainty in power system evolution, and then the production cost and resource adequacy models were used to study a few key scenarios in detail.

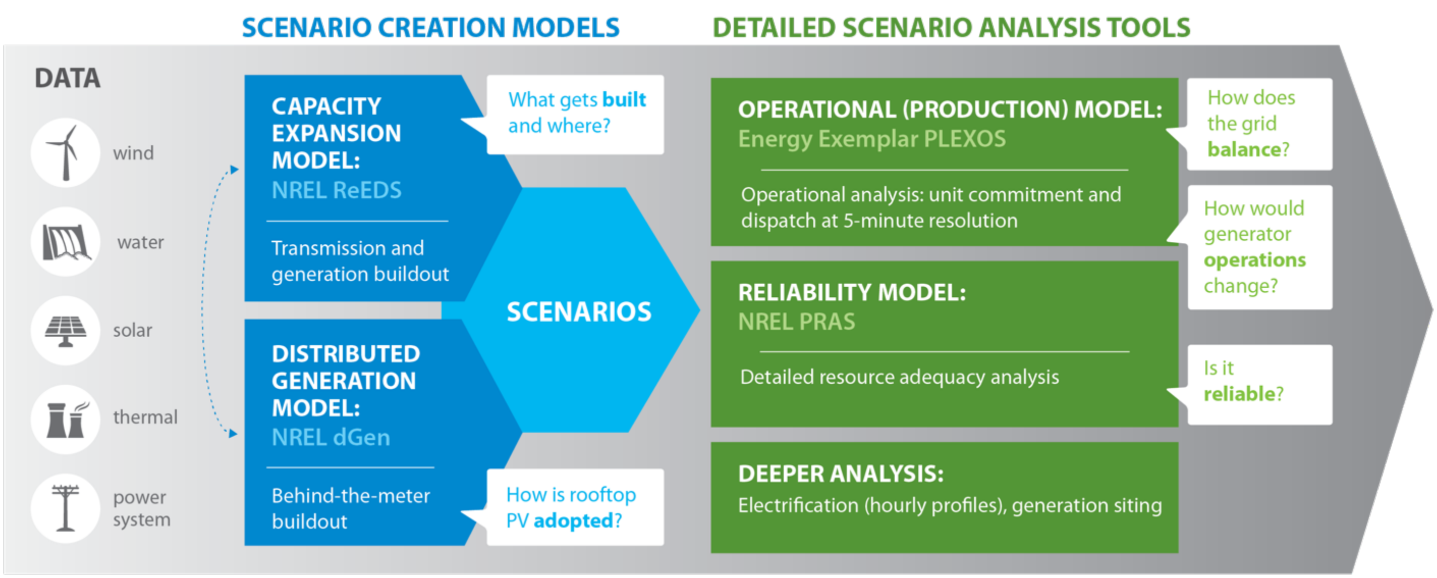


Figure 4. Modeling flow

This diagram shows the modeling flow of the key models, including the transmission-level capacity expansion (NREL ReEDS), distributed PV adoption (NREL dGen), production cost grid simulation (Energy Exemplar PLEXOS), and resource adequacy (NREL PRAS). The reV geospatial tool helps keep the data consistent at all modeling scales.

2.1.1 Capacity Expansion Modeling (ReEDS)

The NREL Regional Energy Deployment System (ReEDS) is an electricity sector capacity expansion model representing the North American power system. The model, through least cost optimization, evaluates the location and timing of generation and transmission investments throughout the system. For a detailed explanation of the model, see Cohen et al. (2019)

ReEDS represents the diverse spectrum of generation, storage, and transmission technologies relevant to power system decision makers. As part of the modeling process ReEDS contains an endogenous representation of power system needs. These include operational requirements in electric power including balancing demand, renewable resource availability, and generation technology limits. System reliability is ensured by including planning reserve and spinning reserve requirements. Planning reserve can be served by all types of resources; capacity credits for wind and solar resources are estimated in each model region and year by estimating the contribution of these resources in periods of high load and low wind and solar generation. These estimates are done using hourly load, wind, and solar data (see Section 2.2) using 2012 meteorology. Other years are tested in the PRAS modeling (see Section 2.1.4). Canadian provincial policies are modeled, including carbon cost policies like British Columbia's.

ReEDS selects a least-cost mix of operations and investment decisions while satisfying all modeled requirements described in this section. Model simulations occur in 2-year periods starting in 2010 (build decisions through 2020 are fixed to historical builds) and ending in 2050. In historical years investment decisions are restricted to match the location and timing transmission and generation developments that occurred. Within each simulation, a year of operations decisions are modeled with a reduced order dispatch, using 17 representative time-slices to represent a year. For each of the four seasons, time blocks of morning, afternoon, evening, and overnight hours are aggregated based on time of day in local time to form time-slices. An additional 17th super-peak time-slice is created from the top 40 summer afternoon (1 pm–5 pm) hours. Although no similar winter super-peak time-slice exists in the model, there are winter planning reserve requirements to consider the highest-load times for many provinces. Reducing the operational dispatch from 8,760 hours to 17 representative time-slices preserves seasonal and diurnal variability within the model while reducing the computational burden. Outside the simulation, more-granular hourly data sets are also used by the model to estimate curtailments and the capacity value provided by variable renewable technologies.

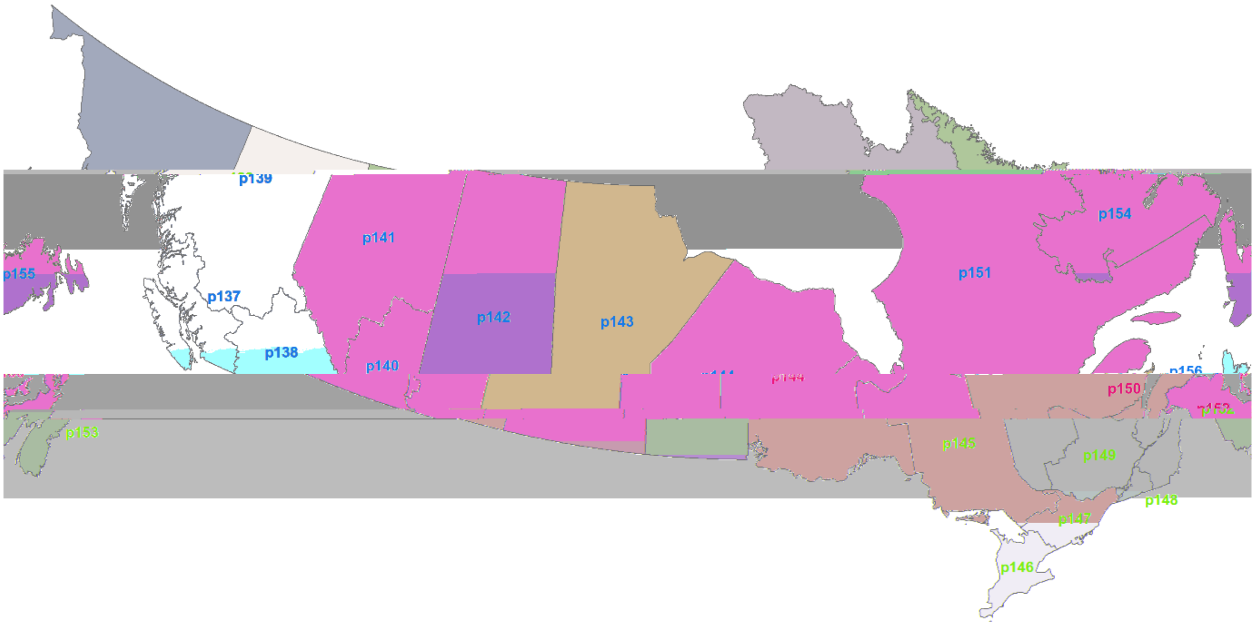


Figure 5. Zonal representation of Canada in ReEDS

Regions represent transmission zones, while the larger provincial balancing authorities are shown in colors

The representation of Canada is divided into 20 balancing areas for transmission modeling (some provinces are split into multiple balancing areas to represent intraprovincial congestion) and 47 wind resource regions. Canadian territories are not included as part of ReEDS' representation of Canada or its non-grid connected generation and load. The Canadian aggregated transmission network is connected by 36 representative transmission lines (that represent interfaces between regions) among three asynchronous interconnections.

The resulting outputs of a ReEDS solution contain detailed information about the evolution of the power system relevant to decision makers. The model outputs extend beyond the energy generated and capacity of plants and transmission interfaces within the United States. Examples of more-detailed operations outputs include the capacity value of wind and solar and the distribution of reserves by region and technology. ReEDS also outputs detailed system cost information, which helps to understand the implications of different regulatory and technological futures. The results also include a diverse range of environmental outputs including, CO_2 emissions, water consumption, and others. Shadow prices are used to understand economic questions, including why certain generation technologies are developed and prices ranging from competitive electricity prices to environmental regulation. Interregional and cross-border international transmission and power flows are also output. The ReEDS model was run on all scenarios described in Section 1.2; additional analysis beyond the ReEDS model was done for several key scenarios, as described later in the report.

Table 3 lists the data sources for all three countries in the core scenarios in ReEDS.

Table 3. Data Sources for All Three Countries in the Core Scenarios in ReEDS

Category	Canada Assumption	Mexico Assumption	U.S. Assumption
Natural gas supply curve and regional consumption	Regional gas supply curves are derived from the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO2018) price and consumption data. Supply curves are extended to include adjacent Canadian provinces by adjusting natural gas consumption based on consumption in National Energy Board's Energy Futures 2017.	Supply curve derived from EIA AEO2018, West South Central region, adjusted for projected gas consumption and prices in PRODESEN 2018–2032.[a]	Supply curve derived from EIA AEO2018 (see Cohen et al. 2019)
Coal prices	National Energy Board's Energy Futures 2017 (Province)	PRODESEN 2018–2032	EIA AEO2018
Electricity demand projections	National Energy Board's Energy Futures 2017 Evolved Energy Research (Electrification)	PRODESEN 2018–2032 Evolved Energy Research (Electrification)	EIA AEO2018 Evolved Energy Research (Electrification)
Hourly electricity demand (See Section 2.2.2 for details.)	Various Provincial Level Sources	PRODESEN 2018–2032	Independent system operator (ISO); Federal Energy Regulatory Commission Form 714
Existing generation fleet	ABB Velocity Suite 2018 is mapped to ReEDS balancing areas using spatial analysis		
Announced retirements	Various Provincial Level Sources	ABB Velocity Suite/ EIA AEO2018	PRODESEN 2018–2032
Plant cost and performance	ABB Velocity Suite 2018, EIA AEO2018		
Transmission costs	Distance per mile costs estimated from Eastern Interconnection Planning Collaborative Phase 2 Report (EIPC 2015). Transmission costs are \$1,347–\$2,333/MW-mile depending on the line voltage. Spur lines connecting utility scale solar and wind to the power system cost \$3,667/MW-mile.		
Planned hydropower builds	National Energy Board's Energy Futures 2017 (Province)	PRODESEN 2018–2032	Hydropower Vision + ABB Velocity Suite

Category	Canada Assumption	Mexico Assumption	U.S. Assumption
Seasonal hydropower capacity factors	National Energy Board's Energy Futures 2017 (Province)	PRODESEN 2018–2032 Fleetwide Average	WECC Transmission Expansion Planning Policy Committee (TEPPC) 2024 (West Only); National Hydropower Asset Assessment Program
Onshore wind resource supply curve	2-km x 2-km Wind Toolkit meteorological processed using the Renewable Energy Potential model (reV) to generate cost and performance supply curves for wind. Generated data are available at the sub-balancing authority level and is consistent with NREL Annual Technology Baseline (ATB) assumptions.		
PV resource supply curve	4-km x 4km National Solar Radiation Database (NSRDB) solar irradiance data processed using reV to generate cost and performance supply curves for Utility Scale PV. Both Utility Scale (rural development) and Distributed Utility Scale (urban development) are included with distinct resource costs consistent with ATB.		
Province renewable portfolio standards (RPS) and clean energy standards	Provincial level policies including the British Columbia Carbon Tax, New Brunswick, Nova Scotia, Prince Edward Island RPS policies as of 2018.[b]		State RPS and clean energy standard policies derived from regular ReEDS updates from the Database of State Incentives for Renewables and Efficiency
International renewable energy certificate trading rules			State specific trading rules (Database of State Incentives for Renewables and Efficiency)

Canada's Energy Future 2018 was not yet published by the National Energy Board when we finalized our assumptions and synchronized the model across the three countries. We did confirm that the key variables did not change significantly from 2017. As of 2019, the Canada Energy Regulator (formerly the National Energy Board) now publishes this report.

[a] PRODESEN, Programa de Desarrollo del Sistema Eléctrico Nacional, https://www.gob.mx/sener/acciones-y-programas/programa-de-desarrollo-del-sistema-electrico-nacional-33462, accessed 2018.

[b] In Canada, the federal assumptions to retire most coal by 2030 and reach 80%–92% carbon reductions (leading to 93%–97% carbon-free generation) by 2050 make many of the provinces near-zero carbon in 2050. Exceptions to the coal retirement rules include carbon capture plants (represented in the NARIS modeling) and some regulatory exceptions (which are not represented in NARIS).

The cost trajectories used for these model runs are from the NREL 2018 Annual Technology Baseline (ATB), as noted above. Figure 6 plots these cost trajectories in comparison to the 2020 ATB equivalent. Note that the NARIS BAU (2018 ATB Mid) case is closer to the 2020 ATB Conservative case costs for PV and wind, and it is slightly higher in 2050. The NARIS Low Cost trajectories are generally in between the Advanced and Moderate trajectories for the 2020 ATB.

These are levelized cost of electricity[9] (LCOE) comparisons based on moderate-quality resource for both wind and solar. Note that LCOE is not used for any purpose in the NARIS modeling; however, it is a useful metric for comparisons that depend on both cost and performance of technologies.

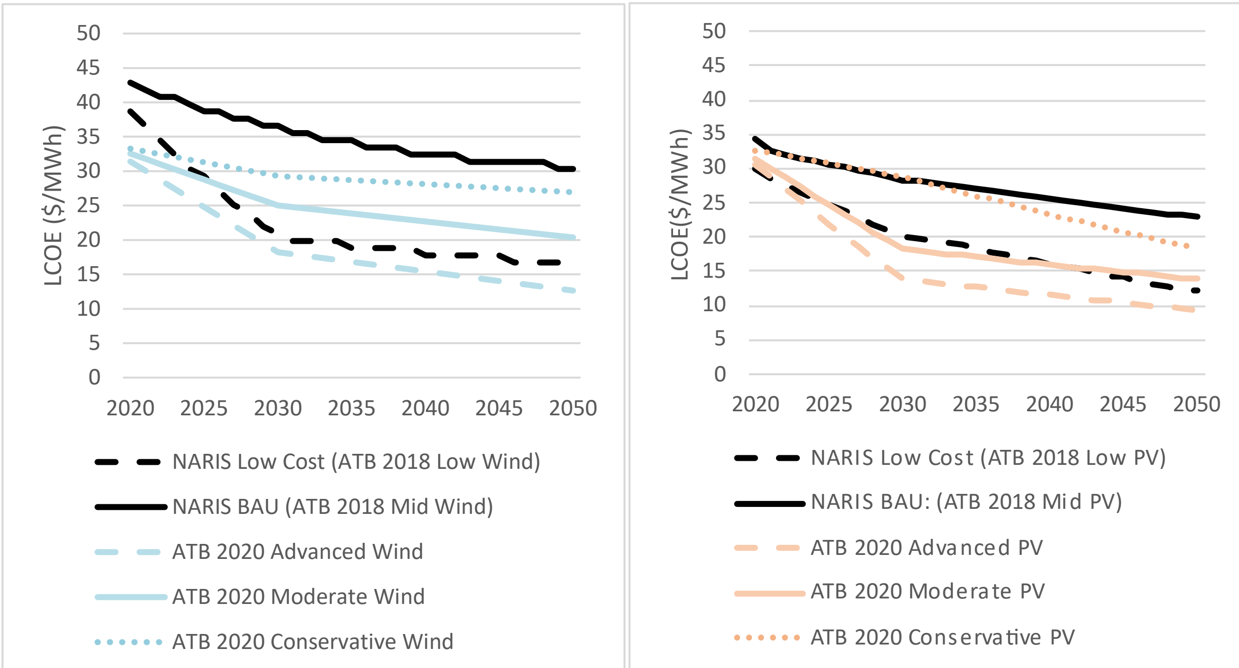


Figure 6. Cost comparison for wind (left) and solar PV (right) in the 2018 ATB and the 2020 ATB

All costs in report are 2018 USD.

2.1.2 Distributed Generation Modeling (dGen)

Consumer adoption of distributed energy resources is analyzed using a different framework than that of transmission-connected generation resources, and thus requires a separate approach. And three aspects are particularly germane to the distribution-connected versus transmission-connected discussion. First, distributed-connected resources are physically sited closer to load, leading to a different power flow than would otherwise be seen. Second, motivations for adoption are wholly different; transmission-connected resources are valued at the wholesale rate of electricity, and behind-the-meter resources are valued at the retail level. Moreover, consumers themselves have several drivers of adoption, including economic factors such as savings on electricity bills and a hedge against future rate changes, but also noneconomic ones such as environmental concerns and social influence from family and peers. Finally, a different set of policies is used to incentivize adoption of distributed energy resources than is used with utility-scale resources.

[9] LCOE is a "summary metric that combines the primary technology cost and performance parameters" to estimate the average cost per MWh of electricity based on cost and performance assumptions. See "Equations and Variables in ATB," NREL, http://atb.nrel.gov/electricity/2020/equations-variables.php.

To reflect these differences in drivers of capacity expansion for distributed energy resources, we utilized the Distributed Generation Market Demand (dGen) model to develop rooftop PV projections for the residential, commercial, and industrial sectors.[10] For NARIS, we developed new modules for Canada and Mexico. dGen is an agent-based model, representing bottom-up customer adoption, where each agent represents an independent decision-making entity (customer, in this case). Agents are statistically representative based on sampling from distributions of customer attributes for each geography modeled. Agent sampling rates vary by country and sector, primarily because of data availability.

For the Canadian implementation of dGen, agents are sampled based on geography for the residential sector by census division (n = 293) and for the commercial and industrial sector by province (n = 10; territories were not considered for consistency with the interconnection-scale modeling throughout NARIS). Thus, an "agent" represents a statistical cluster of multiple customers. Agent sampling rates varied by country and sector, primarily because of data availability.

Adoption projections in dGen are modeled through a four-step approach:

1. Generating agents (i.e., customers) and assigning them attributes based on a statistical sampling of their attributes (e.g., annual electricity consumption and roof size)
2. Applying technical and siting restrictions, such as resource quality, rooftop availability and quality for each agent
3. Analyzing cash flow to consider project costs, retail electricity rates, incentives, and net-billing/net metering policies; agents "select" PV systems that maximize their net present value
4. Projecting the future market share based on a generalized Bass diffusion model[11] to account for consumer behavior (Dong and Sigrin 2019). Market share is primarily determined by the system payback period, and the rate of diffusion is based on regressions of historical growth.

Technical potential is calculated in steps one and two by determining the number of developable roofs and the unshaded area. A building is considered to be developable if it meets shading, tilt, azimuth, and minimum area requirements (Gagnon et al. 2016); additionally, adoption is not considered for multifamily residential or renter-occupied residential buildings. In the Canadian dGen model, average roof sizes are collected for each sector in each geography from Census data; however, variability in roof sizes within a given geography is not considered because of data limitations. For each agent, the annual average capacity factor is used to calculate an upper-bound estimate of generation. Figure 7 displays the total technical potential of rooftop PV across all three countries studied by NARIS ranked by capacity factor and sector. Capacity factors are calculated using data and methods in Section 2.2.1, considering resource, azimuth, tilt, temperature, and other variables.

[10] dGen can also model distributed wind, storage, and geothermal technologies, but we focused on distributed rooftop solar for NARIS.
[11] The Bass diffusion model determines how quickly consumers adopt consumer goods (in this case, PV).

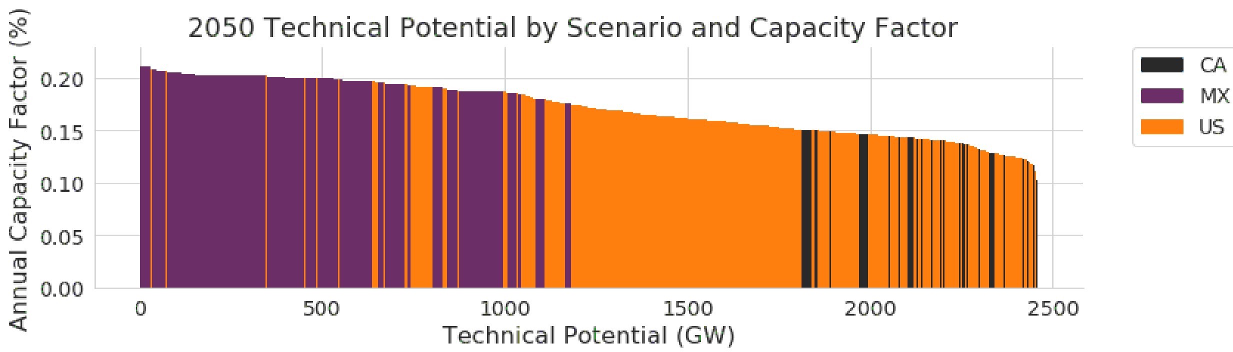


Figure 7. Distributed PV resource quality by country

This graph shows the total rooftop technical potential capacity in each country, ordered by capacity factor (CA = Canada, MX = Mexico, and US = United States). The best Canadian rooftops have a capacity factor of approximately 15%, which can be seen near the 1,800-gigawatt(GW) point in this graph of continental rooftop potential. The graph is based on dGen model inputs using NSRDB and reV tools. Extrapolation for building rooftop area follows the same shape as electricity demand (assuming identical rooftop space per megawatt-hour through 2050).

Within Canada, technical potential varies considerably by sector. Figure 8 displays cumulative technical potential by sector and capacity factor, with the highest capacity factors belonging to commercial and industrial buildings.

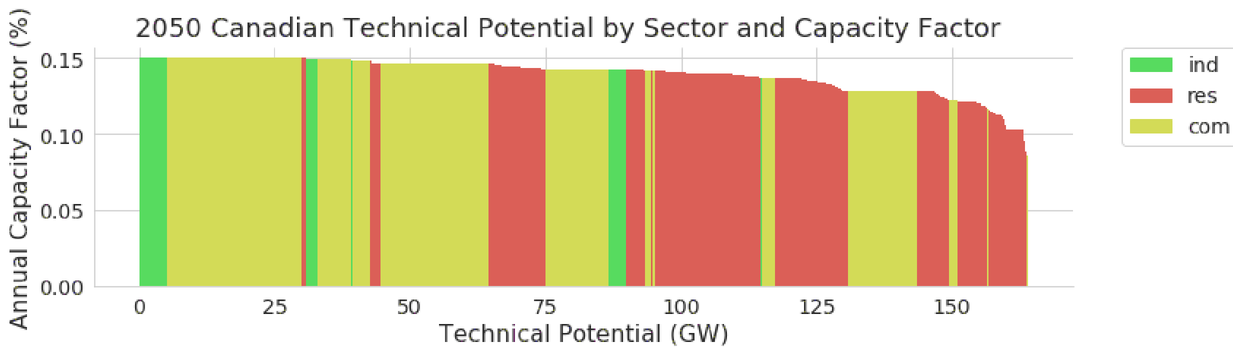


Figure 8. Distributed PV resource quality in Canada by sector

This graph shows the total rooftop technical potential capacity in Canada, ordered by capacity factor and separated by sector (ind = industrial, res = residential, and com = commercial). There is capacity with close to 15% capacity factor in all sectors. Based on dGen model inputs using NSRDB and reV tools.

Though over 160 gigawatts (GW) of rooftop PV capacity is currently assessed to be technically feasible in Canada, most of this is not yet economical based on the NARIS modeling and assumptions. To determine the total potential deployment, dGen performs a detailed cashflow analysis for each agent to calculate the net present value of adopting solar. Various system sizes are tested to determine the economically optimal system size for a given agent based on its unique load consumption profile, solar resource availability profile, roof size, retail rate, and financing terms. The optimal system-size and net present value are calculated and translated into a payback period, which represents the number of years before electricity bill savings from the system's generation will offset system cost.

Previous customer surveys have solicited consumer willingness-to-adopt solar at various payback periods. The results from these surveys are aggregated to determine the rooftop PV maximum market share (Sigrin and Drury 2014). Using historical adoption data and the calculated maximum-market share, a Bass diffusion model is used to project PV market share in each year. Payback period is used to determine the maximum (i.e., terminal) market share, and a regression on historical adoption trends is used to inform the rate of diffusion for each region-sector.

Three scenarios were examined to assess agent sensitivity to changes in PV capital costs. The scenarios were harmonized by country in real terms based on the 2018 ATB for the Mid (Reference), Low, and Constant Costs scenarios. For reference, the 2050 Mid Costs value is $1,140/kW (2018 USD) for residential-scale systems and $954/kW for nonresidential scale systems. In the Low Costs they are $560/kW and $517/kW respectively; in the Constant Costs scenario, they are $2,857/kW and $1,936/kW respectively. Operation and maintenance costs, which include inverter replacement are $3.6–$17.0/kW-year depending on scenario and sector. Although market costs for PV panels and installation costs can vary between the countries and through time (Masson and Kaizuka 2020), we maintained consistency in cost projections for all technologies based on the NREL ATB costs.

We ran scenarios incorporating existing net energy metering (NEM) policies assuming all excess generation is credited at the retail electricity rate. We also ran scenarios assuming NEM policies expire and net billing persists in all jurisdictions. Net billing values exports to the grid at the wholesale cost of electricity, but the self-consumed energy is still valued at the retail rate of electricity. Figure 9 shows the annual capital cost of PV per kilowatt used by dGen by sector and scenario. Note that this cost does not include taxes, incentives, or subsidies, which are determined by country and state or province.

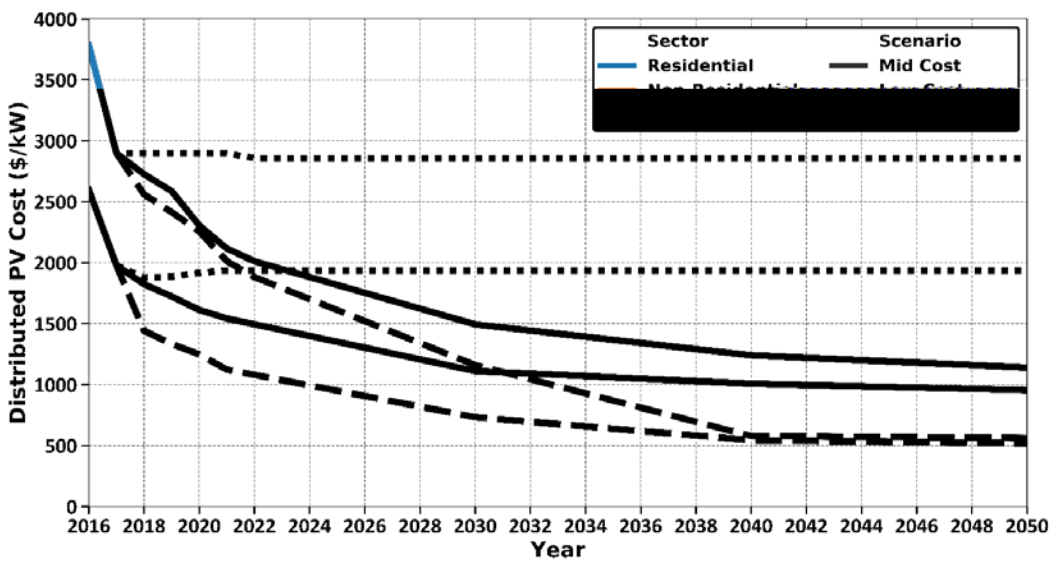


Figure 9. Cost trajectories for distributed PV

Table 4 lists the data sources used by dGen, summarized for each country. For comparability, and where possible, agents across the three countries were derived from common sources. For instance, each country modeled the residential and commercial sector, used common capital cost and financing assumptions, and excluded consideration of multitenant buildings.

Table 4. Data Sources for dGen

Category	Canadian Assumption	Mexico Assumption	U.S. Assumption
Model resolution (number of agents sampled)	Residential-sector by census division (n = 293) Commercial-sector by province (n =10)	State-level by tariff class (n = 1,024)	10 agents per county, by sector (n = 93,240)
Building stock	Building counts by province and sector (2016 Census Program)	Counts determined by tariff classes for each state using SENER-provided data	Building characteristics sampled from Gagnon et al. (2016); Sigrin and Mooney 2018)
Electrical load	See Section 2.2.2.	Annual consumption by state and tariff class; hourly load profiles based on control regions, using SENER-provided data	County-level load by sector (ABB 2013; EIA Residential Energy Consumption Survey and Commercial Buildings Energy Consumption Survey); load profiles based on nearest weather station
Retail tariffs	Detailed calculation for current tariffs by utility using the OpenEI U.S. and International Utility Rate Database[a]		
Policies	Representation of current net metering policies and financial incentives; both assumed to expire based on statute (if applicable), although we explored this with model sensitivities in Section 3.5.2.		
Solar resource	Generation profile for 2012 meteorological year,[b] using for population-weighted regional midpoint, south-facing and tilted at latitude; building roof area based on U.S. sector-specific averages		Generation profile for 134 weather stations using TMY3 irradiance profiles
Existing deployment	Annual installations and installed capacity by province (2016)	System-level interconnection records (2016)	Annual installation by county and sector (2016)
Technology costs	Based on NREL 2018 ATB for residential-scale and commercial-scale PV systems		
Financing			

[a] "Utility Rate Database," OpenEI, https://openei.org/wiki/Utility_Rate_Database, accessed 2018.
[b] NSRDB (National Solar Radiation Database), NREL, https://nsrdb.nrel.gov, accessed 2018.

2.1.3 Production Cost Modeling (PLEXOS)

To understand the operation of future power systems, we used PLEXOS, a production cost model (PCM) developed by Energy Exemplar. The PCM simulates unit commitment and economic dispatch of the future grid infrastructure built by ReEDS. In this report, all production cost modeling results are from the Low Cost VG scenario in 2050. This scenario had a similar build-out to the Carbon Constrained scenario, so the results are generally representative. Because the Electrification scenario might operate quite differently, future work should refine the operational assumptions of these scenarios and study in more detail. The results of the PCM allows us to understand how transmission and generation operations change at hourly and subhourly levels while ensuring a reliable and efficient grid. The goal of modeling with 5-minute resolution 30 years in the future is to understand the overall feasibility and implications of operations, not to make a precise forecast of the future. Overall, the goal of the modeling is to demonstrate supply-demand balance using a unit commitment model, considering forecast error, with 5-minute dispatch resolution, and a nodal transmission network (see Figure 10 for examples of outputs).

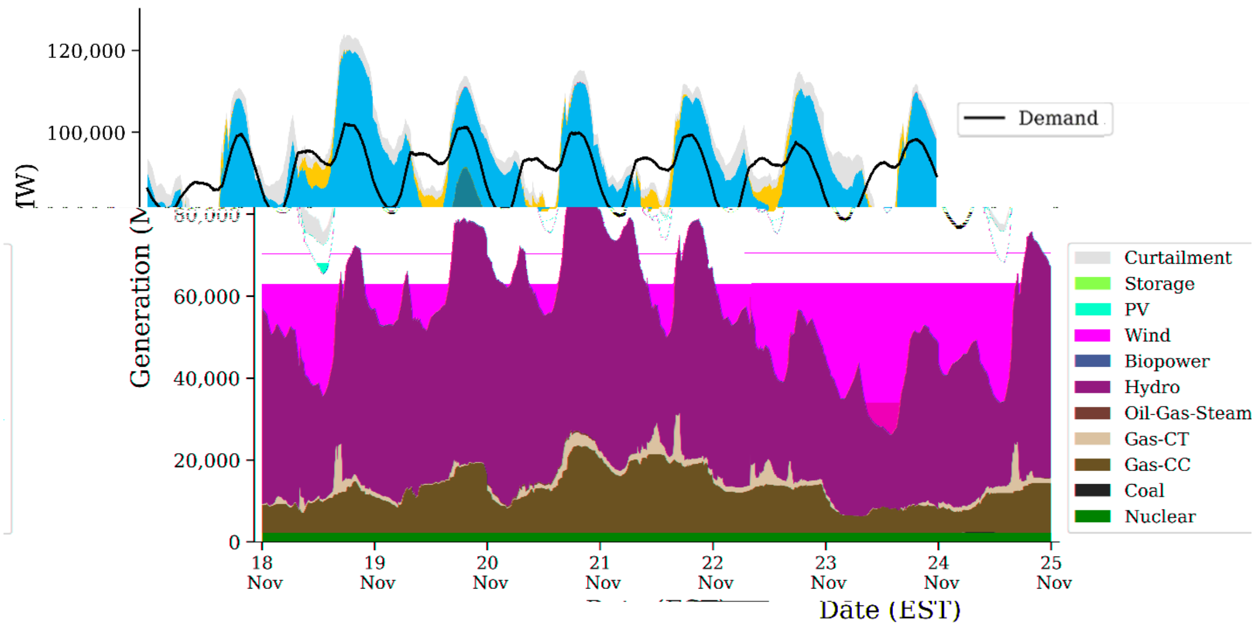


Figure 10. Sample PLEXOS output of Canadian generation dispatch stack for the week of November 18 (Low Cost VG scenario, 2050)

The production cost modeling for NARIS leveraged a variety of assumptions and methods for modeling hydropower and thermal plants in the Western Interconnection (Brinkman et al. 2016) and the Eastern Interconnection (Bloom et al. 2016). Assumptions about thermal unit start-up costs, outage rates, and hydropower conditions in NARIS started from these previous studies, and key differences are described below and in the description of the data (Section 2.2).

Installed capacity assumptions in the base model represented a 2024 power system. The expected installed thermal and hydropower generation capacity in 2024 came from several sources. For the Eastern Interconnection, generation capacity, location and type came from the 2026 Summer

Peak ERAG (Eastern Reliability Assessment Group) MMWG (Multi-regional Modeling Working Group) power flow case. For the Western Interconnection, capacity, location, and type came from the TEPPC (Transmission Expansion Planning Policy Committee) 2024 model with updates from the TEPPC 2026 case. Parameters for the Texas Interconnection came from the Electricity Reliability Council of Texas (ERCOT). Announced retirements and retirements modeled in ReEDS[12] were removed from the model.

Some thermal operating limits for existing generators deviated from Brinkman et al. (2016) and Bloom et al. (2016). The new operating limits were developed by analyzing historical data from the U.S. Environmental Protection Agency's Continuous Emissions Monitoring Systems. The data and approach for parameterizing for production cost modeling is described by Rossol et al. (2019). That analysis provided unit-specific full load heat rates, part load heat rate curves, and minimum generation levels for every generator with enough data in the Continuous Emissions Monitoring Systems data set. Bloom et al. (2016) used generic heat rate curves and minimum stable levels for thermal plants.

Forced outage rates, maintenance outage rates, and mean repair times for nuclear, coal, gas, oil, and hydroelectric generators were taken from NERC Generator Availability Data System data.[13] This system provides detailed information by unit maximum capacity for most of the major generator types, and these data were applied to the PCM. Other assumptions adopted from (Bloom et al. 2016) are documented in Table 5.

Table 5. Select Thermal Plant Assumptions

Category	Gas CT	Gas CC	Coal	Nuclear
Minimum up time (hours)	0	6	24	N/A
Minimum down time (hours)	0	8	12	N/A
Ramp rate (% of maximum capacity per minute)	8	5	2	N/A
Start-up cost ($/MW of maximum capacity)	69	79	129	0
Variable operation and maintenance cost ($/MWh)	0.6	1.0	2.8	2.8
Annual outage rates: sum of forced and maintenance outages (% of year)	5.69%	4.69%	7.00%	3.41%

Hydropower assumptions are described in Section 2.2.3.
CT = combustion turbine, CC = combined cycle

[12] ReEDS retirements were based on both announced retirements and modeled retirements. Modeled retirements are age-based (with thermal unit lifetimes of 55–75 years) or utilization-based (for coal plants under 40% annual capacity factor). See Eurek et al. (2016) for details.
[13] "Generating Availability Data System (GADS)," https://www.nerc.com/pa/RAPA/gads/Pages/GeneratingAvailabilityDataSystem-(GADS).aspx, accessed 2016.

For the base PCM transmission topology, NARIS relied on nodal transmission models developed for the Eastern Interconnection and the Western Interconnection under the guidance of NERC. Power flow and dynamic base case models in the Eastern Interconnection (plus Québec) are released by the ERAG MMWG. We adopted the MMWG 2026 summer case as our base set of assumptions for the Eastern Interconnection. Line limits for the Eastern Interconnection were enforced for those lines included in the NERC Book of Flowgates. The Western Interconnection topology was originally created by the Western Electricity Coordinating Council's (WECC's) TEPPC, which also provides the lines that make up the WECC Paths and identifies the limit to the flow along those paths. The topology for the Texas Interconnection came from ERCOT. The lines connecting the ERCOT zones were enforced as interface constraints. The zonal representation from PRODESEN was used for the Mexican portion of the model.

Figure 11 shows the steps involved in a detailed PCM study. These steps are used to simulate how a system operator might commit and dispatch a given system as forecasts of wind and solar availability and load are updated throughout the day. In NARIS, we did not perform the intraday simulation, but we did perform real-time simulation and day-ahead simulations using several different estimations of uncertainty in forecasts (see Section 3.5.5).

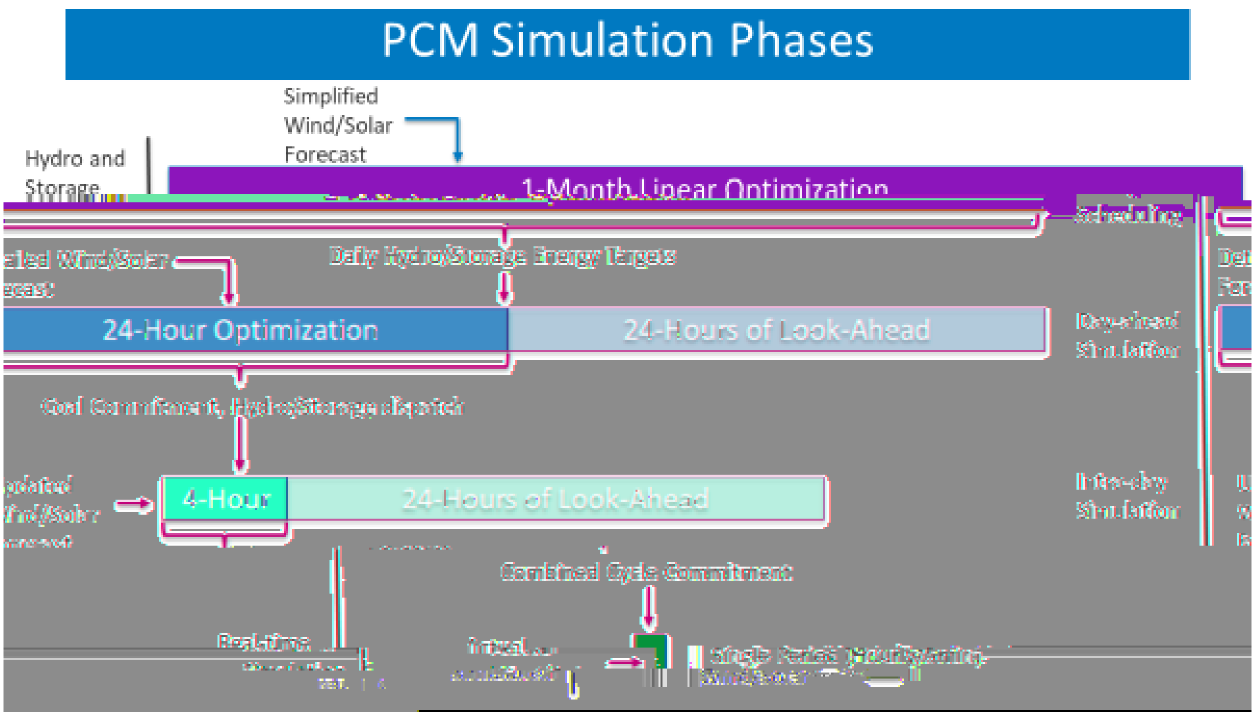


Figure 11. Simulation steps to run the PCM

PCMs are typically run as single-operator models and assume perfect information availability across regions, which is both unrealistic (leading to a solution that is lower in cost than reality) and computationally burdensome. To address these challenges and better reflect market friction and latency between operating regions, NREL designed a geographic decomposition method (Barrows et al. 2018), and we used that method in NARIS. The unit commitment and economic dispatch problem is decomposed into the ISO and utility regions. This decomposition method is based on three steps: interchange forecast, decomposed unit commitment, and power flow reconciliation. This method presents the two major benefits of more accurately reflecting system conditions and reducing computational time by allowing parallelization of the simulation. No hurdle rate or wheeling charge is added to flow power between regions; this assumes more coordination in dispatch than in today's system in some regions.

ReEDS is a zonal model, aggregating actual transmission buses, lines, generators, and loads to a single node for each zone. For the production cost modeling, full nodal detail is maintained. Therefore, new generation capacity, retirement decisions, and transmission expansion must be decomposed from the zonal ReEDS results into the nodal PCM.

The first step to translate a ReEDS result is to determine which units in the PCM are retired. For non-coal units, ReEDS provides a capacity of generation by type for each zone that should be retired. Coal units are tracked individually in ReEDS (as they tend to be larger, and fewer new ones are built), rather than as an aggregated capacity for each zone. Each PCM node is mapped back to a ReEDS zone, and PCM generation capacity within each zone is retired until the ReEDS retirement amount is reached. For non-coal units, units are prioritized for retirement based on their heat rate, retiring the least efficient units first.

The next step is to add new units. Again, ReEDS provides the expanded capacity by type for each zone. That new capacity is broken down into reasonable generator sizes and placed at PCM nodes. Nodes are prioritized for connecting new generation by first adding units to nodes with generation that had been retired, followed by placing units at high-voltage and well-connected (i.e., number of lines and summed capacity of those lines) nodes. New wind and solar locations are determined by reV geospatial tool (Maclaurin et al. 2019) and connected to PCM nodes by placing them at the closest high voltage bus.

Expanded transmission built by ReEDS is also translated to the PCM. We simplified expanded transmission by assuming all new lines are direct current (DC). This reduces the complexity of adding new alternating current (AC) lines, as new DC lines do not impact loop flow on the existing network. However, this does increase the operational flexibility of these lines. The goal of this process is to represent the ReEDS modeled increases to interregional interfaces, and DC lines do that. Bloom et al. (submitted)[14] explore a method to expand AC infrastructure in a zonal-to-nodal translation, but those AC lines do not represent the same new interregional transfer capability. Designing AC infrastructure to expand interfaces while avoiding loop flow constraints for the entire continent is beyond the scope of NARIS. To avoid unrealistic unserved energy because of these AC loop flow constraints (with transformation of the generating fleet compared to today), the flow limits on AC lines and interfaces were allowed to exceed non-emergency ratings for a penalty cost of $12,000/MW.

In reality, the new transmission expansion may be a combination of DC and AC infrastructure, and a variety of transmission or generation infrastructure could alleviate the AC transmission constraints. Detailed, regional power flow studies are needed to determine the local and regional benefits of each option. To test the potential overall cost impact of these two assumptions (DC modeling in production cost tool and penalty on AC violations), we made cost estimates of

[14] "Interconnections Seam Study," NREL, https://www.nrel.gov/analysis/seams.html.

infrastructure to solve the issue in the model. These were both overestimates of potential cost impacts, because the optimal solution would be better than this simplification. For example:

- If we calculated costs to consider the costs of making all AC ReEDS expansion lines into DC (including converter stations), those costs could represent 0.4% of total system costs in the Low Cost VG scenario. This would be an overestimate of the impact, because not all new lines would be DC, but this approach would give us an idea for how significant the assumption could be. This estimate is calculated by multiplying the AC build (in gigawatts) by the cost of the converter stations (80,000 MW * $253,000/MW, the assumed cost of DC converter stations).
- Building new transmission infrastructure to augment every violated line to accommodate its maximum 5-minute violation would add up to 0.1% to the total continental cost in the Low Cost VG scenario (5 TW-mi of violation * $1,347/MW-mi). Some of these costs are already considered in the ReEDS model, which includes costs for intrazonal transmission lines for new generation. Other scenarios would likely have a similar cost increment, making comparisons of scenarios consistent without this cost increment.

End points for the new lines were determined by connecting strongly connected buses within the two regions ReEDS chose to add new transmission capacity between. When possible, because new lines should relieve congestion, buses on opposing sides of an enforced transmission constraint were chosen for connecting the new lines. Given the varying sizes of ReEDS regions, some new transmission capacity between two regions was modeled with multiple new lines, while other regions were modeled with just one new line. The aggregate capacity of the new DC lines between any two regions is set by the amount ReEDS expanded the transmission between them. In reality, paths might be more challenging to build than the paths modeled (e.g., physical or institutional constraints) or less challenging (e.g., reconductoring).

2.1.4 Resource Adequacy Modeling (PRAS)

Resource adequacy refers to the ability of a power system to serve electricity demand with an acceptably low risk of failure that is due to shortfalls in power supply or deliverability. The Probabilistic Resource Adequacy Suite (PRAS [Stephen 2021]) is an NREL-developed collection of tools for quantifying this shortfall risk in terms of standard probabilistic risk metrics, such as loss-of-load hours (LOLH) and expected unserved energy (EUE). PRAS estimates these metrics using a sequential Monte Carlo analysis that performs a simplified power flow to confirm supply exceeds demand for sequences of random generator outage patterns and multiple years of meteorological conditions. Two metrics are reported in NARIS[15]:

- **Loss-of-Load Hours (LOLH)**: LOLH is "generally defined as the expected number of hours per period (often one year) when a system's hourly demand is projected to exceed the generating capacity" (NERC 2018). It is evaluated using every hour of the year, not only the peak hours or days.
- **Expected Unserved Energy (EUE)**: EUE is "the summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of

[15]Definitions are from the 2018 NERC Long-Term Resource
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

demand exceeding the available capacity across all hours" (NERC 2018). For NARIS, annual EUE is reported, representing the sum of expected EUE in all hours of the year. It quantifies both the probability and magnitude of a shortfall occurrence, but as a result is unable to distinguish between a small, likely shortfall and a large, unlikely one. EUE can also be reported as normalized EUE by expressing the expected energy shortfall as a fraction (usually in parts per million, or ppm) of total energy demand in the period; this is convenient for comparing reliability levels across different systems.

For NARIS, PRAS was used to simulate many alternative realizations of simplified annual hourly power system operations over a year. Each realization corresponded to operations under a different collection of representatively-sampled generator unplanned outage profiles. The simulation performs a simplified operational dispatch on every random sample, at every time period. The simplified dispatch constrains the flow between regions to the available transmission capacity, while recording the time and location of events where supply cannot meet demand (see Figure 12 for a diagram of the load balance).

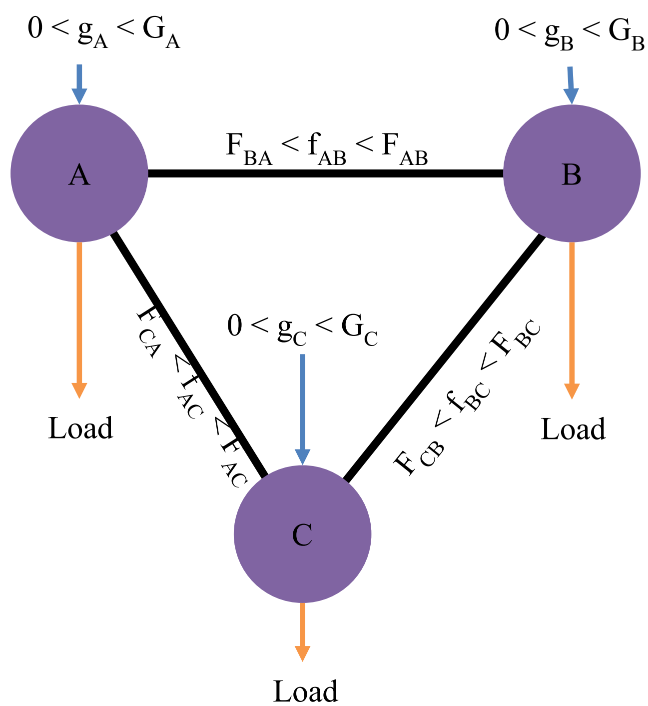


Figure 12. PRAS zonal balancing diagram

PRAS performs an optimized power flow for every sample for each zone, determining whether generation and import supply are sufficient to meet demand (Load) in each zone. Constraints include enforcing that generation (g) is less than generating capacity (G) and interface flow (f) is within flow limits (F_{AC})

By simulating continent-wide system operations under a wide range of generator outage conditions, the risk of encountering a system state in which load is unserved because of a supply or deliverability shortfall can be quantified probabilistically and compared to risk levels of today's grid or industry standards. Figure 13 shows the transmission network representation in the model (which is identical to the ReEDS regions).

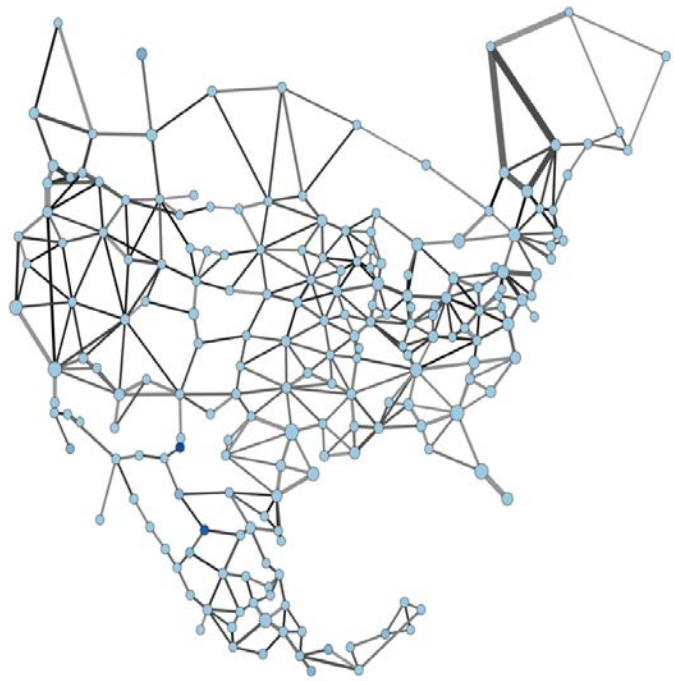


Figure 13. Transmission network representation in PRAS

To perform these simulations fast enough to make simulating tens of thousands of years of operations practical (and to represent a diverse variety of outage patterns), PRAS makes assumptions that are more simplifying than those of nodal static or dynamic power flow model. PRAS does not model power flow between buses, but rather it groups buses into regions (zones). Power transfer between buses within a single region is assumed to take place on a "copper sheet," and neither intraregional transfer limits nor line reliability limitations are considered. Power transfers between regions are modeled with a simple power balance ("pipe-and-bubble") representation constrained by the thermal capacities of interregional lines (in NARIS, all lines were assumed to be 100% reliable). The operational objective is to minimize the system's unserved energy, and unit-level generating costs are not considered.

These simplifications are consistent with commercial resource adequacy models used in industry (e.g., the NERC Long-Term Reliability Assessment [LTRA]). Resource adequacy is a necessary, but not sufficient, condition for power system reliability, and resource adequacy modeling is intended to complement, not replace, other kinds of modeling that can evaluate additional operating considerations such as generator flexibility (ramp rates and unit commitment constraints), AC power flow feasibility, and transient stability issues, albeit for many fewer potential operating conditions.

Capacity expansion models such as ReEDS perform a simplified internal resource adequacy assessment (ReEDS uses a planning reserve margin, with wind and solar resources contributing based on an hourly estimate of the most important hours in each region) to maintain computational tractability. For systems with large contributions of variable and energy-limited resources (e.g., storage), such as those being studied in NARIS, it is desirable to supplement this basic evaluation with a more rigorous probabilistic risk assessment using a dedicated resource adequacy tool such as PRAS. In NARIS, the generation and transmission build-out determined by ReEDS was provided to PRAS, which reported probabilistic risk metrics (loss of load expectation and normalized EUE) corresponding to the system build-out.

PRAS is run hourly with wind, solar, run-of-river hydropower, and load time series data as described in Section 2.2 (the 7-year period represents over 60,000 hours). PRAS was configured in NARIS to ignore monthly energy constraints associated with reservoir hydropower, and this class of resource was treated as capacity that is available to be dispatched. PLEXOS modeling for NARIS demonstrates that hydropower does have the flexibility to contribute significantly during the most important hours (Section 3.3.4). Pumped-storage hydropower and ReEDS-built storage (mostly 4-hour batteries) are dispatched as energy-limited storage resources. These storage resources are optimized for providing capacity; they charge when capacity is available in a region, and they discharge only when needed. Market operations of a storage device could potentially reduce the ability of storage to provide capacity to a region, specifically if forecasting error led to suboptimal storage dispatch.

The PRAS model was developed in part to improve on existing techniques for representing transmission-constrained systems that include significant generation from variable renewable sources that are correlated with load. The key limitations to the PRAS model are the data inputs (which are limited to the 7 years for which we have consistent time-synchronous load, wind, and solar data), and zonal transmission representation. N-1 analysis and dynamic transmission modeling are important for reliability assessment, but these are not considered in adequacy analysis. In this report, the PRAS results for the 2024 model and 2050 in the Low Cost VG and BAU scenarios are described. See Section 3.2.1 for a discussion of the comparison with modeling from NERC and others.

2.2 Data

2.2.1 Wind and Solar Resource

High-quality, highly-resolved wind and solar resource information is important for understanding how the North American grid could evolve and operate in the future. Figure 1 (page 4) shows the wind and solar resource throughout the continent.

The solar data for NARIS (see Figure 1) were developed using the NREL National Solar Radiation Data Base (NSRDB). The NSRDB is based on satellite-based observations of the atmosphere. The database has a 4-km by 4-km spatial resolution and half-hourly temporal resolution covering the 18 years from 1998 to 2017.

We used the Weather Research and Forecasting model (WRF)[16] (Skamarock et al. 2008) to simulate wind speeds for Mexico and Canada by extending existing WRF runs for the United States. The WRF model is a community numerical weather prediction model maintained by the National Center for Atmospheric Research in the United States. It has been successfully applied to wind studies and resource assessments (e.g., Draxl et al. 2013; Carvalho et al. 2014; Garcia-Diez et al. 2012; Ji-Hang et al. 2014; Lundquist et al. 2014). The WRF model allows for accurate

[16] "Weather Research and Forecasting Model," National Center for Atmospheric Research, https://www.mmm.ucar.edu/weather-research-and-forecasting-model.

simulations of winds near the surface and at heights that are important for wind energy purposes. WRF's ability to downscale to required resolutions allows for modeling mesoscale features, such as fronts, sea breezes, or winds influenced by orography, which are all important factors in describing the wind characteristics over the North American continent.

For NARIS, data were simulated over Mexico and Canada and were output every 5 minutes on a 2-km grid following the Wind Integration National Dataset Toolkit setup for the United States for consistency. The details of the setup, and meteorological validation, are available in Draxl et al. (2015). The simulations for Mexico and Canada were different from the Wind Integration National Dataset Toolkit setup in only a few aspects.[17] Figure 14 (page 30) shows the three different domains that were used in the study. All three are publicly available. The vast majority of wind sites in Canada were in Domain A. To ensure consistency with Domain A, the Domain B sites were bias-corrected using time-synchronous information from sites that were nearby in the area overlapping Domain A and Domain B. We bias-corrected the wind speeds and confirmed that annual power output showed no bias between Domains A and Domain B in or near the overlapping region.

Wind and solar data were processed using the NREL System Advisor Model to determine 5-minute resolution generation profiles. All the wind[18] and solar[19] data sets are now publicly available in their resource formats. The cost and performance projections for capacity expansion modeling are consistent across the continent with the 2018 ATB. The amount, location, and transmission spur line costs for new onshore wind and PV resources were assessed using by reV (Maclaurin et al. 2019; Rossol et al. 2021), for input to ReEDS and other models in NARIS. The reV model ensures consistent data are used to source all models from the original, natively formatted wind and solar data. The modeled wind turbine power curve is consistent with improvements made for the 2019 ATB. The wind turbine technology used for the hourly and 5-minute 2050 PCM was based on future technology performance projections from the 2019 ATB (Cole et al. 2019) to better represent the specific power curve of a future (circa 2030) wind turbine. For solar, single-axis panels with an inverter loading ratio of 1.3 were assumed for utility PV (also using parameters from the 2019 ATB) and distributed PV assumes a mixture of orientations, including flat and a variety of tilted orientations based on Sigrin and Mooney (2018). Day-ahead forecasts were used for wind and solar based on the European Centre for Medium-Range Weather Forecasts (ECMWF). The ECMWF historical data were downloaded and processed using identical System Advisor Model parameters. There were no sources of continent-wide real time series data with which to tune any of the state-of-the-art solar

[17] A few changes were needed because of numerical stability and the switch to a newer WRF version. The Mellor–Yamada–Nakanishi–Niino boundary layer parameterization was used. For the sake of numerical stability, we changed the mixing term (dif_opt = 2) and added time off-centering for vertical sound waves (epssm = 0.5); no nudging was applied. Moreover, we upgraded to WRF v3.7.1 with recent versions of netcdf (4.6) with pnetcdf for faster implementations.
[18] "NREL Wind Integration National Dataset," Registry of Open Data on AWS, https://registry.opendata.aws/nrel-pds-wtk/.
[19] "NSRDB: National Solar Radiation Database," NREL, https://nsrdb.nrel.gov/.

forecasting methods (e.g., Dobbs et al. 2017). Also, the WRF model has been extended to improve solar forecasting with WRF-Solar,[20] but it was not used for this project.

Figure 14. The three domains used in NARIS for wind modeling

The wind forecast data were bias-corrected with simple annual correction factors based on the ratio of annual generation in the forecasts versus actual. The forecasted profiles were blended with the actual profiles at various ratios to produce the forecasts described in Section 3.5.5. The 10% mean absolute error (MAE, see Equation 1) wind forecast was created with a 1/3 actual, 2/3 forecast blend (MAE calculated at the plant level and then averaged). This forecast represents improvements that state-of-the-art wind power forecasts have over the raw ECMWF implementation, which is intended for a wide variety of uses and has less-granular spatial resolution than the WRF model. The 5% MAE wind forecast was created with a 2/3 actual, 1/3 forecast blend, and it represents an intraday forecast time horizon:

Equation 1: $$MAE = \frac{\sum_{i=Site}\sum_{t=time}\left|Actual_{i,t} - Predicted_{i,t}\right|}{Number\ of\ Sites \times Number\ of\ time\ intervals}$$

[20] "WRF-Solar," University Corporation for Atmospheric Research, January 24, 2017, https://ral.ucar.edu/pressroom/features/wrf-solar.

2.2.2 Load

Load data were obtained from a variety of sources for 2007–2015. The multiyear time series is important for consistent time-synchronous patterns with the 2007–2013 wind and solar data. The sources of the data were:

- **Independent System Operator (ISO) and Regional Transmission Organization (RTO) Regions:** For ISO/RTO regions, the load data were either downloaded or requested at the most granular spatial resolution available to the public.
- **Utilities:** For utilities outside ISOs in the United States, data were obtained from Federal Energy Regulatory Commission Form 714. For Canada, data were obtained from provincial sources directly for regions outside ISOs.[21]
- **Mexico:** For Mexico, load data from PRODESEN 2018 were used in NARIS.

All load data were cleaned for problems, which were often either erroneous time zone stamps or erroneous data during the hours of switching to or from daylight savings time. The data were extrapolated to 2050 for most scenarios by a simple scalar factor, which was based on extrapolated annual demand projections from the U.S. Energy Information Administration (EIA), Canada's National Energy Board, and SENER (PRODESEN). This means the annual energy demand for all historical meteorological years (2007–2013) is identical for 2050, but the peak demand and hourly shapes are different; in reality, the annual energy demand could vary based on the assumed meteorology. The load factor for each year will be the same because the scalar multiplier is the same for every hour. This will also preserve all correlations between load, wind, and solar for the future year analysis.

The exception to these descriptions is the electrification scenarios, which are discussed separately in Section 3.5.4.

2.2.3 Hydropower

Hydropower generation is a source of flexible, carbon-free generation and storage to the grid. The types of hydropower that exist in North America include run-of-river hydropower (which has power outputs that depend primarily on water inflow at any given time), reservoir hydropower (which can store significant amounts of water and shift energy), and pumped-storage hydropower. The operation of hydropower turbines is very flexible. The overall constraints to hydropower flexibility can be complicated to model, as they come from a variety of both physical and institutional sources (and the constraints are very site-specific). These key sources include:

- **Cascading (Physical):** When hydropower generators exist in a series of cascaded reservoirs in a basin, the inflows at lower reservoirs depend on the outflows from upper reservoirs.
- **Hydrology (Physical):** When and where the water becomes available to the dams is a key constraint on hydropower flexibility and generator outputs. In some seasons, even large reservoirs can fill and need to flow water at high levels at all times.

---

[21] Hourly profiles for Prince Edward Island were taken from the hourly shapes from New Brunswick, scaled to peak load on Prince Edward Island.

- **Flow Requirements (Institutional):** Requirements for water usage from downstream users for agricultural, recreational, environmental, and other needs impact mandatory flow requirements from dams. These detailed constraints are generally not modeled in power systems models, but they are represented with proxy variables for minimum generation, ramp rates, and other characteristics.

The starting point for hydropower dispatch assumptions were the assumptions used in the Eastern Renewable Generation Integration Study (Bloom et al. 2016) for the Eastern Interconnection, the California Low Carbon Grid Study (Brinkman et al. 2016) in the Western Interconnection, and PRODESEN in Mexico. These assumptions were refined based on feedback from the NARIS Technical Review Committee for the PLEXOS modeling. Refinements included:

- Energy limit adjustments for generators in Hydro Québec, Manitoba Hydro, and Bonneville Power Administration
- More-constraining ramp rates for Eastern Interconnection and Hydro Québec generators; for Hydro Québec, this helps act as a proxy for cascading constraints[22] that are not included in the continental model.
- Refinements to the timescale of flexibility (e.g., optimization over a day, a week, or pure run-of-river with no adjustability) at various dams in the Hydro Québec and Bonneville Power Administration areas.

On average, these changes better represent the flexibility of the hydropower generation. See Section 3.4.3 for detailed analysis of hydropower flexibility results from the modeling. Table 6 shows some of the key sources and values for hydropower assumptions in the NARIS PLEXOS model.

Table 6. Hydropower Assumptions

Metric	Eastern Interconnection	Western Interconnection	Québec Interconnection
Water-year used to estimate energy limits (hourly, monthly, or daily)[a]	2006	2005	Multiyear average
Energy limit sources	Eastern Renewable Generation Integration Study (original sources include U.S. EIA, Southwestern Power Administration, Southeastern Power	Western Electricity Coordinating Council and Bonneville Power Administration	Hydro Québec

[22] Cascaded reservoirs have complicated, intertemporal interactions that require significant data inputs and add computational complexities to model. These constraints are typically not included in interconnection-sized production cost studies. In the Western Interconnection, the flexibility limits caused by these types of constraints are often modeled by constraining the outputs of individual dams to historical flows (e.g., treating hydropower as run of river technology). In Hydro Québec, we constrained with a ramp rate to represent the system-wide ramping limitations of a cascaded system. And in the Eastern Interconnection, we added ramping limitations for generators that are not represented in previous studies to address cascading and other flexibility limitations.

Metric	Eastern Interconnection	Western Interconnection	Québec Interconnection
	Administration, U.S. Army Corps of Engineers, and provincial sources)		
Monthly, daily, and hourly (run-of-river) optimization windows (capacity-weighted percentage)[b]	79% monthly 12% daily 9% hourly	50% monthly 11% daily 39% hourly	100% monthly
Ramp rate (Percentage of maximum capacity per minute)[c]	1.1%	0.5%–1.6%	0.2%-0.5%
Minimum generation level range (Percentage of maximum capacity)[d]	0%–20%	0%–45%	20%

The table does not include pumped-storage hydropower.

[a] **Water-Year:** The water-years are intended to be reasonable representations of a "typical" year. It is less important to use time-synchronous data for hydropower than it is for wind, solar, or load, because the hourly shapes of the water flows into a reservoir are not necessarily correlated with the actual power outputs from the dam.

[b] **Optimization Windows:** The optimization windows represent the time-frame which the hydropower generation can shift energy within. A daily limit would limit the total generation from that unit within a day, subject to the other constraints. For the Eastern Interconnection, this does not reflect a plant-specific representation; generic parameters were used until dispatch looked similar to historical dispatch (see below for description). Most Canadian hydropower has more than monthly flexibility; however, interseasonal and interannual flexibility was not studied in NARIS.

[c] **Ramp Rate:** This constrains the ramp rate (rate of change of the power output) of the generators. It is directly comparable to assumed ramp rates for thermal plants in Table 5.

[d] **Minimum Generation Levels:** For the Eastern Interconnection and the Québec Interconnection, a minimum generation value of 20% of maximum capacity was assumed, or the largest value feasible if monthly energy limits require less than 20% capacity factors. See below for more analysis of minimum generation levels by season.

The mixture of flexibility timescale, minimum/maximum generation levels, energy limits, and modeling methodologies leads to different flexibility characteristics at different times of year. To dispatch the hydropower generators with monthly optimization windows, the PLEXOS model runs a simplified, monthly dispatch called the MT (Medium-Term) model. It categorizes every hour of each month into five categories (or time-slices). Next it optimizes dispatch for these time-slices, and it then determines a daily energy limit for each generator. This energy limit is then optimized in the unit commitment model, along with the hydropower with daily energy limits. The hydropower generation is locked in during the unit commitment and does not re-optimize during real-time dispatch. This approach provides a good compromise among model complexity, run time, and representation of reality.

The goal of NARIS is to represent the overall regional character of the dispatch of hydropower generation—not to accurately represent unit-specific detail for every generator. The character of the hydropower dispatch profiles is qualitatively similar to what was seen in U.S. ISOs in 2017, based on figures in the 2017 Hydropower Market Report (Uria-Martinez, Johnson, and O'Connor 2018).

For context, the winter week studied in Section 3.4.3 demonstrate some of the bounds of operation that these hydropower flexibility assumptions provide. In Canada, there is over 50 GW of operating envelope between annual minimum generation levels (which coincide with low-load time periods) and maximum generation levels (which coincide with high-load time periods) in the model. The operating envelope for any given week is closer to 40 GW.

Figure 15 shows the weekly maximum and minimum values of Canadian hydropower generation in the model. This is one way of visualizing the flexibility the model allows hydropower, although there are limitations within this envelope of operation (e.g., ramping and daily/hourly limits). The minimum is on average 50% less than the average weekly operation, while the maximum is approximately 50% higher than average for a typical week. This operating envelope represents a combination of run-of-river constraints, minimum and maximum generation levels at reservoir hydropower, ramping limits, and other constraints. Different regions may have differing levels of flexibility, depending on season, water conditions, and other factors.

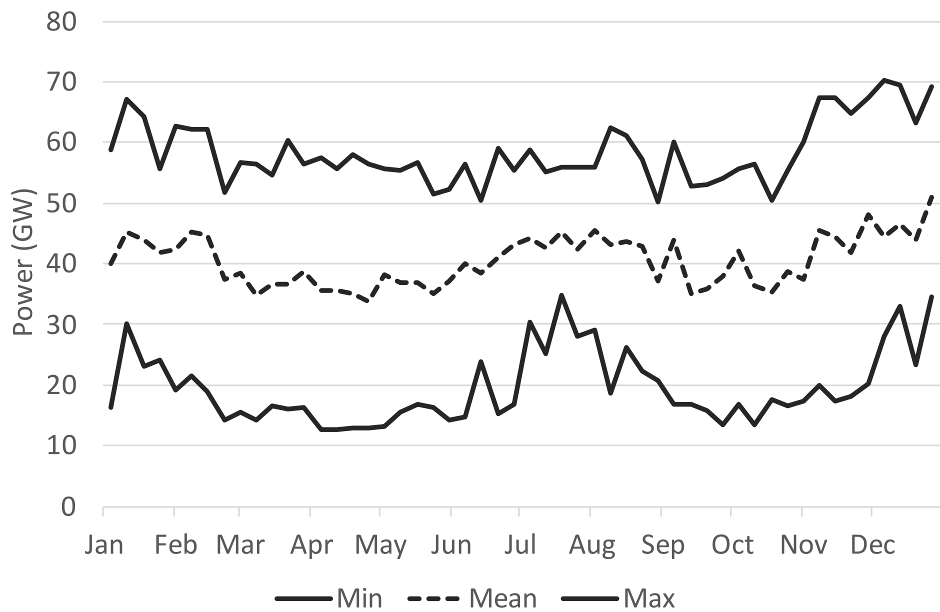


Figure 15. Weekly maximum, mean, and minimum hydropower generation from Canadian generators

These weekly maximum and minimum values show the envelope hydropower operates within Canada. Various factors (including ramping limits, daily limits, hourly limits) further limit the flexibility within this envelope.

To test the impacts of these flexibility assumptions we ran model sensitivities with flexibility eliminated from conventional hydropower resources (treating everything as run of river). Section 3.4.4 presents the results of this analysis, which demonstrate the benefits of hydropower flexibility to a future scenario with very high wind and solar generation.

3 Results

In this section, we discuss the key conclusions of the NARIS work completed for Canada. Although many conclusions are not easily categorized, they are presented in separate sections for improved readability: overview (Section 3.1), adequacy (Section 3.2) , transmission (Section 3.3), flexibility (Section 3.4), and general scenario comparisons (Section 3.5) . All cost outputs are in 2018 USD for direct comparison with the NARIS U.S. report and to avoid the effects of future changes to exchange rates.

3.1 Scenario Overview

Figure 16 (page 36) and Figure 17 (page 37) show the Canadian annual generation and capacity. respectively, by technology type in the core scenarios compared to 2024 in the model. The year 2024 was selected as a near-term year because the composition of the power system in that year is reasonably well known and that is the basis year for the planning cases used to develop some of the models (see Section 2.1.3). The scenarios were designed using traditional planning methods (using regional planning reserve margin constraints in the ReEDS model), and we demonstrated capacity adequacy using stochastic Monte Carlo methods in the PRAS tool.

Consistencies between the scenarios are the major growth in wind generation and the reduction in thermal generation (including coal, nuclear, and natural gas). The largest variation in the core scenarios is the overall increase in generation (mostly from wind) in the Electrification scenario. As noted in Section 1, new hydropower generation is not considered in the core scenarios, but Section 3.1.1 notes that the Electrification scenario would be the most favorable for hydropower development. Another significant difference is the reduction in gas generation in the scenarios that include a more stringent carbon limitation (92% reduction in the CO_2 Constrained and Electrification scenarios versus 80% in the BAU and Low Cost VG). Renewable contribution is high in all scenarios, ranging from 90%–91% in the BAU and Low Cost VG to 95% in the Carbon Constrained and Electrification scenarios. With nuclear, 97% of the generation in the Electrification and Carbon Constrained scenarios is zero-carbon. Eliminating the last few percentage points of CO_2-emitting generation might be the hardest, according to Denholm et al. (2021), although they do not demonstrate that it is impossible to achieve.

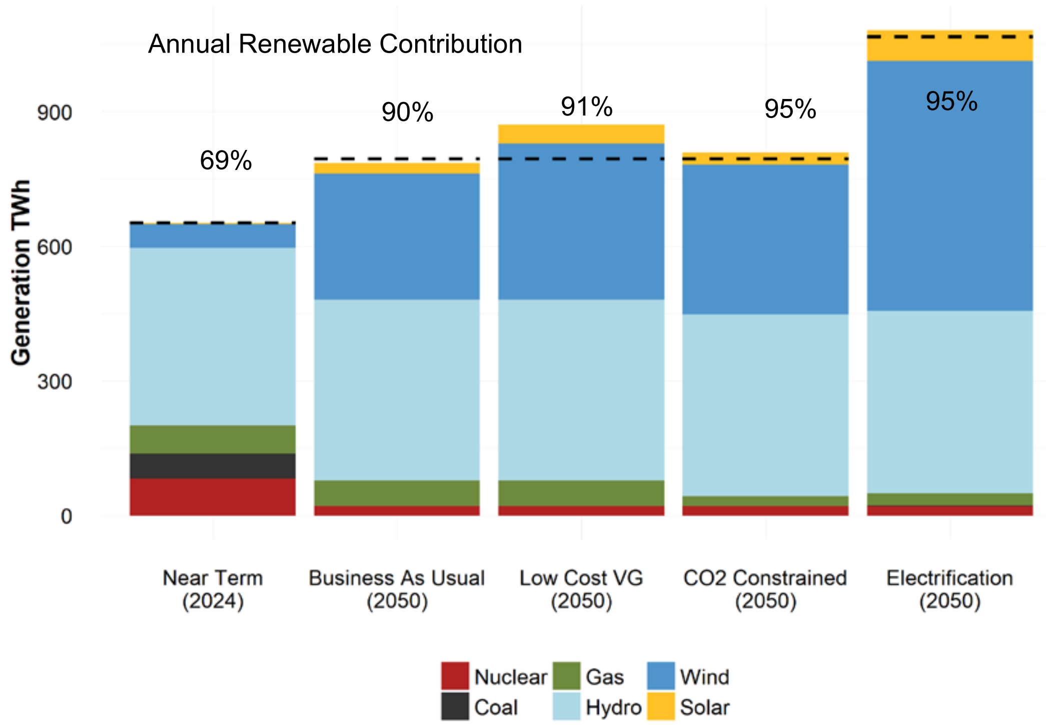


Figure 16. Canadian generation in 2024 and 2050 in the NARIS core scenarios

The dashed lines represent Canadian load (including losses). When the bars are above the load lines, net exports to the United States are happening. There is more discussion of Canadian exports, which vary widely between scenarios, in Section 3.3. Canadian hydropower expansion is explored in Section 3.1.1; it was not considered in these core scenarios because of data availability and consistency concerns. The largest differences between the scenarios are the wind generation levels and demand in the Electrification scenario. This figure represents the ReEDS model results.

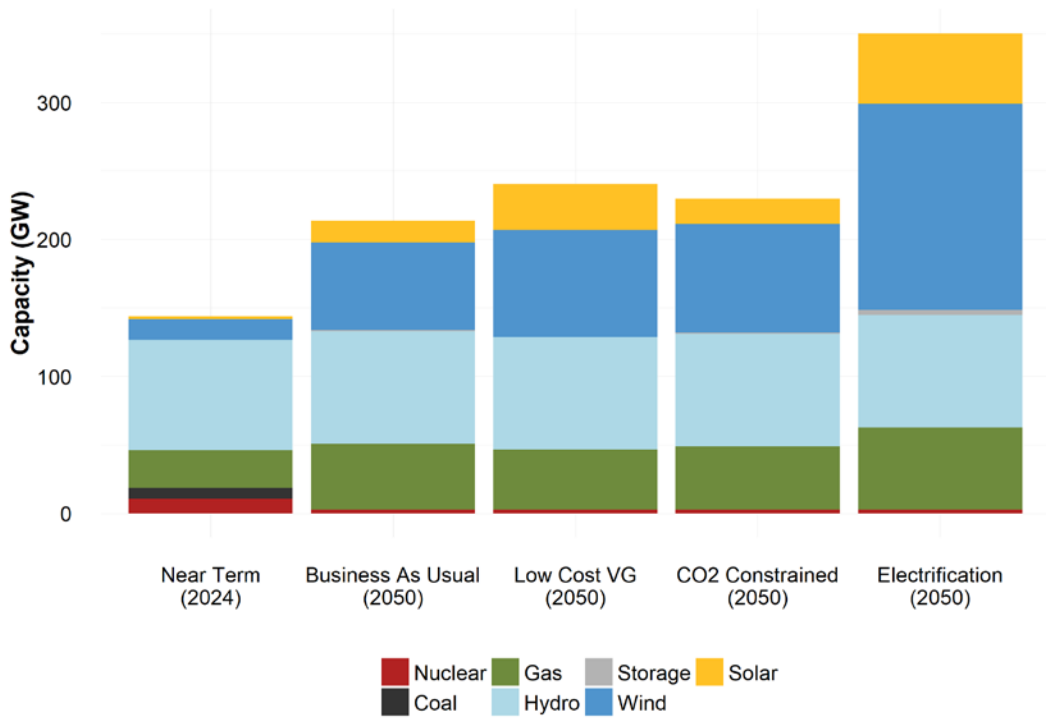


Figure 17. Canada generation capacity in 2024 and 2050 in the NARIS core scenarios

Pumped-storage hydropower is reported in the Storage category throughout the report. Significant capacity of gas exists for adequacy, but it is not frequently operated. The market implications of this are discussed in Section 3.2.3. Wind capacity factors increase by 2050 because of technology improvements (see Section 2.2.1).

Table 7. Canadian Generation Capacity in 2024 and 2050 in NARIS Core Scenarios (GW)

Values are rounded to the nearest gigawatt. Hydropower expansion was not considered in the core scenarios. Rooftop PV values are in parenthesis; the Electrification scenario does not consider new building-level loads in the dGen model. The rooftop adoption ranges between 7 and 32 GW in the cost and policy sensitivities (see Section 3.5.2). As of 2021, the PV capacity in Canada is 3 GW, which is higher than the 2024 projection because of the timing of the data inputs.

Type	Near-Term (2024)	BAU (2050)	Low-Cost VG (2050)	Carbon Constrained (2050)	Electrification (2050)
Nuclear	11	3	3	3	3
Coal	8	0	0	0	0
Gas	28	48	44	46	60
Hydro	80	82	82	82	82
Storage	0	1	0	1	4
Wind	15	64	78	79	150
Solar	2 (2)	16 (8)	34 (23)	19 (8)	51 (8)

Modeled deployment in the CO_2 Constrained and Low-Cost VG scenarios is very similar. The detailed hourly and 5-minute integration analyses focus on the Low-Cost VG scenario. More methodology development is needed to understand the hourly impacts of electrification and how flexible additional electrified end-use demands could be. This scenario is useful for comparison with the others for many key metrics, but we did not do any unit commitment or resource adequacy modeling with it. Future work (along with the recent Electrification Futures Study for the United States[23]) can help address more-detailed issues regarding operations in this scenario. Some technologies, such as nuclear and fossil fuels with carbon capture, have assumed costs that are too high for large-scale adoption in these scenarios. However, cost breakthroughs and newer technologies (like small modular reactors) could change that conclusion. For NARIS, we assumed no breakthrough changes to those technologies to understand how the grid could evolve without large-scale technological breakthrough. Any additional cost breakthroughs would help reduce overall costs compared to these scenarios. Of the wind deployed in these scenarios, 99% continent-wide and 100% in Canada is onshore wind; ongoing changes to the North American offshore wind market and state legislation in the United States will change that conclusion.

Figure 18 shows the fraction of generation coming from renewable generators. Although the scenarios are quite similar in 2050, they do diverge some in the middle years. In the 2030s, the retirement of coal generation makes the carbon limit, both the 80% and 92% reduction targets, nonbinding in many scenarios. On the other hand, less expensive wind and solar in the Low Cost VG scenario leads to higher adoption of renewables earlier than other scenarios. However, the more aggressive carbon limit in the CO_2 Constrained and Electrification scenarios does lead to slightly more variable generation than the Low Cost VG and BAU scenarios by the late 2040s. See Section 3.5 for a discussion of emissions impacts.

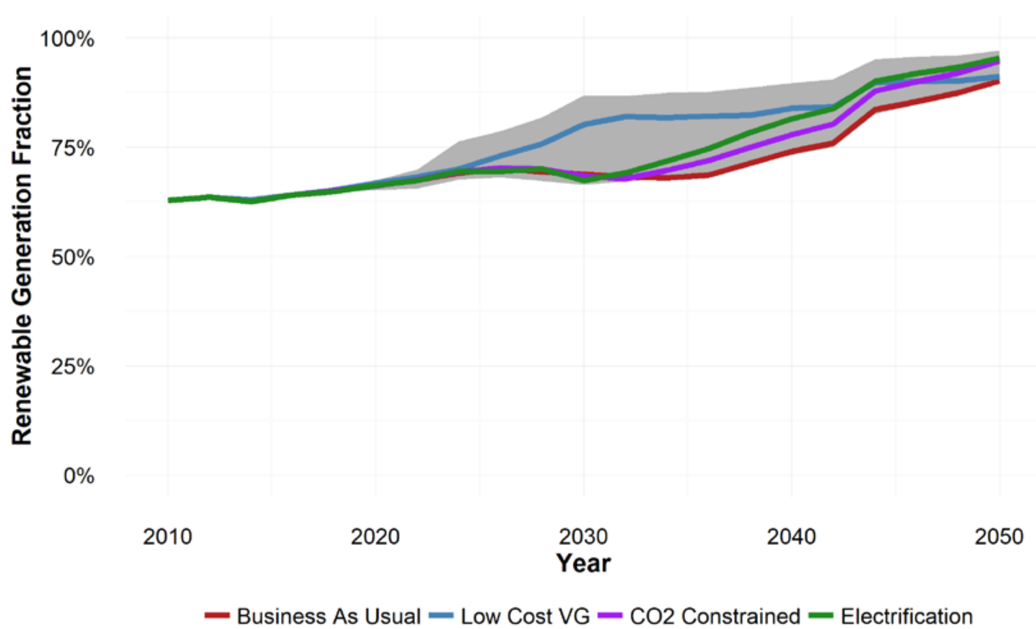


Figure 18. Fraction of generation coming from renewable generators in Canada

[23] "Electrification Futures Study," NREL, https://www.nrel.gov/analysis/electrification-futures.html.

Core scenarios are shown as colored line, and the shaded region represents the range of the maximum and the minimum of all NARIS scenarios (some of which have higher values than the core scenarios shown). The Electrification scenario shows a drop in renewable fraction between 2028 and 2030 as a result of retiring generation that is not replaced with new renewables until 2032.

3.1.1 New hydropower development may be economic if load grows significantly because of electrification.

Because we did not have comprehensive, consistent, site-specific estimates throughout Canada of the cost of new hydropower development,[24] we did not consider new hydropower expansion (beyond what is already planned in the near-term) in the core scenarios. To understand the impact of this assumption, we ran additional scenarios with a generic assumption for hydropower costs and availability. We ran each of the core scenarios with a generic, hypothetical supply of low-cost reservoir hydropower to see what cost it would have to reach to be adopted by the model. The hypothetical hydropower was applied to every province, even though some provinces might not have potential sites for hydropower expansion at these costs. The capacity factor assumptions were based on existing resources within each province. These sensitivities do not provide any insights to specific favorable sites or precise valuations, but they do provide an indication of how the value of hydropower development varies between scenarios. Note that the value of hydropower flexibility is analyzed in other places in this report (including Sections 3.4.3 and 3.4.4).

Table 8 shows the value of the generic hydropower to the model (the maximum of any Canadian region in each scenario). This can also be considered the breakeven LCOE target that the technology would need to reach to be adopted in the model. Note that these LCOEs are much higher than the costs of wind and solar (see 2.1.1), because hydropower provides additional value to the power system that the model captures. Hydropower can be compete with other technologies (e.g., wind and solar) even at a higher LCOE. The LCOE is not used directly in the model; it is used as a metric for comparison. In the nonelectrification scenarios, hydropower costs would need to be 45–50 USD/MWh to be adopted in the model, but in the Electrification scenario, the cost is 70 USD/MWh because of the increased value of capacity (in a carbon-constrained, high-demand scenario) and all energy-related services in the model. This value considers capital costs and operational costs of both generation and transmission.

Table 8. Approximate Value of New Hydropower to the Model, Converted to Value per Megawatt-Hour of Energy

Scenario	Maximum Regional Value of New Hydropower to the Model, per unit of Energy Generated
BAU	\$50/MWh
Low-Cost VG	\$45/MWh
CO_2 Constrained	\$50/MWh
Electrification	\$70/MWh

[24] When possible, using a consistent source of data for all regions is preferred, even for values that are very site-specific, a consistency prevents methodology differences in cost development assumptions from causing changes in model outcomes.

The model runs used to develop these values assumed availability of hypothetical, generic hydropower resource. They can provide for a comparison of scenarios and a cost target for general competitiveness of new hydropower. Although the value is calculated in dollars per megawatt-hour of generation, it represents the total value in ReEDS (e.g., adequacy, energy, and ancillary services). Actual projects might have more value than what is shown here, and additional services (such as frequency support) might also have additional value.

3.2 Adequacy

3.2.1 Resource adequacy can be maintained in low-carbon scenarios through 2050.

To examine resource adequacy in the Canadian power system, we used PRAS to calculate EUE and loss of load hours (LOLH) from selected scenarios as built by ReEDS. As described in Section 2.1.4, PRAS can compute several common resource adequacy metrics. In this analysis we focused on EUE and LOLH for consistency with the NERC 2020 LTRA (NERC 2020). EUE can be aggregated by country or continent; however, the LOLH does not scale with system size, so the reported values are summary statistics of the NERC Assessment Areas. EUE is reported in MWh and ppm, which is the unserved energy as a fraction of the total demand.

We began by assessing the adequacy of the BAU 2024, BAU 2050, and Low Cost VG 2050 scenarios as built by ReEDS. Each scenario was assessed over 7 historical meteorological years, which affects the scenario's load, wind, and solar generation output at an hourly timescale. For each combination of scenario and meteorological year[25], we generated 10,000 sequential Monte Carlo samples of the year and used those samples to calculate EUE for each region in each hour. We report total EUE for each meteorological year, along with the average across meteorological years, for each scenario in Table 9. The NERC 2020 LTRA assessment for 2022 is included for reference. The methods are similar, but not identical, so the numbers are not directly comparable. The general increase in resource adequacy is likely because of the large addition of new wind and solar resources while a significant amount of thermal capacity is maintained.

Table 9. EUE by Scenario and Meteorological Year for Canada, compared to the NERC LTRA

Meteorological Year	BAU 2024		BAU 2050		Low Cost VG 2050	
	MWh	ppm	MWh	ppm	MWh	ppm
2007	195	0.3	145	0.2	68	0.1
2008	173	0.3	92	0.1	33	0.0
2009	212	0.3	66	0.1	25	0.0
2010	210	0.3	64	0.1	33	0.0
2011	189	0.3	44	0.1	20	0.0
2012	215	0.3	45	0.1	12	0.0

[25] Unusual weather events are considered in the 7 years of continental meteorology. Selecting historical years allows greater precision in wind, solar, and load modeling compared to using modeled future data. However, the impacts of climate change on wind, solar, or load patterns are not considered in the present analysis.

Meteorological Year	BAU 2024		BAU 2050		Low Cost VG 2050	
	MWh	ppm	MWh	ppm	MWh	ppm
2013	189	0.3	103	0.1	44	0.0
Annual Average	198	0.3	80	0.1	34	0.0
NERC 2020 LTRA Values for Comparison						
2022 Assessment Year[a]	103	0.5				

The top part of the table presents results from the PRAS modeling for NARIS. EUE values rounded to the nearest megawatt-hour or the nearest 0.1 ppm. This table includes only Canadian regions.

The results demonstrate adequacy generally comparable to or better than the 2020 NERC LTRA for the contemporary grid for the scenarios examined. The NERC assessments were done using industry tools and various statistical methods (depending on the region); some used Monte Carlo methods similar to PRAS. However, PRAS uses consistent simultaneous assessment for all regions for each hour of the simulation to ensure consistency in treatment of both variable renewable and other resources within and between regions. Though there is no national EUE standard in Canada or the United States, for reference, the Australian resource adequacy standard was recently changed from 20 ppm to 6 ppm.[26] EUE in these scenarios is at least 10 times smaller.

Table 10 shows LOLH statistics in several scenarios, compared to the 2020 NERC LTRA. This metric also demonstrates that the NARIS scenarios studied with this model are generally comparable in adequacy to today's grid, and the 2050 scenarios have lower LOLH.

Table 10. Loss of Load Hours (LOLH) by Scenario, Compared to NERC LTRA

Metric	BAU 2024	BAU 2050	Low Cost VG 2050	2020 NERC LTRA (2022 Assessment Year)
Average LOLH of all assessment areas (hours/year)	0.19	0.02	0.01	0.14
Median LOLH of all assessment areas (hours/year)	0.00	0.00	0.00	0.00
Number of areas in green category (below 0.1 LOLH)	6	6	7	6
Number of areas in yellow category (0.1–2.4 LOLH)	1	1	0	1
Number of areas in orange category (>2.4 LOLH)	0	0	0	0

The table compares metrics of LOLH from the PRAS modeling with the 2020 NERC LTRA. All numbers are for Canadian NERC regions only. Most regions have zero LOLH, so the median is zero in all scenarios.

[26] "Energy Security Board Interim Reliability Measures – RRO Trigger," https://energyministers.gov.au/publications/energy-security-board-rro-trigger-rule-change.

To analyze how large the adequacy buffer is on average in each scenario, we repeated the analysis and uniformly scaled the time series of loads in each region to see how many additional EUE resulted. If a load increase yielded only a small increase in EUE, we concluded most hours had a nontrivial adequacy buffer; however, if a load increase yielded a large increase in EUE, we concluded the buffer was exhausted in some hours. This is not always done in adequacy modeling, but it helps identify how overbuilt the system is. There are trade-offs between cost and reliability for customers today and in the future, and these scenarios attempt to build a system that is generally equivalent to today's grid in adequacy.

For each load multiplier (applied by multiplying a uniform scalar value to every hour, preserving the load shapes), we calculated EUE using 1,000 Monte Carlo samples for each meteorological year (2007–2013) for three scenarios (BAU 2024, BAU 2050, and Low-cost VG 2050). We used fewer Monte Carlo draws than the runs for Table 9 and Table 10, above) to reduce computational burden and compare all scenarios with four different multipliers. We then averaged the results over the 7 meteorological years to trace out the relationship between load multiplier and EUE; in particular, we looked for the inflection point that identifies the load multiplier for which most hours shift from having a buffer to having no buffer (Figure 19). This analysis shows that both 2050 scenarios stay below 10 ppm EUE, with a load multiplier of 1.15 (a 15% increase in load).

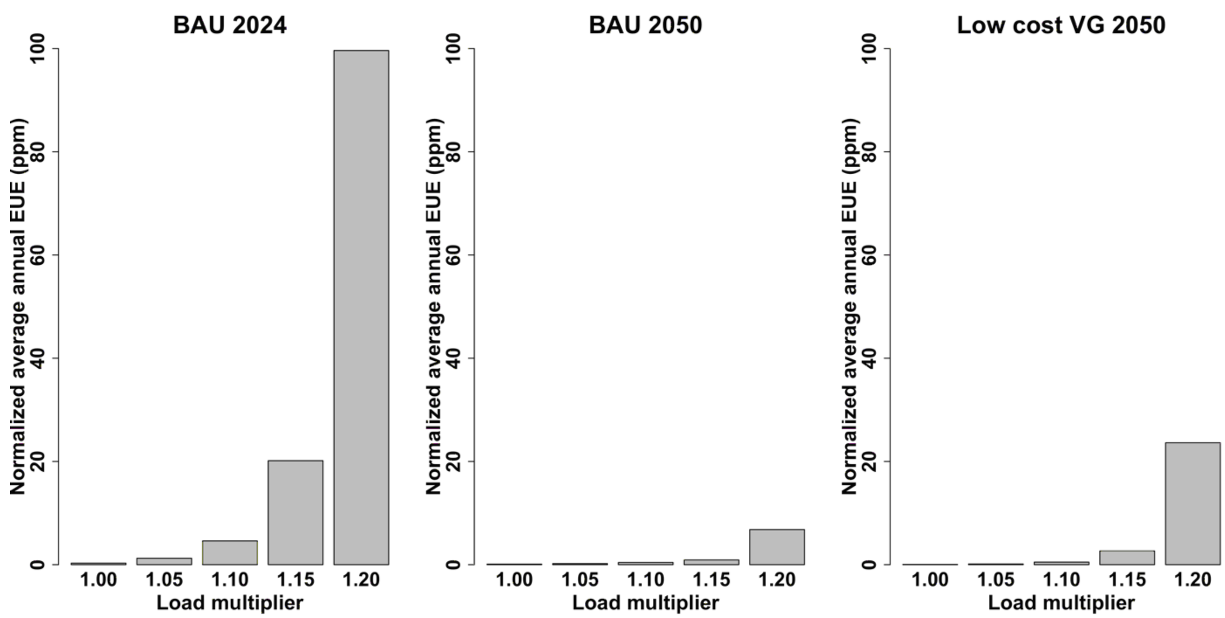


Figure 19. Normalized average aggregate EUE (ppm) by scenario and load multiplier for Canada

Each bar is the average EUE over the 2007–2013 meteorological years. The indicated load multiplier is applied uniformly to each hour of the study year. Note that loads could increase by 15% in the 2050 scenarios and still maintain EUE below 10 ppm.

The key caveats regarding the findings of resource adequacy include that:

- The PRAS model assumes zonal transmission simplifications (in line with industry standard for adequacy models).
- As an adequacy model, PRAS does not consider unit commitment or forecast errors—only whether capacity is sufficient to serve the load in each region at each simulated hour (which is also in line with industry standard for these models).

3.2.2 Adequacy is provided primarily by hydropower, thermal, and wind in these scenarios.

Figure 20 shows the contribution of technologies to energy and capacity adequacy (both summer and winter) based on the ReEDS modeling outcomes. For wind and solar, ReEDS considers the coincidence between hourly generation patterns and load in each region (see Section 2.1.1). The PRAS resource adequacy tool provides additional evidence that these results produce an adequate system, subject to the caveats above.

For Canada, hydropower provides a similar contribution to energy and adequacy: approximately half of the total. Although hydropower energy limits are lower in late summer (when load is still high for summer peaks), the capacity is still generally available. Wind provides more energy than adequacy because on average, the wind generates less during peak load hours. Wind generation is more coincident with winter peaks than summer peaks, leading to more planning reserve contribution in winter. Solar provides a similar contribution to both summer planning reserve and energy. Although solar is very well correlated with summer peak loads, additional contributions from solar eventually shift the net load peak to approximately sunset in many regions. Solar is poorly correlated with winter peak loads, as these often occur during dark hours. Thermal generators provide less energy but significant adequacy to the grid in both seasons (see Section 3.2.3 for a discussion of thermal generator operation). This is because these generators have non-zero marginal cost, and many are primarily providing adequacy and dispatched after the zero-marginal-cost renewable sources. Section 3.2.3 has a discussion of thermal generators operational patterns.[27]

[27] Although there is not significant storage deployment in most scenarios in Canada, the storage category is a combination of pumped-storage hydropower and batteries with 4-hour duration. See Section 3.4.5 for a discussion of scenarios with significant deployment. Recent work by Frazier et al. (2020) characterized impacts of storage duration on planning reserves for a variety of scenarios and modeled most of the additional storage resources as 2-hour and 4-hour batteries. At higher levels of renewable generation and storage deployment, longer-duration storage becomes more relevant.

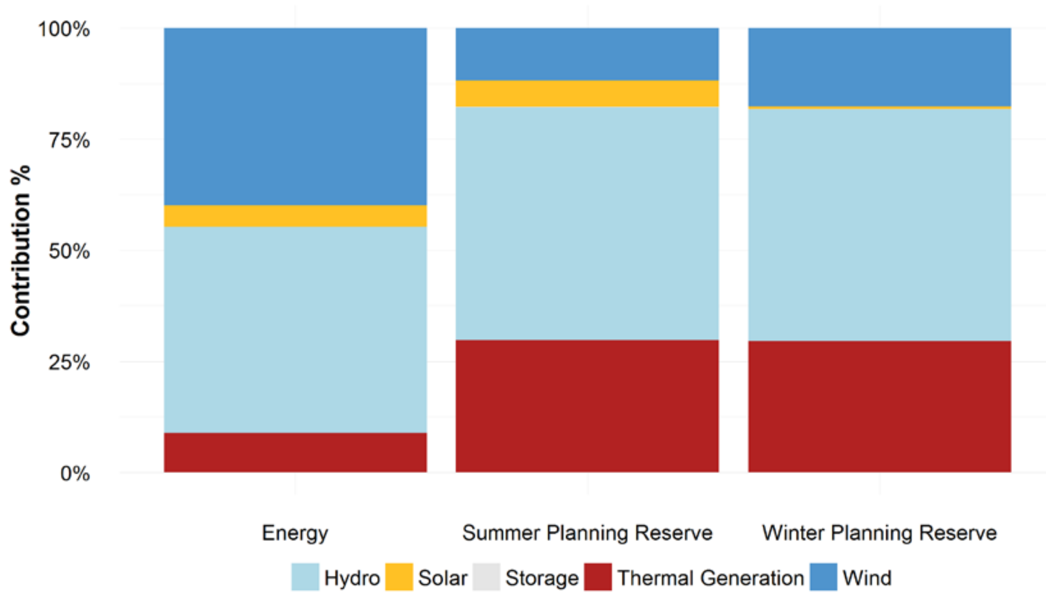


Figure 20. Canada contribution of different technologies to energy and planning reserve in Low Cost VG scenario, 2050

Energy and planning reserve requirements are all different, so this plot shows the ratio for comparison of technologies. Though hydropower provides similar energy and planning reserves, wind provides more energy than planning reserves, and thermal generation provides more planning reserve than energy.

Figure 21 through Figure 23 show the energy generation and planning reserve procurement (including exchange of energy and capacity) by province or region. In general, the regions show similar patterns between energy and planning reserve. Regions where the energy or planning reserve is higher than the dashed line represent regions where power or capacity is being exported, and regions lower than the dashed line are importing. Importing capacity represents transfers similar to those counted by NERC in the LTRA as Net Firm Capacity Transfers toward resource adequacy. They also represent physical transfers of resources that are owned or operated by a balancing authority in one region but physically exist in another region. The ReEDS model does not distinguish between these two categories and does ensure the physical deliverability (with zonal transmission representation) of both energy and capacity. Many regions in Canada and the United States do not import capacity today (i.e., they self-supply), but the model assumes all regions can import planning reserves to find the cost-optimal solution. The energy plot represents the annual totals, snapshots in time can look significantly different. See Section 3.3.2 for a discussion of power flow in the PLEXOS modeling for this scenario.

On average, Canada sends energy to the United States in the Low Cost VG scenario (70 TWh in the ReEDS model). This varies between the scenarios and is examined in Section 3.3. Although this energy comes from a variety of provinces, several provinces are importers. Summer planning reserve follows a similar pattern, although all provinces are exporters except Alberta. Almost all the United States is summer peaking, providing opportunity for winter-peaking regions in Canada to send excess capacity. However, climate change or electrification could affect the seasonal peaking patterns. Winter planning reserve is higher for most regions, and the exported capacity during this season from Canada is lower. The U.S. summer-peaking regions can help by sending capacity during winter. Alberta imports of energy and planning reserves come from both British Columbia and the United States. All scenarios assume typical water conditions; drought impacts on the sharing of planning reserve requires more study. Although these plots show the Low Cost VG scenario, the other scenarios (except the Electrification scenario, which has more wind and solar generation) have generally similar breakdowns by technology (with lower renewable contributions in the case of BAU).

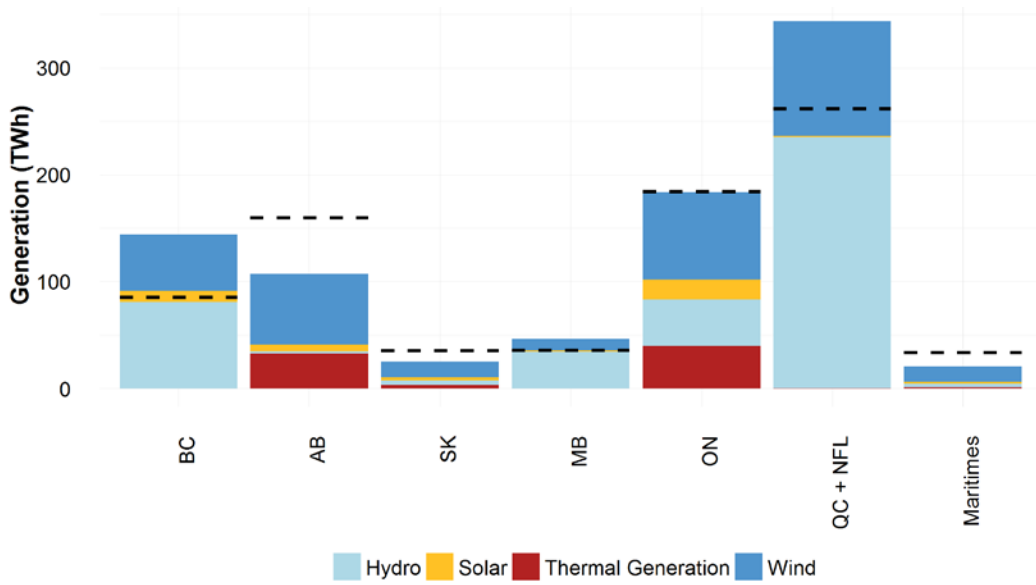


Figure 21. Energy generation in Low Cost VG scenario, 2050

The dashed lines represent the electricity demand for each region (including losses). Regions with bars above the dashed lines are exporting, and regions below the dashed lines are importing. This is a ReEDS model result.

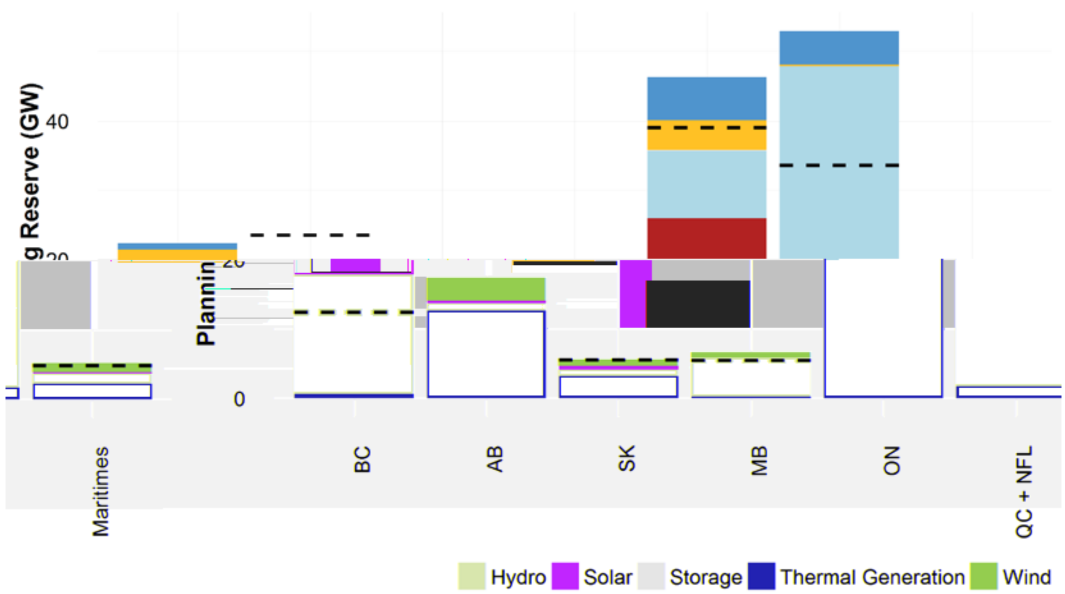


Figure 22. Summer planning reserve in Low Cost VG scenario, 2050

The dashed lines represent the planning reserve requirement for each region. The bars represent the contribution of each resource type to the planning reserve requirement. If the bars are above the dashed line, the excess can be exported to regions that need additional planning reserve. This is comparable to Net Firm Capacity Transfers that NERC includes in the LTRA.

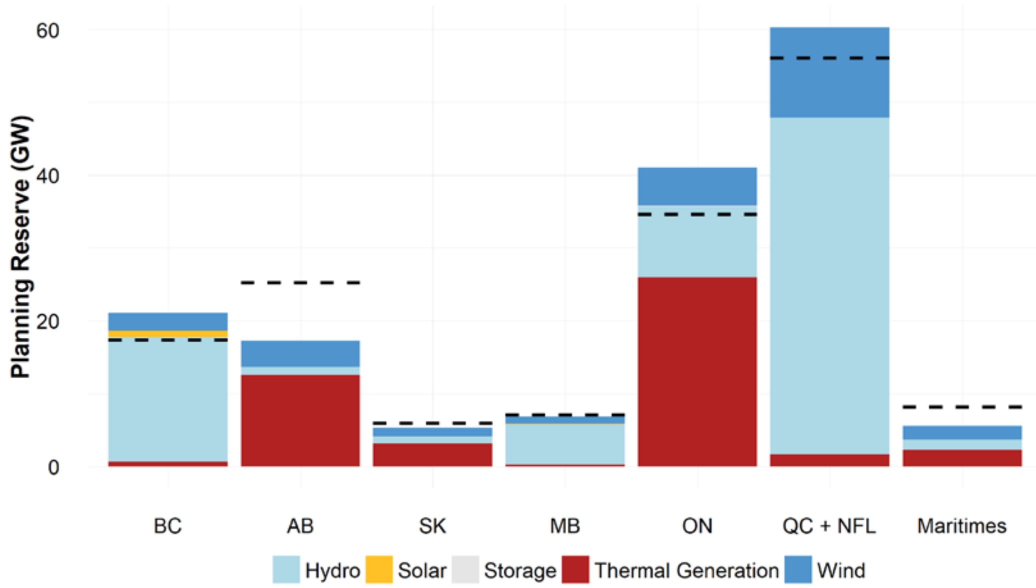


Figure 23. Winter planning reserve in Low Cost VG scenario, 2050

The dashed lines represent the planning reserve requirement for each region. The bars represent the contribution of each resource type to the planning reserve requirement. If the bars are above the dashed line, the excess can be exported to regions that need additional planning reserve. This is comparable to Net Firm Capacity Transfers that NERC includes in the LTRA.

Note that shifting demand patterns (or wind, solar, and hydrological flows) that are due to climate change were not in the scope of NARIS, and they could lead to changing summer and winter peak demand requirements across North America, driven by electric heat and air conditioning.

Figure 24 shows the evolution of winter planning reserve needs in Canada through 2050, along with the renewable contribution to the planning reserve need. Planning reserve need grows by approximately 25% (from 2020), and the additional planning reserve is met almost entirely by additional renewable generation[28] in all scenarios. The contribution of thermal generation remains similar to that of the contemporary grid. In the scenario with low-cost storage, storage also plays a noticeable role and thermal generation plays a smaller role. Storage can provide a variety of services to the grid, including contribution to planning reserve, operating reserve, and energy arbitrage. For more discussion of the Low-Cost Storage scenario, see Section 3.4.5.

[28] Most of the winter planning reserve increase from renewables is due to wind; hydropower expansion that is not considered in the core scenarios could also contribute, especially in the electrification scenarios.

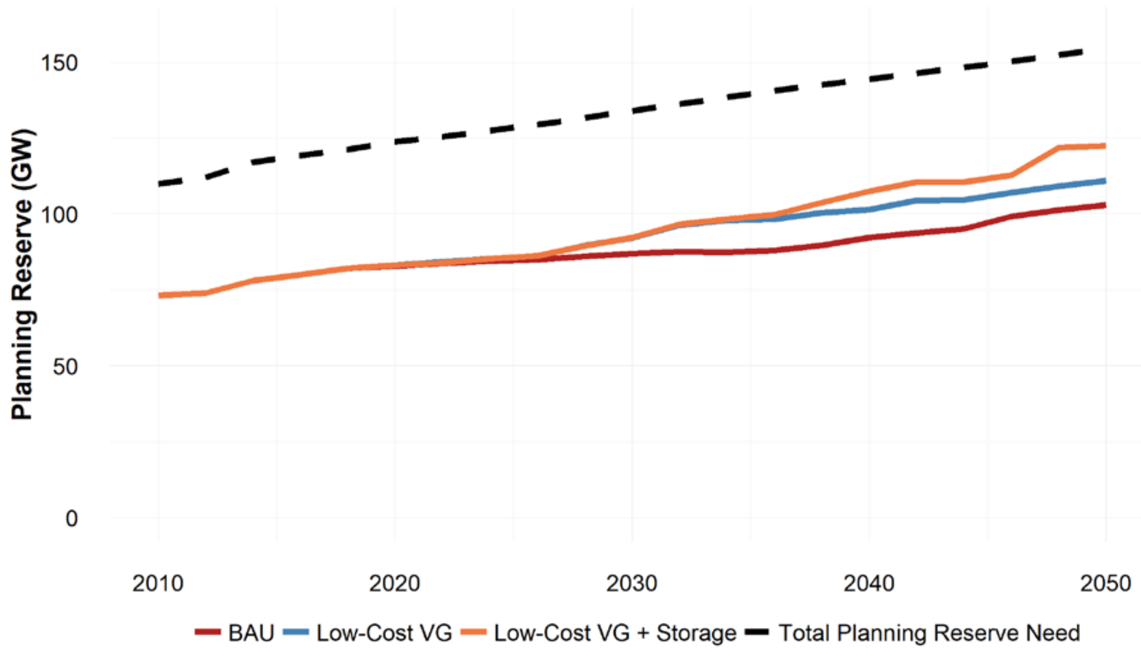


Figure 24. Contribution of renewable generators to winter planning reserve needs in Canada

Hydropower capacity currently serves more than half of the firm capacity needs in Canada; by 2050, all renewables (and storage) make up approximately 70%–80% of the firm capacity needs in the NARIS scenarios. Thermal capacity continues to play a role in resource adequacy to fill the remaining firm capacity needs.

3.2.3 Thermal generation provides more adequacy than energy in future scenarios.

Thermal generation, while serving a smaller portion of energy needs, is important in these scenarios for both energy and adequacy. If other scenarios or sets of assumptions were considered (e.g., technology costs or lower carbon limits), storage or hydropower could potentially fill more of that role. In the 5-minute PLEXOS modeling for the Low-Cost VG scenario (2050), average gas capacity factors in Canadian provinces with significant capacity are 37% in Alberta, 16% in Saskatchewan, and 10% in Ontario. The thermal generators are helping to provide adequacy during key hours when wind and solar generation are low and load is still high. For many of the rest of the hours of the year, the low-marginal-cost resources (hydropower, wind, solar) are providing most of the energy.

Figure 25 shows the duration curve of gas combined cycle and gas combustion turbine generation in the Eastern Interconnection and the Western Interconnection (all of the Western Interconnection gas is in Alberta) from the PLEXOS Low Cost VG 2050 scenario. Nuclear generation patterns are not presented here because they were assumed to be online and generating at maximum capacity whenever they are not on outage in the model. The modeling respects minimum generation levels for each generator at each 5-minute operating interval. At times, few or no fossil-fueled generators are online. It was assumed for NARIS that interconnection-wide frequency support could be provided by technologies like nuclear, hydropower, synchronous condensers, and advanced inverters; if additional generation were required for frequency support, this would increase curtailment.

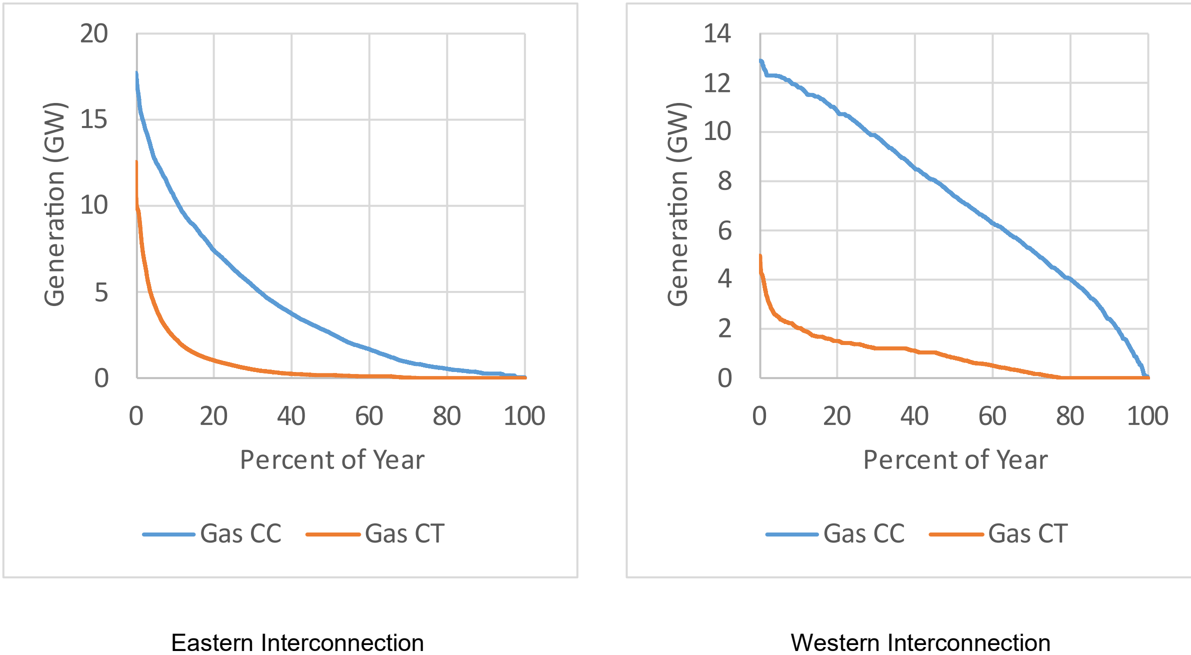


Figure 25. Gas generation utilization in Low Cost VG scenario in 2050 in the Eastern Interconnection (left) and Western Interconnection (right)

Figure 26 through Figure 28 show summaries of the capacity factor of the all the plants in Canada in the Low-Cost VG scenario. The capacity factor of most gas combustion turbines is less than 10%. In the Eastern Interconnection, a significant number of gas combined cycle generators have capacity factors near zero. The Western Interconnection combined cycle units have generally higher capacity factors; these units are mostly in Alberta, which is an overall energy and capacity importer (see Section 3.2.2).

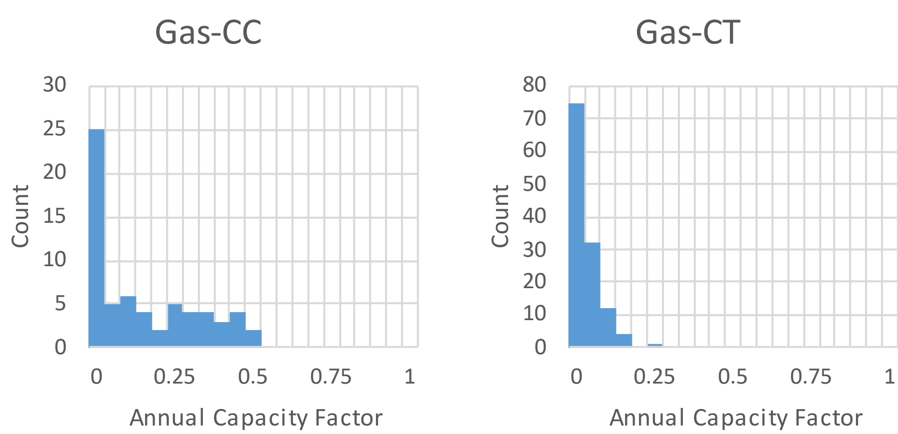


Figure 26. Gas generation utilization in the Canadian Eastern Interconnection (Low Cost VG scenario, 2050)

The count represents the number of units in the model in each capacity factor range.

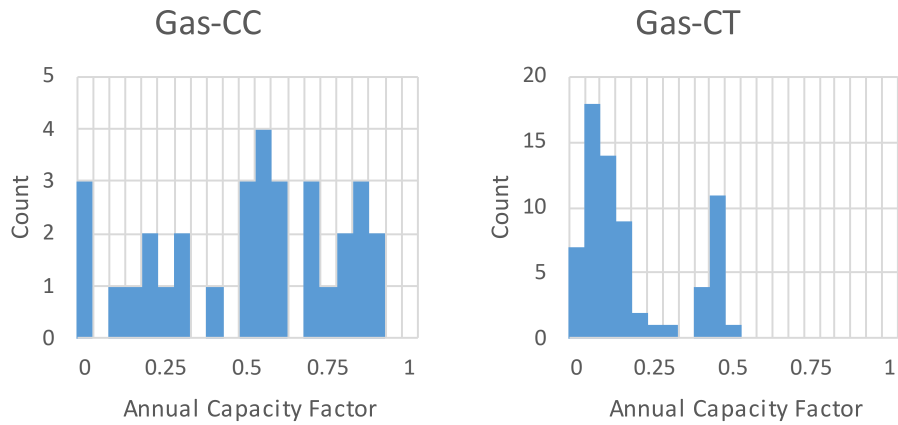


Figure 27. Gas generation utilization in the Canadian Western Interconnection (Low Cost VG scenario, 2050)

The count represents the number of units in the model in each capacity factor range.

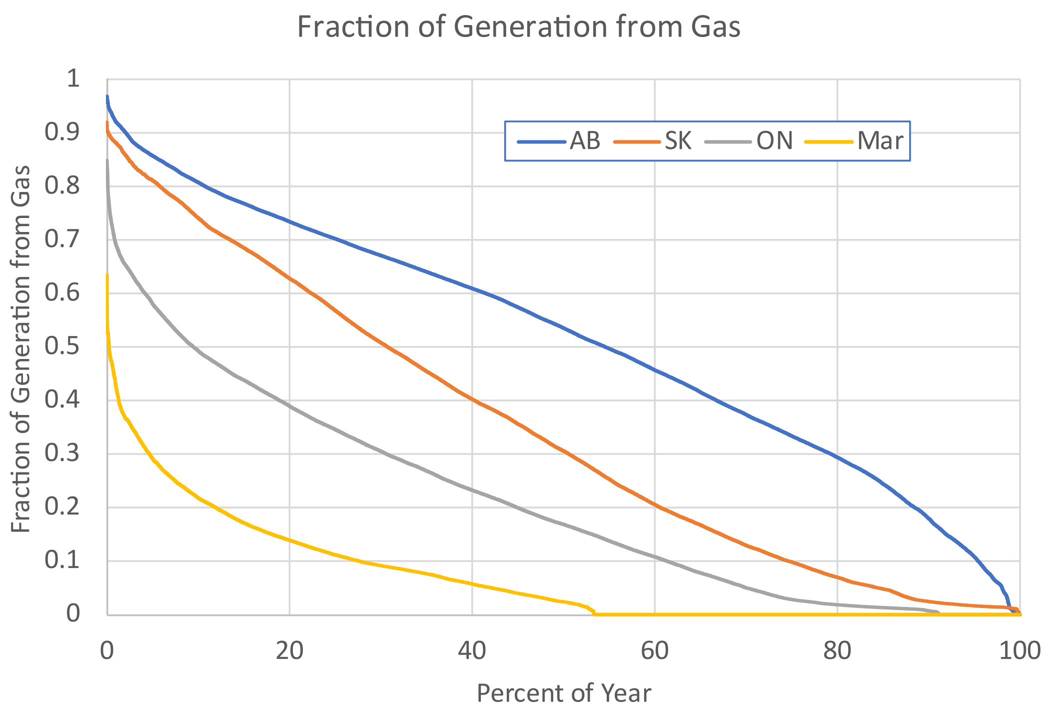


Figure 28. Fraction of generation from gas by province or region (Low Cost VG scenario, 2050)

Although thermal generators produce less energy in these scenarios they do today, they still have a role to play in adequacy for the future system studied in these scenarios. Scenarios with greater deployment of wind, solar, and other zero-carbon resources than the NARIS scenarios might rely more on storage and demand response and less on coal and gas generation for adequacy. In NARIS, we did not attempt to analyze whether revenues would be sufficient for these generators to continue operations. Some compensation method (whether in energy market, capacity market, or regulatory) would have to exist for these generators to be available. The cost of building these units, however, is considered in the capacity expansion modeling as part of the overall cost optimization. There can be generators that are system cost-optimal that are not economically viable in various market structures.

3.3 Transmission

In this section, we discuss some of the transmission-related outcomes of the modeling. including the value of transmission and results from ReEDS and PRAS (Section 3.3.1) and utilization and the results from the PLEXOS modeling (Section 3.3.2). Although this report focuses on Canadian results for NARIS, many of the transmission maps and results are continent-wide for context.

3.3.1 Cooperation and transmission between regions and countries leads to economic and adequacy benefits.

Figure 29 shows transmission investments by scenario, broken out by whether the additional capacity crosses the U.S. border. From this result, we see that transmission capacity increases with wind and solar contribution. The CO_2 Constrained scenario leads to higher transmission investment than the Low Cost VG scenario (despite a similar VG contribution) because variable generation technologies have higher costs in the CO_2 Constrained scenario, thus shifting the optimal balance between transmission and VG investment. As a result, VG is sited at more-optimal locations in the CO_2 Constrained scenario (possibly requiring more transmission), whereas VG can be sited at less-optimal locations closer to load centers in the Low Cost VG scenario. The expansion between the United States and Canada varies between 10 GW and 20 GW, approximately doubling today's capacity in the core scenarios (note that Figure 29 shows the capacity multiplied by distance).[29]

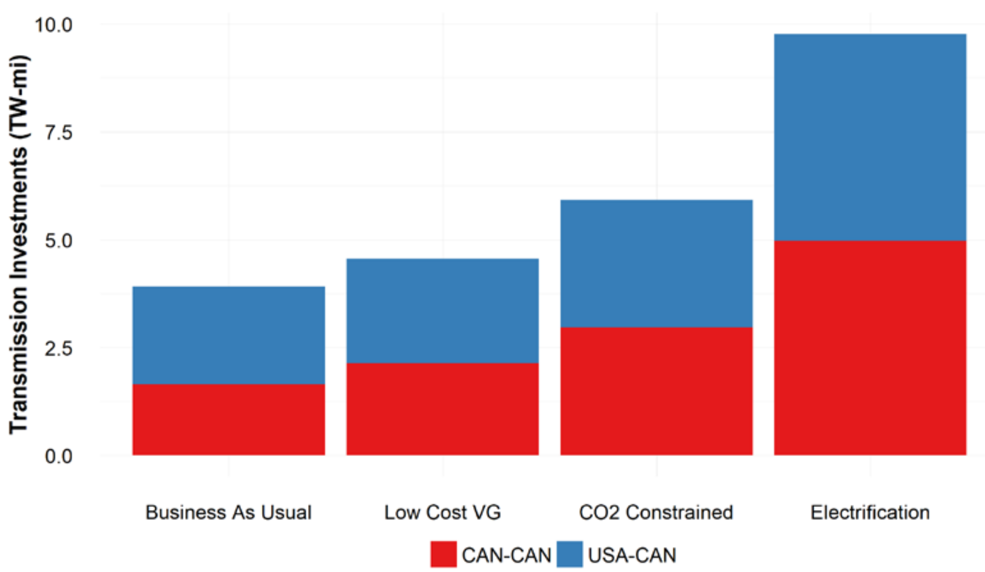


Figure 29 Added transmission capacity in the core scenarios (measured in terawatt-miles of interface expansion)

A terawatt (TW)-mile of transmission is the capacity of the line (or interface) multiplied by the distance. The Electrification scenario has significantly higher load, leading to higher infrastructure build. A detailed comparison is available in Section 3.5.4.

[29] There were approximately 18 GW of capacity between the United States and Canada in 2020.

Figure 30 shows maps of the transmission expansion in the core scenarios based on the ReEDS generation and transmission co-optimization. In all four cases, the model deploys new transmission infrastructure in a variety of regions throughout the continent. Although many of the interfaces are developed in all scenarios, some (including the existing large paths from northern Québec and Labrador into southern Québec that connect hydropower resource with demand) are developed only in the Electrification scenario, where almost twice as much new wind capacity is built than is built in the other scenarios (see Section 3.5.4).

The transmission expansion in the model is part of a co-optimization of generation and transmission resources. Differences in resource quality or cost assumptions could lead to differences in the optimal build-out of renewable generators and transmission infrastructure both. As seen in Figure 30 (page 52), however, much of the transmission that is built in the model is robust to a variety of scenarios and the assumptions we varied.

To understand the importance of this transmission to costs and other outcomes, we ran the ReEDS model with a variety of limitations on transmission expansion. The difference in total system costs between the constrained and unconstrained scenarios demonstrates the value to the system of the changes. We explored the following changes with scenarios (as identified in Section 1.2):

- **International Transmission Expansion:** This comparison estimated the value of allowing new international transmission capacity by comparing each core scenario with a corresponding scenario that disallows transmission expansion across national boundaries (core scenario versus No Cross-Border Expansion scenarios in Section 1.2).
- **Interregional Transmission Expansion and Coordination:** This comparison estimated the value of interregional transmission capacity by comparing a scenario with limited transmission growth and its corresponding core scenario (core scenario versus No Cross-Border Expansion Uncoordinated scenarios in Section 1.2). The limited-growth scenario was created by increasing transmission costs in the optimization, but this increase was not included in cost reporting in Figure 31 so that the system costs were directly comparable to the core scenarios and it represented a scenario with very low transmission build-out.
- **Interregional Transmission Expansion and Coordination with HVDC Macrogrid:** This comparison is similar to the one above, but it compared the core scenarios with limited transmission growth to the corresponding core scenarios with a predesigned HVDC macrogrid shown in Figure 32 and described later in this section (Macro Grid versus No Cross-Border Expansion Uncoordinated scenarios in Section 1.2).

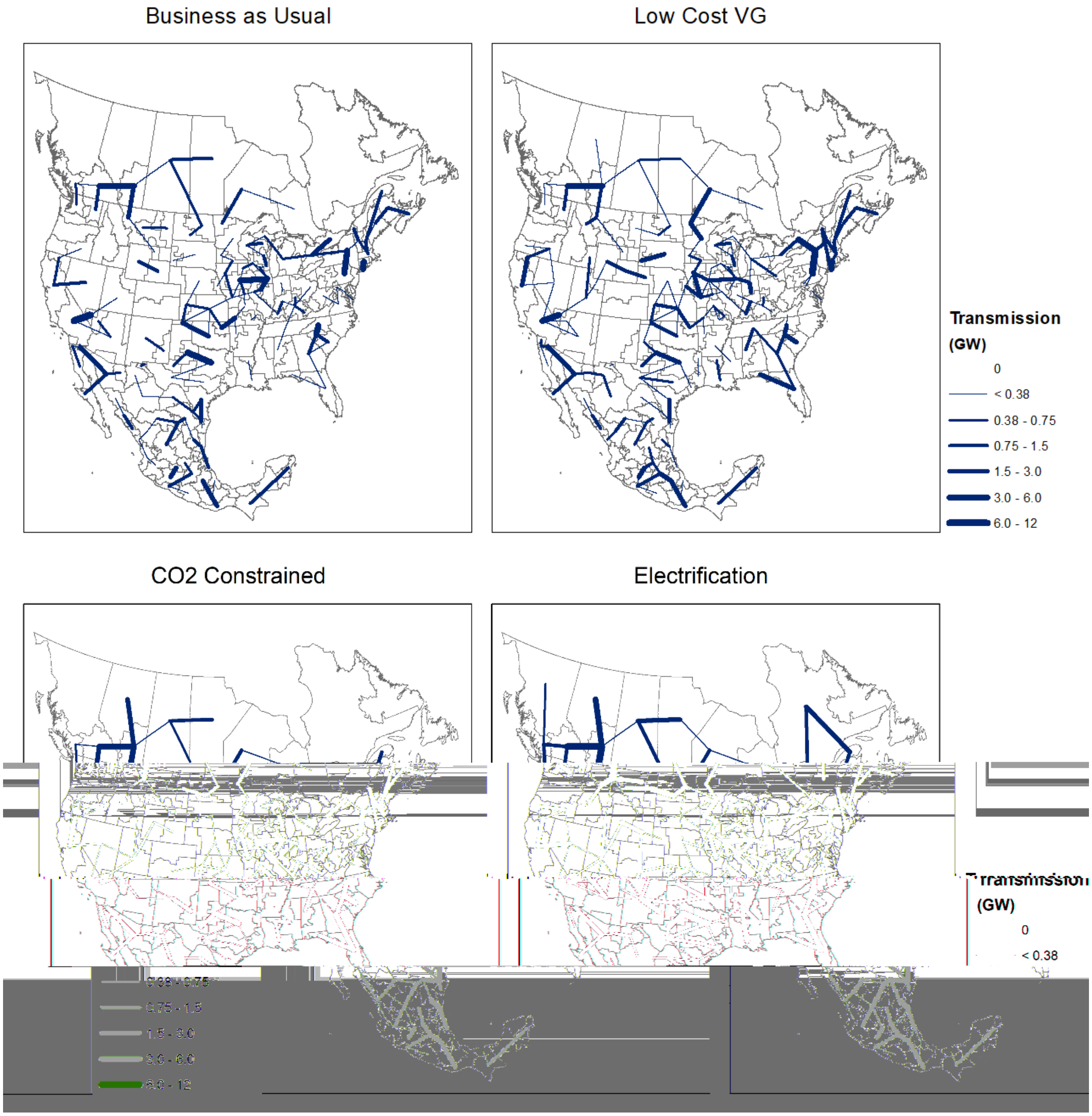


Figure 30. New transmission capacity in the core scenarios

The lines on the maps represent transmission interfaces between the zones in the model, and they typically represent aggregated transmission lines.

Figure 31 shows the value of enabling each of these transmission assumptions in the model (measured as the reduction in overall system costs in ReEDS). The pattern between scenarios is similar to the overall transmission infrastructure build (Figure 29). The net value of international transmission expansion (mostly between Canada and the United States) is $10 billion–$30 billion in all the core scenarios except BAU.[30] Benefits of increased transmission infrastructure would also occur after 2050, and those are not captured here but they represent the sum of all benefits from 2020 to 2050 in 2018 USD values. The net value of interregional transmission ranges from $70 billion to $180 billion in the core scenarios, with the higher values corresponding with scenarios with more transmission build and higher wind and solar generation levels. The macrogrid scenarios showed that requiring the model to build a macrogrid with 2,700-MW HVDC lines (and allowing additional AC builds) would have overall net value similar to the interregional value when the model optimizes the build ($60 billion–$170 billion versus $70 billion–$180 billion). Although the net value of the macrogrid was lower than the net value of the optimal interregional expansion in the model in each scenario, some benefits of the macrogrid are not well captured in the modeling. The macrogrid benefits that are not fully considered in this modeling include self-contingency, controllability, and dynamic performance benefits. The benefits of interregional transmission (which includes international) are significantly higher than international transmission alone is because most interregional interfaces are not between countries.

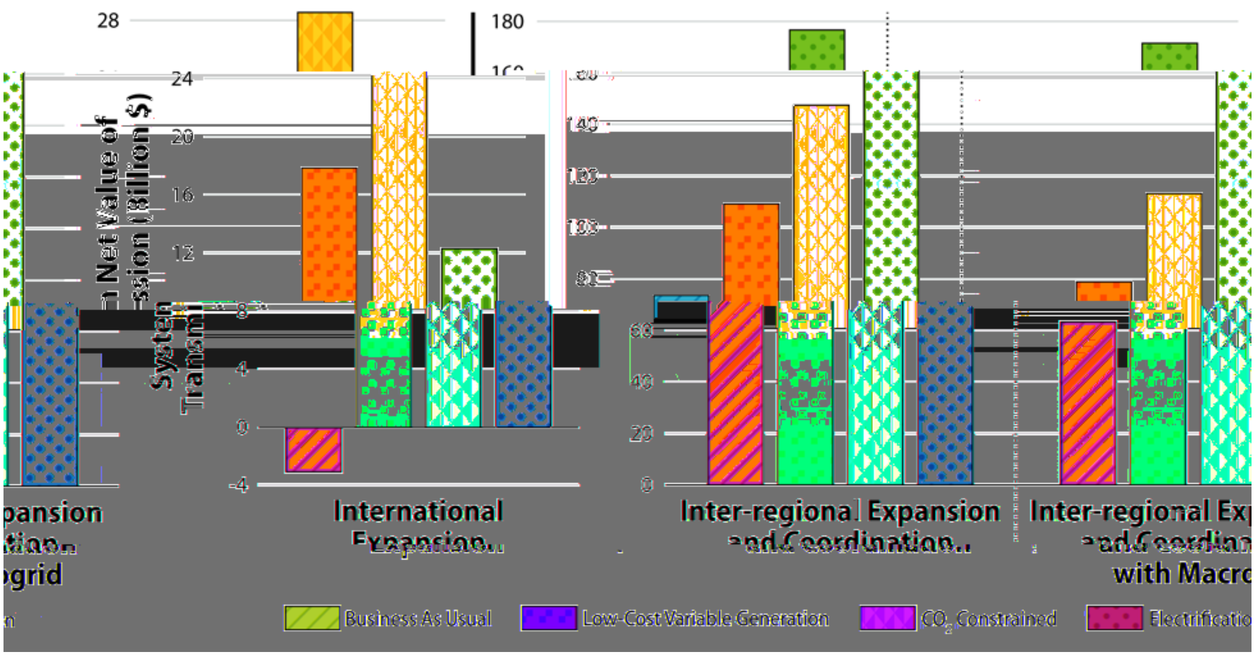


Figure 31. Continent-wide net value of transmission expansion

This plot shows the net value (2018 USD) of allowing different transmission build assumptions in the model. It shows international transmission expansion worth $10 billion–$30 billion, interregional expansion (with or without a macrogrid) worth $60 billion–$180 billion. Note that the macrogrid has additional benefits (e.g., self-contingency and controllability) not fully captured in this modeling.

[30] The BAU scenario had nationwide carbon limitations in Canada but only state limitations on carbon in the United States. This could possibly undercut some of the value of transmission expansion, as Canada had limited ability to import anything from the United States in this scenario.

Figure 32 shows the macrogrid studied in NARIS, which is a predesigned HVDC network that spans most of the United States and some of Canada. It expands on the work done in the U.S. Interconnections Seam Study[31] to include a likely high-value branch into Canada, as designed with help from the NARIS Technical Review Committee. These model runs might not provide sufficient evidence to conclude that the optimal AC build is better than the HVDC macrogrid (or vice versa), but both scenarios offer more than $100 billion in savings than an uncoordinated build (with less transmission expansion).

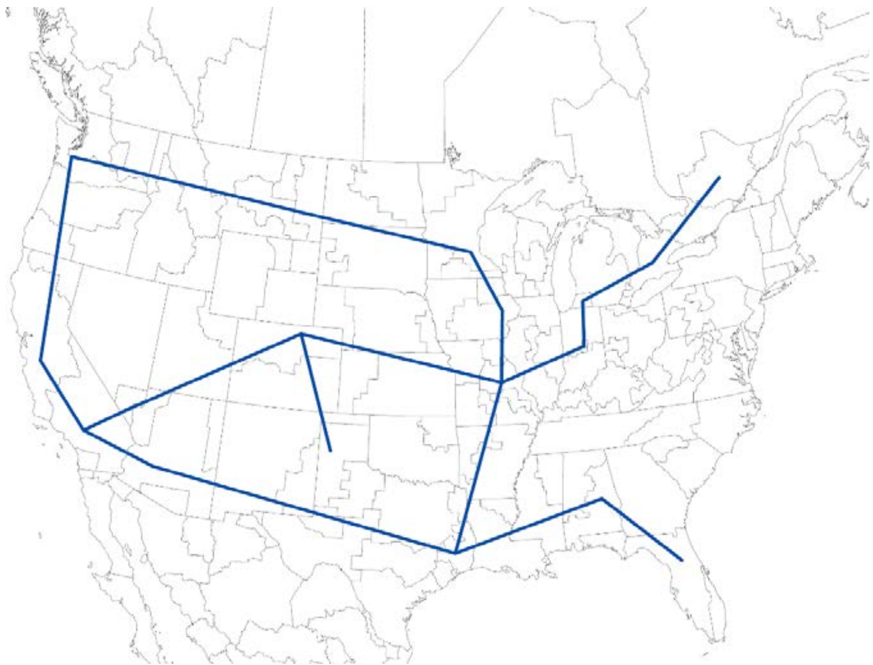


Figure 32. Macrogrid design

Note that additional macrogrid layouts could be more optimal than this. Further work could help determine optimal macrogrid layouts for different scenarios, or robust macrogrid layouts.

Figure 33 (page 55) and Figure 34 (page 56) show the net and gross trade between the United States and Canada, respectively, through 2050. Net trade between the United States and Canada is highly sensitive to model assumptions, as can be seen from the significant spread; some scenarios even represent net Canadian imports from the United States. However, the model results are not consistent between scenarios in suggesting what net Canada exports might look like in 2050. In Section 3.3.3, we discuss scenarios we ran that included a significant Canadian net export requirement (100 TWh/year by 2050), and these scenarios had similar costs to the core scenarios. These specific scenarios are not reflected in the uncertainty bounds of Figure 33.

Gross trade between Canada and the United States (Figure 34) has a more consistent story. Although there is significant spread between the scenarios, it generally increases with continental wind and solar generation levels (which also increase with time). This demonstrates the importance of energy exchange between the United States and Canada increases in scenarios

[31] "Interconnections Seam Study," NREL, https://www.nrel.gov/analysis/seams.html.

with higher renewable contributions. In the Low Cost VG scenario, the PLEXOS model showed that despite an average flow between Canada and the United States of 4,700 MW, power was flowing from the United States to Canada 32% of the time. The attribution of benefits to specific regions—which is challenging and must consider the specific contracted and market prices, practices, and rules within regions—is out of the scope of NARIS. Note that the Electrification scenario assumed electrification for both the United States and Canada, and that gross trade between the countries was much larger than in the other scenarios. As shown in Section 3.3.3, significant net exports from Canada could occur also occur in an electrification future at similar total system costs.

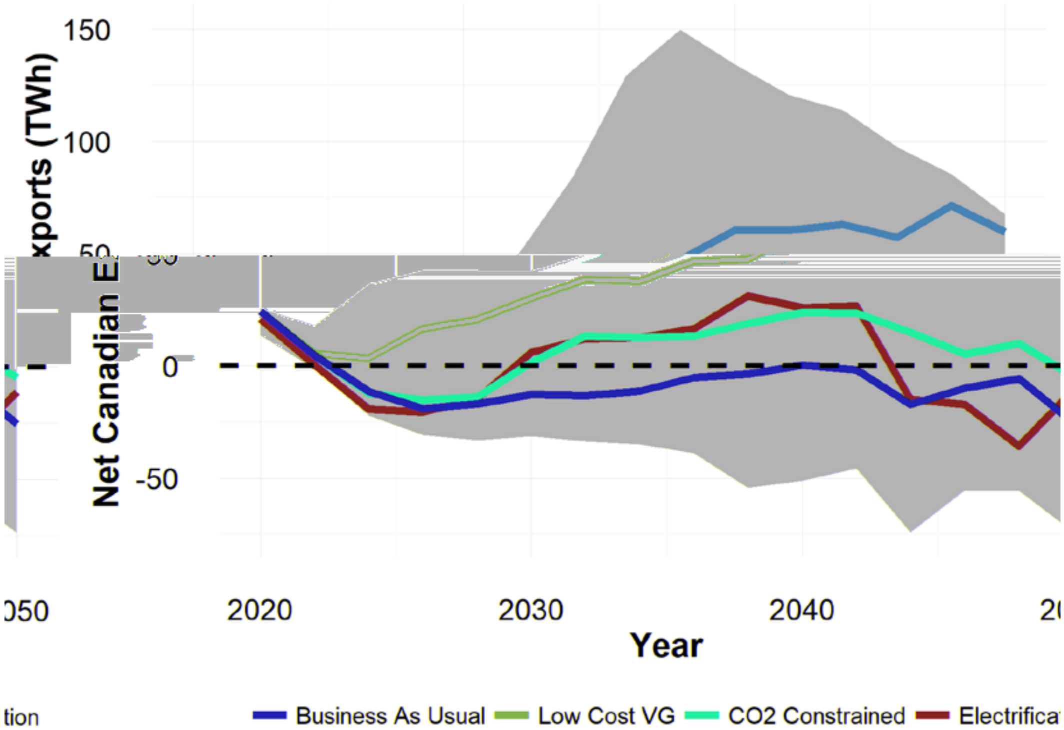


Figure 33. Net U.S./Canada trade in all scenarios (core scenarios colored)

The shaded region represents the envelope of all the scenarios that are mentioned in Section 1.2. There is wide variability between the scenarios, and there is no robust conclusion regarding net exports from Canada. In Section 3.3.3, we discuss additional scenarios where Canadian exports were required in the model, and these scenarios showed no significant cost increases.

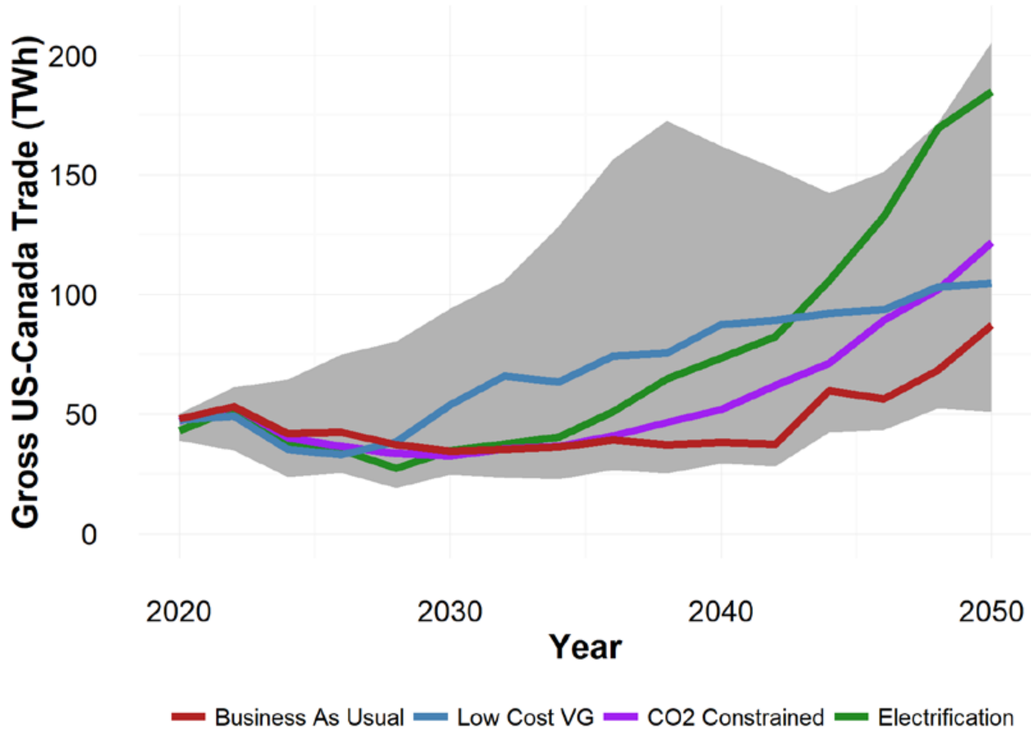


Figure 34. Gross U.S./Canada trade in all scenarios (with core scenarios colored)

The shaded region represents the envelope of all the scenarios.

Transmission is necessary for adequacy in today's grid, and it is even more important with higher loads and greater deployment of renewables in 2050. Using the same random Monte Carlo samples that generated the EUE results discussed in Section 3.1, we computed the maximum utilization of each modeled transmission interface for each scenario in each meteorological year. Maps of these results are presented for selected scenarios in Figure 35 (BAU 2024 with 2010 meteorology; page 57) and Figure 36 (Low Cost VG 2050 with 2010 meteorology; page 58). The results are highly consistent across meteorological years (not shown here). Maximum utilization increases in the 2050 scenarios relative to the 2024 scenario, particularly in the Low Cost VG case. Note that as a resource adequacy model, PRAS only utilizes transmission when it is needed to avoid unserved load, so the utilization maps indicate transmission requirements for adequacy rather than realistic power flow. For the rest of the analysis in this section, economic exchanges were considered at every time step in the modeling.

Figure 35. Maximum utilization of paths in PRAS in the near-term (2024)

The width of the lines represents the capacity of the interface between zones. The color represents the maximum hourly utilization (flow divided by capacity) during the PRAS adequacy analysis for 2010 meteorology (the plot is similar for other years). This is not an economic dispatch; utilization of interfaces happens when absolutely necessary to serve load.

Figure 36. Maximum utilization of paths in the Low Cost VG scenario in 2050 in PRAS

The width of the lines represents the capacity of the interface between zones. The color represents the maximum hourly utilization (flow divided by capacity) during the PRAS adequacy analysis for 2010 meteorology. This is not an economic dispatch; utilization of interfaces only happens when absolutely necessary to serve load.

Though NARIS does demonstrate the value of cooperation and transmission, it does not demonstrate that achieving renewable deployment levels or reliable future grids without extensive new transmission builds is impossible. Those scenarios, if feasible, would come at a higher cost (as shown in Figure 31).

3.3.2 Utilization of transmission infrastructure is very high.

This section describes the utilization of the newly-built transmission lines and the interfaces between regions. Figure 37 shows the utilization of lines built by the ReEDS model (in Canada[32]) in the Low Cost VG 2050 scenario. Most lines have annual utilization greater than 90%, demonstrating the high value of the expanded transmission pathways in the Low Cost VG scenario. These lines are operated as DC lines in the PLEXOS modeling, which allows the model to reach higher levels of utilization versus AC (see Section 2.1.3 for a discussion of the overall impact). The utilization rates are very high, and many are regularly used bidirectionally.

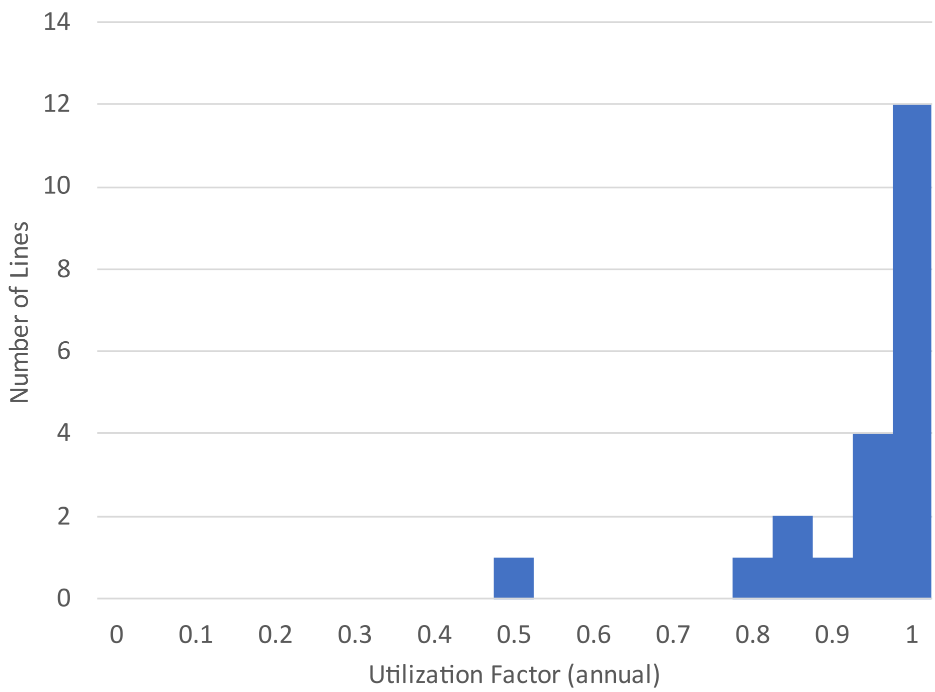


Figure 37. Histogram of total utilization of expansion lines (Low Cost VG scenario, 2050)

Figure 38 shows the net interchange between Canadian regions and their neighbors. The biggest net exchanges (other than Midcontinent Independent System Operator [MISO] to PJM) are from British Columbia to the northwestern United States and Québec to neighbors in Canada and the United States. Flows from Québec into the United States are split onto two interfaces, yet both are significant. Many other interfaces have smaller net flows; some of these have large flows in each direction that balance out over the year.

[32] Continental utilization of the new lines looks similar

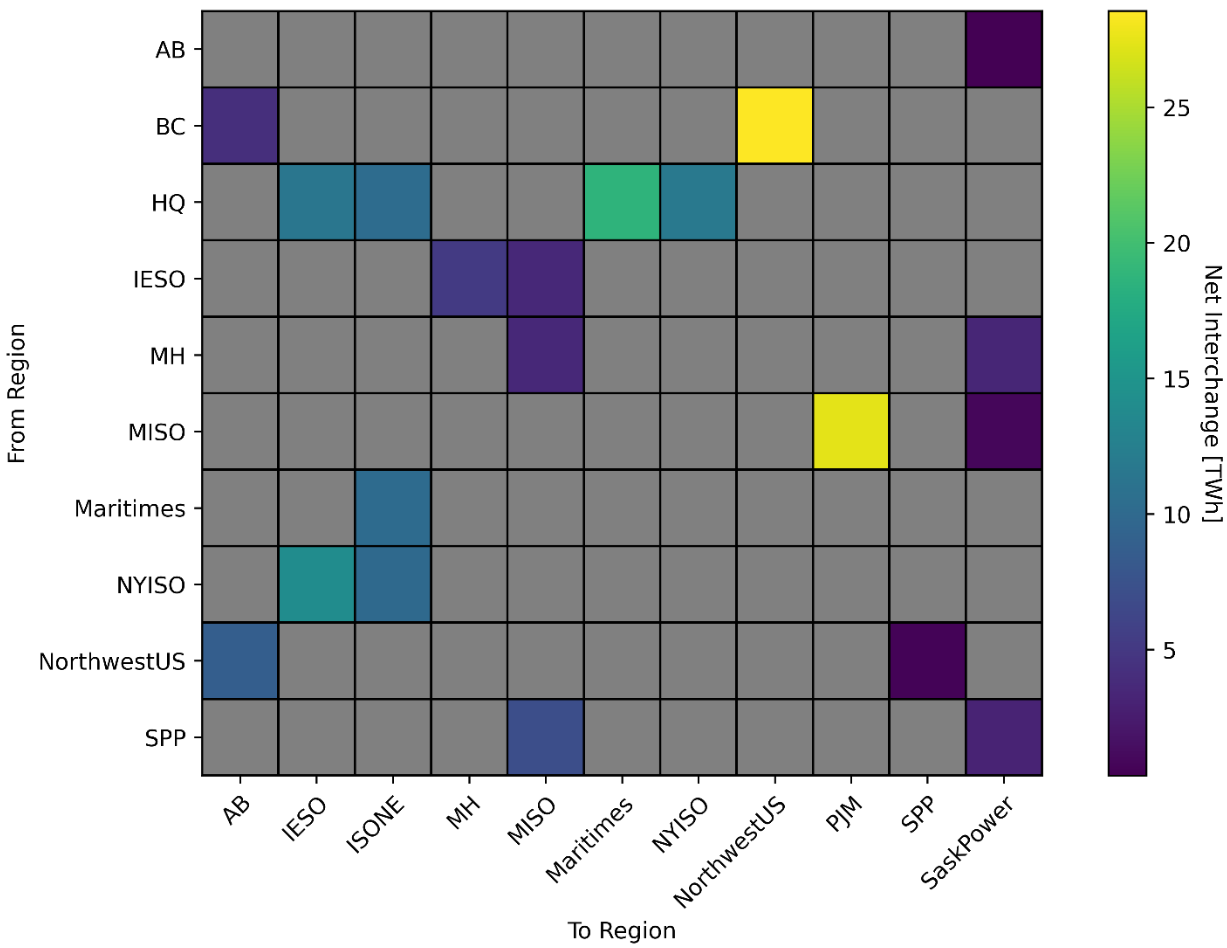


Figure 38. Net interchange between regions and their neighbors over the year (Low Cost VG scenario, 2050)

A gray box indicates there is no connection between the regions (or power is flowing the opposite direction in net).

AB = Alberta
BC = British Columbia
HQ = Hydro Québec
IESO = Independent Electricity System Operator
ISONE = ISO New England
MH = Manitoba Hydro
NYISO = New York Independent System Operator
SPP = Southwest Power Pool

Figure 39 shows the gross interchange patterns between regions. Though many interfaces stand out in both Figure 38 and Figure 39, there are some differences. The IESO-to-MISO and IESO-to-NYISO interfaces are both significant in gross flows. Gross interchanges are also significantly larger than net interchanges because of the bidirectional flow on most interfaces. See below in this section for details about the time series.

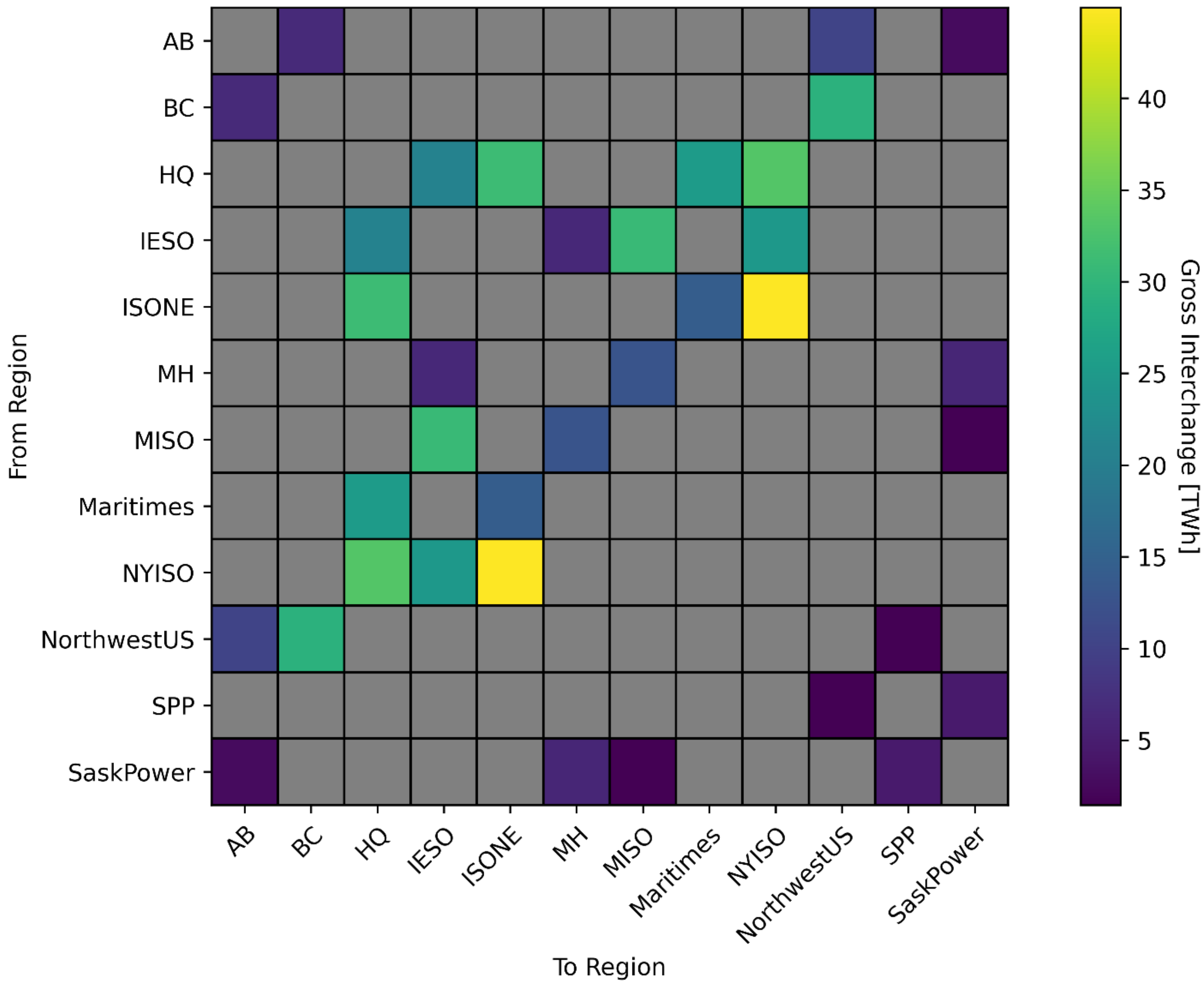


Figure 39. Gross interchange between regions and their neighbors over the year (Low Cost VG 2050)

The MISO/SPP interface exchange was removed from this plot to avoid saturating the scale.
SPP = Southwest Power Pool

Figure 40 shows the duration curve of the flow along major transmission interfaces (including both existing transmission and new builds). Flexibly operating transmission interfaces is useful in these scenarios. Many key interfaces have bidirectional utilization, meaning regions can benefit from cooperation by selling or buying power when the economics (or adequacy) are favorable, which often follows both seasonal and diurnal patterns. In this plot, only the BC-to-Northwest U.S. interface is used primarily in a single direction.

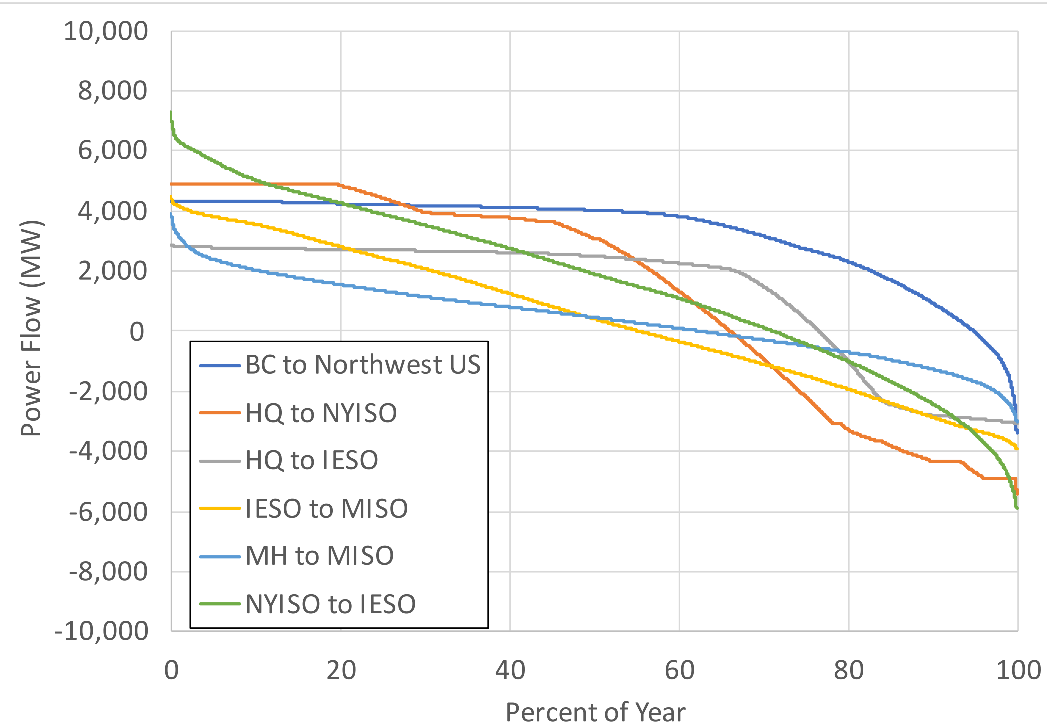


Figure 40. Duration curve of flows along major U.S. interfaces in Low Cost VG scenario, 2050

The region name listed first is the source region of the flows and the second name is the destination region. A positive flow means the source region is exporting to the destination region. A negative flow means the destination region is the exporting region.

3.3.3 Canada can increase electricity exports without affecting system costs or other key NARIS conclusions.

Because of the sensitivity of net exports from Canada to model assumptions (see Section 3.3.1), we ran additional model runs with every core scenario including a requirement that Canada exports at least 100 TWh/year by 2050 (approximately double today's levels and in line with some of the scenarios from the Pan Canadian Wind Integration Study).

System cost differences between each core scenario and the same scenario including the export requirement are shown in Figure 41. Total system costs (continent-wide) exhibit only small differences with the 100 TWh export requirement. Some scenarios (BAU, CO_2 Constrained, and Electrification) actually show a small system cost reduction. The minor cost changes from the export requirement show that the optimization is very shallow—and many solutions are nearly cost optimal. Although looking at Canada-only costs would show a cost increase, these costs are balanced by cost reductions in the United States.

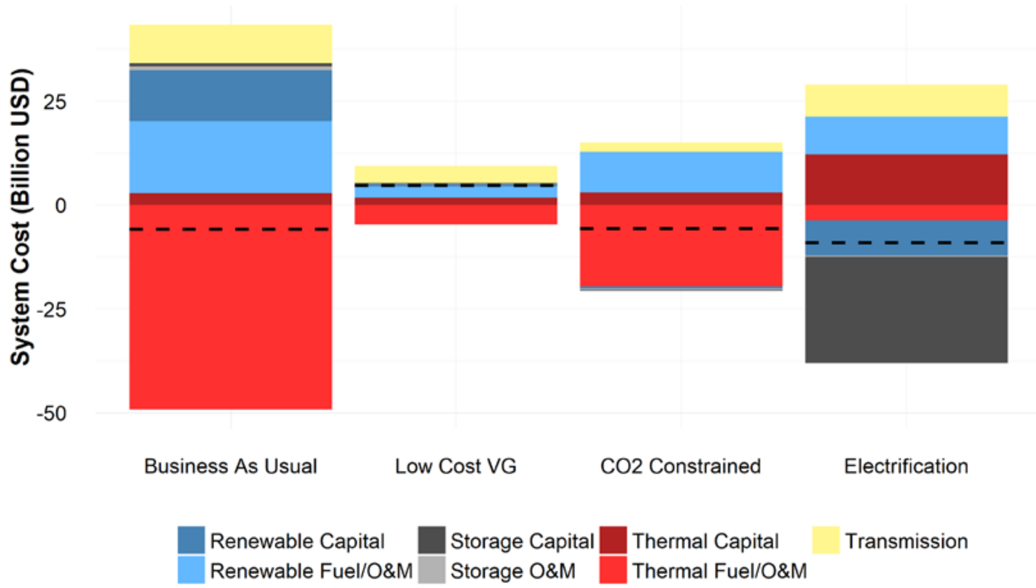


Figure 41. Continent-wide system cost differences between the core scenarios with and without the 100-TWh Canadian export requirement

The dashed line represents the net cost impact, which is minor in across the export sensitivity scenarios. Values below zero indicate cost reductions with the export requirement, while values above zero indicate cost increases. For example, in the BAU scenario, system-wide thermal capital and O&M is reduced in the Canadian export scenario, and transmission and renewable costs increase, for very little change in overall costs.

3.3.4 Canada exports significantly in continental high-load periods.

Exports from Canada are valuable to the rest of the continent during continental high load periods. Figure 42 shows the total dispatch stack for Canada during a very high load period for the continent. During that time, Canada is exporting large amount of power in nearly all hours. Flexibility in hydropower generation adds particular value near sunset, ramping up to increase exports to the United States during high net load (load minus wind and PV generation) hours.

Canadian wind and PV generation is also contributing to the Canadian exports over the period in early July. At this time of year, the U.S. Midwest wind tends to have a diurnal pattern of lower wind during the day contributing little to peak load and higher wind generation in the nighttime hours when load is lower. In Figure 42, Canadian wind does not have the diurnal pattern typical of the U.S. Midwest, providing diversity to the wind resource and therefore increased value. In July and August, Canadian wind averages 20% higher output per megawatt between 3 pm and 7 pm EST (4–8 pm EDT) than U.S. wind.

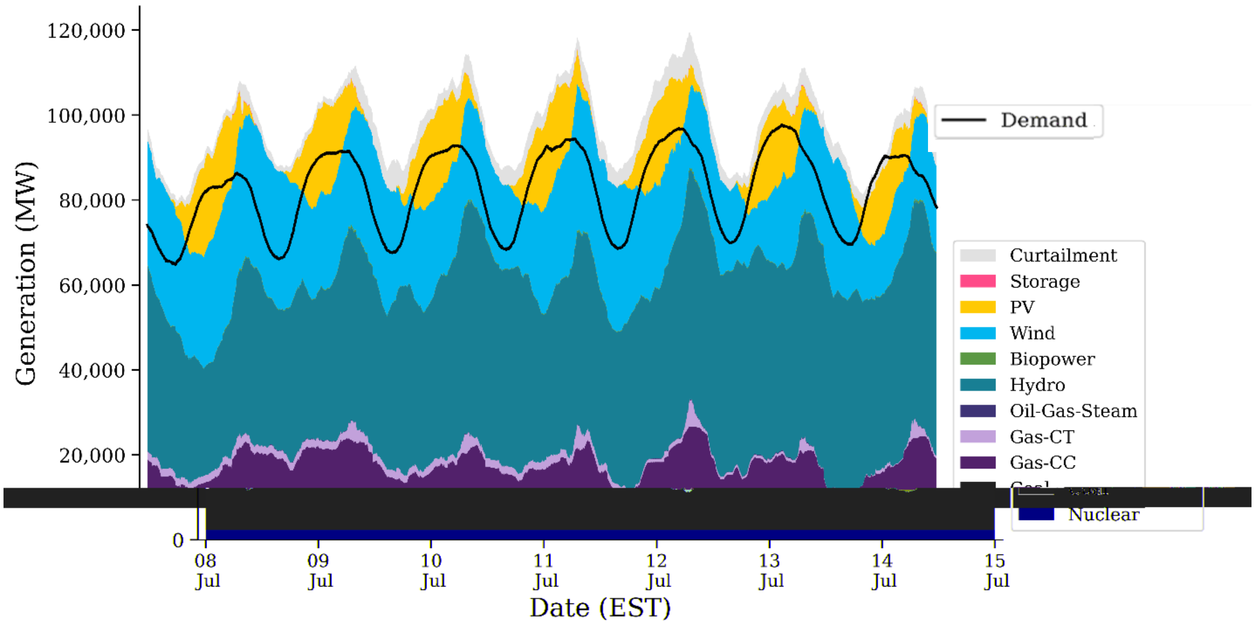


Figure 42. Canadian generation dispatch stack for July 8–14 in Low Cost VG scenario, 2050

Curtailment represents curtailment of wind or solar. Storage deployment in Canada in this scenario is minimal; see Section 3.4.5 for alternative scenario discussion.

Figure 43 shows a period in early January with very high Canadian loads. This week shows times of export to the United States and times of import from the United States. Canadian gas generation is running significantly for most of the period, with both gas and hydropower peaking at peak load times. During some of the evening peaks, Canada is still exporting to the United States despite being near annual peak demand levels, as capacity is sufficient.

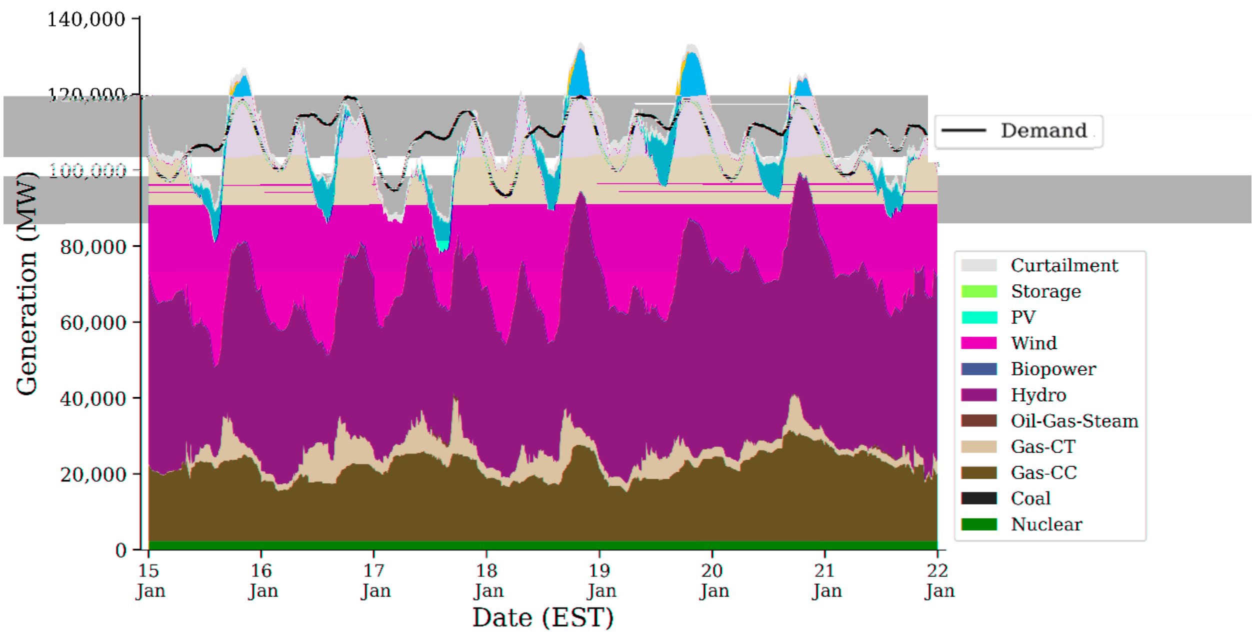


Figure 43. Canadian generation dispatch stack for January 15–21 (peak Canadian load week) in Low Cost VG scenario, 2050

3.4 System Flexibility

This section provides a general overview of flexibility in the scenarios, and the subsections examine specific technologies.

3.4.1 Operational flexibility comes from transmission, flexible operation of hydropower and thermal resources, storage, and curtailment of wind and solar generation.

Canada takes advantage of a diverse set of flexibility options to maintain reliability. Figure 44 through Figure 47 show the dispatch of various aggregations of Canadian generation during mid-November. This period highlights these sources of flexibility; the section above (Section 3.3) shows continental and Canadian high-load periods.

Figure 44 shows the generation dispatch for all of Canada. During the period shown, Canada uses the flexibility in the transmission system. Each day of the week, Canada changes from being a net exporter to the United States, to being a net importer in the middle of the day (taking advantage of low marginal-cost solar in the United States), to being a net exporter again after sunset. The period shown in the figure has higher continental PV resource; therefore, Canada tends to buy power when it is less expensive when there is excess PV generation on the system. Then Canada sells power later in the evening when the sun sets and the continental load peaks at this time of year. The primary Canadian generation source changing its dispatch to accommodate these swings in net imports and exports is hydropower. Given the limited resource, water is held back midday to avoid generating too much when power is less expensive and increasing its output for the continental evening net load peak.

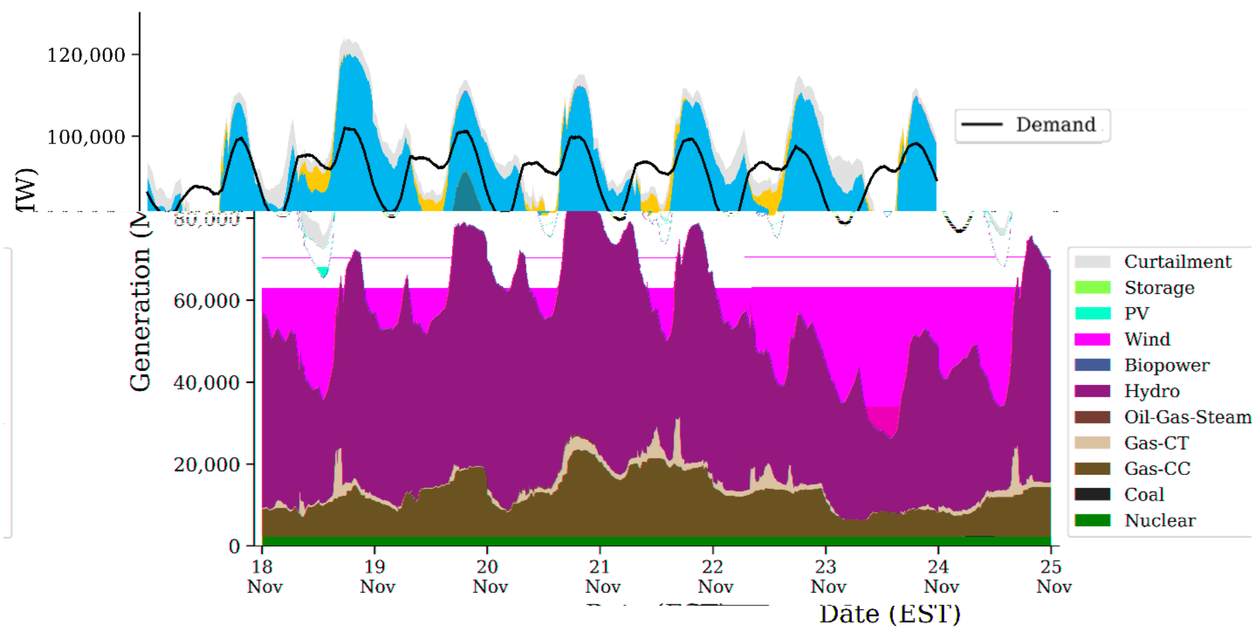


Figure 44. Total Canadian generation dispatch stack for November 18–24 (Low Cost VG scenario, 2050)

Spikes in Gas CT usage are due to peak power needs in the United States and are associated with times of increased exports or reduced imports.

Québec's flexibility is on display in Figure 45. Each day the hydropower ramps down when PV generation throughout the continent is high, and power is held back to be used later in the day. For most days, the load in Québec follows nearly identical pattern. Sharp peaks in the morning and evening hours, ramping down to nearly the same level in the afternoon and nighttime hours. The differences in the daily generation pattern are therefore reactions to changing conditions in other Canadian provinces and in the United States.

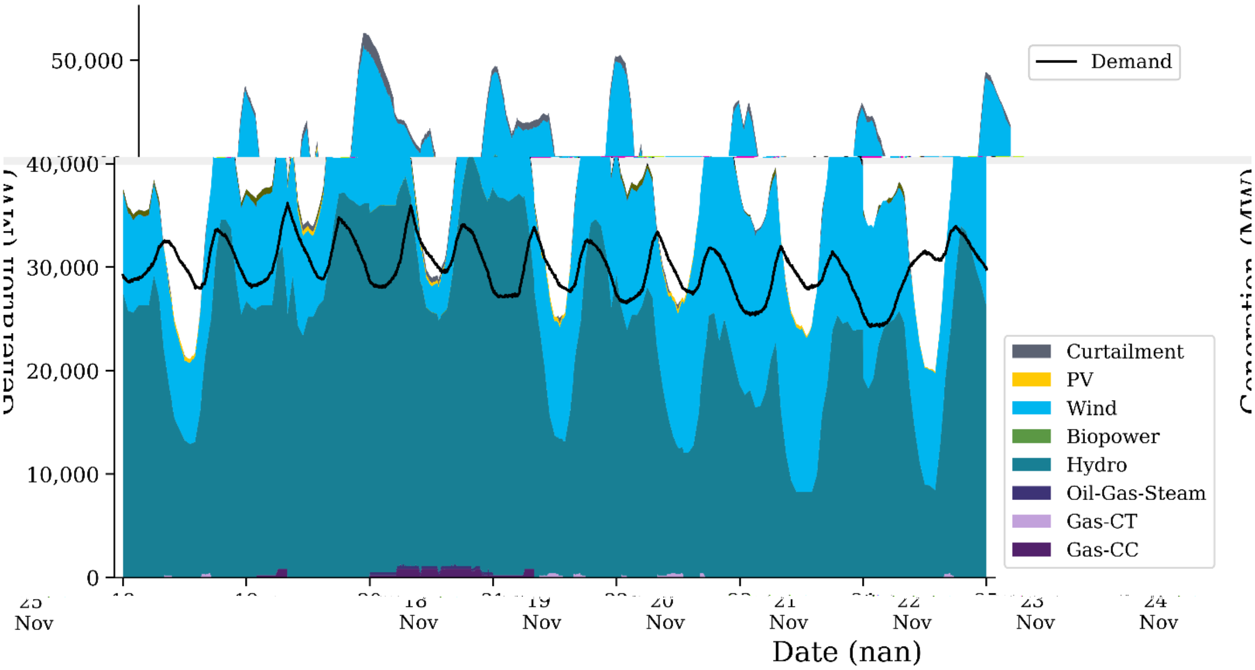


Figure 45. Hydro Québec generation dispatch stack for November 18–24 (Low Cost VG scenario, 2050)

Figure 46 demonstrates thermal unit flexibility in the Canadian Eastern Interconnection (excluding Québec). During the first half of the week, combined cycle units cycle on and off to provide peak power demands near sunset. On several days, gas combustion turbine units turn on at sunset. The diversity of the wind and solar resource is also highlighted in Figure 46. The latter half of the week demonstrates very high wind output in the Canadian Eastern Interconnection, and hydropower and gas generation are low for the entire period. This demonstrates the operational flexibility of these resources.

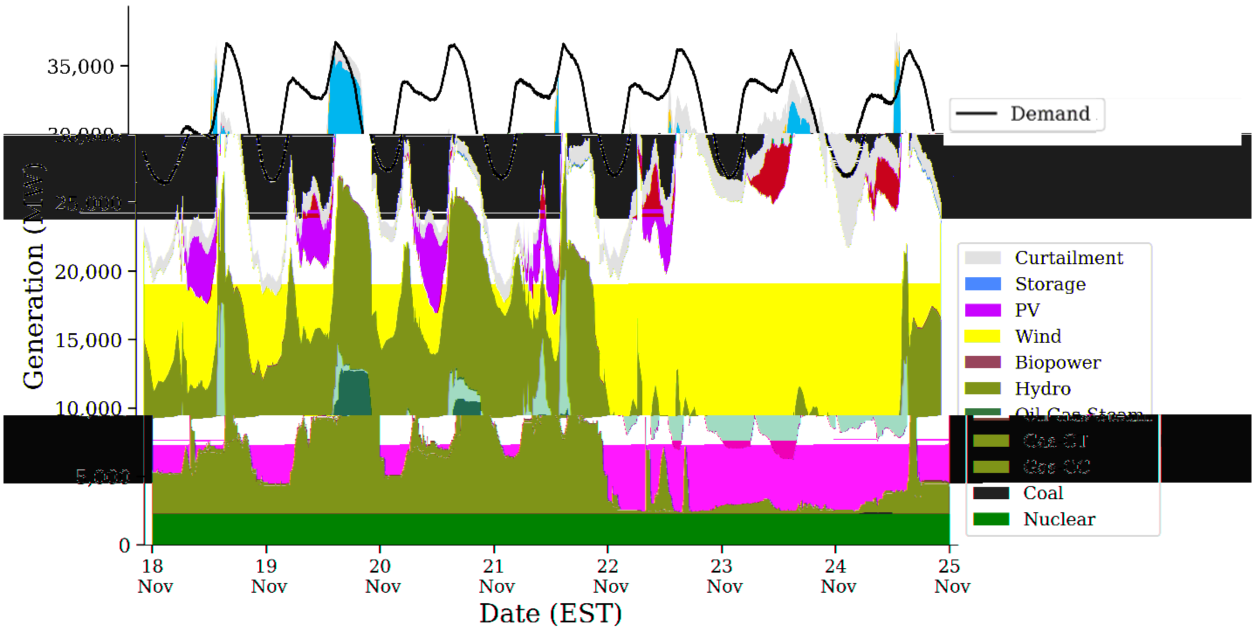


Figure 46. Canada Eastern Interconnection (excluding Québec) generation dispatch stack for November 18–24 (Low Cost VG scenario, 2050)

Figure 47 shows another form of flexibility from the wind and solar in the Western Interconnection. During the first few days of the week, the inability to export more power (because of either congestion or curtailment in the United States) or to turn down hydropower and thermal units results in curtailment of variable generation. Curtailment is a demonstration of variable generation flexibility to ensure reliable operations (i.e., avoid line overload or violations of thermal/hydropower operating parameters). During the middle of the week, the contribution of thermal generation increases significantly.

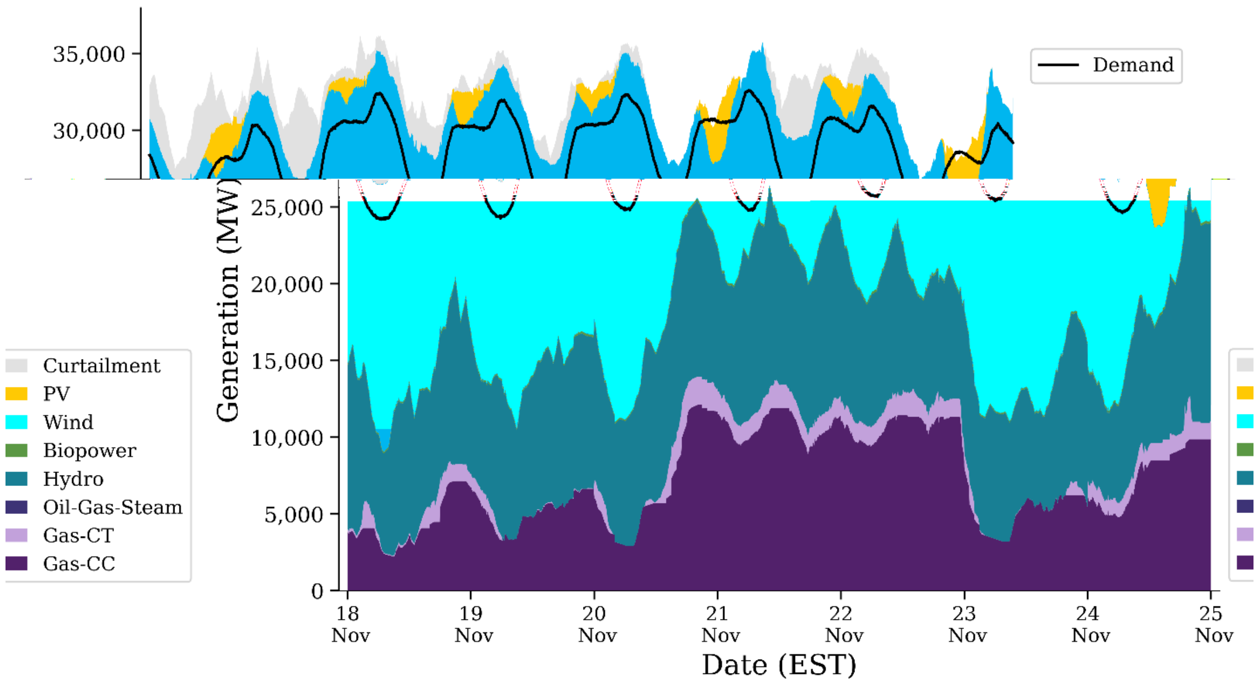


Figure 47. Canada Western Interconnection generation dispatch stack for November 18–24 (Low Cost VG scenario, 2050)

3.4.2 Less than 10% of potential wind and solar is curtailed.

Figure 48 shows the duration curve of curtailment in Canada in the Low Cost VG scenario. In total, curtailment represents 8.1% of the potential wind and solar generation in Canada.[33] The bulk of the curtailment occurs in a small percentage of the hours, but there is curtailment somewhere in the United States in almost every hour. Curtailment represents a trade-off between capital costs of wind and solar, compared to other options, including storage, transmission, and nonrenewable generation (this option is only in unconstrained carbon scenarios).

[33] There is no incentive in the model to curtail wind or solar "first;" the curtailed technology is generally chosen randomly if both are available during times of curtailment.

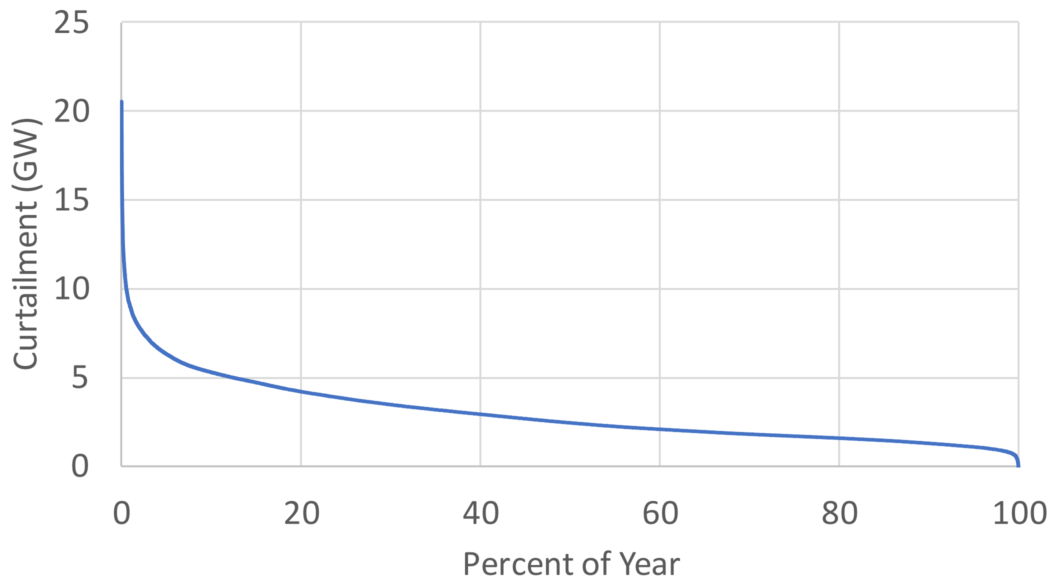


Figure 48. Canadian curtailment duration curve for Low Cost VG scenario, 2050

Figure 49 shows the diurnal and seasonal patterns of curtailment in Canada. The diurnal pattern of curtailment is very consistent throughout the day; there is no significant peak at midday (during high solar output) or overnight (during low loads). The seasonal pattern is also fairly consistent, with the highest curtailment occurring in the spring and fall, when winter loads in Canada, and high summer loads in Canada and the United States keep curtailment down during those seasons.

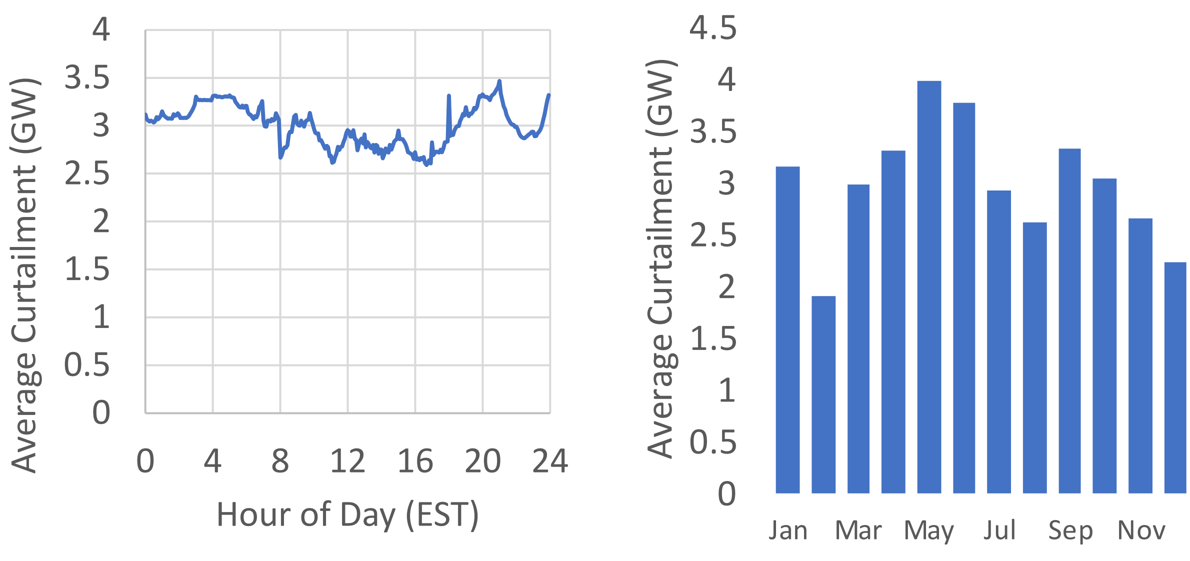


Figure 49. Canadian curtailment duration by hour (left) and month (right)

Because the seasonal and diurnal patterns of curtailment in Canada are less significant than those in the United States, fewer time periods have very high curtailment. Figure 50 shows a week of higher curtailment in spring. This week exhibits many of the patterns seen in Figure 49. No significant curtailment increases during midday or night and consistent curtailment throughout the week. Some gas is online at all times, in places where curtailment is not happening (both the Eastern Interconnection and the Western Interconnection). There is also significant curtailment in the United States during this particular week. This is why Canada imports and curtails at the same time on May 7; the marginal value is zero at that time and curtailment is happening on both sides of the border.

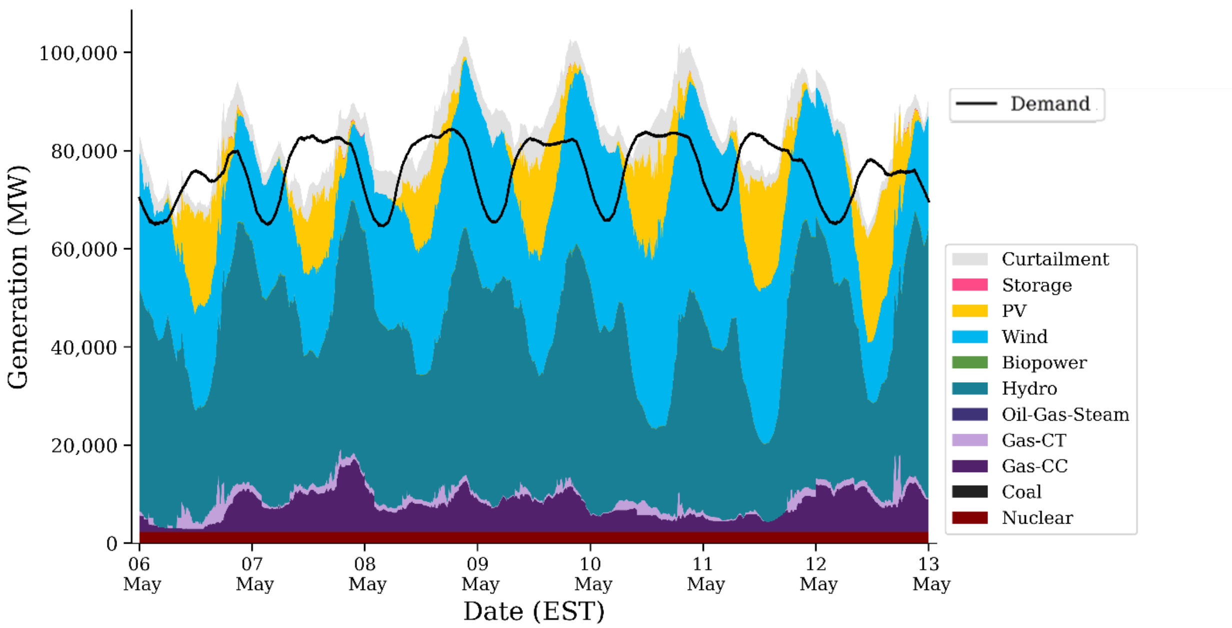


Figure 50. Canada-wide dispatch stack during a high-curtailment period

3.4.3 Hydropower contributes significantly to energy, adequacy, and flexibility.

Figure 51 and Figure 52 qualitatively demonstrate some of the value of Canadian hydropower in the Low-Cost VG scenario. Figure 51 shows the hydropower contribution to the adequacy and flexibility during the net load (load minus wind and PV) peak. At the peak net load, hydropower capacity is meeting about two-thirds or the power requirement. Hydropower can contribute to adequacy in part because of its flexibility to shift *when* it generates. Earlier in the day on January 20, hydropower has ramped down enough that it is only half the generation meeting the net load.

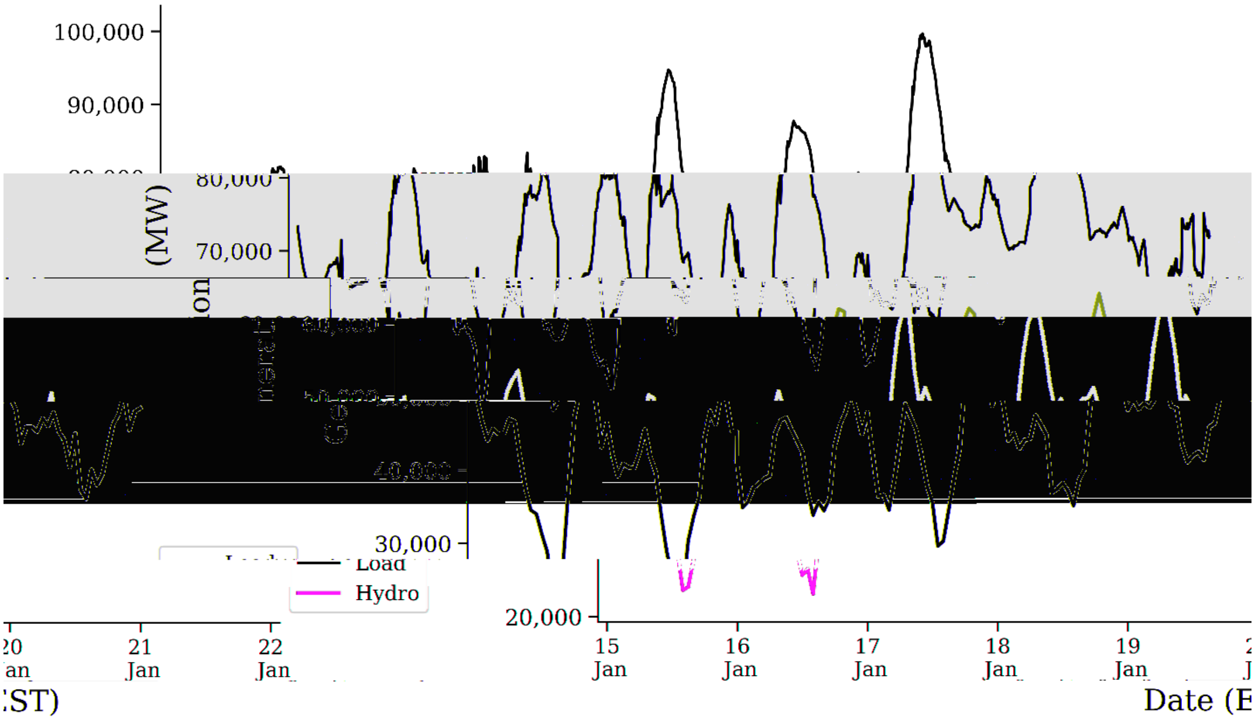


Figure 51. Total Canadian hydropower and net load for Canada's net load peak (January 20) and preceding days

This is the same week from the dispatch stack in Section 3.4.1.

Figure 52 plots continental net load versus Canadian hydropower generation. A strong correlation between increasing net load and Canadian hydropower is evident. The flexibility of Canada's hydropower is not only used to meet adequacy requirements domestically; it also provides energy and adequacy at high net load hours to the rest of the continent. The plot also shows two connections between net load and Canadian hydropower: one during the winter months, when several Canadian provinces are at or near peak load levels, and another during the non-winter months, when more U.S. regions are at or near peak levels.

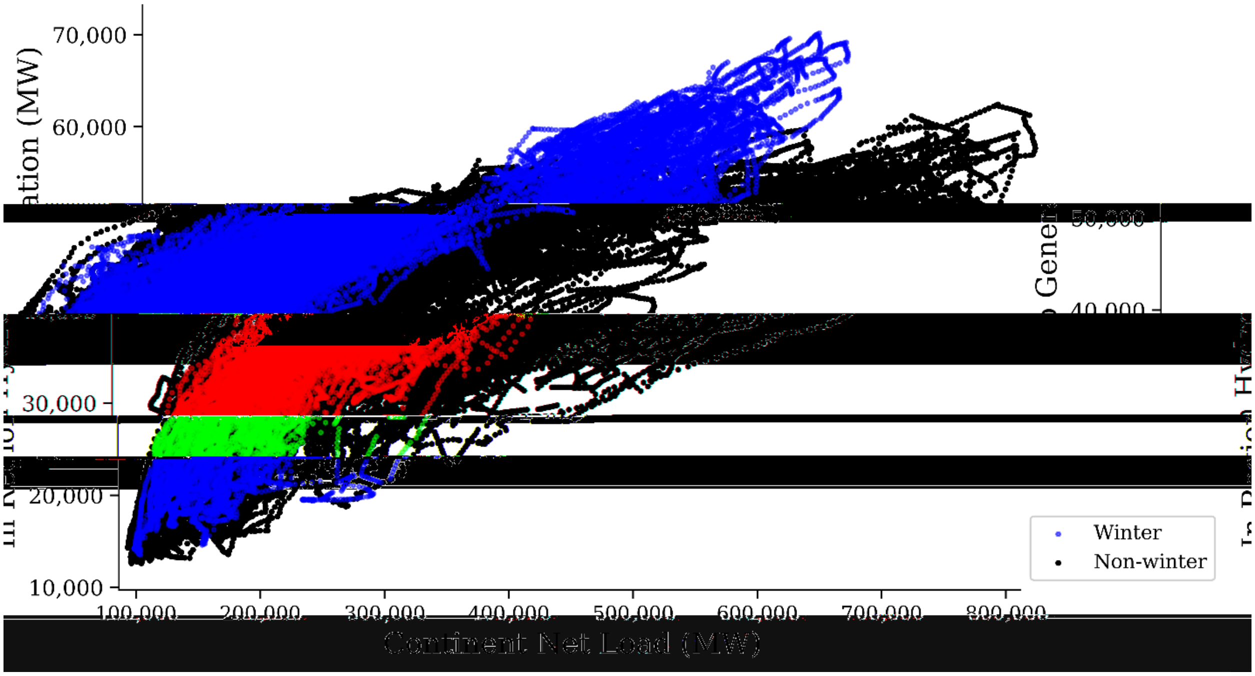


Figure 52 Canadian hydropower generation's relationship to the continental net load

3.4.4 Hydropower flexibility reduces system costs by over $2 billion per year.

The previous section (Section 3.4.3) qualitatively demonstrates some of the value hydropower brings to the system, including generation during times of peak demands and the ability to turn down at other times. To explore these values in quantitatively, we ran the unit commitment and dispatch model again assuming heavily constrained hydropower operations. By comparing the cases, we can understand the value and benefits of hydropower flexibility to this future scenario (Low-Cost VG 2050). The Low-Cost VG scenario assumed hydropower flexibility intended to represent today's levels of flexibility. The constrained case assumed operations at all hydropower plants (not just run-of-river) have no flexibility—they have constant output, with the constant output varying monthly or daily based on water flows. Run of river plants were modeled with the same time series assumptions (historical flows) in both cases. This case was not intended to represent a realistic future but to help estimate the benefits that the flexibility of hydropower provides compared to a hypothetical resource that cannot follow load. The key caveat for this valuation is that it was based on the amount of flexibility allowed in the model (see Section 2.2.3). Future work could further refine the representation of hydropower within the model and disaggregate the types of flexibility (e.g., determine how much benefit is from interday versus intraday flexibility). Note that flexibility constraints could also affect the ability of hydropower to provide adequacy; this adequacy value of flexibility is not addressed here.

Table 11 shows some of the impacts of hydropower flexibility on key metrics in the Low-Cost 2050 production cost modeling. Today's approximate level of hydropower flexibility (compared to a completely inflexible hydropower fleet) could reduce annual operating (production) costs by 3.0%, curtailment by 0.6%, fossil-fueled generation by 1.6%, and emissions by 1.3%.

Table 11. Benefits of Hydropower Flexibility

Metric	Impact
Cost	Today's level of hydropower flexibility reduced annual operating costs by $2.3 billion, which represents 3.0% of the system production costs.
Curtailment	The flexibility of hydropower to turn down in periods of curtailment and generate more during periods of need reduced curtailment from 9.9% to 9.2%.[a]
Generation	The reduction in curtailment leads to a reduction in generation from fossil-fueled units of 22 TWh (1.6%). This includes an increase in coal generation of 4 TWh (all in the United States) and a decrease in gas of 26 TWh.[b]
Emissions	Increased flexibility reduces emissions in this scenario by 1.3%.

These values are based on a comparison of the 5-minute dispatch model runs from the Low-Cost VG scenario with runs from an identical scenario with all hydropower flexibility disabled (i.e., dispatchable hydropower generators are assumed to have flat output levels for each month). The U.S. and Canadian hydropower were included in the flexibility adjustments at the same time, so results presented are aggregated for the continent.

[a] Curtailment reported here is a U.S. and Canada average, because the sensitivity was done for all U.S. and Canada hydropower.

[b] Because the dispatch of generators is a cost optimization, increased flexibility will lead to selecting lower-cost resources (in the case of the Low-Cost VG scenario, the lower-cost resource is coal due to fuel costs)

Figure 53 shows the annual pattern of daily cost reductions from hydropower flexibility. It is smoothed to limit the visibility of interday energy shifting. Although the reasons for the value likely vary by season, the overall value is similar between seasons. Curtailment is likely a strong driver of this value; the highest curtailment in the model and the highest monthly value of hydropower flexibility both occur in April. The lowest curtailment occurs in July and August, along with the lowest monthly value of hydropower flexibility. In high curtailment periods, like the spring, the value comes primarily from avoided curtailment. In low curtailment periods, it comes from a variety of sources, including the substitution of higher-cost peak generation with lower-cost resources.

From a hydrology perspective, the high-value periods do coincide with low-water times of year for these modeling assumptions (see Section 2.2.3 for hydropower output by week). This may be due to the ability to shift power more easily when the quantity of water does not require generators to regularly run near capacity. More study of different hydrological conditions mixed with flexibility changes would help address this question.

Figure 53. Daily value from hydropower flexibility

This figure shows the smoothed daily hydropower flexibility cost reduction, which averages $6.3 million/day. It does not substantially vary by season, except for a period in early March when the model shifts energy to another time if it is feasible to do so. The smoothing is a 30-day filter to limit the impacts of daily variability that are due to substantially more or less energy generation from hydropower.

The analysis described in this section is based on a typical hydropower year for all regions. We also reran the model with a 5% increase (wet) and a 5% decrease (dry) in energy availability of hydropower to see the different impacts (no changes were made to the capacity of the generators). The dry case led to an increase in production costs of $1.1 billion. Most (27 TWh) of the approximately 35 TWh generation needed to make up for the reduced hydropower generation came from gas CCs, while 5 TWh came from reduced curtailment at wind and solar generation. In the wet case, production costs decreased by $0.9 billion. The additional curtailment from wet conditions was slightly higher than the reduction from wet conditions, and the 7 TWh of additional wind and solar curtailment represents approximately 20% of the additional available hydropower energy.

Table 12. Impacts of Different Water Conditions

Metric	Dry	Typical	Wet
Cost, $ billion (change from Typical)	$78.5 b (+ $1.1 billion)	$77.4 billion	$76.5 b (- $0.9 billion)
Gas CT, TWh (change from Typical)	95 (+ 1)	94	93 (- 1)
Gas CC, TWh (change from Typical)	1,584 (+ 27)	1,557	1,534 (- 23)
Wind and Solar, TWh difference	3,492 (+ 5)	3,487	3,480 (-7)

These values are based on a comparison of the 5-minute dispatch model runs from the typical case to wet (5% additional energy from hydropower in every month) and dry (5% reduction in energy) cases. These are all continental totals, and the relative numbers are the key figures of interest.

3.4.5 Even in low storage cost scenarios, storage is a small fraction of overall capacity in 2050.

Figure 54 (page 76) shows the change in capacity in the core scenarios assuming low-cost storage (based on the 2018 ATB).[34] Note that in the core scenarios with standard storage cost assumptions, there is very little (less than 1 GW) storage in the nonelectrification scenarios. With low-cost storage assumptions, the model does adopt more storage in Canada; all new storage installations are assumed to be 4-hour batteries. Ongoing work[35] is analyzing the impacts of varying durations of storage in scenarios very-low carbon emissions targets. In Canada, storage makes up significantly less than 10% of overall capacity in the nonelectrification cases. This is lower than continent-wide adoption rates with low-cost storage, likely because of the flexibility of the hydropower generation in Canada, which provides significant resource adequacy and energy. Hydrogen storage was not considered in NARIS.

The importance of the contribution of storage to adequacy in these low-cost storage scenarios is shown in Section 3.2.2, where storage displaces some of the system need for capacity from thermal generators. The low-cost storage assumptions were not used in the core scenarios, so there is no detailed dispatch modeling using the higher storage builds.

---

[34] 2018 ATB Mid and Low storage costs reach $1,078/kW and $521/kW (2018 USD), respectively, for 4-hour storage devices.

[35] For example: "Storage Futures Study," NREL, https://www.nrel.gov/analysis/storage-futures.html.

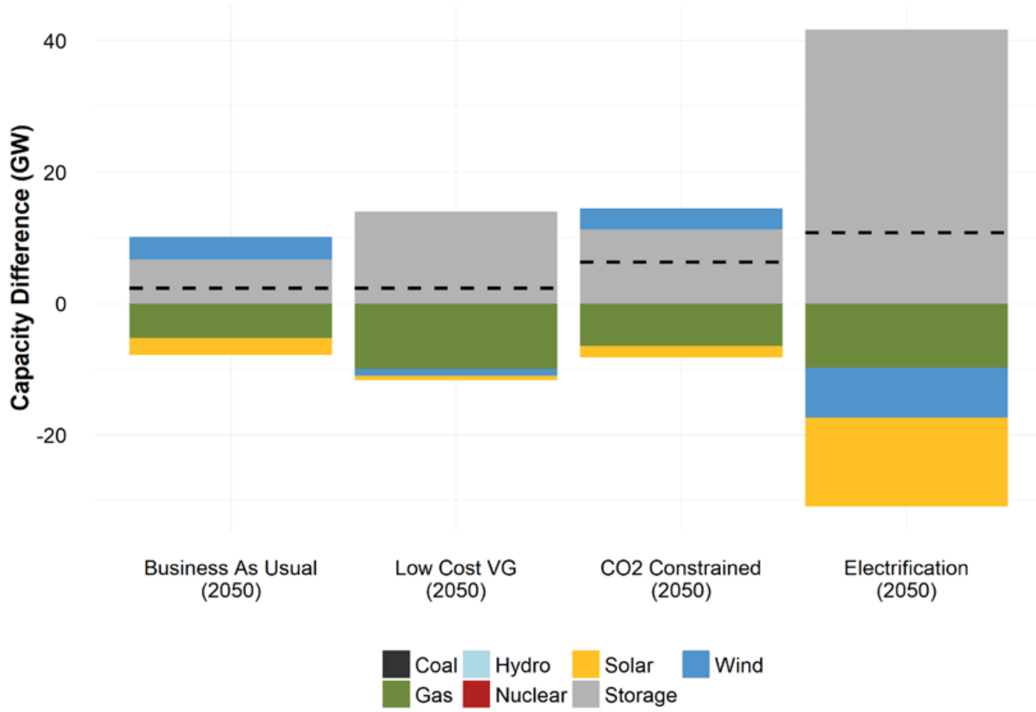


Figure 54. Change in 2050 capacity for core scenarios with lower-cost storage availability

Each core scenario was modeled with standard (NREL ATB) assumptions for storage costs. As a sensitivity, each core scenario was also modeled with lower storage cost trajectories through 2050. The difference between each sensitivity and each core scenario is presented here. The dashed line represents the net capacity impact for each scenario and sensitivity pairing (see Section 3.1 for total capacity in each scenario). The nonelectrification scenarios have similar capacity of natural gas capacity displaced by the new storage.

3.5 Scenario Comparisons

In this section, we compare some of the key outcomes of the scenarios, including costs, emissions, distributed generation, and the impacts of electrification.

3.5.1 Emissions drop substantially in all scenarios.

Figure 55 shows the emissions trajectory through 2050 in the core scenarios. The requirement that all coal generation in Canada retires by 2030 drives much of the emissions reductions in 2025–2040. In the Low Cost VG scenario, almost all the retired generation is replaced with wind immediately in 2030, and then carbon emissions remain stable through 2050 in that scenario.

The carbon limits in the other scenarios (an 80% reduction by 2050 in BAU and a 92% reduction in the CO_2 Constrained and Electrification cases) are binding in the mid-2020s and again in the 2040s. Emissions reductions from the electrification of additional energy end uses in the Electrification scenarios were not considered, so the Electrification scenario could be part of much larger emissions reduction in the overall Canadian and North American energy system.[36]

[36] The Electrification Futures Study estimated that for the United States, annual emissions reductions from electrification of new end uses are larger than the annual electric sector reductions from 2020 to 2050.

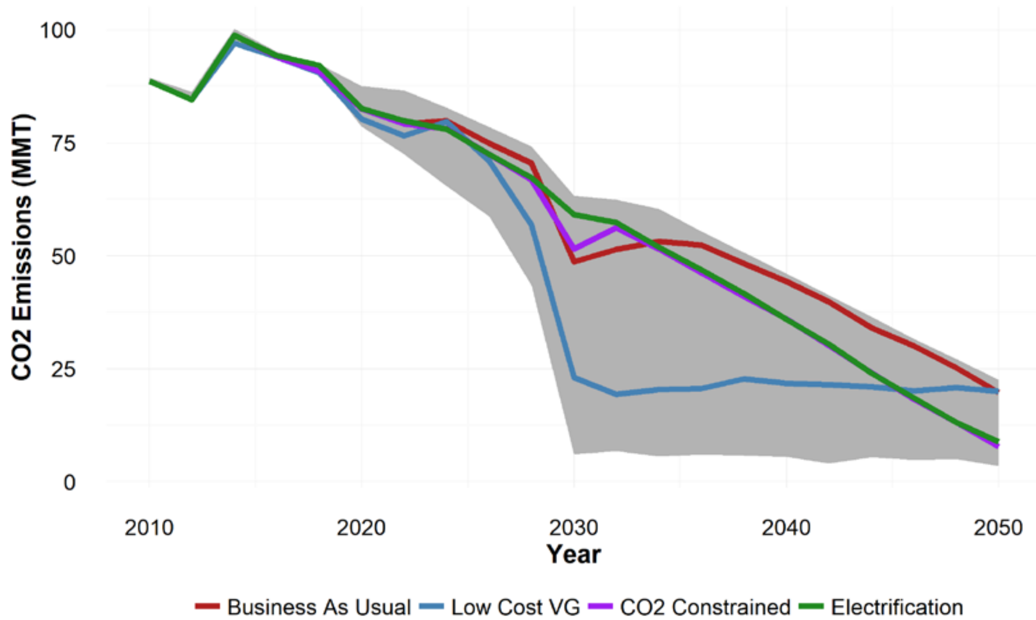


Figure 55. Canada CO_2 trajectory through 2050 in the core scenarios

Note that the emissions reductions from the electrification of energy end uses (e.g., transportation and heating) in the Electrification scenario are not considered in this plot. The CO_2 Constrained and Electrification scenarios follow an identical trajectory after 2028 because of binding carbon constraints. The shaded region represents the envelope of all NARIS scenarios.

3.5.2 Distributed generation plays a significant role in some regions; costs strongly impact adoption.

Though technical potential for rooftop solar PV varies considerably from Canada to the United States and Mexico, retail electricity rates are a more significant factor in determining the customer adoption of distributed energy resources. Marginal cost of retail electricity defines the value to the consumer of adopting distributed PV and thus is an important input to customer adoption models. Furthermore, retail tariffs often have nonlinear elements (e.g., demand charges or tiered pricing); thus, the marginal value of avoided electricity use cannot be well-approximated by the average cost. Figure 56 displays the distribution of retail electricity demand as a function of retail rates of all agents examined by dGen for NARIS, by country and sector. dGen allows customers to adopt systems up to the size of their annual energy demand, or rooftop availability.

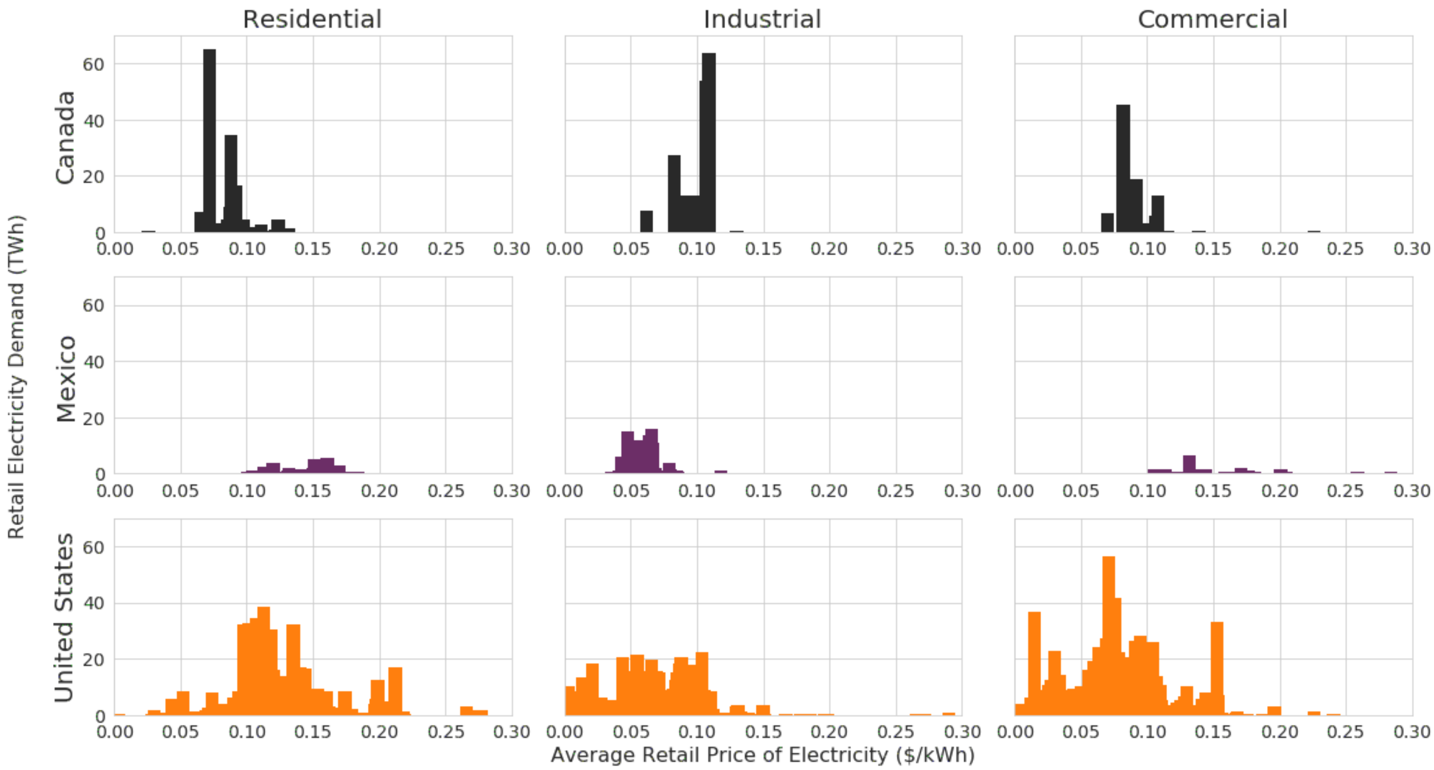


Figure 56. Utility rates throughout North America

Histogram bins are weighted based on total load, with rates based on the total charges (including any metering charges or demand charges) divided by total load. Data are from the Utility Rate Database.[37]

As most distribution utilities in Canada serve large geographic areas with homogenous regulated rates, the distribution of rates in Canada is more concentrated than in the United States or Mexico. Because of this, the payback period for an entire province can be substantially impacted by future changes in retail electricity cost. Figure 57 displays the decline in payback periods by country and scenario. Though Canada does not have the highest solar capacity factor on the continent, persistent net metering policies and higher commercial and industrial retail electricity rates suggest average rooftop PV payback periods in Canada in 2050 could be than in the United States and Mexico (assuming continuation of Canadian net metering programs and rate structures). Though payback periods in the United States and Mexico will remain lower than those in Canada through 2030, declines in PV capital cost allow Canadian payback periods to average below the United States and Mexico by 2050 in each scenario. We also explored scenarios without continued net metering policies; those results are shown later in this section.

[37] "Utility Rate Database," OpenEI, https://openei.org/wiki/Utility_Rate_Database.

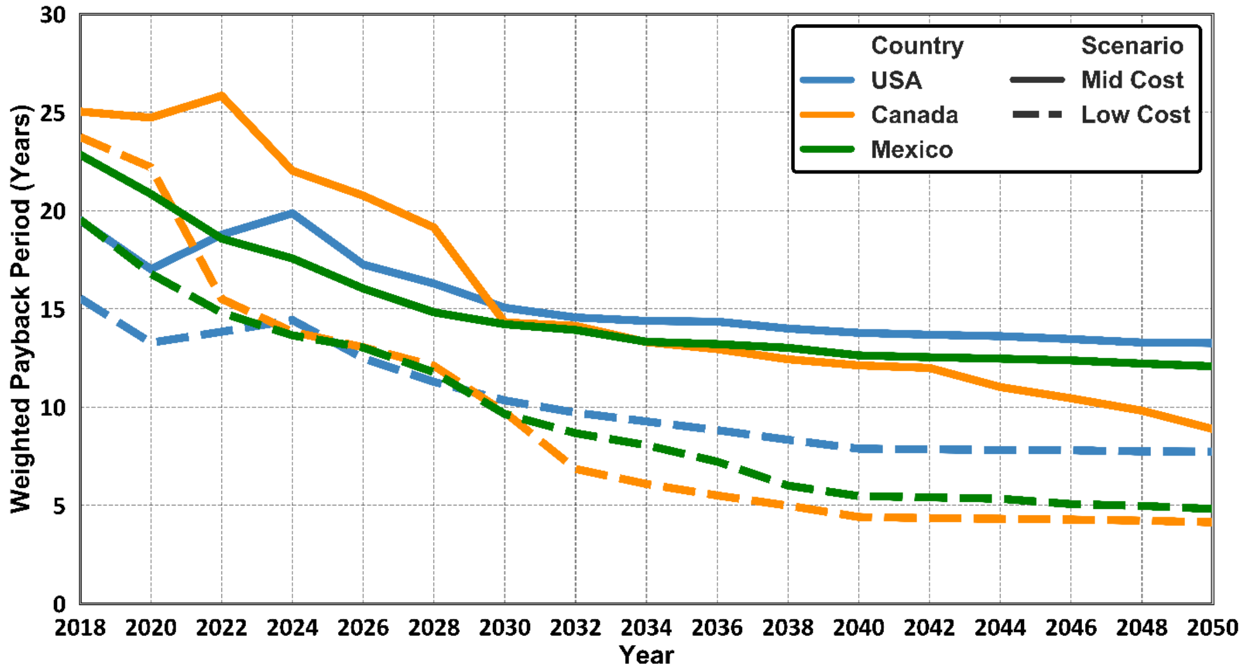


Figure 57. Simple payback period for distributed PV by country

The Low and Mid cost scenarios depend on differences in PV costs as detailed in 2018 ATB. Current net metering policy is assumed to be available within each scenario shown here. Canadian payback periods are lower than U.S. and Mexico averages due to net metering and heavily driven by adoption in Ontario.

Within Canada, payback period varies substantially by province due to differences in solar irradiance, net metering policies, and electricity rates. Table 13 displays the average payback period for each province in the Mid cost scenario for select years.

Table 13. Average Payback Period by Province (Mid Cost NEM Scenario)

Province / Territory	2030	2040	2050
Alberta	6.83	5.14	3.94
British Columbia	23.80	14.07	10.88
Manitoba	> 30	29.22	26.28
New Brunswick	27.51	10.45	9.55
Newfoundland and Labrador	> 30	> 30	> 30
Nova Scotia	11.91	8.18	7.51
Ontario	9.80	8.30	7.57
Prince Edward Island	8.72	7.44	6.88
Québec	29.67	29.65	18.31
Saskatchewan	8.92	6.90	5.78

Alberta, Ontario, and Saskatchewan are the three provinces supportive of average payback periods below 10 years in 2030, and Alberta has a projected average payback period below 5 years in 2050. This aligns with analysis by EnergyHub—a consumer solar information website—

which ranks Alberta as the highest scoring province for rooftop solar feasibility on the basis of policy, compensation, and resource availability.[38]

Figure 58 shows the evolution of rooftop PV adoption in the net metering scenarios through 2050. The Mid and Low cost assumptions lead to 17 and 32 GW of adoption, respectively, by 2050.

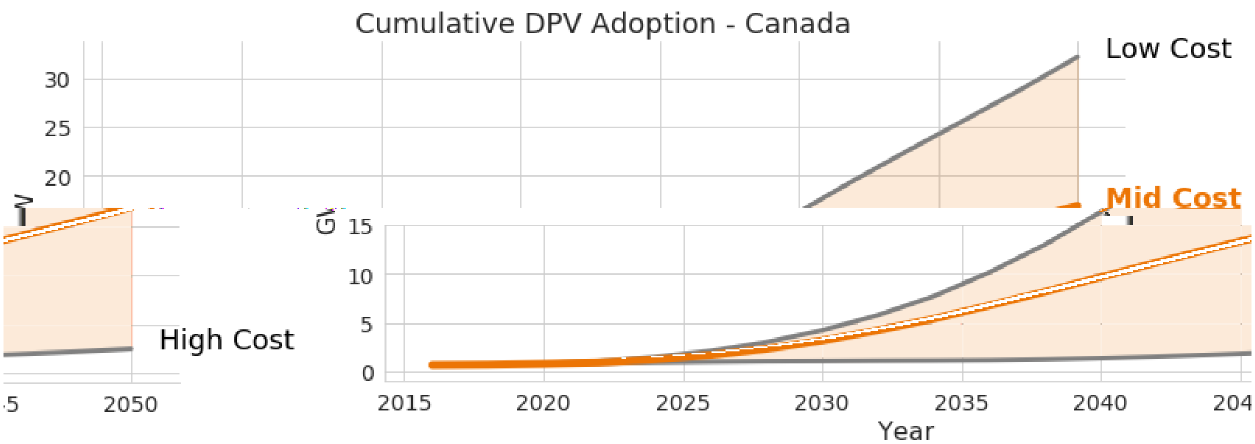


Figure 58. Cumulative dGen distributed PV adoption potential forecast for NEM scenarios

Table 14 shows the adoption by province for 2050 in four scenarios: Mid Cost NEM (net energy metering), Mid Cost (net billing), Low Cost NEM, and Low Cost (net billing). Net billing assumes the consumer displaces on-site retail power when possible and sells power back to the grid at wholesale rates. The compensation framework (net metering versus net billing) has impacts that are substantial but not as substantial as the costs.

Table 14. Cumulative PV Adoption by Province in 2050 (GW)

Province / Territory	2050 Mid Cost (NEM)	2050 Mid Cost (Net Billing)	2050 Low Cost (NEM)	2050 Low Cost (Net Billing)
Alberta	3.92	2.86	5.44	4.92
British Columbia	0.8	0.42	3.20	2.69
Manitoba	0.00	0.00	0.33	0.3
New Brunswick	0.07	0.04	0.41	0.37
Newfoundland and Labrador	0.00	0.00	0.09	0.06
Nova Scotia	0.58	0.25	1.13	0.93
Ontario	10.0	3.64	18.1	11.3
Prince Edward Island	0.11	0.04	0.22	0.16
Québec	0.05	0.04	1.04	0.96

[38] EnergyHub, https://www.energyhub.com, accessed 2019.

Province / Territory	2050 Mid Cost (NEM)	2050 Mid Cost (Net Billing)	2050 Low Cost (NEM)	2050 Low Cost (Net Billing)
Saskatchewan	1.31	0.55	2.07	1.63
Total	**16.8**	**7.8**	**32.0**	**23.3**

NEM cases assume continued NEM policies, and the Net Billing cases assume a net billing framework in all provinces.

While Canada is not projected to install as much capacity as the United States or Mexico by 2050, approximately 17 GW of rooftop distributed PV is installed by 2050 in the Mid cost scenario with net metering policies, and 8 GW without net energy metering. Ontario represents the largest market within Canada, but Alberta and Saskatchewan are also projected to have gigawatt-scale adoption. NEM policies (unlike net billing assumptions) have a significant influence on adoption. The ReEDS simulations use the Low and Mid Net Bill scenarios for rooftop PV assumptions.

3.5.3 Total costs are more sensitive to cost assumptions for wind and solar than to carbon limits.

Figure 59 shows the total system costs through 2050 for the core scenarios. Comparisons of scenarios depend on several key assumptions, the most important of which are likely the assumed cost of wind and solar generation and the assumed price of natural gas. Based on the standard (2018 ATB) cost assumptions, the more stringent carbon constraint in the CO_2 Constrained scenario[39] leads to a 5% increase in costs. The CO_2 constrained scenario reduces cumulative continental emissions by 10.5 billion metric tons at an average cost of $39/metric ton over the 30-year time horizon.

Low-cost wind and solar assumptions lead to overall cost reductions of 11% versus the BAU with even lower carbon emissions (through 2050) than the CO_2 Constrained scenario. Although the exact values are sensitive to assumptions, the low-cost wind and solar trajectories consistently lead to higher deployments of wind and solar in NARIS.

[39] For Canada, the more stringent carbon assumption is 92% reduction—versus 80% in the BAU—from 2005 levels. For the United States, this changes from 80% reduction in Carbon Constrained to state-based laws only in the BAU. General cost conclusions are similar in the two countries.

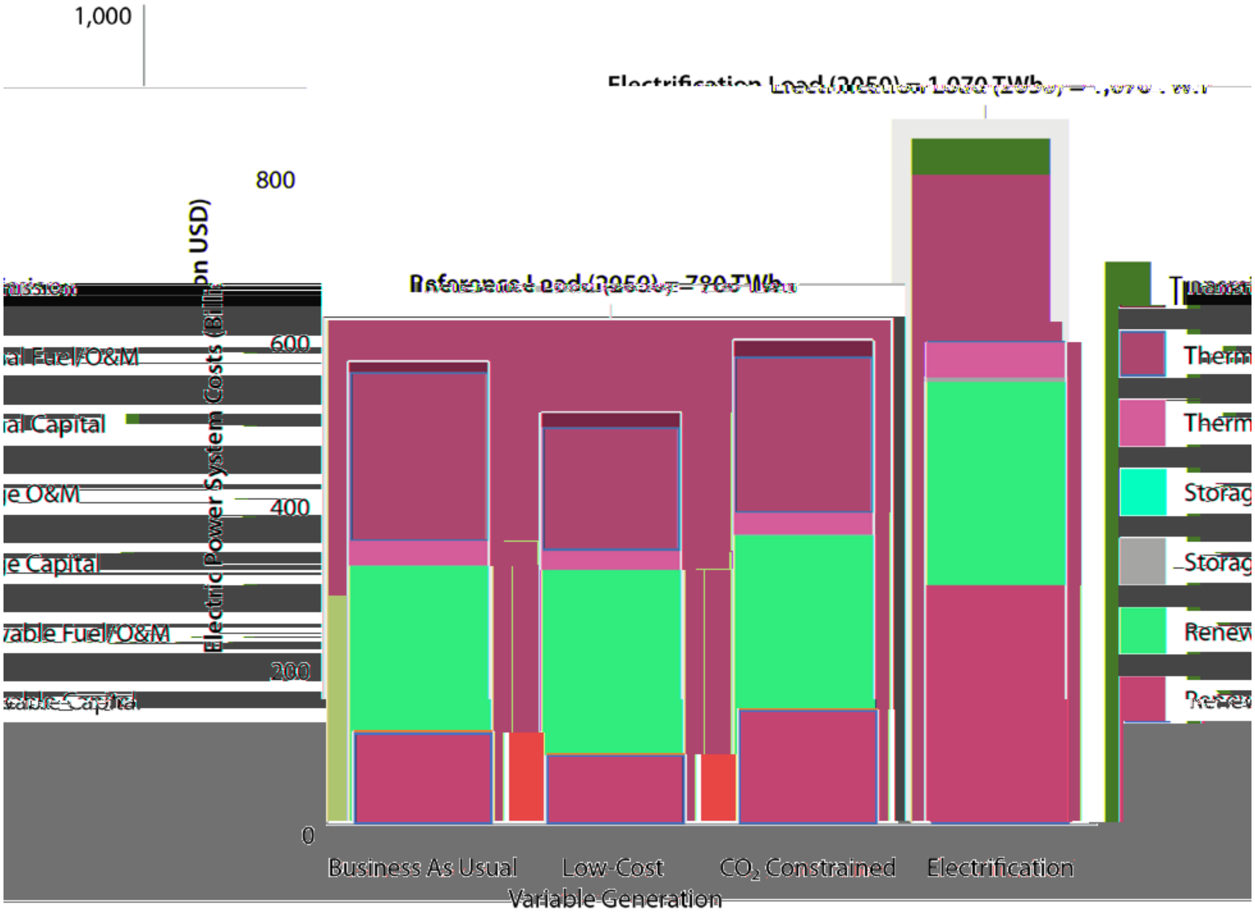


Figure 59. Total Canadian system costs for the core scenarios

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

3.5.4 Widespread electrification shifts infrastructure builds from other sectors to the electric sector.

This section describes some of the changes for the Electrification scenario, which is motivated by the emissions reduction potential discussed in Section 3.5.1. Most of the scenarios in NARIS assumed load growth consistent with default assumptions from the National Energy Board (Canada), EIA (United States), and PRODESEN (Mexico). To understand how key conclusions from the study could change under a high-electrification scenario, we applied the EnergyPATHWAYS model for Canada and Mexico along with assumptions used in the Electrification Futures Study for the United States to produce scenarios that assumed higher electrification of existing energy uses, such as transportation and building heating.

EnergyPATHWAYS is a comprehensive energy accounting and analysis framework specifically designed to examine the large-scale energy system transformations. It has been used in over a dozen national and subnational studies to calculate the impacts of energy system decisions out into the future in terms of infrastructure, emissions, and cost impacts to energy consumers and the economy more broadly. It considers potential electrification in the residential (water and space heating, cooking), commercial (space and water heating, and cooking), transportation (light-, medium-, and heavy-duty vehicles), and industrial process heat. The NARIS Electrification scenarios were designed for Canada to be consistent with the High electrification scenario from the Electrification Futures Study (Mai et al. 2018).

Projections of future energy service are based on projections of variables that correlate with energy services, such as population; these explanatory variables are referred to as service demand drivers, and they are exogenous inputs to the EnergyPATHWAYS model. Often, a chain of explanatory variables is used to determine service demand in a single subsector. For instance, residential space heating demand is based on residential square footage, which is based on the number of households, which is based on total population. Creation of hourly electricity profiles involves the additional step of multiplying annual final energy by a unitized shape representing the portion of electricity demand that occurs in each hour of the year. This type of granular load research data can be difficult to obtain and, in many cases, does not exist. The data sources for each subsector profile are shown in the appendix, and the data borrow from load research data in the United States and regressions on space heating load from the Electrification Futures Study.

Figure 60 and Figure 61 show the projected load growth from electrification through time and by province respectively. Electrification could add 35% to the reference Canadian load in 2050 (representing a 75% increase from 2020), with transportation making the largest share of the new demands. Regional distribution of electrification load growth is generally similar to regional distribution of load, although regions with existing building heating loads (e.g., Québec) tend to see less new electrification from buildings and less new electrification demand overall.

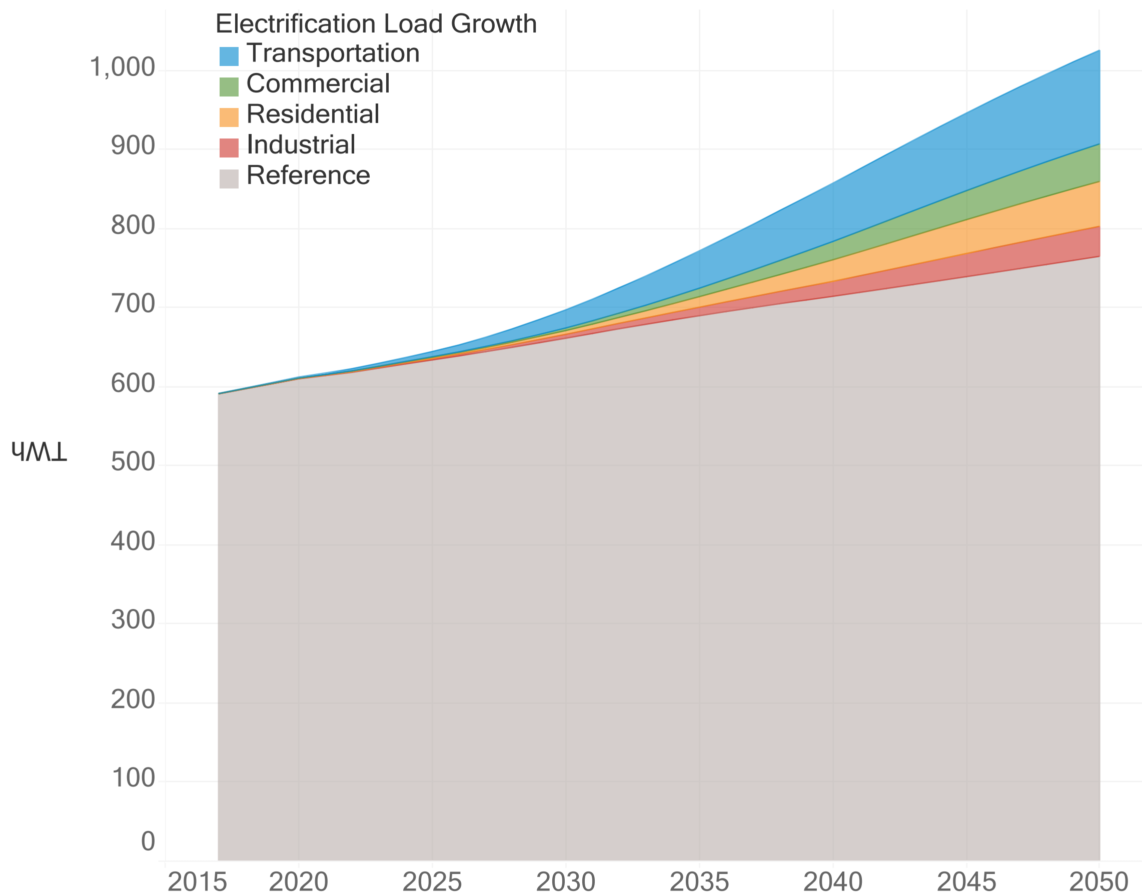


Figure 60. Load growth that is due to additional electrification in the Electrification scenario

The reference electricity growth, without incremental electrification, is shown in gray. The total load growth from electrification, colored for each sector, is 261 TWh (which is approximately 35% higher than the default load assumption) by 2050. The 2050 demand produced for NARIS using EnergyPATHWAYS is consistent with a series of recent internal Natural Resources Canada (NRCan) analyses using a variety of end-use models.

Figure 61. Map of electrification by province in 2050

This map of Canadian provinces shows the load growth in each province that is due to electrification. The size of each circle indicates the amount of electrification load growth. Sectors are divided into buildings (combination of residential and commercial), industry, and transport, with annotated numbers showing 2050 load growth for each in terawatt-hours.

Figure 62 shows the generation (left) and transmission (right) infrastructure built in the Electrification scenario versus the CO_2 Constrained scenario, which is the next-closest scenario in terms of infrastructure built in the model. There are double the wind and solar development and double the transmission development in the Electrification scenario. Though the benefits of electrification (possibly including both economics and emissions) might justify the investment, the quantity of infrastructure development is notable when compared to the other scenarios.

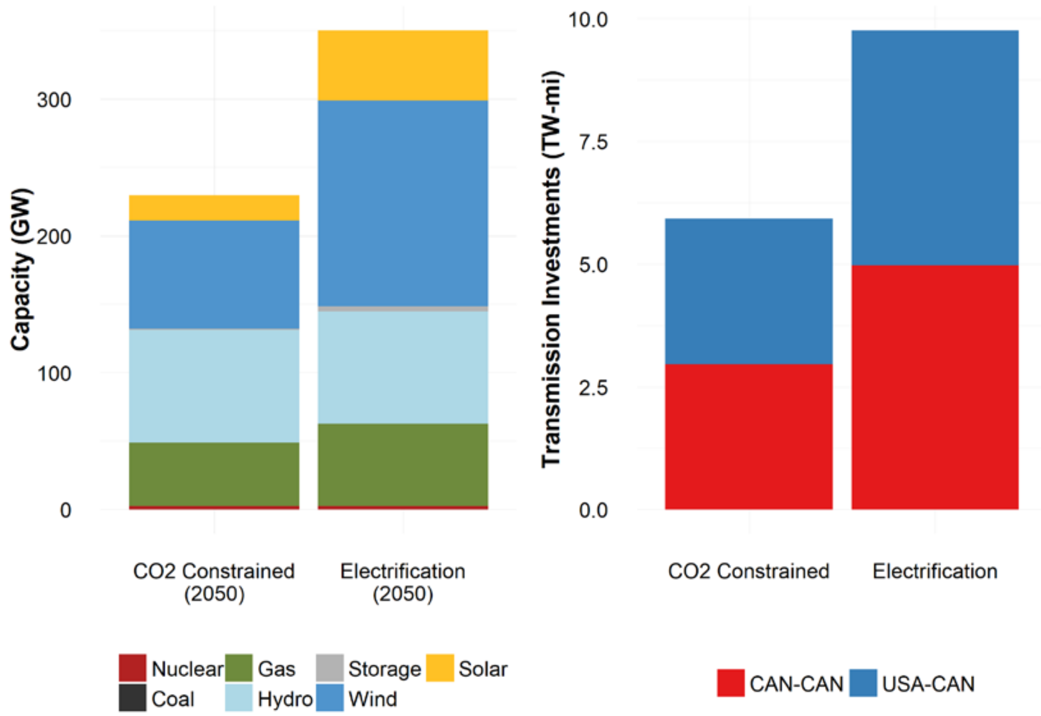


Figure 62. Generation capacity in 2050 (left) and total new transmission builds (right) for CO_2 Constrained and Electrification scenarios

In many respects, the ReEDS model results for the Electrification scenario look similar to those of the other scenarios, with one very substantial difference: the amount of infrastructure built in the Electrification scenario is significantly larger to serve the higher demand (and displace infrastructure in other sectors).

Major increases in capacity occur in gas (46 GW in CO_2 Constrained and 60 GW in Electrification), wind (79–150 GW), and solar (19–51 GW). Total transmission build increases by over 50% in both categories.

Though the figures above consider the total infrastructure in the electric sector, they do not consider the difference in demand. To directly compare the transmission infrastructure per unit of demand, Table 15 shows the total interregional transmission infrastructure (per ReEDS assumptions) and the infrastructure per terawatt-hour of demand in 2050. The nonelectrification scenarios generally have similar normalized transmission infrastructure (within 10% of 2024), but the Electrification scenario has 20% less interregional infrastructure per megawatt-hour of demand.

Table 15. Interregional Transmission per Terawatt-Hour of 2050 Demand

Scenario	Interregional Transmission (including within Canada and to the United States) (TW-mi)	Interregional Transmission per Terawatt-Hour of 2050 Demand (TW-mi/TWh)
Near-term (2024)	31.1	47.7
Business as Usual (2050)	34.2	43.0
Low-Cost VG	34.8	43.8
Carbon Constrained	36.2	45.5
Electrification	40.0	37.5

These results are from the ReEDS model; PLEXOS and PRAS models were not run on any scenarios that included electrification. Studying demand flexibility in PLEXOS and PRAS could lead to conclusions that reduce infrastructure needs (because of lower planning reserve requirements if peak demands were more flexible) or increase infrastructure needs (if nodal power flow analysis demonstrated more intrazonal transmission were needed).

Outside the general infrastructure builds and costs (which occur because of shifting infrastructure and costs to the electricity sector), the results from the Electrification scenario do not conflict with other scenarios on any key findings, including findings related to transmission value, exports, achieving low-carbon targets, and others. Ongoing method development for the Electrification Futures Study should help improve methods for treatment of these new, potentially flexible loads. The value of load flexibility could be addressed in future work. And load flexibility could reduce the need for planning reserve system-wide and increase the total flexibility available for minimizing curtailment.

3.5.5 Using better information during unit commitment reduces costs and curtailment.

There is significant uncertainty about (1) the quality of wind and solar forecasts in 2050 and (2) when commitment decisions will be made in regions both with and without ISOs. To address this uncertainty, we made three types of forecasts and ran the PLEXOS unit commitment and dispatch modeling for the Low-Cost VG scenario with each forecast in the geographically decomposed method described in Section 2.1.3. Forecast data are described in Section 2.2.1.

A system operator on the 2050 grid could use better information during unit commitment in different ways:

- **Improvements in Wind and Solar Forecasting:** Advanced site-specific forecasting techniques were not specifically applied for NARIS, but these techniques could help achieve better information for use by operators in unit commitment.
- **Shorter-Term Commitment Horizons:** Though many unit commitment decisions in system operators today are in the day-ahead time-frame, the U.S. grid in the NARIS 2050 scenarios consists mostly of generators that do not need commitment decisions to be made 24 hours in advance. Improved information could be used during unit commitment

by performing operational commitment closer to real time and repeating the process regularly (i.e., a "rolling" unit commitment). This method, mixed with generators that are flexible enough to adjust, could incorporate better information.

The model runs presented in Table 16 do not assume any specific rolling commitment horizon or forecasting technique; they utilize improved forecast information (from "blending" with real-time actual generation) to understand the potential benefit from using better information during unit commitment. Improving forecast error from 10% average MAE to 5%–0% reduces production costs by approximately $1 billion (1%) per step and reduces curtailment by approximately one percentage point per step.

Table 16. Continent-Wide Cost Impacts of Forecast Quality Used During Unit Commitment for the Low-Cost VG Scenario

Forecast	Annual Production Cost Increase ($)	Annual Production Cost Increase (%)	Total Wind and Solar Curtailment (%)
Perfect forecasts	—	—	9.1%
Forecast with 5% continental MAE (hours-ahead)	$800 million	1.1%	10.4%
Forecast with 10% continental MAE (day-ahead)	$2 billion	2.8%	11.1%

Forecasts were created using day-ahead model runs from the ECMWF model, historically synced with the 2012 meteorology presented in this report for dispatch. The forecast with 5% plant-averaged MAE was used for analysis described in other sections of this report. Note that these sensitivities are based on a penultimate, hourly, version of the model; absolute numbers may not be consistent with other sections.

4 Discussion and Future Work

This report represents the initial findings of NARIS from a Canadian perspective. However, the overarching conclusions are nearly identical throughout the continent; a report from a U.S. perspective is also available.

Summary of key learnings:

- Supply can balance with demand in a variety of scenarios with high contributions of renewable resources continentally. This was demonstrated through unit commitment and dispatch modeling with nodal transmission representation for one year of meteorological data and 7 years of historical meteorology for the Monte Carlo resource adequacy modeling.
- Thermal generators (nuclear, coal, and gas) do not produce as much energy as today, but significant thermal capacity remains in these scenarios to serve capacity adequacy needs of the system. This is economic from a system cost perspective, but more study is needed to understand the market implications. Increased transmission, hydropower, and storage could also fulfill some of these roles, and could be optimal depending on cost and emissions limit assumptions.
- Transmission helps enable economics and reliability (via resource adequacy) in these scenarios. Transmission expansion and cooperation between countries can save the system tens of billions of dollars continent-wide, while transmission and cooperation between regions can save hundreds of billions of dollars continent-wide.
- Flexibility to accommodate the variability in the system can come from flexible operation of hydropower and thermal generators, transmission, storage, curtailment, and other technologies and practices. This flexibility brings value to the system and reduces cost.

Some of the key assumptions and limitations of the study are listed in Section 1.3. These include:

- The ReEDS model used to create the transmission and generation expansion scenarios is a cost optimization. Though this helps illuminate potential low-cost pathways to a reliable grid, it should not be read as a blueprint for the continent or any specific region.
- We have performed scenarios with a variety of assumptions about wind and solar costs, hydropower costs, storage costs, natural gas prices, and other assumptions, and many of the conclusions in this report are robust to these assumptions (detailed results for each scenario are available on the NARIS website[40]). However, we have only represented a small fraction of the infinite possibilities of combinations of all potential grid conditions in 2050.
- Although we have addressed the adequacy portion of reliability, we have not addressed voltage or frequency stability in any detail in this work.
- Much of the work is based on meteorological conditions from 2007 through 2013. If these years are not representative of typical conditions in the future, or certain types of extreme events, there could be gaps in our analysis. Climate change has the potential to lead to meteorological conditions different from what we have studied here.

[40] "North American Renewable Integration Study," NREL, https://www.nrel.gov/analysis/naris.html.

More study is needed to understand some of the key caveats and questions that remain after this work. Some of these include:

- **Market Implications:** The optimizations in our pipeline of models led to very different operation at thermal generators (particularly natural gas combined cycle units) compared to today. Existing market structures may not create sufficient revenue for all generator types.
- **Extreme Events:** These scenarios were analyzed with state-of-the-art tools for data development and modeling. There were a variety of extreme meteorological events considered during the 7 years studied (e.g., storms, heat waves, polar vortex events). More-detailed analysis of how various technologies perform during extreme events (e.g., wind performance during a hurricane) can improve our understanding of grid reliability with today's infrastructure or the infrastructure of the future.
- **Transmission:** More-detailed transmission and power flow modeling can help us better understand the feasibility of these scenarios, and the costs and benefits of new transmission investments.
- **Demand:** The uncertainty of electricity demand patterns in the long-term future is significant due to climate change and electrification of other sectors. Building on recent work, including the Electrification Futures Study, electrification-focused studies can also help refine and quantify the benefits of electrification to other sectors and understand the potential flexibility of new demands. For NARIS, the more-detailed models (production cost and Monte Carlo resource adequacy) were not run on the Electrification scenario.
- **Evolving Technologies:** Assumptions of faster technology cost improvements in NARIS sensitivities for storage and distributed generation led to significant increases in their deployment (hundreds of GW for each). Ongoing cost reductions for offshore wind in North America would also likely lead to significant deployment increases. Other technology breakthroughs, including long-duration storage, carbon capture, geothermal, or concentrating solar power, could possibly lead to similar deployment expectations. Although the key conclusions in this report may be unaffected by these changes, there may be new conclusions and more efficient (or robust) ways to maintain a reliable, low-carbon grid with emerging technologies over the coming decades.

References

ABB. 2018. “Velocity Suite.” https://www.hitachiabb-powergrids.com/us/en/offering/product-and-system/energy-planning-trading/market-intelligence-services/velocity-suite.

Barrows, Clayton, Brendan McBennett, Josh Novacheck, Devon Sigler, Jessica Lau, and Aaron Bloom. 2019. “Multi-Operator Production Cost Modeling.” *IEEE Transactions on Power Systems* 34(6): 4429–4427. https://doi.org/10.1109/TPWRS.2019.2918849.

Bass, Frank M. 1969. “A New Product Growth for Model Consumer Durables.” *Management Science* 15(5): 215–227. https://doi.org/10.1287/mnsc.15.5.215.

Bloom, Aaron, Aaron Townsend, David Palchak, Joshua Novacheck, Jack King, Clayton Barrows, Eduardo Ibanez, et al. 2016. *Eastern Renewable Generation Integration Study*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-64472. https://doi.org/10.2172/1318192.

Bloom, Aaron, J. Novacheck, G. Brinkman, J.D. McCalley, A.L. Figueroa-Acevedo, A. Jahabani-Ardakani, H. Nosair, J. Casparay, D. Osborn, J. Lau. “The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study.” Submitted to *IEEE Transactions on Power Systems*.

Brinkman, Gregory. 2015. *Renewable Electricity Futures: Operational Analysis of the Western Interconnection at Very High Renewable Penetrations*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-64467. https://doi.org/10.2172/1225515.

Carvalho, D., A. Rocha, M. Gómez-Gesteira, and C. Silva Santos. 2014. “WRF Wind Simulation and Wind Energy Production Estimates Forced by Different Reanalyses: Comparison with Observed Data for Portugal.” *Applied Energy* 117: 116–126. https://doi.org/10.1016/j.apenergy.2013.12.001.

Cohen, Stuart, Jon Becker, Dave Bielen, Maxwell Brown, Wesley Cole, Kelly Eurek, Will Frazier, et al. 2019. *Regional Energy Deployment System (ReEDS) Model Documentation: Version 2018*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-72023. https://doi.org/10.2172/1505935.

Cole, Wesley, Will Frazier, Paul Donohoo-Vallett, Trieu Mai, and Paritosh Das. 2018. *2018 Standard Scenarios Report: A U.S. Electricity Sector Outlook*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71913. https://doi.org/10.2172/1481848.

DNV GL. 2014. *Integrating Renewable Energy in Europe: Final Report*. Bonn, Germany: DNV GL - Energy. 9011-700. https://ec.europa.eu/energy/sites/ener/files/documents/201406_report_renewables_integration_europe.pdf.

Dobbs, Alex. Tarek Elgindy, Bri-Mathias Hodge, and Anthony Florita. 2017. "Short-Term Solar Forecasting Performance of Popular Machine Learning Algorithms: Preprint." Presented at the International Workshop on the Integration of Solar Power into Power Systems (Solar Integration Workshop), Berlin, Germany, October 24–26, 2017. NREL/CP-5D00-70030. https://www.nrel.gov/docs/fy18osti/70030.pdf.

DOE (U.S. Department of Energy). 2016. *Hydropower Vision: A New Chapter for America's 1st Renewable Electricity Source*. DOE/GO-102016-4869. https://doi.org/10.2172/1502612.

Dong, Changgui, and Benjamin Sigrin. 2019. "Using Willingness to Pay to Forecast the Adoption of Solar Photovoltaics: A 'Parameterization + Calibration' Approach." *Energy Policy* 129: 100–110. https://doi.org/10.1016/j.enpol.2019.02.017.

Draxl, Caroline, Andrew Clifton, Bri-Mathias Hodge, and Jim McCaa. 2015. "The Wind Integration National Dataset (WIND) Toolkit." *Applied Energy* 151(1): 355–366. http://dx.doi.org/10.1016/j.apenergy.2015.03.121.

Draxl, C., B.M. Hodge, K. Orwig, W. Jones, K. Searight, D. Getman, S. Harrold, et al. 2013. *Advancements in Wind Integration Study Data Modeling: The Wind Integration National Dataset (WIND) Toolkit*. Golden, CO: National Renewable Energy Laboratory. NREL/CP-5D00-60269. https://www.nrel.gov/docs/fy14osti/60269.pdf.

EIA (U.S. Energy Information Administration). 2018. *Annual Energy Outlook 2018 with Projections to 2050*. https://www.eia.gov/outlooks/archive/aeo18/pdf/AEO2018.pdf..

EIPC (Eastern Interconnect Planning Collaborative). 2015. *Phase 2 Report: DOE Draft: Parts 2-7 Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios*. Eastern Interconnect Planning Collaborative.

Eurek, Kelly, Wesley Cole, David Bielen, Nate Blair, Stuart Cohen, Bethany Frew, Jonathan Ho, et al. 2016. *Regional Energy Deployment System (ReEDS) Model Documentation: Version 2016*. Golden, CO: National Renewable Energy Laboratory. TP-6A20-67067. https://doi.org/10.2172/1332909.

Frazier, A. Will, Wesley Cole, Paul Denholm, Daniel Greer, and Pieter Gagnon. 2020. "Assessing the Potential of Battery Storage as a Peaking Capacity Resource in the United States," *Applied Energy* 275: 115385. https://doi.org/10.1016/j.apenergy.2020.115385.

Gagnon, Pieter, Robert Margolis, Jennifer Melius, Caleb Phillips, and Ryan Elmore. 2016. *Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-65298. https://doi.org/10.2172/1236153.

Garcia-Diez, M., J. Fernandez, L. Fita, L., M. Menendez, F.J. Mendez, and J.M. Gutierrez. 2012. "Using WRF to Generate High Resolution Offshore Wind Climatologies." Proceedings: 8º Congreso Internacional AEC, Salamanca, Spain, September 2012. http://www.meteo.unican.es/en/node/73063.

GE Energy. 2010. *Western Wind and Solar Integration Study*. Prepared for the National Renewable Energy Laboratory by GE Energy. Golden, CO: National Renewable Energy Laboratory. NREL/SR-550-47434. https://doi.org/10.2172/981991.

GE Energy Consulting. 2016. *Pan-Canadian Wind Integration Study (PCWIS): Section 1: Summary Report*. Prepared for Canadian Wind Energy Association (CanWEA) by GE Energy Consulting. October 14, 2016. https://canwea.ca/wp-content/uploads/2016/07/pcwis-section01-summaryreport.pdf.

Government of Canada. 2016. *Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy*. Gatineau, Quebec: Environment and Climate Change Canada. https://unfccc.int/files/focus/long-term_strategies/application/pdf/canadas_mid-century_long-term_strategy.pdf.

Heard, B. P., B. W. Brook, T. M. L. Wigley, and C. J. A. Bradshaw. 2017. "Burden of Proof: A Comprehensive Review of the Feasibility of 100% Renewable-Electricity Systems." *Renewable and Sustainable Energy Reviews* 76 (September 1, 2017): 1122–1133. https://doi.org/10.1016/j.rser.2017.03.114.

Ji-Hang, Li, Zhen-Hai Guo, Wang Hui-Jun. 2014. "Analysis of Wind Power Assessment Based on the WRF Model." *Atmospheric and Oceanic Science Letters* 7(2): 126–131. https://doi.org/10.3878/j.issn.1674-2834.13.0078.

Lew, D., G. Brinkman, E. Ibanez, A. Florita, M. Heaney, B. M. Hodge, M. Hummon, et al. 2013. *Western Wind and Solar Integration Study Phase 2*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5500-55588. https://dx.doi.org/10.2172/1095399.

Liu, Shucheng. 2014. "Direct Testimony of Dr. Shucheng Liu on Behalf of the California Independent System Operator Corporation." Rulemaking 13-12-010 for California Public Utilities Commission.

Lundquist, J.K., A. Purkayastha, C. St. Martin, and R. Newsom. 2014. *Estimating the Wind Resource in Uttarakhand: Comparison of Dynamic Downscaling with Doppler Lidar Wind Measurements*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5000-61103. https://doi.org/10.2172/1126840.

MacDonald, Alexander E., Christopher T. M. Clack, Anneliese Alexander, Adam Dunbar, James Wilczak, and Yuanfu Xie. 2016. "Future Cost-Competitive Electricity Systems and Their Impact on US CO_2 Emissions." *Nature Climate Change* 6(5): 526–531. https://doi.org/10.1038/nclimate2921.

Maclaurin, Galen, Nick Grue, Anthony Lopez, and Donna Heimiller. 2019. *The Renewable Energy Potential (reV) Model: A Geospatial Platform for Technical Potential and Supply Curve Modeling*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-73067. https://doi.org/10.2172/1563140.

Mai, Trieu, Paige Jadun, Jeffrey Logan, Colin McMillan, Matteo Muratori, Daniel Steinberg, Laura Vimmerstedt, et al. 2018. *Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71500. https://doi.org/10.2172/1459351.

Masson, G., and I. Kaizuka. 2020. *PVPS Trends in Photovoltaic Applications 2020: Task 1 Strategic PV Analysis and Outreach*. International Energy Agency Photovoltaic Power Systems Programme. IEA-PVPS T1-38:2020. https://iea-pvps.org/wp-content/uploads/2020/11/IEA_PVPS_Trends_Report_2020-1.pdf.

Miller, N.W., M. Shao, S. Pajic, and R. D'Aquila. 2014. *Western Wind and Solar Integration Study Phase 3: Frequency Response and Transient Stability*. Golden, CO: National Renewable Energy Laboratory. NREL/SR-5D00-62906. https://doi.org/10.2172/1167065.

NEB (National Energy Board). 2017. *Canada's Energy Future 2017: Energy Supply and Demand Projections to 2040*. https://doi.org/10.35002/sqvz-gs91.

NERC (North American Electric Reliability Corporation). 2020. *2020 Long-Term Reliability Assessment*. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf.

———. 2018. *2018 Long-Term Reliability Assessment*. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf.

Novacheck, Joshua, Greg Brinkman, and Gian Porro. 2018. *Operational Analysis of the Eastern Interconnection at Very High Renewable Penetrations*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71465. https://doi.org/10.2172/1476255.

Rossol, Michael, Gregory Brinkman, Grant Buster, Paul Denholm, Joshua Novacheck, and Gord Stephen. 2019. "An Analysis of Thermal Plant Flexibility Using a National Generator Performance Database." *Environmental Science & Technology* 53(22): 13486–13494. https://doi.org/10.1021/acs.est.9b04522.

Rossol, Michael, Grant Buster, and Mike Bannister. 2021. "The Renewable Energy Potential Model (reV)." https://github.com/NREL/reV.

Schlag, Nick, Arne Olson, Elaine Hart, Ana Mileva, Ryan Jones, Carlo Brancucci Martinez-Anido, Bri-Mathias Hodge, et al. 2015. *Western Interconnection Flexibility Assessment: Final Report*. San Francisco, CA: Energy and Environmental Economics, Inc. https://www.ethree.com/wp-content/uploads/2017/02/WECC_Flexibility_Assessment_Report_2016-01-11-1.pdf.

SEMARNAT-INECC. 2016. *Mexico's Climate Change Mid-Century Strategy*. Mexico City, Mexico: Ministry of Environment and Natural Resources (SEMARNAT), and National Institute of Ecology and Climate Change (INECC). https://unfccc.int/files/focus/long-term_strategies/application/pdf/mexico_mcs_final_cop22nov16_red.pdf.

SENER (Secretaría de Energía). 2018. "Programa de Desarrollo del Sistema Eléctrico Nacional 2018-2032." Mexico City, Mexico: La Secretaría de Energía. https://www.gob.mx/sener/acciones-y-programas/programa-de-desarrollo-del-sistema-electrico-nacional-33462.

Sigrin, Ben, and Easan Drury. 2014. "Diffusion into New Markets: Economic Returns Required by Households to Adopt Rooftop Photovoltaics." Energy Market Prediction: Papers from the 2014 AAAI Fall Symposium. https://www.aaai.org/ocs/index.php/FSS/FSS14/paper/viewFile/9222/9123

Sigrin, Ben, and Meghan Mooney. 2018. *Rooftop Solar Technical Potential for Low-to-Moderate Income Households in the United States*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-70901. https://doi.org/10.2172/1434891.

Skamarock, William C., Joseph B. Klemp, Jimy Dudhia, David O. Gill, Dale M. Barker, Michael G. Duda, Xiang-Yu Huang, Wei Wang, and Jordan G. Powers. 2008. *A Description of the Advanced Research WRF Version 3*. Boulder, CO: National Center for Atmospheric Research. NCAR Tech Notes-475+STR. http://dx.doi.org/10.5065/D68S4MVH.

Stephen, Gord. 2021. Probabilistic Resource Adequacy Suite (PRAS) v0.6 Model Documentation. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5C00- 79698. https://www.nrel.gov/docs/fy21osti/79698.pdf.

Uría-Martínez, Rocío, Megan M. Johnson, Patrick W. O'Connor, Nicole M. Samu, Adam M. Witt, Hoyt Battey, Timothy Welch, Marisol Bonnet, and Sarah Wagoner. 2018. *2017 Hydropower Market Report*. Oak Ridge, TN: Oak Ridge National Laboratory. OE/EE-1737. https://doi.org/10.2172/1513459.

White House, The. 2016. *United States Mid-Century Strategy for Deep Decarbonization*. November 2016. https://unfccc.int/files/focus/long-term_strategies/application/pdf/mid_century_strategy_report-final_red.pdf.

Appendix. Electrification Data Sources

The tables below list the drivers used to project Canadian energy services. These drivers form the backbone of future projections of energy services.

Table A-1. Key Data Inputs for Electrification Demand Projections

Service Demand Driver	Data Source	Base Driver	Input Rears	Geography
Population	Statistics Canada [2]		2013–2063	Province
Residential Square footage	NRCan [1]	# of households	1990–2015	Province agg. [3]
Number of households	NRCan [1]	Population	1990–2015	Province agg. [3]
Commercial square footage	NRCan [1]	Population	1990–2015	Province agg. [4]
Passenger-kilometers	NRCan [1]	Population	1990–2015	Province agg. [5]
Tonne-kilometers	NRCan [1]		1990–2015	Province agg. [5]

Table A-2. Subsector Data Sources for Electrification Demand Projections

Subsector	Data Source	Methodology	Input Years	Geography	Demand Driver	Electricity Shape
Residential space heating	NRCan [1]	Stock & service	1990–2015	Province agg. [3]	Residential square footage	Regression [6]
Residential water heating	NRCan [1]	Stock & service	1990–2015	Province agg. [3]	Number of households	Regression [6]
Residential cooking	NRCan [1]	Stock & service	1990–2015	Province agg. [3]	Number of households	Northwest Energy Efficiency Alliance Residential Building Stock Assessment Metering Study [8]
Commercial water heating	NRCan [1]	Stock & service	1990–2015	Province agg. [4]	Commercial square footage	Regression [6]
Commercial space heating	NRCan [1]	Stock & service	1990–2015	Province agg. [4]	Commercial square footage	Regression [6]
Commercial cooking [9]	NRCan [1], EIA [6]	Stock & service	1990–2015	Province agg. [4]	Commercial square footage	Electric Power Research Institute (EPRI) Load Shape Library 5.0

Subsector	Data Source	Methodology	Input Years	Geography	Demand Driver	Electricity Shape
Light duty autos	NRCan [1]	Stock & service	1990–2015	Province agg. [5]	Population	Transportation Survey Data [7]
Light duty trucks	NRCan [1]	Stock & service	1990–2015	Province agg. [5]	Population	Transportation Survey Data [7]
Medium duty trucks	NRCan [1]	Stock & service	1990–2015	Province agg. [5]	Extrapolated growth rate	Flat shape
Heavy duty trucks	NRCan [1]	Stock & service	1990–2015	Province agg. [5]	Extrapolated growth rate	Flat shape
Industrial Process Heat [10]	NRCan [1], EIA [6]	Energy projection	1990–2040	Province agg. [3]	Extrapolated growth rate	EPRI Load Shape Library 5.0

[1] NRCan Data: http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive_tables/list.cfm

[2] Statistics Canada: https://www150.statcan.gc.ca/t1/tbl1/en/cv.action?pid=1710005701

[3] NRCan divides residential data into the following eleven regions: Alberta, British Columbia, Manitoba, New Brunswick, Newfoundland, Nova Scotia, Ontario, Prince Edward Island, Québec, Saskatchewan, and Territories

[4] NRCan divides commercial data into the following seven regions: Alberta, Atlantic, British Columbia and Territories, Manitoba, Ontario, Québec, and Saskatchewan

[5] NRCan divides transportation data into the 10 regions: Alberta, British Columbia and Territories, Manitoba, New Brunswick, Newfoundland and Labrador, Nova Scotia, Ontario, Prince Edward Island, Québec, and Saskatchewan

[6] Regressions for weather year 2012 were done using daily heating degree day and cooling degree day values across each of the 150 Canadian Census divisions. Additional independent variables include climate type and daily insolation. The regressions were trained as part of the Electrification Futures Study based on building simulations in different climate zones.

[7] Evolved Energy Research analysis of U.S. National Transportation Survey Data used in the Electrification Futures Study.

[8] Northwest Energy Efficiency Alliance Residential Building Stock Assessment Metering Study

[9] The proportion of total commercial load that is used for cooking was calculated based on EIA data and used to establish stock and service demand estimates for Canada

[10] Canadian process heating estimates for Canada through 2040 come from NRCan data not published online obtained from NRCan staff. The proportion of process heating that becomes electrified is based on the Electrification Futures Study 'high' scenario.

National Renewable Energy Laboratory
15013 Denver West Parkway, Golden, CO 80401
303-275-3000 • www.nrel.gov

NREL prints on paper that contains recycled content.

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency and Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

NREL/TP-6A20-79225 • June 2021