GE
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Western Regional Electricity Cooperation and Strategic Infrastructure (RECSI) Study

Final Report

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Prepared by: GE Energy Consulting

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imagination at work

Legal Notices

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- BC Hydro
- Government of British Columbia
- Government of Manitoba
- Government of Northwest Territories
- Manitoba Hydro
- Natural Resources Canada (NRCan)
- SaskPower

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Acronyms and Nomenclatures

Unit Types

BESS	Battery Energy Storage System
CAES	Compressed Air Energy Storage
CC-GAS	Combined Cycle Gas Turbine
CCS	Carbon Capture and Sequestration
COGEN	Cogeneration Plant
DPV	Distributed Photovoltaic
HYDRO	Hydropower / Hydroelectric plant
IGCC	Integrated Gasification Combined Cycle
NUCLEAR	Nuclear Power Plant
OTHER	Includes Biomass, Waste-To-Energy, Etc.
PEAKER	SC-GAS, RE/IC, and other Peaking Plants
PSH	Pumped Storage Hydro
PV	Photovoltaic
RE/IC	Reciprocating Engine/Internal Combustion Unit
SC-GAS	Simple Cycle Gas Turbine
SOLAR	Solar Power Plant
ST-COAL	Steam Coal
ST-GAS	Steam Gas
WIND	Wind Power Plant

Canadian Provinces and Territories

AB	Alberta
BC	British Columbia
MB	Manitoba
NB	New Brunswick

ON	Ontario
QC	Quebec
MAR	Maritime
NL	Newfoundland and Labrador
NS	Nova Scotia
NT	Northwest Territories
PE	Prince Edward Island
SK	Saskatchewan

General Glossary

AESO	Alberta Electric System Operator
Btu	British thermal unit
CAD	Canadian Dollar
CanWEA	Canadian Wind Energy Association
CF	Capacity Factor
CO2	Carbon Dioxide
DA	Day-Ahead
DR	Demand Response
EI	Eastern Interconnection
ERGIS	Eastern Renewable Generation Integration Study
FERC	Federal Energy Regulatory Commission
FOM	Fixed Operations and Maintenance
GE	General Electric / GE Energy Consulting
GEII	General Electric International, Inc.
GE EC	GE Energy Consulting
GE MAPS	GE's "Multi Area Production Simulation" Software
GE MARS	GE's "Multi Area Reliability Simulation" Software
GE PSLF	GE's "Positive Sequence Load Flow" Software
GPCM	Gas Pipeline Competition Model

GW	Gigawatt
GWh	Gigawatt Hour
HA	Hour-Ahead
HR	Heat Rate
IPP	Independent Power Producers
IRP	Integrated Resource Planning
kJ	Kilo Joules
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
lbs.	Pounds (British Imperial Mass Unit)
LDC	Load Duration Curve
LMP	Locational Marginal Prices
LNG	Liquefied Natural Gas
LNR	Load Net of Renewable Energy
MISO	Midcontinent ISO
MM	Millions (Roman Numerals: Thousand Thousand)
MMBtu	Millions of BTU
MMT	Million Metric Tons
MVA	Megavolt Ampere
MW	Megawatts
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation
NOX	Nitrogen Oxides
NRCan	Natural Resources Canada
NREL	National Renewable Energy Laboratory
NTG	Net to Grid
NWP	Northwest Power Pool
O&M	Operations & Maintenance

PCWIS	Pan-Canadian Wind Integration Study
PPA	Power Purchase Agreement
REC	Renewable Energy Credit
RFP	Request for Proposal
RPS	Renewable Portfolio Standard
RT	Real-Time
SCEC	Security Constrained Economic Dispatch
SCUC	Security Constrained Unit Commitment
SO2	Sulfur Dioxide
SOX	Sulfur Oxides
Tonne	Metric Ton
TW	Terawatts
TWh	Terawatt Hour
USD	USA Dollars
VOM	Variable Operations and Maintenance
WECC	Western Electricity Coordinating Council
WI	Western Interconnection
WWSIS2	Western Wind and Solar Integration Study Phase 2

1 Executive Summary

1.1 Study Objective

The principal objective of this study under the Regional Electricity Cooperation and Strategic Infrastructure Initiative (RECSI), was to evaluate and compare electricity infrastructure projects, in the Western provinces, from a list of proposed projects shown in the table below, based on the projects' costs and their impact on system-wide greenhouse gas (GHG) reductions, with the potential to assist the region, particularly Alberta and Saskatchewan, transition to a sustainable non-emitting electricity generation portfolio. Most of the projects are assumed to come online in 2030, except for the hydroelectric projects - which are expected to require a longer development time - and come on line in 2040.

Table 1-1: List of Study Projects

Project	Description	Number of Projects and Options	Study Year (Year Projects Come Online)
BAU	Business-As-Usual	4	2030 & 2040
A	New intertie between British Columbia and Alberta	2	2030
B	New intertie between Saskatchewan and Manitoba	3	2030
C	New internal transmission added to aid in development of new renewable capacity in Alberta and Saskatchewan	2	2030
D	New hydroelectric capacity in Alberta and Saskatchewan	4	2040
E	Coal conversion in Alberta and Saskatchewan to lower GHG emissions	3	2030
F	Bulk storage addition against value of new hydro or new transmission	2	2030
G	Electrification of LNG and natural gas production	4	2030
H	Construction of hydro and transmission line to interconnect the Northwest Territories with Alberta	1	2040
I	New intertie and incremental upgrade to existing and limited Alberta and Saskatchewan intertie	1	2030
J	Create simultaneous transfer capability between Alberta and British Columbia and Montana-Alberta transmission line	1	2030
K	Combination of Project A and Project C	2	2030
	Total	**29**	

GHG, Carbon, and CO2 are used interchangeably in this report. Although GHG includes other types of gases, CO2 is the major component of GHG[1].

The options within each project are listed in Table 1-2, where "West" refers to the Western Interconnection (also called Western Electricity Coordinating Council or WECC) which includes British Columbia and Alberta, and "East" refers to Eastern Interconnection, which includes Saskatchewan and Manitoba. Hydro plant in Northwest Territories is modeled in the West.

Table 1-2: List of Study Projects (Including Options)

Study Projects	Description
BAU Case, West	Business-As-Usual (BAU) Case, BC+AB
BAU Case, East	Business-As-Usual (BAU) Case, SK+MB
Project A, North, West	New Northern Intertie between BC and AB
Project A, South, West	New Southern Intertie between BC and AB
Project B, Option 1, East	New Intertie between SK and MB - Option 1
Project B, Option 2A, East	New Intertie between SK and MB - Option 2A
Project B, Option 2B, East	New Intertie between SK and MB - Option 2B
Project C, West	New Internal Transmission in AB
Project C, East	New Internal Transmission in SK
Project D, Option 1, West	New Hydropower plant in AB, Option 1
Project D, Option 1, East	New Hydropower plant in SK, Option 1
Project D, Option 2, West	New Hydropower plant in AB, Option 2
Project D, Option 2, East	New Hydropower plant in SK, Option 2
Project E, AB > CC, West	SC-GAS Conversion to CC-GAS in AB
Project E, SK > CCS, East	ST-COAL Conversion to CCS in SK
Project E, SK > CC, East	ST-COAL Conversion to CC-GAS in SK
Project F, West	New CAES Installation in AB
Project F, East	New Grid Scale Battery Storage in SK
Project G, Option 1, West	Electrification of LNG based Load in BC, Option 1
Project G, Option 2, West	Electrification of LNG based Load in BC, Option 2
Project G, Option 3, West	Electrification of LNG based Load in BC, Option 3
Project G, Option 4, West	Electrification of LNG based Load in BC, Option 4
Project H, West	Construction of NT Hydro and T-Line to AB
Project I, West + East	New Intertie between AB and SK
Project J, West	Simultaneous Transfer Capability between AB-BC and MATL
Project K, North. West	Combination of Project A, North, and Project C
Project K, South. West	Combination of Project A, South, and Project C

[1] https://www.epa.gov/ghgemissions/overview-greenhouse-gases

These projects and options are described in more detail in Section 5. In this report, these projects and options are collectively referred to as "study projects".

1.2 Project Tasks

The project team performed a detailed model-based simulation of the Western (i.e., WECC) and Eastern Interconnections and evaluated their overall impact on system-wide carbon emissions and variable production costs, and factored in their high-level capital costs, in order to develop a carbon reduction and annual cost metrics. The study covered seven principal tasks (shown in the table below) which were performed in stages and involved regular meetings with NRCan and TAC members to review and agree on study assumptions and data.

Table 1-3: Western RECSI Study Tasks

Task	Description
Task 1 – Cost and Production Data Gathering	Establish and gather required data for dispatch modeling from each jurisdiction.
Task 2 – Technical Assessment	Develop high level cost estimate, schedule and operational impact (including operating reserves) for the study projects.
Task 3 – Developing production cost model	Establish methodology and run production cost model for base case and compare with each study project.
Task 4 – GHG reduction	Quantify the GHG reduction potential based on Task 3 for each study project.
Task 5 - Additional Analysis	Address sensitivities such as different CO2 prices, varying natural gas prices, dispatch alternatives or hydrology.
Task 6 – Regulatory Considerations	Identify regulatory considerations that may impact development of the projects evaluated in this study.
Task 7 - Final Reporting	Draft final report and obtain report approval from Technical Advisory Committee, Steering Committee and NRCan.

1.3 Approach and Methodology

The study employed the GE Concorda Suite Multi-Area Production Simulation (GE MAPS), a Security Constrained Unit Commitment and Economic Dispatch (SCUC and SCED) production costing model, for simulation of the power systems of the Western provinces. The model includes full representation of the grid-scale generation resources (including net-to-grid portion of cogeneration plants) and all the transmission network topology and grid elements of the North American Western and Eastern Interconnections covering both Canadian and USA power systems. For the purposes of this study, there were in fact two separate and distinct GE MAPS model used. One for the Western Interconnection and one for the Eastern Interconnection, as the two interconnections have no AC interties and therefore are not electrically synchronous.

Inputs into GE MAPS include a solved load flow of the transmission systems of the entire Western and Eastern Interconnections including the following: all the inter-provincial, inter-pool, and inter-country transmission constraints, full representation of the all the grid-scale generation resources, load projections by area (including hourly load shapes), fuel price projections by region and month, and other parameters that define each individual power system's operational characteristics such as operating reserve requirements.

GE MAPS generates a vast amount of output data. Based on previous study experience, the project team recommended a set of output data and metrics that would be adequate to reveal the significant performance attributes of the study projects.

The approach included development of a Business-As-Usual (BAU) case for 2030 and 2040, which was used as the basis for comparison of the incremental impact of the study projects. The evaluation of each study project was based on addition of the proposed transmission, generation, and energy storage elements to the BAU case.

GE MAPS model covers all of North America's Western and Eastern Interconnections. Therefore, the transmission grid and generation resources of the interconnected power systems in the USA are fully represented, which include all the necessary load and fuel price projections to the study year. GE Energy Consulting regularly updates the full GE MAPS database, including the USA data sets. The USA renewable energy resources in the model are based on the projection of the current state-by-state renewable portfolio standards to the study years. All the current applicable environmental regulations are taken into account in the modeling of the USA power systems. The USA portion of the model was kept unchanged across all the projects evaluated in this study.

Detailed model results of each project are provided in Section 5. The overall comparison of projects based on their impact on Adjusted Production Costs and Carbon Emissions are presented in a later sub section of this executive study, and also in Section 7 the report.

A number of sensitivity analyses were also performed in order to assess the impact a number of variables on generation dispatch, variable production costs, and carbon emissions. The list of sensitivities was reviewed and approved by the TAC members. For efficiency the TAC members selected a sub-set of study projects to minimize the amount of effort. Sensitivities considered included: High Carbon Price with Carbon Border Tariff, High Gas Price, Real-Time Hydro, and Operating Reserves. Sensitivity analyses results are described in detail in Section 6. In total, 35 sensitivity runs were performed.

The study also took account of the investment capital costs of each new transmission, generation, and energy storage element within the study projects. The capital costs estimates were mainly provided by the TAC committee members, which were then reviewed and, in some cases, supplemented by GE's project partners, namely Electranix (for transmission projects) and Knight Piésold (for hydropower projects).

1.4 Project Metrics and Key Findings

The principal and relevant metrics based on the outputs of the GE MAPS model are the Carbon Emissions and Adjusted Production Costs. Carbon emissions are the CO2 emissions by the fossil fuel-based generation resources. GE MAPS calculates the CO2 emissions based on each power plant's fuel type and heat rate. Adjusted Production Cost is the sum of annual variable production costs in each province, adjusted to account for the annual net import costs and export revenues. It should be noted that generation dispatch depends on the variable generation costs of each power plant, and the fixed and capital costs of power plants that are already installed are not drivers of dispatch decisions.

In addition to these metrics from GE MAPS modeling, the investment capital costs of each new transmission, generation, and energy storage element within the study projects were also taken into account.

The final set of metrics used for each project evaluated included the following components:

- Carbon Emissions Reductions:
  - The change in annual carbon emissions from generation resources in each province relative to the BAU case.
  - A negative value is a decrease in carbon emissions relative to the BAU case, a positive value is an increase in carbon emissions relative to the BAU case.
  - In units of Million Tonne (i.e., Million Metric Ton)
- Total Capital Costs:
  - The total cost of transmission facilities, generation facilities, conversion, or other costs for the project.
  - In units of CAD $ Millions or ($MM)
- Total Net Annual Costs:
  - The sum of the change in Annual Adjusted Production Costs relative to the BAU case, plus the Annual Capital Costs of the project.
  - A positive value is a net annual cost, a negative value is a net annual saving.
  - In units of CAD $ Millions, or ($MM)

Variable production costs (or production costs for short) is the sum of generation fuel costs, generation start-up costs, variable operation & maintenance (VOM) costs, and carbon emission costs in each province. As noted, Adjusted Production Costs do not include any fixed or capital costs, since these costs do not impact economic dispatch of plants.

The Annual Capital Cost of each project is the annual financial payment required to cover the capital investment cost of the project.

Annual Capital Cost for each project was calculated based on the following assumptions:

- Inflation Rate: 2%
- Cost Base Year: 2018
- Weighted Average Cost of Capital: 7% (Real Rate)
- Economic Life for Transmission projects: 40 Years
- Economic Life for Wind projects: 20 Years
- Economic Life for Coal Conversion projects: 20 Years
- Economic Life for Storage projects: 20 Years
- Economic Life for Hydropower projects: 60 Years

Effective year basis for the cost components are:

- Adjusted Production Costs: The year the project comes online, either 2030 or 2040
- Hydro Capital Costs: 2017
- Transmission Capital Costs: 2018
- All other Costs: 2018

All cost components were converted to 2018 base year in Canadian dollars.

The Carbon Emissions Reduction values and the Annual Cost values were used to assess the annual dollar cost for each unit of reduction in carbon emissions (or inversely, amount of carbon emissions reduced per dollar of annual cost), resulting in the following principal metrics for evaluation of each project:

- Carbon Reduction/Annual Cost (Tonne/$1000)
- Annual Cost/Carbon Reduction ($/Tonne)

The following table summarizes the results for all the projects. The color highlights, described below the table, identify the projects which created either an increase or reduction in carbon emissions while yielding an increase or decrease in annual costs.

The following bullets provide a description and the meaning of the negative and positive values in each column:

- Carbon Emissions: This is the change in carbon emissions relative to the BAU case. A negative value signifies reduction in carbon emissions. A positive value signifies increase in carbon emissions.

- Net Annual Costs: This is the sum of the Annualized Capital Costs of each project and the change in Adjusted Production Costs relative to the BAU case. The change in the Adjusted Production Costs is the difference in the variable production cost, adjusted for import cost and export revenues, of all the Canadian provinces impacted by the project. In some cases, the change in Adjusted Production Costs can result in a reduction in overall system variable production costs because of the project. It is possible that the overall annual system-wide benefits of the project could be greater than the annual capital cost of the project. A negative value for Net Annual Costs represents a decrease in total costs, and an increase in total costs is denoted by a positive value.

- Interpretation of metrics in the following table depend on the signs of their numerator and denominator, as described in the following bullets.

    - If both the Net Annual Cost Change and the Carbon Emissions Change are negative, then the project reduces both system-wide costs and carbon emissions. This is the best outcome, a win-win case.

    - If the Net Annual Cost Change is positive, but the Carbon Emissions Change is negative, then the project increases system-wide costs, but reduces system-wide carbon emissions. This is a lose-win case.

    - If the Net Annual Cost Change is negative, but the Carbon Emissions Change is positive, then the project reduces system-wide cost, but increases system-wide carbon emissions. This is a win-lose case.

    - If both Net Annual Cost Change and the Carbon Emissions Change are positive, then the project increases both system-wide costs and system-wide carbon emissions. This is a lose-lose case.

Table 1-4: Study Project Metrics

Project/Option	Net Annual Cost Change Increase: Positive Decrease: Negative ($Million)	Carbon Emissions Change Increase: Positive Decrease: Negative (Million Metric Tonne)	[Net Annual Cost Change] per Unit of [Change in Carbon Emissions] ($/Tonne)
Project A, North, West	72.36	-1.12	-64.61
Project A, South, West	49.97	-0.86	-58.11
Project B, Option 1, East	87.19	-1.19	-73.27
Project B, Option 2A, East	-5.73	-0.45	12.73
Project B, Option 2B, East	-16.93	-0.41	41.29
Project C, West	146.42	-1.93	-75.87
Project C, East	14.47	0.00	0.00
Project D, Option 1, West	217.31	-0.61	-354.21
Project D, Option 1, East	62.56	-0.16	-381.75
Project D, Option 2, West	451.98	-1.76	-256.30
Project D, Option 2, East	47.98	-0.37	-128.35
Project E, AB > CC, West	916.02	2.11	434.13
Project E, SK > CCS, East	663.34	-6.89	-96.28
Project E, SK > CC, East	321.01	-6.06	-52.97
Project F, West	332.10	-1.88	-176.65
Project F, East	-12.05	0.21	-57.36
Project G, Option 1, West	-41.15	-2.59	15.89
Project G, Option 2, West	-43.26	-3.47	12.47
Project G, Option 3, West	-32.03	-2.12	15.11
Project G, Option 4, West	70.25	-5.19	-13.54
Project H, West	58.89	-0.28	-207.73
Project I, West + East	-13.36	0.40	-33.39
Project J, West	-37.14	-0.51	72.82
Project K, North. West	258.37	-2.71	-95.34
Project K, South. West	227.10	-2.50	-90.84

Green:	Annual Costs Decreased and Carbon Emissions Decreased
Blue:	Annual Costs Increases and Carbon Emissions Decreased
Yellow:	Annual Costs Decreased and Carbon Emissions Increased
Red:	Annual Costs Increased and Carbon Emissions Increased

Table 1-5: Study Project Costs

Project/Option	Storage Capital Costs (2018 CAD $Million)	Additional Wind Capital Costs (2018 CAD $Million)	Coal Conversion Capital Costs (2018 CAD $Million)	Hydro Capital Cost (2018 CAD $Million)	Additional Transmission Capital Costs (2018 CAD $Million)	Total Capital Costs (2018 CAD $Million)
Project A, North, West	0	0	0	0	2,822	2,822
Project A, South, West	0	0	0	0	2,070	2,070
Project B, Option 1, East	0	0	0	0	2,035	2,035
Project B, Option 2A, East	0	0	0	0	345	345
Project B, Option 2B, East	0	0	0	0	167	167
Project C, West	0	3,600	0	0	1,301	4,901
Project C, East	0	0	0	0	193	193
Project D, Option 1, West	0	0	0	3,894	349	4,243
Project D, Option 1, East	0	0	0	694	466	1,160
Project D, Option 2, West	0	0	0	7,271	2,448	9,719
Project D, Option 2, East	0	0	0	694	660	1,354
Project E, AB > CC, West	0	0	8,088	0	0	8,088
Project E, SK > CCS, East	0	0	5,928	0	0	5,928
Project E, SK > CC, East	0	0	1,933	0	0	1,933
Project F, West	3,000	3,600	0	0	0	6,600
Project F, East	160	0	0	0	0	160
Project G, Option 1, West	0	2,800	0	0	265	3,065
Project G, Option 2, West	0	3,800	0	0	449	4,249
Project G, Option 3, West	0	2,300	0	0	224	2,524
Project G, Option 4, West	0	5,700	0	0	2,438	8,138
Project H, West	0	0	0	925	437	1,362
Project I, West + East	0	0	0	0	204	204
Project J, West	0	0	0	0	357	357
Project K, North. West	0	3,600	0	0	4,123	7,723
Project K, South. West	0	3,600	0	0	3,370	6,970

It should be noted that costs are not adjusted for increased reserve margins due to additional wind or hydro or energy storage resources in some of the projects. Section 7 of the report describes an adjustment to these metrics that takes into account the additional cost savings if the reserve margins are maintained at the BAU level by taking out an equivalent amount of capacity that were added in the BAU case to meet the target reserve margin. The carbon reductions and changes in annual costs relative to the BAU case are shown in the following charts.

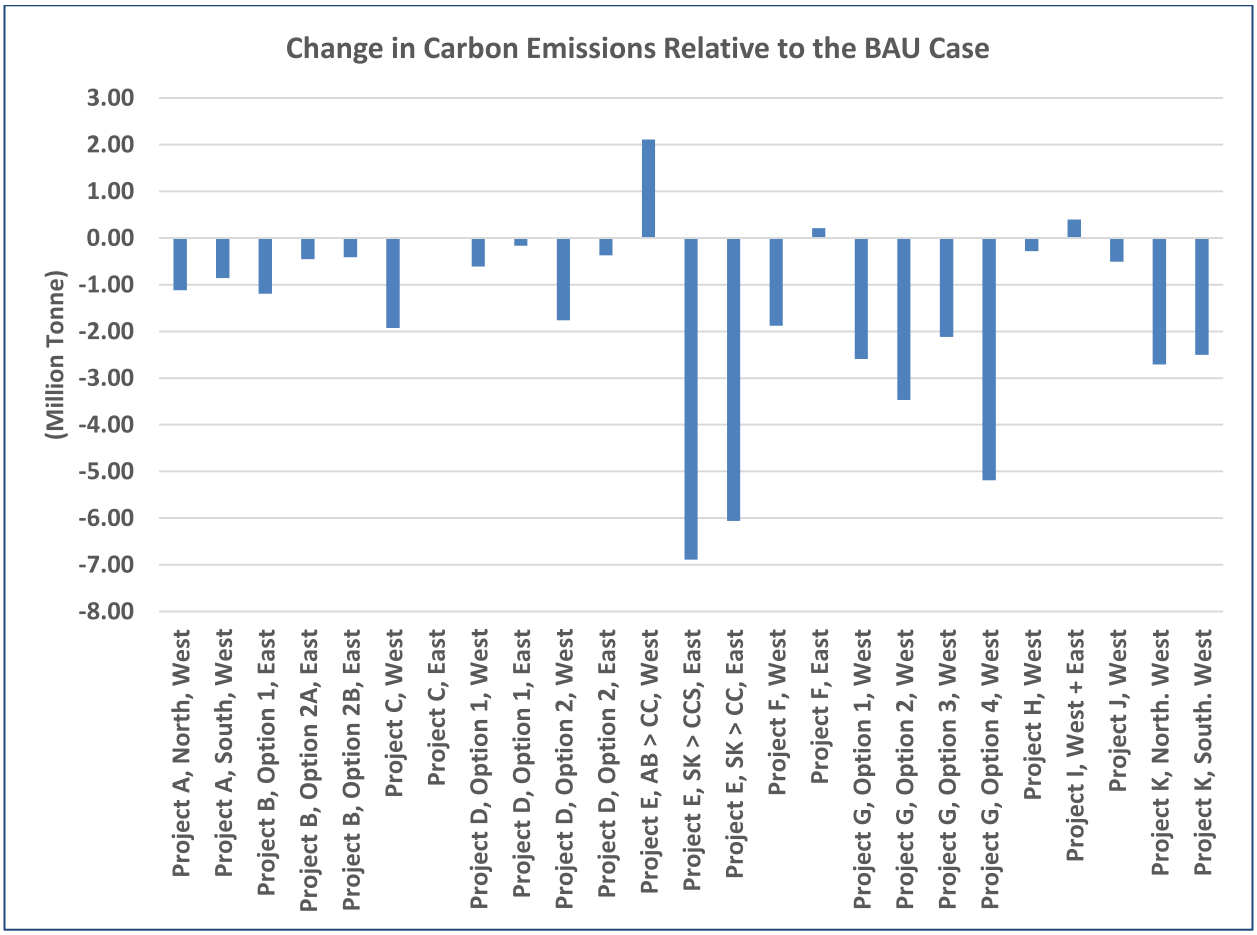

Figure 1-1: Carbon Reduction by Each Project Relative to the BAU Case

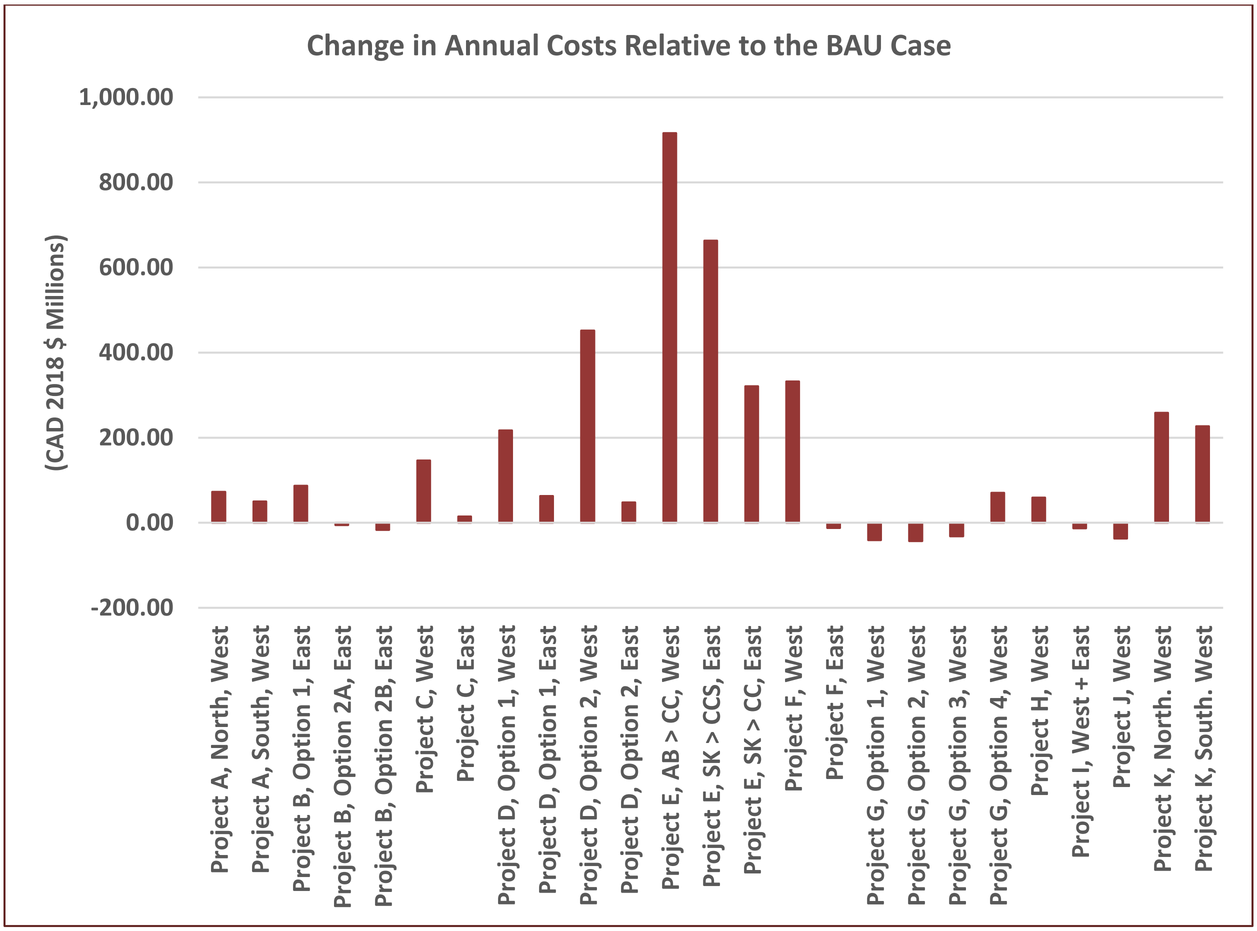

Figure 1-2: Change in Annual Costs by Each Project Relative to the BAU Case

1.5 Context and Limitations

The results of the study should be interpreted in context, taking into account the limitations of the approach which include the following:

- The study focused on impacts to the electricity grid only, in terms of GHG emissions and variable costs, and did not consider second order impacts on the broader economy.
- The study utilized an hourly "peak shaving" approach to modeling of hydropower dispatch given a static monthly energy for each plant and did not consider the capability of large hydro systems to store and shape energy over months, or the ability of large hydro resources to respond to sub-hourly variation in load and in wind and solar generation. Such flexibility, if permissible due to hydraulic, environmental, and societal constraints may contribute to further reductions of carbon emissions, which were not quantified in this study, but could be studied in subsequent studies [2].
- The study was not meant to be a detailed examination of Canadian carbon pricing policies. Simulating the interaction between different carbon policies would require more detailed assumptions, notably on the Carbon Border Tariff sensitivity, and examination of various future scenarios.
- Although this project considered a number of potential future transmission projects, including some inter-province interties and intra-province transmission expansion, this study is not a long-term regional transmission expansion plan. Each considered

[2] Please note:

(a) In GE MAPS, the hydro is optimized to shave loads across the entire month, so in theory one could get a lot of usage in one week and less in others. Although not done in this study, one approach for taking advantage of long-term storage capability of hydro is to do an initial model run and then compare the average monthly LMPs in each region, and then shift hydro energy from low price months to high price months - to the extent allowed by the storage capability of each plant – and re-run the model. However, assuming the hydro energies are based on historical usage, then if the load shapes have not changed significantly, it should have factored in any historical monthly or seasonal shifting of hydro energy.

(b) Sub-hourly modeling was not performed in this study. However, the model imposed additional hourly wind variability reserve requirements based on the analysis of data on sub-hourly wind variability. On an hourly basis, GE MAPS sets aside sufficient capacity to meet both the contingency reserve and the hourly wind variability operating reserve requirements. In theory, any portion of hydro capacity can be assigned to have operating reserve capability in GE MAPS, including wind variability reserves.

(c) This study includes a reserve sensitivity analysis (described in Section 6), where the wind variability reserve requirement was varied by +/- 50%. Hence that analysis provides a view on whether more, or less, stringent wind variability reserve requirements has any significant impact on carbon emissions and system-wide costs.

(d) This study also includes a hydro sensitivity analysis (also described in Section 6). In the BAU case, hydropower is dispatched with knowledge of a day-ahead wind forecast. In the sensitivity analysis, hydropower is dispatched with full knowledge of hourly wind forecast, which implies more flexible hourly hydropower scheduling.

transmission development would require a proper detailed level of study before finalizing the preferred transmission project scope. Nor was the study intended to be an overall integrated resource planning project. This study did not attempt to determine exactly what resources are necessary to meet system performance, reliability, and other objectives. However, additional generation resources were included in the model to maintain target installed reserve margins in each province, when deemed necessary. Each province may have carried out its own resource adequacy and power system expansion assessment which were represented in the provincial resource adequacy and transmission data received by GE.

- With the exception of few well-defined electricity transmission projects, the transmission projects modelled are intended to be representative. Detailed modelling and engineering work will need to be carried out to determine the exact nature of the GHG reductions and costs of specific projects and the relative advantages and disadvantages of sub-options such as the new northern and southern routes for a new BC-AB intertie.
- The study scope did not include evaluation of the economic viability of the generation resources that would be impacted by the study projects. Economic viability of generation resources needed to meet the required installed reserve margins may require additional sources of revenue (such as those from ancillary services and capacity markets) to compensate for revenue shortfalls due to lower utilization and downward pressure on prices caused by some of the study projects.

1.6 Report Sections

Western RECSI Study Report is divided into 8 sections:

- **Section 1 - Executive Summary:** Provides an overall summary and presents the key results of the study.
- **Section 2 - Introduction and Scope:** Introduces the study and describes the study scope.
- **Section 3 - Assumptions and Study Projects:** Presents the underlying assumptions used in the study and provides a list of the projects evaluated in the study.
- **Section 4 - Business-As-Usual (BAU) Scenario:** Describes the Business-As-Usual case which is the basis for comparison of the study projects.
- **Section 5 - Analysis of Projects:** Provides results of the modeling of the study projects, including generation by type, net exports, adjusted production costs, and carbon emissions under each study project.

- **Section 6 - Sensitivity Analysis:** Presents results of a number of sensitivity analyses performed on a number of selected study projects.
- **Section 7 - Project Metrics:** Summarizes project metrics, including carbon emissions and annualized costs associated with each study project.
- **Section 8 - Regulatory Considerations:** Provides an overview of regulatory considerations that may impact development to the study projects.

2 Introduction and Scope

2.1 Project Objectives

The principal objective of this study under the Regional Electricity Cooperation and Strategic Infrastructure Initiative (RECSI), was to evaluate and compare electricity infrastructure projects, in the Western provinces, from a list of proposed projects shown in the table below, based on the projects' costs and their impact on system-wide greenhouse gas (GHG) reductions, with the potential to assist the region, particularly Alberta and Saskatchewan, transition to a sustainable non-emitting electricity generation portfolio.

2.2 Project Team

The project is managed by Natural Resources Canada (NRCan), which is acting on behalf of the RECSI project Steering committee, and the Technical Advisory Committees, which represent the four Western provinces: British Columbia, Alberta, Saskatchewan and Manitoba, the Governments of Northwest Territories and Manitoba, and the Government of Canada represented by Natural Resources Canada.

The Western RECSI TAC member organizations are presented in the table below.

Table 2-1: Technical Advisory Committee (TAC) Members

Alberta Electric System Operator (AESO)
BC Hydro
Government of British Columbia
Government of Manitoba
Government of Northwest Territories
Manitoba Hydro
Natural Resources Canada (NRCan)
SaskPower

TAC members provided support and guidance throughout the project, including review of the data and assumptions and the development of study scenarios and selection of sensitivity analyses to be performed. While members of the TAC were instrumental in ensuring the successful delivery of this work, the findings, opinions, conclusions and recommendations presented herein do not necessarily reflect those of the TAC members or the organizations they represent.

The project team, led by GE Energy Consulting, consisted of five companies providing a broad range of technical analysis required for this study.

GE Energy Consulting partnered with Electranix and Knight Piésold, to develop estimates of capital cost for the proposed projects.

Individual team roles are as follows:

- GE Energy Consulting: Overall project management and leadership, power system modeling, production cost simulation, and regulatory analysis
- Electranix: Development of capital cost estimates for transmission projects
- Knight Piésold: Development of capital cost estimates for hydroelectric plant projects

Project team is shown in Table 2-2 with members of each partner team listed alphabetically by their last names.

The GE team has had deep subject matter expertise and experience in assessing the impacts of increased wind and solar generation on power grid operations and markets. For instance:

- GE has conducted similar studies for Ontario, Nova Scotia, New England, PJM, New York, California, Texas, Western USA (WWSIS), Hawaii, Barbados, and Vietnam. The most recent study performed by GE Energy Consulting and its partners was the CanWEA Pan-Canadian Wind Integration Study completed in 2016.
- The Knight Piésold team contributed hydropower expertise and hydrology analysis to the project to ensure that hydro power is accurately included.

Table 2-2: Project Team

Natural Resources Canada (NRCan)

Bradley Little
Thomas Levy

GE Energy Consulting Team

GE Project team Christina Bisceglia Jingjia Chen Bahman Daryanian Jason Frasier Georges Sassine	*GE Project Advisors* Phillip deMello Gene Hinkle Gary Jordan Richard Piwko Derek Stenclik Robert Woodfield
Knight Piésold Keith Ainsley Sam Mottram Scott Rees	*Electranix* Dennis Woodford

Technical Advisory Committee

Alberta Sami Abdulsalam Chad Ayers Jacques Duchesne Jerry Mossing Roberto Reyes Dan Wiebe	*British Columbia* Warren Bell Steven Pai Amy Sopinka Kevin Zhang Sanjaya De Zoysa
Saskatchewan Jackie Lukey Raman Mall Travis McLellan Shawn Robinson Ross Wilkinson Tim Zulkoski	*Manitoba* Teody Leano Dan Prowse Jacob Snell *Northwest Territories* David Mahon

2.3 List of Projects Evaluated

The projects to be evaluated, listed below, were selected by TAC members and underwent some modifications throughout the study.

Table 2-3: List of Study Projects

Project	Description	Number of Projects and Options	Study Year (Year Projects Come Online)
BAU	Business-As-Usual	4	2030 & 2040
A	New intertie between British Columbia and Alberta	2	2030
B	New intertie between Saskatchewan and Manitoba	3	2030
C	New internal transmission added to aid in development of new renewable capacity in Alberta and Saskatchewan	2	2030
D	New hydroelectric capacity in Alberta and Saskatchewan	4	2040
E	Coal conversion in Alberta and Saskatchewan to lower GHG emissions	3	2030
F	Bulk storage addition against value of new hydro or new transmission	2	2030
G	Electrification of LNG and natural gas production	4	2030
H	Construction of hydro and transmission line to interconnect the Northwest Territories with Alberta	1	2040
I	New intertie and incremental upgrade to existing and limited Alberta and Saskatchewan intertie	1	2030
J	Create simultaneous transfer capability between Alberta and British Columbia and Montana-Alberta transmission line	1	2030
K	Combination of Project A and Project C	2	2030
	Total	**29**	

The options within each project are listed in Table 1-2, where "West" refers to the Western Interconnection (also called Western Electricity Coordinating Council or WECC) which includes British Columbia and Alberta, and "East" refers to Eastern Interconnection, which includes Saskatchewan and Manitoba. Hydro plant in Northwest Territories is modeled in the West.

These projects and options are described in more detail in Section 5. In this report, these projects and options are collectively referred to as the "Study Projects".

Table 2-4: List of Study Projects (including Options)

Project/Option	Description
BAU Case, West	Business-As-Usual (BAU) Case, BC+AB
BAU Case, East	Business-As-Usual (BAU) Case, SK+MB
Project A, North, West	New Northern Intertie between BC and AB
Project A, South, West	New Southern Intertie between BC and AB
Project B, Option 1, East	New Intertie between SK and MB - Option 1
Project B, Option 2A, East	New Intertie between SK and MB - Option 2A
Project B, Option 2B, East	New Intertie between SK and MB - Option 2B
Project C, West	New Internal Transmission in AB
Project C, East	New Internal Transmission in SK
Project D, Option 1, West	New Hydropower plant in AB, Option 1
Project D, Option 1, East	New Hydropower plant in SK, Option 1
Project D, Option 2, West	New Hydropower plant in AB, Option 2
Project D, Option 2, East	New Hydropower plant in SK, Option 2
Project E, AB > CC, West	SC-GAS Conversion to CC-GAS in AB
Project E, SK > CCS, East	ST-COAL Conversion to CCS in SK
Project E, SK > CC, East	ST-COAL Conversion to CC-GAS in SK
Project F, West	New CAES Installation in AB
Project F, East	New Grid Scale Battery Storage in SK
Project G, Option 1, West	Electrification of LNG based Load in BC, Option 1
Project G, Option 2, West	Electrification of LNG based Load in BC, Option 2
Project G, Option 3, West	Electrification of LNG based Load in BC, Option 3
Project G, Option 4, West	Electrification of LNG based Load in BC, Option 4
Project H, West	Construction of NT Hydro and T-Line to AB
Project I, West + East	New Intertie between AB and SK
Project J, West	Simultaneous Transfer Capability between AB-BC and MATL
Project K, North. West	Combination of Project A, North, and Project C
Project K, South. West	Combination of Project A, South, and Project C

2.4 Project Tasks

The Study performed a detailed analysis of the operational, planning and market impacts of the study projects on the Canadian power systems. The Study divided the work into seven major tasks.

Table 2-5: Western RECSI Study Tasks

Task	Description
Task 1 – Cost and Production Data Gathering	Establish and gather required data for dispatch modeling from each jurisdiction.
Task 2 – Technical Assessment	Develop high level cost estimate, schedule and operational impact (including operating reserves) for the study projects.
Task 3 – Developing production cost model	Establish methodology and run production cost model for base case and compare with each study project.
Task 4 – GHG reduction	Quantify the GHG reduction potential based on Task 3 for each study project.
Task 5 - Additional Analysis	Address sensitivities such as different carbon prices, varying natural gas prices, dispatch alternatives or hydrology.
Task 6 – Regulatory Considerations	Identify regulatory considerations that may impact development of the projects evaluated in this study.
Task 7: Final Reporting	Draft final report and obtain report approval from Technical Committee, Steering Committee and NRCan.

2.4.1 Task 1 - Cost and Production Data Gathering

The GE Team signed NDAs with system operators from each jurisdiction and worked with them to collect the information and data necessary for successful execution of the project. The collected information and data was used to define the Business-As-Usual (BAU) scenario that was used for comparing and assessing the impact of the study projects.

With permission of the Canadian Wind Energy Association (CanWEA), the collected data was used to update the BAU scenario database that was developed for the CanWEA Pan-Canadian Wind Integration Study (PCWIS [3]) project.

Task 1.1 - Establish methodology for generation expansion plan

In most cases, generation expansion plans were developed by the provinces. These included proposed future generation additions by type and size for both the BAU case and the study projects.

In cases where the recommended generation expansion plans did not meet the target reserve margins required to accommodate the expected load growth, an iterative approach

[3] https://canwea.ca/wind-integration-study/

was used to add generic single cycle and combined cycle natural gas units (SC-GAS and CC-GAS). The generation expansion methodology is described in Section 3.

Task 1.2 - Review major data assumptions for future energy market conditions

Specific assumptions regarding future market conditions were provided to the GE Team for review. These included expected demand growth, fuel commodity prices, carbon prices, capital costs of new entrants for each generation type, expected levels of hydro-electric output, etc. Assumptions also addressed provincial environmental goals and policy.

The study projects are assumed to come online in 2030 and 2040. Therefore, the future market conditions, including electricity demand levels and fuel prices were provided for those years.

Task 1.3 - Create generation expansion plan for each Study scenario

Starting with existing generation plans, the TAC members presented generation expansion plans for each study project. This plan included the amounts and types of generation expected to be present in the selected study year(s), including amounts of new renewables capacity and conventional generation.

As noted previously, in cases where the reserve margin fell below target levels, even after addition of power plants recommended by the provincial representatives, additional thermal units were added to the model based on the methodology described previously.

2.4.2 Task 2 - Technical Assessment

Task 2.1 – Size and cost estimate for transmission and generation projects

In developing the size and cost estimates required to support the project list, each province was responsible for providing existing transmission infrastructure. The provinces provided information on transmission upgrades regarding the size, cost estimate and estimated in-service date for certain transmission projects as described in the project list.

The project partner, Electranix reviewed the transmission cost information provided by the provinces and performed due diligence to assure continuity across all jurisdictions and compared the information to its own estimates.

Task 2.2 – Impact on Operating Reserves

The GE Team reviewed the impact on regulating and spinning reserves in accordance with applicable reliability standards. New interties or new large internal generators may have an impact on the largest single contingency in a jurisdiction and there may be an associated increased level of reserves required.

The PCWIS study[4] determined the wind variability reserve requirements by province for different levels of wind energy penetration. Western RECSI study is using the scaled wind data from the PWCIS project. Therefore, in the BAU case, the wind variability operating reserves determined in the PCWIS project[5] (referred to as “regulating reserve requirement” in PCWIS) were scaled proportionally to correspond to the size of wind generation and included in the model as the additional wind variability operating reserves.

This wind variability operating reserve is in addition to the conventional contingency reserve that is modeled separately for each province. The wind variability operation reserve is available above and beyond the contingency reserve to mollify the temporal variation in wind power.

Although the GE MAPS simulation did not model the dynamic capability of large hydro systems to respond to the sub-hourly variation in the load and renewable generation, the model allowed for a portion of unused hydro capacity to be counted towards the required contingency operating reserve and also towards wind variability reserve.

The analysis in this task is basically a sensitivity analysis, by scaling the assumed BAU wind variability operating reserve by +/-50% to investigate the sensibility of the study results to the wind variability operating reserves used in the study. This sensitivity case is described in the report section on sensitivity analysis.

2.4.3 Task 3 - Developing Production Cost Model

Task 3.1 - Production Cost Simulation Methodology

This task describes the analysis that was performed by the GE Team to identify the operational and market impacts of the study projects.

The GE Team employed the GE Concorda Suite Multi-Area Production Simulation (GE MAPS)[6] model for simulation of the power systems of the North American Western and Eastern Interconnections (which cover all Canadian provinces USA regions within those interconnections). The market and power system database developed for the PCWIS project, updated with the information and data provided by the TAC members, was also used for the modeling and simulation of the study projects.

GE MAPS simulates hourly power system operation. It is a security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED) model, which

4 https://canwea.ca/wind-integration-study/

5 https://canwea.ca/wp-content/uploads/2016/07/pcwis-section05-statisticalandreserveanalysis.pdf

6 https://www.geenergyconsulting.com/practice-area/software-products/maps

means that generation dispatch takes into account transmission and other system constraints.

GE MAPS inputs include:

- Individual grid scale power plants of all types and sizes by location, capacity, heat rates, and fuel types
- Plant maintenance schedules and forced outage rates
- Wind and solar hourly power profiles
- Plant variable operations and maintenance (VOM) costs
- Plant and fuel related emission rates
- Transmission configuration of North American power systems
- Transmission constraints and flow limits
- Load projections by area for every year of the time horizon (annual energy, annual peak, and daily load shapes)
- Fuel price projections
- Emissions costs
- Operating reserve requirements

The main database of GE MAPS is updated regularly by GE Energy Consulting. Figure 2-1 provides a schematic of the GE MAPS model.

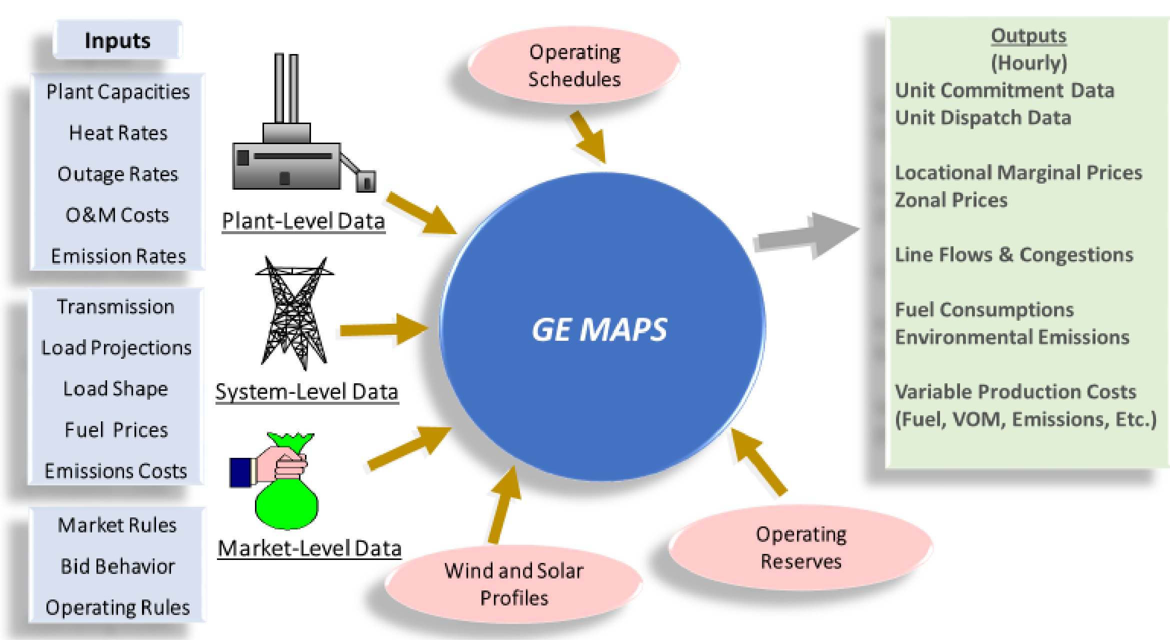

Figure 2-1: GE MAPS Schematic

Consistent metrics such as short and long run production costs were employed to compare alternatives regardless of the market structure. Short run production costs included fuel cost, variable O&M and emission costs. Long run production costs consider capital cost and fixed O&M costs. The opportunity costs of changes in exports to other markets were also quantified.

GE MAPS outputs included annual metrics for each province such as generation by type, net imports/exports, production costs (adjusted for import costs and export revenues), criteria pollutant and greenhouse gas (GHG) emissions, and system congestion based on monitoring of selected transmission constraints.

The GE Team, using GE MAPS, simulated the study years for each of the projects using production cost data (generator, load and transmission data) developed in Tasks 1 and 2. GE MAPS was ideally suited to this study since it simulates a power system from the point of view of a system operator – performing an N-1 security constrained system dispatch with detailed transmission modeling and subject to selected transmission constraints. GE MAPS has been continuously developed, refined and benchmarked for over 30 years and has been applied for system economic analyses for the entire U.S., Canada and many parts of the world.

The GE MAPS production simulations are conducted chronologically at one-hour time steps. Consequently, the real-time adjustments of generation that compensate for variations in the balancing area net demand are not modeled explicitly. Instead, the responsive generation necessary in each hour to regulate and balance is represented as constraints on the unit commitment and economic dispatch algorithms in the production model. Those "operating rules", which use current hour values of load and wind generation along with forecasts of those quantities, was entered into the model as reserve constraints for each hour of the production simulation. The commitment, dispatch and cost implications of those reserves were reflected in the GE MAPS results.

GE MAPS was also used to quantify the hourly operation of each individual generator in Canada. This information was fed into the overall analysis of simulation results, to help identify and quantify performance that may require or benefit from mitigation options.

GE MAPS performs both unit commitment and economic dispatch. Unit commitment is based on the renewable forecast data, in addition to the real-time data. For instance, a day-ahead wind generation forecast is based on the day-ahead weather forecast and wind generation forecasting models. For each operating area, the day-ahead forecasted wind profiles were used in the day-ahead commitment of the rest of the generation in the system. A second wind profile then defines the actual wind generation that would have occurred based on the actual weather for that day. Options within the GE MAPS model allow consideration of no forecast (e.g., wind generation is ignored in the day ahead commitment), realistic forecasts (e.g., present practice or state-of-the-art meso-scale), or perfect wind generation forecasts.

Typically, GE MAPS uses the hydro energy to peak shave the load of the province in which they are located across a month based on the monthly energy and hourly discharge values of each hydropower plant, although the load against which hydro energy is dispatched can defined as composite of any given load shapes). The hydro generation is scheduled during unit commitment after accounting for forecasted wind generation. As described in the section on sensitivities, the study also performed a sensitivity to evaluate the impact of a real-time hydro dispatch (based on a real-time wind generation), compared to the base case day-ahead dispatch (based on day-ahead wind forecast).

Examples of hourly outputs/metrics available from GE MAPS are shown below. Many additional outputs and metrics are possible, and the selection of such metrics was adjusted in collaboration with TAC as interim simulation results were jointly reviewed.

- Unit performance: Generation, Starts, Hours online, capacity factors, cycling, etc.
- Curtailed (spilled) renewable energy
- Annual production cost (variable operating cost)
- Zonal prices and Locational Marginal Prices (LMPs)
- Transmission flows, congestion, and shadow prices
- Changes in emissions (NO_X, SO_X, CO_2)
- Load not served
- Impacts of Wind Forecast Error
- Transmission Tie-Line Utilization with Neighboring Systems
- Reserve Violations

Task 3.2 - Design transmission reinforcement to support new generation

New transmission expansion plans were constructed for each study scenario based on the information provided by TAC. New transmission contingencies were identified to capture future congestion under security constrained economic dispatch.

The GE MAPS production cost simulation includes a full transmission representation of the Eastern Interconnect (MMWG load flow) and Western Interconnect (TEPPC load flow), including a full configuration of the transmission grid including all the major transmission lines and transmission system buses.

The solved load flow is used to create the generation shift factor (GSF) matrix to determine the transmission flows of generation and loads across the network.

Unless data were made available, the production cost modeling did not include a full representation of all transmission constraints across the Pan-Canadian system. At a minimum, the model included all major transmission constraints between each province and neighboring systems (intra-provincial) in both Canada and USA.

Hurdle Rates

In addition to the transmission constraints monitored, the model also includes economic "hurdle rates" that place an economic charge on transfers between operating areas. This is used to simulate both the wheeling charges between balancing areas and market "friction" that may result from different operating rules and procedures in different utilities. It was assumed that the hurdle rate between balancing areas (across both USA and Canada) was USD$5/MWh during the unit commitment process and USD$3/MWh during the economic dispatch process.

After the model runs all the cost data results are converted to CAD$.

Additional Transmission Reinforcements

In evaluation of each Study Project, it was necessary to consider the potential cost of additional transmission reinforcements. New projects may result in changes in flow patterns in the grid and therefore may cause extreme congestion on certain transmission constraints. These additional costs are quantified as increased congestion costs.

Task 3.3 – Development of Project Scenarios

TAC members proposed the study projects, going beyond the ones listed in the Schedule "F" of the RFP.

Before developing these scenarios, GE Team first developed the Business-As-Usual Scenarios (BAU) for both the Eastern Interconnection and Western Interconnection for study years of 2030 and 2040, based on the available data and assumptions applicable to those years. All the system-wide and regional impacts of the study projects were compared to the attributes of the BAU scenarios.

Evaluation of each of these projects included determination of the impact on GHG emissions, fossil fuel consumption, renewable and non-renewable power generation, and fixed and variable costs, relative to the BAU scenarios.

2.4.4 Task 4 - GHG Reduction

The main objective of this Study was to evaluate the study projects based on their cost and carbon emission impacts in Canada's Western provinces. Fossil fuel-based generation is the principal source of environmental emissions in the electricity sector in Canada, including both Criteria Air Contaminants such as Sulfur Oxides (SO_X) and Nitrogen Oxides

(NO_X), and also Greenhouse Gases (GHG) such as CO_2. Each Study Project is expected to impact the dispatch of the fossil fuel-based power resources to different degrees.

In this task, the GE Team explicitly quantified the changes GHG emissions, due to changes in the operation of GHG-emitting generation, compared to the BAU case. The GE MAPS model has the full capability of calculating the hourly GHG emissions by plant and region.

The provincial and system-wide variation in GHG was quantified in both absolute terms by total weight and also in terms of per MWh of provincial and system-wide generation.

2.4.5 Task 5 - Additional Analysis

Additional analysis included performing a number of “sensitivity analyses”, which enabled assessing the sensitivity of the study results to a number of individual drivers.

In the course of performing the overall project, the GE Team worked with TAC members to identify what to include in the sensitivity analyses.

The sensitivity analysis was performed by changing one or two variables at a time on selected study projects, and the BAU case for comparison. The sensitivity analysis list is provided in the section on sensitivity analysis.

2.4.6 Task 6 - Regulatory Considerations

The objective was to identify the existing regulatory requirements and considerations that would need to be addressed in the development of the study projects. Most of the material for this task was provided by the TAC members and NRCan. The GE Team helped compile the information provided by TAC into a consistent format.

As stated in the RFP, this task did not include recommendations for solutions to the identified regulatory considerations.

2.4.7 Task 7 - Reporting & Knowledge Transfer Final Reporting

This task covers development of this report, which includes descriptions of the methods, assumptions, data sources, and analytical results that address the Study objectives. An Executive Summary that includes the key findings is included, as well as suggestions for further work.

To compare study projects, in addition to GHG impacts, projects were evaluated based on their Equivalent Annual Costs (EAC) and their impact on Adjusted Productions Costs (APC). APC is the sum of a province’s production costs (i.e., fuel and variable production costs) adjusted for import costs and export revenues.

2.5 Study Context and Limitations

Focus on The Impact on Electric Grid and Not the Whole Economy

The study focus is on the impact of study projects on the electric grid only and not on the broader economy. The impact on the electric grid is quantified in terms of changes in GHG emissions, projects' equivalent annual costs, and impact on adjusted production costs of each province. Consideration of second order impacts on the broader economy are beyond the scope of this project.

Production Simulation Is Still Simulation

The modeling used is highly sophisticated, and the GE MAPS tool (similar to other production costing models) is an industry standard - widely used for economic and operational evaluation of power systems. Nevertheless, they are still simulations.

Reality is even more complex, and successful grid operation includes the action of experienced, sophisticated humans. There are limits to our ability to exactly replicate present, and even more so, to accurately project possible future operations of the Canadian power systems. GE Energy Consulting has extensive experience and has exercised care and applied engineering judgment to make sure that the simulations are reasonably accurate, and that they provide the quantitative insight into the anticipated power system operations for two future years.

Although the study was focused on the benefits of adding electrical infrastructure in Western Canada, the Canadian results were influenced by the configuration and attributes of the US power system. The TAC members did not review the U.S. model.

Hydro Modeling in This Study is High Level

The modelling does not adequately represent the dynamic capability of large hydro systems to store and shape energy over several days or even months, nor the ability of large hydro resources to respond to the sub-hourly variation in the load and renewable generation.

The study utilized an hourly "peak shaving" approach to modeling of hydropower dispatch given a static monthly energy for each plant and did not consider the capability of large hydro systems to store and shape energy over months, or the ability of large hydro resources to respond to sub-hourly variation in load and in wind and solar generation. Such flexibility, if permissible due to hydraulic, environmental, and societal constraints may contribute to further reductions of carbon emissions, which were not quantified in this study, but could be studied in subsequent studies.

In GE MAPS, the hydro is optimized to shave loads across the entire month, so in theory one could get a lot of usage in one week and less in others. Furthermore, by comparing the average monthly LMP in each region, hydro energy can be shifted from low price months to high price months (to the extent allowed by the storage capability of each plant). However, assuming the hydro energies are based on historical usage, then if the load shapes have not changed significantly, it should have factored in any historical monthly or seasonal shifting of hydro energy.

Sub-Hourly Modeling Was Not Performed in This Study

Sub-hourly modeling was not performed in this study; however, the model imposed additional hourly wind variability operating reserve requirements based on the analysis of data on sub-hourly wind variability. On an hourly basis, GE MAPS sets aside sufficient capacity to meet both the contingency reserve and the hourly wind variability operating reserve requirements. In theory, any portion of hydro capacity can be assigned to have operating reserve capability in GE MAPS, including wind variability reserves.

The sub-hourly behavior is important for power systems with high levels of variable renewables. However, the Pan-Canadian Wind Integration Study (PCWIS)[7] did a detailed analysis of sub-hourly behavior and determined the additional reserve requirements needed to mitigate the sub-hourly variation of wind for different levels of wind resource penetration. The hourly wind variability reserve requirements in each province in the of the RECSI project are scaled values of the wind variability reserve requirements of the PCWIS project, since the wind profiles (i.e., sub-hourly shapes) of the RECSI project are based on the wind profiles of the PCWIS project. Scaling is based on the size of wind energy in each province in the RECSI project relative to the size of wind energy in the PCWIS project.

This study includes a reserve sensitivity analysis (described in Section 6), where the wind variability reserve requirement was varied by +/- 50%. Hence that analysis provides a view on whether more, or less, stringent wind variability reserve requirements has any significant impact on carbon emissions and system-wide costs.

This study also includes a hydro sensitivity analysis (also described in Section 6). In the BAU case, hydropower is dispatched with knowledge of a day-ahead wind forecast. In the sensitivity analysis, hydropower is dispatched with full knowledge of hourly wind forecast, which implies more flexible hourly hydropower scheduling.

[7] https://canwea.ca/wind-integration-study/

This Study Is Not A Detailed Examination of Canadian Carbon Pricing Policies

This study was not a meant to be a detailed examination of Canadian carbon pricing policies. Simulating the interaction between different carbon policies would require more detailed assumptions, notably on the Carbon Border Tariff sensitivity, and examination of various future scenarios (which can be accomplished by GE MAPS or a similar production costing model) to help inform officials of the potential impact of such policies on an inter-jurisdictional electric system.

This Study Is Not A Long-Term Regional Transmission Expansion Project

Although this project considered a number of potential future transmission projects, including some inter-province interties and intra-province transmission expansion, this study is not a long-term regional transmission expansion plan. Each considered transmission development would require a proper detailed level of study before finalizing the preferred transmission project scope. Nor was the study intended to be an overall integrated resource planning project. This study did not attempt to determine exactly what resources are necessary to meet system performance, reliability, and other objectives. However, additional generation resources were included in the model to maintain target installed reserve margins in each province, when deemed necessary. Each province may have carried out its own resource adequacy and power system expansion assessment which were represented in the provincial resource adequacy and transmission data received by GE.

However, this study could be a basis for decision makers in considering valuable projects for the province, although final policy determinations will still require a more thorough study of its social and environmental impact including, for example, its effect on provincial electricity rates.

This project is a simpler production costing project based on GE MAPS modeling which is a Security Constrained Unit Commitment and Economic Dispatch model and provides insight into the anticipated power system operations for two future years modeled in this study.

This Study Is Not an Integrated Resource Plan (IRP) Project

The focus of this project was to evaluate a number of transmission and generation projects based on their costs and impacts on system-wide carbon reductions. It was not intended to be an overall integrated resource planning project.

An IRP study would need to consider other aspects like social and environmental impacts, impacts on provincial electricity rates, demand-side resources, and other factors for a least cost and balanced generation expansion plan under various scenarios, which again was beyond the scope of this project.

This study makes no effort to establish the overall adequacy of the power systems of western provinces, nor does it attempt to determine exactly what resources are necessary to meet system performance and reliability objectives. Nevertheless, additional generation resources were included in the model to maintain target installed reserve margin in the provinces in the BAU case. As such, the study endeavored to establish how additional transmission and generation (and energy storage) projects would work within the existing and future infrastructure, and it provides insights into their impacts on the system-wide variable production costs and carbon emissions. The benefits calculated for two future years are projected to be representative of project lifecycles, but more extensive studies are required to provide more robust projections of lifecycle costs and benefits. The results of this work may be useful to future integrated resource planning undertaken by the provinces.

Limited Focus of The Economic Analysis

The study scope did not include an evaluation of the economic viability of the generation resources that would be impacted by the study projects. Economic viability of generation resources needed to meet the required installed reserve margins may require additional sources of revenue (such as those from ancillary services and capacity markets) to compensate for revenue short falls due to lower utilization and downward pressure on prices caused by some of the study projects.

Furthermore, the production cost simulations quantify variable operating costs only. These are the costs that determine which units, of the ones available to the system operator, should be utilized to serve load in a least cost manner. These costs include fuel consumption, variable operations & maintenance, and unit startup. The production cost analysis does not include costs related to new capital expenditures required study projects or fixed operations & maintenance or power purchase agreements for new generation resources. However, the capacity cost of study projects was taken into account in developing the project metrics.

3 Assumptions and Study Projects

The production cost and reliability modeling involve simulation of the North American power grids and incorporates highly detailed inputs and assumptions for generators, transmission lines, loads, fuels, and emissions. This section outlines the key inputs and assumptions required to accurately simulate system operations across Canada. The data for most of the inputs and assumptions discussed in this section was provided by the Technical Advisory Committee (TAC) members or sourced from Statistics Canada[8] and ABB Velocity Suite[9]. In instances where data was unavailable GE Energy Consulting utilized engineering judgment and past experience when necessary. The inputs and assumptions used to model Western Canada were validated through TAC member review and benchmarking of model results to historical operations.

3.1 Study Assumptions

3.1.1 Model Footprint

While this study was focused on the Western Canadian power system - covering British Columbia, Alberta, Saskatchewan, and Manitoba - it is critical to accurately incorporate interchange of power between provinces and systems in the United States. While Northwest Territories power grid is not modeled in the study, the hydroelectric plant in the study project H is modeled as being connected to the Alberta grid. The North American power grids are large interconnected systems and changes in one region can impact operations in another. In order to capture flows of electricity between the different balancing areas, the modeling incorporated a full nodal representation of the Eastern and Western Interconnections (two of the three asynchronous power grids, with the third being the Electric Reliability Council of Texas). Figure 3-1 provides a geographic representation of the model topology utilized in this study.

The Eastern Interconnection (EI) and Western Interconnection (WI) have limited HVDC interconnections and therefore were modeled as two isolated and separate grids. In addition, Quebec's grid is asynchronous with the rest of the Eastern Interconnection and only connected through HVDC ties. However, given the large number and size of interconnections with neighboring systems, the Quebec system was incorporated directly in the EI model.

[8] http://www.statcan.gc.ca/start-debut-eng.html

[9] http://new.abb.com/enterprise-software/energy-portfolio-management/market-intelligence-services/velocity-suite

The entire footprint represented in GE MAPS, including the Canadian and USA power systems in EI and WI systems were balanced for 2030 and 2040. The Canadian systems included the generation expansion plans provided by the TAC members, and if necessary, complemented by additional generic SC-GAS and CC-GAS units. The U.S. systems were balanced with additional generic SC-GAS and CC-GAS units in addition to the projection of state by state renewable portfolio standards (RPS) to 2030 and 2050.

The footprint in Canada was again subdivided into provincial boundaries. While the main reporting in this study focusses on operations in the four Western Canadian provinces, the simulations were performed for the whole Eastern and Western interconnections.

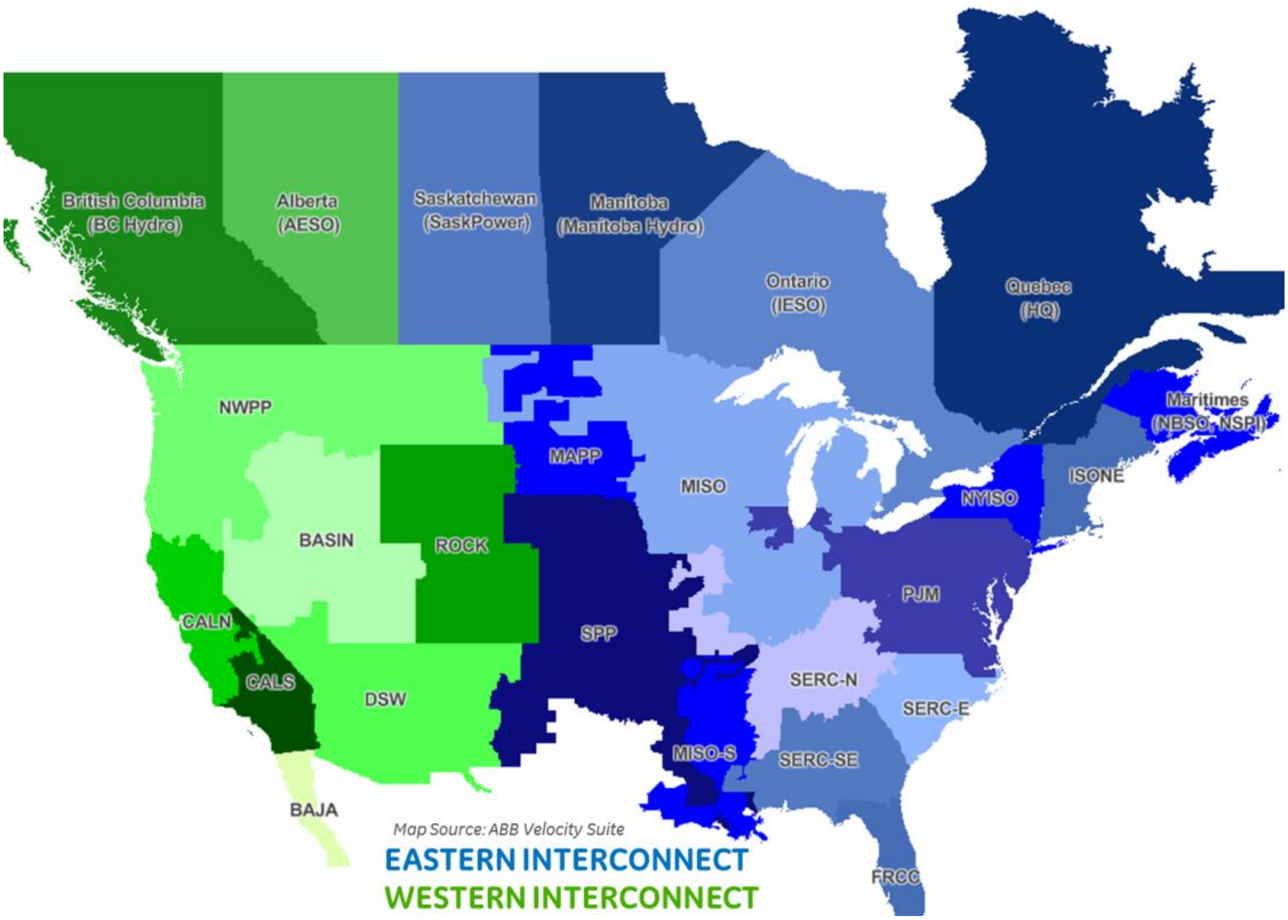

Figure 3-1: Model Topology of the Eastern and Western Interconnections

Note that the Canadian territories of Yukon, Northwest Territories and Nunavut, as well as the province of Newfoundland and Labrador are not included in the model topology because they are composed of isolated power grids and not interconnected to the North American bulk transmission system.

3.1.2 Canadian Power System Overview

The Canadian power system is a large, interconnected network composed of nine distinct grid operators and/or utilities consistent with provincial boundaries. Some provinces are vertically integrated utilities while others are deregulated ISO/RTO markets. Table 3-1 lists the grid operator and market structure in each province, listed from west to east. However, this study is only focused on the power systems of the four Western most provinces in Canada bordering the USA (shown in Bold fonts).

Table 3-1: List of Provincial Grid Operators and Market Structures

Province	Abbrev	Grid Operator	Market Structure
British Columbia	**BC**	**BC Hydro**	**Vertically Integrated Utility**
Alberta	**AB**	**Alberta Electric System Operator (AESO)**	**Deregulated ISO/RTO**
Saskatchewan	**SK**	**SaskPower**	**Vertically Integrated Utility**
Manitoba	**MB**	**Manitoba Hydro**	**Vertically Integrated Utility**
Ontario	ON	Independent Electric System Operator (IESO)	Deregulated ISO/RTO
Quebec	QC	Hydro Quebec (HQ)	Vertically Integrated Utility
New Brunswick	NB	New Brunswick Power	Vertically Integrated Utility
Nova Scotia	NS	Nova Scotia Power (NSPI)	Vertically Integrated Utility
Prince Edward Island	PEI	Maritime Electric	Vertically Integrated Utility

The resource mix in each province reflects that province's resource availability, market structure, and historical development. British Columbia and Manitoba are predominately hydro based, with over 90% of generation being served by hydro resources. Alberta and Saskatchewan contain a mix of coal, gas, hydro and wind resources.

Figure 3-2 and Table 3-2 provide the installed capacity by type across each Canadian province. Note that these figures include new installations and retirements expected between now and the study years 2030 and 2040, but do not include any additional wind capacity added for the study projects. The chart and table also include thermal and hydro generic capacity added to systems in order to maintain reserve margin targets due to load growth between now and the study years.

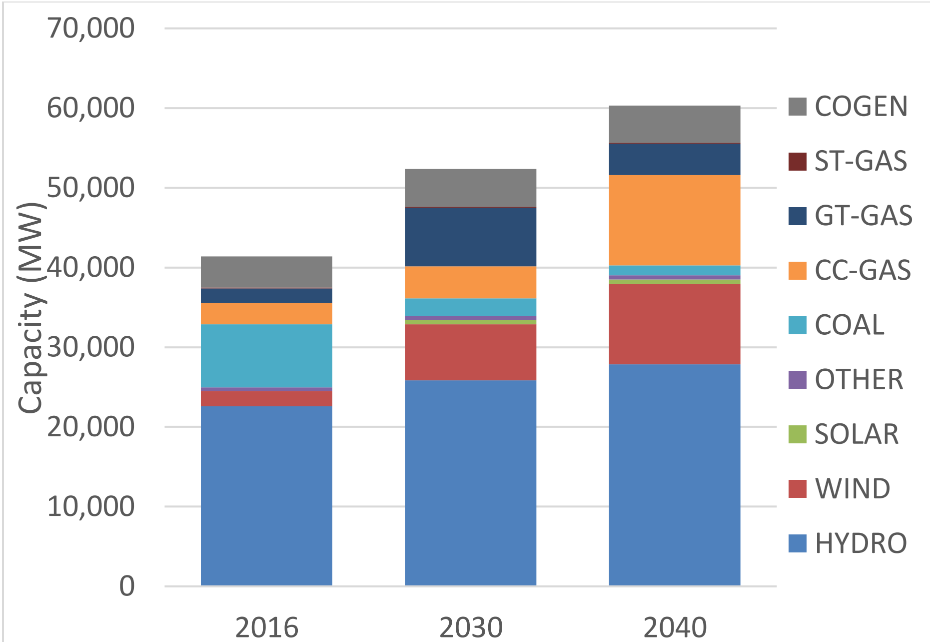

Figure 3-2: Western RECSI BAU Installed Capacity by Type (2030)

Table 3-2: Installed Capacity by Type (MW) and by Province

Type	2030				2040			
	BC	AB	SK	MB	BC	AB	SK	MB
COGEN		4,230	512			4,372	269	
COAL		929	1,255				1,255	
CC-GAS	275	2,466	1,282		275	8,651	1,711	700
ST-GAS				126				126
GT-GAS	50	6,573	555	233	1	2,797	915	233
HYDRO	16,800[10]	894	872	5,895	20,189	894	872	5,895
OTHER		469	30			469	30	
SOLAR		500	60			500	60	
WIND	700	4,045	2,617	258	3,078	4,045	2,617	258
Total	17,825	20,106	7,183	6,512	23,543	21,728	7,729	7,212

It should be noted that the BC resources include some wind, biomass, and other resources. BC Hydro data included these resources within HYDRO for simplicity.

[10] Small volumes of other resources such as biomass are included within this total.

3.1.3 General Modeling Assumptions

The following list includes the basic features and assumptions used in the modeling of the Canadian Power System:

- The assumed year of the analysis was 2030 for the majority of the study projects, and 2040 for those with new hydro power additions, reflecting load energy and peak demand in those years based on the annual growth assumptions for energy.
- For most regions, the hourly load and wind profiles, i.e., diurnal load and wind shapes, but not the annual energy and peak, were based on the 2008 data. The reason is that the wind profiles were taken from the PSWIS project, which used the 2008 base year for wind and load profiles. The wind data developed by the Environment Canada for the PCWIS project, generated wind shapes for 2008, 2009, and 2010. Wind and load profiles should be based on the same profile year in order to preserve any weather-related correlation between wind energy and electricity demand. For each Canadian province and USA pool, if the hourly load and wind data were not provided by the TAC members, then the default PCWIS 2008 load and wind shapes were scaled to the 2030 and 2040 annual load and wind total energy and peak. A sensitivity analysis in the PCWIS project using 2008, 2009, and 2010 profile years showed that the choice of the profile year had minimal impact on the power system operational and economic performance.
- All prices and economic inputs into GE MAPS were in USD but final results were converted into 2018 CAD using the average of five-year historical exchange rates.
- Entire Eastern Interconnect (EI) and Western Interconnect (WI) systems were simulated – a capability provided by the GE MAPS model.
- The GE MAPS model used in the study includes full representation of transmission topology of the Eastern and Western Interconnections, but only with selected transmission constraints being monitored (inclusion of every large and small transmission constraint would have resulted in an inordinate amount of computer running time; and moreover, that level of detail was unnecessary for the purposes of this study).
- Representation of the regions in the USA were kept unchanged in the BAU and study projects.
- US renewable penetration in the BAU and all the study projects was based on existing Renewable Portfolio Standard (RPS) levels projected to years 2030 and 2040.
- The Western Canadian region spans 3 time-zones: British Columbia is in the Pacific time-zone, Alberta is in the Mountain time-zone, and Saskatchewan and Manitoba

are in the Central time-zone. In order to keep hourly load and wind profiles consistent, the Eastern Interconnect modeling was conducted in Eastern Standard Time (EST) and the Western Interconnect modeling was done in Pacific Standard Time (PST). When chronological inputs or results are shown throughout this report, they are shown in EST, unless otherwise noted.

- Added wind plants were connected to high voltage busses (≥230 kV). This facilitates the locating of the wind resources in GE MAPS without modeling distribution level systems and makes the available transmission capacity accessible. The BAU case considers only the inter-province and inter-country intertie constraints. Some of the study projects also include intra-province transmission constraints. Therefore, there may be some lower level constraints that are not being recognized.
- In addition to modeling of existing contingency reserves in each province, additional wind variability reserves that were based on scaling the PCWIS wind variability reserves, were used to mitigate the wind and variability.
- The production simulation analysis assumed that all fossil-fuel based units were economically committed and dispatched while respecting existing and new transmission limits, generator cycling capabilities, and minimum turndowns, with exceptions made for any must-run unit or units with operational constraints.
- Renewable energy units (hydro, wind, and solar) were note economically dispatched, but were either peak shavers (storage hydro) or generators based on fixed profiles (wind and solar).
- Potential increase in operations and maintenance (O&M) cost of conventional thermal generators due to increased ramping and cycling were not included.
- Renewable (hydro, wind, and solar) energy plant O&M costs were not included in the model. Therefore, renewable energy resources were considered to have zero marginal cost, and hence, be price-takers.
- The hydro modeling did not reflect the specific climatic patterns of any specific year, but rather was based on a historical 10-year long-term average flows per month.
- The cost of "Load Shed Services for Import (LSSi) has not been accounted for in this study. LSSi is a transmission system reliability production and "is provided by load customers that agree to be quickly taken offline following sudden loss of imports coming across interties"[11].

[11] https://www.aeso.ca/market/ancillary-services/load-shed-service-for-imports/

3.1.4 Thermal Generator Modeling

The original source of the thermal generator characteristics was ABB Velocity Suite, Generating Unit Capacity dataset (accessed in 2017), and supplemented by additional data provided by the TAC members, where necessary or applicable. The generating thermal unit modeling included all capacity that was operating, restarted, standby, or under construction at the time of the data query, including all thermal generators with a capacity of 3 MW or larger.

Power plants were modeled by individual unit to ensure proper simulation of operation. Combined cycle gas units were modeled as a single unit, aggregating the gas turbines and steam turbine into a single generator. Steam turbine and combined cycle generating units were modeled with multi-block, incremental heat rate curves, whereas gas turbines and reciprocating engines (quick-start units) were modeled with a single power point. Other parameters that define thermal plants in GE MAPS include the following:

- **Primary Fuel:** Each unit was assigned a primary fuel type. Although units may have dual fuel capability, this study only evaluated a single, primary fuel for each unit. The fuel assignment is used to calculate total fuel cost and evaluate fuel consumption.
- **Max Capacity:** The max capacity (MW) represents the maximum amount of power a given unit can produce in the economic production cost simulations.
- **Minimum Rating (P-Min Operating):** Minimum rating refers to the minimum stable power output for each unit. The number of MWs between the minimum rating and maximum rating represents the unit's operating range. In addition, once a unit is committed and online, it must operate at least at its minimum rating.
- **Heat Rate Curves:** The incremental heat rate curves provided for each generator are used to calculate fuel consumption based on loading level.
- **Variable O&M (VOM):** Variable operations and maintenance costs are also modeled during the production cost optimization. The maintenance cost is dependent on the unit's utilization and represents ancillary maintenance costs associated with running a unit. This includes, but is not limited to, maintenance on turbine parts, water consumption, lubricating oils, etc.
- **Planned Outage Rate:** Planned outage represents the percent of time the generating unit is unavailable to serve system load in order to conduct planned and scheduled routine maintenance. These maintenance outages are scheduled optimally by the model.
- **Forced Outage Rate:** In order to account for unexpected and random generator outages, each unit is assigned a forced outage rate dictating the amount of time that

the unit is unavailable to produce energy. This outage rate is in addition to any planned or scheduled maintenance or fixed operating schedules.

- **Min Down Time & Min Run Time:** In order to constrain the operational flexibility of a unit due to thermal cycling constraints, each generator is assigned a minimum down time and minimum run time in hours.
- **Must-run:** A unit with the forced commitment (must-run) property must be online at all times, with the exception of planned and forced maintenance events. When committed, the units must be producing at or above the unit's minimum power rating, regardless of economics. This constraint is included for cogeneration units which serve a local steam host and sell excess electricity to the grid.
- **Start-Up Energy:** Start-up energy is the amount of fuel consumption required to start up a unit. If multiplied by the fuel cost, the resulting value represents the total start-cost for the unit. This cost is applied every time the unit comes online.

3.1.5 Hydro Generator Modeling

Canada is the world's second largest producer of hydroelectricity after China[12]. Among western provinces, British Columbia and Manitoba produce over 90% of their electricity from Hydro[13]. The underlying data source for the hydro modeling efforts was a compilation of sources and the best available data was assumed based on the hierarchy listed below. The proprietary data shared directly from TAC was utilized as the primary data source. Other publicly available data by plant and by province was used as secondary sources where required.

1. Proprietary data for pondage hydro was provided directly by members of the TAC members.
2. Publicly available historic data is published at plant granularity, accessed via ABB Velocity Suite, Monthly Plant Generation and Consumption dataset.
3. Publicly available historic data, published at provincial granularity, accessed via Statistics Canada, CANISM dataset, Table 127-0002 Electric Power Generation, by Class of Electricity Producer, Month (MWh), or other applicable public sources.
4. Hydrology information was also supplied by the TAC members.

The GE MAPS has limited capability to model flexible hydro systems that have large storage capability. The ability of such systems to provide sub-hourly regulation that can assist in

12 https://en.wikipedia.org/wiki/Hydroelectricity_in_Canada

13 Ibid.

managing intermittency of renewables and their ability to store energy over weeks, months, and seasons are not captured in the modelling process.

Run-of-river hydro is either represented by stream of hourly generation values or by the minimum monthly generation capacity of storage hydro (the minimum MW per hour that is generated each hour).

While seasonal and annual variation in hydro resources is expected, this study assumed "normal" hydro operating conditions. The normal hydro conditions were based on historical average monthly generation and capacity factor profiles from 2003 to 2012, unless normal conditions were explicitly specified by TAC members.

In the GE MAPS model each hydro plant is characterized, at a minimum, by the following information:

- **Monthly Minimum Hourly Generation (MW):** Minimum power plant rating in MW, which represents any run-of-river portion of the plant, or water flow that must occur with or without generating power (spillage). The default assumption was 10% of Monthly Maximum, unless otherwise provided by TAC feedback.
- **Monthly Maximum (MW):** Maximum power plant rating in MW, usually represents the capacity of the plant, but can be limited by seasonal, environmental, or other factors. Default assumption was assumed to be winter (October to April) and summer (May to September) ratings from ABB Velocity Suite, unless otherwise provided by TAC feedback.
- **Monthly Energy (MWh):** This represents the total available energy that the plant can produce in the given month. The default assumption was a 10-year average capacity factor for each month from 2003-2012, CANSIM Table 127-00001, unless otherwise provided by TAC feedback.
- **Spinning Reserve Capability (% of Up-Range):** this number, between 0 and 1, specifies the percent of unused pondage capacity – or per unit (P.U.) For Spinning Reserve - that can be used to provide spinning reserve. For example, a 100 MW hydro plant with 0.5 P.U. For Spinning Reserve, running at 60 MW, would have (100 – 60) x 0.5 = 20 MW of spinning reserve capability. If P.U. For Spinning Reserve were, in this case, 0.1, then the unit will have 4 MW available for spinning reserve. The default assumption was 1.0, unless otherwise provided by TAC feedback.

Within the bounds of min hourly generation and max hourly generation and the total monthly energy generation, the dispatch of pondage hydro units is scheduled by the GE MAPS program against the province's net load curve (load minus wind and solar generation). For the base case study scenarios, it was assumed that the scheduling was done against the day-ahead *forecasted* wind profiles. This process is illustrated in Figure 3-3, where the hydro plants would be scheduled against the black dotted line. As a result, the hydro schedules were coordinated with the forecasted wind resource, but unable to compensate directly against real-time forecast errors. For some run-of-river hydro plants or resources with significant operational limitations, the plants were modeled with a fixed hourly profile.

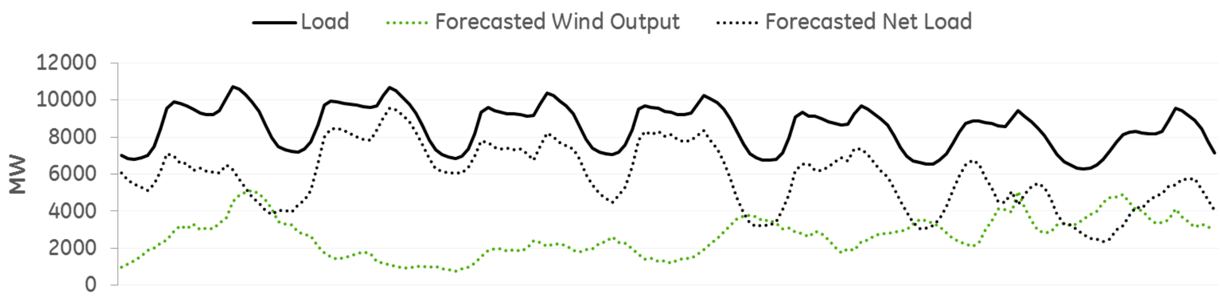

Figure 3-3: Net Load Hydro Scheduling Methodology Example

Additional constraints were modeled for many plants in the Pan-Canadian database. In general, these assumptions were provided by the TAC members or assembled through research by the project team. These constraints were modeled on an as needed or as available basis:

- **Sequential Dam Logic:** By default, the hydro plants were independently scheduled in an effort to optimally dispatch against system loads. If hydro plants are part of a hydro system where one plants operation affects another's, then the sequential dam logic grouped plants together to coordinate the hydro schedule.
- **Company, Area, Pool Scheduling:** By default, the hydro plants were scheduled to peak shave the pool (provincial) load where they reside, as shown in Figure 3-4. As a result, they were only scheduled against that pool's unique load shape. However, some hydro plants were also scheduled against a combined load shape, which aggregated multiple pools or areas together to form a new composite load profile for scheduling. This was useful for plants in places like Quebec which are used to export into New England, New York, and Ontario markets, or for plants in Manitoba that are used to serve Midcontinent ISO (MISO) load.
- **Unavailability:** Some hydro resources are unavailable during certain periods (hours, days, months, etc.) due to resource or environmental constraints.
- **Scheduling Order:** Hydro units were scheduled against the pool loads based on a preset priority list. By default, this list is sorted from largest to smallest, but was rearranged in some cases based on system operating rules.

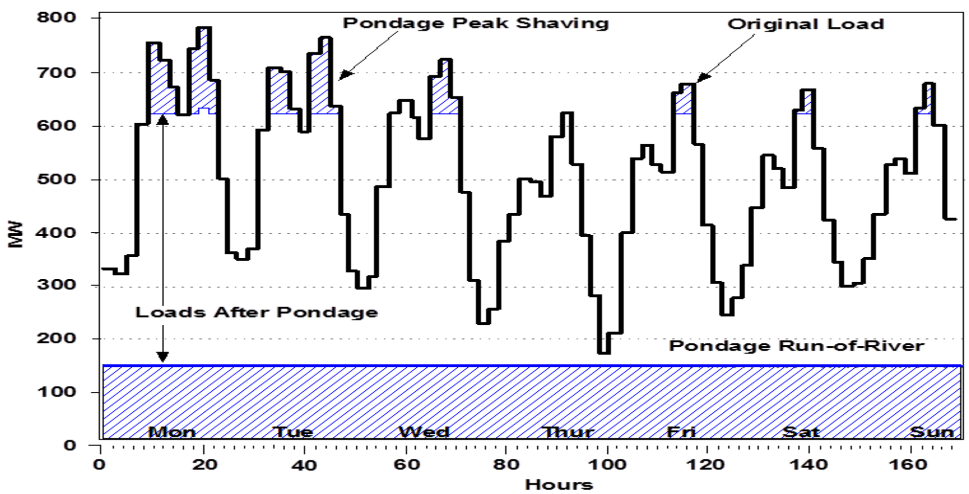

Figure 3-4: Peak Shaving of Load by Hydro Generation

3.1.6 Wind Generator Modeling

All wind units were modeled as hourly load modifiers in GE MAPS and follow a pre-defined hourly generation pattern. Two profiles were modeled for each unit, one forecast profile that was used during the unit commitment process, and a "real-time" profile that was used during the dispatch process. Unit commitment of thermal units and the hydro scheduling created from forecasted profiles. Any forecast errors during the dispatch process must be compensated by surplus up-range on the committed thermal units or by quick-start units (gas turbines, reciprocating engines, etc.).

In general, the wind profiles were based on the wind data developed in the PCWIS project, with the agreement of the TAC members.

Wind resources were assumed to have zero fuel and O&M costs, and hence are assumed to be available at no cost in the dispatch stack. The model does not take into account any power purchase agreement (PPA) based prices of independent power producers (IPP) in dispatch of wind and solar resources. However, payments to IPPs can be post-processed.

The hourly load and wind profiles (i.e., diurnal hourly shapes) used in the study are based on load and generation patterns of the meteorological data from 2008. This was the base year of hourly load and wind profiles (i.e., diurnal hourly load and wind shapes) used in the CanWEA's PCWIS[14] project. The wind data used in the RECSI project are scaled versions of the PCWIS wind data, which were based on 2008 profiles. The choice of 2008 or any other

[14] https://canwea.ca/wp-content/uploads/2016/07/pcwis-section03-winddatadevelopment.pdf

year for load and wind shapes does not impact the total wind energy or peak values for 2030 and 2040. The base profile year only defines the diurnal hourly shape of load and wind. To preserve any weather-related correlation between hourly wind and electricity load, it is necessary to use the same base year for hourly load and wind profiles. PCWIS project also performed sensitivity analyses using load and wind shapes from 2009 and 2010 and using different load and wind profile years exhibited minimal impact on the power system operational and economic performance. Each wind plant has a unique production profile based on its geographic location and scaled according to the MW rating of the plant.

3.1.7 Generation Expansion Methodology

The GE MAPS production cost model was updated to incorporate changes in the supply mix to reflect the North American grid in the year 2030 and 2040. This process incorporated public announcements of new installations and retirements as well as generic expansion generators required to maintain reserve margin adequacy.

Generation Additions and Retirements

<u>New Installations</u>

New installations include any units that are under construction, site-prep and testing in ABB Velocity Suite (6/1/2017). Specific new installations were provided by TAC members. New plant installations include the Table 3-3.

As part of the generation expansion process, about 20 GW of additional power plants, coming online by 2040, were specified by TAC members. Table 3-4 shows the total additional capacity by province.

<u>Plant Retirements</u>

Retired plants include any publicly announced retirements listed in ABB Velocity Suite (6/1/2017). Additional specific retirements/contract expirations were requested by TAC members. For Alberta, the majority of remaining coal plants were converted to gas. Plant retirements are presented in Table 3-5.

Table 3-3: New Generation Installations (ABB Velocity Suit)

- Christina Lake Cenovus (101 MW)- AB
- Medicine Hat Unit 16 (43 MW) –AB
- Fort Hills Cogen (199 MW)-AB
- Site C Hydro (1,145 MW) – BC
- Shaunavon Kineticor Flare Gas (20 MW)- SK
- Swift Current Chinook CC (350 MW)- SK
- Blue Hills Wind (177 MW)- SK
- Riverhurst Wind (10 MW) –SK
- Western Lily Wind (20 MW) –SK
- Keeyask Hydro (630 MW)- MB

Table 3-4: Additional New Generation Installations by 2040 (TAC Additions)

Province	Number of New Plants	New Generation Capacity (MW)
AB	39	7,904
BC	16	6,078
MB	2	700
SK	15	3,140
Total	**72**	**17,822**

Note: Table 3-4 excludes the new generation from the ABB Velocity list.

Table 3-5: Generation Retirements

- Battle River Coal units 3,4 (304 MW) – AB
- Sundance units 1-2 (560 MW) – AB
- H.R. Milner Coal (144 MW) – AB
- Queen Elizabeth qeb3 (95 MW) –SK
- Landis GT (79 MW) –SK
- Meadow Lake (44 MW) –SK
- Boundary Dam Coal units 4,5 (278 MW)- SK
- Sunbridge Wind Farm (11 MW)- SK
- Meridian (243 MW)- SK
- North Battleford (271 MW)- SK
- Brandon Unit 5 (97 MW)- MB

Thermal Generation Expansion Planning Process

If generation additions and retirements specified by the TAC members for the BAU case were deemed insufficient to balance each province's system in 2030 and 2040, additional generic units were added to the system in and iterative process in order to ensure that the system has enough capacity to maintain reliability given the expected load growth.

The additional generation expansion plan (above and beyond the generation additions and retirements specified by the TAC members for BAU case) was developed based on the load and capacity assumptions of the BAU case. The expansion plan was then kept the same across all the study projects, regardless of the firm capacity benefits provided by each study project's proposed generation and transmission additions.

The amount of added generation capacity was based on the installed reserve margin (RM) requirement in each province in Canada and in each pool in the USA. The reserve margin in each province or pool should be at or exceed the reserve margin target listed in the 2017 NERC Long Term Reliability Assessment (LTRA). If the given load growth, new installation, and planned retirements in the BAU case resulted in an installed reserve margin deficit, then additional "generic" units were added to the system so that the target installed reserve margin targets would be achieved. The equation for the reserve margin calculation is provided below:

$$\boldsymbol{Reserve\ Margin} = \frac{[\boldsymbol{Qualified\ Capacity} + \boldsymbol{Firm\ Net\ Imports} - \boldsymbol{DSM}]}{\boldsymbol{Peak\ Demand}}$$

Where:

- Qualified Capacity is the firm capacity value of generation resources.
- Firm Net Imports is the net (Imports – exports)
- DSM is the Demand Side Management resources
- Peak Demand is the annual peak demand for the year under consideration.

Two main types of generic Candidate Thermal Plants were selected:

- A future Combined Cycle Natural Gas Turbine (CC-GAS) Type, rated at 350 MW with an assumed heat rate of 6,600 Btu/kWh, reflective of future CC-GAS power plants.
- A future Single Cycle Natural Gas Turbine (SC-GAS) Type, rated at 180 MW with an assumed heat rate of 9,800 Btu/kWh, reflective of future SC-GAS power plants.

For wind and hydro resources, the firm capacity is lower than the nameplate capacity due to resource availability during peak time periods. It should be noted that the capacity value for wind resources used in this part of the analysis are based on values provided by TAC members or based on the PCWIS results.

Targeting the installed reserve margin targets based on province specific requirements and/or NERC 2017 LTRA data, GE MAPS was run iteratively to refine the SC-GAS and CC-GAS mix in order to meet the reserve margin targets and also achieve the reasonable utilization (i.e., capacity factor) for each generic unit type. The technology choice (SC-GAS vs. CC-GAS) was based on a utilization threshold of >30% for CC-GAS units and <10% for SC-GAS units. If the resulting utilization from the GE MAPS simulation was outside of those constraints, the additional capacity of each generic type was adjusted, and GE MAPS was rerun. The iterative process was repeated until the capacity factors of the generic SC-GAS and CC-GAS units met their thresholds.

As shown in Table 3-6 and Table 3-7, there was no need for generic additions in 2030. There were some additions in Saskatchewan and Manitoba in 2040.

Table 3-6: Generic CC and GT Additions in 2030

2030	Unbalanced RM %	Target RM%	Generic CC Add	Generic GT Add	Balanced RM %
AB	19.3%	11.0%	0	0	19.3%
BC	14.4%	14.0%	0	0	14.4%
SK	14.0%	11.0%	0	0	14.0%
MB	26.2%	12.0%	0	0	26.2%
Total			**0**	**0**	

Table 3-7: Generic CC and GT Additions in 2040

2040	Unbalanced RM %	Target RM%	Generic CC Add	Generic GT Add	Balanced RM %
AB	15.9%	11.0%	0	0	15.9%
BC	17.7%	14.0%	0	0	17.7%
SK	-8.5%	11.0%	700	360	11.8%
MB	2.9%	12.0%	700	0	14.7%
Total			**1400**	**360**	

For wind and hydro resources, the firm capacity may be lower than the nameplate capacity due to resource availability during peak time periods. It should be noted that the capacity value for wind resources used in this part of the analysis was the existing firm capacity value used by each province and not the capacity values calculated later in this report.

Table 3-8 provides assumptions regarding the capacity value (or capacity de-rate for capacity valuation purposed), which were applied for determination of installed reserve margins.

Table 3-8: Renewable Capacity Value

	Hydro Capacity Value	Wind Capacity Value
AB	67%	22%
BC	Varying	Varying
SK	100%	20%
MB	100%	20%

A capacity value of 65% indicates that 65% of the plant's capacity is counted towards the installed reserve margin target.

Generic Renewable Additions in the United States

With significant amount of interconnection and power flows between the United States and Canada, it was important to include renewable expansion in the USA power systems as well. To do this the study team leveraged scenarios and wind profiles developed for previous studies lead by the USA Department of Energy National Renewable Energy Laboratory (NREL), including the Eastern Renewable Generation Integration Study (ERGIS) and the Western Wind and Solar Integration Study Phase 2 (WWSIS2) studies. As a result, no new analysis for the wind resource, hourly profiles, or site selection was conducted by the project team for this study. The USA portions of the GE MAPS database were modified to incorporate the NREL wind capacity additions and hourly profiles for the year 2008. In addition, the same sub-hourly regulation reserve requirements from the NREL studies were used in the USA power pools. The USA portion of the BAU case included a build out of additional renewable capacity in order to achieve full compliance from state renewable portfolio standard (RPS) requirements projected to 2030 and 2040. It should be noted that the any generation expansion plan determined for the USA pools in the BAU case accounted for the additional NREL wind additions and RPS based renewable additions. Hence, the USA pools in the BAU case are also balanced for 2030 and 2040.

3.1.8 Curtailment

Curtailment refers to the reduction of generation from renewable resources below the levels available in the underlying resource. For example, if the wind resource is able to produce 100 MW of generation, but the system operators dispatch the plant at 60 MW, there is 40 MW of curtailed, or unused, power. There are several reasons why a system operator may choose to curtail a renewable resource, including transmission congestion, grid stability or reliability concerns, ramp rate or cycling constraints of other generators, environmental constraints, or other engineering, economic, or system constraints. The curtailed energy represents an opportunity cost, because absent storage, the energy is wasted and must be supplied by other sources.

It is important to distinguish between the available generation profiles (GE MAPS inputs) and the actual dispatched generation profiles (GE MAPS outputs). The hourly dispatched generation is an output from the GE MAPS algorithm that takes into account any necessary curtailment. Wind generation is the last resource to be curtailed (i.e., spilled) during the low load and high supply periods. In such times, GE MAPS uses a priority order, whereby more expensive thermal unit operations are reduced, but only up to their minimum load (they are still kept online if already committed). If no more thermal generation is available for backing down, then GE MAPS uses an assigned priority order to curtail the remaining wind, solar, and hydro energy (i.e., curtailed wind and solar and spilled hydro). The last in the priority order is typically non-grid scale distributed solar generation, which is assumed not to be responsive to system operators' curtailment commands. Another important curtailment input was that the study assumed nuclear units would not decrease generation to accommodate additional wind energy.

Throughout this study, curtailment includes unused wind and solar energy and spilled hydro energy, which are treated equivalently for reporting purposes. The system operator's decision of which resource, or individual plant, to curtail is based on different environmental, economic, contractual, and engineering considerations, but the net effect is the same – the grid is unable to accommodate resource with zero marginal cost. The curtailed energy is wasted and must be provided by other resources. The alternate resources may have higher operating costs and thereby lead to reduced system economic efficiency. As a result, the project reporting does not differentiate between different types of resource curtailment. For modeling purposes, it was assumed that new wind additions (absent other constraints) were curtailed before the existing hydro and solar plants. This curtailment order is a practical assumption for this study but is not intended to represent existing operational practices or a recommended future practice.

One possible option for reducing curtailment to lower levels is scheduling hydro resources based on the knowledge of real-time wind. In the BAU case, hydro resources were scheduled with the knowledge of day-ahead wind forecast. Scheduling hydro resources against real-time wind is akin to assuming at least hourly flexibility in dispatch of hydro resources. This option was considered and is one of the sensitivity analyses that was performed in this study.

Other options for reducing curtailment to lower levels that were not part of the current modeling exercise but could be part of further detailed investigation. include:

- Additional transmission infrastructure, which would relieve congestion and enable access to load centers by more renewable energy. The optimum level of transmission reinforcements would depend on the value of additional recovered renewable energy versus cost of additional transmission.
- Shifting of hydro energy usage, with hydro pondage acting as storage of potentially curtailable energy by reducing hydro generation and shifting discharge by hours, days, weeks, months, or seasons. This would involve changing the monthly hydro energy dispatch schedules to be more compatible with short-term variability as well as seasonal patterns in wind generation. Several Canadian provinces have large hydro resources with long-term pondage, so this option for mitigating curtailment offers significant opportunity to reduce energy curtailment with higher penetration of wind power.
- Providing more operational flexibility in thermal generation, such as increasing ramp rates, decreasing unit minimum run time and down time, and lowering the minimum operating load of units.

3.1.9 Fuel Price Projections

Natural Gas Price Assumptions

The natural gas price assumption is one of the most important economic variables in the model. This is because the marginal generator on the system is typically fueled by natural gas and thus represents the generation type displaced by renewable energy.

Monthly natural gas prices are based on the Henry Hub prices from the EIA Annual Energy Outlook 2016 Report[15,16]. Delivered prices across the Canadian regions provide the additional "basis differentials" reflecting the time and location dependent variations in the cost of natural gas. Regional basis differentials were developed using 2008-2013 average monthly delivered gas price at the CA-US border. The same methodology is used for US pricing nodes. The basis differentials are the average monthly differentials relative to Henry

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[15] https://www.eia.gov/outlooks/aeo/pdf/0383(2016).pdf

[16] Note: EIA Annual Energy Outlook available at http://www.eia.gov/forecasts/aeo/er/index.cfm

Hub and sourced from Enerfax historical data, accessed via ABB Velocity Suite. The study used AESO gas prices for all of the western provinces. The natural gas basis differentials data used are based on GE analysis using the Gas Pipeline Competition Model (GPCM).

The delivered natural gas prices for each province are provided in the following figures. Natural gas Prices are provided in $/MMBtu[17]. The underlying seasonality (higher prices in winter) also coincides with peak demand for both electricity and gas heating demand.

All price inputs into GE MAPS are based on real USD 2017 dollars. The final model monetary results were converted in CAD 2018 dollars.

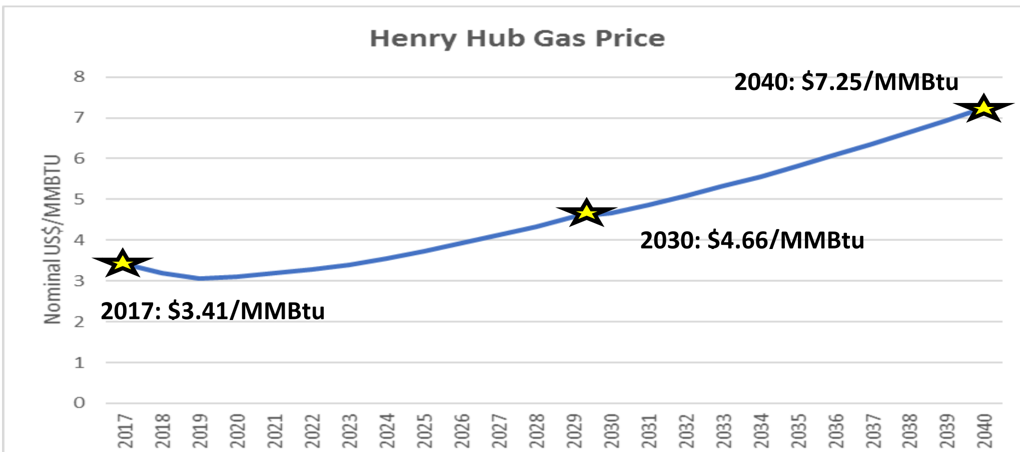


Figure 3-5: Henry Hub Natural Gas Prices

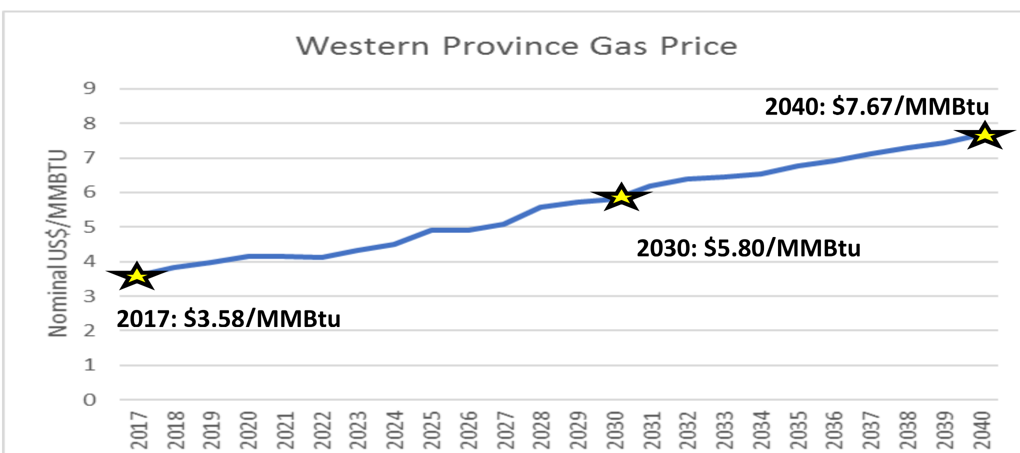
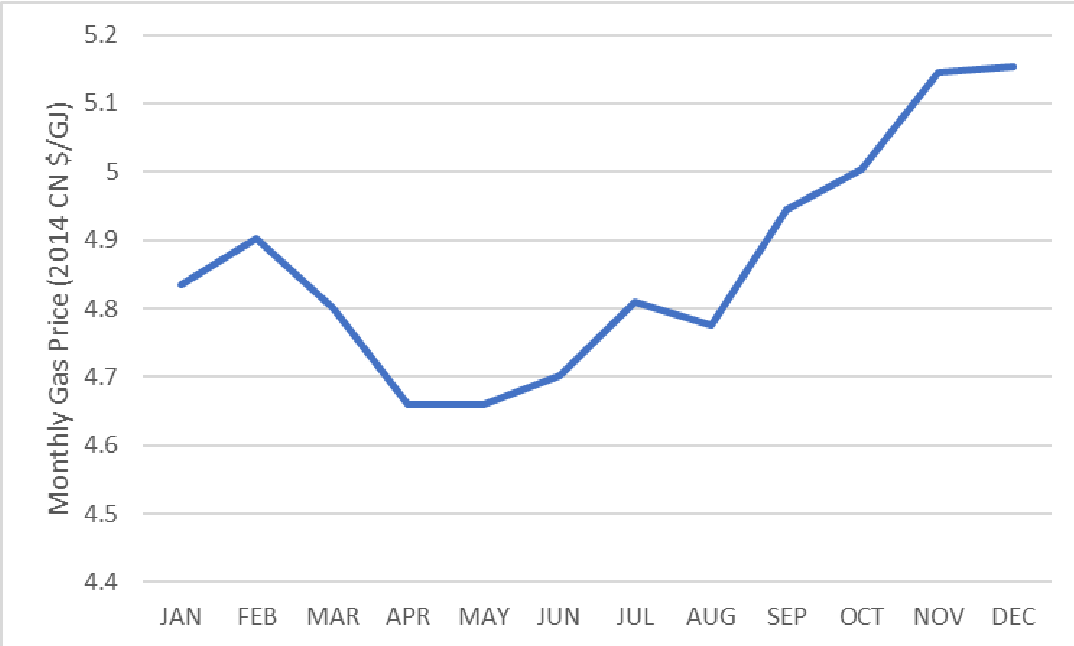


Figure 3-6: Western Provinces Natural Gas Prices

[17] There is 0.947 MMBtu per GJ.



Source: AESO

Figure 3-7: Monthly 2030 AESO Gas Price Assumption: $4.34 2014 C$/GJ

Other Fuel Price Assumptions

The assumed fuel prices for coal and biomass/other/waste, etc. are provided in Table 3-9 for the 2030 simulation year. The underlying data source for the coal prices is based on TAC feedback in Alberta and Saskatchewan.

Table 3-9: Coal and Other Fuel Price Assumptions (C$/GJ)

Fuel Type	Data Source	2030 Avg. Price
SK Coal	EIA Annual Energy Outlook	$1.64
Biomass/Other	GE Energy Consulting	$1.24

U.S. Coal Prices are developed for each coal plant and based on EIA Annual Energy Outlook coal price forecast by basin, plus transportation costs to each individual plant. Biomass, wood, waste, etc. has a generic fuel pricing across the North American database. Unless a custom coal price is provided, coal prices are developed for coal plants based on EIA coal basin price forecasts and plant specific transportation costs.

3.1.10 Load Projections

Annual Energy and Peak Demand Forecast

A 2030 and 2040 load forecast of the annual energy (GWh) and peak demand (MW) was used throughout the model footprint. A chart of monthly load energy by province is provided in the following figure. The load data for the Canadian provinces were provided by the TAC members. The USA load data is based on the ABB Velocity Suite "Historical Demand by Zone, Hourly dataset".

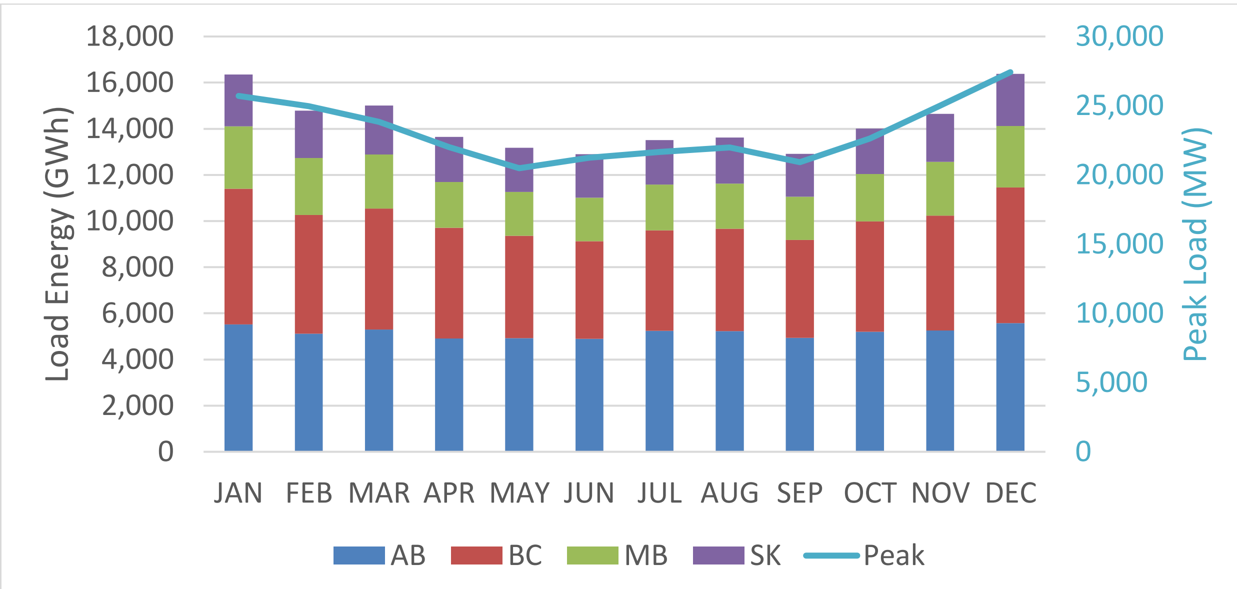


Figure 3-8: Western Region Monthly Load in 2030

Chronological Load Patterns

The annual energy and peak demand targets are used to scale the hourly chronological loads for each province. The chronological load patterns were based off historical load data, accessed via ABB Velocity Suite's Historical Demand by Zone Hourly dataset. In order to maintain weather-linked correlation between historical load and wind profiles the 2008 weather year load profile was scaled up to the annual energy and peak demand targets by the GE MAPS model. The chronological load pattern of the western provinces is shown in the following figures.

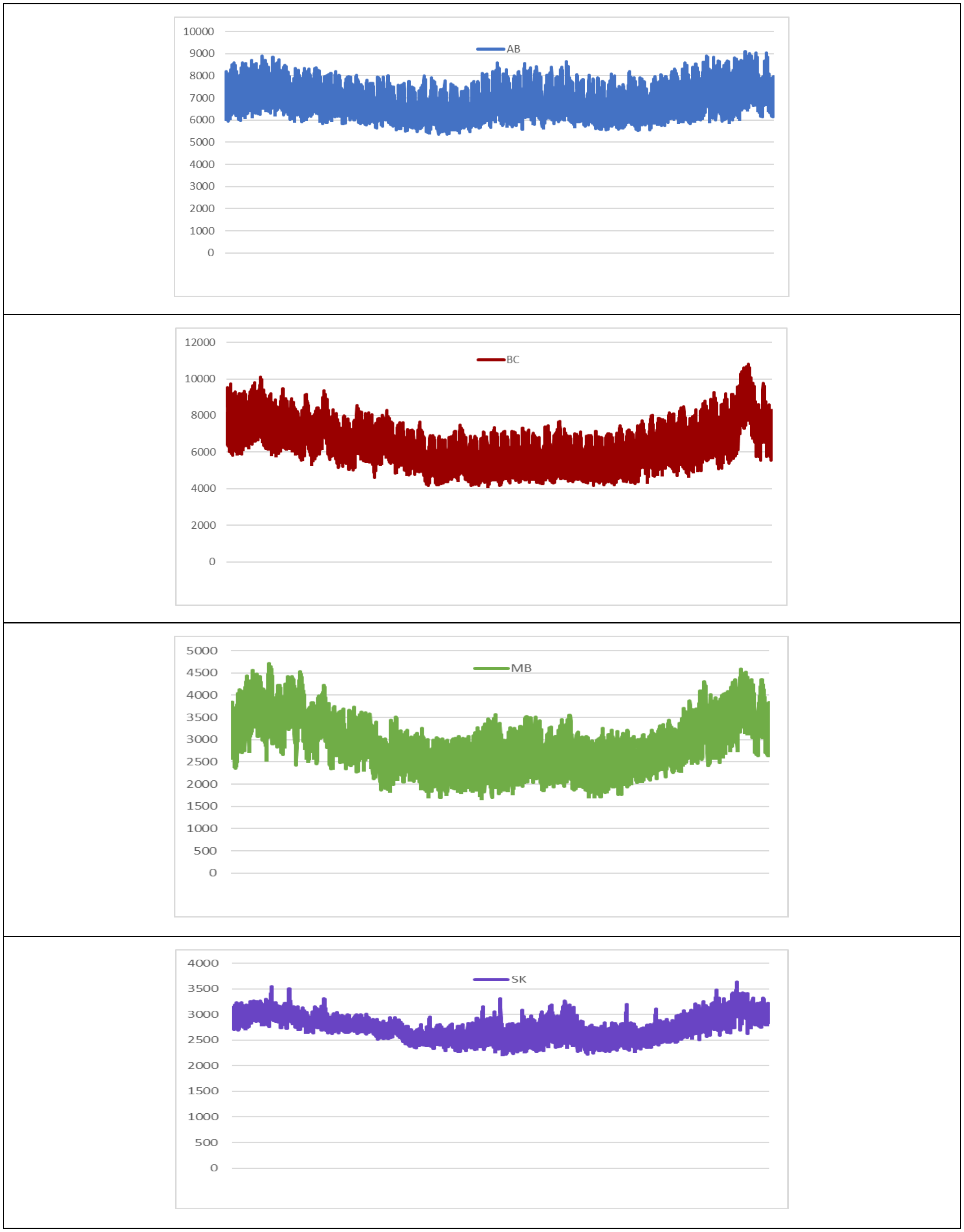


Figure 3-9: Western Region Hourly Load Patterns

3.1.11 Carbon Emissions

The following carbon emissions rates were assumed for burning of coal and natural gas:

- Coal (blended): 88.1 kg/GJ
- Natural Gas: 51.5 kg/GJ

The rate is based on the amount of carbon pollution released by the fuel when it is combusted, not on the mass of fuel itself.

The federal government plans to introduce new legislation and regulations to implement a carbon pollution pricing system – the "backstop"[18] – to be applied in jurisdictions that do not have carbon pricing systems that align with the benchmark.

The federal backstop on the fuel levy will start at $10/Tonne in 2018 and increment up by 10$ until $50/Tonne in 2022. For this study, TAC members assumed an annual 2% escalation after 2022. However, there is no firm commitment from the federal government after 2022. It should be noted that the carbon price applies to fuels used in systems that do not have an "output-based pricing system[19]."

3.1.12 Transmission

Transmission Constraints and Interface Definitions

The GE MAPS production cost simulation included a full transmission representation of the Eastern Interconnect (MMWG load flow) and Western Interconnect (TEPPC load flow), including a full configuration of the transmission grid including all the major transmission lines and transmission system buses. All load busses were assigned to the appropriate GE MAPS areas and corresponding load forecast and all generating units were assigned to the correct generation bus. The solved load flow is used to create the generation shift factor (GSF) matrix to determine the transmission power flows across the network. In addition, transmission losses are modeled in GE MAPS.

A map of the high voltage transmission network in Western Canada is provided in Figure 3-10. The map was constructed by the GE Team using the ABB Velocity Suite database reflecting the latest transmission data as of January 2018. However, it is possible that it may be missing some of the latest transmission developments in Canada.

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[18]https://www.canada.ca/en/services/environment/weather/climatechange/technical-paper-federal-carbon-pricing-backstop.html

[19]https://www.canada.ca/en/services/environment/weather/climatechange/climate-action/pricing-carbon-pollution/output-based-pricing-system.html

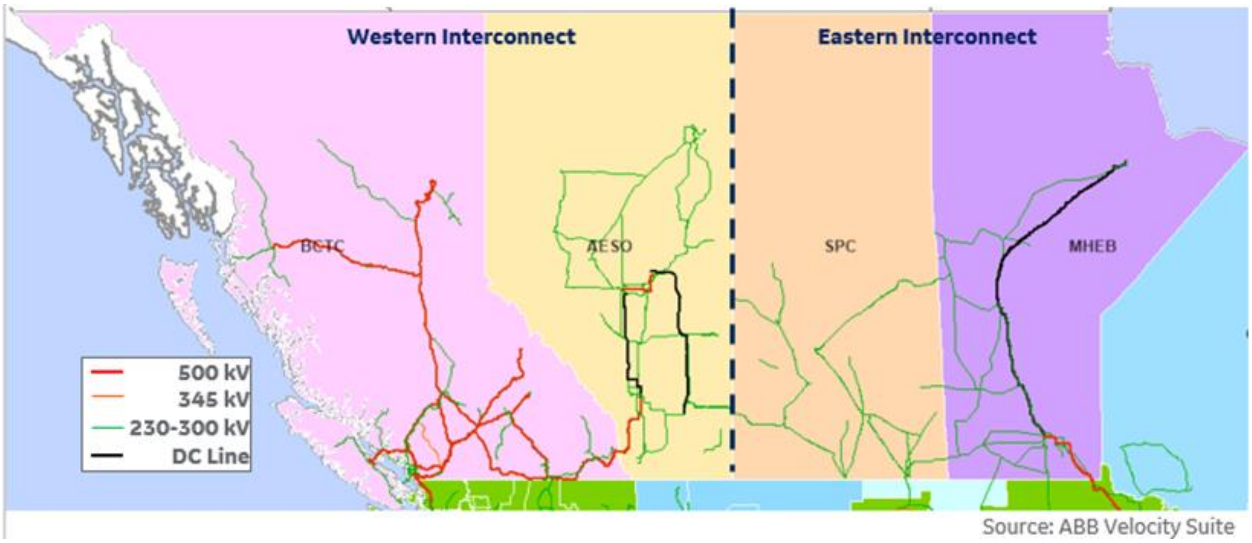


Figure 3-10: High Voltage Transmission Network Map of Canada

Based on data availability, the production cost modeling did not include a full representation of all transmission constraints across the Pan-Canadian system. Instead the model included major transmission constraints between each province and neighboring systems (intra-provincial) in both Canada and USA. Transmission interties in the BAU case are listed in Table 3-10.

Table 3-10: Transmission Interties in the BAU Case

Intertie	Export/Import
BC to WA (3 ties, 1 interface)	3,150 MW / -3,000 MW
AB to BC (Path 1)	1,000 MW / -800 MW
AB to SK	150 MW / -150 MW
AB to MT (1)	325 MW / -300 MW
SK to MB (SP & WP)	
Tie 1	(60 MW / -45 MW) & (90 MW/ -25 MW)
Tie 2	(25 MW / -250 MW) & (75 MW /-250 MW)
SK to ND	165 MW / -150 MW
MB to ON (SP & WP)	(293 MW / -225 MW) & (368 MW / -300 MW)
MB to ND & MN	2,833 MW / -1,583 MW

Note: In project evaluation runs, the MT to AB limit is set to 310 MW.

Hurdle Rates

In addition to the transmission constraints listed above, the model included economic "hurdle rates" that place an economic charge on transfers between operating areas. This is used to simulate both the wheeling charges between balancing areas and market "friction" that may result from different operating rules and procedures in different utilities. It was assumed that the hurdle rate between balancing areas (across both USA and Canada) was USD$5/MWh during the unit commitment process and USD$3/MWh during the economic dispatch process.

4 Business-As-Usual (BAU) Scenario

4.1 BAU Case Features

4.1.1 BAU Installed Capacity and Energy Generation

Study projects are compared to a Business-As-Usual (BAU) scenario. The BAU case represents the base case without any of the additional projects evaluated in this study. It is an extension and projection of electric loads and fuel prices into the future study years of 2030 and 2040 and includes planned new generation and transmission installations and expected generation retirements. Year 2016 was used as the base year for the BAU model database set up, and for benchmarking of the model results with available actual data.

The new installations include all the generation units that were specified by the TAC members, plus some additional generic single cycle gas turbines (GT-GAS) and natural gas combined cycle (CC-GAS) generation units in 2040 that need to be added in order to satisfy the installed reserve margin requirements in each province in the study years.

The following tables present the installed capacity and annual generation by plant type in the four western provinces in 2016, 2030, and 2040. The annual generation is based on the net-to-grid (NTG) generation, which excludes portions of industrial on-site cogeneration that is used to meet on-site loads of those facilities.

Table 4-1: Western RECSI Generation Capacity (MW)

	2016				2030				2040			
	BC	AB	SK	MB	BC	AB	SK	MB	BC	AB	SK	MB
HYDRO	15,544	894	872	5,265	18,189	894	872	5,895	20,189	894	872	5,895
WIND		1,445	221	258		4,045	2,617	258	3,078	4,045	2,617	258
CC-GAS	275	1,716	677		275	2,466	1,282		275	8,651	1,711	700
GT-GAS	1	916	678	233	1	6,573	555	233	1	2,797	915	233
OTHER		428	30			469	30			469	30	
COGEN		3,425	492			4,230	512			4,372	269	
ST-COAL		6,283	1,533	95		929	1,255				1,255	
SOLAR						500	60			500	60	
ST-GAS				126				126				126
Total	15,820	15,107	4,503	5,977	18,465	20,106	7,183	6,512	23,543	21,728	7,729	7,212

Table 4-2: Western RECSI NTG Annual Electricity Production (GWh)

	2016				2030				2040			
	BC	AB	SK	MB	BC	AB	SK	MB	BC	AB	SK	MB
HYDRO	63,709	1,348	3,267	32,970	68,988	1,875	3,335	36,287	65,915	1,875	3,515	37,473
WIND		4,443	718	992		12,910	7,995	913	10,599	12,871	8,092	966
CC-GAS	1,265	9,012	5,201		522	17,989	3,814		0	47,627	7,191	1,313
GT-GAS	0	224	221	0	0	2,347	109	8	0	232	420	14
OTHER		475	150			1,925	133			1,850	146	
COGEN		10,627	3,670			22,819	2,430			15,324	1,391	
ST-COAL		39,812	10,827	0		7,107	8,108				8,742	
SOLAR						775	184			774	184	
ST-GAS				0				48				73
Total	64,974	65,941	24,054	33,961	69,510	67,746	26,108	37,255	76,515	80,555	29,681	39,838

Summer Capacities by plant type in each province and the annual NTG electricity productions in 2016, 2030, and 2040 are shown in the following six figures.

Substantial amounts of new hydro and wind capacity are added in 2030 and 2040 in the four western provinces. As the figures show, hydropower plants are the dominant generation resources in the western provinces in the base case and both study years. They are concentrated mainly in British Columbia and Manitoba. Most of the wind resources are expected to be added in British Colombia, Alberta, and Saskatchewan.

Alberta Keephills 3 and Genesee 3 supercritical coal facilities are expected to be the last generating assets to convert to gas or to retire. Most of the existing steam coal plants (ST-COAL) in Alberta and Saskatchewan are planned to be converted to single cycle natural gas (GT-GAS) plants in 2030 and then to combined cycle (CC-GAS) plants in 2040. Hence, by 2040 the dominant generation resources by type in 2040 are hydro, CC-GAS, and wind plants.

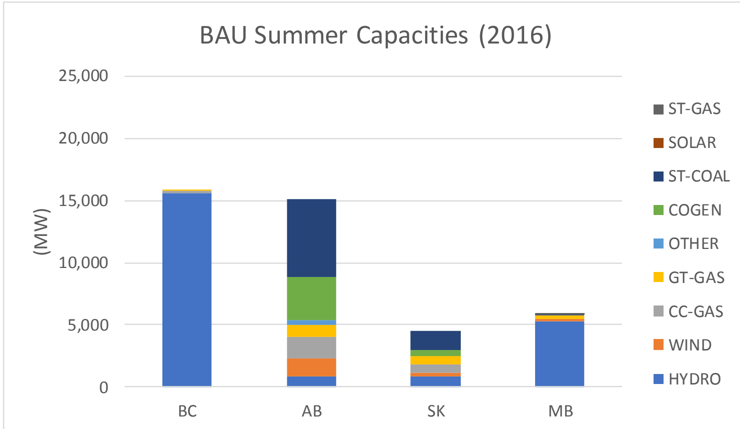


Figure 4-1: BAU Summer Capacities in 2016

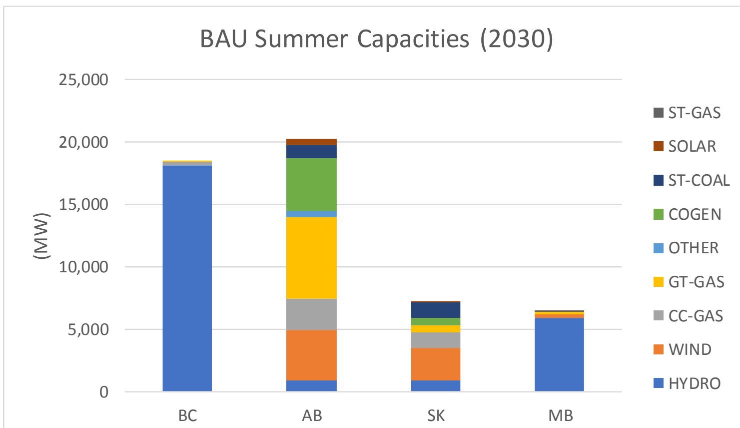


Figure 4-2: BAU Summer Capacities in 2030

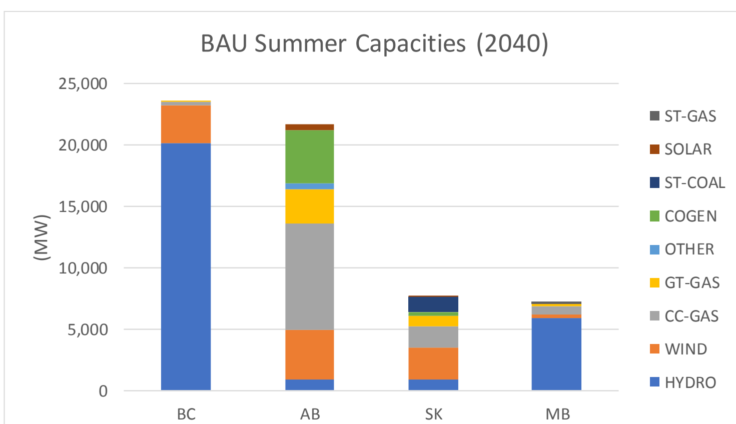


Figure 4-3: BAU Summer Capacities in 2040

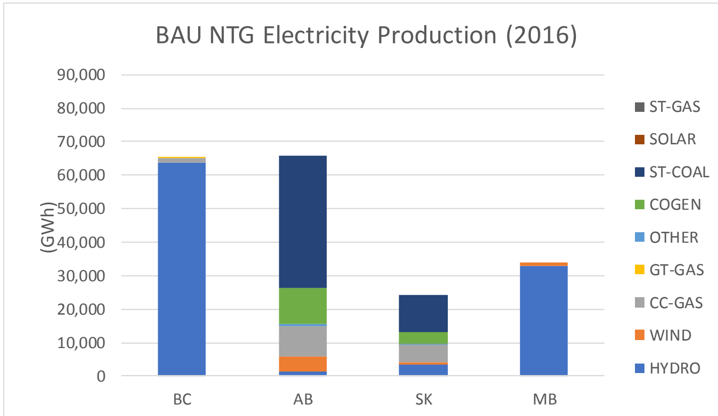


Figure 4-4: BAU NTG Electricity Production in 2016

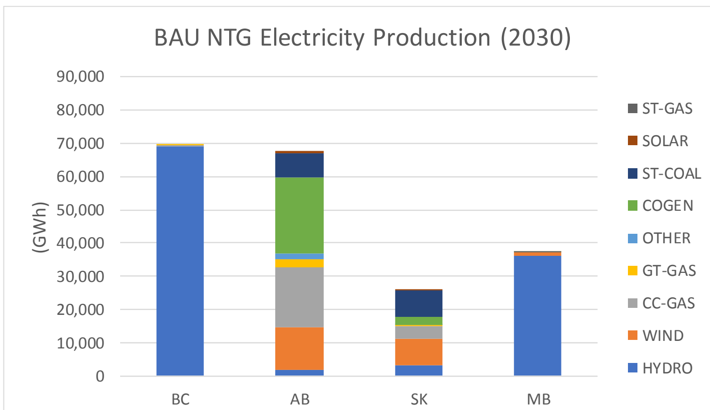


Figure 4-5: BAU NTG Electricity Production in 2030

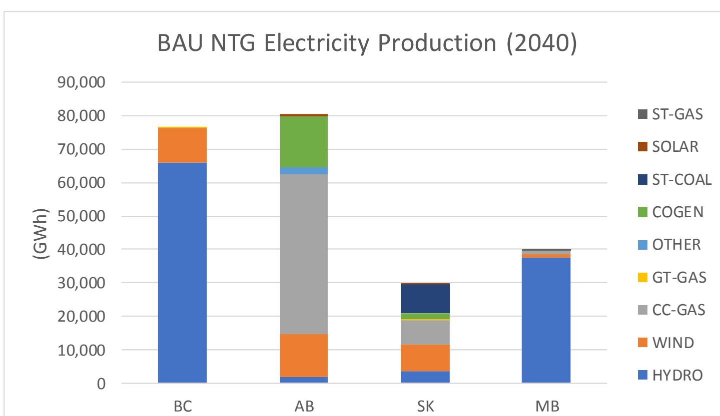


Figure 4-6: BAU NTG Electricity Production in 2040

4.1.2 BAU Imports and Exports

The GE MAPS model, by virtue of simulating all of Western and Eastern Interconnections based on the security constrained[20] day-ahead unit commitment and hourly economic dispatch, is able to estimate hourly electric power transfers between USA and Canada. The resulting annual net exports (to other provinces and to the USA) for each province are shown in the following figure.

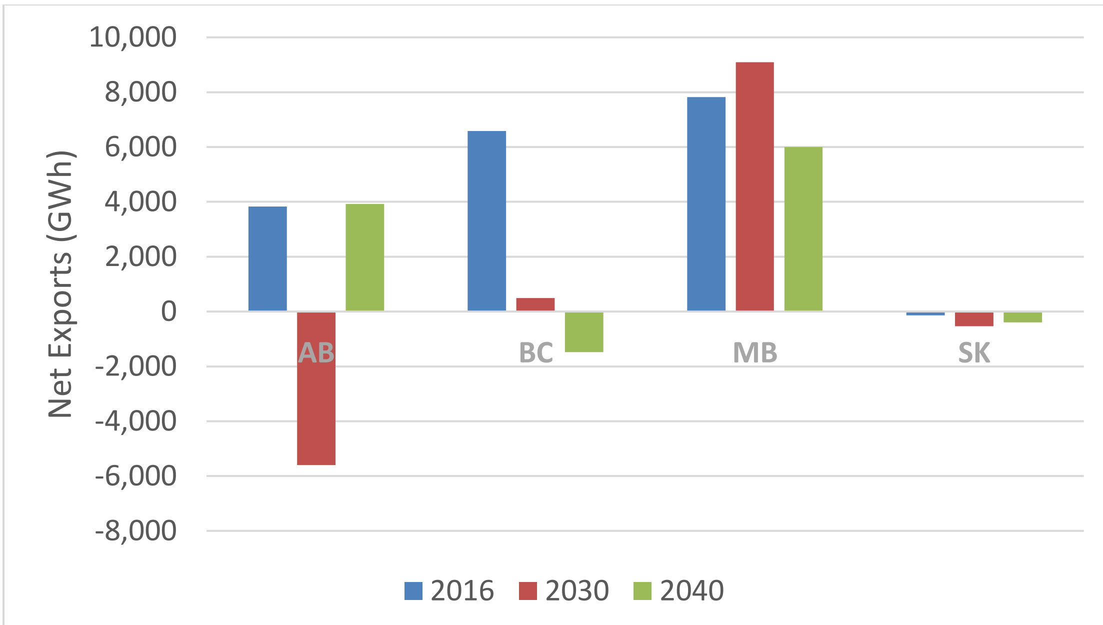


Figure 4-7: Net Exports by Provinces

By 2030, most of the remaining ST-COAL plants in Alberta are set to be converted to GT-GAS plants. With additional wind, solar, and some CC-GAS plants being added, total generation in Alberta would increase by about 1000 GWh between 2016 and 2030. During the same period, Alberta load increases by more than 11,000 GWh. Therefore, by 2030, Alberta becomes a net importer of electricity.

Between 2030 and 2040 Alberta converts the GT-GAS plants to more efficient CC-GAS plants and with some additional generation installed, electricity production increases by 13,500

[20] Security Constrained Economic Dispatch (SCED) Definition: "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities", Security Constrained Economic Dispatch: Definition, Practice, Issues, and Recommendations, A Report to Congress, Federal Energy Regulatory Commission, July 31, 2006.

https://www.ferc.gov/industries/electric/indus-act/joint-boards/final-cong-rpt.pdf

GWh. During the same period, Alberta load grows only by 3,800 GWh. Due to this surplus electricity generation, Alberta reverts to becoming a net exporter.

In British Colombia between 2016 and 2030, 2,600 MW of mostly hydro generation is added, resulting in about 4,500 GWh of additional electricity production. However, during the same period, British Columbia load grows by about 6,200 GWh, resulting in a decrease in British Columbia exports. Between 2030 and 2040, electricity production increases by 7,000 GWh, whereas in the same period, British Columbia load grows by only about 8,800 GWh. Hence, British Columbia switches to becoming a net importer in order to cover its operational energy shortfall.

In Manitoba, between 2016 and 2030, electricity production is increased by about 3,000 GWh, but Manitoba load grows only by about 1,440 GWh, resulting in more Manitoba exports. Between 2030 and 2040 those exports decrease because although electricity production is increased by about 2,500 GWh, load grows by a wider margin to 6,125 GWh.

In Saskatchewan, between 2016 and 2030, electricity production is increased by about 1,870 GWh, but load grows by about 2,250 GWh, resulting in Saskatchewan importing more electricity. Between 2030 and 2040, electricity production increases by about 3,750 GWh while load grows to only about 3,400 GWh, resulting in Saskatchewan importing less electricity.

4.1.3 BAU Case Emissions

GE MAPS determines the amount of CO2 emitted by each fossil-fuel consuming power plant modeled - the only greenhouse gas (GHG) modeled in GE MAPS - and also the amount of emitted criteria pollutants, such as SO2 and NOX, by each power plant in the model. Annual emission data can be aggregated by plant type and by province.

CO2 Emissions

CO2 emissions in the BAU case for each year modeled are shown in the Figure 4-8. As can be seen, there is substantial reduction in CO2 emissions in 2030 and 2040 relative to 2016, even though the total installed capacity is substantially higher in the later years. The principal reason is the conversion of the ST-COAL plants in the later years. Burning coal, produces approximately twice as much CO2 as burning the same amount of natural gas in terms of equivalent energy content (i.e., burning 1 kilojoules of coal produces approximately twice as much CO2 as burning 1 kilojoules of natural gas). Since Alberta and Saskatchewan have the largest amount of ST-COAL plants in 2016, that will be converted to GT-GAS and CC-GAS in future years, they experience the largest reduction in CO2 emissions in those future years.

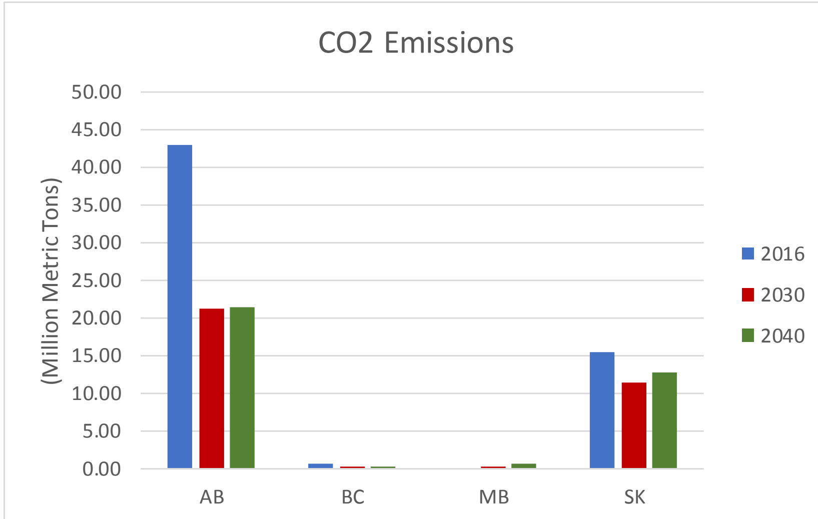


Figure 4-8: CO2 Emissions in BAU Case

Relatively much lower CO_2 emissions in British Columbia and Manitoba reflect the fact that hydro resources have a substantial share of generation capacity in those provinces. In the case of Saskatchewan, the principal change from 2030 to 2040 is the addition of more CC-GAS plants, which contribute to additional CO_2 emissions in 2040 relative to 2030.

The following figure shows the CO_2 intensity, defined as the metric tons of CO_2 emitted per MWh of electricity production.

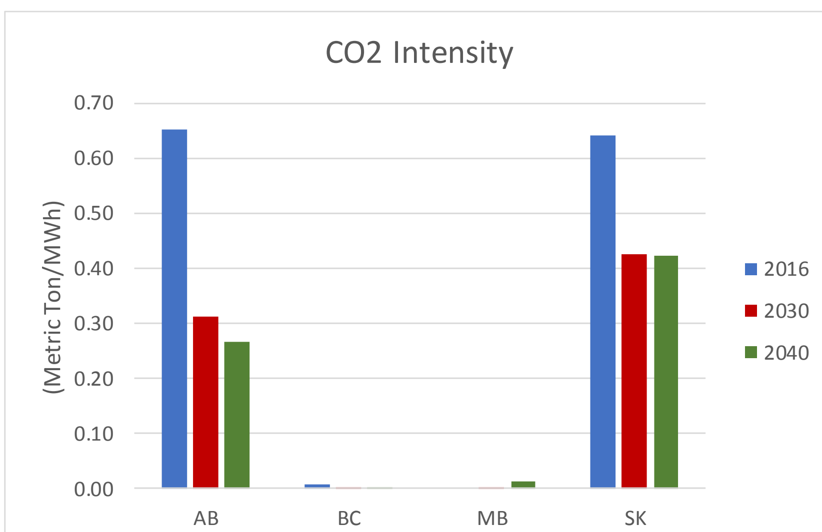


Figure 4-9: CO2 Emissions Intensity by Province and Year

As shown, CO2 intensity is also reduced in later years relative to 2016. Again, the principal reason is conversion of the ST-COAL plants to GT-GAS and CC-GAS units which have relatively lower carbon footprints.

4.1.4 USA and Canada Electricity Generation

As noted earlier, the GE MAPS model covered all of WECC and the Eastern Interconnection. In other words, the model performed day-ahead unit commitment and hourly economic dispatch of all the U.S. states and Canadian provinces within WECC and the Eastern Interconnection. Hence, the regions outside the four western provinces are relatively accurately represented.

It should be noted that in addition, changes in the Canadian power systems, including changes in load and supply, transmission grid, fuel prices, and the relative marginal costs of generation, do impact generation dispatch in the U.S. and transfer of power between the two countries.

The following figures depict the annual generation by type and year in both USA and Canada. Changes in generation dispatch in USA are due to load growth, generation expansion, and fuel prices, among other factors.

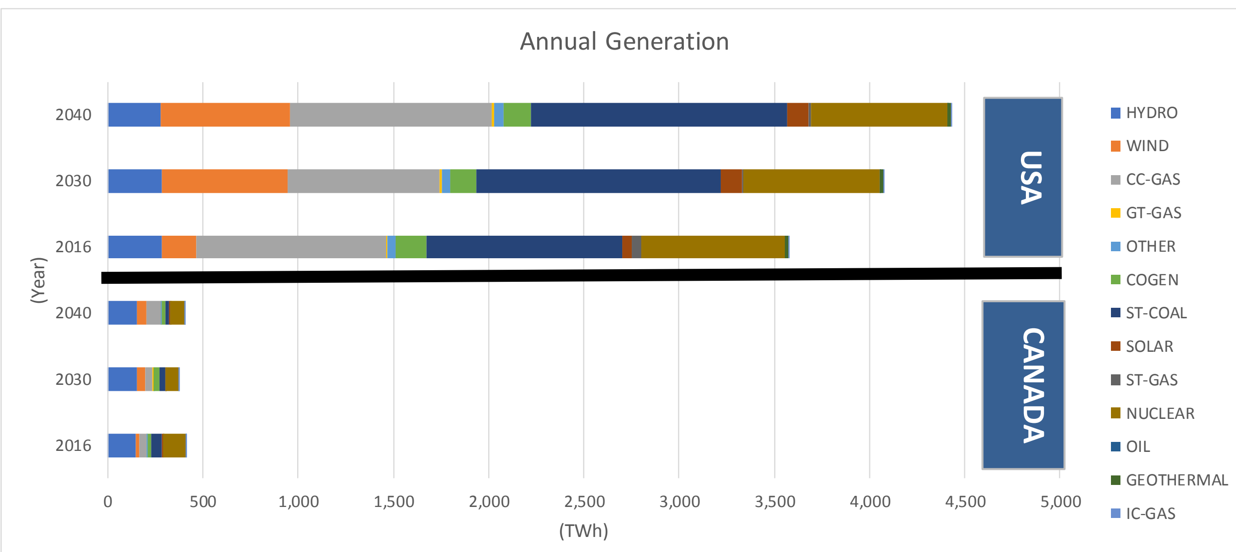


Figure 4-10: Annual Generation by Country and Type and Year

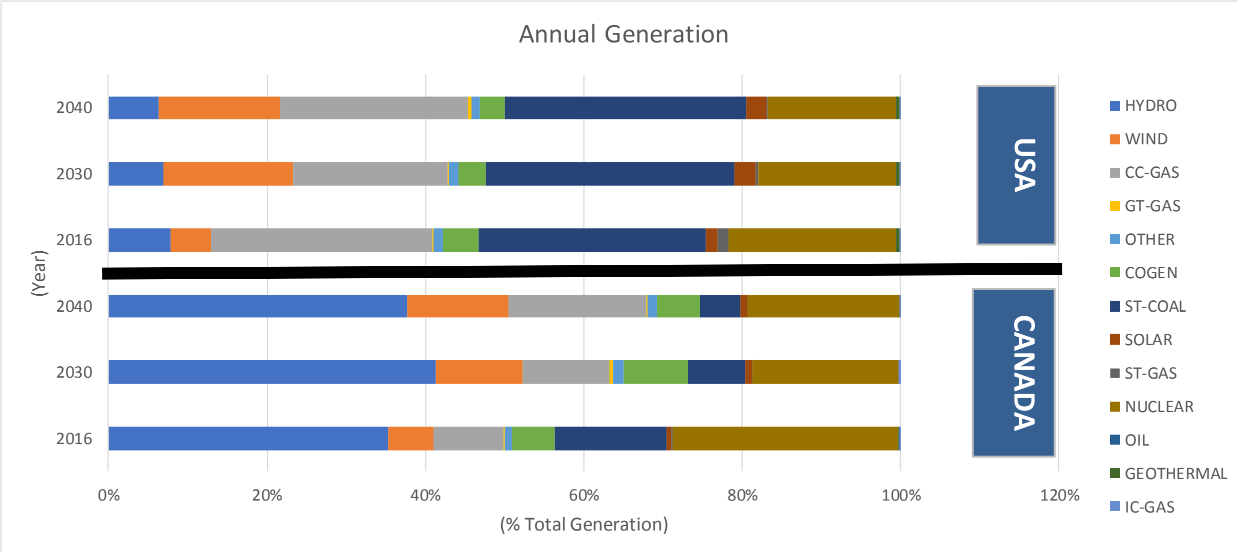


Figure 4-11: Annual Generation by Country and Type and Year as Percentage of Total Generation

The following sections provide overviews of the power systems in the four western provinces in the BAU case.

4.2 Alberta BAU Case

Alberta's total installed capacity, annual energy generation, and capacity factor by type in 2016 is provided in the following table.

ST-COAL generation is the largest generation capacity, providing most of the generation in 2016. In fact, ST-COAL has a relatively high capacity factor of about 67%, indicating that ST-COAL generation is running mostly as a baseload. Cogeneration by industrial/commercial entities in Alberta has the second largest share of capacity and electricity production in the province.

It should be noted that since the load projection excludes the industrial/commercial load that is supplied by on-site generation, GE MAPS models only the portion of the cogeneration capacity that exports power to the larger gird, i.e., net to grid (NTG). Therefore, the portion of cogeneration capacity that directly supplies the on-site load is not modeled in GE MAPS.

Table 4-3: Alberta Installed Capacity and Generation by Type in 2016

Type	Summer Capacity (MW)	Energy (GWh)	CF (%)
HYDRO	894	1,348	17%
WIND	1,445	4,443	35%
CC-GAS	1,716	9,012	60%
GT-GAS	916	224	3%
OTHER	428	475	13%
COGEN	3,425	10,627	35%
ST-COAL	6,283	39,812	72%
SOLAR	0	0	0%
Total	**15,107**	**65,941**	**50%**

The following figures depict the summer capacity and annual NTG electricity production in Alberta by plant type in 2016.

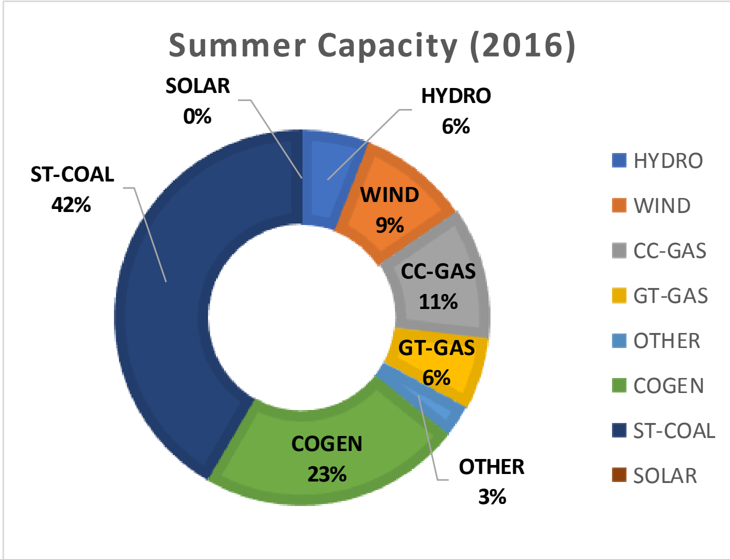


Figure 4-12: Alberta Installed Capacity by Type in 2016

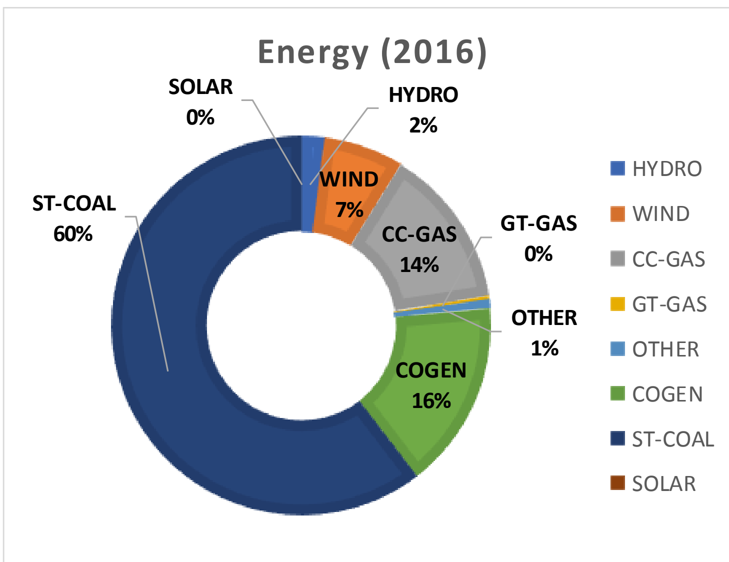


Figure 4-13: Alberta Annual Net to Grid (NTG) Generation by Type in 2016

Alberta's summer NTG Capacities (i.e., excluding industrial on-site capacity that provides on-site generation to meet on-site load) for 2030 and 2040 in the BAU case are shown in the following figures.

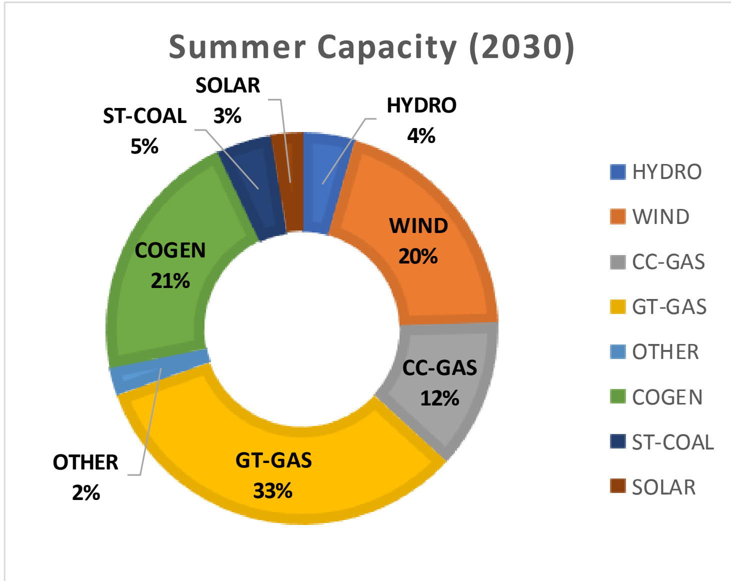


Figure 4-14: Alberta Summer Capacity in 2030 in the BAU Case

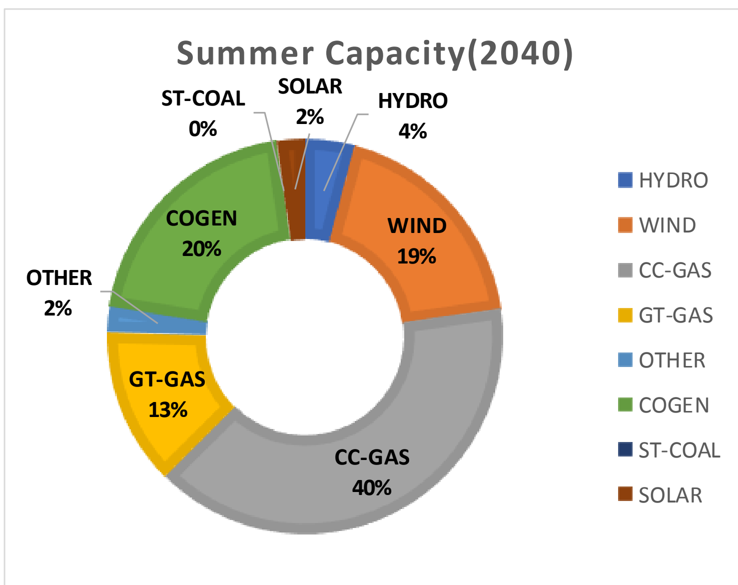


Figure 4-15: Alberta Summer Capacity in 2040 in the BAU Case

As can be seen, the 2016 ST-COAL plants are mostly converted to GT-GAS plants in 2030, and then to CC-GAS plants in 2040.

2016 Capacity factors by generation type in Alberta are shown in the following figure. As expected, ST-COAL plants have the highest capacity factor followed by CC-GAS plants.

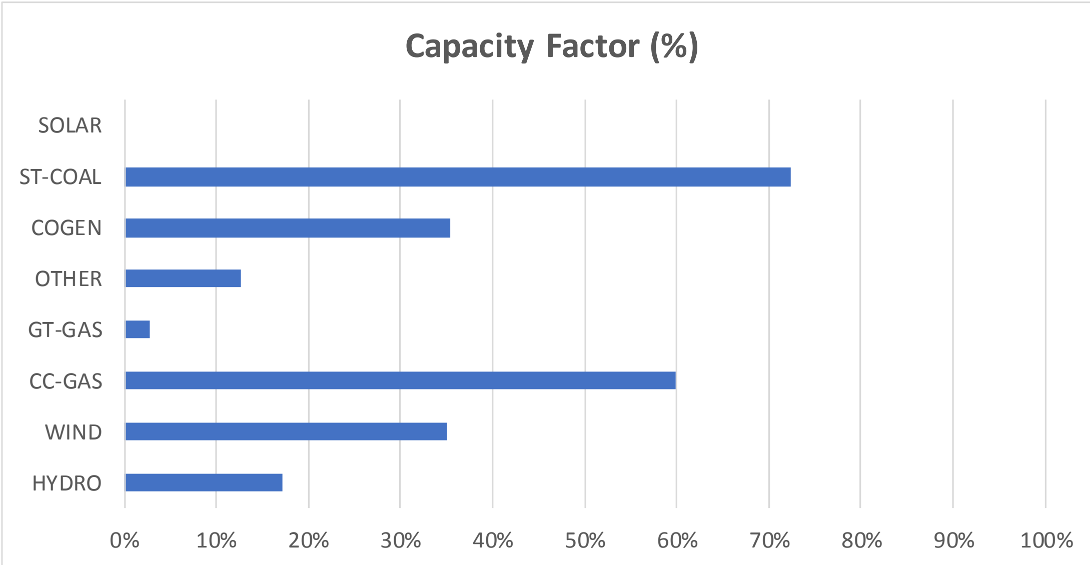


Figure 4-16: 2016 Capacity Factors by Plant Types in Alberta

To ensure fidelity of the model to the actual power system performance, Alberta's GE MAPS model-based electricity production by type was benchmarked against actual Alberta electricity production (with data provided by AESO). As shown in the following figure, the GE MAPS model output and actual historical electricity productions by plant type are very close.

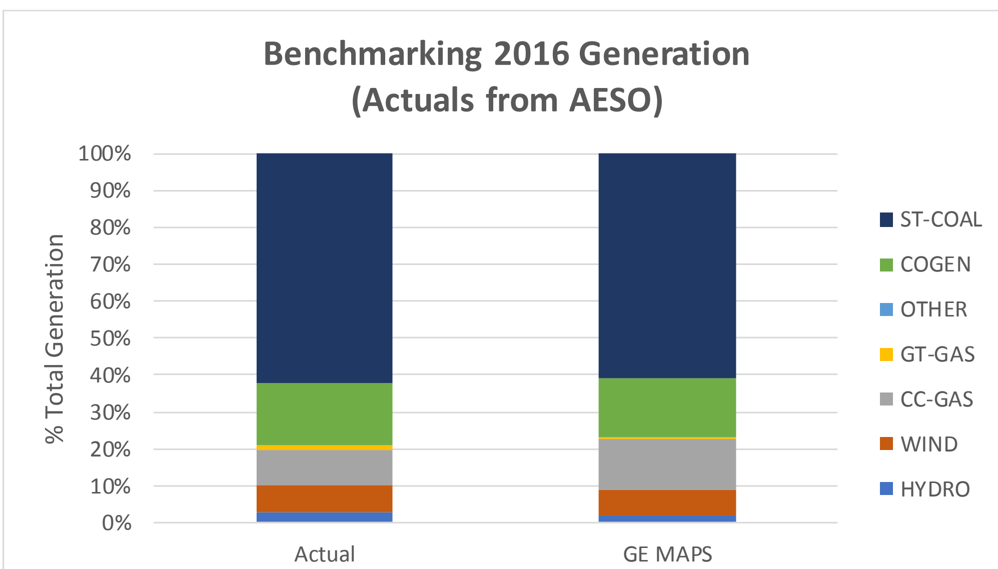


Figure 4-17: Benchmarking of Alberta Electricity Production

Alberta's total installed capacity and its peak load in 2030 and 2040 are provided in the following table.

Table 4-4: Alberta Installed Capacity and Peak Load

	2030	2040
Total Installed Capacity (MW)	20,106	21,728
Peak Load – Winter (MW)	10,419	11,027

The annual Alberta load modeled in GE MAPS is shown in the following figure. The left-hand Y-Axis represents the Annual Energy in GWh. The right-hand Y-Axis represents the annual Peak Demand in MW.

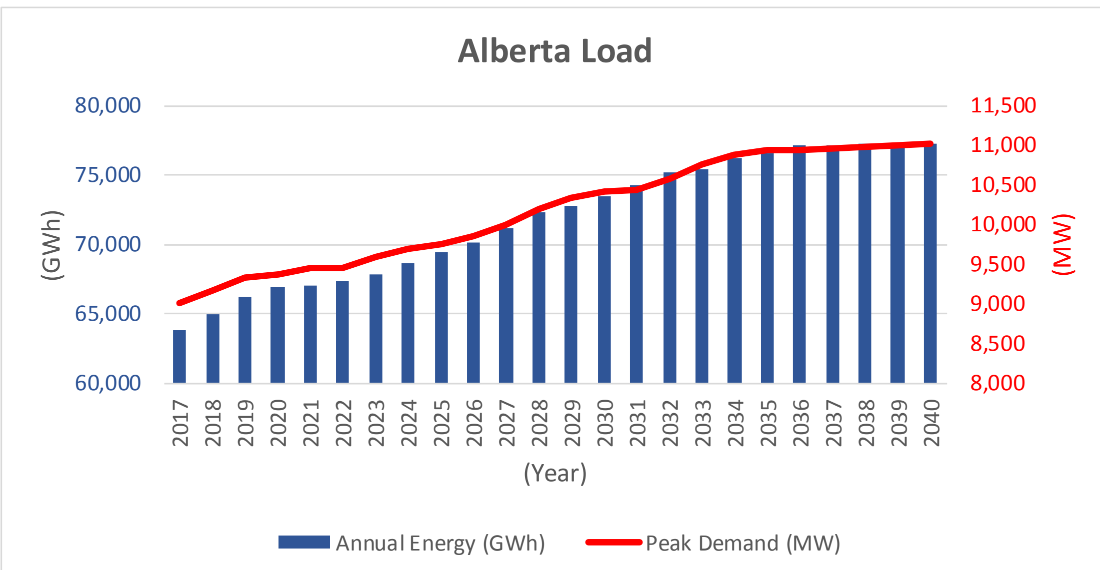


Figure 4-18: Alberta Load Forecast

The Alberta related tie-lines modeled in the BAU case are shown in the following table. These include the AB to BC Path 1, the AB to SK tie-line and AB to MT (Montana) tie-line.

Table 4-5: Alberta Tie-Lines in BAU Case

BAU Transmission Interfaces (Export/Import)	Limits
AB to BC (Path 1)	1000 MW / -800 MW
AB to SK	150 MW / -150 MW
AB to MT (230 kV)	325 MW / - 300 MW

Note: In project evaluation runs, the MT to AB limit is set to 310 MW.

4.3 British Columbia BAU Case

British Columbia's total installed capacity, annual energy generation, and capacity factor by plant type in 2016 are provided in the following table and figures. British Columbia's electricity production is almost entirely based on hydropower (except for a very small amount of thermal plants).

Table 4-6: British Columbia Installed Capacity and Generation by Type in 2016

Type	Summer Capacity (MW)	Energy (GWh)	Capacity Factor (%)
RENEWABLES	15,544	63,709	47%
THERMAL	275	1,265	53%
Total	**15,819**	**64,974**	**47%**

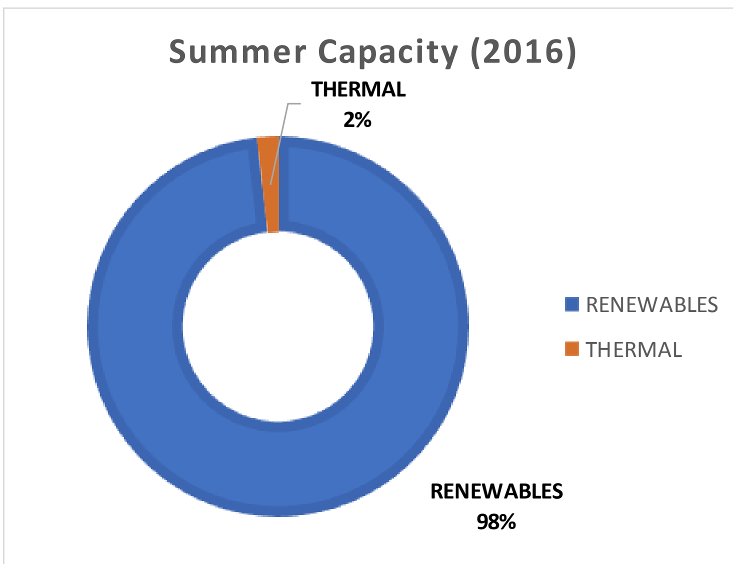


Figure 4-19: British Columbia Installed Capacity by Type in 2016

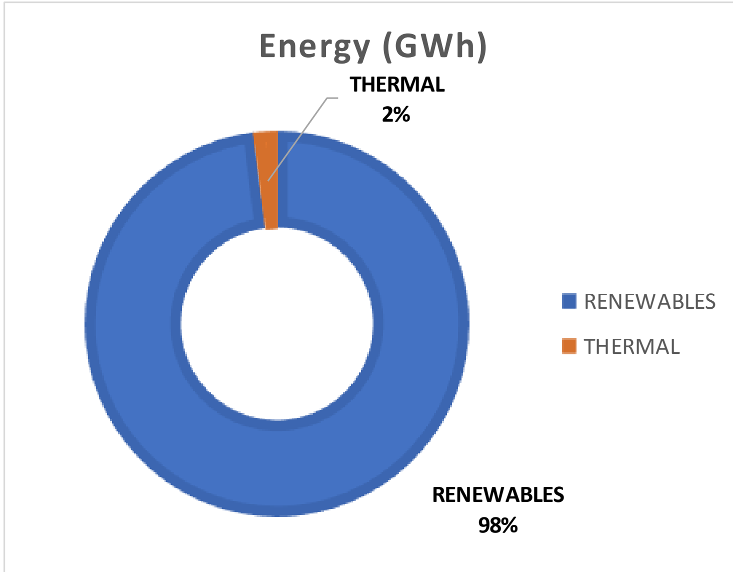


Figure 4-20: British Columbia Annual Net to Grid (NTG) Generation by Type in 2016

British Columbia's summer capacities for 2030 and 2040 in the BAU case are shown in the following figures.

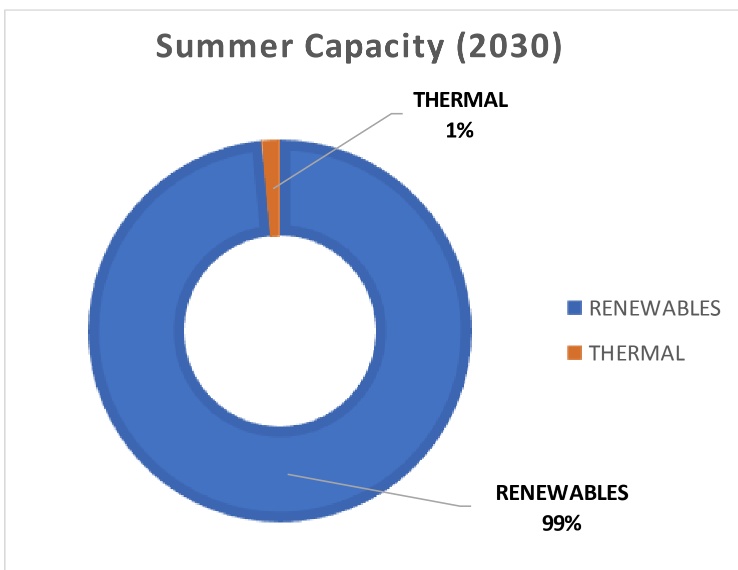


Figure 4-21: British Columbia Summer Capacity in 2030 in the BAU Case

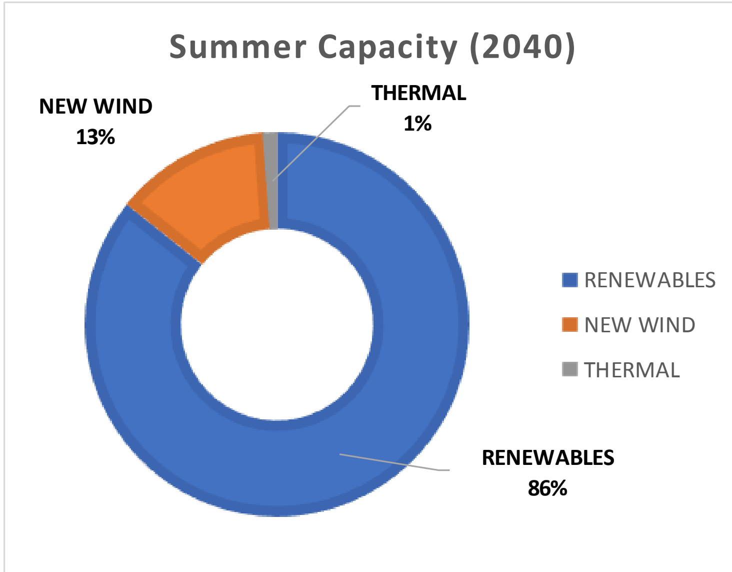


Figure 4-22: British Columbia Summer Capacity in 2040 in the BAU Case

As can be seen, a substantial amount of wind is planned to be added in British Columbia by 2040.

2016 Capacity factors by generation type in British Columbia are shown in the following figure.

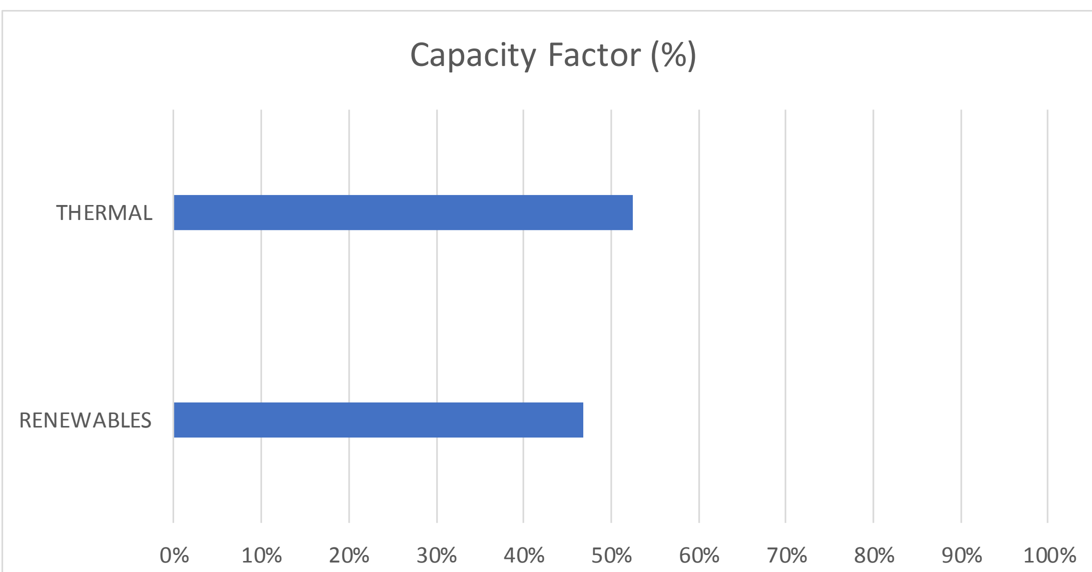
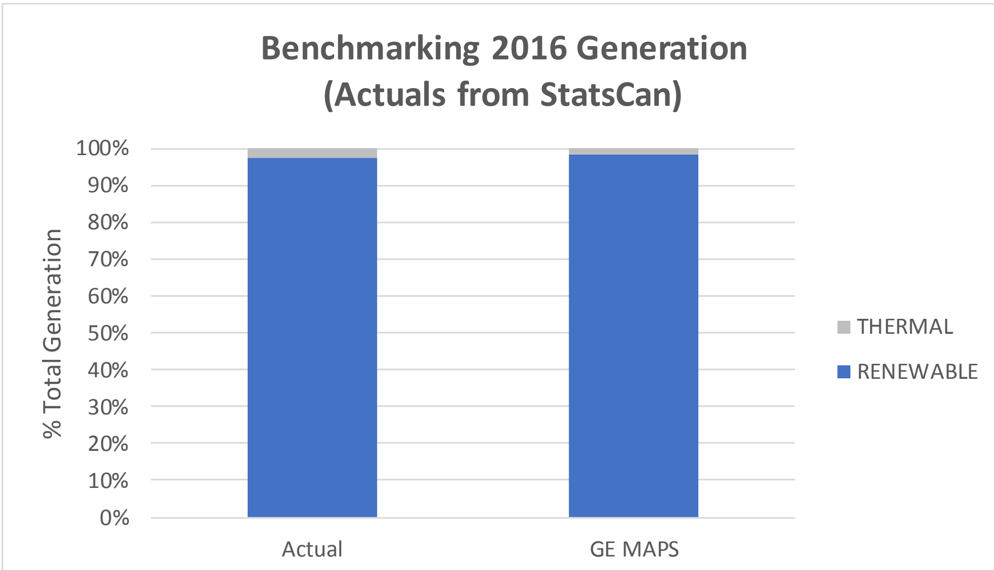


Figure 4-23: 2016 Capacity Factors by Plant Types in British Columbia

To ensure fidelity of the model to the actual power system performance, British Columbia's GE MAPS model-based electricity production by type was benchmarked against actual British Columbia electricity production (with data taken from StatsCan). As shown in the following figure, the GE MAPS model output and actual historical electricity productions by plant type are very close.



Note: In the figure, the 2015 StatsCan data is compared to 2016 GE MAPS results.

Figure 4-24: Benchmarking of British Columbia Generation

British Columbia's total installed capacity and its peak load in 2030 and 2040 are provided in the following table. As shown, the planned generation additions (as provided by BC Hydro) appear to result in maintaining a high installed reserve margin. However, hydroelectric plants do not always run at their full capacity, and therefore, capacity of certain BC Hydro plants should be de-rated to reflect the time-based variation in the maximum available loading of hydro plants, resulting in lower reserve margin. In other words, only a portion of the full capacity of hydro plants should be counted towards meeting the installed reserve requirements.

Table 4-7: British Columbia Installed Capacity, Peak Load, and Number of Plants and Units

	2030	2040
Total Installed Capacity (MW)	18,465	23,543
Peak Load – Winter (MW)	12,847	14,846

The annual British Columbia load modeled in GE MAPS is shown in the following figure.

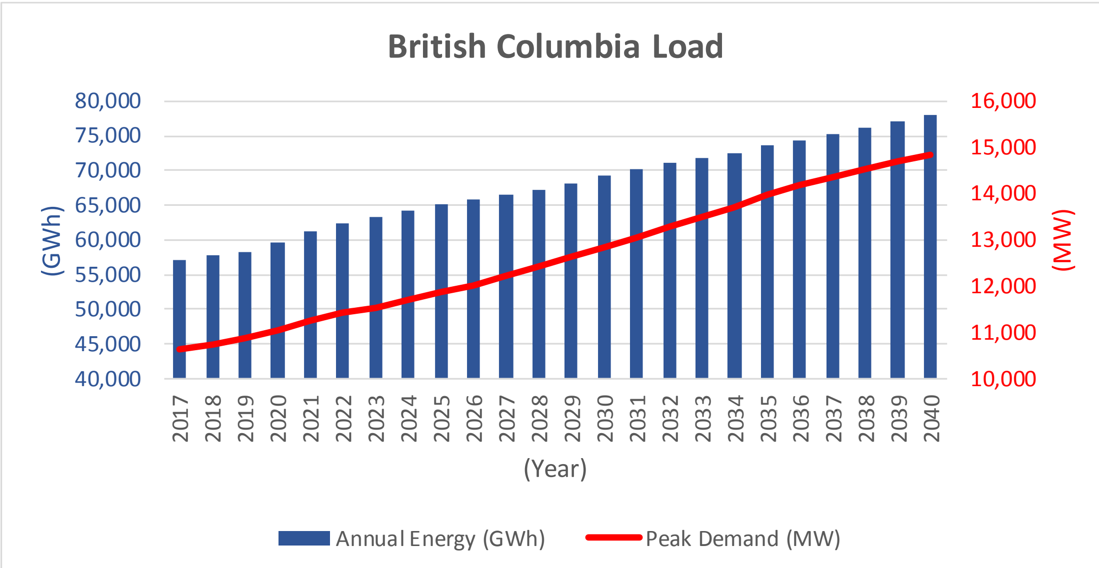


Figure 4-25: British Columbia Load Forecast

The British Columbia related tie-lines modeled in the BAU case are shown in the following table.

Table 4-8: British Columbia Tie-Lines in BAU Case

BAU Transmission Interfaces (Export/Import)	Limits
BC to AB: Path 1	800 MW / -1000 MW
BC to WA: 3 ties, 1 interface	3150 MW / -3000 MW

4.4 Manitoba BAU Case

Manitoba's total installed capacity, annual energy generation, and capacity factor by type in 2016 are provided in the following table and figures. Hydro generation is the largest generation capacity and providing most of the generation in 2016. There are also a number of fossil fuel-based plants in Manitoba, but with rather minimal utilization and electricity production.

Table 4-9: Manitoba Installed Capacity and Generation by Type in 2016

Type	Summer Capacity (MW)	Energy (GWh)	CF (%)
HYDRO	5,265	32,970	71%
WIND	258	992	44%
GT-GAS	233	0	0%
ST-GAS	126	0	0%
CC-GAS	0	0	0%
ST-COAL	95	0	0%
Total	**5,977**	**33,962**	**65%**

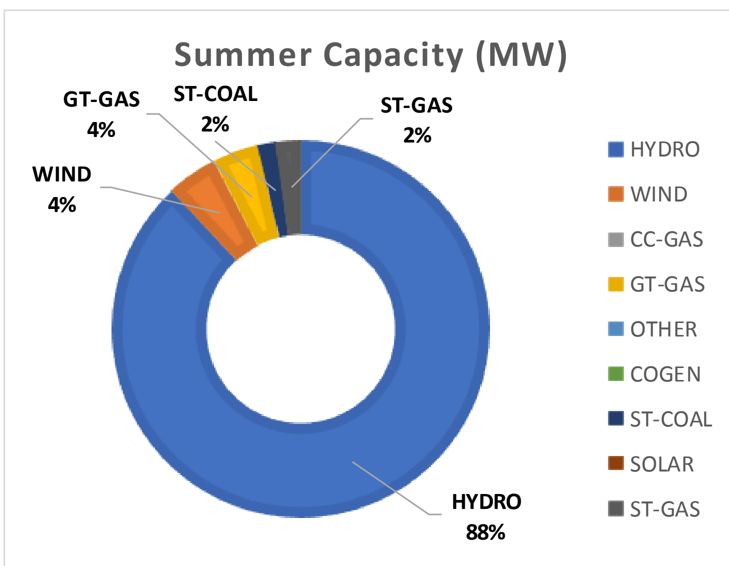


Figure 4-26: Manitoba Installed Capacity by Type in 2016

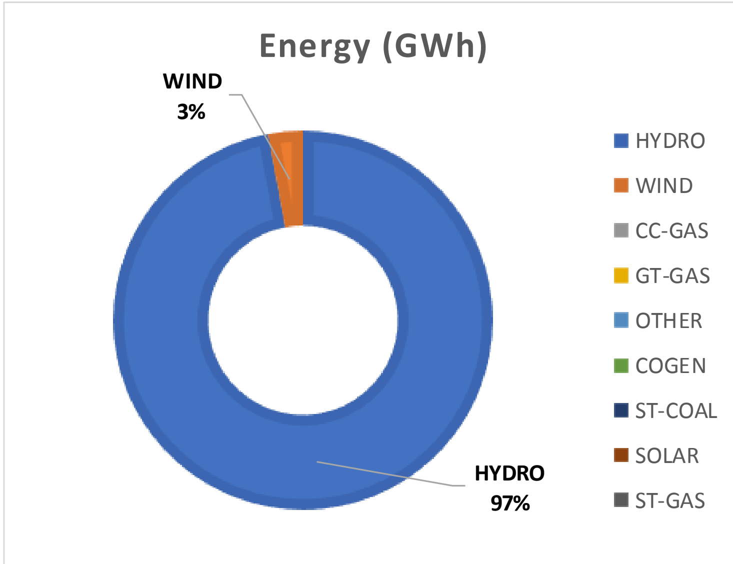


Figure 4-27: Manitoba Annual Net to Grid (NTG) Generation by Type in 2016

Manitoba's summer capacities for 2030 and 2040 in the BAU case are shown in the following figures.

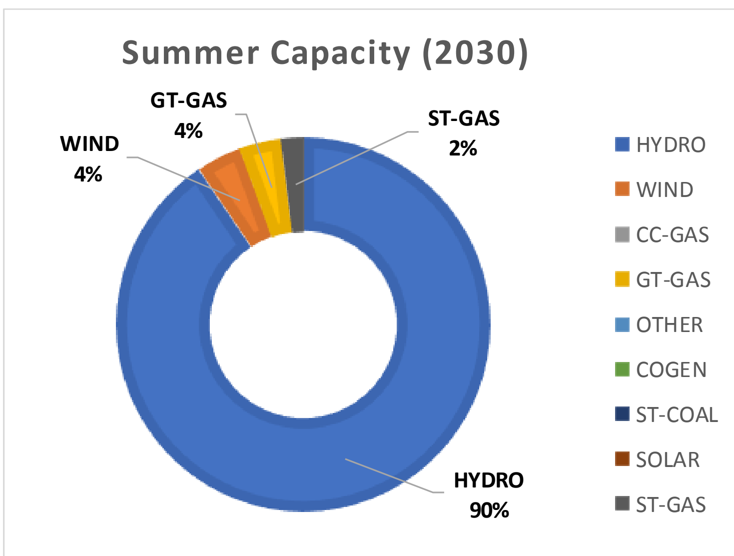


Figure 4-28: Manitoba Summer Capacity in 2030 in the BAU Case

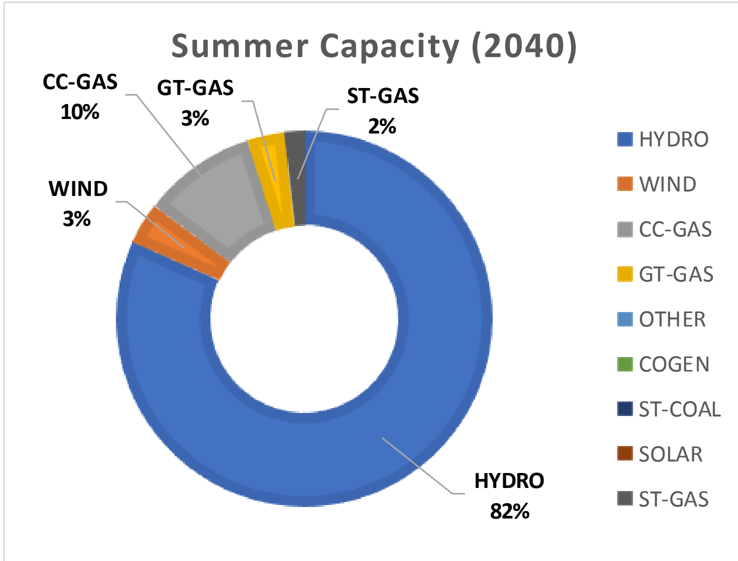


Figure 4-29: Manitoba Summer Capacity in 2040 in the BAU Case

As can be seen, in Manitoba, some additional hydro capacity is added in 2030. Additional generic thermal capacity is added in 2040

2016 Capacity factors by generation type in Manitoba are shown in the following figure.

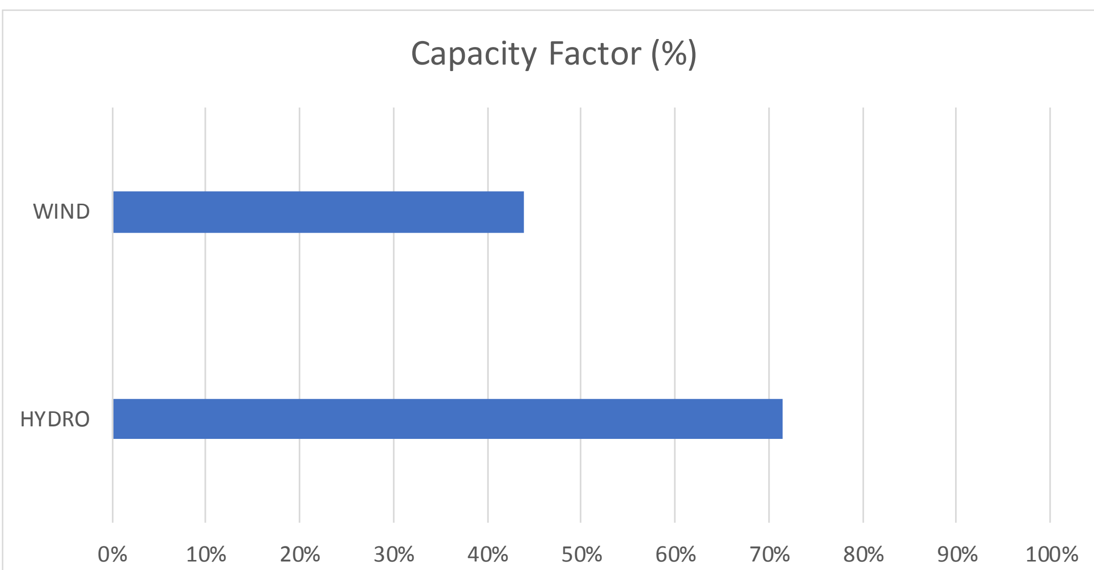
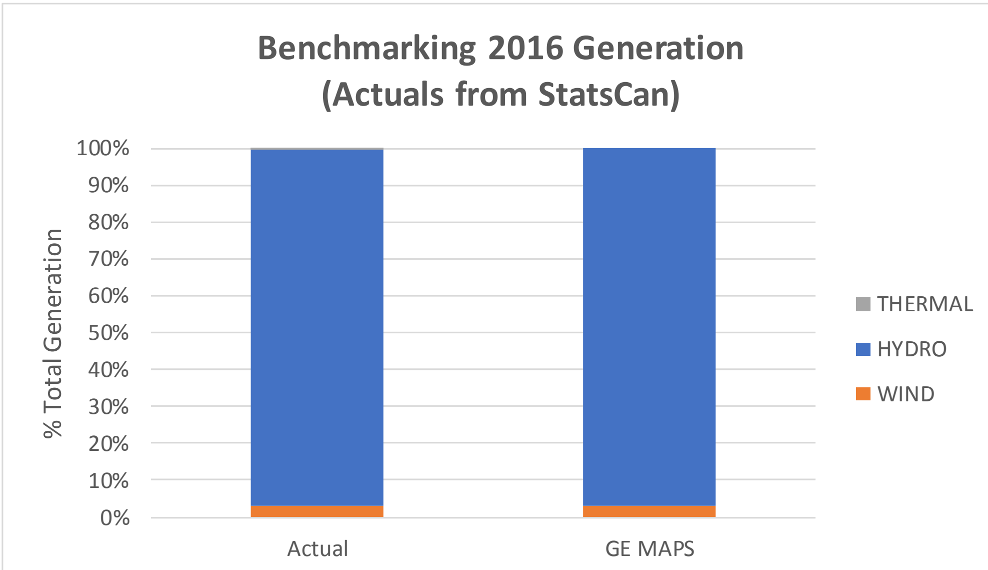


Figure 4-30: 2016 Capacity Factors by Plant Types in Manitoba

To ensure fidelity of the model to the actual power system performance, Manitoba's GE MAPS model-based electricity production by type was benchmarked against actual

Manitoba electricity production (with data taken from StatsCan). As shown in the following figure, the GE MAPS model output and actual historical electricity productions by plant type are very close.



Note: In the figure, the 2015 StatsCan data is compared to 2016 GE MAPS results.

Figure 4-31: Benchmarking of Manitoba Generation

Manitoba's total installed capacity and its peak load in 2030 and 2040 are provided in the following table.

Table 4-10: Manitoba Installed Capacity, Peak Load, and Number of Plants and Units

	2030	2040
Total Installed Capacity (MW)	6,512	7,212
Peak Load – Winter (MW)	4,859	5,959

The annual Manitoba load modeled in GE MAPS is shown in the following figure. The left-hand Y-Axis represents the Annual Energy in GWh. The right-hand Y-Axis represents the annual Peak Demand in MW.

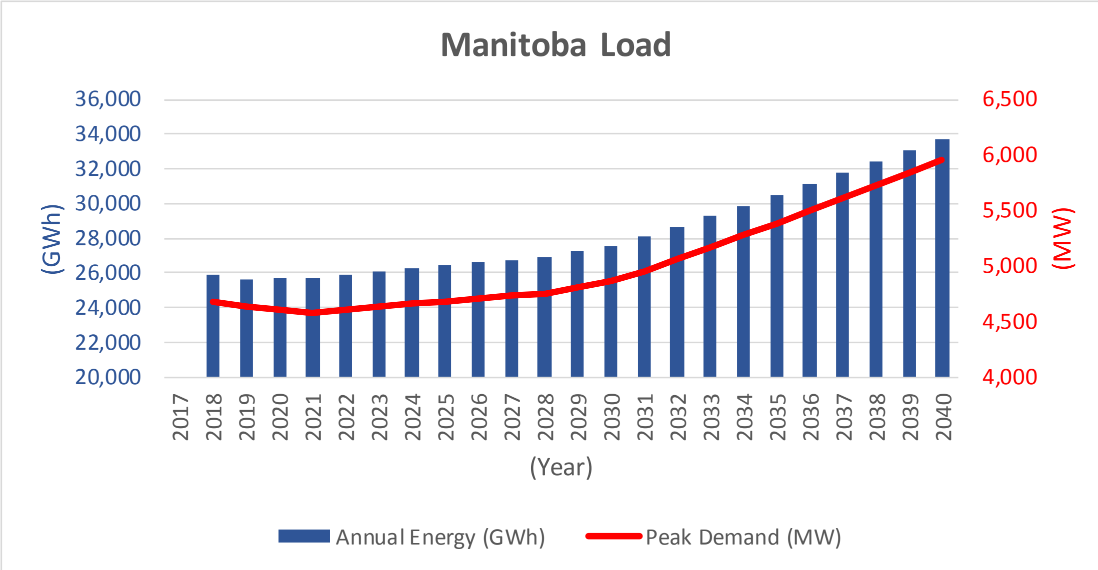


Figure 4-32: Manitoba Load Forecast

The Manitoba related tie-lines modeled in the BAU case are shown in the following table.

Table 4-11: Manitoba Tie-Lines in BAU Case

BAU Transmission Interfaces (Export/Import)	Limits
MB to ON: SP&WP	(293/-225) MW & (368/-300) MW
MB to SK: SP&WP	
Tie 1	(45/-60) MW & (25/-90) MW
Tie 2	(250/-25) MW & (250/-75) MW
MB to ND & MN	(2833/-1583) MW

4.5 Saskatchewan BAU Case

Saskatchewan's total installed capacity, annual energy generation, and capacity factor by type in 2016 are provided in the following table and figures. ST-COAL plants provide the largest generation capacity and provide most of the generation in 2016. In fact, it has a very high capacity factor, about 81% on the average, indicating that Coal based generation is running mostly as a baseload.

Table 4-12: Saskatchewan Installed Capacity and Generation by Type in 2016

Type	Summer Capacity (MW)	Energy (GWh)	CF (%)
HYDRO	872	3,267	43%
WIND	221	718	37%
CC-GAS	677	5,201	88%
GT-GAS	678	221	4%
OTHER	30	150	57%
COGEN	492	3,670	85%
ST-COAL	1,533	10,827	81%
Total	**4,503**	**24,054**	**61%**

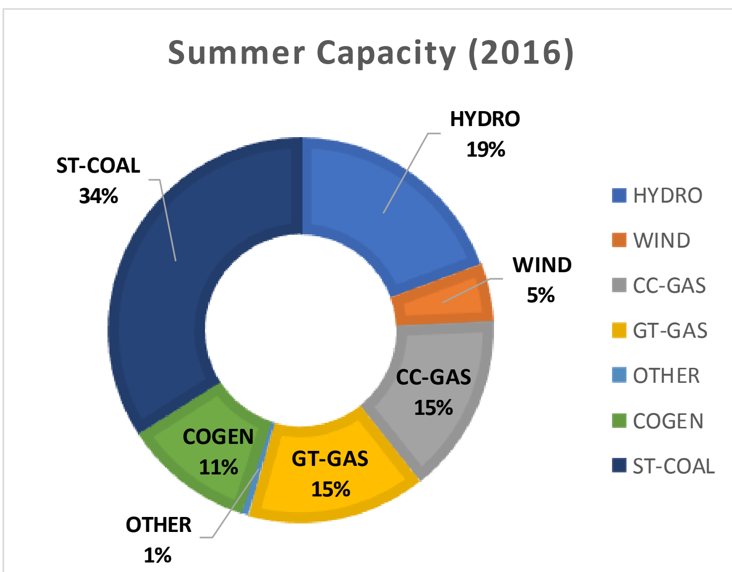


Figure 4-33: Saskatchewan Installed Capacity by Type in 2016

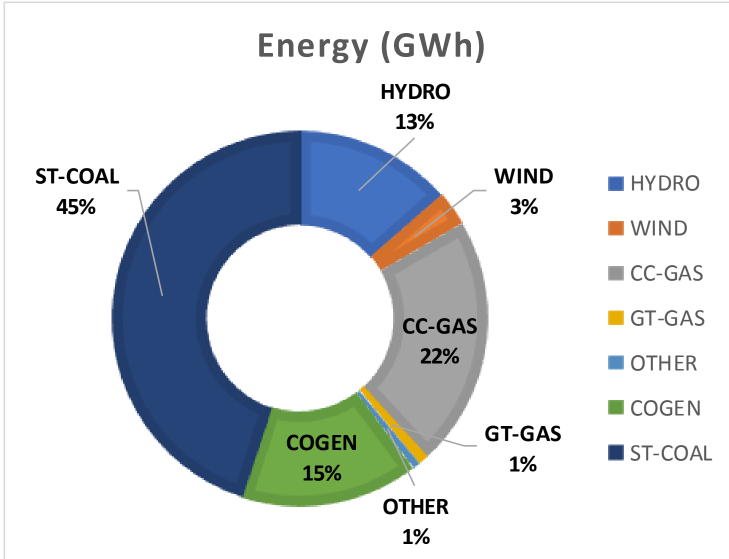


Figure 4-34: Saskatchewan Annual Net to Grid (NTG) Generation by Type in 2016

Saskatchewan's summer capacities for 2030 and 2040 in the BAU case are shown in the following figures.

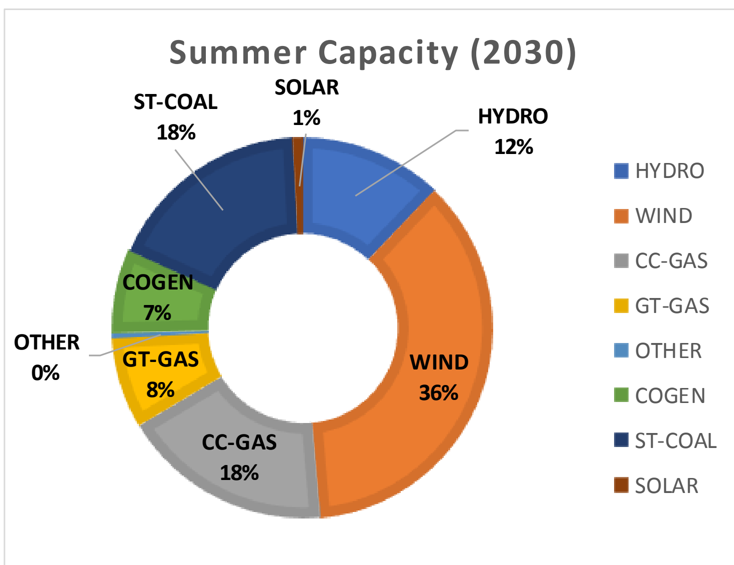


Figure 4-35: Saskatchewan Summer Capacity in 2030 in the BAU Case

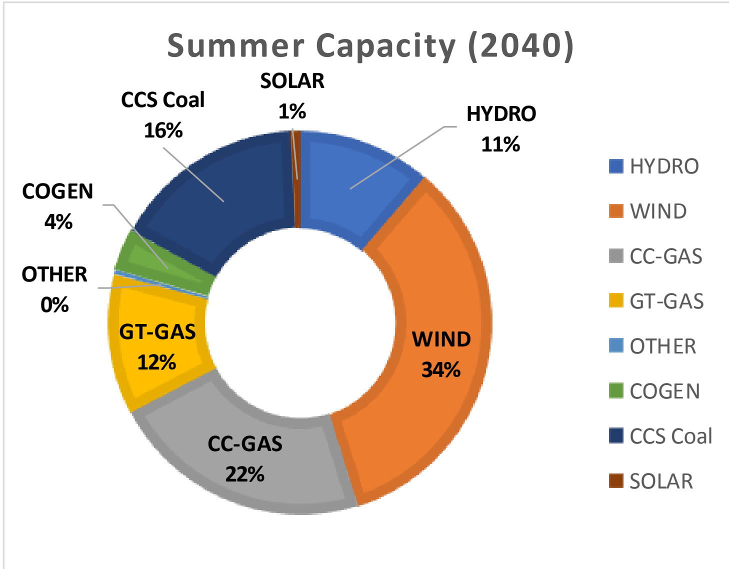


Figure 4-36: Saskatchewan Summer Capacity in 2040 in the BAU Case

As can be seen, by 2030 and 2040, wind energy will be the dominant generation resource in Saskatchewan, followed by CC-GAS. The 2030 ST-COAL is converted to CCS Coal by 2040.

2016 capacity factors by generation type in Saskatchewan are shown in the following figure. As expected, coal-based generation has the highest capacity factor followed by CC-GAS units.

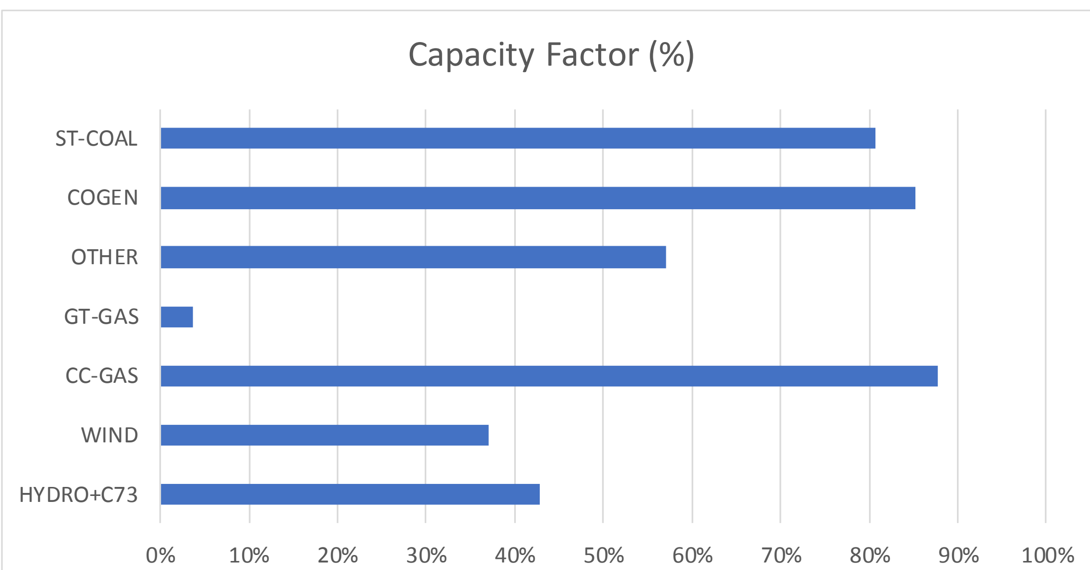


Figure 4-37: 2016 Capacity Factors by Plant Types in Saskatchewan

To ensure fidelity of the model to the actual power system performance, Saskatchewan's GE MAPS model-based electricity production by type was benchmarked against actual Saskatchewan electricity production (with data provided by SaskPower). As shown in the following figure, the GE MAPS model output and actual historical electricity productions by plant type are very close.

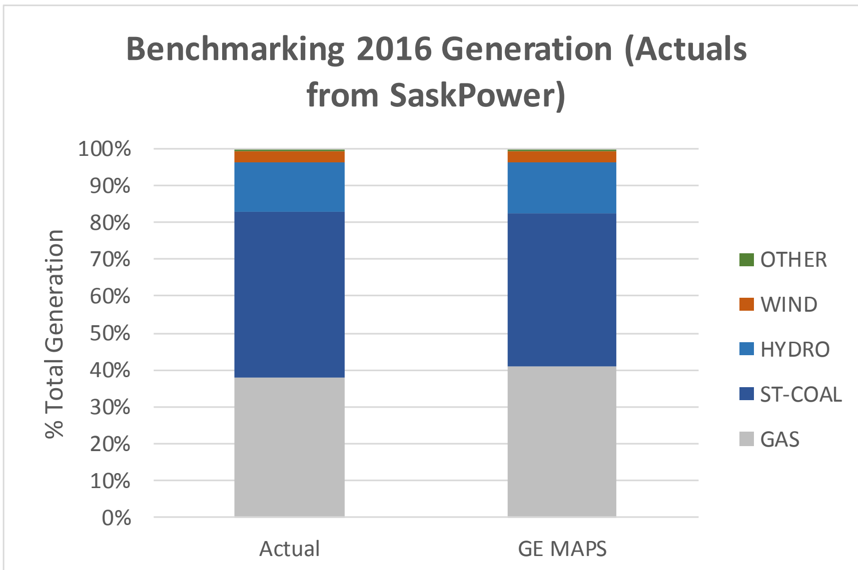


Figure 4-38: Benchmarking of Saskatchewan Generation

Saskatchewan's total installed capacity and its peak load in 2030 and 2040 are provided in the following table.

Table 4-13: Saskatchewan Installed Capacity, Peak Load, and Number of Plants and Units

	2030	2040
Total Installed Capacity (MW)	7,183	7,728
Peak Load – Winter (MW)	4,646	5,222

The annual Saskatchewan load modeled in GE MAPS is shown in the following figure. The left-hand Y-Axis represents the Annual Energy in GWh. The right-hand Y-Axis represents the annual Peak Demand in MW.

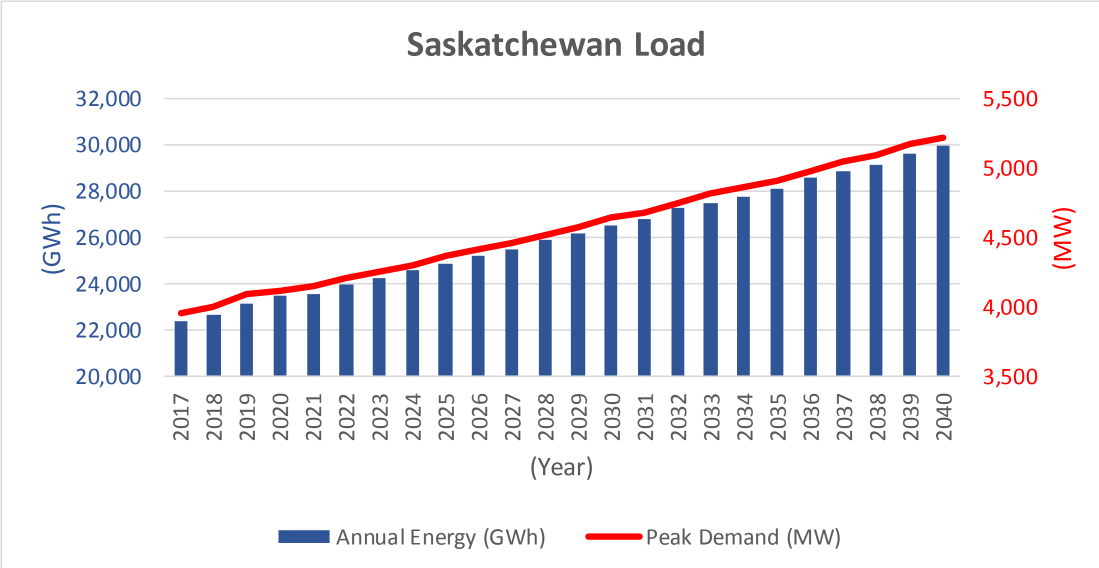


Figure 4-39: Saskatchewan Load Forecast

The Saskatchewan related tie-lines modeled in the BAU case are shown in the following table.

Table 4-14: Saskatchewan Tie-Lines in BAU Case

BAU Transmission Interfaces (Export/Import)	Limits
SK to MB: SP & WP	
Tie 1	(60/-45) MW & (90/-25) MW
Tie 2	(25/-250) MW & (75/-250) MW
SK to ND	165 MW/-150 MW

5 Analysis of Projects

5.1 Study Projects

Study projects were previously listed in Table 2-4. They are listed again in the following table in order to facilitate reference to projects when reviewing the contents of this section.

Table 5-1: Study Projects

• Business-As-Usual (BAU) Case

• Project A: New intertie between BC and AB
  ○ Option 1: North Tie-Line
  ○ Option 2: South Tie-Line

• Project B: New intertie between SK and MB
  ○ Option 1: Regina to Dorsey
  ○ Option 2A: Kennedy to Cornwallis with internal upgrades
  ○ Option 2B: Kennedy to Cornwallis only

• Project C: New internal transmission or distribution added to aid in development of new renewable capacity in AB and SK

• Project D: New hydroelectric capacity in AB & SK
  ○ Option 1: Brazeau, Peace River, Tazi Twe
  ○ Option 2: Slave River, Tazi Twe

• Project E: Coal conversion in AB and SK
  ○ Option 1: SK coal units to Carbon Capture, AB coal to CC's
  ○ Option 2: SK coal units to CC's, AB coal to CC's

• Project F: Bulk storage addition against value of new hydro or new transmission

• Project G: Electrification of LNG and natural gas production in BC
  ○ Option 1: Peace Region, 600 MW, 5,000 GWh
  ○ Option 2: Peace Region, 800 MW, 6,700 GWh
  ○ Option 3: Prince George to Terrace, 500 MW, 4,100 GWh
  ○ Option 4: Prince George to Terrace, 1200 MW, 10,00 GWh

• Project H: Construction of hydro and transmission line to interconnect the NWT to AB
• Project I: New intertie and incremental upgrade to existing and limited AB and SK intertie
• Project J: Create simultaneous transfer capability between AB and BC and Montana-AB transmission line
• Project K: Combination of Project A and Project C

5.2 Adjusted Production Costs

One of the principal metrics used for evaluation and comparison of the projects is "production costs", which refers to the sub-set of operational costs of power systems. Production costs, as defined in this study, include fuel costs, generation variable operations and maintenance (VOM) costs, generation start-up costs, and generation-related emissions costs. Production costs do not include capital and fixed costs, since those costs are assumed not to change with hourly generation, and therefore, are not a factor in generation unit commitment or economic dispatch. In addition, as the modeling domain did not include sub-hourly generation dispatch, the benefits or costs associated with sub-hourly dispatch are not captured in this analysis.

GE MAPS model's optimization engine minimizes the total system-wide variable production costs subject to generation and transmission constraints. Production costs in each province need to be adjusted by accounting for import costs and export revenues in order to properly account for the cost meeting the province's own demand for electricity. The reason is that provinces that are net exporters of electricity, generate more electricity than needed to meet their electricity demand, and get paid for it by the export revenues. On the other hand, provinces that are net importers of electricity, generate less electricity than needed to meet their electricity demand, and have to spend more to cover their generation shortfall.

Therefore, any evaluation of each province's production costs requires accounting for imports costs and export revenues. There is no single or simple methodology to accurately evaluate these costs and revenues, since in actual operations, these costs and revenues depend on inter-province and inter-government agreements and negotiation-based prices. Therefore, this study uses a simple but approximate methodology to account for imports costs and export revenues. The methodology is based on valuing power imports and exports based on the Average Production Costs of the exporting region. The resulting annual import costs and export revenues are then added to each province's in-province production costs, and the result is the "Adjusted Production Cost" of each province.

The basic steps in calculation of Adjusted Production Cost are:

- For the BAU scenario and each study project, compute the in-province annual production costs (i.e., sum of fuel costs, VOM costs, start-up costs, and emission costs) for each province and each U.S. pool neighboring these provinces.
- In the BAU scenario, for each province in Canada and adjacent US State Pool. calculate the "Average Production Cost" in $/MWh, which is the Total Annual Production Costs (in $) in the province or the pool, divided by the Total Annual Electricity Generation (in MWh) in the province or the pool.

- The resulting value is the Annual Average Production Cost (in $/MWh) of the province or the pool.
- For each province, calculate annual import costs or export revenues by multiplying Annual Imports/Exports (in MWh) by the Annual Average Production Cost (in $/MWh) of the exporting region.
- For each province, evaluate the adjusted production costs by adding the import costs (a positive value) and export revenues (a negative value) to the province’s production costs.

The adjusted production costs, although still based on a simplified methodology, is a better measure of the province-based costs compared to the in-province generation production cost alone. Typically, an economic hourly or annual export price would be at a minimum higher than the marginal cost of exporting region. Therefore, it is likely that using an average annual cost would result in imports and exports being valued below their costs.

5.3 Evaluation of Project A

Project A: New Intertie between British Columbia and Alberta by 2030

Project A includes two options: a northern route and a southern route. Following additions were made in each of the options relative to the BAU case.

<u>Project A, Option 1 - Northern Route</u>

- Increased the limit of the existing Path 1 to +/-1600 MW
- Added new Northern intertie: 500 kV AC line from BC Hydro's new 500 kV Southbank substation near Fort St. John, BC to Alberta's Livock with a limit of +/-1600 MW
- MATL limit remains the same (+325 MW/ -310 MW). The total maximum import from AC interconnection with BC and Montana to AB would be 1,910 MW.

<u>Project A, Option 2 - Southern Route</u>

- Increased the limit of the existing Path 1 to +/-1600 MW
- Added new Southern intertie: 500 kV AC line from BC Hydro's Selkirk substation (via Cranbrook substation) to Alberta's Bennet substation (via Chapel Rock substation) with a limit of +/-1600 MW
- MATL limit remains the same (+325 MW/ -310 MW). The total maximum import from AC interconnection with BC and Montana to AB would be 1,910 MW.

Eastern and Western Interconnections are modeled separately, since they are separate asynchronous systems with no AC interties between them, and with very small capacity DC connections. Therefore, only the Western Interconnection provinces are impacted by Project A.

Following tables and charts provide an overview of the performance of power systems under the BAU case and each of the Project A options. It should be noted that the routing options modelled are intended to be representative. Detailed modelling and engineering work will need to be carried out to determine the exact nature of the GHG reductions and costs of various routing options to determine an optimal route for a new BC-AB intertie.

Key Observations

<u>Alberta</u>

- AB generation is somewhat lower in the Project A options relative to the BAU case. The largest reductions are by COGEN and GT-GAS units. BC generation is not significantly impacted, which indicates that AB generation is mainly displaced by imports from the USA.

- A new intertie and higher carbon tax in Canada is enabling higher dispatch of comparatively less costly U.S. Generation (mainly CC-GAS, ST-COAL, and COGEN) and hence, increased flow into AB, causing displacement of more expensive natural gas units in AB, including CC-GAS, GT-GAS, and net-to-grid COGEN.
- CO2 emissions are reduced in AB relative to the BAU case. Slightly higher emissions in Southern Route relative to Northern Route are the result of more of AB COGEN generation in the Southern Route option. While emissions are reduced in AB, the imported electricity from the U.S. may have an equal or higher carbon intensity that may result in no reduction in the GHGs consumed by AB. Although GE MAPS calculates emissions from each unit in the system both in Canada and the USA, this analysis did not take into account the carbon footprint of the imported electricity from the U.S.
- Project A shows Alberta imports increasing in 2030 relative to the BAU case, more in the North Option than the South Option, which may reflect the differences in the generation shift factors[21] over the two routes. Flows on the interties are dependent on generation shift factors, and therefore, generation at one location may result in different levels of power flows in the two intertie options.
- At the same time in 2030, Alberta's Adjusted Production Costs decrease relative to BAU case. There is a slightly larger reduction with the North Option which is likely due to more imports displacing higher costly in-province generation.
- Therefore, the higher imports observed under Project A are lowering the Adjusted Production Costs in Alberta.
- It should be noted that the sub-hourly hydro dispatch was not analyzed in this study, which likely has resulted in an underestimation of the GHG emission reduction benefit of the project as more flexible hydro units could be used to replace fossil-based generation to smooth out the sub-hourly wind variability.

<u>British Columbia</u>

- BC Hydro's existing generation fleet is predominantly hydro with some wind, biomass, and other generation. Most non-gas generation is shown as hydro for simplicity (per decision by BC Hydro).

[21] Generation Shift Factor (GSF) is the percentage of flow increase in transmission elements and constraints due to a 1 MW increase in generation of a given plant. For more exact definition, please see the following NERC document:

https://www.nerc.com/comm/OC/IDC%20Training%20DL/IDC_Training_Document_for_Reliability_Coordinators_and_Control_Areas_2005_Revision.pdf

- BC net exports are relatively much smaller than Alberta imports, which indicates that some of the power imported into Alberta coming through British Columbia originates in the U.S.
- Adjusted Production Cost in BC is negative under the BAU case and in each of Project A options, which implies that that BC experiences higher export revenues relative to its internal production costs. BC net revenues increase further in Project A options relative to the BAU case.

Table 5-2: Project A - Alberta Generation

AB Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	1,875	12,910	775	1,925	7,107	17,989	2,347	0	22,819	**67,746**
Project A, North	1,875	12,910	775	1,853	7,107	17,842	1,636	0	20,889	**64,886**
Project A, South	1,875	12,910	775	1,868	7,107	17,813	1,745	0	21,425	**65,516**
Change from BAU										
Project A, North	0	0	0	-71	0	-148	-711	0	-1,930	**-2,860**
Project A, South	0	0	0	-57	0	-177	-603	0	-1,394	**-2,230**

Table 5-3: Project A - British Columbia Generation

BC Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	68,988	0	0	0	0	522	0	0	0	**69,510**
Project A, North	68,988	0	0	0	0	574	0	0	0	**69,562**
Project A, South	68,988	0	0	0	0	609	0	0	0	**69,597**
Change from BAU										
Project A, North	0	0	0	0	0	52	0	0	0	**52**
Project A, South	0	0	0	0	0	87	0	0	0	**87**

Table 5-4: Project A - Adjusted Production Costs

Adjusted Production Cost ($MM)	BAU	Project A, North	Project A, South
AB	3,165	3,087	3,109
BC	-187	-286	-264
Total	**2,978**	**2,801**	**2,844**
Change from BAU		**Project A, North**	**Project A, South**
AB		-78	-56
BC		-99	-77
Total		**-177**	**-133**

Table 5-5: Project A - Carbon Emissions

CO2 Emissions (Million Tonne)	BAU	Project A, North	Project A, South
AB	21.12	19.98	20.23
BC	5.40	5.42	5.44
Total	26.52	25.40	25.66
Change from BAU		**Project A, North**	**Project A, South**
AB		-1.14	-0.90
BC		0.02	0.04
Total		-1.12	-0.86

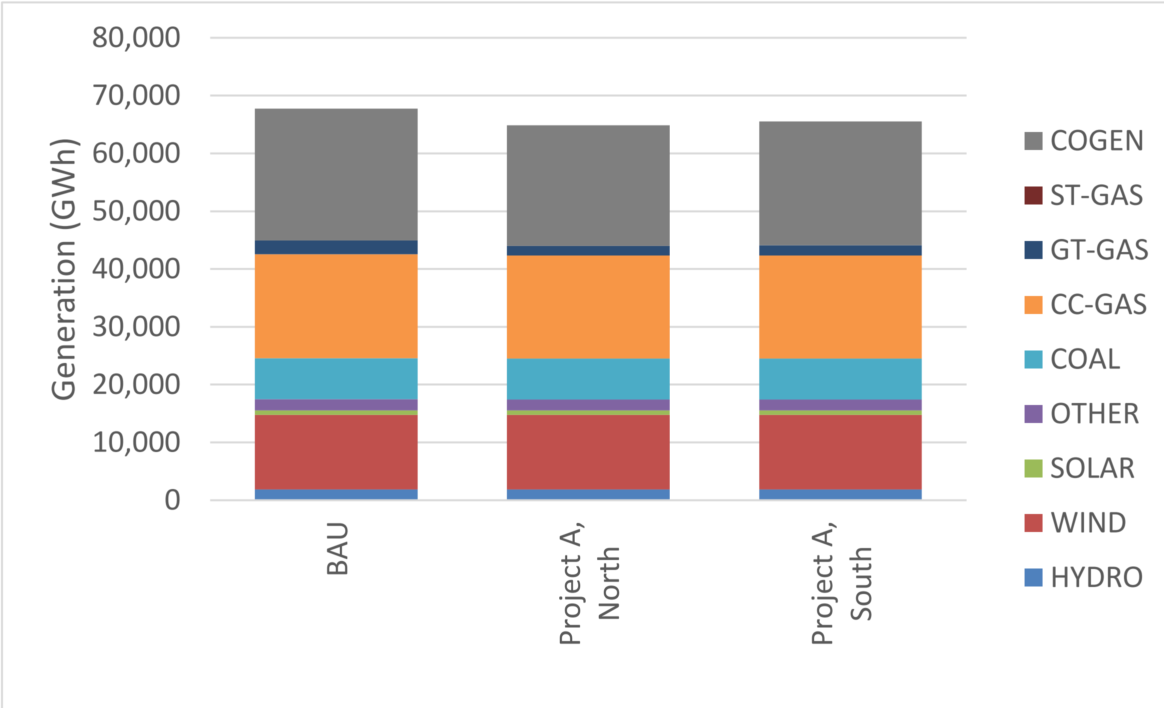


Figure 5-1: Project A - Alberta Generation by Type (2030)

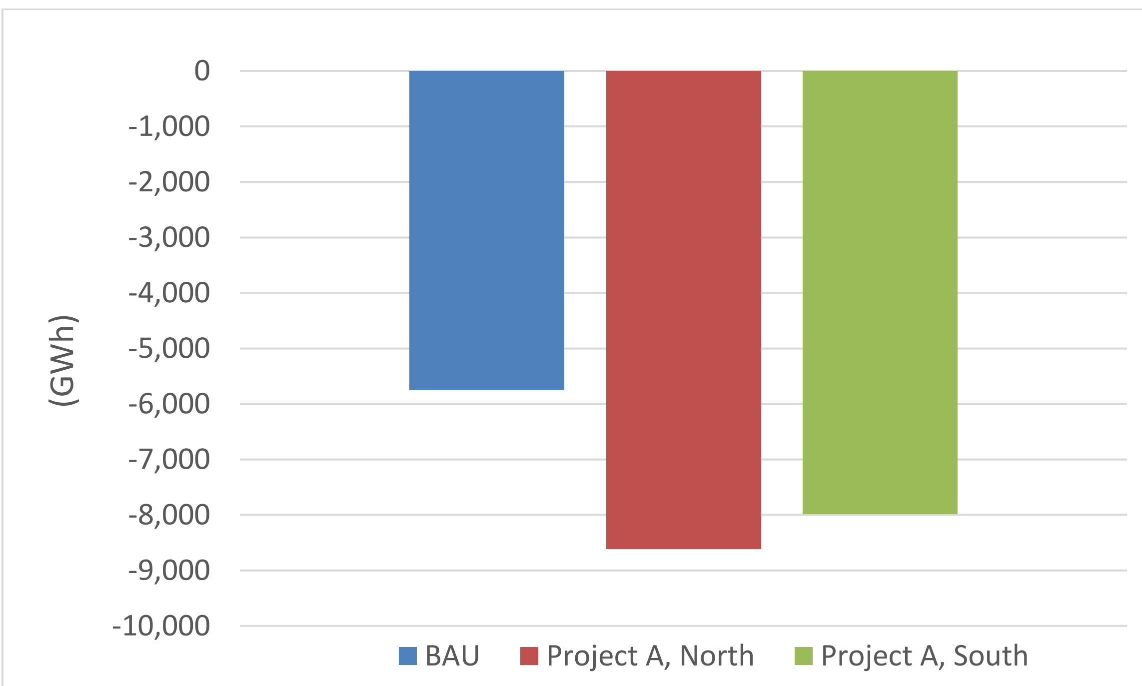


Figure 5-2: Project A - Alberta Net Exports (2030)

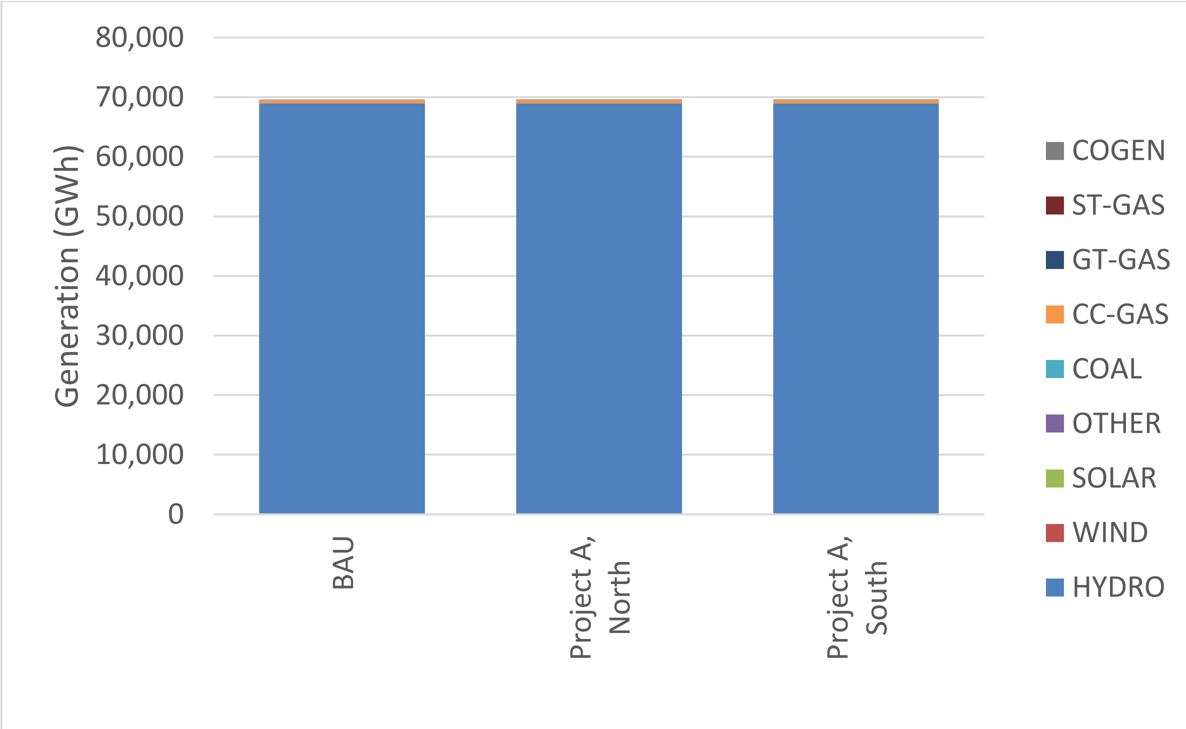


Figure 5-3: Project A - British Columbia Generation (2030)

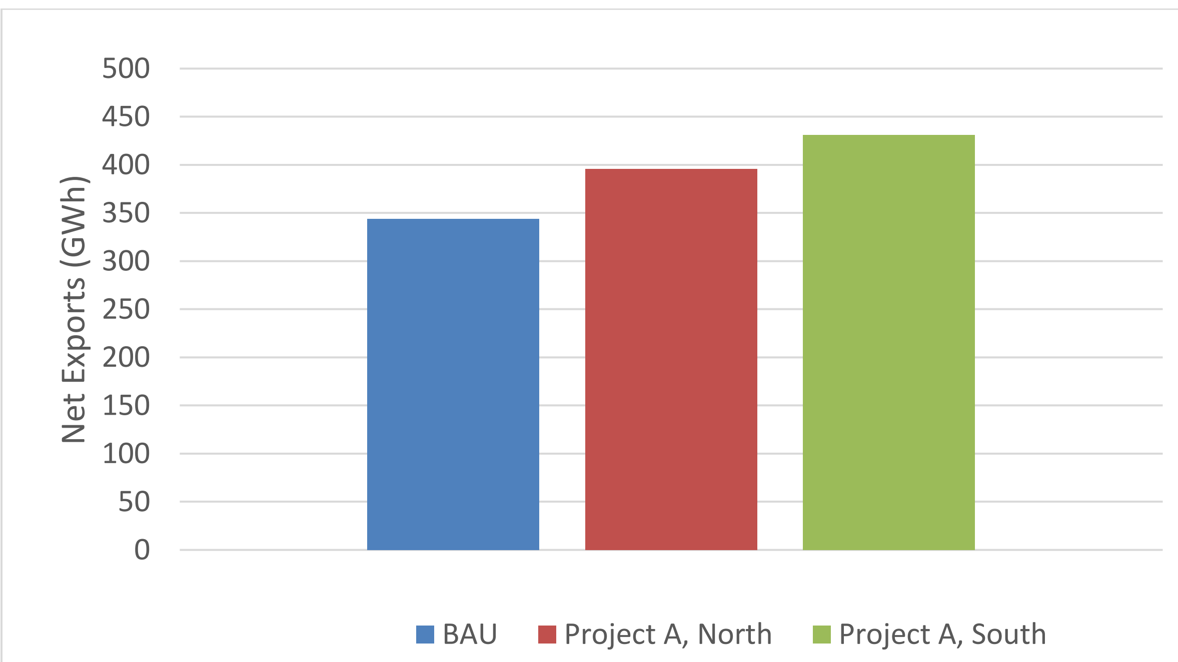


Figure 5-4: Project A - British Columbia Net Exports (2030)

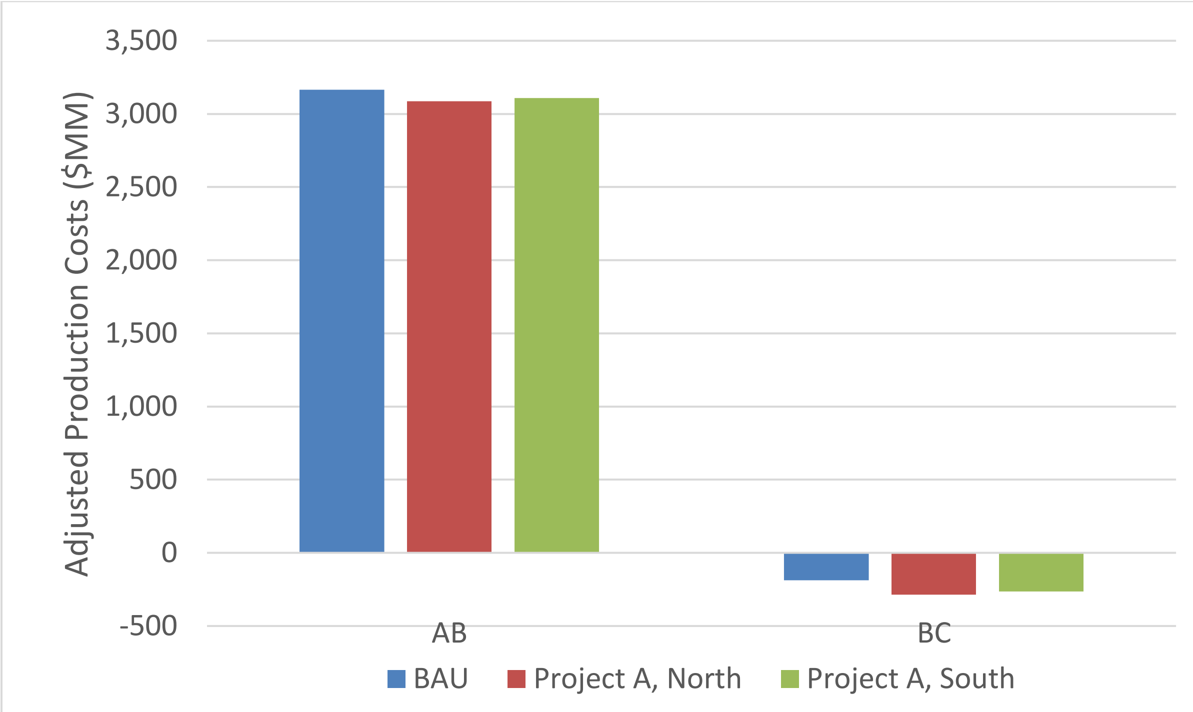


Figure 5-5: Project A - Adjusted Production Costs by Province (2030)

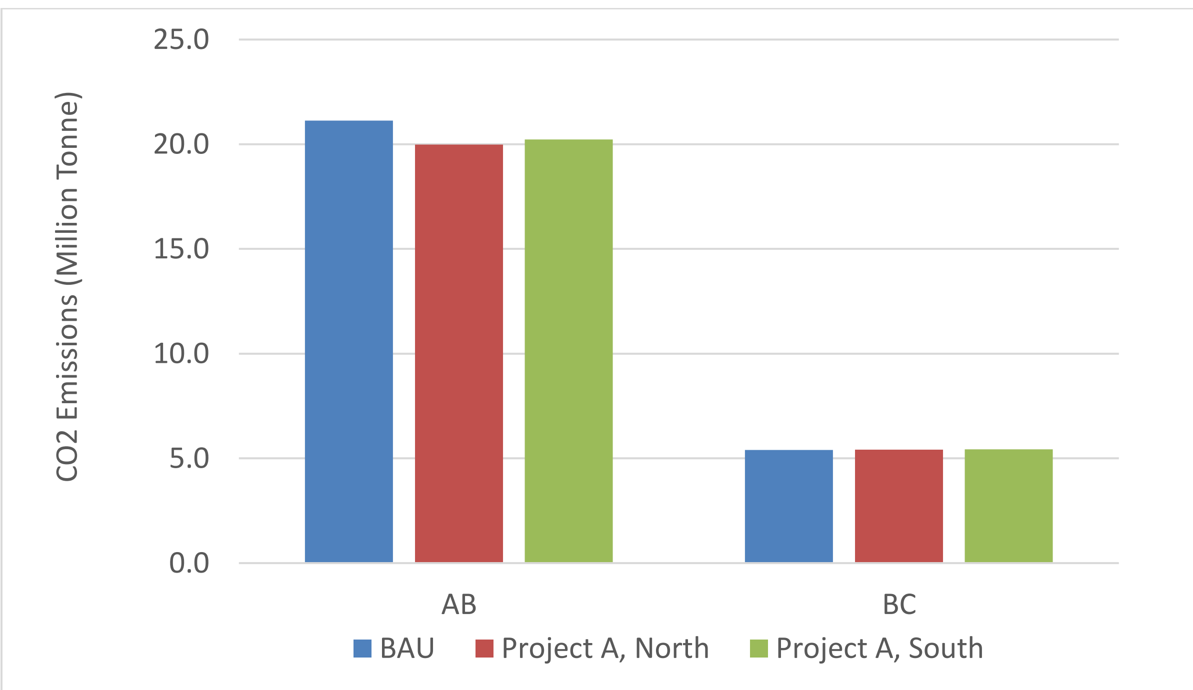


Figure 5-6: Project A - CO2 Emissions by Province (2030)

5.4 Evaluation of Project B

Project B: A New Intertie between Saskatchewan and Manitoba by 2030

Project B includes three options as described below. Following additions were made in each of the options relative to the BAU case.

Project B - Option 1

- 500 KV line Regina to Dorsey
- Limit: 600 MW/-1150 MW (Regina to Dorsey as the positive direction)

Project B - Option 2A

- 230 KV line Kennedy to Cornwallis, plus other internal upgrades
- Limit: 500 MW/ -750 MW (Kennedy to Cornwallis as the positive direction)

Project B - Option 2B

- 230 KV line Kennedy to Cornwallis, only
- Limit: 500 MW/ -350 MW (Kennedy to Cornwallis as the positive direction)

Following tables and charts provide an overview of the performance of the power systems under the BAU case and each of the Project B options. Also included are sets of charts that depict the relative size of hydro curtailments in MB under different scenarios.

Although included in these charts, since BC and AB are in the Western Interconnection, Project B has no impact on the performance of their power system.

Note on Project B Hydro Curtailments

In the course of simulating Project B, model results showed relatively high curtailment of hydro generation in Manitoba. Consequently, additional investigation was performed in order to understand the reasons for the higher than expected curtailment results.

A major driver of higher hydro curtailment in the model appeared to be transmission congestion. This was a modeling issue and not reflective of real-world estimated curtailments. Additional remedial action included better siting the hydropower plants on the transmission grid, and some adjustments to the original transmission settings in the BAU case. These changes were applied to both the original BAU case and also to the Project B options. Since the original BAU case assumptions were implemented in all the projects, it was decided that modified BAU case would only be used for comparison of the Project B options, without applying the changes to all the other projects, which would have required redoing the simulation and modeling of all the other projects, which would have not only extended the project timeline but also would have had minimal impact on the results of the other projects. In the following charts, this modified special BAU case is referred to as "Project B BAU".

Key Observations

Saskatchewan

- SK generation is reduced in the modified BAU case and all the Project B options, with the highest reduction observed in Option 1. Most of the changes are due to reduction in ST-COAL and CC-GAS generation.
- SK is a net importer in all Project B options, with the highest import occurring under Option 1, which corresponds to an increase in SK Adjusted Production Cost under all the projects options relative to "Project B BAU", with the highest increase under Option 1.
- The main environmental impact is a reduction in CO2 emissions in SK under Project B options, with the highest impact occurring under Option 1. These reductions are due to lower generation by ST-COAL and CC-GAS plants.

Manitoba

- MB generation demonstrates a slight increase in hydro generation relative to the Project B BAU case.
- MB is a net exporter, with exports slightly higher under Project B options.
- Higher MB exports correspond to higher negative Adjusted Production Cost (i.e., net revenues) in MB, with the highest value under Option 1.
- As shown on the Manitoba Curtailment charts, some of the hydro generation is curtailed (or spilled), mainly due to transmission congestion, although other drivers or model constraints may also be impacting hydro generation.
- As noted previously, further investigation and additional model runs were performed to improve the modeling and enhance the model assumptions that would decrease the curtailments.
- Comparing total hydro generation and total hydro curtailments in the "Manitoba Curtailment Results" charts, Figure 5-11 and Figure 5-12, it is observed that the curtailments are less than 4% of the total generation, which from a modeling perspective, is within reasonable range. These curtailments indicate that the modeling software was not able to use about 4% of the hydropower but does not necessarily imply that such curtailments would be experienced in actual operation. It is not clear why the majority of the curtailments modeled occurred at the Keeyask hydro station.

- The chart on Manitoba curtailments by hydropower plants, Figure 5-13, presents hydro curtailments by individual plants under the BAU. Again, relative to the total size and generation of each hydro plant, the hydro curtailments appear to be within reasonable ranges.
- The main environmental impact is a reduction in CO_2 emissions in MB under Project B options, with the highest impact occurring under Option 1.

Table 5-6: Project B - Saskatchewan Generation

SK Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project B BAU	3,488	7,943	184	133	7,785	3,209	55	0	2,378	**25,175**
Project B, Option 1	3,476	7,989	184	113	6,962	2,235	30	0	2,312	**23,301**
Project B, Option 2A	3,485	7,989	184	126	7,543	2,682	35	0	2,341	**24,384**
Project B, Option 2B	3,485	7,988	184	127	7,572	2,717	34	0	2,338	**24,445**
Change from Project B BAU										
Project B, Option 1	-12	46	0	-20	-823	-974	-25	0	-66	**-1,874**
Project B, Option 2A	-3	46	0	-7	-242	-527	-20	0	-37	**-791**
Project B, Option 2B	-3	45	0	-6	-213	-492	-21	0	-40	**-730**

Table 5-7: Project B - Manitoba Generation

MB Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project B BAU	36,495	916	0	0	0	0	4	48	0	**37,463**
Project B, Option 1	36,747	927	0	0	0	0	4	48	0	**37,725**
Project B, Option 2A	36,720	894	0	0	0	0	5	48	0	**37,666**
Project B, Option 2B	36,677	904	0	0	0	0	5	48	0	**37,634**
Change from Project B BAU										
Project B, Option 1	252	11	0	0	0	0	0	0	0	**262**
Project B, Option 2A	225	-22	0	0	0	0	1	0	0	**203**
Project B, Option 2B	182	-12	0	0	0	0	1	0	0	**171**

Table 5-8: Project B - Adjusted Production Costs

Adjusted Production Cost ($MM)	Project B BAU	Project B, Option 1	Project B, Option 2A	Project B, Option 2B
MB	-94	-211	-158	-156
SK	678	713	702	702
Total	**584**	**501**	**544**	**547**
Change from Project B BAU		**Project B, Option 1**	**Project B, Option 2A**	**Project B, Option 2B**
MB		-117	-64	-62
SK		35	24	24
Total		**-83**	**-40**	**-37**

Table 5-9: Project B - Carbon Emissions

CO2 Emission (Million Tonne)	Project B BAU	Project B, Option 1	Project B, Option 2A	Project B, Option 2B
MB	0.04	0.04	0.04	0.04
SK	10.75	9.55	10.29	10.33
Total	**10.78**	**9.59**	**10.33**	**10.37**
Change from Project B BAU		**Project B, Option 1**	**Project B, Option 2A**	**Project B, Option 2B**
MB		0	0	0
SK		-1.2	-0.46	-0.42
Total		**-1.19**	**-0.45**	**-0.41**

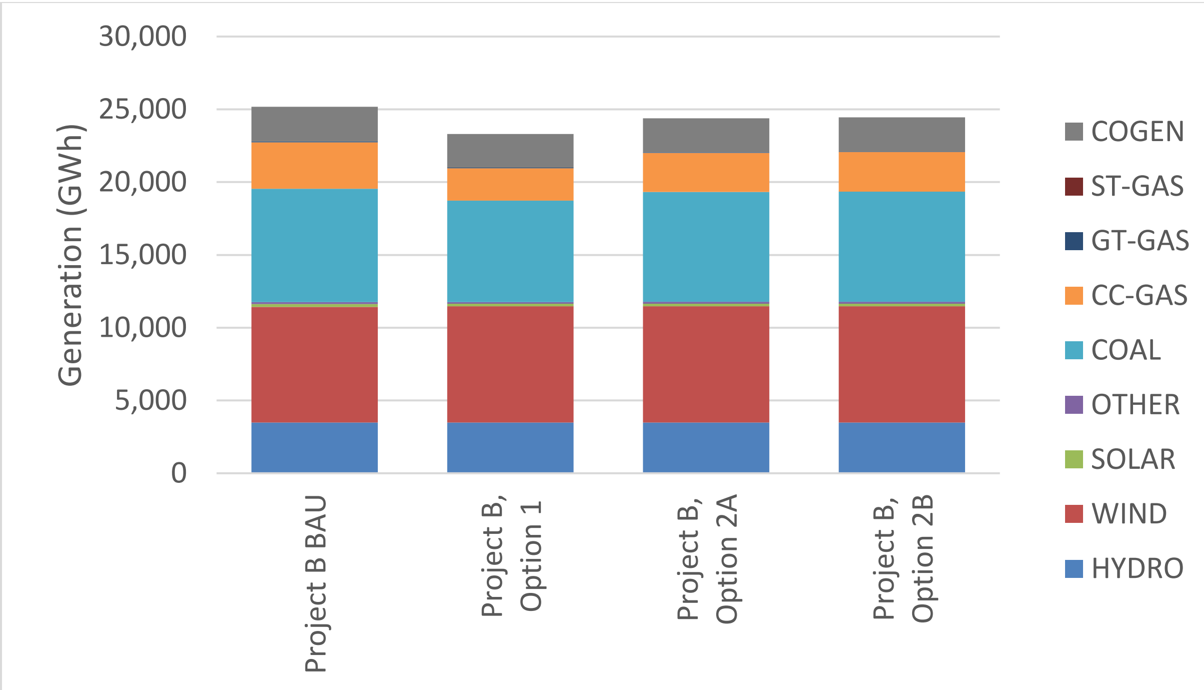


Figure 5-7: Project B - Saskatchewan Total Generation by Type (2030)

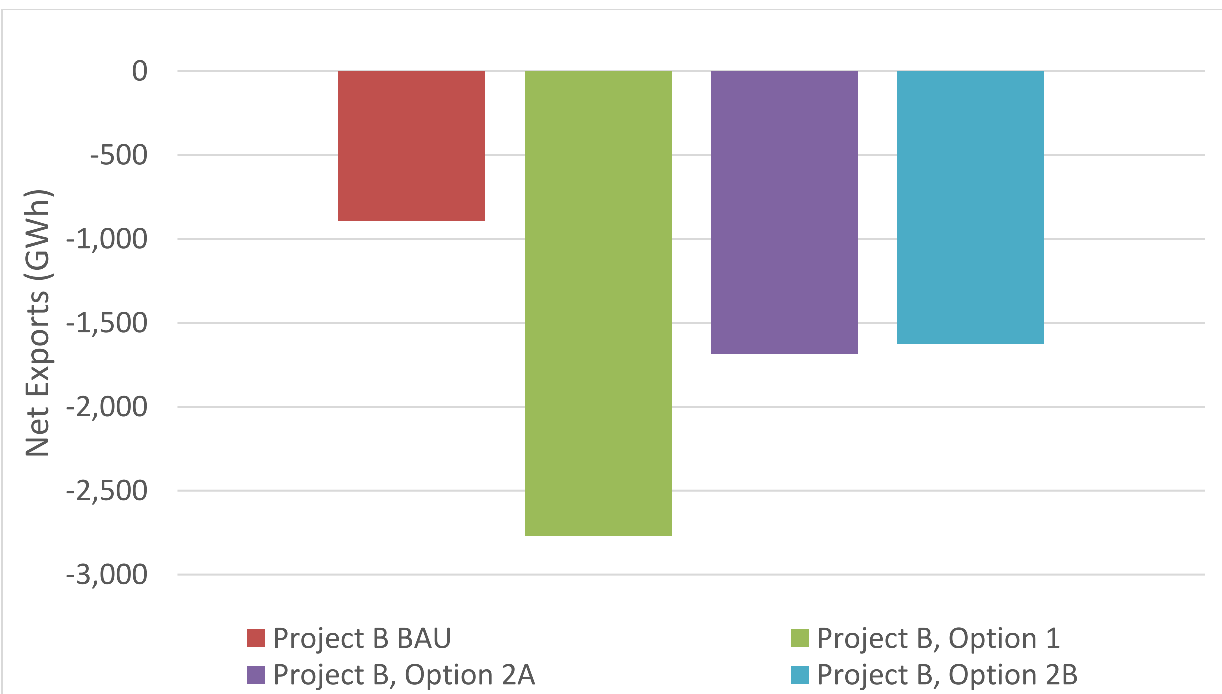


Figure 5-8: Project B - Saskatchewan Net Exports (2030)

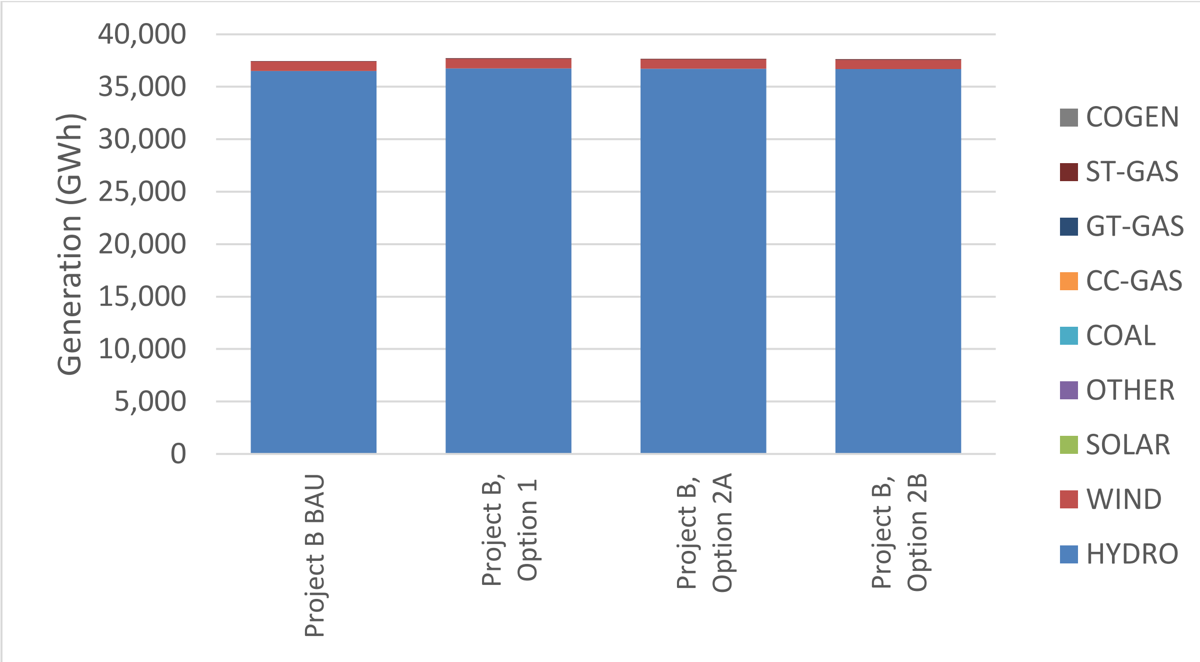


Figure 5-9: Project B - Manitoba Generation by Type (2030)

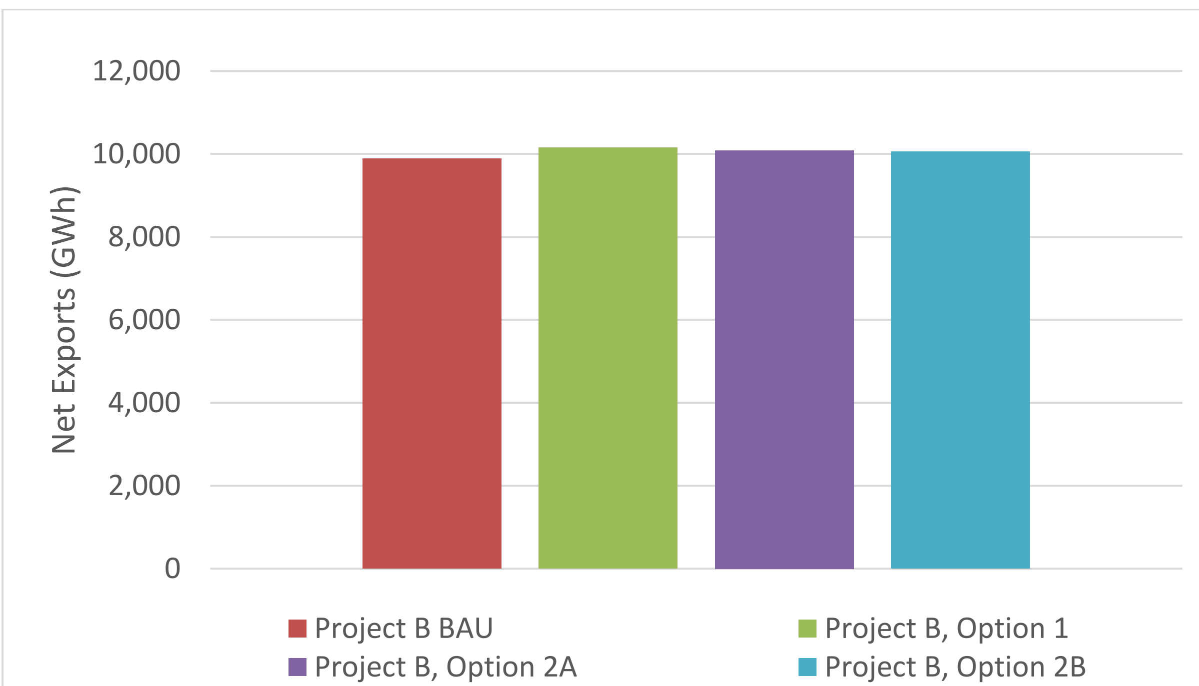


Figure 5-10: Project B - Manitoba Net Exports (2030)

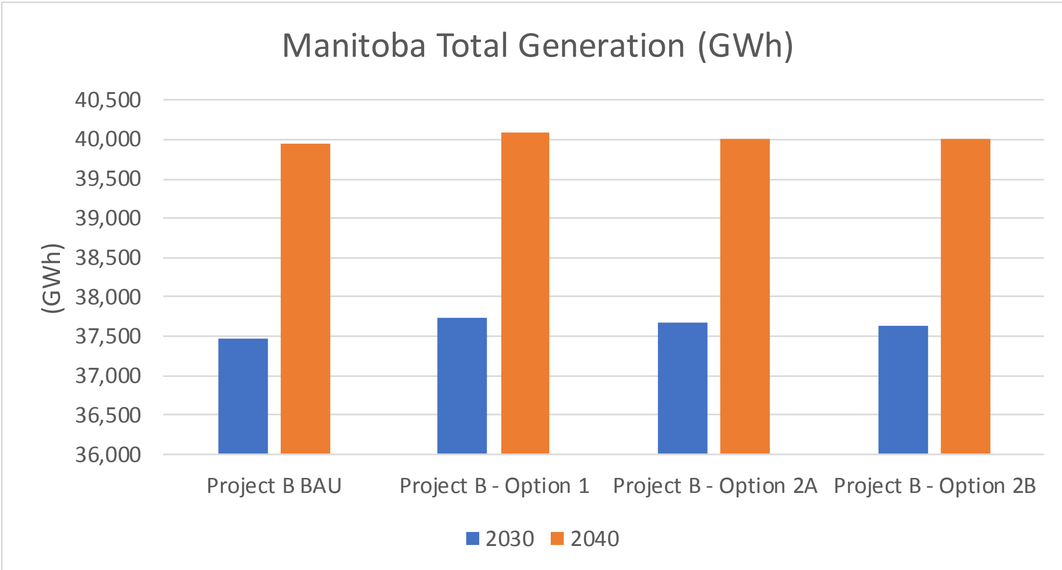


Figure 5-11: Project B - Manitoba Total Generation (GWh)

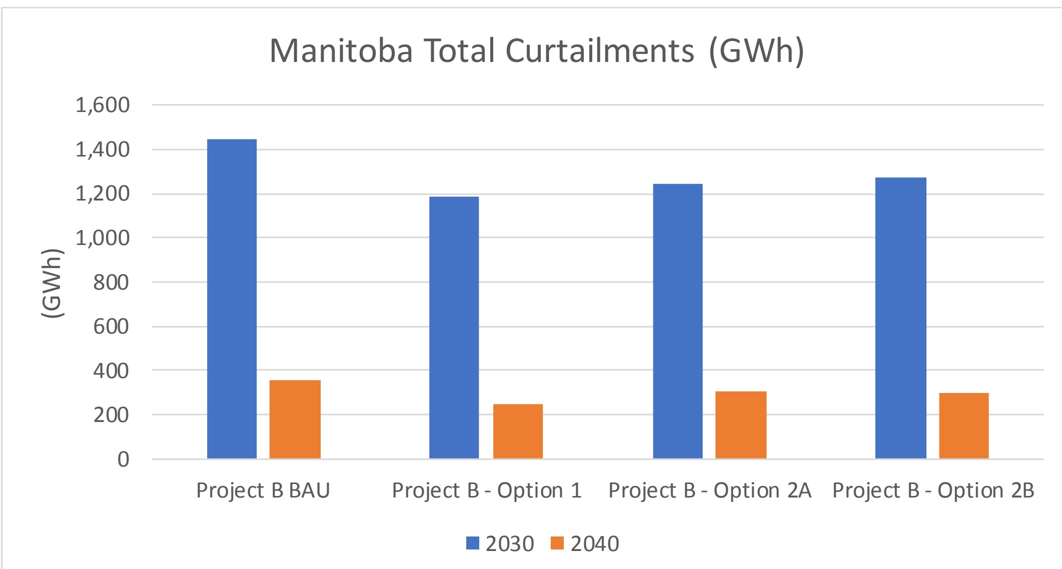


Figure 5-12: Project B - Manitoba Total Curtailments (GWh)

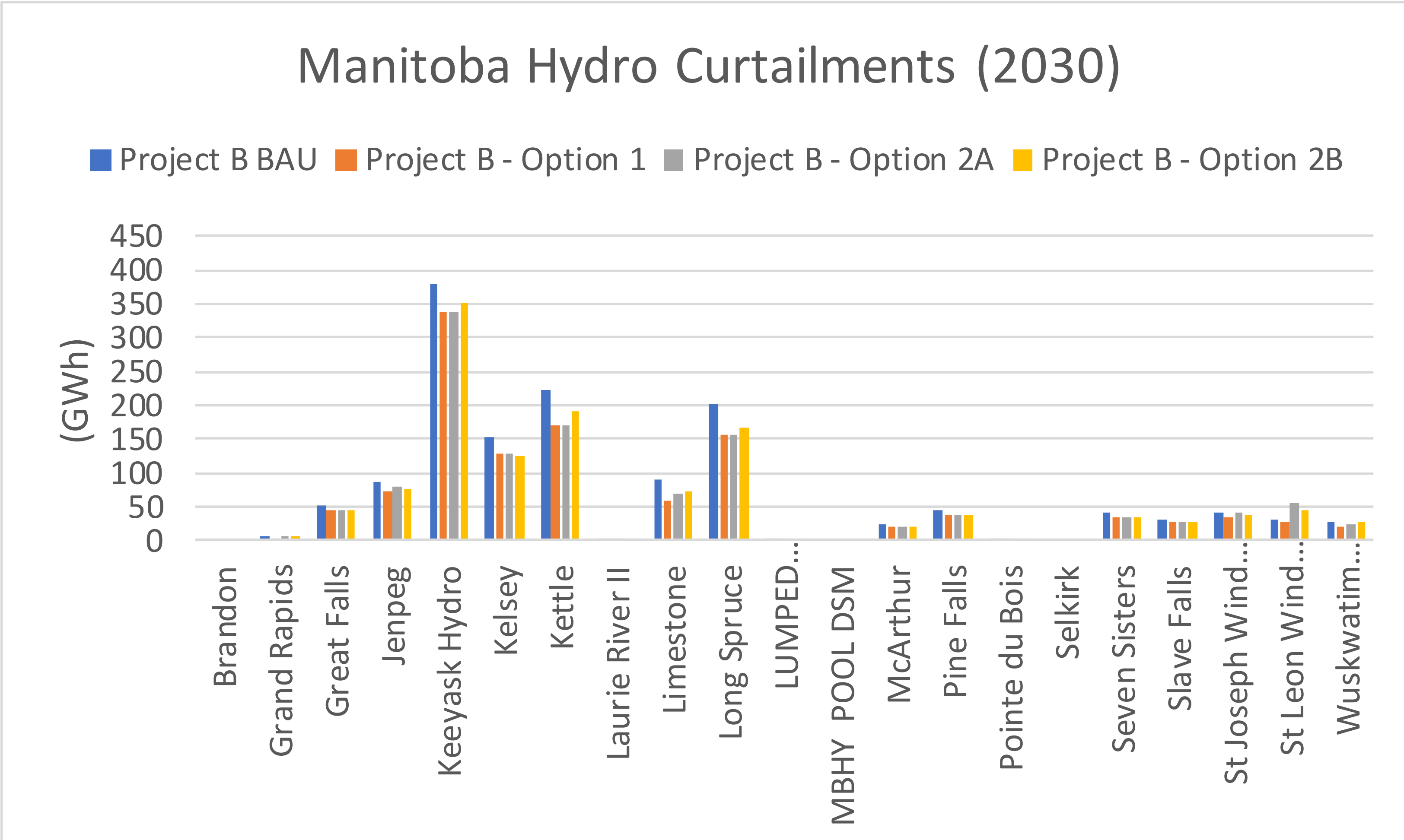


Figure 5-13: Project B - Manitoba Hydro Curtailment by Hydropower Plant (2030)

Note: “LUMPED” represents “Other Small Hydro”

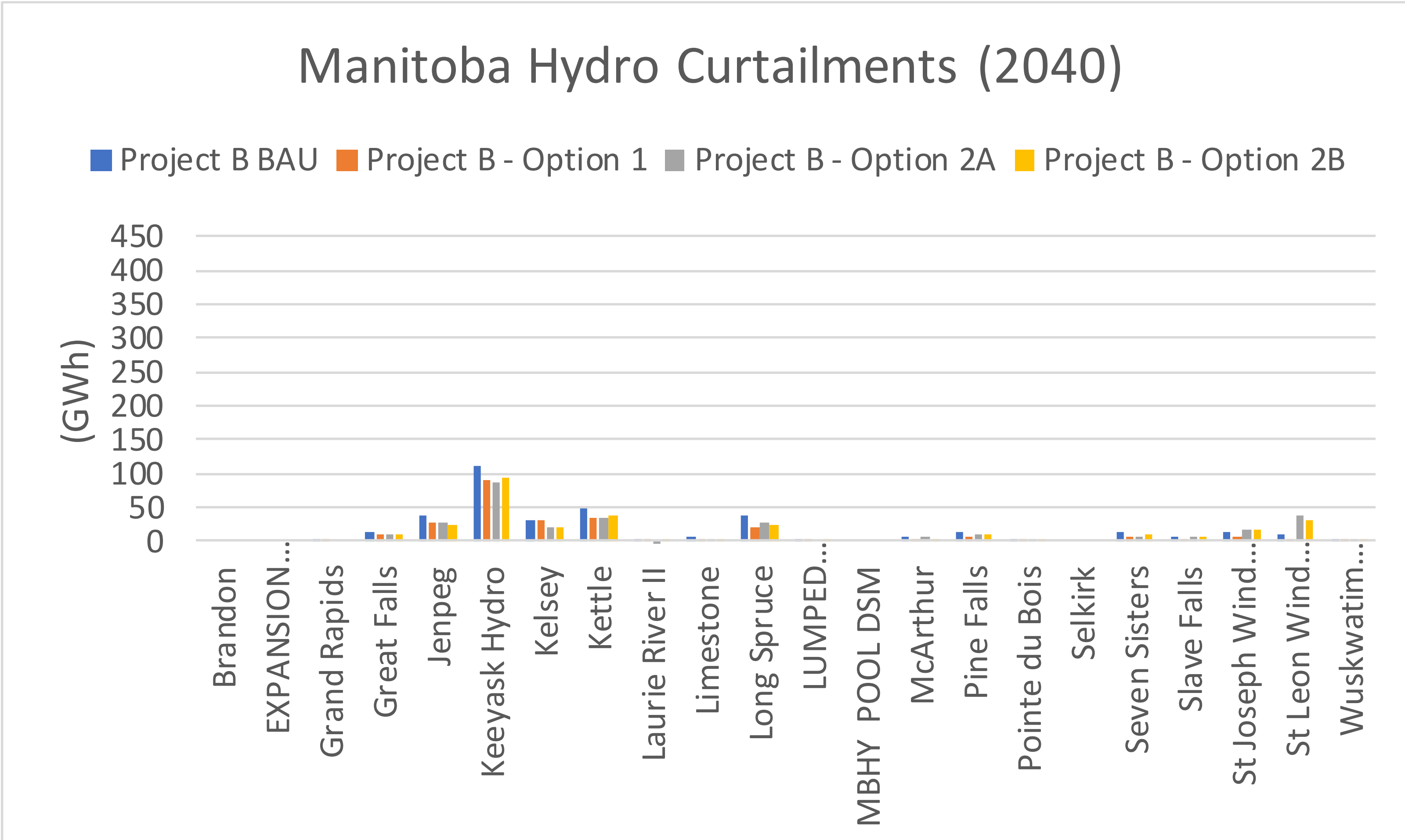


Figure 5-14: Project B - Manitoba Hydro Curtailment by Hydropower Plant (2040)

Note: “LUMPED” represents “Other Small Hydro”

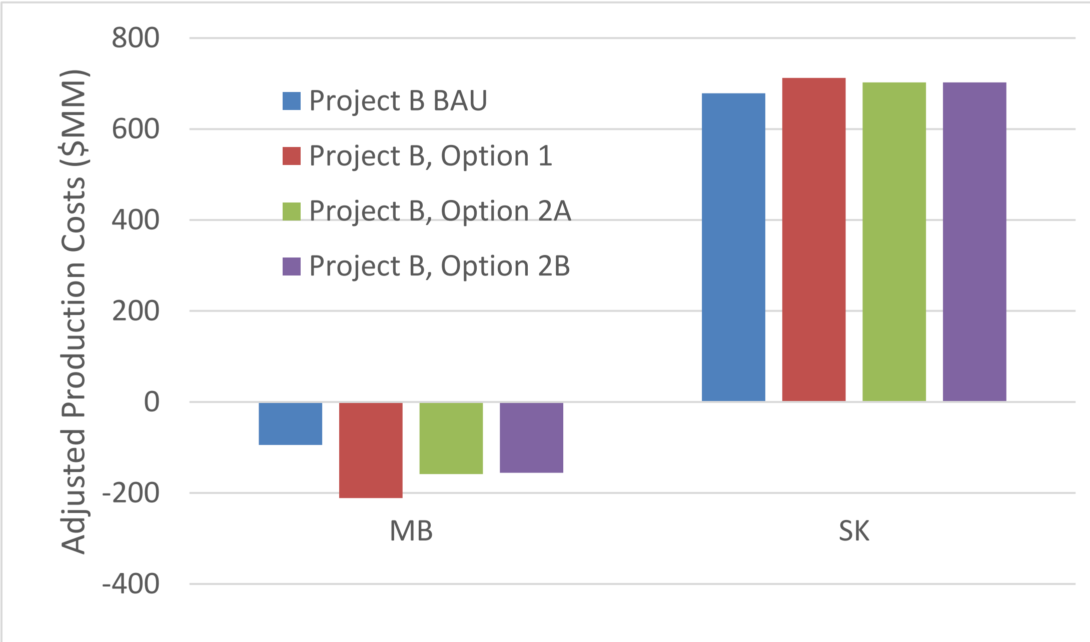


Figure 5-15: Project B - Adjusted Production Costs by Province (2030)

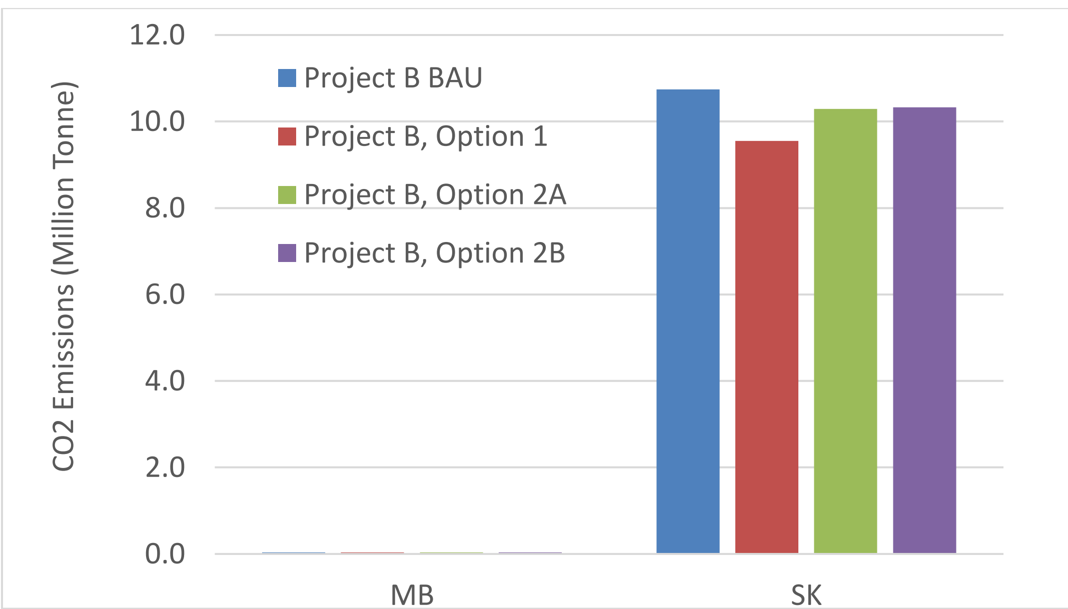


Figure 5-16: Project B - CO2 Emissions by Province (2030)

It should be noted that the proper base case for evaluation of the impact of projects is the "Project B BAU" and not the

5.5 Evaluation of Project C

Project C: New internal transmission or distribution added to aid in development of new renewable capacity in AB and SK by 2030

Project C includes two scenarios as described below. Following additions were made in each of the options relative to the BAU case.

In the case of AB, additional internal transmission (which were specified by AESO), enable access to additional wind resources within Alberta, which currently cannot access the AB market due to inadequacy of current transmission system within Alberta. Size of additional available wind resources were also specified by AESO.

In the case of SK, no additional wind resources were specified by SaskPower.

<u>Alberta Scenario</u>

- Current (i.e., 2018) wind in AB is 1,445 MW. Total AB wind in the BAU case in 2030 is 4,045, In Project C, wind installation in AB is increased by 2,400 MW over the BAU case to a total of 6445 in 2040. This is about 5,000 MW more wind compared to the current (i.e., 2018) AB wind.
- Added the following transmission lines:
    - Chapel Rock 500/240 kV Substation and Chapel Rock 240 kV line (d/c) to Pincher Creek
    - PENV 240kV east lines (s/c) 650s Hansman Lake – 267s Killarney Lake Tap – 899s Edgerton, PENV 240 kV west line (s/c)574s Nilrem – 2007s Drury and Drury Substation2007s substation near Vermilion
    - 240 kV S/C (Tinchebray_Gaetz) 972s Tinchebray – 87s Gaetz

<u>Saskatchewan Scenario</u>

- Added the following transmission lines:
    - Swift Current SS to Ermine SS 230 kV Line
    - Regina area to Fleet Street area 230 kV Line

Following tables and charts provide an overview of the performance of the power systems under the BAU case and each of the Project C scenarios.

Key Observations

<u>Alberta</u>

- Additional internal transmission in AB is enabling market access to additional 2,400 MW of renewables in the provinces. This is shown as an increase for the studied projects in wind generation in the province and also as a reduction in gas fired generation. The additional 2,400 MW of capacity is the projected wind installation that AESO indicated would not have access to AB market without additional internal transmission.

- A major impact of additional internal transmission and wind generation in AB is lowering of energy imports into the province by half.
- Access to markets by additional wind in AB also results in reduction of CO2 emissions related to the BAU case.
- Lowering of imports in AB results in corresponding decrease in Adjusted Production Cost in the province. Results also show a lowering of BC revenues by a relatively small amount. This reflects a decrease of power imports from the USA rather than from BC.

<u>Saskatchewan</u>

- Additional internal transmission in SK appears to have no significant impact on SK generation or net exports or its Adjusted Production Cost. The main reason is that no additional wind or other resources were added to SK in Project C relative to the BAU case.

Table 5-10: Project C - Generation by Province

Generation by Province (GWh)	AB	BC	MB	SK	Total West	Total East
BAU	67,746	69,510	37,255	26,108	**137,256**	**63,363**
Project C	70,397	69,446	37,253	26,108	**139,844**	**63,361**
Change from BAU						
Project C	2,651	-63	-3	0	**2,588**	**-2**

Table 5-11: Project C - Alberta Generation

AB Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	1,875	12,910	775	1,925	7,107	17,989	2,347	0	22,819	**67,746**
Project C	1,875	20,841	775	1,876	7,102	17,496	1,689	0	18,744	**70,397**
Change from BAU										
Project C	0	7,932	0	-49	-5	-494	-659	0	-4,074	**2,651**

Table 5-12: Project C - Saskatchewan Generation

SK Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	3,335	7,995	184	133	8,108	3,814	109	0	2,430	**26,108**
Project C	3,335	7,995	184	133	8,108	3,814	109	0	2,430	**26,108**
Change from BAU										
Project C	0	0	0	0	0	0	0	0	0	**0**

Table 5-13: Project C - Adjusted Production Costs

Adjusted Production Cost ($MM)	BAU	Project C
AB	3,165	2,754
BC	-187	-145
MB	-75	-75
SK	720	720
Total West	**2,978**	**2,609**
Total East	**646**	**646**
Change from BAU		**Project C**
AB		-411
BC		42
MB		0
SK		0
Total West		**-411**
Total East		**42**

Table 5-14: Project C - Carbon Emissions

CO2 Emissions (Million Tonne)	BAU	Project C
AB	21.12	19.22
BC	5.40	5.38
MB	0.04	0.04
SK	11.32	11.32
Total West	**26.52**	**24.59**
Total East	**11.36**	**11.36**
Change from BAU		**Project C**
AB		-1.91
BC		-0.02
MB		0.00
SK		0.00
Total West		**-1.91**
Total East		**-0.02**

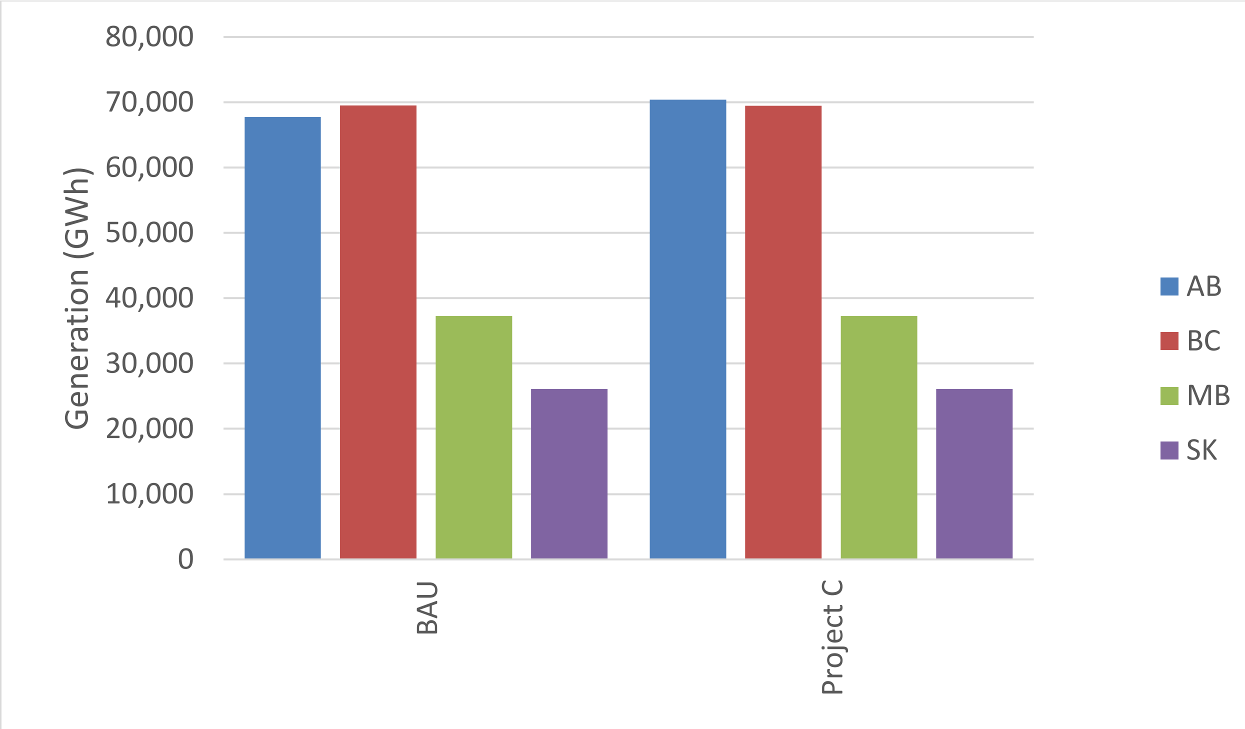


Figure 5-17: Project C - Total Generation by Province (2030)

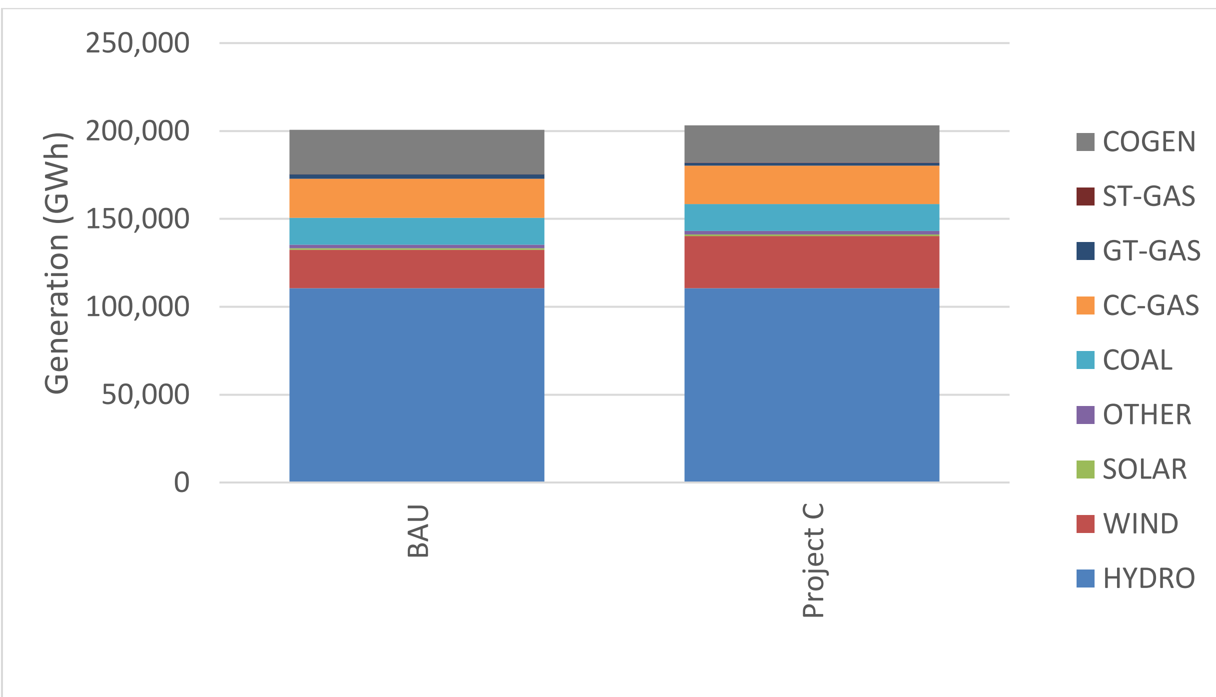


Figure 5-18: Project C - Total Generation by Type (2030)

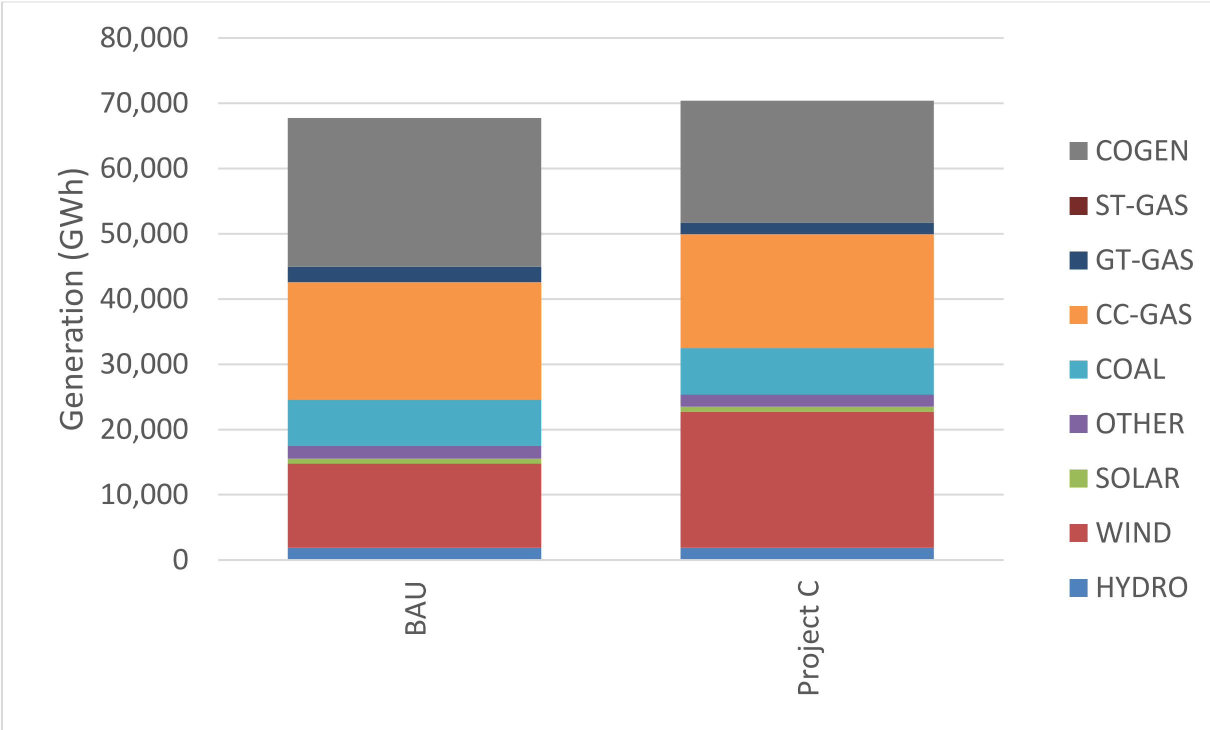


Figure 5-19: Project C - Alberta Generation by Type (2030)

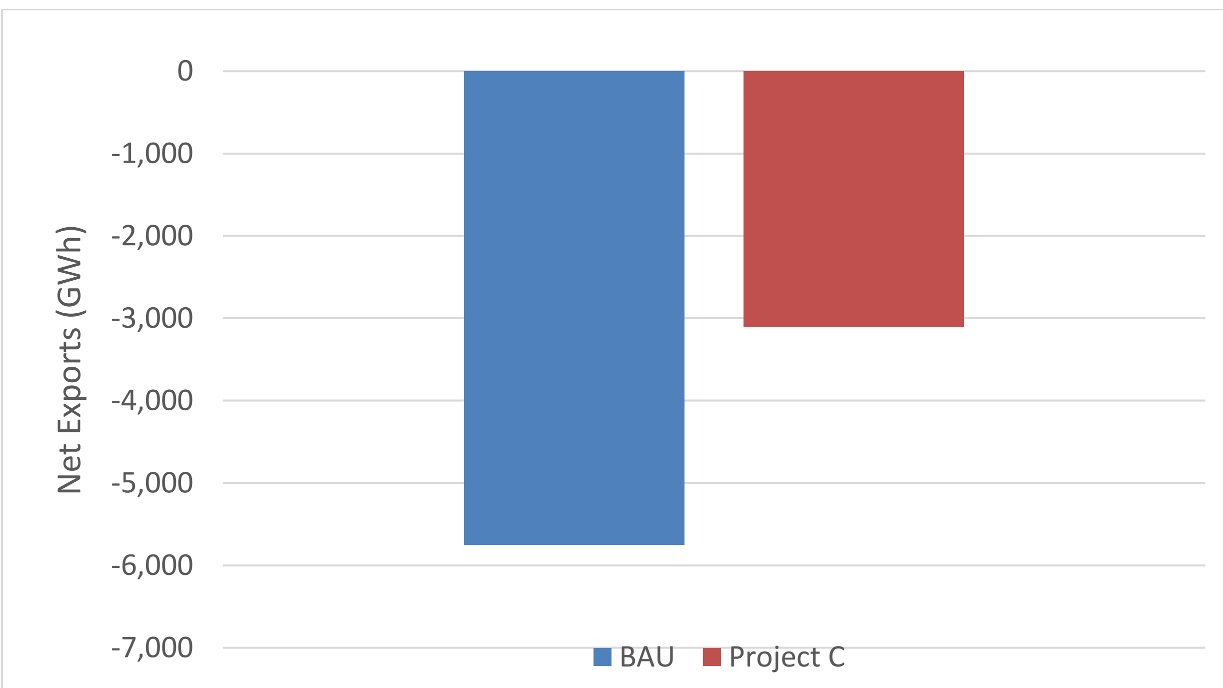


Figure 5-20: Project C - Alberta Net Exports (2030)

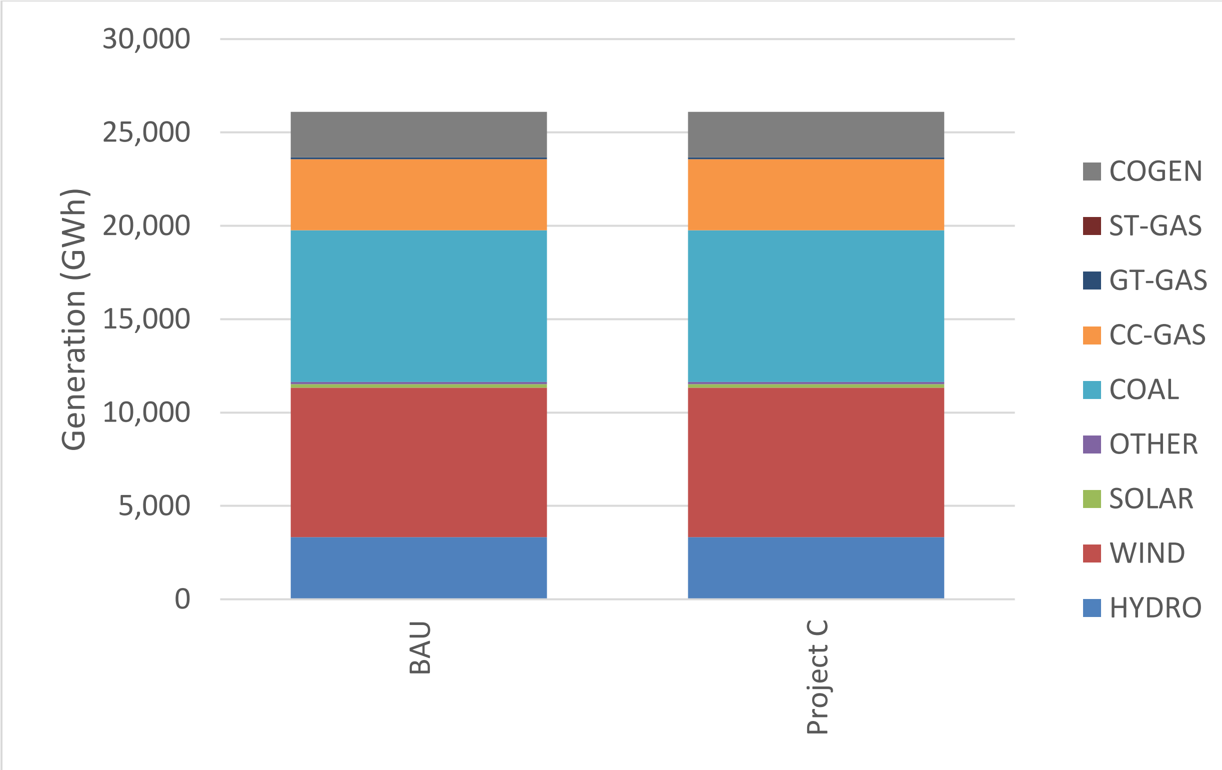


Figure 5-21: Project C - Saskatchewan Generation (2030)

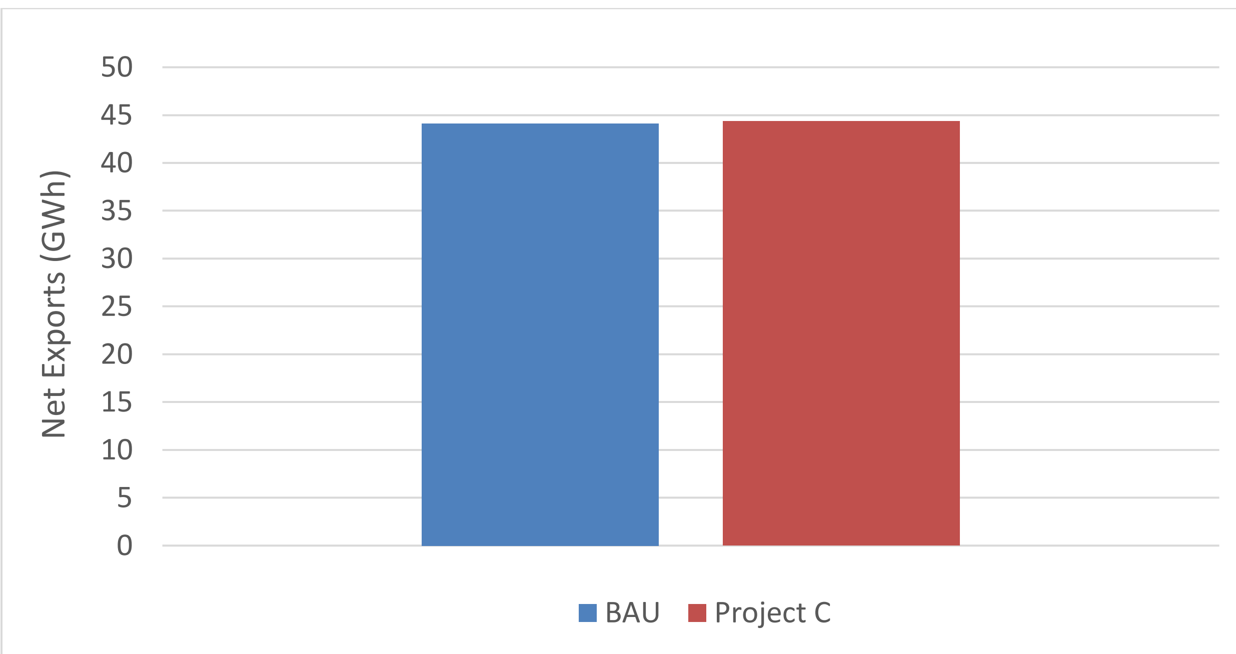


Figure 5-22: Project C - Saskatchewan Net Exports (2030)

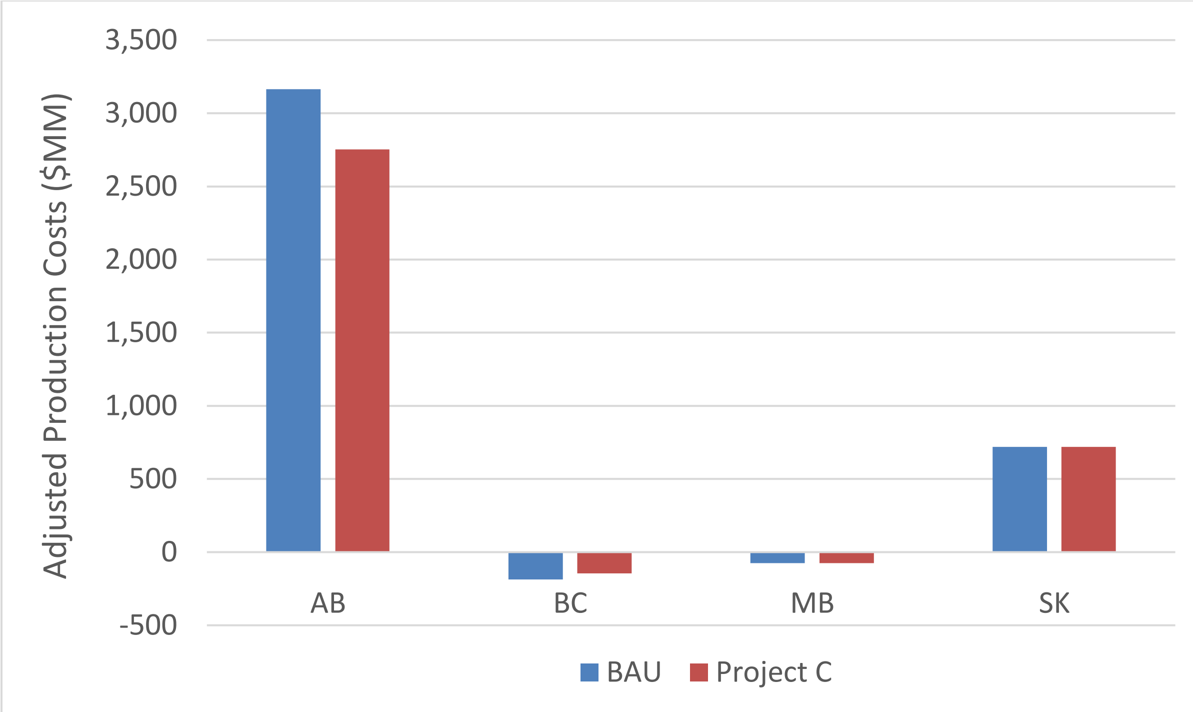


Figure 5-23: Project C - Adjusted Production Costs by Province (2030)

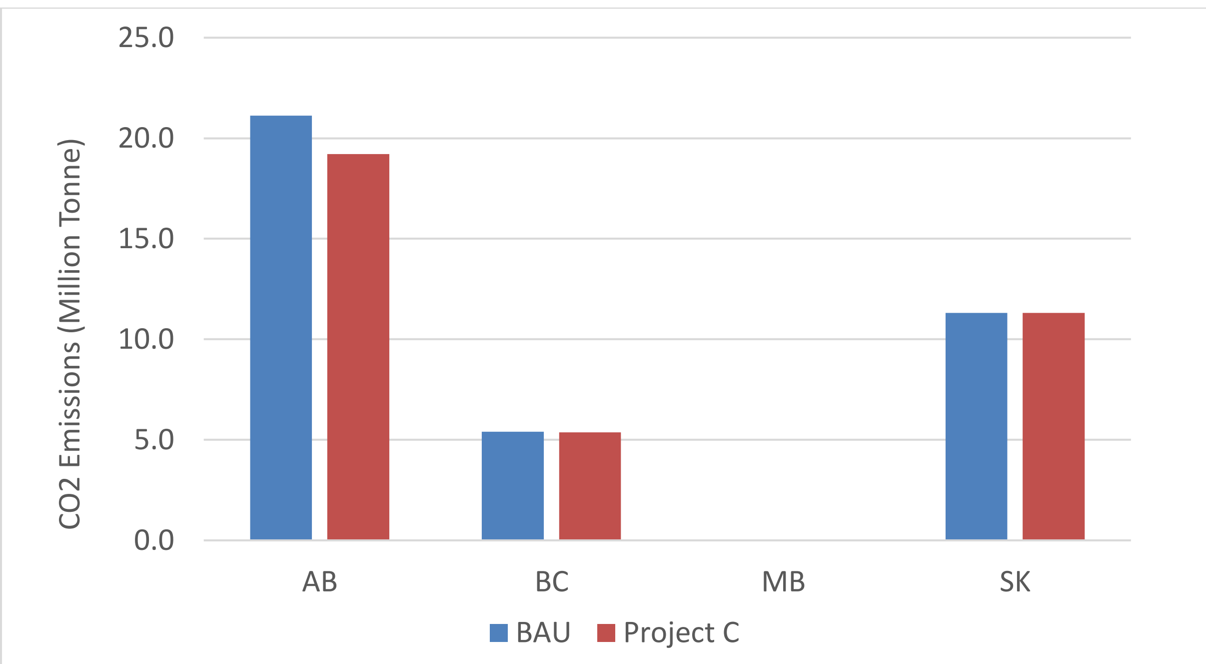


Figure 5-24: Project C - CO2 Emissions by Province (2030)

5.6 Evaluation of Project D

Project D: New hydroelectric capacity in Alberta and Saskatchewan by 2040

Project D includes two options as described below. Following additions were made in each of the options relative to the BAU case. Note that the results reflect evaluation of the 2040 scenario due to the relatively long lead time for such hydro development.

<u>Project D – Option 1 - Alberta</u>

- Upgraded Brazeau River capacity to 520 MW from 350 MW, using the same hydrology supplying the current Brazeau asset
- Added Peace River Hydro, 330 MW, 1,734 GWh
- Added 240 kV transmission line to connect Peace River project to Wesley Creek
- Added 240 kV Brazeau to Benalto transmission line
- Added 138 kV Brazeau to Lodgepole transmission line

<u>Project D – Option 1 - Saskatchewan</u>

- Added Tazi Twe Hydro, 50 MW, 402 GWh
- Added Island Falls to Border Station transmission line.
- Added Stony Rapids to Points North Station transmission line
- Added Points North to Key Lake Station transmission line

<u>Project D - Option 2 - Alberta</u>

- Added Slave River Hydro, 1,000 MW, 5,261 GWh
- Added 2, 500 kV transmission lines from Slave River to Thickwood Hills

<u>Project D – Option 2 - Saskatchewan</u>

- Added Tazi Twe Hydro, 50 MW, 402 GWh
- Added Stony Rapids to Points North Station transmission line
- Added Points North to Key Lake Station transmission line
- Added Island Falls to E.B Campbell transmission line

Following charts provide an overview of the performance of power systems under the BAU case and each of the Project D options.

Key Observations

<u>Alberta</u>

- Hydro additions in AB in the two Project D options results in increased hydro generation in the province. However, they appear to be mainly displacing CC-GAS generation, without significantly impacting the total generation in the province.
- Additional hydro generation in AB translated into progressively higher net exports from AB.
- Higher net exports by AB results in lower Adjusted Production Cost in Project D options relative to the BAU case.
- Displacement of the CC-GAS generation by hydro generation also results in reduction of CO2 generation in AB.

<u>Saskatchewan</u>

- Project D impacts on SK are less significant, mainly due to the small size of the hydro additions in the province. Hydro generation is also impacted by their siting on the transmission grid, depending on the power flows and transmission congestion.
- SK total generation is somewhat higher in Option 1 relative to the BAU case, but slightly less in Option 2 relative to the BAU case and also relative to the Option 1. Hence, SK changes from a small net exporter in the BAU case and Option 1, to a small net importer in Option 2.
- However, hydro generation is actually slightly greater in both Option 1 and Option 2 relative to the BAU case. In both options, hydro generation is displacing generation by the other thermal resources. However, in Option 2, thermal generation is reduced by more than the increase in hydro generation. This reduction in total generation, results in making SK a net importer in Option 2.
- Additional hydro generation and displacement of thermal generation in Option 1 and Option 2, and the more economic import in place of in-province thermal generation, results in lowering the Adjusted Production Cost in SK in both Option 1 and Option 2 relative to the BAU case.
- Commensurate with displacement of thermal generation in SK, CO2 emissions are also reduced in proportion to reduction in thermal generation in the two options.

Table 5-15: Project D - Generation

Project D Generation (GWh)	AB	BC	MB	SK	Total West	Total East
BAU	80,555	76,515	39,838	29,681	**157,070**	**69,520**
Project D, Option 1	80,603	76,514	39,835	29,800	**157,117**	**69,636**
Project D, Option 2	80,652	76,515	39,938	29,361	**157,167**	**69,299**
Change from BAU						
Project D, Option 1	48	0	-3	119	**48**	**116**
Project D, Option 2	49	0	103	-440	**50**	**-336**

Table 5-16: Project D - Alberta Generation

AB Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	1,875	12,871	774	1,850	0	47,627	232	0	15,324	**80,555**
Project D, Option 1	3,689	12,871	774	1,851	0	45,907	214	0	15,296	**80,603**
Project D, Option 2	7,136	12,871	774	1,850	0	42,560	203	0	15,258	**80,652**
Change from BAU										
Project D, Option 1	1,814	0	0	1	0	-1,721	-19	0	-28	**48**
Project D, Option 2	5,261	0	0	0	0	-5,068	-30	0	-66	**97**

Table 5-17: Project D - Saskatchewan Generation

SK Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	3,515	8,092	184	146	8,742	7,191	420	0	1,391	29,681
Project D, Option 1	3,989	8,093	184	145	8,707	6,970	346	0	1,365	29,800
Project D, Option 2	4,056	8,096	184	145	8,672	6,632	236	0	1,339	29,361
Change from BAU										
Project D, Option 1	475	1	0	-1	-35	-221	-74	0	-26	119
Project D, Option 2	541	4	0	-1	-70	-559	-184	0	-52	-320

Table 5-18: Project D - Adjusted Production Costs

Adjusted Production Cost ($MM)	BAU	Project D, Option 1	Project D, Option 2
AB	4,766	4,631	4,375
BC	-196	-194	-190
MB	64	63	57
SK	1,104	1,070	1,031
Total West	**4,570**	**4,437**	**4,185**
Total East	**1,167**	**1,134**	**1,089**
Change from BAU		**Project D, Option 1**	**Project D, Option 2**
AB		-135	-391
BC		2	6
MB		-1	-6
SK		-33	-72
Total West		**-133**	**-386**
Total East		**-34**	**-79**

Table 5-19: Project D - Carbon Emissions

CO2 Emissions (Million Tonne)	BAU	Project D, Option 1	Project D, Option 2
AB	21.43	20.83	19.67
BC	5.17	5.17	5.17
MB	0.54	0.54	0.54
SK	12.78	12.62	12.40
Total West	**26.60**	**25.99**	**24.84**
Total East	**13.31**	**13.15**	**12.94**
Change from BAU		**Project D, Option 1**	**Project D, Option 2**
AB		-0.60	-1.76
BC		0.00	0.00
MB		0.00	0.00
SK		-0.16	-0.38
Total West		**-0.60**	**-1.76**
Total East		**-0.16**	**-0.37**

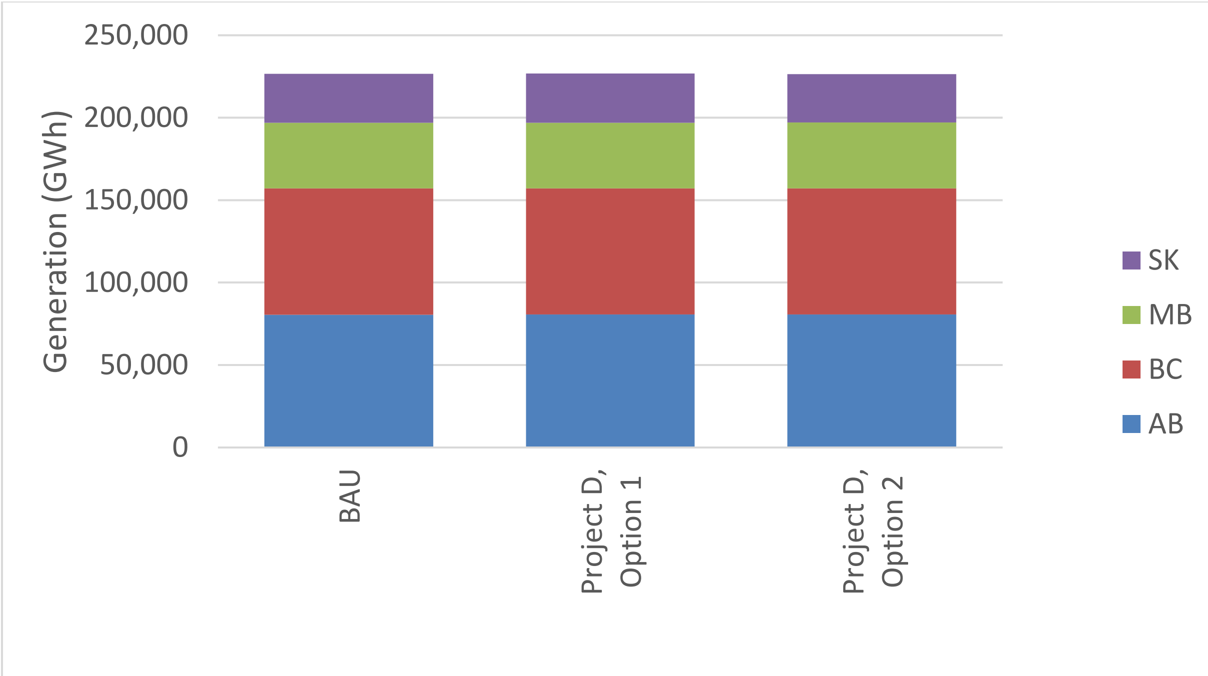


Figure 5-25: Project D - Total Generation by Province (2040)

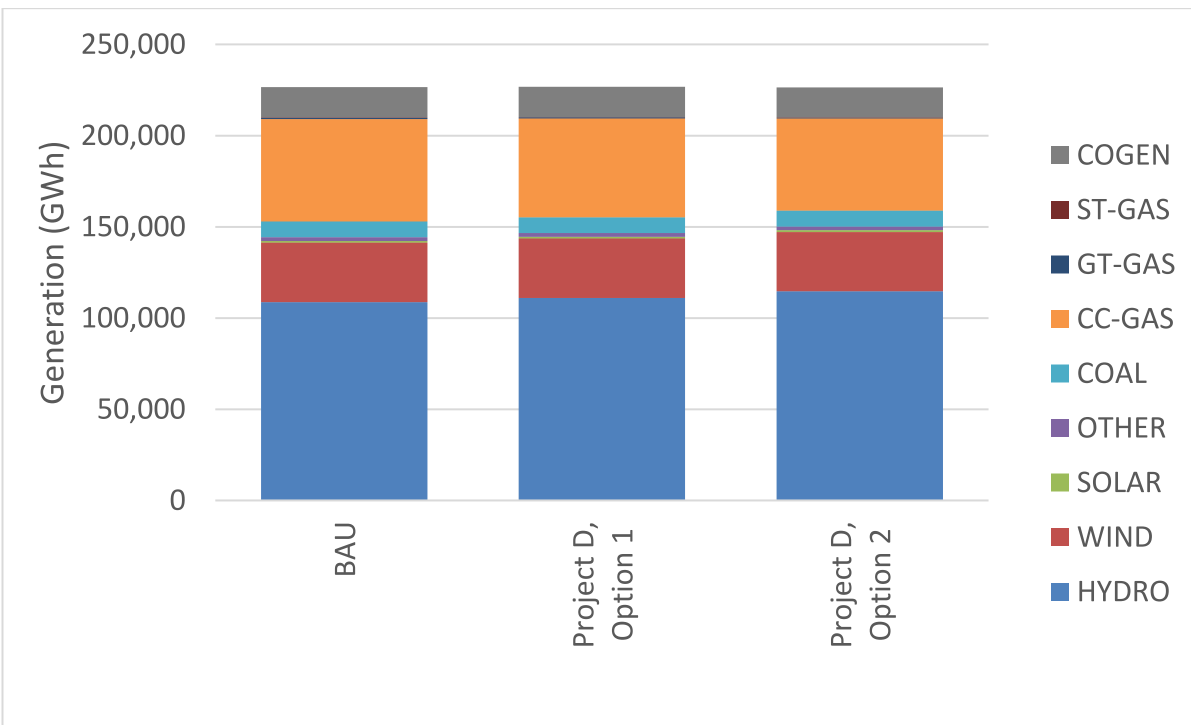


Figure 5-26: Project D - Total Generation by Type (2040)

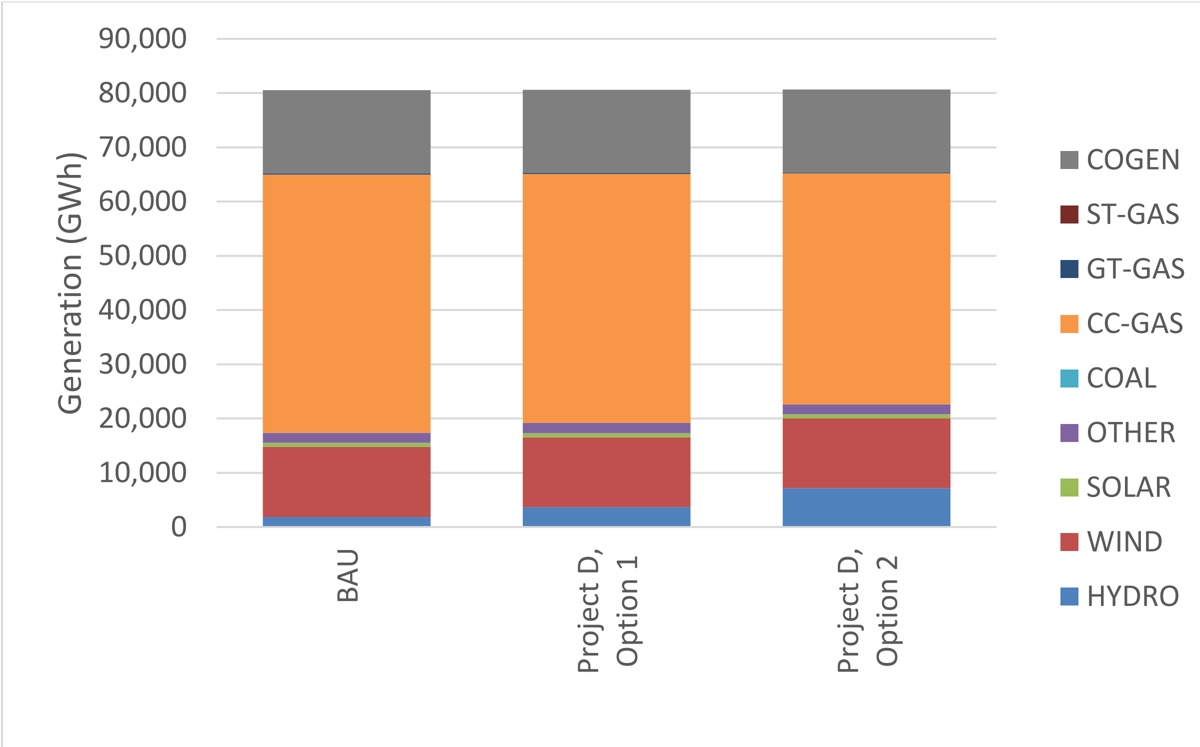


Figure 5-27: Project D - Alberta Generation by Type (2040)

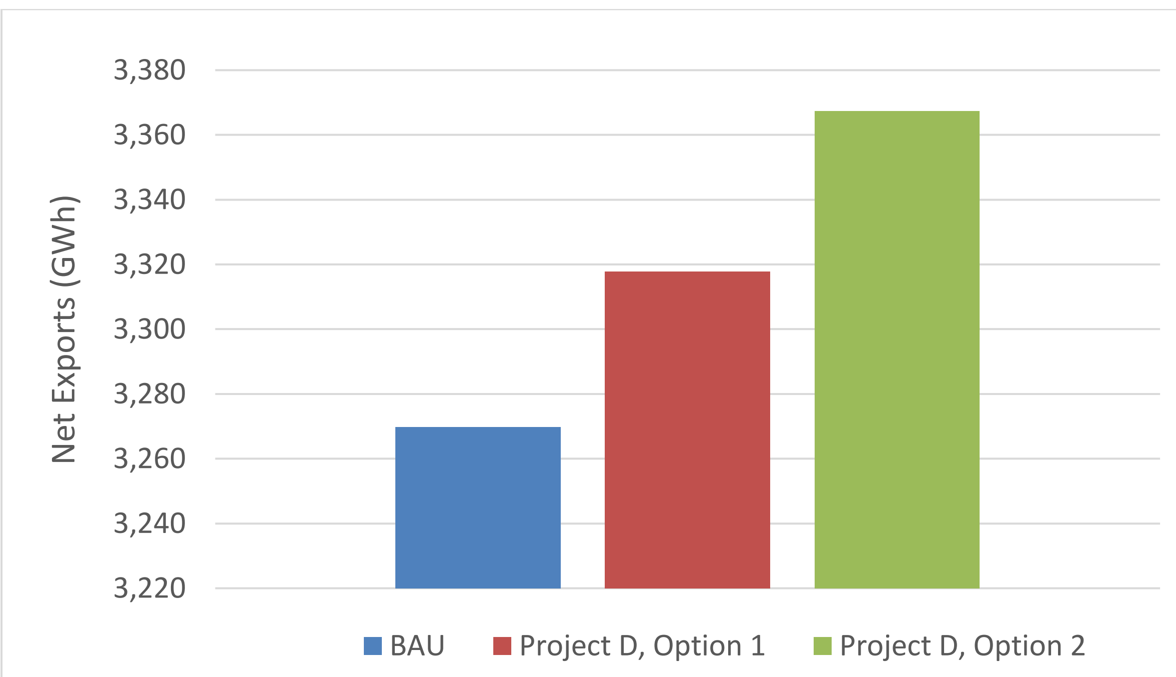


Figure 5-28: Project D - Alberta Net Exports (2040)

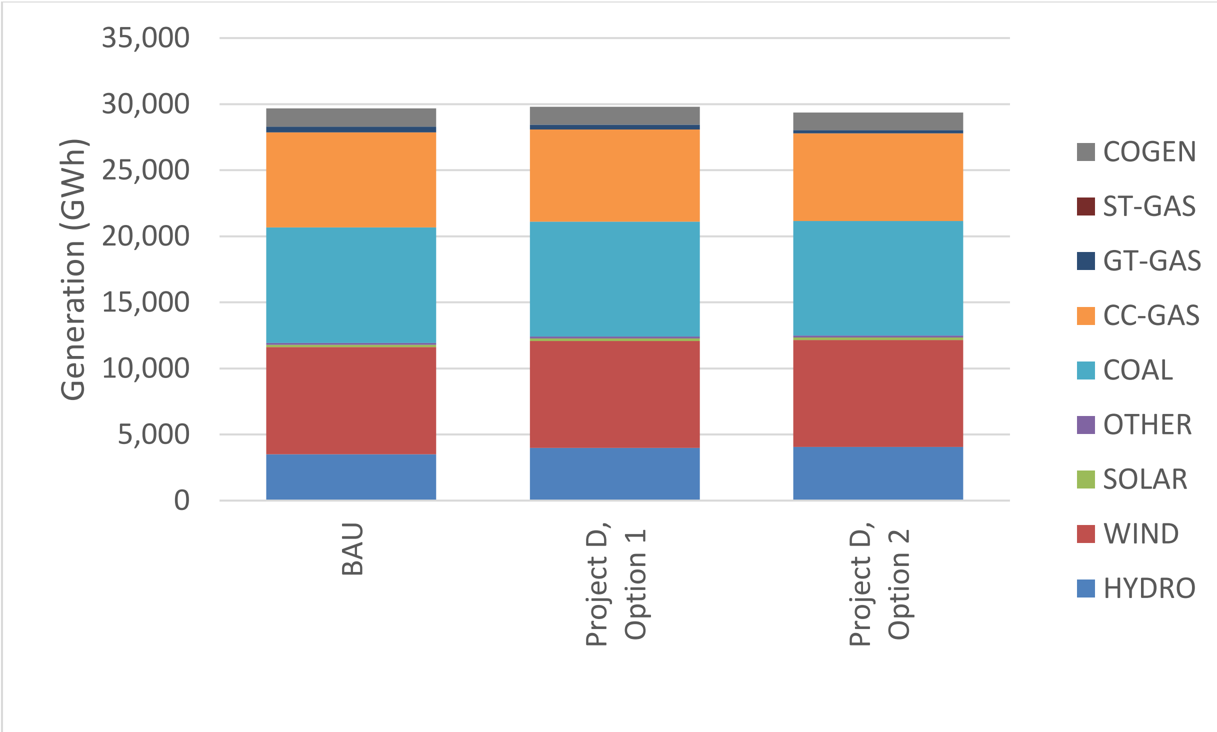


Figure 5-29: Project D - Saskatchewan Generation by Type (2040)

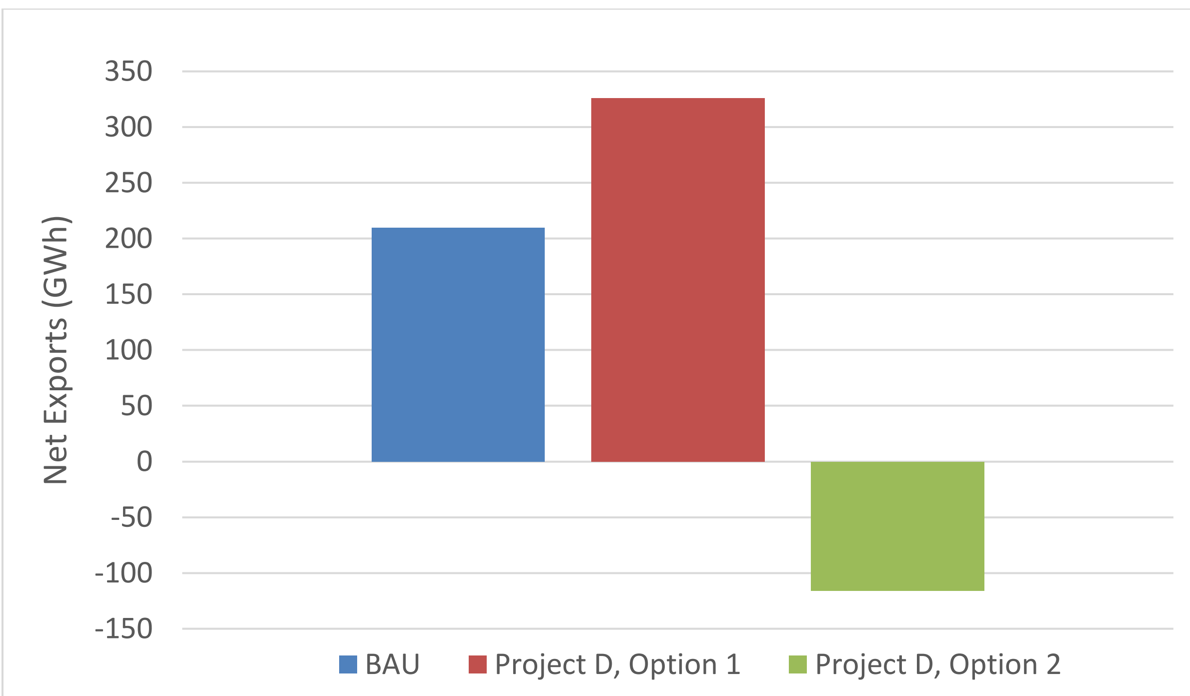


Figure 5-30: Project D - Saskatchewan Net Exports (2040)

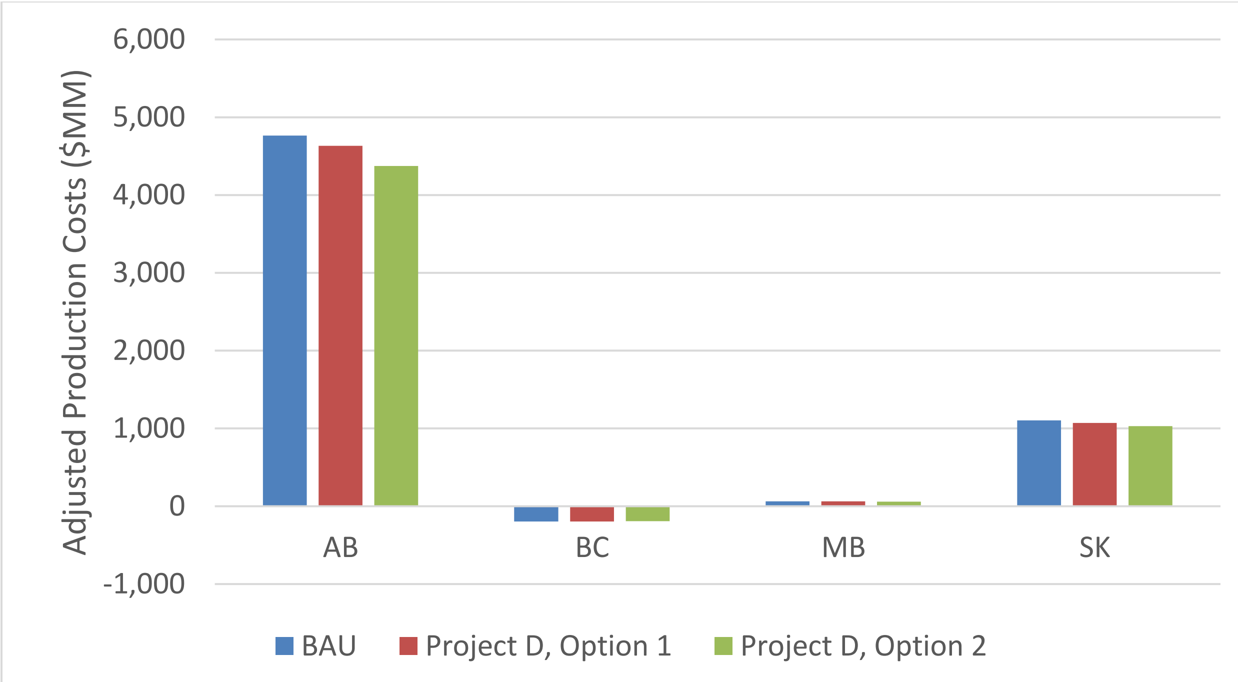


Figure 5-31: Project D - Adjusted Production Costs by Province (2040)

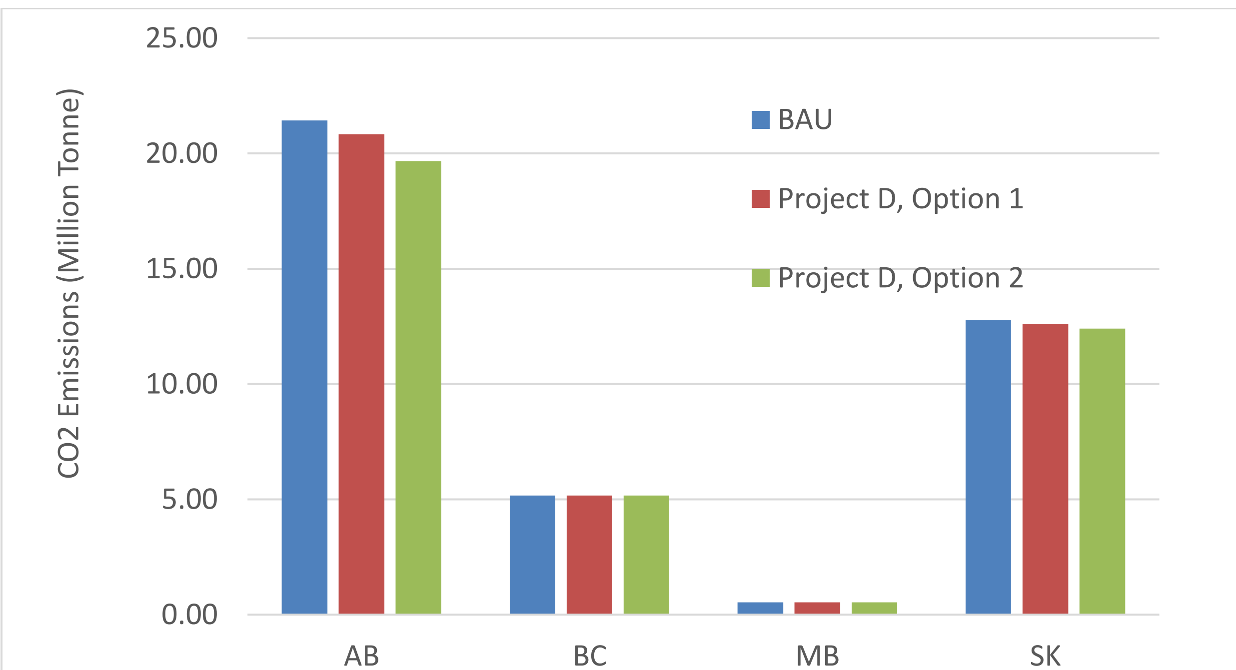


Figure 5-32: Project D - CO2 Emissions by Province (2040)

5.7 Evaluation of Project E

Project E: Coal conversion in Alberta and Saskatchewan to lower GHG emissions by 2030

Project E evaluates the impact of coal conversion in both Alberta and Saskatchewan independently. All together three options were considered as described below.

Following changes in the model were made in each of the options relative to the BAU case.

Project E – Option 1 - Alberta Scenario

- Converted the following units from Gas Fired generation (which were previously converted from COAL generation) into CC-GAS in 2030 (bringing forward the BAU's 2040 conversion date):
    - Genesee 1 & 2
    - Sheerness 1 & 2
    - Keephills 1 & 2
    - Sundance 3-6
    - Battle River 5

Project E – Saskatchewan Scenario

Option 1 - Carbon Capture Option

- Converted the following units to Carbon Capture & Sequestration (CCS):
    - Boundary Dam 6
    - Shand
    - Poplar Creek 1 & 2
- Reduced CO2 rate on these plants to capture approximately 90% of emissions
- Adjusted capacity, heat rate, and variable operation and maintenance costs on all units by scaling information provided by SaskPower on Shand

Option 2 - Combined Cycle Option

- Converted the units above to combined cycle
- Used Chinook CCGT assumptions (scaled appropriately) for each new CCGT unit.

The following charts provide an overview of the performance of power systems under the BAU case and each of the Project E options.

Key Observations

Alberta

- In Project E, CC-GAS become base generation and replaces Gas Fired generation (due to conversion of COAL to SC-GAS and COGEN).
- Coal to Gas Fired assets conversion and subsequent conversion to CC-GAS in AB results in the displacement of other Gas Fired generation, but also a higher level of generation by CC-GAS due to higher operational efficiency, which also results in displacement of some of the net-to-grid COGEN generation.
- There is still some ST-COAL in AB until the end of the year 2030 per AESO assumptions. The super-critical coal units Keephills 3 and Genesee 3 units will retire at the end of 2030 based on remaining life. All the rest of the ST-COAL are subject to conversion.
- Consequently, AB experiences a switch from being a net importer in the BAU case to a net exporter in Project E, with the assumed coal generation conversion scenario.
- Although AB becomes a net exporter in Project E, its Adjusted Production Cost is increased due to a much higher in-province generation. The main reason is that an average price is used for exports which may be underestimating the actual export prices, and hence, the additional export revenues are not compensating the increase in generation for exports.
- Additional in-province generation by CC-GAS, which is many times the amount of GT-GAS and COGEN generation that it displaces, results in higher CO2 emissions.

Saskatchewan

- All the ST-COAL generation reductions occur in SK, with 2030 drop caused by ST-COAL conversion to CCS, and with “Project E, AB > CC, SK > CCSs” and “Project E, AB > CC, SK > CC” drop due to ST-COAL conversion to CC-GAS.
- SK is a very small net exporter in the BAU case but becomes a net importer in Project E options due a small drop in SK total generation. As a result of higher import costs, SK experiences an increase in Adjusted Production Cost under each of the Project E options.
- The conversion of the ST-COAL units to CCS and to CC-GAS in SK results in reductions in CO2 emissions. However, since SK has higher imports under Option 1, its CO2 reductions is greater under Option 1.

Table 5-20: Project E - Generation

Project E Generation (GWh)	AB	BC	MB	SK	Total West	Total East
BAU	67,746	69,510	37,255	26,108	**137,256**	**63,363**
Project E, AB>CC, SK>CCS	75,714	69,169	37,214	25,753	**144,883**	**62,968**
Project E, AB>CC, SK>CC	75,714	69,169	37,250	25,919	**144,883**	**63,168**
Change from BAU						
Project E, AB>CC, SK>CCS	7,968	-341	-41	-354	**7,627**	**-395**
Project E, AB>CC, SK>CC	7,968	-341	-6	-189	**7,627**	**-195**

Table 5-21: Project E - Alberta Generation

AB Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	1,875	12,910	775	1,925	7,107	17,989	2,347	0	22,819	**67,746**
Project E	1,875	12,910	775	1,629	7,107	36,946	165	0	14,308	**75,714**
	1,875	12,910	775	1,629	7,107	36,946	165	0	14,308	**75,714**
Change from BAU										
Project E	0	0	0	-296	0	18,956	-2,182	0	-8,511	**7,968**

Table 5-22: Project E - Saskatchewan Generation

SK Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	3,335	7,995	184	133	8,108	3,814	109	0	2,430	**26,108**
Project E, AB>CC, SK>CCS	3,314	8,001	184	137	6,257	5,056	280	0	2,525	**25,753**
Project E, AB>CC, SK>CC	3,344	7,996	184	137	806	10,994	86	0	2,372	**25,919**
Change from BAU										
Project E, AB>CC, SK>CCS	-21	5	0	4	-1,851	1,242	172	0	95	**-354**
Project E, AB>CC, SK>CC	9	1	0	4	-7,303	7,180	-23	0	-58	**-189**

Table 5-23: Project E - Adjusted Production Costs

Adjusted Production Cost ($MM)	BAU	Project E, AB>CC, SK>CCSs	Project E, AB>CC, SK>CC
AB	3,165	3,281	3,281
BC	-187	-110	-110
MB	-75	-74	-76
SK	720	852	897
Total West	**2,978**	**3,171**	**3,171**
Total East	**646**	**777**	**821**
Change from BAU		**Project E, AB>CC, SK>CCSs**	**Project E, AB>CC, SK>CC**
AB		116	116
BC		77	77
MB		0	-1
SK		131	177
Total West		**194**	**193**
Total East		**132**	**176**

Table 5-24: Project E - Carbon Emissions

CO2 Emission (Million Tonne)	BAU	Project E, AB>CC, SK>CCS	Project E, AB>CC, SK>CC
AB	21.12	23.39	23.39
BC	5.40	5.25	5.25
MB	0.04	0.04	0.04
SK	11.32	4.43	5.26
Total West	**26.52**	**28.63**	**28.63**
Total East	**11.36**	**4.47**	**5.30**
Change from BAU		**Project E, AB>CC, SK>CCS**	**Project E, AB>CC, SK>CC**
AB		2.26	2.26
BC		-0.15	-0.15
MB		0.00	0.00
SK		-6.89	-6.06
Total West		**2.11**	**2.11**
Total East		**-6.89**	**-6.06**

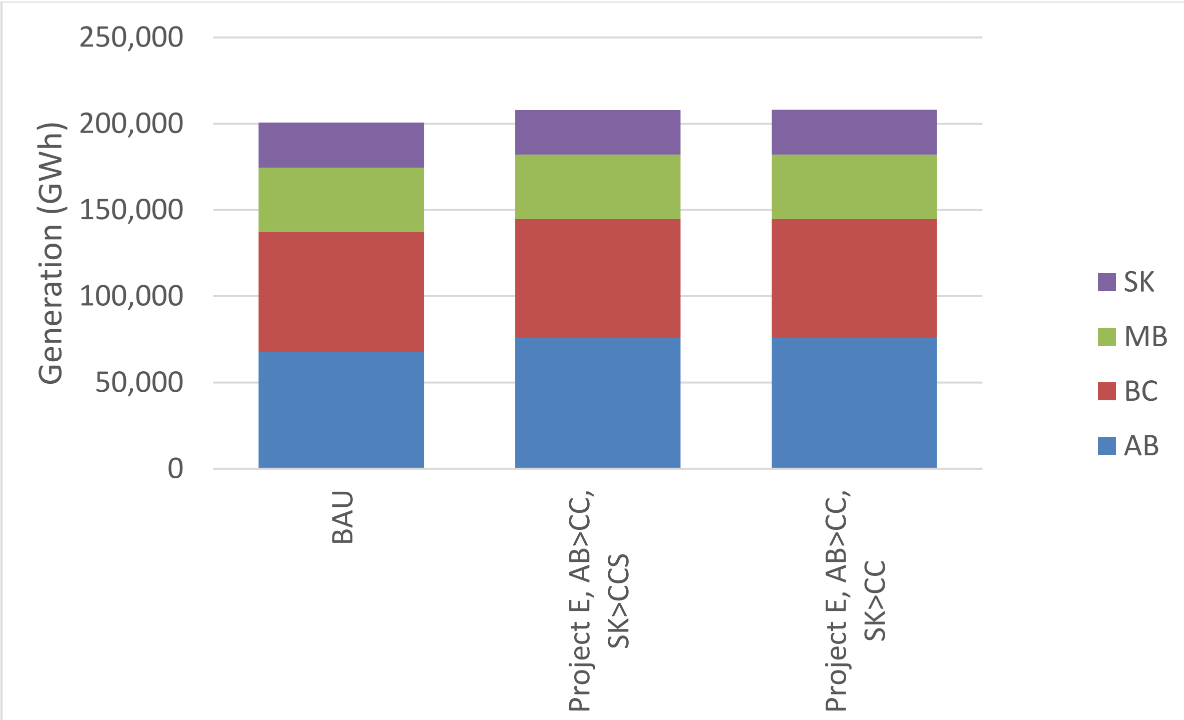


Figure 5-33: Project E - Total Generation by Province (2030)

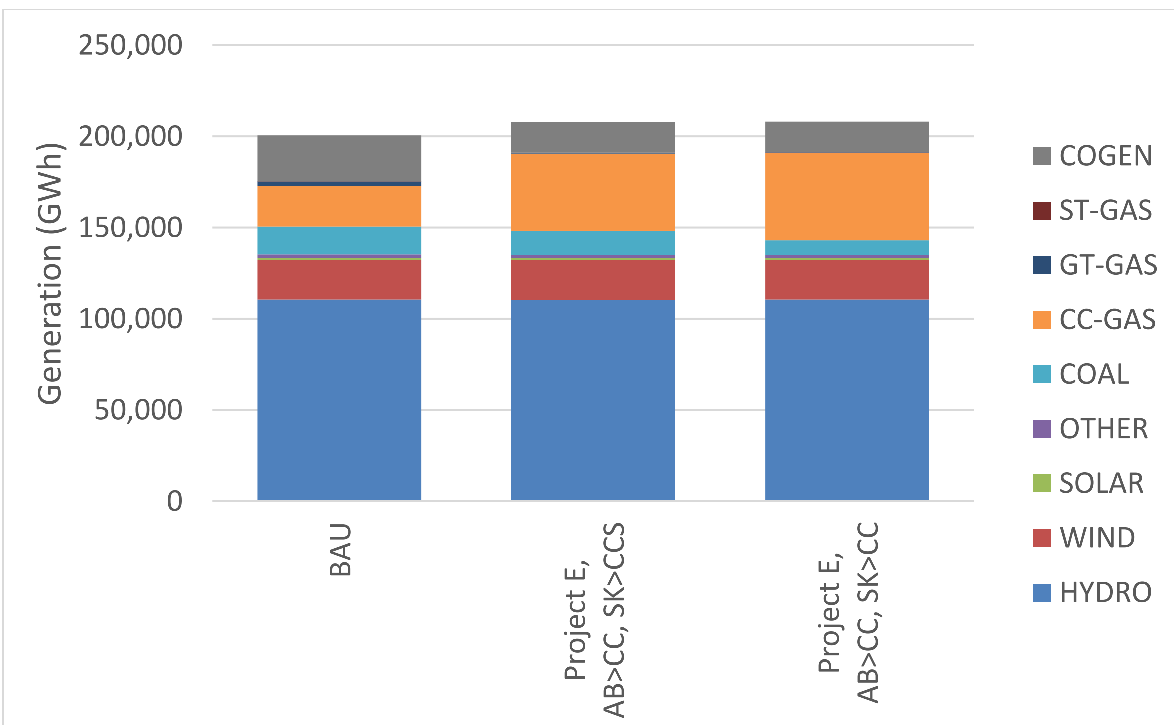


Figure 5-34: Project E - Total Generation by Type (2030)

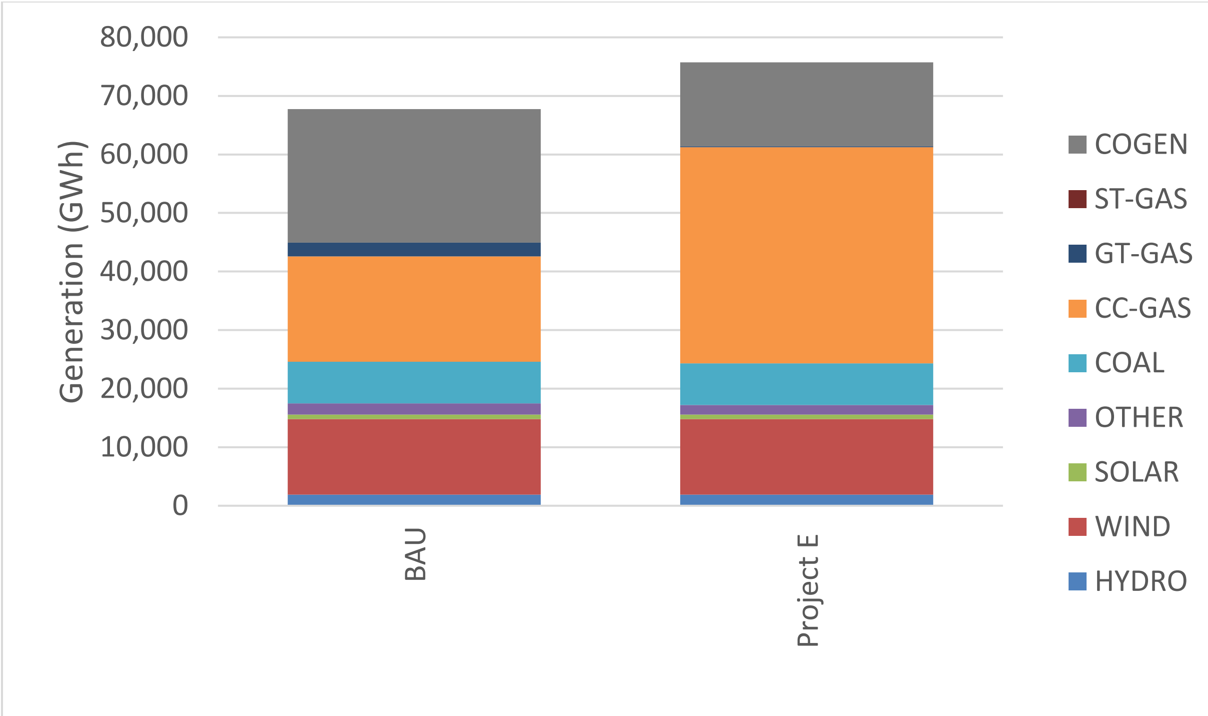


Figure 5-35: Project E - Alberta Generation by Type (2030)

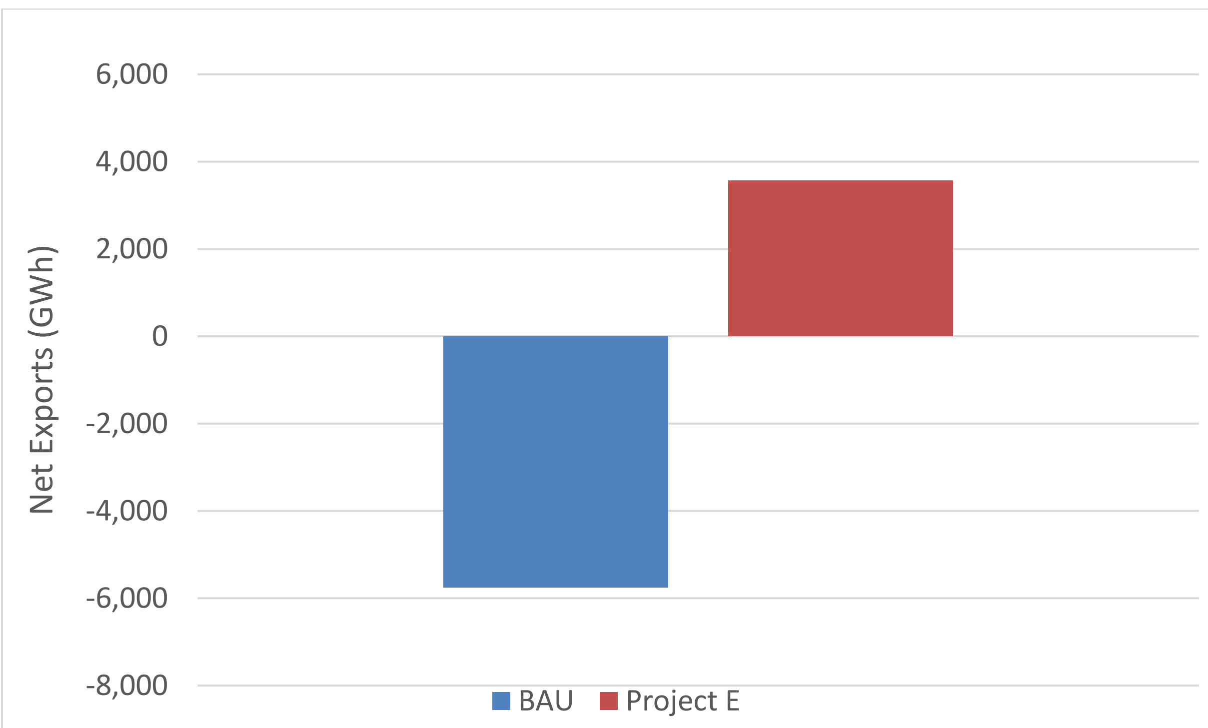


Figure 5-36: Project E - Alberta Net Exports (2030)

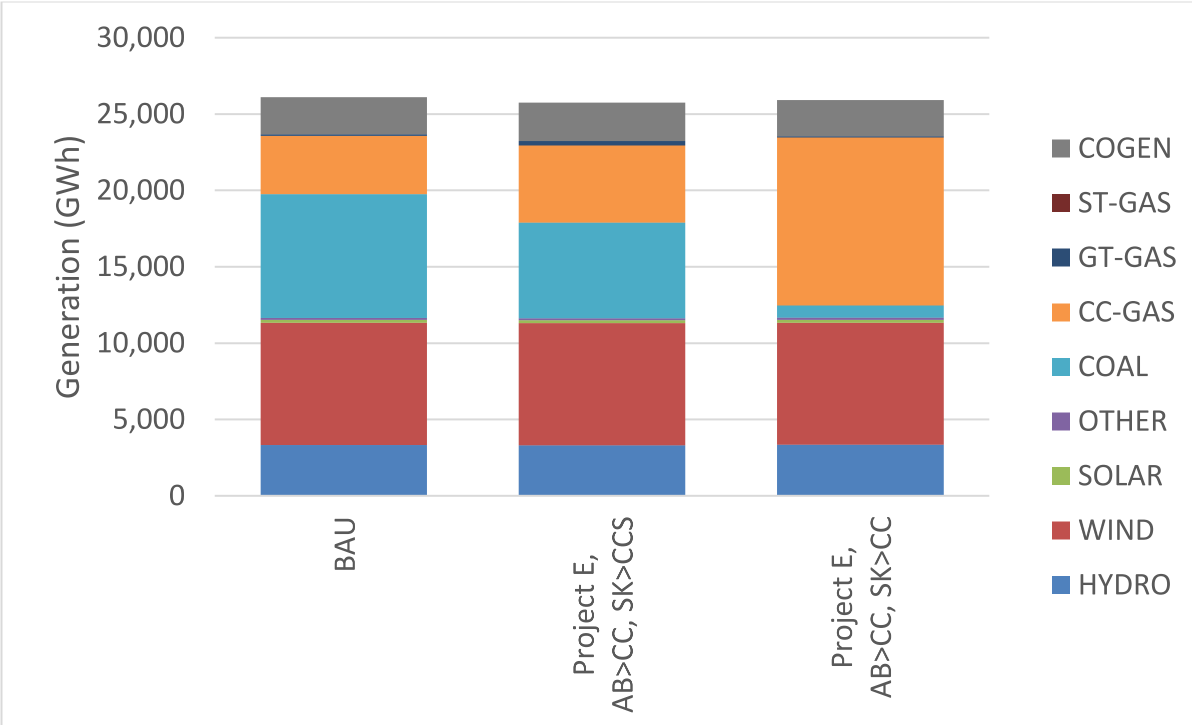


Figure 5-37: Project E - Saskatchewan Generation by Type (2030)

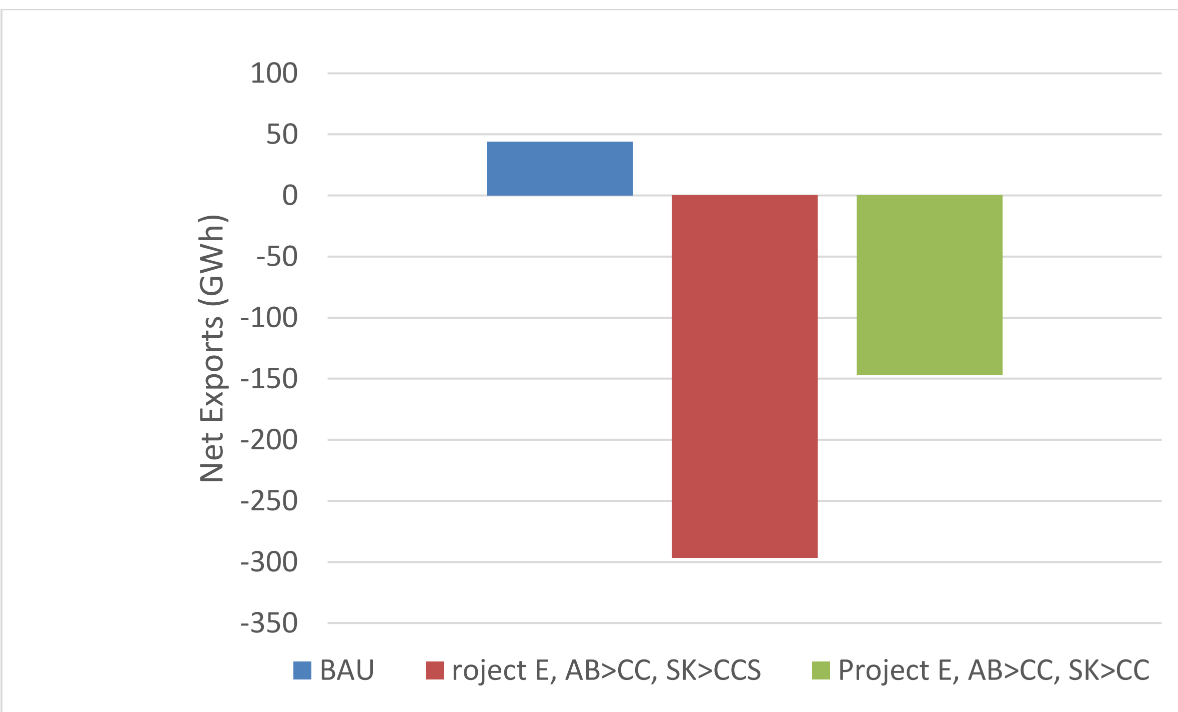


Figure 5-38: Project E - Saskatchewan Net Exports (2030)

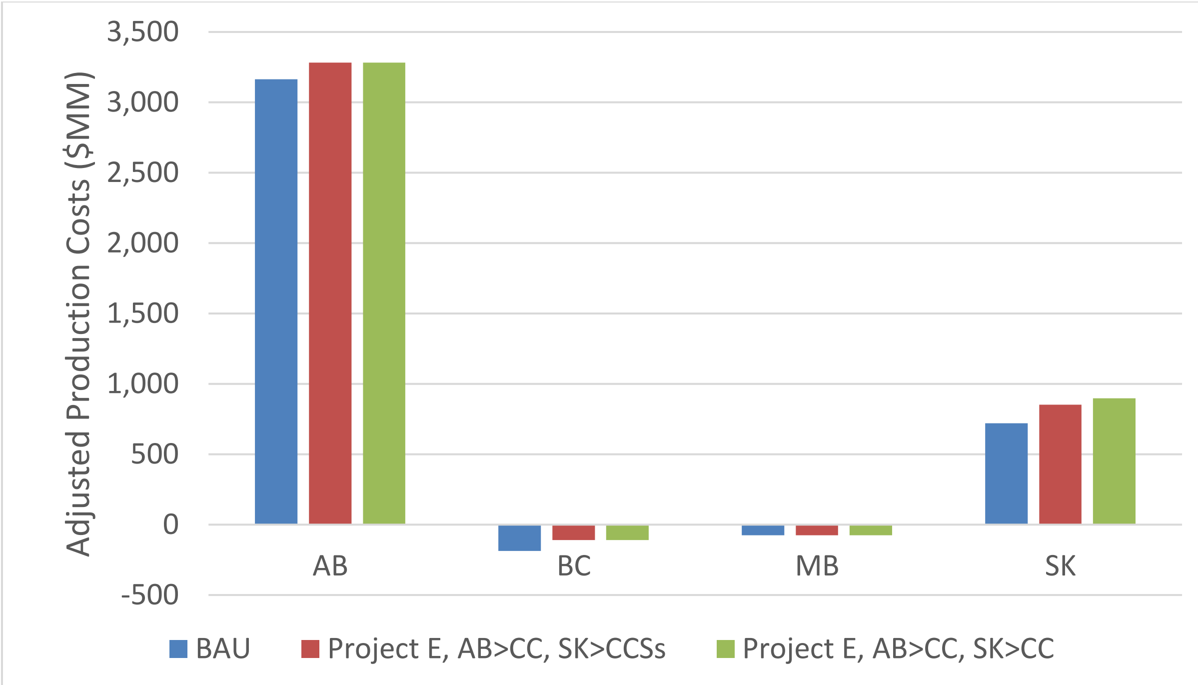


Figure 5-39: Project E - Adjusted Production Costs by Province (2030)

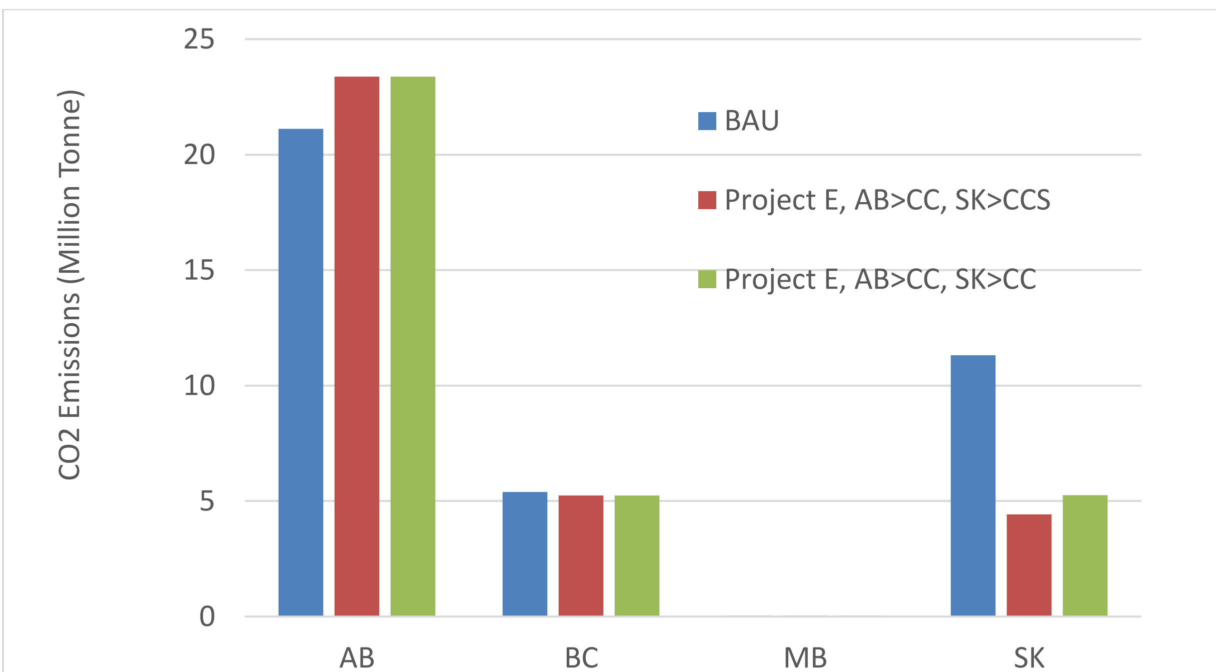


Figure 5-40: Project E - CO2 Emissions by Province (2030)

5.8 Evaluation of Project F

Project F: Bulk storage addition against value of new hydro or new transmission by 2030

Project F includes two scenarios as described below. Following additions were made in each of the options relative to the BAU case. For Alberta, geological salt deposits or saline aquifers are common throughout the province. Underground gas and oil storage facilities such as salt caverns or salt dome caverns have been used since the 1940's. AESO assumed that underground storage is technically feasible in Alberta for compressed air energy storage.

Project F – Alberta Scenario

- Per AESO's request the following storage projects were added. Capacity and efficiency were assumed based on internal AESO evaluation as follows:
  - Goose Lake, Compressed Air Energy Storage, 500MW, 77% efficiency, 160hr duration
  - Lethbridge, Compressed Air Energy Storage, 500MW, 77% efficiency, 160hr duration
  - Cordel, Compressed Air Energy Storage, 500MW, 77% efficiency, 160hr duration
- A 160-hour duration was assumed by AESO and included in the cost estimates for CAES.
- In AB, according to AESO, addition of bulk storage with the assumed locations and capacities would enable access to additional 2,400 MW of wind energy that would otherwise be curtailed. Hence, together with the storage additions, 2,400 MW of wind energy was added in AB.

Project F – Saskatchewan Scenario

- SaskPower requested that storage projects be placed at the 2 largest cities and for GE to select specifications they felt were appropriate.
  - Regina, Lithium Ion Battery, 200 MW, 90% efficiency, 4-hour duration
  - Saskatoon, Lithium Ion Battery, 200 MW, 90% efficiency, 4-hour duration
- Based on the urban location GE selected battery technology since it requires the least amount of space.
- Looking at the US DOE's Global Energy Storage Database (http://www.energystorageexchange.org), the most common form of battery storage

in operation in North America is Lithium Ion. The average duration of lithium ion batteries over 90 MW is 4 hrs.

- A current popular technology is Tesla, so we modelled the units using the parameters of their latest offering. (https://www.tesla.com/powerpack)

Following charts provide an overview of the performance of power systems under the BAU case and each of the Project F scenarios.

Key Observations

Alberta

- CAES was assumed to have a 77% round trip efficiency, and therefore, over the year more generation is required to compensate for the energy lost during CAES charge and discharge cycles.
- In addition to more wind generation, there is a small drop in GT-GAS and COGEN generation.
- The increased generation is also results in reducing the imports needs of AB. The combined effect of higher wind generation and reduced import is a drop in AB's Adjusted Production Cost. It should be noted that energy storage is both a consumer (during charging) and a producer (during discharging) of electric power and therefore, and depending on its roundtrip efficiency, its operation would contribute to higher production costs, which may be more than compensated by freeing up lower cost generation in the system.
- Addition of bulk storage results in higher wind generation and decreases the GT-GAS generation by about 50% causing reduction in CO2 emissions in AB.

Saskatchewan

- In SK, there were no wind additions complementing the energy storage additions, and therefore, the impact of energy storage on dispatch of other generation types was not very significant.
- It can be observed that there some minimal drop in total generation and displacement of some GT-GAS generation, which causes SK to change from a small net exporter of electricity in the BAU case to a very small net importer of electricity in Project F.
- As noted above, operation of energy storage would contribute to higher production costs, however due to its operational schedule, and the fact some lower cost imports may be displacing the other generation types, there is drop in SK's ACP.

- The mix of generation whose dispatch would be impacted by energy storage would depend on the time of day when storage is getting charged and when it is discharging energy. For instance, charging at night may results in higher usage of coal generation in SK. For instance, in SK, coal-based generation is increases by about 440 GWh in Project F.
- The impact of higher coal generation in SK in Project F is a slightly higher emission of CO2 in SK relative to the BAU case.

Table 5-25: Project F – Generation by Province

Project F Generation (GWh)	AB	BC	MB	SK	Total West	Total East
BAU	67,746	69,510	37,255	26,108	**137,256**	**63,363**
Project F	70,352	69,412	37,270	26,052	**139,763**	**63,322**
Change from BAU						
Project F	2,606	-98	15	-56	**2,507**	**-41**

Table 5-26: Project F - Alberta Generation

AB Generation (GWh)	STORAGE	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	0	1,875	12,910	775	1,925	7,107	17,989	2,347	0	22,819	**67,746**
Project F	-467	1,875	20,814	775	1,839	7,107	16,759	1,171	0	20,480	**70,352**
Change from BAU											
Project F	-467	0	7,904	0	-86	0	-1,231	-1,176	0	-2,339	**2,606**

Table 5-27: Project F - Saskatchewan Generation

SK Generation	STORAGE	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	0	3,335	7,995	184	133	8,108	3,814	109	0	2,430	**26,108**
Project F	-47	3,347	8,021	183	138	8,540	3,428	32	0	2,408	**26,052**
Change from BAU											
Project F	-47	12	26	0	5	432	-386	-77	0	-22	**-56**

Table 5-28: Project F - Adjusted Production Costs

Adjusted Production Costs ($MM)	BAU	Project F
AB	3,165	2,751
BC	-187	-142
MB	-75	-74
SK	720	686
Total West	**2,978**	**2,609**
Total East	**646**	**611**
Change from BAU		**Project F**
AB		-414
BC		45
MB		0
SK		-35
Total West		**-369**
Total East		**-34**

Table 5-29: Project F - Carbon Emissions

CO2 Emissions (Million Tonne)	BAU	Project F
AB	21.12	19.29
BC	5.40	5.36
MB	0.04	0.04
SK	11.32	11.53
Total West	**26.52**	**24.64**
Total East	**11.36**	**11.57**
Change from BAU		**Project F**
AB		-1.84
BC		-0.04
MB		0.00
SK		0.21
Total West		**-1.88**
Total East		**0.21**

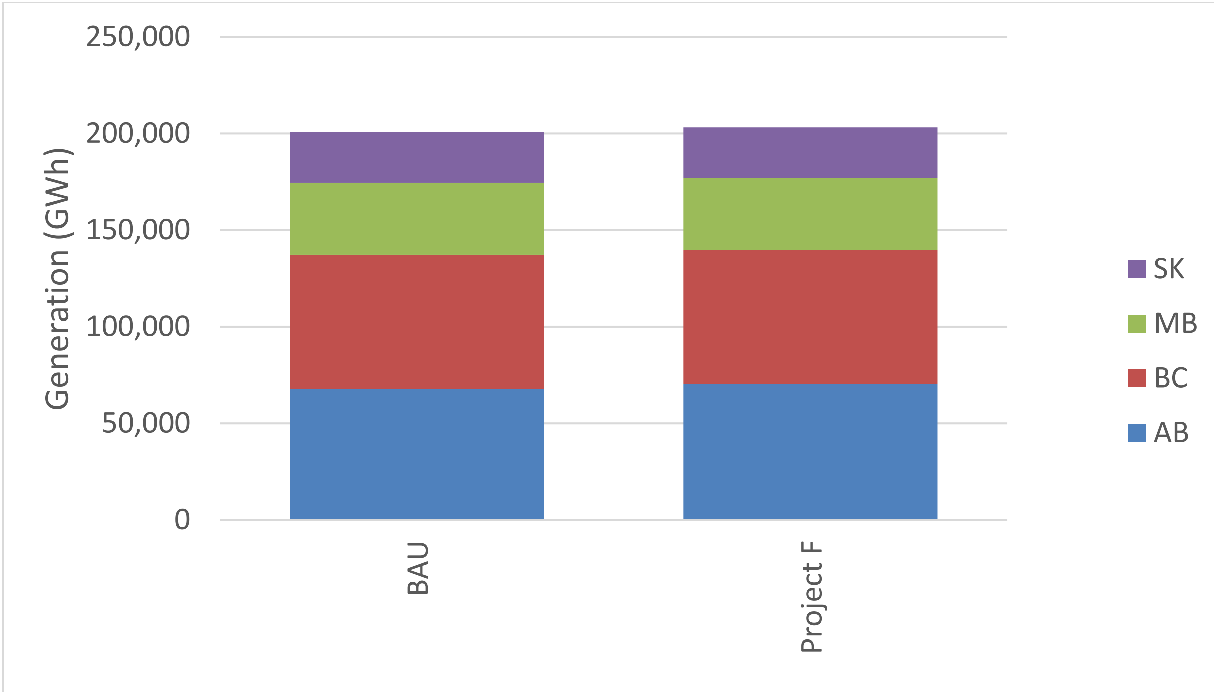


Figure 5-41: Project F - Total Generation by Province (2030)

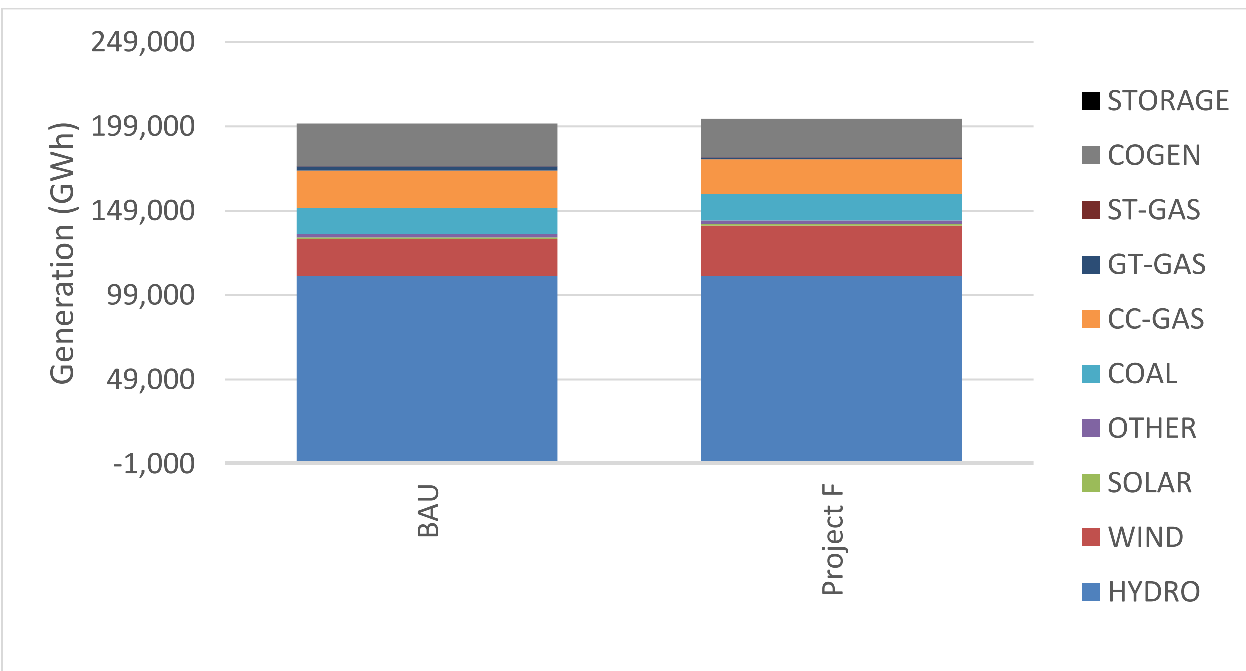


Figure 5-42: Project F - Total Generation by Type (2030)

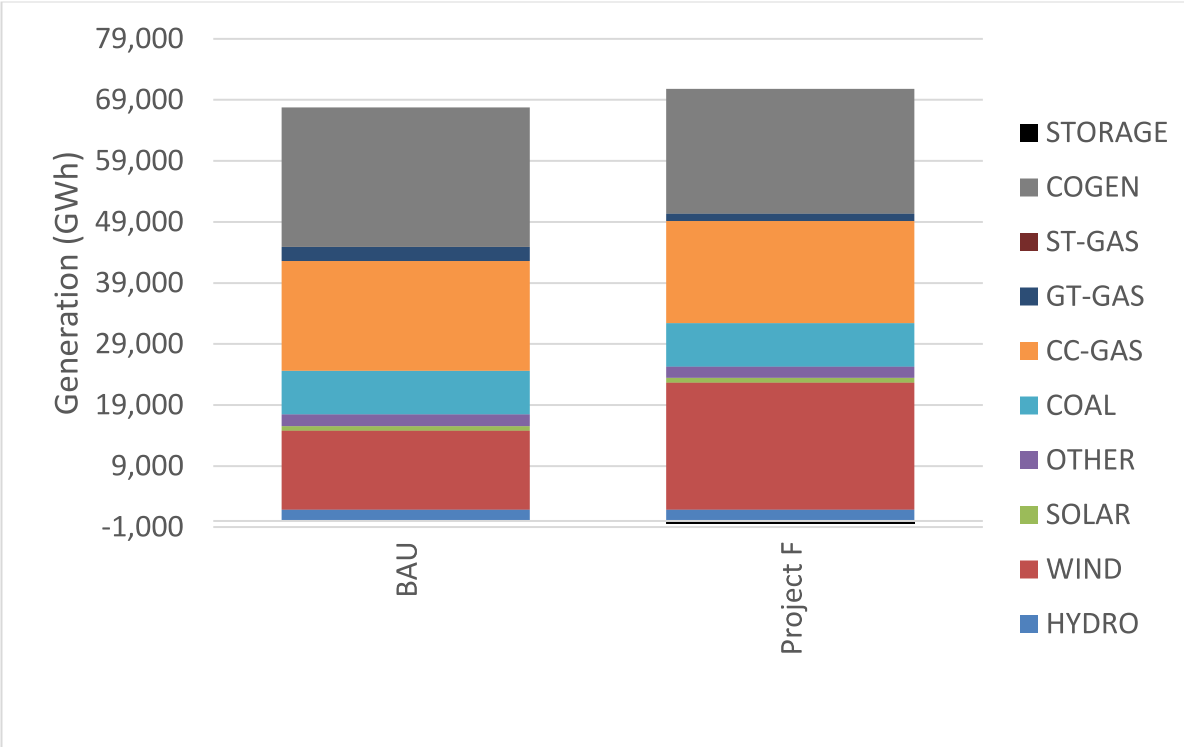


Figure 5-43: Project F - Alberta Generation by Type (2030)

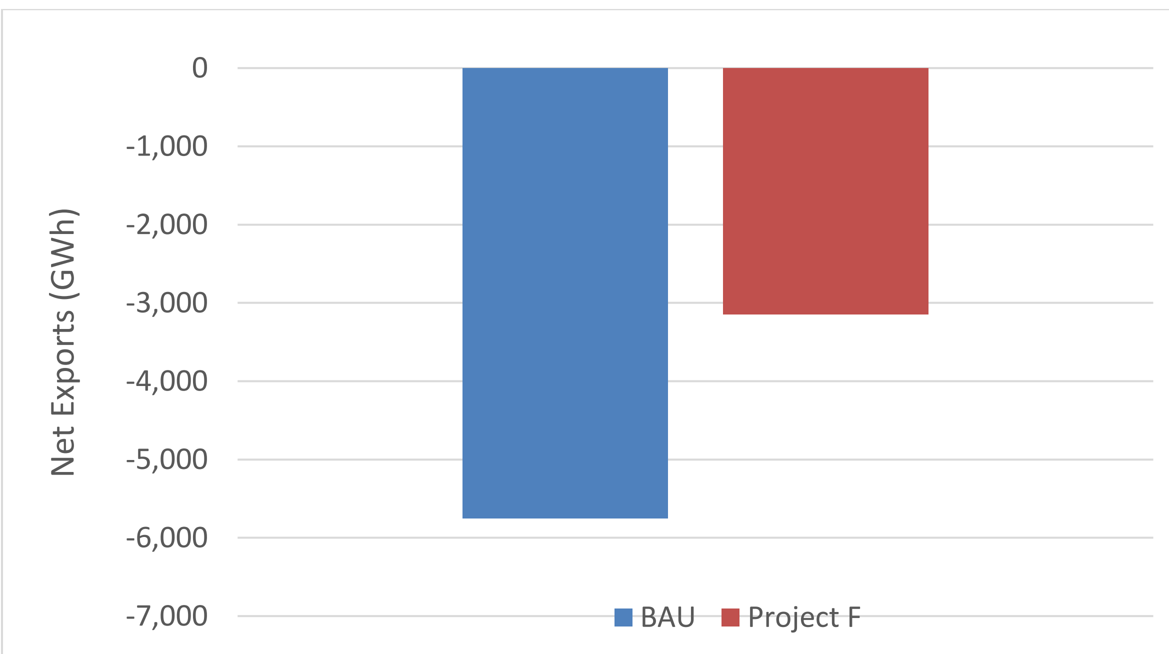


Figure 5-44: Project F - Alberta Net Exports (2030)

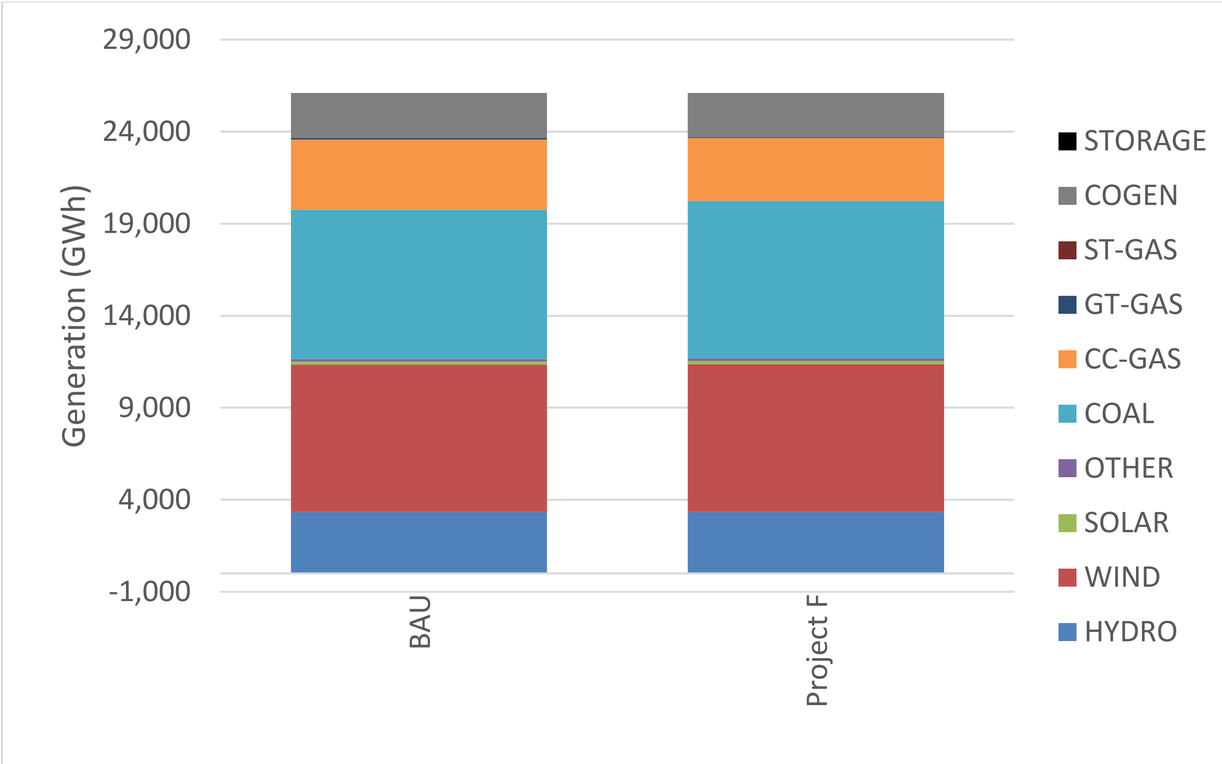


Figure 5-45: Project F - Saskatchewan Generation by Type (2030)

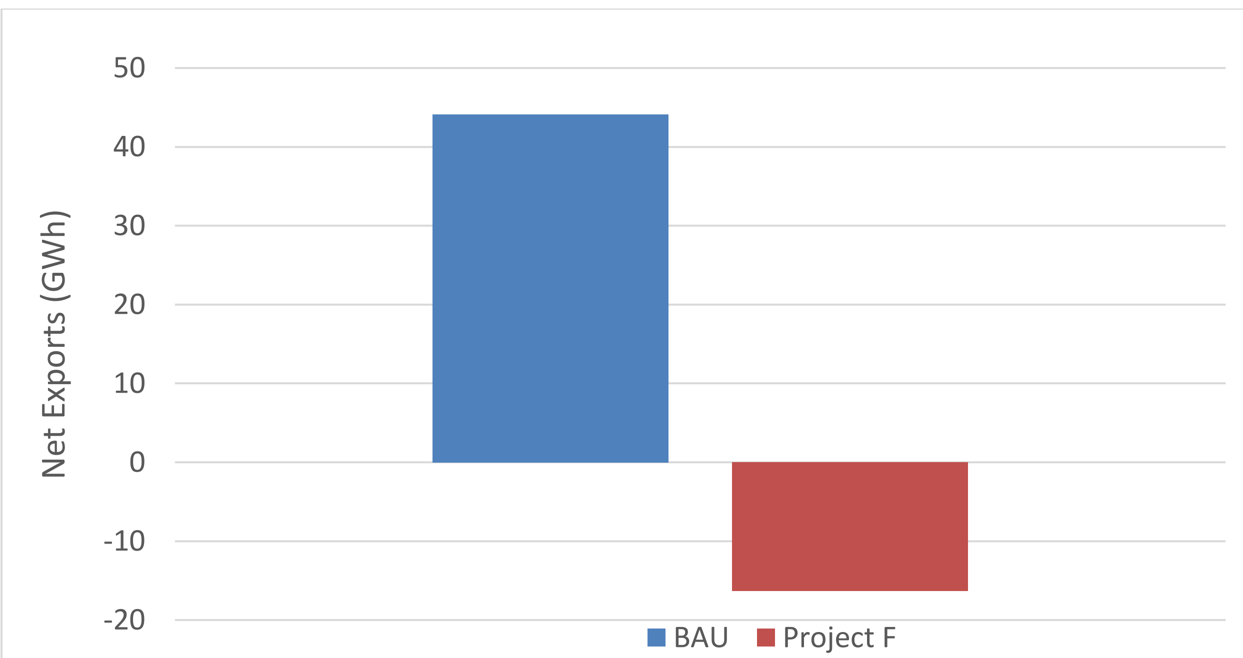


Figure 5-46: Project F - Saskatchewan Net Exports (2030)

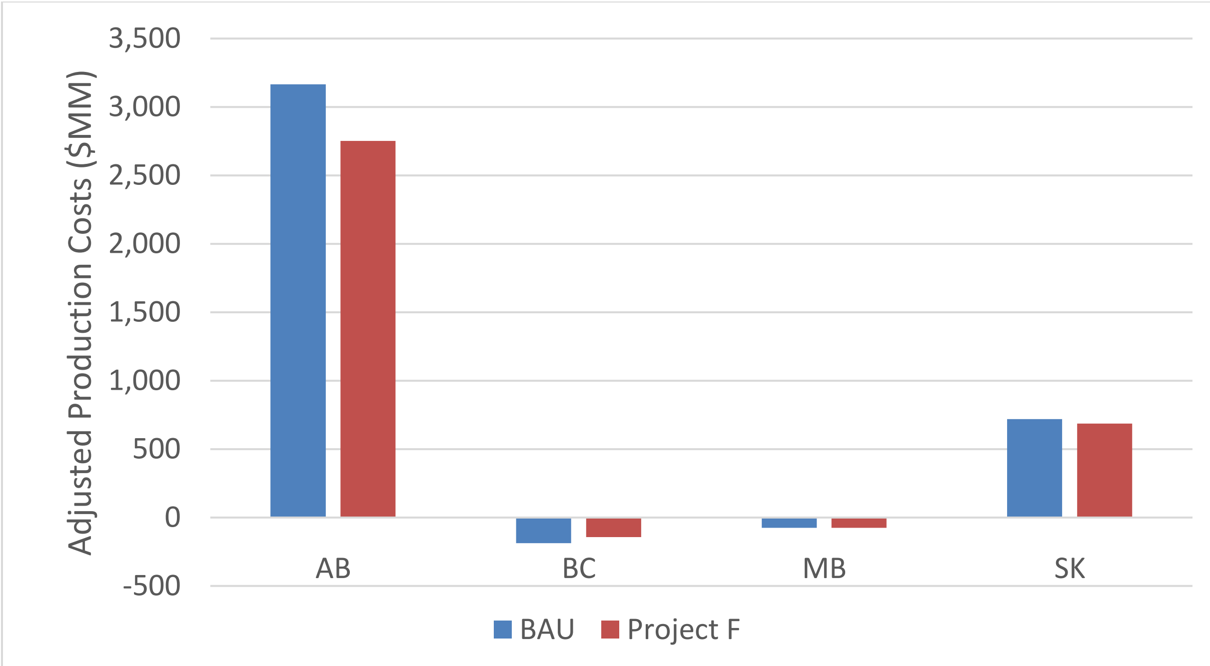


Figure 5-47: Project F - Adjusted Production Costs by Province (2030)

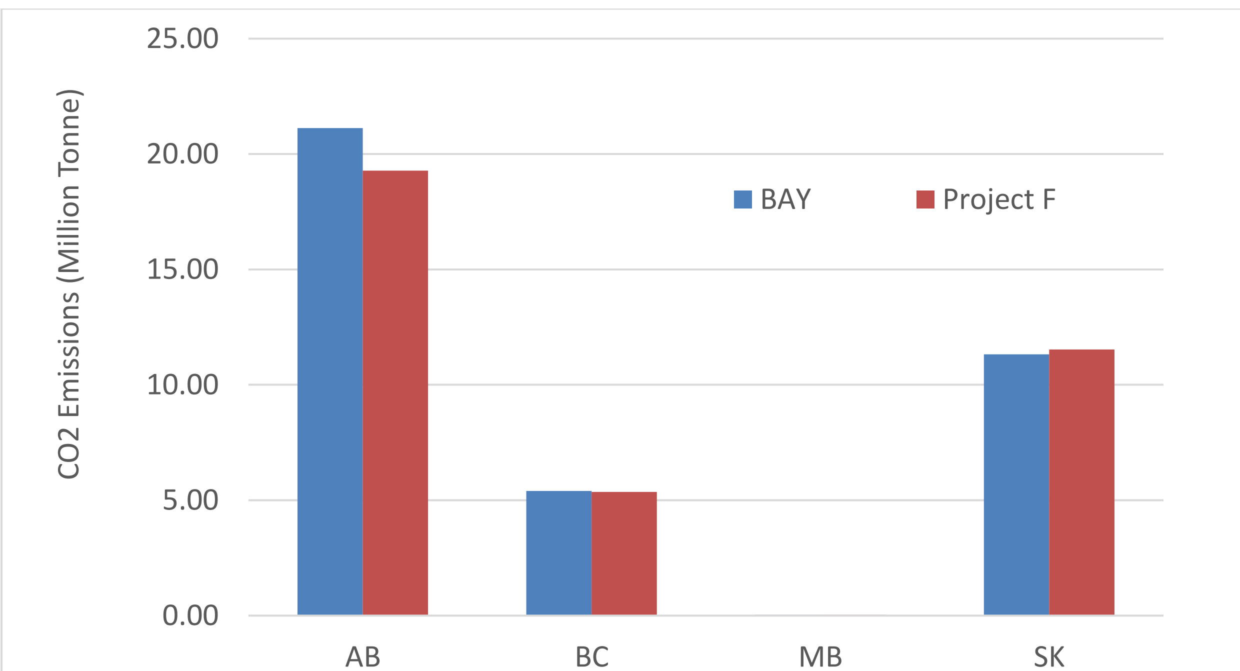


Figure 5-48: Project F - CO2 Emissions by Province (2030)

5.9 Evaluation of Project G

Project G: Electrification of LNG and Natural Gas Production by 2030

Project G involves replacing gas-turbine driven compressors which use locally available natural gas, to meet off-grid load, with clean power from BC's grid. There are four options as described below.

The environmental emissions for the original off-grid gas turbines (based on the equivalent of1,200 MW and 10,000 GWh of load) were accounted for in the BAU case and also in all the emission data of the Study Projects. The emissions in Project G are then adjusted by displacement of the off-grid emissions by any estimated grid-based emissions.

Following additions were made in each of the options relative to the BAU case.

Project G – Option 1

- Peace Region Electricity Supply, 600 MW, 5,000 GWh, located at SBK substation

Project G - Option 2

- Option 1 & BMT-DAW Voltage Conversion, 800 MW, 6,700 GWh, located at SBK substation

Project G – Option 3

- Prince George to Terrace Capacitors Project and other regional upgrade to supply, 500 MW, 4,100 GWh, located at MIN substation

Project G – Option 4

- Option 3 & New 500 kV line form Prince George to Terrace and two 500 kV lines from Terrace to Prince Rupert, 1,200 MW, 10,000 GWh, located at RUP substation

➢ Added proposed renewable generation and pumped storage hydro to accommodate the new load.

Following charts provide an overview of the performance of power systems under the BAU case and Project G.

Key Observations

British Columbia

- In all the Project G options, connecting the off-grid loads to the BC Hydro grid, which were formerly serviced by on-site gas turbines, results in increased grid-based generation in BC.

- Additional generation is mainly due to the additional wind that was added, together with pumped storage hydro units, to maintain reserve margins.
- Additional load on the BC grid results in lowering BC exports in all the Project G options relative to the BAU case.
- The impact on the Adjusted Production Cost of BC is minimal, mainly because wind is assumed to produce zero cost energy. The cost of wind and pumped storage hydro is captured as annual capital costs.
- The move from on-site natural gas turbines to grid-based generation (mostly renewable in BC) results in cutting the CO_2 emissions in BC.

Table 5-30: Project G - British Columbia Generation

BC Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	68,988	0	0	0	0	522	0	0	0	**69,510**
Project G, Option 1	69,181	4,794	0	0	0	490	0	0	0	**74,465**
Project G, Option 2	69,131	6,470	0	0	0	498	0	0	0	**76,100**
Project G, Option 3	69,185	3,875	0	0	0	499	0	0	0	**73,559**
Project G, Option 4	68,991	9,759	0	0	0	477	0	0	0	**79,227**
Change from BAU										
Project G, Option 1	193	4,794	0	0	0	-32	0	0	0	**4,955**
Project G, Option 2	143	6,470	0	0	0	-24	0	0	0	**6,590**
Project G, Option 3	197	3,875	0	0	0	-23	0	0	0	**4,049**
Project G, Option 4	3	9,759	0	0	0	-45	0	0	0	**9,717**

Table 5-31: Project G - Alberta Generation

Alberta Gen	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	1,875	12,910	775	1,925	7,107	17,989	2,347	0	22,819	**67,746**
Project G, Option 1	1,875	12,910	775	1,927	7,107	17,995	2,353	0	22,824	**67,764**
Project G, Option 2	1,875	12,910	775	1,926	7,107	17,987	2,346	0	22,824	**67,749**
Project G, Option 3	1,875	12,910	775	1,926	7,107	17,994	2,352	0	22,825	**67,763**
Project G, Option 4	1,875	12,910	775	1,933	7,107	17,980	2,333	0	22,819	**67,730**
Change from BAU										
Project G, Option 1	0	0	0	2	0	5	6	0	5	**18**
Project G, Option 2	0	0	0	1	0	-2	-1	0	5	**3**
Project G, Option 3	0	0	0	1	0	5	5	0	6	**17**
Project G, Option 4	0	0	0	8	0	-10	-15	0	0	**-16**

Table 5-32: Project G - Adjusted Production Costs

Adjusted Production Costs ($MM)	BAU	Project G Option 1	Project G Option 2	Project G Option 3	Project G Option 4
AB	3,165	3,166	3,165	3,166	3,162
BC	-187	-189	-188	-188	-187
Total West	**2,978**	**2,977**	**2,977**	**2,978**	**2,975**
Change from BAU					
AB		1	0	1	-3
BC		-2	-1	-1	0
Total West		**-1**	**-1**	**0**	**-3**

Table 5-33: Project G - Carbon Emissions

CO2 Carbon Emissions (Million Tonne)	BAU	Project G, Option 1	Project G, Option 2	Project G, Option 3	Project G, Option 4
AB	21.12	21.13	21.12	21.13	21.11
BC	5.40	2.80	1.93	3.27	0.21
Total West	**26.52**	**23.93**	**23.05**	**24.40**	**21.33**
Change from BAU					
AB		0.01	0.00	0.01	-0.01
BC		-2.60	-3.47	-2.13	-5.19
Total West		**-2.59**	**-3.47**	**-2.12**	**-5.20**

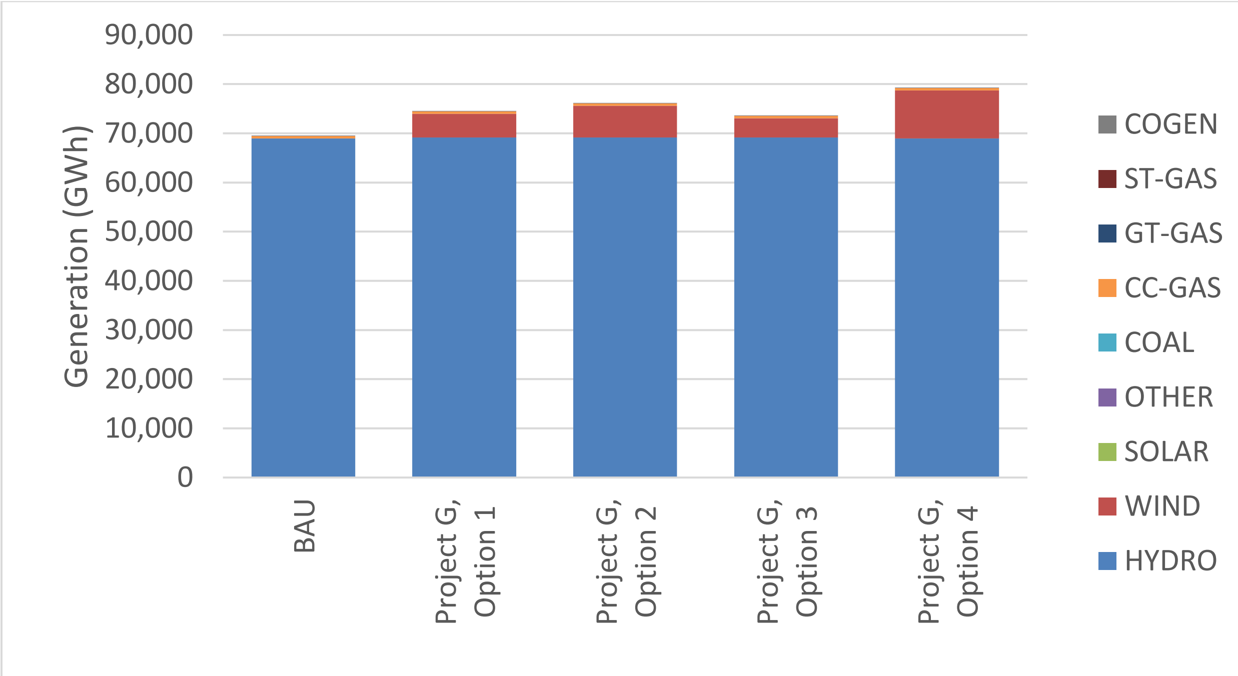


Figure 5-49: Project G - British Columbia Generation by Type (2030)

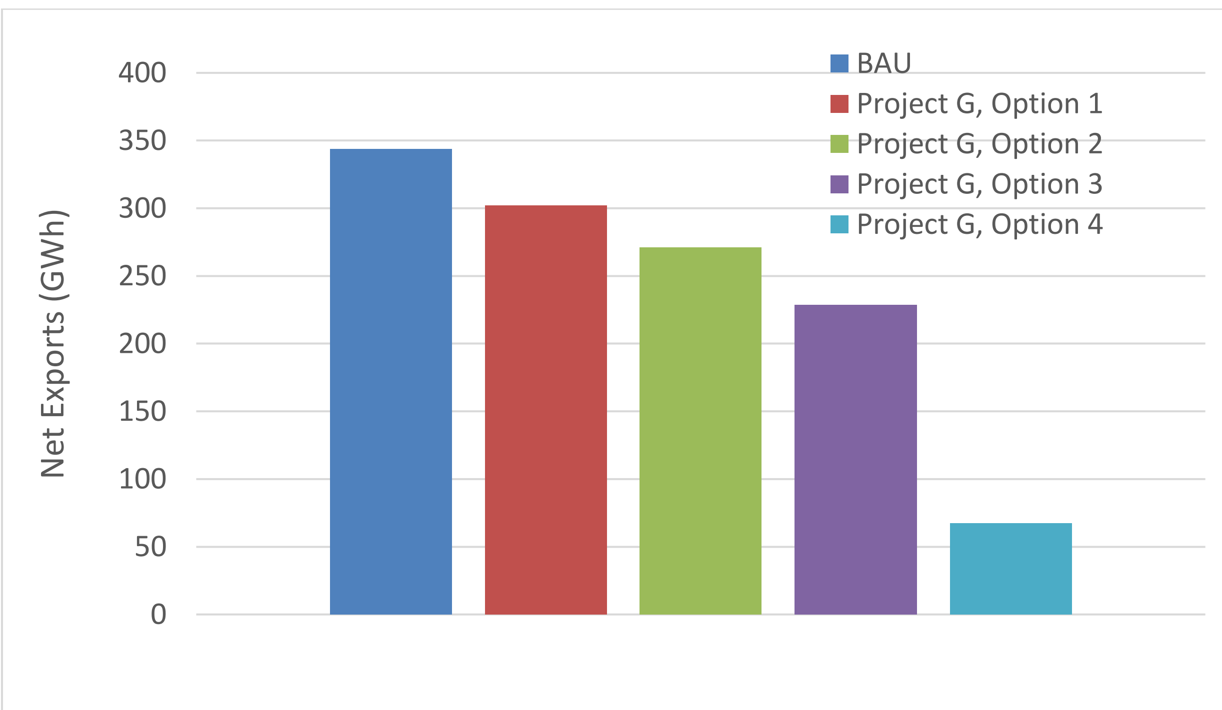


Figure 5-50: Project G - British Columbia Net Exports (2030)

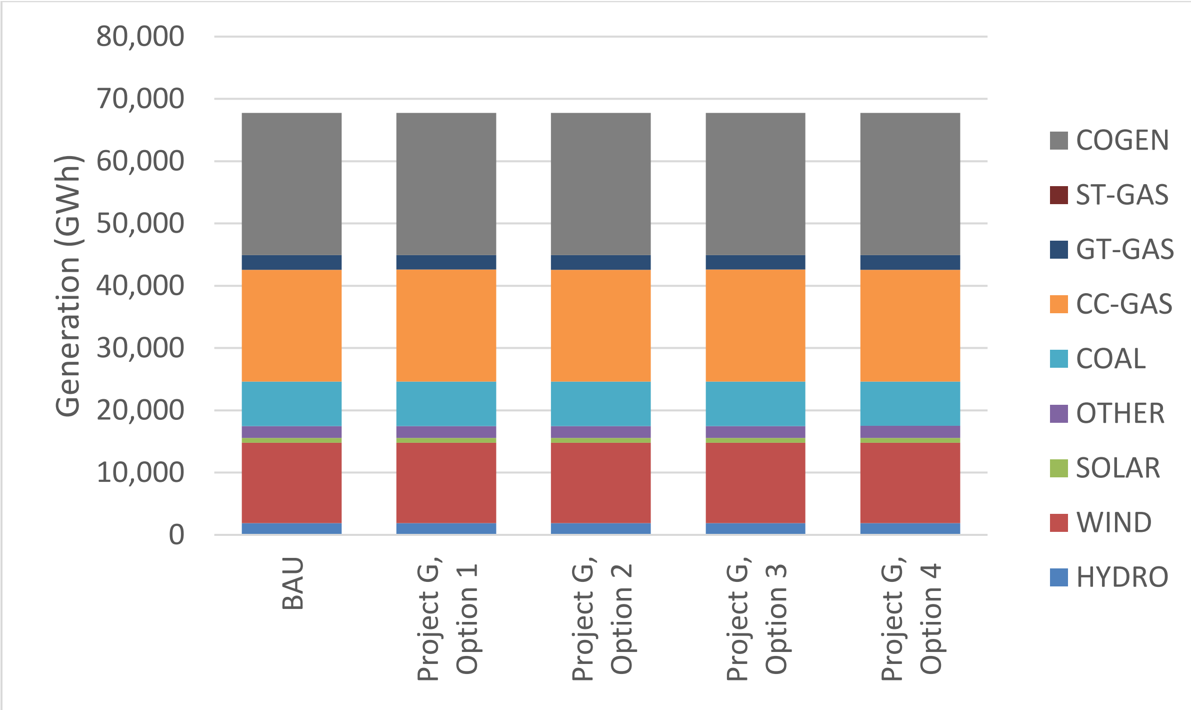


Figure 5-51: Project G - Alberta Generation by Type (2030)

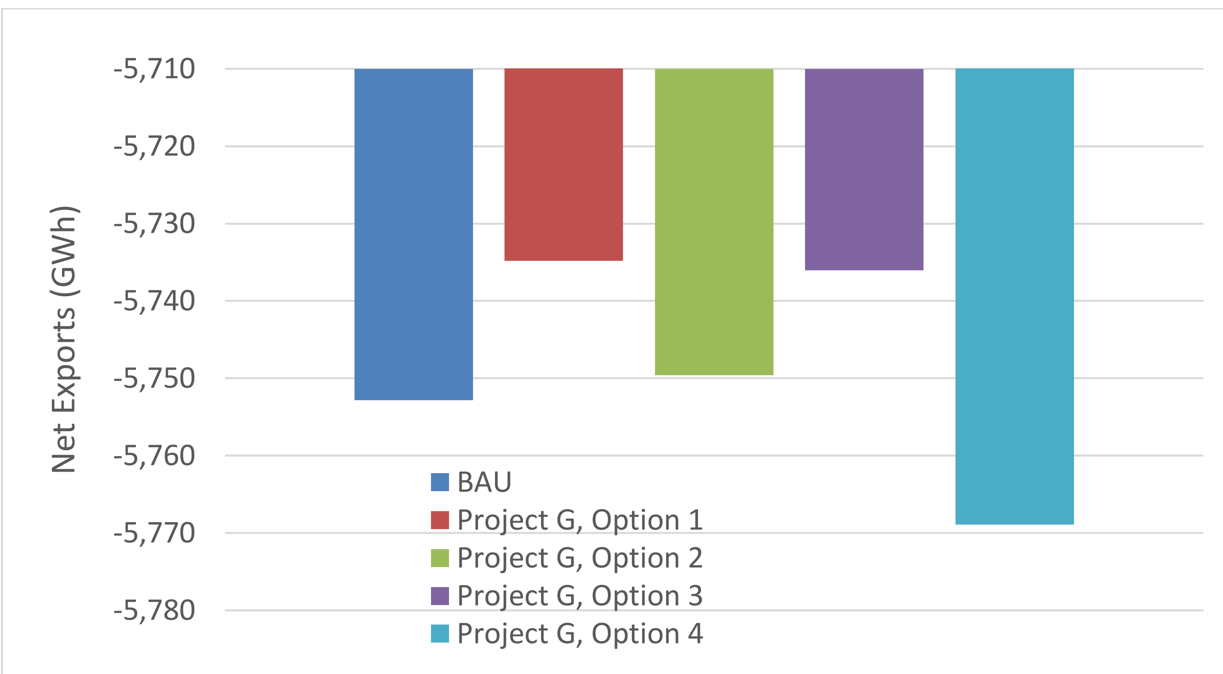


Figure 5-52: Project G - Alberta Net Exports (2030)

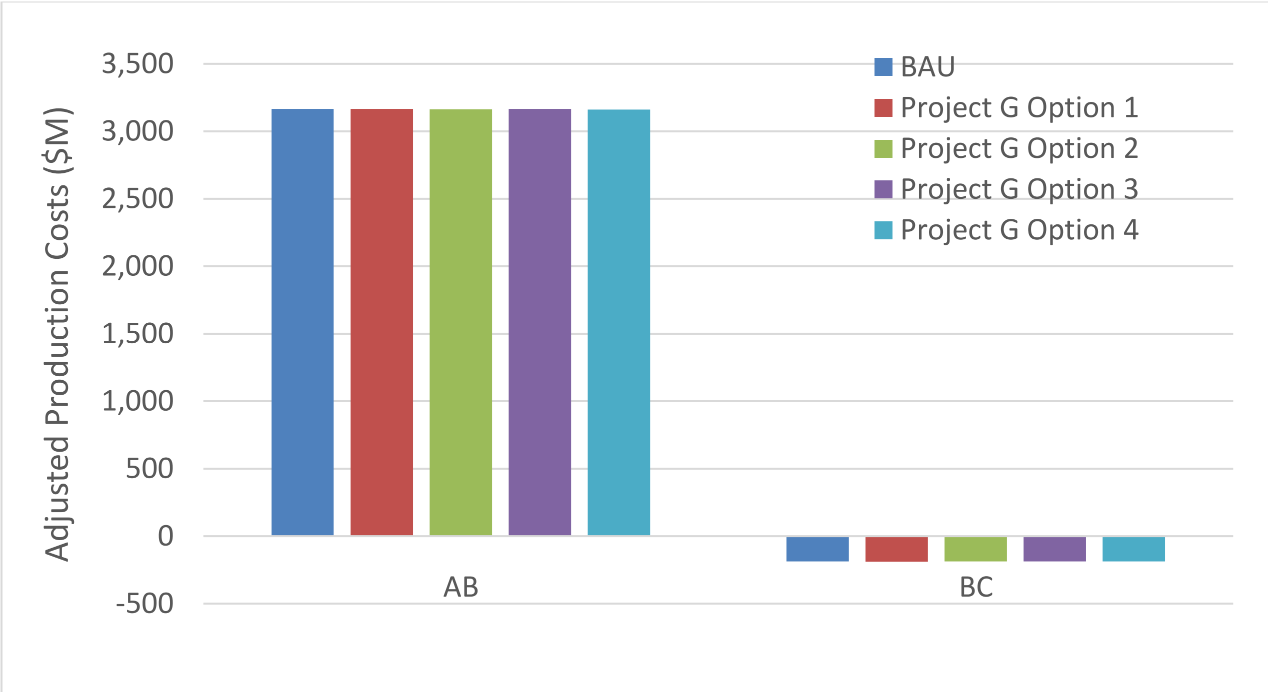


Figure 5-53: Project G - Adjusted Production Costs by Province (2030)

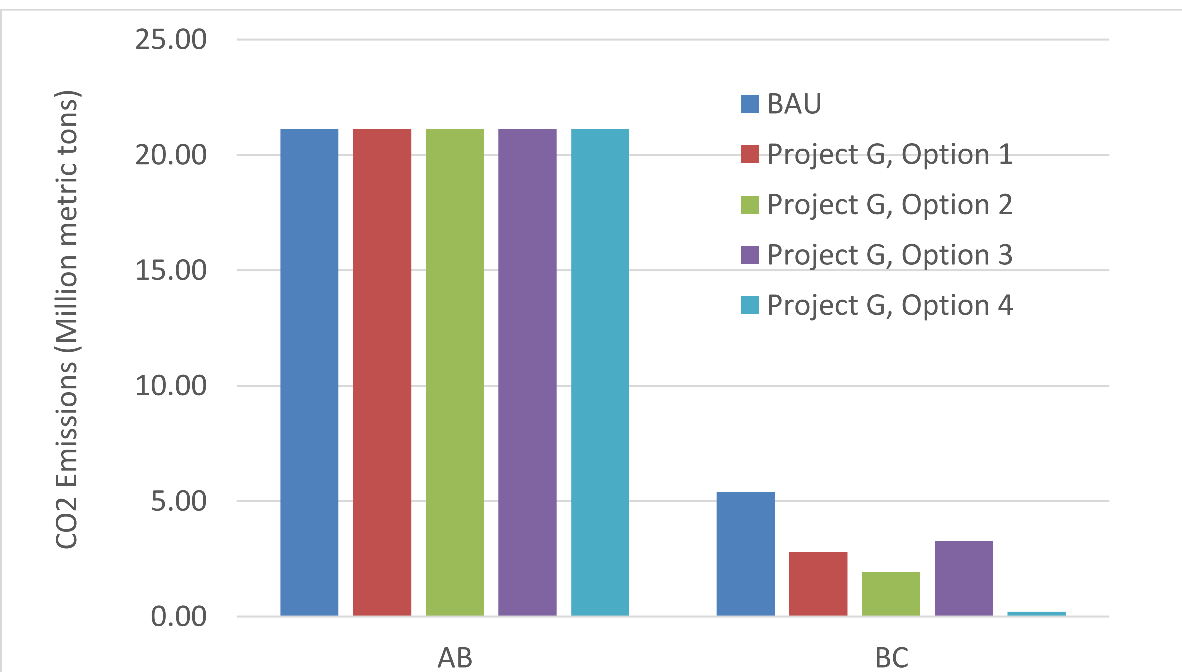


Figure 5-54: Project G - CO2 Emissions by Province (2030)

5.10 Evaluation of Project H

Project H: Construction of hydro and transmission line to interconnect the Northwest Territory Alberta by 2040

Project H consisted of connecting the Taltson hydro project to the Alberta grid. Following additions were made in each of the options relative to the BAU case.

Project H

- Modelled Taltson Hydro Project's available capacity
    - Approximately 115 MW, 820 GWh available for AB
    - Located at Joslyn Creek for modeling purposes

Following charts provide an overview of the performance of power systems under the BAU case and Project H.

Key Observations

Alberta

- The principal impact of connecting the Taltson hydro project to the AB grid is displacement of CC-GAS generation in AB.
- Total generation and net imports in AB are not impacted significantly.
- However, displacement of CC-GAS generation with hydro generation results in slight reduction of Adjusted Production Cost in AB.
- The reason for minimal change in net imports is because AB was a net importer in the BAU case. Displacement of CC-GAS generation by the Taltson hydro generation simply replaces a high variable cost generation with zero variable cost generation. Therefore, there is no economic reason for AB imports to change.
- Decrease in CC-GAS generation and its displacement by Taltson hydro generation results in a corresponding decrease in CO_2 emissions in AB.

Table 5-34: Project H - British Columbia Generation

BC Generation (2040) (TWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	65.915	10.599	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**76.515**
Project H	65.915	10.599	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**76.515**
Change from BAU										
Project H	0	0	0	0	0	0	0	0	0	**0**

Table 5-35: Project H - Alberta Generation

AB Generation (2040) (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	1,875	12,871	774	1,850	0	47,627	232	0	15,324	**80,555**
Project H	2,695	12,871	774	1,852	0	46,809	224	0	15,333	**80,558**
Change from BAU										
Project H	820	0	0	2	0	-818	-9	0	8	**3**

Table 5-36: Project H - Adjusted Production Costs

Adjusted Production Costs ($MM)	BAU	Project H
AB	4,766	4,704
BC	-196	-195
Total West	**4,570**	**4,509**
Change from BAU		
AB		-62
BC		1
Total West		**-61**

Table 5-37: Project H - Carbon Emissions

CO2 Emissions (Million Tonne)	BAU	Project H
AB	21.43	21.15
BC	5.17	5.17
Total West	**26.60**	**26.32**
Change from BAU		
AB		-0.28
BC		0.00
Total West		**-0.28**

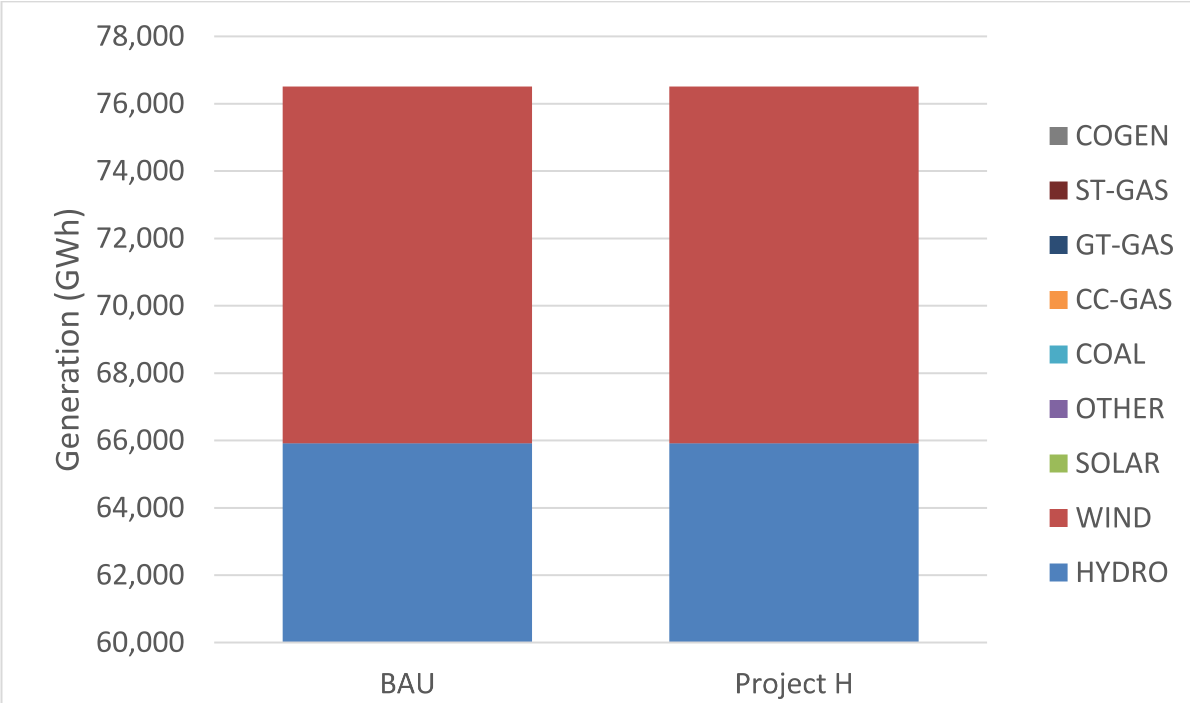


Figure 5-55: Project H - British Columbia Generation by Type (2040)

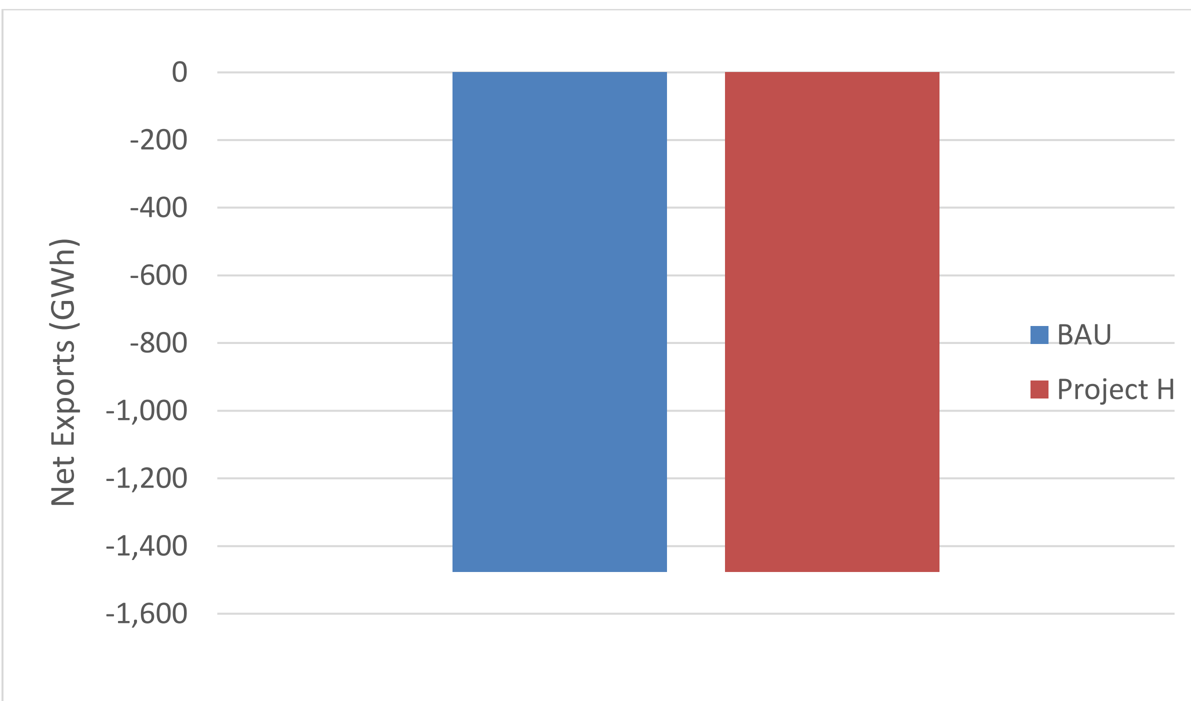


Figure 5-56: Project H - British Columbia Net Exports (2040)

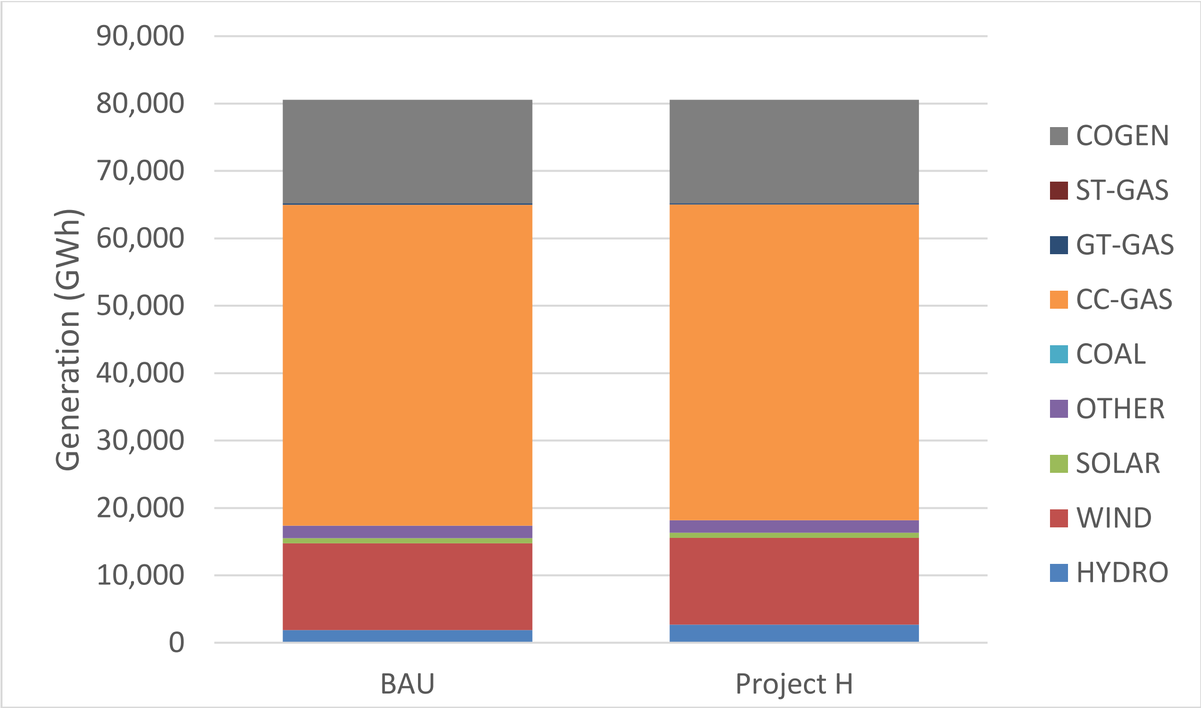


Figure 5-57: Project H - Alberta Generation by Type (2040)

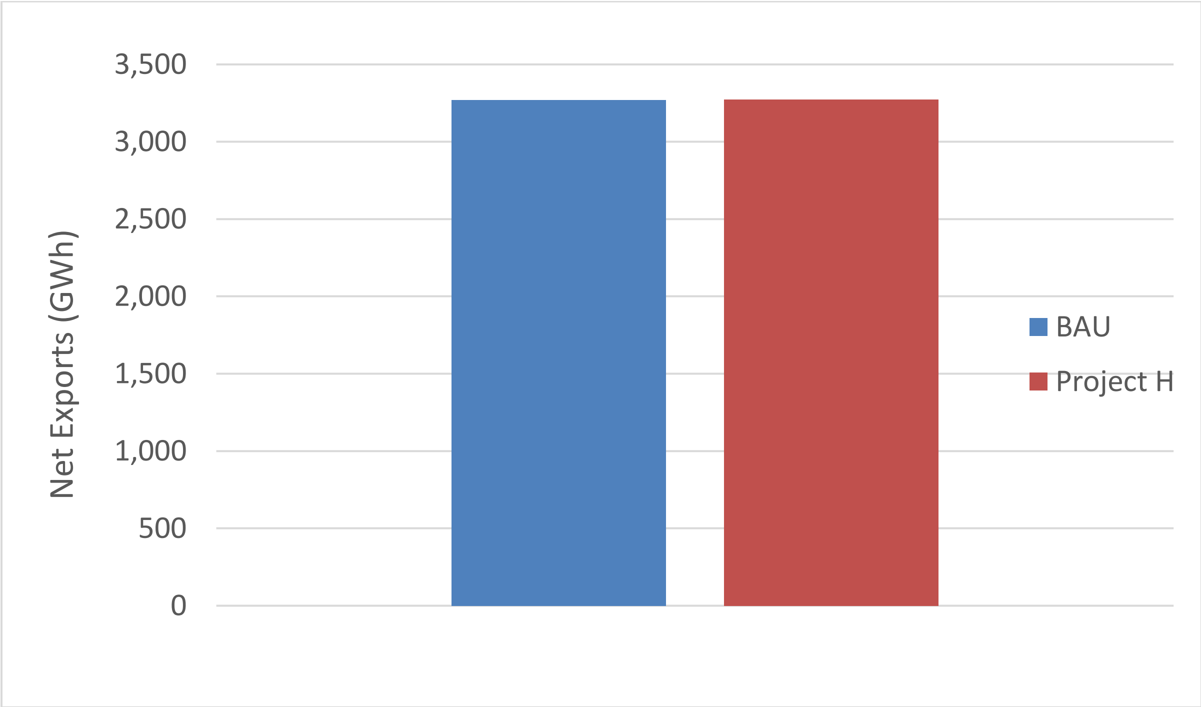


Figure 5-58: Project H - Alberta Net Exports (2040)

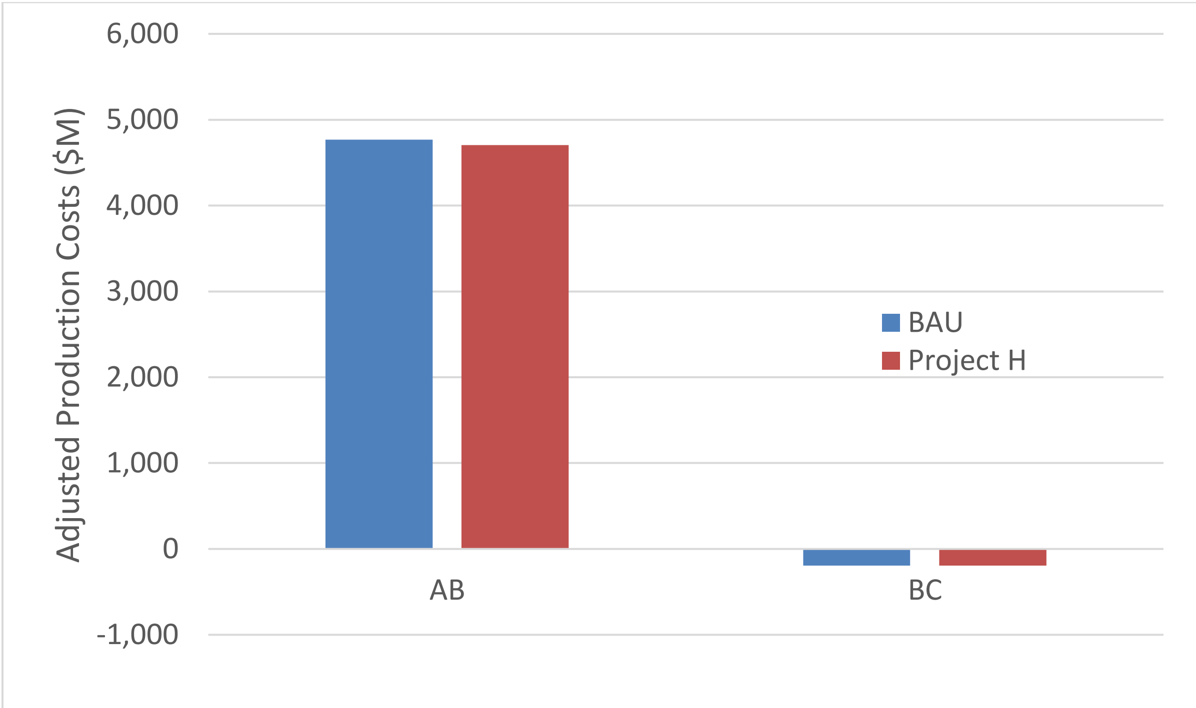


Figure 5-59: Project H - Adjusted Production Costs by Province (2040)

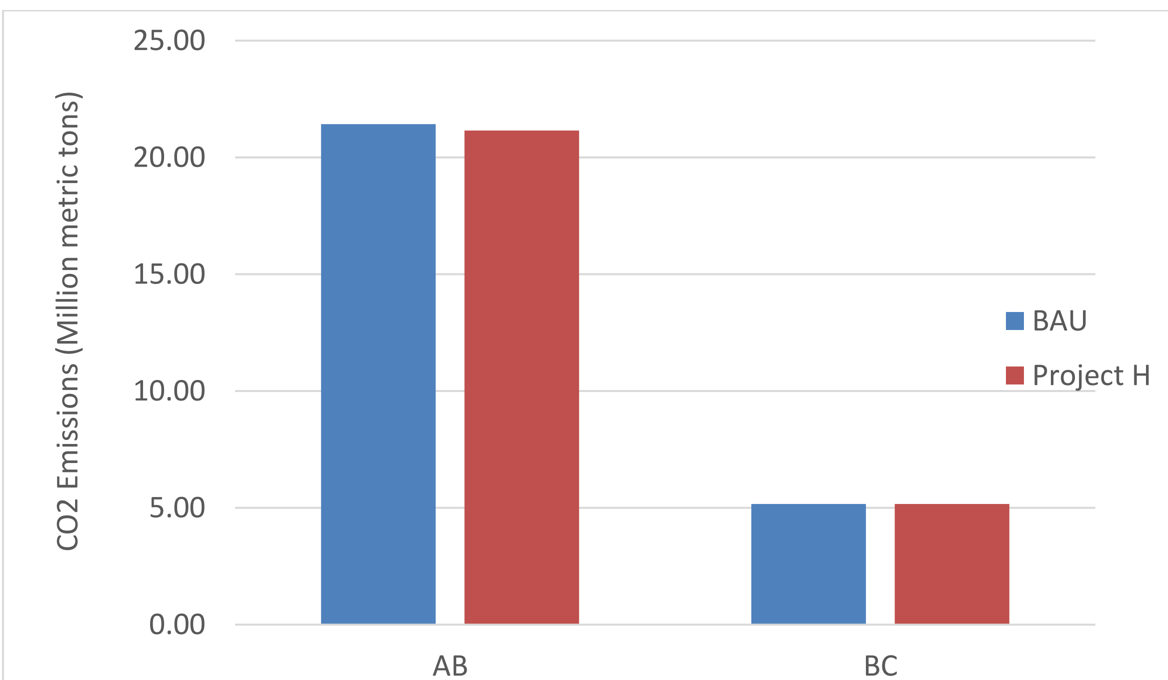


Figure 5-60: Project H - CO2 Emissions by Province (2040)

5.11 Evaluation of Project I

Project I: New intertie and incremental upgrade to existing and limited Alberta and Saskatchewan intertie by 2030

In Project I, a new AB-SK intertie was added at same location as the existing tie (McNeil) with +/- 450MW limit

Modeling Approach

There is no single production costing model that simultaneously covers and models both the Western and Eastern Interconnections. The two interconnections, although connected by HVDC lines, are not synchronous systems.

For Project I, it was necessary to run the Western and Eastern GE MAPS models iteratively with an assumed HVDC based flow between the two interconnections. In each iteration, hourly prices on the western and eastern side were determined, and the hourly flow between AB and SK was set in the direction of lower to higher price.

At each hour, the intertie itself was modeled as a load bus on the exporting side and an equivalent generation bus on the importing side. At each iteration of the models (i.e., running each model for a full year, new prices on the two sides of the intertie were determined, based on which a new hourly set of flows were represented by a new set of load and generation values on the two opposites buses of the intertie.

The iterations were stopped when either of two conditions were met: (1) if prices on the two sides converged and price differentials reached a set value, or (2) when prices started fluctuating around the same values in each iteration.

The following figure is the hourly SK to AB flow in the year sorted from lowest to highest value.

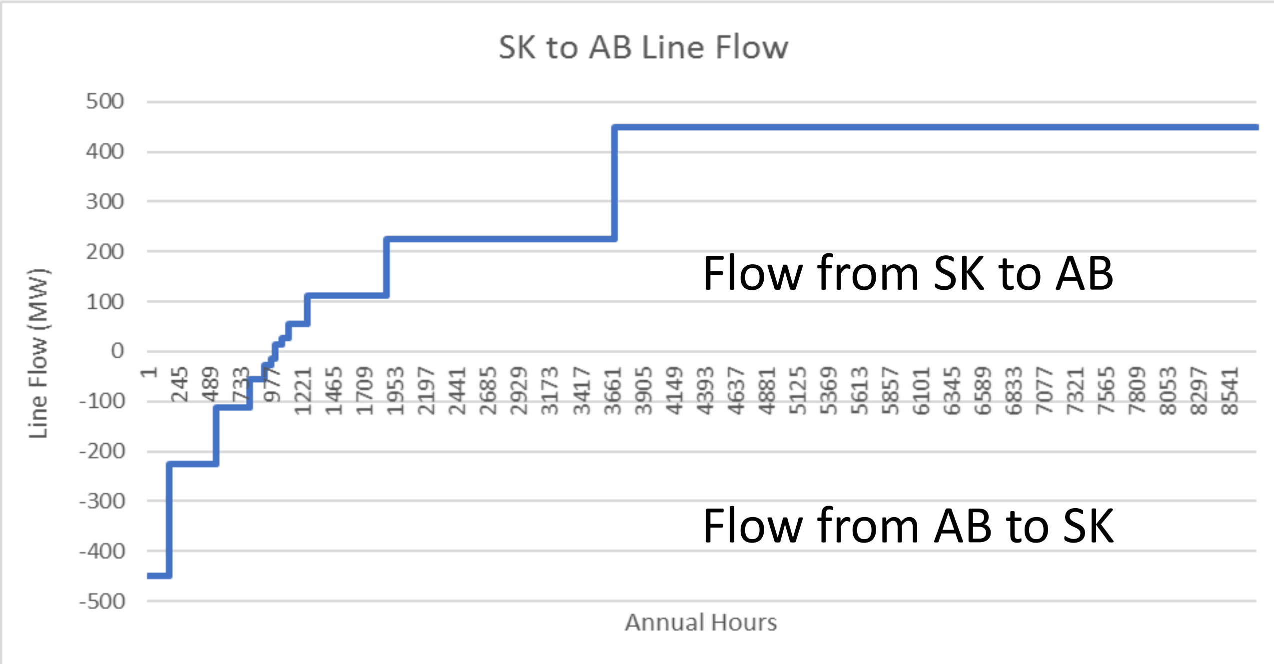


Figure 5-61: Project I - SK to AB Line Flow

Following charts provide an overview of the performance of power systems under the BAU case and Project I.

Key Observations

General

- The principal impact of additional intertie between AB and SK is a net flow of electricity from SK (in Eastern Interconnection) to AB (in Western Interconnection).
- Direction of the hourly flow of electricity is determined by the direction of the price gradient on the intertie. Results indicate that on average, LMP prices were higher on the AB side relative to the SK side.

Alberta

- Fossil fuel-based generation in AB are displaced to various degrees by less expensive electricity flowing from the Eastern Interconnection through the AB-SK intertie. The most impacted is the gas-fired generation.
- The net effect of the additional east-west power transfer capacity appears to be displacement of more expensive GT-GAS and COGEN generation by less expensive ST-COAL and CC-GAS generation.
- In Project I, AB replaced some of its imports from BC and USA with imports from SK. Net imports are a bit lower overall because of the hours where AB is exporting to SK.

- AB's Adjusted Production Cost is reduced slightly, since its costly generation is displaced with less expensive generation from the east.
- CO2 emissions in AB are also reduced, due to shift of CO2 emitting generation from AB to SK. The combined CO2 emission for AB and SK actually goes up 0.43 MM tons compared to the BAU case.

Saskatchewan

- In Project I, ST-COAL and CC-GAS generation, and to a lesser degree the COGEN generation, increase relative to the BAU case.
- These cheaper electricity flows to the west, replacing more expensive AB GT-GAS and COGEN generation.
- Because we model this east-west intertie as an hourly load (negative and positive) on the sides, SK increased generation but also began importing small amount of electricity from MB and a larger amount from USA to cover the "load" in AB.
- There appears to be a very small reduction in SK's Adjusted Production Cost. This is because the incremental cost of additional generation in SK and the imports from USA are almost negated by the exports to the AB.
- Higher fossil-based generation in SK results in an increase in CO2 emissions in SK.

Table 5-38: Project I - Generation by Province

Generation by Province (GWh)	AB	BC	MB	SK	Total West	Total East
BAU	67,746	69,510	37,255	26,108	**137,256**	**63,363**
Project I	65,986	69,456	37,224	28,227	**135,442**	**65,451**
Change from BAU						
Project I	-1,760	-54	-31	2,119	**-1,814**	**2,088**

Table 5-39: Project I - Alberta Generation

AB Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	1,875	12,910	775	1,925	7,107	17,989	2,347	0	22,819	**67,746**
Project I	1,875	12,910	775	1,862	7,107	17,830	1,792		21,837	**65,986**
Change from BAU										
Project I	0	0	0	-63	0	-159	-556	0	-982	**-1,760**

Table 5-40: Project I - Saskatchewan Generation

SK Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	3,335	7,995	184	133	8,108	3,814	109	0	2,430	**26,108**
Project I	3,333	8,028	184	142	8,704	5,266	34		2,535	**28,227**
Change from BAU										
Project I	-1	33	0	9	596	1,452	-75	0	105	**2,119**

Table 5-41: Project I - Adjusted Production Costs

Adjusted Production Costs ($MM)	BAU	Project I
AB	3,165	3,107
BC	-187	-165
MB	-75	-74
SK	720	719
Total West	**2,978**	**2,942**
Total East	**646**	**645**
Change from BAU		
AB		-58
BC		22
MB		1
SK		-1
Total West		**-36**
Total East		**-1**

Table 5-42: Project I - Carbon Emissions

CO2 Emissions (Million Tonne)	BAU	Project I
AB	21.12	20.42
BC	5.40	5.38
MB	0.04	0.04
SK	11.32	12.45
Total West	26.52	25.79
Total East	**11.36**	**12.49**
Change from BAU		
AB		-0.71
BC		-0.02
MB		0.00
SK		1.13
Total West		**-0.73**
Total East		**1.13**

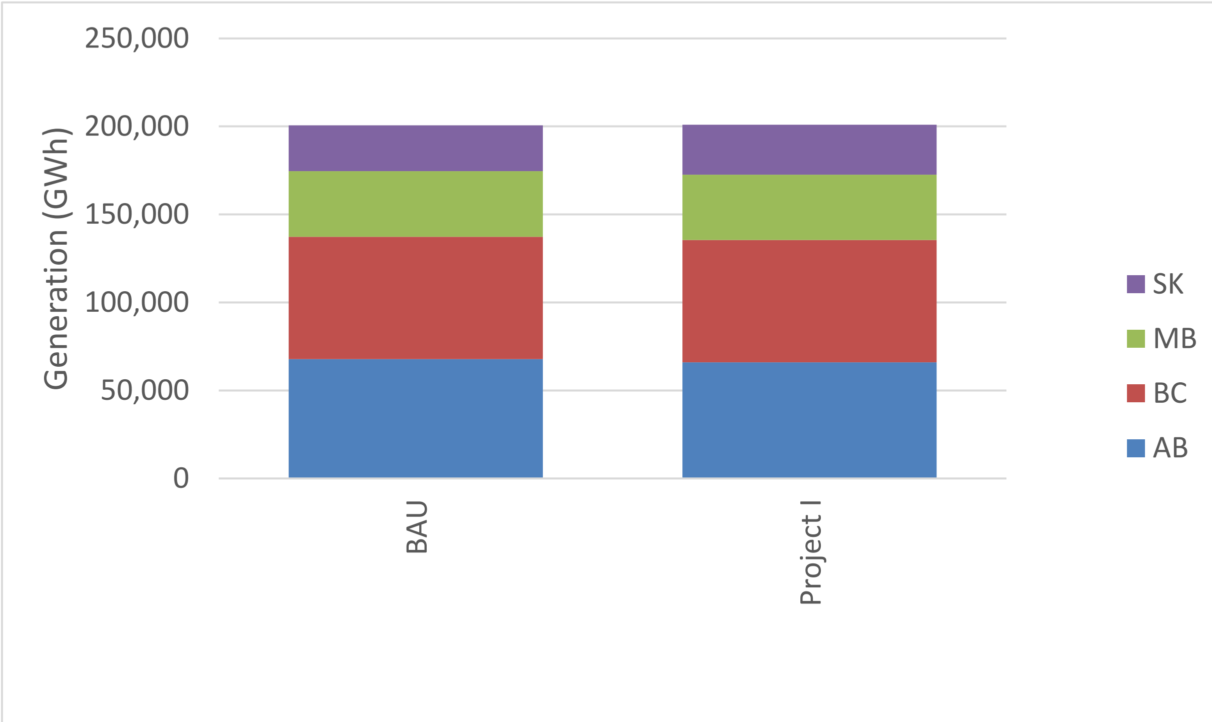


Figure 5-62: Project I - Total Generation by Province (2030)

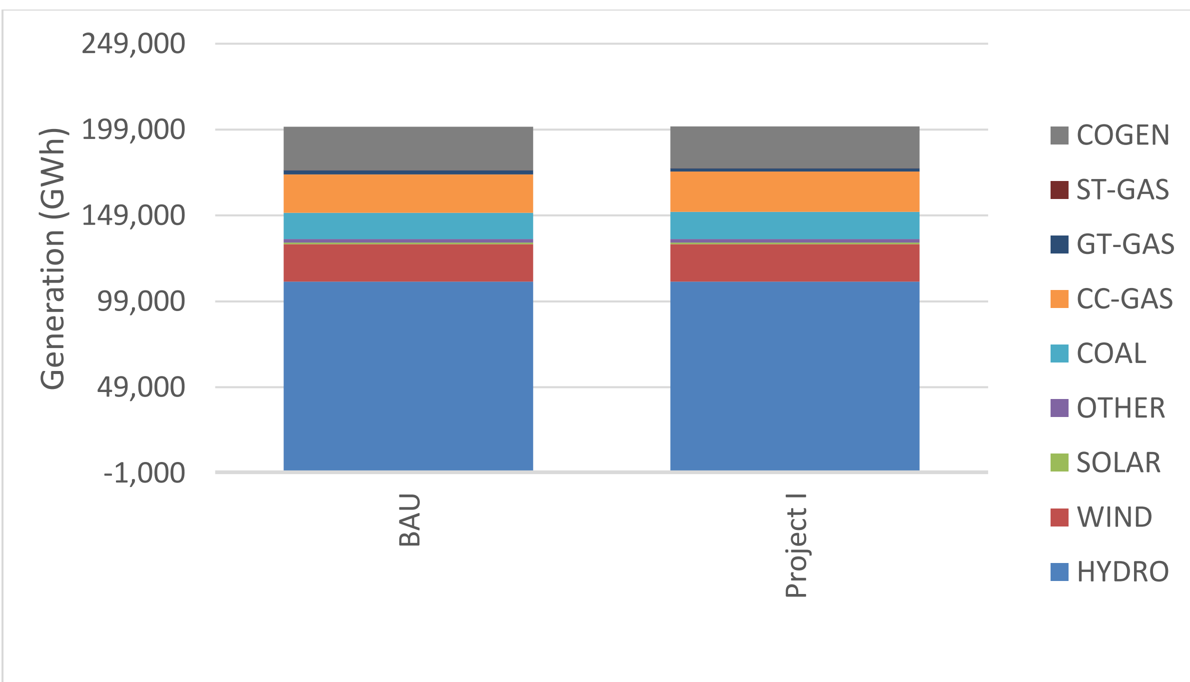


Figure 5-63: Project I - Total Generation by Type (2030)

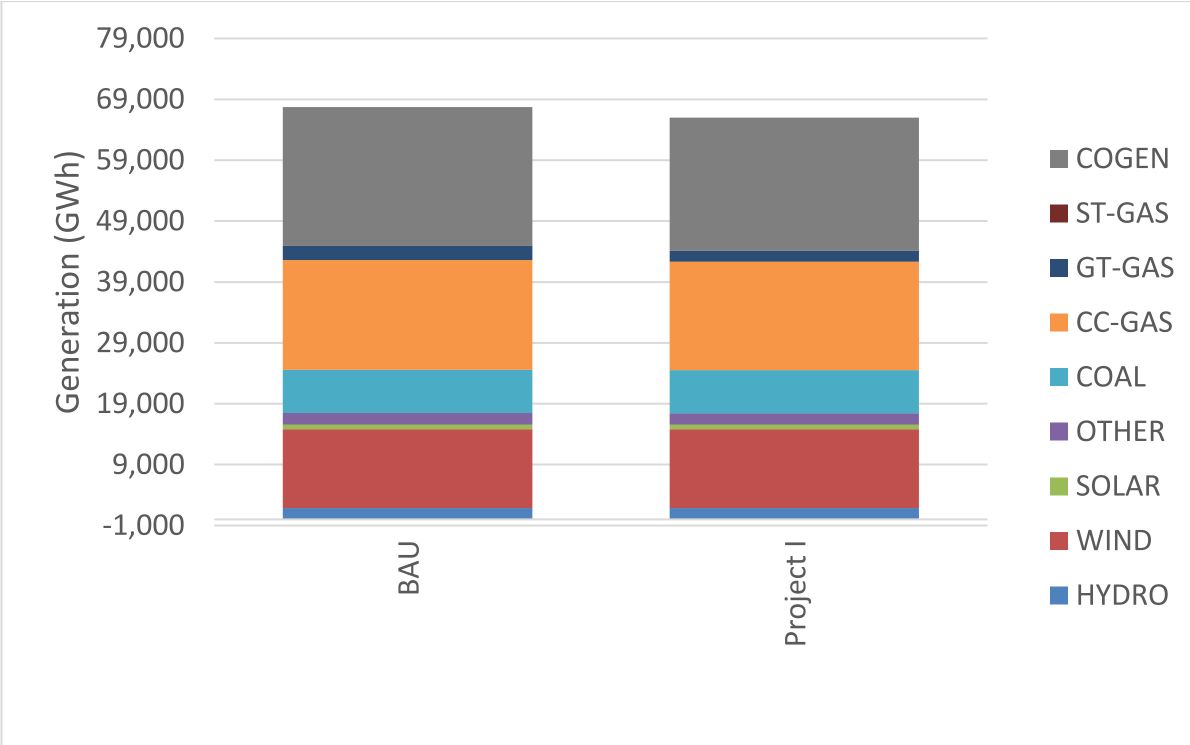


Figure 5-64: Project I - Alberta Generation by Type (2030)

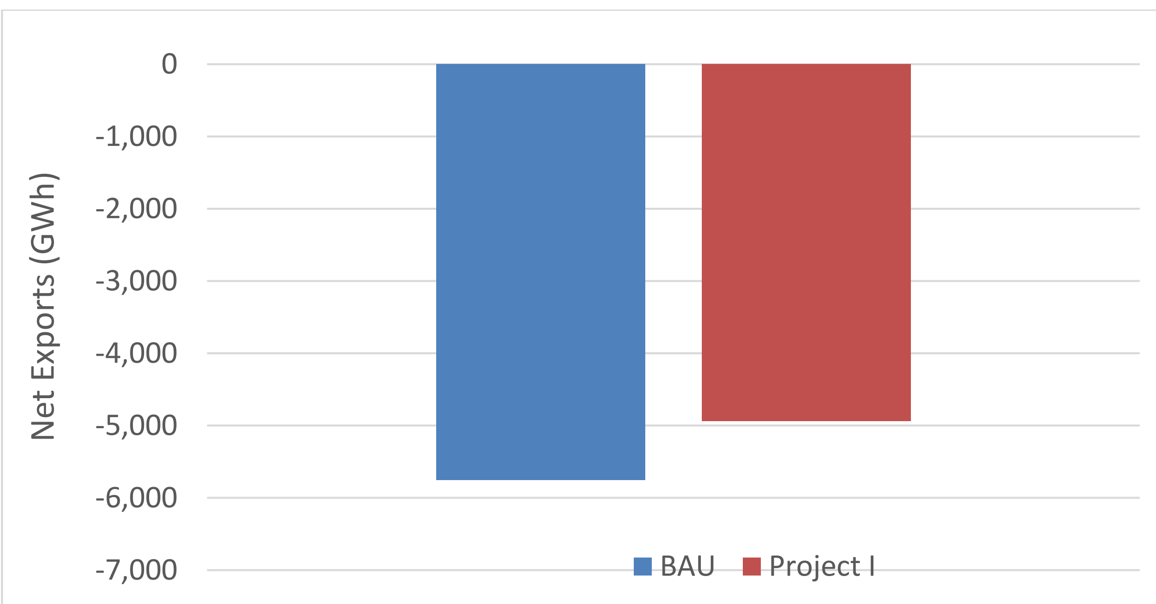


Figure 5-65: Project I - Alberta Next Exports (2030)

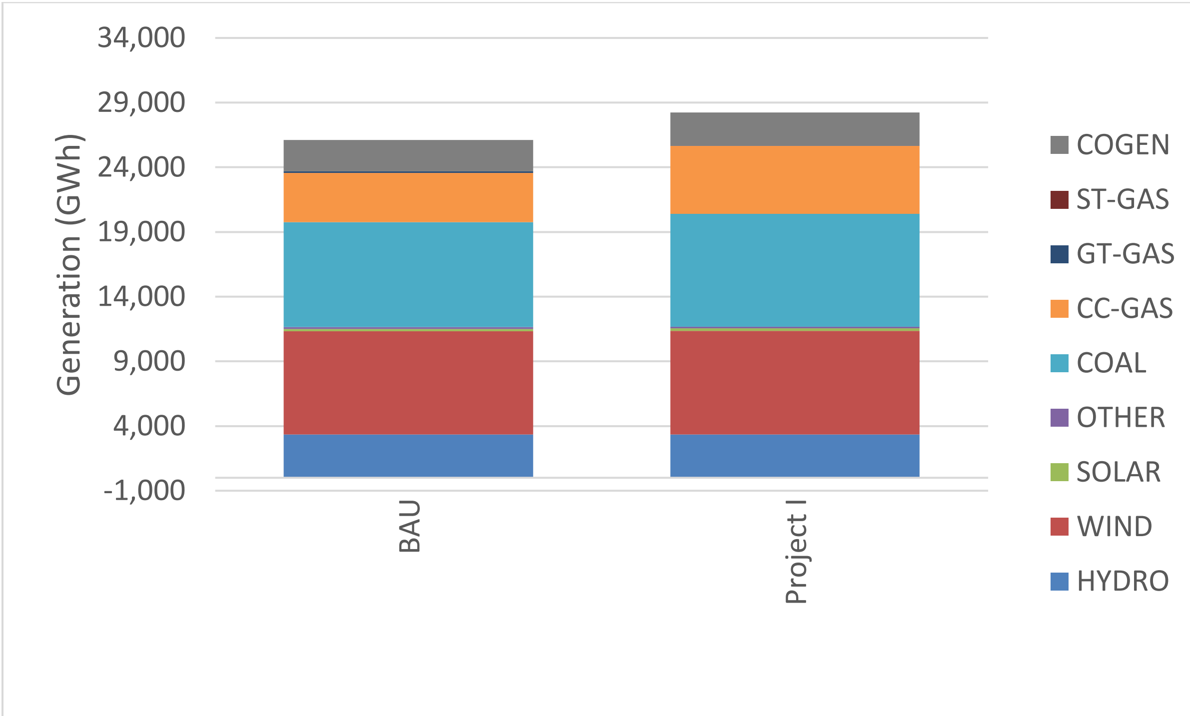


Figure 5-66: Project I - Saskatchewan Generation by Type (2030)

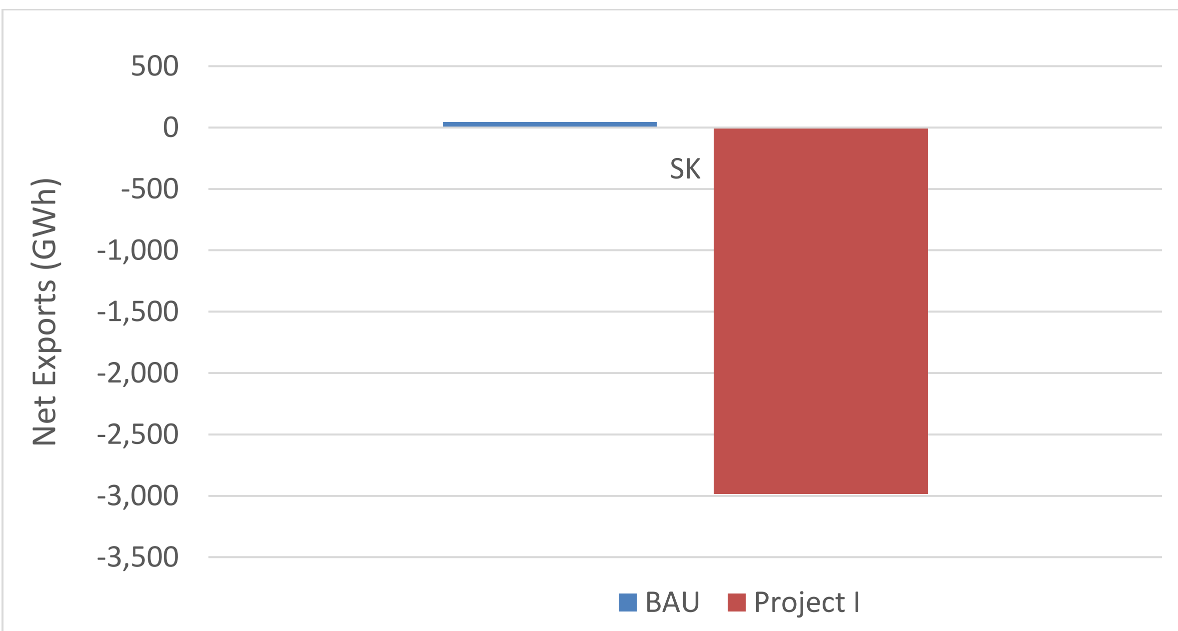


Figure 5-67: Project I - Saskatchewan Net Exports (2030)

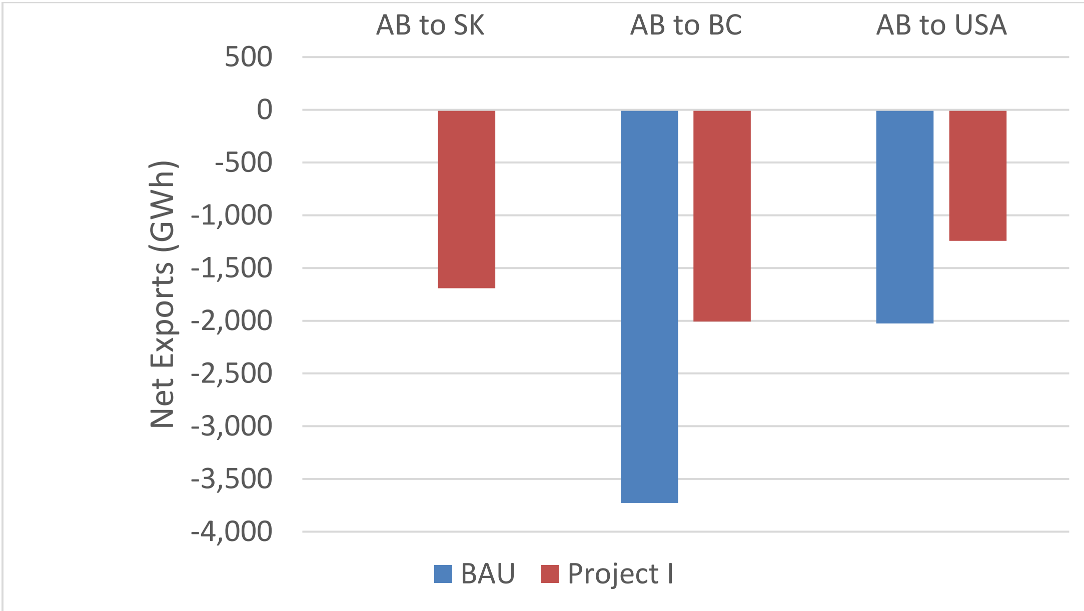


Figure 5-68: Project I - Saskatchewan Net Export (2030)

Note: AB replaced some of its imports from BC and USA with imports from SK. Net imports are a bit lower overall because of the hours where AB is exporting to SK.

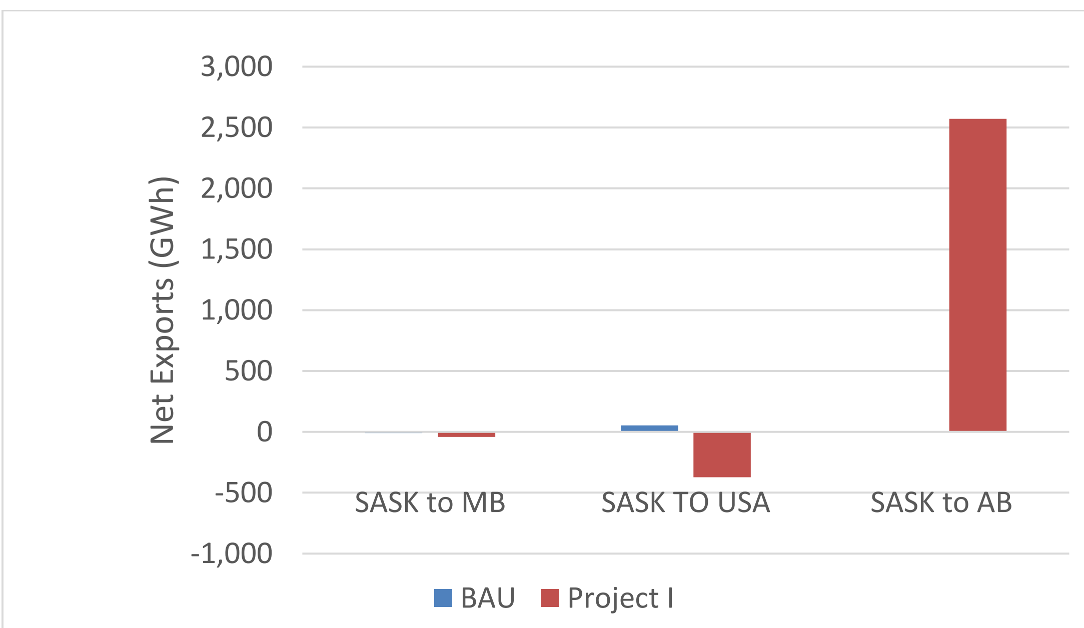


Figure 5-69: Project I - Saskatchewan Net Exports (2030)

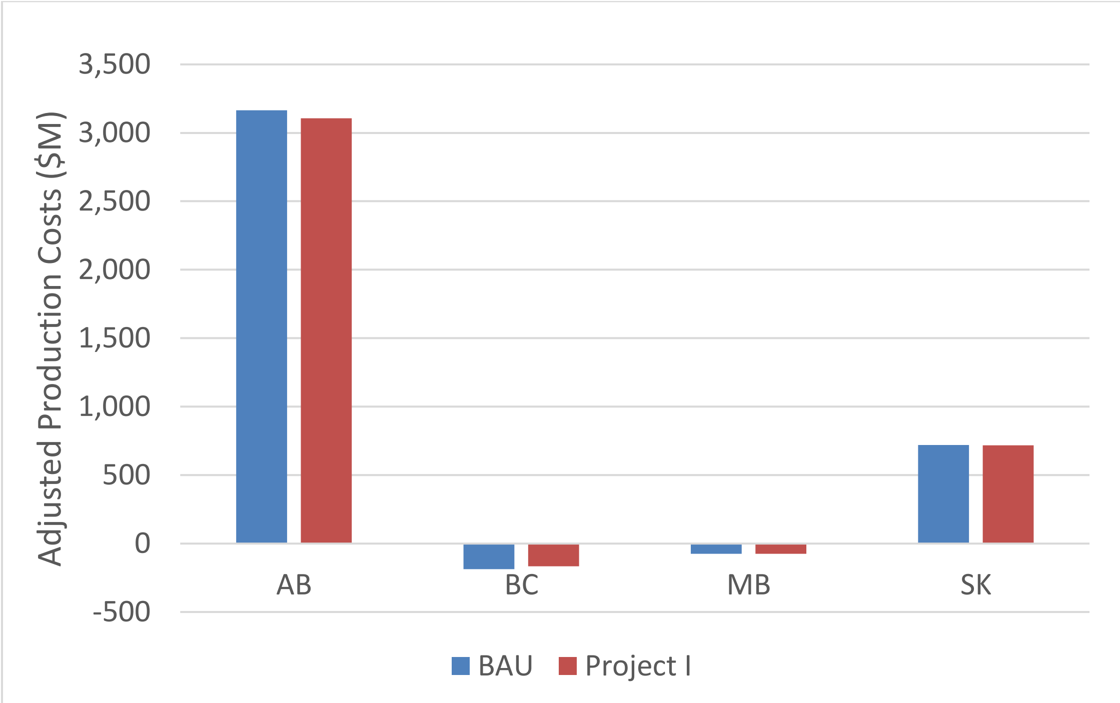


Figure 5-70: Project I - Adjusted Production Costs by Province (2030)

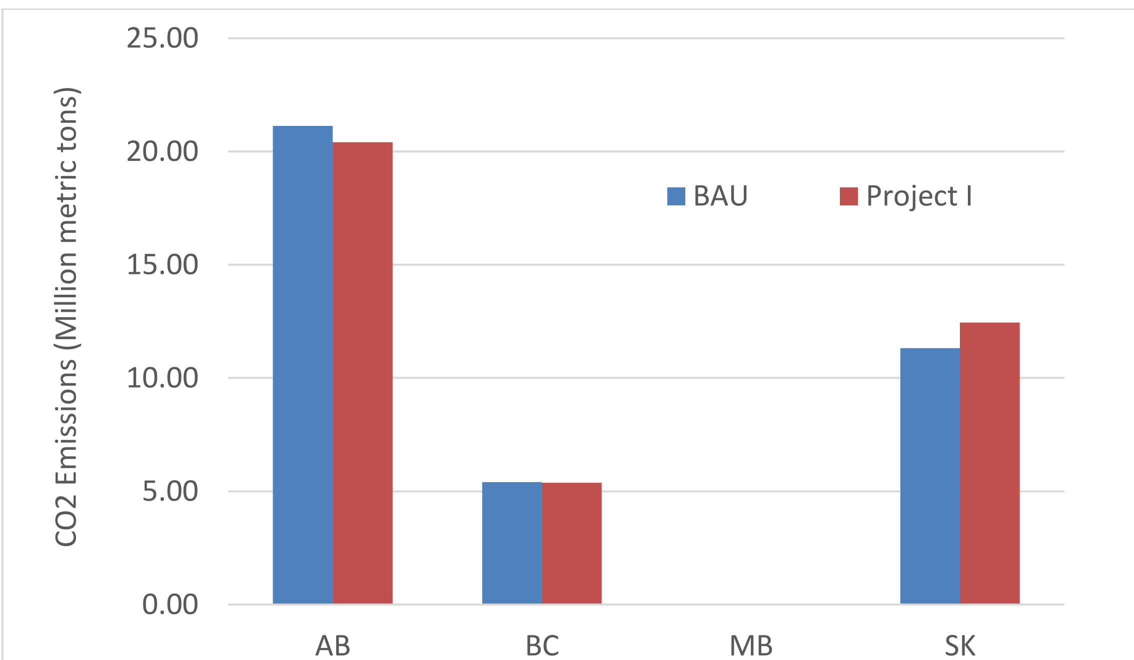


Figure 5-71: Project I - CO2 Emissions by Province (2030)

5.12 Evaluation of Project J

Project J: Create simultaneous transfer capability between AB-BC and MATL Interties by 2030

In Project J, the AB-BC Path 1 intertie is restored to its full path rating. Following additions were made relative to the BAU case.

Project J Description

- Restored AB-BC Path 1 Intertie transfer capability to its full path rating of 1000 MW / -1200 MW
- Allowed 310 MW import from MATL independently.
- The combined import will be 1,510 MW.

The following charts provide an overview of the performance of power systems under the BAU case and Project J.

Key Observations

Alberta

- In project J, a small part of in-province generation is displaced by imports, principally from USA.
- The most impacted are gas-fired generation.
- Project J shows AB imports increasing relative to the BAU case.
- At the same time, AB's Adjusted Production Cost decreases relative to BAU case due to increased imports, which are more economic that in-province generation.
- Restored intertie transfer capability to its path rating and higher carbon tax in Canada is enabling more of less costly generation to flow into AB, primarily from the U.S.
- Reduced gas-fueled generation in AB results in lower CO2 emissions.
- While emissions are reduced in AB, it is possible that the imported electricity from the U.S. may have an equal or higher carbon intensity, thus possibly resulting in no reduction in the GHGs consumed by AB.

British Columbia

- Although not clearly observable from the charts, the underlying data indicate that BC's CC-GAS generation increases slightly, and a corresponding amount of electricity is exported to AB.

- The large amount of imports by AB, and small amount of exports by BC, indicates that most of electricity flowing into AB originates in the USA.
- The impact on BC is decrease in Adjusted Production Cost (i.e., slight increase in revenue relative to the BAU case).
- Due to minimal changes in BC generation and a very small amount of net export increase, there is no significant impact on BC carbon emissions.
- It should be noted that the sub-hourly hydro dispatch was not analyzed in this study, which may result in an underestimation of the GHG emission reduction benefit of the project. The reduction is expected to be due to replacement of the fossil-based generation by more flexible hydro dispatch to smooth out the sub-hourly wind variability.

Table 5-43: Project J - Alberta Generation

AB Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	1,875	12,910	775	1,925	7,107	17,989	2,347	0	22,819	**67,746**
Project J	1,875	12,910	775	1,894	7,107	17,874	1,928	0	22,114	**66,476**
Change from BAU										
Project J	0	0	0	-31	0	-116	-419	0	-705	**-1,270**

Table 5-44: Project J - British Columbia Generation

BC Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	68,988	0	0	0	0	522	0	0	0	**69,510**
Project J	68,987	0	0	0	0	538	0	0	0	**69,525**
Change from BAU										
Project J	-1	0	0	0	0	17	0	0	0	**16**

Table 5-45: Project J - Adjusted Production Costs

Adjusted Production Costs ($MM)	BAU	Project J
AB	3,165	3,130
BC	-187	-233
Total West	**2,978**	**2,897**
Change from BAU		
AB		-35
BC		-46
Total West		**-81**

Table 5-46: Project J - Carbon Emissions

CO_2 Emissions (Million Tonne)	BAU	Project J
AB	21.12	20.60
BC	5.40	5.41
Total West	**26.52**	**26.01**
Change from BAU		
AB		-0.52
BC		0.01
Total West		**-0.52**

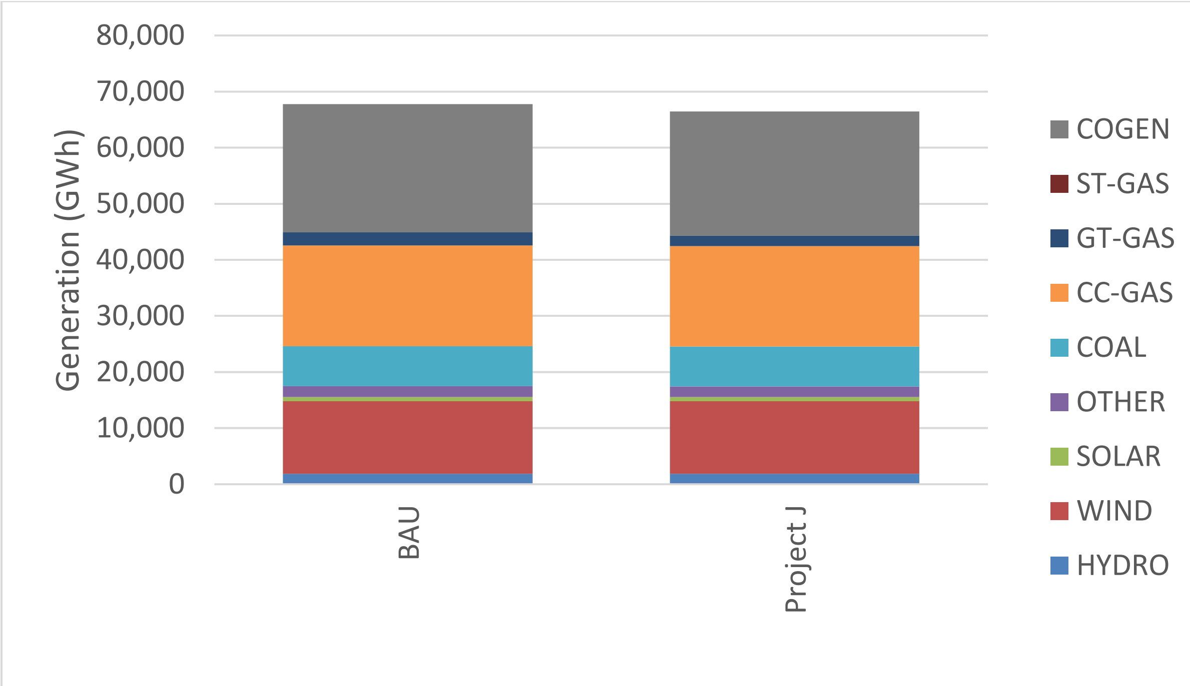


Figure 5-72: Project J - Alberta Generation by Type (2030)

Figure 5-73: Project J - Alberta Net Exports (2030)

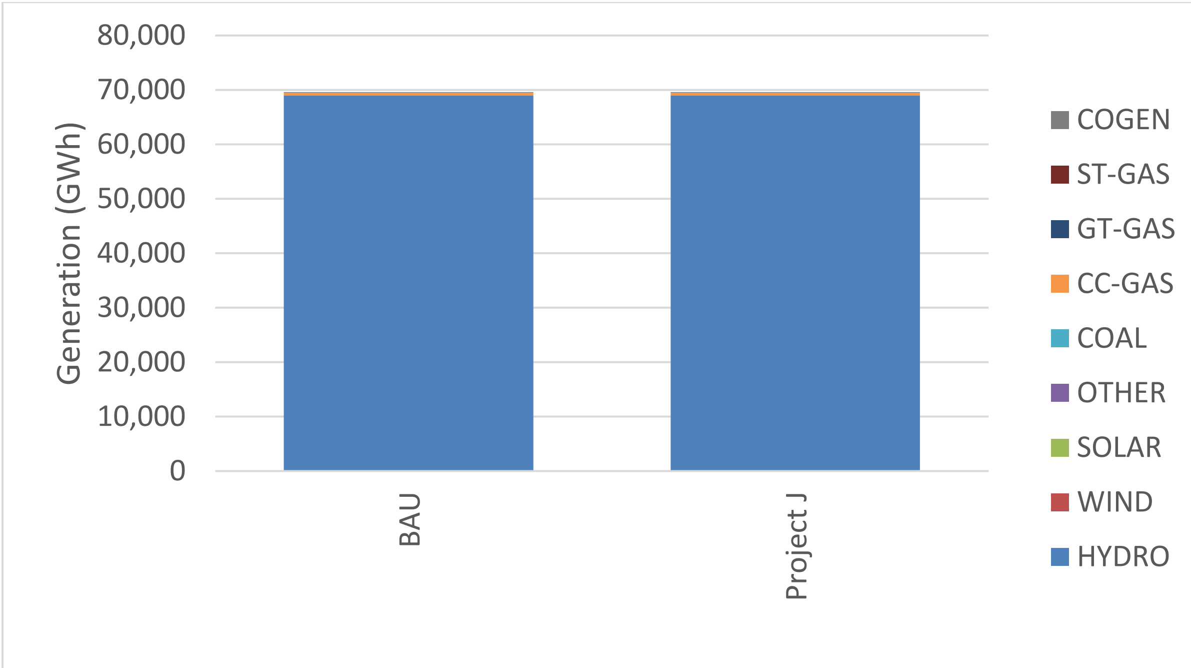


Figure 5-74: Project J - British Columbia Generation (2030)

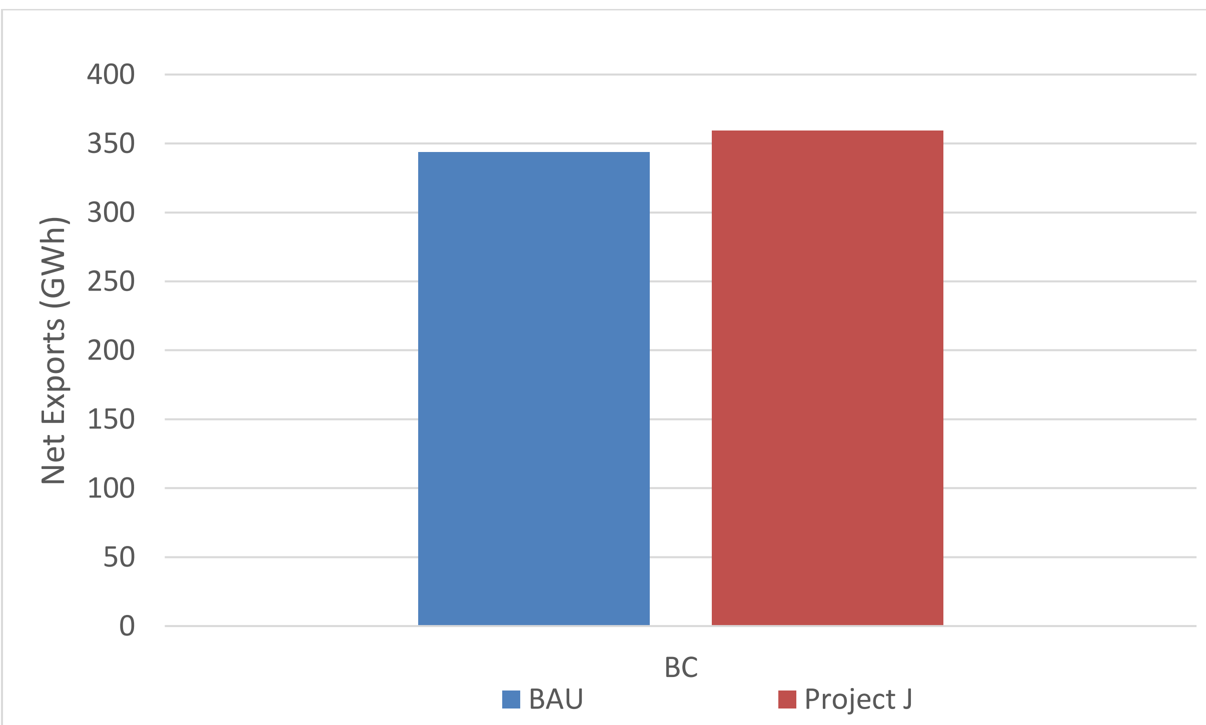


Figure 5-75: Project J - British Columbia Net Exports (2030)

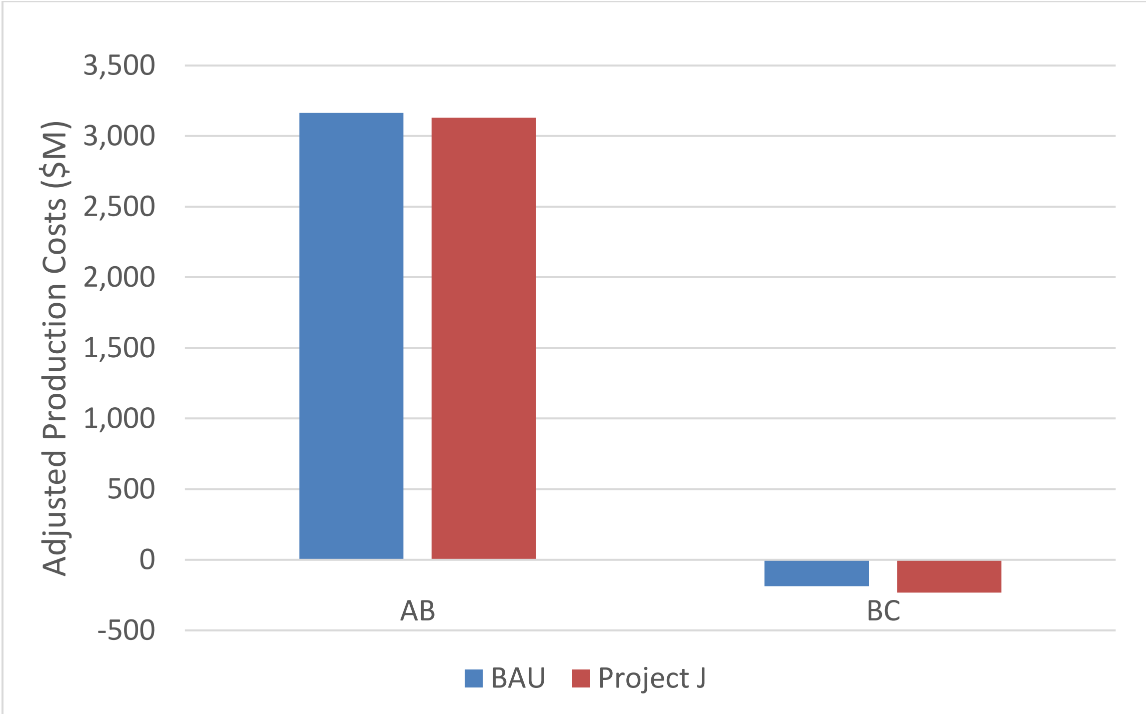


Figure 5-76: Project J - Adjusted Production Costs by Province (2030)

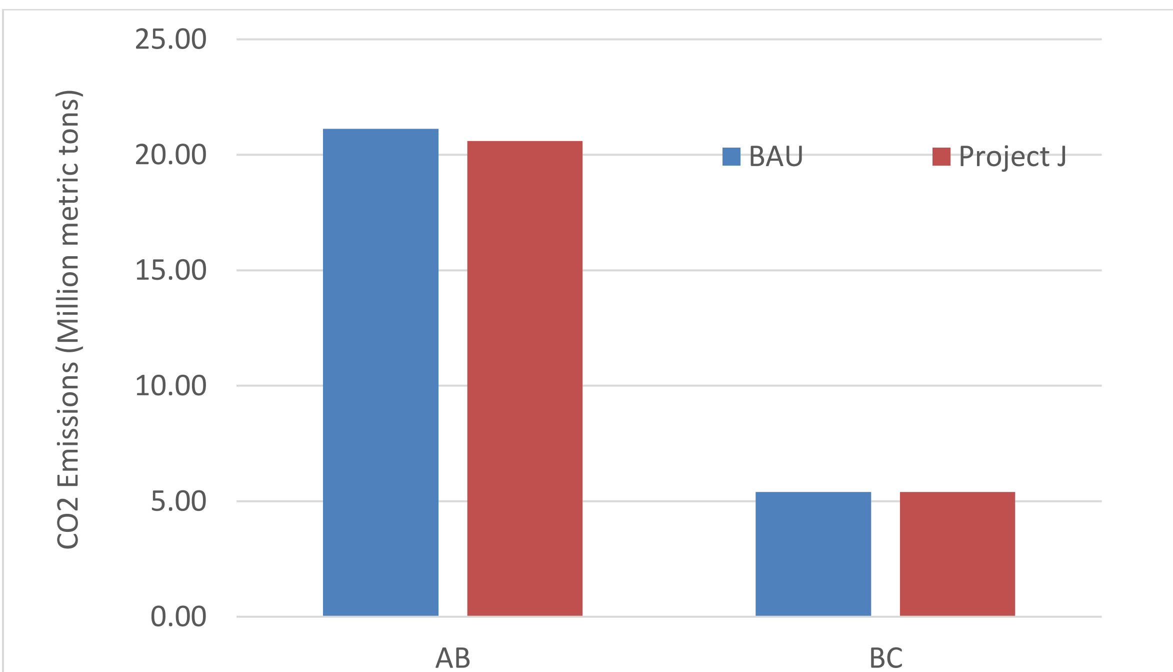


Figure 5-77: Project J - CO_2 Emissions by Province (2030)

5.13 Evaluation of Project K

Project K: Combination of Project A and Project C

Project K is a combination of Project A (new BC-AB Intertie) and Project C (new internal transmission in AB). It should be noted that Project K also includes Project J, since Project J is subset of Project A.

Key Observations

Alberta

- Additional wind generation in AB displaces COGEN and GT-GAS generation relative to the BAU case in both the North and South options. There is a slight increase in AB generation, which is consistent with decrease in electricity imports into AB.
- CO2 emissions are reduced in AB relative to the BAU case, reflecting the displacement of COGEN and GT-GAS generation by wind.
- AB Adjusted Production Costs (Adjusted Production Cost) decrease relative to BAU case, again reflecting the displacement of COGEN and GT-GAS generation by wind.

British Columbia

- There is a very small decrease in BC hydro, wind, and GT-GAS generation.
- BC net exports drop a little bit relative to the BAU case, which is consistent with the decrease in BC generation.
- Adjusted Production Cost in BC is negative under the BAU case and in each of Project A options, which implies that that BC experiences higher export revenues relative to its internal production costs. However, although net exports drop BC, the decrease in GT-GAS generation also reduces the production costs relative to the BAU case net revenues increase further in Project A options relative to the BAU case (or in BC's case, increases the net revenues).
- Due to the very small change in GT-GAS generation, the impact on BC carbon emission reduction is insignificant.

Table 5-47: Project K - Alberta Generation

AB Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	1,875	12,910	775	1,925	7,107	17,989	2,347		22,819	**67,746**
Project K, North	1,875	20,841	775	1,817	7,090	17,366	1,186		17,425	**68,374**
Project K, South	1,875	20,841	775	1,827	7,105	17,391	1,239		17,889	**68,941**
Change from BAU										
Project K, North	0	7,932	0	-108	-16	-624	-1,161	0	-5,394	**628**
Project K, South	0	7,932	0	-97	-2	-599	-1,108	0	-4,930	**1,195**

Table 5-48: Project K - British Columbia Generation

BC Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	68,988	522					0			**69,510**
Project K, North	68,987	512					0			**69,500**
Project K, South	68,986	517					0			**69,503**
Change from BAU										
Project K, North	-1	-9					0			**-10**
Project K, South	-2	-5					0			**-7**

Table 5-49: Project K - Adjusted Production Costs

Adjusted Production Costs ($MM)	BAU	Project K, North	Project K, South
AB	3,165	2,697	2,716
BC	-187	-215	-201
Total West	**2,978**	**2,482**	**2,514**
Change from BAU			
AB		-468	-449
BC		-28	-14
Total West		**-495**	**-464**

Table 5-50: Project K - Carbon Emissions

CO2 Emissions (Million Tonne)	BAU	Project K, North	Project K, South
AB	21.12	18.41	18.61
BC	5.40	5.40	5.40
Total West	**26.52**	**23.81**	**24.02**
Change from BAU			
AB		-2.71	-2.51
BC		0.00	0.00
Total West		**-2.71**	**-2.51**

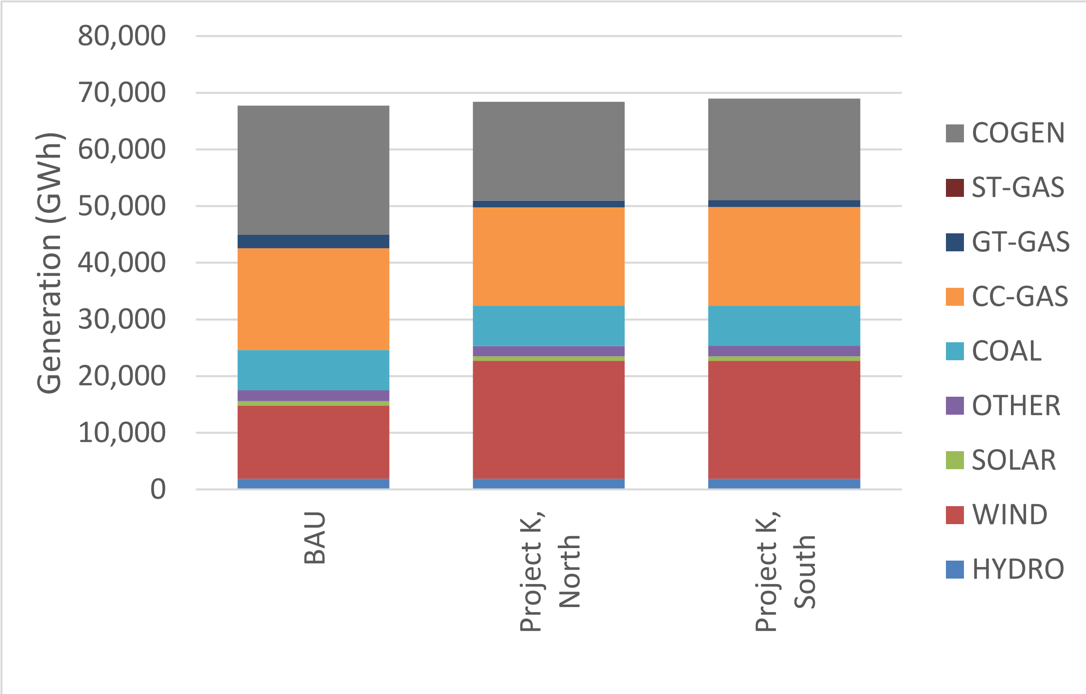


Figure 5-78: Project K - Alberta Generation by Type (2030)

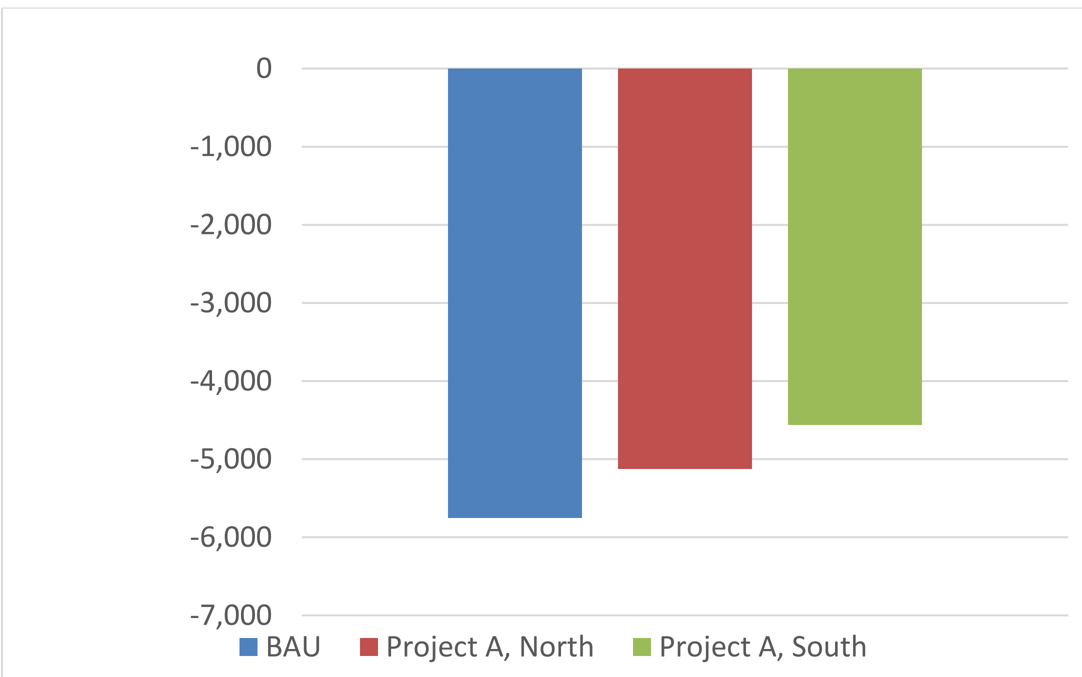


Figure 5-79: Project K - Alberta Net Exports (2030)

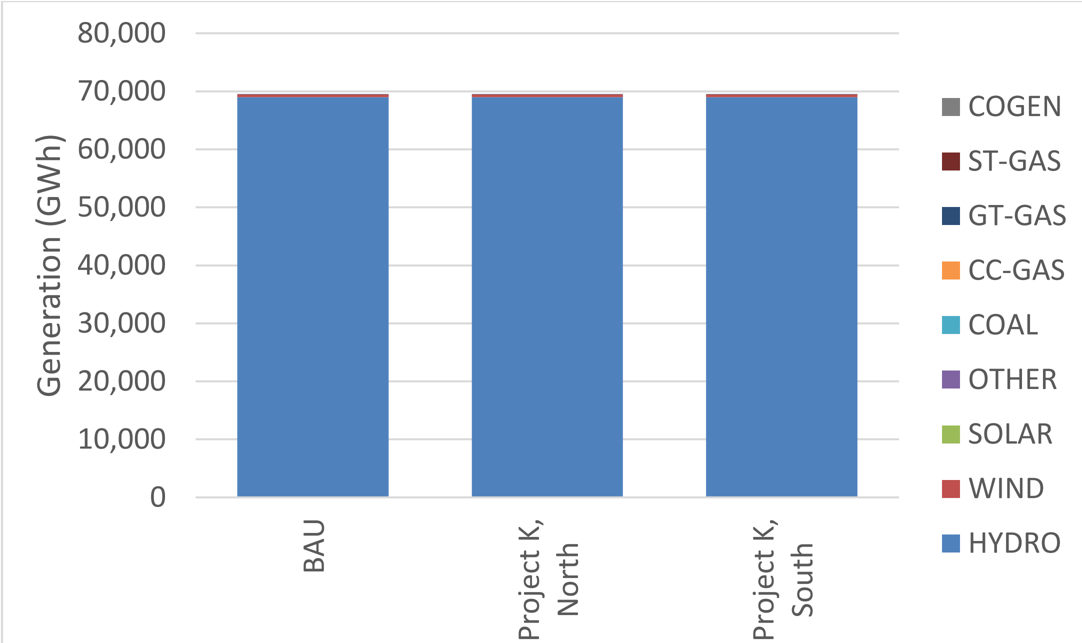


Figure 5-80: Project K - British Columbia Generation (2030)

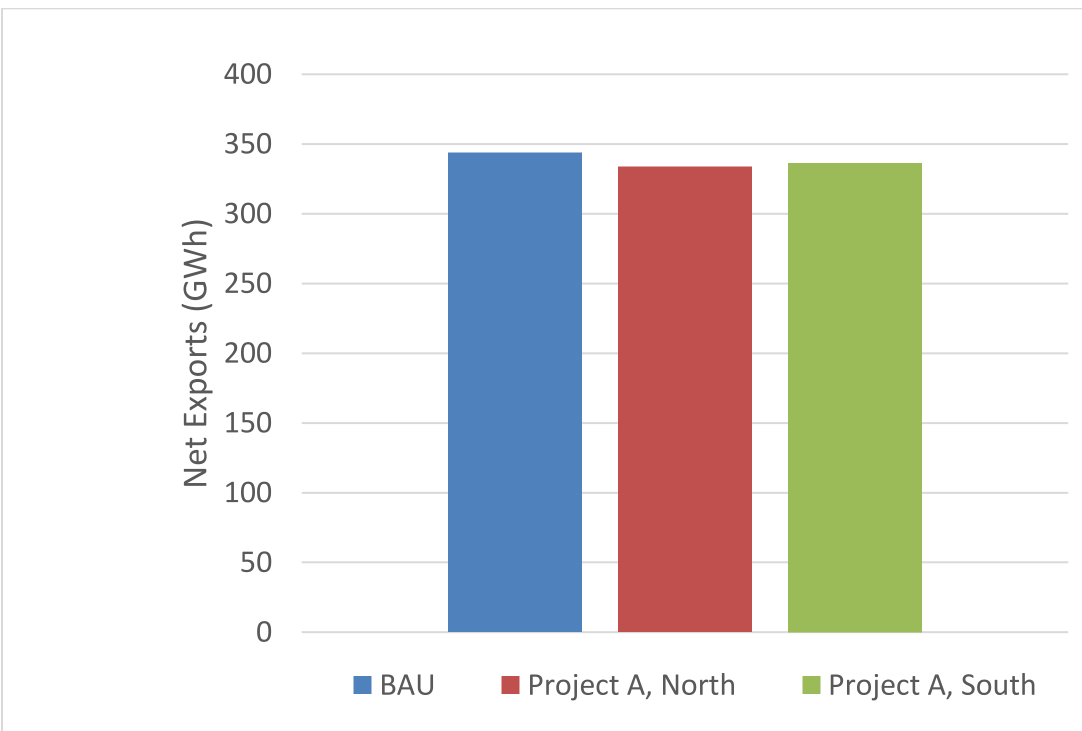


Figure 5-81: Project K - British Columbia Net Exports (2030)

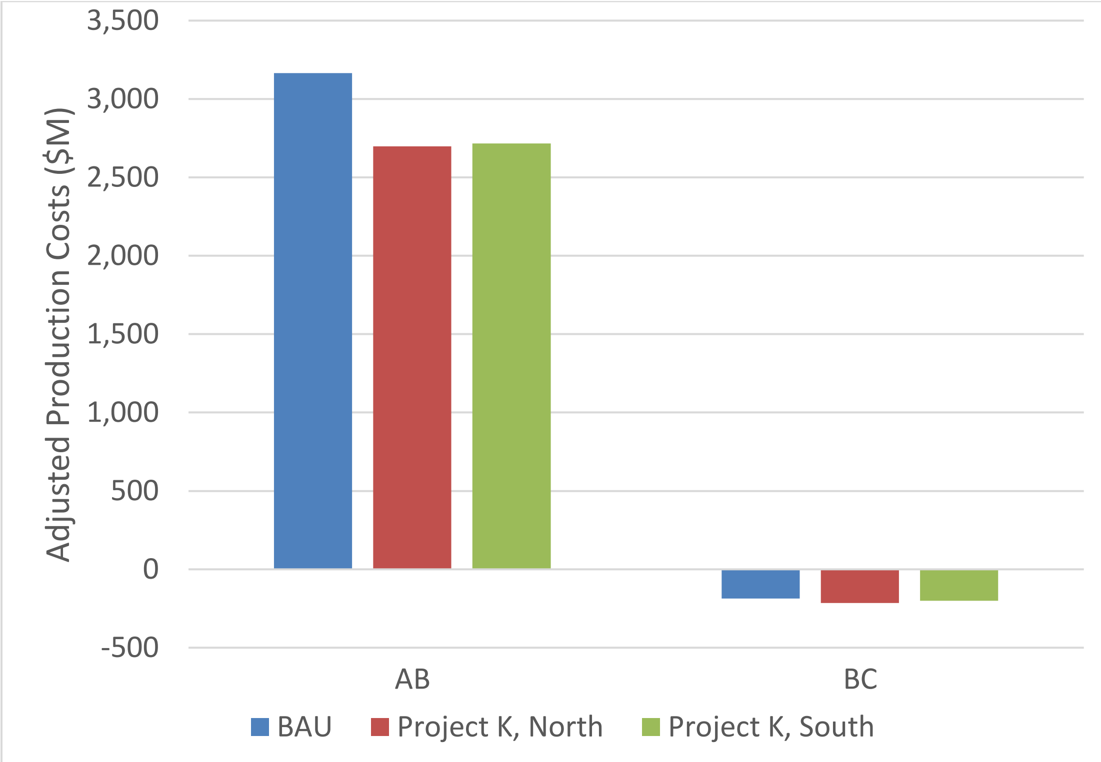


Figure 5-82: Project K - Adjusted Production Costs by Province (2030)

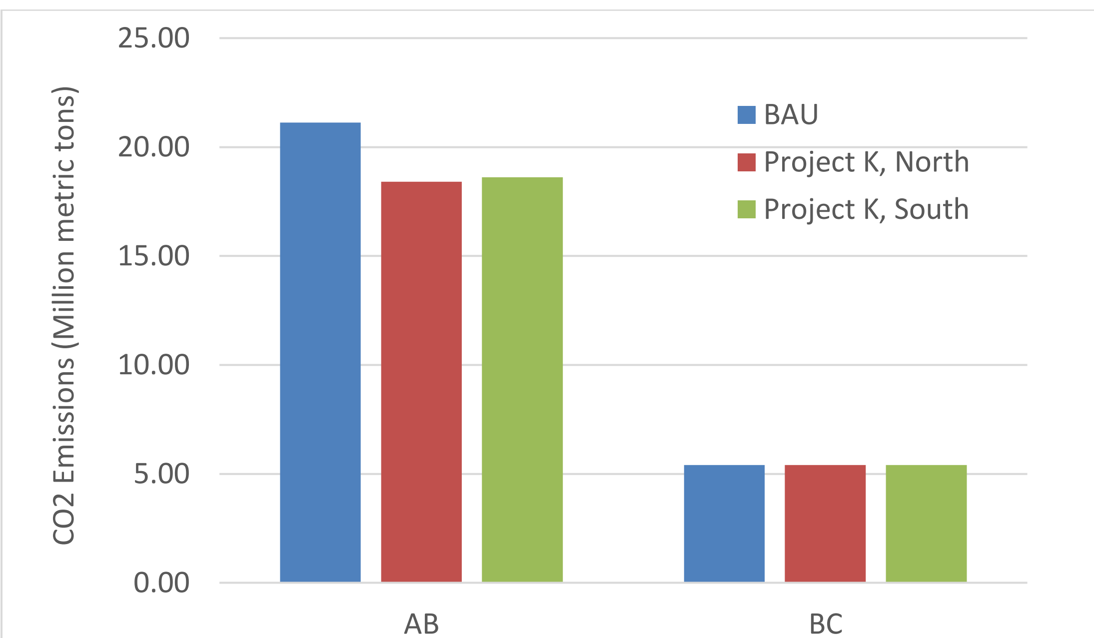


Figure 5-83: Project K - CO2 Emissions by Province (2030)

5.14 Comparison of All Projects

The figures and tables in this section provide a view of the system-wide impacts of the study projects, compared to the BAU scenario and also to each other.

These figures do not include capital cost impacts, which are considered later in Section 7 on project metrics.

Table 5-51: British Columbia Generation (2030)

BC Generation (2030) (TWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	STORAGE	Total
BAU	68.988	0.000	0.000	0.000	0.000	0.522	0.000	0.000	0.000	0.000	**69.510**
Project A, North	68.988	0.000	0.000	0.000	0.000	0.574	0.000	0.000	0.000	0.000	**69.562**
Project A, South	68.988	0.000	0.000	0.000	0.000	0.609	0.000	0.000	0.000	0.000	**69.597**
Project B BAU	68.988	0.000	0.000	0.000	0.000	0.522	0.000	0.000	0.000	0.000	**69.510**
Project B, Option 1	68.988	0.000	0.000	0.000	0.000	0.522	0.000	0.000	0.000	0.000	**69.510**
Project B, Option 2A	68.988	0.000	0.000	0.000	0.000	0.522	0.000	0.000	0.000	0.000	**69.510**
Project B, Option 2B	68.988	0.000	0.000	0.000	0.000	0.522	0.000	0.000	0.000	0.000	**69.510**
Project C	68.986	0.000	0.000	0.000	0.000	0.460	0.000	0.000	0.000	0.000	**69.446**
Project D, Option 1	68.988	0.000	0.000	0.000	0.000	0.483	0.000	0.000	0.000	0.000	**69.470**
Project D, Option 2	68.988	0.000	0.000	0.000	0.000	0.522	0.000	0.000	0.000	0.000	**69.510**
Project E, AB>CC, SK>CCS	68.989	0.000	0.000	0.000	0.000	0.180	0.000	0.000	0.000	0.000	**69.169**
Project E, AB>CC, SK>CC	68.989	0.000	0.000	0.000	0.000	0.180	0.000	0.000	0.000	0.000	**69.169**
Project F	68.986	0.000	0.000	0.000	0.000	0.424	0.000	0.000	0.000	0.000	**69.411**
Project G, Option 1	69.181	4.794	0.000	0.000	0.000	0.490	0.000	0.000	0.000	0.000	**74.465**
Project G, Option 2	69.131	6.470	0.000	0.000	0.000	0.498	0.000	0.000	0.000	0.000	**76.100**
Project G, Option 3	69.185	3.875	0.000	0.000	0.000	0.499	0.000	0.000	0.000	0.000	**73.559**
Project G, Option 4	68.991	9.759	0.000	0.000	0.000	0.477	0.000	0.000	0.000	0.000	**79.227**
Project H	68.988	0.000	0.000	0.000	0.000	0.498	0.000	0.000	0.000	0.000	**69.486**
Project I	68.989	0.000	0.000	0.000	0.000	0.467	0.000	0.000	0.000	0.000	**69.456**
Project J	68.987	0.000	0.000	0.000	0.000	0.538	0.000	0.000	0.000	0.000	**69.525**
Project K, North	68.987	0.512	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**69.500**
Project K, South	68.986	0.517	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**69.503**

Table 5-52: Alberta Generation (2030)

AB Generation (2030) (TWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	STORAGE	Total
Base	1.875	12.910	0.775	1.925	7.107	17.989	2.347	0.000	22.819	0.000	**67.746**
Project A, North	1.875	12.910	0.775	1.853	7.107	17.842	1.636	0.000	20.889	0.000	**64.886**
Project A, South	1.875	12.910	0.775	1.868	7.107	17.813	1.745	0.000	21.425	0.000	**65.516**
Project B BAU	1.875	12.910	0.775	1.925	7.107	17.989	2.347	0.000	22.819	0.000	**67.746**
Project B, Option 1	1.875	12.910	0.775	1.925	7.107	17.989	2.347	0.000	22.819	0.000	**67.746**
Project B, Option 2A	1.875	12.910	0.775	1.925	7.107	17.989	2.347	0.000	22.819	0.000	**67.746**
Project B, Option 2B	1.875	12.910	0.775	1.925	7.107	17.989	2.347	0.000	22.819	0.000	**67.746**
Project C	1.875	20.841	0.775	1.876	7.102	17.496	1.689	0.000	18.744	0.000	**70.397**
Project D, Option 1	3.689	12.910	0.775	1.890	7.107	17.831	1.750	0.000	22.188	0.000	**68.139**
Project D, Option 2	1.875	12.910	0.775	1.925	7.107	17.984	2.345	0.000	22.837	0.000	**67.757**
Project E, AB>CC, SK>CCS	1.875	12.910	0.775	1.629	7.107	36.946	0.165	0.000	14.308	0.000	**75.714**
Project E, AB>CC, SK>CC	1.875	12.910	0.775	1.629	7.107	36.946	0.165	0.000	14.308	0.000	**75.714**
Project F	1.875	20.814	0.775	1.839	7.107	16.759	1.171	0.000	20.480	-0.467	**70.352**
Project G, Option 1	1.875	12.910	0.775	1.927	7.107	17.995	2.353	0.000	22.824	0.000	**67.764**
Project G, Option 2	1.875	12.910	0.775	1.926	7.107	17.987	2.346	0.000	22.824	0.000	**67.749**
Project G, Option 3	1.875	12.910	0.775	1.926	7.107	17.994	2.352	0.000	22.825	0.000	**67.763**
Project G, Option 4	1.875	12.910	0.775	1.933	7.107	17.980	2.333	0.000	22.819	0.000	**67.730**
Project H	2.695	12.910	0.775	1.908	7.107	17.941	2.109	0.000	22.490	0.000	**67.934**
Project I	1.875	12.910	0.775	1.862	7.107	17.830	1.792	0.000	21.837	0.000	**65.986**
Project J	1.875	12.910	0.775	1.894	7.107	17.874	1.928	0.000	22.114	0.000	**66.476**
Project K, North	1.875	20.841	0.775	1.817	7.090	17.366	1.186	0.000	17.425	0.000	**68.374**
Project K, South	1.875	20.841	0.775	1.827	7.105	17.391	1.239	0.000	17.889	0.000	**68.941**

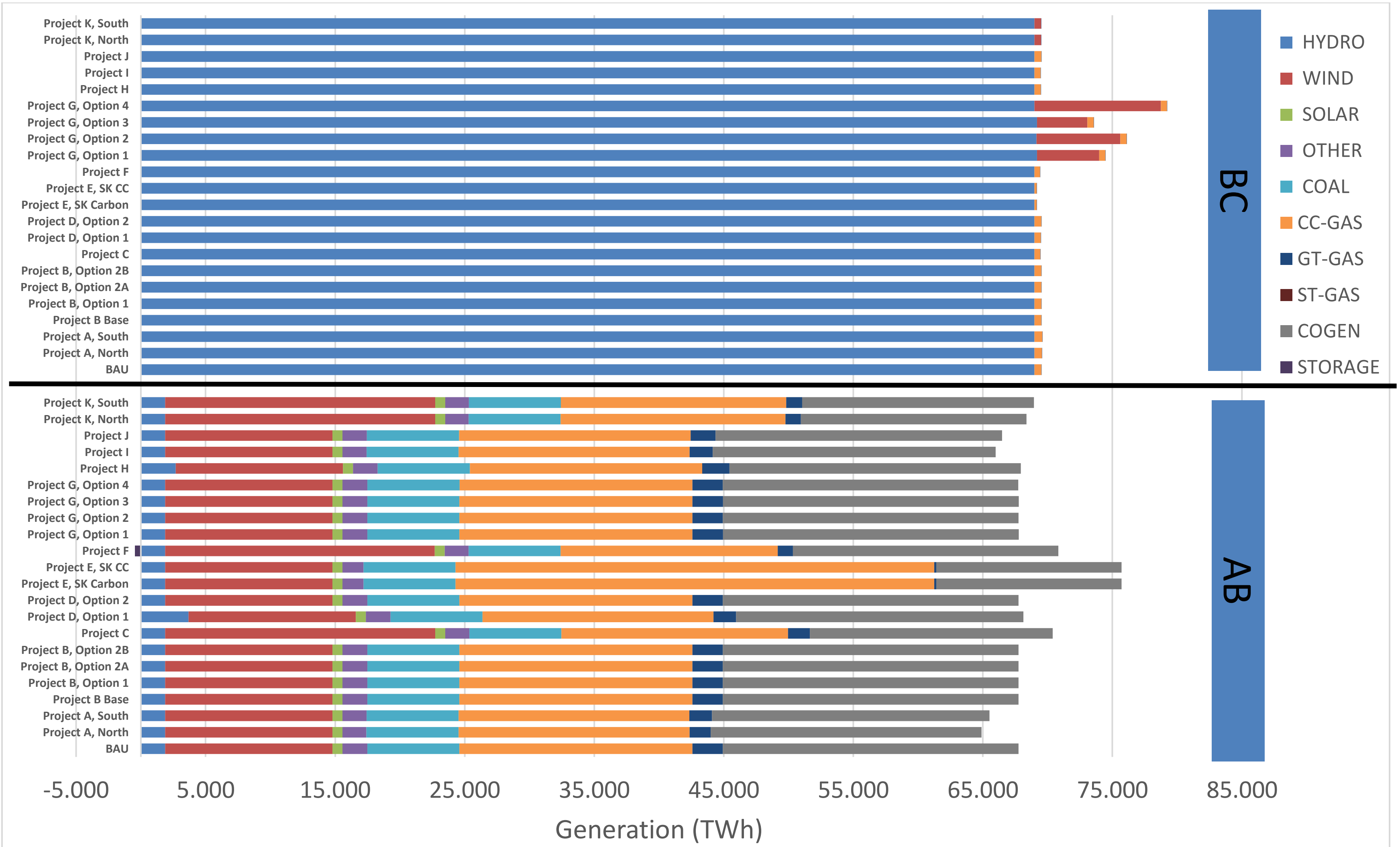


Figure 5-84: All Projects - Annual Generation by Type - BC & AB (2030)

Table 5-53: Saskatchewan Generation (2030)

SK Generation (2030) (TWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	STORAGE	Total
BAU	3.335	7.995	0.184	0.133	8.108	3.814	0.109	0.000	2.430	0.000	**26.108**
Project A, North	3.335	7.995	0.184	0.133	8.108	3.814	0.109	0.000	2.430	0.000	**26.108**
Project A, South	3.335	7.995	0.184	0.133	8.108	3.814	0.109	0.000	2.430	0.000	**26.108**
Project B BAU	3.488	7.943	0.184	0.133	7.785	3.209	0.055	0.000	2.378	0.000	**25.175**
Project B, Option 1	3.476	7.989	0.184	0.113	6.962	2.235	0.030	0.000	2.312	0.000	**23.301**
Project B, Option 2A	3.485	7.989	0.184	0.126	7.543	2.682	0.035	0.000	2.341	0.000	**24.384**
Project B, Option 2B	3.485	7.988	0.184	0.127	7.572	2.717	0.034	0.000	2.338	0.000	**24.445**
Project C	3.335	7.995	0.184	0.133	8.108	3.814	0.109	0.000	2.430	0.000	**26.108**
Project D, Option 1	3.392	7.995	0.184	0.133	8.150	3.741	0.106	0.000	2.433	0.000	**26.133**
Project D, Option 2	3.624	8.042	0.180	0.133	8.022	3.412	0.063	0.000	2.379	0.000	**25.855**
Project E, AB>CC, SK>CCS	3.314	8.001	0.184	0.137	6.257	5.056	0.280	0.000	2.525	0.000	**25.753**
Project E, AB>CC, SK>CC	3.344	7.996	0.184	0.137	0.806	10.994	0.086	0.000	2.372	0.000	**25.919**
Project F	3.347	8.021	0.183	0.138	8.540	3.428	0.032	0.000	2.408	-0.047	**26.052**
Project G, Option 1	3.335	7.995	0.184	0.133	8.108	3.814	0.109	0.000	2.430	0.000	**26.108**
Project G, Option 2	3.335	7.995	0.184	0.133	8.108	3.814	0.109	0.000	2.430	0.000	**26.108**
Project G, Option 3	3.335	7.995	0.184	0.133	8.108	3.814	0.109	0.000	2.430	0.000	**26.108**
Project G, Option 4	3.335	7.995	0.184	0.133	8.108	3.814	0.109	0.000	2.430	0.000	**26.108**
Project H	3.335	7.995	0.184	0.133	8.108	3.814	0.109	0.000	2.430	0.000	**26.108**
Project I	3.333	8.028	0.184	0.142	8.704	5.266	0.034	0.000	2.535	0.000	**28.227**
Project J	3.335	7.995	0.184	0.133	8.108	3.814	0.109	0.000	2.430	0.000	**26.108**
Project K, North	3.335	7.995	0.184	0.133	8.108	3.814	0.109	0.000	2.430	0.000	**26.108**
Project K, South	3.335	7.995	0.184	0.133	8.108	3.814	0.109	0.000	2.430	0.000	**26.108**

Table 5-54: Manitoba Generation (2030

MB Generation (2030) (TWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	STORAGE	Total
BAU	36.287	0.913	0.000	0.000	0.000	0.000	0.008	0.048	0.000	0.000	**37.255**
Project A, North	36.287	0.913	0.000	0.000	0.000	0.000	0.008	0.048	0.000	0.000	**37.255**
Project A, South	36.287	0.913	0.000	0.000	0.000	0.000	0.008	0.048	0.000	0.000	**37.255**
Project B BAU	36.495	0.916	0.000	0.000	0.000	0.000	0.004	0.048	0.000	0.000	**37.463**
Project B, Option 1	36.747	0.927	0.000	0.000	0.000	0.000	0.004	0.048	0.000	0.000	**37.725**
Project B, Option 2A	36.720	0.894	0.000	0.000	0.000	0.000	0.005	0.048	0.000	0.000	**37.666**
Project B, Option 2B	36.677	0.904	0.000	0.000	0.000	0.000	0.005	0.048	0.000	0.000	**37.634**
Project C	36.284	0.913	0.000	0.000	0.000	0.000	0.008	0.048	0.000	0.000	**37.253**
Project D, Option 1	36.298	0.913	0.000	0.000	0.000	0.000	0.009	0.048	0.000	0.000	**37.267**
Project D, Option 2	36.150	0.896	0.000	0.000	0.000	0.000	0.008	0.047	0.000	0.000	**37.101**
Project E, AB>CC, SK>CCS	36.245	0.913	0.000	0.000	0.000	0.000	0.009	0.048	0.000	0.000	**37.214**
Project E, AB>CC, SK>CC	36.281	0.912	0.000	0.000	0.000	0.000	0.009	0.048	0.000	0.000	**37.250**
Project F	36.299	0.914	0.000	0.000	0.000	0.000	0.009	0.048	0.000	0.000	**37.269**
Project G, Option 1	36.287	0.913	0.000	0.000	0.000	0.000	0.008	0.048	0.000	0.000	**37.255**
Project G, Option 2	36.287	0.913	0.000	0.000	0.000	0.000	0.008	0.048	0.000	0.000	**37.255**
Project G, Option 3	36.287	0.913	0.000	0.000	0.000	0.000	0.008	0.048	0.000	0.000	**37.255**
Project G, Option 4	36.287	0.913	0.000	0.000	0.000	0.000	0.008	0.048	0.000	0.000	**37.255**
Project H	36.287	0.913	0.000	0.000	0.000	0.000	0.008	0.048	0.000	0.000	**37.255**
Project I	36.258	0.909	0.000	0.000	0.000	0.000	0.008	0.048	0.000	0.000	**37.224**
Project J	36.287	0.913	0.000	0.000	0.000	0.000	0.008	0.048	0.000	0.000	**37.255**
Project K, North	36.284	0.913	0.000	0.000	0.000	0.000	0.008	0.048	0.000	0.000	**37.253**
Project K, South	36.284	0.913	0.000	0.000	0.000	0.000	0.008	0.048	0.000	0.000	**37.253**

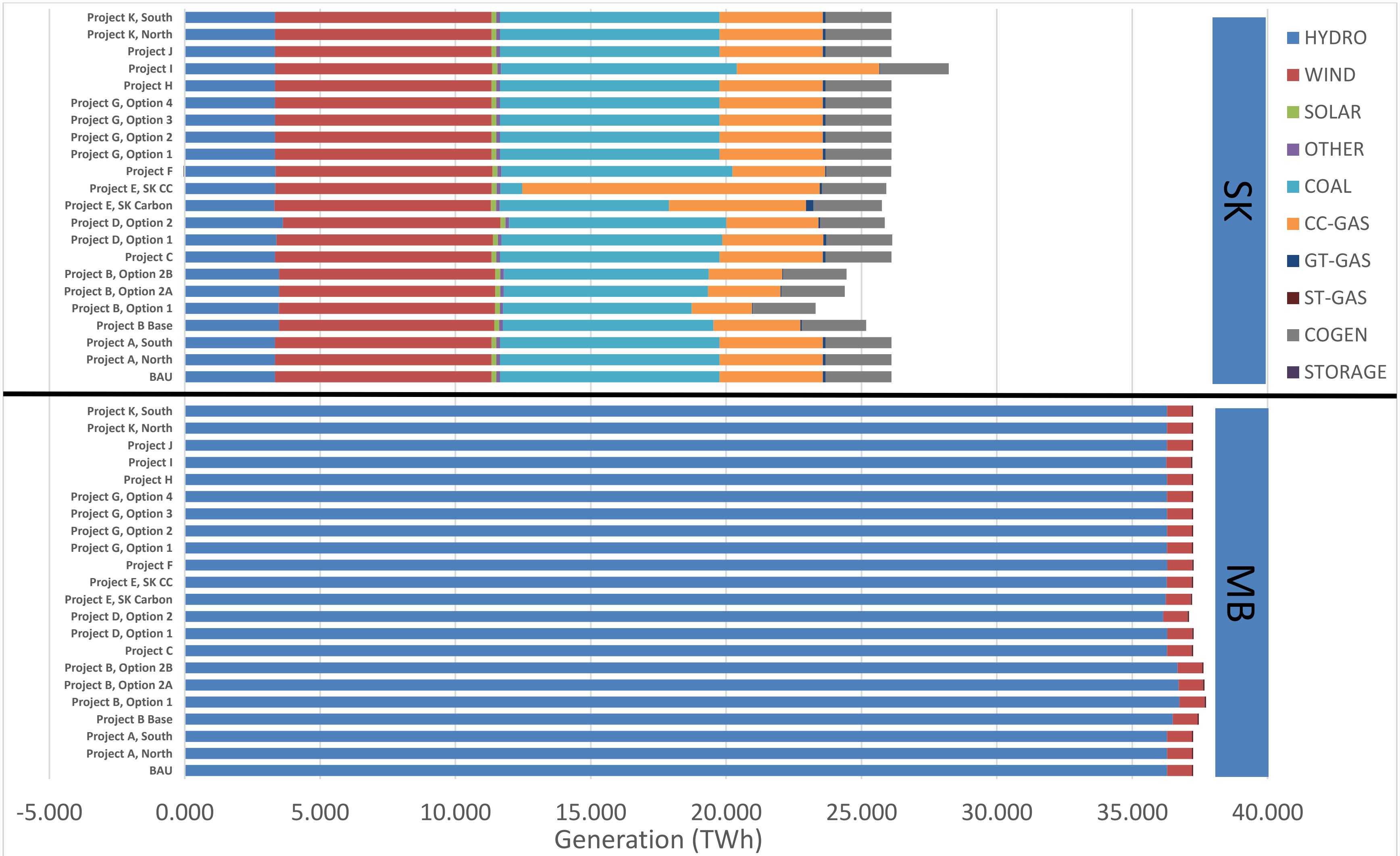


Figure 5-85: All Projects - Annual Generation by Type - SK & MB (2030)

Table 5-55: British Columbia Generation (2040)

BC Generation (2040) (TWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	STORAGE	Total
BAU	65.915	10.599	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**76.515**
Project A, North	65.919	10.599	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**76.518**
Project A, South	65.918	10.599	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**76.517**
Project B BAU	65.915	10.599	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**76.515**
Project B, Option 1	65.915	10.599	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**76.515**
Project B, Option 2A	65.915	10.599	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**76.515**
Project B, Option 2B	65.915	10.599	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**76.515**
Project C	65.915	10.599	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**76.515**
Project D, Option 1	65.915	10.599	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**76.514**
Project D, Option 2	65.915	10.599	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**76.515**
Project E, AB>CC, SK>CCS	65.915	10.599	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**76.515**
Project E, AB>CC, SK>CC	65.915	10.599	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**76.515**
Project F	65.916	10.599	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**76.515**
Project G, Option 1	66.083	15.477	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**81.561**
Project G, Option 2	65.987	17.186	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**83.174**
Project G, Option 3	66.091	14.548	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**80.639**
Project G, Option 4	65.773	20.510	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**86.283**
Project H	65.915	10.599	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**76.515**
Project I	65.915	10.599	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**76.514**
Project J	65.917	10.599	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**76.517**
Project K, North	65.919	10.599	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**76.518**
Project K, South	65.917	10.599	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**76.517**

Table 5-56: Alberta Generation (2040)

AB Generation (2040) (TWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	STORAGE	Total
BAU	1.875	12.871	0.774	1.850	0.000	47.627	0.232	0.000	15.324	0.000	**80.555**
Project A, North	1.875	12.871	0.774	1.840	0.000	49.306	0.276	0.000	15.106	0.000	**82.050**
Project A, South	1.875	12.871	0.774	1.845	0.000	49.101	0.282	0.000	15.285	0.000	**82.033**
Project B BAU	1.875	12.871	0.774	1.850	0.000	47.627	0.232	0.000	15.324	0.000	**80.555**
Project B, Option 1	1.875	12.871	0.774	1.850	0.000	47.627	0.232	0.000	15.324	0.000	**80.555**
Project B, Option 2A	1.875	12.871	0.774	1.850	0.000	47.627	0.232	0.000	15.324	0.000	**80.555**
Project B, Option 2B	1.875	12.871	0.774	1.850	0.000	47.627	0.232	0.000	15.324	0.000	**80.555**
Project C	1.875	20.815	0.774	1.758	0.000	45.251	0.124	0.000	11.600	0.000	**82.197**
Project D, Option 1	3.689	12.871	0.774	1.851	0.000	45.907	0.214	0.000	15.296	0.000	**80.603**
Project D, Option 2	7.136	12.871	0.774	1.850	0.000	42.560	0.203	0.000	15.258	0.000	**80.652**
Project E, AB>CC, SK>CCS	1.875	12.871	0.774	1.850	0.000	47.627	0.232	0.000	15.324	0.000	**80.555**
Project E, AB>CC, SK>CC	1.875	12.871	0.774	1.850	0.000	47.627	0.232	0.000	15.324	0.000	**80.555**
Project F	1.875	20.798	0.774	1.846	0.000	40.075	0.274	0.000	15.216	-0.004	**80.854**
Project G, Option 1	1.875	12.871	0.774	1.848	0.000	47.743	0.231	0.000	15.289	0.000	**80.632**
Project G, Option 2	1.875	12.871	0.774	1.848	0.000	47.810	0.224	0.000	15.265	0.000	**80.668**
Project G, Option 3	1.875	12.871	0.774	1.849	0.000	47.721	0.232	0.000	15.300	0.000	**80.623**
Project G, Option 4	1.875	12.871	0.774	1.847	0.000	47.952	0.219	0.000	15.221	0.000	**80.759**
Project H	2.695	12.871	0.774	1.852	0.000	46.809	0.224	0.000	15.333	0.000	**80.558**
Project I	1.875	12.871	0.774	1.851	0.000	45.189	0.225	0.000	15.282	0.000	**78.067**
Project J	1.875	12.871	0.774	1.849	0.000	47.558	0.229	0.000	15.279	0.000	**80.435**
Project K, North	1.875	20.814	0.774	1.759	0.000	46.870	0.158	0.000	11.674	0.000	**83.924**
Project K, South	1.875	20.813	0.774	1.761	0.000	46.831	0.160	0.000	11.741	0.000	**83.956**

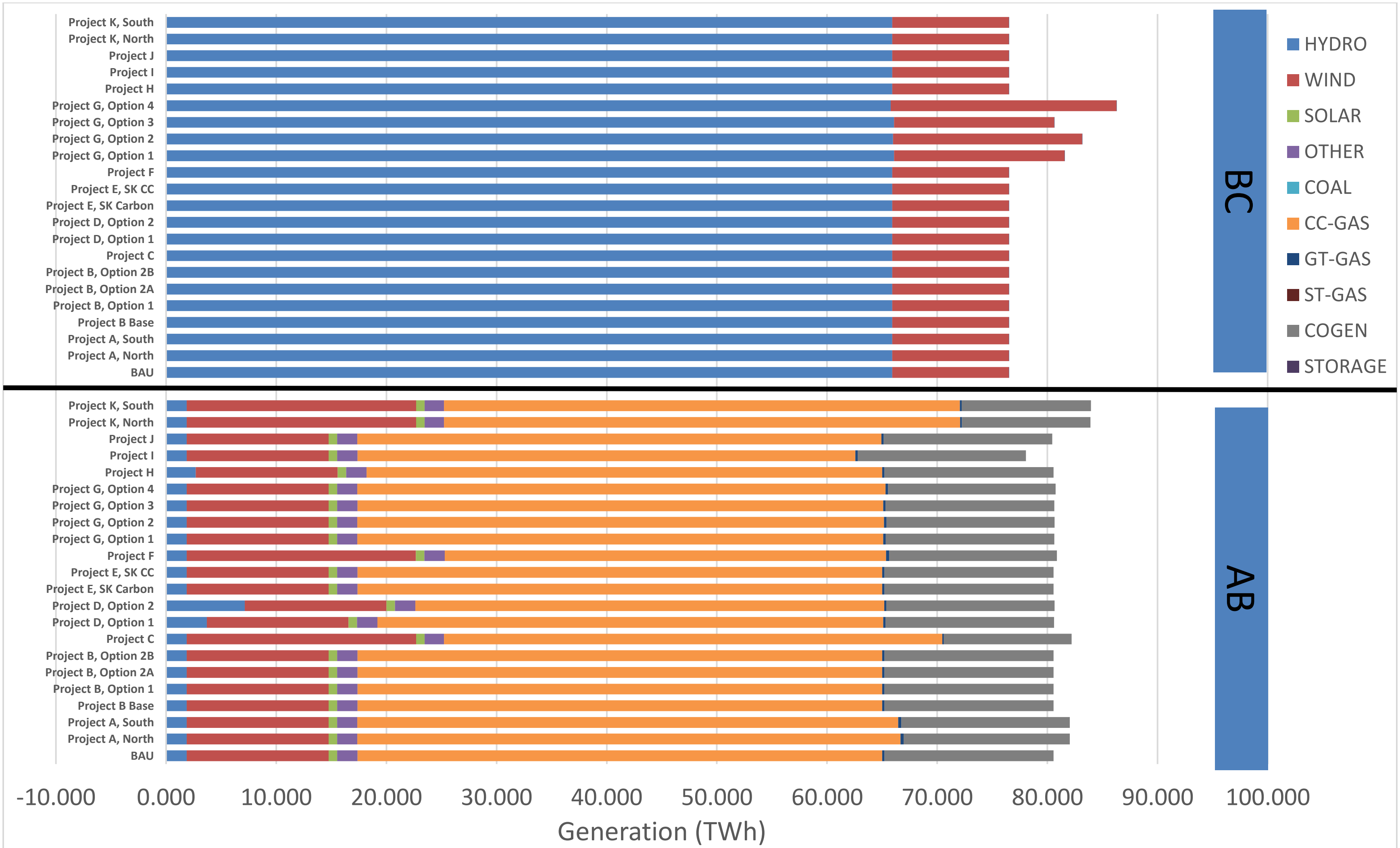


Figure 5-86: All Projects - Annual Generation by Type - BC & AB (2040)

Table 5-57: Saskatchewan Generation (2040)

SK Generation (2040) (TWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	STORAGE	Total
BAU	3.515	8.092	0.184	0.146	8.742	7.191	0.420	0.000	1.391	0.000	**29.681**
Project A, North	3.515	8.092	0.184	0.146	8.742	7.191	0.420	0.000	1.391	0.000	**29.681**
Project A, South	3.515	8.092	0.184	0.146	8.742	7.191	0.420	0.000	1.391	0.000	**29.681**
Project B BAU	3.539	8.068	0.184	0.144	8.539	6.365	0.231	0.000	1.329	0.000	**28.400**
Project B, Option 1	3.536	8.029	0.184	0.134	7.944	4.605	0.138	0.000	1.299	0.000	**25.870**
Project B, Option 2A	3.538	8.063	0.184	0.142	8.402	5.756	0.137	0.000	1.322	0.000	**27.543**
Project B, Option 2B	3.537	8.062	0.184	0.142	8.408	5.777	0.145	0.000	1.323	0.000	**27.579**
Project C	3.515	8.092	0.184	0.146	8.742	7.191	0.420	0.000	1.392	0.000	**29.681**
Project D, Option 1	3.989	8.093	0.184	0.145	8.707	6.970	0.346	0.000	1.365	0.000	**29.800**
Project D, Option 2	4.056	8.096	0.184	0.145	8.672	6.632	0.236	0.000	1.339	0.000	**29.361**
Project E, AB>CC, SK>CCS	3.513	8.093	0.184	0.146	6.699	8.435	0.853	0.000	1.440	0.000	**29.362**
Project E, AB>CC, SK>CC	3.517	8.087	0.184	0.145	0.831	15.098	0.410	0.000	1.373	0.000	**29.644**
Project F	3.511	8.109	0.184	0.149	9.234	7.133	0.157	0.000	1.355	-0.047	**29.786**
Project G, Option 1	3.515	8.092	0.184	0.146	8.742	7.191	0.420	0.000	1.391	0.000	**29.681**
Project G, Option 2	3.515	8.092	0.184	0.146	8.742	7.191	0.420	0.000	1.391	0.000	**29.681**
Project G, Option 3	3.515	8.092	0.184	0.146	8.742	7.191	0.420	0.000	1.391	0.000	**29.681**
Project G, Option 4	3.515	8.092	0.184	0.146	8.742	7.191	0.420	0.000	1.391	0.000	**29.681**
Project H	3.515	8.092	0.184	0.146	8.742	7.191	0.420	0.000	1.391	0.000	**29.681**
Project I	3.517	8.112	0.184	0.149	9.105	8.713	0.681	0.000	1.458	0.000	**31.919**
Project J	3.515	8.092	0.184	0.146	8.742	7.191	0.420	0.000	1.391	0.000	**29.681**
Project K, North	3.515	8.092	0.184	0.146	8.742	7.191	0.420	0.000	1.392	0.000	**29.681**
Project K, South	3.515	8.092	0.184	0.146	8.742	7.191	0.420	0.000	1.392	0.000	**29.681**

Table 5-58: Manitoba Generation (2040)

AB Generation (2040) (TWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	STORAGE	Total
BAU	37.473	0.966	0.000	0.000	0.000	1.313	0.014	0.073	0.000	0.000	**39.838**
Project A, North	37.473	0.966	0.000	0.000	0.000	1.313	0.014	0.073	0.000	0.000	**39.838**
Project A, South	37.473	0.966	0.000	0.000	0.000	1.313	0.014	0.073	0.000	0.000	**39.838**
Project B BAU	37.536	0.968	0.000	0.000	0.000	1.364	0.011	0.073	0.000	0.000	**39.952**
Project B, Option 1	37.629	0.982	0.000	0.000	0.000	1.391	0.007	0.074	0.000	0.000	**40.083**
Project B, Option 2A	37.620	0.937	0.000	0.000	0.000	1.372	0.008	0.074	0.000	0.000	**40.011**
Project B, Option 2B	37.619	0.947	0.000	0.000	0.000	1.367	0.008	0.074	0.000	0.000	**40.015**
Project C	37.474	0.966	0.000	0.000	0.000	1.313	0.014	0.073	0.000	0.000	**39.839**
Project D, Option 1	37.474	0.966	0.000	0.000	0.000	1.306	0.017	0.072	0.000	0.000	**39.835**
Project D, Option 2	37.571	0.958	0.000	0.000	0.000	1.322	0.015	0.072	0.000	0.000	**39.938**
Project E, AB>CC, SK>CCS	37.474	0.966	0.000	0.000	0.000	1.332	0.015	0.073	0.000	0.000	**39.861**
Project E, AB>CC, SK>CC	37.473	0.967	0.000	0.000	0.000	1.304	0.015	0.072	0.000	0.000	**39.831**
Project F	37.474	0.967	0.000	0.000	0.000	1.315	0.015	0.072	0.000	0.000	**39.843**
Project G, Option 1	37.473	0.966	0.000	0.000	0.000	1.313	0.014	0.073	0.000	0.000	**39.838**
Project G, Option 2	37.473	0.966	0.000	0.000	0.000	1.313	0.014	0.073	0.000	0.000	**39.838**
Project G, Option 3	37.473	0.966	0.000	0.000	0.000	1.313	0.014	0.073	0.000	0.000	**39.838**
Project G, Option 4	37.473	0.966	0.000	0.000	0.000	1.313	0.014	0.073	0.000	0.000	**39.838**
Project H	37.473	0.966	0.000	0.000	0.000	1.313	0.014	0.073	0.000	0.000	**39.838**
Project I	37.472	0.966	0.000	0.000	0.000	1.323	0.015	0.073	0.000	0.000	**39.849**
Project J	37.473	0.966	0.000	0.000	0.000	1.313	0.014	0.073	0.000	0.000	**39.838**
Project K, North	37.474	0.966	0.000	0.000	0.000	1.313	0.014	0.073	0.000	0.000	**39.839**
Project K, South	37.474	0.966	0.000	0.000	0.000	1.313	0.014	0.073	0.000	0.000	**39.839**

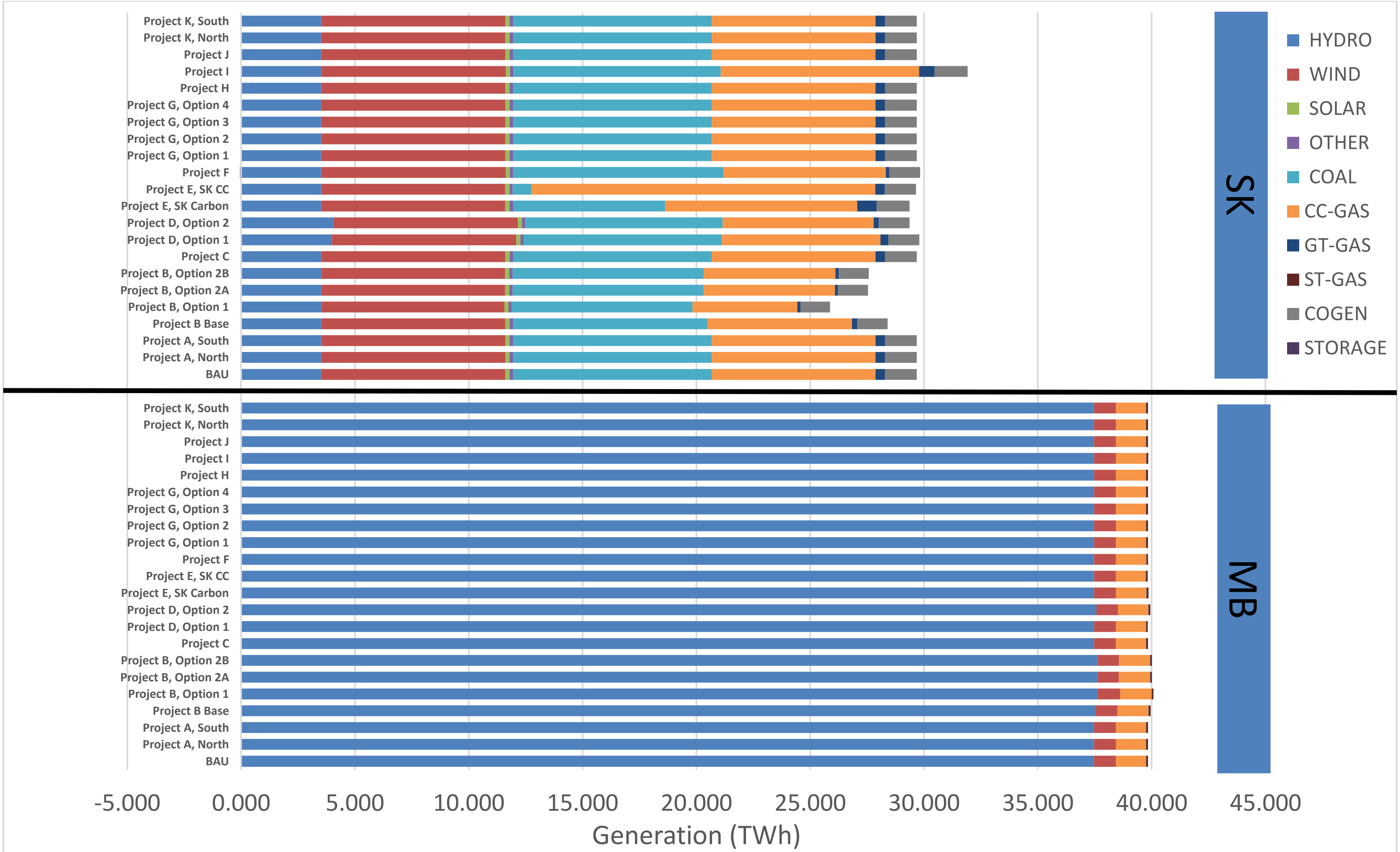


Figure 5-87: All Projects - Annual Generation by Type - SK & MB (2040)

Table 5-59: Adjusted Production Costs (2030)

Adjusted Production Costs (2030) ($MM)	AB	BC	MB	SK	Total West	Total East
BAU	3,165.0	-187.1	-74.7	720.2	**2,977.9**	**645.5**
Project A, North	3,087.0	-285.8	-74.7	720.3	**2,801.2**	**645.6**
Project A, South	3,108.7	-264.3	-74.7	720.3	**2,844.4**	**645.6**
Project B BAU	3,165.0	-187.1	-94.3	678.4	**2,977.9**	**584.2**
Project B, Option 1	3,165.0	-187.1	-211.5	712.6	**2,977.9**	**501.1**
Project B, Option 2B	3,165.0	-187.1	-158.2	702.3	**2,977.9**	**544.1**
Project B, Option 2A	3,165.0	-187.1	-155.7	702.5	**2,977.9**	**546.8**
Project C	2,753.6	-144.7	-74.7	720.3	**2,608.9**	**645.6**
Project D, Option 1	3,033.3	-172.2	-74.9	715.7	**2,861.1**	**640.7**
Project D, Option 2	3,165.3	-186.8	-78.4	681.4	**2,978.4**	**603.0**
Project E, AB>CC, SK>CCS	3,281.5	-110.0	-74.4	851.5	**3,171.4**	**777.1**
Project E, AB>CC, SK>CC	3,281.5	-110.0	-75.7	897.0	**3,171.4**	**821.3**
Project F	2,751.1	-142.1	-74.4	685.5	**2,609.0**	**611.1**
Project G, Option 1	3,165.5	-188.9	-74.7	720.2	**2,976.6**	**645.5**
Project G, Option 2	3,164.6	-188.0	-74.7	720.2	**2,976.6**	**645.5**
Project G, Option 3	3,165.6	-187.8	-74.7	720.2	**2,977.9**	**645.5**
Project G, Option 4	3,162.1	-186.8	-74.7	720.2	**2,975.3**	**645.5**
Project H	3,107.1	-180.8	-74.7	720.2	**2,926.4**	**645.5**
Project I	3,107.3	-165.1	-74.0	718.9	**2,942.2**	**644.9**
Project J	3,130.2	-233.4	-74.7	720.2	**2,896.9**	**645.5**
Project K, North	2,697.4	-214.9	-74.7	720.3	**2,482.4**	**645.6**
Project K, South	2,715.9	-201.5	-74.7	720.3	**2,514.4**	**645.6**

Table 5-60: Adjusted Production Costs (2040)

Adjusted Production Costs (2040) ($MM)	AB	BC	MB	SK	Total West	Total East
BAU	4,766.3	-195.8	63.8	1,103.7	**4,570.4**	**1,167.5**
Project A, North	4,898.1	-243.4	63.8	1,103.7	**4,654.6**	**1,167.5**
Project A, South	4,895.8	-242.0	63.8	1,103.7	**4,653.8**	**1,167.5**
Project B BAU	4,766.3	-195.8	41.1	1,029.4	**4,570.4**	**1,070.5**
Project B, Option 1	4,766.3	-195.8	-128.0	1,040.8	**4,570.4**	**912.8**
Project B, Option 2B	4,766.3	-195.8	-38.8	1,049.1	**4,570.4**	**1,010.3**
Project B, Option 2A	4,766.3	-195.8	-37.3	1,049.5	**4,570.4**	**1,012.2**
Project C	4,294.5	-196.5	63.8	1,103.7	**4,098.0**	**1,167.5**
Project D, Option 1	4,631.4	-194.2	63.3	1,070.4	**4,437.1**	**1,133.7**
Project D, Option 2	4,374.8	-190.1	57.4	1,031.3	**4,184.7**	**1,088.7**
Project E, AB>CC, SK>CCS	4,766.3	-195.8	65.8	1,289.0	**4,570.4**	**1,354.8**
Project E, AB>CC, SK>CC	4,766.3	-195.8	63.0	1,379.6	**4,570.4**	**1,442.5**
Project F	4,227.2	-195.8	63.8	1,056.5	**4,031.4**	**1,120.3**
Project G, Option 1	4,769.6	-200.4	63.8	1,103.7	**4,569.1**	**1,167.5**
Project G, Option 2	4,770.8	-200.7	63.8	1,103.7	**4,570.1**	**1,167.5**
Project G, Option 3	4,769.0	-198.3	63.8	1,103.7	**4,570.7**	**1,167.5**
Project G, Option 4	4,775.6	-198.5	63.8	1,103.7	**4,577.1**	**1,167.5**
Project H	4,704.0	-195.0	63.8	1,103.7	**4,509.0**	**1,167.5**
Project I	4,729.3	-196.2	65.1	1,133.4	**4,533.1**	**1,198.5**
Project J	4,765.5	-201.0	63.8	1,103.7	**4,564.5**	**1,167.5**
Project K, North	4,440.3	-249.3	63.8	1,103.7	**4,191.0**	**1,167.5**
Project K, South	4,440.1	-246.7	63.8	1,103.7	**4,193.5**	**1,167.5**

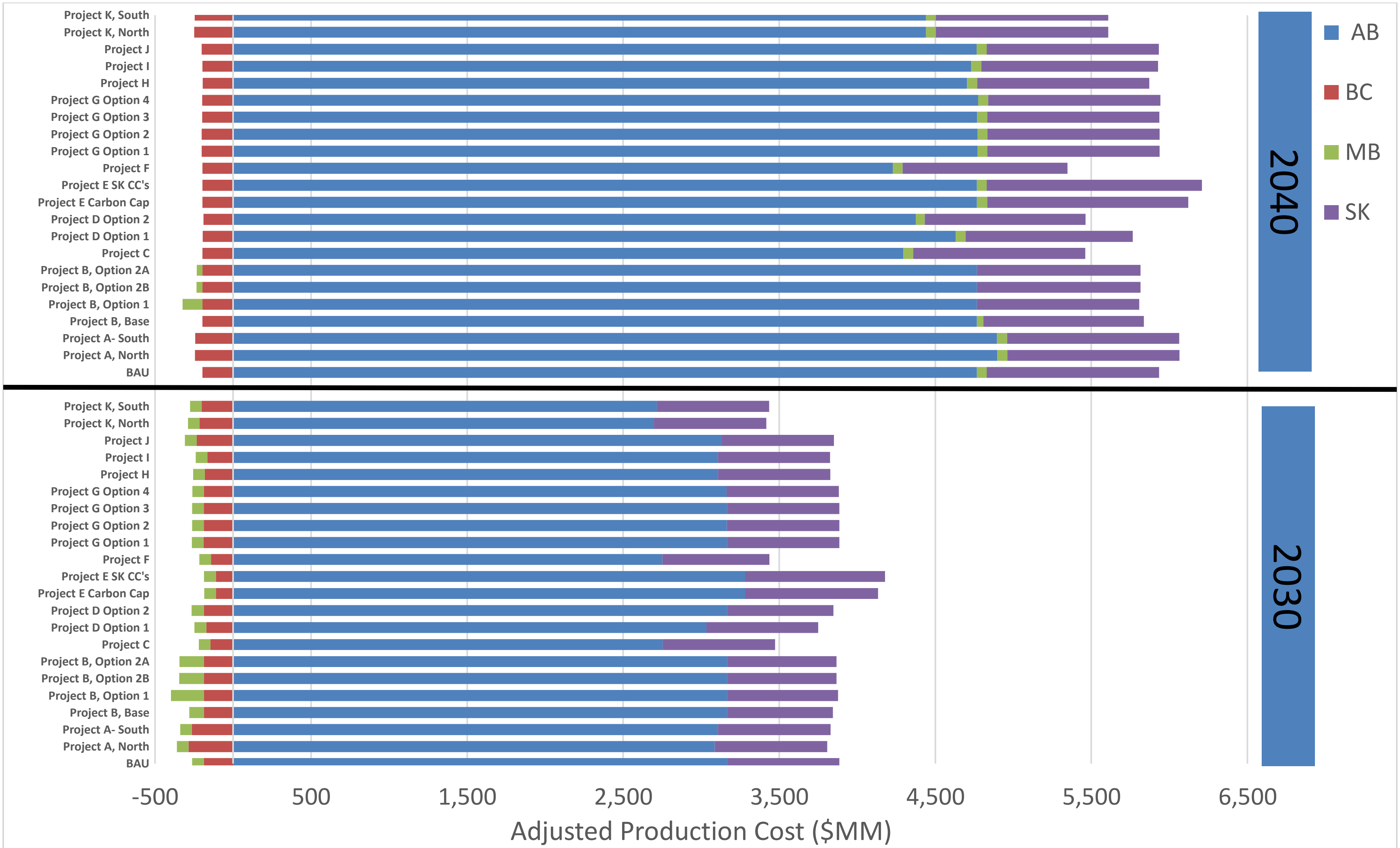


Figure 5-88: All Projects - Adjusted Production Costs

Table 5-61: Carbon Emissions (2030)

CO2 Emissions (2030) (Million Tonne)	AB	BC	MB	SK	Total West	Total East
BAU	21.1	5.4	0.0	11.3	**26.5**	**11.4**
Project A, North	20.0	5.4	0.0	11.3	**25.4**	**11.4**
Project A, South	20.2	5.4	0.0	11.3	**25.7**	**11.4**
Project B BAU	21.1	5.4	0.0	10.7	**26.5**	**10.8**
Project B, Option 1	21.1	5.4	0.0	9.6	**26.5**	**9.6**
Project B, Option 2A	21.1	5.4	0.0	10.3	**26.5**	**10.3**
Project B, Option 2B	21.1	5.4	0.0	10.3	**26.5**	**10.4**
Project C	19.2	5.4	0.0	11.3	**24.6**	**11.4**
Project D, Option 1	20.5	5.4	0.0	11.3	**25.9**	**11.4**
Project D, Option 2	21.1	5.4	0.0	11.0	**26.5**	**11.1**
Project E, AB>CC, SK>CCS	23.4	5.2	0.0	4.4	**28.6**	**4.5**
Project E, AB>CC, SK>CC	23.4	5.2	0.0	5.3	**28.6**	**5.3**
Project F	19.3	5.4	0.0	11.5	**24.6**	**11.6**
Project G, Option 1	21.1	2.8	0.0	11.3	**23.9**	**11.4**
Project G, Option 2	21.1	1.9	0.0	11.3	**23.1**	**11.4**
Project G, Option 3	21.1	3.3	0.0	11.3	**24.4**	**11.4**
Project G, Option 4	21.1	0.2	0.0	11.3	**21.3**	**11.4**
Project H	20.9	5.4	0.0	11.3	**26.3**	**11.4**
Project I	20.4	5.4	0.0	12.5	**25.8**	**12.5**
Project J	20.6	5.4	0.0	11.3	**26.0**	**11.4**
Project K, North	18.4	5.4	0.0	11.3	**23.8**	**11.4**
Project K, South	18.6	5.4	0.0	11.3	**24.0**	**11.4**

Table 5-62: Carbon Emissions (2040)

CO2 Emissions (2040) (Million Tonne)	AB	BC	MB	SK	Total West	Total East
BAU	21.4	5.2	0.5	12.8	**26.6**	**13.3**
Project A, North	22.0	5.2	0.5	12.8	**27.1**	**13.3**
Project A, South	22.0	5.2	0.5	12.8	**27.1**	**13.3**
Project B BAU	21.4	5.2	0.6	12.2	**26.6**	**12.7**
Project B, Option 1	21.4	5.2	0.6	10.9	**26.6**	**11.5**
Project B, Option 2A	21.4	5.2	0.6	11.8	**26.6**	**12.3**
Project B, Option 2B	21.4	5.2	0.6	11.8	**26.6**	**12.4**
Project C	19.5	5.2	0.5	12.8	**24.7**	**13.3**
Project D, Option 1	20.8	5.2	0.5	12.6	**26.0**	**13.2**
Project D, Option 2	19.7	5.2	0.5	12.4	**24.8**	**12.9**
Project E, AB>CC, SK>CCS	21.4	5.2	0.5	5.4	**26.6**	**6.0**
Project E, AB>CC, SK>CC	21.4	5.2	0.5	6.3	**26.6**	**6.9**
Project F	18.9	5.2	0.5	13.1	**24.1**	**13.6**
Project G, Option 1	21.5	2.6	0.5	12.8	**24.0**	**13.3**
Project G, Option 2	21.5	1.7	0.5	12.8	**23.2**	**13.3**
Project G, Option 3	21.5	3.0	0.5	12.8	**24.5**	**13.3**
Project G, Option 4	21.5	0.0	0.5	12.8	**21.5**	**13.3**
Project H	21.2	5.2	0.5	12.8	**26.3**	**13.3**
Project I	20.6	5.2	0.5	13.8	**25.8**	**14.4**
Project J	21.4	5.2	0.5	12.8	**26.6**	**13.3**
Project K, North	21.4	5.2	0.5	12.8	**26.6**	**13.3**
Project K, South	20.1	5.2	0.5	12.8	**25.3**	**13.3**

Figure 5-89: All Projects - CO2 Emissions by Project

6 Sensitivity Analysis

6.1 Sensitivities Evaluated in this Study

A number of sensitivity analyses were performed in order to assess the impact of a number of variables on generation dispatch, adjusted production costs, and CO2 emissions.

The generation build-out is assumed to remain constant in all jurisdictions and for all sensitivities, except for additional generation capacity that was explicitly added to some of the projects.

Due to the sizable number of projects and options evaluated in this study, applying the sensitivities to all the projects and options, and analyzing all the results, would have been a daunting task. Instead, the TAC members were asked to select a sub-set of projects and options for evaluation in the sensitivity analysis. The list of sensitivities was reviewed and approved by the TAC members.

Table 6-1 provides a short description of the sensitivities. Table 6-2 lists the sensitivities together with the projects and options that were selected for the sensitivity analysis.

Table 6-1: List of Sensitivities

Sensitivity	Description
High Carbon Price	• Carbon Price at CAD$130/Metric Ton in 2030
Carbon Border Tariff	• Carbon Border Tariff based on Canada Carbon Price, applied to annual CO2 Tonne/MWh of generation in neighbouring USA Pools
High Carbon Price + Carbon Border Tariff	• Carbon Price at CAD$130/Metric Ton in 2030 • Carbon Border Tariff based on Canada Carbon Price applied to annual CO2 Tonne/MWh of generation in neighbouring USA Pools
High Gas Price	• Higher gas prices in Canada and USA by 57% over the BAU scenario
Real-Time Hydro	• Hydro dispatch after Real-Time Wind instead of 24-Hour Forecast Wind.
Operating Reserves	• Re-run of BAU Scenario with +/- 50% of BAU Wind Variability Reserves (This sensitivity covers the Task 2.2 scope)

Table 6-2: List of Sensitivities

Projects \ Sensitivities	High Carbon Price	Carbon Border Tariff	High Carbon Price + Carbon Border Tariff	High Gas Price	Real Time Hydro	Operating Reserves	Total
BAU	2 Runs: EI & WI	2 Runs: EI & WI	2 Runs: EI & WI	2 Runs: EI & WI	2 Runs: EI & WI	4 Runs: EI & WI	14
Project A: New Intertie BC & AB			1 Run: WI, Southern Route		1 Run: WI, Southern Route		2
Project B: New Intertie SK & MB			1 Run: EI, Option 1	1 Run: EI, Option 1	1 Run: EI, Option 1		3
Project C: New internal Transmission							
Project D: New Hydro in AB & SK			4 Runs: EI & WI, Options 1 & 2	2 Runs: EI, Options 1 & 2	2 Runs: EI & WI, Option 1		8
Project E: Coal Conversion			2 Runs: EI & WI	2 Runs: EI, Options 1 & 2			4
Project F: Bulk Storage			1 Run: WI				1
Project G: LNG Conversion							
Project H: Taltson Hydro							
Project I: New Intertie SK & AB				1 Run: EI			1
Project J: BC-AB and MATL Simultaneous Transfer Capability			1 Run: WI				1
Project K: A + C			1 Run: WI				1
Total	2	2	13	8	6	4	35

6.2 High Carbon Price and Carbon Border Tariff

The High Carbon Price and Carbon Border Tariff sensitivity considers the impact of higher carbon prices in Canada and a carbon price related tariff on imports of electricity from the USA, on the operational, emissions, and economic performance of the selected projects and options.

A higher Canada Carbon Price without an equivalent carbon price in the USA will simply result in a comparative advantage for the USA based power generation relative to Canada based generation, and cause an increase in imports from the USA, and thus, disadvantaging electricity generation in Canada.

In the absence of a similar carbon regulation, a fair and balanced policy to mitigate the resulting disparity in carbon pricing of the two countries is to apply an equivalent Carbon Border Tariff to all the electricity imported from the USA. The main reason to include all the electricity imports under this approach is that it is an almost impossible task to tag imports and identify to originating sources all electricity crossing the border and flowing through the USA-Canada interties.

A simple way is to calculate the carbon border tariff is to apply the same Canadian carbon price to all the power generation-based carbon emitted in the neighbouring USA pools, and determine the annual average value on a per kWh of annual generation basis in those pools, resulting in a $/kWh carbon border tariff that gets applied to each kWh of electricity imported from the USA. It should be noted that applying an annual average Carbon Border Tariff results in all electricity flowing into Canada from the United States being charged the annual average Carbon Border Tariff, regardless of whether the source is more or less carbon intensive than the annual average and the degree of carbon intensity may have considerable variation from hour to hour and season to season. While this simple Carbon Border Tariff does work to address the disparity in carbon pricing between the two countries, it is not a perfect offset. However, it is not clear whether there is workable process to identify the source of imported electricity since in most cases, the path of power flows cannot be specified, and electricity flowing from each generating source on each segment of the grid is based on the generation shift factors that depend on hourly generation and load and based on electric circuit laws.

This high carbon price and carbon border tariff sensitivity is defined as follows:

- Carbon Price: CAD$130/Tonne in 2030.
- Carbon Border Tariff: Carbon parity tariff in $/MWh applied to all electricity imports from the USA, based on the annual CO2 Tonne/MWh emissions of bordering US pools, priced at Canada Carbon Price.

  - For the BAU Border Tariff sensitivity, used a carbon price of $50/Tonne in 2022 escalated at 2% a year to derive the Carbon Border Tariff.
  - For the High Carbon and Border Tariff sensitivity, used CAD$130/Tonne in 2030 to derive the Carbon Border Tariff.

6.2.1 Carbon Border Tariff Calculation

The steps for calculating the Carbon Border Tariffs in 2030 and 2040 are as follows:

- For the Western Interconnection runs in GE MAPS, select the Northwest Power Pool (NWP), which is south of BC and AB.
- For the Eastern Interconnection runs in GE MAPS, select Midwest ISO (MISO), which is south of SK and MB.
- For each of these two pools, calculate Total Carbon Emission in metric tons in 2030 and 2040.
- For each of these pools and years, calculate the Carbon Costs ($): For each Pool and Year, Multiply the Total Carbon Emissions by the applicable Canadian Carbon Price (For BAU Case, use the BAU carbon price, for the High Carbon Price Sensitivity, use the High Carbon Price).

Then:

- For the Western Interconnection BAU and High Carbon Sensitivity cases in 2030 and 2040, divide the NWP Carbon Cost ($) by Total Generation in NWP (MWh) to get an Average Carbon Cost per MWh ($/MWh). Results are the Carbon Border Tariffs applied to the USA imports from NWP to Canada in the BAU and High Carbon Sensitivity cases.
- For the Eastern Interconnection BAU and EI High Carbon Sensitivity cases in 2030 and 2040, divide the MISO Carbon Cost ($) by Total Generation in MISO (MWh) to get an Average Carbon Cost per MWh ($/MWh). Results are the Carbon Border Tariffs applied to the USA imports from MISO to Canada in the BAU and High Carbon Sensitivity cases.

Following table provides the Carbon Price and Carbon Border Tariff values under various cased examined in this sensitivity;

Table 6-3: Carbon Price and Carbon Border Tariff Values

2030 Cases	Carbon Price ($CAD/tonne)	EI Carbon Border Tariff ($CAD/MWH)	WECC Carbon Border Tariff ($CAD/MWH)
BAU	50	0	0
High Carbon Price	130	0	0
Carbon Border Tariff	50	25.02	10.28
High Carbon Price and Carbon Border Tariff	130	65.05	26.72

2040 Cases	Carbon Price ($CAD/tonne)	EI Carbon Border Tariff ($CAD/MWH)	WECC Carbon Border Tariff ($CAD/MWH)
BAU	50	0	0
High Carbon Price	230	0	0
Carbon Border Tariff	50	25.14	9.06
High Carbon Price and Carbon Border Tariff	230	115.67	41.68

6.2.2 Business-As-Usual - BAU- Case (2030) and (2040)

Since the original BAU scenario evaluation did not include a carbon border tariff, three sensitivities were applied to the BAU scenario: (a) A run with only Canadian Carbon Price, (b) A run with only the Carbon Border Tariff, and (c) A run with both a Canadian Carbon Price and a Carbon Border Tariff.

All the study projects other than the BAU scenario were run with the combined Carbon Price and Carbon Border Tariff.

In the original BAU case, the Carbon Price was set to $50/Tonne in 2022, and escalated at 2% per year, resulting in a Carbon Price of $58.6/Tonne in 2030. In the original BAU runs, a Carbon Border Tariff was not applied to the imports from the USA.

The following charts and tables present the impact of high carbon price sensitivity on the BAU scenario. General observations include:

- A high carbon price alone, results in lower generation and reduced CO_2 emissions in Canada, while increasing the Adjusted Production Costs in Canada. This is due to the combination of a higher cost of carbon, increased imports, and decreased exports. CO_2 emissions in the USA would be expected to change as well; however, the direction of the change would depend on the dispatch of different types of generation resources impacted by the Canadian carbon prices and the carbon border tariff.

- The carbon border tariff, with and without the high carbon price, increases generation in Canada – mainly due to the higher cost of electricity imported, and also due to the significant increase in CC-GAS, GT-GAS, and COGEN generation.
- In the case of carbon border tariff alone, COAL generation in Canada is increased, mainly because imports become more expensive. However, adding the high carbon prices, suppresses COAL generation and increases generation by the natural gas-based units.
- The carbon border tariff has a major impact in reversing the impact of high carbon price alone, causing higher exports to the USA (or lower imports from USA) than either the original BAU case or the high carbon price case alone.
- High carbon price alone, which results in lowering generation in Canada, also results in lowering the CO2 emissions in Canada, while increasing the Adjusted Production Costs, due to the combination of a higher cost of carbon, increase imports, and decrease exports. CO2 emissions in the USA would be expected to change as well, however, the direction change would depend on the dispatch of different types of generation resources impacted by the Canadian carbon prices and the carbon border tariff.
- However, the carbon border tariff without high carbon prices, by making the imports from the USA more expensive, results in more generation by both coal and natural gas-based units in Canada, and hence, in higher levels of net exports and CO2 emissions, while lowering adjusted production costs compared to the high carbon price alone.
- High carbon price and carbon border tariff together result in suppression of COAL generation and suppressing imports from the USA, causing a substantial increase in generation of natural gas-based units. The result is both higher CO2 emissions and higher adjusted production costs relative to the original BAU case.
- It is likely that these results depend on the relative values of the carbon border tariff and the carbon price. This is an interesting outcome, suggesting that further analyses would be necessary in order to develop a carbon regulation policy that would strike the right balance between carbon price and carbon border tariff that could help achieve the carbon policy objectives in Canada.

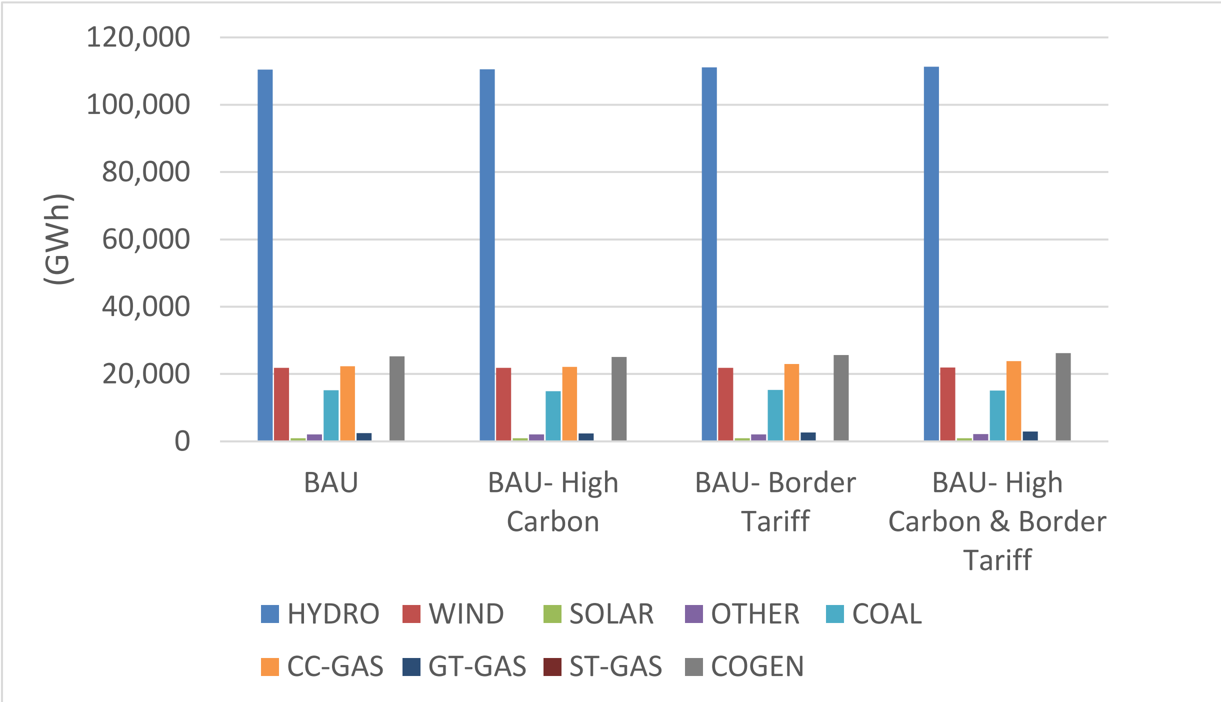


Figure 6-1: High Carbon Sensitivity - BAU Generation by Type (2030)

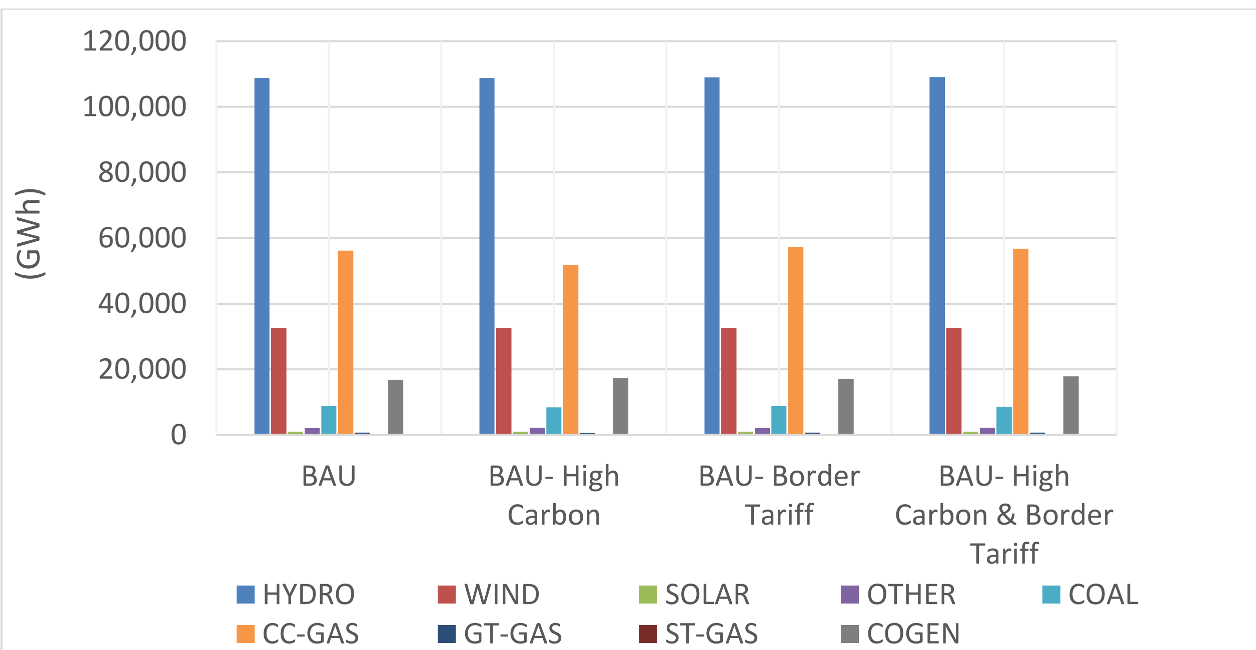


Figure 6-2: High Carbon Sensitivity - BAU Generation by Type (2040)

Table 6-4: High Carbon Price Sensitivity - BAU Generation in 2030 (GWh)

(GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	110,485	21,818	958	2,057	15,215	22,326	2,464	48	25,249	**200,619**
BAU- High Carbon	110,527	21,817	958	2,063	14,876	22,125	2,330	46	25,082	**199,825**
BAU- Border Tariff	111,092	21,888	959	2,115	15,291	23,032	2,670	46	25,668	**202,762**
BAU- High Carbon & Border Tariff	111,275	21,899	960	2,175	15,122	23,858	2,922	39	26,269	**204,520**
Change from BAU										
BAU- High Carbon	42	-1	0	6	-339	-201	-134	-2	-166	**-794**
BAU- Border Tariff	608	70	1	57	76	706	206	-2	419	**2,143**
BAU- High Carbon & Border Tariff	791	81	1	118	-93	1,533	458	-9	1,020	**3,900**

Table 6-5: High Carbon Price Sensitivity - BAU Generation in 2040 (GWh)

(GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	
BAU	108,778	32,528	959	1,996	8,742	56,131	667	73	16,716	**226,589**
BAU- High Carbon	108,788	32,526	959	2,173	8,330	51,711	611	65	17,264	**222,426**
BAU- Border Tariff	109,015	32,571	959	2,005	8,813	57,318	664	69	17,028	**228,442**
BAU- High Carbon & Border Tariff	109,072	32,575	959	2,178	8,547	56,697	678	57	17,880	**228,641**
Change from BAU										
BAU- High Carbon	10	-3	0	177	-412	-4,420	-56	-8	549	**-4,163**
BAU- Border Tariff	237	42	0	10	71	1,187	-3	-4	312	**1,853**
BAU- High Carbon & Border Tariff	294	46	0	183	-196	566	11	-16	1,164	**2,052**

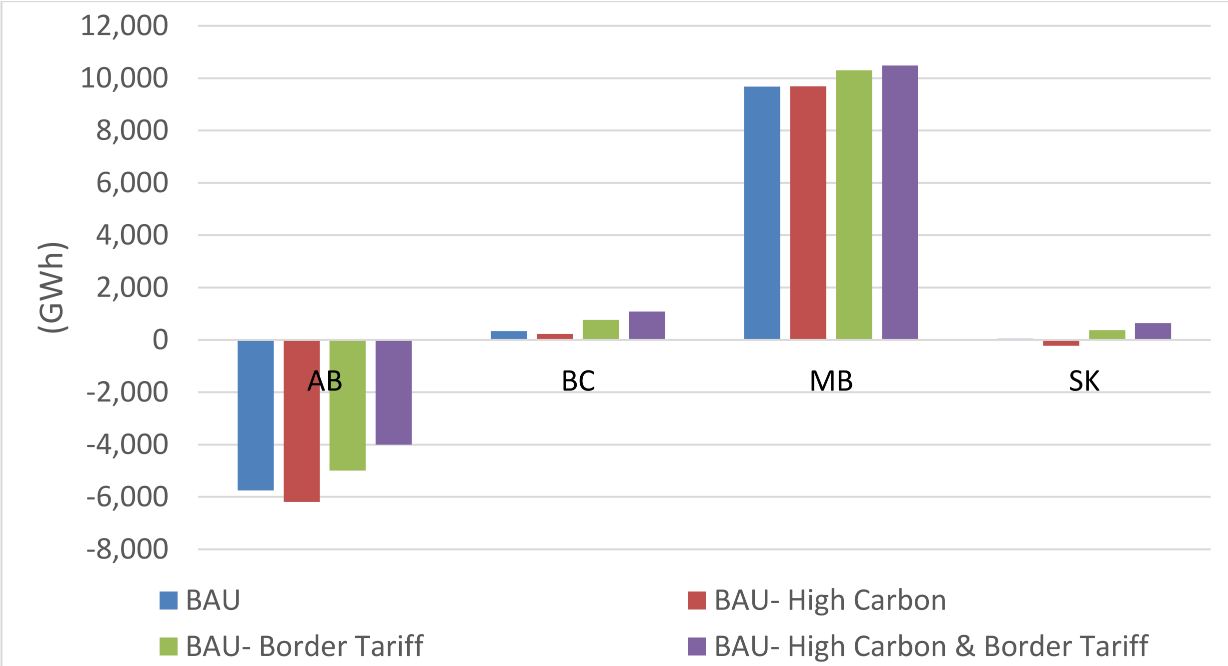


Figure 6-3: High Carbon Sensitivity - BAU Net Export by Province (2030)

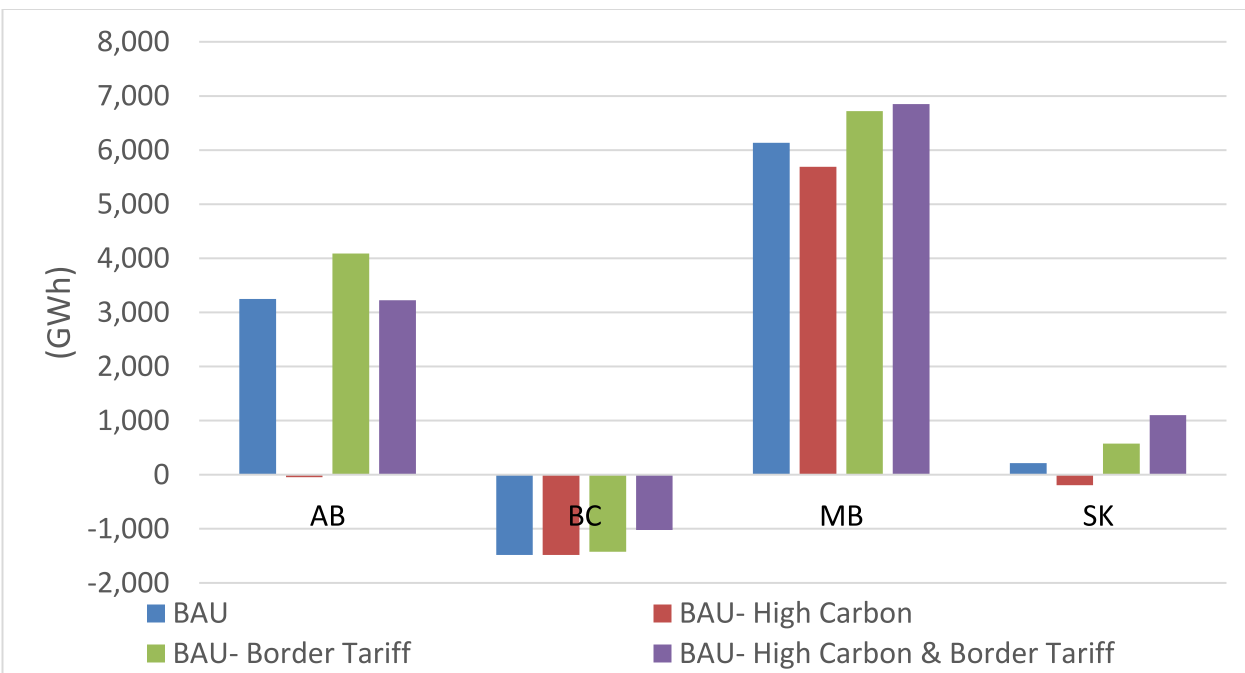


Figure 6-4: High Carbon Sensitivity - BAU Net Export by Province (2040)

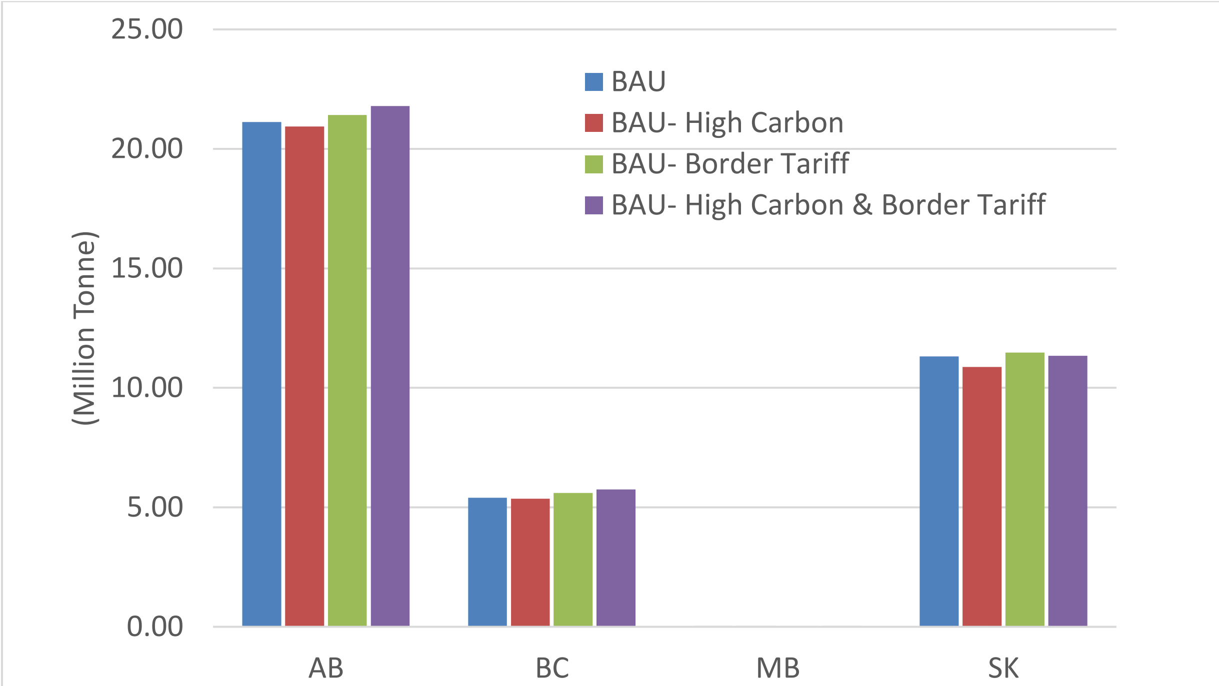


Figure 6-5: High Carbon Sensitivity - BAU CO2 Emissions by Province (2030)

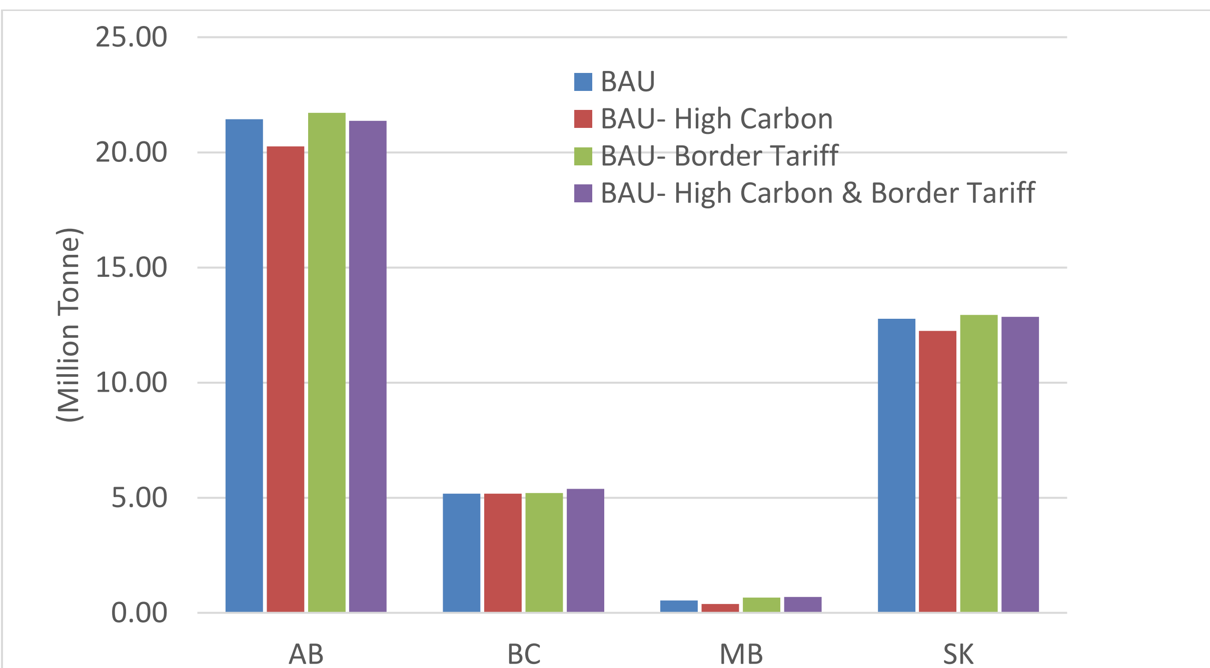


Figure 6-6: High Carbon Sensitivity - BAU CO2 Emissions by Province (2040)

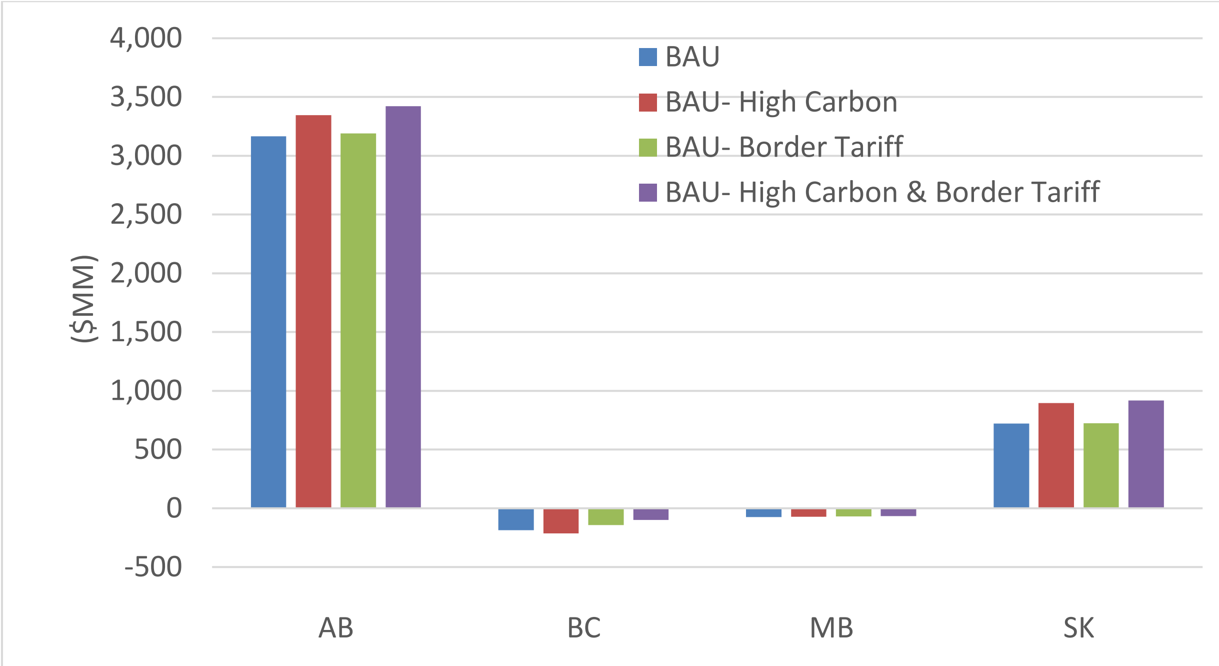


Figure 6-7: High Carbon Sensitivity - BAU Adjusted Production Costs by Province (2030)

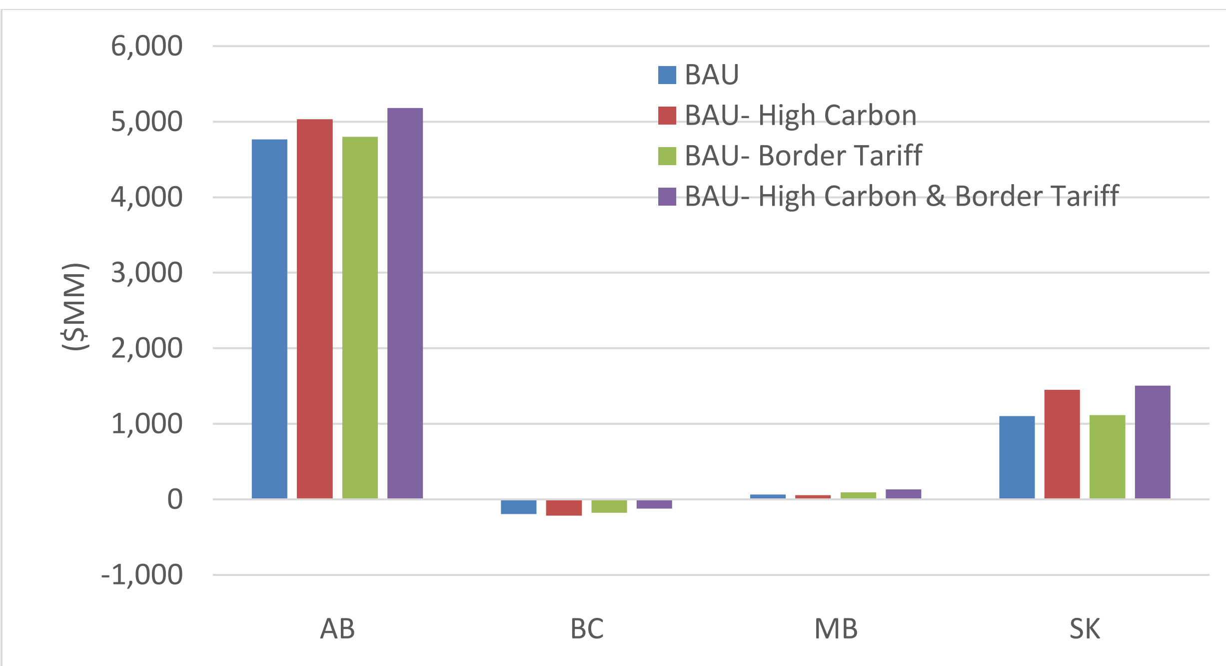


Figure 6-8: High Carbon Sensitivity - BAU Adjusted Production Costs by Province (2040)

6.2.3 Project A: South Intertie (2030)

Project A's South Intertie option was evaluated under the high carbon price with carbon border tariff sensitivity.

The following charts and tables present the impact of high carbon price sensitivity on Project A, South Intertie. General observations include:

- A high carbon price with carbon border tariff results in increased natural gas-based generation in both British Columbia and Alberta.
- The carbon border tariff makes the generation in Canada more competitive compared to the base case, thus resulting in more exports by British Columbia and less imports by Alberta, resulting in net export increase to the USA.
- The outcome is higher CO2 emissions and higher adjusted production costs in British Columbia and Alberta.

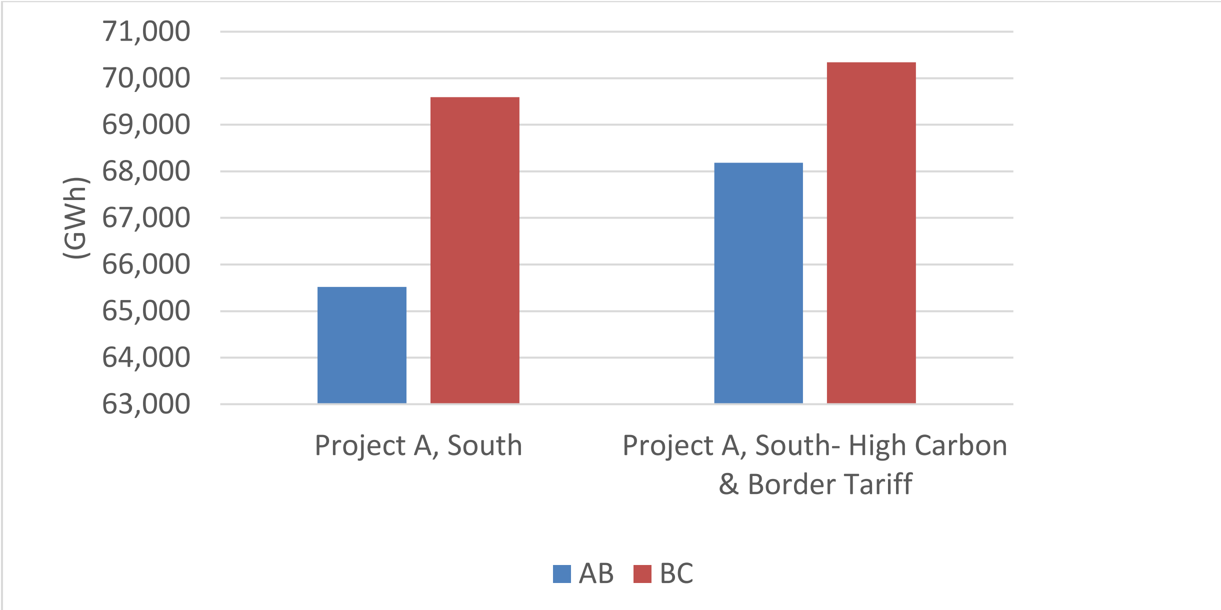


Figure 6-9: High Carbon Sensitivity - Project A - Generation by Province (2030)

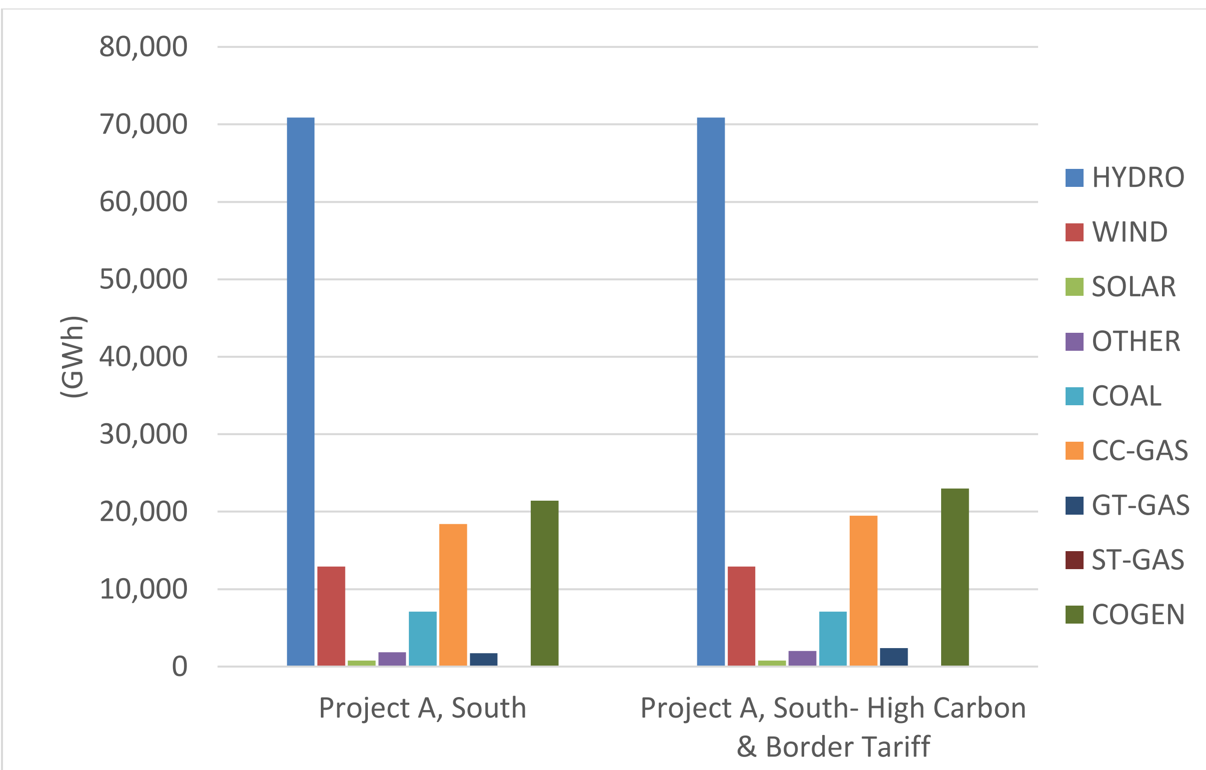


Figure 6-10: High Carbon Sensitivity - Project A - Generation by Type (2030)

Table 6-6: High Carbon - Project A - Generation by Province (2030)

(GWh)	AB	BC	Total
Project A, South	65,516	69,597	**135,113**
Project A, South- High Carbon & Border Tariff	68,185	70,340	**138,525**
Change	**2,669**	**743**	**3,412**

Table 6-7: High Carbon - Project A - Generation by Type (2030)

(GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project A, South	70,863	12,910	775	1,868	7,107	18,422	1,745	0	21,425	**135,113**
Project A, South- High Carbon & Border Tariff	70,865	12,910	775	2,004	7,107	19,470	2,395	0	22,999	**138,525**
Change	**2**	**0**	**0**	**136**	**0**	**1,049**	**651**	**0**	**1,574**	**3,412**

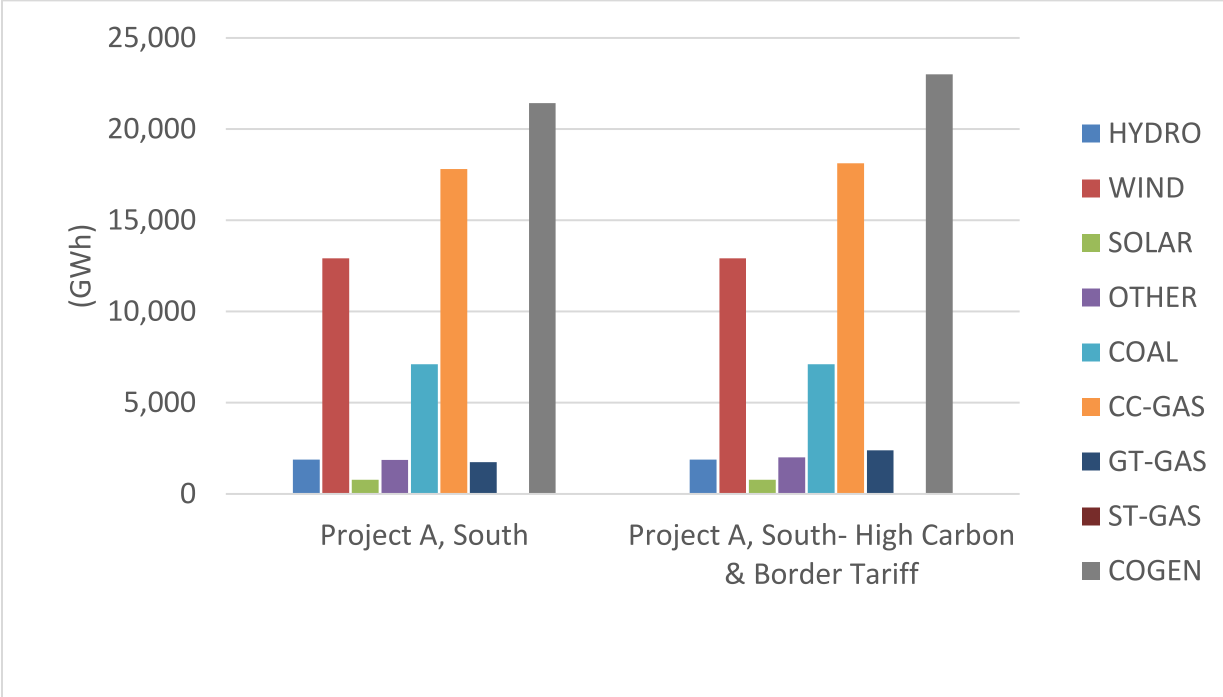


Figure 6-11: High Carbon Sensitivity - Project A - Alberta Generation (2030)

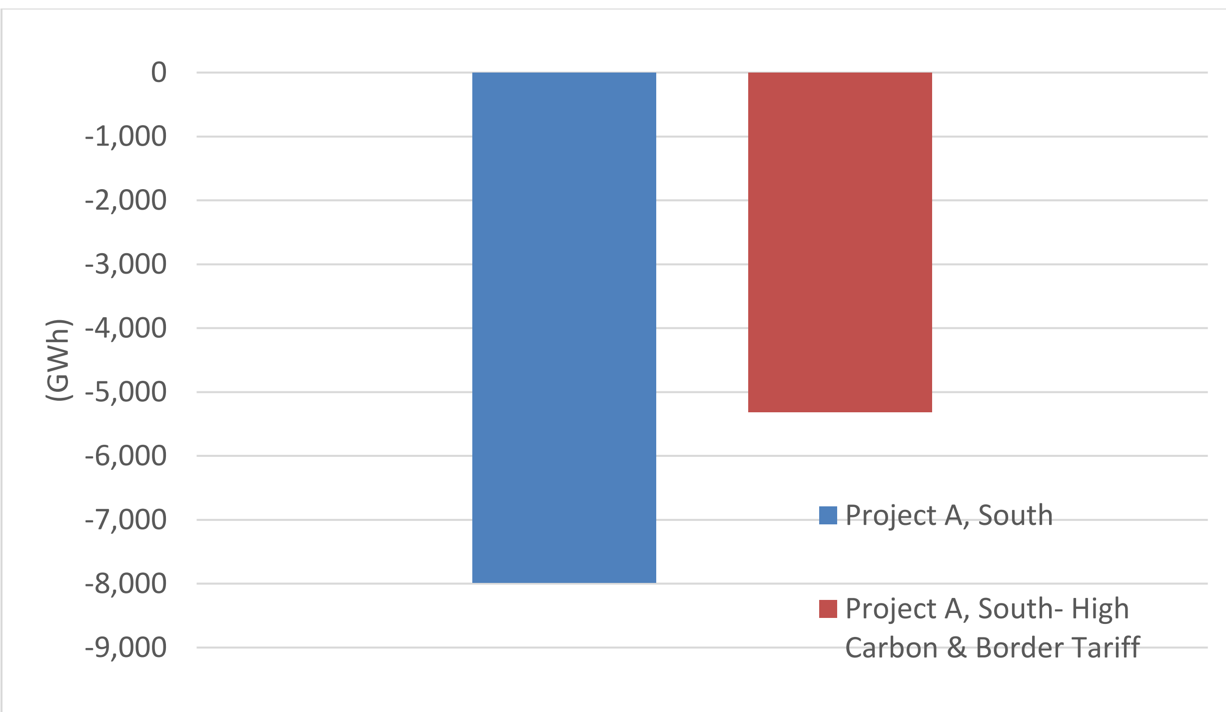


Figure 6-12: High Carbon Sensitivity - Project A - Alberta Net Exports (2030)

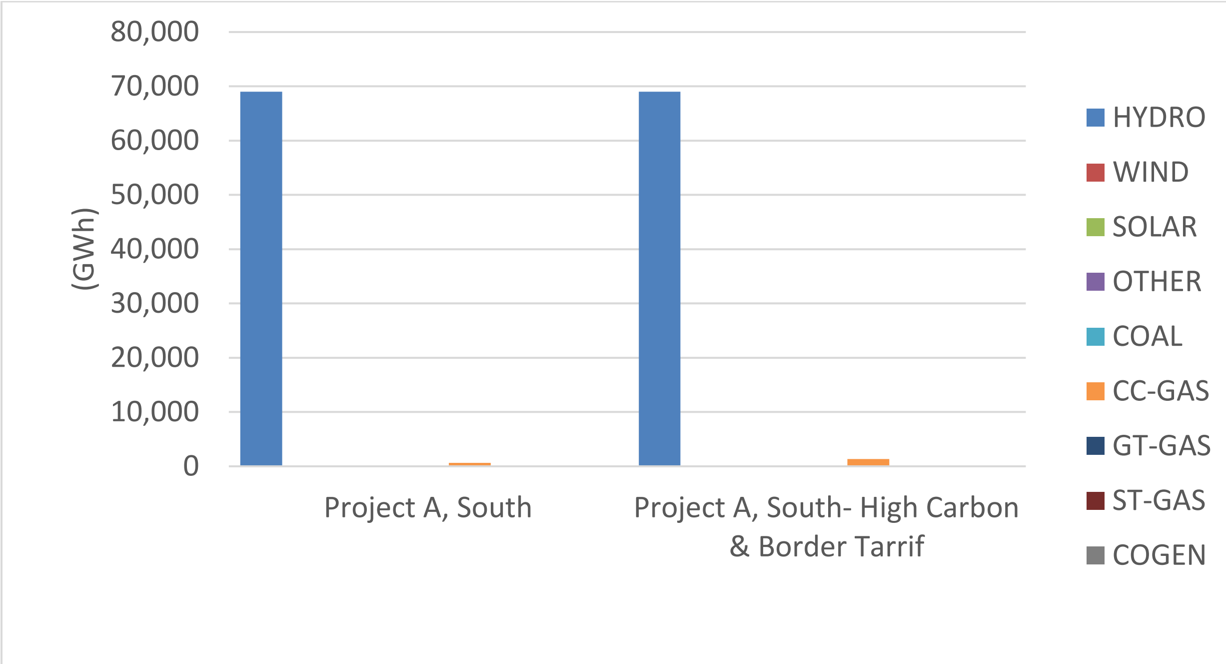


Figure 6-13: High Carbon Sensitivity - Project A - British Columbia Generation (2030)

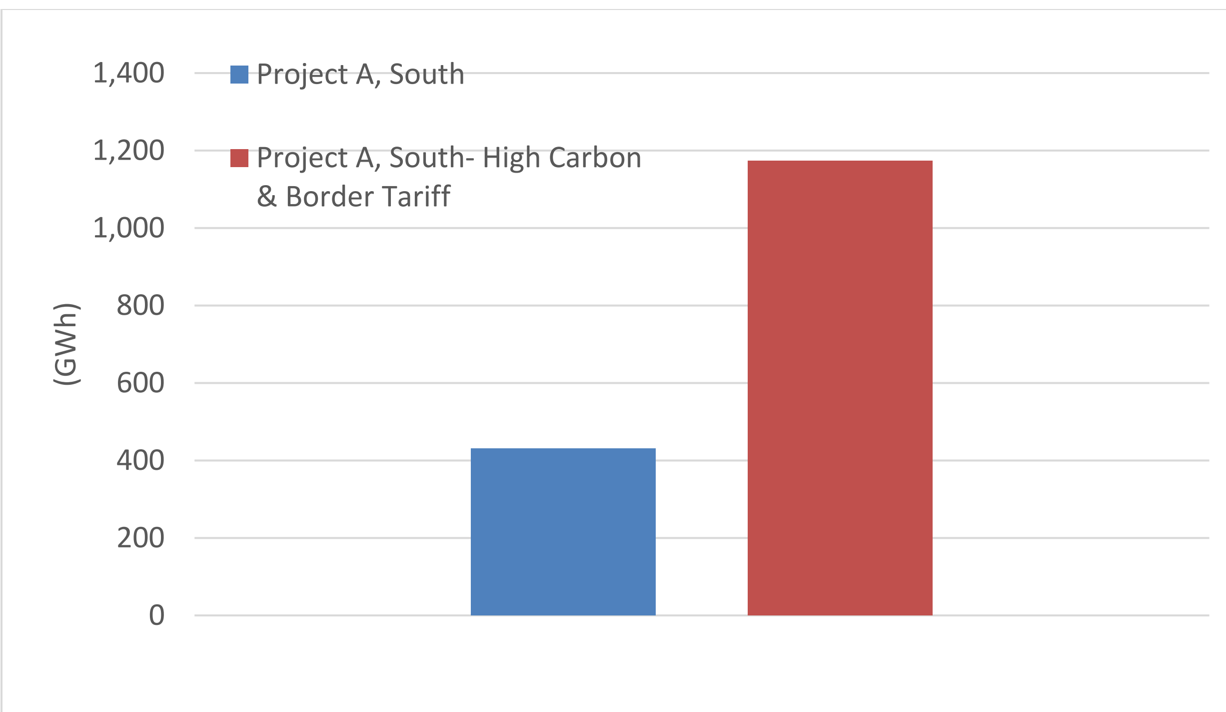


Figure 6-14: High Carbon Sensitivity - Project A - British Columbia Net Exports (2030)

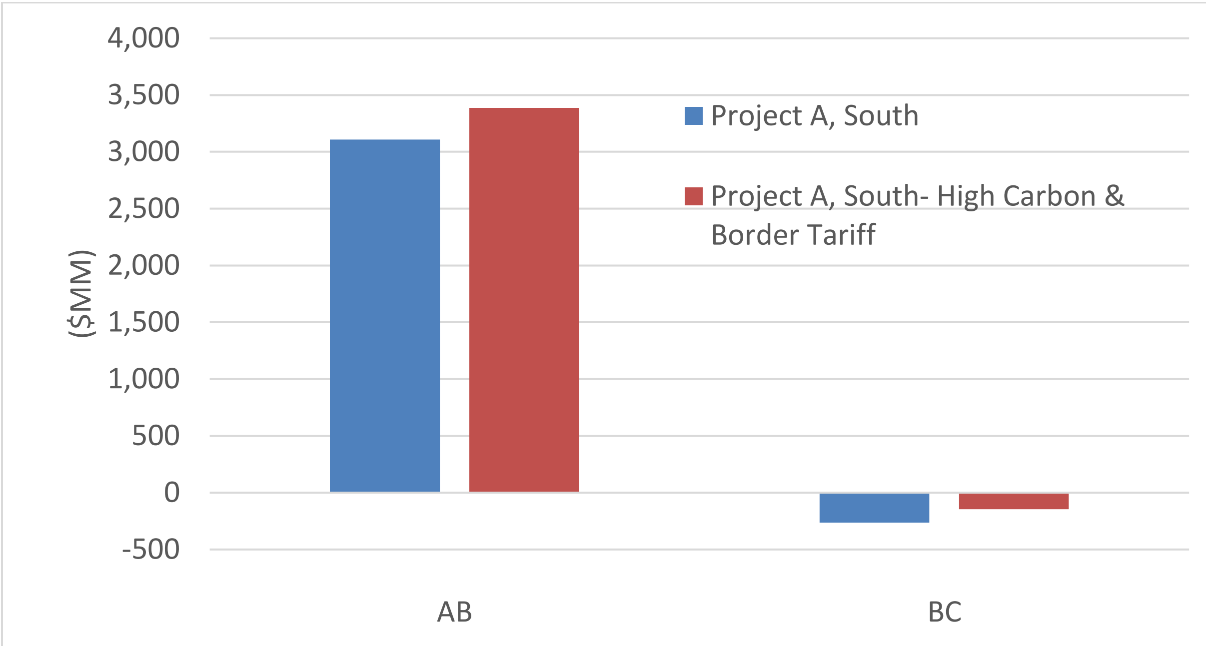


Figure 6-15: High Carbon Sensitivity - Project A - Adjusted Production Costs (2030)

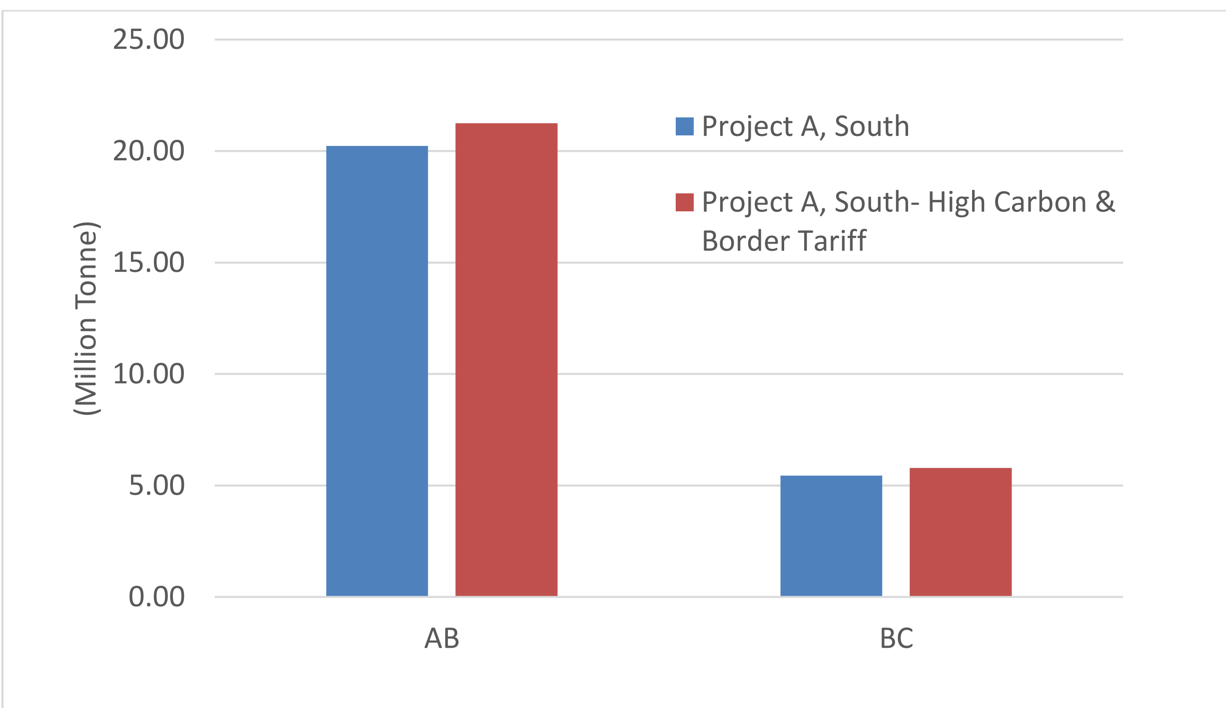


Figure 6-16: High Carbon Sensitivity - Project A - CO2 Emissions (2030)

6.2.4 Project B: New Intertie between SK and MB - Option 1 (2030)

Project B's Option 1, which includes a new 500 kV line from Saskatchewan to Manitoba, was evaluated under the high carbon price with carbon border tariff sensitivity.

The following charts and tables present the impact of high carbon price sensitivity on Project B's Option 1. General observations include:

- A high carbon price with carbon border tariff results in reduced COAL generation, which is more than offset by increase in HYDRO, WIND, and GT-GAS generation. Increase in renewable energy may be due to alleviation of congestion in some of the transmission constraints.
- The carbon border tariff and the increased hydro and wind generation results in increased exports from Manitoba to the USA. There is little change in imports by Saskatchewan.
- Furthermore, the adjusted production cost in Manitoba is decreased, but it increases in Saskatchewan.
- There is little CO2 emission in Manitoba in either the base or the sensitivity case, because hydropower is the overwhelming source of electric energy in Manitoba, with a very small portion covered by thermal energy. But in Saskatchewan, reduction in COAL generation and a relatively smaller increase in CC-GAS generation results in lower CO2 emissions.

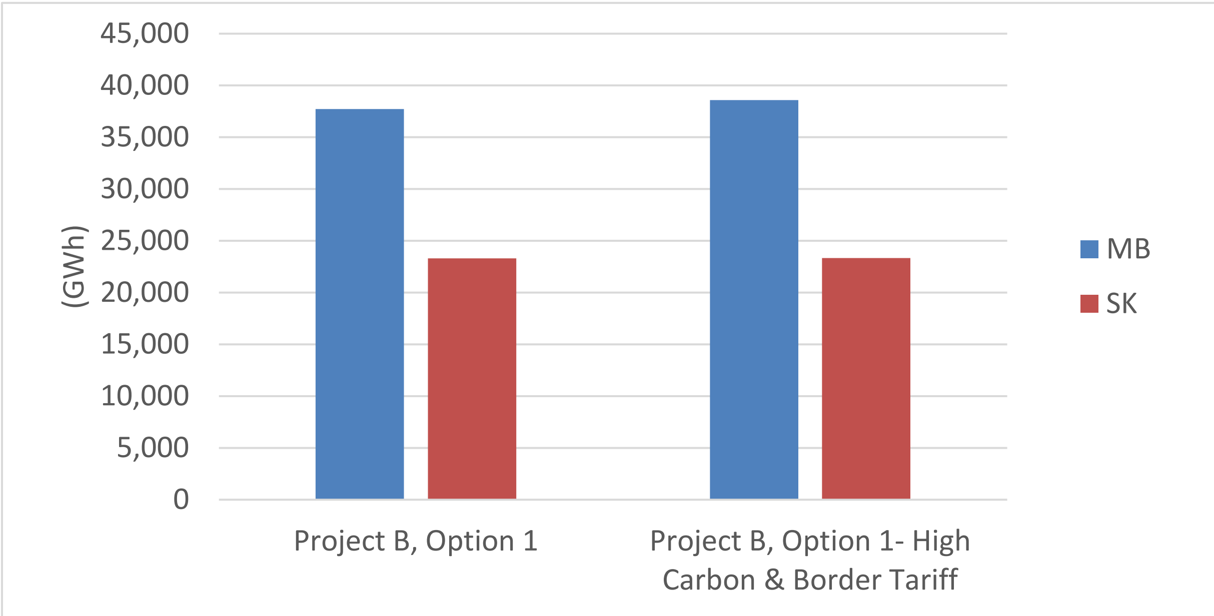


Figure 6-17: High Carbon Sensitivity - Project B - Total Generation by Province (2030)

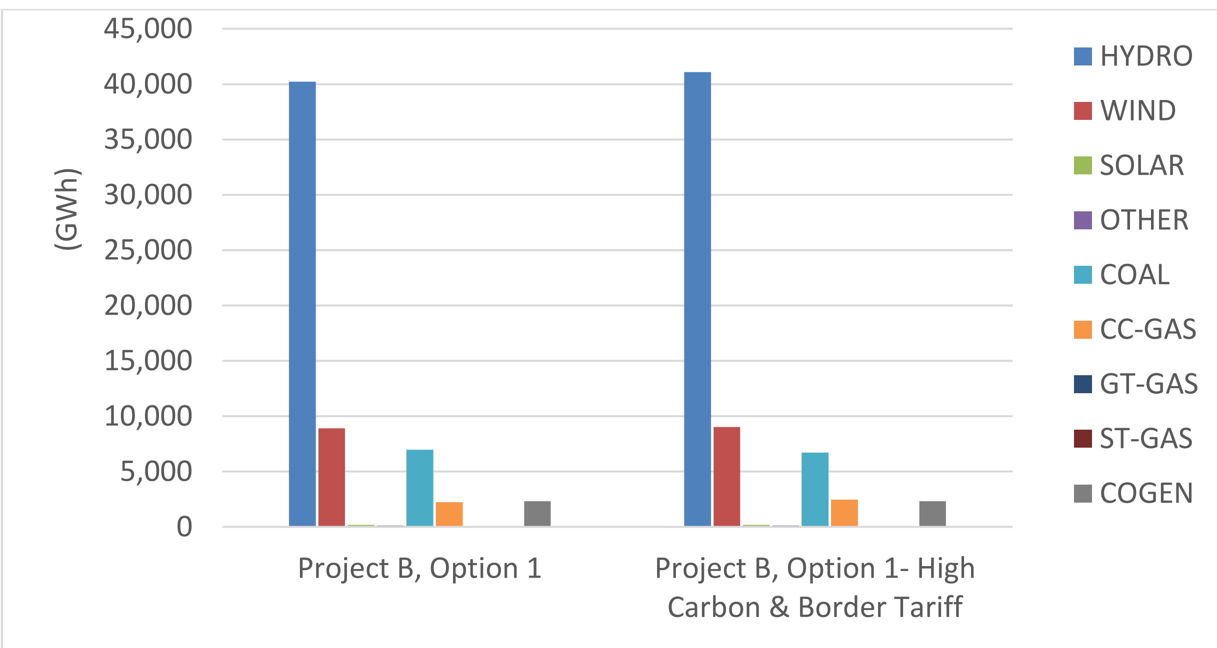


Figure 6-18: High Carbon Sensitivity - Project B - Total Generation by Type (2030)

Table 6-8: High Carbon - Project B - Option 1 - Generation by Province (2030)

(GWh)	MB	SK	Total
Project B, Option 1	37,725	23,301	**61,027**
Project B, Option 1- High Carbon & Border Tariff	38,589	23,334	**61,923**
Change	**864**	**33**	**896**

Table 6-9: High Carbon - Project B - Option 1 - Generation by Type (2030)

(GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project B, Option 1	40,223	8,916	184	113	6,962	2,235	34	48	2,312	**61,027**
Project B, Option 1- High Carbon Border Tariff	41,082	9,021	184	120	6,696	2,460	7	37	2,315	**61,923**
Change	**860**	**105**	**0**	**7**	**-266**	**226**	**-28**	**-11**	**3**	**896**

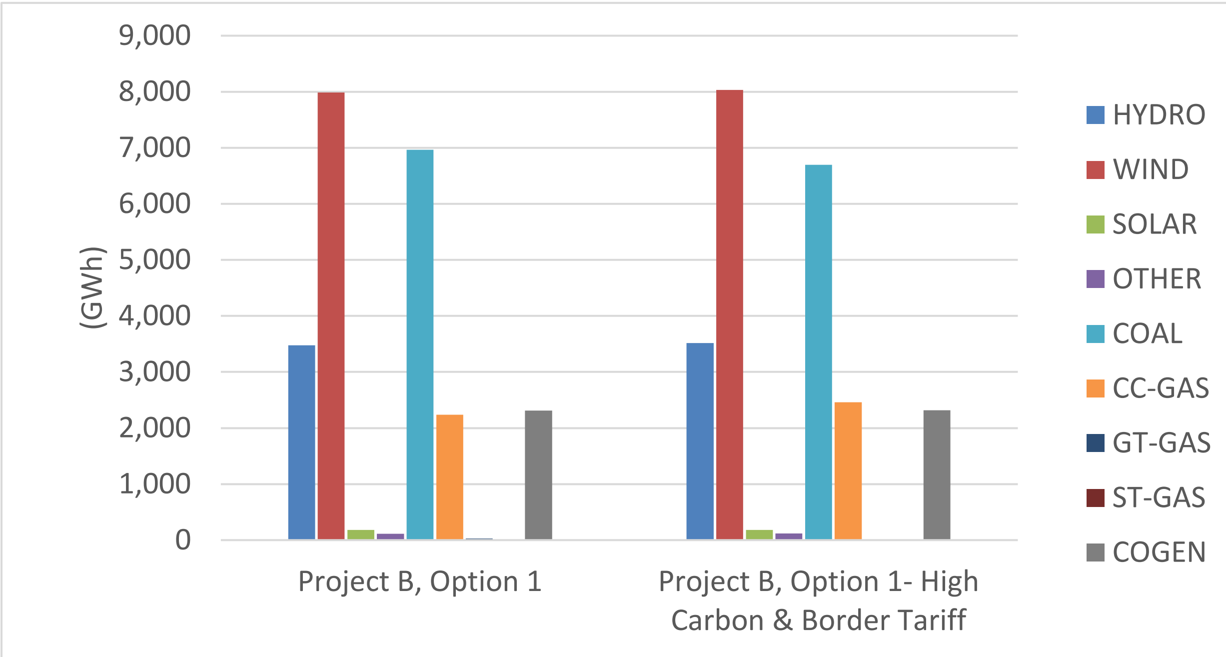


Figure 6-19: High Carbon Sensitivity - Project B - Saskatchewan Generation (2030)

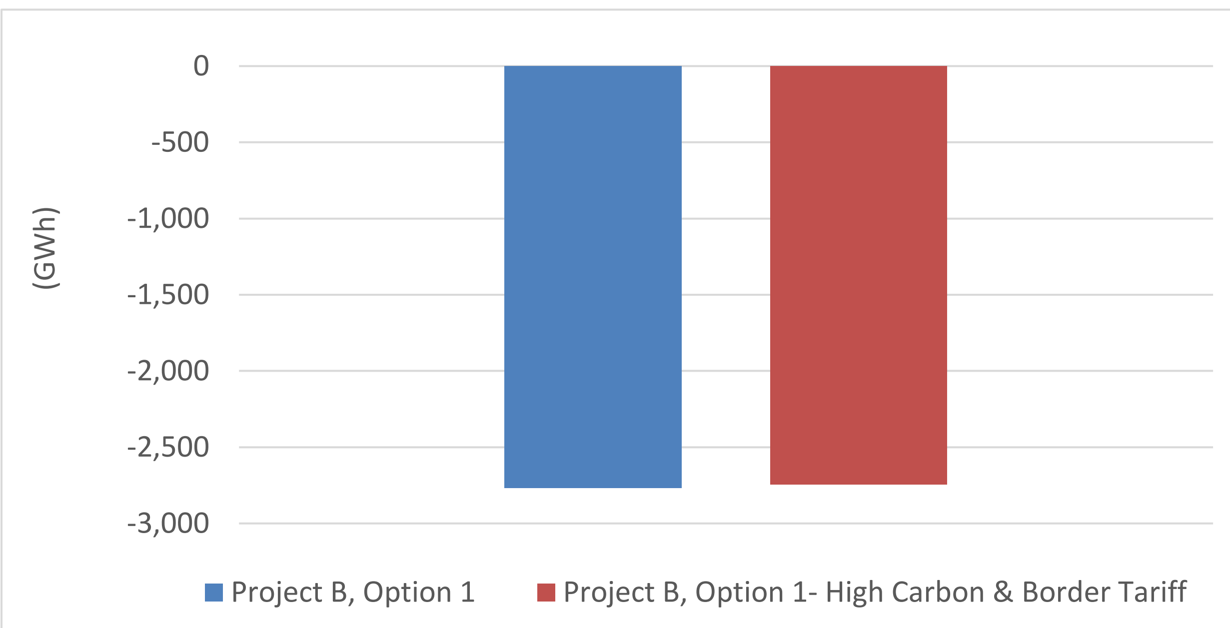


Figure 6-20: High Carbon Sensitivity - Project B - Saskatchewan Net Exports (2030)

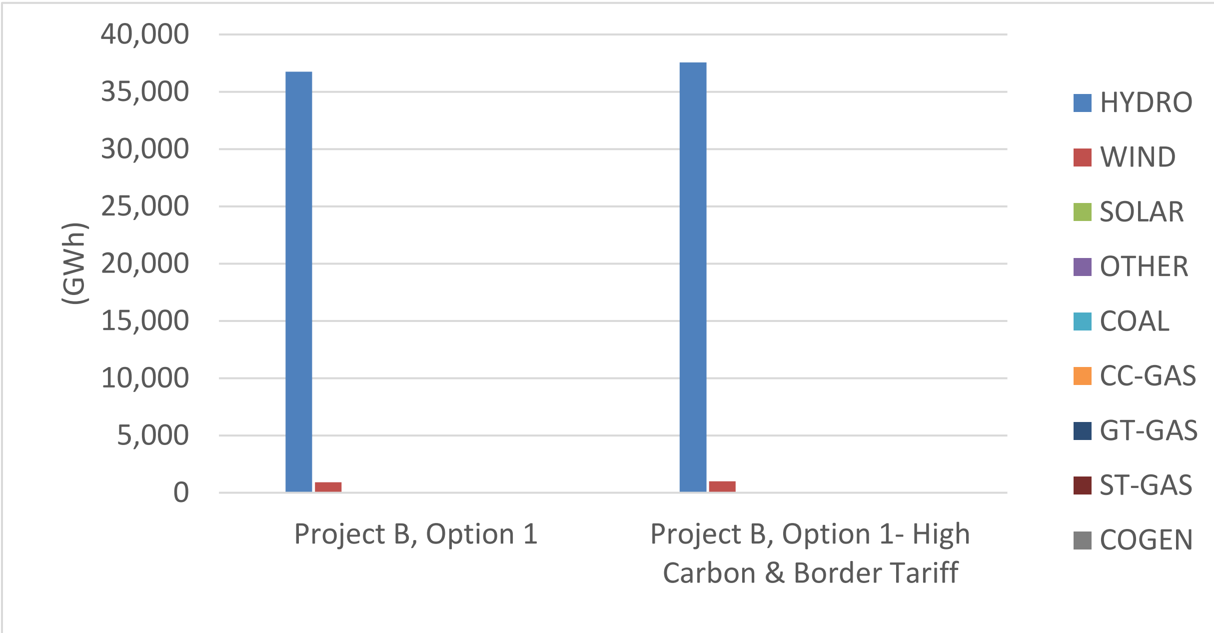


Figure 6-21: High Carbon Sensitivity - Project B - Manitoba Total Generation (2030)

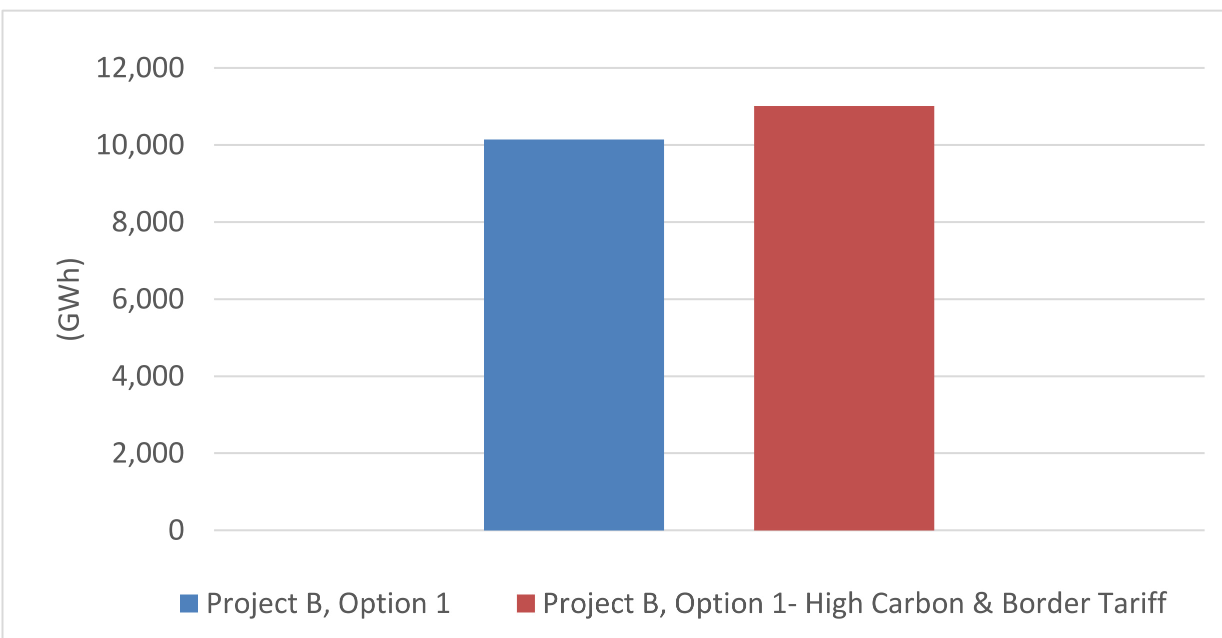


Figure 6-22: High Carbon Sensitivity - Project B - Manitoba Net Exports (2030)

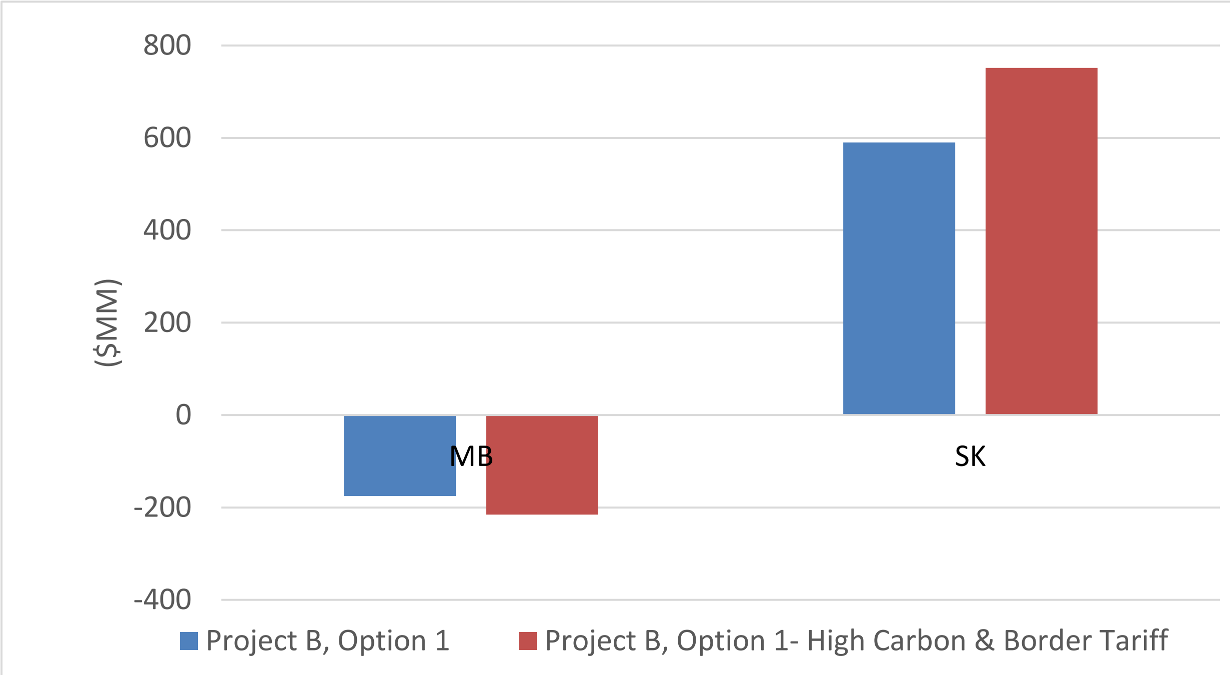


Figure 6-23: High Carbon Sensitivity - Project B - Adjusted Production Cost (2030)

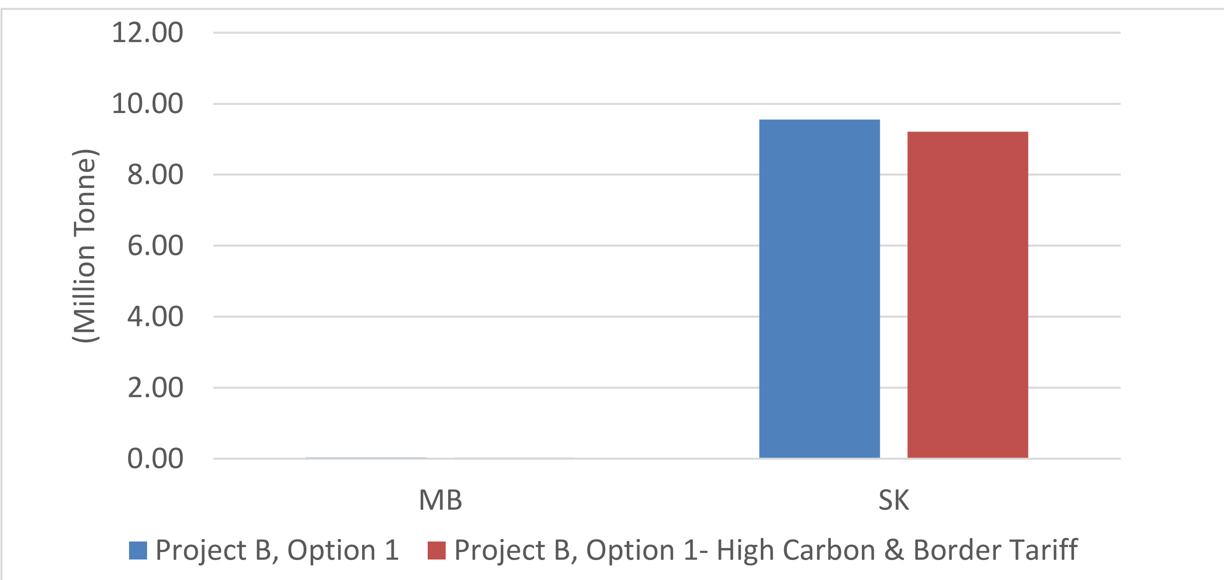


Figure 6-24: High Carbon Sensitivity - Project B - CO2 Emissions (2030)

6.2.5 Project D: New Hydroelectric Capacity in AB and SK (2040)

Project D's Option 1 and Option 2 - representing different sets of hydropower additions in Alberta and Saskatchewan – were evaluated under the High Carbon and Carbon Border Tariff sensitivity.

The following charts and tables present the impact of high carbon price sensitivity on Project D's Options 1 and 2. General observations include:

- It should be noted that in Project D, Option 1 and 2, by 2040 almost all of the COAL generation asset in 2040 are converted to CCS (in Saskatchewan) or CC-GAS (in Alberta and Saskatchewan).
- The principal impact of high carbon price with carbon border tariff on Alberta is the displacement of CC-GAS generation by COGEN generation, which have a lower average full load cost, and a slight decrease in total Alberta generation. These two types of generation are somewhat similar in terms of their carbon emission rates and the impact on their adjusted production costs.
- Reduced generation also results in lowering of Alberta net exports.
- As the charts show, this sensitivity increases Alberta's adjusted production costs, mainly due to the higher carbon prices, even with reduced exports. Production costs go up because the emission costs are higher, and it costs more to run each plant. The higher costs decrease excess generation and reduce exports, but the plants are still run to cover the load; and when it is still economically viable, to export, although the cost to do so is higher.
- Since CC-GAS and COGEN units are rather similar in terms operational parameters and fuel type used, there is miniscule reduction in CO2 emissions.
- Saskatchewan still has COAL based generation in 2040. Consequently, the main impact of high carbon price with carbon border tariff on Saskatchewan is the displacement of the COAL generation by lower cost CC-GAS generation, which also results in higher exports to USA.
- Higher carbon prices, together with higher generation and exports in Saskatchewan, result in higher adjusted production costs.
- Similar to Alberta's case, the reduction in CO2 emissions is also miniscule, mainly because reduction in COAL generation is more than compensated by increase in CC-GAS generation.

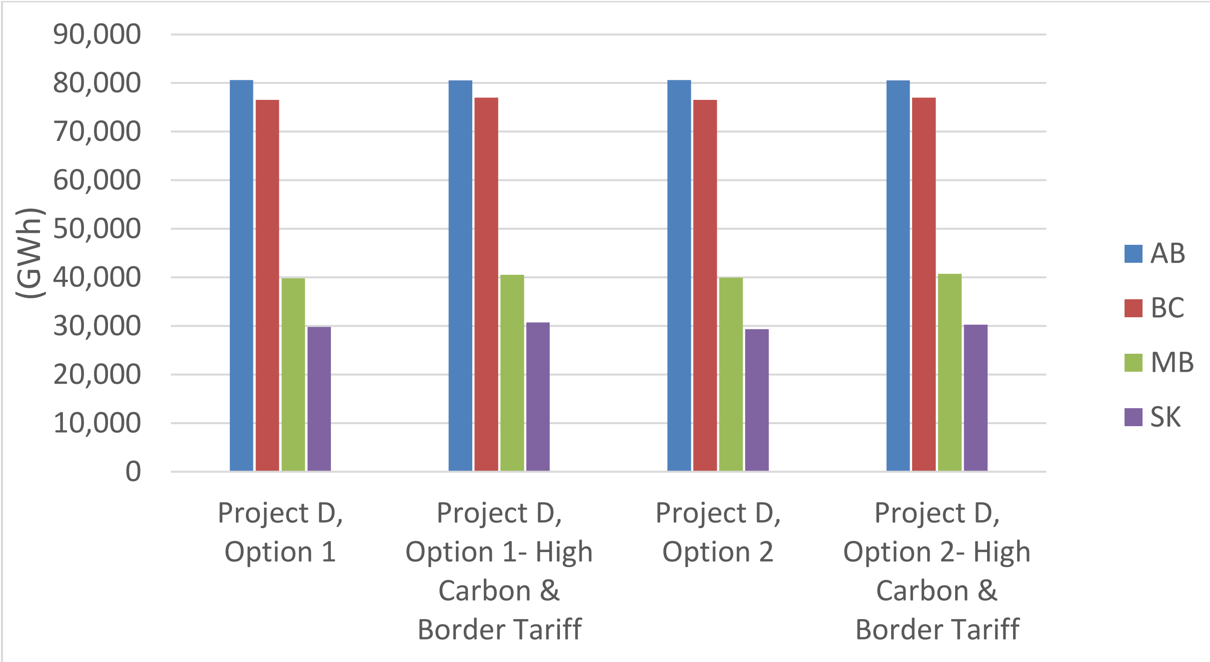


Figure 6-25: High Carbon Sensitivity - Project D - Generation by Province (2040)

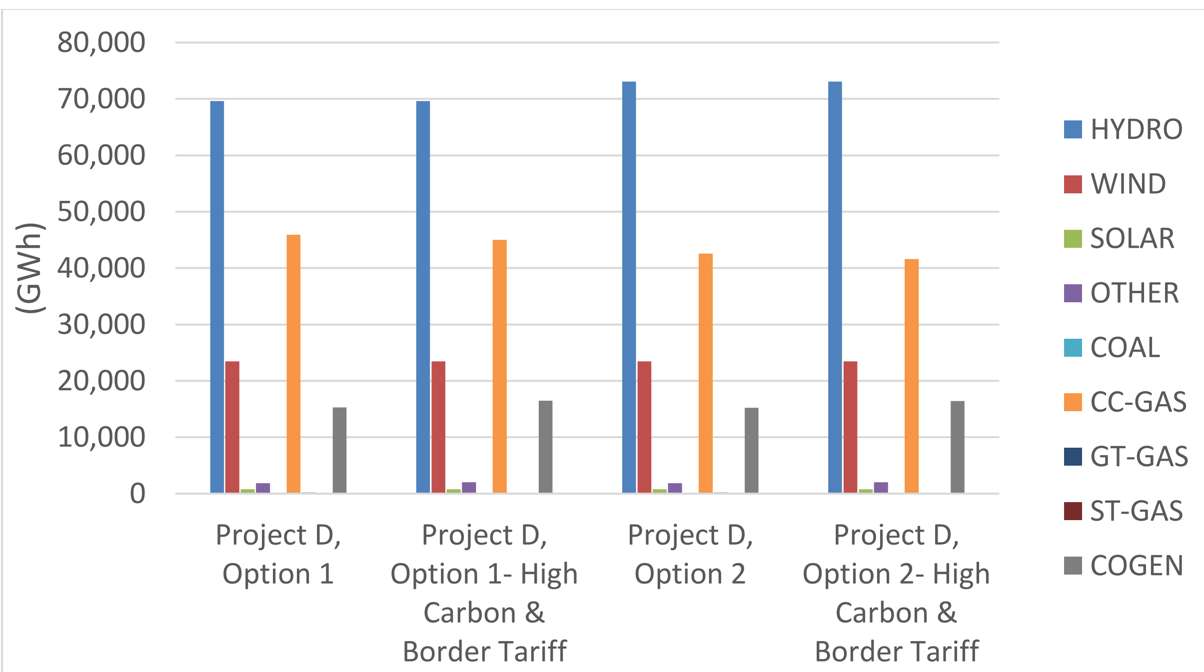


Figure 6-26: High Carbon Sensitivity - Project D - Generation by Type (2040)

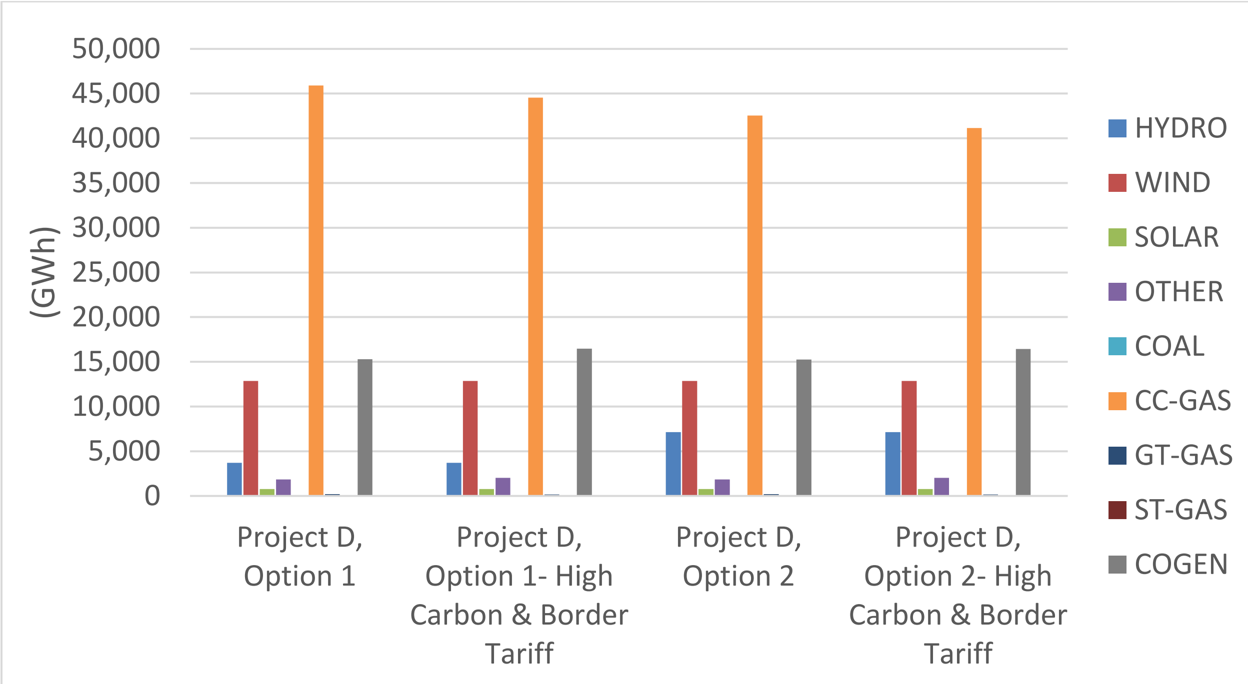


Figure 6-27: High Carbon Sensitivity - Project D - Alberta Generation by Type (2040)

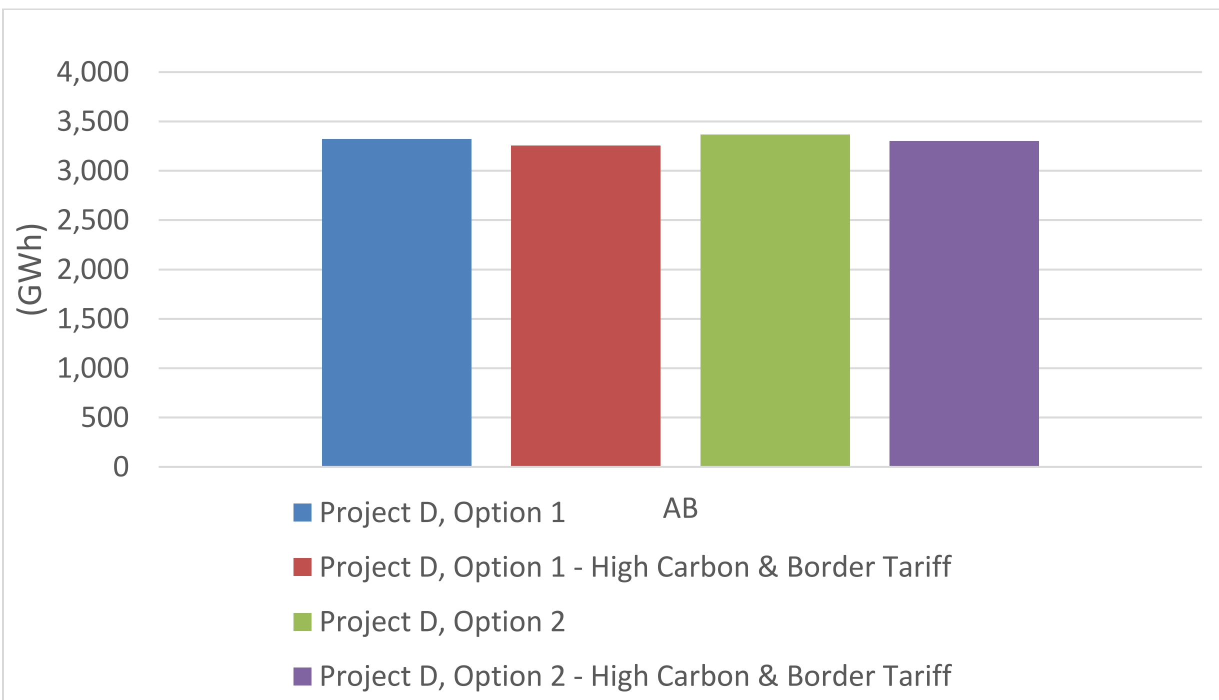


Figure 6-28: High Carbon Sensitivity - Project D - Alberta Next Exports (2040)

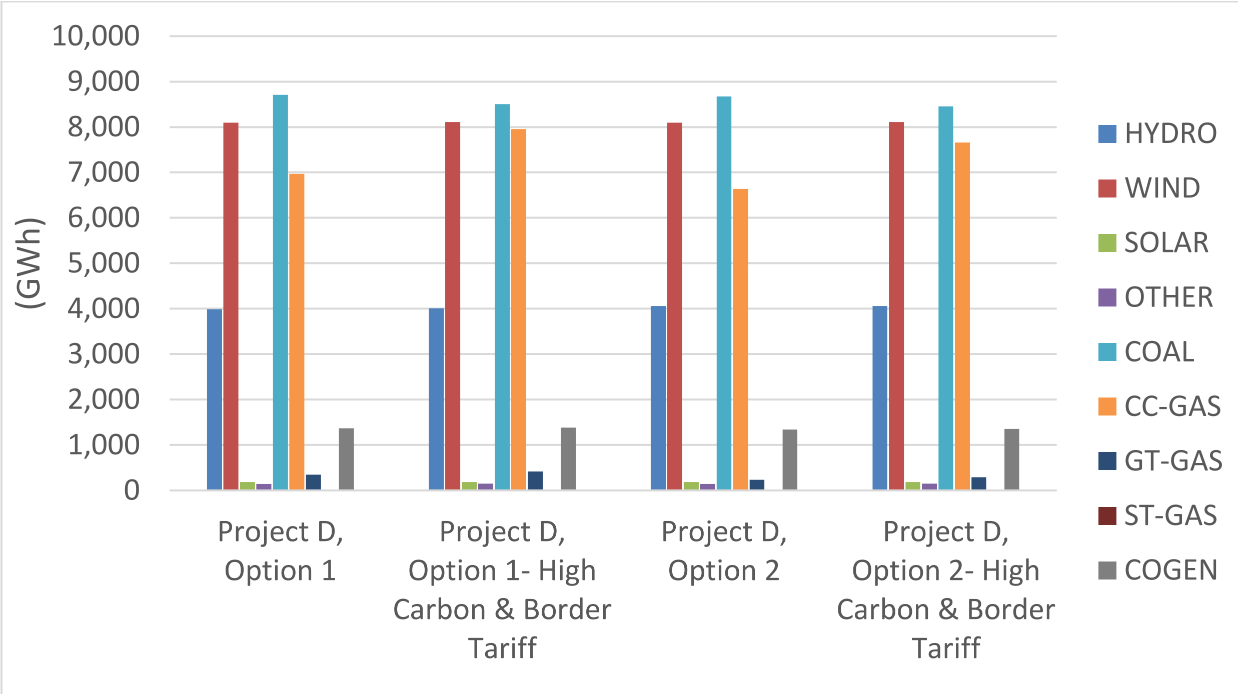


Figure 6-29: High Carbon Sensitivity - Project D - Saskatchewan Generation (2040)

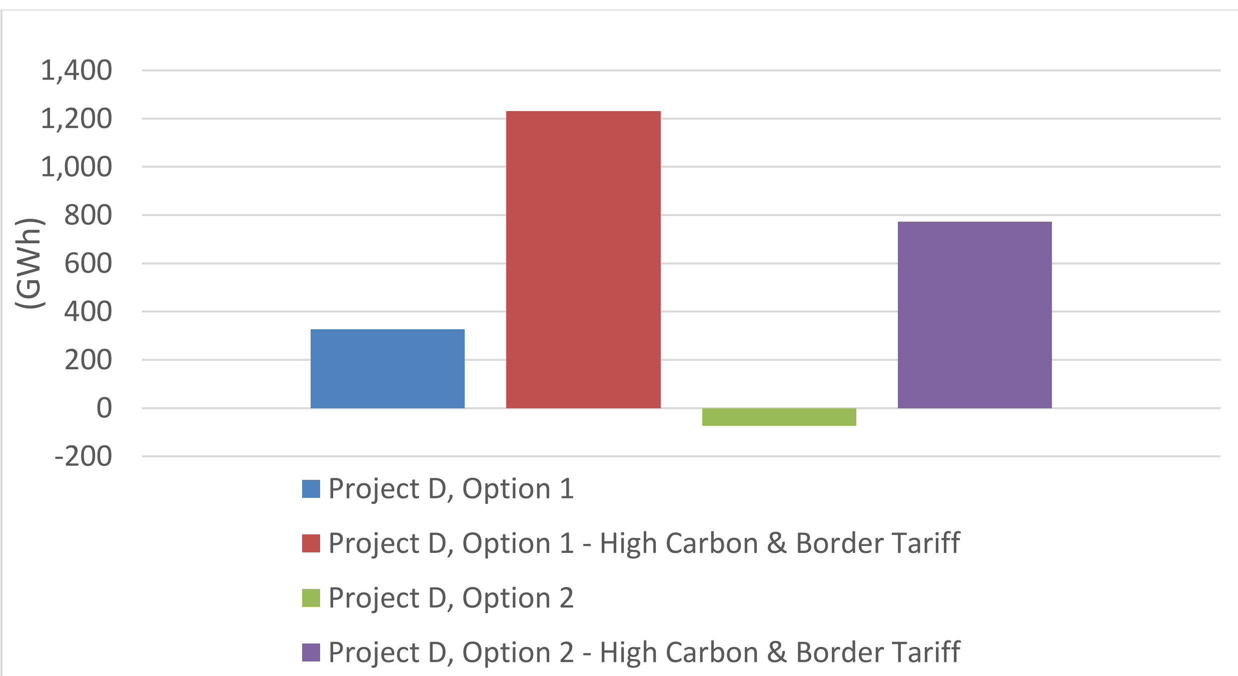


Figure 6-30: High Carbon Sensitivity - Project D - Saskatchewan Net Exports (2040)

Table 6-10: High Carbon Sensitivity - Project D - Alberta Generation by Type (2040)

AB Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project D, Option 1	3,689	12,871	774	1,851	0	45,907	214	0	15,296	**80,603**
Project D, Option 1- High Carbon & Border Tariff	3,689	12,871	774	2,031	0	44,545	172	0	16,459	**80,541**
Project D, Option 2	7,136	12,871	774	1,850	0	42,560	203	0	15,258	**80,652**
Project D, Option 2- High Carbon & Border Tariff	7,136	12,871	774	2,033	0	41,156	161	0	16,453	**80,585**
Option 1 Change from the Base	0	0	0	180	0	-1,362	-42	0	1,163	**-62**
Option 2 Change from the Base	0	0	0	182	0	-1,403	-41	0	1,195	**-68**

Table 6-11: High Carbon Sensitivity - Project D - Saskatchewan Generation by Type (2040)

SK Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project D, Option 1	3,989	8,093	184	145	8,707	6,970	346	0	1,365	**29,800**
Project D, Option 1- High Carbon & Border Tariff	4,009	8,112	184	148	8,507	7,954	414	0	1,382	**30,710**
Project D, Option 2	4,056	8,096	184	145	8,672	6,634	235	0	1,339	**29,360**
Project D, Option 2- High Carbon & Border Tariff	4,059	8,112	184	147	8,452	7,658	287	0	1,351	**30,249**
Option 1 Change from the Base	20	19	0	2	-200	984	67	0	18	**910**
Option 2 Change from the Base	3	16	0	2	-220	1,024	52	0	12	**889**

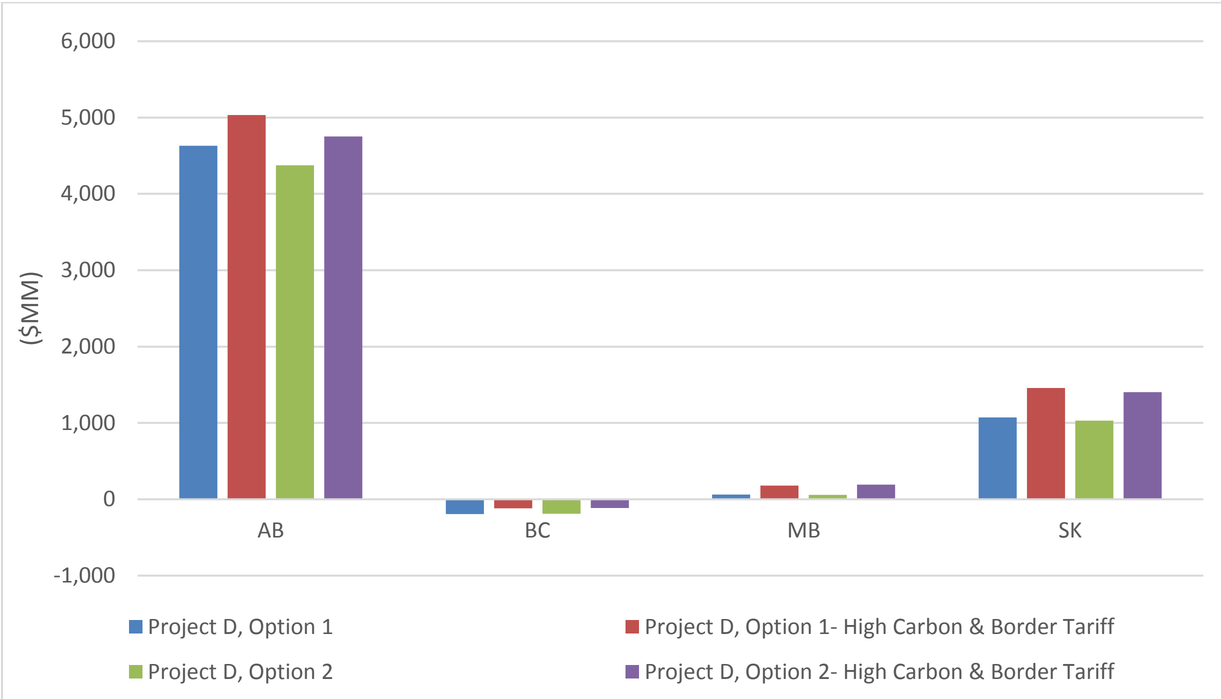


Figure 6-31: High Carbon Sensitivity - Project D - Adjusted Production Cost (2040)

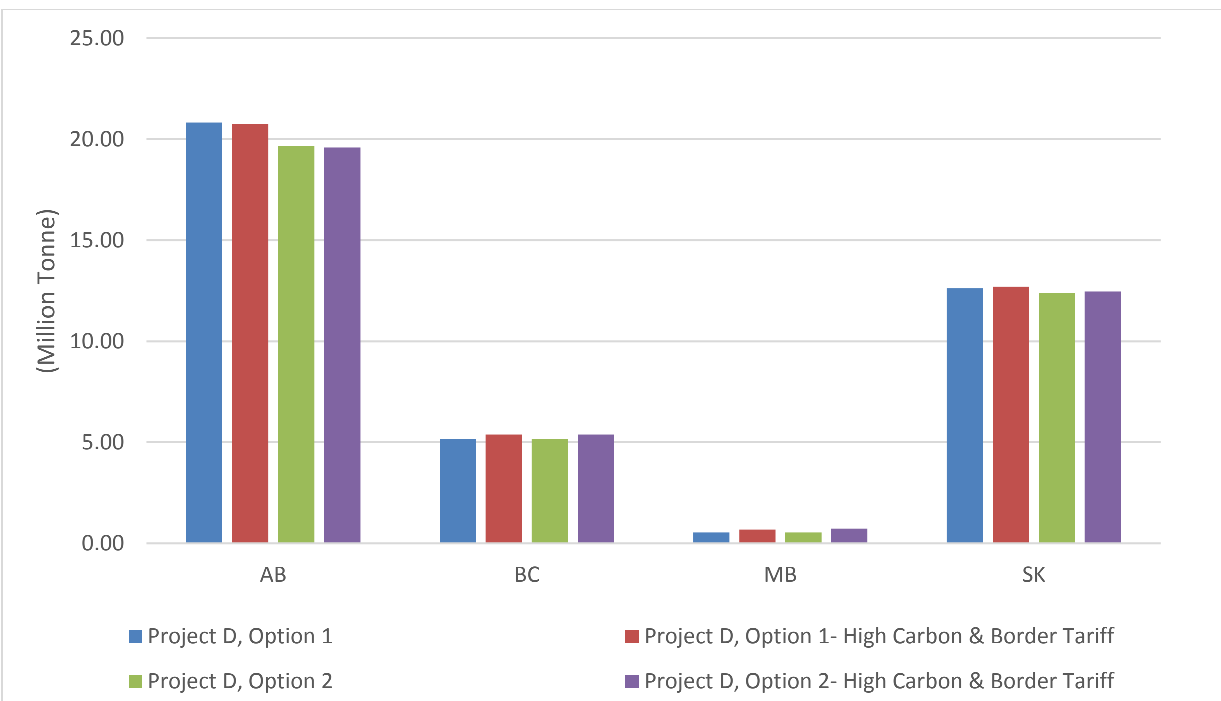


Figure 6-32: High Carbon Sensitivity - Project D - CO2 Emissions (2040)

6.2.6 Project E: Coal Conversion in AB and SK (2030)

Project E's coal conversion options - one option in Alberta (conversion to CCs), and two options in Saskatchewan (Conversion to CCS and Conversion to CCs) - were evaluated under the high carbon price with carbon border tariff sensitivity.

The following charts and tables present the impact of high carbon price sensitivity on Project E options. General observations include:

- In all of Project E's options, the main impact of high carbon price with carbon border tariff appears to be an increase CC-GAS generation. Apparently, the carbon border tariff makes the Canadian power more competitive relative to the USA generation, resulting in higher exports from Alberta and Saskatchewan under all options.
- Alberta is already using its renewable resources fully, so any higher carbon prices (or higher gas prices) would impact only the fossil fuel-based plants. Even with higher carbon prices, the average full load cost of the COAL generation is lower than any of the natural gas-based generation, with COAL being the lowest cost thermal option, and consequently, COAL generation runs similarly in both cases.
- However, in Saskatchewan Carbon Capture option, most of the COAL generation has been converted to CCS, which is the source of the slight increase in COAL generation. The carbon border tariff makes Saskatchewan generation more economical compared to the USA generation, so the in-province generation more than displaces the imports, resulting in increased exports from Saskatchewan.
- It should be noted that the waste burning units (i.e., OTHER units) and coal are still the least expensive options, so they are generating more to cover what would have come from the USA.
- Even with the higher exports, the additional carbon related costs result in higher adjusted production costs in both Alberta and Saskatchewan.
- Increased generation and higher exports also result in a slim increase in CO2 emissions in both Alberta and Saskatchewan.

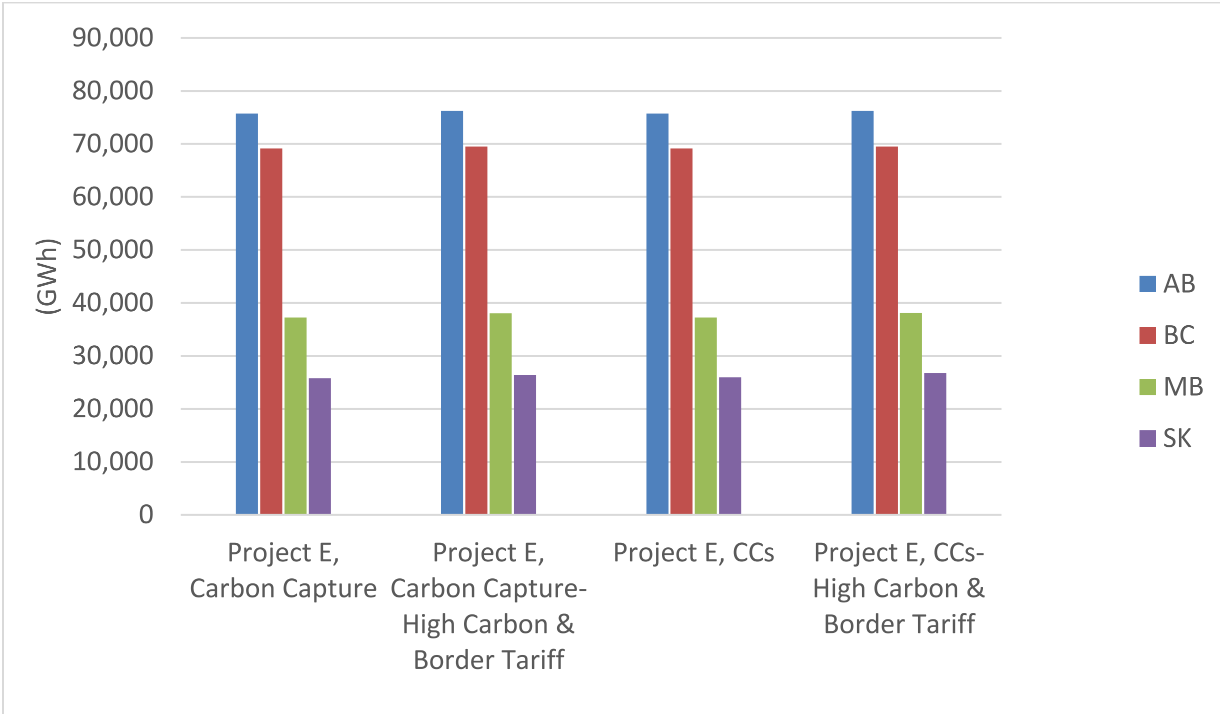


Figure 6-33: High Carbon Sensitivity - Project E - Generation by Province (2030)

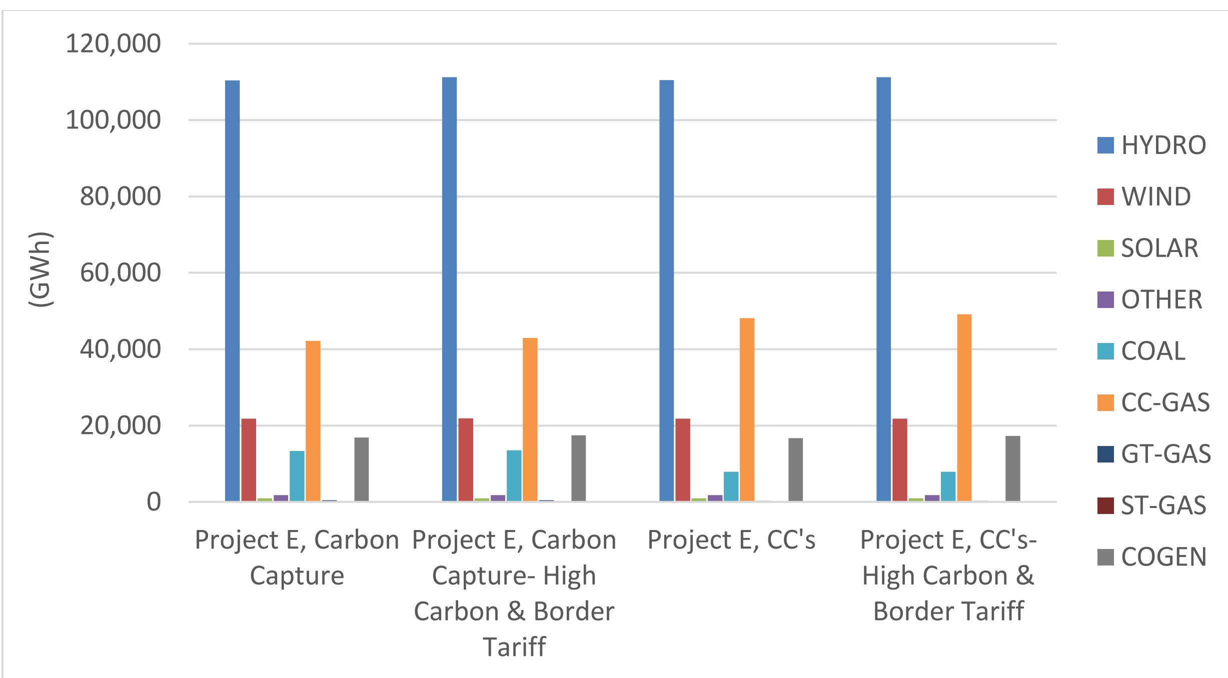


Figure 6-34: High Carbon Sensitivity - Project E - Generation by Type (2030)

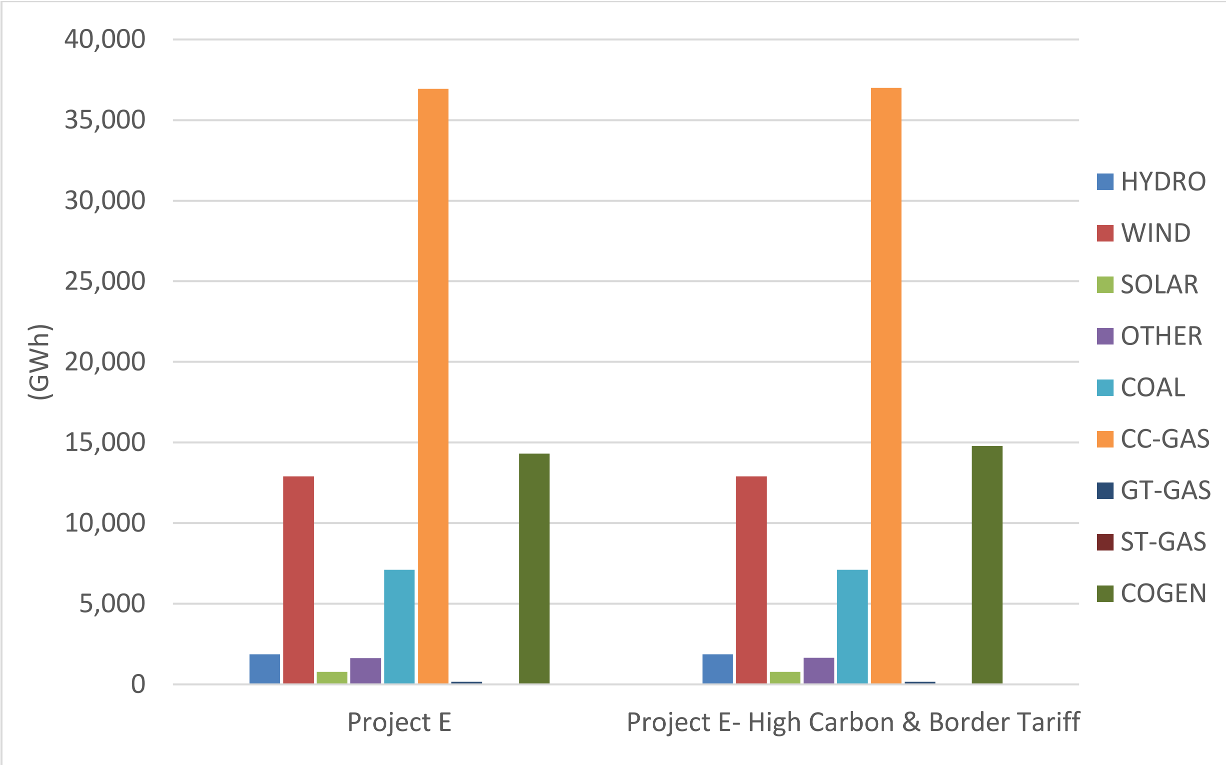


Figure 6-35: High Carbon Sensitivity - Project E - Alberta Generation (2030)

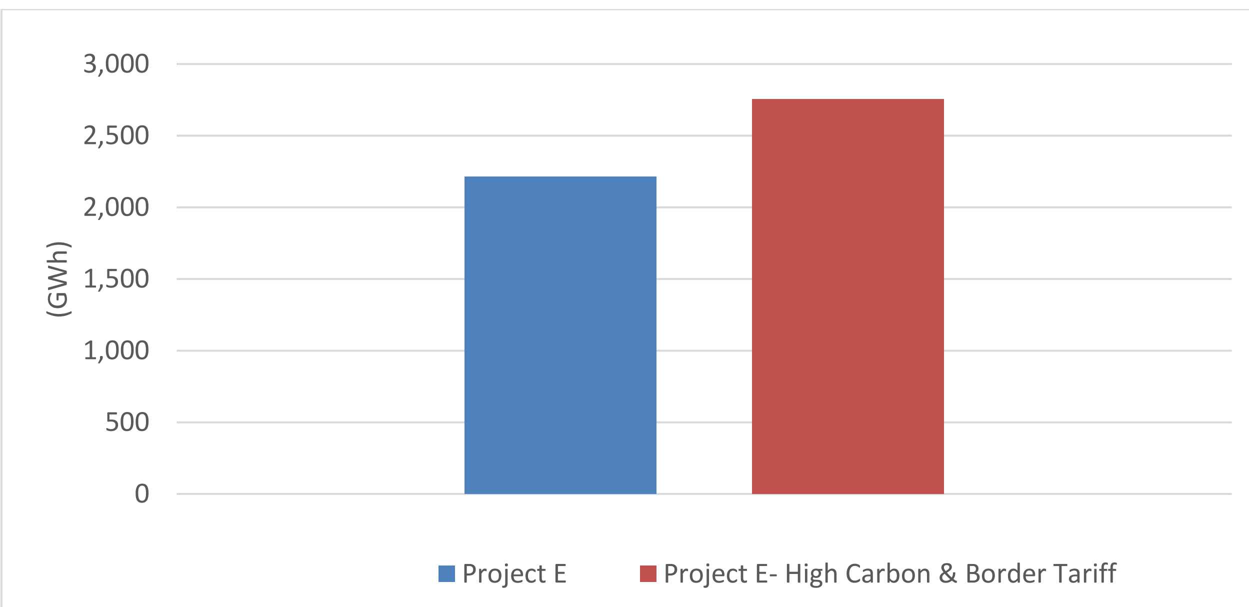


Figure 6-36: High Carbon Sensitivity - Project E - Alberta Net Exports (2030)

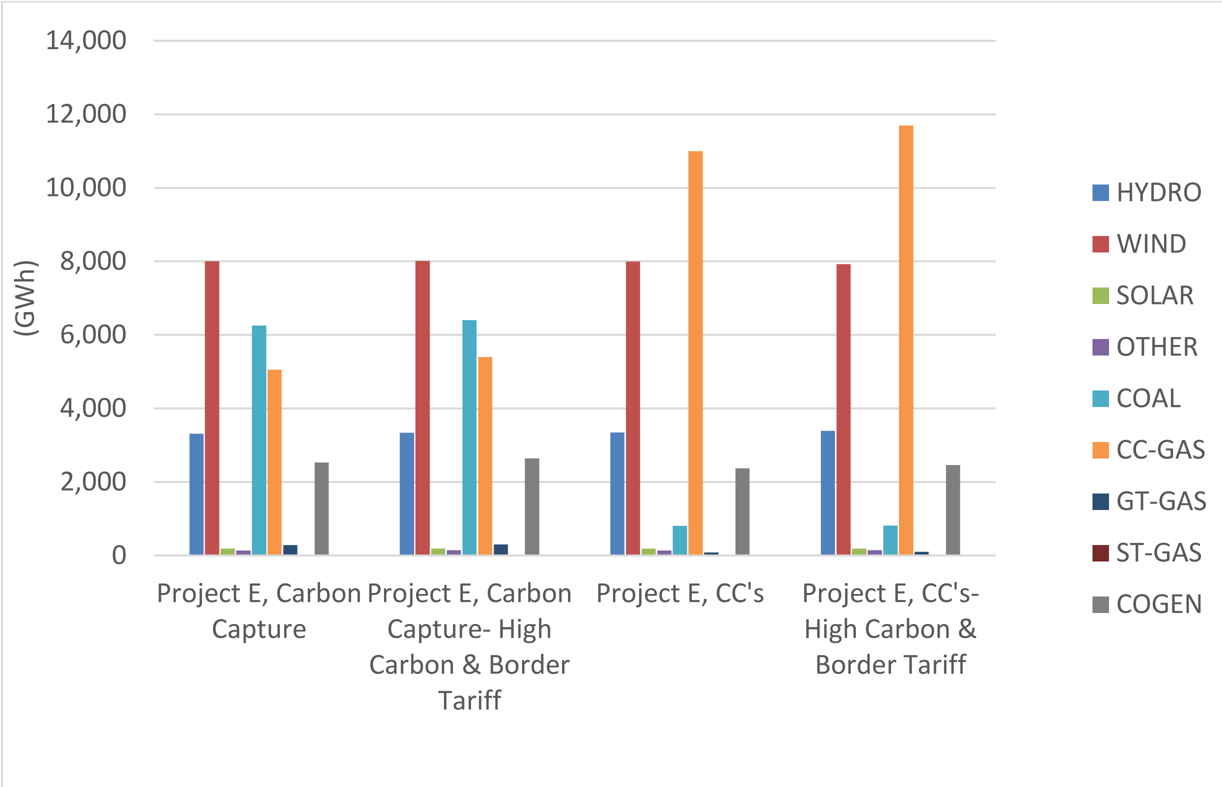


Figure 6-37: High Carbon Sensitivity - Project E - Saskatchewan Generation (2030)

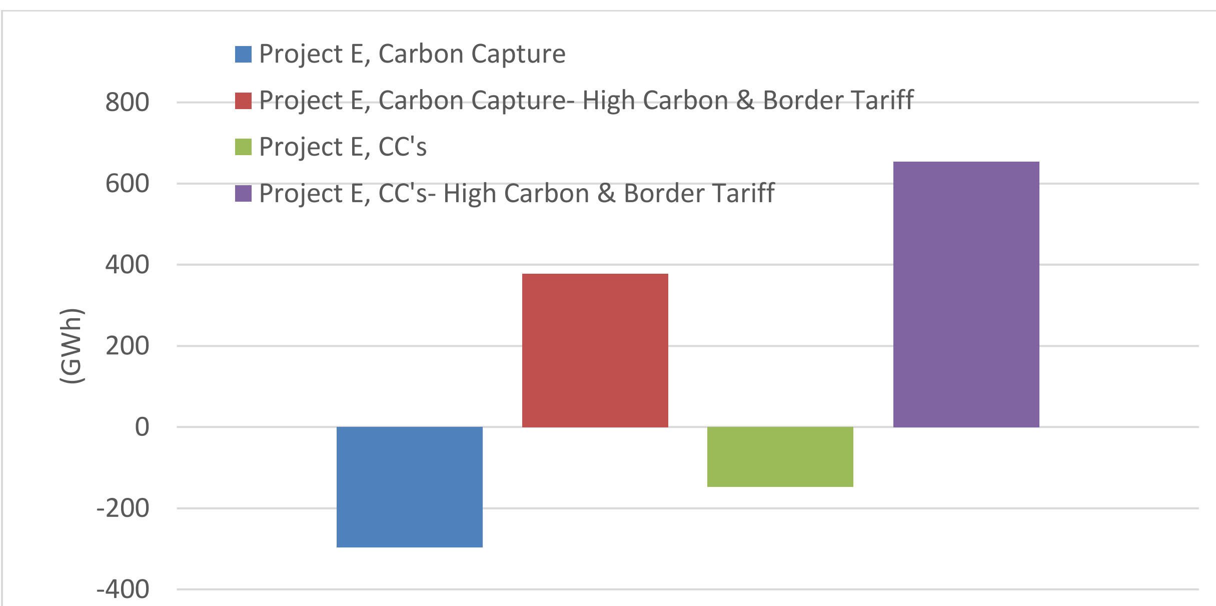


Figure 6-38: High Carbon Sensitivity - Project E - Saskatchewan Net Exports (2030)

Table 6-12: High Carbon Sensitivity - Project E - Alberta Generation (2030)

AB Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project E	1,875	12,910	775	1,629	7,107	36,946	165	0	14,308	**75,714**
Project E- High Carbon & Border Tariff	1,875	12,910	775	1,650	7,107	36,992	154	0	14,791	**76,254**
Change	**0**	**0**	**0**	**22**	**0**	**46**	**-11**	**0**	**483**	**540**

Table 6-13: High Carbon Sensitivity - Project E - Saskatchewan Generation (2030)

SK Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project E, Carbon Capture	3,314	8,001	184	137	6,257	5,056	280	0	2,525	**25,753**
Project E, Carbon Capture- High Carbon & Border Tariff	3,340	8,010	185	140	6,405	5,405	296	0	2,641	**26,423**
Project E, CC's	3,344	7,996	184	137	806	10,994	86	0	2,372	**25,919**
Project E, CC's- High Carbon & Border Tariff	3,387	7,921	188	140	814	11,692	99	0	2,459	**26,699**
Change, Carbon Capture	27	10	1	3	148	349	16	0	116	**670**
Change, CC's	42	-75	4	3	8	698	13	0	87	**781**

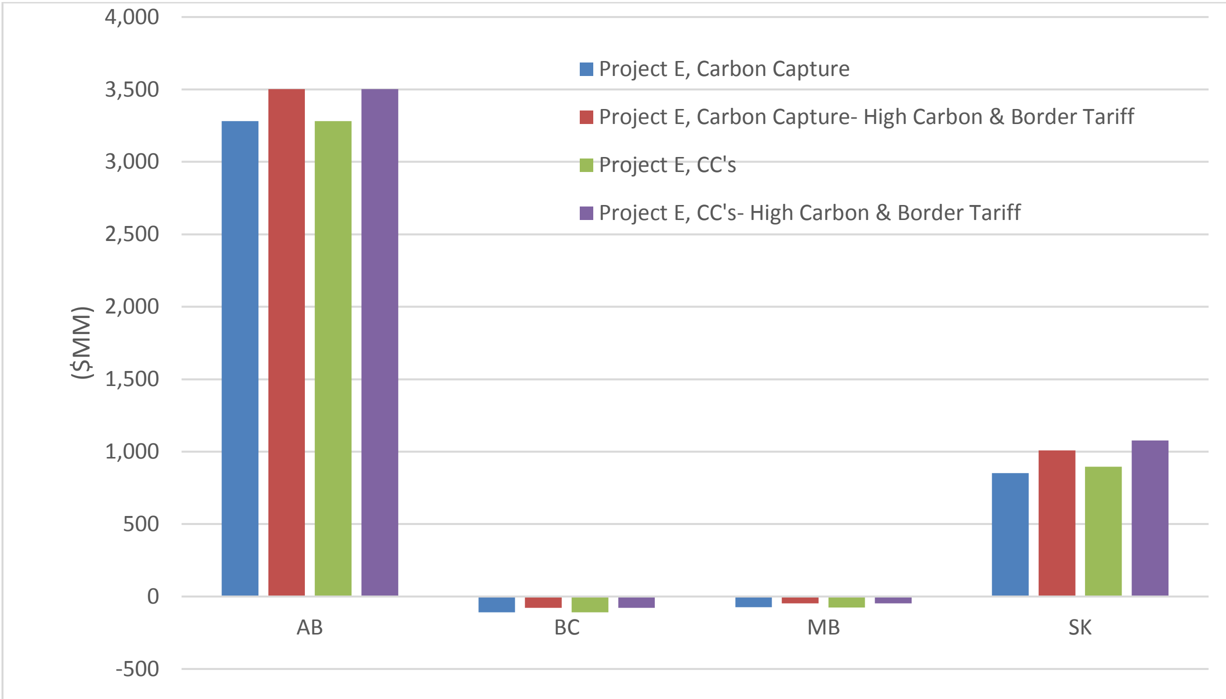


Figure 6-39: High Carbon Sensitivity - Project E - Adjusted Production Cost (2030)

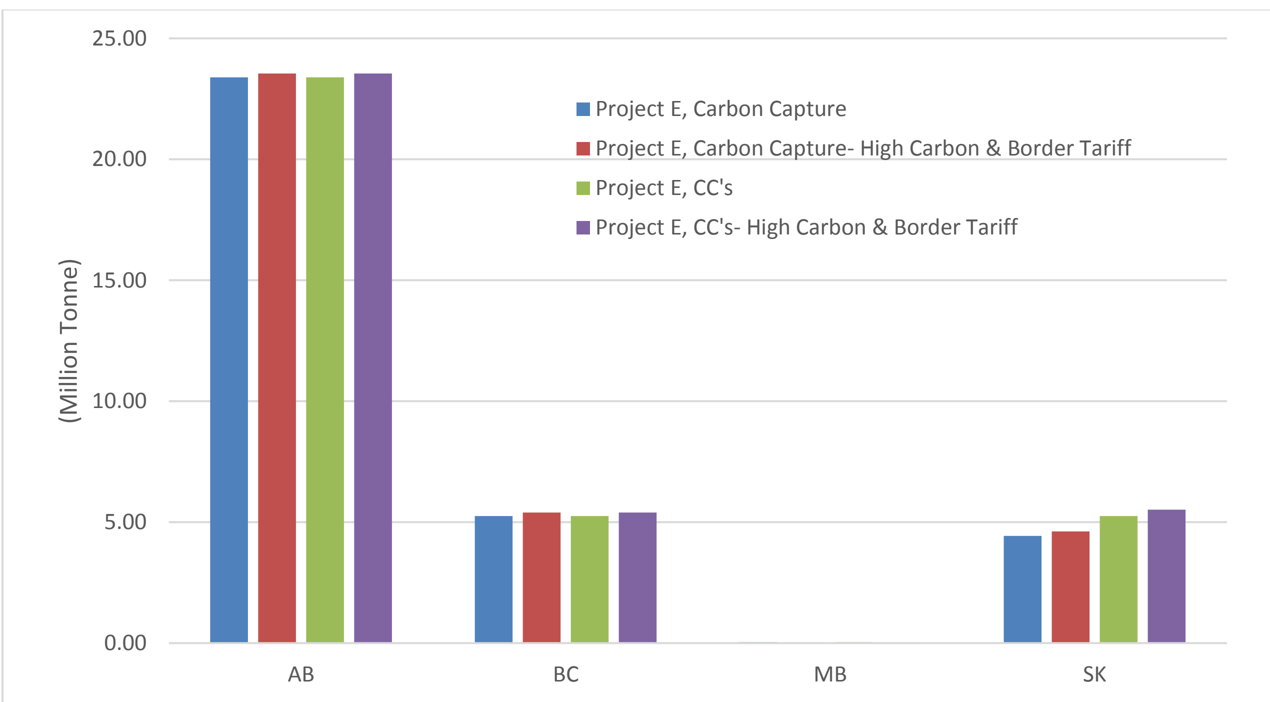


Figure 6-40: High Carbon Sensitivity - Project E - CO2 Emissions (2030)

6.2.7 Project F: Bulk Storage in AB (2030)

Project F - Bulk Storage, in Alberta – was evaluated under the high carbon price with carbon border tariff sensitivity.

The following charts and tables present the impact of high carbon price sensitivity on Project B, Option 1 case. General observations include:

- The underlying data shows that the net electricity usage by the bulk storage does not change significantly. The net annual generation of energy storage is negative, which reflects the fact that energy storage takes in more energy than it gives back due to its less than unity roundtrip efficiency.
- The carbon border tariff limits the imports from the USA, and sometimes reverses the net flow directions, resulting in more generation in Alberta and British Columbia.
- Coal is the cheapest and was already running as much as it could. Next in line are the OTHER units but there isn't much capacity there to cover what used to come from the USA, and hence, CC-GAS and COGEN units have to pick up the larger portion of the displaced generation.
- As a result, even with high carbon price, in addition to all the COAL generation being needed in Alberta, additional natural gas-based generation is also utilized to replace the imports from the USA.
- As the following figures show, Imports into Alberta are reduced, and exports by British Columbia are increased.
- Due to higher natural gas-based generation in both provinces together with higher carbon prices, adjusted production costs are increased in both provinces (costs are increased in Alberta and net revenues are decreased in British Columbia).
- As expected, in both provinces, CO2 emissions increase.

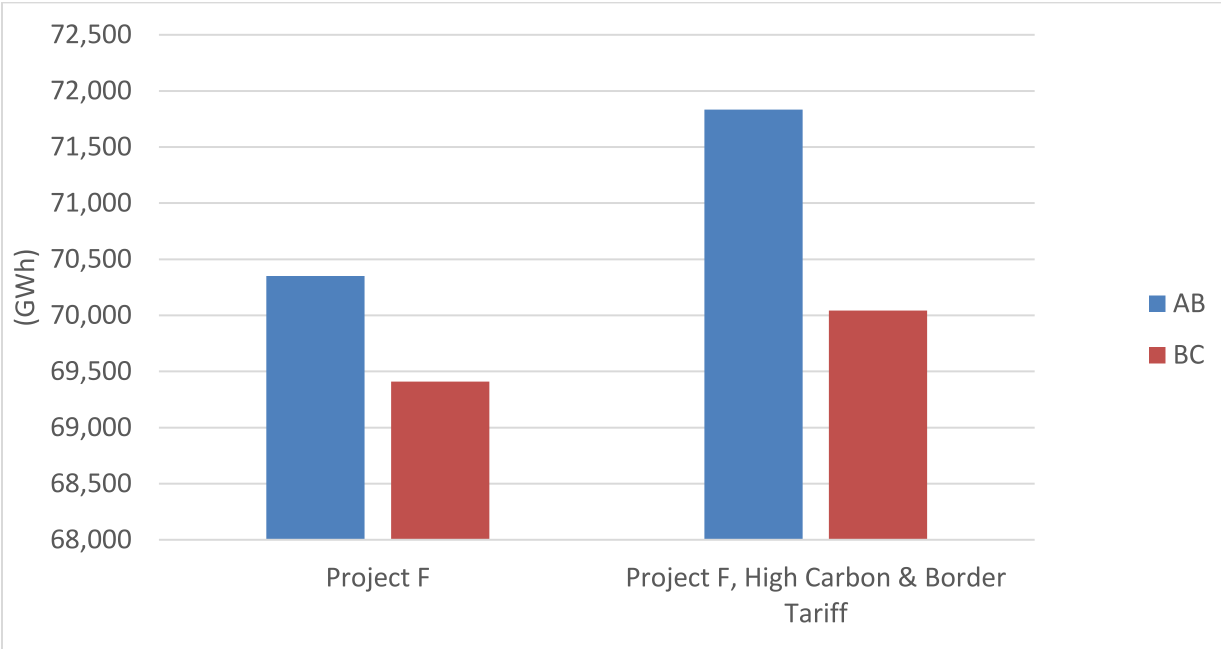


Figure 6-41: High Carbon Sensitivity - Project F - Generation by Province (2030)

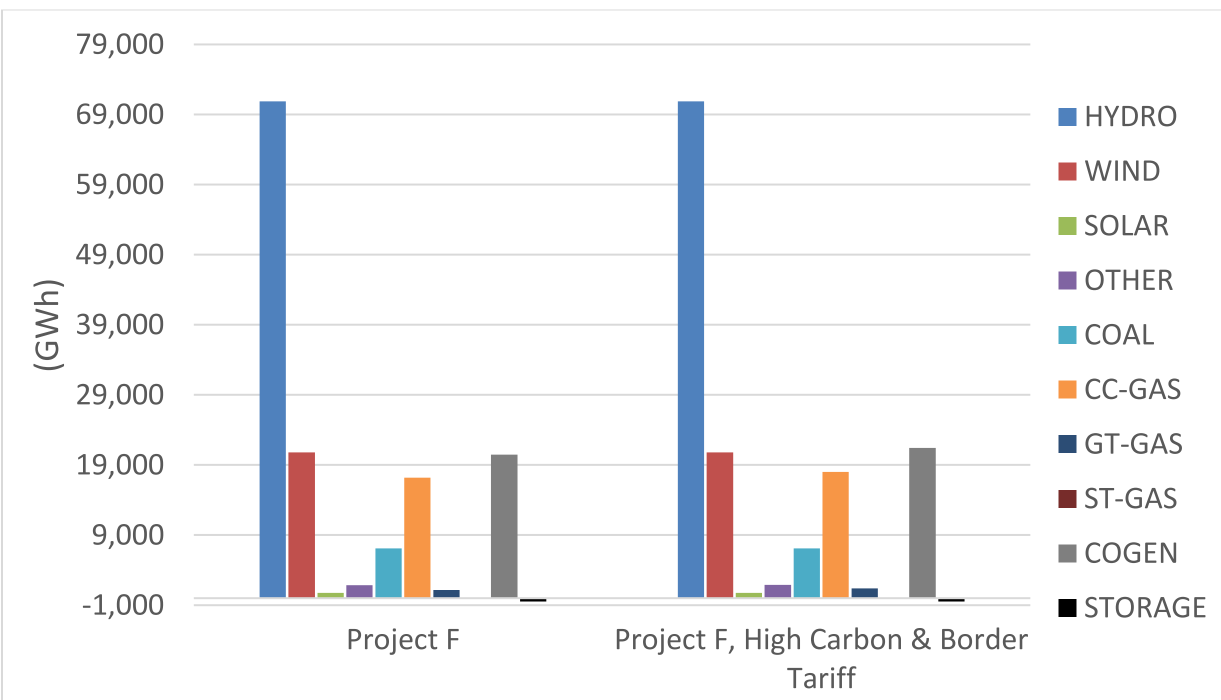


Figure 6-42: High Carbon Sensitivity - Project F - Generation by Type (2030)

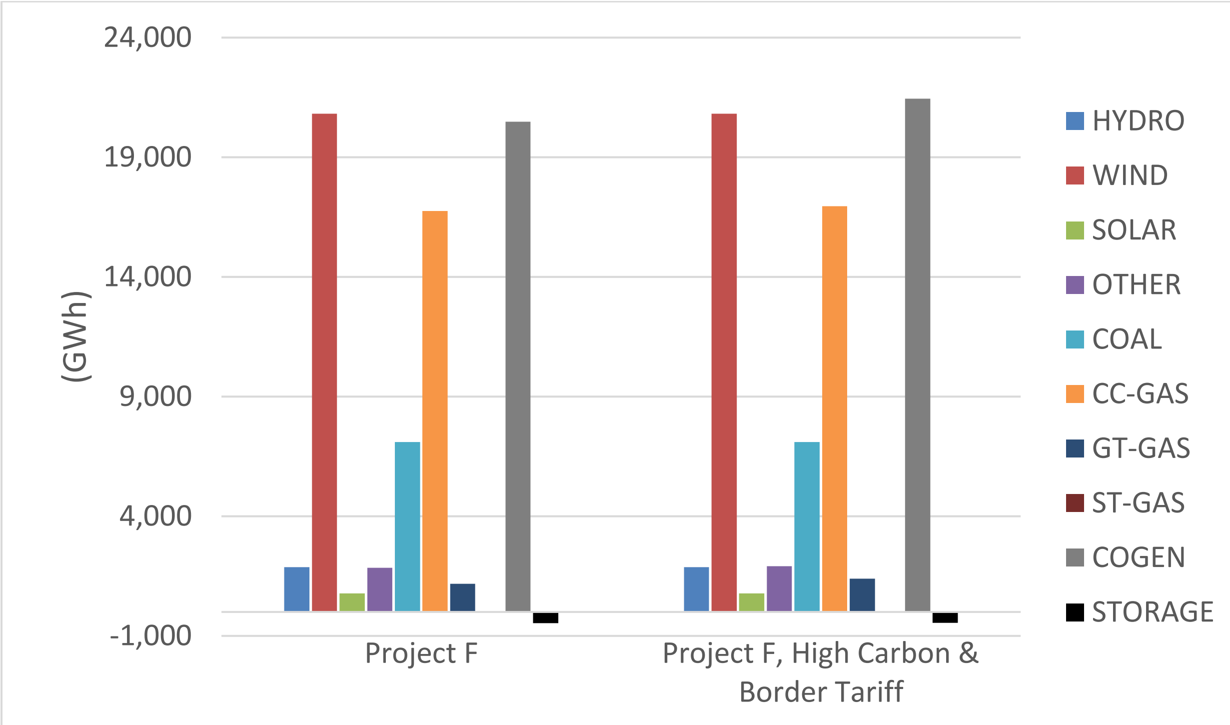


Figure 6-43: High Carbon Sensitivity - Project F - Alberta Generation (2030)

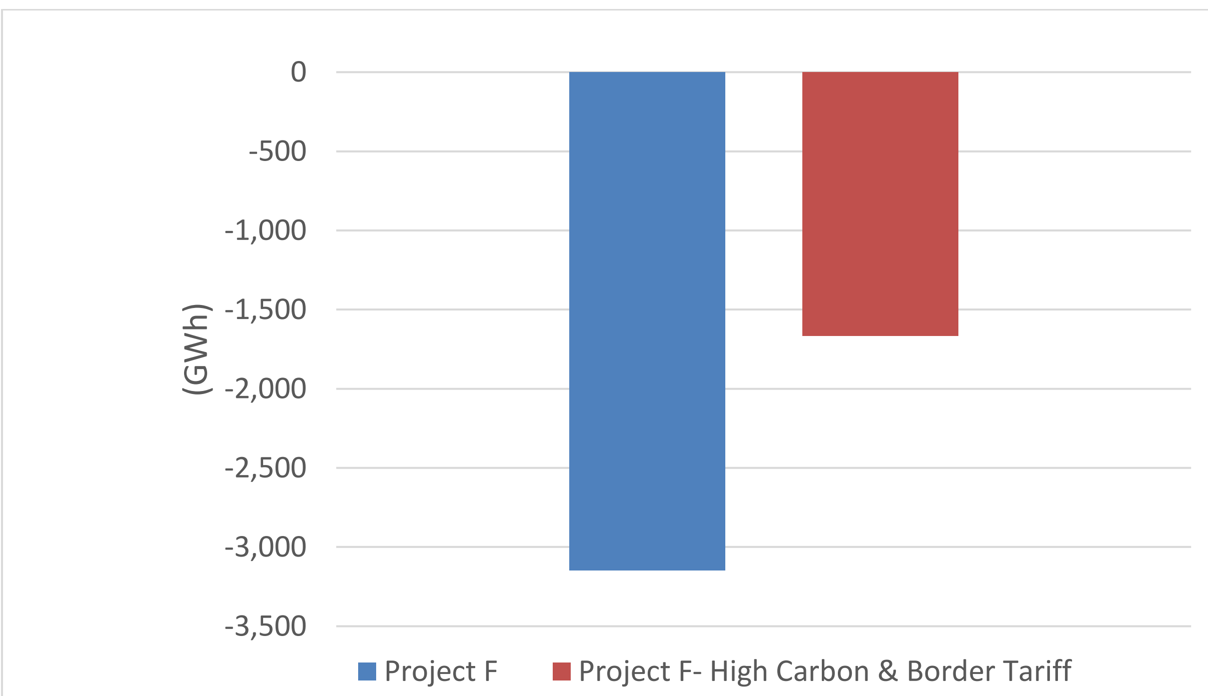


Figure 6-44: High Carbon Sensitivity - Project F - Alberta Net Exports (2030)

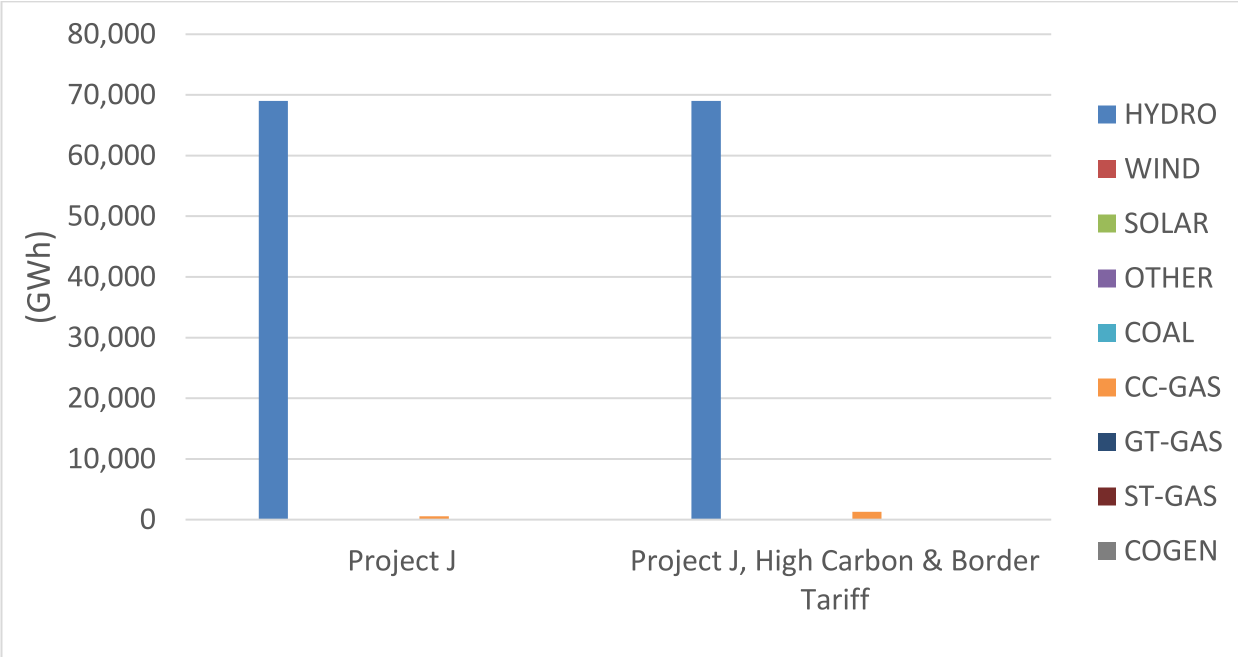


Figure 6-45: High Carbon Sensitivity - Project F - British Columbia Generation (2030)

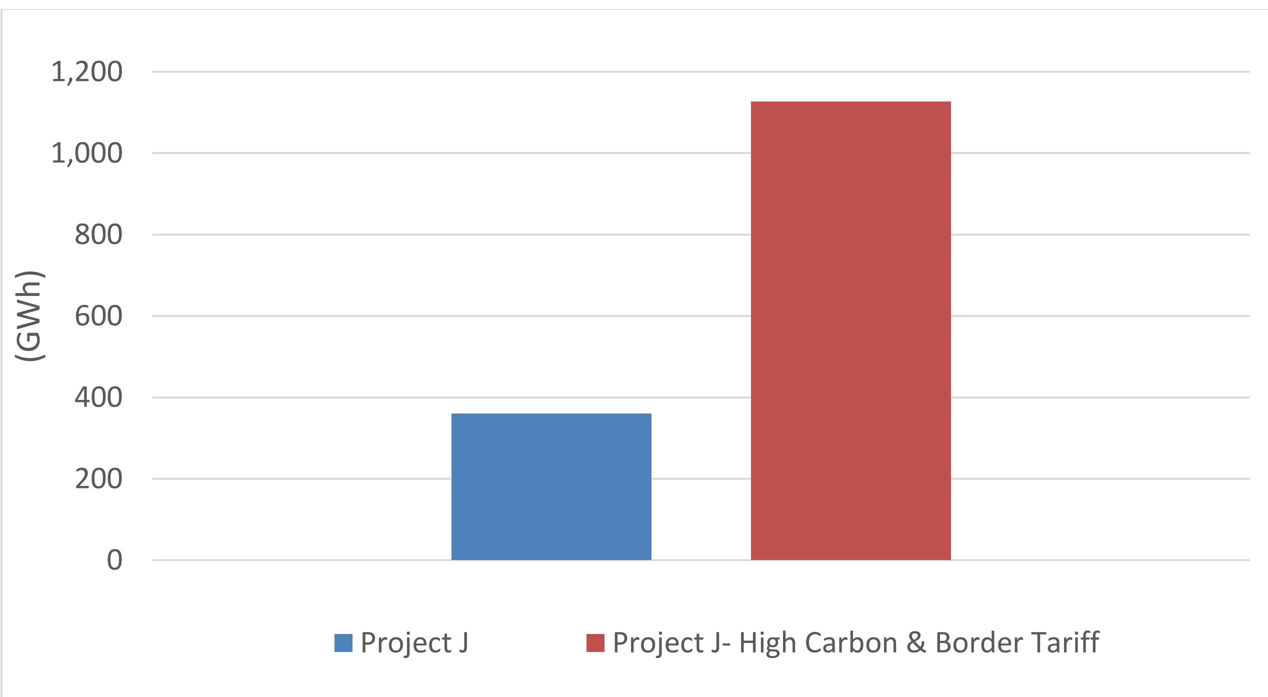


Figure 6-46: High Carbon Sensitivity - Project F - British Columbia Net Exports (2030)

Table 6-14: High Carbon Sensitivity - Project F - Alberta Generation (2030)

AB Generation (GWh)	STORAGE	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project J	-467	1,875	20,814	775	1,839	7,107	16,759	1,171	0	20,480	**70,352**
Project J, High Carbon & Border Tariff	-456	1,875	20,820	775	1,915	7,107	16,950	1,396	0	21,450	**46,903**
Change	**11**	**0**	**6**	**0**	**76**	**0**	**191**	**225**	**0**	**971**	**1,481**

Table 6-15: High Carbon Sensitivity - Project F - British Columbia Generation (2030)

BC Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project J	68,987	0	0	0	0	538	0	0	0	**69,525**
Project J, High Carbon & Border Tariff	68,990	0	0	0	0	1,302	0	0	0	**70,292**
Change	**3**	**0**	**0**	**0**	**0**	**764**	**0**	**0**	**0**	**767**

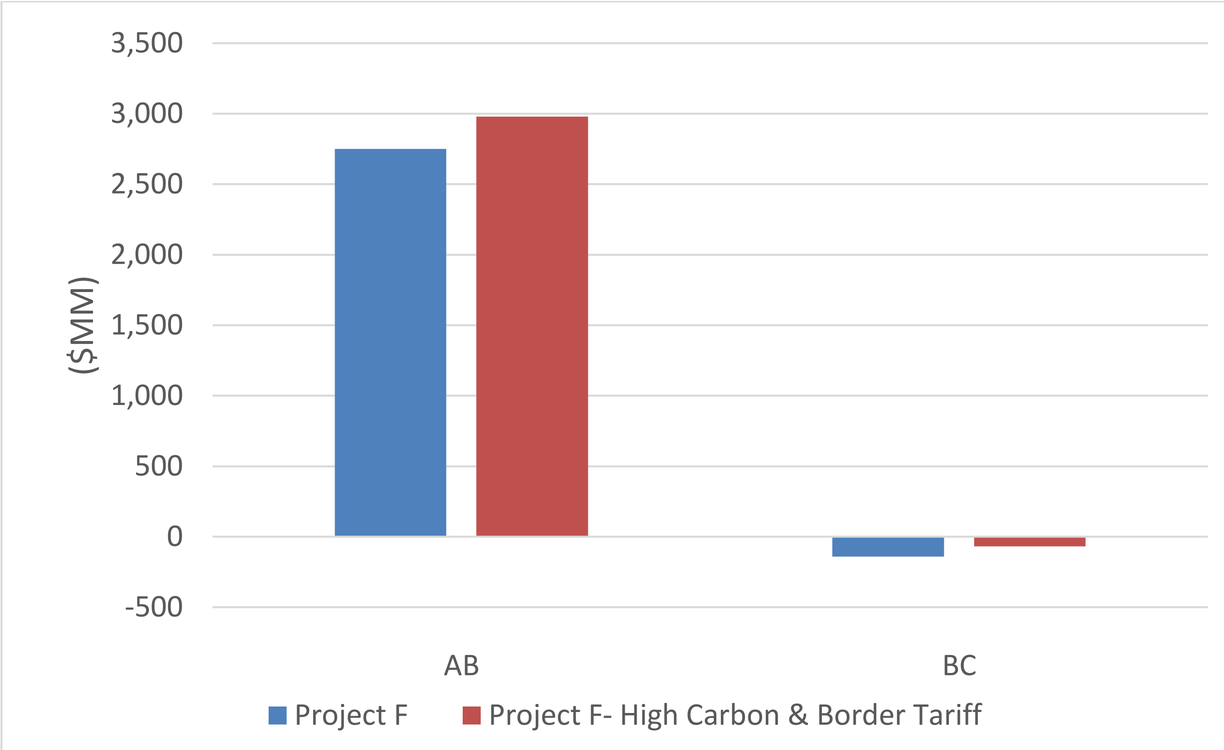


Figure 6-47: High Carbon Sensitivity - Project F - Alberta Adjusted Production Costs (2030)

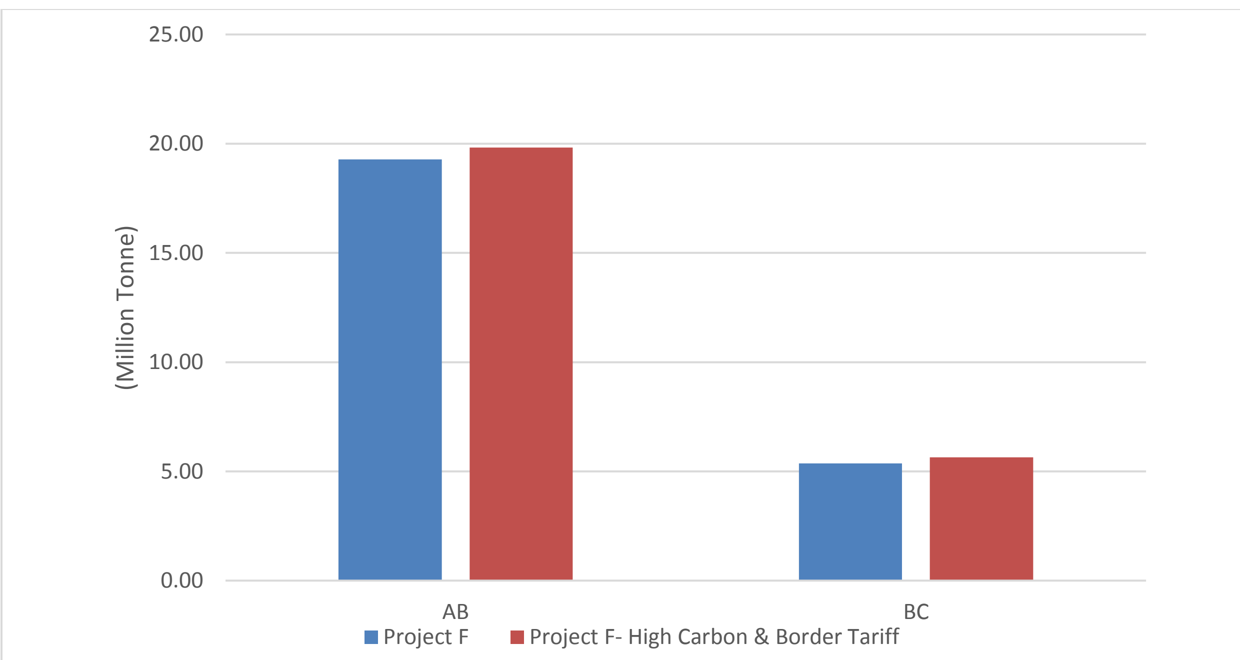


Figure 6-48: High Carbon Sensitivity - Project F - CO2 Emissions (2030)

6.2.8 Project J: Simultaneous Transfer Capability between AB-BC and MATL interties (2040)

Project J was evaluated under the high carbon price with carbon border tariff sensitivity.

The following charts and tables present the impact of high carbon price sensitivity on Project J. General observations include:

- As with the previous cases, the carbon border tariff limits the imports from the USA into Canada, resulting in more generation in Alberta and British Columbia. Hence, even with a higher carbon price, in addition to needing all the COAL generation in Alberta, additional natural gas-based generation is utilized in order to replace the imports from the USA.
- Alberta COAL generation does not change from the original Project J, because the carbon border tariff thwarts more imports from the USA. Although no carbon tax is applied in the USA, any electricity crossing the border into Canada is subject to carbon border tariff.
- As the following figures show, Imports into Alberta are reduced, and exports by British Columbia are increased.
- Due to higher natural gas-based generation in both provinces and higher carbon prices, adjusted production costs are increased in both provinces (costs are increased in Alberta and net revenues in British Columbia are decreased.
- As expected, in both provinces, CO_2 emissions increase.

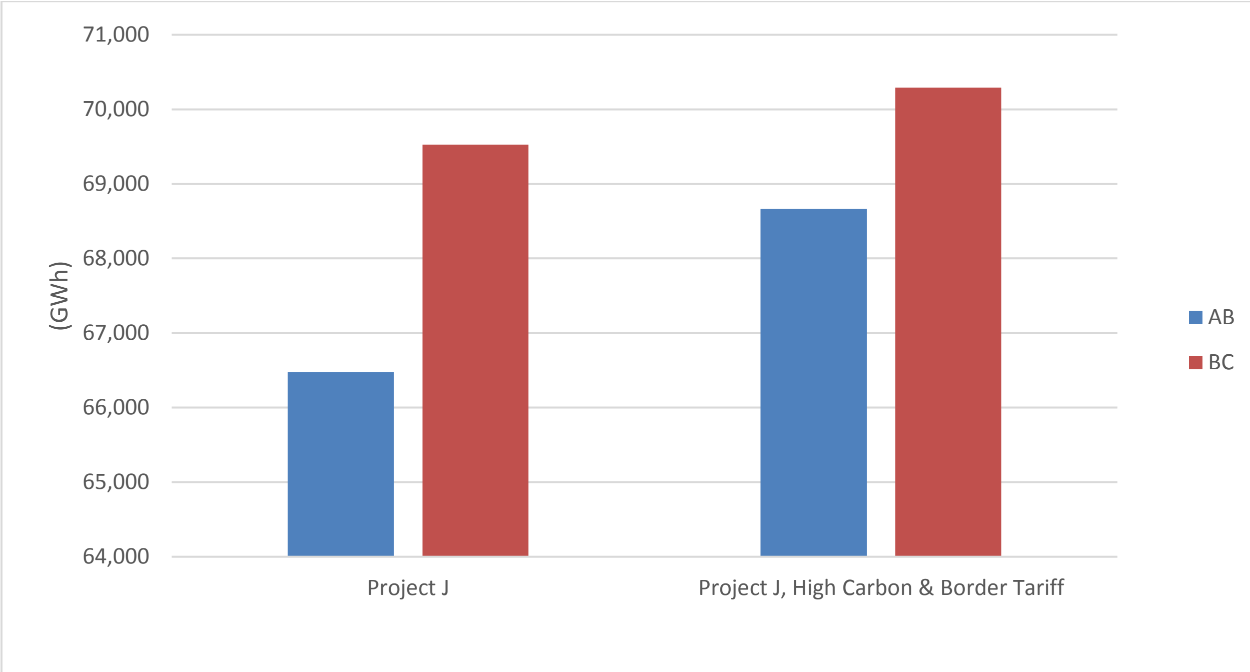


Figure 6-49: High Carbon Sensitivity - Project J - Generation by Province (2030)

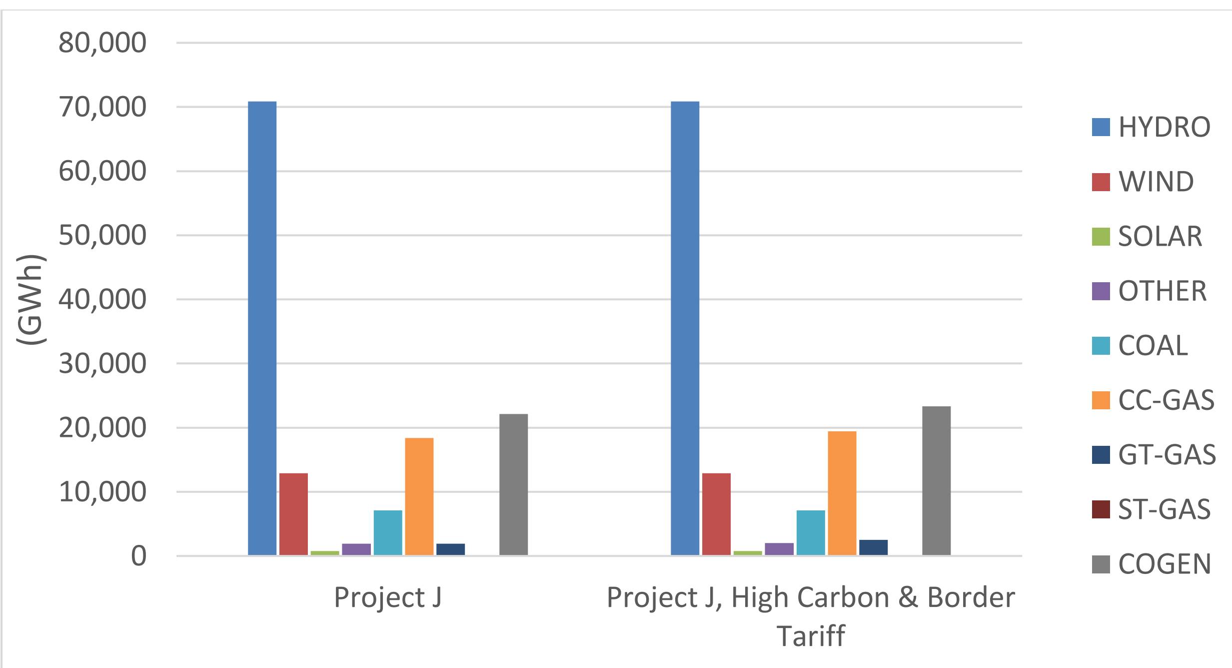


Figure 6-50: High Carbon Sensitivity - Project J - Generation by Type (2030)

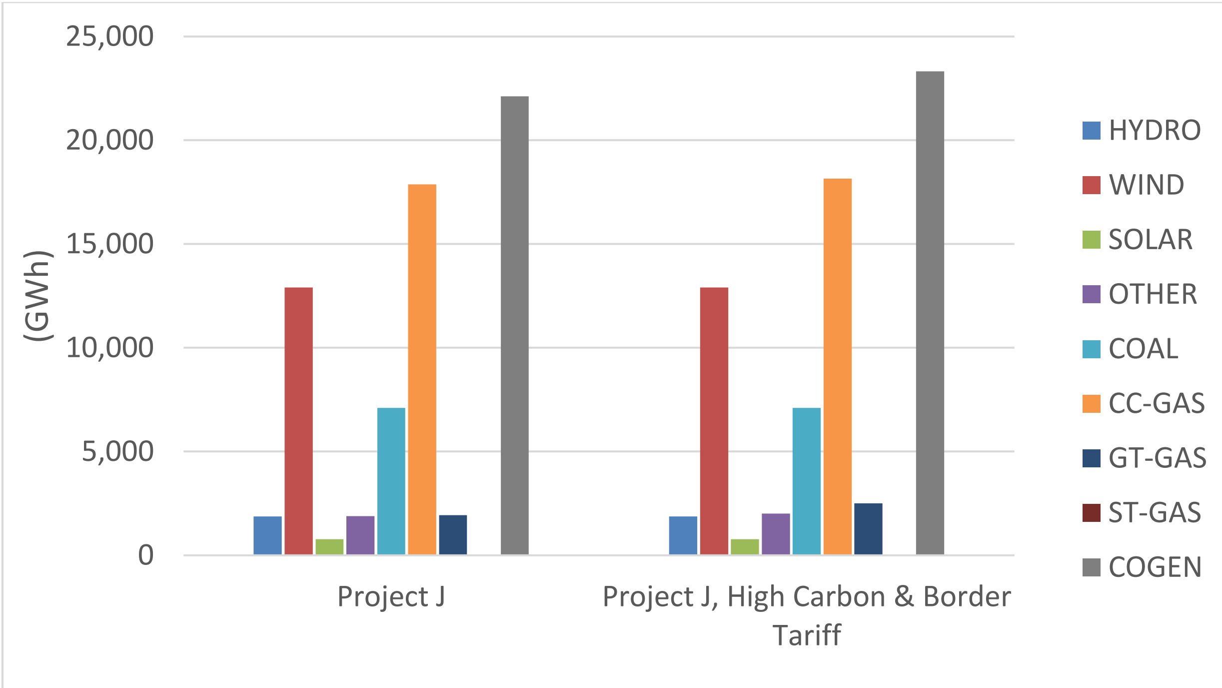


Figure 6-51: High Carbon Sensitivity - Project J - Alberta Generation (2030)

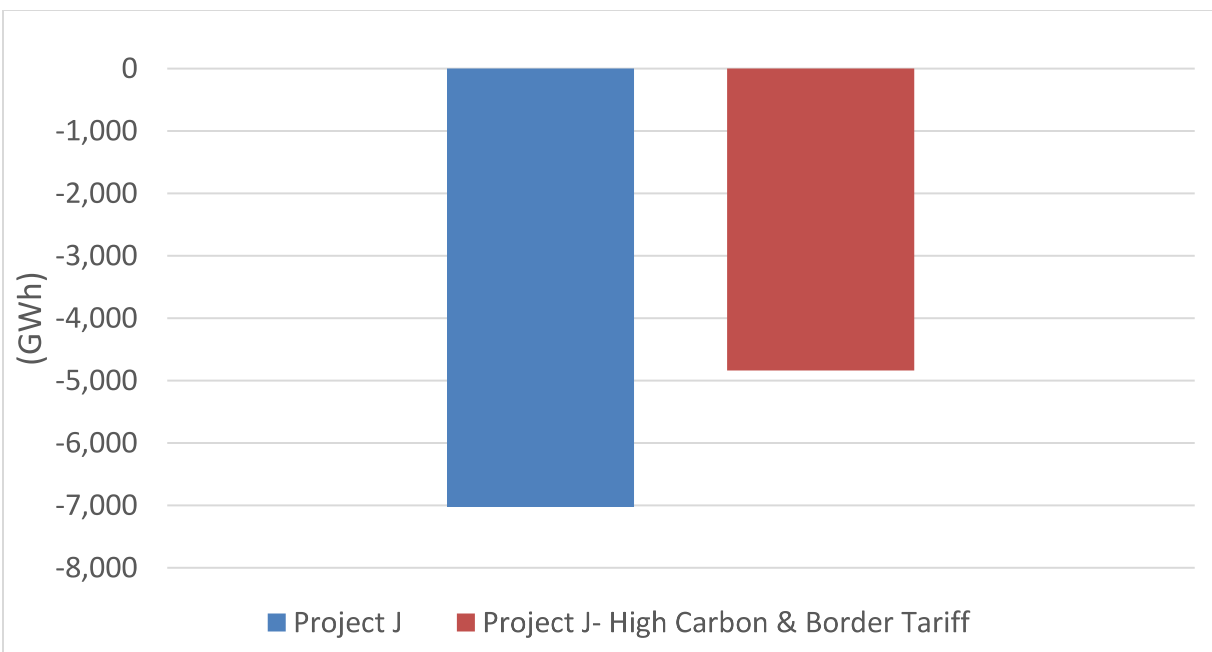


Figure 6-52: High Carbon Sensitivity - Project J - Alberta Net Exports (2030)

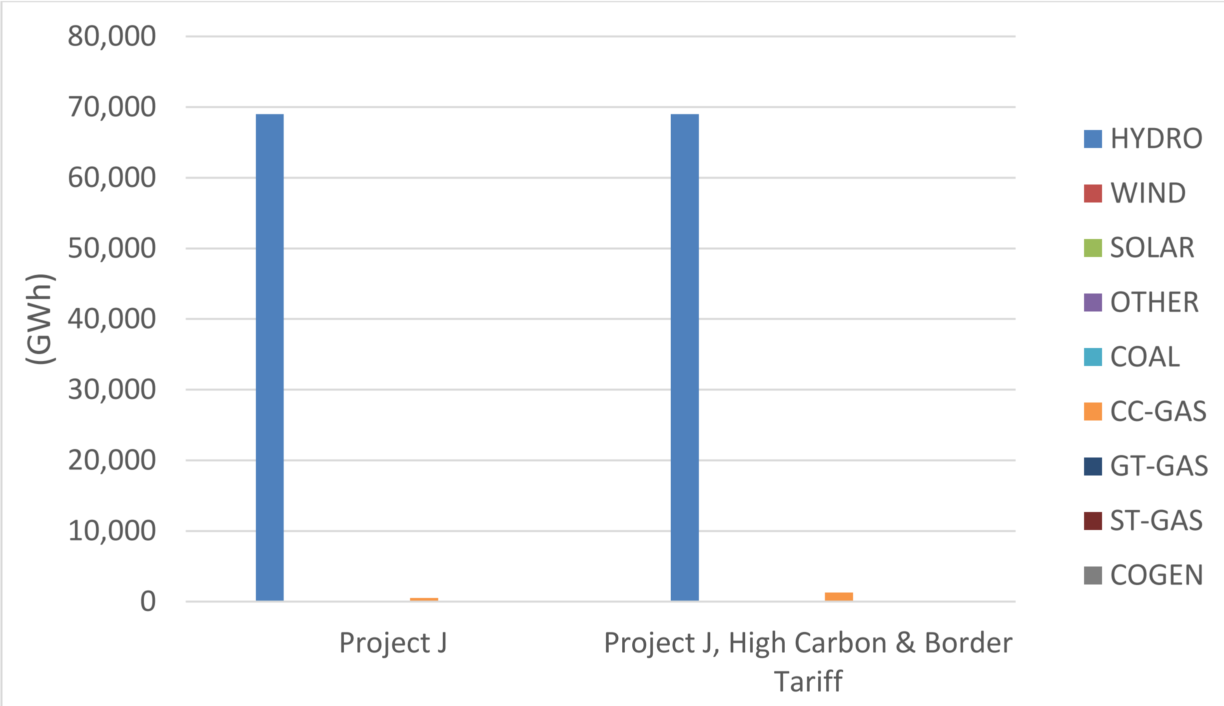


Figure 6-53: High Carbon Sensitivity - Project J - British Columbia Generation (2030)

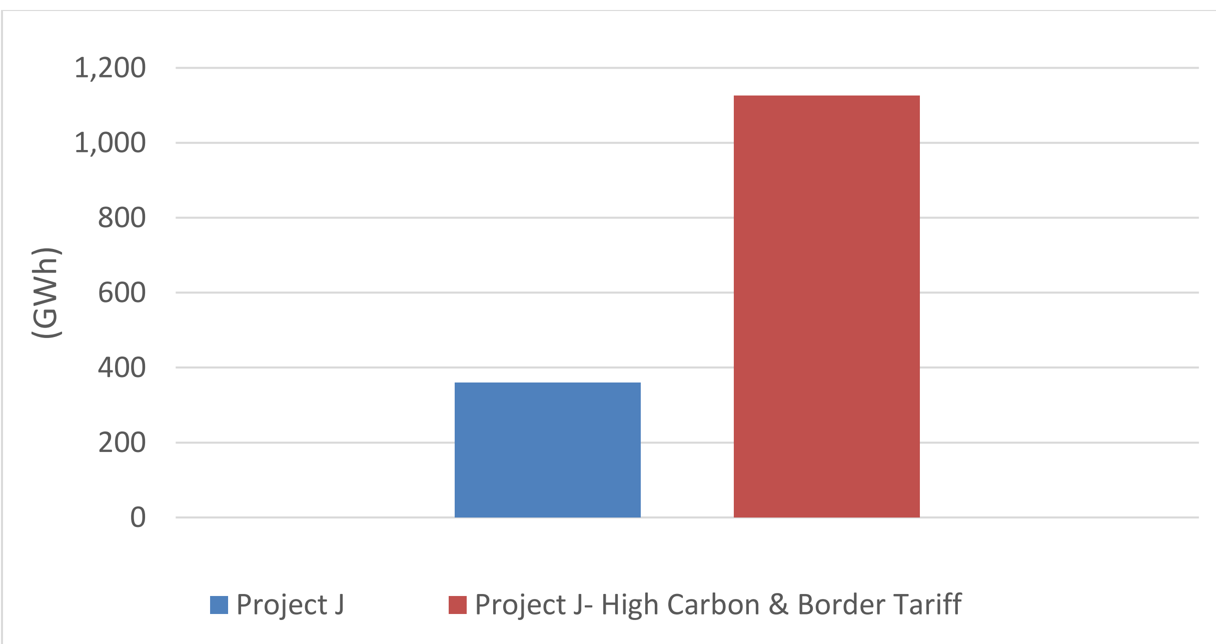


Figure 6-54: High Carbon Sensitivity - Project J - British Columbia Net Exports (2030)

Table 6-16: High Carbon Sensitivity - Project J - Alberta Generation (2030)

AB Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project J	1,875	12,910	775	1,894	7,107	17,874	1,928	0	22,114	**66,476**
Project J, High Carbon & Border Tariff	1,875	12,910	775	2,014	7,107	18,155	2,502	0	23,327	**68,664**
Change	**0**	**0**	**0**	**121**	**0**	**281**	**573**	**0**	**1,212**	**2,187**

Table 6-17: High Carbon Sensitivity - Project J - British Columbia Generation (2030)

BC Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project J	68,987	0	0	0	0	538	0	0	0	**69,525**
Project J, High Carbon & Border Tariff	68,990	0	0	0	0	1,302	0	0	0	**70,292**
Change	**3**	**0**	**0**	**0**	**0**	**764**	**0**	**0**	**0**	**767**

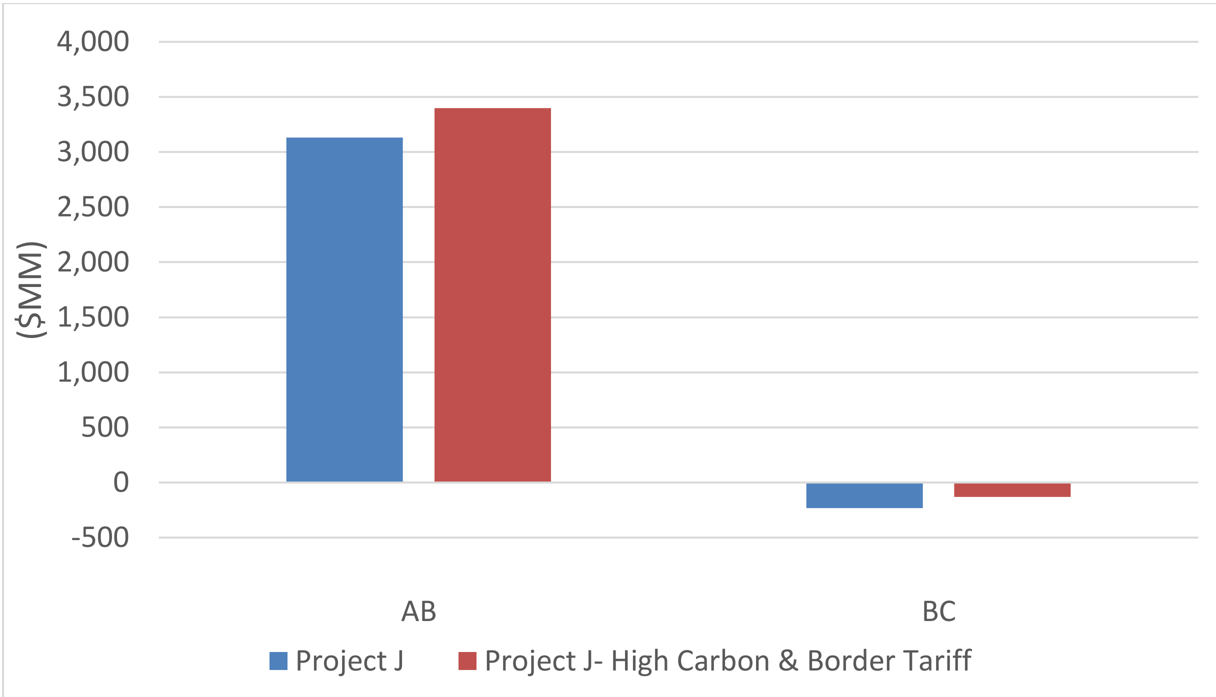


Figure 6-55: High Carbon Sensitivity - Project J - Adjusted Production Cost (2030)

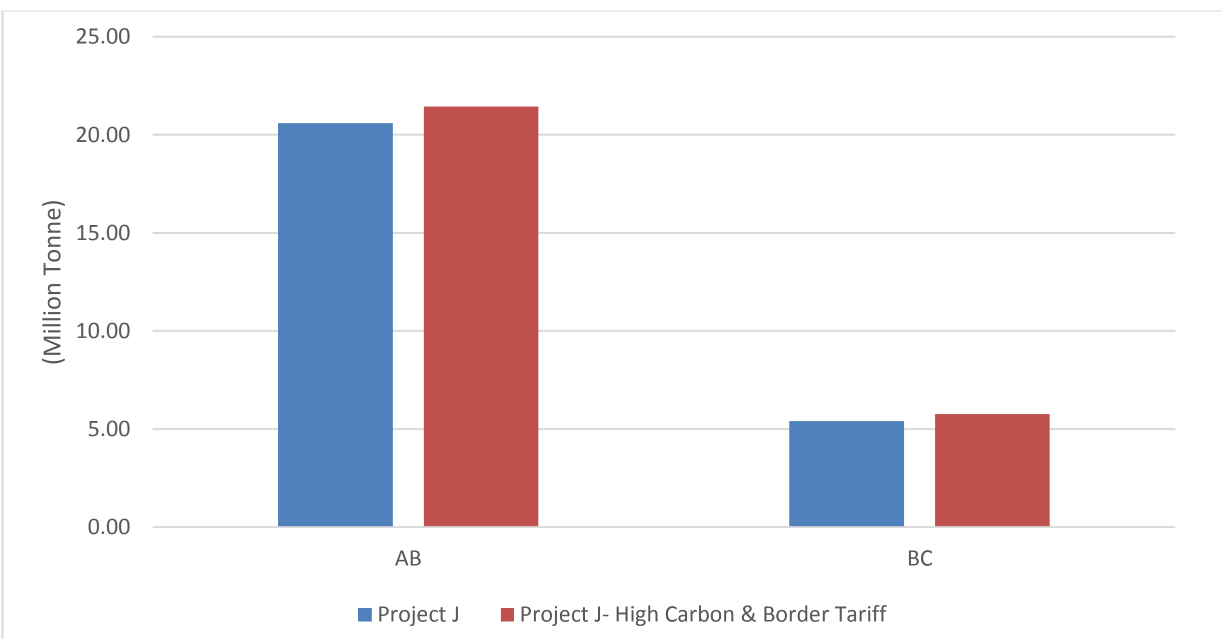


Figure 6-56: High Carbon Sensitivity - Project J - CO2 Emissions (2030)

6.2.9 Project K: Combination of Projects A and C (2030)

Project K (combination of Projects A and C) was evaluated under the high carbon price with carbon border tariff sensitivity.

The following charts and tables present the impact of high carbon price sensitivity on Project K. General observations include:

- As with other cases, the carbon border tariff limits the imports from the USA into Canada, resulting in more generation in Alberta and British Columbia. Hence, even with a higher carbon price, in addition to all the COAL generation being needed in Alberta, additional natural gas-based generation needs to be utilized in order to replace the imports from the USA.
- As the following figures show, imports into Alberta drop and exports from British Columbia rise.
- Due to higher natural gas-based generation in both provinces together with higher carbon prices, adjusted production costs are increased in both provinces (costs drop in Alberta and net revenues rise in British Columbia).
- As expected, in both provinces, CO_2 emissions increase.

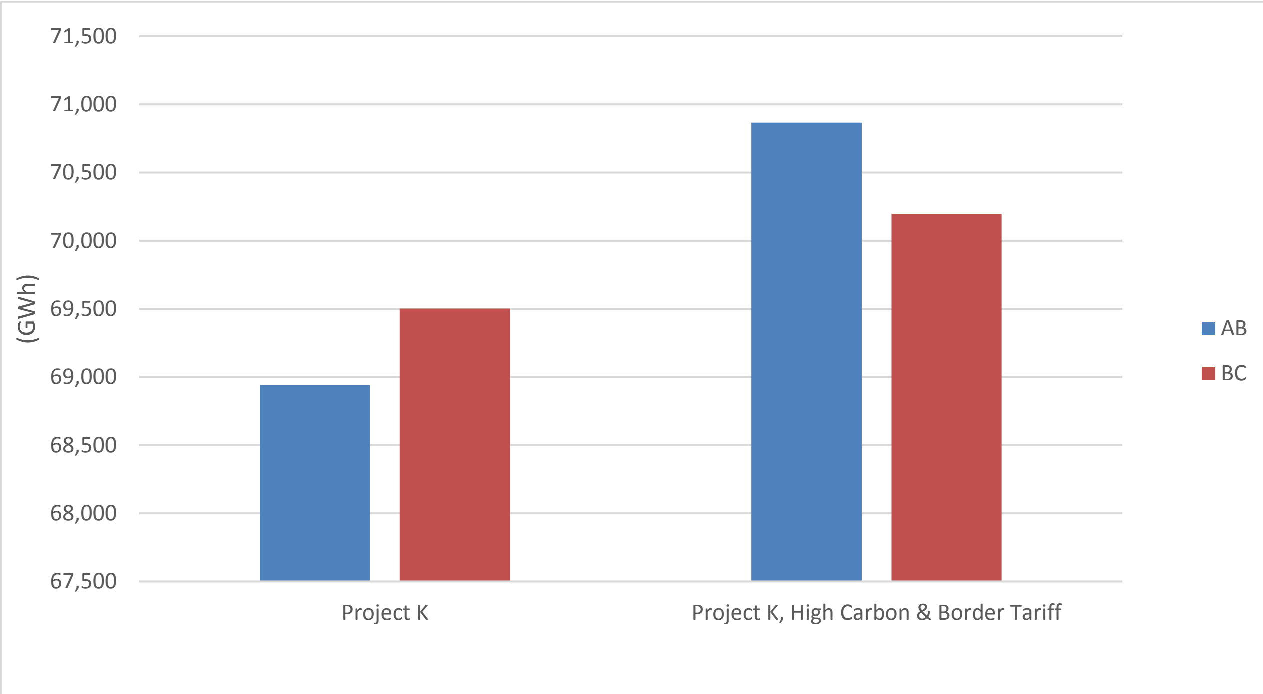


Figure 6-57: High Carbon Sensitivity - Project K - Generation by Province (2030)

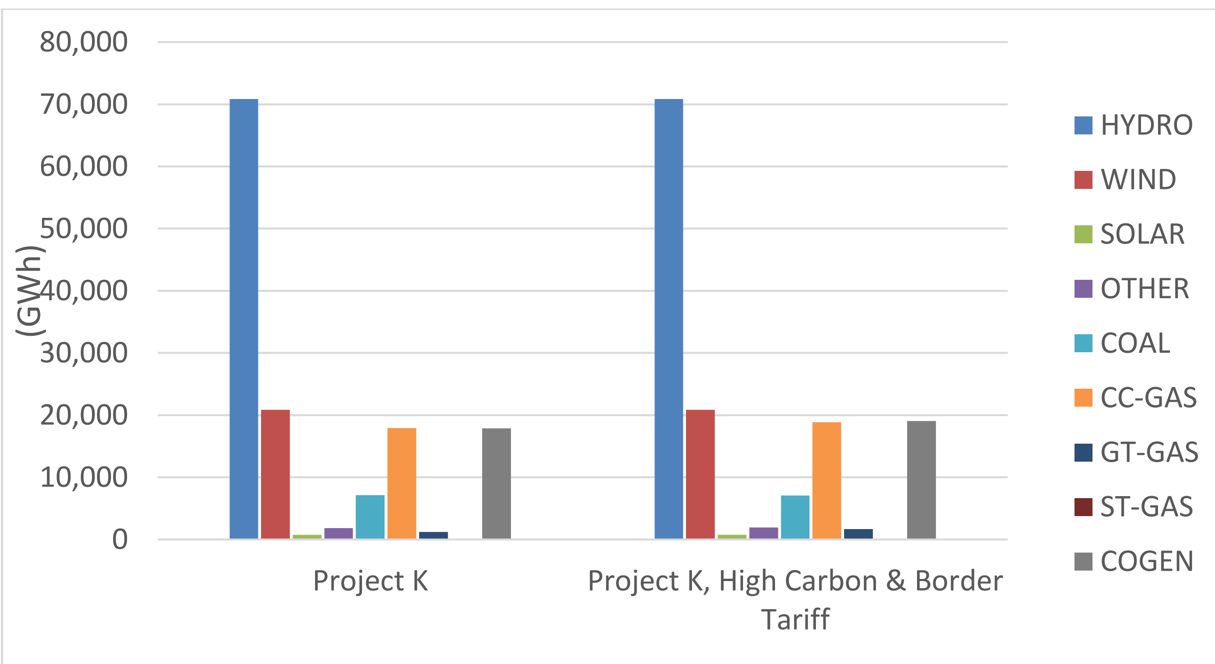


Figure 6-58: High Carbon Sensitivity - Project K - Generation by Type (2030)

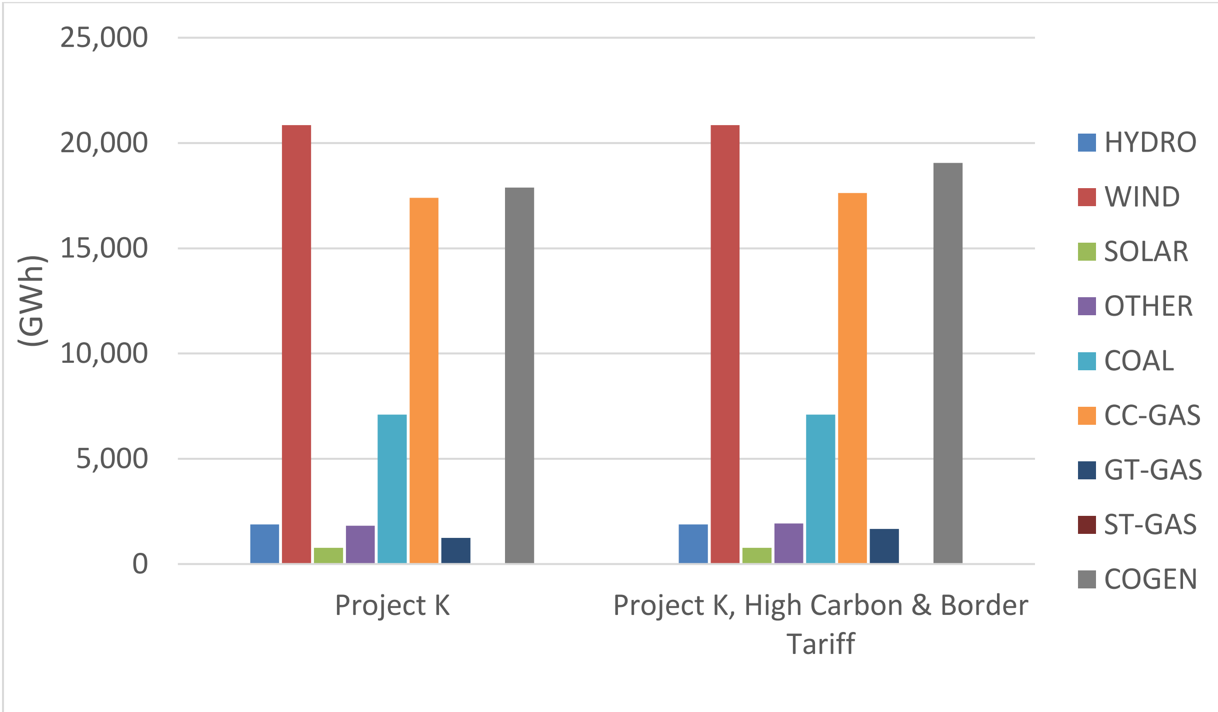


Figure 6-59: High Carbon Sensitivity - Project K - Alberta Generation (2030)

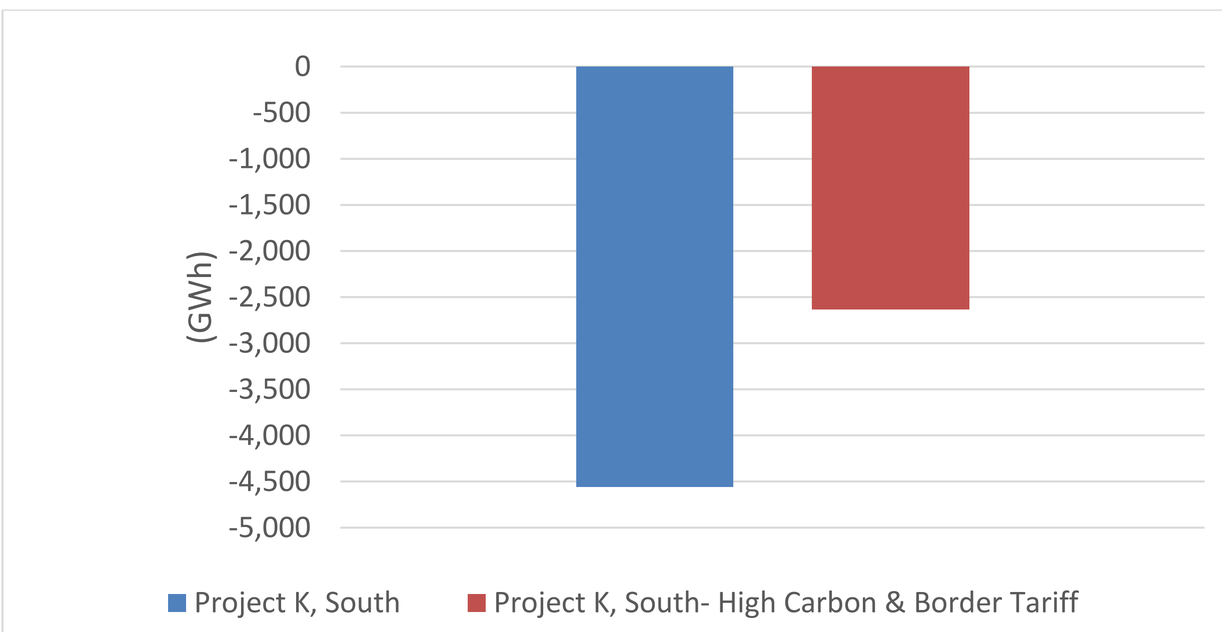


Figure 6-60: High Carbon Sensitivity - Project K - Alberta Net Exports (2030)

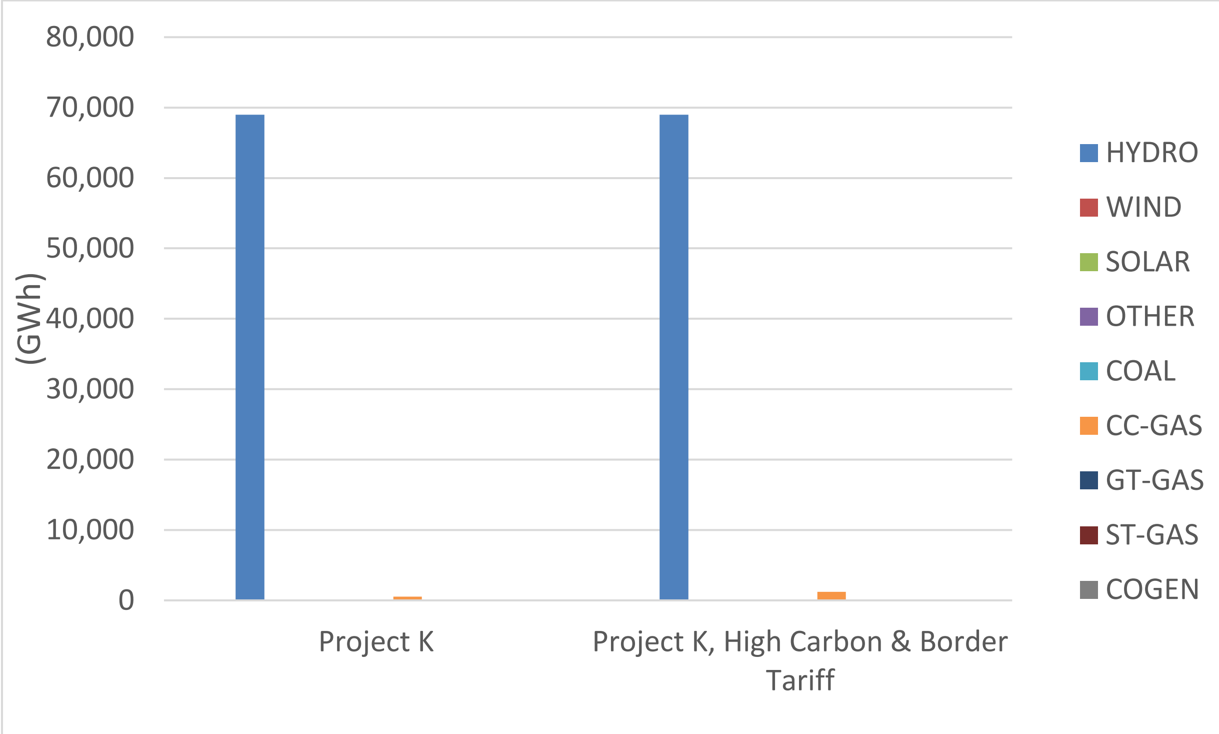


Figure 6-61: High Carbon Sensitivity - Project K - British Columbia Generation (2030)

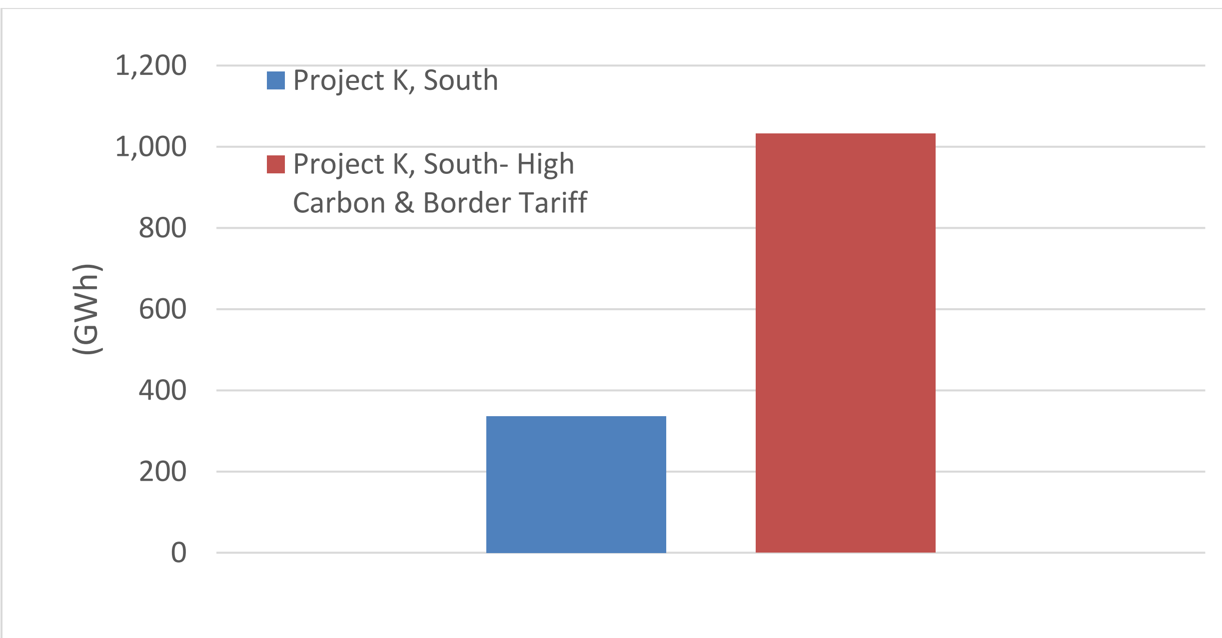


Figure 6-62: High Carbon Sensitivity - Project K - British Columbia Net Exports (2030)

Table 6-18: High Carbon Sensitivity - Project K - Alberta Generation (2030)

AB Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project K	1,875	20,841	775	1,827	7,105	17,391	1,239	0	17,889	**68,941**
Project K, High Carbon & Border Tariff	1,875	20,841	775	1,934	7,099	17,620	1,675	0	19,048	**70,867**
Change	**0**	**0**	**0**	**107**	**-5**	**229**	**436**	**0**	**1,159**	**1,926**

Table 6-19: High Carbon Sensitivity - Project K - British Columbia Generation (2030)

BC Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project K	68,986	0	0	0	0	517	0	0	0	**69,503**
Project K, High Carbon & Border Tariff	68,987	0	0	0	0	1,211	0	0	0	**70,198**
Change	**2**	**0**	**0**	**0**	**0**	**694**	**0**	**0**	**0**	**696**

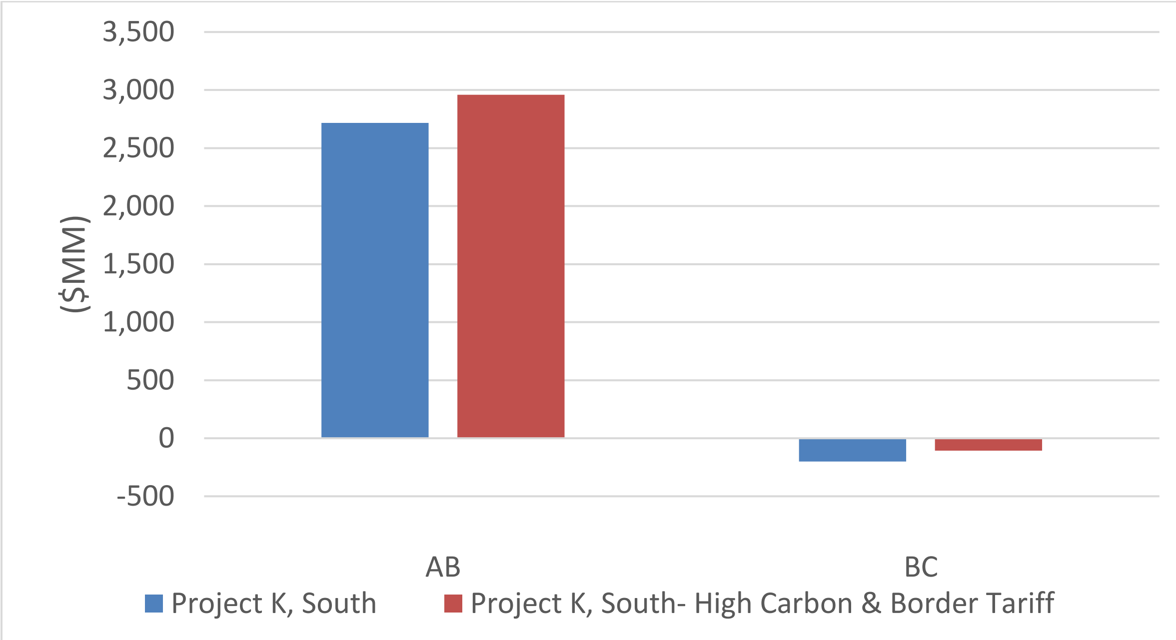


Figure 6-63: High Carbon Sensitivity - Project K - Adjusted Production Costs (2030)

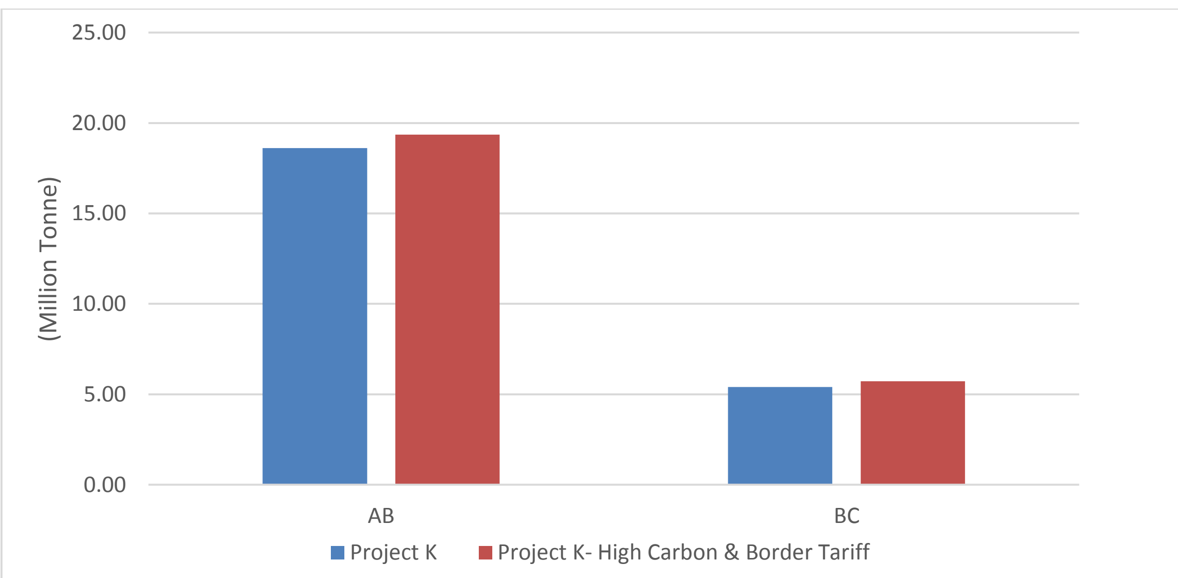


Figure 6-64: High Carbon Sensitivity - Project K - CO2 Emissions (2030)

6.3 High Gas Sensitivity

In the High Gas Sensitivity, natural gas prices in Canada and USA were increased by 57% over the original BAU prices.

It should be noted that coal has twice as much carbon content than an equivalent kJ of natural gas. Furthermore, ST-COAL has a higher heat rate (kJ/kWh) than CC-GAS, which means it consumes more kJ of coal per kWh of electric energy produced compared to kJ of natural gas consumed by CC-GAS to produce one kWh of electric energy.

6.3.1 Business-As-Usual - BAU – Case (2030) and (2040)

The BAU case was evaluated under the high gas price sensitivity.

The following charts and tables present the impact of high carbon price sensitivity on the BAU case. General observations include:

- The principal impact of higher natural gas prices is shifting of generation among natural gas-based generation due to different average full load costs of such generating assets. An even higher gas prices may have resulted in displacement of natural gas-based generation by COAL generation.
- Since natural gas prices were raised in both Canada and USA, the relative economic advantage of one country's generation to the other do not change significantly. The only impact is a minor increase in exports to the USA.
- Since the generation shift is mostly between natural gas-based generation, the impact on CO2 emissions is minimal.
- However, higher gas prices result in higher adjusted production costs in provinces which have significant amount of natural gas-based generation.

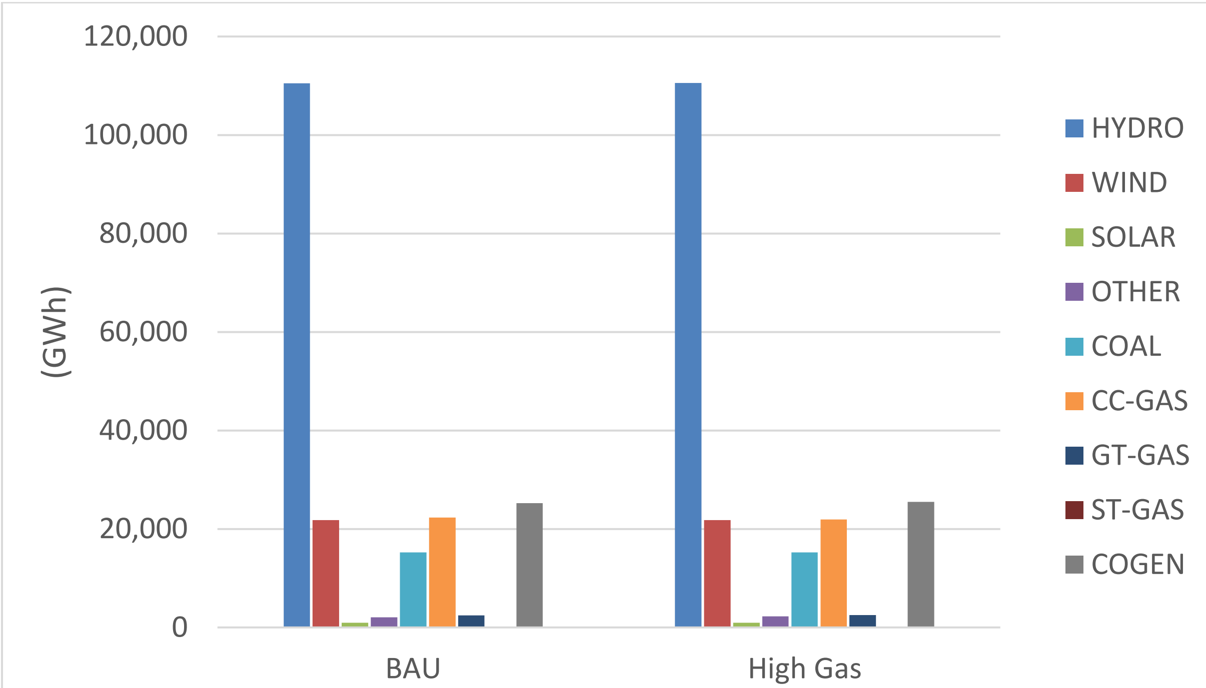


Figure 6-65: High Gas Sensitivity - BAU Generation (2030)

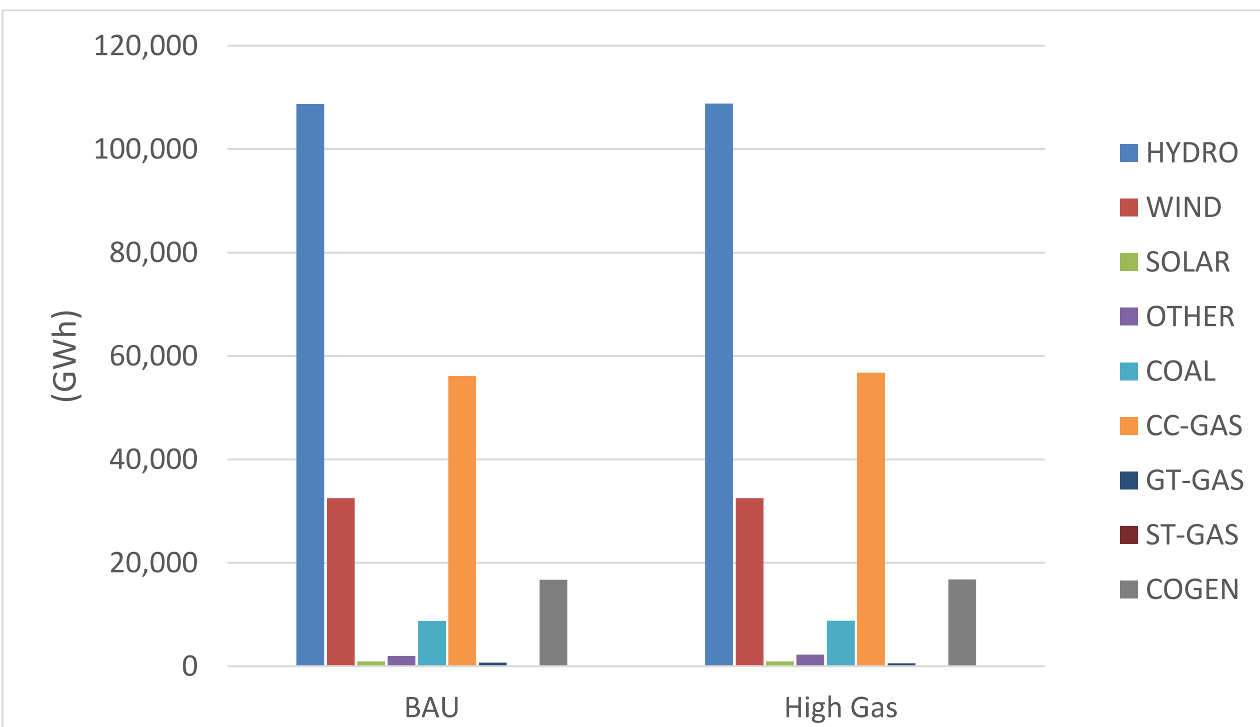


Figure 6-66: High Gas Sensitivity - BAU Generation (2040)

Table 6-20: High Gas Sensitivity - BAU Generation (2030)

(GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	110,485	21,818	958	2,057	15,215	22,326	2,464	48	25,249	**200,619**
High Gas	110,581	21,809	958	2,242	15,269	21,949	2,529	48	25,528	**200,914**
Change	**97**	**-9**	**0**	**184**	**54**	**-376**	**65**	**0**	**280**	**295**

Table 6-21: High Gas Sensitivity - BAU Generation (2040)

(GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	108,778	32,528	959	1,996	8,742	56,131	667	73	16,716	**226,589**
High Gas	108,815	32,525	959	2,255	8,778	56,776	578	69	16,766	**227,520**
Change	**37**	**-4**	**0**	**259**	**35**	**645**	**-88**	**-4**	**50**	**931**

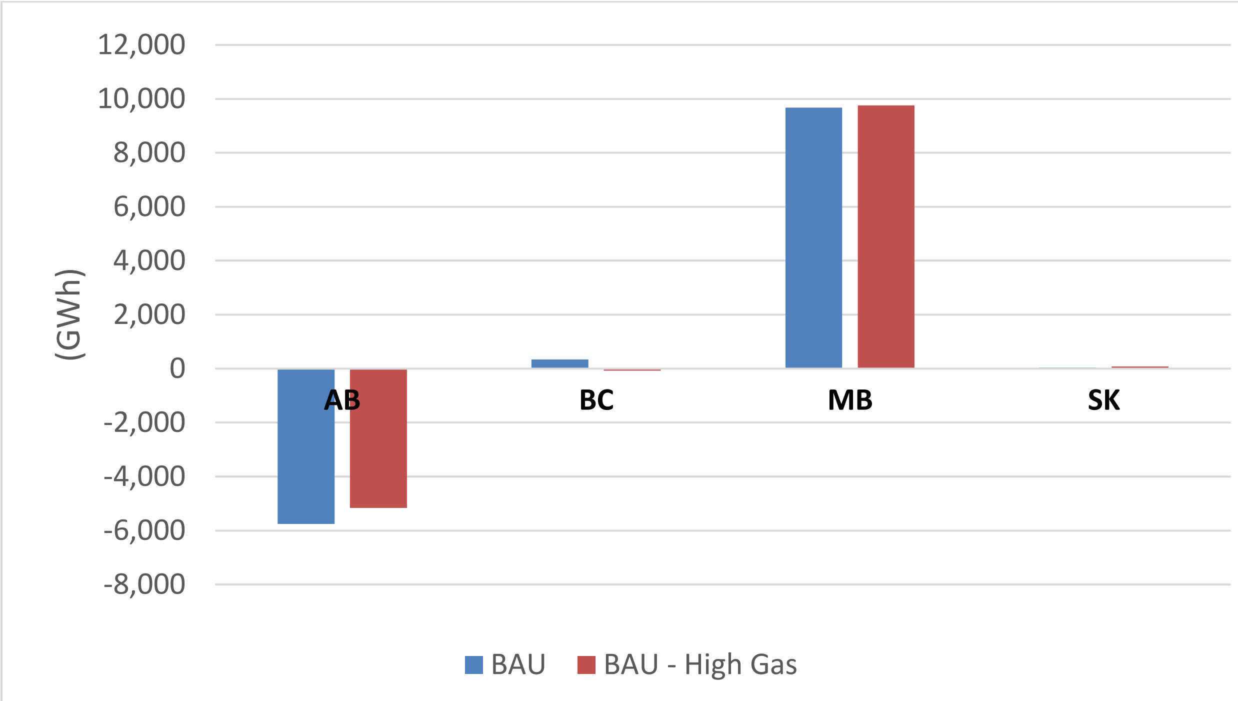


Figure 6-67: High Gas Sensitivity - BAU Net Exports (2030)

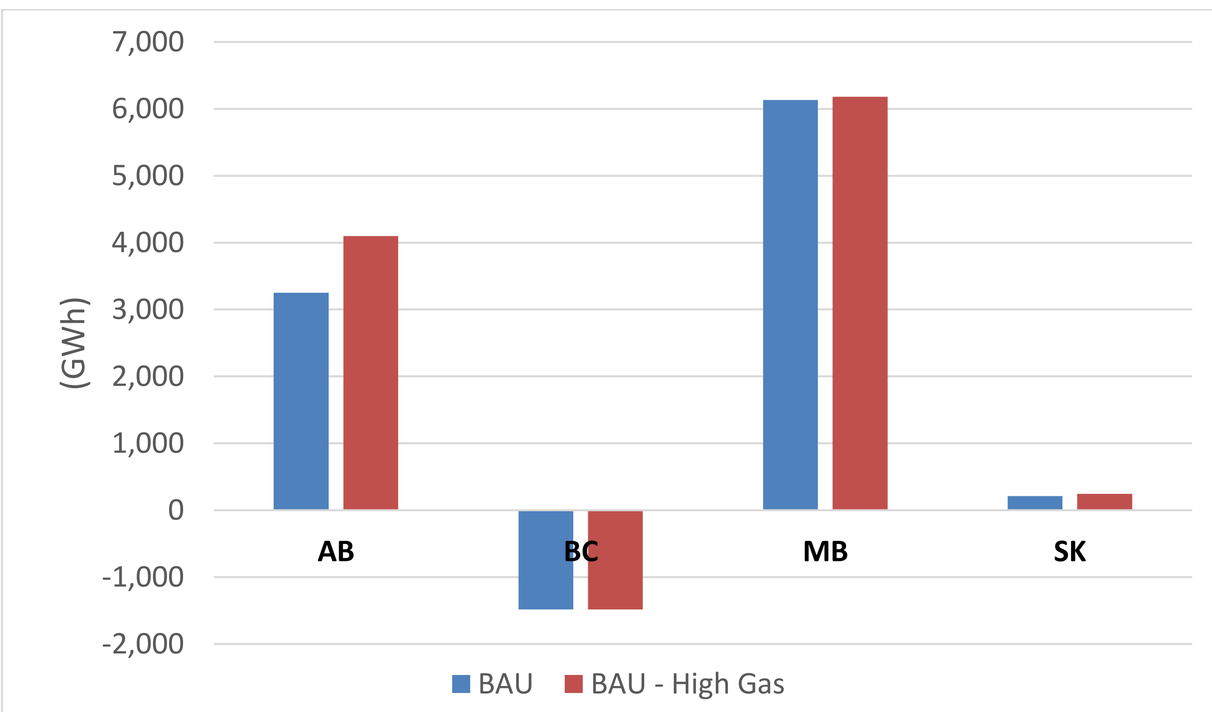


Figure 6-68: High Gas Sensitivity - BAU Net Exports (2040)

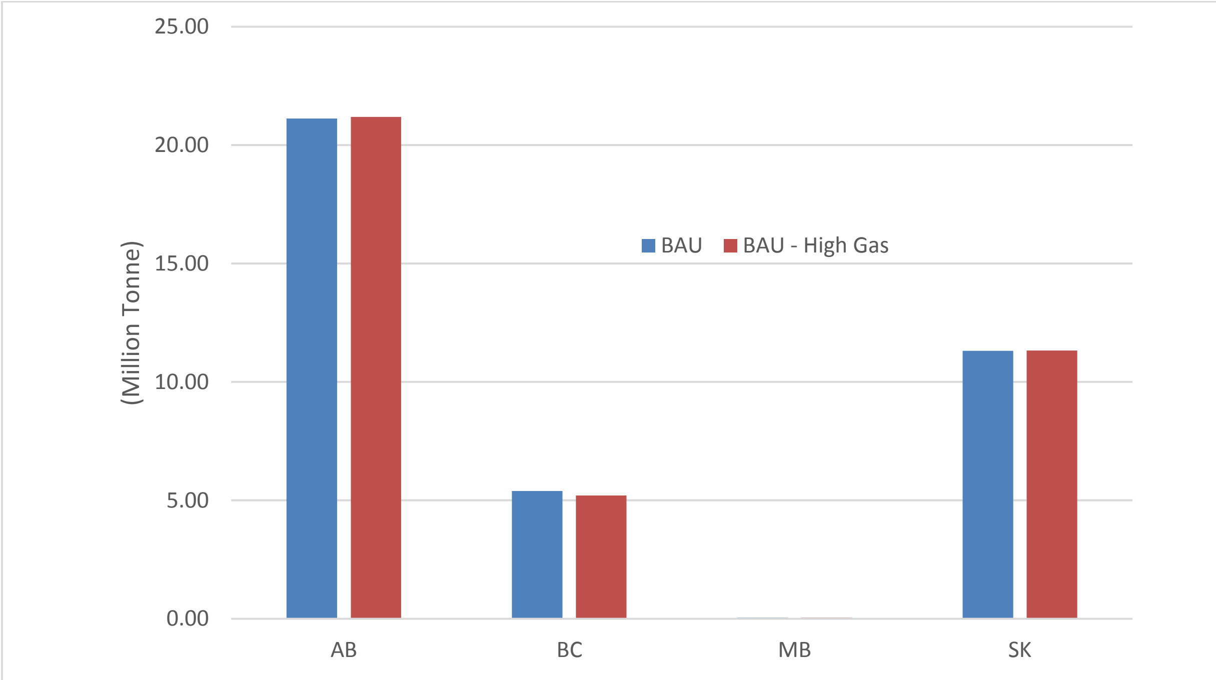


Figure 6-69: High Gas Sensitivity - BAU CO2 Emissions (2030)

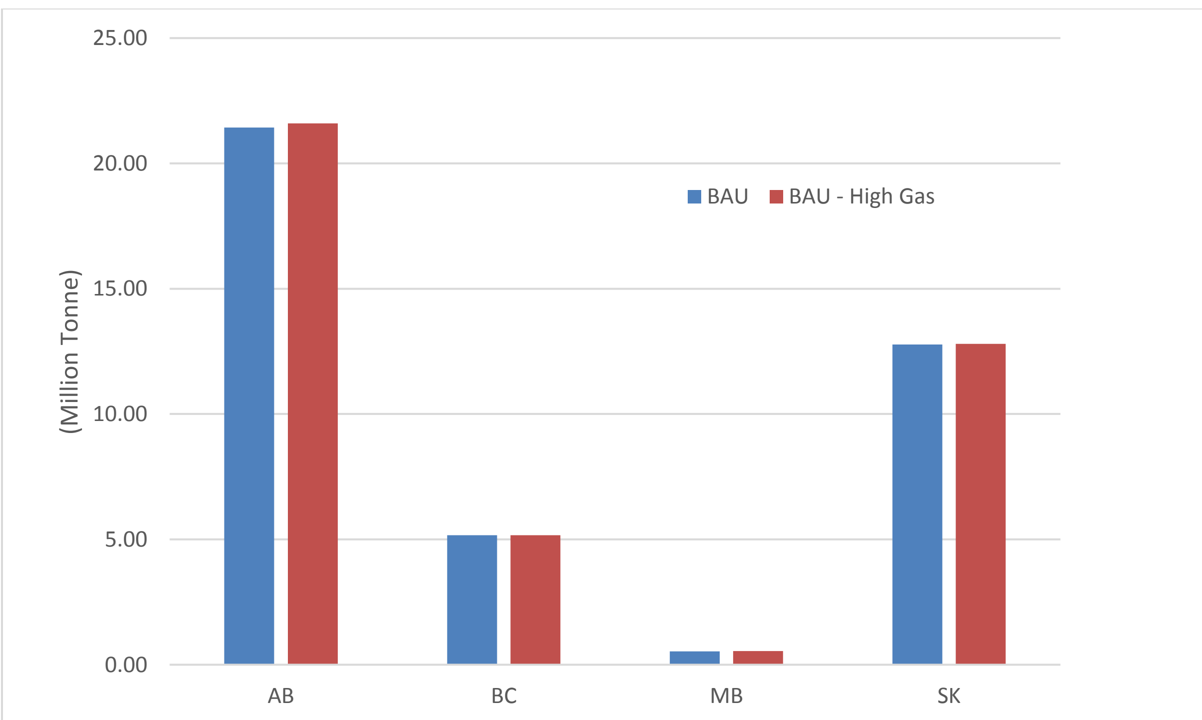


Figure 6-70: High Gas Sensitivity - BAU CO2 Emissions (2040)

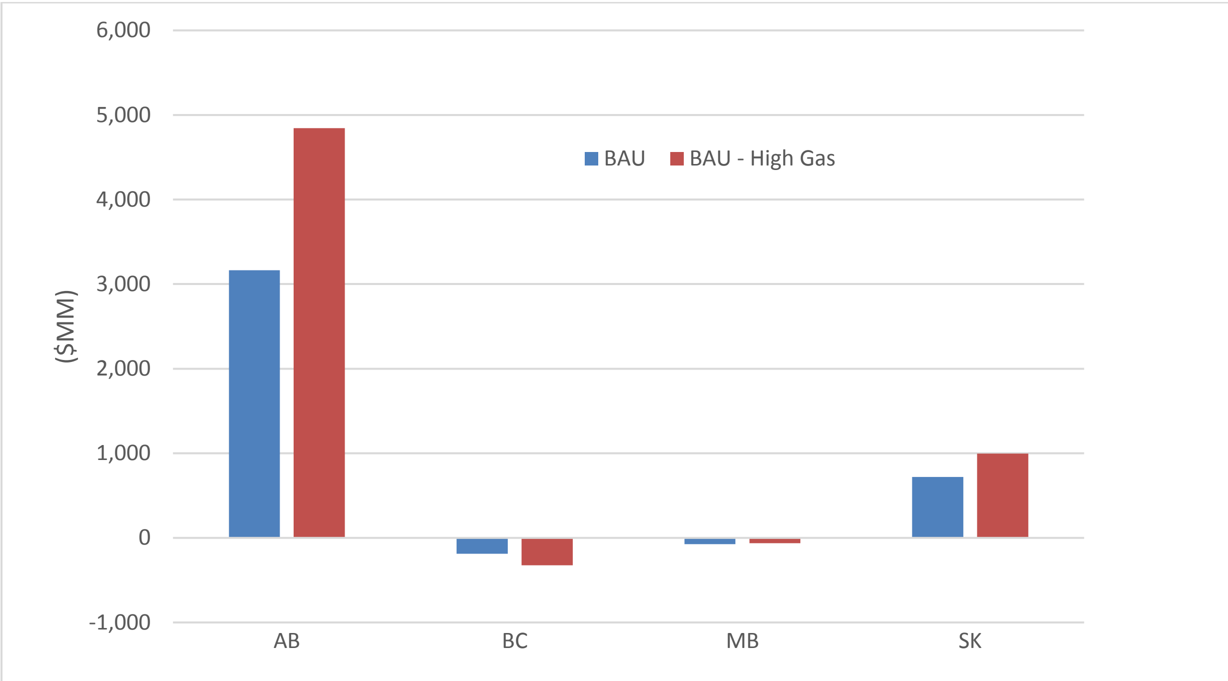


Figure 6-71: High Gas Sensitivity - BAU Adjusted Production Costs (2030)

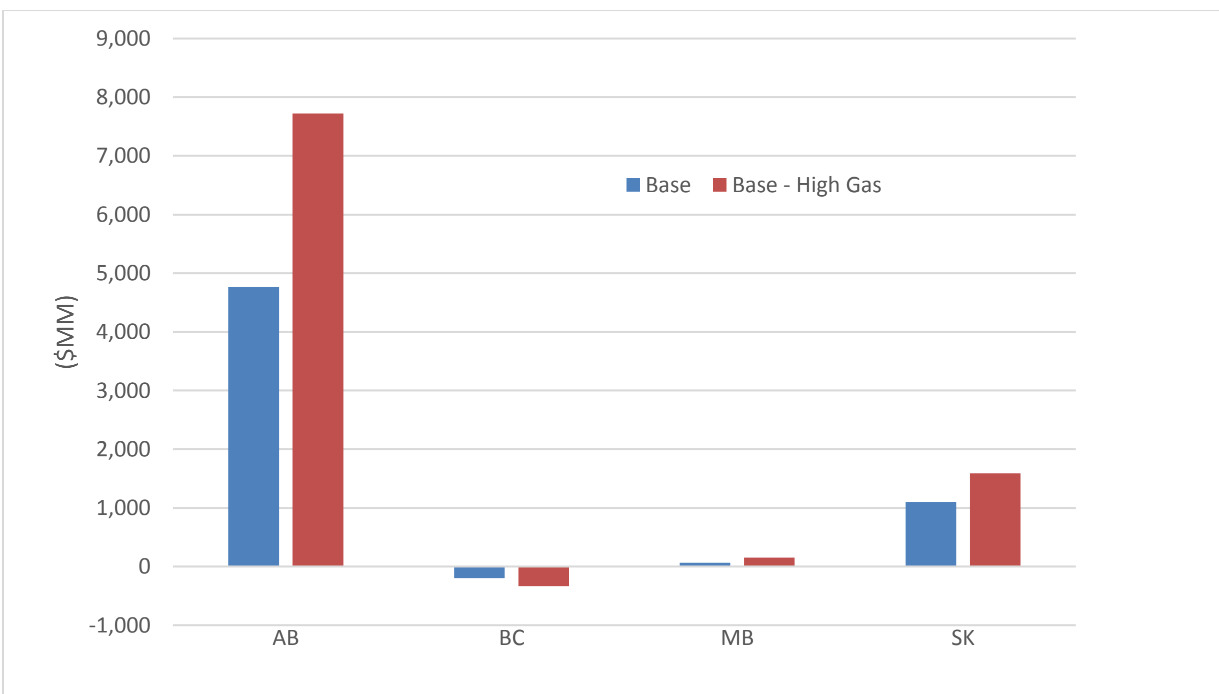


Figure 6-72: High Gas Sensitivity - BAU Adjusted Production Costs (2040)

6.3.2 Project B: New Intertie between SK and MB (2030)

Project B's Option 1, which includes a new 500 kV line from Saskatchewan to Manitoba, was evaluated under the high gas price sensitivity.

The following charts and tables present the impact of high carbon price sensitivity on Project B, Option 1 Intertie. General observations include:

- The major impact of higher gas price is a reduction in CC-GAS generation in Saskatchewan, some of displaced generation is picked up by additional COAL generation, causing an increase in net imports into Saskatchewan.
- The higher gas price has minimal impact on Manitoba, except possibly for relieving some of the congestion on transmission constraints. This is implied by additional hydro generation.
- The net changes in Manitoba and Saskatchewan generation indicate that most of the imports are sourced outside Manitoba.
- Manitoba experiences lower adjusted production costs due to increase in its exports, rather than higher gas prices, since it has small natural gas-based generation. On the other hand, Saskatchewan experiences higher adjusted production costs due to higher imports and the high gas price, which more than compensate for the reduced production costs of CC-GAS generation in the province.
- As expected, there are minimal CO_2 emissions in Manitoba, but Saskatchewan experiences higher CO_2 emissions. However, the impact of the high gas price sensitivity on CO_2 emissions in Saskatchewan is negligible as the reduction in CC-GAS generation emissions are offset by higher COAL generation emissions.

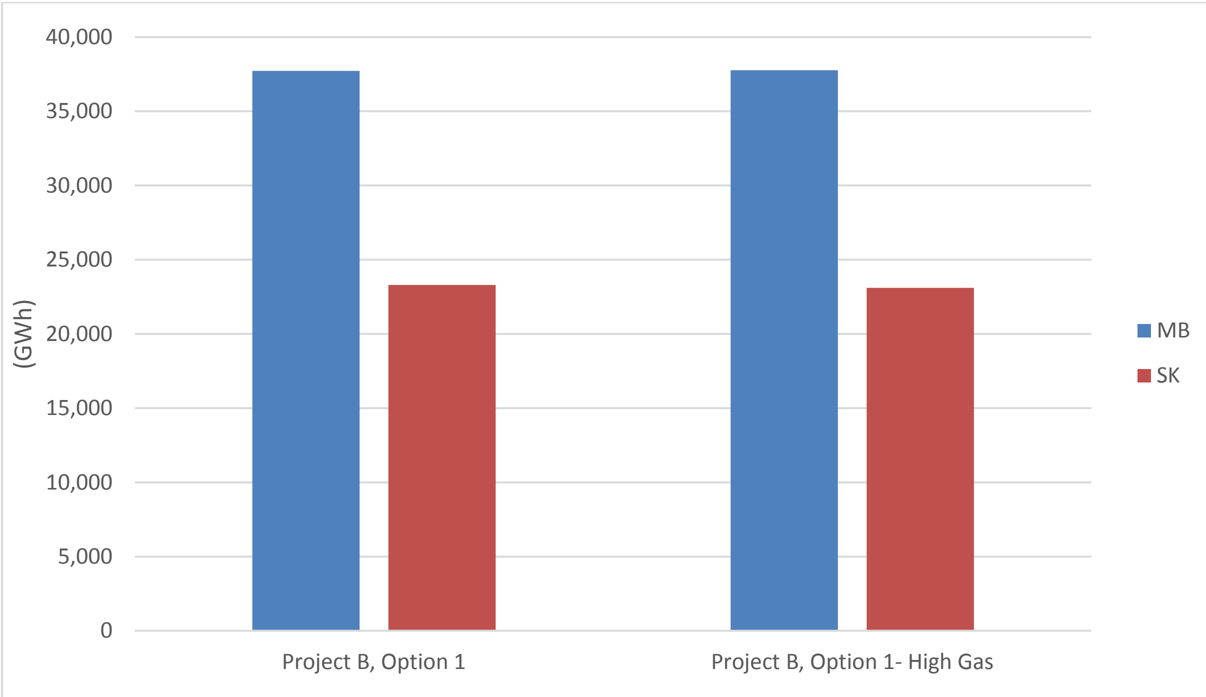


Figure 6-73: High Gas Sensitivity - Project B - Generation by Province (2030)

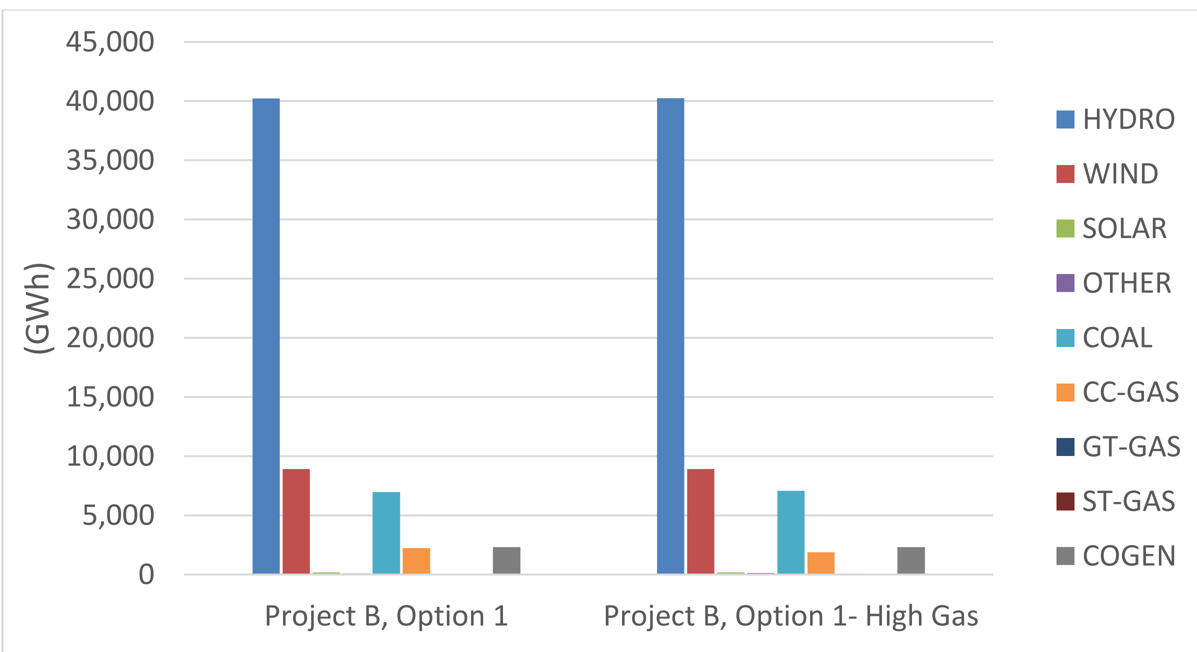


Figure 6-74: High Gas Sensitivity - Project B - Generation by Type (2030)

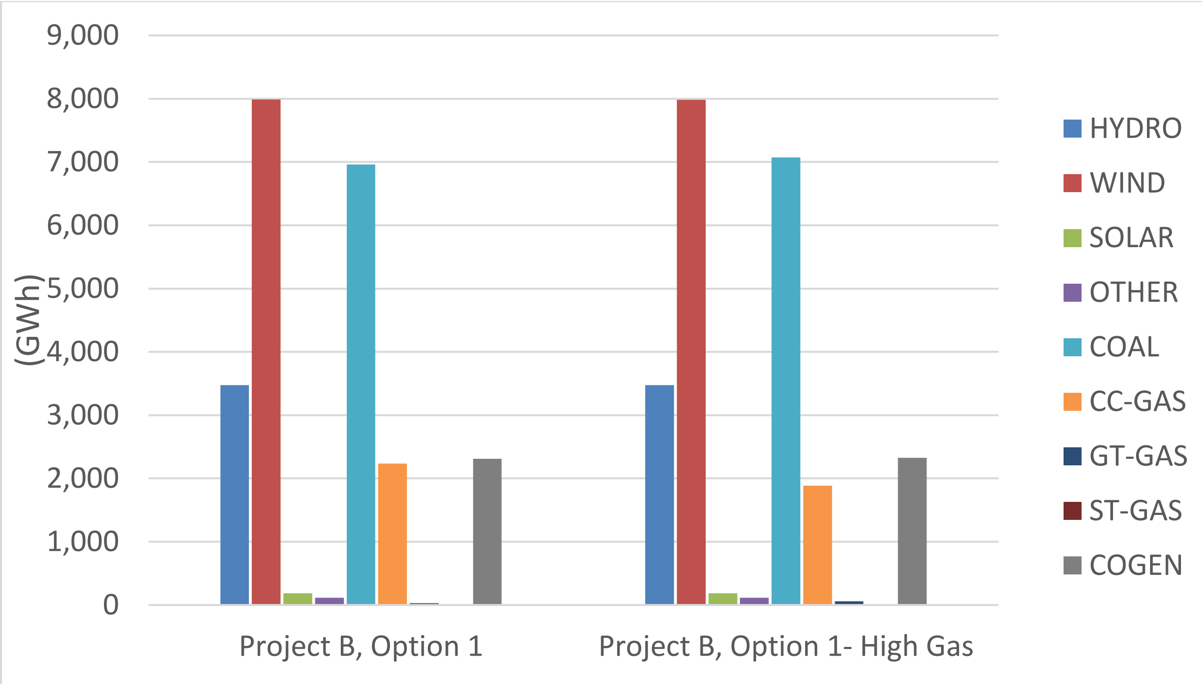


Figure 6-75: High Gas Sensitivity - Project B - Saskatchewan Generation (2030)

Figure 6-76: High Gas Sensitivity - Project B - Saskatchewan Net Exports (2030)

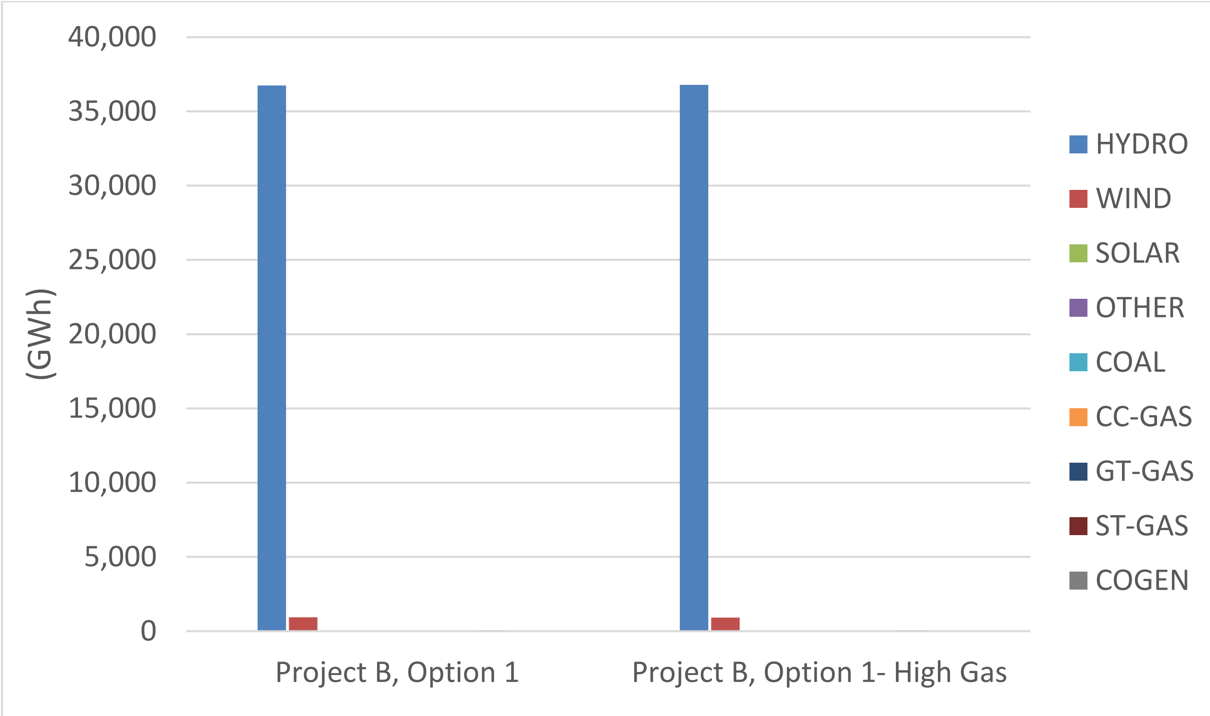


Figure 6-77: High Gas Sensitivity - Project B - Manitoba Generation (2030)

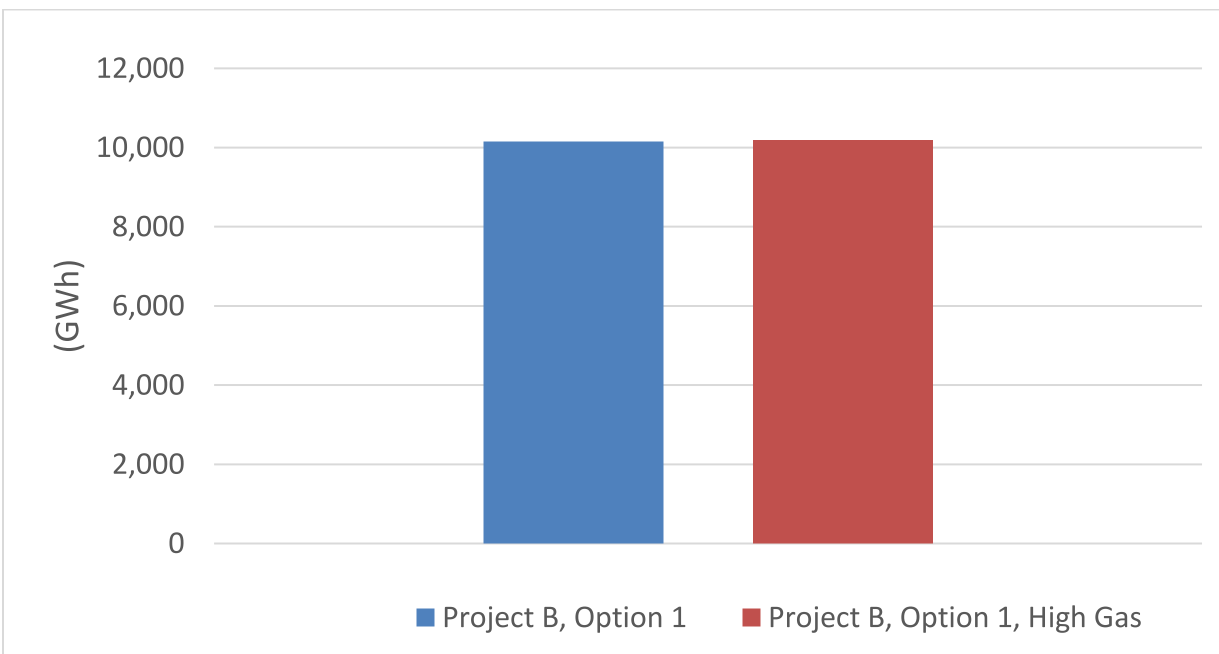


Figure 6-78: High Gas Sensitivity - Project B - Manitoba net Exports (2030)

Table 6-22: High Gas Sensitivity - Project B - Saskatchewan Generation (2030)

SK Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project B, Option 1	3,476	7,989	184	113	6,962	2,235	30	0	2,312	**23,301**
Project B, Option 1-High Gas	3,475	7,982	184	114	7,072	1,888	59	0	2,327	**23,100**
Change	**-1**	**-7**	**0**	**1**	**110**	**-347**	**29**	**0**	**15**	**-202**

Table 6-23: High Gas Sensitivity - Project B - Manitoba Generation (2030)

MB Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project B, Option 1	36,747	927	0	0	0	0	4	48	0	**37,725**
Project B, Option 1-High Gas	36,788	923	0	0	0	0	5	48	0	**37,764**
Change	**41**	**-4**	**0**	**0**	**0**	**0**	**1**	**0**	**0**	**39**

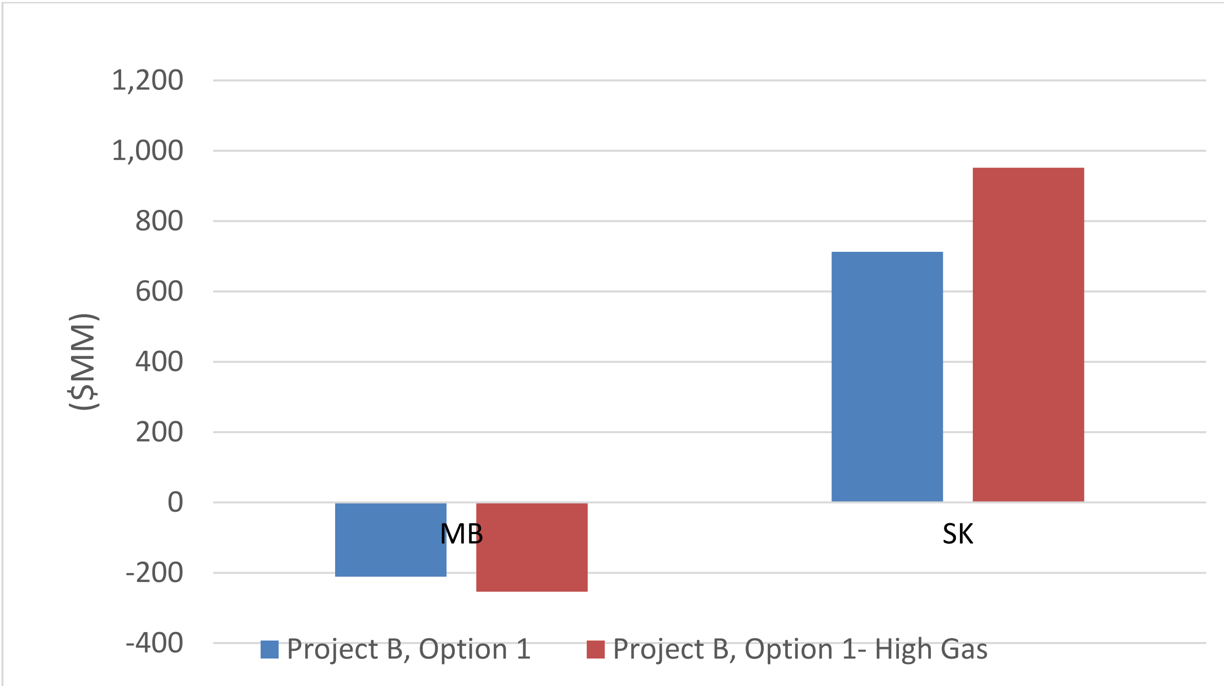


Figure 6-79: High Gas Sensitivity - Project B - Adjusted Production Costs (2030)

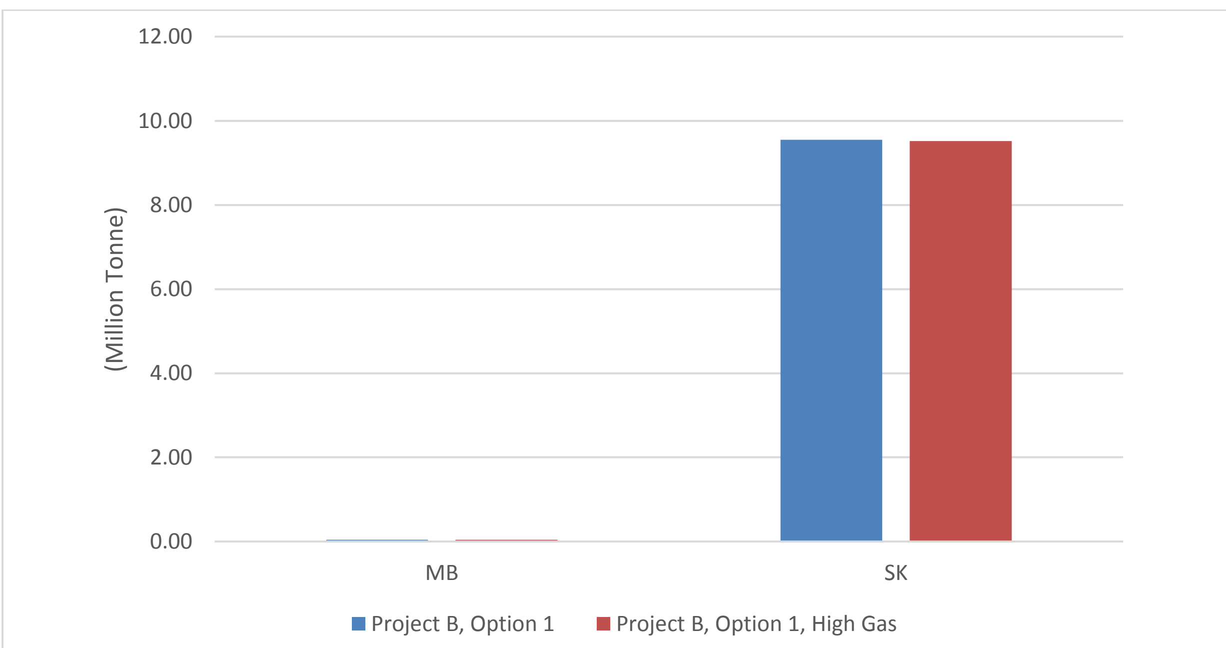


Figure 6-80: High Gas Sensitivity - Project B - CO2 Emissions (2030)

6.3.3 Project E: Coal Conversion in SK (2030)

Project E's Saskatchewan coal conversion options (CCS conversion option and CC conversion option) were evaluated under the high gas sensitivity.

The following charts and tables present the impact of high carbon price sensitivity on Project E's Saskatchewan coal conversion options. General observations include:

- In Project E's Saskatchewan's two coal conversion options, the foremost impact of high gas price appears to be a displacement of CC-GAS generation by GT-GAS and COGEN generation. In the CCS conversion option, some of the displacement is by COAL generation. In the CC conversion option, most of the coal has already been converted to CC-GAS.
- The small increase in generation in Saskatchewan reduces the need for imports under both conversion options.
- Additional generation together with higher gas prices results in higher adjusted production costs.
- Partial displacement of CC-GAS by lower CO2 emitting COAL in the CCS option results in a slight drop in CO2 emissions. However, in the CC conversion option, additional generation and displacement of CC-GAS by other natural gas-based generation results in higher CO2 emissions.

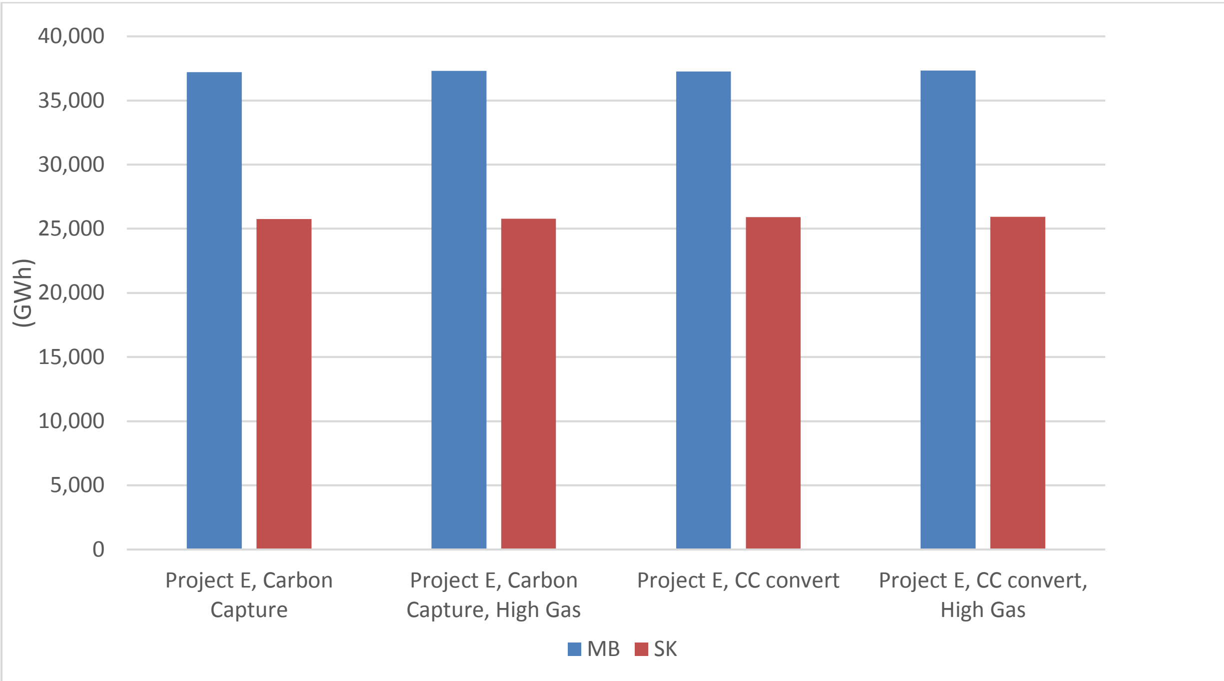


Figure 6-81: High Gas Sensitivity - Project E - Generation by Province (2030)

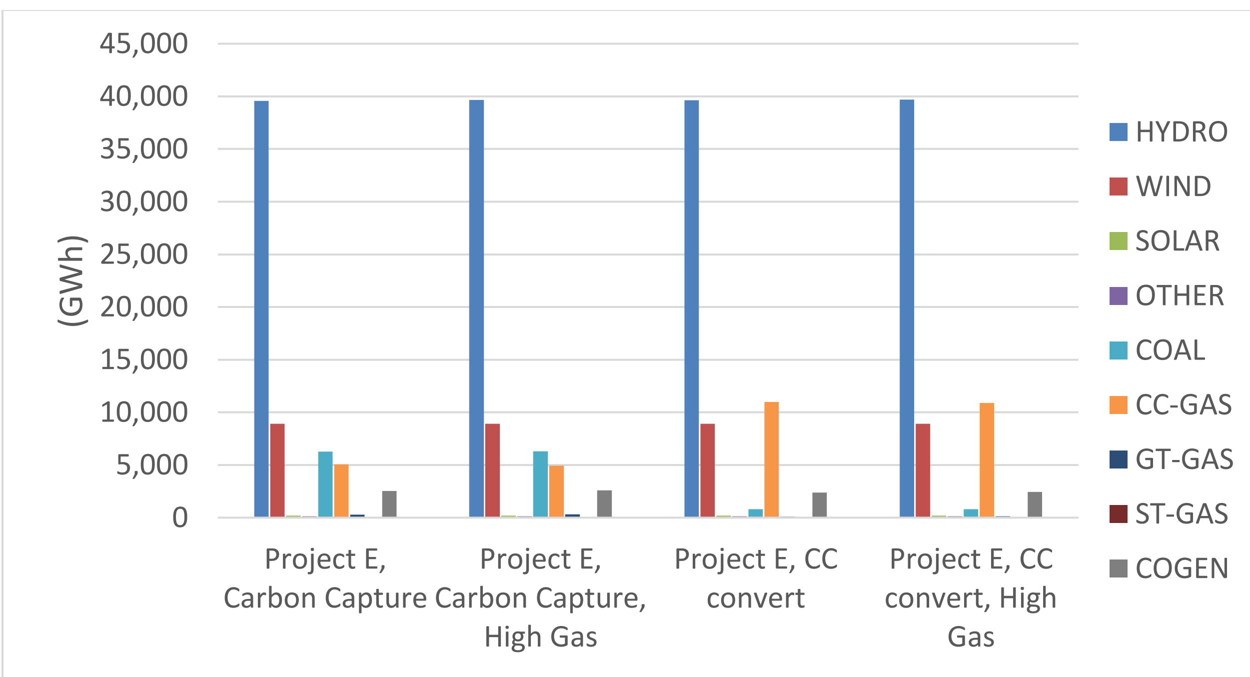


Figure 6-82: High Gas Sensitivity - Project E - Generation by Type (2030)

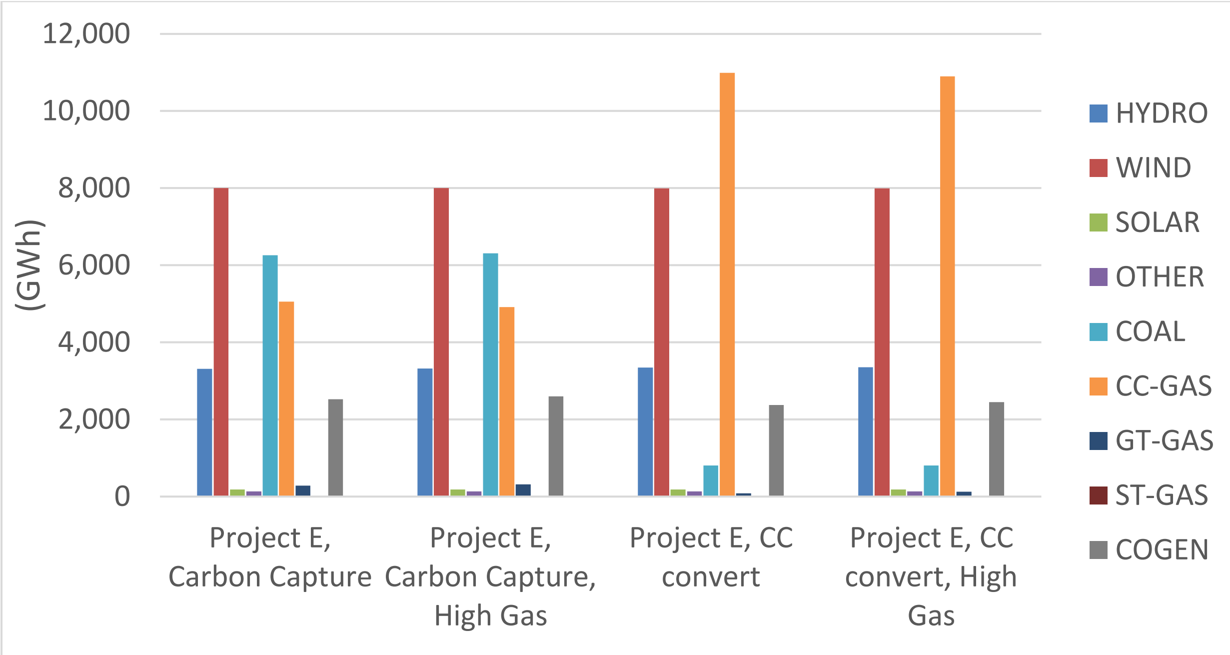


Figure 6-83: High Gas Sensitivity - Project E - Saskatchewan Generation (2030)

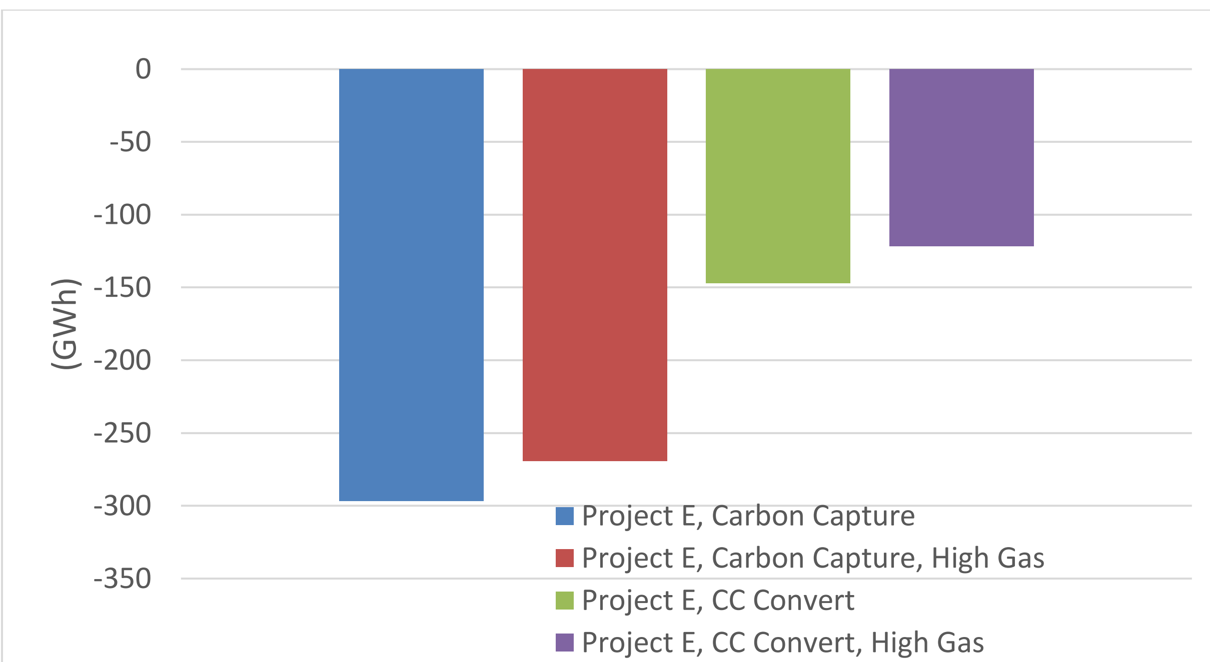


Figure 6-84: High Gas Sensitivity - Project E - Saskatchewan Net Exports (2030)

Table 6-24: High Gas Sensitivity - Project E - Saskatchewan Generation (2030)

SK Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project E, Carbon Capture	3,314	8,001	184	137	6,257	5,056	280	0	2,525	**25,753**
Project E, Carbon Capture-High Gas	3,320	8,000	184	136	6,309	4,918	313	0	2,601	**25,781**
Project E, CC convert	3,344	7,996	184	137	806	10,994	86	0	2,372	**25,919**
Project E, CC convert-High Gas	3,351	7,997	184	137	807	10,900	124	0	2,446	**25,944**
Change, Carbon Capture	7	0	0	-1	51	-138	33	0	76	**28**
Change, CC Convert	7	1	0	0	1	-95	38	0	74	**26**

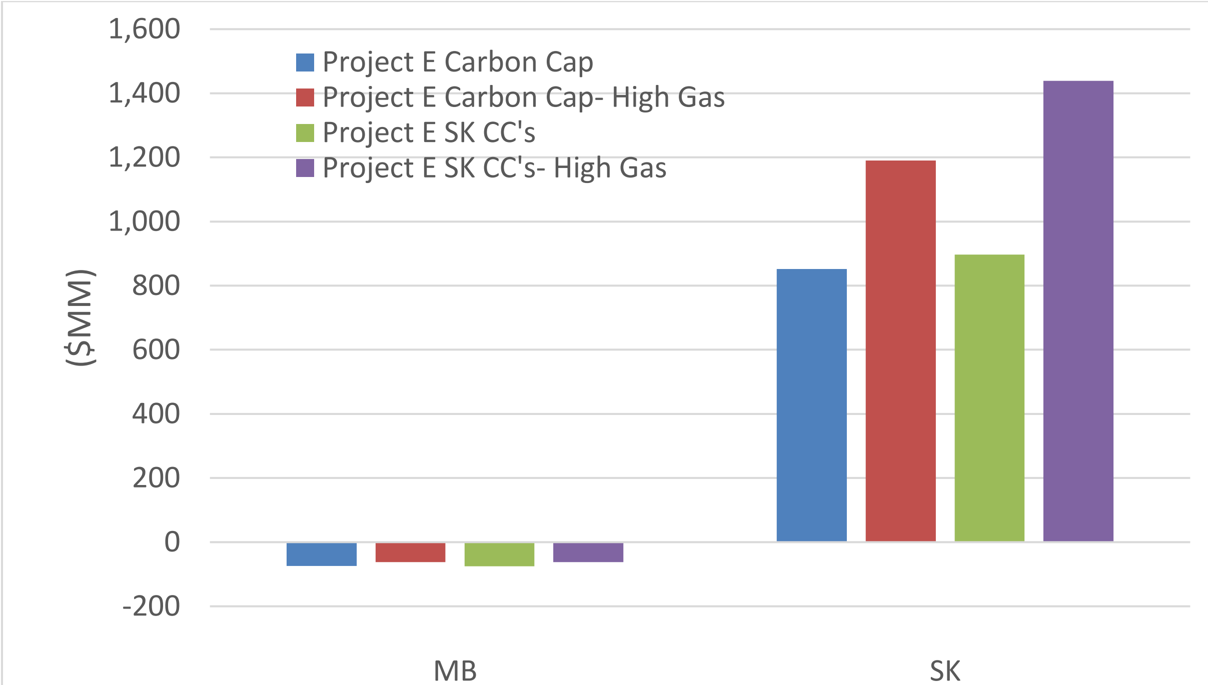


Figure 6-85: High Gas Sensitivity - Project E - Adjusted Production Costs (2030)

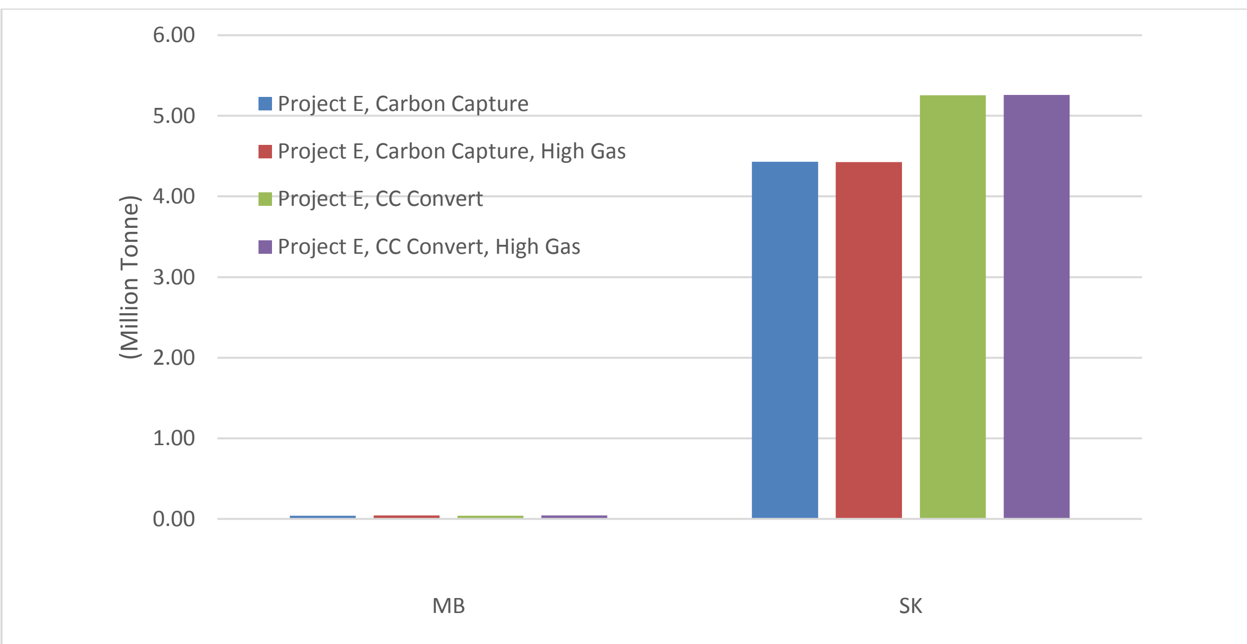


Figure 6-86: High Gas Sensitivity - Project E - CO2 Emissions (2030)

6.3.4 Project I: New AB – SK Intertie (2030)

Project I (new intertie between Alberta and Saskatchewan) was evaluated under the high gas price sensitivity.

The following charts and tables present the impact of high carbon price sensitivity on Project I. General observations include:

- In Project I, the main impact of high gas price in Saskatchewan appears to be displacement of CC-GAS generation by GT-GAS and COGEN.
- With a higher gas price, the displacement of CC-GAS generation by other natural gas-based generation, even without almost no additional generation, results in higher adjusted production costs.
- However, since CC-GAS is displaced by other natural gas-based generation, the impact on CO2 emissions is minimal.

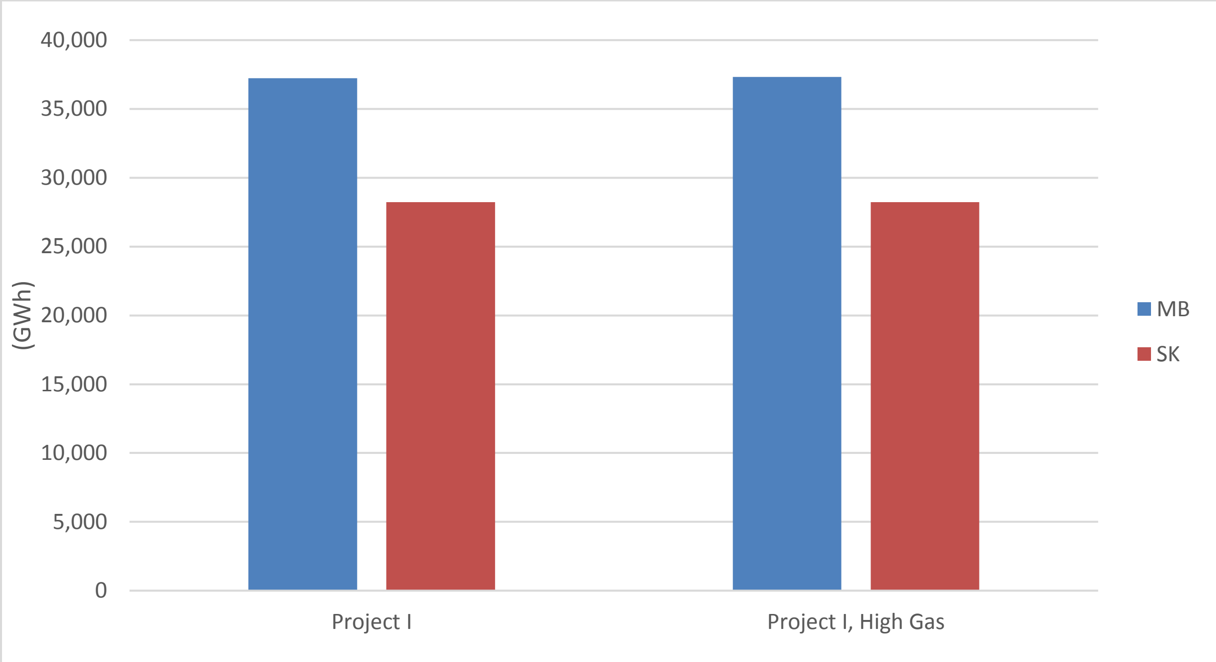


Figure 6-87: High Gas Sensitivity - Project I - Generation by Province (2030)

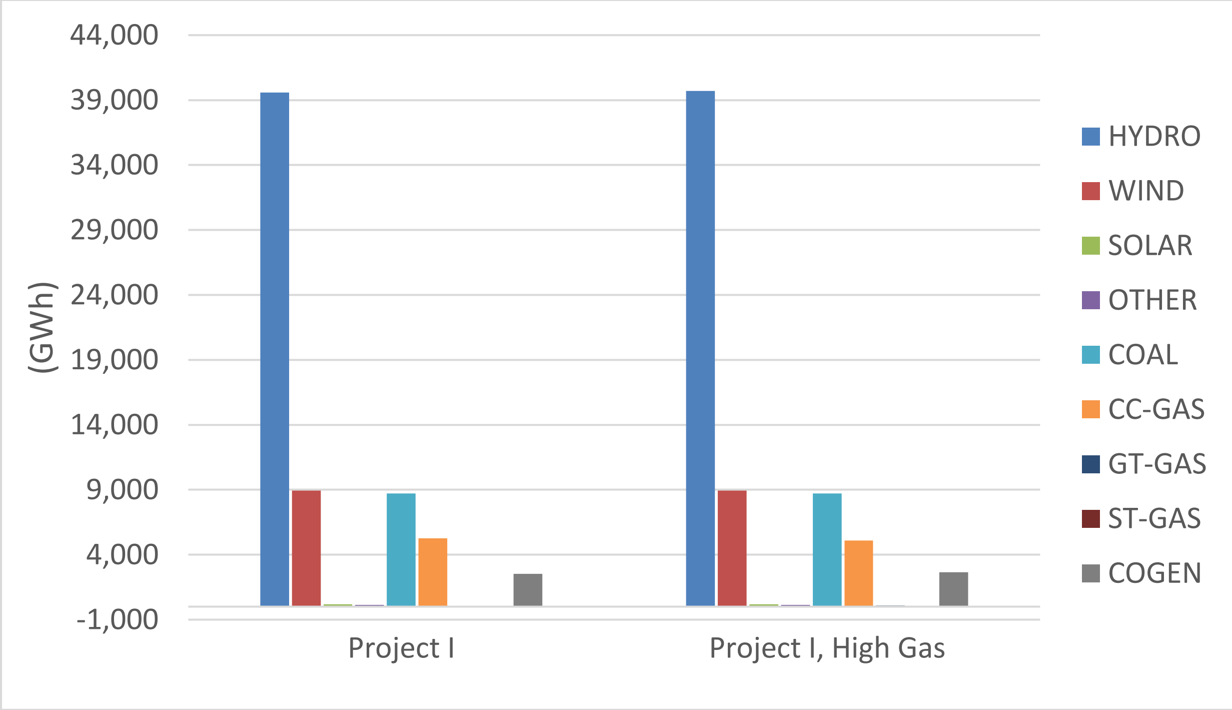


Figure 6-88: High Gas Sensitivity - Project I - Generation by Type (2030)

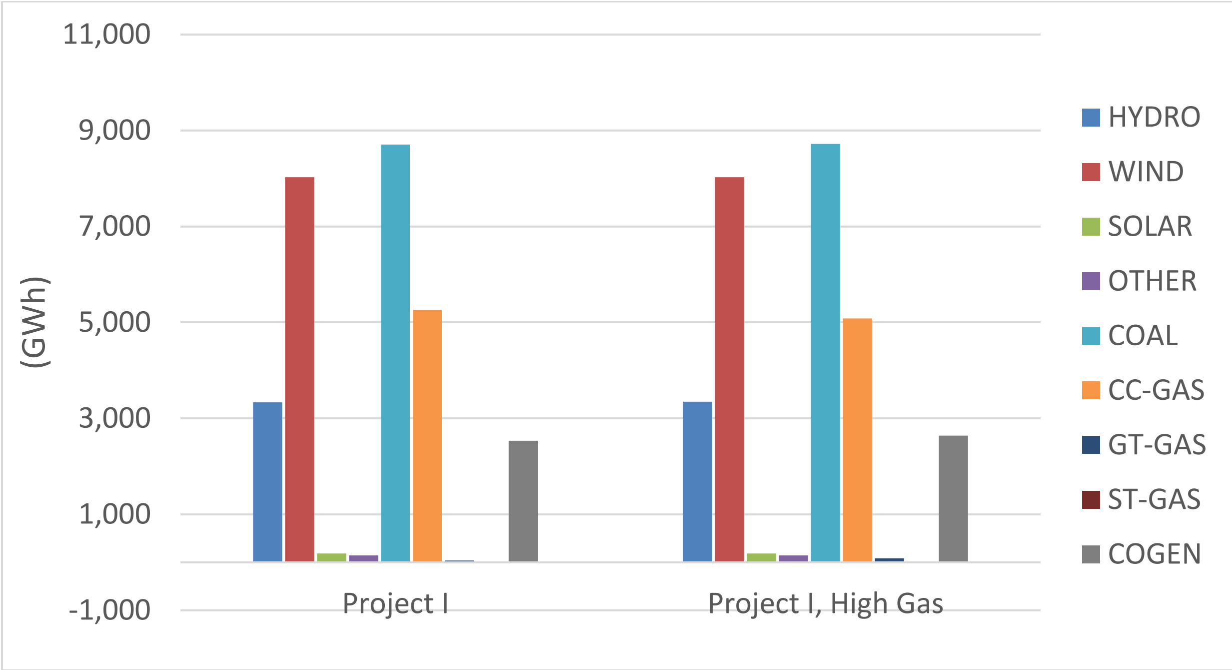


Figure 6-89: High Gas Sensitivity - Project I - Saskatchewan Generation (2030)

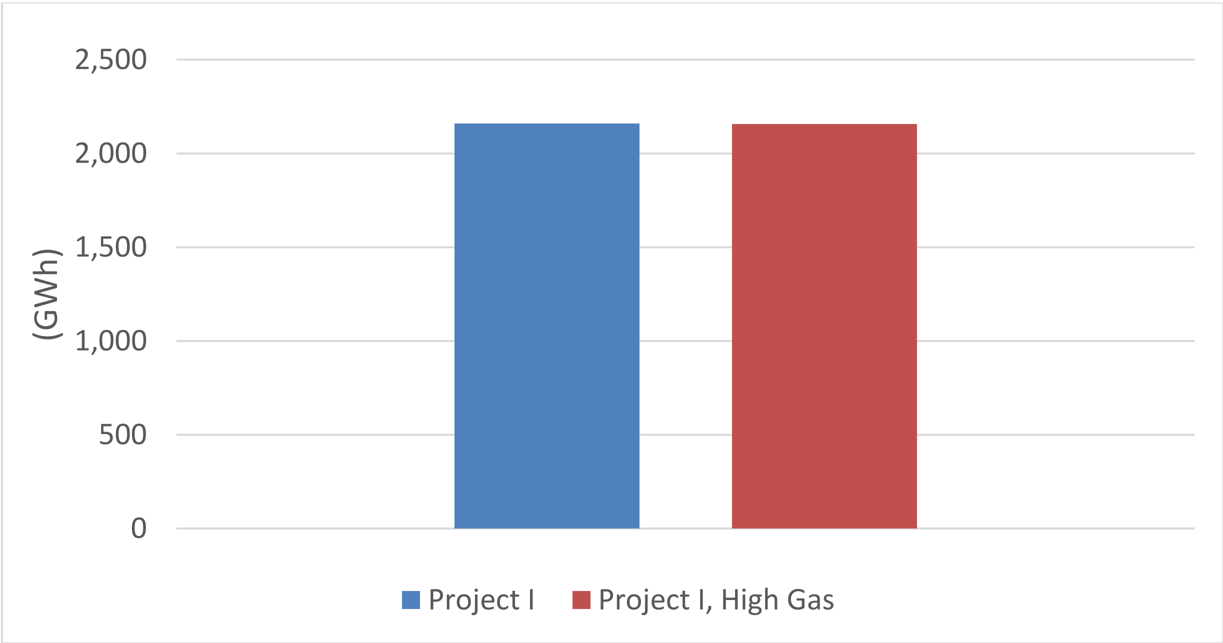


Figure 6-90: High Gas Sensitivity - Project I - Saskatchewan Net Exports (2030)

Table 6-25: High Gas Sensitivity - Project I - Saskatchewan Generation (2030)

SK Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project I	3,333	8,028	184	142	8,704	5,266	34	0	2,535	**28,227**
Project I, High Gas	3,347	8,026	184	142	8,719	5,084	81	0	2,643	**28,225**
Change	**14**	**-2**	**0**	**-1**	**15**	**-182**	**47**	**0**	**108**	**-2**

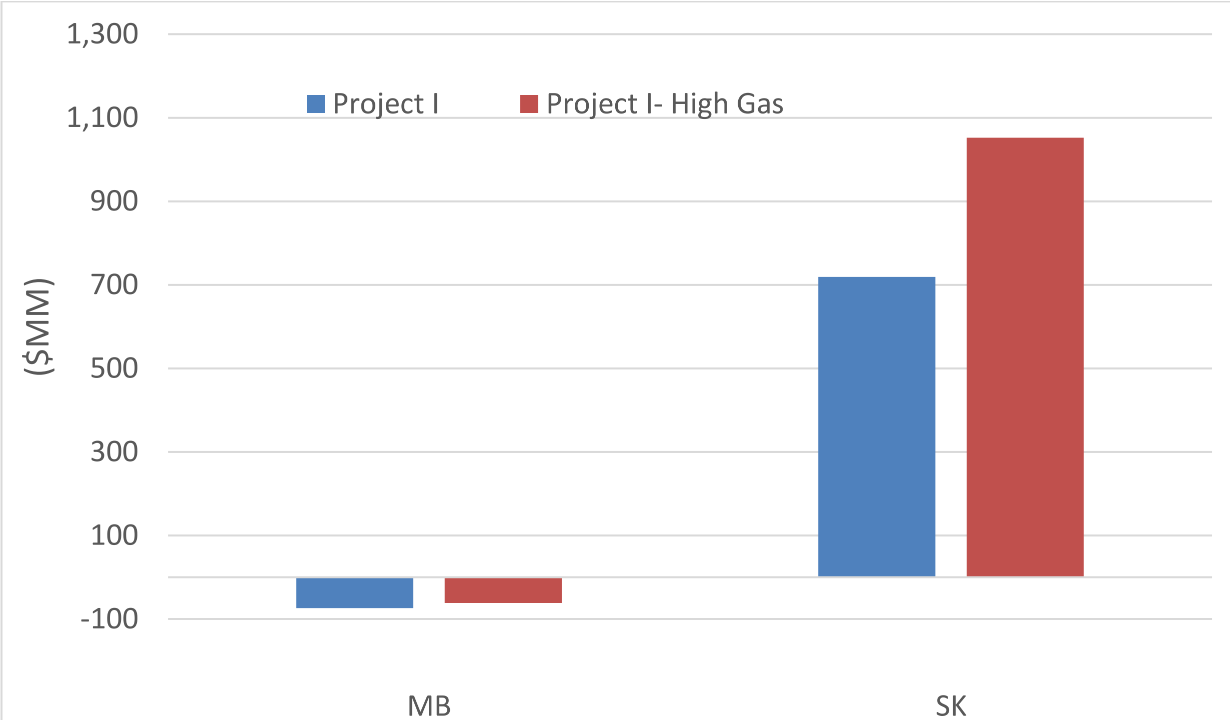


Figure 6-91: High Gas Sensitivity - Project I - Adjusted Production Costs (2030)

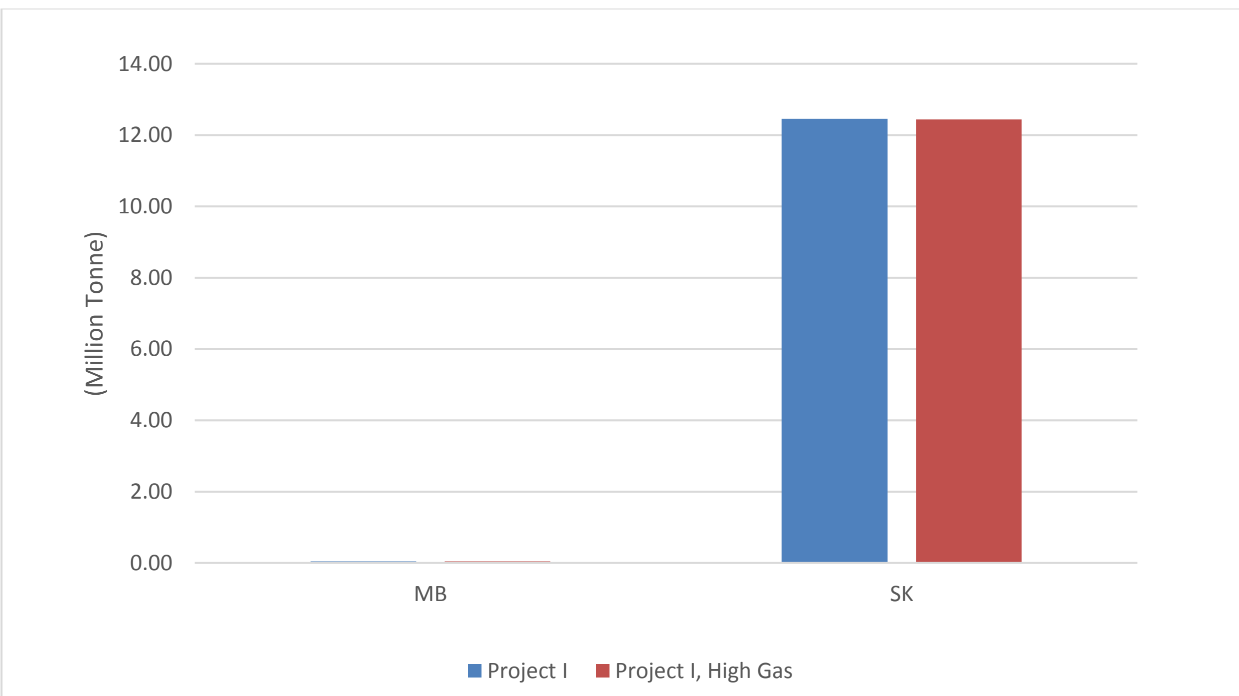


Figure 6-92: High Gas Sensitivity - Project I - CO2 Emissions (2030)

6.4 Real-Time Hydro Sensitivity

The Real-Time Hydro sensitivity considers scheduling of hydropower resources in a near real-time basis using very short-term forecast of wind generation, as opposed to the base case where hydropower is scheduled based on a day-ahead forecast of wind generation. In other words, the real-time hydro sensitivity assumes a more flexible and dynamic hydro scheduling based on the most recent and short-term forecast of wind generation.

As a general fact, because of the forecast error, the day-ahead unit commitment and scheduling of hydropower based on day-ahead forecast of wind - and the subsequent deviation of actual wind from the forecast wind - would result in either underestimation or overestimation of required generation supply. A consequence of this fact is either over-commitment or under-commitment of generation units. Over-commitment results in unneeded committed thermal units idling at their minimum load and/or curtailment of surplus renewable energy. Under-commitment results in the need for utilization of more expensive peaking units. Both situations result in economically less efficient operation of the power system.

6.4.1 Business-As-Usual - BAU – Case (2030) and (2040)

The BAU case was evaluated under the real-time hydro sensitivity.

The following charts and tables present the impact of real-time hydro sensitivity on the BAU case. General observations include:

- It appears that real-time hydro scheduling does not have any significant impact on the generation dispatch, other than some decrease in GT-GAS generation in 2030 and 2040.
- A closer to real-time hydro scheduling results in reduced wind forecast error and a more fine-tuned unit commitment, whereby hydropower gets scheduled against an hourly “Load minus Real Wind” profile that is more representative of the real-time “net load” profile, as opposed to the “Load – Forecast Wind” profile.
- Therefore, even if the amount of hydro generation did not change in the sensitivity run, the hourly hydro generation pattern changed, resulting in a more modified net load, i.e., an hourly “Load minus Wind minus Hydro” pattern, against which the thermal generation gets dispatched. Hence, a real-time hydro dispatch causes a change in dispatch pattern of thermal plants.
- The outcome is a small decrease in Alberta generation in 2030, which caused an increase in net imports into Alberta; and even a smaller increase in Alberta generation in 2040, which increased net exports from Alberta.

- Therefore, the overall impact of real-time hydro sensitivity is very small changes in adjusted production costs and CO_2 emissions of provinces.

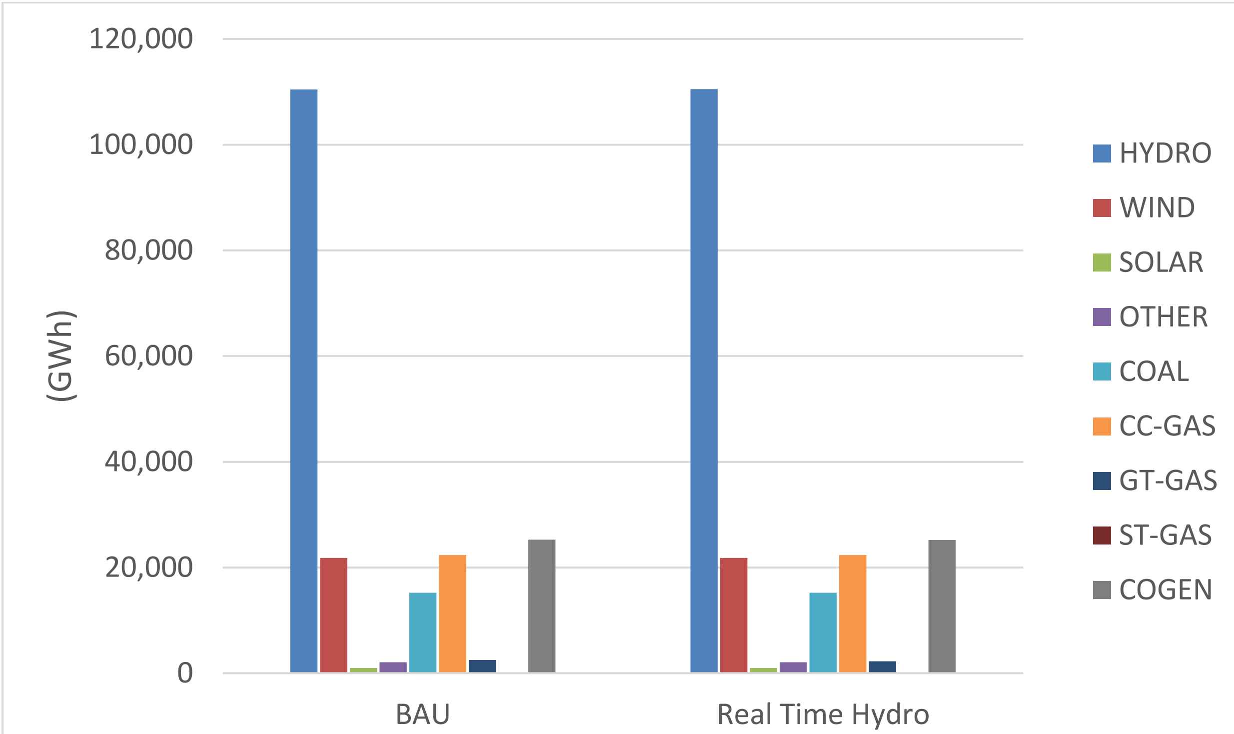


Figure 6-93: Real-Time Hydro Sensitivity - BAU Generation (2030)

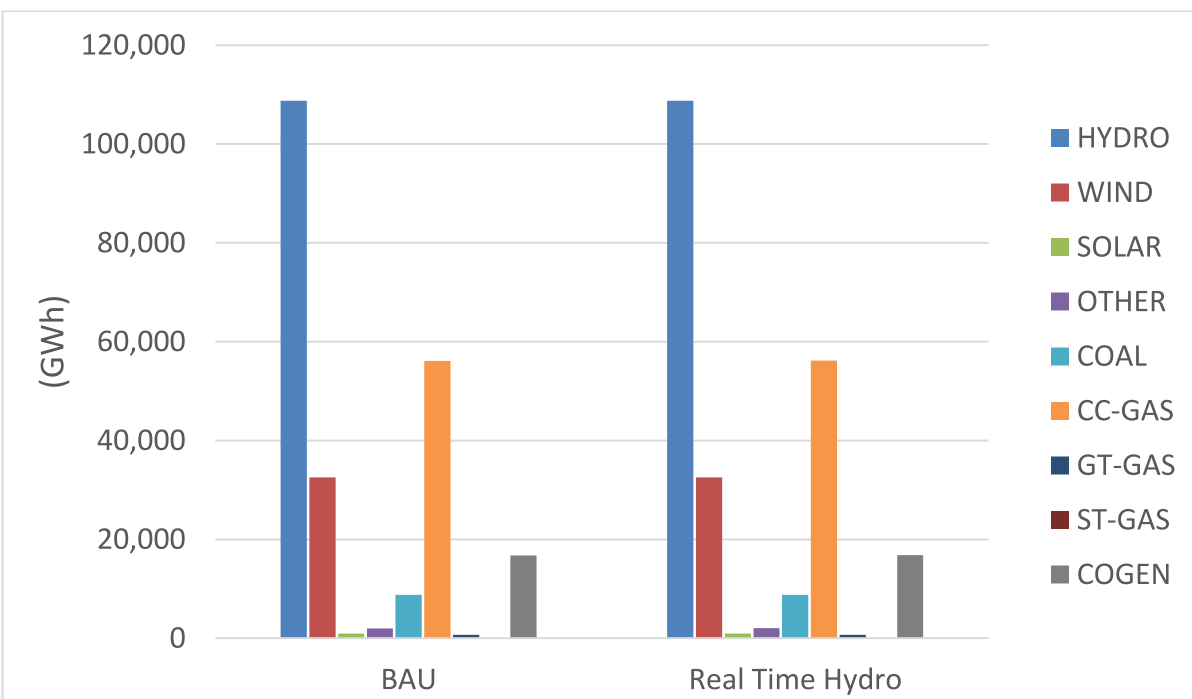


Figure 6-94: Real-Time Hydro Sensitivity - BAU Generation (2040)

Table 6-26: Real-Time Hydro Sensitivity - BAU Generation (2030)

(GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	110,485	21,818	958	2,057	15,215	22,326	2,464	48	25,249	**200,619**
Real Time Hydro	110,503	21,818	958	2,057	15,212	22,349	2,250	48	25,230	**200,426**
Change	**18**	**0**	**0**	**0**	**-3**	**23**	**-214**	**0**	**-19**	**-194**

Table 6-27: Real-Time Hydro Sensitivity - BAU Generation (2040)

(GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	108,778	32,528	959	1,996	8,742	56,131	667	73	16,716	**226,589**
Real Time Hydro	108,783	32,528	959	2,000	8,745	56,147	644	73	16,787	**226,665**
Change	**5**	**0**	**0**	**4**	**2**	**16**	**-23**	**1**	**71**	**76**

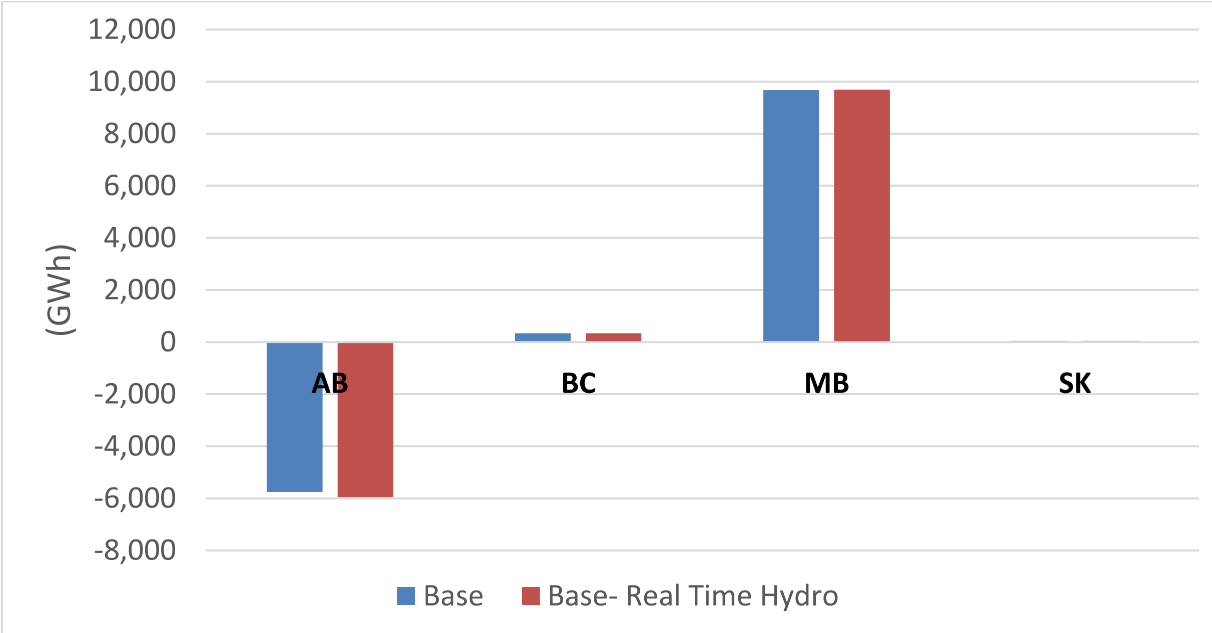


Figure 6-95: Real-Time Hydro Sensitivity - BAU Net Exports (2030)

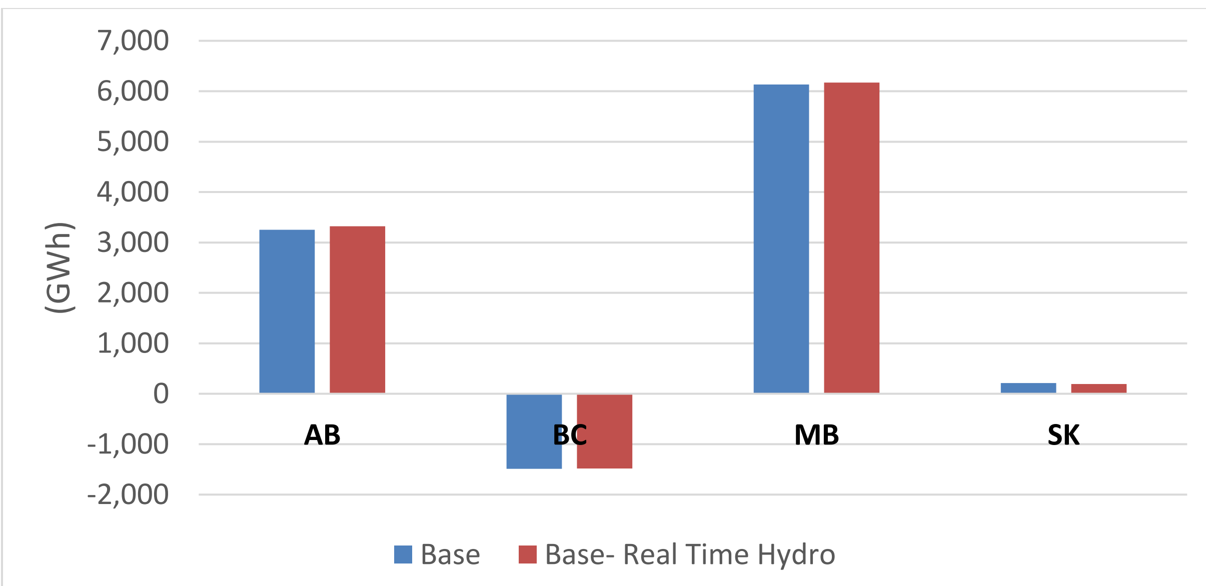


Figure 6-96: Real-Time Hydro Sensitivity - BAU Net Exports (2040)

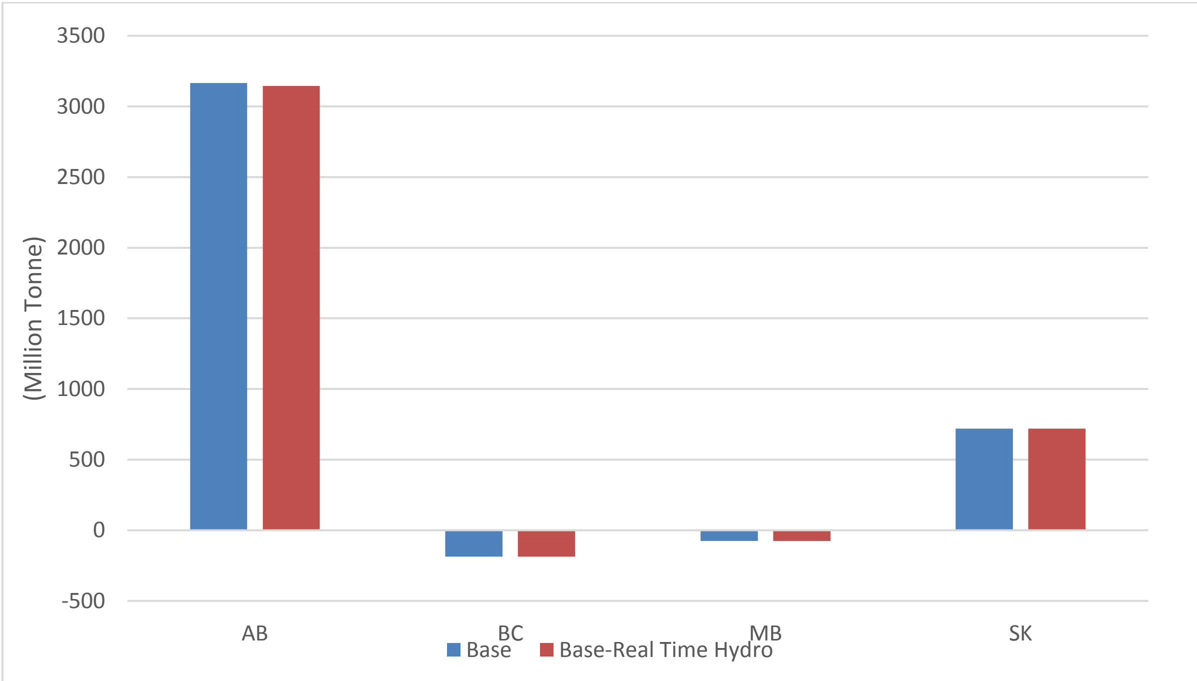


Figure 6-97: Real-Time Hydro Sensitivity - BAU Adjusted Production Costs (2030)

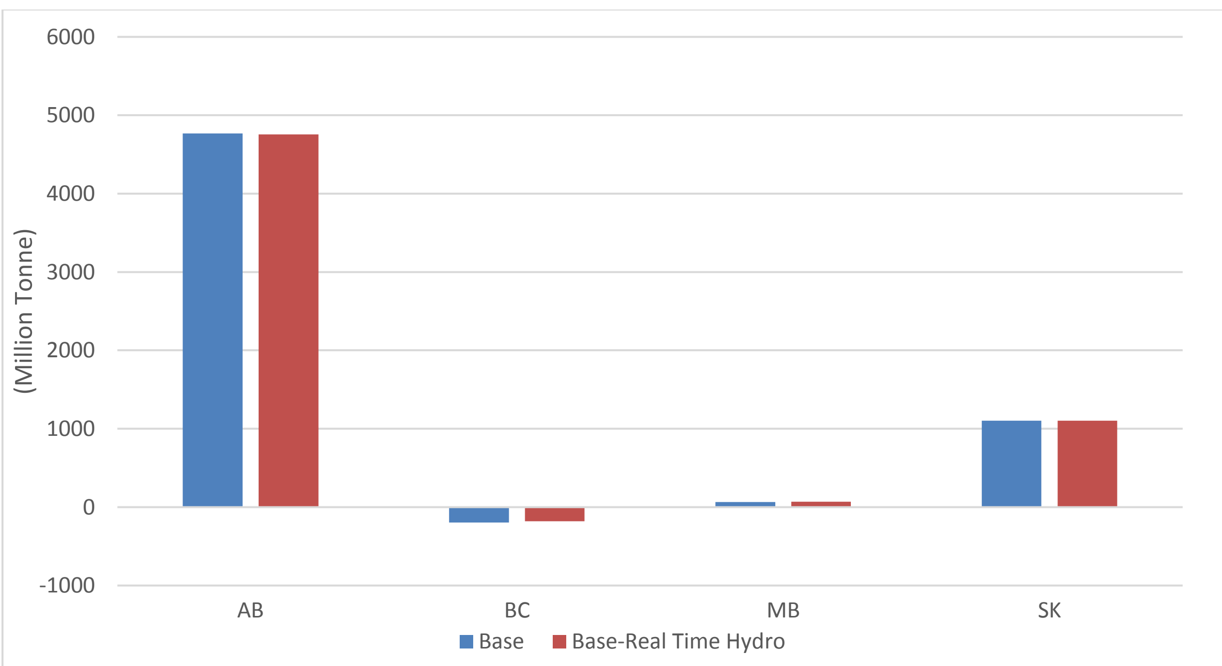


Figure 6-98: Real-Time Hydro Sensitivity - BAU Adjusted Production Costs (2040)

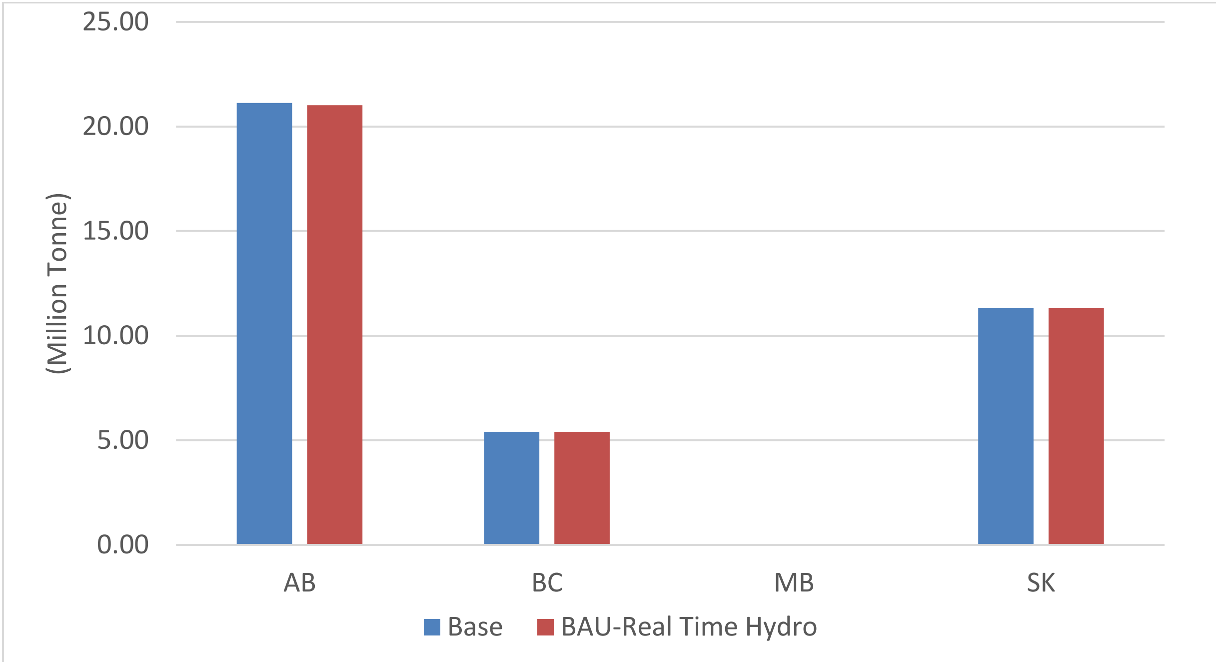


Figure 6-99: Real-Time Hydro Sensitivity - BAU CO2 Emissions (2030)

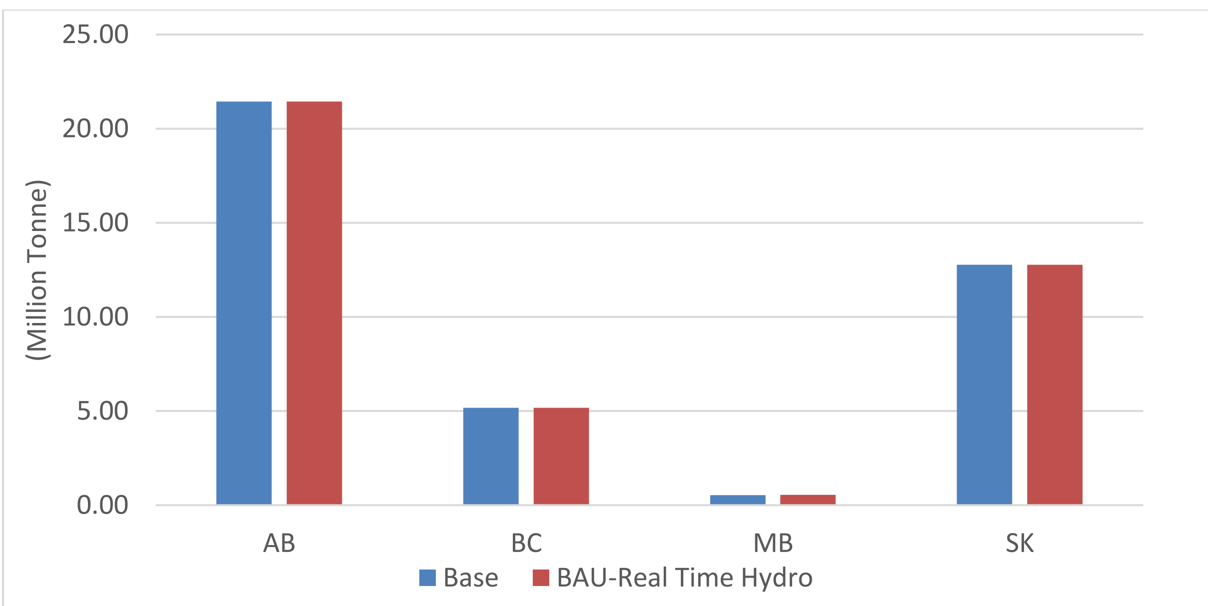


Figure 6-100: Real-Time Hydro Sensitivity - BAU CO2 Emissions (2040)

6.4.2 Project A: New intertie between BC and AB (Southern Route) (2030)

Project A’s Southern Route option was evaluated under the real-time hydro sensitivity.

The following charts and tables present the impact of real-time hydro sensitivity on Project A, Southern Route option. General observations include:

- It appears that real-time hydro scheduling does not have a significant impact on the generation dispatch other than slight reduction in natural gas-based generation in British Columbia and Alberta.
- As noted previously, a closer to real-time hydro scheduling results in better utilization of thermal generation.
- Results indicate that there was, in fact, no change in annual hydro generation. However, the hourly generation pattern changed because of the change in the hourly hydro generation pattern.
- The outcome is a very small decrease in Alberta and British Columbia generation in 2030,
- Generation results indicate that net exports from British Columbia decreased while net imports in Alberta increased. One possible interpretation is that the real-time hydro sensitivity caused more imports from the USA into Canada.
- The overall impact of real-time hydro sensitivity is very small changes in adjusted production costs and CO_2 emissions of provinces.

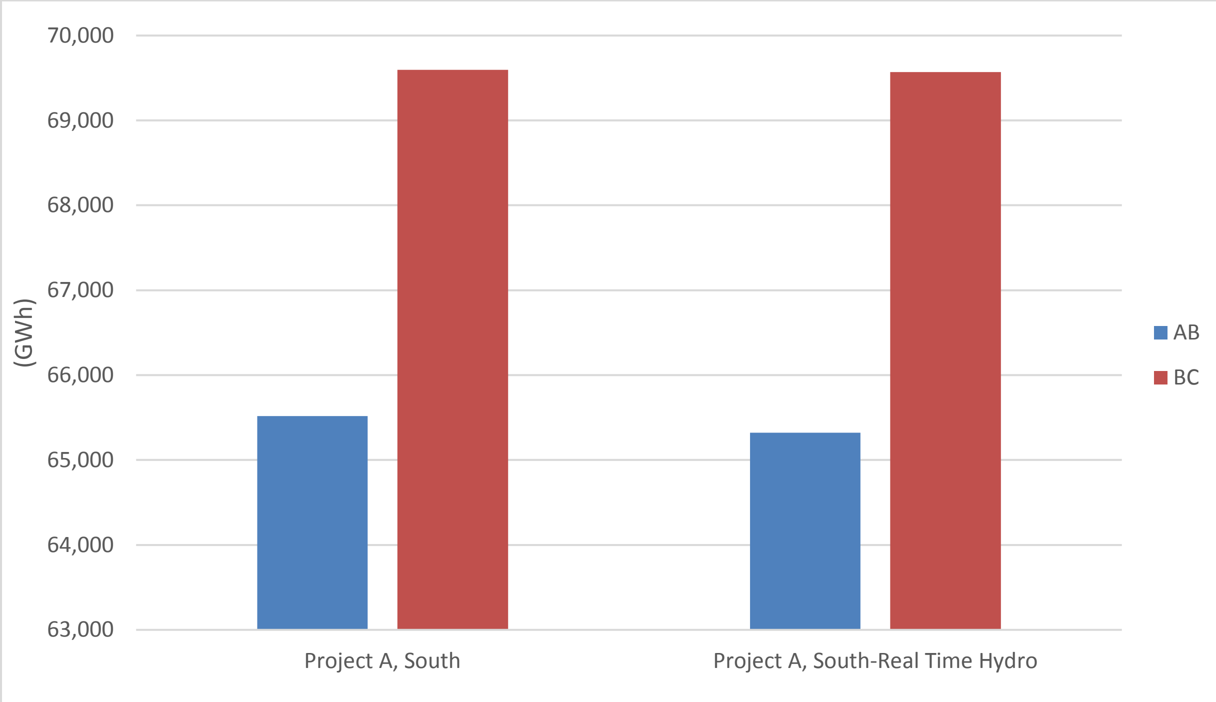


Figure 6-101: Real-Time Hydro Sensitivity - Project A - Generation by Province (2030)

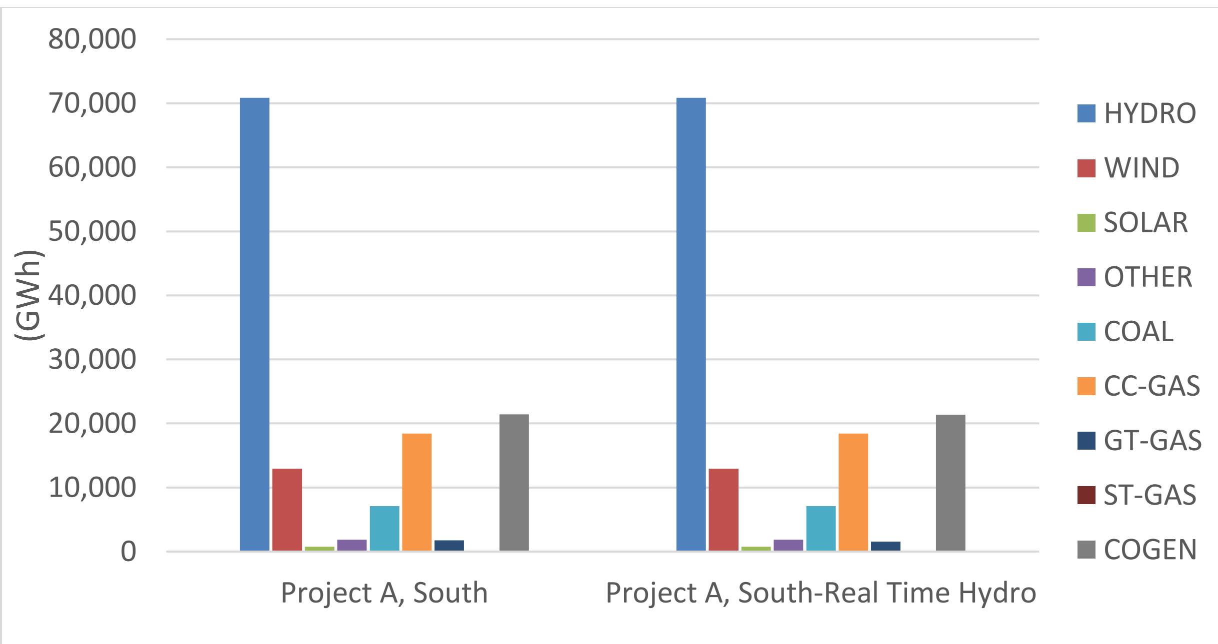


Figure 6-102: Real-Time Hydro Sensitivity - Project A - Generation by Type (2030)

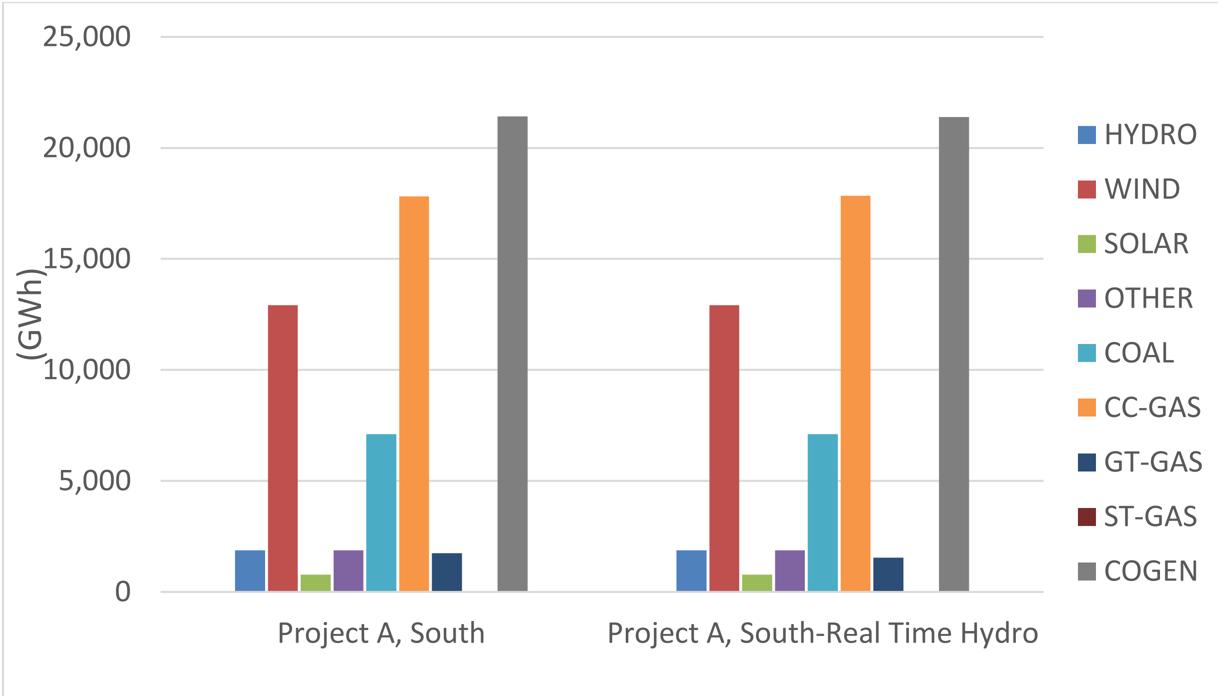


Figure 6-103: Real-Time Hydro Sensitivity - Project A - Alberta Generation (2030)

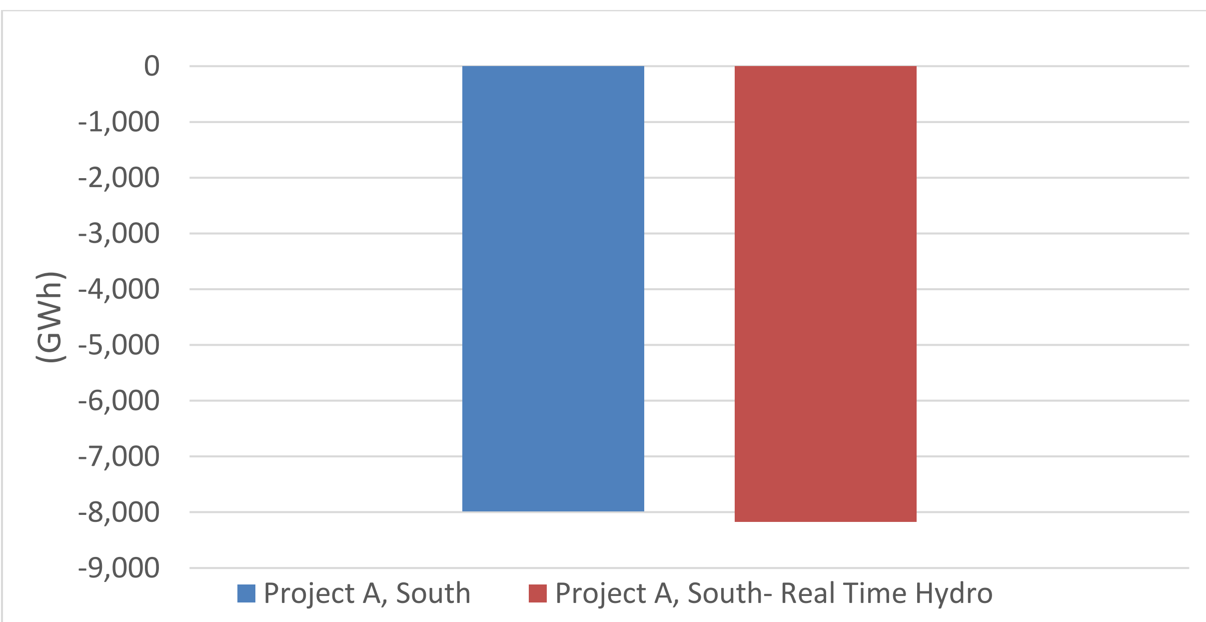


Figure 6-104: Real-Time Hydro Sensitivity - Project A - Alberta Net Exports (2030)

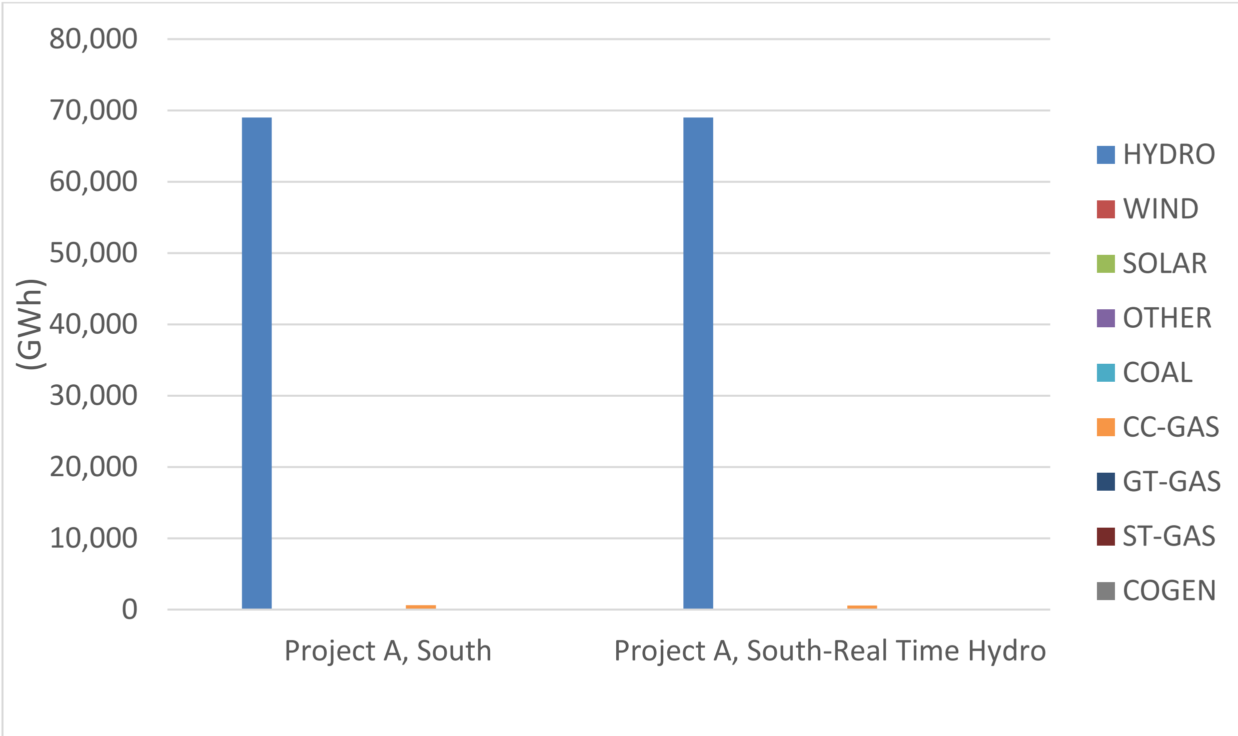


Figure 6-105: Real-Time Hydro Sensitivity - Project A - British Columbia Generation (2030)

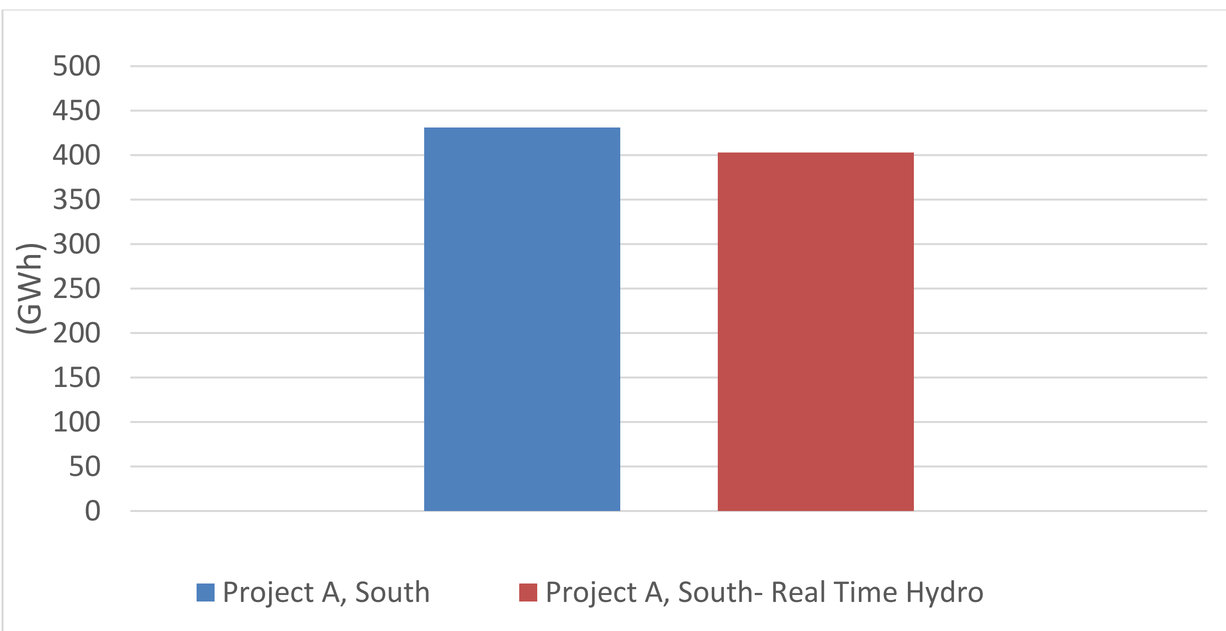


Figure 6-106: Real-Time Hydro Sensitivity - Project A - British Columbia Net Exports (2030)

Table 6-28: Real-Time Hydro Sensitivity - Project A - Alberta Generation (2030)

AB Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project A, South	1,875	12,910	775	1,868	7,107	17,813	1,745	0	21,425	**65,516**
Project A, South-Real Time Hydro	1,875	12,910	775	1,870	7,107	17,852	1,544	0	21,391	**65,322**
Change	**0**	**0**	**0**	**2**	**0**	**39**	**-201**	**0**	**-34**	**-194**

Table 6-29: Real-Time Hydro Sensitivity - Project A - British Columbia Generation (2030)

BC Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project A, South	68,988	0	0	0	0	609	0	0	0	**69,597**
Project A, South-Real Time Hydro	68,988	0	0	0	0	580	0	0	0	**69,568**
Change	**0**	**0**	**0**	**0**	**0**	**-29**	**0**	**0**	**0**	**-28**

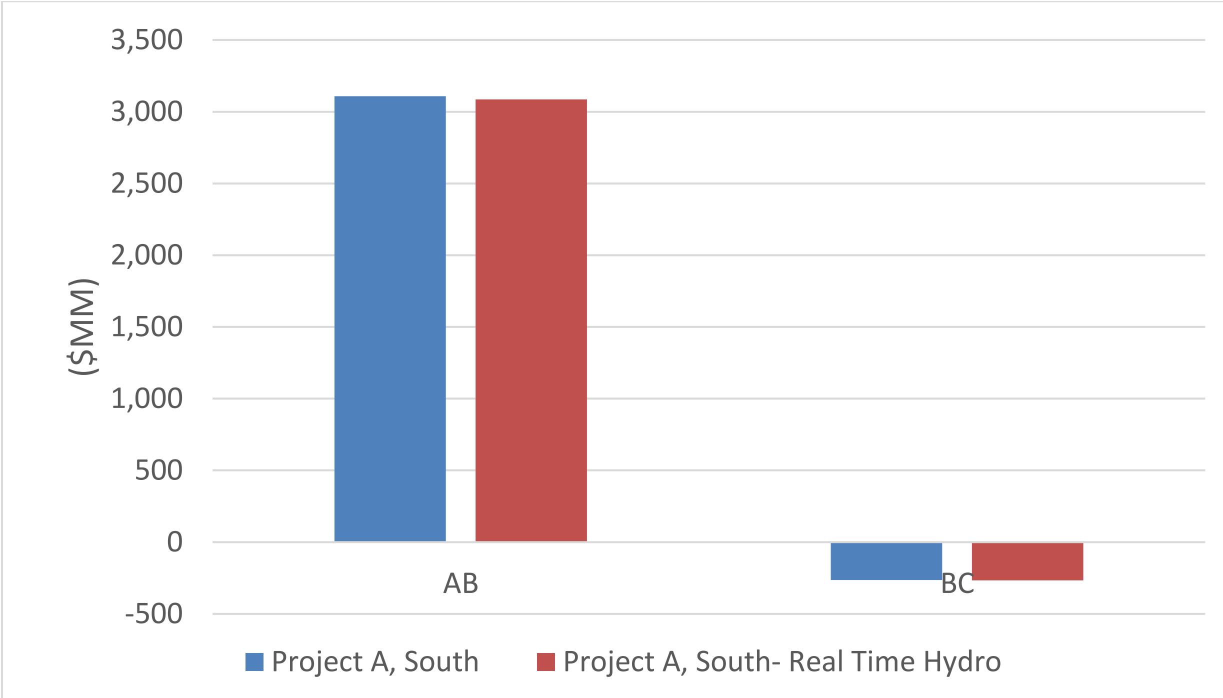


Figure 6-107: Real-Time Hydro Sensitivity - Project A - Adjusted Production Costs (2030)

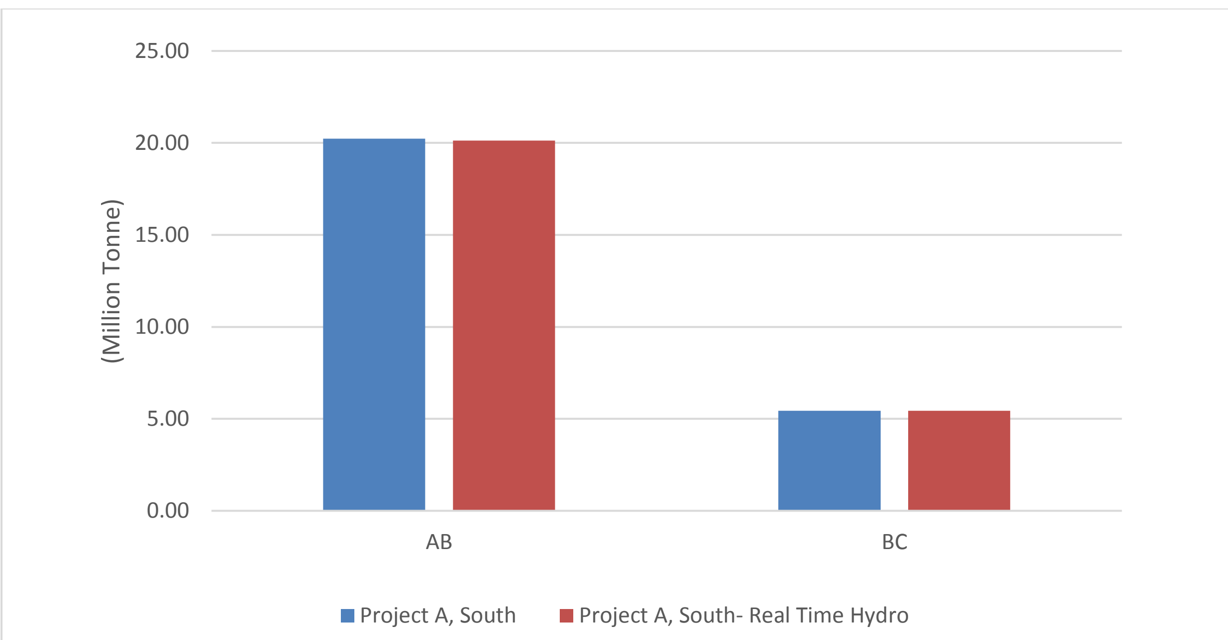


Figure 6-108: Real-Time Hydro Sensitivity - Project A - CO2 Emissions (2030)

6.4.3 Project B: New intertie between SK and MB (Option 1(2030)

Project B's Option 1, which includes a new 500 kV line from Saskatchewan to Manitoba, was evaluated under the real-time hydro sensitivity.

The following charts and tables present the impact of the real-time hydro scheduling on Project B, Option 1 Intertie. General observations include:

- It appears that real-time hydro scheduling does not have a significant impact on the generation dispatch, other than a small reduction of natural gas-based generation in Saskatchewan and Manitoba.
- Any changes in net exports, adjusted production costs, and CO2 emissions are rather negligible.

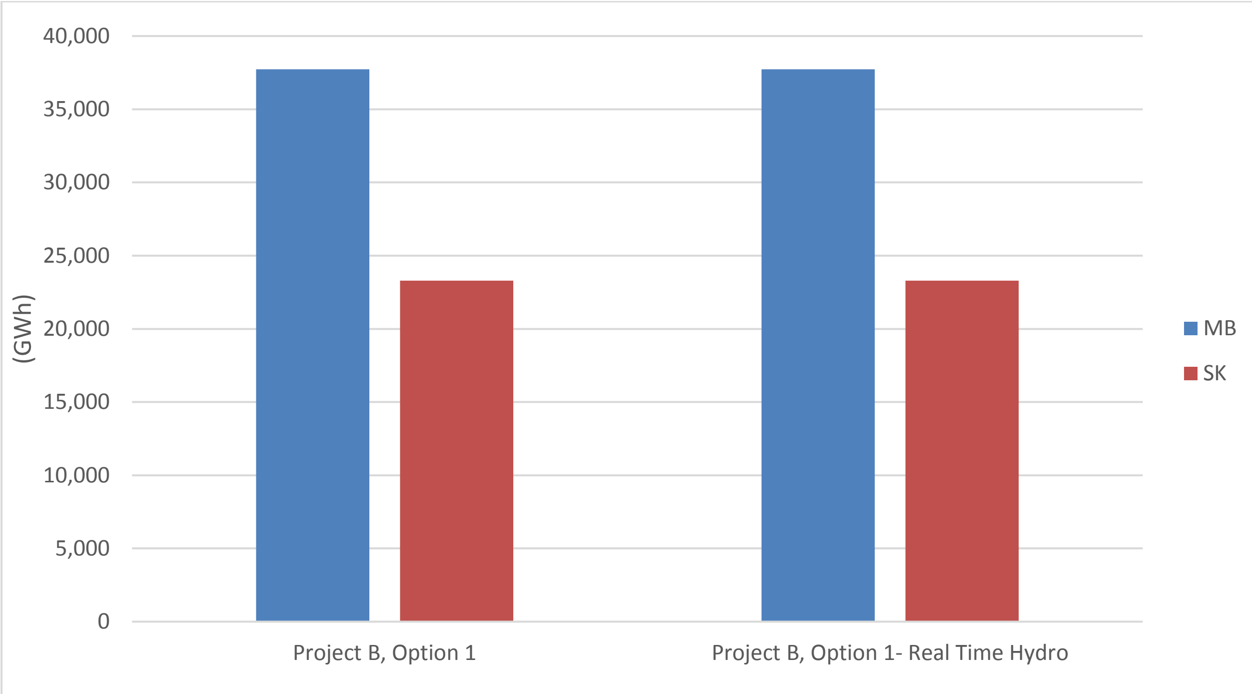


Figure 6-109: Real-Time Hydro Sensitivity - Project B - Generation by Province (2030)

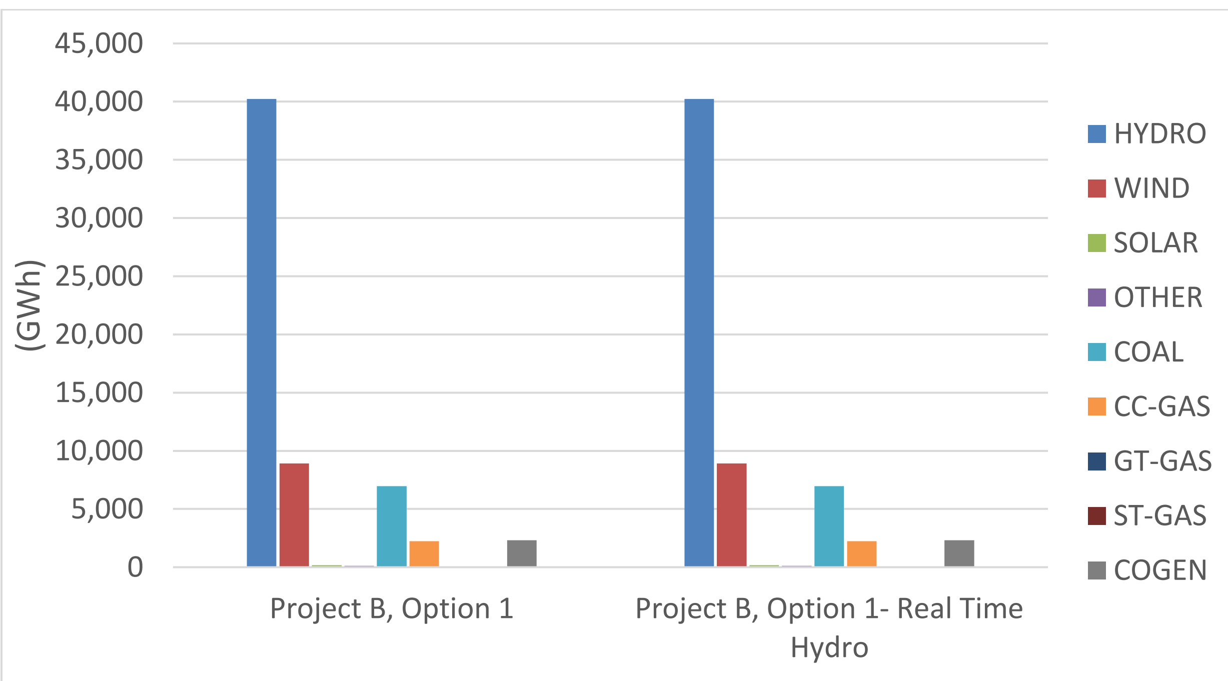


Figure 6-110: Real-Time Hydro Sensitivity - Project B - Generation by Type (2030)

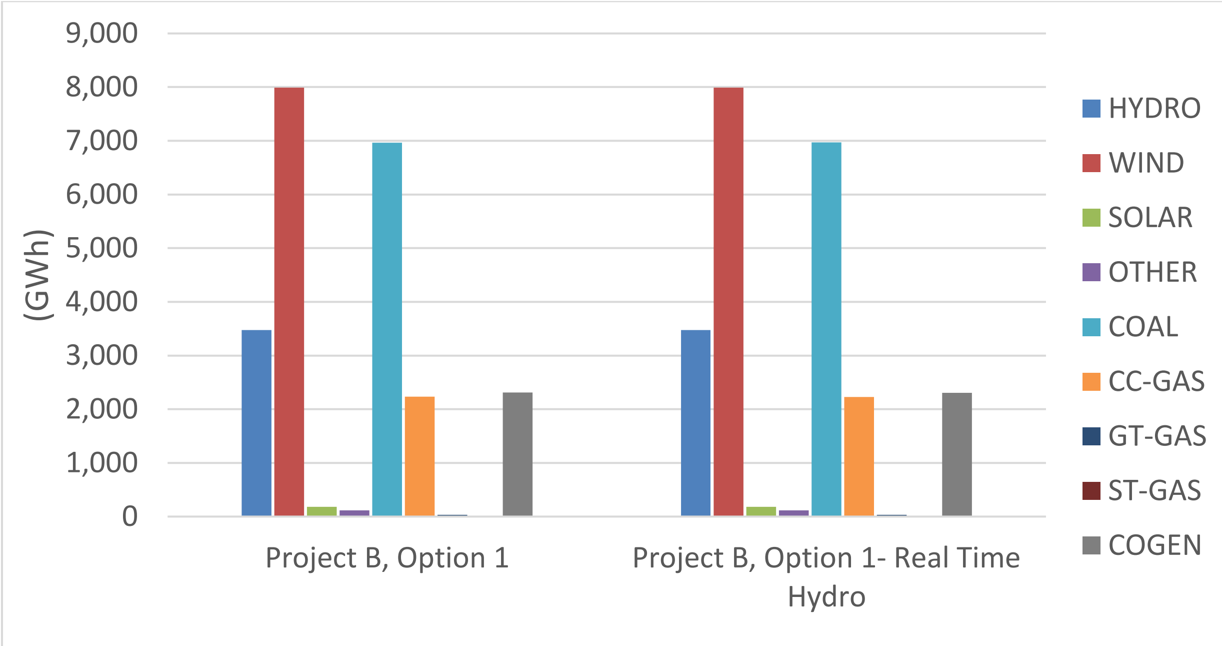


Figure 6-111: Real-Time Hydro Sensitivity - Project B - Saskatchewan Generation (2030)

Figure 6-112: Real-Time Hydro Sensitivity - Project B - Saskatchewan Net Exports (2030)

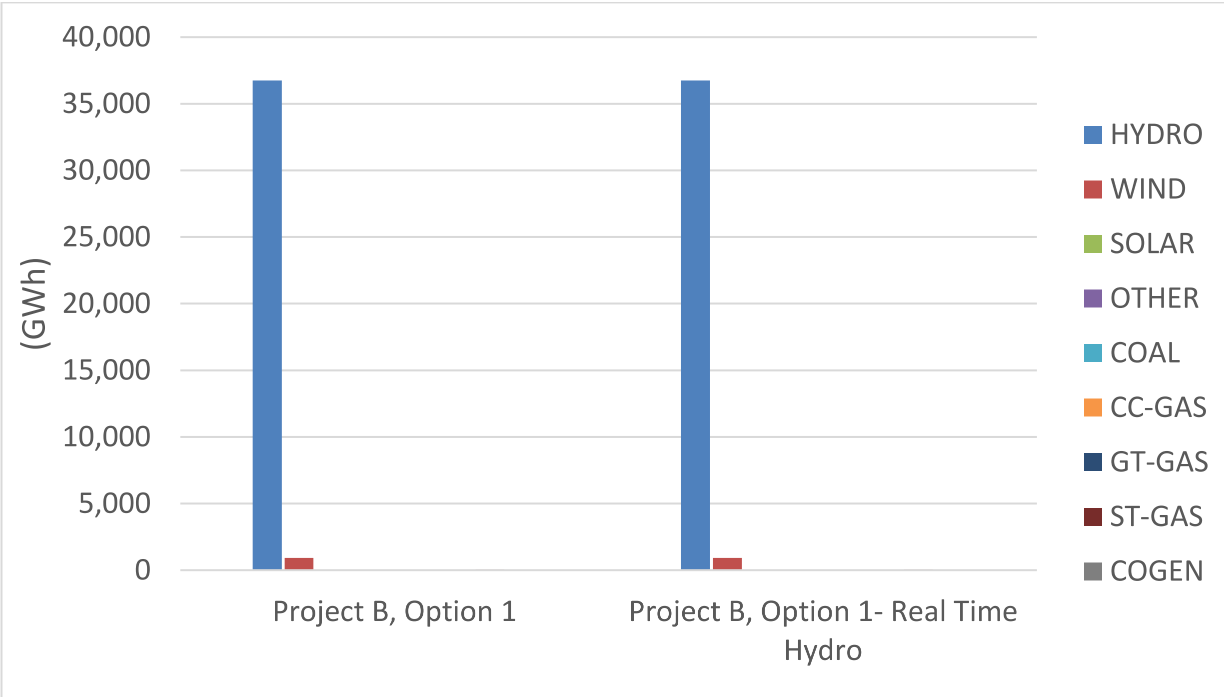


Figure 6-113: Real-Time Hydro Sensitivity - Project B - Manitoba Generation (2030)

Figure 6-114: Real-Time Hydro Sensitivity - Project B - Manitoba Net Exports (2030)

Table 6-30: Real-Time Hydro Sensitivity - Project B - Saskatchewan Generation (2030)

SK Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project B, Option 1	3,476	7,989	184	113	6,962	2,235	30	0	2,312	**23,301**
Project B, Option 1-Real Time Hydro	3,473	7,989	184	113	6,971	2,230	30	0	2,308	**23,297**
Change	**-3**	**0**	**0**	**0**	**9**	**-5**	**0**	**0**	**-5**	**-4**

Table 6-31: Real-Time Hydro Sensitivity - Project B - Manitoba Generation (2030)

MB Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project B, Option 1	36,747	927	0	0	0	0	4	48	0	**37,725**
Project B, Option 1-Real Time Hydro	36,750	928	0	0	0	0	4	48	0	**37,730**
Change	**4**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**5**

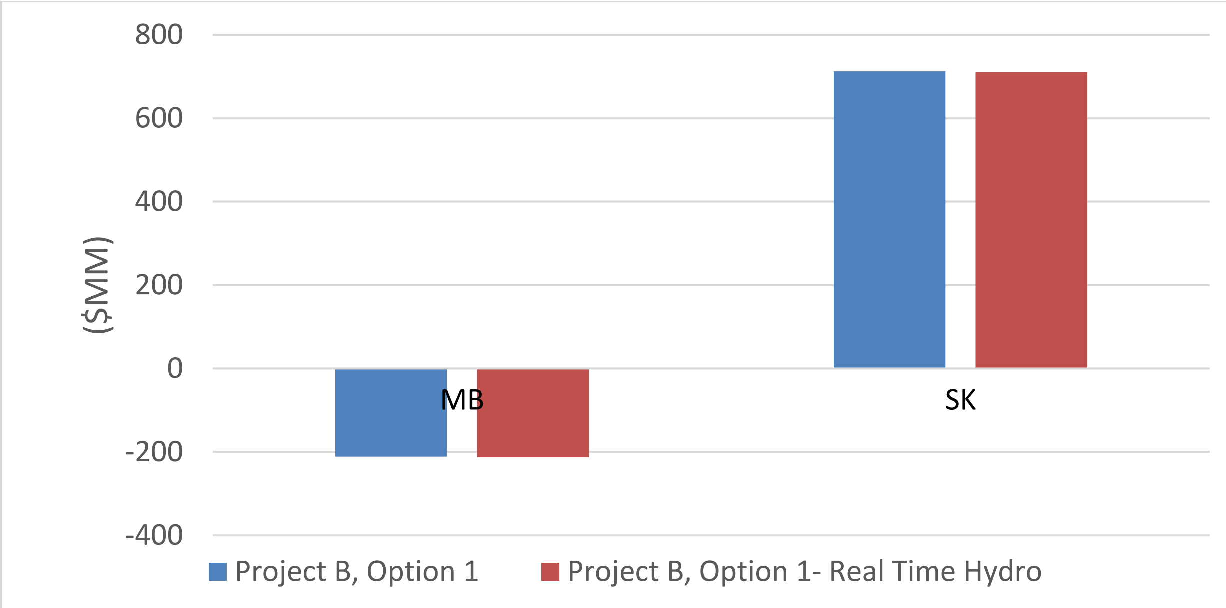


Figure 6-115: Real-Time Hydro Sensitivity - Project B - Adjusted Production Costs (2030)

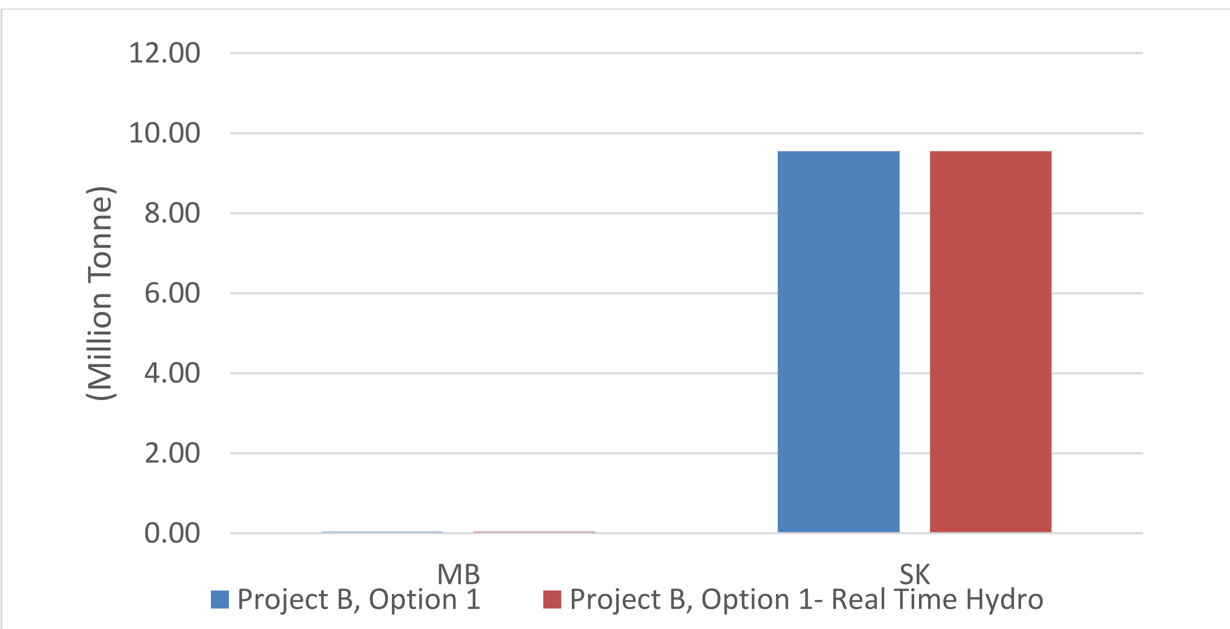


Figure 6-116: Real-Time Hydro Sensitivity - Project B - CO2 Emissions (2030)

6.4.4 Project D: New hydroelectric capacity in AB and SK (2040)

Project D's Option 1 which represent different sets of hydropower additions in Alberta and Saskatchewan were evaluated under the real-time hydro sensitivity.

The following charts and tables present the impact of high carbon price sensitivity on Project B, Option 1 case. General observations include:

- As in previous cases of real-time hydro sensitivity, the impacts on generation dispatch, adjusted production costs, and CO2 emissions are negligible.

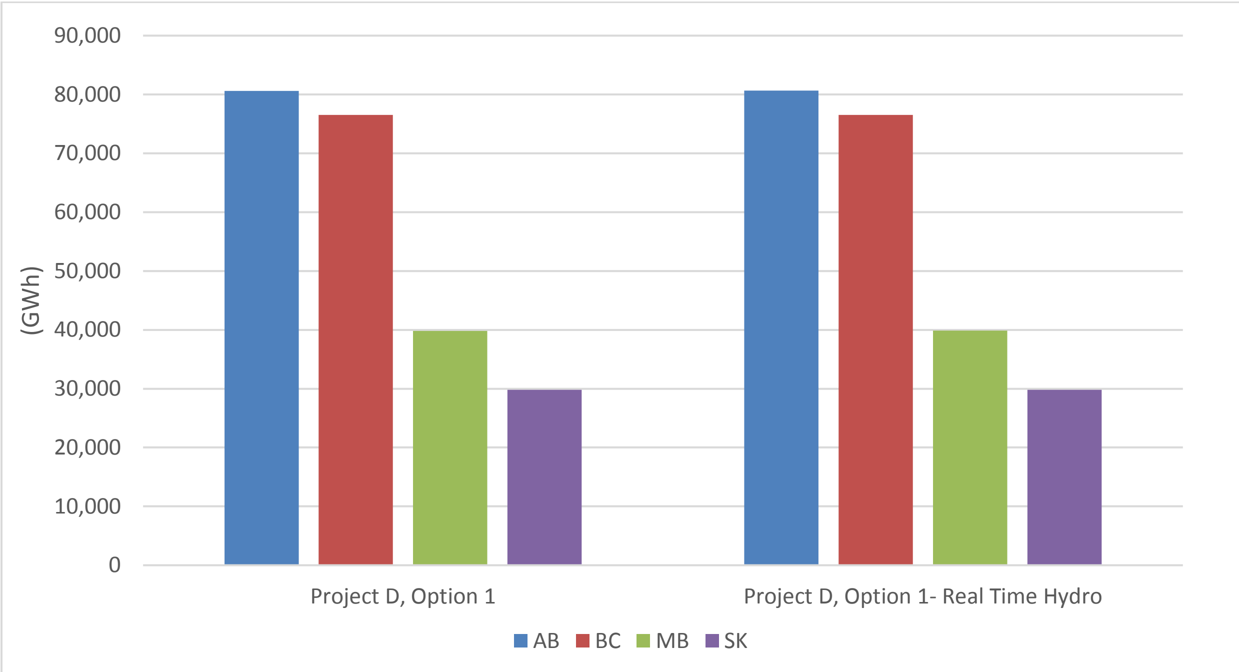


Figure 6-117: Real-Time Hydro Sensitivity - Project D - Generation by Province (2040)

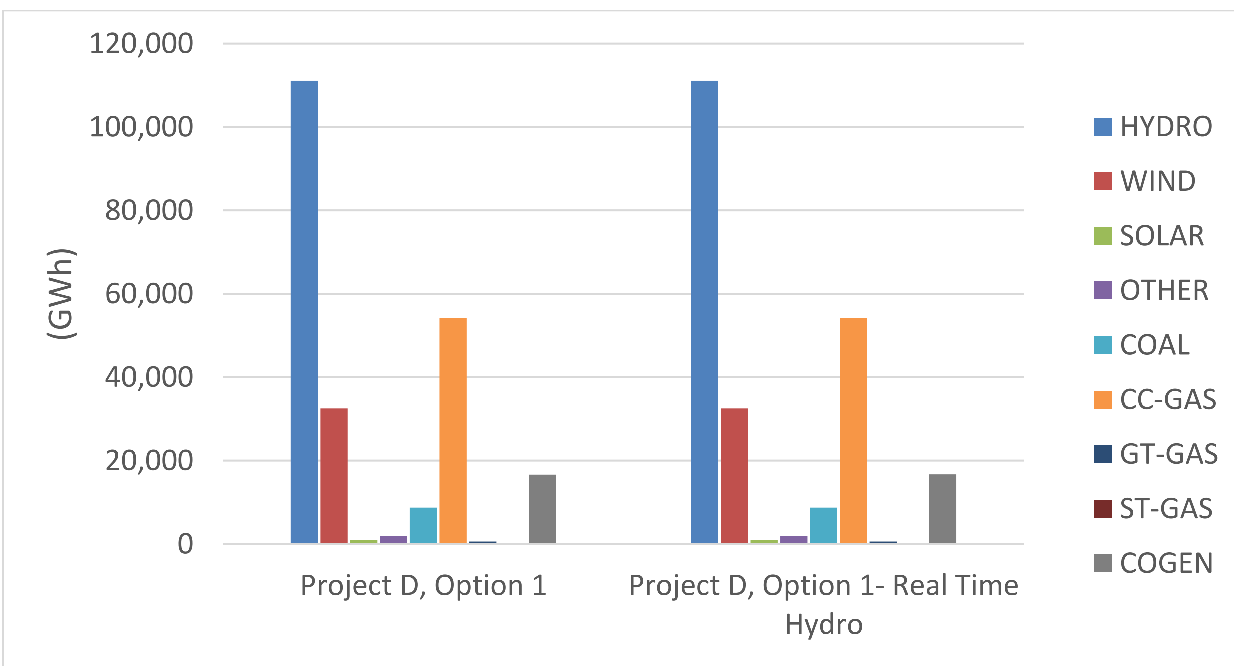


Figure 6-118: Real-Time Hydro Sensitivity - Project D - Generation by Type (2040)

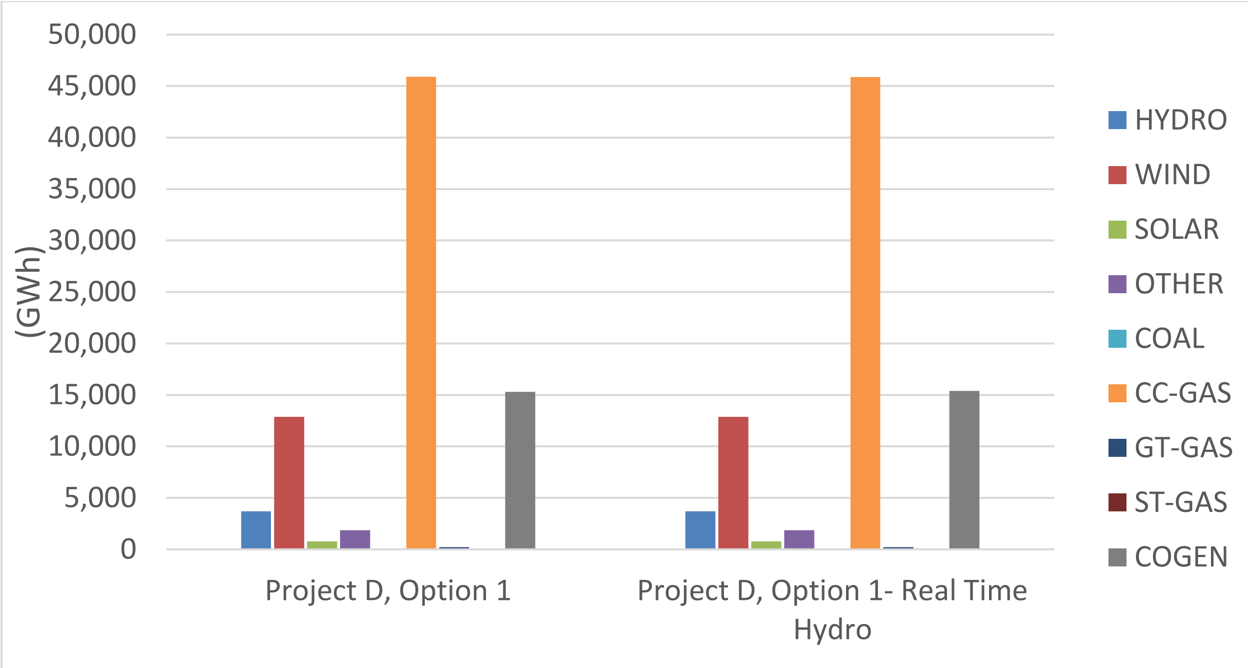


Figure 6-119: Real-Time Hydro Sensitivity - Project D - Alberta Generation (2040)

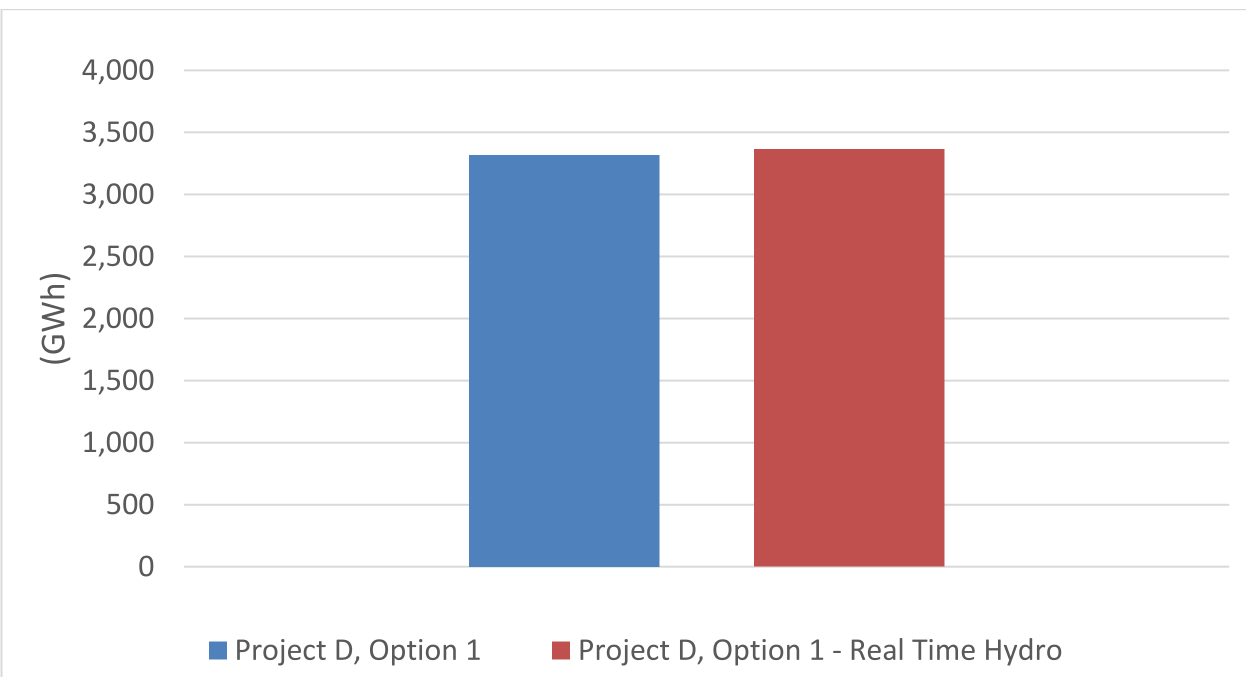


Figure 6-120: Real-Time Hydro Sensitivity - Project D - Alberta Net Exports (2040)

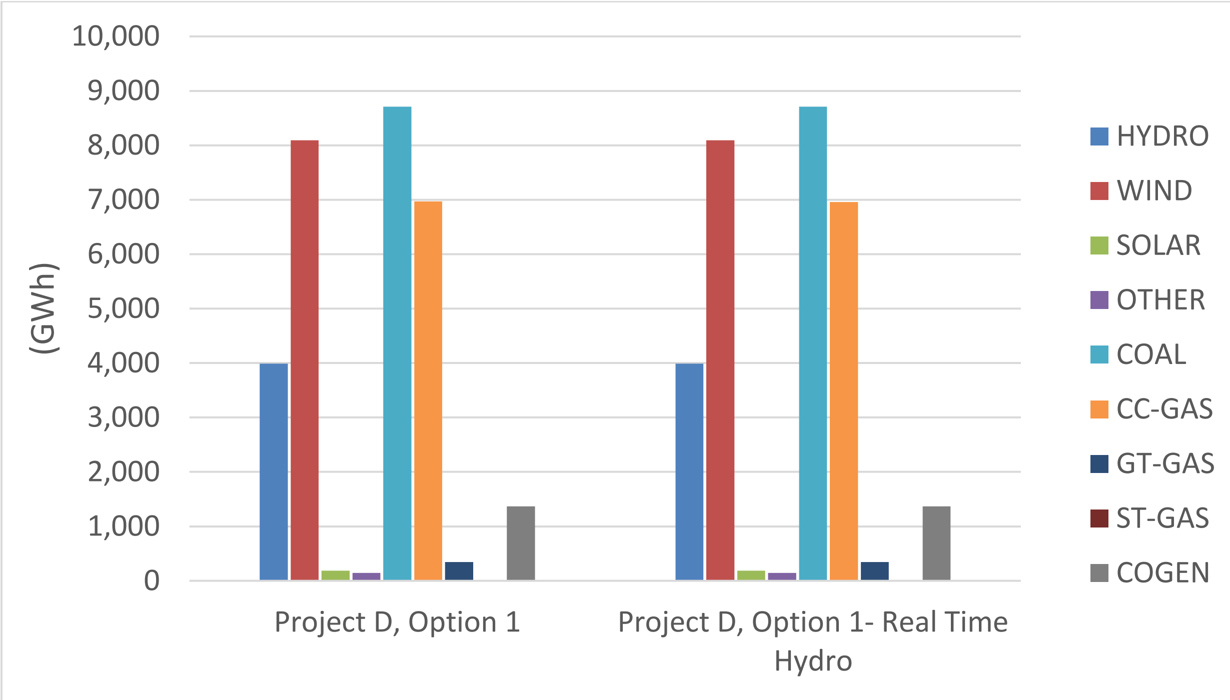


Figure 6-121: Real-Time Hydro Sensitivity - Project D - Saskatchewan Generation (2040)

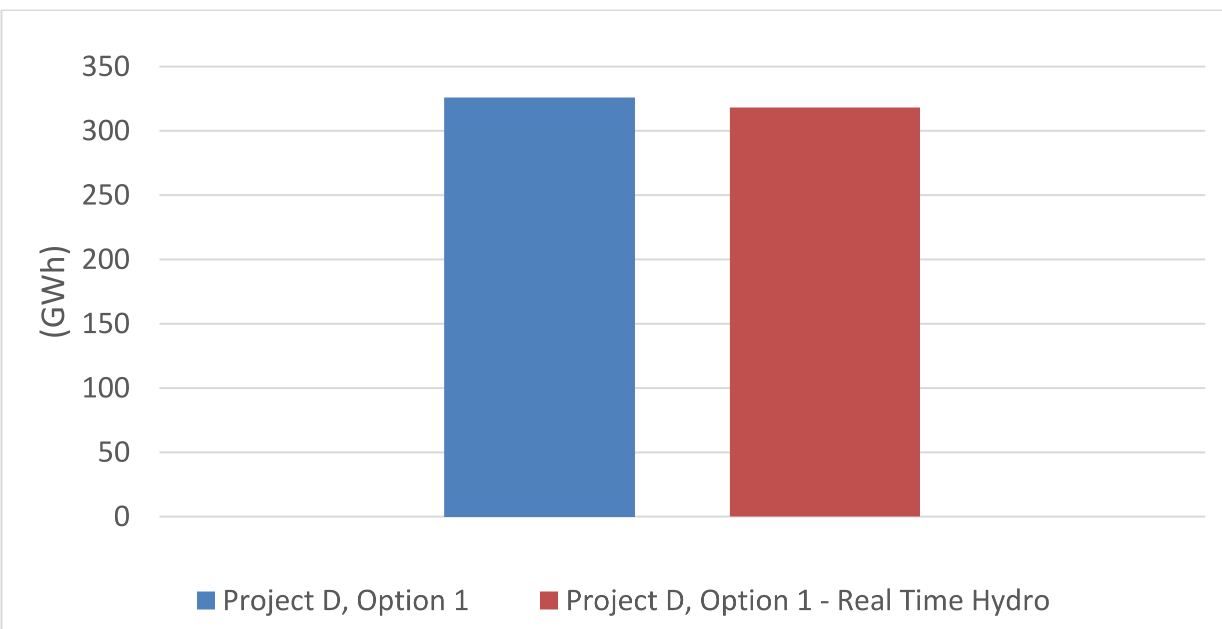


Figure 6-122: Real-Time Hydro Sensitivity - Project D - Saskatchewan Net Exports (2040)

Table 6-32: Real-Time Hydro Sensitivity - Project D - Alberta Generation (2040)

AB Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project D, Option 1	3,689	12,871	774	1,851	0	45,907	214	0	15,296	**80,603**
Project D, Option 1-Real Time Hydro	3,689	12,871	774	1,854	0	45,885	197	0	15,377	**80,648**
Change	**0**	**0**	**0**	**3**	**0**	**-21**	**-17**	**0**	**81**	**45**

Table 6-33: Real-Time Hydro Sensitivity - Project D - Saskatchewan Generation (2040)

SK Generation (GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
Project D, Option 1	3,989	8,093	184	145	8,707	6,970	346	0	1,365	**29,800**
Project D, Option 1-Real Time Hydro	3,988	8,092	184	145	8,709	6,959	345	0	1,367	**29,790**
Change	**-1**	**-1**	**0**	**0**	**2**	**-11**	**-2**	**0**	**3**	**-11**

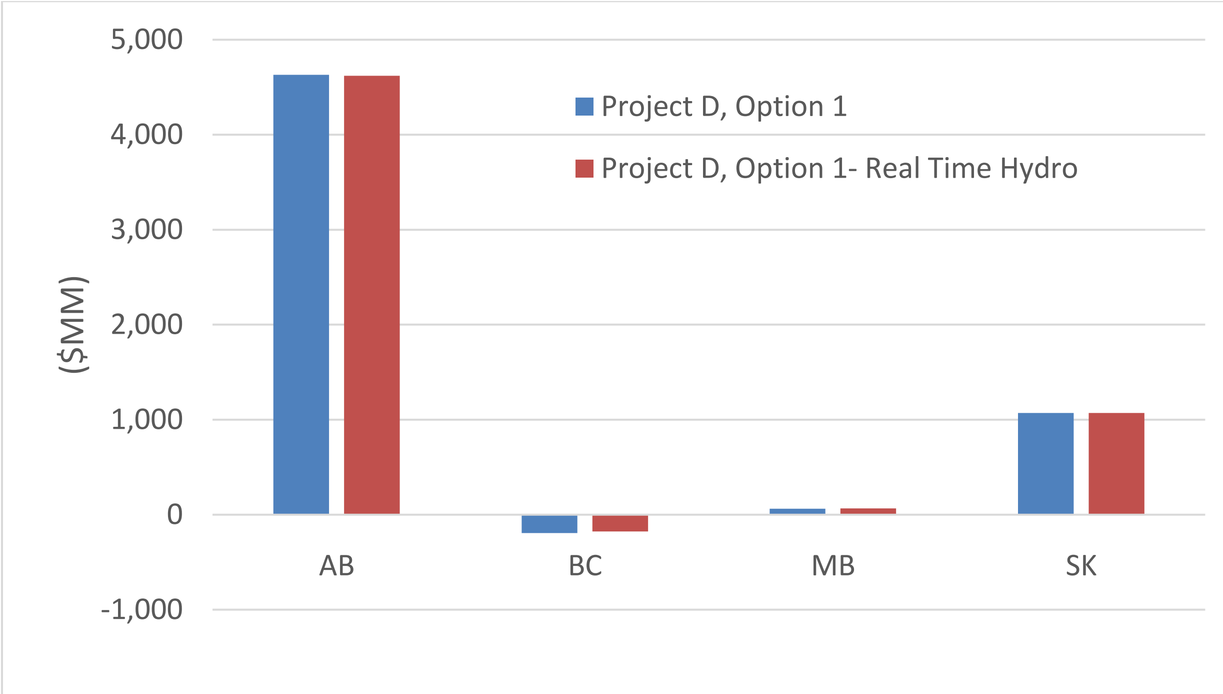


Figure 6-123: Real-Time Hydro Sensitivity - Project D - Adjusted Production Costs (2030?)

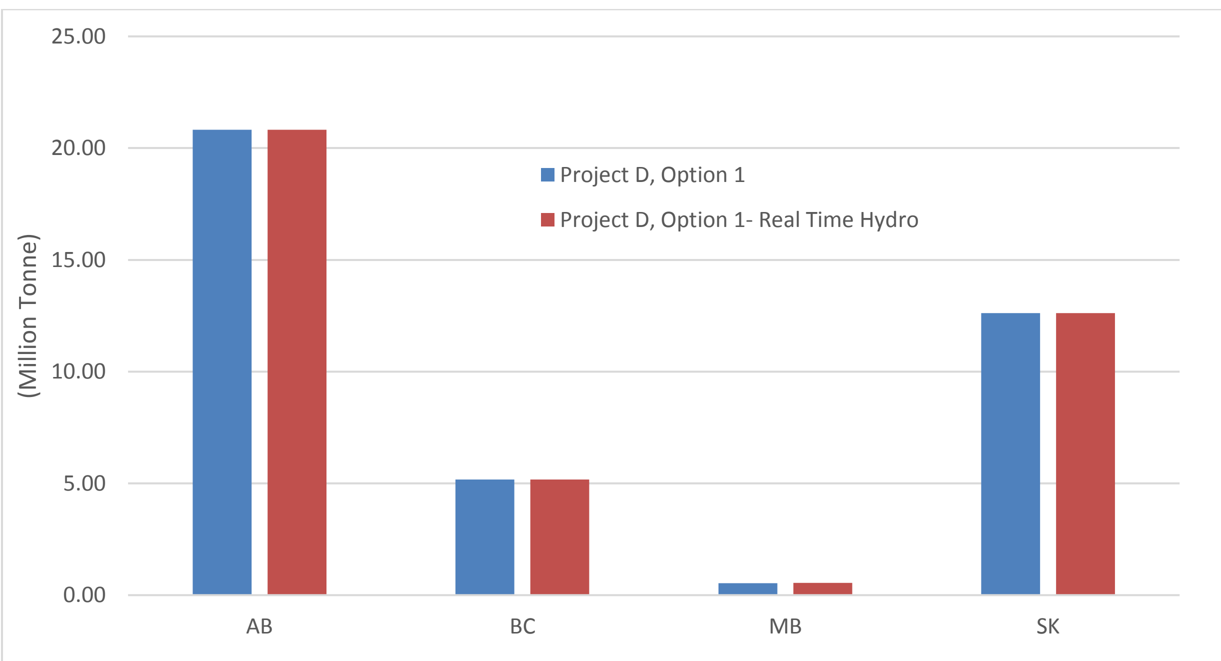


Figure 6-124: Real-Time Hydro Sensitivity - Project D - CO2 Emissions (2030?)

6.5 Operating Reserves Sensitivity

The operating reserve sensitivity analyses presented in this section was performed to evaluate the impact of change in wind variability reserve requirements on the power system performance.

This sensitivity was performed to also satisfy the requirement of the Task 2.2 of the study, which was part of scope of work in the original project RFP. Task 2.2 required evaluation of the impact on operating reserves by the study projects. Since the modeling in this study already included additional hourly wind variability reserve requirements depending on the amount of the additional wind in the BAU case and the study projects (based on the findings from the PCWIS project), this sensitivity, instead, evaluated the impact of change in those hourly requirements.

The operating sensitivity considered only the "Wind variability Reserve" in order to examine the impact of variation in wind variability based operating reserve requirement on the power system's operational and economic performance.

The wind variability reserve is defined as the additional reserves - above and beyond the conventional and contingency based operation reserves - that would be required to mitigate the sub-hourly variation of more volatile renewable energy.

Most recently, GE Energy Consulting and its partners evaluated the hourly wind variability reserve in the PJM Renewable Integration Study (PRIS)[22] and also in the CanWEA Pan-Canadian Wind Integration Study (PCWIS)[23]. The more recent PCWIS is more relevant to this Western RECSI study, because the hourly wind data and the hourly load shapes of the current project are based on the scaled PCWIS wind and load data.

The wind variability reserve requirements that were developed in the PCWIS study were scaled proportionally based on the size of wind in the RECSI project relative to the size of wind in the PCWIS project and applied in this study.

To determine the impact of more or less wind variability reserves, two sensitivities were performed using the BAU Scenario, one with a +50% scaling of hourly BAU wind variability reserve requirements, and one with a -50% scaling of hourly BAU wind variability reserve requirements.

[22] http://www.pjm.com/committees-and-groups/subcommittees/irs/pris.aspx

[23] https://canwea.ca/wind-integration-study/

6.5.1 Business-As-Usual – BAU – Case (2030) and (2040)

Following figures present the impact of operating reserve sensitivity on the BAU scenario. General observations include:

- There is minimal impact on dispatch of generation by type in 2030 and 2040. The underlying data indicate that with higher reserve requirements, more of the COAL unit capacities are kept in reserve, resulting in increased generation by CC-GAS and GT-GAS units. With lower reserve requirements, more of COAL unit capacities are freed up, resulting in more COAL generation but less CC-GAS generation and GT-GAS generation.
- In 2030 and 2040, the impact on British Colombia and Alberta appear to be minimal. There are greater impacts on Manitoba and Saskatchewan, most likely due to increased generation by less expensive CC-GAS units caused by more COAL capacity being kept in reserve. It should be noted that Manitoba and Saskatchewan together are small systems compared to the British Colombia and Alberta taken together.
- The decrease in CO2 emissions in the higher reserve requirement case is due to the displacement of higher CO2 emitting COAL generation by lower CO2 emitting resources. Decreasing reserve requirements frees up the COAL generation, resulting in higher CO2 emissions.
- The increase in adjusted production costs in the higher reserve requirement case is due to the displacement of less expensive COAL generation by more expensive resources. Decreasing reserve requirements frees up the less expensive COAL generation, resulting in lower adjusted production costs.

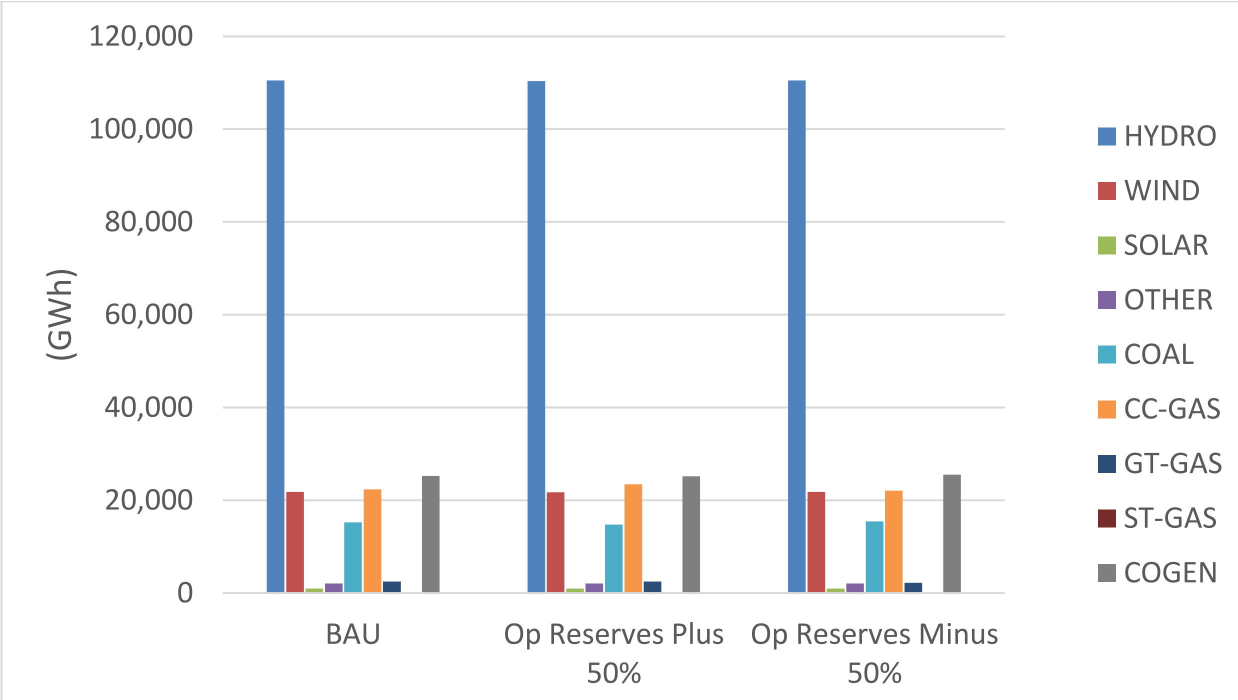


Figure 6-125: Operating Reserve Sensitivity - BAU Generation (2030)

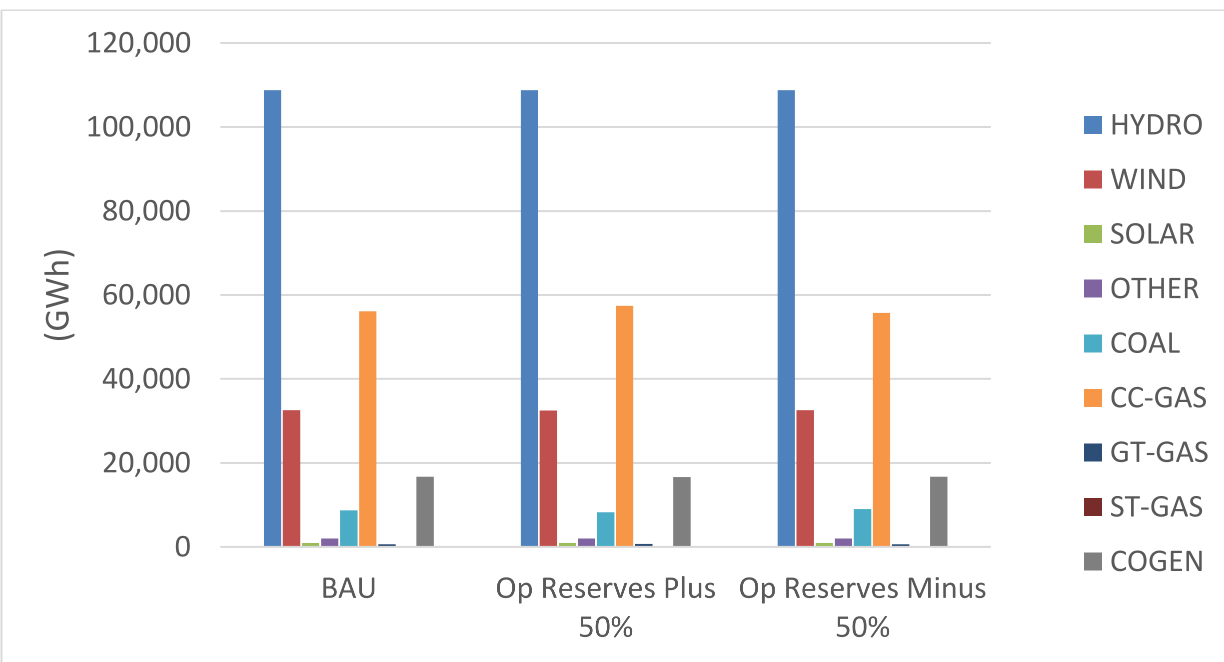


Figure 6-126: Operating Reserve Sensitivity - BAU Generation (2040)

Table 6-34: Operating Reserve Sensitivity - BAU Generation (2030)

(GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	110,485	21,818	958	2,057	15,215	22,326	2,464	48	25,249	**200,619**
Op Reserves Plus 50%	110,396	21,739	958	2,047	14,750	23,423	2,471	84	25,146	**201,014**
Op Reserves Minus 50%	110,495	21,822	958	2,058	15,443	22,100	2,234	25	25,504	**200,640**
Change, Plus 50%	-89	-79	0	-11	-464	1,098	7	36	-103	**395**
Change, Minus 50%	10	4	0	1	229	-226	-230	-23	255	**21**

Table 6-35: Operating Reserve Sensitivity - BAU Generation (2040)

(GWh)	HYDRO	WIND	SOLAR	OTHER	COAL	CC-GAS	GT-GAS	ST-GAS	COGEN	Total
BAU	108,778	32,528	959	1,996	8,742	56,131	667	73	16,716	**226,589**
Op Reserves Plus 50%	108,763	32,480	959	1,988	8,269	57,390	703	113	16,659	**227,324**
Op Reserves Minus 50%	108,784	32,531	959	1,998	9,023	55,696	596	44	16,716	**226,347**
Change, Plus 50%	-15	-49	0	-8	-473	1,259	36	40	-57	**735**
Change, Minus 50%	6	3	0	2	280	-435	-70	-28	1	**-242**

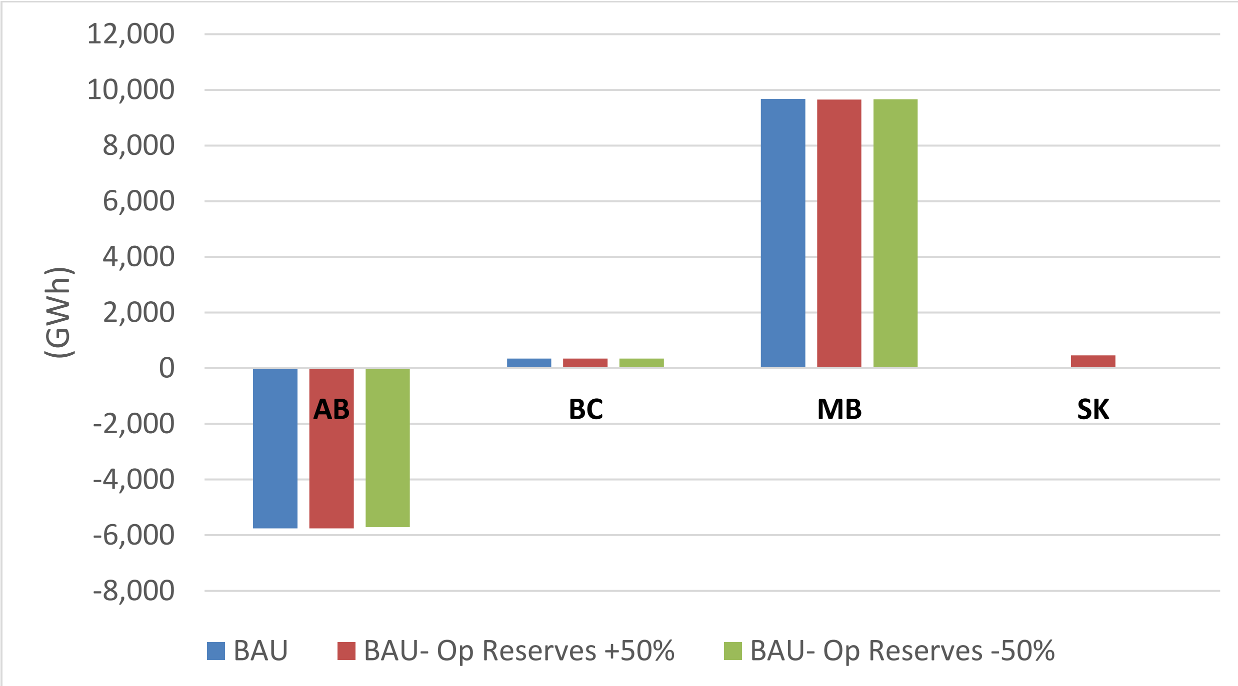


Figure 6-127: Operating Reserve Sensitivity - BAU Net Exports (2030)

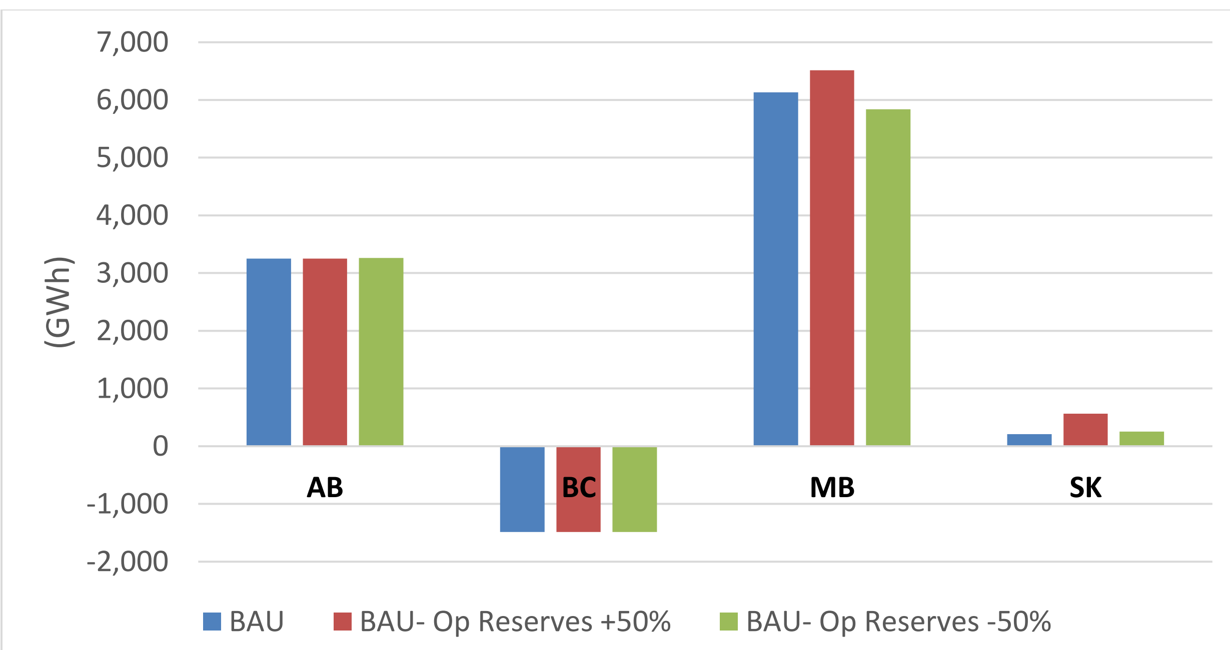


Figure 6-128: Operating Reserve Sensitivity - BAU Net Exports (2040)

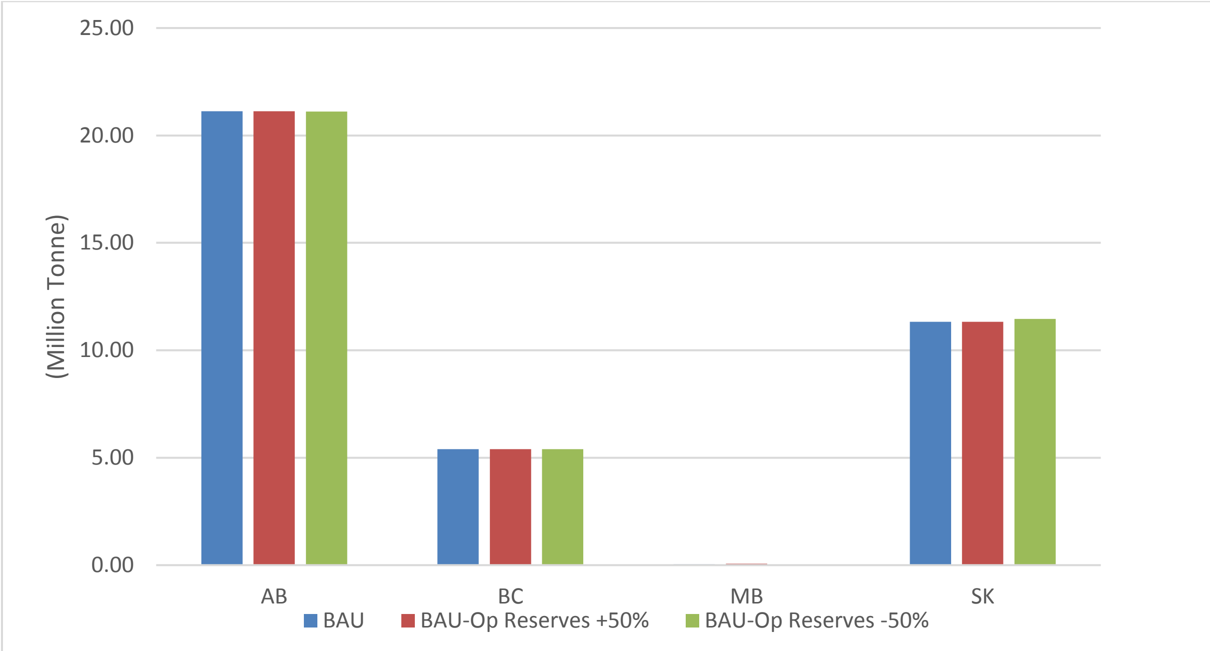


Figure 6-129: Operating Reserve Sensitivity - BAU CO2 Emissions (2030)

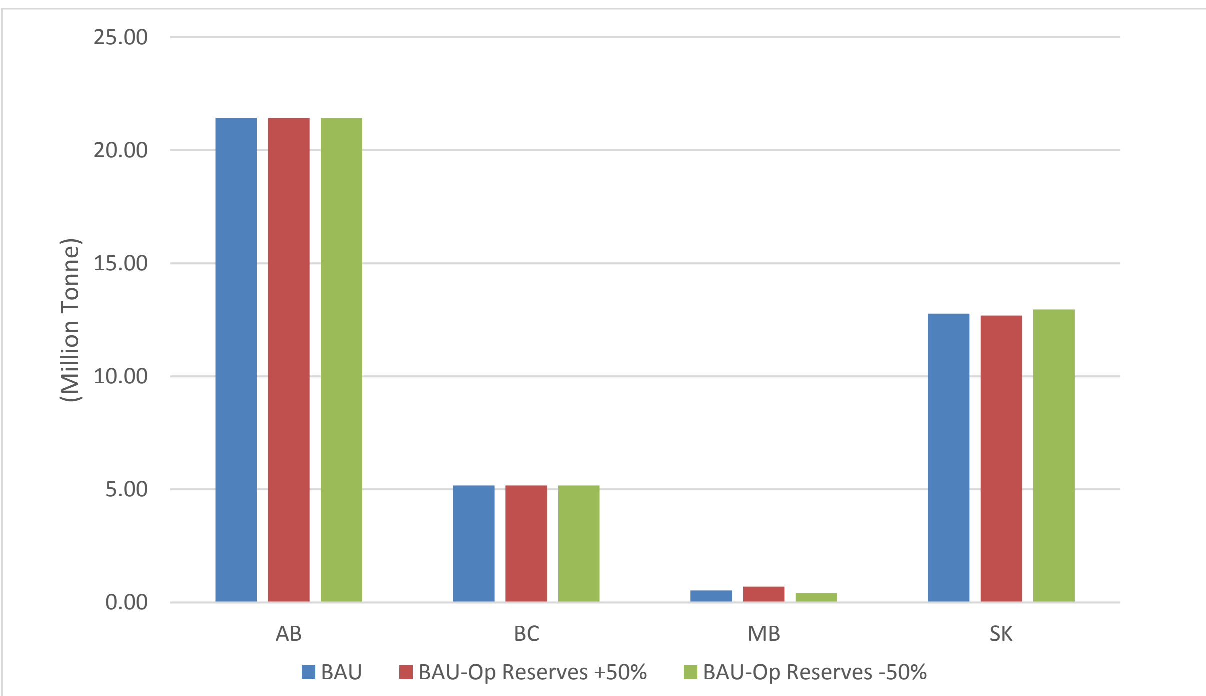


Figure 6-130: Operating Reserve Sensitivity - BAU CO2 Emissions (2040)

Figure 6-131: Operating Reserve Sensitivity - BAU Adjusted Production Costs (2030)

Figure 6-132: Operating Reserve Sensitivity - BAU Adjusted Production Costs (2040)

7 Project Metrics

7.1 Project Metrics and Key Findings

The principal and relevant metrics based on the outputs of the GE MAPS model are the Carbon Emissions and Adjusted Production Costs. Carbon emissions are the CO2 emissions from the fossil fuel-based generation resources. GE MAPS calculates the CO2 emissions based on each power plant's fuel type, heat rate, and power output. Adjusted Production Costs are the sum of annual variable production costs in each province, adjusted to account for the annual net import costs and export revenues. It should be noted that generation dispatch depends on the variable generation costs of each power plant; the fixed and capital costs of power plants that are already installed are not drivers of dispatch decisions.

In addition to these metrics from the GE MAPS modeling, the investment capital costs of each new transmission, generation, and energy storage element within the study projects were also taken into account.

The final set of metrics used for each project evaluated included the following components:

- Carbon Emissions Reductions:
  - The change in annual carbon emissions from generation resources in each province relative to the BAU case.
  - A negative value is a decrease in carbon emissions relative to the BAU case, a positive value is an increase in carbon emissions relative to the BAU case.
  - In units of Million Tonne (i.e., Million Metric Ton)
- Total Capital Costs:
  - The total cost of transmission facilities, generation facilities, conversion, or other costs for the project.
  - In units of CAD $ Millions or ($MM)
- Total Net Annual Costs:
  - The sum of the change in Annual Adjusted Production Costs relative to the BAU case, plus the Annual Capital Costs of the project.
  - A positive value is a net annual cost, a negative value is a net annual saving.
  - In units of CAD $ Millions, or ($MM)

Variable production costs (or Production Costs for short) is the sum of generation fuel costs, generation start-up costs, variable operations & maintenance (VOM) costs, and carbon emission costs in each province. As noted, Adjusted Production Cost does not include any fixed or capital costs, since these costs do not impact economic dispatch of plants.

The Annual Capital Cost of each project is the annual loan payment to cover the capital investment cost in the project.

Annual Capital Cost for each project was calculated based on the following assumptions:

- Inflation Rate: 2%
- Cost Base Year: 2018
- Weighted Average Cost of Capital: 7% (Real Rate)
- Economic Life for Transmission projects: 40 Years
- Economic Life for Wind projects: 20 Years
- Economic Life for Coal Conversion projects: 20 Years
- Economic Life for Storage projects: 20 Years
- Economic Life for Hydropower projects: 60 Years

Effective year basis for the cost components are:

- Adjusted Production Costs: The year the project comes online, either 2030 or 2040
- Hydro Capital Costs: 2017
- Transmission Capital Costs: 2018
- All other Costs: 2018

All cost components were converted to 2018 base year in Canadian dollars.

The Carbon Emissions Reduction values and the Annual Cost values were used to assess the annual dollar cost for each unit of reduction in carbon emissions (or inversely, amount of carbon emissions reduced per dollar of annual cost), resulting in the following principal metrics for evaluation of each project:

- Carbon Reduction/Annual Cost (Tonne/$1000)
- Annual Cost/Carbon Reduction ($/Tonne)

The following table summarizes the results for all the projects. The color highlights, described below the table, identify the projects which created either an increase or reduction in carbon emissions while yielding an increase or decrease in annual costs.

The following bullets provide a description and the meaning of the negative and positive values in each column:

- Carbon Emissions: This is the change in carbon emissions relative to the BAU case. A negative value signifies reduction in carbon emissions. A positive value signifies increase in carbon emissions.

- Net Annual Costs: This is the sum of the Annualized Capital Costs of each project and the change in Adjusted Production Costs relative to the BAU case. The change in the Adjusted Production Costs is the difference in the variable production cost, adjusted for import cost and export revenues, of all the Canadian provinces impacted by the project. In some cases, the change in Adjusted Production Costs can result in a reduction in overall system variable production costs because of the project. It is possible that the overall annual system-wide benefits of the project could be greater than the annual capital cost of the project. A negative value for Net Annual Costs represents a decrease in total costs, and an increase in total costs is denoted by a positive value.

- Interpretation of metrics in the following table depend on the signs of their numerator and denominator, as described in the following bullets.

    - If both the Net Annual Cost Change and the Carbon Emissions Change are negative, then the project reduces both system-wide costs and carbon emissions. This is the best outcome, a win-win case.

    - If the Net Annual Cost Change is positive, but the Carbon Emissions Change is negative, then the project increases system-wide costs, but reduces system-wide carbon emissions. This is a lose-win case.

    - If the Net Annual Cost Change is negative, but the Carbon Emissions Change is positive, then the project reduces system-wide cost, but increases system-wide carbon emissions. This is a win-lose case.

    - If both Net Annual Cost Change and the Carbon Emissions Change are positive, then the project increases both system-wide costs and system-wide carbon emissions. This is a lose-lose case.

Table 7-1: Project Metrics

Study Projects	Net Annual Cost Change Increase: Positive Decrease: Negative ($Million)	Carbon Emissions Change Increase: Positive Decrease: Negative (Million Tonne)	[Net Annual Cost Change] per Unit of [Change in Carbon Emissions] ($/Tonne)
Project A, North, West	72.36	-1.12	-64.61
Project A, South, West	49.97	-0.86	-58.11
Project B, Option 1, East	87.19	-1.19	-73.27
Project B, Option 2A, East	-5.73	-0.45	12.73
Project B, Option 2B, East	-16.93	-0.41	41.29
Project C, West	146.42	-1.93	-75.87
Project C, East	14.47	0.00	0.00
Project D, Option 1, West	217.31	-0.61	-354.21
Project D, Option 1, East	62.56	-0.16	-381.75
Project D, Option 2, West	451.98	-1.76	-256.30
Project D, Option 2, East	47.98	-0.37	-128.35
Project E, AB > CC, West	916.02	2.11	434.13
Project E, SK > CCS, East	663.34	-6.89	-96.28
Project E, SK > CC, East	321.01	-6.06	-52.97
Project F, West	332.10	-1.88	-176.65
Project F, East	-12.05	0.21	-57.36
Project G, Option 1, West	-41.15	-2.59	15.89
Project G, Option 2, West	-43.26	-3.47	12.47
Project G, Option 3, West	-32.03	-2.12	15.11
Project G, Option 4, West	70.25	-5.19	-13.54
Project H, West	58.89	-0.28	-207.73
Project I, West + East	-13.36	0.40	-33.39
Project J, West	-37.14	-0.51	72.82
Project K, North. West	258.37	-2.71	-95.34
Project K, South. West	227.10	-2.50	-90.84

Green:	Annual Costs Decreased and Carbon Emissions Decreased
Blue:	Annual Costs Increases and Carbon Emissions Decreased
Yellow:	Annual Costs Decreased and Carbon Emissions Increased
Red:	Annual Costs Increased and Carbon Emissions Increased

Table 7-2: Project Capital Costs

Study Projects	Storage Capital Costs (2018 $Million)	Additional Wind Capital Costs (2018 $Million)	Coal Conversion Capital Costs (2018 $Million)	Hydro Capital Cost (2018 $Million)	Additional Transmission Capital Costs (2018 $Million)	Total Capital Costs (2018 $Million)
Project A, North, West	0	0	0	0	2,822	2,822
Project A, South, West	0	0	0	0	2,070	2,070
Project B, Option 1, East	0	0	0	0	2,035	2,035
Project B, Option 2A, East	0	0	0	0	345	345
Project B, Option 2B, East	0	0	0	0	167	167
Project C, West	0	3,600	0	0	1,301	4,901
Project C, East	0	0	0	0	193	193
Project D, Option 1, West	0	0	0	3,894	349	4,243
Project D, Option 1, East	0	0	0	694	466	1,160
Project D, Option 2, West	0	0	0	7,271	2,448	9,719
Project D, Option 2, East	0	0	0	694	660	1,354
Project E, AB > CC, West	0	0	8,088	0	0	8,088
Project E, SK > CCS, East	0	0	5,928	0	0	5,928
Project E, SK > CC, East	0	0	1,933	0	0	1,933
Project F, West	3,000	3,600	0	0	0	6,600
Project F, East	160	0	0	0	0	160
Project G, Option 1, West	0	2,800	0	0	265	3,065
Project G, Option 2, West	0	3,800	0	0	449	4,249
Project G, Option 3, West	0	2,300	0	0	224	2,524
Project G, Option 4, West	0	5,700	0	0	2,438	8,138
Project H, West	0	0	0	925	437	1,362
Project I, West + East	0	0	0	0	204	204
Project J, West	0	0	0	0	357	357
Project K, North. West	0	3,600	0	0	4,123	7,723
Project K, South. West	0	3,600	0	0	3,370	6,970

It should be noted that costs are not adjusted for increased reserve margins due to additional wind or hydro or energy storage resources in some of the projects. Sub Section 7.2 of the report describes an adjustment to these metrics by taking into account the additional cost savings if the reserve margins are maintained at the BAU level by taking out an equivalent amount of capacity that were added in the BAU case to meet the target reserve margin. The carbon reductions and changes in annual costs relative to the BAU case are shown in the following charts.

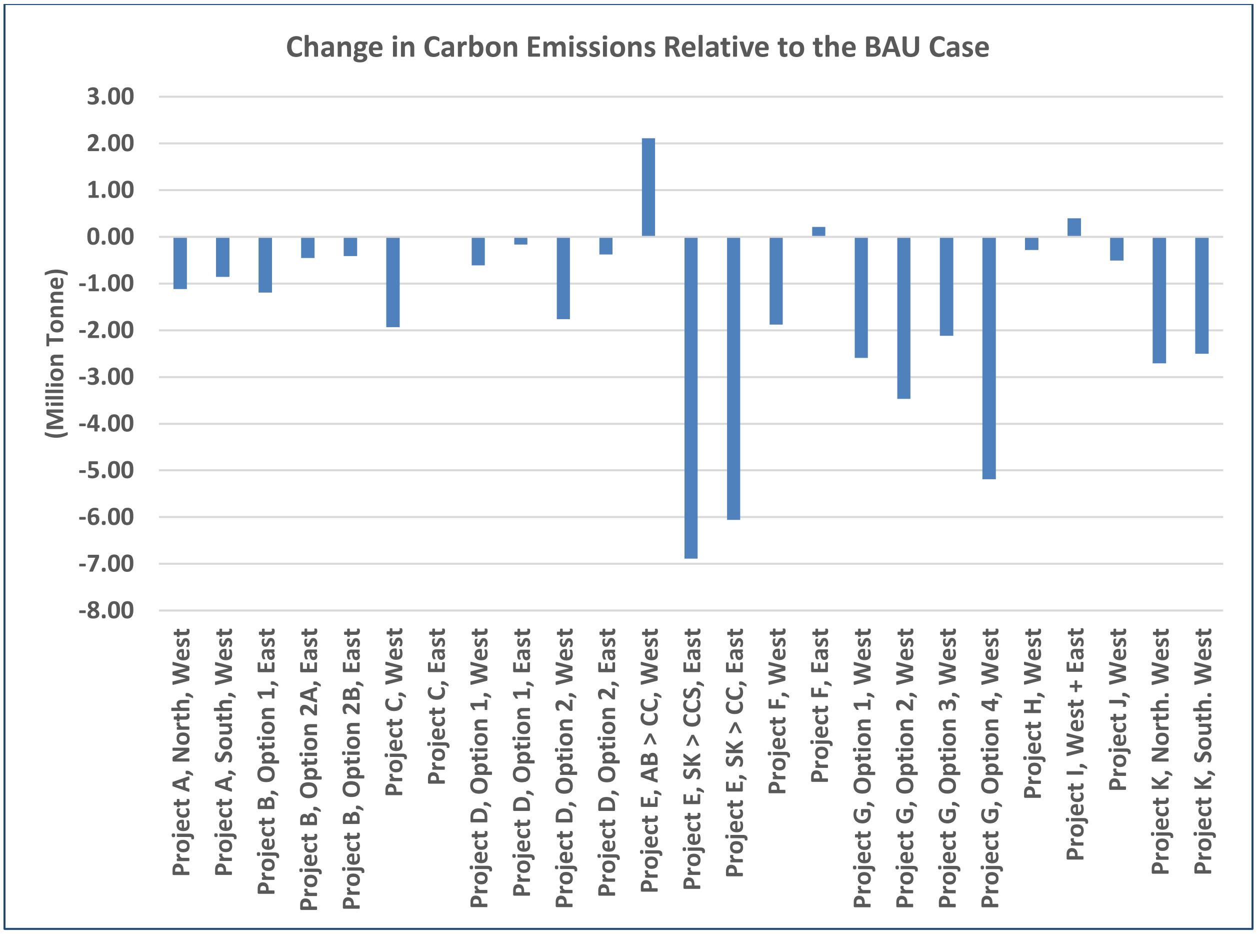


Figure 7-1: Carbon Reduction by Each Project Relative to the BAU Case

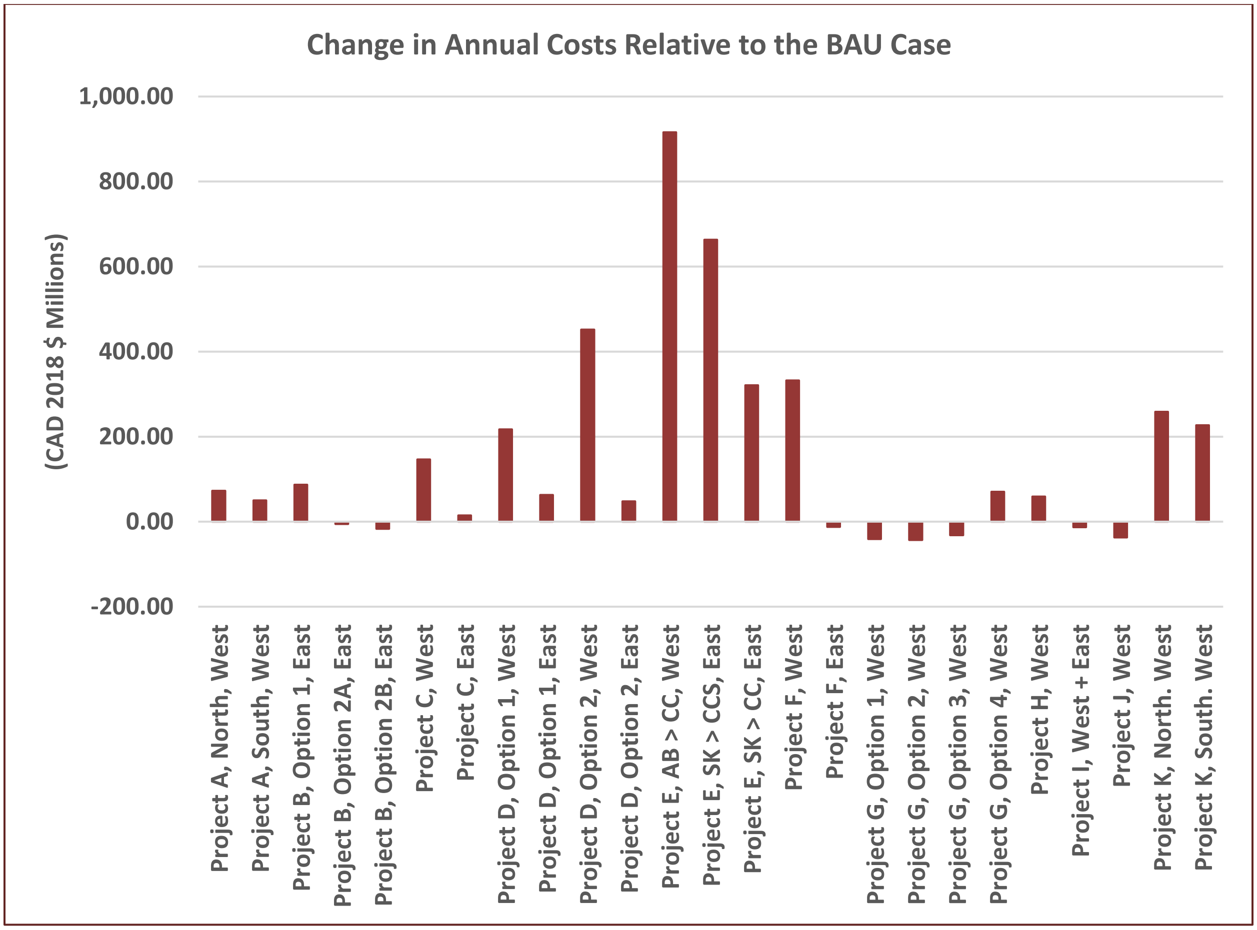


Figure 7-2: Change in Annual Costs by Each Project Relative to the BAU Case

7.2 Adjustments for Increase in Installed Reserve Margins

This study entailed employing a production cost simulation model and was not meant to be an integrated resource planning or a regional long-term transmission expansion planning study. All the study projects were compared to the BAU cases in the 2030 and 2040 study years. The BAU cases were balanced in each of those years, i.e., they included additional future generation resources that achieved target installed reserve margins in each province in each of those years. Some of the future generation resources were based on generation expansion plans provided by the TAC members. Any capacity shortfalls were covered by additional generic SC-GAS and CC-GAS units, as described in Section 3.

One issue in the evaluation of the study projects is the fact that installing additional new generation assets in a province (such as new wind, hydro, and energy storage resources), will result in raising the installed reserve margin in that province relative to the BAU case for its study year, and also relative to other provinces which do not have new additional generation.

To provide a level playing field and equalize the basis for the comparison of the study projects, an equivalent amount of generation should be uninstalled in that province, in order to restore the original target installed reserve margin. This will apply to projects where wind, hydro, or storage was added. For projects where new transmission was added, the adjustment depends on the availability of surplus capacity in the neighboring province for reserve sharing and the size of the added transmission transfer capability.

However, that level of precision would have required load and supply balancing to be performed separately for each project and option, followed by rerunning all the projects, and then accounting for all the resulting changes in both operational costs and investment costs. That exercise was beyond the scope and timeline of this project and is more akin to an integrated resource planning exercise.

Consequently, a simple adjustment can be made to account for the capital cost savings to keep the installed reserve margin unchanged (i.e., by uninstalling generation units from the original expansion plan), and accounting for the forgone capital cost of the uninstalled plants in our analysis. This simple adjustment ignores impacts to variable production costs which uninstalling the generation units may have.

The adjustment is based on estimating the capital cost of the capacity that is displaced by the additional wind, hydro, and energy storage assets. The simple methodology is to assume that the new additional assets would displace peaking capacity equal to the “capacity value” of the new assets. To create a level playing field for comparison of the study projects, the capital costs of those study projects which included new generation, can be reduced by the estimated cost of the peaking capacity (i.e. a SC-GAS unit) that would have been displaced in the generation expansion process.

The proposed methodology is to subtract capital cost of an amount of gas peaking capacity equivalent to the capacity value of new renewable additions. For the cost adjustments, the following approximate capacity values were assumed: Wind: 11%, Hydro: 67%, Storage: 50%. Roundtrip efficiency assumptions for energy storage were: Compressed Air Energy Storage (CAES): 77%, Battery Energy Storage Systems (BESS): 90%.

For Project B, where new transmission additions between Saskatchewan and Manitoba are considered, adjustment to capital costs were made to reflect the capacity reserve sharing between Saskatchewan and Manitoba. The key considerations were:

- Manitoba has nearly 1000 MW of surplus generation capacity above its reserve margin in 2030, of which the majority is uncommitted to other jurisdictions
- From 2016 to 2030, Saskatchewan adds over 600 MW of CC-GAS that could be offset with Manitoba's capacity surplus.
- Manitoba's surplus in 2030 could defer Saskatchewan's planned CC-GAS buildout until load growth in either province requires additional generation. However, without additional transmission to Saskatchewan, most of Manitoba's surplus capacity cannot substitute for the required capacity in Saskatchewan.
- The existing MB-SK southern interface has 250 MW of capacity in the MB-to-SK direction that could be used to offset SK's capacity buildout in both the BAU and Project B cases. Therefore, the "reserve margin adjustment" attributable to Project B could account for the remaining 350 MW of CC-Gas buildout, subject to the transmission capacity addition (100 MW limit in Project B 2B).

To estimate SK's CC-GAS additions, data from Section 4 (Business-As-Usual Case) was considered. Table 4-10 has the 2016 values (677 MW of CC-Gas), Table 4-11 has total 2030 capacity in SK (7183 MW), and Figure 4-42 has the CC-Gas percent in 2030 (18%). Combining this, the 2016-2030 CC-GAS additions Saskatchewan is approximately 616 MW (7183 x 0.18 – 677).

To determine the dollar value of the capital cost reduction, a capital cost of $1500/kW of new SC-GAS was assumed (this is a conservative assumption for the Project B adjustments, since the capacity that would be replaced are CC-GAS).

Table 7-3 provides the assumptions for the capital cost adjustments of the relevant projects. Using this methodology, the project evaluation metrics were adjusted in Table 7-4.

Table 7-3: Capital Cost Adjustments

Project	Added Wind (MW)	Wind Capacity Value (%)	Added Hydro (MW)	Hydro Capacity Value (%)	Added Storage (MW)	Storage[1] Capacity Value (%)	Trans-mission Capacity Transfer (MW)	Equivalent SC-GAS Capacity[2] (MW)	Capital Cost Reduction (MM)
	A	B	C	D	E	F	G	H	I
C	2400	11	0	67	0	100	0	264	396
D1, AB	0	11	500	67	0	100	0	335	503
D1, SK	0	11	50	67	0	100	0	34	50
D2, AB	0	11	1000	67	0	100	0	670	1005
D2, SK	0	11	50	67	0	100	0	34	50
F AB (CAES)	2400	11	0	67	1500	100	0	1764	2646
F SK (BESS)	0	11	0	67	400	90	0	180	270
H	0	11	115	67	0	100	0	77	116
K	2400	11	0	67	0	100	0	264	396
B 1	0	11	0	67	0	100	350	350	525
B 2A	0	11	0	67	0	100	350	350	525
B 2B	0	11	0	67	0	100	100	100	150

Notes:

[1]Formulae for calculation of values in columns H and I are:

H = (A x B) + (C x D) + (E x F) + G

I = H x 1000 x 1500 / 1000,000

Where Overnight cost for SC-GAS is assumed to be $1500/kW.

[2] Capacity value of compressed air energy storage (CAES) is assumed to be 100%, since the assumed 77% roundtrip efficiency applies to the portion of charged MWh energy that is available for discharge, but it does not affect the MW discharge capacity. Hence, a CAES plant with a discharge capacity of 1 MW (and roundtrip efficiency of 77%) is equivalent to and can displace 1 MW of SC-GAS plant.

Table 7-4: Adjusted Project Evaluation Metrics

Study Projects	Net Annual Cost Change Increase: Positive Decrease: Negative ($Million)	Carbon Emissions Change Increase: Positive Decrease: Negative (Million Metric Tonne)	[Net Annual Cost Change] per Unit of [Change in Carbon Emissions] ($/Tonne)
Project A, North, West	72.36	-1.12	-64.61
Project A, South, West	49.97	-0.86	-58.11
Project B, Option 1, East	37.63	-1.19	-31.63
Project B, Option 2A, East	-55.29	-0.45	122.86
Project B, Option 2B, East	-31.09	-0.41	75.82
Project C, West	109.04	-1.93	-56.50
Project C, East	14.47	0.00	0.00
Project D, Option 1, West	181.48	-0.61	-295.81
Project D, Option 1, East	58.99	-0.16	-360.02
Project D, Option 2, West	380.39	-1.76	-215.70
Project D, Option 2, East	44.42	-0.37	-118.82
Project E, AB > CC, West	916.02	2.11	434.13
Project E, SK > CCS, East	663.34	-6.89	-96.28
Project E, SK > CC, East	321.01	-6.06	-52.97
Project F, West	82.34	-1.88	-43.80
Project F, East	-37.53	0.21	-178.73
Project G, Option 1, West	-41.15	-2.59	15.89
Project G, Option 2, West	-43.26	-3.47	12.47
Project G, Option 3, West	-32.03	-2.12	15.11
Project G, Option 4, West	70.25	-5.19	-13.54
Project H, West	50.63	-0.28	-178.59
Project I, West + East	-13.36	0.40	-33.39
Project J, West	-37.14	-0.51	72.82
Project K, North. West	220.99	-2.71	-81.55
Project K, South. West	189.72	-2.50	-75.89

Green:	Annual Costs Decreased and Carbon Emissions Decreased
Blue:	Annual Costs Increases and Carbon Emissions Decreased
Yellow:	Annual Costs Decreased and Carbon Emissions Increased
Red:	Annual Costs Increased and Carbon Emissions Increased

8 Regulatory Considerations

8.1 Background of the Task – Regulatory Considerations

A survey of regulatory considerations related to the study projects could help inform potential proponents' investment decisions, including Federal government, Provinces, and private investors. This section of the report identifies regulatory considerations for the projects under study. These could include variances across federal and/or provincial regulations related to projects falling under multiple jurisdictions. This report will not attempt to offer solutions to respective regulatory challenges faced by any level of government.

It is important to recognize that regulations are evolving and may change beyond the scope of this report, which may have an impact on the generation and transmission infrastructure outlook of some Provinces.

8.2 Methodology

Regulatory considerations across jurisdictions in the study were surveyed by:

1. **Collecting input from the Technical Advisory Committee (TAC) members:** relevant information on provincial regulatory considerations within each province was collected from the TAC members. Additional information on federal and national regulations and policy directives was collected from NRCan.

2. **Consolidating input from TAC members:** after the receipt of regulatory considerations from individual TAC members, the Consultant consolidated the various input into one report. The Consultant analyzed the various inputs, complemented the information by performing additional research, and synthesized key regulatory considerations in a final draft report.

3. **Validating and summarizing input from TAC members:** the final draft report was shared with TAC members and discussed in follow-up conversations. The final document was completed in alignment with TAC members which includes, key messages, content and structure of section 6 of this report.

The following sections will detail the results of the analysis. Section 6.3 provides a high-level overview of federal and provincial regulatory considerations. Section 6.4 provides a synthesis of regulatory considerations across projects and jurisdictions.

8.3 Overview of Federal and Provincial Regulatory Landscape

This analysis summarizes Federal and Provincial regulatory considerations that could pertain to the projects under study. It is important to recognize that regulations are evolving and may change beyond the scope of this report, which may have an impact on the generation and transmission infrastructure outlook of some Provinces.

8.3.1 Overview of Federal Regulatory Landscape

a) Canada's policy direction to meet Paris Accord

In December 2016, the federal government released the *Pan-Canadian Framework on Clean Growth and Climate Change* (the Framework). The Framework is based on four "pillars": (1) carbon pricing; (2) complementary action to reduce emissions across the economy; (3) adaptation measures; and (4) actions to accelerate innovation, support clean technology, and create jobs.

Central to the Framework is the carbon pricing program, which requires all Canadian jurisdictions to have carbon pricing in effect by 2018. Provinces and territories remain free to choose whether to implement a carbon tax or a cap-and-trade system, as long as they meet the minimum federal pricing and emissions reduction targets. For jurisdictions that do not implement a carbon tax or cap-and-trade system by 2018, or that do not meet the federal pricing and emissions reduction minimums, the federal government will provide a mandatory pricing system, expected to start at a minimum of $20 per tonne in 2019 escalating to $50 per tonne in 2022. For jurisdictions with explicit price-based systems, carbon pricing is to start at a minimum of $10 per tonne in 2018, rising by $10 a year to reach $50 per tonne in 2022. Additional details on this pricing system are currently under development by the Government of Canada.

Additional key commitments under the Framework include a full phase out of conventional coal-fired generation by 2030[24], developing increasingly stringent building codes starting in 2020, developing a clean fuel standard based on a full life-cycle analysis, continuing the phase down of hydrofluorocarbons (HFCs), implementing methane regulations with the goal of reducing methane emissions by 40-45% by 2025, and reducing federal government GHG emissions by 40% below 2005 levels by 2030 or sooner. The federal government intends to meet its own emissions reduction targets by cutting emissions from government buildings and fleets, scaling up clean procurement, and modernizing the government's current

[24] http://gazette.gc.ca/rp-pr/p1/2018/2018-02-17/html/reg3-eng.html

procurement criteria to address GHG sources embedded in many economic sectors supply chain.

The Canadian Environmental Protection Act, 1999 provides enabling legislation for the federal government to address the pillars of the Pan-Canadian Framework on Clean Growth and Climate Change. More details on the regulatory efforts are described below.

b) Proposed amendments to regulations to limit carbon dioxide emissions from coal-fired generation of electricity

A key federal regulatory measure supporting the Framework is the regulation of conventional coal-fired electricity generation. Effective July 1, 2015, the *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations* [25] (SOR/2012-167) came into force under *the Canadian Environmental Protection Act, 1999*. The current regulation sets a stringent performance standard for new coal-fired electricity generation units and those that have reached the end of their useful life. The level of the performance standard is fixed at 420 tonne of carbon dioxide per gigawatt hour (CO2/GWh).

The proposed amendment, *Regulations Amending the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*, to the regulation accelerate compliance with the same performance. Compliance with these regulations will be required by 2030, effectively phasing out the use of conventional coal-fired generation in Canada.

This approach will implement a permanent shift to lower- or non-emitting types of generation, supply options, such as high-efficiency natural gas, nuclear, renewable, or fossil fuel-fired power with carbon capture and storage (CCS).

c) Proposed regulations to limit carbon dioxide emissions intensities from natural gas-fired generation of electricity

The objectives of the proposed regulation, as reported in the February 17, 2018 Canada Gazette [26], is to ensure new and converted natural gas-fired electricity units would be subject to achievable emissions performance standards.

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[25] Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations (SOR/2012-167): http://laws-lois.justice.gc.ca/eng/regulations/SOR-2012-167/FullText.html

[26] http://gazette.gc.ca/rp-pr/p1/2018/2018-02-17/html/reg4-eng.html

The new regulations would impose CO2 emission intensity-based performance standards on new and significantly modified natural gas-fired electricity generating units, including combustion engines and boiler units. Key requirements include:

- Performance standards of 420 t CO_2/GWh will apply for large new (or significantly modified) combustion units (>150 MW) built two years after the adoption of these regulations;
- Performance standards of 550 t CO_2/GWh will apply for smaller, new (or significantly modified) combustion units (>25 MW and <150 MW, built two years after the adoption of these regulations;
- Performance standards of 420 t CO_2/GWh will apply for new natural gas boiler units (>25 MW) built after the adoption of these regulations; and,
- Performance standards for modified boiler units converted from coal to natural gas will be based on emissions performance tests. The results of the emissions performance tests will determine the year the performance requirement of 420 t CO_2/GWh would apply.

For full criteria and performance requirements, review the full Canada Gazette notice on *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*[27]. ECCC will consult with stakeholders in 2018 with the intent to publish final regulations at the end of 2018. New regulations are expected to come into force in 2020.

It is important to note that these performance standards will allow the construction of new fossil fuel generation; however, any size facility that emits more than a target carbon intensity (still to be confirmed in 2018) will be subject to a carbon price applied to the portion of industry emissions that exceeds this performance requirement.

d) Equivalency agreements with provinces to allow them to meet or improve federal emission requirements over time

As recognized in Order Declaring that the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations Do Not Apply in Nova Scotia (SOR/2014-265) provinces can negotiate with the federal government an alternate method to achieving equivalent carbon dioxide reductions.

Some provinces and the federal government are currently in negotiations to meet the appropriate level of environmental outcomes.

[27] http://gazette.gc.ca/rp-pr/p1/2018/2018-02-17/html/reg4-eng.html

e) Federal backstop to carbon pricing

To meet the commitment for pricing carbon pollution across the country by 2018, the federal government published a benchmark to ensure a broad set of emissions will be covered throughout Canada by 2018. The benchmark allows for provinces and territories flexibility to implement their own carbon pricing systems. To ensure compliance, the federal government committed to implementing a federal backstop to provincial efforts to implement measures to price carbon pollution.

A proposal was released outlining the government's latest efforts - http://www.fin.gc.ca/drleg-apl/2018/ggpp-tpcges-eng.asp

f) Overhaul of federal environmental review and assessment processes

The current government committed to review both the National Energy Board and the federal environmental assessment processes to, respectively, ensure regional views are reflected, sufficient expertise exists and to regain public trust and introduce new, fair processes. Until new legislation or processes receive Royal Assent, it is uncertain how this might impact building new electricity infrastructure.

Under present regulatory regimes, both large transmission lines and fossil fuel-fired electoral generating facilities are subject to federal environmental assessment reviews. The length of a transmission line and the voltage determine the type of approval processes required. From a federal perspective, the construction of a new electrical transmission line with a voltage of 345 kV or more that requires a total of 75 km or more of new right-of-way is a "designated project" pursuant to Section 39 of the Regulations Designating Physical Activities (SOR/2012-147) under the Canadian Environmental Assessment Act 2012 (S.C. 2012, c. 19, s. 52). Transmission lines less than these criteria thresholds are addressed through provincial processes; however, any project located on certain sensitive or protected lands, as well as projects that could impact aspects of aboriginal peoples' rights in Canada. are subject to review by the federal government. The Canadian Environmental Assessment Act 2012 is currently administered by the Canadian Environmental Assessment (CEA) Agency.

While the National Energy Board Act (R.S.C., 1985, c. N-7) has jurisdiction over International powerlines, it also has jurisdiction over "designated" inter-provincial power lines, by determination of the federal Cabinet. However, since this was introduced in 1990, no such line has ever been designated and regulatory approvals are currently carried out by provincial processes. The National Energy Board Act is administered by the National Energy

Board (NEB), who would also administer the Canadian Environmental Assessment Act 2012 requirements for a designated inter-provincial power line [28,29].

Bill C-69, *An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to Amend the Navigation Protection Act and to make consequential amendments to other Acts*, was introduced into Parliament on February 8, 2018. This proposed act will replace the Canadian Environmental Assessment Act, 2012 with the *Impact Assessment Act* [30]. According to the federal government, the new act, and responsible Impact Assessment Agency, will provide greater clarity and consistency to all federal reviews of major projects. Bill C-69 also proposes to replace the *National Energy Board Act*, and National Energy Board, with the *Canadian Regulator Act* [31], and Canadian Energy Regulator. The new regulator would provide more clarity on expectations to project proponents and provide a more open, inclusive and transparent process for public engagement. Debate on Bill C-69 will occur in 2018 and could undergo changes before receiving Royal Assent. Nonetheless it is expected that these changes will require longer project planning phases for large projects in Canada, to better incorporate aboriginal people's rights, traditions and treaties as well as to ensure public confidence in the federal governments processes.

8.3.2 Overview of Provincial Regulatory Landscape

This section reviews the regulatory landscape across the regions included in the study: British Columbia, Alberta, Saskatchewan, Manitoba, and Northwest Territories.

8.3.2.1 British Columbia Regulatory Landscape

Description of the British Columbia Certificate of Public Convenience and Necessity (CPCN) process:

Extensions to public utility systems, including transmission lines, require approval from the BC Utilities Commission (BCUC) in the form of a Certificate of Public Convenience and

[28] Government of Canada, A proposed new impact assessment system:
https://www.canada.ca/en/services/environment/conservation/assessments/environmental-reviews/environmental-assessment-processes.html

[29] Government of Canada, A new Canadian Energy Regulator:
https://www.canada.ca/en/services/environment/conservation/assessments/environmental-reviews/national-energy-board-modernization.html

[30] https://www.canada.ca/en/services/environment/conservation/assessments/environmental-reviews/environmental-assessment-processes.html

[31] https://www.canada.ca/en/services/environment/conservation/assessments/environmental-reviews/national-energy-board-modernization/cer-handbook.html

Necessity (CPCN), pursuant to Section 45(1) of the Utilities Commission Act (UCA). A public application for a CPCN must be made to the BCUC.

BC Hydro's Capital Project Filing Guidelines set out expenditure thresholds for projects that determine whether BC Hydro will file an application for a CPCN with the BCUC. The threshold for generation and transmission projects is $100 million. The BCUC can also direct the filings of CPCN application.

The 2015 Certificate of Public Convenience and Necessity Application Guidelines (http://www.bcuc.com/Documents/Guidelines/2015/DOC_25326_G-20-15_BCUC-2015-CPCN-Guidelines.pdf) issued by the BCUC set out the requirements for a CPCN application. Key elements include (1) project need, alternatives and justification and (2) First Nations consultation.

The application must demonstrate a need for the project and confirm the technical, economic and financial feasibility of the project, identifying assumptions, sources of data, and feasible alternatives considered. The application must also include a comparison of the costs, benefits and associated risks of the project and feasible alternatives, including estimates of the value of all the costs and benefits of each alternative or, where these costs and benefits are not quantifiable, identification of the cost area or benefit that cannot be quantified.

If the proponent is a Crown corporation (like BC Hydro), and if the project triggers the duty to consult with First Nations, then the BCUC has the obligation to assess the adequacy of Crown consultation with First Nations. Information to be provided in the application includes, for each potentially affected First Nation, a full record of consultation with the First Nation, and a description of how the specific issues or concerns raised by the First Nation were avoided, mitigated or otherwise accommodated, or an explanation of why no further action is required to address an issue or concern.

In considering an application for a CPCN, the BCUC may choose to hold a public hearing, either written or oral.

Option 1 and Option 3 modelled as part of Project J were exempted from CPCN requirements. Option 1 (Peace Region Electricity Supply project) received its exemption under s. 18 of British Columbia's Clean Energy Act provided it is brought into service by 2022. Option 3 received an exemption by way of a Ministerial order.

British Columbia Economic Regulatory Requirements:

Notable economic regulatory requirements to consider in British Columbia (BC) include the following:

- British Columbia Utilities Commission (BCUC), under the *Utilities Commission Act* and BC Hydro's *Capital Project Filing Guidelines*; and
- National Energy Board – Under *Nation Energy Board Act* – Part III- Construction and Operation of Power Lines, Sections 58.16 (issue certification) and 58.4 (designate interprovincial line requires certification)
- The *National Energy Board Act*, administered by the National Energy Board, has jurisdiction over "designated" inter-provincial power lines, as determined by federal Cabinet. As a result, transmission lines could be subject to NEB regulatory approval. However, to date no power line has been designated and regulatory approvals occur at the provincial level.

British Columbia Environmental Regulatory Requirements:

Notable environmental regulatory requirements to consider in British Columbia (BC) include the following:

- BC Environmental Assessment Office (BCEAO) - under Reviewable Project Regulation Part 4 – Energy Projects, Table 7 Electricity Projects Criteria Columns 1-3 [32]
- The Canadian Environmental Assessment Act (CEAA) defines a designated project as the construction of a new electrical transmission line with a voltage of 345 kV or more that requires a total of 75 km or more of new right-of-way.
- According to the criteria, this requirement would be triggered if the transmission line project involves a 500-kilovolt line, which in this context would be relevant only to projects electrifying LNG loads on the North Coast and not to the electrification projects in North and South Montney.
- In addition to provincial environmental approvals, Federal approval under the Canadian Environmental Assessment Act may be required.

British Columbia Stakeholder Engagement Requirements:

Notable environmental regulatory requirements to consider in British Columbia (BC) include the following engagement requirements:

- No standalone engagement regulation, however, engagement and consultation form part of other regulatory requirements listed above.
- A northern intertie option would require a new route and right-of-way. Deeper engagement with Indigenous communities may be required for this option relative to

[32] *Environmental Assessment Act* has an-opt in provision -- a project could be designated reviewable by Minister under section 6 or the Executive Director under section 7.

southern intertie option, which uses an existing right-of-way.

8.3.2.2 Alberta Regulatory Landscape

For all projects that fall under Alberta's jurisdiction there are a number of notable regulatory requirements (including regulatory, environmental and stakeholder engagement requirements).

Alberta regulatory requirements:

- **Competitive Procurement Processes required:** The person eligible to apply for the construction and operation of a new non-merchant intertie must be determined by the AESO through a competitive procurement process.
- **Alberta Utilities Commission approvals required:** The AESO must present technical solutions (and alternatives) to meet an identified need for proposed transmission development, typically by way of a needs identification document or "NID" application that the AESO is required to submit for approval to the Alberta Utilities Commission (AUC). A NID application may be challenged through a regulatory proceeding on public interest and technical deficiency grounds. Approvals from the AUC must also be obtained by the person eligible to construct, own and operate a proposed transmission development.
- **Fair, Efficient and Openly Competitive Market:** Alberta's deregulated electricity market is intended to provide an efficient market for electricity based on fair and open competition, in which neither the market nor the structure of the Alberta electric industry is distorted by unfair advantages of government-owned participants or any other participant. This includes extra-provincial market participants. Building an additional tie with Alberta may be a concern for generation that operates internally within Alberta.
- **Lack of regulatory clarity on treatment of energy storage facility:** The existing legislative framework in Alberta appears to support the treatment of energy storage as a market participant that alternately supplies electric energy to the transmission system (similar to a generator) or withdraws it (similar to load). However, the AESO considers that its existing tariff structure may need to be modified to adequately address the characteristics of energy storage that operates as part of the deregulated market. Legislative revisions would likely be required to support the use of energy storage as a regulated transmission asset.
- **Obligation to restore existing interties in Alberta**: The AESO is legislatively obliged to restore existing interties to their path rating. Capital costs of the required facilities to achieve the intertie restoration, and the recovery of those costs will be a relevant

consideration for this project given its funding source may be different than current mechanisms for cost recovery under the AESO's Tariff.

Specific regulatory requirements applicable to three of the projects under study include the following:

1- Restoring existing tie with British Columbia (BC)

The regulatory process for the restoration of the existing non-merchant tie with BC is already well established and is part of the AESO's current mandate:

- The AESO prepares a NID Application describing the need for transmission development, including associated benefits, cost and options etc. and files it with the AUC for approval.
- The construction and operation of the intertie restoration project is then directly assigned by the AESO to a regulated Transmission Facility Owner (TFO), which is AltaLink in this case. The TFO files and obtains approval from the AUC to construct and operate the intertie restoration project.
- Under the current cost recovery mechanism, the costs of restoring the tie would be recoverable through the AESO's tariff. Most of the costs are on the Alberta side but a small portion could be on the BC side. Subject to approval from the AUC, the costs on the BC side associated with restoring the tie could be included and recovered though the AESO's tariff.
- The same process would be applied to internal transmission expansions or upgrades that may be required to accommodate renewables.

2- Building new ties

There are several options for building new ties and they will take considerably longer to develop and implement.

- A new merchant tie could be proposed by a project proponent, similar to the existing Montana/Alberta (MATL) tie line. MATL is treated as a generator at the border. The AESO would be required to file and obtain approval of a NID application with the AUC. The entities eligible to construct, own and operate the new intertie facilities would also be required to obtain approval to construct and operate from the AUC.
- The AESO could also propose a new non-merchant intertie for system reliability reasons, in which case, as noted above, the person eligible to construct, own and

operate the tie would be determined by the AESO through a competitive procurement process. Approval of a NID application, as well as associated approvals to construct and operate, would be required from the AUC.

3- New hydro and storage assets

The AESO is currently executing the first round of procurement under the Renewables Energy Program (REP) to meet the 30% energy renewables goal as per the provincial leadership plan. A possible option is to consider a carve out for renewable technologies as they cannot compete on a levelized cost of energy basis, but they offer other significant benefits to the grid.

Bulk Storage is a hybrid option and the concept of energy storage was not considered when the current legislative framework for electricity (including the *Electric Utilities Act* and associated regulations) was developed.

Today, the AESO plans for the transmission system to serve load and connect generation but does not dictate where load and generation will develop. In the 2013 report[33] to the Alberta legislative assembly, the committee made two key recommendations for hydro: (1) consider long-term power purchase agreements; and (2) consider public-private partnerships.

Alberta environmental requirements:

- **Normal course for environmental approvals** from Alberta Environment and Parks under Water Act, Wildlife Act, Historical Resources Act, and Environmental Protection and Enhancement Act. There are no specific regulatory considerations known at this time, but hydro development can be more difficult to site and permit.

Alberta stakeholder engagement requirements:

- **Bill passage in Alberta Legislature required for new hydro developments:** Approvals of new hydro developments are subject to a Bill passing through the Legislature and gaining Royal Assent prior to Alberta Utilities Commission approval to construct and operate.

[33] Link to report:

http://www.assembly.ab.ca/committees/resourcestewardship/HP/Reports/2013/Review%20of%20the%20Potential%20for%20Expanded%20Hydroelectric%20Energy%20Production%20in%20Northern%20Alberta%20-%20RS%20March%202013.pdf

- **Election by intertie proponent to seek a certificate or a permit before the National Energy Board:** Uncertain regulatory process. Certificate requires a public hearing, while a permit may be issued without a hearing. Either option requires provincial approvals from the Alberta Utilities Commission.
- **Time limits on proposed intertie and hydro developments:** 15 months under NEB rules, 3-month extension with Ministerial approval. 180 days under AUC rules, with 90-day extension. Further extensions require Ministerial approval.

8.3.2.3 Saskatchewan Regulatory Landscape

Below are Saskatchewan's required approvals for transmission related projects at the 230+ kV voltage level. Each step has an established application and approval process. Additional mitigations may be required depending on the complexity or impact of the project. This could result in increased scope, cost, and/or schedule.

Saskatchewan Regulatory Approvals:

- Submission to Ministry of Environment (MoE) SK, Environment Assessment and Stewardship branch.
    - Any project determined to be a Development will be required to undertake an Environmental Impact Assessment (EIA) and the Minister of the Environment will make a Decision. Such a Decision can carry conditions. A project which receives a Determination that it is not a Development can also be subjected to certain environmental conditions. Additional provincial environmental legislation may apply in certain circumstances (i.e. if water supply is impacted or if tree clearing on crown land is required).
- Aquatic Habitat Protection Permit from Fish Wildlife and Lands Branch in MoE.
- Crown Clearance from Fish Wildlife and Lands Branch in MoE SK.
- Approval / Easement from Ministry of Agriculture (MoA) for access and construction operations on agricultural Crown lands.
- Approval of Heritage Resource Impact Assessment (HRIA) from Ministry of Parks, Culture and Support.
- There are additional approval(s) required if the transmission line is built on Federal land.
- For tie line projects, there is the possibility of having to apply to the National Energy Board (NEB) for approval. More clarity is needed of NEB applicability on inter-provincial lines. However, it is realistic to assume that large (i.e., long, high voltage) interprovincial transmission projects would require significant time for planning and

engagement with communities and First Nations, and due to the number of lands that could potentially be crossed, a federal environmental assessment may be needed, other than that no other unusual or exceptional approvals would be likely.

Saskatchewan Stakeholder Engagement Requirements:

All major projects involving SaskPower require stakeholder engagement to consult and inform directly and indirectly affected parties. These aspects may include:

- Agreement on the tie point with other utility
- Project specific details discussed with directly and indirectly affected entities such as MoE, MoA, RMs, Towns, Landowners and others
- Duty to consult with indigenous groups
- Coordination for Distribution Line Crossings within SaskPower
- Easements / Expropriations

The routing and environmental process involves gathering input from directly and indirectly impacted stakeholders. The input collected is factored into the decision making and/or applications for the various approvals.

Saskatchewan Internal Governance:

All major projects involving SaskPower require internal approval by the SaskPower executive and Board. Depending on the complexity/cost of the project, further internal approvals maybe required by various levels of the shareholder (Minister Responsible for SaskPower, Crown Investments Corporations, Cabinet, etc.). For inter provincial transmission lines, these approvals are anticipated to be required.

Saskatchewan Approvals Timelines:

Once a corporate decision has been made to proceed with the project, 12-36 months are required to prepare the approvals submission documents. These documents include data gathering, routing, engagement, and assessment/writing tasks. The duration depends on the complexity of the project. Regulatory approval times will vary amongst projects and are dependent on a variety of factors.

8.3.2.4 Manitoba Regulatory Landscape

Manitoba Regulatory Acts and Requirements:

From a provincial perspective, the transmission project would be "development" pursuant to the Classes of Development Regulation (164/88) under The Environment Act (C.C.S.M. c. E125) (the "Act"). The construction of electrical transmission lines greater than 230 kV and associated facilities is considered a Class 3 Development and is subject to licensing under

Section 12 of the Act. Transmission lines 115 kV-230 kV are designated as Class 2 Developments. The Licensing Procedures Regulation of the Act (163/88) outlines information requirements for proposals under the Act. The primary difference between Class 2 and 3 Developments is the greater likelihood for a public hearing administered by the Clean Environment Commission with Class 3 Developments. The Act is administered by the Environmental Approvals Branch of Manitoba Sustainable Development.

Provincial and federal governments are also required to consult with Indigenous people during project approvals under Section 35 of the Constitution Act, 1982, which provides constitutional protection to the Aboriginal and treaty rights of Aboriginal peoples in Canada.

In addition to the above, there are a variety of provincial (and sometimes) federal permits to acquire to conduct certain activities in certain areas (e.g., timber harvest on crown lands, establishing a borrow site, etc.).

Manitoba Hydro, as a Crown Corporation of the province of Manitoba, may be subject to an external review and assessment directed by the Government of Manitoba of its development plan for major new hydro-electric generation projects and interconnection facilities. Previously, the Government of Manitoba directed such a review, which it assigned to the Public Utilities Board of Manitoba (the "PUB") under the PUB's statutory authority to perform duties assigned to it by the Lieutenant Governor in Council of Manitoba. There is no established threshold for the size of the project which would trigger such a review.

Manitoba Data Requirements:

Data requirements include information on the project design, environment, socioeconomics and people in a defined study area that supports the transmission line routing and environmental assessment processes.

Manitoba Hydro's transmission line routing process involves a standard, transparent, multi-phase GIS-based decision-making approach that incorporates feedback from stakeholders at key milestones. It incorporates the consideration of the environment, opportunities and constraints for transmission line development, and the interests and concerns that influence the use of the land or could be affected by the route. In addition to characterizing the region through field studies and data gathering the process involves a structured multi-step process to select a mutually appropriate border crossing where applicable.

The environmental assessment process requires a structured analysis of the interactions among the various project components and environmental/socioeconomic components and the application of mitigation where necessary to manage potential adverse effects. It includes the development of an environmental protection program that addresses monitoring and management requirements through construction and into operation for some elements.

The routing and environmental assessment is documented in either and Environmental Assessment (EA) Report for a Class 2 provincial development, or a more detailed, comprehensive Environmental Impact Statement (EIS) for a federal designated project and/or a Class 3 provincial development.

Manitoba Stakeholder Input:

The routing and environmental process involves several rounds of input from the public and Indigenous communities and organizations at key milestones, to support decisions on border crossings, alternate routes, and the preferred route. This information and how it influenced the project is provided in the EA or EIS.

Once the EA Report or EIS is finalized it is filed on a public registry and undergoes a public/regulatory review. Manitoba Hydro may be required to respond to several rounds of questions from the public and regulators, until the regulator determines that the information is adequate.

In a provincially-led class 3 process the province may ask the Clean Environment Commission (CEC) to facilitate a public hearing, and Manitoba Hydro provides funding for participants (and CEC) to review the EIS. Manitoba Hydro then responds to several rounds of questions from the public and CEC, and then participants and Manitoba Hydro take turns presenting and questioning each other at the hearing. The CEC then develops recommendations for the province in terms of licensing the project.

Should the federal process be triggered the CEA Agency (or NEB) may use the output of the CEC public hearing to develop its own Environmental Assessment Report, in conjunction with a recommendation to the federal Minister of Environment. There is also the potential that CEA and or NEB may determine an additional public hearing process is required.

In the Class 2 provincial process the next step is the issuance of a license, with conditions, after the crown has conducted the Section 35 Aboriginal Consultation process, summarized separately and approved by provincial cabinet. This is also the case for the class 3 provincial process – the province will not issue the license following the CEC recommendation until the Section 35 process has concluded.

For the federal process, the Section 35 consultation is included in the federal EA Report, and undergoes a review by participating Indigenous communities/organizations before being finalized. The public has an opportunity to comment on the final report while the Minister of Environment is considering the recommendation. Approvals occur through a Decision Statement with a series of conditions.

Manitoba Regulatory Approvals Criteria:

Regulatory approvals are generally based on the following criteria:

- Public and Indigenous communities and organizations have been adequately engaged and relevant concerns addressed;
- All relevant interactions between the project and environment/ socioeconomic components have been adequately assessed;
- Potential adverse effects have been adequately dealt with, including mitigation where necessary;
- Appropriate monitoring and follow-up management plans have been developed; and
- Aboriginal and treaty rights have been adequately addressed.

Manitoba Approvals Timelines:

Once a corporate decision has been made to proceed with the project anywhere from 12-36 months are required to prepare the approvals submission document, including data gathering, routing, engagement, and assessment/writing tasks. The duration depends on the complexity of the project. Regulatory approval times will vary amongst projects and are dependent on a variety of factors.

Manitoba Financial Considerations:

As noted above, the construction of new interconnections may be subject to an external review and assessment directed by the Government of Manitoba. There is no established threshold which would trigger such a review. The relative costs and benefits associated with a new interconnection and any associated long-term power exchange agreements will determine how Manitoba Hydro would approach the financing of the construction, operation and maintenance of such an interconnection.

8.3.2.5 Northwest Territories Regulatory Landscape

Northwest Territories Regulatory Requirements:

Legislative jurisdiction for an environmental assessment (EA) for the project would fall under the Mackenzie Valley Resource Management Act[34] (MVRMA) and the EA would be executed by the Mackenzie Valley Environmental Impact Review Board (MVEIRB). Section 141 (1) of the MVRMA specifies that the MVEIRB will coordinate its EA functions with the appropriate regulatory authority responsible for EA's in the Province of Alberta.

If the project was referred to an Environmental Impact Review due to significant public concern or environmental impacts, section 141 (2) of the MVRMA notes that the MVEIRB would enter into an agreement with CEAA to form a joint review panel for the project.

[34] https://laws-lois.justice.gc.ca/eng/acts/m-0.2/

At the end of the EA process, the regulatory process issues Land Use Permits and Water Licenses which will be conducted by the Mackenzie Valley Land and Water Board. They will hold a public hearing(s) to get stakeholders' input before issuing the approvals to construct the project.

For regulatory requirements under the Public Utilities Act (PUA), section 2.1 (2) specifies that the PUA does not apply to the supply and sale generated by the Twin Gorges Hydroelectric Facility on the Taltson River. The NWT Public Utilities Board is responsible to regulating the NWT's electricity rate base; however, the project would not be subject to PUB regulation due to the exemption outlined above and the project would not impact the NWT rate base since the project would be funded by sources outside the rate base.

The National Energy Board Act has jurisdiction over International power lines and jurisdiction over "designated" inter-provincial power lines, by determination of the Federal Cabinet. However, since this jurisdiction was introduced in 1990, no transmission line projects have been designated and regulatory approvals are currently carried out by territorial and provincial processes.

Territorial and federal governments are also required to consult with Indigenous people during project approvals under Section 35 of the Constitution Act, 1982, which provides constitutional protection to the Aboriginal and treaty rights of Aboriginal peoples in Canada.

Northwest Territories Data Requirements:

Data requirements include information on the project design, environment, socioeconomics and people in a defined study area that supports the transmission line routing and environmental assessment processes.

Design of the project would require consultations and input from NWT Aboriginal Governments, communities and First Nations far in advance of finalizing routing and filing regulatory applications to ensure their input is incorporated in the routing of the project. Environmental baseline programs would also be a key component in the data gathering process and would include: identifying areas of cultural and traditional land use, using traditional knowledge in project design, identifying areas of ecological and biological importance, etc.

Traditional methods and best practices for designing transmission lines will also be used. This would include GIS mapping, detailed engineering, field studies, ground truthing and other relevant information.

The EA and regulatory processes in the NWT are very transparent and inclusive with funding available to support intervener participation in the process which helps engage a wide range of stakeholders, which in turn, also contributes information and data to the project.

Northwest Territories Stakeholder Input:

The project will face several rounds of review and information requests from stakeholders that will include the public, Aboriginal Governments, First Nations, communities, government departments and other organizations.

Public Hearings will be required for the EA process as well as for Land Use Permitting/Water Licensing for the project. The hearings will be held in affected communities in the project area and will involve many stakeholders, including Aboriginal Governments, communities, First Nations, the public, non-government organizations and government departments.

Once the draft EA Report or EIR is completed, interveners have the chance to review the report and its recommendations and mitigation measures. The proponent and regulatory authorities also conduct a detailed review of the report's recommendations and additional information requests and discussions may have to occur before these can be finalized.

In the NWT, the federal government relies on the EA and regulatory processes for information in the event that Aboriginal Governments or First Nations bring forward an issue or claim related to Section 35 consultation. Depending on the nature and scope of the issue, the federal government may have to conduct additional consultations to work through and resolve the issues.

Northwest Territories Schedule:

If a decision is made to proceed with the project, a lead time of 12-36 months will be needed to prepare regulatory applications and all the work associated with the regulatory aspect of the project.

8.4 Summary of Regulatory Considerations

The variety of projects studied in this report require regulatory considerations and processes. General conclusions are not necessarily applicable and regulatory considerations are project specific.

There are nonetheless three general considerations that apply to inter-provincial projects which are worth highlighting.

1. Different provincial electricity infrastructure approval processes

Each jurisdiction involved in the Western RECSI study has their own respective electricity infrastructure approval process. Project proponents will require detailed knowledge of each respective jurisdiction to navigate approvals for construction and operation, which is similar to any cross-border development project.

2. Projects might require both Federal Provincial environmental assessments and consultations

The proposed *Impact Assessment Act* will include a defined project list. The intent of the new Act is to consolidate project impact assessments to allow for "one project – one assessment," but it is currently unclear which projects will fall under this regime. More clarity will come with the completion of the project list. This also applies to the consultation process. Currently, projects might require federal and provincial consultations with a variety of stakeholders. The proposed system will include more initial consultation and engagement to inform the impact assessment, and because of this, project planning timelines would be expected to be longer and structured so that engagement with stakeholders and First Nations would continue through the life of the project. This would mean ongoing communication through feasibility, construction, operation and maintenance activities over the life of the project; an aspect of project approval that is not well incorporated into many existing utilities.

3. Different provincial market structures

Each Canadian jurisdiction's market structure is shaped by their own provincial/territorial policies and their respective interactions with their neighbouring Canadian/U.S. markets. In North America, electricity markets are regional. Project proponents will need to understand how the different market structures interact.

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