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Greenhouse Gas Emissions Reductions in Canada Through Electrification of Energy Services

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GREENHOUSE GAS EMISSIONS REDUCTIONS IN CANADA THROUGH ELECTRIFICATION OF ENERGY SERVICES

Greenhouse Gas Emissions Reductions in Canada
Through Electrification of Energy Services

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Executive Summary

Mitigating climate change is one of the formidable challenges of our time. More than 190 nations – including Canada – have agreed and committed to take action to significantly reduce greenhouse gas (GHG) emissions to stabilize the global temperature at 1.5° C above pre-industrial levels. As announced by a joint federal-provincial declaration (Vancouver Declaration), Canada is to undertake efforts to reduce GHG emissions by 30 percent below 2005 levels by 2030. Canada's 2050 reduction targets are set at 80 percent below 2005 levels. Achieving these emissions reduction goals require transformational changes in the way we procure and consume energy.

Electricity as an energy carrier has a pivotal role in achieving economy-wide deeper emissions reductions. It is a highly versatile form of energy and converting electricity into end-use energy services can be done at high efficiencies. As such, an economy-wide transition from current energy end-use fuel mix to one dominated by electricity is an option to satisfy future energy demands, while achieving deep GHG gas emissions reductions. Through electrification, emissions can be moved from some millions of spatially dispersed sources such as vehicles and building sources to several hundred point sources (i.e., electric power generating units), making the emissions reduction more manageable. Furthermore, commercially proven technology exists – for example, wind, solar, tidal, geothermal and nuclear power – to produce electricity with zero GHG emissions. Transitioning to an energy system with electricity as the dominant end-use energy source requires changing the existing infrastructure stock – vehicle fleets, buildings, and equipment – across all sectors of the economy. Furthermore, it requires much larger electricity generation and transmission infrastructure than today. That would inevitably have significant economic impacts resulting from new investments, stranded assets, and changes to energy markets. As such, to set up a realistic technology and policy road map to deploy electrification as a climate change mitigation strategy, it is important to gain insights into those complicating factors through analyses that explicitly model those factors with sufficient spatial, sectoral, and temporal granularity.

The objective of this study is to provide such insights by assessing energy system, environmental, and economic implications of transforming energy end-use conversion technology mix into one dominated by electricity in the residential, commercial, and passenger road transportation sectors of the 10 Canadian provinces. The study does not include the three territories, the industrial sector, or the freight transportation sector. These are questions for further work.

We focus on energy end-use services that can be electrified by utilizing commercial or near to commercialization equipment. In the analysis, we focus on three key questions:

1. What major transitions in energy systems are required to electrify the end-use energy services of the residential, commercial, and passenger transportation sectors?
2. What level of emissions reductions can be achieved through electrification of energy services?
3. What would it cost?

In this analysis, we did not assess implications of electrifying industrial or freight transportation end-use energy demands. However, we estimated the total energy demand of those two sectors to make economy-wide energy and emissions estimates.

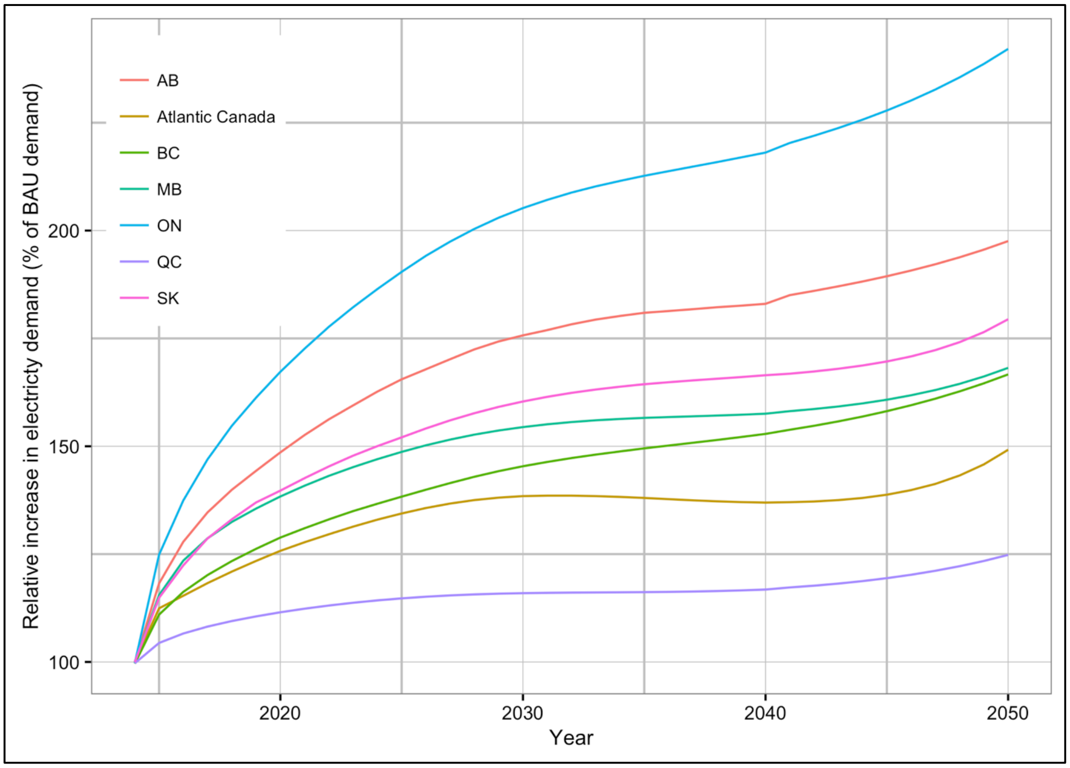
Our Business as Usual (BAU) scenario to 2050 shows that total energy demand in the residential sector grows from 5 percent (in Quebec) to almost 68 percent (in Alberta) depending on the province. In the Atlantic provinces, however, residential sector demand drops by 13 percent over the same period.

As end-use energy services are electrified under our electrification scenario, in most provinces electricity replaces natural gas as a residential heating fuel. In Atlantic Canada, electricity mainly displaces heating oil. The residential sector electricity demand across all provinces increases by 45 percent by 2030 and 66 percent in 2050. The exact increase depends on the region (highest in Alberta and lowest in Quebec). At the same time, combined natural gas demand drops by 48 percent by 2030 and 70 percent by 2050. Similarly, in the commercial sector, electricity displaces natural gas in most provinces and displace heating oil in Atlantic Canada.

In the passenger transportation sector, electricity displaces gasoline and diesel. Deployment of electric vehicles starts at a slow rate as it is constrained by full scale availability of electric vehicles.

Electrification will improve the efficiency of end-use energy conversions significantly. This is due to the higher efficiencies of electrical devices. We find that under electrification, energy intensity of household energy usage drops by up to 30 percent. More profound efficiency improvements are observed in the passenger transportation sector, where energy intensity falls by up to 71 percent.

Figure E.1: Relative Increase in Electricity Demand



Source: CERI

Figure E.1 shows the relative growth in electricity demand compared to the BAU scenario in all provinces. Ontario sees the highest relative electricity demand growth compared to BAU where, by 2050, the electricity demand is almost 2.5 times that of BAU. This is mainly due to the higher population and associated building and transportation energy demand. Ontario is followed by Alberta, where 2050 demand is 2 times that of BAU. The lowest demand growth is observed in Quebec and the Atlantic provinces. Quebec's 2050 electricity demand is only 20 percent higher than the BAU and this increase is driven predominantly by passenger transportation sector demand. The estimated cost of building and operating electric power systems under the electrification scenario is 1.5 to 3 times than the BAU scenario. The highest total electricity sector cost was observed in Ontario and the lowest in Quebec.

GHG emissions reductions from electrification of residential, commercial, and passenger transportation sectors over the analysis period (2020-2050) in all Canadian provinces are depicted in Table E.1.

Table E.1: GHG Emissions Reductions Achievable by Electrifying End-use Energy Demand of Residential, Commercial and Passenger Transportation Sectors of Canadian Provinces

	Emissions reduction (% of 2005 GHG emissions)		Cumulative emissions reductions in the period 2020-2050 (% of study BAU emissions) [i]	GHG emissions abatement cost ($/tCO2eq) [ii]
	In 2030	In 2050		
Atlantic Canada	7%	13%	16%	14
Quebec	9%	35%	11%	36
Ontario	14%	31%	20%	114
Manitoba	11%	24%	17%	8
Saskatchewan	8%	16%	13%	58
Alberta	6%	16%	8%	176
British Columbia	9%	16%	10%	13

[i] The business as usual (BAU) scenario assumes that end-use energy demands would be satisfied by current technology and fuel mix
[ii] Abatement cost is calculated based on cumulative emissions reduction in the period 2020-2050

Source: CERI

The exact level of achievable reductions varies by province (Table E.1). The GHG emissions reduction achievable in 2030 is 6 percent (in Alberta) to 14 percent (in Ontario) below 2005 levels. In 2050, the achievable GHG emissions reductions varies in the range of 16 percent (in Alberta) to 31 percent (in Ontario) below 2005 levels. Details of the sector results are shown in Table E.2.

Table E.2: GHG Emissions and Relative Magnitude of Avoided Emissions by Sector

		Electrification (million tCO2eq)			Emissions reduction (% of 2005 provincial emissions)	
Region	**Sector**	**2020**	**2030**	**2050**	**2030**	**2050**
Alberta	Residential	7.6	3.9	2.4	3.6%	6.3%
	Commercial	1.8	1.3	1.4	2.6%	3.4%
	Passenger Transportation	7.5	8.2	0.9	0.1%	3.7%
	Freight Transportation	22.1	28.4	40.5	0.0%	0.0%
	Industrial	149.9	163.6	169.9	0.0%	0.0%
	Electricity	17.3	17.1	16.0	0.2%	1.3%
Atlantic Canada	Residential	2.1	0.7	0.3	4.4%	4.9%
	Commercial	0.3	0.3	0.3	1.8%	2.0%
	Passenger Transportation	5.8	5.4	0.4	0.0%	7.1%
	Freight Transportation	6.0	6.0	6.0	0.0%	0.0%
	Industrial	11.7	11.0	10.9	0.0%	0.0%
	Electricity	2.2	2.3	1.6	0.5%	-1.3%
British Columbia	Residential	3.9	2.3	1.5	4.8%	8.4%
	Commercial	0.8	0.6	0.5	3.4%	3.6%
	Passenger Transportation	7.8	7.7	0.8	0.6%	11.1%
	Freight Transportation	14.1	16.4	21.2	0.0%	0.0%
	Industrial	20.1	24.1	24.3	0.0%	0.0%
	Electricity	0.1	0.3	2.0	-0.3%	-2.9%
Manitoba	Residential	1.2	0.7	0.5	4.4%	6.9%
	Commercial	0.4	0.3	0.3	6.3%	7.6%
	Passenger Transportation	3.1	3.0	0.3	0.3%	13.3%
	Freight Transportation	3.2	3.7	4.7	0.0%	0.0%
	Industrial	4.9	4.8	4.9	0.0%	0.0%
	Electricity	0.2	0.2	1.0	-0.1%	-4.1%
Ontario	Residential	16.8	8.7	5.2	7.2%	10.8%
	Commercial	3.8	2.9	3.6	6.2%	9.2%
	Passenger Transportation	29.5	27.4	2.7	0.4%	11.6%
	Freight Transportation	27.9	32.6	43.3	0.0%	0.0%
	Industrial	48.4	49.0	49.8	0.0%	0.0%
	Electricity	6.5	6.5	7.0	0.0%	-0.2%
Quebec	Residential	4.5	2.5	1.7	3.4%	4.4%
	Commercial	1.6	1.3	1.5	4.5%	6.3%
	Passenger Transportation	26.1	23.9	2.4	1.4%	24.2%
	Freight Transportation	17.1	19.9	25.5	0.0%	0.0%
	Industrial	22.9	22.8	23.0	0.0%	0.0%
	Electricity	0.1	0.1	5.0	-0.1%	-5.5%
Saskatchewan	Residential	1.5	0.7	0.3	1.9%	2.4%
	Commercial	0.4	0.3	0.4	1.8%	2.5%
	Passenger Transportation	3.4	3.3	0.3	0.0%	4.2%
	Freight Transportation	6.8	8.1	10.2	0.0%	0.0%
	Industrial	18.4	18.6	17.7	0.0%	0.0%
	Electricity	6.5	3.2	1.6	0.2%	3.1%

Source: CERI

Although a considerable amount of emissions reductions is achieved by electrifying the residential, commercial and passenger transportation sectors, a larger amount of emissions would still be produced by industrial activities, and freight transportation. Mitigation actions are required in those sectors to achieve deeper emissions reductions.

Higher investment and operating costs will inevitably lead to higher average costs of electricity. We estimated the increase in average cost to be 16-77 percent in 2050 depending on the province. GHG emissions abatement cost of electrification is lower ($14-$38/tCO2eq) in Quebec, Manitoba, British Columbia and the Atlantic provinces. Abatement costs are higher in Alberta, Ontario, and Saskatchewan. It is well over $100/tCO2eq in Alberta and Ontario. Availability of natural gas-fired generation with carbon capture and storage leads to 8-18 percent lower abatement cost compared to an electricity supply without that technology in those three provinces.

Electrification of end-use energy services will make transformational changes in energy systems and will change the way we source and consume energy. However, the level of end-use energy services will remain unchanged. To achieve emissions reductions through electrification requires both transforming the end-use energy conversion infrastructure stock as well as decarbonizing the electricity supply. This requires coordinated efforts in policy, technology developments, and energy infrastructure deployments.

Chapter 1: Introduction

In Paris in November of 2015, 195 nations agreed to reduce their greenhouse gas (GHG) emissions and do their best to keep global warming to well below 2 degrees Celsius compared to pre-industrial levels. With a signed version of the agreement, commonly known as the "Paris Agreement", the signatories also agreed to "pursue efforts to" limit the global temperature rise 1.5° C above pre-industrial levels. The Paris agreement allows the ratified nations to set their own targets and mechanisms to achieve emissions reductions. Canada is one of the signatories of the Paris agreement and the Canadian House of Commons formally ratified the agreement on October 5, 2016.[1]

As announced by a joint federal-provincial declaration (Vancouver Declaration), Canada is to undertake joint efforts to reduce GHG emissions by 30 percent below 2005 levels by 2030 to meet or exceed Paris agreement commitments.[2] Canada's 2050 reduction targets are set at 80 percent below 2005 levels.[3]

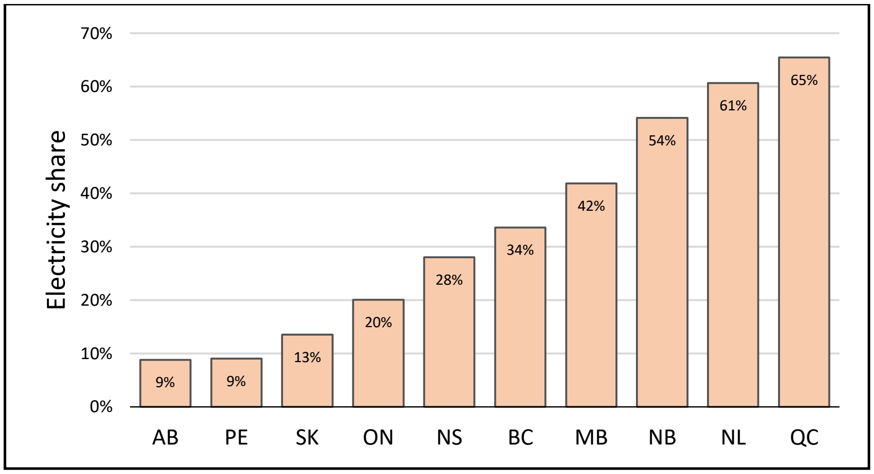
Electricity as an energy carrier has a pivotal role in achieving economy-wide deeper emissions reductions. It is a highly versatile form of energy and converting electricity into end-use energy services can be done at high efficiencies. As such, an economy-wide transition from the current energy end-use fuel mix to one dominated by electricity is an option to satisfy future energy demands while achieving deep GHG gas emissions reductions.

Through electrification, emissions can be moved from some millions of spatially dispersed sources such as vehicles and buildings, to several hundred point sources (i.e., electric power generating units), making the emissions reduction more manageable. Furthermore, commercially proven technology exists – for example, wind, solar, tidal, geothermal and nuclear power – to produce electricity with zero GHG emissions.

Transitioning to an energy system with electricity as the dominant end-use energy source requires changing the existing infrastructure stock—vehicle fleets, buildings, and equipment—across all sectors of the economy. Furthermore, it requires much larger electricity generation and transmission infrastructure than today. That would inevitably have significant economic impacts resulting from new investments, stranded assets, and changes to energy markets.

[1] Liberal government formally ratifies Paris climate accord, Globe and Mail, Oct. 25, 2016. http://www.theglobeandmail.com/news/politics/ottawa-formally-ratifies-paris-climate-accord/article32267242/
[2] Vancouver Declaration on clean growth and climate change. http://www.scics.gc.ca/english/conferences.asp?a=viewdocument&id=2401
[3] Canada sets 2050 emission target as Trump Presidency Approaches http://ipolitics.ca/2016/11/17/canada-sets-2050-emissions-target-as-trump-presidency-approaches/

Figure 1.1: Electricity Share of the Residential Sector Energy Mix in Canadian Provinces, 2014



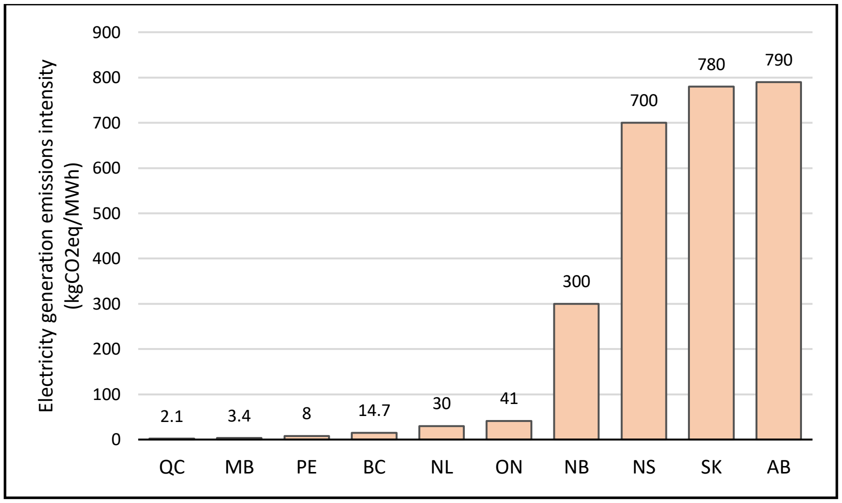
Source: NRCan,[4] Figure by CERI

In Canada, electricity share of the end-use energy mix varies by province and final consuming sector (residential, commercial, etc.). Figure 1.1 depicts the shares of electricity in the final end-use energy mix in different provinces in 2014. As can be seen from Figure 1.1, the electricity share varies from 9 percent in Alberta and Prince Edward Island to as high as 65 percent in Quebec. In the same year, electricity share in the commercial and institutional sector energy mix varies from 32 percent (in Alberta) to 51 percent (in Quebec). Therefore, if electrification of end-use energy services is to be used as a climate change mitigation strategy, the level of required changes varies by province.

The viability of electrification as a GHG emissions reduction strategy depends on the electric power sector's ability to produce and deliver low or zero GHG emissive electricity. In Canada, the primary jurisdiction over the electricity supply lies at the provincial level. The level of changes required in the electricity supply to decarbonize the power supply varies greatly by province.
Figure 1.2 shows the GHG emissions intensity of Canadian provincial electricity generation mixes in 2014. It is evident that some provinces (mainly Alberta, Saskatchewan, New Brunswick and Nova Scotia) require significant changes in the generation mix to reduce emissions from the electricity sector. Other provinces, although currently with low emissive electricity supply, may face challenges in sustaining those lower levels of emissions under increasing demand resulting from economy-wide electrification of energy services.

[4] NRCan Comprehensive Energy Use Database
http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/data_e/query_system/querysystem.cfm?attr=0

Figure 1.2: GHG Emissions Intensity of Electricity Generation Mix of Canadian Provinces, 2014



Source: National Greenhouse Gas Inventory, 2016,[5] Figure by CERI

Study Scope and Objectives

Decarbonizing the electricity supply and electrifying end-use energy services is a technology option to achieve economy-wide deeper emissions reductions. However, the viability of that option is complicated by existing infrastructure stock, path dependencies, resource constraints, and technology availability. As such, to set up a realistic technology road map to deploy electrification as a climate change mitigation strategy, it is important to gain insights into those complicating factors through analyses that explicitly model those factors with sufficient spatial, sectoral, and temporal granularity.

The objective of this study is to provide such insights by assessing energy system, environmental, and economic implications of transforming energy end-use conversion technology mix into one dominated by electricity in the residential, commercial, and passenger road transportation sectors of the 10 Canadian provinces. The territories were not included in the analysis. One key question we investigate is the level of emissions reductions that can be achieved through electrification compared to Canada's emissions reduction targets and at what cost. We focus on energy end-use services that can be electrified by utilizing commercial or near commercial (i.e., within 10 years) technologies.

Notable exclusions in this study are the industrial sector (including agricultural) and freight transportation sector. Two main reasons lead to the exclusion of these two sectors. First, the level of publicly accessible data to track the existing infrastructure and energy consumption details in those two sectors remains limited. Without such data, it was not possible to build robust models to track current energy use patterns and required transitions. Second, without full insights into the current operations it is not possible to make reliable judgements on technologies that can be used to electrify the end-use services in those two sectors.

[5] Environment and Climate Change Canada, https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=83A34A7A-1

Furthermore, the maturity of the technologies that can electrify the long-haul freight transportation and thermal energy-intensive industrial processes, such as cement production or bitumen extraction, is unclear. Without reliable technology details (e.g., cost, performance) it is not possible to make reliable energy and economic assessments. The three sectors we assessed are important in terms of their contributions to GHG emissions as well as their ability to electrify end-use energy services by utilizing proven technologies.

In the residential and commercial sectors, effectively what is being assessed is the energy use in buildings. Buildings represent a critical piece of a low-carbon future. In 2010, buildings accounted for 32 percent of total global final energy use, and 19 percent of energy-related GHG emissions (including electricity-related).[6]

Building emissions showed little change between 1990 and 2010 due to counterbalancing trends. Population growth, increased floor space from larger house sizes, increased use of air conditioning, and increased uptake of computers, photocopiers, and other equipment —all contributed to upward pressure on energy and emissions. However, improvements in energy efficiency (such as increased uptake of high-efficiency gas furnaces) and changes in fuel mix (such as reduced use of coal and heating oil as fuels) resulted in downward trends on energy consumption and emissions (Environment Canada, 2015c). The net result was a modest increase in energy consumption but a slight decline in emissions from residential buildings (NRCan, 2013).[7]

Residential and commercial sectors have been the focus of current and previous federal and provincial efforts to cut GHG emissions as well as reduce energy demand. Several federal programs are addressing emissions in the building sector, such as the *Ecoenergy Efficiency* suite of programs (including the *Ecoenergy Efficiency for Buildings* and *Ecoenergy Efficiency for Housing* programs), which contributes to improving energy efficiency across Canada. Through Canada's Energy Efficiency Act (1992), regulations are in place for minimum energy performance standards for energy consuming products. These energy efficiency regulations are effectively reducing emissions in key sectors including buildings and industry.

The implementation of building codes is the responsibility of provinces and territories, and the federal government established a national energy code that provinces and territories can adapt or surpass to suit their circumstances. For example, Quebec's *Novoclimat standard* for new houses exceeds the recommendations included in the national model building code.[8] Net zero

[6] http://www.ipcc.ch/pdf/assessment-report/ar5/wg3/ipcc_wg3_ar5_chapter9.pdf
[7]Council of Canadian Academics, Technology and Policy Options for a Low-Emission Energy System in Canada. http://www.scienceadvice.ca/uploads/eng/assessments%20and%20publications%20and%20news%20releases/magna/energyuse_fullreport_en.pdf
[8] Environment and Climate Change Canada (2016), Canada's Second Biennial Report on Climate Change. https://www.ec.gc.ca/GES-GHG/default.asp?lang=En&n=02D095CB-1

carbon building code in Ontario and financial incentives for net zero buildings in Quebec and British Columbia can be considered as the leading provincial electrification policies.[9]

In terms of GHG emissions reduction, the transportation sector remains one of the main challenges. Canada is a vast country with 5,187 kilometers (3,223 miles)[10] from east to west; the transportation industry is one of the major economic sectors (4.7 percent of GDP in 2010[11]). It is also the second largest energy consumer with 23 percent of the total energy demand (2,620 petajoules in 2015[12]) and 24 percent (in 2012)[13] of the overall GHG emissions. As such, transportation sector electrification is seen as one of the climate mitigation tools to meet Canada's efforts to reduce GHG emissions to 30 percent below 2005 by 2030.[14]

In terms of electrifying passenger transportation, two main technologies can be deployed. First, Plugin hybrid electric vehicles (PHEV) can act as a bridging option. A PHEV is powered by two sources: an internal combustion engine (gasoline, diesel, and/or biofuel-fired) and electric motors. Batteries that power the motors are being recharged while the vehicle is driven (i.e., during idling, coasting, and braking). It can also be recharged by plugging into the grid.

Table 1.1: Battery Electric Vehicles Announced by Major Manufacturers

Vehicle Manufacturer	Model	Energy intensity (kWh/100km)	Capital Cost	Fuel Cost[i]
Smart	Fortwo	19.6	$25,750	$ 470
Nissan	LEAF	18.6	$32,698	$ 442
Ford	Focus Electric	23	$34,725	$ 990
BMW	i3	16.8	$43,350	$ 403
Tesla	Model X	22.6	$95,500	$ 542
Chevrolet	Bolt	19.9	$35,170	$ 653

[i]Based on annual driving distance of 20,000 km and average Canadian electricity prices

Source: CERI

In contrast, battery electric vehicles (BEV) operate solely on electricity. In this case, electric motors are the prime movers that utilize electrical energy stored in a battery bank. In contrast to internal combustion engine, electric motors are highly efficient, leading to some significant fuel cost savings. Some recent experimentation across Canada shows electric cars have significant fuel cost savings.

For example, a test conducted by Hydro Quebec cites $1,301 of annual cost savings (for 20,000 km/year of usage). In addition to the savings, an electric car requires less energy per kilometer,

[9] Navius Research (2016), Mitigating Climate Change through Electrification. http://cleanenergycanada.org/wp-content/uploads/2016/10/Navius-Electrification-Modelling-Technical-Report-092016.pdf
[10] Natural Resources Canada
[11] Statistic Canada
[12] National Energy Board
[13] Environment and Climate Change Canada
[14] ibid

0.65 MJ/km (18 kWh/100 km), far less than 2.8 MJ/km (equivalent to gasoline demand of 7.1 L/100 km) for conventional internal combustion engine cars.[15] BEVs are going through rapid developments and several vehicle manufacturers are now selling or are in the process of rolling out fully electric vehicles. Costs and performances (i.e., fuel economy) are listed in Table 1.1.

In this study, we assess the implications of electrification of end-use energy services of residential, commercial, and passenger transportation sectors in ten Canadian provinces. In the analysis, we focus on three key questions:

1. What major transitions in energy systems are required to electrify the end-use energy services of the residential, commercial, and passenger transportations sectors?
2. What level of emissions reductions can be achieved through electrification of energy services?
3. What would it cost?

To gain insights into these questions, we develop a stock-rollover model to simulate the changes in physical infrastructure, an electric power generation unit investment and operations model, and then constructed scenarios to assess electrification as a climate change mitigation option. We then estimate the magnitude of the physical changes required in the energy systems and changes in energy flows within the economy.

We measure the GHG emissions reductions that are plausible through this option against an established baseline (i.e., an energy system mix with fuel mixes that is similar to current levels) as well as the 2005 emissions level of respective provinces. In all cases, we estimate the total cost, fuel cost savings, average cost of electricity, and GHG emissions abatement cost.

[15] Hydro Quebec (2016), Transportation Electrification. http://www.hydroquebec.com/electrification-transport/transport-individuel/cout-energie.html

Chapter 2: Methodology

In this analysis we divided the respective Canadian provincial economies into five main energy demand sectors: residential, commercial, passenger transportation, freight transportation, and industrial. We deployed large scale electrification in the first three sectors as a climate change mitigation strategy. To conduct systematic analysis of costs and emissions under large scale electrification, scenarios are constructed.

Scenario Development

The analysis is developed around three main scenarios that represent two end-use demand scenarios and three electricity supply scenarios. These scenarios are listed in Table 2.1 and are described in the remainder of this section.

Table 2.1: Scenario Matrix

		Electricity supply scenarios		
		Business as Usual Scenario	High % of Hydropower and Renewables plus Natural Gas Generation	Scenario S1 plus Carbon Capture and Storage
Demand side scenarios	Business as usual scenario	BAU scenario		
	Electrification scenario		S1	S2

Source: CERI

BAU: This scenario assumes that the technology stock that is being utilized to satisfy end-use energy services (e.g., space heating, water heating, passenger transportation, etc.) will follow the currently observed technology transition trends, and minimum cost approach. Electricity supply will follow minimum cost approach or, where applicable, integrated resource plans of respective provinces. This scenario is set to be the reference or business as usual scenario (BAU).

Scenario S1: Scenario S1 assumes that in each Canadian province, end-use energy service demand of residential, commercial, and passenger transportation sectors is satisfied by a device stock that converts electricity into energy services (e.g., space heating, water heating, commuting). The electricity supply is decarbonized by deploying technically feasible low/zero GHG emissive power generation options available in respective provinces. New nuclear power and fossil fuel-fired power generation with carbon capture and storage (CCS) are excluded. Existing nuclear power units (in Ontario and New Brunswick) and CCS units (Boundary Dam coal CCS unit in Saskatchewan) were operated until their retirements.

Scenario S2: Scenario S2 assumes the same demand side technology stock as Scenario S1. Electricity supply is also decarbonized using the resources available in respective provinces. However, natural gas power generation with CCS was allowed to be deployed after 2025. New nuclear power deployments are excluded.

Under all scenarios, macro-economic factors such as population and provincial gross domestic product (GDP) are assumed to be the same. Consequently, the final energy service demand (e.g., level of space heating, total passenger kilometres travelled, etc.) is set to be the same.

Under the electrification scenarios, energy system transitions are assumed to take place in the period from the present (i.e. 2016) till 2050. The end-use energy conversion device stock (e.g., furnaces, boilers, vehicles, etc.) in each electrified sector is adjusted as new infrastructure is needed or as existing ones retire. Due to the lead time required to plan and deploy electricity generating units, new units were added in 5-year intervals starting in 2020.

General Model Structure

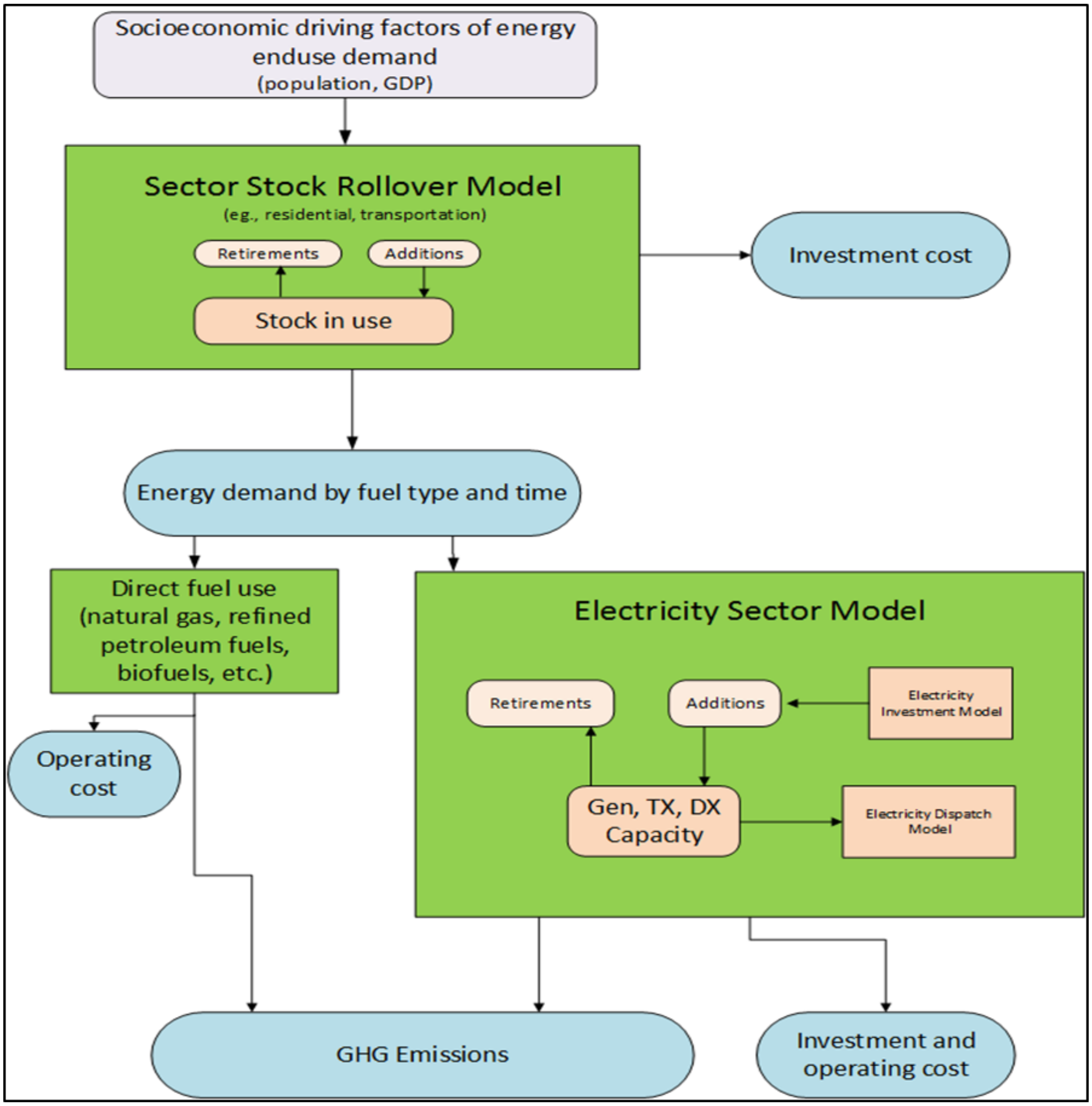
The model that was developed for the analysis consists of stock-rollover modules, electricity supply module, energy and emissions assessment modules and economic cost estimation modules. The general model structure is depicted in Figure 2.1. The general modeling framework was developed by following a previous study by Williams et al., 2012[1] that explored deep decarbonizing pathways for California. The model was developed and calibrated within CERI.

The end-use energy demand over time (2016-2050) and space (i.e., 10 provinces) are estimated using a stock-rollover model. Utilization of stock-rollover methodology allows simulation and tracking of physical infrastructure at a disaggregated level. Through individual sector models, the demand for different fuel types by space and time are determined. In the case of non-electricity fuel demands, estimation of total fuel demands and associated GHG emissions is straightforward and is a function of the total final energy service demand and conversion efficiencies of the device stock that converts fuel into energy services (lighting, heating, mobility, etc.).

In case of energy services that are satisfied using electricity, primary energy demands and associated GHG emissions are calculated by the electricity sector model by taking into account the installed generation capacity, conversion efficiencies, resource availability, and transmission/distribution losses. Economic cost calculation submodules calculate the investment and operation costs associated with different sectors.

[1] Williams, J. H. et al. The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity. Science 335, 53–59 (2012).

Figure 2.1: General Model Structure



Source: CERI

Residential Sector Model

Currently, the main fuel used in the Canadian residential sector for space heating is natural gas. Few exceptions do exist however. For example, in some Atlantic provinces heating oil is used as the primary space heating fuel. In Quebec, electricity is already being used for space heating. Under electrification scenario, the natural gas-fueled equipment systems are mainly substituted with electric ones (i.e., electric baseboards and heat-pumps). To analyze the effects of this change in the equipment stock and in the residential final energy demand, one needs to track the stock of different vintages of each equipment over time.

A stock-rollover model of the energy end-use services is developed to construct projections of residential sector energy demand in the analysis period. This approach requires data on initial composition of equipment (including vintage, fuel type, efficiencies, etc. of each stock of equipment) as well as estimates of the useful lives of each type of equipment. The mechanism tracks building stock and equipment stock vintage – the year in which a building was constructed or a piece of equipment purchased – by province and by housing type (i.e., single-detached, single-attached, apartments, and mobile homes).

In this model, each equipment stock retires following an assumed retirement function that takes into account the expected lifetime of equipment type. New equipment additions in each year has two parts: 1) equipment stock that replaces any retiring equipment; and 2) additions to the equipment stock that are installed in new houses. First, total new additions for each year is calculated using the retirement function and the estimated housing stock within the analysis period. Then, these new sales in each year is decomposed to different equipment types (e.g., medium efficiency natural gas, high efficiency natural gas, electric baseboards, heat pumps, etc.) under different scenarios.

Under the BAU scenario, the new sales of each equipment follow its historic trend. However, under the electrification scenario the new sales follow an S-shaped adoption curve and reaches a mix in 2050 that is dominated by electrical devices. For example, under electrification scenario, the new sales of heat-pumps and electric baseboards for space heating reach 70 percent and 20 percent, respectively of total new equipment sales for space heating equipment in 2050.

Currently the most common type of heat pump found in Canadian houses is the air-source heat-pumps. An air-source heat pump absorbs heat from the outdoor air in winter and rejects heat into outdoor air in summer. However, geothermal heat pumps, which draw heat from the ground or ground water, are becoming more widely used, particularly in British Columbia, the Prairies and central Canada.

Although heat pumps have lower energy costs, they are more expensive than the conventional space heating methods. It is also important to realize that heat pumps will be most economical when used year-round. Investing in a heat pump will make more sense if they are going to be used for both summer cooling and winter heating.

Today's heat pumps can reduce the electricity use for heating by approximately 50 percent compared to electric resistance heating such as furnaces and baseboard heaters. In recent years, air-source heat pump technology has advanced so that it now offers a legitimate space heating alternative in colder regions. Furthermore, for homes without ducts, air-source heat pumps are also available in a ductless version called a mini-split heat pump. In addition, a special type of air-source heat pump called a "reverse cycle chiller" generates hot and cold water rather than air, allowing it to be used with radiant floor heating systems in heating mode.

In this study, the current natural gas equipment systems for all end-uses are substituted with the above-mentioned technologies under the electrification scenario and the final energy use is calculated accordingly. The residential sector module projects the sector's final energy consumption by type of fuel and by province in each year of the analysis period for four end-uses shown in Table 2.1. The main driver of the equipment stock changes over time is the housing stock, whose projection is explained in Appendix A.

Final energy consumption under each demand side scenario (Table 2.1) is calculated for all end-uses shown in Table 2.2 for all home types in each province by taking into account the total service demand (e.g., space heating, water heating, space cooling, etc.) and equipment stock that is available to provide the energy service. As described above, equipment stock at any given year is estimated using the stock roll-over model. For example, Figure 2.2(a) depicts the space heating equipment stock in single detached houses in Alberta under the electrification scenario. This equipment is utilized to satisfy the space heating service demand of single detached houses (Figure 2.2(b)) resulting in a total fuel mix that is depicted in Figure 2.2(c).

By following a similar procedure, time series data of total energy demands are constructed for all end-uses in all housing types under each scenario within the analysis period. For example, the residential final energy demand for space heating end-use for single-detached houses in Alberta, in the first (2014) and the last year (2050) of projection is shown in Table 2.3 under the two scenarios. Similarly, final energy consumption for water heating in single detached houses in Alberta (in 2014 and 2050) is shown in Table 2.4.

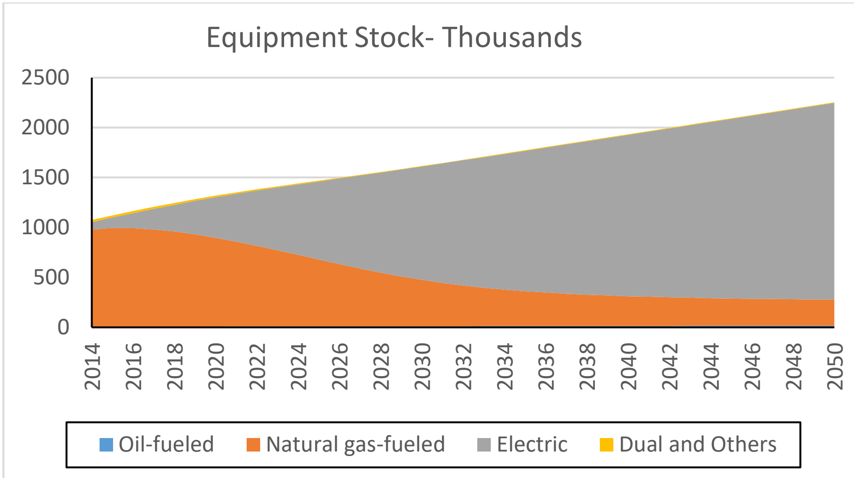
Different time series data sets pertain to energy demand of different end-uses and housing types and are then aggregated to construct the full residential sector energy demand (by fuel type and by year) of each province. Full details and mathematical relationships of the residential sector models are presented in Appendix A.

Table 2.2: Residential Sector End-uses and Device Stock

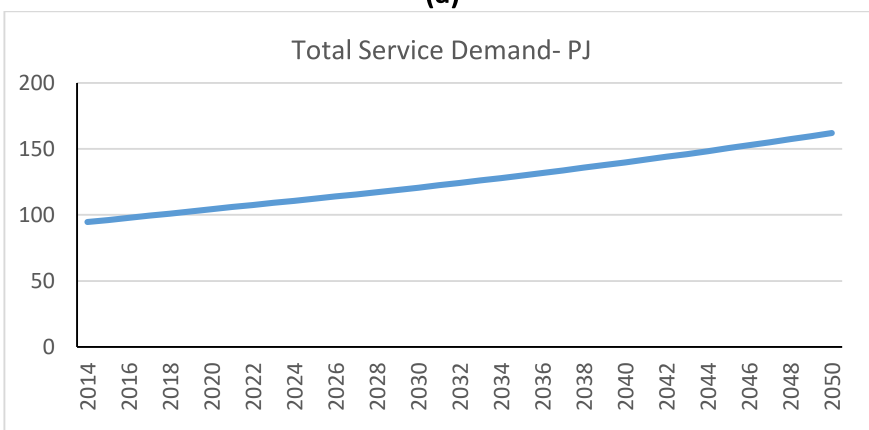
End-uses	Equipment Type
Space Heating	Heating Oil – Normal Efficiency
	Heating Oil – Medium Efficiency
	Heating Oil – High Efficiency
	Natural Gas – Normal Efficiency
	Natural Gas – Medium Efficiency
	Natural Gas – High Efficiency
	Electric
	Heat Pump
	Other
	Wood
	Dual Systems
	Wood/Electric
	Wood/Heating Oil
	Natural Gas/Electric
	Heating Oil/Electric
Space Cooling	Electricity
Water Heating	Electricity
	Natural Gas
	Heating Oil
	Steam
	Wood
	Other
Appliances	Refrigerator (Electricity)
	Freezer (Electricity)
	Dishwasher (Electricity)
	Clothes Washer (Electricity)
	Clothes Dryer (Electricity, Natural Gas)
	Range (Electricity, Natural Gas)

Source: CERI

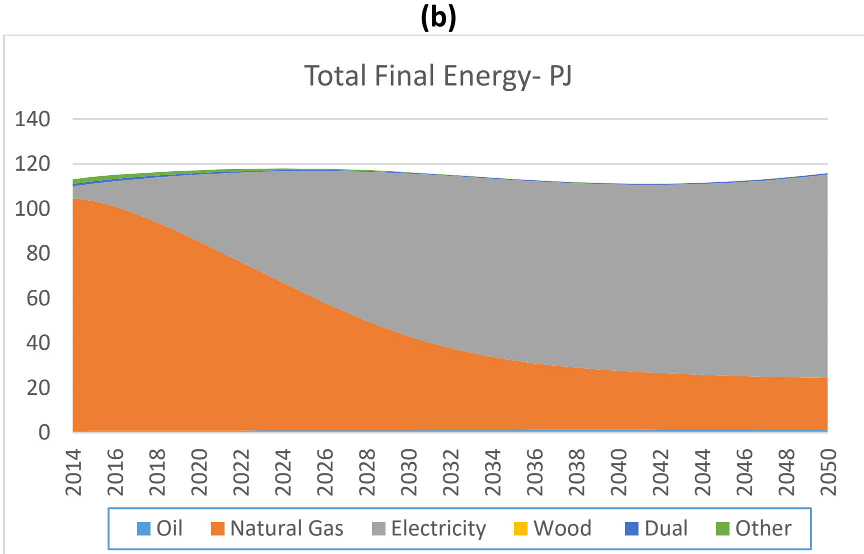
Figure 2.2: Space Heating Energy Demand of Single Detached Homes in Ontario – Electrification Scenario



(a)



(b)



(c)

Source: CERI

Table 2.3: Residential Final Energy Demand for Space Heating – Alberta Single Detached Homes (petajoules)

	First Year of Projection	BAU Scenario	Electrification Scenario
Year	**2014**	**2050**	**2050**
Total	113	192	116
Oil	0.7	1	2
Natural Gas	104	176	23
Electricity	5	9	91
Wood	0	0	0
Dual	1	2	1
Others	2	4	0

Source: CERI

Table 2.4: Residential Final Energy Demand for Water Heating – Alberta Single Detached Homes (petajoules)

	First Year of Projection	BAU Scenario	Electrification Scenario
Year	**2014**	**2050**	**2050**
Total	34.7	75.3	68.4
Electricity	2.2	4.3	57.9
Natural Gas	31.2	67.5	9.4
Oil	0.5	1.7	1
Wood	0.1	0.2	0
Others	0.7	1.5	0.1

Source: CERI

Commercial Sector Model

Since the equipment stock data is not available for the commercial sector, just the energy mix of each subsector is used to project the future energy use. The commercial sector includes 10 subsectors: Wholesale Trade, Retail Trade, Transportation and Warehousing, Information and Cultural Industries, Offices, Educational Services, Health Care and Social Assistance, Arts and Entertainment and Recreation, Accommodation and Food Services, and Other Services.

Total energy use for each subsector will grow with the same growth rate as the average of its annual growth rate over the last 10 years. This total energy use is then decomposed under two demand side scenario scenarios:

- **Business as Usual:** share of each fuel will be equal to its share in 2013
- **Electrification Scenario (S1 & S2):** share of each fuel follows an S-shaped adoption curve to reach a fuel mix in 2050 which is dominated by electricity

Passenger Transportation Sector Model

Development of passenger transportation sector model was challenging due to limited data on vehicle stocks, vintages, and driving patterns. To develop this model, we primarily relied on two federal databases: Natural Resources Canada's (NRCan) Comprehensive Energy Use database and the National Energy Board (NEB) Canada's Energy Future 2016 report (NEB Energy Futures 2016 update[2]).

The modeling framework we designed for the transportation sector is presented in Figure 2.3 and Table 2.5. The NRCan Office of Energy Efficiency (OEE) publishes historic transportation data by transportation mode, by fuel type, and by province. The most recent year is 2013 and the OEE does not provide long-term transportation energy use projections. The NEB energy futures report provides projections of combined transportation energy demand (i.e., passenger and freight transportation) for the period 2015-2040. Projections are aggregated by fuel type and by province. From OEE data we constructed historic trends in type of transportation (i.e., passenger and freight transportation) and mode of transportation (see Table 2.5) as well as consumption trends (e.g., passenger kilometers driven). These trends are used along with NEB transportation energy demand projections to establish the passenger transportation energy demand in the period 2020-2050 under BAU and electrification scenarios. Under both BAU and electrification scenarios, transportation service demand (i.e., total kilometers travelled) was kept constant. See Appendix A for further model details and mathematical relationships.

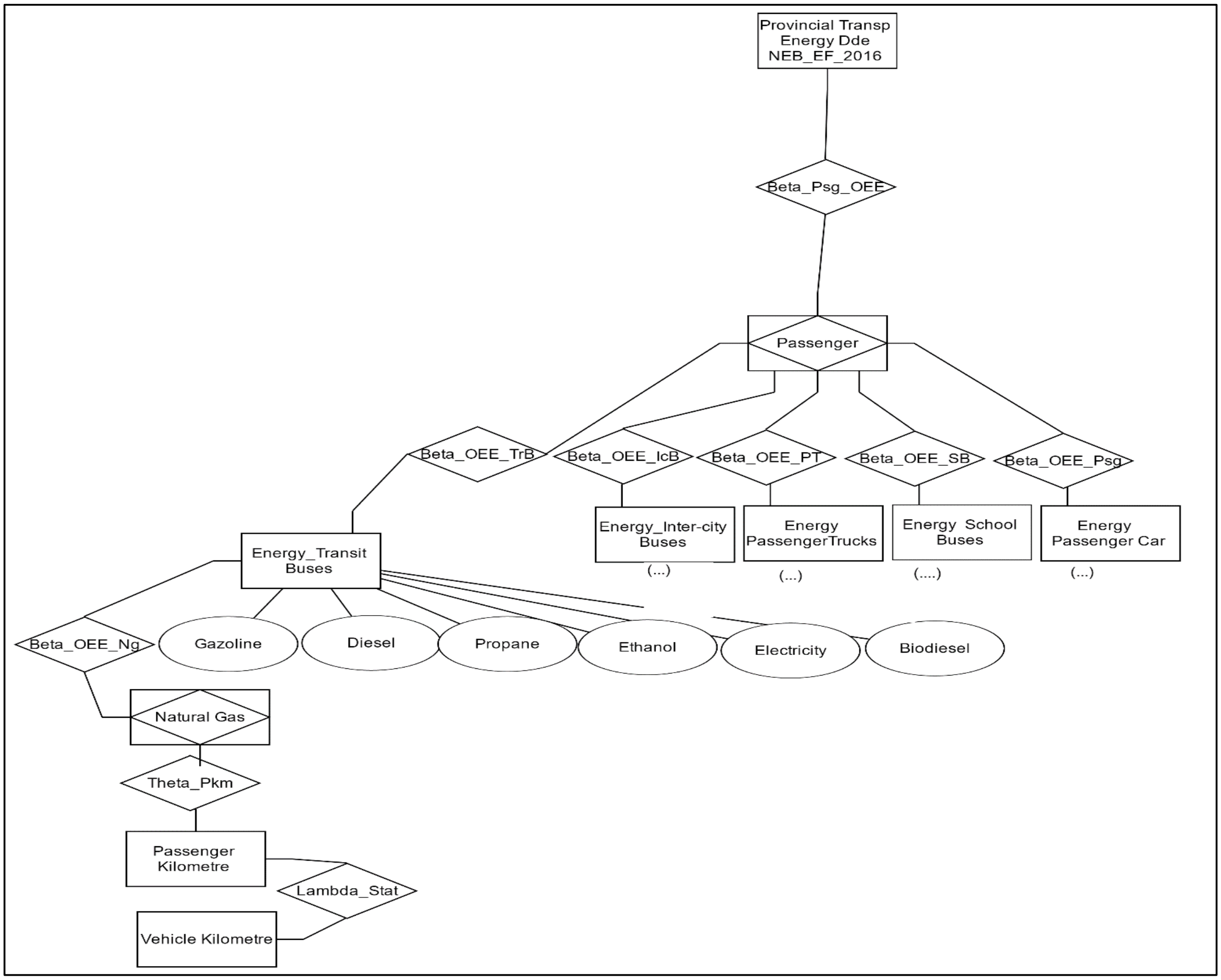
Table 2.5: Passenger Transportation Vehicle Types and Fuels

Transportation type	Transportation Mode				Fuel type
	Road	**Marine**	**Rail**	**Air**	
Passenger	Car	Ferries	Light rail transit	Aviation	Natural gas
	Light trucks	Recreational boats	Passenger trains		Motor gasoline
	School buses				Diesel
	Urban transit buses				Ethanol
	Intercity buses				Biodiesel
	Motor cycles				Propane
Freight	Light freight trucks	Freight vessels	Freight trains	Air freight	Electricity
	Medium duty trucks				Aviation gasoline
	Heavy duty trucks				Aviation turbo fuel
Off-road	Military vehicles				Heavy fuel oil
	Snowmobiles				

Source: CERI

[2] Canada's Energy Future 2016: Update - Energy Supply and Demand Projections to 2040. https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016updt/index-eng.html

Figure 2.3: Passenger Transportation Sector Model



Source: CERI

Freight Transportation Sector Energy Use and Emissions

Electrification was not deployed in the freight transportation sector. However, in order to estimate full provincial energy demands and associated GHG emissions, freight transportation sector energy consumption in the analysis period was modeled using regression relationships. In this case, the provincial GDP was assumed to be a predictor of total transportation fuel demand in a given province. Simple linear regression models were fitted to historical passenger transportation data obtained from NRCan's comprehensive energy use database. With R^2 values of over 0.85, sufficient predictive power was observed under this modeling framework. The GDP forecast we used for the reference scenarios is then used to predict the total freight transport fuel demand within the analysis period (2020-2050). The fuel mix was assumed to be the same as the 2009-2013 period.

Industrial Sector Energy Use and Emissions

The industrial sector was not electrified in this analysis. We used the industrial energy use outlook under the reference case of the NEB's Canada's Energy Future 2016 (Updated) report to estimate the total energy demand and GHG emissions. The NEB outlook only extends to 2040. For the period 2041-2050, we assumed that the total industrial energy demand and energy mix to be the same as the last 5 years of the NEB outlook (i.e., 2036-2040).

Electricity Sector Model

The electricity sector model determines how the electricity demand in different provinces are satisfied over time. The model considers the existing generation capacity and transmission infrastructure and determines which units are utilized to satisfy the time varying electricity demand. The model also tracks the retirements of existing capacity and required new capacity additions. When determining new capacity additions, the following factors are taken into account:

- Generation expansion plans/integrated resource plans as announced by provincial power system operators
- Provincial energy and climate policies
- Applications submitted by private investors to provincial regulators
- Resource availability
- Study scenario

A cost minimizing generation dispatch unit is used to determine which units are utilized to satisfy the demand. Use of dispatch models allow us to determine both energy and capacity requirements to satisfy future demand. For example, that allows us to capture the implications of changes to demand profiles due to higher usage of electricity under electrification scenarios.

We also develop data sets of generation resources available in different provinces. This includes both renewable and non-renewable resources.

Using this data set and the aforementioned factors, we developed an optimal generation investment and dispatch model. In the model, when required, new generating units are added every 5 years starting from 2020. Generating units were dispatched to satisfy the power demand of each province in the period 2020-2050. Addition and operation of generating units was determined so that the total discounted cost of satisfying the electricity demand is minimized. The discount rate was set to be 5 percent.

In the dispatch model, electricity demand in each year is modeled by 25 representative time slices as follows:

- A reference day in a given season (4 seasons: winter, spring, summer, and fall) is represented by 6 demand slices (4 seasons/year x 1 day/season x 6 demand slices/day = 24 demand slices/year)

- Another demand slice was added representing the peak demand period (1 demand slice/year)

Most Canadian provinces have winter peaking electricity systems. However, Ontario is currently a summer peaking system. As such, the peak time slice was adjusted accordingly, depending on the province. Electricity demand profiles in each province is estimated using historic demand data.[3] Use of these time slices allows us to take into account diurnal and seasonal changes in electricity demand and variable resource supplies (e.g., wind, solar, hydro availability).

Capital and operational costs assumed for different generation technologies are listed in Table 2.6. When adding generating units, resource availability in respective provinces was taken into account. CCS was allowed to be built only under Scenario S2 and only after 2025. This takes into account that CCS technologies are still under active development and not commercially ready for widespread deployment. The electric power generation investment model also ensures that a sufficient amount of supply reserves is maintained. In this analysis, we set the required supply reserves to be 10 percent of the annual peak demand. When operating power systems with large amounts of variable generating sources such as wind and solar, power systems will have to carry sufficient ramping reserves to manage variability in supply.[4] Determination of the exact reserve requirements and alternative technology options (for example, electricity storage technologies) to manage this variability requires power system operations models with high temporal resolution, which is beyond the capabilities of the models developed for this study. Therefore, by following previous analyses[5] we require that the investment model ensures sufficient ramping capabilities of the overall system where that ramping capacity is at least 10 percent of the capacity of intermittent resources.

[3] Alberta Electric System Operator https://www.aeso.ca/download/listedfiles/Hourly-Load-Data-for-Years-2005-to-2015.pdf; Independent Electric System Operator of Ontario; Régie de l'énergie http://www.regie-energie.qc.ca/audiences/Suivis/Suivi_HQD_D-2009-107.html; NB Power https://tso.nbpower.com/Public/en/op/market/data.aspx; BC Hydro https://www.bchydro.com/energy-in-bc/our_system/transmission/transmission-system/balancing-authority-load-data/historical-transmission-data.html; Manitoba load shape was assumed to be the same as that of Quebec. Saskatchewan load shape was assumed to be the same as that of Alberta central and south region

[4] Brouwer, A. S., van den Broek, M., Seebregts, A., & Faaij, A. (2014). Impacts of large-scale Intermittent Renewable Energy Sources on electricity systems, and how these can be modeled. Renewable and Sustainable Energy Reviews, 33, 443–466.

[5] Brouwer, A. S., van den Broek, M., Seebregts, A., & Faaij, A. (2014). Impacts of large-scale Intermittent Renewable Energy Sources on electricity systems, and how these can be modeled. Renewable and Sustainable Energy Reviews, 33, 443–466; Doluweera, G., 2011. Assessing the effectiveness of wind power and cogeneration for carbon management of electric power systems, Doctoral dissertation, University of Calgary.

Table 2.6: Capital and Operating Costs of Generating Units[6]

Technology	Overnight Capital Cost [i] (2014 $CAD)	Financing Multiplier	Connection Cost (2014 $CAD)	Heat Rate (GJ/MWh)	Variable Cost ($CAD/MWh)
NGCC	1483	1.35	137.94	7.1	4.2
NGSC	1000	1.34	137.94	9.8	4.2
NG Cogen	1900	1.35	137.94	7.1	4.2
Hydro	5289	1.34	274.67	-	6.2
Wind	2100	1.18	137.94	-	2
Solar	3700	1.18	137.94	-	2
Biomass	3775	1.49	137.94	14	4.2
Coal SCPC – CCS [ii]	5367	1.64	274.67	11	31
NGCC CCS [ii]	2537	1.49	174.24	8.3	19

[i]Capital cost of new generating units

[ii]CCS variable cost of CCS units includes CO2 transport and storage cost that was assumed to be $15/tCO2. CCS capture rate was assumed to be 90%.

Source: CERI

When dispatching generating units to satisfy the electricity demand, GHG emissions limits were enforced as needed to decarbonize the electricity supply. The emissions limit was iteratively determined so that meaningful emissions reductions are obtained, while minimizing the average and total cost. For example, the emissions cap progressively increased, until marginal emissions reductions diminish with increasing cost. However, generation additions and operations in some provinces (mainly Quebec and Manitoba) were not impacted by the emissions cap as sufficient low emissive generation sources are available even under the BAU scenario.

Fuel prices in the electricity sector model are assumed to be the same as the industrial fuel prices in respective provinces under the reference scenario of the NEB's Canada's Energy Future 2016 report.

The electricity sector model did not explicitly deploy transmission and distribution infrastructure. Instead we assumed that the average cost of transmission and distribution to be $20/MWh. This inevitably varies by province and needs further investigation. In cases where high amounts of variable generating sources are deployed, it is plausible that the transmission system may be underutilized, increasing the average cost. In such situations, the transmission costs were

[6] Data sources: AESO. (2015). Long-term Transmission Plan. Alberta Electric System Operator. Retrieved from https://www.aeso.ca/grid/long-term-transmission-plan; NETL. (2015). Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3. US National Energy Technology Laboratory. Retrieved from http://netl.doe.gov/research/energy-analysis/publications/details?pub=b50504f1-cef2-4aef-bd01-146638252f67; EIA. (2013). Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants. U.S. Energy Information Administration. Retrieved from http://www.eia.gov/outlooks/capitalcost/pdf/updated_capcost.pdf

adjusted accordingly depending on the amount of variable supply in the generation mix (in the range of $25-$30/MWh). This too requires further refinement. This assumption impacts the cost estimates but not energy or emissions estimates. In the dispatch model, electricity transmission losses are assumed to be 7 percent in all provinces.

Two generation technologies that are assessed in this study are currently undergoing rapid development. The most prominent ones are solar and CCS technologies. It is plausible that these technologies would see a reduction in capital costs and improvements in performance (i.e., efficiency) within the analysis period of this study. Therefore, we applied exogenous technology learning, where the capital costs would be reduced at a rate of 1 percent (for CCS) to 1.5 percent (for solar) per year over the analysis period.

Data Limitations and Regional Aggregation

Poor data availability in technology stock was a main challenge throughout the model development. We utilized the best possible data available and made assumptions as needed while checking the impacts of such assumptions. Model results were compared with historic trends to check for robustness.

In Chapter 3, the four Atlantic provinces – Newfoundland and Labrador, Nova Scotia, New Brunswick, and Prince Edward Island – were aggregated and reported as a single region. The main reason was the aggregated nature of the data set we used to model the commercial sectors of the four provinces. Furthermore, the transmission developments that are currently being deployed with the Muskrat Falls generation project will lead to higher integration of electricity systems of the four provinces.[7] Prince Edward Island already imports most of its electricity from New Brunswick.

[7] Muskrat Falls Project. http://muskratfalls.nalcorenergy.com/

Chapter 3: Results and Discussion

Total Energy Demand

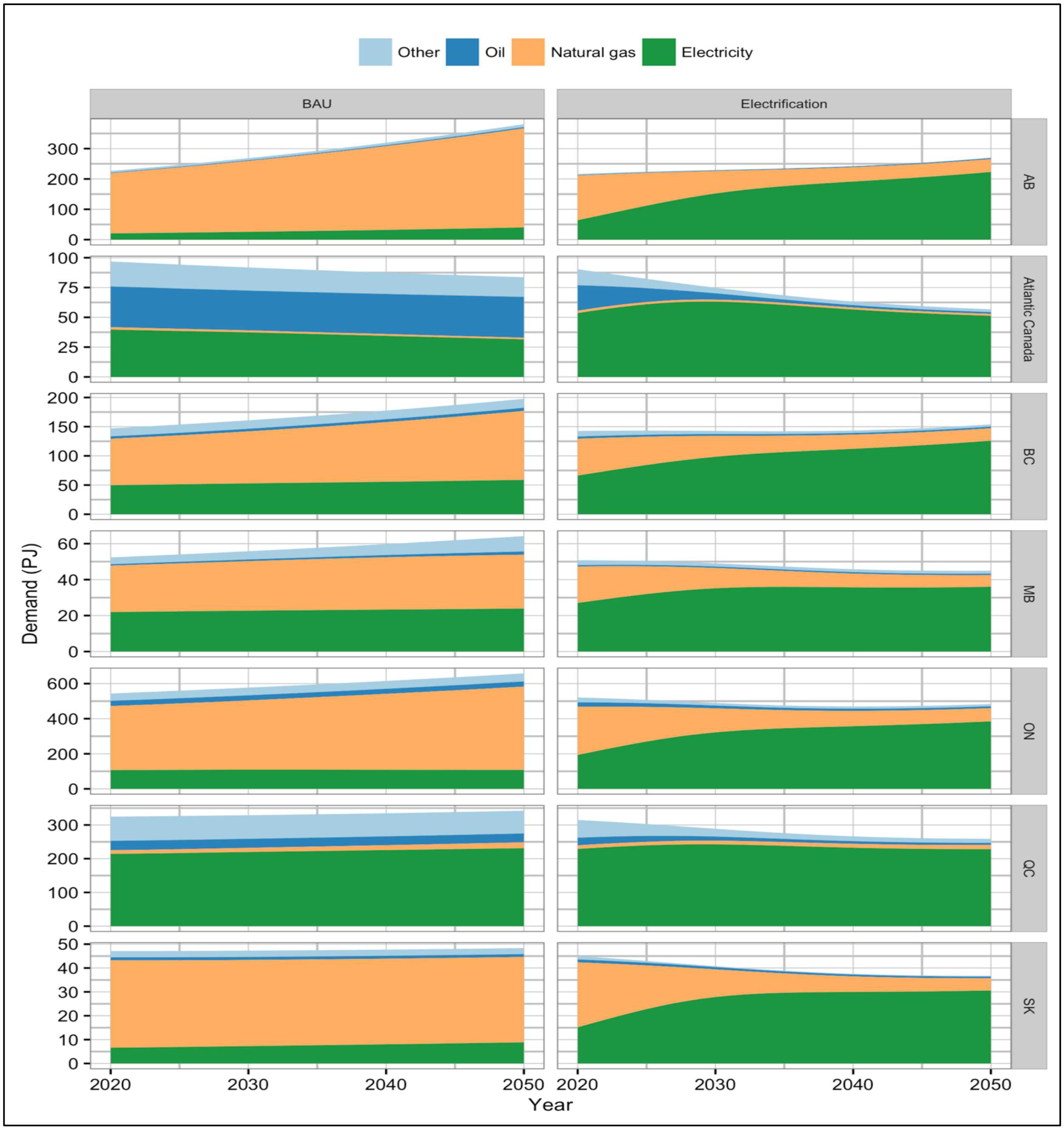
In this chapter, we discuss the main results of the analysis. Figure 3.1 depicts the residential sector end-use fuel demand under the BAU scenario and two electrification scenarios (S1 & S2).

The share of electricity as a residential sector end-use energy under the BAU scenario varies by province. It is lowest in Alberta (9 percent) and highest in Quebec (66 percent) in 2020. From 2020 to 2050, under the BAU scenario, the total energy demand in the residential sector grows by 5 percent (in Quebec) to almost 68 percent (in Alberta). In the Atlantic provinces however, residential sector demand drops by 13 percent over the same period.

As the end-use services are electrified, in most provinces, electricity displaces natural gas from the residential sector energy mix. As such, the combined electricity demand (across all provinces/regions) increases by 45 percent by 2030 and 66 percent in 2050. Exact increases depend on the region (highest in Alberta and lowest in Quebec). At the same time, combined natural gas demand drops by 48 percent by 2030 and 70 percent by 2050. In the Atlantic provinces, electricity mainly displaces heating oil.

An important observation is that total energy demand is lower under the electrification scenarios. This is due to the higher efficiencies of electrical device stock. This is further discussed later in this chapter.

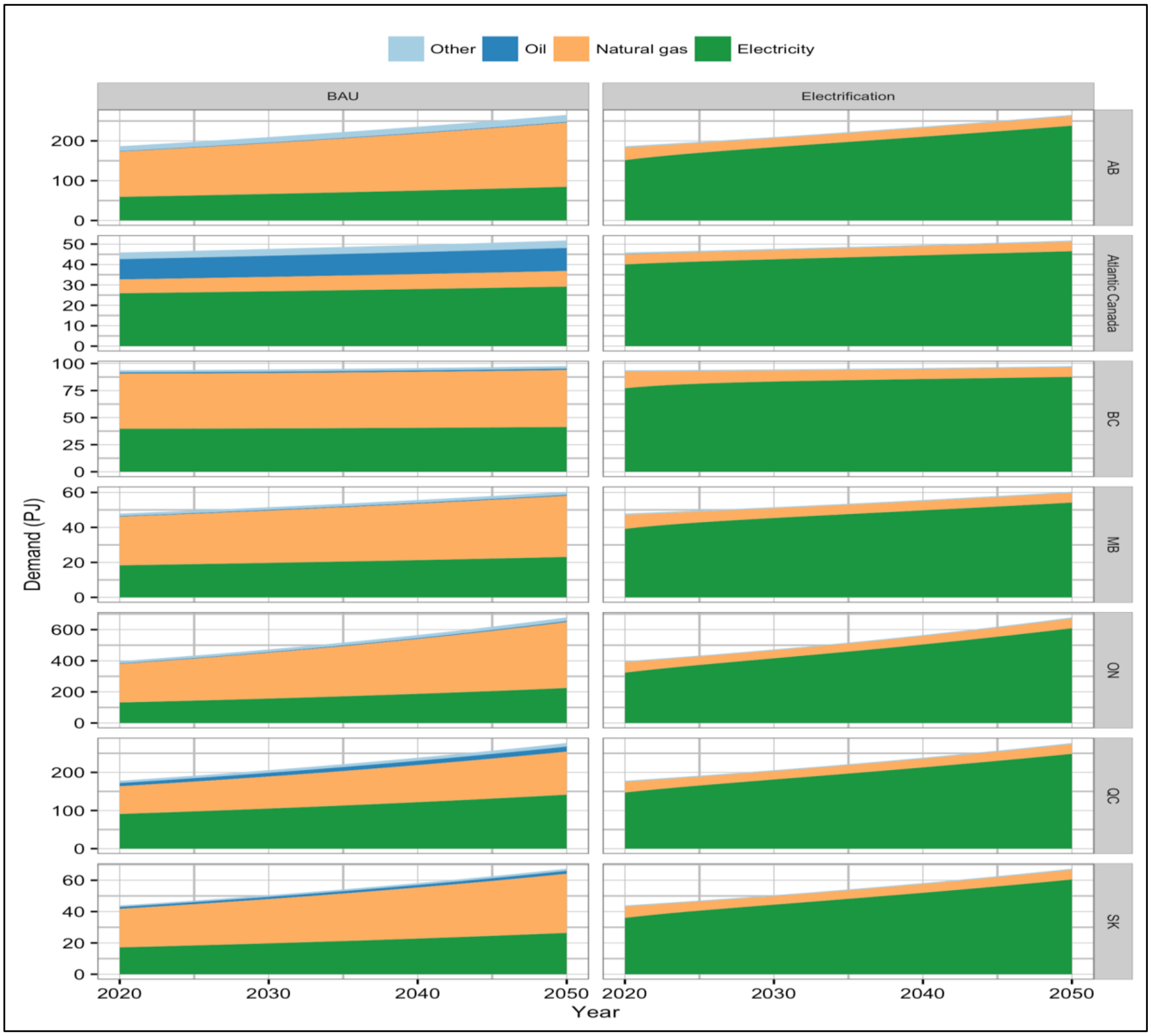
Figure 3.1: Residential Sector Energy Demand under the BAU and Electrification Scenarios



Source: CERI

Figure 3.2 depicts the commercial sector total energy demand under the two demand side scenarios. In this sector, electricity displaces natural gas in most provinces and displaces heating oil in the Atlantic provinces. The relative decrease in total energy demand under the two demand side scenarios is lower compared to the residential sector.

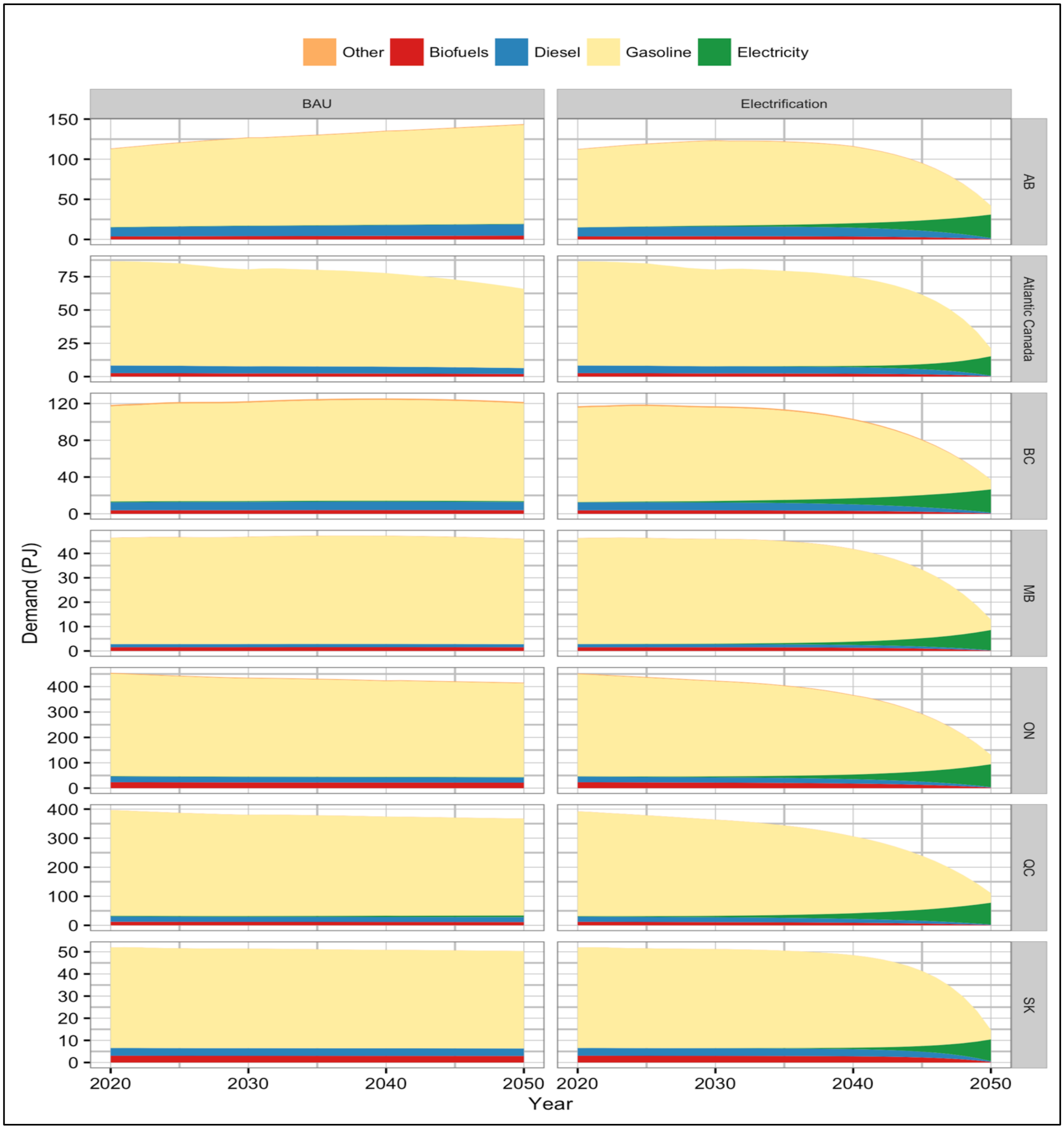
Figure 3.2: Commercial Sector Energy Demand under the BAU and Electrification Scenarios



Source: CERI

Figure 3.3 depicts the passenger transportation sector energy demand under the BAU and electrification scenarios. As expected, electricity displaces gasoline and diesel from the passenger transportation sector as electricity vehicles are deployed. Deployment of electric vehicles starts at a slower rate as it is constrained by full scale availability of electric vehicles. Profound reductions in total energy demand – in the order of 70 percent – is observed in the passenger transportation sector. This is primarily due to the high efficiency of electric vehicles. This is further discussed later in this chapter.

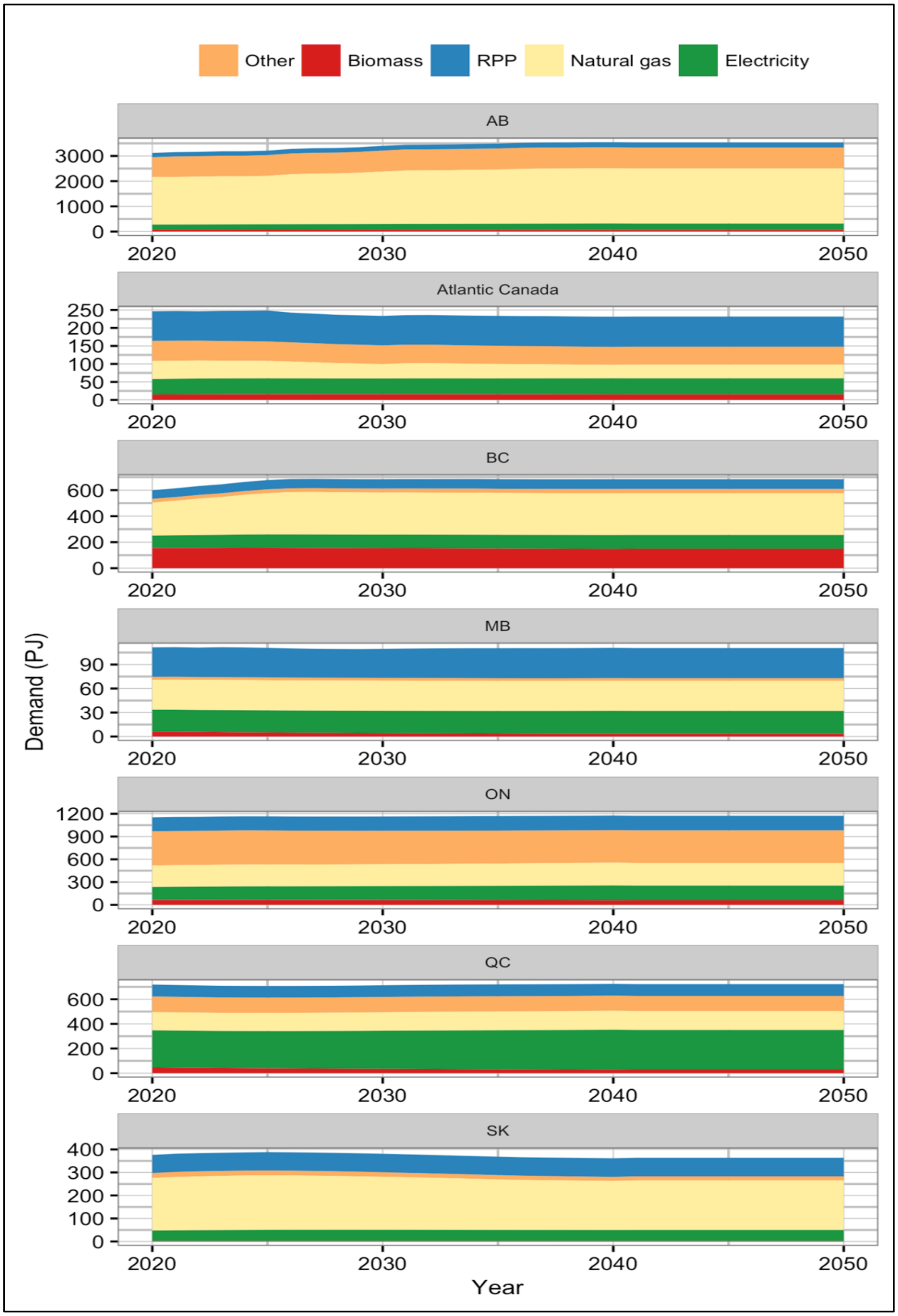
Figure 3.3: Passenger Transportation Sector Energy Demand under the BAU and Electrification Scenarios



Source: CERI

In this analysis, we did not assess the implications of electrifying industrial or freight transportation end-use energy demands. However, we estimated the total energy demand of those two sectors to make economy-wide energy and emissions estimates. Energy demand of those two sectors are depicted in Figures 3.4 and 3.5.

Figure 3.4: Industrial Sector Energy Demand

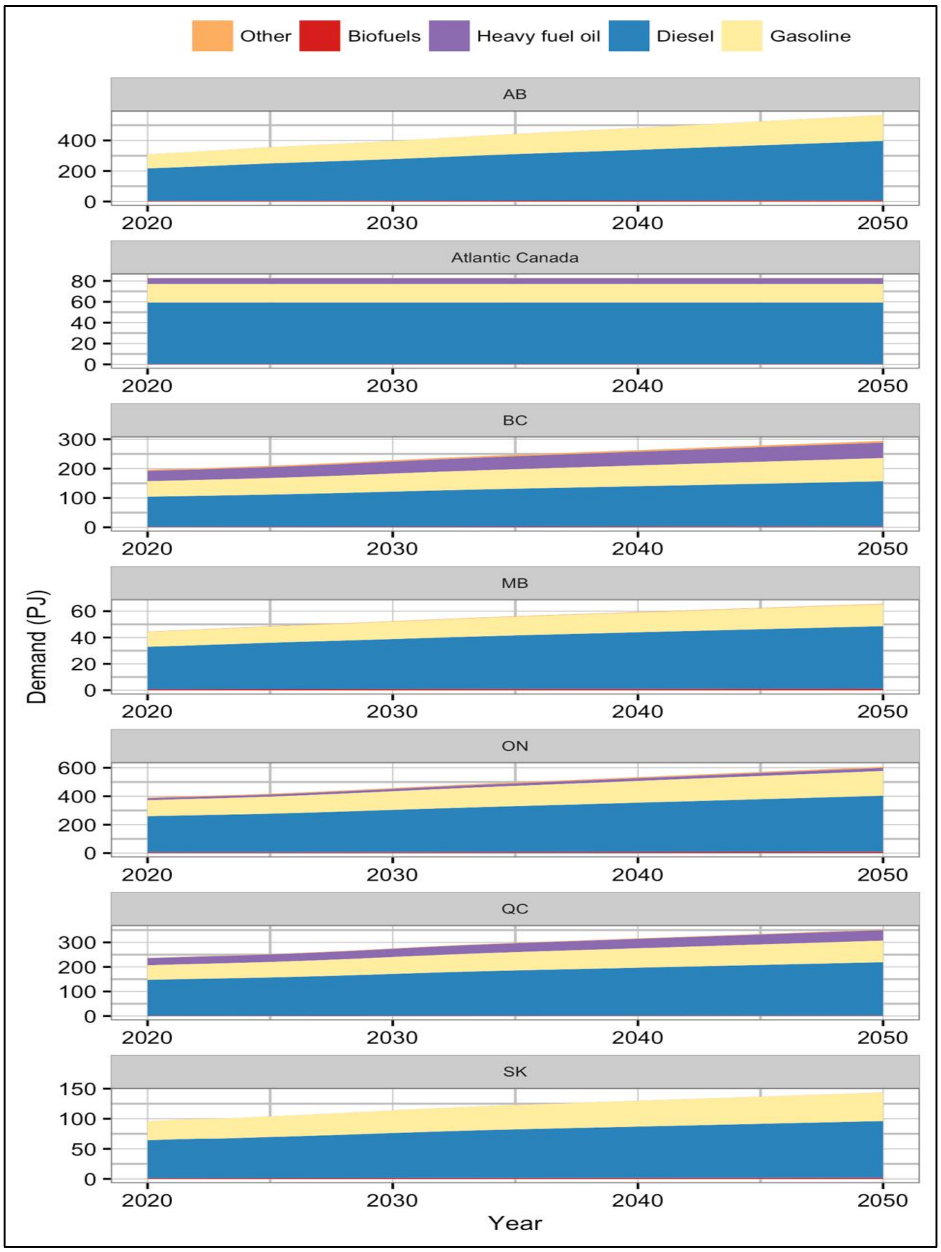


Source: CERI

The industrial sector already consumes a large amount of electricity in all provinces. In Quebec, electricity dominates the energy mix of the industrial sector. In other provinces, fossil fuels such as natural gas or refined petroleum products (e.g., diesel, higher heating oil) dominate the industrial energy mix.

Under our modeling assumptions, the freight transportation sector does not consume any electricity within the analysis period. Diesel fuel dominates the freight transportation fuel mix in all provinces (Figure 3.5).

Figure 3.5: Freight Transportation Sector Energy Demand

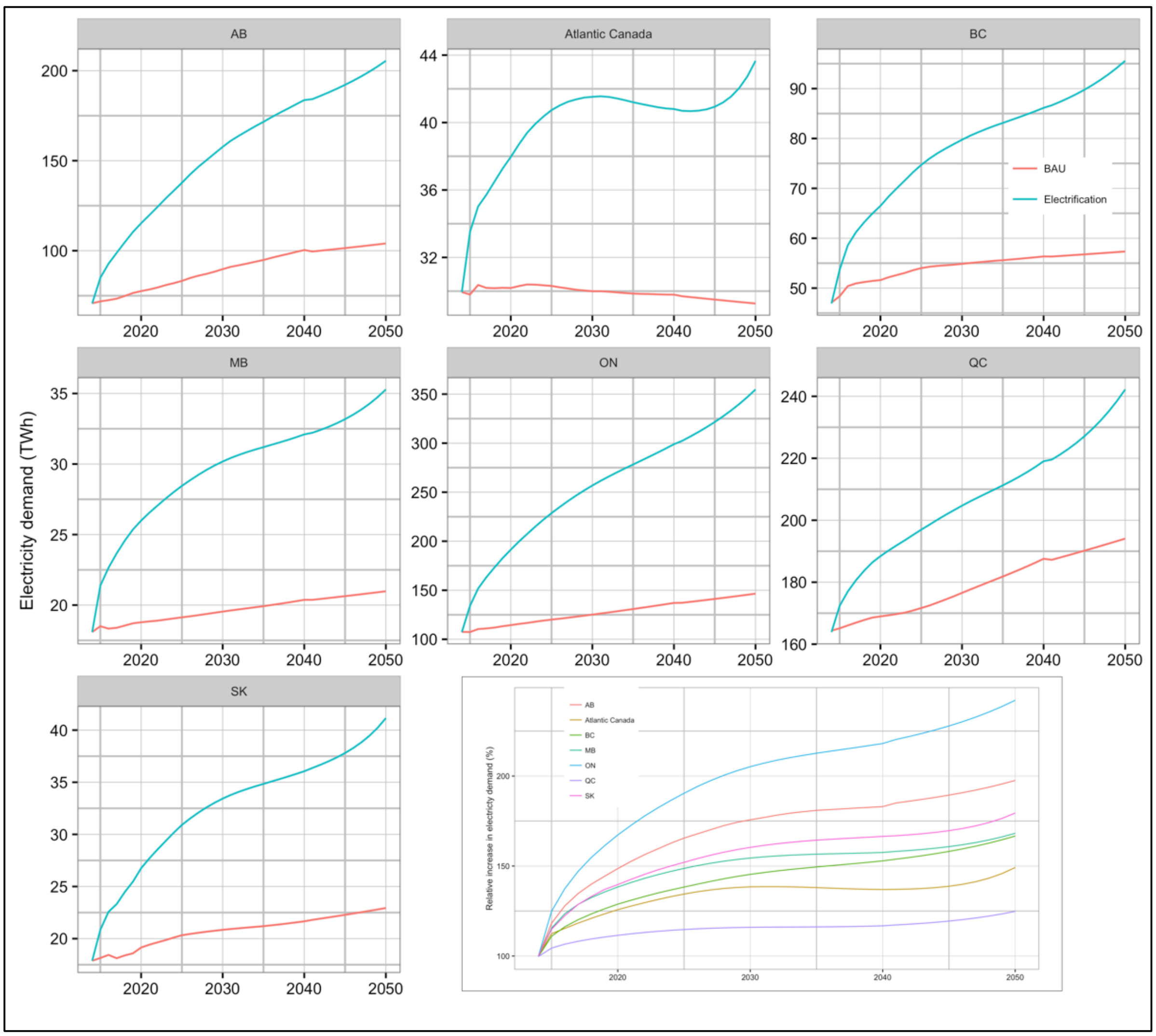


Source: CERI

Electricity Demand and Supply

Electrification of energy end-use services increases the electricity demand in all provinces compared to the BAU scenario. Figure 3.6 shows the electricity demand under the BAU and electrification scenario in all provinces. The figure also shows the relative increase in electricity demand over time. Ontario sees the highest relative electricity demand growth compared to BAU, where by 2050 the electricity demand is almost 2.5 times that of BAU. This is mainly due to the higher population and associated building and transportation energy demand. Ontario is followed by Alberta, where 2050 demand is 2 times that of BAU. In Alberta, in addition to population growth, high electricity demand in the residential sector compared to the current lower level of 9 percent is also a driving factor. The lowest demand growth is observed in Quebec and the Atlantic provinces. Quebec's 2050 electricity demand is only 20 percent higher than BAU and this increase is driven predominantly by passenger transportation sector demand.

Figure 3.6: Electricity Demand and Relative Increase in Demand in all Provinces under the BAU and Electrification Scenarios



Source: CERI

In order to satisfy the increased electricity demand under the electrification scenarios, additional generating units and other electricity infrastructure are needed. Furthermore, overall emissions from power generation needs to be kept low to achieve significant enough emissions reductions, constraining the power generation technologies that can be added.

As discussed in Chapter 2, in this study we assessed two electricity supply scenarios to satisfy the increasing electricity. Under both scenarios, thermal power generating units were allowed to be added and operated by the electricity sector model, but emissions were constrained through an emissions cap that ensures overall GHG emissions reductions.

Under the S1 scenario, only hydropower, wind, solar, and biomass resources available in respective provinces were made available for the electricity investment model to be picked to satisfy the future demand. Under the S2 scenario, the addition of coal and natural gas power generating units with carbon capture (CCS) was allowed starting from 2025. Power generating units that are currently under active construction or directed to be used were added to the generation supply at their planned commission dates.

In four of the seven regions we analyzed – namely, the Atlantic provinces, Quebec, Manitoba, and British Columbia – electricity supply under the S1 and S2 scenarios was identical. In other words, sufficient low carbon power generation options are available in those provinces so that CCS was not deployed by the total cost minimizing electricity generation investment model. Power systems in these provinces already have large amounts of hydropower generation capacity as well as some large scale new hydropower units that are currently under construction. Relatively smaller amounts of natural gas-fired simple cycle (NGSC), natural gas-fired combined cycle (NGCC), and some other renewable power generating units – mostly wind – were deployed by the electricity sector model to satisfy the overall demand. Utilization of natural gas-fired generation marginally increases the emissions intensity of electricity supply (measured in tCO2eq/MWh). However, net emissions reductions are nonetheless achieved. In the case of British Columbia, annual emissions from power generation needed to be capped at 1 million tCO2eq/year to achieve overall emissions reductions (in 2014, BC's power sector emissions were 0.79 million tCO2eq).

In contrast, the availability of NGCC units with CCS capability (i.e., S2 scenario) leads to lower total cost while achieving overall emissions reductions. The S1 electricity supply scenario leads to lower overall emissions but the total cost is high. The main reason for that is in these provinces, relatively high amounts of low carbon electricity supply is needed. Relying only on variable renewable electricity sources that have lower capacity factors leads to high capital cost. In those three provinces, GHG emissions needed to be capped to achieve province wide emissions reductions.

In all three provinces, deployment of NGCC with CCS was not required until 2035. This indicates that while CCS can be pivotal to decarbonize the electricity supply at a manageable cost, there is approximately 15 years available to develop the technology to commercially deployable levels. It was also observed that new coal with CCS was not deployed in any of the provinces. This is due to the high capital cost as well as higher GHG emissions, even after capturing 90 percent of GHG emissions.

Tables 3.1-3.7 present the end-use energy mix in energy consuming sectors and the electricity sector in 2030 and 2050 in all provinces. In the case of electricity supply, the results presented in Tables 3.1-3.7 refer to the electricity supply scenarios that lead to the lowest overall cost of power (i.e., S2 scenario for Alberta, Ontario and Saskatchewan; S1 scenario for all other provinces).

Table 3.1: Energy Use and Direct GHG Emissions by Sector in Atlantic Canada

	Energy Consumption (PJ)				Emissions (million tCO2eq)			
	2030 BAU	2030 Electrification	2050 BAU	2050 Electrification	2030 BAU	2030 Electrification	2050 BAU	2050 Electrification
Residential	**91.8**	**74.8**	**83.6**	**56.7**	**3.1**	**0.7**	**3.1**	**0.3**
Electricity	37.3	63.1	31.5	51.3	0.00	0.00	0.00	0.00
Natural Gas	1.7	1.7	1.4	1.6	0.08	0.09	0.07	0.08
Refined petroleum products	33.5	5.3	34.3	1.4	2.36	0.37	2.42	0.10
Other	19.4	4.7	16.5	2.4	0.70	0.22	0.60	0.12
Commercial	**47.6**	**47.6**	**51.8**	**51.8**	**1.3**	**0.3**	**1.4**	**0.3**
Electricity	26.86	42.54	29.17	46.54	0.00	0.00	0.00	0.00
Natural gas	7.03	4.45	7.65	4.64	0.35	0.22	0.38	0.23
Refined petroleum products	10.39	0.07	11.30	0.06	0.74	0.00	0.80	0.00
Other	3.35	0.57	3.65	0.53	0.20	0.03	0.22	0.03
Passenger transportation	**80.5**	**80.3**	**65.9**	**21.2**	**5.4**	**5.4**	**4.4**	**0.4**
Electricity	0.0	0.1	0.0	14.7	0.00	0.00	0.00	0.00
Gasoline	72.8	72.6	59.5	5.9	4.98	4.97	4.07	0.41
Diesel	5.3	5.3	4.5	0.4	0.40	0.39	0.33	0.03
Other fossil fuels	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00
Bio-fuels	2.4	2.4	2.0	0.2	0.01	0.01	0.01	0.00
Freight Transportation	**82.9**	**82.9**	**82.9**	**82.9**	**6.0**	**6.0**	**6.0**	**6.0**
Electricity	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00
Gasoline	17.6	17.6	17.6	17.6	1.20	1.20	1.20	1.20
Diesel	59.0	59.0	59.0	59.0	4.37	4.37	4.37	4.37
Other fossil fuels	5.9	5.9	5.9	5.9	0.44	0.44	0.44	0.44
Bio-fuels	0.4	0.4	0.4	0.4	0.00	0.00	0.00	0.00
Industrial	**233.6**	**233.6**	**231.8**	**231.8**	**11.0**	**11.0**	**10.9**	**10.9**
Electricity	43.8	43.8	44.7	44.7				
Natural gas	40.3	40.3	38.1	38.1				
Coal & coke	4.6	4.6	4.9	4.9				
Refined petroleum products	82.0	82.0	83.8	83.8				
Other	63.0	63.0	60.4	60.4				
Electricity generation	**157.2**	**194.6**	**145.0**	**206.6**	**2.6**	**2.3**	**1.2**	**1.8**
Coal	24.9	21.80	0.0	0.0	2.3	2.0	0.0	0.0
Natural gas/Oil	4.7	4.78	20.78	31.32	0.3	0.4	1.2	1.8
Nuclear	34.3	26.93	31.34	31.86	0.0	0.0	0.0	0.0
Biomass	2.2	1.76	2.19	2.00	0.0	0.0	0.0	0.0
Hydro	63.3	57.58	62.95	59.70	0.0	0.0	0.0	0.0
Wind	27.6	81.60	27.62	81.60	0.0	0.0	0.0	0.0
Solar	0.1	0.14	0.14	0.14	0.0	0.0	0.0	0.0
Total emissions					29.4	25.6	27.0	19.8
Emissions reduction (% of BAU)						13%		27%
Emissions reduction (% of 2005 total GHG emissions)						7%		13%

Source: CERI

In Atlantic Canada, the S2 electricity supply scenario did not result in any improvements. Therefore, all natural gas- and coal-fired generation is from non-CCS units. Overall emissions reductions are 7 percent below 2005 levels in 2030 and 13 percent below 2005 levels in 2050.

Table 3.2: Energy Use and Direct GHG Emissions by Sector in Quebec

	Energy Consumption (PJ)				Emissions (million tCO2eq)			
	2030 BAU	2030 Electrification	2050 BAU	2050 Electrification	2030 BAU	2030 Electrification	2050 BAU	2050 Electrification
Residential	**328.9**	**288.7**	**342.2**	**258.9**	**5.6**	**2.5**	**5.6**	**1.7**
Electricity	219.9	242.4	231.2	228.2	0.00	0.00	0.00	0.00
Natural Gas	12.2	10.9	17.4	12.6	0.61	0.54	0.87	0.63
Refined petroleum products	26.9	12.3	26.3	6.3	1.89	0.87	1.85	0.44
Other	69.9	23.1	67.2	11.8	3.06	1.13	2.88	0.59
Commercial	**205.8**	**205.8**	**276.9**	**276.9**	**5.3**	**1.3**	**7.1**	**1.5**
Electricity	105.09	181.33	141.49	248.58	0.00	0.00	0.00	0.00
Natural gas	83.91	21.77	112.84	25.22	4.19	1.09	5.63	1.26
Refined petroleum products	9.87	0.26	13.35	0.31	0.70	0.02	0.94	0.02
Other	6.89	2.40	9.26	2.82	0.42	0.15	0.56	0.17
Passenger transportation	**380.7**	**363.9**	**367.3**	**111.0**	**25.2**	**23.9**	**24.1**	**2.4**
Electricity	2.5	5.0	5.7	75.0	0.00	0.00	0.00	0.00
Gasoline	348.2	330.5	332.9	33.2	23.85	22.64	22.80	2.27
Diesel	17.6	16.6	16.9	1.7	1.31	1.23	1.25	0.12
Other fossil fuels	0.7	0.7	0.7	0.1	0.04	0.04	0.04	0.00
Bio-fuels	11.8	11.1	11.2	1.1	0.03	0.03	0.03	0.00
Freight Transportation	**275.6**	**275.6**	**352.3**	**352.3**	**19.9**	**19.9**	**25.5**	**25.5**
Electricity	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00
Gasoline	68.6	68.6	87.7	87.7	4.70	4.70	6.01	6.01
Diesel	170.1	170.1	217.5	217.5	12.60	12.60	16.11	16.11
Other fossil fuels	35.4	35.4	45.2	45.2	2.62	2.62	3.35	3.35
Bio-fuels	1.5	1.5	1.9	1.9	0.00	0.00	0.01	0.01
Industrial	**1163.9**	**1163.9**	**1174.2**	**1174.2**	**22.8**	**22.8**	**23.0**	**23.0**
Electricity	183.0	183.0	193.2	193.2				
Natural gas	289.1	289.1	297.4	297.4				
Coal & coke	92.2	92.2	81.8	81.8				
Refined petroleum products	187.4	187.4	192.6	192.6				
Other	412.2	412.2	409.2	409.2				
Electricity generation	**572.0**	**684.5**	**640.3**	**856.9**	**0.1**	**0.3**	**0.1**	**2.5**
Natural gas	1.0	5.8	2.4	49.3	0.1	0.3	0.1	2.5
Biomass	0.1	1.7	0.1	9.5	0.0	0.0	0.0	0.0
Hydro	564.9	671.0	631.8	723.4	0.0	0.0	0.0	0.0
Wind	6.0	6.0	6.0	74.7	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0
Total emissions					78.8	70.5	85.3	54.0
Emissions reduction (% of BAU)						11%		37%
Emissions reduction (% of 2005 total GHG emissions)						9%		35%

Source: CERI

In Quebec, the S2 electricity supply scenario did not result in any improvements. Therefore, all natural gas-fired generation is from non-CCS units. Quebec shows a higher reduction result compared to Atlantic Canada of 9 percent in 2030 and 35 percent in 2050.

Table 3.3: Energy Use and Direct GHG Emissions by Sector in Ontario

	Energy Consumption (PJ)				Emissions (million tCO2eq)			
	2030 BAU	2030 Electrification	2050 BAU	2050 Electrification	2030 BAU	2030 Electrification	2050 BAU	2050 Electrification
Residential	**577.2**	**489.9**	**658.2**	**483.7**	**23.8**	**8.7**	**27.9**	**5.2**
Electricity	109.3	322.0	108.0	384.9	0.00	0.00	0.00	0.00
Natural Gas	395.0	136.7	475.1	75.0	19.70	6.82	23.70	3.74
Refined petroleum products	29.1	16.5	29.4	10.9	2.05	1.17	2.07	0.77
Other	43.8	14.6	45.7	12.9	2.02	0.73	2.12	0.65
Commercial	**472.8**	**472.8**	**678.7**	**678.7**	**16.0**	**2.9**	**23.0**	**3.6**
Electricity	156.90	415.81	224.99	609.08	0.00	0.00	0.00	0.00
Natural gas	294.79	50.94	423.73	61.93	14.70	2.54	21.14	3.09
Refined petroleum products	4.53	0.54	6.53	0.75	0.32	0.04	0.47	0.06
Other	16.58	5.51	23.41	6.92	1.01	0.33	1.42	0.42
Passenger transportation	**435.4**	**423.7**	**415.9**	**131.5**	**28.3**	**27.4**	**27.1**	**2.7**
Electricity	1.4	3.7	1.3	90.0	0.00	0.00	0.00	0.00
Gasoline	386.8	374.3	369.5	37.0	26.49	25.64	25.31	2.53
Diesel	21.6	20.9	20.6	2.1	1.60	1.55	1.53	0.15
Other fossil fuels	3.2	3.1	3.1	0.3	0.19	0.18	0.18	0.02
Bio-fuels	22.5	21.7	21.5	2.2	0.07	0.06	0.06	0.01
Freight Transportation	**457.9**	**457.9**	**608.2**	**608.2**	**32.6**	**32.6**	**43.3**	**43.3**
Electricity	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00
Gasoline	130.6	130.6	173.5	173.5	8.95	8.95	11.88	11.88
Diesel	297.2	297.2	394.8	394.8	22.01	22.01	29.24	29.24
Other fossil fuels	23.2	23.2	30.9	30.9	1.64	1.64	2.18	2.18
Bio-fuels	6.9	6.9	9.1	9.1	0.02	0.02	0.03	0.03
Industrial	**1163.9**	**1163.9**	**1174.2**	**1174.2**	**49.02**	**49.02**	**49.77**	**49.77**
Electricity	183.0	183.0	193.2	193.2				
Natural gas	289.1	289.1	297.4	297.4				
Coal & coke	92.2	92.2	81.8	81.8				
Refined petroleum products	187.4	187.4	192.6	192.6				
Other	412.2	412.2	409.2	409.2				
Electricity generation (S2)	**1009.0**	**1427.0**	**1249.0**	**2367.0**	**14.0**	**13.6**	**12.9**	**14.0**
Natural gas	278.0	270.0	257.0	221.0	13.9	13.5	12.8	11.0
Natural gas with CCS	0.0	0.0	0.0	586.0	0.0	0.0	0.0	2.9
Nuclear	494.0	354.0	752.0	754.0	0.0	0.0	0.0	0.0
Biomass	11	11.0	11.0	11.0	0.1	0.1	0.1	0.1
Hydro	145.0	145.0	148.0	148.0	0.0	0.0	0.0	0.0
Wind	58.0	624.0	58.0	624.0	0.0	0.0	0.0	0.0
Solar	23	23	23	23	0.0	0.0	0.0	0.0
Total emissions					163.8	134.3	184.0	118.5
Emissions reduction (% of BAU)						18%		36%
Emissions reduction (% of 2005 total GHG emissions)						14%		31%

Source: CERI

Emissions reductions in Ontario are 14 percent in 2030 and 31 percent in 2050. Again, similar to Quebec and Atlantic Canada, electrification of the residential, commercial and passenger transportation sectors are not enough to meet government targets.

Table 3.4: Energy Use and Direct GHG Emissions by Sector in Manitoba

	Energy Consumption (PJ)				Emissions (million tCO2eq)			
	2030 BAU	2030 Electrification	2050 BAU	2050 Electrification	2030 BAU	2030 Electrification	2050 BAU	2050 Electrification
Residential	**55.8**	**49.1**	**64.2**	**44.9**	**1.6**	**0.7**	**1.9**	**0.5**
Electricity	22.7	35.2	23.9	36.0	0.00	0.00	0.00	0.00
Natural Gas	27.5	11.3	29.9	6.5	1.37	0.56	1.49	0.32
RPP	0.9	0.8	1.8	0.8	0.06	0.06	0.13	0.06
Other	4.6	1.8	8.5	1.6	0.17	0.09	0.27	0.08
Commercial	**51.52**	**51.52**	**60.36**	**60.36**	**1.61**	**0.31**	**1.89**	**0.32**
Electricity	19.70	45.37	23.10	54.18	0.00	0.00	0.00	0.00
Natural gas	29.89	5.54	34.96	5.51	1.49	0.28	1.74	0.27
RPP	0.43	0.02	0.55	0.05	0.03	0.00	0.04	0.00
Other	1.50	0.59	1.75	0.61	0.09	0.04	0.11	0.04
Passenger transportation	**46.8**	**46.0**	**45.9**	**12.9**	**3.1**	**3.0**	**3.1**	**0.3**
Electricity	0.0	0.2	0.0	8.3	0.00	0.00	0.00	0.00
Gasoline	43.9	42.9	43.0	4.3	3.00	2.94	2.95	0.29
Diesel	1.3	1.3	1.3	0.1	0.10	0.09	0.09	0.01
Other fossil fuels	0.1	0.1	0.1	0.0	0.01	0.01	0.01	0.00
Bio-fuels	1.5	1.5	1.5	0.2	0.00	0.00	0.00	0.00
Freight Transportation	**52.4**	**52.4**	**65.7**	**65.7**	**3.7**	**3.7**	**4.7**	**4.7**
Electricity	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00
Gasoline	13.1	13.1	16.5	16.5	0.90	0.90	1.13	1.13
Diesel	38.0	38.0	47.5	47.5	2.81	2.81	3.52	3.52
Other fossil fuels	0.4	0.4	0.5	0.5	0.03	0.03	0.03	0.03
Bio-fuels	0.9	0.9	1.1	1.1	0.00	0.00	0.00	0.00
Industrial	**109.6**	**109.6**	**110.7**	**110.7**	**4.81**	**4.81**	**4.90**	**4.90**
Electricity	27.9	27.9	28.5	28.5				
Natural gas	37.7	37.7	37.5	37.5				
Coal & coke	0.5	0.5	0.5	0.5				
Refined petroleum products	36.3	36.3	37.8	37.8				
Other	7.3	7.3	6.4	6.4				
Electricity generation (S1)	**76.5**	**117.7**	**82.0**	**144.9**	**0.2**	**0.2**	**0.2**	**1.0**
Natural gas	2.4	2.9	2.4	14.7	0.2	0.2	0.2	1.0
Biomass	0.0	0.1		0.4	0	0.0	0	0.0
Hydro	69.1	109.8	74.6	124.9	0	0.0	0	0.0
Wind	4.9	4.9	4.9	4.9	0	0.0	0	0.0
Solar	0.1	0.1	0.1	0.1	0	0.0	0	0.0
Total emissions					15.1	12.8	16.6	11.7
Emissions reduction (% of BAU)						15%		30%
Emissions reduction (% of 2005 total GHG emissions)						11%		24%

Source: CERI

In Manitoba, there was no improvement in emissions reduction in either electricity supply scenario. Emissions were reduced by 11 percent in 2030 and by 24 percent in 2050.

Table 3.5: Energy Use and Direct GHG Emissions by Sector in Saskatchewan

	Energy Consumption (PJ)				Emissions (million tCO2eq)			
	2030 BAU	2030 Electrification	2050 BAU	2050 Electrification	2030 BAU	2030 Electrification	2050 BAU	2050 Electrificatio
Residential	47.3	40.8	48.4	36.7	2.0	0.7	2.0	0.3
Electricity	7.3	27.8	8.9	30.6	0.00	0.00	0.00	0.00
Natural Gas	36.1	11.6	35.8	5.1	1.80	0.58	1.78	0.26
Refined petroleum products	1.3	1.0	1.2	0.7	0.09	0.07	0.08	0.05
Other	2.6	0.4	2.5	0.3	0.10	0.02	0.09	0.02
Commercial	50.46	50.46	67.41	67.41	1.58	0.31	2.11	0.35
Electricity	19.73	44.43	26.41	60.51	0.00	0.00	0.00	0.00
Natural gas	28.23	5.41	37.71	6.15	1.41	0.27	1.88	0.31
Refined petroleum products	1.46	0.05	1.89	0.07	0.11	0.00	0.14	0.01
Other	1.03	0.56	1.40	0.68	0.06	0.03	0.08	0.04
Passenger transportation	51.4	51.3	50.4	14.7	3.3	3.3	3.3	0.3
Electricity	0.0	0.0	0.0	9.8	0.00	0.00	0.00	0.00
Gasoline	44.9	44.7	44.0	4.3	3.07	3.06	3.01	0.29
Diesel	3.5	3.4	3.4	0.3	0.26	0.25	0.25	0.02
Other fossil fuels	0.1	0.1	0.1	0.0	0.00	0.00	0.00	0.00
Bio-fuels	3.0	3.0	3.0	0.3	0.01	0.01	0.01	0.00
Freight Transportation	114.0	114.0	143.8	143.8	8.1	8.1	10.2	10.2
Electricity	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00
Gasoline	37.4	37.4	47.1	47.1	2.56	2.56	3.23	3.23
Diesel	74.8	74.8	94.3	94.3	5.54	5.54	6.99	6.99
Other fossil fuels	0.3	0.3	0.4	0.4	0.02	0.02	0.02	0.02
Bio-fuels	1.6	1.6	2.0	2.0	0.00	0.00	0.01	0.01
Industrial	381.2	381.2	363.9	363.9	18.56	18.56	17.74	17.74
Electricity	48.0	48.0	47.3	47.3				
Natural gas	230.8	230.8	215.5	215.5				
Coal & coke	1.9	1.9	2.0	2.0				
Refined petroleum products	80.2	80.2	80.6	80.6				
Other	20.3	20.3	18.6	18.6				
Electricity generation (S2)	178	202	195	260	6.8	3.9	6.2	1.6
Coal	36.0	10.7			3.3	1.0		
Coal with CCS	8.9	3.9	8.9	3.4	0.1	0.0	0.1	0.0
Natural gas	64.8	53.3	117.6	16.5	3.2	2.7	5.9	0.8
Natural gas with CCS	0	0	0	123.3	0	0	0	0.6
Biomass	49.8	49.8	49.8	28.7	0.2	0.2	0.2	0.1
Hydro	13.1	13.1	13.5	13.5	0.0	0.0	0	0
Wind	5.2	70.9	5.21	74.3	0.0	0.0	0	0
Solar	0.2	0.2	0.22	0.2	0.0	0.0	0	0
Total emissions					40.4	34.9	41.5	30.6
Emissions reduction (% of BAU)						14%		26%
Emissions reduction (% of 2005 total GHG emissions)						8%		16%

Source: CERI

We observe that for Saskatchewan, electrification creates emissions reductions of 8 percent in 2030 and 16 percent in 2050. Coal-fired generation with CCS remains in the generation mix throughout the study period.

Table 3.6: Energy Use and Direct GHG Emissions by Sector in Alberta

	Energy Consumption (PJ)				Emissions (million tCO2eq)			
	2030 BAU	2030 Electrification	2050 BAU	2050 Electrification	2030 BAU	2030 Electrification	2050 BAU	2050 Electrification
Residential	269	229	381	270	12	4	17	2
Electricity	25.7	152.1	40.2	223.1	0.00	0.00	0.00	0.00
Natural Gas	233.7	74.1	326.8	42.6	11.66	3.70	16.30	2.13
Refined petroleum products	2.5	2.2	4.2	3.4	0.17	0.16	0.29	0.24
Other	6.8	1.0	9.5	1.1	0.37	0.05	0.52	0.06
Commercial	210	210	265	265	7	1	9	1
Electricity	66.7	184.2	84.6	238.2	0.0	0.0	0.0	0.0
Natural gas	127.7	22.6	161.6	24.2	6.4	1.1	8.1	1.2
Refined petroleum products	1.5	0.2	1.8	0.3	0.1	0.0	0.1	0.0
Other	13.7	2.5	17.4	2.7	0.8	0.2	1.1	0.2
Passenger transportation	127	124	144	42	8	8	10	1
Electricity	0.4	1.0	0.5	29.3	0.00	0.00	0.00	0.00
Gasoline	109.2	105.5	123.4	11.0	7.48	7.23	8.45	0.76
Diesel	12.6	12.2	14.3	1.3	0.94	0.91	1.06	0.09
Other fossil fuels	0.9	0.9	1.0	0.1	0.05	0.05	0.06	0.01
Bio-fuels	4.1	4.0	4.6	0.4	0.01	0.01	0.01	0.00
Freight Transportation	396.7	396.7	566.6	566.6	28.4	28.4	40.5	40.5
Electricity	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00
Gasoline	117.1	117.1	167.3	167.3	8.02	8.02	11.46	11.46
Diesel	273.2	273.2	390.2	390.2	20.24	20.24	28.91	28.91
Other fossil fuels	1.3	1.3	1.8	1.8	0.08	0.08	0.11	0.11
Bio-fuels	5.1	5.1	7.3	7.3	0.01	0.01	0.02	0.02
Industrial	3401.9	3401.9	3535.2	3535.2	163.6	163.6	169.9	169.9
Electricity	230.3	230.3	249.2	249.2				
Natural gas	2079.4	2079.4	2187.8	2187.8				
Coal & coke	4.6	4.6	4.6	4.6				
Refined petroleum products	186.8	186.8	199.0	199.0				
Other	900.8	900.8	894.7	894.7				
Electricity generation	527.7	829.1	657.5	1136.2	16.4	16.1	22.5	16.0
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural gas	327.0	312.0	447.6	285.2	16.3	15.6	22.3	14.2
Natural gas with CCS	0.0	90.0	0.0	352.2	0.0	0.4	0.0	1.8
Biomass	26.0	23.9	33.4	4.6	0.1	0.1	0.2	0.0
Hydro	6.8	5.4	7.5	7.5	0.0	0.0	0.0	0.0
Wind	163.9	394.0	164.2	481.9	0.0	0.0	0.0	0.0
Solar	3.9	3.9	4.9	4.9	0.0	0.0	0.0	0.0
Total emissions					236.4	221.5	268.8	231.1
Emissions reduction (% of BAU)						6%		14%
Emissions reduction (% of 2005 total GHG emissions)						6%		16%

Source: CERI

Alberta shows a reduction in emissions of 6 percent below 2005 levels in 2030 and 16 percent below 2005 levels in 2050. Natural gas remains a significant contributor to the electricity grid throughout the study period.

Table 3.7: Energy Use and Direct GHG Emissions by Sector in British Columbia

	Energy Consumption (PJ)				Emissions (million tCO2eq)			
	2030 BAU	2030 Electrification	2050 BAU	2050 Electrification	2030 BAU	2030 Electrification	2050 BAU	2050 Electrification
Residential	160.88	142.62	197.74	153.99	5.43	2.27	6.96	1.46
Electricity	52.8	98.4	58.9	125.9	0.00	0.00	0.00	0.00
Natural Gas	89.1	35.8	118.2	21.5	4.44	1.78	5.89	1.07
Refined petroleum products	4.5	3.2	5.4	2.8	0.32	0.23	0.38	0.20
Other	14.4	5.2	15.3	3.9	0.66	0.26	0.69	0.19
Commercial	94.50	94.51	97.56	97.57	2.77	0.57	2.86	0.51
Electricity	40.01	83.31	41.33	87.59	0.00	0.00	0.00	0.00
Natural gas	51.16	10.13	52.60	8.90	2.55	0.51	2.62	0.44
Refined petroleum products	1.29	0.05	1.39	0.09	0.09	0.00	0.10	0.01
Other	2.04	1.02	2.26	0.99	0.12	0.06	0.14	0.06
Passenger transportation	122.5	117.0	121.7	37.3	8.1	7.7	8.0	0.8
Electricity	0.9	1.7	0.9	25.3	0.00	0.00	0.00	0.00
Gasoline	107.0	101.5	106.3	10.6	7.33	6.95	7.28	0.73
Diesel	9.0	8.5	8.9	0.9	0.67	0.63	0.66	0.07
Other fossil fuels	1.7	1.6	1.6	0.2	0.09	0.09	0.09	0.01
Bio-fuels	3.9	3.7	3.9	0.4	0.01	0.01	0.01	0.00
Freight Transportation	228.7	228.7	294.7	294.7	16.4	16.4	21.2	21.2
Electricity	0.0	0.0	0.0	0.0	0.00	0.00	0.00	0.00
Gasoline	61.2	61.2	78.9	78.9	4.19	4.19	5.41	5.41
Diesel	120.0	120.0	154.6	154.6	8.89	8.89	11.45	11.45
Other fossil fuels	45.6	45.6	58.8	58.8	3.34	3.34	4.31	4.31
Bio-fuels	1.9	1.9	2.4	2.4	0.01	0.01	0.01	0.01
Industrial	684.0	684.0	684.0	683.9	24.1	24.1	24.3	24.3
Electricity	103.7	103.7	105.3	105.3				
Natural gas	324.1	324.1	321.8	321.8				
Coal & coke	6.8	6.8	7.3	7.3				
Refined petroleum products	72.0	72.0	74.4	74.4				
Other	177.5	177.5	175.1	175.0				
Electricity generation	212.2	339.3	221.8	472.9	0.1	0.1	0.7	5.4
Natural gas	1.8	11.5	1.8	102.6	0.1	0.1	0.6	5.1
Biomass	0	35.3	0	62.6	0.0	0.0	0.2	0.3
Hydro	200.8	278.9	210.4	294.1	0.0	0.0	0.0	0.0
Wind	9.6	13.6	9.6	13.6	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total emissions					56.9	51.2	64.1	53.6
Emissions reduction (% of BAU)						10%		16%
Emissions reduction (% of 2005 total GHG emissions)						9%		16%

Source: CERI

In British Columbia, there is no difference in emissions in the two different electricity supply scenarios. All natural gas electricity generation is from non-CCS units. British Columbia's emissions reductions in 2030 are 9 percent below 2005 levels and 16 percent below 2005 levels in 2050.

Increase in Efficiency Under Electrification

From the results depicted in Figures 3.1-3.3, it can be seen that with electrification, the total energy demand in the residential, commercial, and passenger transportation sectors is lower than BAU. It is important to recall that this reduction is achieved without any change in the final energy service demand. This is due to the high conversion efficiencies of electricity to energy service converters (e.g., heat pumps, electric vehicles, etc.). In addition to electrification, if these sectors implement conservation measures such as better insulations or ride sharing, further emissions reductions could be achieved.

We further assess the level of efficiency improvement by estimating energy intensity of households (in GJ/household) and energy intensity of passenger kilometres (Pkm) travelled (in MJ/Pkm). Although direct conversion efficiency with electricity is high, electricity needs to be produced and transmitted to consumers.

Energy losses are incurred in both electricity generation and transmission. Therefore, it is plausible that although direct energy intensity is lower with electricity, generation and transmission losses may make the net energy intensity higher. Therefore, we estimated two energy intensities: one considering only direct energy inputs and another considering the losses associated with producing and transmitting electricity.

Table 3.8 and Figure 3.7 present the two estimated energy intensities of the residential sector in 2030 and 2050 under the BAU and electrification scenarios.

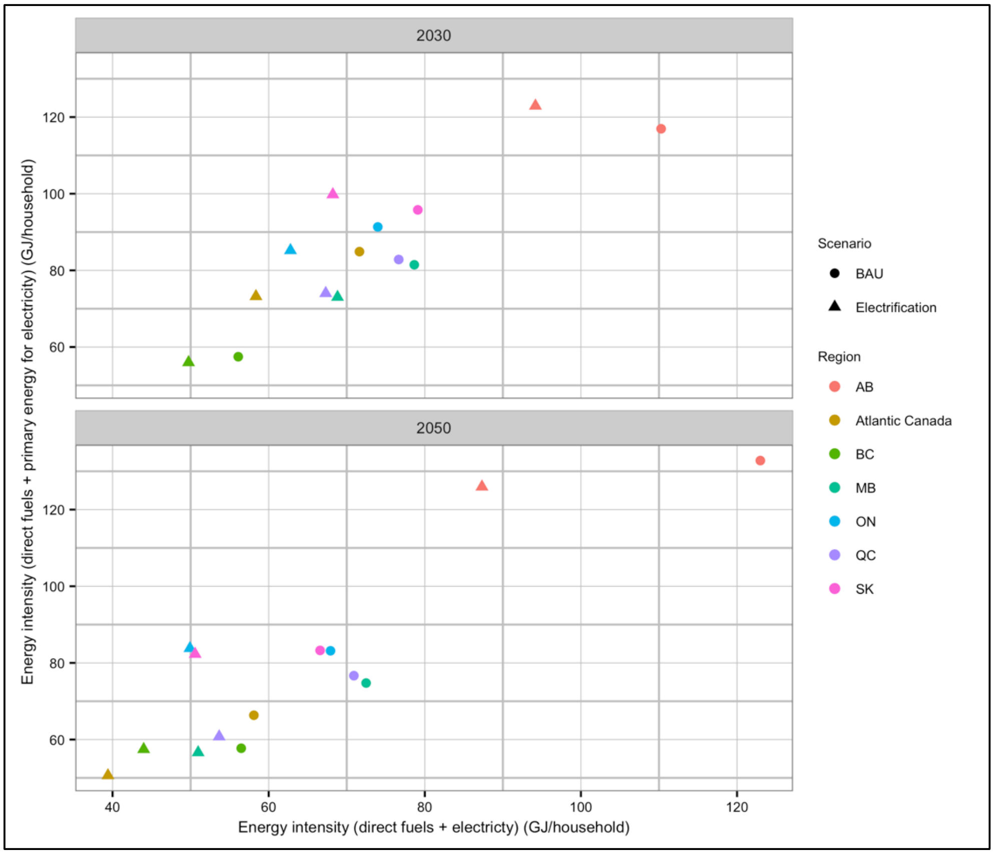
Under electrification, both the direct energy intensity and the net energy intensity of households in all provinces decreases. The reduction in direct energy intensity is in the range of 11-19 percent in 2030 and 22-32 percent in 2050. However, for net energy intensity, where the losses associated with generation is considered, the reduction is less. In fact, in Saskatchewan, Alberta and Ontario, net energy intensity increases (by about 1-5 percent) in 2030. The main reason for that is the higher share of thermal generation (mainly natural gas-fired and nuclear) in these provinces. The conversion efficiencies of thermal generation are in the range of 33 percent to 55 percent, which lowers the net energy intensity.

Table 3.8: Energy Intensity of Household Energy Consumption under the BAU and Electrification Scenarios

		Energy Intensity including direct fuel combustions and electricity (GJ/household)			Energy Intensity including direct fuel combustions and primary energy for electricity (GJ/household)		
Region	**Year**	**BAU**	**Electrification**	**Reduction under electrification**	**BAU**	**Electrification**	**Reduction under electrification**
Atlantic Canada	2030	72	58	19%	85	73	14%
Atlantic Canada	2050	58	39	32%	66	51	24%
Quebec	2030	77	67	12%	83	74	11%
Quebec	2050	71	54	24%	77	61	21%
Ontario	2030	74	63	15%	91	85	7%
Ontario	2050	68	50	27%	83	84	-1%
Manitoba	2030	79	69	13%	81	73	10%
Manitoba	2050	72	51	30%	75	57	24%
Saskatchewan	2030	79	68	14%	96	100	-4%
Saskatchewan	2050	67	51	24%	83	82	1%
Alberta	2030	110	94	15%	117	123	-5%
Alberta	2050	123	87	29%	133	126	5%
British Columbia	2030	56	50	11%	57	56	3%
British Columbia	2050	56	44	22%	58	57	0%

Source: CERI

Figure 3.7: Direct and Net Energy Intensity of Household Energy Intensity under the BAU and Electrification Scenarios



Source: CERI

Table 3.9 and Figure 3.8 detail the energy intensities for the passenger transportation sector. When electrified, transportation sector energy intensity is unequivocally lower compared to BAU due to the high efficiency of electric motors compared to internal combustion engine-based vehicles. However, reduction in 2030 is marginal as the transportation sector is still dominated by conventional vehicles in that year. In 2050, the reduction is in the order of 60-70 percent.

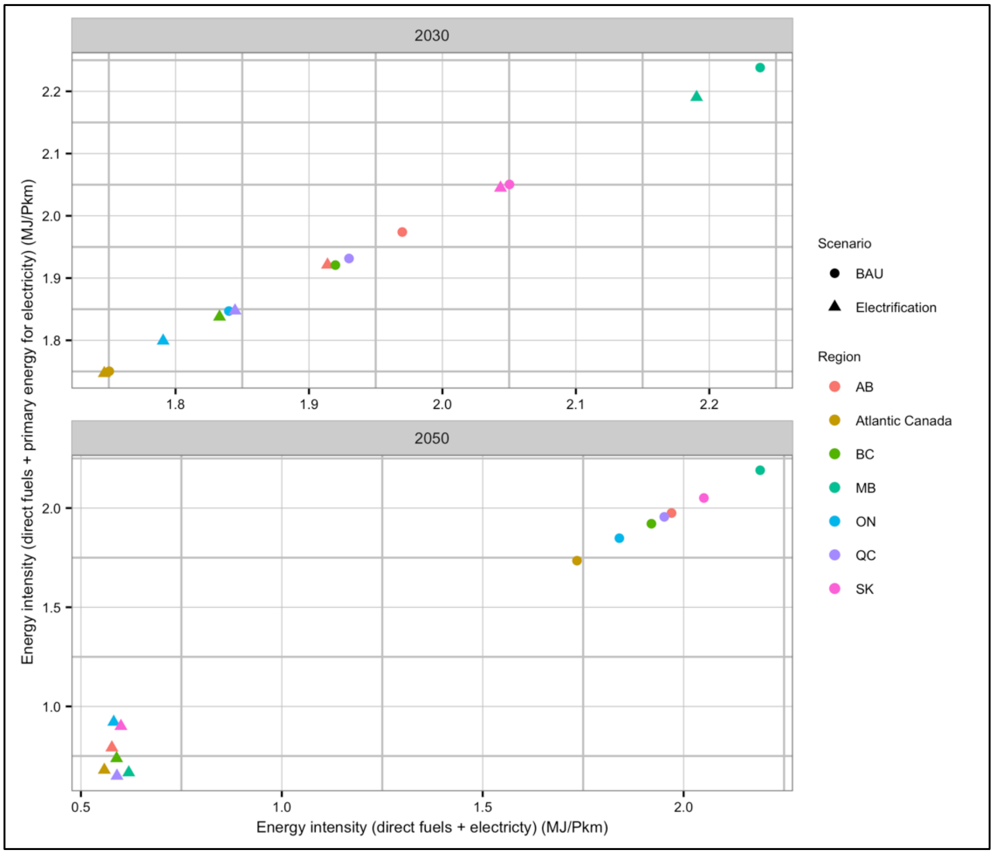
In addition to lowered GHG emissions, low energy intensities decrease the fuel costs for final consumers as the same level of energy service can be obtained with lower amounts of input energy.

Table 3.9: Energy Intensity of Passenger Transportation under the BAU and Electrification Scenarios

		Energy Intensity including direct fuel combustions and electricity (MJ/Pkm)			Energy Intensity including direct fuel combustions and primary energy for electricity (MJ/Pkm)		
Region	**Year**	**BAU**	**Electrification**	**Reduction under electrification**	**BAU**	**Electrification**	**Reduction under electrification**
Atlantic Canada	2030	1.75	1.75	0.2%	1.75	1.75	0.2%
Atlantic Canada	2050	1.73	0.56	67.8%	1.73	0.68	60.8%
Quebec	2030	1.93	1.84	4.4%	1.93	1.85	4.3%
Quebec	2050	1.95	0.59	69.8%	1.96	0.65	66.8%
Ontario	2030	1.84	1.79	2.7%	1.85	1.80	2.6%
Ontario	2050	1.84	0.58	68.4%	1.85	0.92	50.1%
Manitoba	2030	2.24	2.19	2.1%	2.24	2.19	2.1%
Manitoba	2050	2.19	0.62	71.7%	2.19	0.67	69.6%
Saskatchewan	2030	2.05	2.04	0.3%	2.05	2.04	0.3%
Saskatchewan	2050	2.05	0.60	70.8%	2.05	0.90	56.1%
Alberta	2030	1.97	1.91	2.8%	1.97	1.92	2.7%
Alberta	2050	1.97	0.58	70.7%	1.97	0.79	59.9%
British Columbia	2030	1.92	1.83	4.5%	1.92	1.84	4.3%
British Columbia	2050	1.92	0.59	69.3%	1.92	0.74	61.6%

Source: CERI

Figure 3.8: Direct and Net Energy Intensity of Passenger Transportation under the BAU and Electrification Scenarios (Pkm = Passenger kilometre travelled)



Source: CERI

Greenhouse Gas Emissions Reductions

Through this analysis, we find that it is possible to achieve net GHG emissions reduction by electrifying the residential, commercial, and passenger transportation sectors and decarbonizing the electricity supply. GHG emissions reductions achievable to electrification of those three sectors over the analysis period (2020-2050) in all Canadian provinces are shown in Table 3.10.

Table 3.10: GHG Emissions Reductions Achievable by Electrifying End-use Energy Demands of Residential, Commercial and Passenger Transportation Sectors of Canadian Provinces

	Emissions reduction (% of 2005 GHG emissions)		Cumulative emissions reductions in the period 2020-2050 (% of study BAU emissions)
	In 2030	In 2050	
Atlantic Canada	7%	13%	16%
Quebec	9%	35%	11%
Ontario	14%	31%	20%
Manitoba	11%	24%	17%
Saskatchewan	8%	16%	13%
Alberta	6%	16%	8%
British Columbia	9%	16%	10%

Source: CERI

The GHG emissions reduction achievable in 2030 range from a low of 6 percent (in Alberta) to a high of 14 percent (in Ontario) below 2005 levels. In 2050, the achievable GHG emissions reductions varies from 16 percent (in Alberta) to 31 percent (in Ontario) below 2005 levels. Federal-provincial economy-wide emissions reductions target set for 2030 is 30 percent below 2005 levels. In 2050, the reduction target is 80 percent below 2005 levels. Therefore, electrification of the three sectors assessed in this study can contribute to but not fully achieve those targets.

It should be noted that the above emissions reductions are annual values. Global climate change is caused by atmospheric accumulation of greenhouse gases.[1] Therefore, it is important to gain insights into cumulative emission reductions achievable through mitigation options. The cumulative emission reductions in the period 2020-2050 range from 8 percent (in Alberta) to 20 percent (in Ontario) compared to the study baseline scenario (BAU scenario) emissions.

Despite the emissions reductions achievable under the electrification scenarios, large amounts of unmitigated emissions remain within all provinces. These emissions are produced by the industrial, freight transportation, and electricity generation sectors. Some remaining un-electrified end-use energy services of the residential, commercial, and transportation sectors also contribute to the emissions.

[1] Meinshausen, M. et al, "Greenhouse-Gas Emission Targets for Limiting Global Warming to 2 °C." Nature 458, no. 7242 (April 30, 2009): 1158–62.

Economic Cost Analysis

In the cost analysis, the capital cost of deploying or replacing energy infrastructure (i.e., end-use energy conversion devices, electric power plants) and operating costs (i.e., energy and other operating costs) are estimated in the residential, commercial, passenger transportation and electric power sectors. The cumulative discounted costs in those four sectors over the analysis period are listed in Table 3.11. The cumulative cost of energy in the three consuming sectors does not include the cost of electricity as the cost of producing electricity is included in the electricity sector cost calculations.

Table 3.11: Emissions and Cost Analysis under All Scenarios

	Cumulative spending in capital equipment and energy in the period 2020-2050 (billion 2014 CAD)				Cumulative emissions in the period 2020-2050 (million tCO2eq)	Cumulative emissions reduction (% of BAU)	GHG emissions abatement cost (CAD/tCO2eq)[ii]
	Residential sector	Commercial sector	Passenger transportation sector	Electricity sector[i]			
Atlantic Canada							
No electrification (BAU)	28	12	45	29	909		
Electrification (S1)	10	7	46	54 (186%)	767	16%	14
Quebec							
No electrification (BAU)	13	46	238	89	3552		
Electrification (S1)	13	28	230	129 (145%)	3173	11%	36
Manitoba							
No electrification (BAU)	9	10	25	13	481		
Electrification (S1)	5	7	25	22 (169%)	397	17%	8
British Columbia							
No electrification (BAU)	35.6	20.7	71.6	33.8	1806		
Electrification (S1)	20.9	12.4	69.4	61.4 (182%)	1621	10%	13
Ontario							
No electrification (BAU)	140	112	243	117	5144		
Electrification (S1)	73	64	242	366 (313%)	4074	21%	124
Electrification with Gas CCS (S2)	73	64	242	352 (301%)	4101	20%	114
Saskatchewan							
No electrification (BAU)	12	13	27	23	1251		
Electrification (S1)	6	7	28	45 (196%)	1084	13%	65
Electrification with Gas CCS (S2)	6	7	28	43 (187%)	1088	13%	58
Alberta							
No electrification (BAU)	32	34	65	108	7606		
Electrification (S1)	16	25	65	244 (226%)	7016	8%	216
Electrification with Gas CCS (S2)	16	25	65	234 (217%)	6994	8%	176

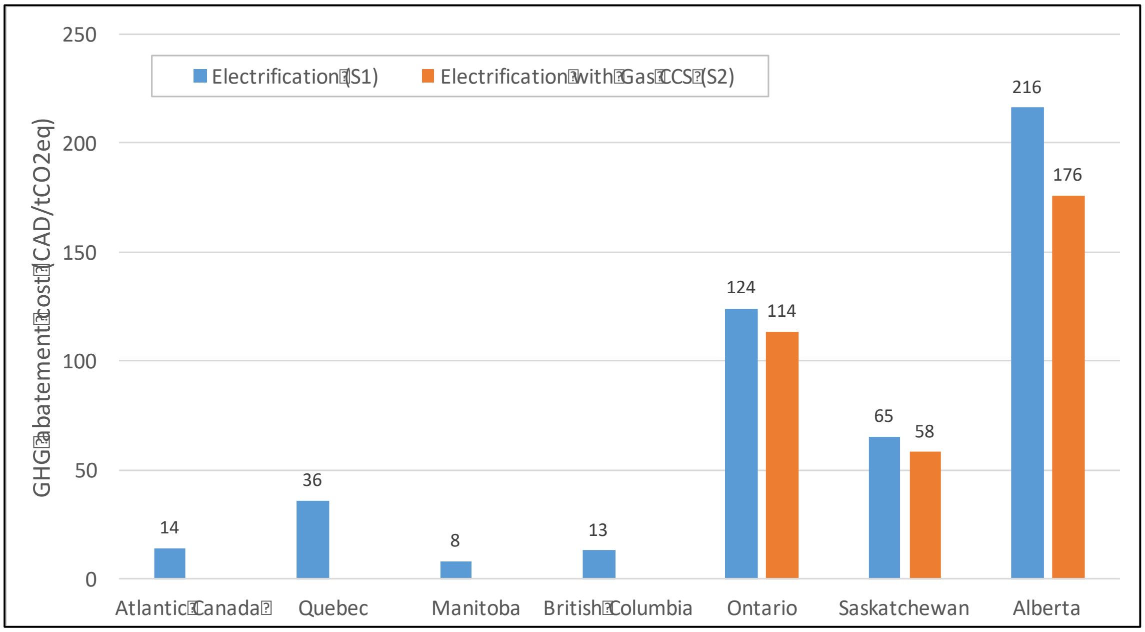
[i]Percentage numbers within parenthesis in electrification rows indicate the relative magnitude of cumulative electricity sector spending compared to BAU scenario electricity sector spending.

[ii]Abatement cost is calculated by taking the BAU scenario as the reference case and considering cumulative emissions reductions

Source: CERI

GHG emissions abatement cost of electrification as a climate change mitigation option is calculated by taking into account the cumulative emissions reductions and cumulative total cost. Estimated abatement costs are depicted in Figure 3.9 and also presented in Table 3.11. The highest cost per tonne of emissions reduction is found in Alberta at $216, while Manitoba has the lowest cost at $8 per tonne. The passenger transportation sector has the highest investment cost of the three demand sectors. Investment in the electricity sector is higher than BAU ranging from an increase of 145 percent in Quebec to 313 percent in Ontario.

Figure 3.9: GHG Emissions Abatement Costs under Electrification Scenarios



Source: CERI

When electricity costs are excluded, the three consuming sectors face a net cost reduction due to the fuel cost savings. However, due to increased electricity demand, new investments and operating costs incurred in the electricity sector are significantly higher than the BAU scenario. The highest electricity sector spending of approximately 3 times that of BAU spending was observed in Ontario.

The increase in electricity demand under electrification is the highest in Ontario (2.5 times that of BAU) and therefore, higher amounts of new generation infrastructure are required. A bulk of the nuclear fleet of Ontario, which currently provide zero GHG emissive baseload electricity, retires within the analysis period. Consequently, higher amounts of variable renewable generation sources are deployed by the investment model to replace them and to satisfy the increasing demand while meeting the GHG emissions restrictions. Higher electricity sector spending was also observed in Alberta and Saskatchewan. In these two cases, higher amounts of low GHG emissive generating units are required to decarbonize the electricity supply that is currently dominated by fossil fuel-fired generating units.

A clear clustering of GHG emissions abatement costs was observed among the provinces (see Figure 3.9). A relatively lower GHG abatement cost was observed in Quebec, Manitoba, British Columbia, and Atlantic Canada whose electricity supply is dominated by hydropower. The abatement cost varies in the range of \$8-\$36/tCO2eq. Relatively lower electricity demand growth also contributed to the lower abatement cost.

Alberta, Ontario, and Saskatchewan see higher abatement costs. In the former two provinces, the abatement cost was well above \$100/tCO2eq. In these three provinces, availability of NGCC units with CCS under the S2 scenario leads to lower abatement and total costs. For example, in Ontario, the S2 abatement cost is 18 percent lower than S1 abatement cost. Reduction in abatement cost under S2 compared to S1 is 8 percent in Alberta and 11 percent in Saskatchewan. With NGCC-CCS units, it is possible to produce low GHG emissions intensive electricity at a high capacity factor, reducing the capital cost contribution. Relatively lower natural gas prices also contributed to lowered abatement cost under S2.

Table 3.12: Average Cost of Electricity under the BAU and Electrification Scenarios

	Average cost of electricity ($/MWh)			Relative increase (%)	
Atlantic Canada	BAU	S1	S2	S1	S2
2030	61	81		33%	
2050	68	91		34%	
Quebec					
2030	40	50		25%	
2050	41	57		39%	
Manitoba					
2030	44	48		9%	
2050	44	51		16%	
British Columbia					
2030	40	54		35%	
2050	41	63		54%	
Ontario					
2030	55	95	93	73%	
2050	57	101	101	77%	
Saskatchewan					
2030	67	85	86	27%	28%
2050	77	99	101	29%	31%
Alberta					
2030	75	103	106	39%	42%
2050	85	109	113	28%	33%

Source: CERI

Higher investment and operation costs under electrification will lead to higher average cost electricity and consequently higher electricity rates. We estimated the average cost of electricity under all scenarios by considering operation costs and investment cost of new generating units. Excluded from this estimate is the unrecovered capital cost of generating units that are currently available in provincial power systems. We were unable to obtain unrecovered capital costs of the current units through publicly available information.

While exclusion of these capital costs does not change the absolute difference of the average costs, it over estimates the relative increase. Estimated average cost of electricity and their relative increase under electrification are listed in Table 3.12. As can be observed from this table, the average cost of electricity increases from 9 percent to 73 percent in 2030, and 16 percent to 77 percent in 2050 compared to a business as usual case. The impact of increased electricity cost will be partially compensated by reduced spending on direct fuel purchases.

Unintended Consequences: Impact on Existing Infrastructure and Government Revenues

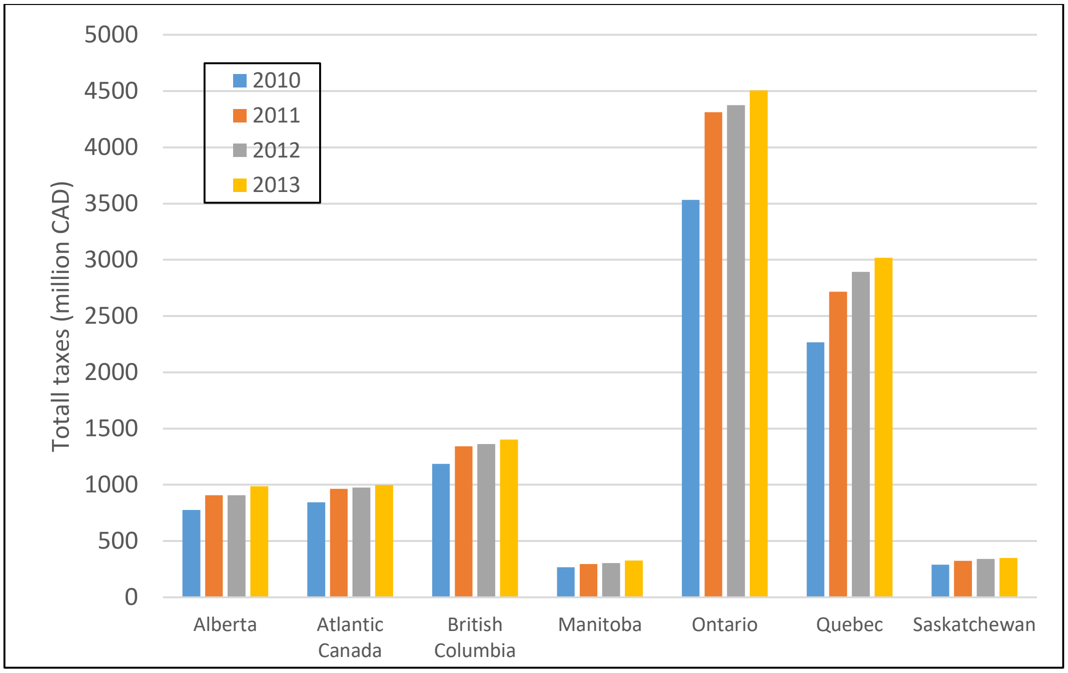
Electrification of end-use energy services inevitably changes the fuel mix demanded by final consumers. As discussed previously, electrification leads to lower overall GHG emissions and higher efficient end-use energy conversions. However, there are several unintended consequences that would potentially complicate an economy-wide electrification.

With electrification in the residential and commercial sectors, the main fuel that gets replaced by electricity is natural gas. Natural gas is delivered to over 6.6 million residential, commercial and institutional customers across Canada. The gas delivery system consists of over 450,000 kilometres of transmission and distribution pipelines as well as above ground and underground storage facilities.[2] The investment in this infrastructure will be stranded with electrification. For example, capital investments made by natural gas distribution utilities over the last ten years is in the order of CAD $1.2 - $3 billion per year.[3] Investment and operating cost of natural gas distribution infrastructure is recovered through regulated tariffs. Estimation of the exact value of the infrastructure that could potentially be stranded under large scale electrification requires extensive analysis that takes into account the vintage of the existing distribution networks as well as their spatial distribution, which is beyond the capabilities of the models developed for this analysis. Furthermore, it is plausible that investment cost of the current natural gas infrastructure may be recovered before their utilization diminishes due to gradual electrification of end-use energy services that they serve. What would inevitably be stranded under the electrification scenario is new natural gas distribution networks that would be built after rolling out of economy-wide electrification as a climate change mitigation strategy. This emphasizes the importance of coordinating policy goals and physical investments.

[2] Helping Middle Class Families, Growing the Economy, Driving Innovation - 2016 Pre-budget Submissions. Canadian Gas Association. Retrieved from http://www.parl.gc.ca/Content/HOC/Committee/421/FINA/Brief/BR8115793/br-external/CanadianGasAssociation-e.pdf

[3] Statistics Canada. (2016). CANSIM Table 029-0046 Capital and repair expenditures by North American Industry Classification System (NAICS).

Figure 3.13: Taxes on Gasoline



Source: Statistics Canada; Figure by CERI)

Electrification of the passenger transportation sector – where electricity mainly displaces gasoline – also have some unintended consequences. In this case, the current transportation fuel distribution and dispensing infrastructure can potentially be stranded. The most notable one is the network of filling stations. As of December 2014, there were approximately 17,200 gasoline stations in Canada. About 29 percent of these stations had 1-5 employees and 70.9 percent had more than 5 employees.[4] These filling stations primarily serve personal transportation fuel demands. Under electrification of passenger transportation, these stations may lose the primary market they serve, depending on how the charging station infrastructure is developed.

Another impact of displacement of gasoline as transportation fuel is the potential loss of government tax revenues. There are several taxes – for example, federal excise tax, provincial fuel taxes, municipal transit taxes – that are enforced specifically on gasoline. These tax revenues are utilized for building and maintaining roads and funding public transit services. Figure 3.13 shows the total taxes (excise, fuel and sales) paid by Canadian households on gasoline purchases over the period 2010-2013.[5] Total taxes collected from gasoline sales to households (gasoline is purchased primarily as a transportation fuel) amounts to CAD $11 billion per year (highest in Ontario at approximately CAD $4.3 billion/year and lowest in Manitoba at about CAD $0.3 billion/year). Large scale electrification of passenger transportation would lead to a loss of these

[4] Gasoline Stations (NAICS 447): Establishments, Statistics Canada, https://www.ic.gc.ca/app/scr/sbms/sbb/cis/establishments.html?code=447&lang=eng

[5] Data source: Statistics Canada. (2016). CANSIM Table 381-0033 Supply and use tables (Detail level, provincial and territorial). Retrieved from http://www5.statcan.gc.ca/cansim/a33?RT=TABLE&themeID=2745&spMode=tables&lang=eng

tax revenues. It should, however, be noted that under the stock-rollover model results of this study, significant reduction of gasoline demand – consequently loss of tax revenues – would start around 2035.

Study Limitations and Future Work

For this analysis, we developed an infrastructure stock-rollover model, electric power generation investment and operations model, and constructed scenarios to assess the implications of electrification as a low carbon economy option. Development of these models was challenging mainly due to availability of reliable and consistent data sets to calibrate the models. Furthermore, several scoping and structural assumptions were made to ensure that we can make clear causal relationships between impacts and energy system changes. However, data challenges and scoping assumptions inevitably leads to model limitations.

One primary limitation of the study is that we focus only on three economic sectors. Notable exclusions are the industrial sector (including the agricultural sector) and the freight transportation sector. The main reasons for exclusion of these two sectors was first, the limited amount of publicly accessible data to track the existing infrastructure and energy consumption details. Without such data, it is not possible to build robust models to track current energy use patterns and required transitions. Second, without full insights into the current operations it is not possible to make reliable judgements on technologies that can be used to electrify the end-use services in those two sectors. It is evident, however, that these two sectors emit a significant amount of GHG emissions. Therefore, to gain insights into deeper emissions reduction options, future work should focus on assessing mitigation options in these two sectors.

The fuel prices used for this analysis were obtained from the NEB's Canada's Energy Future 2016 report. However, changes in demand for fuels under electrification would likely impact fuel prices. Comprehensive model developments need to be made to incorporate such endogenous changes in energy prices.

Similarly, under both the reference scenario and electrification scenarios, we assumed that final energy service demand would remain the same. However, with changes in energy prices as well as federally and provincially announced carbon pricing, energy service demands could potentially change. This will be assessed in future studies.

We also did not model energy service demand changes due to life style and behavioral changes. Such changes quite plausibly impact the evolution of future energy systems; the models we developed cannot directly capture such impacts. However, some insights into impacts of those factors can be gained through scenario-based modeling.

Future developments to the current models will be focused primarily on enhancing the technology modeling. This applies to both demand-side technologies as well as electricity generation technologies. Electricity investment and dispatch models in particular will be enhanced to expand the generation technology considerations, to include electricity storage technologies, to incorporate endogenous estimation of transmission and distribution system needs, to improve variable generation technology modeling, and to improve resource and demand representation (for example, incorporation of updated time series data on demand, wind, solar, and hydro resources). On the demand side, further model enhancements will be made to assess energy efficiency improvements (e.g., use of high performance building insulations) that can be used to reduce energy demand. One other aspect that needs to be assessed in future work is the impact of potential changes to electricity demand profiles under increased use of electricity as a residential and transportation fuel.

Chapter 4: Concluding Remarks

An economy-wide transition from current energy end-use fuel mix to one dominated by electricity is seen as a viable option to satisfy future energy demands, while achieving deep greenhouse gas emissions reductions. In this study, we assessed the energy, environmental, and economic implications of electrifying the end-use energy services in the residential, commercial, and passenger transportation sectors of 10 Canadian provinces.

Electrification of energy services in the aforementioned three sectors provides a feasible "technology path" to reduce economy-wide GHG emissions reductions. GHG emissions reductions achievable by 2030 is in the order 6 percent (in Alberta) to 14 percent (in Ontario) below 2005 levels. In 2050, the achievable GHG emissions reductions varies in the range of 16 percent (in Alberta) to 31 percent (in Ontario) below 2005 levels. Electrification of the three economic sectors that were assessed in this study can contribute to partial achievement of Canadian federal-provincial emissions reduction targets.

Although a considerable amount of emissions reductions is achieved by electrifying three economic sectors, a larger amount of emissions would still be produced by the industrial and freight transportation sectors. Mitigation actions are required in those sectors to achieve deeper emissions reductions.

Viability of electrification as a climate change mitigation strategy depends on decarbonizing the electricity supply. Furthermore, it requires much larger electricity generation and transmission infrastructure than today. We find that depending on the province, the electricity supply needs to be 1.2 (in Quebec) to 2.5 (in Ontario) times that of the reference scenario, where end-use energy mixes are kept in current levels.

This leads to a further consideration. The land use required to provide the additional electricity supply will mean an expanded grid in all provinces. Renewable electricity generation options are at a lower energy density than fossil-based generation. Therefore, approximately two times more electricity demand will likely result in more than doubling of land-use requirements. Given current citizen concerns related to siting of energy infrastructure projects, electrification of end-use services will see a heightened challenge for building the corresponding electricity supply requirements.

The estimated cost of building and operating electric power systems under electrification is 1.5 to 3 times that of the reference scenario. The highest total electricity sector cost was observed in Ontario; the lowest is in Quebec. Higher investment and operating costs will inevitably lead to higher average costs of electricity. We estimated the increase in average cost to be 16-77 percent in 2050, depending on the province. GHG emissions abatement cost of electrification is lower (\$14-\$38/tCO2eq) in Quebec, Manitoba, British Columbia and the Atlantic provinces. Abatement cost is higher in Alberta, Ontario, and Saskatchewan – well over \$100/tCO2eq in Alberta and

Ontario. The availability of natural gas-fired generation with carbon capture and storage leads to 8-18 percent lower abatement costs in those three provinces.

Electrification will improve the efficiency of end-use energy conversions significantly. We found that under electrification, energy efficiency is improved by up to 30 percent. More profound efficiency improvements are observed in the passenger transportation sector where energy intensity is reduced by up to 71 percent. Lower energy bills due to higher efficiency can potentially compensate for the higher per unit electricity costs under the electrification scenarios. Electrification of end-use energy services will make transformational changes in energy systems and will change the way we source and consume energy. This would form only part of the solution to meeting stated federal and provincial government emissions reductions targets.

Appendix A: Further Information Regarding the Stock-rollover Model

Housing Stock Over Time

For each home type (single-detached, single-attached, apartments and mobile homes) and for each province, the housing stock is projected for the years after 2011, using the following equation:

$$TH_{y+1j} = \sum_{\nu}^{y} TH_{\nu yj} \times (1 - \beta_{\nu y}) + [TH_{\nu yj} \times \beta_{\nu y} + NHH_{y+1}]\theta_{yj}$$

j : home types (single-detached, single-attached, apartments, mobile homes)

y : model year (2014 to 2050)

v : house vintages (1990 to year y)

TH_{y+1j}: the number of housing units of type j in year y+1

$TH_{\nu yj}$: the number of housing units of vintage v and type j in year y

NHH_{y+1} : the number of new households in year y+1

θ_{yj} : the share of housing unit type j in total housing units in year y

$\beta_{\nu y}$: the replacement coefficient for vintage v in year y

Based on this equation, housing units that are being renovated or retired are replaced with a new vintage and type of house ($TH_{\nu jy} \times \beta_{\nu y}$). New vintage housing units of different types are also added as the number of households in each region grows (NHH_{y+1}). Data for the new household formation for each province comes from Statistic Canada's Long-term household projections – 2013 update.[1] The fraction of these new housing units ($TH_{\nu jy} \times \beta_{\nu y} + NHH_{y+1}$) that are being added to the stock of each home type (j) is determined by the ratio of each home type in the whole housing stock of the previous year (θ_{jy}).

The replacement coefficients are generated by a survival function that uses Poisson distribution, with a mean (λ) equal to the expected useful life of the building or equipment. The replacement coefficient for vintage v in year y is $\beta_{\nu y}$:

[1] http://publications.gc.ca/collections/collection_2014/schl-cmhc/nh18-23/NH18-23-113-006-eng.pdf

$$\beta_{\nu y} = e^{-\lambda} \frac{\lambda^{y-\nu+1}}{(y-\nu+1)!}$$

The Poisson distribution has a right-skewed density function, which becomes more bell-shaped around λ _at higher λ _values. For the housing stock, the expected lifetime is assumed to be 50 years, where "lifetime" is more precisely defined as the time before retirement or renovation. This housing stock is used in the following sections as an activity driver in calculating the changes in the stock of equipment over time and also the final energy consumption for each end-use/province.

Equipment Stock

For years 1990-2013, for each end-use k mentioned in Table 2.1, and for each home type/ province, only the total stock of each equipment system from 1990 to 2013 is available from the Comprehensive Energy Use database. Since there is no information on the vintages of these system types, we use a survival function to infer the stock of each vintage in each year. Using the survival function explained above, the number of the total stock of each equipment system is decomposed to the stock of each vintage. For example, the stock of vintage 1991 in year 1991 ($EQP_{k1991\ 1991j}$) equals the total stock of 1991 (EQP_{k1991j}), which data is available, minus whatever is remaining from the vintage 1990 in 1991 (which is the stock of vintage 1990 ($EQP_{k1990\ 1990j}$) minus the fraction of 1990 stock that has been replaced in 1991, $EQP_{k1990\ 1990j}\beta_{1990\ 1991}$). Similarly, for other years we have:[2]

$$EQP_{kyyj} = EQP_{kyj} - \sum_{\nu=1990}^{y-1} [EQP_{k\nu\nu j} - \sum_{t=\nu+1}^{y} EQP_{k\nu\nu j}\beta_{\nu t}]$$

k : end-uses in Table 2.1
j : home types (single-detached, single-attached, apartments, mobile homes)
y : year, model year (2014 to 2050)
v : equipment system vintages (1990 to year y)

For the equipment stock, the expected lifetime λ is assumed to be 15 years. Given the available data for the total stock of each equipment for years 1990-2013, the above calculations give us the number of each vintage (vintage 1990 to vintage 2013) in the total stock over time.

[2] It is assumed that the total stock in the initial, 1990, just contains the vintage of year 1990.

Equipment Stock Projection

For years after 2013, total new sales in each year ($EQP_{ky+1y+1j}$) equals the total number of new houses of type j in that year plus total number of equipment for end-use k of all vintages before year y+1 that are replaced in year y+1:

$$EQP_{ky+1j} = EQP_{ky+1y+1j} + \sum_{\nu=1990}^{y} [EQP_{k\nu\nu j} - \sum_{t=\nu+1}^{y} EQP_{k\nu\nu j}\beta_{\nu t}]$$

Total new sales in year y+1 ($EQP_{ky+1y+1j}$) is the total number of new houses of type j plus total number of equipment for end-use k of all vintages before year y+1 that were replaced in year y+1:

$$EQP_{ky+1y+1j} = NH_{y+1j} + \sum_{\nu=1990}^{y+1} EQP_{k\nu\nu j}\beta_{\nu y+1}$$

where $EQP_{ky+1y+1j}$ represents the new sales in each year. To decompose this number to all equipment types, we need the market shares of each equipment type for years after 2013.

Market Share of Each Vintage

For each equipment system, different saturation rates (i.e., share of each equipment in the total new sales) are assumed in year 2050 under two scenarios (i.e., business-as-usual and electrification). For example, new sales of high efficiency natural gas equipment for space heating saturate at 50 percent, and 1 percent of total new equipment sales for space heating in 2050 under the BAU and electrification scenarios, respectively. Under the electrification scenario, the new sales of heat pumps and electric baseboards for space heating saturate at 70 percent and 20 percent of total new equipment sales for space heating in 2050, respectively.

The sales penetration rate (SPN) for each equipment (i.e., its share in total new sales) reaches the assumed saturation level (SAT) in 2050 along an S-shaped adoption curve. Users change sales' penetrations by choosing the level and approximate timing of saturation for a given type of equipment.

The S-shaped curve has a scaling parameter (α) that changes the shape of the curve. This parameter was chosen in a way that the initial point of the S-shaped adoption curve (i.e., the first year of the projection, 2014) to be equal to the share of that equipment in the total stock[3] of space heating equipment in 2013. This condition was used to determine the scaling parameter of the S-shaped adoption curve. The S-shape adoption curve is characterized as follows:

$$SPN_{kmy} = \frac{SAT_{km}}{1 + \alpha e^{x}}$$

$$x = \frac{MSY_{km} + TRG_{km} - y}{TRG_{km}}$$

$$TRG_{km} = \frac{ASY_{km} - MSY_{km}}{2}$$

k : end-uses in Table 2.1
m : equipment system (based on equipment systems specific to the end-uses in Table 2.1)
y : year, model year (2014 to 2050)
SPN_{kmy} : sales penetration of equipment system m for end-use k in year y
SAT_{km} : saturation level (share of the new sales) of equipment system m for end-use k in a specified year (2050 here)
α : is a generic shape coefficient, which changes the shape of the S-curve
MSY_{km} : measure start year for equipment system m for end-use k in a specified year
TRG_{km} : time-to-rapid-growth for adoption of equipment system m for end-use k in a specified year
ASY_{km} : approximate saturation year for adoption of equipment system m for end-use k

Multiplying the sales penetration rates derived from the S-shaped adoption curves (SPN_{kmy}) by the number of new sales of each year (EQP_{kyyj}), gives the number of sales of each equipment m in year y:

$$EQP_{kmyyj} = SPN_{kmy} \times EQP_{kyyj}$$

By adding the new sales of each equipment for each year (EQP_{kmyyj}) to the stock of previous vintages that are remaining in that year ($\sum_{\nu=1990}^{y-1} [EQP_{km\nu\nu j} - \sum_{t=\nu+1}^{y} EQP_{km\nu\nu j}\beta_{\nu t}]$), we can derive the total stock of each vintage of each equipment over time (EQP_{kmyj}) under different scenarios:

[3] Since data for the new sales for each equipment is not available, the share of each equipment in the total stock of space heating in 2013 is used as a proxy for the share of each equipment in the new sales in 2014.

$$EQP_{kmyj} = EQP_{kmyyj} + \sum_{\nu=1990}^{y-1} [EQP_{km\nu\nu j} - \sum_{t=\nu+1}^{y} EQP_{km\nu\nu j}\beta_{\nu t}]$$

Market share for an equipment vintage in a given year is the initial stock of that vintage, determined by the adoption curve, minus the stock that has turned over and been replaced, divided by the total stock of equipment in that year (e.g., the share of 2020 vintage natural gas-fueled equipment in the total stock of equipment used for space heating in 2025).

$$MKS_{km\nu y+1j} = \frac{EQP_{km\nu yj} - \sum_{\nu}^{y} EQP_{km\nu yj} \times \beta_{\nu y}}{EQP_{ky+1j}}$$

where

$$EQP_{ky+1j} = \sum_{m} EQP_{kmy+1j}$$

$MKS_{km\nu y+1j}$: is the market share of vintage v of equipment system m for end-use k in year y+1 of home type j
$EQP_{km\nu yj}$: is the stock of equipment system m adopted for end-use k that has vintage v in year y home type j
EQP_{ky+1j} : is the total stock of equipment for end-use k in year y+1 for home type j

For appliances, since there is no equipment type and each new house needs at least one unit of each appliance, there is a slight change in the model. For example, total number of refrigerators (m) in 2014 is the number of refrigerators in 2013 plus the number of new houses multiplied by the number of refrigerators per household plus the total number of refrigerators of the previous vintages that must be replaced in 2014.

$$EQP_{my+1j} = EQP_{myj} + [NH_{yj} \times PH_m] + \sum_{\nu=1990}^{y-1} EQP_{m\nu\nu j}\beta_{\nu y}$$

The total stock of appliances is the summation of the stock of all appliances:

$$EQP_{ky+1} = \sum_{m} EQP_{kmy+1}$$

Market shares are then calculated as the share of the stock of each vintage of each equipment in the total stock of appliances:

$$MKS_{m\nu y+1} = \frac{EQP_{m\nu y} - \sum_{\nu}^{y} EQP_{m\nu y} \times \beta_{\nu y}}{EQP_{ky+1}}$$

All appliances use just electricity, except for a small fraction of clothes dryers and ranges which use natural gas. Therefore, the adoption to the electricity is defined for just these two equipment systems such that under the electrification scenario, the share of gas-fueled ones in the new sales becomes zero in 2050.

Residential Final Energy Consumption

Final Energy for each end-use and home type is assumed to be growing with its annual average rate over the last 20 years. To derive the total service demand of each end-use, in addition to the final energy, we need efficiency rates. We use a weighted average of the efficiency rates of all equipment systems where the weights are the market share of that equipment system over time. These market shares are the results of the above stock-rollover model under BAU.

$$EFF_{kyj} = \sum_{m} MKS_{kmyj} \times EFF_{kmyj}$$

where

$$MKS_{kmyj} = \sum_{\nu=1990}^{y} MKS_{km\nu yj}$$

k : end-uses in Table 2.1
m : equipment system (based on equipment systems specific to the end-uses in Table 2.1)
j : home types (single-detached, single-attached, apartments, mobile homes)
y : year, model year (2014 to 2050)
v : equipment system vintages (1990 to year y)

$MKS_{km\nu yj}$: market share for vintage v of equipment system m for end-use k home type j in year y

EFF_{kmyj} : energy efficiency of equipment system m for end-use k in year y (reported in Table A.1)

Table A.1: Heating System Stock Efficiencies by System Type (%)

Heating Oil - Normal Efficiency	60
Heating Oil - Medium Efficiency	78
Heating Oil - High Efficiency	85
Natural Gas - Normal Efficiency	62
Natural Gas - Medium Efficiency	80
Natural Gas - High Efficiency	90
Electric	100
Heat Pump	190
Other	50
Wood	50
Dual Systems	80

Source: Comprehensive Energy Use database, Residential Sector, Alberta, Table 26

Using the weighted average of energy efficiency rates and the final energy projection, the total service demand is:

$$TSD_{kyj} = EFF_{kyj} \times FE_{kyj}$$

TSD_{kyj}: total service demand for end-use k home type j in year y
EFF_{kyj}: average efficiency rate of equipment systems for end-use k home type j in year y
FE_{kyj} : residential final energy consumption of end-use k home type j in year y
The above total service demand is assumed to be the same under all scenarios. Energy use of each fuel (FE_{kmyj}) is calculated using this total service demand, the market shares of each equipment system (which are derived from the stock-rollover model and are different for each scenario) and the energy efficiency rates of each equipment system:

$$FE_{kmyj} = \frac{TSD_{kyj} \times MKS_{kmyj}}{EFF_{kmyj}}$$

Transportation Sector Model Structure

In the model, the energy demand forecast from the NEB is split using historical factors from the Office of Energy Efficiency historical trend to set a Business as Usual scenario.

The electrification scenario is built by running a continuous increase of the electric car share in the total vehicle kilometers.

1. Energy demand by fuel type is derived from the OEE factor for each province on a yearly basis.

$$\beta_{2013} = E_{kj2013}/E_{oee}$$

2. Energy demand by vehicle type and fuel type is the value added of energy demand by fuel type ***k*** and per year ***y*** for vehicle type ***j***

$$E_{kjy} = \beta_{2013} * E_{y-EF-2016}$$

Where, $E_{y-EF-2016}$ is the energy demand forecasted by the NEB energy future update 2016.

3. when Energy demand by fuel type and vehicle type is calculated, we estimated the passenger kilometer equivalent using historical data sets obtained from OEE.

$$E_{kjy}/\Theta_{Pkm} = Pkm_{kjy}$$

Where j for the vehicle type, k for the fuel type, y for year and Θ_{Pkm} is constant

4. From the passenger kilometer determined by fuel type, the Vehicle kilometer is established to set a business as usual scenario.

$$Pkm_{kjy}/\lambda_{2013} = Vkm_{kjy}$$

and

$$Vkm_{ky} = \sum_{j} Vkm_{kjy}$$

Lambda λ_{2013} calculation is based on Statistic Canada's vehicle survey 2004 to 2009 and Data provided by CANESS represent the number of passengers per car and in average.

5. Electrification scenario consists of increasing electricity fueled vehicle kilometer share for each vehicle type continuously to reach 90 percent in 2050, the share of other fuel type decreases proportionally.

$$\varepsilon_j = (\beta_j/\beta_{2013})^{1/n} - 1$$

Where β_j represents the share of each fuel type and n is the difference between current year y and the base year. For the model, 2013 is the base year and ε_j for electricity reaches 90 percent in year 2050, ε_j the average annual growth of share of fuel

$$\beta_{jy} = \beta_{2013} * (1 + \varepsilon_j)^n$$

The vehicle kilometer equivalent is calculated by the following relationship:

$$Vkm_{kjy} = \beta_{jy} * Vkm_{ky}$$

A capital cost premium is considered for each marginal vehicle kilometer travelled per year.