Mitigating variability of energy demand and supply in highly decarbonized energy systems

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Abstract

Transitioning towards sustainable energy systems requires elimination of greenhouse gas emissions associated with end-use energy demands and electricity generation. Electrification of end-use demands that traditionally use fossil fuels and expanding variable renewable energy generation are considered key strategies in achieving emission reduction targets. This dissertation investigates end-use electrification and renewable supply impacts on future electricity system infrastructure. Three studies analyze demand- and supply-side transition options for the province of British Columbia, Canada.

The first study investigates building heat electrification impacts on capacity and flexibility requirements of the electricity grid in British Columbia. Energy demands are projected for 2050 considering variations in building stock evolution, building code implementation strategies, and building envelope efficiency improvements. Varying shares of heat pump penetration rates can be applied using hourly temperature-dependent COP profiles. This study examines the shape and magnitude of peak electricity demands and ramping requirements for electrified heating by computing regional end-use energy demand profiles for space and water heat in British Columbia's residential and commercial building sectors. Results show that with an emphasis on building stock improvements, 90% heat pump penetration leads to an increase in electrical energy of 6% despite an annual population growth rate of 1.1%. The impact of high heat pump penetration rates on capacity requirements is significantly larger, with an increase of 37% in peak electricity demand for a 90% heat pump penetration rate. However, results of this study show that building energy codes and retrofit rates contribute relatively little to achieving net-zero emissions in the building sector.

The second study provides a more comprehensive analysis of end-use electrification by combining the electrification of building heat with electrification of space cooling and road transportation to examine changes in capacity and flexibility requirements for British Columbia's electricity grid. Two high-resolution demand simulation models are introduced that project electricity load curves for electrified end-uses in the building and road transportation sectors. Electric vehicle charging and space heating control are introduced as demand-side management strategies to examine the effect of load reduction and load shifting on capacity and flexibility requirements. In this work, building demands are modelled in hourly resolution and transportation demands are modelled in 15-minute time-steps. The shape and magnitude of peak electricity demands, range of electric loads, and ramping requirements are examined for a simultaneous electrification of 10 end-uses in varying temporal resolution. Results show that capacity and flexibility requirements increase by up to 93% and 320%, respectively, where future ramping requirements are largely driven by electrification of road transportation. Utilizing electric vehicle charging and space heating control reduces the increase in capacity and flexibility requirements by 19% and 238%, respectively, while shifting the timing of the peak event to early morning hours. Temporal resolution of demand models is an important determinant of flexibility requirements, leading to an increase of 520% when changing from an hourly to a 15-minute resolution.

The third study assesses the duration and magnitude of periods with excess energy generation and energy deficiency in British Columbia's energy system by 2050 where building heating, cooling, and road transportation is electrified using a portfolio of renewable energy sources. Future net load which is defined as the difference between electricity demand and variable renewable energy generation is determined to investigate dispatchable capacity requirements. The study examines net load for installed wind and solar capacities up to 50 GW for three wind penetrations. Three water supply scenarios are tested to identify changes in net load due to drought conditions and increased precipitation impacting hydroelectric power generation, an important consideration in hydro-dominant electricity systems. A one-year production cost model is used to quantify surplus energy and energy deficiency for a range of variable renewable supply scenarios. Results show that peak net load in 2050 will exceed present-day peak electricity demand in British Columbia, when building and road transportation end-uses are electrified, thereby necessitating built-out of variable renewable energy generation capacity. Individual hours of energy deficiency can be avoided with demand-side management or import of electricity from neighbouring systems. For an installed capacity of 30 GW, energy storage with a duration of 5 hours would enable system operators to manage most deficiency periods for all supply scenarios. A combination of large-scale built-out of variable renewable energy generation and short-duration energy storage can increase operational flexibility to meet growing electricity demand in 2050 after end-use electrification of building heating, cooling, and road transportation.

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Chapter 1

Introduction

1.1 Motivation

Achieving greenhouse gas (GHG) emission reduction targets requires, in many regions globally, decarbonization efforts on both the demand and the supply side [1]. Electrification of end-use demands and integration of variable renewable energy (VRE) sources are among the most effective strategies to reduce emissions [2]. Current electricity grids are ageing infrastructures that were not designed to serve electrified end-uses while making use of large shares of VRE resources [3], [4] and significant portions of these grids are likely to continue operating through 2050. As a result, these grids and the associated generation assets are vulnerable to challenges that will arise as we strive to achieve mid-century decarbonization targets [5].

The interdependence of electricity demand and supply requires a coordinated approach to planning the design and operation of electricity systems as they transition to sustainable energy systems [6]. Quantitative forecasts of post-electrification electricity demand are needed to inform capacity and flexibility requirements to ensure reliable electricity supply at all timescales [7]. Integrating large shares of VRE resources will affect infrastructure requirements and grid operations due to reduced system inertia and flexibility in the absence of dispatchable generation assets [8]. Changes to regional demand and supply mixes will, further, cause a shift in transmission and distribution infrastructure requirements placing reliable energy supply at risk. Where investments are needed, when and how much electricity is required are regionally specific questions that call for detailed understanding of regional demand profiles and supply options.

Due to climate change, extreme weather events are expected to become more frequent, affecting demand patterns, VRE supply potential and infrastructure requirements to provide grid resiliency [9], [10]. End-use demands are challenged by cold and warm temperature events as the performance of heat pumps and battery electric drivetrains are impacted by ambient temperature variations [11], [12]. On the supply-side, changes in weather conditions impact wind and solar generation [13] and large-scale shifts in precipitation patterns affect water supply availability for hydroelectric power generation [14] impacting the reliability of energy supply in hydro-dominant regions [15]. Providing sufficient grid resiliency, therefore, necessitates the consideration of these climate-induced changes [14], [16].

A future mismatch between energy demand and supply can be mitigated through demand-side management (DSM), long-term energy storage and overproduction of VRE resources. DSM strategies such as EV charging or space heating control reduce capacity and flexibility requirements of the electricity grid and, thereby, decrease supply-side technology requirements [17], [18]. Reducing net load, which is defined as the difference between electricity demand and VRE generation, can be achieved by integrating energy storage or overproduction of VRE resources where excess energy can either be exported or curtailed [19]. Analysis of periods with excess energy and energy deficiency can inform the development of strategies to enhance system flexibility when addressing energy demand and supply imbalances resulting from end-use electrification and variations of VRE supply.

Transitioning to sustainable energy systems requires an electricity supply that is secure and affordable while ensuring environmental goals are met [20]. Although decarbonization strategies addressing changes in energy demand and supply due to weather variability is an increasingly urgent issue faced by utilities, governments, and policy makers, a comprehensive analysis capturing changes in demand and supply due to weather variations to examine strategies that enhance resource adequacy is not included in most energy system models [21]. New modelling approaches are needed that address the complex interactions between changes in energy demand and supply patterns to ensure secure electricity supply [20]. The research presented in this dissertation seeks to provide insight into how these interactions can be modelled with high spatial and temporal scales to identify possible grid bottlenecks. Specifically, this research focuses on: (i) creation of heating demand profiles for the building sector to examine the impact of building heat electrification on capacity and flexibility requirements for a range of ambient temperature scenarios, (ii) assessing the potential of DSM strategies to limit increases in capacity and flexibility requirements when electrifying heating, cooling and road transportation energy demands, and, (iii) examining strategies to enhance operational flexibility to mitigate imbalances of demand variations due to end-use electrification and variations in VRE supply availability.

1.2 Previous work

1.2.1 Assessing changes in energy demand after end-use electrification

Demand models are important tools for assessing end-use demands as part of the analysis of alternative energy system decarbonization strategies [11], [22], [23]. Demand models can be used to assess potential transformations of end-use sectors in the context of ambient temperature, population dynamics, consumer behaviour, and technology changes. Regional electricity grids are interconnected with national networks, requiring high resolution demand models to capture the effects of decarbonizing demand on high temporal and spatial scales [24]. Moreover, high spatial and temporal resolution of demand becomes increasingly important in combination with future energy systems holding large shares of VRE generation where large-scale energy storage is to be deployed [25]. Spatial detail in demand models captures geographical characteristics driving future infrastructure investments while temporal detail captures load profile changes and the correlation with other coincident loads [22], [24].

With electrification of road transportation and heating incented in many jurisdictions [26], a better understanding of these demands is needed to ensure secure electricity supply. Electrifying end-uses that traditionally use fossil fuels might coincide with other electric loads which affects the timing and magnitude of peak electricity demand, thereby, determining future electricity grid capacity requirements [7]. Additionally, end-use electrification increases the magnitude and frequency of more extreme hourly load changes, here defined as ramping rates, and range of electricity demand, affecting flexibility requirements of the electricity grid [27], [28]. Understanding the temporal profile and the geographic variability of electricity demand after end-use electrification is key to support long-term electricity grid planning and operation to reliably supply electricity [24].

Future demand resulting from electrification of end-uses in the building and road transportation sectors is difficult to quantify as these demands are driven by a variety of factors. Energy demand for building heating, cooling, and road transportation end-uses are driven by ambient temperature [17], [29], [30]. In the building sector, energy demand is further driven by building stock evolution, building envelope efficiency improvements, consumer behavior, technology choices and technology efficiencies while in the road transportation sector, energy demand is further driven by electric vehicle (EV) penetration rates, charging strategies and rates, and driver behavior [11], [17], [24], [31].

The effect of end-use electrification on capacity and flexibility requirements may change non-linearly with population growth when multiple end-uses are electrified simultaneously due to temporal correlation of electricity loads [28]. This effect can be mitigated with DSM strategies that limit the temporal correlation of electricity loads [17], [22]. These strategies include flexible vehicle charging [17], [28], [32]; vehicle-to-grid services [33]; building envelope improvements [18]; deployment of high-efficiency heating equipment or hybrid heating systems [18], [34]; and night ventilation or window shading to limit cooling demands [30].

1.2.2 Quantifying impacts of variable renewable energy supply on net load

Integrating large shares of VRE resources leads to an increase in supply variability in most electricity systems [35]. A large penetration of VRE resources will increase the volatility and uncertainty of net load [36]. System operators have begun to confront this problem by making efforts to enhance operational flexibility as a lack of flexibility may cause an unserved net load, thereby, threatening stable system operations [37]. With the ability to balance fluctuating VRE generation and electricity demand, increasing flexibility allows system operators to utilise VRE resources reliably, ensuring a more resilient energy system [38].

In hydro-dominant regions, flexible hydroelectric power generation is the sole dispatchable generation asset. In these regions, changes in dispatchable capacity requirements due to variations in VRE supply may lead to extremely large energy storage capacities [39]. Examining the effect of VRE supply variability on future net load will support system planners in identifying periods of surplus energy or energy deficiency. This provides the means to assess potential strategies to avoid surplus energy and bridge any periods of energy deficiency [39].

To assess strategies for increasing operational flexibility, analyses of future net load are necessary to determine, for example, periods of surplus energy and periods of unserved net load. Strategies to enhance operational flexibility include overproduction of VRE resources, energy storage, transmission and distribution upgrades, import of electricity from neighboring systems, and DSM [19], [39]–[41]. Identifying the most effective flexibility strategy – or combination of flexibility strategies – will largely depend on the shape of electricity demand, the type of generators in an energy system, the penetration of VRE resources, and spatial and temporal characteristics of the electricity system [7], [42].

1.2.3 Key limitations

Although electrification of end-uses is considered an effective strategy to reduce GHG emissions, only a small number of supply-side analyses include detailed consideration of changes in energy demand due to end-use electrification [2], [43]. These analyses are, therefore, not helpful in planning for sufficient capacity and flexibility to ensure resource adequacy across the entire energy system. Long-term electricity grid planning scenarios should include projections of energy demands where key aspects of end-use demands, such as fuel type, consumer behavior, and equipment adoption, are considered. Eggimann et al. [24] create a high spatiotemporal tool for projecting future energy demands in the residential building, service, and industry sectors for a range of energy vectors considering technology equipment efficiency improvements and penetration rates. A further important aspect of their model is the integration of load shifting to off-peak hours. However, the inclusion of building stock turnover, energy efficiency improvements through retrofits and building code standards, and temperature-dependent equipment operations is not included. Moreover, the commercial building and transportation sectors are disregarded entirely, and the model does not include supply-side considerations.

On the supply side, the resource mix will likely shift toward more variable resources that will be impacted by weather variability and future climate conditions [14], [44]. Future climate conditions and the resulting changes in ambient temperature are highly uncertain, thereby, necessitating electricity grid infrastructure in hydro-dominant regions to be designed such that it can cope with variations in water supply. Previous studies on net load variability in highly renewable energy systems using statistical analyses do not include heating and transportation energy demands and the optimal dispatch of generation assets [19]. Combining increasing variability of electricity demand with rising variability of VRE generation adds significant complexity to electricity system operations [45], [46]. This requires systems planners to ensure resource adequacy when balancing supply- and demand-side variability [7]. However, studies that focus on reduction of net load under consideration of energy demand evolution and water supply variability are sparse because of the focus on hydro-dominant jurisdictions where end-use electrification is incentivized.

1.3 Objectives and outline

Examining potential flexibility strategies to mitigate demand and supply variability for multiple weather conditions such as prolonged drought periods, increasing precipitation, heat domes or cold snaps would provide a more comprehensive basis for long-term resource planning of electricity grids. Additional modelling of future demand dynamics and VRE supply strategies under climate-induced water supply variability will provide capabilities to assess electricity grid infrastructure requirements across a range of potential futures. Greater spatial detail is needed to account for the impact of ambient temperature on energy demands, equipment operations, and VRE generation potential. Greater temporal detail is needed to examine regional aggregation effects on the timing and magnitude of future electricity demand and supply. Combining high spatiotemporal demand projections with a high-resolution production cost model will support the analysis of trade-offs between ambient temperatures, energy demand drivers, and VRE generation for a range of water supply availability scenarios.

The objective of this dissertation is to assess the technological implications of decarbonizing energy demand and supply. For this purpose, a computational analysis tool projecting future energy demand is developed. Specifically, a high-resolution energy demand model is developed to examine heating demands that incorporates: (i) a detailed building stock model projecting building stock turnover and envelope improvements by mid-century and (ii) an endogenous, spatially distributed representation of heating and cooling equipment operation as a function of ambient temperature. Moreover, an improved version of a computational analysis tool is developed to examine generator dispatch behavior in a highly renewable electricity grid. Specifically, a production cost modelling framework is enhanced to incorporate multiple types of hydroelectric power generation to capture changes in hydro-climatic conditions. The modelling tools are demonstrated within three case studies to assess regionally specific issues surrounding energy system infrastructure planning.

In Chapter 2, the building heating demand model is applied to examine the impact of end-use electrification for heating on capacity and flexibility requirements in British Columbia, Canada. The scenario analysis developed for this chapter integrates changes in ambient temperature with changes in building envelope efficiency improvements, heating equipment penetration, and heating equipment operation. Investigating the impact of heating equipment penetration is crucial in this region, mainly due to the large financial incentives offered to customers when switching from gas to electric heat. The model is then extended in Chapter 3 to include electrified space cooling energy demand for the residential building sector and combined with a demand model projecting road transportation energy demands to examine the impact of DSM strategies on capacity and flexibility requirements in British Columbia, Canada.

In Chapter 4, the demand modelling tools are combined with an improved representation of hydroelectric power generation in a production cost model to assess flexibility strategies in a hydro-dominant region such as British Columbia, Canada. Hydroelectric power generation is crucial in this region, mainly due to the large contribution of hydropower to provincial electricity supply. To assess flexibility strategies periods of surplus energy and periods of unserved net load are examined. These objectives are selected as the focus for the analysis due to the anticipated challenges in balancing future end-use electrification with high penetrations of VRE supply. The former is a concern in jurisdictions where the electrification of certain end-uses is being incented. A better understanding of the shape and magnitude of future electricity demand is required to understand the implications of end-use electrification on future electricity grid requirements. Assessing the impact of climate on VRE supply in British Columbia’s hydro-dominated electricity grid requires analyses of annual changes in water supply due to drought conditions or additional precipitation. This establishes the need to analyse the generation potential of other VRE resources such as wind and solar in combination with large-scale hydroelectric power generation and to assess flexibility strategies to bridge periods of energy deficiency.

In Chapter 5, the contributions of this dissertation are summarized to present the impact of end-use electrification on capacity and flexibility requirements and to show the effect of increasing shares of VRE generation on dispatchable generation capacity requirements when planning for resource adequacy in future electricity systems. Finally, recommendations for future work are presented that warrant further investigation.

Chapter 2

Heating electrification in cold climates: Invest in grid flexibility[1]

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Preamble

One strategy to significantly reduce greenhouse gas emissions in end-use sectors such as building heat is to switch from fossil fuels to electricity. To date, electricity consumption follows a regular and predictable pattern; however, electrifying building heat, which is driven by ambient temperature, causes this pattern to change. Previous work has not fully addressed the implications of building heat electrification on the timing and magnitude of peak demands and on flexibility requirements of the electricity grid. In this work, a high-resolution heating demand model, featuring building stock turnover forecasts, is developed, and applied to British Columbia. The study determines energy, capacity, and flexibility requirements by computing regional energy load profiles for space and water heat. Six scenarios were developed to examine the decarbonization potential in the residential and commercial building sector, considering increased heat pump adoption, building envelope energy efficiency improvements, and the implementation of building energy codes. With an emphasis on building stock improvements, 90% heat pump penetration results in only 6% increase in electrical energy even with an annual population growth rate of 1.1%; however, this scenario leads to 37% increase in peak electricity demand. Over the time-period considered, building energy codes, and retrofit rates contribute relatively little to achieving net-zero emissions in the buildings sector, while building heat electrification has significant impacts on future flexibility requirements of the electricity grid.

Nomenclature

Acronyms

ASHP	Air-Source Heat Pump
AWHP	Air-Water Heat Pump
BC	British Columbia
COP	Coefficient of Performance
EUI	Energy Use Intensity
GHG	Greenhouse Gas
HDD	Heating Degree Days
VRE	Variable Renewable Energy

2.1 Introduction

Transitioning towards a sustainable energy system requires changes in both energy supply and energy demand. The supply side has received a lot of attention, mainly regarding variable renewable energy (VRE) generation and the resulting changes in capacity and dispatch [43], [47], [48]. However, supply-side technology requirements can not be fully determined in the absence of knowledge of energy demand shapes and magnitude [7]. With electrification of transportation and heating being incented in various jurisdictions, a better understanding of these demands is needed to support system planning. Moreover, in more northern regions such as Canada, the implications of heating electrification on capacity and ramping requirements are of particular importance for reliable and cost-effective electricity systems [49].

Electrifying building heat in jurisdictions where natural gas serves a significant fraction of heating demand might coincide with other loads causing peak electricity demands to increase significantly [49]. In 2019, the residential building sector consumed ~15% of global final energy with natural gas being the main energy source [50]. Reducing the associated greenhouse gas (GHG) emissions can be achieved by using renewable and low-carbon fuels for heating [51]; however, direct electrification of space and water heating is also seen as an effective strategy [52]. Electrifying both space and water heat poses risks such as insufficient dispatchable capacity and unpredictable variations in the spatiotemporal pattern of electricity consumption [7], [52]. In warmer climates electrifying building heat may shift peak demand from summer to winter [7], whereas in colder climates, such as Canada's, the magnitude of peak and annual electricity demand could increase significantly [49]. These effects may be mitigated by reducing heating and electricity demands through energy efficiency improvements [53]; implementation of building energy codes for new builds [54], including policies setting maximum allowable levels for the energy use of a building; and, the use of high-efficiency heating equipment [55].

The impacts of heating demand drivers such as weather conditions, building design, population dynamics, consumer behaviour, and heating technologies are investigated using demand modelling [22], [24], [56]. Many studies simulating building heating consider annual energy requirements with geographical resolution ranging from regional [22] to national [56]. Spatial detail is important so as to capture the regional characteristics driving specific future infrastructure investments [22], [24]. Temporal detail is crucial to capture fluctuations of heating demands and to determine how they may correlate with other coincident loads thereby shaping the timing and magnitude of peak demand [29]. High spatiotemporal resolution of demand becomes increasingly important when we consider future energy systems with high shares of VRE generation and where large-scale energy storage is to be deployed [25].

This work is the first to examine the magnitude and timing of peak demands and ramping requirements for electrified heating that considers building stock envelope and technology efficiency improvements. In this paper, a high-resolution demand model for space and water heating in residential and commercial buildings is introduced. The main objective is the generation of end-use specific, hourly demand profiles capturing the effects of building stock composition and temperature variability. Arbitrary mixtures of heating technologies can be applied to examine the shape and magnitude of peak electricity demands and ramping events after building heat electrification. In addition, we consider the composition of building stock, its turnover due to renovation, construction and demolition, and the stringency of building codes. Model results support the development and implementation of policy in the building sector and provide guidance to utilities in planning for sufficient capacity and flexibility in the electricity grid.

The following section presents a review of related modelling approaches. Section 2.3 introduces the current methodology (full details provided in the Supplementary Material). Section 2.4 describes the input data and introduces a regional study in which the model is applied to the province of British Columbia (BC), Canada. Modelling results are presented in Section 2.5 and discussed in Section 2.6. Section 2.7 provides concluding remarks.

2.2 Background

This section reviews approaches for modelling space and water heat demand that consider drivers such as weather variability, building stock forecasts, building envelope efficiency improvements, and equipment selection. These demand drivers are reflected in a large range of policy strategies, and together provide a comprehensive framework to simulate potential futures.

In colder climates, modelling heating demand is of particular interest as the electrification of building heat is challenged by low ambient temperatures and high heating demands in winter months. The impact of ambient temperature on heating demand is well recognized [29], [57]. A UK study indicates that a decrease of ambient temperature by 1°C increases final heating demand by 1 MWh/year per household [57]. Heating energy demands in Italy vary by up to 20% depending on the weather year; however, regional variations in ambient temperature lead to variations in specific heating demand profiles. These results highlight that regional variability of ambient temperature can cause spatial and temporal asymmetries of heating demands directly impacting the shape and magnitude of peak demands [29]. The magnitude of temporal fluctuations in heating demand due to variations in ambient temperature can be mitigated through energy efficiency improvements in the building stock [18] and the deployment of high efficiency electric heating technologies [34].

Improving the energy efficiency of buildings is a known strategy to reduce energy consumption and CO_2 emissions in the building sector [58]. To model energy demands in the building sector, some studies determine end-use energy consumption based on historical data [59] while others analyze energy consumption for individual building archetypes [60]. Table 2.1 summarizes the advantages, disadvantages, and limitations of both approaches. Previous work shows that, in Finland, energy efficiency improvements in the residential and commercial building stock (i.e. retrofits and building codes) could reduce CO_2 emissions by up to 30% and energy use by up to 13% by 2050 [61]. In the residential building stock in Sweden, CO_2 emissions and energy use could be reduced by 63% and 55%, respectively [62].

If modelling approaches do not consider retrofits as part of building stock turnover, energy reductions are determined for the existing rather than a future building stock composition [63]. Some studies find that a retrofit rate of 2.5% to 3% of floor area per year is achievable [64] while others conclude that the maximum annual retrofit rate is limited to 1.6% [31], [65]. If the lower rates prevail, some existing buildings will not be retrofit by 2050, whereas if the higher rates prevail it is crucial to consider the age of a building stock to avoid full building envelope retrofits in newer dwellings where lower energy savings would be achieved [31].

To limit peak demands when electrifying building heat, heat pumps should be prioritized over resistance heaters due to their enhanced efficiencies. However, switching to heat pumps without concurrent improvements to buildings will likely increase electricity peak demands in colder climates due to the large share of gas heating that will need to be electrified [18]. While the impact of heat pumps on the grid, more specifically on the temporal variability, is not well understood [66], some studies find that heat pump penetration rates of 20% can lead to an increase in peak electricity demand of 14% [67]. However, penetration rates of 30% could start to threaten secure electricity supply in rural areas due to voltage issues [66]. If lower efficiency resistance heating were the sole electric heating technology, peak electricity demand would be even higher [68].

Table 2.1. Advantages, disadvantages, and limitations of two approaches to determine energy use in the building sector.

	End-use energy consumption [59]	**Energy consumption of individual building archetypes** [60]
Advantages	Historic data is used to establish a relationship between end-use and energy consumption (i.e., through regression analysis)	More detail in energy consumption of individual building archetypes
Disadvantages	Availability of historical high-resolution data	Detailed analysis of various building types needed to represent the full building stock
Limitations	High-resolution data required for each end-use to obtain detailed information on i.e., residential space heating	Representing full building stock via building archetypes is computationally complex

To identify the implications of building heat electrification on peak demands, a realistic representation of heat pump behaviour is needed [11], [69], [70]. Some studies generate heating demand profiles by assuming a constant or average coefficient of performance (COP) for heat pumps [22], [56]. However, at sufficiently low ambient temperature, the COP of a heat pump decreases and will eventually be similar to a resistance heater. Applying a constant COP for heat pumps might be acceptable for estimating energy demand; however, this approach can lead to underestimating the impact on peak demands. Recognizing this underestimation, some studies generate hourly COP profiles for heat pumps based on regional temperature data to capture realistic heat pump operations [23], [71].

Limiting increases in peak electricity demand while significantly reducing GHG emissions in the building stock can further achieved by hybrid heating systems [72]. In a hybrid configuration, a gas system is installed in parallel with an electric heat pump such that during periods of high demand, heating is served by the gas system [18]. An analysis where electric-gas hybrid heating systems replace gas boilers in residential buildings shows a potential to decrease peak electricity demand by 30% compared to a 100% heat pump penetration rate [22]. The advantage of these systems lays in their potential to reduce GHG emissions and simultaneously minimize capacity and flexibility requirements of the electricity grid [73].

Reducing energy use of buildings can be achieved by setting stringent building codes or providing financial incentives to improve existing building envelopes and upgrade heating equipment [31], [74], [75]. The highest energy savings are attributed to retrofitting full building envelopes [76]; however, due to relatively long periods (~40 years) between full building envelope retrofits, the impact of policies on retrofit rates are limited, establishing the need for a rapid, large-scale penetration of high-efficiency heating technologies [31]. Replacing heating equipment with more efficient units is financially more advantageous compared to retrofitting full building envelopes and can be achieved on shorter timescales through financial incentives [75], [77]. However, policies to incent the replacement of heating equipment will have to be in place in the next few years to take advantage of phasing out systems that naturally reach the end of their lifetime [77].

Understanding the temporal profile of electricity demand, after electrification of building heating, is key to ensuring electricity system planning and reliability. As discussed in previous studies, ambient temperature, building envelope efficiencies, and heating equipment selection are fundamental drivers of heating demand. Previous work shows that building stock composition has significant impact on space and water heating demands [78]. However, among building stock models forecasting space and water heating demands, inclusion of building stock turnover and energy efficiency improvements through retrofits and building code standards are not common and many disregard the commercial building sector entirely [62], [79], [80]. To determine future space and water heating demands, detailed building stock models are needed that forecast building stock turnover due to new construction and demolition and energy efficiency improvements through retrofits, building code standards, and heating equipment upgrades.

The current study presents a model that addresses this gap by generating space and water heat demand profiles for the residential and commercial building sectors considering seasonal weather variations with detailed building stock turnover, efficiency improvements, and equipment operations. Changes in building envelope efficiencies are captured by projecting building stock turnover to 2050 under various retrofit rates and building energy codes. To identify the effect of heating technology upgrades, adoption rates, and equipment operations, temperature-dependent heat pump COP profiles are generated. The novelty of this work is its method, which enhances heat demand projections by considering changes in building stock compositions, strategies to improve building envelope efficiencies, shifts in heating equipment penetration, and variations of weather. This enables investigations of heat demand drivers on the timing and magnitude of peak demands, and thus, capacity and flexibility requirements of the electricity grid.

In the following section, the modelling methodology is described. First, the spatiotemporal load disaggregation method is presented. This method is used to generate region- and end-use specific normalized demand profiles. Next, the generation of useful energy demand profiles including building stock turnover forecasts is discussed. Finally, the generation of final energy demand profiles for varying heating technology mixes and efficiencies is presented. Additional details on the modelling methodology are provided in the Supplementary Material.

2.3 Methodology

Fig. 2.1 shows an overview of the model scope. In this model, useful energy demand, on the right, for each end-use is determined based on future building stock composition and envelope efficiencies. Final energy demand, on the left, is converted using a mixture of end-use heating technologies to provide useful energy demand within the building sector. Useful energy demand is defined as the energy that is required to satisfy end-use demands while final energy demand is defined as the energy required to satisfy a specific end-use, using a specific technology. Residential and commercial space and water heat demands are modelled individually whereas a residual load profile serving non-heating energy demands in the building, transportation, agricultural and industry sector is generated using regional electricity load data. We focus on electricity as the final energy vector so that a range of electrification strategies for building heat can be investigated; however, energy demand profiles for natural gas or hydrogen can be generated using performance metrics for appropriate end-use technologies.

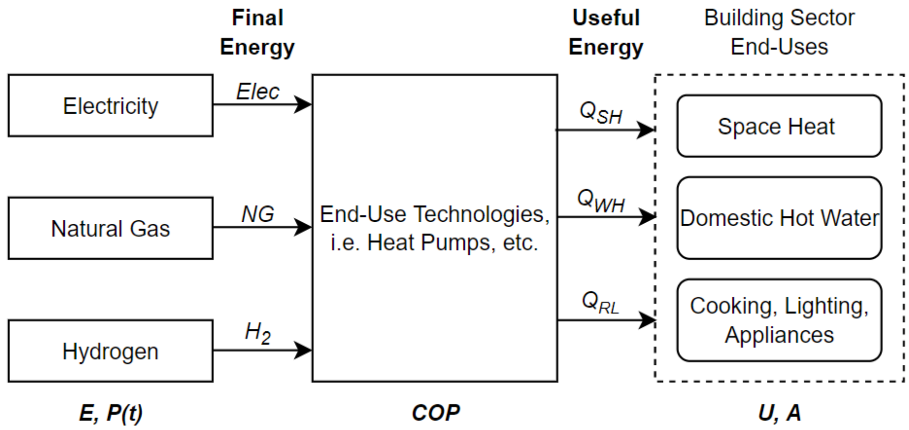


Figure 2.1. Useful energy demand profiles are generated for individual end-uses and converted to final energy demand profiles using a mixture of end-use heating technologies that fulfill the heat demand.

Key to our analysis is the development of end-use demand profiles reflecting specific regional characteristics. Energy demand profiles prescribe the temporal variations of heating and electricity demand such that the impact of peak demands, varying in timing and magnitude, can be identified. Fig. 2.2 summarizes the methodology. The left column shows data inputs, followed by modelling steps in the middle and results on the right. In a first step, end-use specific, hourly demand profiles are generated using real-world load profiles for space and water heat as well as gross electricity. In the second step, useful energy demands are projected to future years based on variations in weather conditions, annual energy use, and future building stock compositions. Last, based on the useful energy demand profiles obtained in step two, final energy demands are determined using the heating technology mix. The heating technology mix defines the share that each heating technology provides to final energy demand for space and water heating.

The following sections describe the spatiotemporal load disaggregation, useful energy demands, and final energy demands in more detail. The key principles are summarized to enable understanding of the analysis presented in this paper, while all model equations and supporting details are outlined in Appendix A of the Supplementary Material.

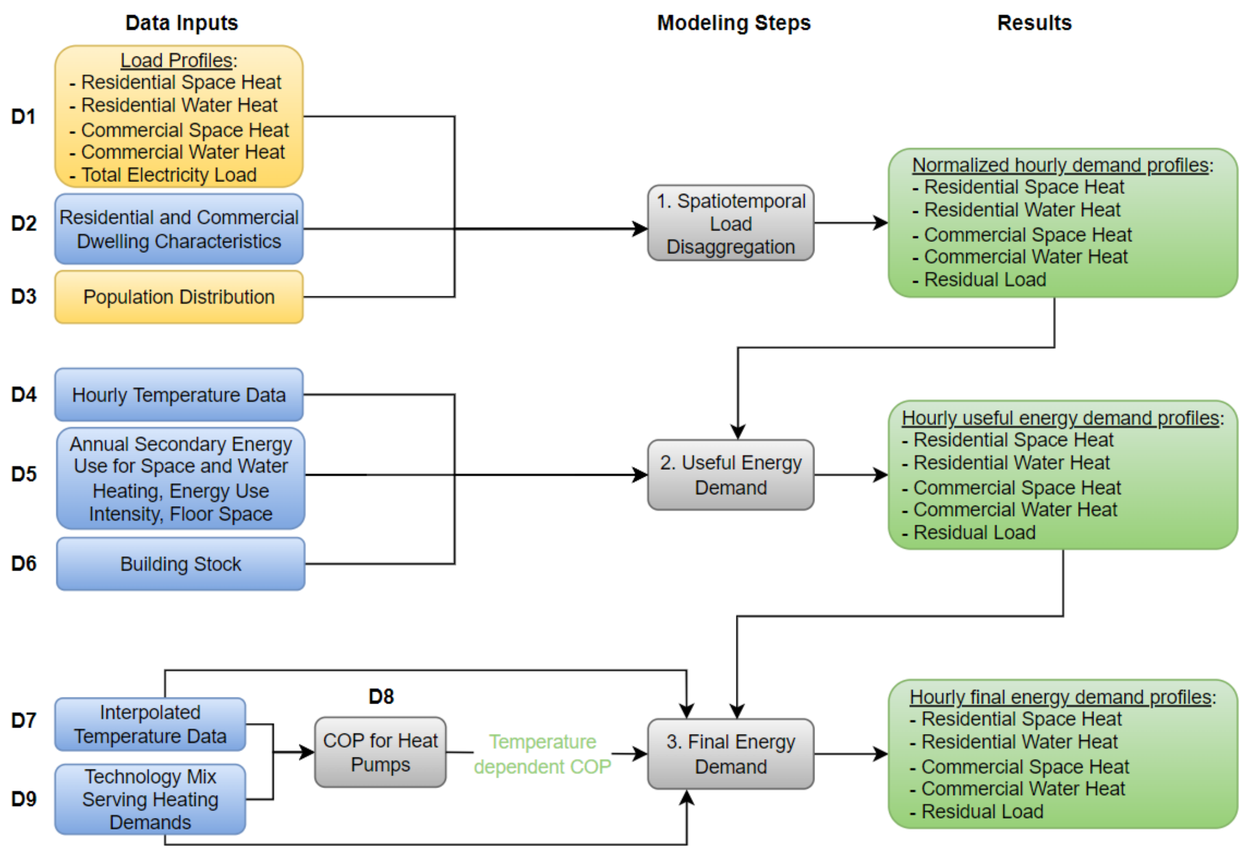


Figure 2.2. Conceptual overview of the space and water heat demand model. Constant data inputs (shown on the left in yellow boxes) include real-world load profiles for residential and commercial space and water heating, total electricity load, and population distribution for regional disaggregation. Scenario-dependent, variable data inputs (shown on the left in blue boxes) include dwelling characteristics, ambient temperature data, building stock composition and energy consumption of the building stock, and heating technology efficiencies as a function of ambient temperature. Modelling steps are shown in grey boxes. First, normalized energy demand profiles are generated through spatiotemporal load disaggregation (Section A.1 Supplementary Material). Second, the normalized profiles are then upscaled to match the annual useful energy demand obtained (D4 – D6, Section A.2 Supplementary Material). Finally, technology mixes and efficiencies (D7 – D9) are applied to the useful energy demand to generate final energy demand profiles (Section A.3 Supplementary Material).

2.3.1 Spatiotemporal load disaggregation

Fig. 2.3 shows the method to generate end-use specific future useful ($E_{u,y+1}$) and final energy demand profiles based on end-use specific reference year data (E_u). First (Fig. 2.3(a)), real-world end-use specific load profiles E_u (Fig. 2.2, data input D1) are normalized by dividing each hourly energy demand by the total annual energy demand ((Fig. 2.3(b)). These normalized profiles are then used to create region-specific aggregated profiles by weighting demands according to the fraction of each building type in a region (Fig. 2.2 data input D2). The spatial disaggregation of provincial data (Fig. 2.2 data input D3) is performed based on the proportion of population in individual sub-regions. In the next step (Fig. 2.3(c)), the regional profiles are scaled up to match end-use specific future annual useful energy demands $E_{u,y+1}$ based on ambient temperature, building stock forecasts and annual energy use (Fig. 2.2 data input D4-

D6). Finally, heating technology mixes and efficiencies (Fig. 2.2 data inputs D7-9) are applied to the useful energy demand profiles to generate final energy demand profiles as shown in Fig. 2.3(d). The methodology for spatiotemporal load disaggregation is presented in Section A.1 in the Supplementary Material.

Residential heating profiles have a unique level of detail in step 2 of Fig. 2.2. Heating load curves are determined using a confidential dataset from the BC electricity balancing authority consisting of over 5000 residential hourly electricity demand profiles. The dataset includes loads for individual dwellings of five dwelling types within four regions and indicates whether homes use electric or non-electric space heating. Whilst the total number of dwellings in the dataset comprise only a small proportion of the dwellings in BC, the composition with regards to dwelling type and region are representative of the entire province. The electric heating demand for each dwelling type is determined by comparison to non-electric building demands. The temperature threshold at which electric heat is turned on for each region and building type is determined from linear regression. Based on the extrapolated heating load-lines, future heating demand profiles are constructed based on samples from two-decades of weather data. Building stock evolution and energy intensity assumptions are applied to scale the load-lines. Further details are presented in Supplementary Material A.1.

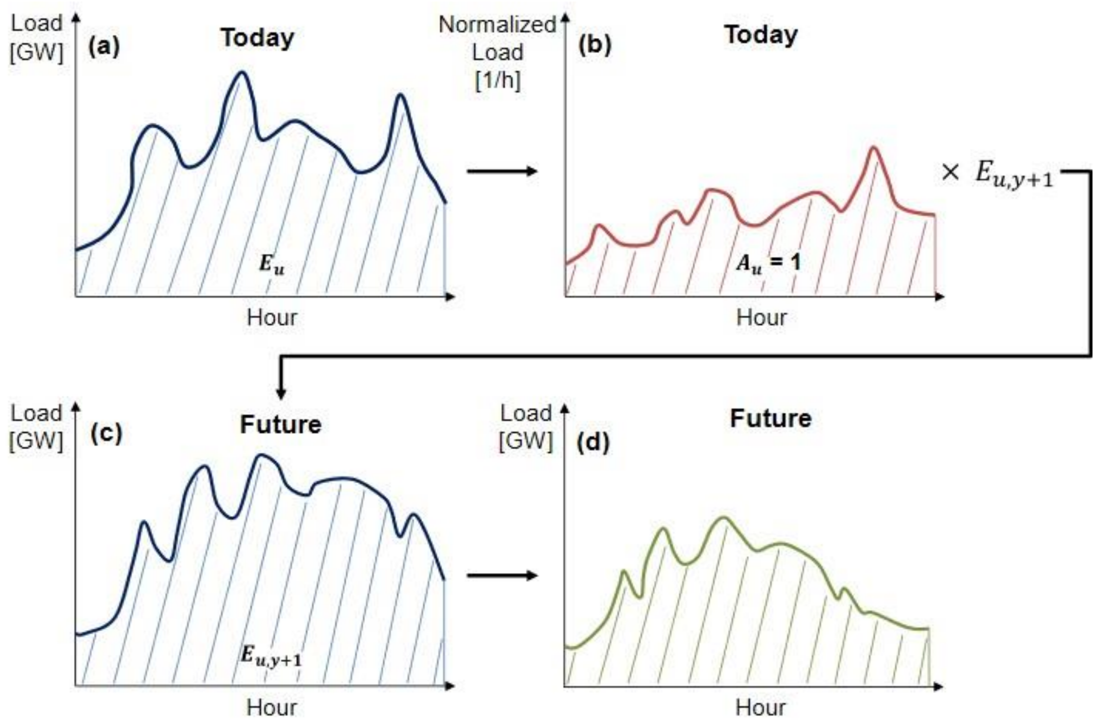


Figure 2.3. (a) shows an end-use specific real-world load profile E_u used for the spatiotemporal load disaggregation. The end-use specific real-world load profile is normalized by dividing each hourly energy demand by the total annual energy demand which is shown in (b). The normalized profile is scaled up to future annual useful energy demand $E_{u,y+1}$ to obtain the useful energy demand profile in (c). Useful energy demand is determined based on the energy consumption of buildings and building stock turnover. Applying technology mix and efficiencies to the useful energy demand profile in (c) results in the final energy demand profile in (d).

2.3.2 Useful energy demands

A key factor determining future space heat demands in residential buildings is the growth and evolution of the stock itself. For this, we consider the building stock age distribution, also called vintages, and their associated projections of energy use intensities as defined by building code implementation. In the case of future residential water heat demands, for now we assume this is dependent on population growth only. For projections of future residential space heating demand, retrofit, demolition, and new construction rates are applied. Future commercial space and water heat demands are assumed to grow proportionately to population and with a change in energy use intensity that is half that forecasted for the residential sector. The methodology to forecast space and water heat demands in the residential building stock is presented in section A.2.1 of the Supplementary Material. The methodology for commercial space and water heat demand forecasts is presented in section A.2.2 in the Supplementary Material. The high-level methodology is described below.

Today's residential building stock is a collection of vintages with a defined proportion of floor area. Knowing the average energy use intensity for heating for each vintage, we can determine the aggregate intensity for the stock. Thus, to estimate future end-use heating demand we project stock change due to new construction, demolition, and retrofits and, as defined by scenario, apply expected building code requirements for energy use intensity on new and renovated area. Fig. 2.4 shows an example of this process.

Fig. 2.4(a) shows historical area per vintage while Fig. 2.4(b) shows an example of changes in floor space due to demolition and new construction. Demolition removes less efficient floor space from the building stock; however, some fraction of stock may never be demolished to retain what are called heritage buildings. New construction is required to satisfy population growth, changes in area per capita, and the replacement of demolished buildings. In Fig. 2.4(b) all floor space subject to demolition over the previous year is removed while newly constructed floor space is added for the year $y + 1$. In this work, the share of the building stock that is exposed to retrofit activities during the ageing process is assumed not to add any additional floor space to the building stock. Fig. 2.4(c) shows the distribution of energy use intensities per vintage in year *y*, while Fig. 2.4(d) shows an example of changes in energy use intensities due to new construction and retrofits. Energy use intensity per vintage is kept constant for the remaining building stock. For retrofits, a deep renovation of the building envelope is assumed such that their energy use intensity meets those of new buildings.

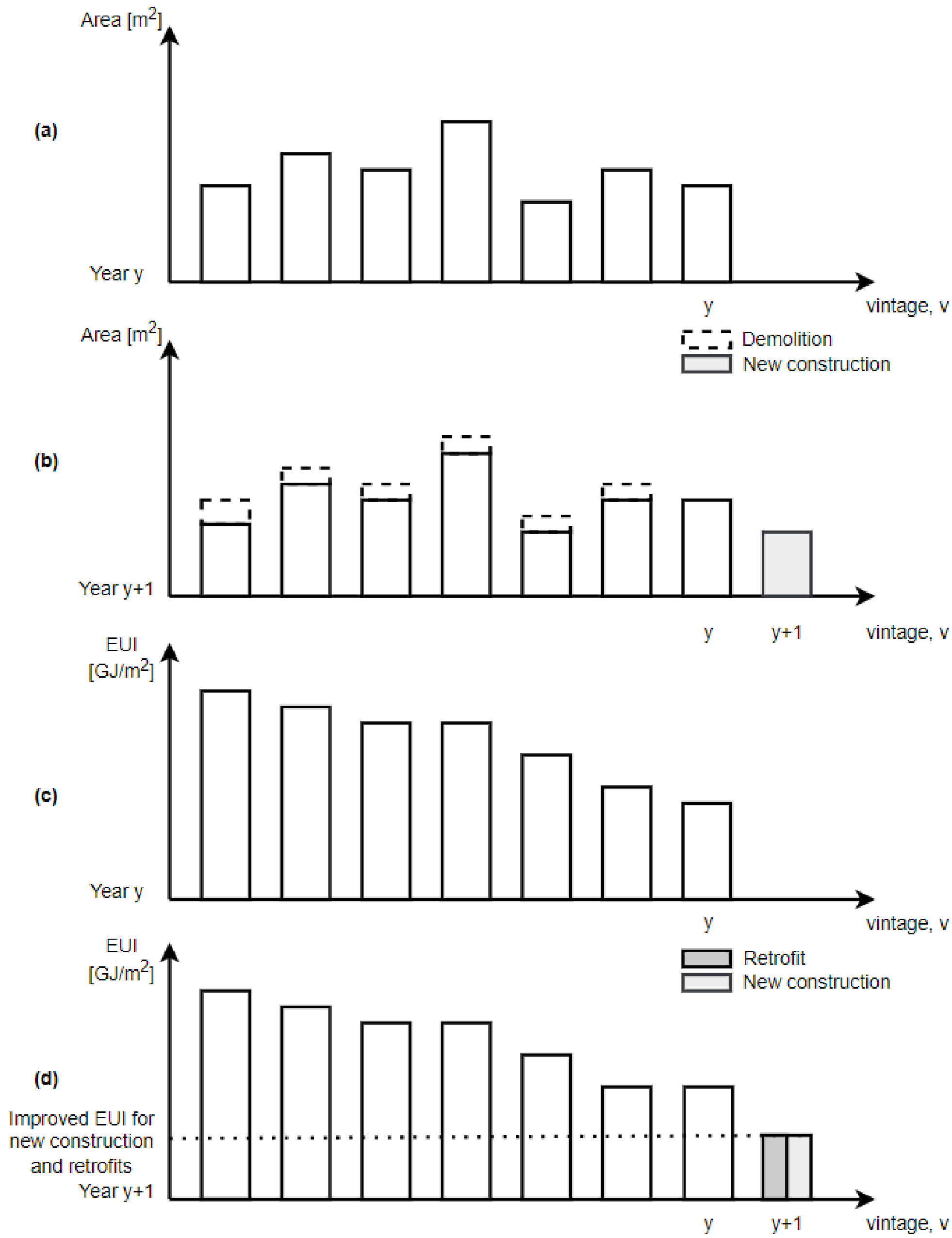


Figure 2.4. (a-b) show the evolving residential building stock composition per vintage. (a) shows historical area per vintage, (b) shows how each vintage could evolve depending on demolition and new construction rates. (c-d) show changes in energy use intensity per vintage. (c) shows historical energy use intensity per vintage, (d) shows how energy use intensities could evolve depending on retrofit and new construction rates.

The changes in floor space and energy use intensities in Fig. 2.4(b) and Fig. 2.4(d) due to renovation and demolition can vary across vintage v and are exogenously defined by normalized distributions of renovation and demolition activities per vintage (See section A.2.1 Fig 1. In the Supplementary Material). Historical new construction and demolition rates are used as a starting point for future building stock turnover (Supplementary Material B.1); however, future new construction, demolition and retrofit rates are exogenous model variables and depend on scenario data such that a range of different futures can be investigated.

Electricity serving non-heating demands is included as residual electricity load. We define the residual load as the difference between an hourly 3-year average of gross electricity demand (Fig. 2.5(a)) and a 3-year average of real-world load curves of each end-use (Fig. 2.5(b)) (Fig. 2.2 Data input D1; Supplementary Material A.2.3).

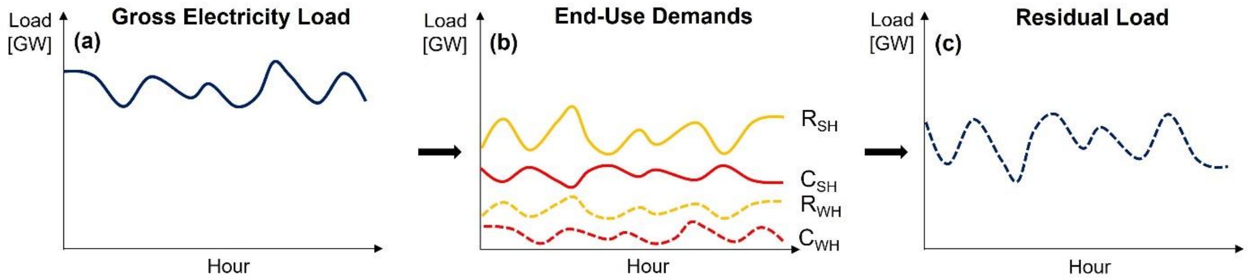


Figure 2.5. Using a 3-year average from 2017 to 2019, (a) shows the average gross electricity demand while (b) shows actual end-use specific electricity load curves for residential and commercial space and water heat. The residual load curve in (c) is obtained by subtracting the electricity load curve of each end-use in (b) from the gross electricity load curve in (a).

Finally, a fraction of the useful heat demands is electrified depending on the applied electrification strategy. In future years, the total electrified heat demand is the sum of existing electric heat demand and the fraction of fossil-fuel heat demand assumed to be electrified.

2.3.3 Final energy demands

In the third modelling step, final energy demand profiles are generated by applying heating technology assumptions that account for the efficiency as a function of operating conditions. Energy savings from energy efficiency programs to a large extent are generated by increasing the share of new high-efficiency heating technologies for space and water heating. In this work, hot water technology efficiency is an exogenous model variable that is represented as a constant value for electric water heaters or an hourly time series for Air-to-Water Heat Pumps (AWHP). For space heating, a range of different technologies can be applied with varying efficiencies. An hourly temperature dependent COP time series for Air-Source Heat Pumps (ASHP) is created according to [49]. Heat pump efficiencies vary between the residential and commercial building sectors, while the share of space heat met by heat pumps is dependent on specific scenarios. In this work, it is assumed that any electrified space heat demand not served by heat pumps is met using electric resistance heaters. The resulting regional and end-use specific final energy demand profiles are then summed to yield provincial load curves.

2.4 Data

Heating electrification and the method described in the previous section is applied to the province British Columbia (BC), Canada. BC has an ambitious policy for emissions mitigation using the existing low-carbon electricity system. Unlike other provinces in Canada, much of the population resides in areas with characteristics of Climate Zone 4, and, therefore, has a lower number of heating degree days (HDD). The government of BC has introduced financial incentives to make the switch from fossil fuel-based heating to more efficient electric heat pumps more attractive for consumers [67]. In 2019, the building sector in the province was responsible for 14% of total GHG emissions [7], [68], [69]. Table 2.2 shows all data inputs used to model energy demand profiles for BC with references to individual data inputs introduced in Fig. 2.2.

Table 2.2. Data inputs for regional study.

	Data	**Description**	**Reference**
D1	Load profiles for residential space and water heat	Load profiles for residential space heat and domestic water heat demands in hourly resolution for 2016.	BC Hydro Confidential
D1	Load profiles for commercial space and water heat	Hourly load data for commercial space and water heating in 2016 and weighting factors representing 15 commercial reference building models.	[81]
D1	Residential and commercial dwelling characteristics	Weighting factors based on annual space and water heating demands for residential and commercial building types	[82]–[85]
D1	Gross Electricity Demand	Gross electricity demand observed in 2016 represents the total electricity supplied to BC Hydro customers in the fiscal year 2016, including losses and system use, and after trade	[86]
D1	Hourly Electricity Demand	Observed hourly electricity demand in British Columbia from 2002 to 2019	[87]
D3	Population distribution	British Columbia is aggregated into four regions based on population to represent regionally specific heating demands	[88]
D4 **D7**	Temperature data	Hourly temperature data from select weather stations across BC; temperature data for commercial heat demand regression	[89]–[95]
D5	Annual energy demands, Total floor space, Energy Use Intensity, Observed efficiencies	Provincial values for annual residential and commercial space and water heating energy use, energy use intensities, heating system stock efficiencies	[82]–[85], [96], [97]
D6	Building stock	Housing stock classification by vintage and floor space in British Columbia; Provincial population growth of 1.1%/yr is expected	[98]
D6	Energy Use Intensities	Energy Use Intensities for residential and commercial buildings in different climate zones according to the BC Energy Step Code	[99]
D8	Heat Pump Coefficient of Performance Curve	Residential • Low Efficiency Air-source Heat Pump (ASHP): Data from 23 residential non-cold climate heat pumps is used. • High Efficiency Air-source Heat Pump (ASHP): Data from 26 ductless mini split and central heat pump systems at 24 distinct single-family residential sites on Vancouver Island and in the Southern Interior in 2019 is used. Commercial: • Low Efficiency Air-water Heat Pump (AWHP) • High Efficiency Air-water Heat Pump (AWHP)	[71], [100], [101]
D9	Resistance heater efficiency Electric water heater efficiency	1.0 0.95 (5% standby losses)	Assumed

In this work, we do not consider future changes to the industrial, agricultural, or transportation sectors and the residual load is assumed constant at 51.6 TWh/yr. Our analysis examines the impact of ambient temperature, building stock forecasts, and technology mix and efficiencies on residential and commercial heating demands only. The building stock turnover in this work captures the evolution of the residential and commercial building stock between 2017 and 2050. 20 years of data on historical floor space by building type and vintage in BC's residential building sectors are used to determine historical new construction and demolition rates [102] (See section A.2.1 in the Supplementary Material). To preserve the provincial building heritage, it is assumed that 5% of the building stock per vintage in 2017 is never demolished. It is assumed that retrofits start 20 years after new construction and that retrofitted dwellings meet energy use intensities of new dwellings according to the BC Step Code.

Fig 2.6. shows the relationship between ambient temperature and heat pump COP that is used in this work to compute hourly temperature dependent COP profiles for low- and high-efficiency heat pumps in the residential and commercial building sectors. Hybrid Heat Pump – Gas Furnace systems are represented by the low-efficiency heat pump curve (orange) and use gas furnaces as backup heating during cold weather events. In this work, it is assumed that in a hybrid heating configuration the gas furnace replaces heat pump operation below an environmental temperature of 4°C. For extremely cold temperatures a minimum COP for all heat pump types and hybrid heating systems of 1 is assumed.

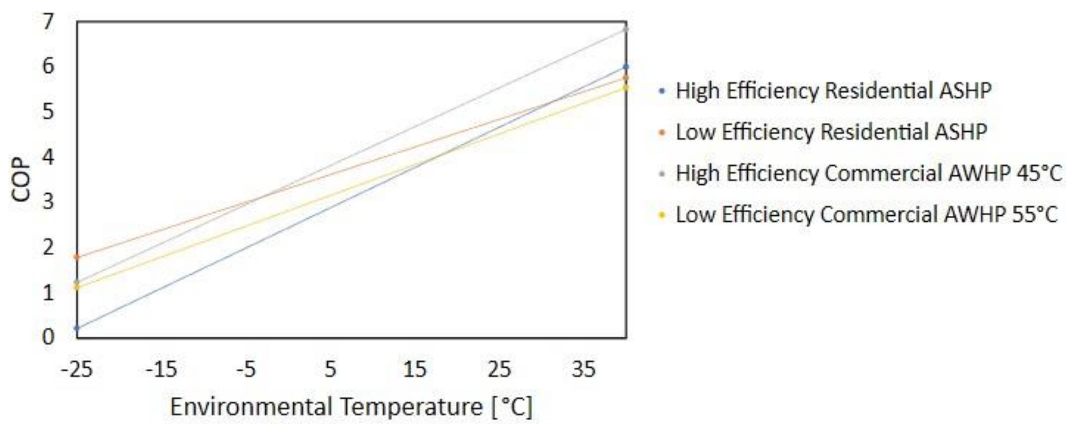


Figure 2.6. Relationship between outdoor temperature and heat pump Coefficient of Performance (COP) used to create hourly temperature dependent COP profiles. Data distinguishes between low [100] and high [101] efficiency residential air-source heat pumps (ASHP), and low and high efficiency commercial air-water heat pumps (AWHP) [71].

As ambient temperature has been identified as the main driver of building heating demands [56], BC is spatially disaggregated into four regions showing significant temperature differences (Fig. 2.7). To establish the impact of ambient temperatures on heating demands and heat pump effectiveness, hourly energy demand profiles are generated for 18 temperature scenarios using historical weather years.

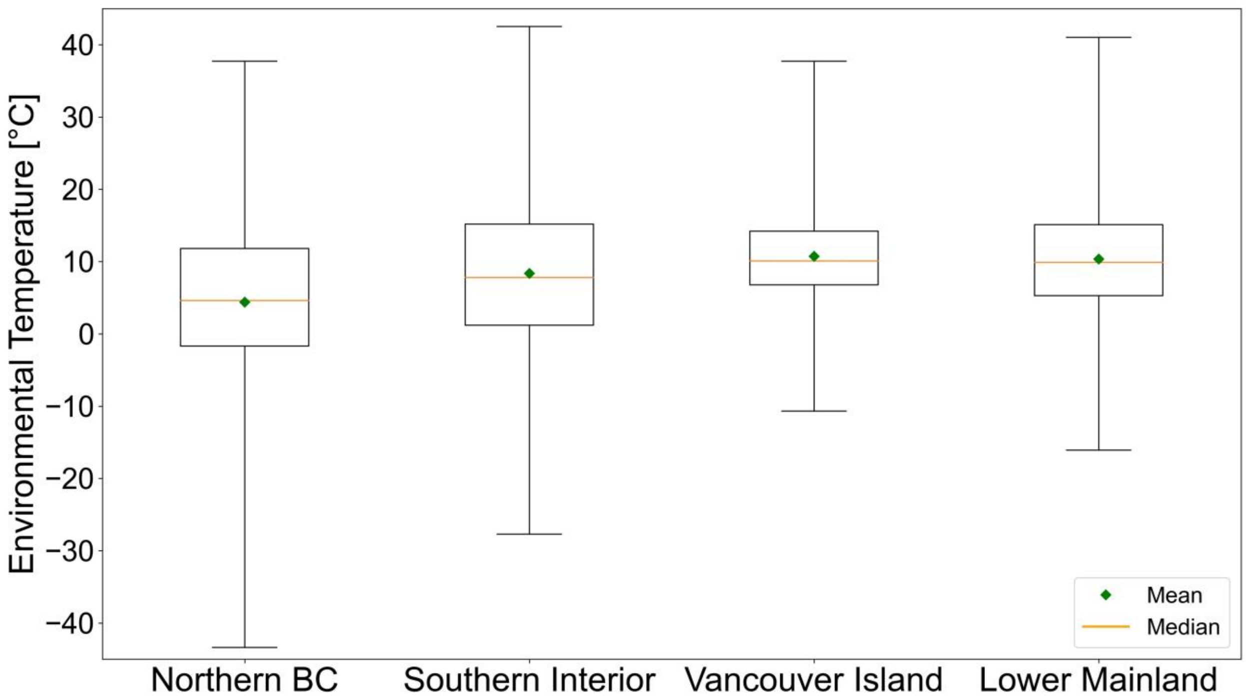


Figure 2.7. Hourly temperature distribution between 1995 and 2021 taken from different weather stations across British Columbia, Canada [89]–[93].

The energy performance per floor area varies depending on the age of the building. BC has enhanced its building insulation standards and as a result, the heating energy consumption per unit area for houses built between 2016 and 2019 experienced a 60-75% reduction, compared to houses built before 1946 (refer to Table 2.3). The end of a building lifecycle is typically reached within 40 years after which the building is either demolished or retrofitted [31]. By 2019, buildings older than 40 years accounted for 20% of the total residential building stock in BC highlighting the potential of deep retrofits [103], [104].

Table 2.3. Floor Space [103], [104] and Energy Use Intensity [105] of residential building types by vintage in British Columbia in 2019.

	Total Floor Space [million m^2]				**Energy Use Intensity [GJ/m^2]**			
	Single Detached	**Single Attached**	**Apartments**	**Mobile Homes**	**Single Detached**	**Single Attached**	**Apartments**	**Mobile Homes**
Before 1946	7.2	0.3	1.3	0.3	0.6	0.5	0.4	0.8
1946-1960	9.2	0.4	1.8	0.2	0.5	0.5	0.4	0.7
1961-1977	32.5	1.5	6.0	1.1	0.4	0.4	0.3	0.6
1978-1983	25.9	4.1	7.4	1.1	0.4	0.3	0.3	0.5
1984-1995	38.8	8.6	15.0	1.4	0.3	0.3	0.2	0.4
1996-2000	13.9	4.1	7.0	0.4	0.3	0.2	0.2	0.4
2001-2005	15.4	3.8	5.9	0.5	0.3	0.2	0.2	0.4
2006-2010	17.3	5.3	9.1	0.5	0.2	0.2	0.2	0.3
2011-2015	14.5	4.4	8.0	0.4	0.2	0.2	0.2	0.3
2016-2019	15.2	5.1	12.3	0.5	0.2	0.2	0.1	0.3

This study examines the impact of building stock turnover, envelope efficiency improvements, heating technology efficiency and technology mix assumptions, and electrification of gas heat on future electricity grid requirements. Seven scenarios are developed comprising combinations of these drivers, as shown in Table 2.4. The scenarios examine a range of policies aimed to improve building envelope efficiency and incent heating electrification. A business-as-usual (BAU) scenario based on historical 2016 data is used as a reference case (see Table 2.4). All other scenarios project final energy demand for space and water heat to 2050 with varying assumptions for retrofit rates, building code implementation strategies, heat pump adoption, heating equipment efficiencies, and electrification rates of gas heat. The effect of building code implementation as possible a policy strategy to decarbonize the building sector is examined with the Planned and Accelerated Step Code scenarios while the effect of building retrofits is analyzed using the Low and Moderate Retrofit Rate scenarios. Lastly, the Diversified Heat Sources and Full Electrification scenarios examine the impact of heating technology and technology efficiency on final energy demand for space and water heat.

Table 2.4. Seven scenarios assess potential activities in reducing heating demands or improving energy efficiencies in the building sector. All scenarios are evaluated for 18 temperature scenarios.

	BAU 2016	Planned Step Code	Accelerated Step Code	Low Retrofit Rate	Moderate Retrofit Rate	Diversified Heat Sources	Full Electrification
Population Growth	-	1.1%/yr [95]	1.1%/yr [95]	1.1%/yr [95]	1.1%/yr [95]	1.1%/yr [95]	1.1%/yr [95]
Building stock turnover	Building Stock Floor Space by Vintage [102]	New construction: 1.5%/yr Demolition: 0.4%/yr Retrofit: 1.2%/yr [31]	New construction: 1.5%/yr Demolition: 0.4%/yr Retrofit: 1.2%/yr [31]	New construction: 1.5%/yr Demolition: 0.4%/yr Retrofit: 0.5%/yr	New construction: 1.5%/yr Demolition: 0.4%/yr Retrofit: 1.6%/yr [31]	New construction: 1.5%/yr Demolition: 0.4%/yr Retrofit: 2.5%/yr [106]	New construction: 1.5%/yr Demolition: 0.4%/yr Retrofit: 2.5%/yr [106]
Building envelope efficiency	EUI by Vintage [102], [107]	Planned Step Code Implementation for new builds [99]: Step 2 [2017-2022] Step 3 [2023-2030] Step 4 [2031-2040] Step 5 [2041-2050]	Accelerated Step Code Implementation for new builds: Step 3 [2020-2027] Step 4 [2028-2037] Step 5 [2038-2050]	Delayed Step Code Implementation for new builds [99]: Step 2 [2023-2030] Step 3 [2031-2040] Step 4 [2041-2050]	Accelerated Step Code Implementation for new builds: Step 3 [2020-2027] Step 4 [2028-2037] Step 5 [2038-2050]	Accelerated Step Code Implementation for new builds: Step 3 [2020-2027] Step 4 [2028-2037] Step 5 [2038-2050]	Accelerated Step Code Implementation for new builds: Step 3 [2020-2027] Step 4 [2028-2037] Step 5 [2038-2050]
Electrification Building Heat	40% [107]	100%	100%	100%	100%	70%	100%
Technology Mix – Residential	7% ASHP[a] 25.9% Resistance heat 60.5% Gas furnaces 6.6% Wood	30% ASHP[a] 70% Resistance heat	30% ASHP[a] 70% Resistance heat	50% ASHP[a] 50% Resistance heat	50% ASHP[a] 50% Resistance heat	New builds: 100% ASHP[b] Gas conversion buildings: 80% ASHP[b]/20% Hybrid ASHP[a]-GS Existing electrified buildings: 50% ASHP[a] 50% Resistance heat	New builds: 100% ASHP[b] Gas conversion buildings: 100% ASHP[b] Existing electrified buildings: 50% ASHP[a] 50% Resistance heat
Technology Mix – Commercial	7% ASHP[a] 10% Resistance heat 83% Gas furnaces	100% AWHP[c]	100% AWHP[c]	100% AWHP[c]	100% AWHP[c]	70% AWHP[d] 30% Gas Heat Pump	100% AWHP[d]

[a] Low Efficiency Residential Air-source Heat Pump
[b] High Efficiency Residential Air-source Heat Pump
[c] Low Efficiency Commercial Air-water Heat Pump
[d] High Efficiency Commercial Air-water Heat Pump

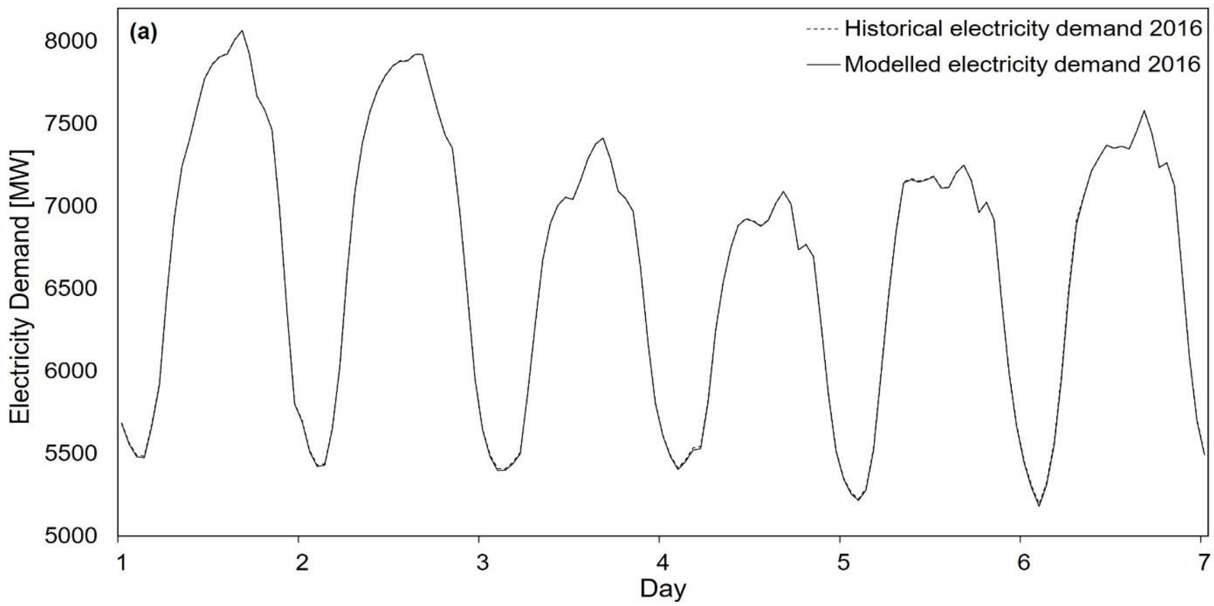
2.5 Results

Our results examine the impacts of building stock turnover, envelope efficiency improvements, technological efficiency and technology mix assumptions, and electrification of gas heat. Six scenarios are developed comprising combinations of these drivers as shown in Table 2.4. The scenarios examine a range of policy objectives for building code and heating electrification. A business-as-usual (BAU) scenario based on historical 2016 data is used as a reference case (see Table 2.4). All other scenarios project heating electricity demand for 2050 with varying assumptions around retrofit rates, building code implementation strategies, heat pump adoption, heating equipment efficiencies, and electrification rates for gas heat.

2.5.1 Model calibration

For 2016, the modeled electricity demand profile is calibrated against historical provincial electricity demand. Fig. 2.8 shows the historical and the computed electricity demand in 2016 for the warmest and coldest one-week period in hourly resolution. The warmest one-week period is shown in Fig. 2.8(a) and the coldest is shown in Fig. 2.8(b). During the summer, when space heating demand is low, the computed profile shows a variation to historical electricity demand of 0.1%. During the winter, when space heating demand is high, this variation increases to 0.96%. In 2016, the peak event occurred in December during the one-week period captured in Fig. 2.8. Compared to the historical peak of 11 GW in 2016 [87], the model underestimates peak demand for the computed electricity demand profile by 0.8%.

The cumulative energy of the residual load, for 2016, is 50.7 TWh for the computed profile. According to [108], industrial, agricultural and transportation sectors reached 26.5 TWh of electricity consumption in 2016 and non-heating related demands in the building sector reached 22.2 TWh, indicating an overestimation of the residual load of approximately 4%.



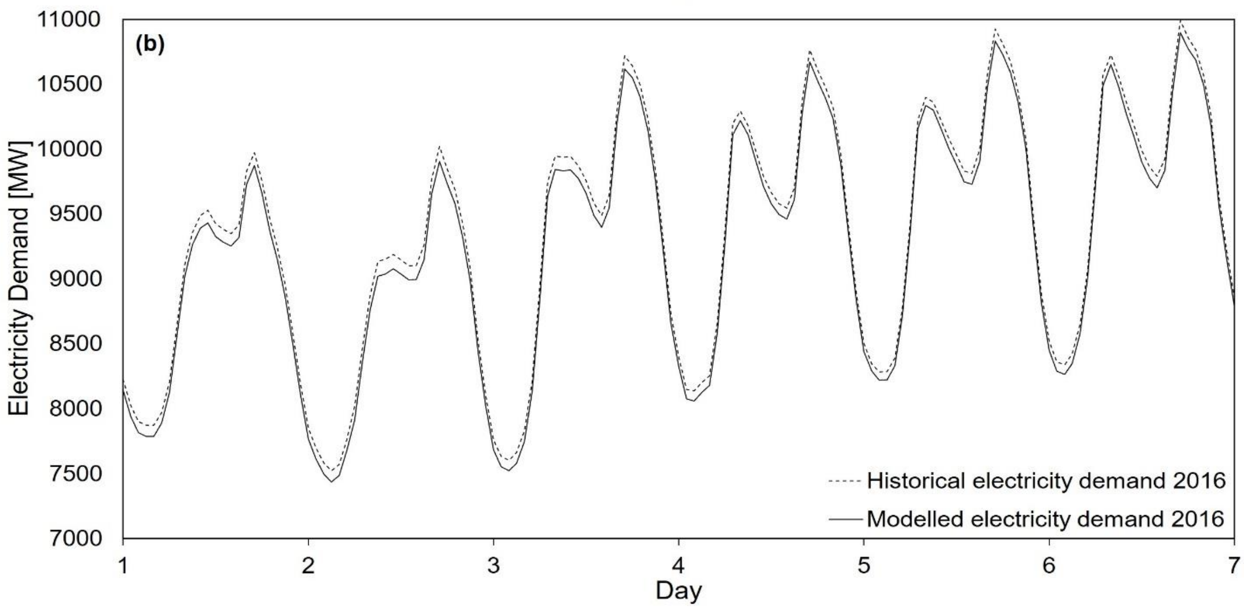


Figure 2.8. Comparison of modelled and historical final electricity demand in 2016. Fig. 2.8(a) shows a one-week snapshot for August while Fig. 2.8(b) shows a one-week snapshot for December. The dashed line shows the historical electricity demand profile for 2016. The solid line shows the modelled final electricity demand in 2016.

2.5.2 Future demand profiles

2.5.2.1 Construction and retrofit activity

Low rates of future retrofit activities pose a challenge to rapidly achieve decarbonization targets set for the building sector. This is demonstrated in Fig. 2.9 which shows the relative floor area of residential dwellings newly constructed and retrofitted between 2017 and 2050 as a percentage of the stock size in 2050. In Fig 2.9, the share of newly constructed dwellings is constant across all scenarios due to the assumed constant annual new construction rate of 1.5%. The share of retrofitted dwellings increases with larger retrofit rates; the Low Retrofit Rate scenario features the lowest annual retrofit rate of 0.5% whereas the Diversified Heat Sources and Full Electrification scenarios feature the highest annual retrofit rate of 2.5%. In the Diversified Heat Sources and Full Electrification scenarios 11% of dwellings are retrofitted twice by 2050 (starting in 2046). In this work, it is assumed that once a dwelling is retrofitted it meets the energy efficiency standard of a newly constructed home, and thus, higher retrofit rates lead to larger efficiency improvements in the building stock.

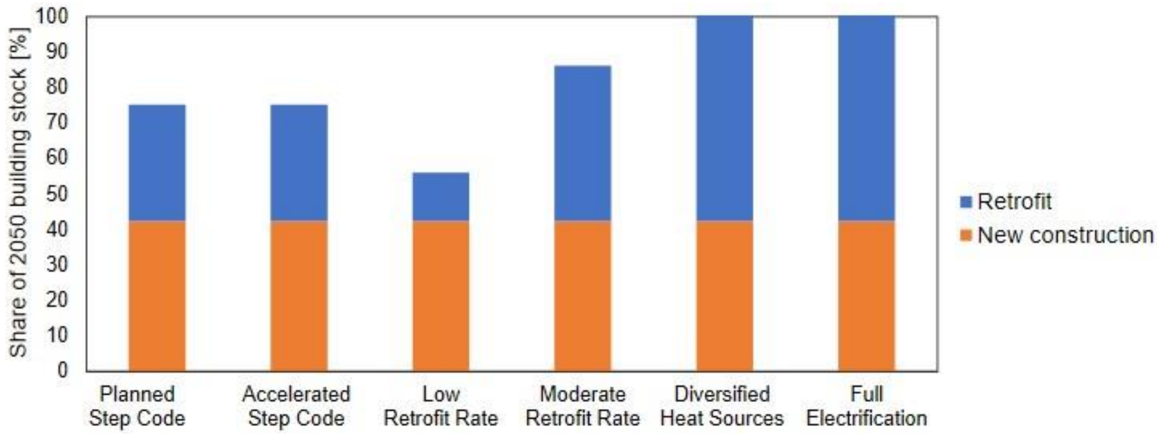


Figure 2.9. Distribution of floor area newly constructed or renovated in the period 2017–2050 shown as percentage of the 2050 building stock.

2.5.2.2 Dwelling stock composition and energy use intensity

Accelerating building code implementation under a constant retrofit rate leads to a greater reduction in energy use intensities and space heating demand than increased retrofit rates. As shown in Fig. 2.10, assumptions of constant new construction, demolition, and population growth rates for all scenarios lead to a total floor space of 423.2 million m^2 in the residential building stock and 152.4 million m^2 in the commercial building stock by 2050. However, variations in building code implementation strategies and annual retrofit rates impact final energy use intensities for space heating. Fig. 2.10(a) illustrates an improvement of average energy use intensity for space heating in the residential building stock by up to 29.7%. Accelerating building code implementation by 3 years under a constant retrofit rate leads to an improvement of average energy use intensity by 2.6% while doubling the annual retrofit rate under a constant building code implementation strategy improves average energy use intensity by only 0.8%.

The same behavior is observed in the commercial sector. This is demonstrated in Fig. 2.10(b) which show an improvement of average energy use intensity for space heating in the commercial sector by up to 7.8%. Here, accelerating the building code implementation by 3 years under a constant retrofit rate results in an improvements of average energy use intensity by 0.6%. Doubling the annual retrofit rate under a constant building code implementation strategy improves average energy use intensity by only 0.3%. Space heating energy demand is calculated by multiplying the average energy use intensity for space heating with the total floor space. While total floor space is constant across all scenarios, the improvement of energy use intensity is more pronounced for an accelerated building code implementation than an increase in retrofit rates. Accelerating building code implementation under a constant retrofit rate leads to a greater reduction in energy use intensities and therefore space heating demand.

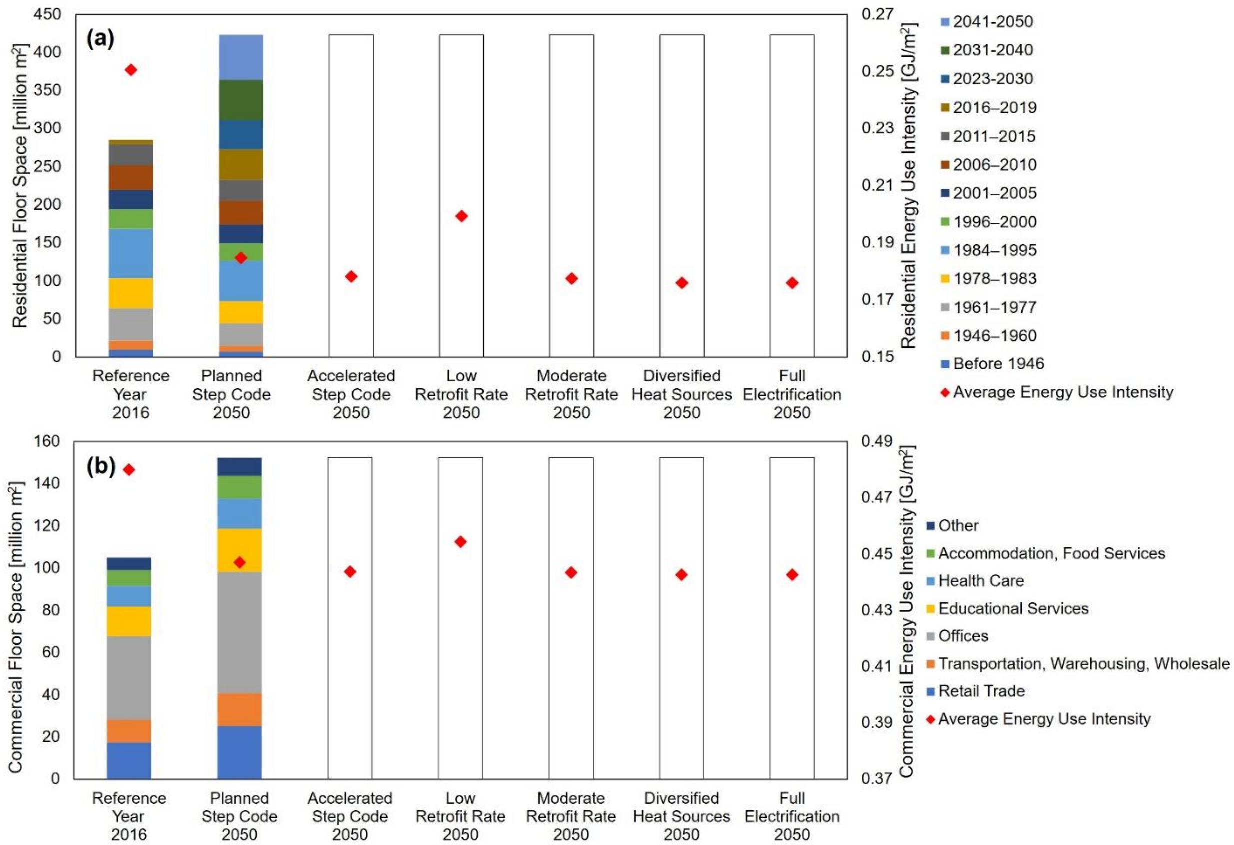


Figure 2.10. Floor space per vintage after new construction and demolition in 2050 compared to the stock size in 2016. (a) shows the residential building stock per vintage in 2050. Due to constant new construction and demolition rates, the total residential floor space is constant for all forecast 2050 scenarios. Changes in energy use intensity for space heating are caused by varying retrofit rates and step code implementation strategies. (b) shows the commercial building stock per vintage in 2050. Due to a constant population growth rate, the total commercial floor space is constant for all forecasted 2050 scenarios. Commercial heating energy intensity change is assumed to be 50% of the change seen in the residential sector.

2.5.2.3 Effects of increased heat pump penetration rates

Fig. 2.11 shows projected future energy demand for building heat in 2050. On the left, the impact of building code implementation strategies, retrofit rates, and building stock turnover on residential space heat demand is shown. On the right, the red bar shows final electricity demand for residential space with varying heat pump penetration rates. As shown in Fig. 2.11, the highest final electricity demand occurs in the Planned Step Code scenario. Here, a low-efficiency heat pump penetration rate of 30% is combined with moderate energy efficiency improvements in the building stock. Annual final electricity demand for residential space heat increases by 125%, relative to 2016, in this scenario. The Full Electrification scenario has 89% penetration of high-efficiency heat pumps combined with the most optimistic efficiency improvements in the building stock. For this scenario, annual electricity demand for residential space heat increases by 6%, relative to 2016, despite an annual population growth rate of 1.1% between 2017 and 2050. This indicates that the energy requirement for full electrification of heat can be mitigated by efficiency gains in the building stock through retrofits, building codes, and high-efficiency heating equipment installations. As illustrated in Fig. 2.11, it is assumed that in Diversified Heat Sources scenario

30% of heat demand is served by non-electric fuels (i.e., gas). Combined with an annual population growth rate of 1.1%, the most optimistic efficiency improvements of the building stock, and the use of hybrid heating systems the Diversified Heat Sources scenario shows a reduction in final electricity demand for space heating of 19% compared to 2016.

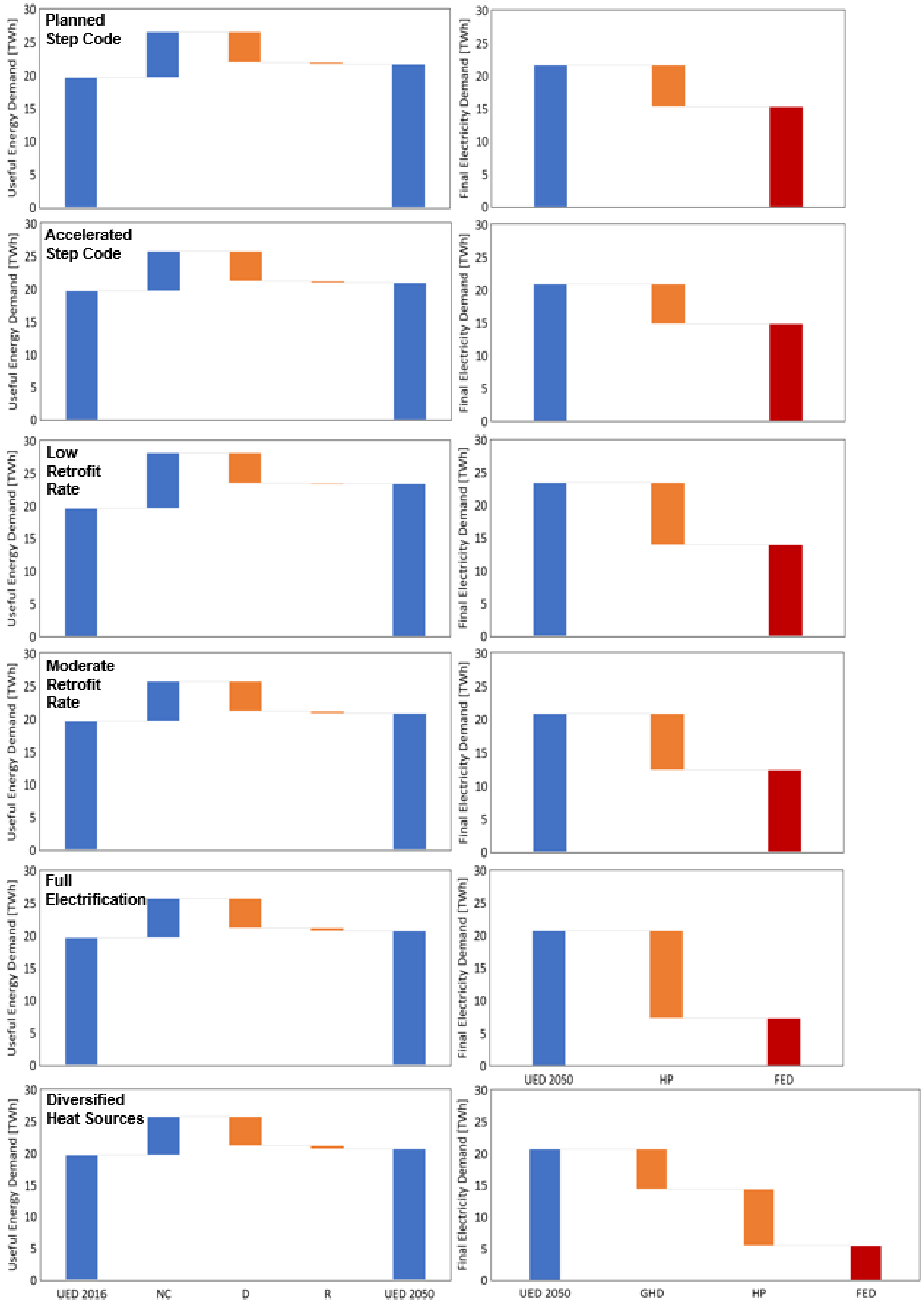


Figure 2.11. Change in residential space heat demand due to new construction, demolition, retrofits, and assumed technology mix. The graphs on the left show the final heat demand in 2050 after new construction, demolition, and retrofits. The graphs on the right show the conversion of heat to electricity via heat pumps for the average Heating Degree Day (HDD) year. UED = Useful Energy Demand; NC = New construction; D = Demolition; R = Retrofits; HP = Heat Pump; GHD = Gas Heat Demand; FED = Final Electricity Demand

2.5.2.4 Implications for electricity grid operations

Annual electricity demand after building heat electrification decreases with higher efficiency gains through retrofits, building codes, and the use of high efficiency heating equipment. In comparison to historical loads, maximum annual electricity demand is projected to increase by up to 32% in the Planned Step Code scenario. This scenario features the lowest heat pump adoption rate of 30% using low-efficiency ASHP and a moderate annual retrofit rate. The results in Table 2.5 illustrate that accelerating step code implementation by 3 years, increasing annual retrofit and heat pump adoption rates by 1.3% and 59%, respectively, as captured in the Full Electrification scenario, can decrease maximum annual electricity demand by up to 10% compared to the Planned Step Code scenario. In comparison to historical loads, maximum annual electricity demand in the Full Electrification scenario increases by 19%. Building heat electrification coupled with efficiency gains due to retrofits, building codes, and high efficiency heating equipment leads to higher annual electricity demand; however, increases in annual electricity demand can be limited by more effective enforcements of efficiency improvements in the building stock and increasing heat pump penetration.

Table 2.5. Evaluation criteria for the projected 2050 load curves for all six modelling scenarios, compared against the historical years from 2002 to 2019. The load curve in 2019 showed the maximum negative ramp rate for the last 20 years in British Columbia. Increases and decreases compared to historical load curves are listed as percentage in the brackets.

		Historical [2002-2019]	**Planned Step Code**	**Accelerated Step Code**	**Low Retrofit Rate**	**Moderate Retrofit Rate**	**Diversified Heat Sources**	**Full Electrification**
Load duration curve	Minimum Annual Electricity Demand [TWh]	56.7	83.9 (+48%)	83.3 (+47%)	82.5 (+46%)	80.9 (+43%)	66.8 (+18%)	75.3 (+33%)
	Maximum Annual Electricity Demand [TWh]	64.0	84.4 (+32%)	83.8 (+31%)	83.2 (+30%)	81.5 (+27%)	67.4 (+5%)	75.9 (+19%)
	Minimum Electricity Demand [GW]	4.0	5.6 (+40%)	5.6 (+40%)	5.6 (+40%)	5.6 (+40%)	5.2 (+30%)	5.5 (+38%)
	Maximum Peak Electricity Demand [GW]	11.2	17.8 (+59%)	17.6 (+57%)	17.9 (+60%)	17.1 (+53%)	12.1 (+8%)	15.3 (+37%)
	Min/max load ratio [%]	36.1	31.7	32.1	31.6	32.9	43.2	36.3
Stable load situations	Average number of hours above historical max load of 11 GW [h]	3	2324	2243	2144	1900	7	844
Load change between consecutive hours	Max negative ramp rate [GW/h]	-1.2	-1.5 (+25%)	-1.5 (+25%)	-1.5 (+25%)	-1.5 (+25%)	-0.8 (-33%)	-1.4 (+17%)
	Max positive ramp rate [GW/h]	1.6	3.8 (+138%)	3.7 (+131%)	3.9 (+144%)	3.7 (+131%)	1.9 (+19%)	3.5 (+119%)
Temperature sensitivity	Mean temperature sensitivity [GW/°C]	0.72	1.00 (+39%)	1.00 (+39%)	1.00 (+39%)	0.97 (+35%)	0.80 (+11%)	0.90 (+25%)

In the absence of building stock efficiency improvements, heat pump penetration rates of 30% can already threaten the reliability of the electricity grid, requiring analyses about peak electricity demands, stable load situations, and ramping rates [66]. Peak electricity demands decrease with larger efficiency improvements to the building stock and heating equipment. This is demonstrated in Table 2.5, which shows that in comparison to the historical loads, maximum peak electricity demands increase by up to 60% for a heat pump penetration rate of 50% combined with the smallest building envelope efficiency improvements. The smallest variation in electricity load curves is observed for a partial electrification of building heat. For a full electrification of building heat, the variability of electricity load curves decreases with larger efficiency improvements of the building envelope and heating equipment. This is demonstrated in Fig. 2.12 which presents load duration curves for each scenario for 18 weather years. For all scenarios, the loads are higher than historical loads (Fig. 2.12 black lines) for the entire year. Between 2002 and 2019, only 3 hours exceeded 11 GW of total gross electricity demand. The average number of hours for all six scenarios above 11 GW of electricity demand ranges between 7 and 2324 per year (Table 2.5, Fig. 2.12(a)). The Diversified Heat Sources scenario has the lowest load curves with only 7 hours above the historical maximum load of 11 GW (Fig. 2.12(a) yellow solid lines). Across all scenarios, the number of hours above the historical maximum load decreases with efficiency improvements to the building stock and heating equipment. This results in an average of 844 hours above 11 GW for the Full Electrification scenario which features the most efficient building stock and heating equipment for a full substitution of gas heat with electricity.

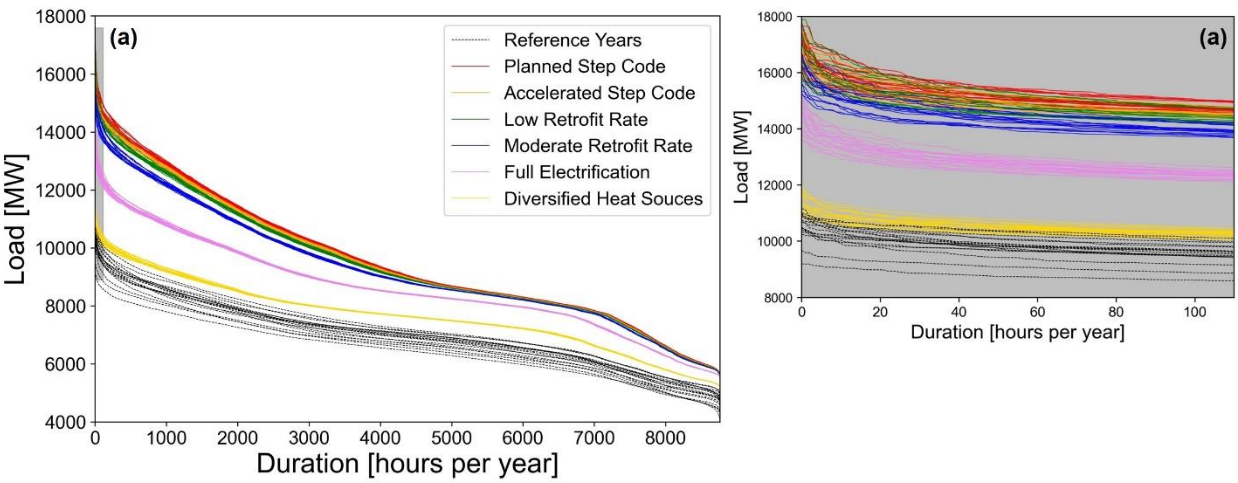


Figure 2.12. Load duration curves projecting energy demands after building heat electrification for British Columbia in 2050 compared to the load duration curve of historical transmission data between 2002 and 2019 [87]. The load duration curves show energy demands for 18 weather years. Fig. 2.12 (a) on the right zooms into the variation of load duration curves in the grey shaded area (a) on the left graph for the first 110 hours.

The electrification of building heat causes future electricity load profiles to become more dynamic. More dynamic loads result in increasing ramping events at the hourly scale, leading to issues for a stable operation of the future electricity grid in BC. Fig. 2.13 shows hourly electricity demand for a one-week period in August and December for historical electricity loads and for the electricity load in 2050 under the Planned Step Code scenario. This scenario features moderate energy efficiency improvements and a heat pump penetration rate of 30% in the residential building sector. As shown in Fig. 2.13, hourly changes in demand (ramping rates) increase for future electricity loads in both magnitude and their probability of occurrence. Compared to historical electricity demand profiles, ramping events of 3.9 GW per hour are possible in 2050 (Table 2.5). This results in a significant increase in negative and positive ramping rates by up to 25% and 144%, respectively. Higher ramping rates due to more dynamic loads lead to more complexity in operating BC’s electricity grid. However, significant increases in the magnitude and frequency of extreme ramping events can be limited if not all building heat is electrified. This is illustrated in Table 2.5, which shows a decrease in negative ramping rates of 33% and an increase in positive ramping rates of 19% in the Diversified Heat Sources scenario. In this scenario, 70% of building heat is electrified under the most optimistic energy efficiency improvements in the building stock. Additionally, an 82% heat pump penetration rate in the residential building sector is assumed while 7% of residential homes are using hybrid heating systems.

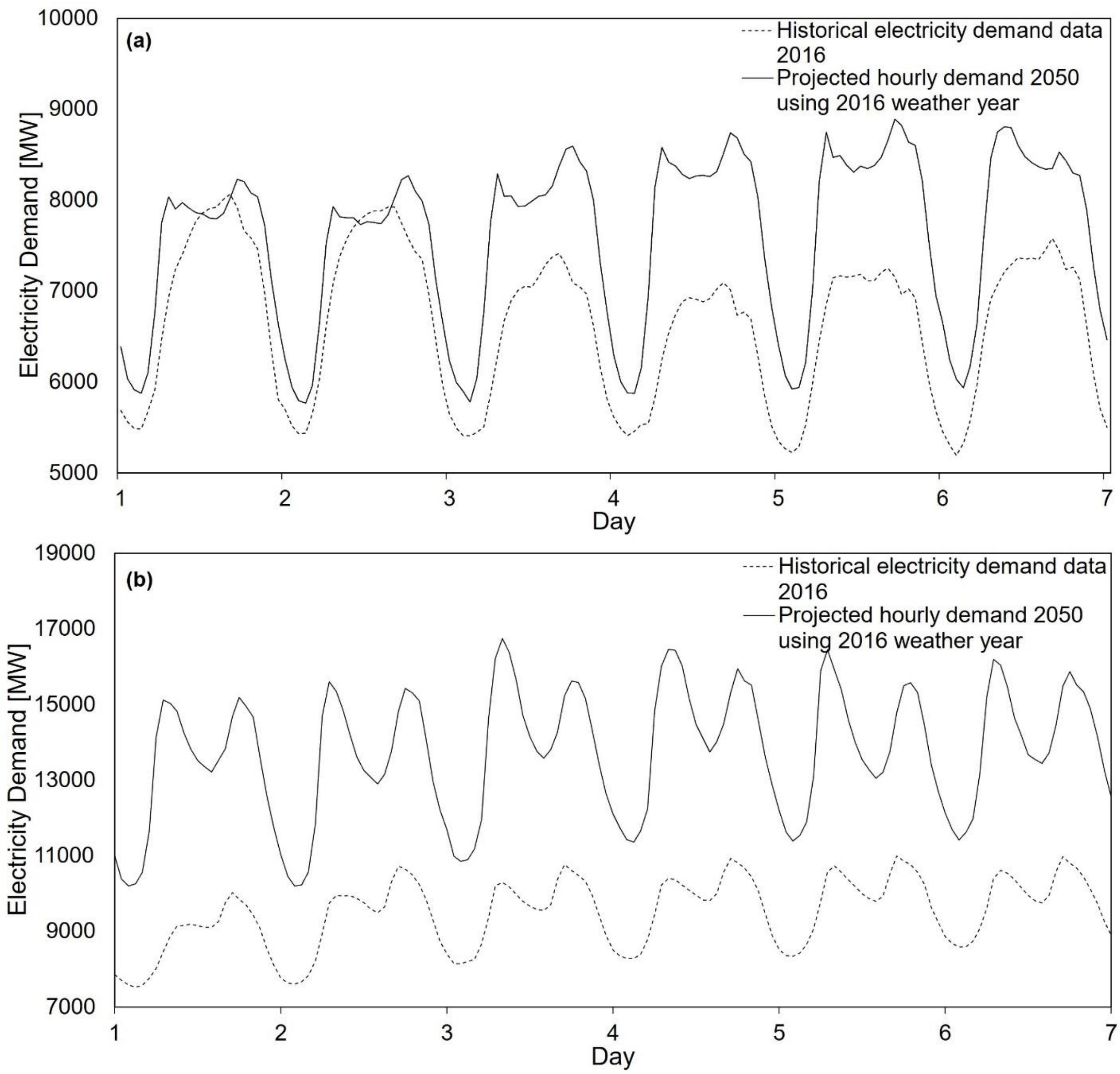


Figure 2.13. Comparison of historical electricity demand data in 2016 for British Columbia to the projected hourly demand in 2050 for the Planned Step Code scenario using the 2016 weather year. Fig. 2.13(a) shows the comparison for a one-week period in August. Fig. 2.13(b) shows the comparison for a one-week period in December.

2.5.2.5 Temperature sensitivity of heating demands

Ambient temperature is the main driver of space heating demands. In this work, hourly electricity demand profiles are generated for 18 weather years to determine the temperature sensitivity of the load. The impact of ambient temperature on heating demands is demonstrated in Fig. 2.14 which shows end-use specific normalized load profile projections for 2050 for four regions in BC using the highest Heating Degree Day (HDD) weather year, 2011. These profiles capture the impact of ambient temperature on space heating demands, and thus, look significantly different for each region. Northern BC and the Southern Interior experience colder temperatures, leading to large peaks of space heat demand from October to March. As illustrated in Fig. 2.14, water heating and residual load are less impacted by ambient temperature, which aligns with the findings in other studies [11].

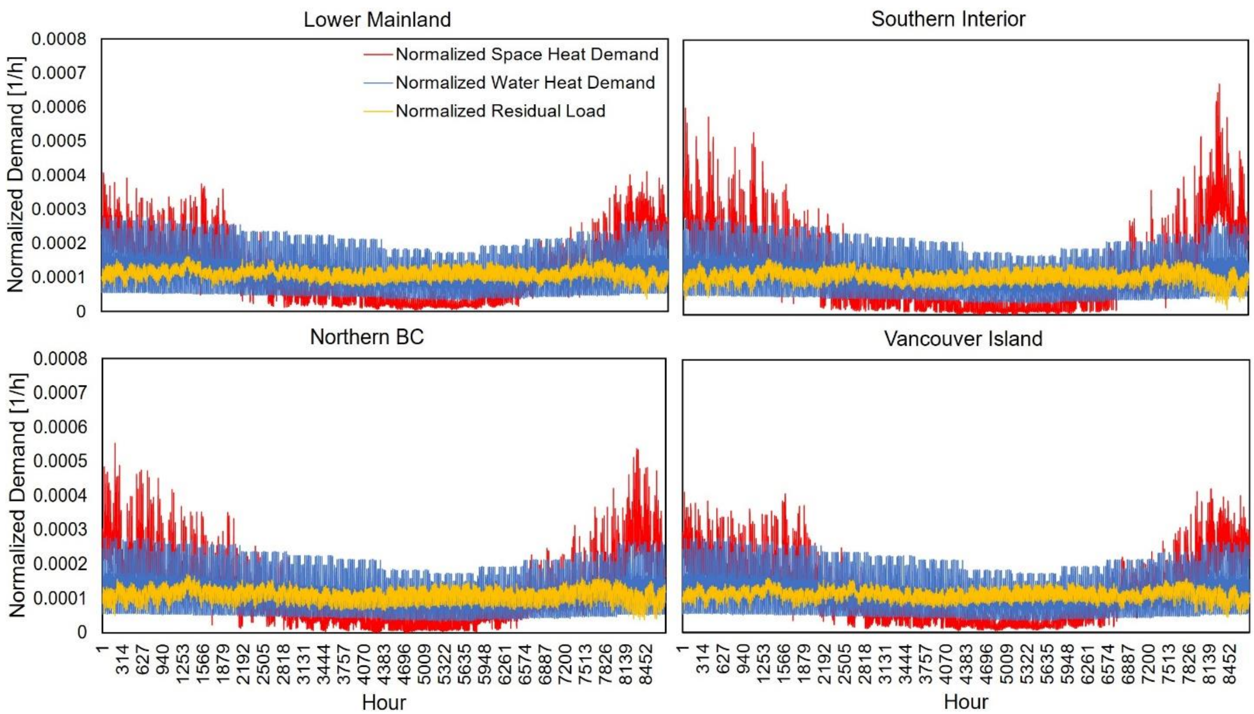


Figure 2.14. Regional normalized load profiles for space heat (red), water heat (blue), and residual load (yellow) in 2050 in British Columbia for the highest Heating Degree Day (HDD) weather year 2011. Residual load includes all non-heating loads in the building sector as well as electricity in the industrial, agricultural and transportation sectors.

Heating energy for a building with an inefficient building envelope is more sensitive to ambient temperatures than a building envelope that meets energy use intensity targets set by the BC Energy Step Code [99]. This is demonstrated by the variation in maximum annual electricity demand, maximum peak electricity demand, and mean temperature sensitivity in Table 2.5. Here, the Low Retrofit Rate scenario shows the largest variation in annual electricity demand of 0.8 TWh and the largest variation in peak electricity demand by 2.2 GW depending on the applied weather scenario. The smallest variation in annual and peak electricity demand of 0.7 TWh and 1.6 GW, respectively, is observed in the Full Electrification scenario which features the largest building envelope efficiency improvements. Historically, a mean temperature sensitivity of 0.72 GW per °C was observed in BC; however, as building heat is electrified, the mean temperature sensitivity increases by as much as 39% in the scenarios featuring the smallest efficiency gains (Table 2.5). In the most efficient Full Electrification scenario, temperature sensitivity increases by 25%.

Variations between weather years change both the timing and the magnitude of peak electricity demand. Table 2.6 highlights the variation in time and magnitude of the minimum and maximum total system peak in the Low Retrofit Rate and Full Electrification scenarios. Results show a maximum total system peak of 17.9 GW in the Low Retrofit Rate scenario that occurs on January 4th at 8 am using the 2004 temperature scenario. Changing the temperature scenario to 2006 results in a peak electricity demand of 15.7 GW that occurs on November 28th at 8 am.

Table 2.6. Timing and magnitude of maximum and minimum total system peak demand for the Low Retrofit Rate and Full Electrification scenarios using different weather years including the fraction of peak demand serving space and water heat.

Low Retrofit Rate scenario				
Temperature scenario	**Total System Peak [GW]**	**Space Heat [GW]**	**Water Heat [GW]**	**Timing of Total System Peak**
2004	17.9	9.6	3.1	January 4th at 8am
2006	15.7	8.4	3.3	November 28th at 8am
Full Electrification scenario				
Temperature scenario	**Total System Peak [GW]**	**Space Heat [GW]**	**Water Heat [GW]**	**Timing of Total System Peak**
2014	15.2	5.4	3.7	February 6th at 8am
2010	13.6	4.1	3.6	February 21st at 8am

2.6 Discussion

For a full electrification of building heat an annual retrofit rate of 2.5% leads to an increase in peak and annual electricity demand of 37% and 19%, respectively. Compared to this, a more moderate retrofit rate causes an additional increase in peak and annual electricity demand due to a smaller share of retrofitted buildings that can mitigate temporal fluctuations of heating demands [18]. In the absence of financial incentives or other funding opportunities for homeowners, annual retrofit rates of 2.5% are likely not going to be achieved by 2050. This is in line with a study that investigates future retrofit rates for 11 European countries as a result of building stock ageing [31]. Financial incentives for homeowners are important in achieving more optimistic rates for deep retrofits of the building envelope; however, investigating the impact of financial incentives on future retrofit rates is beyond the scope of this work.

Our results assume deep retrofits (i.e., the building is brought to new-build code), and that the energy use intensity is actually achieved – both assumptions may be optimistic and over-estimate the effectiveness of envelope improvements. The BC Energy Step Code aims to achieve net-zero ready new construction by 2032 [109] which is unlikely to be met if building energy codes setting energy efficiency measures for new builds are not made mandatory. Buildings newly constructed by 2030 will live past 2050, so any new building that exceeds certain energy requirements would need to be retrofitted before the end of its life to meet the net-zero target, which will be more costly than implementing mandatory building codes.

The results of this work confirm that supply-side energy and capacity limits on the share of building heating demands served by heat pumps can be avoided by improving building envelope efficiencies. Combining significant building envelope efficiency improvements with a heat pump penetration rate of 89% results in an increase of annual and peak electricity demand by 19% and 37%, respectively. In comparison, annual and peak electricity demand increases by up to 27% and 53% for moderate improvements of the building envelope combined with a 50% heat pump penetration rate. When electrifying additional end-uses, capacity requirements grow at a faster pace than generation assets, leading to a mismatch in the supply and demand balance. With peak electricity demand potentially increasing by up to 60% all scenarios exceed currently installed generation capacity in BC. However, the potential increase in peak electricity demand by 60% does not consider electrified road transportation, electrification of the industrial and agricultural sectors, or an increase in electric space cooling. For 2041, BC Hydro's system peak load carrying capability before planned resources is forecasted to be 11.8 GW [110]. This will not be sufficient to meet electricity demand in 2050 assuming space and water heat are the sole end-uses that are partially or fully electrified. Accommodating building heat electrification in the absence of significant efficiency improvements would therefore lead to a profound mismatch of supply and demand in BC. In the absence of efficiency improvements in the building stock, large-scale heat pump penetration rates can significantly increase the flexibility requirements of the electricity grid [66]. Our results illustrate that ramping rates increase by up to 144% for the smallest building envelope improvements in combination with a 50% heat pump penetration rate.

Ambient temperature is the main driver of space heating demand and impacts the variability of electricity loads when building heat is electrified. Assuming that by 2050 all building heat in BC is electrified will significantly impact the frequency, timing, and magnitude of peak electricity demand. These impacts will be even larger during cold weather events. To match the variation in time and magnitude of peak demands in the absence of additional dispatchable generation capacity in BC's electricity grid is challenging. In the context of climate change, a significant change in ambient temperature is expected in BC by 2050. By mid-century, the minimum temperature is projected to increase by 4.5°C in the winter with the largest temperature difference expected in Northern BC [111]. Future power system analyses must therefore consider the impact of ambient temperature on both supply and demand to identify peaking and additional dispatchable capacity requirements and reserve capacity needs [112]. However, the use of hybrid heating systems is a further strategy to limit growing peak capacity needs due to building heat electrification in cold climate regions. Due to regular low temperature events, efforts to ban fossil fuel heating by 2035, as implemented in the UK [113], are difficult to implement in BC. Here, the installation of hybrid heating system provides a potential alternative. In cold climates, the use of hybrid ASHP-gas furnace systems is favourable during cold weather events as large strains on the electricity grid can be avoided. Results of this work indicate that capacity requirements for scenarios with hybrid heating systems using gas furnaces as a backup heating technology during cold weather events are 20% lower compared to a fully electrified scenario.

Building heat electrification has significant impacts on future flexibility requirements of the electricity grid. Consequently, future projections of hourly electricity loads are crucial to identify extreme ramping events [114]. In the most energy efficiency scenario, an average of 844 hours per year are projected to be above BC Hydro's system peak load carrying capability before planned resources of 11.8 GW. However, a partial electrification of gas heat combined with the use of hybrid heating system results in an average of 7 hours above BC Hydro's system peak load carrying capability and has the potential to reduce negative ramping rates by 33% while positive ramping rates increase by only 19%. This suggests that a large fraction of gas heat can be electrified without large electricity system investments. Negative and positive ramping rates for fully electrified scenarios are determined to increase by up to 25% and 144%, respectively. This poses significant challenges for electricity system operators and will become even more challenging with increasing shares of VRE generation where supply needs to meet demand almost instantly [25].

In this work, provincial hourly electricity demand can be compared to historical electricity demand data; however, the model has some clear limitations. First, the spatial disaggregation of electricity demand to a regional level cannot be compared to actual regional electricity demand data due to the unavailability of regional electricity demand profiles. To capture regional variations in electricity demand due to ambient temperature, regional demand profiles in this work are represented by proxies of regional population. Second, ambient temperature is the main driver of heating demand; however, non-heating electricity demands in the building sector, which are captured in the residual load profile, are assumed to be independent of temperature. Due to the dependence on data availability of real-world hourly demand profiles to generate sector and end-use specific demand profiles, the residual load profile cannot be disaggregated further into sectors and end-uses. Agricultural and industrial electricity demands are spatial in nature, and thus, assuming proxies of regional population will not capture electricity demands in the agricultural and industrial sector accurately. The lack of data for spatial disaggregation of electricity demand can lead to modelling inaccurate regional electricity demand that drive regional capacity needs. While determining the accuracy of sector and end-use electricity demand is challenging, this work provides a method to generate high spatiotemporal electricity demand profiles for space and water heating based on real-world data.

Although this work focuses on British Columbia, Canada, as regional study, this method is transferrable and can be applied to any jurisdiction. The results presented in this study are a result of local climate, the distribution of building types across the province of BC and proposed strategies to decarbonize the building stock via the BC Energy Step Code. Thus, the results are not transferrable to regions with different climate conditions, as the strategies to decarbonize the building stock in BC might not be as effective in other regions. However, jurisdictions with other characteristics such as climate conditions, distribution of building types, or policies to decarbonize the building stock can be explored to examine energy, capacity, and flexibility requirements of the electricity grid.

2.7 Conclusion

This work addresses the current gap of high spatiotemporal heat demand modelling with detailed building stock considerations by introducing a new modelling framework simulating residential and commercial space and water heat demands. Considering the electrification of building heat, this study demonstrates how the shape of electric load curves will change for highly electrified futures.

The high-resolution heating demand modelling framework is applied to BC, Canada to explore implications of energy efficiency improvements in the building stock, large-scale heat pump adoption, and gas heat electrification on the timing and magnitude of peak demands under different temperature scenarios. The presented scenarios include demand drivers such building stock turnover rates, building envelope efficiency improvements, technological efficiency and technology mix assumptions, and electrification of gas heat. Regional variations are modelled as a function of population distribution.

This study revealed that it is necessary to improve the energy performance of the building stock when electrifying space and water heat. Compared to present-day annual electricity demand and peak load, an increase of up to 5% and 8%, respectively, is observed for a partial electrification of gas heat while a full electrification of gas heat under the most optimistic efficiency improvements increases annual electricity and peak demand by up to 19% and 37%, respectively, compared to present-day values. Introducing building envelope efficiency improvements and building code standards in the Full Electrification scenario can reduce final electricity demand by 8.5 TWh despite an 89% heat pump diffusion rate for space and water heat in comparison to the Planned Step Code scenario. Total system peak load in the Full Electrification scenario can be reduced by 2.6 GW compared to the Low Retrofit Rate scenario by introducing large-scale efficiency improvements in the building stock and heating equipment. The move towards electrification of building heat in the future seems likely; however, achieving an 89% heat pump adoption rate across the province of BC does not. It will be necessary for utilities to increase system flexibility to accommodate large peak demands by adequately following steep increases or decreases in load during cold weather periods, as ramping rates after building heat electrification increase by up to 144%.

In the absence of dispatchable capacity alternatives, forecasting the timing and magnitude of peak electricity demand is crucial for energy systems with large shares of VRE generation. Further research could address other strategies that limit peak electricity demand after building heat electrification such as demand response (DR) with flexible heat pump controls [115]. On the supply-side, future research could investigate the potential of using renewable gases such as hydrogen for building heat [116] or the use of distributed solar PV to reduce future net loads [117]. Combining high resolution modelling of load profiles for electric building heat with electric vehicles and electrification of the agricultural and industrial sectors will provide a more comprehensive basis for future electricity system analyses. In a next step, capacity expansion and economic dispatch models could provide insights into generation capacity and ramping requirements as well as electricity storage capacities. These approaches have the potential to achieve the same decarbonization targets as electrification of building heat without the associated increases in peak electricity demand.

Chapter 3

Electrifying end-use demands: A rise in capacity and flexibility requirements[2]

[2] The body of this chapter was submitted for publication in *Energy*, and is reproduced with the permission of Elsevier. Tamara Knittel, Colton Lowry, Peter Wild, and Andrew Rowe conceived and designed the study. Tamara Knittel and Colton Lowry performed the analysis. Tamara Knittel drafted the initial manuscript and finalized the published version. Colton Lowry, Madeleine McPherson, Peter Wild, and Andrew Rowe contributed to the refinement of further manuscript drafts.

Preamble

The reliable provision of electricity requires sufficient capacity and flexibility to meet demand over a wide range of spatial and temporal scales. Thus, the electrification of end-uses where consumption patterns are linked to behaviour, weather, and technology characteristics is expected to impact grid infrastructure in a variety of ways. One way to limit a rise in grid capacity and flexibility is the utilization of demand-side management strategies. Previous work has yet to address the simultaneous impact of electrifying building heating, cooling, and road transportation on capacity and flexibility requirements of the electricity grid. In this paper two high-resolution models are combined to generate regional demand profiles for building heating, space cooling, passenger, and commercial road transportation. Road transportation demands are modelled in 15-minute time-steps and building demands in hourly resolution. Results show that simultaneous electrification in the building and road transportation sectors increases capacity and flexibility requirements by 93% and 320%, respectively. A synergy of demand-side measures limits the increase in capacity and flexibility requirements to 74% and 82%, respectively. We show that temporal resolution of demand models is an important determinant of flexibility requirements, leading to an increase of 520% in maximum positive ramping rates when changing from an hourly to a 15-minute resolution.

3.1 Introduction

To achieve climate-related emission reduction targets, decarbonization efforts on both the supply and demand side are needed [1]. Supply-side analyses of the emission reduction potential of highly renewable electrical systems have received a lot of attention [118], [119]. However, future supply-side technology requirements are dependent on the magnitude and shape of electricity demand [7]; thus, determining regional supply mixes, transmission, and distribution infrastructure requirements necessitates understanding of the impacts of electrifying end-use energy services.

In 2021, the building and road transportation sectors in Canada contributed 25% of total greenhouse gas (GHG) emissions [120]. Direct electrification of these end-uses is among the most effective strategies to reduce emissions on the demand-side [52], [121]; however, this may lead to a substantial change in the magnitude and shape of electricity demand due to consumer behavior and ambient temperature variability. Compounding the impacts of demand electrification are increasing penetrations of VRE supply, a variability linked to weather [44]. These combined effects lead to concerns that fluctuations of net load, which is defined as electricity demand minus VRE generation, may threaten stable system operations in future energy systems [38], [46].

Grid operators have multiple options for managing and mitigating challenges of demand and supply variability [33]. On the demand-side, strategies include envelope improvements in the building stock [53], [54]; heating system upgrades to more efficient units or the use of hybrid heating systems [72]; and electric vehicle (EV) charging control [17]. On the supply-side, additional investments in dispatchable generation capacity or energy storage could provide valuable flexibility to mitigate the variability of VRE supply [40], [122]. Finally, stronger interties may allow system operators to procure needed services from under-utilized or over-supplied neighboring systems [41]. Exactly what options are preferred, where investments are needed, and when and how much electricity is required are regionally specific questions that call for a detailed understanding of regional demand profiles.

Determining grid flexibility requirements is of high priority for system planners [42], [123], [124]. Flexibility allows balancing spatial and temporal variability of energy supply and demand and is key to the resilience of future electricity systems [125], [126]. The unique temporal characteristic of electrical power makes electricity grid planning and operations significantly more challenging than for other fuel infrastructure. Moreover, it is not energy *per se* that is difficult to source but, rather, the technical requirements of adequate capacity and dynamic response. Thus, to better support the planning and management of future electricity grids, demand models with high temporal resolution are required [127], [128].

In this work, demand models are used to generate regional end-use-specific electricity load profiles for the building and road transportation sectors. Factors such as building composition by vintage and envelope efficiency of the existing building stock, future building code standards, drivetrain stock, vehicle efficiency, charging strategies and rates, population growth, temperature dependent technology efficiency, and regional ambient temperature variability are included. To examine the effect of temporal resolution on capacity and flexibility requirements, this work projects energy demand profiles for future end-use electrification in the building and road transportation sectors in 15-minute and hourly resolution. Variability parameters such as range of electricity load, peak electricity demand and ramping rates are quantified while the effect of DSM strategies such as EV charging and space heating control on variability parameters is assessed. Model results can be used to support the development and implementation of policy in the building and road transportation sectors and provide guidance to utilities in planning for sufficient capacity and flexibility in the electrical grid.

Section 3.2 reviews related modelling approaches. Section 3.3 introduces the modelling methodology. Section 3.4 describes the scenario analysis, input data, and introduces a regional study in which the models are applied to the province of British Columbia (BC), Canada. Modelling results are presented and discussed in Section 3.5 and 3.6, respectively. Section 3.7 provides concluding remarks.

3.2 Background

The demand resulting from electrification of the building and road transportation sectors is difficult to quantify accurately due to the non-linear impact of weather on technology performance and consumer behavior [17], [29], [30]. Short duration, cold temperature events can lead to accelerated battery degradation for battery electric vehicles and a significant rise in heating demands, a consideration in cold regions [12], [112], [129]. A similar but opposite effect arises for electrification of cooling where singular high temperature events result in increased cooling capacity at reduced efficiency which can be exacerbated by over-sizing of capacity [130]. Moreover, in some regions, space cooling demand is expected to increase by 5% per year due to rising ambient temperature [131]. The impact of ambient temperature on the performance of heat pumps for heating and cooling and on battery electric drivetrains can, thereby, lead to different electricity demands for the same service in different climate zones.

Variations in ambient temperature associated with extreme weather events in both winter and summer increases the magnitude of electricity demand as heating, cooling and road transportation end-uses are electrified. In cold climates, peak electricity demand increases at a higher rate than total electricity load due to end-use electrification [7]. Previous work suggests that a simultaneous electrification of heating and road transportation in the UK would double peak electricity demand, relative to 2015 [33]. End-use electrification thereby causes changes in the seasonal dynamic of electricity load profiles and is specific to regions.

End-use electrification and its impact on demand variability requires analyses of the temporal characteristics of demand [28]. In a recent paper, Bistline et al. [7] find that increasing ambient temperature variability in both winter and summer may lead to a shift in the timing of peak electricity demands if certain end-uses are electrified. They show that in cold climate regions, peak electricity demand may shift from summer to winter when space heat and road transportation are electrified. A summer peak electricity event could occur if more dwelling floor space is cooled; however, this is dependent on technology efficiencies of air conditioning units. Changes in the temporal profile of electricity demand are thereby impacted by the degree of end-use electrification, equipment penetration rates and technology efficiencies [24].

In addition to temporal, the spatial profile of demand is important for ensuring electricity system reliability; supply and demand-side resources may have limited value if there is insufficient transmission infrastructure. Policies targeting end-use electrification may lead to increased spatial differences in future electricity demand [28]. Energy efficiency improvements of the building stock are dominating in urban areas while in rural areas an increased usage of rooftop solar PV is observed. It is important to understand the spatial nature of technology choices as end-use electrification benefits may be impacted by network constraints [132].

The effect of end-use electrification on capacity and flexibility requirements may change non-linearly when multiple end-uses are electrified simultaneously due to temporal correlation of electricity loads [28]. DSM strategies can mitigate increasing demand associated with end-use electrification [17], [22]. These strategies include flexible vehicle charging [17], [28], [32]; vehicle-to-grid services [33]; building envelope improvements [18]; deployment of high-efficiency heating equipment or hybrid heating systems using a backup gas furnace during cold weather events [18], [34]; and night ventilation or window shading to limit cooling demands [30]. Previous work has shown that day-time charging for EVs significantly reduces capacity and flexibility requirements while the use of hybrid heating systems in residential buildings reduces peak electricity demand by 30% compared to a 100% heat pump penetration [17], [22].

In the existing literature, demand models used to examine future electrification scenarios often focus on electrifying a single end-use in one economic sector, such as residential space heating [11], [24], [133], residential space cooling [130], or heavy-duty road transportation [32]. Some studies have investigated simultaneous electrification of multiple end-uses including building heating, space cooling, and light-duty transportation [7]; or passenger vehicles, light-duty commercial vehicles and other types of road transportation in addition to space and water heating [134].

Existing demand models project future energy demands with temporal resolution ranging from representative days to half-hourly intervals [11], [24], [33], [133]–[135]; however, electricity market demand data is forecast using a much finer resolution and VRE generation varies significantly over minutes to hours [136]–[138]. Modelling approaches focusing on the variability of demand over short time intervals are sparse due to the lack of historical high-resolution data [127], [139]; however, reduced temporal resolution in energy demand models is known to underestimate capacity and flexibility requirements of the electricity grid [128].

Our understanding of the impact of broad end-use electrification at timescales needed to characterize flexibility requirements is poor as compared to energy and capacity. Because industrial demands tend to be relatively constant in time, future flexibility requirements are expected to be driven by changes in residential and commercial thermal demands and passenger and commercial road transportation. Further, the aggregated impact of DSM strategies such as EV charging control and price-responsive demands such as heating requires a more detailed understanding of temporal behavior to determine systemic value.

To address this gap, this work generates regional electricity demand profiles for 10 end-uses in the building and road transportation sectors with detailed building stock turnover, building envelope efficiency improvements, heating and cooling equipment operations, and EV charging strategies. Five scenarios differing in heating equipment penetration and EV charging strategies are explored and compared to historical data to evaluate system-wide implications of end-use electrification by 2050. The novelty of this work lies in the comprehensive consideration of end-use electrification on electricity load profiles with time increments as short as 15-minutes covering a full year. Temperature-dependent COP profiles are considered for heat pumps and hybrid heating systems, resulting in weather-specific hourly demand profiles for electrified building heating and cooling.

In the following section, the modelling methodology is described. First, the demand modelling tools are presented. Next, the generation of residential space cooling demand profiles is introduced. Finally, the difference in temporal resolution is discussed.

3.3 Methodology

Fig. 3.1 shows the modelling methodology whereby energy demand profiles are generated for individual vehicle weight classes, residential and commercial space and water heat, residential space cooling, and residual load. Model inputs include hourly temperature data, projected future residential and commercial floor space considering new construction, demolition and building retrofits, changes in envelope performance due to building code standards, varying shares of heating technology penetration rates and efficiency assumptions, projected EV penetration rates, EV efficiencies, vehicle charging rates and charging strategies. Model outputs are regional demand time-series which are used to quantify demand variability using three parameters: range of electricity load, peak electricity demand, and ramping rates.

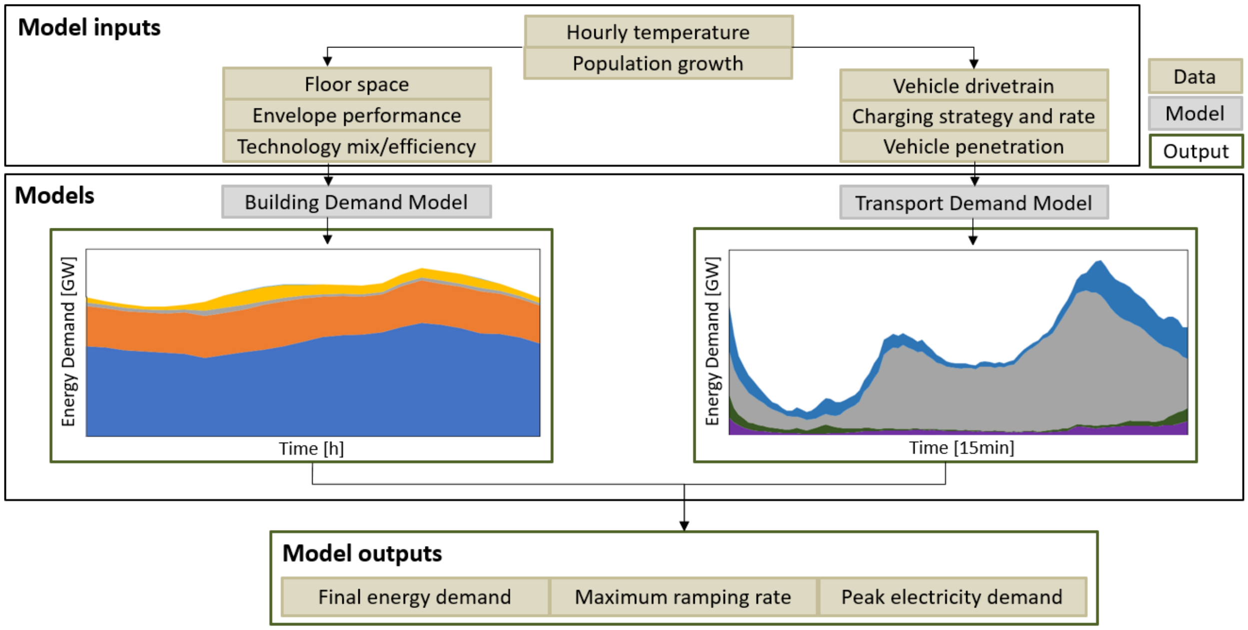


Figure 3.1. Model inputs feed into the building and transport demand models that generate end-use specific demand profiles of different temporal resolutions. Colored stacked areas represent individual end-uses in each model. In the building demand model, individual end-uses include residential space heat, water heat and space cooling, commercial space and water heat, and the residual load. In the transport demand model, individual end-uses include passenger vehicles, light-duty, medium-duty, and heavy-duty commercial vehicles. Model outputs include final energy and peak electricity demand and maximum negative and positive hourly load changes.

The model used to generate demand profiles for passenger vehicles and light-, medium-, and heavy-duty commercial vehicles is described in detail by Lowry et al. [140]. The model used to generate energy demand profiles for space and water heating for the residential and commercial building sectors is described by Knittel et al. [141]; here, we extended the model to enable calculation of residential space cooling demand.

The generation of space cooling demand profiles for the residential sector is summarized in Fig. 3.2. First, a regional cooling load line is defined assuming that the slope of the cooling load line is equal in magnitude to that of the heating load line; a cooling setpoint temperature is also defined as a parameter. Second, using regional hourly temperature data, a cooling load profile is generated for each weather scenario and region, as shown in Fig. 3.2(b), where cooling load is zero for all temperatures below the cooling setpoint. For temperatures above the cooling setpoint, cooling demand is determined based on the cooling load line. Third, hourly cooling demand is normalized by annual cooling energy demand so that the sum of the normalized demand over all hours in a year is equal to one (Fig. 3.2(c)). Future annual useful energy demand for space cooling Q_C is defined based on changes to the aggregate Thermal Energy Demand Intensity (TEDI) of the building stock, growth of floor area, and the fraction of floor area assumed to have cooling (Fig. 3.2(d)). Lastly, the temperature-dependent COP of air conditioning units is applied to future annual useful energy demand giving the final electricity demand profile for space cooling.

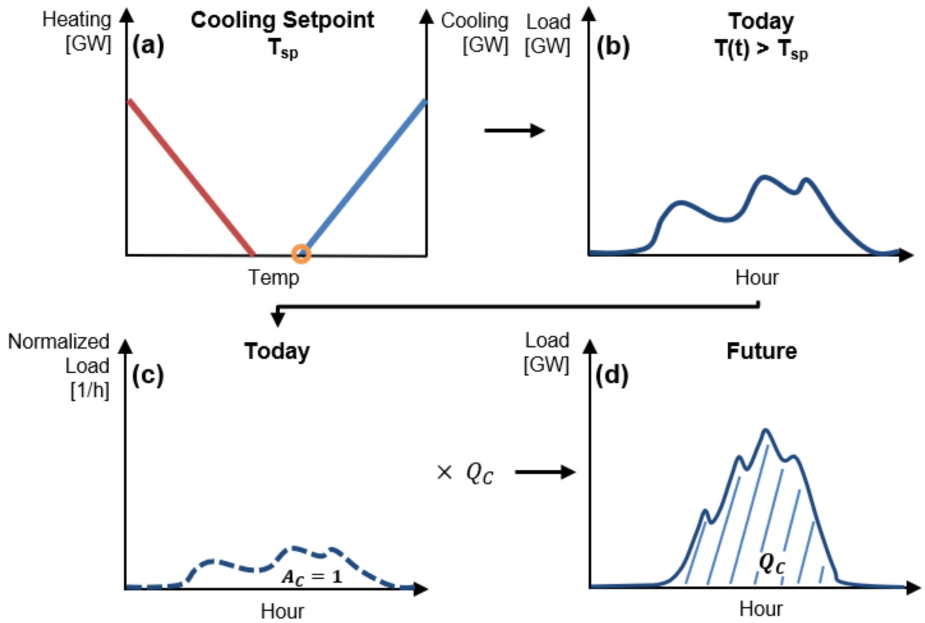


Figure 3.2. (a) Temperature setpoint for cooling. The cooling setpoint temperature (indicated by the orange circle) and the slope of the cooling load line can be varied to investigate cooling demands for a range of operating conditions. For each weather year, a temporal cooling load profile is created that estimates cooling as a function of temperature described by the cooling load line. (b) The cooling profile for a specific weather year informs the normalized profile, shown in (c). The normalized profile is scaled up to future annual useful energy demand for cooling in (d).

The residual load profile is the difference between the reference year electricity demand data and the modeled reference year heat and hot water profiles. Unlike the work in [141] which focused only on building heat electrification, and thus, included historical residential space cooling and road transportation electricity demands in the residual load, we remove these historical demands to avoid double counting. To do so, a 3-year average of historical electric residential space cooling and road transportation demands between 2017 and 2019 is subtracted from the residual load profile in [141].

The building demand model generates energy demand profiles with hourly resolution, while the transport demand model generates demand profiles with 15-minute resolution. To enable merging of these demands, linear interpolation is used to create building energy demand data with 15-minute resolution. To examine the effect of temporal resolution on capacity and flexibility requirements hourly, daily, and weekly demand profiles are generated by averaging the 15-minute time series data over the respective periods. For each time-series resolution we determine six metrics: minimum load, peak load, mean load, median load, maximum negative ramping rate, and maximum positive ramping rate. The effects of the temporal resolution on capacity and flexibility requirements are investigated in Section 3.5.5.

3.4 Scenarios and data

The effect of end-use electrification is examined for a range of possible futures, as represented by the six scenarios shown in Table 3.1. These scenarios consider a range of technology penetrations and use-cases regarding vehicle charging and heating technology conversion.

The 2020 Scenario captures the “current” state of building heat and road transportation demands in BC, providing a reference for all other scenarios. This scenario is based on the publicly available data noted in Table 3.1 and makes use of 2020 hourly gross electrical load data for BC. To account for transmission and distribution losses, 10.3 % of the total energy is subtracted from the historical gross load [142].

The 2050 Reference Scenario extrapolates from 2020 assuming a population growth rate of 1.1.% leading to an increase in the number of EVs and residential and commercial floor space. In this scenario, the floor space heated by resistance heaters and gas furnaces is fixed at 2020 levels. All new heating demand is assumed to be served by heat pumps while 76% of all residential floor space is assumed to be equipped with cooling units. For road transportation, it is assumed that 90% of light-duty commercial and passenger vehicles and 11% of medium-and heavy-duty commercial vehicles are electrified.

Scenarios 2050 A – D assume building services are equivalent to the 2050 Reference Scenario; however, the technology mix for heating changes. It is further assumed that now 100% of light-duty commercial and passenger vehicles and 60% of medium-and heavy-duty commercial vehicles are electrified. Scenario 2050 A captures a high level of electrification in both the building and road transportation sectors. For all EVs, it is assumed that charging begins immediately following the end of each on-shift period. For the building sector in this scenario, it is assumed that all gas heat is converted to electric heat pumps. Scenario 2050 B represents a variation of Scenario 2050 A in which all gas heat is converted to hybrid heat. Scenario 2050 C represents a variation of Scenario 2050 B where 80% of all EVs charge during prescribed hours such that charging occurs at the lowest possible rate to minimize peak power for each individual vehicle weight class (here referred to as ‘off-peak charging’). Scenario 2050 D assumes that all gas heat is converted to electric heat pumps, in combination with an off-peak charging strategy for 80% of EVs.

Table 3.1. Six scenarios test end-use electrification in the building and road transportation sectors. In Scenarios 2050 A – D, all building and transportation services are equivalent to the 2050 Reference. LD = Light-duty commercial vehicles; P = Passenger vehicles; MD = Medium-duty commercial vehicles; HD = Heavy-duty commercial vehicles

<table>
<tr><th>Scenario name</th><th>Share of EVs by weight class</th><th>Charging strategy</th><th>Heating conversion</th><th>Notes</th></tr>
<tr><td>2020</td><td>None</td><td>None</td><td>None</td><td>Historical data</td></tr>
<tr><td>2050 Reference</td><td>90% of PV, LDV
11% of MDV, HDV</td><td>Immediate</td><td>None</td><td rowspan="5">Vehicles
Vehicle population growth (2020 – 2050): 1.1%/yr

Buildings
<u>Floor space & envelope</u>
Building floor space growth (2020 – 2050): 1.1%/yr
Building retrofit rate: 1%/yr
Follow BC Step Code Strategy/Schedule
<u>Heating</u>
Floor space with resistance heat fixed at 2020 level
Floor space with gas heat fixed at 2020 level
Balance of floor space heat pumps
<u>Cooling</u>
Cooled floor space growth (2020-2050): 1.1%/yr</td></tr>
<tr><td>2050 A – Immediate charging & electric heat</td><td rowspan="4">100% of PV, LDV
60% of MDV, HDV</td><td>Immediate</td><td>Gas to heat pumps</td></tr>
<tr><td>2050 B – Immediate charging & hybrid heat</td><td>Immediate</td><td>Gas to hybrid</td></tr>
<tr><td>2050 C – Off-peak charging & hybrid heat</td><td>Off-peak</td><td>Gas to hybrid</td></tr>
<tr><td>2050 D – Off-peak charging & electric heat</td><td>Off-peak</td><td>Gas to heat pumps</td></tr>
</table>

3.4.1 Equipment penetration rates

Fig. 3.3 shows the penetrations of electric heat pumps in the residential building sector for all scenarios. Floor space is expected to grow from 2020 to 2050 while the average Thermal Energy Demand Intensity (TEDI) is expected to decrease due to building retrofits and building energy code standards for new buildings. For all 2050 Scenarios, TEDI remains constant due to equal new construction, demolition, and retrofit rates and regional building energy code (BC Step Code) implementation for all new builds and retrofits. In the 2050 Reference scenario, gas heat stays fixed at the 2020 level and new buildings are expected to install high-efficiency heat pumps. Scenarios 2050 A and D feature the highest heat pump penetration as all gas heat is converted to high-efficiency heat pumps. In Scenarios 2050 B and C, a large fraction of heating is supplied via hybrid heating systems. Hybrid heating systems in this work are modelled such that below an ambient temperature of -4°C electric heat pump operations switch to gas furnace operations.

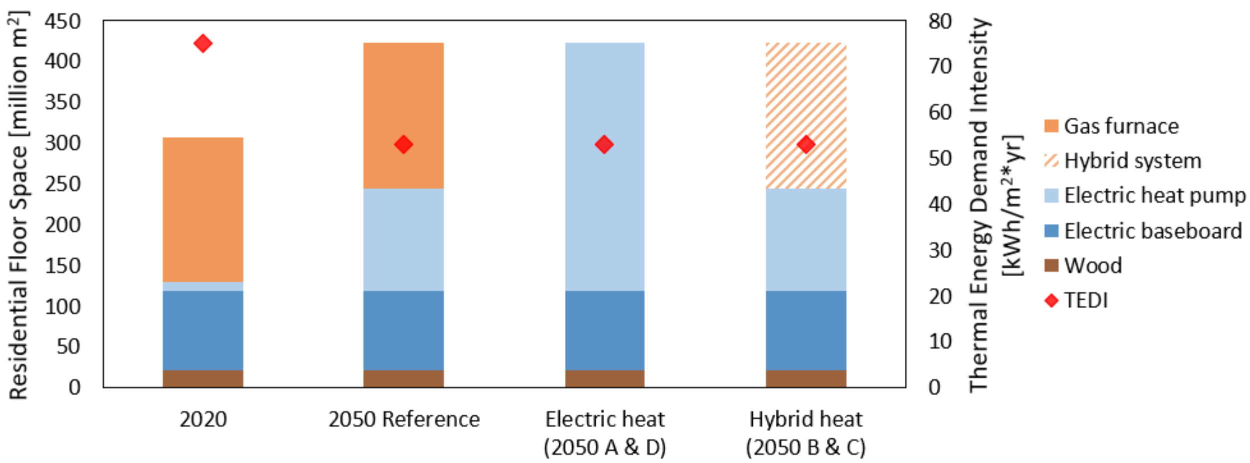


Figure 3.3. Heating equipment penetration rates per floor space and average Thermal Energy Demand Intensity (TEDI) in the residential building sector in British Columbia. TEDI changes based on building code standards, new construction, demolition and retrofit rates. For all 2050 Scenarios, the average TEDI does not vary due to constant building code standards, new construction, demolition and retrofit rates.

Fig. 3.4 shows secondary energy demand for electric and internal combustion engine vehicles and drivetrain types for all scenarios. Vehicle stock is projected to grow from 2020 to 2050 due to an increase in population, while vehicle efficiency is increasing, thereby resulting in more secondary energy demand for EVs. In Scenarios 2050 A – D, the only difference is the charging strategy which is not impacting secondary energy demand for electrified road transportation.

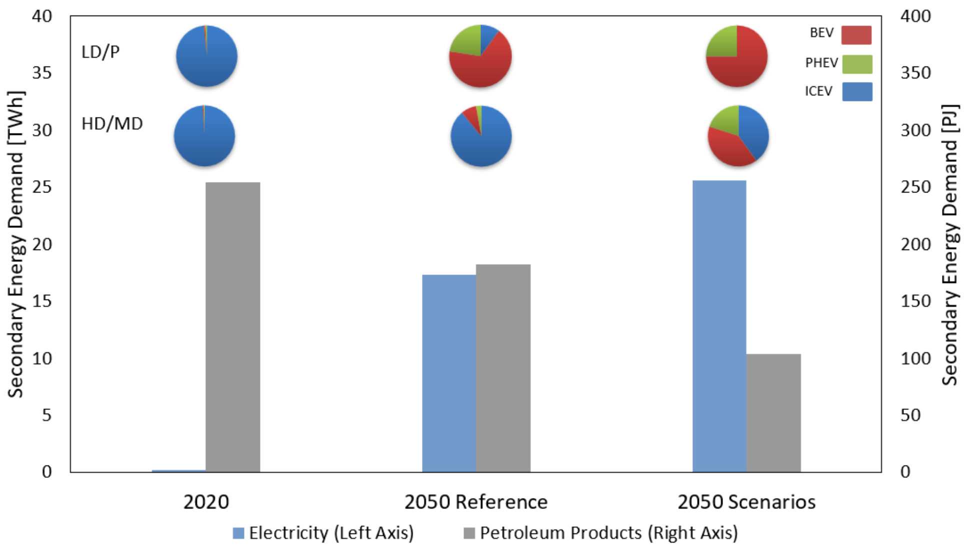


Figure 3.4. Vehicle stock by drivetrain type and secondary energy demand for electricity and petroleum products for all scenarios. The drivetrain proportions and secondary energy demand stays constant across Scenarios 2050 A – D.

3.4.2 Data inputs

To investigate the impact of ambient temperature on end-use demands, 27 years of historical temperature data are analyzed. Hourly temperature data from five climate stations across BC is used to calculate population weighted average hourly temperatures [89]–[93]. As illustrated in Fig. 3.5, the 2021 weather year showed a minimum and maximum hourly temperature of -16.2°C and 39.5°C, respectively. To investigate future capacity and flexibility requirements taking into consideration electrified heating, cooling, and road transportation during a cold and warm weather event, the 2021 temperature data is used for this study.

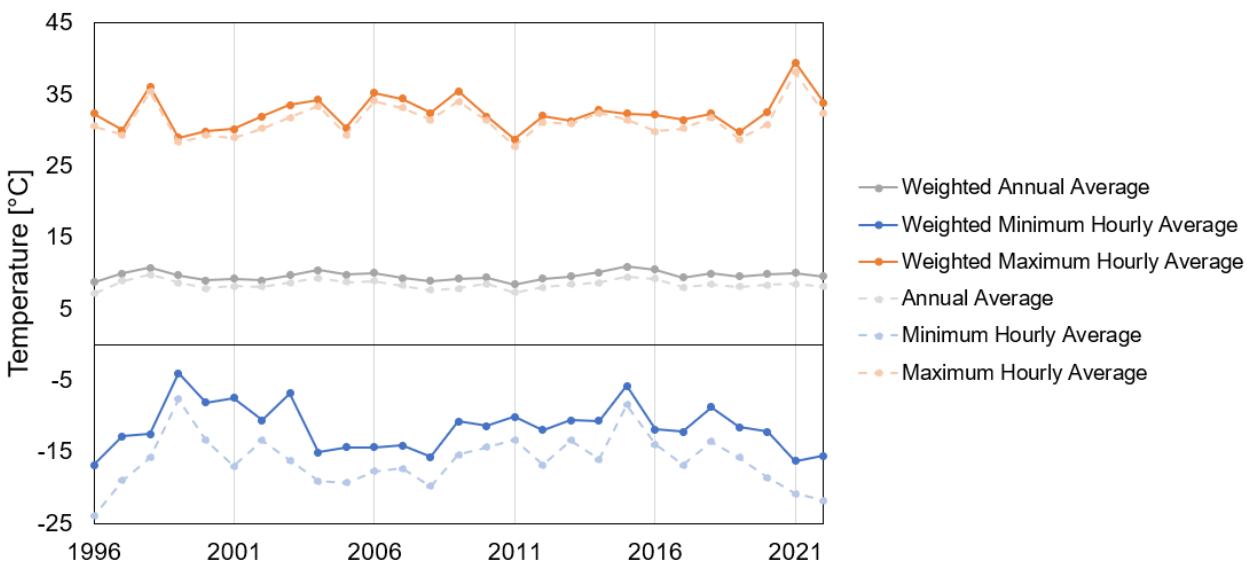


Figure 3.5. Provincial annual temperatures weighted according to population distribution between 1996 and 2022. Hourly temperature data was taken from five climate stations across BC [89]–[93].

Table 3.2 shows all data inputs used to model heating, cooling, and road transportation demand profiles for BC. For residential space cooling, it is assumed that cooling load lines and cooling setpoint temperatures vary across the four modelled regions according to the data sources listed in Table 3.2.

Table 3.2. Data inputs for modelling heating, cooling and road transportation demands in BC.

Data	**Reference**
Temperature data	[89]–[93]
Population growth; Population distribution	[88], [95]
Annual energy demand for cooling; Total floor space cooled	[143]
Cooling Load Line	[144]
Cooling Setpoint Temperature	[145]
Cooling Coefficient of Performance Curve	[71]
2020 historical gross load data	[87]
2020 GHG emissions by activity type	[146]
2020 Secondary energy use by fuel type in the residential and commercial building sector	[82], [83], [85], [143], [147]–[154]
Annual energy demand for heating; Total floor space heated	[82], [83], [85], [96], [97], [151]
Energy Use Intensity, BC Energy Step Code	[99], [105], [155]
2020 Secondary energy use by fuel type and vehicle kilometres travelled in the transportation sector	[156]–[161]

3.5 Results

3.5.1 Seasonal range of electricity load

Fig. 3.6 shows the seasonal range of hourly electricity demand for the 2020 and 2050 Reference Scenarios capturing minimum and peak electricity demand, mean electricity demand and electricity loads within 2σ of the mean. Winter peak electricity demand in 2020 reached 10.3 GW while summer peak electricity demand reached 7.9 GW, as illustrated in Fig. 3.6(a). In the 2050 Reference Scenario, peak electricity demand reaches 17.1 GW and occurs during the winter while the highest electricity demand during the summer reaches 15 GW due to the large share of residential floor space equipped with air conditioning units (Fig. 3.6(b)). This represents an increase in summer and winter peak electricity demand of 90% and 66%, respectively, relative to 2020. Further, as illustrated in Fig. 3.6(b), the range of electricity demand as defined by the difference between the lowest and highest demand in an hour is largest during the summer months in the 2050 Reference Scenario, increasing by 120% relative to 2020, while the range of electricity demand during the winter months increases by only 27%.

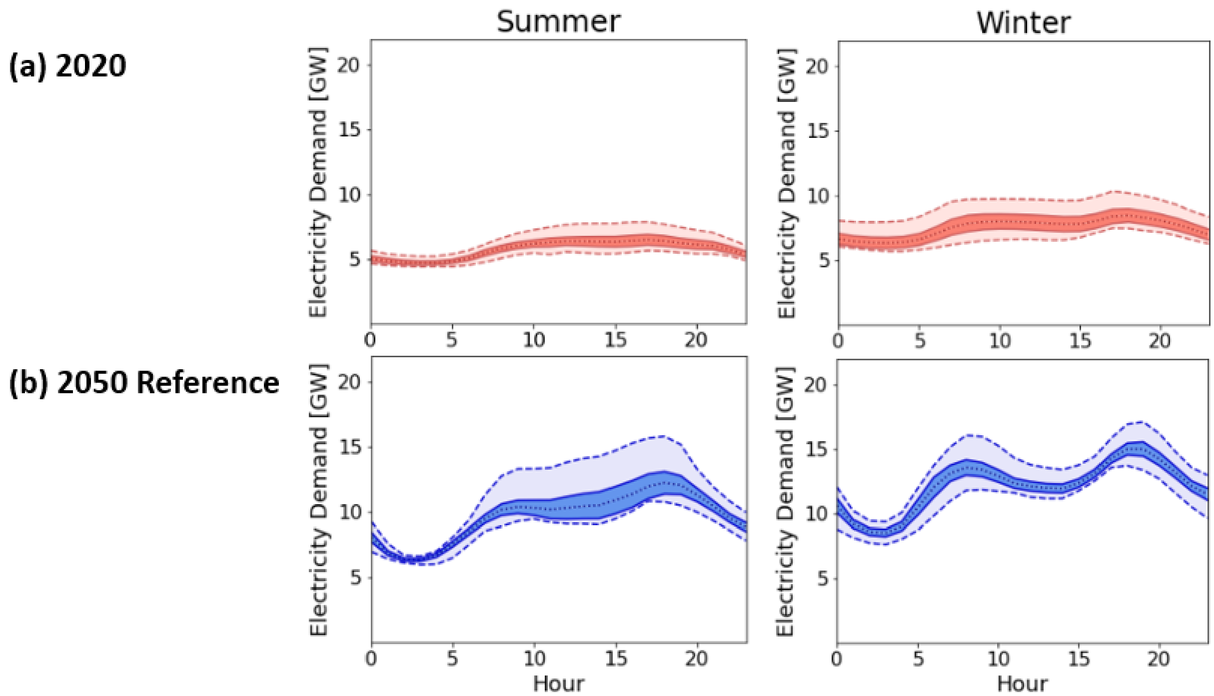


Figure 3.6. Seasonal range of hourly electricity loads for the 2020 scenario is shown in Fig. 3.6(a). Fig 3.6(b) shows the seasonal range of hourly electricity loads for the 2050 Reference Scenario. The inner dotted lines show the mean electricity load while the outer orange/blue dashed lines show the minimum and maximum electricity loads, respectively. The solid orange/blue lines show the bounds of loads within 2σ of the mean. Winter captures the months of December, January, and February. Summer represents June, July, and August. Seasonal range of hourly electricity loads for Spring and Fall are shown in Section B.1 in the Supplementary Material.

Fig. 3.7 shows the seasonal range of hourly electricity loads for Scenarios 2050 A – D. The high penetration of heat pumps in Scenario 2050 A combined with an immediate charging strategy leads to an evening peak electricity demand during the winter, reaching up to 20 GW. Adoption of hybrid heating systems in Scenario 2050 B reduces this winter peak by 5%, compared to Scenario 2050 A. However, due to the immediate charging strategy deployed in this scenario, the timing of the peak event does not change. Combining the use of hybrid heating systems with an off-peak charging strategy (Scenario 2050 C) further reduces winter peak electricity demand by 5%, relative to Scenario 2050 B, reaching the lowest peak electricity demand in 2050 of 18 GW while simultaneously shifting the peak event to early morning hours.

In addition to driving peak electricity demand, EV charging strategies also impact minimum electricity demand. This is illustrated in Fig. 3.7(a) and Fig. 3.7(b) where minimum electricity demand reaches 8.4 GW and 8.3 GW, respectively, for Scenario 2050 A and B. Both scenarios utilize the immediate charging strategy. Results for Scenarios 2050 C and D show that use of the off-peak charging strategy for 80% of all EVs, Fig. 3.7(c) and Fig. 3.7(d), increases minimum electricity demand by 10% and 11%, respectively, relative to Scenario 2050 B.

The increasing range of electricity demand by 2050 is driven by electrified road transportation and low temperature events that cause high heating demand. As illustrated in Fig. 3.7(a), electricity load shows the largest range, up to 7.8 GW at midnight, due to heating and road transportation electrification. This represents a 130% increase in winter electricity load range, relative to 2020. The use of hybrid heating systems (Scenario 2050 B, Fig. 3.7(b)) results in a smaller range of electricity load of -10% relative to Scenario 2050 A. Combining an off-peak charging strategy with the use of hybrid heating systems (Scenario 2050 C, Fig. 3.7(c)) results in the smallest range of electricity load during the winter, representing a 32% reduction, relative to Scenario 2050 A.

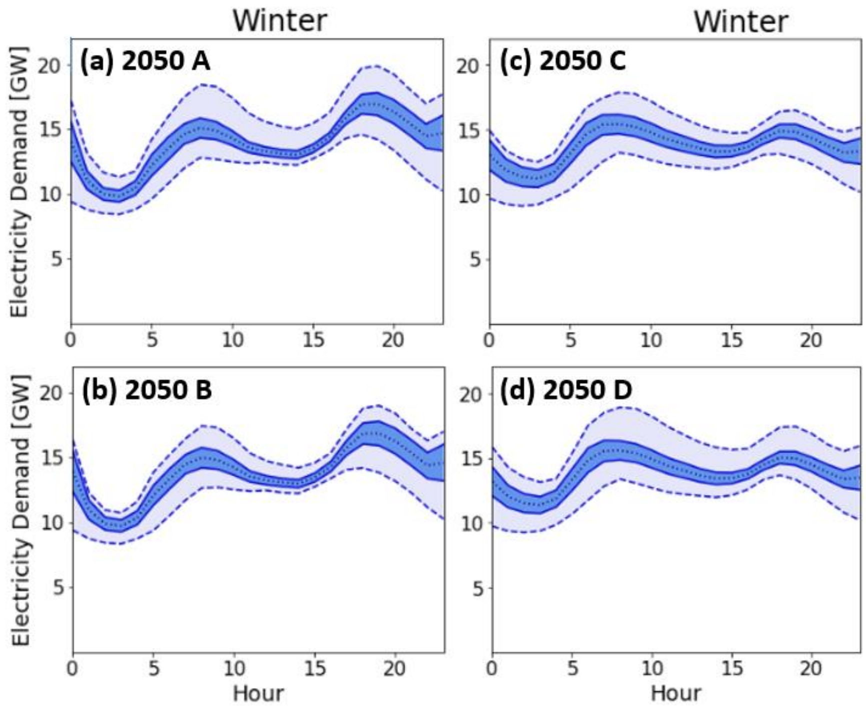


Figure 3.7. Range of hourly electricity loads during the winter months for Scenarios 2050 A – D. The inner dotted lines show the mean electricity load while the outer blue dashed lines show the minimum and maximum electricity loads, respectively. The solid blue lines show the bounds of loads within 2σ of the mean. Range of hourly electricity loads for spring, summer, and fall are shown in Section B.1 in the Supplementary Material.

Summer peak electricity demand is driven by the penetration of air conditioning units and the selection of EV charging strategies. This is illustrated in Fig. 3.8(a), where summer peak electricity demand for Scenarios 2050 A and B (immediate EV charging) reaches 17 GW, an increase of 120% relative to the summer peak electricity demand in 2020. Utilizing an off-peak charging strategy (Fig. 3.8(b) Scenarios 2050 C and D) leads to a summer peak electricity demand of 15.3 GW. Fig. 3.8(b) further shows that introducing off-peak EV charging shifts peak events to 2 p.m., thereby reducing other coincident electric loads and leading to a reduction of peak electricity demand by 10%, relative to Scenarios 2050 A and B.

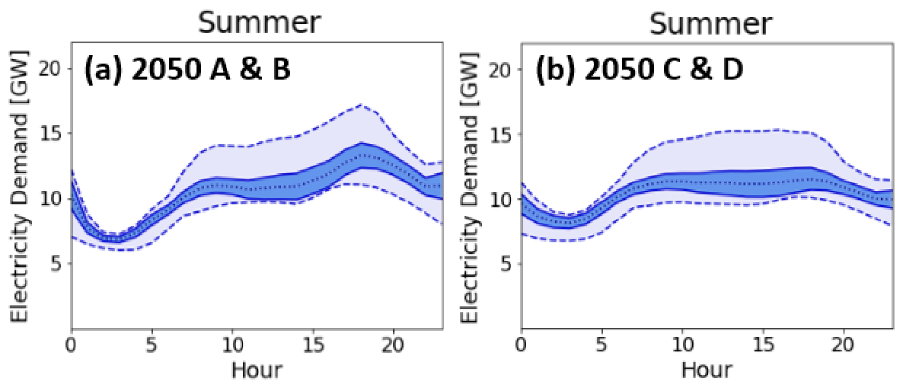


Figure 3.8. Range of hourly electricity loads during the summer months for Scenarios 2050 A – D.

3.5.2 Annual peak electricity demand

For all scenarios, the annual peak electricity demand occurs during the winter. This is illustrated in Fig. 3.9 where, during a cold weather event, peak electricity demand increases by 93% in Scenario 2050 A, relative to 2020. Utilizing EV charging and space heating control, as represented by Scenario 2050 C, limits the increase in peak electricity demand to 74%, relative to 2020.

The integration of DSM strategies in the building and road transportation sectors reduces the magnitude of peak electricity demand. This is illustrated in Fig. 3.9, where the share of electricity for residential space heat during a heating dominated peak event is reduced by 18% when utilizing a 60% penetration rate of hybrid heating systems (i.e., Scenarios 2050 B and C, relative to Scenarios 2050 A and D). In addition, the share of peak electricity demand for electrified road transportation is reduced by 30% (i.e., 2 GW), for the off-peak charging strategy (Scenario 2050 C and D) relative to the immediate charging strategy (Scenario 2050 A and B). Combining the off-peak charging strategy with hybrid heating systems, as represented by Scenario 2050 C, reduces total peak electricity demand by 20%, relative to Scenario 2050 A. This decrease is observed despite a lower ambient temperature (-16.2°C) at the time of the peak in Scenario 2050 C. The lower temperature causes electricity demand for space and water heat to increase by 15%; however, due to the use of hybrid heating systems peak electricity demand is reduced by 20% as compared to Scenario 2050 A. Charging strategies for electrified road transportation impact the timing of peak electricity demand. As shown in Fig. 3.9, peak electricity demand in Scenarios 2050 A and B, which both use an immediate charging strategy, occurs during evening peak hours. Using an off-peak charging strategy, as represented by Scenarios 2050 C and D, shifts the timing of the peak event to early morning hours.

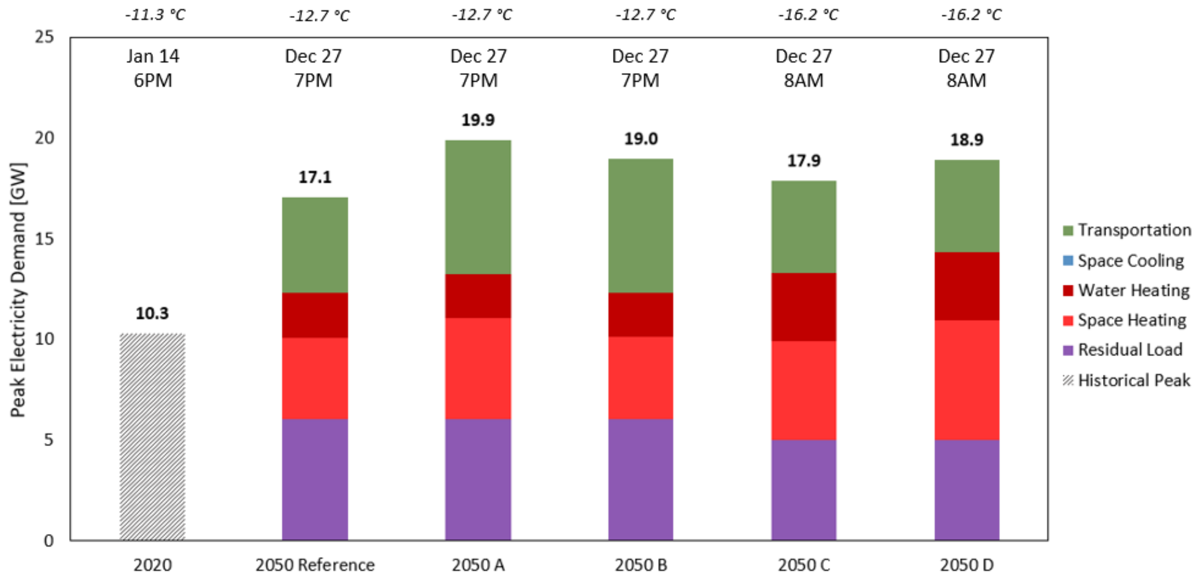


Figure 3.9. Peak electricity demand disaggregated into end-use sectors for 2020 and all 2050 scenarios. The date and time at which peak electricity demand occurs is shown above the bars and the provincial weighted average temperature during the peak hour is shown at the top of the figure.

In relative terms, the impact of electrification is more significant for the summer season. This is shown in Fig. 3.10 for the 2050 Reference Scenario, where a 44% penetration rate of gas furnaces for residential space heat results in a summer peak electricity demand up to 53% larger, relative to the 2020 historical winter peak and almost double the 2020 summer peak. When off-peak EV charging is combined with significant cooling loads during high temperature events (i.e. Scenarios 2050 C and D), cooling accounts for 30% of summer peak electricity demand. In combination with an immediate charging strategy, electricity for space cooling accounts for 22% of summer peak electricity demand by 2050.

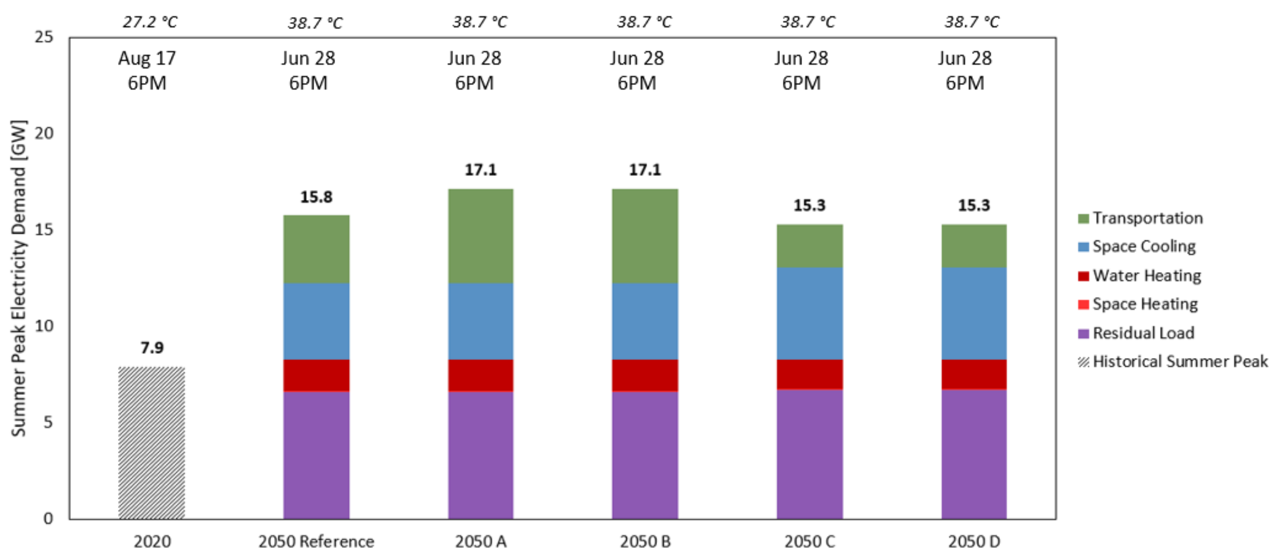


Figure 3.10. Summer peak electricity demand disaggregated into end-use sectors for 2020 and all 2050 scenarios. The date and time at which peak electricity demand occurs is shown above the bars and the provincial weighted average temperature during the peak hour is shown at the top of the figure.

3.5.3 Ramping rates

Fig. 3.11 shows the maximum negative and positive ramping rates based on hourly load changes, relative to 2020. Maximum negative and positive ramping rates increase by 320% and 120%, respectively, for the immediate charging strategy (Scenario 2050 A and B). Adoption of the off-peak charging strategy (Scenarios 2050 C and D) limits the increase in maximum positive ramping rates to 82% and maximum negative raping rates to 70%. For all scenarios, maximum ramping rates occur between 11.45 p.m. and 12 a.m. (not shown in Fig. 3.11) which is driven by the completion of charging activities of the commercial vehicle fleets.

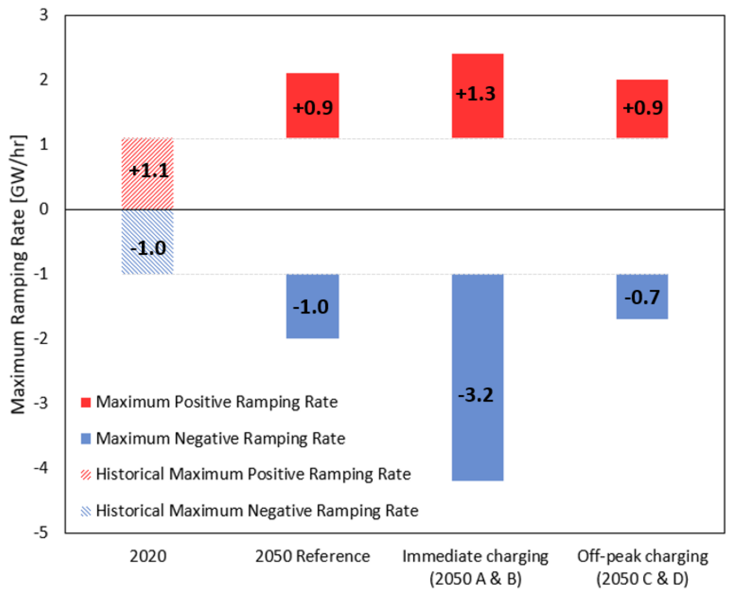


Figure 3.11. Ramping requirements of the electricity grid to meet hourly load changes in 2050, relative to historical ramping requirements in 2020.

3.5.4 Regional requirements

Regional energy, capacity, and flexibility requirements vary due to differences in population, ambient temperature, and technology performance. Fig. 3.12 shows energy, capacity, and flexibility requirements are largest in the Lower Mainland, which is home to approximately 61% of BC's total population [88]. Here, annual electricity demand reaches 60.4 TWh while peak demand and ramping rates reach 11.2 GW and -2 GW/hr, respectively. Among the four regions, the largest relative increase in energy, capacity, and flexibility requirements occurs in Northern BC which had 5063 heating degree days (HDD) in 2021, highest among the four regions. This leads to an increase of annual electricity and capacity requirements in Northern BC of 120% and 230%, respectively, while ramping rates increase by 7000%.

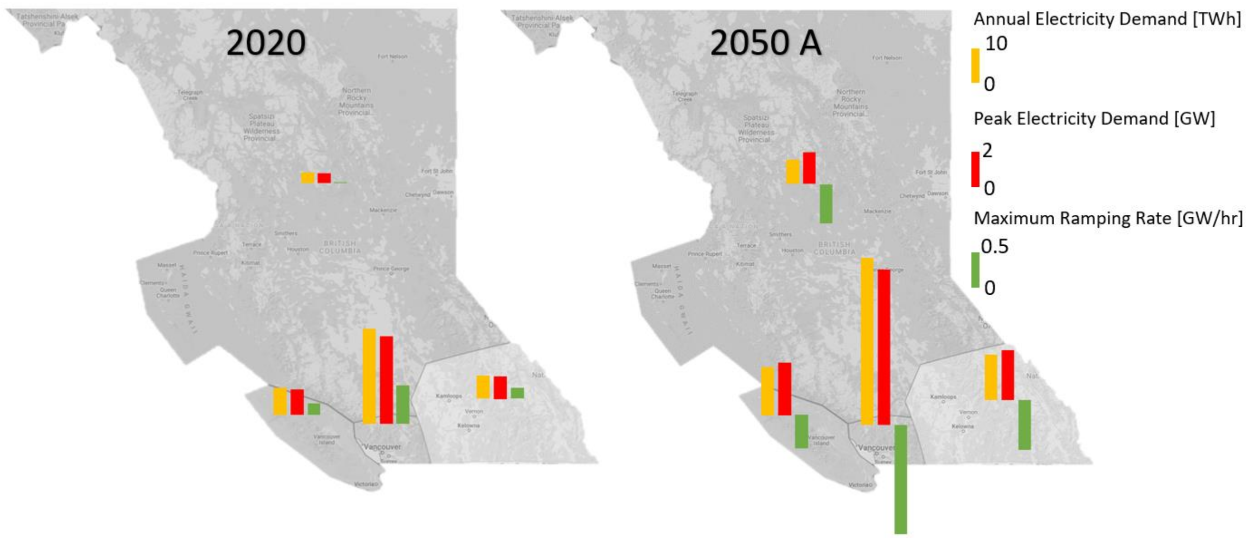


Figure 3.12. Changes in regional annual electricity demand, peak electricity demand and maximum ramping rate for Scenario 2050 A, relative to 2020. In the 2021 weather year, Northern BC has 5063 HDD, Southern Interior has 3760 HDD and Vancouver Island and the Lower Mainland have 2859 and 2815 HDD, respectively.

3.5.5 Temporal resolution effects

Temporal resolution is an important modelling choice and is usually chosen to balance computational complexity with accuracy. Coarser resolutions are common when focusing on energy metrics. However, for assessing flexibility much finer scales are needed. The effects of temporal resolution are explored by averaging our 15-minute data points over longer periods to represent hourly, daily, and weekly resolution. Fig. 3.13 shows the electricity load for Scenario 2050 A in January for four temporal resolutions.

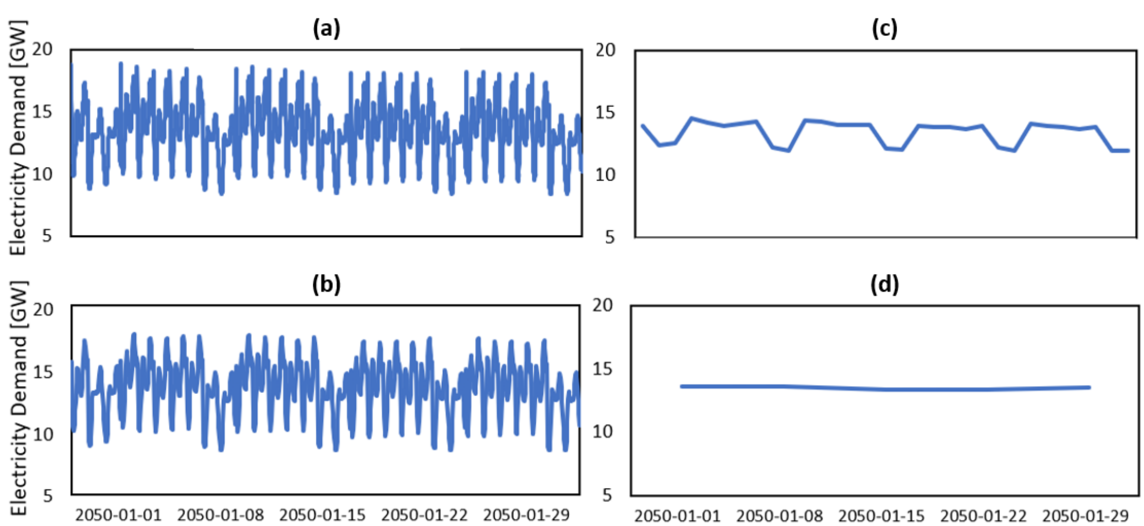


Figure 3.13. Time series plots of electricity demand for the month of January in Scenario 2050 A with (a) 15-minute, (b) hourly, (c) daily, and (d) weekly resolution.

The impacts of resolution are compared in Table 3.3 where metrics are determined by analyzing the time-series data over the entire year. As can be seen, the mean load and, therefore, the annual energy demand is essentially the same for all cases; however, as temporal resolution is reduced, capacity and flexibility requirements are increasingly underestimated. Table 3.3 shows maximum positive and negative ramping rates for each resolution, converted to GW/15min, to provide equivalent comparison. Results indicate that both maximum negative and maximum positive ramping rates decrease as the temporal resolution is reduced. When changing from hourly to a 15-minute resolution, maximum ramping rates increase by 180% for negative ramping rates and 520% for positive ramping rates. Therefore, temporal resolution has significant impacts on flexibility requirements.

Table 3.3. Descriptive statistics for the total electricity consumption for end-use electrification in the building and transportation sectors according to Scenario 2050 A over the yearly period.

Load Characteristic	**15-min**	**Hourly**	**Daily**	**Weekly**
Minimum Load [GW]	5.95	5.99	9.02	10.09
Mean Load [GW]	11.69	11.69	11.69	11.68
Median Load [GW]	11.59	11.58	11.26	11.18
Peak Load [GW]	20.57	19.90	16.27	14.63
Maximum Negative Ramping Rate	-2.89 GW/15min	-4.17 GW/hr [-1.04 GW/15min]	-0.88 GW/d [-0.01 GW/15min]	-1.08 GW/wk [-0.002 GW/15min]
Maximum Positive Ramping Rate	+3.78 GW/15min	+2.43 GW/hr [+0.61 GW/15min]	+0.67 GW/d [+0.01 GW/15min]	+1.20 GW/wk [+0.002 GW/15min]

Fig. 3.14 shows the distribution of electric load for four temporal resolutions for Scenario 2050 A. The largest distribution is observed for the 15-minute resolution. For all four resolutions, the top whisker in Fig. 3.14 is longer than the bottom whisker. This suggests that there is a larger variance among the peak values, since there is a greater distance from the 3rd quartile to the upper extreme than from the median to the 3rd quartile. Fig. 3.14 also highlights outliers, shown above the top whisker, thereby suggesting that the impact of temporal resolution on peak electricity demand is larger than on minimum load. In the 15-minute resolution, 0.4% of all datapoints are outliers while the weekly resolution does not have any outliers. Therefore, the coarser the temporal resolution, the more likely future capacity requirements will be underestimated.

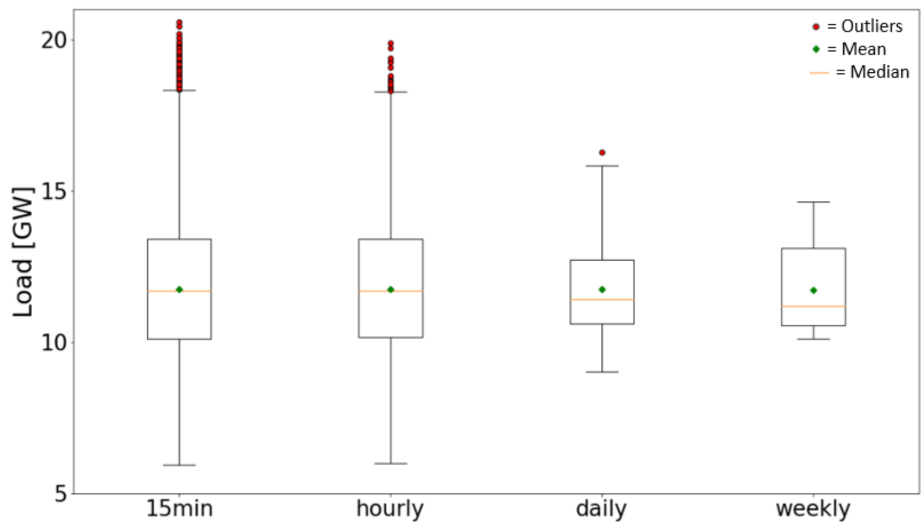


Figure 3.14. Distribution of electric load in Scenario 2050 A for four temporal resolutions. The box is described as the interquartile range between the 25th and 75th percentile. The bottom whisker represents the 25th percentile times 1.5 times the interquartile range while the top whisker represents the 75th percentile times 1.5 times the interquartile range. Outliers are outside of the 25th and 75th percentile times 1.5 times the interquartile range.

Fig. 3.15 shows coefficient of variation as a function of peak electricity demand on the left and standard deviation as a function of maximum positive ramping rate on the right. As temporal resolution increases, the coefficient of variation increases. This indicates the risk that with low temporal resolution, peak events will be underestimated. As shown on the right, temporal resolution has a significant impact on capturing ramping events particularly when changing from an hourly to a 15-minute resolution. Regarding ramping, the largest standard deviation is observed in the 15-minute resolution, indicating the highest variability of ramping rates. The standard deviation decreases by 46% in the hourly resolution, relative to the 15-minute resolution indicating that flexibility requirements for future electricity grids are significantly underestimated in the hourly resolution.

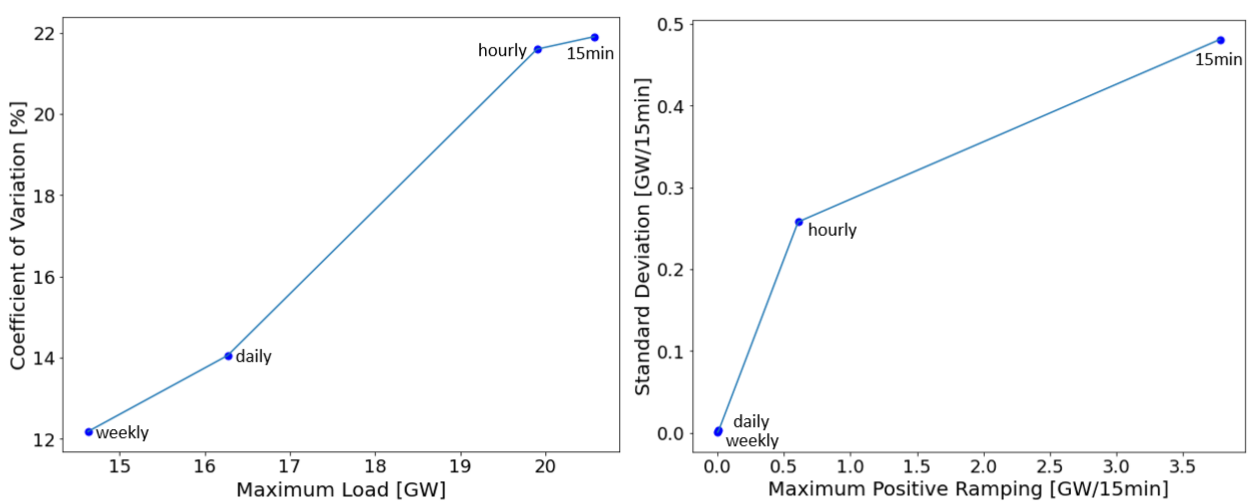


Figure 3.15. Coefficient of variation as a function of peak electricity demand for four temporal resolutions is shown on the left. Standard deviation as a function of maximum positive ramping is shown on the right.

3.6 Discussion

The findings of this study reveal that it is necessary to introduce DSM strategies to limit increases in capacity and flexibility requirements of the electricity grid after end-use electrification. Compared to present-day peak electricity demand and maximum ramping rates, an increase of up to 74% and 82%, respectively, is observed for a simultaneous electrification of heating, cooling and road transportation using off-peak EV charging and hybrid heating systems. For a simultaneous electrification of heating, cooling, and road transport in the absence of DSM strategies, peak electricity demand and maximum ramping rates increase by up to 93% and 320%, respectively, compared to present-day values. The move towards electrification of building and road transportation end-use demands in the future seems likely; however, achieving a 60% hybrid heating system adoption rate and an 80% off-peak charging rate for all EVs across the province of BC by 2050 does not. It will be necessary for utilities to expand current generation capacities and increase system flexibility to accommodate increasing peak demands and to adequately meet steep increases or decreases in load changes. Incentivizing both, off-peak EV charging activities and the switch from electric heating to hybrid heating systems is necessary to limit increases in peak electricity demand and ramping rates while shifting peak events from winter to summer when electricity demand is lower. Additional electricity demand during the summer can be met more easily by the hydroelectric power supply in BC without the need to invest in additional generation capacity [162].

Hybrid heating systems with backup gas furnaces that are used to serve heating demands during cold weather events significantly reduce capacity requirements, thereby, alleviating additional stress on the electricity grid in meeting future electricity demand; however, only during a heating dominated peak event. During the peak event, replacing gas furnaces with hybrid heating systems leads to a reduction in electricity demand for residential space heating of 20% in Scenarios 2050 B and C, relative to Scenarios 2050 A and D, as illustrated in Fig. 3.9. This finding is aligned with studies that investigate the impact of hybrid heating systems on peak heat demands in Europe and the UK which find that capacity requirements are significantly reduced when utilizing hybrid heating systems with backup gas heat [112], [163].

Using the off-peak EV charging strategy alleviates additional pressure on the grid by shifting the timing of the peak event to early afternoon so that electricity demand for road transportation is less coincident with other electric loads. Fig. 3.8 shows that introducing off-peak EV charging shifts peak events to 2 p.m., thereby avoiding other coincident electric loads at the same time which leads to a reduction of peak electricity demand by 7%. These results confirm the findings in [17] for electrified road transportation in the US Western Interconnection. In [17], a range of at-home and workplace charging strategies were examined, resulting in peak electricity demand between 10 a.m. and 11 a.m. in some cases, thereby not coinciding with typical evening peak loads.

Due to increasing electrification of end-use demand in the building and road transportation sectors, BC may experience an increasing range in electricity load by 2050 which can be partially mitigated using DSM strategies. The electricity load shows the largest range of up to 7.8 GW during the winter due to heating and road transportation electrification in Scenario 2050 A. This represents a 130% increase, relative to 2020, and is a result of large-scale adoption of electric heat pumps and increasing penetration of EVs. The larger range of electricity load can be decreased by combining the use of hybrid heating systems with an off-peak charging strategy, reducing the range of electricity load by 32%, relative to Scenario 2050 A.

Historically, BC is a winter-peaking region but, in recent years, high temperature events during the summer have led to increased electricity demand due to cooling loads [145]. For example, in August 2023 a heat wave resulted in a peak electricity demand of 8.4 GW at night [164]. In 2020, 26% of residential floor space in BC was equipped with cooling units, an increase of 4% as compared to 2015 [143]. This percentage is likely to increase significantly in the coming years as extreme weather events are expected to occur more frequently, thereby increasing cooling demand [165]. Depending on the heating technology mix, BC may experience a shift from winter to summer peak events associated with increased adoption of air conditioning units. Results show that for the 2050 Reference Scenario summer peak electricity demand increases by 53%, relative to the historical winter peak electricity demand in 2020, where electricity for space cooling accounts for 30% of peak electricity demand, assuming 76% of residential floor space is equipped with cooling units by 2050. The seasonal range of electricity demand and existing capacity constraints limit the ability of BC's electricity grid to accommodate additional electricity demand in the winter; however, it is possible that larger summer peak demands could be met more easily as compared to larger winter peak demands due to dispatchable hydroelectric supply resulting from snowmelt-freshet inflows in June and July [162].

The effect of temporal resolution of end-use demand profiles is explored using 15-minute, hourly, daily, and weekly intervals. Our findings show that coarse temporal resolution can lead to underestimation of capacity and flexibility requirements. Results in Table 3.3 show that with 15-minute resolution, capacity requirements are 3% larger than with hourly resolution. Maximum positive ramping requirements increase from 2.4 GW/h to 3.8 GW/15min while maximum negative ramping requirements increase from -4.2 GW/h to -2.9 GW/15min. This has significant implications on flexibility requirements, as it will be much more challenging to meet ramping requirements on the order of 4 GW within a 15-minute interval as compared to 2 GW within an hourly interval.

The results presented in this study are based on local climate data, the distribution of building types in BC and the strategies to decarbonize the building and road transportation sectors captured by the scenarios considered. While the results are not directly transferrable to regions with different climate conditions the method of this analysis is transferrable to other jurisdictions.

3.6.1 Limitations

Within the context of this study, the demand modelling has some clear limitations. The generation of future energy demand profiles for individual vehicle weight classes requires user inputs such as vehicle drivetrain stock, charging strategies and rates, and vehicle efficiencies to predict what future road transportation and the supporting infrastructure will look like. In this work, it is assumed that commercial vehicle charging is not continuous between weekdays and weekends, and thus, that commercial vehicles do not charge on the weekends. This assumption leads to extreme ramping rates on Monday mornings and Friday evenings. To avoid overestimating ramping requirements, any ramping rates occurring between 7 p.m. on Fridays and 7 a.m. on Mondays have not been considered in the results analysis. Demand profiles for building end-use demands are dependent on data availability of real-world hourly heating demand profiles for space and water heating. For space cooling, real-world cooling demand profiles are not available; thus, cooling demand profiles are estimated based on a cooling load line with slope that is equal in magnitude to the slope of the heating load line which was obtained from real-world data. For all energy demand simulations, regional demand profiles are represented by proxies of regional population.

3.6.2 Future work

Future research can enhance the results of this study by investigating the impact of switch-over temperature points of hybrid heating systems on electricity grid requirements. As outlined in a recent study that examined smart hybrid heating systems in Ontario, the representation of hybrid heating system in this model could be improved to take into account time-of-day pricing of electricity usage and heat pump efficiencies to determine whether electric heat pumps or gas furnace would be the cheaper heating technology [166]. This work could also benefit from including other DSM strategies that shift electricity demand arising from end-use electrification, such as thermal heat storage and utility-controlled EV charging. High-resolution modelling of end-use demand profiles in the building and road transportation sectors could be complemented by adding load profiles for the agricultural and industrial sectors to provide a more comprehensive basis for future electricity system analyses.

On the supply-side, electricity system modelling could provide insights into generation capacity and flexibility planning; green hydrogen production potentials to serve commercial road transportation; and seasonal energy storage requirements to meet increasing peak electricity demand and ramping rates. Examining the potential of supply-side strategies to balance the mismatch of demand and supply under multiple weather conditions such as prolonged drought periods, increasing precipitation, heat domes or cold snaps would provide a more comprehensive basis for long-term resource planning of electricity grids.

3.7 Conclusion

This work addresses the current gap of high spatiotemporal demand modelling for building and road transportation end-use demands. Considering the electrification of building heating, space cooling, and road transportation, this study demonstrates how the magnitude and shape of electric load curves will change for highly electrified futures. The high-resolution demand modelling tools are applied to BC, Canada, to explore implications of electrified road transportation, large-scale heat pump adoption, and DSM strategies such as EV charging and space heating control on the timing and magnitude of capacity and flexibility requirements of the electricity grid.

Results show that the introduction of DSM strategies is necessary to limit increases in capacity and flexibility requirements of the electricity grid. For a simultaneous electrification in the building and road transportation sectors in the absence of DSM strategies capacity and flexibility requirements increase by up to 93% and 320%, respectively. A synergy of DSM strategies involving EV charging and space heating control decreases capacity and flexibility requirements by up to 19% and 238%, respectively, relative to end-use electrification without DSM. To accommodate increasing peak electricity demand and ramping rates, utilities need to expand current generation capacities and system flexibility capabilities while government should incentivize off-peak EV charging activities and the use of hybrid heating systems to alleviate additional stress on electricity grid infrastructure due to end-use electrification.

Forecasting the magnitude and timing of peak electricity demand is crucial for energy systems with large shares of VRE generation. Electrifying building heat alone already exceeds currently installed capacities in BC, showing that in the absence of dispatchable capacity alternatives, simultaneous electrification of several end-uses cannot be accommodated by the current energy system [49]. Electrifying end-uses in the building and road transportation sectors requires additional investment in generation capacity, transmission, and distribution infrastructure. Future research should investigate the potential of energy storage to provide peaking capacity, or the use of low-carbon gases for commercial road transportation to avoid an additional rise in electricity grid capacity and flexibility requirements.

Chapter 4

Electrification of end-use services in a 100% renewable grid: The value of operational flexibility

Preamble

Electricity system operators are substituting dispatchable generation assets with VRE resources to achieve greenhouse gas emission reduction targets. Rising shares of VRE generation affect electricity system characteristics including net load. Understanding the impact of increasing VRE generation capacity on net load is crucial in planning for resource adequacy in future electricity systems. In this work, we examine generator dispatch behavior using a production cost model with hourly resolution and apply it to British Columbia, Canada. Electricity demand is projected to 2050 and includes electrified building heating, cooling, and road transportation demands. In addition to wind and solar resources, large-scale hydroelectric power generation is divided into must-take and flexible generation assets to simply complex hydro operations. Three water supply scenarios were developed to identify changes in net load due to drought conditions and increased precipitation impacting hydroelectric power generation. The study determines peak net load for installed wind and solar capacities up to 50 GW for multiple wind penetrations to examine the magnitude and duration of excess energy and energy deficiency periods. Results show that peak net load in 2050 exceeds present-day peak electricity demand in British Columbia, necessitating large-scale built-out of VRE generation capacity. For 30 GW installed wind and solar capacity, energy storage with a duration of 5 hours is sufficient to manage most deficiency periods for all VRE supply scenarios. However, managing all periods of energy deficiency can only be achieved by a combination of flexibility strategies.

4.1 Introduction

An increasing penetration of power generation coming from renewable resources with variable output may cause significant operational challenges in future electricity grids [41]. When combined with increasing variability of electricity demand due to end-use electrification, variability of VRE generation adds significant complexity to electricity system operations [45], [46]. As energy systems evolve toward net zero the need for strategies to enhance operational flexibility to mitigate short-term fluctuations of demand and supply increases [40].

Grid operators have multiple options to balance the mismatch of energy demand and supply [33]. One strategy to enhance operational flexibility is the expansion of inter-regional electricity system infrastructure that may allow system operators to procure needed services from under-utilized or over-supplied regions [41]. Another effective flexibility strategy may be overproduction of VRE resources where excess energy is either curtailed, exported to neighbouring jurisdictions, or used for producing electrolytic hydrogen [19]. Energy storage is an effective strategy to minimize VRE generation costs while avoiding VRE curtailment; however, combining VRE curtailment with energy storage can lead to a significant reduction in power and energy capacity requirements for energy storage [40], [167]. Identifying the most effective flexibility strategy – or combination of flexibility strategies – will largely depend on the type of generators in an energy system, the penetration of VRE resources, and spatial and temporal characteristics of electricity demand [42].

Increasing penetrations of VRE resources may cause the variability of net load, which is defined as electricity demand minus VRE generation, to increase [19]. Peak net load provides an estimate on dispatchable capacity requirements that can be reduced by a range of flexibility strategies [35]. In hydro-dominant regions, annual changes in water supply due to drought conditions or additional precipitation are expected in the future, which will impact the magnitude of net load [14]. Net load analyses are necessary to determine periods of surplus energy and periods of unserved net load for a range of VRE supply scenarios as the effectiveness of flexibility strategies will be determined by the magnitude and duration of energy deficiency periods.

This paper aims to analyze generator dispatch behavior for multiple VRE generation scenarios by considering the relationship among different types of renewable generation assets to examine the magnitude and duration of excess energy and energy deficiency periods. In this paper, two high-resolution energy demand models are integrated with a production cost model to investigate the impact of end-use electrification on detailed generator dispatch behavior. Electricity demand is projected to 2050 and includes additional electricity demand for electrification of building heating, cooling, and road transportation end-use services. Further, periods of excess energy and energy deficiency are examined for multiple VRE supply scenarios to assess potential flexibility strategies. Hydroelectric power generation in this work is modelled to represent must-take energy, which cannot be stored in reservoirs for later use, and flexible energy that can be used as dispatchable generation asset to meet future net load.

Section 4.2 reviews the literature on flexibility strategies to reduce net load. In Section 4.3, the modelling methodology is described. Section 4.4 describes the input data, scenario analysis, and introduces a regional study in which the models are applied to the province of British Columbia (BC), Canada. Modelling results are presented and discussed in Section 4.5 and 4.6, respectively. Section 4.7 provides concluding remarks.

4.2 Background

Integrating large shares of VRE generation into power systems and electrifying end-use energy demands will cause a significant mismatch in demand and supply [44], [46]. Combining the increasing variability of electricity demand and with increasing variability of VRE supply has a profound impact on the magnitude of peak net load [19]. System operators need to plan for enhanced system flexibility in future electricity grids to meet growing peak net load [37]. Planning for sufficient operational flexibility allows system operators to utilize generation assets reliably, thereby ensuring a more resilient energy future [38].

Analyses of peak net load inform dispatchable capacity requirements needed to secure future electricity supply [35]. Strategies to increase operational flexibility in highly renewable energy systems include built-out of VRE generation capacity; expansion of transmission and distribution infrastructure; energy storage; and trade [168]. An expansion of VRE resources may have limited value if there is insufficient transmission infrastructure but may be necessary in the absence of energy storage [41], [169].

The penetration of VRE generation in an electricity system determines the effectiveness of flexibility strategies. Overvaluing VRE generation capacity could lead to prolonged periods of generation shortages, necessitating an expansion of electricity grid infrastructure or integration of energy storage to ensure resource adequacy [170]. Undervaluing VRE generation capacity, however, could lead to suboptimal deployment of VRE resources resulting in a more expensive, overbuilt electricity system and increasing VRE curtailment [169].

Previous work has examined net load for different energy system compositions. Cole et al. [168] evaluate the timing of peak net load hours for increasing penetrations of solar PV generation. Results of this work highlight that how peak net load is served is dependent on the interaction of generation types in an energy system. Schill et al. [39] examine the effect of increasing VRE generation capacities on net load in a highly renewable system and compare it to an energy system that utilizes thermal baseline generators. Results show that VRE curtailment occurs in 19% of all hours and increases even more once thermal baseline generators are added to the energy system. In a highly renewable energy system, avoiding VRE curtailment may lead to extremely large energy storage requirements. Therefore, results suggest that a combination of VRE curtailment and energy storage would be optimal to limit large energy storage capacities. While this work considers only VRE curtailment and energy storage as flexibility strategies to decrease net load, investigations of additional strategies such as electricity exports to avoid VRE curtailment and DSM to reduce VRE capacity requirements are recommended. Ruggles et al. [35] examine inter-annual variability of peak net load for historical electricity demand and historical wind and solar generation. Results show that inter-annual variability of peak net load can be reduced for increasing shares of wind generation in regions that experience a winter peak. While this work did not assess surplus energy generation as possible strategy to enhance operational flexibility, energy storage was found to be an effective strategy to reduce inter-annual variability of peak net loads. Olauson et al. [19] conduct a statistical study on net load variability in Nordic countries for a range of VRE generation mixes. Results show that net load rarely becomes negative; however, the magnitude of hourly net load changes increases. Additional examinations of flexibility strategies to limit net load variability such as overproduction of VRE resources and energy storage are recommended.

Strategies to increase electricity system flexibility such as expansion of VRE generation capacity, transmission and distribution expansion, and energy storage have been explored in the literature [19], [40], [41]. However, none of these studies have examined the impact of flexibility strategies on net load or considered flexible hydroelectric power generation as dispatchable generation asset. Previous work has yet to examine the impact of changing climate conditions on water supply availability and consider demand projections for future end-use electrification when assessing the effectiveness of strategies to enhance grid flexibility.

In this work, we explore the following research questions:

- In a 100% renewable grid, which power generation mix could limit excess energy while reducing the amount of energy deficiency? How will a change in water supply for hydroelectric power generation impact excess energy and energy deficiency?
- Will VRE capacity requirements change for variations in water supply for hydroelectric power generation caused by prolonged drought periods or increased precipitation?
- Is the magnitude and duration of energy deficiency changing for different VRE supply scenarios and which flexibility strategy could be used to avoid energy deficiency in a highly renewable electricity grid?

To address these research questions, this work presents a novel integration of two high-resolution energy demand models and a production cost model to investigate the impact of VRE supply uncertainties on excess energy and energy deficiency. This involves a comparative assessment of different scenarios based on the combination of the following variables: increasing VRE capacities up to 50 GW; penetration levels of wind generation between 50% and 80%; and variation in water supply for hydroelectric power generation. In the following section, the modelling methodology is described. First, the demand modelling tools are introduced. Then, the production cost model used in this work is presented.

4.3 Methodology

Fig. 4.1 shows an overview of the modelling methodology. Regional data is used to model end-use demands in the building and road transportation sectors. Energy demands for residential and commercial space and water heating, residential space cooling, passenger vehicles, light-, medium-, and heavy-duty commercial vehicles, are modelled individually. The residual load profile captures non-heating and non-cooling energy demands in the building sector and electricity demands in the agricultural and industrial sectors. The electricity end-use demand profiles are the summed to represent one provincial electricity demand profile that is used as input for the production cost model SILVER.

SILVER cost-optimizes generator dispatch for specific grid characteristics to meet provincial electricity demand, providing information on generator dispatch behavior in meeting peak electricity demand and hourly load changes. The generator dispatch behavior provides insights into interactions of different generator types; flexibility of individual generator types; and whether installed power capacities are sufficient to serve electricity demand.

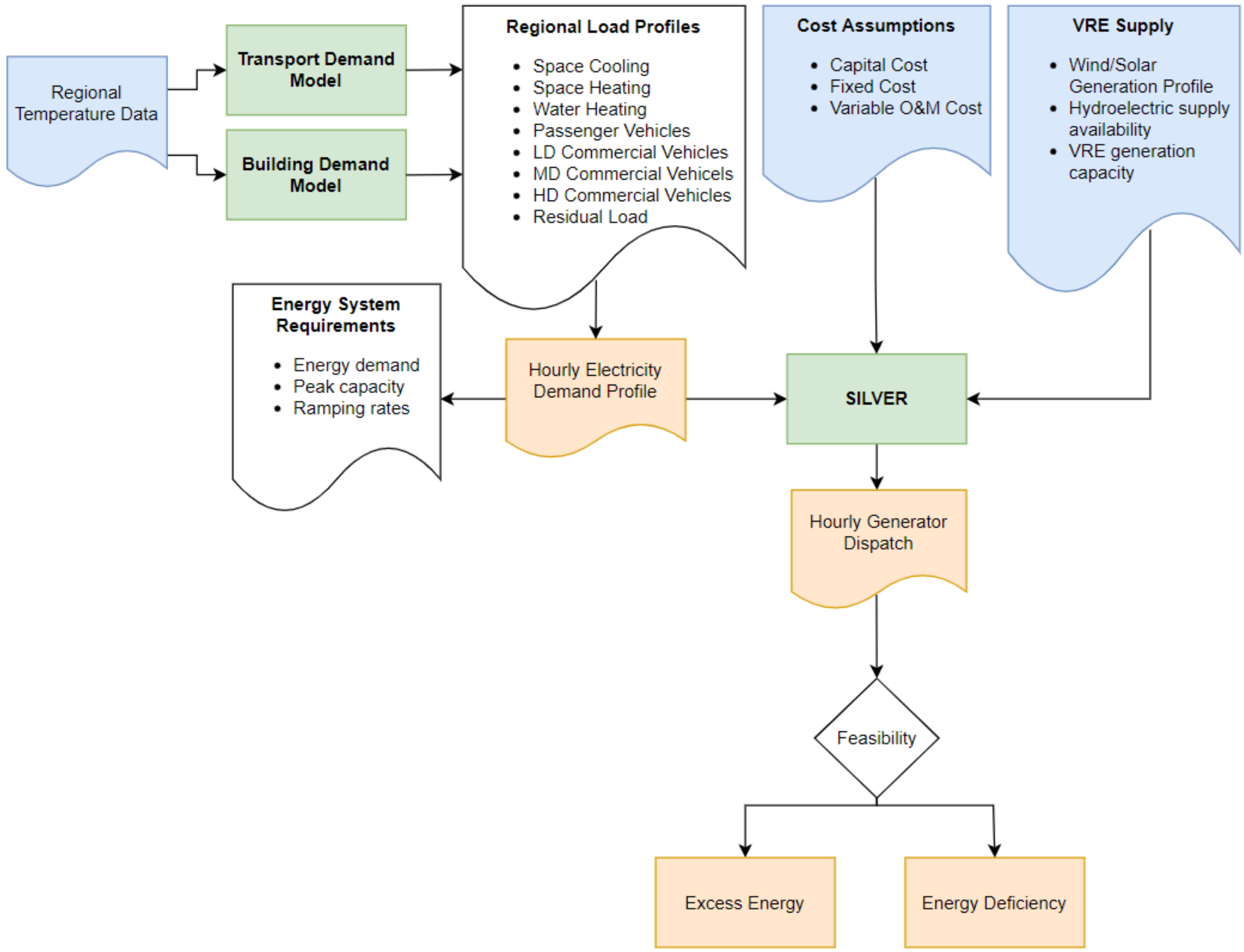


Figure 4.1. Energy system model used to investigate energy, capacity, and flexibility requirements. Blue boxes represent model inputs; green boxes represent the modelling tools used in this paper; orange boxes are model outputs.

4.3.1 Energy demand

The model used to generate demand profiles for passenger vehicles and light-, medium-, and heavy-duty commercial vehicles is described in detail by Lowry et al. [140]. The model used to generate energy demand profiles for space and water heating for the residential and commercial building sectors is described by Knittel et al. [141].

The energy demand profile used in this work is taken from Knittel et al. [171] (Scenario 2050 A – Immediate charging & electric heat). Energy demand for electrified heating, cooling and road transportation is projected to 2050 using a population growth rate of 1.1%/yr. It is assumed that 100% of passenger and light-duty commercial vehicles are electrified as well as 60% of medium- and heavy-duty commercial vehicles. All electric vehicles are assumed to use an immediate charging strategy described in more detail by Lowry et al. [140]. In the building sector, a 1% retrofit rate of the existing building stock was assumed in combination with a planned step code strategy for all new buildings and retrofits, which is described in more detail by Knittel et al. [141]. For this work, it is assumed that all new buildings install high-efficiency electric heat pumps and that all gas heat is converted to high-efficiency electric heat pumps.

4.3.2 Production cost modelling

SILVER is a mixed-integer linear programming model with high spatial and temporal resolution. The model informs economic dispatch behaviour of a generator fleet adhering to a variety of operating constraints while minimizing total system cost. Available balancing options in SILVER besides demand response, load shedding and storage are transmission expansion and electric vehicle integration, allowing for investigations of trade-offs and interactions among a variety of VRE integration strategies. VRE generation is based on location-specific resource data to investigate the effects of changing weather conditions on VRE generation profiles. The model has been developed as a generic tool that can be used for detailed energy system analyses in any jurisdiction under specific system constraints [43]. Previously, the model has been used for investigations of storage operations [172], a 100% renewable electricity grid in Ontario [43], VRE production expansion with a simultaneous electrification of the transportation and building sectors in Regina, Saskatchewan [173], and to assess the potential of utility-controlled electric vehicle charging strategies to reduce VRE curtailment in a highly decarbonized energy system [174]. The high spatial and temporal resolution of the model enables detailed representation of VRE generation and transmission network configurations, making SILVER an attractive energy system model for identifying generator dispatch, operating cost, and emissions.

Besides hourly load profiles, generator characteristics, such as energy and power capacities, ramping constraints, operating costs, renewable energy generation profiles are inputs into SILVER. To limit modelling complexity, a copper-plate version of SILVER is used that does not consider transmission constraints, enabling investigation of power system operations to meet provincial capacity and flexibility requirements.

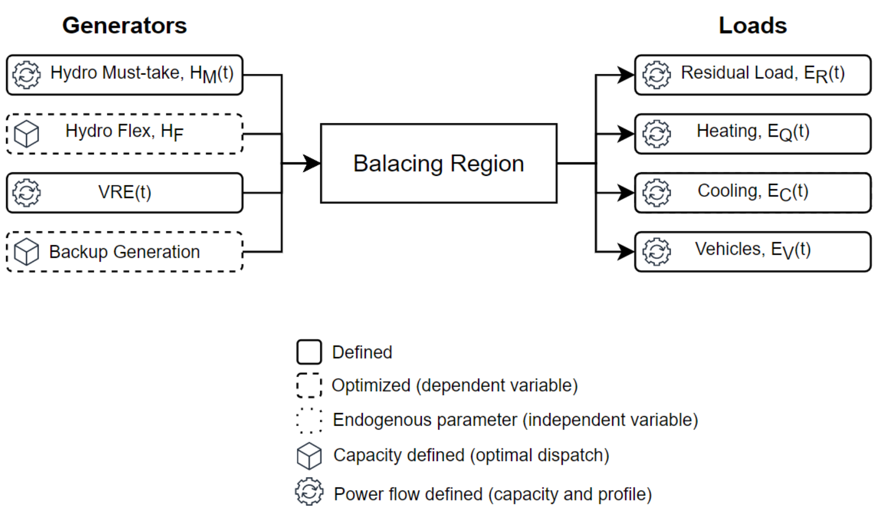


Figure 4.2. Representation of the SILVER framework used in this study. Solid boxes indicate defined capacities and/or defined power flows. Dashed boxes indicate variables that are optimized.

Fig. 4.2 shows the SILVER framework with generator technologies on the left and energy demands on the right. On the generator side, hydroelectric power generation is split into must-take and flexibly dispatchable power generation. Must-take wind and solar PV are described by hourly capacity factors and installed power capacities. To ensure model feasibility even in the absence of sufficient generation capacity, a flexibly dispatchable backup generator is included.

4.4 Data and scenarios

The method described in the previous section is applied to BC, Canada. Table 4.1 shows all data inputs used in this paper.

Table 4.1. Data inputs used in this paper.

Data input	Description	Reference
Transmission and distribution losses	Transmission and distribution losses of 10.34% are added to the hourly electricity demand profile	[142]
Installed power capacity for must-take and flexible hydro	12.965 GW	[110]
Total Hydroelectric Energy supplied in an average water year	58.920 TWh	[110]
Monthly must-take energy for multiple water years	34.817 TWh – 60.275 TWh	[162]
Wind energy generation data	Hourly mean capacity factors were calculated for each of the four regions using the 2010 dataset. The annual mean capacity factors for wind generation at the four locations range between 28% and 41%.	[175]
Solar PV generation data	Hourly solar PV capacity factors were obtained for four regions across BC.	[176]

4.4.1 Hydroelectric power generation

Complex operating constraints observed by large hydro and run-of-river power stations such as snowmelt-driven water inflows, minimum water discharge rates, or flood control are simplified by dispatching hydroelectric energy on a partially flexible, partially pre-determined profile [177]. Hydro must-take describes the energy that cannot be stored in the reservoir and includes generation from large reservoirs, generation from large storage plants that is required during the freshet to maintain an acceptable spill risk, independent power producers, and large storage basins required to meet local reliability requirements or water license commitments. Therefore, the must-take energy increases significantly during the freshet due to increased water inflow.

Hydroelectric power generation in this work is modelled to represent three water supply scenarios. Table 4.2 shows total hydroelectric energy supply, must-take energy and flexible energy supply for an average water year, a low water and a high water year. The total hydroelectric energy supply accounts for Site-C as additional hydroelectric power generation facility, which is expected to be operational in 2024 [178].

Table 4.2. Annual Energy Generation from Hydroelectric Power Sources for three water years.

	Low Water Year	Average Water Year	High Water Year
Must-take Energy [TWh]	34.8 (-24.3%)	46	60.3 (+31.1%)
Total Energy [TWh]	44.6 (-24.3%)	58.9	77.2 (+31.1%)
Flexible Energy [TWh]	9.8	12.9	17.0

The total hydroelectric energy supply and the must-take energy which describes hydroelectric energy that cannot be stored are used to determine the hydroelectric energy that can be dispatched flexibly:

$$E_{Flex} = E_{Total} - E_{Must-take} \qquad 4.\ 1$$

Monthly availability factors are determined that define the profile shape of must-take hydroelectric energy. Monthly availability factors for flexible hydroelectric energy are determined by subtracting the must-take profile from total hydroelectric energy. Fig. 4.3 shows the availability factors for must-take energy on the left and flexible energy on the right for a low, average and high water year.

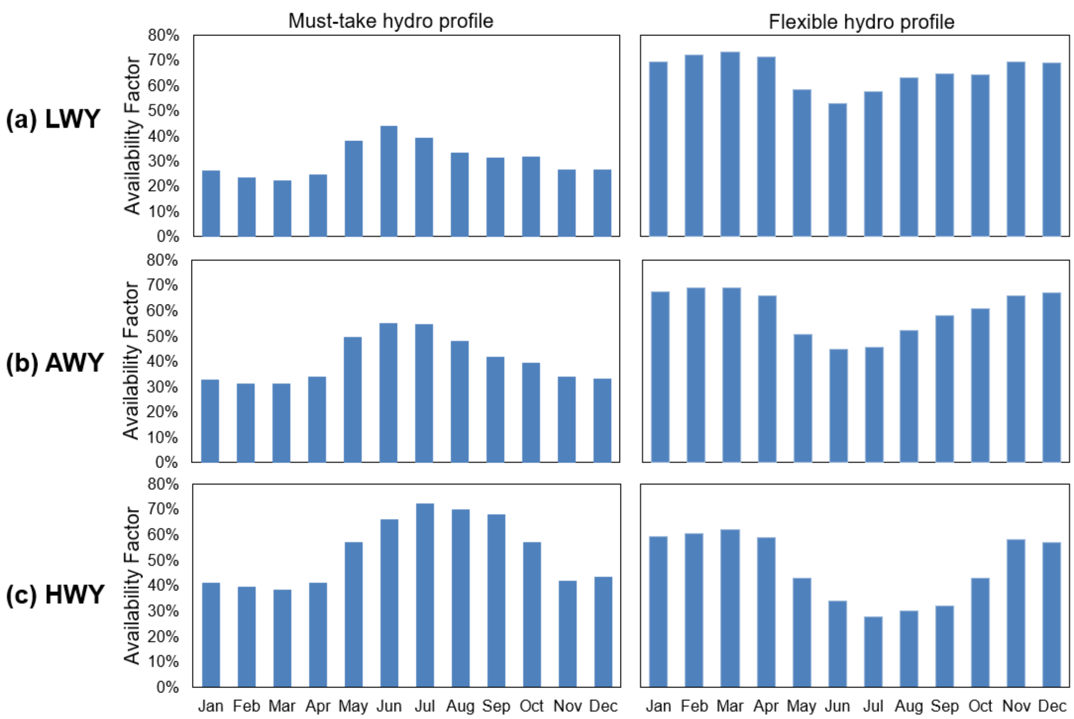


Figure 4.3. Monthly availability factor of must-take hydro on the left and flexible hydro on the right for (a) a low water year, (b) an average water year, and (c) a high water year.

4.4.2 Optimum weighting of wind and solar resources

Instantaneous generation for a single wind or solar location i is determined by the installed capacity, G_i , and the instantaneous capacity factor, CF_i:

$$\boldsymbol{P_i = G_i\, CF_i} \qquad Eq.\ 4.2$$

The aggregated production time series across all wind and solar locations is determined by:

$$P_{agg}(t) = \sum_i G_i CF_i(t) \qquad \textit{Eq. 4.3}$$

Installing G_{total} of VRE capacity and normalizing the aggregated production time series results in:

$$\frac{P_{agg}(t)}{G_{total}} = \sum_i \frac{G_i}{G_{total}} CF_i(t) \qquad \textit{Eq. 4.4}$$

Where the weighting factor w_i can be defined as:

$$w_i = \frac{G_i}{G_{total}} \qquad \textit{Eq. 4.5}$$

Using *Eq. 4.5*, *Eq. 4.4* can be rewritten to:

$$\frac{P_{agg}(t)}{G_{total}} = \sum_i w_i CF_i(t) \qquad \textit{Eq. 4.6}$$

The normalized production time series is defined as $p(t)$:

$$p(t) = \frac{P_{agg}(t)}{G_{total}} \qquad \textit{Eq. 4.7}$$

Using *Eq. 4.7*, *Eq. 4.6*, the normalized production time-series is,

$$p(t) = \sum_i w_i CF_i(t) \qquad \textit{Eq. 4.8}$$

The weighting factors w_i for all wind and solar locations are optimized such that the difference between electricity demand $D(t)$ normalized by the maximum electricity demand D_{max} and aggregated VRE production $p(t)$ is minimized:

$$Min \left\{ \frac{D(t)}{D_{max}} - p(t) \right\} \qquad \textit{Eq. 4.9}$$

Using *Eq. 4.8*, *Eq. 4.9* can be rewritten to:

$$Min \left\{ \frac{D(t)}{D_{max}} - \sum_i w_i CF_i(t) \right\} \qquad \textit{Eq. 4.10}$$

Where the sum of all weighting factors must sum up to 1 according to *Eq. 4.11*:

$$\sum_i w_i = 1 \qquad \textit{Eq. 4.11}$$

Table 4.3 shows the optimized weighting factors w_i for each wind location with constrained bounds between 0.1 and 0.5. Table 4.4 shows the optimized weighting factors w_i for each solar location with unconstrained bounds.

Table 0.1. Optimized weighting factors for four wind sites across BC with constrained bounds between 0.1 and 0.5.

	North Coast	North Central	Southern Interior	Northeast
Wind	0.396	0.1	0.303	0.201

Table 0.2. Optimized weighting factors for four wind sites across BC with unconstrained bounds.

	Lower Mainland	Vancouver Island	Southern Interior	Northern BC
Solar	0.119	0.205	0.382	0.295

Based on the optimized weighting factors for wind and solar locations, periods of excess energy and energy deficiency are examined for installed VRE capacities between 0 and 50 GW in 5 GW increments for wind penetrations of 50%, 60%, and 80%.

4.5 Results

Results showing the effect of water supply variations differing in must-take and flexible energy for hydroelectric power generation on excess energy and energy deficiency is presented. In addition, the variation of excess energy and energy deficiency is examined for installed VRE capacities ranging from 0 to 50 GW and for wind penetration rates of 50%, 60%, and 80%.

4.5.1 Net load analysis

Analyses of peak net load indicate how much dispatchable generation capacity is required to meet growing electricity demand by 2050. Table 4.5 shows changes in peak net load for an electricity system without wind and solar PV generation and an electricity system in which 50 GW of VRE generation is installed. Results show that peak net load decreases with an increase in wind penetration and water supply availability.

Electrifying building heating, cooling and road transportation demands in BC by 2050 leads to a peak electricity demand of 21.95 GW on December 27 at 7PM, including 10.34% of transmission and distribution losses. For 0 GW installed VRE capacity, the sole must-take renewable generation type is must-take hydro. Depending on the water supply scenario, peak net load therefore varies between 16.3 and 18.5 GW and occurs during the same hour than the peak electricity demand on December 27. With an installation of 50 GW wind and solar capacity, the smallest peak net load of 13.8 GW is observed during a high water year in combination with an 80% wind penetration. Further, the timing of the peak net load is shifted to February 19 at 7PM, away from the peak electricity demand on December 27.

Table 0.3. Peak net load in 2050 if building heating, cooling, and road transportation is electrified for 0 GW and 50 GW installed VRE capacity. Average net load is shown in brackets.

Water Supply	Wind – Solar PV share	VRE Installed Capacity	
		0 GW	50 GW
Low Water Year (LWY)	50-50	18.5 GW (8.9 GW)	16.2 GW (-3.3 GW)
	60-40		16.1 GW (-4.3 GW)
	80-20		15.9 GW (-6.3 GW)
Average Water Year (AWY)	50-50	17.6 GW (7.7 GW)	15.2 GW (-4.5 GW)
	60-40		15.1 GW (-5.5 GW)
	80-20		14.9 GW (-7.5 GW)
High Water Year (HWY)	50-50	16.3 GW (6.0 GW)	14.1 GW (-6.2 GW)
	60-40		14.0 GW (-7.2 GW)
	80-20		13.8 GW (-9.2 GW)

As shown in Table 4.5, the average net load decreases for an increase in wind penetration and water supply. Without wind and solar generation, the average net load can increase by +16% or decrease by -22% depending on water supply availability, relative to an average water year. In the absence of wind and solar generation capacity, average net load is positive, highlighting a significant generation shortage in BC's energy system by 2050. For an installed VRE capacity of 50 GW, average net load is negative for all VRE supply scenarios, indicating large levels of excess energy generation.

Variability of average net load is reduced with an increase in water supply. Fig. 4.4 shows normalized average net demand and normalized root mean square values for three water supply scenarios and installed VRE capacities ranging from 0 to 60 GW in 5 GW increments, assuming 80% wind penetration. In a low water year, the smallest variability of average net load is observed for an installed VRE capacity of 20 GW which reduces to 10 GW in a high water year.

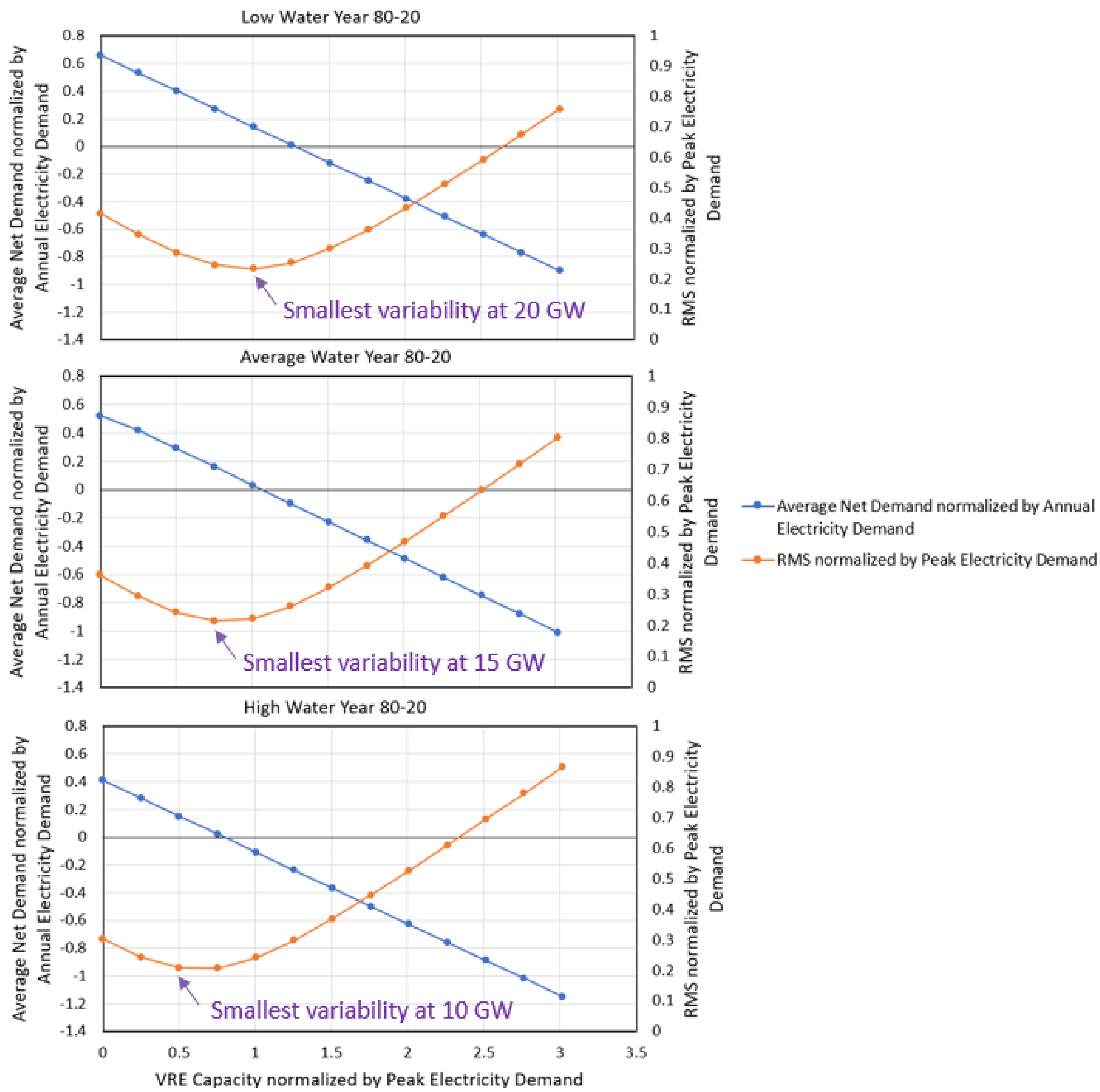


Figure 0.1. Average net load normalized by annual electricity demand and RMS normalized by peak electricity demand for installed VRE capacities between 0 and 60 GW in 5 GW increments for an 80% - 20% split in wind and solar PV generation for three water supply scenarios.

4.5.2 Energy generation by technology type

British Columbia needs significantly more electric power capacity to meet electricity demand by 2050 if additional end-uses are electrified. Fig. 4.5 shows energy generation during the peak month December in 2050 for a 50% and 80% wind penetration in a low water year for VRE capacities ranging from 0 GW to 50 GW. For a 50% wind penetration, energy deficiency ranges between 8.1 TWh in a system without wind and solar resources and 0.9 TWh for 50 GW VRE capacity. Therefore, in the absence of wind and solar generation capacity, 70% of monthly energy demand in December will be unmet. This share decreases to 8% when 50 GW of wind and solar capacity is installed. An increase in wind penetration from 50% to 80%

significantly reduces energy deficiency, where monthly energy demand that is unmet for 50 GW installed VRE capacity is less than 1%.

For 50 GW VRE capacity in combination with 50% wind penetration, excess energy generation reaches a total of 1.6 TWh in the month of December, as illustrated in Fig. 4.5. Increasing wind penetration to 80% leads to 5.3 TWh of excess energy generation. This represents an increase in curtailment of 230% as compared to 50% wind penetration. Across all water years, VRE curtailment is largest for 80% wind penetration in combination with a high water year, with 40% of surplus energy generation in December. Energy generation by technology for 50% and 80% wind penetration in an average and high water year are shown in Supplementary Material C.1. Across all VRE supply scenarios, the largest generation shortage is observed for the smallest wind penetration of 50% in combination with a low water year, leading to 910 GWh of energy deficiency in December. However, for 80% wind penetration 73 GWh of energy will be unmet in all water supply scenarios, indicating the benefit of wind generation in British Columbia.

Excess flexible hydro energy in a low water year is only observed in combination with an 80% wind penetration and 50 GW installed capacity, where 120 GWh can be stored in reservoirs for usage in the following month. In an average water year, flexible hydro energy is not fully utilized starting at 35 GW installed VRE capacity for 80% wind penetration, reaching a maximum of 600 GWh of flexible hydro energy that is stored in the reservoir for later use at 50 GW installed capacity. In a high water year, flexible hydro energy is not fully utilized starting at 25 GW installed wind and solar capacity in combination with an 80% wind penetration. At 50 GW VRE capacity, a total of 1.3 TWh of flexible hydro energy is stored in the reservoir for later use. This indicates that for increasing wind penetrations and VRE capacities, long-term storage options such as pumped hydro storage may represent an effective flexibility strategy to make use of unused energy from flexible hydroelectric power generation assets.

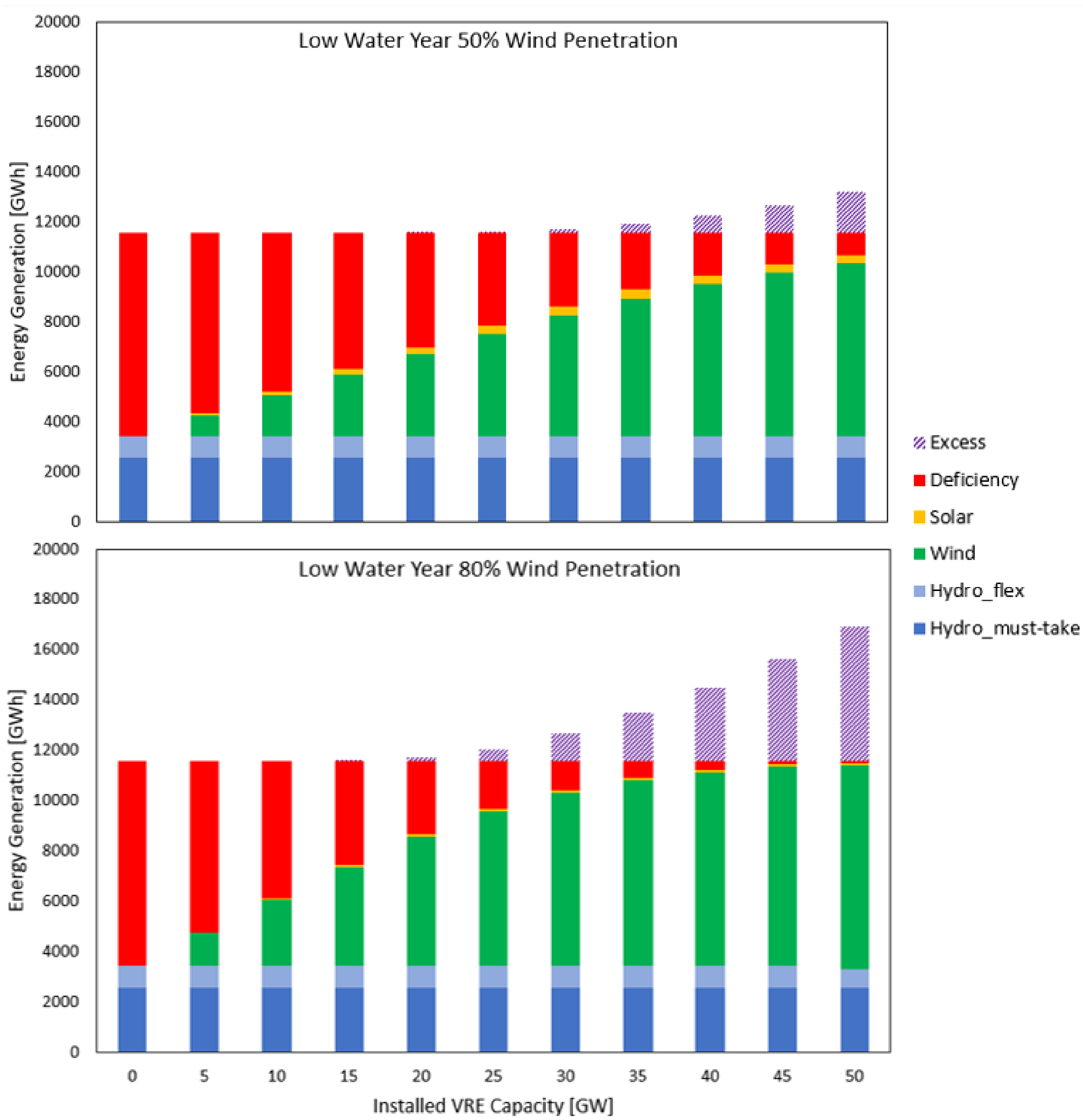


Figure 0.2. Energy generation by technology type in December for 11 installed VRE capacities in a low water year for 50% wind penetration at the top and 80% wind penetration at the bottom. Energy generation by technology type in December for 11 installed VRE capacities for an average and high water year are shown in the Supplementary Material Section C.1.

In a highly renewable electricity grid, additional electricity generation from wind and solar PV resources is needed to limit periods of energy deficiency. Fig. 4.6 shows excess energy and energy deficiency in December for installed VRE capacities ranging from 0 to 50 GW for all VRE supply scenarios. For an 80% wind penetration (Fig. 4.6(a)) no excess energy is generated between 5 to 20 GW installed VRE capacity depending on water supply availability. Reducing wind penetration to 50% (Fig. 4.6(c)) leads to no excess energy generation between 10 and 25 GW depending on the water supply.

Increasing variability of VRE generation causes periods of energy deficiency and excess energy to occur in the same month. To overcome the mismatch in energy demand and supply energy storage may be a suitable flexibility strategy. As shown in Fig. 4.6(a), VRE capacities between 25 and 40 GW, depending on the water year, lead to more excess energy generation than energy deficiency. This makes energy storage a suitable flexibility option to avoid curtailment arising from VRE overproduction while simultaneously bridging periods of energy deficiency. However, the ideal combination of VRE generation and energy storage capacities is dependent on wind penetration in the electricity system. Fig. 4.6(c) shows that for 50% wind penetration, the share of VRE capacity needed to ensure more excess energy generation than energy deficiency increases to between 35 and 50 GW.

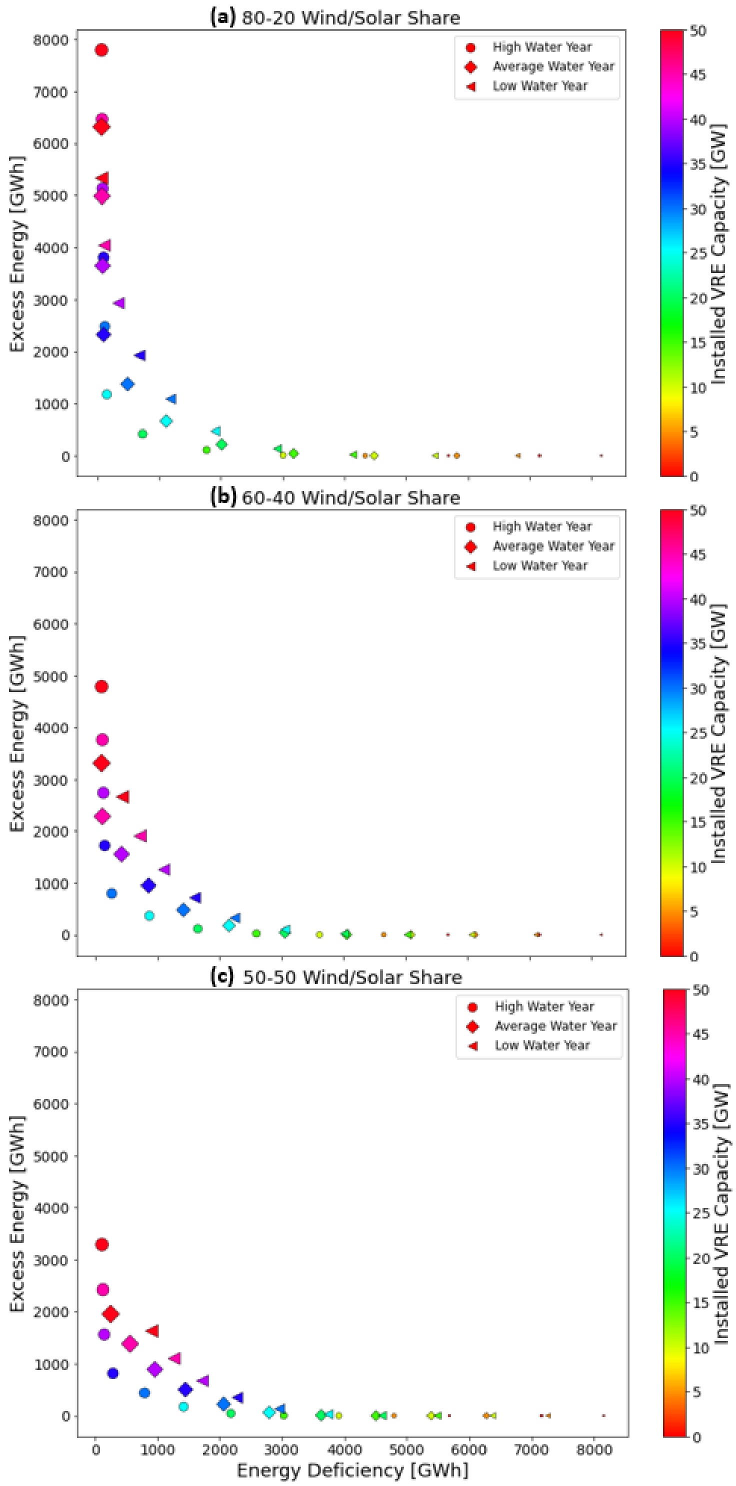


Figure 0.3. Excess energy and energy deficiency in December for installed VRE capacities from 0 to 50 GW in 5 GW increments. (a) shows the effects of three water supply scenarios in combination with 80% wind penetration on excess energy and energy deficiency. (b) captures results for 60% wind penetration and (c) captures results for 50% wind penetration.

Overproduction of VRE resources can significantly limit periods of energy deficiency while simultaneously reaching large levels of VRE curtailment. An example of generator dispatch during the winter peak electricity month is shown in Fig. 4.7 for (a) 10 GW and (b) 40 GW installed VRE capacity. Results in Fig. 4.7(a) show that there is no excess energy generation for an installed VRE capacity of 10 GW; however, 40% of electricity demand in December cannot be met. In one single hour, a generation shortage of 15 GW is observed for 10 GW of installed VRE capacity. In Fig. 4.7(b) 24% of total monthly energy generation is curtailed due to the overproduction of VRE resources while less than 1% of total energy generation is needed to serve periods of energy deficiency. However, a generation shortage of 6 GW in one single hour is observed. In comparison to this, 17 GW of energy is curtailed in one single hour for an installed VRE capacity of 40 GW.

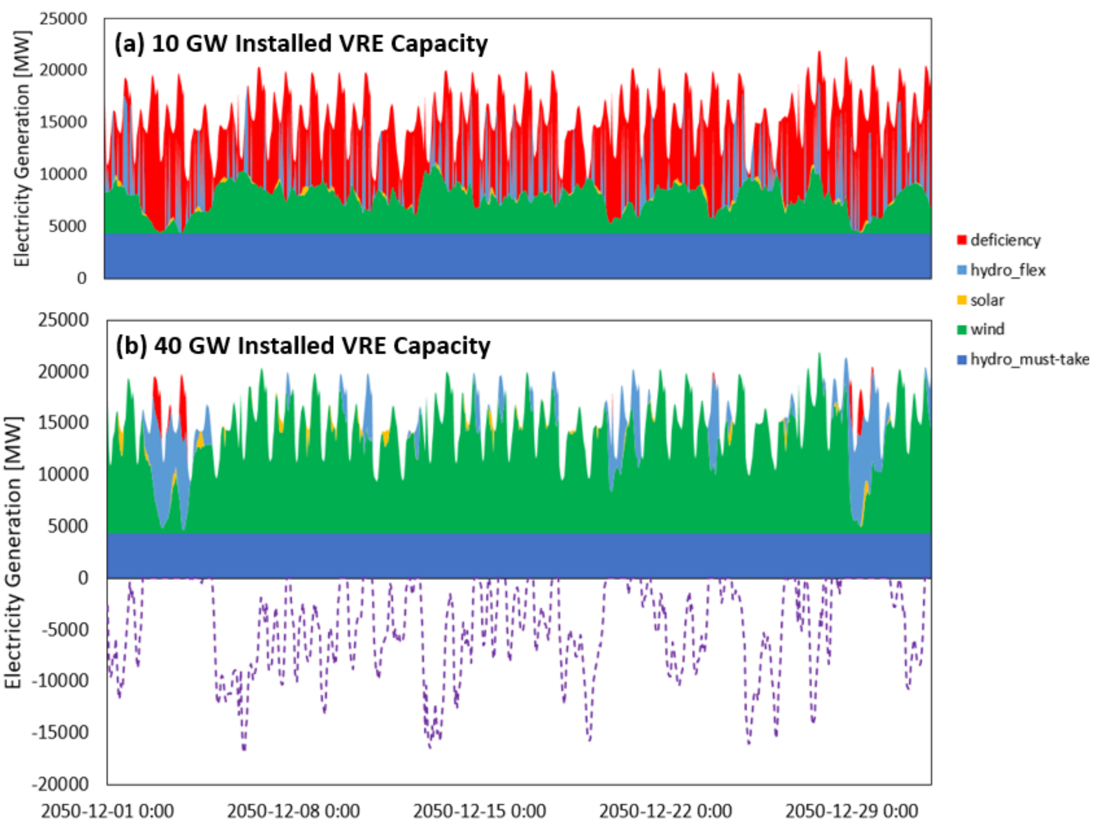


Figure 0.4. Electricity dispatch profile in 2050 for December if heating, cooling, and road transportation is electrified during an average water year and 80% wind penetration in combination with: (a) 10 GW installed VRE capacity, and (b) 40 GW installed VRE capacity.

4.5.3 Duration of energy generation shortages

For a high penetration of wind and 20 GW installed VRE capacity, the mean consecutive hours of excess energy and energy deficiency are comparable across all water supply scenarios. Fig. 4.8(a-c) show a maximum of 5 mean consecutive hours of energy deficiency and excess energy for 20 GW installed VRE capacity where the number of mean consecutive hours for excess energy is slightly larger than that of energy deficiency. However, for 20 GW installed VRE capacity, outliers of energy deficiency can reach up to 38 consecutive hours in an average water year.

If VRE capacity is increased to 30 GW, the mean consecutive hours of excess energy and energy deficiency would be further apart, with mean consecutive hours of energy deficiency between 2 and 4 and mean consecutive hours of excess energy between 10 and 11 hours depending on water supply. However, a maximum number of 9 consecutive hours of energy deficiency is observed in an average and high water year, while a limited supply of water as represented by the low water year leads to a maximum of 23 consecutive hours of energy deficiency.

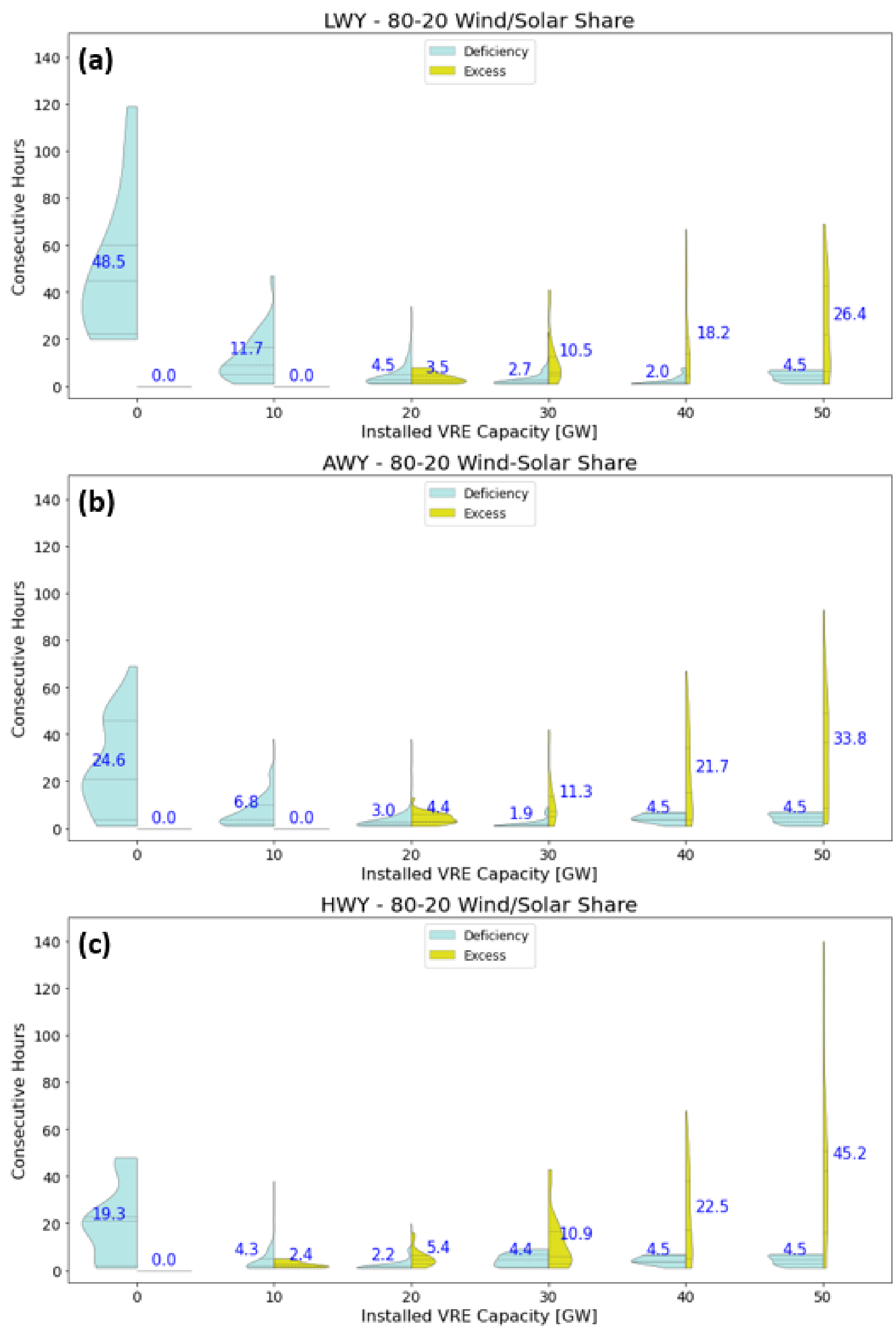


Figure 0.5. Number of consecutive hours of energy deficiency (blue) and excess energy (yellow) for 0 to 50 GW installed VRE capacity with an 80% wind penetration for (a) a low water year, (b) an average water year, and (c) a high water year. Numbers in the plot show mean consecutive hours.

Sizing a storage facility according to mean consecutive hours of energy deficiency for an installed capacity of 30 GW would be sufficient to manage most energy deficiency periods for all wind penetrations and water supply scenarios. As shown in Table 4.6, the mean consecutive hours of energy deficiency never exceed 5 hours. This indicates that a short-duration storage of 5 hours is an effective flexibility strategy to manage most deficiency periods. For all water supply scenarios, a wind penetration of 80% results in a doubling of mean consecutive hours of excess energy compared to energy deficiency. This excess energy may be curtailed once storage is fully charged.

Table 0.4. Mean consecutive hours of energy deficiency and excess energy for 30 GW installed VRE capacity.

Water Supply	**Wind – Solar PV share**	**Mean consecutive hours energy deficiency**	**Mean consecutive hours excess energy**
Low Water Year (LWY)	50-50	5	4
	60-40	4	5
	80-20	3	10
Average Water Year (AWY)	50-50	5	4
	60-40	3	6
	80-20	2	11
High Water Year (HWY)	50-50	5	5
	60-40	3	8
	80-20	4	11

In addition to the duration of deficiency and excess energy events, the most appropriate flexibility strategy that would enable system operators to meet growing electricity demand by 2050 is further dependent on energy deficiency and excess energy generation. Results in Fig. 4.9 show that for a low water year, excess energy generation exceeds energy deficiency starting at a VRE capacity of 40 GW. In an average and a high water year excess energy exceeds deficiency at an installed VRE capacity of 30 GW. In a low water year, energy deficiency is 10%, or 104 GWh, larger than excess energy for 30 GW installed VRE capacity. 104 GWh of energy deficiency can be met by importing electricity from neighboring jurisdictions or utilizing DSM strategies. In an average water year for 30 GW installed VRE capacity, excess energy is 180% larger than energy deficiency. With an increase in water supply, this share increases to 1860% for a high water year. The large difference in excess energy and energy deficiency renders short-term energy storage as single flexibility strategy insufficient as very large storage capacities would be required to utilize all excess energy. Therefore, the optimum VRE capacity for a resilient energy system is 30 GW for an 80% wind penetration. Here, short-duration storage can be used to manage the mismatch of excess energy and energy deficiency in both, the average and high water year, while excess energy generation could either be exported or curtailed to limit storage capacities. In the low water year, short-duration storage can be completed by DSM and electricity imports to reduce energy deficiency by 104 GWh in December.

Large-scale integration of VRE resources cannot bridge all periods of energy deficiency, independent of water supply availability. For all water supply scenarios with 50 GW installed VRE capacity, 73 GWh of energy deficiency is observed in December alone, with individual hours showing as much as 6 GW of additional electricity needed to meet demand. Therefore, an overproduction of VRE resources to meet all periods of energy deficiency would significantly exceed 50 GW of installed VRE capacity.

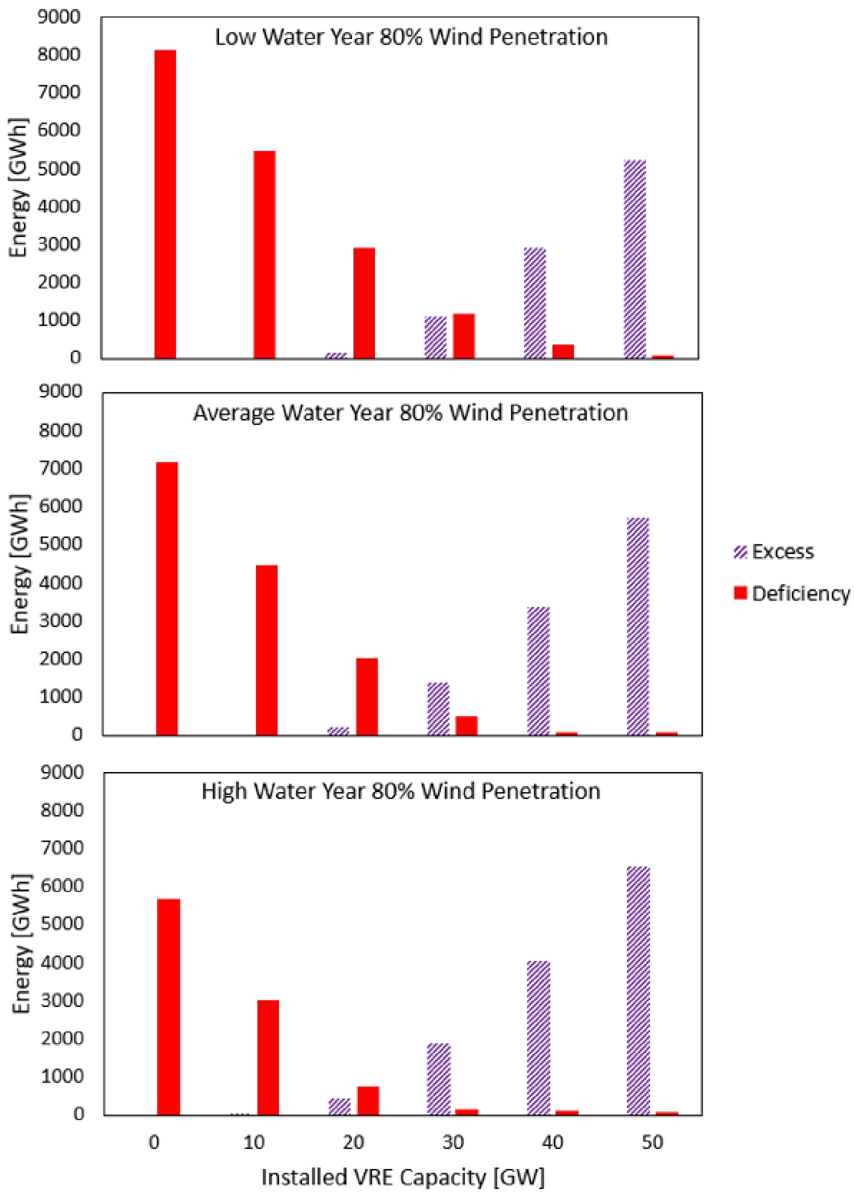


Figure 0.6. Excess energy and energy deficiency in December for installed VRE capacities between 0 and 50 GW with an 80% wind share for a low water year at the top, an average water year in the middle, and a high water year at the bottom.

4.6 Discussion

Peak net load for electrified futures can be reduced by investments in VRE resources but will likely require system planners to invest in other flexibility strategies as well. Results of this work show that without wind and solar generation peak net load varies between 16.3 and 18.5 GW, depending on water supply availability. BC Hydro's historical peak electricity demand reached 11.3 GW in January 2024 [179]. The historical peak electricity demand in BC is significantly smaller than the peak net load demand projected for a highly electrified future in 2050. Supply-side strategies to meet future peak net load include an increase in wind and solar resources and import of electricity. An expansion of wind and solar resources is part of BC Hydro's call for power in its 10-Year capital plan, where the development of additional wind and solar resources across the province is expected to add 3 TWh of renewable electricity to the system [180]. Historically, between 2019 and 2023 BC has imported 155 GWh of electricity on average from neighbouring jurisdictions [181]. However, during the peak net load event without wind and solar capacity on December 27 at 7PM, BC has historically required an additional 1.3 GW of electricity to meet demand. By 2050, demand is expected to increase due to population growth and end-use electrification which will increase import requirements well beyond 1.3 GW. Results of this work show that 50 GW installed wind and solar capacity leads to peak net loads between 13.8 and 16.2 GW, depending on wind penetration and water supply availability. Therefore, a combination of VRE generation expansion and import will reduce peak net load to some extent; however, additional investment in energy storage may be required to meet future peak net load.

Demand-side management strategies can further be utilized to reduce future electricity demand and thereby peak net load. Among these strategies are flexible EV charging [17], [28], [32]; vehicle-to-grid services [33]; deployment hybrid heating systems using a backup gas furnace during cold weather events [18]; and a time-of-day pricing scheme for electricity usage giving consumers financial incentives to shift their electricity use to off-peak hours [182]. Previous work revealed that in BC a combination of off-peak EV charging, and the use of hybrid heating systems can reduce peak electricity demand by 10% [171]. However, the impact of time-of-day pricing schemes on peak electricity demand reduction is yet to be examined.

Future net load variability will be smallest for 20 GW installed wind and solar capacity during a low water year. One strategy to meet future net load is the increase in dispatchable generation assets. Approximately one third of annual hydroelectric energy can be dispatched flexibly in BC; however, in the absence of additional wind and solar capacity this will not suffice to meet rising peak net load by 2050 and may be further impacted by future drought conditions [162]. Flexibly dispatchable capacity within a system that to date produces more than 97% of its electricity via renewable sources is limited to flexible hydroelectric energy generation to achieve greenhouse gas emission reduction targets by 2050 [183], highlighting the importance of large-scale integration of wind and solar resources.

Large-scale integration of VRE generation capacity is needed to overcome generation shortages. Results of this work show that for highly electrified futures 10 GW installed VRE capacity is insufficient to meet demand. As shown in Fig. 4.7(a), 4.5 TWh of energy deficiency is observed in December, which represents 40% of total monthly energy demand. Managing 40% of energy demand in December by DSM or energy storage alone would not be sufficient to overcome generation shortages. Increasing VRE installed capacity to 40 GW reduces energy deficiency to less than 1% of total monthly energy demand in December. However, 24% of total VRE generation will be curtailed. Strategies to bridge periods of energy deficiency include overproduction of VRE resources and energy storage [169]. While overproduction of VRE resources would significantly limit periods of energy deficiency, installed VRE capacities that would entirely avoid any energy deficiency would likely exceed 50 GW. Integration of energy storage to avoid any energy deficiency would make the system more resilient to changes in VRE generation and water supply availability. For 40 GW installed VRE capacity, 91 GWh of energy deficiency is observed in

December with 6 GW of energy deficiency in one single hour. Energy storage with sufficient power capacity to supply 6 GW in one hour could therefore significantly reduce VRE capacity requirements.

The number of mean consecutive hours of energy deficiency and excess energy is a valuable parameter in sizing future storage facilities. Results in this work show that short-duration storage of 5 hours would be an effective flexibility strategy to manage most deficiency periods for all VRE supply scenarios. Even though mean consecutive hours of excess energy are larger than those of energy deficiency, any excess energy not used for charging short-duration storage can be curtailed.

To react to changes in water supply and wind generation in a highly renewable grid a combination of flexibility strategies should be deployed to meet growing electricity demand by 2050 under various supply scenarios. Long-term strategies to manage increasing net load should combine the expansion of VRE capacities with energy storage, DSM, and electricity imports to avoid energy shortages while making use of excess energy during times of overproduction. However, due to changing climate conditions, BC is expected to experience droughts more frequently. To manage water levels during dry years, the BC electricity balancing authority deploys a range of strategies that including storing of water during the summer months in anticipation of dry conditions in late summer and early fall and reducing electricity exports [184], [185]. Further, BC Hydro is planning to expand inter-provincial transmission and distribution infrastructure to facilitate sending electricity from large hydroelectric power generation facilities located in regions less affected by drought conditions to regions experiencing significant drought conditions to ensure reliable electricity supply [180], [184]. The expansion of inter-provincial transmission infrastructure would avoid costly electricity imports during dry water years while enabling system operators to maximize utilization of VRE generation.

Future research can enhance the results of this study by examining the effect of long-duration energy storage where electricity can be stored during the summer when electricity demand is low and water supply peaks due to additional snowmelt-freshet inflows. With long-term storage, energy deficiency periods during the winter months, where electricity demands are larger due to electrified heating and road transportation, could be avoided. As outlined in previous work on energy storage, linking of capacity expansion and production cost modelling tools of different resolutions is vital in assessing the value of long-term energy storage [186]. Further, identifying the benefits of expanding transmission and distribution infrastructure may provide insights into VRE utilization levels and the magnitude of stranded power [187]. On the demand side, examining strategies that motivate consumers to defer electricity consumption, for instance through a time-of-day pricing scheme would provide additional information on the amount of electricity that can be shifted to off-peak hours.

4.7 Conclusion

This work addresses the current gap of combining high spatiotemporal demand modelling tools with a high-resolution production cost model to examine periods of energy deficiency. The demand profile used in this work simulates a highly electrified future in British Columbia, Canada, where building heating, cooling and road transportation is electrified by 2050. Using the production cost model, this work assesses variations in net load and resulting generation shortages for a range of VRE supply scenarios including varying shares of wind penetration and water supply availability to identify suitable flexibility strategies based on the magnitude and duration of excess energy and energy deficiency periods.

Forecasting future peak net load is crucial for energy systems with large shares of VRE generation. Peak net load for electrified futures already exceeds historical peak electricity demand in BC, indicating that an increase in wind and solar resources, import of electricity, and expansion of transmission and distribution infrastructure is needed [180]. Results show that periods of energy deficiency exist even for large-scale VRE integration in BC's energy system, rendering short-duration storage as an effective strategy to limit VRE curtailment while avoiding energy shortages. Future research should investigate the impact of financial incentives to encourage consumers to shift electricity use to off-peak hours and to examine the effect of long-duration energy storage to bridge periods of energy deficiency.

Chapter 5

Summary and contributions

The anticipated changes in water supply availability arising from climate change will pose challenges to hydro-dominant electricity grids. When combined with growing electricity demand due to end-use electrification and large-scale integration of wind and solar resources, the variability of future supply and demand may lead to a significant mismatch. System planners can hedge against the increasing mismatch in energy demand and supply by deploying flexibility strategies. These strategies include demand-side management such as EV charging and space heating control; overproduction of wind and solar resources; expansion of inter-provincial transmission and distribution infrastructure; integration of energy storage; and trade. This dissertation assesses the technological implications of strategies to decarbonize energy demand and supply, and presents an integrated modelling methodology for projecting future electricity demands after end-use electrification and quantifying energy generation from wind and solar resources in combination with changes of water supply availability. A high spatiotemporal representation of energy demand capturing building and road transportation end-use demands is derived to examine capacity and flexibility requirements, and to assess the impact of demand-side management strategies such as EV charging and space heating control on electricity grid infrastructure requirements. Additionally, a production cost model incorporating must-take and flexible hydroelectric power generation assets to capture changes in water supply availability is derived to quantify excess energy and energy deficiency for varying VRE supply scenarios, and, to identify suitable flexibility strategies for the hydro-dominated electricity grid of British Columbia, Canada.

5.1 Key findings

The results of this research demonstrate a crucial need for regional planners to account for changes in the magnitude and timing of peak electricity demand and variations in renewable energy supply availability when developing long-term energy strategy. Of particular concern are energy systems in a hydro-dominated region that incentivize end-use electrification and frequently experience drought conditions that can cause challenges in securing sufficient water supply for hydroelectric power generation. Key findings of this research applicable to energy systems planning include:

- Adequate quantification of energy demand requires high spatial and temporal resolution to capture the impact of ambient temperature and demand-side management on individual end-use demands.

• Adapting to uncertainties surrounding future water supply for hydroelectric power generation will require large-scale built-out of wind and solar generation capacity.

• Hydroelectric power, wind and solar generation constraints limit the availability of supply-side options to meet increasing net load, rendering a combination of flexibility strategies important to ensure resource adequacy.

• Suitable strategies to increase operational flexibility can be assessed by the duration and magnitude of excess energy and energy deficiency periods.

These general observations are consistent with previous research on energy demand projections and net load variability analyses [19], [24], [39]. In addition to this, novel contributions of this research emerge from the regional case studies. Specifically, the analysis provides important insights and guidance to utilities in British Columbia, Canada:

• The effect of building envelope efficiency improvements on heating demands is moderate, requiring widespread implementation of retrofit activities, building energy codes, and high-efficiency heating technologies to offset electrification of building heat.

• Combining end-use electrification in the building and road transportation sectors increases capacity and flexibility requirements by up to 93% and 320%, relative to 2020. Future flexibility requirements are largely driven by the electrification of medium- and heavy-duty commercial vehicles.

• A synergy of demand-side management strategies combining EV charging and space heating control decreases capacity and flexibility requirements by 19% and 238%, respectively, relative to end-use electrification without demand-side management.

• Expansion of renewable energy resources is necessary to meet growing electricity demand as peak net load for a highly electrified future in 2050 exceeds present-day peak electricity demand.

• A combination of flexibility strategies including short-duration energy storage, overproduction of wind and solar resources, and electricity imports will enable system operators to react to changes in electricity demand and renewable energy supply to ensure secure electricity supply at all timescales.

5.2 Future work

On the demand side, future research should consider expanding system boundaries to allow assessment of different energy vectors providing end-use services. Investigating the potential of using renewable gases such as hydrogen for building heat would allow mapping the impacts for a more comprehensive set of technologies that can achieve comparable decarbonization targets than end-use electrification without the associated increase in peak electricity demand [81]. Demand-side management strategies considered in this work should be extended to include utility-controlled EV charging and smart hybrid heating systems where time-of-day pricing schemes determine the most cost-effective operation modes [166], [188]. Combining high resolution modelling of load profiles for electric building heating, cooling, and road transportation with electrification of the agricultural and industrial sectors would provide a more comprehensive basis for future analyses of electricity grid infrastructure requirements.

On the supply side, adequate quantification of water supply availability for individual generation facilities requires greater spatial resolution than that typically seen in production cost models. Increased spatial resolution for hydroelectric power generation would enable investigations of optimum siting of pumped hydro storage facilities. Capacity expansion models have the capability to identify optimal VRE generation levels, determine hydrogen production potentials to serve certain end-uses such as commercial road transportation, quantify infrastructure requirements taking into account the cost of VRE curtailment, and examine long-term energy storage requirements [49], [189]. However, most capacity expansion models lack the spatial and temporal detail to explore high resolution energy storage dynamics. Linking of capacity expansion and production cost models of different spatial and temporal resolutions is therefore vital in assessing the value of long-term energy storage at a granular level. Examining the dynamic relationship between long-term energy storage behavior and VRE generation assets may identify periods in which the storage facility cannot be sufficiently recharged, making the chronology of energy storage an important characteristic in production cost models [186]. Finally, systemic cost analyses on the different combinations of flexibility strategies to meet increasing net loads would provide a more comprehensive analysis of the energy system and identify financial impacts on end-consumers.

Appendix A

Supplementary material: Heating electrification in cold climates: Invest in grid flexibility

All model equations listed in the following sections are region-specific.

Nomenclature

Symbol	Description	Unit
A	Area	m^2
d_i	Load of dwellings with electric heat	kW
d_j	Load of dwellings with non-electric heat	kW
E	Useful energy demand	TWh
$\hat{E}$	Annual energy consumption	TWh
EUI	Energy Use Intensity	GJ/m^2
F	Final energy demand	TWh
$\mathcal{H}$	Hour	h
η_{obs}	Observed efficiency	kWh/kWh
o_i	Dwelling offset	kW
$\vec{P}$	Normalized demand	1/h
P_h	Energy demand in hour h	TW
$P_u(y)$	Annual end-use specific energy demand	TWh
T_{amb}	Ambient temperature	°C
Subscripts	**Description**	
e	Electricity	
f	Fossil fuels	
i	Dwelling	
v	Vintage	
u	End-use specific	
act	Building stock turnover activity	
$demo$	Demolition	
new	New construction	
$reno$	Renovation	
D	Total Demand	
E	Remaining Electricity	
G	Gross Electricity	
H	Heat Demand	
SC	Commercial Space Heat	
SH	Space Heat	
SR	Residential Space Heat	
WC	Commercial Water Heat	
WH	Water Heat	
WR	Residential Water Heat	

A.1 Normalized Profiles for Residential and Commercial Space and Water Heat

A.1.1 Residential Sector

BC Hydro provided confidential information on BC's residential space heating load profiles in 2016 with hourly resolution. The dataset includes space heating loads for individual dwellings of five dwelling types within four regions and indicates whether those use electric or non-electric space heating. Whilst the total number of dwellings in the dataset comprise only a small proportion of the dwellings in BC, the composition with regards to dwelling type and region are representative of the entire province.

To extract the electric heating demand for each dwelling type, the temperature threshold at which electric heat is turned on is determined. Here, the electricity demand profile for each dwelling of one type is normalized and plotted against the historical outdoor temperature data of that region. Then, the data is fitted with a piecewise linear function such that the variance is minimized.

To determine the average electric residential space heating demand $\vec{d_i}$ each dwelling, i, that use non-electric space heating and that is outside of defined minimum (A. 1) and maximum (A. 2) load boundaries are excluded from the dataset where $\mathcal{H}$ is the relevant set of hours:

$$\vec{d}_{i,min} > 0\,kW \quad \forall\ h\ \in \mathcal{H} \qquad A.\ 1$$

$$\vec{d}_{i,max} < 15\,kW \quad \forall\ h\ \in \mathcal{H} \qquad A.\ 2$$

From the set of hours, two subsets are defined:

$$\mathcal{H} = \mathcal{H}^- \cup \mathcal{H}^+ \qquad A.\ 3$$

where $\mathcal{H}^-$ is the set of hours where the outdoor temperature is below the temperature threshold and $\mathcal{H}^+$ is the set of hours where the outdoor temperature is greater than or equal to the temperature threshold. Then, the electric space heating demand of dwelling i is determined for each subset of hours, with the electric heating demand of dwelling i is described as:

$$\vec{d}_i^- = \{d_{i,h}\} \ \ \forall\ h\ \in \mathcal{H}^- \qquad A.\ 4$$

$$\vec{d}_i^+ = \{d_{i,h}\} \ \ \forall\ h\ \in \mathcal{H}^+ \qquad A.\ 5$$

with $\vec{d}_i^-$, describing the demand for all hours $\mathcal{H}^-$ and $\vec{d}_i^+$, describing the demand for all hours $\mathcal{H}^+$. The dwelling offset is the average electricity demand of dwelling i in all hours $\mathcal{H}^+$ minus the average electricity demand of all dwellings i of a specific dwelling type without electric heating is calculated as:

$$o_i = \sum \vec{d}_i^+ - \frac{1}{NH} \sum \vec{d}_j^+ \qquad 1\ \leq j \leq NH \qquad A.\ 6$$

where NH is the number of a specific dwelling type with non-electric space heating. This results in an electric heating demand for dwelling i as:

$$\vec{ehd}_i = \{ehd_{i,h}\} \quad \forall \ h \in \mathcal{H} \qquad A.7$$

where

$$ehd_i = \begin{cases} 0 & if\ h \in \mathcal{H}^+ \\ d_{i,h} - o_i - \frac{1}{NH}\sum d_{j,h} \quad \forall \ 1 \le j \le NH & if\ h \in \mathcal{H}^- \end{cases} \qquad A.8$$

assuming the electric space heating demand is 0 in hours where the temperature is above the heating threshold, and that it equals the electricity demand, minus the offset, minus the average electricity demand of all dwellings without electric space heating in hour h. To obtain the average space heating demand for a dwelling type, Equations A.4 to A.8 are followed for all dwellings i of one dwelling type before taking the average to determine the mean electric space heating demand.

To weight the normalized residential space heating demand according to the residential building composition, each average electric space heating demand for one dwelling type d_t is multiplied by the number of dwellings of that type, where the number of dwellings per dwelling type and region that use electric space heating is obtained from the confidential load dataset.

Confidential water heating load profiles for BC are provided by GuideHouse in hourly resolution for the base year 2016. Water heat load in BC is assumed to be constant across all four regions as it does not change based on outdoor temperatures. The normalized residential water heat demand profile is created by dividing each hourly total residential water heat demand by the annual total residential water heat demand for a specific year.

A.1.2 Commercial Sector

Regionally aggregated commercial and industrial space and water heating demand profiles are determined using 15 reference building models providing space and water heating load profiles for different climate zones based on average Heating Degree Days (HDD) [81]. To represent the four regions in BC, average HDD are calculated such that each region can be assigned to a climate zone, and thus specific space and water heating load profiles that inform the normalized demand. NRCan provides annual space and water heating energy demands for the commercial sector in BC disaggregated into 10 building types. To represent the NRCan building types while using the NREL load profiles, the 15 reference building models are assigned to the NRCan building types. In cases where more than one NREL load profile is assigned to a NRCan building type, the average load profile is taken. To represent the commercial building stock in BC weighting factors describing end-use specific annual energy use by building type are created. Weighting factors for space and water heat are calculated by normalizing annual energy demands such that the annual energy demand for space and water heating of one building type is divided by the total annual energy demand for the specific end-use. Thus, the weighting factors informing the normalized commercial demand profiles vary between years and end-use activity while the input load profiles from NREL vary within climate zones. Load profiles taken for the commercial sector that inform the normalized heating demand profiles only represent a fraction of the commercial building stock in the US while the annual heating demands represent the commercial building stock in British Columbia.

A.1.3 Gross Electricity and Residual Load

Gross telemetered load data from [87] inform the generation of normalized gross electricity demand profiles $\vec{P}_G$ for 18 temperature years. The normalized profile $\vec{P}_R$ for the residual load is determined using equations A.9 and A.10:

$$P_R = E_G - \left[\left(\vec{P}_{SR} * E_{SR}\right) + \left(\vec{P}_{WR} * E_{WR}\right) + \left(\vec{P}_{SC} * E_{SC}\right) + \left(\vec{P}_{WC} * E_{WC}\right)\right] \qquad A.9$$

$$\vec{P}_R = \frac{P_R}{\sum_{i=0}^{8760} P_R} \qquad A.10$$

A.1.4 End-use normalized Profiles

All five normalized profiles $\overrightarrow{P(y)}$ are created by dividing each hourly demand P_h in year y by the total annual demand $P_u(y)$ for the base year 2016 such that each normalized profile contains 8760 hourly values.

$$\overrightarrow{P(y)} = \frac{P_h(y)}{\sum_{i=0}^{8760} P_h(y)} \qquad A.11$$

A.2 Useful Energy Demands

A.2.1 Residential Building Stock Turnover

Equation A.12 defines the total floor space $A(y)$ of today's building stock as the sum of area per vintage while equation A.13 introduces the average energy use intensity for residential space heating. Here, the product of area $A_v(y)$ and energy use intensity $EUI_v(y)$ per vintage is summed for all vintages v and divided by the total floor space $A(y)$ in year y:

$$A(y) = \sum_{v=0}^{y} A_v(y) \qquad A.12$$

$$EUI(y) = \frac{1}{A(y)} \sum_{v=0}^{y} A_v(y) \times EUI_v(y) \qquad A.13$$

Historical new construction and demolition rates are determined based on newly constructed and demolished floor space in vintage v using equations A.14 and A.15, respectively:

$$A_{new}(y) = \sum_{v=0}^{y} A_v(y) - A_v(y-1) \qquad A.14$$

$$A_{demo}(y) = \sum_{v=0}^{y} A_v(y-1) - A_v(y) \qquad A.15$$

where $A_v(y)$ describes the area per vintage in year y and $A_v(y-1)$ describes the area per vintage in the previous year. Thus, the area of an activity (retrofit, demolition, new construction) in year y is defined as the sum of the area subject to an activity in vintage v:

$$A_{act}(y) = \sum_{v=0}^{y} A_{v,act}(y) \qquad A.\ 16$$

Then, annual new construction and demolition rates are determined by dividing the floor space of the activity $A_{act}(y)$, new construction or demolition, in year y by the total floor space of the building stock in the same year:

$$act(y) = \frac{A_{act}(y)}{A(y)} \qquad A.\ 17$$

Demolition replacement $d(y)$ is defined by new construction $n(y)$, population growth $p(y)$, and relative change of area per capita $c(y)$ as shown in equation A.18:

$$d(y) = n(y) - p(y) + c(y) \qquad A.\ 18$$

From year y to $y + 1$, some faction of area for each vintage is demolished or retrofit (Fig. 2.4). The area of vintage v that is retrofitted and demolished in year y is described by a retrofit distribution $a_{v,retro}(y)$ and a demolition distribution $a_{v,retro}(y)$ shown in Fig. A.1. The normalized distribution of demolition activities is based on historical data, where demolition historically started 10 years after new construction at a rate of 0.05%. The distributions are exogenously defined and then applied to the demolition rate $d_v(y)$ and retrofit rate $r_v(y)$ and the total area minus any heritage building stock. Assumptions about heritage buildings vary across scenarios. Once the total area of a vintage v is demolished and retrofit, demolition and retrofit activities are applied to the following vintage period. This ensures that energy efficiency improvements through retrofits and demolition is applied to the oldest vintage periods first.

$$A_{v,demo}(y) = a_{v,demo}(y) \times d_v(y) \times \left[A_v(y) - A_{v,heritage}\right] \qquad A.\ 19$$

$$A_{v,retro}(y) = a_{v,retro}(y) \times r_v(y) \times \left[A_v(y) - A_{v,heritage}\right] \qquad A.\ 20$$

The normalized distribution for demolition activities changes 10 years after a new vintage period is created. Starting with the building stock forecast in 2017, it is assumed that the largest share of demolition is applied to vintage periods prior to 1995. From 2017 to 2043, the demolition activity assigned to the vintage periods from 1996 to 2005 increases significantly as new buildings during these vintages are reaching a lifetime of 36 to 47 years in 2043.

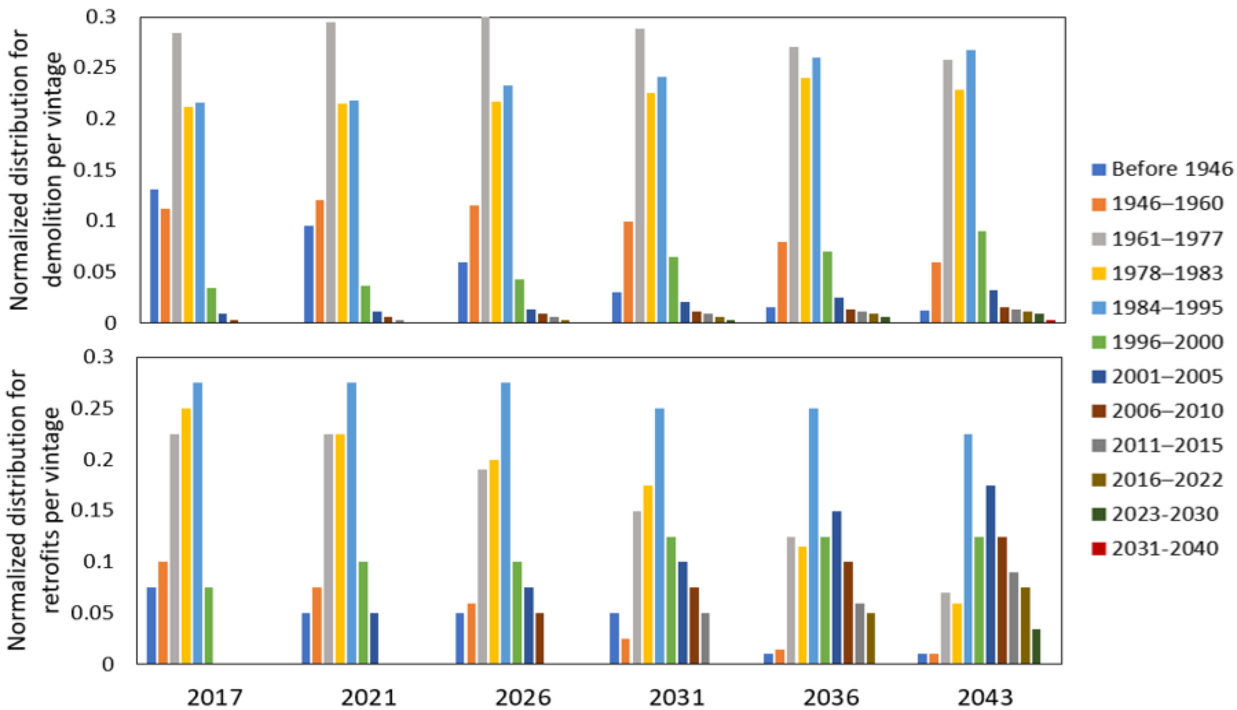


Figure A.1. Top graph shows normalized distribution describing demolition per vintage starting 10 years after new construction. Historical demolition rates are calculated from [102]. Bottom graph shows normalized distribution describing retrofits per vintage starting 20 years after new construction. No historical data is available to determine retrofit distribution across vintages. In this work, retrofits are assumed to be deep retrofits that improve the EUI of a building to this of a newly constructed dwelling.

When forecasting building stock turnover for vintage v, demolition is completely removed from the building stock. In year $y+1$, $t$he area in vintage v, thus, is reduced due to demolition and retrofits:

$$A_v(y+1) = A_v(y) - A_{v,demo}(y) - A_{v,retro}(y) \qquad A.\ 21$$

The total retrofit area is defined as the sum of the area subject to retrofit in each vintage v. New construction is determined by applying the exogenous new construction rate to the previous years' building stock:

$$A_{retro}(y) = \sum_{v=0}^{y} A_{v,retro}(y) \qquad A.\ 22$$

$$A_{new}(y) = A\,(y-1) \times n(y) \qquad A.\ 23$$

Then, any retrofitted and newly constructed floor space in year y is added to the newest vintage period $v+1$:

$$A_{v+1}(y+1) = A_{retro}(y) + A_{new}(y) \qquad A.\ 24$$

Finally, the remaining area per vintage is defined as the area that is not retrofit or demolished and protected area for heritage buildings $A_{v,heritage}$:

$$A_{v,remain}(y+1) = A_v(y+1) + A_{v,heritage} \quad \textit{A. 25}$$

For the remaining building stock, energy use intensities in year $y+1$ remain the same than in year y (Equation A.26). The constant energy use intensity $EUI_v(y+1)$ per vintage v is then multiplied by the remaining floor space per vintage v to determine space heating energy demands for the evolving remaining building stock (Equation A.27). Improvements of energy use intensities apply to any area that is retrofit as well as newly constructed buildings. Here, new energy use intensities $EUI_{v,new}(y)$ are exogenously defined to meet new building codes and are applied to any newly constructed area $A_{v,new}(y+1)$ and any area that is retrofit $A_{v,retro}(y)$ in vintage v:

$$EUI_v(y+1) = EUI_v(y) \quad \textit{A. 26}$$

$$E_{SH,res,remain}(y+1) = \sum_{v=0}^{y} A_{v,remain}(y+1) \times EUI_v(y+1) \quad \textit{A. 27}$$

$$E_{SH,res,new}(y+1) = \sum_{v=0}^{y} A_{v,new}(y+1) \times EUI_{v,new}(y) \quad \textit{A. 28}$$

$$E_{SH,res,retro}(y+1) = \sum_{v=0}^{y} A_{v,retro}(y+1) \times EUI_{v,new}(y) \quad \textit{A. 29}$$

Finally, the total space heating energy demand for the residential building stock is defined as the sum of space heating energy demands for new builds, retrofits, and the remaining building stock:

$$E_{SH,res}(y+1) = E_{SH,res,new}(y+1) + E_{SH,res,retro}(y+1) + E_{SH,res,remain}(y+1) \quad \textit{A. 30}$$

Forecasting residential water heat demands in year $y+1$ is subject to population growth impacting the total floor space $A(y+1)$ such that the floor space in year $y+1$ is determined by adding new area in year $y+1$ to the existing area in year y:

$$A(y+1) = A(y) + A_{new}(y+1) \quad \textit{A. 31}$$

where the new area in year $y+1$ is described by population growth from year y to $y+1$ applied to the existing area in year y:

$$A_{new}(y+1) = A(y) \times p(y+1) \quad \textit{A. 32}$$

Residential water heat demands in year $y+1$ are defined as the product of total residential floor space due to population growth A_{new} and the average energy use intensity for water heat $EUI_{WH}(y)$ in year y which is assumed to stay constant:

$$E_{WH,res}(y+1) = A_{new}(y+1) \times EUI_{WH,res}(y) \quad \textit{A. 33}$$

A.2.2 Commercial Building Stock Turnover

Forecasting commercial space and water heat demands in year $y+1$ is subject to population growth impacting the total floor space $A(y+1)$ such that the floor space in year $y+1$ is determined by adding new area in year $y+1$ to the existing area in year y according to Equation A.31. The new area A_{new} in year $y+1$ is described by population growth from year y to $y+1$ applied to the existing area in year y according to Equation A.32.

Total space and water heating demands in the commercial sector are determined by multiplying the forecasted floor space in year $y+1$ with 50% of the relative change in energy use intensity forecasted in the residual building sector in the same year:

$$E_{SH,com}(y) = A_{new}(y+1) \times \left[50\% \left(\frac{EUI_{SH,res}(y+1) - EUI_{SH,res}(y)}{EUI_{SH,res}(y)}\right)\right] \quad A.34$$

$$E_{WH,com}(y) = A_{new}(y+1) \times \left[50\% \left(\frac{EUI_{WH,res}(y+1) - EUI_{WH,res}(y)}{EUI_{WH,res}(y)}\right)\right] \quad A.35$$

A.2.3 Residual Load

The residual load is kept constant for all temperature years. To determine the residual load, the average between 2017 and 2019 of electric residential and commercial space and water heat demands was taken and subtracted from the gross electricity average of those 3 years according to Equation A.34. The normalized gross electricity demand profile is generated using an average gross electricity demand profile of the years 2017 to 2019. First, end-use specific normalized profiles $\vec{P}_u$ and the normalized electricity demand profile $\vec{P}_G$ are scaled to match annual end-use specific heating demands E_u and the annual gross electricity demand E_G. The residual load E_R is then defined as the difference between the gross electricity demand E_G and all electric end-use heating demands:

$$E_R(y) = \vec{P}_G(y)E_G(y) - \left[\vec{P}_{SR}(y)E_{SR}(y) + \vec{P}_{SC}(y)E_{SC}(y) + \vec{P}_{WR}(y)E_{WR}(y) + \vec{P}_{WC}(y)E_{WC}(y)\right] \quad A.36$$

A.2.4 Total Space and Water Heating Energy Use Under Different Electrification Strategies

A fraction of the resulting end-use specific heat demands using fossil fuels is electrified depending on the applied electrification strategy. For this, the fraction of end-use specific heat demands using fossil fuels is set to the average of historical fossil fuel-based heating. The total electrified end-use specific energy demand is then defined as the sum of the end-use specific heating demand using electricity $E_e(y)$ with a specific electric heating system observed efficiency $\eta_{e,obs}$ and the electrified fraction of the end-use specific heating demand using fossil fuels $E_f(y)$ with a specific fossil fuel heating system observed efficiency $\eta_{f,obs}$ where e describes the fraction of fossil fuel heating that is electrified in year y:

$$E_u(y) = (E_e(y) \times \eta_{e,obs}) + (e \times E_f(y) \times \eta_{f,obs}) \quad A.37$$

A.3 Final Energy Demands

Final energy demand for space or water heating is calculated by dividing hourly space or water heating demands for each technology by its efficiency:

$$F_u(y) = \frac{E_u(y)}{COP(T_{amb})} \qquad A.\ 38$$

where $E_u(y)$ represents the end-use specific useful energy demands obtained in the previous modelling step and $COP(T_{amb})$ represents the technology performance based on the applied technology mix. Finally, the total annual electrified heating demand $F_D(y)$ is determined as the sum of final energy demands for electrification of building heat $F_H(y)$ and the residual load $E_E(y)$:

$$F_D(y) = F_H(y) + E_E(y) \qquad A.\ 39$$

where F_H describes the sum of all end-use specific final heating energy demands $F_u(y)$:

$$F_H(y) = \sum F_u\,(y) \qquad A.\ 40$$

Appendix B

Supplementary material: Electrifying end-use demands: Capacity and flexibility requirements

B.1 Seasonal variability of electricity load

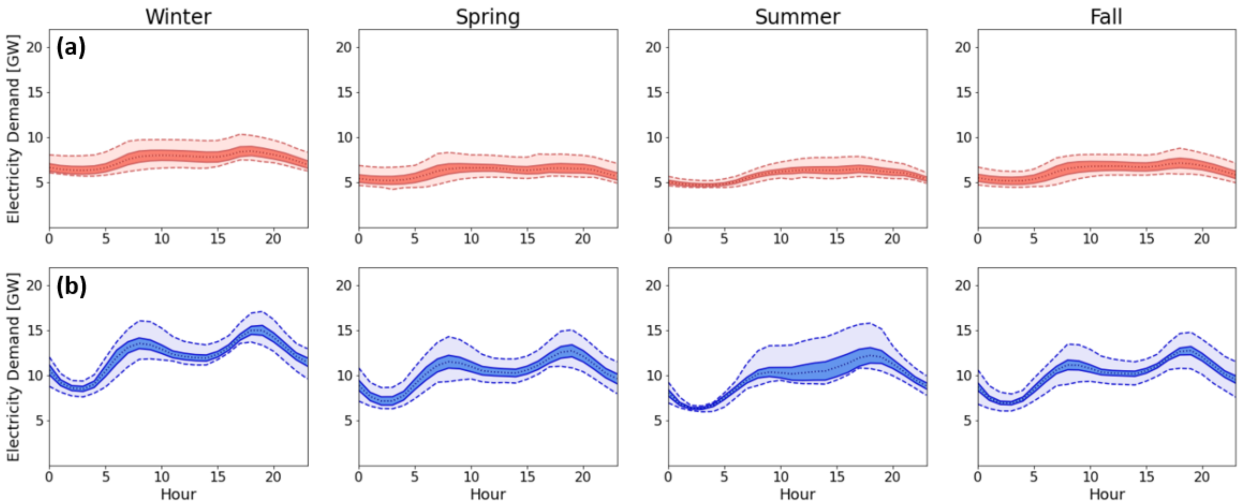


Figure B.1. Seasonal variability of hourly electricity loads for the 2020 and 2050 Reference Scenarios. The inner dotted lines show the mean electricity load while the outer orange/blue dashed lines show the minimum and maximum electricity loads, respectively. The solid orange/blue lines show the bounds of loads within 2σ of the mean. Winter captures the months December, January, February. Spring captures March, April, and May. Summer represents June, July, and August. Fall represents the months September, October, and November.

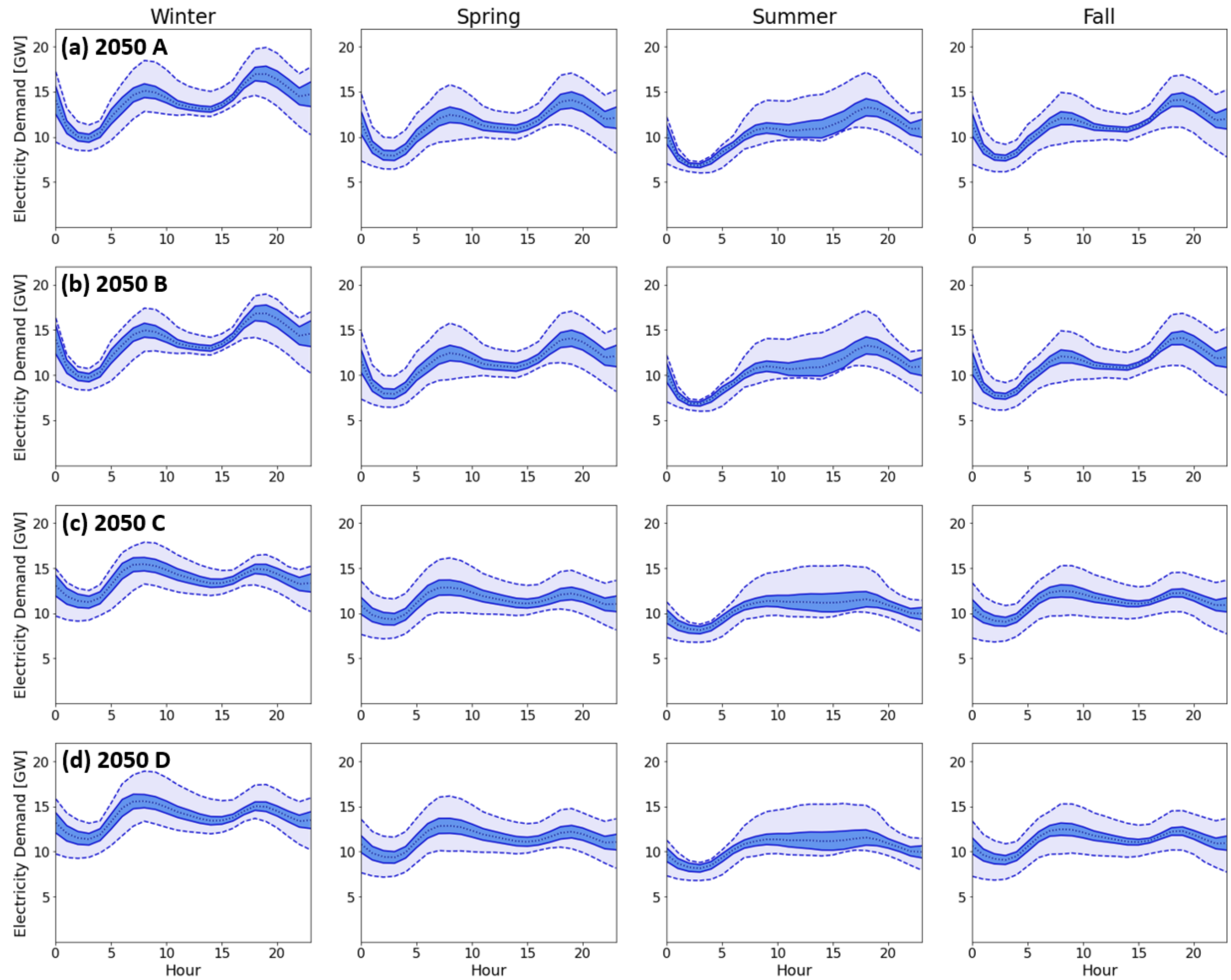


Figure B.2. Seasonal variability of hourly electricity loads for Scenarios 2050 A – 2050 D. The inner dotted lines show the mean electricity load while the outer orange/blue dashed lines show the minimum and maximum electricity loads, respectively. The solid orange/blue lines show the bounds of loads within 2σ of the mean. Winter captures the months December, January, February. Spring captures March, April, and May. Summer represents June, July, and August. Fall represents the months September, October, and November.

Appendix C

Supplementary material: Electrifying end-use demands in a 100% renewable grid: The value of flexibility to enhance grid resilience

C.1 Energy generation by technology type

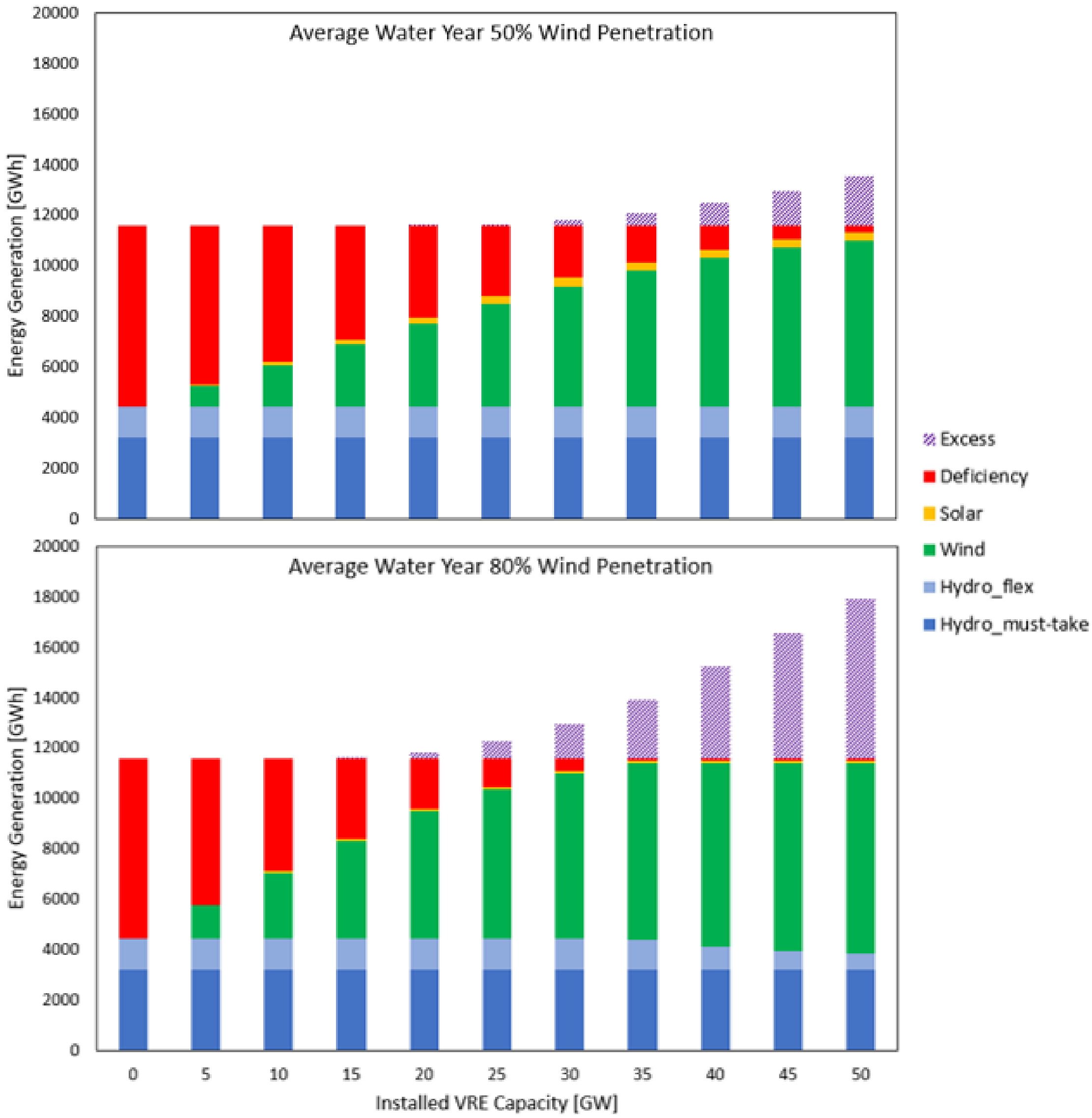


Figure C.1. Energy generation by technology type in December for 11 installed VRE capacities in an average water year for 50% wind penetration at the top and 80% wind penetration at the bottom.

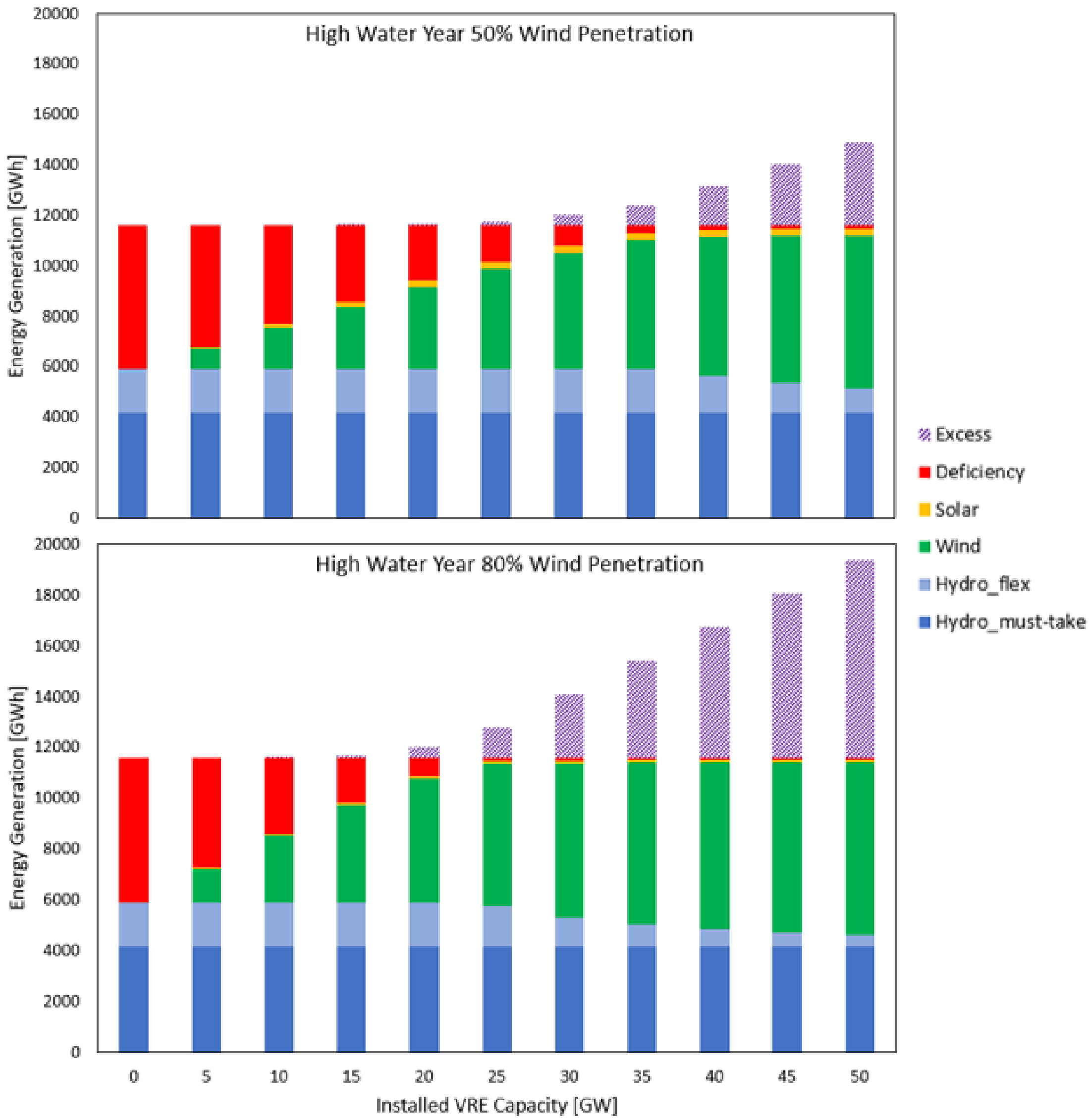


Figure C.2. Energy generation by technology type in December for 11 installed VRE capacities in a high water year for 50% wind penetration at the top and 80% wind penetration at the bottom.

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