Integrated assessment of water use and greenhouse gas footprints of Canada's electricity generation and oil and gas sectors

by

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A thesis submitted in partial fulfillment of the requirements for the degree of

Master of Science

in

Engineering Management

Department of Mechanical Engineering

University of Alberta

Abstract

The energy sector is responsible for a significant portion of global greenhouse gas emissions, water withdrawal, and water consumption. There are strong dependences between energy production and water use, and the adoption of more clean energy production technologies will affect water use. Such technological changes are not well understood. There is very little research assessing the water use associated with clean energy pathways in the energy sector. The objective of this research is to understand and evaluate the water-use impacts of Canada's renewable energy transition. This research developed an integrated energy-water model to assess clean energy scenarios and the resulting technology penetration, water use, and cumulative and marginal greenhouse gas (GHG) emissions abatement costs. The energy sectors considered in this work are the oil and gas sector and the electricity generation sector. The Canadian Water Evaluation and Planning model (WEAP-Canada) was developed and integrated with the Long-range Energy Alternative Planning (LEAP-Canada) system model to determine integrated water-greenhouse gas footprints for the electricity generation sector and the oil and gas sector for the years 2005-2050.

This research develops integrated water-greenhouse gas footprints for future electricity generation mix pathways in Canada with a focus on deep decarbonization. The LEAP model of Canada's electricity system was developed by using technology system capacity requirements, technology capacity addition, and technology and economic inputs to provide electricity generation technology capacities and generation, system costs, and GHG emissions. A Water Evaluation and Planning model for Canada's electricity generation sector was also developed by considering one-hundred-fifty-six electricity generation water demand sites and seventy-four major rivers. The two models were integrated to analyze electricity production and its associated greenhouse gas emissions and water use. Two scenarios were developed and evaluated for a planning horizon of 2019 to 2050. First scenario was based on current policy and second scenario was developed with a deep decarbonization target of 100%. In the current policy scenario, water consumption is projected to decrease by 5% and GHG emissions to decrease by 81% by 2050 compared to 2019. In the 100% decarbonization scenario, the water consumption is projected to increase by 3% by 2050 compared to 2019. Setting decarbonization targets of 100% resulted in a marginal water

consumption of 3.6% and marginal GHG abatement costs of $23 per tonne of CO_2 equivalent. There are water consumption tradeoffs in the 100% decarbonization scenario, but they are relatively small compared to those in other water-consuming sectors in Canada. Assessing the water-use impacts and costs of GHG emission reduction pathways helps to identify the co-benefits or tradeoffs associated with decarbonizing this sector and may be useful in policy development.

This research also develops water use footprints for future oil and gas production in Canada by considering different energy pathways. The oil and gas section of the thesis focuses on developing a baseline for future water-GHG analysis in the oil and gas sector rather than understanding the water-GHG trade-off for clean energy scenarios. The WEAP model of Canada's oil and gas sector (WEAP-COG) was developed using production, water-use intensities, and production shares based on watersheds to provide water withdrawal and consumption at the watershed level. Using the six water withdrawal sectors of the oil and gas sector (oil sands mining, oil sands in situ production, bitumen upgrading, conventional crude oil production, natural gas production, and crude oil refining), we modelled twenty rivers and forty-five demand sites. Energy scenarios were adopted from literature for high-price and low-price cases and then run in the WEAP-COG model. The results were compared to the reference scenario results to obtain marginal water use and GHG footprints for each scenario. The GHG emissions, water withdrawal, and water consumption for the oil and gas sector will increase by 80%, 21%, and 39% by 2050 from 2005, respectively, because of the increase in oil production. GHG emissions from the oil and gas sector will exceed Canada's nationally determined contributions (NDC) target. The adoption of clean energy, less water-consuming technologies is recommended in order to achieve the current NDC target or to mitigate future water stress. The results developed in this research can be used by the decision makers in the government and industry for investment decision and policy formulation.

Preface

This thesis is an original work by Ankit Gupta under the supervision of Dr. Amit Kumar. Chapter 2 will be submitted to a peer-reviewed journal as “An integrated assessment of the water use footprint and marginal costs for decarbonization of Canada’s electricity generation sector,” coauthored by Ankit Gupta, Matthew Davis, and Amit Kumar.

I was responsible for defining the problem, data collection, data analysis, model development, and manuscript composition. Matthew Davis reviewed the research, provided feedback, and corrected the manuscript. Amit Kumar was the supervisory author and provided supervision on problem formulation, development of modelling framework, input data and assumptions, results, and manuscript edits.

Acknowledgements

I would like to express my sincere gratitude to my supervisor, Dr. Amit Kumar, for his guidance, mentorship, and support throughout my research work. His supervision, insight, and continuous feedback were invaluable in conducting the research. I would also like to extend sincere thanks to Matthew Davis, a research engineer at the University of Alberta, for his timely feedback, knowledge sharing, and continuous support, which encouraged me towards the completion of my research. I would also like to thank Astrid Blodgett for editing my papers.

I am thankful to the NSERC/Cenovus/Alberta Innovates Associate Industrial Research Chair in Energy and Environmental Systems Engineering and the Cenovus Energy Endowed Chair in Environmental Engineering for financial support. I am also grateful to representatives from Alberta Innovates (AI), Suncor Energy Inc., Cenovus Energy Inc., Natural Resources Canada, and Environment and Climate Change Canada for their valuable input and comments in various forms. Many thanks to the University of Alberta's Future Energy Systems research initiative, which made this research possible, in part through the Canada First Research Excellence Fund (CFREF).

I highly appreciate the assistance of Drs. Eskinder Gemechu and Abayomi Olufemi Oni for their feedback on my journal papers. I am thankful to the members of the Sustainable Energy Research Group for their support, comments, and useful discussions throughout my research. Special thanks to my friends for sharing this journey. I am grateful to the Mechanical Engineering Graduate Students Association and the Faculty of Engineering Graduate Research Symposium committee, which provided me with the opportunity for professional development.

Finally, I would like to acknowledge my parents for their overwhelming support and for believing in me. I would not be the same person without their love and encouragement.

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List of Abbreviations

AB	Alberta
AESO	Alberta Electric System Operator
ATL	Atlantic
BC	British Columbia
Binsitu	Bitumen in situ extraction
Bmine	Bitumen mining extraction
CANSIM	Canadian Socio-economic Information Management System
CO_2	Carbon dioxide
Cogen	Cogeneration
ConvOil	Conventional crude oil extraction
DCT	Dry cooling towers
GCAM	Global Change Assessment Model
GHG	Greenhouse gas
GIS	Geographic information system
GJ	Gigajoules
IESO	Independent Electricity System Operator
LEAP	Long-range Energy Alternatives Planning system
MMBtu	Million British thermal units
MT	Manitoba
MW	Megawatt
MWh	Megawatt hours
NB	New Brunswick
NDC	Nationally determined contribution
NEB	National Energy Board
NFL	Newfoundland & Labrador
NGext	Natural gas extraction
NPV	Net present value
NS	Nova Scotia

O&M	Operation and maintenance
OECD	Organization for Economic Co-operation and Development
ON	Ontario
OSeMOSYS	Open source energy modelling system
OT	Once-through
POND	Cooling pond
QB	Quebec
ReEDS	Regional Energy Deployment System
REF	Reference scenario
SELS	System energy load shape
SK	Saskatchewan
StatCan	Statistics Canada
TWh	Terawatt hours
WCEP	Water consumption for total energy production
WCT	Wet cooling towers
WEAP	Water Evaluation and Planning system

1 Introduction

1.1 Clean energy transition and water impacts

The energy sector is responsible for most of the global greenhouse gas (GHG) emissions. As global energy demands grow, so do GHG emissions. These rising GHG emissions increase the atmospheric GHG concentration and lead to excessive global warming. In addition to the high GHG emissions, the energy sector uses a significant amount of water. Water is a key resource in the energy sector and is required for energy production. Rising energy demands will increase global water demands. The water scarcity problem will get worse if water demands and global temperature continue to rise. It is important to understand the relationship between energy and water when planning for a sustainable future.

According to the 2017 International Energy Outlook, world energy demand will increase by 28% from the 2015 level by 2040 (1), and this increase will be met mostly by fossil fuels (1). Of the fossil fuels, petroleum and liquid fuels will be consumed the most (1). The increase in fossil fuel consumption will increase GHG emissions. Global GHG emissions are projected to increase by 57% by 2050 (80 billion MT CO_2 eq.) from 2015 (51 billion MT CO_2 eq.) (2). If the emissions continue to increase at this rate, the global average temperature will rise (3). In order to curb rising GHG emissions, in 2016, 197 countries signed the Paris Agreement and pledged to reduce GHG emissions and keep the global mean temperature rise to under 2°C. According to the agreement, countries are obligated to develop a goal to mitigate GHG emissions, known as a nationally determined contribution (NDC) (3). Large economies such as those of the United States (US), Europe, China, and Canada declared their NDCs with an aim to decrease GHG emissions by 26% by 2025 from 2005, 40% by 2030 from 1990, 60% by 2030 from 2005 (GHG emissions per unit GDP), and 30% by 2030 from 2005, respectively (3).

The share of global energy-related GHG emissions will increase from 65% in 2015 (33 billion MT CO_2 eq.) to 75% in 2050 (60 billion MT CO_2 eq.) (2). Within the energy sector, the electricity generation and the oil and gas sectors will continue to be responsible for most of the emissions (2). Following the Paris Agreement, the energy sector witnessed a significant shift toward renewables. In the electricity sector, the year 2017 saw the largest global increase in renewables. In that year, 70% of net electricity capacity additions were renewable, with solar and wind accounting for 55% and 29% of renewable additions, respectively (4). It is expected that renewables will continue to grow at an average of 2.8% per year until 2040 (1), faster than any other source of electricity. Meanwhile, coal generation shares are expected to decline and supply 31% of electricity by 2040 (1). Governments around the world are looking for alternative to coal power (5). In the oil extraction sector, the integration of unconventional, less energy-intensive extraction technologies, such as hybrid steam-solvent technology and carbon capture and sequestering, are being considered (6). Refineries are exploring ways to meet their fossil-fueled hydrogen production processes by switching to electrolysis powered by renewable sources (7).

Shifts to clean energy technology may reduce GHG emissions compared to fossil fuels but may in turn increase water consumption. In energy industries, water is required for many purposes, i.e., cooling, processing, extraction, and process feedstock (8). In 2014, the energy sector was responsible for 10% (398 bcm) and 3% (48 bcm) of global withdrawal and consumption (8). The electricity generation sector was responsible for 88% (350 bcm) and 36% (17 bcm) of energy-related withdrawal and consumption (8), and primary energy production (fossil fuels and biofuels extraction and processing) was responsible for the rest (8). It has been estimated that the energy sector's water withdrawal and consumption will increase 1.5% and 60% by 2040, even after a future decrease of fossil fuel dependency and wider adoption of clean technology by the energy industry (8).

The increase in water consumption in the energy sector could have a detrimental effect on the already threatened global water resources. Global freshwater demand is projected to increase 55% by 2050 from 2005 (2). It is estimated that 40% of the world's population will live in severely water-stressed areas by then (9). With the adoption of clean energy in the energy industry, water availability can further be threatened depending on the type of clean technology adopted. For instance, carbon capture and sequestering (CCS) projects claim to capture 90% of the coal CO_2 emissions, but they require an additional 20-60% water (10). Similarly, replacing natural gas generation with carbon-neutral biomass generation will also increase the water needed for MWh of electricity generation (11) (12). There are some clean technologies that are not water intensive. Solar and wind generation require minimal water to produce electricity (12). But the underlying assumption that shifting toward cleaner technology will be good for the environment overall needs to be comprehensively assessed. Understanding the trade-offs between reducing GHG emissions through technology change and associated changes in water withdrawal and consumption levels is something that should be well understood. This thesis investigates such trade-offs and conducts a case study for Canada, a country that is undergoing energy transitions toward clean technologies in both the electricity and oil and gas sectors.

1.2 The Canadian context

1.2.1 **Clean energy transition and water impacts**

Canada emitted 716 MT of CO_2 equivalent in 2017, 3% less than in 2005 (738 MT of CO_2 eq.) (13). Most of this reduction was in the electricity generation sector, where GHG emissions were 38% below 2005 levels (13). But Canada still stands third in terms of GHG emissions per capita among the Organization for Economic Co-operation and Development (OECD) countries (14) and in 2017 had only reached 6% of its 2030 NDC target of 513 MT of CO_2 eq. (15). There is still a good deal to be done to achieve the NDC target. The energy sector, which includes the oil and gas sector and the electricity generation sector, contributes more than any other sector to the national GHG emissions (38% in 2017) (13). This is the key sector where clean energy adoptions are likely to happen if Canada is to achieve the GHG emissions target.

The implications of using clean energy technologies on Canada's water resources could be adverse in some water-stressed regions, given the country's high water use per capita and concentrated population at the water stress regions (16). Canada is home to 0.5% of the global population (14), but its water use per capita is second highest in the world (16). In 2008, Canada ranked second among OECD countries in terms of water consumption for total energy production (WCEP) (17).

Canada is also second after the USA in terms of water consumption for fossil fuel and nuclear electricity production among OECD countries (17).

Environment and Climate Change Canada's (ECCC's) bi-annual water use survey provides insight into the country's sectorial water use patterns (18). The report quantifies sectorial water withdrawal, water consumption, and water return for seven sectors – thermal power, manufacturing, households, commercial and institutional, agriculture, mining, and oil and gas (18). In 2013, around 38 billion cubic meters of water was diverted for human activities (18). The thermal power sector withdrew the largest share (67.6%), followed by manufacturing (10.45%), residential (8.54%), and agricultural (5.29%) (18). In terms of water consumption, the agriculture sector's share is the highest (44.18%), followed by manufacturing (11.35%), thermal power (10.96%), and oil and gas (10.54%) (18). The agriculture sector uses water to improve crop yield and consumes most of the water it withdraws (18). Similarly, the oil and gas sector consumes 95% of its withdrawn water (18).The thermal power sector, on the other hand, returns most of the diverted water and consumes only 1.5% of its withdrawn water (18).

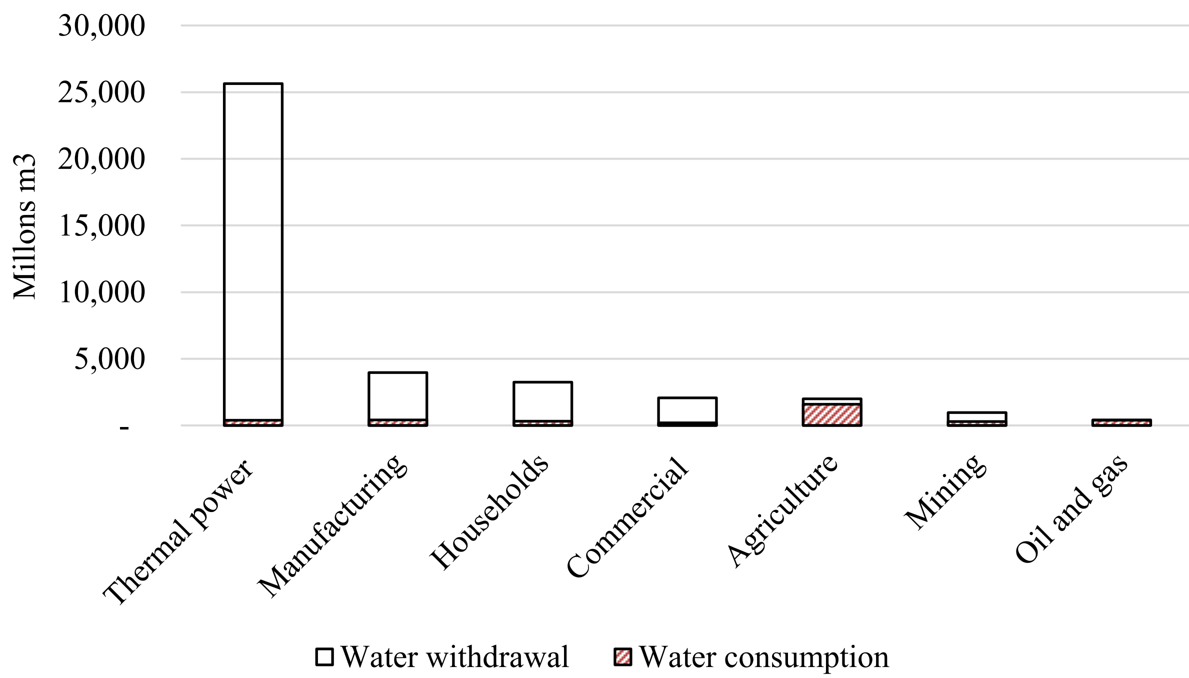

Figure 1-1: Water withdrawal and consumption for Canada's major water withdrawal sectors (18)

If the current trend continues, Canada's energy sector water consumption will continue to increase. Davies et al. forecasted an increase in water consumption in the electricity generation sector (19). Conventional oil and bitumen are projected to increase 15% from the 2017 levels (20). Water consumption will increase if water intensities do not decrease. Adopting clean energy technologies might further increase water consumption. Hence, this needs to be assessed comprehensively.

The high water use by the energy sector possess challenge to many watersheds. The St. Lawrence River, which flows between Ontario and Quebec, has witnessed a severe change in water flows and levels because of dam development for hydropower generation and shipping seaways (21). New Brunswick's Saint John River hydrology was negatively influenced after three dams were built on its course (21). According to StatCan's Human Activity and the Environment 2016 report, the Assiniboine-Red, the Great Lakes drainage regions, the South Saskatchewan, and the Okanagan-Similkameen are the most vulnerable watersheds in Canada (16). The Great Lakes hold 20% of the world's surface freshwater but their watershed is stressed because of enormous withdrawals by nuclear and natural gas power plants and the residential sector (22). These examples demonstrate the need for integrated energy-GHG-water assessments of Canada's clean energy transition.

1.2.2 **Canadian electricity generation background**

In 2017 Canada generated 636 TWh of electricity, 85% of it through non-GHG emitting sources (23). Hydro (60%) was the main contributor to the grid, followed by nuclear (16%), coal (9%), gas (8%), and non-hydro renewables (7%) (23). Canada emitted 74.3 million MT of CO_2 equivalent in 2017, a 38% decrease from the 2005 level (13). This was due to the increase in the non-emitting generation share from 75% to 85% between 2005 and 2017 (23). An overview of the provincial electricity generation sector is provided in Table 1-1 (23).

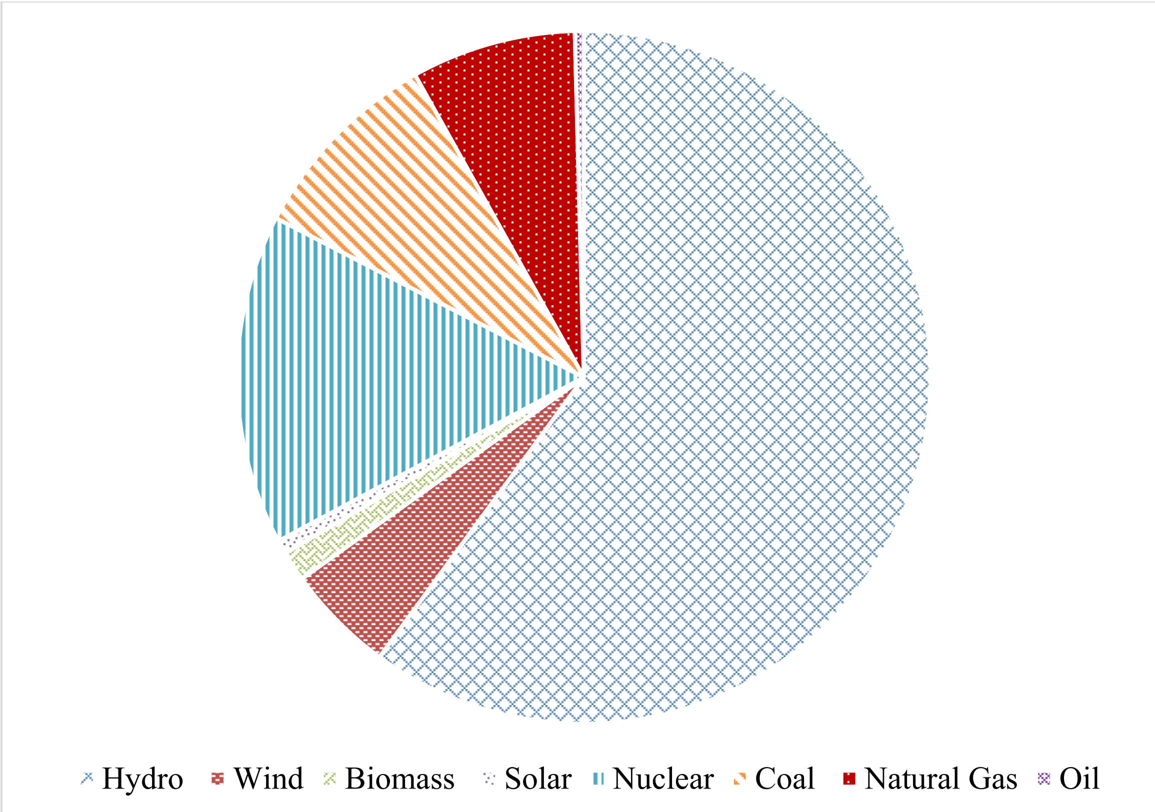

Figure 1-2: Canada's electricity generation by technology in 2017 (23)

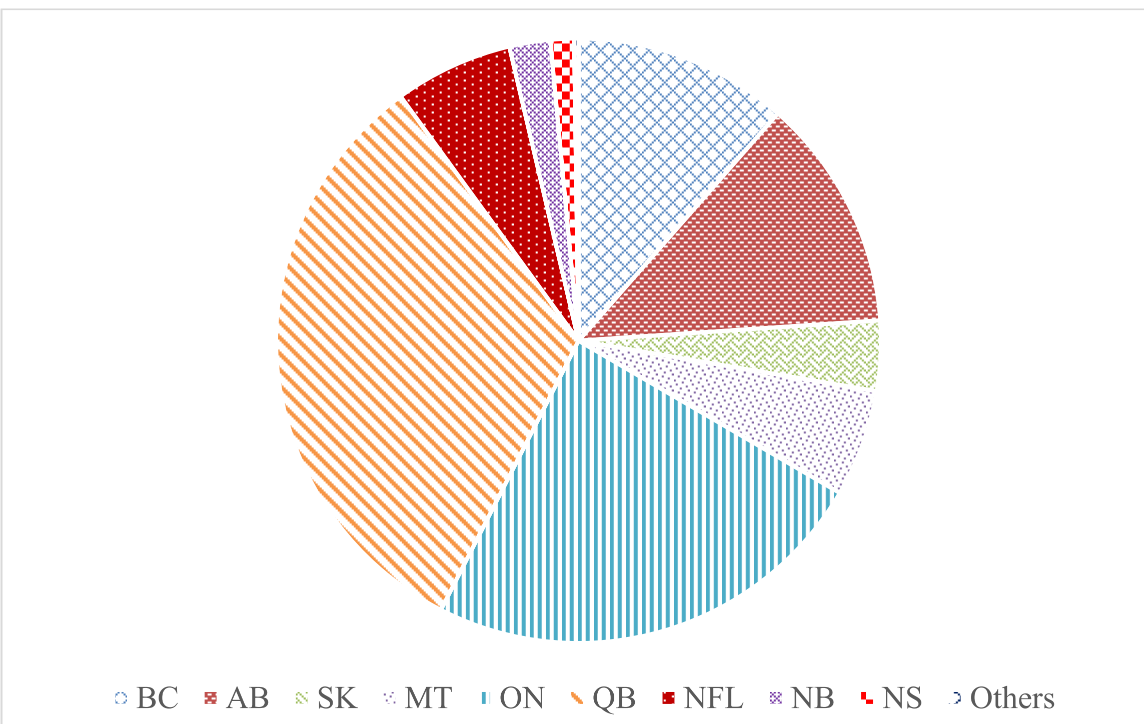

Figure 1-3: Canada's electricity generation by province in 2017 (23)

Table 1-1: Status of electricity generation and renewable plans as of 2017

British Columbia	• Renewables made up 99% of the provincial electricity generation. • Hydro was the largest contributor to provincial electricity generation with a share of 91% (23).
Alberta	• The coal power sector met half of the province's electricity demand (23). • The government committed to zero pollution from coal power by 2030 (24).
Saskatchewan	• The coal power sector made up 44% of the provincial electricity generation (23). • The provincial utility company committed to 50% renewable generation by 2030 (25).
Manitoba	• Renewables generate 99% of Manitoba's electricity. Hydro is the major electricity source with a share of 97% (23).
Ontario	• 95% of the electricity comes from non-emitting sources (23). • Ontario's nuclear power plants generated 61% of the province's electricity (23). • The government committed to 20,000 MW from renewables by 2025 (26).
Quebec	• Quebec produced more than 90% of its electricity through hydro-power (23). • Quebec has some of Canada's biggest hydro reservoir projects (27).
Newfoundland and Labrador	• Newfoundland and Labrador rely mainly on hydro generation for their electricity needs. Hydro provides more than 95% of the province's electricity (23).
Nova Scotia	• Coal power is the primary source of electricity with a generation share of 61% (23). • The province set a target to achieve 40% of generation from renewables by 2020 (28).
New Brunswick	• 65% of the province's electricity comes from non-emitting sources (23). • The province set a target to increase renewable electricity penetration to 40% by 2020 from the current 32% (29).
Prince Edward Island:	• Wind is the dominant source of electricity generation and provides 97% of the provincial electricity demand (23).

1.2.3 Canadian oil and gas sector background

Canada is the fifth largest oil producer in the world and has the third largest oil reserves (30). Canada's oil and gas reserves are primarily concentrated in the vast Western Canadian Sedimentary Basin (WCSB), which includes western Canada, northeastern British Columbia, southern Saskatchewan, and southwestern Manitoba (31). In 2017, 2.7 million barrels of unconventional oil (bitumen) per day and 1.5 million barrels of conventional oil per day were extracted (31). Canada has 5 bitumen upgraders to process bitumen and produced 1 million barrels of synthetic crude oil (SCO) in 2017 (32). Canada also had 17 refineries to process crude oil with a refining capacity of 1.842 million barrels per day in 2017 (33). Canada is the fourth largest producer and fourth largest exporter of natural gas and in 2017 produced 442 million m^3 of natural gas per day (34) (35). The federal government committed to reduce oil and gas sector methane emissions by 40-45% of the 2015 level by 2025 in 2016 (36). Oil and gas sector GHG emissions have increased by 23% since 2005 (13) due to a 68% increase in production (23). The GHG emission intensity fell by 16% during the same period (13), suggesting a slow adoption of clean energy technology. An overview of the oil and gas sector by province is provided in Table 1-2.

Table 1-2: Status of oil and gas sector and clean technology adoption as of 2017

British Columbia	• British Columbia has a one-third share in natural gas production in Canada (35) and produced 129.14 million cubic meters (MCM) in 2017 (35). • The Montney formation is a significant gas reserve and produces 75% of the province's gas (37). • Provincial oil production is limited and makes up only 1.7% of national conventional oil production (38). • The province has two oil refineries with a crude oil refining capacity of 11 thousand m^3/day (39).
Alberta	• Alberta is Canada's largest producer of crude oil, including conventional crudes, bitumen, and synthetic crude oil from upgraded bitumen

	• Alberta's share in conventional oil and natural gas production was 36% and 67%, respectively, in 2017 (35) (38). • Alberta's oil sands reserve is the largest in the world and in 2017 had a mined bitumen production of 1.15 million bpd (31) and in situ bitumen production of 1.40 million bpd (38). • Alberta has five bitumen upgraders and five oil refineries (32) (33). • Alberta's oil sands GHG emission intensity fell by 29% from 2005-2016 (31). • Low GHG extraction options such as solvent extraction, electro-thermal extraction, and hybrid steam-solvent extraction are experimented on as alternatives to steam-based bitumen extraction (6).
Saskatchewan	• The province produced 0.48 bpd conventional oil and 11.31 million cubic meters (MCM) natural gas in 2017 (35) (38). • The province has three refineries with a crude oil refining capacity of 36 thousand m^3/day (39).
Manitoba	• With 36.7 thousand bpd of conventional light output, Manitoba stands fourth in oil production in Canada (38).
Ontario	• Four oil refineries with a crude oil refining capacity of 63 thousand m^3/day (39).
Quebec	• Two oil refineries with a crude oil refining capacity of 64 thousand m^3/day (39).
New Brunswick	• One oil refinery with a crude oil refining capacity of 48 thousand m^3/day (39).
Newfoundland and Labrador	• The province's off-shore and on-shore facilities produced 220.75 thousand bpd of crude oil in 2017 (38). • One oil refinery with a crude oil refining capacity of 18 thousand m^3/day (39).

1.3 Literature review

Earlier models analyzed anthropogenic impacts on a single aspect (i.e., the water or the GHG emissions). For this work, integrated models that assess the effects of implementing scenarios that consider several aspects were reviewed. Liu et al. used Global Change Assessment Model (GCAM) results to analyze seven carbon mitigation and water savings scenarios (40) (41). GCAM is a popular integrated-modelling tool and is excellent for integrating multiple factors such as energy, water, land, GHG, etc., but requires extensive code writing and long setup and debugging times. Shaikh et al. used the autoregressive integrated moving average (ARIMA) forecasting tool to forecast future electricity generation to 2030 and to estimate generation-related water use for a business-as-usual (BAU) and two renewable scenarios (42). But the ARIMA forecast is based on historical trends and the model is not robust enough to predict generation fluctuations resulting from a price change or technological advancements (42). Clemmer et al. used the National Renewable Energy Laboratory's Regional Energy Deployment System (ReEDS) to project future water use in low carbon electricity pathways (43). The ReEDS model is specific to the United States (US) electricity sector and is generally used to plan US capacity expansion (43). Okadera et al. studied Thailand's transitioning energy sector and calculated the water use for historical years (44). The authors used Excel-based non-optimization models and government data for capacity expansion and production. The scenarios were solely based on the modelers' assumptions, and the scenarios are not robust enough to capture market-based trends. Zhou et al. used LEAP-WEAP integrated modelling to understand the water-GHG trade-offs for clean energy scenarios in China (45). The scenarios are specifically for Chinese planners and were developed by using government reports on China's energy-GHG-water policies.

Canada-specific models were also reviewed to understand the progress in the field of water-GHG studies both to define the scope of this work and to fill knowledge gaps. There are nine integrated water-GHG studies on Canada's electricity generation sector and the oil and gas sector. Davies et al. used the Global Change Assessment Model (GCAM) to project water withdrawal and consumption from the electricity sector to 2095 for 14 global regions, including Canada (19). The authors provided high level water withdrawal information but did not investigate water withdrawal at the provincial level. Davis et al. also developed an energy model to estimate Canada's GHG emissions. Their work uses a bottom-to-top approach (46). The research did not explore GHG mitigation scenarios nor the associated water impacts. Miller and Carriveau projected future water demand and CO_2 emissions from Ontario's electricity sector (47). The authors assessed the water-GHG impact of a changing energy mix scenario through Excel-based modelling. Dolter and Rivers used linear programming optimization models to identify the lowest-cost pathway for the electricity generation sector to achieve net zero emissions by 2050 (48). Their work focused on the GHG emissions aspects of the transitioning electricity generation sector but did not look into the water impacts. Agrawal et al. describe the impact on water resources of nine GHG mitigation scenarios. Through an integrated LEAP-WEAP model, the authors derived water use-GHG footprint results for Alberta's electricity sector; however, they used assumed future capacities instead of assessing penetration based on cost and policy (49). Moreover, the studies by Miller and Carriveau, and Agrawal et al. considered only a single province in their analyses.

There are no Canada-specific integrated water-GHG studies on the oil and gas sector. Most of the studies referred to above investigated either the water use or GHG footprints for the oil and gas sector. Ali and Kumar estimated water withdrawal and consumption intensities for various oil and gas extraction and processing techniques for Canada (50) (51). Their work developed data for future water-GHG studies. Davis et al. developed the LEAP-Canada model and projected the GHG emissions in the oil and gas sector to 2050 (46); however, the work did not include GHG mitigation scenarios or associated water impacts.

1.4 Research gaps

These integrated water-GHG analyses and GHG emissions studies on Canada's energy sector are limited either to a single province or focus on part of the water-GHG nexus. There is currently is scarcity of study that assesses the water use associated with clean energy pathways in Canada's energy sector. This research gap can be addressed by developing an integrated energy-water model to assess clean energy scenarios as well as the resulting technology mixes, water use, and marginal GHG abatement costs. To the best of the author's knowledge, the approach used to conduct this analysis for Canada is novel in its application of the LEAP-WEAP integrated framework using multi-regional, bottom-up electricity demands and electricity generation, along with geographic-specific water use. Although a water model in WEAP for the oil and gas sector was developed, the integration of an energy model with a water model has been left for future studies.

1.5 Research objectives

The overall objective of this research is to fill the literature gap by developing an integrated water-GHG model for Canada's energy sector. The model was developed with the aim of understanding the water-GHG trade-offs from the adoption of clean energy technologies. In addition, the focus is to understand the cost implications of reducing GHG emissions. The specific objectives of this research are to:

- Develop a baseline energy supply and demand model in LEAP and to estimate the GHG emissions from electricity generation from 2005-2050.
- Develop a baseline water supply and demand model in WEAP and to estimate the water use in the electricity generation and oil and gas sectors from 2005-2050.
- Identify GHG mitigation scenarios that incorporate clean energy growth in the electricity generation sector.
- Estimate the GHG reduction potential of the identified scenarios with reference to the baseline emissions in LEAP over the planning horizon (from 2020-2050).
- Integrate the WEAP-Canada model with the LEAP-Canada model by modeling LEAP scenarios in WEAP and estimate the effects of GHG reduction on water use in relation to the baseline scenario in WEAP.
- Perform cost analyses of the identified scenarios and present the results from the LEAP and WEAP models in a single chart for effective comparison.

1.6 Organization of thesis

This thesis has 4 chapters. The contents of Chapter 2 will be submitted for publication. Chapter 1 (introduction) and Chapter 4 (conclusion) include relevant content from the submitted paper.

Chapter 1 introduces the importance of an integrated water-GHG study. The global shift towards clean energy technologies is discussed and the water-GHG trade-offs in clean energy adoption is highlighted. Canada's electricity and oil and gas sectors are discussed in detail. The literature review identifies the knowledge gaps in in terms of understanding the integrated GHG-water impacts of energy transition in energy sector for Canada and the reason for using the LEAP-WEAP framework.

Chapter 2 describes water-GHG trade-offs in the electricity generation sector from clean energy adoption. The section discusses the methods used to develop the LEAP-WEAP-Canada electricity generation model. The key results associated with water-GHG trade-offs for the current policy and 100% decarbonization scenarios are discussed.

Chapter 3 talks about water-GHG trade-offs in the oil and gas sector in different energy scenarios. The section discusses the methods used to develop the WEAP-Canada oil and gas model. The key GHG emissions and water withdrawal and consumption results for different energy scenarios are discussed.

Chapter 4 describes the conclusions and make recommendations for future work, highlights the limitations of LEAP-WEAP modelling, and makes suggestions for model improvements.

2 Chapter 2: An integrated assessment of water use footprints and marginal costs for the decarbonization of Canada's electricity generation sector [1]

2.1 Framework

Figure 2-1 shows the integrated modelling framework used in this study. Two separate models were used together to perform the study. The first model, developed by Davis et al. (52), uses the LEAP modelling framework, which is commonly used for energy policy analysis and climate change mitigation assessments (53). LEAP has a bottom-up multi-regional accounting-based framework that allows the user to specify technology-level energy details and model sectorial and regional energy demand and energy transformation processes. Intergovernmental Panel on Climate Change (IPCC) emission factors are used in the model to calculate GHG emissions. The LEAP model of Canada (LEAP-Canada) was first developed by Davis et al. (46) and covers bottom-up economy-wide energy supply and demands to 2050. The model was developed with electricity capacity projections from various sources and a basic merit order-based technology dispatch to simulate annual electricity generation. While this approach was validated and found to give an accurate account of the sector, the model was not capable of responding to decarbonization constraints since all electricity technology capacities are exogenously fixed and technology costs do not influence generation.

For the present study, the LEAP-Canada model was redesigned to use the Open Source Energy Modelling System (OSeMOSYS) for electricity supply (54). OSeMOSYS optimizes electricity plant capacity expansion and dispatches subject to user-defined constraints. This new LEAP-Canada model was used to project the electricity technology capacity and generation mix, GHG emissions, and marginal GHG abatement costs of a current policy scenario and decarbonization scenario to 2050. A more comprehensive description of electricity supply and demand in the LEAP-Canada model is provided in Section 2.2. The technology-specific electricity generation results are used in the second model that was developed with the Water Evaluation and Planning

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[1] A version of this chapter is to be submitted to Applied Energy titled "An integrated assessment of water use footprints and marginal costs for the decarbonization of Canada's electricity generation sector"

(WEAP) system to calculate location-specific water use (55). WEAP is an integrated water resource planning tool developed, like LEAP. It uses geographic information to model geography-specific water demand sites and river basins. The model equates water demand with water supply and can calculate water demand, water consumption, water shortage, and wastewater discharge. WEAP also has scenario analysis capabilities to which LEAP scenarios can be linked. The WEAP model of Canada's electricity system (WEAP-Canada) was developed in this paper from inputs of technology-specific electricity generation (from the LEAP-Canada model), technology specific water-use intensities, plant-specific cooling technology, and plant locations relative to water supply sources. A more comprehensive description of the WEAP-Canada model is provided in Section 2.3.

Section 2.4 provides details on the developed reference and decarbonization scenarios. Section 2.5 provides details on the key parameters analyzed for the sensitivity analysis. Section 2.6 describe the Canada's electricity demand, electricity generation, water use validation with the developed LEAP-Canada and WEAP-Canada electricity generation model. The decarbonization scenario results are compared to the results of the current policy scenario for a marginal GHG abatement cost-benefit analysis considering system costs, GHG emissions, and water use. Section 2.6 describes the methods used to conduct the cost-benefit analysis and evaluate the tradeoffs between decarbonization and water use.

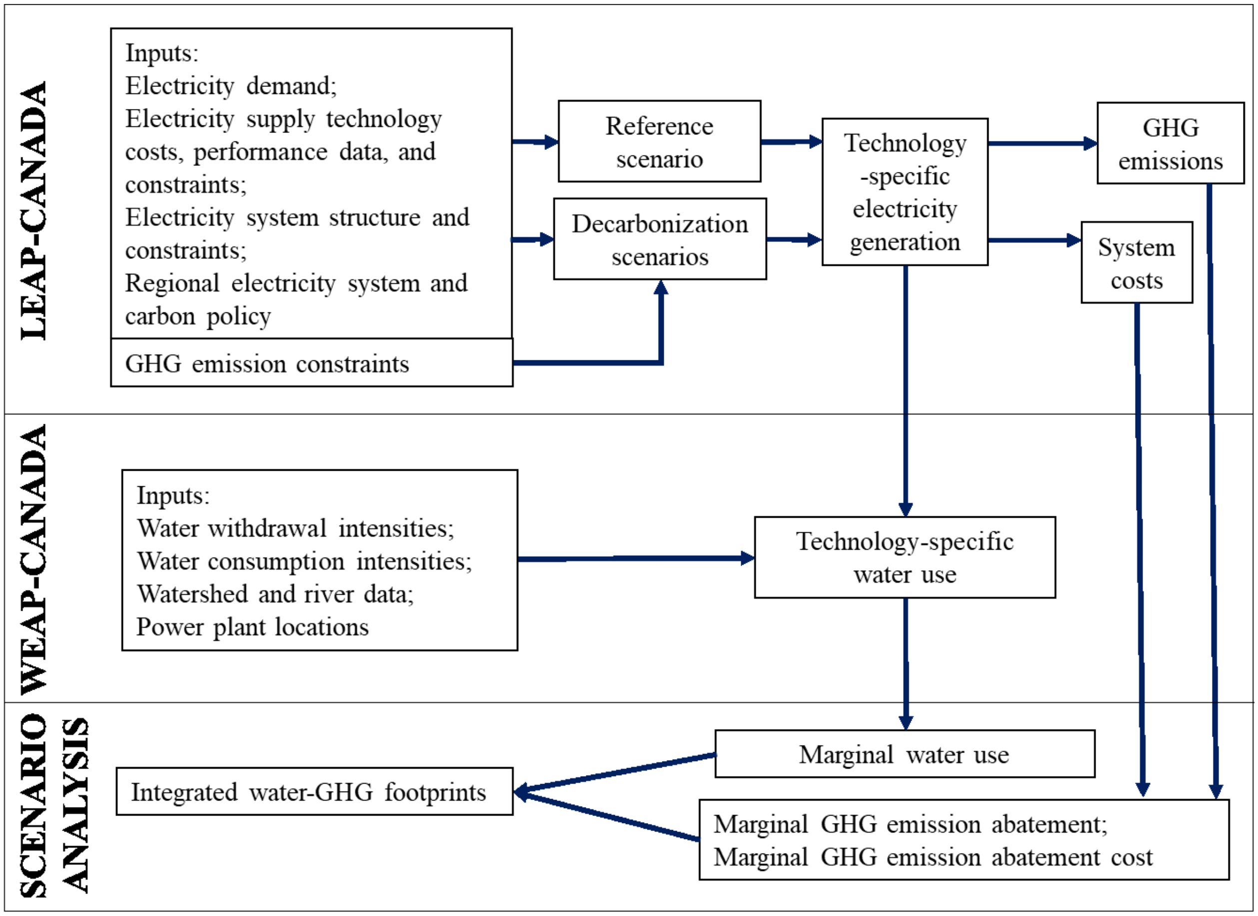

Figure 2-1: Study framework

2.2 Electricity generation model development (LEAP-Canada)

2.2.1 Model overview

Figure 2-2 shows the electricity supply portion of LEAP-Canada model, used to calculate technology and region-specific electricity supply capacity, generation, costs, and GHG emissions. Region-specific (RS) indicators are included in calculations made at the provincial/territorial level. Scenario- specific (SS) indicators are included in calculations that change depending on the decarbonization scenario. Each bold step corresponds to a subsection of this paper where details of the assumptions and calculations are described.

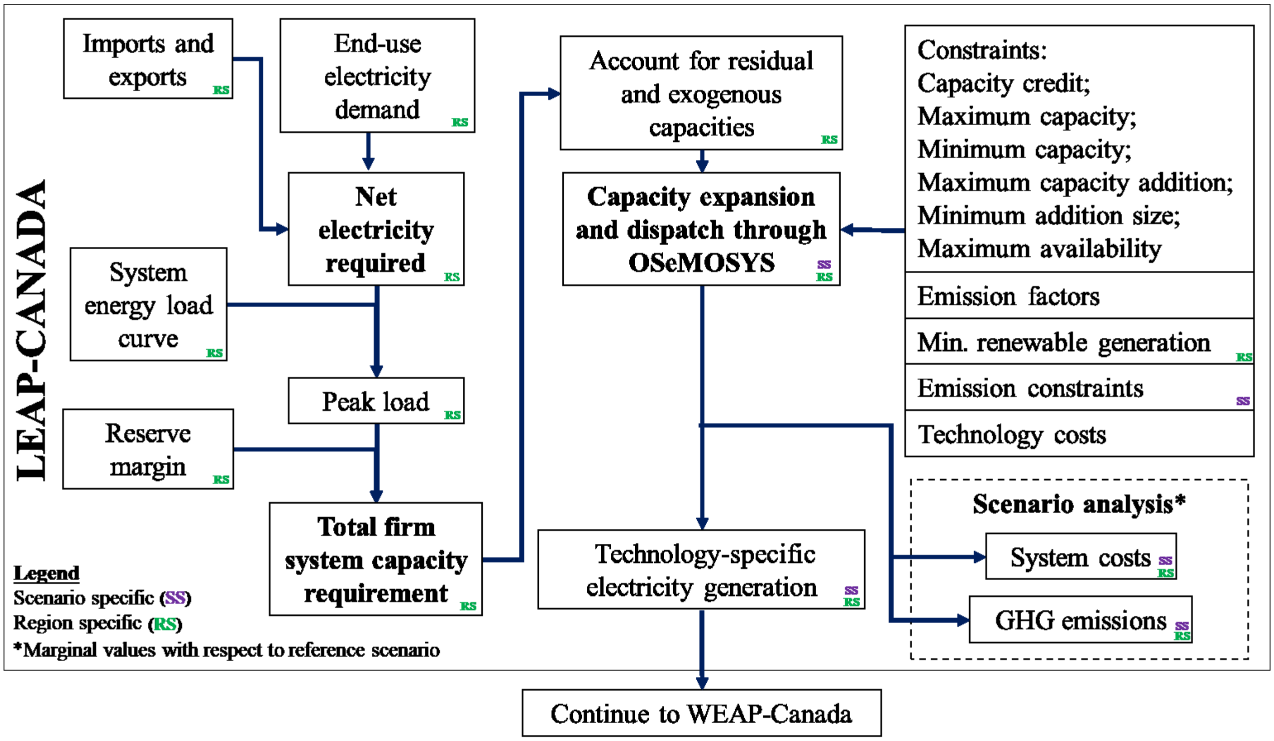

Figure 2-2: LEAP-Canada electricity generation framework

2.2.2 Net electricity demand

The model developed by Davis et al. (46) calculates annual electricity demand to 2050. The model is divided into 6 sectors, including households, commercial and institutional buildings, industries, transportation, and agriculture, and 13 regions and maps economy-wide electricity demand. More detailed account of the model development can be found in an earlier publication by Davis et al. (46). For the present study, the input data has been revised and updated because the data sources have been revised and updated. Specifically, the macro-economic indicators and primary energy production projections were updated by the National Energy Board (NEB) (Table 2-1) (56) and end-use energy use data by Statistics Canada (StatCan) (57) and Natural Resources Canada (NRCan) (58).

Table 2-1: Aggregated data of macro-indicators used to forecast electricity demands for Canada (33)

Parameters for electricity demand	2005	2010	2020	2030	2040	2050
Real GDP ($2007 millions)	1,502,318	1,589,956	1,924,025	2,273,525	2,622,546	2,936,563
Population (thousands)	32,242	34,005	37,647	41,053	44,067	46,903
Households (thousands)	12,587	13,378	14,850	16,271	17,550	18,770
Commercial floor space (million m^2)	654	714	819	929	1,038	1,147

The net electricity requirement is calculated in LEAP with Equation 2-1; further details related to equation derivation are given in (53):

$$\boldsymbol{Ereq_y = E_y + Ex_y - Im_y} \qquad \textbf{2-1}$$

where y is the year, $Ereq_{\mathrm{y}}$ is the net electricity required in a given year, E_{y} is the total domestic end-use electricity demand in a given year, Ex_{y} is the electricity exported, and Im_{y} is the electricity imported in a given year. Imports and exports were assumed to follow the average historical provincial interchange from 2005-2016; these values are given Table 2-2 and Table 2-3.

Table 2-2: Export generation target for 2005-2050 (59)

Export (GWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017 (onwards)
BC	9247	6133	11198	9956	8304	7566	15552	16929	13576	8706	13330	14474	11247
AB	1284	861	1373	755	865	769	397	342	564	596	1029	1154	833
SK	1461	1778	1232	920	607	720	829	814	763	97	150	397	814
MT	15442	14543	12875	10626	9630	9723	10277	8932	10627	9500	10075	11019	11106
ON	14287	15862	16565	23334	20935	21754	19932	17864	19698	23611	23783	23001	20053
QB	13446	14828	19758	24444	25886	23010	25925	32530	36663	28689	34907	34254	26195
NFL	30205	31348	30095	31431	27432	30401	30208	32321	31256	27616	30303	28342	30080
NB	5323	4144	3337	2531	3212	2506	2619	2487	6452	3184	3191	3084	3506
NS	137	347	58	24	39	5	9	35	12	10	35	160	73

Table 2-3:Import generation target for 2005-2050 (59)

Import (GWh)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017 (onwards)
BC	7206	12687	8390	12431	12075	10768	10973	9738	10335	10084	7673	8909	10106
AB	2192	2235	2004	3060	5112	5488	10086	7438	4781	1910	1559	741	3884
SK	953	1749	1235	1115	772	693	477	601	784	768	500	429	840
MT	310	1131	708	261	339	333	156	566	405	709	899	502	527
ON	14698	10993	11268	11762	8509	7584	5940	5681	6661	4755	6341	7828	8502
QB	40059	39837	38295	38947	30419	39134	35209	34357	40611	34337	33441	32674	36443
NFL	16	16	17	17	20	21	23	22	23	22	25	30	21
NB	2988	1802	2605	2054	4194	4842	4969	5493	4508	3681	7550	3311	4000
NS	255	131	344	573	623	476	528	189	560	230	623	388	410

2.2.3 Total firm system capacity requirement and capacity expansion and dispatch through OSeMOSYS

As previously mentioned, a key limitation of the original LEAP-Canada model is that capacities were exogenously specified using government projections and thus would not respond to any model input variation. For the present study, the model was redesigned so that capacities can be endogenously added when required through OSeMOSYS. The total firm system capacity requirement is the capacity required to reliably meet the peak load of a province and is determined from the net electricity demand, system energy load curve (SELC), and reserve margins. SELCs are used in the model to determine peak loads by distributing the annual electricity generation over a non-linear hourly time curve. SELCs were developed from historical daily load data available from the provinces of Alberta (60) and Ontario (61). There is no publicly available data from other regions. Thus, the Ontario SELC was used for Manitoba and the Atlantic provinces, as the residential sector has largest percentage share of electricity demand in these provinces and so it is assumed they follow a similar time cycle of demand load (62). British Columbia, Saskatchewan, and Quebec are assumed to follow the Alberta SELC, as a large portion of electricity consumption in these provinces is from industry (62). The assumptions related to the SELCs were entered into the model and peak load was calculated. Reserve margins (specified in Table 2-4) were used to determine total firm system capacity requirements; further details related to equation derivation are given in (53):

$$Cap_r = \frac{E_{net}\ x\ max\ (Lh\%)\ x\ (1 + rm\%)}{8760} \quad \textbf{2-2}$$

$$Lh\% = \frac{Lh}{\sum_{h=0}^{8760} Lh}\ x\ 100 \quad \textbf{2-3}$$

where Cap_r is the total firm system capacity requirement, E_{net} is the net electricity demand for a given year, Lh is the hourly load at hour h, obtained from SELC, and rm is the reserve margin.

Table 2-4: Electricity generation planning reserve margins for the provinces

	Reserve Margins
British Columbia (BC)	10% (63)
Alberta (AB)	15% (64)
Saskatchewan (SK)	11% (65)
Manitoba (MT)	12% (65)
Ontario (ON)	19.44% (66)
Quebec (QB)	12.61% (65)
Newfoundland and Labrador (NFL)	20% (65)
Nova Scotia (NS)	20% (65)
New Brunswick (NB)	20% (65)

Once the total firm capacity requirement is calculated for a given year, the residual firm technology capacities and firm exogenous capacities are deducted and the remaining required firm capacity is added through OSeMOSYS. The residual firm technology capacities are the capacities remaining in the system from previous years, and firm exogenous capacities are specified capacities that are not optimized; they are manually included. In the LEAP-Canada model, the annual capacity expansion was taken from the NEB and generated based on certain policy and technical-based assumptions. These assumptions mostly change over time, are not available in the public domain, and affect the accuracy of the results. With the optimization approach, the assumptions are defined by the modeler and can be updated anytime, and the latest capacity expansion and generation data can be generated. Historic capacities for the years 2005-2019 make up the residual capacities.

Exogenous capacity additions include the planned hydro capacities in the provinces until 2024 (given in Table 2-5). Input exogenous capacity for 2019 are given in Table 2-6.

Table 2-5: Provincial capacity addition plans and renewable targets

British Columbia	• The province will add a 1100 MW of Site-C dam by 2024 (67) (23).
Alberta	• No generation from coal power (64). • A 900 MW of pumped hydro in 2025 (68). • Coal-to-gas conversion of 774MW in 2021, 807MW in 2022, and 790MW in 2023 (64).
Saskatchewan	• 50% of renewable by 2030. (23)(25).
Manitoba	• A 695 MW of hydro addition in 2022 (69).
Nova Scotia	• Targets to achieve 40% of generation from non-nuclear renewable by 2020 (28).
New Brunswick	• Targets to achieve 40% of generation from renewable by 2020 (29).

Table 2-6: Electricity generation capacity by provinces and technologies in 2019

	British Columbia (70),(71),(72)	**Alberta** (64),(73), (74)	**Saskatchewan** (75),(74)	**Manitoba** (76)	**Ontario** (77),(78),(79)	**Quebec** (80)	**Newfoundland and Labrador** (81)	**New Brunswick** (82)	**Nova Scotia** (83)
Subcritical coal	0	5,190	0	98	0	0	0	467	1,099
Supercritical coal	0	929	1,530	0	0	0	0	0	0
Simple cycle	46	934	442	0	1,267	591	252	0	0
Combined cycle	73	1,748	905	453	7,537	0	0	290	482
Cogeneration	395	5,290	477	0	649	0	0	88	0
Nuclear	0	0	0	0	12,833	0	0	660	0
Wind (84)	752	2,081	398	258	5,341	4545	54	294	515
Solar PV (84)	27	21	22	7	3,071	0	0	0	0
Hydroelectric	16,005	894	889	5,349	8,977	40,866	6,794	961	392
Oil combustion (84)	122	7	17	5	250	253	723	1,593	222
Industrial waste CHP (biomass)	1,008	404	161	22	670	371	0	127	128

The first year that endogenous technology capacity additions occur through OSeMOSYS is 2020. Endogenous technology selection for capacity addition was limited by several constraints as shown in Figure 2-2. Each technology was assigned a capacity credit value that determines the percent of capacity that is firm. For example, solar capacities were assigned 0% capacity credit as they are intermittent in nature, and therefore, cannot be relied upon to provide power when needed. The capacity credit for wind are taken from the scenarios inputs used by GE energy consulting (85). The capacity credit of the technologies is mentioned in Table 2-7, Table 2-8, Table 2-9, and Table 2-10. Renewable technologies are also expanded through OSeMOSYS, if needed, to meet renewable generation targets and/or carbon constraints. The maximum capacity addition constraint sets the upper limit of any technology addition in a year. Table 2-7, Table 2-8, Table 2-9, and Table 2-10 shows the values assumed in the model which were based on the historical trend from 2005-2016. Natural gas capacity addition for the provinces with more than 90% of hydro generation (British Columbia (86), Manitoba (87), Quebec (88), Newfoundland and Labrador (89)) was assumed to be zero since these provinces are targeting 100% carbon-free generation.

Table 2-7: LEAP-Canada input assumptions for BC, MT, QB, NFL

BC/MT/QB/NFL	Minimum capacity addition	Maximum availability	Capacity credit
Supercritical coal	0	85	100
Subcritical coal	0	85	100
Simple cycle	0	20	100
Combined cycle	0	70	100
Cogeneration	0	70	100
Biomass	50	59	100
Hydroelectric	1600	48-76	100
Nuclear	0	90	100
Oil combustion	0	95	100

Table 2-8: LEAP-Canada input assumptions for AB, SK, ON, NB, NS

AB/SK/ON/NB/NS	Minimum capacity addition	Maximum availability	Capacity credit
Supercritical coal	0	80	100
Subcritical coal	0	80	100
Simple cycle	400	20	100
Combined cycle	1650	70	100
Cogeneration	1000	70	100
Biomass	50	60	100
Hydroelectric	1600	29-56	50
Nuclear	0	90	100
Oil combustion	0	20	100
Coal-to-gas converted	NA	13	100

Table 2-9: LEAP-Canada input assumptions for wind technology

Provinces	Minimum capacity addition	Maximum availability (Current Scenario)	Capacity credit (Current Scenario)	Maximum availability (100% DECARB)	Capacity credit (100% DECARB)
BC	600	33	19.2	33	19.2
AB	600	38	7.1	37	7.1
SK	600	38	9.7	38	9.7
MT	600	38	37.5	38	37.5
ON	600	37	24.2	37	24.2
QB	600	36	26.5	36	26.5
NFL	600	38	43.3	38	43.3
NB	600	38	31.7	38	31.7
NS	600	38	31.7	38	31.7

Table 2-10: LEAP-Canada input assumptions for solar technology

Provinces	**Minimum capacity addition**	**Maximum availability**	**Capacity credit**
BC	600	15	0
AB	600	15	0
SK	600	15	0
MT	600	15	0
ON	600	15	0
QB	600	15	0
NFL	600	15	0
NB	600	15	0
NS	600	15	0

Table 2-11 shows the maximum capacities for technologies which limits the maximum generation that can be technically and economically feasible in the provinces (90).

Table 2-11 values are calculated by using Equation 2-4, 2-5, and 2-6.

$$Biomass \;=\frac{Biomass\ potential\ (TWh/yr)\ x\ 10^6}{31\%\ x\ 8760} \qquad \textbf{2-4}$$

$$Wind \;=\frac{Wind\ offshore\ potential\ (TWh/yr)\ x\ 10^6}{33\%\ x\ 8760} \qquad \textbf{2-5}$$

$$Solar \;=\frac{Solar\ potential\ (TWh/yr)\ x\ 10^6}{15\%\ x\ 8760} \qquad \textbf{2-6}$$

Table 2-11: Maximum Capacity at any year (90)

Maximum Capacity	BC	AB	SK	MT	ON	QB	NFL	NB	NS
Supercritical coal	UL	UL	UL	UL	UL	UL	UL	UL	UL
Subcritical coal	UL	UL	UL	UL	UL	UL	UL	UL	UL
Simple cycle	UL	UL	UL	UL	UL	UL	UL	UL	UL
Combined cycle	UL	UL	UL	UL	UL	UL	UL	UL	UL
Biomass	7291	33289	NA	NA	31853	7659	331	1473	331
Hydroelectric+	32000	11800	4000	8800	10200	42400	8500	1000	8500
Wind	8994	58461	94783	27328	10378	65726	2421	3459	10378
Solar PV	1294	47945	42618	42618	100457	3653	457	628	913
Nuclear	UL	UL	UL	UL	UL	UL	UL	UL	UL
Oil combustion	UL	UL	UL	UL	UL	UL	UL	UL	UL

*UL: Unlimited, NA: Not available, +Directly taken from (91)

Cogeneration capacity is assumed not to grow after 2019 as the cogeneration plant addition are based on the industrial steam requirements which are difficult to forecast. Alberta AESO report forecasted the Alberta's future installed cogeneration capacity and is used in LEAP-Canada model (92). Table 2-12 shows the Alberta exogenous cogeneration capacity addition after 2020. Cogeneration capacities are mentioned in 'maximum capacity' constraint instead 'exogenous capacity' to account the cost of addition in the model.

Table 2-12: Cogeneration capacity forecast for Alberta for reference scenario (24)

Year	AESO-2017-Long-term-Outlook cogen capacity addition forecast	Alberta cogen capacity (MW)	Comment
2020		5285	
2022	90	5375	
2027	90	5465	
2032	90	5555	
2037	90	5645	
2042*	90	5735	Extrapolated
2047*	90	5825	Extrapolated

The OSeMOSYS technology capacity expansion is based on the net present value (NPV) of a technology, subject to constraints (54). NPV is calculated by inputs such as capital, fixed operation and maintenance (O&M), variable O&M, fuel cost, carbon cost, maximum availability, and discount rate:

$$NPV = \sum_{t=2020}^{2050} \frac{CC_t + FOM_t + VarOM_t + FC_t \; x \; HR}{(1+r)^{(t-2020)}} \qquad 2\text{-}7$$

where CC_t is the capital investment at year t, FOM_t is the fixed operation and maintenance cost for year t, $VarOM_t$ is the variable operation and maintenance cost for year t, FC_t is the fuel cost at year t, HR is the heat rate, and r is the discount rate (5%).

Technology capacities are expanded in the order of lowest to highest costs (subject to constraints) until the electricity demands, peak loads, renewable generation targets, and decarbonization targets are met. The renewable electricity generation target is a key constraint that will prompt the model to add renewable technologies before less expensive fossil fuel alternatives. Provincial renewable electricity generation targets are mentioned in Table 2-5. Table 2-13 shows the technology and economic inputs used to calculate the net present value of the technologies. All monetary calculations are in 2020 Canadian dollars (CAD).

Table 2-13: LEAP-Canada electricity generation input

Technology (CAD 2020)	Life (yrs)	Overnight capital cost ($/KW)	Fixed O&M cost ($/MW)	Variable O&M cost ($/MWh)	Heat rate (GJ/MWh)	Fuel price ($/GJ)	Capacity credit	Maximum availabilit y	Source
Subcritical coal	35 (93)	2,991	86,427	10.49	9.22	1.94 (94)	100	85	(94)
Supercritical coal	35 (93)	3,087	89,181	10.32	10.32	1.94 (94)	100	85	(94)
Simple cycle	25	1,229	18,105	5	12.85	3.5-50.1[1] (95)	100	20[2]	(96)
Combined cycle	25	1,649	20,692	5	7.10	3.5-50.1[1] (95)	100	70	(96)
Cogeneration	25	1,408	15,881	4.20	6.66	3.5-50.1[1] (95)	100	70[3]	(97)
Nuclear[4]	40	8,428	146,252	3.06	NA	NA	100	90	(98)
Biomass	30	5,875	174,061	7.91	14.24	NA	100	59[5] (99)	(98)
Wind	25	1,661[6]	42,030[6]	-	NA	NA	9.7-43.3[1]	29-38[1]	(96)
Solar PV	25	1,697[6]	23,278[6]	-	NA	NA	0	15	(96)
Hydroelectric	35	4,438	62,857	1.89	NA	NA	50-100[1]	29-76[1]	(98)
Coal-to-gas converted plant	15	238	23,278	4.23	11	3.5-50.1[1] (95)	100	13	(24)
Industrial waste CHP (biomass)	30	NA	NA	NA	NA	NA	100	17-60[1]	

[1]varies from province-to-province
[2]assumed to be equal to the maximum capacity factor achieved in historical years,
[3]assumed to be the same as combined cycle,
[4]provincial nuclear power retirement schedule was used for existing plants (Table 2-14), fuel price of C$3.75/MWh (100) was used
[5]estimated based on the capacity and generation from wood fuel,
[6]refer to Table 2-15 for future changes in overnight capital, fixed, and O&M costs,
[6]estimated based on the capacity and generation from wood fuel,

The costs from literature in US$ are converted into Canadian $ (CAD) using a capital cost location index of 1.08 (101), labour (fixed OM) location index of 1.09 (102) (103), inflation factor (104), and the US to CAD exchange rate for the cost year (105). The carbon taxes included in the model are given in Table 2-16.

Table 2-14: Ontario nuclear capacity over a year

Year	**Bruce (MW)** (106)	**Darlington (MW)** (107)	**Pickering (MW)** (108)	**Total nuclear capacity (MW)**
2005	5167	3736	2694	11597
2006	5167	3736	3234	12137
2007	5167	3736	3234	12137
2008	5167	3736	3234	12137
2009	5167	3736	3234	12137
2010	5167	3736	3234	12137
2011	5167	3736	3234	12137
2012	5167	3736	3234	12137
2013	6797	3736	3234	13767
2014	6797	3736	3234	13767
2015	6797	3736	3234	13767
2016	6797	3736	3234	13767
2017	6797	2802	3234	12833
2018	6797	2802	3234	12833
2019	6797	2802	3234	12833
2020	6797	2802	3234	12833
2021	6797	2802	3234	12833
2022	6797	1868	2154	10819
2023	6797	934	2154	9885
2024	6797	1868	2154	10819
2025	6797	2802	0	9599
2026	6797	3736	0	10533

Table 2-15: Wind and solar technologies cost (109)

Technology	Year	Overnight Capital cost (CAD $2020) *	Fixed cost (CAD $2020) *
Wind	2020	1,661	42,030
	2030	1,465	42,030
	2040	1,293	42,030
Solar	2020	1,697	23,278
	2030	1,293	23,278
	2040	1,035	23,278

* Multiply by inflation rate factor, 1 CAD 2018 = 1.034 CAD 2020 (104), and US to CAD currency exchange rate, 1 US 2018 = 1.25 CAD 2018 (105).

Table 2-16 shows the carbon tax rate based on the provincial carbon tax levy plan. It is assumed that the carbon tax rate will remain constant after 2025. There was no carbon tax before 2017 except in British Columbia which was CAD$ 30 since 2012.

Table 2-16: Provincial carbon tax rates (110)

in CAD \$/tonnes of CO_2 equiv.	2017	2018	2019	2020	2021	2022	2023	2024	2025
BC[2]	30	35	40	45	50	50	50	50	50
AB	20	30	30	30	40	50	50	50	50
SK	0	0	20	30	40	50	50	50	50
MT	0	25	25	25	25	25	50	50	50
ON	0	0	20	25	30	35	40	45	50
QB	0	0	20	25	30	35	40	45	50
NFL	0	0	20	30	40	50	50	50	50
NS	0	0	20	30	40	50	50	50	50
NB	0	0	20	30	40	50	50	50	50

Electricity generation dispatch is based on the lowest generation cost of the technologies and is calculated by variable O&M, fuel costs, carbon costs, and renewable targets (54). Electricity generation GHG emissions from each technology were calculated by multiplying the feedstock fuel inputs with GHG emissions factors. Feedstock fuels required for each technology were determined by the electricity generation and the efficiency value. For coal, NGSC, NGCC, cogeneration, biomass, and oil technology, IPCC tier 1 default emissions factors were used (Table 2-17).

Table 2-17: Emissions factors of the technologies

Technology	Carbon dioxide (MT/TJ of energy consumed)	Carbon monoxide (kg/TJ of energy consumed)	Methane (kg/TJ of energy consumed)	Nitrogen oxide (kg/TJ of energy consumed)	Non-methane volatile (kg/TJ of energy consumed)	Nitrous oxide (kg/TJ of energy consumed)	Sulfur oxide (kg/kg of energy consumed)	Carbon dioxide biogenic (MT/TJ of energy consumed)
Simple cycle	55.78	20	1	150	5	0.1	0	0
Combined cycle	55.78	20	1	150	5	0.1	0	0
Cogeneration	55.78	20	1	150	5	0.1	0	0
Biomass	0	1000	30	100	50	4	0	109.56
Oil combustion	72.55	15	3	200	5	0.6	0.01	0

2.3 Water-use model development (WEAP-Canada)

2.3.1 Model overview

To estimate water withdrawal and consumption from specific watersheds due to electricity generation, we assigned a watershed to each power plant in Canada. The power plants were located geographically with Google Maps to approximate their proximity to watersheds (111). The data was later used to develop a WEAP model by integrating a geographic information system (GIS) schematic and manually locating each power plant site and defining the water-use intensity of that site. 156 demand sites and 74 rivers were modelled in WEAP schematics with data from 530 power plants. The plant site water withdrawal and consumption were calculated based on the amount of generation and the water-use intensities and are explained further in Section 2.3.2.

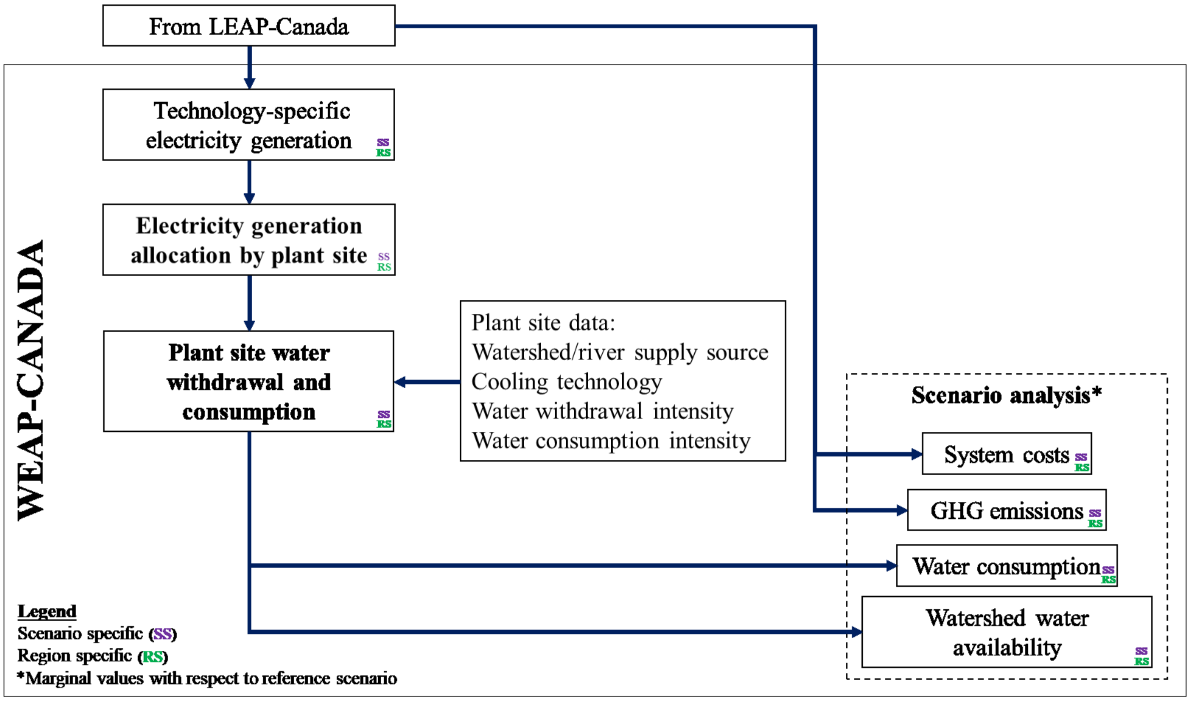

Figure 2-3: WEAP-Canada electricity generation water-use framework

2.3.2 Plant site water withdrawal and consumption

The two water-use parameters considered are water withdrawal and water consumption. Water withdrawal is the water diverted by the power plants from rivers, lakes, and the ground, as well as the water reclaimed from municipal sources. Water consumption is the water consumed in the power plants from evaporative cooling towers and steam turbines. Plant cooling technology (once-through, wet cooling, and dry cooling) plays a large role in determining the magnitude of the water intensity values. Once-through (OT) cooling uses a large amount of water, as the water from the water source is returned after heat is exchanged in the condenser (112). Closed-loop (CL) cooling uses comparatively less water because it reuses the discharge water by cooling it in cooling towers or cooling ponds. There are two types of cooling towers – wet cooling towers (WCTs) and dry cooling towers (DCTs). In a WCT, hot discharge stream passes over an updraft of air and rejects heat through evaporation (112). DCTs use fans to create a high force draft that removes heat from the hot discharge stream (112). The consumptive loss is highest in WCTs because some of the discharged water evaporates in the cooling tower structure (112). Cooling ponds are the artificial ponds constructed to store the hot discharge water and they reject heat through convection and evaporation (113).

Table 2-18 shows the water intensities used for electricity generation as taken directly from the sources cited in the table and used in the WEAP model. Water intensities vary significantly between cooling technologies. The cooling technologies for the plants were identified and the associated water-use intensities were used for the demand sites. Information for cooling technology type was found for coal and nuclear plants but not for natural gas or biomass plants. Davies at al. estimated the national shares of OT (71%) and WCT (29%) for natural gas combined cycle plants for the year 2005 (19). With the cooling technology shares and the water intensity of natural gas combined cycle OT and WCT plants, Davies et al. calculated the weighted average water withdrawal (29.2 m^3/MWh) and consumption (19.8% of water withdrawal) and used these figures for all-natural gas combined cycle plants. The DCT water intensity figures are used only for the North Battleford Generating Station (commissioned in 2013) in Saskatchewan, which uses DCT cooling. The natural gas cogeneration plants are assumed to follow OT cooling because cogen plants supply the waste heat for industrial processes. For biomass, all the plants are assumed to follow OT as biomass plants have low capacity, and installing a cooling tower at low capacity is not economically feasible. It is more economical to get a large amount of water from watersheds than to recycle and reuse water in the cooling tower (114). It is assumed that the cooling technologies' shares will not change until 2050 since OT cooling is preferred in Canada as it doesn't require complex infrastructure and is less expensive to operate (114), and Canada has abundant freshwater resources.

Hydro-electric power plants generate electricity from flowing water, and hydro dams restrict the water flow that creates artificial lakes that undergoes evaporation. Hydro generation was divided into reservoir and run-of-the-river (ROR) based on capacity share for the year 2016. There is no water use associated with ROR technology. Water consumption intensity due to evaporation in the reservoir was based on the estimates of the average evaporation from Alberta reservoirs and is assumed to be the same for other provinces since there is no data for other provinces (115). The value is on par with Bakken et al.'s water consumption range of 14-34 m^3/MWh (116) for standalone hydroelectric reservoirs, which are located in climatic zones similar to Canada (116). Hydro water withdrawal was assumed to equal water consumption because water that evaporates in a dam's artificial lake is no longer available.

Table 2-18: Power generation water intensities

Power plant	Type	Cooling type	Withdrawal (m^3/MWh)	Consumption %	Source
Coal[1]	Subcritical	OT	116.48	1%	(117)
		Pond	2.33	84%	
		WCT	2.31	87%	
		DCT	0.23	87%	
	Supercritical	OT	88.9	0.50%	(117)
		Pond	1.6	55%	
		WCT	2.19	74%	
		DCT	0.22	73%	
Natural gas	Simple cycle	OT	0.38	24%	(11)
	Combined cycle	OT	40.79	0.88%	(11)
		WCT	0.96	66%	
		DCT	0.10	60%	
	Co-generation	OT	14.62	1.30%	(11)
		WCT	0.58	48%	
		DCT	0.06	50%	
Biomass		OT	110.25	1%	(12)
		WCT	2.19	87%	
		DCT	0.22	86%	
Nuclear		OT	205	0.69%	(12)(118)
		WCT	4.17	65%	
Hydroelectric	Reservoir		18.2	100%	(119)
	Run-of-river		0	0%	
Fossil Non-Coal/Oil		OT	86	0.4%	(120)
		WCT	0.94	64%	

[1]For Ontario, coal power's water use and consumption are 183 m^3/MWh and 1.2%, respectively (121) (117).

2.4 Scenario analysis

Most of the provinces are observed to reduce their GHG emissions by 90% in the current policy scenario. The research assumed a country-wide GHG emissions reduction target of 100% by 2050 from the 2005 level. The reduction targets were linearly interpolated between 2030 and 2050, that is, capacities were added at regular intervals to meet the 2050 GHG emissions targets. The 100% scenario was implemented in the LEAP-Canada model by using two minimum GHG emission constraints. The first constraint was set for 2030 and was equivalent to the GHG emissions reduction achieved in the current policy scenario by 2030 and the second constraint was set to zero GHG emissions by 2050.

A cost-benefit analysis was performed to understand the cost-effectiveness of the scenario in terms of GHG reductions and the tradeoffs with water use. The marginal cost of avoiding GHGs (in \$/tonnes of CO_2e) is calculated using Equation 2-8.

$$\$/tonnes\ of\ CO2e\ saved\ = \frac{NPVr\ -\ NPVs}{CGHGr -\ CGHGs}\ x\ 100 \qquad \textbf{2-8}$$

where *NPVr* and *NPVs* are the net present value in the reference scenario *r* and decarbonization scenario *s,* respectively; *CGHGr* and *CGHGs* are the cumulative GHG emissions from 2020-2050 in the reference scenario *r* and decarbonization scenario *s,* respectively. The total cost associated with water for the acquisition, intake treatment, recirculation, and discharge treatment was CAD$ 0.73/MWh of thermal electricity generated in 2009 (122) (23). The water cost is part of the overall O&M cost of the plant (94) and is not considered separately.

The results are used to develop a multi-dimensional water-carbon bubble chart that shows the combined GHG, water, and cost impacts of several provinces for the 100% decarbonization scenario (see Figure 2-11). The x-axis gives the cumulative GHG emissions that can be saved and the y-axis gives the amount that needs to be spent to mitigate one tonne of CO_2 equivalent. Solid and hollow bubbles represent the increase and decrease in water consumption, respectively.

2.5 Sensitivity analysis

The sensitivity analysis is conducted by varying the key input parameters to identify the degree of variability in results for input key assumptions. The maximum wind capacity addition constraint was varied from -20% to +20% to cover uncertainly of future deployment speed of the technology.

The natural gas prices were varied based on the high and low natural gas price forecasts from the CER (109). The forecasts cover up to 2040 and then the prices were assumed to remain constant to 2050. The natural gas electricity performance benchmark for which carbon tax is applied was varied from the baseline case to zero by 2030 to reflect the impact that recent regulation developments might have (123).

2.6 Validation

2.6.1 Electricity demand validation

Figure 2-4 gives the provincial end-use electricity demands input used in this study. Government historical data from StatsCan and historical and projection data from the NEB on electricity demands are also plotted in the figure for comparison. The LEAP-Canada electricity demand differs by maximum 3% and average 1% compared to StatsCan electricity demand data. The LEAP-Canada electricity demand follows similar long-term trends as the NEB electricity demand projections.

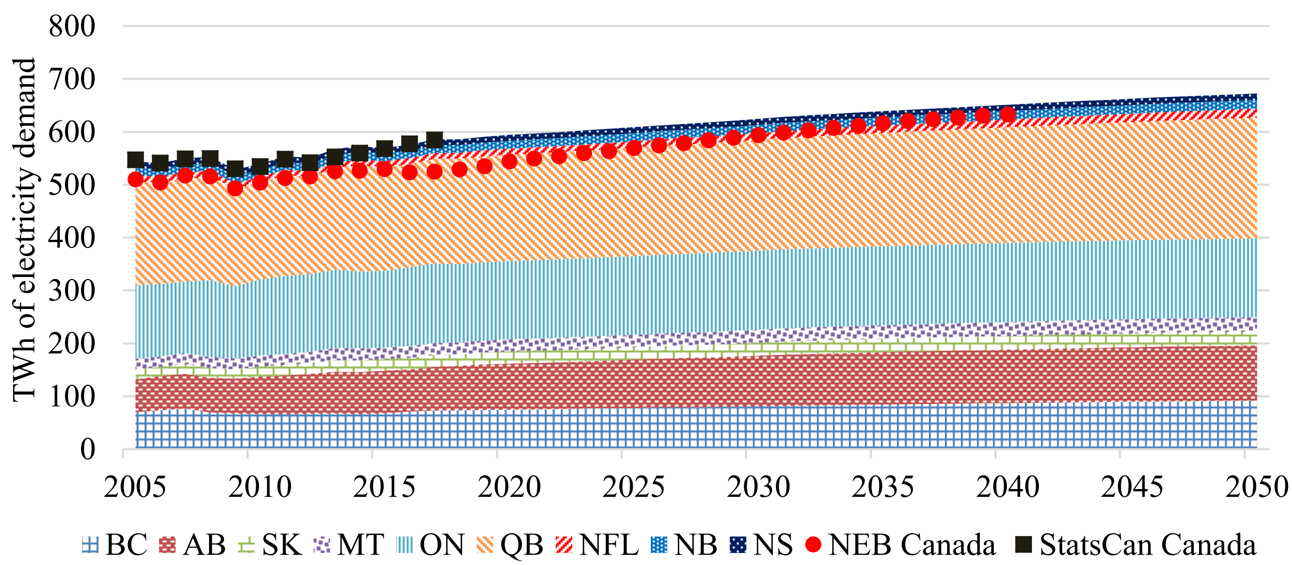

Figure 2-4: Provincial end-use electricity demands from 2005-2050

2.6.2 **Electricity generation and GHG emissions validation**

The LEAP-Canada electricity generation and GHG emissions from the reference scenario were compared to the National Energy Board (NEB) (23) and Environment and Climate Change Canada (ECCC) (18) government data for validation, respectively. The electricity generation deviations are within 5% which suggests that the model and assumptions are reasonable. The deviation is likely due to a higher electricity demand in NEB's projection period. The GHG emissions from LEAP-Canada's electricity generation are also within a reasonable range compared to ECCC, with the largest difference of 10% occurring in 2005.

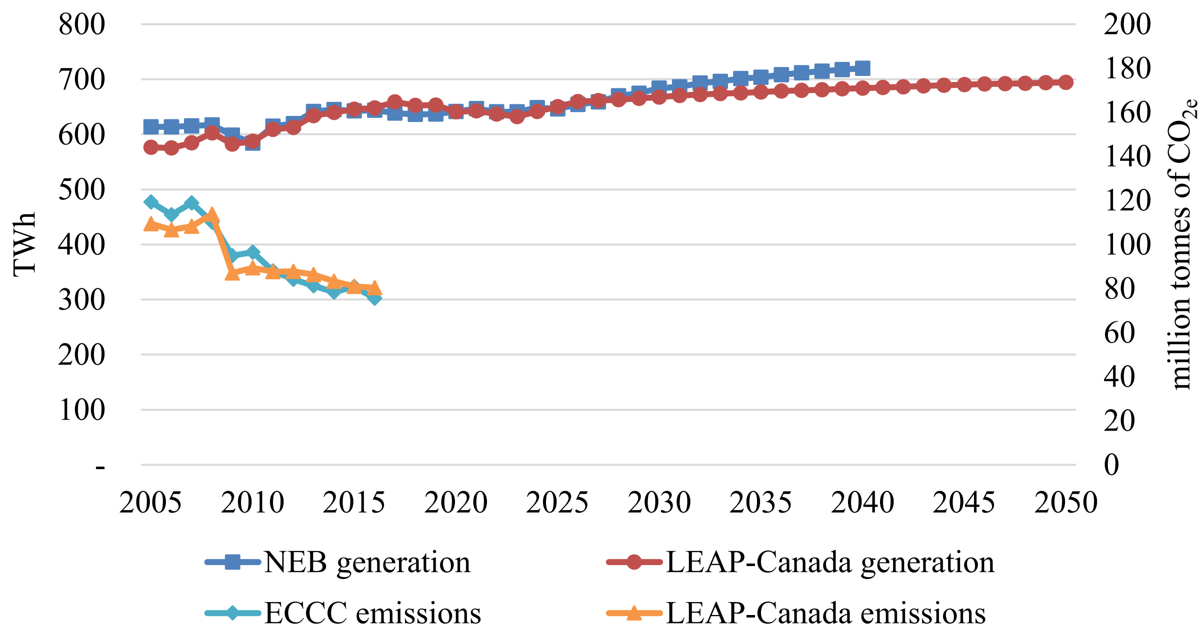

Figure 2-5: Electricity generation and GHG emissions validation

2.6.3 **Water use validation**

The thermal power water use values from WEAP-Canada was compared to Statistics Canada (StatsCan) for the year 2005, 2007, 2009, 2011, 2013 and 2015 based on available data as shown in Figure 2-6 (124)(125). Only thermal generation is compared as StatsCan only provides data for thermal generation. The lines in Figure 2-6 represent the water withdrawal. For all the years in Figure 2-6, the WEAP-Canada water withdrawal values fall under 10% deviation from StatsCan values. There is a large discrepancy between the consumption values for 2005, 2007 and 2009. It is possible that past plants have had abnormally high water uses and since a constant water use intensity was used in the WEAP model, this variation in past years would not be accounted for. The generation output from the Ontario's Atikokan (211 MW), Lambton (1980 MW),Nanticoke (3940 MW), and Thunder Bay (306 MW) coal plants reduced drastically after 2010 which correlates with the reduction in consumption decrease and eventual alignment with WEAP-Canada results (126). The information on type of cooling technology adopted by these plants is not publicly available. WEAP-Canada model assumed once-through cooling technology water use intensities for these plants and that could be the reason for the significant difference in the water consumption values from the StatsCan. But the WEAP-Canada water consumption validation improves significantly after 2010 where the model values for 2011, 2013 and 2015 fall under 8% deviation from StatsCan values.

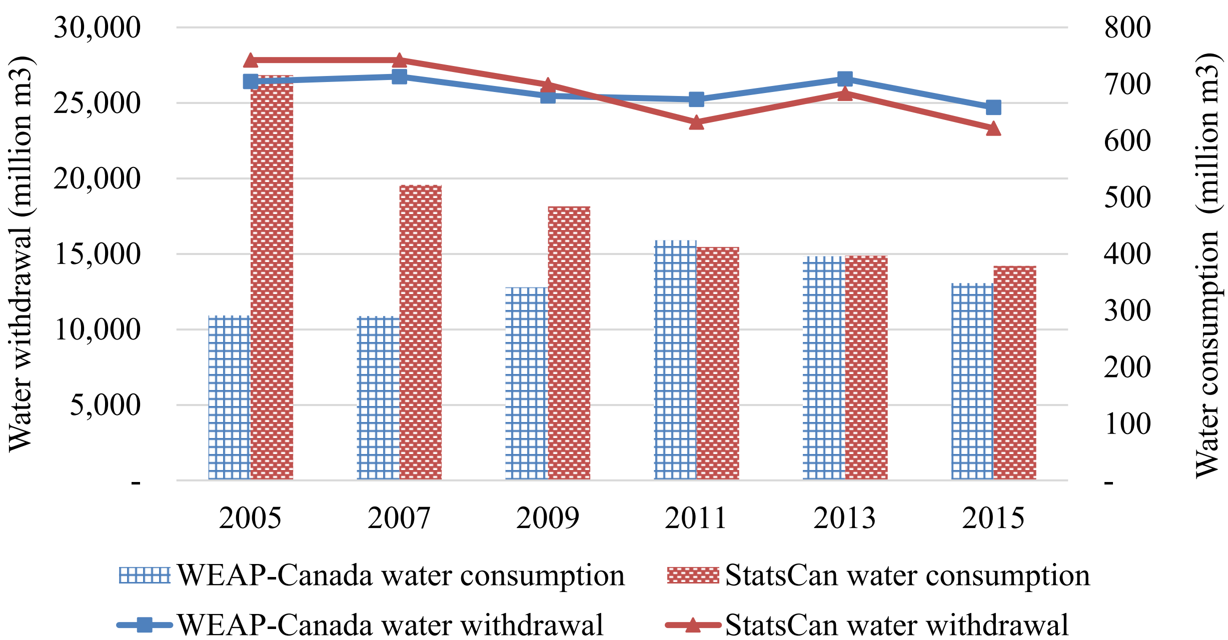

Figure 2-6: Water withdrawal and consumption validation

2.7 Results and discussion

2.7.1 **Current policy scenario**

Under the current policy scenario, Canada is projected to produce 694 TWh of electricity in 2050, an increase of 20% from the base year of 2005 (see Figure 2-7). Alberta experienced the most growth (66%) in electricity generation by 2050. The share of carbon-free generation sources in Canada is projected to increase from 76% to 94% driven by provincial renewable targets and competitive renewable generation prices (see Figure 2-7). Projections show that wind power experiences the most growth by 2050 among technologies. As capacity coal retires in Alberta, Saskatchewan, New Brunswick, and Nova Scotia the capacity is replaced by wind and natural gas. The hydro power generation share is projected to fall from 59% to 54% by 2050 from 2019 as increases in electricity capacity requirements are met by wind and natural gas. New capacity requirements in the hydro-dominated provinces of British Columbia, Manitoba, Quebec, and Newfoundland & Labrador are projected to be met mainly by wind. Standalone biomass plant additions were not projected in the model because of relatively high capital and O&M cost compared to other options. The model did not project notable growth in solar capacity. However, one should note that battery storage was not considered which could change the outcome for solar penetration.

For the decarbonization scenario, hydro, wind, and solar increased by about 37, 9, and 1 TWh or 10%, 5% and 19% compared to the current policy scenario. British Columbia, Saskatchewan, Ontario, Newfoundland & Labrador, New Brunswick, and Nova Scotia achieved full electricity decarbonization through adding wind-based generation. It is projected that solar and hydro would be required for electricity decarbonization in Alberta as wind reached the assumed maximum capacity addition constraint (600 MW/year). No notable change in the generation mix was observed for Manitoba and Quebec. The modelling results show that natural gas plant capacity was required to maintain reliability, but were not dispatched in the model in 2050.

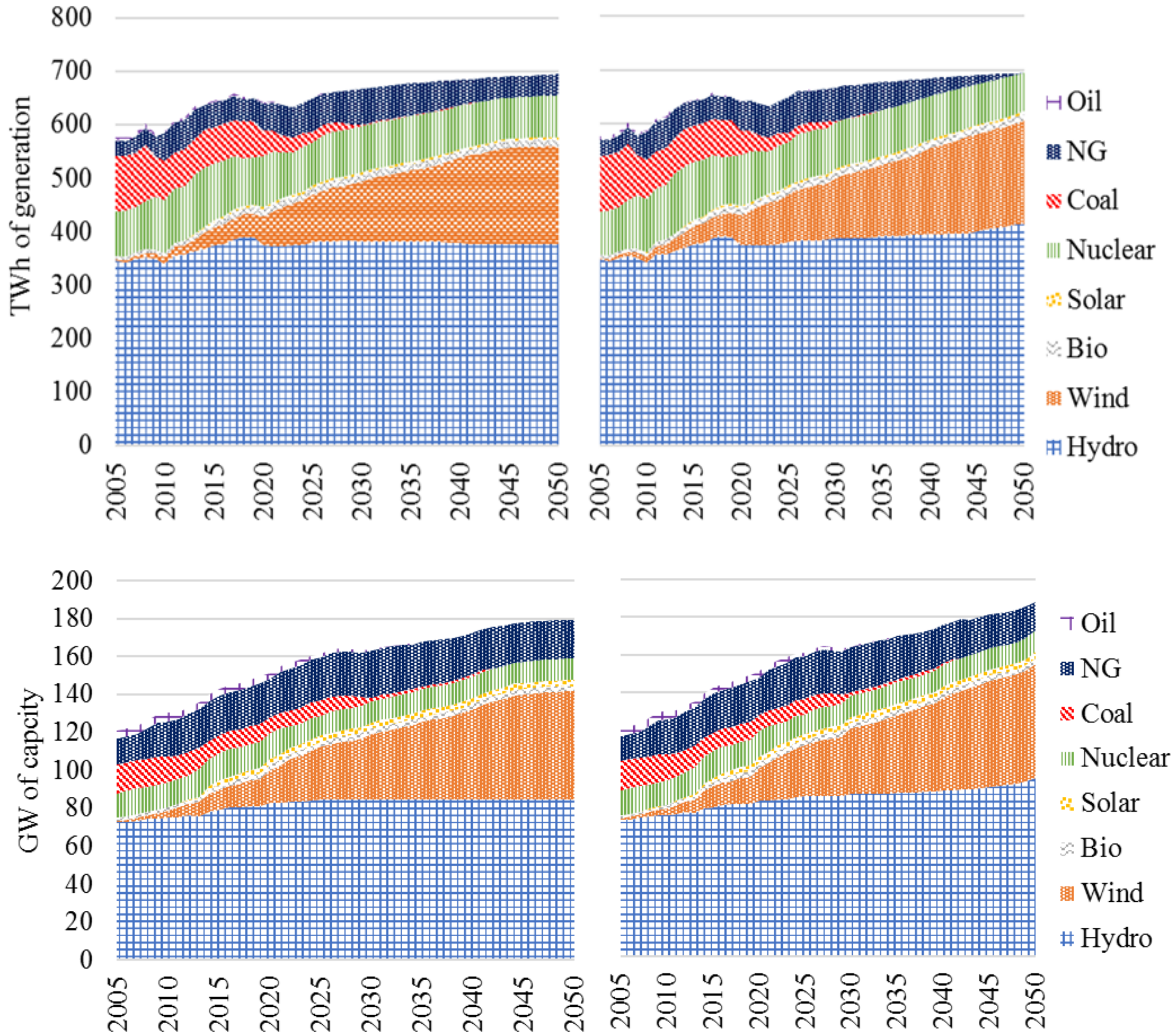

Figure 2-7: Electricity generation (top) and capacity (bottom) in the current policy (left) and 100% (right) scenarios

National GHG emissions are projected to reach 15 million tonnes of CO_2e in 2050, a decrease of 86% and 81% from 2005 and 2019, respectively (see Figure 2-8). Alberta, Saskatchewan, Ontario, Nova Scotia, and New Brunswick reduce their GHG emissions by 71%, 97%, 98%, 99%, and 99%, respectively, by 2050 from 2019 in the current policy scenario. This was driven by coal retirements, renewable generation policy targets, and declining costs of renewables leading to a transition from fossil-fuel generation to renewable generation. British Columbia's, Manitoba's, Quebec's, and Newfoundland & Labrador's GHG emissions are projected to remain low throughout the study period with no significant changes.

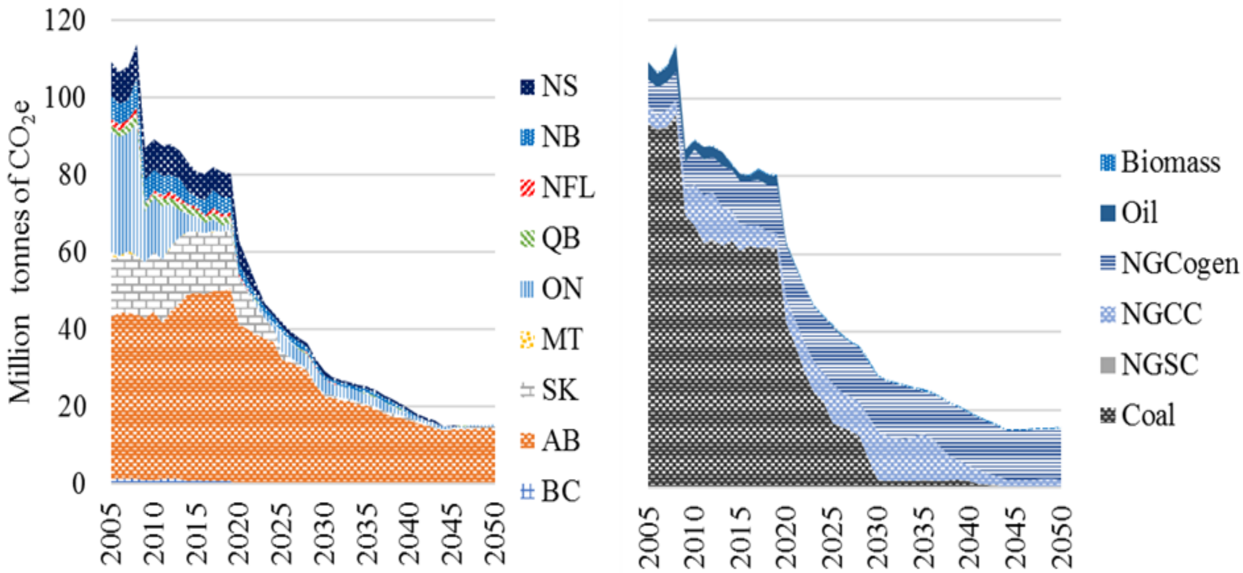

Figure 2-8: GHG emissions by province (left) and by fuel type (right) in the current scenario

Figure 2-9 shows the water withdrawal breakdown by feedstock used for power generation for the current policy scenario and the 100% scenario. Under the current policy scenario, water withdrawal is projected to decrease 22.8 billion m^3 by 2050, down 17% from 2019. Most of the water withdrawal savings is expected to occur in Alberta, Saskatchewan, Ontario, Quebec, New Brunswick and Nova Scotia and would be 33%, 57%, 11%, 39% and 94% less than from 2019 because of the high wind penetration after decreasing in generation from fossil-fuel plants. Manitoba water withdrawal is projected to increase 2% respectively by 2050 due to an increase in hydroelectricity for meeting increasing electricity demand. Increasing wind generation in British Columbia and Newfoundland and Labrador is expected to reduce water withdrawal demand from electricity generation and would decrease 2% and 24%, respectively by 2050.

Under the 100% scenario, the national water withdrawal is projected to decrease to 21.5 billion m^3 by 2050, down 6% from the current policy scenario. The cumulative water withdrawal from 2020-

2050 would be 0.3% less than the current policy scenario. The transition from natural gas generation to majorly wind generation reduces the water withdrawal demand. Most of the cumulative water withdrawal savings is expected to occur in Saskatchewan, Ontario, New Brunswick and Nova Scotia and would be 9.6%, 0.6%, 1.7% and 1.8% because of the more wind generation in the 100% scenario compared to the current policy scenario. Alberta cumulative water withdrawal is projected to increase 4% from the current policy scenario because of the increase in generation from the hydro plants which offset the water withdrawal savings from natural gas plants. Other provinces would have minimal change in the generation mix and a slight decrease in water withdrawal.

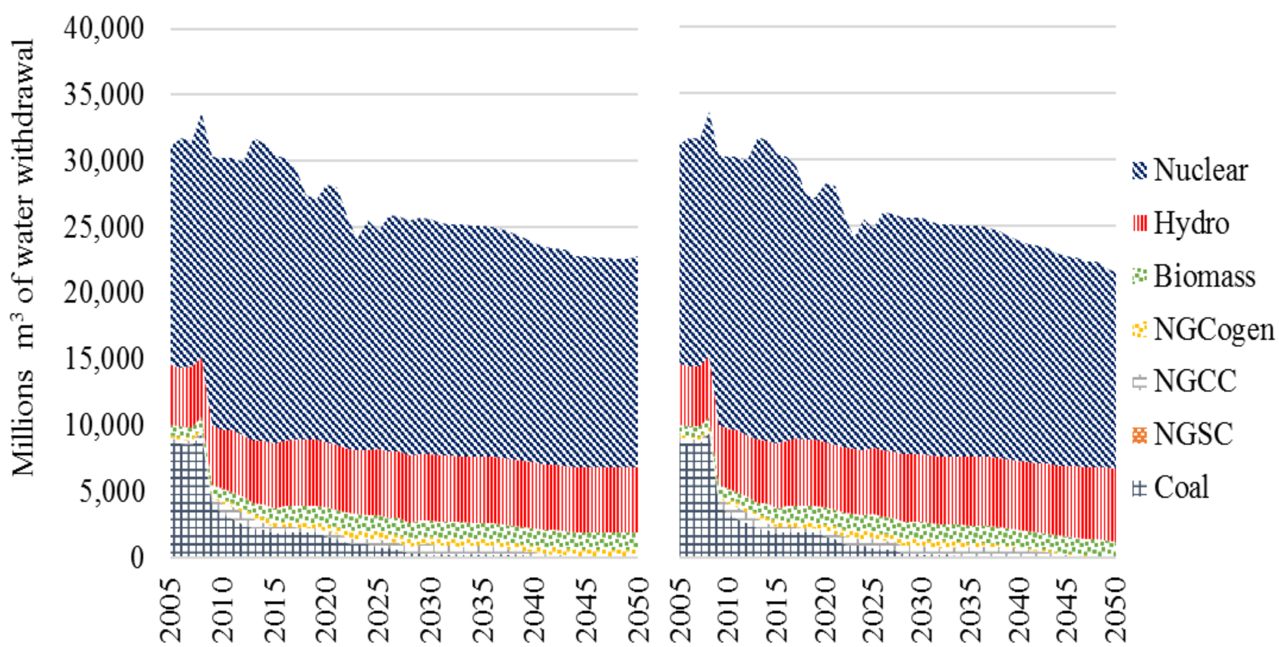

Figure 2-9: Water withdrawal in the current policy (left) and 100% (right) scenarios

Figure 2-10 shows the water consumption breakdown by feedstock used for power generation for the current policy scenario and the decarbonization scenario. Under current policy conditions, water consumption decreased to 5.1 billion m^3 in 2050, down 5% from 2019. The average yearly decrease in water consumption was 0.16% from 2020-2050. A transition from natural gas to wind generation drives decreases in water consumption, however, the national water consumption intensity (m^3/MWh) does not result in a notable change. The water consumption decrease is projected to occur in all provinces in the current policy scenario, except British Columbia and Manitoba. Most notably, the water consumption in Alberta, Saskatchewan, New Brunswick and Nova Scotia is shown to decrease by 16%, 32%, 27% and 66%, respectively, by 2050. Coal plant closures would result in water savings, and the wind generation growth would retain these savings and lead to a net decrease in water consumption. Ontario's water consumption is projected to decrease by 2% by 2050 because of retirement of nuclear generation and replacement with wind and natural gas-based power. Quebec's and Newfoundland and Labrador's water consumption is projected to decrease by 8% and 9%, respectively by 2050 because of decreases in hydro generation and growth in wind generation. British Columbia's and Manitoba's, water consumption is shown to increase by 3%, and 3%, respectively, by 2050 because of increases in hydro generation.

With a 100% GHG emissions mitigation target, the absolute change in water consumption between 2019 and 2050 is projected be 9% (see Figure 2-10). Cumulative water consumption is projected to reach 3.6% more than the current policy scenario, an additional 5.9 billion m^3 by 2050 (enough to meet Canada's residential sector annual water consumption for 18 years, based on 2013's annual water consumption estimate of 324 million m^3 [19]). Among provinces, only Alberta experienced a notable water consumption increase, driven by increases in hydro power from reaching the maximum assumed annual wind addition constraint, which offset the water savings from other provinces. Alberta's cumulative water consumption is projected to be 45.9% more than the current policy scenario's from 2020-2050 (see Figure 2-11). But other provinces with no significant increase in hydro generation would consume less water than in the current policy scenario. Saskatchewan's, Ontario's, New Brunswick's, and New Scotia's cumulative water consumption is projected to be 8.5%, 0.1%, 0.2% and 2.5% less than the current policy scenario's from 2020-2050 (see Figure 2-11). British Columbia and Newfoundland & Labrador would have minimal change in the generation mix and a slight increase in water consumption.

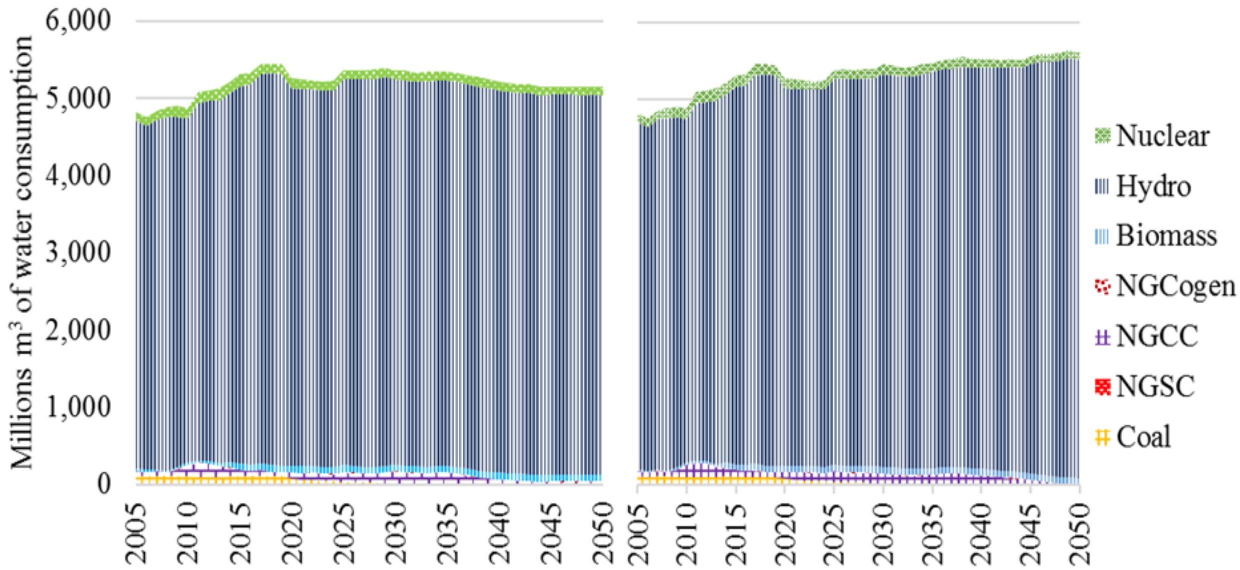

Figure 2-10: Water consumption in the current policy (left) and 100% (right) scenarios

2.7.2 Decarbonization scenario analysis

Figure 2-11 shows that the decarbonization scenario results in 138 million tonnes of CO_{2e} fewer cumulative GHG emissions than the current policy scenario, on average about 4.6 Mt CO_2e annually between 2020 and 2050. The marginal GHG abatement cost to achieve 100% decarbonization is estimated to be \$23 per tonne of CO_2e compared to the current policy scenario with most of the cost occurring in Alberta. The decarbonization pathway leads to an increase of 3.6% in cumulative water consumption compared to the current policy scenario also mostly occurring in Alberta. Saskatchewan, New Brunswick, and Nova Scotia have relatively low marginal GHG emission abatement costs. Those provinces have relatively small electricity systems (in terms of capacity) with relatively low GHG emissions in the current policy scenario and so a transition to a completely decarbonized system could be achieved through additions of wind power. In the case of Alberta, a high amount of capacity transition was required, exhausting the upper limit of annual wind capacity additions and requiring solar and hydro capacity expansion which are more costly than wind. Ontario's relatively high GHG abatement cost is driven by a low GHG abatement required for decarbonization compared to the reference scenario and late additions of wind power. The transition to decarbonized electricity generation was shown to reduce water consumption in all provinces except Alberta, where hydro power was expanded resulting in high consumption rates. British Columbia, and Newfoundland & Labrador experience nearly 0 GHG emissions by 2050 in the current policy scenario, leading to misleadingly high marginal GHG emission abatement costs due to the small GHG emissions savings and hence, small denominator in the calculation (Equation 2-8). Manitoba, and Quebec experience no change in generation from the current policy scenario and hence, they have 0 GHG abatement cost.

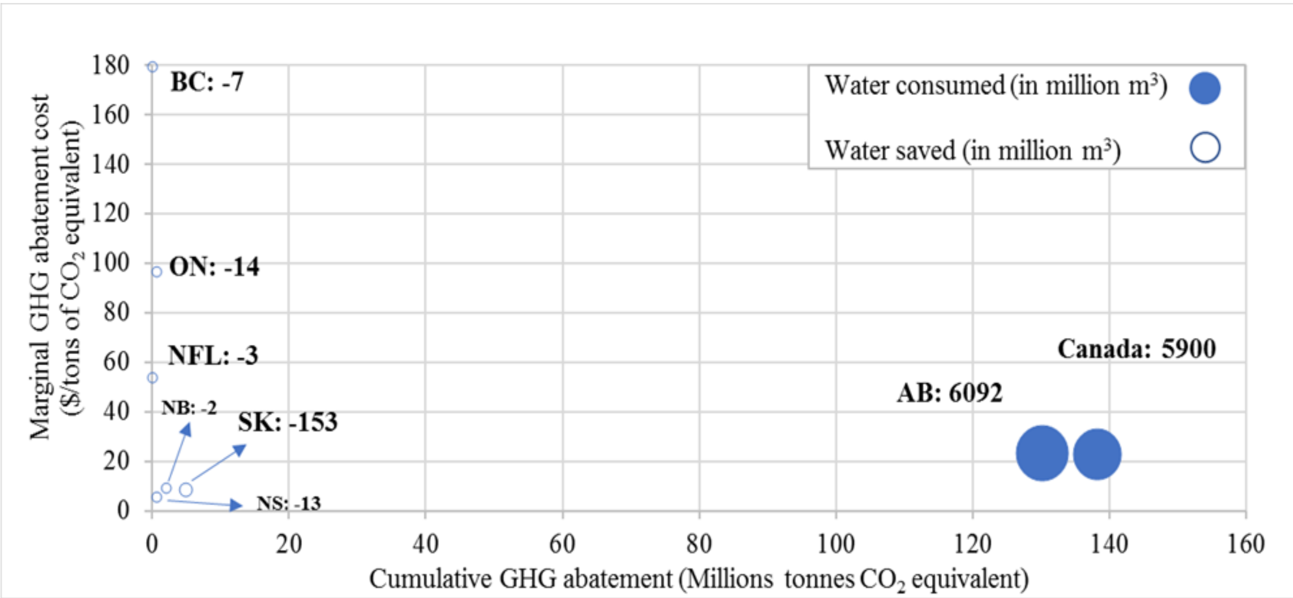

Figure 2-11: Bubble plot showing marginal values for electricity system costs, GHG emissions, and water consumption under a national decarbonization requirement

2.8 Sensitivity Analysis

Figure 2-12 and Figure 2-13 shows the sensitivity of the results to a change in the maximum annual wind capacity addition constraint. With a higher limit, the model added more wind in the current policy scenario which reduced GHG emissions and the NPV of the scenario. This resulted in the decarbonization scenario to have lower a GHG emission reduction requirement and higher marginal GHG emission abatement costs because of a smaller denominator and larger marginal NPV. The corresponding impact to water use in the current policy scenario shows little effect, however in the decarbonization scenario, the there is less water consumption with higher amounts of wind deployment due to more displacement of natural gas generation and hydro capacity development.

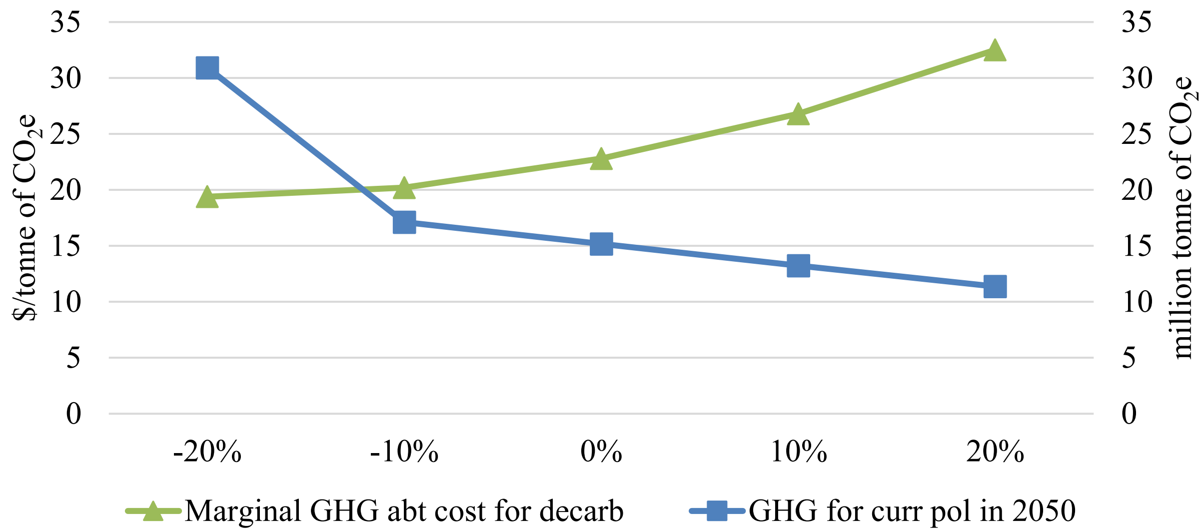

Figure 2-12: Sensitivity analysis for maximum annual wind capacity addition constraint on the GHG emissions for the current policy scenario and the GHG emissions abatement cost for the decarbonization scenario

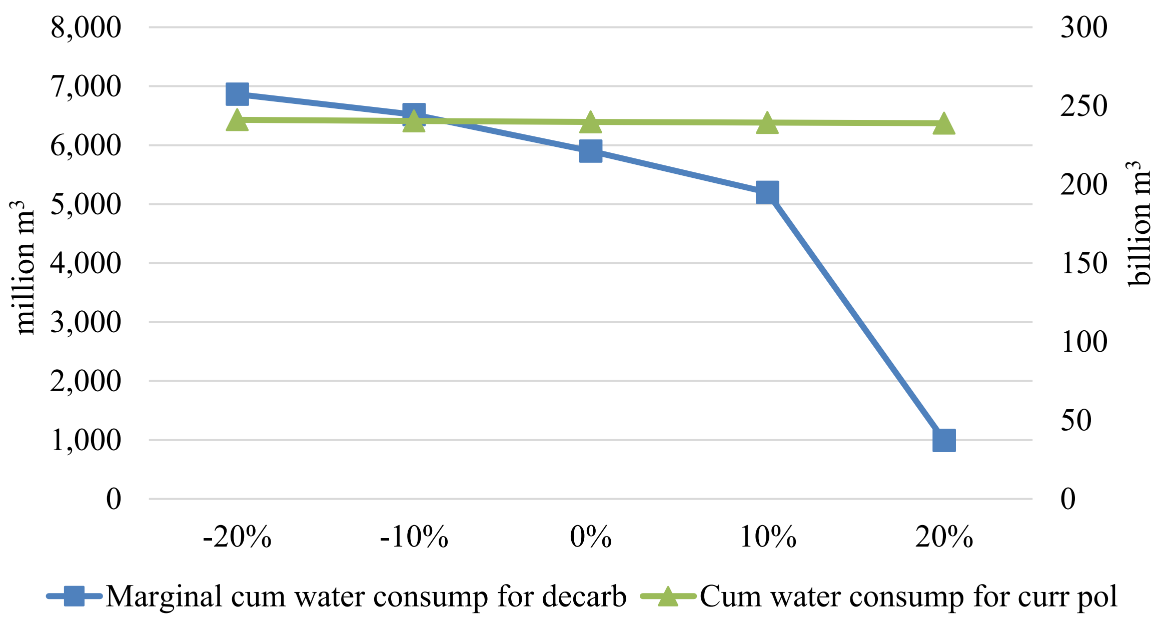

Figure 2-13: Sensitivity analysis for maximum annual wind capacity addition constraint on the cumulative water consumption for the current policy scenario and marginal cumulative water consumption for the decarbonization scenario

As seen in Figure 2-14 and Figure 2-15, lower natural gas price drives more natural gas generation which increases GHG emissions in the current policy scenario. This did not result in a notable change to the marginal GHG emission abatement cost for the decarbonization scenario since the investment costs for low carbon generation increased almost proportionally with higher GHG emission reduction. Higher natural gas price reduced natural gas generation and GHG emissions in the current policy scenario. In this case, the marginal NPV is less for the same amount of GHG emissions savings and hence, the decarbonization scenario has lower marginal GHG abetment cost. Cumulative water consumption in the current policy scenario does not change drastically with the natural gas price variability, however the decarbonization scenario shows an increase in water consumption with higher natural gas price, due to more natural based electricity generation.

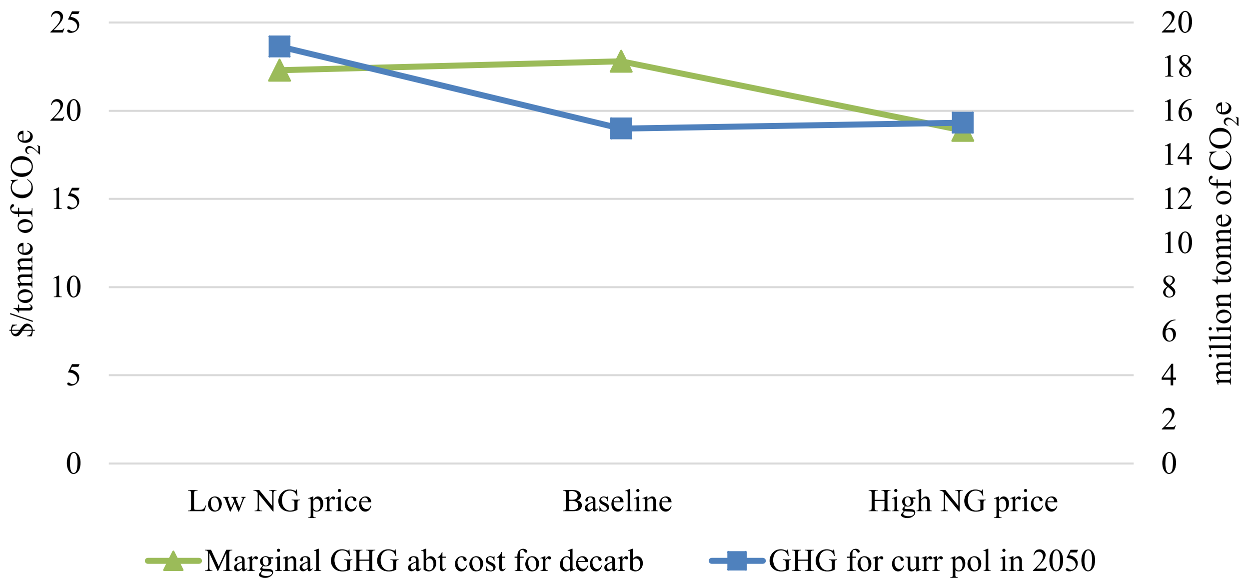

Figure 2-14: Sensitivity analysis for natural gas price constraint on the GHG emissions for the current policy scenario and the GHG emissions abatement cost for the decarbonization scenario

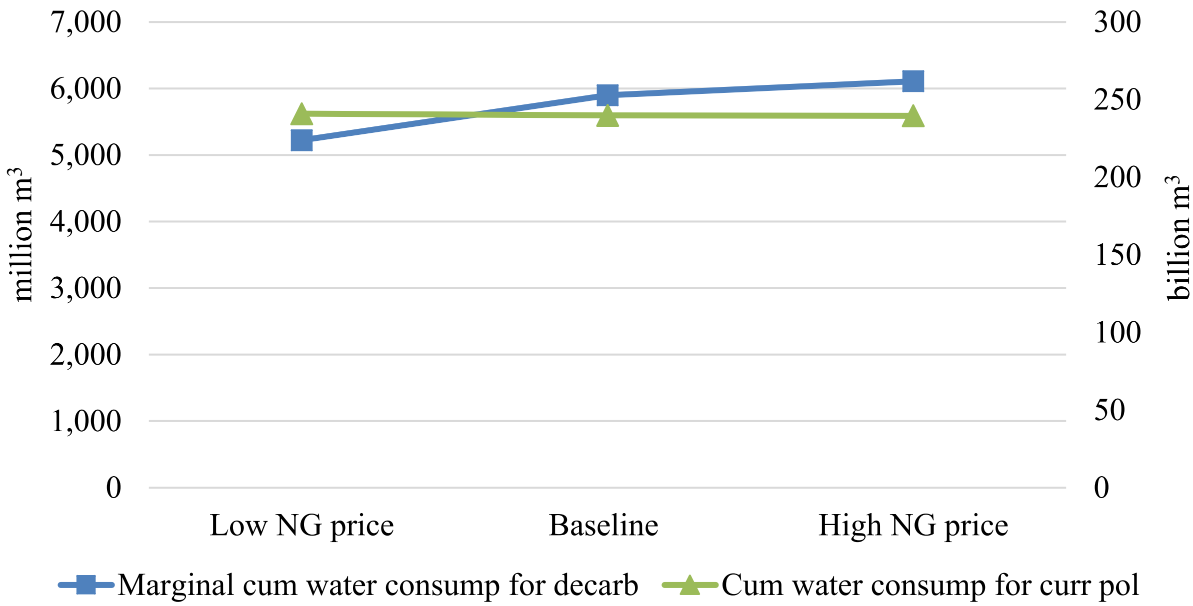

Figure 2-15: Sensitivity analysis for natural gas price constraint on the cumulative water consumption for the current policy scenario and marginal cumulative water consumption for the decarbonization scenario

Figure 2-16 and Figure 2-17 shows the results corresponding to a different benchmark (zero by 2030) for natural gas electricity facility carbon tax application. With the new performance intensity values, carbon tax is now applicable to all GHG emissions from natural gas generation past 2030. This reduced natural gas generation and the GHG emissions values in the current policy scenario. However, the GHG abatement cost does not change much because the decrease in the GHG emissions savings are proportional to decrease in the marginal net present value for the decarbonization scenario. The water consumption for the current policy scenario increases by about 5% due to the performance benchmark tightening to zero by 2030.

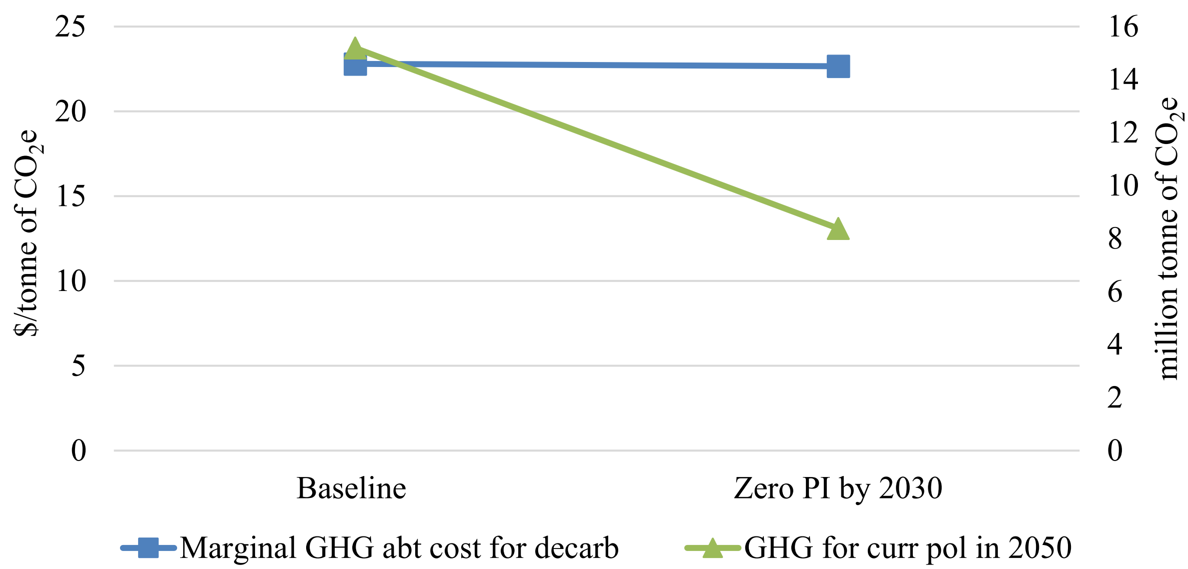

Figure 2-16: Sensitivity analysis for GHG emissions performance intensity on the GHG emissions for the current policy scenario and the GHG emissions abatement cost for the decarbonization scenario

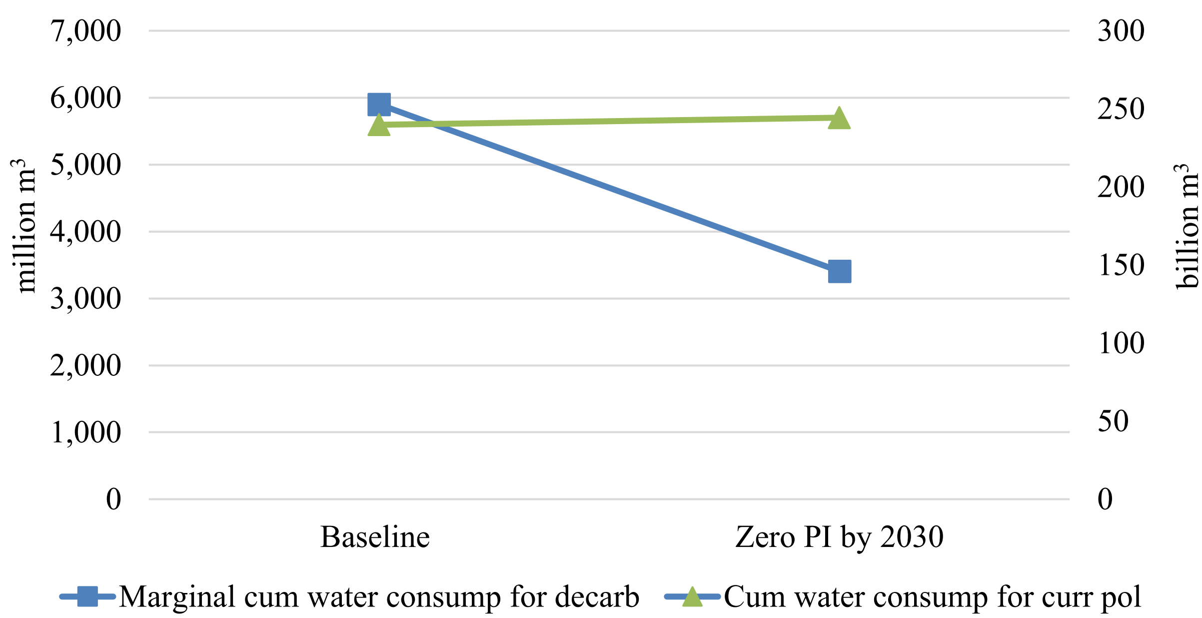

Figure 2-17: Sensitivity analysis for GHG emissions performance intensity on the cumulative water consumption for the current policy scenario and marginal cumulative water consumption for the decarbonization scenario

3 Chapter 3: Integrated assessment of water use and greenhouse gas footprints for the oil and gas sector in Canada

3.1 Overview

The primary purpose of this part of research was to develop a water evaluation model of Canada's oil and gas sector. This chapter describes the development of the water demand and supply model, its application in estimating baseline projections for future water use, and its integration with the existing energy-environment model to study integrated water and GHG emission footprints of Canada's oil and gas sector.

The background on the WEAP model is provided in Section 3.2. A WEAP model of Canada's oil and gas sector (WEAP-COGM) was developed that provides water withdrawal and consumption corresponding to the expected annual oil and gas activity in Canada to 2050. A business-as-usual (BAU) scenario was developed for the 2005-2050 time period to provide a reference for scenario analysis. This study used Davis et al.'s LEAP-Canada model (52) to run energy scenarios corresponding to high and low energy price cases, described in detail in Section 3.3. The alternative energy scenarios are described in detail in Section 3.4. The scenarios were run in the WEAP-COG and LEAP-Canada, and the results were compared to the results of the reference scenario; the marginal GHG emissions, as well as water withdrawal and consumption, are discussed in Section 3.5. The results were used to provide an integrated analysis of GHG emissions and water use (withdrawal and consumption).

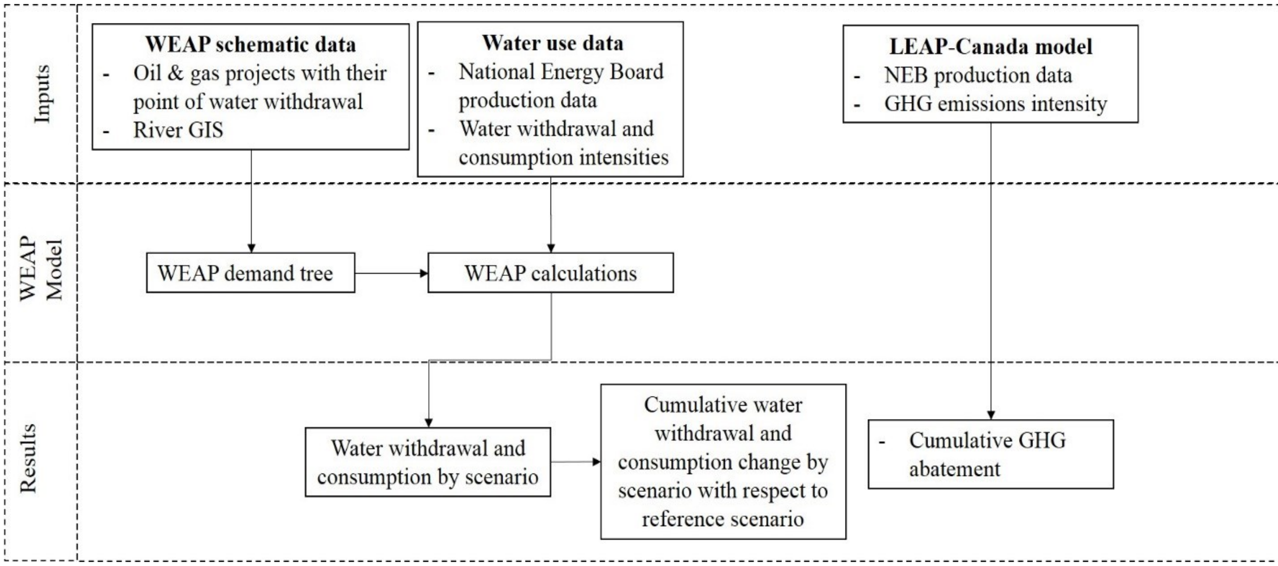

Figure 3-1: Water-energy modelling framework for the oil and gas sector

3.2 Canada's oil and gas water use model development

To estimate the water use impacts from the oil and gas sector for the years 2005-2050, a water model was developed in WEAP. The overview of the model is given in Figure 3-1. The WEAP-COG geographical schematic was developed by collecting river geographic information system (GIS) data and drawing in 20 major Canadian rivers (the blue lines in Figure 3-2) in the WEAP schematic interface. The oil and gas extraction projects and processing industries' water withdrawals were aggregated based on their water sources and were marked as red dots in the figure to develop 40 demand sites. A water demand tree, a hierarchical tree with bottom-up water demand sites, was used to calculate end-use, sectorial, provincial, and national water demand (see Figure 3-3). The water demands for the reference scenario were calculated with water use data inputs such as National Energy Board (NEB) production data and water withdrawal and consumption intensities. A river's water supply potential was measured through streamflow gauges (phi markers in Figure 3-2). We used NEB high and low energy price scenarios' oil and gas production data and estimated water use and GHG emissions. The output of the WEAP-COG model is water withdrawal and consumption for each scenario from 2005-2050. The results were used to calculate cumulative water consumption by scenario with respect to the reference scenario from 2019-2050.

3.2.1 **Water supply and oil and gas site locations**

Modelling the supply side in WEAP-Canada can facilitate an in-depth analysis of water supply and demand at the watershed level. To estimate water withdrawals from watersheds for oil and gas extraction projects, the regional production distribution of oil and gas projects were identified from government reports (see Table 3-1); these are cited in later sections. The largest watershed for a region was identified through Google Maps (111) and is assumed to supply water to the projects in that region. The regional production distribution for various oil and gas sub-sectors were also calculated. Similarly, to estimate water withdrawals from watersheds by refineries and upgraders, each refinery's and upgrader's nearest water bodies was located. To facilitate this, each industry was located geographically with Google Maps to estimate its proximity to watersheds.

Table 3-1: Identified data sources for production distribution calculations for the oil and gas sub-sectors

Oil and gas sub-sector	Source
Bitumen mining	ST-98 reports by the Alberta Energy Regulator – 2008 (127), 2010 (128), 2011 (129), 2012 (130), 2013 (131), 2014 (132).
Bitumen in situ	ST-98 report (133), thermal in situ report by the Alberta Energy Regulator (134).
Bitumen upgrading	Upgraders and Refineries Facts and Stats sheet published by the Government of Alberta (32).
Conventional crude oil extraction	Water Use for Oil and Gas Activity from the BC Oil and Gas Commission (135), ST-98 reports by the Alberta Energy Regulator (136), Crude Oil Volume and Value Summary by Area Crude Type from the Government of Saskatchewan (137), Petroleum industry – Ontario by Oil; Gas and Salt Resource Library (138), The Economy 2017: Oil and Gas from the Government of Newfoundland and Labrador (139).
Natural gas extraction	Water Use for Oil and Gas Activity from the BC Oil and Gas Commission (135), ST-98 reports by the Alberta Energy Regulator (140), Monthly Crude Oil and Natural Gas Production Reports from the Government of Saskatchewan (141), Petroleum industry – Ontario by Oil; Gas and Salt resource library (138), The Economy 2017: Oil and Gas from the Government of Newfoundland and Labrador (142).
Crude oil refining	Canadian Refinery Overview by National Energy Board (33).

River supply capacity with streamflow gauge data was modeled. Streamflow gauges measure flow rate at various monitored points along with a river. Government of Canada streamflow gauge data from 2010-2016 was used (143). The flow rate is assumed to be cyclic after 2016 until 2050 (55). A supply module was developed in WEAP-COG to determine whether the demand sites are withdrawing more water than the river supply capacity.

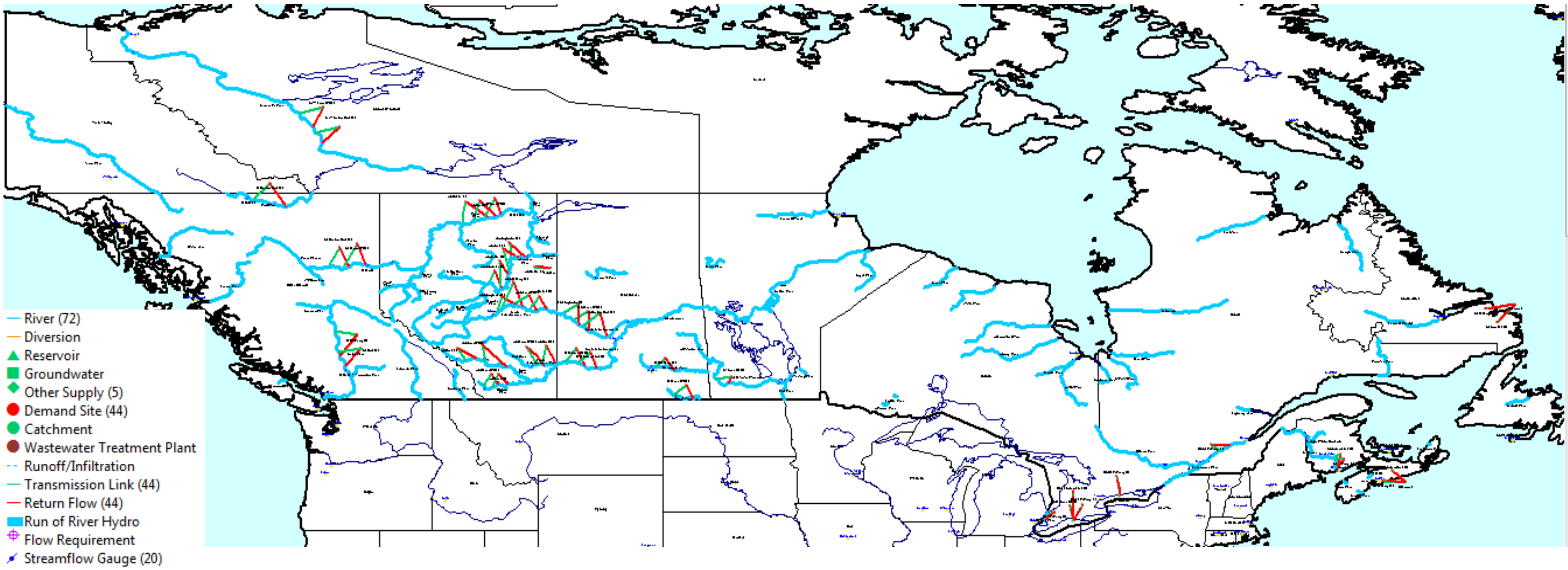

Figure 3-2: The WEAP Canada oil and gas model showing Canada's oil and gas water demand sites (144)

3.2.2 **Water withdrawal and consumption**

Two water-use parameters – water withdrawal and water consumption – were considered in this study. Water withdrawal refers to the water diverted by oil and gas projects from rivers, lakes, and the ground. Water withdrawal intensity (WWI) is defined as the freshwater intake per m^3 of annual activity. Water consumption in oil and gas operations is the water consumed from steam loss in the boiler, oil and gas wells, hydrogen production, and evaporation. Water consumption intensity (WCI) is defined as the freshwater consumed per m^3 of annual activity. Water consumption percentage (WCP) is calculated instead of WCI as WEAP takes consumption inputs in percentages. WCP is defined as the percentage of water consumed from the withdrawn water from river/lakes/groundwater. Recycling plays a large role in determining the magnitude of water intensity values. Oil and gas wells discharge water to the surface after they are flooded with water or steam. The discharged water can be disposed of or recycled and reused in operations. WWI is calculated based on the recycle percentage.

The WEAP-COG is divided into six sub-sectors – bitumen mining, bitumen in situ production, bitumen upgrading, conventional crude oil production, natural gas extraction, and crude oil refining. The total water withdrawal is calculated by adding the water withdrawal from these sub-sectors.

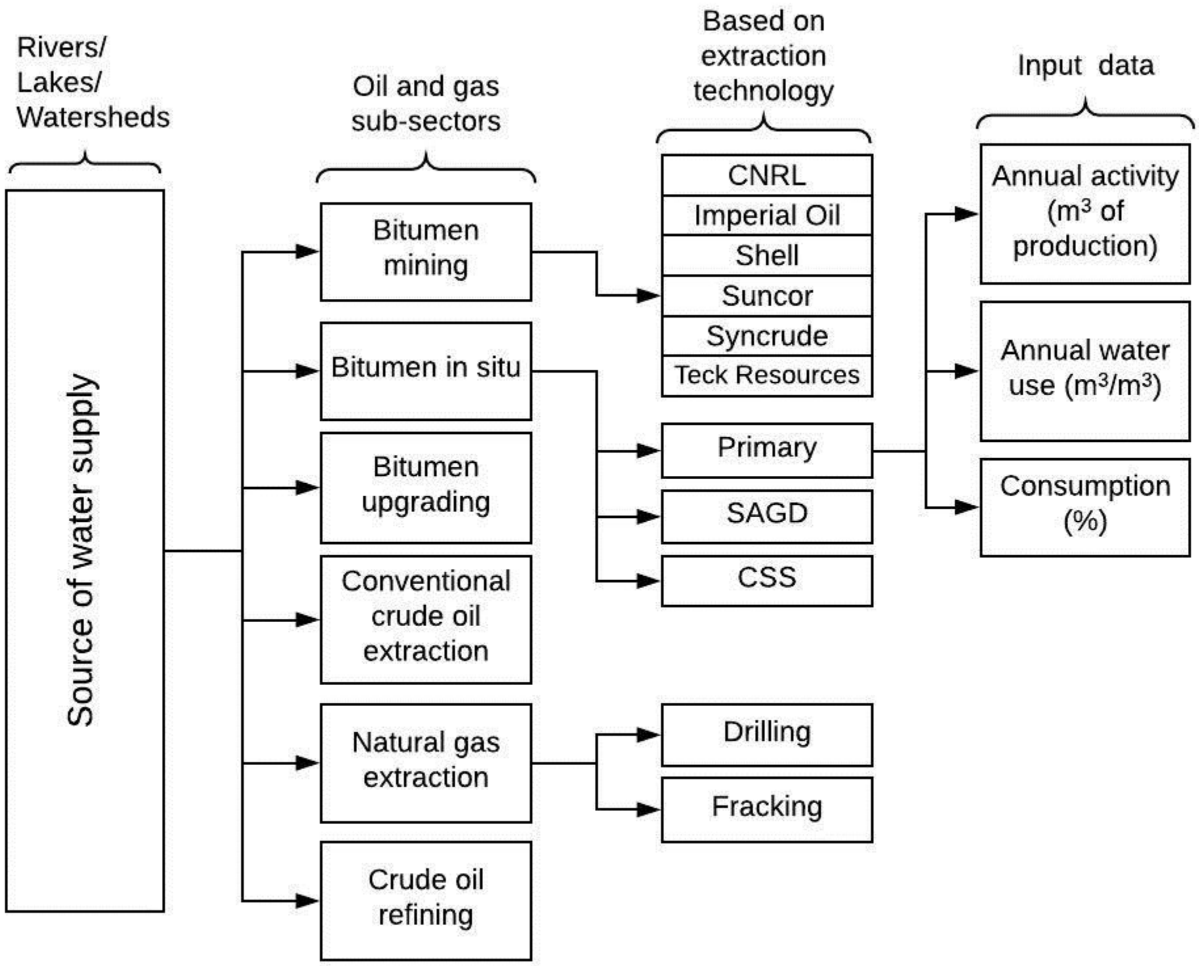

Figure 3-3: Water demand tree for the oil and gas sector as modeled in WEAP

3.2.2.1 Bitumen mining

Oil sands mining bitumen is extracted via open-pit mining (145). A significant amount of water is required in the hot water separation process to separate bitumen from the oil sands (146). Alberta is the only province with operational bitumen extraction projects. There are five companies in the Alberta oil sands – CNRL, Imperial Oil, Shell, Suncor and Syncrude – with a total production of 1,161 thousand bbl/day in 2015 (20) (132). A fifth, Teck Resources, is scheduled to start its Frontier phase 1 project in Fort Hills in 2019 (147).

Table 3-2: Bitumen mining industry production shares

	CNRL	Imperial Oil	Shell	Suncor	Syncrude	Teck Resource	Comment	Ref
2005	0%	0%	19%	34%	47%	0%	Assumed to be equal to the 2008 value	
2006	0%	0%	19%	34%	47%	0%	Assumed to be equal to the 2008 value	
2007	0%	0%	19%	34%	47%	0%	Assumed to be equal to the 2008 value	
2008	0%	0%	19%	34%	47%	0%		(127)
2009	0%	0%	17%	32%	44%	0%	Average of 2008 and 2010	
2010	13%	0%	15%	31%	41%	0%		(128)
2011	5%	0%	24%	32%	39%	0%		(129)
2012	11%	0%	24%	29%	36%	0%		(130)
2013	12%	3%	24%	28%	33%	0%		(131)
2014	11%	7%	32%	23%	27%	0%		(132)
2019	12%	7%	23%	25%	29%	4%	Intermediate values from 2015-2018 are linearly interpolated based on 2014 and 2019 values.	(132)
2025	11%	7%	20%	23%	26%	13%	Intermediate values from 2020-2024 are linearly interpolated based on 2019 and 2025 values.	(132)

A comprehensive literature review was conducted including several companies' sustainability report to develop the water withdrawal intensity (WWI) of the company's operation. The historical WWIs were calculated for companies using mined bitumen production data (obtained from the National Energy Board's Canada's Energy Future 2018 report [20]), those companies' production shares (obtained from Alberta Energy Regulator ST-98 reports [2008-2015]), and water intake and return statistics (obtained from mining companies sustainability reports [2010-2015]). Table 3-2 and Table 3-3 show the production share and WWI values for each company, respectively. Equation 3-1 is used to calculate WWIs.

WWI (ground + river source) for the bitumen mining company in a given year =

$$\frac{\text{Water intake}}{\text{Total mined bitumen production x Production share of the company}} \qquad \textbf{3-1}$$

Table 3-3 shows that the WWI for bitumen mining declined as the recycling rate improved; recycling the process water lowers the demand for freshwater intake. In 2015, 70-80% of the operation's water was recycled in the tailing's ponds (148). The recycling rates now approach almost the maximum industrial rate; this means that the WWI is not expected to improve much in future years. It was assumed that the WWI will remain constant to 2050 and is equal to the 2015 value. Given the lack of data for few companies, we assumed the industrial best WWI of 1.06 m^3/m^3 of bitumen mined in the model (51).

The WCP is 100%, as water consumption is assumed to be equal to water withdrawal. This is in accordance with province's "zero discharge policy," which restricts operators from discharging any operation-related water into rivers (148).

Table 3-3: Total water intake by the bitumen mining industry from 2010-2015

	2010	2011	2012	2013	2014	2015	Ref
CNRL Prod (in 1000's m3/yr.)	6,465	2,590	5,951	6,797	6,129	7,510	(20)
Water Intake (m^3)	20,845,454	10,305,506	22,942,743	18,222,541	21,409,907	22,762,471	(149)
WWI (m^3/m^3 of prod)	3.22	3.98	3.86	2.68	3.49	3.03	
Imperial Oil Prod (in 1000's m3/yr.)	-	-	-	1,699	3,900	4,718	(20)
Water Intake (m^3)	-	-	-	19,984,541	20,636,490	37,801,630	(150)
WWI (m^3/m^3 of prod)	-	-	-	4.89*	2.42*	3.52*	(151)
Shell Prod (in 1000's m3/yr.)	7,459	12,430	12,984	13,594	17,830	20,701	(20)
Water Intake (m^3)	24,284,000	28,906,800	26,600,000	34,900,000	32,900,000	21,900,000	(152),(153)
WWI (m^3/m^3 of prod)	3.26	2.33	2.05	2.57	1.85	1.06	
Suncor Prod (in 1000's m3/yr.)	15,416	16,574	15,689	15,859	12,815	15,694	(20)
Water Intake (m^3)	37,300,000	38,700,000	44,810,000	51,350,000	37,360,000	25,560,000	(154),(155)
WWI (m^3/m^3 of prod)	2.42	2.33	2.86	3.24	2.92	1.63	
Syncrude Prod (in 1000's m3/yr.)	20,388	20,199	19,476	18,691	15,044	18,390	(20)
Water Intake (m^3)	50,700,000	50,050,000	51,480,000	48,360,000	47,840,000	48,880,000	(156)
WWI (m^3/m^3 of prod)	2.49	2.48	2.64	2.59	3.18	2.66	

*Taken directly from the AER report.

3.2.2.2 **Bitumen in situ extraction**

Water withdrawn for in situ bitumen production is used in three major extraction techniques – primary, steam-assisted gravity drainage (SAGD), and cyclic steam stimulation (CSS). Primary development is similar to the extraction of conventional crude oil, wherein the bitumen flows to the surface because of the natural pressure of the reservoirs (145). If the pressure drops, a pool of water is injected to increase the reservoir pressure.

SAGD and CSS are enhanced techniques in which the reservoir is heated (by injecting steam) to reduce the viscosity of the bitumen. Reducing its viscosity allows the bitumen to flow through the wellbore (145) (157). SAGD and CSS are distinguished by the position and number of wellheads. SAGD uses two horizontal wells, a steam injection well and a bitumen-producing well. The steam injection well is drilled just above the bitumen-producing well. The steam mobilizes the bitumen in the reservoir, allowing it to flow to the producing well because of gravity pull (145) (157). The bitumen is then pumped to the surface via the producing well. In CSS, the same well is used to inject steam and obtain the bitumen, which flows after few days of steam injection (145). The produced bitumen is separated from the water, which is recycled and used in the process.

The in situ bitumen production for all the processes for a region was estimated, as shown Figure 3-4. The regional production share was calculated with figures from the "In situ bitumen production by oil sands area" table in the Alberta Energy Regulator (AER) ST-98 report (133) (132). The process-level share was calculated with AER-TIWP estimates from 2012-2015 (134) as shown in Table 3-4, Table 3-5, and Table 3-6. The future production shares were assumed to remain constant after 2015.

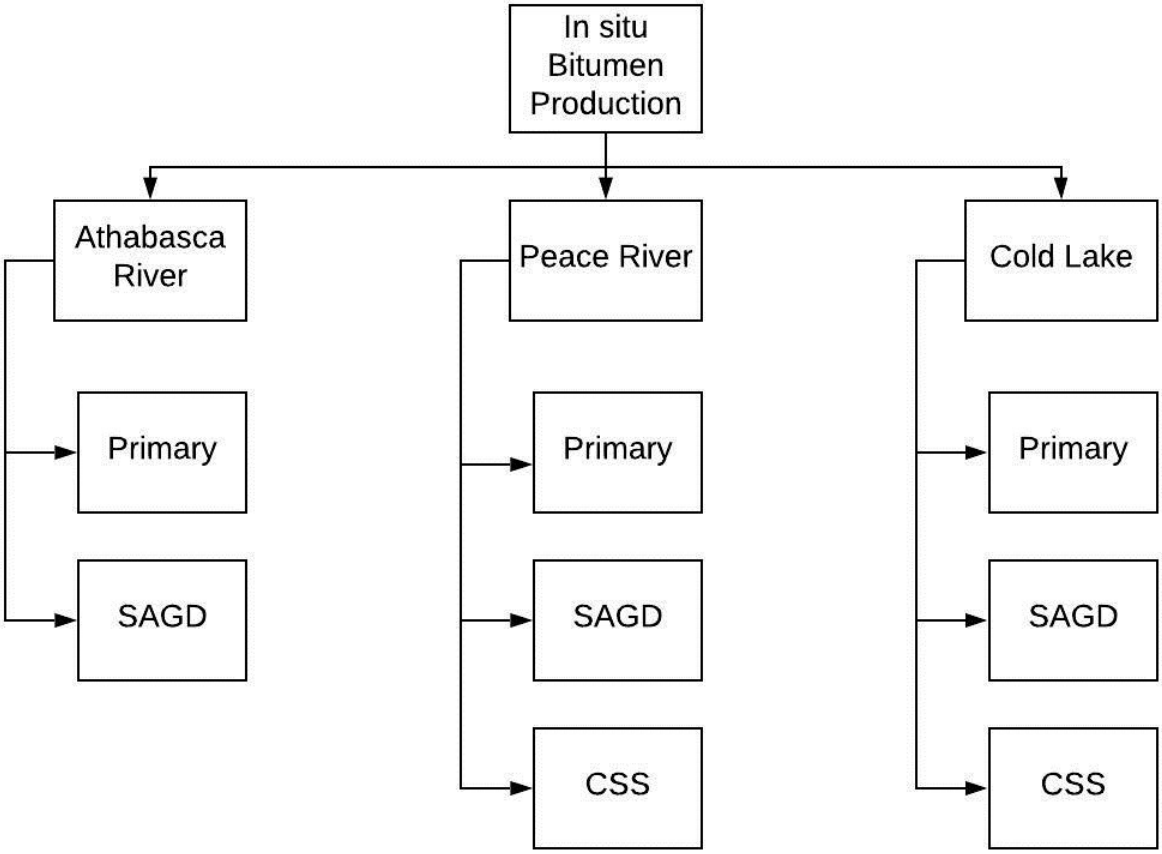

Figure 3-4: Division of production regions for in situ bitumen extraction based on watershed and technology

Distribution of in situ bitumen production based on region and technology =

$$\frac{\text{Total prod in a region from an extraction process}}{\text{Total NEB In situ prod}} \text{ x } 100 \qquad \textbf{3-2}$$

Table 3-4: Distribution of in situ bitumen production for Athabasca river region

Athabasca River	**Regional Production** (133)	**Regional Production**	**SAGD** (134)	**Primary***	**Regional Production**	**SAGD**	**Primary***
Year	1000 m^3/d	(in m^3/yr.)	(in m^3/yr.)	(in m^3/yr.)	%	%	%
2012	87.0	31,755,000	27,902,485	3,852,516	55.3%	48.6%	6.7%
2013	103.5	37,777,500	32,825,127	4,952,373	58.9%	51.1%	7.7%
2014	129.3	47,194,500	41,484,796	5,709,704	64.4%	56.6%	7.8%
2015	143.7	52,437,543	46,962,684	5,474,858	66.4%	59.4%	6.9%

Table 3-5: Distribution of in situ bitumen production for Peace river region

Peace River	**Regional Production** (133)	**Regional Production**	**CSS** (134)	**SAGD** (134)	**Primary***	**Regional Production**	**CSS**	**SAGD**	**Primary***
Year	1000 m^3/d	(in m^3/yr.)	(in m^3/yr.)	(in m^3/yr.)	(in m3/yr.)	%	%	%	%
2012	8.0	2,920,000	447,656	-	2,472,344	5.1%	0.8%	0.0%	4.3%
2013	8.5	3,102,500	292,784	-	2,809,716	4.8%	0.5%	0.0%	4.4%
2014	8.6	3,139,000	307,157	3,305	2,828,538	4.3%	0.4%	0.005%	3.9%
2015	7.4	2,698,336	312,272	20,210	2,365,853	3.4%	0.4%	0.026%	3.0%

Table 3-6: Distribution of in situ bitumen production for Cold Lake region

Cold Lake	**Regional Production** (133)	**Regional Production**	**CSS** (134)	**SAGD** (134)	**Primary***	**Regional Production**	**CSS**	**SAGD**	**Primary***
Year	1000 m^3/d	(in m^3/yr.)	(in m^3/yr.)	(in m^3/yr.)	(in m^3/yr.)	%	%	%	%
2012	62.7	22,885,500	14,655,441	868,425	7,361,634	39.8%	25.5%	1.5%	12.8%
2013	64.2	23,433,000	14,354,188	1,023,308	8,055,504	36.5%	22.4%	1.6%	12.5%
2014	63.3	23,104,500	13,785,442	1,172,419	8,146,639	31.5%	18.8%	1.6%	11.1%
2015	65.8	24,029,848	14,942,815	1,749,536	7,337,497	30.4%	18.9%	2.2%	9.3%

*Estimated based on formula below:

Primary prod = Total regional prod. – CSS prod. – SAGD prod.

The WWIs for primary extraction were obtained from literature (51). SAGD and CSS WWIs were based on the Alberta Energy Regulator's Thermal In Situ (TIS) water publication (AER-TIWP). The AER publishes yearly estimates of freshwater, brackish water, steam injected, water disposal, and bitumen production for all active SAGD and CSS projects (134). We calculated the WWIs for CSS and SAGD with Equation 3-4 for three oil sands regions – Athabasca, Peace, and Cold Lake – for the years 2012-2016. The calculations are shown in Table 3-7, Table 3-8, and Table 3-9.

WWI for bitumen in situ for a region in a given year

$$= \frac{\text{Total freshwater intake} + \text{Total brackish water}}{\text{Total bitumen production}} \quad \textbf{3-3}$$

% Recycle =

$$\frac{\text{Produced in}}{\text{Produced in} + \text{Total disposal}} \quad \textbf{3-4}$$

Future WWIs were assumed to remain constant after 2016 for all regions except Peace River. Table 3-7 shows that the Peace River region has a low recycling rate of 40-50% and is still improving. The WWI will decrease as the recycling rate is assumed to reach the industrial best by 2020.

Table 3-7: Calculation of WWI for an in situ project at the Athabasca river region

Athabasca River (134)	**SAGD**				
	2012	2013	2014	2015	2016
Fresh In (m3)	7,843,599	8,367,728	7,841,563	9,719,778	8,035,252
Total Steam Injected (m3)	78,284,483	93,199,411	111,674,300	124,595,780	138,856,590
Brackish In (m3)	7,116,399	6,810,983	8,039,762	7,704,890	8,615,195
Total Disposal (m3)	10,442,685	12,037,893	13,368,819	13,409,225	14,852,026
Bitumen Production (m3)	27,902,485	32,825,127	41,484,796	46,962,684	51,882,692
Produced In (m3)	74,524,184	91,633,730	110,500,821	119,518,933	135,323,597
Water withdrawal intensity	0.54	0.46	0.38	0.37	0.32
% recycle	88%	88%	89%	90%	90%

Table 3-8: Calculation of WWI for an in situ project at the Peace river region

Peace River (134)	**CSS**					**SAGD**		
	2012	2013	2014	2015	2016	2014	2015	2016
Fresh In (m3)	1,780,212	1,633,445	1,766,914	1,760,420	1,617,955	52,315	122,608	17,609
Total Steam Injected (m3)	1,564,823	1,567,347	1,634,728	1,533,820	1,451,404	37,106	94,726	12,777
Brackish In (m3)	55,737	76,557	101,729	42,822	-	-	-	-
Total Disposal (m3)	1,649,337	1,966,009	1,899,613	1,963,270	2,043,855	36,182	104,602	20,438
Bitumen Production (m3)	447,656	292,784	307,157	312,272	308,583	3,305	20,210	5,953
Produced In (m3)	1,440,037	1,799,458	1,567,561	1,702,536	1,893,793	20,973	76,737	15,596
Water withdrawal intensity	4.10	5.84	6.08	5.77	5.24	15.83	6.07	2.96
% recycle	47%	48%	45%	46%	48%	37%	42%	43%

Table 3-9: Calculation of WWI for an in situ project at the Cold Lake region

Cold Lake	**CSS**				**SAGD**			
(134)	2012	2013	2014	2015	2012	2013	2014	2015
Fresh In (m3)	6,470,427	6,193,250	4,564,707	4,387,548	203,995	254,539	429,900	252,277
Total Steam Injected (m3)	55,558,074	52,010,420	49,835,185	61,492,073	4,949,852	4,971,072	5,711,698	6,545,844
Brackish In (m3)	6,923,292	4,773,943	4,701,865	4,947,828	777,011	397,936	584,599	673,173
Total Disposal (m3)	3,461,665	4,254,100	3,532,922	2,467,831	1,003,700	693,563	1,162,886	898,655
Bitumen Production (m3)	14,655,441	14,354,188	13,785,442	14,942,815	868,425	1,023,308	1,172,419	1,749,536
Produced In (m3)	47,419,034	46,681,150	46,038,589	55,660,290	4,915,526	5,144,506	5,793,184	6,542,187

Water withdrawal intensity	0.91	0.76	0.67	0.62	1.13	0.64	0.87	0.53
% recycle	93%	92%	93%	96%	83%	88%	83%	88%

3.2.2.3 Bitumen upgrading

Extracted bitumen requires upgrading before being fed into the refinery. The output is a mixture of pentanes and hydrocarbon known as synthetic crude oil (SCO) (145). An upgrader requires water for steam generation and cooling. Large amounts of water are consumed in the steam-methane reformer and the cooling towers (158).

Alberta has five bitumen upgraders as of 2016 – Shell Scotford, Suncor Base and Millennium, Syncrude Mildred Lake, and CRNL Horizon – with 1.3 million bbl/d capacity (32). The Nexen Long Lake Upgrader, with 58.5 thousand bbl/d capacity, ceased operation in 2016 (159). All the upgraders are located in the Athabasca watershed near Fort McMurray except Shell Scotford, which is in Fort Saskatchewan near the North Saskatchewan River (32). The production volumes were obtained from the NEB's upgraded bitumen data (20). The WWI and WCP for the upgrader were obtained from literature (51).

3.2.2.4 Conventional crude oil Extraction

Conventional crude oil is extracted by traditional drilling. Oil wells need little water at the start of the production as the oil flow is maintained by the natural pressure of the reservoir. As the pressure falls, the oil wells are injected with a large amount of water (or fluids) to recover the declining productivity. This process is known as water flooding enhanced oil recovery (160).

Conventional oil extraction is done in British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, and Newfoundland and Labrador (20). Production values were taken from the NEB's "Crude Oil Production Conventional Light and Conventional Heavy" data tables (20). The production distribution of oil wells based on watershed sources is shown in Table 3-10 .

Table 3-10: Production shares of conventional oil by extraction region and province

Province	Watershed	Production share	Comment	Ref
BC	Peace	100%		(135)
AB (2014 est.)	Oldman	1%	Used AER PSAC-1 share	(136)
	Bow	26%	Used AER PSAC-2 share	
	S. Saskatchewan	17%	Used AER PSAC-3 share	
	N. Saskatchewan	39%	Used AER PSAC-4 & 5 shares	
	Peace	18%	Used AER PSAC-7 share	
SK (2015 est.)	N. Saskatchewan	30%	Considered Lloydminster prod	(137)
	S. Saskatchewan	32%	Considered Kindersley & Swift Current prod	
	Souris	38%	Considered Estevan prod	
MT	Assiniboine	100%		(161)
ON (2010 est.)	Lake Eerie	100%	Considered Devonian, Salina, Clinton, Ordovician & Cambrian Prod	(138)
NFL	Offshore	100%		(139)

Alberta Energy Regulator (AER) estimates for water withdrawal (total make-up water) of Alberta's wells were used as the WWI for the model, and the calculations are shown in (162).

The WWI for conventional crude oil extraction in a given year =

$$\frac{\text{Total make-up water}}{\text{Hydrocarbon production}} \qquad \textbf{3-5}$$

The WWI was assumed to be constant after 2016. The sector's WCP is 92% (50).

Table 3-11: Conventional oil extraction WWI calculation

Year	Make-up water (m^3) (162)	Hydrocarbon Production (in barrels) (162)	Hydrocarbon Production (m^3)	WWI
2012	24,727,483	205,569,747	32,681,995	0.76
2013	22,385,502	215,906,133	34,325,299	0.65
2014	20,659,081	218,487,566	34,735,702	0.59
2015	19,972,029	208,731,790	33,184,704	0.60
2016	17,518,233	182,792,952	29,060,883	0.60

3.2.2.5 **Natural gas extraction**

Natural gas is extracted through oil and gas wells, coal beds, and shale wells. Natural gas extraction's water intensities depend on the extraction method. The NEB categorized the natural gas into solution, non-associated, tight, shale, and coal-bed methane based on the extraction method (163). Solution or associated gases are the dissolved gases in the oil extracted from the oil wells (164). The water withdrawal associated with solution gas extraction is accounted for in crude oil extraction. Non-associated gases are produced from conventional gas reservoirs (164). Conventional reservoirs contain permeable rocks such as siltstones, sandstones, and carbonate. Gases can be extracted by simple drilling. Reservoirs with lower permeable rocks such as shale plays, coal basins, and tight gas sands are non-conventional (165). Tight and shale gases are found in non-conventional reservoirs and are difficult to obtain. They require advanced extraction techniques such as horizontal drilling and fracking. In fracking, the trapped gases are released by fracturing the rocks by a jet of water (166) and are also considered non-conventional gases. Coal-bed methane (CBM) is a type of non-conventional gas that requires additional production and stimulation. It is found in absorbed form in the coal beds and can be obtained by drilling wells into coal seams (165). Horizontal drilling or fracking may also be used in deep seams (167).

The Western Canadian Sedimentary Basin (parts of British Columbia, Alberta and Saskatchewan) produced 99% of Canada's natural gas in 2017 (168). The rest was from Ontario, Nova Scotia, and New Brunswick and is excluded from the study because there is no available data. The production distribution of the gas wells based on watershed sources is shown in Table 3-12.

Table 3-12: Production shares of natural gas by extraction region and province

Province	**Watershed**	**Production share**	**Comment**	**Ref**
BC (2015 est.)	Peace	95.8%	Considered Montney and Hay river region	(169)
	Liard	1.8%	Considered Liard and Horn river region	
	Unknown	2.4%	Assumed Fraser watershed	
AB (2014 est.)	Oldman	5.7%	Used AER PSAC-1 share	(140)
	Bow	55.0%	Used AER PSAC-2 share	
	S. Saskatchewan	14.4%	Used AER PSAC-3 share	
	N. Saskatchewan	10.2%	Used AER PSAC-4 & 5 shares	
	Athabasca	2.7%	Used AER PSAC-6 share	
	Peace	11.9%	Used AER PSAC-7 share	
SK (2015 est.)	N. Saskatchewan	12%	Considered Lloydminster prod from gas well	(141)
	S. Saskatchewan	88%	Considered Kindersley & Swift Current prod from gas well	
ON	Lake Eerie	100%	Considered Devonian, Salina, Clinton, Ordovician & Cambrian Prod	(138)
NB	St. John	100%	Considered Frederick Brook Shale, Albert county	(142)

The water withdrawal was calculated through Equation 3-6. The well numbers were taken from the NEB's "Natural Gas Drilling" table (163). The hydraulic fracturing water withdrawal is 15,663 m^3/well (170) and is calculated by averaging the water withdrawal of 45,191 US wells. The water withdrawal data for drilling was taken from the Canadian Association of Petroleum Producers' (CAPP's) report "Water Conservation, Efficiency and Productivity Plan Progress Report – Upstream Oil and Gas Sector" (171).

Water withdrawal from well drilling and fracking activity in a given year =

No. of conventional & CBM wells x WWI for drilling + No. of shale & tight portion wells x WWI for fracking **3-6**

The WCP was considered to be 100% as the discharge water from the well (produced water) is either re-used or disposed into disposal wells. Current regulations restrict operators from discharging the produced water into water bodies (166).

3.2.2.6 **Crude oil refining**

A petroleum refinery converts crude oil into useful products such as gasoline, fuel oil, jet fuels, fuel oil, liquefied petroleum gases, lubricants, naphtha, ethane, etc. (172) The refinery requires water for steam generation and cooling purposes. Water is consumed primarily in the steam methane reformer and in cooling towers (158).

Canada had an oil refining capacity of 326 thousand m^3/day in 2018. British Columbia, Alberta, Saskatchewan, Ontario, Quebec, New Brunswick, and Newfoundland & Labrador had refinery capacities of 11, 86, 37, 63, 64, 48, and 18 thousand bbl/day, respectively, in 2018 (39). Canada's refining capacity fell after the Montreal East Refinery in Quebec and the Dartmouth Refinery in Nova Scotia ceased operation in 2010 and 2013, respectively, (33). Capacity is assumed to grow by 0.497% per year from 2019 until 2050.

The volume of crude oil processed was calculated to estimate the total input to the refinery. The volume of crude oil processed in a year is the multiplication of capacity and refinery use. The refinery capacity use is assumed to be 87% and is calculated by taking the average refinery use value from the years 2005-2018 (39). The volume of processed crude oil can be estimated with Equation 3-7. The future refining capacity is assumed to grow at a yearly rate of 0.439% until 2050 for each province and is extrapolated from the historical petroleum refining GDP growth rate for the years 1990-2014 (173).

$$\text{Crude oil processed in a year} = \text{Refinery capacity x Refinery use} \qquad \textbf{3-7}$$

The WWI was calculated using with Equation 3-8 for the years 2005-2015 per m^3 of refinery input from historical water use values from "Water – A Precious Resource" by the Canadian Fuels Association (174) and mentioned in Table 3-13.

The WWI for crude oil refining in a given year =

$$\frac{\text{Total water withdrawn by refineries}}{\text{Refinery input}} \qquad \textbf{3-8}$$

The WCP for crude oil refining in a given year =

$$\frac{\text{Total water withdrawn} - \text{Total water return}}{\text{WWI x Refinery input}} \text{ x } 100 \qquad \textbf{3-9}$$

Future WWIs and WCPs were assumed to equal to the average WCI and WCP from 2005-2015.

Table 3-13: Refinery water withdrawal and consumption intensities' calculation (175)

Year	Water withdrawn (174)	Water released (174)	Production	WWI	WCP
	(in 1000 m^3)	(in 1000 m^3)	(in m^3)	(in m^3/m^3)	(in m^3/m^3)
2005	320,000	300,000	93,474,817	3.42	6%
2006	310,000	275,000	93,474,817	3.32	11%
2007	315,000	300,000	93,474,817	3.37	5%
2008	285,000	255,000	93,474,817	3.05	11%
2009	300,000	270,000	93,474,817	3.21	10%
2010	275,000	260,000	86,281,010	3.19	5%
2011	260,000	250,000	86,281,010	3.01	4%
2012	265,000	230,000	86,281,010	3.07	13%
2013	225,000	210,000	82,304,308	2.73	7%
2014	200,000	190,000	82,304,308	2.43	5%
2015	220,000	195,000	82,304,308	2.67	11%
Avg.				3.04	8%

3.3 Energy demand and supply model

This study used an existing LEAP-Canada energy demand and supply model to estimate GHG emissions from the oil and gas sector. Since this model is not the focus of this work, details about the model can be found in earlier publications by Davis et al. (46) (52). The LEAP-Canada demand and transformation branches for bitumen surface mining, bitumen in situ extraction, bitumen upgrading, conventional crude oil extraction, and natural gas extraction were used for this study.

Since the publication of the LEAP-Canada model(46), oil and gas production data have been updated. The NEB production values for bitumen mining, bitumen in situ, bitumen upgrading, conventional crude oil extraction, and natural gas extraction were updated with the latest available data. Crude oil refining production was updated by taking refinery capacity inputs from CAPP's "Refinery Crude Oil and Oil Sands Mining Upgrader Capacity" data table (39). End-use energy consumption GHG emissions and energy production fugitive GHG emissions were derived from these branches of the LEAP-Canada model and were used in the integrated assessment of water-GHG footprints for the oil and gas sector.

3.4 Scenario analysis

Scenario analysis was carried out by changing production variables from the reference scenario. The production values for bitumen mining, bitumen in situ, bitumen upgrading, and conventional crude oil extraction were modified to create two alternative scenarios with future production levels at lower and higher energy prices than the reference scenario oil price. These production levels are taken from the NEB's "High Price" and "Low Price" data tables (20). Crude oil refining capacity is assumed to remain the same as that of the reference scenario as there is no refining projection available from the NEB. The scenarios, named HIG_PRICE and LOW_PRICE here, used different primary and secondary fuel prices and are described in Table 3-14. Because of the price differences, the NEB demand and supply model predicted growth rates of 1.76%, 1.84%, and 1.58% for the reference, low, and high price cases from 2017-2040 (109). Growth rates determine crude oil production rates; these will be 1.0, 1.5, and 0.6 million m^3 per day (see Bmine_ref, Binsitu_ref, and ConvOil_ref in Figure 3-5) by 2040 in the reference, HIG_PRICE, and LOW_PRICE scenarios, respectively, (109). Gas production will be 593, 755 and 355 million m3 per day (see Figure 3-6) for the respective scenarios in 2040. The production values for 2041-2050 were extrapolated based on the 2035-2040 growth rates.

Table 3-14: Scenario description

Scenario	Description
Reference	The business-as-usual case. The production values are from the NEB reference case. The Brent crude oil price is assumed to reach US$68/bbl (in constant 2016 US$) in 2019 and remain constant to 2021. The price is expected to settle to US$75/bbl by 2027 and remain constant until 2040. The Henry Hub natural gas price is assumed to rise to US$4.16/MMBtu by 2040. The energy price is assumed to increase at an inflation rate of 1.95%. The production values of bitumen, upgraded bitumen and conventional crude oil production are expected to reach 0.71, 0.20, and 0.24 million m^3 per day by 2040 (109).
HIG_PRICE	The production values are from the NEB high price case. High economic growth will be driven by more fossil-fuel production compared to the NEB reference case. Crude oil price is assumed to rise to US$120/bbl by 2024 and remain constant until 2040. The Henry Hub natural gas price is assumed to rise to US$5.26/MMBtu by 2040. High inflation rate of 1.97%. The production values of bitumen, upgraded bitumen and conventional crude oil production are expected to reach 0.85, 0.24, and 0.42 million m^3 per day by 2040 (109).
LOW_PRICE	The production values are from the NEB low price case. This scenario assumes see low economic growth and less fossil fuel production compared to the NEB reference case. Crude oil price is assumed to drop to US$40/bbl by 2023 and remain constant until 2040. The Henry Hub natural gas price is assumed to fall to US$2.15/MMBtu by 2020 and rise to US$2.92 by 2040. Low inflation rate of 1.87%. The production values of bitumen, upgraded bitumen and conventional crude oil production are expected to reach 0.44, 0.18, and 0.08 million m^3 per day by 2040 (109).

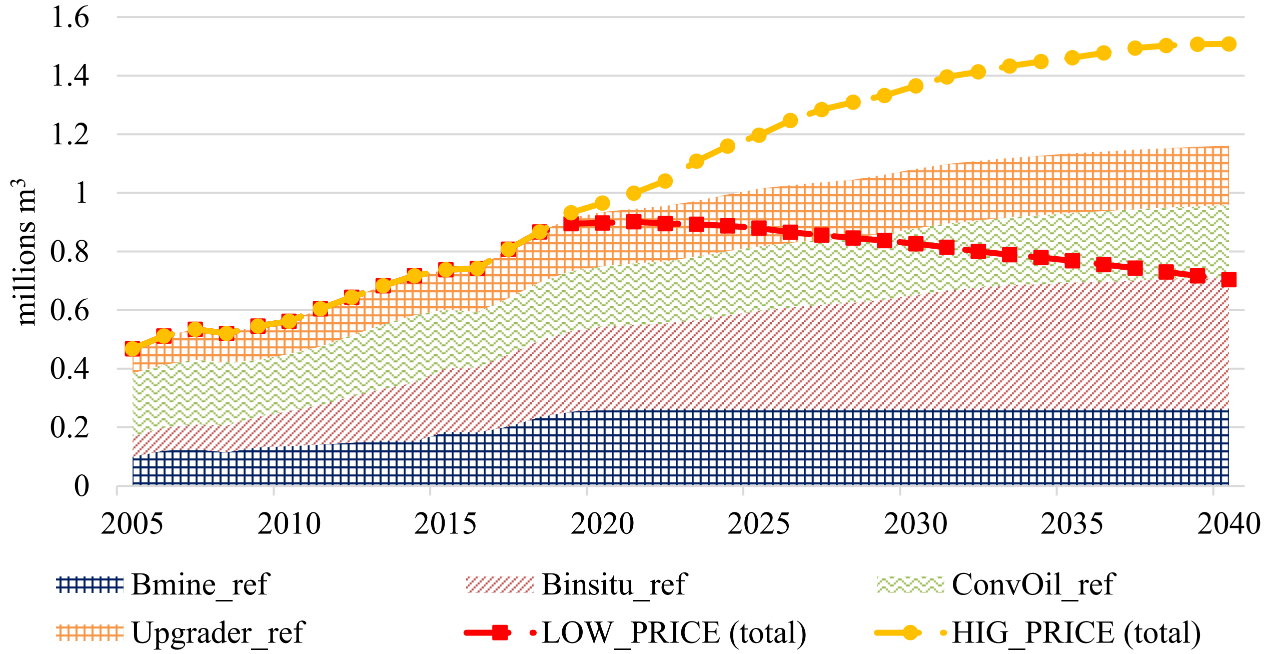

Figure 3-5: Crude oil extraction and upgrading volumes for the three scenarios (data from the NEB [20])

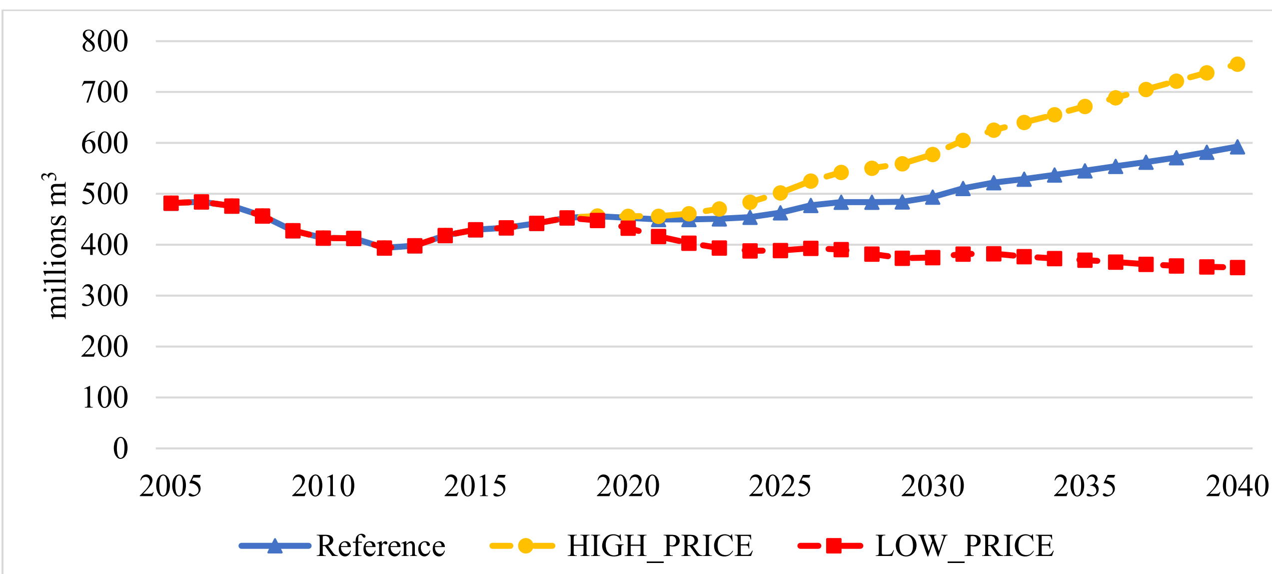

Figure 3-6: Canada's natural gas extraction volumes for the three scenarios (data from the NEB [20])

3.5 Results

3.5.1 **Validation**

Statistics Canada (StatCan) compiles a Biennial Industrial Water Survey and reports the aggregated values of water use for "the production of oil, the mining and extraction of oil from oil shale and oil sands, and the production of gas and hydrocarbon liquids, through gasification, liquefaction and pyrolysis of coal at the mine site" (176). This aggregated water use data includes sectors that are not considered in WEAP-COG model. Thus, the water withdrawal figure for the WEAP-COG upstream oil and gas sector is lower than the StatCan value. Moreover, there is uncertainty about whether the water use associated with upgraders and refineries is included in the reported value and whether the survey includes 100% of the oil and gas projects; hence, the StatCan survey is not used for validation.

Instead, CAPP's (171) reported values are used to compare the water withdrawal associated with bitumen mining, bitumen in situ, and conventional crude oil extraction (upstream oil sector). Figure 3-7 shows that the WEAP-COG model's water withdrawal values are under 10% compared to CAPP's values from 2005-2014 except in 2007 and 2008. In 2007 and 2008, CAPP shows 14% lower and 17% higher water withdrawals than the WEAP-COP model. In 2007, CAPP reported 25% less water withdrawal in the bitumen in situ sector; this is the primary reason for the model's overall deviation from the CAPP value. The bitumen in situ sector used the earliest available (2010) water withdrawal intensity for the 2007 water withdrawal calculations. In 2008, CAPP reported 37% more water withdrawal in the bitumen mining sector; this is the primary reason for the model's overall deviation from the CAPP value. The bitumen mining sector used the earliest available (2010) water withdrawal intensity for the 2008 water withdrawal calculations. The water withdrawal intensity difference between the model and CAPP's values could be the reason for the water withdrawal mismatch. The water consumption values are 100% of the water withdrawal for all the sectors considered in the validation except for conventional oil extraction, which has slightly lower water consumption than withdrawal. The water consumption values are not validated, given that they are almost equal to the water withdrawal values.

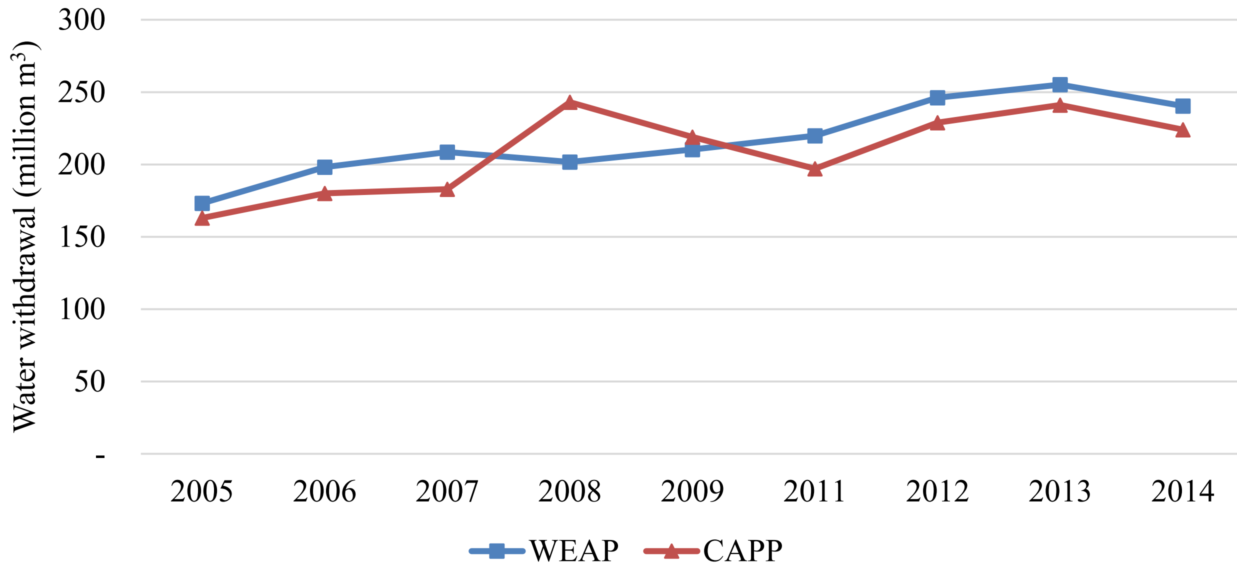

Figure 3-7: Water withdrawal validation

3.5.2 Reference scenario results

3.5.2.1 GHG emissions

GHG emissions from the oil and gas sector are projected to be 257 million tonnes of CO_{2e} by 2050, an increase of 80% from 2005 based on the LEAP-Canada model. The GHG emissions' shares of bitumen mining, bitumen in situ, bitumen upgrading, conventional crude oil extraction, natural gas extraction and crude oil refining were 4%, 7%, 6%, 15%, 54%, and 15% in 2005. The GHG emissions in these sectors is projected to change by 163%, 646%, 237%, 45%, 22%, and -15% by 2050. The GHG emissions' shares of British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, New Brunswick, Nova Scotia, and Newfoundland and Labrador were 9%, 59%, 18%, 0%, 5%, 3%, 2%, 1%, and 3% in 2005. The GHG emissions for these provinces is projected to change to 190%, 113%, 15%, 33%, -69%, -57%, 33%, -100%, and -79% by 2050 based on the results from the LEAP-Canada model.

The change in production values is the driver for changes in emissions in each sector. The production of bitumen mining, bitumen in situ, bitumen upgrading, conventional crude oil extraction, natural gas extraction, and crude oil refining is projected to increase 86%, 62%, 59%, 21%, 43%, and 27% by 2050. All the bitumen extraction activities are in Alberta and thus, Alberta is expected to have the highest change in GHG emissions because of the increase in bitumen extraction based the results from the LEAP-Canada model. The GHG emissions is also expected to increase in British Columbia, Saskatchewan, and Manitoba, because of the increase in oil and gas activity. The GHG emissions from Ontario and Nova Scotia, where the refineries are the major emitters, are projected to reduce because of decrease in GHG emissions intensity from refineries. The GHG emissions from the natural gas extraction is not included in the results for Nova Scotia and Newfoundland and Labrador. The GHG emissions from New Brunswick, where the refineries are the major emitters, are projected to increase because of increase in refining activity despite decrease in GHG emissions intensity from refineries. The shut-down of oil extraction activity would reduce GHG emissions in Newfoundland and Labrador.

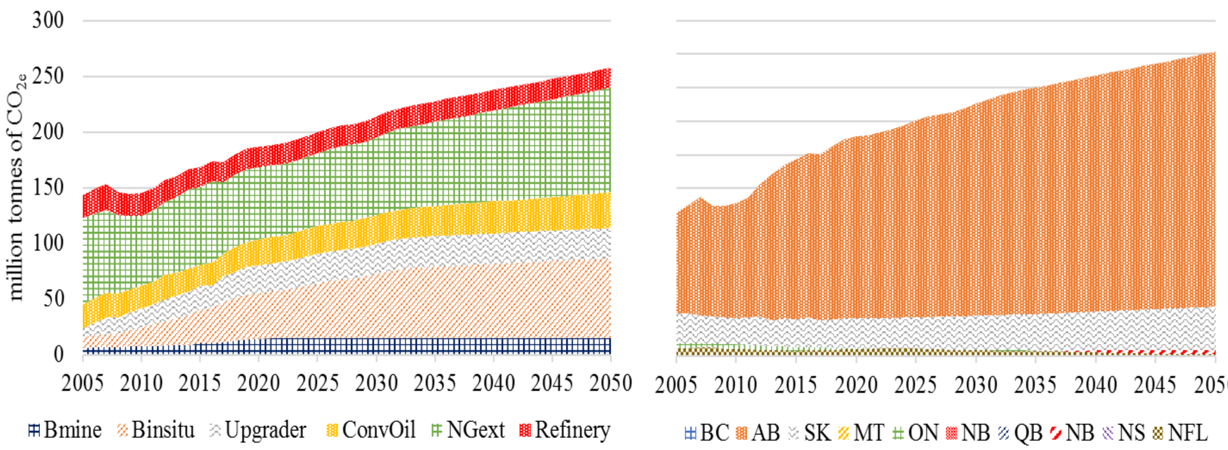

Figure 3-8: GHG emissions by sector (left) and by province (right) based on results from LEAP-Canada model

3.5.2.2 **Water withdrawal**

The water withdrawal from the oil and gas sector is expected to be 794 million m^3 by 2050, an increase of 21% from 2005 as projected by the WEAP-COG model. The withdrawal shares of bitumen mining, bitumen in situ, bitumen upgrading, conventional crude oil extraction, natural gas extraction, and crude oil refining were 14%, 3%, 4%, 9%, 16%, and 54% in 2005. The water withdrawals for the respective sector is projected to change by 101%, 358%, 144%, 1%, -73%, and 4% by 2050. The water withdrawal shares of British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, New Brunswick Nova Scotia and Newfoundland and Labrador were 3%, 50%, 8%, 0%, 11%, 13%, 7%, 2%, and 5% in 2005. The water withdrawals for respective province is projected to change to 29%, 46%, 28%, 6%, -1%, -18%, 16%, -100%. -37%, and 21% by 2050 as obtained from the WEAP-COG model.

The increase in water withdrawal corresponds to the change in production values. The percentage increase of bitumen and oil production values are given in Section 3.5.2.1. Natural gas extraction is the only sector in which water withdrawal is expected to decrease despite production increase. The water withdrawal for the natural gas extraction sector depends on the number of wells drilled in a given year, not the gas production. Natural gas production is observed to increase because of the accumulation of gas producing wells over the years despite a decrease in drilling activity. Water withdrawals in British Columbia, Alberta, and Saskatchewan is expected to increase because of the increase in oil activity. Water withdrawals in Ontario is expected to decrease, despite an increase in refinery activity, due to a decrease in water withdrawal intensity in the refinery. Water withdrawal is expected to increase in New Brunswick, despite improvements in the water withdrawal intensity because of the increase in refinery activity. Water withdrawals in Quebec and Nova Scotia would decrease because of refinery closures. The shut-down of oil extraction activity would reduce water withdrawal in Newfoundland and Labrador.

Water withdrawals from three highly allocated watersheds – the North Saskatchewan, the South Saskatchewan, and the Athabasca – were also analyzed from 2005-2050. The water withdrawals from the North Saskatchewan and Athabasca is projected to increase 16% and 126% by 2050 because of the increase in oil activity. But the water withdrawal from the South Saskatchewan watershed is projected to decrease 56% by 2050 because of the reduction in gas well drilling activity.

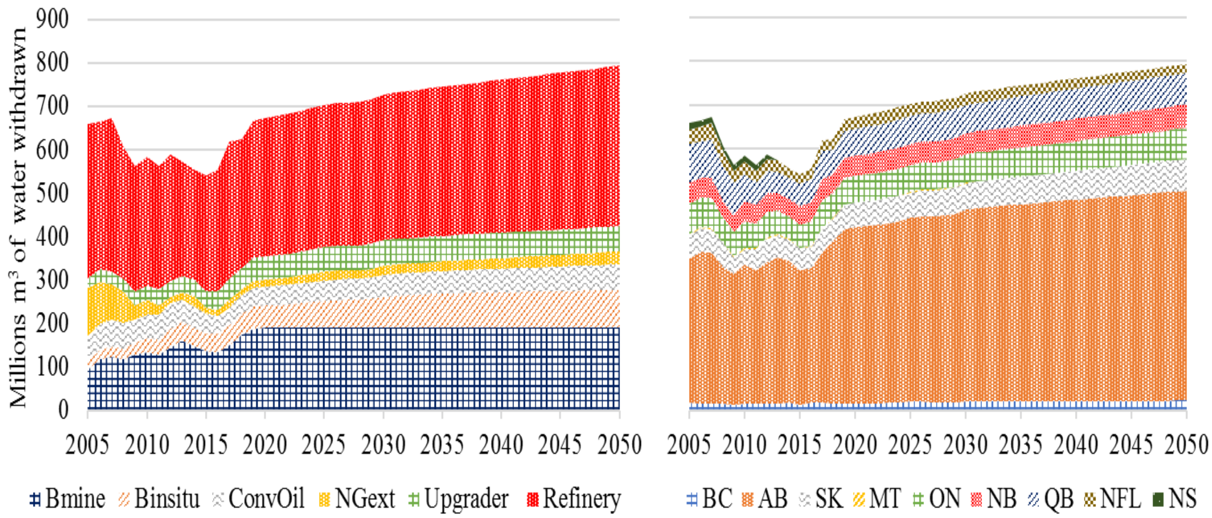

Figure 3-9: Water withdrawal by sector (left) and by province (right) based on results from the WEAP-COG model

3.5.2.3 Water consumption

Water consumption from the oil and gas sector is projected to be 441 million m^3 by 2050, an increase of 39% from 2005. The consumption shares of bitumen mining, bitumen in situ, bitumen upgrading, conventional crude oil extraction, natural gas extraction, and crude oil refining were 30%, 6%, 6%, 17%, 34%, and 7% in 2005. Water consumption for the respective sectors is projected to change by 101%, 358%, 144%, 1%, -73%, and 39% by 2050 as projected by the WEAP-COG model. The consumption shares of British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, New Brunswick, Nova Scotia, and Newfoundland and Labrador were 2%, 78%, 12%, 0%, 1%, 2%, 1%, 0%, and 4% in 2005. Water consumption for the respective provinces is projected to change to 78%, 54%, -19%, 6%, 30%, 9%, 54%, -100%, and -88% by 2050.

The increase in water consumption corresponds to the change in production values. Natural gas extraction is the only sector in which water consumption is expected to decrease despite a production increase; the reasons behind this are given in Section 3.5.2.2. Water consumption in British Columbia, Alberta, and Manitoba is expected to increase because of the increase in oil activity. Ontario's, Quebec's, and New Brunswick's water consumption is expected to increase because of slight increase in water consumption intensity. In Saskatchewan, despite the increase in oil production, because of the decrease in gas well drilling activity. There has been no refining water consumption in Nova Scotia since the refinery closed in 2013. The shut-down of oil extraction activity would reduce water consumption in Newfoundland and Labrador.

Water consumption from the North Saskatchewan, South Saskatchewan, and Athabasca watersheds were also analyzed. Water consumption from the North Saskatchewan and Athabasca watersheds is projected to increase by 10% and 126% by 2050 because of the increase in oil activity. But water consumption from the South Saskatchewan watershed is projected to decrease by 56% by 2050 because of the reduction in gas drilling activity.

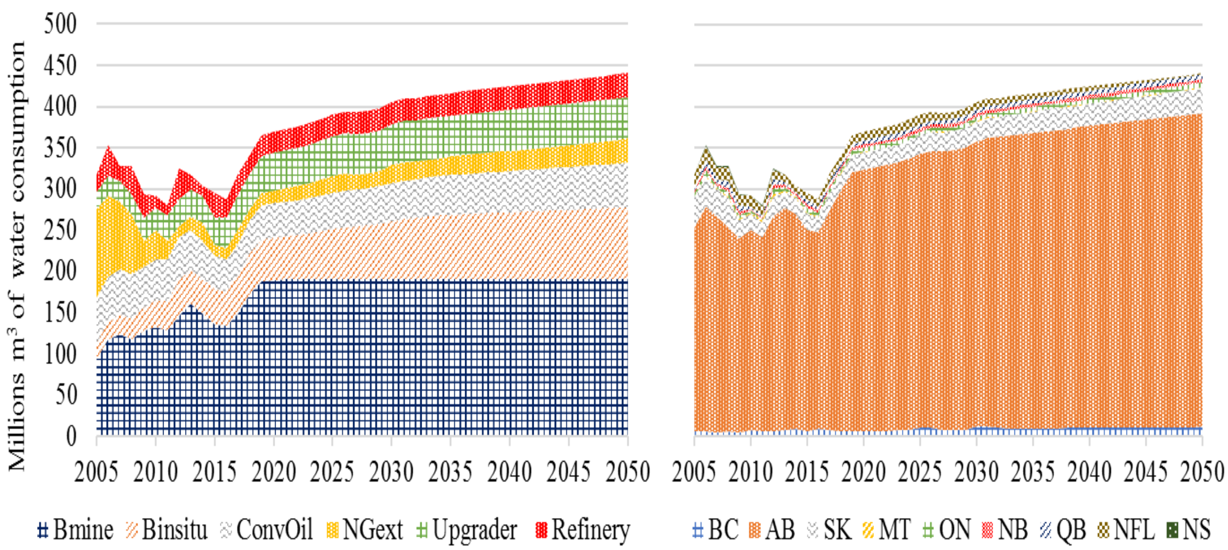

Figure 3-10: Water consumption by sector (left) and by province (right) based on results from the WEAP-COG model

3.5.3 Scenarios results

3.5.3.1 HIG_PRICE

Under the HIG_PRICE scenario, GHG emissions is projected to be 336 million tonnes of CO_{2e} by 2050 as projected by the LEAP-Canada model, an increase of 135% from 2005. Cumulative GHG emissions is projected to be 23% higher than the reference scenario's from 2019-2050. Cumulative

GHG emissions from bitumen mining, bitumen in situ, bitumen upgrading, conventional crude oil extraction, natural gas extraction, and crude oil refining is projected to be 12%, 22%, 16%, 54%, 22%, and 0% more than the reference scenario's from 2019-2050. Cumulative GHG emissions in British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, New Brunswick, Nova Scotia, and Newfoundland and Labrador is projected to be 16%, 22%, 42%, 54%, 0%, 0%, 0%, 0%, and 23% more than reference scenario's from 2019-2050 based on the LEAP-Canada model.

The higher emissions in the HIG_PRICE scenario are due to the increase in oil and gas activity. The bitumen mining, bitumen in situ, bitumen upgrading, conventional crude oil extraction, natural gas extraction, and crude oil refining sectors is projected to have 14%, 27%, 19%, 65%, 34%, and 0% more activity than the reference scenario will by 2050. The conventional crude oil extraction sector is projected to have the highest percentage change in GHG emissions. The GHG emissions from the crude oil refining sector would not change because this sector has no change in activity from the reference scenario. The GHG emissions from Ontario, Quebec, New Brunswick, and Nova Scotia, where the refineries are the major emitters, would remain the same.

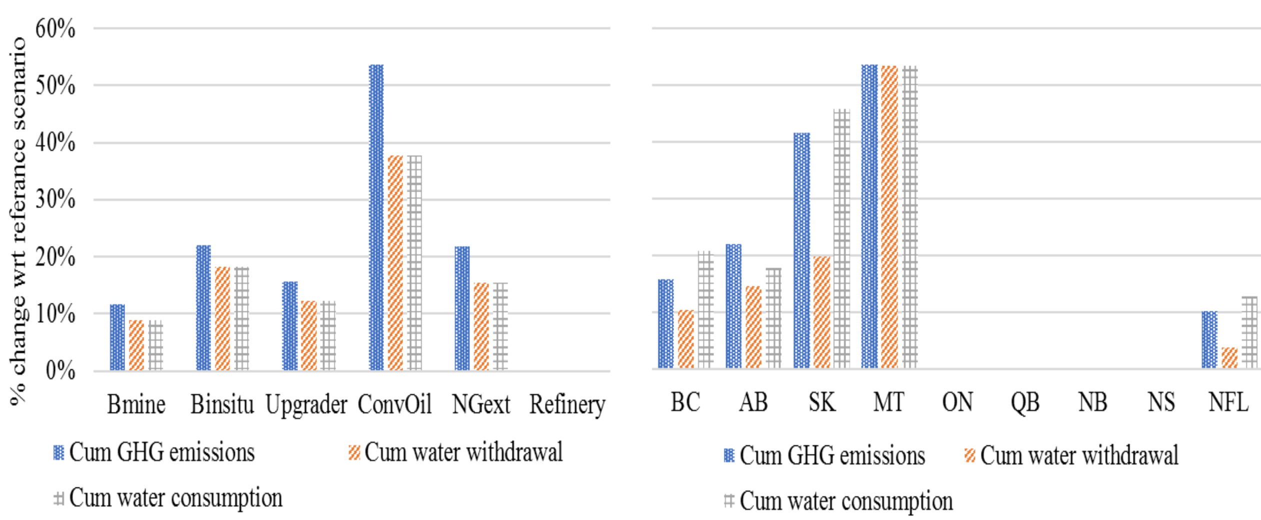

Figure 3-11: Percentage change of parameters with respect to reference scenario by sector (left) and by province (right) in the HIG_PRICE scenario based on developed LEAP-Canada and WEAP-COG models

Under the HIG_PRICE scenario, water withdrawal is projected to be 905 million m^3 by 2050, an increase of 37% from 2005. Cumulative water withdrawal is projected to be 11% higher than the reference scenario's from 2019-2050 based on WEAP-COG model. Cumulative water withdrawals from the bitumen mining, bitumen in situ, bitumen upgrading, conventional crude oil extraction, natural gas extraction, and crude oil refining sectors is projected to be 9%, 18%, 22%, 38%, 15%, and 0% more than the reference scenario's from 2019-2050. Cumulative water withdrawals in British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, New Brunswick, Nova Scotia, and Newfoundland and Labrador is projected to be 10%, 15%, 20%, 54%, 0%, 0%, 0%, 0%, and 4% more than the reference scenario's from 2019-2050 as projected by WEAP-COG model.

The increase in water withdrawal corresponds to an increase in production values. The percentage increase of bitumen and oil production values are mentioned in Section 3.5.3.1.1. The percentage increase in cumulative GHG emissions is expected to be more than the percentage increase in water withdrawals for the same production percentage increase. In terms of absolute value as well as percentage change, the conventional crude oil extraction sector is expected to have the highest cumulative change in water withdrawal compared to other sectors. The crude oil extraction activity is expected to be more than double in Alberta, Saskatchewan, and Manitoba, which would drive the high-water withdrawal. The increase in crude oil extraction would also increase the water withdrawal in British Columbia and Newfoundland and Labrador.

Under the HIG_PRICE scenario, water consumption is projected to be 547 million m^3 by 2050, an increase of 72% from 2005. Cumulative water consumption is projected to be 19% more than the reference scenario's from 2019-2050 as projected by WEAP-COG model. Cumulative water consumption from the bitumen mining, bitumen in situ, bitumen upgrading, conventional crude oil extraction, natural gas extraction, and crude oil refining sectors is projected to be 9%, 18%, 12%, 38%, 15%, and 0% more than the reference scenario's from 2019-2050. Cumulative water consumption in British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, New Brunswick, Nova Scotia. And Newfoundland and Labrador are projected to be 21%, 18%, 46%, 54%, 0%, 0%, 0%, 0%, and 13% more than reference scenario's from 2019-2050 as projected by WEAP-COG model.

In terms of absolute value as well as percentage change, the conventional crude oil extraction sector is expected to have the highest cumulative change in water consumption compared to other sectors. The increase in crude oil extraction activity would be responsible for the increase in water consumption in British Columbia, Alberta, Saskatchewan, Manitoba, and Newfoundland and Labrador.

3.5.3.2 **LOW_PRICE**

Under the LOW_PRICE scenario, the GHG emissions is projected to be 123 million tonnes of CO_{2e} by 2050, a decrease of 14% from 2005 as projected by the LEAP-Canada model. Cumulative GHG emissions is projected to be 31% less than the reference scenario's from 2019-2050. Cumulative GHG emissions from the bitumen mining, bitumen in situ, bitumen upgrading, conventional crude oil extraction, natural gas extraction, and crude oil refining sectors is projected to be 7%, 44%, 9%, 51%, 33%, and 0% less than the reference scenario's from 2019-2050. Cumulative GHG emissions in British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, New Brunswick, Nova Scotia, and Newfoundland and Labrador is projected to be 25%, 32%, 41%, 52%, 0%, 0%, 0%, 0%, and 16% less than the reference scenario's from 2019-2050 based on results from the LEAP-Canada model..

Under the LOW_PRICE scenario, fewer GHGs would be emitted than in the reference scenario's because of the decrease in oil and gas activity. The bitumen mining, bitumen in situ, bitumen upgrading, conventional crude oil extraction, natural gas extraction, and crude oil refining sectors is projected to have 16%, 74%, 14%, 80%, 53%, and 0% less activity than the reference scenario in 2050. The conventional crude oil extraction is expected to have the highest cumulative GHG emissions change from the reference scenario's because of the more than two-fold decrease in crude oil extraction. The bitumen in situ sector is expected to have the highest absolute change in cumulative GHG emissions and is affected the most because of lower crude oil prices. Significant GHG emissions' reduction from the bitumen in situ, conventional crude oil extraction, and natural gas extraction sectors would give higher cumulative GHG emissions savings to Alberta than any other province. GHG emissions from the other provinces is also expected to decrease compared to the reference scenario because of the decrease in crude oil extraction.

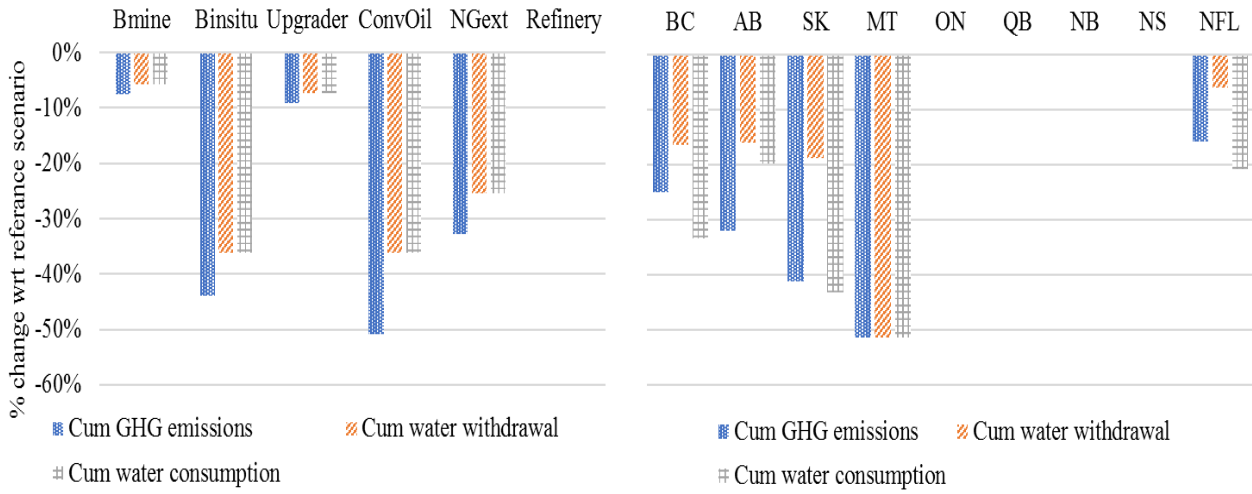

Figure 3-12: Percentage change of parameters with respect to the reference scenario by sector (left) and by province (right) in the LOW_PRICE scenario based on developed LEAP-Canada and WEAP-COG models

Under the LOW_PRICE scenario, water withdrawal is projected to be 605 million m^3 by 2050, a decrease of 3% from 2005 as projected by the WEAP-COG model. Cumulative water withdrawal is projected to be 15% less than the reference scenario's from 2019-2050. Cumulative water withdrawals from the bitumen mining, bitumen in situ, bitumen upgrading, conventional crude oil extraction, natural gas extraction and crude oil refining sectors is projected to be 6%, 36%, 7%, 36%, 25%, and 0% less than the reference scenario's from 2019-2050. Cumulative water withdrawals in British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, New Brunswick, Nova Scotia, and Newfoundland and Labrador is projected to be 17%, 16%, 19%, 52%, 0%, 0%, 0%, 0%, and 6% less than the reference scenario's from 2019-2050 2050 based on the WEAP-COG model.

The decrease in water withdrawal corresponds to the decrease in production values. The percentage decrease of bitumen and oil production values are given in Section 3.5.3.2.1. In terms of absolute values as well as percentage change, the conventional crude oil extraction sector is expected to have the highest change in cumulative water withdrawal. The crude oil extraction activity is expected to decrease by more than two-fold in Alberta, Saskatchewan, and Manitoba, and this would reduce water withdrawal. The decrease in water withdrawals in British Columbia and Newfoundland and Labrador is also because of the decrease in crude oil extraction.

Under the LOW_PRICE scenario, water consumption is projected to be 278 million m^3 by 2050, a decrease of 13% from 2005 as projected by the WEAP-COG model. Cumulative water consumption is projected to be 21% less than the reference scenario's from 2019-2050. Cumulative water consumption from the bitumen mining, bitumen in situ, bitumen upgrading, conventional crude oil extraction, natural gas extraction and crude oil refining sectors is projected to be 6%, 36%, 7%, 36%, 25%, and 0% less than the reference scenario's from 2019-2050 based on results from the WEAP-COG model. Cumulative water consumption in British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, New Brunswick, Nova Scotia, and Newfoundland and Labrador is projected to be 33%, 20%, 43%, 52%, 0%, 0%, 0%, 0%, and 21% less than the reference scenario's from 2019-2050. The decrease in water consumption corresponds to a decrease in production values and is discussed in Section 3.5.2.

In terms of absolute value as well as percentage change, the bitumen in situ sector is expected to have the highest change in cumulative water consumption. Since all the bitumen extraction projects are in Alberta, the province's water consumption would decrease significantly. The decrease in crude oil extraction activity would be responsible for the decrease in water consumption in other provinces.

4 Conclusion and recommendations

4.1 Conclusion

As a significant source of GHG emissions, the energy sector needs to adopt clean energy technologies in order to meet Canada's NDC target by 2030. The integration of new technologies will impact the sector's water use. The quantification of water use and GHG footprints is essential to understand the water-GHG footprint trade-off in the changing energy sector. This research estimated the electricity generation and oil and gas sector water use and GHG footprints at regional and provincial levels in Canada through the development of integrated LEAP-WEAP model. The results are summarized in Table 4-1. Different energy scenarios were analyzed, and it can be concluded that there are minimal trade-offs associated with clean energy transition.

Table 4-1: Summary of GHG emissions and water consumption for the electricity generation sector and oil and gas sector

Sector	GHG emissions in 2005 (million tonnes of CO_{2e})	GHG emissions in 2050 (million tonnes of CO_{2e})	Water consumption in 2005 (million m^3)	Water consumption in 2050 (million m^3)
Electricity generation sector	110.47	41.69	4,803.06	5,770.65
Oil & gas sector – Bitumen extraction and upgrading	23.29	113.84	134.38	327.78
Oil & gas sector – Conventional crude oil extraction & refining	43.14	49.84	75.63	84.25
Oil & gas sector – Natural gas extraction	77.16	94.12	108.05	29.00

Table 4-1 shows that GHG emissions is expected to decrease in the electricity generation sector and increase in the oil and gas sector. The electricity generation sector would adopt clean energy technologies faster than the oil and gas sector because of provincial clean electricity generation targets and decreasing cost of wind and solar generation. Similar renewable integration targets are required in the oil and gas sector, specifically in bitumen extraction and upgrading. Water consumption is expected to remain high in both sectors. This suggests that water could still play a critical role in Canada's future energy industry.

The decarbonization of the electricity generation sector is an international concern because of climate change. The water footprints associated with decarbonizing electricity generation have not been widely considered and require quantification to identify trade-offs that greenhouse gas emissions' reduction may have with water use. This research developed an integrated electricity generation and water use model to estimate the future water use and GHG footprint of Canada's electricity generation to 2050. The water impacts, cost, and GHG emissions of the deep decarbonization scenarios were also determined.

Canada can achieve 100% carbon-free generation with an increase in water consumption (3.6% more than the current policy scenario). With a small marginal GHG abatement cost of $23/tonnes of CO_{2e} compared to the current policy scenario, fossil-fuel plants can be displaced with renewables. Wind power could play an important role in Canada's decarbonization transition not only because it has a low net present value but also because high wind additions will decrease the national water footprint through fossil displacement. The carbon price mechanism is no longer required to improve the competitiveness of wind over fossil-fuel plants. However, wind can only be integrated in limited amounts because of environmental factors and grid integration challenges. Hydro could be required in addition to wind power to achieve high levels of decarbonization. Our analysis also shows that hydro plants will be responsible for most of the future water consumption with high decarbonization. Solar, like wind, has a low water footprint, but is relatively costly and thus requires incentives for penetration. Innovations in storage technology, grid capabilities, and further cost reductions could enable non-hydro technologies to penetrate more. But until then, Canada's high renewable transition could have a slight trade-off with water consumption.

The research also developed an oil and gas water use model to estimate future water use in Canada to 2050. Water use and GHG emissions in the NEB's high and low price scenarios were investigated. The increase in production volume increases GHG emissions, water withdrawal, and water consumption in the oil and gas sector. The high price for crude oil increases bitumen, crude oil, and gas production compared to the reference scenario but comes at the expense of high GHG emissions, water withdrawal, and water consumption. Low oil and gas prices would reduce oil and gas activity and this, in turn, would reduce GHG emissions and water withdrawal and consumption.

The high GHG emissions in the reference and HIG_PRICE scenarios are expected to impede Canada's ability to achieve the NDC emissions' target by 2030. Further, the high water use in the reference and HIG_PRICE scenarios is not effective for the country's sustainable development. Canada should adopt clean and less water-consuming energy technologies in order to achieve the NDC emissions' target without exploiting water resources.

This research adopted a holistic approach to study GHG emissions and water use in the electricity sector and the oil and gas sector that included geographical and technological details. The approach fulfils the objective to incorporate water use implications in clean energy assessments. The developed model and the results of this study provide new knowledge about the co-benefits and trade-offs of water use and GHG emissions' mitigation that can help inform government/industry as they develop sustainable policies.

4.2 Recommendations for future research

Given the technology improvements in both the electricity generation and the oil and gas sectors, this study did not assume any changes in water intensities. Forecasting water use intensity for a technology is challenging because water use intensity is mostly driven by technological improvements, which are unknown. It is recommended that a study be developed on future water intensities for a technology or a process to improve the model's ability to predict water use.

The scope of the study could be extended by modeling more sectors. The study did not use the full functionality of WEAP. The degree of future water stress in the watersheds can be estimated in WEAP based on the total water withdrawn by all sectors from the source and its supply capability. Since this study is limited to two sectors, water stress cannot be accurately predicted. Adding other sectors can improve the model's ability to forecast future water stress areas.

With respect to electricity generation models, the study did not consider changes in generation cost from technological improvements in a natural gas or biomass unit. Since capacity addition is cost-driven, the cost variation could change the generation mix. The capacity addition depends on capacity constraints such as maximum capacity addition, minimum capacity, minimum addition size, and maximum availability. The selected values in the model are based on historical trends and the authors' best estimates.

The scenarios analysis in the oil and gas sector considered only three energy scenarios. It is recommended that clean energy technologies be analyzed in order to identify the water impacts of GHG mitigation scenarios. GHG mitigation scenarios with different GHG emissions targets could help understand the clean energy technologies' penetrations and give better insights into the effects of the oil and gas sector's clean energy transition.

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Appendix

A.1 Power plant database

This section gives the details of 530 power plants used to calculate the aggregate capacity by technology for provinces in LEAP-Canada model. The database is also used to estimate the share of capacity by technology withdrawing water from a watershed in WEAP-Canada model.

Table A- 1: Powerplant database

Power plant	MW	Watershed	Fuel/type	Sub-type	Province	Commencement year
Burrard Generating Station	950	Fraser river	Natural gas	NGCC	BC	1961
Fort Nelson Generating Station	73	Liard river	Natural gas	NGCC	BC	1999
Island Generating Station	275	Campbell	Natural gas	Cogen	BC	2002
McMahon Cogeneration Plant	120	Peace river	Natural gas	Cogen	BC	1993
Prince Rupert Generating Station	46	Skeena river	Natural gas	Simple	BC	1975
Furry Creek	11	Campbell	Hydro	Reservoir	BC	NA
John Hart Dam	126	Campbell	Hydro	Reservoir	BC	NA
Ladore Falls	47	Campbell	Hydro	Reservoir	BC	NA
Lois Lake	37	Campbell	Hydro	Reservoir	BC	NA
Malibu Hydro	1	Campbell	Hydro	Reservoir	BC	NA
Puntledge	24	Campbell	Hydro	Reservoir	BC	NA
Strathcona	64	Campbell	Hydro	Reservoir	BC	NA
Akolkolex	10	Columbia	Hydro	ROR	BC	NA
Eldorado Reservoir	1	Columbia	Hydro	Reservoir	BC	NA
Mica Dam	2800	Columbia	Hydro	Reservoir	BC	NA

Pingston Creek	45	Columbia	Hydro	Reservoir	BC	NA
Revelstoke Dam	2480	Columbia	Hydro	Reservoir	BC	NA
Seven Mile Dam	805	Columbia	Hydro	Reservoir	BC	NA
Shuswap River	6	Columbia	Hydro	Reservoir	BC	NA
South Cranberry Creek	9	Columbia	Hydro	Reservoir	BC	NA
Walter Hardman	8	Columbia	Hydro	Reservoir	BC	NA
Waneta Dam	490	Columbia	Hydro	Reservoir	BC	NA
Whatshan Dam	54	Columbia	Hydro	Reservoir	BC	NA
Arrow Lakes/Keenleyside Dam	185	Columbia	Hydro	Reservoir	BC	NA
Alouette Lake	9	Fraser	Hydro	Reservoir	BC	NA
Ashlu Creek	50	Fraser	Hydro	ROR	BC	NA
bear Creek	20	Fraser	Hydro	ROR	BC	NA
Bone Creek	19	Fraser	Hydro	ROR	BC	NA
Boston Bar Hydro (Scuzzy Creek)	6	Fraser	Hydro	ROR	BC	NA
Brandywine Creek	8	Fraser	Hydro	Reservoir	BC	NA
Bridge River Power Project	478	Fraser	Hydro	Reservoir	BC	NA
Buntzen Lake	73	Fraser	Hydro	Reservoir	BC	NA
Castle Creek	8	Fraser	Hydro	ROR	BC	NA
Cheakamus	158	Fraser	Hydro	Reservoir	BC	NA
Clowhom Dam	33	Fraser	Hydro	Reservoir	BC	NA
Douglas Creek (Kwalsa Energy)	28	Fraser	Hydro	ROR	BC	NA
Eagle Lake Micro Hydro	0	Fraser	Hydro	Reservoir	BC	NA
East Toba	123	Fraser	Hydro	Reservoir	BC	NA
East Twin	2	Fraser	Hydro	ROR	BC	NA
Eldorado Reservoir	1	Fraser	Hydro	Reservoir	BC	NA
Fire Creek	25	Fraser	Hydro	ROR	BC	NA
Fitzsimmons Creek	8	Fraser	Hydro	ROR	BC	NA
Hauer Creek (aka Tete)	3	Fraser	Hydro	Reservoir	BC	NA

Hystad Creek	6	Fraser	Hydro	Reservoir	BC	NA
Jamie Creek	22	Fraser	Hydro	ROR	BC	NA
Lajoie Dam	25	Fraser	Hydro	Reservoir	BC	NA
Lamont Creek	28	Fraser	Hydro	ROR	BC	NA
Lower Clowhom	11	Fraser	Hydro	Reservoir	BC	NA
Mamquam Hydro	52	Fraser	Hydro	ROR	BC	NA
McNair Creek Hydro	10	Fraser	Hydro	Reservoir	BC	NA
Miller Creek	33	Fraser	Hydro	ROR	BC	NA
Montrose Creek	73	Fraser	Hydro	Reservoir	BC	NA
Morehead Creek	0	Fraser	Hydro	Reservoir	BC	NA
Northwest Stave River	18	Fraser	Hydro	ROR	BC	NA
Powell Lake	46	Fraser	Hydro	Reservoir	BC	NA
Ruskin Dam	105	Fraser	Hydro	Reservoir	BC	NA
Rutherford Creek	50	Fraser	Hydro	ROR	BC	NA
Sakwi Creek	6	Fraser	Hydro	ROR	BC	NA
Sechelt Creek (Salmon Inlet)	17	Fraser	Hydro	Reservoir	BC	NA
Seton Powerhouse	48	Fraser	Hydro	Reservoir	BC	NA
Soo River	14	Fraser	Hydro	Reservoir	BC	NA
Stave Falls Dam	91	Fraser	Hydro	Reservoir	BC	NA
Stokke Creek (Kwalsa Energy)	21	Fraser	Hydro	ROR	BC	NA
Tipella Creek (Kwalsa Energy)	17	Fraser	Hydro	ROR	BC	NA
Trethaway Creek	21	Fraser	Hydro	ROR	BC	NA
Tyson Creek Hydro	9	Fraser	Hydro	Reservoir	BC	NA
Upper Clowhom	11	Fraser	Hydro	Reservoir	BC	NA
Upper Mamquam	25	Fraser	Hydro	ROR	BC	NA
Upper Stave River	34	Fraser	Hydro	ROR	BC	NA
Wahleach Lake	63	Fraser	Hydro	Reservoir	BC	NA
Walden North	18	Fraser	Hydro	Reservoir	BC	NA

Woodfibre Dam	3	Fraser	Hydro	Reservoir	BC	NA
Barr creek	4	Gold	Hydro	Reservoir	BC	NA
Cypress Creek	3	Gold	Hydro	Reservoir	BC	NA
Kokish River	45	Gold	Hydro	ROR	BC	NA
Mears Creek	4	Gold	Hydro	Reservoir	BC	NA
Raging River 1 Small Hydro	2	Gold	Hydro	Reservoir	BC	NA
Zeballos Lake	23	Gold	Hydro	Reservoir	BC	NA
Aberfeldie	24	kootenay	Hydro	Reservoir	BC	NA
Elko	12	kootenay	Hydro	Reservoir	BC	NA
Lower Bonnington	66	kootenay	Hydro	Reservoir	BC	NA
Ptarmigan Creek – RBV	4	kootenay	Hydro	Reservoir	BC	NA
Seaton Creek Hydro (Homestead)	0	kootenay	Hydro	Reservoir	BC	NA
Upper Bonnington	66	kootenay	Hydro	Reservoir	BC	NA
Bonnington Falls	16	kootenay	Hydro	Reservoir	BC	NA
Brilliant Dam	145	kootenay	Hydro	Reservoir	BC	NA
Brilliant Expansion	120	kootenay	Hydro	Reservoir	BC	NA
Corra Linn Dam	49	kootenay	Hydro	Reservoir	BC	NA
Kootenay Canal	583	kootenay	Hydro	Reservoir	BC	NA
South Slocan	54	kootenay	Hydro	Reservoir	BC	NA
Spillimacheen	4	kootenay	Hydro	Reservoir	BC	NA
Coats IPP	1	Nanimo	Hydro	Reservoir	BC	NA
Jordan River Dam	170	Nanimo	Hydro	Reservoir	BC	NA
Gordon M. Shrum GS	2876	Peace	Hydro	Reservoir	BC	NA
Peace Canyon Dam	694	Peace	Hydro	Reservoir	BC	NA
Brown Lake	7	Skeena	Hydro	ROR	BC	NA
clayton falls	2	Skeena	Hydro	Reservoir	BC	NA
Dasque Middle	20	Skeena	Hydro	ROR	BC	NA
Falls River	7	Skeena	Hydro	Reservoir	BC	NA

Kemano Generating Station	790	Skeena	Hydro	Reservoir	BC	NA
Ocean Falls	15	Skeena	Hydro	Reservoir	BC	NA
Ash River	28	Stamp	Hydro	Reservoir	BC	NA
Canoe Creek	6	Stamp	Hydro	ROR	BC	NA
China Creek	7	Stamp	Hydro	ROR	BC	NA
Doran Taylor Hydro	6	Stamp	Hydro	Reservoir	BC	NA
Haa-ak-suuk Creek	6	Stamp	Hydro	Reservoir	BC	NA
Marion 3 Creek	5	Stamp	Hydro	Reservoir	BC	NA
South Sutton Creek	5	Stamp	Hydro	Reservoir	BC	NA
Forrest Kerr Generating Station	195	Stikine	Hydro	Reservoir	BC	NA
Hluey Lake (SNP)	3	Stikine	Hydro	Reservoir	BC	NA
Long Lake Hydro	31	Stikine	Hydro	ROR	BC	NA
McLymont Creek	66	Stikine	Hydro	Reservoir	BC	NA
Pine Creek	2	Stikine	Hydro	Reservoir	BC	NA
Volcano Creek	16	Stikine	Hydro	Reservoir	BC	NA
Armstrong Cogen	20	Columbia	Biomass	Waste	BC	2002
Celgar Mill	52	Columbia	Biomass	Waste	BC	2011
Tolko Kelowna Cogeneration	36	Columbia	Biomass	Waste	BC	2012
Burnaby Incinerator (SEEGEN)	22	Fraser	Biomass	Waste	BC	2004
Cache Creek Landfill Gas Utilization Plant	5	Fraser	Biomass	Waste	BC	2015
Cariboo Pulp and Paper	27	Fraser	Biomass	Waste	BC	2015
Fort St. James	40	Fraser	Biomass	Waste	BC	2014
Fraser Lake	12	Fraser	Biomass	Waste	BC	2015
Fraser River Soil and Fibre	2	Fraser	Biomass	Waste	BC	2015
Howe Sound Green Energy	15	Fraser	Biomass	Waste	BC	2011
Kamloops Green Energy	76	Fraser	Biomass	Waste	BC	2011
Merritt	40	Fraser	Biomass	Waste	BC	2017
PGP Bio Energy Project	60	Fraser	Biomass	Waste	BC	2014

Powell River Generation	38	Fraser	Biomass	Waste	BC	2015
Vancouver Landfill Project	7	Fraser	Biomass	Waste	BC	2004
Williams Lake Power Plant	66	Fraser	Biomass	Waste	BC	1993
150 Mile House	6	Fraser	Biomass	Waste	BC	2008
Savona Generating Station	6	Fraser	Biomass	Waste	BC	2008
Houweiling Nurseries	9	Fraser	Biomass	Waste	BC	2016
Intercon Green Power	32	Fraser	Biomass	Waste	BC	2004
Northwood Green Power	63	Fraser	Biomass	Waste	BC	2014
Golden LP	8	kootney	Biomass	Waste	BC	2017
Skookumchuk Power Project	51	kootney	Biomass	Waste	BC	2007
Crowsnest Pass	7	kootney	Biomass	Waste	BC	2013
Cedar Road LFG Inc.	1	Nanaimo	Biomass	Waste	BC	2010
Hartland Landfill Project	2	Nanaimo	Biomass	Waste	BC	2004
Nanaimo Reservoir #1 Energy Recovery	1	Nanaimo	Biomass	Waste	BC	2014
Harmac Biomass	55	Other	Biomass	Waste	BC	2015
Chetwynd Biomass	13	Peace	Biomass	Waste	BC	2015
Conifex Green Energy	36	Peace	Biomass	Waste	BC	2015
Battle River 3	149	Battle	Coal	Sub-critical	AB	<2005
Battle River 4	155	Battle	Coal	Sub-critical	AB	<2005
Battle River 5	385	Battle	Coal	Sub-critical	AB	1981
Genesee 1	400	N. Sask	Coal	Sub-critical	AB	<2005
Genesee 2	400	N. Sask	Coal	Sub-critical	AB	<2005
Genesee 3	466	N. Sask	Coal	Super-critical	AB	2005
H.R. Milner	144	Peace	Coal	Sub-critical	AB	<2005
Keephills 1	395	N. Sask	Coal	Sub-critical	AB	<2005
Keephills 2	395	N. Sask	Coal	Sub-critical	AB	<2005
Keephills 3	463	N. Sask	Coal	Super-critical	AB	2012
Sheerness 1	400	Red deer	Coal	Sub-critical	AB	<2005

Sheerness 2	390	Red deer	Coal	Sub-critical	AB	1990
Sundance 1	280	N. Sask	Coal	Sub-critical	AB	<2005
Sundance 2	280	N. Sask	Coal	Sub-critical	AB	<2005
Sundance 3	368	N. Sask	Coal	Sub-critical	AB	<2005
Sundance 4	406	N. Sask	Coal	Sub-critical	AB	<2005
Sundance 5	406	N. Sask	Coal	Sub-critical	AB	<2005
Sundance 6	401	N. Sask	Coal	Sub-critical	AB	<2005
AltaGas Bantry (ALP1)	7	S. Sak	Natural gas	Simple	AB	<2005
AltaGas Parkland (ALP2)	10	S. Sak	Natural gas	Simple	AB	<2005
Drywood (DRW1)	6	Oldman	Natural gas	Simple	AB	<2005
Lethbridge Burdett (ME03)	7	Oldman	Natural gas	Simple	AB	<2005
Lethbridge Coaldale (ME04)	6	Oldman	Natural gas	Simple	AB	<2005
Lethbridge Taber (ME02)	8	Oldman	Natural gas	Simple	AB	<2005
NPC1 Denis St. Pierre (NPC1)	11	Peace	Natural gas	Simple	AB	<2005
Northern Prairie Power Project (NPP1)	105	Peace	Natural gas	Simple	AB	<2005
Devon	1	S. Sak	Natural gas	Simple	AB	<2005
Poplar Hill #1 (PH1)	48	Peace	Natural gas	Simple	AB	1998
Rainbow #5 (RB5)	50	Peace	Natural gas	Simple	AB	2001
Valley View 1 (VVW1)	50	Peace	Natural gas	Simple	AB	2001
Valley View 2 (VVW2)	50	Peace	Natural gas	Simple	AB	2008
Cloverbar #1 (ENC1)	48	N. Sak	Natural gas	Simple	AB	2009
Cloverbar #2 (ENC2)	101	N. Sak	Natural gas	Simple	AB	2009
Cloverbar #3 (ENC3)	101	N. Sak	Natural gas	Simple	AB	2009
Crossfield Energy Centre #1 (CRS1)	48	Bow	Natural gas	Simple	AB	2009
Crossfield Energy Centre #2 (CRS2)	48	Bow	Natural gas	Simple	AB	2009
Crossfield Energy Centre #3 (CRS3)	48	Bow	Natural gas	Simple	AB	2009
Carson Creek (GEN5)	15	Athabasca	Natural gas	Simple	AB	2013
House Mountain (HSM1)	6	Athabasca	Natural gas	Simple	AB	2013

Ralston (NAT1)	20	S. Sak	Natural gas	Simple	AB	2013
West Cadotte (WCD1)	20	Peace	Natural gas	Simple	AB	2013
B Newsprint (ANC1)	63	Athabasca	Natural gas	Simple	AB	2014
Judy Creek (GEN6)	15	Athabasca	Natural gas	Simple	AB	2014
Bellshill Power Centre	6	N. Sak	Natural gas	Simple	AB	2014
High River (MFG1)	16	S. Sak	Natural gas	Simple	AB	2015
Peace River Power Centre	20	Peace	Natural gas	Simple	AB	2015
Maxim APP	1	S. Sak	Natural gas	Simple	AB	2015
AltaGas Harmattan (HMT1)	45	Red deer	Natural gas	Cogen	AB	<2005
BuckLake (PW01)	5	Red deer	Natural gas	Cogen	AB	<2005
CNRL Horizon (CNR5)	203	Athabasca	Natural gas	Cogen	AB	<2005
Christina Lake (CL01)	101	Athabasca	Natural gas	Cogen	AB	<2005
Edson (TLM2)	13	Red deer	Natural gas	Cogen	AB	<2005
Mahkeses (IOR1)	180	Athabasca	Natural gas	Cogen	AB	<2005
University of Alberta (UOA1)	39	N. Sak	Natural gas	Cogen	AB	<2005
Permolex Co-gem	4	Red deer	Natural gas	Cogen	AB	<2005
Rainbow Lake #1 (RL1)	47	Peace	Natural gas	Cogen	AB	1968
Primrose #1 (PR1)	100	Athabasca	Natural gas	Cogen	AB	1998
Dow Hydrocarbon (DOWG)	326	N. Sak	Natural gas	Cogen	AB	1999
Syncrude #1 (SCL1)	510	Athabasca	Natural gas	Cogen	AB	1999
Air Liquide Scotford #1 (ALS1)	96	N. Sak	Natural gas	Cogen	AB	2000
Joffre #1 (JOF1)	474	Red deer	Natural gas	Cogen	AB	2000
Bear Creek 2 (BCR2)	36	Peace	Natural gas	Cogen	AB	2001
Carseland Cogen (TC01)	95	Bow	Natural gas	Cogen	AB	2001
Nexen Inc #2 (NX02)	220	Athabasca	Natural gas	Cogen	AB	2001
Poplar Creek (SCR5)	376	Athabasca	Natural gas	Cogen	AB	2001
Redwater Cogen (TC02)	46	N. Sak	Natural gas	Cogen	AB	2001
Base Plant (SCR1)	50	Athabasca	Natural gas	Cogen	AB	2002

Bear Creek 1 (BCRK)	64	Peace	Natural gas	Cogen	AB	2002
Muskeg River (MKR1)	202	Athabasca	Natural gas	Cogen	AB	2002
ATCO Scotford Upgrader (APS1)	195	N. Sak	Natural gas	Cogen	AB	2003
Foster Creek (EC04)	98	Athabasca	Natural gas	Cogen	AB	2003
MacKay River (MKRC)	205	Athabasca	Natural gas	Cogen	AB	2003
Firebag (SCR6)	473	Athabasca	Natural gas	Cogen	AB	2008
Shell Caroline (SHCG)	19	Red deer	Natural gas	Cogen	AB	2008
Conacher algar cogen	13	Athabasca	Natural gas	Cogen	AB	2011
MEG1 Christina Lake (MEG1)	202	Athabasca	Natural gas	Cogen	AB	2013
U of C Generator (UOC1)	12	Bow	Natural gas	Cogen	AB	2012
Camrose (CRG1)	10	N. Sak	Natural gas	Cogen	AB	2015
Kearl (IOR3)	84	Athabasca	Natural gas	Cogen	AB	2015
Lindbergh (PEC1)	16	N. Sak	Natural gas	Cogen	AB	2015
Nabiye (IOR2)	195	Athabasca	Natural gas	Cogen	AB	2015
Grizzly algar cogen	15	Athabasca	Natural gas	Cogen	AB	2015
Syncrude Mildred	270	Athabasca	Natural gas	Cogen	AB	2016
Fort Hills (FH1)	199	Athabasca	Natural gas	Cogen	AB	2017
Mulligan (MUL1) *	5	Peace	Natural gas	Cogen	AB	2019
Cavalier (EC01)	120	S. Sak.	Natural gas	Combined	AB	2001.00
ENMAX Calgary Energy Centre (CAL1)	320	Lake McDonald	Natural gas	Combined	AB	2002.00
Fort Nelson (FNG1)	73	Peace	Natural gas	Combined	AB	<2005
Medicine Hat #1 (CMH1)	210	S. Sak.	Natural gas	Combined	AB	2012.00
Nexen Inc #1 (NX01)	120	Lake McDonald	Natural gas	Combined	AB	2001.00
Shepard (EGC1)	860	Reclaimed	Natural gas	Combined	AB	2015.00
Bow River Hydro (BOW1)	320	Bow river	Hydro	Reservoir	AB	NA
bighorn Hydro (BIG)	120	N. Sak.	Hydro	Reservoir	AB	NA
Brazeau Hydro (BRA)	350	N. Sak.	Hydro	Reservoir	AB	NA
CUPC Oldman River (OMRH)	32	Oldman	Hydro	ROR	AB	NA

Chin Chute (CHIN)	15	Oldman	Hydro	Reservoir	AB	NA
Irrican Hydro (ICP1)	7	Oldman	Hydro	ROR	AB	NA
Raymond Reservoir (RYMD)	21	Oldman	Hydro	Reservoir	AB	NA
Taylor Hydro (TAY1)	14	Oldman	Hydro	ROR	AB	NA
Dickson Dam (DKSN)	15	Red deer	Hydro	Reservoir	AB	NA
Whitecourt Power (EAGL)	25	Athabasca	Biomass	Waste	AB	1994
Drayton Valley (DV1)	11	N. Sask	Biomass	Waste	AB	1996
Cancarb Medicine Hat (CCMH)	42	S. Sak	Biomass	Waste	AB	2000
APF Athabasca (AFG1)	131	Athabasca	Biomass	Waste	AB	2001
Grande Prairie EcoPower (GPEC)	27	Peace	Biomass	Waste	AB	2005
DAI1 Daishowa (DAI1)	52	Peace	Biomass	Waste	AB	2012
NRGreen (NRG3)	16	Athabasca	Biomass	Waste	AB	2014
Slave Lake (SLP1)	9	Peace	Biomass	Waste	AB	2014
Weldwood #1 (WWD1)	50	Athabasca	Biomass	Waste	AB	2014
Westlock (WST1)	18	N. Sask	Biomass	Waste	AB	2014
Weyerhaeuser (WEY1)	48	Peace	Biomass	Waste	AB	2014
Poplar River Power Station	582	Souris	Coal	Supercritical	SK	<2005
Boundary Dam Power Station	672	Souris	Coal	Supercritical	SK	<2006
Shand Power Station	276	Souris	Coal	Supercritical	SK	<2007
Meadow Lake Power Station	44	N. Sak	Natural gas	Simple	SK	1984
Meridian Cogeneration Station	228	N. Sak	Natural gas	Co-gen	SK	1999
North Battleford Generating Station	271	N. Sak	Natural gas	Combined	SK	2013
Yellowhead Power Station	138	N. Sak	Natural gas	Simple	SK	2010
Ermine Power Station	92	N. Sak	Natural gas	Simple	SK	2010
Landis Power Station	79	N. Sak	Natural gas	Simple	SK	1975
Cory Cogeneration Station	249	S. Sak	Natural gas	Co-gen	SK	2003
Queen Elizabeth Power Station	634	S. Sak	Natural gas	Combined	SK	1959
Spy Hill Generating Station	89	Assiniboine	Natural gas	Simple	SK	2011

Chinook Power Station	350	S. Sak	Natural gas	Combined	SK	2020
Wellington Power Station	5	Athabasca	Hydro	ROR	SK	NA
Waterloo Power Station	8	Athabasca	Hydro	ROR	SK	NA
Charlot River Power Station	10	Athabasca	Hydro	ROR	SK	NA
Island Falls Power Station	111	Churchill	Hydro	ROR	SK	NA
Nipawin Hydroelectric Station	255	Saskatchewan	Hydro	Reservoir	SK	NA
E.B. Campbell Hydroelectric Station	289	Saskatchewan	Hydro	Reservoir	SK	NA
Coteau Creek Hydroelectric Station	186	S. Sak	Hydro	Reservoir	SK	NA
Wuskwatim	211	Nelson River	Hydro	Reservoir	MT	NA
Laurie River 1 Generating Station	10	Laurie River	Hydro	Reservoir	MT	NA
Laurie River 2 Generating Station	10	Laurie River	Hydro	Reservoir	MT	NA
Jenpeg Generating Station	122	Nelson River	Hydro	Reservoir	MT	NA
Kelsey Generating Station	287	Nelson River	Hydro	Reservoir	MT	NA
Kettle Generating Station	1220	Nelson River	Hydro	Reservoir	MT	NA
Limestone Generating Station	1350	Nelson River	Hydro	ROR	MT	NA
Long Spruce Generating Station	980	Nelson River	Hydro	ROR	MT	NA
Grand Rapids Generating Station	479	Nelson River	Hydro	Reservoir	MT	NA
Great Falls Dam	129	Winnipeg River	Hydro	ROR	MT	NA
McArthur Falls Generating Station	56	Winnipeg River	Hydro	ROR	MT	NA
Pine Falls Generating Station	87	Winnipeg River	Hydro	ROR	MT	NA
Pointe du Bois Hydroelectric Dam	75	Winnipeg River	Hydro	ROR	MT	NA
Seven Sisters Generating Station	165	Winnipeg River	Hydro	ROR	MT	NA
Slave Falls Generating Station	68	Winnipeg River	Hydro	ROR	MT	NA
Selkirk Generating Station	125	Red River	Natural gas	Combined	MT	<2005
Brandon GS	340	Assiniboine river	Coal	Sub-critical	MT	<2005
Bruce Unit 1	750	Lake Huron	Nuclear	NA	ON	<2005
Bruce Unit 2	750	Lake Huron	Nuclear	NA	ON	<2005
Bruce Unit 4	750	Lake Huron	Nuclear	NA	ON	<2005

Bruce Unit 6	825	Lake Huron	Nuclear	NA	ON	<2005
Bruce Unit 7	825	Lake Huron	Nuclear	NA	ON	<2005
Bruce Unit 3	750	Lake Huron	Nuclear	NA	ON	<2005
Bruce Unit 5	825	Lake Huron	Nuclear	NA	ON	<2005
Bruce Unit 8	825	Lake Huron	Nuclear	NA	ON	<2005
Darlington Unit 1	878	Lake Ontario	Nuclear	NA	ON	<2005
Darlington Unit 2	878	Lake Ontario	Nuclear	NA	ON	<2005
Darlington Unit 3	878	Lake Ontario	Nuclear	NA	ON	<2005
Darlington Unit 4	878	Lake Ontario	Nuclear	NA	ON	<2005
Pickering Nuclear GS	3100	Lake Ontario	Nuclear	NA	ON	<2005
Iroquois Falls	85	Abitibi River	Natural gas	Combined	ON	<2005
Brunato Farms Ltd.	10	Lake Eerie	Natural gas	Cogen	ON	2016
C.L. Solutions	13	Lake Eerie	Natural gas	Cogen	ON	2016
Cervini Generation	10	Lake Eerie	Natural gas	Cogen	ON	2020
Countryside London	17	Lake Eerie	Natural gas	Cogen	ON	2016
Great Northern Tri-Gen	12	Lake Eerie	Natural gas	Cogen	ON	2008
Ontario Plants Power Co	6	Lake Eerie	Natural gas	Cogen	ON	2016
Neven Produce Cogen	3	Lake Eerie	Natural gas	Cogen	ON	2017
Rosa Flora Growers Limited	4	Lake Eerie	Natural gas	Cogen	ON	2015
Sudbury District Energy	12	Lake Huron	Natural gas	Combined	ON	2006
eNature Cogeneration Project	5	Lake Ontario	Natural gas	Cogen	ON	2016
Goreway Station	874	Lake Ontario	Natural gas	Simple	ON	2009
GTAA Cogeneration Plant	90	Lake Ontario	Natural gas	Cogen	ON	2006
Halton Hills Generating Station	683	Lake Ontario	Natural gas	Combined	ON	2010
Napanee Generating Station	900	Lake Ontario	Natural gas	Combined	ON	2020
Portlands Energy Centre	550	Lake Ontario	Natural gas	Combined	ON	2008
Lennox Generating Station	2000	Lake Ontario	Natural gas	Combined	ON	1976
Thorold Cogen	265	Lake Ontario	Natural gas	Cogen	ON	2010

Trent Valley	7	Lake Ontario	Natural gas	Combined	ON	<2005
Warden Energy Centre	5	Lake Ontario	Natural gas	Cogen	ON	2000
Birchmount Energy Centre	3	Lake Ontario	Natural gas	Cogen	ON	2014
Bur Oak Energy Centre	4	Lake Ontario	Natural gas	Cogen	ON	2014
Durham College CHP	2	Lake Ontario	Natural gas	Cogen	ON	2008
Foothill Greenhouses Ltd.	3	Lake Ontario	Natural gas	Cogen	ON	2017
HCE Port Lands West CHP	2	Lake Ontario	Natural gas	Cogen	ON	2020
Pearl Street Steam Plant	4	Lake Ontario	Natural gas	Cogen	ON	2016
Ravensbergen	3	Lake Ontario	Natural gas	Cogen	ON	2017
Regent Park Cogeneration Facility	3	Lake Ontario	Natural gas	Cogen	ON	2009
Kingston generating station	115	Lake Ontario	Natural gas	Combined	ON	1997-2017
Algoma Energy Cogeneration	63	Lake Ontario	Natural gas	Cogen	ON	2009
Brighton Beach Power Station	541	Lake St. Clair	Natural gas	Combined	ON	2004
Cedarline Greenhouse	5	Lake St. Clair	Natural gas	Cogen	ON	2016
East Windsor Cogen	84	Lake St. Clair	Natural gas	Cogen	ON	2009
West Windsor Power	123	Lake St. Clair	Natural gas	Combined	ON	1996
Lake superior power facility	110	Lake Superior	Natural gas	Cogen	ON	<2005-2015
Kirkland Lake GS	30	Ottawa River	Natural gas	Combined	ON	2017
Ottawa Health Sciences Centre	74	Ottawa River	Natural gas	Combined	ON	2014
York Energy Centre	393	Ottawa River	Natural gas	Simple	ON	2012
Green Electron Power Plant	314	St. Clair River	Natural gas	Combined	ON	2016
Greenfield Energy Centre	1005	St. Clair River	Natural gas	Combined	ON	2008
Sarnia Cogeneration Plant	444	St. Clair River	Natural gas	Combined	ON	2003
St. Clair Energy Centre	577	St. Clair River	Natural gas	Combined	ON	2009
Cardinal Power Plant	156	St. Lawrence River	Natural gas	Combined	ON	2015
Maitland Site GS	46	St. Lawrence River	Natural gas	Cogen	ON	2016
Tunis GS	37	Abitibi River	Natural gas	Combined	ON	2019
Island Falls	38	Abitibi River	Hydro	ROR	ON	NA

Abitibi Canyon	182	Abitibi River	Hydro	Reservoir	ON	NA
AP Iroquois falls	30	Abitibi River	Hydro	ROR	ON	NA
Carmichael Falls	20	Abitibi River	Hydro	ROR	ON	NA
Harmon	220	Abitibi River	Hydro	Reservoir	ON	NA
Kipling	232	Abitibi River	Hydro	Reservoir	ON	NA
Little long	200	Abitibi River	Hydro	Reservoir	ON	NA
Long sault rapids	16	Abitibi River	Hydro	ROR	ON	NA
Otter Rapid	182	Abitibi River	Hydro	Reservoir	ON	NA
Smoky falls	267	Abitibi River	Hydro	Reservoir	ON	NA
Caribou falls	91	English River	Hydro	Reservoir	ON	NA
Ear falls	29	English River	Hydro	ROR	ON	NA
Manitou Falls	73	English River	Hydro	ROR	ON	NA
White Dog Falls	68	English River	Hydro	Reservoir	ON	NA
Aubrey falls	162	Lake Huron	Hydro	Reservoir	ON	NA
Rayner	46	Lake Huron	Hydro	Reservoir	ON	NA
Red Rock Falls	41	Lake Huron	Hydro	ROR	ON	NA
Wells	293	Lake Huron	Hydro	Reservoir	ON	NA
Decew Falls	23	Lake Ontario	Hydro	ROR	ON	NA
Sir Adam Beck	1997	Lake Ontario	Hydro	Reservoir	ON	NA
Aguasabon	47	Lake Superior	Hydro	ROR	ON	NA
Alexander	69	Lake Superior	Hydro	ROR	ON	NA
Cameron Falls	92	Lake Superior	Hydro	ROR	ON	NA
Clergue	52	Lake Superior	Hydro	ROR	ON	NA
Gartshore	23	Lake Superior	Hydro	ROR	ON	NA
hollingsworth	23	Lake Superior	Hydro	ROR	ON	NA
Kakbeka Falls	25	Lake Superior	Hydro	ROR	ON	NA
Mackay	62	Lake Superior	Hydro	ROR	ON	NA
Pine portage	144	Lake Superior	Hydro	Reservoir	ON	NA

Silver Falls	48	Lake Superior	Hydro	ROR	ON	NA
Umbata Falls	23	Lake Superior	Hydro	ROR	ON	NA
Andrews GS	47	Lake Superior	Hydro	ROR	ON	NA
Dunford GS	45	Lake Superior	Hydro	ROR	ON	NA
Scott Falls GS	22	Lake Superior	Hydro	ROR	ON	NA
Peter Sutherland Sr. GS (New Post Creek)	25	Moose River	Hydro	ROR	ON	NA
Arnprior	82	Ottawa River	Hydro	Reservoir	ON	NA
Barrett chute	176	Ottawa River	Hydro	Reservoir	ON	NA
Chats falls	192	Ottawa River	Hydro	Reservoir	ON	NA
Chenaux	144	Ottawa River	Hydro	Reservoir	ON	NA
Des Joachims	429	Ottawa River	Hydro	Reservoir	ON	NA
Lower Notch	274	Ottawa River	Hydro	Reservoir	ON	NA
Mountain Chute	170	Ottawa River	Hydro	Reservoir	ON	NA
Otto Holden	243	Ottawa River	Hydro	Reservoir	ON	NA
Stewartville	182	Ottawa River	Hydro	Reservoir	ON	NA
Hull No. 2	27	Ottawa River	Hydro	ROR	ON	NA
Twin Falls	23	Ottawa River	Hydro	ROR	ON	NA
Chaudiere Hydro GS2 Facility	29	Ottawa River	Hydro	ROR	ON	NA
Saunders	1045	St. Lawrence River	Hydro	ROR	ON	NA
Cochrane	42	Abitibi River	Biomass	Waste	ON	<2005
Atikokan Generating Station	205	English River	Biomass	Forest residue	ON	2013
Brampton	23	Lake Ontario	Biomass	Waste	ON	<2005
Index Energy Mills Road Corporation	18	Lake Ontario	Biomass	Waste	ON	2018
Becker Cogeneration Plant	15	Lake Superior	Biomass	Waste	ON	2014
Chapleau Cogeneration Facility	5	Lake Superior	Biomass	Waste	ON	1985
Thunder Bay Condensing Turbine Project	153	Lake Superior	Biomass	Waste	ON	2013
Thunder Bay GS Unit 3	135	Lake Superior	Biomass	Waste	ON	2015
Calstock Power Plant	35	Moose River	Biomass	Waste	ON	<2005

La Grande-1	1436	La Grande	Hydro	ROR	QB	NA
Robert-Bourassa	5616	La Grande	Hydro	Reservoir	QB	NA
La Grande-4	2779	La Grande	Hydro	Reservoir	QB	NA
La Grande-3	2417	La Grande	Hydro	Reservoir	QB	NA
La Grande-2-A	2106	La Grande	Hydro	Reservoir	QB	NA
Laforge-2	319	La Grande	Hydro	ROR	QB	NA
Laforge-1	878	La Grande	Hydro	Reservoir	QB	NA
Eastmain-1-A	768	Rivière Eastmain	Hydro	Reservoir	QB	NA
Eastmain-1	480	Rivière Eastmain	Hydro	Reservoir	QB	NA
Brisay	469	La Grande	Hydro	Reservoir	QB	NA
Sarcelle	150	Rivière Eastmain	Hydro	ROR	QB	NA
Lac-Robertson5	22	Lac Robertson	Hydro	Reservoir	QB	NA
René-Lévesque (Manic-3)	1326	Manicouagan	Hydro	ROR	QB	NA
Manic-5	1596	Manicouagan	Hydro	Reservoir	QB	NA
Jean-Lesage (Manic-2)	1229	Manicouagan	Hydro	ROR	QB	NA
McCormick4	235	Manicouagan	Hydro	ROR	QB	NA
Manic-5-PA	1064	Manicouagan	Hydro	Reservoir	QB	NA
Toulnustouc	526	Manicouagan	Hydro	Reservoir	QB	NA
Manic-1	184	Manicouagan	Hydro	ROR	QB	NA
Hart-Jaune	51	Manicouagan	Hydro	Reservoir	QB	NA
Romaine-2	640	Romaine	Hydro	Reservoir	QB	NA
Romaine-1	270	Romaine	Hydro	ROR	QB	NA
Péribonka	385	Saguenay	Hydro	ROR	QB	NA
Outardes-3	1026	St. Lawrence River	Hydro	ROR	QB	NA
Outardes-4	785	St. Lawrence River	Hydro	Reservoir	QB	NA
Outardes-2	523	St. Lawrence River	Hydro	ROR	QB	NA
Saint-Narcisse	15	St. Lawrence River	Hydro	ROR	QB	NA
Bersimis-1	1178	St. Lawrence River	Hydro	Reservoir	QB	NA

Bersimis-2	869	St. Lawrence River	Hydro	ROR	QB	NA
Beauharnois	1877	St. Lawrence River	Hydro	ROR	QB	NA
Mitis-1	6	St. Lawrence River	Hydro	ROR	QB	NA
Mitis-2	4	St. Lawrence River	Hydro	ROR	QB	NA
Carillon	753	St. Lawrence River	Hydro	ROR	QB	NA
Paugan	226	St. Lawrence River	Hydro	ROR	QB	NA
Rapides-des-Îles	176	St. Lawrence River	Hydro	ROR	QB	NA
Chelsea	152	St. Lawrence River	Hydro	ROR	QB	NA
Première-Chute	131	St. Lawrence River	Hydro	ROR	QB	NA
Rapides-Farmer	104	St. Lawrence River	Hydro	ROR	QB	NA
Rapides-des-Quinze	103	St. Lawrence River	Hydro	ROR	QB	NA
Chute-des-Chats	92	St. Lawrence River	Hydro	ROR	QB	NA
Rapide-2	67	St. Lawrence River	Hydro	ROR	QB	NA
Rapide-7	67	St. Lawrence River	Hydro	Reservoir	QB	NA
Bryson	56	St. Lawrence River	Hydro	ROR	QB	NA
Mercier	55	St. Lawrence River	Hydro	Reservoir	QB	NA
Chute-Bell	10	St. Lawrence River	Hydro	ROR	QB	NA
Sept-Chutes	22	St. Lawrence River	Hydro	ROR	QB	NA
Sainte-Marguerite-3	882	St. Lawrence River	Hydro	Reservoir	QB	NA
Chute-Hemmings	29	St. Lawrence River	Hydro	ROR	QB	NA
Drummondville	16	St. Lawrence River	Hydro	ROR	QB	NA
Trenche	302	St. Lawrence River	Hydro	ROR	QB	NA
La Tuque	294	St. Lawrence River	Hydro	ROR	QB	NA
Beaumont	270	St. Lawrence River	Hydro	ROR	QB	NA
Rocher-de- Grand-Mère	230	St. Lawrence River	Hydro	ROR	QB	NA
Rapide-Blanc	204	St. Lawrence River	Hydro	Reservoir	QB	NA
Shawinigan-2	200	St. Lawrence River	Hydro	ROR	QB	NA
Shawinigan-3	194	St. Lawrence River	Hydro	ROR	QB	NA

La Gabelle	131	St. Lawrence River	Hydro	ROR	QB	NA
Rapide-des-Cœurs	76	St. Lawrence River	Hydro	ROR	QB	NA
Grand-Mère	67	St. Lawrence River	Hydro	ROR	QB	NA
Chute-Allard	62	St. Lawrence River	Hydro	ROR	QB	NA
Les Cèdres	113	St. Lawrence River	Hydro	ROR	QB	NA
Bécancour gas turbine	411	St. Lawrence River	Natural gas	Simple	QB	<2005
Chapais Énergie	27	Lac Laura	Biomass	Waste	QB	NA
Senneterre	35	Lac Parent	Biomass	Waste	QB	NA
Témiscaming mill	8	Ottawa river	Biomass	Waste	QB	NA
Thurso Cogeneration Plant	24	Ottawa river	Biomass	Waste	QB	NA
Dolbeau Biomass Cogen.	27	Saguenay	Biomass	Waste	QB	NA
Fibrek Saint-Félicien	43	Saguenay	Biomass	Waste	QB	NA
Brompton Biomass Cogen.	19	St. Lawrence River	Biomass	Waste	QB	NA
Churchill Falls Generating Station	5428	Churchill	Hydro	Reservoir	NFL	NA
Menihek Hydroelectric Generating Station	19	Churchill	Hydro	ROR	NFL	NA
Lower Churchill Generation Project	824	Churchill	Hydro	Reservoir	NFL	NA
Bay d'Espoir Hydroelectric Generating Facility	613	Meelpaeg Lake	Hydro	Reservoir	NFL	NA
Cat Arm Hydroelectric Generating Station	134	Cat arm river	Hydro	Reservoir	NFL	NA
Granite Canal Hydroelectric GS	40	Meelpaeg Lake	Hydro	ROR	NFL	NA
Hinds Lake Hydroelectric Generating Station	75	Exploits	Hydro	ROR	NFL	NA
Paradise River Hydroelectric GS	9	Exploits	Hydro	ROR	NFL	NA
Upper Salmon Hydroelectric GS	84	Meelpaeg Lake	Hydro	Reservoir	NFL	NA
Roddickton Hydroelectric generating station	0	Exploits	Hydro	ROR	NFL	NA
Snooks Arm Hydroelectric Generating Station	1	Exploits	Hydro	ROR	NFL	NA
Star Lake Hydroelectric Generating Station	18	Exploits	Hydro	ROR	NFL	NA
Exploits River (Grand Falls) Hydroelectric GS	75	Exploits	Hydro	ROR	NFL	NA

Exploits River (Bishops Falls) Hydroelectric GS	22	Exploits	Hydro	ROR	NFL	NA
Corner Brook Cogeneration Plant	15	Grand Lake	Natural gas	Cogen	NFL	<2005
Belledune Generating Station	467	St. Lawrence	Coal	Sub-critical	NB	<2005
Point Lepreau Nuclear Generating Station	705	Bay of Fundy	Nuclear		NB	<2005
Grandview Cogeneration Plant	88	Saint John River	Natural gas	Cogen	NB	<2005
Bayside Power	290	Saint John River	Natural gas	Combined	NB	<2005
Edmundston Pulp Mill	45	Saint John River	Natural gas	Biomass	NB	<2005
Beechwood Generating Station	112	Saint John River	Hydro	Reservoir	NB	NA
Grand Falls Generating Station	66	Saint John River	Hydro	Reservoir	NB	NA
Mactaquac Dam	668	Saint John River	Hydro	ROR	NB	NA
Madawaska Hydro-Dam Fraser Plant	5	Saint John River	Hydro	Reservoir	NB	NA
Milltown Generating Station	3	Saint John River	Hydro	Reservoir	NB	NA
St. George Dam	15	Saint John River	Hydro	Reservoir	NB	NA
Tinker Dam	35	Saint John River	Hydro	Reservoir	NB	NA
Nepisiguit Falls Generating Station	11	Tobique River	Hydro	Reservoir	NB	NA
Second Falls Dam	3	Tobique River	Hydro	Reservoir	NB	NA
Sisson Generating Station	9	Tobique River	Hydro	Reservoir	NB	NA
Tobique Narrows Generating Station	20	Tobique River	Hydro	Reservoir	NB	NA
Lingan Generating Station	620	Atlantic	Coal	Subcritical	NS	1979
Point Aconi Generating Station	171	Atlantic	Coal	Subcritical	NS	1994
Point Tupper Generating Station	154	Atlantic	Coal	Subcritical	NS	1973
Trenton Generating Station	307	Atlantic	Coal	Subcritical	NS	1969
Tufts Cove Generating Station	150	Atlantic	Natural gas	Combined	NS	<2005
Brooklyn Energy Centre	27	Atlantic	Biomass	Waste	NS	NA
Port Hawkesbury Biomass	63	Atlantic	Biomass	Waste	NS	NA
Annapolis Royal Generating Station	20	Annapolis	Hydro	Tidal	NS	1984
Avon	7	Annapolis	Hydro	Reservoir	NS	<2005

Black River	23	Annapolis	Hydro	Reservoir	NS	1984
Dickie Brook	4	Annapolis	Hydro	Reservoir	NS	NA
Bear River	13	Annapolis	Hydro	Reservoir	NS	<2005
Lequille	11	Annapolis	Hydro	Reservoir	NS	<2005
Nictuax	7	Annapolis	Hydro	Reservoir	NS	NA
Paradise	5	Annapolis	Hydro	Reservoir	NS	NA
Sissiboo	24	Annapolis	Hydro	Reservoir	NS	NA
Tusket	2	Annapolis	Hydro	Reservoir	NS	NA
Wreck Cove	200	Cheticamp River	Hydro	Reservoir	NS	<2005
Fall River	1	Mersey River	Hydro	Reservoir	NS	NA
Mersey	43	Mersey River	Hydro	Reservoir	NS	<2004
Roseway	2	Mersey River	Hydro	ROR	NS	NA
Sheet Harbour	11	Mersey River	Hydro	Reservoir	NS	NA
St. Margaret's Bay Hydro	11	Mersey River	Hydro	Reservoir	NS	NA

A.2 WEAP Canada oil and gas model by provinces

The section shows the schematic view of the WEAP-Canada electricity generation model and oil and gas model by provinces.

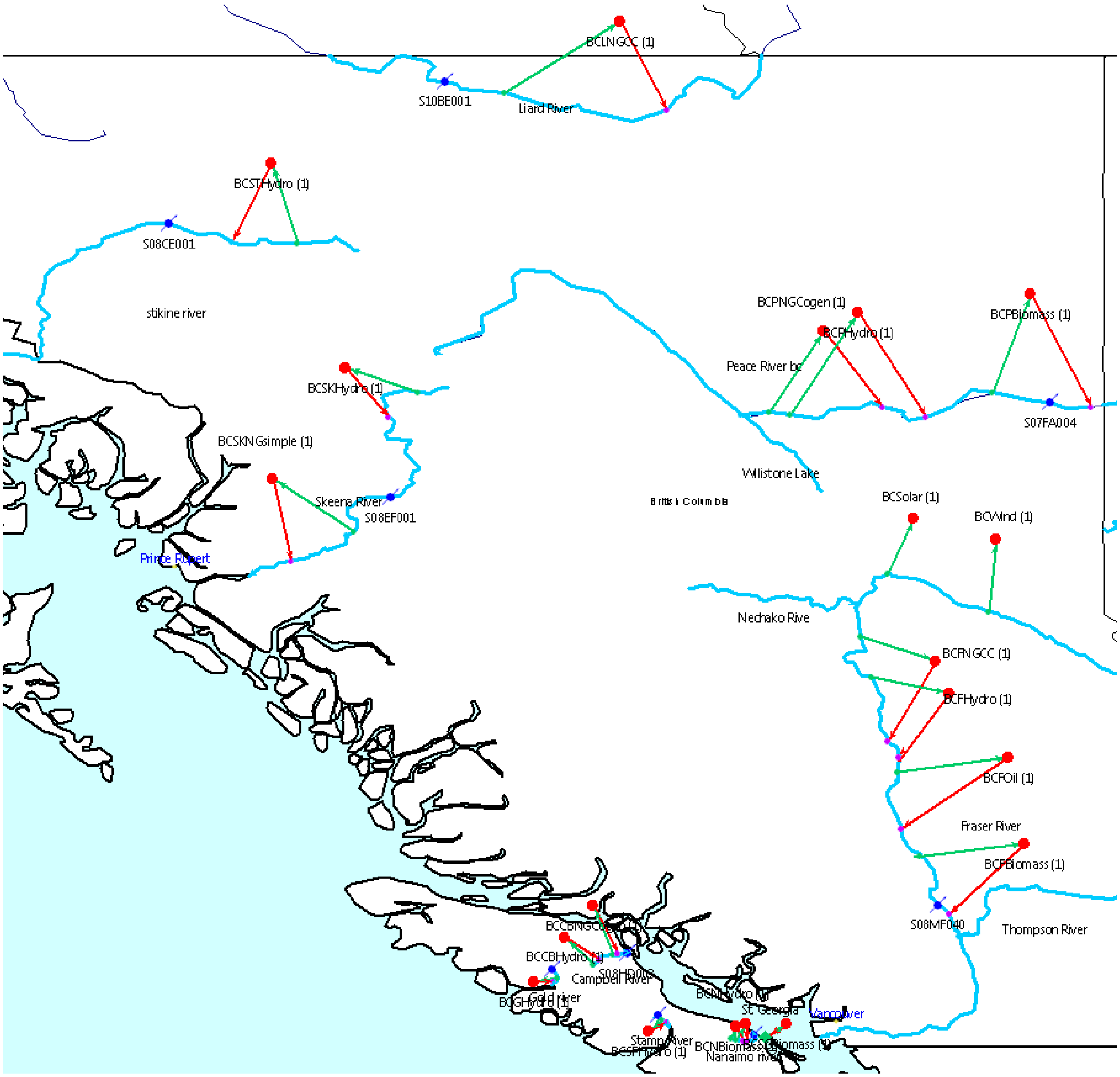

Figure A-1: The WEAP Canada electricity generation model showing British Columbia's water demand sites

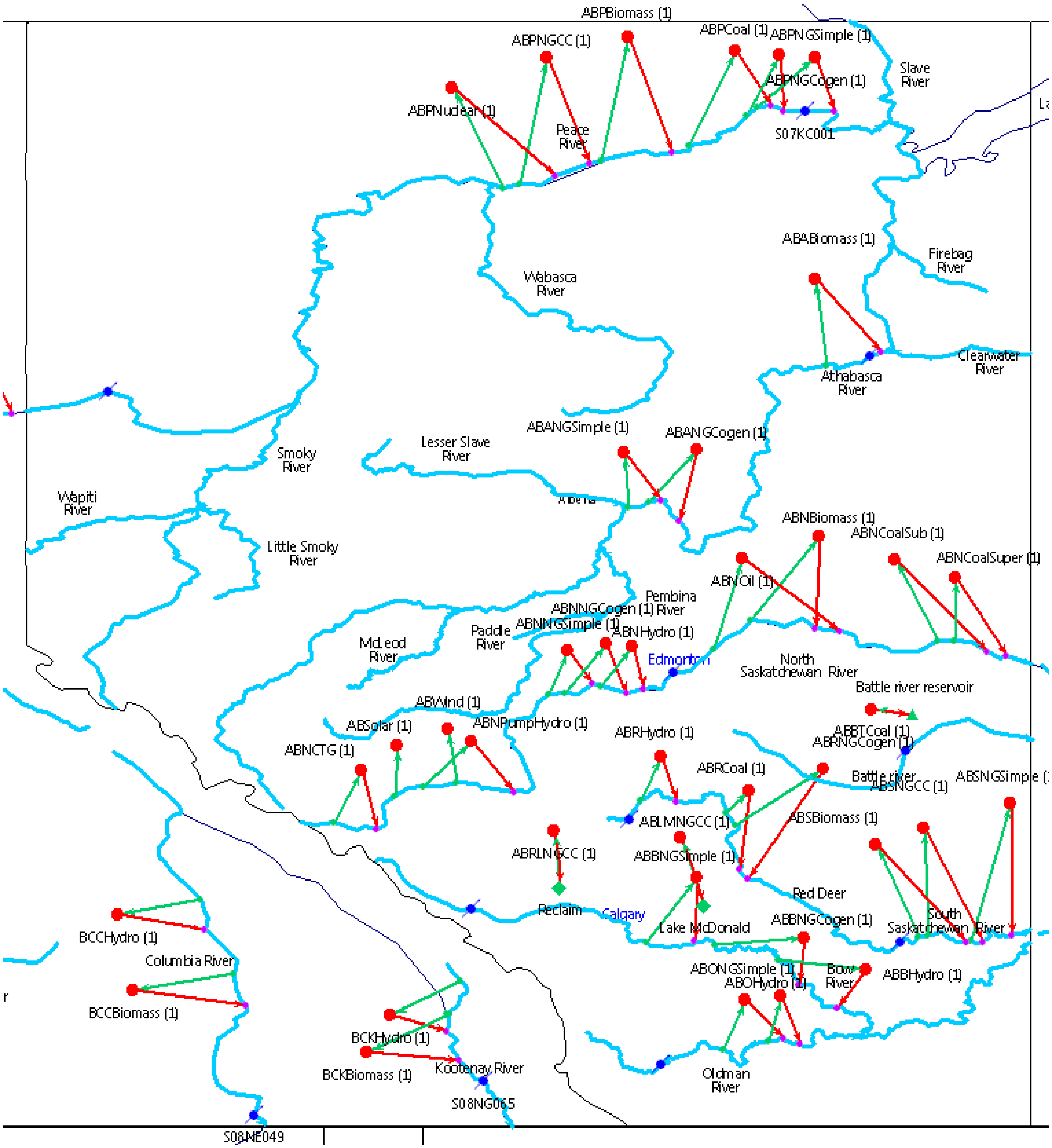

Figure A-2: The WEAP Canada electricity generation model showing Alberta's water demand sites

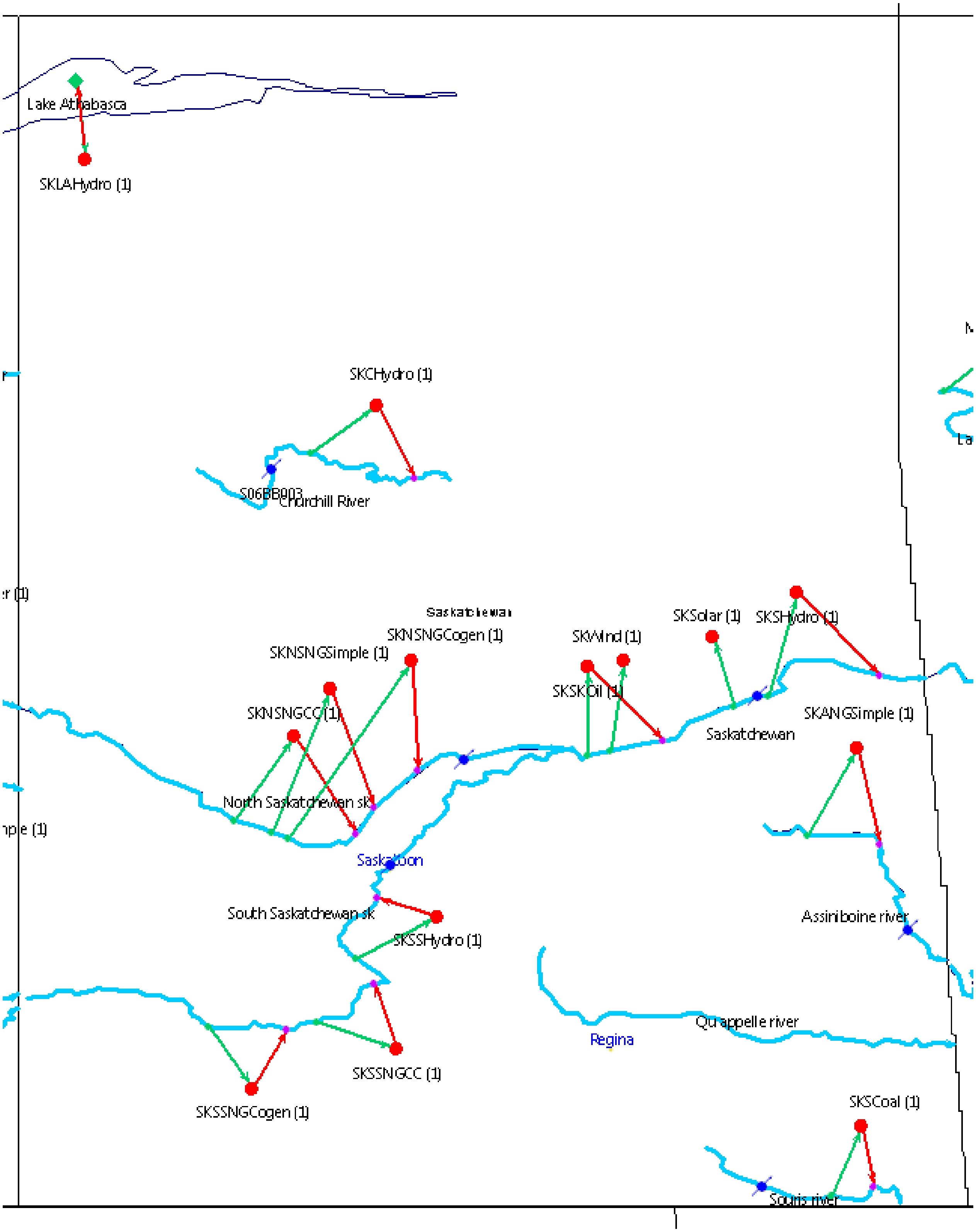

Figure A-3: The WEAP Canada electricity generation model showing Saskatchewan's water demand sites

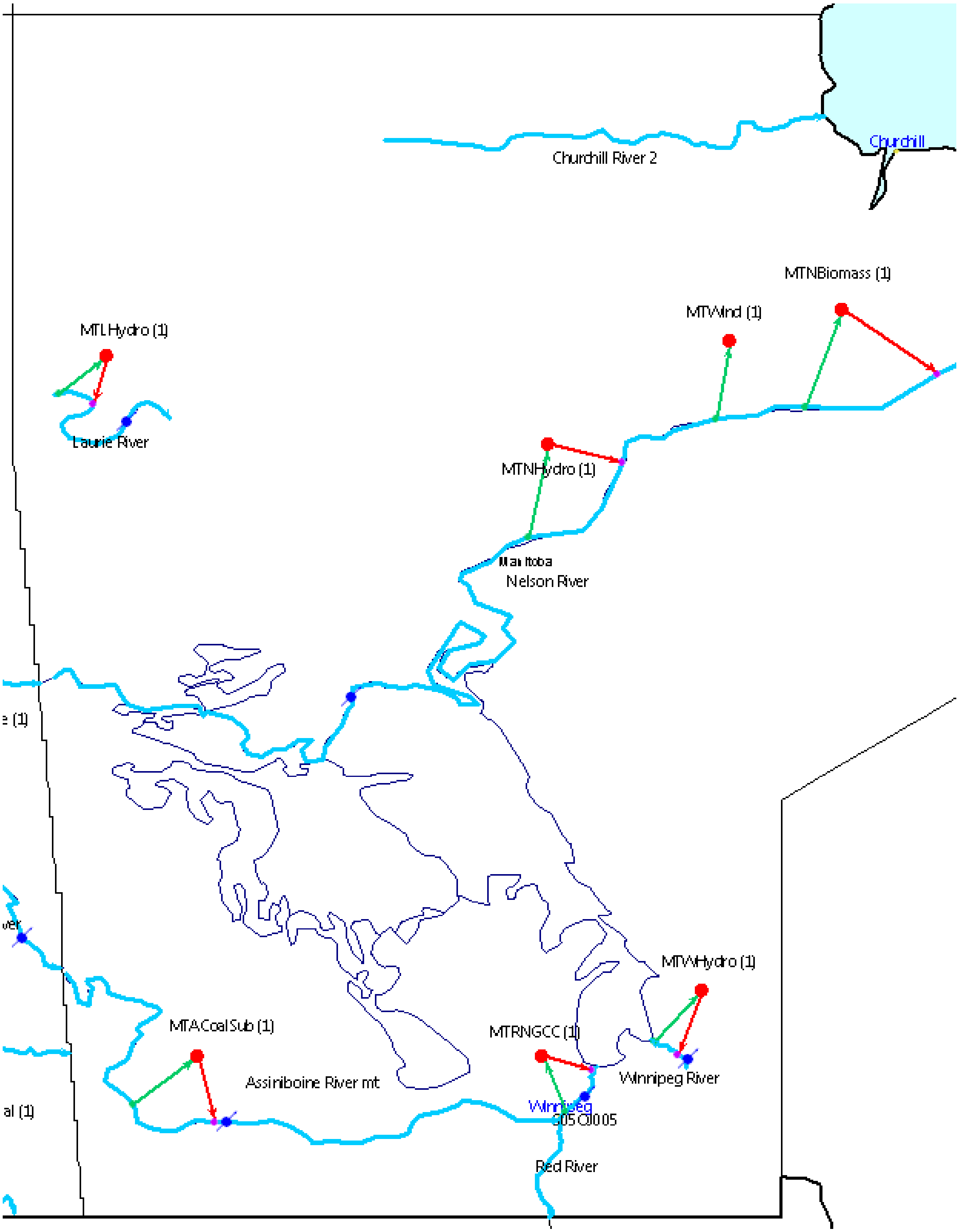

Figure A-4: The WEAP Canada electricity generation model showing Manitoba's water demand sites

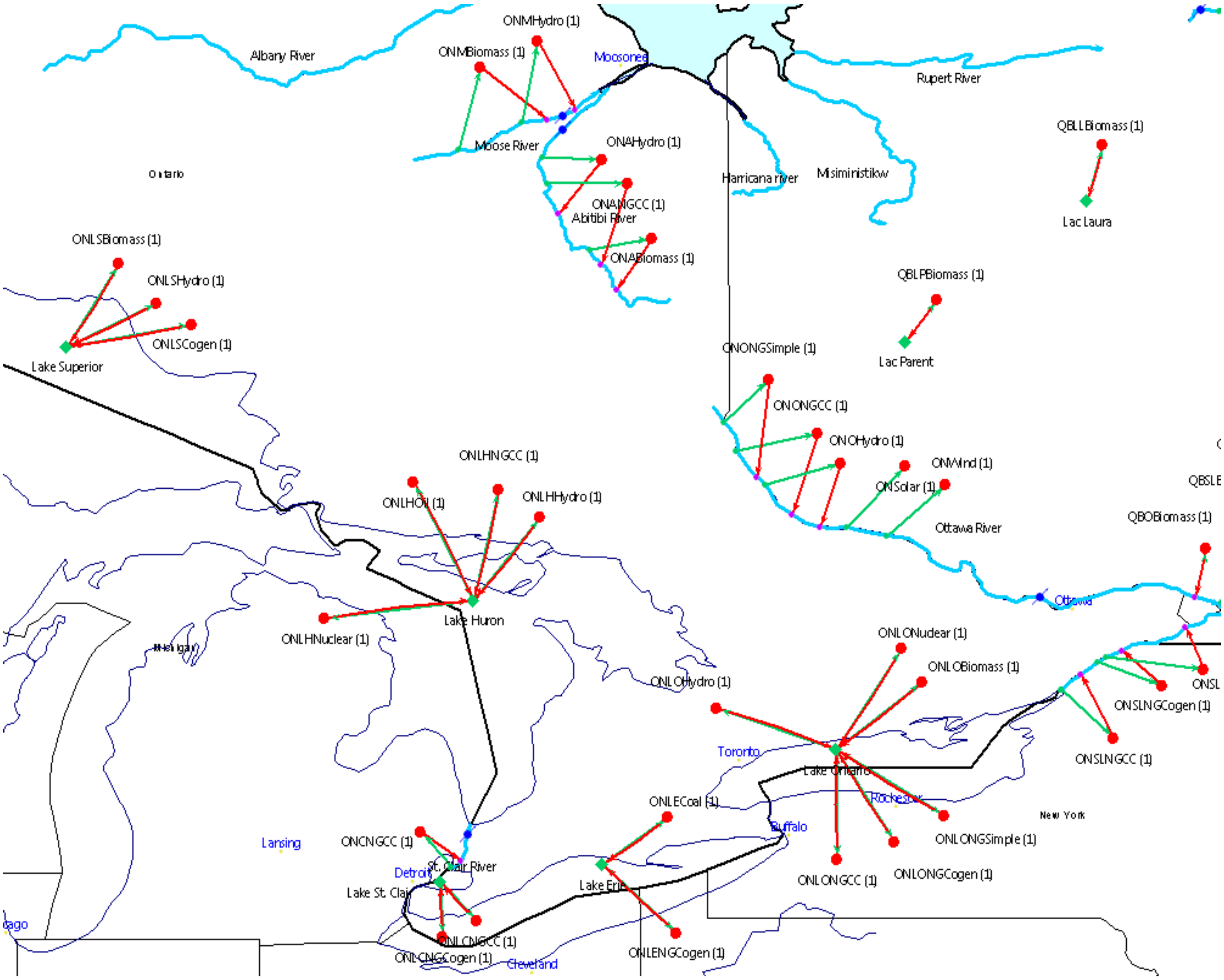

Figure A-5: The WEAP Canada electricity generation model showing Ontario's water demand sites

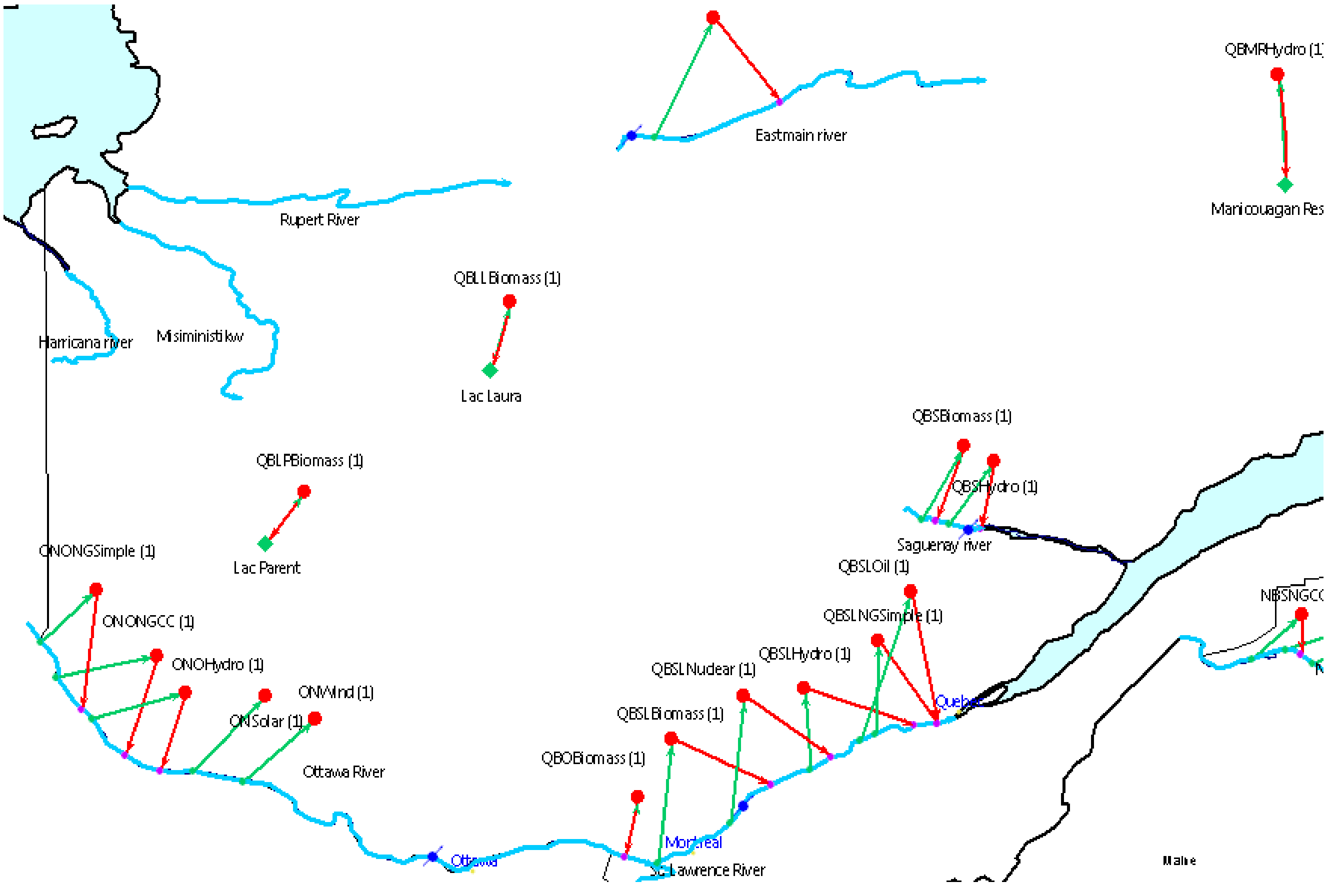

Figure A-6: The WEAP Canada electricity generation model showing Quebec's water demand sites

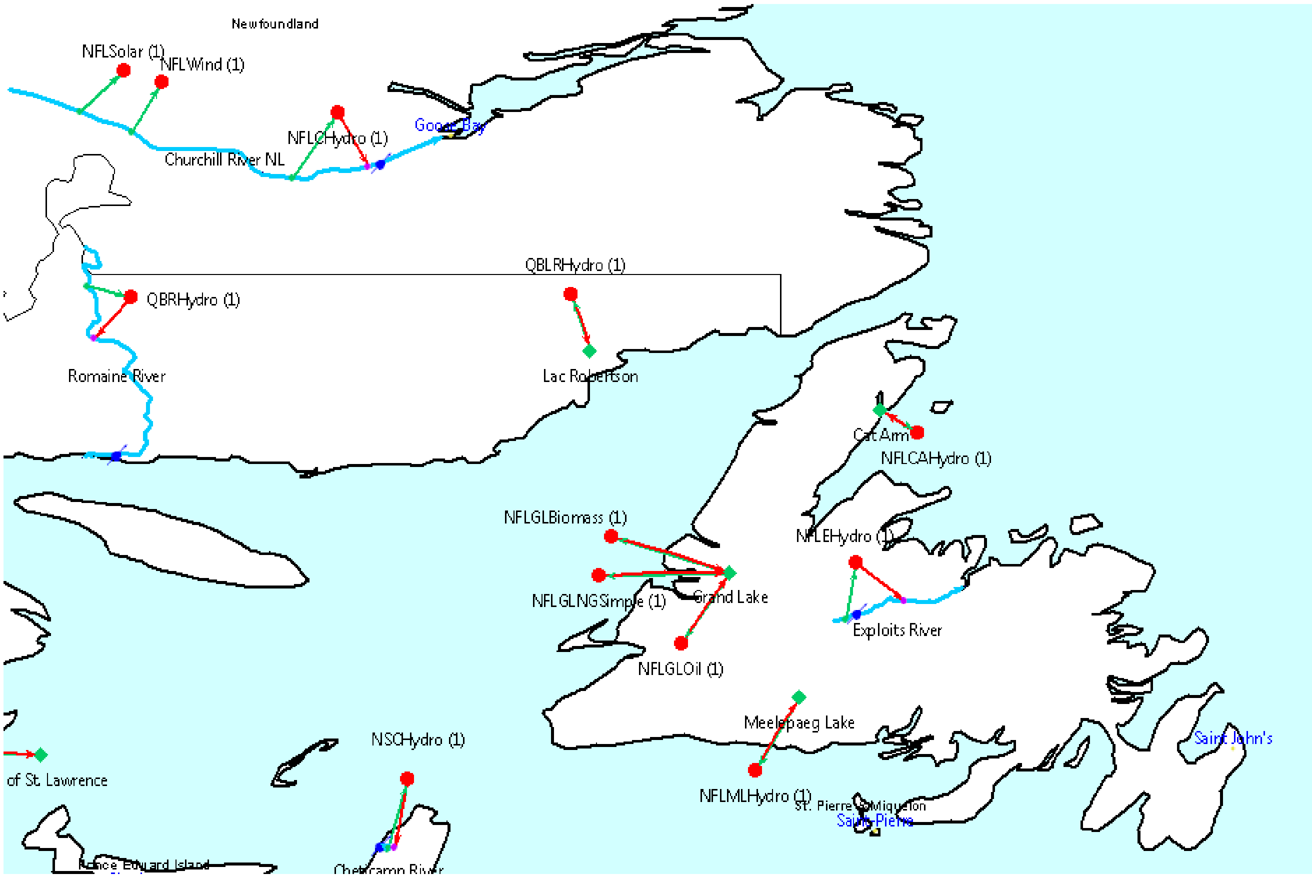

Figure A-7: The WEAP Canada electricity generation model showing Newfoundland and Labrador's water demand sites

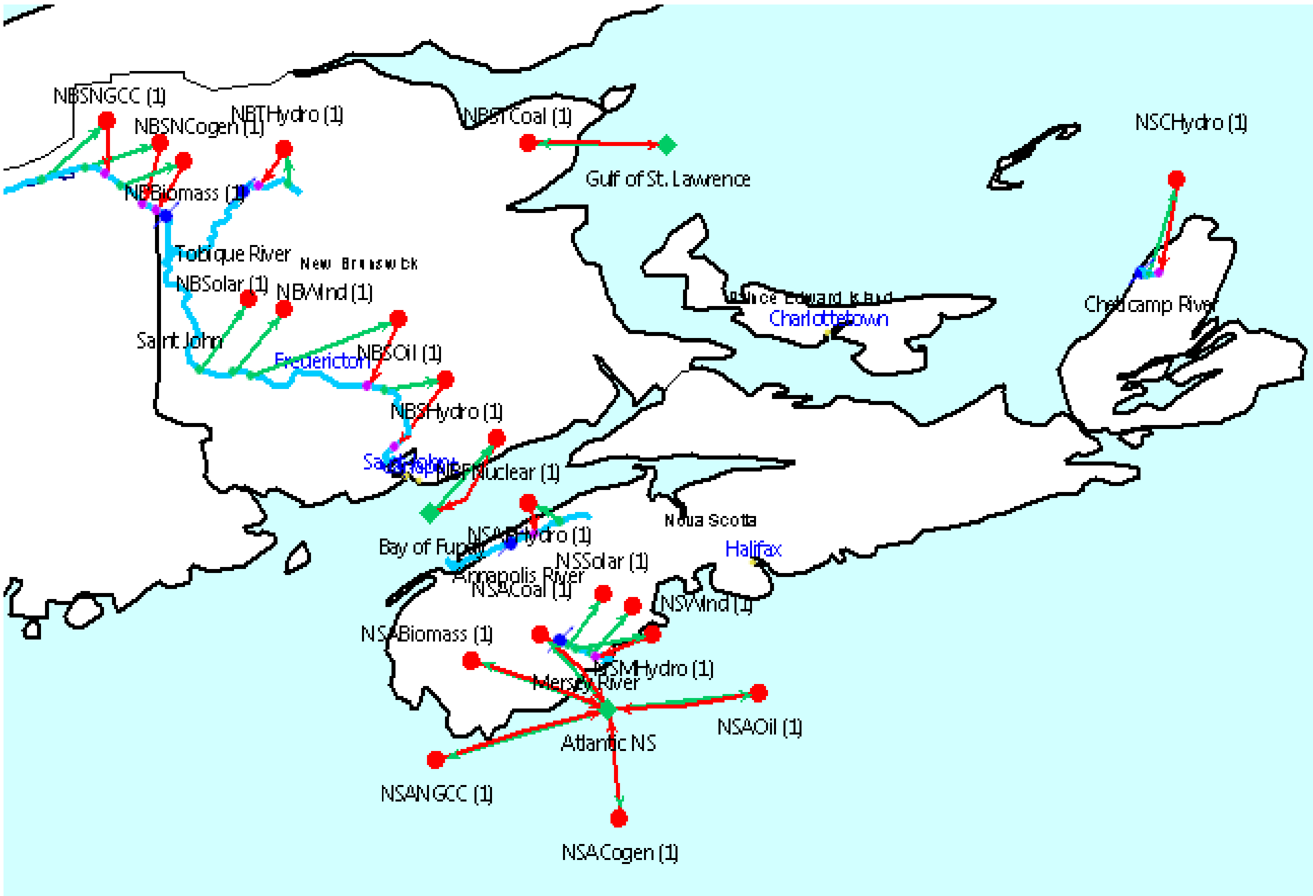

Figure A-8: The WEAP Canada electricity generation model showing New Brunswick's and Nova Scotia's water demand sites

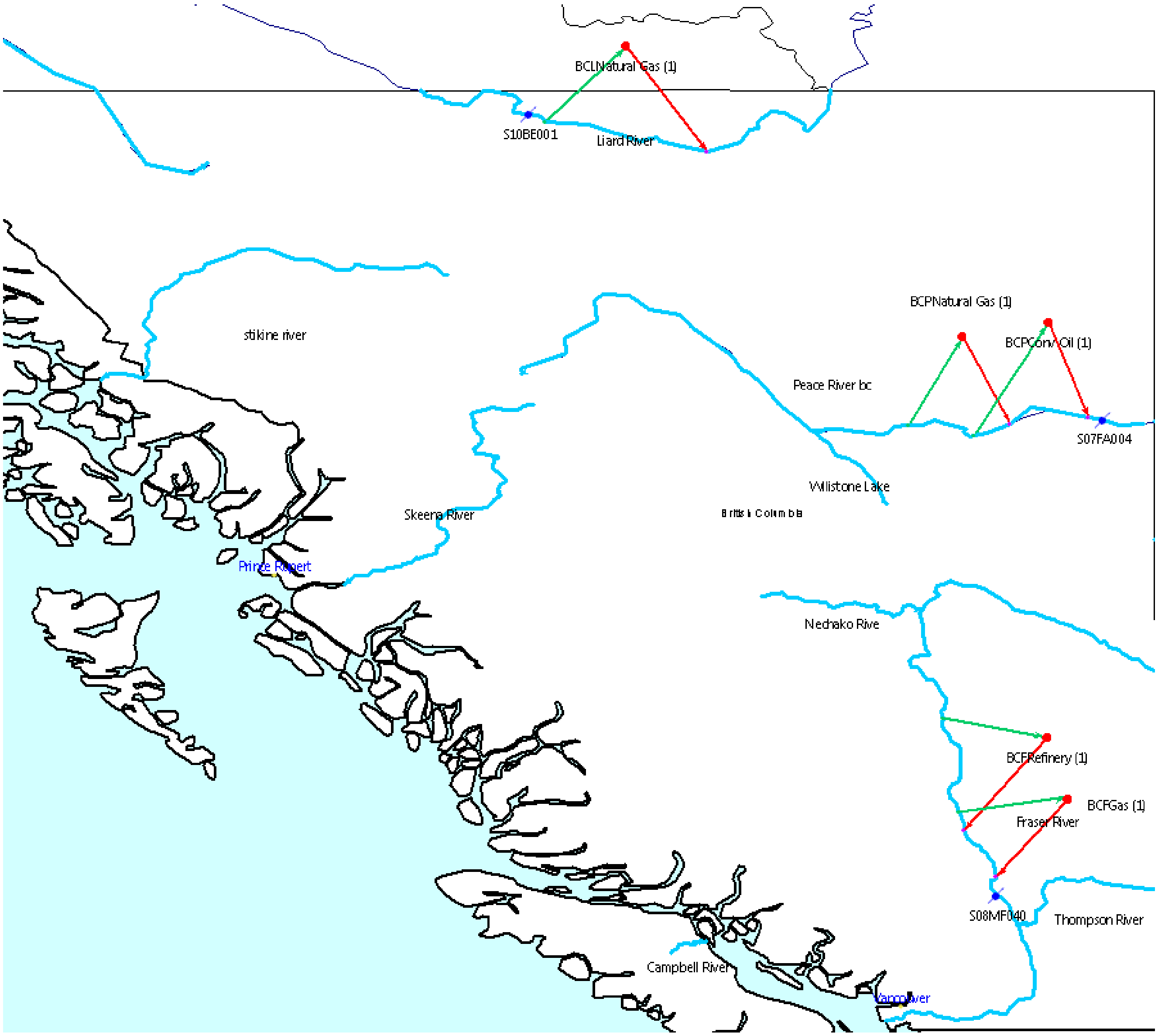

Figure A-9: The WEAP-Canada oil and gas model showing British Columbia's water demand sites

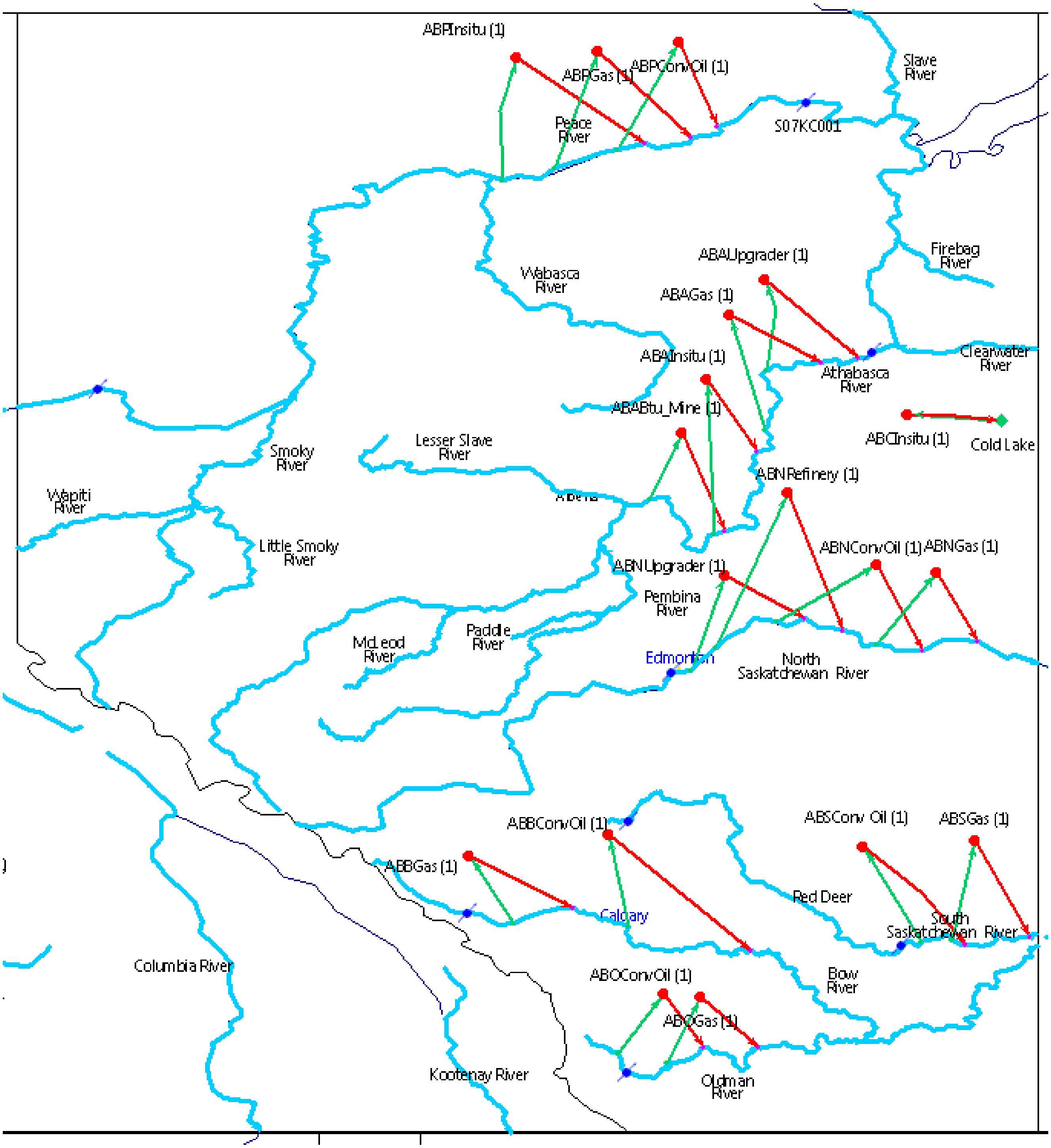

Figure A-10: The WEAP-Canada oil and gas model showing Alberta's water demand sites

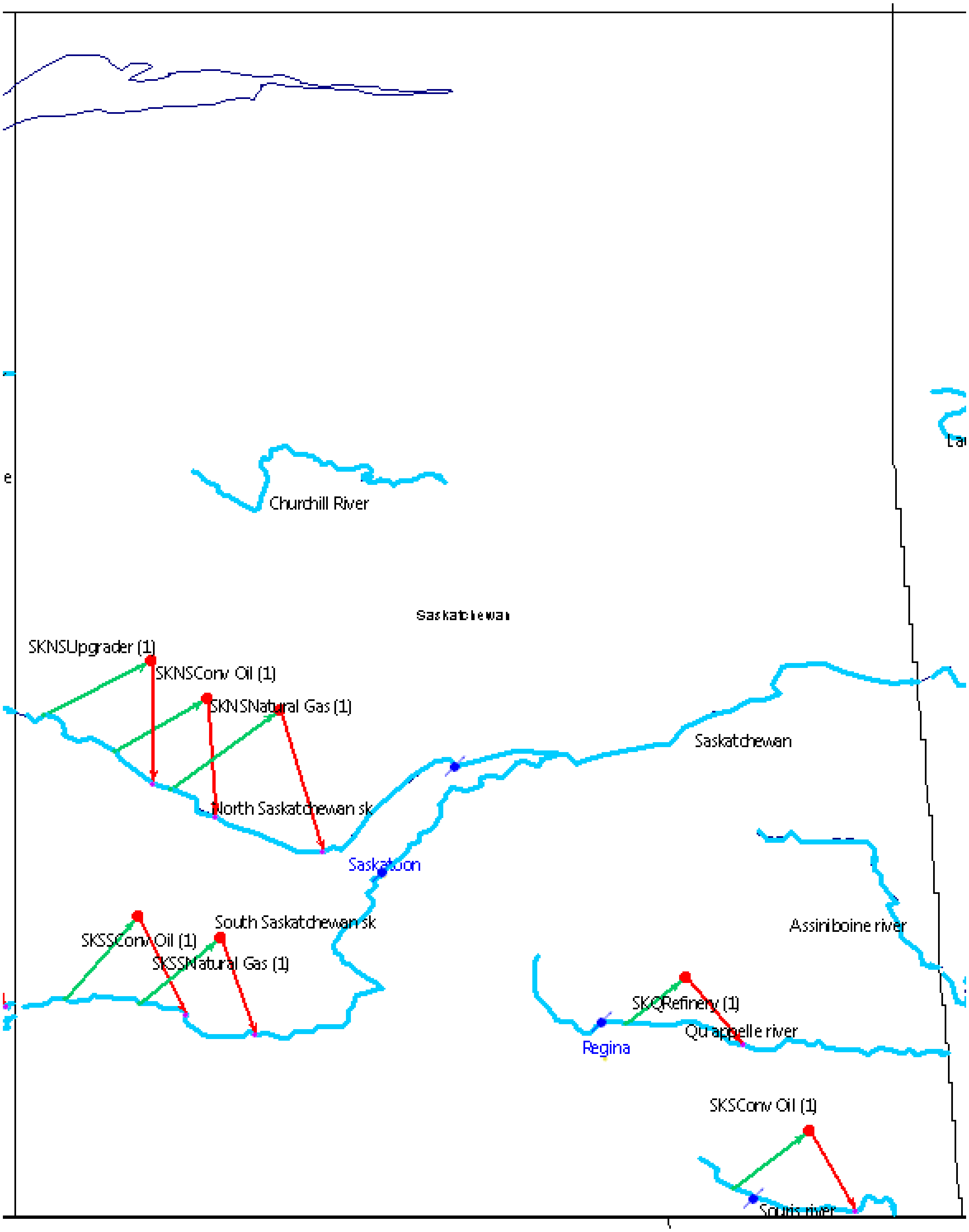

Figure A-11: The WEAP-Canada oil and gas model showing Saskatchewan's water demand sites

Figure A-12: The WEAP-Canada oil and gas model showing Manitoba's water demand sites

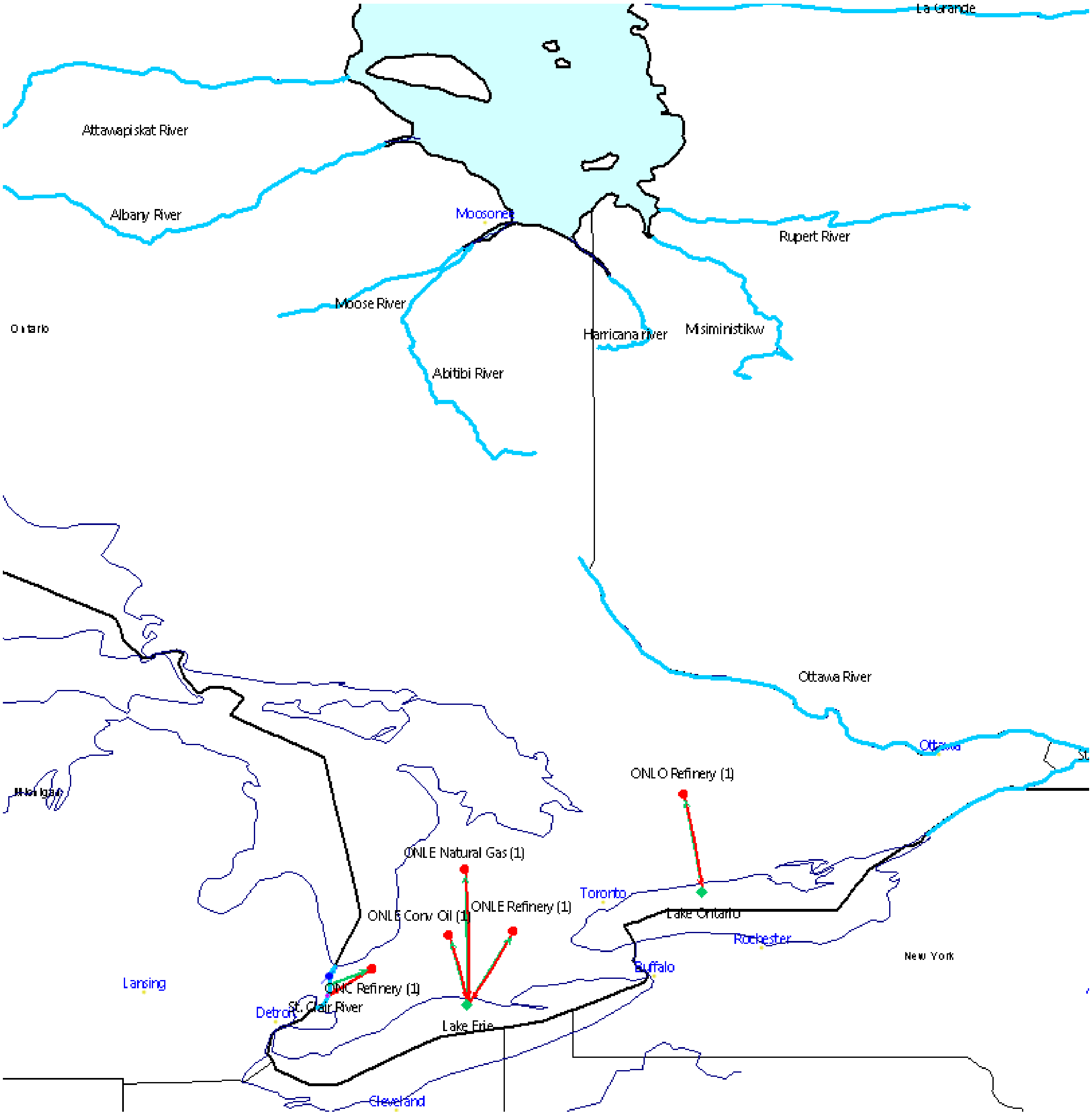

Figure A-13: The WEAP-Canada oil and gas model showing Ontario's water demand sites

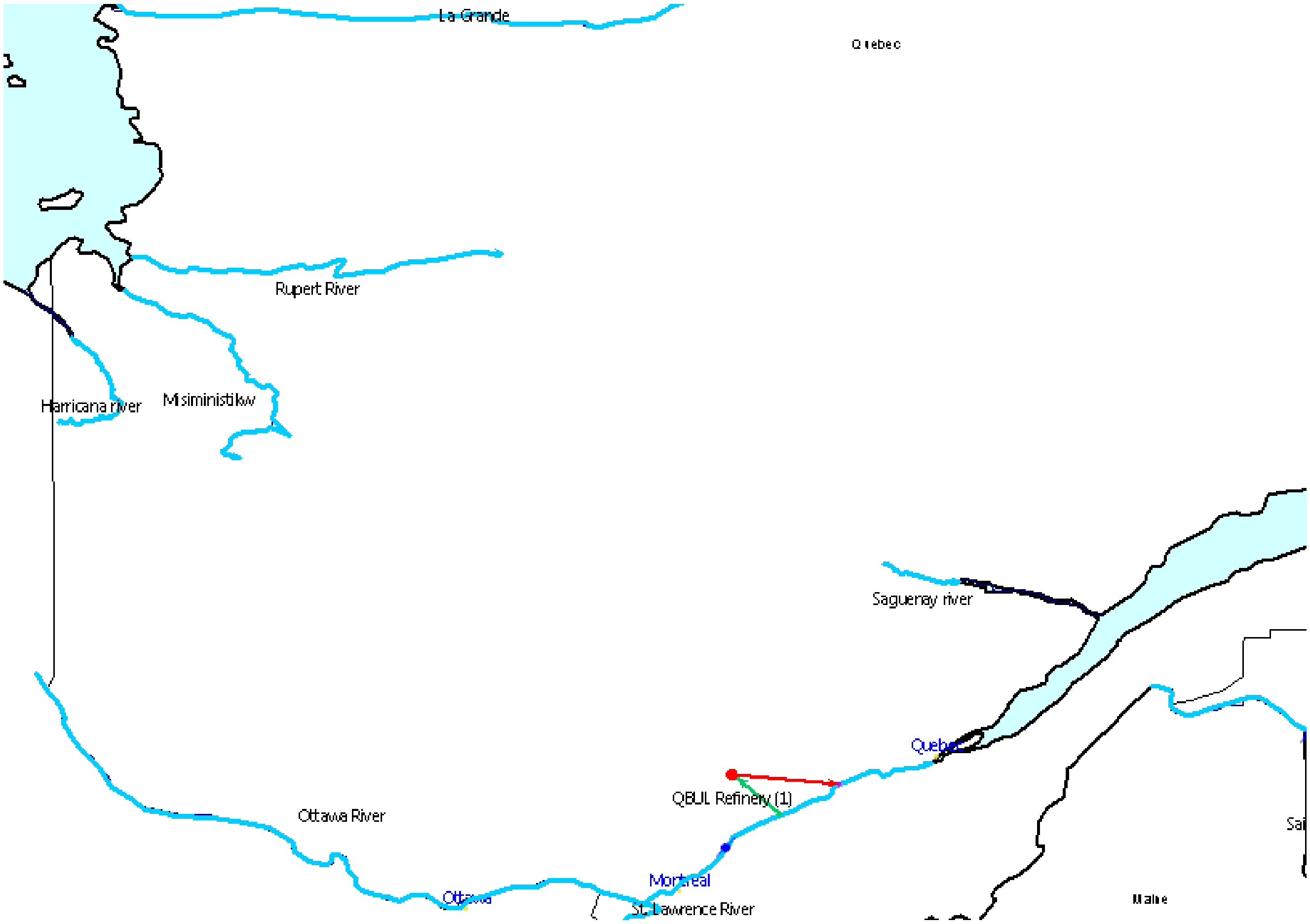

Figure A-14: The WEAP-Canada oil and gas model showing Quebec's water demand sites

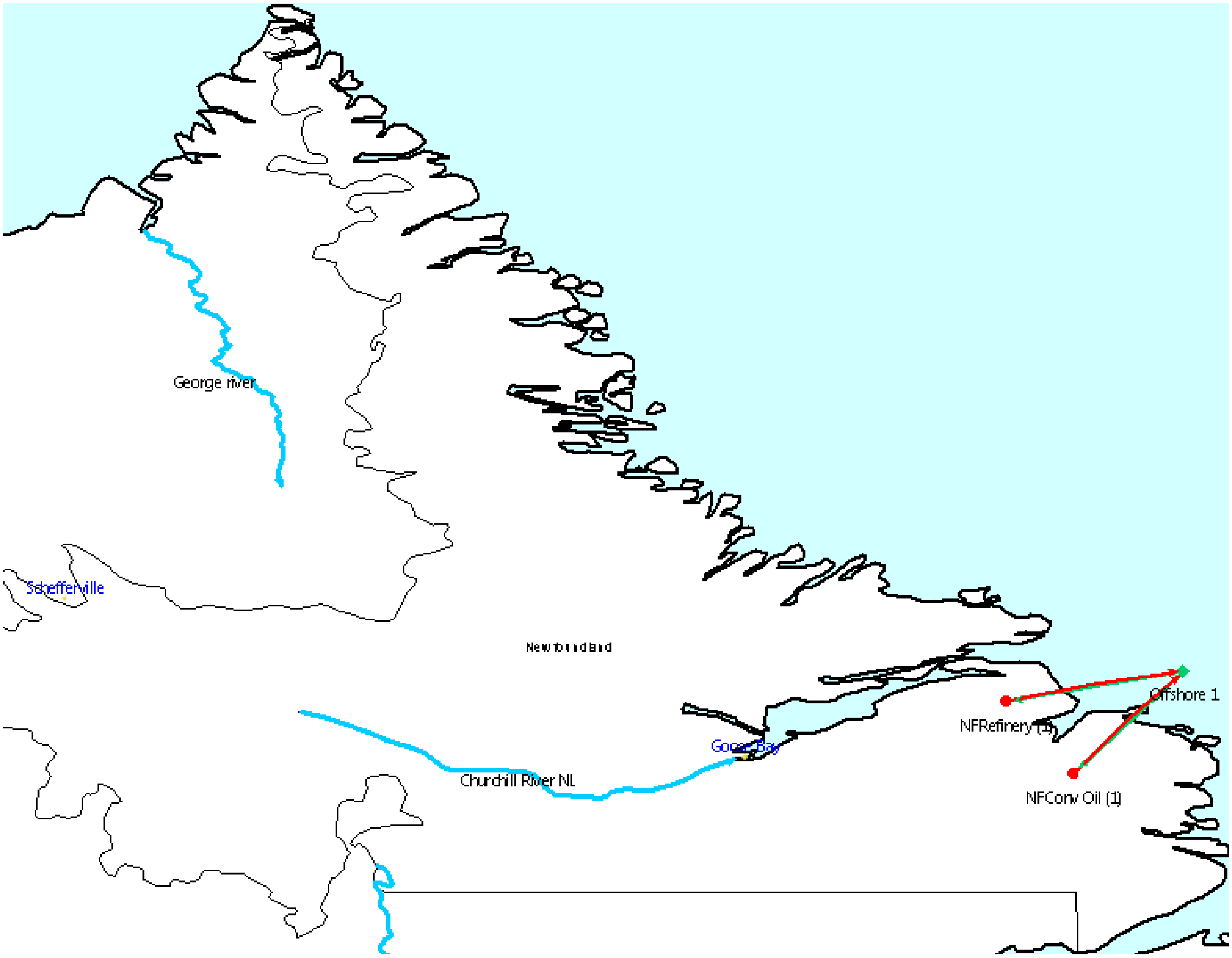

Figure A-15: The WEAP-Canada oil and gas model showing Newfoundland and Labrador's water demand sites

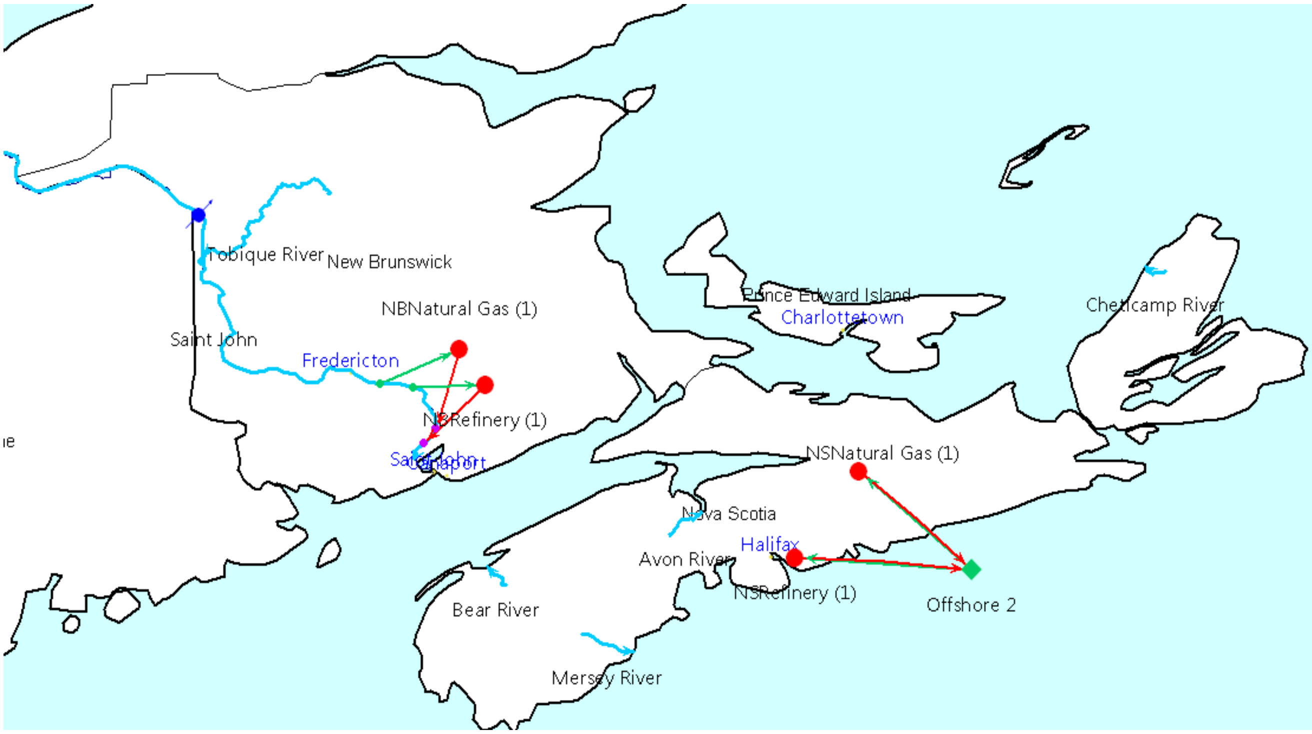

Figure A-16: The WEAP-Canada oil and gas model showing New Brunswick's and Nova Scotia's water demand sites