GE
Energy Consulting

Pan-Canadian Wind Integration Study (PCWIS)

Final Report

Prepared for: Canadian Wind Energy Association (CanWEA)

Prepared by: GE Energy Consulting

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imagination at work

Legal Notices

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Technical Advisory Committee Members:

- Alberta Electric System Operator (AESO)
- BC Hydro
- Hydro Quebec
- Independent Electricity System Operator (IESO)
- ISO-New England (ISO-NE)
- Manitoba Hydro
- Midcontinent Independent System Operator (MISO)
- National Renewable Energy Laboratory (NREL)
- New York Independent System Operator (NYISO)
- SaskPower
- Utility Variable-Generation Integration Group (UVIG)
- Western Electricity Coordinating Council (WECC)

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Acronyms and Nomenclatures

Base Scenarios

5% BAU	5% Wind Penetration – Business-As-Usual
20% DISP	20% Dispersed Wind Penetration
20% CONC	20% Concentrated Wind Penetration
35% TRGT	35% Targeted Wind Penetration

Unit Types

CC-GAS	Combined Cycle Gas Turbine
COGEN	Cogeneration Plant
DPV	Distributed Photovoltaic
HYDRO	Hydropower / Hydroelectric plant
NUCLEAR	Nuclear Power Plant
OTHER	Includes Biomass, Waste-To-Energy, Etc.
PEAKER	SC-GAS and RE/IC
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 in PCWIS

AB	Alberta
BC	British Columbia
MB	Manitoba

NB	New Brunswick
ON	Ontario
QC	Quebec
MAR	Maritime
NL	Newfoundland and Labrador
NS	Nova Scotia
PE	Prince Edward Island
SK	Saskatchewan

USA Pools in PCWIS

BAS	Basin
CAL	California ISO
DSW	Desert Southwest
FRCC	Florida Reliability Coordinating Council
ISONE	ISO New England
MISO	Midcontinent ISO
NWP	Northwest Power Pool
NYISO	New York ISO
PJM	PJM Interconnection
RMP	Rocky Mountain Pool
SERC-E	SERC Reliability Corporation- East
SERC-N	SERC Reliability Corporation- North
SERC-S	SERC Reliability Corporation- South
SERC-W	SERC Reliability Corporation- West
SPP	Southwest Power Pool Regional Entity

General Glossary

AESO	Alberta Electric System Operator
BAA	Balancing Area Authority

Btu	British thermal unit
CanWEA	Canadian Wind Energy Association
CF	Capacity Factor
CO_2	Carbon Dioxide
DA	Day-Ahead
DNV GL	DNV GL Group
DPV	Distributed PV
DR	Demand Response
EI	Eastern Interconnection
ELCC	Effective Load Carrying Capability
EUE	Expected Un-served Energy
ERGIS	Eastern Renewable Generation Integration Study
EV	Electric Vehicle
EWITS	Eastern Wind Integration and Transmission Study
FERC	Federal Energy Regulatory Commission
FOM	Fixed Operations and Maintenance
GE	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
GT	Gas Turbine
GW	Gigawatt
GWh	Gigawatt Hour
HA	Hour-Ahead
HR	Heat Rate
IEC	International Electrotechnical Commission
IESO	Independent Electricity System Operator

IPP	Independent Power Producers
IRP	Integrated Resource Planning
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
lbs.	Pounds (British Imperial Mass Unit)
LDC	Load Duration Curve
LMP	Locational Marginal Prices
LNR	Load Net of Renewable Energy
LOLE	Loss of Load Expectation
MAE	Mean-Absolute Error
MMBtu	Millions of BTU
MMT	Million Metric Tons
MVA	Megavolt Ampere
MW	Megawatts
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation
NO_X	Nitrogen Oxides
NRCan	Natural Resources Canada
NREL	National Renewable Energy Laboratory
O&M	Operational & Maintenance
PCWIS	Pan-Canadian Wind Integration Study
PPA	Power Purchase Agreement
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standard
RT	Real-Time
RTEP	Regional Transmission Expansion Plan
SCUC	Security Constrained Unit Commitment
SCEC	Security Constrained Economic Dispatch

SO_2	Sulfur Dioxide
SO_X	Sulfur Oxides
ST	Steam Turbine
TW	Terawatts
TWh	Terawatt Hour
UTC	Coordinated Universal Time
VOC	Variable Operating Cost
VOM	Variable Operations and Maintenance
WECC	Western Electricity Coordinating Council
WI	Western Interconnection

1 Summary Report

1.1 Project Overview

The Pan-Canadian Wind Integration Study (PCWIS) was performed to assess the implications of integrating large amounts of wind in the Canadian electrical system: Specifically,

- To develop a consistent database of chronological wind data for potential wind sites across Canada
- To provide an improved understanding of the operational challenges and opportunities associated with high wind energy penetration in Canada, and
- To provide an improved understanding of the operational and production costs and benefits of high wind penetration in Canada.

This study aimed to develop an understanding of the operational implications of how variable wind energy resources would affect the existing and future electricity grid, and what environmental and economic costs and benefits may be associated with integrating large amounts of wind energy in Canada. System operators have a desire to understand how much wind energy can be reliably integrated onto the electricity grid and at what cost. Opportunities for greater penetration and more cost-effective integration are enhanced when these issues are considered on a regional or national basis. While the benefits of wind energy are widely known, the results of this study will help ensure that the benefits of wind energy are most efficiently realized.

Project Team

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 - Overall project leadership, production cost simulation and reliability analysis
- Vaisala - Wind profile and forecast data
- EnerNex - Wind plant data assembly and management, statistical analysis, regulation/reserve requirements
- Electranix - Transmission reinforcement design
- Knight Piésold - Canadian hydropower resource data and modeling

Figure 1-1 shows a flowchart of the major project tasks and indicates the team members who participated in each task. Several tasks also involve the project Technical Advisory Committee (TAC) review and feedback.

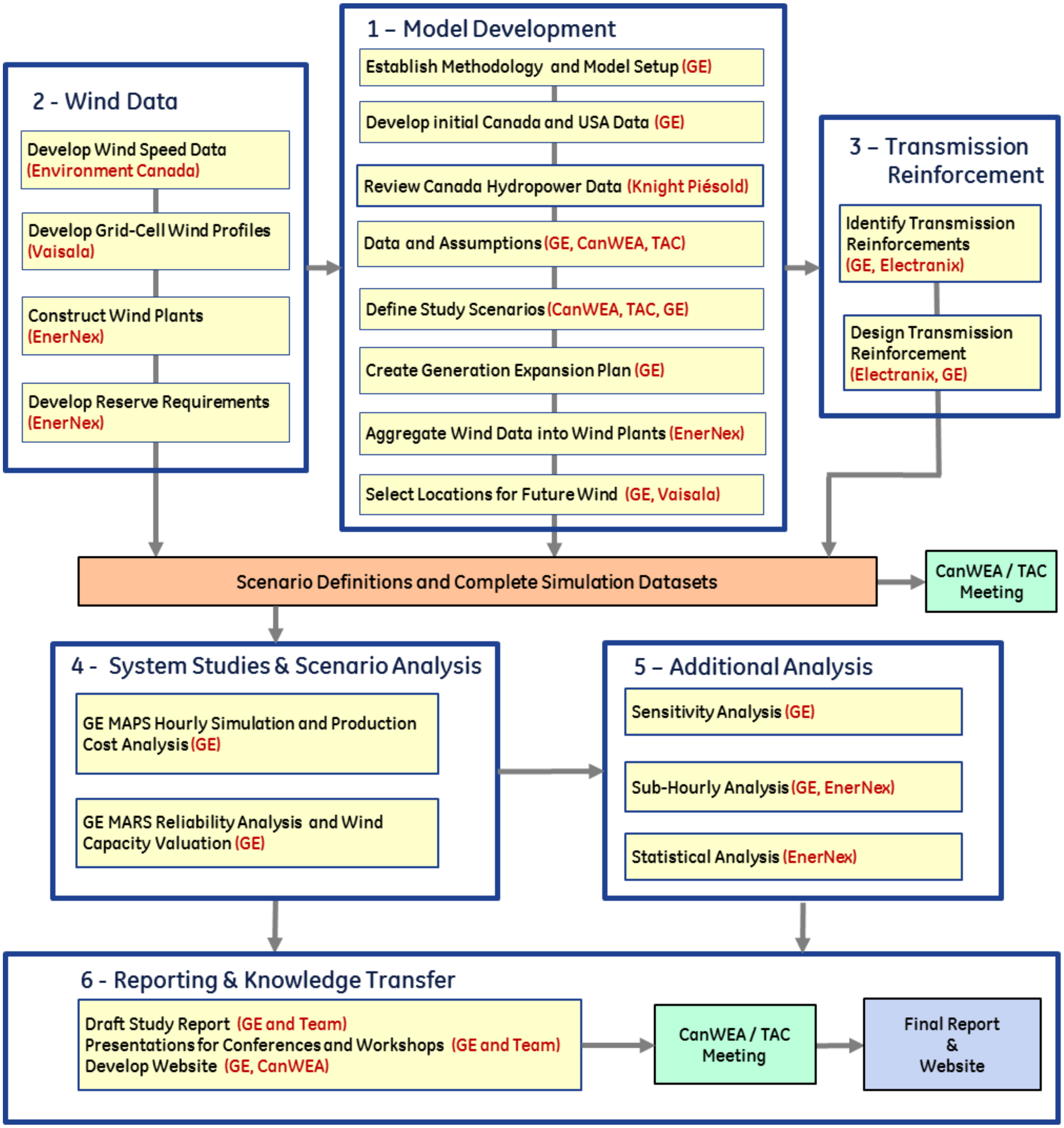


Figure 1-1: Flowchart of Project Tasks

Data Sources

This study used a combination of publicly available and confidential data to model the interconnected power grids covering the majority of Canada and the USA (Eastern

Interconnection, Western Interconnection, and Quebec). The hourly production simulation analysis was performed using GE's Concorda Suite Multi-Area Production Simulation (GE MAPS) model. In order to protect the proprietary interests of Canadian grid operators, the production simulation analysis was primarily based on publically available data, reviewed and in some cases modified by the grid operators to assure consistency with the operating characteristics of the provincial power grids and the power plants under their control.

Wind speed and meteorological data were provided by Environment and Climate Change Canada and were the basis for developing wind power profiles for both existing and future wind plants in Canada. This wind data set included 54,846 individual 2km square grid cells at 10-minute time intervals for 3 calendar years (2008 to 2010). Vaisala processed the grid-cell wind speed data into power output profiles by applying composite wind turbine power curves and also accounting for the effects of dynamic turbulence/wake losses, icing effects due to temperature and humidity[1], and turbine low-temperature cut-off[2]. EnerNex aggregated the grid-cells into a large number of wind plants across all Canadian provinces, ranging from 16 megawatts (MW) to 448 MW in capacity. GE then selected appropriate combinations of these wind plants to create the required simulation models for each of the study scenarios.

Wind plants in the USA were modeled using publically available wind profile data from the National Renewable Energy Laboratory (NREL).

Monetary Unit Used

The economic data and results are expressed in real 2016 Canadian dollars. The ("$") or (C$) symbols represent 2016 Canadian dollars in all text, tables and figures. The United States Dollar (USD) and Canadian Dollar (CAD) exchange rate was assumed to be 1USD:1.385CAD based on the market exchange rate as of January 1st 2016.

1.2 Novel Features of the PCWIS Project

The novel features of the PCWIS project include the following:

a) The geographic footprint of the study included all of Canada and 47 US states, covering 4 time zones from east to west. The size of the model and the massive

[1] Turbine power set to zero when relative humidity is above 88% and air temperature at 100 metre tower elevation is less than 0°C.

[2] Turbine power set to zero when air temperature at 100 metre tower elevation falls below -35°C. Restart when temperature rises to -30°C.

amount of data (generation, transmission, load profiles, wind profiles) posed new challenges of scale that exceeded previous wind integration studies.

b) This is the most northerly wind integration study, which required taking into account various wind loss components, including losses due to icing and low-temperature cut-out. New procedures were developed to calculate these losses from the meteorological weather and wind speed datasets.

c) The study utilized production cost analysis to determine economically justifiable levels of transmission reinforcement between balancing areas. Given the variable nature of the wind resources that require increased transmission capacity, this method balances the ratings (and therefore costs) of the reinforcements with their potential level of utilization.

1.3 Study Scenarios

The study considered four scenarios with wind penetration levels ranging from 5% to 35% of annual system load energy.

5% BAU	The 5% Business As Usual (BAU) reference case includes existing wind plants as well as new plants under construction as of 4/25/2015. This case serves as a benchmark for how grid operations will change as wind penetration increases.
20% DISP	The 20% Dispersed (DISP) wind resources, refers to 20% wind penetration in the study footprint and in each Canadian province. This scenario includes the sites in the 5% BAU scenario and selects the best additional sites within each province to achieve 20% of annual energy demand.
20% CONC	The 20% Concentrated (CONC) wind resources, is also a 20% wind penetration for the entire study footprint, which includes the sites in the 5% BAU scenario, but concentrates additional wind plants in regions with the highest capacity factor wind resources resulting in some provinces with more than 20% wind energy penetration and other provinces with less.
35% TRGT	The 35% TRGT scenario refers to wind resources concentrated in selected, or targeted, provinces (TRGT), with 35% wind penetration across Canada, targeting more wind plants in provinces with high thermal generation. This scenario builds on the 20% DISP scenario, with additional wind locations targeted to achieve thermal generation displacement and emissions reduction in Canada, subject to 25% minimum and 50% maximum limits of penetration in any given province.

The highest level of available wind penetration considered by the study was 35% of annual system electrical energy. The study could have considered higher penetration levels but 35% presented a reasonable final scenario for study and does not represent a technical limit on wind penetration. The 35% scenario considered the case where wind generation resources are installed in provinces where thermal generation can be reduced or where large hydro resources can operate flexibly and in concert with the wind generation to serve the energy needs of both Canada and the USA.

Figure 1-2 shows the geographic locations of the wind plants in the study scenarios. Table 1-1 summarizes the load and generation mix by type for each province, and nationally. The numbers highlighted in **bold** near the top of Table 1-1 show that the installed wind capacity in the two 20% scenarios is nearly the same. This is because the quality (capacity factor) of wind power resources is fairly consistent across most of the provinces. Hence, placing wind plants in regions with higher capacity factors results in a reduction of only 820 MW in capacity (about 2% of the total).

This suggests that there is little incentive to "concentrate" wind resources in provinces with marginally better wind resources. Instead, this work demonstrates that it may make more sense to install wind plants near where the energy would provide the most benefit to the power grid. In other words, there is no significant incentive to transport wind energy from slightly better wind locations over long distances (likely requiring new transmission facilities) when wind resources of almost equal quality are located closer to the provincial load centers where the energy would be used. This observation is discussed further in the key findings of this study.

Figure 1-3 graphically illustrates the installed wind capacity by province for the scenarios. Most of the wind resources are installed in Alberta, Ontario and Quebec, the provinces with the higher levels of system load. In comparing the two 20% scenarios, it is evident that some 20% DISP wind resources in BC, SK and QC are replaced with slightly higher capacity factor resources in AB, MB, ON, NS and NL for the 20% CONC scenario. However, as mentioned above, this represents only a 2% change in total installed wind plant capacity. The lower plot in Figure 1-3 illustrates the reason; wind plant capacity factors are very similar across most provinces in Canada; regardless of the scenario.

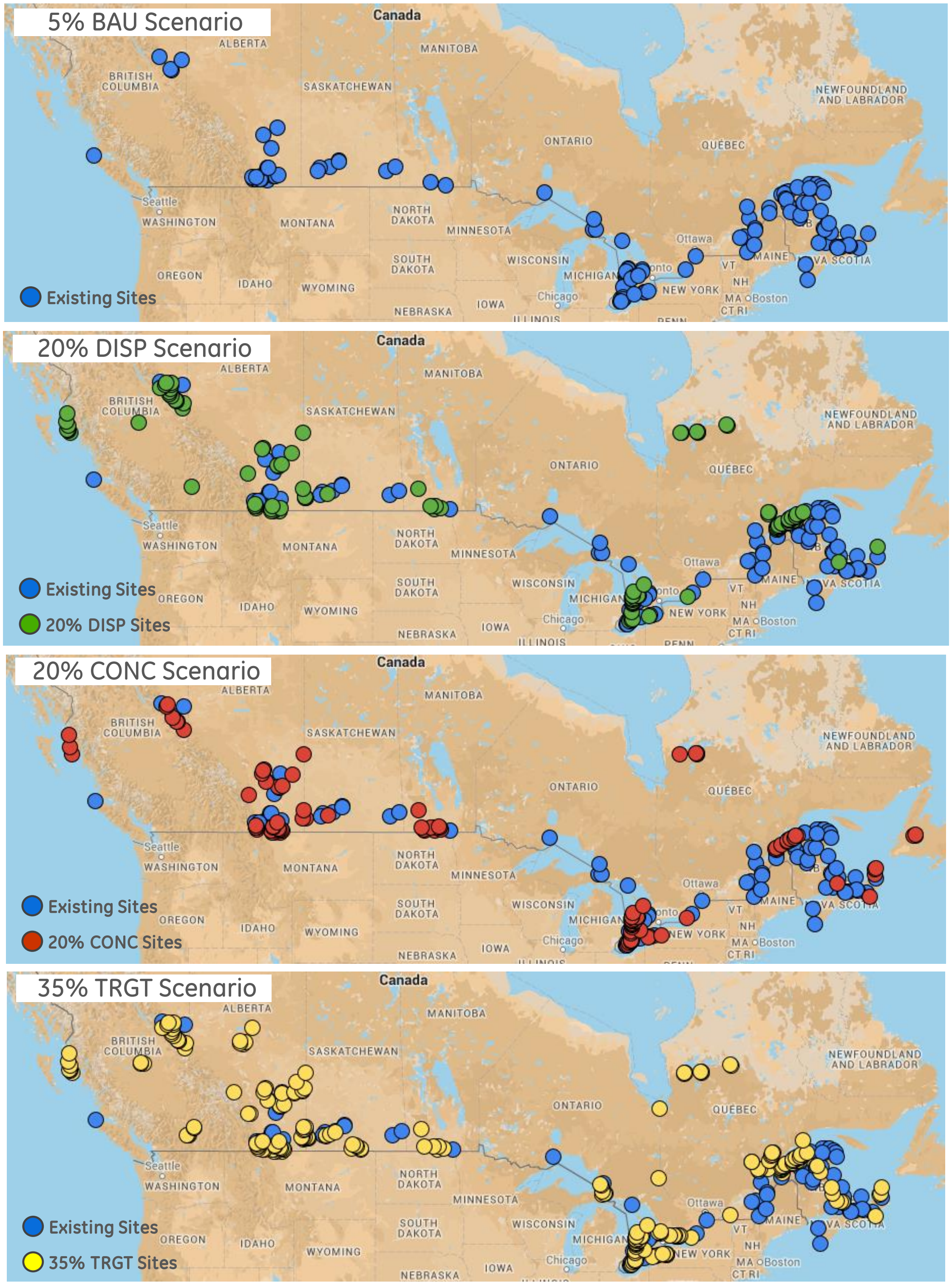


Figure 1-2: Locations of Wind Plants in Study Scenarios

Table 1-1: Summary of System Load and Generation by Province for Study Scenarios

Region	Scenario	Load (GWh)	Peak (MW)	Thermal Cap (MW)	Hydro Cap (MW)	Wind Cap (MW)	Available Wind Energy (GWh)	Available Wind Energy (% of Load)
CANADA	5% BAU	609,618	108,421*	51,835	70,037	10,970	34,717	5.7%
CANADA	20% DISP	609,618	108,421*	51,835	70,037	37,131	122,054	20%
CANADA	20% CONC	609,618	108,421*	51,835	70,037	36,311	121,584	20%
CANADA	35% TRGT	609,618	108,421*	51,835	70,037	65,225	212,734	35%
BC	5% BAU	63,433	11,622	780	13,385	685	1,751	2.8%
BC	20% DISP	63,433	11,622	780	13,385	4,270	12,592	20%
BC	20% CONC	63,433	11,622	780	13,385	2,221	6,520	10%
BC	35%TRGT	63,433	11,622	780	13,385	5,445	15,734	25%
AB	5% BAU	116,234	16,318	16,700	445	1,438	4,527	3.9%
AB	20% DISP	116,234	16,318	16,700	445	6,944	23,148	20%
AB	20% CONC	116,234	16,318	16,700	445	9,840	32,874	28%
AB	35% TRGT	116,234	16,318	16,700	445	17,728	57,879	50%
SK	5% BAU	29,626	4,444	4,013	902	451	1,471	5.0%
SK	20% DISP	29,626	4,444	4,013	902	1,749	5,923	20%
SK	20% CONC	29,626	4,444	4,013	902	915	3,077	10%
SK	35% TRGT	29,626	4,444	4,013	902	4,407	14,804	50%
MB	5% BAU	30,149	5,261	400	5,915	258	859	2.9%
MB	20% DISP	30,149	5,261	400	5,915	1,781	6,008	20%
MB	20% CONC	30,149	5,261	400	5,915	2,789	9,495	32%
MB	35% TRGT	30,149	5,261	400	5,915	2,213	7,502	25%
ON	5% BAU	143,670	24,358	22,985	6,035	4,103	13,610	9.5%
ON	20% DISP	143,670	24,358	22,985	6,035	8,440	28,640	20%
ON	20% CONC	143,670	24,358	22,985	6,035	10,056	34,162	25%
ON	35% TRGT	143,670	24,358	22,985	6,035	16,124	53,651	38%
QC	5% BAU	200,736	41,171	2,255	41,956	2,960	9,074	4.5%
QC	20% DISP	200,736	41,171	2,255	41,956	12,275	40,118	20%
QC	20% CONC	200,736	41,171	2,255	41,956	6,128	20,100	10%
QC	35% TRGT	200,736	41,171	2,255	41,956	15,490	50,128	25%
MAR**	5% BAU	25,770	5,247	4,701	1,899***	1,074	3,426	13%
MAR**	20% DISP	25,770	5,247	4,701	1,899***	1,673	5,626	22%
MAR**	20% CONC	25,770	5,247	4,701	1,899***	4,361	15,356	35%
MAR**	35% TRGT	25,770	5,247	4,701	1,899***	3,819	13,035	50%

Notes: All thermal and hydro capacities are provided for winter capability period.
* Peak for Canada is the sum of non-coincident peaks of the provinces.
** MAR = Maritimes region, including PEI, NB, and NS.
*** Maritimes hydro capacity includes 500 MW Maritime Link (Muskrat Falls).

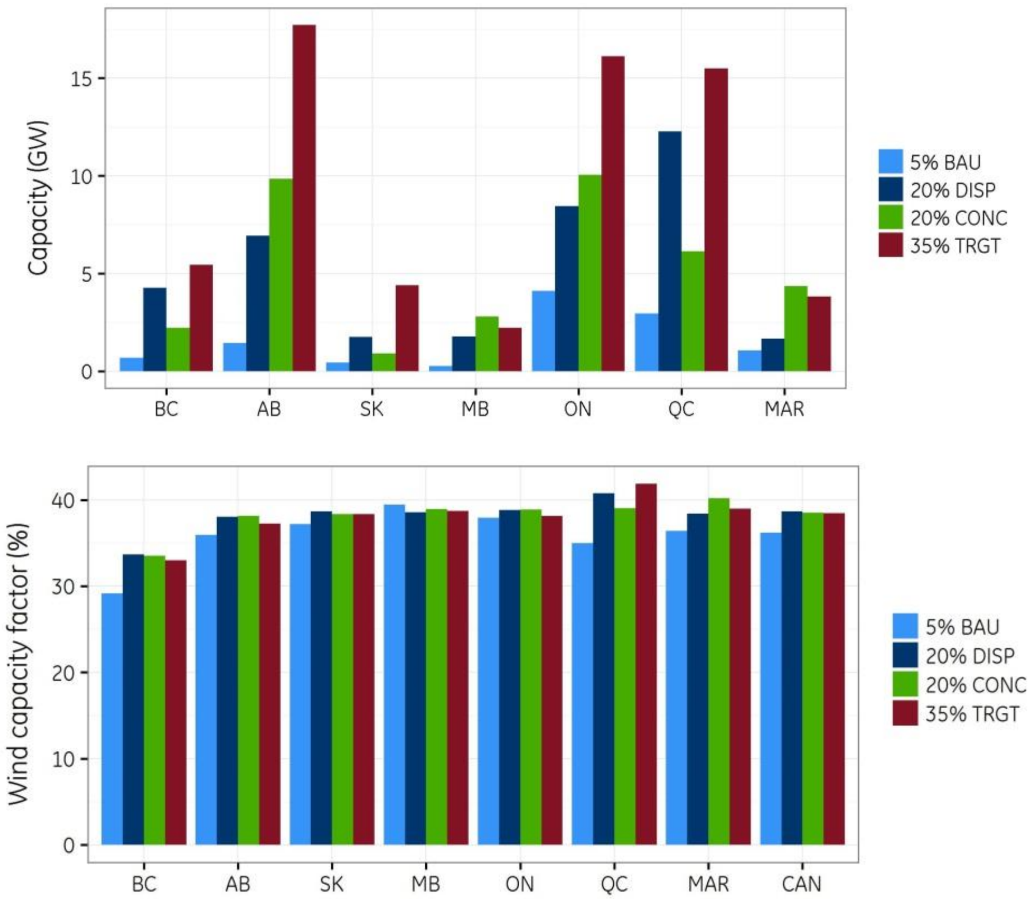


Figure 1-3: Total Installed Wind Capacity and Average Capacity Factor by Province for Study Scenarios

1.4 Study Assumptions and Modeling Approach

The Canada and USA power grids were modeled to represent year 2025. System load for year 2023 was derived from NERC LTRA 2013[3] and escalated upward for an additional two years[4]. GE MAPS[5] was used for the production simulations (hourly commitment and dispatch for a year) and GE MARS[6] for the reliability simulations (capacity value analysis). The model included the two major North-American interconnections with full transmission systems

[3] Based on data from the North American Electric Reliability Corporation (NERC) Long-Term Reliability Assessment (LTRA), December 2013

[4] Representatives of BC Hydro, AESO and IESO provided additional load growth data for those three grids.

[5] Multi-Area production Simulation program

[6] Multi-Area reliability Simulation program

represented; WECC/Western Interconnection (WI) and Eastern Interconnection (EI). The geographic footprint of the model is shown in Figure 1-4. All Canadian provinces interconnected with the North American bulk transmission system were included, with renewable energy penetrations defined by the four study scenarios. Renewable penetration in the USA was based on existing Renewable Portfolio Standard (RPS) levels projected to year 2025, and was held constant for all study scenarios.

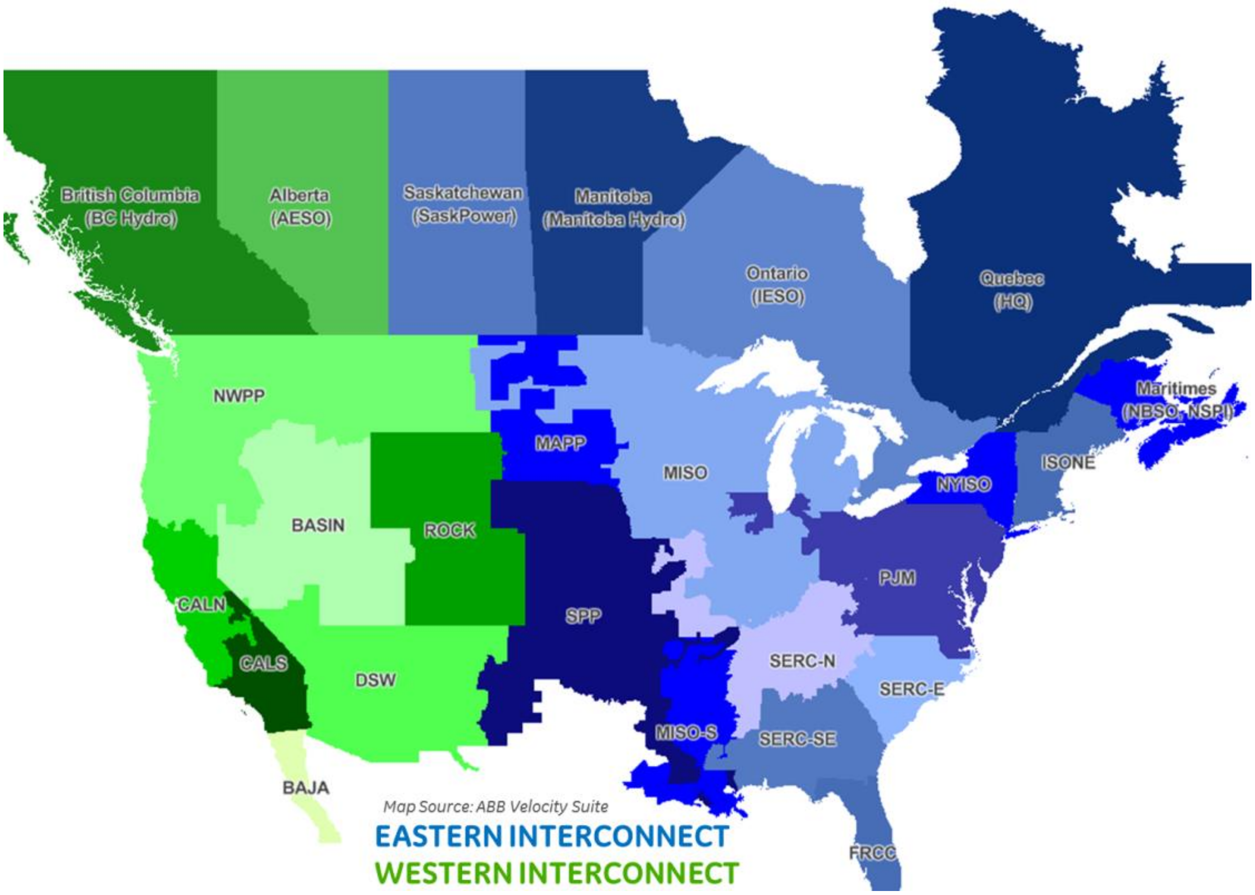


Figure 1-4: Model Topology of the Eastern and Western Interconnections

Although full integrated resource planning (IRP) type analysis was beyond the scope of this study, a heuristic generation expansion planning approach was used to add enough new generation capacity so that all balancing areas would meet their installed reserve margin requirements with anticipated 2025 system load levels in the 5% BAU scenario.

All existing conventional generation units were included in the system model, as well as new units currently under construction. Units with announced retirement dates prior to 2025 were not included the model. A combination of new generic combined cycle gas turbines (CC-GAS) and simple cycle gas turbines (SC-GAS) were added to the system in the 5% BAU scenario to meet the reserve margin requirements in 2025 consistent with the assumed load growth for a total of about 7 gigawatts (GW) of CC-GAS and 1.6 GW of SC-GAS. These generation units were added to provide firm capacity requirements; however, there are other forms of firm capacity that can be considered, that would not necessarily have the same emissions as the CC-GASs or SC-GASs, but would provide the same firm requirements. For consistency across scenarios, these new generators remained available in all higher wind penetration scenarios, regardless of changes to reserve margin due to additional wind capacity.

Fuel price estimates were derived from the following sources:

- Natural Gas: Monthly price forecast, by region (Henry Hub + Differential), from Energy Information Administration (EIA) 2014 Annual Energy Outlook[7].
- Coal: Annual price forecast, by type, including bituminous coal (Bit), subbituminous coal (Sub), lignite coal (Lig), and "powder river basin" coal (PRB) by province, from EIA 2014 Annual Energy Outlook and some province-specific sources of proprietary data.
- Oil: Annual price forecast, by type (distillate, residual), from EIA 2014 Annual Energy Outlook.

Proprietary hydro plant data was provided by BC Hydro, SaskPower, IESO, Manitoba Hydro, and Hydro-Quebec, including monthly energy targets for large dispatchable pondage hydro plants and daily fixed generation targets for run-of-river facilities. Monthly energy targets for other Canadian hydro plants were derived from published historical data. 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 technical advisory committee members.

Each province was modeled as a separate balancing area with its own reserve requirements for regulation and contingencies, its own day-ahead unit commitment and its own hourly real-time dispatch. Imports/exports between neighbouring provinces or between provinces and neighbouring USA operating areas were determined by regional price differentials and constrained by inter-area flow limits.

[7] http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf

1.5 Key Findings

The study findings indicate that the Canadian power system, with adequate transmission reinforcements and additional regulating reserves, will not have any significant operational issues operating with 20% or 35% of its energy provided by wind generation.

1. In the 20% and 35% scenarios, wind energy displaced more expensive gas and coal-fired generation in both Canada and the USA. About half of the total displacement occurred in Canada, resulting in economic benefits for the Canadian systems. This study did not include any carbon tax. If a carbon tax were implemented, then more of the energy displacement would shift from natural gas to coal generation.
2. Canada has high quality wind resources in all provinces. Capacity factors of potential wind plants range from 34% in British Columbia to 40% in Nova Scotia. The study results indicated that there is no significant advantage to concentrate wind resources in provinces with slightly higher wind capacity factors. Instead, it is more beneficial to add the wind generation in regions where the energy can be partially used within the province and partially shared with neighbouring USA states.
3. Hydro generation, particularly hydro with pondage, provides a valuable complement to wind generation. Canada has several hydro-rich provinces. The combination of wind and hydro provides a firm energy resource for use within Canada or as an opportunity to increase exports to USA neighbours. Canada is unique in this regard. With 20% wind penetration, annual hydro energy is still twice the annual wind energy and far exceeding that of the USA.

   In addition, the study highlighted a value for ensuring flexibility in existing hydro resource utilization. While hydro resources typically have significant technical flexibility, other operational, political, and environmental constraints can limit this support. These potential constraints should be investigated in more detail.
4. Inter-area transmission reinforcements are required to accommodate the increased levels of wind generation in order to limit curtailment. The 20% scenarios require 4.6 to 4.8 GW of new inter-area transfer capacity with a total estimated cost of C$2.7B. The 35% scenario requires about 10 GW of new transfer capacity with an estimated cost of C$3.7B. Production simulation results show that operating cost savings in all of North America (USA and Canada) from these transmission reinforcements would pay for the capital investments in approximately 4 years in the 5% BAU scenario and 3 years in the 35% TRGT scenario. This is an approximate straight line payback analysis, and does not account for interest, financing costs, etc.
5. The production cost analysis shows that wind energy has a value (avoided cost) of about C$43.4/megawatt hour (MWh) in 20% DISP scenario and about C$40.5/MWh in the 35% TRGT scenario. Recent projects in North America at sites with similar capacity factors

have been developed with levelized cost of energy (LCOE) in that same range. This indicates that the wind energy postulated in the study scenarios is very likely to be economically feasible.

6. Even in hydro-rich provinces, natural gas prices are the primary driver for the economic benefits of wind. This is because natural gas is the marginal fuel for the system, and increased exports from hydro systems will ultimately displace gas generation.

7. The study assumed that hydro energy would be scheduled a day ahead, based on day-ahead load and wind energy forecasts, and that those schedules would be held constant for real-time operation. However, some hydro resources may have the capability to adjust output during real time operation, thereby compensating for forecast errors in wind energy. Production simulation results showed that re-dispatching hydro resources during real time operation would reduce annual operation costs by C$228M in the 20% DISP scenario for all of the Eastern Interconnection (EI). This essentially removes the negative impacts of wind forecast error, as the hydro resources "firm up" the uncertainty of the wind resources.

8. Regulation reserve requirements to mitigate wind variability appear to be a small fraction of the additional installed wind capacity. For example, the 20% scenarios require slightly less than a 40% increase in load alone regulating reserves. The 20% CONC scenario requires a 38% increase in the average load regulating reserves without wind. The 20% DISP scenario requires 34% increase in the average load regulating reserves without wind; and the 35% TRGT scenario requires a 68% increase in the average load regulating reserves without wind. Overall the additional regulation across all of Canada was less than 1.7% of the installed wind capacity across all scenarios.

9. The Canadian power grid is tightly interconnected with the USA power grid, and operations are interdependent. In fact, most Canadian provinces have more interconnection capacity to USA states to their south than to their neighbouring Canadian provinces. Therefore, when wind penetration increases in Canada, impacts and benefits are shared by both Canada and the USA. For every 1 MWh of additional wind generation in Canada (relative to 5% BAU scenario), energy exports from Canada to the USA increase by about 0.5 MWh.

10. Power plant emissions are reduced significantly with increasing wind penetration in Canada. Those reductions are shared by both Canada and the USA. See Table 1-2.

Table 1-2: CO_2 Emissions Reductions Relative to 5% BAU Scenario

	CO_2 Reductions (MMT)		
Scenario	**Canada**	**USA**	**Total**
20% DISP	12.3	25.6	37.9
20% CONC	17.0	22.7	39.7
35% TRGT	32.3	46.5	78.8

11. There is only a modest amount of curtailed wind energy in the study scenarios: about 6.5% to 6.9% energy curtailment with 20% wind penetration in Canada. The amount of curtailment is higher in the scenarios with more wind energy. See Table 1-3. Curtailment is primarily due to transmission congestion in Alberta, Ontario, Quebec, and the Maritimes during periods of high wind generation. Options for reducing curtailment to lower levels 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.

Table 1-3: Wind Energy Curtailment in Study Scenarios

Scenario	Wind Energy Available (TWh)	Wind Energy Delivered (TWh)	Total Curtailed Energy (TWh)*	Curtailment (%)
5% BAU	34.7	34.3	0.5	1.4%
20% DISP	122.1	117.4	8.5	6.9%
20% CONC	121.6	114.6	7.9	6.5%
35% TRGT	212.7	196.1	23.6	11.1%

* Total curtailed energy includes curtailed wind, solar, and hydro energy to account for displacement of all zero marginal cost resources. Therefore the sum of total curtailed energy and delivered wind energy will not equal available wind energy.

1.6 Statistical Characteristics of Load and Wind Profiles

A wide variety of statistical evaluations were performed on the load and wind profiles to build understanding on how they would impact the annual, seasonal, daily, and short-term operation of the Canadian provincial power grids. A few examples are presented here.

Figure 1-5 shows duration curves of load (top trace) and net load for the study scenarios. Net load is the portion of the system load that must be served by generation resources other than wind. Total 2025 load in Canada ranges from a maximum of about 100 GW to a minimum of about 45 GW. For the scenarios with 20% wind penetration, the net load ranges from 85 GW down to 20 GW. With 35% wind energy, there are a few hours of the year when the amount of wind generation is nearly equal to the system's total load, and the net load approaches zero. This does not mean that Canada's entire load is served by wind during those hours, as there are significant exports to the USA and curtailment of a portion of the wind generation. However, this plot provides a useful visual indication of the amount of wind energy in the scenarios relative to the load energy.

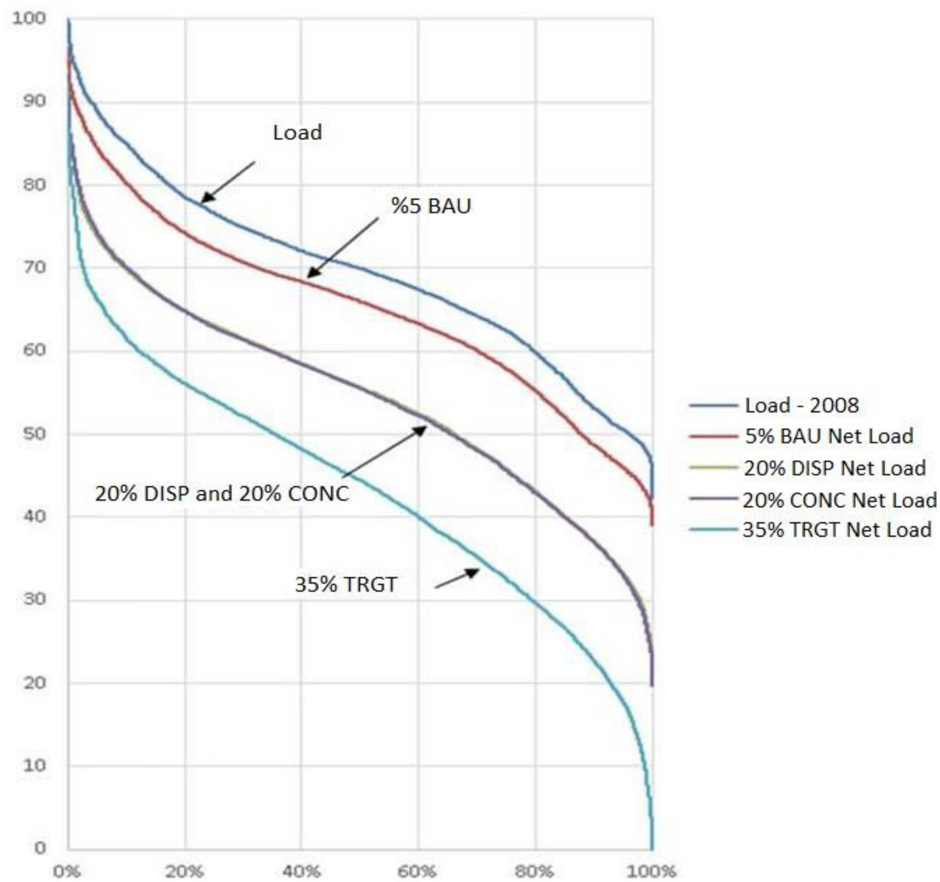


Figure 1-5: Duration Curves of Canada Load and Net-Load for Study Scenarios

Figure 1-6 shows average daily load and wind profiles by season for the 20% DISP scenario. The load profiles show that Canada has higher load in the winter than in other seasons[8]. The daily peak occurs between hours 18 and 21. The wind profiles show more wind energy in fall and winter. During the peak load hours, there is more wind energy in winter than in other seasons. This is a positive influence on the capacity value of the Canadian wind resources (see the section on Reliability Analysis and Wind Capacity Valuation).

8 This is true for all provinces except Ontario, where average daily peaks in the summer are similar to those in winter.

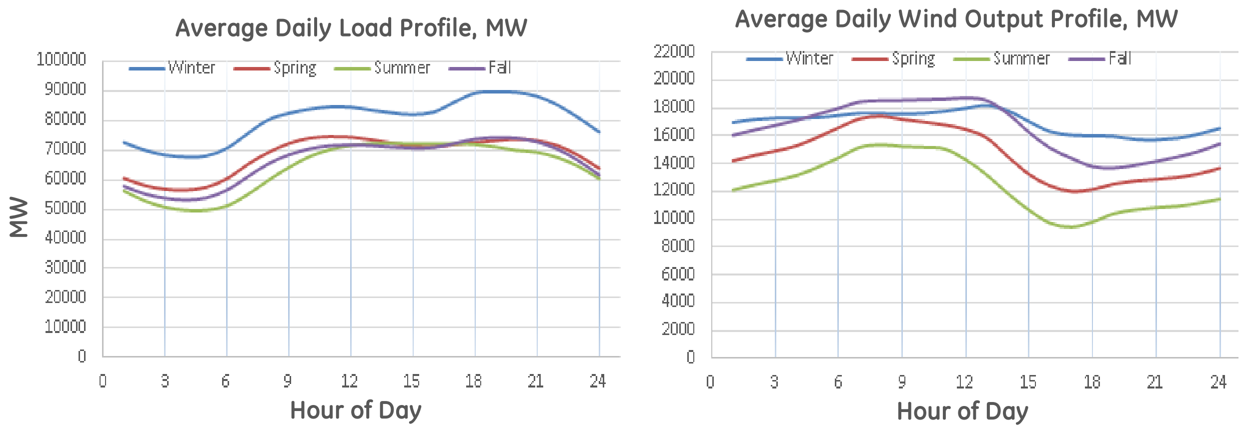


Figure 1-6: Average Daily Load and Wind Profiles by Season for all of Canada (20% DISP Scenario)

Figure 1-7 shows 10-minute variability (i.e., the change in 10-minute wind production from one 10-minute period to the next) as a function of total wind power production for the four study scenarios with increasing wind penetration (5%, 20%, and 35%). One significant observation is that the maximum 10-minute variations occur when wind production is about half of total wind capacity. Variability is lower near maximum production levels, partly because many wind plants are operating "above the knee" in the wind-power curve where changes in wind speed do not affect electrical power output (see Figure 1-8). "Above the knee" refers to the flat power curve region above a certain wind speed where power output remains unchanged as the wind speed increases. This characteristic of variability is relevant to the regulation requirements, which is discussed later.

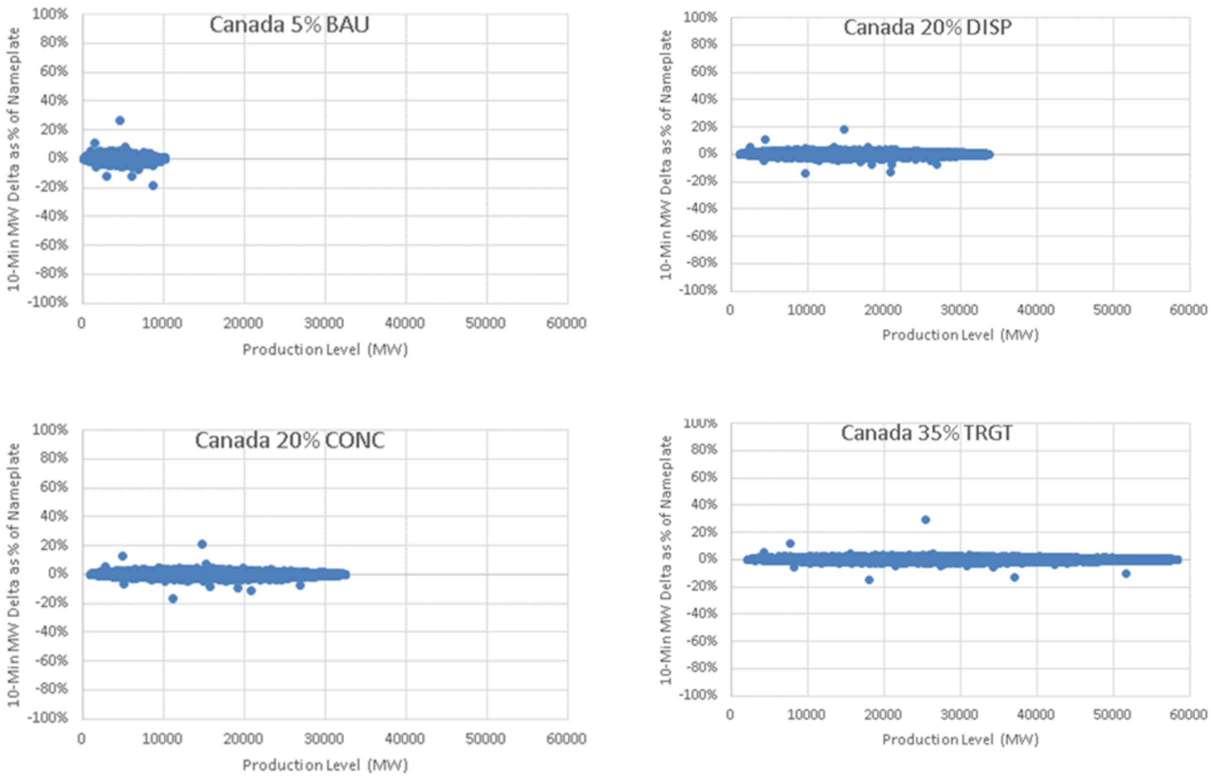


Figure 1-7: Ten-Minute Wind Variability as Function of Production Level for Study Scenarios

The data patterns in Figure 1-7 show (a) that wind variability covers a narrow region (i.e., the vertical thickness of the solid area) for a wide range of wind production levels, and (b) that the "trend" that variability is higher in the middle of the production range and lower at the ends, which justifies having the regulation requirement be a function of wind production as shown in the next section.

Figure 1-8 shows the wind turbine power curves that were used to develop the wind power profiles, which in turn determines their variability characteristics. In the figure, Class 1, 2, and 3 refer to different classes of on-shore wind turbines based on the average annual wind speeds that the turbines must be designed to withstand[9]. The wind classes are defined by an International Electrotechnical Commission Standard (IEC). The three wind classes are 1: High Wind, 2: Medium Wind, and 3: Low Wind.

[9] http://cvi.se/uploads/pdf/Master%20Literature/Wind%20Turbine%20Technology/Turbine_wind_class.pdf

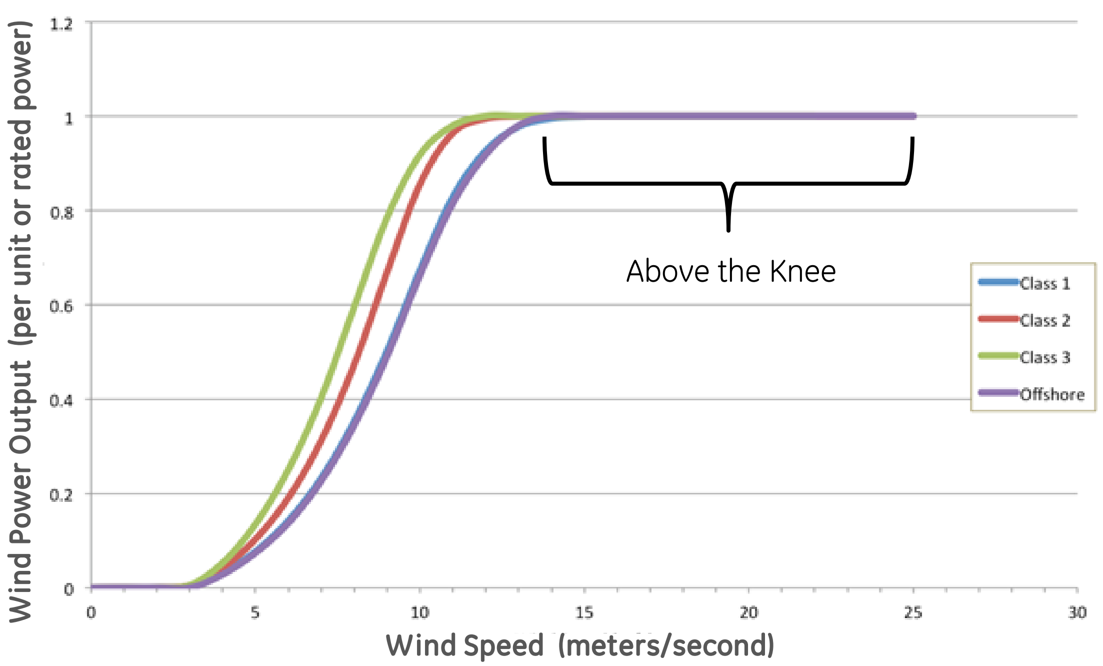


Figure 1-8: Composite Wind Turbine Power Curves for PCWIS Study

1.7 Regulation and Reserves

With increasing levels of wind generation, it will be necessary for the balancing areas to carry higher levels of reserves to respond to the additional variability and uncertainty in the output of those resources. Statistical analysis of wind and load data was employed to determine how much additional regulation capacity would be required to manage the additional variability in each of the study scenarios. The regulation requirement for wind was combined with the regulation requirement for load to calculate a total regulation requirement.

The analysis illustrated that the variability of wind power output is a function of the total production level. Figure 1-9 shows an illustrative example for Alberta. Wind variability is higher when total production is at mid-level (on the steep parts of the turbine power curves in Figure 1-8). Variability is lower when wind production is low or near full output. Therefore, more regulating reserves are needed when wind production is at mid-level and less regulating reserves are needed when production is very low or very high – proportional to the shape of the curves in Figure 1-9. Previous studies have established that a statistically high level of confidence for reserve is achieved at about 3 standard deviations (or 3σ) of 10-minute wind variability. This conservative 3σ criterion was also adopted for this study, which means that the regulation requirements are designed to cover 99.7% of all 10-minute variations. This criterion is very conservative and above requirements in most regions. Figure

1-10 shows the regulation reserve required for wind variability in Alberta (as an example) for the study scenarios.

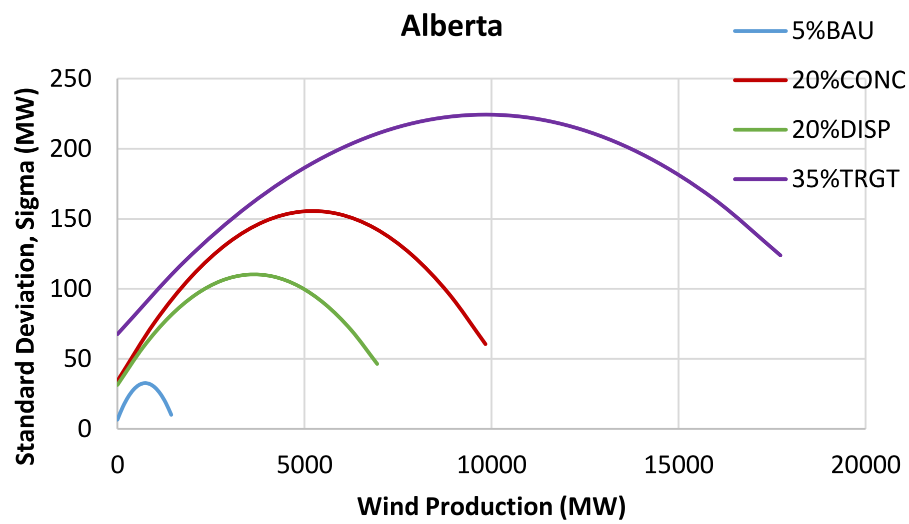


Figure 1-9: Wind Power 10-minute Variability as a Function of Total Wind Production in Alberta

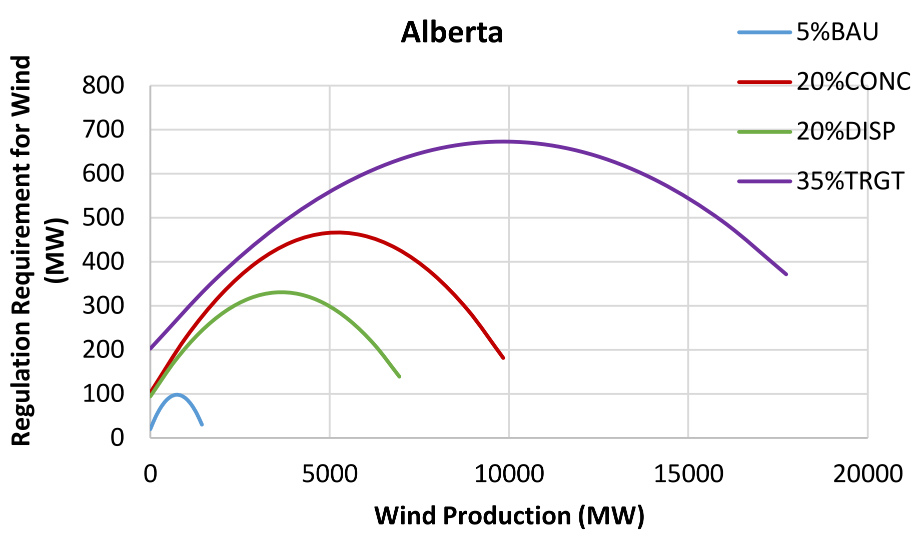


Figure 1-10: Regulation Requirement for Wind Variability as a Function of Total Wind Production in Alberta

In the production cost simulations, the amount of regulation reserve was adjusted hourly as a function of the total wind energy production in each province in each hour. The total regulation reserve requirement was calculated by combining the load and wind regulation requirements using this equation.

$$3 * \sqrt{\left(\frac{R_l}{3}\right)^2 + \sigma_w^2}$$

where,
R_l = Load regulation in MW
σ = std deviation of wind variability in MW

Table 1-4 summarizes the estimated average amounts of regulation required by each province for each scenario. For example, in the 20% DISP scenario, Alberta requires an average of 117 MW of regulating reserve for load alone. This increases to an average of 282 MW of regulating reserve to cover the variability of both load and the 6944 MW of wind plant capacity in that scenario. These are annual average values. The total regulating reserve requirement in Alberta for the 20% DISP scenario varies from 149 MW to 352 MW, depending on wind production in each hour of the year.

Table 1-4: Estimated Regulating Reserve Requirements by Province for Study Scenarios

5% BAU	BC	AB	SK	MB	ON	QC	MAR	CAN
Wind Capacity MW	685	1,438	450	258	4,101	2,959	1,074	10,966
Average Load Regulation MW	180	117	132	110	442	528	82	1,591
Average Load + Wind Regulation MW	183	138	139	115	471	535	90	1,671
Change in Regulation MW	3	21	7	5	29	7	8	79
Increase Regulation %	2%	18%	6%	4%	6%	1%	10%	5%
Increase Regulation as % of Capacity	0.4%	1.5%	1.6%	1.8%	0.7%	0.2%	0.7%	0.7%
20% DISP	**BC**	**AB**	**SK**	**MB**	**ON**	**QC**	**MAR**	**CAN**
Wind Capacity MW	4,269	6,944	1,748	1,781	8,438	12,274	1,673	37,127
Average Load Regulation MW	180	117	132	110	442	528	82	1,591
Average Load + Wind Regulation MW	216	282	201	172	539	622	100	2,131
Change in Regulation MW	35	165	69	62	97	94	18	540
Increase Regulation %	20%	141%	52%	56%	22%	18%	22%	34%
Increase Regulation as % of Capacity	0.8%	2.4%	3.9%	3.5%	1.2%	0.8%	1.1%	1.5%
20% CONC	**BC**	**AB**	**SK**	**MB**	**ON**	**QC**	**MAR**	**CAN**
Wind Capacity MW	2,221	9,840	914	2,789	10,054	6,127	4,361	36,307
Average Load Regulation MW	180	117	132	110	442	528	82	1,591
Average Load + Wind Regulation MW	195	365	153	196	572	556	156	2,193
Change in Regulation MW	15	248	21	86	130	28	74	602
Increase Regulation %	8%	212%	16%	78%	29%	5%	91%	38%
Increase Regulation as % of Capacity	0.7%	2.5%	2.3%	3.1%	1.3%	0.5%	1.7%	1.7%
35% TRGT	**BC**	**AB**	**SK**	**MB**	**ON**	**QC**	**MAR**	**CAN**
Wind Capacity MW	5,445	17,728	4,406	2,213	16,122	15,489	3,819	65,221
Average Load Regulation MW	180	117	132	110	442	528	82	1,591
Average Load + Wind Regulation MW	231	545	273	185	638	652	143	2,666
Change in Regulation MW	50	428	141	74	196	123	62	1,075
Increase Regulation %	28%	366%	107%	67%	44%	23%	76%	68%
Increase Regulation as % of Capacity	0.9%	2.4%	3.2%	3.4%	1.2%	0.8%	1.6%	1.6%

The following approach was adopted to assess the adequacy of the regulating reserves, on a sub-hourly basis:

- Simulate hourly operation using GE MAPS, with regulation allocated in each province per the criteria described above and contingency reserves per present practices.
- Using the hourly results of the GE MAPS simulations, compare the ramping capability of the committed units each hour with the sub-hourly variability of wind production in that hour.
- Quantify the number of periods where ramping capability is insufficient.

The results of the analysis showed that with 5% and 20% wind penetration, all provinces have adequate ramping capability to follow variations in wind and load during 10-min dispatch periods. At 35% penetration, all provinces have adequate ramp-up capability, but Alberta may experience down-ramp (or minimum power) constraints on conventional units about 5% of the time. However, this could be mitigated by curtailment or up-ramp rate limits on wind plants.

There are relatively few periods in a year when wind ramps exceed operating area ramping capability by a small amount, and those few events would not likely result in an unacceptable decrease in Control Performance Standard (CPS) measures as defined by NERC[10]. A ramp rate limitation would result in unintended tie flow for that 10-minute period. The CPS2 standard[11] allows for such events in up to 10% of the 10-minute time periods in each month.

1.8 Transmission System Reinforcement

Increases in new wind generation resources will result in new flow patterns in the grids and will therefore require new transmission in regions on paths with increased flows. This study examined the need for transmission reinforcements in each of the four study scenarios using the following process:

1. Selected transmission projects already in the planning stages were included in the 5% BAU scenario (per guidance from the technical advisory committee):
    - Alberta to British Columbia: Increased existing interface capacity to 1,200 MW.
    - Manitoba to USA: Included proposed 500 kV tie-lines between Manitoba and Minnesota.

[10] "Balancing and Frequency Control", Prepared by the NERC Resource Subcommittee, January 26, 2011.

[11] CPS2 (percent) = 100 * (periods without violations) / (all periods in the month). CPS2 is a monthly standard intended to limit unscheduled flows. The minimum allowable CPS2 score is 90 percent. This means that on the average, a Balancing Authority may have roughly one violation ever other hour and still pass CPS2. Source: "Balancing and Frequency Control", prepared by the NERC Resources Subcommittee, January 26, 2011, Page 37. http://www.nerc.com/docs/oc/rs/NERC%20Balancing%20and%20Frequency%20Control%20040520111.pdf

- Quebec to US: Included Northern Pass (1,200 MW), New England Clean Power Link (1,000 MW), Champlain Hudson Power Express (1,000 MW) proposed high-voltage direct current (HVDC) additions.

2. Perform production cost simulations to identify congestion. Increase inter-area transmission capacity to level where the average annual shadow prices fall below C$10/MW.
3. Identify specific physical transmission line additions that would provide the necessary inter-area flow capacity (substations at each end of the line, voltage level, circuit type, phase shifters, etc.).

It should be noted that this study did not evaluate the intra-provincial transmission required to connect the additional wind plants to the local high-voltage transmission system, or any potential localized transmission reinforcements.

The approach used in this study is adequate for determining the appropriate levels of inter-area transmission reinforcements for the bulk power system. Doing a more detailed long-term regional transmission expansion planning study was beyond the scope of this project.

Historically there has been a strong and active energy trade between USA and Canada that drives significant power flows. In fact, many provinces have more transmission capacity to the USA than to neighbouring Canadian provinces. Some of the new transmission lines identified by the above transmission reinforcement process were between provinces; others were between Canadian provinces and USA states.

Figure 1-11 shows the existing transmission capacities (in gray) between the various provinces and states. The coloured segments on top show the incremental capacity additions for the study scenarios, as determined by the process described above. Three of the largest capacity paths (on the left) are between Canada and the USA. Table 1-5 also summarizes the incremental transmission capacity requirements for the scenarios, serving as the basis for defining the specific transmission lines and costs shown in Table 1-6. Detailed information for each transmission line and its interconnection points are presented in the full project report.

The 5% BAU scenario is a benchmark case that includes existing wind and transmission as well as wind plants under construction and transmission projects in the planning stage. Hence, the five transmission reinforcements shown for the 5% BAU scenario (all involving Ontario) indicate opportunities to relieve near-term congestion that is not related to increased penetration of wind generation (shaded blue in Table 1-6). Three of the paths are within Canada and two paths are between Canada and the USA (see the right-hand column of Table 1-6). The cost of these reinforcements is estimated to be C$2,130M.

Production cost results indicate that the annual operating cost savings with these reinforcements is C$565M, indicating an approximate investment payback period of about 4 years (not accounting for interest, financing costs, etc.).

The middle (green) section of Table 1-6 shows incremental reinforcements for the 20% wind penetration scenarios. Four of six projects are within Canada, although the two USA interties have the highest costs. The bottom (red) section of the table shows that essentially all of the additional transmission capacity for the 35% TRGT scenario is between Canada and the USA.

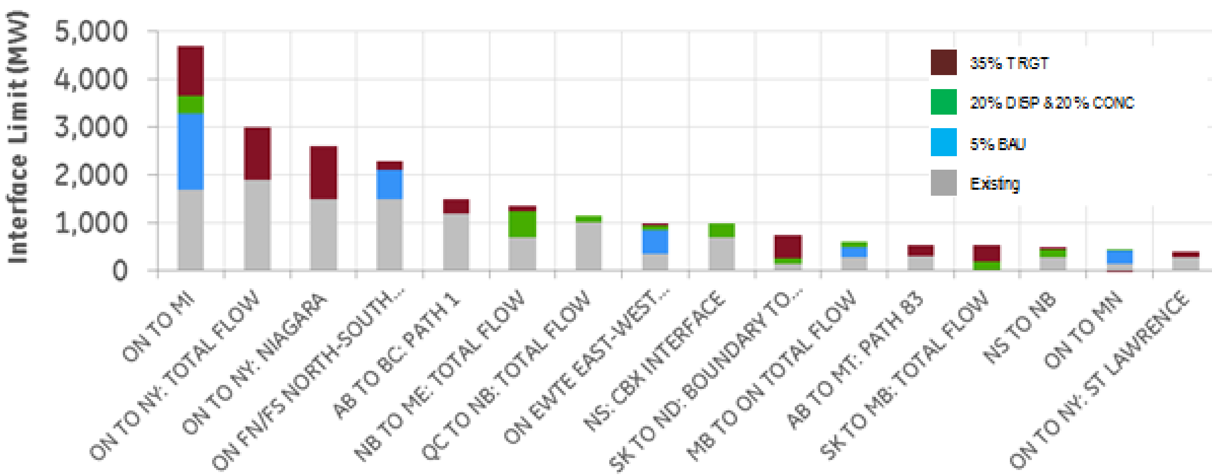


Figure 1-11: Existing and New Transmission Capacity for Study Scenarios

Table 1-5: Incremental Transmission Capacity Additions for Study Scenarios

	INCREMENTAL INTERFACE ADDITIONS (MW)			
INTERFACE	5% BAU	20% DISP	20% CONC	35% TRGT
AB TO BC: PATH 1	0	0	0	300
AB TO MT: PATH 83	0	0	0	235
SK TO MB: TOTAL FLOW	0	200	0	550
SK TO ND: BOUNDARY TO TIOGA	0	110	0	585
MB TO ON TOTAL FLOW	200	300	300	300
ON TO MN	275	275	300	275
ON TO MI	1600	1900	1950	3000
ON TO NY: NIAGARA	0	0	0	1100
ON TO NY: ST LAWRENCE	0	0	0	100
ON TO NY: TOTAL FLOW	0	0	0	1100
ON EWTE EAST-WEST TRANSFER	500	600	600	650
ON FN/FS NORTH-SOUTH TRANSFER	600	600	600	800
QC TO NB: TOTAL FLOW	0	120	120	120
NB TO ME: TOTAL FLOW	0	500	550	650
NS TO NB	0	50	150	200
NS: CBX INTERFACE	0	0	300	0

Table 1-6: Summary of Inter-Area Transmission Reinforcements and Costs (C$M 2016)

Inter-Area Transmission Path	5% BAU	20% DISP	20% CONC	35% TRGT	Description	CAN or USA
MB TO ON	$491	$491	$491	$491	1 - 230 kV line, 280 km, with phase shifter	CAN
ON TO MN	$188	$188	$188	$188	1 - 230 kV line, 149 km, with phase shifter	USA
ON TO MI	$672	$672	$672	$672	2 - 500 kV lines, 220 km	USA
ON EWTE EAST-WEST TRANSFER	$306	$306	$306	$306	2 - 230 kV lines, 130 km	CAN
ON FN/FS NORTH-SOUTH TRANSFER	$661	$661	$661	$661	1 - 500 kV line, 330 km	CAN
SK TO MB		$332		$657	1 - 230 kV line, 195 km	CAN
SK TO ND: BOUNDARY TO TIOGA		$272		$516	1 - 230 kV lines, 210 km, phase shifter (20% DISP) 2 - 230 kV line, 210 km, phase shifter (35% TRGT)	USA
QC TO NB		$66	$66	$66	1 - Back-to-Back DC at Madawaska, 120 MW	CAN
NB TO ME		$358	$358	$358	1 - 345 kV line, 250 km	USA
NS TO NB		$168	$207	$207	1 - 138 kV lines, 130 km (20% DISP) 2 - 138 kV lines, 130 km (20% CONC, 35% TRGT)	CAN
NS: CBX INTERFACE			$292		1 - 230 kV line, 170 km	CAN
AB TO BC: PATH 1				$16	150 MVAR series capacitor	CAN
AB TO MT: PATH 3				$273	1 - 230 kV line, 160 km, with phase shifter	CAN
ON TO NY: NIAGARA				$25	1 - 345 kV overhead line, 5 km	USA
ON TO NY: ST LAWRENCE				$34	1 - 230 kV line, 17 km	USA
Total (C$M 2016)	$2,130	$2,696	$2,695	$3,724		

1.9 Impact of Renewables on Annual Grid Operations

This section summarizes the results of the production cost simulations (hour-by-hour operations for an entire year). The hourly production cost simulations were performed for a chronological, 8,760 hour dispatch of the Canadian power system. This analysis takes into account the commitment and dispatch of both conventional thermal generators and wind generators to serve the system load in a least cost manner. Included in the optimization are constraints on system operations including transmission constraints, fixed operating schedules of some baseload units (must-run status), spinning reserve provision for contingency events and wind variability, minimum run times, down times, and generator outages.

Figure 1-12 shows the annual generation, including generation by plant types such as nuclear (NUCLEAR), cogeneration (COGEN), coal steam turbine (ST-COAL), natural gas combined cycle (CC-GAS), natural gas steam turbine (ST-GAS), peaking units such as simple cycle gas (SC-GAS) and internal combustion (IC) engine (PEAKER), solar (SOLAR), hydropower (HYDRO), wind (WIND), and other (OTHER), broken down by province and for all of Canada, expressed in percent of total annual load energy. The figure shows that Canada is a net exporter of energy in all scenarios. As wind penetration increases from 5% to 20% to 35%, coal and gas generation decreases and exports to the USA increase. Hydro, nuclear and cogeneration resources remain constant.

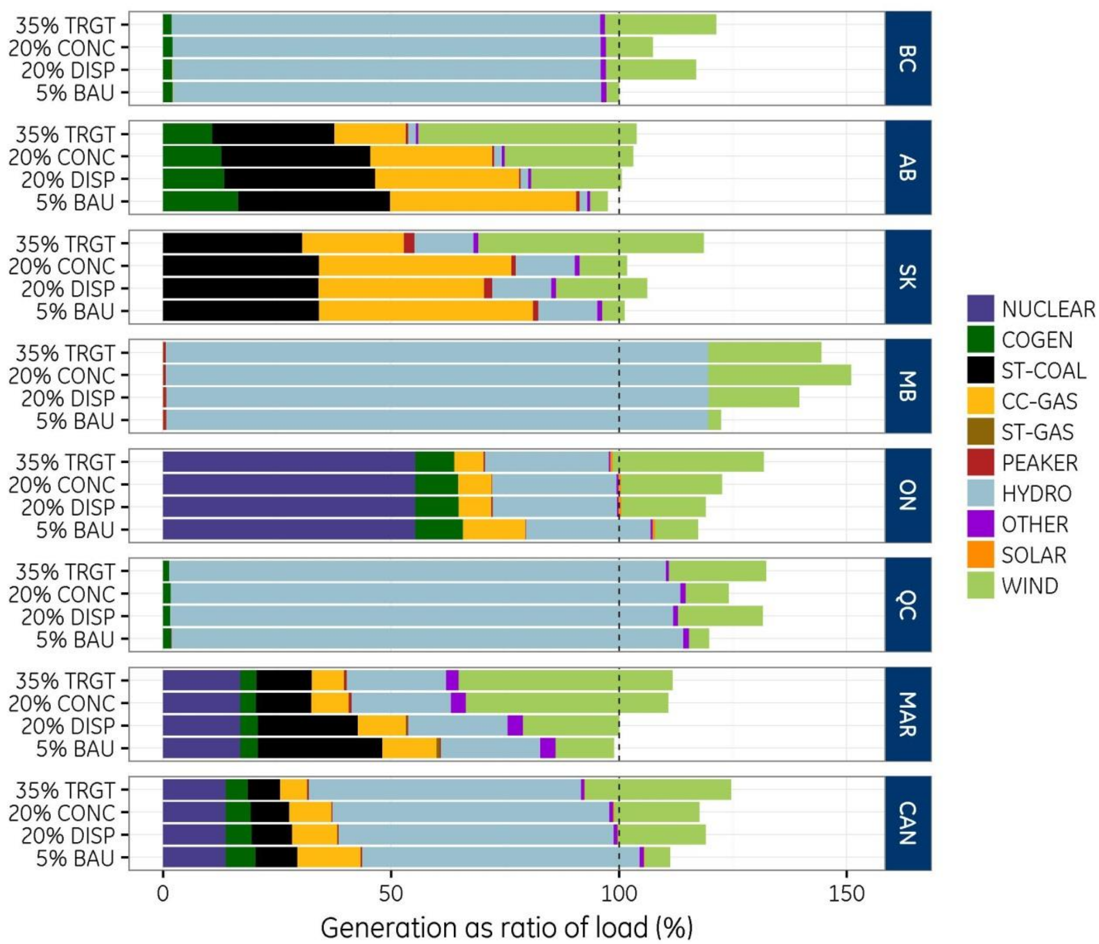


Figure 1-12: Generation by Type for Individual Provinces

Figure 1-13 and Table 1-7 show further details of exports from Canada to the USA. The bar chart on the left shows exports in TWh for the four study scenarios. The plot and table below show the relationship between increased wind production and increased exports. The trend shows that exports increase by 54% of incremental wind generation in the 20% DISP scenario and 46% of the incremental wind generation in the 35% TRGT scenario, as compared to the 5% BAU scenario.

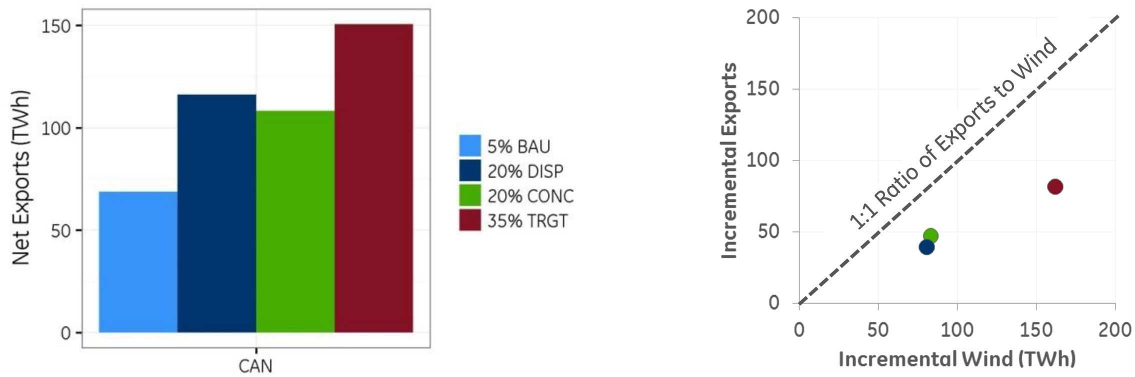


Figure 1-13: Increase in Exports with Increasing Wind Penetration

Table 1-7: Increase in Exports with Increasing Wind Penetration

	5% BAU	20% DISP	20% CONC	35% TRGT
Total Available Wind (GWh)	34,717	122,054	121,584	212,734
Total Generation (GWh)	678,833	726,222	718,180	760,495
Incremental Wind (GWh)	-	87,337	86,867	178,017
Incremental Exports (GWh)	-	47,389	39,347	81,662
Exports/Wind Ratio	-	54%	45%	46%

Figure 1-14 and Table 1-8 show the same information by province. In the provinces that are dominated by hydro generation (BC, MB, QC), exports increase nearly the same amount as increases in wind energy. In thermal-rich provinces, wind energy primarily displaces coal and gas resources and there are smaller increases in exports relative to hydro-rich provinces.

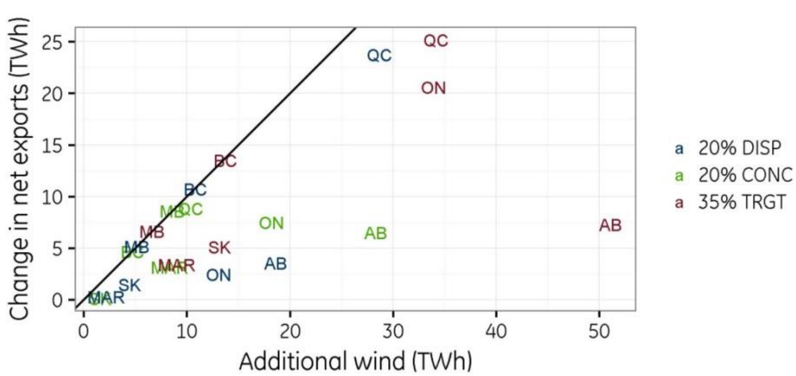


Figure 1-14: Increase in Exports with Increasing Wind Penetration, by Province

Table 1-8: Exports to Wind Ratio

	20% DISP	20% CONC	35% TRGT
BC	99%	98%	98%
AB	19%	23%	14%
SK	32%	7%	39%
MB	100%	100%	100%
ON	19%	41%	61%
QC	83%	85%	74%
MAR	13%	38%	38%

Figure 1-15 shows a high-level summary of what other North American generating resources are displaced by the additional Canadian wind resources in the 20% and 35% scenarios, relative to the 5% BAU scenario. Wind primarily displaces gas, coal, and cogeneration resources in both Canada and the USA. There is also a small increase in energy from peaking units in the USA, a consequence of coal and gas units being de-committed during some time periods. A portion of the of the available wind energy that cannot be used is therefore curtailed; 5 terawatt hour (TWh) (4%) in the 20% DISP scenario, 7 TWh (6%) in the 20% CONC scenario, and 18 TWh (9%) in the 35% TRGT scenario. Figure 1-16 shows this same information for individual Canadian provinces.

It should be noted that the reason that natural gas is displaced over coal is because natural gas is presently more expensive than coal within the current policy context – however, if the price of coal or natural gas were to change due to either shifts in policy or due to pure economic reasons, the study results would be impacted. For instance, if coal were more expensive than natural gas – perhaps due to some future high carbon taxes or GHG emission allowance prices - then coal would be displaced first (This may not be the case with the Maritimes, since in Maritimes, the little gas they may have is actually very expensive). Accordingly, under the current policy context/environment, gas is displaced over coal.

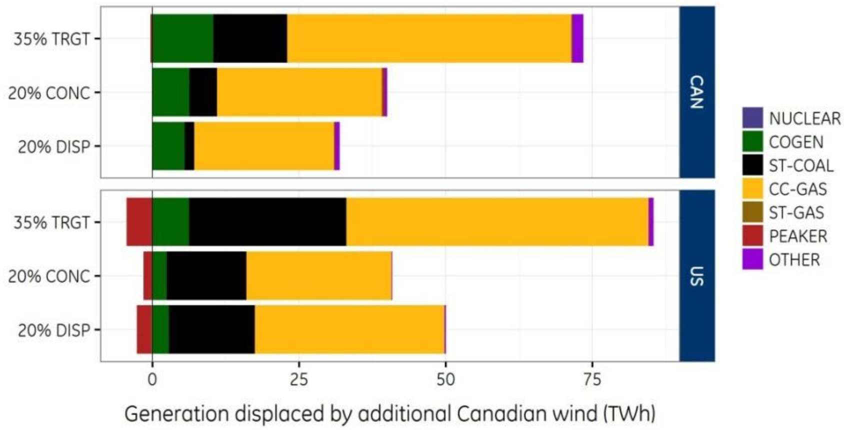


Figure 1-15: Thermal Generation Displaced by Additional Canadian Wind Resources, by Country

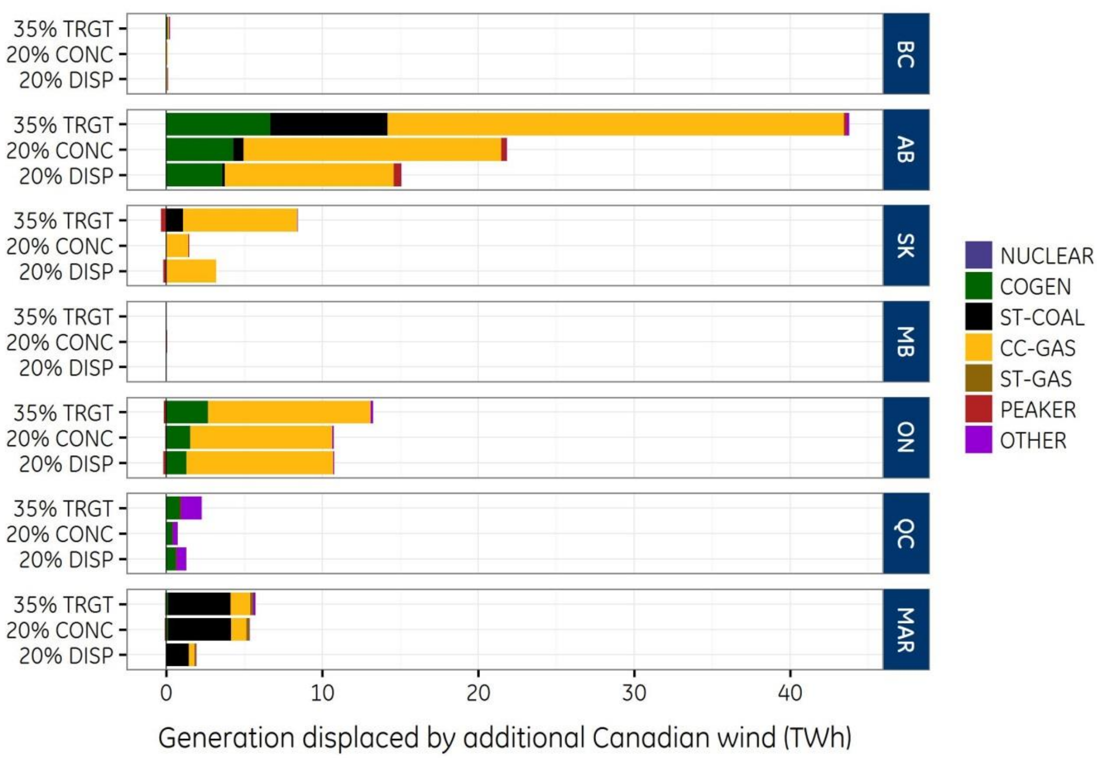


Figure 1-16: Thermal Generation Displaced by Additional Canadian Wind Resources, by Province

Figure 1-17 illustrates total wind energy available, delivered, and curtailed by province. There is no significant curtailment in the 5% BAU scenario. Ontario, Quebec and the Maritimes show some curtailment in the 20% scenarios. At 35% wind penetration, most curtailment occurs in Ontario and Quebec. Note that in this figure, total curtailed energy includes curtailed wind, solar, and hydro energy to account for displacement of all zero marginal cost resources. Therefore the sum of total curtailed energy and delivered wind energy will not equal available wind - i.e., the heights of some bars exceed the total available wind energy, because curtailment is shared across the resources.

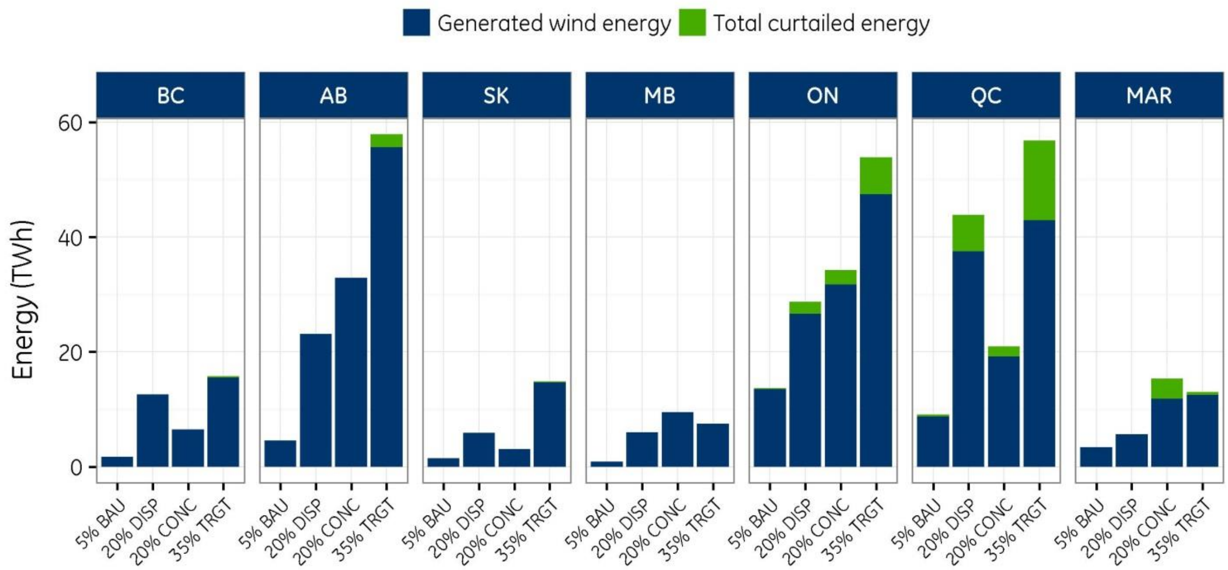


Figure 1-17: Available and Delivered Wind Energy and Total Curtailed Energy by Province

Figure 1-18, Figure 1-19, and Figure 1-20 summarize the annual economic benefits of the wind resources in the study scenarios. The benefits have two components:

- Reduction in production costs in Canada (displacement of thermal generation and consequential reduction in fuel costs and variable O&M costs).
- Revenues from increased exports to the USA, calculated as the product of energy delivered and the Locational Marginal pricing (LMP) at the receiving area.

These components are shown in Figure 1-18 and Figure 1-19. Adjusting the production costs, by taking account of the revenue from increased exports to the USA, results in the adjusted production cost, shown in Figure 1-20.

Higher penetration of zero cost wind has two main consequences: (a) it displaces higher cost fossil fuel based generation, resulting in reduction of the system-wide production costs in Canada, and (b) it increases the supply of zero cost energy in Canada, which competes with higher cost fossil-fuel generation in the USA, thus increasing exports to the USA, and resulting in higher export revenues.

When increasing net export revenues are taken into account, then the adjusted production cost (i.e., production cost minus net export revenue), is further reduced, to the extent that the adjusted production cost becomes negative in some of the provinces under some of the study scenarios.

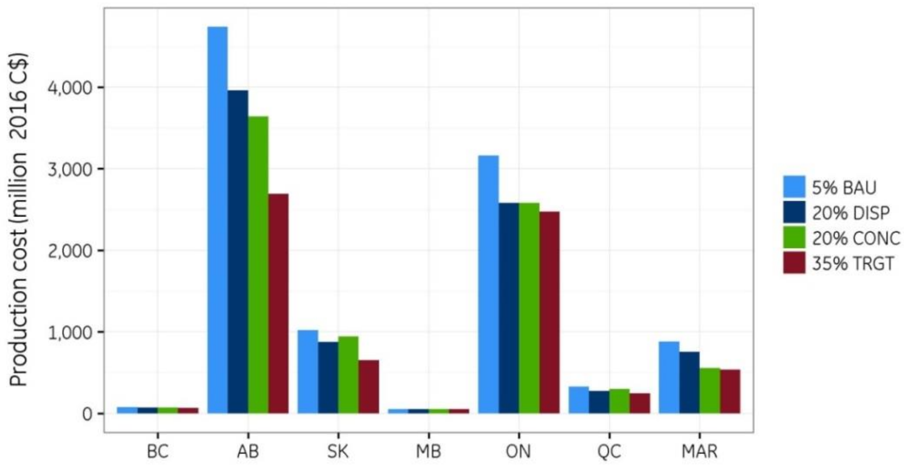


Figure 1-18: Production Costs in Each Province

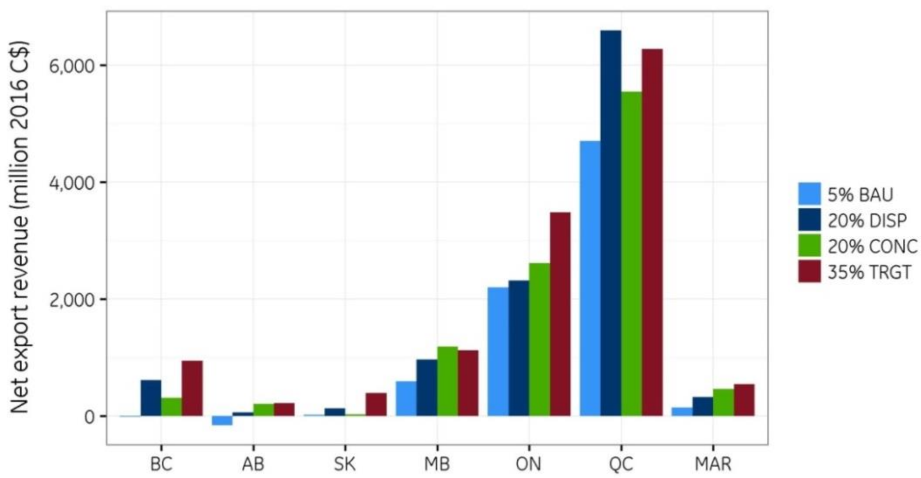


Figure 1-19: Net Export Revenues in Each Province

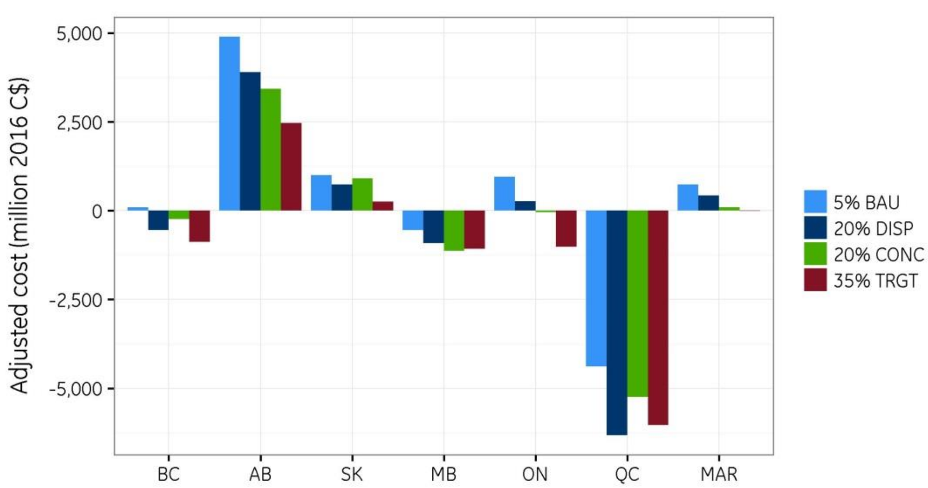


Figure 1-20: Adjusted Production Costs in Each Province

Table 1-9 presents the change in productions costs and delivered wind energy in each scenario relative to the 5% BAU scenario. The production cost analysis shows that wind energy has a value (avoided cost) of about C$43.4/MWh in 20% DISP scenario and about C$40.5/MWh in the 35% TRGT scenario. Recent projects in North America at sites with similar capacity factors have been developed with levelized cost of energy (LCOE) in that same range. This indicates that the wind energy postulated in the study scenarios is very likely to be economically feasible.

If incremental wind penetration was based on linear increase of wind capacity at the same locations as the 5% BAU scenario, one would expect an ever decreasing value of wind with higher wind penetration. In other words, the marginal value of wind (based on production cost savings and increased export revenues) would be expected to decrease as more wind capacity is added to the system. An estimated marginal value of wind can be the basis for the energy portion of power purchase agreements (PPA) and bilateral contracts with wind capacity owners, and even potential price ranges for renewable energy credits (RECs).

Table 1-9: Value of Wind

Changes Relative to 5% BAU Scenario	20% DISP	20% CONC	35% TRGT
Reduction in Adjusted Production Costs (C$M)	3,786.5	4,098.7	7,211.8
Incremental Wind (GWh)	87,336.5	86,866.6	178,016.4
Value per MWh of Added Wind (C$/MWh)	**43.4**	**47.2**	**40.5**

Table 1-10 summarizes the estimated costs for transmission reinforcements as well as the annual reductions (savings) in system-wide (Canada and USA) production costs that directly result from those transmission additions. Export revenues are account for, since export revenues in one country are import costs in another. These values were calculated by performing production cost simulations on each of the scenarios both with and without the transmission reinforcements listed in Table 1-6. The results indicate that the payback periods for the added transmission are in the range of 2.4 to 3.8 years.

The reductions in production cost are in both Canadian and USA operating areas, and about half of the transmission reinforcements are between Canada and the USA. Implementing such projects would necessarily involve entities from both sides of the US-Canada border, as multiple entities would share costs and benefits.

Table 1-10: Cost and Value of Transmission Reinforcements

Scenario	Estimated Cost of Transmission Reinforcements (C$M 2016)	Annual Reduction in System-Wide Production Cost (C$M/Year)	Payback Time (Years)
5% BAU	$2,130	$565	3.8
20% DISP	$2,696	$758	3.6
20% CONC	$2,695	$882	3.1
35% TRGT	$3,724	$1,523	2.4

As more wind generation is added to the power system, it displaces energy that would have been otherwise generated by gas and/or coal-fired generators. Figure 1-21 shows the reductions in CO_2, NO_X and SO_X emissions for the 20% and 35% scenarios, relative to the 5% BAU scenario. Given that the Canadian and USA grids are highly interconnected and that the USA has a much higher penetration of gas and coal resources than Canada, most of the emission reductions occur in the USA. This is expected since exports from Canada to the USA increase significantly with increasing wind penetration in Canada (e.g., increases from 5% to 20% to 35%).

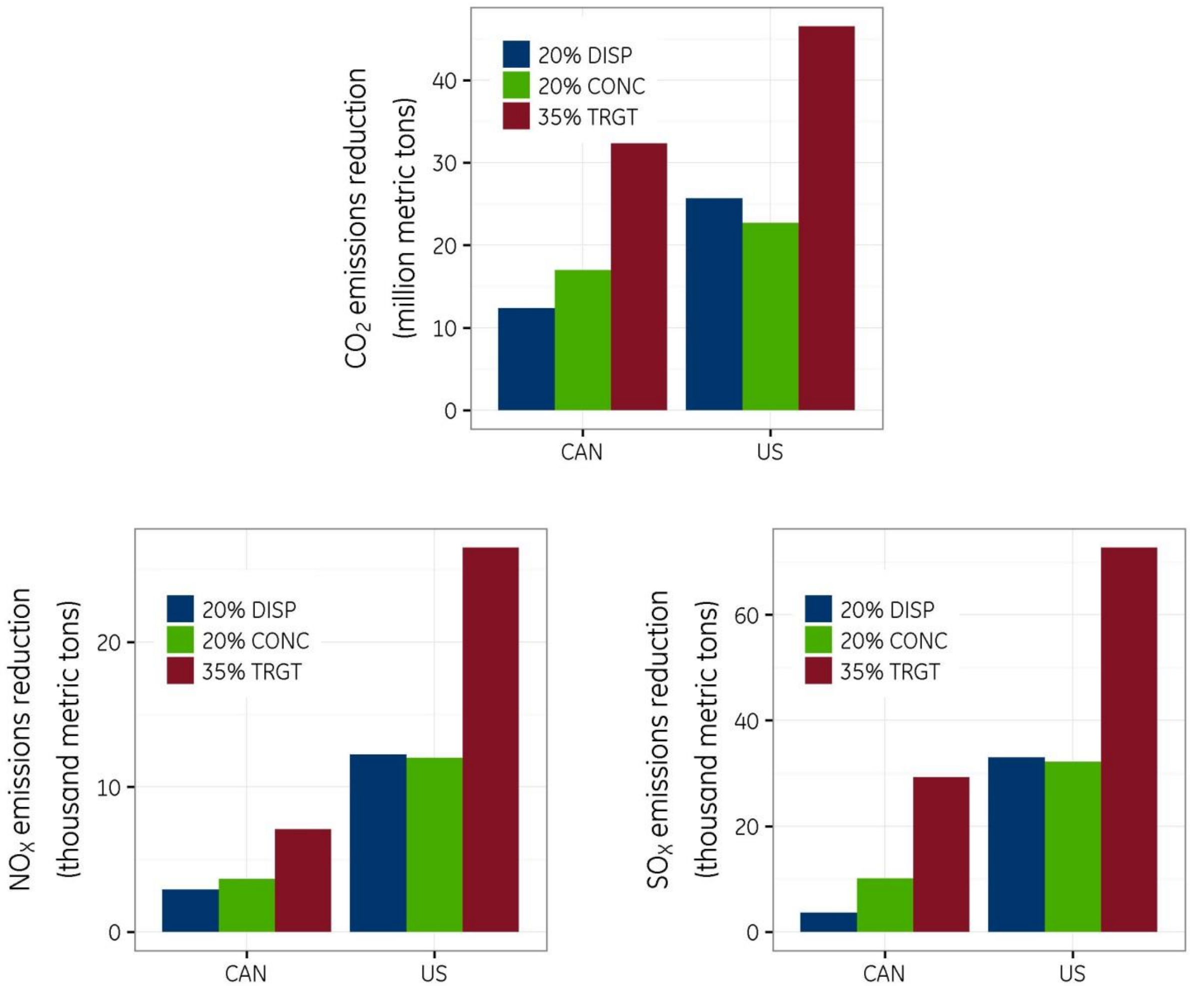


Figure 1-21: Reductions in Emissions Relative to 5% BAU Scenarios

1.10 Capacity Value of Wind Resources

The reliability of a power system is governed by having sufficient generation capacity to meet the load at all times. There are several types of randomly occurring events, such as generator forced outages, unexpected de-ratings, etc., which must be taken into consideration during the planning stage in order to ensure sufficient generation capacity is available. Since the rated MW of installed generation may not be available at all times, due to the factors described above, the effective capacity value of generation is normally lower than 100% of its rated capacity. This effect becomes more pronounced for variable resources such as wind. As an example, a 100 MW gas turbine will typically have a capacity value of approximately 95 MW, while a 100 MW wind plant may only have a capacity value of approximately 20 to 30 MW. It is therefore important to characterize the capacity value of variable wind resources so grid planners can ensure sufficient reserve margin or generation capacity is available at all times under a projected load growth scenario.

This report presents the analysis on the capacity value of wind resources in four scenarios with increasing wind penetration. The analysis was conducted using GE Multi-Area Reliability Simulation (GE MARS) Software, and the capacity value was measured in terms of “Effective Load Carrying Capability” (ELCC). The ELCC of a resource is defined as the increase in peak load that will give the same system reliability as the original system without the resource. Consider a system where the existing Loss of Load Expectation (LOLE) is 0.1 days/year. When 4,000 MW of new wind generation is added to the system, the LOLE drops to 0.001 days/year. Figure 1-22 shows that the new wind generation allowed the peak load to increase by 1,000 MW in order to bring the system reliability back to the original design criteria of 0.1 days/year. Therefore, the ELCC of the new wind generation is 1,000/4,000 = 25%.

This approach was used to calculate ELCC for new wind generation added in each of the four study scenarios. Figure 1-23 shows the results by scenario for all of Canada. The plot shows wind has a capacity value[12] of 36% in the 5% BAU scenario, an impressive result given that the average capacity factor[13] of the wind generation is also near 35%. This is significantly higher than the values observed in previous studies of USA operating areas. One likely reason is that wind generation tends to be higher in the winter season, and Canada’s load is also typically higher in the winter (with noted exception of Ontario, which experiences a summer peak as well as a winter peak). The USA power grids are predominantly summer-peaking, and wind generation tends to be lower in summer than in other seasons. The figure also shows that the capacity value of wind generation decreases as the wind penetration increases.

Capacity value of wind resources is highly correlated to the output of wind plants during the peak load hours of the year. Given that both wind and load are driven by weather, there can be significant variation between years. Figure 1-24 shows that variation over the three years of data that were analyzed for this study. There is also significant variation in capacity value across the different provinces, as illustrated in Figure 1-25. Wind resources in the Maritimes and Quebec have consistently higher capacity values than the other provinces. Alberta and Saskatchewan have significantly lower capacity values for wind.

[12] The capacity value of a generator is the contribution that a given generator makes to overall system adequacy.

[13] The capacity factor of a generator is the ratio of actual annual energy produced by the generator to the hypothetical energy produced from continuous operation at full rated power.

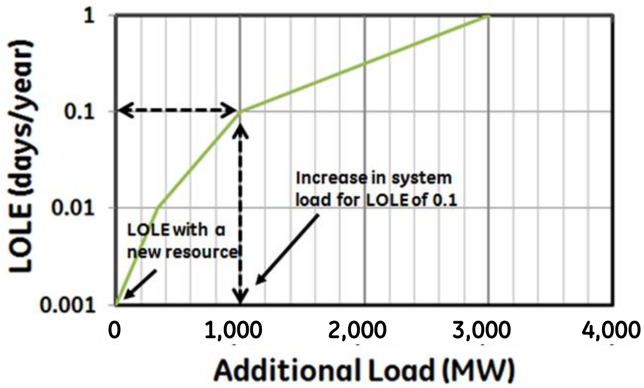
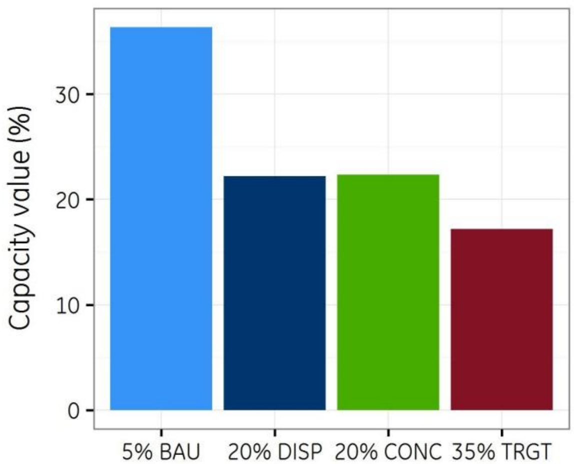
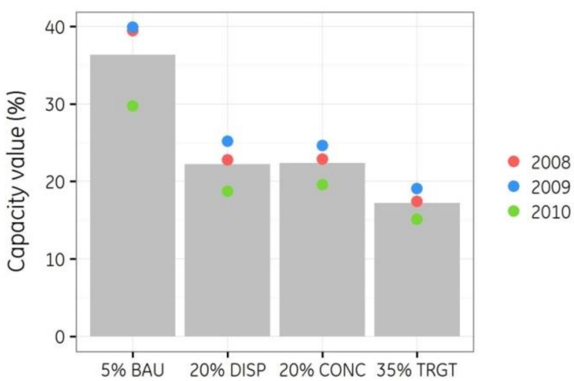


Figure 1-22: Effective Load Carrying Capability of a Resource



Scenario	Wind capacity (MW)	Capacity value (MW)	Capacity value (%)
5% BAU	10,966	3,987	36.4%
20% DISP	37,114	8,251	22.2%
20% CONC	36,312	8,118	22.4%
35% TRGT	65,222	11,214	17.2%

Figure 1-23: Average Capacity Values of Wind Resources across Canada



Scenario	2008	2009	2010	Average
5% BAU	39.4%	39.9%	29.7%	36.4%
20% DISP	22.8%	25.2%	18.7%	22.2%
20% CONC	22.9%	24.6%	19.6%	22.4%
35% TRGT	17.4%	19.0%	15.1%	17.2%

Figure 1-24: Capacity Value Variations over Three Years of Wind Profile Data

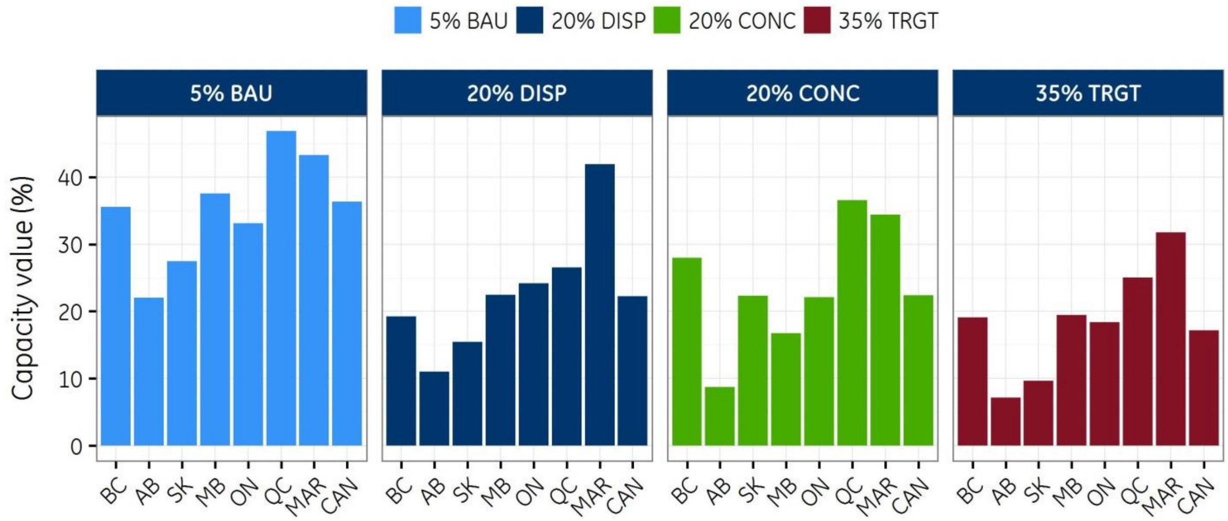


Figure 1-25: Capacity Value of Wind Resources by Province

1.11 Sensitivities to Changes in Study Assumptions

Sensitivity analysis was conducted to determine if and how much the results of the four study scenarios would change if some of the fundamental data assumptions were changed. The sensitivity analysis considered:

- Extent of transmission reinforcement to accommodate new wind resources
- Market price of natural gas
- Types of wind forecasts used in unit commitment and dispatch
- Extent of coal plant retirements
- Operational practices for scheduling of hydro generation resources
- Different historical weather years with different load and wind patterns
- Penetration of wind energy in the USA
- Distributed energy resources including PV solar generation, price-sensitive demand response, energy storage, and electric vehicle charging
- Reduced reserve requirements from conventional generation
- Additional transmission interconnection between Alberta (Western Interconnection) and Saskatchewan (Eastern Interconnection)

The sensitivity analysis is performed by changing one or two variables at a time, and comparing results to the base case scenario. The intent is to isolate, in so far as possible, specific factors that will influence operations or costs. The differential approach tends to filter out much of the impact of assumptions that are unimportant to the specific investigation, while providing insights for stakeholders. Many of the sensitivities presented are aimed at providing guidance on the efficacy of various strategies or options aimed at improving system performance.

The discussion presented here is intentionally brief, only presenting selected significant findings from the sensitivity analysis. Many more details are presented in the full project report.

1.11.1 Additional Transmission Reinforcement

Sensitivity analysis examined changes in system performance with unconstrained transmission capacity between Canadian provinces, unconstrained transmission between Canada and the USA, and unconstrained transmission everywhere. The results indicate that the transmission reinforcements assumed in the base scenarios are adequate. Additional inter-province transmission capacity (Copper Prov in Figure 1-26) would provide very little change in provincial generation patterns. For AB, SK and ON, more transmission capacity to the USA (Copper USA) would enable more exports of coal and gas resources that are displaced by Canadian wind generation in the base scenarios. For BC, MB, QC and MAR, adding more transmission to the USA provides no significant benefit.

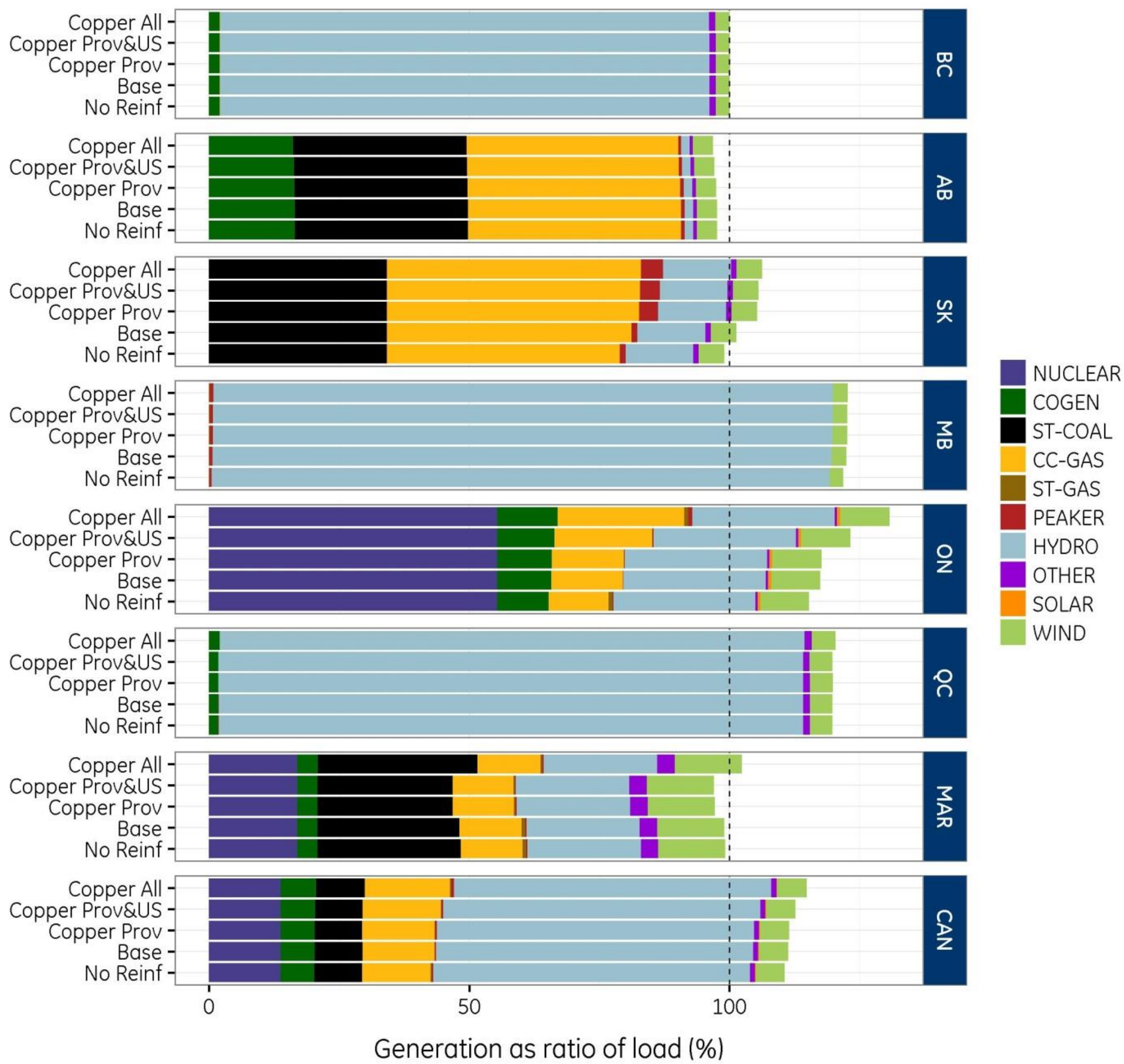


Figure 1-26: Sensitivity of Energy Production to Additional Transmission Reinforcements

1.11.2 Price of Natural Gas

Natural gas generation is on the margin in both the USA and Canada for essentially all hours of the year, and therefore determines the hourly price of electrical energy. The gas price sensitivity analysis (±20%) shows that the energy price in Canada and the USA goes up and down with the price of natural gas. For example, a 20% increase in the price of natural gas results in a 20% increase in the avoided cost of wind energy. But otherwise, there are no significant changes in generation commitment, dispatch, or utilization of wind energy. Variations in gas price do not affect the findings and conclusions from the base scenarios.

1.11.3 Wind Energy Forecasts

The base case study scenarios assumed that day-ahead wind forecasts are used for unit commitment and hydro scheduling. The sensitivity analysis considered 4-hour-ahead forecasts and, as a bookend for maximum achievable performance, perfect wind forecasts. Table 1-11 shows production cost results. If unit commitment and hydro scheduling practices are changed to use 4-hour-ahead wind forecasts, it is possible to reduce energy production costs in North America by C$73M/year to C$198M/year for the study scenarios. Table 1-12 shows that the operation of expensive PEAKER units would decline by 8% to 15%. Wind energy curtailment would also decline slightly with 4-hour-ahead forecasts.

Table 1-11: Production Cost Reductions with Improved Wind Forecasts

Scenario	Change in Production Cost (C$M/year)	
	4-Hr Ahead Forecast	Perfect Forecast
5% BAU	-73	-287
20% DISP	-124	-517
20% CONC	-119	-425
35% TRGT	-198	-772

Table 1-12: Change in PEAKER Energy Production with 4-Hour-Ahead Forecasts

Scenario	PEAKER Energy with Day-Ahead Forecasts (GWh)	PEAKER Energy with 4-Hour Ahead Forecasts (GWh)	Change in PEAKER Energy (GWh)	Change in PEAKER Energy (%)
5% BAU	1,684	1,549	135	8 %
20% DISP	1,550	1,345	205	13 %
20% CONC	1,404	1,208	196	14 %
35% TRGT	2,003	1,707	296	15 %

1.11.4 Coal Plant Retirements

The base study scenarios accounted for coal plant retirements that are already planned. Additional coal unit retirements were examined as sensitivities.

- A “Part-Coal” sensitivity where coal plant capacity was retired equivalent to the capacity value of the wind plants (only in provinces that have coal plants). The oldest plants were selected for retirement. This scenario is realistic in that the installed reserve margin of the remaining generation satisfies the system reliability requirements.

- An "All-Coal" sensitivity where all coal plants in Canada were retired. This scenario is not realistic unless additional capacity is added to satisfy reliability requirements. It was analyzed as the extreme bookend sensitivity.

Table 1-13 shows the MW capacity of coal plants retired and the corresponding changes in production costs for the sensitivity cases. For the Part-Coal sensitivity in the 20% DISP scenario, it was assumed that 402 MW of coal capacity was retired (all in Alberta). Coal energy is replaced by increased utilization of natural gas generation (cheapest option) and decrease in exports to the USA. CO_2 emissions decline by 3 million metric tons in Canada and increase by 0.5 million tons in the USA (due to USA replacing Canadian imports with local coal and gas generation). Production costs increase as the coal energy is replaced by higher-cost natural gas resources.

For the All-Coal sensitivity, it was assumed that all 7,215 MW of coal capacity was retired (4,857 MW in Alberta, 1,111 MW in Saskatchewan, 458 MW in New Brunswick, and 789 MW in Nova Scotia). In all scenarios, CO_2 emissions decline by about 30 million metric tons in Canada and increase by about 8 million tons in the USA. Adjusted production costs in Canada increase by C$780M to C$1,819M depending on how much wind energy is available in the scenario. In the All-Coal case, it is highly likely that during many hours, some provinces such as Alberta will experience significant shortages resulting in unserved energy or application of demand response. In practice, additional resources will be added (e.g., additional wind, natural gas units, demand response, or firm imports, etc.) to ensure resource adequacy.

Table 1-13: Changes in Production Costs for Coal Plant Retirement Sensitivities

Scenario	Part-Coal Retirement		All-Coal Retirement	
	Coal Retired (MW)	Change in Adjusted Production Cost (C$M/year)	Coal Retired (MW)	Change in Adjusted Production Cost (C$M/year)
5% BAU	0	0.0	7,215	1,818.7
20% DISP	402	37.7	7,215	1,168.9
20% CONC	713	0.3	7,215	892.4
35% TRGT	1850	137.3	7,215	780.0

1.11.5 Hydro Scheduling

The base scenarios assume that hydro energy is scheduled according to a day-ahead wind and load forecast, and that hydro dispatch cannot be changed during real time operations. Sensitivity analysis revealed that if wind forecasts are not used in hydro scheduling (i.e., hydro is scheduled against the day-ahead load forecast, ignoring any anticipated wind energy), then adjusted production costs in Canada increase significantly (C$100M/year for 5% BAU scenario and C$494M/year for 20% DISP scenario). This indicates it is economically inefficient to ignore forecasted wind energy during the day-ahead unit commitment process.

On the other hand, if hydro resources are operated in a more flexible manner by adjusting their dispatch in real-time to compensate for errors in the day ahead wind forecast (i.e., real-time net load), then adjusted production costs in Canada are reduced. This benefit is relatively small (C$16M/year reduction) with 5% wind penetration in Canada, but increases substantially (to C$144M/year reduction) with 20% wind penetration. As wind penetration increases in Canada, there is a substantial incentive to use flexible hydro generation to compensate for the inherent errors in day-ahead wind energy forecasts.

Table 1-14: Changes in Production Cost for Different Hydro Scheduling Practices

Scenario	Change in Adjusted Production Cost (C$M/year)	
	Hydro Scheduled Against Day-Ahead Load Only	Hydro Scheduled Against Real-Time Net Load
5% BAU	100	-16
20% DISP	494	-144

1.11.6 Different Weather-Years

The base scenarios used load and wind profiles from year 2008. Profiles from years 2009 and 2010 were analyzed as sensitivities. The results show that 2008 had highest wind energy. 2010 was lowest year with about 5% less wind energy than 2008, and 2009 was about halfway in between. The value of wind energy was relatively constant over the three years (see Table 1-15). Curtailment was slightly lower in 2010 with less wind energy available. No significant changes in hourly operations were observed.

Table 1-15: Value of Wind Energy for Different Weather Years ($/MWh)

Year	20% DISP	20% CONC	35% TRGT
2008 (Base)	43.4	47.2	40.5
2009	44.0	46.7	40.9
2010	41.3	44.0	39.2

Note: Value in $/MWh is calculated as the change in annual Adjusted production cost divided by the change in Available wind energy.

1.11.7 Penetration of Wind Energy in the USA

In the base scenarios, it was assumed that wind energy penetration in the USA was at a level that satisfied all existing RPS requirements. This sensitivity examined the impact of a 20% increase in USA wind energy penetration. Figure 1-27 shows Canadian energy production by province for the 20% DISP scenario for the base case and with increased USA wind penetration. The hydro-rich provinces are not significantly affected. In Alberta, Saskatchewan, Ontario and the Maritimes, there is a small decline in production from combined cycle gas generation due to decreased exports to the USA.

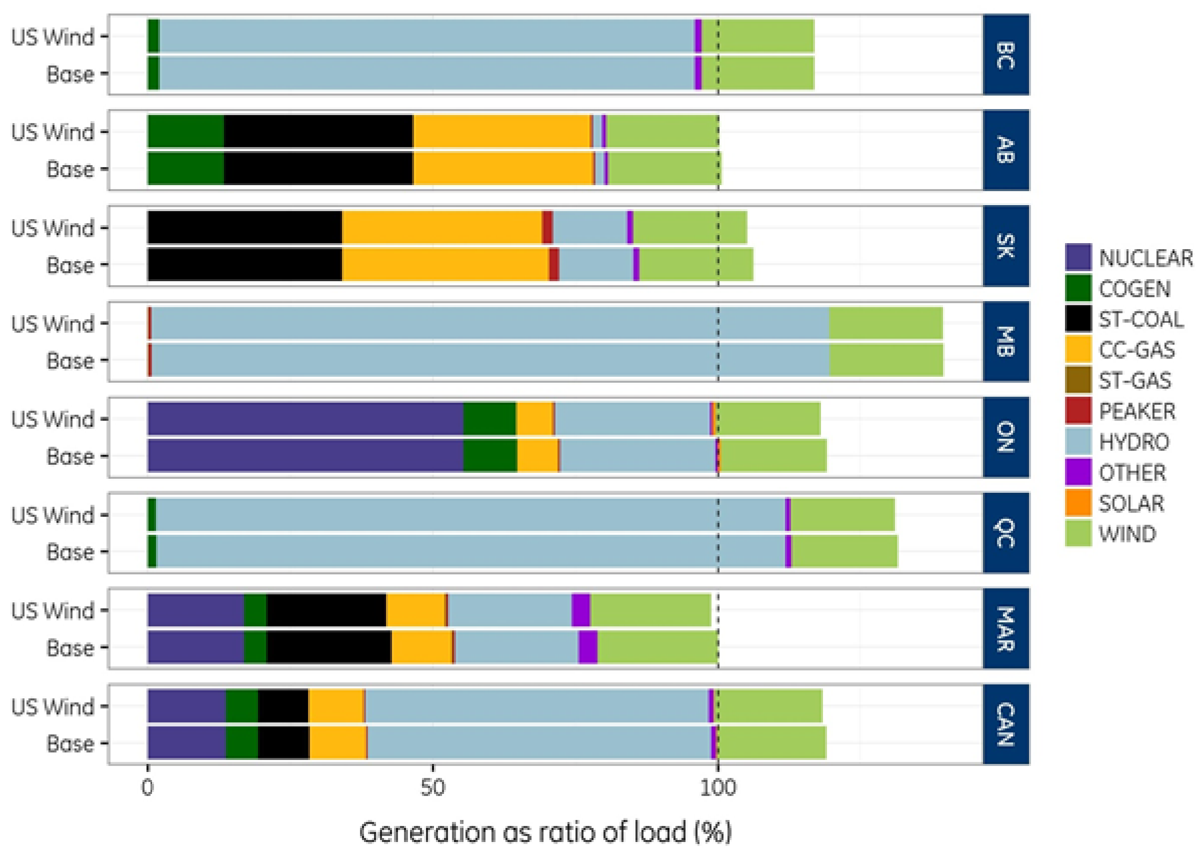


Figure 1-27: Sensitivity of Canadian Energy Production to Increased USA Wind for 20% DISP Scenario

1.11.8 Distributed Energy Resources

1.11.8.1 Distributed Photovoltaic (PV) Solar

This sensitivity assumed that distributed solar photovoltaic (DPV) resources were added with sufficient capacity to serve 5% of Canada's annual load. Table 1-16 shows the installed capacity of DPV resources by province. With these increased generation resources, Ontario, Quebec and the Maritimes provinces experience a generation surplus during some periods. And when transmission capacity is insufficient to share the excess energy with neighbours, curtailment occurs. Table 1-17 shows DPV energy and curtailed energy with and without the DPV resources. In the 5% BAU scenario, the Canadian grid is able to absorb all the DVP energy with only a slight increase in curtailment. In the 20% DISP scenario, 30.5 TWh of DPV energy results in an additional 5.2 TWh of curtailment (about 17%). Curtailment increases to nearly 36% of the DPV energy in the 35% TRGT scenario. These results indicate that while DPV resources can be complementary to wind resources, changes to operating practices and transmission reinforcement will likely be required to minimize energy curtailment as penetration increases.

Table 1-16: Distributed PV Capacity in Canada for DPV Sensitivity Analysis

	BC	AB	SK	MB	ON	QC	MAR
DPV Capacity (MW)	2617	4,110	963	1,032	5,416	7,657	985
DPV Capacity Factor (%)	13.8%	16.1%	17.6%	16.7%	15.1%	15.0%	14.9%

Table 1-17: Total Energy Curtailment for DPV Sensitivity Cases

Scenario	DPV Solar generation (TWh)	Base Case Curtailment (TWh)	Curtailment with DPV (TWh)	Change in Curtailment (TWh)	Change in Curtailment (% of DPV)
5% BAU	30.5	0.5	1.4	0.9	3.1%
20% DISP	30.5	8.5	13.7	5.2	17.0%
20% CONC	30.5	7.9	10.9	3.0	9.8%
35% TRGT	30.5	23.6	34.4	10.9	35.7%

1.11.8.2 Price-Sensitive Demand Response

A two-step demand response (DR) resource was analyzed in the four study scenarios. 5% of system load was available for curtailment in the first step and another 5% in the second step. Table 1-18 shows the dispatch prices for the DR resources. The results show no change in wind curtailment since DR is used during peak load periods when more generation is needed. DR is essentially engaged as an alternative to using quick-start gas turbines (GTs) during peak load periods or to cover short-term dispatch shortages in committed generation. DR utilization and its impact on GT operation is summarized in Table 1-19. In the 20% DISP scenario, DR reduces system load energy by 2,147 gigawatt hours (GWh)/year, and reduces GT generation by about 537 GWh/year. Corresponding reductions in 35% TRGT scenario are 2,444 GWh/year of load reduction and 536 GWh/year of GT generation reduction.

Table 1-18: Dispatch Prices for Two Steps of Price-Sensitive Demand Response

	BC	AB	SK	MB	ON	QC	MAR
First Step of DR (5%)	$71.50	$72.90	$78.10	$86.80	$77.40	$76.60	$92.50
Second Step of DR (5%)	$82.80	$85.70	$84.00	$100.50	$88.40	$94.80	$175.70

Table 1-19: Change in PEAKER Utilization with Price-Sensitive Demand Response

Scenario	DR Energy (GWH)	DR Energy (% of System Load)	PEAKER Energy without DR (GWH)	PEAKER Energy With DR (GWH)	Change in PEAKER Energy due to DR (GWH)
5% BAU	2,305	0.38%	1,684	1,152	-536
20% DISP	2,147	0.35%	1,550	1,012	-537
20% CONC	1,857	0.30%	1,404	951	-453
35% TRGT	2,444	0.40%	2,003	1,467	-536

1.11.8.3 Energy Storage

The 5% BAU and 20% DISP scenarios were analyzed with the addition of 1083 MW of storage (equivalent to 1% of peak load in all provinces) with 10 hours of capacity. In the 20% DISP scenario, wind energy curtailment was reduced from 8,467 GWh to 8,205 GWh (3.1% reduction). The assumed storage resource is of marginal benefit for reducing curtailment and would not be an economical investment. Given Canada's substantial hydro resources, increasing flexibility of hydro operations would likely provide far better performance improvements at much lower cost.

Table 1-20: Change in Total Energy Curtailment with Energy Storage

Scenario	Curtailment Without Storage (GWh)	Curtailment With Storage (GWh)	Change in Curtailment (GWh)	Change in Curtailment (%)
5% BAU	469	412	57	12.2%
20% DISP	8,467	8,205	262	3.1%

1.11.8.4 Electric Vehicles

Another sensitivity that was examined is the impact of electric vehicle (EV) charging on grid performance, assuming 20% of automobiles and busses in Canada were EVs. A simple charging pattern was assumed, where most charging occurred overnight and a small amount during midday hours. Total annual EV charging energy was 17,804 GWh, which increased total Canada load by 3%. Table 1-21 shows the impact of EV charging on total generation and curtailment. Most of the EV load is served by increasing generation, a portion of which is from wind plants that were curtailed in the base scenarios (without EV). The remainder of EV load is balanced by reductions in exports. These results are highly dependent on charging profile (time of day, if centrally controlled by grid operator, etc.). Further study would be needed to better understand the implications of EV charging and to improve grid impacts.

Table 1-21: Impact of EV Charging on Generation and Curtailment

	Increase in Generation with EV (GWh)	Curtailment without EV (GWh)	Curtailment with EV (GWh)	Curtailment Reduction due to EV (GWh)
5% BAU	9,251	469	544	-75 (+16%)
20% DISP	9,270	8,467	8240	227 (3%)
20% CONC	8,943	7,929	7361	568 (7%)
35% TRGT	10,022	23,562	20787	2,775 (12%)

1.11.9 Reduced Reserves from Conventional Generation

This sensitivity examined the impact of reducing the level of spinning reserves obtained from conventional generation resources (thermal and hydro). Instead the reserves could be obtained from demand response, storage devices, or other nonconventional resources. This approach could reduce curtailment during periods where conventional generation resources are dispatched to their minimum output limits. The sensitivity cases assumed zero variability regulation reserves in each province, relative to the base scenarios which included additional calculated hourly variability reserve requirements in each province to mitigate the variability of net load.

Production simulation results show no significant reduction in curtailment. This indicates that the system is not constrained by the commitment of conventional generation units for reserve services.

1.11.10 East-West HVDC Tie

This sensitivity examined changes in system operation with a 1000 MW HVDC transmission tie between Alberta and Saskatchewan, enabling energy exchanges between the asynchronous Eastern and Western Interconnections which were modeled separately in this study. The main objectives were to confirm the reasonableness of that necessary modeling approach and to identify potential operational or economic benefits from such an intertie.

Figure 1-28 shows flow duration curve on the HVDC tie for two scenarios and Table 1-22 summarizes its utilization. The results show that utilization of the tie is relatively small. It is at full capacity only a few hours of the year. Utilization increases somewhat with increased wind penetration. Production cost results indicate that the Eastern and Western grids have similar operating costs and similar operating patterns, with only occasional opportunities to economically exchange energy. Therefore, modeling the Eastern and Western Interconnections separately for this study does not significantly affect the results. There may be more elaborate related scenarios or sensitivities, not studied here, that would show other benefits to this increased interchange capacity.

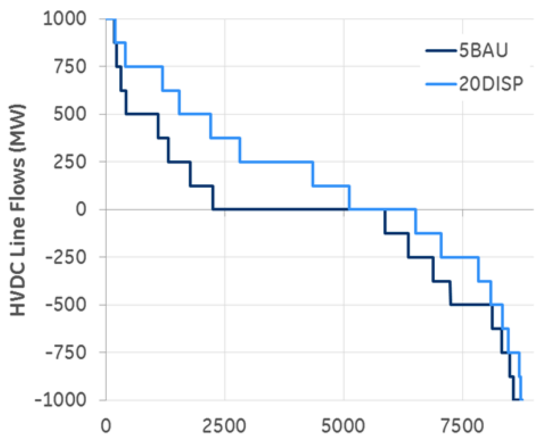


Figure 1-28: East-West HVDC Tie Flow Duration Curve

Table 1-22: East-West HVDC Tie Utilization

	5% BAU	20% DISP
AB --> SK Energy (GWh)	941.12	2220.87
AB --> SK Hours	2242	5113
AB --> SK Utilization	11%	25%
SK --> AB Energy (GWh)	1274	795
SK --> AB Hours	2887	2247
SK --> AB Utilization	15%	9%
Total Energy Flow	2215.50	3015.50
Total Hours of Flow	5129	7360
Total Utilization	25%	34%
Hours of Zero Flow	3631	1400

1.12 Topics for Further Study

The results of the study suggest several technical areas that would justify further investigation.

Seasonal Hydro Scheduling: Canada has substantial hydro generation resources, and some facilities have large pondage reservoirs capable of storing energy for months or years. Wind power varies seasonally due to climatological weather patterns (i.e., more wind in winter and less in summer). Coordinated seasonal scheduling of hydro generation that accounts for seasonal wind and load profiles could significantly improve overall system operational efficiency, reduce costs, and reduce energy curtailment.

Another 20% Penetration Scenario: Results of the four study scenarios suggest that another 20% penetration scenario could warrant analysis – a scenario with a higher concentration of wind resources in provinces with more thermal generation and less wind in the hydro-rich provinces. This would be similar to the 35% TRGT scenario.

Regional Province Collaboration: A regional analysis where operations of a hydro-rich province could be more integrated/coordinated with a neighbouring province that has more thermal generation (e.g., British Columbia and Alberta, or Manitoba and Saskatchewan). It is likely that shared hydro flexibility could relieve some of the balancing area constraints that lead to wind curtailment and operational inefficiencies with increased renewable energy penetration.

Impacts on Canadian Energy Markets: This analysis could be done where applicable, in Alberta and Ontario and would address questions like; what will be the energy market impacts of additional wind? Will thermal generators recoup enough revenue in the energy markets to cover their fixed operating costs or will there likely be generator retirements? Is a capacity market or other form of payment required to maintain reliability?

Grid Frequency Response: With additional wind energy penetration, system inertia will be reduced, fewer thermal units with governors will be operating, and the system's response to loss of generation events may deteriorate. This type of analysis would quantify the impacts and, if necessary, explore mitigations.

Transmission Options: A more rigorous examination on how transmission affects the integration of new renewable resources, including intra-province resource connections to the bulk grid and inter-province transfer capacity to enable better collaboration of grid operations.

Solar Energy: This study examined one case of adding solar energy in Canada, with promising results for some scenarios. Further analysis could investigate where (in which provinces) solar energy fits best into Canada's portfolio of generation resources.

Electric Vehicle Charging: This study considered in a limited way the impact of electric vehicle (EV) charging on grid performance, with narrow assumptions and a simple charging pattern, which showed a measurable increased total Canadian load. Further analysis could help improve understanding of the grid impacts of EV charging.

1.13 PCWIS Full Report Sections

This summary report presents a brief overview of the project and its key findings. The full PCWIS Final Report includes much more comprehensive information about the input data, scenarios, modeling assumptions, analytical techniques, and technical results. The final report includes following major sections:

2 Introduction and Scope

2.1 Project Objectives

The Pan-Canadian Wind Integration Study (PCWIS) was performed to assess the implications of integrating large amounts of wind in the Canadian electrical system: Specifically,

- To develop a consistent database of chronological wind data for potential wind sites across Canada,
- To provide an improved understanding of the operational challenges and opportunities associated with high wind energy penetration in Canada, and
- To provide an improved understanding of the operational and production costs benefits of high wind penetration in Canada.

This study aimed to develop an understanding of the operational implications of how variable wind energy resources would affect the existing and future electricity grid, and what environmental and economic costs and benefits may be associated with integrating large amounts of wind. System operators have a desire to understand how much wind energy can be reliably integrated onto the electricity grid and at what cost. Opportunities for greater penetration and more cost-effective integration are enhanced when these issues are considered on a regional or national basis. While the benefits of wind energy are widely known, the results of this study will help ensure that the benefits of wind energy are most efficiently realized.

It should be noted that the wind penetrating scenarios evaluated in this study (up to 35% nationally) do not represent technical, operational, or economic limits or constraints on wind integration, but represent the study scenarios selected by the Technical Advisory Committee.

2.2 Project Team

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 - Overall project leadership, production cost simulation and reliability analysis
- Vaisala - Wind profile and forecast data development,
- EnerNex - Wind plant data assembly and management, statistical analysis, regulation/reserve requirements
- Electranix - Transmission reinforcement design

- Knight Piésold - Canadian hydropower resource data and modeling

Project team is shown in Figure 2-1 with members of each partner team listed alphabetically by their last names. In addition to the five company team, other entities supporting the project include DNV GL, acting as advisors to CanWEA, and Environment and Climate Change Canada, which performed the mesoscale atmospheric modeling and provided the raw wind related data to Vaisala.

To fulfill the objectives of the study, the GE team quantified the impacts of increasing wind energy penetration on the operation and reliability of the Canadian power systems, evaluated system performance and operating costs, and identified methods and approaches to mitigate the potential adverse impacts of renewable energy integration. The results of this study are intended to provide guidance and quantitative metrics to aid Canadian power systems in future development decisions.

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.
- EnerNex has deep experience in methods and tools to quantify the effect of wind resource variability on a system's need for ancillary services, including spinning reserves and regulation.
- The Electranix team, based in Winnipeg, Manitoba, has extensive experience performing analysis and design of transmission systems, both AC and HVDC, including transmission for wind power (including large scale offshore wind).
- The Vaisala team prepared wind power output profiles and wind power forecasts for simulation in the study scenarios. Vaisala is previously developed a similar dataset for NREL for the US.
- The Knight Piésold team contributed hydropower expertise and hydrology analysis to the project to ensure that hydro power is accurately included.

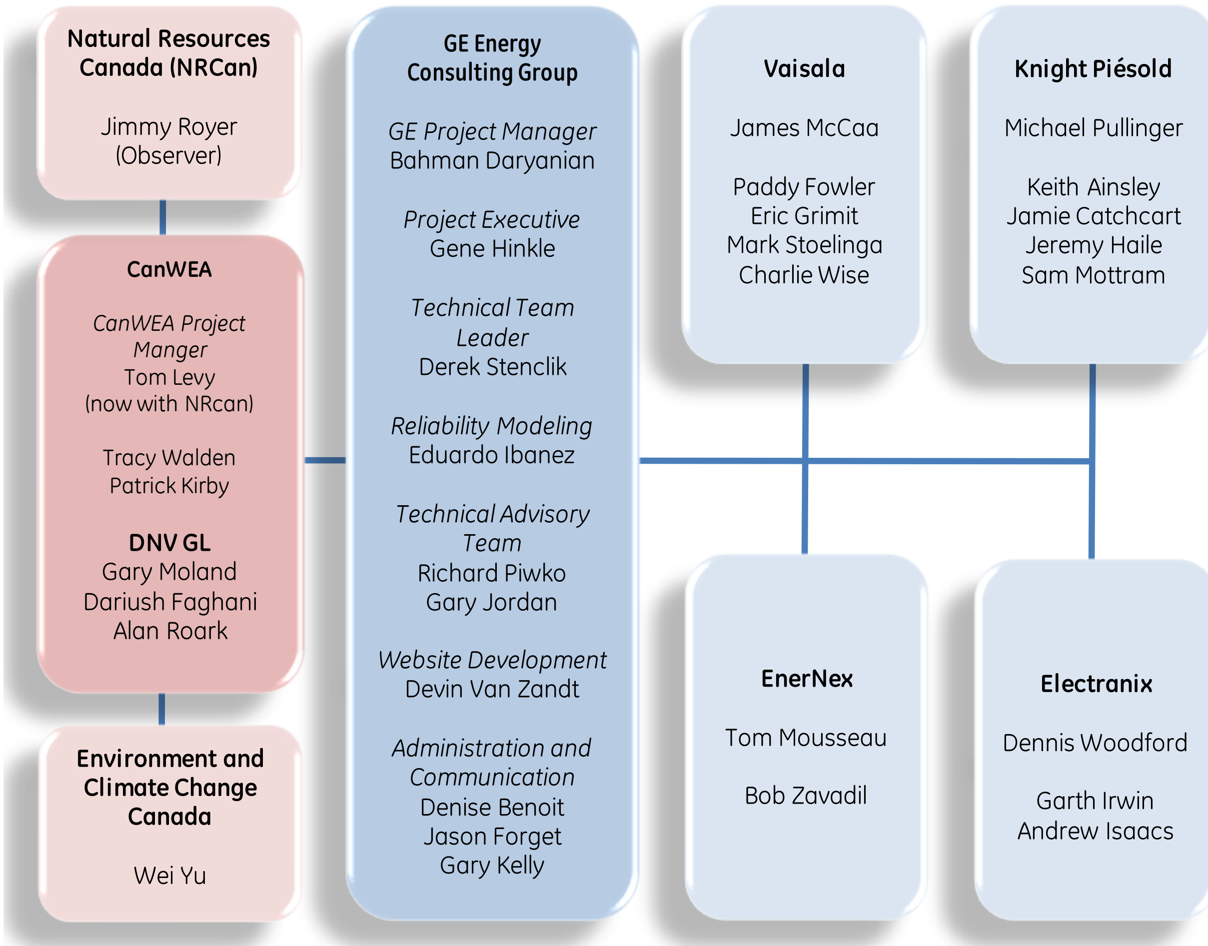


Figure 2-1: Project Team

A Technical Advisory Committee (TAC) 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. TAC member organizations are presented in Table 2-1.

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

Alberta Electric System Operator (AESO)
BC Hydro
Hydro Quebec
Independent Electricity System Operator (IESO)
ISO-New England (ISO-NE)
Manitoba Hydro
Midcontinent Independent System Operator (MISO)
National Renewable Energy Laboratory (NREL)
New York Independent System Operator (NYISO)
SaskPower
Utility Variable-Generation Integration Group (UVIG)
Western Electricity Coordinating Council (WECC)

2.3 Project Tasks

2.3.1 Major Tasks

The Study performed a detailed analysis of the operational, planning and market impacts of high penetration of renewable generation on the Canadian power systems. The Study divided the work into 6 major tasks.

Task 1 defined 4 study scenarios and developed a generation expansion plan for each scenario.

Task 2 developed wind profiles for the Study with sufficient accuracy and flexibility to allow for simulation of power system and renewable generation operation and interaction over the time scales of interest.

Task 3 focused on the development of the transmission reinforcement to support generation expansion.

Task 4 focused on a detailed evaluation of the impact of wind generation variability and uncertainty on Canadian power systems' operations and markets, including a reliability analysis of the affected systems.

Task 5 considered additional sensitivity analyses determined later in the course of the study.

Task 6 produced a final report including a set of recommendations based on the results of the study. This task also included development of a study website to provide access to the study reports.

Figure 2-2 shows a flowchart of GE's plan used to execute this study. It identifies the project tasks, primary contributors to each task, and how work product and results flowed from task to task (indicating critical task interdependencies). An overview of the project plan is described below. Details of each task and subtask are presented in Section 3.

Task 1: Generation Expansion

In Task 1, study data assumptions and scenarios were defined by CanWEA, DNV GL, and the TAC, and provided to the GE Team for review and feedback. The GE Team developed a generation expansion methodology, created the generation expansion plan for each scenario, and selected specific locations and ratings for wind resources to build the study scenario datasets.

In addition to Tasks 1.1 through 1.5 specified in the RFP, the proposed scope included Task 1.6. The Knight Piésold team contributed information for the Canadian hydro power database and assisted the GE Team in appropriate modeling of hydro power in the production simulation analysis.

Task 2: Wind Generation

In Task 2, the Vaisala team developed a methodology for developing hourly wind power production data using the data provided by Environment and Climate Change Canada, executed the methodology to generate the wind profiles, and developed hourly wind power forecasts. The wind power output profiles were used in Task 1.5 to select wind locations and build wind generation datasets for each study scenario.

Also in Task 2, EnerNex developed hourly regulation reserve requirements to account for net load (i.e., load minus wind generation) variability based on the developed wind power profiles and load assumptions. These hourly wind variability related regulation reserves were incorporated into the production cost modeling in Task 4.

In addition, EnerNex performed statistical analysis on the load and wind data to characterize wind resources, to provide insights on the load and wind variability and understanding study results obtained in later tasks.

Task 3: Transmission Reinforcements

Task 3 identified the need for additional transmission reinforcements under the study scenarios needed to maintain a reasonable level of congestion caused by higher penetration of wind energy in the system. The size of the transmission reinforcements were determined by the GE MAPS modeling, based on which recommendations and cost estimates for transmission upgrades across modeled transmission interfaces were developed.

Based on the analysis of Task 4 (described below) GE determined the additional modeling based transmission reinforcements needed to keep the transmission congestion at a reasonable level at different wind penetration levels. Electranix used that information to develop the actual new physical transmission elements that would provide the additional transmission capacity identified by the model. Electranix also provided a high level estimate of the cost of additional transmission.

Task 4: Scenario Analysis

In Task 4, the GE Energy Consulting team performed production simulations of hourly operation of the Canadian and the U.S. interconnected systems for each of the 4 scenarios. The output of the simulation provided generation dispatch, annual production cost, locational marginal prices (LMP), congestion, emissions etc.

Also as part of Task 4, GE used the GE Multi-Area Reliability Simulation (GE MARS) model to evaluate resource adequacy, reliability, LOLE and wind capacity value for each of the study scenarios.

Task 5: Sensitivity Analysis

GE performed additional Sensitivity Analysis in Task 5, based on new objectives and issues that were raised over the course of the initial work, which were determined based on inputs from CanWEA, GL GH, and the Technical Advisory Committee.

Task 6: Reporting and Website Development

Finally in Task 6, the entire project team worked on preparing the presentation material for the later Technical Advisory Committee meetings and drafting of the final report. GE worked with CanWEA to develop a website for distributing the study findings that can be accessed and downloaded for review and further studies.

A high-level overview of the key contributions of the GE team members, the software tools employed and how they fit together is depicted in Figure 2-2.

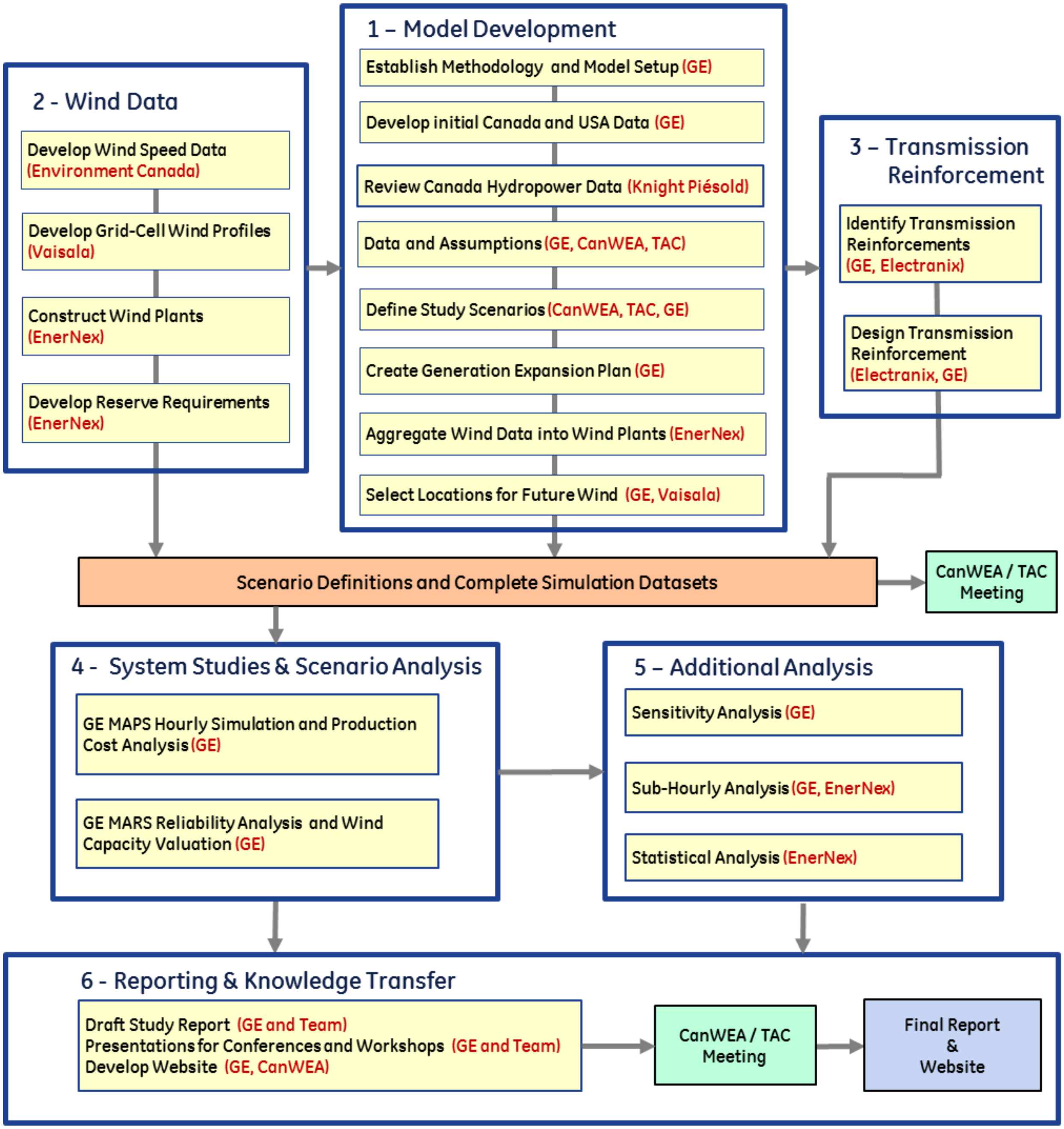


Figure 2-2: Study Process Flowchart

2.3.2 Additional Analysis

Statistical and Reserve Analysis

Impacts on system-level operating reserves were also analyzed using a variety of techniques including statistics and production simulation. This analysis quantified the effects of variability and uncertainty, and related that information to the system's increased need for operating reserves to maintain reliability and security.

The results from these analytical methods together with the additional analytical work on operating reserve requirements, cycling analysis, and emissions analysis complemented each other and provided a basis for developing observations, conclusions, and recommendations with respect to the successful integration of wind generation into the Canadian power grid.

Sub-Hourly Analysis

Additional analysis included analysis of sub-hourly reserve by quantifying the adequacy of available capacity of dispatchable generation resources to cover 10-minute variability of wind generation and load in the study footprint subject to unit ramp rates and ramp range constraints.

2.4 Analytical Approach

2.4.1 Methodology and Modeling Tools

The core analysis of this study required detailed production simulation analysis and reliability analysis. The study utilized the GE Concorda Suite Multi-Area Production Simulation (GE-MAPS) model for production costing analysis, and the GE Multi-Area Reliability Simulation (GE-MARS) model for reliability analysis and wind capacity valuation. Brief overviews of these models are presented below, and more extensive descriptions are presented in the Appendix.

The power grids represented in this study are extremely large and complex systems, covering most of North America. The underlying model included representation of both the entire Eastern Interconnection (EI) and the Western Interconnection (WI). In other words, the representation of the power systems was not limited just to the Canadian provinces, and included the entire U.S. regions, other than ERCOT – covering most of Texas – which is an isolated interconnection and not synchronized with either EI or WI. Simulation of hourly nodal security constrained unit commitment and economic dispatch of the entire North American power system was made possible by GE's High-Performance Cluster Computing capability. This was an important asset to enable full nodal simulation of the combined US and Canada power grids.

2.4.2 Hourly Production Cost Analysis (GE MAPS)

The GE team utilized GE Concorda Suite Multi-Area Production Simulation (GE MAPS) model to perform simulation of the selected four scenarios and the requisite sensitivities. GE MAPS is a proven tool that has been used in previous renewable (wind and solar) integration studies performed by GE and its partners in the course of the last 10 years. GE MAPS is a nodal, security-constrained, unit commitment and economic dispatch model with detailed realistic representation of all generation types and the underlying transmission grid. Generation of all types, including existing and future thermal, hydro, wind, and solar plants were represented as connected to nodes or buses (substations) on the grid. The model provided detailed hourly outputs of operational and economic performance of all generation units. The modeling results also provided hourly information on transmission flows, binding transmission constraints, shadow prices, and congestion costs.

For the purposes of this study, the GE MAPS model covered both U.S. and Canadian interconnections. Hence, the modeling provided detailed information on inter-country power flows, based on a nodal based realistic representation of the neighbouring power systems in the U.S. The model was run for each modeled interconnection (i.e., both EI and WI), with the degree of detail based on additional information that the GE team was able to collect and incorporate in the existing GE MAPS database of U.S. and Canada.

The production simulation results quantified numerous impacts on grid operation under different scenarios on an hourly basis, including, but not limited to:

- Electricity generation by each defined generation resource and unit type
- Operational performance of generation resources
- Curtailed energy due to higher penetration of wind and congestion
- Environmental emissions (SO2, NOX, and CO2)
- System-wide operational costs (so-called production costs)
- Power flows and congestion on monitored transmission tie-lines

2.4.3 Reliability Analysis and Wind Capacity Valuation (GE MARS)

The GE team utilized the GE Concorda Suite Multi-Area Reliability Simulation (GE MARS) model to perform reliability analysis (loss of load expectation, LOLE) and wind capacity valuation (effective load carrying capability, ELCC).

A sequential Monte Carlo simulation formed the basis for GE MARS. Chronological system histories were developed by combining randomly-generated operating histories of the generating units, with inter-area transfer limits and hourly chronological loads. Consequently, the system was modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules and policies which govern system operation. GE MARS does not require simplified or idealized assumptions often required for other analytical methods.

The following reliability indices were produced on both isolated (zero ties between areas) and interconnected (using the input tie ratings between areas) basis:

- Daily LOLE (days/year)
- Hourly LOLE (hours/year)
- LOEE (MWh/year)
- Frequency of outage (outages/year)
- Duration of outage (hours/outage)
- Need for initiating emergency operating procedures (days/year)

2.4.4 High Performance Computing Facility

The GE team leveraged its High Performance Computing (HPC) Center capabilities to perform the analysis in a timely and efficient manner using parallel computing techniques. GE Energy Consulting uses a Linux-based High Performance Cluster to significantly reduce runtimes of the GE MAPS and GE MARS models. Each of these programs is highly suited for parallel processing and the GE Energy Consulting software team has developed customized code to maximize the HPC benefit.

2.5 Study Limitations

Heuristic-Based Generation Expansion Plan

The focus of this project was to determine the various impacts of wind energy additions in Canada. It was not intended to be an overall integrated resource plan (IRP). The study makes no effort to establish the overall adequacy of the Canadian power grid, nor does it attempt to determine exactly what resources are necessary to meet system performance and reliability objectives.

Although full integrated resource planning (IRP) type analysis was beyond the scope of this study, a heuristic generation expansion planning approach was used to add enough new generation capacity so that all of the balancing areas would meet their installed reserve margin requirements with anticipated 2025 system load levels in the 5% BAU scenario.

Transmission Reinforcements in lieu of Long-Term Regional Transmission Expansion Planning

In addition, this study is not meant to be a long-term regional transmission expansion plan. The approach used in this study is adequate for determining the appropriate levels of transmission reinforcements. Doing a more complex long-term regional transmission expansion planning study was beyond the scope of this project.

Limited Focus of the Economic Analysis

The study scope did not include evaluation of the economic viability of the generation resources that would be significantly impacted by the higher penetration of wind and their downward pressure on electricity costs caused by displacement of fossil fuel based generation. 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 additional wind in the system.

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 for new wind additions or fixed operations & maintenance or power purchase agreements for new generation resources.

Production/Reliability Simulation

The modeling used is highly sophisticated, and the tools (GE MAPS and GE MARS) are industry standards - 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 human operators. There are limits to our ability to exactly replicate present, and even more so, to accurately predict possible future operations of the Canadian grid. GE 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 necessary for Canadian stakeholders to make good investment and operational decisions. Perfect accuracy is neither possible nor necessary.

Engineering Analysis

This study included a technical evaluation of the economics, operations, and reliability of increased renewable penetration, but it did not include an evaluation of system stability associated with those changes. Technical engineering analysis related to dynamic frequency response, grid strength, power-swing stability, and transmission related interconnection studies and transfer analyses should be evaluated in future study work.

3 Wind Data Development

Section Acknowledgement:

Sub-section 3-1 was written by the Environment and Climate Change Canada team[14].

Sub-section 3-2 and the following sub-sections were written by the Vaisala team.

3.1 Mesoscale Modeling of Wind Speed Time Series

3.1.1 Introduction

The objective of this project was to generate multi-year time series of surface-layer meteorological fields as part of the Pan-Canadian Wind Integration Study (PCWIS). The Canadian Wind Energy Association (CanWEA) has a target of generating 20% of Canada’s electricity by 2025 from wind energy. In this regard, CanWEA will analyze the time series generate by this project for devising a viable strategy for such large-scale integration of wind energy within the Canadian power grids.

The project was mandated to generate the relevant time series using a three-dimensional mesoscale atmospheric model with 2-km horizontal grid spacing and 10 min time resolution, over all of Canada (south of 70º N). Mandatory outputs for the project include wind speed and direction, air temperature, specific humidity at 80, 100, and 120 m above ground level along with surface pressure.

3.1.2 Methodology

Mesoscale simulations for this project were carried out using the limited-area configuration of the Global Environmental Multiscale (GEM) atmospheric model (GEM-LAM hereafter). In general, the GEM model works by first solving a set of dynamical equations directly on the model grid. Physical processes including atmospheric radiation, fluxes from different land-surface components, boundary-layer turbulent mixing as well as clouds and precipitation are not directly resolved at the grid scale. These subgrid-scale processes are accounted for in the model by supplementing the solutions of the dynamical equations with parameterized tendencies associated with the pertinent physical processes.

[14] "Mesoscale Modeling Of Wind Speed Time Series, A Summary Report", Prepared by: W. Yu, S. Z. Husain, L. Separovic, and D. Fernig, Atmospheric Numerical Weather Prediction Research Section, Meteorological Research Division, Atmospheric Science and Technology Directorate, Environment and Climate Change Canada, 2121 TransCanada Highway, Dorval (Quebec), Canada H9P 1J3, "Funding for this project (RENI 546) was provided by the ecoENERGY Innovation Initiative (ecoEII) of Canada, March 16, 2015

Large-scale atmospheric features in the meteorological fields simulated with limited-area models are susceptible to deviations from the generally coarse-resolution driving fields over time, particularly for large continental-scale spatial domains. A major scientific challenge for this project was, therefore, to determine the appropriate strategy to address the issue of large-scale deviations for multi-year simulations.

In order to minimize the impact of large-scale deviations associated with a large spatial domain over extended-range simulations, the problem may be separated into multiple periods of sufficiently short time-frames. Construction of a final continuous time-series of any meteorological variable in this approach however suffers from abrupt changes due to temporal blending. Furthermore, individual shorter integration requires time for spin-up of clouds that are not analyzed in the regional analysis files from the Meteorological Service of Canada (MSC). The spin-up issue would therefore increase the computational cost of the project.

Dividing the problem into multiple mesoscale simulations over smaller domains each running for extended time-periods (from weeks to months) followed by spatial blending of the end results on the other hand results in spatial discontinuities in the meteorological fields, particularly along the lateral boundaries of the smaller domains. Furthermore, existing literature shows that the nested simulation domains cannot be arbitrarily small in order to permit proper development of small scales.

Based on the aforementioned adverse implications associated with temporal and spatial blending, a continuous temporal integration over the entire spatial domain appears to be the most suitable approach for this project, provided a mechanism is put in place to restrict large-scale deviations in the simulated fields. Large-scale atmospheric deviations are controlled by spectrally nudging the model outputs to the driving fields. Spectral nudging of the atmospheric large scales, as implemented in this project, is found to effectively control any undesirable deviation without considerable suppression of the small scales. The research conducted during this project have shown that simple temporal interpolation to derive the reference fields, in between two analysis hours, can lead to mesoscale variance deficiency in the spectrally-nudged simulated fields. Two different strategies have been proposed and examined during this project to deal with such variance deficiencies. One option is to use a time-varying nudging coefficient that puts the maximum weight on the analyses fields only when the simulation time is very close to the time for which valid analyses fields are available. The other approach, which has been demonstrated to be more effective, is to produce hourly estimates of analyses by running 6-hour forecasts initialized with the analyses and assuming a linear growth of forecast error within the first 6 hours of model simulation. The later approach is found to effectively eliminate any variance deficiency associated with the temporally-interpolated analysis fields. Furthermore, different spectral nudging approaches, including the appropriate nudging length scales as well as the vertical profiles and temporal relaxations for nudging, have been investigated to determine the optimal nudging strategy. Analysis conducted during the course of this project has shown that specific humidity is well constrained during extended-range simulations when only temperature and wind speed are controlled by nudging. As a result, only the simulated temperature and horizontal wind speed fields were selected for nudging in this project. Further details regarding the spectral nudging approach developed for this project are provided in (Husain et al., 2014).

Although controlling the evolution of the atmospheric large scales generally improves the outputs of high-resolution mesoscale simulations within the surface layer, the prognostically evolving surface fields can nevertheless deviate from their expected values leading to significant inaccuracies in the predicted surface-layer meteorology. A forcing strategy based on grid nudging of the different surface fields, including surface temperature, soil-moisture, and snow conditions, towards their expected values obtained from a high-resolution offline surface scheme was therefore developed to limit any considerable deviation. The offline surface scheme used to downscale the surface fields (surface temperature, soil moisture, snow depth, and snow density) is known as the Surface Prediction System (SPS) which is based on the ISBA (Interactions between Soil, Biosphere, and Atmosphere) land-surface scheme. The standard implementation of the SPS scheme was considerably modified in the course of this project to include weighted blending of the driving forecasts fields to remove abrupt changes during switching between the driving forecast fields. Furthermore, a large-scale relaxation scheme for the evolving soil moisture field towards its regional analysis counterpart was implemented to restrict intermittent large-scale deviations. Additional details on the land-surface component of this project are provided in (Separovic et al., 2014).

3.1.3 Simulation Strategy

The basic simulation followed a two-stage strategy. First, the MSC's regional analysis fields, available every 6 hours (0000, 0600, 1200 and 1800 UTC, where UTC denotes the Coordinated Universal Time), were used to initialize and drive a GEM-LAM simulation involving 15 km horizontal grid spacing over the entire simulation domain over the entire time period (2008-2010). The 15-km GEM-LAM (LAM-15 hereafter) simulation included large-scale nudging of horizontal wind speed and temperature toward the operational regional analysis fields. The relevant surface fields in LAM-15 simulation were also nudged towards to SPS-generated reference fields. The purpose of the LAM-15- simulation was to produce three-dimensional meteorological fields with large scales features closely resembling those embedded in the driving analysis fields, but available more frequently (every 20 min) to force the second-stage 2-km GEM-LAM (LAM-2 hereafter) simulation. The LAM-2 simulation also involved atmospheric and surface nudging towards the appropriate reference fields to produce the final desired outputs.

3.1.4 Verification of Strategy

Outputs of the LAM-15 and LAM-2 simulations were extensively analyzed to verify the validity of the strategy developed during the course of this project. The verifications that were conducted during this project are provided below.

I. Similarity between the large-scales of the driving and the simulated field were compared to determine the impact of different atmospheric nudging configurations and to identify the most appropriate nudging strategy. Similarity of large-scales is compared for both LAM-15 and LAM-2 simulations that were forced with the operation regional analysis and LAM-15 outputs, respectively.

II. The ratios of spectral variance between the driving and analysis fields for different length scales and at different vertical levels were compared to study the impact of different nudging configurations. It helped to identify the appropriate nudging length scales. Variance spectra ratio was analyzed for both LAM-15 and LAM-2 simulation outputs. It was also useful in determining the impact of surface nudging.

III. Simulated fields are compared at the screen level (2-m temperature and dew point, and 10 m wind speed) against those obtained from ground-based stations spread all across Canada. In addition to the entire domain, screen-level statistical scores (bias, root-mean-square error, standard error) were compared for individual regions. The results have shown that both LAM-15 and LAM-2 simulations coupled with atmospheric and surface nudging resulted in improved screen-level temperature compared to the operational regional forecast while wind speed scores were also found to be equivalent. Over complex terrain, e.g., over British Columbia, LAM-2 simulations were found to result in improved scores for wind speed.

IV. Simulated fields were also compared against the limited wind turbine data that were available. For those limited number of stations, the simulated fields demonstrated improved statistical score compared to the operational forecasts. Moreover, the results for the optimal LAM-2 simulation were found to clearly outperform the optimally configured LAM-15 simulation.

3.1.5 Conclusions

A dynamical downscaling strategy based on high-resolution mesoscale simulations over a large continental-scale spatial domain and an extended time-period has been developed within the course of this project. Continuous temporal integration over the entire domain, as opposed to extended integrations over smaller spatial domains or multiple simulations with shorter time periods over larger domains followed by spatiotemporal blending, was found to be the most suitable approach for accomplishing the high-resolution downscaling objectives of the project.

The developed scheme was employed during the project to generate the multi-year time series of meteorological variables for CanWEA as a contribution to the broader PCWIS.

In order to improve the impact of spectral-nudging two novel methods have been developed that reduces or eliminates variance deficiency in the simulated fields. This includes the concept of time-varying nudging increment and the method of computing frequent analysis estimates. Extensive sensitivity studies have been carried out to identify the optimal nudging configuration in terms of the shape of nudging vertical profile, nudging length-scales and the type of temporal relaxation.

Large-scale spectral nudging of horizontal wind speed and temperature was found to adequately control large-scale deviations in specific humidity. In order to overcome intermittent deviations the surface fields were nudged towards some reliable reference dataset obtained from the modified SPS external surface model. Results show that compared to the coarse-resolution regional analysis fields, the SPS fields when used as reference for surface nudging clearly led to improved screen-level scores for both temperature and dew point. Nudging of the surface fields was however found to be neutral for the screen-level wind speed. Increasing the strength of surface nudging was found to improve screen-level scores further.

Meteorological fields obtained through high resolution LAM-2 simulations following the nudging strategy adopted in this project is able to maintain large-scale similarity with the driving LAM-15 fields, while adding substantially increased spatial variance for the smaller scales (less than 200 km). In terms of screen-level score, LAM-2 simulations were, in general, found to be equivalent compared to the LAM-15 simulations over the entire domain, although over BC and the North, where orography-induced spatial variance is more influential, LAM-2 simulations were found to improve both screen-level temperature and wind speed. Performance of different atmospheric nudging configurations for both LAM-15 and LAM-2 simulations was also evaluated against 80-m wind and temperature data obtained from three wind farm locations. For all three stations, LAM-2 simulation with its optimal nudging configuration was found to deliver better statistical accuracy for both wind speed and temperature over its LAM-15 counterpart.

3.1.6 References

- Husain, S.Z., Separovic, L., Yu, W., and Fernig, D. (2014): Extended-range high-resolution dynamical downscaling over a continental-scale spatial domain with atmospheric and surface nudging. Journal of Geophysical Research – Atmospheres, 119(24): 13720-13750.
- Separovic, L., Husain, S.Z., Yu, W., and Fernig, D. (2014): High-resolution surface analysis for extended-range downscaling with limited-area atmospheric models. Journal of Geophysical Research – Atmospheres, 119(24): 13651-13682.

3.2 Wind Integration Dataset

3.2.1 Introduction

Vaisala was retained to produce an integration dataset in support of the PCWIS. An integration dataset provides the simulated raw production and forecasts that act as inputs to the models and scenarios used in an integration study. A primary focus of integration datasets is to attain realistic properties of wind energy generating facilities, and realistic forecast levels of forecast skill in the simulated retrospective forecasts.

The PCWIS is an integration study intended to cover a broad swath of southern Canada. The main components of the dataset delivered by Vaisala are a synthetic history for more than 50,000 hypothetical wind energy locations consisting of simulated 10-minute production, and simulated hourly energy production forecasts for the hour-ahead, four hour-ahead, six hour-ahead, and 24 hour-ahead forecast horizons for each of the locations over a three-year period from 2008 through 2010. The wind production dataset uses the meteorological dataset described above as provided by Environment and Climate Change Canada as its basis, with algorithms to convert the meteorology into time series of synthetic energy generation developed and applied by Vaisala. The production estimates include losses specially formulated for the Canadian domain and parameters of the wind integration study, and include dynamic wake losses, icing losses, and low temperature losses.

Because of the importance of transmission interconnects to the United States, attempts were made where possible to follow the procedures established during the creation of the US Wind Integration National Dataset (Draxl et al, 2015), which Vaisala created in collaboration with the U.S. National Renewable Energy Laboratory.

3.2.2 Meteorological Datasets

Two independent meteorological datasets were used for the creation of production and forecasted production data, and these were produced by Environment and Climate Change Canada and Vaisala, respectively.

3.2.2.1 Simulated Production

Environment and Climate Change Canada generated the meteorological dataset that provided the basis for simulated energy production, using a limited area mesoscale numerical weather prediction (NWP) model, run at a horizontal grid resolution of 2km as described previously. Variables provided at each of the cell locations were: wind speed at 80m (m/s), 100m (m/s), and 120m (m/s), wind direction at 100m (degrees), temperature at 80m (Celsius), 100m (Celsius), and 120m (Celsius), humidity at 100m (kg/kg), and surface pressure (hPa). The output interval was 10 minutes, and data was delivered for the period from January 1, 2008 through December 31, 2010.

3.2.2.2 Simulated Forecasts

Vaisala produced a second, independent meteorological dataset that provided the basis for the simulated energy production forecasts. The fundamental tool employed in the creation of the meteorological dataset was the Weather Research and Forecasting (WRF) modeling framework. WRF is maintained by the U.S. National Center for Atmospheric Research (NCAR), but includes contributions from institutions worldwide. Specifically, version 3.4.1 of the WRF Advanced Research and Weather (ARW) model was used.

Vaisala's base simulation consisted of 41 full eta levels and had the following configuration:

- Planetary Boundary Layer Scheme - YSU model
- Surface Parameterization - Monin-Obukhov similarity model
- Land-surface option – NOAH LSM
- Scale selective nudging

Nested domains of 54km, 18km, and 6km were used. The model was initialized once per day at 0000 UTC, with no spin-up period. The 1-degree NOAA GEFS Reforecast 2 (Hamill et al, 2013) control simulation was used to specify initial and lateral boundary conditions. Each forecast simulation was run out 48 hours to ensure that the day-ahead (i.e. next day) period was covered. The output interval was 60 minutes.

3.2.3 The Wind Hourly Production Dataset

3.2.3.1 Cell selection

The initial target for the total number of sites in PCWIS was 50,000, distributed across the various provinces in proportions determined in coordination with the steering committee. Varying proportions of onshore and offshore sites on a per-province basis were specified, depending on the feasibility of offshore production and quality of wind resource. A maximum of 15% offshore penetration was considered for the Maritimes, Ontario, Quebec, and British Columbia, leading to an overall offshore penetration of roughly 10% for all of Canada. Hudson Bay was considered unfeasible. Provinces with no access to large open bodies of water had zero offshore sites.

In total, 54,846 onshore and offshore cells were prescribed. A cell in the context of this project refers to a point location and hypothetical wind development site in the Canadian domain collocated with a numerical weather prediction (NWP) grid point. Each cell represents four square kilometers, with a presumed maximum installation capacity of eight 2MW modern utility-scale wind turbines. Each cell therefore has a maximum rated capacity of 16MW. The turbine density specification was identical to that in the US Wind Integration National Dataset, and is based on examination of turbine density within modern North American wind projects.

While each cell has a maximum rated capacity of 16MW, individual cell power curves are one of four available classes, based on the simulated 2008 annual average wind speed at each cell. Specifics of the power curves are described below.

The strategy for cell selection was to grossly oversample the potential number of cells required for the integration study, in order to provide maximum flexibility during the selection of scenarios. Due to technical restrictions at Environment and Climate Change Canada, all cells needed to be selected before any modeling could begin. Starting with a list of all cells within each province, many cells were excluded according to criteria developed in collaboration with the steering committee. Specifically, areas that were excluded from the site selection process met at least one of the following conditions:

- An area with a terrain slope of greater than 20°
- Surface elevation of greater than 2000m
- Area within a Provincial park or Wilderness
- Populated areas
- Aboriginal and Indian Areas
- Major lakes and rivers

After these areas were excluded, the remaining cells were sorted by annual mean wind speed at 80m, and the windiest cells were included. In order to meet the target numbers for each province, different lower threshold values for wind speed were developed for each province. These, along with the resultant number of grid cells, are shown in Table 3-1.

Table 3-1: Initial Set Of Onshore Site Selection by Province

Province	Wind speed cutoff (m/s)	Selected onshore sites
British Columbia	8.2	4,935
Alberta	7.1	9.314
Saskatchewan	7.9	2,949
Manitoba	7.4	2,987
Ontario	6.9	9,511
Quebec	7.9	13,663
Maritimes (NB,NS, PEI)	8.7	2,203
ALL CANADA ONSHORE		**45,562**

Working from this initial list, additional sites were added to represent all existing known and planned wind energy installations, and hand-selected offshore locations. Offshore sites are situated between 10 and 50 km from shorelines, and locations were chosen in coordination with the steering committee. The final set of 54,846 selected cell locations is shown in

Figure 1, and the full list of locations, along with their geographic coordinates, is available as a comma separated values (CSV) file (to be made available through CanWEA PCWIS website).

Figure 3-1: Selected PCWIS Sites.

3.2.3.2 Power production profiles

Power production profiles were generated for each site by applying a power curve to the 100m winds for every 10-minute time period in the meteorological dataset. The power curves used were taken from the Eastern Renewable Generation Integration Study (ERGIS) (Bloom et al, 2015), and are shown in Figure 2. There is a different power curve for each of the IEC classes 1, 2, and 3, and a special power curve was applied for offshore locations. These power curves represent composite curves for existing and in-development utility-scale wind turbines. A density correction (proportional to the cube root of the ratio of the modeled density to the turbine reference density) was applied to estimate an effective wind speed at the turbine reference density. A high wind speed cut-out of 20 m/s was used for class 3, and 25 m/s for the other classes. Hysteresis cut-in values were set to be 5 m/s below the high wind cut-out values.

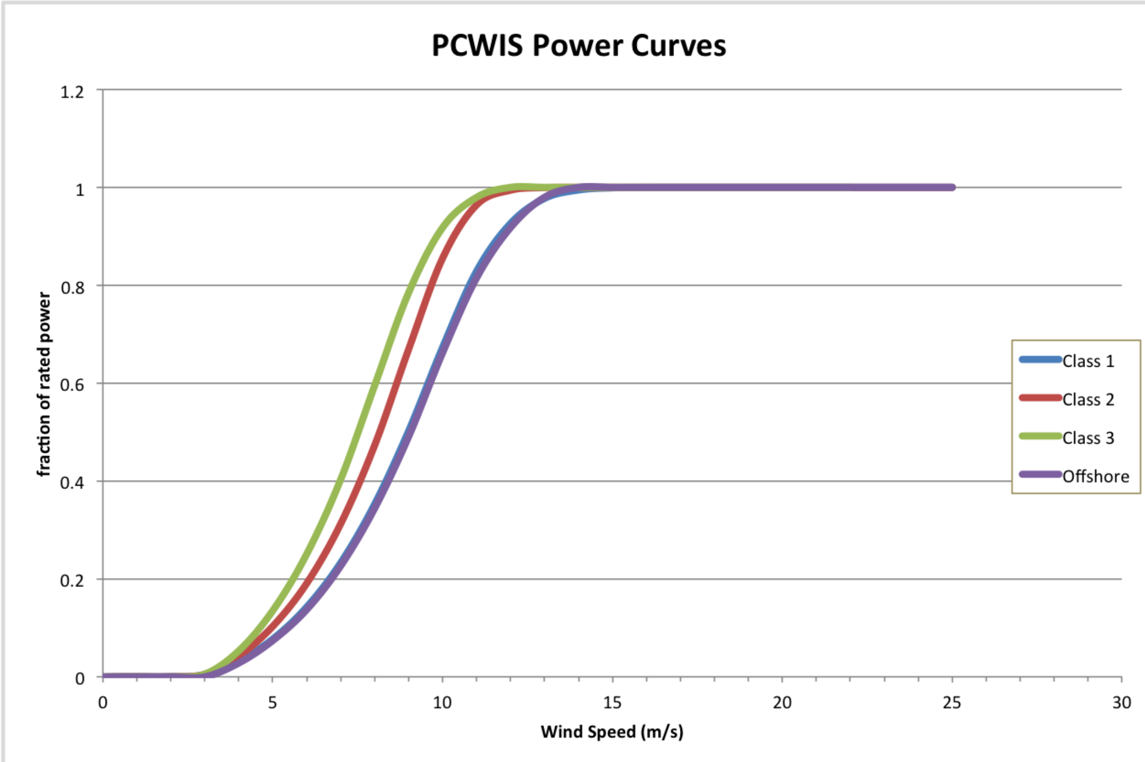


Figure 3-2: PCWIS Power Curves

3.2.3.3 Production losses

Several loss types were implemented in the simulated production dataset. These were array losses, icing losses, and low temperature losses. Loss targets were established by the PCWIS steering committee. Losses were tested and formulated on the simulated production data, then applied consistently to both simulated production and simulated forecasts.

Array Losses

Array losses depend on the size and layout of the array. Based on industry experience, the combined turbulence and wake loss factor was estimated to be 10% for the average size in plant used in this study (270MW). The same loss factor was applied to all wind plants in all study scenarios. The PCWIS steering committee identified a target array loss that would result in system-wide power reduced by 10%. To achieve this loss, a factor was applied to wind speed at each cell. This modified wind speed was used to generate cell-specific power profiles that were summed to calculate the differential impact on the power at the system level. Applying a correction to the wind speed allows wind turbines to still reach rated power.

The process of identifying the appropriate wind speed correction factor was an iterative one that first determined the baseline system-wide annual power production with no array losses. Subsequent iterations, as shown in Table 3-2, applied progressively conservative correction until system-wide power production for all hours of 2008 had been reduced by 10% of the baseline. It was found that a loss factor of 6.5% applied to wind speed at all times resulted in a 10% reduction in system-wide power. This loss factor was then applied in a similar manner to 2009 and 2010 wind speeds.

Table 3-2: Iterations of Array Losses

PWCIS Array Losses Iteration Experiments			
Wind Speed Correction Factor	0.93	0.94	0.935
System Wide Power Production Reduction	11%	9%	10%

Icing Losses Overview

Icing losses are complex in nature, and there are significant differences between operational and meteorological icing conditions. For the PCWIS dataset, only simple icing losses that depend on relative humidity and temperature were considered. Nonetheless, this represents a novel consideration for an integration study.

Icing losses in PCWIS wind hourly dataset

Based on a review of previous icing studies and the meteorological fields available from Environment and Climate Change Canada, Vaisala recommended modeling the energy reduction as a function of time during which temperature was below zero (T < 0 °C) and relative humidity exceeded a threshold value (RH > 88%). This value is quite low as a threshold for icing, and may be a result of biases with Environment and Climate Change Canada's model. Whenever these conditions were met in a grid cell, production in that cell was set to zero and a data flag was set to indicate that icing was in effect. This ensured that periods of cold conditions, and no production, would not be mistaken for icing if the relative humidity criterion was not met. In addition, it allowed for simple accounting of the system-wide number of icing hours. The PCWIS steering committee suggested a targeted icing loss in terms of system-wide icing hours per annum of between 5-10%. An iterative approach to threshold selection was used. The iterative process took place on the simulated production meteorology for 2008 provided by Environment and Climate Change Canada. Temperature at 100m, pressure at the surface, and the specific humidity were used to produce a value for relative humidity. The temperature criterion was held constant at 0 °C, while the relative humidity threshold was varied. After several iterations, it was found that a relative humidity threshold of 88% resulted in 8.1% hours affected by icing conditions annually. This value is quite low as a threshold for icing, and I was flagged as an issue that was not further investigated. Figure 3-3 shows the seasonal variation in the percentage of hours affected by icing. Naturally the numbers peak in winter, though there was no obvious reason for the sharp difference between December and January. The relative humidity threshold was applied to simulated production and simulated production forecasts for the remaining years.

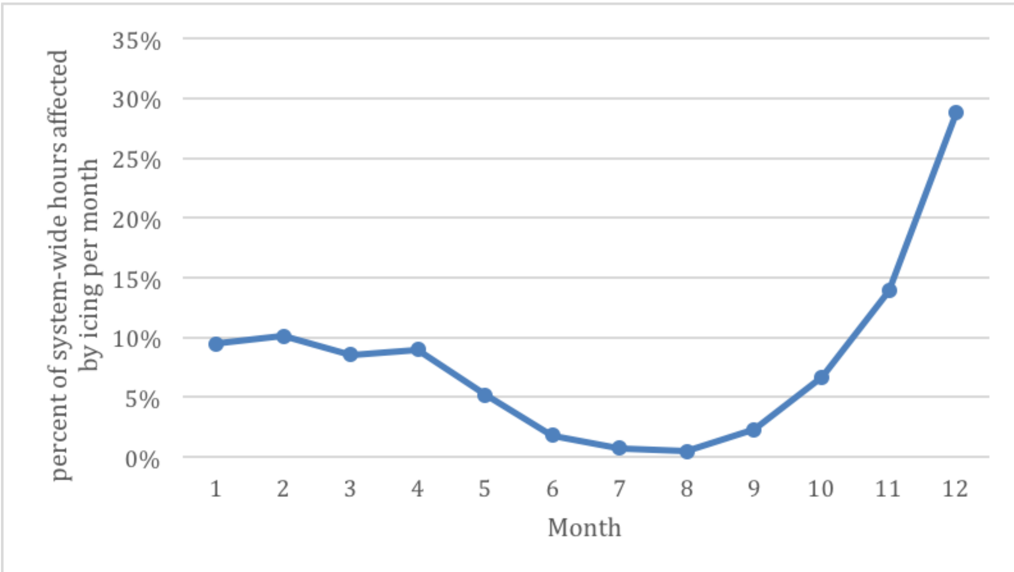


Figure 3-3: Percent of System-Wide Hours Affected By Icing per Month

Low Temperature Losses

A wind turbine will shut down when the air temperature falls below a threshold value, to avoid risk of mechanical system damage. For this study, wind turbine generators are assumed to have cold weather operation packages with a low-temperature cutout of -35°C, including 5° of hysteresis. Therefore, the wind turbine generators will shut down when the air temperature falls to -35°C and return to operation when the temperature rises to -30°C. For this study, Vaisala set generation to zero for each cell any time that the temperature dropped below -35°C, and production was kept at zero until the temperature for the cell returned to -30°C. However, while the 100% shut-off may not actually happen, this assumption was deemed satisfactory.

3.2.4 Simulated Wind Energy Production Forecast Data

A key requirement for wind energy integration work is the availability of wind energy forecasts to go with the modeled estimates of production. These forecasts were designed to have error characteristics similar to the current state of the art of operational wind forecasting.

Power forecasts at 1, 4, 6, and 24-hour lead times were produced to correspond to each hour of the wind power production dataset. A mesoscale NWP model-based approach was used to realistically capture the natural spatiotemporal correlations between the wind sites, i.e. to ensure that neighbouring sites have forecast errors in the same direction and of similar magnitudes. Each power forecast contains a deterministic, best-estimate value.

3.2.4.1 24-hour lead-time forecasts

The WRF model was used to create the meteorological data set to achieve reasonable 24-hour lead-time forecasts. The model was run over Canada with progressively finer nested domains of 54km, 18km, and 6km. The model was initialized once per day at 0000 UTC, with no spin-up period. The 1-degree NOAA Reforecast2 GEFS Control simulation was used to specify initial and lateral boundary conditions. Each forecast simulation was run out 48 hours to ensure that the day-ahead (i.e. next day) period was covered. The output interval was 60 minutes.

Due to computational limits, the forecast NWP simulations were initialized only once per day (at 00Z). Forecast errors are relatively flat during the 24-48 hour period, but there is a discontinuity in the forecast properties as a result.

Forecasts of simulated actuals are often overly skillful, because many of the same observations go into both the global reanalysis datasets used to create the simulated actuals, and the global reforecast datasets used to create the historical forecasts. In this case, the use of GEFS boundary conditions and reduced resolutions resulted in forecasts that had sufficient error to proceed. To adjust this error further, as described below, Vaisala used a combination of time series smoothing and “truth” blending, which is simply a weighted average of the raw forecast and the simulated actual value at a given time. This mimicked operational model output statistics (MOS) by reducing bias and improving skill, but not by too much. At the same time, it was computationally efficient relative to running full MOS at all of the sites.

Vaisala used an iterative approach to the statistics; adjusting smoothing and blending amounts upward until forecast time series and error histograms appeared reasonable and bulk error metrics were similar to state-of-the-art day-ahead forecasts.

From experience with previous integration work, the 24-hour-ahead noise and error statistics were deemed appropriate when the forecast was a result of an 80%/20% mixture of a 13-hour centered moving average of the raw NWP forecasts and 13 hour centered moving average of the simulated actuals, respectively. In this context, the simulated actuals were treated as “truth”. The mixture of simulated actuals into the raw NWP forecast is what is meant by “truth” blending.

Table 3-3 describes the subjective characteristics of forecast error tuning throughout the iterative process of choosing the right weighting of smoothed raw NWP forecast and smoothed “truthful” simulated actuals. With the underlying goal of mimicking appropriate typical operational forecasts, Vaisala tested various configurations of raw NWP forecast smoothing windows, simulated actual smoothing windows, and blending weights. Based on industry experience with operational forecasts, Vaisala identified appropriate error statistics.

Table 3-3: Iterations of Day-Ahead Forecasting Smoothing

Forecast Smoothing	Observation Smoothing	Observation Weight	Subjective Character	Subjective Bias	Subjective Skill
3 h	N/A	N/A	Too Noisy	Too Large	Too Low
3 h	1 h	10%	Too Noisy	A Bit Large	Too Low
3 h	3 h	10%	Noisy, But Less So	A Bit Large	Too Low
7 h	7 h	10%	A Little Noisy	A Bit Large	A Bit Low
13 h	7 h	10%	About Right	A Bit Large	About Right
7 h	7 h	30%	A Little Noisy	Much Lower	Too High
13 h	13 h	20%	About Right	Acceptable	About Right

Forecast Production Bias Correction

One of the potential effects of conducting analysis on datasets produced by different numerical weather prediction models is systematic bias arising from differences in model physics and discretization. A unique challenge for PCWIS was that Environment and Climate Change Canada used a model for the simulated actuals that was not available for the simulated forecasting.

Initial comparison of the simulated actuals and simulated forecasts for a selection of aggregated sites for the year of 2008 by the project team showed significant forecast bias in the day-ahead forecasts. In independent analysis, Vaisala was able to reproduce the bias on the same selection of aggregated sites. Since bias was found in the aggregated sites it was assumed that the bias applied system wide.

To correct for the system-wide bias between the simulated actuals and simulated forecasts, Vaisala implemented a cell-based wind speed scaling of the forecast wind speeds, based on the ratio of the mean 2008 wind speeds in the production and forecast datasets. In other words, for each cell the 2008 annual mean wind speed ratio between the simulated actuals and simulated forecasts was applied to the simulated forecast. This one-time cell-based correction was applied across 2009 and 2010. In other words, new annual wind speed bias correction factors were not reproduced for 2009 and 2010. However, the project team was able to confirm that this correction had a satisfactory effect.

Correction of Under-Forecast Production Due to Conservative Icing

During a secondary phase of the dataset creation, after losses were applied, subsequent analysis found that the forecasted production for an aggregation of cells was again showing under-production. The simulated forecasts were, on an annual basis, predicting significantly less power than the simulated actuals. Vaisala found this to be due to an excess amount of icing losses in the forecast dataset. The likely reason for the differences in icing conditions between the simulated actual production and simulated forecasted production is due to the different manner in which atmospheric moisture content is derived by the different NWP models. WRF alone has more than 6 moisture models to choose from.

Vaisala addressed the difference in icing losses by applying a correction that eliminated the condition where it was possible to have zero-forecasted production and non-zero actual production, retaining the conditions where zero forecasted production and zero actual production existed, and where non-zero forecasted production and zero actual production existed. This had the effect of eliminating false positive icing conditions and suitably corrected the forecasted under-production.

3.2.4.2 Short lead-time forecasts

Statistical forecasts were generated for each site for the short lead-time (1, 4, and 6 hour) forecasts, based on a dispersive persistence method. Vaisala's operational short lead-time forecasts outperform a simple persistence forecast through sophisticated statistical methods not employable for this dataset, therefore special approximations were used with the simulated actuals to approximate the error statistics of operational short lead-time forecasts. The selected mechanism used shortened persistence lead times to increase the skill of the forecasts to the desired level, using the two parameters of persistence interval and lead-time, as described below.

The most basic persistence forecast uses the current value as a prediction for some future value. The length of the time between the observation and the predicted time is referred to as the 'lead time', and the length of the lead time has a significant impact on the skill of the forecaster. In the present convention, period-ending time was used. The enhanced skill of operational forecasts can be approximated using lead times shorter than would be available in a real time system, but using a constant lead time does not properly characterize the distribution of events in time – the errors are not properly dispersed.

For this dataset, the lead-time parameter was randomly sampled from a normally distributed population of 8,760 10-minute interval lead times, with a range of 0-80 minutes and a mean of 40 minutes. In other words, the population contains lead times of 0, 10, and 20 minutes, and so on up to 80 minutes. The most common lead time is 40 minutes. The effect of the mean 40-minute lead time is to improve average forecast skill.

The second parameter was the persistence interval. The persistence interval is the length of time over which the simulated actual (observed) data is averaged, and in the case of high-resolution (e.g. 1-minute) observations can be used to resample the observed data to a longer period, for instance from 1 minute to 10 minutes. However, for this study since the simulated actuals were only available every 10 minutes, the persistence parameter was held constant.

Two examples along with figures of the algorithm are given below:

Example #1: As shown in Figure 3-4, if the present time is T_0 and we are tasked with producing a forecast valid from T_{+60} to T_{+120} and a 40-minute lead time is sampled, then the algorithm takes the value at T_{+20} and selects this value as the forecast.

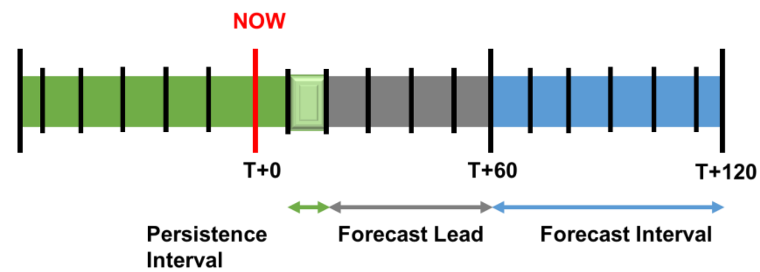


Figure 3-4: Graphical Example of Forecast Algorithm: 40min Lead Time

Example #2: As shown in Figure 3-5, if the present time is T_0 and we are tasked with producing a forecast valid from T_{+60} to T_{+120} and an 80-minute lead time is sampled, then the algorithm takes the value at T_{-20} and selects this value as the forecast.

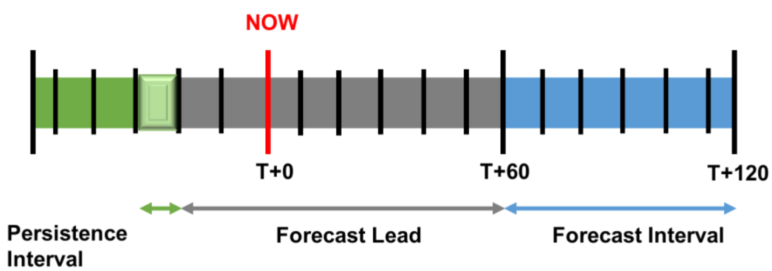


Figure 3-5: Graphical Example of Forecast Algorithm: 80min Lead Time

An iterative procedure similar to that of the 24-hour lead-time forecasts was followed, starting with a 1-hour forecast comprised of 10-min persistence at 40-min lead. This was adjusted until the improvement over persistence was similar to current operational forecasts, as shown in Table 3-4.

In practice, the long-term statistics of short lead-time forecasts show a greater skill than a simple persistence forecast, however at any given time, it is possible for such a forecast to be more skillful than normal, or less skillful than normal. A range of lead-times ensured a varying measure of success in the 1-hour forecasts.

Table 3-4: Iterations of Short-Term Forecast Parameters

Persistence Interval	Mean Lead Time	Lead Time Range	Auto-Correlation	Subjective Skill
10 min	40 min	N/A	N/A	A Bit High
10 min	45 min	0-90 min	0.9	A Bit Low
10 min	40 min	0-80 min	0.9	Barely High
10 min	40 min	0-80 min	0.9	Just Right

After parameters for the 1-hour forecasts were determined, the 4-hour lead-time forecasts were computed using an 80% to 20% blending of the 24-hour and 1-hour forecasts, and the 6-hour lead-time forecasts were computed using a 90% to 10% blending of the 24-hour and 1-hour forecasts. The equations used to calculate 4 (F_4) and 6 (F_6) hour-ahead forecasts are as follows:

$$F_4 = 0.8(F_{24}) + 0.2(F_1)$$

$$F_6 = 0.9(F_{24}) + 0.1(F_1)$$

3.2.5 Epilogue

The objective of the wind data production task was to generate synthetic wind production data and associated forecasts in support of the PCWIS. Where possible, methodologies consistent with the creation of the US Wind Integration National Dataset were employed. Several challenges emerged during the work described above: notably consistency issues between the meteorological dataset created by Environment and Climate Change Canada and the forecasting dataset created by Vaisala. Nonetheless, good communication between the project team, CanWEA and its consultants, and the Technical Advisory Committee made it possible to address issues as they arose, and it is the project team's view that the resulting production and forecasting datasets address the needs of the integration study.

3.2.6 References

- Bloom, A., A. Townsend, and D. Palchak (2015), *Eastern Renewable Generation Integration Study: Flexibility and High Penetrations of Wind and Solar*. NREL (National Renewable Energy Laboratory), Golden, CO (US). NREL/PR-6A20-64795.

- Draxl, C., B.-M. Hodge, A. Clifton, and J. McCaa (2015). *Overview and Meteorological Validation of the Wind Integration National Dataset Toolkit*. National Renewable Energy Laboratory (NREL), Golden, CO (US). NREL/TP-5000-61740.

Hamill, T. M., G. T. Bates, J. S. Whitaker, D. R. Murray, M. Fiorino, T. J. Galarneau, Jr., Y. Zhu, and W. Lapenta (2013). *NOAA's second-generation global medium-range ensemble reforecast data set*. Bull Amer. Meteor. Soc., 94, 1553-1565.

4 Assumptions and Scenarios

The production cost and reliability modeling conducts a detailed 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 underlying data source for most of the inputs and assumptions discussed in this section was either from the Technical Advisory Committee (TAC) members, Statistics Canada[15], or from ABB Velocity Suite[16]. In instances where data was unavailable GE Energy Consulting utilized engineering judgment and past experience where necessary. The inputs and assumptions were validated through TAC member review and detailed benchmarking of model results to historical operations.

4.1 Study Assumptions

4.1.1 Model Footprint

While this study was focused on the Canadian power system, it is critical to accurately incorporate imports and exports of power between provinces and systems in the United States. 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 4-1 provides a geographic representation of the model topology utilized in this study and represents the largest renewable integration study performed to date.

The Eastern Interconnection (EI) and Western Interconnection (WI) have limited HVDC interconnections and therefore were modeled as two isolated and separate models. 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 neighbouring systems, the Quebec system was incorporated directly in the EI model.

The footprint in Canada was again subdivided by balancing area or "pool." Unlike the United States, the pool boundaries directly correspond to provincial boundaries. In some cases inputs and results are aggregated in the Maritimes region. This is consistent with reserve

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

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

sharing practices between New Brunswick, Nova Scotia and Prince Edward Island as part of the Northeast Power Coordinating Council (NPCC). While the majority of the reporting in this study focusses on operations in the Canadian provinces, the simulations were performed for the whole system.

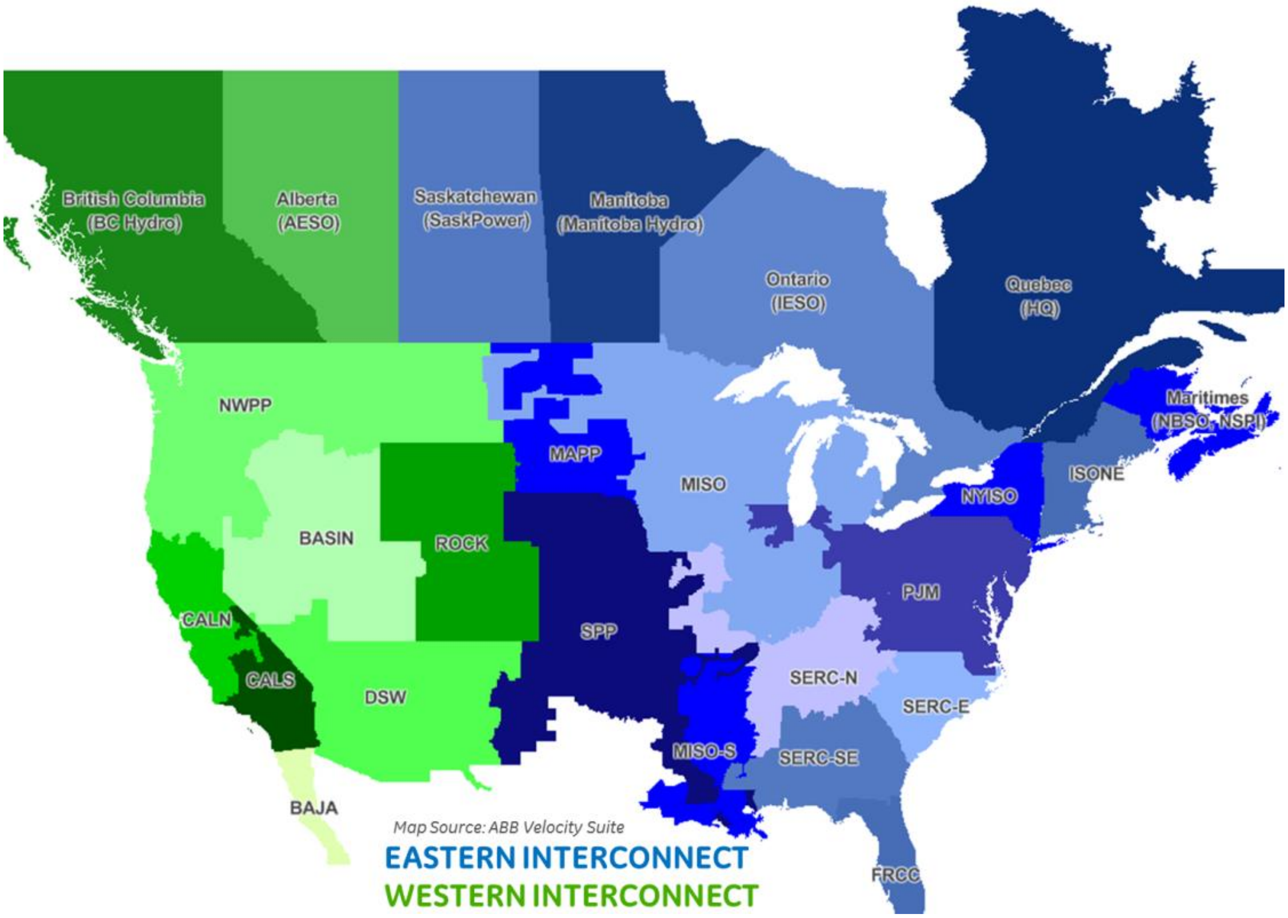


Figure 4-1: Model Topology of the Eastern and Western Interconnections

Note that the Canadian territories of Yukon, Northwest Territories and Nunavut, as well as the province of Newfoundland and Labrador were not included in the model topology because they are composed of isolated power grids and not interconnected to the North American bulk transmission system. In some cases, existing and proposed power plants (Churchill Falls and Muskrat Falls) located in Newfoundland and Labrador, but connected via transmission to Quebec and Nova Scotia, were modeled as generators on the terminal end of the transmission network. Wind sites and selections were also made in Newfoundland and Labrador to explore the potential of increasing interconnections to neighbouring systems.

4.1.2 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 4-1 lists the grid operator and market structure in each province, listed from west to east.

Table 4-1: 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. The British Columbia, Manitoba, and Quebec systems are predominately hydro based, with over 90% of generation being served by hydro resources. Alberta, Saskatchewan, New Brunswick and Nova Scotia constitute a mix of coal, gas, hydro and wind resources. Ontario has a large installed nuclear base, with significant hydro resources, natural gas capacity, and recent retirement of all coal capacity. Prince Edward Island load is served predominately from on-island wind and other off-island generation from New Brunswick. The New Brunswick resource mix also includes the Point Lepreau Nuclear Generating Station.

Figure 4-2 and Table 4-2 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 year 2025, but do not include any additional wind capacity added for the scenarios. 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 2025 study year.

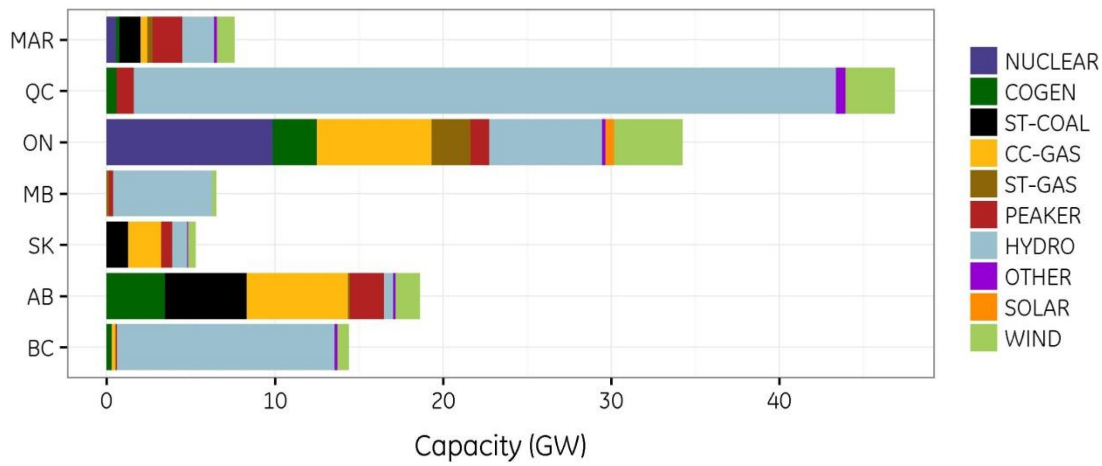


Figure 4-2: Installed Capacity by Type, by Province (2025, without wind additions)

Table 4-2: Installed Capacity by Type (MW), by Province (2025, without wind additions)

	BC	AB	SK	MB	ON	QC	MAR	CAN
NUCLEAR					9,865		558	10,423
COGEN	307	3,476			2,624	576	208	7,190
ST-COAL		4,857	1,271				1,247	7,375
CC-GAS	211	6,020	1,970		6,822		409	15,432
ST-GAS		116		126	2,331		321	2,894
PEAKER	90	2,039	649	257	1,123	1,053	1,764	6,975
HYDRO	12,942	523	901	5,891	6,711	41,734	1,893	70,596
OTHER	162	159	65		200	570	152	1,308
SOLAR					490			490
WIND	685	1,438	451	258	4,103	2,960	1,074	10,970
TOTAL	14,397	18,628	5,307	6,532	34,269	46,893	7,626	133,653

In this study, the installed capacity in 2025 in the "business-as-usual" case (without wind additions after 2015) is 10,970 MW, with wind plants distributed in each of the Canadian provinces. Wind resources currently supply approximately 5% of Canada's annual electricity demand; and with 36 new wind projects installed in 2015 (1506 MW), wind is the largest source of new generation capacity in Canada from 2011 to 2015[17].

4.1.3 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 2025, reflecting load energy and peak demand in 2025 based on the annual growth assumptions for energy; however, the hourly load shape was based on the historical years of the hourly patterns of the renewable energy, which for all the base scenarios is based on the year 2008.
- All prices and economic inputs and results were quoted in real 2016 Canadian Dollars, unless otherwise noted.
- The United States Dollar (USD) and Canadian Dollar (CAD) exchange rate was set at 1USD:1.385CAD based on the market exchange rate as of January 1st 2016.
- Entire Eastern Interconnect and Western Interconnect systems were simulated – a capability provided by the GE MAPS model.
- The Pan-Canadian model spans 4 time zones (Atlantic, Eastern, Central, Mountain, and Pacific). 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.
- It was assumed that nuclear plants would not cycle to accommodate additional variable wind energy. This is a conservative assumption, noting that some nuclear plants in Ontario are already cycling to accommodate additional wind. However, this cycling is highly situational and subject to many constraints that cannot be modeled practically.
- Existing contingency reserve practices were used in addition to the regulation reserves calculated to cover the wind and solar variability. Where applicable, the modeling used the 10-minute spinning reserve portion of the contingency reserve constraints for each balancing authority.

[17] Canadian Wind Energy Association, http://canwea.ca/wind-energy/installed-capacity/

- The production simulation analysis assumed that all 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.
- Potential increase in operations and maintenance (O&M) cost of conventional thermal generators due to increased ramping and cycling were not included.
- Renewable energy plant O&M costs were not included. Renewable energy was considered to be a price-taker.
- The hydro modeling did not reflect the specific climatic patterns of 2008, 2009, and 2010, but rather was based on a 10-year long-term average flow per month.

4.1.4 Thermal Generator Modeling

The original source of the thermal generator characteristics was ABB Velocity Suite, Generating Unit Capacity dataset (accessed on September 26, 2013), and supplemented by additional data provided by the TAC, 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 to 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 MW 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 the 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 cost is 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 that are accrued

when the unit is running. This includes, but is not limited to, things such as 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.

4.1.5 Hydro Generator Modeling

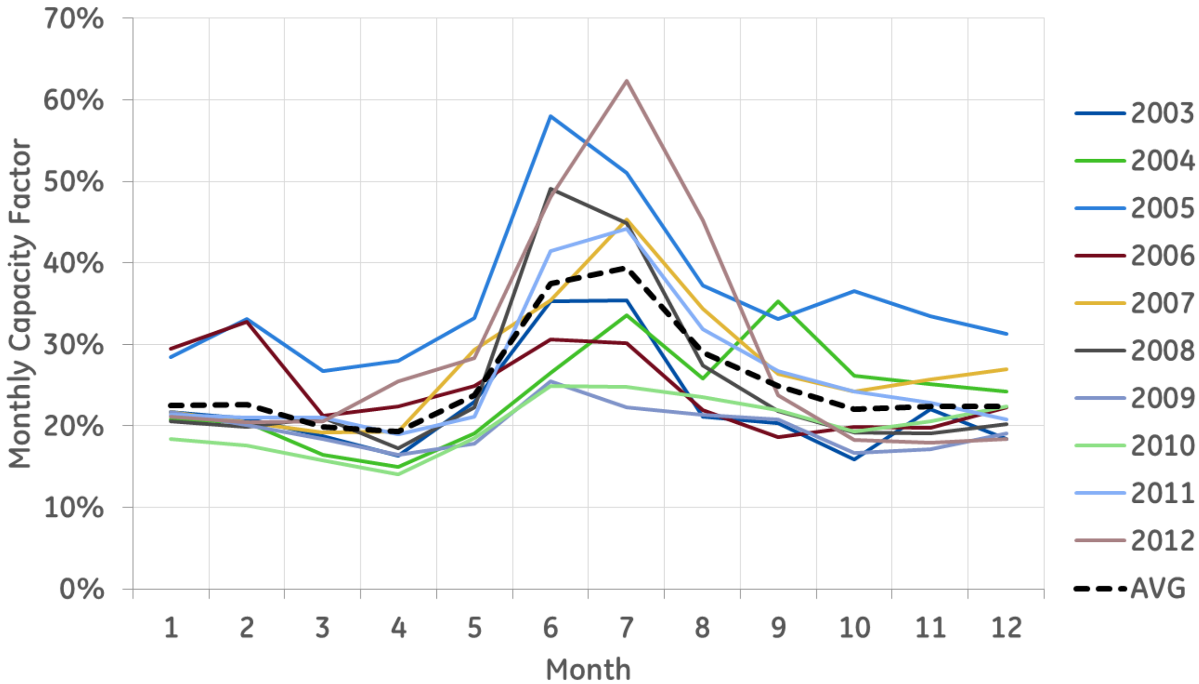
Modeling hydro resources is especially important for the Canadian power system, attributing more than half of the overall capacity. As a result the study team spent significant effort developing hydro assumptions for Canadian plants and river systems. The underlying data source for the hydro modeling 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:
   a. BC Hydro provided monthly average generation targets for each of the large reservoir plants, plus aggregated targets for IPP and small hydro generators.
   b. SaskPower provided monthly targets for each plant.
   c. IESO provided monthly energy targets for each region (East, Niagara, Northeast, and Northwest).
   d. Manitoba provided monthly energy targets for large dispatchable pondage hydro, and daily fixed generation targets for each of the run-of-river plants.

    e. Hydro Quebec provided monthly energy targets for each plant or plant group.

2. Publicly available historic data is published at plant granularity, accessed via ABB Velocity Suite, Monthly Plant Generation and Consumption dataset.
    a. AESO publicly releases hourly hydro generation by plant. This data was summarized across multiple years to develop monthly minimum, maximum and average energy assumptions based on historical operations.
    b. New Brunswick releases monthly generation by plant. This data was summarized across multiple years to develop monthly minimum, maximum and average energy assumptions based on historical operations.
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.

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 steering committee members. Figure 4-3 shows an illustrative example of the monthly and annual variation for Alberta. A similar process was done for each plant using the underlying best available data source listed above.



Data Source: Statistics Canada, CANISM dataset, Table 127-0002 Electric Power Generation, by Class of Electricity Producer, Month (MWh)

Figure 4-3: Monthly and Annual Hydro Capacity Factor Variation, Alberta Example

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. Default assumption was a 10-year average capacity factor for each month from 2003-2012, CANISM 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 4-4, 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 unless previously curtailed surplus energy from the week was available. This assumption was investigated further through sensitivity analysis. For some run-of-river hydro plants or resources with significant operational limitations, the plants were modeled with a fixed hourly profile.

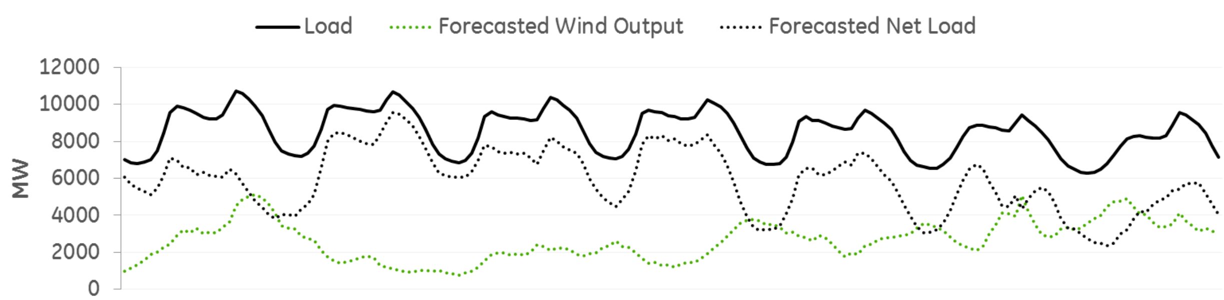


Figure 4-4: Net Load Hydro Scheduling Methodology Example

Additional constraints were modeled for many plants in the Pan-Canadian database. In general these assumptions were based off of data provided by the TAC or 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 against the pool (provincial) load where they reside. 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 like Wuskwatim in Manitoba that are used almost exclusively 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.

4.1.6 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. The base case assumption utilized a day-ahead wind forecast, but additional forecast time horizons were evaluated in sensitivity analysis. In the GE MAPS model, the commitment of thermal units and the hydro scheduling was done off of the 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.).

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 wind profiles used throughout the study are discussed in detail throughout Section 4.3, and represent modeled wind generation patterns based on meteorological data from the years 2008, 2009, and 2010. The year 2008 was the default assumption for wind and load profiles, with other years evaluated in sensitivity analysis. Each wind plant has a unique production profile based on its geographic location and scaled according to the MW rating of the plant.

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 are the last resources to be curtailed (i.e., spilled) during the low load and high supply periods. In such times, GE MAPS uses a priority order, whereby the 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 and hydro resources. The last in the priority order is typically non-grid scale distributed solar generation, assumed to be not 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.

4.1.7 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.

Throughout this study, curtailment includes unused wind, solar, and hydro resources and 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 a zero marginal cost resource. 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 the sake of modeling assumptions, it was assumed that new wind additions (absent other constraints) were curtailed before the existing hydro and solar plants, because in this study they represent the agent of change and incremental additions to the system. This curtailment order is a practical assumption for this study, but is not intended to represent existing operational practices or a recommended future practice.

In some cases, pondage hydro resources have the ability to store curtailed or unused energy. The amount of storage available depends on the size of reservoir, along with environmental and societal limitations. While the model did assume some curtailed energy could be carried forward for relatively short periods of time (days), this study did not analyze the ability to shift energy across seasons or years. This modeling decision was made with support of the Technical Advisory Committee, with an expectation that longer-term hydro storage would likely be evaluated in subsequent studies.

Options for reducing curtailment to lower levels 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.
- Scheduling hydro resources against real-time wind and load, which assumes that hydro resources are more flexible than the Base Case assumption in the study, which assumes hydro resources are scheduled against net load and the day-ahead wind forecast. This option was considered and is reported as a sensitivity analysis in this study.
- 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.

4.1.8 Fuel Price Projections

4.1.8.1 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 fuel displaced by wind. This is true even for Canadian regions with limited gas consumption because the USA export market is still based on natural gas as the marginal fuel.

Monthly natural gas prices are based on the Henry Hub prices from the EIA Annual Energy Outlook 2014 Report[18]. Delivered prices across the Canadian regions provide the additional "basis differentials" reflecting the time and location dependent variations in the cost of natural gas. The basis differentials are the 2008-2013 average monthly differentials relative to Henry Hub and sourced from Enerfax historical data, accessed via ABB Velocity Suite.

The delivered natural gas prices for each province are provided in Figure 4-5 and Table 4-3 for each province and each month. Prices are quoted in C$/GJ, assuming a conversion factor of 0.947 MMBtu per GJ. As the table and chart illustrate, prices are, in general, lowest

[18] http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf

in Alberta and highest in the Maritimes region at the extremity of the pipeline network. The underlying seasonality (higher prices in winter) also coincides with peak demand for both electricity and gas heating demand.

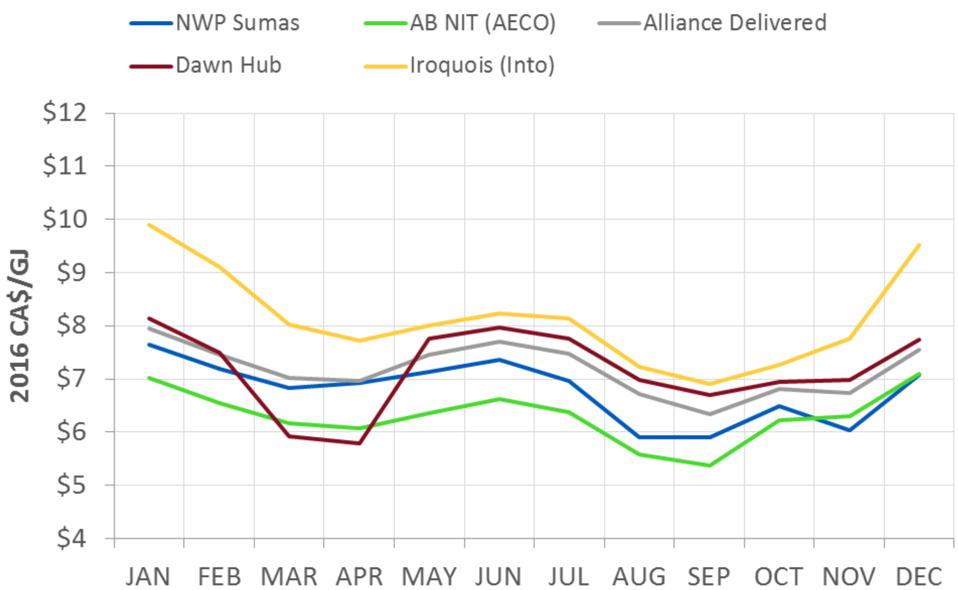


Figure 4-5: 2025 Natural Gas Price Assumptions by Pricing Node (2016 C$/GJ)

Table 4-3: 2025 Natural Gas Price Assumptions by Pricing Node (2016 C$/GJ)

	BC NWP Sumas	AB AB NIT (AECO)	SK AB NIT (AECO)	MB Alliance Delivered	ON Dawn Hub	QC Iroquois (Into)	NB Iroquois (Into)	NS Iroquois (Into)
JAN	7.64	7.03	7.03	7.95	8.14	9.90	9.90	9.90
FEB	7.19	6.55	6.55	7.47	7.50	9.11	9.11	9.11
MAR	6.83	6.16	6.16	7.03	5.92	8.02	8.02	8.02
APR	6.93	6.07	6.07	6.97	5.80	7.72	7.72	7.72
MAY	7.14	6.37	6.37	7.45	7.76	8.01	8.01	8.01
JUN	7.37	6.63	6.63	7.70	7.97	8.22	8.22	8.22
JUL	6.96	6.38	6.38	7.47	7.77	8.13	8.13	8.13
AUG	5.91	5.59	5.59	6.71	6.98	7.23	7.23	7.23
SEP	5.90	5.37	5.37	6.34	6.71	6.91	6.91	6.91
OCT	6.48	6.22	6.22	6.81	6.95	7.26	7.26	7.26
NOV	6.03	6.29	6.29	6.74	6.98	7.76	7.76	7.76
DEC	7.08	7.09	7.09	7.55	7.74	9.52	9.52	9.52
AVG	6.79	6.31	6.31	7.18	7.18	8.15	8.15	8.15

4.1.8.2 Other Fuel Price Assumptions

The assumed fuel prices for coal, oil, uranium and biomass/other/waste, etc. are provided in Table 4-4 for the 2025 simulation year. The underlying data source for the coal prices is based on TAC feedback in Alberta and Saskatchewan. This data was supplemented for New Brunswick and Nova Scotia by using on an average of delivered coal price from EIA Annual Energy Outlook for New England. The oil prices are also based on the EIA 2014 Annual Energy Outlook. Since the start of the study, prices in global oil markets have decreased considerably. However, given that oil based generation is a very small portion of the overall generation mix, the oil price assumption will only have a marginal impact on the study results.

Table 4-4: 2025 Coal, Oil, Uranium and Other Fuel Price Assumptions (2016 C$/GJ)

Fuel Type	Data Source	2025 Price (2016 C$/GJ)
AB Coal	AESO	$2.40
SK Coal	SaskPower	$2.14
NB Coal	Assumed from US Data (average of ISONE)	$6.40
NS Coal	Assumed from US Data (average of ISONE)	$6.40
Oil (distillate)	EIA 2014 Annual Energy Outlook	$28.79
Oil (residual)	EIA 2014 Annual Energy Outlook	$19.20
Uranium	GE Energy Consulting	$1.10
Biomass/Other	GE Energy Consulting	$1.10

4.1.9 Load Projections

4.1.9.1 Annual Energy and Peak Demand Forecast

The demand forecast used throughout the study is used for two purposes; it is used during the production cost and reliability simulations and it determines the amount of wind penetration assumed in each scenario. For example, a 20% wind penetration assumes that 20% of the annual load energy is served by wind energy. Therefore a higher load forecast will yield further wind capacity additions.

A 2025 load forecast of the annual energy (GWh) and peak demand (MW) was used throughout the model footprint. The load projections were based on the 2013 NERC Long Term Reliability Assessment[19] for both the United States and Canada, unless data was

[19] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf

supplemented by input provided by the TAC members (BC Hydro, AESO, and IESO). Table 4-5 provides the annual load energy (GWh), peak demand (MW), and load factor for each Canadian province in the model footprint for the forecast year 2025. Load factor is defined as the annual energy divided by the product of the peak demand and the number of hours in the year.

Table 4-5: 2025 Load Forecast by Province

	Annual Energy (GWh)	Peak Demand (MW)	Load Factor (%)
BC	63,433	11,622	0.62
AB	116,234	16,318	0.81
SK	29,626	4,444	0.76
MB	30,149	5,261	0.65
ON	143,670	24,358	0.67
QC	200,736	41,171	0.56
NB	12,780	2,973	0.49
NS	11,904	2,176	0.62
PEI	1,086	241	0.51
CAN*	609,618	108,564	0.64

*Total peak demand is non-coincident

4.1.9.2 Chronological Load Patterns

The annual energy and peak demand targets shown in Table 4-5 are used to scale the hourly chronological loads for each province. The chronological load patterns were based off of 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. This process was repeated for 2009 and 2010 weather years in the sensitivity analyses. The hourly data is summarized by month for the Pan-Canadian system is provided in Figure 4-6.

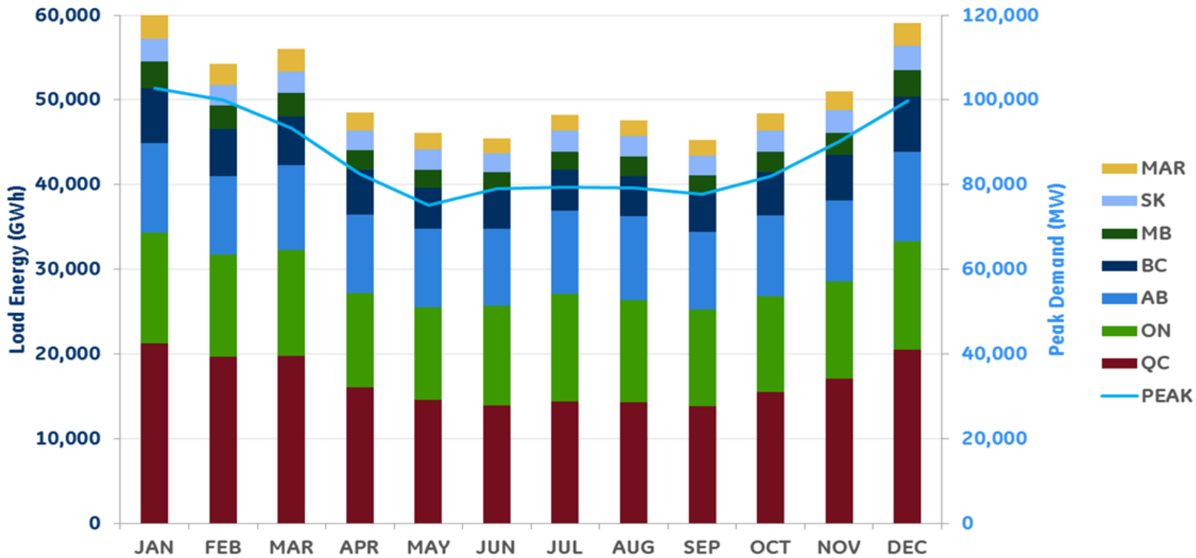


Figure 4-6: 2025 Monthly Load Energy and Peak Demand for Canada

4.1.10 Transmission

4.1.10.1 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 flows of generation and loads across the network. A map of the high voltage transmission network across Canada is provided in Figure 4-7.

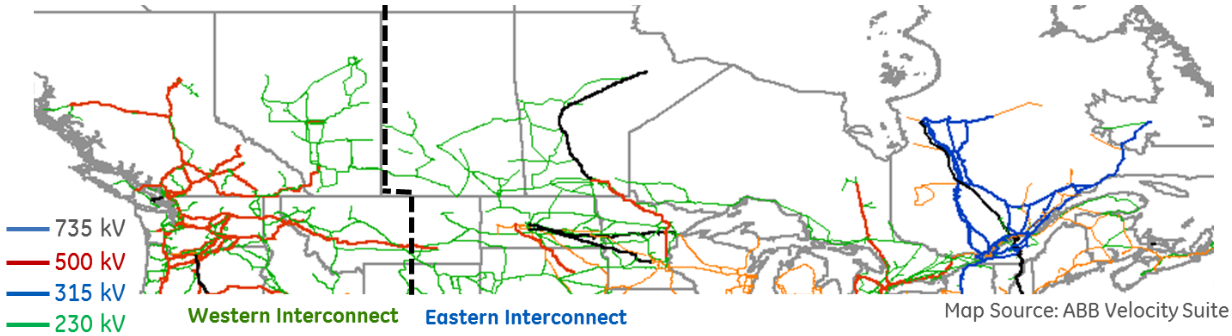


Figure 4-7: High Voltage Transmission Network Map of Canada

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 neighbouring systems (intra-provincial) in both Canada and USA. In Ontario and Nova Scotia additional inter-provincial constraints were also added to the model to represent historical transmission congested interfaces. The transmission interface definitions assumed existing operating constraints used throughout planning studies in Canada and are provided in Table 4-6, Table 4-7, and Figure 4-8. The interfaces include additional transmission lines that are currently in advanced stages of development or under construction and listed below. These added transmission lines were assumed exogenously based in input provided by the TAC members, and not part of the transmission expansion methodology discussed in later sections of this report.

- **Alberta to British Columbia:** Increased existing interconnection capacity to 1,200 MW based on TAC feedback regarding plans to increase the WECC Path 1 Rating in the future.
- **Manitoba to Minnesota:** Included the new 500 kV transmission project currently under construction.
- **Quebec to United States:** Included three proposed HVDC projects from Quebec to New York (Champlain Hudson Power Express, 1,000 MW) and New England (Northern Pass, 1,200 MW and New England Clean Power Link, 1,000 MW)

Table 4-6: Inter-Provincial Transmission Interface Limits

From Side: Canada Province	Inter-Area Tie Branch					Limit (MW)				To Side: Canada Province
						From->To		To->From		
	From Bus	To Bus	CKT	kV	DC	SP	WP	SP	WP	
British Columbia	Rainbow Lake	Fort Nelson	1	138	AC	-	-	-	-	Alberta
	Fording Coal	Pocaterra	1	138	AC	1200	1200	1200	1200	
	Cranbrook	Langdon	1	500	AC					
	Natal	Coleman	1	138	AC					
Saskatchewan	Swift Current	McNeill	1	230	DC	150	150	150	150	
	Island Falls	Flin Flon	1	115	AC	-	-	-	-	Manitoba
	Island Falls	Flin Flon	2	115	AC					
	E B Campbell	Pas Ralls Island	1	230	AC	0	0	150	150	
	Yorkton	Roblin	1	230	AC					
	Bounpary Dam	Reston	1	230	AC					
Ontario	Kenora	Whiteshell	1	220	AC	288	300	288	300	
	Kenora	Whiteshell	2	220	AC					
	Kenora	Seven Sisters	1	115	AC					
	Hawthorne	Outaouais	1	230	DC	1250	1250	1250	1250	Quebec
	Hawthorne	Outaouais	2	230	DC					
New Brunswick	Madawaska	Riviere du Loup	1	230	DC	785	785	1029	1029	
	Eel River	Matapedia	1	230	DC					
	Eel River	Matapedia	2	230	DC					
	Salisbury	Onslow	1	345	AC	300	300	350	300	Nova Scotia
	Memramcook	Maccan	1	138	AC					
	Memramcook	Maccan	2	138	AC					
	Murray Corner	Borden	1	138	DC	200	200	200	200	Prince Edward Island
	Murray Corner	Borden	2	138	DC					

Table 4-7: International Transmission Interface Limits between Canada and USA

From Side: Canada Province	Inter-Area Tie Branch					Limit (MW)				To Side: US State
						From->To		To->From		
	From Bus	To Bus	CKT	kV	DC	SP	WP	SP	WP	
British Comlubia	Ingledow	Custer	1	500	AC	3150	3150	3000	3000	Washington
	Ingledow	Custer	2	500	AC					
	Nelway	Boundary	1	230	AC					
	Waneta	Boundary	1	230	AC					
Alberta	Marias	MATL	1	230	AC	315	315	310	310	Montana
Saskatchewan	Boundary Dam	Tioga	1	230	AC	165	165	150	150	North Dakota
Manitoba	Glenboro	Rugby	1	230	AC	2833	2833	1400	1400	
	Letellier	Drayton	1	230	AC					
	Dorsey	Forbes	1	500	AC					Minnesota
	Dorsey	Blackberry	1	500	AC					
	Richer South	Moranville	1	230	AC					
Ontario	Fort Francis	International Falls	1	115	AC	150	150	100	100	
	Keith	Waterman	1	230	AC	1700	1750	1550	1550	Michigan
	Scott	Bunce Creek	1	230	AC					
	Lambton	St. Clair	1	230	AC					
	Lambton	St. Clair	1	345	AC					
	St. Lawrence	Moses	1	230	AC	300	300	300	300	New York
	St. Lawrence	Moses	2	230	AC					
	Beck 2BP76	Packard	1	230	AC	1760	2090	1320	1570	
	Beck 2PA27	Moses Niagara	1	230	AC					
	Beck A	Moses Niagara	1	345	AC					
	Beck B	Moses Niagara	1	345	AC					
Quebec	Les Cedres	Dennison	1	115	DC	199	180	100	100	
	Les Cedres	Dennison	2	115	DC					
	Chateauguay	Massinna	1	765	DC	1500	1500	1000	1000	
	Chateauguay	Massinna	2	765	DC					
	HER735	Astoria	1	765	DC	1000	1000	1000	1000	
	HER735	Coolidge	1	765	DC	1000	1000	1000	1000	Vermont
	Standstead	Derby	1	115	AC	35	35	0	0	
	Bedford	Highgate	1	115	DC	225	200	170	170	
	Canton	Deerfield	1	765	DC	1200	1200	1200	1200	New Hampshire
	Nicolet	Sandy Pond	1	765	DC	1700	1700	1700	0	Massachusetts
	Nicolet	Sandy Pond	2	765	DC					
New Brunswick	Keswick	Keane Road	1	345	AC	700	700	500	500	Maine
	Point Lepreau	Orrington	1	345	AC					

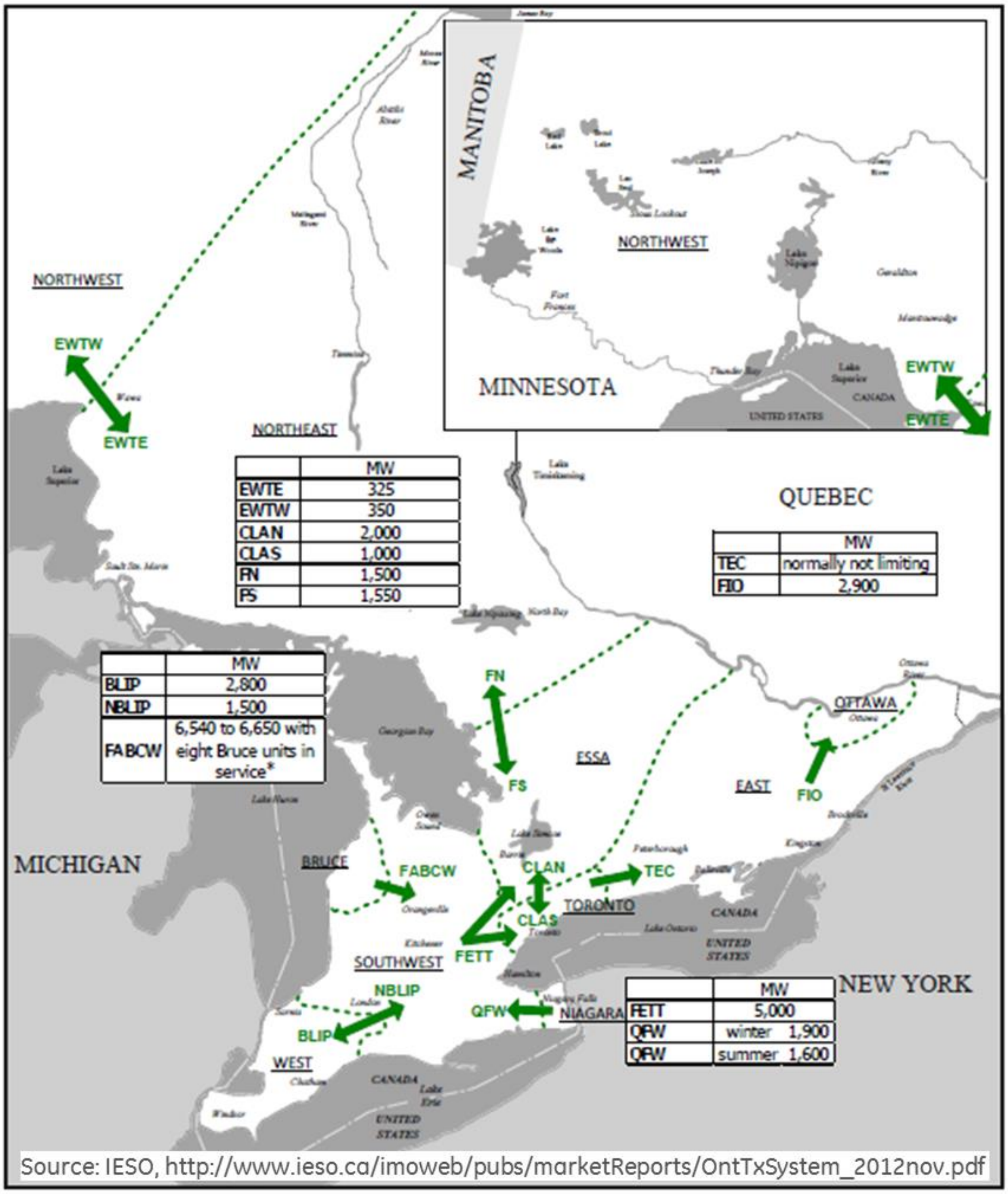


Figure 4-8: IESO Intra-Provincial Transmission Interfaces

4.1.10.2 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 C$5/MWh during the commitment process and C$3/MWh during the dispatch process.

4.1.11 Generation Expansion Methodology

The GE MAPS production cost and GE MARS reliability models were also updated to incorporate changes in the supply mix to reflect the North American grid in the year 2025. This process incorporated public announcements of new installations and retirements as well as generic expansion generators required to maintain reserve margin adequacy.

4.1.11.1 New Installations and Retirement Assumptions

The model included any units that had a unit status of under construction, site-prep, and/or testing along with planned and proposed plant retirements. The primary data source for the installations and retirements data was the ABB Velocity Suite, Generating Unit Capacity dataset as of January 1st, 2014. In addition, specific proposed installations and retirements were added based on TAC member suggestions. The study assumptions also retired coal plants that reach the end of their useful life based on federal coal regulation (>=50 years old or build before 1975) before the study year of 2025. Note that since the start of the study, some provinces may have changed the coal retirement timeline (most notably Alberta), but this new policy was not reflected in the base case assumptions. Instead it was evaluated as a sensitivity analysis. The list of new generator installations and generator retirements are provided in Table 4-8 and Table 4-9.

Table 4-8: New Firm Installations (Non-Wind)

Plant Name	Province	Capacity (MW)
Site C Hydro	BC	1,090
Conifex MacKenzie Biomass	BC	36
Cold Lake Nabiye GT	AB	170
Mustus Biomass	AB	42
Kearl Oil Sands Project	AB	100
Shephard Energy Center	AB	821
Queen Elizabeth Exp. CC	SK	205
La Romaine Hydro	QC	1,305
Muskrat Falls (Through Maritime Link)	NS	500

Table 4-9: Generator Retirements

Plant Name	Province	Capacity (MW)
Burrard Thermal STs	BC	900
Battle River Coal Units 3, 4, 5	AB	690
H.R. Milner Coal	AB	144
Sundance Coal Units 1, 2	AB	560
Boundary Dam Coal Units 2, 4, 5[20]	SK	339
Landis GT[21]	SK	78
Brandon Coal Unit 5	MB	97
Dalhousie ST Units 1, 2	NB	300
Lingan Coal Units 1, 2	NS	306
PT Tupper Coal	NS	154

4.1.11.2 Thermal Generation Expansion Planning Process

In order to ensure that the system has enough capacity to maintain reliability given the expected load growth, the following generation expansion methodology was used. A thermal generation expansion plan used in all study scenarios, including those with higher penetration of wind, was developed based on the load and capacity assumptions used in the first scenario, without any additional wind capacity additions. The expansion plan was then held constant across the scenarios evaluated, regardless of the firm capacity benefits provided by the incremental wind additions. The consistent thermal expansion plan was used to ensure that all changes between the scenarios could be attributed only to the addition of wind energy and avoid adding additional changes to the system that could impact results.

The amount of generation capacity to add was based on the installed reserve margin (RM) in each pool. It was determined that the reserve margin in each pool should be at or exceed the reserve margin target listed in the 2013 NERC Long Term Reliability Assessment. If the given load growth, new installation, and retirement forecast resulted in a reserve margin deficit, then generic expansion units were added to the model so that the reserve margin target was achieved. The equation for the reserve margin calculation is provided below:

[20] According to communication from SaskPower, final decision on the retirement or conversion to carbon capture and storage for units BD4 and BD5 has not been made. BD2 has been retired.

[21] According to communication from SaskPower, final decision on the retirement of Landis Power Station has not been made.

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

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.

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.

In cases where the reserve margin fell below target levels, additional units were added to the model based on the following methodology, the results of which are provided in Table 4-10. While this is not intended to be an optimal expansion plan, it is sufficient to balance the system and for use in a wind integration study.

- Two main types of generic Candidate Plants were selected:
  - o A future Combined Cycle Natural Gas Turbine (CC-GAS) Type, rated at 500 MW with an assumed heat rate of 6,800 b Btu/KWh
  - o A future Single Cycle Natural Gas Turbine (SC-GAS) Type, rated at 200 MW with an assumed heat rate of 10,800 Btu/KWh
  - o Although firm capacity was added in the form of hydro natural gas-fueled generation, there can be other, less emitting forms of firm capacity that could be considered – e.g., contractual imports, energy storage, demand response, etc.
  - o Note: British Columbia, Manitoba and Quebec TAC Members suggested that the model should not include any future thermal generation, but instead use hydro resources for capacity expansion. In addition, capacity additions were not required for those regions.
- In 5% BAU Scenario, added an initial set of CC-GASs & SC-GASs to meet annual reserve margin target.
- Ran GE MAPS iteratively to refine SC-GAS and CC-GAS mix to quantify the expected utilization of the capacity additions. 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 technology choice was switched.

Table 4-10: Generation Expansion Plan by Province

	Hydro Firm Capacity (%)	Wind Firm Capacity (%)	Unbalanced RM (%)	Target RM (%)	Generic CC-GAS Add (MW)	Generic SC-GAS Add (MW)
BC	87%	21%	23%	16%	0	0
AB	67%	20%	-17%	12%	4,000	800
SK	100%	20%	1%	11%	500	200
MB	100%	0%	20%	12%	0	0
ON	72%	13%	8%	20%	2,500	600
QC	96%	28%	11%	10%	0	0
MAR	100%	31%	20%	20%	0	0

4.2 Study Scenarios

4.2.1 Selected Scenarios

The PCWIS evaluated four main scenarios in an effort to understand the operational and grid impacts of increased wind energy across Canada. The scenarios were selected to provide insight on both the magnitude and location of wind expansion. The level of wind penetration ranged from approximately existing 2016 levels (5%) up to 35% of annual load energy (nationally) in the highest scenario. The locations of wind additions also varied, with some scenarios having dispersed wind across Canadian provinces, while other scenarios concentrated wind to the best resource locations or regions where displacement of thermal generation (and therefore emissions reductions) could be maximized. The four scenarios evaluated throughout the study are:

- **5% Business-as-Usual Scenario (5% BAU):** The 5% BAU Scenario represents an approximation of the Canadian power system and includes all wind plants in Canada that were operating or under construction as of 4/25/2015. Each wind plant was assigned to the nearest wind profile site and the output was scaled to align with the current plant capacity (while assuming state of the art turbine technology to be consistent with other scenarios).
- **20% Dispersed Scenario (20% DISP):** The 20% DISP Scenario represents the Canadian power system with enough wind energy available to serve 20% of the annual load energy *in each province*. Wind sites were selected, incrementally to the

sites already included in the 5% BAU Scenario, so that each province had enough wind locally to serve 20% of the annual provincial load. Incremental sites were selected based on the best available resources within each province, while accounting for distance to nearest high voltage transmission. As a result, wind site selection was dispersed across Canada, in proportion to the load in each province.

- **20% Concentrated Scenario (20% CONC):** Similar to the 20% DISP Scenario, the 20% CONC Scenario represents the Canadian power system with enough wind energy available to serve 20% of the annual load energy *across Canada*. The site selections were incremental to the 5% BAU Scenario. As a result, the annual available energy is the same as the 20% DISP scenario, but the 20% CONC scenario concentrated the wind site location in regions with the best wind resources and therefore less installed wind capacity. This is the only scenario where wind sites were allowed to be selected in Newfoundland and Labrador, based on the quality of the wind resource in the province. Wind sites were selected based on capacity factor and distance to transmission only, irrespective of the provincial load energy.

  In addition, the 20% CONC scenario included additional site selection criteria to limit the geographic concentration of wind sites. The additional criteria included:

  - Minimum penetration limit of 10% annual energy penetration for each province (applied to British Columbia, Saskatchewan, and Quebec)
  - Maximum penetration limit of 50% (applied to Nova Scotia)
  - A selection of at least one additional site in each province relative to the 5% BAU Scenario.
  - In Alberta, to avoid an over concentration of wind expansion exclusively in the southern region of the province, some wind locations were manually adjusted to a to 70%/30% split by adding wind to more northern Red Deer area.

- **35% Targeted Scenario (35% TRGT):** 35% TRGT Scenario represents the Canadian power system with enough wind energy available to serve 35% of the annual load energy across Canada, with wind locations targeted to achieve thermal generation displacement, emissions reduction in Canada. This scenario was developed after preliminary review of the first three scenarios. The starting point of the scenario was the 20% DISP scenario included all of the 5% BAU and 20% DISP sites and added new incremental wind sites proportional to each province's thermal generation in the 5% BAU case. As a result, new wind sites were targeted to Alberta, Saskatchewan, Ontario, and the Maritimes regions.

  In addition, the 20% CONC scenario included additional site selection criteria to limit the geographic concentration of wind sites. The additional criteria included:

- o Minimum penetration limit of 25% annual energy penetration for each province (applied to British Columbia, Saskatchewan, and Quebec)
- o Maximum penetration limit of 50% (applied to Alberta, Saskatchewan, New Brunswick, and Nova Scotia)
- o In Alberta, to avoid an over concentration of wind expansion exclusively in the southern region of the province, some wind locations were manually adjusted to a to 70%/30% split by adding wind to more northern Red Deer area.
- o No additional sites were selected in the Bruce Peninsula region of Ontario and the Gaspe Peninsula region of Quebec in an effort to increase geographic diversity and over correlation of wind output.

A map showing the geographic locations of the wind plants selected in each scenario is provided in Figure 4-9, followed by additional summaries.

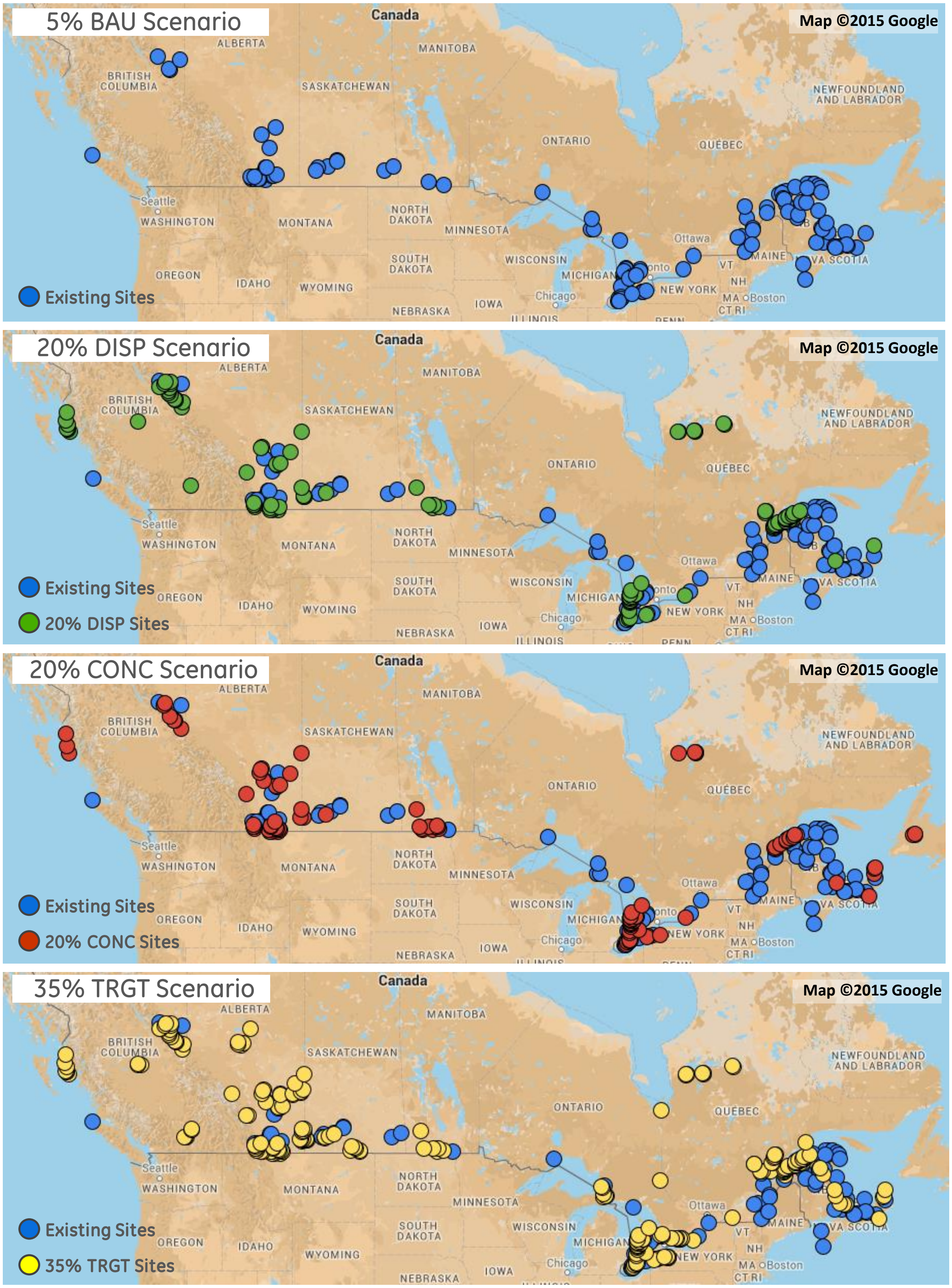


Figure 4-9: Locations of Selected Wind Plants by Study Scenario

A summary of the Scenario Development is provided in Figure 4-10 and Table 4-11, with additional details provided for each province in Table 4-12, Figure 4-11, and Figure 4-12. These tables and figures provide a detailed overview of the amount of wind capacity (MW), energy (GWh), and quality of wind resource in each region (capacity factor %). Note that in the 20% DISP scenario the annual penetration is slightly higher than 20% CONC for Canada because Prince Edward Island already has more than 20% annual penetration. In addition, the wind energy, capacity factor, and penetration values presented in this section represent *available* wind energy and do not take into account potential curtailment which was addressed in the production cost modeling.

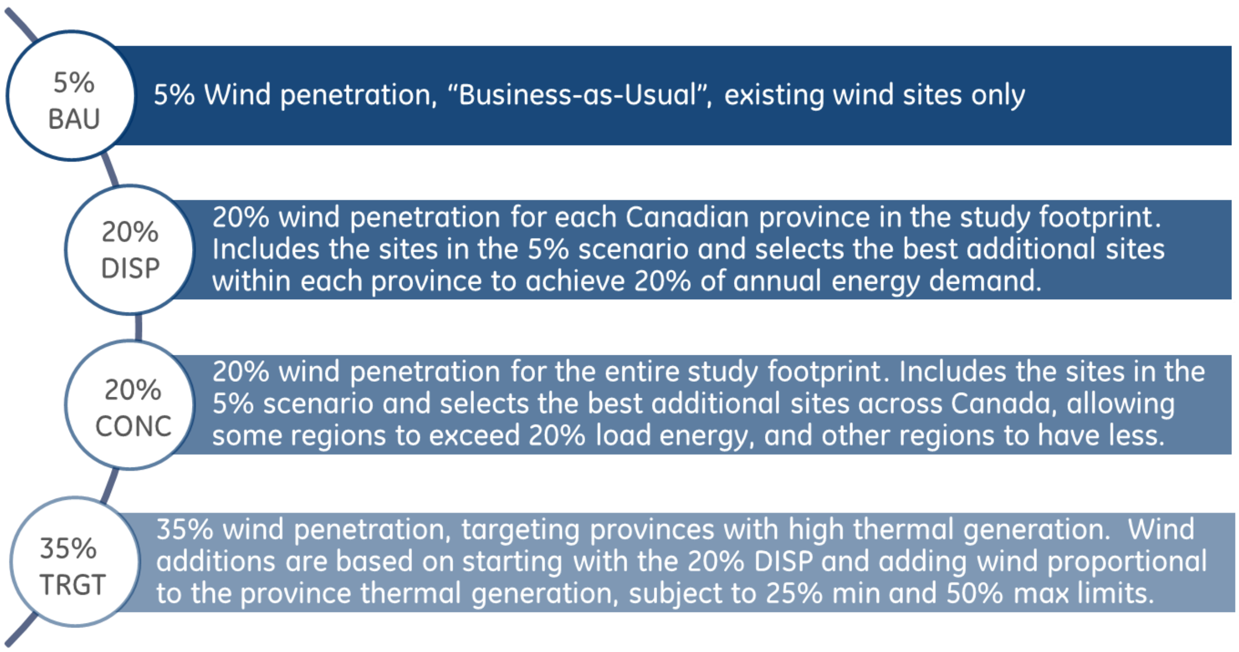


Figure 4-10: Study Scenario Overview

Table 4-11: Study Scenario Overview, Canada Total

Scenario	Wind Penetration Level (%)	Number of Wind Sites Used	Wind Capacity (MW)	Wind Energy (GWh)	Average Capacity Factor (%)
5% BAU	5.7%	116	10,970	34,717	36.1%
20% DISP	20%	229	37,131	122,054	37.5%
20% CONC	20%	220	36,311	121,584	38.2%
35% TRGT	35%	333	65,225	212,734	37.2%

Note: Totals and capacity factors may not match due to rounding.

Table 4-12: Scenario Details by Province

	BC	AB	SK	MB	ON	QC	NB	PEI	NS	NL	CAN
Wind Capacity (MW)											
5% BAU	685	1,438	451	258	4,103	2,960	484	201	390	0	10,970
20% DISP	4,270	6,944	1,749	1,781	8,440	12,275	796	201	675	0	37,131
20% CONC	2,221	9,840	915	2,789	10,056	6,128	796	201	1,587	1,776	36,311
35% TRGT	5,445	17,728	4,407	2,213	16,124	15,490	1,967	201	1,651	0	65,225
Available Wind Energy (GWh)											
5% BAU	1,751	4,527	1,471	859	13,610	9,074	1,479	686	1,261	0	34,717
20% DISP	12,592	23,148	5,923	6,008	28,640	40,118	2,559	686	2,381	0	122,054
20% CONC	6,520	32,874	3,077	9,495	34,162	20,100	2,556	686	5,782	6,332	121,584
35% TRGT	15,734	57,879	14,804	7,502	53,651	50,128	6,397	686	5,952	0	212,734
Available Wind Capacity Factor (%)											
5% BAU	29.2%	35.9%	37.2%	38.0%	37.9%	35.0%	34.9%	39.0%	36.9%		36.1%
20% DISP	33.7%	38.1%	38.7%	38.5%	38.7%	37.3%	36.7%	39.0%	40.3%		37.5%
20% CONC	33.5%	38.1%	38.4%	38.9%	38.8%	37.4%	36.7%	39.0%	41.6%	40.7%	38.2%
35% TRGT	33.0%	37.3%	38.3%	38.7%	38.0%	36.9%	37.1%	39.0%	41.2%		37.2%
Available Wind Penetration (% of Load)											
5% BAU	2.8%	3.9%	5.0%	2.9%	9.5%	4.5%	11.6%	63%	10.6%	N/A	5.7%
20% DISP	20%	20%	20%	20%	20%	20%	20%	63%	20%	N/A	20%
20% CONC	10%	28%	10%	32%	24%	10%	20%	63%	49%	N/A	20%
35% TRGT	25%	50%	50%	25%	37%	25%	50%	63%	50%	N/A	35%

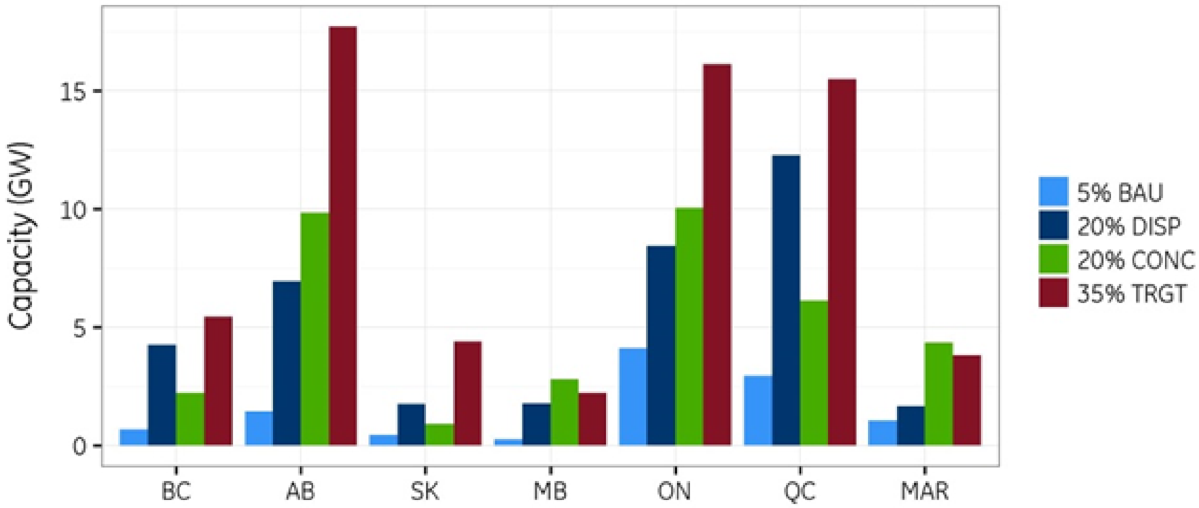


Figure 4-11: Installed Wind Capacity by Scenario, by Province

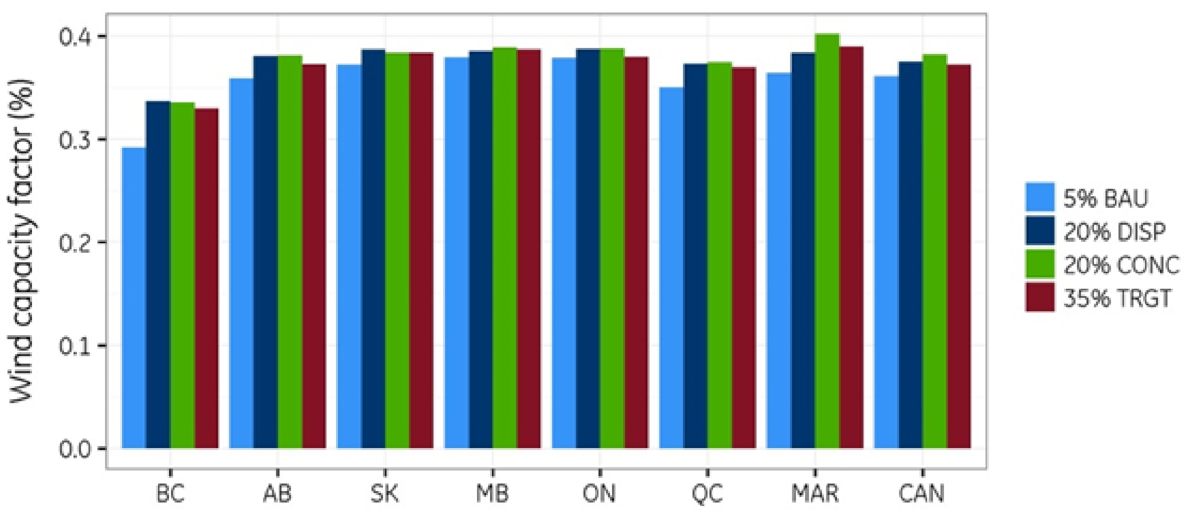


Figure 4-12: Average Available Capacity Factor by Scenario, by Province

4.2.2 Wind Additions in the United States

With significant amount of interconnection and power flows between the United States and Canada, it was important to include wind expansion in the USA power systems as well. Each scenario included a build out of wind capacity in the USA to achieve full compliance from state renewable portfolio standard (RPS) requirements. 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 wind capacity and available wind energy in the USA remained unchanged throughout the Scenarios. This was done to ensure that any changes taking place on the power system were a direct result of the additional wind installations evaluated in each of the four scenarios. However, a sensitivity analysis was conducted to evaluate the impact of a 20% increase in wind energy availability in the USA system. Table 4-13 provides an overview of the wind build-out in the USA across all scenarios.

Table 4-13: Wind Build-out for the USA in all Scenarios

	Annual Load (GWh)	Wind Capacity (MW)	Available Wind Energy (GWh)	Available Capacity Factor (%)	Available Wind Penetration (%)
BAS	87,598	995	2,975	34%	3%
CAL	332,500	7,299	23,212	36%	7%
DSW	167,059	4,174	12,254	34%	7%
FRCC	259,363	0	0	0%	0%
ISONE	133,902	5,218	19,016	42%	14%
MISO	636,222	40,343	156,898	44%	25%
NWP	193,991	10,392	32,875	36%	17%
NYISO	173,294	12,076	43,130	41%	25%
PJM	969,027	15,630	55,680	41%	6%
RMP	78,160	5,040	18,483	42%	24%
SERC-E	255,709	3,760	14,098	43%	6%
SERC-N	249,537	200	467	27%	0%
SERC-S	293,229	0	0	0%	0%
SERC-W	148,672	0	0	0%	0%
SPP	288,431	28,927	118,873	47%	41%
TOTAL USA	4,266,695	134,054	497,960	42%	12%

4.3 Wind Site Selections

Wind data used in the study and described previously in Section on "Wind Data Development" consists of numerous (54,846) 2 km x 2 km grid cells at 100M tower height spanning the Canadian continent. Each grid cell represents eight 2MW wind turbines. Figure 4-13, depicts locations of each grid cell provided in this study. Each grid cell has numerous data types spanning years 2008 through 2010. Of particular interest were the production data from each grid cell that included profiles of 10 minute wind power production and hourly forecast data for day ahead, 6-hour ahead, 4-hour ahead, and 1-hour ahead production.

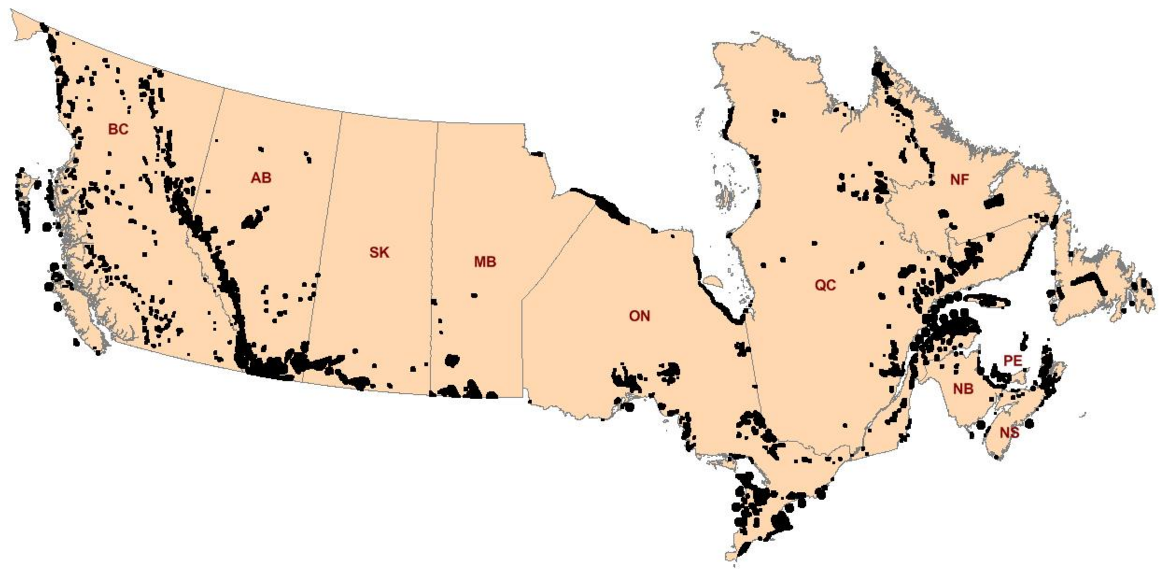


Figure 4-13: Wind Grid Cell Locations

Given the large amount of data encompassed in the 54,846 grid cell dataset, it was determined by the study team to group and aggregate the grid cell data to create individual utility size wind sites for further analysis. These wind sites consist of an aggregation of grid cells that are located within a 10 km^2 area. To do this, a grid of 10 km x 10 km square areas were tiled from east to west and south to north over the region containing the individual grid cells. The boundary limits in the 10 km^2 area are shown in Table 4-14. All grid cells within the boundaries of each 10 km^2 area were aggregated into a single wind site and assigned a unique site ID with a location central to all grid cells making up the wind plant as shown in Figure 4-14. Figure 4-15 shows additional detail of grid cell to wind plant aggregation. Each unique grid cell was used only once in the wind plant development. In other words no two wind plants share any grid cells. The aggregating process consolidated all grid cells into 4984 unique wind sites. Each wind site consists of 1 to 28 grid cells (Note that technically a 10x10 km grid should only accommodate 25 grid cells. However, during the aggregation process the central point of a 2 km x 2 km grid cell was used for the aggregation. If only a portion of the grid cell fell within the 10 km x10 km grid aggregation, the entire grid cell was included, thus creating a few sites with more than 25 grid cells included). A distribution of the number and size of different wind sites resulting from the aggregation is shown in profiles for each wind plant were calculated that included 10-minute production and hourly forecasts for day ahead, 6-hour ahead, 4-hour ahead and 1-hour ahead. Site ID's were selected in the development of each scenario and used in the evaluation of reserve requirements, statistical analysis and sub hourly analysis described in other sections in the report.

Table 4-14: Wind Plant Aggregation Boundaries

Furthest point	Longitude	Latitude
North	-136.027	60.000
South	-82.297	42.170
East	-52.820	47.369
West	-136.203	59.979

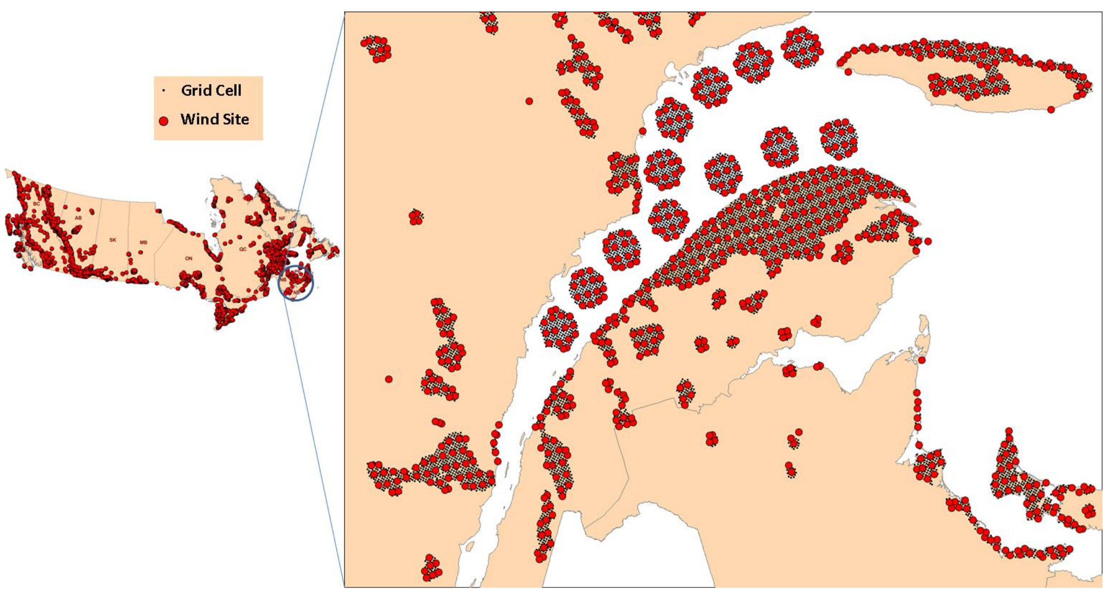


Figure 4-14: Red Dots Represent Wind Plants and Black Dots Represent Grid Cells

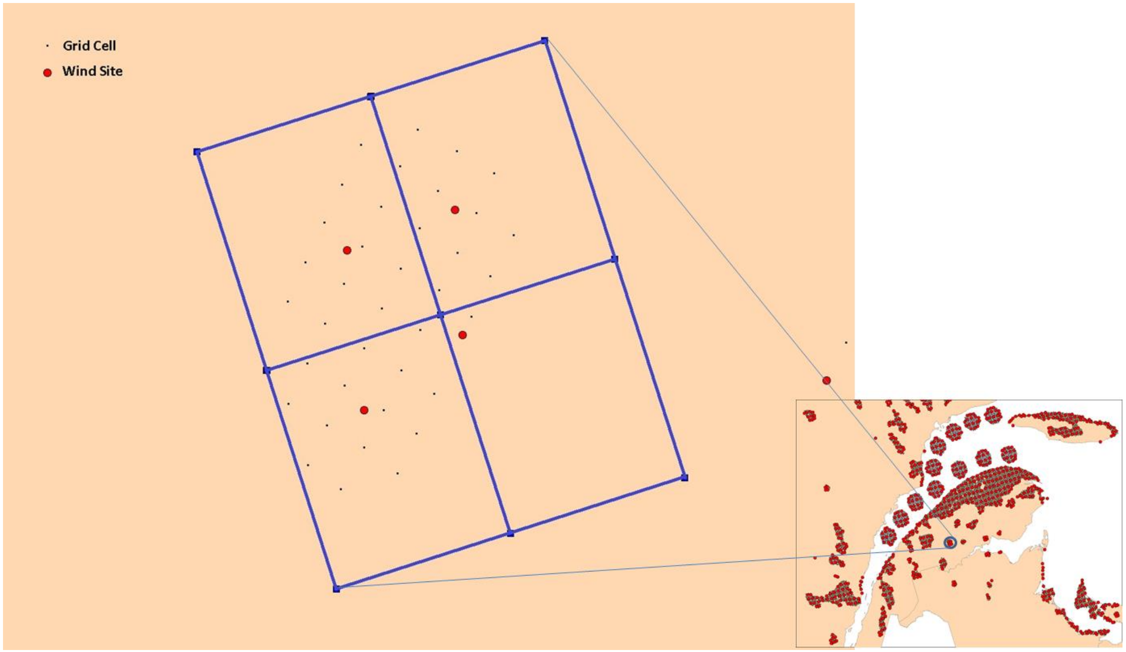


Figure 4-15: Example of 10 km x 10 km Areas That Are Tiled To Identify Grid Cells To Be Aggregated Into Wind Plants

Figure 4-16 shows the number of wind sites at different rated capacities, which range from 16 MW to 432 MW.

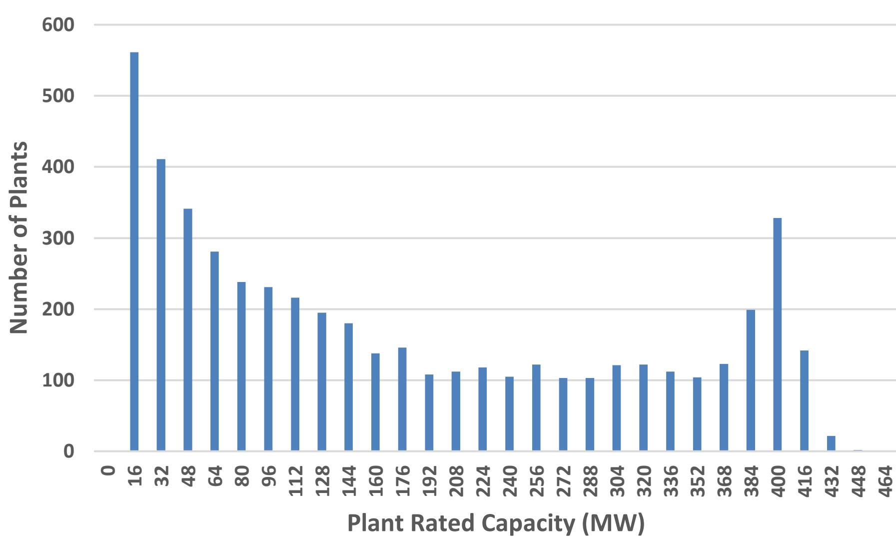


Figure 4-16: Number of Wind Sites at Different Rated Capacities

Table 4-15 shows the summary statistics for grid cell aggregation by province.

Table 4-15: Summary Statistics for Grid Cell Aggregation by Province

	BC	AB	SK	MB	ON	QC	NB	NS	PEI	NL	CAN
Number of Grid Cells	6,505	9,570	2,379	2,341	12,179	16,441	613	1,686	473	2,659	54,846
Number of Aggregated Sites	1,033	706	167	187	997	1,382	78	171	44	219	4,984
Total Site Capacity (MW)	104,080	153,120	38,064	37,456	194,864	263,056	9,808	26,976	7,568	42,544	877,536
Avg. Site Capacity (MW)	101	217	228	200	195	190	126	158	172	194	176
Max Site Capacity (MW)	416	448	432	432	432	448	416	416	416	416	448
Min Site Capacity (MW)	16	16	16	16	16	16	16	16	16	16	16
Avg. Site Capacity Factor (%)	27.5%	32.4%	37.1%	37.2%	35.4%	35.8%	37.5%	39.1%	39.3%	38.8%	33.9%
Max Site Capacity Factor (%)	44.5%	42.6%	40.8%	40.5%	43.2%	48.0%	45.3%	48.5%	42.3%	47.1%	48.5%
Min Site Capacity Factor (%)	8.6%	7.1%	33.3%	23.4%	24.8%	20.6%	28.0%	33.6%	36.9%	26.4%	7.1%
Total Available Energy (GWh)	265,962	446,555	123,793	122,735	608,568	817,104	32,860	92,512	25,640	143,273	2,679 TWh

5 Statistical and Reserve Analysis

5.1 Statistical Analysis

This section of the report was developed and prepared by EnerNex.

5.1.1 Introduction

This section provides information in charts and tables that describe and characterize the Provincial and Canadian system load and wind resource data. Wind generation is variable across time scales ranging from 10-minute to hourly resolution and cannot be perfectly forecast over any time horizon. Balancing Area load also exhibits variability and uncertainty across many operational time frames. Wind resource variability and uncertainty increase the overall variability and uncertainty of net load (system load net of wind generation).

The main purpose of the analysis provided in this section is to convey familiarity to the reader of the chronological load and wind data which are the primary inputs to the technical analysis described in the report. In general it is not possible to extract quantitative conclusions about operating impacts directly from statistics of wind and load data. While certain features may stand out from a system operations perspective – such as a difference in time when peak and net load peak occur – several other factors must be considered to determine the magnitude of the impact. Production simulations take many of these other factors into account as they seek to mimic the actual operation of the system against the array of operating constraints, and therefore are the better framework for drawing operational conclusions.

Renewable generation scenarios consisting of different penetrations of wind are defined for the study and shown in Table 5-1. Scenarios were defined in consultation with CanWEA and the TAC, and selected from the data provided by Vaisala described in this report. Chronological wind production data at 10-minute intervals over the calendar years of 2008, 2009 and 2010 were extracted and aggregated for this analysis.

Table 5-1: Wind Installed Capacity (MW) for each Scenario

	BC	AB	SK	MB	ON	QC	NB	PEI	NS	NL	CAN
5% BAU	685	1,438	451	258	4,103	2,960	484	201	390	0	10,970
20% DISP	4,270	6,944	1,749	1,781	8,440	12,275	796	201	675	0	37,131
20% CONC	2,221	9,840	915	2,789	10,056	6,128	796	201	1,587	1,776	36,311
35% TRGT	5,445	17,728	4,407	2,213	16,124	15,490	1,967	201	1,651	0	65,225

In the GE MAPS production simulations, individual sites were assigned to existing or planned network buses. The statistical analysis and characterization of the renewable resources examine the aggregate production i.e. the total generation of all wind sites in each scenario.

Subsequent sections examine and characterize the sub-hourly and hourly wind production as well as hourly wind forecasts, and net load data. These data are presented by province and for the entire country.

5.1.2 Load

In this section load data is characterized by examining hourly values over three profile years, 2008, 2009 and 2010 for each province and Canada. These profile years coincide with the wind profile years to maintain the underlying weather patterns that affect wind and load profiles.

Table 5-2 provides information showing a general characterization of the load that includes annual energy, annual peak demand, minimum demand, load factor, average hourly load and hourly standard deviation for each Province and all of Canada. Escalation to the study year set the energy as constant for each study profile while attempting to keep the same annual peak. The peak and minimum demand for each province occurs at different times over the year. Load factors are based upon each individual province's peak demand. Hourly standard deviations depict the variations of hourly demand from the average. Seeing the change in standard deviation between profile years gives an indication of different load patterns that can occur over different time intervals such as daily, monthly or seasonal, shown later in this section. Figure 5-1, depicts a graphical representation of annual provincial energy demand and shows the annual demand is nearly the same in each profile year. Quebec, Ontario and Alberta have the largest demand while Saskatchewan, Manitoba and the Maritimes have close to the same annual demand.

Table 5-2: Load Characterization by Profile Year for each Province and all Canada

2008	BC	AB	SK	MB	ON	QC	Mar	Canada
Annual Energy (GWH)	63,433	116,234	29,626	30,149	143,255	200,736	26,528	609,961
Peak Demand (MW)	11,622	16,318	4,444	5,261	24,331	41,171	5,247	100,891
Min Demand (MW)	4,546	10,686	2,392	2,079	10,348	7,356	1,739	42,255
Load Factor (%)	62%	81%	76%	65%	67%	56%	58%	69%
Average (MW)	7,241	13,269	3,382	3,442	16,353	22,915	3,028	69,630
Std. Deviation	1,346	1,076	389	643	2,678	5,789	637	11,169
2009	**BC**	**AB**	**SK**	**MB**	**ON**	**QC**	**Mar**	**Canada**
Annual Energy (GWH)	63,433	116,234	29,626	30,149	143,255	200,736	26,528	609,961
Peak Demand (MW)	11,622	16,318	4,444	5,261	24,477	41,171	5,277	99,540
Min Demand (MW)	4,524	11,296	2,437	2,243	11,079	10,687	1,688	46,572
Load Factor (%)	62%	81%	76%	65%	67%	56%	57%	70%
Average (MW)	7,241	13,269	3,382	3,442	16,353	22,915	3,028	69,630
Std. Deviation	1,338	905	390	670	2,466	5,754	652	10,917
2010	**BC**	**AB**	**SK**	**MB**	**ON**	**QC**	**Mar**	**Canada**
Annual Energy (GWH)	63,433	116,234	29,626	30,149	143,255	200,736	26,528	609,961
Peak Demand (MW)	11,622	16,318	4,444	5,261	24,383	41,171	5,328	100,949
Min Demand (MW)	4,498	10,995	2,630	2,029	11,032	11,028	1,601	47,037
Load Factor (%)	62%	81%	76%	65%	67%	56%	57%	69%
Average (MW)	7,241	13,269	3,382	3,442	16,353	22,915	3,028	69,630
Std. Deviation	1,254	1,042	318	711	2,472	5,430	647	10,441

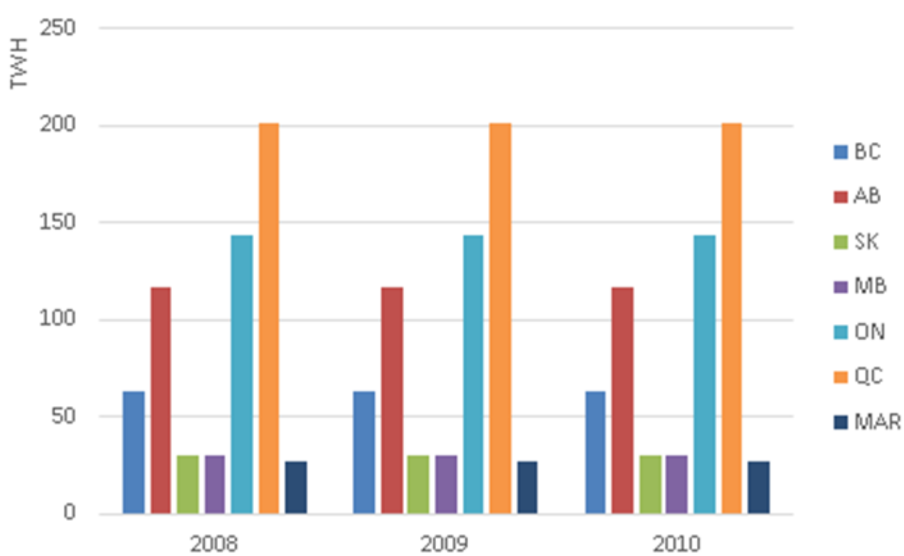


Figure 5-1: Annual Load Energy by Province

Examining the monthly load data for Canada in each profile year shows the monthly difference in demand. The annual load demand for each profile year is the same. The Canada monthly load demand energy for each profile year is shown in Figure 5-2. Here it is seen that the months of January and December in each profile year have the greatest demand while the mid-year months have lower demand energy. Individual province monthly load demand is shown in Figure 5-3. The diversity of the different provinces can be seen in this figure where Ontario has peak load demand in winter and summer months while Quebec monthly demand trends are similar to that of the Canadian monthly demand.

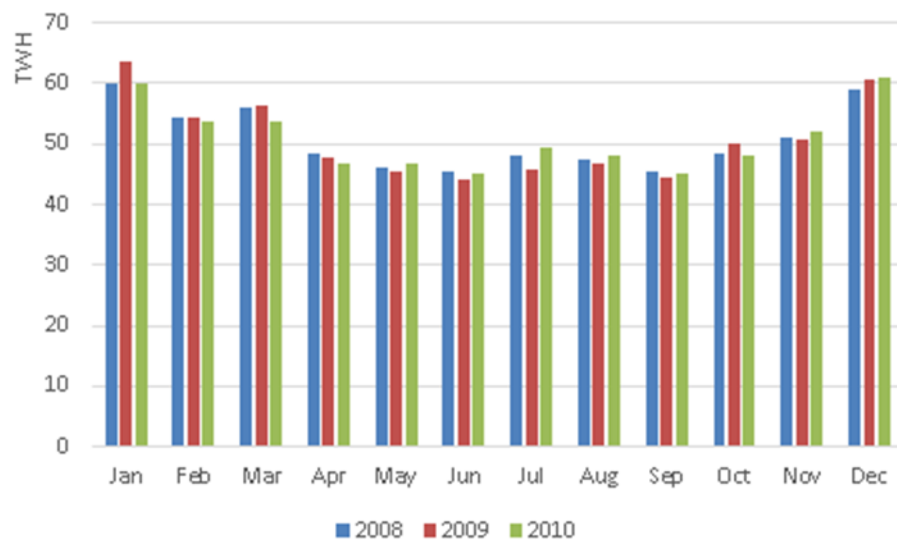


Figure 5-2: Canada Monthly Load Demand for each Profile Year

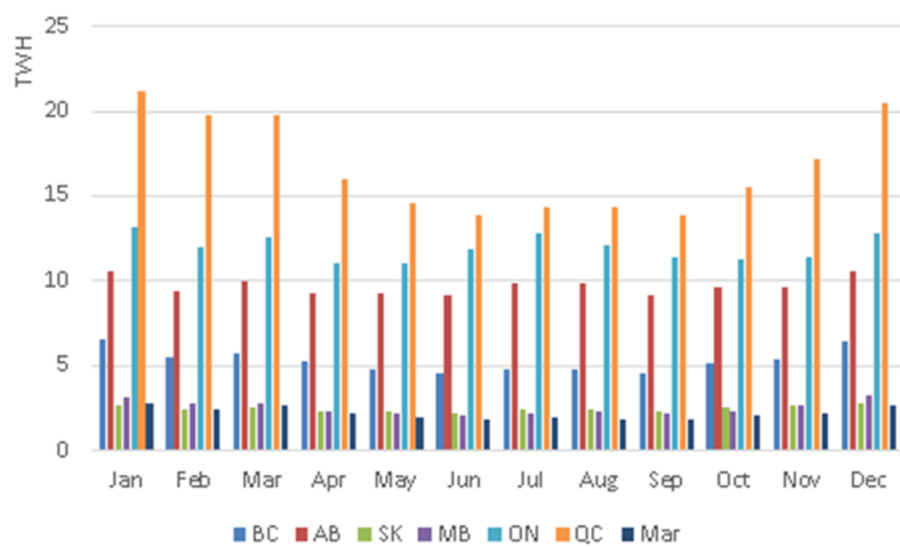


Figure 5-3: Province Monthly Load Demand for 2008 Profile Year

Examination of monthly peak load for each province and Canada are shown in Figure 5-4 and Figure 5-5. For Canada the peak load trends like the load demand energy in the winter months of January and December. Individual provincial monthly peak load shows a different characterization with Ontario having a summer peak load, while Quebec, British Columbia, Manitoba and the Maritimes have predominantly winter peaks; Alberta and Saskatchewan tend to have peak loads as approximately the same for each month.

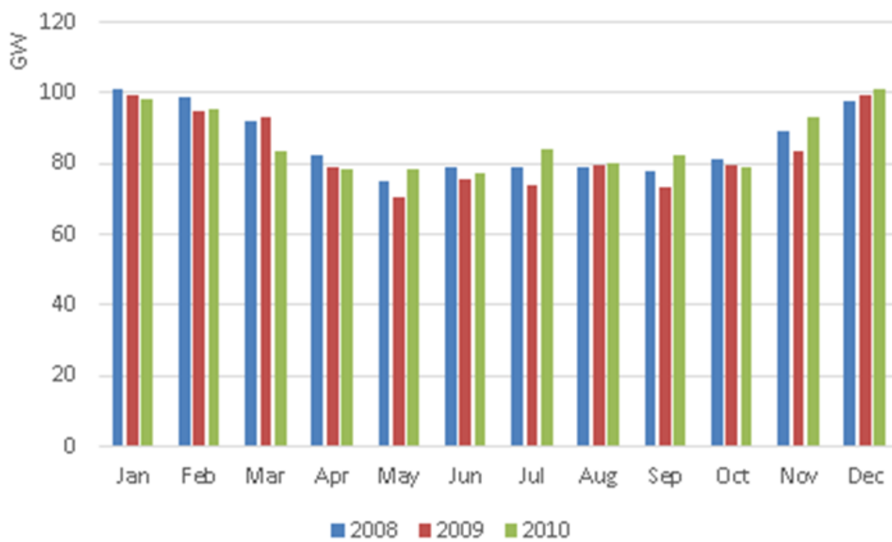


Figure 5-4: Canada Monthly Peak Load by Profile Year

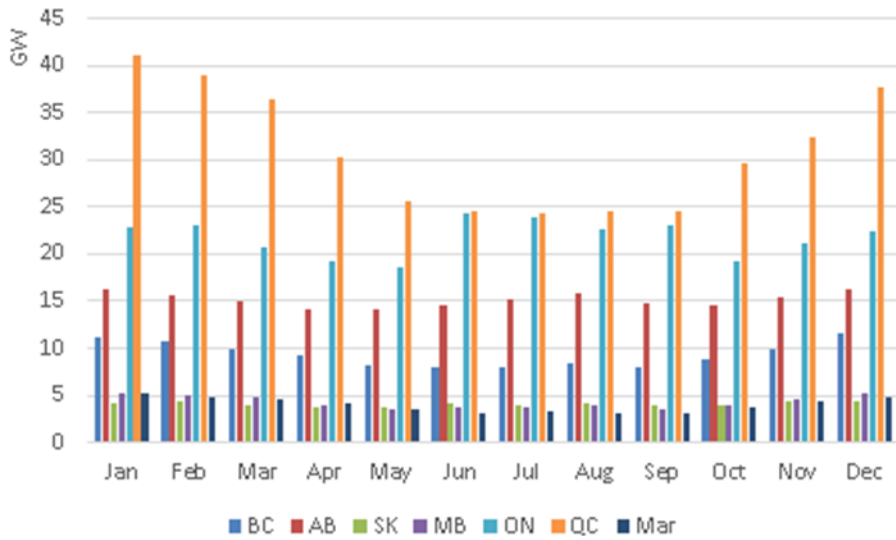


Figure 5-5: Province Monthly Peak Load for 2008 Profile

Seasonal load demand is another aggregation of system loads where the winter months consist of December, January and February. Spring is the aggregate of March, April and May; summer is the aggregate of June, July and August; and fall is the aggregate of September, October and November. In Figure 5-6 the winter season period has the largest demand energy while summer is the lowest demand energy season. Figure 5-7 depicts provincial demand energy by season; here it can be seen that Quebec demand is the largest contributor to the Canada demand energy, and is the determining province for the seasonal load energy.

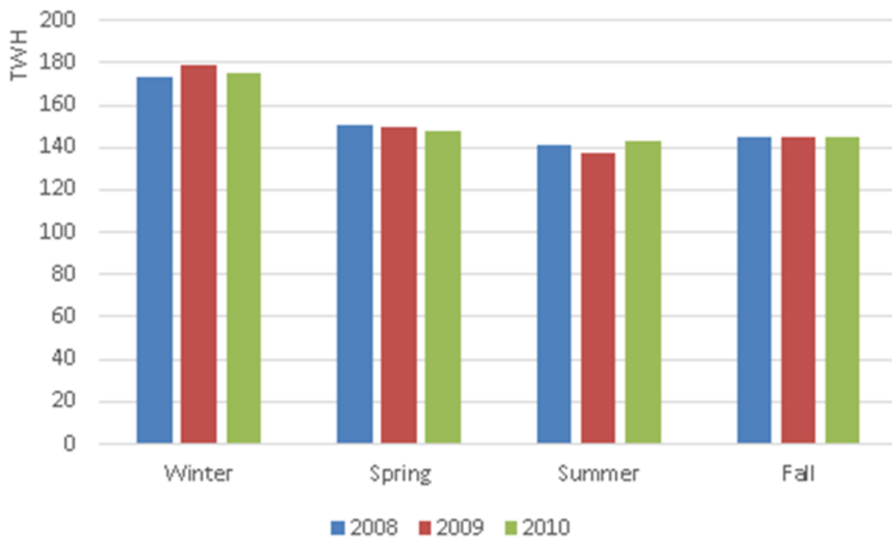


Figure 5-6: Canada Demand Energy by Season for each Profile Year

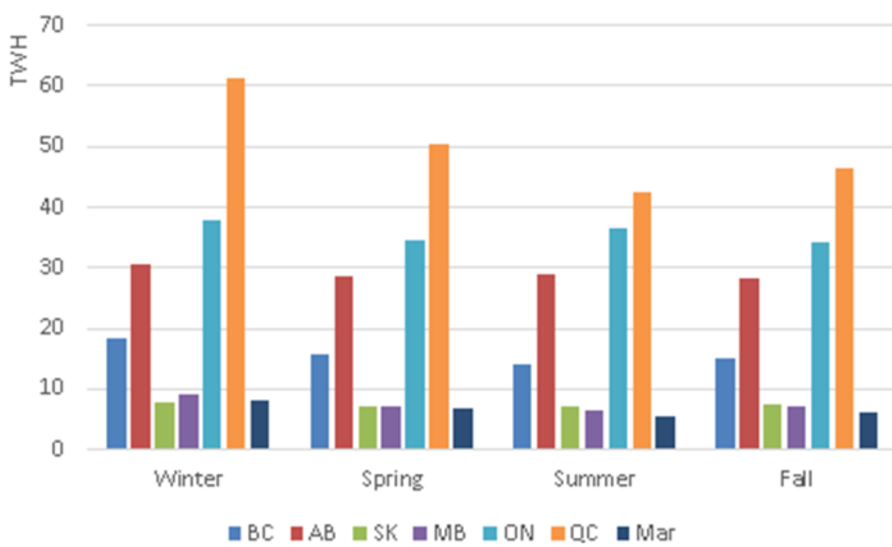


Figure 5-7: Province Demand Energy for Profile Year 2008

A load duration curve provides a different perspective of hourly load over the year by ordering each hourly load value from high to low. This provides an insight to the maximum and minimum load values with a perspective of the magnitude of other hourly load values in the year. A load duration curve with a sharp initial decline in the first few periods of the curve indicate a system with fewer peaking values. On the other hand, load duration curve with a slow sloping decline in the initial hours of the year indicate several hours when loads near the peak load exist. Figure 5-8 depicts load duration curves for each province and all of Canada by profile year. Each profile year can be seen in each of the provinces and provide very similar shapes. The 2009 profile in Manitoba does not have as many low load periods as the other years, while Saskatchewan has more low demand periods in 2009 when compared to the other two profile years. These curves also provide an indication of the range of load demand over the year. For example, British Columbia load demand is between 5,000 MW and 10,000 MW, except for a few hours between 10,000 MW and 12,000 MW for each profile year. With regards to Quebec and the Maritimes, there are more values around the peak demand which can be seen by the slow sweeping concave decline in the curve. The remainder of the year gradually declines until there is a sharp drop for the minimum demand.

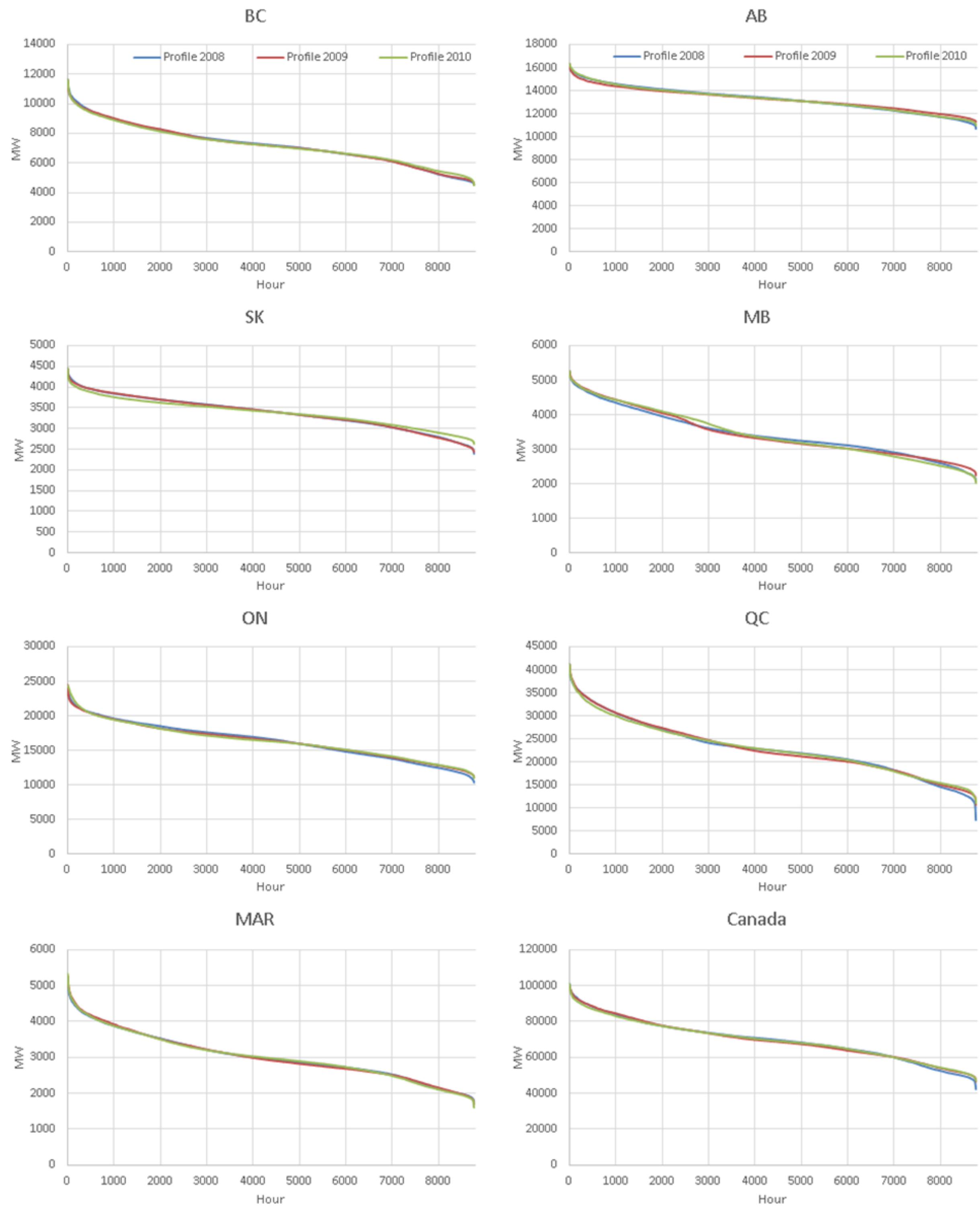


Figure 5-8: 2025 Load Duration Curves for each Province and Canada for all Load Profile Years

Another way to glean information from a system load is by examining the average hourly load in a day for each season of the year. This provides a general impression of a typical load shape being studied. Figure 5-9 shows the time of the day when load trends high or low and how different seasons affect these changes,

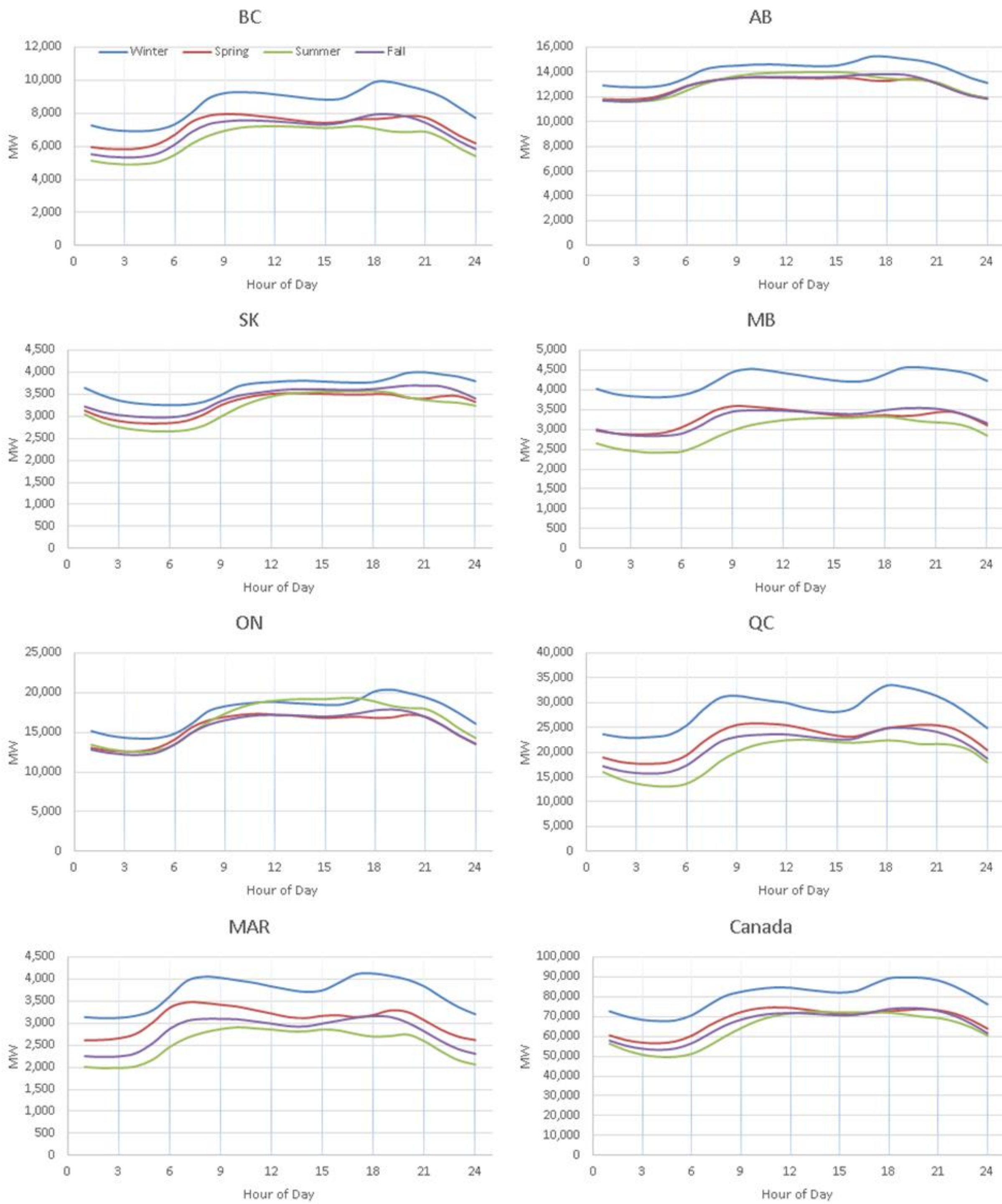


Figure 5-9: Average Daily Load by Province and Canada for 2008 Profile

5.1.3 Wind

Each scenario in the study consists of a selection of wind plants that span Canada. An analysis of the wind plant production is provided below. Wind plant characterization includes charts and tables representative of each Province and Canada.

5.1.3.1 Wind Energy

Figure 5-10, Figure 5-11, Figure 5-12, and Figure 5-13 present Scenario annual wind energy by province for each profile year in each study scenario. Figure 5-14 depicts the annual aggregated wind energy for Canada in each profile year.

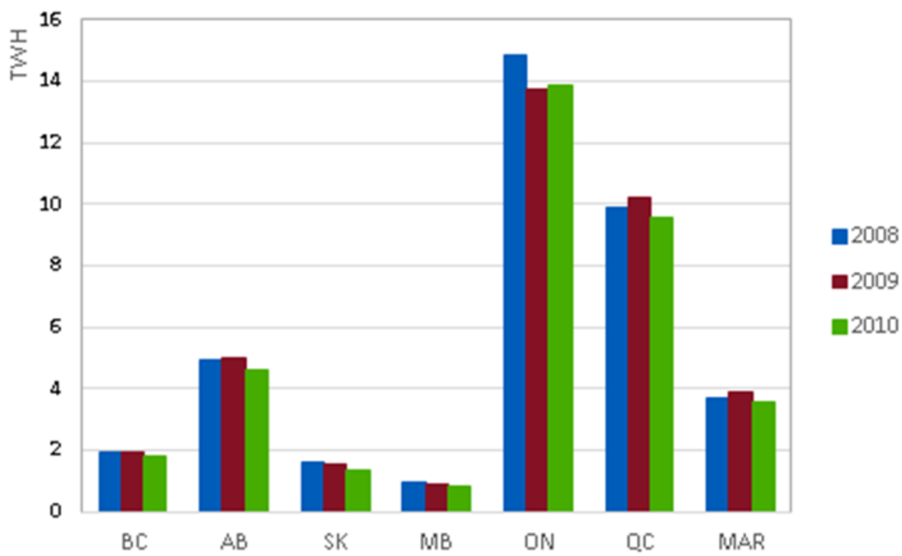


Figure 5-10: Annual Wind Energy Production by Province for 5% BAU Scenario

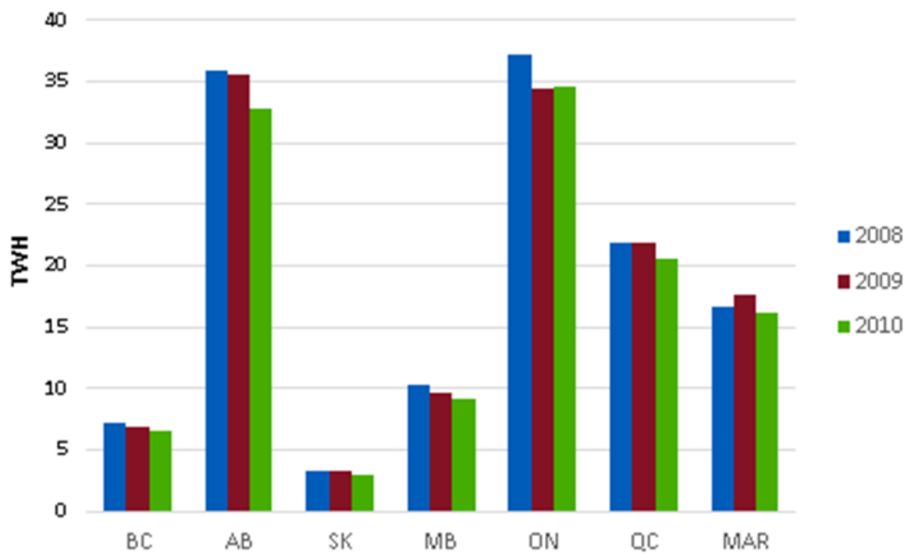


Figure 5-11: Annual Wind Energy Production by Province for 20% CONC Scenario

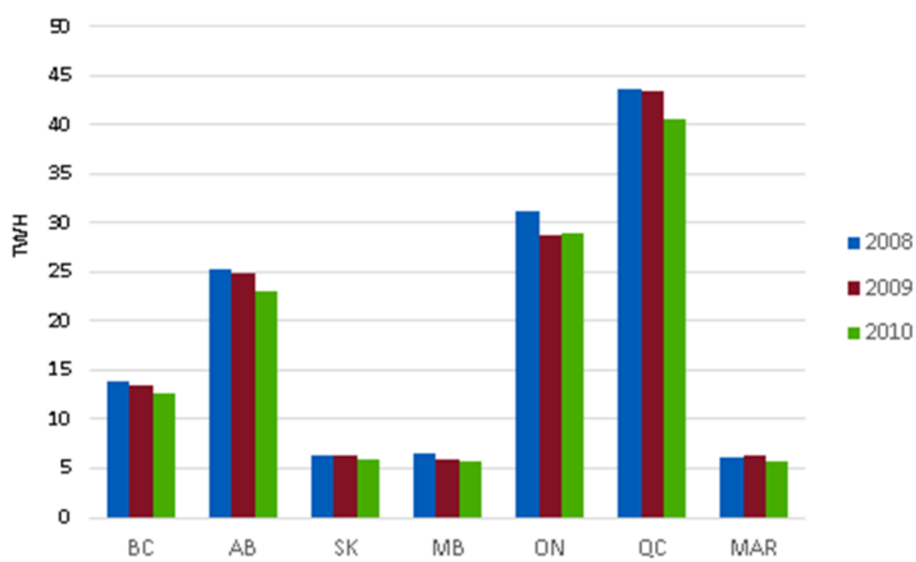


Figure 5-12: Annual Wind Energy Production by Province for 20% DISP Scenario

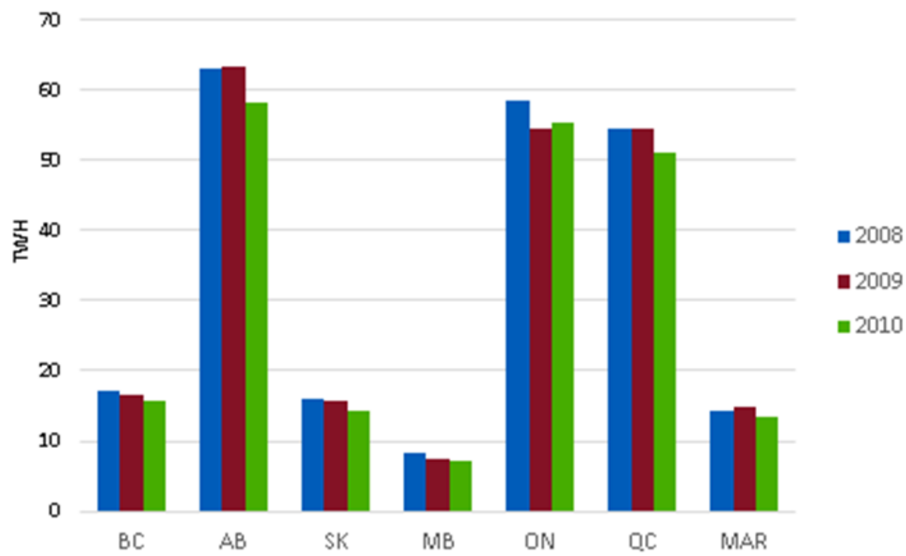


Figure 5-13: Annual wind Energy Production by Province for 35% TRGT Scenario

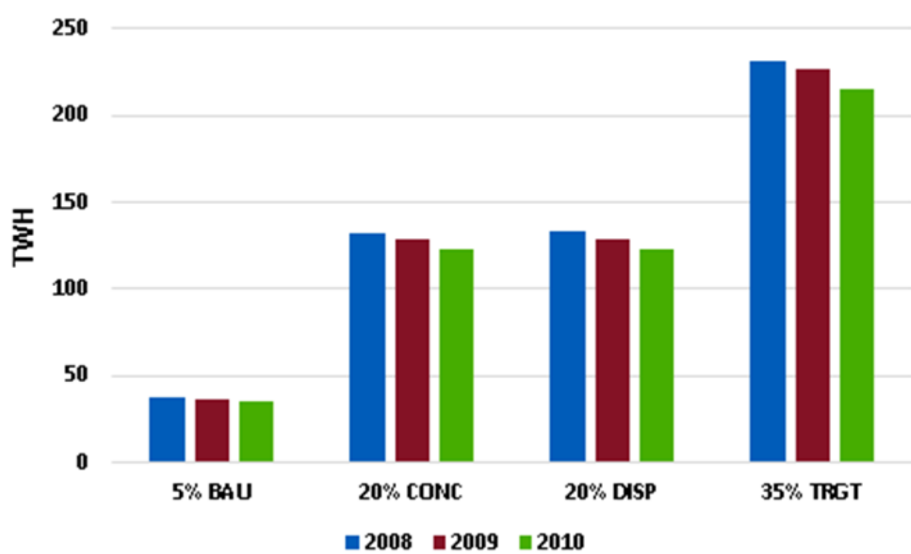


Figure 5-14: Canada Annual wind Energy Production for each Scenario

Table 5-3 provides the available wind energy by Province and Canada for each Scenario and Profile Year.

Table 5-3: Available Wind Energy by Province and Canada for each Scenario and Profile Year (GWh)

Scenario	Profile Year	BC	AB	SK	MB	ON	QC	MAR	CAN
5% BAU	2008	1,751	4,527	1,471	859	13,610	9,074	3,426	34,717
5% BAU	2009	1,768	4,618	1,408	787	12,617	9,394	3,553	34,145
5% BAU	2010	1,640	4,239	1,263	771	12,658	8,794	3,263	32,627
20% DISP	2008	12,592	23,148	5,923	6,008	28,640	40,118	5,626	122,054
20% DISP	2009	12,349	22,968	5,900	5,531	26,526	39,939	5,878	119,092
20% DISP	2010	11,731	21,212	5,413	5,318	26,539	37,346	5,330	112,890
20% CONC	2008	6,520	32,874	3,077	9,495	34,162	20,100	15,356	121,584
20% CONC	2009	6,335	32,903	3,018	8,816	31,696	20,094	16,179	119,040
20% CONC	2010	6,062	30,343	2,716	8,378	31,604	18,963	14,830	112,896
35% TRGT	2008	15,734	57,879	14,804	7,502	53,651	50,128	13,035	212,734
35% TRGT	2009	15,267	58,422	14,505	6,915	50,174	50,257	13,610	209,151
35% TRGT	2010	14,543	53,701	13,055	6,614	50,701	47,044	12,364	198,022

Providing a seasonal perspective on wind energy production allows for insights into differences in wind production over the year. The 2008 wind profile is selected for provincial seasonal comparisons of each scenario in Figure 5-15, Figure 5-17, Figure 5-19, and Figure 5-21 while the total Canada aggregated wind for each profile year is depicted in Figure 5-16, Figure 5-18, Figure 5-20 and Figure 5-22.

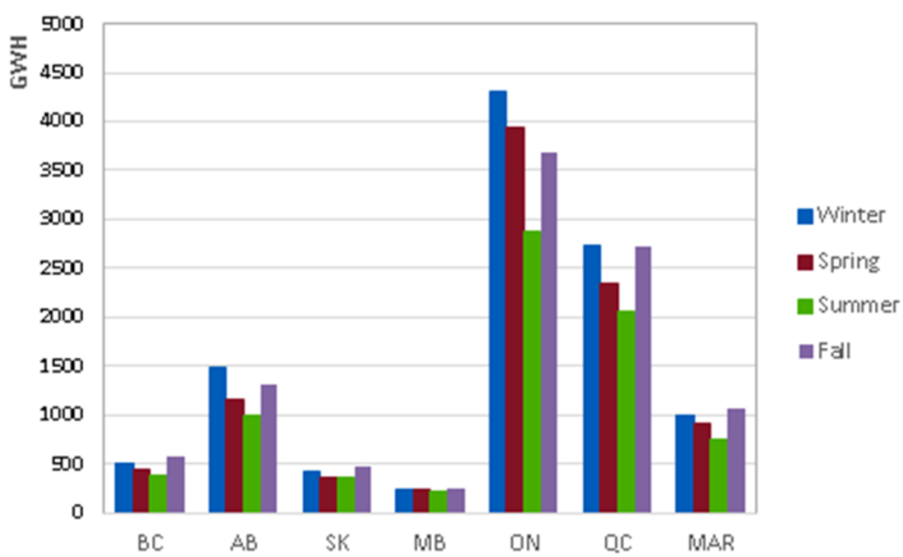


Figure 5-15: Seasonal Wind Energy Production for 5% BAU Scenario 2008 Profile Year

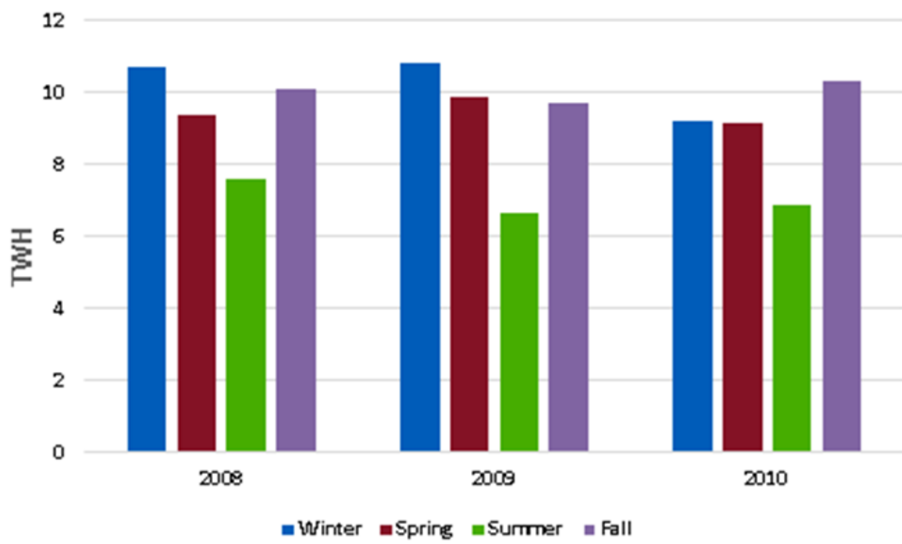


Figure 5-16: Canada Seasonal Wind Energy Production for 5% BAU Scenario in each Profile Year

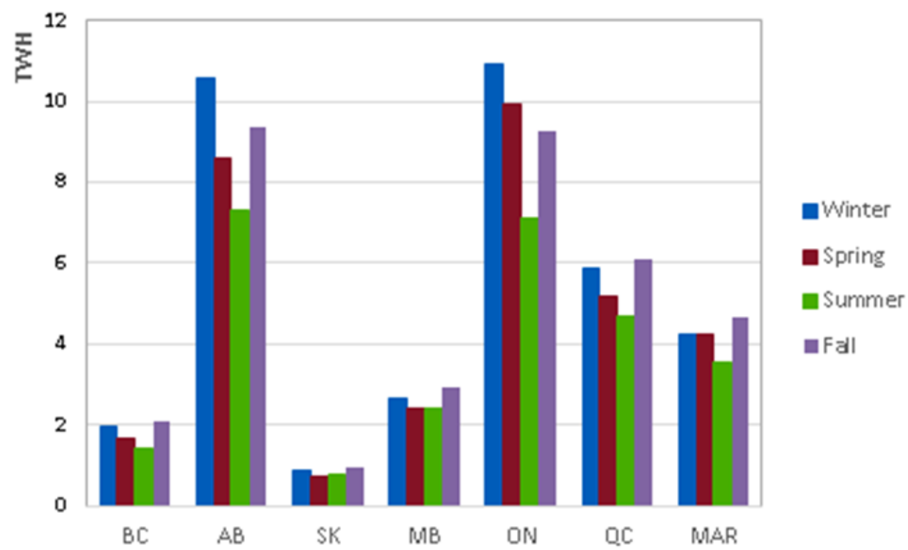


Figure 5-17: Seasonal Wind Energy Production by Province for 20% CONC Scenario 2008 Profile Year

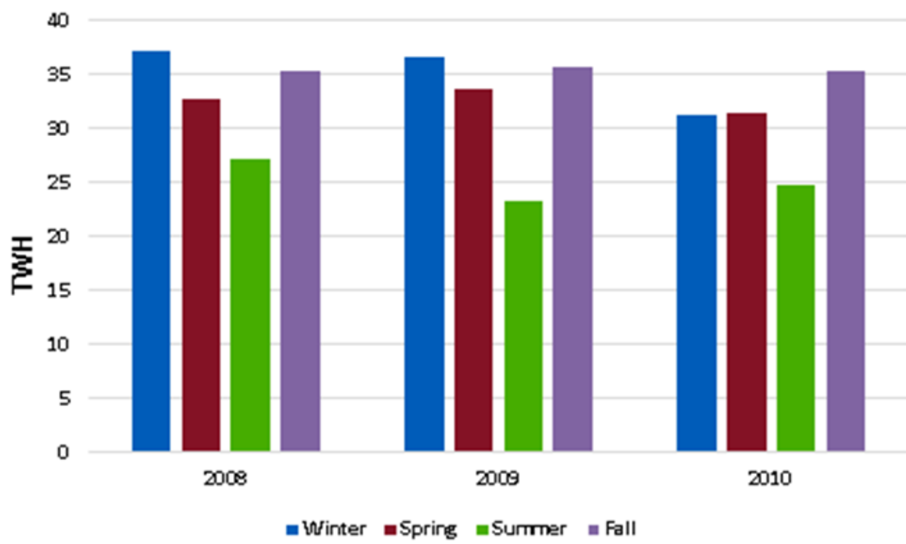


Figure 5-18: Canada Seasonal Wind Energy Production for 20% CONC Scenario in each Profile Year

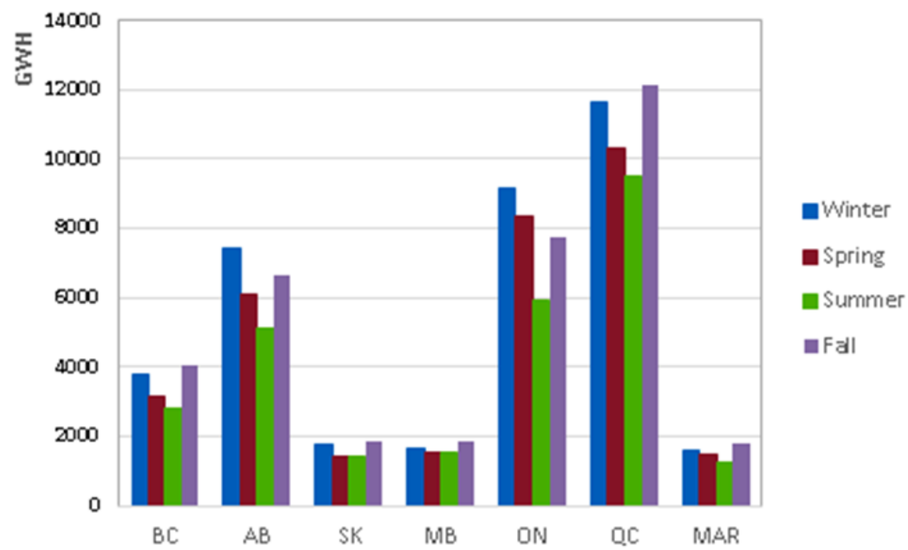


Figure 5-19: Seasonal Wind Energy Production by Province for 20% DISP Scenario 2008 Profile Year

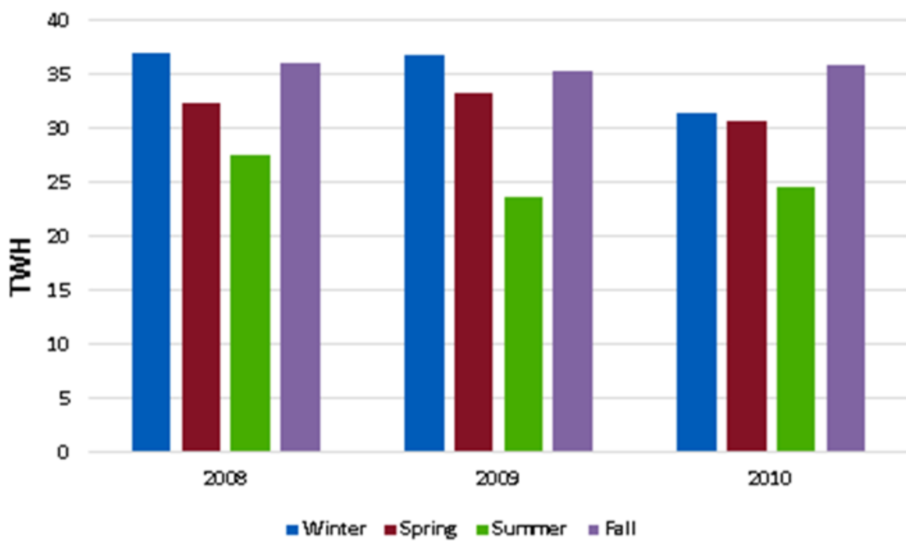


Figure 5-20: Canada Seasonal Wind Energy Production for 20% DISP Scenario in each Profile Year

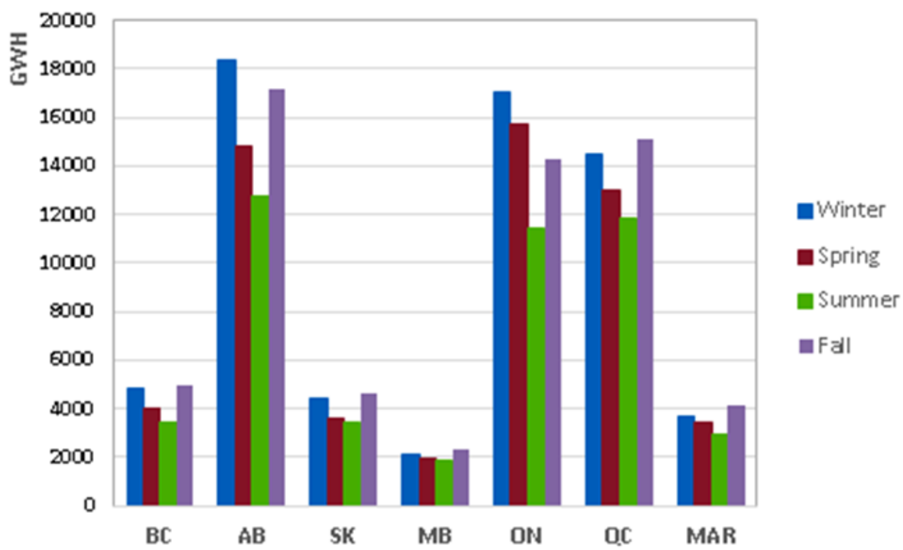


Figure 5-21: Canada Seasonal Wind Energy Production for 20% DISP Scenario in each Profile Year

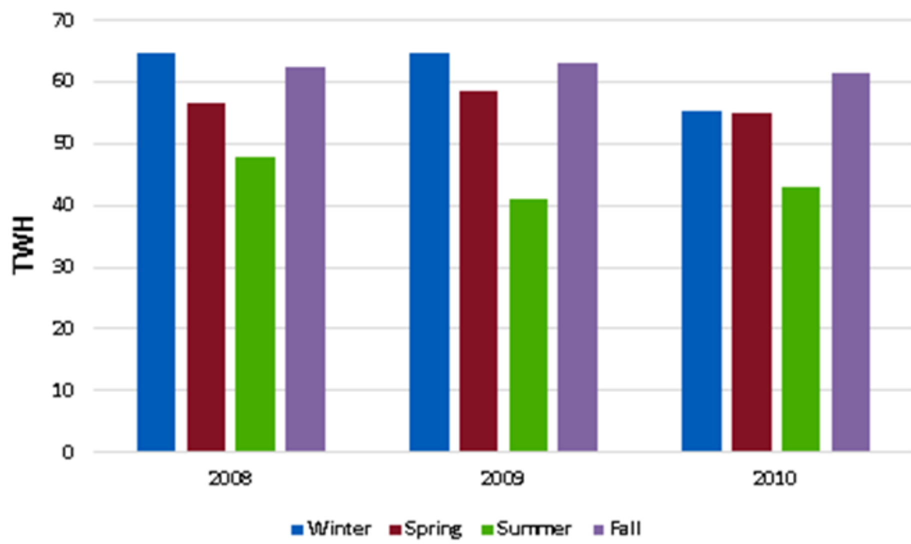


Figure 5-22: Canada Seasonal Wind Energy Production for 35% TRGT Scenario in each Profile Year

Looking at wind energy production by month provides a refined examination of the seasonal wind energy production. For example, in each scenario the wind energy production for Alberta in January and November exceeded all other months by at least 10%. The 2008 profile year is depicted in Figure 5-15, Figure 5-17, Figure 5-19, and Figure 5-21.

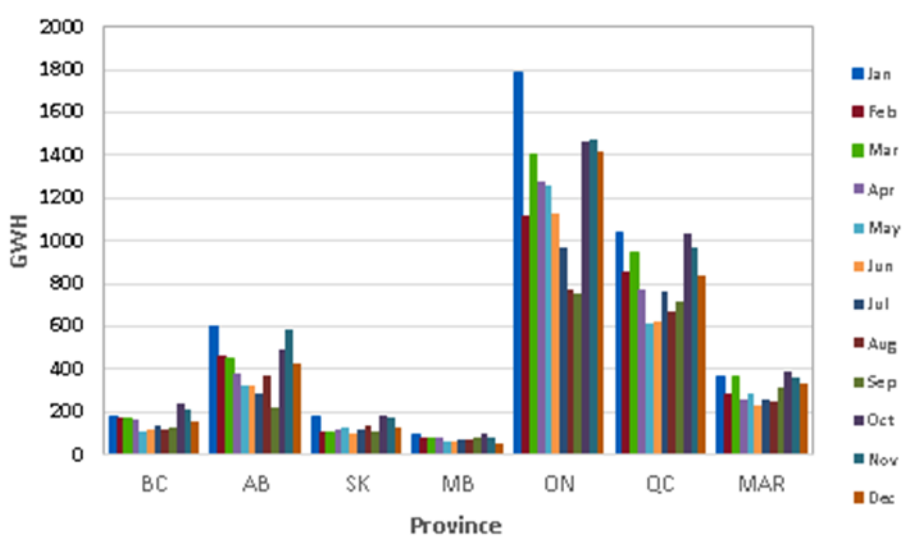


Figure 5-23: Monthly Wind Energy Production by Province for 5% BAU Scenario 2008 Profile Year

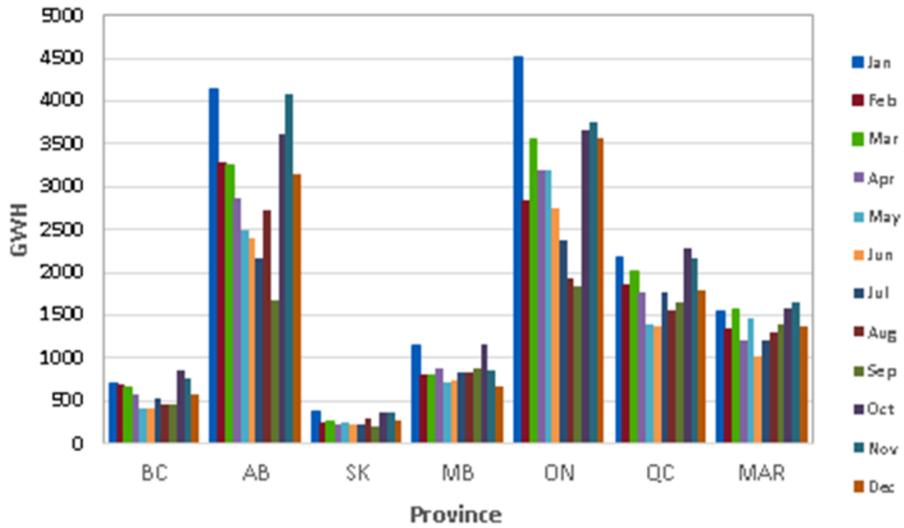


Figure 5-24: Monthly Wind Energy Production by Province for 20% CONC Scenario 2008 Profile Year

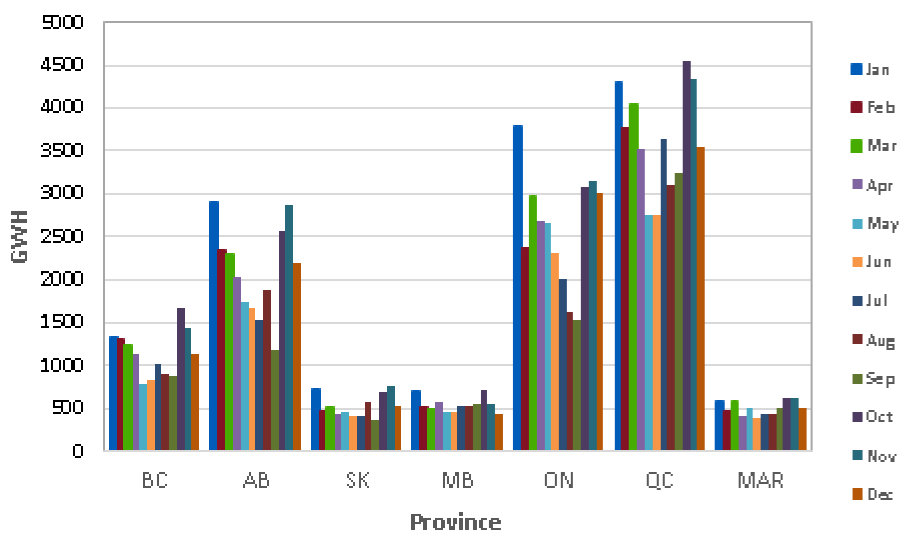


Figure 5-25: Monthly Wind Energy Production by Province for 20% DISP Scenario 2008 Profile Year

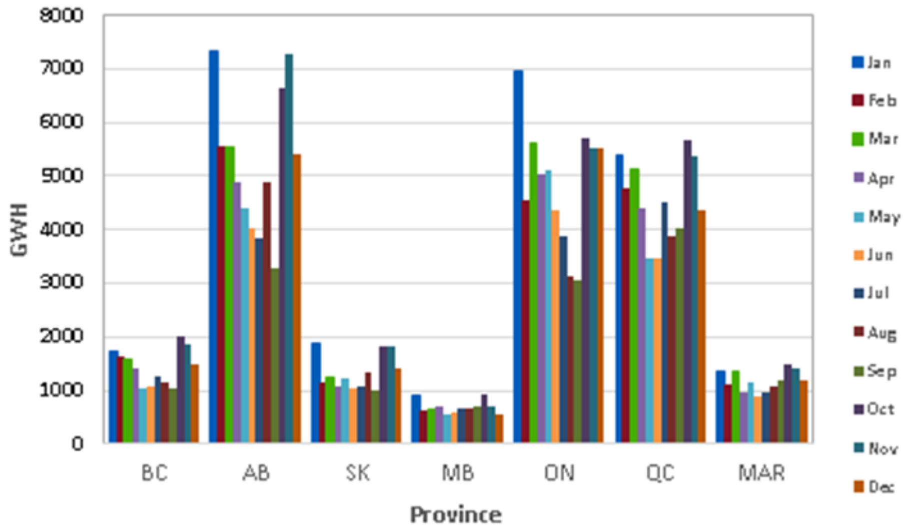


Figure 5-26: Monthly Wind Energy Production by Province for 35% TRGT Scenario 2008 Profile Year

5.1.3.2 Wind Production

Examining hourly wind production over the year can be shown by ordering the hourly values from high to low for all hours in the year. A sample of wind duration curves for each province and each profile year is shown in Figure 5-27. A duration curve provides a visualization of non-chronological production over the year. For example, comparison of the shape of the BC curves with those for MB indicates the wind in MB has several hours of production near the annual wind production maximum causing the curve to have a slight initial slope downward, while the BC curve slope is much steeper at the annual peak. It is also noticeable how the increased penetration in each scenario tends to maintain a similar shape. The Canada wind duration curves exemplify diversity benefits in the 20% scenarios. In the individual provincial figures there is a distinct difference between the 20% CONC and 20% DISP duration curves. The Canada duration curves for the 20% scenarios tend to overlap and a specific distinction between CONC and DISP is not as obvious.

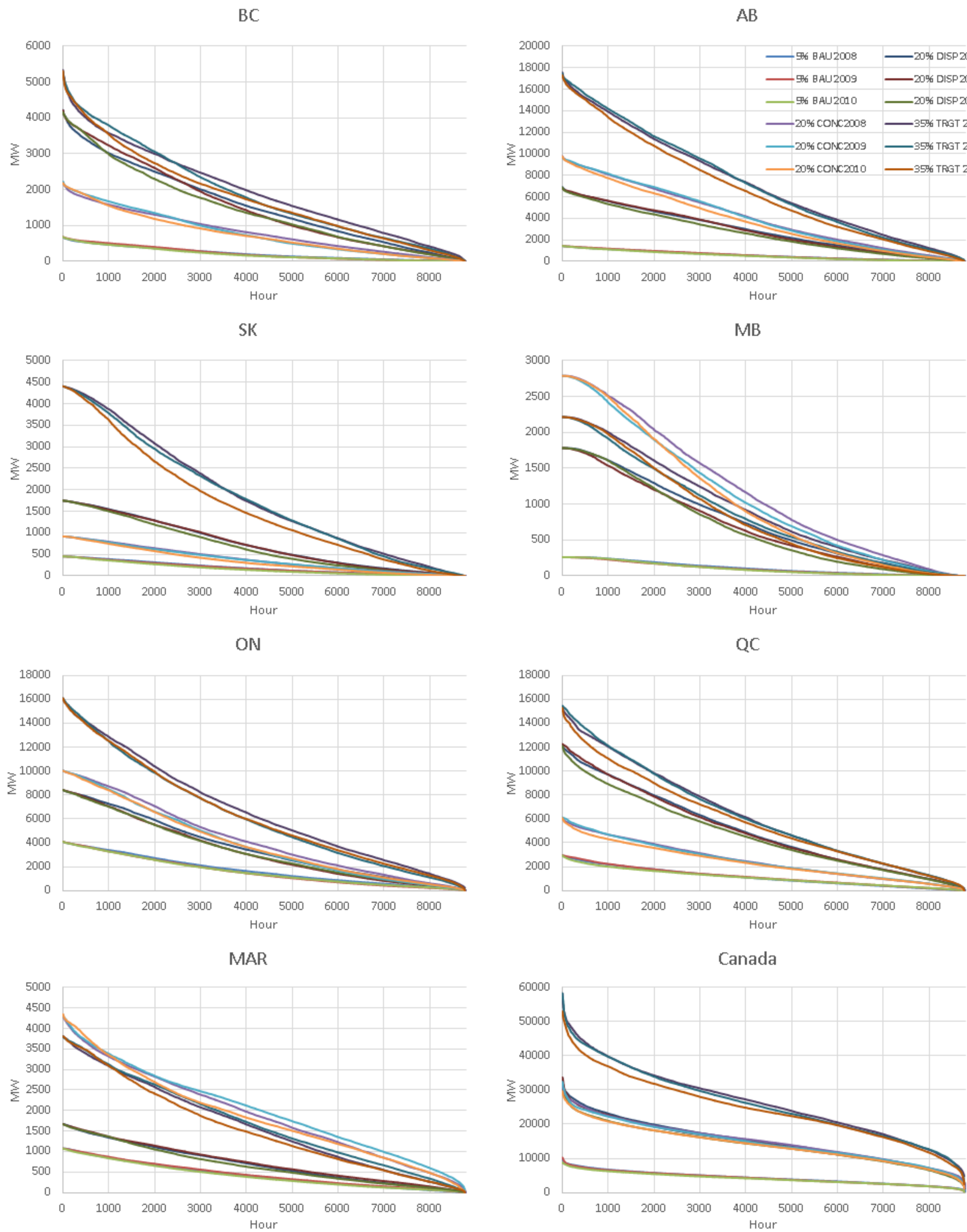


Figure 5-27: Wind Production Duration Curves by Scenario for each Province, Canada and Profile Year

The seasonal behavior of wind production can be examined by looking at the average production in each province of the hour in the day. The following charts in Figure 5-28, Figure 5-29, Figure 5-30, and Figure 5-31 display wind hourly average for each province and Canada for each scenario. These plots display the wind diurnal patterns that exist and vary by season. The aggregate of all Canada wind has a diversity advantage in that across the continent, wind does not have the same production level and therefore in some periods when wind production is low, other areas benefit from higher production levels. Winter and fall tend to have the highest production levels, while summer tends to have the lowest.

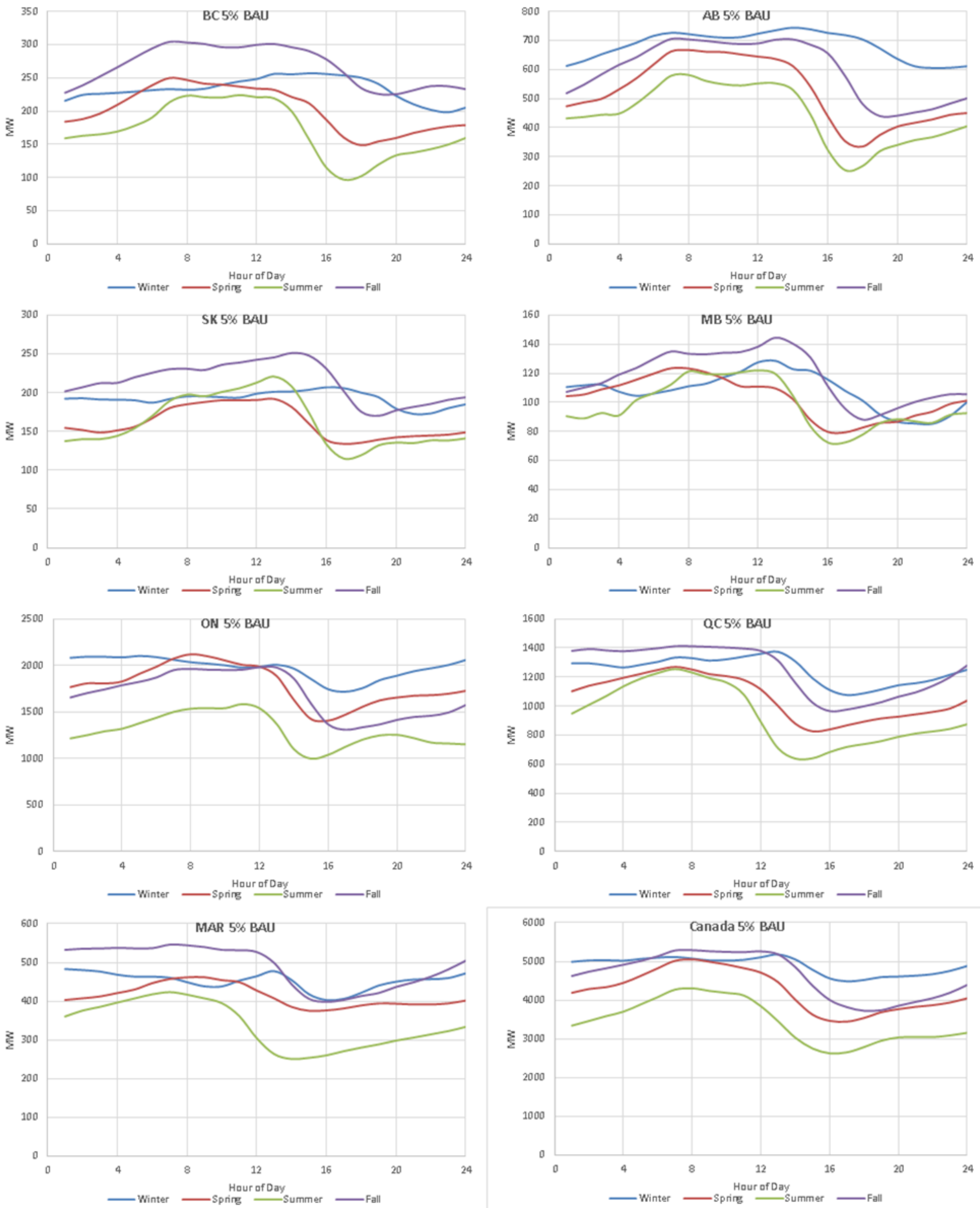


Figure 5-28: Average Wind Hour Production by Season for each Province and Canada 5% BAU

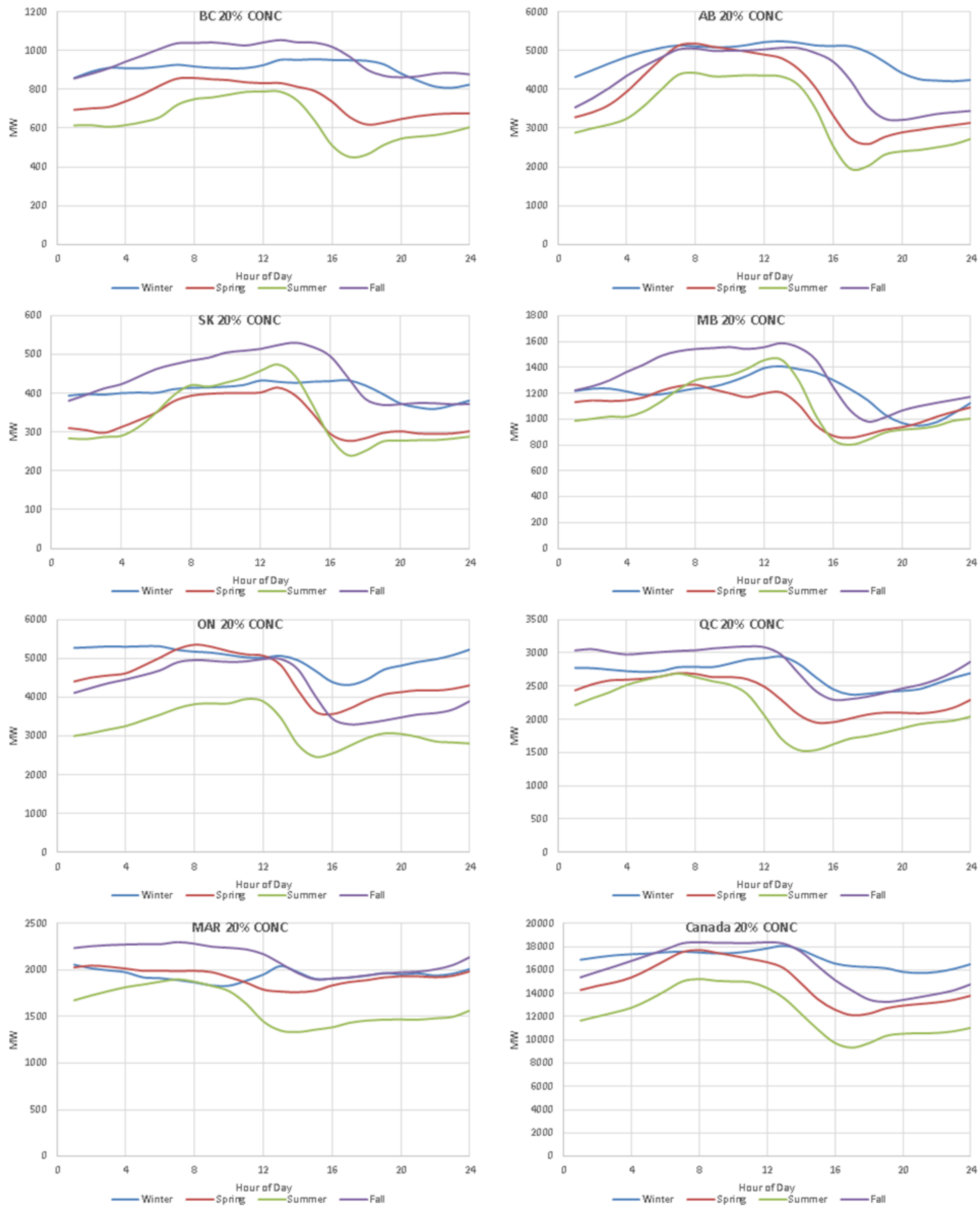


Figure 5-29: Average Wind Hour Production by Season for each Province and Canada 20% CONC

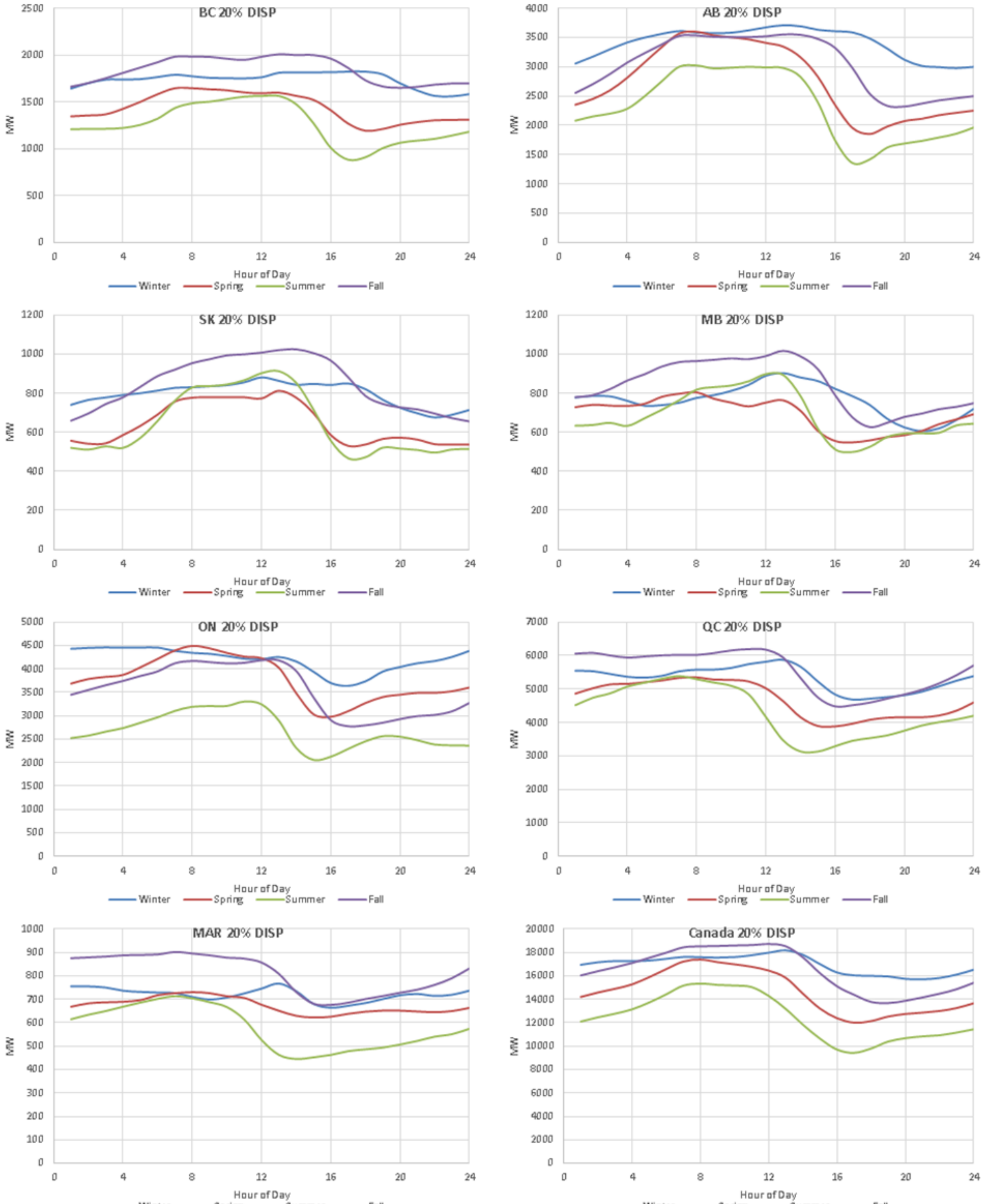


Figure 5-30: Average Wind Hour Production by Season for each Province and Canada 20% DISP

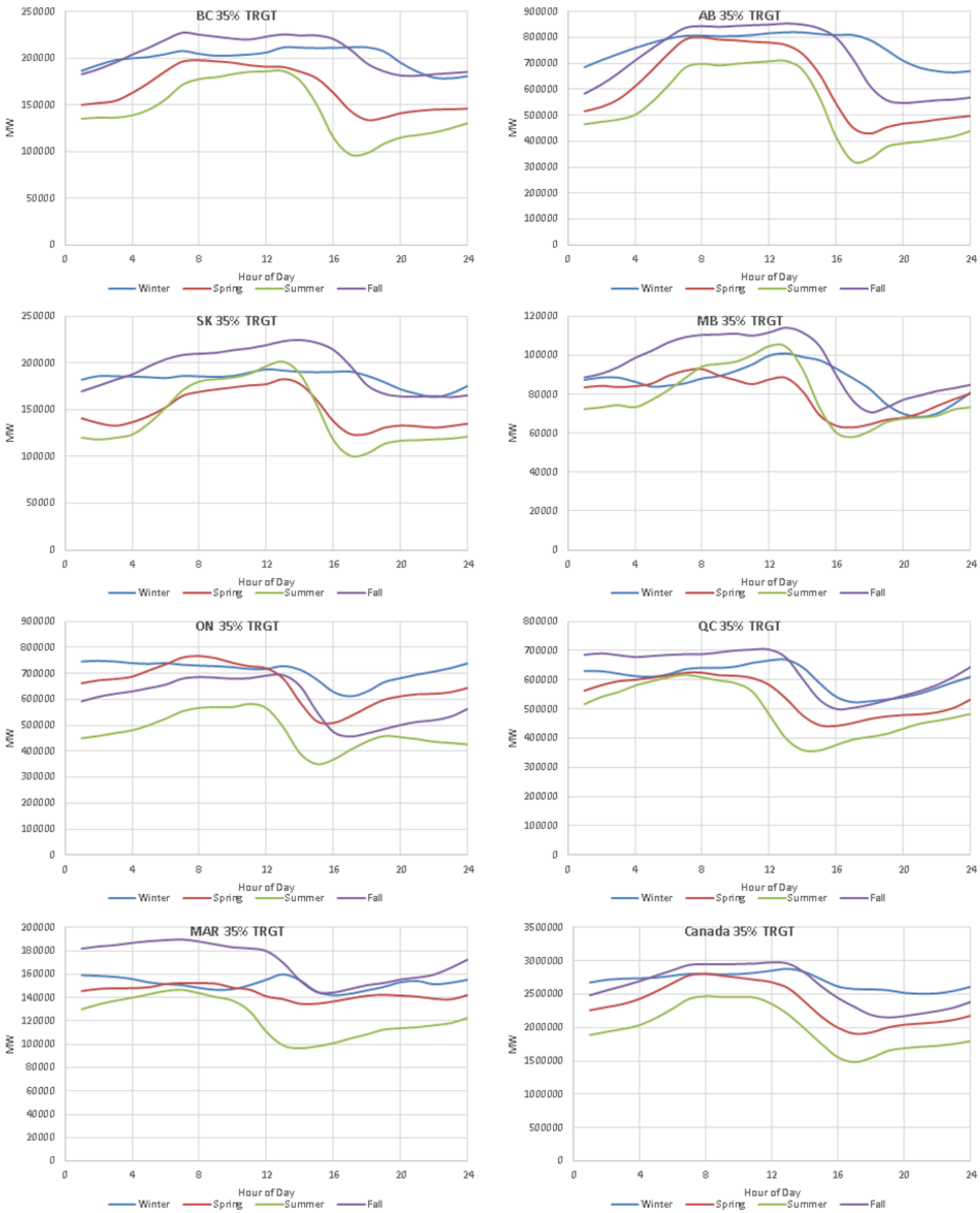


Figure 5-31: Average Wind Hour Production by Season for each Province and Canada 35% TRGT

5.1.3.3 Wind Variability

Investigating the amount of change of wind production is seen by ordering hourly wind changes from high to low. This investigation provides information as to the magnitude of hourly change in wind production over the year. Figure 5-32 depicts the duration curve for each province and Canada representing the hourly changes in wind production. The figure also shows the peak demand of each province and Canada. It is typical to observe the variability increasing as wind penetration increases. The 20% CONC scenario depicts a larger variability as compared to the 20% DISP which indicates the benefit of diversity of site selection in the 20% DISP scenario.

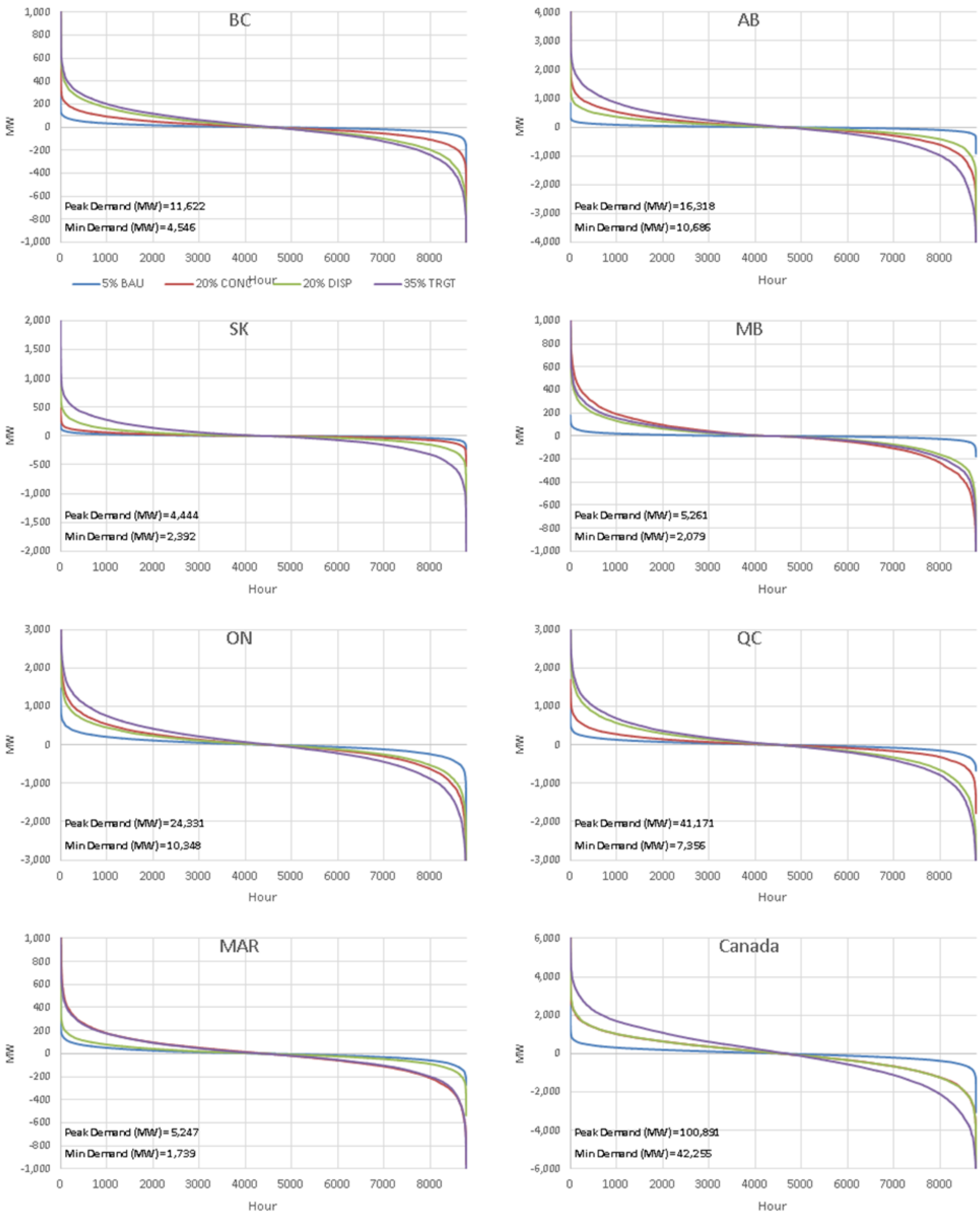


Figure 5-32: Province and Canada Annual Hourly Change Duration Curve

Sub-hourly (10-minute periods) wind production change was also examined with three years of wind profile data. In this analysis, the 10-minute change in wind production as a percentage of the nameplate capacity was plotted on the y-axis, and the corresponding wind production on the x-axis. The plots show a positive value on the ordinate when the 10-minute wind change increases and a negative value when the 10-minute wind change decreases. Figure 5-33 depicts plots for Canada aggregated wind production. These plots show how 10-minute wind variability as a percent of nameplate capacity increases as wind production increases from 0 MW to the mid-range production level. From mid-range upward the wind variability decreases as the wind production approaches the maximum capacity. This is consistent with the findings in the section on regulation calculations.

The benefit of diversity of wind production can be seen in these plots, as the penetration of wind increases from the 5% BAU to the 35% TRGT scenario. The variability as a percent of the nameplate capacity trends downward, as shown in Table 5-4. In the 5% BAU scenario, the variability averages near plus or minus 0.5%. As the penetration increases to the 35% TRGT scenario the variability decreases to plus or minus .35% and .38% respectively. It also worth noting that the 20% DISP scenario variability is less than the 20% CONC scenario, verifying the benefits of diversity among the wind plant selection process. While there are outliers depicting sudden increase or decrease in production, these are limited to a few points out of the nearly 158,000 points analyzed.

Table 5-4: Canada Average 10-minute variability as a Percent of Nameplate Capacity

	5% BAU	20% CONC	20% DISP	35% TRGT
Up	0.48%	0.42%	0.41%	0.37%
Down	0.49%	0.42%	0.41%	0.38%

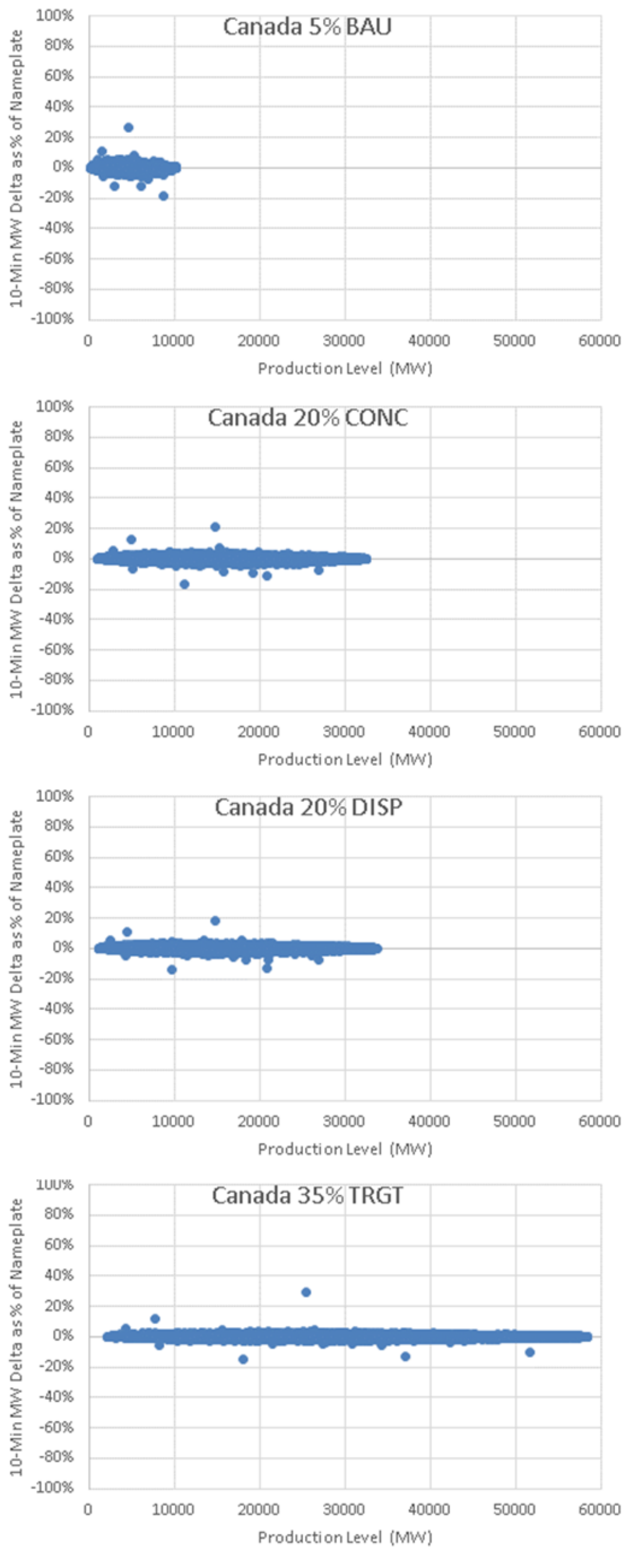


Figure 5-33: Scatter Plot of 3-Years of 10-minute Wind Production and Period Variability for each Scenario

5.1.3.4 Wind Forecast Error

Variability of wind production is an expected behavior that is typically mitigated by dispatching quick response resources. Knowing if a dispatch should be up or down is dependent upon load and wind forecast accuracy. Hourly wind production forecasts for day-ahead periods were provided in this study. This analysis examines a day ahead forecast for accuracy by comparing it to the actual wind production. Each hour in the day ahead forecast is compared to the hour of actual production. If the actual production value is greater than the forecast value then the forecast is considered to be under forecast. Similarly if the actual production value is less than the forecast value then the forecast is considered to be over forecast. When evaluating the forecast error an under forecast is assigned a negative value equal to the difference of the day ahead forecast minus the actual wind production, while an over forecast results in a positive difference of the forecast and actual wind production. Evaluating the forecast error for each hour of the year and then sorting these errors from high to low provide a duration curve depicting a continuous curve that shows the magnitude of the over and under forecasts. An ideal curve produced by a perfect forecast would be a straight line with zero value. Forecast error duration curves for each province and Canada are shown in Figure 5-34.

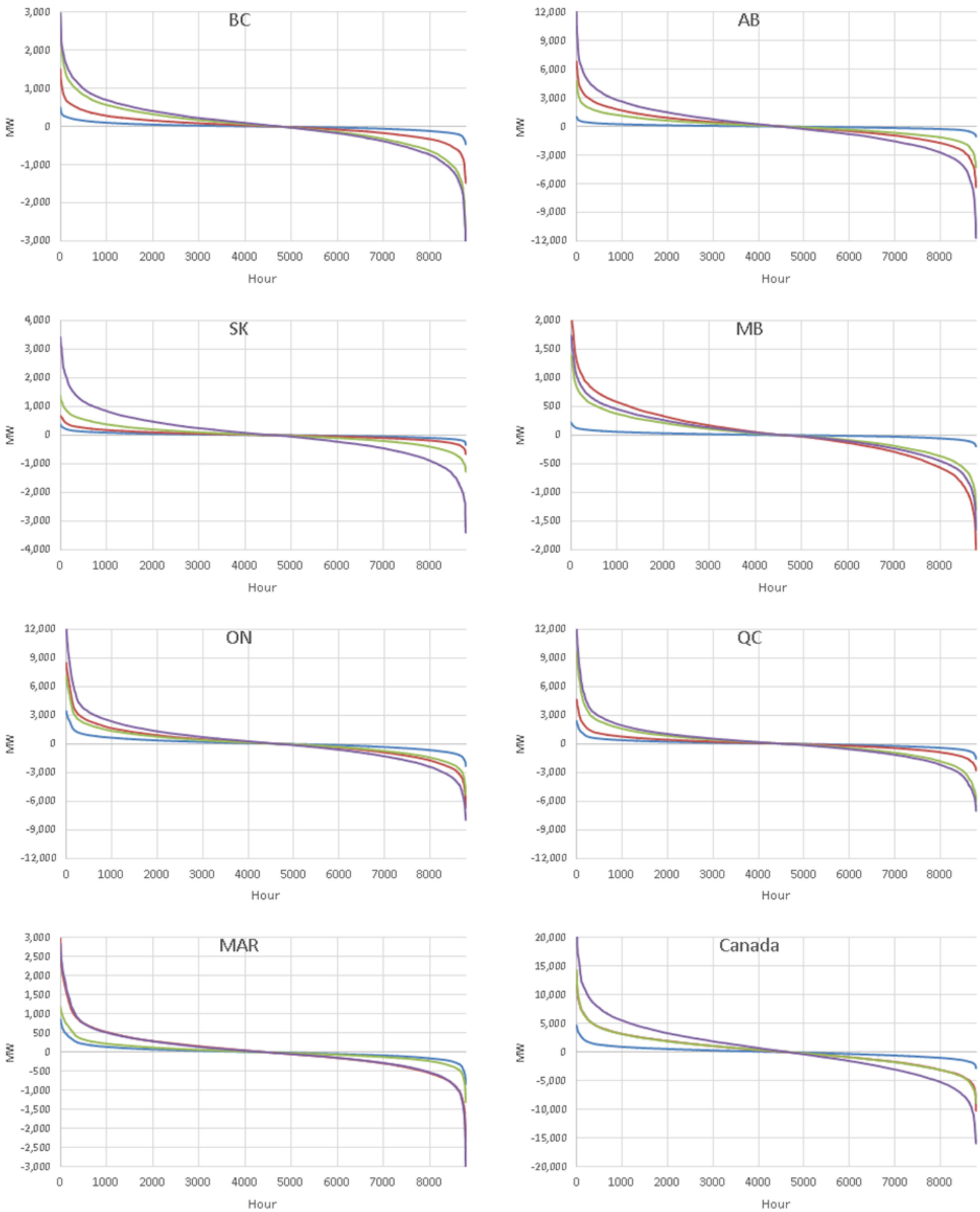


Figure 5-34: Day Ahead Forecast Error Duration Curve for each Province and Canada

Examining specific hourly forecast errors to provide the mean absolute error (MAE) was measured. This is a quantifiable value that measures how close the forecasts are to the actual production. As shown above the forecast error can be over or under forecast yielding a positive or negative value. The MAE computes the absolute value of the difference between the day ahead forecast and the actual production value of wind normalized by nameplate capacity. The average of the normalized values is the MAE. Figure 5-35 depicts the MAE for each province and Canada for each scenario. For Canada the MAE tends lower as the penetration of wind increases. This trend can be contributed to the diversity of wind. Saskatchewan, Ontario and Quebec have wind sites in the 20% scenarios that are close in proximity (see site selection maps) thus the benefits of diversity are not as apparent until the 35% TRGT scenario. Table 5-5 depicts MAE for each profile year.

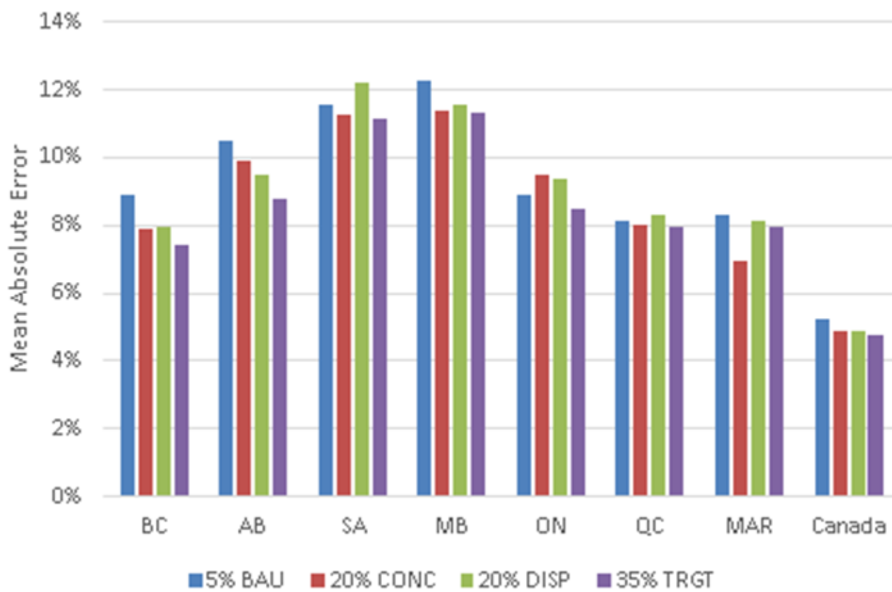


Figure 5-35: Mean Absolute Error of Day Ahead Forecast for all Profile Years, Provinces and Scenarios

Table 5-5: Mean Absolute Error of Day Ahead Forecast for each Province, Canada and Scenario

Scenario	Year	BC	AB	SA	MB	ON	QC	MAR	Canada
5% BAU	2008	9.69%	11.04%	12.41%	13.51%	10.03%	8.83%	9.37%	5.73%
5% BAU	2009	8.72%	10.39%	11.79%	12.09%	8.10%	7.67%	7.89%	4.97%
5% BAU	2010	8.33%	10.02%	10.42%	11.25%	8.60%	7.82%	7.70%	5.02%
5% BAU	**All Years**	**8.91%**	**10.49%**	**11.54%**	**12.29%**	**8.91%**	**8.10%**	**8.32%**	**5.24%**
20% DISP	2008	8.92%	10.28%	13.59%	12.82%	10.49%	8.96%	9.22%	5.37%
20% DISP	2009	7.75%	9.04%	11.68%	11.34%	8.59%	7.66%	7.74%	4.62%
20% DISP	2010	7.22%	9.08%	11.39%	10.43%	9.02%	8.22%	7.44%	4.67%
20% DISP	**All Years**	**7.97%**	**9.47%**	**12.22%**	**11.53%**	**9.37%**	**8.28%**	**8.14%**	**4.89%**
20% CONC	2008	8.79%	10.77%	12.44%	12.67%	10.64%	8.61%	7.99%	5.45%
20% CONC	2009	7.64%	9.44%	11.05%	11.19%	8.70%	7.47%	6.38%	4.58%
20% CONC	2010	7.31%	9.45%	10.28%	10.22%	9.14%	7.92%	6.42%	4.68%
20% CONC	**All Years**	**7.91%**	**9.89%**	**11.26%**	**11.36%**	**9.50%**	**8.00%**	**6.93%**	**4.91%**
35% TRGT	2008	8.37%	9.59%	12.18%	12.65%	9.49%	8.62%	9.07%	5.29%
35% TRGT	2009	7.11%	8.39%	10.97%	11.16%	7.67%	7.38%	7.48%	4.49%
35% TRGT	2010	6.79%	8.36%	10.19%	10.23%	8.24%	7.83%	7.38%	4.51%
35% TRGT	**All Years**	**7.43%**	**8.78%**	**11.12%**	**11.35%**	**8.47%**	**7.94%**	**7.98%**	**4.76%**

5.1.4 Net Load

Net load is defined as the difference between load and aggregated wind production. Analysis of net load and its variability helps to get a view of the reserve requirements and the amount of load that should be met by other types of supply or demand side resources. Typically wind production is assumed to be a must take resource and therefore other resource production must be adjusted to compensate for the natural variability of the wind resource. Since resources are dispatched to serve variable load and wind production is also variable, the net impact of the combination of these two components in balancing the system can be analyzed as net load.

5.1.4.1 Load Characterization

The first analysis of net load is a summary of demand assuming no wind curtailment and all wind production is used to serve load or transferred off system. Table 5-6 shows the annual demand for each profile year, province and Canada. Table 5-6 depicts peak net demand for each profile year, province and Canada. It is observed that the different wind production for each profile year has an effect on the annual peak. Different wind productions in each profile year results in different net load energy and peak demand. It is interesting to note the difference in net load energies of the two 20% penetration scenarios. In both scenarios, the all Canada the net load energy is similar in magnitude; however due to the dispersed versus concentrated wind site selections, the net load energy in each province under the two scenarios are not similar.

Table 5-6: Net Load Demand by Province and Canada for each Profile Year and Scenario

2008 Annual Demand (GWH)	BC	AB	SK	MB	ON	QC	MAR	Canada
Load	63,433	116,234	29,626	30,149	143,255	200,736	26,528	609,963
5% BAU Net Load	61,533	111,321	28,030	29,217	128,486	190,890	22,810	572,289
20% DISP Net Load	49,769	91,115	23,198	23,629	112,169	157,196	20,423	477,500
20% CONC Net Load	56,358	80,560	26,287	19,845	106,174	178,924	9,864	478,013
35% TRGT Net Load	46,359	53,425	13,560	22,007	85,034	146,338	12,383	379,108
2009 Annual Demand (GWH)	**BC**	**AB**	**SK**	**MB**	**ON**	**QC**	**MAR**	**Canada**
Load	63,433	116,234	29,626	30,149	143,255	200,736	26,528	609,962
5% BAU Net Load	61,514	111,223	28,098	29,295	129,564	190,541	22,672	572,910
20% DISP Net Load	50,032	91,309	23,223	24,147	114,469	157,395	20,149	480,726
20% CONC Net Load	56,559	80,528	26,351	20,582	108,859	178,930	8,971	480,782
35% TRGT Net Load	47,651	57,958	15,459	22,972	88,236	149,685	13,111	395,073
2010 Annual Demand (GWH)	**BC**	**AB**	**SK**	**MB**	**ON**	**QC**	**MAR**	**Canada**
Load	63,433	116,234	29,626	30,149	143,255	200,736	26,528	609,963
5% BAU Net Load	61,653	111,634	28,256	29,313	129,519	191,192	22,988	574,557
20% DISP Net Load	50,703	91,309	23,751	24,378	114,456	160,209	20,744	485,551
20% CONC Net Load	56,855	83,306	26,679	21,057	108,957	180,158	14,989	492,003
35% TRGT Net Load	47,651	57,958	15,459	22,972	88,236	149,685	13,111	395,073

Table 5-7: Peak Demand Load and Net Load by Province and Canada for each Profile Year and Scenario

2008 Peak Demand (MW)	BC	AB	SK	MB	ON	QC	MAR	Canada
Load	11,622	16,318	4,444	5,261	24,331	41,171	5,247	100,891
5% BAU Net Load	11,449	16,267	4,333	5,111	22,756	40,124	4,696	96,647
20% DISP Net Load	11,375	16,137	4,333	4,944	22,276	38,618	4,623	93,479
20% CONC Net Load	11,398	16,124	4,333	4,905	22,021	39,613	4,440	93,888
35% TRGT Net Load	11,252	15,948	4,333	4,926	21,603	38,050	4,496	92,449
2009 Peak Demand (MW)	**BC**	**AB**	**SK**	**MB**	**ON**	**QC**	**MAR**	**Canada**
Load	11,622	16,318	4,444	5,261	24,477	41,171	5,277	99,540
5% BAU Net Load	11,172	16,057	4,293	5,230	22,786	39,303	4,816	94,904
20% DISP Net Load	10,816	16,013	4,234	4,988	22,383	37,452	4,548	91,897
20% CONC Net Load	10,868	16,013	4,234	4,919	22,345	38,491	4,174	90,106
35% TRGT Net Load	10,759	15,458	4,134	4,947	21,823	36,706	4,371	85,412
2010 Peak Demand (MW)	**BC**	**AB**	**SK**	**MB**	**ON**	**QC**	**MAR**	**Canada**
Load	11,622	16,318	4,444	5,261	24,383	41,171	5,328	100,949
5% BAU Net Load	11,622	16,318	4,444	5,261	24,331	41,171	5,247	100,891
20% DISP Net Load	11,193	15,904	4,265	5,110	23,114	38,692	4,962	88,914
20% CONC Net Load	11,307	15,991	4,268	5,097	22,893	39,581	4,259	91,025
35% TRGT Net Load	10,813	15,832	4,221	5,109	22,336	38,184	4,645	89,295

Figure 5-36 and Figure 5-37 show a graphical representation of the tables above. Here it can be seen the differences in each scenario. Alberta, Manitoba, Ontario and the Maritimes increase wind production in the 20% DISP scenario compared to the 20% CONC scenario in the 2008 profile year, while the remaining provinces show a reduction in wind production.

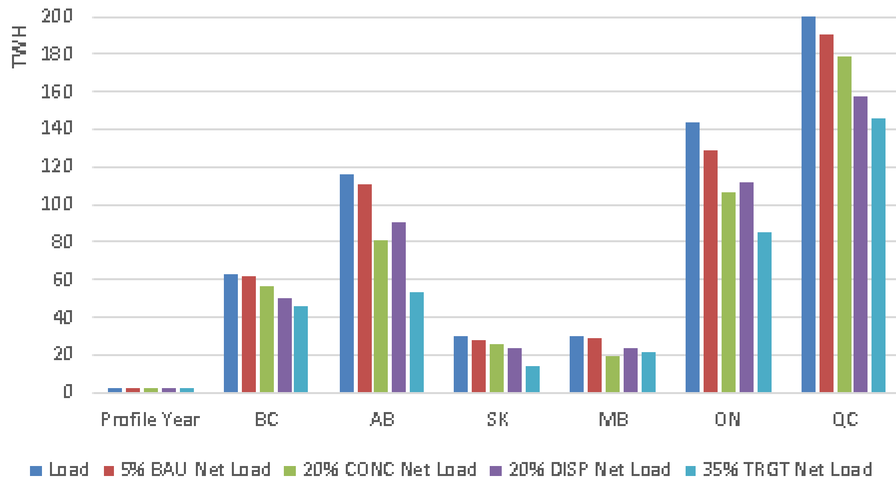


Figure 5-36: Province Annual Load and Net Load Demand for each scenario 2008 Profile

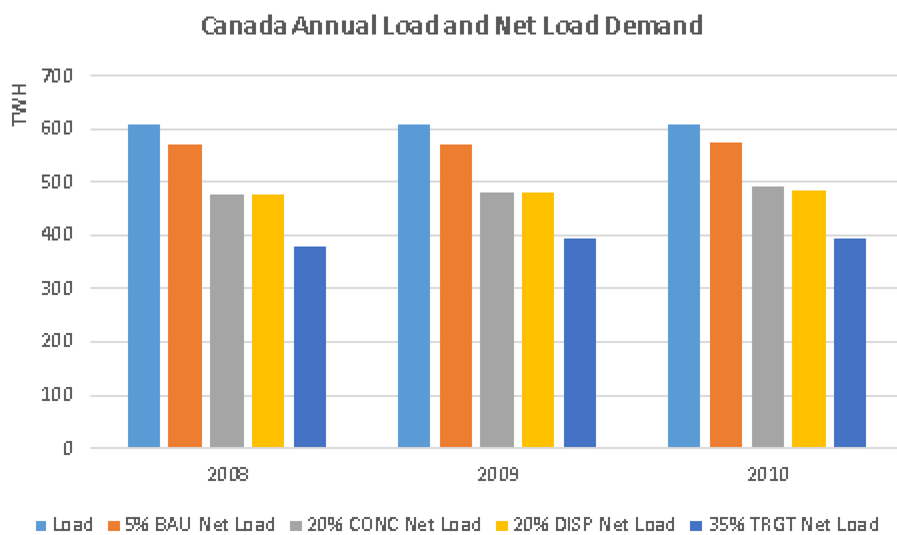


Figure 5-37: Canada Annual Load and Net Load Demand for each Scenario

As described in the load analysis section, the load duration curves provide a way of visualizing hourly loads over an annual period. Duration curves of load for each scenario were created to examine how wind modifies the load. Figure 5-38 provides a view of each provincial duration curve for each scenario. It can be seen by the shapes of the curves that wind production has different contributions to reducing load. For example there is little noticeable difference between load and 5% BAU scenario. The duration curves for the 20% scenarios also show little difference.

In the 20% scenarios, the Maritimes have more hours when wind production exceeds load demand as compared to the 35% TRGT scenario.

The 35% TRGT scenario shows the greatest reduction in load over the year. There are several provinces, Alberta, Saskatchewan, Manitoba, Ontario, Quebec and Maritimes, where the wind production is greater than load for many hours during the year. The duration curves do not maintain the same chronology between provinces, which explains the Canada duration curve as not having as many hours with negative net load in this scenario

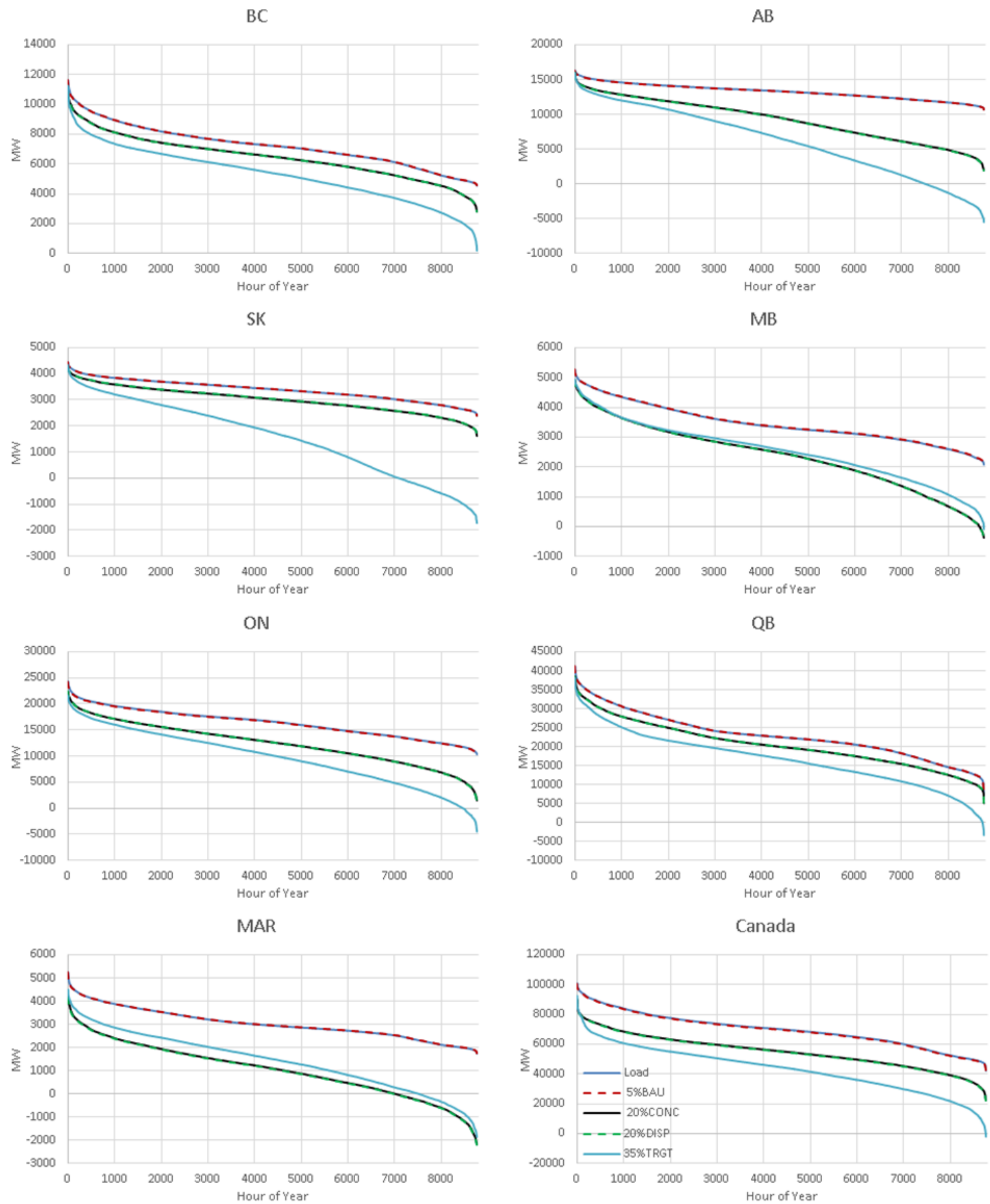


Figure 5-38: Province and Canada Net Load Duration Curves for each Scenario

Figure 5-40 depicts the seasonal average hourly load and net load for all of Canada. Although the winter load is higher than the summer load, as wind penetration increases, winter mid-day net load approaches the summer net load. This is due to the fact that wind production is greater in winter compared to summer.

The average summer morning ramp is approximately 5 GW in the 20% DISP and 20% CONC scenarios and 10 GW in the 35% TRGT scenario. This is approximately 20 MW per minute in the 20% DISP and 20% CONC scenarios and 40 MW per minute in the 35% TRGT scenario.

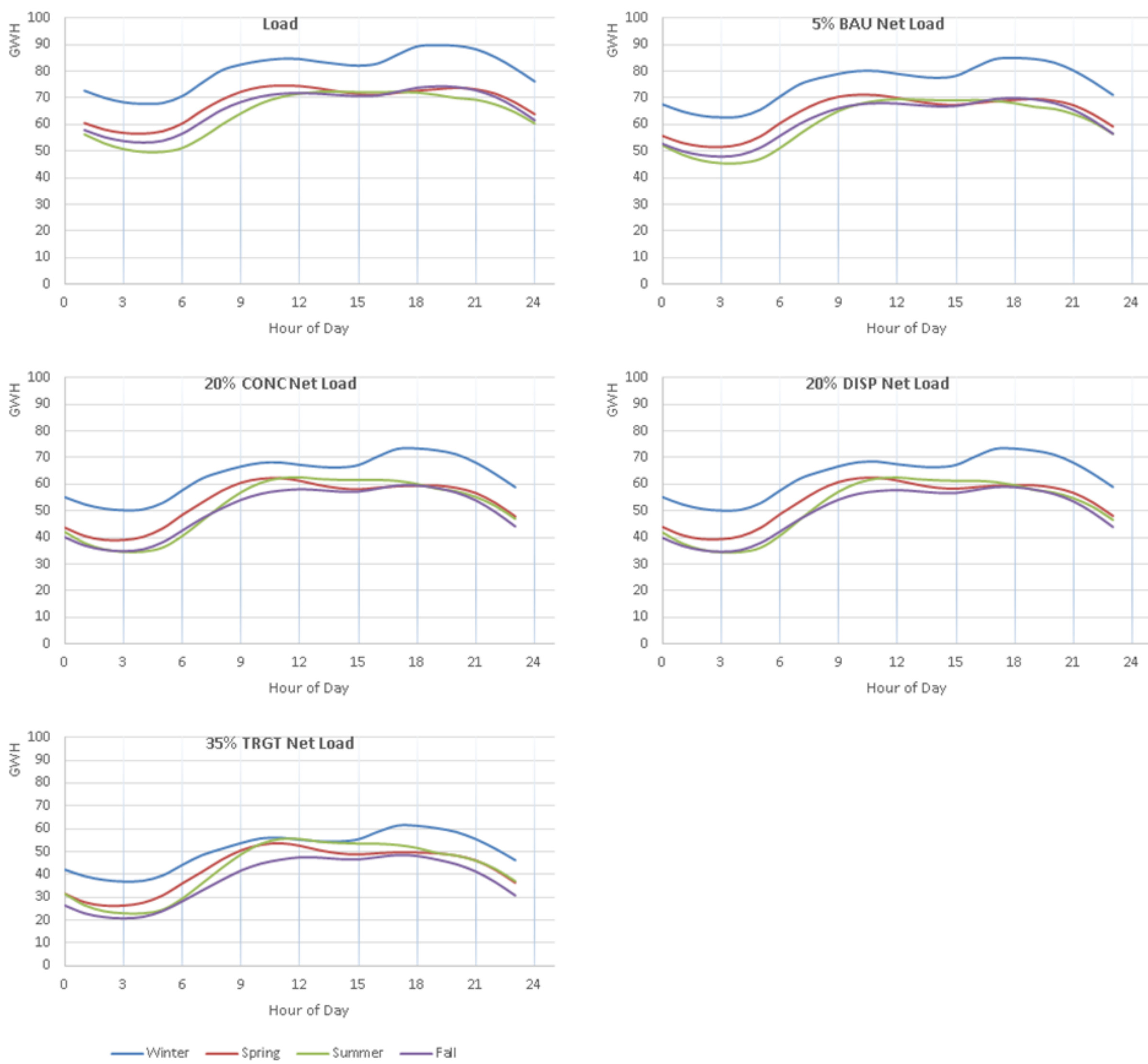


Figure 5-39: Canada Seasonal Average Hour Load and Net Load for each Scenario 2008 Profile

5.1.4.2 Net Load Variability

Both system load and wind production vary hour to hour. Some hours wind production can be beneficial to serving the load demand such as times when load increases and wind production increases or times when load decreases and wind production decreases. However there are other periods of time when load increases and wind production decreases or load decreases and wind production increases. System resources must respond to variability of net load. A scatter plot shown in Figure 5-40 depicts load and net load variability in each scenario for Alberta which has a large amount of wind as compared to system load in the 35% TRGT scenario. The top left plot shows the change in load only that occurs from one hour to the next for a given level of demand. As the level of wind penetration increases it can be seen that the hour to hour net load variability also increases. The level of load and net load demand was reduced by the amount of wind production. The 35% TRGT scenario shows the wind production exceeds load demand for many hours in the year. This coincides with the duration curve for the same scenario shown in Figure 5-38 and represents exports from Canada.

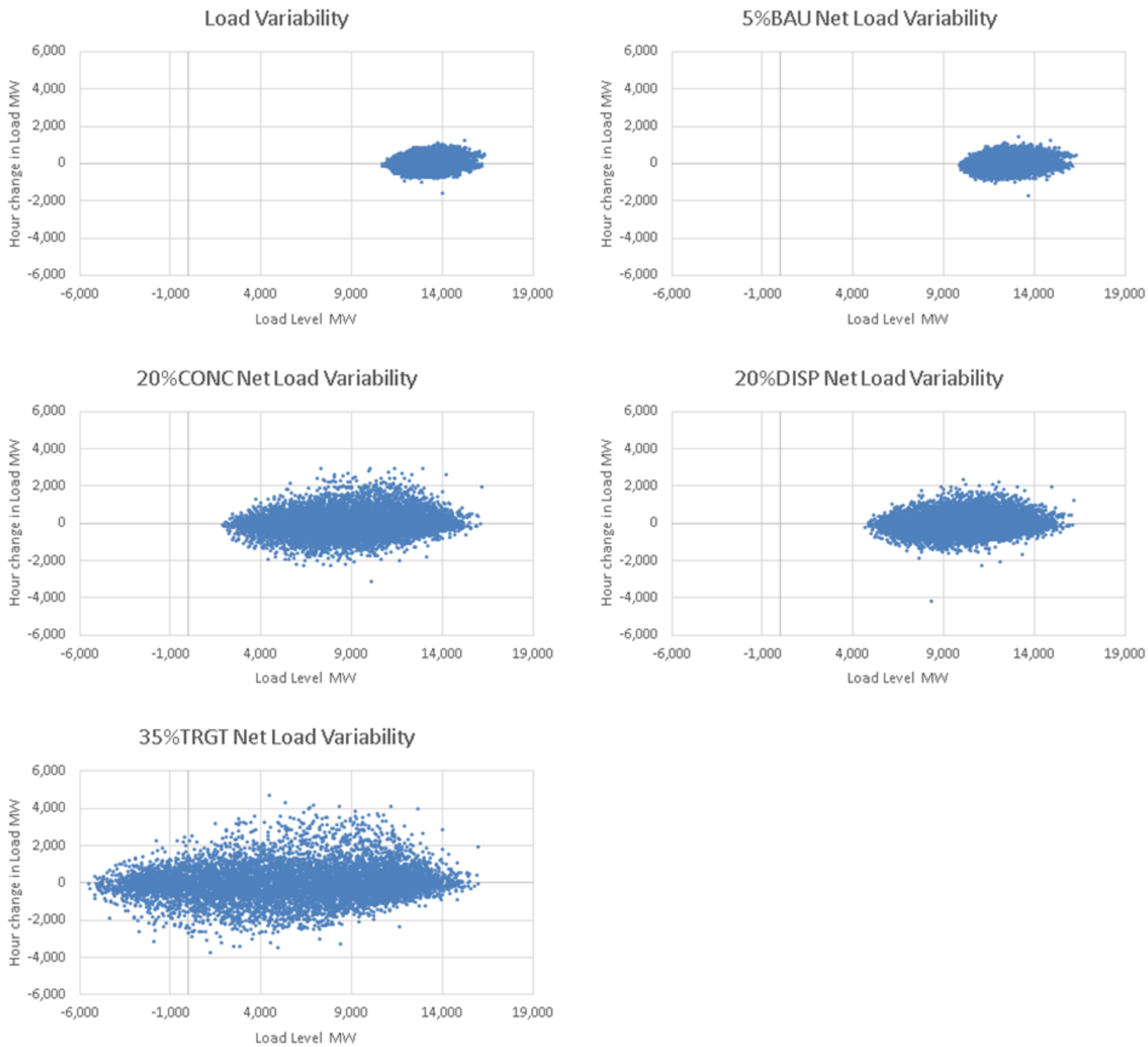


Figure 5-40: AB Load and Net Load Hourly Variability Scatter Plot by Scenario

Scatter plots of load and net load variability for Canada are shown in Figure 5-41. The effects of wind diversity can be seen in these scatter plots. At each level of penetration the limits of variability remain about the same. This was different than the plots shown above in Figure 5-40 where hour to hour net load variability tends to increase as wind penetration increases. Another observation as the wind penetration level increases was the decline in net load. There was greater reduction in the minimum net load than the maximum. This was consistent with wind production being at lower levels during peak hours. In the 35% TRGT scenario, the hours when wind production exceeds load demand, represent exports from Canada, which is consistent with the duration curve shown in Figure 5-38. The scatter plot also shows the maximum limits of variability for the 5% and 20% penetration scenarios remain about the same whereas, as shown in the plots above, individual province penetrations have increasing hour to hour variability as wind penetration increased.

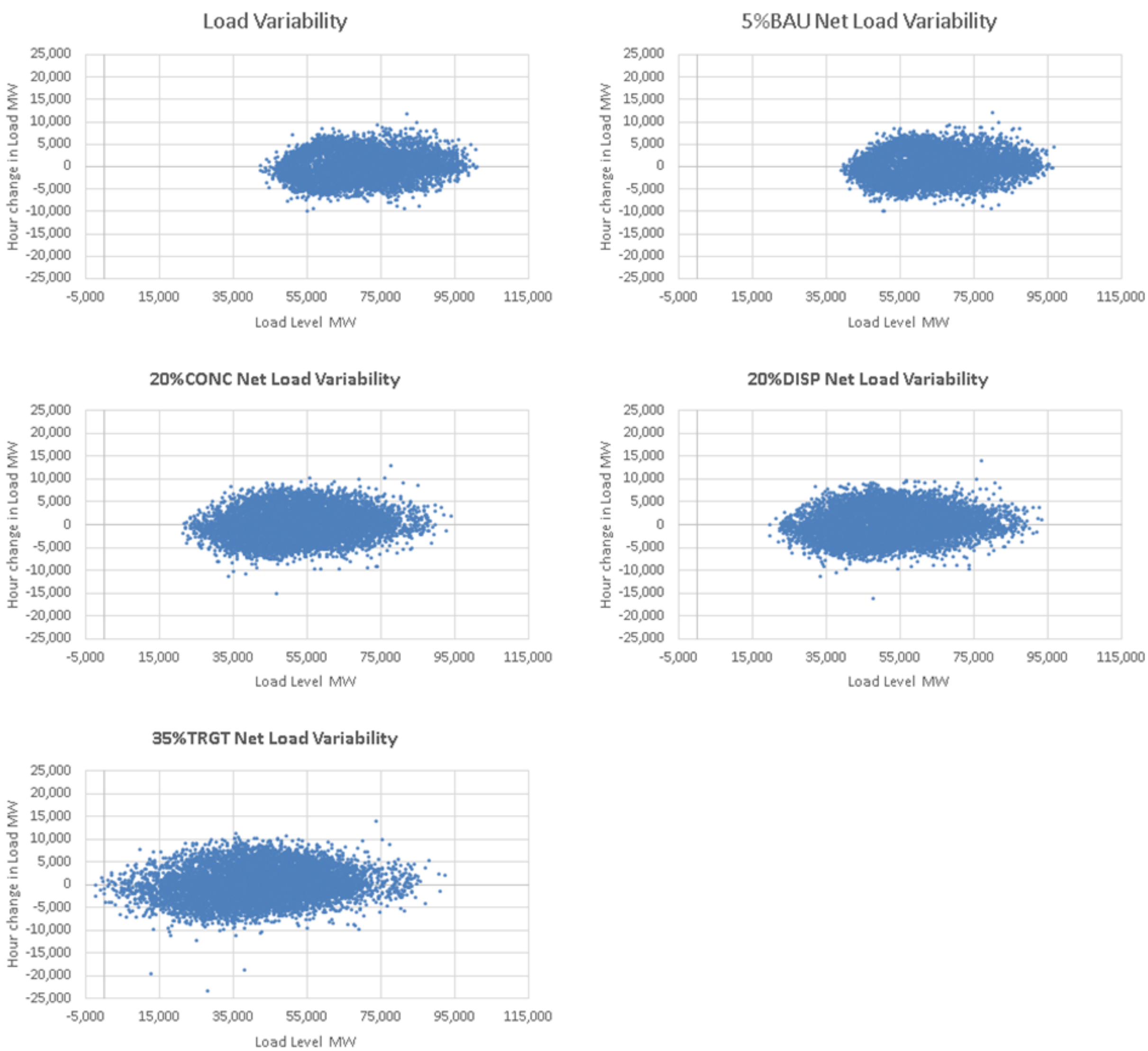


Figure 5-41: Canada Load and Net Load Hourly Variability Scatter Plot by Scenario

5.1.4.3 Interesting day investigation

The approach taken to investigate an interesting day in this study was to examine days when the Canada load experienced the greatest up or down ramp. Because Canada load is the aggregate of all the provinces, this approach can overlook times specific to a province that can also be challenging. It is anticipated that this approach captures periods of time when several provinces have large hour to hour changes, thus aggregating into the large Canada load hour change.

In Table 5-8 and Table 5-9, periods of Canada load increase and decrease are listed with corresponding province load change. There are a few periods when province hourly change is opposite from Canada (hence the negative numbers in Table 5-8), but for most provinces hourly change moves in the same direction as Canada load change.

Table 5-8: Date and Time when Canada Load Increases the most in MW with Province Load MW Change

Top 10 Hours with Increasing Canada Load (MW)								
Date/Time	BC	AB	SK	MB	ON	QC	Mar	Canada
12/18/2025 6:00	813	840	18	218	1,673	9,327	430	11,714
12/17/2025 7:00	948	313	80	277	1,948	7,055	60	9,784
12/2/2025 7:00	1,041	351	103	324	2,083	6,400	29	9,433
2/18/2025 6:00	985	775	23	123	1,690	6,399	412	8,794
3/18/2025 6:00	875	-26	100	182	2,215	5,795	25	8,604
10/14/2025 6:00	1,056	-25	93	393	2,228	5,374	33	8,572
3/12/2025 6:00	1,109	75	111	201	1,769	6,027	79	8,560
12/3/2025 16:00	694	413	3	64	947	7,356	293	8,556
12/1/2025 8:00	220	-100	185	294	557	6,405	25	8,548
1/27/2025 6:00	922	769	-23	152	1,668	6,426	348	8,545

Table 5-9: Date and Time when Canada Load decreases the most in MW with Province Load MW Change

Top 10 Hours with Decreasing Canada Load (MW)								
Date/Time	BC	AB	SK	MB	ON	QC	Mar	Canada
7/10/2025 0:00	-340	-212	-205	-241	-2,711	-5,884	-65	-9,839
11/2/2025 23:00	-481	-269	-101	-130	-1,028	-7,503	-77	-9,428
12/19/2025 23:00	-666	-441	-115	-216	-1,482	-6,696	-229	-9,396
12/17/2025 22:00	-724	-742	-33	-92	-1,481	-6,696	-247	-8,879
12/18/2025 22:00	-658	-577	-11	-110	-1,396	-6,636	-284	-8,695
12/16/2025 23:00	-769	-403	-93	-245	-1,547	-5,381	-135	-7,991
2/28/2025 0:00	-488	-214	-205	-260	-918	-5,488	-54	-7,906
5/24/2025 23:00	-428	-287	-14	-194	-938	-6,572	-108	-7,730
11/13/2025 23:00	-587	-306	-166	-176	-1,458	-5,051	-141	-7,649
3/11/2025 23:00	-464	-271	-200	-280	-1,091	-5,100	-44	-7,600

The daily plot with Canada's largest annual hourly increase in load demand is shown in Figure 5-42. Note that the MW scale for each province chart is different in order to show the relative magnitude of load and net load demand. On December 18 Canada experiences the largest increase in demand from hour 5 to hour 6 of 11,714 MW. AB, QC and the Maritimes have large load demand increase in the same hours. The remaining provinces experience the largest increase in demand for this day in hours seven, eight, and nine. The change in load between hours 5 and 6 is mostly influenced by the QC load. In these hours wind production decreases (while load increases), resulting in an exasperation of the up ramp for resources to serve that load. Hours 21 and 22 is the period with the largest decline in load and also the period when wind production increases. This also exasperates the down ramp of resources to serve load.

The daily plot for Canada's largest annual hourly decrease in load demand is 7/10/2025 and shown in Figure 5-43. On this day, the Canada load for each scenario shows wind in the early morning and evening hours with a wind decline in the mid-day. The change in load between hours 6 and 7 is mostly influenced by the QC load. As wind penetration increases the amount of wind production in these hours will exasperate the upward ramp. The hour decrease in load occurs between hours 23 and 24. During this period, as wind penetration increases, the amount of down-ramp capability of resources increases. In these hours wind production exasperates the down ramp requirement to serve load. It should be noted in the

SK and MAR, early morning wind exceeds the province load in the 35% TRGT scenario. In these hours, mitigating practices would curtail or export this wind production.

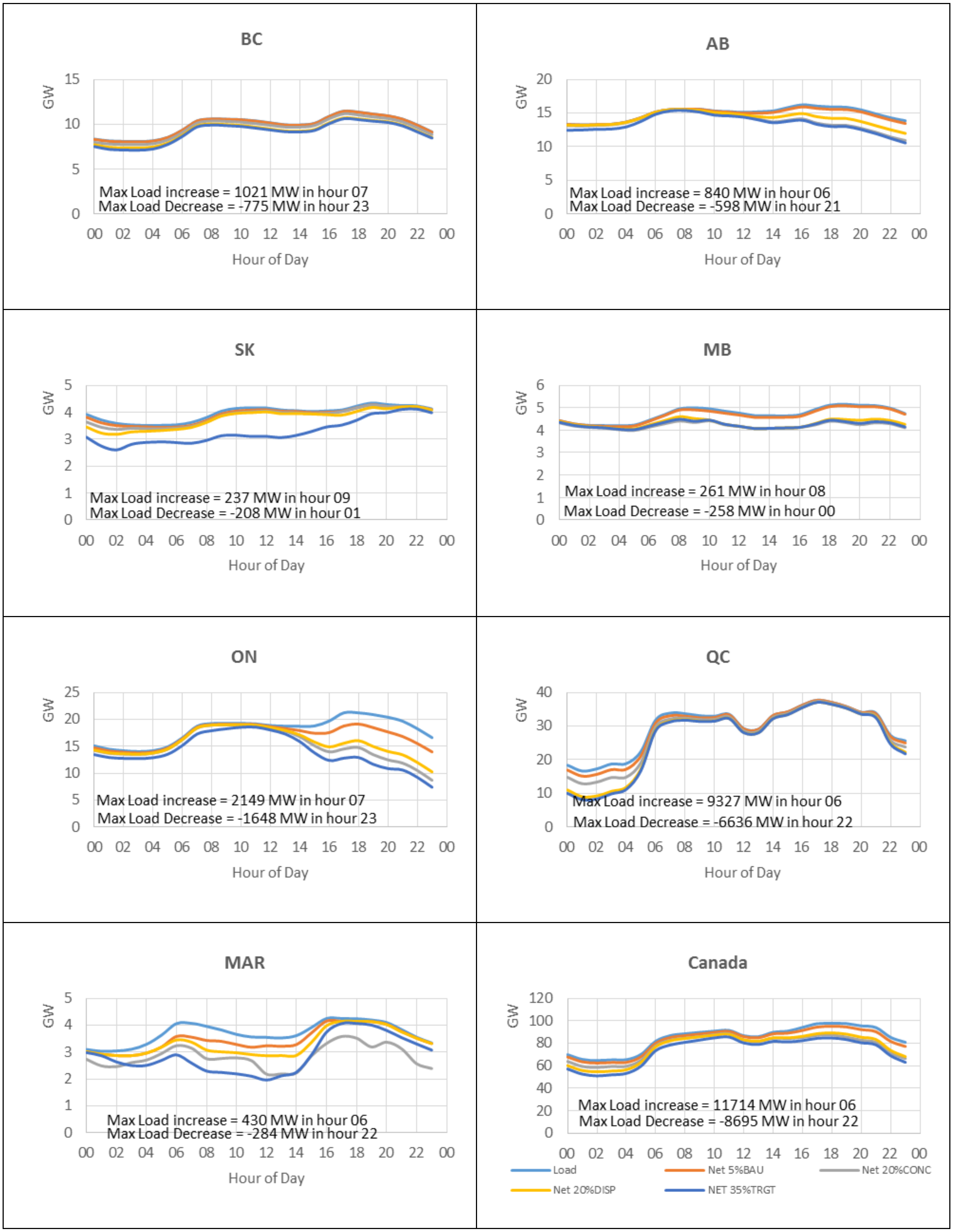


Figure 5-42: Day with Largest Canada Hour to Hour Demand Increase, December 18, 2025

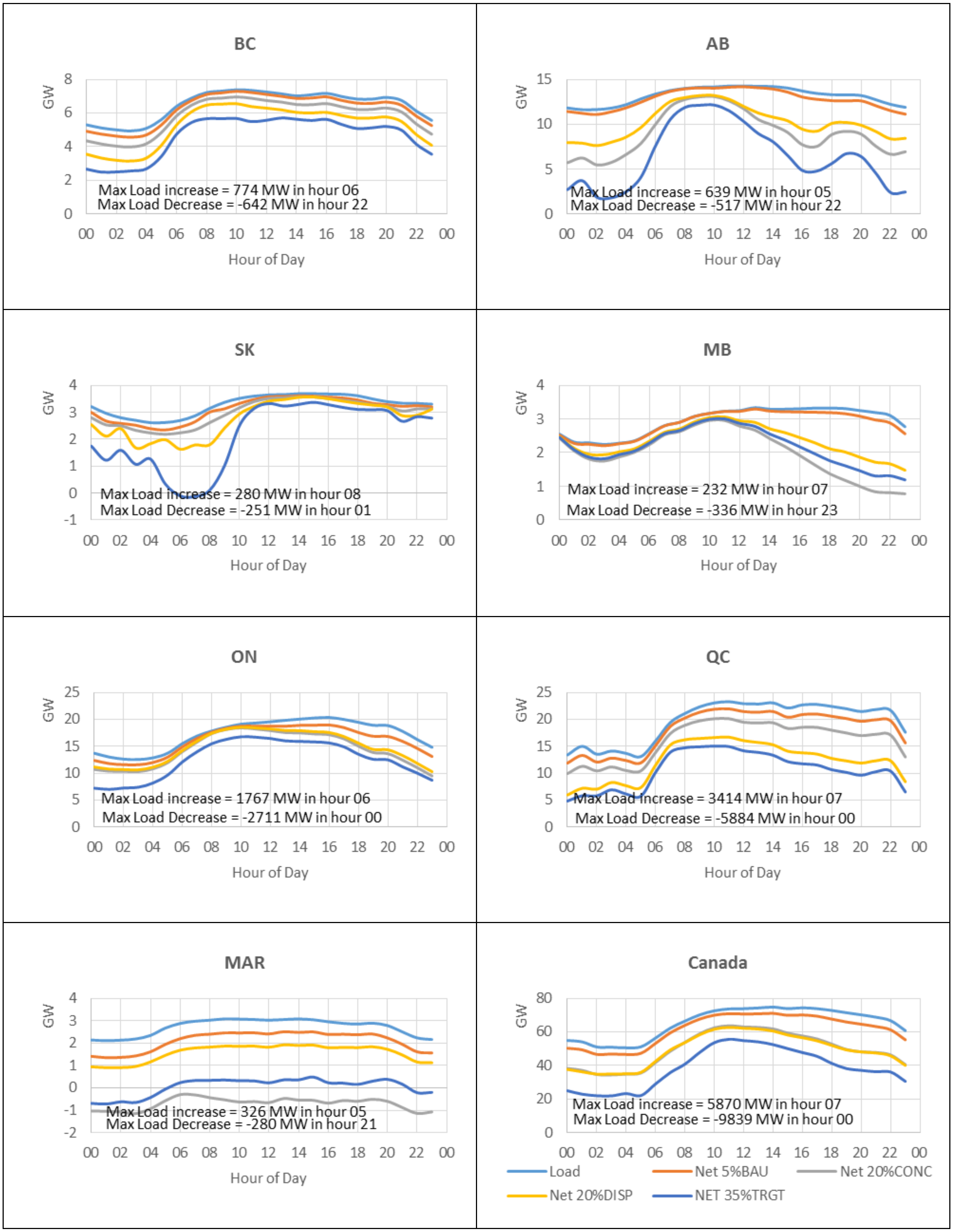


Figure 5-43: Day with Largest Canada Hour to Hour Demand decrease, July 10, 2025

5.2 Reserve Profile Development

5.2.1 Wind Penetration Effects on Regulation Reserves

This section of the report describes the analysis performed to account for Regulating Reserves required for each Canadian Province in each scenario. Regulating Reserves consist of on-line synchronized generation, typically by Automatic Generation Control (AGC) that provide a balance with load and generation to maintain interconnection frequency. Introducing wind generation into the operating fleet will create an increased requirement of on-line synchronized generation to adjust for the variability and uncertainty of wind generation production in the sub hourly time periods. To be consistent in the application of regulating reserve across Canada a statistical analysis of sub hourly load by balancing area was performed to determine the Regulating Reserves during the on and off peak time periods.

Operating Reserves is the term used in this report that consists of generation resources that can be counted on to serve load during different time intervals within the hour. Resources identified for this category of reserve must be capable of ramping (up or down) within a predetermine interval to satisfy changes in load. Operating Reserves are then divided into two categories, Contingency Reserves and Supplemental Reserves. Contingency Reserves consist of synchronized reserves and quick-start reserves. Synchronized reserves are spinning on-line generation or customer demand response. In various balancing areas, spinning resource requirements are typically set equal to all or a large portion of the Contingency Reserves; and if demand response can be included as an operating reserve resource, it usually cannot be more than a very small portion of the Contingency Reserves. Quick start resources consist of resources that can be brought on-line and synchronized within a 10-minute period. Contingency Reserves have a magnitude typically less than the largest resource contingency. Supplemental Reserves are categorized as available resources that can be brought on-line and provide energy to the system within a 10 to 30 minute period. Figure 5-44 provides a pictorial representation of Regulating and Operating Reserves.

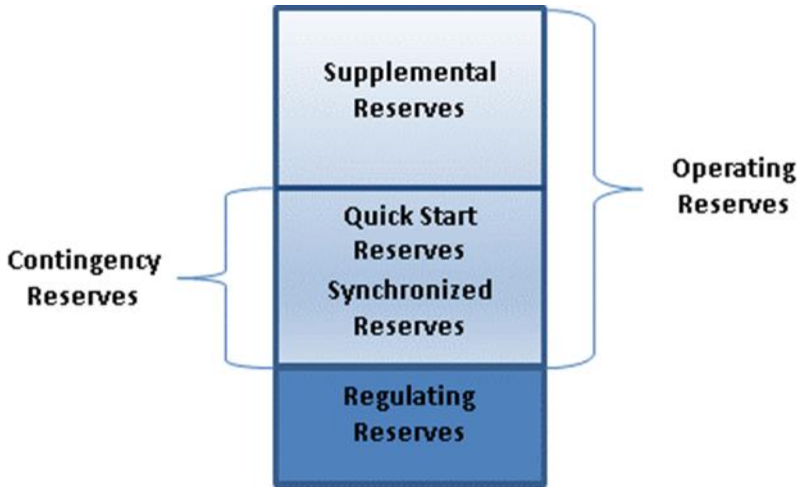


Figure 5-44: Categories of Operating Reserves used in Study

For this study the total capacity of wind resources in each scenario as an aggregated capacity is sizeable. However, due to the diversity of the wind site locations and size of each wind site, it is unlikely that a combined wind plant outage would approach the aggregated wind capacity or exceed the size of the largest resource contingency in any of the balancing areas. Therefore, the operating reserves for each balancing area are not adjusted to account for increased wind penetration.

The reserve requirement that wind has the largest effect on is Regulating Reserve. Because the wind blows at different times and rates, and in different areas of the continent, the variability and uncertainty of wind is dependent on the wind penetration and location. The selection of wind sites are different in each scenario, thus the calculation of regulating reserves is different as well. The method used to determine Regulating Reserves for each scenario follows.

5.2.2 Regulating Reserves for Load

Regulating Reserves provide on-line synchronized generation, typically on Automatic Generation Control (AGC), which provide a balance with load and generation to maintain an interconnection frequency of 60 Hz. These generating resources assist in the control of moment to moment changes in load, usually measured in seconds. For example, as load increases within the hour, on-line generation must also increase by the same amount. When wind production is added to the generation fleet, the wind variability must be accounted for in addition to load variability. If load and wind production both increase, then generation by other units must also adjust accordingly. In this example, if load increases more than the wind production increases then generating resources must adjust upward to meet the additional load requirement. If the load increase is less than the wind production increase, then generation must adjust downward.

Chronological production simulations at hourly resolution are the typical approach for assessing wind integration impacts in previous studies, including all of the studies that have involved the GE team and its partners. Effects of wind inside of the hour on regulation, balancing, and reserves in general cannot be directly evaluated at that level of granularity. Consequently, statistical techniques have been developed for application to hourly and higher resolution wind and load data to estimate the impacts within the hour.

Sub hourly (10-minute) actual load data was provided by different balancing areas. These data were analyzed to obtain a statistical characterization of each balancing area. General characterization of provided load is shown in Table 5-10. Quebec has the largest annual production of 170.5 TWH followed by Ontario at 149.7 TWH, Alberta at 70.0 TWH, British Columbia at 57.0 TWH, Manitoba at 24.3 TWH, and Saskatchewan at 20.1 TWH. The Quebec peak load is 34,459 MW occurring in January evening. Ontario has the second largest peak load of 24,326 MW that occurs in June evening. All other province peak loads occur in the afternoon to evening hours of the winter months of December or January. Load minimums occur in the morning hours during the spring months of April, May or June for Alberta, Manitoba, Ontario and Quebec, while British Columbia and Saskatchewan minimum loads occur in August. Note that British Columbia's annual energy is lower than Alberta's annual energy, while the annual peak of British Columbia is greater than Alberta's, which can be an indication of greater load variability. The sigma for British Columbia is much larger than the sigma for Alberta.

Table 5-10: Province Historical Load Characterization

10-min period	BC	AB	SK	MB	ON	QC
Annual TWH	57.0	70.0	20.1	24.3	148.7	170.5
Max MW	10,065	9,829	3,191	4,321	24,326	34,459
Min MW	3,933	6,375	1,666	1,642	11,369	10,355
Date/Time of Max	12/19/2008 17:50	12/15/2008 17:30	12/15/2008 18:40	01/07/2010 17:20	06/09/2008 15:00	01/16/2012 07:20
Date/Time of Min	08/22/2008 08:40	06/01/2008 05:50	08/05/2008 05:40	05/16/2010 06:30	05/11/2008 03:20	04/12/2012 09:40
Average MW	6,495	7,964	2,292	2,782	16,929	20,868
Sigma MW	1,085	648	262	543	2,454	4,478

The hourly load characteristics in MAPS for Manitoba and the Maritimes balancing areas for the study period were similar as shown in Table 5-11. The Regulating Reserves for the Maritimes balancing areas were divided proportionally using the Manitoba load characteristics.

Table 5-11: Manitoba and Maritime Load Characteristic

MAPS 2025 Hour Data	Annual Energy (TWh)	Peak Demand (MW)	Min Demand (MW)	Load Factor (%)	Hourly Variability Sigma
Manitoba	30.1	5,261	2,079	65%	643
Maritimes	26.5	5,247	1,739	58%	637

The intra hour 10-minute load data for each balancing area was used along with the 10-minute wind generation data for years 2008, 2009 and 2010. In order to statistically derive the load alone Regulation Reserve, the 10-minute movement in load is compared to a load forecast to determine the size of the forecast error. A 10-minute persistence load forecast is used in this derivation, as shown in Figure 5-45. In other words, using the current load value for the next 10-minute forecast and evaluating the difference between this forecast and the next 10-minute actual load, provides the forecast error for that period. The derivation of the forecast error for each 10-minute period over the year is used in the analysis of the 10-minute load variability.

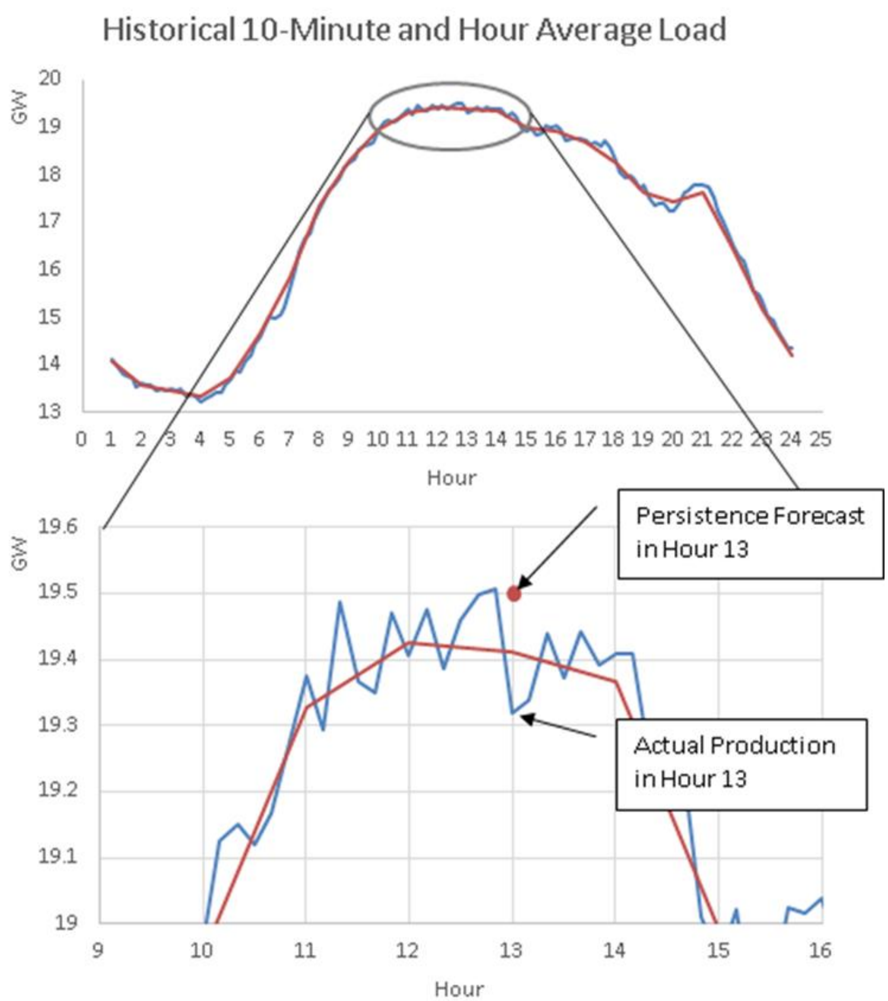


Figure 5-45: Example of Intra Hour Load Variability and Persistence Forecast Error

Figure 5-46, depicts a histogram of the 10-minute load forecast errors over the year for Alberta. The error distribution appears to be approximately normal. Therefore the standard deviation of the forecast errors represents a measure that quantifies the amount of variation between each 10-minute interval. By definition +/- three standard deviations encompass 99.7% of all of the 10-minute interval forecast errors. Using three standard deviations of the forecast errors for each province then represents a regulation value of sufficient size to account for the 10-minute variations within the hour over the year.

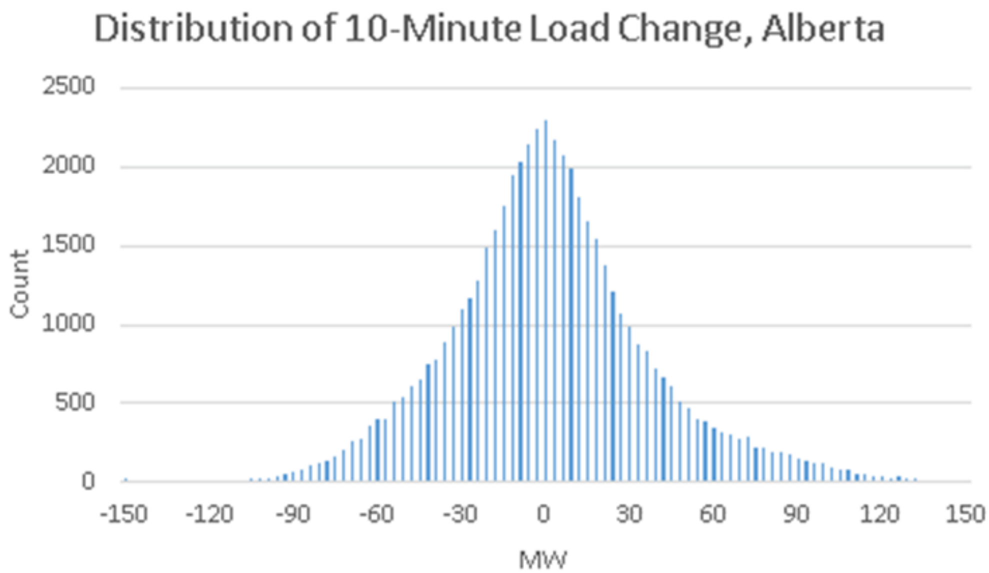


Figure 5-46: Histogram of Alberta 10-minute Load Variability

Load variations vary by time of day; in order to account for this, the 10-minute load variations were grouped into day and night periods. The day time period began in hour 7 and ended in hour 22 while the night periods were the hours not included in the day time. This approach created two Regulating Reserve values, one for the day time period and one for the night time period. Table 5-12 depicts the Regulating Reserve values for each balancing area. It is observed that the greatest variability of load occurs in the night time except for British Columbia. Quebec, on the other hand, has the largest requirement.

Table 5-12: Regulation by Province for Load (MW)

	BC	AB	SK	MB	ON	QC	MAR
Night	168	121	133	147	482	539	146
Day	187	115	131	92	422	523	91

5.2.3 Regulating Reserves for Load and Wind

Chronological production simulations at hourly resolution have been one of the approaches for assessing wind integration impacts. Wind variability and uncertainty that occur within the hour has an effect on the amount of regulation required in each study hour. As previously discussed, wind variability can have both positive and negative implications to Regulating reserves. Positive when wind variability moves in the same direction as the load variability, and negative if movements are in opposite directions. The Regulating Reserve calculated for the load should be adjusted to account for the uncertainty and variability of wind production.

Wind forecasts are used in this analysis in a similar manner as used with load. The wind forecast error is computed by using a persistence forecast of the 10-minute wind production. The standard deviation of the wind forecast errors provide the statistical basis for determining the wind component of Regulating Reserves.

As seen in several studies such as the Eastern Wind Integration and Transmission Study (EWITS) wind variations are uncorrelated with those in load[22]. Therefore, the standard deviation of load variations can be combined geometrically with the standard deviations of wind forecast errors as shown in the equation below. Here R_i is the load Regulating Reserve and σ_w is the standard deviation of the wind forecast error.

$$\mathbf{3} * \sqrt{\left(\frac{\boldsymbol{R_i}}{\mathbf{3}}\right)^{\mathbf{2}} + \boldsymbol{\sigma_w^2}}$$

A sample plot showing each wind scenario for Alberta is shown in Figure 5-47. Here it is observed that the greatest variability of wind occurs when the plant production is in the mid-range. At this range the wind plant has the ability to increase or decrease production. At the lower production range the variability is limited to upward movement and in the upper range it is limited downward movement. The resulting curves are parabolic and used to determining the hourly sigma for the wind production portion of the Regulating Reserves formula shown above.

[22] Eastern Wind Integration and Transmission Study Prepared for: Then National Renewable Energy Laboratory by EnerNex Corporation, January 2010, P142

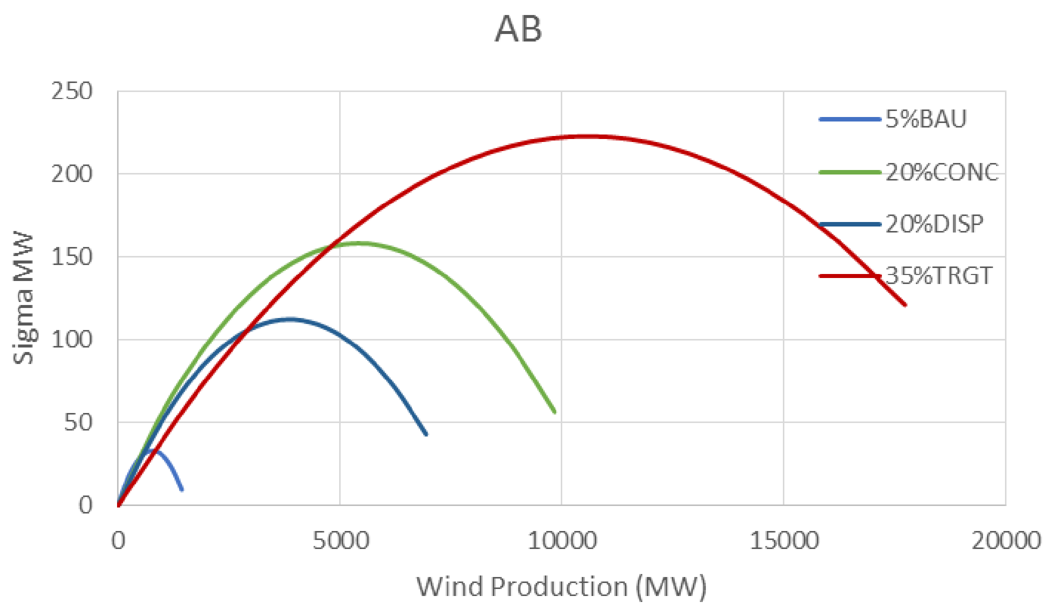


Figure 5-47: Wind Forecast Error, sigma, of Alberta Wind Plants Operating at Different Production Levels for each Scenario

Balancing area Regulating Reserves were calculated for each hour in the year. These hourly profiles or Regulating Reserves were analyzed for comparative purposes between the balancing areas. Characterizations of the Regulation Reserve profiles are shown in Table 5-13. This table depicts for each province and scenario the wind capacity, Regulating Reserve for balancing area load, Regulating Reserve for wind and balancing area load, the change in Regulating Reserve due to the wind, the percentage increase in Regulating Reserve due to wind penetration and the increase in Regulating Reserve as a percentage of increasing wind nameplate capacity.

From the table it can be concluded that the introduction of wind on the Canada system has an effect on the amount of regulating reserves required. From a total Canada perspective regulating reserves increase less than 2% of the installed wind capacity in all scenarios. In all of Canada the percentage of reserve increase is approximately twice the energy penetration. For example the 20% scenarios require slightly less than a 40% increase in load alone regulating reserves. The 20% CONC scenario requires a 38% increase in the average load regulating reserves without wind. The 20%DISP scenario requires 34% increase in the average load regulating reserves without wind. And the 35% TRGT scenario requires a 68% increase in the average load regulating reserves without wind. This generalization is a result of the diversity of the wind selection and does not hold for individual balancing areas. Based on this analysis, wind has the greatest effect on Regulating Reserves in Alberta, increasing Regulating Reserves by 21 MW, 248 MW, 165 MW and 428 MW for scenarios 5% BAU, 20%

CONC, 20% DISP and 35% TRGT respectively. For all of Canada the increase in Regulating Reserves as a percentage of nameplate capacity is 0.8%, 1.7%, 1.5% and 1.7% for the same respective scenarios.

Table 5-13: Regulation Reserve Summary for Each Province in Each Scenario

5% BAU	BC	AB	SK	MB	ON	QC	MAR	Total
Wind Capacity MW	685	1,438	450	258	4,101	2,959	1,074	10,966
Average Load Regulation MW	180	117	132	110	442	528	82	1,591
Average Load + Wind Regulation MW	183	138	139	115	471	535	90	1,671
Change in Regulation MW	3	21	7	5	29	7	8	79
Increase Regulation %	2%	18%	6%	4%	6%	1%	10%	5%
Increase Regulation as % of Capacity	0.4%	1.5%	1.6%	1.8%	0.7%	0.2%	0.7%	0.7%
20% DISP	**BC**	**AB**	**SK**	**MB**	**ON**	**QC**	**MAR**	**Total**
Wind Capacity MW	4,269	6,944	1,748	1,781	8,438	12,274	1,673	37,127
Average Load Regulation MW	180	117	132	110	442	528	82	1,591
Average Load + Wind Regulation MW	216	282	201	172	539	622	100	2,131
Change in Regulation MW	35	165	69	62	97	94	18	540
Increase Regulation %	20%	141%	52%	56%	22%	18%	22%	34%
Increase Regulation as % of Capacity	0.8%	2.4%	3.9%	3.5%	1.2%	0.8%	1.1%	1.5%
20% CONC	**BC**	**AB**	**SK**	**MB**	**ON**	**QC**	**MAR**	**Total**
Wind Capacity MW	2,221	9,840	914	2,789	10,054	6,127	4,361	36,307
Average Load Regulation MW	180	117	132	110	442	528	82	1,591
Average Load + Wind Regulation MW	195	365	153	196	572	556	156	2,193
Change in Regulation MW	15	248	21	86	130	28	74	602
Increase Regulation %	8%	212%	16%	78%	29%	5%	91%	38%
Increase Regulation as % of Capacity	0.7%	2.5%	2.3%	3.1%	1.3%	0.5%	1.7%	1.7%
35% TRGT	**BC**	**AB**	**SK**	**MB**	**ON**	**QC**	**MAR**	**Total**
Wind Capacity MW	5,445	17,728	4,406	2,213	16,122	15,489	3,819	65,221
Average Load Regulation MW	180	117	132	110	442	528	82	1,591
Average Load + Wind Regulation MW	231	545	273	185	638	652	143	2,666
Change in Regulation MW	50	428	141	74	196	123	62	1,075
Increase Regulation %	28%	366%	107%	67%	44%	23%	76%	68%
Increase Regulation as % of Capacity	0.9%	2.4%	3.2%	3.4%	1.2%	0.8%	1.6%	1.6%

6 Scenario Analysis

6.1 Multi-Area Production Simulation

The GE Multi Area Production Simulation (GE MAPS) model was used for hourly simulation of the unit commitment and economic dispatch of the generation resources in the four study scenarios listed in Table 6-1. Scenario definitions and wind plant site selections have been outlined in previous sections, along with the underlying modeling assumptions which were finalized after review and feedback by the CanWEA team and the Technical Advisory Committee (TAC) members.

Table 6-1: Study Scenarios Overview, Canada Total

Scenario	Wind Penetration Level (%)	Number of Wind Sites Used	Wind Capacity (MW)	Wind Energy (GWh)	Average Capacity Factor (%)
5% BAU	5.7%	116	10,970	34,717	36.1%
20% DISP	20%	229	37,131	122,054	37.5%
20% CONC	20%	220	36,311	121,584	38.2%
35% TRGT	35%	333	65,225	212,734	37.2%

Note: Totals and capacity factors may not match due to rounding.

The GE-MAPS production cost model is a security constrained unit commitment and economic dispatch program that simulates the power system operation on an hourly, chronological basis over the course of the year. The model simulates the system operator's unit commitment (to select which units have to be online during the commitment period) and economic dispatch (to determine the hourly MW output of committed units) decisions necessary to supply the electricity load in a least cost manner, while appropriately reflecting transmission flows across the grid and simultaneously preparing the system for unexpected contingency events and variability. The chronological modeling is crucial to understanding renewable integration because it simulates chronological changes to electrical load and the underlying variability and forecast uncertainty associated with wind and solar resources.

The daily unit commitment process accounts for the day-ahead wind forecast, whereas hourly economic dispatch is performed based on information on real-time wind. The availability of renewable resources is determined by day-ahead (DA) forecasts before the commitment of thermal generation resources. Once the thermal units are committed, there may be limited flexibility on the system to compensate for short-term wind forecast errors. If more wind shows up in the real-time (RT) dispatch, then the thermal generators will back down to minimum loading levels, but may not be able to turn off completely. If less wind shows up than expected, committed thermal generators must increase their output accordingly. If there is insufficient committed capacity, the system operator must then call on quick-start peaking units (PEAKER) to balance the system. Reserve requirements in each province include modeled contingency reserves, plus additional calculated hourly requirements for variability regulation reserve deemed to be necessary to offset the 10-minute wind and load variability.

The final transmission models in the study scenarios are based on multiple iterative runs of the model that determined the size of transmission reinforcements required to force a reduction – down to a reasonable level - in the observed transmission congestions caused by the higher penetration of wind. Transmission reinforcements refer to the incremental new transmission or transmission upgrades over and above the present transmission system.

The following sub-sections present the results of the hourly simulation with focus on number of themes that are most relevant to system operations with variable renewable energy with implications for the type of mitigation measures potentially available to the Canadian system operators.

The Study scope did not include evaluation of the economic viability of the generation resources that would be significantly impacted by the higher penetration of wind and their downward pressure on electricity costs caused by displacement of fossil fuel based generation. However, to the extent possible, some operational production cost data are highlighted.

It should be noted that 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 generating costs associated with fuel consumption, variable operations & maintenance, emissions, and unit startup. The production cost analysis does not include costs related to new capital expenditures required for new wind additions or fixed operations & maintenance.

6.2 Province and Unit Type Name Abbreviations

In this and following sections, following abbreviations are used for the province and unit type names, in order to be consistent with the naming standard used in the figures and tables:

Canadian Provinces in PCWIS

AB Alberta

BC British Columbia

MB Manitoba

NB	New Brunswick
ON	Ontario
QC	Quebec
MAR	Maritime
NL	Newfoundland and Labrador
NS	Nova Scotia
PE	Prince Edward Island
SK	Saskatchewan

Unit Types

CC-GAS	Combined Cycle Gas Turbine
SC-GAS	Single Cycle Gas Turbine
COGEN	Cogeneration Plant
HYDRO	Hydropower / Hydroelectric plant
NUCLEAR	Nuclear plant
OTHER	Includes biomass, waste-to-energy, Etc.
PEAKER	SC-GAS and internal combustion / reciprocating engines
SOLAR	Solar energy resource
ST-COAL	Steam Coal
ST-GAS	Steam Gas
WIND	Wind energy resource

6.3 Overall System Performance

Table 6-2 displays the generation capacity by unit type in the 5% BAU scenario. Peaking units (PEAKER) include Single Cycle Natural Gas Turbines (SC-GAS) and smaller Internal Combustion / Reciprocating Engines (IC or RE) units. The wind capacities shown are based on the existing installed nameplate capacity in each province, excluding new additions evaluated across the scenarios.

Table 6-2: Generation Capacity by Unit Type in each Province and Type (MW) in 5% BAU Scenario

Unit Type	BC	AB	SK	MB	ON	QC	MAR	CAN
NUCLEAR					9,865		558	10,423
COGEN	307	3,476			2,624	576	208	7,190
ST-COAL		4,857	1,271				1,247	7,375
CC-GAS	211	6,020	1,970		6,822		409	15,432
ST-GAS		116		126	2,331		321	2,894
PEAKER	90	2,039	649	257	1,123	1,053	1,764	6,975
HYDRO	12,942	523	901	5,891	6,711	41,734	1,893	70,596
OTHER	162	159	65		200	570	152	1,308
SOLAR					490			490
WIND	685	1,438	451	258	4,103	2,960	1,074	10,970

In the 5% BAU scenario, hydropower and natural gas based capacities include the additional hydropower and generic natural gas based capacities that will be needed to be installed in order to meet the reliability based installed reserve margin requirements by 2025. These additional non-wind capacities were not changed in the other study scenarios.

Therefore, the only differences between the four study scenarios are the amount of wind capacity and available energy in each scenario and the transmission reinforcements added in each scenario. The reason for not balancing of each scenario was to keep the number of variable changes across the scenarios to a minimum (just the wind and transmission), so that the impact of higher wind penetration could be evaluated without the impact of other variables.

Consequently, the 5% BAU scenario is capacity balanced to meet installed reserve margin requirements. The other scenarios have surplus capacity, so therefore they meet and exceed their reliability requirements. Although thermal unit capacity across the scenarios remains the same, the amount of annual energy output from thermal units will not be the same due to the impact of higher penetration of wind.

Figure 6-1 presents generation capacity by type in each province and under each scenario. Provinces where hydro capacity is dominant include BC, MB, and QC. ON has as much hydro as MB, but being a larger system, also includes other unit types as well. AB has the largest concentration of COGEN and ST-COAL units, and the second largest fleet of CC-GAS units after ON. ON also holds substantial amount of COGEN, ST-GAS, CC-GAS, and HYDRO, and also the bulk of NUCLEAR capacity in Canada. The chart below highlights the diversity of resources across Canada, and the unique nature of each of the provinces. As a result, the different underlying resources across the different provinces will lead to very different impacts of wind integration.

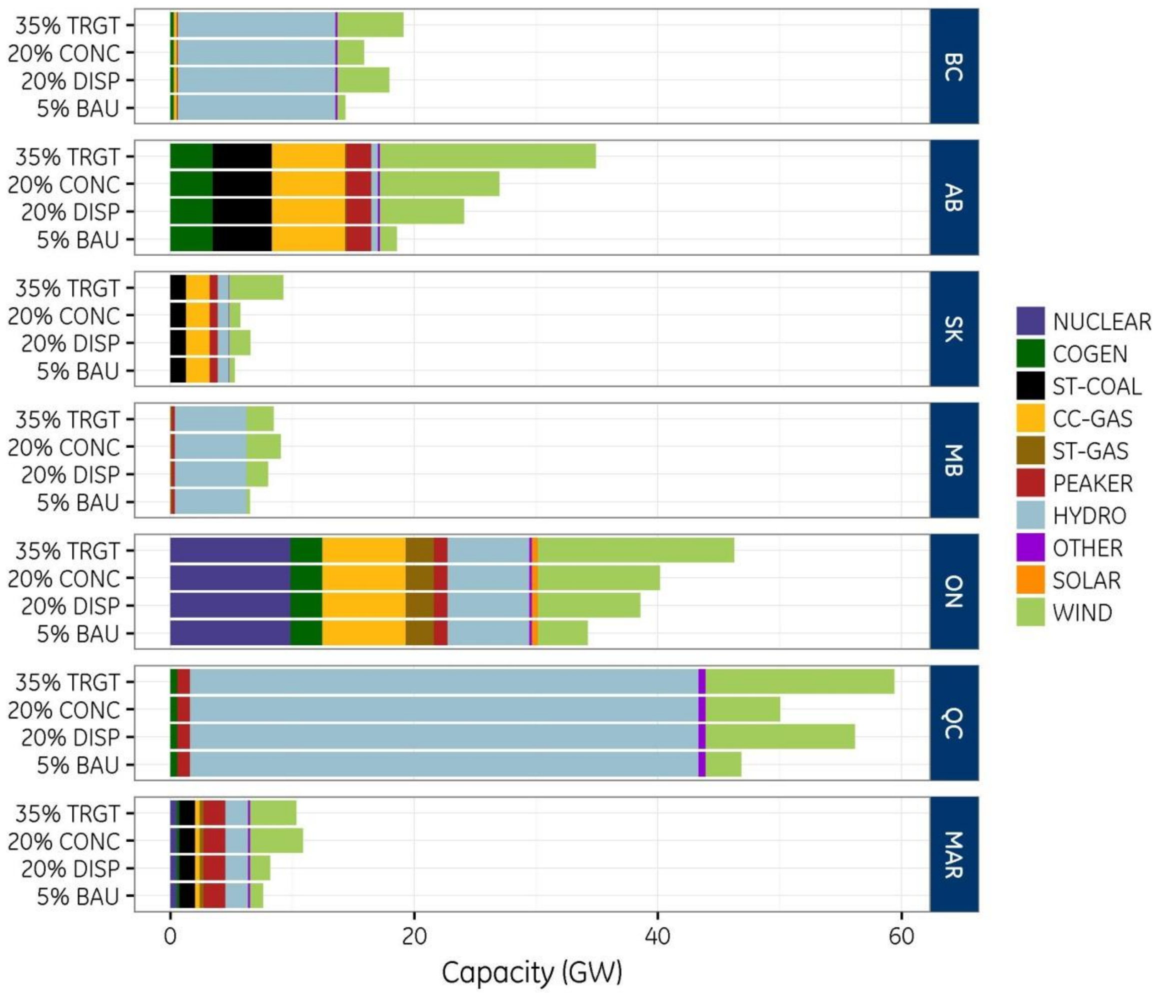


Figure 6-1: Generation Capacity (GW) by Type and Province

Annual generation in Canada by unit type in each scenario is shown in Figure 6-2. Also provided are changes in total generation and net export relative to the 5% BAU scenario.

Although the transmission reinforcements included in different scenarios will have some impact on the generation dispatch pattern, the overall changes in generation by type are mainly due to the higher penetration wind. Because wind is a zero variable cost resource (free fuel), wind generation will be utilized before more expensive forms of generation, to the extent that technical constraints allow. As a result, the addition of wind capacity will impact the dispatch of other generation types.

Given that the underlying capacity of thermal generation is the same across the scenarios, zero fuel cost wind will be expected to displace more costly fossil-fueled generation. It will also impact curtailment of other types of energy during times when there is too much energy supply but too little demand for electricity. It will be shown that higher penetration of wind in Canada, result in displacement of thermal generation not only in Canada but also in the USA.

Figure 6-2 highlights other important observations:

- Wind increases from approximately 5% of the total annual generation in Canada in the 5% BAU Scenario, to 26% of annual generation in the 35% TRGT Scenario.
- The difference between the annual generation and the Scenario target is due to exports. The scenarios were designed to achieve a specific level of *load* penetration, while the annual generation changes due to exports to neighbouring markets in the USA.

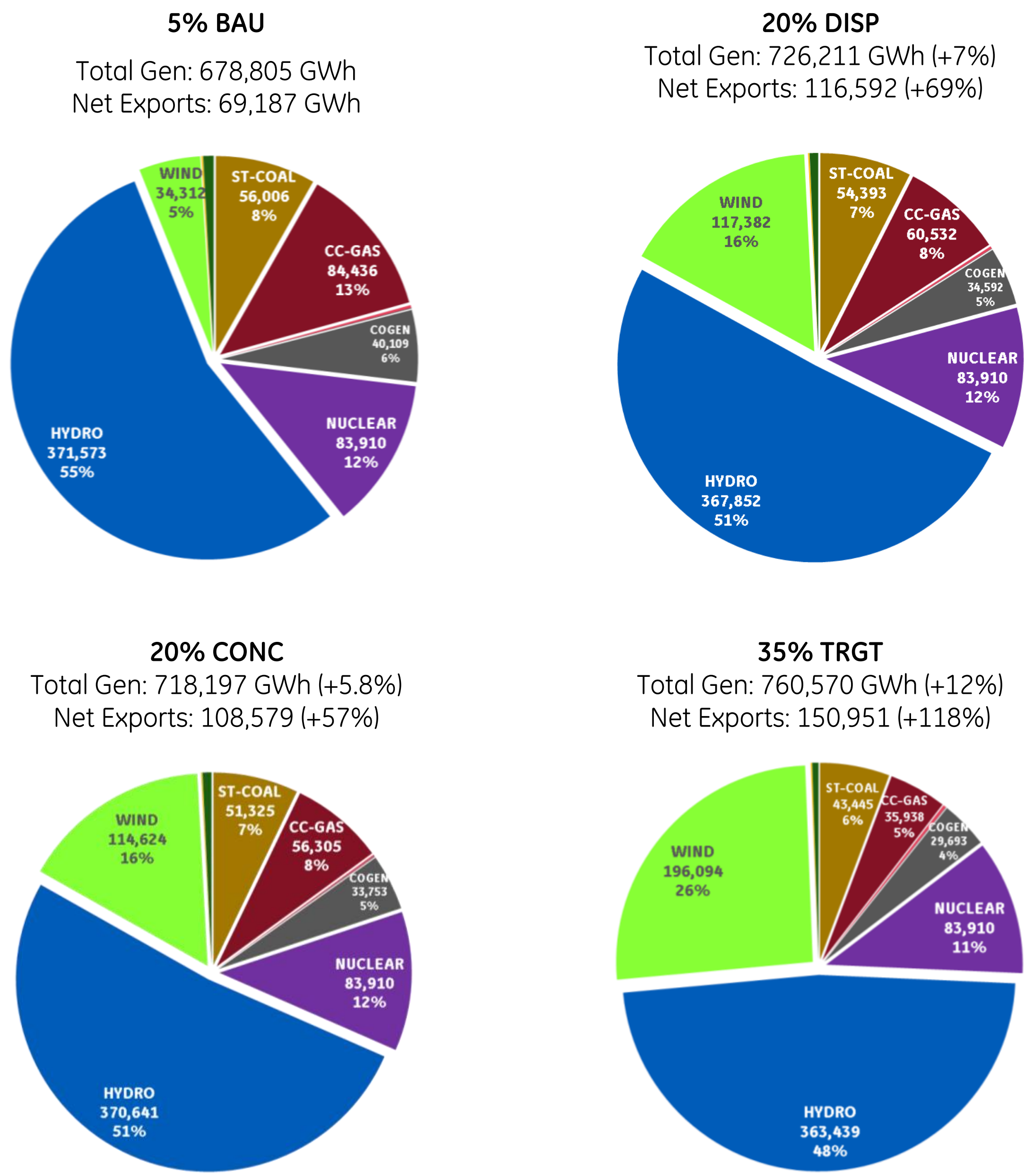


Figure 6-2: Canadian Generation by Type (in GWh and % of total) in Study Scenarios

Table 6-3 presents the total generation in TWh by unit type in Canada and the USA for each scenario. Although the table shows variation in generation by unit types across the four scenarios; the underlying capacities are the same in all the scenarios, except for the wind in Canada.

Table 6-3: Generation by Country and Unit Type (TWh)

	Unit Type	5% BAU	20% DISP	20% CONC	35% TRGT
CAN	NUCLEAR	83.9	83.9	83.9	83.9
	COGEN	40.1	34.6	33.8	29.7
	ST-COAL	56.0	54.4	51.3	43.4
	CC-GAS	84.3	60.5	56.3	36.0
	ST-GAS	0.2	0.1	0.1	0.1
	PEAKER	1.7	1.5	1.4	2.0
	HYDRO	371.6	367.9	370.7	364.7
	OTHER	5.8	5.1	5.4	3.9
	SOLAR	0.8	0.8	0.8	0.8
	WIND	34.3	117.4	114.6	196.1
	TOTAL	**678.8**	**726.2**	**718.2**	**760.6**
USA	NUCLEAR	803.4	803.4	803.4	803.4
	COGEN	179.9	177.1	177.5	173.7
	ST-COAL	989.9	976.0	976.8	964.0
	CC-GAS	1281.4	1249.1	1256.7	1229.9
	ST-GAS	30.2	30.4	30.2	30.2
	PEAKER	91.1	93.5	92.5	95.5
	HYDRO	272.0	272.2	272.1	272.2
	OTHER	44.6	44.3	44.5	43.8
	SOLAR	19.4	19.4	19.4	19.4
	WIND	497.9	497.7	497.8	497.0
	TOTAL	**4209.8**	**4163.1**	**4170.9**	**4129.1**
Grand Total		**4888.5**	**4889.3**	**4889.2**	**4889.7**

Figure 6-3 and Figure 6-4 provide a graphical representation of annual generation by unit type in Canada and the USA under the four scenarios. It can be seen that the higher wind penetration impacts CC-GAS generation most. The main reason is that under the study assumptions, natural gas units are more costly to operate than the coal units, and therefore, are the marginal units most of the time. Being on the top of dispatch stack (the economic merit order of commitment and dispatch across all generators); they get replaced by wind ahead of the coal-based generation. The decision on which units are displaced by additional wind is an economic one, based on the underling operating costs of the different resources. Further drops in natural gas prices, or relative increase in coal prices, or any regulatory or policy changes that impact the relative cost of natural gas versus coal - such as adoption of high carbon taxes or high carbon emission allowance prices - may make coal units more costly to operate relative to the gas units, resulting in the displacement of coal units ahead of the natural gas units.

Higher wind penetration in Canada also results in reduction of generation by CC-GAS units in the USA. In effect, higher penetration of wind in Canada is introducing additional low cost power into the North American power systems, and causing displacement of more costly generation.

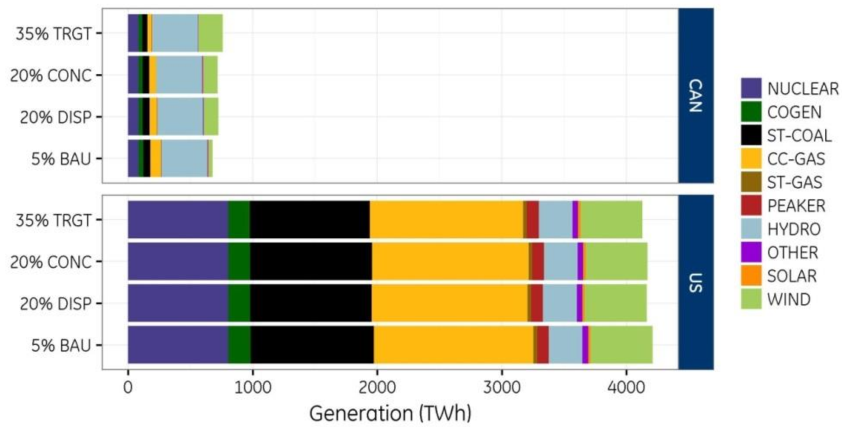


Figure 6-3: Generation by Country and Scenario (TWh)

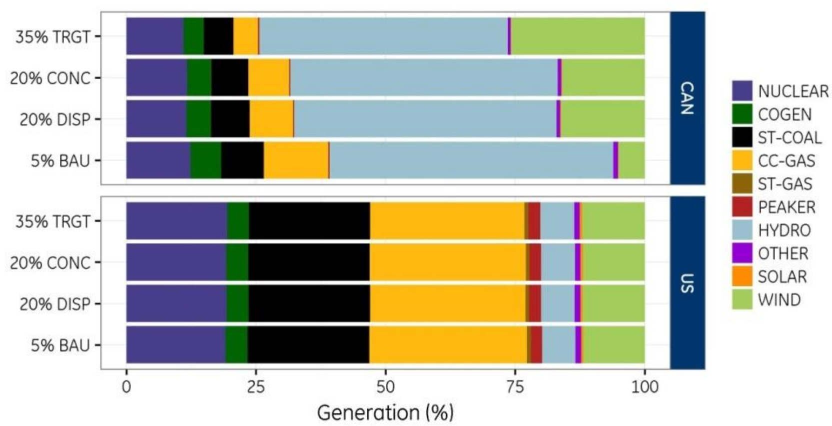


Figure 6-4: Generation by Country and Scenario as Percent of Total Generation

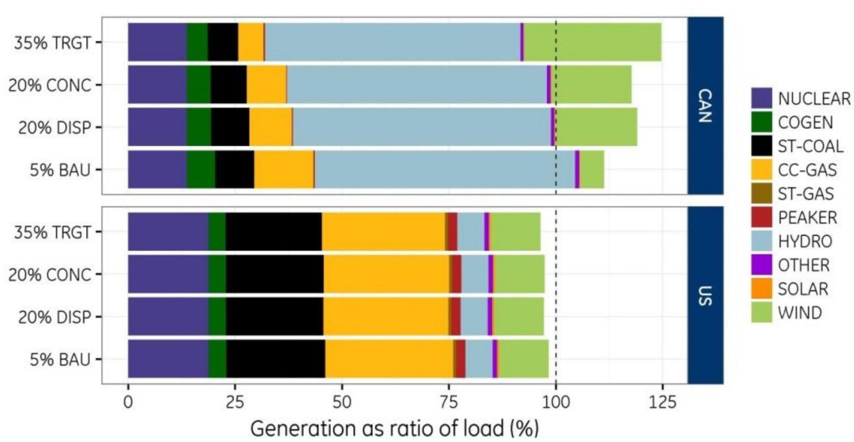


Figure 6-5: Generation by Country and Scenario as Percent of Total Load

Figure 6-6 shows the degree of displacement of thermal units in Canada and the USA in each scenario relative to the 5% BAU scenario. Displacement is a measure of how much each unit type's energy production goes down as wind energy production goes up in the study scenarios. It is important to note that the displacement from additional wind is nearly equal in both the US and Canada, suggesting significant changes in cross-border transmission flows. As can be observed, the CC-GAS fleet is most impacted by the higher wind penetration, but other sources, such as COGEN and ST-COAL are also impacted. The only unit types that experience higher generation with the higher penetration of wind are the PEAKER units in the USA, and to a lesser extent in Canada. A number of drivers are the likely cause, including higher variability of system-wide generation as well as inherent errors in day-ahead wind forecasts, resulting in the need for more response by flexible PEAKER units, which USA has in more abundance compared to Canada.

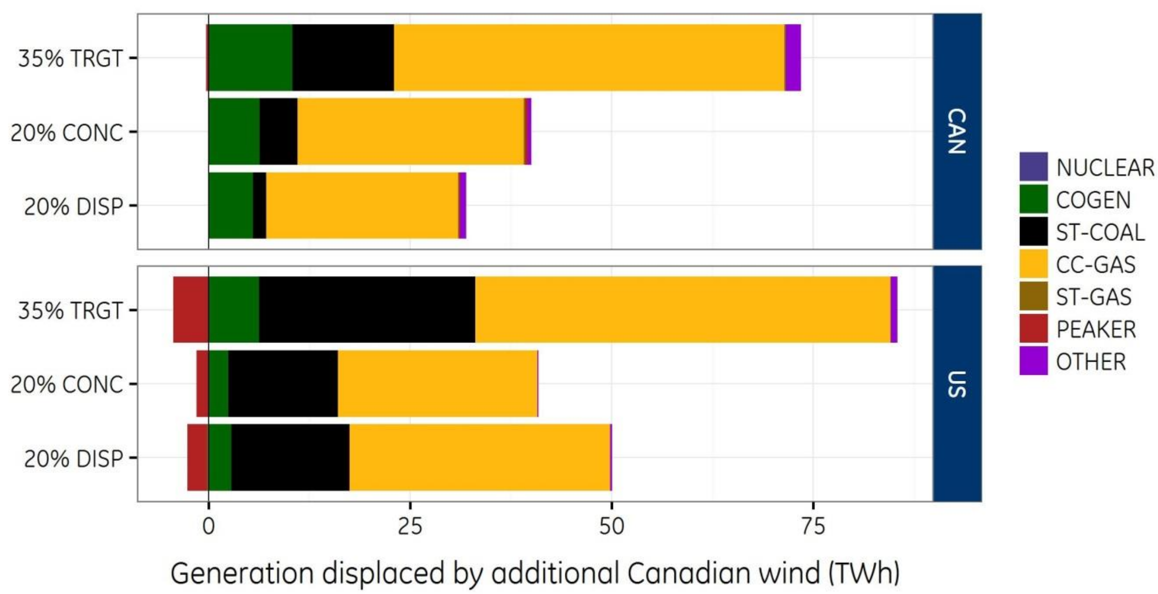


Figure 6-6: Displaced Thermal Generation by Country and Type Relative to the 5% BAU Scenario

The next figures provide more detailed information on generation by unit type in each province under each scenario. Figure 6-7 shows the total generation by unit type in each province. BC, MB, ON, and QC are rich in hydro resources, with thermal generation concentrated mostly in AB, SK, ON, and MAR. A significant portion of generation in ON is nuclear power. The figure shows that in 20% CONC scenario, BC and QC have less wind resources compare to the 20% DISP scenario.

Figure 6-7, Figure 6-8, and Figure 6-9 represent the same underlying data and results (showing annual generation by unit type), but are visualized differently. The first chart shows total generation in TWh, the second chart shows percent generation relative to the total annual generation (which varies across the scenarios), and the third chart shows the percent generation relative to the total annual load (which remains constant across the scenarios).

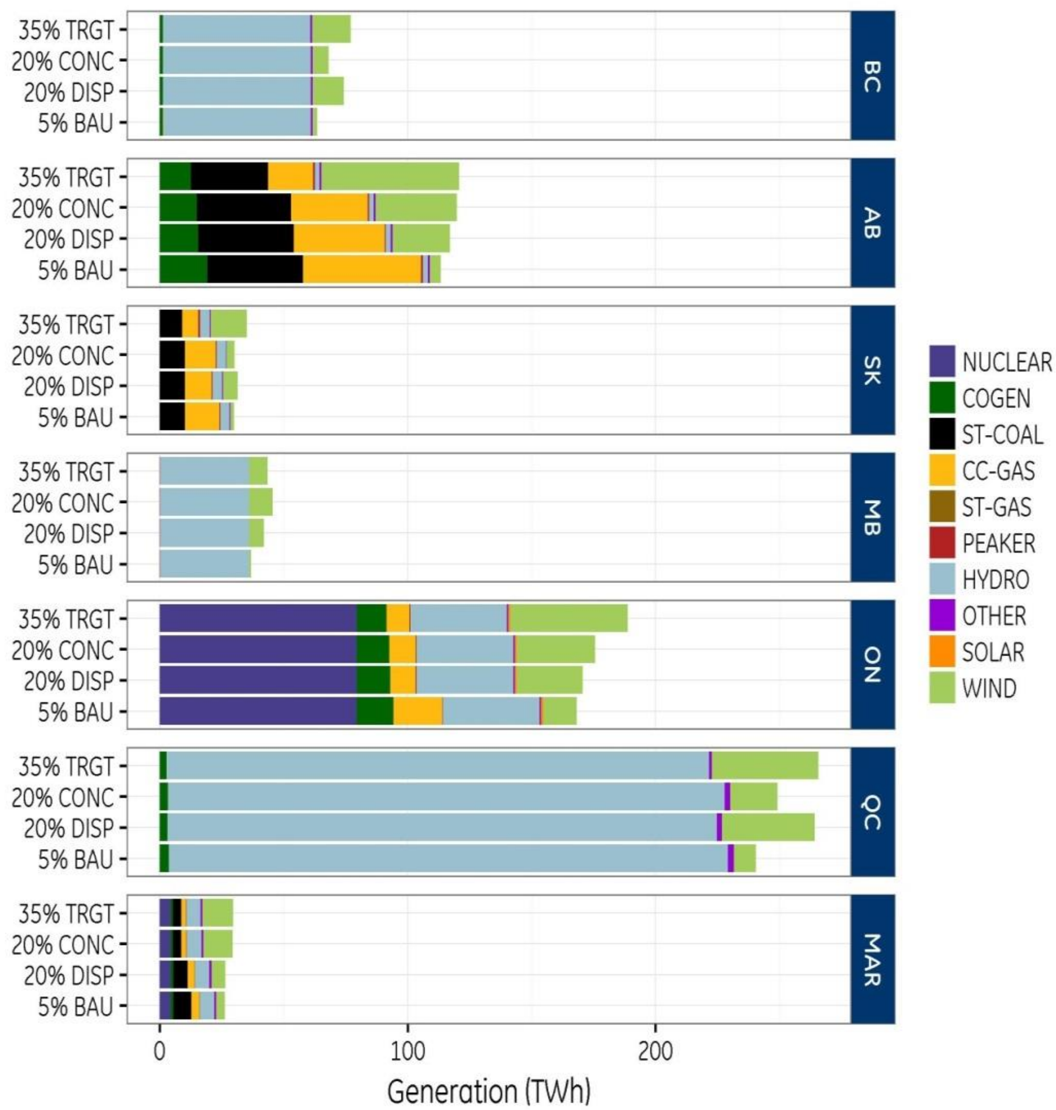


Figure 6-7: Generation by Unit Type in each Province under each Scenario (TWh)

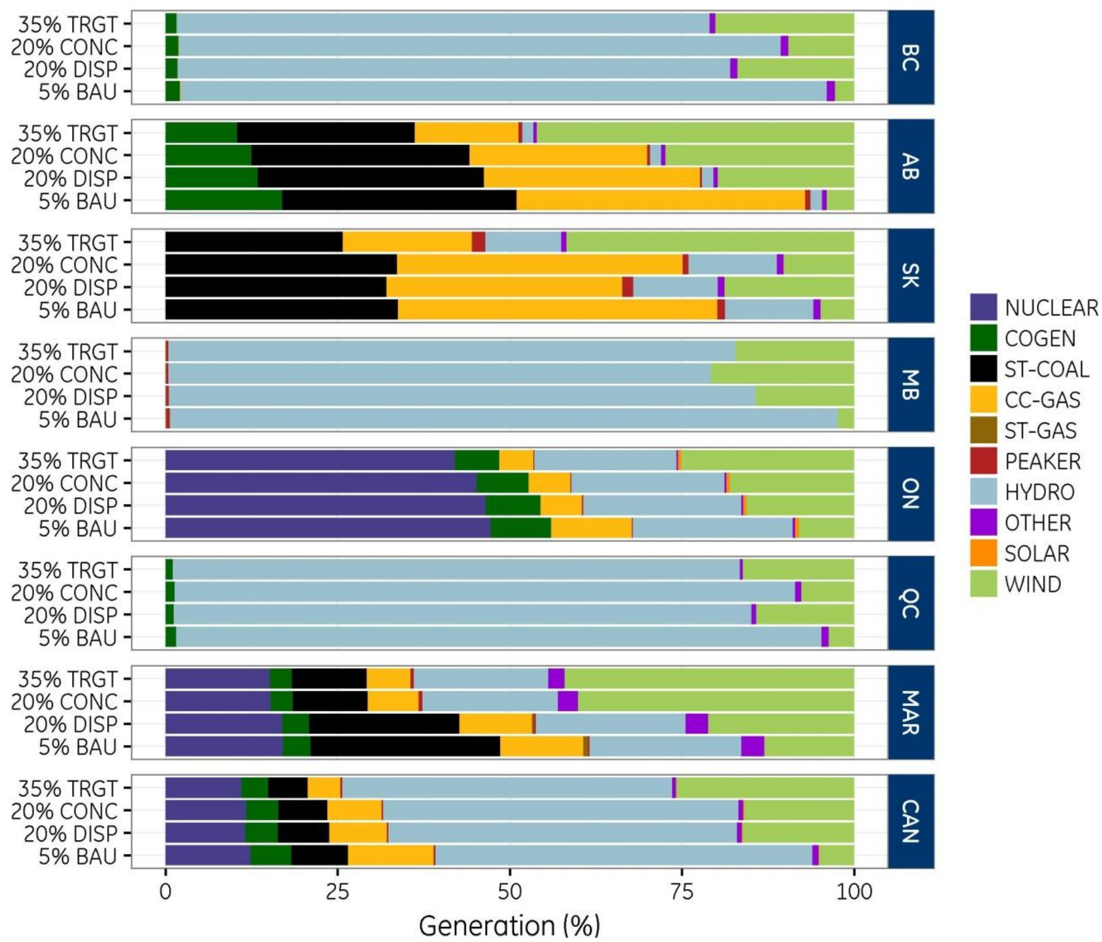


Figure 6-8: Generation by Province, Unit Type, and Scenarios as Percent of Total Generation

Figure 6-9 shows that in the majority of cases, more wind generation in a province displaces generation by thermal units, and at the same time causes more net exports from that province to its neighbours, either in Canada or the USA. Low cost wind displaces high cost thermal units in both Canada and USA.

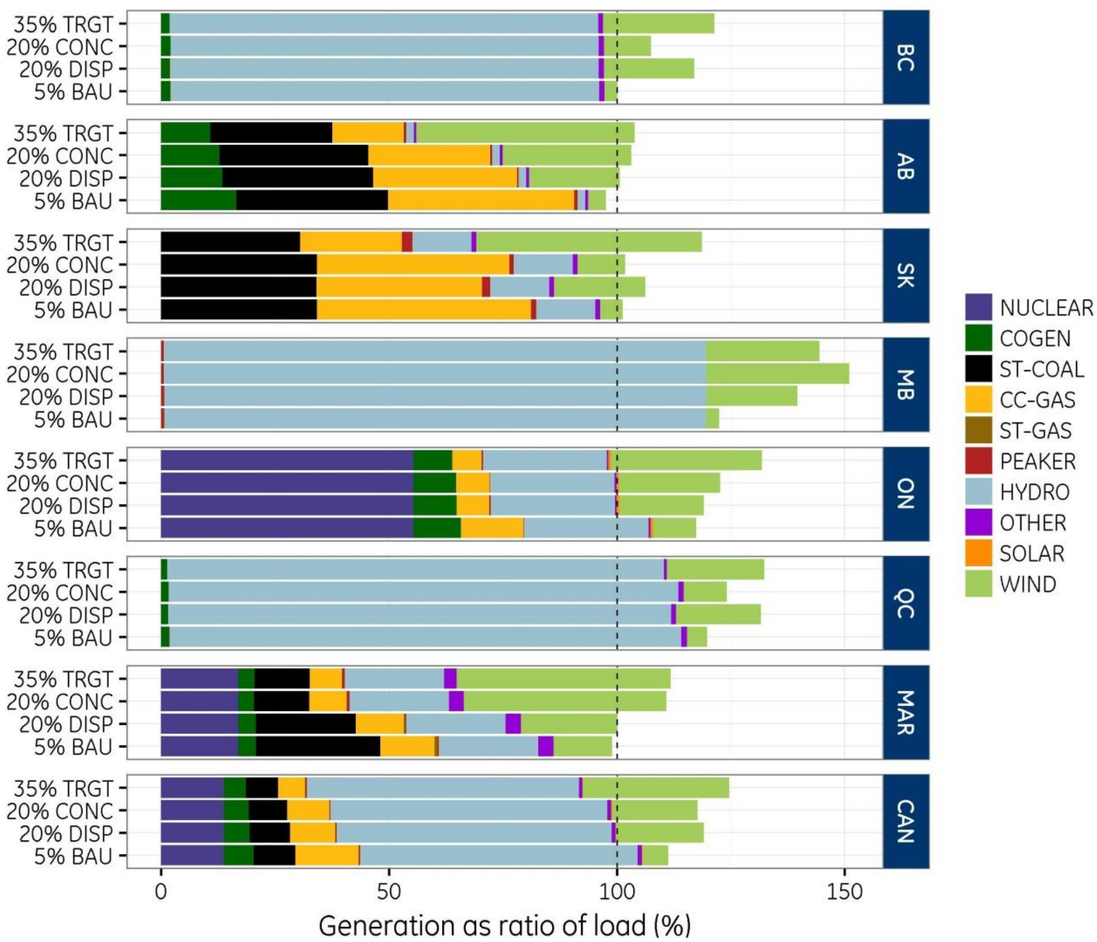


Figure 6-9: Generation by Province, Unit Type, and Scenarios, as Percent of Total Load

Figure 6-10 illustrates the degree of displacement of other generation types caused by higher penetration of wind. The bars to the right of the vertical line in each province are the sizes of reduction in generation, which are mostly CC-GAS, ST-COAL, and COGEN, and in case of QC, some HYDRO. Conversely, bars to the left of the vertical line in each province represent increase in generation. PEAKER units, mainly SC-GAS and IC/RE, experience slight increase in energy production (mostly in SK).

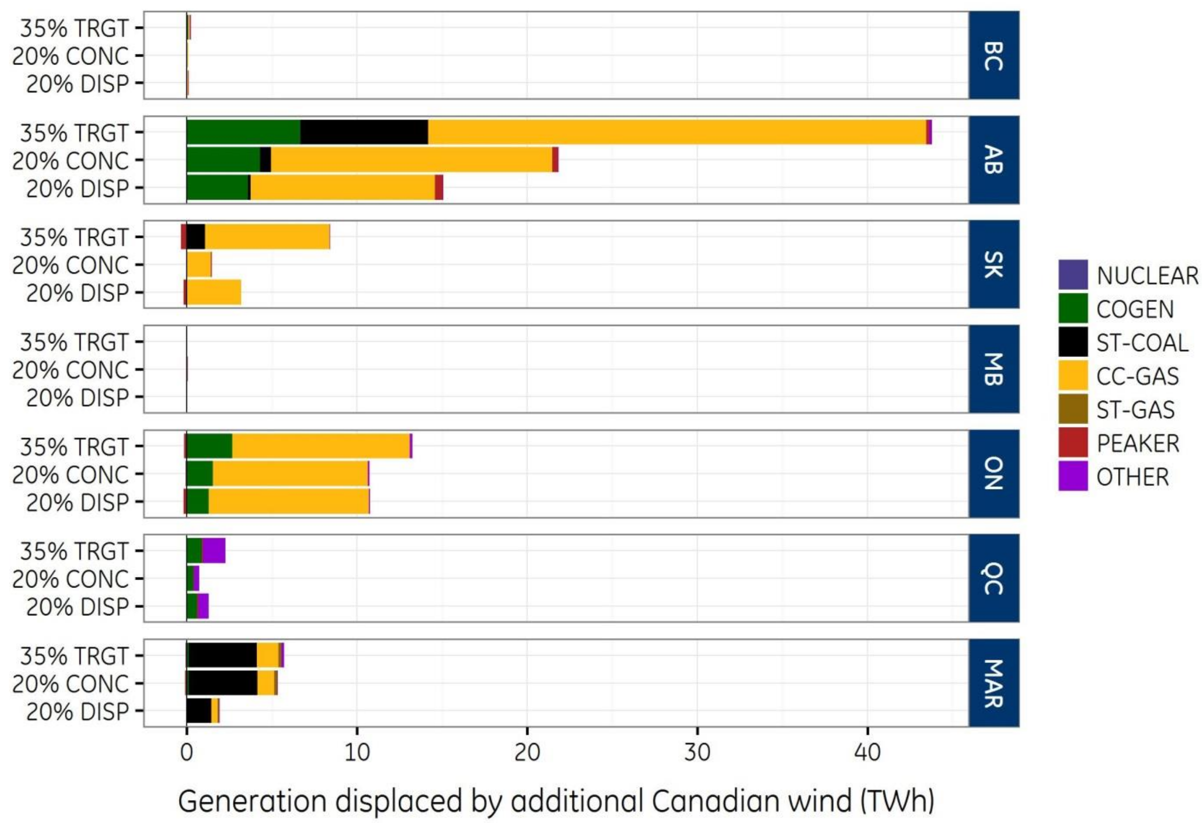


Figure 6-10: Displaced Thermal Generation by Province, Unit Type, and Scenarios (TWh)

Figure 6-11 depicts the weekly, chronological system dispatch consisting of generation by different unit types under each of the four study scenarios for a selected week in the year. The dotted lines represent total Canada load. As more wind is added to the system, generation by other types are pushed down (either turned offline or dispatched to lower loading levels), with CC-GAS most affected; and net exports are increased, represented by areas above the dotted lines (total Canada Load).

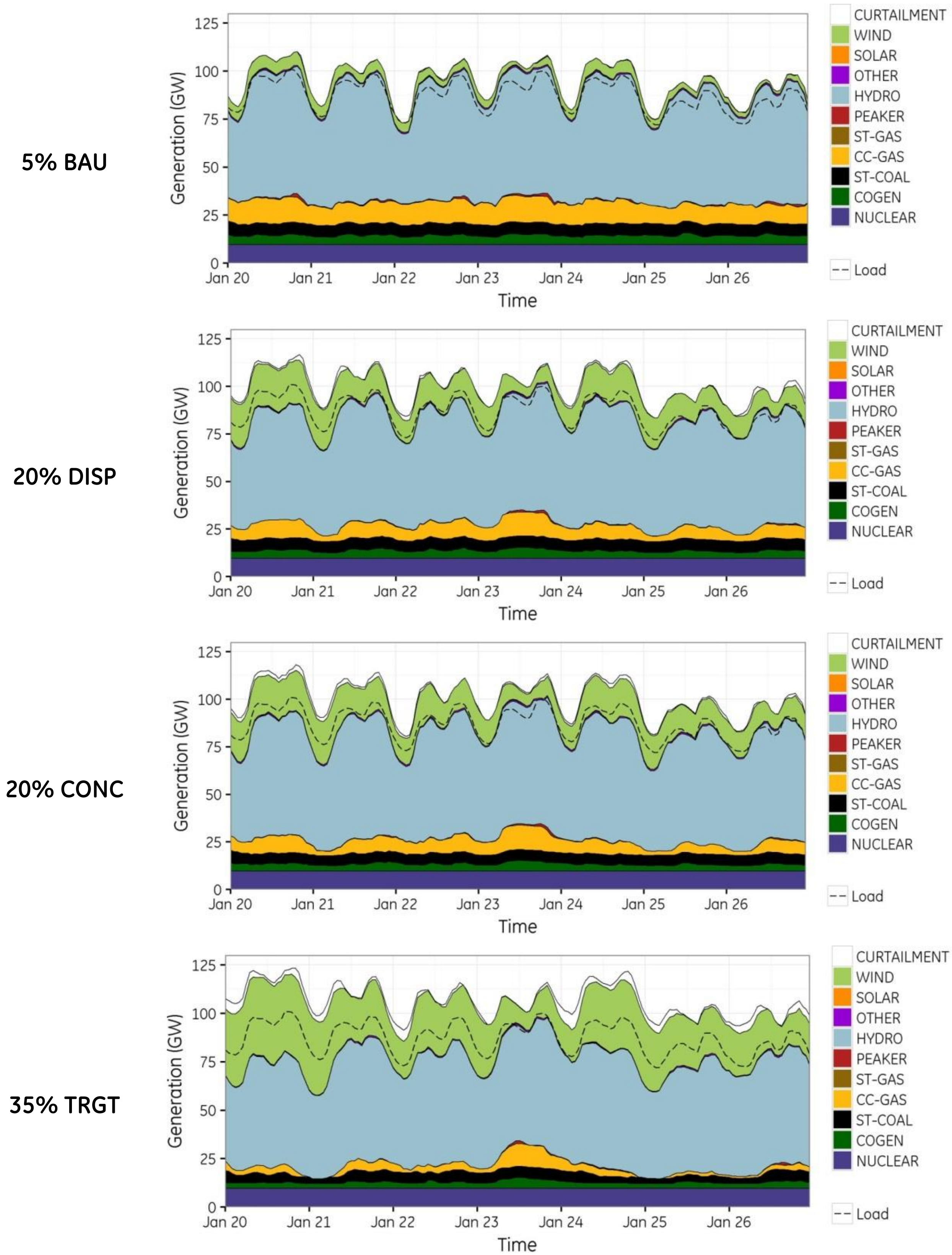


Figure 6-11: Dispatch Stack for Sample Week - All Canada

Figure 6-12 to Figure 6-15 show the chronological system dispatch for the same selected week for each province under each of the four study scenarios. These figures show the variation of the dispatch patterns across provinces and scenarios.

The same general theme of CC-GAS and other thermal unit displacement and increased export is evident in these figures. The most drastic changes are observed in AB and SK with higher penetration of wind, which increasingly push down dispatch of CC-GAS and in the 35% TRGT scenario completely displace CC-GAS at times. Dispatch of ST-COAL generation is also significantly reduced in some hours. Additional wind is also pushing the total generation above the dashed load curve, indicating surplus generation that is either exported from each province or curtailed.

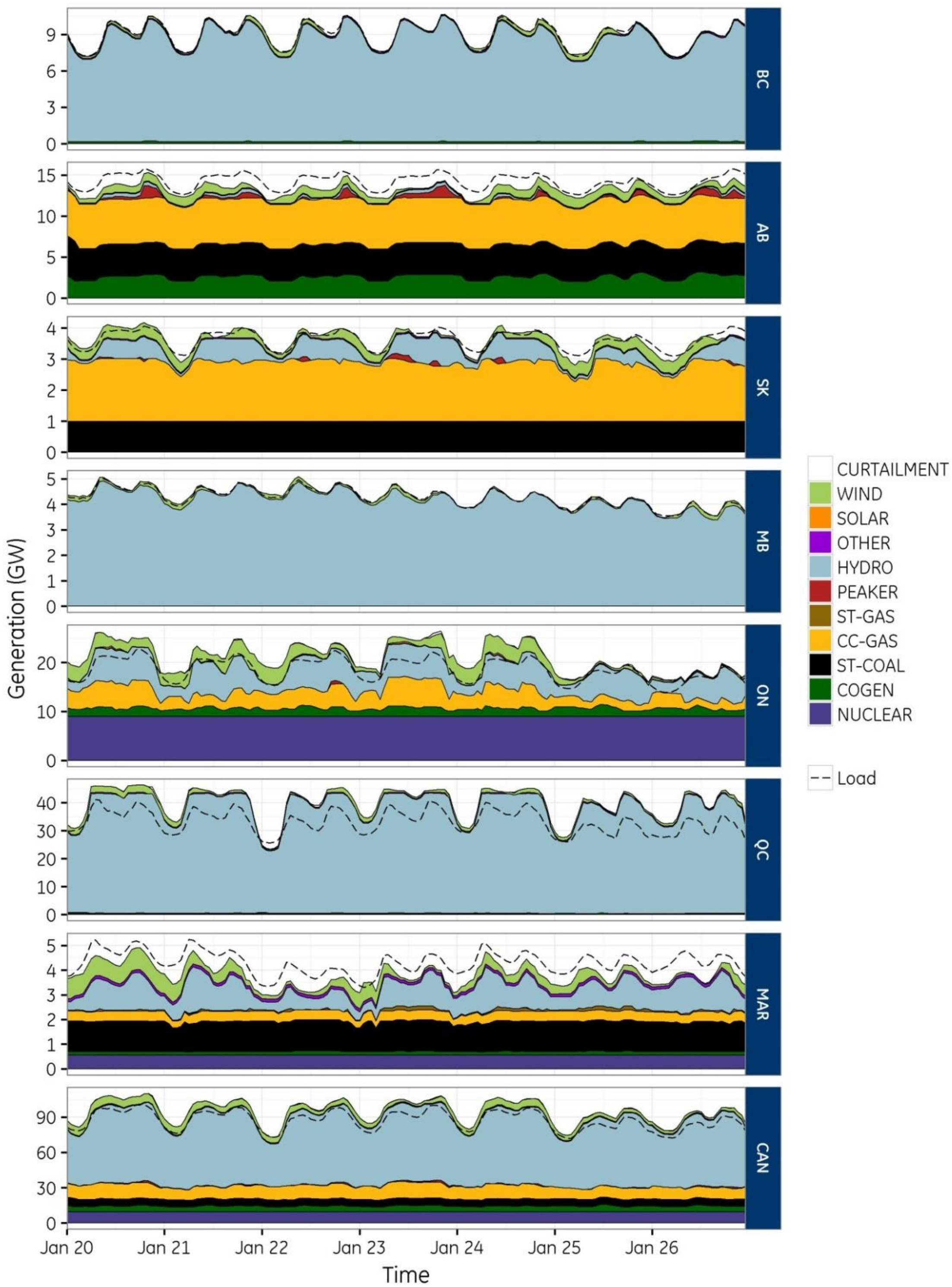


Figure 6-12: Chronological Generation Dispatch by Unit Type and Province for 5% BAU Scenario

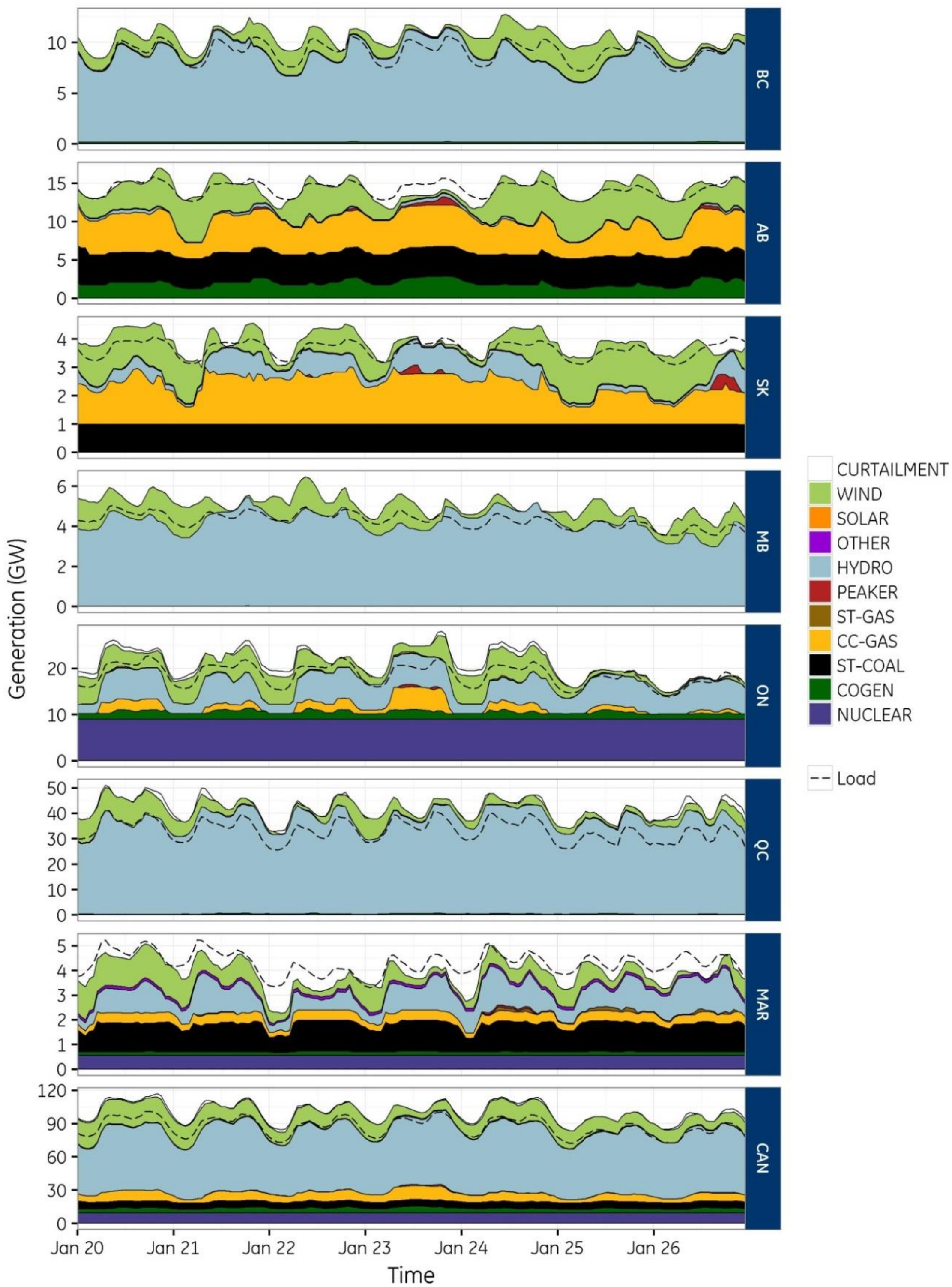


Figure 6-13: Chronological Generation Dispatch by Unit Type and Province for 20% DISP Scenario

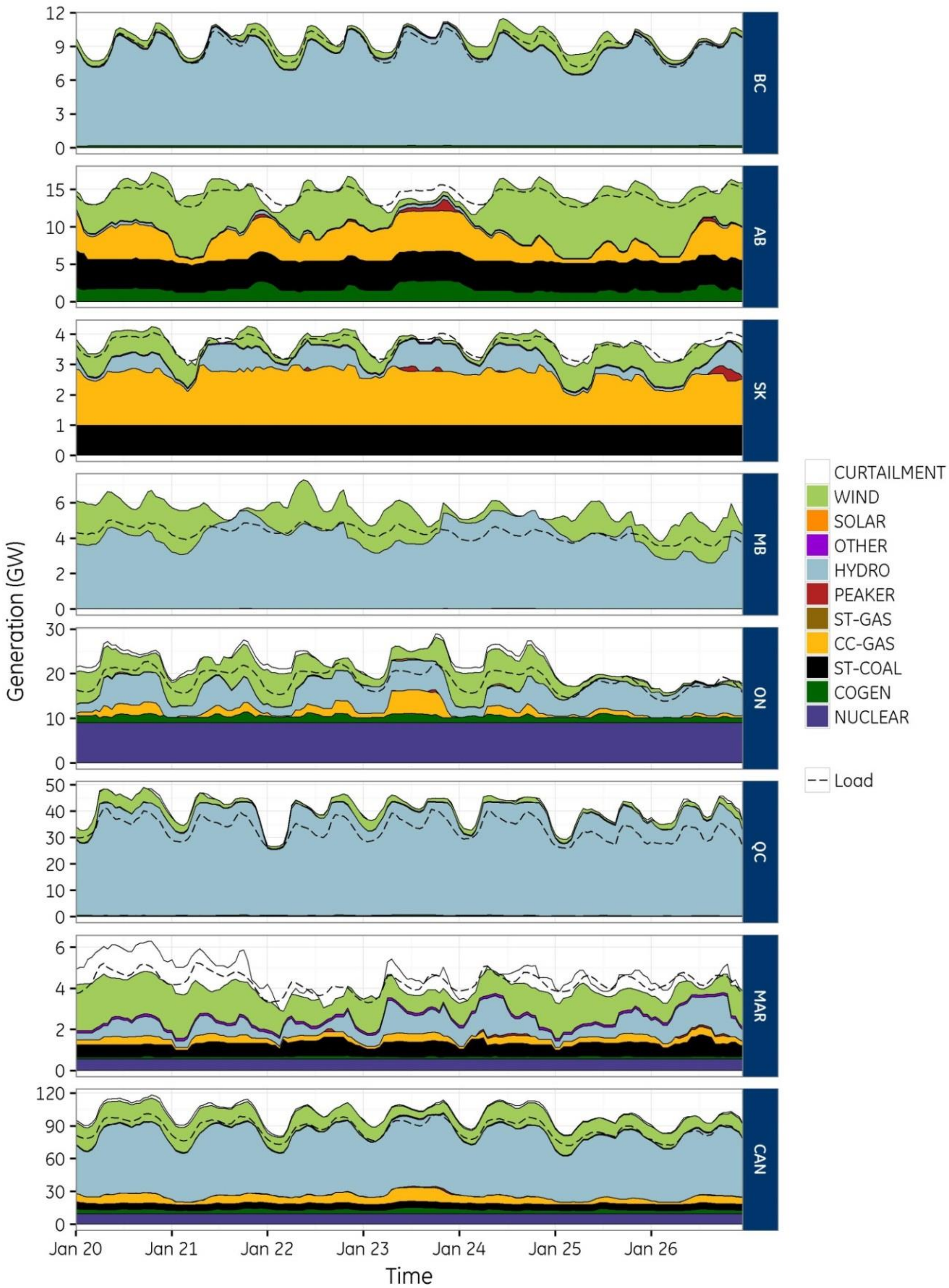


Figure 6-14: Chronological Generation Dispatch by Unit Type and Province for 20% CONC Scenario

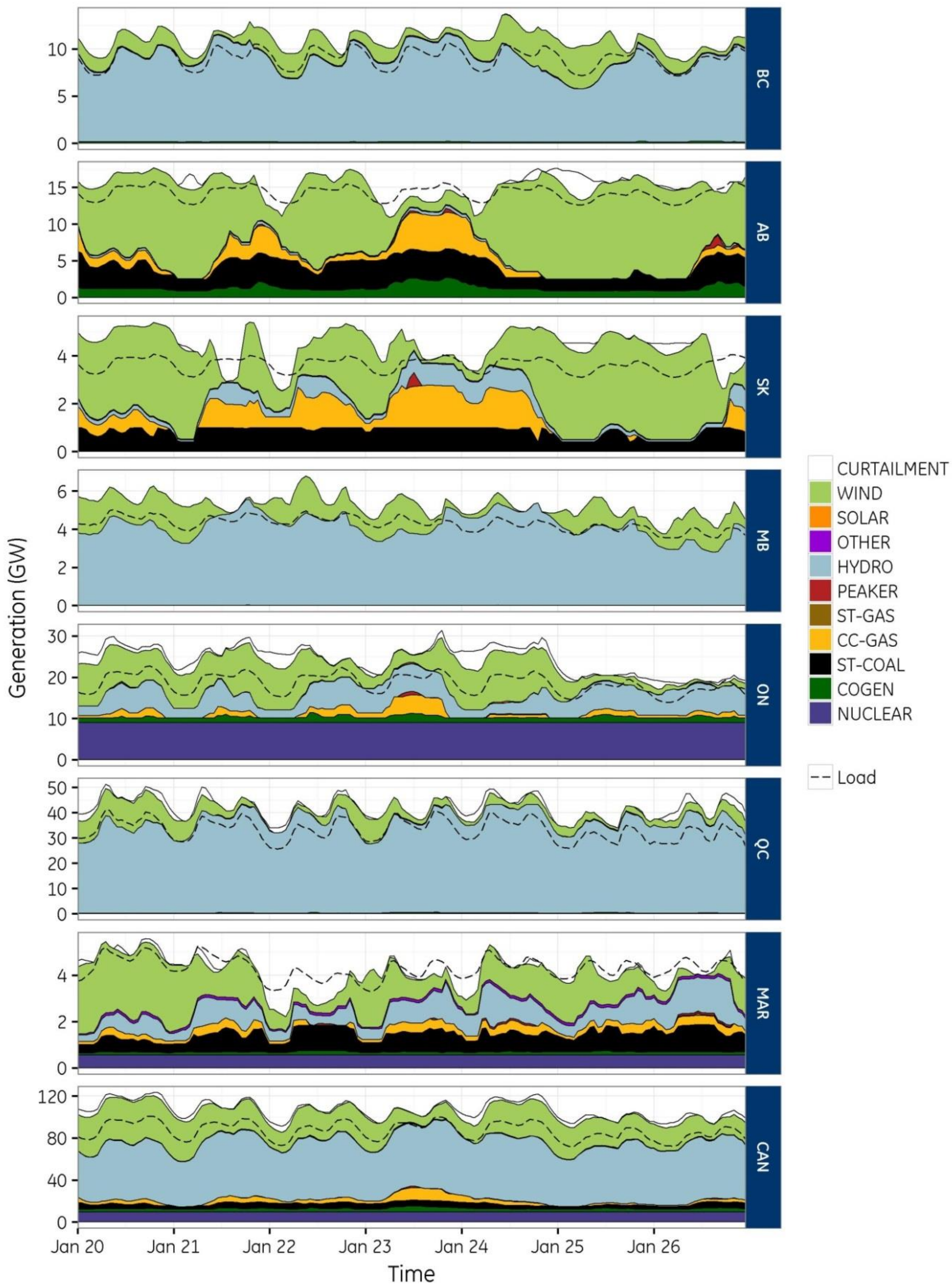


Figure 6-15: Chronological Generation Dispatch by Unit Type and Province for 35% TRGT Scenario

6.4 Operational Performance of Wind Resources

Due to the variable nature of wind and existing operational constraints, adding more wind to the system may result in additional curtailed energy, caused either by increase in supply of generation, or conversely, by low electricity demand in the system in export constrained areas. In the absence of storage, the power grid's generation and load must always remain in balance. If available energy exceeds demand during a particular time period, generation must be decreased. To the extent possible, thermal generators will be decreased first because the higher variable costs of thermal generation. This is subject to system constraints such as must-run requirements of cogeneration units or reliability constraints, minimum run times and down times, and ramp-rate constraints.

After all options for backing down thermal generation are exhausted, the next operational action is curtailment of renewable energy resources, including any grid scale hydro, solar, and wind. However, some types of renewable energy are assumed not to be controllable or dispatchable. For example distributed renewable energy resources are not normally controlled by dispatch signals from system operators. Hence, in most cases, distributed solar energy is assumed to be non-dispatchable, and hence, non-curtailable.

Figure 6-16 shows the amount of wind generation in each province and under each scenario. The blue segment shows the delivered wind energy that is used by the grid and the green segment shows the portion that is curtailed. Note that in this figure, total curtailment includes curtailment from all zero marginal cost resources (wind, solar, and hydro). Therefore the height of the bar exceeds the total available wind energy, because curtailment is shared across the resources. There is little observable curtailed energy in the 5% BAU scenario. But curtailment increases in some provinces with higher penetration of wind, particularly in AB, ON, QC, and MAR.

It should be noted that in this report and related charts and tables, the "curtailed energy" refers to total curtailed renewable energy of all types, including hydro, solar, and wind energy. The reason they are grouped together rather than shown individually is because apart from the transmission reinforcements, wind additions were the only change in the system across the scenarios, and hence, any additional energy curtailment is due to the additional wind. In addition, wind, solar and hydro represent zero marginal cost resources, so the curtailment (also known as spillage for hydro resources) is equally detrimental to system economics. Absent transmission constraints, the choice of which resource to curtail first will likely be dependent on environmental constraints, but the impact to the overall system is the same. See the Inputs and Assumptions Section for more discussion on this topic.

The complimentary nature of wind and hydro resources is more pronounced in Canada due to the abundance of hydro resources with multi-year storage in hydro reservoirs. These reservoirs are better suited to absorb the curtailment, by storing the extra energy for use in later dry years. While some curtailed energy could be stored for later use, eventually some reservoirs may reach their storage limits and lead to further curtailment or spillage.

One peculiar behavior depicted in the Figure 6-16 is the incidence of energy curtailment in MAR in the 20% CONC scenario, and lack thereof in the 35% TRGT scenario. The reason is that the 20% CONC scenario concentrated the wind site location in regions with the best wind resources, and it was only scenario where wind sites were allowed to be selected in Newfoundland and Labrador, based on the quality of the wind resource in the province. In the 20% CONC scenario, the flow of power from that heavy concentration of wind in that region faced transmission constraints downstream from the sources, i.e., intra-provincial transmission constraints in Nova Scotia and additional inter-provincial transmission constraints into New Brunswick, Quebec and New England. The transmission bottlenecks contributed to curtailed energy in MAR in the 20% CONC scenario. The other scenarios have fewer wind resources in MAR and hence less curtailment.

In most cases, additional transmission reinforcement would decrease levels of curtailment. However, based on the transmission reinforcement methodology conducted in this study, additional reinforcement appears to yield decreased economic benefits. This suggests that it is not always economic or optimal to reduce all curtailment on the system.

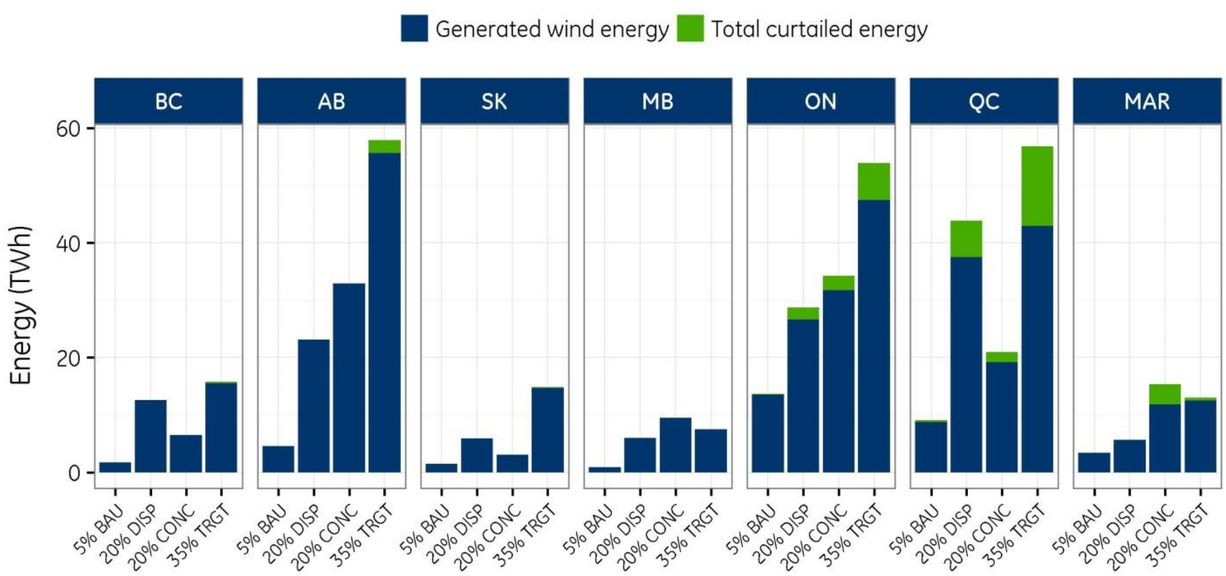


Figure 6-16: Total Wind Generation and Curtailed Energy by Province and Scenario (TWh)

The total curtailed energy relative to the total available wind energy is shown in Figure 6-17 and Table 6-4. The curtailed energy as a fraction of available wind energy increases with higher wind penetration, starting with 1.4% curtailment the 5% BAU scenario and increasing to 11% curtailment in the 35% TRGT scenario.

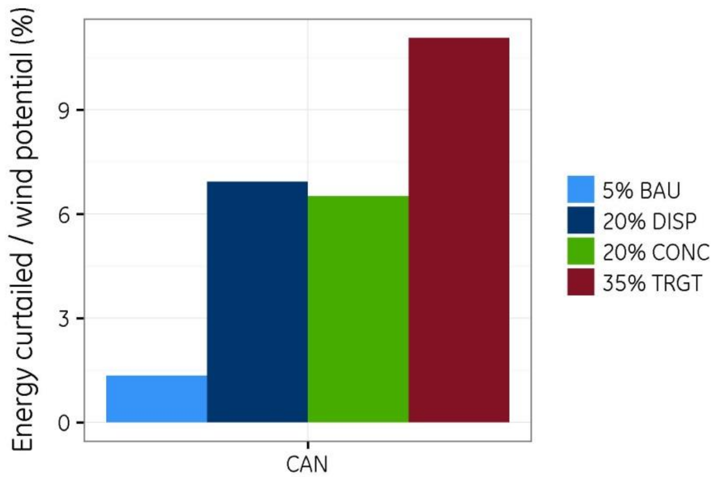


Figure 6-17: Curtailed Energy in Canada as Fraction of Available Wind Energy

As shown in Table 6-4, energy curtailment is most pronounced in ON, QC, and MAR. In the 35% TRGT scenario, the highest penetration level considered in the study, curtailed energy in Canada is about 11% of the available wind energy.

In NB, ON, and MAR, the 20% CONC scenario has more energy curtailment than the 20% DISP scenario. This may be the result of more concentrated deployment of wind plants, leading to more transmission congestion, and therefore, to increased energy curtailment. Furthermore, increased clustering of wind plants accentuates the wind forecast errors, and therefore amplifies the local impact of underestimating real-time wind, and hence contributes to increased local energy curtailment.

Therefore, one important finding is that <u>the higher capacity factors at the best sites do not outweigh the benefits of proximity to the loads</u>. In this study, the DISP scenario benefits from having the wind resources closer to the loads, lowering the risk of transmission congestion that could cause curtailment (as in the CONC scenario). In general, geographic diversity for wind is normally associated with reducing overall variability and forecast error by averaging over a bigger area; but the particular value of geographic diversity here is the placement of the wind resources closer to loads.

Table 6-4: Potential Wind Energy and Curtailed Wind by Province and Scenario

Province	Scenario	Available Wind Energy (TWh)	Delivered Wind Energy (TWh)	Total Curtailed Energy (TWh)*	Curtailment (%)
BC	5% BAU	1.75	1.75	0.00	0.00
BC	20% DISP	12.59	12.59	0.00	0.02
BC	20% CONC	6.52	6.52	0.00	0.00
BC	35% TRGT	15.73	15.50	0.24	1.51
AB	5% BAU	4.53	4.53	0.00	0.00
AB	20% DISP	23.15	23.15	0.00	0.00
AB	20% CONC	32.87	32.87	0.01	0.02
AB	35% TRGT	57.88	55.61	2.27	3.92
SK	5% BAU	1.47	1.47	0.00	0.06
SK	20% DISP	5.92	5.92	0.00	0.00
SK	20% CONC	3.08	3.08	0.00	0.01
SK	35% TRGT	14.80	14.67	0.13	0.89
MB	5% BAU	0.86	0.86	0.03	4.03
MB	20% DISP	6.01	6.01	0.01	0.09
MB	20% CONC	9.49	9.46	0.05	0.53
MB	35% TRGT	7.50	7.49	0.01	0.20
ON	5% BAU	13.61	13.52	0.12	0.90
ON	20% DISP	28.64	26.63	2.09	7.31
ON	20% CONC	34.16	31.74	2.52	7.39
ON	35% TRGT	53.65	47.44	6.44	12.01
QC	5% BAU	9.07	8.76	0.31	3.41
QC	20% DISP	40.12	37.46	6.36	15.85
QC	20% CONC	20.10	19.16	1.79	8.90
QC	35% TRGT	50.13	42.94	13.90	27.73
MAR	5% BAU	3.43	3.42	0.00	0.05
MAR	20% DISP	5.63	5.62	0.00	0.08
MAR	20% CONC	15.36	11.80	3.56	23.18
MAR	35% TRGT	13.04	12.47	0.57	4.35
CAN	5% BAU	34.72	34.31	0.47	1.35
CAN	20% DISP	122.05	117.37	8.47	6.94
CAN	20% CONC	121.58	114.62	7.93	6.52
CAN	35% TRGT	212.73	196.12	23.56	11.08

* Total curtailed energy includes curtailed wind, solar, and hydro energy to account for displacement of all zero-cost marginal resources. Therefore the sum of total curtailed energy and delivered wind energy will not equal available wind energy.

Energy curtailment data presented in the above table are shown graphically, in terms of total annual energy and as a fraction of the total available wind, in Figure 6-18 and Figure 6-19, respectively.

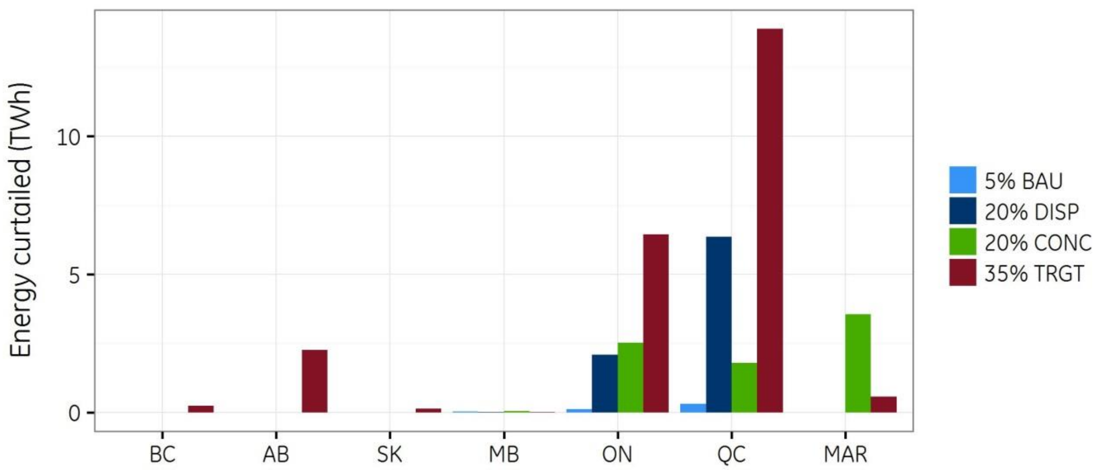


Figure 6-18: Curtailed Energy by Province and Scenario (TWh)

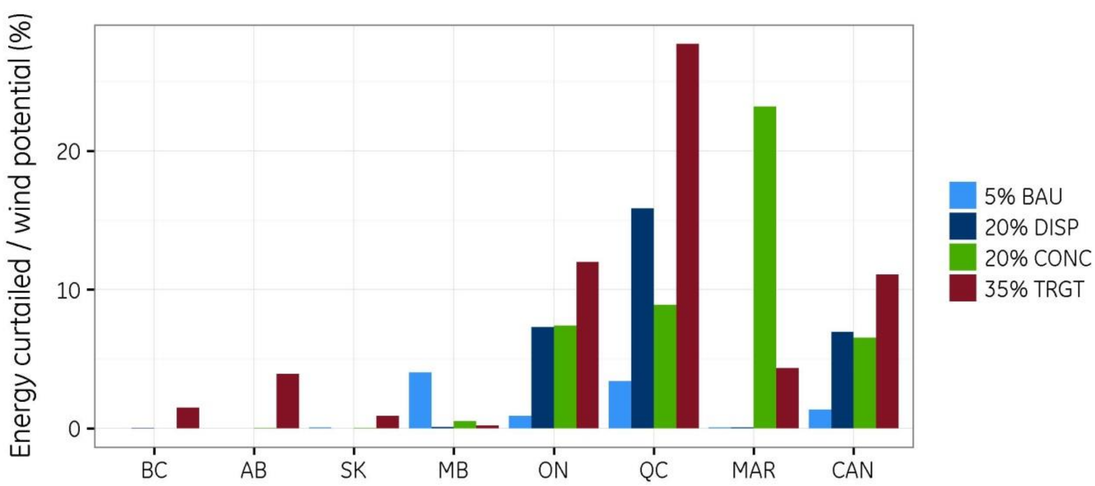


Figure 6-19: Curtailed Energy by Province and Scenario as a Fraction of Available Wind

Figure 6-20 provides a view of available and delivered wind generation relative to load in each province. Curtailed energy is shown as the difference between the potential (dotted line) and the delivered wind generation (solid line). There are some hours when delivered wind is more than 50% of load, and even some hours in AB, MB, SK and MAR when delivered wind is at or more than 100% of load. This does not mean that the provincial grid is running completely on wind energy, but rather represents time periods of exports to neighbouring systems.

A close inspection of the charts confirm that MB overall has the least wind curtailment (difference between projected and delivered wind). In some of the provinces, wind curtailment occurs during in about 1,000 hours of the year (BC, AB, SK, and MB). For others, wind curtailment appears to happen in most hours of the year (ON, QC, and MAR).

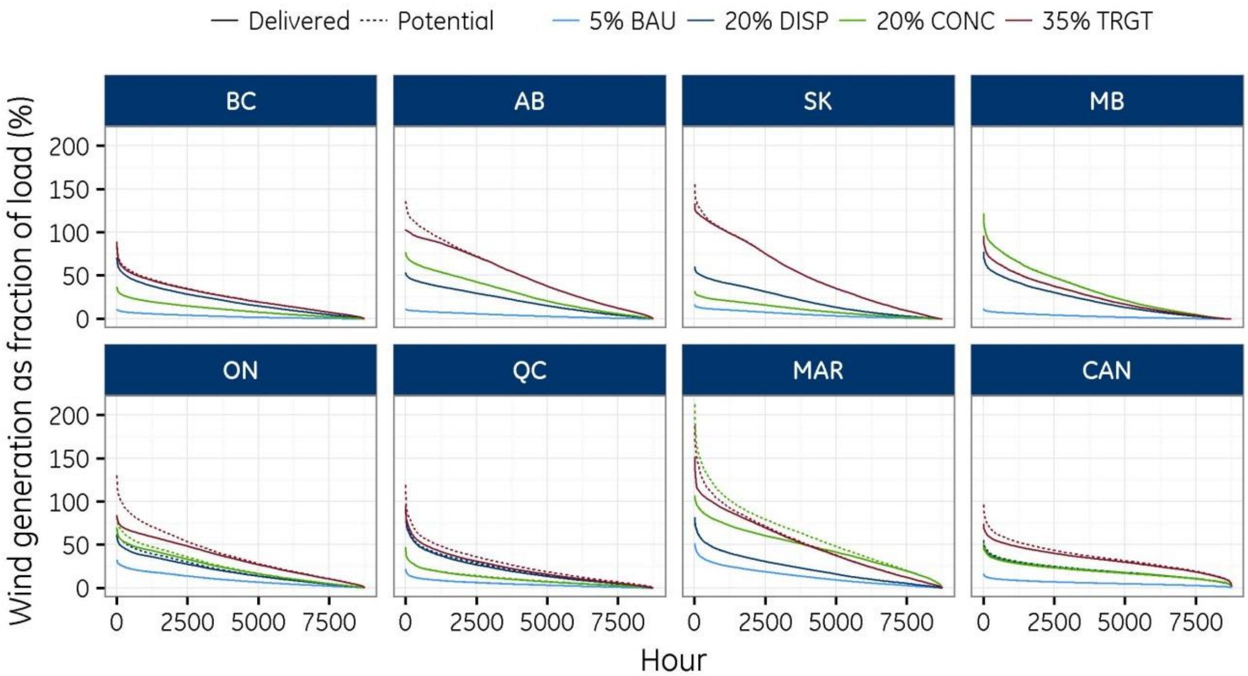


Figure 6-20: Duration Curves of Available and Delivered Wind Energy as a Fraction of Hourly Load

Figure 6-21 displays the curtailed wind duration curve in each province. This curve is actually the difference between the projected wind and delivered wind. This figure highlights the finding that in BC, AB, SK, and MB, wind curtailment occurs in about 1000 hours of the year, and in ON, QC, and MAR, wind curtailment occurs most hours of the year.

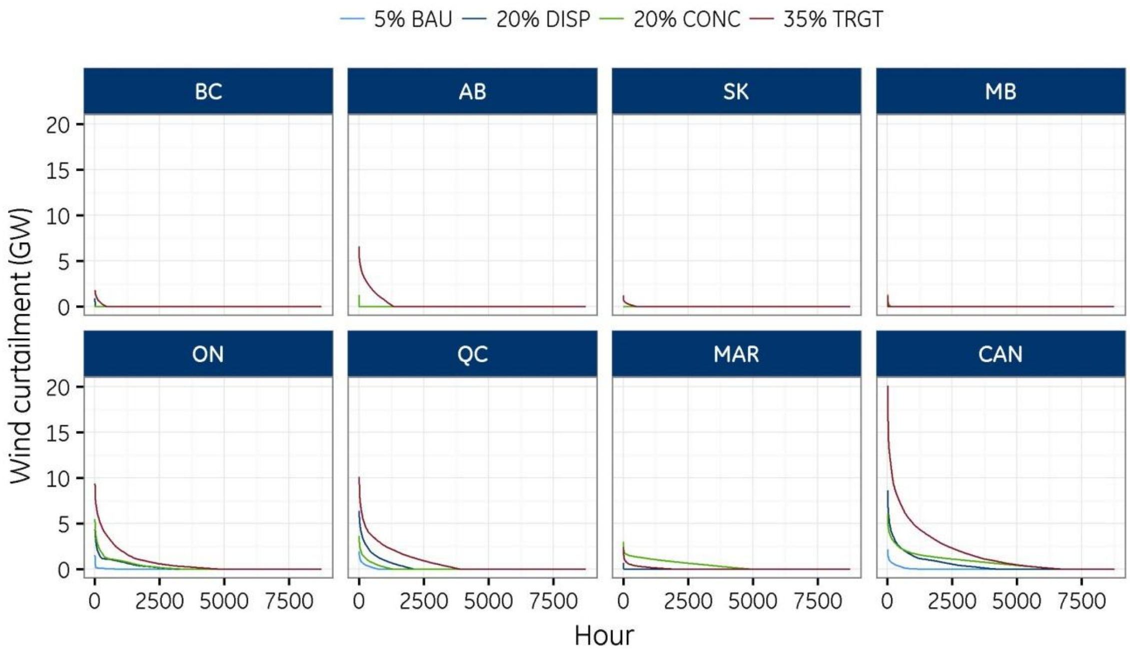


Figure 6-21: Duration Curves of Curtailed Energy in GW by Province

Curtailment by hour-of-day is shown in Figure 6-22 for the four seasons of the year. Energy curtailments are lower during on-peak hours (daytime) and higher during off-peak hours (overnight). This is consistent with the notion that low system load and high wind production occur mostly during off-peak hours, and hence, result in higher levels of energy curtailment during those hours.

The bump in the energy curtailment in the early evening hours is most likely due to forecast errors in QC, with hydro being scheduled against the peak load curve and more wind showing up than expected. In such a case, a good approach to avoid hydro curtailment is to shift the hydro dispatch to a later period.

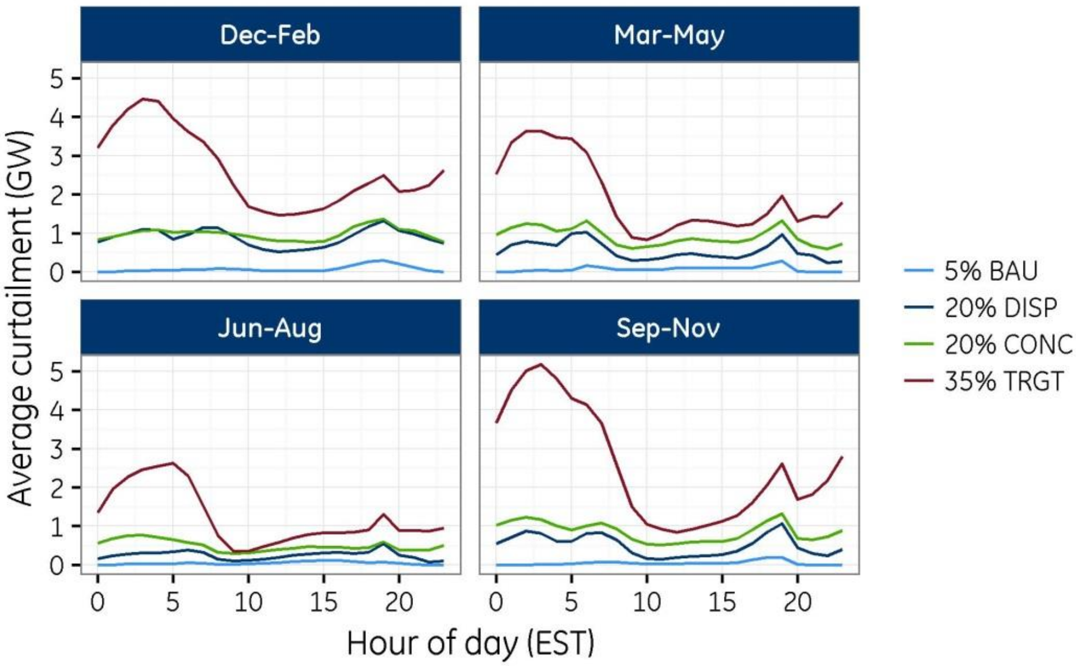


Figure 6-22: Average Hourly Energy Curtailment by Hour of Day for Four Seasons

6.5 Operational Performance of Thermal Generation

Performance of thermal generating units depends mostly on their relative operational costs, which include fuel prices, variable operations and maintenance (VOM) costs, and their operational constraints. Annual generation by unit type in Canada is shown in Figure 6-23. The corresponding capacity factors are shown in Figure 6-24. Both figures illustrate the fact that higher wind penetration results in displacement of mostly CC-GAS, COGEN, and ST-COAL generation. However, not all natural gas units fare similarly. For instance, PEAKER units, which include SC-GAS and IC/RE unit types, are utilized slightly more in the 35% TRGT scenario, reflecting the likely value of relatively more flexible generation to mitigate the higher variability of wind generation and increasing impact of wind forecast errors on grid operations.

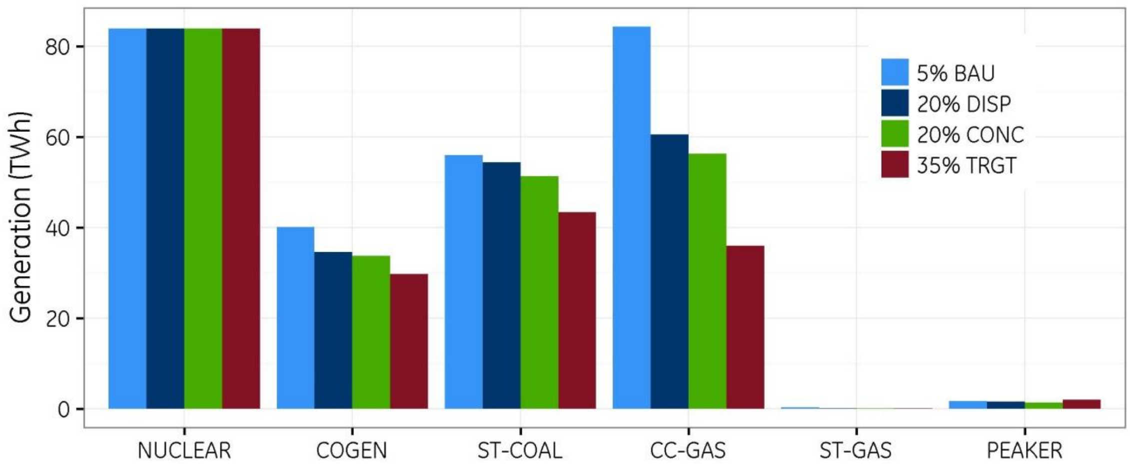


Figure 6-23: Generation of Thermal Units by Unit Type and Scenario (TWh)

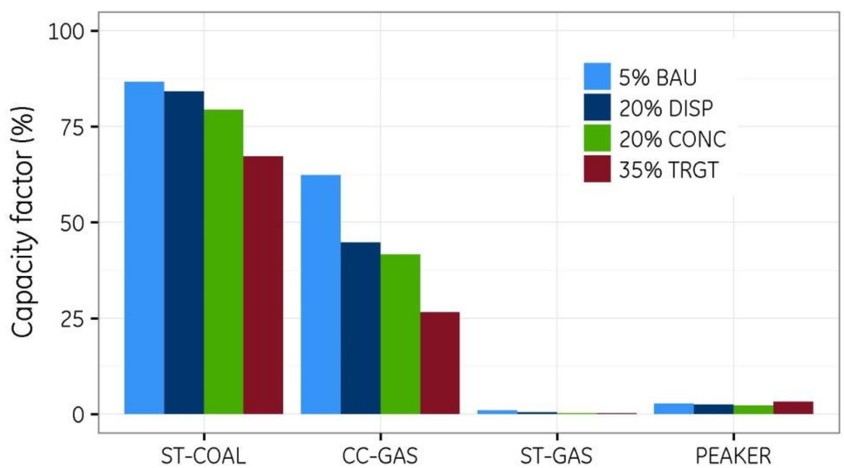


Figure 6-24: Average Capacity Factor by Unit Type and Scenario

Figure 6-25 shows the average number of starts per year, average number of hours online per start, and average hours online, by unit type and scenario. With higher wind penetration, both ST-COAL and CC-GAS units experience more starts and fewer hours online. PEAKER units experience more starts and more hours online.

A fairly typical impact is that in low wind energy situations (as in 5% BAU scenario), PEAKER units are used to meet peak demand, but get displaced as more wind is added to the system (as in 20% scenarios). But at significantly higher penetration levels (as in 35% TRGT scenario), PEAKER units are again used more to meet the higher wind forecast errors. With the higher wind forecast errors in the 35% TRGT scenario, there is a great deal of de-commitment.

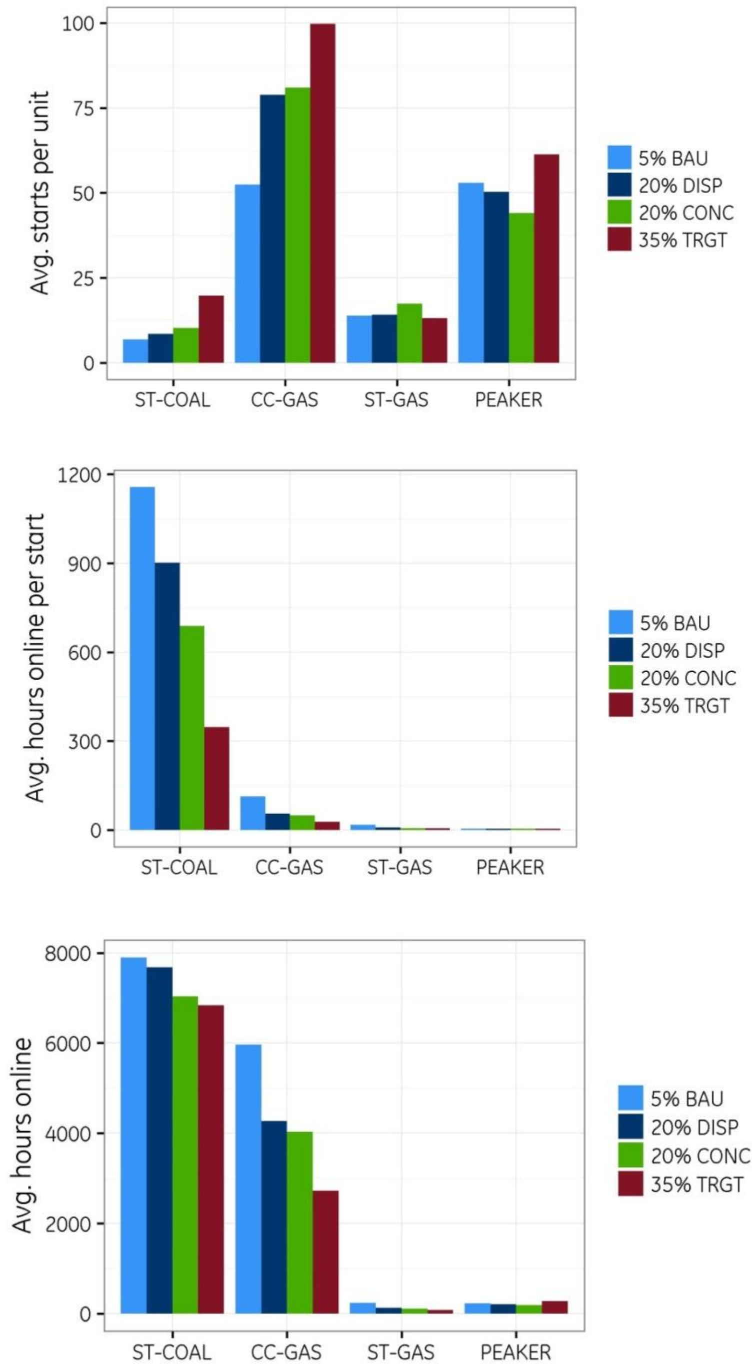


Figure 6-25: Average Annual Starts and Hours Online by Unit Type and Scenario – All Canada

Average annual starts, hours online per start, and average hours online by unit type are also provided in Table 6-5. CC-GAS units have more starts than PEAKER units. One reason could be that CC-GAS units are mid-range units and tend to cycle more with more wind in the system. PEAKERS start fewer times in the year, and as their name indicates, mostly when needed during peak hours of the year or during large (relatively rare) wind forecast errors.

CC-GAS units have more starts that PEAKERs, mainly because CC-GAS units are needed more than PEAKERS – since they are midrange units and cycle more due to additional wind energy variability.

Table 6-5: Average Starts and Hours Online by Unit Type and Scenario

Unit Type	5% BAU	20% DISP	20% CONC	35% TRGT
Average Starts per Unit				
ST-COAL	6.8	8.5	10.2	19.7
CC-GAS	52.4	78.9	81.0	99.8
ST-GAS	13.9	14.1	17.4	13.1
PEAKER	52.9	50.4	44.1	61.3
Average Hours Online per Unit				
ST-COAL	7,900	7,678	7,034	6,837
CC-GAS	5,963	4,275	4,033	2,722
ST-GAS	236	127	104	77
PEAKER	231	209	188	274
Average Hours Online per Start				
ST-COAL	1,162	903	690	347
CC-GAS	113.8	54.2	49.8	27.3
ST-GAS	17.0	9.0	6.0	5.9
PEAKER	4.4	4.1	4.3	4.5

Figure 6-26 to Figure 6-29 show these thermal unit performance indicators broken down by province.

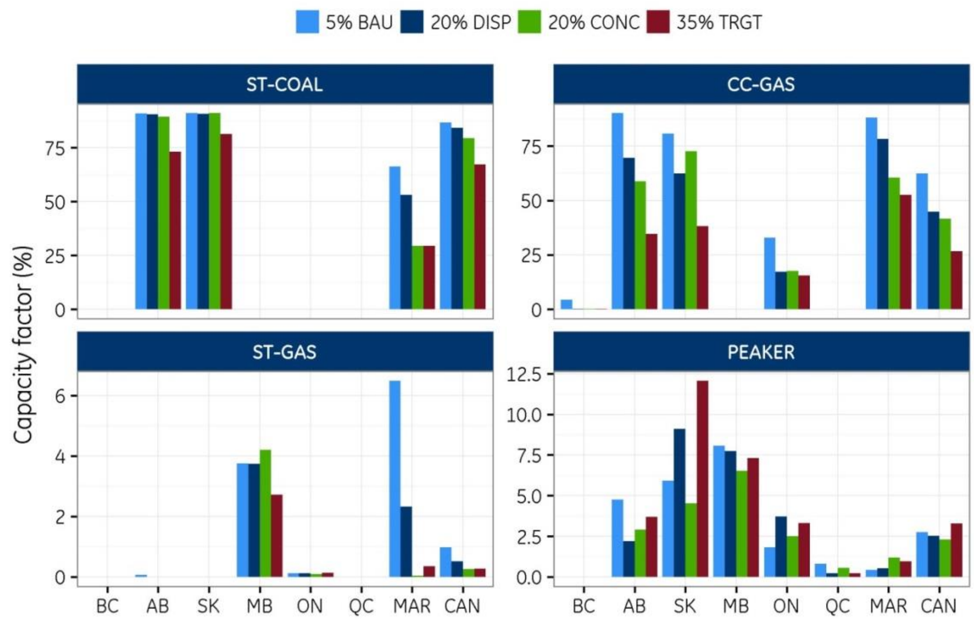


Figure 6-26: Average Capacity Factor by Unit Type, Province, and Scenario

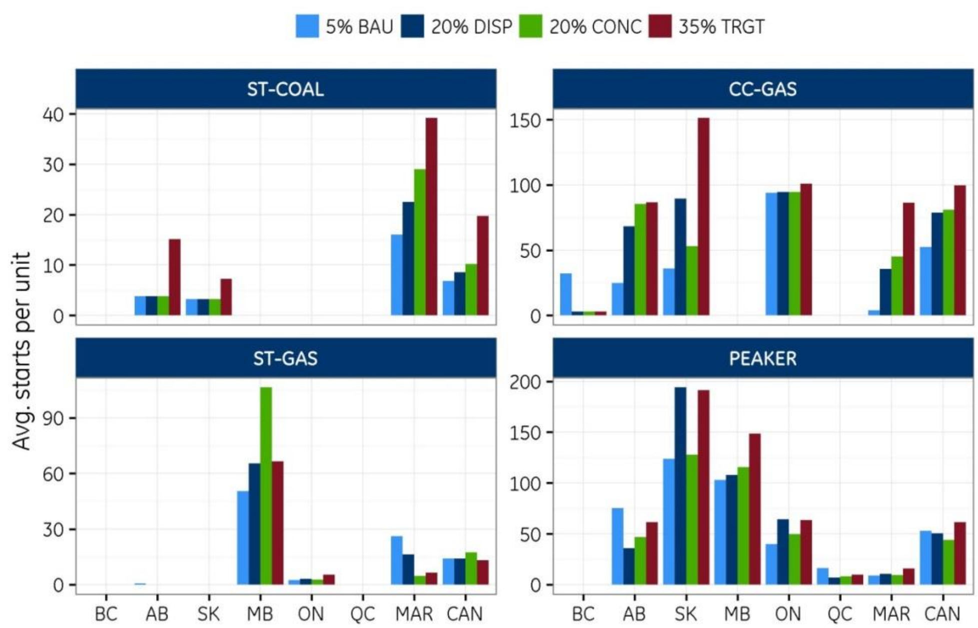


Figure 6-27: Average Number of Starts Unit Type, Province, and Scenario

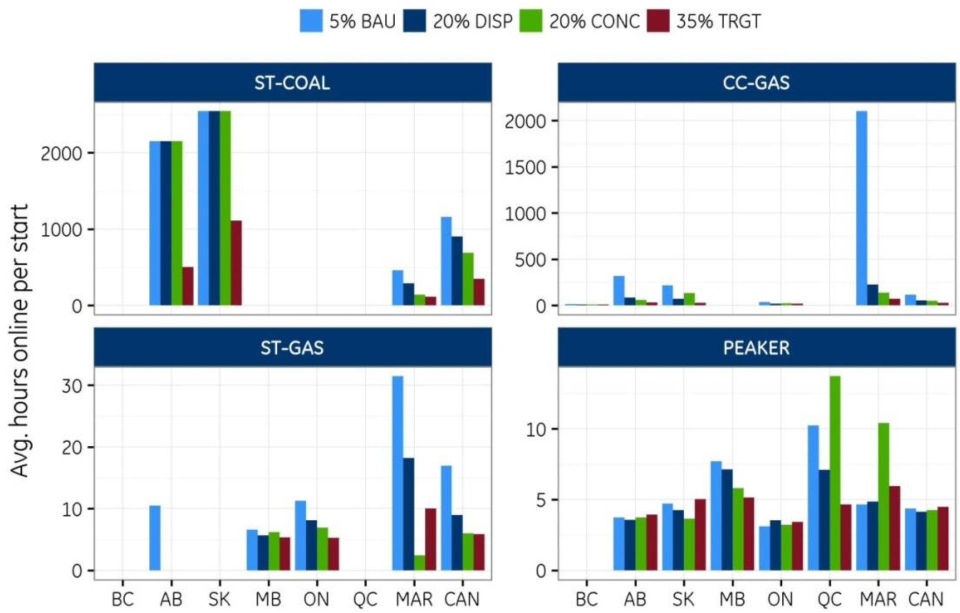


Figure 6-28: Average Hours Online per Start by Unit Type, Province, and Scenario

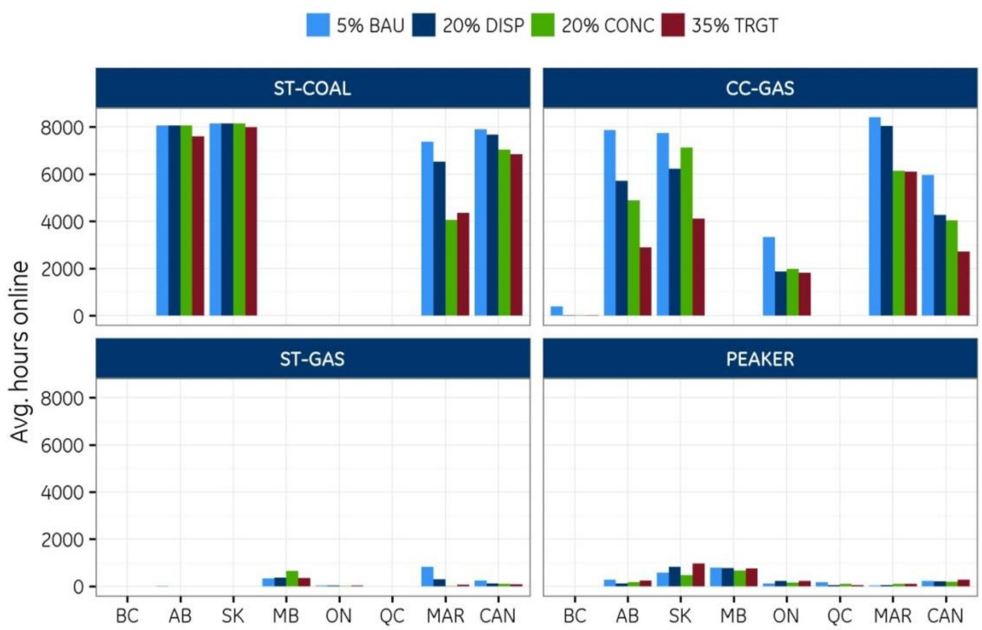


Figure 6-29: Average Hours Online by Unit Type, Province, and Scenario

In summary, as more wind energy is added to the system:

- ST-COAL units: Capacity factor drops, average number of starts goes up, average hours online per start goes down, and average hours online is generally reduced. Therefore, the drop in energy production is accompanied with more on/off cycling.
- CC-GAS units: Follow a similar pattern to ST-COAL, but are impacted more than ST-COAL units. Their reduction in capacity factor is more pronounced, they generate less energy, and they cycle more often. This is because they are marginally more expensive than the ST-COAL units and therefore will be displaced first.
- ST-GAS and PEAKER units: The ST-GAS and PEAKER fleet represents the most expensive form of generation across the system. Therefore they are the first to be displaced by additional wind energy. However, because the units were used very rarely in the 5%BAU case to begin with, the higher wind penetration does not yield significant decrease in their utilization. However, in the highest wind penetration scenario (35% TRGT) the PEAKER units are utilized to cover wind forecast errors during times when baseload units (ST-COAL and CC-GAS) were already cycled offline (de-committed).

6.6 Unit Commitment versus Hourly Economic Dispatch

Deviation of the forecasted wind generation (used in the day-ahead commitment) from the real-time wind generation (used in the economic dispatch process) results in either over- or under-commitment of the thermal units. Figure 6-30 and Figure 6-31 display weekly patterns of unit commitment and hourly dispatch of ST-COAL and CC-GAS, respectively, during a selected week in the year. Unit commitment is represented by solid lines at the top of each plot. Economic dispatch is represented by shaded areas. Periods where the shaded area reaches the solid line represents time periods where the committed ST-COAL or CC-GAS fleet are running at max output. When there is a gap between the shaded region and the solid line, the fleet is dispatched to lower loading levels and there is increased headroom on the units.

Due to its lower generation cost, ST-COAL is committed mainly as baseload unit. In the lower wind penetration scenarios, ST-COAL commitment has a more of a uniform pattern across many hours during the week, with economic dispatch of nearly all of the committed capacity. Higher wind penetration causes a less uniform unit commitment and a more patchy economic dispatch of the committed capacity. In the 35% TRGT scenario, more wind is causing more displacement of the ST-COAL units.

Due to their relatively higher generation costs, CC-GAS units are committed more as mid-range units, which are illustrated by a peak and valley commitment patterns where some CC-GAS units are cycled offline during low-load, overnight periods. Additional wind appears to push the CC-GAS commitment downward and further with additional wind in each scenario, and at the same time reduce the size the dispatched capacity relative to the committed capacity.

Both figures clearly illustrate the incremental displacement of CC-GAS and ST-COAL generation with higher wind penetration. It should be noted that some of the unused committed capacity may represent capacity set asides as operations reserves, including variability regulation reserve.

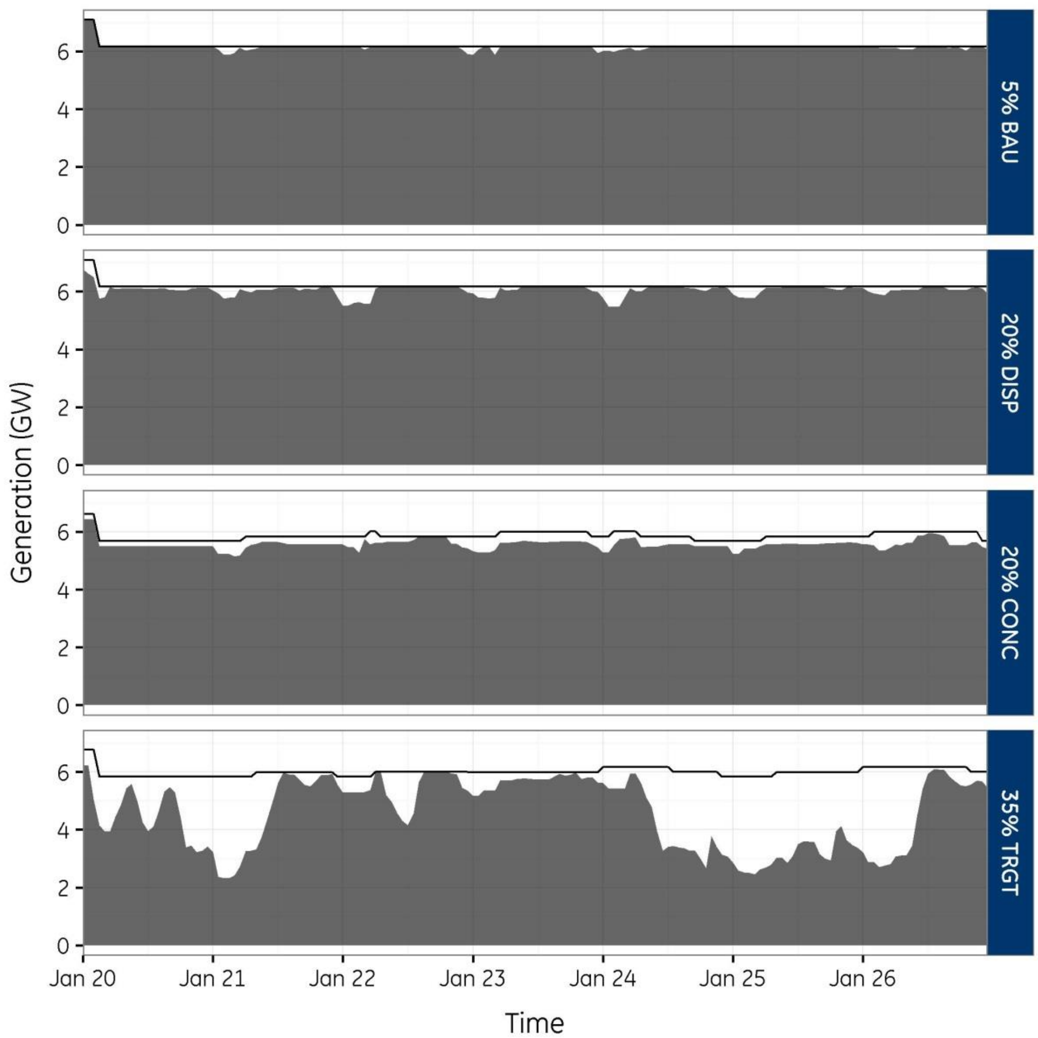


Figure 6-30: Day-Ahead Unit Commitment (Solid Line) and Hourly Economic Dispatch (Shaded Area) of ST-COAL Units

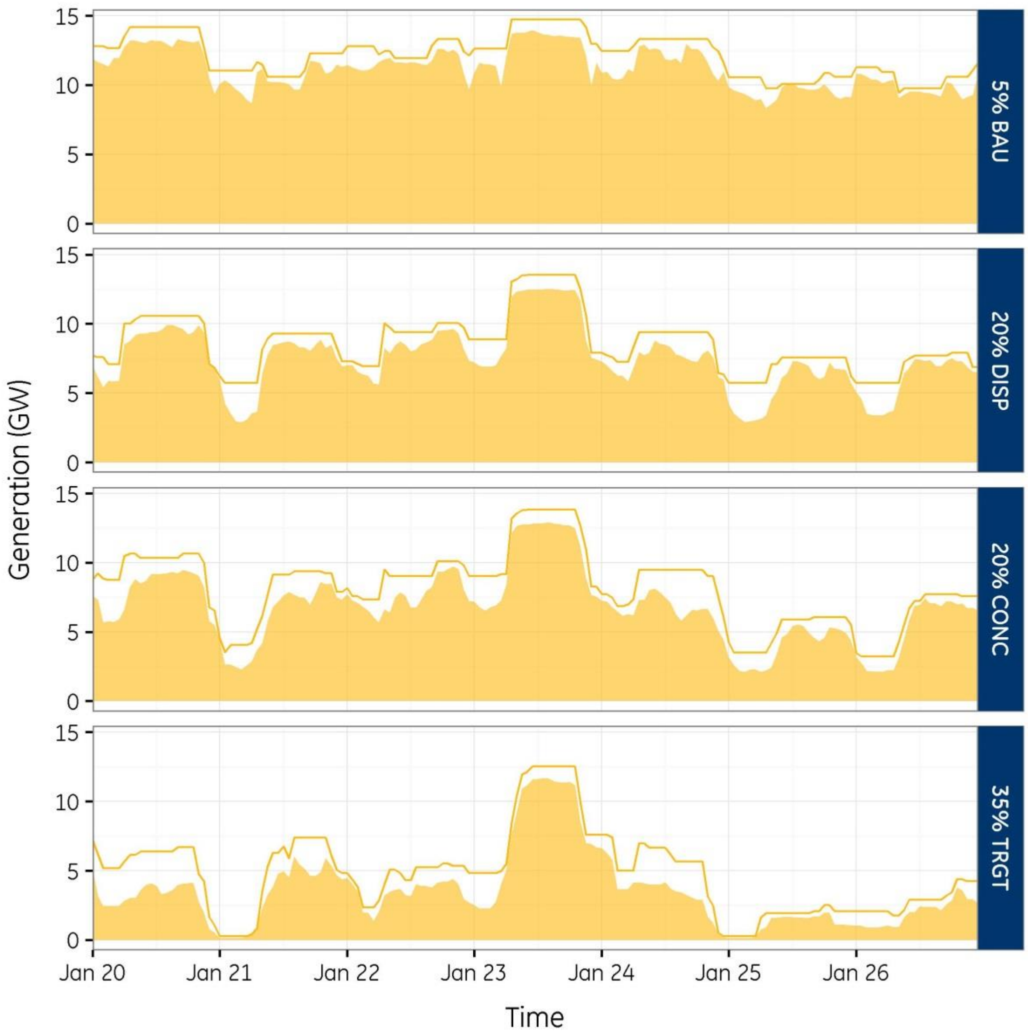


Figure 6-31: Day-Ahead Unit Commitment (Solid Line) and Hourly Economic Dispatch (Shaded Area) of CC-GAS Units

6.7 Exports and Interface Flows

Canada and the USA share interconnected power grids and exchange energy as a normal course of operations. Energy exchanges are governed by established energy contracts and market forces. As noted earlier, higher wind penetration in Canada results in increased net exports from each province in general and from Canada to the USA in particular. This is simply the outcome of deploying more zero marginal cost generation in Canada which tends to displace costlier generation both in Canada and in the USA, hindered only by transmission constraints on the interconnected electric grid.

Figure 6-32 shows the size of net exports from Canada to the USA under the four study scenarios, which increase with higher penetration of wind energy. The difference between the 20% DISP and 20% CONC scenarios is due to the difference in geographic placement of wind plants across Canada and the transmission reinforcements in each of these two scenarios. The net exports are increased from about 70 TWh of electric energy in the 5% BAU scenario to about 150 TWh of electric energy in the 35% TRGT scenario.

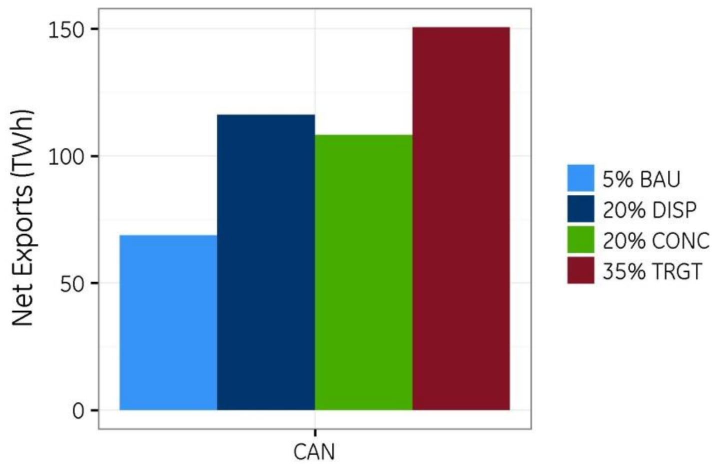


Figure 6-32: Net Exports by Scenario – Canada Total

Corresponding data for provinces are shown in Figure 6-33 and Table 6-6. The largest exports are from the hydro-rich provinces, mainly because there are fewer fossil based generation resources that can be displaced by wind in those provinces. The only net importing provinces are AB and MAR, but only in the 5% BAU scenario. In the other three study scenarios, all of the provinces are net exporters. Again, the difference in export patterns of the 20% DISP and 20% CONC is mainly due to the difference in geographic placement of the wind plants and the transmission reinforcements of the two scenarios. In general, and by coincidence, the wind locations in the 20% CONC scenario was concentrated in provinces with more thermal generation to displace, rather than in hydro provinces which tended to export additional energy added to the system.

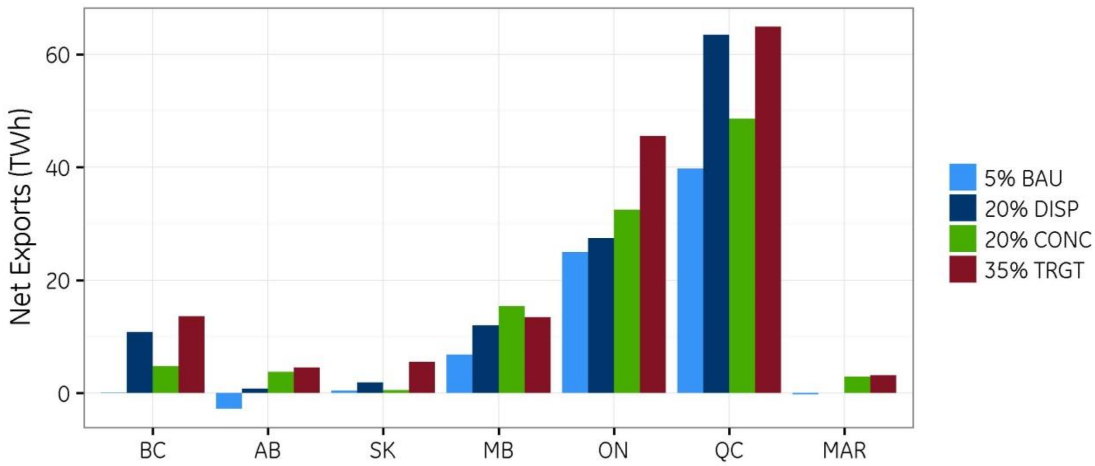


Figure 6-33: Net Exports by Province and Scenario

Table 6-6: Net Exports by Province and Scenario (TWh)

Province	5% BAU	20% DISP	20% CONC	35% TRGT
BC	0.06	10.79	4.73	13.56
AB	-2.78	0.77	3.72	4.51
SK	0.40	1.85	0.53	5.53
MB	6.78	11.95	15.37	13.41
ON	24.94	27.41	32.44	45.55
QC	39.71	63.44	48.54	64.90
MAR	-0.26	0.03	2.90	3.14
CAN	68.84	116.25	108.24	150.61

Figure 6-34 displays side by side the net exports and the wind generation in each province. There is a general correlation between net exports in each province and whether the province is hydro-rich or thermal-heavy. Being a wind-rich province does not necessarily imply more net exports, as exemplified by the case of AB. In that province, more wind is actually displacing province's own thermal generation. Hydro-rich provinces do not have much thermal generation that would be displaced by the additional wind.

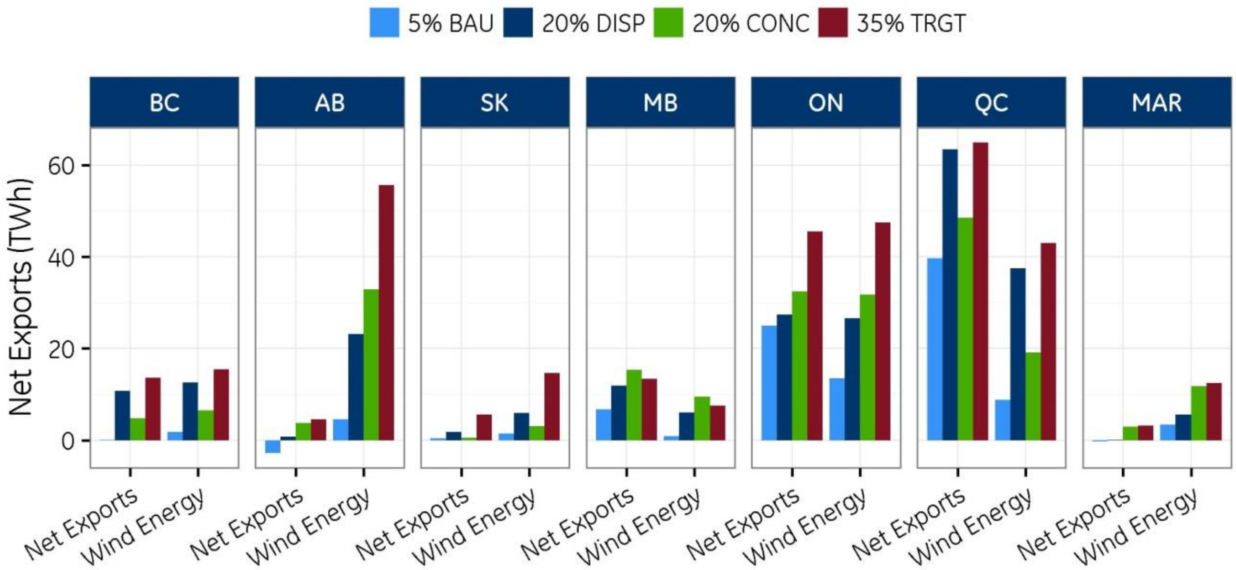


Figure 6-34: Net Export Relative to Wind Energy by Province and Scenario

As can be seen in Figure 6-35 and Table 6-7, there is a good correlation between net exports and whether a province is hydro-rich. The solid black line in Figure 6-35 represents a 1:1 ratio of wind energy to export energy. Changes in net exports in BC, MB, and QC are better aligned with additional wind, compared to AB, ON, and MAR.

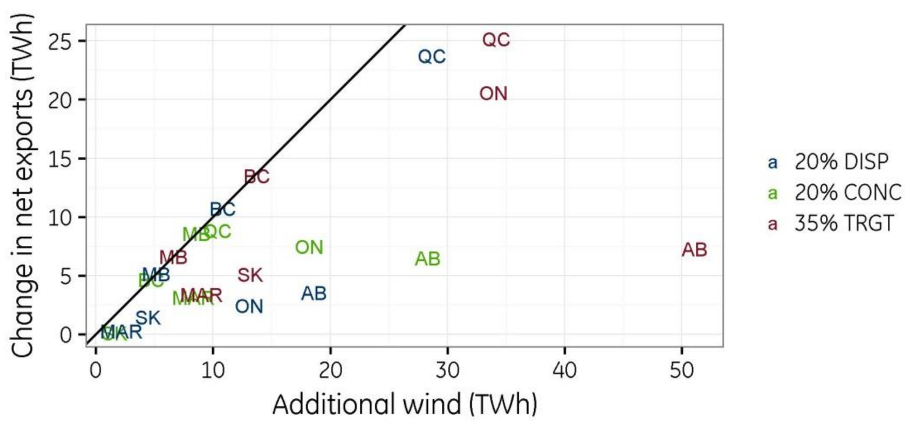


Figure 6-35: Change in the Net Exports Relative to Additional Wind in Each Province and Scenario Relative to the 5% BAU Scenario

Table 6-7: Export to Wind Ratio in Each Province

Province	20% DISP	20% CONC	35% TRGT
BC	99%	98%	98%
AB	19%	23%	14%
SK	32%	7%	39%
MB	100%	100%	100%
ON	19%	41%	61%
QC	83%	85%	74%
MAR	13%	38%	38%

Export to Wind ratio for all of Canada is shown in Table 6-8.

Table 6-8: Export to Wind Ratio in Canada

	4% BAU	20% DISP	20% CONC	35% TRGT
Total Delivered Wind (GWh)	34,312	117,382	114,624	196,094
Total Generation (GWh)	678,833	726,222	718,180	760,4956
Incremental Wind (GWh)	-	83,070	80,312	161,782
Incremental Exports (GWh)	-	47,389	39,347	81,662
Exports/Wind Ratio	-	57%	49%	50%

Figure 6-36 shows power flow duration curves for all the inter-province and inter-country tie lines for each of the four study scenarios. The primary characteristics of the power flow duration curves are as follows:

- Y-Axis is the power flow in MW and X-Axis hours of the year.
- Power flows are sorted from the hour with the highest flow in the forward direction to the lowest net flow (high flows in the reverse direction).
- Duration curves are bi-directional: they cover both positive and negative flows across the interfaces.
- Flat lines at the high flow limits (positive or negative) represent the maximum interface limits. The extended flat lines represent the hours when an interface constraint (i.e., transmission capacity transfer limit) is binding.
- Flat lines at zero flow level represent the hours with no net exports. In these hours, the marginal cost of generation on both sides of the interface are close to one another and do not exceed the economic "hurdle rate" between the two systems.
- Some interface limits are different in each scenario due to transmission reinforcements, which is why for interfaces such as SK to US, the high limits vary by scenario.

A number of observations can be made from these curves:

- Under almost all of the scenarios, flows on the Canada-USA interfaces are mostly in the forward (positive) direction, from Canada to the USA,
- A major exception is the AB to US flow in the 5% BAU scenario, where most of the hours AB is an importer of power. AB becomes a net exporter in higher wind penetration scenarios.
- AB is an exporter to BC most of the time with increased wind penetration,
- SK is an exporter to MB as wind penetration increases, and in turn, MB is an exporter to ON and the USA.
- QC is an exporter to ON most of the time
- QC is also an exporter to MAR most of the time

Hence, the salient features of the power flows over the monitored transmission interfaces are:

- In the Western Interconnection (BC and AB), in most scenarios, power flows mostly to the West and to the South
- In the Eastern Interconnection, in most scenarios, power flows to the South and also from the West to the Center (i.e., ON) and from the East to the Center

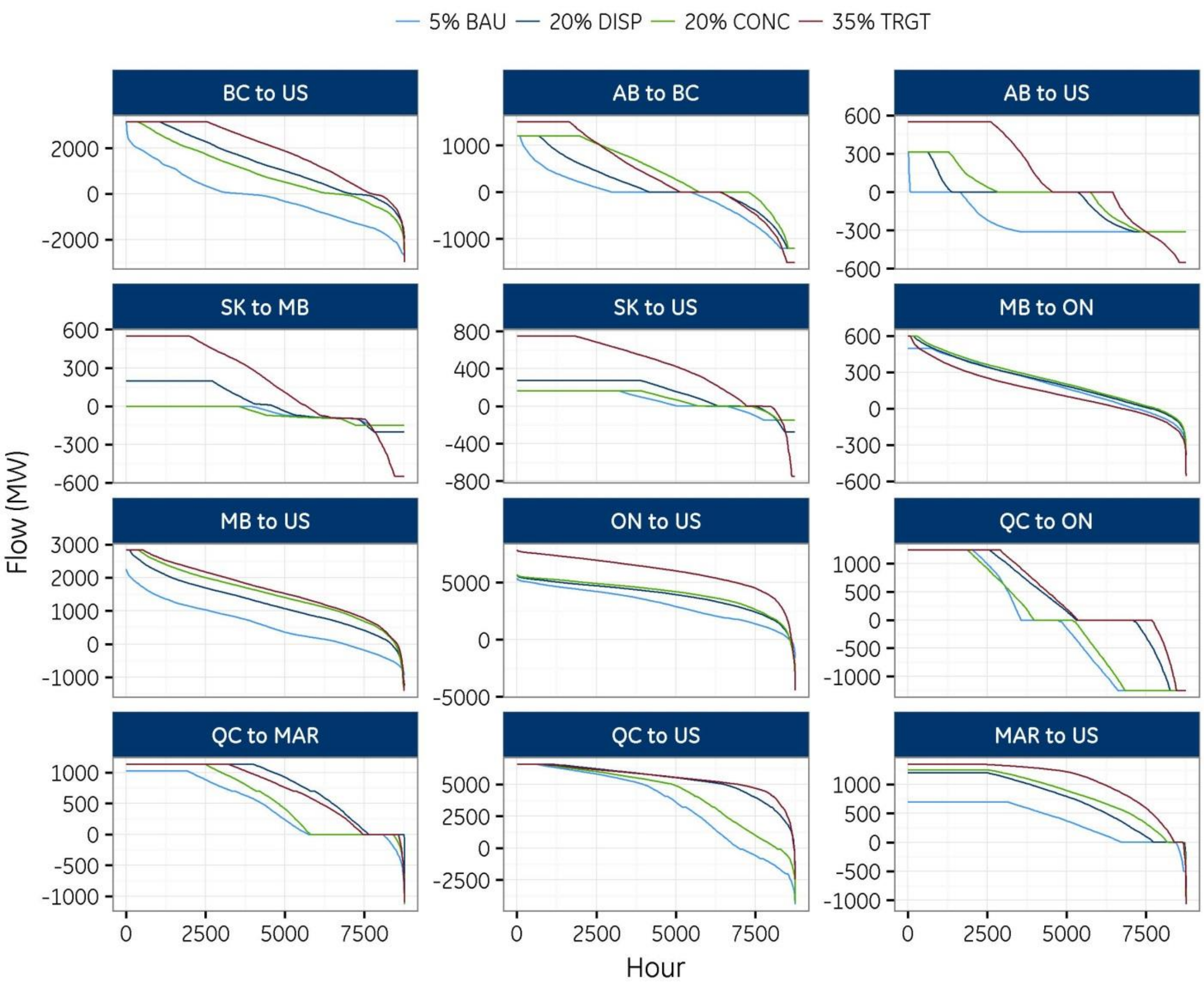


Figure 6-36: Inter-Provincial and Canada USA Power Flow Duration Curves by Scenario

6.8 Environmental Emissions

One prominent impact of additional wind energy in the Canadian power system is the displacement of the fossil fuel based thermal generation, both in Canada and in the USA. Fossil fuel based generation is principal source of environmental emissions in the electricity sector in Canada, including both Criteria Air Contaminants (CAC) such as Sulfur Oxides (SO_X) and Nitrogen Oxides (NO_X), and also the Greenhouse Gases (GHG) such as CO_2. Therefore, an important benefit of higher penetration of wind in Canada is the corresponding reduction of system-wide CAC and GHG emissions in both Canada and USA.

As shown in Figure 6-37, absolute amount of CAC and GHG emissions in both Canada and USA are reduced significantly in higher penetration wind scenarios relative to the 5% BAU scenario. Increased electricity exports to the USA - resulting from higher penetration of zero marginal cost wind energy - produce a greater reduction in environmental emissions in USA compared to Canada.

The reductions in SO_X, NO_X, and CO_2 relative to the 5% BAU scenario are shown in the left-hand side of Figure 6-37. The reductions in environmental emissions are clearly larger in the USA than in Canada. More fossil-based generation is being displaced in the USA than in Canada. In other words, higher wind penetration in Canada essentially results in environmental benefits that are shared by both Canada and the USA, in the form of reduction in CAC and GHG emissions.

The charts in the right-hand side of Figure 6-37 show the emissions intensities of all types of generation, in Canada and USA. Emission intensities for both CAC and GHG pollutants are successively reduced with each additional level of wind penetration. Reductions in emission intensities are more discernable in Canada, because of the size of additional wind, and hence, the emissions reductions, relative to the overall generation capacity base of Canada.

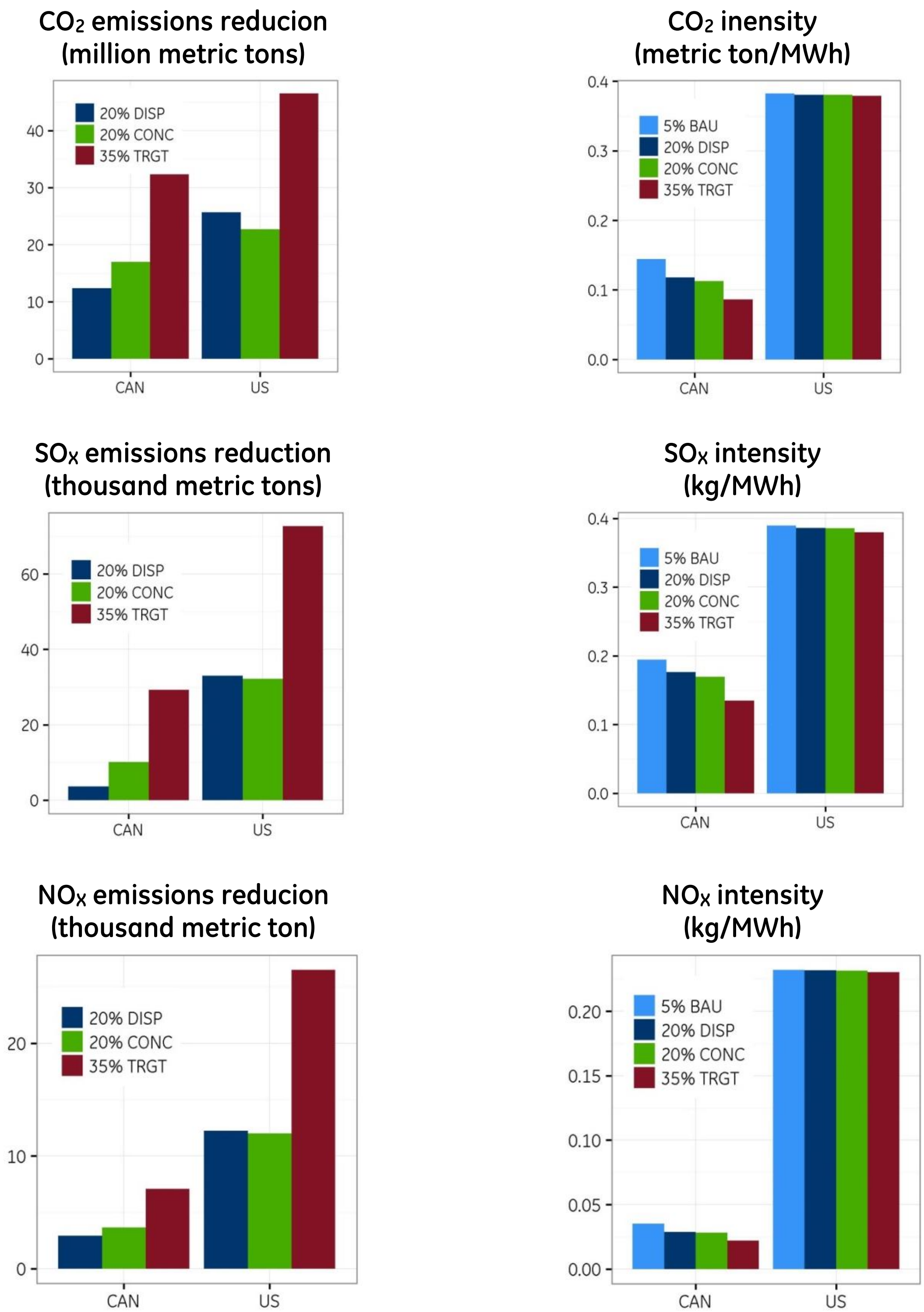


Figure 6-37: Emission Reduction from the 5% BAU Scenario and Intensity by Country

Emissions amounts and emission intensities in Canada and USA for each study scenario are also presented in Table 6-9.

Table 6-9: Canadian and USA Emissions by Scenario

Province	Scenario	CO2 emissions (million metric ton)	CO2 intensity (metric ton/MWh)	SOX emissions (thousand metric ton)	SOX intensity (kg/MWh)	NOX emissions (thousand metric ton)	NOX intensity (kg/MWh)
CAN	5% BAU	98,0	0.14	131.9	0.19	23.9	0.04
CAN	20% DISP	85.7	0.12	128.3	0.18	21.0	0.03
CAN	20% CONC	81,0	0.11	121.8	0.17	20.3	0.03
CAN	35% TRGT	65.7	0.09	102.6	0.13	16.8	0.02
US	5% BAU	1611.6	0.38	1642.3	0.39	977.9	0.23
US	20% DISP	1586.0	0.38	1609.3	0.39	965.7	0.23
US	20% CONC	1588.9	0.38	1610.1	0.39	965.9	0.23
US	35% TRGT	1565.1	0.38	1569.6	0.38	951.4	0.23

6.9 Economic Performance

6.9.1 Operational Economic Metrics

The Pan-Canadian Wind Integration Study (PCWIS) was performed to assess the implications of integrating large amounts of wind in Canada's electricity system. Previous sections provided an assessment of the operational implications of how variable wind energy resources would impact the power grid. This section provides an improved understanding of the operational cost and benefits associated with integrating large amounts of wind.

The economic data and results are expressed in 2016 Canadian dollars. The ("$") and ("C$") symbols represent 2016 Canadian dollars in all text, tables and figures.

Throughout the work reported here, the focus is on "variable operating cost", also known as "production cost", which is the critical operational economic metric. Production cost is not the total cost incurred to serve load, but rather it is the component of cost that varies with operation, and which can be affected by operating decisions. Production costs reported in this study include the following:

- Fuel expense (the largest component by far)
- The costs of starting and stopping plants
- The costs of operation and maintenance that vary with energy produced, i.e., variable operations and maintenance (VO&M) cost

- Any applicable emissions costs

Other costs are fixed and do not count towards production cost. Examples of fixed costs Include the following:

- The cost of capital for all plant and equipment
- The cost of capital for all grid investment
- The fixed cost of operation and maintenance independent of energy production (i.e. the cost that a plant incurs just to stay able to produce power)
- Financial transactions based on market rules or bilateral and power purchase agreements (PPA)

While these costs play a role in whether to invest in a new plant or keep a plant in service, they play no role in operational decision making. The cost of producing hydroelectric power is also fixed. This is less intuitive, but the fuel is free and the other costs do not vary with energy produced. Consequently, the operational consideration for hydro power is how to use it to its best advantage to reduce the operational costs that are variable.

This logic applies to wind power as well: the "fuel" has no cost. Although there is a cost for payments to some independent power producers, power purchase agreement (PPA) price has no impact on system operations as wind will always be accepted by the grid, unless it needs to be curtailed or exported when there is surplus wind energy generated.

In summary:

$$\boldsymbol{Production\ Cost = Fuel\ Cost + VOM\ Cost + Emissions\ Cost + Startup\ Cost}$$

Nevertheless, production cost alone is not an adequate metric for the assessment of the economics of the grid operations. This is especially true in Canada, where the hydro-rich provinces (BC, MB, QC) have very low variable operating costs. In addition, the large volume of exports engendered by the high amount of wind, particularly in the study scenarios with higher wind penetration. Therefore, with a sizable portion of generated power being exported, the production costs need to be adjusted by accounting for the export revenues and import costs (or for short "net export revenue"). Hence, the appropriate metric to be employed is the Adjusted Production Cost, defined as:

$$\boldsymbol{Adjusted\ Production\ Cost = Production\ Cost - Net\ Export\ Revenue}$$

The Net Export Revenue is calculated by summing across the year the hourly export revenues minus the hourly import costs. Hourly net export revenue on each tie-line is the product of the hourly outflow times the LMP at the receiving node of the tie-line.

Under some of the study scenarios or sensitivity cases, in some of the provinces the substantial size of exports may result in annual net export revenues to be greater than the annual production costs. This is particularly true in the case of BC, MB, and QC; because a considerable portion of their generation capacity is based on zero variable cost hydro resources, which results in minimal annual production costs in those provinces.

Figure 6-38 and Table 6-10 summarize economic impacts of the wind resources on the annual costs of system-wide operations in Canada. These individual cost/revenue components are shown for each study scenario.

As expected, production costs decrease with higher penetration of wind. Higher penetration of zero variable cost wind has two main economic consequences: (a) it displaces higher cost fossil fuel based generation, resulting in in reduction of the system-wide production costs in Canada, and (b) it increases the supply of zero cost energy in Canada, which competes with higher cost fossil-fuel generation in the USA; therefore, increasing exports to the USA and resulting in increase in net export revenues.

When increasing net export revenues are taken into account, then the adjusted production cost (i.e., production cost minus net export revenue), is further reduced, to the extent that under the 35% TRGT scenario, the adjusted production cost becomes positive. In other words, the net export revenues more than compensate for the total cost of production in Canada.

Table 6-10: All Canada Production Cost and Net Export Revenue by Study Scenario

	5% BAU	20% DISP	20% CONC	35% TRGT
Production Cost (C$M)	10,254	8,569	8,135	6,713
Net Export Revenue (C$M)	5,608	7,709	7,587	9,278
Adjusted Production Cost (C$M)	4,646	860	548	-2,565

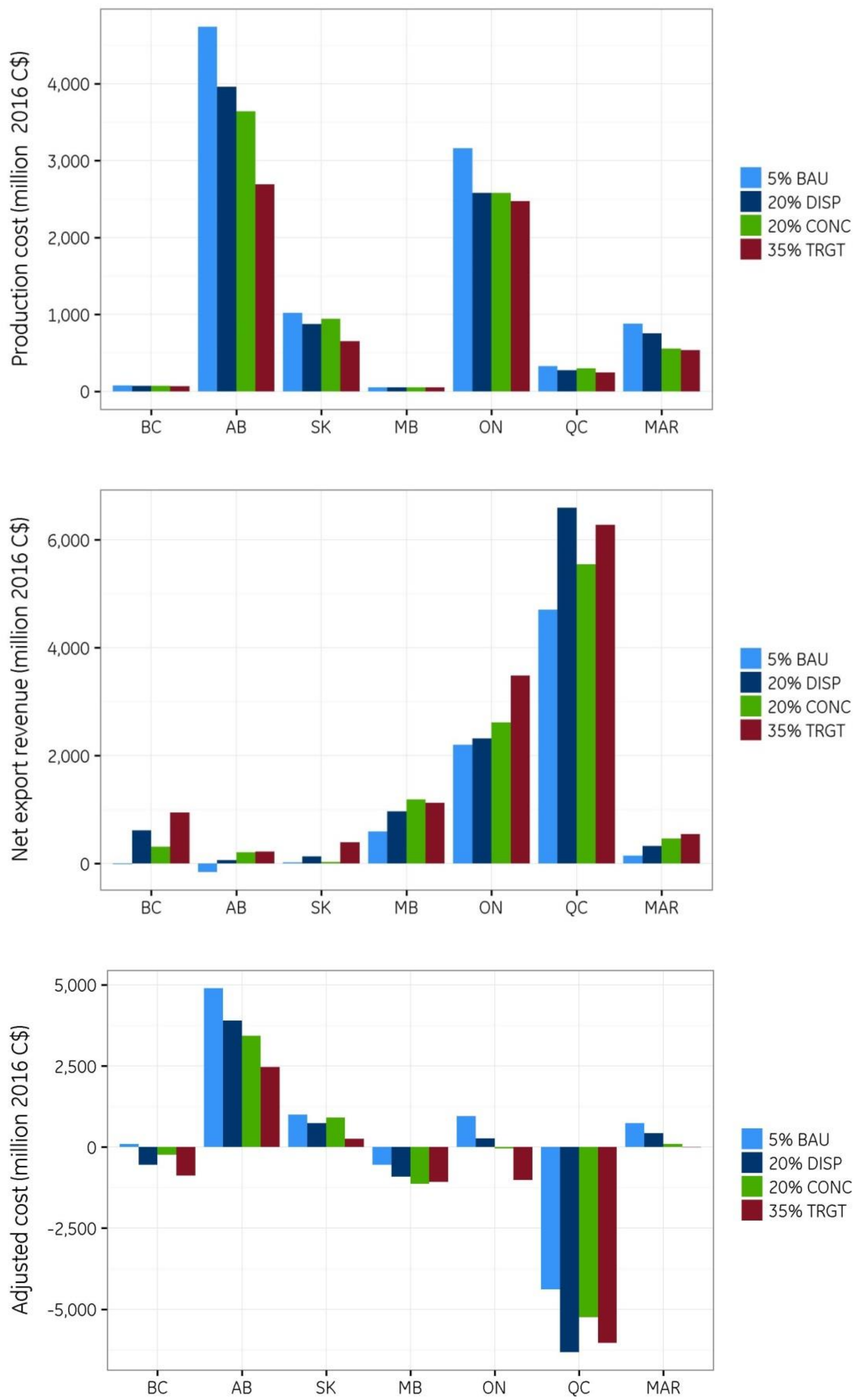


Figure 6-38: Operational Economic Performance Metrics by Province under Each Study Scenario

6.9.2 Value of Wind

To account for the impact of each additional unit of wind on reducing system costs, an appropriate metric to use is the "Value of Wind", which is the economic value that is added to the system in terms of avoided cost of generation, due to each new unit of wind generation, as defined in the following relationship:

$$\boldsymbol{Value\ of\ Wind} = \frac{\boldsymbol{Change\ in\ Adj.Produciton\ Cost\ relative\ to\ 5\%\ BAU\ Scenario}}{\boldsymbol{Change\ in\ Wind\ Generation\ relative\ to\ 5\%\ BAU\ Scenario}}$$

Table 1-9 presents the change in adjusted productions costs and delivered wind energy in each scenario relative to the 5% BAU scenario. The production cost analysis shows that wind energy has a value (avoided cost) of about C$43.4/MWh in 20% DISP scenario and about C$40.5/MWh in the 35% TRGT scenario. Recent projects in North America at sites with similar capacity factors have been developed with levelized cost of energy (LCOE) in that same range. This indicates that the wind energy postulated in the study scenarios is very likely to be economically feasible.

If incremental wind penetration was based on linear increase of wind capacity at the same locations as the 5% BAU scenario, one would expect an ever decreasing value of wind with higher wind penetration. In other words, the marginal value of wind would be expected to decrease as more wind capacity is added to the system. An estimated marginal value of wind can be the basis for the energy portion of power purchase agreements (PPA) and bilateral contracts with wind capacity owners.

Table 6-11: Value of Wind

Changes Relative to 5% BAU Scenario	20% DISP	20% CONC	35% TRGT
Reduction in Adjusted Production Costs (C$M)	3,786.5	4,098.7	7,211.8
Incremental Wind (GWh)	87,336.5	86,866.6	178,016.4
Value per MWh of Added Wind (C$/MWh)	**43.4**	**47.2**	**40.5**

6.9.3 Cost and value of Transmission Reinforcements

Table 1-10 summarizes the estimated costs for transmission reinforcements as well as the annual reductions (savings) in production costs that directly result from those transmission additions. These values were calculated by performing production cost simulations on each of the scenarios both with and without the transmission reinforcements described in the section on transmission reinforcements. The results indicate that the payback periods for the added transmission are in the range of 4 to 6 years.

The reductions in production cost are in both Canadian and USA operating areas, and about half of the transmission reinforcements are between Canada and the USA. Implementing such projects would necessarily involve entities from both sides of the US-Canada border, as multiple entities would share costs and benefits.

Table 6-12: Cost and Value of Transmission Reinforcements

Scenario	Estimated Cost of Transmission Reinforcements (C$M 2016)	Annual Reduction in System-Wide Production Cost (C$M/Year)	Payback Time (Years)
5% BAU	$2,130	$565	3.8
20% DISP	$2,696	$758	3.6
20% CONC	$2,695	$882	3.1
30% TRGT	$3,724	$1,523	2.4

7 Transmission Reinforcements

Section Acknowledgement:

This section of the report was developed and prepared by Dennis Woodward (P. Eng.) of Electranix.

This task derived one possible option for transmission reinforcements to satisfy the increased capacity indicated by the production cost analysis. Other reinforcement options are also possible, but it was beyond the scope of this study to evaluate a range of options in detail and optimize the transmission reinforcement plan. Instead, this analysis was intended to provide one reasonable plan for the reinforcements and the costs associated with the new/upgraded facilities.

7.1 Additional Transmission Capacity Requirements

The existing high voltage Canadian and Northern USA transmission lines are shown in Figure 7-1. There are existing interprovincial and international transmission lines and their existing and additional capacities needed for the wind integration are presented in Table 2-1 and Table 7-2.

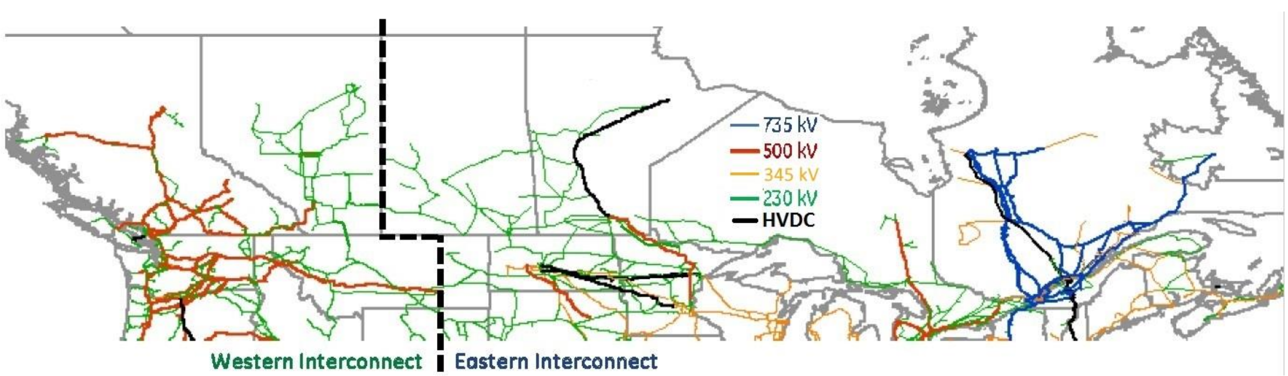


Figure 7-1: Existing Canadian and Northern USA Major Transmission Lines

Each existing interface shown in Figure 7-1 and applied in Table 2-1 and Table 7-2 are designated and described as follows:

- **AB to BC: Path 1:** This Alberta to British Columbia interconnection is a 500 kV AC transmission line
- **AB to MT: Path 83:** This Alberta to Montana interconnection is a 230 kV AC transmission line with a phase shift transformer to regulate its power flow

- **SK to MB TOTAL FLOW:** This Saskatchewan to Manitoba interconnection is consists of three 230 kV AC transmission lines
- **SK to ND: BOUNDARY (DAM) TO TIOGA:** This Saskatchewan to North Dakota interconnection is a 230 kV AC transmission line with a phase shift transformer to regulate its power flow
- **MB to ON TOTAL FLOW:** This Manitoba to Ontario interconnection is two 230 kV AC transmission lines with phase shift transformers to regulate its power flow
- **ON to MN:** This Ontario to Minnesota interconnection is a 230 kV transmission line with a phase shift transformer to regulate its power flow
- **ON to MI:** This Ontario to Michigan interconnection consists of three 230 kV AC lines and a 500 kV AC transmission line that cross the Saint Clair River
- **ON to NY: NIAGARA:** This Ontario to New York interconnection downstream from the Niagara Falls consists of a double circuit 345 kV AC transmission line and two double circuit 230 kV AC transmission circuits
- **ON to NY: ST LAWRENCE:** This Ontario to New York interconnection consists of a double circuit 230 kV AC transmission line
- **ON EWTE EAST-WEST TRANSFER:** This is an interconnection between Northwest Ontario at Algoma and the beginning of central and east Ontario at Sudbury consisting of three 230 kV circuits
- **ON FN/FS NORTH-SOUTH TRANSFER:** These are the interconnections into the southern Ontario regions of Windsor to Toronto to Ontario from northern Ontario with two 500 kV AC circuits and three 230 kV AC circuits
- **QC TO NB: TOTAL FLOW:** These are the two back-to-back HVDC interconnections into New Brunswick from Quebec, located at Madawaska and Eel River
- **NB TO ME: TOTAL FLOW:** This is an interconnection between New Brunswick and Maine consisting of two 345 kV AC circuits
- **NS TO NB:** This is an interconnection between Nova Scotia to New Brunswick consisting of a single 345 kV AC circuit
- **NS:CBX INTERFACE:** This is an interconnection internal to Nova Scotia to Cape Breton consisting of an 345 kV AC circuit and a double circuit 230 kV AC transmission line

The results of the GE MAPS simulations showing existing interconnection capacities and additional interconnection capacity requirements for the four study scenarios are presented in Table 2-1.

Table 7-1: Existing Interconnection Capacity Limit and What Is Needed For Each of the Study Scenarios

TOTAL INTERFACE LIMITS (MW)					
INTERFACE	Type	5% BAU	20% DISP	20% CONC	35% TRGT
AB TO BC: PATH 1	Inter-Province	1200	1200	1200	1500
AB TO MT: PATH 83	International	315	315	315	550
SK TO MB: TOTAL FLOW	Internal	0	200	0	550
SK TO ND: BOUNDARY TO TIOGA	International	165	275	165	750
MB TO ON TOTAL FLOW	Inter-Province	500	600	600	600
ON TO MN	International	425	425	450	425
ON TO MI	International	3300	3600	3650	4700
ON TO NY: NIAGARA	International	1500	1500	1500	2600
ON TO NY: ST LAWRENCE	International	300	300	300	400
ON TO NY: TOTAL FLOW	International	1900	1900	1900	3000
ON EWTE EAST-WEST TRANSFER	Internal	850	950	950	1000
ON FN/FS NORTH-SOUTH TRANSFER	Internal	2100	2100	2100	2300
QC TO NB: TOTAL FLOW	Inter-Province	1030	1150	1150	1150
NB TO ME: TOTAL FLOW	International	700	1200	1250	1350
NS TO NB	Inter-Province	300	350	450	500
NS: CBX INTERFACE	Internal	700	700	1000	700

The "EXISTING" values are the limits of the starting transmission configuration before the transmission reinforcements. The incremental transmission reinforcements over the "Existing" interconnection capacities are presented in Table 7-2.

Table 7-2: Incremental Increase in Interconnection Capacities for the Study Scenarios

INCREMENTAL ITERFACE ADDITIONS (MW)				
INTERFACE	5% BAU	20% DISP	20% CONC	35% TRGT
AB TO BC: PATH 1	0	0	0	300
AB TO MT: PATH 83	0	0	0	235
SK TO MB: TOTAL FLOW	0	200	0	550
SK TO ND: BOUNDARY TO TIOGA	0	110	0	585
MB TO ON TOTAL FLOW	200	300	300	300
ON TO MN	275	275	300	275
ON TO MI	1600	1900	1950	3000
ON TO NY: NIAGARA	0	0	0	1100
ON TO NY: ST LAWRENCE	0	0	0	100
ON TO NY: TOTAL FLOW	0	0	0	1100
ON EWTE EAST-WEST TRANSFER	500	600	600	650
ON FN/FS NORTH-SOUTH TRANSFER	600	600	600	800
QC TO NB: TOTAL FLOW	0	120	120	120
NB TO ME: TOTAL FLOW	0	500	550	650
NS TO NB	0	50	150	200
NS: CBX INTERFACE	0	0	300	0

The results in Table 2-1 and Table 7-2 provide the basis for determining realistic transmission upgrades or additional transmission facilities to meet the increased transmission capacity across each interface.

7.2 Pan-Canadian Interconnection Options

The Canadian interconnection capacities required as determined by the wind integration study result in Table 2-1 and Table 7-2 are shown in Figure 7-2. These are results from the GE MAPS study and provide a high level assessment of the incremental transmission facilities and costs required.

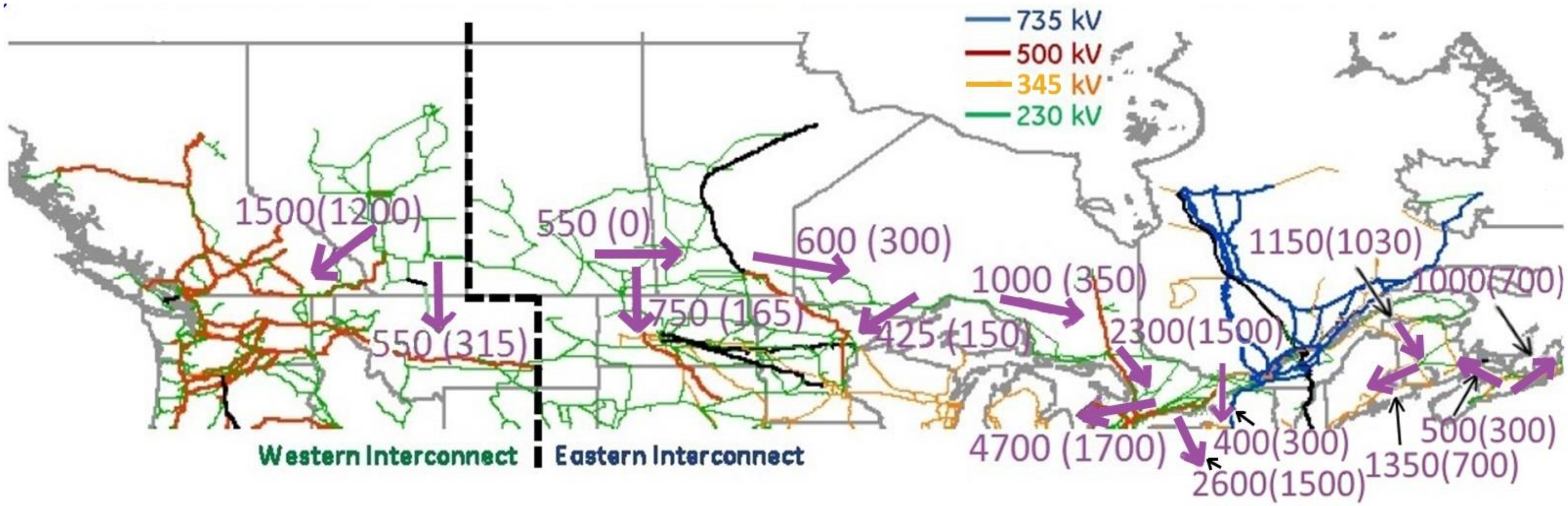


Figure 7-2: Western Canada transmission expansion planning approach.

The summary of the required capacity of the interconnections at each location for 35% TRGT is the first number shown in Figure 7-2 at each location followed by the existing interconnection capacity in parenthesis. One exception is the Nova Scotia interconnection to Cape Breton (NS CBX INTERFACE in Table 2-1 and Table 7-2) 1000(700) where the 1000 MW increase in interconnection capacity from 700 MW occurs for the 20% CONC instead of 35% TRGT.

7.2.1 Basic Assumptions

Transmission system expansion planning normally includes extensive power flow and contingency analysis that was beyond the scope of this study. Therefore, to develop a technically reasonable and practical set of transmission reinforcements for the study scenarios, the following assumptions were made:

1. New interconnections are terminated at the closest substation across the border that appears to be capable of supporting the incremental power required for the interconnection.
2. Since wind energy is intermittent and subject to an amount of uncertainty and not "firm", the added transmission between the regions is considered "conditional firm transmission service" which is a way for more generators (including wind turbine generators) to use transmission lines that are under long term contracts [1]. In addition, conditional firm transmission service may not be N-1 contingency compliant for the additional wind power being transmitted on the added transmission facilities.
3. The averaged transmission line cost values used for this study are in C$ Million/km. They are typical costs that are derived from various sources and are summarized below:

Table 7-3: Average Cost Values and Approximate Maximum Capacity of Transmission Lines

Single and Double Circuit Transmission Lines in kV	C$M/km	Approximate Maximum Capacity (MW)
1 - 138	1.2	120
2 - 138	1.5	240
1 - 230	1.6	330
2 - 230	2.2	660
1 - 345	1.9	750
2 - 345	2.4	1,500
1 - 500	2.1	1,500
2 - 500	2.9	3,000

4. Incremental average substation and facility costs. These are the estimated incremental cost for terminating new or upgraded transmission lines at an existing substation:

Table 7-4: Incremental Average Substation and Facility Costs

Substation or Facility	C$M
138 kV Substation	7
230 kV Substation	10
345 kV Substation	13
500 kV Substation	17
150 MVAR Series Capacitor	16
230 kV Phase Shifting Transformer	15
120MW Back-to-Back HVDC Station	66

5. The tolerance of transmission line cost estimates is approximately +/- 30%. The estimates for substation upgrades have wider variation as they depend on specific substation layouts and expansion options. However, substation costs are a relatively small percentage of the overall transmission reinforcement costs.
6. All funds applied in Canadian dollars at $1.385 CAD = $1 US
7. 2016 costs are inflated at 7% per year from published data or project costs from corporate files.
8. All lines are assumed to be overhead. No cables are used in any interconnections.

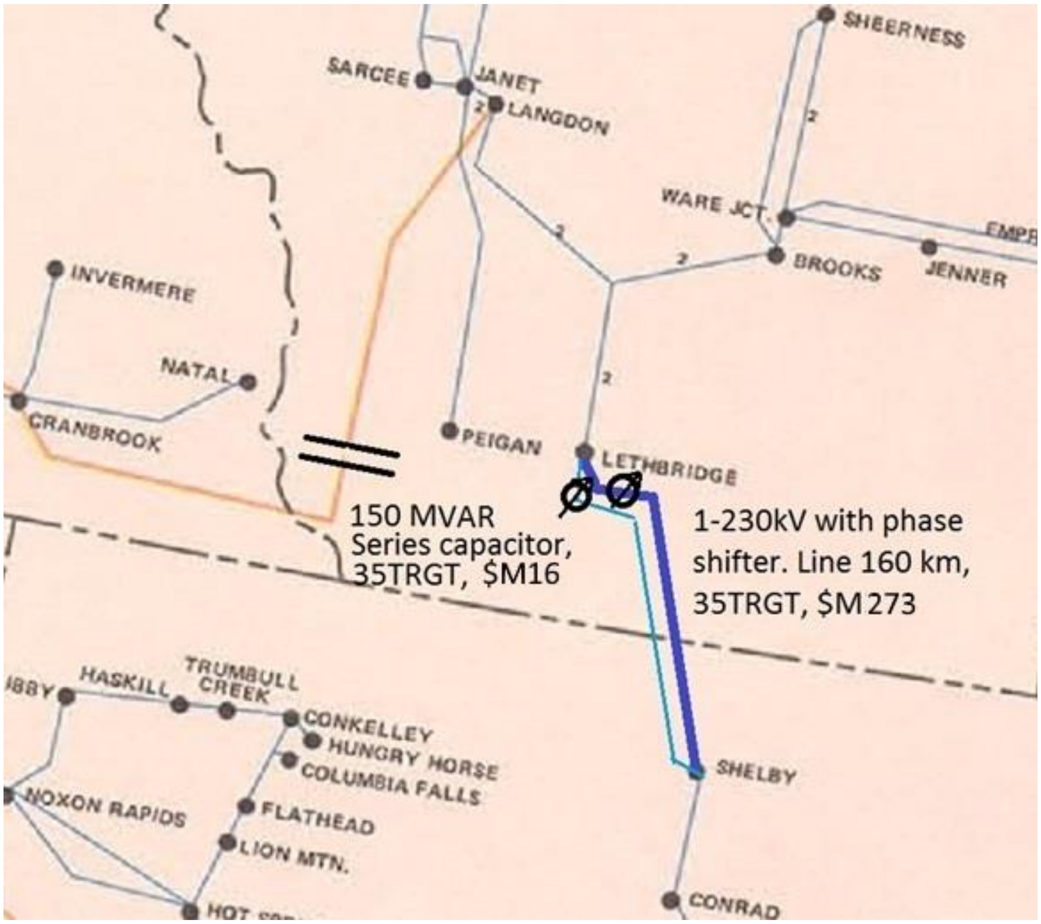
7.3 Basic Transmission Expansion Costs and Facilities

The various transmission expansion projects as generated from the results of the production cost analysis are presented and summarized for the various interconnections.

7.3.1 Alberta to BC and Alberta to Montana

The dominant transmission line between Alberta and British Columbia is a single 500 kV circuit rated at 1,200 MW Alberta to BC. It requires an increase in capacity of 300 MW for 35% TRGT, and for this study is assumed it can be accomplished with a series capacitor bank, located preferably mid-line as shown in Figure 7-3. This may require adoption of a remedial action system and a second 500 kV transformer at Langdon substation near Calgary.

An additional 230 kV transmission line from Alberta to Montana is required with a phase shift transformer also as shown in Figure 7-3.



INCREMENTAL INTERFACE ADDITIONS (MW)

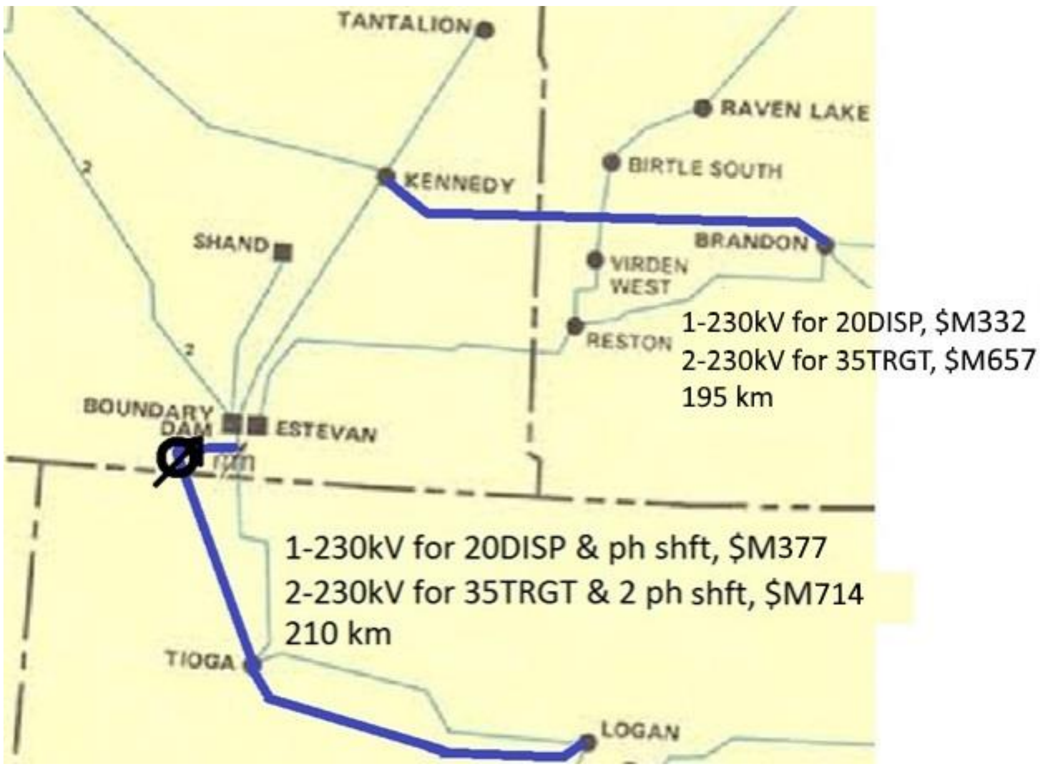
INTERFACE	5BAU	20DISP	20CONC	35TRGT
AB TO BC: PATH 1	0	0	0	300
AB TO MT: PATH 83	0	0	0	235

Figure 7-3: Transmission and Facility Additions to Accommodate The 35%TRGT Wind Energy Penetration Scenario for Alberta to BC and Alberta to Montana

7.3.2 Saskatchewan to Manitoba and North Dakota

A second 230 kV transmission line from Saskatchewan near Boundary Dam to North Dakota is required and needs to be extended into North Dakota to at least Logan substation as shown in Figure 7-4. A stronger termination in North Dakota would be Charlie Creek substation due south from Tioga and approximately the same distance as to Logan but with the disadvantage of crossing Lake Sakakawea. A single additional 230 kV circuit is required for 20% DISP and a double circuit 230 kV additional line is required for 35% TRGT. In addition phase shift transformers are needed at the Boundary Dam end of the new lines.

Similar 230 kV transmission additions are required between Saskatchewan and Manitoba but without the phase shift transformers. Line terminations were chosen at Kennedy substation in Saskatchewan and Brandon substation in Manitoba.



INCREMENTAL INTERFACE ADDITIONS (MW)

INTERFACE	5BAU	20DISP	20CONC	35TRGT
SK TO MB: TOTAL FLOW	0	200	0	550
SK TO ND: BOUNDARY TO TIOGA	0	110	0	585

Figure 7-4: Transmission and Facility Additions to Accommodate The 20% DISP And 35% TRGT Wind Energy Penetration Scenario for Saskatchewan to BC and Saskatchewan to Manitoba

7.3.3 Manitoba to Ontario and Ontario to Minnesota

This is an interesting power flow situation as similar amounts of incremental power flow from Manitoba into Ontario and from Ontario into Minnesota. An examination of the areas of potential wind energy development reveals where these incremental power flows are flowing as indicated in Figure 7-5. The maximum capacity increase Manitoba to Ontario is 300 MW and the flow increase to from Ontario to Minnesota of 300 MW. With no new wind energy designated in Northwest Ontario, there is no obvious source for this 300 MW into Minnesota.

The wind power flows of Figure 7-5 and no new wind power generation in Northwest Ontario suggest that a transmission line straight from Manitoba through Ontario to Minnesota is needed.

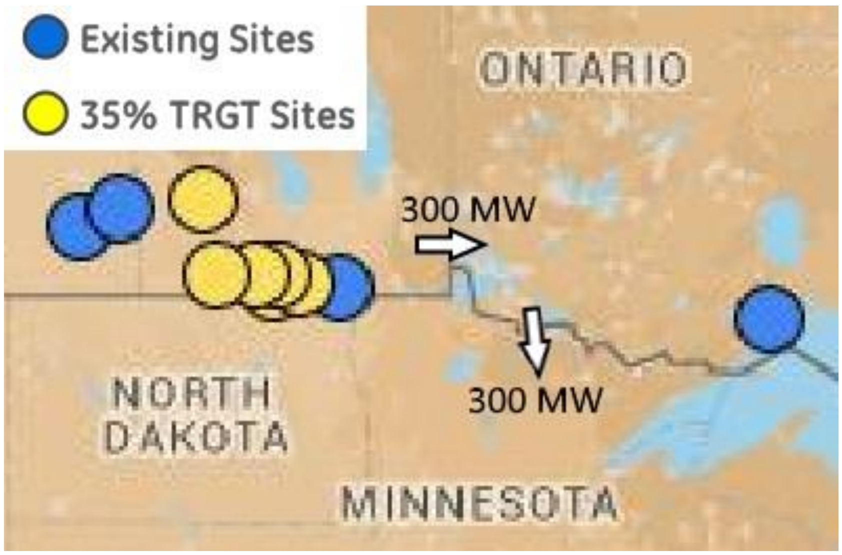


Figure 7-5: Manitoba to Ontario Incremental Wind Power Flows and Where Wind Sites Are Located

It would seem practical to go straight from Manitoba to Minnesota without interconnecting to Ontario. However, the interconnection of a single 230 kV line interconnecting into Kenora and Fort Francis in Ontario with necessary phase shift transformers is presented in Figure 7-6. An alternative would be use of back-to-back HVDC converters or HVDC transmission in the area. This is a consideration with future increase of Manitoba – Ontario interconnection capacity.

INCREMENTAL INTERFACE ADDITIONS (MW)

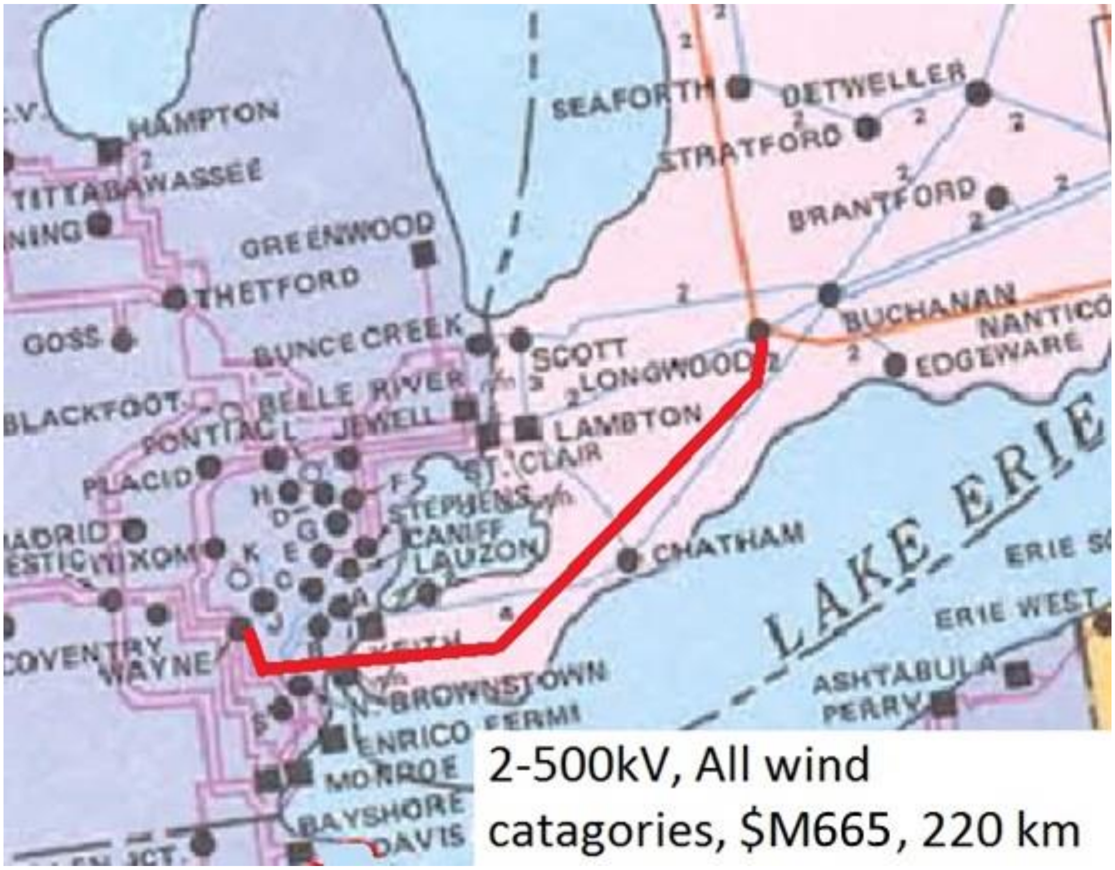
INTERFACE	5BAU	20DISP	20CONC	35TRGT
MB TO ON TOTAL FLOW	200	300	300	300
ON TO MN	275	275	300	275

Figure 7-6: Transmission and Facility Additions to Accommodate All Wind Energy Penetration Scenarios for Manitoba to Ontario and Ontario to Minnesota

7.3.4 Ontario to Michigan

The existing power flow capability from Ontario to Michigan is 1,700 MW, largely through a number of 230 kV AC interconnections and a 500 kV interconnection that cross the Saint Clair River between Sarnia and Windsor. The incremental power that can flow to Michigan from Ontario increases from 1,600 MW for 5% BAU to 3,000 MW for 35% TRGT above the present 1,700 MW level. A double circuit overhead 500 kV AC transmission line from Longwood substation in Ontario to Wayne substation in Michigan is included for all levels of penetration as shown in Figure 7-7.

If built as a double circuit 500 kV AC transmission line, a Remedial Action System may be needed to accommodate loss of both circuits in the event that one or more transmission towers collapse causing a double circuit simultaneous outage.



INCREMENTAL INTERFACE ADDITIONS (MW)				
INTERFACE	5BAU	20DISP	20CONC	35TRGT
ON TO MI	1600	1900	1950	3000

Figure 7-7: Transmission to accommodate all wind energy penetration scenarios for Ontario to Michigan

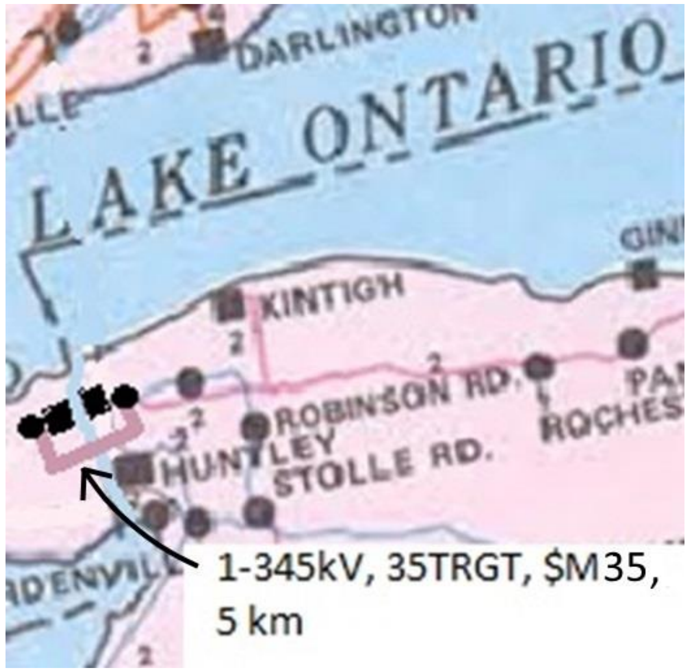
7.3.5 Ontario to New York near Niagara

There are hydroelectric generating stations on both sides of the Niagara River downstream from Niagara Falls as shown in Figure 7-8. On the Ontario (left) side is Sir Adam Beck I and II. On the New York (right) side is the Robert Moses generating station.

Figure 7-8: Sir Adam Beck and Robert Moses Generating Stations Downstream From Niagara Falls

There are existing overhead transmission interconnections across the Niagara River with an existing rating of 1,500 MW. For 35%TRGT, this rating must incrementally increase by 1,100 MW.

Since only a short distance is involved (about 5 km), it is proposed an additional single circuit 345 kV overhead transmission line be conductored to accommodate the 1,100 MW incremental interconnection capacity required for 35%TRGT as shown in Figure 7-9.



INCREMENTAL INTERFACE ADDITIONS (MW)

INTERFACE	5BAU	20DISP	20CONC	35TRGT
ON TO NY: NIAGARA	0	0	0	1100

Figure 7-9: Transmission to Accommodate 35%TRGT Wind Energy Penetration Scenario for Ontario to New York Below Niagara Falls

7.3.6 Ontario to New York across the St. Lawrence

There is an existing interconnection across the St. Lawrence Seaway near Cornwall, Ontario consisting of two double circuit 138 kV overhead transmission lines, currently scheduled for 300 MW. In reality, there may be enough capacity in these interconnections to accommodate the additional 100 MW required for the 35% TRGT penetration scenario. These two double circuit lines located in New York near the St. Lawrence Seaway crossing are shown in Figure 7-10.

Figure 7-10: Existing Double Circuit 138 KV Interconnection Transmission Lines Near the St. Lawrence Seaway in New York

However, for the purpose of this study, a single circuit 230 kV overhead transmission line is added between Saunders substation in Ontario and Massena substation in New York. This new line would parallel the existing interconnections of Figure 7-10 and accommodate single contingency operation.

The depiction of the added 230 kV interconnection transmission line of 17 km length is shown in Figure 7-11.

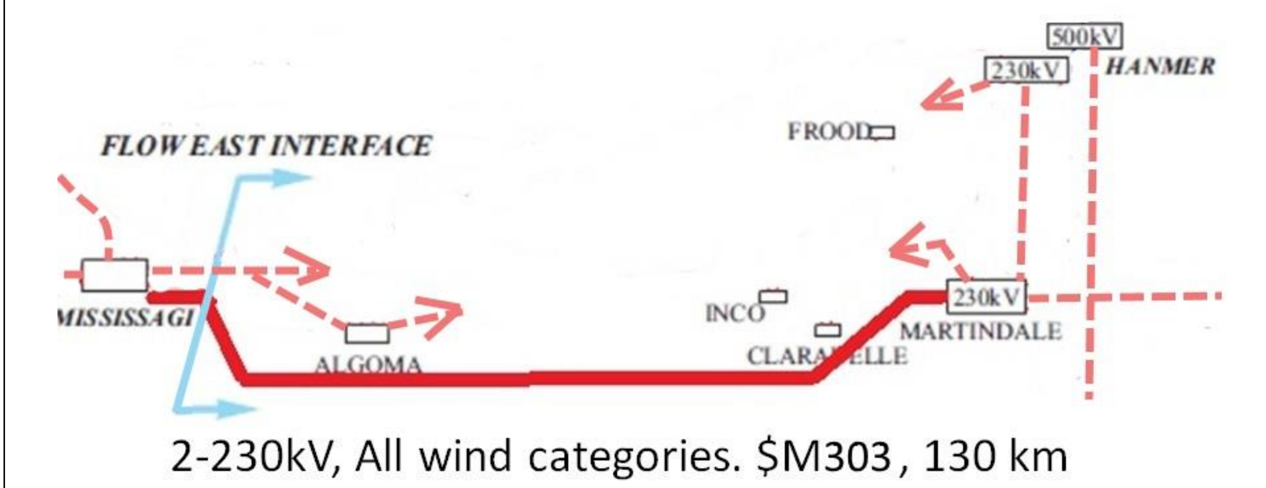
INCREMENTAL INTERFACE ADDITIONS (MW)

INTERFACE	5BAU	20DISP	20CONC	35TRGT
ON TO NY: ST LAWRENCE	0	0	0	100

Figure 7-11: Transmission to Accommodate 35%TRGT Wind Energy Penetration Scenario for Ontario to New York

7.3.7 Ontario East to West Transfer

The existing east to west power transfer capacity across north-west Ontario is 350 MW. The incremental power flows across the range of wind energy penetration options is from 500 MW for 5% BAU to 650 MW for 35% TRGT. One double circuit 230 kV transmission line will accommodate this incremental range of east to west power transfers. The proposed new line is terminated at Mississagi substation near Algoma and Martindale substation near Sudbury. The pertinent part of the Ontario transmission system where this double circuit 230 kV transmission line is added is shown in Figure 7-12.



INCREMENTAL INTERFACE ADDITIONS (MW)

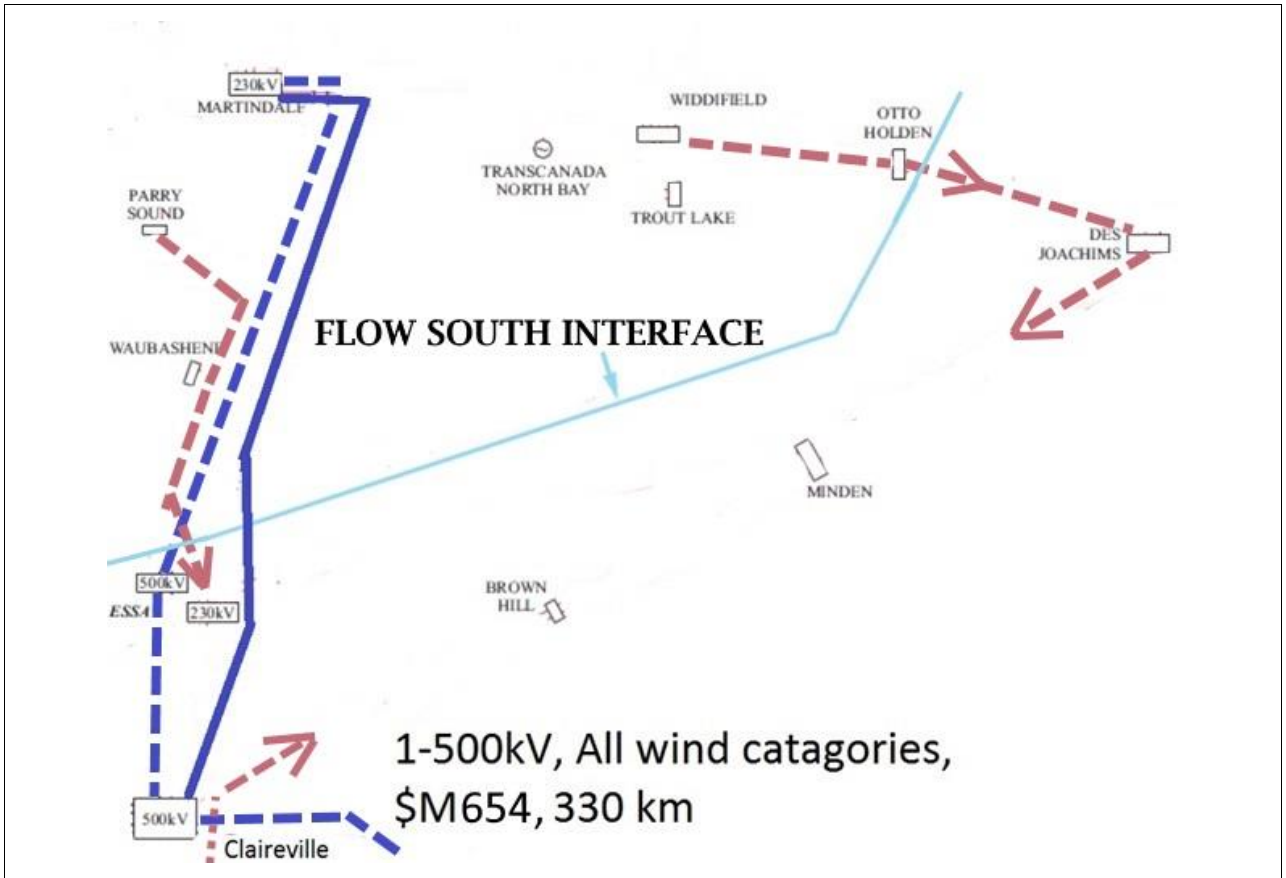
INTERFACE	5BAU	20DISP	20CONC	35TRGT
ON EWTE EAST-WEST TRANSFER	500	600	600	650

Figure 7-12: Additional Transmission to Accommodate All Wind Energy Penetration Scenarios for Ontario East To West Incremental Power Transfer

It should be noted that the existing transmission network is not shown in Figure 7-12.

7.3.8 Ontario North to South Transfer

The north to south power transfer to the Greater Toronto Area is 1,500 MW with the existing transmission system. The incremental power flows across the range of wind energy penetration options is from 600 MW for 5% BAU, 20% DISP and 20% CONC to 800 MW for 35% TRGT. A single circuit 500 kV transmission line will accommodate this incremental range of north to south power transfers. The proposed new line would be terminated in the north at Martindale substation near Sudbury and at in the south at Claireville substation near Toronto. The pertinent part of the Ontario transmission system where this single circuit 500 kV transmission line is added is shown in Figure 7-13.



INCREMENTAL INTERFACE ADDITIONS (MW)

INTERFACE	5BAU	20DISP	20CONC	35TRGT
ON FN/FS NORTH-SOUTH TRANSFER	600	600	600	800

Figure 7-13: Additional 500 KV Transmission to Accommodate All Wind Energy Penetration Scenarios for Ontario North To South Incremental Power Transfer

It should be noted that the existing transmission network is not shown in Figure 7-13.

7.3.9 Quebec to New Brunswick

There is the existing 350 MW Madawaska back-to-back HVDC transmission link in service between Quebec and New Brunswick close to the northwest New Brunswick provincial border. In addition there is the Eel River back-to-back HVDC transmission link in service between Quebec and New Brunswick also rated at a 350 MW and located close to the northeast provincial border. This is a total HVDC interconnection power transfer capability of 700 MW.

Some of NB Power loads in these areas can be islanded and supplied through AC transmission as part of the Quebec grid, which increases New Brunswick's import capability to 1,080 MW, whereas export capability to Quebec is limited to 700 MW. The existing input rating is stated at 1,030 MW and this is based on HVDC power flows being at normal steady state ratings with the islanded AC system.

The incremental increase in power flow into New Brunswick due to the wind penetration of 20% DISP, 20% CONC and 35% TRGT is 120 MW for all three scenarios. This is achieved by adding a 120 MW back-to-back HVDC link in parallel to the 350 MW Madawaska back-to-back HVDC link as shown in Figure 7-14.

INCREMENTAL INTERFACE ADDITIONS (MW)

INTERFACE	5BAU	20DISP	20CONC	35TRGT
QC TO NB: TOTAL FLOW	0	120	120	120

Figure 7-14: Additional Back-To-Back HGDC Line at Madawaska to Accommodate Wind Energy Penetration Scenarios 20% DISP, 20% CONC And 35% TRGT for Incremental Power Transfer From Quebec into New Brunswick

7.3.10 New Brunswick to Maine

The existing power transfer capability from New Brunswick to Maine is 700 MW. The incremental wind power transfer over this 700 MW was shown to be 500 MW at 20% DISP, then 550 MW at 20% CONC and reaching 650 MW at 35% TRGT. At these incremental powers, a single circuit 345 kV transmission line from Keswick substation in New Brunswick to Orrington substation in Maine is selected as shown in Figure 7-15.

INCREMENTAL INTERFACE ADDITIONS (MW)

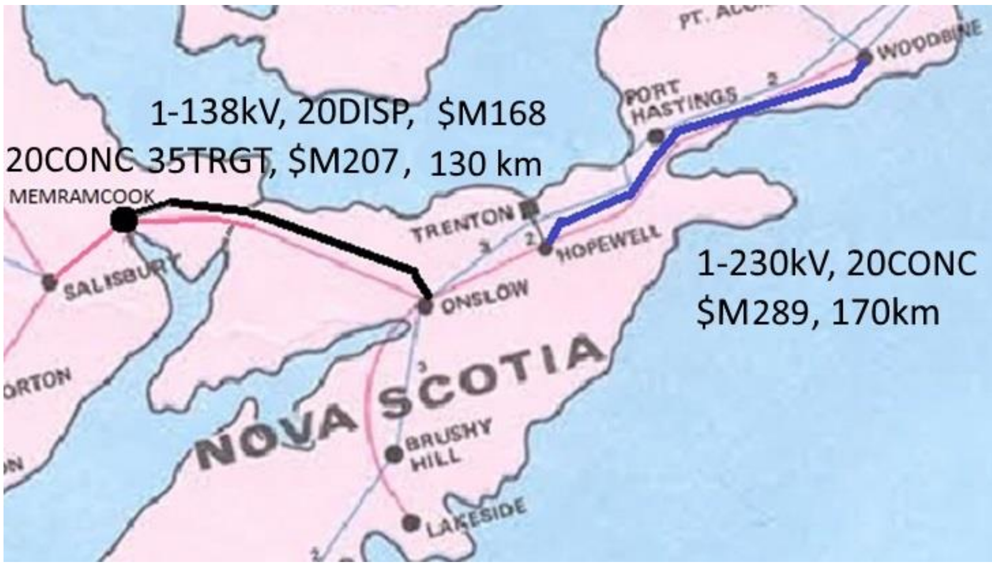
INTERFACE	5BAU	20DISP	20CONC	35TRGT
NB TO ME: TOTAL FLOW	0	500	550	650

Figure 7-15: Additional 345 KV Transmission Interconnection between New Brunswick and Maine to Accommodate Wind Energy Penetration Scenarios for New Brunswick to Maine 20% DISP, 20% CONC And 35% TRGT Incremental Power Transfers

7.3.11 Nova Scotia to New Brunswick and Nova Scotia to Cape Breton

The dominant transmission line between Nova Scotia to New Brunswick is a single 345 kV circuit rated at 300 MW. It requires an increase in capacity of 200 MW for 35%TRGT, and for this study is assumed it can be accomplished with a double circuit 138 kV transmission interconnection as shown in Figure 7-16.

An additional 230 kV transmission line from Hopewell substation in Nova Scotia to Cape Breton is required also as shown in Figure 7-16 to accommodate the incremental 300 MW just for the 20% CONC scenario:



INCREMENTAL INTERFACE ADDITIONS (MW)

INTERFACE	5BAU	20DISP	20CONC	35TRGT
NS TO NB	0	50	150	200
NS: CBX INTERFACE	0	0	300	0

Figure 7-16: Transmission Additions to Accommodate The 20% DISP, 20% CONC And 35% TRGT Wind Energy Penetration Scenario for Nova Scotia to New Brunswick and for Just 20% CONC for Nova Scotia to Cape Breton

7.4 Transmission Reinforcement Costs for Study Scenarios

The transmission interconnections added to accommodate the incremental transmission capacities needed for each of the wind energy penetration scenarios 5% BAU, 20% DISP, 20% CONC and 35% TRGT were determined and their costs estimated in millions of 2016 Canadian dollars. A summary the total costs for the incremental transmission interconnections are summarized in Table 7-5 and displayed graphically in Figure 7-17.

Table 7-5: Summary of Total Transmission Costs for Each Wind Penetration Scenario

Inter-Area Transmission Path	5% BAU	20% DISP	20% CONC	35% TRGT	Description	CAN or USA
MB TO ONT	$491	$491	$491	$491	1 - 230 kV line, 280 km, with phase shifter	CAN
ON TO MN	$188	$188	$188	$188	1 - 230 kV line, 149 km, with phase shifter	USA
ON TO MI	$672	$672	$672	$672	2 - 500 kV lines, 220 km	USA
ON EWTE EAST-WEST TRANSFER	$306	$306	$306	$306	2 - 230 kV lines, 130 km	CAN
ON FN/FS NORTH-SOUTH TRANSFER	$661	$661	$661	$661	1 - 500 kV line, 330 km	CAN
SK TO MB		$332		$657	1 - 230 kV line, 195 km	CAN
SK TO ND: BOUNDARY TO TIOGA		$272		$516	1 - 230 kV lines, 210 km, phase shifter (20% DISP) 2 - 230 kV line, 210 km, phase shifter (35% TRGT)	USA
QC TO NB		$66	$66	$66	1 - Back-to-Back DC at Madawaska, 120 MW	CAN
NB TO ME		$358	$358	$358	1 - 345 kV line, 250 km	USA
NS TO NB		$168	$207	$207	1 - 138 kV lines, 130 km (20% DISP) 2 - 138 kV lines, 130 km (20% CONC, 35% TRGT)	CAN
NS: CBX INTERFACE			$292		1 - 230 kV line, 170 km	CAN
AB TO BC: PATH 1				$16	150 MVAR series capacitor	CAN
AB TO MT: PATH 3				$273	1 - 230 kV line, 160 km, with phase shifter	CAN
ON TO NY: NIAGARA				$25	1 - 345 kV overhead line, 5 km	USA
ON TO NY: ST LAWRENCE				$34	1 - 230 kV line, 17 km	USA
Total (C$M 2016)	$2,130	$2,696	$2,695	$3,724		

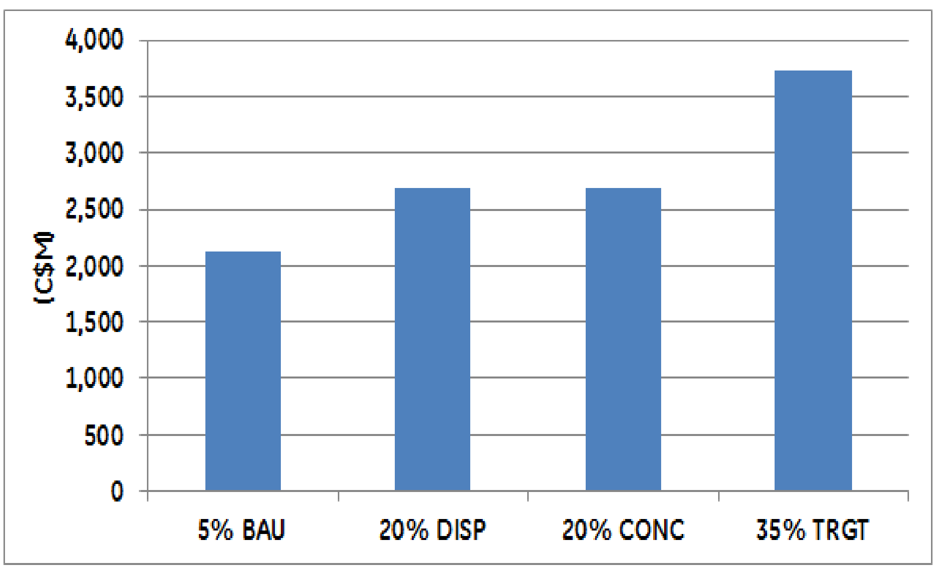


Figure 7-17: Total Capital Expense For Each Of The Four Wind Penetration Categories

7.5 References

1) "Conditional Firm Transmission Service Factsheet". National Wind Coordinating Collaborative and Western Governors' Association,

https://www.google.ca/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=0ahUKEwj7iJKWjorLAhWERCYKHZ61AfUQFggbMAA&url=https%3A%2F%2Fwww.nationalwind.org%2Fwp-content%2Fuploads%2Fassets%2Fblog%2FWGA_NWCC_Conditional_Firm_Factsheet.pdf&usg=AFQjCNGIsu6lfSUx_b_nUIMIvJsKK9NWww

8 Sensitivity Analysis

8.1 Sensitivity List

This section covers the sensitivity analyses performed to evaluate the relative impact of variations to some of the key inputs and assumptions. The purpose of this analysis was primarily to understand the sensitivity of the study results to individual inputs, but also to determine how the operational and economic behavior of the Canadian power systems can be mitigated under high wind penetration.

Each sensitivity case started with the underlying assumptions and wind penetration included in the original Scenarios discussed in Section 4. These original scenarios are referred to as the Base Scenarios or Base Case to differentiate them from the Sensitivity Cases with variations in selected assumptions and data.

The sensitivity analysis was performed by changing one or two variables at a time, and comparing results to the base case scenario. The intent was to isolate, in so far as possible, specific factors that will influence operations or costs and whether or not the key conclusions of the study are altered if an individual input or assumption is changed. The differential approach tends to filter out much of the impact of assumptions that are unimportant to the specific investigation, while providing insights for CanWEA and other stakeholders. Many of the sensitivities presented are aimed at providing guidance on the efficacy of various strategies or options aimed at improving performance. The choices of variables cover a wide range of drivers of interest that impact the robustness of the system to respond to renewable resource volatility.

There are two major elements that are different between the four base scenarios:

(a) The additional wind plants and their locations that set the level of wind penetration in each scenario.

(b) Specific transmission reinforcements that relieve congestion, caused by additional wind in the system, down to a defined “reasonable” level.

As described in the section on scenario analysis, increased wind penetration in Canada has a significant impact on system operations, performance, emissions, and operating costs.

Table 8-1 shows all sensitivities that were selected for analysis based on discussion and agreement with CanWEA and the Technical Advisory Committee (TAC). In this list, sensitivities are grouped according to the underlying sensitivity driver. Although this list is not exhaustive, the sensitivity selections cover many of the principal drivers that may impact operations and performance of the Canadian power system with different levels of wind energy.

The rest of this section reviews the key results associated with each sensitivity case. However, this section does not cover all operational and economic results for each sensitivity case. Instead it highlights the key changes associated with the changed input or assumption. In general, the results of this analysis show that changes to most inputs and assumptions, in isolation, do not have a significant impact on the study's results, key findings and conclusions. This indicates that the Base Scenarios provide robust analysis. While the quantified results will change slightly with different assumptions, the direction and magnitude of results will not lead to material changes or a reversal of findings.

Table 8-1: Sensitivity List

Group	Short Name	Description
Transmission		
	No Reinf	Remove transmission reinforcements in the base case
	Copper Prov	Unconstrained transmission within Canadian footprint
	Copper Prov&US	Unconstrained transmission within Canadian footprint and interconnections to the USA
	Copper All	Unconstrained transmission in all of Canada and the USA
Natural Gas Price		
	HiGas	Natural gas prices in Canada and USA increase by 20%
	LoGas	Natural gas prices in Canada and USA decrease by 20%
Wind Forecast		
	4HA	Commitment performed using 4 hour-ahead forecast
	1H Pers	Commitment performed using 1 hour persistence forecast
	Pfct	Commitment performed using perfect forecast
Coal Retirement		
	Part coal	Coal plant retirements equal wind firm capacity additions
	All coal	All Canadian coal plants retired
Hydro Scheduling		
	DA load	Hydro scheduled against day-ahead load (ignoring wind), less flexible
	RT net load	Hydro scheduled against load with hourly real-time wind, more flexible
Wind And Load Weather Year		
	2009	2009 chronological load and wind profiles
	2010	2010 chronological load and wind profiles
USA Wind Build-Out		
	US Wind	Wind penetration in the USA increases by 20%
Emerging Energy Technology Sensitivities		
	DPV	Incorporate distributed PV in Canada
	DR	Incorporate demand response in Canada
	Storage	Incorporate energy storage in Canada
	EV	Incorporate electric vehicle charging in Canada
Relaxed Reserve Requirements		
	Relax Reserves	Reduced operating reserves for wind variability
East-West HVDC Connection		
	HVDC EI-WI	Increase East-West ties in Canada by 1,000 MW

8.2 Transmission Sensitivities

The transmission sensitivities consider different interface flow limits on major transmission interfaces. The four cases considered, in order of increasing transmission, include the following:

- **NoReinf**: This case is based on the existing modeled transmission interface ratings before the additional transmission reinforcements were applied to each of the four scenarios in order to bring down congestion due to wind additions to reasonable levels.

- **Copper Prov**: This case removes all the interface transfer limits within the modeled Canada footprint. It does not change transmission limits in the USA, or on the Canada-USA tie-lines. Therefore, the transmission within the Canada footprint is assumed to be a "copper sheet" with no transmission constraints.

- **Copper Prov&US**: This case is similar to the Copper Prov sensitivity, but also removes the interface transfer limits on the Canada-USA interconnections, but does not change transmission limits within the USA.

- **Copper All**: This case assumes unlimited transmission reinforcement across the entire modeled North American footprint, covering Canadian, USA, and Baja-Mexico regions included in the Western and Eastern Interconnections. This case removes all transmission constraints, relieves all congestion, and provides a bookend value for additional transmission expansion.

Similar to the Base Cases, all transmission sensitivities continue to include monetary hurdle rates applied to inter-provincial and inter-regional transmission interfaces. These hurdle rates are representative of regulatory, policy, and operational barriers and market friction that typically impose some costs on transfer of electrical energy between different jurisdictions. In brief, hurdle rates represent the economic cost of wheeling power between one balancing area and another, even under the full copper sheet transmission. See the Inputs and Assumptions section for more information.

Figure 8-1 shows what portion of the available wind energy is curtailed in each scenario under different transmission sensitivities. Figure 8-2 displays similar results for each province. As expected, with each additional transmission reinforcement (or constraint relaxation), energy curtailment is reduced in each province and in all of Canada. Curtailment is reduced with increased transmission reinforcement because it removes congestion caused by over-supply of wind energy in localized regions of the grid. The "Base" in the following figures refers to the base scenarios that include the transmission reinforcements needed to maintain congestions at defined reasonable levels.

The residual curtailed energy in the Copper All case is due to hurdle rates. In these rare cases locational marginal prices (LMPs) are suppressed on both sides of the regional boundary due to surplus wind energy and a reduction in curtailment will not lead to cost savings for either system. A contributing factor is the pancaking of hurdle rates across several areas.

The results show that the energy curtailment observed in different scenarios and sensitivity cases is entirely due to transmission constraints, which limit flow of power from areas of high wind to load centers on the grid. The following observations can be made:

- Without any transmission reinforcement, the total energy curtailment (in No Reinf case) is approximately double the results seen in the Base Scenarios with transmission reinforcement (the Base case).
- With the "base case" transmission reinforcements, energy curtailment ranges from 1.4% in the 5% BAU scenario to 11.1% in the 35% TRGT scenario.
- Copper All case eliminates all energy curtailment, except for some residual curtailment due to the hurdle rates.
- It is not economic, or practical, to relieve all transmission congestion across the North American power system, even with increased wind penetration. Targeted transmission reinforcements, included in the Base Case, lead to a significant reduction in curtailment. Additional transmission reinforcement beyond this level will lead to a smaller amount of reductions in curtailment per MW of additional transmission capacity.

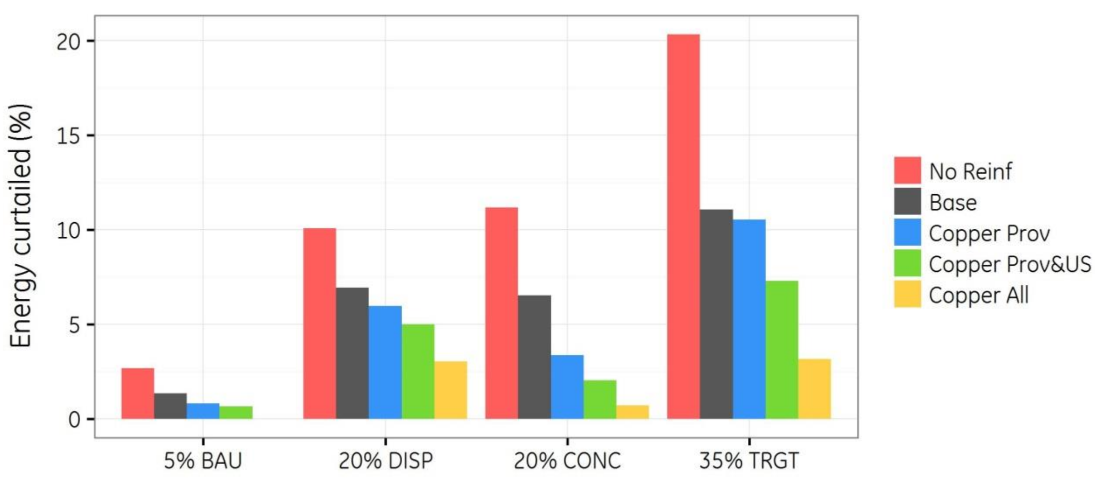


Figure 8-1: Curtailed Energy (of All Generation Types) in Canada under Different Transmission Sensitivity Cases

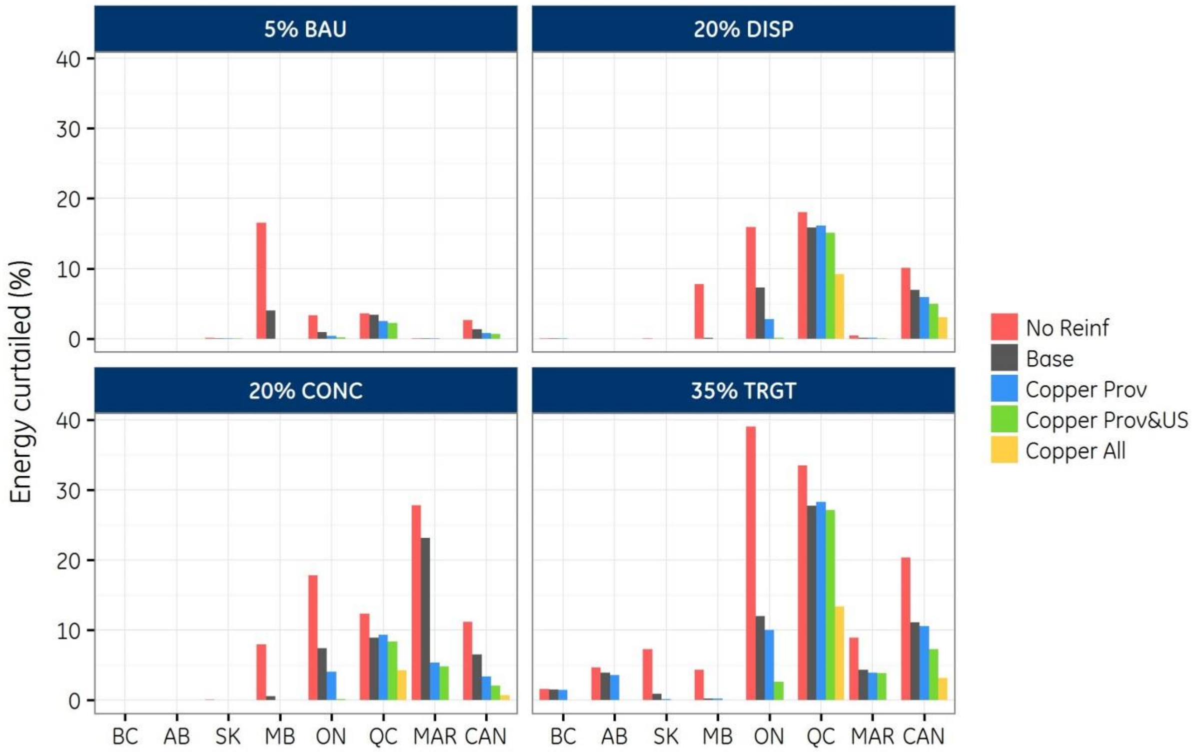


Figure 8-2: Curtailed Energy in Provinces under Different Transmission Sensitivity Cases and Scenarios

Figure 8-3 shows generation by unit types in each province for the different transmission sensitivity cases in the 20% DISP scenario. Increased transmission capacity reduces curtailment and also enables more generation from thermal resources in Canada for export to USA.

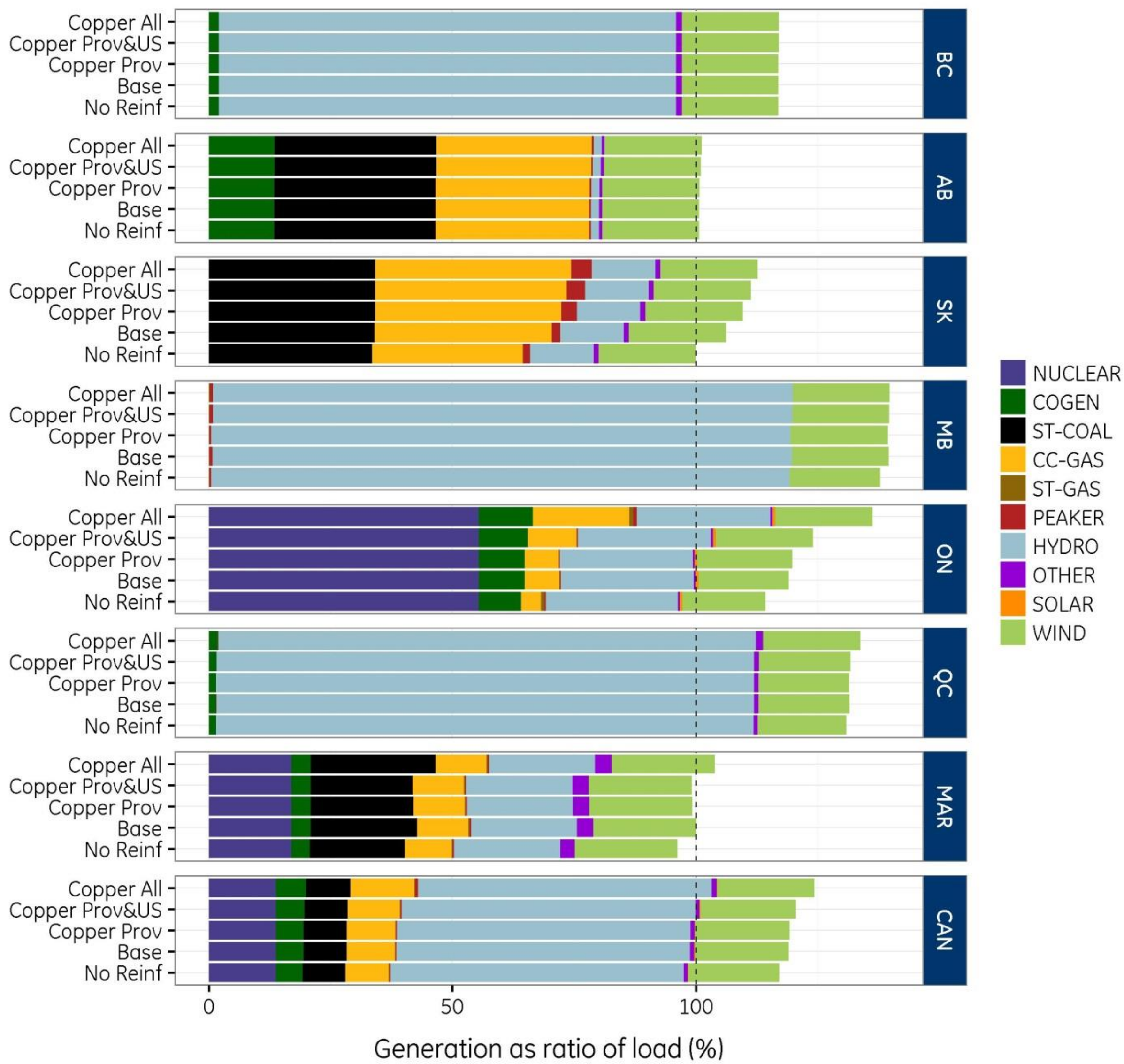


Figure 8-3: Generation by Type in each Province and Canada under Different Transmission Sensitivity Cases in the 20% DISP Scenario

The following two figures illustrate the change in power flows during the year on two selected interfaces under three transmission cases.

Figure 8-4 displays the Ontario - Michigan power flow duration curves for three transmission sensitivities, indicating that power flows increase significantly with additional transmission reinforcements. The plateaus in duration curves represent times when transmission flows on the Ontario – Michigan interface reach the imposed transfer limits.

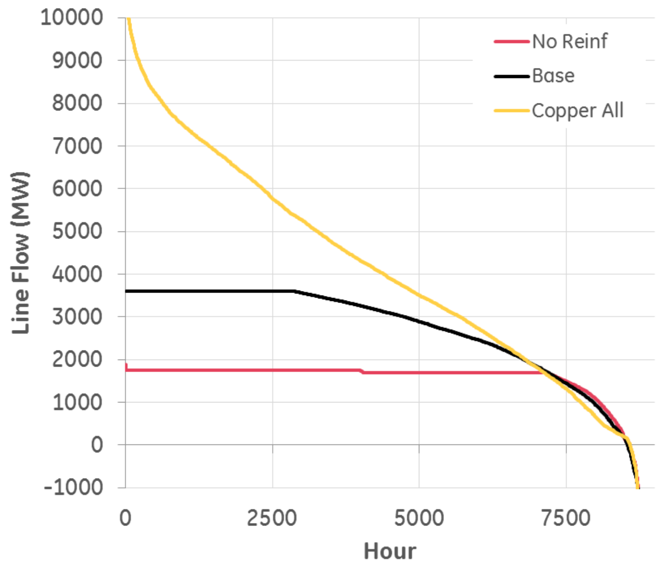


Figure 8-4: Ontario - Michigan Interface Power Flow Duration Curves in 20% DISP Scenario

Figure 8-5 displays the New Brunswick - Maine power flow duration curves under the three transmission sensitivities. This plot shows that increased flows on some interfaces caused by relaxation of transmission limits may actually reduce flows on other interfaces.

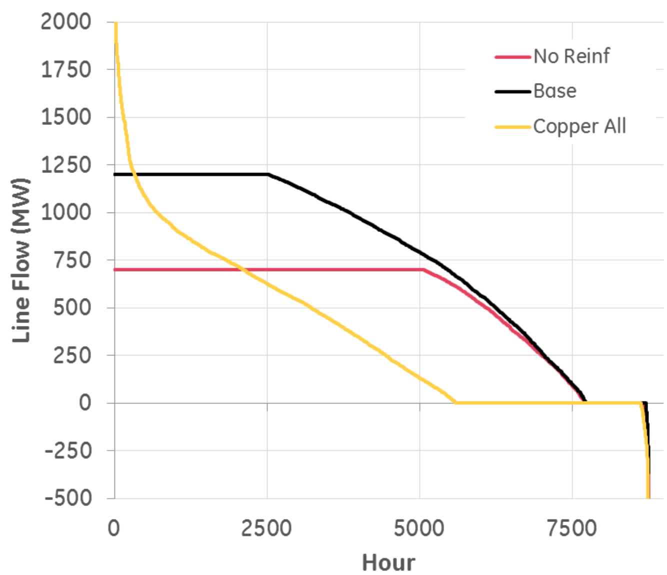


Figure 8-5: New Brunswick to Maine Power Flow Duration Curves in 20% DISP Scenario

More transmission reinforcements also reduce the system-wide operational production costs as shown in Table 8-2

Table 8-2: Change in System-Wide Production Costs under Different Transmission Sensitivities Relative to the Base Scenarios (C$M)

	5% BAU	20% DISP	20% CONC	35% TRGT
No Reinf	565	758	882	1,523
Copper Prov	-102	-103	-254	-160
Copper Prov&US	-240	-305	-540	-664
Copper All	-956	-1,323	-1,517	-2,341

Since value of transmission increases with wind penetration, reductions in production cost can be used to offset transmission investments. A more complex question is distribution of costs and benefits of additional transmission among different stakeholders, but this study does not consider the questions of cost recovery or allocation among different stakeholders.

8.3 Natural Gas Price Sensitivities

As shown in the section on scenario analysis, per the fuel cost assumptions in the base scenarios, the marginal operating costs of natural gas units are higher than coal units. Hence, wind generation displaces CC-GAS units before ST-COAL units. Therefore, when calculating the economic benefits associated with wind additions, the avoided cost metric is highly dependent on the assumed natural gas price.

The Natural Gas Price Sensitivities consider higher and lower natural gas prices relative to the base case natural gas prices.

The two sensitivities considered include:

- **HiGas**: Natural gas prices in Canada and USA increase by 20%
- **LoGas**: Natural gas prices in Canada and USA decrease by 20%

Because the natural gas markets are liquid across North America, these sensitivities were applied uniformly to the entire North American System.

Impact of different natural gas price cases on operational costs are shown in the following figures. Figure 8-6 shows the adjusted production cost in each scenario. In the 5% BAU Scenario, there is a direct relationship with the gas price and the adjusted production cost for the system (an increase in the natural gas price will increase the adjusted production cost, and vice-versa). However, as wind penetration increases, this relationship flips; an increase in the gas price will actually reduce the adjusted production cost. The indirect relationship occurs because of the impact of the net export revenue on the adjusted production cost. As the gas price increases, the LMP in the USA markets also increases, thus increasing the value of exported energy. This highlights the economic benefits of wind to serve as a fuel price hedge, especially when there is export potential to natural-gas based markets, as is the case in Canada. This becomes more prevalent in the 35% TRGT scenario when net export revenues outweigh domestic production costs.

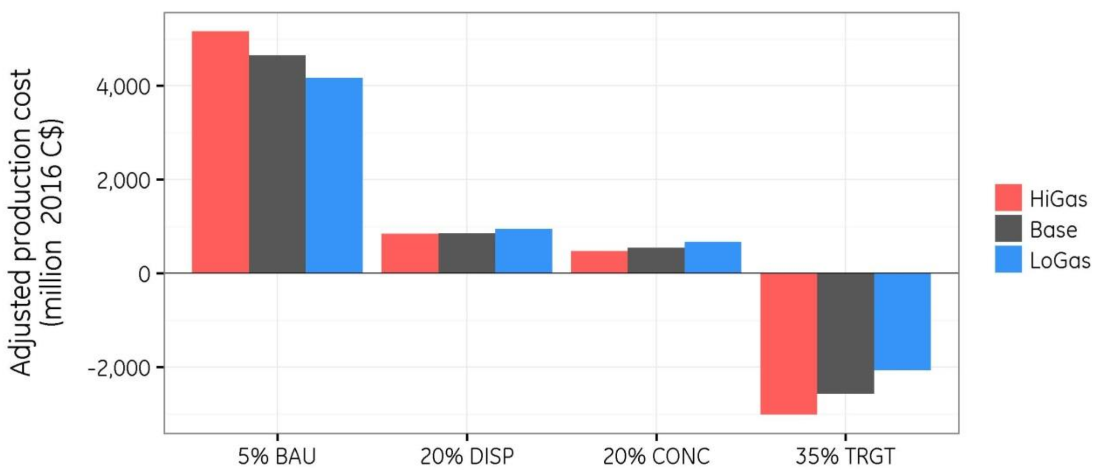


Figure 8-6: Adjusted Production Cost under Different Fuel Sensitivity Cases in Each Scenario

Figure 8-7 shows the adjusted production cost reduction per additional unit of wind generation in each scenario. This metric is also referred to as the avoided cost associated with wind additions. Each MWh of wind addition in the 20% DISP scenario will yield approximately C$50/MWh of savings in the HiGas sensitivity, C$43/MWh of savings in the Base Case, and approximately C$37/MWh of savings in the LoGas sensitivity. This shows that there is nearly a one-to-one relationship between the gas price and avoided cost of wind (wind benefits) and that a 20% increase/decrease in the gas price assumption will yield a 20% increase/decrease in the resulting value of wind. It is important to note that this is true, even in Canada, which is much less dependent on natural gas for electric power generation. This is because much the marginal price of electricity is still set to gas generation because of the high degree of imports and exports to the United States markets.

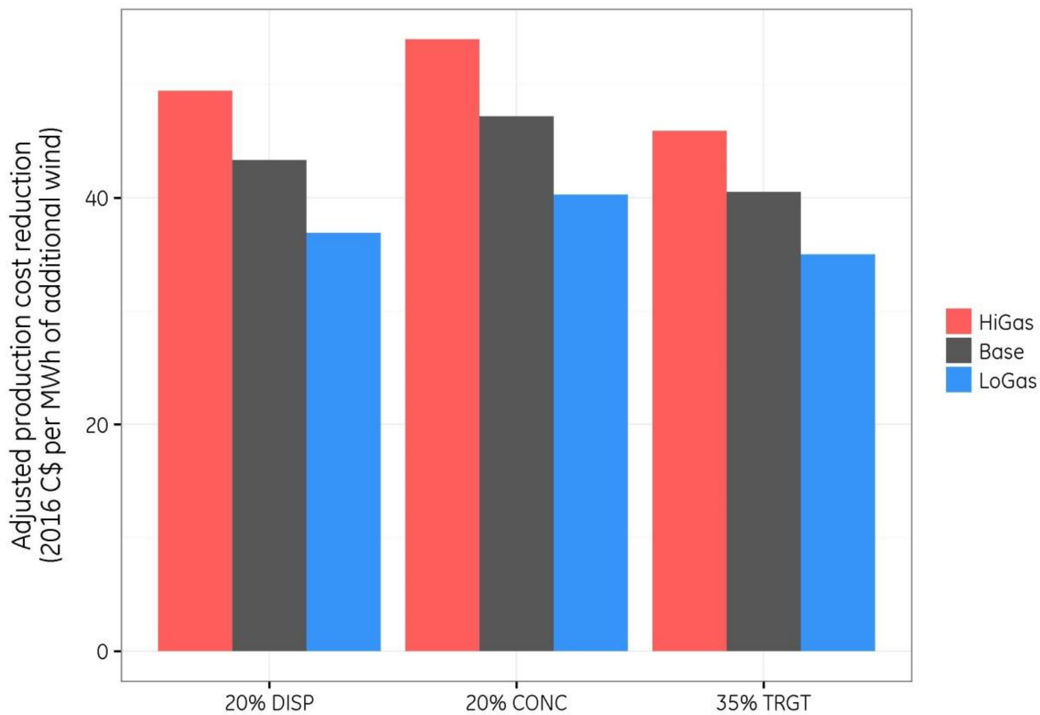


Figure 8-7: Adjusted Production Cost Reduction under Different Fuel Sensitivity Cases in Each Scenario Relative to the 5% BAU Scenario

Even in the HiGas case, natural gas is still the system-wide marginal fuel, which would still result in displacement of more natural gas-based units relative to the coal-based units due to higher wind penetration. "System-wide" includes both Canada and USA, and therefore energy dispatch and prices are determined by the interconnected energy market.

The main observations include:

- Even in Canada, with low gas generation relative to the overall resource mix, the avoided cost of wind is highly dependent on the price of natural gas, because gas units are normally on the dispatch margin in the interconnected Canada and USA system.
- There is nearly a one-to-one relationship between the gas price and avoided cost of wind (wind benefits) and that a 20% increase/decrease in the gas price assumption will yield a 20% increase/decrease in the resulting value of wind.

8.4 Wind Forecast Sensitivities

An accurate wind forecast is an essential component of power systems operations and planning for all systems with significant wind penetration. The production cost analysis conducted for this study assumed that the day-ahead unit commitment is performed using day-ahead wind forecast data; but in real-time operation, economic dispatch is performed using the real-time wind data. The difference between the wind forecast and the real-time wind production (forecast accuracy) impacts the adequacy of unit commitment. In general, a more accurate wind forecast will yield a more optimal unit commitment and dispatch schedule. Errors in wind forecast, or longer forecasting horizons, will result in either over-commitment or under-commitment of thermal generation, and hence result in either too many or too few committed units available for real time economic dispatch. Wind forecast sensitivities evaluate the impact of more accurate and more frequent (i.e., shorter time horizon) wind forecasts on the power system operational performance. Forecasts with shorter time horizons are inherently more accurate. The sensitivities considered include the following, ordered based on improved wind forecast accuracy:

- **Base:** Unit commitment and hydro scheduling in the Base Case assumed a Day Ahead wind forecast.
- **4HA**: Unit Commitment and hydro scheduling performed based on 4 hour-ahead wind forecast. This timeframe is generally considered short enough to improve wind forecast accuracy, while still providing a long enough lead-time to start combined-cycle or steam units if necessary.
- **1H Pers**: Unit Commitment and hydro scheduling performed based on 1 hour persistence, which is grounded on the notion that "this hour's wind is next hour's forecast", which is generally about as accurate as a 2-hour-ahead forecast.
- **Pfct**: Unit commitment and hydro scheduling performed based on perfect wind forecast, which assumes perfect knowledge of wind availability during unit commitment, and with no wind forecast error. This sensitivity provides an upper bound on the value of improved forecasting. Pfct forecast is identical to real time wind used in hourly unit commitment and economic dispatch.

Sensitivity case results are compared to the day-ahead unit wind forecast and unit commitment, which were used in the base scenario analysis).

Figure 8-8 presents all four wind forecasts on the same chart for a 2-week time period. The plot highlights the differences between the forecasts and the Pfct case (i.e., real time wind). The 1H Pers case is very close to the Pfct wind (i.e., actual wind), and hence, they appear to be nearly on top of each other. Figure 8-9 provides a closer look by zooming on a shorter time period. As can be seen, the 1H Pers is identical to the Real Time (same as Pfct and Actual) but lagging by one hour.

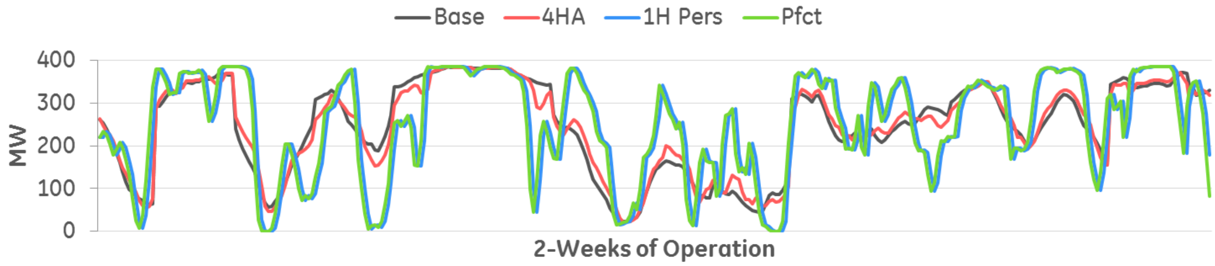


Figure 8-8: Wind Forecasts under Different Wind Forecast Sensitivities

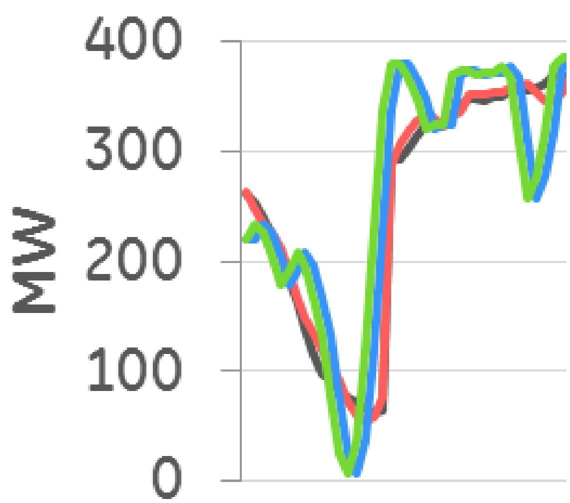


Figure 8-9: Wind Forecasts under Different Wind Forecast Sensitivities (Zoomed)

The Forecast Error is the difference between the Real Time wind and the Forecast Wind (i.e., the "expected" wind). Figure 8-10 and Figure 8-11 depict the forecast errors by plotting the forecast error as fraction of nameplate capacity, for a selected 384 MW wind plant in Alberta, and for Alberta total, respectively.

These figures clearly show that forecast accuracy improves significantly when aggregated over a large geographical area. This is a key message of the study: Forecast error is significantly reduced by aggregation across multiple wind plants in a balancing area, as grid operations depend on the aggregated forecast for a balancing area, not individual plant forecasts.

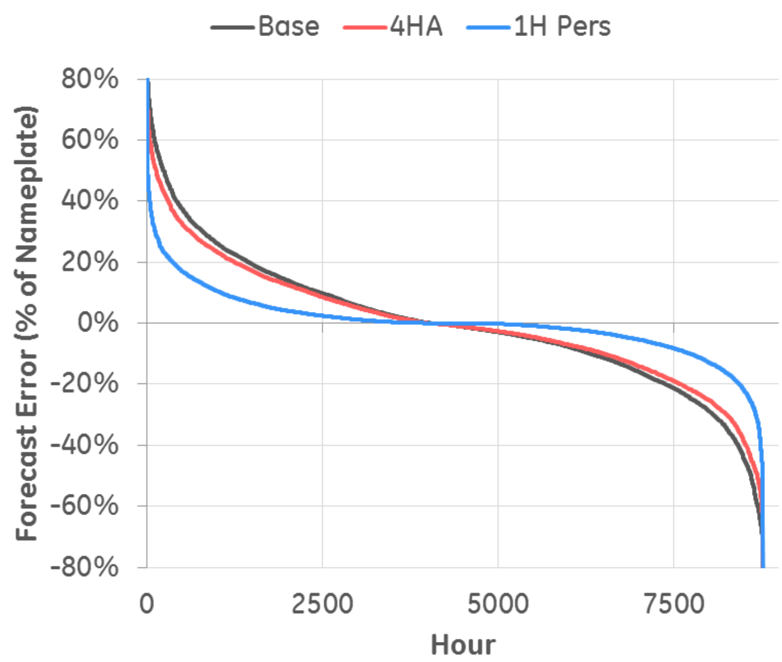


Figure 8-10: Wind Forecast Error for an Individual Plant (Plant #1988-385 MW)

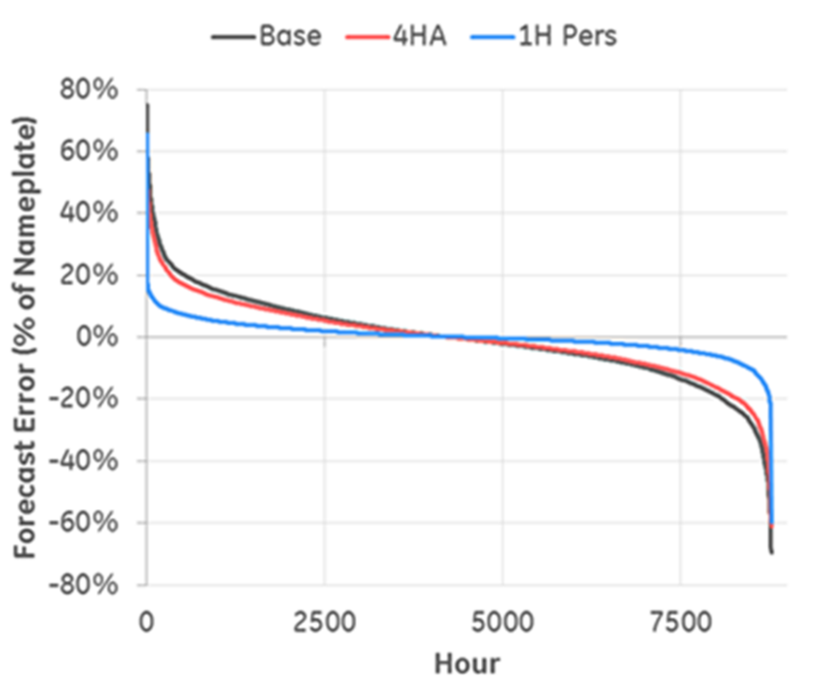


Figure 8-11: Wind Forecast Error for the Entire Alberta Footprint in 20% DISP Scenario

Day-ahead forecast errors for an individual plant can be large, but when aggregated on a province basis they are within +/- 10% for most hours of the year. 4HA forecast is slightly more accurate than the Day-Ahead forecast. 1H Pers forecast provides a half-way benchmark between 4HA and Pfct forecast.

Over-forecast errors are of greater concern than under-forecast errors. Over-forecasts of wind can lead to under-commitment of thermal units, and therefore, increased need for PEAKER units or demand response.

Figure 8-12 shows energy curtailment as fraction of available wind in each scenario and under different wind forecast sensitivities. It is evident that better forecast reduces energy curtailment, but even a perfect forecast cannot totally eliminate energy curtailment. This is because the curtailment is driven, in large part, by transmission congestion, not by the over-commitment of thermal generation.

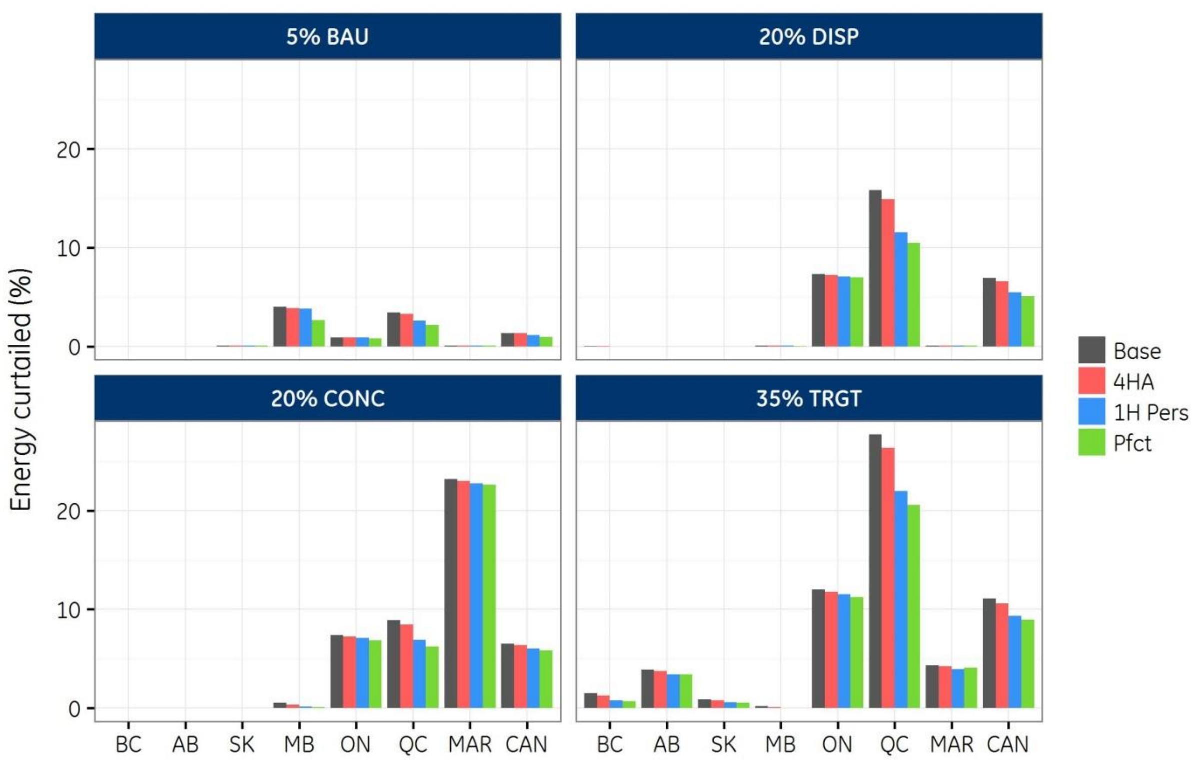


Figure 8-12: Energy Curtailment in Each Province under Different Wind Forecast Sensitivities

Under-forecast errors, on the other hand, can lead to over-commitment of thermal units. Therefore, in real time the committed units must be dispatched at lower and less-economic output levels. This increases operating costs. With too much generation committed, there are more reserves and headroom than needed.

Figure 8-13 illustrates the performance of PEAKER units under different wind forecast sensitivities. Results shown are based on aggregation of all quick-start units across Canada. Improved forecast reduces operation of PEAKER units (which are the quick-start units) in terms of their geneation, their number of hours online, and their capacity factor. However, as seen in the bottom chart of the same figure, PEAKER utilization is very low to begin with (between 2% to 3.5% capacity factor), and therefore, the overall economic impact will not be substantial.

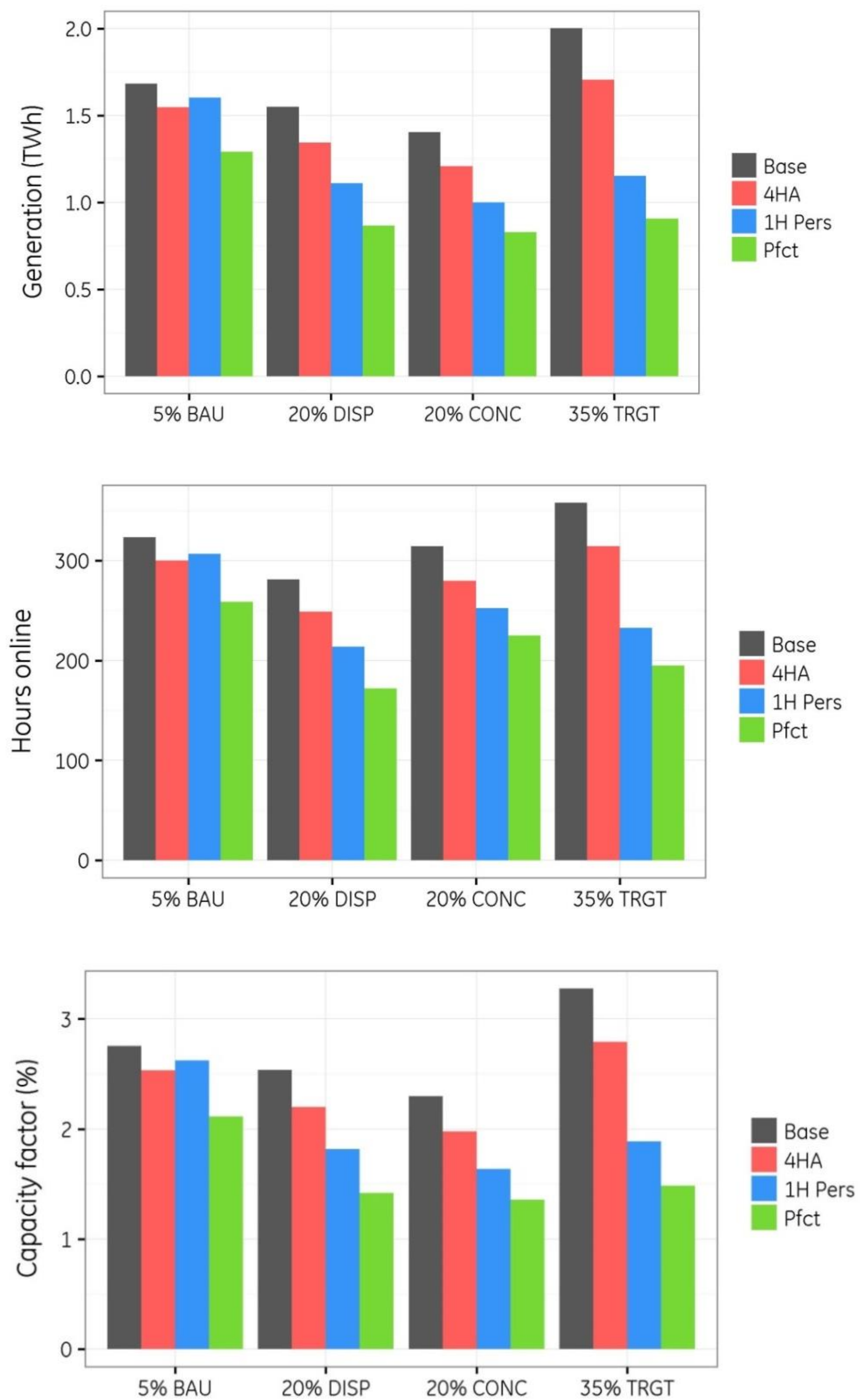


Figure 8-13: Peaking Unit Generation, Hours Online, and Capacity Factor under Different Wind Forecast Sensitivities

Figure 8-14 shows the value of the wind energy in C$/MWh for the different wind forecast assumptions. Wind value is calculated based on the difference in adjusted production cost for each scenario and its respective 5%BAU scenario. As expected, the value of the wind energy increases with higher accuracy forecasts in each scenario due to the improved efficiency of unit commitment based on those forecasts.

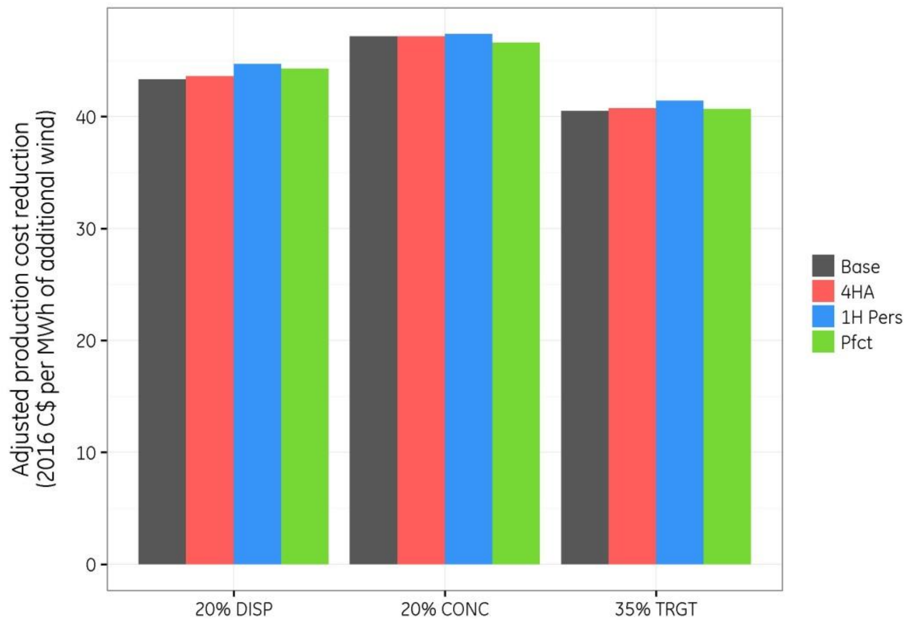


Figure 8-14: Adjusted Production Cost Reduction per MWh of Additional Wind under Different Wind Forecast Sensitivities Relative to the 5% BAU Scenario

The absolute value of the improved forecast within each scenario is simply the delta between the adjacent columns of each scenario times the incremental amount of the wind in that scenario over the amount of the wind in the 5% BAU scenario. An improved forecast helps, but it is not a radical change in system costs. It should be pointed out that perfect forecast breaks the trend. This is due to perfect wind forecast in the US too, which marginally reduces the value of imports.

Figure 8-14 shows that the value of wind in C$/MWh goes down as penetration goes up. But improved forecast accuracy has a slightly bigger positive impact with higher wind penetration.

8.5 Coal Retirement Sensitivities

The base study scenarios already account for all the publicly announced coal plant retirements scheduled before 2025 and based on the federal limitations of plant life (see Inputs and Assumptions section for more information). Canadian governments, both national and provincial, are considering additional retirement of coal based generation. This sensitivity considers impact of additional coal plant retirements in Canada.

The coal retirement sensitivities include:

- **Part coal**: In this sensitivity case, the coal-based generation capacity that is retired in Canadian provinces is set to be equal to the additional firm capacity provided by wind resources. As described in Section 10 on reliability analysis and capacity valuation, the wind firm capacity is based on the Effective Load Carrying Capability (ELCC) of the additional wind, which quantifies the wind capacity that can be counted on during peak demand hours. In this sensitivity case, system reliability is not reduced below required targets, since the added wind in each scenario is above and beyond what is needed for system reliability. Additional hydro and generic natural gas units were added to the system in the 5% BAU scenario in order to meet the installed reserve margin requirements in 2025, and these resources were retained in the higher penetration scenarios.

- **All coal**: In this sensitivity case, all Canadian coal is retired without any replacement with other unit types. This case provides a bookend for the analysis, but is not expected to be a reliable operating point without further addition of other types of capacity. Some balancing areas (i.e., AB and SK) will not meet installed reserve margin requirements without some new generation to replace the retired coal units.

Table 8-3 provides total nameplate wind capacity and firm wind capacity value in the four provinces with coal based generation. The incremental firm wind capacity above and beyond the 5% BAU scenario is provided in the columns to the right, which are roughly equal to the amount of coal capacity retired in the Part Coal sensitivity case. In the Part Coal sensitivity, coal retirements were selected based on unit age (oldest units retired first).

Table 8-3: Wind Capacity, Total and Firm, in Provinces with Coal Based Generation

Province	Coal Capacity (MW)	Wind Capacity (MW)				Firm Wind Capacity Value (MW)				Incremental Firm Wind Capacity Value (MW)			
		5% BAU	20% DISP	20% CONC	35% TRGT	5% BAU	20% DISP	20% CONC	35% TRGT	5% BAU	20% DISP	20% CONC	35% TRGT
AB	4,857	1,438	6,942	9,838	17,728	317	764	862	1,263	0	447	546	947
SK	1,111	450	1,747	914	4,406	124	270	204	426	0	147	81	302
MAR	1,247	874	1,471	2,383	3,618	378	617	820	1,146	0	238	441	769

Figure 8-15 shows total generation by unit type under different coal sensitivity cases for those provinces that have coal-based generation, i.e., AB, SK, and MAR (Maritime coal is in New Brunswick, and Nova Scotia). Coal retirements reduce total generation in all three provinces relative to the base cases. In each of the study scenarios, retiring coal reduces exports. In lower levels of wind penetration, these provinces become importers to meet internal demand.

Figure 8-16 shows the displacement in generation of other unit types under different coal sensitivity cases. Retiring coal, in addition to reducing exports (or turning provinces into importers), also results in increased generation by some unit types, particularly, CC-GAS and PEAKER units in AB and SK, and COGEN in AB. Therefore, to meet internal demand, some energy is provided from increased utilization of other in-province resources, mainly natural gas units, with rest made up by imports from neighbouring areas. There is also increase ST-GAS generation in the All Coal case in MAR.

As noted before, the All Coal sensitivity case may not be realistic, since to maintain system reliability, and to meet installed reserve margin targets in 2025, additional capacity of other units types may have to be added to the province's installed base.

Some of the increased generation by CC-GAS units caused by coal retirements is actually the generation that was previously displaced by wind. This increased generation also replaces some of the needed imports caused by the retirement of the coal units.

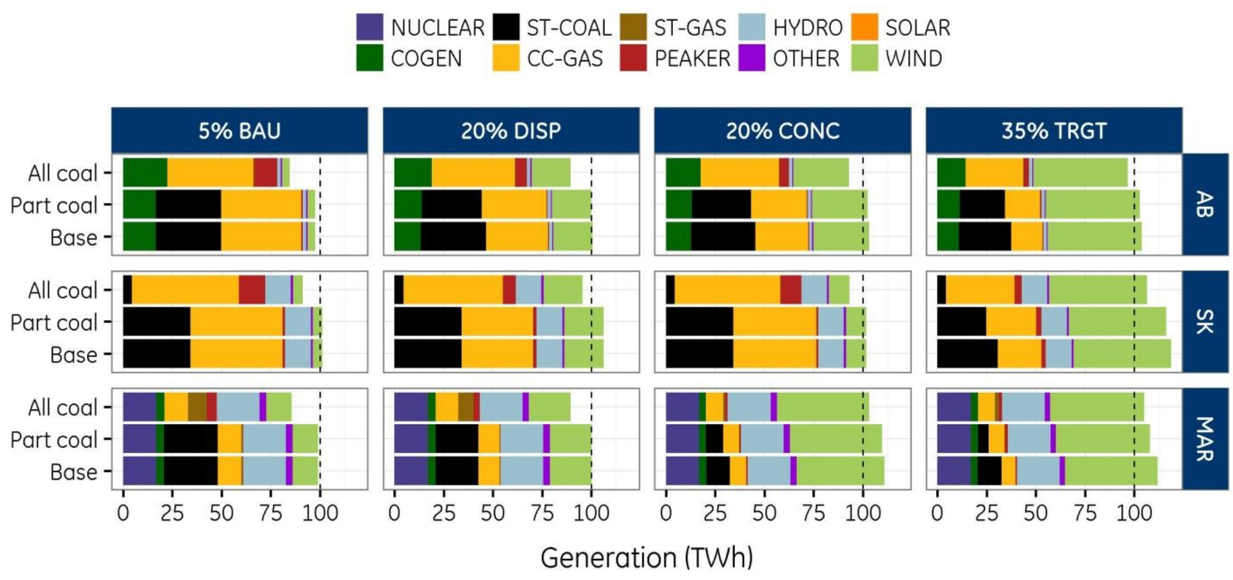


Figure 8-15: Generation by Unit Type under Different Coal Sensitivity Cases

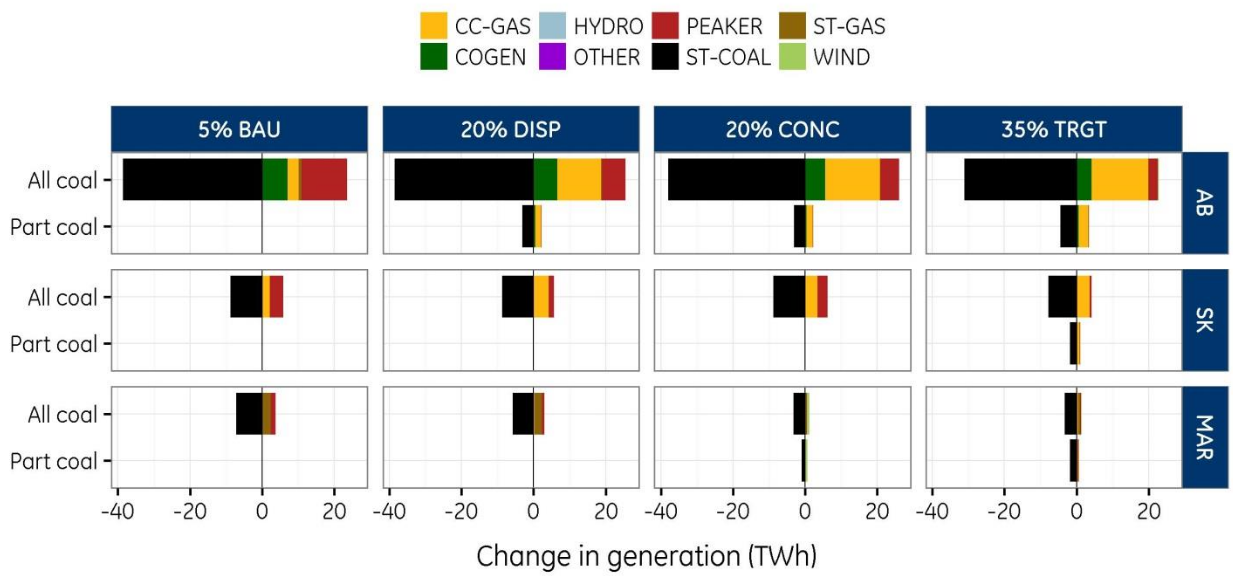


Figure 8-16: Displaced Generation by Unit Type under Different Coal Sensitivity Cases

Coal plant retirement also has a significant impact on CO2 emissions. Figure 8-17 depicts changes in emissions under the Part Coal and All Coal sensitivity cases compared to the base case scenarios. A number of observations can be made:

- Coal retirements result in lower CO2 emissions in Canada, and higher CO2 emissions in the USA. The coal generation in Canada is replaced by relatively cleaner natural gas (which produces only half as much CO2 compared to coal per unit of heat content). However, coal retirements in Canada also result in less energy export to the USA, and hence, result in less displacement of fossil-fuel based generation in the USA
- The increase in USA CO2 emissions could be construed as a case of "carbon leakage[23]", which occurs when a carbon emissions reduction policy in one region leads to an increase in carbon emissions in another
- Even with increased CO2 emissions in USA, total CO2 emissions are reduced system-wide with coal retirements in Canada.
- For the All Coal sensitivity, CO2 reductions in Canada are lower with 35% wind penetration than with 5% wind penetration. This counter-intuitive result is because the 5% BAU scenario is balanced capacity-wise (that is, installed capacity exactly meets the minimum requirement). Hence in the All Coal retirement case, there is no surplus capacity to replace the retired coal capacity within Canada, so the needed energy is met by

[23] http://ec.europa.eu/clima/policies/ets/cap/leakage/index_en.htm

imports from USA. But in higher wind penetration scenarios, there is surplus capacity in the system due to additional wind resources. The retired coal capacity is partially replaced by under-used natural gas based generation, which emits some CO2 (but not much as would have been emitted by the retired coal units).

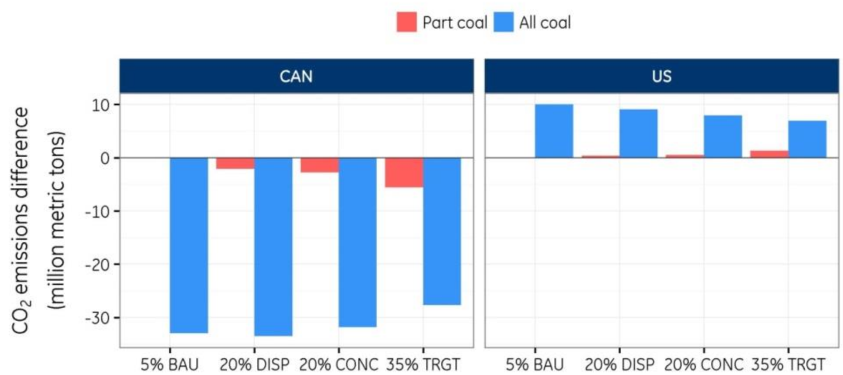


Figure 8-17: Changes in CO2 Emissions in Different Coal Sensitivity Cases Relative to the Base Case

Adjusted production costs under coal sensitivity cases are shown in Figure 8-18.

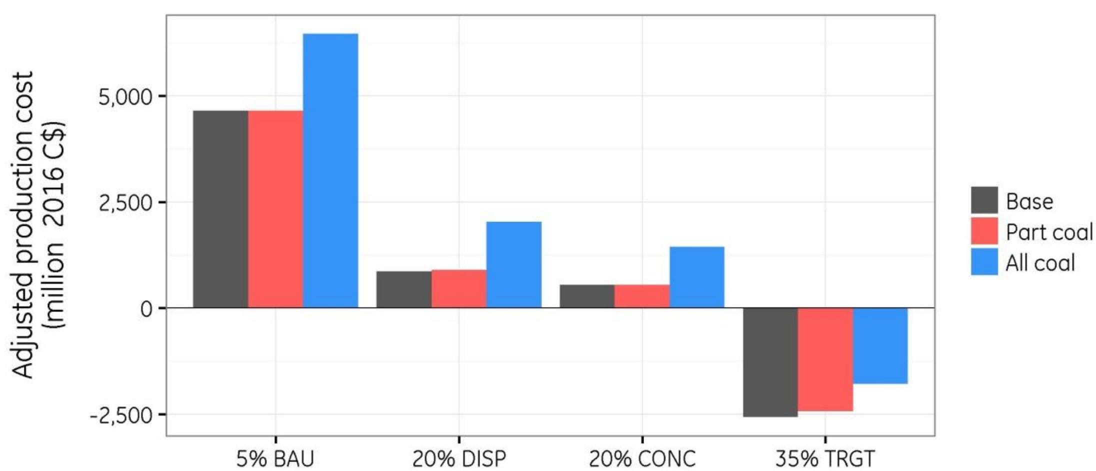


Figure 8-18: Adjusted Production Cost under Coal Sensitivity Cases

Key takeaways from the coal retirement sensitivity cases are:

- Retiring coal leads to increased operating costs because coal generation is replaced by higher cost natural gas-based resources together with increased imports (or reduced exports).

- If all coal units are retired in AB and SK, load shedding or demand response may be required during peak load periods without the coal generation.
- The increase in production costs between Base and Part Coal retirement scenario is relatively small. This is because the amount of retired coal is equal to the capacity value of the added wind. Therefore, in Part Coal cases, all balancing areas meet their required installed capacity margin requirements, and in most likelihood, the retired coal capacity would not have been fully utilized.
- In the All Coal cases, AB, SK, and MAR are deficient in generation capacity, resulting in more imports (or conversely, less exports), and also possibly dispatching of expensive demand response or load shedding.
- Additional replacement capacity from firm resources would be required in the All Coal case in order to maintain system reliability. This would require capital investment for new equipment.

8.6 Hydro Scheduling Sensitivities

It was assumed in our analysis that the thermal and hydro generation is typically scheduled (committed) against the forecast of net load (i.e., Load minus Day-Ahead Wind Forecast). Therefore, wind forecasts affect the scheduling of hydro generation, which in turn affects the commitment of thermal generation to serve the remaining load. As noted before, over- and under-commitment of thermal generation will impact the system-wide operational and economic performance.

The hydro scheduling sensitivity analysis considers two distinct hydro scheduling methods as alternatives to the base case method:

- Base: Hydro resources are scheduled against net load, assuming a day-ahead wind forecast. This method is used in the analysis of the base scenarios, which assumes some flexibility in hydro scheduling, and access to the day-ahead wind forecast and next day's load data. The Base case hydro hourly dispatch schedule does not change when real-time wind is different from the forecasted wind, unless surplus hydro is available that would otherwise be wasted (spilled).
- DA load: Hydro resources are scheduled against load only, while ignoring the wind forecast. This case assumes hydro resources are less flexible than in the Base Case. Hydro scheduling is determined before the wind forecast, and hence would not take into account the additional wind energy in the system, and would not respond to net load variability introduced by the wind energy. In general, this will lead to over-commitment of thermal resources.

- RT net load: Hydro resources are scheduled against real-time wind and load. This case assumes that hydro resources are more flexible than the Base Case assumption. Hydro scheduling can be adjusted in real time (hourly), allowing hydro generation to respond to deviation of real-time wind from the forecasted wind.

Figure 8-19 illustrates the different load profiles against which hydro resources are scheduled in each of the three hydro scheduling sensitivities. The three load shapes against which hydro is scheduled have different peak and valleys during the week. Therefore, a peak shaving hydro schedule under these three different load shapes will result in different net loads against which thermal generation have to be committed and dispatched.

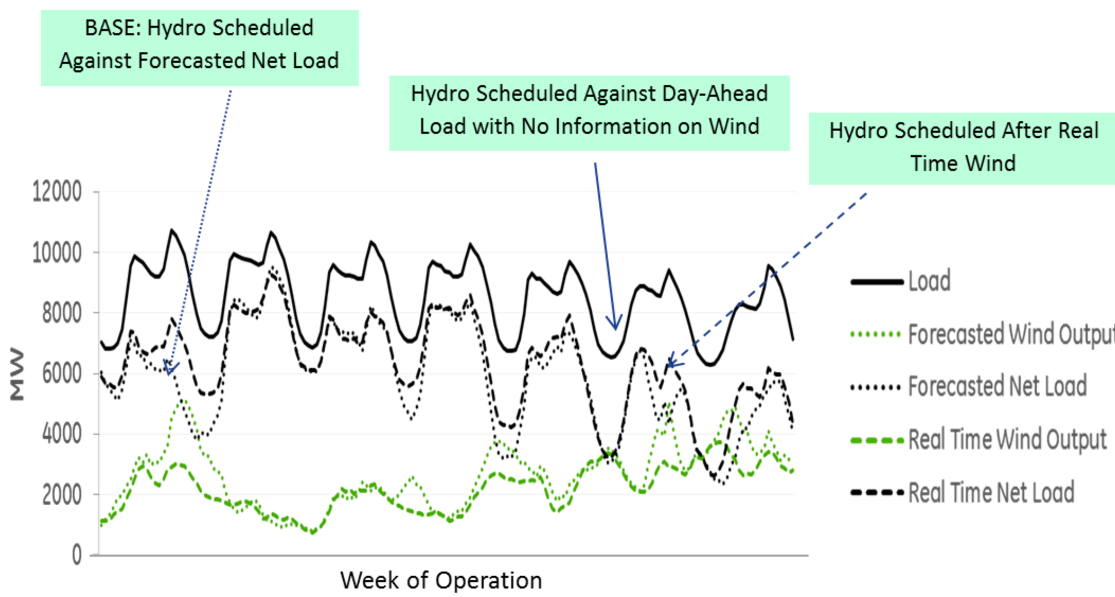


Figure 8-19: Actual Load, Forecasted Net Load, and Real Time Net Load for One Week

Figure 8-20 displays levels of energy curtailment relative to load in each province under different hydro scheduling sensitivities. As expected, energy curtailment is highest under the DA Load case (the least flexible hydro scheduling), and is lowest under the RT Net Load (the most flexible hydro scheduling). The impact is most pronounced in QC, where hydro generation dominates the generation portfolio. In the 20% DISP scenario, energy curtailment in Canada is about 15% in the DA Load case, but it drops to less than 5% in the RT Net Load case. The results demonstrate that using wind forecast information to schedule hydro generation will improve system efficiency significantly. Much of that efficiency benefit is achieved by using day-ahead wind forecasts for day-ahead hydro scheduling. Additional benefit is possible if hydro generation dispatch can be adjusted in real time to compensate for errors in the day-ahead wind forecast.

Note that the curtailment values in this chart include hydro spillage, along with wind curtailment. It is therefore evident that the hydro resources in QC can be constrained by HVDC transmission limits to neighbouring markets if not scheduled properly.

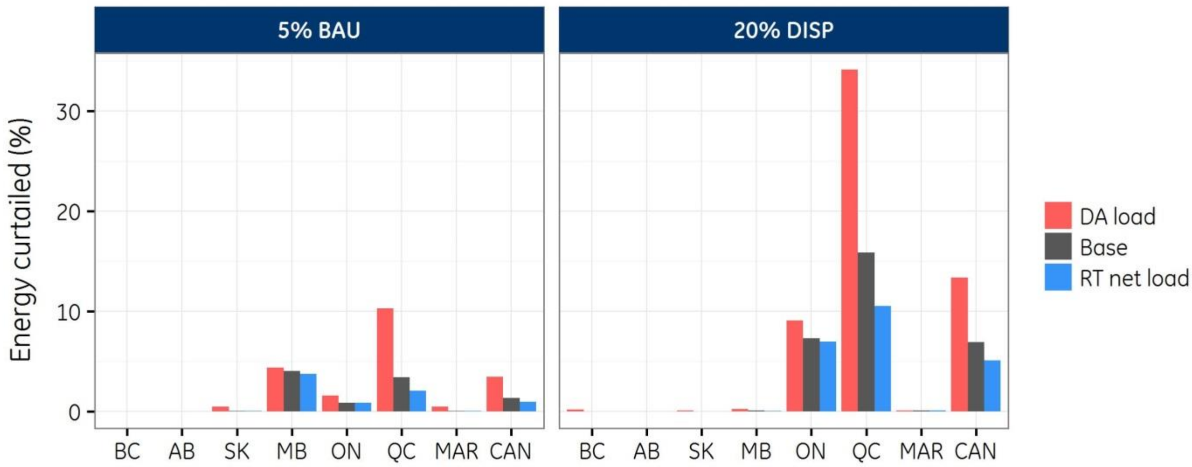


Figure 8-20: Energy Curtailment in Each Province under Different Hydro Sensitivities

Table 8-4 shows the change in production costs from the Base case under the two bookend hydro flexibility cases. Under the two scenarios tested, the less flexible scheduling (not using wind forecast to schedule hydro) results in higher production costs compared to the Base case. Conversely the more flexible scheduling (adjusting hydro dispatch in real time) results in lower production costs compared to the Bae case.

Table 8-4: Changes in Production Cost for Different Hydro Scheduling Practices

Scenario	Change in Adjusted Production Cost (C$M/year)	
	Hydro Scheduled Against Day-Ahead Load Only	Hydro Scheduled Against Real-Time Net Load
5% BAU	100	-16
20% DISP	494	-144

8.7 Wind and Load Weather Year Sensitivities

Although the year of the study is 2025 with the corresponding projected annual load energy and peaks for each region, the underlying hourly wind and load shapes are based on the historical data from the 2008 weather year. Having the same weather year as the basis for the wind and load hourly profiles is important, since it preserves any underlying weather related correlation between wind and load's temporal variations.

The wind and load weather year sensitivities assess impact of using different weather years for the analysis. As noted earlier, the project team collected wind and load data for years 2008, 2009, and 2010. Note that these weather years were also used in the Effective Load Carrying Capability (ELCC) reliability analysis conducted in this study. Therefore, the wind and load weather year sensitivities include the following cases:

- 2008 weather year hourly wind and load profiles, scaled to 2025 peak and energy (the Base Case)
- 2009 weather year hourly wind and load profiles, scaled to 2025 peak and energy
- 2010 weather year hourly wind and load profiles, scaled to 2025 peak and energy

Base scenario analysis and the all other sensitivity analysis are performed using the 2008 weather year. The chronological wind and load profiles were scaled up to projected 2025 annual peak and energy targets. The corresponding 2008 to 2010 load and wind duration curves are shown in Figure 8-21. From an annual perspective, the total Canada load and wind energy are very similar across the three years.

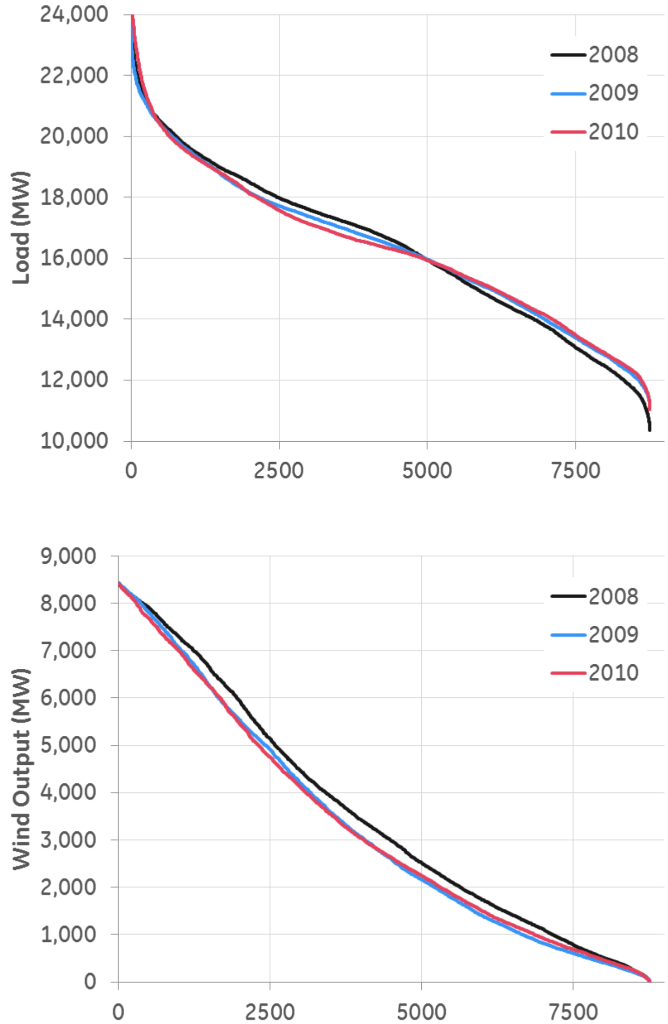


Figure 8-21: Load and Wind Duration Curves in 2008, 2009, and 2010 Weather Years (20%DISP)

Using different profile years for the same plants in the base scenarios results in slightly different penetration levels compared to the original profile years used for construction of the scenarios. Figure 8-22 depicts the wind energy penetration as a percentage of total annual load energy by province and scenario.

Total annual load energy is the same in all three years, but the daily shapes are based on historical load profiles from each year. Wind energy is a function of the wind profiles at the wind plants in each scenario, which depends on the unique weather conditions in each year. The figure shows that there are modest variations in wind energy across the three years. The Base Case (2008) has the highest wind penetration across Canada. Generally, individual plants or chronological profiles may change more significantly, but overall difference across the three years is small.

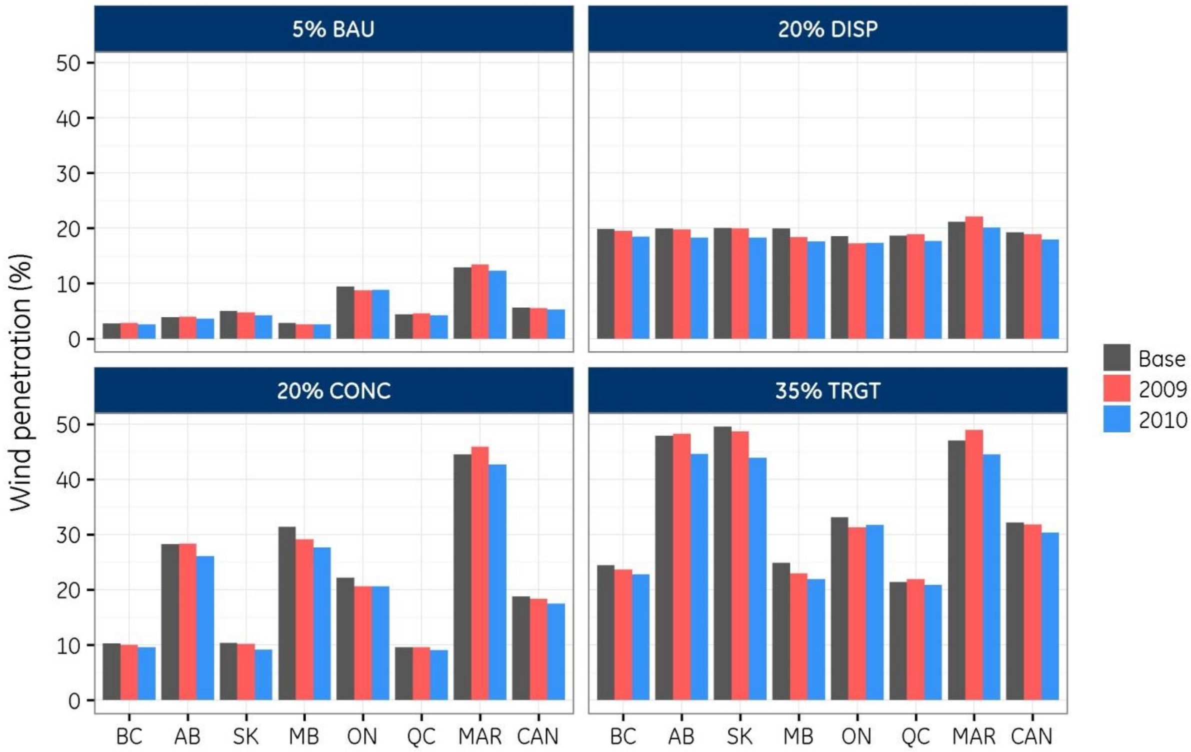


Figure 8-22: Wind Penetration as Percent of Load by Province under Different Wind/Load Profile Years

Different wind plant power output profiles produce different levels of energy curtailment under the three wind and load weather years, as shown in Figure 8-23. The 2008 weather year has slightly more wind energy and consequently has slightly more energy curtailment than the other years. But in general, system operational performance is similar in all three years.

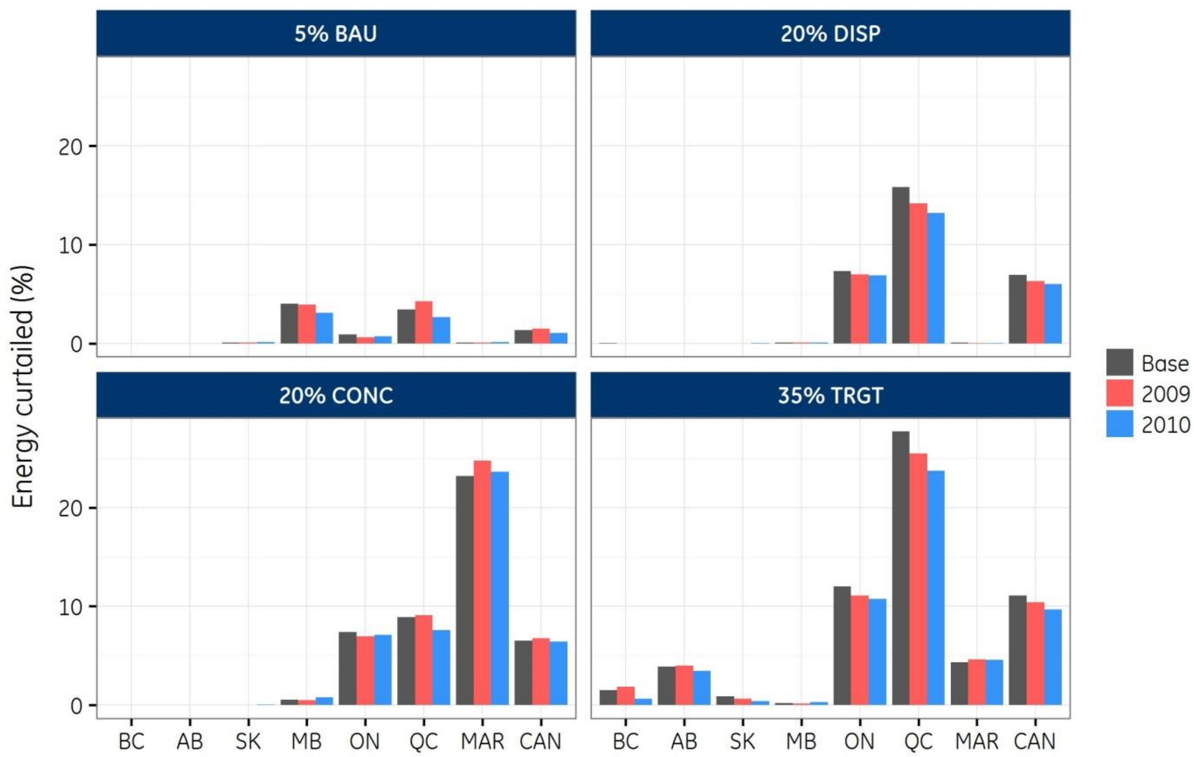


Figure 8-23: Energy Curtailment in each Province under Different Wind-Load Profile Years

The variations in annual curtailment between 2008, 2009, and 2010 weather years appear to be small. Differences in curtailment are most likely due to differences in the underlying resource production profiles. However, the general trend observed is a correlation between energy curtailment and wind penetration level.

Figure 8-24 provides the generation by type (as ratio of load) in each province under different weather years, in the 20% DISP scenario. Lower wind penetration years are associated with higher generation by thermal units. But overall in Canada, changes in generation by unit type are relatively small

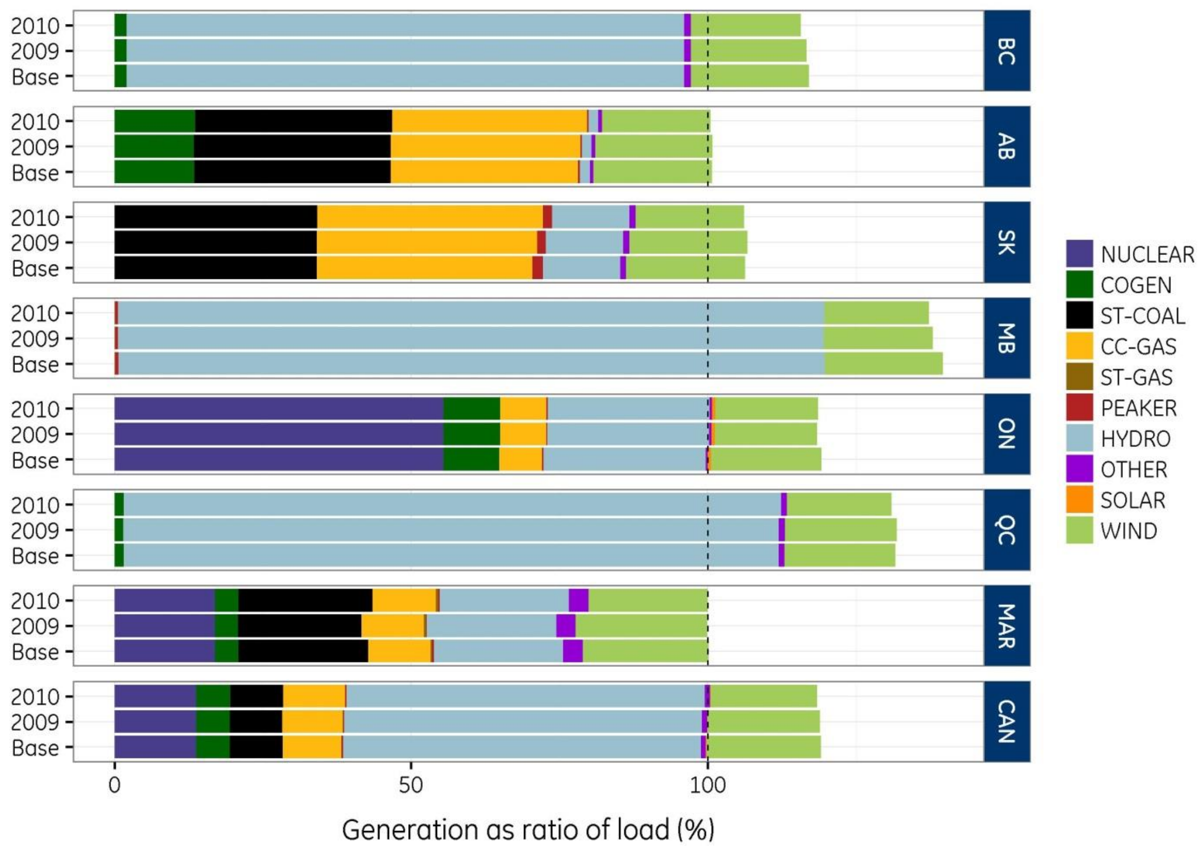


Figure 8-24: Generation as Ratio of Load under Different Wind-Load Profile Years (2008) in 20% DISP Scenario

Figure 8-25 shows the "value of wind energy", expressed in $/MWh of additional wind production above the 5% BAU scenario. It is the reduction in adjusted production cost divided by the additional MWh of wind energy that caused the cost reduction.

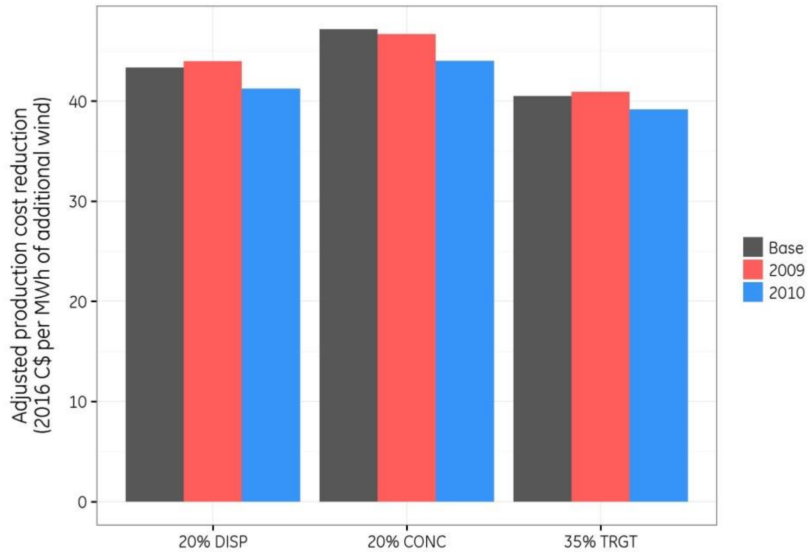


Figure 8-25: Change in Adjusted Production Cost Relative to the 5% BAU Scenario under Different Wind-Load Profile Years

The changes across the three years are small enough to conclude that variations in wind and load profiles based the underlying wind and load weather year will not materially impact the general findings of this study. In addition, because 2008 had the highest wind penetration rates for the Canadian system; it confirms that using 2008 as the Base Case assumption was most conservative because it required the most changes to system operations.

8.8 USA Wind Build-Out Sensitivity

The four base scenarios in this study, i.e., 5% BAU. 20% DISP, 20% CONC, and 35% TRGT, represented 5%, 20%, and 35% wind penetration levels (as a percent of load) in 2025 across Canada. In contrast, the USA wind penetration was kept constant across all 4 scenarios, with a wind energy penetration based on achieving the USA renewable portfolio standard (RPS) targets by 2025.

This sensitivity analysis considers the case when wind resources in USA are increased by 20% beyond their RPS target levels in 2025. The increase in wind was accomplished simply by scaling up of existing wind profiles in the USA linearly by 20%, without adding any new wind plants. Apart from scaling up of energy production of wind plants, no other data parameters were changed in USA.

Table 8-5 provides a summary of the 2025 Base Case USA wind capacity and generation by pool, which is based on the projection of RPS targets applied to the wind plant portfolio used in the NREL ERGIS and WWSIS2 studies.

Figure 8-26 shows the original and added wind capacity in USA In this analysis, MISO is the pool with the largest installed wind base, and is also one of the largest pools bordering Canada.

Table 8-5: Base Case USA Wind Capacity and Generation

Pool	Pool Load (GWh)	Wind Capacity (MW)	Available Wind Energy (GWh)	Available Wind Capacity Factor (%)	Available Wind Penetration (%)
BAS	87,598	995	2,975	34%	3%
CAL	332,500	7,299	23,212	36%	7%
DSW	167,059	4,174	12,254	34%	7%
FRCC	259,363	0	0	0%	0%
ISONE	133,902	5,218	19,016	42%	14%
MISO	636,222	40,343	156,898	44%	25%
NWP	193,991	10,392	32,875	36%	17%
NYISO	173,294	12,076	43,130	41%	25%
PJM	969,027	15,630	55,680	41%	6%
RMP	78,160	5,040	18,483	42%	24%
SERC-E	255,709	3,760	14,098	43%	6%
SERC-N	249,537	200	467	27%	0%
SERC-S	293,229	0	0	0%	0%
SERC-W	148,672	0	0	0%	0%
SPP	288,431	28,927	118,873	47%	41%
TOTAL US	**4,266,695**	**134,054**	**497,960**	**42%**	**12%**

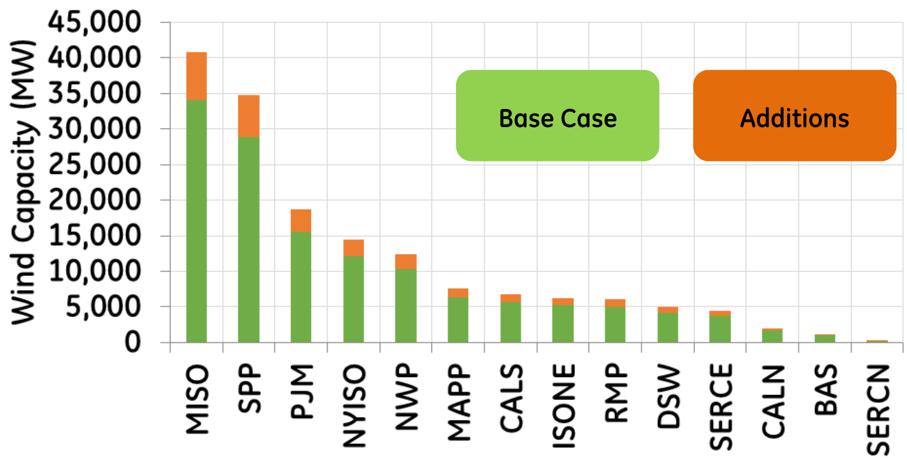


Figure 8-26: Base Additional Wind Capacity in USA by Pool

Table 8-6 summarizes the total wind generation in Canada and USA under the Base and US Wind cases. Increases in USA wind results in some reduction in wind generation in Canada due to curtailment associated with transmission congestion for Canada to USA exports. However, at 0.8%, the reduction is a very small fraction of the available wind in Canada and considering the amount of wind additions in the USA. The total energy curtailment in Canada is around 1.1% of wind energy increase in USA.

Table 8-6: Comparison of Canada and USA Wind Capacity under Base and US Wind Cases in 20% DISP Scenario

	BASE CASE (GWh)	US Wind Case (GWh)	DELTA (GWh)	Delta (%)
Canada Wind	117,372	116,379	-993	-0.8%
USA Wind	497,960	588,785	90,825	18.2%
Canada/USA	**23.6%**	**19.8%**	**-1.1%**	

Increased energy curtailment by province under the US Wind case relative to the Base case is shown in Figure 8-27. Consistent with the previous table, additional wind in the USA causes a small increase in energy curtailment in Canada.

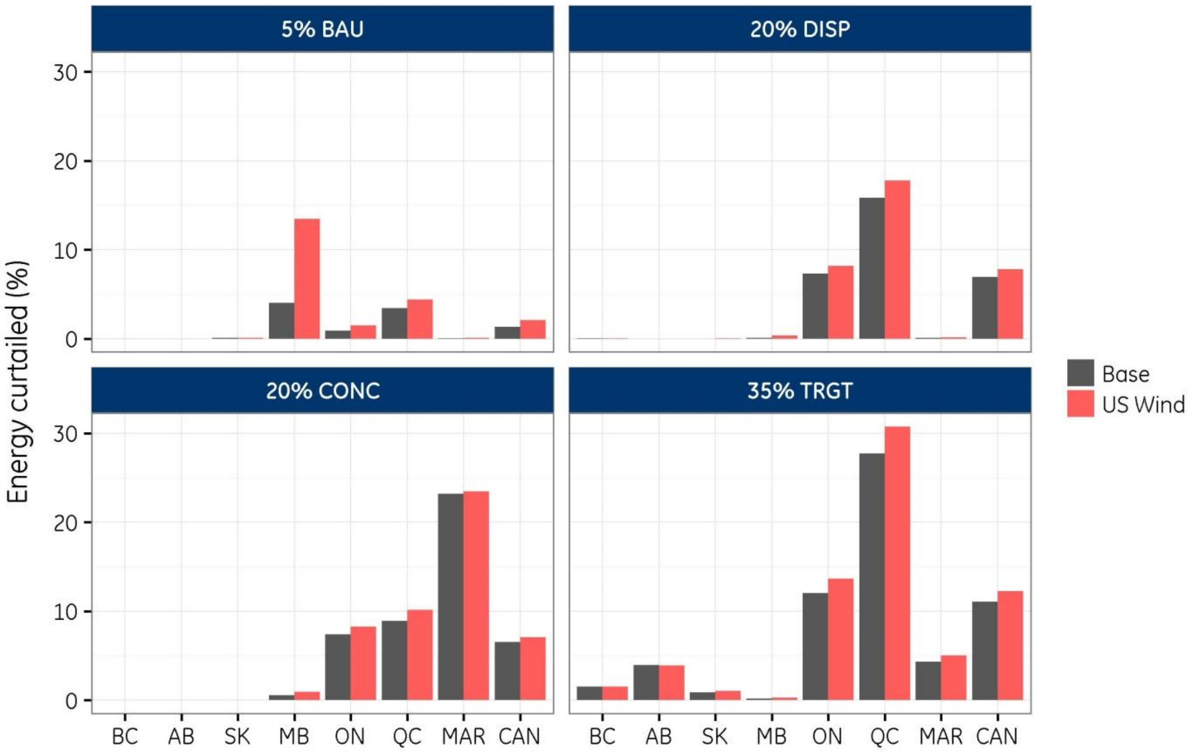


Figure 8-27: Energy Curtailment under Base and US Wind Sensitivity Cases

Impact of additional wind in USA on generation by unit type in Canada in 20% DISP scenario is provided in Figure 8-28. The largest impacts are on the thermal generation in Canadian provinces with the most thermal generation, as the additional USA wind energy displaces some of their production. Hydro-rich provinces are not significantly affected by increased wind energy in the USA.

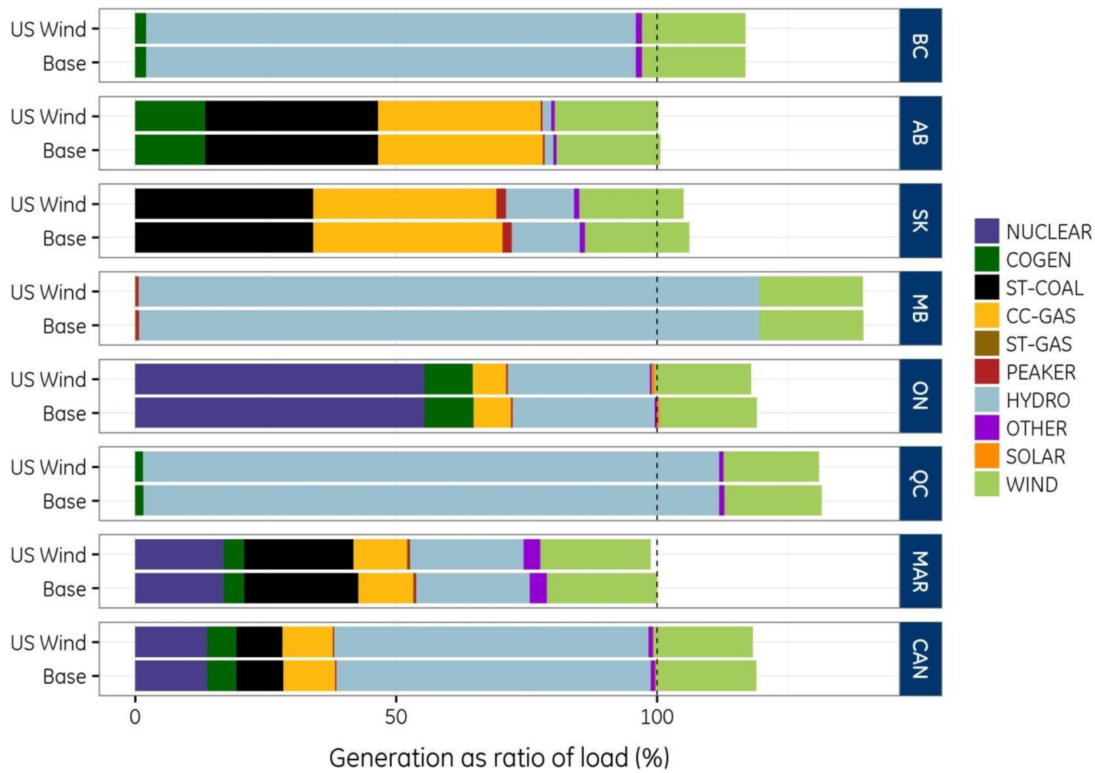


Figure 8-28: Generation as Ratio of Load under Base and US Wind Sensitivities in the 20% DISP Scenario

System-wide adjusted production cost reduction per unit of added wind in the USA over the 5% BAU scenario is provided in Figure 8-29.

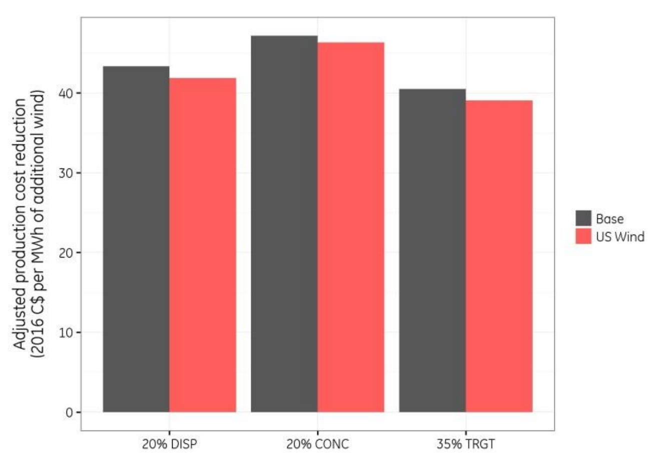


Figure 8-29: Changes in System-Wide Adjusted Production Cost Per MWh of Added Wind Relative to the 5% BAU Scenario under Different Base and US Wind Sensitivity Cases

8.9 Emerging Energy Technology Sensitivities

This set of sensitivities considers the impact of more intensive deployment of different types of distributed energy resources (DER) in the Canadian power system.

Sensitivities considered include the following technology deployments in Canada:

- DPV: Increased distributed solar photovoltaic (PV) resources
- DR: Increased demand response resource participation
- Storage: Increased grid scale energy storage installation
- EV: Increased penetration of electric vehicles and electric vehicle charging

These sensitivities are compared to the Base scenarios which do not include any of these DER technologies.

8.9.1 Distributed PV Sensitivity

Distributed PV (DPV) sensitivity assumes addition of distributed solar PV capacity to meet 5% of annual energy in each province. DPV is set to be below wind and other resources in the curtailment priority order (i.e., DPV is curtailed last), based on the assumption that central control of widely distributed and small scale DPV resources is far more technically challenging than other grid scale resources.

Individual solar profiles were constructed using the NREL PVWatts SAM Tool[24]. Residential solar profiles were created for each major population center in Canada based on the population weighted average of each province.

Table 8-7 lists the NREL sites (cities and provinces) used for the construction of the solar profiles. The last column in the table shows the distribution of the solar capacity by the major cities in each province in proportion to the population of the cities within each province. The reasoning is that, everything else being equal, the geographic distribution of residential solar PV capacity in Canada will be proportional to the underlying population.

All the profiles were then scaled to reach the 5% annual energy target for each province. A normal solar weather year was assumed, which does not necessarily match the solar profile of the 2008 wind and load weather year used in most of the modeling.

[24] http://pvwatts.nrel.gov/

Table 8-7: NREL Solar Sites and Their Populations

NREL Site	Province	Population	Scalar
Vancouver	BC	2,135,201	82%
Victoria	BC	316,327	12%
Abbotsford	BC	149,855	6%
Calgary	AB	1,095,404	50%
Edmonton	AB	960,015	44%
Medicine Hat	AB	65,671	3%
Fort McMurray	AB	61,374	3%
Winnipeg	MB	671,551	100%
Saskatoon	SK	222,035	54%
Regina	SK	192,756	46%
Toronto	ON	5,132,794	78%
Ottawa	ON	697,267	11%
London	ON	366,191	6%
Windsor	ON	276,165	4%
Thunder Bay	ON	102,222	2%
Montreal	QC	3,407,963	83%
Quebec	QC	696,946	17%
St John	NB	95,902	61%
Fredericton	NB	61,522	39%
Shearwater	NS	297,943	75%
Sydney	NS	97,398	25%
Charlottetown	PE	N/A	100%

Resulting DPV capacity and capacity factors are provided in Table 8-8 for each province. DPV's annual capacity factors vary between a low of 13.8% in BC to a high of 17.6% in SK. DPV capacity values may seem optimistic, but they are simply used as assumptions for the sensitivity analysis. They are not projections of future DPV capacity in Canada.

Table 8-8: Distributed PV Capacity in Canada under DPV Sensitivity

	BC	AB	SK	MB	ON	QC	MAR
DPV Capacity (MW)	2617	4,110	963	1,032	5,416	7,657	985
DPV Capacity Factor (%)	13.8%	16.1%	17.6%	16.7%	15.1%	15.0%	14.9%

Monthly DPV capacity factors by province are shown in Figure 8-30. Monthly patterns reveal that DPV capacity factors are 5% to 15% in the winter months and 20% to 25% in summer months.

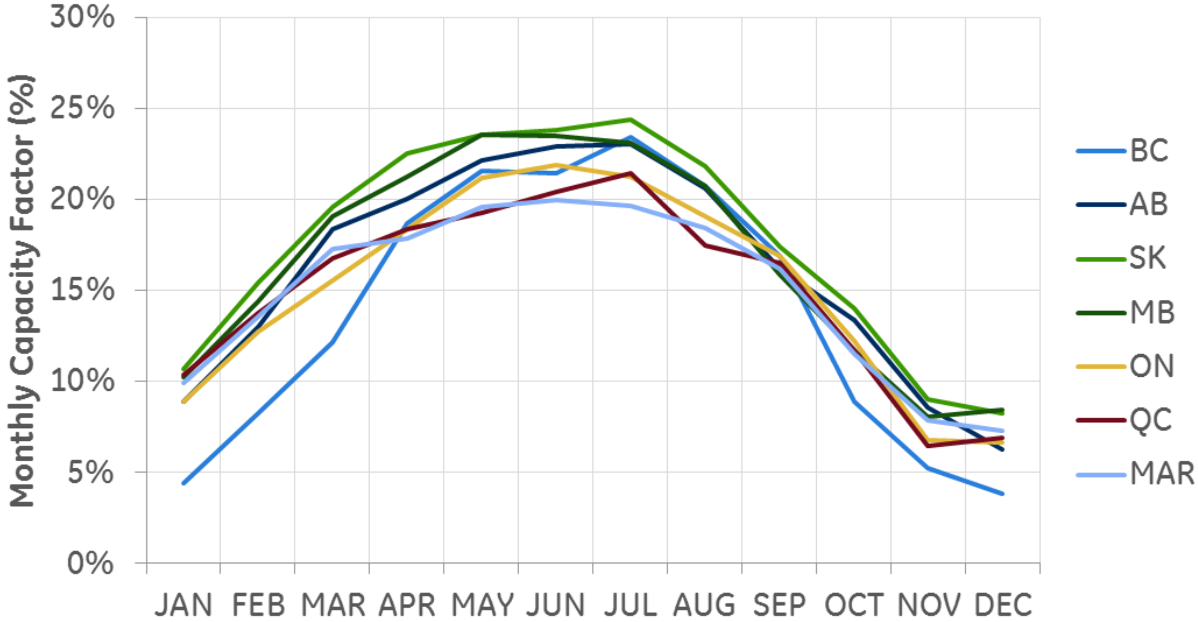


Figure 8-30: Monthly DPV Capacity Factors by Province

Figure 8-31 compares the total annual curtailed energy as ratio of load in Canada under the Base and DPV cases. Additional renewable solar energy is merely adding to the existing generation, and therefore causing more energy curtailment. As noted, it was assumed that DPV is ahead of wind and other renewable resources in the curtailment priority list. Therefore, DPV is not curtailed in the study scenarios.

In the 5% BAU scenario, curtailment increases from about 1% to about 4% of annual wind energy available. In the 35% TRGT scenario, curtailment increases from about 12% to 17% of available wind energy. However, these changes in energy curtailments should be viewed against an additional 5% annual energy in the DPV case (a further 5% renewable penetration). A change or adjustment in transmission reinforcements, which would account for the DPV additions, may reduce energy curtailments observed in this sensitivity.

Differences in diurnal pattern and seasonality show wind and solar can be complimentary resource.

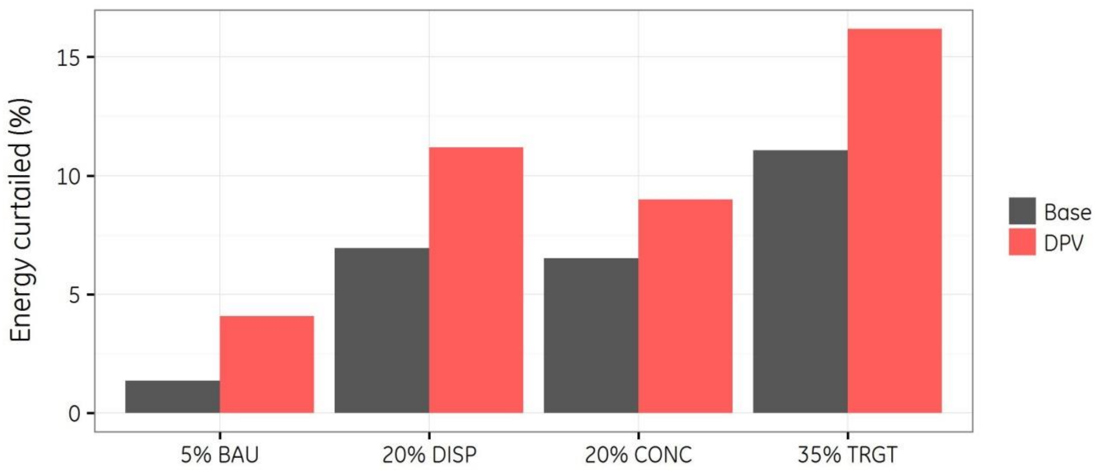


Figure 8-31: System-Wide Energy Curtailment under Different Distributed PV Sensitivity Cases

Figure 8-32 displays the increase in energy curtailment per MWh of DPV energy added in each province. Results indicate that with each additional MWh of DPV, additional energy is curtailed but the amount of new curtailment is a fraction of the additional energy from DPV. It is likely that additional energy curtailments would be reduced if the transmission reinforcement is done with accounting for the new DPV additions

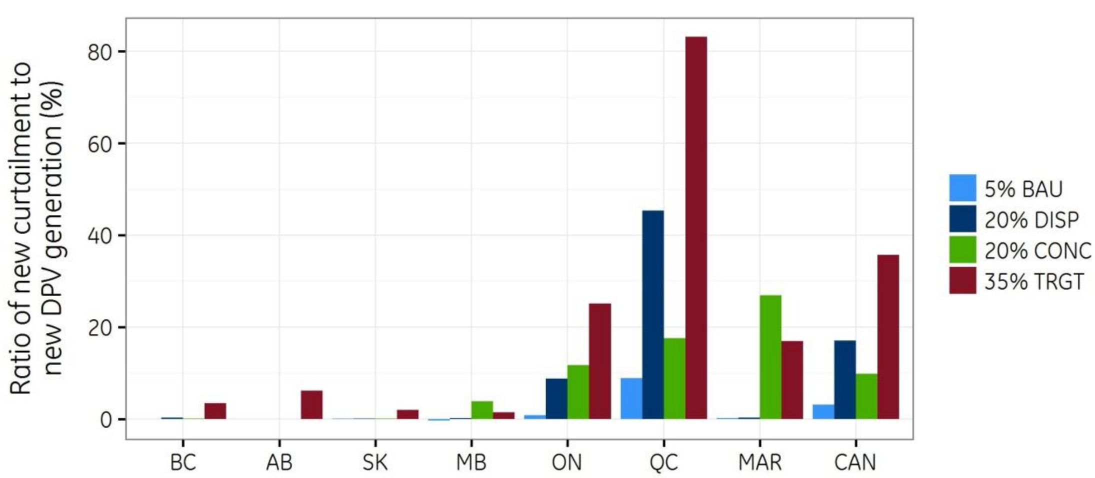


Figure 8-32: Increase in Energy Curtailment per MWh of DPV Energy Added

Figure 8-33 presents generation by unit types in the Base and DPV cases. The solar DPV additions are shown in orange colour. The additional DPV energy results in reduced utilization of thermal resources (coal and gas) as well as increased exports from the hydro-rich provinces.

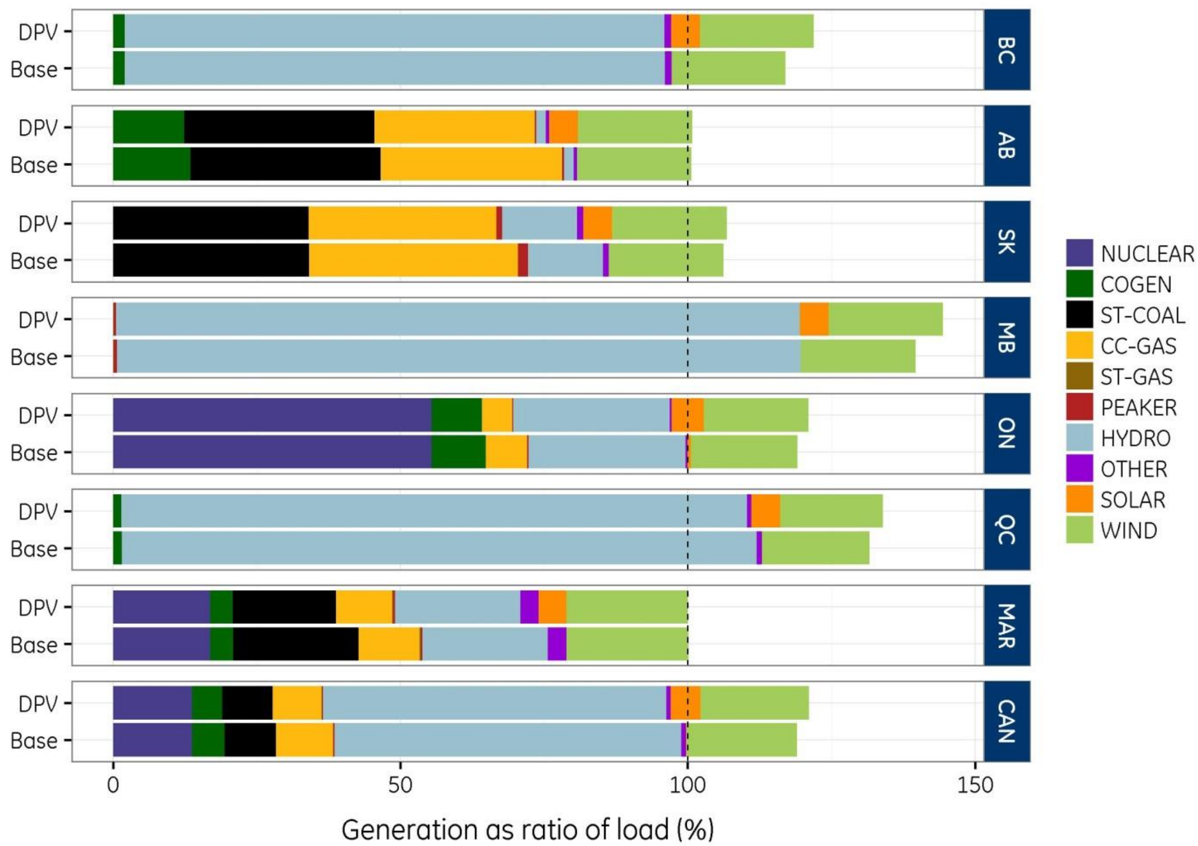


Figure 8-33: Generation by Type as Ratio of Load for Distributed PV Sensitivity Cases in 20% DISP Scenario

8.9.2 Demand Response Sensitivity

Demand Response (DR) together with Energy Efficiency is expected to play a significantly larger role in the grid of the future, enabled through technology innovation, smart grid, and automation, and with electricity customers exercising choice through proactive participation in electricity markets, by offering DR services to utilities and ISOs. Recent studies in the USA project a reduction of about 15% in peak load by 2030 using DR compared to a business-as-usual scenario.

DR programs come in many shapes and forms. Evaluating impacts of all such programs could be the subject of a separate study. This sensitivity considers only one representative type of DR deployment in the Canadian power system, where price responsive loads can be reduced if prices exceed a certain threshold. The modeled DR program is a two-step price responsive DR program, where 5% of province’s hourly load would be curtailed (or shed) when energy prices reach the top 90th percentile and an additional 10% of load is curtailed when prices reach the top 98th percentile. In this analysis, LMPs are used as a proxy for market prices. The GE MAPS model determines the LMPs at each network node (i.e., transmission bus) in all of Canada and USA, even if LMP is not actually used for energy markets in many of the balancing areas. An example of pricing triggers for dispatch of DR resources is provided in Figure 8-34. In this example, 5% of load in the form of DR are offered in the form load shedding / load curtailment when prices rise above $73/MWh. At $86/MWh or higher, an additional 10% of the load is offered as DR.

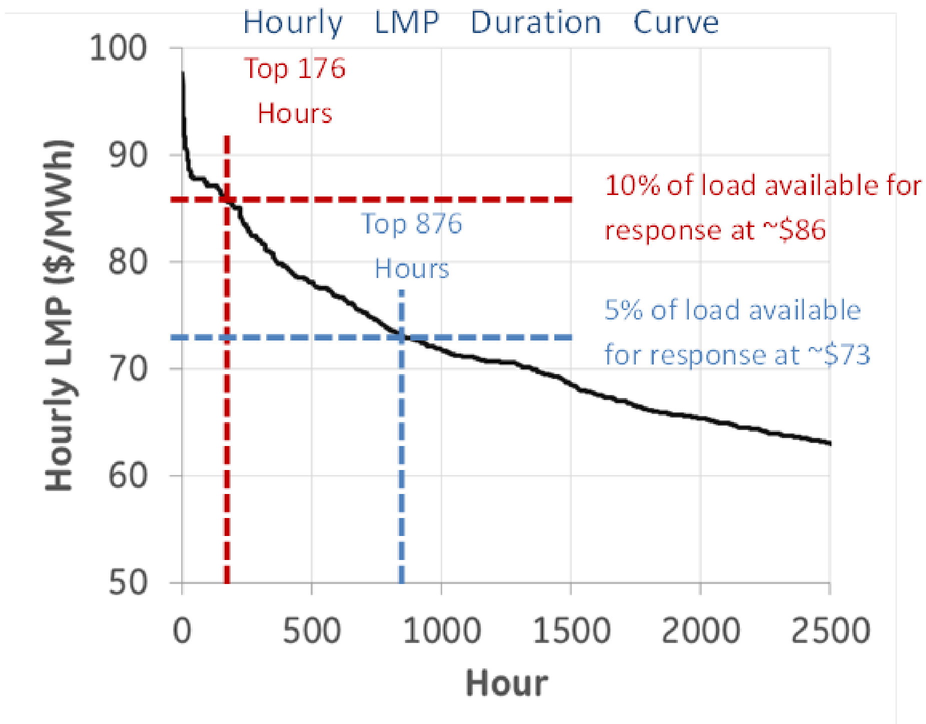


Figure 8-34: Example of a Two-Step Price Responsive Demand Response

The 90th and 98the percentile prices, taken from the 5% BAU scenario, are shown in Table 8-9. Similar percentile based prices were calculated for DR resources in the 20% and 35% penetration scenarios.

Table 8-9: Dispatch Prices of the Two-Step Price Responsive DR (C$/MWh)

	BC	AB	SK	MB	ON	QC	MAR
5% of load under active DR	$71.50	$72.90	$78.10	$86.80	$77.40	$76.60	$92.50
10% of load under active DR	$82.80	$85.70	$84.00	$100.50	$88.40	$94.80	$175.70

Figure 8-35 is a duration curve showing utilization of DR in the 20% DISP scenario. The horizontal axis is the number of hours in the year. Only the top 1000 hours are shown. Most of the DR is dispatched in the top 600 hours of the year.

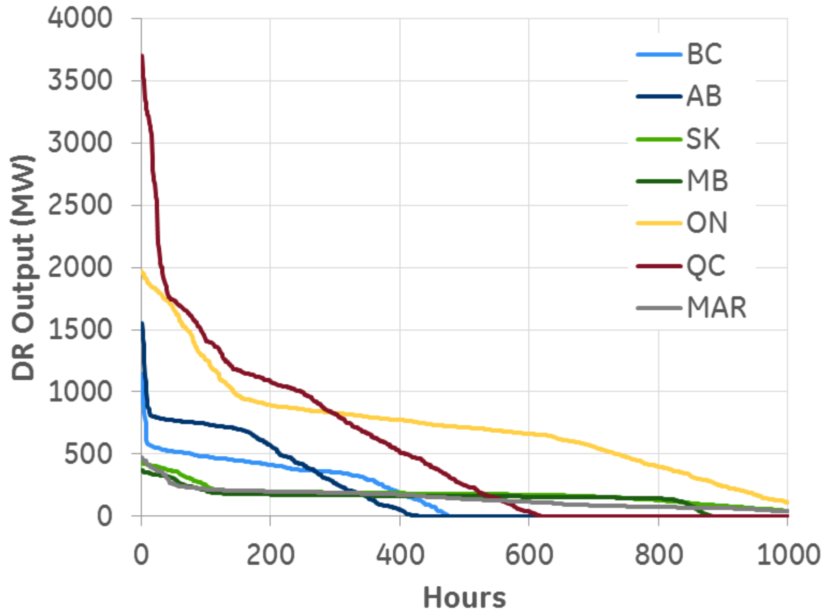


Figure 8-35: DR Duration Curves (20% DISP)

Figure 8-36 shows these same results broken down by province for the top 1,500 hours. As noted, up to 15% of hourly load in each province can be curtailed, depending on the proxy market price at each hour of the year in each province.

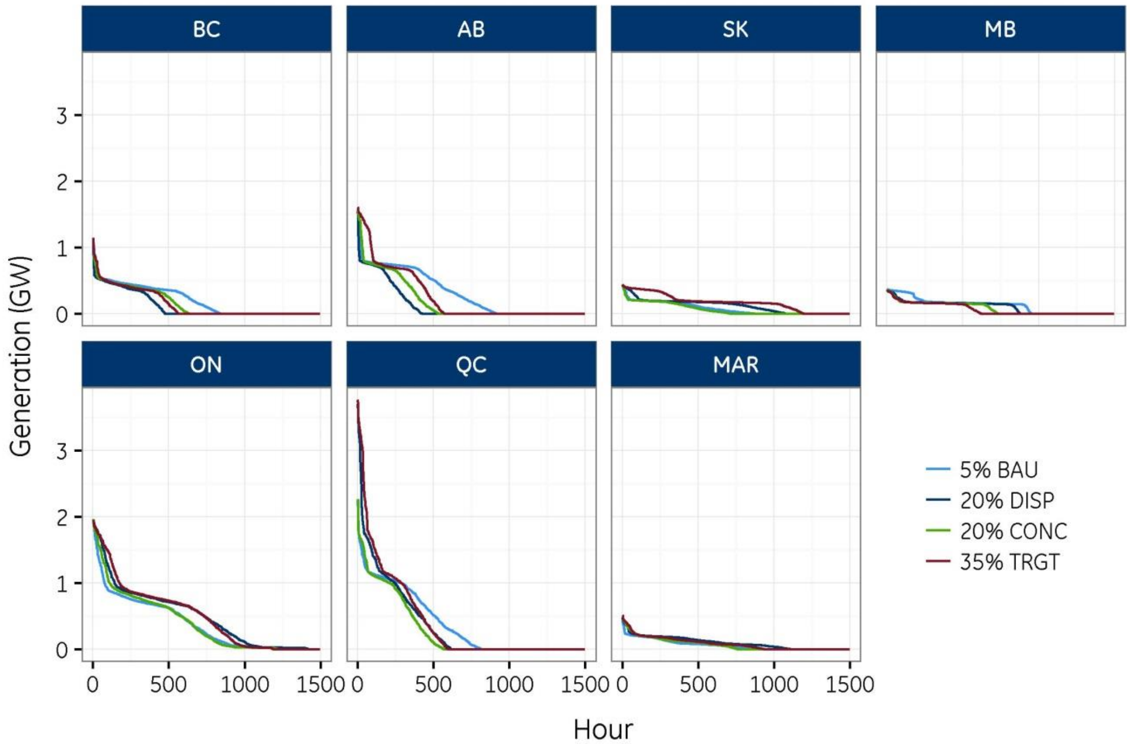


Figure 8-36: Demand Response Duration Curve in Demand Response Sensitivity under Different Scenarios

Because the DR is priced at only the highest priced hours of operation, and thus used rarely, DR does not have a significant impact on operations or the annual results highlighted throughout this report. However, DR can be a valuable tool to maintain system reliability, with or without significant wind additions. Having a diverse DR program is another tool available to system operators to accommodate wind integration and other changes taking place on their systems.

8.9.3 Energy Storage Sensitivity

This sensitivity case evaluates the impact of installing energy storage in each province. It is assumed to be an energy shifting storage resource that is charged and discharged based on arbitrage in time, i.e., charging at low priced hours, and discharging at high priced hours.

The assumed energy system in each province has a power (MW) rating (i.e., charging) capacity equivalent to 1% of peak load of the province, with 10 hours of energy storage capacity, and a round trip efficiency of 70% (i.e., a 1.0 MWh charge results in 0.70 MWh of discharge).

Selected energy storage ratings for in each province are provided in Table 8-10.

Table 8-10: Energy Storage Ratings Selected for Each Province

	BC	AB	SK	MB	ON	QC	MAR
Storage Rating (MW)	116	163	44	53	243	412	52
Storage Energy (MWh)	1160	1630	440	530	2430	4120	520

A scatter plot of charge/discharge of the energy storage in AB is provided in Figure 8-37. It indicates that most of the charging occurs during hours when prices are C$40/MWh to C$60/MWh, and most of the discharging occurs when prices are C$50/MWh to C$90/MWh.

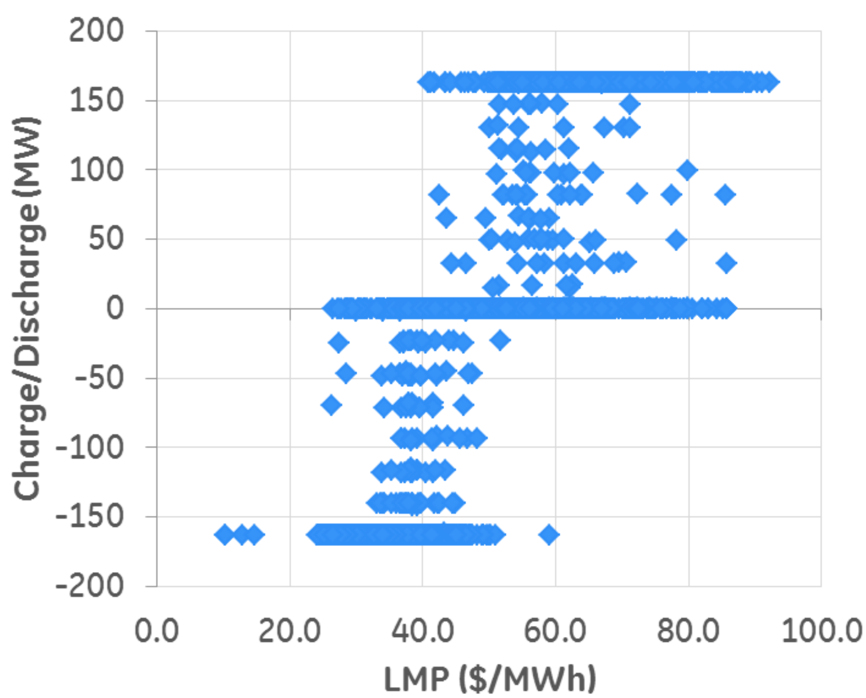


Figure 8-37: Scatter Plot of AB Energy Storage Charge/Discharge versus LMP

Figure 8-38 displays the charge/discharge duration curve of AB energy storage in 5% BAU and 20% DISP scenarios. Utilization of energy storage (i.e., its capacity factor) increases from 19.6% in 5% BAU scenario to 22.4% in 20% DISP scenario.

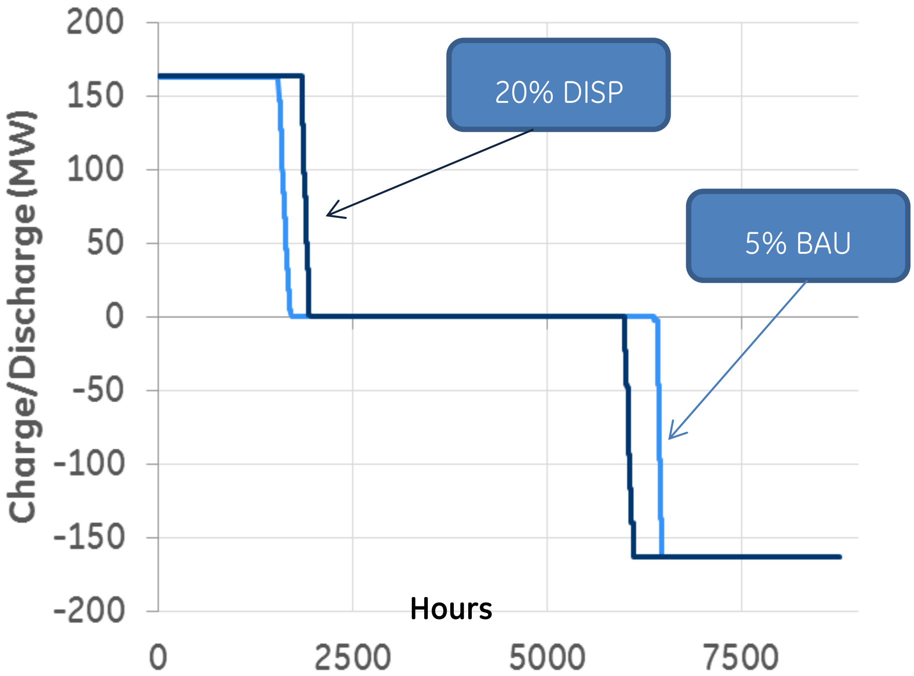


Figure 8-38: Charge/Discharge Duration Curve of Energy Storage in AB in 5% BAU and 20% DISP Scenarios

Similar charge/discharge duration curves in 20% DISP scenario for all provinces are plotted in Figure 8-39. Charging occurs during about 3,200 hours of the year, and discharge occurs during about 2,500 hours of the year. Figure 8-40 provides the charge/discharge duration curves for all the provinces in 5% BAU and 20% DISP scenarios.

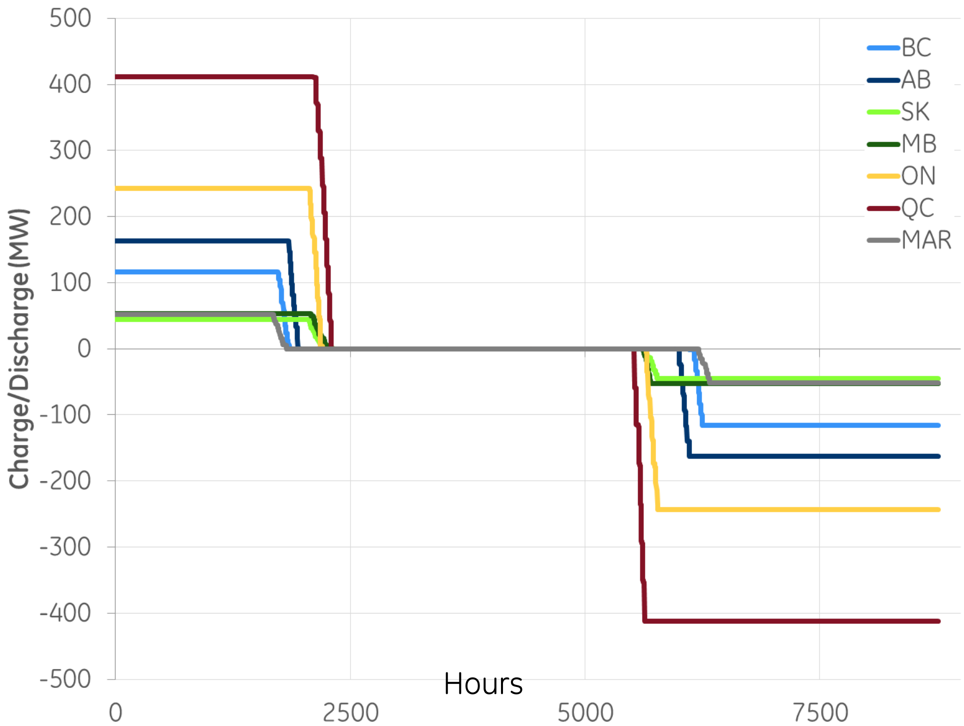


Figure 8-39: Charge/Discharge Duration Curve

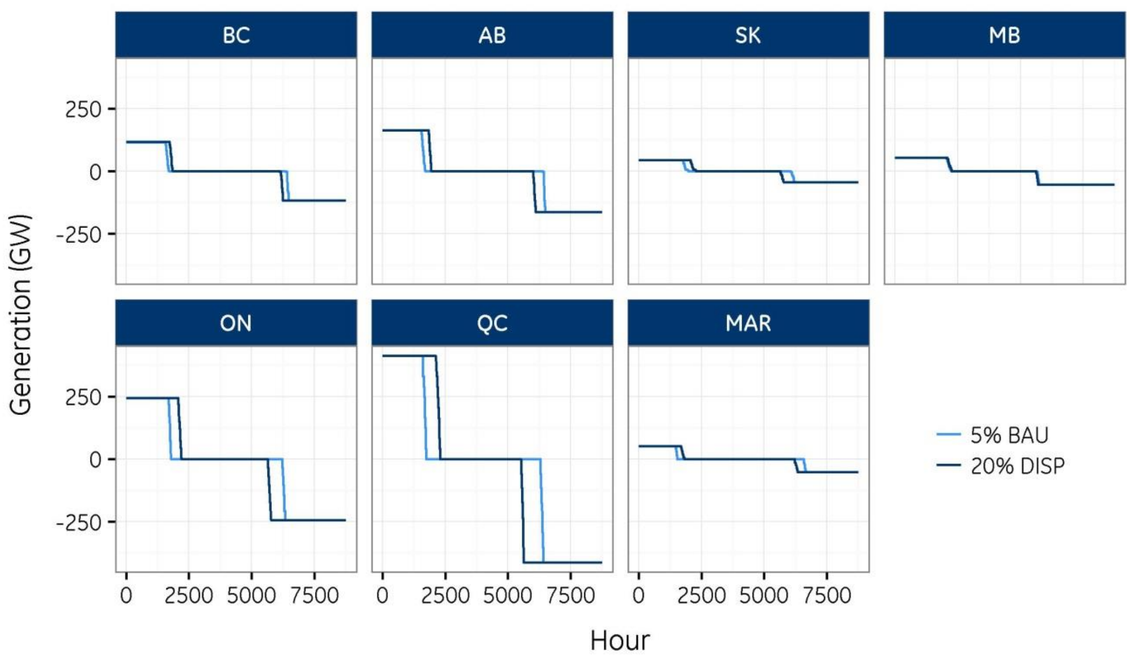


Figure 8-40: Energy Storage Charge/Discharge Duration Curve in 5% BAU and 20% DISP Scenarios

Curtailed energy under Base case and Storage case is shown in Figure 8-41. Energy storage contributes to the reduction of the curtailed energy, but based on the sizing assumptions selected for this sensitivity, its impact on reducing energy curtailments is not significant.

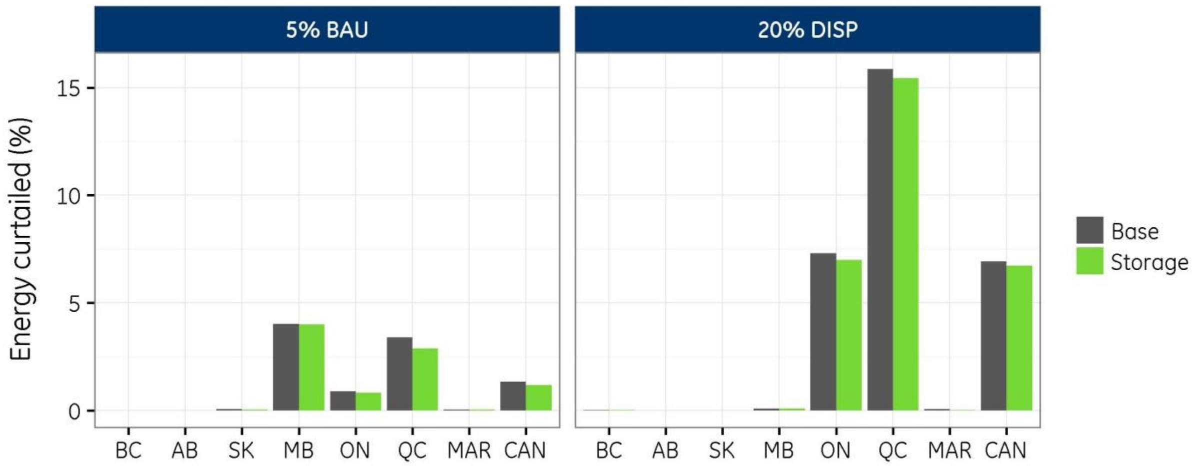


Figure 8-41: Energy Curtailment with Energy Storage in each Province

8.9.4 Electric Vehicle Charging Sensitivity

Electric Vehicle (EV) charging sensitivity considers the impact of adding a significant number of EVs to the Canadian transportation markets by 2025.

Approach to the modeling was based on the following steps:

Step 1: Determined the number of vehicles in each province.

- Used data from the CANISM website[25], Table 405-0004 Road motor vehicles, registrations, annual, based on 2014 registration data.
- Included all vehicles and buses (Ignore motorcycles, trucks, or trailers) (See Table 8-11)

Step 2: Assumed an EV penetration level of 20% vehicles and busses

Step 3: Assumed annual energy consumption per vehicle and bus based on the following[26]:

25 http://www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=4050004&&pattern=&stByVal=1&p1=1&p2=37&tabMode=dataTable&csid=

26 Based on information provided by David Jacobson of Manitoba Hydro (a member of PCWIS Steering Committee)

- 3,500 kWh/year for personal electric vehicles
- 123,500 kWh/year for buses

Step 4: Assumed a daily profile that repeated every day

- Based on Seattle Power & Light hourly profile used in their IRP (see Figure 8-42).
- http://www.seattle.gov/light/news/issues/irp/docs/dbg_538_app_d_3.pdf

Table 8-11: Number of Vehicles and Buses by Province in the EV Charging Sensitivities

PROVINCE	VEHICLES	BUSES	LOAD (GWH)
BC	2,935,526	9,985	2,301
AB	3,293,336	16,332	2,709
SK	877,150	3,972	712
MB	805,974	4,189	668
ON	7,949,541	29,706	6,298
QC	5,228,858	18,952	4,128
NB	547,690	2,453	444
NS	605,960	1,992	473
PE	88,339	361	71

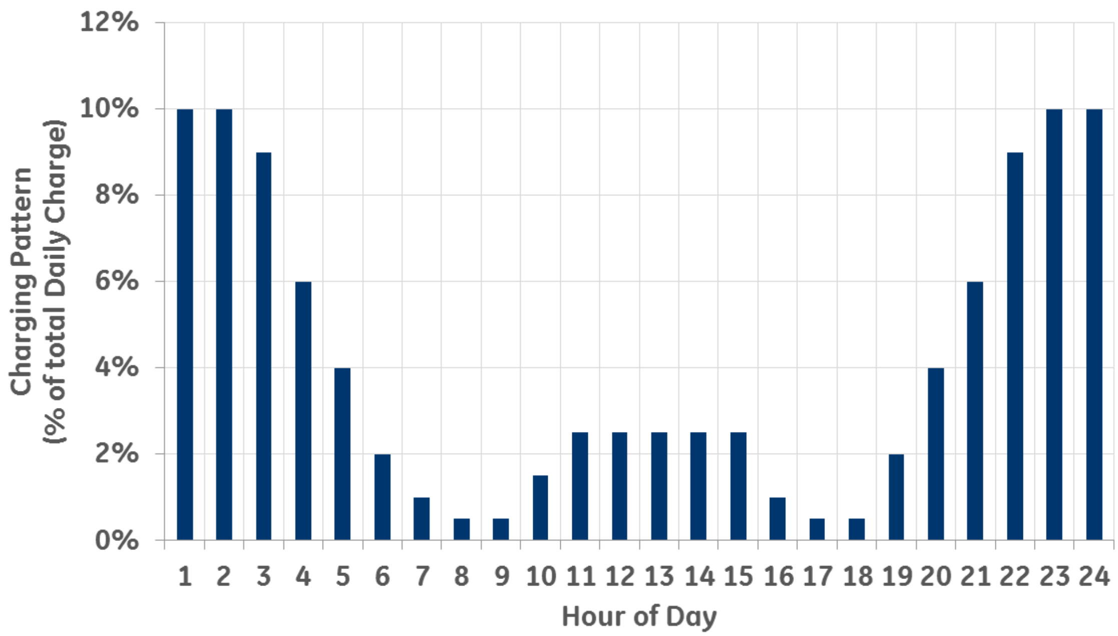


Figure 8-42: Hourly EV Charging Pattern Used in the EV Charging Sensitivity

Figure 8-43 displays the energy curtailment in each province with higher EV penetration. It can be observed that in most cases, higher EV penetration results in reducing energy curtailments. The main cause of energy curtailment is surplus generation relative to load in export constrained areas. More EV charging in a region, results in higher load levels in that region; thus utilizing some of the energy that would have been curtailed without the EV load. As shown in Figure 8-44, the EVs also increase the overall generation in the system. Both coal based and natural gas based generation increase generation from higher penetration of EV charging in the system due to the increased load on the system.

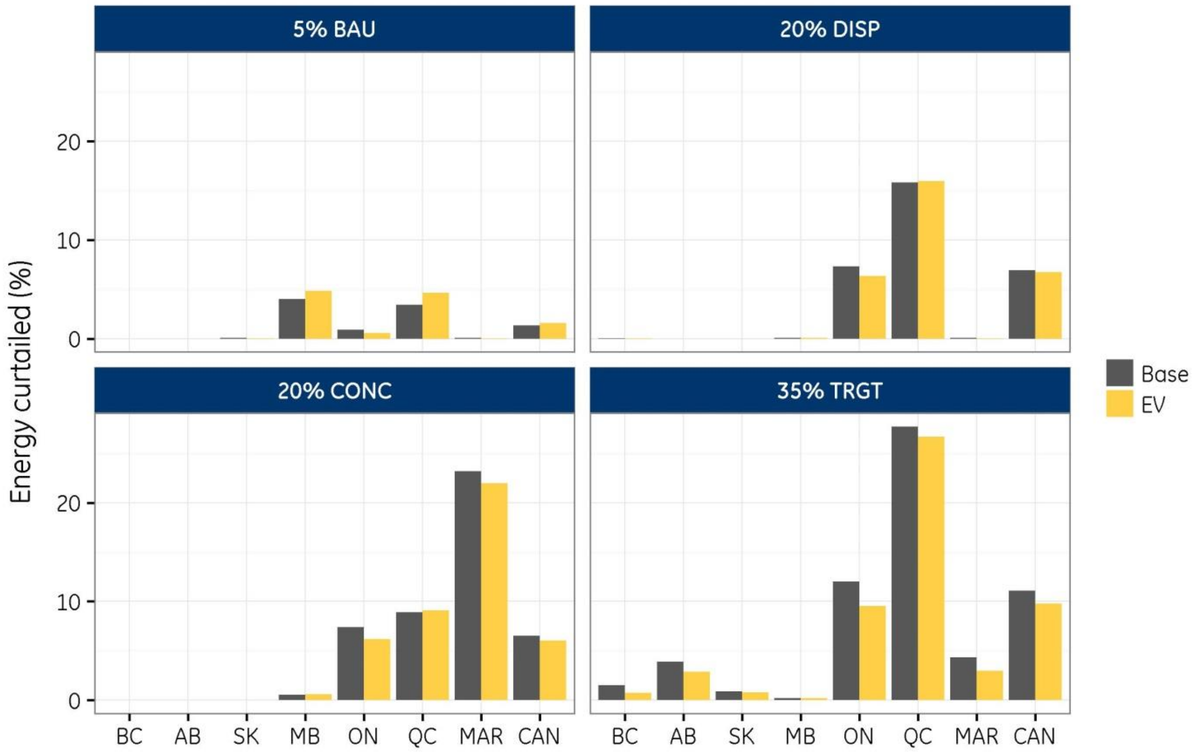


Figure 8-43: Energy Curtailment in Each Province with Higher EV Penetration

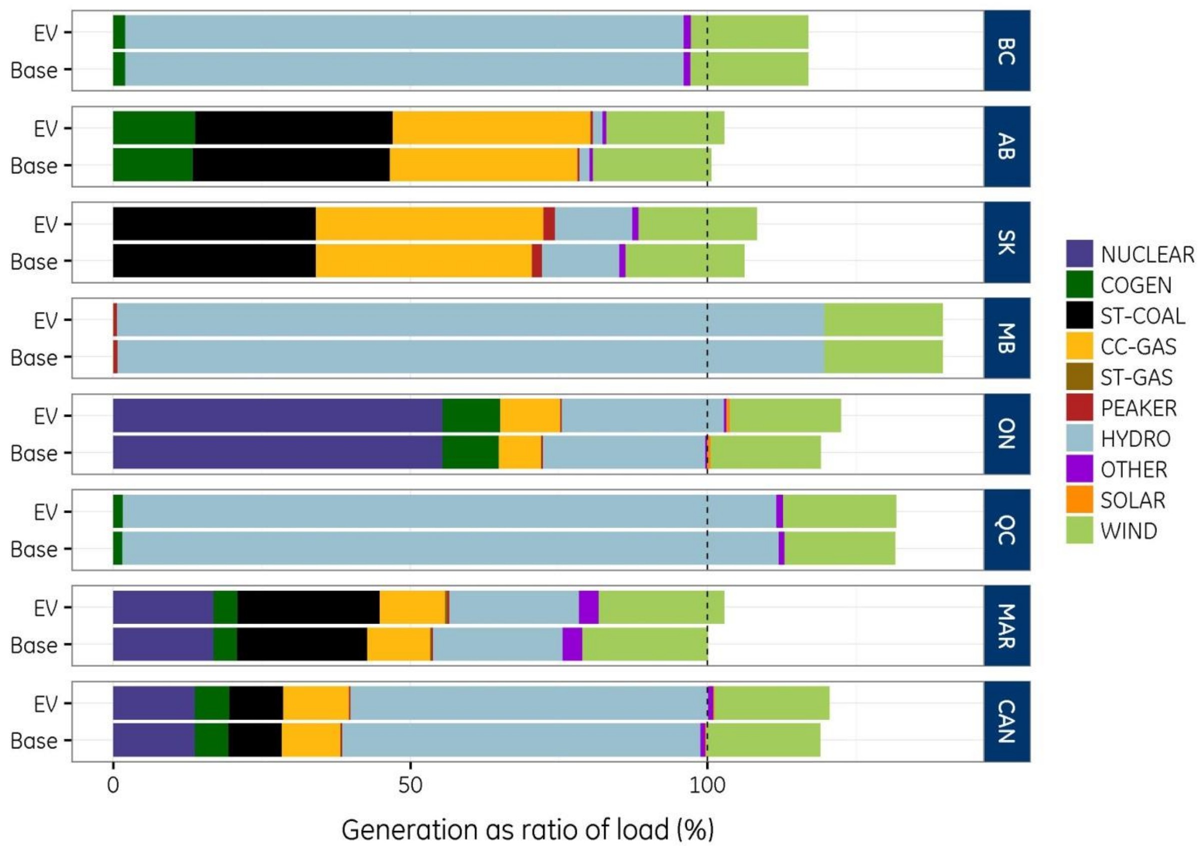


Figure 8-44: Generation by Type as Ratio of Load in Each Province with Higher EV Penetration

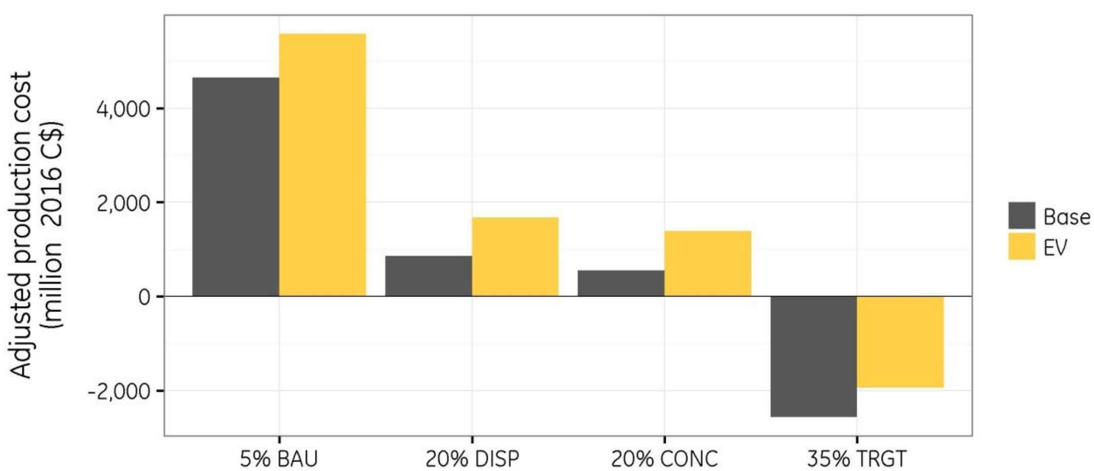


Figure 8-45: Adjusted Production Cost with Higher EV Penetration

8.10 Relaxed Reserve Requirements Sensitivity

Reserve requirements impose a constraint on the system operations by requiring a certain amount of generation capacity to be held back in reserve and be available when it is called upon by the operator to provide operating reserves.

This held-back capacity has an associated opportunity cost equal to the lost energy revenue. But the reserve resource is typically compensated above and beyond its opportunity cost of not selling energy. There is a cost associated with keeping some portion of the committed generation spinning but not producing energy so it can respond to contingency events or unanticipated load ramps.

This sensitivity evaluates the impact of reducing the amount of spinning reserves required from conventional generation resources (thermal plants), and replacing them with reserves from other non-conventional reserve resources such as storage devices or demand response.

To simulate such replacement, the GE MAPS model is run without the variability regulation reserve. These are the additional reserves in each scenario that are intended to cover the increased variability caused by wind generation. The impact of Relaxed Reserves sensitivity on energy curtailment is shown in Figure 8-46. Production simulation results show no significant reduction in curtailment. This indicates that the system is not constrained by the commitment of conventional generation units for reserve services.

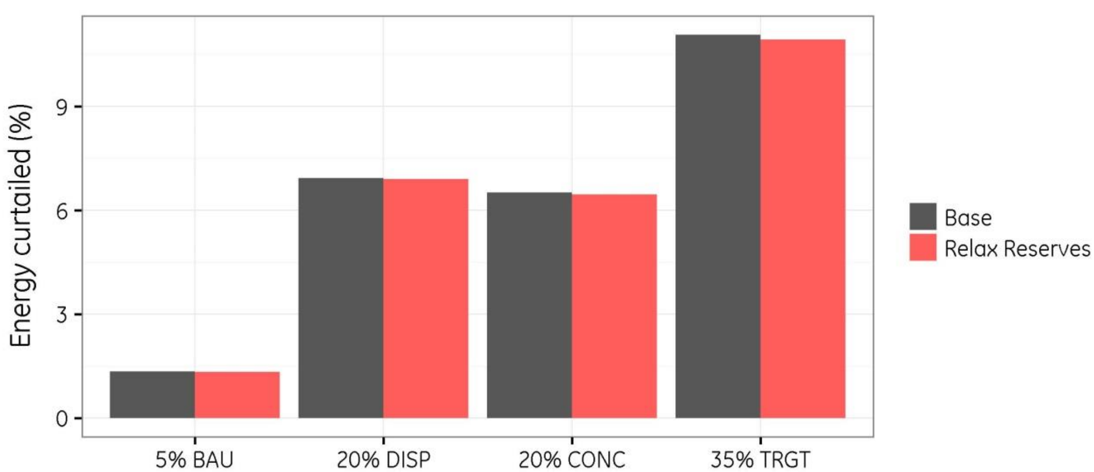


Figure 8-46: System-Wide Energy Curtailment with More Relaxed Reserve Requirement

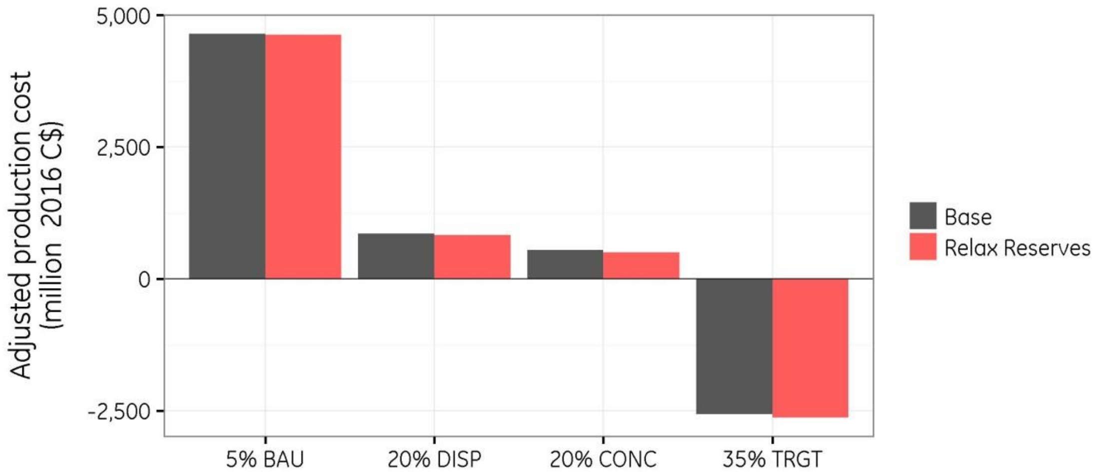


Figure 8-47: Adjusted Production Cost with More Relaxed Reserve Requirement

8.11 East-West HVDC Connection Sensitivity

The base scenario analysis in this study treated the Western Interconnection and Eastern Interconnection as two separate electrical networks with no connection between the two. Even though these two interconnections function independently of each other - because they are two separate AC systems and not synchronized - in reality, there are several HVDC connections between the two, some in Canada and others in the USA - that allow for the transfer of power from one system to another. These AC-DC-AC tie-lines make up a very small portion of the overall energy flows across the Eastern and Western Interconnections and were therefore ignored in the base scenario analysis in this study, with GE MAPS simulating each interconnection separately and independently from each other.

The East-West HVDC Connection Sensitivity (HVDC EI-WI) assessed the impact of having a 1000 MW HVDC line between WI and EI, or more specifically between AB and SK.

The two interconnections were still run separately, but power flows between the two were simulated by assuming either a withdrawal or an injection on each side of the divide based on the LMP differentials between AB and SK. The models of the two interconnections were run iteratively. At each run of the two interconnections, the hourly prices in AB and SK were compared; and depending on the direction of the price differentials, power was withdrawn from the lower priced side and injected to the higher priced side to simulate hourly flows between the two sides.

The decision logic used was as follows:

- If difference in LMP is greater than $5/MWh, then add 125 MW of flow
- If difference in LMP is greater than $10/MWh, then add 250 MW of flow

- Direction depends on price differential with power flowing from low to high price sides.

This process was repeated for four iterations to allow for increasing capacity of the HVDC transmission lines and to allow prices between the two systems to converge.

Figure 8-48 displays the LMP Delta (i.e., AB – SK price differentials) duration curves of a number of iterations in the 20% DISP scenario. As can be seen, starting with the price differentials of the Base case, successive iterations resulted in lowering the price differentials and the duration curves flatten and converge towards zero. After four iterations, with a reasonable convergence of prices, a final HVDC bi-directional flow pattern was determined.

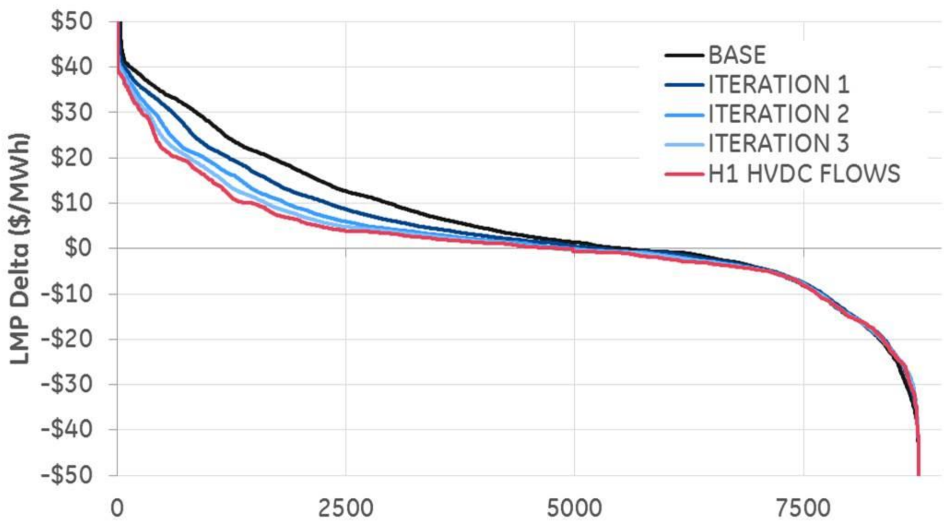


Figure 8-48: AB-SK Price Differential Duration Curve in the 20% DISP Scenario

Figure 8-49 shows the duration curves for the resulting HVDC line flows between AB and SK. Curves are shows for the 5% BAU and 20% DISP scenarios. The top part (positive flows) represents power flows form AB to SK. The bottom part (negative flows) represents power flows from SK to AB.

General findings include:

- Utilization increases from 26% to 35% from the 5% BAU to the 20% DISP scenario.
- Increased flow is observed from AB to SK. This is because more wind capacity was added to AB and because SK has more transmission interconnections to the rest of the system.
- As more wind is added to the system, the price differential can increase, resulting in the need to shift surplus energy.

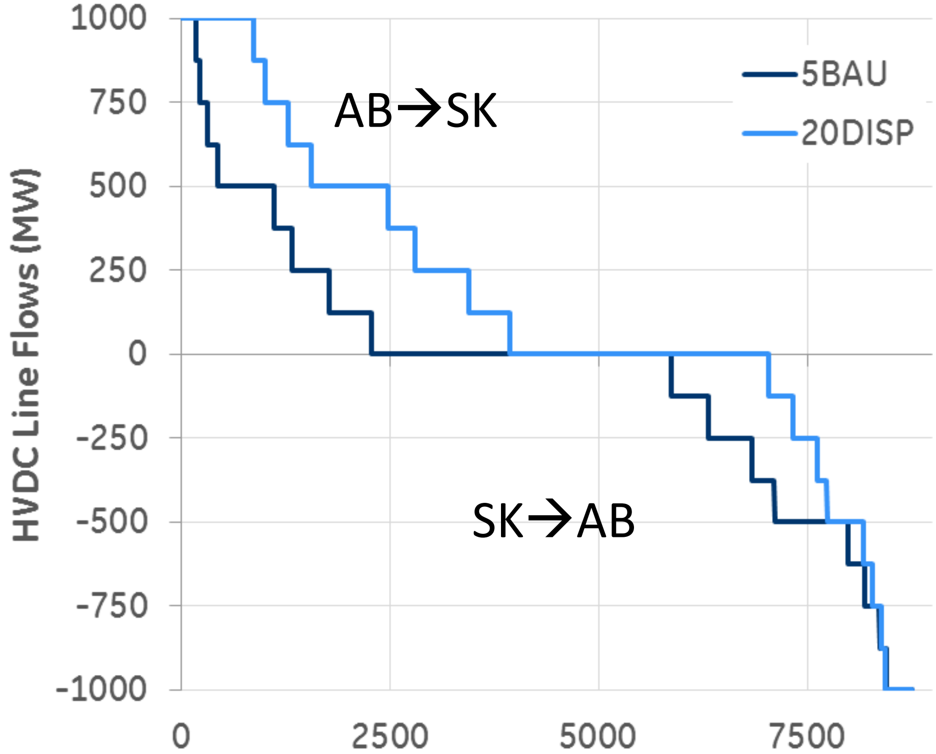


Figure 8-49: Alberta-Saskatchewan HVDC Line Flow Duration Curve

Energy curtailment in Base and HVDC EI-WI cases are shown in Figure 8-50 and Canada-wide production cost is shown in Figure 8-51. The differences between the two cases are minimal and actually difficult to discern, implying that the additional link between the WI and EI does not significantly affect the overall wind integration analysis related to the two separate interconnection regions.

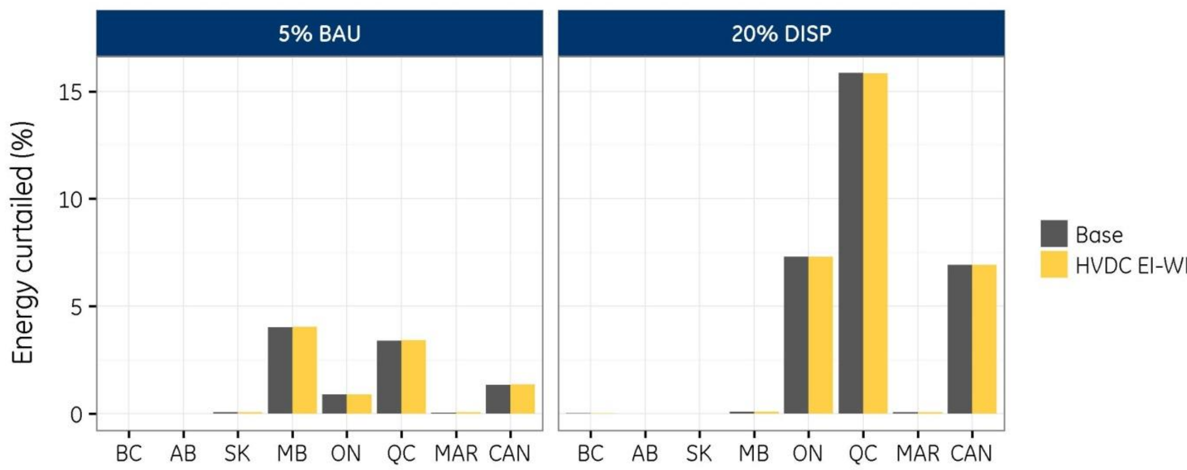


Figure 8-50: Energy Curtailment by Province with the Addition of AB-SK HVDC

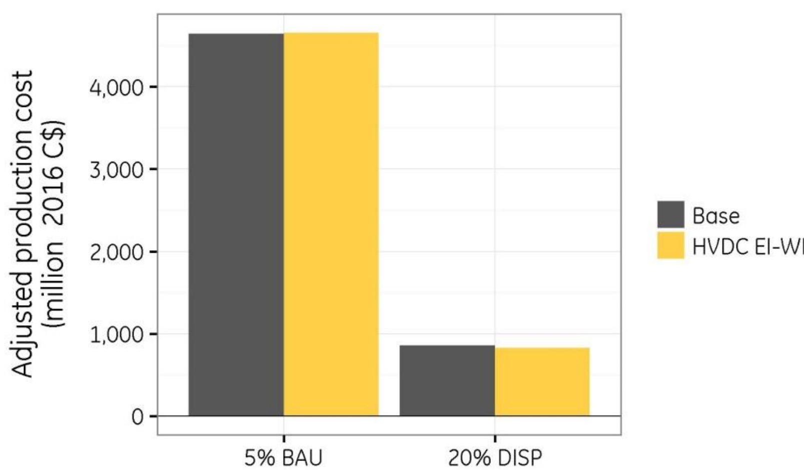


Figure 8-51: Canada-Wide Adjusted Production Cost with Addition of AB-SK HVDC

9 Sub-Hourly Analysis

Section Acknowledgement:

This section of the report was written by the EnerNex and GE teams.

9.1 Reserve Adequacy

This section presents a post-simulation analysis of the GE MAPS production cost results to examine whether regulation reserves for each scenarios penetration levels of wind were sufficient to cover sub-hourly variations in load and net load. GE MAPS provided in each hour of the scenario run a resource dispatch that provides sufficient ramping capability of resources to move from one hour to the next. This analysis examines the potential ramping limitations that may occur within the hour due to error in forecasting of load or wind resources. The study looks at the resource ramping limitations, both up and down, that come from the GE MAPS scenario runs. Specifically the total 10-minute up-ramps and down-ramps are provided.

Over the year there are hours when the variability of the intra-hourly wind production could theoretically create a situation where on-line resources may be unable to ramp sufficiently up or down to satisfy the system load requirements. Looking at the sub hourly 10-minute periods there may be times when wind production supports the directional changes in load, for example when load is increasing while wind production is increasing the need for additional ramping generation is not as great than if the wind production moved in the opposite direction. In other intra-hour periods when load is increasing and wind is decreasing the need for additional generating resources would be greater than if wind production was increasing. The up-ramp or down-ramp requirements of generating resources are accounted for in the hour to hour modeling and provide sufficient resource capability to meet regulation requirements. This analysis approximates potential issues that may arise because of inter hour variability of load and wind.

The production cost runs performed in the study provide a solution to the commitment and dispatch of resources in each pool in the Canada system while meeting given constraints on the system for each hour of the year. Given that wind production is variable by its very nature and can move up or down within an hourly period it was decided to examine if the hourly dispatch solution would provide sufficient flexibility to account for the wind resource variability. Having 10-minute actual wind production available provided six periods over the hour for examination. To account for load movement over the hour each 10-minute period was derived by interpolating values over the hour to hour period.

Results for each scenario run provide a value of available dispatched capacity that can move up or down over the hour to satisfy regulating reserves. These values provided included total thermal and hydro up-reg and down-reg amounts. These values were based upon data provided from the TEPPC database[27] and are shown in Table 9-1.

Table 9-1: Average Characteristics Used for Thermal Units in PLEXOS Optimization

Type of Unit	Minimum Generation (as a % of maximum capacity)	Ramp Rate (%/min)	Heat Rate (at full load)	WWSIS-2 Nonfuel Start Cost ($/MW)	TEPPC Nonfuel Start Cost ($/MW)
Coal	40[a]	1.1[a]	10.5	124	11[a]
CC	52[a]	0.9[a]	7.6	81	47[a]
CT	38[a]	4.5[a]	10.7	67	93[a]
Steam	12[a]	1.7[a]	10.7	86	12[a]
Nuclear	95	0.3[a]	11.0	155	-[a]

[a] Denotes an original assumption from the TEPPC database (aggregated for all units of each type). Other information in this table was created for this study as described in Section 2. The TEPPC start costs were not used for this study.

9.2 Sub-Hourly Analysis Methodology

Within every hour of the year, each 10-minute period of wind production and each 10-minute load demand was examined. If the combined change of 10-minute wind production and load demand exceeded either the upward or downward available ramping capability of the committed resources, then this period was noted as having insufficient ramping capacity for the balancing area to satisfy the regulation requirement. This could impact Area Control Error (ACE) and potentially cause a Control Performance Standard 2 (CPS2) violation.

Insufficient ramping capacity can result in a system frequency variation for the Province if external ramping capacity from transmission interties is not available to compensate for the difference. In other words if there was a period of insufficient ramping capacity it does not necessarily mean the Province has a reliability issue. Reliability standards have been set by NERC that provide guidance to account for periods when a system over or under generates. NERC has set a CPS2 requirement that allows a Balancing Authority to have as many as one violation every other hour over the year. Another measure is that there should be no violations in at least 90% of clock 10-minute periods during a calendar month within a specific limit referred to as L10.

[27] Global CCS Institute Website: https://hub.globalccsinstitute.com/publications/western-wind-and-solar-integration-study-phase-2/32-production-simulation-methodology-and-operational-assumptions

Over the year there are 52,560 ten-minute periods examined in each scenario for each province as well as for all of Canada. Thus the maximum number of periods in a year where ramping limitations may be tolerated is 5,256. Up-ramp and down-ramp limits were tested against the 10-minute change in load. Next, the up-ramp and down-ramp limits were tested against the 10-minute change in net load change, where net load is calculated to be load demand minus wind production. The number of times that ramp capacity did not meet the 10-minute change in load or net load, were counted separately. The results of this analysis indicate that there are only a small number of 10-minute periods when resource ramping fell below the 10-minute variability for load or net load.

In Table 9-2 the percent of periods when a ramping constraint is in violation is shown. Violations were determined for both load and net load. It can be seen that the number of up-ramp and down-ramp violations are very small and fall well within the NERC CSP2 requirements.

Table 9-2: Canada And Province Up-Ramp And Down-Ramp 10-Minute Violations For Each Scenario As A Percent Of All Periods

	Percent of 10-Minute Periods in Year Exceeding Up-Ramp Limits						
	BC	AB	SK	MB	ON	QC	MAR
5% BAU Load	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
5% BAU Net Load	0.000%	0.000%	0.000%	0.000%	0.006%	0.000%	0.000%
20% DISP Load	0.000%	0.000%	0.000%	0.002%	0.011%	0.000%	0.000%
20% DISP Net Load	0.002%	0.023%	0.049%	0.004%	0.093%	0.000%	0.002%
20% CONC Load	0.000%	0.000%	0.000%	0.105%	0.002%	0.000%	0.000%
20% CONC Net Load	0.000%	0.040%	0.004%	0.154%	0.156%	0.000%	0.004%
35% TRG Load	0.000%	0.000%	0.000%	0.025%	0.032%	0.000%	0.000%
35% TRG Net Load	0.002%	0.186%	0.120%	0.038%	0.441%	0.000%	0.006%

	Percent of 10-Minute Periods in Year Exceeding Down-Ramp Limits						
	BC	AB	SK	MB	ON	QC	MAR
5% BAU Load	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
5% BAU Net Load	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
20% DISP Load	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
20% DISP Net Load	0.000%	0.008%	0.051%	0.000%	0.000%	0.000%	0.002%
20% CONC Load	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
20% CONC Net Load	0.000%	0.019%	0.000%	0.000%	0.002%	0.000%	0.086%
35% TRG Load	0.000%	2.367%	0.000%	0.000%	0.000%	0.000%	0.000%
35% TRG Net Load	0.002%	5.953%	0.504%	0.000%	0.002%	0.000%	0.067%

To provide another perspective, the actual count of violations for each province is shown in Table 9-3. Although the number of violations is small, Alberta tends to have periods with many 10-minute up-ramp or down-ramp violations. In the 35% TRGT scenario Alberta has a larger number of violations than the other Provinces. A contributing factor for the large number of down-ramp violations can be that this analysis does not include transmission interchange between Alberta and other pools, a result of the analysis focusing on Provinces without the consideration of transmission interchange. In addition, down ramp limitations in the net load are due to the wind ramping up too fast. This can be easily mitigated by limiting the up ramp of the wind. This will result in slightly more curtailment but will avoid violations. In the 35% TRGT scenario, the high wind penetration levels results in a net-load that is negative for 14% of the 10-minute periods. With the wind rated capacity being over 17 GW, Alberta's minimum load of 11 GW also contributes to the negative net load conditions. In reality, the excess wind generation would be exported or curtailed, thereby avoiding many of the down ramp violations.

Table 9-3: Count of all Canada and Province Up-Ramp and Down-Ramp Violations in each Scenario

	Number of 10-Minute Periods in Year Exceeding Up-Ramp Limits						
	BC	AB	SK	MB	ON	QC	MAR
5% BAU Load	0	0	0	0	0	0	0
5% BAU Net Load	0	0	0	0	3	0	0
20% DISP Load	0	0	0	1	6	0	0
20% DISP Net Load	1	12	26	2	49	0	1
20% CONC Load	0	0	0	55	1	0	0
20% CONC Net Load	0	21	2	81	82	0	2
35% TRG Load	0	0	0	13	17	0	0
35% TRG Net Load	1	98	63	20	232	0	3

	Number of 10-Minute Periods in Year Exceeding Down-Ramp Limits						
	BC	AB	SK	MB	ON	QC	MAR
5% BAU Load	0	0	0	0	0	0	0
5% BAU Net Load	0	0	0	0	0	0	0
20% DISP Load	0	0	0	0	0	0	0
20% DISP Net Load	0	4	27	0	0	0	1
20% CONC Load	0	0	0	0	0	0	0
20% CONC Net Load	0	10	0	0	1	0	45
35% TRG Load	0	1,244	0	0	0	0	0
35% TRG Net Load	1	3,129	265	0	1	0	35

Table 9-4 shows the resulting maximum MW exceeding up-ramp and down-ramp limits. A few data points were removed due to discontinuities in the raw data. The values shown represent the largest violations in each province; and therefore, they represent the very extreme 10-minute up-ramp and down-ramp violation hours during the year.

Table 9-4: Maximum MW Exceeding Up-Ramp and Down-Ramp Limits in Each Scenario

	Maximum Additional MWs Needed to Meet Up-Ramp Requirements						
	BC	AB	SK	MB	ON	QC	MAR
5% BAU Load	0	0	0	0	0	0	0
5% BAU Net Load	0	0	0	0	0	0	0
20% DISP Load	0	0	0	0	42	0	0
20% DISP Net Load	0	213	251	0	229	0	0
20% CONC Load	0	0	0	34	0	0	0
20% CONC Net Load	0	693	0	163	290	0	0
35% TRG Load	0	0	0	18	100	0	0
35% TRG Net Load	0	1,653	404	44	410	0	15

	Maximum Additional MWs Needed to Meet Down-Ramp Requirements						
	BC	AB	SK	MB	ON	QC	MAR
5% BAU Load	0	0	0	0	0	0	0
5% BAU Net Load	0	0	0	0	0	0	0
20% DISP Load	0	0	0	0	0	0	0
20% DISP Net Load	0	160	145	0	0	0	0
20% CONC Load	0	0	0	0	0	0	0
20% CONC Net Load	0	629	0	0	0	0	238
35% TRG Load	0	89	0	0	0	0	0
35% TRG Net Load	0	1,469	517	0	0	0	140

Alberta has the largest ramp-up and ramp-down violations in the 35% TRGT scenario. Again, it should be noted that these values represent extreme cases in the year and may occur during a tiny fraction of the 10-minute intervals in the year.

The up-ramps can be managed by applying wind curtailment. However, to deal with severe ramp-down violations, other mitigation options can be considered, including, but not limited to, improved wind ramp forecasts, demand response, energy storage, pre-contingency curtailment of wind, and use of transmission interties.

To get a better perspective, the magnitude and number of ramp violations in Alberta for the 35% TRGT scenario can be seen in Figure 9-1. The underlying data is shown in Table 9-5. It can be shown that:

- In the 35% TRGT scenario, 76.3% of the net load ramp violations in Alberta (out of the total of 8.6% of the 10-minute periods with violations) are less than 100 MW.
- In the 35% TRGT scenario, 99.7% of the net load ramp violations in Alberta (out of the total of 8.6% of the 10-minute periods with violations) are less than 500 MW.
- In the 35% TRGT scenario, 0.22% of net load violations in Alberta (out of the total of 8.6% of the 10-minute periods with violations) require more than 500 MW of additional up-ramp capability to meet the up-ramp requirements.
- In the 35% TRGT scenario, 0.09% of net load violations in Alberta (out of the total of 8.6% of the 10-minute periods with violations) require more than 500 MW of additional down-ramp capability to meet the down-ramp requirements.

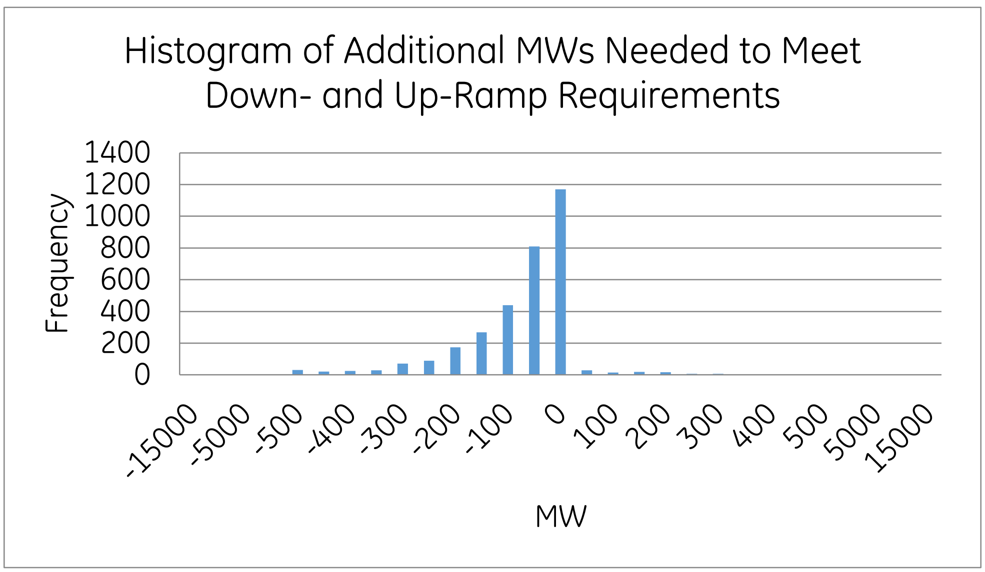


Figure 9-1: Number and Magnitude of 10-Minute Ramp Violations in Alberta for 35% TRGT Scenario

Table 9-5: Data for Histogram of Additional MW Needed to Meet the 10-Minute Net Load Up-Ramp and Down-Ramp Requirements in Alberta in the 35% TRGT Scenario

Bin	Frequency	Percent
-15000	0	0.0%
-10000	1	0.0%
-5000	0	0.0%
-1000	2	0.1%
-500	31	1.0%
-450	21	0.7%
-400	24	0.7%
-350	28	0.9%
-300	71	2.2%
-250	90	2.8%
-200	174	5.4%
-150	268	8.3%
-100	439	13.6%
-50	810	25.1%
0	1170	36.3%
50	28	0.9%
100	15	0.5%
150	18	0.6%
200	16	0.5%
250	6	0.2%
300	6	0.2%
350	1	0.0%
400	0	0.0%
450	0	0.0%
500	1	0.0%
1000	3	0.1%
5000	2	0.1%
10000	2	0.1%
15000	0	0.0%
TOTAL	**3227**	**100.0%**

9.3 Key Finding and Conclusion

In conclusion the regulation reserve requirements provided in each scenario provide sufficient operating capacity to meet 10-minute up-ramp and down-ramp constraints more than 99% of the time in all provinces in Canada, except Alberta.

The up-ramps can be managed by applying wind curtailment. However, to deal with more severe sub-hourly ramp-down violations in Alberta and to a lesser extent in Saskatchewan and Maritime provinces, other mitigation measures can be considered. These include, but are not limited to, improved wind ramp forecasts, demand response, fast ramping energy storage, pre-contingency wind curtailment, and use of transmission interties.

10 Capacity Valuation Analysis

10.1 Introduction

The capacity of a system to reliably serve its load can be quantified through resource adequacy studies. Capacity value is the contribution of any resource in the system to meet that goal and maintain a reliable supply of power. The capacity value of conventional thermal resources is rather straightforward to calculate because their capacity is largely the same year round. However, the output from wind generation depends on ever-changing wind speeds driven by underlying weather patterns. Thus, wind nameplate capacity might rarely be fully available to contribute to resource adequacy.

This chapter summarizes the steps taken in this study to calculate the wind capacity for each scenario and province. Several simulations using GE's Multi-Area Reliability Simulation (GE MARS) model were performed. The model was built based on the production cost database and utilized the three years of load and wind data available (for the years 2008, 2009 and 2010). More details on the implementation and assumptions are provided in this chapter.

The results in this section were also used to create the partial coal retirement scenario in the production cost sensitivities, as reported in section on "Sensitivity Analysis". In that scenario, the amount of coal capacity retired was equal to the wind capacity value reported in this chapter.

Before proceeding with the details of the calculations, it is important to distinguish between wind capacity value and wind capacity factor. The two can be defined as follows:

- Wind capacity value is the contribution of wind generation to resource adequacy and generally depends on its output during the riskiest hours of the years
- Wind capacity factor is the measure of average wind generation and depends on its output throughout the year

While wind capacity value calculations in this study take into account the output of wind power for the entire year, only a fraction of those hours has a meaningful impact on the results. Those are the hours in which the system presents the highest risk of loss of load, which generally corresponds to the hours with highest net load, i.e., load minus wind.

Wind capacity factors by scenario and province were provided in the section on "Assumptions and Scenarios", and those results should not be confused with the wind capacity values provided here.

10.2 GE Multi-Area Reliability Simulation (GE MARS) Model

A loss of load expectation (LOLE) reliability evaluation was performed for each of the four wind-deployment scenarios. The GE MARS model was used to calculate the daily LOLE, in days per year, for each scenario. The daily LOLE determines the numbers of days in which a loss of load is expected to occur, by taking the maximum loss of load probability (LOLP) among all the hours in a day. The remainder of this section details the assumptions that were made in this study.

10.2.1 Modeling Assumptions

GE MARS is based on a sequential Monte Carlo simulation, which provides for a detailed representation of the hourly loads, generating units, and interfaces between the interconnected areas. In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly generated operating histories of the generating units with the inter-area transfer limits and the hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events (e.g., equipment failures), as well as deterministic rules and policies, which govern system operation, without the simplifying or idealizing assumptions often required in analytical methods.

GE MARS is based on a sequential Monte Carlo simulation, and it uses state transition rates rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if one assumes that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on its state in previous hours and influences its state in future hours. It thus requires the additional information that is contained in the transition rate data.

For this analysis, each of the Canadian provinces represented in the production cost model were isolated, i.e., no ties or assistance were represented between Canadian provinces or to the United States. The inclusion of ties across Canada and the United States would require the determination of maximum transfer limits between areas and the inclusion of a portion of the U.S. system, both of which are time consuming and beyond the scope of this study. Nevertheless, the isolation of provinces allows for the fast calculation of wind capacity values, assuming that the wind in each province contributes to the resource adequacy in the province.

The number of units and their capacities were extracted from the production cost (GE MAPS) database. They were represented using a two-state model with an expected forced outage rate (EFOR) derived from the latest NERC Generating Availability Data System (GADS) report[28]. Given the large storage size present in Canadian hydropower generation, they were assumed to contribute their full capacity with no energy restrictions. No demand response program or other emergency operating procedures were modeled in the system, due to the size of the footprint and the very different nature of the markets.

10.2.2 Load Shapes

The reliability analysis used the same load and wind power shapes developed for the production cost model. Load profiles are based on historical 2008, 2009 and 2010 hourly data and are scaled to represent load in the year 2025, using the peak and energy levels summarized in section on "Assumptions and Scenarios". As a result, the load levels across the year are very similar across years (Figure 10-1), although the timing across the year does change.

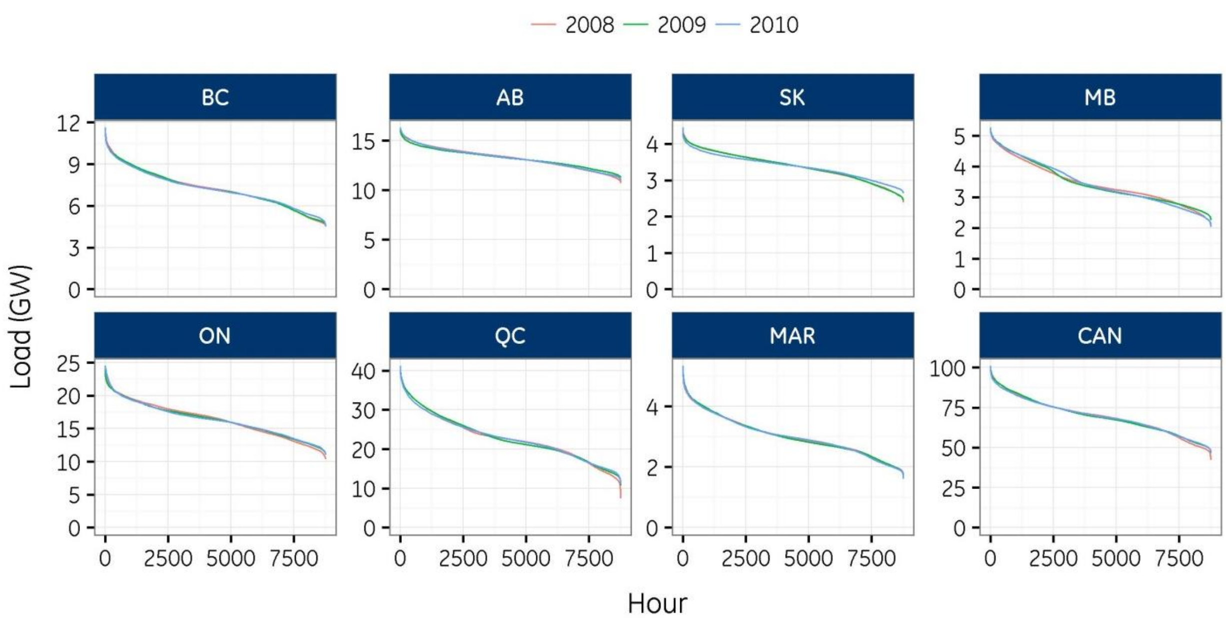


Figure 10-1: Load Duration Curves By Province and Canada by Year

Nearly of all the provinces are winter-peaking systems and their maximum load was reported between November and January for the three years of data, as shown in Figure 10-2. However, Ontario is a summer peaking system and the peak load happened in June, August and July for 2008, 2009 and 2010, respectively (Figure 10-2).

28 http://www.nerc.com/pa/RAPA/gads/Pages/default.aspx, need to find out the exact version

Similarly, most provinces experienced their peak load in the late evening (Figure 10-3). Quebec and the Maritimes showed a double peak pattern, with an additional peak in the morning hours that on occasion matched or exceeded the evening peak.

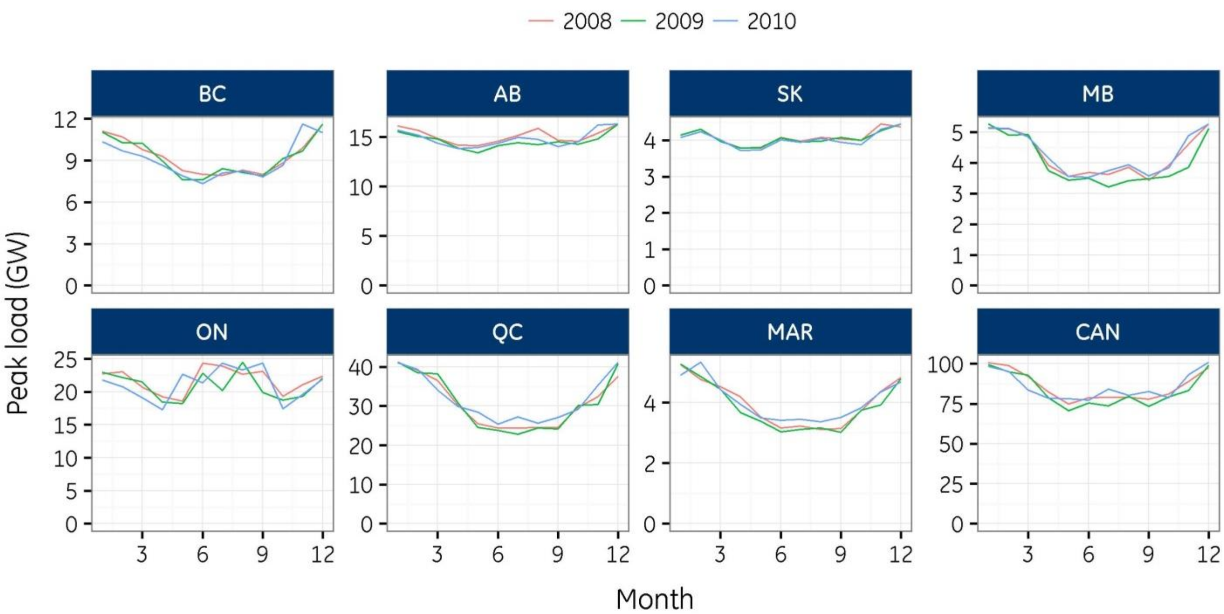


Figure 10-2: Peak Load by Month and Data Year

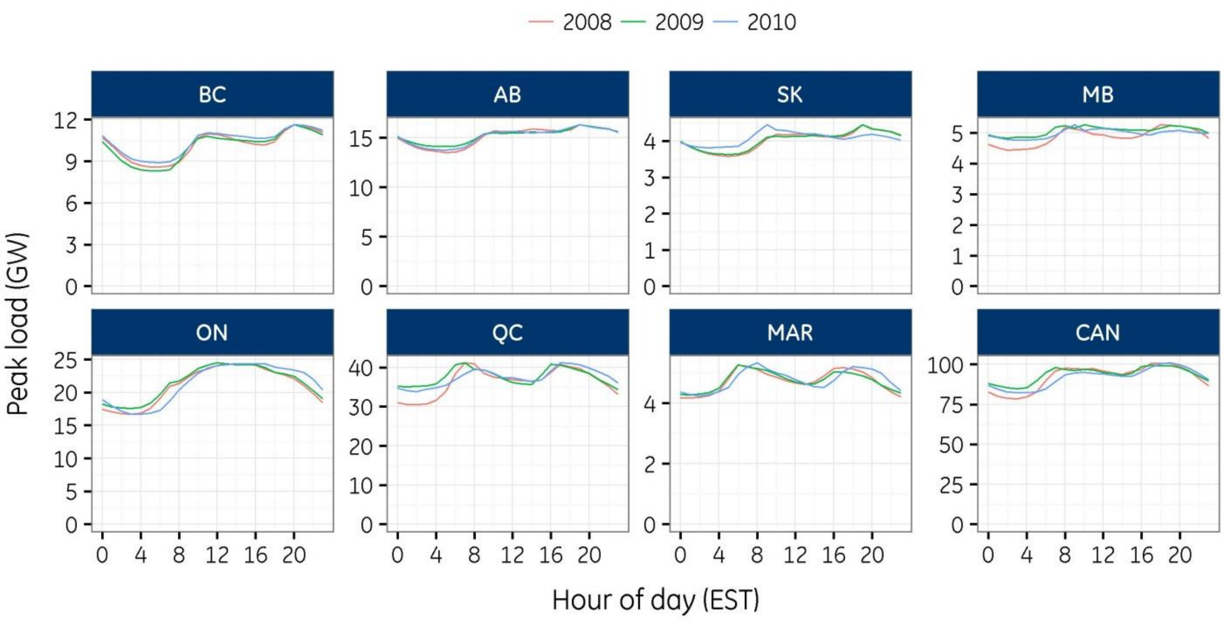


Figure 10-3: Peak Load by Hour of Day and Data Year

10.2.3 Wind Shapes

Wind power profiles were generated using numerical weather models that reproduce the meteorological conditions in 2008, 2009, 2010. The description of this process can be found in Section on "Wind Data Development" and a statistical analysis comparing the three years was performed and reported in Section on "Statistical and Reserve Analysis".

As previously stated, wind capacity value usually depends on the generation from wind during a limited number of hours. *This can cause the results to be influenced by rare unusual events. For this reason it is* typically recommended to perform this type of analysis with many years of wind and load data to perform a robust capacity value analyses[29].

This study was limited to the analysis of three years of data but, in an effort to improve the robustness of the results, the study team used a 7-day sliding window method[30] in the selection of wind data. For each replication in GE MARS, the model was allowed to shift the wind profiles with respect to the load profile. The shift was randomly chosen for each iteration in 24-hour increments. The result of this process is depicted in Figure 10-4 and

[29] NERC IVGTF report: http://www.nerc.com/comm/PC/Pages/Integration-of-Variable-Generation-Task-Force-(IVGTF)-2013.aspx

[30] Milligan M, Porter K, "Determining the Capacity Value of Wind: An Updated Survey of Methods and Implementation", National Renewable Energy Laboratory, NREL/CP-500-43433, June 2008, http://www.nrel.gov/docs/fy08osti/43433.pdf

paired each load hour with up to 7 hours of wind data, increasing the robustness of the results and preserving the daily and seasonal correlations between load and data.

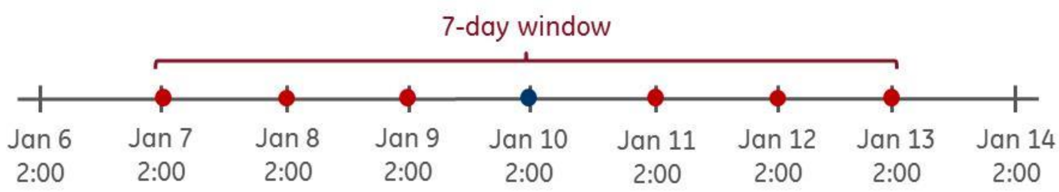


Figure 10-4: Graphical Representation of the 7-Day Window for Wind Data Selection

10.3 Capacity Value Methodology

This study follows NERC's Integration of Variable Generation Task Force (IVGTF) recommendation[31] to use a probabilistic-based method to calculate wind capacity value. More specifically, the study team utilized the Expected Load Carrying Capability (ELCC) method to calculate the capacity value by province, as follows[32]:

1. In the absence of wind, the province load was scaled until the province LOLE reached 0.1 days/year
2. Wind power was added to the system, which caused the LOLE metric to decrease
3. Load was increased until the resulting LOLE reached 0.1 days/year once again
4. Wind capacity value is measured as the difference in peak capacity between steps 3 and 1

Thus, wind capacity value is the additional load that can be served while maintaining the same reliability level. This level was set to 0.1 days/year, which is a de-facto standard in the industry. However, capacity value calculations are not substantially affected by the selection of this level.

Capacity value calculations were performed for each data year and each province. Each simulation consisted of 50,000 replications. Canada-wide capacity values were calculated by adding the capacity values in each province. Average capacity values across by provinces and for the entire Canadian footprint were calculated by averaging the results for years 2008, 2009 and 2010. Individual and average values are reported in the next section.

[31] http://www.nerc.com/files/IVGTF_Task_1_5_Final.pdf

[32] Keane, A., Milligan, M., Dent, C.J., et al., "Capacity Value of Wind Power", IEEE Transactions on Power Systems, Vol. 26(2):564-572, 2011.

10.4 Canada-wide Capacity Value Results

10.4.1 Average Capacity Values

This section summarizes the capacity value results, which are averaged across the three years of data and aggregated for the entire Canadian footprint. Table 10-1 includes the installed wind capacity and capacity values by scenarios. For convenience, it also includes the capacity value as a fraction of nameplate capacity, which is also commonly referred to as "capacity credit". Absolute and relative capacity values are also represented in Figure 10-5.

Table 10-1: Canada-Wide Wind Capacity and Capacity Value

Scenario	Wind capacity (MW)	Capacity value (MW)	Capacity value (%)
5% BAU	10,966	3,987	36.4%
20% DISP	37,114	8,251	22.2%
20% CONC	36,312	8,118	22.4%
35% TRGT	65,222	11,214	17.2%

Higher penetrations of wind generation lead to higher capacity values, in absolute terms, going from just under 4 GW in the 5% BAU scenario to 11.2 GW in the 35% TRGT scenario. However, the capacity value as a percentage of installed capacity declines, from 36.4% to 17.2%, and is very similar for the 20% scenarios (around 22%). This means that as more wind is injected into the system, its relative contribution to resource adequacy declines.

This is primarily due to two reasons: (a) the wind added in the higher-penetration scenarios tends to be of lesser quality, and (b) the additional wind is highly correlated to existing wind. The latter reason is crucial because with more wind in the system, the highest net load hours tend to have smaller amounts of wind generation, and it is these hours that contribute to the calculation of capacity value.

A similar situation is often found when adding solar PV to an evening-peaking system. In that case, as more solar is added to the system, the net load peak moves later into the evening. With enough solar in the system, the net load hour will occur after sunset and additional PV in the system will have no contribution in that hour and, thus, a capacity value of zero.

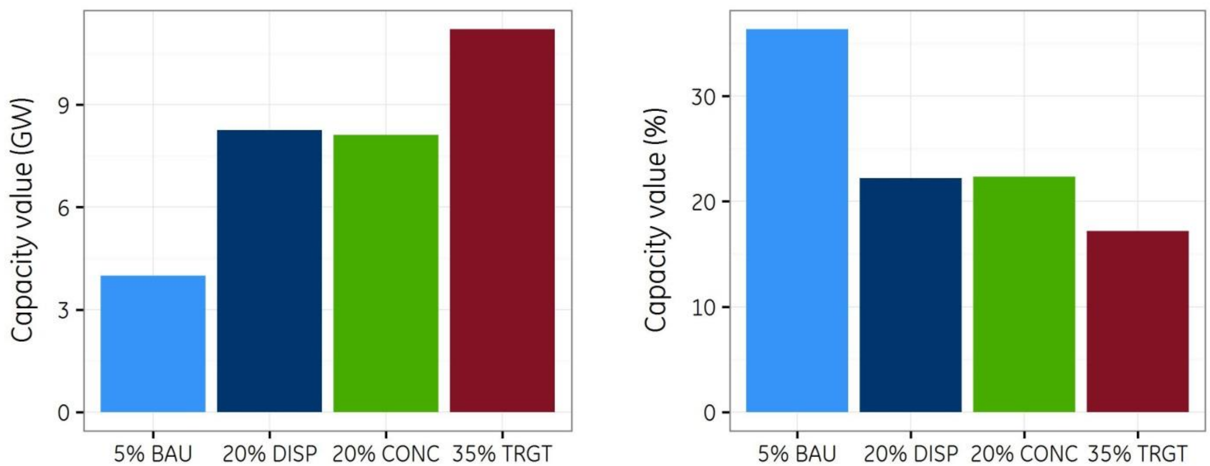


Figure 10-5: Canada-Wide Wind Capacity Value by Scenario in Absolute Terms (Left) and Relative to Capacity (Right)

10.4.2 Capacity Value by Year

The average capacity values presented in the previous section are derived from the annual values, which are reported in this section. The relative capacity value results are depicted in Figure 10-6, Table 10-2, and Table 10-3 In general, 2009 presented higher-than-average capacity values, while 2010 is smaller. However, these trends did not occur for all the individual provinces. The spread of capacity values across years was higher for smaller penetrations and vice versa.

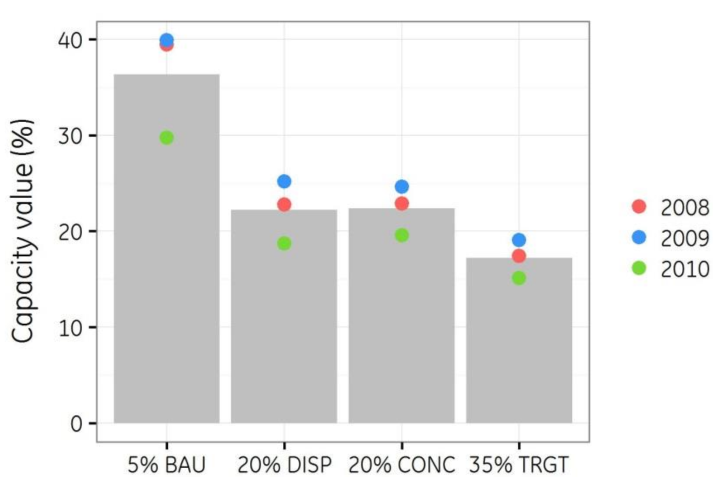


Figure 10-6: Canada-Wide Wind Capacity Value by Year (Points) and Average Values (Bars)

Table 10-2: Canada-Wide Absolute Wind Capacity Value by Year and Averaged

Scenario	2008	2009	2010	Average
5% BAU	4,325	4,377	3,261	3,988
20% DISP	8,446	9,352	6,955	8,251
20% CONC	8,306	8,942	7,107	8,118
35% TRGT	11,354	12,424	9,866	11,215

Table 10-3: Canada-Wide Relative Wind Capacity Value by Year and Averaged

Scenario	2008	2009	2010	Average
5% BAU	39.4%	39.9%	29.7%	36.4%
20% DISP	22.8%	25.2%	18.7%	22.2%
20% CONC	22.9%	24.6%	19.6%	22.4%
35% TRGT	17.4%	19.0%	15.1%	17.2%

Figure 10-7 represents the relationship between absolute and relative wind capacity values and nameplate capacity. The reduction in relative capacity value observed for the average values were also present for the individual years. The two 20% scenarios presented similar results both in absolute and relative terms.

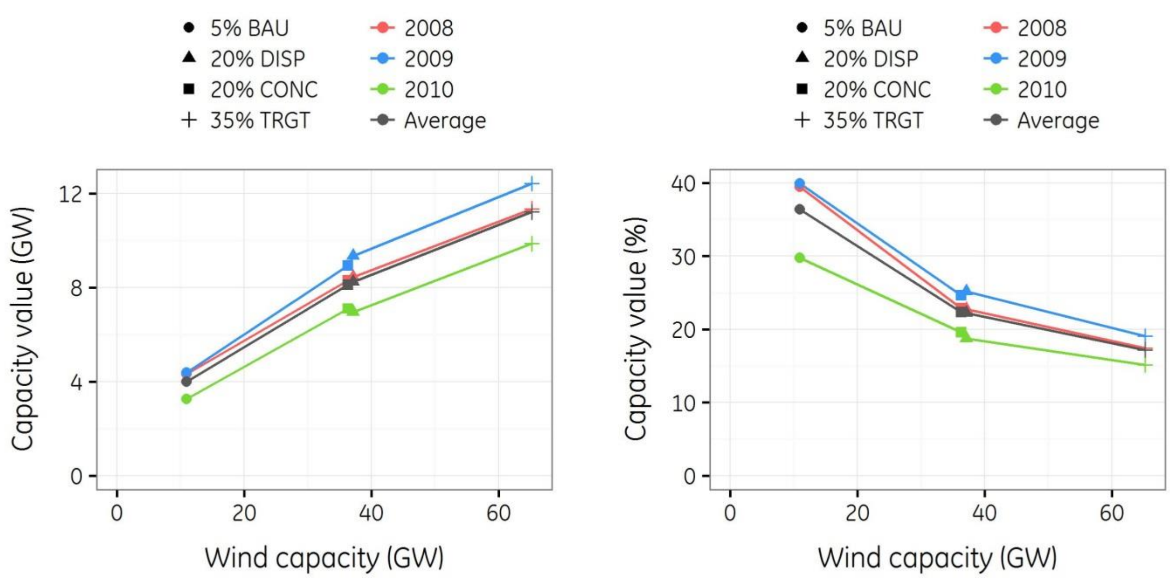


Figure 10-7: Canada-Wide Wind Capacity Value vs. Nameplate Capacity in Absolute (Left) and Relative Terms (Right)

10.5 Capacity Value Results by Province

10.5.1 Average Capacity Values

This section presents capacity values by province, after aggregation of results for the three years of data. Results by province and scenario are presented in Table 10-4 and Table 10-5. Relative wind capacity value is represented in Figure 10-8. In general, Quebec and Maritimes had the highest capacity values across all scenarios, while the lowest were found Alberta and Saskatchewan. For all provinces, higher wind penetrations resulted in lower relative capacity value results.

Table 10-4: Capacity Value (GW) By Province and Scenario

Scenario	BC	AB	SK	MB	ON	QC	MAR	CAN
5% BAU	731	950	370	291	4,070	4,157	1,395	11,963
20% DISP	2,464	2,292	811	1,200	6,124	9,757	2,104	24,752
20% CONC	1,861	2,587	613	1,402	6,675	6,714	4,503	24,355
35% TRGT	3,116	3,790	1,277	1,294	8,902	11,630	3,636	33,644

Table 10-5: Capacity Value (As Percentage of Nameplate Capacity) By Province and Scenario

Scenario	BC	AB	SK	MB	ON	QC	MAR	CAN
5% BAU	35.5%	22.0%	27.4%	37.5%	33.1%	46.8%	43.3%	36.4%
20% DISP	19.2%	11.0%	15.5%	22.5%	24.2%	26.5%	41.9%	22.2%
20% CONC	27.9%	8.8%	22.4%	16.8%	22.1%	36.5%	34.4%	22.4%
35% TRGT	19.1%	7.1%	9.7%	19.5%	18.4%	25.0%	31.7%	17.2%

The Canada-wide results were mainly driven by the results in Alberta, Ontario and Quebec, where 72% to 78% of the wind capacity is installed. The high capacity values in Quebec were offset by the lower capacity values in Alberta and, as a result, Canada-wide results were very close to those obtained for Ontario.

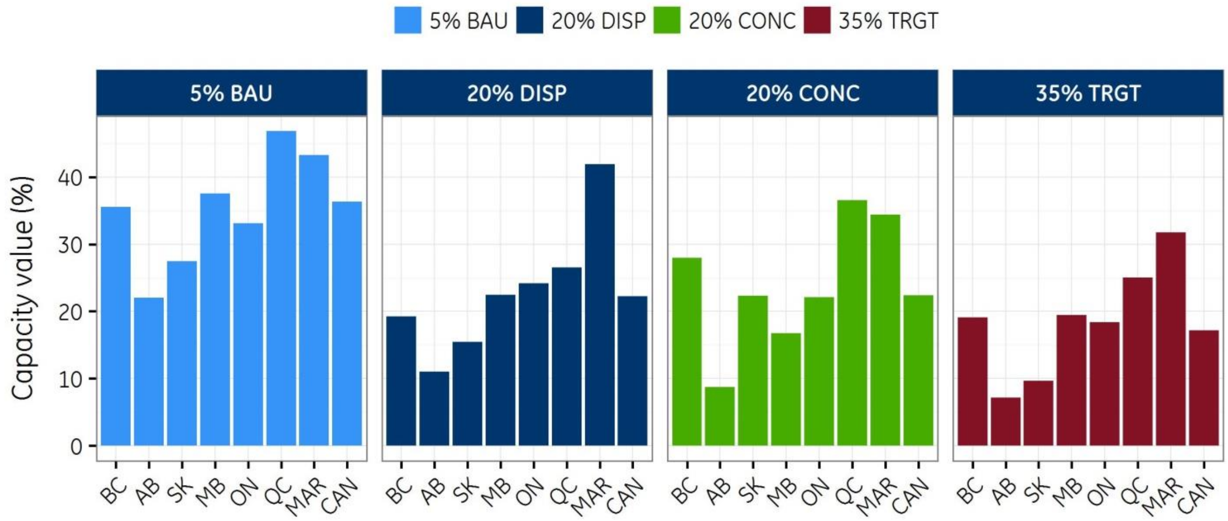


Figure 10-8: Wind Capacity Value by Province and Scenario

10.5.2 Capacity Value by Year

This section presents the capacity value results with the highest level of detail: by province, scenario and data year. Results for absolute and relative capacity values are presented in Table 10-6 and Table 10-7, respectively.

Table 10-6: Capacity Value (GW) By Data Year, Province and Scenario

Scenario	Year	BC	AB	SK	MB	ON	QC	MAR	CAN
5% BAU	2008	140	332	131	111	1,670	1,454	487	4,325
	2009	317	346	129	105	1,293	1,698	489	4,377
	2010	274	272	110	75	1,107	1,004	419	3,261
20% DISP	2008	655	806	270	459	2,379	3,168	708	8,446
	2009	1,046	808	291	470	1,920	4,050	768	9,352
	2010	762	678	250	271	1,825	2,540	628	6,955
20% CONC	2008	477	887	204	523	2,530	2,203	1,482	8,306
	2009	772	911	215	572	2,076	2,784	1,613	8,942
	2010	612	789	194	307	2,069	1,728	1,408	7,107
35% TRGT	2008	836	1,260	450	483	3,402	3,719	1,206	11,354
	2009	1,173	1,398	442	525	2,628	4,904	1,354	12,424
	2010	1,107	1,132	385	286	2,873	3,006	1,077	9,866

Table 10-7: Capacity Value (As Percentage of Nameplate Capacity) By Data Year, Province and Scenario

Scenario	Year	BC	AB	SK	MB	ON	QC	MAR	CAN
5% BAU	2008	20.4%	23.1%	29.2%	43.0%	40.7%	49.1%	45.3%	39.4%
	2009	46.2%	24.1%	28.7%	40.5%	31.5%	57.4%	45.5%	39.9%
	2010	40.0%	18.9%	24.5%	29.1%	27.0%	33.9%	38.9%	29.7%
20% DISP	2008	15.3%	11.6%	15.5%	25.8%	28.2%	25.8%	42.4%	22.8%
	2009	24.5%	11.6%	16.7%	26.4%	22.8%	33.0%	45.9%	25.2%
	2010	17.9%	9.8%	14.3%	15.2%	21.6%	20.7%	37.6%	18.7%
20% CONC	2008	21.5%	9.0%	22.3%	18.8%	25.1%	35.9%	34.0%	22.9%
	2009	34.8%	9.3%	23.5%	20.5%	20.6%	45.4%	37.0%	24.6%
	2010	27.5%	8.0%	21.2%	11.0%	20.6%	28.2%	32.3%	19.6%
35% TRGT	2008	15.3%	7.1%	10.2%	21.8%	21.1%	24.0%	31.6%	17.4%
	2009	21.5%	7.9%	10.0%	23.7%	16.3%	31.7%	35.5%	19.0%
	2010	20.3%	6.4%	8.7%	12.9%	17.8%	19.4%	28.2%	15.1%

Figure 10-9 represents the relative capacity value by province and scenario, comparing the individual years to the average values. Year-to-year variability changed drastically between provinces but tended to be higher with lower wind penetrations. The highest spread was found in British Columbia, Quebec and Manitoba, and it was smallest for Alberta and Saskatchewan. With the exception of British Columbia, the capacity values based on the 2010 data were the smallest across all scenarios. 2009 capacity values were the highest in Quebec and British Columbia and 2008 was the highest for Ontario. Elsewhere, the 2008 and 2009 were very similar.

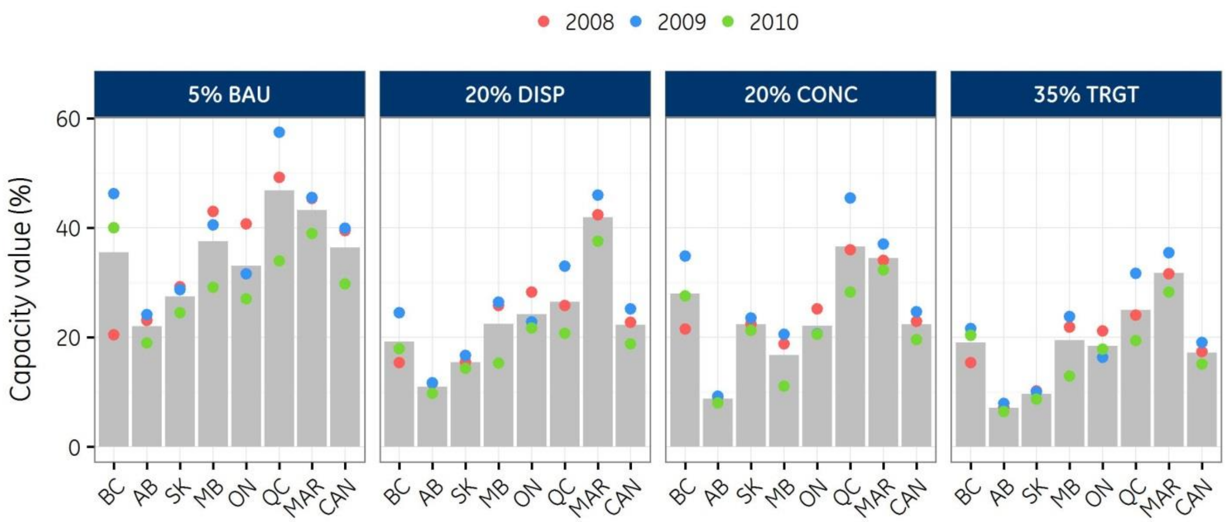


Figure 10-9: Wind Capacity Value by Province and Scenario by Year (Points) and Average Values (Bars)

Finally, Figure 10-10 presents the relationship between installed wind capacity and relative capacity value. Due to the site selection process described in section on “Assumptions and Scenarios”, the two 20% scenarios resulted in different capacities by province, but the graph identifies the scenario through different point markers.

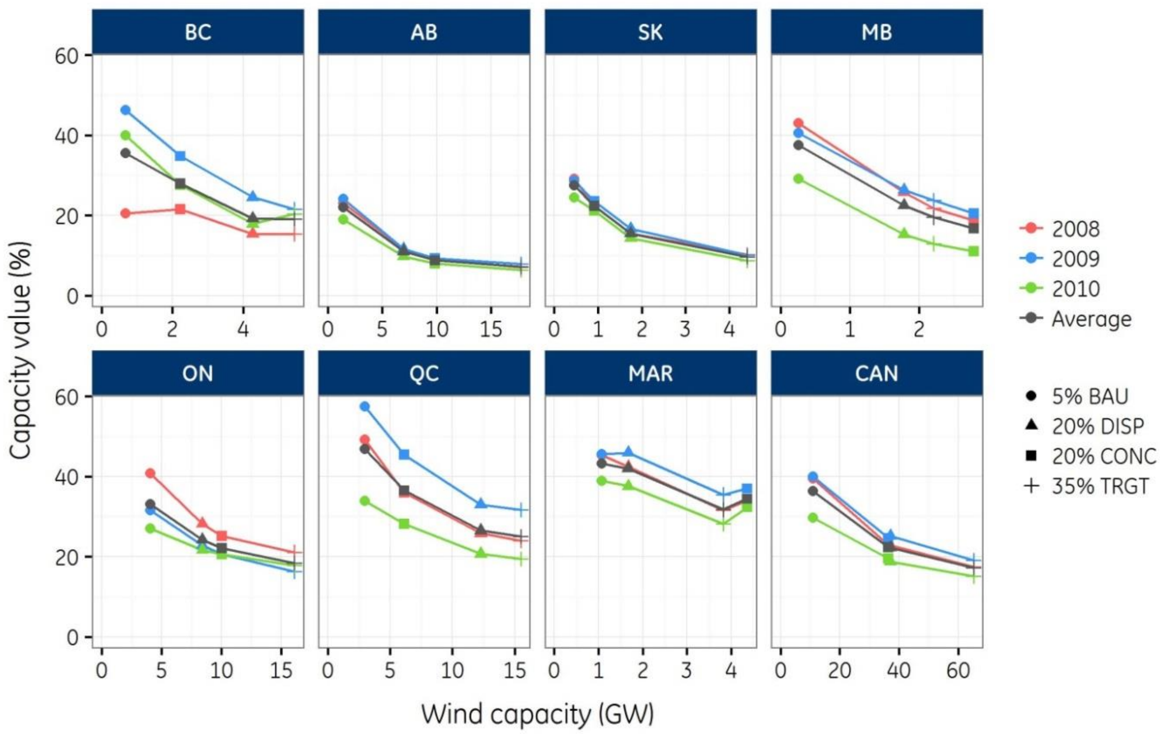


Figure 10-10: Wind Capacity Value vs. Nameplate Capacity by Province

Across all provinces and scenarios, relative capacity values decrease with additional capacity. The biggest exception is the 20% DISP scenario for the Maritimes. In that scenario, wind from Newfoundland (which represents a better resource) is included in the Maritimes province. This creates an increase in capacity value across all years.

10.6 Conclusions

This section presented the capacity value calculations for all wind scenarios considered in this study. Simulations were performed for each province in the Canadian footprint, for the weather years 2008, 2009 and 2010. Wind capacity values represented 4 GW for the 5% BAU scenario, 8 GW for the two 20% scenarios and 11 GW for the 35% TRGT scenario. These capacity values represented 36%, 22% and 17% of the nameplate capacity, respectively.

We observed a wide variation of wind capacity value results across years for most of the provinces, which suggests that further years of data would improve the robustness of the results. A sliding-window method was used to minimize the variation and to capture seasonal wind and load trends.

Capacity value results were quite different across provinces. In general, Quebec and Maritimes had the highest capacity values across all scenarios, while the lowest were found

Alberta and Saskatchewan. The Canada-wide results were mainly driven by the results in Alberta, Ontario and Quebec, where 72% to 78% of the wind capacity is installed. Canadian and provinces capacity values decreased as a fraction of installed capacity with higher wind penetrations.

11 Appendices & References

11.1 Appendix A: GE MAPS Model

Application of GE MAPS

GE's Multi Area Production Simulation (GE MAPS)[33] software program is a transmission based Production cost model to be used for the execution of the wind integration study. This GE proprietary (but commercially available) modeling tool has a long history of governmental, regulatory, independent system operator and investor-owned utility applications. The production cost model provides unit-by-unit production output (MW) on an hourly basis for an entire year of production (GWh) of electricity production by each unit). The results also provide information about the variable cost of electricity production, emissions, fuel consumption, etc.

The overall simulation algorithm is based on standard least marginal cost operating practice. That is, generating units that can supply power at lower marginal cost of production are committed and dispatched before units with higher marginal cost of generation. Commitment and dispatch are constrained by physical limitations of the system, such as transmission thermal limits, minimum spinning reserve, as well as the physical limitations and characteristics of the power plants.

The primary source of model uncertainty and error for production cost simulations, based on the model, consist of:

- Some of the constraints in the model may be somewhat simpler than the precise situation dependent rules used by electricity market operators and utilities.
- Marginal production-cost models consider heat rate and a variable O&M cost. However, the models do not include an explicit heat-rate penalty or an O&M penalty for increased maneuvering that may be a result of incremental system variability due to as-available renewable resources (in future scenarios).
- The production cost model requires input assumptions like forecasted fuel price, forecasted system load, estimated unit heat rates, maintenance and forced outage rates, etc. Variations from these assumptions could significantly alter the results of the study.
- Prices that utilities pays to IPPs for energy are not in general equal to the variable cost of production for the individual unit; nor are they equal to the systemic marginal cost of production. Rather, they are governed by PPAs. The price that utilities pay to

33 http://www.geenergyconsulting.com/practice-area/software-products/maps

third parties can be reflected in the simulation results insofar as the conditions can be reproduced.

The simulation results provide insight into hour-to-hour operations, and how commitment and dispatch may change subject to various changes, including equipment or operating practices. Since the production cost model depends on fuel price as an input, relative costs and change in costs between alternative scenarios tend to produce better and more useful information than absolute costs. The results from the model approximate system dispatch and production, but do not necessarily identically match system behavior. The results do not necessarily reproduce accurate production costs on a unit-by-unit basis and do not accurately reproduce every aspect of system operation. However, the model reasonably quantifies the incremental changes in marginal cost, emissions, fossil fuel consumption, and other operations metrics due to changes, such as higher levels of wind power.

Unique Features of GE MAPS

GE MAPS is a highly detailed model that calculates hour-by-hour production costs while recognizing constraints on the dispatch of generation imposed by the transmission system. When the program was initially developed over twenty years ago, its primary use was as a generation and transmission planning tool to evaluate the impacts of transmission system constraints on the system production cost. In the current deregulated utility environment, the acronym GE MAPS may more also stand for Market Assessment & Portfolio Strategies because of the model's usefulness in studying issues such as market power and the valuation of generating assets operating in a competitive environment.

The unique modeling capabilities of GE MAPS use a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved ac load flow, to calculate the real power flows for each generation dispatch. This enables the user to capture the economic penalties of re-dispatching the generation to satisfy transmission line flow limits and security constraints.

Separate dispatches of the interconnected system and the individual companies' own load and generation are performed to determine the economic interchange of energy between companies. Several methods of cost reconstruction are available to compute the individual company costs in the total system environment. The chronological nature of the hourly loads is modeled for all hours in the year. In the electrical representation, the loads are modeled by individual bus.

In addition to the traditional production costing results, MAPS can provide information on the hourly spot prices at individual buses and on the flows on selected transmission lines for all hours in the year, as well as identifying the companies responsible for the flows on a given line.

Because of its detailed representation of the transmission system, GE MAPS can be used to study issues that often cannot be adequately modeled with conventional production costing software. These issues include:

Market Structures – GE MAPS is being used extensively to model emerging market structures in different regions of the United States. It has been used to model the New York, New England, PJM and California ISOs for market power studies, stranded cost estimates, and project evaluations.

Transmission Access – GE MAPS calculates the hour spot price ($/MWh) at each bus modeled, thereby defining a key component of the total avoided cost that is used in formulating contracts for transmission access by non-utility generators and independent power producers.

Loop Flow or Uncompensated Wheeling – The detailed transmission modeling and cost reconstruction algorithms in MAPS combine to identify the companies contributing to the flow on a given transmission line and to define the production cost impact of that loading.

Transmission Bottlenecks – GE MAPS can determine which transmission lines and interfaces in the system are bottlenecks and how many hours during the year these lines are limiting. Next, the program can be used to assess, from an economic point of view, the feasibility of various methods, such as transmission line upgrades or the installation of phase-angle regulators for alleviating bottlenecks.

Evaluation of New Generation, Transmission, or Demand-Side Facilities – GE MAPS can evaluate which of the available alternatives under consideration has the most favorable impact on system operation in terms of production costs and transmission system loading.

Power Pooling – The cost reconstruction algorithms in GE MAPS allow individual company performance to be evaluated with and without pooling arrangements, so that the benefits associated with pool operations can be defined.

Modeling Capabilities of GE MAPS

GE MAPS has evolved to study the management of a power system's generation and transmission resources to minimize generation production costs while considering transmission security. The modeling capabilities of MAPS are summarized below:

Time Frame – One year to several years with ability to skip years.

Company Models – Up to 175 companies.

Load Models – Up to 175 load forecasts. The load shapes can include all 365 days or automatically compress to a typical week (seven different day shapes) per month. The day shapes can be further compressed from 24 to 12 hours, with bi-hourly loads.

Generation – Up to 7,500 thermal units, 500 pondage plants, 300 run-of-river plants, 50 energy-storage plants, 15 external contracts, 300 units jointly owned, and 2,000 fuel types. Thermal units have full and partial outages, daily planned maintenance, fixed and variable operating and maintenance costs, minimum down-time, must-run capability, and up to four fuels at a unit.

Network Model –Includes 50,000 buses, 100,000 lines, 145 phase-angle regulators, and 100 multi-terminal High-Voltage Direct Current lines. Line or interface transmission limits may be set using operating nomograms as well as thermal, voltage and stability limits. Line or interface limits may be varied by generation availability.

Losses - Transmission losses may vary as generation and loads vary, approximating the ac power flow behavior, or held constant, which is the usual production simulation assumption. The incremental loss factors are recalculated each hour to reflect their dependence on the generation dispatch.

Marginal Costs – Marginal costs for an increment such as 100 MW can be identified by running two cases, one 100 MW higher, with or without the same commitment and pumped-storage hydro schedule. A separate routine prepares the cost difference summaries. Hourly bus spot prices are also computed.

Operating Reserves – Modeled on an area, company, pool and system basis.

Secure Dispatch – Up to 5,000 lines and interfaces and nomograms may be monitored. Each study hour considers the effect of hundreds of different network outages.

Report Analyzer – MAPS allows the simulation results to be analyzed through a powerful report analyzer program, which incorporates full screen displays, customizable output reports, graphical displays and databases. The built-in programming language allows the user to rapidly create custom reports.

Accounting – Separate commitment and dispatches are done for the system and for the company own-load assumptions, allowing cost reconstruction and cost splitting on a licensee-agreed basis. External economy contracts are studied separately after the base dispatch each hour.

Bottom Line – Annual fuel plus O&M costs for each company, fuel consumption, and generator capacity factors.

11.2 Appendix B: GE MARS Model

The Multi-Area Reliability Simulation software program (GE MARS)[34] enables the electric utility planner to quickly and accurately assess the reliability of a generation system comprised of any number of interconnected areas.

GE Mars Modeling Technique

A sequential Monte Carlo simulation forms the basis for MARS. The Monte Carlo method provides a fast, versatile, and easily-expandable program that can be used to fully model many different types of generation and demand-side options.

In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly-generated operating histories of the generating units with the inter-area transfer limits and the hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules and policies which govern system operation, without the simplifying or idealizing assumptions often required in analytical methods.

Reliability Indices Available From Mars

The following reliability indices are available on both an isolated (zero ties between areas) and interconnected (using the input tie ratings between areas) basis:

- Daily LOLE (days/year)
- Hourly LOLE (hours/year)
- LOEE (MWh/year)
- Frequency of outage (outages/year)
- Duration of outage (hours/outage)
- Need for initiating emergency operating procedures (days/year)

The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for all of the reliability indices. These values can be calculated both with and without load forecast uncertainty.

Description of Program Models

Loads - The loads in MARS are modeled on an hourly, chronological basis for each area being studied. The program has the option to modify the input hourly loads through time to meet specified annual or monthly peaks and energies. Uncertainty on the annual peak load forecast can also be modeled, and can vary by area on a monthly basis.

[34] http://www.geenergyconsulting.com/practice-area/software-products/mars

MARS has the capability to model the following different types of resources:

- Thermal
- Energy-limited
- Cogeneration
- Energy-storage
- Demand-side management

An energy-limited unit can be modeled stochastically as a thermal unit with an energy probability distribution (Type 1 energy-limited unit), or deterministically as a load modifier (Type 2 energy-limited unit). Cogeneration units are modeled as thermal units with an associated hourly load demand. Energy-storage and demand-side management are modeled as load modifiers.

For each unit modeled, the user specifies the installation and retirement dates and planned maintenance requirements. Other data such as maximum rating, available capacity states, state transition rates, and net modification of the hourly loads are input depending on the unit type.

The planned outages for all types of units in MARS can be specified by the user or automatically scheduled by the program on a weekly basis. The program schedules planned maintenance to levelize reserves on an area, pool, or system basis. MARS also has the option of reading a maintenance schedule developed by a previous run and modifying it as specified by the user through any of the maintenance input data. This schedule can then be saved for use by subsequent runs.

Thermal Units - In addition to the data described previously, thermal units (including Type 1 energy-limited units and cogeneration) require data describing the available capacity states in which the unit can operate. This is input by specifying the maximum rating of each unit and the rating of each capacity state as a per-unit of the unit's maximum rating. A maximum of eleven capacity states are allowed for each unit, representing decreasing amounts of available capacity as a result of the outages of various unit components.

Because MARS is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if you assume that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on its state in previous hours and influences its state in future hours. It thus requires the additional information that is contained in the transition rate data.

For each unit, a transition rate matrix is input that shows the transition rates to go from each capacity state to each other capacity state. The transition rate from state A to state B is defined as the number of transitions from A to B per unit of time in state A:

$$\boldsymbol{TR\ (A\ to\ B) = \frac{Number\ of\ Transitions\ from\ A\ to\ B}{Total\ Time\ in\ State\ A}}$$

If detailed transition rate data for the units is not available, MARS can approximate the transitions rates from the partial forced outage rates and an assumed number of transitions between pairs of capacity states. Transition rates calculated in this manner will give accurate results for LOLE and LOEE, but it is important to remember that the assumed number of transitions between states will have an impact on the time-correlated indices such as frequency and duration.

Energy-Limited Units - Type 1 energy-limited units are modeled as thermal units whose capacity is limited on a random basis for reasons other than the forced outages on the unit. This unit type can be used to model a thermal unit whose operation may be restricted due to the unavailability of fuel, or a hydro unit with limited water availability. It can also be used to model technologies such as wind or solar; the capacity may be available but the energy output is limited by weather conditions.

Type 2 energy-limited units are modeled as deterministic load modifiers. They are typically used to model conventional hydro units for which the available water is assumed to be known with little or no uncertainty. This type can also be used to model certain types of contracts. A Type 2 energy-limited unit is described by specifying a maximum rating, a minimum rating, and a monthly available energy. This data can be changed on a monthly basis. The unit is scheduled on a monthly basis with the unit's minimum rating dispatched for all of the hours in the month. The remaining capacity and energy can be scheduled in one of two ways. In the first method, it is scheduled deterministically so as to reduce the peak loads as much as possible. In the second approach, the peak-shaving portion of the unit is scheduled only in those hours in which the available thermal capacity is not sufficient to meet the load; if there is sufficient thermal capacity, the energy of the Type 2 energy-limited units will be saved for use in some future hour when it is needed.

Cogeneration - MARS models cogeneration as a thermal unit with an associated load demand. The difference between the unit's available capacity and its load requirements represents the amount of capacity that the unit can contribute to the system. The load demand is input by specifying the hourly loads for a typical week (168 hourly loads for

Monday through Sunday). This load profile can be changed on a monthly basis. Two types of cogeneration are modeled in the program, the difference being whether or not the system provides back-up generation when the unit is unable to meet its native load demand.

Energy-Storage and DSM - Energy-storage units and demand-side management are both modeled as deterministic load modifiers. For each such unit, the user specifies a net hourly load modification for a typical week which is subtracted from the hourly loads for the unit's area.

Transmission System

The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of areas. Simultaneous transfer limits can also be modeled in which the total flow on user-defined groups of interfaces is limited. Random forced outages on the interfaces are modeled in the same manner as the outages on thermal units, through the use of state transition rates.

The transfer limits are specified for each direction of the interface or interface group and can be input on a monthly basis. The transfer limits can also vary hourly according to the availability of specified units and the value of area loads.

Contracts

Contracts are used to model scheduled interchanges of capacity between areas in the system. These interchanges are separate from those that are scheduled by the program as one area with excess capacity in a given hour provides emergency assistance to a deficient area.

Each contract can be identified as either firm or curtailable. Firm contracts will be scheduled regardless of whether or not the sending area has sufficient resources on an isolated basis, but they can be curtailed because of interface transfer limits. Curtailable contracts will be scheduled only to the extent that the sending area has the necessary resources on its own or can obtain them as emergency assistance from other areas.

Emergency Operating Procedures

Emergency operating procedures are steps undertaken by a utility system as the reserve conditions on the system approach critical levels. They consist of load control and generation supplements which can be implemented before load has to be actually disconnected. Load control measures could include disconnecting interruptible loads, public appeals to reduce demand, and voltage reductions. Generation supplements could include overloading units, emergency purchases, and reduced operating reserves.

The need for a utility to begin emergency operating procedures is modeled in MARS by evaluating the daily LOLE at specified margin states. The user specifies these margin states for each area in terms of the benefits realized from each emergency measure, which can be expressed in MW, as a per unit of the original or modified load, and as a per unit of the available capacity for the hour.

The user can also specify monthly limits on the number of times that each emergency procedure is initiated, and whether each EOP benefits only the area itself, other areas in the same pool, or areas throughout the system. Staggered implementation of EOPs, in which the deficient area must initiate a specified number of EOPs before non-deficient areas begin implementation, can also be modeled.

Resource Allocation among Areas

The first step in calculating the reliability indices is to compute the area margins on an isolated basis, for each hour. This is done by subtracting from the total available capacity in the area for the hour the load demand for the hour. If an area has a positive or zero margins, then it has sufficient capacity to meet its load. If the area margin is negative, the load exceeds the capacity available to serve it, and the area is in a loss-of-load situation.

If there are any areas that have a negative margin after the isolated area margins have been adjusted for curtailable contracts, the program will attempt to satisfy those deficiencies with capacity from areas that have positive margins. Two methods are available for determining how the reserves from areas with excess capacity are allocated among the areas that are deficient. In the first approach, the user specifies the order in which an area with excess resources provides assistance to areas that are deficient. The second method shares the available excess reserves among the deficient areas in proportion to the size of their shortfalls.

The user can also specify that areas within a pool will have priority over outside areas. In this case, an area must assist all deficient areas within the same pool, regardless of the order of areas in the priority list, before assisting areas outside of the pool. Pool-sharing agreements can also be modeled in which pools provide assistance to other pools according to a specified order.

Output Reports

The following output reports are available from MARS. Most of the summaries of calculated quantities are available for each load forecast uncertainty load level and as a weighted-average based on the input probabilities.

- Summary of the thermal unit data.
- Summary of installed capacity by month by user-defined unit type.
- Summary of load data, showing monthly peaks, energies, and load factors.
- Unit outage summary showing the weeks during the year that each unit was on planned outage.

- Summary of weekly reserves by area, pool, and system.
- Annual, monthly, and weekly reliability indices - by area and pool, isolated and interconnected.
- Expected number of days per year at specified margin states on an annual, monthly, and weekly basis.
- Annual and monthly summaries of the flows, showing for each interface the maximum and average flow for the year, the number of hours at the tie-line limit, and the number of hours of flow during the year.
- Annual summary of energy and hours of curtailment for each contract.
- Annual summary of energy usage for the peaking portion of Type 2 energy-limited units.
- Replication year output, by area and pool, isolated and interconnected, showing the daily and hourly LOLE and LOEE for each time that the study year was simulated. This information can be used to plot distributions of the indices, which show the year-to-year variation that actually occurs.
- Annual summary of the minimum and maximum values of the replication year indices.
- Detailed hourly output showing, for each hour that any of the areas has a negative margin on an isolated basis, the margin for each area on an isolated and interconnected basis.
- Detailed hourly output showing the flows on each interface.

Program Dimensions

All of the program dimensions in MARS can be changed at the time of installation to size the program to the system being studied. Among the key parameters that can be changed are the number of units, areas, pool, and interfaces.

11.3 Appendix C: GE PSLF Model

Effective power system analysis often requires large-scale simulations and manipulation of large volumes of data. When performing these analyses, efficient algorithms are just as important as the engineering models in which the data is used. GE Energy recognizes these imperatives, and has developed Concorda Positive Sequence Load Flow (GE PSLF)[35] model.

The algorithms in the GE PSLF suite have been developed to handle large utility-scale systems of up to 80,000 buses.

A complete set of tools allows the user to switch smoothly between data visualization, system simulation, and results analysis.

GE PSLF Features & Benefits

- Comprehensive System Modeling: provides precise models for lines, transformers, generators, and other components, at a nameplate level
- Highly Accurate: enabling more detailed system and modeling capabilities
- Efficient Data Management: full-screen data editor, tools for searching, sorting and selecting data, numerous reports which facilitate system planning
- Customizable: extendable data records, user defined data tables
- Enhanced Graphics: allow the user to inspect power system models, select, display, and edit components; view the system from a specific component.
- Dynamic Model Library: generators, turbines, excitation controls, governors, power system stabilizers, loads, relays and other power system components
- Renewable Generation Models: detailed dynamic models of GE wind turbine generators, a GE PV solar plant, and a suite of generic wind and solar models.
- Automation and Scripting: Engineer Program Control Language (EPCL), provides detailed access to internal data, internal commands and math functions.

GE PSLF Applications

Concorda GE PSLF is a comprehensive system modeling tool which can be used for many aspects of system planning and analysis

- steady state, load flow simulation
- short circuit analysis
- dynamic simulation

[35] http://www.geenergyconsulting.com/practice-area/software-products/pslf

- identifying system bottlenecks
- identify grid code violations

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