Energy modelling for low carbon pathways for the electricity and transportation systems in British Columbia and Alberta

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Abstract

Currently, the electricity, heat and transport sectors are responsible for 40% of all global greenhouse gas emissions. To avoid intensification of anthropogenic climate change, emissions from these sectors must be significantly decreased in the coming decades. This dissertation focuses on pathways to low-carbon futures for the electricity and transport systems using the Canadian provinces of British Columbia and Alberta as case studies. Firstly, a model of the Alberta system is used to study coal-to-biomass conversion as a means to achieve mid term renewable energy targets at lower cost. Results show that meeting a 30% renewable energy target by 2030 with a 7% share of bioenergy leads to electricity system cost reductions of 5%, compared to a system where this target is met predominantly with wind generation. Further, it is shown that although bioenergy has a higher unit energy cost than wind, a small share of bioenergy leads to lower system cost due to lower backup capacity needs.

The second study focuses on the conversion of the Alberta heavy duty transport system to battery electric or fuel cell vehicles with and without carbon taxes and assesses

the impact of electrification on buildout of electricity generators, costs and emissions. It is found that without carbon taxes, electrifying the heavy duty transport sector leads to a combined electricity system and heavy duty transport system cumulative emission reduction of only 3% by 2060, in the best case, relative to a scenario where electrification does not take place. However, when a carbon tax of $150/t$CO_{2e}$ is applied, cumulative emission reductions of up to 43% are achieved. Further, it is found that although overall electricity demand is 10% higher in scenarios with fuel cell vehicles, compared to scenarios with battery electric vehicles, system costs may be up to 4% lower. The flexibility provided by electrolysers enables the buildout of low cost solar generators which leads to this cost savings.

Finally, the third study focuses on the electrification of all modes of road transport in British Columbia with and without a 93% renewable energy penetration target. Varying levels of controlled charging are assessed as a method to manage variability of wind and solar photovoltaic generators. Model results show that the electricity system capacity doubles by 2055, relative to current values, to accommodate growing electricity demand associated with population growth, industry expansion and electric vehicles. Furthermore, use of utility controlled charging leads to a decrease in excess electricity generation and lower capacity installation, however, no further decrease in excess energy is achieved for a utility controlled charging with a participation rate of 30% of the vehicle fleet.

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Dedication

To my grandfather Sergio, who encouraged me to become an engineer and spent many nights teaching me physics in my childhood. You are greatly missed.

Chapter 1

Introduction

1.1. Motivation and context

The Fifth assessment report of the Intergovernmental Panel on Climate Change (IPCC) states that, based on their most comprehensive assessment to date, the evidence clearly points to a causal link between human activity and climate change (1). The report states, with a 95% confidence, that anthropogenic GHG emissions are the principal cause of global warming. Although there is some debate regarding the human impacts on climate change (2) (3), over 97% of the scientific community who are expressing an opinion, endorse the consensus that humans are responsible for global warming (4).

To address the threat of climate change, in December of 2015, the Paris agreement was signed by 195 member countries, in which it was agreed that each country was to curb its emissions to avoid worldwide global warming well below 2°C, while pursuing efforts to limit it to 1.5 °C (5). To achieve the below 1.5 °C warming target, global emissions would need to achieve a 45% reduction from 2010 levels by 2030 and net-zero by 2050 (6). As Canada was one of the member countries to sign the agreement, it must now take measures to ensure its GHG emissions are curbed.

Emissions from stationary energy use, transportation and electricity and heat production combined make up almost 75% of Canada's total emissions, as shown in Fig. 1-1 (7). Transport emissions include light-duty passenger vehicles, freight vehicles, heavy-duty vehicles, public transport and domestic aviation. Fugitive emissions are primarily associated with leakage during the oil and gas production and transportation processes. Industrial processes and product use include cement production, lime production and use of mineral products. Agriculture emissions include emissions from livestock, manure management, field burning and use of fertilizers. Waste accounts for solid waste disposal, biological treatment of waste and incineration of waste. Electricity and heat account for fuel burned to produce electricity and heat for public use. Other stationary energy includes petroleum refining, upstream oil and gas production, use of fossil fuels for energy in industrial applications, and construction.

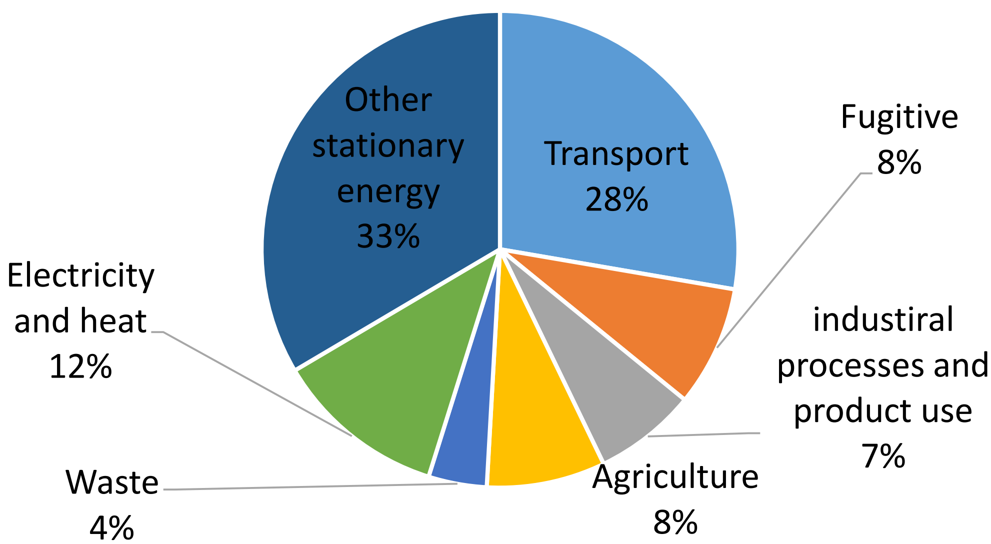

Figure 1-1. Share of emissions in Canada by sector.

Sources of emissions vary significantly by province due to availability of natural resources, population size, local economy and policies. As a result, different provinces may need to focus on different sectors to meet short and mid term carbon emission targets.

BC and Alberta, the two westernmost Canadian provinces, differ significantly in terms of per capita emissions and emission share by sector, as shown in Figure 1-2. Although these two provinces have a similar population size, Alberta's emission per capita of 66.7 tCO_{2e} per annum, is five times that of British Columbia, at 13.4 tCO_{2e} per annum.

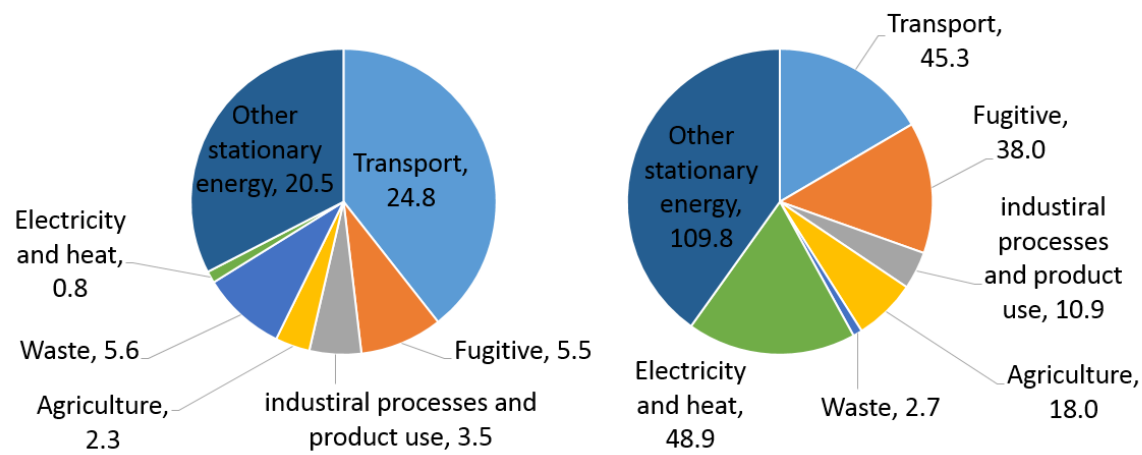

Figure 1-2. Share of annual emissions in British Columbia (left) and Alberta (right) by sector. All values in $MtCO_{2e}$.

British Columbia has recently announced targets to decrease annual emissions by 40% from a 2007 baseline by 2030 (8). In December of 2018, the BC government announced a set of measures aiming to reduce GHG emissions in the province. The plan focuses on the larger emission intensive sectors in the province, targeting annual GHG reductions by 2030 of 8.4 tons from industry, 6 Mt for transportation, 2 Mt from buildings, and 0.7 Mt from waste. Further, an additional 1.8 Mt reduction is expected from the carbon tax, which is set to reach $ 50/ tonne by 2021.

Long term targets in BC include the conversion of the vehicle fleet to zero emissions vehicles (ZEV). Although the plan sets numerous mid-term targets, as mentioned in the previous paragraph, it also includes longer-term targets such as conversion of the vehicle fleet to zero emissions vehicles, such as battery electric vehicles (BEVs) or fuel cell vehicles (FCVs). The standard will require automakers to meet an annual escalating share of ZEVs of 10% by 2025, 30% by 2030 and 100% by 2040. Due to BC's low carbon electricity, the conversion of the entire vehicle fleet to ZEVs would be a significant step towards long-term decarbonisation targets set by the Paris agreement.

Alberta is focusing its GHG emission targets on electricity and oil and gas sectors (9). In November of 2015, the Alberta Government announced the Climate Leadership Plan (CLP), including numerous measures to reduce the province's GHG emissions. The plan targeted a phase out of coal electricity generation by the year 2030, increasing the renewable share to 30%, by the same date, cutting methane emissions from the oil and gas sectors by 45% by 2025 and capping the emission from the oil sands. At the same time, the province is applying a \$30/tCO_2 carbon levy to on all transportation and heating fuels.

Electricity and transport are the second and third highest sources of emissions in Alberta. As shown in Figure 1-2 above, electricity production and transport are responsible for 35% of Alberta emissions. The high emission intensity in the electricity sector is due to the reliance on fossil fuels, with coal responsible for over half of the generation, while gas contributes 35% (10). The higher transportation emissions in Alberta, compared to BC, are associated with higher activity of the freight sector, especially the heavy-duty transport sub-sector, which emits 3.5 times that of B.C (11).

Conversion of vehicles to ZEV along with adoption of renewable electricity may enable Alberta to reach long-term GHG emission targets. Unlike BC, Alberta has not set province-wide GHG emission targets, or longer-term ZEV adoption targets. However, if Canada is to honour its Paris agreement commitments, all provinces, including Alberta must comply with longer-term emission reductions. As a result, adoption of renewable electricity sources such as wind and solar photovoltaic (PV) or conversion of stranded coal units to biomass may enable the Alberta electricity system to reach significant emission reductions. Further, adoption of ZEVs, in conjunction with this move towards renewable electricity may further allow the province to honour the Paris agreement climate commitments.

This dissertation addresses the opportunity to reduce GHG emissions in BC and Alberta through adoption of ZEVs for transportation and adoption of renewable electricity generation for Alberta. Three studies are presented. In the first study, the Alberta electricity system is analysed for pathways for adoption of renewable electricity generators to meet the 2030 targets mentioned above. This study focuses primarily on modelling the Alberta electricity system, focusing on the adoption of coal-to-biomass conversion as a means to re-purpose stranded coal units and manage the variability of wind and solar PV. In the second study, the same model is adapted to consider direct (use of BEVs) and indirect (use of FCVs) electrification of the heavy-duty transport sector in Alberta. The third study uses a similar model, modified for the BC system, focusing on pathways for the electrification of all modes of road transportation, by the year 2050.

1.2. Literature

1.2.1. Coal to biomass conversion

Decreasing electricity system emissions by phasing out coal generation is likely to lead to the creation of significant electricity generation stranded capacity. Coal generation has a high emission intensity, ranging from 0.8 to 1.3 tCO_2 /MWh (12) (13). As the Alberta system still gets over half of electricity from coal, emission reduction efforts have focused on this generator type (9). As a result, the 2030 coal phase out deadline will create significant stranded capacity. In other words, some generators will be forced to shut down before their expected end of life, leading to economic loss (14). Other jurisdictions with high shares of coal generation such as the U.S., China and India, may soon face similar issues if they decide to address the emission intensity of their electricity system (15) (16) (17).

Coal to biomass conversion may offer a low emission alternative to stranded coal generators. Although different biomass retrofit types exist, the most common include co-firing coal and biomass pellets and dedicated biomass pellet retrofit (18) (19) (20) (21).

Co-firing coal and biomass offers short-term CO_2 emission reductions. Co-firing involves replacing a portion of a coal generators fuel with biomass (18). Although capital cost investments of co-firing are relatively low, at 20 – 145 $/kW, co-firing is typically limited to 20% biomass energy content, due to the different characteristics between coal and biomass combustion (19) (22) (21). As a result, this co-firing type only offers limited emission reduction potential.

Dedicated biomass retrofit offers greater emission reduction potential as the entirety of the fuel is converted to biomass. Full conversion from coal-to-biomass is possible, leading to higher GHG emission reduction potential. However, higher capital cost expenditures are necessary, estimated at 640 $/kW (21). The high capital cost is due to necessary modifications to the unit including installation of fire suppression equipment, fuel storage, and modification of pulverisers (23).

Emission reduction potential depends on biomass type used. Biomass can be procured from several sources including standing trees or residues. Use of standing trees has been shown to not be an effective method for lowering emissions from coal, as it removes large amounts of carbon from forests and releases it as emissions (24), leading to a multi decadal time delay until carbon neutrality is achieved (25). Use of residue, however, has been shown to be highly effective at mitigating GHG emissions, when replacing coal (25) (26) (24) (27). The use of forest residue has been shown to lead to carbon payback times ranging from 1 to 16 years, depending on assumptions on tree growth period and coal fuel type.

The few studies that have considered cost implications of coal to biomass conversion tend to focus on levelized cost of energy, rather than system cost. Retrofitting coal units to bioenergy has been shown to lead to an increase in levelized cost of energy (LCOE), primarily associated with the high cost of fuel due to transportation (28) (29) (30). A few studies have shown that bioenergy generators may require economic incentives to be cost competitive with coal units in a per unit energy basis (20) (21). However, none of these studies consider the system wide impact that bioenergy may have in the system and potential cost reductions in achieving renewable energy targets by allowing a small share of bioenergy in the electricity mix. A more detailed review of the literature is presented in Chapter 3.

1.2.2. Electrification of vehicles

As shown above, transportation constitutes significant shares of the total GHG emissions in both BC and Alberta. Worldwide, the transportation sector contributes to 14% of all anthropogenic emissions (31) (6). As a result, ZEV technologies such as BEVs and FCVs have received increased attention recently as technological substitutes to internal combustion engine (ICE) vehicles to mitigate emissions from the transport sector (32) (33) (34).

Pathways for electrification of the transport sector include partial electrification, direct, and indirect electrification (35) (36) (37) (38) (39) (40) (41) (42) (43). Partial electrification comprises of adoption of hybrid or plug-in hybrid technologies (44) (45). These vehicle types typically include a small on-board battery offering short range all electric drive, coupled with an ICE for range extension or ICE vehicles equipped with batteries for short bursts of power-boost. Although this technology offers short-term potential for emission reduction due to the lower fossil fuel usage, it is not a viable option for long term deep emission reductions as it still largely relies on fossil fuels. Examples include the Toyota Prius and the Chevrolet Volt. Direct electrification consists of vehicles solely powered by an electric motor using a battery for energy storage. The term direct electrification is used as electricity is directly stored in the vehicle on-board battery. Although the GHG emission reduction benefit depends highly on the electricity mix (42) (44), it has a high potential for emission reduction if used in jurisdictions with low GHG electricity. Examples include the Nissan Leaf and the Tesla model S. Indirect electrification is a term used to describe the use of electricity to make an alternative energy carrier. Typically, it is used in electrolysis of water for the production of hydrogen (37) (34). The hydrogen is stored in on-board pressurized tanks and used for propulsion with fuel cells, which convert the hydrogen back to electricity. Similar to BEVs, the extent of GHG emission reductions depend on the electricity GHG intensity. Examples include the Nikola one and the Mercedes Benz GLC fuel cell.

Electrification of vehicles has been shown to lead to significant vehicle life-cycle emission reductions. Vehicle emissions are typically separated into manufacturing emissions and usage emissions (46) (47). Manufacturing emissions account for all emissions associated with the manufacturing process of the vehicle, while usage represent fuel consumption over the vehicle's lifetime and vehicle maintenance. Life-cycle emissions from ICE vehicles typically constitute 20% manufacturing and 80% usage, although this number varies depending on specific vehicle models and mileage at end of life. Although manufacturing emissions of BEVs are up to 60% higher than those of ICE vehicles, its ability for usage with carbon-free electricity leads to significant emission reductions potential. Fuel-cell vehicles have lower manufacturing emissions than BEVs, only 10-20% higher than ICE vehicles, but lead to higher electricity consumption associated with energy loss during electricity-to-hydrogen conversion, potentially leading to higher usage emissions (48).

Research to date has overwhelmingly focused on the passenger vehicle sector (32) (33) (34) (49). Research has been carried out studying the evolution of the electricity system to accommodate vehicle electrification and quantify necessary capacity expansion. Studies have shown that current systems may only be able to accommodate a 10% penetration of BEVs for the passenger vehicle sector with current generation infrastructure and that peak loads may increase by as much as 75% with a 30% BEV penetration (50) (51). However, the majority of studies considering electricity system capacity expansion due to electrification of vehicles only consider the passenger vehicle sub-sector, excluding a significant portion of the source of emissions from the transportation sector. One exception in the recently published work by Taljegard et al (43), who in 2019 published their work on electrification of the entire fleet of passenger vehicles, light and heavy duty trucks and transit in Northern Europe and Germany. However, vehicle charging behaviour is optimized for the entire fleet in all scenarios, not considering that part of the fleet may oppose participation into such a scheme. Further, a cost benefit of implementation of optimized charging per vehicle user is not quantified. More information on direct and indirect electrification and pathways for the heavy-duty freight sector can be found is presented in Chapter 4.

A number of studies analysing the evolution of the electricity system with transportation electrification and adoptions of renewable energy regenerators has suggested that use of utility controlled charging (UCC) may lower system costs and lead to lower excess generation (42) (41) (40). UCC allows the utility to control the timing of charging of vehicles, allowing it to adjust power consumption and shift certain aspects of the load by a number of hours, similar to demand side management. It has been suggested that UCC may lead to lower electricity peaking capacity buildout, reduce costs, and potentially reduce emissions (42) (41) (40). However, studies that include use of UCC have focused on the passenger vehicle sector only and typically conduct a one-year optimization, rather than a long term system expansion study. More information on use of UCC is found in Chapter 5.

1.3. Objectives and outline

The objectives of this research are to identify least cost pathways for the implementation of renewable generators in the electricity system in coal dominated jurisdictions, such as Alberta, and to identify pathways for electrification of the transport sector in coal dominated and hydroelectric dominated jurisdictions. Specifically, this work addresses the following questions:

i. Is coal-to-biomass retrofit a viable option to enable higher renewable energy penetrations in fossil dominated jurisdictions at low cost?
ii. Is direct or indirect electrification the least cost and lowest emission pathway for the electrification of the heavy-duty transportation sector?
iii. What are the electricity system capacity expansion requirements to electrify the entire road transportation sector with a high share of renewable electricity? What are the emission impacts of removing renewable electricity share targets and how may the use of UCC impact these results?

In Chapter 2, a review of alternative energy system modelling tools is presented as well as the rationale for selection of the modeling tool used in the current work. In Chapter 3, a techno-economic study of coal to biomass electricity generation retrofit in Alberta is presented. A forest residue biomass supply stack is created for key coal generators in the province facing earlier than expected shutdown. Alternative scenarios are modelled to evaluate cost and emissions of meeting a 30% penetration of renewable electricity in the province by 2030 with and without the use of bioenergy. In Chapter 4, electrification of the heavy-duty transport sector is assessed. BEV and FCV options are included in scenarios with and without a carbon tax. The study further evaluates the impact of alternative charging profiles for BEV vehicles and its impact on generation buildout by type. Chapter 5 focuses on the electrification of all road transport modes in British Columbia. The study compares scenarios with and without a renewable electricity target of 93% on costs, buildout by type and emissions. Further, the study also quantifies the impact of implementing varying levels of UCC and quantifies its impact on costs and capacity installation requirements. Finally, Chapter 6 provides a summary of conclusions, contributions and future work.

Chapter 2

Energy systems modelling

2.1. The importance of appropriate energy planning

In the previous chapter, the need to address climate change by reducing emissions in the electricity and transportation sectors was established. To achieve these reductions, phase out of coal electricity generation, adoption of variable renewable energy (VRE) generation e.g. wind and solar PV and widespread electrification of transportation is anticipated. The challenges related to these transitions were also highlighted.

Adequate planning is required to ensure that these challenges are addressed as electricity systems transition to these new technologies. Energy system modelling is widely used in the planning of electricity systems. An energy system model is a numerical approximation of an energy system which can be used to evaluate its reaction to perturbations such as policy change, demand profile change and disruptive technologies, among others. These models can assist decision makers in identifying optimal generation capacity and type for the system, policy requirements to achieve specified targets and estimating future system emissions and cost.

The results of energy system models are inherently wrong. According to John Sterman, Director of the System Dynamics Group at the MIT Sloan School of Management, "All decisions are based on models, and all models are wrong. These statements are deeply counterintuitive. Few people actually believe them. Yet accepting them is central to effective systems thinking" (52). Sterman further mentions in his text that the electricity system is complex due to its many feedbacks, stocks and flows, time delays and non-linearity. As a result, it is virtually impossible to create a model that will 100% represent reality due to necessary simplifications and the lack of perfect foresight. However, using these models is necessary for effective system thinking and planning, as the results can corroborate a previously proposed hypothesis (53).

Lack of system planning was shown to be partially responsible for the challenges faced by the Spanish electricity system since the early 2000s (54). In 2015, the system had 8.3 GW of excess capacity. Model results show that, had appropriate modelling and planning been undertaken, up to 5.3 GW of the excess 8.3 GW could have been avoided, while the rest is attributed to the unforeseen economic crisis. The cost of this failure to plan is estimated at 2010 € 28.6 billion.

A similar study evaluating the evolution of the British electricity system through two decades was conducted by Trutnevyte (55). A capacity expansion cost-optimization model for the years 1990 to 2010 was conducted, using only information available at the time. The optimal 2010 system was then compared to the actual system in 2010. Model results were found to differ from the actual system by only 9 to 23%, depending on the scenario, over the 20-year period. Unforeseen events such as the "dash for gas" and the 2008 economic crisis are the principal causes of these differences.

System planning exercises have been used to guide policy. The previous two examples demonstrate inherent inaccuracy of models. However, they are still an essential part of planning for the future, as mentioned by John Sterman. As a result, models are typically relied upon for decision making. One example of this is the recently announced Clean B.C (8). program. The program relied on modelling carried out by Navius Research to forecast the impacts of the many measures employed and help set guidelines to achieve the targeted GHG emission reductions to 2030 (56).

2.2. Alternative modelling platforms

Many types of energy models exist. This section provides as a brief description of the principal types of energy models, highlighting their strengths and weaknesses. Based on this discussion, the rationale for the selection of the modelling platform used in this research is also presented.

2.2.1. Input – output models

Input-output models represent the relationships between different economic sectors using a set of linear equations. The coefficients of the equations describe parameters that quantify all goods and services required by a specific project (57). As the output of the model is a measure of the value of goods and services, this type of model can quantify economy-wide impacts of a policy change such as and economic incentive e.g. a feed in tariff.

An input-output model was used by Lixon et al, to measure the economic impact of reduced industrial output in Canada to meet the Kyoto protocol (58). Targeting reduced output for the 12 highest emitting sectors was found to be more cost effective at reducing GHG emissions than focusing on the entire country's economy uniformly. The authors further conclude that adopting the Kyoto protocol would decrease the Canadian gross domestic product (GDP) by 3.1%, as an upper bound, contradicting those who claim that the protocol would place an unbearable burden on the economy. A study employing a similar method, by Sanchez-Choliz and Duarte, described direct and indirect sectorial impacts of the Spanish international trade on GHG emissions (59). The authors found that although sectors such as food, construction, transportation goods and general services do not have a high direct contribution to GHG emissions, are indirectly responsible for 68% of the nation's emissions to satisfy their demand.

While input-output models may provide valuable information regarding total economic impact of policies and trace emissions back to their sources, they are not without limitations. As the model does not allow for product substitution, and has fixed coefficients, it is only relevant for short term studies (5-10 years) and to incremental levels of output (60). As a result, while this model type might be of use to governments deciding where to allocate resources for the budget in coming years, it is inappropriate for long term energy systems changes.

2.2.2. Computational General equilibrium models

Computational General equilibrium (CGE) models are top-down macro–economic models that include economic data to achieve equilibrium of supply, demand and prices for specific markets. In this model type, households attempt to maximize their utility by selecting which goods to consume based on a budget constraint, while companies aim to maximize profits given their own budget constraints (61). Model outputs include supply and demand curves for goods and services. More advanced models also include government, external sectors, investments, savings and intermediate inputs (61).

CGE models have been used to evaluate the effect of environmental policies on productivity of firms. Tombe and Winter used a CGE model calibrated to the United States to evaluate how alternative policies distort productivity of firms (62). The authors study three types of emission intensity standards for firms: firm specific targets, sector specific targets and targets that are only applied to large emitters. The authors find that applying these standards leads to lower productivity and that this phenomenon is exacerbated for low-productivity firms when sector specific targets are applied. Further, the study finds that uniform taxes that achieve the same standards have a significantly lower effect on productivity. In another CGE-based study, Beck et al study the impact of a carbon tax of \$30/ tCO_2 implemented in British Columbia on different household types (63). The authors find that the existing carbon tax disproportionally impacts lower income households, as this household type spends a greater portion of its income on carbon intense energy-related products and services. However, the authors further find that the revenue neutral nature of the tax, which provides rebates for low income households, make it a progressive scheme. In other words, the income-side effects outweigh the spending side effect for low income households.

2.2.3. Partial equilibrium (bottom-up) optimization models

Partial equilibrium or bottom-up optimization models, are technology oriented models that find the lowest cost option to meet an exogenously defined demand (60). The term partial equilibrium is used as these models only include the supply side of the market, with prices generally being fixed during the analysis. These models are typically used for longer time scales, typically up to a 50-year horizon. Costs often include technology investment, operation and GHG emission taxes. These models are used to assess which technologies form the optimal system under assumed of costs and policies. Examples include MARKAL/TIMES, MESSAGE, OSeMOSYS and PRIMES, among others (64).

For example, the TIMES model has been used to model future hydrogen infrastructure development in California to the year 2050 (65). The model allows capacity expansion to meet a hypothetical hydrogen demand in eight regions within the state, where hydrogen can be sourced from electrolysis powered by renewable energy or from local biomass gasification. The authors identify a set of policies (i.e. prohibition of coal generation without carbon capture and storage, a renewable hydrogen mandate and a fuel carbon intensity constraint) that lead to a total GHG emission reductions of 85%, relative to a reference scenario. In an OSeMOSYS-based study, generation alternatives for Bolivia and their impacts on the South American electricity system are assessed (66). Four scenarios are modeled, representing alternative development pathways for large hydropower. The study finds that a combination of the El Bala and Cachuela Esperanza dams would provide Bolivia with enhanced operational flexibility and greater opportunity to sell electricity to neighbouring jurisdictions.

Although this model type provides valuable insight into system evolution and reaction to different perturbations such as policy or cost changes, it has received criticism for its lack of demand elasticity and operational constraints (67). However, recent work with these models has incorporated elasticity of demand and added operational constraints for individual generators such as start-up/ shut-down time, ramp rates, minimum up/ down time, and minimum generation levels (60) (67) (68). However, this additional functionality comes at the cost of added computational complexity, leading to longer model time runs.

2.2.4. Bottom-up simulation models

Simulation models predict energy production and consumption patterns based on expected microeconomic decision-making (69). Unlike the optimization models described in the previous section, in a simulation model, technology choice is based on end-user behaviour rather than on least cost.

The U.S. Energy information Administration (EIA) uses this model type to forecast residential energy demand (70). Model inputs include energy prices, consumer behaviour, technology preference by household, housing stocks, and other macro economic indicators. This information is used to generate energy consumption by fuel type and household type. These models are used to inform the EIA projections of energy demand by type, as presented in their 40-year annual energy outlook (12).

2.2.5. Hybrid models

Different model types can be combined in a technique often referred to as hybrid modeling. Hybrid models can, for example, integrate bottom up simulation models with optimization models, or combine aspects of bottom-up and top-down models.

One example of this is the CIMS model, which incorporates behavioural parameters associated with risk and product quality based on market research into past technological choices (71). Risk accounts for possible failure of new technologies, longer than expected payback times, or consumer preference for other products, while quality considers differences between technologies providing the same service e.g. incandescent versus LED light bulbs. The authors claim that this model captures intangible costs or feedback interactions such as energy consumption increases associated with energy efficiency gains.

2.2.6. Model used in present work: OSeMOSYS

A partial equilibrium optimization model is selected for the three studies presented in this thesis. This model type is well suited for long-term electricity system studies as it operates in similar time scales to the operational lifetime of electricity generators, and a variety of technological options and policy options may be considered. Further, gradual technological performance improvements and cost reductions may be accounted for, providing a tool well suited for a long term analysis, rather than a snapshot into of a specific year.

Of the available options, which include MARKAL/TIMES, MESSAGE, OSeMOSYS and Primes, OSeMOSYS is selected as it is open source, transparent, and has a fast growing international user community (64) (72). OSeMOSYS has been extensively used to study capacity expansion of electricity systems in many jurisdictions including: Alberta, Ireland, Bolivia, Portugal, Egypt and Texas, among others (66) (72) (73) (74) (75) (76).

The default version of OSeMOSYS minimizes system net present cost, subject to constraints such as demand being met, capacity adequacy, capacity to meet a reserve margin, minimum renewable generation targets, and emission limits.

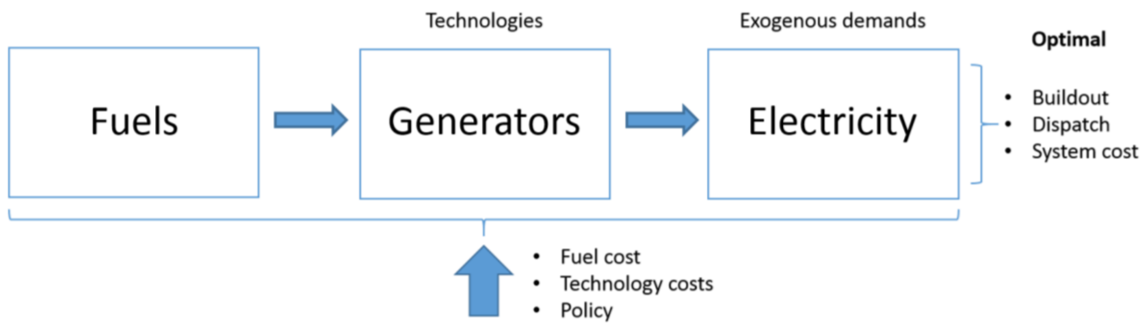

Figure 2-1. Schematic representation of the OSeMOSYS model.

As seen in Figure 2-1, technologies are operated to meet exogenous demands. Some technologies may require fuel inputs to operate e.g. nuclear power generators require uranium fuel, while other types of technologies require no fuel usage e.g. wind or solar PV (photovoltaics) generators. Fuels are also assigned a cost per unit energy and a carbon intensity, although some fuels such as uranium have a carbon intensity of zero.

Technologies are assigned capital costs, fixed and variable costs, lifetimes and fuel consumption rates, as seen in Figure 2-1. Technologies are assigned modes of operation to represent different possible outputs. Modes of operation allow technologies to operate in alternative modes to represent ramping and cold starts and for technologies that produce more than one output type. For example, a combined heat and power generator may operate in mode one, where its power output is lower but it produces both electricity and heat, or in mode two, where its power output is higher but it only produces electricity.

Technologies may also consume more than one fuel type. This allows the model to represent technologies that are flexible in its fuel intake e.g. coal generators that may consume different grades of coal or biomass fuels. Further it also allows modellers to create a supply stack. Modellers can create a fuel type with a low cost but limited availability. Once that fuel is depleted, if the generator is to produce more output, it would require using a secondary fuel at a higher cost.

OSeMOSYS allows the implementation of certain policies. For example, carbon taxes can be applied to discourage the use of heavy emitting technologies such as coal. Other policies that can be applied include: feed-in-tariffs, renewable portfolio standards, caps on model emissions and self sufficiency standards, among others, leading to different outputs for optimal technology buildout mix, dispatch and system cost, as seen in Figure 2-1.

The model is separated into years. Energy demands are defined for every model year. Maximum annual capacity by technology, maximum annual emissions and technology costs and efficiencies can be further defined for every model year.

Each model year is divided into timeslices. Timeslices are used to capture the variability of demand and supply for several types of days i.e. different seasons, windy vs non-windy days, rainy vs sunny days, etc.

Annual demands are subsequently broken down into a specified demand profile, that assigns a percentage of the annual demand to a specific timeslice. Capacity factors are specified per timeslice to represent the variability of generators such as wind and solar.

For more information on the OSeMOSYS model and its formulation, refer to the supplemental material or references (64) (72).

Chapter 3

Coal-to-biomass retrofit in Alberta value of forest residue bioenergy in the electricity system[1]

Preamble

The use of forest residue may mitigate greenhouse gas emissions by displacing the use of coal or other fossil fuels for electricity generation. However, economic viability of bioenergy requires availability of feedstock at appropriate cost. The current work attempts to quantify delivered biomass cost at plant gate and estimate cost and emission benefits to the electricity system associated with the conversion of coal units to bioenergy. This study is carried out with the optimization model OSeMOSYS, analyzing the Alberta electrical system, its mid-term coal phase-out and renewable energy targets. Alternative scenarios were compared to evaluate the effect of a biomass retrofit option on the incentives needed to achieve 30% renewable penetration by 2030. Results show that although bioenergy has a higher levelized cost than wind power, the system requires less backup capacity and less renewable energy credits to meet renewable energy goals when the biomass retrofit is allowed. In addition, the total system cost to 2060 is found to be 5% less than the scenario without the biomass option. The firm capacity provided by biomass compensates for its higher levelized cost of energy.

[1] The body of this chapter was published in V. Keller et al. Renewable Energy Vol. 125, pp. 373-738, 2018

3.1. Introduction

Following the United Nations Framework Convention on Climate Change 2015, a number of countries have announced policies to phase out, or significantly decrease, the use of coal for energy; these include the U.S.A. (77) (78), Finland (79), France (80) and Canada (81) (82). Coal fired electricity is a greenhouse gas (GHG) intensive generator accounting for over 40% of the world's electricity production (13). Given the long operational lifetime of coal generating facilities, accelerated coal phase out can lead to significant stranded capacity and economic cost (83). These factors may impede participation in climate agreements from nations such as China or India where coal represent over 55% of the installed capacity.

Coal units can be retrofitted to burn alternative fuels thereby preventing early shut down associated with phase out of coal generation and potentially decreasing greenhouse gas (GHG) emissions. Retrofit types include co-firing coal with pellets (18) (19), co-firing with gasified biomass and dedicated biomass pellet retrofit (20) (21). Co-firing biomass with coal can be a low cost option for emissions reduction. However, without plant modifications, co-firing ratios are typically limited to 10 – 20% biomass (energy content) due to differences in combustion characteristics (22). As a result, coal use reductions with co-firing are limited. Alternatively, dedicated pellet retrofit, henceforth referred to as biomass retrofit, may provide a viable option for reduction or phase out of coal use.

Fuel biomass can be procured from resources including live stemwood harvest, sawmill residue, agricultural residue and forest residue after stemwood harvest (tree tops, branches and all non-merchantable material), each with different costs and GHG emission impact (27) (84) (26) (85) (86). As shown in (24), live stemwood harvest for bioenergy is not an effective method for mitigating GHG emissions. Using this biomass type for energy removes large amounts of carbon from forests and releases it as GHG emissions. The slow re-growth of forest, especially in temperate climates, leads to a decadal time delay before carbon neutrality can be achieved (25). Sawmill residue is a low cost source of biomass fuel; however, this biomass type suffers from relatively low availability compared to the amount necessary to fuel coal generating units. Agricultural residues are subject to higher unit energy costs and lower energy density than other biomass types. Additionally, repetitive agricultural residue recovery can lead to soil nutrient depletion and high replenishment costs (87). Forest residue, however, has been demonstrated to be a relatively low cost option and highly effective in displacing GHG emissions from coal generation, while meeting availability requirements necessary to fuel generating units.

Forest residue suffers from higher costs than conventional fuel options primarily due to high transportation costs (28) (29) (30). Studies have estimated the levelized cost of electricity (LCOE) of coal units retrofitted to burn forest residue to determine the level of economic support required to make bioenergy cost competitive. Cleary et al. investigated the cost of collecting forest residue to fire the Atikokan coal power plant in Ontario, with biomass. Due to the long railing and trucking distances, biomass costs were as high as 170 \$/tonne. Resulting electricity costs, estimated at 149 \$/MWh, were found not to be competitive with other generating options. The authors concluded that further subsidies would be necessary to support production (20). Cuellar and Herzog compared the levelized cost of electricity for coal plants retrofitted to burn farmed trees, switchgrass and forest residue (21). For forest residue at 86 \$/tonne, carbon taxes of 89 \$/tonne CO_{2e} would be necessary for dedicated biomass firing to be cost competitive with coal. Although these studies demonstrate that support mechanisms may have to be put in place to make bioenergy cost competitive with other conventional options, they do not account for the value that biomass may provide to the electrical system besides energy delivery.

Although LCOE is a useful metric for estimating total cost of a generator, it does not account for other parameters, such as resource temporal variability and the need for backup capacity. With the necessity to decarbonize the electrical system and increase the share of renewable energy, much attention has been given to wind and solar power. However, LCOE comparisons of these technologies with biomass do not provide a complete picture of the costs or value they may have to the system. Both wind and solar power suffer from intermittency (88). As a result, when significant penetrations exist, additional backup capacity is necessary for times when demand cannot be met with intermittent renewables. As a result, a broader perspective is useful when evaluating the value, a generation technology may have on the system.

In this study, the system value of dedicated biomass retrofits to meet renewable energy targets in an electrical system is quantified. Policy scenarios with carbon taxes and renewable energy incentives are used to determine carbon abatement costs. As a case study, the province of Alberta (AB), Canada is used due to its high share of coal generation, aggressive 2030 decarbonisation and renewable energy targets, and proximity to existing forestry operations. The paper is divided as follows: Section 3.2 provides an overview of the Alberta electrical system and modelling approach; Section 3.3 summarizes cost and biomass supply data; Section 3.4 presents key findings for capacity changes, carbon emissions and system costs. Section 3.5 discusses the findings and differences between LCOE of technologies and their system value. Finally, we conclude with a discussion of policy implications.

3.2. Methods

3.2.1. System representation

The system analysed consists of a forest biomass feedstock model and an electrical system model represented in Figure 3-1. The feedstock model determines delivered costs of biomass fuel to existing coal units. The biofuel cost estimates are combined with coal retrofit costs and estimates of other generating options to determine the minimum cost generation mixture for specified emission targets over a 50 year planning period. Section 3.2.2 offers a brief overview of the jurisdiction characteristics. Section 3.2.3 describes the methodology for estimating the biofuel supply from forest residue. Finally, Section 3.2.4 describes the approach for modelling the optimal capacity expansion and operation of the electrical system.

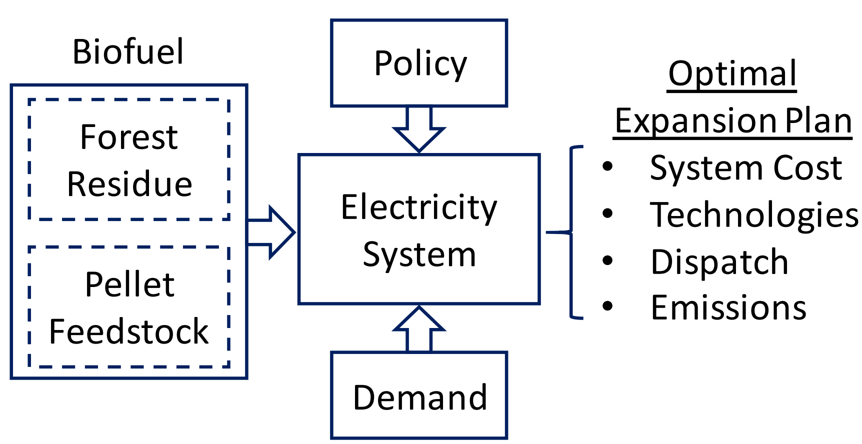

Figure 3-1. Schematic representation of the modelled system.

3.2.2. Alberta electrical system

Alberta has the third highest electricity demand in Canada and accounts for 13% of Canada's total demand (89). At the same time, the province produces 38% of the countries GHG emissions. The emission profile is driven by carbon intensive industries such as mining, oil and gas extraction (90), and the reliance on fossil fuels for electricity. In 2015, 51% of the provincial electricity demand was generated by coal, natural gas contributed 39%, and the remaining 10% was from renewables such as wind hydro and biomass.

In November, 2015 the Alberta government announced the *Climate Leadership Plan (CLP*) and ambitious plans to terminate all coal generation and achieve a renewable energy penetration of 30% by 2030. To achieve the renewable energy target, the government has proposed incentives for renewable energy, and an increase in the carbon levy to 30 \$/tCO_2 by 2018 (9). While these measures are expected to decrease the emission intensity of the electricity sector, they also result in over 2 GW of coal capacity becoming stranded at 2030. The stranded coal plants we consider are Genesee units 1 and 3 and Keephills 3. All three units possess a residual lifespan of at least nine years beyond 2030.

3.2.3. Biomass feedstock

AB and the neighboring province of British Columbia (BC) are home to strong forest industries. Combined, the two provinces have an annual allowable cut of timber of almost 100 Mm^3, just below half of the national total (91) (92). As not all the wood harvested from forestry is merchantable, some material such as tree tops and branches are left on site. As a result, 10 M oven dry tonnes (odt) of forest residue are available for harvest every year - enough to fuel all of Alberta's stranded coal capacity and provide 18% of the demand by 2030.

Forest residue originating from AB and BC is considered as potential feedstock for retrofitted coal units. As shown in Figure 3-2 the provinces are divided into forest management units (FMUs); orange for BC and blue for AB. Provincial guidelines allow up to 50% residue recovery in AB while this number varies between 5 – 35 % in BC It is assumed that all available resource for harvest for the closest FMU to a coal unit is harvested first, followed by the next closest FMU. A uniform calorific value of 5600 KWh/odt is assigned for residue found in all FMUs, similar to other local estimates (93).

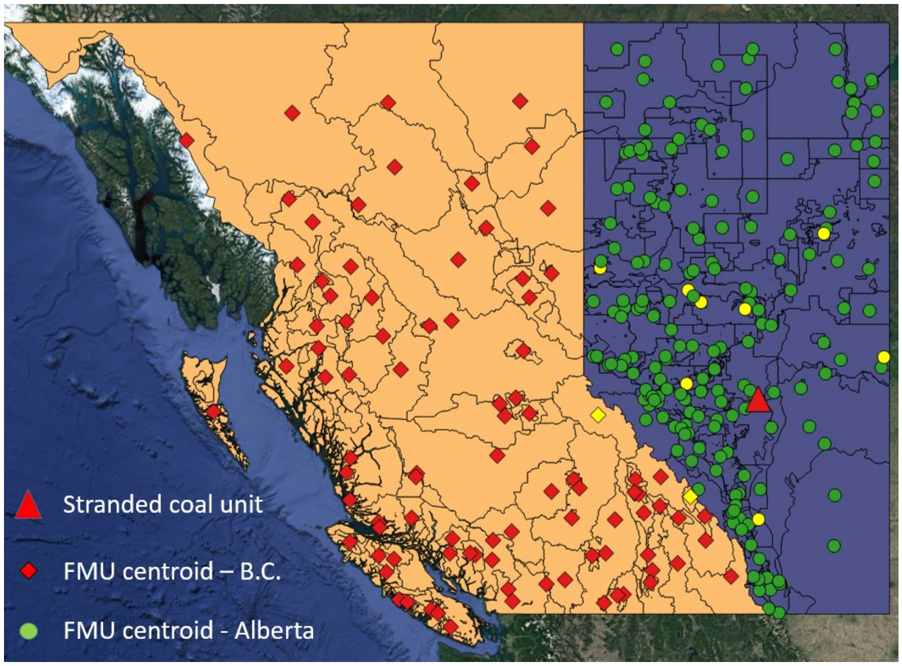

Figure 3-2. GIS map of FMUs in the provinces of British Columbia (left) and Alberta (right).

The open source GIS software QGIS is used to define the feedstock for stranded coal units, represented by a red triangle in Figure 3-2. Total resource for all FMUs are considered to be located at their centroids, shown as red diamonds for BC and green circles for AB. We assume that residual biomass in an FMU is processed to pellets which are then transported from the centroid of the FMU to a coal facility. Straight line distances for each FMU to the location of the coal units (red triangle) is further calculated in GIS.

To account for road curvature, a *tortuosity factor* (T.F.) of 1.33 is applied. The tortuosity factor is calculated by comparing GIS straight-line distances, and length of existing roads as described in equation (3-1),

$$T.F. = \frac{1}{n}\sum_{i=0}^{n}\left(\frac{d_{GIS}}{d_r}\right) \qquad (3\text{-}1)$$

where d_{GIS} is the straight-line GIS distance, d_r is the road distance between the same two points obtained from Google Earth, and n is the number of points sampled. The ten points sampled to determine tortuosity factor are shown in yellow in Figure 3-2. The value of 1.33 is consistent with other local estimates (94).

Delivered biomass costs are comprised of three parts: harvesting, C_h, transportation, C_t and pelletizing, C_{pellet}. Harvesting costs include processing, C_p, avoided cost of slash burn, C_{sb}, and administrative, C_a.

$$C_h = C_p + C_{sb} + C_a \tag{3-2}$$

Transportation costs per unit of energy are a function of local fuel costs, operations and maintenance, and the moisture content of biomass. In the current work, transportation is divided into fuel costs, C_{tf}, and operations and maintenance cost, C_{tom}. Operations and maintenance costs are based on (20) (95) (96) and include labour. A 1st and 2nd tier cost is assumed accounting for differences between transportation on secondary roads versus highways. 1st tier costs are applied to the first 50 km travelled, while the 2nd tier cost applies for any additional transport distance.

Transportation fuel costs per tonne of biomass for year *i*, $C_{tf}^{y=i}$ $\left[\frac{\$}{km\ t}\right]$, are calculated as shown in equation 3-3:

$$C_{tf}^{y=i} = c \times \frac{c_d}{Cap} \times r_e^{y=i} \tag{3-3}$$

where, c is the vehicle's diesel consumption $\left[\frac{L}{km}\right]$, c_d is the 2016 diesel cost $\left[\frac{\$}{L}\right]$, Cap is the dry hauling capacity of the truck $[odt]$ and $r_e^{y=i}$ is the escalation rate of diesel in year *i* in relation to 2016 costs. The escalation rate of diesel cost is based on the EIA AEO (12), for the mountain region. Total transportation cost, C_t is the sum of operations and maintenance and fuel cost,

$$C_t = \quad C_{tom}^{1st} \times 50 + \ C_{tom}^{2md} \times (d - 50) + \ C_{tf}^{y=i} \times \ d \tag{3-4}$$

where *d*, is the total transport travelled distance.

Pelletizing cost, C_{pellet}, covers the process of transforming wood chips into wood pellets for ease of transportation and use in a generating unit. Biomass pelletization costs account for pelletizing facility capital expenditures , $CAPEX$, storage costs, C_s, equipment and controls, C_C, labour costs, C_L, fixed (FOM) and variable (VOM) operation and maintenance, C_{FOM} and C_{VOM}, and any utilities cost, C_u (97) (98). 15% of all collected biomass is used to provide the necessary heat for the pelletization process (20). In addition, it is assumed that there is one pellet facility per FMU, handling all the resource available within it. The method used to calculate pelletization cost is consistent with Mani et al (97).

Total cost per FMU is subsequently calculated as shown in equation 3-5:

$$C_{FMU} = (C_h + C_t + C_{pellet}) \times Q \tag{3-5}$$

Where C_{FMU} is the cost for a particular FMU and Q is the resource quantity [odt] at the FMU in question. Marginal cost per FMU is defined by dividing cost per FMU, C_{FMU}, by 85 % of the total resource quantity in the FMU, as seen in equation 3-6. The 85% factor accounts for the utilization of 15% of raw biomass as a heat source during the pelletization process.

$$MC = \frac{C_{FMU}}{0.85Q} \tag{3-6}$$

A feedstock supply stack is created by aggregating the total resource from all FMUs and ordering their respective marginal costs from lowest to highest.

3.2.4. Electrical system model - OSeMOSYS

The analysis of the AB electrical system is conducted with the Open Source Energy Modelling System (OSeMOSYS) (64) (99) (66). OSeMOSYS is a tool for optimal capacity expansion and dispatch to meet exogenous demands through technologies consuming specific energy carriers. OSeMOSYS has been used in the past to study impacts of carbon taxes on the electricity system in Alberta (100) and the impact of expanding electricity intertie between a fossil dominated and a hydro dominated jurisdiction (99). More recently, the OSeMOSYS model was used to study different generation alternatives in Bolivia and their impact on exports to the South American electricity system (66).

Inputs to the model include definition of demands, technologies and fuels used. Technologies are defined by capital and operating costs and which energy carriers are used to produce electricity as well as conversion efficiencies and emission intensities. Energy carriers are defined in terms of costs, available quantities, and productions constraints. Every time a technology is used to generate energy or more capacity of a specific technology is built, a cost is incurred.

By minimizing net present cost over the study period, the model calculates the optimal system mix for every year. Outputs for the model include yearly system capacity, dispatch of each technology for every time slice and total annual emissions. More details on the formulation, inputs and outputs of OSeMOSYS can be found in (64) (101).

Temporal structure

The model runs from the year 2010 to 2060, with each year divided into 36 annual time slices. The time slices account for monthly peak, mid peak and off peak demand. Technology specific capacity factors for wind, solar and hydro generators are defined for the same 36 time slices to represent resource availability and variability.

Solar capacity factors are based on NREL's PVWatts calculator (102). Hourly solar power output is used to create time slice specific capacity factors, and the annual profile is assumed constant for all years. Wind capacity factors are based on historical values in Alberta from 2009 to 2013. Three different annual profiles are created with capacity factors for each time slice in a year. These three years are repeated in succession from 2010 to 2060. Hydro capacity factors are based on averaged historical generation in the province from 1994 to 2011 (103). To reduce computational complexity, each technology type is aggregated into a single generator. Capacity factors and production profiles for solar, wind and hydro are described in (101).

Generation options

Generation options consist of coal, biomass, natural gas, geothermal, wind, solar photovoltaic (PV) and hydraulic (hydro) generation, as seen in Figure 3-3. Green arrows indicate flow of biomass, while red and black arrows indicate flows of natural gas and coal, respectively. Electricity generation is indicated by yellow arrows, while reserve margin is denoted by a blue arrow.

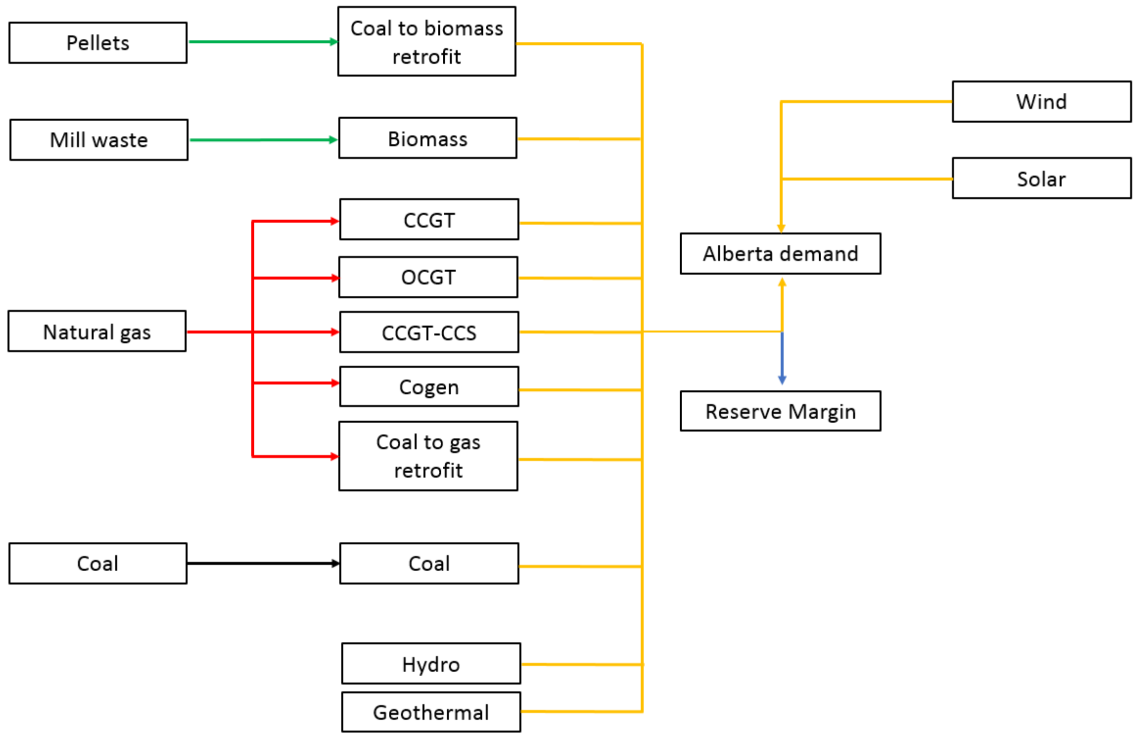

Figure 3-3. Schematic representation of electrical system model and its generating options.

The 2010 year is initialized with technologies representing existing generators. These technologies only incur operation and maintenance costs while any new capacity is subject to additional capital investment costs. Operational and maintenance costs (O&M) are divided into fixed (FOM) for all installed capacity, and variable (VOM) for all capacity generating energy. Values for capital costs, FOM and VOM, lifetime and efficiency are based on U.S. Energy Information Administration (EIA) estimates for utility scale electricity generating plants.

As per the AB CLP, all coal generation is phased out by 2030, preventing it from providing energy and reserve margin. As a result, no new coal generating capacity is allowed in the model (except for the 450 MW which became operational in 2011.) Stranded capacity may be retrofitted to biomass or natural gas past 2030.

In addition to coal-to-gas retrofit (CTG), there are four other types of gas generators: open cycle natural gas (OCGT), combined cycle natural gas (CCGT), combined cycle with carbon capture and storage (CCGT-CCS), and cogeneration (Cogen). OCGT units are typically smaller units with lower efficiency but low capital cost, ideal for peaking capacity. CCGT units tend to be higher capacity units with high efficiency, but their capital cost and O&M is also higher than OCGT, making them ideal for baseload operation. These units can be further equipped with carbon capture and storage (CCGT-CCS) but with increased capital and O&M costs, and lower thermal efficiency. Cogen is used primarily for heat, steam and power generation in the oil sands in Alberta.

Renewable options are subdivided into technologies with (geothermal and hydro) and without (wind and solar) the ability to meet reserve margin. As a result, large buildouts of variable renewables may incur additional backup capacity to ensure reliability.

The following section summarizes key data, assumed costs, and model scenarios involving technology options and carbon policies.

3.3. Data and scenarios

Data defining the biomass supply stack is presented in section 3.3.1, while cost assumptions, heat rates, lifetimes and maximum capacity build by technology are described in section 3.3.2. Study scenarios are presented in section 3.3.3.

3.3.1. Biomass supply data

Forest residue resource data in BC and AB is taken from Natural Resources Canada (NRCan) (26). Processing, operation and avoided costs of slash burning are from (20) (22) (95) (96) (12) (104) (105) (106) and are summarized in Table 3-1. Pelletization data are based on reported costs for plants in the province of Ontario (98). It is assumed that capital costs for pelletization must be incurred for all FMUs where resource is extracted. Pellet plant capacity factor, lead time and capacity factor are taken from Mani et al. and listed in Table 3-2 (97).

The resulting biomass supply stack is divided into 10 bins using increments of 0.5 Modt. The cost for each bin is equivalent to the marginal cost of the aggregated quantity, shown as red dots in Figure 3-4 where the supply stack is shown for the year 2010. Future costs escalate due to increasing diesel prices, as detailed in section 3.2.3

Table 3-1. Cost assumptions for biomass feedstock supply stack.

Parameter	Symbol	Value	Notes
		Harvesting	
Processing	C_p	29 \$ odt^{-1} (35)(44)	Grinding and loading and unloading
Avoided cost of slash burn	C_{sb}	-5 \$ odt^{-1} (46)	
Administrative	C_a	8 \$ odt^{-1} (35)(45)	Administrative and operational planning
Harvesting cost	C_h	32 \$ odt^{-1}	Sum of processing, transportation – fixed, avoided costs and operational
		Transportation	
Transportation equipment and maintenance (1st and 2nd tier)	C_{tom}	0.16 and 0.08 \$ odt^{-1} km^{-1} (11)(34)(35)	
Diesel consumption	c	70 L/100 km (11)	
Diesel	c_d	0.85 \$/L	
Diesel escalation rate	$r_e^{y=i}$	1 – 2.38 (36)	Diesel escalation rate based on EIA AEO 2015 – Mountain region
Truck hauling capacity	Cap	37.2 tons (11)	Based on 40 T nominal hauling capacity and moisture content of 7%

Table 3-2. Summary of costs for pellet facilities.

Parameter	Symbol	Value
Capital cost	$CAPEX$	125 \$/ton (38)
Pellet loading + storage	C_s	20 \$/ ton (38)
Equipment and Controls	C_C	10 \$/ ton (38)
Labour	C_L	12 \$/ton (38)
FOM	$C_{FO\&M}$	5 \$/ton (38)
VOM	$C_{VO\&M}$	5 \$/ton (38)
Pellet plant utilities	C_u	10 \$/ ton (38)
Pellet plant lifetime	yr	20 years
Discount rate	i_d	6%
Pellet plant capacity factor	cf	85% (37)
Lead time	t	1 year (37)

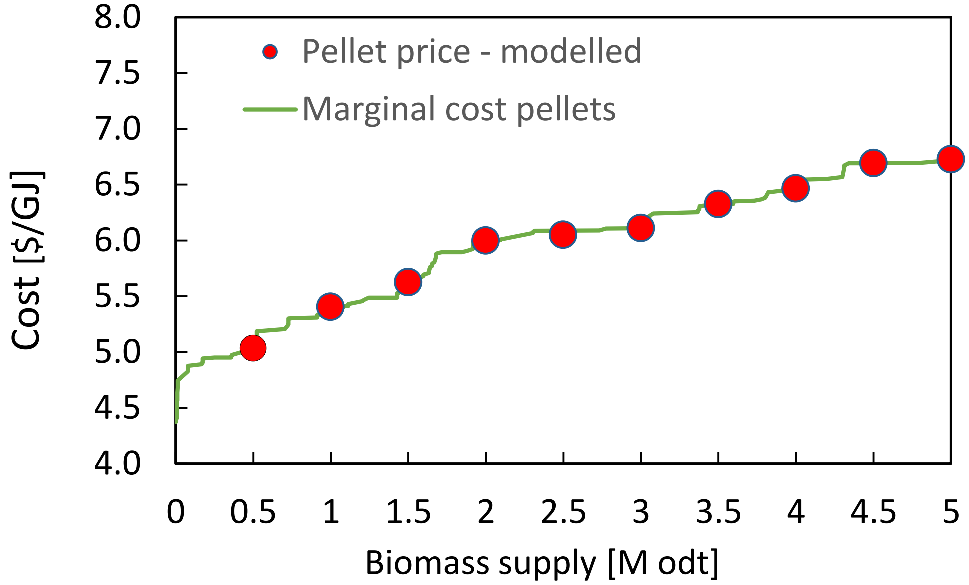

Figure 3-4. Biofuel supply from residual biomass for all FMUs in BC and AB.

3.3.2. Electricity system

Electricity system characteristics are determined by capital costs, FOM and VOM, fuel type, heat rates, lifetime and carbon taxes. Other parameters include electricity demand, residual capacity of generators, and technology specific constraints including maximum annual capacity change, and maximum overall capacity.

Assumptions on technology costs, heat rates and lifetimes are summarized in Table 3-3. Costs are based on EIA *Updated Capital Costs Estimates for Utility Scale Generating Plants 2013,* when available. As EIA does not provide costs for Cogen units, costs are taken from (101). Biomass and CTG retrofit costs are 640 $/kW (21) and 250 $/kW (107) respectively. The lifetime of retrofitted units is assumed to be 20 years (21). VOM for retrofitted biomass is based on a 30% increase from coal (23). Wind and solar are subject to learning rates, to represent forecast decrease in capital costs. Learning rates from the International Energy Agency (IEA) are applied to wind generators, while *International Renewable Energy Agency (*IRENA) learning rates are applied to solar generators (108) (109). Capital costs are assumed to decrease linearly to 2030 values, as shown in table 3-3. Geothermal capital costs are increased over EIA estimates by a factor of two to account for costs of drilling and exploration (110) (111). Heat rates for existing coal generation are based on (19) (101). Biomass retrofit incurs no efficiency drop (23), as both sub-bituminous and lignite coal have very similar moisture contents and calorific value as wood pellets (20).

Table 3-3 Summary of costs and generator assumptions by type.
[a] Weighted average of existing generators. Value changes to 2030 depending on generators still operational.

Technology	Capital cost 2010 [$/kW]	Capital cost 2060 [$/kW]	FOM [$/kW-yr]	VOM [$/MWh]	Heat rate [Btu/kWh]	Lifetime [yr]
Coal	-	-	37.8	4.47	9036 [a]	-
CCGT	1023	1023	15.37	3.27	6430	30
CCGT-CCS	2095	2095	31.79	6.78	7525	30
OCGT	676	676	7.04	10.37	9750	30
Cogen	1203	1203	15.37	3.27	4845	30
CTG	250	250	37.8	4.47	9638	20
Dedicated biomass	4114	4114	105.63	5.26	13500	20
Conversion to Biomass	640	640	37.8	5.81	8885	20
Wind	2213	1848	39.55	-	-	25
Solar	3679	1214	27.75	-	-	25
Hydro	2936	2936	14.3	-	-	80
Geothermal	8724	8724	100	-	-	40

Units converted from coal to natural gas (CTG) incur an 8% efficiency decrease in accordance with recent reports (107) (112). Emission intensity of CTG units is calculated based on natural gas carbon content of 0.05 tCO_2/GJ and the thermal efficiency (heat rate) (113). Additional generation technologies include dedicated biomass units utilizing mill residue which reflect historical production of bioenergy in the province. Availability of mill residue is limited to 8 TWh annually (101).

Coal and natural gas fuel costs are based on the 2015 EIA *Annual Energy Outlook* (EIA AEO) (12). Both are subject to escalation rates, according to EIA forecasts. As forecast data is only available to 2040, prices are extrapolated to 2060 using averaged growth rate from 2036 to 2040. Sawmill fuel costs are from (101).

Carbon costs are modelled in accordance with current regulations. Carbon levy regulations specify a price of 15 $/$tCO_2$ from 2010 to 2016, increasing to 20 $/$tCO_2$ in 2017 and 30 $/$tCO_2$ by 2018. However, these rates are only applied to emissions above a 'best in class' generator, with an intensity of 0.4 t CO_2/MWh, or roughly that of a CCGT unit. As a result, carbon costs are modelled to represent effective cost per unit of emissions starting at 1.8 $/t CO_2 for the first six years, escalated to 3 $/t CO_2 by 2017 and subsequently increasing to 6 \$/t CO_2 by 2018 (101). Renewable energy credits (RECs) are modelled by applying negative values for VOM costs for renewable generators i.e. hydro, wind, solar, geothermal and biomass. RECs are applied equally to all renewable generators within scenarios. REC prices are parametrically varied to determine values needed to reach a specified renewable target.

Historical values and forecasts of electricity demands are used for 2010 – 2037, and then extrapolated using a fixed growth rate of 0.6% from 2038 – 2060 (10). To ensure system reliability, a reserve margin is implemented based on the historic reserve margin in Alberta (101) (114). Due to the aggregation of load into 36 time slices, peak load information is lost. To account for this, a peak load factor is added which accounts for the difference between the true annual peak and the reduced peak appearing in the time slices. This ensures the reserve capacity approximately meets the historical 18% value. Wind and solar resources cannot contribute to reserve margin due to their intermittency.

Residual capacity accounts for any pre-existing capacity in the system, and the expected retirement date. Residual capacity and retirement dates are based on (115) (116). Residual capacity also accounts for the addition of 450 MW of coal, 60 MW of CCGT, 184 MW of Cogen, and 740 MW of wind capacity between 2010 and 2017, as seen in Figure 3-5.

Natural gas generators have a maximum capacity limit and/or an annual maximum capacity investment based on AESO's long term outlook (115). CCGT, CCGT-CCS and OCGT are unconstrained for maximum capacity as it is assumed there is an unlimited amount of natural gas resource. Annual maximum capacity investment is limited to 5% of annual peak demand for these technologies, consistent with average additions over the last ten years (101). Cogeneration units are limited to a maximum capacity of 7.5 GW in 2060, extrapolated from AESO 2014 *Long Term Outlook* (117).

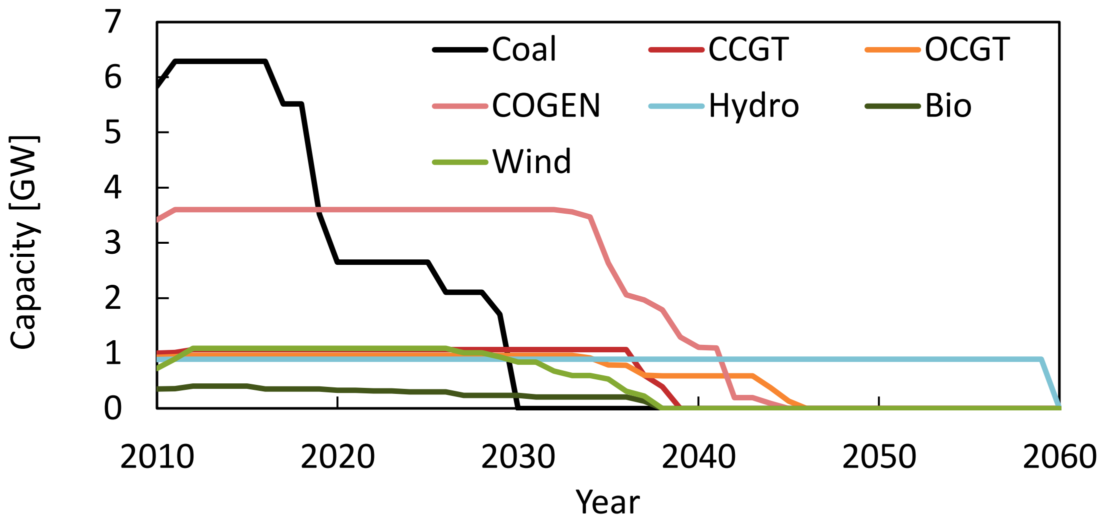

Figure 3-5. Residual capacity by generator type with expected decommission time.

Renewable generators have an imposed maximum capacity limit and/or an annual maximum rate of buildout. Geothermal is constrained to a maximum capacity of 1000 MW, starting from 2020, double the currently estimated maximum capacity (115) (101). Hydro maximum capacity is constrained to 1.2 GW until 2026, with an additional 330 MW increase by 2027 and an additional 770 MW by 2036, in accordance with AESO's 2016 *Long Term Outlook, Alternate-Policy Scenario*. Wind and solar are constrained to annual additions of 600 MW starting in 2018 for wind and 100 MW starting in 2020 for solar. Mill waste biomass units are constrained by fuel availability of 8 TWh/year, based on plant efficiencies of 25% and average bioenergy production of 2 TWh annually.

3.3.3. Scenarios

Four scenarios are analyzed - *Reference* (REF), *Stranded* (STR), *Retrofit* (RET), and *High carbon tax* (HCT). As shown in Table 3-4, scenarios are defined by renewable energy target for the year 2030, conversion to biomass as an option, availability of renewable energy credits (RECs), and carbon price.

The REF scenario assumes no RECS and no renewable penetration target, but conversion of coal to gas or biomass are options. In the STR and RET scenarios, RECs are applied to renewable generators so that renewable energy penetration by 2030 is 30% (simulating current policy targets.) RECs are uniform for all renewable generators and are available from 2016 until 2060 at a fixed value. Unlike the RET case, no coal conversion option is given in the *STR* scenario. Retrofit for coal plants is allowed beginning in year 2030. The HCT examines the impact of a higher carbon tax without a renewable target in place for 2030. In this scenario, the carbon tax increases up to 50 $/t$CO_2$ by 2022, representing a recent federal policy.

Table 3-4. Summary of modelled scenarios. [a] Carbon prices in HCT scenario increase to 10 $/t$CO_2$ in 2018, increasing by a further 10 $/t$CO_2$ annually to 50 $/t$CO_2$ in 2022.

Scenario name	Renewable target for 2030 [%]	Convert to Biomass or Gas Option	RECs	Carbon price [$/t$CO_2$]
REF	-	Yes	No	1.8 - 6
STR	30	No	Yes	1.8 - 6
RET	30	Yes	Yes	1.8 - 6
HCT	-	Yes	No	1.8 – 50[a]

3.4. Results

Results are presented in three parts: (3.4.1) generation mixtures in terms of capacity buildout and energy shares; (3.4.2) carbon emissions; and, (3.4.3) abatement costs.

3.4.1. Generation mixtures

Reference scenario

Results for the reference scenario represent a least-cost supply plan for capacity expansion and dispatch where coal is phased out by 2030 and current carbon policy is in effect. Figure 3-6 (a) shows the optimized, least-cost, annual energy supply by technology while Figure 3-6 (b) shows the changing installed capacity of technology types.

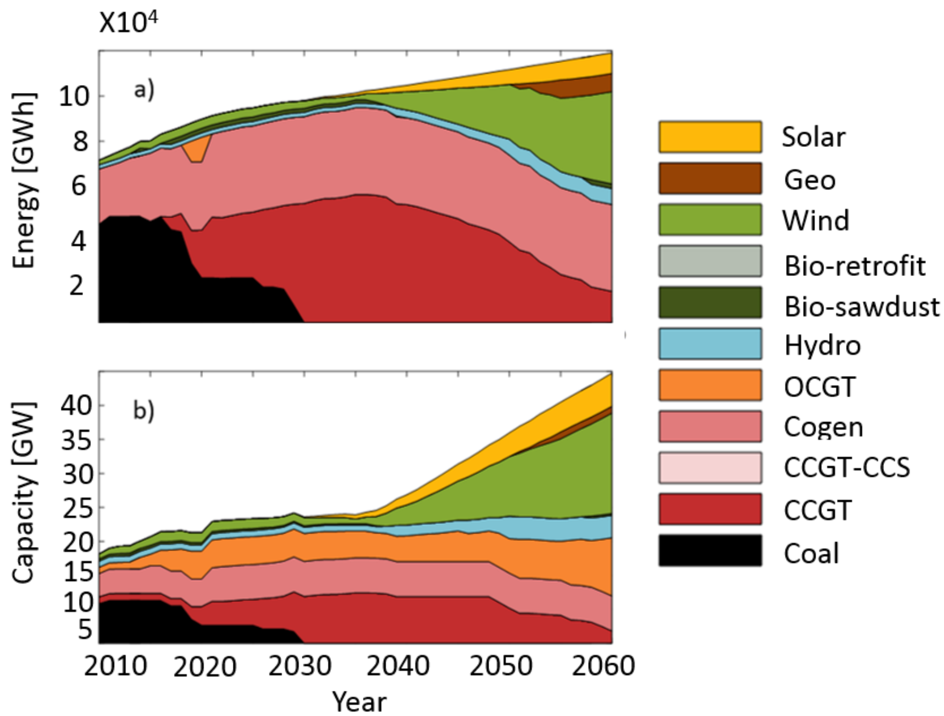

Figure 3-6. Results for the reference scenario for stacked energy (a) and stacked capacity (b).

The system transitions from coal generation to natural gas, followed by a transition to renewables and natural gas. The shift from coal to natural gas is due to the low cost of natural gas fuel, high efficiency of CCGT, and the high emission penalty incurred by coal generation due to the increasing carbon tax. Due to the escalation of natural gas prices and the decrease in capital cost of wind and solar power, the coal to natural gas shift is followed by a shift to renewable power and natural gas. By 2030, renewable energy comprises approximately 7% of annual generation.

From a least-cost system perspective, retrofitting coal to biomass or natural gas is not economical. Even though both options have a relatively low capital cost, biomass retrofit is too costly due to high pellet cost compared to natural gas, while CTG conversion is uneconomical due to the lower efficiency compared to CCGT. As a result, the system opts to not to retrofit any of the three stranded units.

2030 Renewable target

The stranded (STR) and retrofit (RET) scenarios consider a 30% renewable energy penetration target by 2030. The carbon price from the reference scenario remains the same, and, in addition, a REC value is applied. The energy and mixture capacities for the REF, STR, and RET scenarios are compared in Figure 3-7.

As shown for the stranded scenario in Figure 3-7 (a), without the biomass retrofit option, the bulk of the renewable generation is achieved by wind power. Wind is responsible for one quarter of the total generation, with biomass sawdust, hydro and solar completing the remaining 5% to reach the 30% target. In contrast, when retrofit is an option, conversion to residual biomass occurs and provides 7 TWh of energy, reducing the share of wind from 25% to 18%.

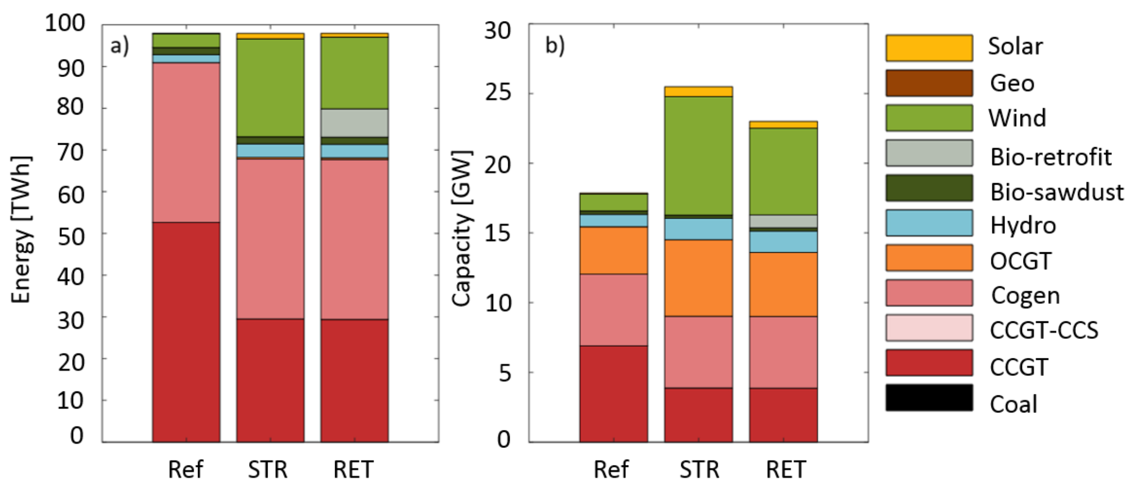

Figure 3-7. Stacked energy (a) and capacity (b) bar plots 2030 for the Reference, Stranded, and Retrofit scenarios.

With biomass retrofits, both overall capacity and backup capacity decrease relative to the stranded case, as shown in Figure 3-7 (b). The optimal retrofit of 900 MW of coal capacity to biomass allows the system to forgo 2.3 GW of new wind buildout and 900 MW of new OCGT buildout, as shown in

Table 3-5. This decrease in system capacity leads to a decrease in capital cost investments of 2.6 $B by 2030.

To achieve the 30% renewable energy penetration by 2030, the use of RECs is necessary in both the STR and the RET scenarios. In the STR scenario, a REC of 18.7 $/MWh achieves the 2030 target. This value drops to 16.5 $/MWh in the retrofit scenario, equivalent to nearly 700 $M in REC payments to 2030, as shown in

Table 3-5. As a result of lower capital cost investments and renewable energy credits, the STR scenario achieves a total system cost 5% lower that that of the STR scenario by 2060.

Table 3-5. REC and capacity costs for meeting 2030 renewable energy targets.

Scenario Name	REC [$/MWh]	REC payments 2016 -2030 [$B]	Total installed Capacity [GW]	Additional capacity cost over REF [$B]
Reference	0	0	17.9	-
Stranded	18.7	2.1	25.5	6.7
Retrofit	16.5	1.4	23.0	4.1

High carbon tax

As seen in Figure 3-8, the implementation of the higher carbon tax pushes coal generation out by 2020, a decade earlier than the REF scenario. A small amount of CCGT-CCS also appears in the system, providing just over 4.5% of the energy. Wind buildout starts by 2020, over 15 years before the REF scenario. Only one of the three coal units is retrofitted to residual biomass in this scenario.

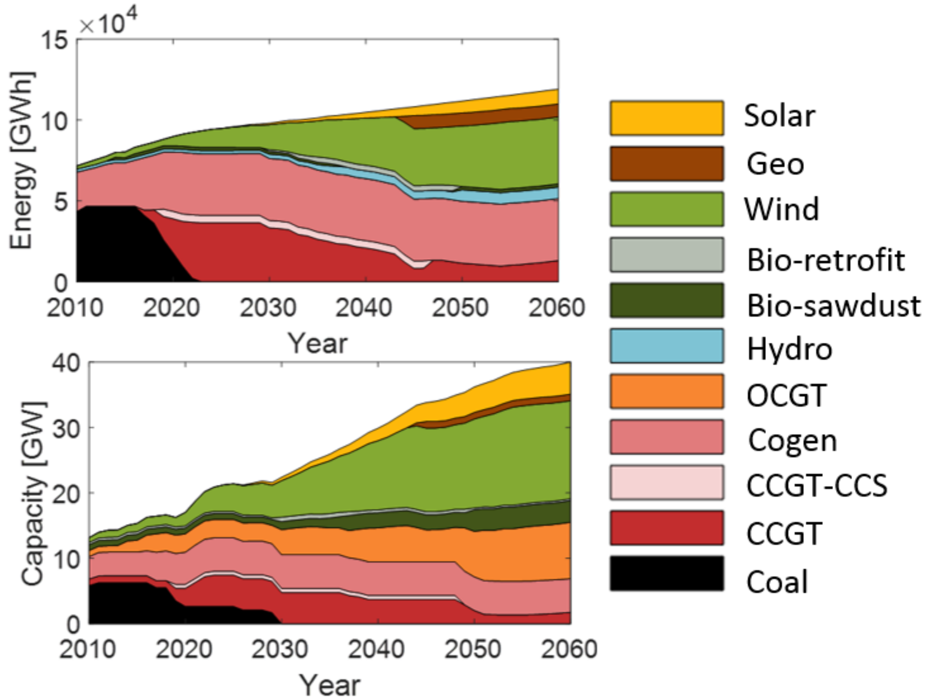

Figure 3-8. Results for the HCT scenario for stacked energy (a) and stacked capacity (b).

3.4.2. Carbon emissions

Figure 3-9 shows the annual carbon emissions for each scenario over the model period. Emissions only account for point use of fuels, and do not account for material use of land change during construction of generators. Biomass emissions account for diesel fuel used for biomass transportation only.

For all cases, an emissions peak in 2017 is followed by a period of sharp decrease due mostly to the phase out of coal and replacement by CCGT. Emission reductions continue at a lower pace from 2030 to 2060 due to the displacement of natural gas by renewable energy. Annual emissions are similar at the year 2060 for all scenarios; however, the RECs and higher carbon prices lead to wind and solar being adopted significantly earlier. As a result, cumulative emissions for the RET and STR scenarios are 20 – 22% lower than the reference scenario. As seen in Figure 3-9, the HCT scenario leads to a rapid decrease in annual emissions from 2017 to 2022. Due to high emission intensity, coal units become uneconomical more rapidly, being substituted by a mix of CCGT, wind, biomass and CCGT with CCS. The rapid increase in carbon price, and resulting early retirement of coal, makes the cumulative emissions over the model period 23% lower than the REF scenario.

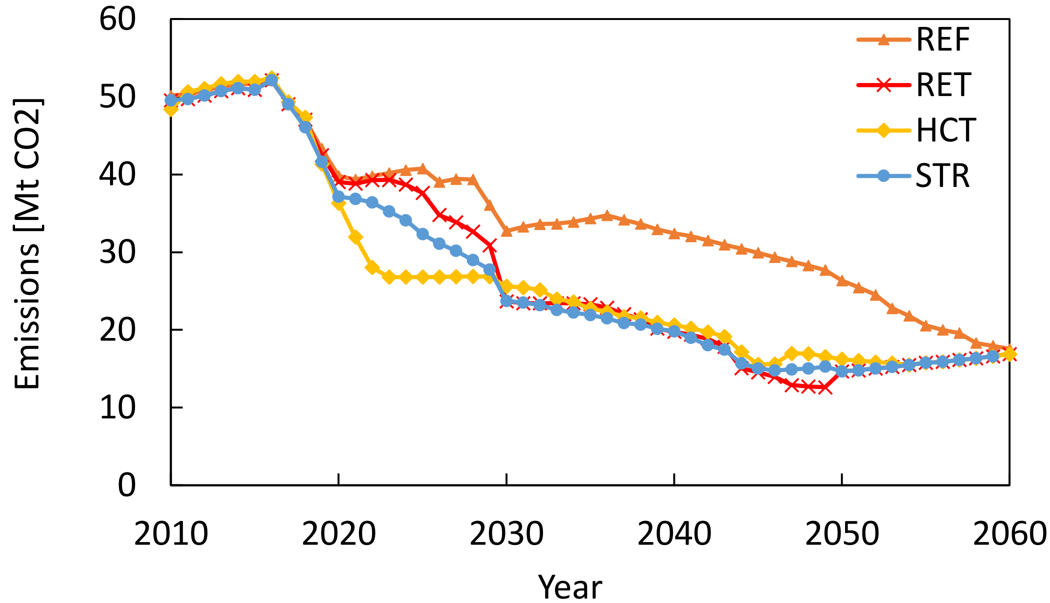

Figure 3-9. Annual emissions from 2010 to 2060 for Reference, Stranded and Retrofit scenarios.

3.4.3. Carbon abatement costs

Carbon abatement cost is defined here as the increase in cost from the reference scenario divided by the emission reduction relative to the reference scenario. Results for each scenario are summarized in Table 3-6. The retrofit scenario leads to lower carbon abatement cost than the STR or HCT scenarios. Although the STR scenario has lower cumulative emissions than the RET scenario, this comes at a higher cost. The resulting carbon abatement cost for the STR scenario is approximately three times higher than RET scenario. The cumulative emissions in the HCT scenario are lower than the STR or RET scenario, but the cost per unit of reduced CO_2 is over five times higher than the RET scenario. These results suggest that targeted RECs in conjunction with carbon pricing may be a more effective policy than only carbon pricing.

Table 3-6. **Annual emissions for 2030 and cumulative emissions for 2030 and 2060 for Reference, Retrofit and Stranded scenarios.**

Scenario Name	Cumulative emissions 2010-2030 [Gt CO_2]	Cumulative emissions 2010 -2060 [Gt CO_2]	Total system cost 2010 - 2060 [$B]	Carbon abatement cost to 2060 [$/t$CO_2$]
Reference	0.92	1.77	67.4	-
Stranded	0.85	1.38	72.5	13.25
Retrofit	0.88	1.42	69.1	4.52
HCT	0.80	1.36	77.5	25.4

3.5. Discussion

It is important to mention that emissions from bioenergy are not accounted for in the current study. Previous research has shown that this is only true in multi-decadal time spans (27) (26) (25) . The GHG emissions impact of bioenergy depends on the source of biomass, the fuel displaced, length of time after biomass harvest and alternative fate of biomass. Although the time for carbon mitigation using biomass typically is region specific, it has been demonstrated that the use of forest residue to displace coal is an effective emissions mitigation strategy. However, future research is necessary to assess the carbon impact of biomass displacement of coal in Alberta and length of time to carbon sequestration parity.

Due to the perfect foresight of the model, emissions in the RET scenario may be overestimated. Because wind is limited to an annual buildout of 600 MW per year, to reach a renewable penetration of 30% by 2030, strong wind buildout must start by 2018 in the STR scenario, with average installation of 540 MW per year to 2030. As wind has no fuel or VOM cost, once the capacity is installed, it displaces the generators with the higher variable cost i.e. coal. However, in the RET scenario, there are over 900 MW of retrofitted biomass that will be installed in 2030. As a result, the model decides to delay installation of wind power, with average capacity buildout of only 247 MW per year to 2030. Non-perfect foresight of the future may lead to higher addition of wind power in the RET scenario.

Curtailment costs, not captured in the model, could lead to higher costs in some of the scenarios. This situation can arise when renewable capacity is large relative to flexible capacity. Because a significant fraction of Alberta's electrical energy is from industrial cogeneration, which is relatively inflexible, curtailment can become a system cost in future years. Another factor not considered is the impact of power purchase agreements (PPA) with any generator being displaced prior to end of life. If curtailment is to be avoided, the system would then incur additional costs to satisfy contractual agreements. As a result, the total system cost presented in Table 5 may be underestimated in some scenarios.

LCOE is a metric commonly used to evaluate costs of electricty generation for a specific technology without regard to the system it is operating in (20). This metric accounts for capital costs, operation and maintenance costs, number of years of operation, and fuel costs. As wind power does not consume fuel, its LCOE can be lower than that of bioenergy. However, LCOE does not capture other system requirements such as need for backup capacity due to intermitency. Other metrics such as *system* LCOE or levelized avoided cost of energy (LACE) are sometimes used to identify the value of a technology with respect to a specific system (118) (119).

Table 3-7 compares the capacity-average LCOE for wind and the three coal units considered as options for retrofit to biomass in the year 2030 where each LCOE is normalized by the cost of wind. The calculated LCOE for wind includes a reduced capital cost due to learning rates, while the LCOE for the retrofitted plants includes higher fuel cost due to escalation in diesel costs. The LCOEs for wind and Keephills 3 are sufficiently close that no obvious choice can be made based on LCOE alone.

Accounting for forest carbon stocks and fluxes is a complex problem and the subject of ongoing research. Alternative pathways for residual forest biomass, such as the creation of long-life wood products, in conjunction with alternative electricity generation options warrant further investigation to determine the value in a broader carbon abatement strategy.

Table 3-7. LCOE for wind and three retrofitted coal to biomass units using 2030 fuel, capital and operational costs.

Generation option	Normalized LCOE [-]
Wind	1.00
Keephills 3	0.99
Genesee 3	1.05
Genesee 1	1.28

3.6. Conclusions

We have investigated the impacts of a biomass retrofit option in the Alberta electricity system and associated cost implications. A biomass feedstock supply model is combined with a hybrid capacity expansion and dispatch model to assess the impact of this technology on reaching a 30% renewable energy target by 2030 in the Alberta electrical system.

Comparison of the two scenarios with RECs shows that allowing the biomass retrofit leads to a 5% reduction in system cost by 2060. Converting 0.9 GW of coal to biomass leads to a reduction of 2.5 GW of wind capacity and 0.9 GW of OCGT backup capacity. The savings from avoiding this additional capacity buildout lead to a lower REC requirement to meet the 2030 renewable energy goals. The combination of lower REC and lower capacity requirements lead to a 5% lower cost system, or savings of B$ 3.4 by 2060.

System cost reduction with bioenergy is achieved even though bioenergy is found to have similar or higher LCOE than wind generation. These results show that LCOE alone is not an appropriate metric for evaluating which generators comprise a least-cost mixture to decarbonize the electrical system. Variability of wind energy requires extra backup capacity which is not captured by LCOE.

The scenario with carbon taxes is found to lead to a higher cost system than scenarios with RECs, while achieving similar goals. Lower abatement costs are found for both scenarios with RECs than the scenario with carbon taxes. The abatement cost is found to be 25.4 $\$/tCO_2$ for the HCT scenario, while this value is 4.52 $\$/tCO_2$ for the Retrofit scenario, where RECs are applied.

Chapter 4

Electricity system and emission impact of direct and indirect electrification of heavy-duty transportation[2]

Preamble

Widespread adoption of alternative fuel vehicles in the heavy-duty transportation sector could significantly mitigate carbon emissions of this important sector. However, the extent of emission reductions and their feasibility will depend on the carbon intensity of the electricity system, alternative fuel vehicle technologies and vehicle charging profiles. Utilizing a capacity expansion and dispatch model, this study compares alternative pathways for decarbonizing the electricity and heavy duty transportation sector to 2060. Scenarios with battery electric vehicles, with three alternative charging profiles, and fuel cell vehicles are compared with 0 and 150 \$/tCO2 carbon taxes. Results show that adoption of alternative fuel vehicles in the absence of carbon taxes leads to, in the best case, cumulative emission reductions of 3% relative to a reference scenario due to the reliance on natural gas generation. In scenarios with a tax of 150\$/tCO2e, results show that adoption of fuel cell vehicles achieves the highest emission reduction of all studied scenarios with cumulative reductions of 43% from the reference scenario and the lowest carbon abatement cost, at 15.2 \$/tCO2e. The flexibility of electrolysers allows low cost renewable energy to be stored as hydrogen thereby avoiding investment in higher cost and higher emitting technologies.

[2] The body of this chapter was published in V. Keller et al. Renewable Vol. 1, pp. 740-751, 2019

4.1. Introduction

According to the IPCC, the global transportation sector produced 7.0 $GTCO_{2e}$ in 2010, equivalent to 23% of all energy-related green house gas (GHG) emissions (120). Of these transportation emissions, 20% or 1.4 $GtCO_{2e}$ was produced by the heavy-duty (HD) freight sub-sector (121). As freight demand is projected to increase in coming decades (121) (122) (7), emissions from this sub-sector are likely to increase, unless mitigated. Direct and indirect electrification technologies such as battery electric vehicles (BEVs) and fuel cell vehicles (FCVs), respectively, have potential to reduce emissions from HD freight (35). Class-8 HD vehicles, 33,000 lb and over (123), are typically used for longer hauls, ranging from 800 to 1500 km daily (36). These long hauls require a high energy density fuel (120) (36) (37) which makes electrification challenging, due to the limited energy density of batteries. However, developments in both battery and fuel cell technology (49) are sparking activity in this field, as illustrated by the recent announcements of the Tesla Semi BEV (38) and the Nikola One and Nikola Two fuel cell trucks (39).

The GHG intensity of the electricity generation mix and charging profiles of vehicles impact the extent to which electrification of vehicles mitigates emissions (49) (124) (45) (125). A low GHG intensity mix is necessary to achieve significant emission reductions (49) (45). However, hourly GHG intensity can vary, particularly in jurisdictions with high penetrations of intermittent renewable generation, such as wind and solar (45). In these cases, the vehicle charging profile (i.e. time of the day during which vehicles draw electricity from the grid) can affect mitigation of emissions. For example, in a study by Tamayo et al, the authors studied marginal emissions for charging passenger BEVs across different areas of the United States (45). The authors found that the vehicle option (BEV vs plug in hybrid) that lead to lowest emissions varied with the GHG intensity of the local generation mix. Furthermore, charging the vehicle at night generally lead to higher emissions as coal is often the marginal generator at this time.

Widespread conversion to electric vehicles can lead to increased demand for electricity. Studies suggest that existing generation infrastructure may be able to accommodate penetrations up to 10% of passenger BEVs (126) (50), although this number could be higher if “smart charging” algorithms are used. However, to achieve a complete shift in transportation from fossil fuels to electrification, electricity systems will likely need to expand generation capacity. For example, a recent study of British Columbia found that electricity generation would have to increase by up to 33 TWh annually, equivalent to about half the current demand, to electrify all heavy, medium and light freight (49).

Long term capacity expansion and dispatch models have been used to compare electricity system evolution pathways for alternative vehicle technology types, i.e. BEVs and FCVs (32) (33) (34). These models have also been used to study impacts of charging profiles of passenger vehicles on renewable energy penetration and electricity prices (42). Although these studies shed light on the broad issues of electrification of transport, none focus on the HD transport sector where the energy and charging demands may be more challenging than for light-duty vehicles. Furthermore, to the knowledge of the authors, no long term capacity expansion studies assess the interactions of vehicle charging profiles and temporal variations in GHG intensity of the generation mix for BEV and FCV technologies.

In this work, we study the long-term electricity system impacts of conversion of the HD transport sector to BEVs or FCVs. We use a bottom-up linear programing model to determine which generators are built to meet conventional electricity system demand and load due to charging of electric vehicles. The effects of alternative HD vehicle charging profiles and of carbon taxes are explored using the province of Alberta, Canada, where there is rapidly increasing demand for HD transportation, low availability of flexible hydroelectric energy options and high reliance on fossil power.

4.2. Methods

A linear programing cost optimization tool is used to determine the lowest cost pathway to meet exogenous demands for electricity and transportation over a 45-year period. Alternative technologies, each of which has prescribed capital and operation costs, are endogenously selected to meet these demands. Each year is subdivided into 48 representative timeslices and energy supply must balance energy demand within each timeslice.

Section 4.2.1 provides a more detailed system representation. Section 4.2.2 provides further detail on the model, with details on temporal structure, technology options and demand forecasts for transportation. Section 4.3 provides a summary of costs used in the optimization.

4.2.1. System representation

Exogenously defined transportation and electricity demands are met using technologies with associated fuel type, consumption, capital and operational costs, as shown in Fig. 4-1. Electrical energy demand (GWh) per year is met by electricity generators, while the transportation demand, expressed in distance (km), is met by a fleet of vehicles. Both electricity generation capacity and stock of vehicles may be expanded to meet increasing demand. Further, electricity generators can also provide electricity for BEVs or for electrolysers that produce hydrogen for FCVs. Costs and availability of fuels are exogenously defined.

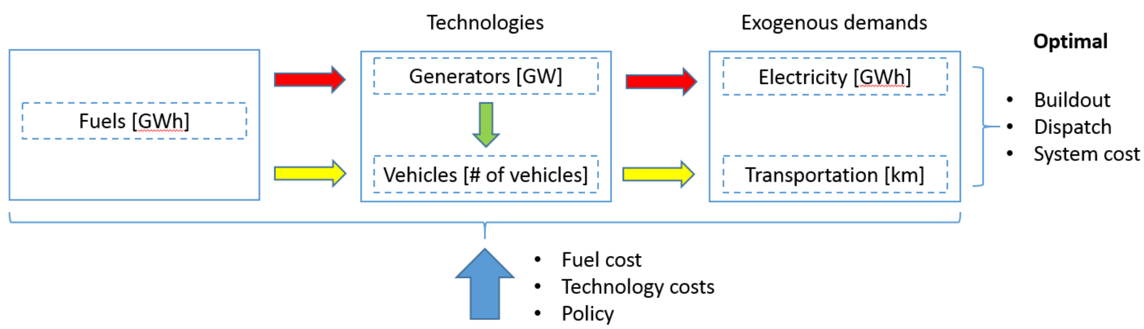

Figure 4-1. Schematic representation of the modelled system.

4.2.2. Model platform

Modelling is carried out in the Open Source Energy Modelling System (OSeMOSYS) (64) (99). OSeMOSYS is a linear programing optimization tool, which has previously been used in a wide range of energy system studies including analyses of the impact of carbon taxes on fossil dominated jurisdictions, use of biomass to replace coal in coal-fired plants in Alberta, expansion of hydroelectric energy in Bolivia to export energy to neighbouring South American jurisdictions and incorporation of flexibility requirements to meet high levels of renewable penetration in Ireland, among others (101) (127) (66) (72). More details on the model's formulation, inputs and outputs can be found in (64) (101).

Temporal structure

The study period spans from 2015 to 2065. A clustering algorithm is used for temporal aggregation, so that 8760 hourly data points are reduced into 48 representative timeslices, corresponding to six representative days. Each day comprises 8 multi-hour periods. Duration and energy demand of timeslices vary so that, peak load and peak VRE generation events are captured.

The clustering method combines similar data points into groups, or clusters, and determines one representative data point per cluster, similar to the work by Namacher et al (128). A benefit of this approach is its ability to retain the peaks and troughs inherent to load and VRE generation profiles. More detailed information is available in supplemental material.

Technology options

Available technologies fall into three categories: electricity generators, HD vehicles and electrolysers. Electricity generators are those technologies that meet the electricity demand, as shown in Figure 4-2. Thermal generators include coal, natural gas, biomass and nuclear plants. Natural gas generators are broken down into cogeneration (cogen), combined cycle gas turbine (CCGT) and open cycle gas turbine (OCGT). CCGT generators can adopt carbon capture and storage (CCS) to decrease emissions, but at a higher capital cost and lower efficiency. All thermal generators consume fuels with an exogenously defined cost for the modeled time period. Additionally, the model includes renewable generator options consisting of: wind, solar photovoltaics (PV), hydro and biomass.

Electricity generators must also satisfy a reserve margin constraint which is equal to 18% of demand for each timeslice, consistent with (101). Coal, natural gas, biomass, nuclear and hydro contribute 100% of their capacity to the reserve margin. It is assumed that wind power contributes 15% of its capacity to the reserve margin while solar photovoltaics (PV) does not contribute to the reserve margin.

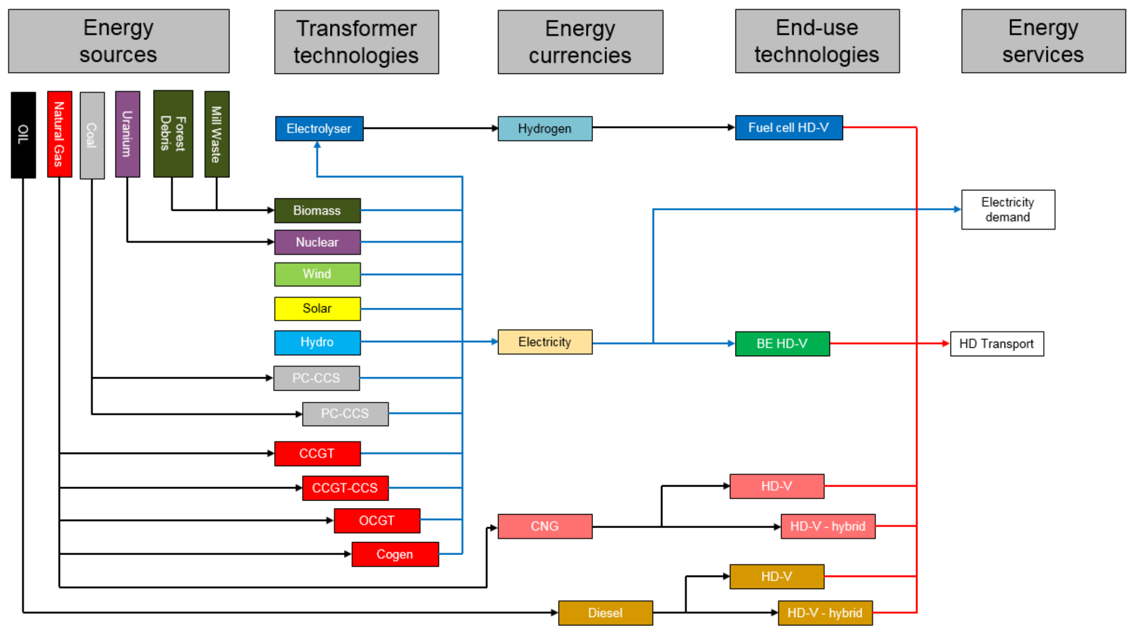

Figure 4-2. Schematic representation of energy system model with generating options

HD vehicle technologies are used to meet HD transportation demand, as shown in Figure 4-2. Vehicles fall into two categories: conventional and alternative fuel vehicles (AFV). Four conventional vehicle types are available: Diesel, hybrid diesel, compressed natural gas (CNGV), and hybrid compressed natural gas vehicles. Hybrid technologies provide higher efficiency than their conventional counterparts but at higher capital cost. All conventional vehicles consume fuel with exogenously defined costs. AFVs comprise BEVs and FCVs. All transportation technologies have a prescribed fuel efficiency [kWh/km], which is exogenously defined. BEVs consume electricity from electricity generators while FCVs consume hydrogen synthesized from electrolysers (129). .

Electrolyser are technologies that consume electricity and produce hydrogen (130). The electricity consumed by the electrolysers is produced endogenously. Electrolysis is the only source of hydrogen in the model.

Each technology option has associated capital and fuel costs as well as variable and fixed operation and maintenance (VOM and FOM) costs. Each generator type has a prescribed lifetime, maximum annual capacity factor, efficiency and emission intensity. When part of the stock of a technology reaches its end of life, it may be replaced by new capacity of the same type, or by a different technology that can meet the same demand.

Technologies consuming fossil fuels (i.e. generators and vehicles) emit CO_2 and incur carbon taxes based on the associated emissions. Emissions for each generation technology are calculated based on the CO_2 content of the fuel type (kg CO_{2e}/kWh) and the efficiency (%) of generator. Similarly, vehicles emit CO_2 based on the carbon intensity of the fuel (kg CO_{2e}/kWh) and the vehicle's fuel economy (km/kWh). Generator efficiency and vehicle fuel do not vary with load.

Transportation demand forecast

Demand for HD vehicles is estimated using forecast data for GDP per capita in the province, as in Telebian et al (49). Vehicles per GDP per capita, $\bar{X}$, is used to forecast the number of HD vehicles in the province based on economical growth forecasts. Historical data for GDP growth and number of HD vehicles for the years 2000 to 2013 is used to determine $\bar{X}$. The vehicle stock in year k is determined from the stock in previous year, *k-1*, and forecast GDP per capita, as shown in Equation 4-1,

$$Stock_k = Stock_{k-1} + \bar{X}\,(GDP_k - GDP_{k-1}) \qquad (4\text{-}1)$$

where $Stock_k$ is the total number of vehicles in year k. As GDP per capita forecast data is available only to 2040 for Alberta, the data set is extrapolated to 2060 assuming an annual increase of 2%, which is the average rate for 2030 to 2040 (131). A vehicle lifetime of 900,000 km (49), or roughly 9 years, is assumed.

Transportation demand is calculated by multiplying the stock of vehicles in year, k, by the annual average distance travelled by each truck in Alberta, D_v.

$$Demand_k = D_v\ Stock_k \qquad (4\text{-}2)$$

The annual average from 2010 to 2014 is used for D_v, equivalent to 100,000 km per vehicle per year (11).

4.3. Data

This section provides input data for costs, efficiencies and lifetime of electricity generators, HD vehicles and electrolysers. Data for electricity generators is primarily based of EIAs Annual Energy Outlook 2018 (132), while data for HD vehicles is primarily based on the International Council for Clean Transportation (ICCT) (35).

Data for costs, heat rates, maximum lifetime and maximum capacity build limit by technology are presented in Section 4.3.2. Costs, fuel consumption and lifetime of vehicles is provided in Section 4.3.3 and 4.3.4. Residual capacities for all technologies is provided in Section 4.3.5, while the scenarios modelled are described in Section 4.3.6.

4.3.1. Electricity demand

There are two types of electricity demand in the model, conventional electricity demand and AFV electricity demand. Conventional electricity demand refers to forecasted demand for electricity from the Alberta Electric System Operator's (AESO) 2016 long term outlook, reference case (115). This demand refers to expected electricity system demand in the province and does not include electrification of vehicles. This demand is exogenously defined.

AFV electricity demand refers to the additional electricity demand incurred in the model as a result of direct or indirect electrification of HD vehicles. The magnitude of this demand varies annually and depends on transportation demand, vehicle energy consumption and electrolyser efficiency.

4.3.2. Electricity generation technologies and electrolysers

Assumed costs, heat rates and lifetimes for electricity generators are shown in Table 4-1 (132). The heat rate of coal is based on the average of existing generators and improves to 2030 as older generators are decommissioned. As cogeneration costs and heat rates are not provided by the EIA, Alberta-specific generation data is used (117) (133).

Solar generation is provided by two technologies; commercial solar (solar-C) and residential rooftop solar (solar-RRT). Solar-C data is based on EIA data, while Solar-RRT data is based on NREL data for residential systems with capacity of up to 10 kW (134).

Wind generation and costs are determined by region: north (Wind-N), south-west (Wind-SW), south-central (Wind-SC) and south-east (Wind-SE), as shown in Table 4-1. These four regions represent the diversity in costs and generation profiles in the province. Each region is further sub-divided into a low and a high cost resource. A finite capacity is assigned for each of the four low cost resources. High cost resources are assigned an unlimited capacity. Capital costs are based of distance to high voltage transmission lines, with further decrease in capital cost by 15% to 2030 and 20% by 2050, from 2015 values. Further information on the four wind regions is available at (73).

Capital and fixed costs for electrolysers are based on values from the U.S. Department of Energy (DOE), shown in Table 4-1. Capital costs decrease linearly to 2025 to meet targets set by the DOE (135) (136). Compression and storage costs are applied as a variable cost of 56 \$/MWh, equivalent to 2 \$/kg of hydrogen. Efficiency is based on expected maximum potential of 74% (137). Further, a 2 kWh/kg penalty is incurred by electrolysers to account for energy consumption associated with compression. This value is accounted for in the electrolyser heat rate shown in Table 4-1.

Table 4-1. Summary of costs and generator assumptions by type.
[a] Weighted average of existing generators. Value changes to 2030 depending on generators still operational

Technology	Capital cost 2015 [$/kW]	Capital cost 2060 [$/kW]	FOM [$/kW-yr]	VOM [$/MWh]	Heat rate [Btu/kWh]	Lifetime [yr]
Nuclear	5880	5880	99.65	2.29	10,459	60
Coal	3392	3392	39.5	4.67	10,543-9349[a]	-
CCGT	1094	1094	9.94	1.99	6,300	30
CCGT-CCS	2153	2153	33.21	7.08	7,525	30
OCGT	672	672	6.76	10.63	9,920	30
Dedicated biomass	3790	3790	110.34	5.49	13,500	20
Cogeneration	1357	1357	9.94	1.99	4,845	30
Hydro	2442	2442	14.93	2.66	-	80
Wind-N (high)	1983-(2183)	1582-(1741)	46.71	-	-	25
Wind-SW (high)	1903-(2174)	1518-(1734)	46.71	-	-	25
Wind-SC (high)	2171-(2181)	1731-(1740)	46.71	-	-	25
Wind-SE(high)	2154-(2193)	1718-(1749)	46.71	-	-	25
Solar-C	2277	659	21.66	-	-	25
Solar-RRT	3897	1127	21.66	-	-	25
Electrolyser	987	462	56	56	4,778	20

4.3.3. Heavy duty vehicles

The stock of existing HD vehicles in 2015 is set to 111,000, based on the number of registered vehicles in Alberta weighing 15,000 kilograms or more in 2014 (138). The existing vehicle stock decreases linearly to zero by 2024, equivalent to a nine year lifetime, to account for decommissioning of older vehicles (49).

Fuel consumption data is shown in Table 4-2. Up to 2030, annual fuel consumption is based on the ICCT (35). Between 2030 and 2050, efficiency improvement rates from the

EIA *Annual Energy Outlook (AEO), 2017* are applied (139). This outlook forecasts rates with and without the implementation of the EPA's *Phase II* regulation, which stipulates further increases in fuel efficiency for medium and HD vehicles. Fuel efficiency improvements for hybrids, FCVs and BEVs are based on the EIA AEO Phase II regulation. Fuel efficiency for conventional diesel and NG vehicles do not include this regulation. Fuel consumption for all vehicles remain constant after 2050.

Table 4-2. Fuel consumption for all transportation technologies.

Technology	Fuel consumption (km/kWh)		
	2015*	2030**	>2050
Diesel	0.257	0.387	0.397
Diesel hybrid	0.257	0.404	0.475
NGV	0.225	0.327	0.336
NGV hybrid	0.225	0.342	0.403
FCV	0.379	0.474	0.560
BEV	0.4	0.522	0.62

* Based on ICCT - Transitioning to Zero-Emission Heavy-Duty Freight Vehicles (35)
** Based on EIA AEO Phase II regulations (139)

Capital and variable costs for HD vehicles are taken from the ICCT (35) for all technologies except BEVs, as shown in Table 4-3. As no values are provided for BEVs, these costs are based on values for EVs with overhead catenary connections. To estimate the capital cost of BEVs, the costs provided by the ICCT for catenary equipment and grid connection fees are subtracted from the total capital cost of catenary vehicles. Further, it is assumed that batteries are scaled up to a capacity of 1.3 MWh, similar to current estimates of the battery size of the Tesla semi. Battery cost is scaled up linearly.

Capital and variable costs, exclusive of fuel, are shown in Table 4-3. Capital costs, in thosands of dollars, entail the purchase cost of vehicles. Capital costs decrease up to 2030, consistent with the ICCT (35). Modelled capital costs for BEVs decrease at rates provided by the ICCT forecast for catenary BEVs, as values for BEVs are not provided. Costs remain constant past 2030 for all vehicles. Conventional vehicles are assigned a variable cost of 0.12 \$/km, while hybrids, FCVs and BEVs are assigned a variable cost of 0.11 \$/km, in accordance to the ICCT (35).

Table 4-3. Capital and variable costs for transportation technologies (35). Capital costs are in thousands of dollars per vehicle.

Technology	Capital cost 2015 [k$/vehicle]	Capital cost 2030 [k$/vehicle]	Variable cost [$/km]
Diesel	210	210	0.12
Diesel hybrid	235	235	0.11
NGV	259	255	0.12
NGV hybrid	284	280	0.11
FCV	345	255	0.11
BEV	721	357	0.11

4.3.4. Fuel costs

Fuel costs are based on data from the EIA AEO 2017 (132). Fuel costs for electricity generators are taken from EIA AEO's cost assumptions for electricity generators. EIA AEO data for transportation HD is used for modelled vehicles. As the EIA provides forecasts only to 2050, these costs are extrapolated to 2060, assuming a constant growth rate equal to the average rate of the final fifteen years of the forecast. Fuel costs for FCVs and BEVs are not specified exogenously, as electricity is generated endogenously to power these technologies.

4.3.5. Capacity constraints

Residual capacity accounts for the stock of existing electricity generators and their respective decommissioning dates. Residual capacity for coal is based on decommissioning dates for current generators and a 2030 deadline for coal phase out, consistent with the Alberta Climate Leadership Plan (140) (115) (127). Wind residual capacity is based on commissioning dates of projects in Alberta and an expected lifetime of 25 years (115). Biomass residual capacity is based on the 8 TWh annual generation in the province and an efficiency of 25%, consistent with previous work (101) (127). Hydro and gas generator residual capacities are consistent with previous work, based on Alberta Utilities Commission (101) (127) (141). Further information on residual capacity in provided in the supplemental materials.

Buildout of technologies is restricted by maximum capacity (MC) and annual maximum capacity investment (AMCI). MC is the maximum allowable capacity for a specific technology for any given year. AMCI is the maximum allowable annual capacity increase for a given technology from one year to the following.

For coal, MC is capped to comply with the scheduled decommissioning dates of current coal generators, in Alberta Climate Leadership Plan (9). Hydro and cogen MC are consistent with maximum resource AESO data for the availability of hydro (142) and maximum expansion limits of cogen (115). MC for solar-RRT is capped at 2 GW, based on the California target for installed solar-RRT capacity (143) (144), scaled to the number of single detached homes in Alberta (i.e. equivalent to 2.2 kW per household). MC for wind is defined for each of the four regions. MC for low cost resource, as seen in Table 4-1, is consistent with (73), while MC is unconstrained for high cost wind resource. MC for CCGT, OCGT, coal-CCS, Solar-C, electrolysers and HD vehicles is unconstrained.

AMCI for all electricity generators is based on the historical rate of buildout of total generation capacity in the province, which is 5% of average load (101). This is, for example, equivalent to 0.46 GW for the year 2015. However, each wind region and each solar technology is treated as a separate technology. As a result, wind has an AMCI equivalent to 20 % of average load, while solar has an AMCI of 10% of average load. Vehicles and electrolysers do not have an AMCI.

4.3.6. Scenarios

Two sets of five scenarios are modelled, as shown in Table 4-4. In the first set of scenarios, there is no carbon tax. In the second set a carbon tax starts in 2018 at 10$/tCO_2$ escalating by a further 10 $/tCO_2$ annually up to 2032 where it reaches a value of 150 $/tCO_2$, remaining constant after this date.

Table 4-4. Summary of modelled scenarios.

Scenario name	Type of AFV	Maximum carbon tax [$/tCO$_2$] *	Notes
REF	None	0	Only fossil vehicles allowed. Mix is defined endogenously
BEV-N	BEV	0	Vehicles can only charge at night
BEV-B	BEV	0	Load for charging vehicles spread evenly throughout day
BEV-D	BEV	0	Vehicle can only charge during hours of day light
FCV	FCV	0	H_2 demand is endogenously defined
REF-T	None	150	Same as REF but with carbon tax
BEV-N-T	BEV	150	Same as BEV-N but with carbon tax
BEV-B-T	BEV	150	Same as BEV-N but with carbon tax
BEV-D-T	BEV	150	Same as BEV-D but with carbon tax
FCV-T	FCV	150	Same as FCV but with carbon tax

* Carbon taxes increase linearly from zero in 2017 to 150$/tCO2 in 2032 and are constant thereafter.

The first set of five scenarios comprise: a reference scenario with only fossil vehicles (REF); three scenarios with alternative charging profiles for BEV vehicles (BEV-N), (BEV-B) and (BEV-D); and one scenario with FC vehicles (FCV). The three alternative charging profiles for BEVs are: charging at night only (BEV-N); charging equivalent to constant demand throughout day (BEV-B) and charging during hours of solar radiation only (BEV-D). Further in the FCV scenario, rather than BEVs, FCVs are used to meet the HD transportation demand. In this scenario, it is assumed that sufficient hydrogen storage capacity exists so that hydrogen production is not required to follow a schedule dictated by FCV duty cycles. Further, electrolysers are able to ramp up and down without constraint. All scenarios are summarized in Table 4-4. Electricity demand during a charging event in any scenario is assumed to be constant.

As noted above each of these five scenarios is repeated with a carbon tax. These scenarios are denoted REF-T, BEV-N-T, BEV-B-T, BEV-D-T and FCV-T.

Total demand for HD vehicles in all scenarios is as indicated by the upper limit of the shaded areas in Figure 4-3. In the REF and REF-T scenarios, fossil vehicles meet the total demand for the full time period of the model. In scenarios with AFVs, fossil vehicles are phased out and AFVs are phased in, as shown in Figure 4-3. The proportion of AFVs is based on the market share of sales of new AFVs increasing linearly from 0% in 2030 to 100% by 2040. The vehicle stock is fully converted to AFVs by 2049.

Output for cogen and hydro are not modelled to prevent these generators from providing system flexibility. Rather, the output from these generators is exogenously set. In the model, generation capacity for cogen increases from 4.5 GW in 2015 to 6.0 GW by 2050, consistent with AESO projections (115). Although its capacity factor varies throughout the year, this is primarily for heat for oil production in the oil sands, with electricity as a by-product (101). Therefore, in the model, cogen is assumed to have a constant capacity factor of 66%, equivalent to the annual average output of this generation type in the province (145). Hydro capacity increases from the current 0.9 GW to 3.3 GW 2050 (115), while its capacity factor is held constant at 25%, equivalent to the annual average.

All scenarios are constrained to reach a minimum renewable penetration of 20% by 2030. This is equivalent to provincial targets for a 5 GW buildout of wind power by 2030 (146). Further details of charging profiles and scenarios are provided in the supplementary material.

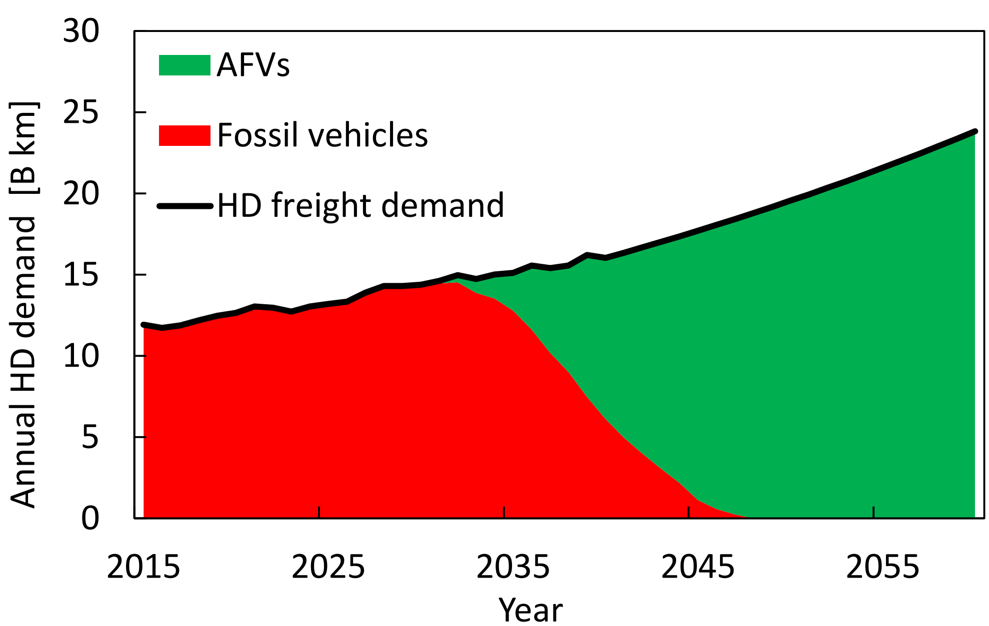

Figure 4-3. Total HD transportation demand for all scenarios. The black line represents the annual demand [B km] for HD vehicles. In scenarios with AFVs, the area shaded in red represents the share that must be met with fossil vehicles, while the area in green must be bet my AFVs. In the REF and REF-T scenarios, the entire demand is met by fossil vehicles.

4.4. Results

Section 4.4.1 presents the results for the REF scenario, while Section 4.4.2 compares the REF scenario to scenarios with AFVs. In Section 4.4.3, results for scenarios with carbon taxes are presented.

All results include electricity generation to meet the conventional electricity demand and transportation electricity. Electricity generated to meet the transportation demand is referred to as AFV electricity.

4.4.1. Reference scenario

In the Reference Scenario, the electricity system remains dependent on fossil fuels throughout the model period, as shown in Figure 4-4. Coal is phased out by 2030 due to regulations (30), and is replaced by cogeneration and CCGT. Cogen is restricted to 6 GW and, as a result, CCGT makes up the balance of the fossil generation due to its low cost and flexibility.

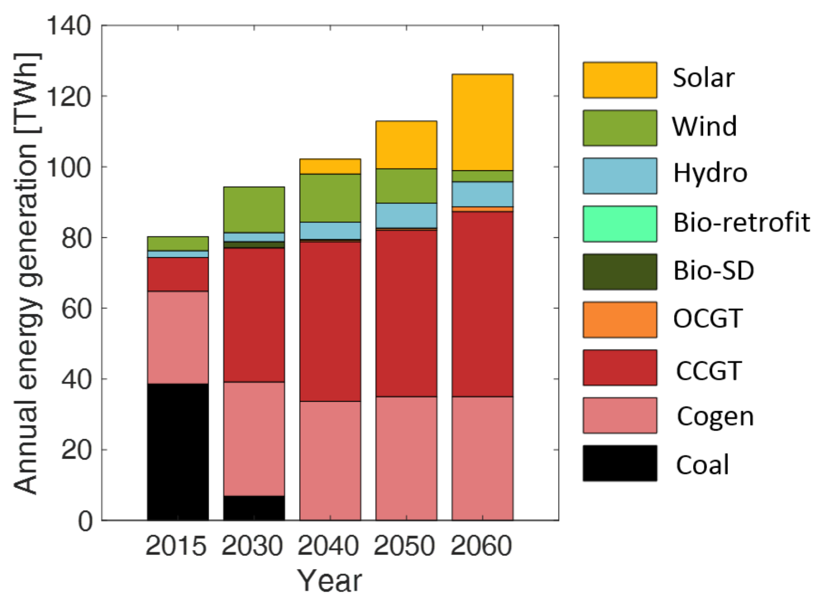

Figure 4-4. Electricity generation by source for the REF scenario for selected years.

Wind penetration increases from 2015 to 2030 due to regulations mandating a minimum level of renewable generation by 2030 (9). From 2040 to 2060, solar PV replaces wind as the dominant renewable generation technology because the capital cost of PV decreases more quickly than that of wind, as shown in Table 4-1. As a result, by 2060, renewables comprise 30% of total generation, with solar accounting for 70% of this share.

The HD transportation sector transitions from diesel to NG by 2030, and then to hybrid technology two decades later, as shown in Figure 4-5. Diesel is the lowest cost option until the early 2020s, when the fuel switch to natural gas begins. By 2030, diesel meets only 15% of all HD transportation demand. NGVs remain the lowest cost technology from the 2030s until the early 2050s, when adoption of hybrid NGVs begins. At this time, the high capital cost of hybrid vehicles is offset by high fuel efficiency coupled with increasing costs of NG.

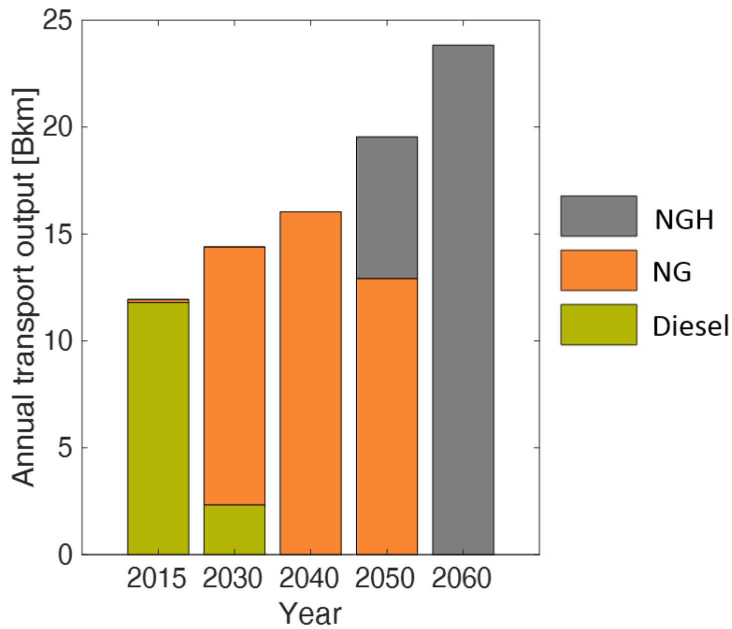

Figure 4-5. Annual HD transportation output by vehicle type for the REF scenario for selected years.

Total system emissions, including both NT electricity and HD transportation, decrease by 36% from 2015 to 2030 due primarily to phasing out of coal generation, as shown in Figure 4-6. After 2030, emissions remain relatively stable as cogen and CCGT persist in the system to provide both baseload and flexibility.

Total emissions for the HD transportation sector undergo a small increase from 2015 to 2060, as shown in green and grey in Figure 4-6. As shown in Figure 4-3, HD transportation demand more than doubles from 2015 to 2060. However, emission intensity for HD vehicles decrease from 957 g_{CO2}/km in 2015 to 528 g_{CO2}/km in 2060 due to fuel switching and increases in fuel economy. As a result, emissions from the HD transport sector only increase by 10% over this period in the REF scenario.

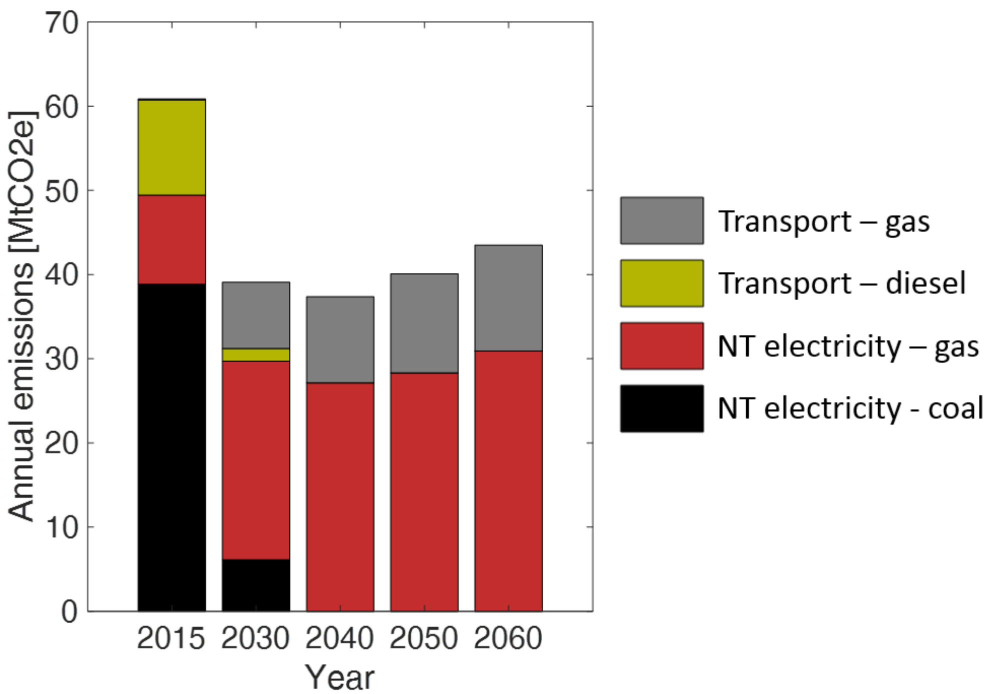

Figure 4-6. Source of emissions for reference scenario for conventional electricity and HD transport.

4.4.2. Energy mix and emissions – AFVs – 0$/tCO$_{2e}$ tax

In this section, the results for AFV scenarios are presented and compared to the REF scenario results. Relative to the REF scenario, total electricity demand in 2060 is 32% and 46% higher in the BEV and FCV scenarios, respectively (Figure 4-7), due to the additional electricity needed to power the AFVs. Load in the FCV scenario is higher than in the BEV scenarios, due to the higher energy consumption of FCVs, relative to BEVs, and losses associated with electrolysis to produce hydrogen.

In the BEV-N scenario, most of the demand increase is met by CCGT generation, followed by wind and a small share of OCGT. This scenario is the only one where solar generation decreases relative to the REF scenario. Charging vehicles at night leads to increased load that cannot be met by solar PV, making it difficult to meet the 30% RE constraint with this technology. As a result, wind generation increases by a factor of five, relative to the REF scenario.

In the BEV-B scenario, most of the demand increase in met by CCGT, as in the BEV-N scenario, followed by solar PV and a small increase in wind generation. AFV electricity demand behaves as baseload, due to its flat profile. As a result, solar PV may satisfy part of this demand during the day, while CCGT is to meet the demand at night and during periods of low solar PV generation (not shown in Figure 4-7).

In the BEV-D scenario, total demand increase is met by almost doubling solar generation and increasing both CCGT and OCGT by approximately 10 TWh/year, each. As vehicles charge during the day, solar PV is used to meet much of the AFV electricity demand. However, the strong buildout of solar PV requires additional backup capacity to meet reserve margin constraints. This results in lower efficiency OCGT generators being built and generating more electricity than in previous scenarios.

In the FCV scenarios the AFV electricity demand is decoupled from HD vehicle duty-cycles. This decoupling enables additional buildout of solar PV in the system. This results in solar PV provides generation to conventional electricity demand and in times of excess solar PV generation, it is used to produce hydrogen to meet the AFV electricity demand. Consequently, this scenario achieves a 50% share of RE at 2060, higher than the minimum 30% stipulated by the model.

Also shown in Figure 4-7 is excess generation that occurs in both the BEV-N and BEV-B scenarios. The term excess generation is used here electricity generation in excess of total demand. In reality excess generation would need to either be sold or curtailed.

However, management of excess generation falls outside the scope of this study. Excess generation is 3% and 1% of total demand in the BEV-N and BEV-B scenarios, respectively.

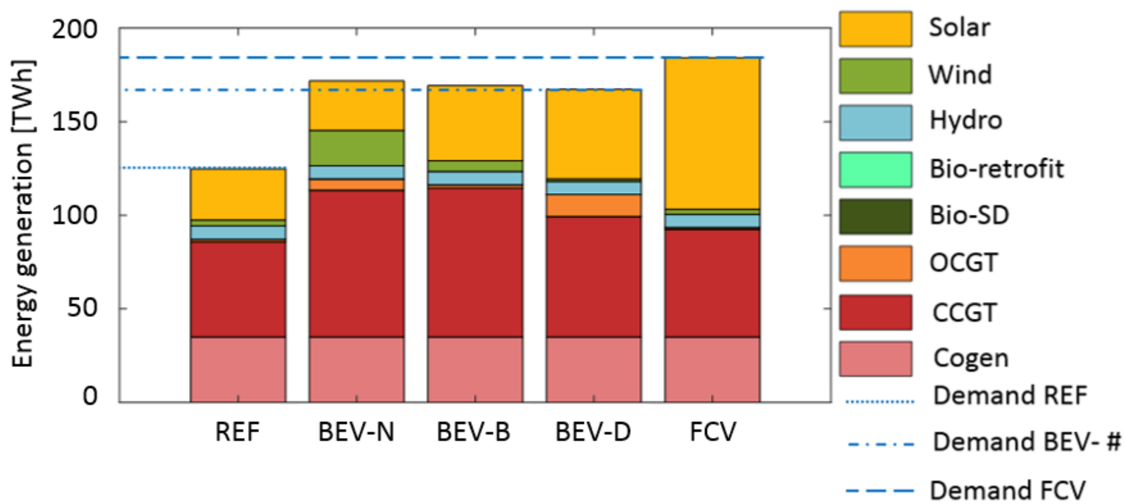

Figure 4-7. Energy mix for the year 2060 for scenarios with imposed AFV market share and no carbon tax.

In the BEV-N scenario, excess generation is associated with high penetrations of VRE and inflexible AFV electricity demand. Charging vehicles at night leads to significant load differences between night and day, as shown in Figure 4-8. This figure shows the demand profile and generation mix for the BEV-N scenario for one of the eight representative days, representing a summer like day. However, similar patterns are observed in the BEV-B scenario, in which excess generation also occurs, although to a lesser extent. It is seen in Figure 4-8 that there is consistent solar insolation from 7:00 to 18:00 and strong wind generation throughout the day, which along with generation from cogen and hydro exceed total demand.

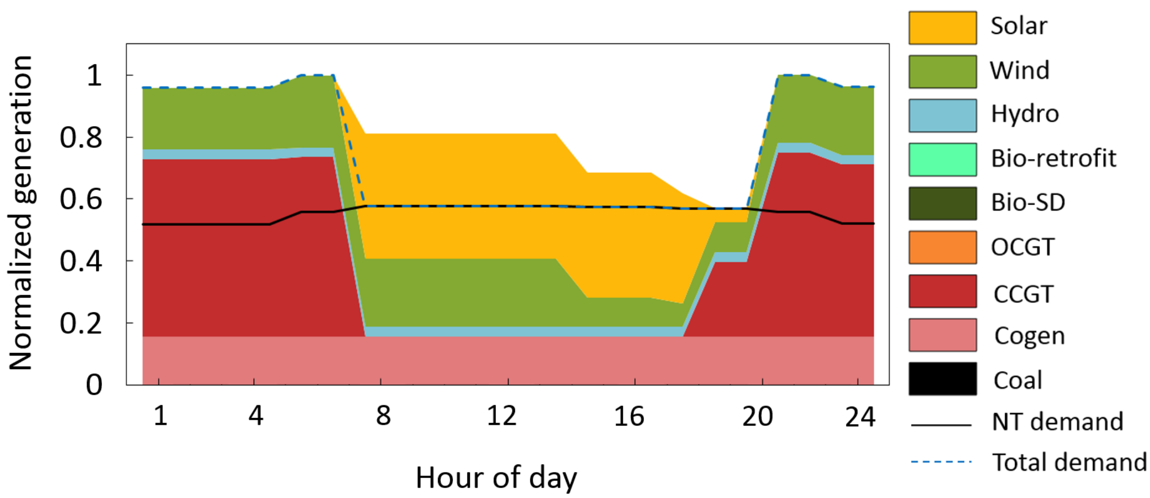

Figure 4-8. Electricity and total demand profile for one representative day in the BEV-N scenario. Values are normalized to peak daily demand. Total demand accounts for the sum of NT electricity and AFV electricity.

Table 4-5 summarizes the emissions and costs for the scenarios shown in Figure 4-7. The BEV-D scenario, the scenario with the lowest emissions, only achieves modest emission reductions relative to the reference scenario. Accumulated emissions are 3.3% lower than the reference case. This modest decrease in emissions are a result of the electricity generation mix remaining dependent on natural gas, as shown in Figure 4-7and discussed above. The FCV scenario achieves the second lowest accumulated emission. Although its annual emissions are the lowest by 2060, the higher demand than the BEV scenarios and late adoption of solar PV (not shown) lead to higher accumulated emissions than the BEV-D scenario. The BEV-B scenario achieves the second highest accumulated emissions due to the lower penetration of solar energy, relative to other scenarios, and the increased use of CCGT generation. Lastly, the scenario with the highest accumulated emissions is the BEV-N scenario, as it has more fossil generation than other scenarios due, in part, to AFV electricity demand appearing at night.

Table 4-5. Summary of emissions, system cost and abatement cost for scenarios with 0 $/tCO_2$ carbon tax.

Scenario	REF	BEV-N	BEV-B	BEV-D	FCV
Annual emissions 2060 [MtCO2e]	43	44	42	42	33
Accumulated emissions 2015-2060 [MtCO2e]	2015	2009	1969	1949	1955
System cost [B$]	185.4	194.2	192.4	193.8	188.7
Abatement cost [$/tCO_{2e}$]	-	1399	154	126	55

Also, shown in Table 4-5 are abatement costs, calculated as the quotient of the cost increase, relative to the REF scenario, and the accumulated emission reductions, relative to the REF scenario. All costs are discounted.

The FCV scenario leads to the lowest abatement cost. The emissions for this scenario are comparable to those of the BEV-B and BEV-D scenarios but its lower system cost, due in part to the large share of solar energy, leads to a lower abatement cost. The BEV-B and BEV-D scenarios lead to abatement costs 2.8 and 2.3 times higher than the FCV scenario, respectively. Finally, the BEV-N scenario has the highest abatement cost, over 25 times that of the FCV scenario, due to its high emissions and costs originating from the higher dependency on natural gas generation.

4.4.3. Energy mix and emissions – AFVs – 150 $/tCO_{2e}$ tax

This section presents the results for AFV scenarios with a maximum carbon tax of 150 $/tCO_2$. These results are compared to those of the REF-T scenario, where carbon taxes are also applied, but only fossil fueled transportation is allowed. Figure 4-9 shows that nuclear generation is present in all scenarios. Furthermore, renewable penetration is higher in all scenarios with the 150 $/tCO_2$ tax than in the corresponding scenarios with no tax, shown in Figure 4-7.

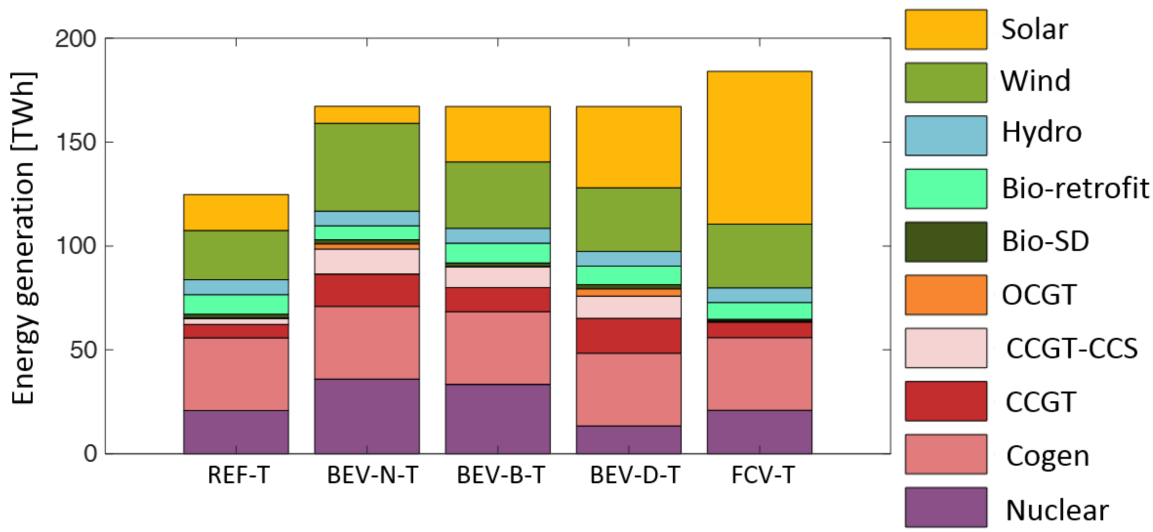

Figure 4-9. Energy mix for the year 2060 for scenarios with imposed AFV market share and carbon taxes of 150 \$/tCO$_2$.

Introduction of the carbon tax has a similar effect in all the analysed scenarios, leading to a greater penetration of renewables and low carbon emitting baseload generators. Comparing the corresponding scenarios in Figure 4-7 and Figure 4-9, the carbon tax makes high cost, low emitting generators like nuclear and CCGT-CCS cost competitive with other generation options. As a result, nuclear power and, to a lesser extent, CCGT-CCS replace CCGT when the carbon tax is applied. Due to high capital cost, these generators provide baseload, operating at or near their maximum capacity factors. Consequently, this switch from CCGT to nuclear and CCGT-CCS provides less flexibility to the system, resulting in some of the solar generation being replaced by wind. Wind power, although costlier than solar, has fewer hours of zero or near zero output, demanding less flexibility from the system.

The FCV-T scenario is the only scenario in Figure 4-9 not to use CCGT-CCS and has the lowest share of gas than any of the AFV scenarios. This is achieved by the flexibility provided by the electrolysers, as hydrogen can be produced to effectively energy for use in the transportation sector. As a result, total renewable penetration achieves 65% by 2060.

Hydrogen production in the FCV scenario occurs primarily during hours of high solar PV generation. Figure 4-10 shows hourly generation for solar PV, wind and hydrogen for the FCV-T scenario for one of the six representative days. Across the 48 timeslices of the year, the correlation coefficients between hydrogen production and wind generation and between hydrogen production and solar generation are 0.42 and 0.97, respectively, indicating that solar energy is primarily used for hydrogen production.

Table 4-6 shows emissions and costs for the REF-T scenario and all AFV scenarios with a maximum carbon tax of 150 $/tCO_2$. Abatement costs are calculated relative to the REF scenario, where no carbon taxes were applied. System cost and abatement cost do not include carbon-tax costs.

Table 4-6. Summary of emissions, system cost and abatement cost for scenarios with 0 $/tCO_2$ carbon tax. System cost and abatement cost exclude carbon cost payments.

Scenario	REF	REF-T	BEV-N-T	BEV-B-T	BEV-D-T	FCV-T
Annual emissions 2060 [MtCO2e]	43	24.8	18.81	15.5	19.73	12.33
Accumulated emissions 2060 [MtCO2e]	2015	1388.7	1271	1198	1259	1154
Cost [B$]	185.4	194.9	205.9	203.8	203.8	198.5
Abatement cost [$/tCO2e]	-	15.2	27.5	22.5	24.4	15.2

Annual emissions are significantly lower in all scenarios, relative to the comparable scenarios with no carbon tax. In the REF-T scenario, emissions decrease by 31% from the REF scenario to, the highest of any scenario witht the carbon tax. The BEV-N-T scenario has the highest emissions of BEV scenarios, mirroring the results of the BEV-N sceaniro. The high emissions are a result of the lower renewable share and higher reliance of gas. The BEV-B-T scenario leads to lower emissions than the BEV-N-T and BEV-D-T scenarios. Even though the renewable share is lower that in the BEV-D-T scenario, this scenario has a large share of nuclear replacing gas, lowering its emissions. The BEV-D-T scenario leads to the second highest emissions, even though it leads to a high renewable share. Its reliance of CCGT and OCGT for backup lead to higher emissions. The FCV-T leads to the lowest emissions as it achieves a high share of solar and wind and a small share of CCGT.

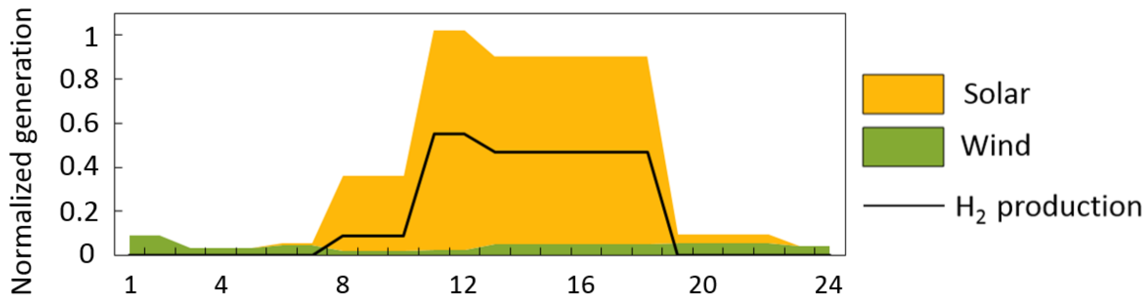

Figure 4-10. VRE production and hydrogen generation for a representative day in the FCV-T scenario. The representative day represents a shoulder season day with sunny afternoon and low wind generation.

Abatement cost are lower in scenarios with carbon taxes, compared to scenarios with no tax, as shown in Table 4-5 and Table 4-6. The REF-T scenario achieves the lowest abatement cost, along with the FCV-T scenario, at 15.2 \$/tCO_{2e}. Althought emissions were the highest for the REF-T scenario, its lower cost leads to a lower abatement cost. The BEV-N-T, BEV-B-T and BEV-D-T all lead to similar abatement costs as costs and emissions are similar for these scenarios, with the BEV-B-T the lowest of the three at 22.5 \$/tCO_{2e}. The BEV-F-T scenario leads to the second lowest abatement cost of all scenarios considered. It is higher than the FCV-T scenario due to BEVs costing more than FCVs and as the emissions are found to be slightly higher. Finally, the FCV-T scenario leads to the lowest abatement cost, along with the REF-T scenario. Its lower emissions and lower cost due to primarily the high share of solar PV, make it the lowest cost option for reducing emissions.

4.5. Discussion

The modelling results show that in the absence of a carbon taxes, scenarios with direct or indirect electrification of HD transportation only lead to modest reductions in emissions. As seen in Figure 4-11, which shows a summary of cost and emissions for all scenarios relative to the reference scenario, in the absence of carbon taxes the best performing scenario only achieves a 3% reduction in cumulative emissions from the reference scenario. These scenarios are represented as non-shaded polygons in Figure 4-11. Although costs are lower in these scenarios when compared to scenarios with carbon taxes, so are the emission reductions, leading to high carbon abatement costs. These modest emission reductions are caused by the buildout of predominantly gas (CCGT) generation to meet this additional electricity demand. These results suggest that even if HD vehicles are electrified, additional policy is still necessary to decrease the carbon intensity of the electricity system to achieve significant emission reductions.

In contrast, scenarios with carbon taxes are more effective at decreasing carbon emissions, leading to lower abatement costs. As seen in Figure 4-11, the scenarios where the carbon tax are applied, all achieve significant carbon emission reductions, even if transportation is not electrified. The REF-T scenario, achieves significantly higher carbon emission reductions than any of the scenarios where the HD transportation sector is electrified but carbon taxes are not applied.

Transition to hydrogen FCVs, rather than BEVs, leads to lower carbon abatement cost. Of the scenarios with AFVs and carbon taxes, the FCV-T scenario leads to the lowest system cost and emissions to 2060, as seen in Figure 4-11. This ultimately leads to a lower carbon abatement cost. The lower system cost is achieved due to higher penetration of low cost variable renewables in the electricity system in the FCV-T scenario and to a small extent due to lower vehicle cost for FCVs, compared to BEVs. The lower emissions of the FCV-T are achieved due to the higher penetration of VRE in this scenario when compared to BEV scenarios, even though overall energy demand is higher in the FCV-T scenario.

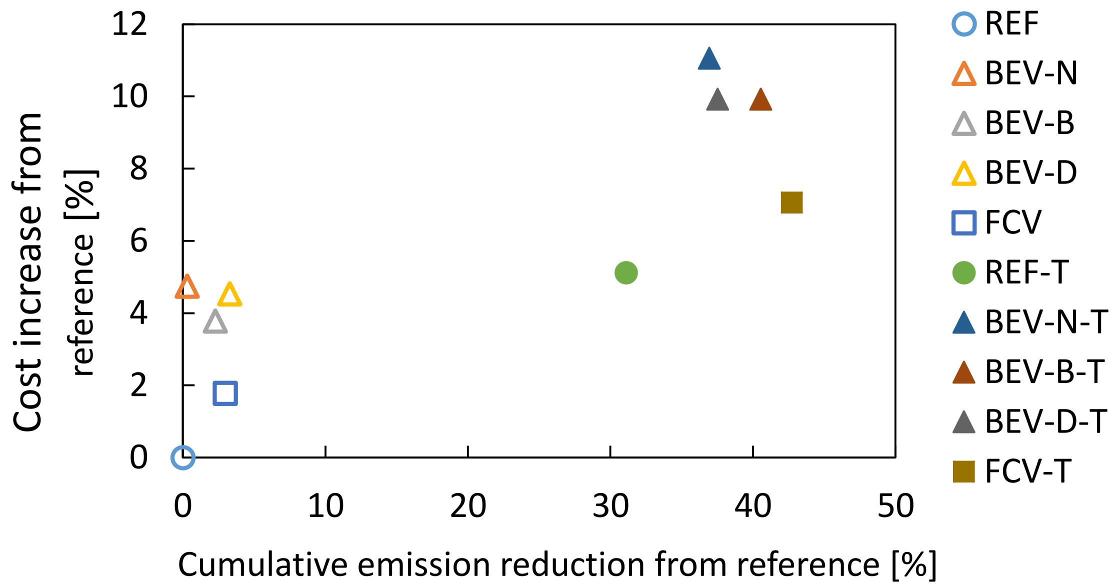

Figure 4-11. Summary of costs and emissions of all studied scenarios. Circles represent use of fossil vehicles only, triangles represent scenarios with BEVs and squares represent scenarios with FCVs. Geometries without shading represent scenarios without carbon taxes, while geometries with shading represent scenarios with a carbon tax escalating to 150 \$/tCO_2.

The flexibility provided by hydrogen storage enables scenario with FCVs to achieve higher VRE penetration than scenarios with BEVs. The FCV-T scenario achieves a VRE penetration of 60% by 2060, significantly higher than the next highest, the BEV-D-T scenario, at 46%. The reason for this higher VRE penetration is the flexibility provided by storage of hydrogen, allowing for seasonal storage of solar energy. Electrolysers have a lower efficiency compared to batteries (147), leading to the higher overall demand in the scenarios with fuel cell vehicles. However, the low rate of self discharge enables seasonal storage of excess solar energy in the form of hydrogen, further enabling higher penetrations of VRE into the electricity system. This decoupling enables a higher buildout of low cost wind and solar generators. These results corroborate the findings of Vandewalle et al and Lyseng et al (42) (148) (73) who argue that power to gas effectively displaces capacity and flexibility needs, accommodating larger shares of VRE.

Flexibility could also be achieved by utility controlled charging of BEVs. Although the results of the current study indicate scenarios with FCVs provide electricity system flexibility, system flexibility through utility controlled charging or smart charging of BEVS has been demonstrated to enable higher penetration of VREs and decrease capacity needs by Wolinetz et al and Madzharov et al (42) (50). However, these studies focus on passenger vehicles and do not capture seasonal energy storage. The HD freight sector may be less prone to adopt these techniques due to requirements of the industrial sector such as scheduling and vehicle availability.

Hydrogen storage costs of up to 4.6 $/kg would make the FCV-T scenario the lowest abatement cost option. The results presented here show that the FCV-T scenario, where a hydrogen storage cost of 2.2 $/kg is assigned, leads to an abatement cost of 15.5.2 $/tCO_2$, the lowest of all scenarios studied. At a costs of 4.6 $/kg, the abatement cost of the FCV-T scenario would reach 22.5 $/tCO_2$, matching the BEV-BT scenario. As a result, if hydrogen storage could be accomplished at a cost of 4.6 $/kg or lower, then use of fuel cell vehicles would likely lead to the lowest carbon abatement cost. However, if hydrogen storage costs were higher than 4.6 $/kg, then BEVs would leads to lower abatement costs. These costs, however, do not account for costs associated with infrastructure such as electricity transmission and distribution costs.

Buildout of nuclear power is present in all scenarios with carbon taxes. Even though buildout of cogen is forced in all scenarios, contributing 20% of the annual energy requirement as baseload, all scenarios further experience buildout of other forms of dispatchable generation. In the case of the FCV-T scenario, where 40% of the annual electricity demand is time independent, nuclear energy is built to meet 11% of the annual energy demand. This results in dispatchable generation contributing to 40% of total demand, with intermittent renewables contributing the remaining 60%. Our results corroborate the findings by Andrees et al who argued that some combination of carbon capture and storage and/or nuclear power will be necessary in the future to aid decarbonisation of the transportation and electricity sectors (149). These results, however, are in contrast with Jacobson et al who found in 2015 that the United States could meet 88% of its electricity demand relying on a mixture of wind and PV solar, with a modest amount of concentrated solar power for storage (150).

4.5.1. Study limitations

Although the model used in the current study provides insights into the transpiration and electricity system, a number of shortcomings are present.

The model does not account for ramping constraints. Due to the use of representative days subdivided into representative hours, it would be difficult to implement ramping constraints for thermal electricity generators. As a result, the flexibility of some generators such as CCGT-CCS and biomass may be overestimated and use of peaking generators such as OCGT may be underestimated. Therefore, if ramping constraints were to be implemented, the results shown in Fig.9 would likely have some deviations, with a smaller share of biomass and CCGT-CCS and higher shares of CCGT or OCGT.

In scenarios with a carbon tax, biomass represents an energy share of 4 – 6% while CCGT-CCS achieves a share of 6 - 7 %, depending on the scenario. Further, both generators operate at capacity factors higher than 70% for most of the model run, suggesting that they are not being used for peaking purposes. Other research indicates ramping for CCGT-CCS generators is similar to CCGT units, ranging from 1 - 6 % of load per minute (151). Combined, all these factors suggest that if ramping constraints were to be implemented, the deviations from the results presented here are likely to be small. It is, however, difficult to accurately predict what this deviation would be without a sub-hourly one-year dispatch model.

Battery storage and transport technologies options other than BEVs and FC HDVs such as catenary, induction charging, or rail, are not considered in the current work. While all these options deserve consideration, this study focuses on comparing battery electric and fuel cell vehicles for the heavy-duty transport sector.

4.6. Conclusions

The current study investigates alternative pathways for direct and indirect electrification of the HD transportation sector and the impacts on the electricity sector. A capacity expansion and dispatch model is used to investigate the impact of different alternative fuel vehicles (AFVs) on the electricity sector and estimate cost and emission reductions. Fuel cell and battery electric heavy-duty vehicles are considered with alternative charging cycles.

Scenarios with a AFV market share of 100% penetration by 2040 are used to analyse the impact of these technologies separately.

Results show that switching from conventional vehicles to AFVs without further applying any incentives to decarbonize the electricity system leads to only modest emission reductions. The best performing scenario, making use of FCVs, only achieved a cumulative emissions reduction from 2015 to 2060 of 3% relative to a reference scenario while costs increased by over B$ 3 for the same period. Other scenarios such as charging BEVs at night only led to over-generation at certain times associated with inability to manage excess VRE.

Combination of 150 $/tCO_{2e}$ and FCVs achieves lowest carbon abatement cost of all scenarios. Due to the flexibility offered by electrolysers, the FCT scenario is able to leverage low cost VRE at times of high energy output leading to an increased penetration of renewable energy and lower emission intensity. While using batteries to manage variability was found to lead to similar results in emission reduction, storing excess energy in batteries is shown to cost significantly more than in the form of H_2, leading to higher abatement costs.

Chapter 5

Electrification of road transportation with utility controlled charging: A case study for British Columbia with a 93% renewable electricity target

Preamble

To mitigate emissions from the electricity and transportation sectors, large scale deployment of renewable energy generators and battery electric vehicles are expected in the coming decades. However, adoption of these technologies may exacerbate issues related to mismatch of electricity supply and demand. In this study, we utilize a hybrid capacity expansion and dispatch model to quantify grid impacts of the conversion of the entire road vehicle fleet to electric vehicles by 2050. We examine impacts of policies, such as targeting a renewable energy penetration of 93%, using British Columbia as a case study. Scenarios making use of utility controlled charging of vehicles to balance supply and demand are further analyzed. Results show that although electrifying the entire road vehicle fleet will require generation capacity to increase by up to 60%, relative to a scenario without electrification, levelized cost of electricity only increases by 9% in the same scenario, due to availability of low cost generation options such as wind and solar. We also found that the scenario utilizing a 93% renewable energy target leads to carbon abatement costs 30% lower than a scenario where this policy is removed. Further use of utility controlled charging would also lead to total system capacity needs reduction of up to 7%. However, due to low cost benefit per vehicle and diminishing returns, this scheme is likely to have limited impact.

5.1. Introduction

The electricity and transportation sectors respectively account for 25 and 14% of global anthropogenic emissions as of 2010 (31). As demand in both sectors is expected to continue to grow over the coming decades (152), increased use of low-carbon energy supplies, such as wind and solar PV (photovoltaic), and electric vehicles (BEVs) are necessary to mitigate emissions. At large penetrations, these technologies impact grid operations due to issues such as excess generation (153), lack of flexibility (154), and increased localized peak demands due to coincident vehicle charging (51). As a result, there is a need to understand how simultaneous integration of variable renewable energy (VRE) supplies and BEV vehicles may affect electrical system structure and costs.

Globally, the electricity sector has made significant progress in implementing renewable energy, with its generation growing more than 30% in the last five years (155), however this may generate load balancing issues (154). Renewable energy generation in the U.S.A. increased nearly 50% over the last 5 years and forecasts suggest strong growth to 2050 (156). As described elsewhere, high penetrations of renewable supplies can be challenging due to the need for additional system flexibility (157) and mechanisms such as storage to ensure load-balancing (153) . Curtailment of total wind generation grew from virtually zero in 2007 to 2 – 4% by 2013 in U.S. jurisdictions (158) and British Columbia (BC) experienced a 1.5 TWh increase in surplus energy from 2006 to 2016 as a result of increased run-of-the-river capacity (159).

Excess electricity supply may at times lead to financial loss to the electricity system operator or to generator owners (153). Although VRE generators typically decrease system cost as they may replace fuel based generation at zero marginal cost, when energy is curtailed a financial loss is incurred by the generator owner as fixed and capital costs are amortized over a lower amount of generation (153). From the perspective of the system operator, if the electricity is “must take” it may require system operators to sell it at times of low or negative values. This has been observed in the Mid-C market where negative prices associated with excess wind generation have been realized during the freshet season in recent years (159). Alternatively, contractual obligations may require the system operator to pay generators to curtail energy, as exemplified in Germany, where in 2015 wind generators were paid an average of €53/MWh to curtail their generation (153). These factors highlight the need for careful planning of electricity system evolution to manage future increases in renewable penetration.

Flexibility requirements for electricity systems are being challenged by more than the addition of VRE generators; new demands are expected due to the conversion of internal combustion engine (ICE) vehicles to BEVs. BEV sales increased by 70% from 2014 to 2015, followed by an additional 40% growth from 2015 to 2016, at which point the global EV stock reached 2 million vehicles (155). With decreasing battery costs and recent announcements made by several jurisdictions such as France, U.K. (160) and B.C., where targets have been put in place to phase out ICE vehicles before mid-century (161), the demand for BEVs is expected to experience strong growth in coming decades. As a result, careful system planning is necessary to balance future supply and demand.

Numerous studies have been carried out in recent years to determine the impact that electrification of the transportation sector may have on the electricity system. Madzhrov et al use a unit commitment model to study a hypothetical country with a generic energy mix and the European average number of vehicles per capita (50). The authors demonstrate that this system would only be able to serve up to a 10% penetration of passenger EVs with decentralized charging and no capacity expansion. Kelly et al developed a model to simulate fleet average electricity consumption based on driving pattern data (162). The authors found that for the hypothetical case where 50% of the passenger vehicle sector is converted to plug-in hybrid electric vehicles (PHEVs), peak electricity demands could increase by as much 12%, in the worst case. Rosler et al conducted a long term optimization study of the European system focusing on electrification of the transport sector through use of battery electric or fuel cell technology (163). The authors found that in the scenario where BEVs have fully replaced conventional passenger vehicles by mid century, the electricity production in 2060 is over 50% higher than it was in 2010. Graabak et al studied the adoption of 100% electrified passenger transportation in the Nordic system by 2050 (164). The authors found that energy demand increases by 7.5% as a result of electrification. Further, uncontrolled "dumb" charging leads to load increase during periods of peak energy demand such as early morning or evening peaks. Schill et al studied the grid impacts of converting over 10% of the passenger vehicle sector to battery electric in Germany by 2030 (165). Even though demand from electric vehicles only represents 1.5%

of total electricity demand, peak load increases by up to 5.5%. The authors concluded that while energy requirements from electrifications of vehicles is not a concern over the short term, the impact on peak loads should be considered closely by policy makers.

Utility controlled charging (UCC) has been suggested as a method to manage the intermittency of VREs, lessen the effects of the peak demands issues mentioned above and to enable larger shares of vehicle electrification. UCC allows for the utility to control how much energy is fed into an electric vehicle that is connected to the grid at a given time, allowing it to displace part of or the entirety of its demand by a number of hours.

A number of studies have evaluated the impact that employing UCC on the passenger vehicle segment may have on the electricity system. Li et al used an hourly multi region unit commitment model of China in the year 2030 to evaluate how the use of UCC may impact the electricity system with a 30% penetration of battery electric vehicles in the passenger vehicle sector (166). The authors found that employing UCC leads to higher emissions than scenarios with static charging as demand is shifted to hours when low marginal cost, high emitting technologies, i.e. coal, are the marginal generators. Similar results were found by Hedegaard et al, who modelled the Northern European system to 2030, with the passenger vehicle sector achieving a 53% penetration of BEVs by the end of the model period (167). Vehicles were assumed to be able to meet peak demand and employ UCC or “smart charging”, allowing their demand to be time shifted. The results showed that in some jurisdictions, use of UCC leads to increased wind penetration, while in others, such as Germany and Denmark, use of UCC leads to higher usage of coal generation. Prebeg et al conducted long term optimization of the Croatian energy system to 2050 with 100% penetration of battery electric or plug-in hybrid vehicles (168). In the study, a maximum of 25% of the vehicle fleet is committed to vehicle to grid applications at any one point it time. The authors found that shifting vehicle demand to the night time, when demand is lower, can keep peak demands from increasing, leading to overall cost savings. Weis et al studied the impact of UCC given a 10% penetration of plug-in hybrid electric vehicles (PHEV) in the NYISO system (41). The authors found a 54 – 73% PHEV integration cost reduction by making use of UCC. Lyon et al, studied the impact of demand shifting of PHEVs on the MISO and PJM independent system with a 60% penetration of BEVs in the passenger vehicle sector (40). Although the use of UCC led to billions in savings, this represented less than a 1% reduction from a scenario employing uncontrolled charging. Wolinetz et al studied the impact of adoption of utility controlled charging on varying portion of the passenger vehicle fleet in British Columbia and Alberta, Canada (42). They found that UCC could lead to a capacity requirement reduction of up to 8% compared to a scenario where UCC was not used. Further, UCC was found to modestly reduce wholesale electricity prices (0.7%). These studies show the restricted extent to which UCC can make a contribution to lowering the cost of integration of BEVs with the electricity system; however, they only consider the passenger vehicle segment and partial electrification of the fleet. The implications of broader transport electrification that includes freight and transit - often representing a larger portion of the transportation sector energy demand – have not been examined thoroughly. To the knowledge of the authors, only Taljegard et al have attempted to quantify the combined effect of widespread electrification of passenger vehicles and freight recently (43). The authors evaluated the electricity system impact of electrification of the road transportation fleet in Northern Europe and Germany, including passenger vehicles and the freight sector. Although the study provided valuable insight into system expansion needs, the authors did not quantify UCC cost benefits per vehicle and did not employ varying penetration levels of UCC.

Here, we study the impacts on the electricity system of electrification of the entire road vehicle fleet, including passenger vehicles, light, medium and heavy duty freight and transit. A bottom-up linear programing model is used to determine the optimal generation capacity and dispatch to meet an exogenous demand. As a case study, the province of B.C. is considered due to its high share of freight in comparison to passenger vehicles, its aggressive targets for electrification of transportation, and existing low-carbon generation mixture. Scenarios evaluate varying adoption levels of UCC and the impact of enforcing a renewable portfolio standard aiming to achieve a 93% renewable penetration. Further, the value of UCC per vehicle-year is further quantified.

Methods are described in section 5.2. Section 5.3 provides data on costs and other parameters used in the model. Section 5.4 details the results, followed by a discussion in section 5.5. Finally, section 5.6 provides the conclusions.

5.2. Methods

Section 5.2.1 provides an overview of the modelling approach. Section 5.2.2 provides details on model platform, technology assumptions, and temporal structure. Section 5.2.3 provides details on transportation forecast.

5.2.1 Model overview

A linear programing optimization tool is used to compare pathways for the electricity and transportation sectors. As a case study, the B.C. system is modelled. Although the B.C. system has connections to Alberta and to the United States, in this work it is modelled as an isolated system for simplicity. The model period analyzed spans from 2015 to 2055, meeting demands for conventional electricity and electricity for BEVs.

As shown in Figure 5-1, demands are met by generators, which in turn consume resources to operate. Conventional electricity demand and transportation demand are exogenously defined by annual quantity and their temporal profiles. Technologies are defined by capital cost, fixed and variable costs (FOM & VOM), resource consumption rate (efficiency), lifetime and production profile in the case of variable renewable energy (VRE) generators such as wind and solar. Resources are also assigned a cost and may further be defined by a finite annual or model period maximum availability.

Each year is further subdivided into representative days with representative hours to capture seasonal and daily variability of demand and renewable output. More detailed information is given in section 5.2.3.

System optimization is performed using the Open Source Energy Modelling System (OSeMOSYS) (64) (99). OSeMOSYS is a linear programing tool used for capacity expansion and dispatch of energy systems. It has been used in a variety of studies ranging from expansion of hydroelectric systems in Bolivia (66), flexibility requirements to meet high levels of VRE in Ireland (72), and adoption of biomass retrofitted units to replace stranded coal assets in Alberta (127). Equations 1 and 2 describe the key mathematical formulations of the model. Shown in equation 1 is the objective function of the model, which minimizes total discounted cost over the model period. Equation 2 ensures that production of each fuel must be greater or equal to its demand plus its use in any intermediate process.

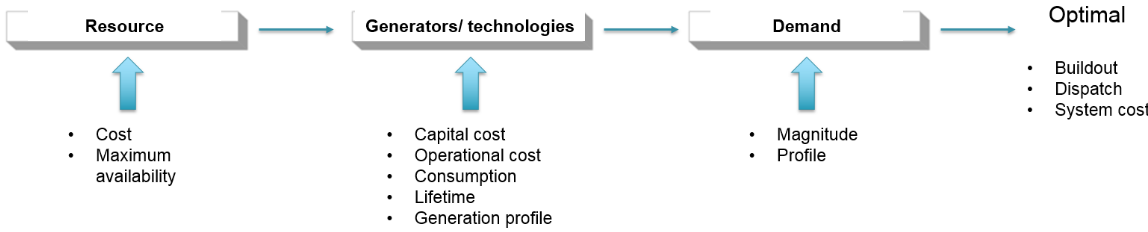

Figure 5-1. Schematic representation of the model. Exogenous demands are met by generators that incur capital, operational and fuel (when applicable) costs. Model calculates optimal capacity mix and dispatch that leads to lowest system cost.

$$Minimize \sum_{y,t,r} CC_{y,t,r} + OC_{y,t,r} + EC_{y,t,r} - SV_{y,t,r} \tag{1}$$

$$\forall_{y,l,f,r}, \quad Production_{y,l,f,r} \geq Demand_{y,l,f,r} + Use_{y,l,f,r} \tag{2}$$

Where CC stands for capital investment costs, OC represents operational costs (fixed and variable), EC stands for emissions costs, and SV is the salvage value of remaining technologies at the end of the model period. $Production$ stands for the production of a particular fuel type, $Demand$ stands for the demand of a fuel type and Use refers to intermediate use of fuels as input for other processes. The subscripts y, t, r, l, f represent year, technology, region, time step, and fuel, respectively.

The model is also subject to numerous constraints to ensure that enough capacity is built to meet demand and a reserve margin, that technology capacity limits are not violated, and that carbon emissions limits are enforced, when applicable, among others. A thorough description and full mathematical formulation of the model can be found in (64). Changes in transmission and distribution capacity are not considered, in the current version.

5.2.2. Technology options

Available technologies fall into two categories: electricity generators and vehicles. Electricity generators are the technology options that meet the electricity demand, as shown in Figure 5-2.

Hydroelectric generators are subdivided into storage hydroelectric (hydro) and run-of-the-river (ROR) hydroelectric. A portion of the energy available from storage hydro is considered as "must run", in other words, part of it must operate according to seasonal constraints of water inflow into the system (159), the remaining portion of storage hydro, or flexible hydro, may be dispatched at any point in the year, as long as the total annual energy budget is respected. ROR hydro operates similarly to the must run portion of storage hydro, where minimum generation values are assigned depending on time of the year.

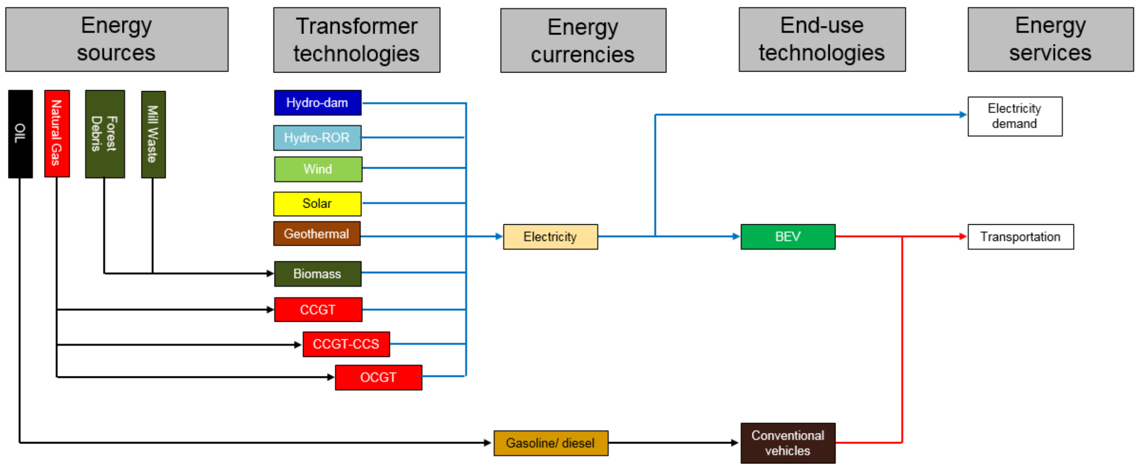

Figure 5-2. Schematic representation of the modeled energy systems including energy sources, technologies, currencies and services.

Additional renewable supplies include wind, solar photovoltaic (PV), and geothermal. Wind and solar have pre-specified generation profiles representing regional resources in BC Wind is separated into three regions, the Peace region, the North Coast (NC) region and the Kelly Nicola (KN) region (169). Profiles for the three wind regions are based on the CanWEA study on wind integration in Canada, 35% TRGT scenario, actual data, where the largest site, by capacity, in each region is selected (170). The solar generation profile is based on data from PV Watts, for the Cranbrook region. Geothermal and biomass are considered dispatchable generators. Generation from wind, solar PV and hydro ROR is considered as "must take". In other words, these three generator types can not curtail generation if the energy is not required at a given time step; however, no monetary penalty is applied to excess electricity generation.

Thermal generation options include open cycle gas turbines (CCGT), combined cycle gas turbines (CCGT) and combined cycle gas turbines with carbon capture and storage (CCGT-CCS). All three generator types consume the same fuel – natural gas. OCGT has a lower capital cost and lower efficiency, used for peaking demand, while CCGT is commonly used at higher capacity factors. CCGT-CCS is similar to CCGT; however, its capital cost is higher and efficiency is lower, with the benefit of a 90% reduction to its carbon intensity.

Some electricity generators can satisfy reserve margin requirements. In addition to the electricity demand, a capacity reserve constraint is also present to ensure firm resource adequacy requirements are met. A reserve margin of 14% of peak annual demand is required, in accordance with B.C. Hydro's IRP (171). Storage hydro, geothermal, biomass and thermal generators may contribute 100% of their capacity to the reserve margin. Wind contributes 26% of its capacity to the reserve margin, while ROR hydro only contributes 10% of its capacity, equivalent to its lowest annual generation divided by its capacity, in accordance with BC hydro's IRP (169). Solar PV cannot contribute to the reserve margin. All generators are further assigned a lifetime, a fuel consumption rate, maximum annual output, and when applicable, a CO_2 emission rate. Values are provided Values are provided in section 5.3.

Vehicle demand is divided into five sub-sectors: heavy-freight, medium-freight, light-freight, passenger vehicles and transit. Each vehicle type is prescribed a demand, fuel consumption rate and lifetime. Capital costs for vehicles are not considered; however, fuel consumption for vehicles is accounted for. Each vehicle type is assumed to have a battery electric counterpart. This allows for a comparison of variable costs for transportation with and without electrification. Fuel consumption for all vehicle types is provided in section 5.3.

5.2.3. Temporal structure

The model period spans from 2015 to 2055. A clustering algorithm is used to reduce computational effort while maintaining temporal accuracy. The temporal clustering method is based on the work by Namacher et al (128) and similar to that employed by Palmer-Wilson et al (172) and Keller et al (173). Clustering analysis using BC profiles for generation and load results in ten representative days per year. Each representative day clusters together days with similar demand profiles, wind capacity factors, and solar capacity factors. Each day is subdivided into 8 representative hours. Electricity demand

and wind and solar capacity factor per region is assigned for each representative hour based on historical values for the province.

To capture minimum generation requirements of storage hydro, representative days are assigned from one of three “seasons”. Each model year is comprised of four days from the “off-freshet” season (August to April), three days from the “mid-freshet” season (May and July) and three days from the “peak-freshet” season (June). Additional information on temporal structure can be found in supplemental material.

5.2.4. Transportation demand

The forecast for transport electricity demand in terms of annual energy requirement by sub-sector is shown in Figure 5-3. Conventional electricity demand projection (Elec) is shown in blue (excludes transportation), HD stands for heavy-freight, MD stands for medium-freight, LD is light-freight, passenger refers to personal use vehicles and transit includes buses, trains or any other type of government operated transportation. The forecast excludes air transport and marine transport; which represent a small portion of transportation demand in the province. Transportation demand forecast is based on exponential regression of the past 20 years of demand for each sub-sector, based on data from NRCan (174). Vehicle energy consumption data is provided in section 5.3.

In scenarios with electrification of vehicles, it is assumed that 100% of new vehicles entering the stock are electric by 2040, in accordance with recent announcements made by U.K., France and British Columbia (161). This transition of new vehicles from conventional to electric is assumed to increase linearly from zero starting in 2030. Vehicles are assumed to have a 10-year lifetime such the total stock is fully electrified by 2050.

Charging profiles are uncertain and a subject of research. As no data for charging profiles is currently available for BC, charging profiles are modelled in accordance with previous studies. Demand for passenger vehicles is akin to residential charging, as demonstrated by Lojowska et al (175) and Schey et al (176). Commercial use vehicles have been found to have similar charging profiles to personal use vehicles, although demand peaks were found to occur slightly earlier in the day (177). However, a worst case scenario is taken here, where charging for personal vehicles and commercial use vehicles is coincident. Demand for Freight-heavy and transit fleets are assumed to be distributed uniformly throughout a day thereby appearing as a baseload, consistent with Keller et al (173). Due to limited data on the charging profile for transit, it is assumed to have an identical profile to HD-freight. Further, individual vehicles are not explicitly modelled. Rather, a fleet-average demand is imposed, as shown in Figure 5-4.

An alternative charging profile is examined by defining a daily profile representing a utility controlled charging scenario (UCC). The UCC profile is described in Section 5.3.7.

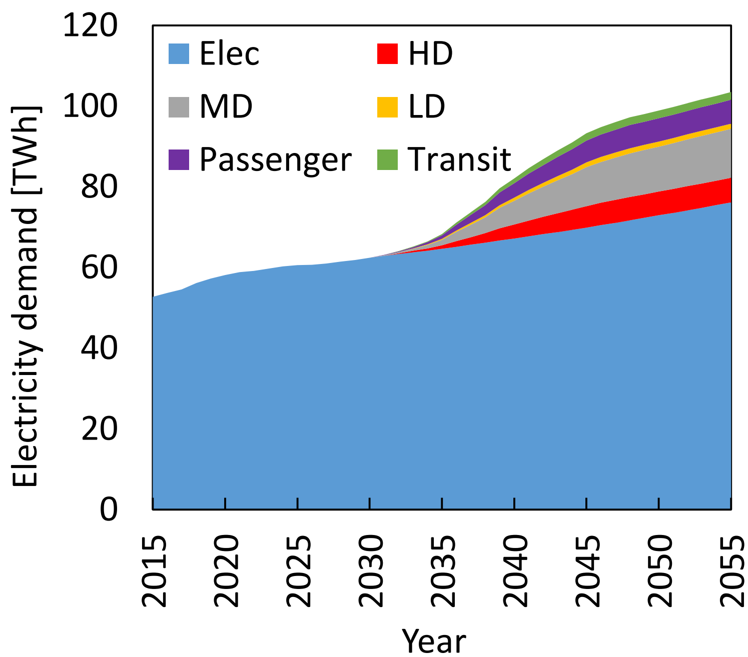

Figure 5-3. Electricity forecast including conventional demand and vehicle electrification. Vehicle stock is assumed to be fully electric by 2050.

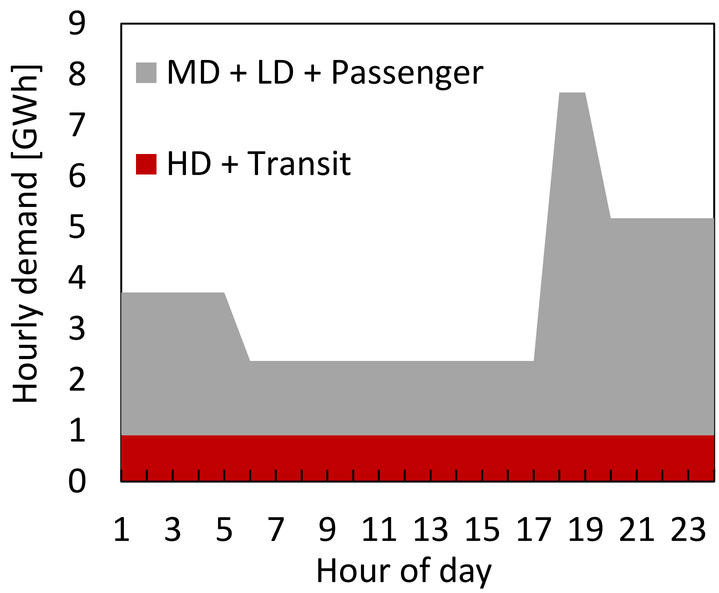

Figure 5-4. Example of the baseline charging profile for vehicles for a given model day for the year 2055.

5.3. Data

In this section, input data for costs, efficiencies and lifetime of electricity generators is presented. As costs for vehicles are not accounted for, only their energy consumption is considered.

5.3.1. Electricity demand

Total electricity demand is subdivided into transportation and standard (or conventional) electricity demand. Transportation demand is described above in section 5.2.4. Standard electricity demand is based on BC Hydro's "Electric Load Forecast, 2012, Reference scenario" (178). As demand growth from 2012 to 2018 has been slower than forecasted, a factor of ¾ is applied to match realized demand growth. The demand forecast also includes a component representing electrification of vehicles which is removed to avoid double counting.

5.3.2. Technologies

Cost, lifetime and heat rate of electricity generators is primarily based on the U.S. Energy Information Administration (EIA) - Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2018, unless otherwise stated (179).

As wind generation costs are dependant on region, wind costs are based on regionally specific estimates provided by BC Hydro (169), but updated to reflect recent cost reductions. The three lowest cost wind regions from the report are used: Peace, North Coast and Kelly Nicola. The Peace region is further divided into three parts, a low cost, medium cost and high cost portion. The North Coast regions is divided into a low cost and a high cost portion. Capital cost is calculated based on the report's unit energy cost and the capacity factor per region, as described in section 5.2.2. Further, a learning rate is applied to capital costs of wind generators decreasing linearly to 2055, consistent with the work of English et al (99). Solar generators are subject to learning rates consistent with Keller et al (173). Capital costs in 2015 and 2055, efficiency, and lifetimes are listed in Table 5-1. Further information on the temporal structure of wind can be found in supplemental material. Solar temporal data is described in section 5.2.2

Table 5-1. Summary of costs and generator assumptions by type.

Technology	Capital cost 2015 [$/kW]	Capital cost 2055 [$/kW]	FOM [$/kW-yr]	VOM [$/MWh]	Heat rate [Btu/kWh]	Lifetime [yr]
Hydro*	2898	2898	13.42	5.95	-	80
CCGT	982	982	11.11	3.54	6,300	30
CCGT-CCS	2175	2175	33.21	7.08	7,525	30
OCGT	680	680	6.87	10.81	9,800	30
Biomass	3584	3584	112.15	5.58	13,500	20
Geothermal	5492	5492	119.87			40
Wind – Peace, High	4610	4385	47.47	-	-	25
Wind – Peace, Med	2590	2463	47.47	-	-	25
Wind – Peace, Low	1900	1807	47.47	-	-	25
Wind – NC, High	5300	5041	47.47	-	-	25
Wind – NC, Low	3100	2948	47.47	-	-	25
Wind - KN	2220	2111	47.47	-	-	25
Solar	2004	848	22.02	-	-	25

* Hydro values apply to both storage hydro and ROR hydro. Based on (173).

5.3.3. Vehicles

Vehicle fuel consumption is based on demand by sub-sector (section 5.2.4) and fuel consumption by vehicle type. Fuel consumption by vehicle type is based on Natural Resources Canada's Comprehensive Energy Use Database (174). As Natural Resources Canada does not provide an energy consumption forecast, fuel efficiency gains are based on the same rate as EIA's Annual Energy Outlook 2018 (180). Vehicle fuel consumption per kilometer for fossil fuel technologies is summarized in Table 5-2. Vehicle efficiency is assumed constant past 2030.

It is important to note that there are two technology options for passenger vehicles; passenger cars and passenger trucks. To keep the model from selecting only the most efficient type, a minimum annual market share of 44% for passenger trucks is enforced, reflecting current shares (174). Similarly, annual market shares of 41% and 59% for medium-freight gasoline and medium-freight diesel is enforced, respectively, in accordance with the current stock mix.

Table 5-2. Fuel consumption data for all fossil based transportation technologies.

Fossil Technology	Fuel consumption (GJ/thousand-km)	
	2015	2030
Passenger car	2.8	2.0
Passenger trucks	3.9	2.7
Light-freight	4.0	3.7
Medium-freight diesel	8.6	7.8
Medium-freight gasoline	7.9	7.4
Heavy-freight diesel	16.1	10.7
Heavy-freight natural gas	7.6	13.0
Transit	6.1	4.4

Energy consumption for BEVs is based on the Argonne National Laboratory's GREET model (181), and summarized in Table 6, "Car – EV conventional weight" values are used for passenger cars. Values for "electric SUV" are used for passenger trucks and light-freight, as these two sub-sectors are not available in the model. "Refuse truck" values are used for medium-freight. Transit is taken as an average between light-freight and medium-freight. Heavy-freight BEV and heavy-freight fuel cell values are taken from ICCT (35).

Table 5-3. Fuel consumption data for all electric based transportation technologies.

Alternative Technology	Energy consumption (kWh/km)	
	2015	2030
Passenger car	0.23	0.18
Passenger trucks	0.3	0.24
Light-freight	0.3	0.24
Medium-freight	1.22	0.98
Heavy-freight BEV	2.93	2.13
Heavy-freight fuel cell	2.64	2.07
Transit	0.76	0.61

5.3.4. Fuel costs

All fuel costs are based on the EIA AEO 2017 (132). Fuel costs for OCGT, CCGT and CCGT-CCS are taken from EIA AEO's electricity generators for Pacific region. Gasoline, diesel and compressed natural gas for transportation costs are taken from the EIA AEO data for transportation for the same region. As the EIA forecast only goes to 2050, data for the last five years is extrapolated assuming a constant growth rate equal to the average of the prior ten years. Additional information on fuel costs is available on supplemental material.

5.3.5. Residual capacity

The model residual capacity entails the current capacity of electricity generators by type and their respective expected decommissioning dates. Storage hydro and ROR hydro have decommissioning dates past 2055, hence the initial capacity remains for the entire model period (99). Wind capacity is based on (99) and assumed to be located at the peace region. All initial 630 MW of capacity are present in the system until 2032, at which point generators start being decommissioned with current capacity fully retired by 2040. Current biomass capacity decreases from 500 MW in 2015 to 40 MW by 2030 and is fully retired by 2045. CCGT capacity decreases from 500 MW in 2015 to 88 MW in 2033, later decreasing to zero by 2045, based on commissioning dates of the four existing generators and an expected lifetime of 30 years (99) (182) (183).

5.3.6. Capacity constraints

All modelled technologies are allowed to expand their capacity to meet increasing demand and to replace existing capacity being decommissioned. Capacity for all technologies is restricted to a maximum capacity (MC) and an annual maximum capacity investment (AMCI). MC is the maximum capacity a technology may reach. Gas and solar generators are assigned an unlimited MC. MC for remaining technologies are primarily based on regional limits (171). Storage hydro is enforced an expansion of 1.1 GW, equivalent to a new reservoir currently under construction; however, beyond this, no further expansion of storage hydro is allowed. ROR hydro is allowed to expand from 5.5 GW to a maximum of 6 GW. Geothermal capacity has a maximum MC of 1 GW. Biomass is allowed to expand to a maximum of 1.2 GW. Wind MC is based on regional supply curves and capacity factors (169). The values are available on Table 5-4.

Table 5-4. Maximum capacity limits by wind region

Region	Maximum model capacity (GW)
Wind – Peace, High	Unlimited
Wind – Peace, Med	2.21
Wind – Peace, Low	6.67
Wind – NC, High	0.96
Wind – NC, Low	2.37
Wind - KN	3.33

AMCI is defined as the maximum annual increase in capacity from a given year to the following. Storage and ROR hydro, wind and solar are not constrained by AMCI. Gas, geothermal and biomass generators AMCI are equal to 5% of average annual demand, consistent with Keller et al (127) and Lyseng et at (101).

5.3.7. Scenarios

A reference scenario along with an additional three scenarios are modelled, as seen in Table 5. The reference scenario (REF) assumes no vehicles are electrified, mandates a renewable portfolio standard (RPS) consisting of a minimum 93% share of electricity sourced from renewable sources (184), and a carbon tax of 30 $/tCO_{2e}$ (consistent with current provincial policy.) Two scenarios impose electrification of vehicles in the province, where all road vehicles studied are gradually converted to battery electric, as described in Fig. 3 and in section 5.2.4. In the first electrification scenario (ELE-RPS), the renewable energy mandate is enforced. In the other electrification scenario, (ELE-N) the renewable energy mandate is removed. In both scenarios, BEVs follow the charging profile shown in Fig. 4.

The last scenario, UCC-X, is similar to the ELE-RPS scenario, but with a X% of the medium and light freight and passenger vehicle fleet participating in a UCC scheme. X varies between 10 and 50%. In this scenario, the utility controls the time of day when vehicles participating in the scheme are charged. The daily energy demand by sub-sector type is identical to the ELE-RPS scenario, but the utility may decide the time of day when a percentage of the demand is realized. Heavy duty freight and transit demands remain unchanged for all UCC scenarios, as it is assumed these transportation methods operate under strict schedules.

Table 5-5. Summary of modelled scenarios.

Scenario	Description
REF	Vehicles remain fossil fuel dependent. Renewable energy requirement enforced.
ELE- RPS	All road vehicles are gradually electrified. Charging profile for all vehicles is fixed. Renewable energy requirement enforced.
ELE-N	Similar to ELE-RPS, but renewable energy mandate is removed.
UCC-X	Similar to ELE-RPS, but X% of vehicles adopt UCC. X varies from 10 – 50%

5.4. Results

Scenarios are compared based on generation capacity buildout, energy mix, share of emissions to 2055, cost, magnitude of excess supply and its temporal characteristics. The REF scenario is presented, followed by vehicle electrification (with and without renewable mandate), and, finally, utility controlled charging.

5.4.1. Reference scenario

Capacity and generation

Reference scenario results (no vehicle electrification) for system expansion (capacity) and dispatch (energy) are shown in Figure 5-5. From 2015 to 2055, the system remains dependent on hydroelectricity due to its low cost and flexibility. Storage hydro is expanded by 1.1 GW in the 2020s, providing an additional 5 TWh of energy annually. ROR hydro expands by 0.5 GWs in the 2020s, but due to its low capacity factor, only adds 0.7 TWh of annual energy generation. CCGT generation is expanded due to low cost and flexibility, but remains limited as a result of RPS requirements. OCGT capacity is expanded from zero in 2015 to 1.7 GW in 2055 primarily for system reliability, with a capacity factor of just 0.5 % in the last 10 years of the model period. Combined, OCGT and CCGT reach the RPS limit of 7% of energy every year after 2033.

Geothermal capacity reaches 0.7 GW by 2055, which is 0.3 GW less than the capacity limit set exogenously. Although more expensive than wind and solar on a levelized cost of energy basis, geothermal is built due to its dispatchability and because it is able to contribute 100% of its capacity to the reserve margin requirement. Biomass capacity is eventually retired past the mid 2030s whereas wind capacity is expanded until the late 2020s due to more favourable costs and to ensure the minimum renewable generation constraint of 93% set by the RPS is met. Starting in the early 2040s, wind capacity is replaced by solar due to decreasing PV system costs. Although wind can contribute a portion of its capacity to the reserve margin, the increasing difference between the capital cost of solar and wind in the last third of the model period makes solar the preferred option.

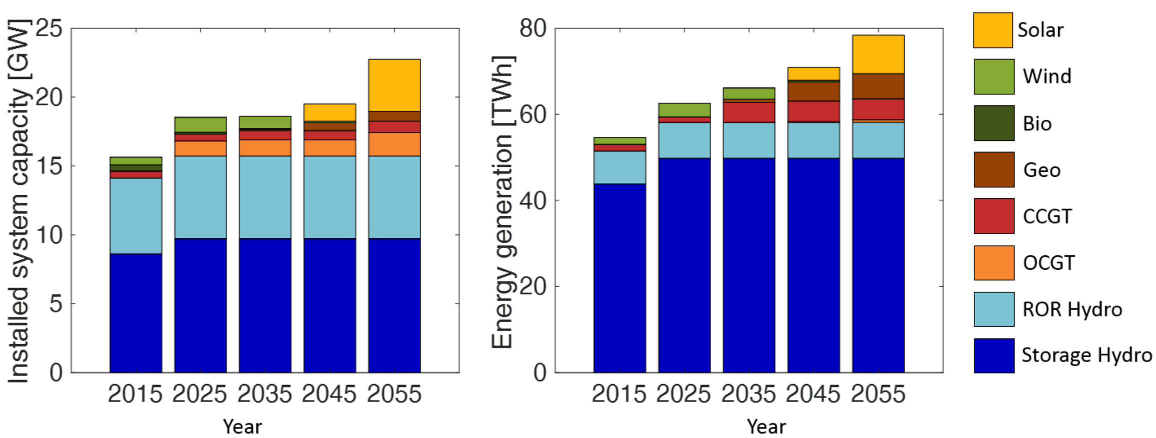

Figure 5-5. Model results for REF scenario installed system capacity mix (left) and energy generation by source (right) for selected years.

Emissions

Total emissions, including electricity and transport, experience a 30% increase from 2015 to 2055, as shown in Figure 5-6. Emissions from the electricity sector quadruple between this period, increasing from 0.5 $MtCO_{2e}$ per year in 2015 to just below 2 $MtCO_{2e}$ by 2055. This increase is due to the fact that currently the system does not reach its maximum allowable share of fossil generation allowed by the RPS (7%) and demand is low. However, increase in demand and flexibility requirements lead to an increase in gas generation.

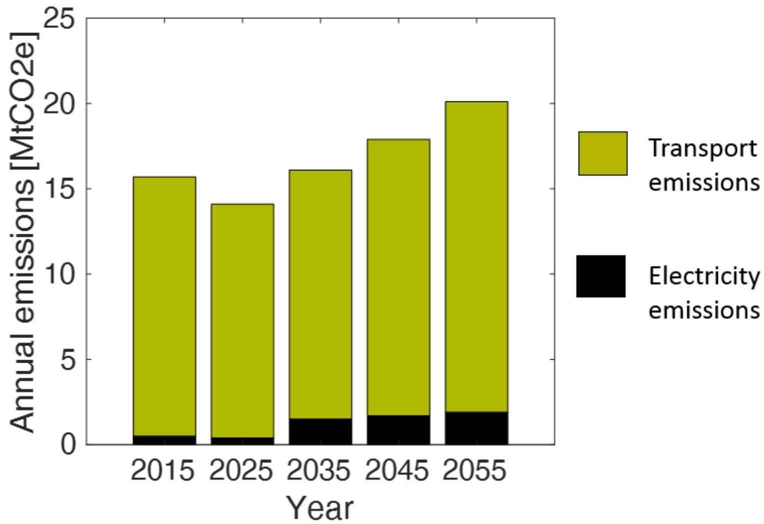

Figure 5-6. Total system emissions for REF scenario including electricity and transport sectors.

Emissions from the transport sector experience a small decrease to the mid 2020s, before monotonically increasing to 2055. Although demand for vehicles increases from 2015 to 2055, expected gains in fuel efficiency lead to modest decreases in transport emissions to the mid 2020s. After this period, vehicle fuel efficiencies increase at a lower rate, and, combined with the increasing transport demand, lead to increase in fuel emissions.

Operation

Excess supply of electricity happens in every year of the REF scenario. As mentioned in section 5.2.2, excess generation from wind, solar PV and hydro is not curtailed. The magnitude of excess supply varies by year, ranging from 0.7 – 3 TWh annually, and is primarily a seasonal phenomenon with roughly 30% of excess supply happening during the peak freshet period (June) and the remaining happening in the mid-freshet period (May and July). Although the magnitude of excess supply remains somewhat constant throughout the model period, typically between 1.7 to 2 TWh per year, the driver behind it changes over time. As shown in Figure 5-7, excess supply happens early in the model period (2015) primarily due to excess supply of ROR hydro generation, minimum generation requirements from storage hydro, and wind contributing to a smaller degree. However, as seen in Figure 5-7 (right), late in the model period (2055) minimum demand has increased, closely matching minimum generation requirements from ROR hydro and storage hydro. At this point, the minimum generation requirements of hydro combined with solar PV generation lead to excess supply during sunny hours of the day.

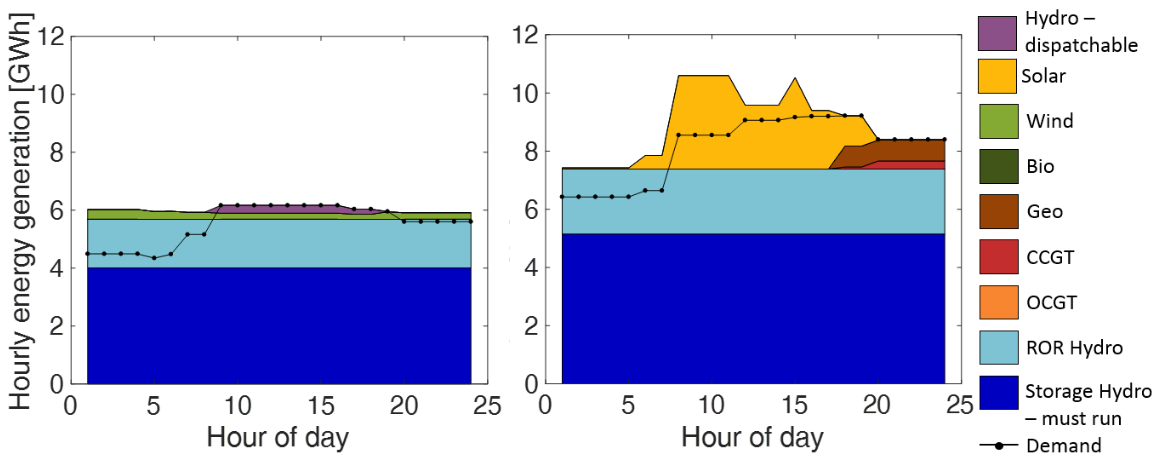

Figure 5-7. Hourly demand (dotted line) and generation results for a mid-freshet day for 2015 (left) and 2055 (right).

5.4.2. Electrification of transport

Capacity and generation

Scenarios for electrification of transportation with (ELE-RPS) and without (ELE-N) a renewable energy requirement are compared to the reference case. The impacts of vehicle electrification on generation capacity in the years 2015 and 2055 are summarized in Figure 5-8. In the reference scenario, with no electrification of vehicles, capacity expands from 15.6 GW in year 2015 to 23 GW - an increase of nearly 50%. This increased demand is associated with population growth and expansion of industry and commerce in the province (178). To meet the RPS requirement, geothermal and solar PV account for 60% of the capacity increase.

Capacity growth is larger for the transport electrification scenarios. In the ELEC-RPS scenario, total installed capacity increases by a factor of 2.35 from 2015 values, or 60% higher than the REF scenario. By 2055 with 100% electric transport, wind capacity reaches 7.5 GW along with 5.5 from solar and 1 GW from geothermal. Combined, the installed capacity of these three generators nearly match the system capacity of 15.6 GW in 2015.

Transport electrification without the RPS requirement (ELE-N) leads to a reduction of nearly 5 GW of installed capacity compared to the ELE-RPS scenario. For ELE-N, wind capacity is zero in 2055 while CCGT capacity has increased. Further, both electrification scenarios show roughly 5 GW of OCGT capacity in 2055. However, as shown in Figure 5-8 (right), OCGT is mainly present to back up solar PV, as capacity factors in both scenarios are close to 3%.

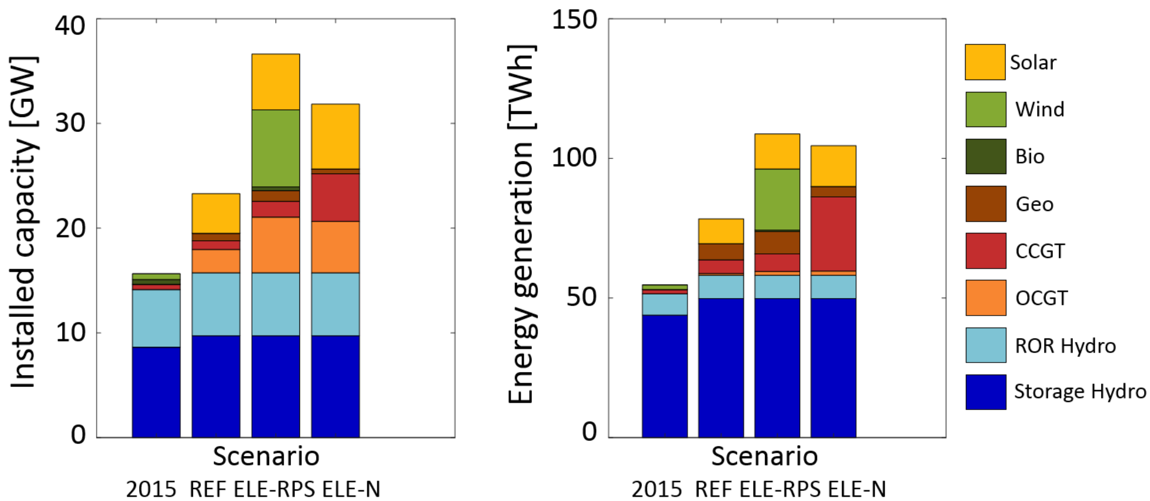

Figure 5-8. Total installed capacity (left) and generation by source (right) for year 2015 and for REF, ELE-RPS and ELE-N scenarios for year 2055.

Costs and emissions

summarizes system cost (present value of total cost) and cumulative emissions for the REF and vehicle electrification scenarios, ELE-RPS and ELE-N. Total system cost increases by 17 and 10% from reference scenario for the ELE-RPS and ELE-N, respectively. However, demand in the scenarios with electrification is 36% higher than in the REF scenario. The unit energy cost (UEC) is defined as the total system cost divided by total electricity generated. Compared to the reference case, UEC increases by 9% in the ELE-RPS scenario and 3% in the ELE-N scenario. Although the increase in electricity cost is lower in the ELE-N scenario than in the ELE-RPS scenario, so is the total emission reduction.

The ELE-RPS scenario achieves a cumulative emission reduction of 260 $MtCO_2$, or a 38% reduction relative to the REF scenario whereas the ELE-N scenario results in a 15% reduction from the REF scenario. Abatement costs are calculated by dividing the increase of total electricity system cost by the emission decrease relative to REF scenario. At 14.1 $/tCO_2$ the ELE-RPS abatement cost is 32% lower than the ELE-N scenario. The system costs represent generation fixed and variable costs only; transmission and distribution or re-charging infrastructure costs are not accounted for.

Table 5-6. Summary of system costs, unit energy costs, emissions, and abatement cost for REF and vehicle electrification scenarios. Abatement costs represent cost increase over REF scenario divided by emission decrease

Scenario	Total electricity system cost [$B]	Unit Energy Cost [$/MWh]	Cumulative Emissions [MTCO2]	Abatement Cost [$/tCO2]
REF	21.9	21.8	691	-
ELE-RPS	25.6	23.7	430	14.1
ELE-N	24.0	22.4	588	20.8

Total combined electricity and transport system cost decreases with electrification of vehicles. Figure 5-9 shows total costs for electricity system and transportation fuels. Although the electricity system cost is found to slightly increase with electrification of vehicles due to the demand growth, this cost increase is offset by the cost reduction associated with phasing out fossil fuels for transport. Model results show that a 17.13 $B and 18.66 $B total cost reduction would be achieved with the ELE-RPS and ELE-N scenarios, respectively, in reference to the REF scenario. However, as mentioned above, this cost reduction does not account for electricity transmission and distribution costs, nor incremental capital costs for electric vehicles.

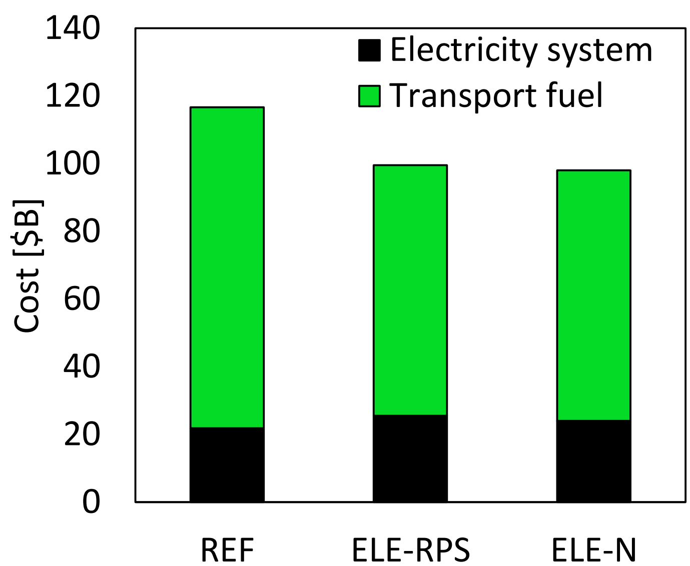

Figure 5-9. Total cost for electricity system and transport fuel (gasoline and diesel) by scenario. Results do not account for electricity transmission and distribution costs.

Operation

One of the consequences of the RPS requirement is that excess energy supply increases by a factor of 2.4 from the REF scenario by 2055. Fig. 10 shows a five year moving average of excess supply over the model period for the same three scenarios. As seen, excess electricity supply remains relatively constant for the REF scenario, varying between 1.7 and 2 TWh per year, as discussed in the previous section. However, in the ELE-RPS scenario, where vehicles are electrified and the renewable standards are kept, excess electricity supply grows quickly in the 2040s, due to mismatch between electricity demand and solar PV generation. As the overall electricity must comply with the minimum 93% renewable standard and renewables generation is considered "must take", excess generation increases. However, in the ELE-N scenario, where electrification of vehicles happens, but the RPS standards are removed, excess generation decreases to zero by the late 2030s due to the increased use of natural gas. Excess generation starts increasing again in the early 2050s due to the increased share of solar PV. In the modelled system, there is no monetary penalty for any excess generation.

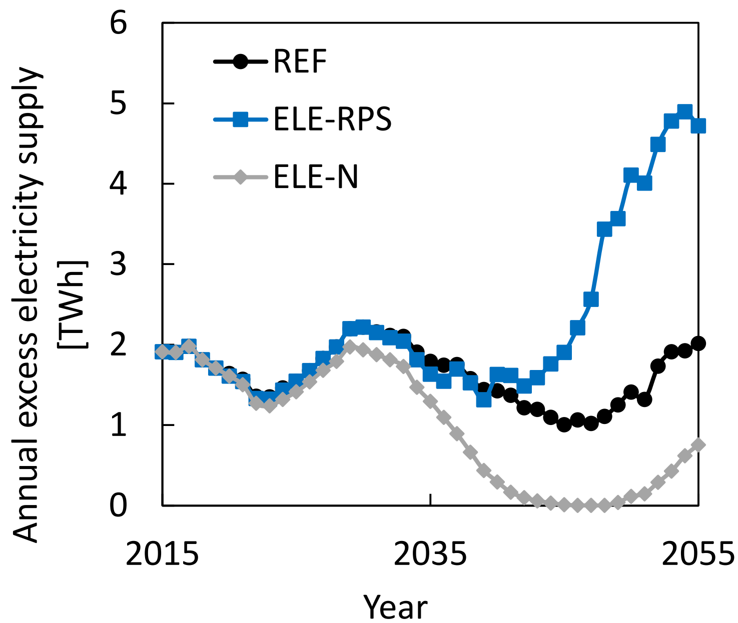

Figure 5-10. Five year moving average of excess energy generation by scenario.

5.4.3. Utility controlled charging

In this section, model results for scenarios employing varying levels of utility-controlled charging (UCC-X) are shown. Results only include scenarios with RPS standards, as scenarios without the RPS were found not to vary significantly with UCC level.

Capacity and generation

Implementation of UCC leads to a decrease in total installed capacity as well changes in the generation mix. Figure 5-11 shows the difference in installed capacity with varying levels of UCC. Positive values represent an increase in installed capacity from the ELE-RPS scenario, while negative values represent a decrease. In the UCC-10 scenario, total capacity decreases by 1 GW, or just less than 3% of the total capacity of the ELE-RPS scenario. In the UCC-50 scenario, total capacity decreases 2.6 GW or just over 7% of the capacity of the ELE-RPS scenario.

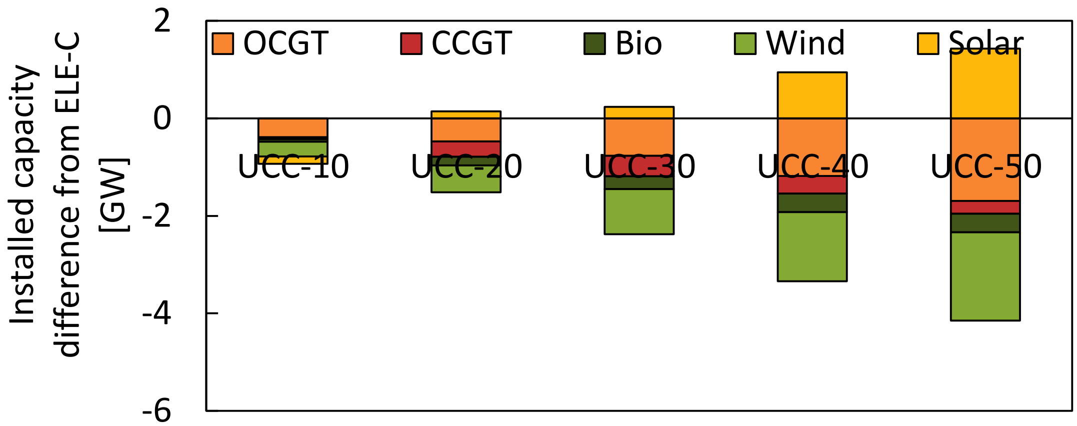

Figure 5-11. Difference in installed capacity, in reference to ELE-RPS scenario, with varying levels of UCC.

UCC does not impact hydro and geothermal capacity, however, other technologies experiences capacity changes. In the UCC-10 scenario, capacity of OCGT, CCGT wind and solar decrease by allocating vehicle charging to times of wind and solar generation, decreasing overall capacity requirements. However, in higher UCC levels, OCGT, CCGT, biomass and wind capacities decrease and are partially replaced by solar PV. This can be attributed to vehicles being charged during the day when low cost solar electricity is available.

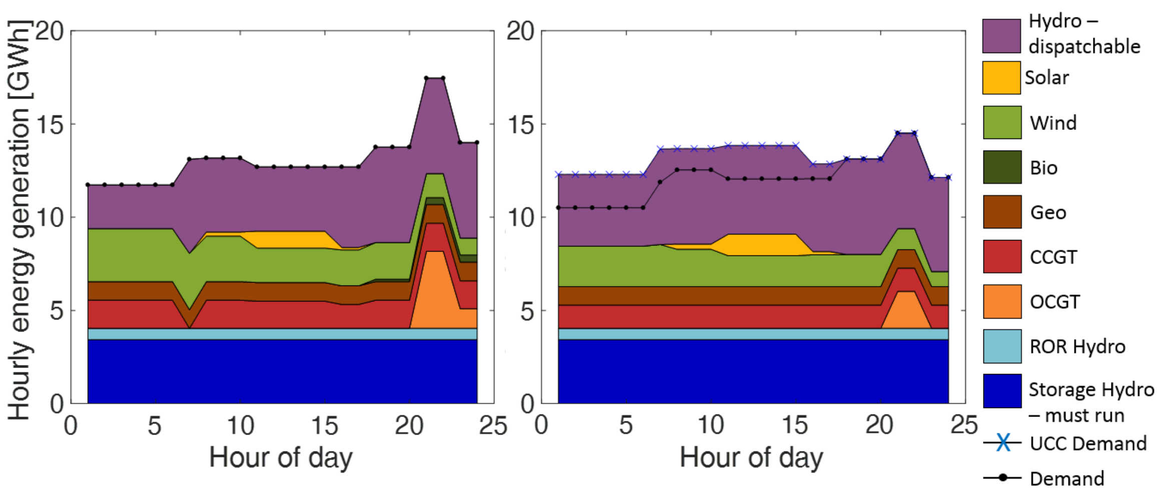

Figure 5-12. Hourly generation for ELE-RPS (left) and UCC-50 (right) scenarios for the same representative day in 2055. Area between line with black dots and line with blue crosses represent shifted demand resulting from UCC.

The decrease in OCGT capacity is due to the beneficial effects of increased penetration of UCC to manage demand during annual peak periods. As shown in Figure 5-12, in the winter, when storage hydro generation is lower, the system needs to deploy OCGT generation to meet peaks associated with vehicle charging demand (charging profile as shown in Figure 5-4.) However, with higher levels of UCC, the system is able to displace some of this demand to other times of the day, when either flexible hydro or solar have available capacity to meet it.

Cost and emissions

System cost is reduced relative to the ELE-RPS scenario when UCC is implemented. Results in Table 7 show that implementation of UCC leads to an economic benefit to the system. The decreased installation capacity needs and shift in capacity type shown in Fig. 11 lead to decreases in system cost. Employing UCC in 50% of the available fleet leads to a system cost decrease of 3.5%. Although there is no significant change in emissions with the use of UCC, the lower system cost leads to lower carbon abatement cost due to decreased system cost. A decrease of up to 25% from the ELE-RPS scenario is achieved, as seen in Table 5-7.

Table 5-7. Summary of system costs, unit energy costs, emissions, and abatement cost for REF, ELE-RPS and UCC scenarios.

Scenario	Total electricity system cost [$B]	Unit Energy Cost [$/MWh]	Cumulative Emissions [MTCO2]	Abatement Cost [$/tCO2]
REF	21.9	21.8	691.0	-
ELE-RPS	25.6	23.7	430.0	14.2
UCC 10%	25.3	23.5	430.0	13.2
UCC 20%	25.2	23.3	429.3	12.5
UCC 30%	25.0	23.2	429.0	11.8
UCC 40%	24.8	23.1	428.5	11.2
UCC 50%	24.7	22.9	427.9	10.6

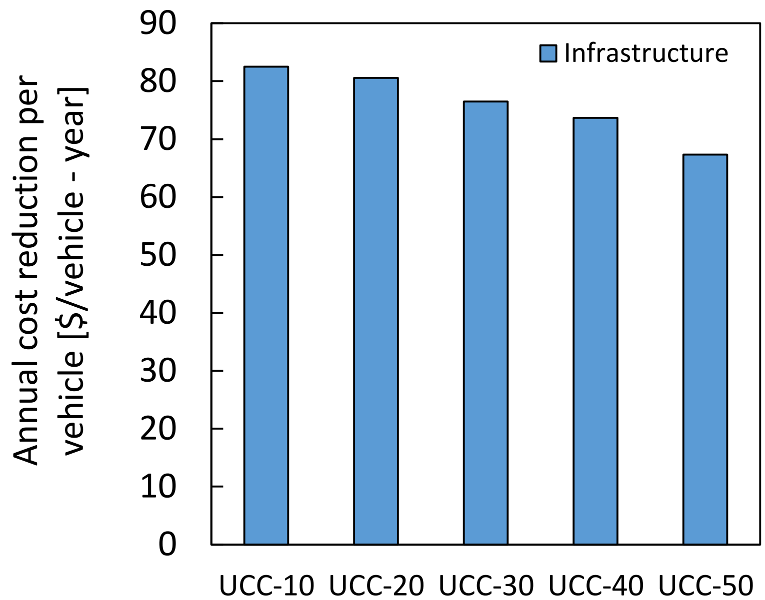

Figure 5-13. Annual equivalent cost savings resulting from implementation of UCC per participating vehicle.

UCC leads to cost savings equivalent to up to $82/vehicle-year, in the best case. However, as UCC penetration increases, the value of additional unit of energy displaced diminishes. This leads to the diminishing returns seen in Fig. 13. At a penetration of 50%, the value of UCC drops from $82 to $67 /vehicle-year. It is important to note, however, that these costs do not account for transmission and distribution system costs. Cost savings would likely be higher if these were considered.

Operation

Dispatchable capacity decreases with UCC level due to decreased seasonal peak demands. Model results show that although use of UCC leads to a modest annual peak demand reduction, off-freshet demand reduction is significant, as shown in Table 5-8, which summarizes peak demand by season for the year 2055 (only ELE-RPS and UCC-50 are shown.) As seen in Table 5-8, annual peak demand decreases by 0.4 GW when employing UCC at 50% of the available fleet, whereas, the off-freshet peak is reduced by 2 GW. During the mid and peak-freshet seasons, backup capacity needs are lower, due to the high amounts of storage hydro and hydro ROR available; therefore, decreased peak demand in these periods has a reduced value to the system. In the off-freshet season hydro generators have a lower output, effectively lowering their contribution towards capacity needs. Consequently, lowering peak demand in the off-freshet season has a greater value to the system as it enables lower backup capacity installation.

Table 5-8. Peak generation by period for varying UCC levels for year 2055 in GW

	Off-freshet	Mid-freshet	Peak-freshet	Annual peak
ELE-RPS	17.5	16.1	16.8	17.5
UCC-50	15.5	15.8	17.1	17.1

5.5. Discussion

This work studies the impacts of electrifying all road transportation sub-sectors in the province of British Columbia and the effects in terms of capacity buildout and excess electricity generation to the electricity system. It is important to note, however, that all costs reported here only include the electricity system, and exclude transmission and distribution system costs, vehicle costs and charging infrastructure costs. Further, this study only accounts for vehicles emissions associated with vehicle operation. Vehicle manufacturing emissions are not accounted for. It is important to note that all results of the current study are system specific and only fully applicable to BC. However, similar results could be found for regions with a similar hydroelectricity share such as Quebec, Northern Europe or South America if they were to apply a similar RPS.

Eliminating the RPS would decrease the accumulated carbon reduction impact of electrification of transportation, leading to higher carbon abatement costs. Model results show that total system carbon emission reductions are achieved by electrification of transport when the RPS is eliminated. However, this effect is 60% lower, when compared to the scenario where the RPS is maintained. Although system capacity requirements decrease when eliminating the RPS, unit energy cost only increase by less than 6%. Removing the RPS would negate some of the benefits of electrification of the vehicle fleet as carbon abatement costs increase by 44%. If governments are serious about deep decarbonisation targets, combined measures in both the electricity and transportation sectors are necessary.

Electricity system cost increases by 17% in the ELE-RPS scenario in comparison to the REF scenario; however, this is due to larger demand for electric vehicles. When accounting for the additional electricity being generated, unit electricity cost only increases by 9% in the ELE-PRS scenario and 5.5% in the UCC-50 scenario. These results suggest that the use of renewable generators may enable an expansion of the electricity system to meet demand from electric vehicles, while keeping emissions low and maintaining electricity prices to a minimal increase from a reference scenario where electrification would not happen.

Results show a capacity expansion requirement from 2015 to 2055 of 134% in the ELE-RPS scenario to accommodate demand from electric vehicles. This value is shown to reduce to 117% employing UCC of 50% of the available fleet. Although this difference in system capacity between the ELE-RPS and the UCC-50 scenarios is significant, a smaller cost difference between these scenarios is found, as system cost only differ by 3.3%. These results suggest that total system capacity expansion requirements may not be proportionally representative to system cost increase due to the falling costs of wind and solar PV generators.

Use of UCC leads to system benefits by reducing peak demand and shifting it to hours of low demand. The results of the study suggest that there are system benefits to employing UCC, by displacing demand from the early evening peaks to the middle of the day where generation from solar PV is abundant. In this context, our study is in agreement with Gnann et al, who found that use of UCC would displace peak night charging events to the middle of the day when electricity from solar PV is more abundant (185). In contrast, the works of Schill et al (165) and Li et al (166) found that rather than promoting increased use of VRE, UCC predominantly displaced demand to hours where coal was the marginal generator, leading to lower emission benefits. These results suggest that these dynamics are system specific and careful consideration of each jurisdiction is necessary.

UCC leads to increased freshet peak demand. The results of the study find that the use of UCC resulted in decreased peak demand for the majority of the year. However, freshet peak demands increased with the use of UCC, which may be counterintuitive. Due to low cost of solar PV by mid-century, the system opts to increase the buildout of this generator type and displace demand in the freshet to mid-day, effectively increasing the peak demand in this season. By doing so, water is saved, which can then be used at other times when its value is higher. These results demonstrate that use of UCC does not necessarily reduce demand peaks, rather it leads to demand shifting that leads to lowering system cost.

Economic benefit per vehicle UCC is low. Wolinetz et al (42) and Weis et al (41) find benefits of \$50 to \$70/vehicle-year and \$100/vehicle-year, respectively. Although both studies only consider the passenger vehicle sector and with partial BEV penetration, 50% and 10% respectively, their results are similar to the maximum \$82/vehicle-year found in the current study. In comparison, the average passenger vehicle in BC would be expected to consume close to \$700 a year in terms of electricity for vehicle recharging, considering a 25,000 km annual range and electricity prices at \$0.14/Kwh. A benefit of \$82/vehicle-year would result in a cost benefit of only 12% of annual electricity costs per vehicle. This ratio could be even lower for commercial vehicles. Consequently, drivers may find that this benefit may not be worth the inconvenience of having to displace their charging hours, leading to reluctance in adopting such a scheme.

The study also finds that electrification of vehicles may lead to a total combined electricity and transport system cost reduction. As is shown previously in Fig. 9, total the cost increase of the electricity system is offset by savings associated with phasing out use of gasoline and diesel. The current study does not account for transmission and distribution system expansion, rather it is a single region "copper plated" model. The cost savings may be considered an upper bound for additional infrastructure costs, after which electrification would be more expensive than fossil transportation. Future work is necessary to evaluate broader system costs of electrification of the road transportation segment accounting for infrastructure changes.

The option of using hydrogen fuel cells for heavy-duty vehicles as a load shifting method by creating hydrogen from excess electricity was examined following the study in (173). However, results showed that system costs increased from the ELE-RPS scenario by using fuel cell vehicles. This is in disagreement with our previous piece that found cost savings associated with using fuel cell heavy duty vehicles in Alberta, compared to battery electric vehicles (173). The difference in the results is due to two features. Firstly, Alberta does not have the hydroelectricity resources present in British Columbia. As a result, additional flexibility has a much greater value to Alberta than in B.C. for managing variability. Secondly, Alberta has better solar resources than B.C. Use of electrolysers were found to have a high temporal correlation with solar generation in the previous study. The lower solar resource in B.C. would ultimately lead to higher hydrogen costs, making use of fuel cell vehicles less economical.

In the current piece, the only considered charging profile for vehicles is found on Figure 5-4. The profile used for passenger vehicles, light duty freight and medium duty freight assumes that most of the charging for these vehicles happens in the late evening hours, akin to home charging or charging after business hours. However, commercial charging has been demonstrated to lead to demand peaks happening earlier in the day (186). If charging profiles focusing on commercial charging were to be used, it is likely that the value of UCC would be further decreased, as the majority of UCC displaced the demand to hours of high solar output.

5.5.1. Model limitations

Although the current study provides insights into electrification of vehicles for hydroelectric dominated jurisdictions, a number of limitations exist. The main limitations are the lack of ramping constraints and assuming that customers are willing to let the utility control the charging of their vehicles.

The electricity system cost does not account for ramping constraints. Due to the temporal structure of the model it would be difficult to implement ramping constraints. Therefore, the ramping ability of thermal generators such as biomass of CCGT may be overestimated. However, model results show limited use of both generator types. Biomass represents 3.5% of total generation at its peak, likely leading to minor deviation of results. Further, CCGT generators have been reported to be able to ramp 8% of full load per minute (187). As a results it is unlikely, it is unlikely that this constraint would lead to a significant change in model results.

No ancillary services are considered. Ancillary services may include spinning reserves, voltage regulation and ramping capacity. These services are not considered in the current model for simplicity. At the time of submission of the current research piece, the authors have another research piece under review that explores these ancillary services requirements and demonstrates that BC has sufficient hydro resources to provide them. As a result, removing these services is not likely to lead to significant changes in the results. However, other techniques such as the use unit commitment modelling as shown in Dagoumas (188) and Koltsaklis (189) could be employed in the future to address this issue.

Modelled capacity margin contribution of wind generators is static. Firm capacity contribution of wind power decreases with wind penetration. However, due to the linear nature of the model, a variable capacity margin contribution is not possible to implement. As a result, a static contribution of 26% is applied, in accordance with BC Hydro's IRP (169). However, the results of previous studies suggest that a 26% contribution may be appropriate for the wind penetration values achieved (190) and capacity factors used in the current study (191).

5.6. Conclusions

Using the British Columbia system as a case study, we analyzed the impact on electricity generation capacity expansion, cost and emissions associated with electrifying the entire road vehicle fleet. In addition to electrification of passenger vehicles, the model includes electrification of the entire freight and transit sectors, which have received little attention in the literature to date. Electricity system cost and unit energy cost increase resulting from vehicle electrification are also quantified. A capacity expansion and dispatch model spanning from 2015 to 2055 is used to analyze scenarios with and without a renewable portfolio standard, where a minimum of 93% of electricity generated in the province must be sourced from renewables. We further studied the impact of applying utility controlled charging on up to 50% of the vehicle fleet, in steps of 10% and quantified the value of this scheme per vehicle-year.

Results show that in scenarios with electrification of vehicles, capacity expansion to 2055 is up to 60% higher than in a scenario where vehicle electrification does not take place. Although this may seem like a significant difference, model results show that unit energy cost only increases by 9%. Further, this value is found to decrease to 5% when UCC is used. These results demonstrate that electrification of the transport system can be carried out at low additional cost to the electricity system.

Removing the renewable portfolio standard diminishes emission reduction benefits of electrification by 60%. Electrification of vehicles with the Renewable portfolio standard leads to emissions reduction of 260 $MtCO_2$ over the model period, however, this value drops to 102 $MtCO_2$ if the renewable portfolio standard is removed, which is equivalent to a reduction of 60%. This decrease in emission reductions diminishes the impact of electrification of vehicles, further increasing the carbon abatement cost by 47%. However, the scenario where the renewable portfolio standard is enforced leads to excess energy generation over 6 times higher than the scenario without the renewable portfolio standard.

Use of utility controlled charging leads to a reduction in excess energy generation and reduction in required generation capacity, however, marginal impact diminishes with number of participating vehicles. Results show that use of utility controlled charging may decrease capacity needs by up to 7%, in comparison to a scenario where the scheme is not employed, leading to a system cost decrease of 3.3%. However, due to the large number of vehicles participating, the value per vehicle is relatively low. In the best case, value is found to be $ 82/vehicle-year, with a participation rate of 10% of eligible vehicles. However, when the participation rate increases to 50%, the value decreases to just $ 67/vehicle-year. These results suggest that the low value per vehicle-year might lead to reluctance in the adoption of UCC, especially in the freight segment.

Chapter 6

Contributions and future work

6.1. Summary and contributions

The IPCC has reported with a 95% confidence that human activity is responsible for climate change (6). To limit its effects, the Paris agreement was signed in 2015 by 195 member countries, in which it was agreed that each country must reduce their greenhouse gas emissions to limit global warming below 2°C, while pursuing efforts to limit it to 1.5°C.

Due to the contrast in the source of their emissions, BC and Alberta are focusing on different sectors to mitigate GHG emissions (174). As generation of electricity and heat represent 19% of Alberta's current emissions, a phase out of coal by 2030 and a 30% renewable energy penetration target, by the same date, have been legislated (9). Longer-term measures may include electrification of the transportation sector, which currently represents 17% of the province's emissions. Focus on the heavy duty freight sector is necessary, as it is currently the highest emitting transportation sub-sector, and is growing rapidly.

BC has set strong targets to decarbonise its transportation sector. Along with other short-term measures such as the increase of the low-carbon fuel standard, long term goals set electric vehicle sales targets along with a complete phase out of ICE vehicle sales by 2040 (8).

This dissertation presents three studies that investigate low cost pathways for BC and Alberta to meet its GHG emission targets. The work of all three studies is carried out with the OSeMOSYS partial equilibrium (bottom-up) optimization model.

In addition to the individual contributions of each individual research piece, this dissertation provides insight into the magnitude of cost increases associated with the mitigation of emissions from the electricity and transportation sectors. As shown in all three pieces, costs associated with significantly cutting emissions from these sectors are in the magnitude of billions of dollars. Although these figures may seem high at first glance, it is important to keep in perspective the size of these systems. The billion dollar figures necessary to address climate change are but a small percentage increase in costs for the electricity and transport sectors. The results presented here show that the electricity and transportation systems can undergo the necessary modifications to address climate change with relatively small cost increases if there is political will to apply the necessary policies. In the first study, a model of Alberta's electricity system is used to assess the impacts of retrofitting coal generators with forest residue biomass. In a system with a renewable electricity penetration target of 30% by 2030, scenarios with and without the biomass retrofit option are compared based on system cost and emissions.

It is found that although, in the scenario with the retrofit option, bioenergy makes up less than 7% of the electricity mix, total installed capacity decreases by 10% while total system cost is reduced by 5%. The difference in installed capacity and cost is associated with the reduced need for wind generators and the associated backup capacity, in the retrofit scenario, due to the dispatchability of biomass generators. The first research piece also provides the following general literature contributions:

i. Levelized cost of energy alone is not an appropriate metric for evaluating which generator mix leads to the lowest cost system. A broader perspective is necessary to evaluate the value of a technology in the system. This has previously been eluded by Ueckerdt et al in 2013 where the concept of system LCOE was introduced to attempt to capture integration costs (118).

ii. Although bioenergy typically has a higher levelized cost of energy than wind generators, installation of biomass may lead to renewable energy targets being met a lower cost than pathways dependent on wind energy alone, due to the reduced integration costs of bioenergy. However, this is highly sensitive to wind energy and biomass costs and system mix. A careful evaluation of each system is necessary to evaluate lowest cost option.

iii. Carbon taxes lead to lower carbon abatement costs than renewable energy credits. The two scenarios with renewable energy credits lead to carbon abatement costs significantly lower than that of the scenario with carbon taxes when the cost of the tax is accounted for in the analysis. However, if the carbon tax cost is excluded from the cost analysis, carbon taxes would actually lead to a lower abatement cost to reach the same emission reduction level as renewable energy credits. It is reasonable to exclude the carbon tax cost from the analysis as many jurisdictions, such as British Columbia and Alberta, offer carbon tax rebates to families (9).

Implementation of the biomass retrofit in Alberta would require that large amounts biomass residue to be transported in the province via heavy-duty trucks. Although the focus of the second research piece is heavy-duty trucks in Alberta, the two research pieces are separate. However, an additional study integrating the two research pieces could be carried out in the future.

The second study addresses electrification of heavy-duty freight in Alberta and the associated impacts to the electricity system. Scenarios include: electrification with BEVs or FCV; three alternative charging profiles for BEVs; and no carbon tax or a carbon tax of \$150/tCO_{2e}.

It is found that, in the absence of carbon taxes, electrification of the heavy duty transport sector leads to minimal GHG emission reductions and carbon abatement costs as high as \$1400/tCO_{2e}. However, when a carbon tax of \$150/tCO_{2e} is applied, the system achieves cumulative carbon emission reductions of up to 43%, relative to a reference scenario, leading to a carbon abatement cost of \$15/tCO_{2e}. It should be noted that the abatement cost is the averaged discounted cost of reduction of carbon emissions over the entire model period, which explains its lower value in reference to the carbon tax. Further, although scenarios with FCVs lead to a higher electricity demand than scenarios with BEVs, due to energy conversion losses associated with electrolysers, scenarios with FCVs lead to lower cost and emissions due the flexibility electrolysers offer. Contributions to the literature from this research piece are:

i. Higher cost dispatchable generators may still be required in the future, despite the lowering cost of variable renewable generators. Nuclear generation is installed in all scenarios with the \$150/tCO2e carbon tax. Even in the scenario with FCVs, where 40% of the electricity demand is time independent, dispatchable generators such as nuclear and gas still make up 30% of the energy mix.

ii. The flexibility offered by electrolysers leads to partial decoupling of supply and demand. Although this leads to overall higher electricity demand, it enables greater buildout of low cost technologies that do not necessarily match supply with demand, such as solar PV, ultimately leading to lower system cost.
iii. The emission benefit of electrifying the HD transport system is almost negligible without further policies targeting the emission intensity of the electricity system. BEVs tend to have a lower emission intensity than the current diesel trucks, even with an electricity mix with a relatively high emission intensity. However, internal combustion engine HD vehicles are expected to drastically decrease their emission intensity in the coming decades due to a fuel switch from diesel to natural gas, adoption of hybrid technology and general efficiency gains. As a result, for BEVs to offer an emission benefit relative to these future lower emitting vehicles, it is imperative that the emission intensity of the electricity mix be lowered.

In the third study, electrification of all modes of road transport in BC is assessed, as well as the impacts of this transition on capacity expansion and cost of the electricity system. The model includes scenarios with and without a renewable portfolio standard, mandating a minimum renewable energy penetration target of 93% and scenarios that represent various levels of utility controlled charging (UCC).

The results demonstrate that to meet the growing electricity demand and demand from electric vehicles, system capacity will have to at least double by the mid 2050s. Additionally, it is found that abatement cost of electrification of vehicles ranges from 14.1 to 20.8 $\$/tCO_{2e}$, with and without the renewable portfolio standard, respectively. The resulting electricity cost is found to increase by 9 and 3% for the same two scenarios, respectively. Lastly, UCC on up to 30% of the available fleet was found to lead to lowering excess generation production. However, penetrations higher than 30% were found to have no further effect. Contributions to the literature from this piece consist of:

i. The electricity generation cost is not likely to significantly rise as a result of mass transportation electrification. In the third research piece, we found that demand would increase by 40% more by the year 2055 in the scenario where all road vehicles are electrified, compared to the scenario where vehicles remain fossil fuel dependent. Although this demand growth is significantly higher due to electrification of vehicles, the electricity generation costs do not increase at the same rate; costs only increase by 9% as compared to the reference scenario without electrification of vehicles. This value further drops to 5% if UCC is employed. This moderate cost increase is a result of the falling costs of renewable generators such as wind and solar PV, suggesting that mass electrification may be achieved with relatively low electricity cost increases.

ii. Jurisdictions targeting full electrification of the transportation sector may require significant expansion of their electricity systems. However, due to the low cost of VRE generators such as wind and solar PV, hydroelectricity dominated jurisdictions are not likely to experience substantial cost increases.

iii. UCC may lower excess generation from VRE generators by displacing time of charging of vehicles. However, vehicle UCC alone is not likely to completely eliminate excess electricity generation. As a result, opportunities exist for low cost electricity use.

iv. UCC leads to lower system costs by decreasing overall capacity needs and switching capacity type to low cost solar PV. However, cost reduction benefits per vehicle for UCC is low, valued at $80/vehicle-year, in the best case. As a result, customers may find that the additional inconvenience of not being able to charge their vehicles at the desired times is not worth the additional monetary value UCC offers. This analysis, however, does not include the additional cost associated with transmission and distribution system expansion requirements, which would likely increase the cost benefit of employing UCC.

v. Savings associated with the phase out of gasoline and diesel due to electrification of vehicles lead to total system cost savings. The saving from phasing out fossil transportation fuels is greater than the cost increase associated with electricity system expansion. However, this study did not consider costs of charging stations nor of distribution system expansion.

As a result, these savings may be understood as an upper bound to the cost necessary for additional infrastructure associated with vehicle electrification, after which point, electrification becomes more expensive.

6.2. Future work

Future work should include incorporation of electricity storage in the model. Battery technology costs have dropped significantly in the last few years. As a result, grid-scale systems have been installed in Australia and have been announced in other jurisdictions, such as New York and Arizona (192). Implementation of storage may be of particular importance to Alberta, due to its limited access to dispatchable renewable energy. However, implementation of energy storage is difficult in long term capacity expansion models due to computational requirements and system characteristics i.e. use of representative days (43).

Alternative to storage, increased intertie capacity between BC and Alberta is another option for enabling higher penetration of VRE or adoption of BEVs due to BC's large hydro reservoir. Although some work has already been done in studying impacts of intertie expansion between the two provinces (99), its impacts on implementation of electrification of transportation have not yet been studied. Further, it is difficult to capture in mathematical models provincial opinions on rather or not the intertie should be expanded, by how much, and how it is to be operated, as it may involve political disputes between the two provinces.

Hard linking model results to sub-hourly unit commitment and economic dispatch optimization models may provide additional insights. To maintain model run times manageable, some approximations and simplifications are necessary in long-term capacity expansion models such as OSeMOSYS. One such approximation is the aggregation of demand into representative time slices. Although this leads to shorter model runs, temporal resolution and chronology is lost. Hard linking the results of the three studies presented here to an hourly or sub-hourly model may provide insights into short-term demand fluctuations and be better suited for implementation of storage.

Assumptions on generator constraints may provide further insight into system needs. Additional to temporal aggregation, the models used in this work also make use of technology aggregation. As a result, limitations of individual generators such as ramp rates or minimum partial load are difficult to implement. These issues could be addressed through implementation of unit commitment and dispatch modelling. This type of modelling may serve to provide additional insights into unit scheduling and system reserve capacity needs. Although use of unit commitment modelling is commonplace (168) (166), it is at times used to further validate long term capacity expansion model results by conducting a more detailed analysis of a specific model year (43).

Ancillary services are not considered in the present work. Electricity generators provide a multitude of services such as energy generation, firm capacity, ramping capability and load regulation (193) (194). However, in the current work, the only services considered are energy generation and capacity reserve margin. Due to the limited ability of renewable generators to provide services such as ramping and firm capacity, additional backup capacity needs may be necessary. A model with these additional considerations may provide further insight into system needs.

The electricity system is normally divided into generators, transmission and distribution (195). Transmission typically refers to high voltage power cables that deliver electricity from generators to substations that supply distribution facilities, while distribution normally refers to lower voltage cables that deliver energy to individual customers. Although costs for transmission and distribution are considerable, and at times are higher than costs for generator assets, depending on customer type, these are not considered in the current work. Electrification of transportation may require significant upgrades to the distribution system depending on where the recharging takes place i.e. at home or at designated charging stations. Further research is necessary in this area to quantify these transmission and distribution upgrade needs depending on vehicle charging characteristics. Due to their potentially high costs, when accounting for transmission and distribution networks, optimal generation mix results may presumably differ from the results presented in the third research piece. Investments in storage or demand side management may postpone costly grid upgrades.

Electrification of transport may lead to significantly lower gasoline prices. If the entire road transportation sector is electrified, demand for gasoline is likely to decrease significantly. A simultaneous price drop would be expected. However, it is difficult to accurately estimate what the degree of this price drop would be without an in-depth economic analysis. The results of research piece number 3 do not account for this supposed price drop. A more detailed analysis may lead to different results in economic differences between scenarios with and without electrification.

Assumptions on charging duty cycles should be refined. In the studies presented in Chapters 4 and 5, the charging duty cycle of vehicles was taken as an average of duty cycles reported for other jurisdictions, as data is not currently available for BC nor for Alberta.

Import and export markets should be enhanced. In all three pieces, the provinces modelled are considered isolated “islanded” systems, i.e. no interconnections are considered. However, the BC system and the Alberta system are connected to each other, the BC system is further connected to the U.S.A. system and the Alberta system also possess small connections to Saskatchewan and to the U.S.A. This is of special relevance with growth of renewable penetration in California and seasonality of prices in the Mid-Columbia (U.S. Pacific North-West) market.

Results of linear programing models such as OSeMOSYS are highly sensitive to prices. This is a phenomenon commonly referred to as “penny switching”. The technology with the lowest cost will dominate new capacity investments, even if the cost difference is marginal. Stochastic modelling considering a range of prices for technologies and fuels may provide one alternative to this. Alternatively, the modelling to generate alternatives (MGA) has been proposed recently, where near optimal, feasible solutions which are different in the decision space are also considered (196).

Finally, although numerous possibilities for future work and model upgrades have been identified, this does not undermine the validity of the modelling exercise. As mentioned in Chapter 2, all models are wrong and are a simplification of reality (52). Model results should no be interpreted as predictive, rather it is an exercise to acquire insights into model dynamics and responses to different perturbations.

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Appendices

Supplementary material – OSeMOSYS model

This section describes in detail the OSeMOSYS model and its formulation.

OSeMOSYS is an energy systems optimization model developed at the Royal Institute of Technology (KTH) in Sweden and released in 2010. The model was developed as an open source tool to enable graduate students, business analysts and developing countries to conduct energy analysis at low up-front costs. The default OSeMOSYS version optimizes an energy system model, minimizing total cost over the studied time span while meeting pre-specified exogenous demands.

Demands are met by a number of available technologies. Technologies may operate in one of several modes of operation. Modes of operation may be defined for production of alternative outputs or for variations in efficiency.

The model period is separated into years, each of which contains a set of timeslices. Timeslices can be considered as different time steps within a year, used to provide variability in demand and variability in output of renewable technologies.

A demand profile is exogenously defined to assign a fraction of the annual demand to each timeslice for each demand type, for each region, and for each year. The output of each technology at each timeslice is defined optimally by the model.

The model can be separated into seven key components: (1) the objective function, (2) costs, (3) storage, (4) capacity adequacy, (5) energy balance, (6) constraints, and (7) emissions. The following is a description of these components with supporting mathematical formulation, when necessary. As energy storage is not used in any of the three studies in this dissertation, this component is not included here.

1. The objective function

The objective function of the model is to minimize net present value of the system to meet exogenous demands. The mathematical formulation is shown in equation 1.

$$Minimize \sum_{y,t,r} CC_{y,t,r} + OC_{y,t,r} + EC_{y,t,r} - SV_{y,t,r} \tag{1}$$

Where, CC represents the capital investment costs, OC stands for operational costs (fixed and variable), EC is the emissions costs, and SV is the salvage value of existing generators at the end of the model period. The subscripts y, t, r represent year, technology, and region, respectively.

2. Costs

As shown in equation (1) above, costs are incurred by each technology, for every model year and every region. It is important to further add that all costs are discounted to the first model year, depending on the selected discount rate. Discount rates can be applied uniformly through all technologies or specific to each technology.

Costs can be subdivided into capital costs, operational costs and salvage costs. Operational costs are further subdivided into fixed costs, variable costs, and fuel costs. Costs are defined for every technology for every year. Variable costs also depend on mode of operation. Emission costs are detailed in section 7.

Capital costs are the costs associated with commissioning new capacity. Capital costs are calculated annually. It is assumed that the entirety of the capital cost for a new technology is incurred in the year they are commissioned. Capital costs are technology specific and relative to capacity. The total capital cost scales linearly with total commissioned capacity. For example, if the capital cost of solar generators at year 2020 is \$1,200/ kW and the model builds 200 kW of this generator, then total incurred capital cost for solar in year 2020 is \$ 240,000. Further, total capital cost for year 2020 would include the total capital cost of solar plus total capital costs of any other commissioned technologies in that year.

Fixed cost is associated with operational and maintenance costs of a technology that are independent of its annual output. Fixed costs are usually a given per unit capacity per year. For example, if the fixed cost of solar generators at year 2020 is \$20/ kW–year and there are 200 kW of installed capacity that year, then fixed cost for solar in year 2020 would add up to \$4,000.

Variable costs are costs associated with the output of a technology for a given mode of operation. Variable costs may change depending on mode of operation of a specific technology. For example, a gas generator may have modes of operation "A" and "B". In this example, mode A has a variable cost of $1.2/ MWh, while mode B has a variable cost of $2/ MWh. If this gas generator was to output 100 MWh in mode A and 50 MWh in mode B in year 2020, then the total variable cost for this gas generator in 2020 would be ($ 1.2 / MWh X 1,000 MWh) + ($2 / MWh X 500 MWh), adding up to a total of $2,200.

Fuel costs are costs associated with fuel use for a specific technology. OSeMOSYS does not model fuel costs *per se*. Rather, fuels are considered as technologies in the model that have an associated variable cost to produce an unit of output, which is in turn consumed by a subsequent technology to produce another energy currency. However, these can be effectively understood as fuel costs associated with fuel usage. For example, a technology "r_gas" may be used as the technology that produces the fuel "f_gas", with an associated variable cost of $10/ MWh. In turn, a gas generator may need to consume two units of "f_gas" in a given mode of operation to produce one unit of electricity. Then, the gas generator is said to have a fuel cost of $20/ MWh to produce a unit of electricity in that mode of operation. Fuel costs are also discounted to the original year.

Salvage costs are associated with the non-sunk costs of technologies at the end of the model period. All technologies are assigned an operational lifetime in the model. Once this technology reaches its end of life, it is assumed to have no value and to no longer be operational. Therefore, its salvage cost would be zero. However, technologies may still have a number of operational years left at the end of the model period. In order to keep the model from not installing high cost technologies close to the end of the model period, salvage costs are accounted for. Salvage costs account for the remaining value of a technology depending on its remaining life at the end of the model year.

3. Storage

As energy storage is not employed in any of the three research pieces in this dissertation, this part is not described. For reference the reader is forwarded to (64) (72).

4. Capacity adequacy

To ensure that enough capacity is present in the system at all times to meet demand, capacity adequacy constraints are added to the model. There are three capacity adequacy constraints. These are named CA1, CA2 and CA3.

CA1 ensures that new commissioned capacity at year y is added to the residual capacity from the previous years, as shown in equation (2).

$$Cap_{r,t,y} = \left(NC_{r,t,y} + EC_{r,t,y} - RC_{r,t,y}\right) \tag{2}$$

Where Cap stands for the total capacity of a technology at year y, NC stands for new commissioned capacity at the same year, EC stands for existing capacity in the system carried over from previous years and RC stands for retiring capacity at year y. In reality, OSeMOSYS does not remove retiring capacity from the system, as shown in equation (2). Instead, capacity becomes "inactive" once its end of life is achieved. At that point, the retiring capacity may no longer produce outputs or contribute to the system. However, this can effectively be understood as retiring capacity, as shown in equation (2).

CA2 ensures that for a given timeslice, generation of a specific technology does not exceed its pre-determined capacity factor. This is shown in equation (3).

$$Activity_{r,l,t,m,y} \leq Cap_{r,t,y}\ X\ cf_{r,t,l,y}\ X\ CtA_{t,r} \tag{3}$$

Where, $Activity$ stands for the energy output of a generator in a given timeslice, cf stands for the technology's exogenously defined capacity factor at a given timeslice l, and CtA stands for capacity to activity unit. CtA can be understood as the maximum units of output of a given technology per model year. For electricity generators, this number is set as default to 8760 to account for every hour of the year. In other words, a one MW generator could output 8760 MWh per year. Subscript m stands for mode of operation.

CA3 accounts for the need that technologies have for planned maintenance. An availability factor may be imposed to technologies in OSeMOSYS. This availability factor accounts for required down time for planned maintenance of a given technology. CA3 ensures that the output of a given technology throughout a model year does not exceed its available time, where available time is defined as total time in a year minus downtime. CA3 is described in equation (4).

$$\forall\ y \leq OP_{r,t}, \sum_{l,m} Activity_{r,l,t,m,y}\ X\ YS_{l,y} \leq \sum_{l} Cap_{r,t,y}\ X\ cf_{r,t,l,y}\ X\ CtA_{t,r}\ \ X\ AF_{r,t,y} \quad (4)$$

Where, YS stands for the year split of a given timeslice, OP is the operational life in years of a given technology, and AF is the availability factor of a technology, given as a percentage of the number of hours of the year the technology is available. YS is defined as the number of hours the corresponding timeslice represents. For example, if timeslice l represents 10% of the year, then YS would be equal to 876 hours.

5. Energy balance

Energy balances are set in the model to ensure conservation of energy, that production of outputs meet the exogenous timeslice demands and annual aggregated demands. There are three energy balance equations in the model, EB1, EB2 and EB3, as described below.

EB1 accounts for trade between region r and region rr. Where rr is simply a region other than region r. This is shown in equation (5).

$$Trade_{r,rr,l,f,y} = -Trade_{rr,r,l,f,y} \quad (5)$$

Where $Trade$ accounts for exchange of outputs between two regions and subscript f stands for fuel. For example, in a model including the regions British Columbia and Alberta, equation (5) ensures that if British Columbia exported 100 MWh of electricity to Alberta during timeslice l, the same 100 MWh would be imported by Alberta during the same timeslice. Transmission lines are modelled as technologies and their efficiency is accounted for in activity ratios, described below in section 6.

EB2 is an energy balance for technologies per timeslice. EB2 ensures that demand is met at every timeslice of the year, as shown in equation (6).

$$\sum_{m,t}^{out}(Activity_{r,l,t,m,y}\ X\ YS_{l,y}\ X\ OutR_{r,t,f,m,y}) - \sum_{m,t}^{in}(Activity_{r,l,t,m,y}\ X\ YS_{l,y} X InR_{r,t,f,m,y}) + \ Trade_{r,rr,l,f,y} \geq SD_{r,f,y}\ X\ SDP_{r,f,l,y} \quad (6)$$

Where $OutR$ stands for output activity ratio and InR stands for input activity ratio. These two variables can be thought of as the efficiency of a technology. For example, if the output activity ratio of a gas generator is set to one MWh in a given mode of operation and the input activity ratio is two MWh in gas fuel for the same mode of operation, said generator is said to have an efficiency of 50% in that mode of operation. *SD* stands for specified demand for a specific fuel type while *SDP* defines what fraction of *SD* occurs in each timeslice of the year.

EB3 is similar to EB2, bur rather than defining an energy balance for demands with a specified annual profile per timeslice, it defines an energy balance for demands that are annually aggregated. This is shown in equation (7).

$$\sum_{m,t}^{out}(Activity_{r,l,t,m,y}\ X\ YS_{l,y}\ X\ OutR_{r,t,f,m,y}) - \sum_{m,t}^{in}(Activity_{r,l,t,m,y}\ X\ YS_{l,y}\ X\ InR_{r,t,f,m,y}) + Trade_{r,rr,l,f,y} \geq AAD_{r,f,y} \qquad (7)$$

Where AAD is the annual accumulated demand. Please note that while the right hand side of the inequality in equation (6) is a function of timeslice l, this is not the case for the right hand side of equation (7). This is because AAD is an annual aggregated demand without a specified temporal profile.

6. Constraints

A number of additional constraints exist in the model to keep it from achieving specific conditions or to ensure that others are met. The following is a description of these constraints.

Maximum and minimum capacity limits exist per technology. The annual maximum capacity limit may impose an annual limit on the installed capacity of a specific technology. This maximum capacity limit may be increased or decreased over the model period. This Constraint is useful for accounting for technologies with limited availability such as geothermal or hydroelectric generators. Similarly, a minimum annual capacity limit may be imposed to ensure that a specific technology type is built. This value may also change annually.

Similar to the maximum and minimum capacity limits, an additional maximum and minimum capacity investment limit may also be set. This Constraint may require that a set number of MW of a technology must be installed every year, or it may place a limit on the annual buildout of said technology, given that it does not contradict maximum and minimum capacity limits, as explained in the previous paragraph. Maximum and minimum capacity investment limits may also be set for every individual year.

Maximum and minimum annual output levels may also be set for specific technologies. For example, it may be required that the generation from wind turbines exceed 100 GWh per year or that the generation from coal does not exceed 50 GWh per year. This constraint can be assigned a value for every technology for every modelled year. Applying this constraint is useful for modelling specific renewable targets or for modelling thermal generators with limited fuel supply.

A model period maximum or minimum activity may also be imposed. This is similar to the maximum and minimum annual output levels, bur rather then being specified for every model year, it is a model time span aggregate. For example, it may be specified that only 1 TWh of biomass fuel is available during the entire model period.

A reserve margin requirement may be further specified. This constraint requires that for every model year and fuel demand type, enough redundant capacity is available in excess of the peak demand. For example, if the peak demand for electricity in year y is 10 GW and a reserve margin of 10% is required, the model will be forced to have at least 11 GW of installed capacity that are able to produce electricity in that same year. Technologies can be tagged as able/ unable to provide capacity to reserve margin and what percentage of their capacity may contribute to the reserve margin. Thermal generators typically contribute 100% of their capacity to the reserve margin while renewable generators may contribute only a portion or none of their capacity to reserve margin.

Renewable shares my also be imposed. Generators may be tagged as renewable/ non-renewable. A minimum renewable share may be set for every fuel demand type for every model year. For example, while modelling Alberta, a minimum renewable share of 30% may be set for the year 2030. If the demand for that year was 100 TWh, then at least 30

TWh would have to come from generators that are tagged as renewable, such as wind, solar, hydroelectric of geothermal.

7. Emissions

OSeMOSYS is also able to account for various emission types from technologies, impose annual or model period limits or emission penalties. This section described how emissions are accounted for in the model.

An emission intensity is typically assigned to a fuel. The higher the output of a generator consuming a fuel with an associated emission intensity or the lower the generator efficiency, the higher the emission output of said generator. For example, take a combined cycle gas turbine generator as the technology outputting electricity. Natural gas fuel has an associated carbon intensity of approximately 0.25 tCO_2/ GWh. If the generator had an efficiency of 50% and were to generate 100 GWh of electricity by 2020, it would consume 200 GWh of gas fuel. Therefore, it would emit 50 tCO_2 in that year.

Emission costs are applied to every unit of emission by year and emission type. Following from the example in the previous paragraph, if an emission penalty of $ 10/ tCO_2 was to be applied in model year 2020, then the system would incur an additional $500 cost in that year, based on the 50 tCO_2 emitted that year. But if the emission penalty was to increase to $ 100/ tCO_2 in 2021 and the generator output remained the same, then emission penalty incurred would increase to an additional $5,000 by 2021. Multiple emission types can be applied to the model.

It is also possible to impose annual or model period emission limits by emission type.

Supplementary material for Chapter 4

Temporal structure

The temporal structure of the model consists of 48 annual timeslices. The 48 timeslices are divided into 6 representative days per year with 8 representative hours per day. These representative days are selected from historical data using a clustering algorithm. The clustering algorithm is based on hourly electricity demand, hourly wind and hourly solar generation.

A k-means clustering algorithm assigns each historical day to one of six clusters (197). The algorithm selects a representative day within a cluster for each of the six clusters. The probability of any one given day of being selected as the representative day for a given cluster is inversely proportional to the "distance" to the cluster centroid.

Each day is subsequently sub-divided into 8 representative hours. The model creates all possible permutations by combining subsequent hours of the day into representative hour sets. For example, one option would be to combine every 3 hours of the day into 8 representative hours, where the first representative hour would combine the first 3 hours of the day. The representative set of 8 hours is selected by minimizing root-mean-square error between the 8 representative hour set to the original set.

Representative days are subsequently weighted in accordance to their cluster sizes.

Residual capacity

Residual capacity in the model accounts for existing electricity generation capacity in the system and expected retirement dates. Values are shown in Fig. A1. Residual capacity of all generators is based on (127) (101).

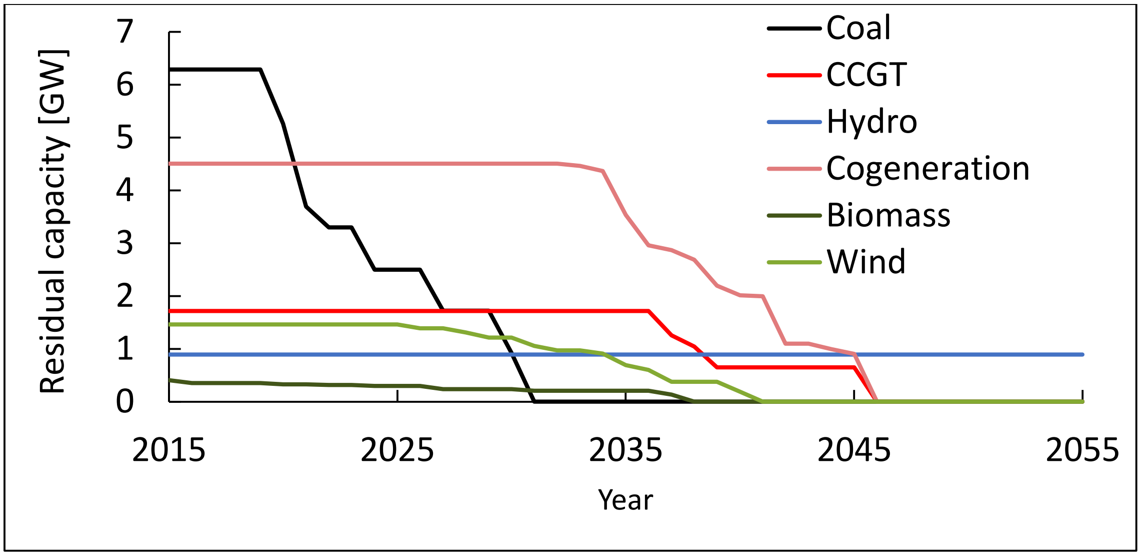

Figure A1: Modelled residual capacity in Alberta

Supplementary material for Chapter 5

Temporal structure

Historical hourly data, i.e. hourly data for 365 days for 3 years, on wind and solar generation and load is used to select representative days. Load duration curves (LDC) and production duration curves (PDC) of historical data are created to assess accuracy of model timeslices. Timeslices are made up of 10 representative days, each of which contain 8 representative hours. Representative days are sampled from three annual seasons. Representative days are not chronological and are not linked to one another within the model year. Rather, they are simply sub-divisions of a model year. This temporal structure is used for both capacity expansion and dispatch planning. An explanation of the process to create model timeslices follows.

Seasons

Seasons are defined to ensure the annual variability of hydro generators is captured. Fig. B.1. shows a ten-year average of minimum generation requirements for storage hydro and run-of-the-river hydro. The peak-freshet season is defined as the month with the highest minimum generation requirement i.e. June. The mid-freshet season is defined as the average generation of the months with the second and third highest annual minimum generation requirement i.e. May and July. The off-freshet season is defined as the monthly generation average of the remaining nine months of the year i.e. August to April.

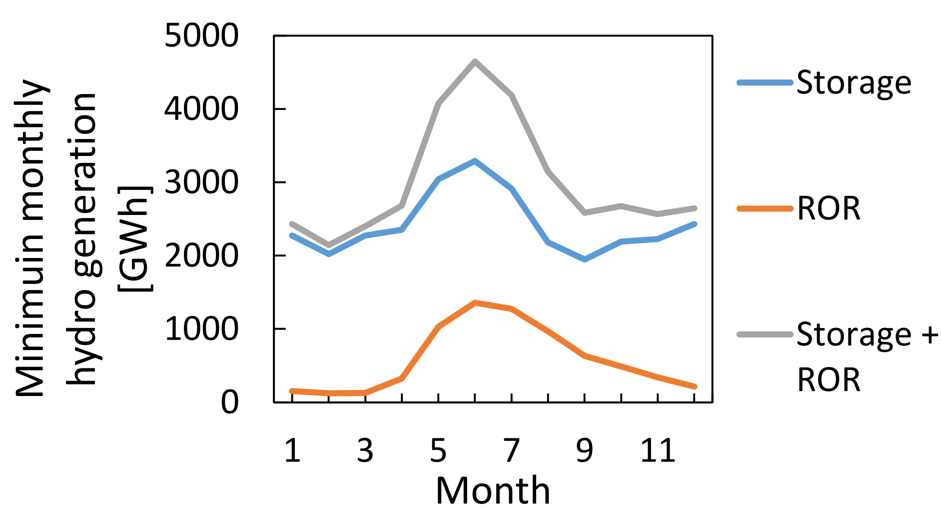

Fig. B.1. Minimum monthly generation for hydro-electric generators in British Columbia.

Representative days

A clustering method is used to combine similar days, in terms of wind, solar and hydro generation and load, into groups. A representative data point per cluster is selected, similar to the work of Namacher et al (128) and employed in Palmer-Wilson et al (172) and Keller et al (173).

Representative days must be sampled from all three seasons. A number of alternative combinations of representative days are sampled, as shown in Table A.1.

Representative days are weighted according to cluster size. For example, a day in the off-freshet season represents a larger portion of the model year than a day in the peak-freshet season.

Table B.1. Alternative sets of representative days sampled

Name	Number of representative days per season		
	Off-freshet	Mid freshet	Peak-freshet
2-2-2	2	2	2
3-2-2	3	2	2
4-3-3	4	3	3
4-4-4	4	4	4
5-2-2	5	2	2
5-3-3	5	3	3
5-4-4	5	4	4

Representative hours

Each representative day is further sub-divided into eight representative hours, or timeslices. All possible combinations of eight representative timeslices are created. Each timeslice is assigned the average value of hourly load and wind and solar production for the hours within it. The set with lowest root mean squared error (RMSE) between representative hours and historical data is selected.

For example, a representative day can be made up of eight timeslices, each representing a period of 3 hours of data. Alternatively, a representative day could also be made up of seven one hour timeslices and one seventeen hour timeslice.

Each representative hour, or timeslice, is assigned a fraction of the model year, proportional to the size of the cluster making up the representative day and the number of hours of the day it represents.

Minimizing RMSE

Once representative hours for each set of representative days, as shown in Table B.1., is created, model LDC and PDC for wind and solar PV are created. The model LDC/ PDC are compared to historical LDC/ PDC, as described in the first paragraph of section I., and RMSE is calculated. RMSE for load, solar PV generation and wind generation is averaged for each set of representative days. Results are shown in Fig. B.2. The 4-3-3 set is selected for the model as it leads to the lowest averaged RMSE.

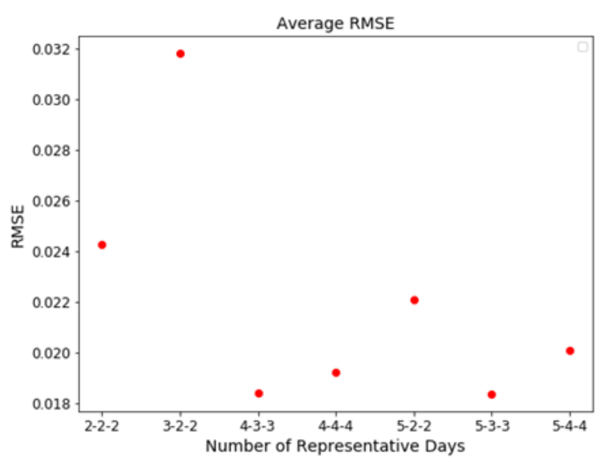

Fig. B.2. Average RMSE for load, wind generation and solar PV generation for each set of representative days.

Wind and solar PV profile

Wind generation profiles are based on the Pan Canadian Wind Integration Study from the Canadian Wind Energy Association (170), 35% TRGT scenario, acuatl data. As the study provides generation profiles for multiple sites for each of the three wind regions, i.e. Peace, North Coast and Kelly Nicola, the site with the highest capacity availability is selected for each region. The site ID # is shown in Table B.2.

Table B.2. Site ID#, capacity and capacity factor for the three wind regions

Site ID#	Capacity [MW]	Capacity Factor	Region
2478	336	0.3	Kelly Nicola
3719	584	0.38	North Coast
4015	483	0.35	Peace

CANWEA hourly modelled generation data for the three sites is available for the years 2008 – 2010. A PDC for the three regions for 2010 data is shown in Fig. B.3.

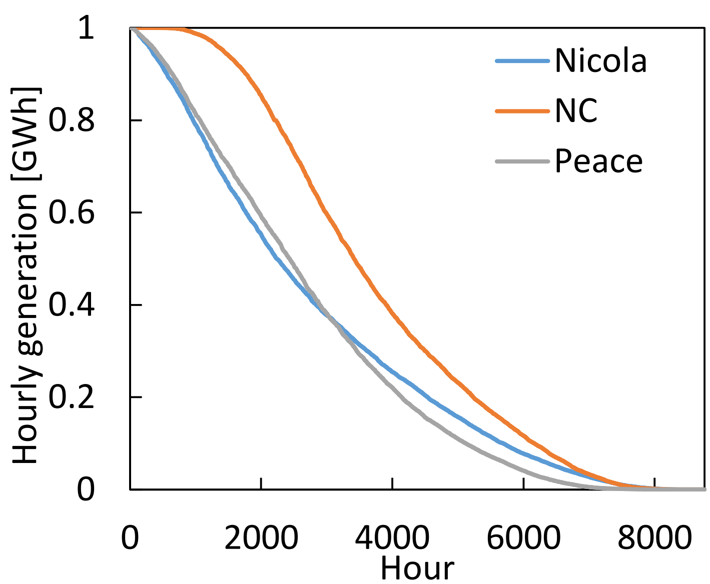

Figure B.3. Production duration curves for CANWEA model year 2010 for the three wind regions.

Computational cost

All modelling was carried out in an Intel core i7-4900 MQ CPU @ 2.8 GHz computer. Model run time and size are scenario dependent. The scenario without vehicle electrification has a model size of 2,400 Mb, requiring 90,568 iterations with a model run time of 836.8 seconds. While the most computationally intensive of the electrification scenarios had a model size of 2,404 Mb, requiring 147,487 iterations and required 1,669 seconds to solve.

Fuel costs

Fuel costs are based on EIA AEO 2017 (132), pacific region. Fuel costs for natural gas are taken from assumptions for electricity generators, while gasoline, diesel and compressed natural gas fuel costs are taken from transportation assumptions. Values are shown in Figure B.4.

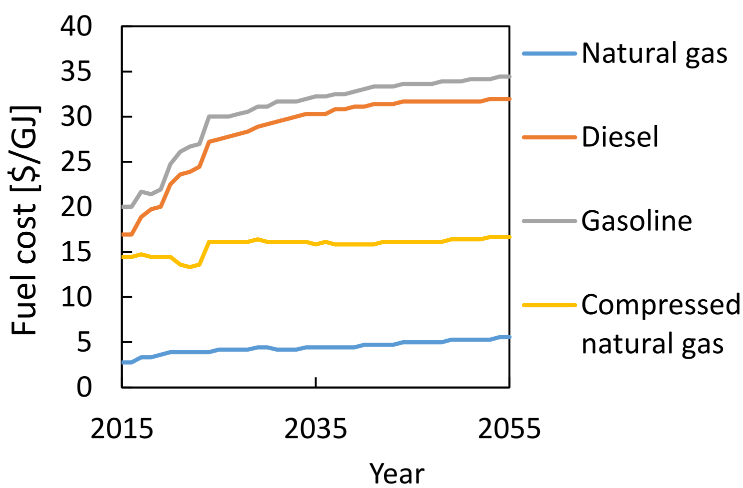

Figure B.4. Fuel cost assumptions