The balancing act of renewable transitions: Modelling demand response programs to facilitate variable renewable energy integration at the city-scale

By

Madeleine Seatle
B.Eng., McMaster University, 2019

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We acknowledge and respect the lək̓ʷəŋən peoples on whose traditional territory the university stands and the Songhees, Esquimalt and W̱SÁNEĆ peoples whose historical relationships with the land continue to this day.

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Abstract

Evolving technologies and ambitious decarbonization policies require a shift away from carbon intensive fuels and, if the electricity grid is decarbonized, the path forward is heavily reliant on electrification. Besides the effectiveness in emission reduction, electrification offers opportunities to increase grid flexibility through programs such as demand response (DR). Despite being widely seen in literature that DR programs are beneficial to the grid, there are limited, if any, DR programs available. As DR programs span sectors, building and transportation demand models are linked with an electricity system model for the purpose of determining the viability of city-scale decarbonization policies, in which DR programs play a role. Further, this work outlines two approaches to modelling DR programs, iterative and non-iterative. The iterative approach is found to be a viable option for situations where scenario feasibility is being assessed, though the solution may end up being non-optimal. In contrast, the non-iterative approach is found to be effective at assessing the value of DR to the grid and to the consumer as the optimal solution for the scenario is determined. Key insights from this research extend further than the Canadian context; as decarbonization is an urgent goal at the global scale, these modelling approaches can be applied to any international jurisdictions considering leveraging the advantages of DR programs.

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List of abbreviations

ASHP – air source heat pump

ASHRAE – American Society of Heating, Refrigeration and Air-Conditioning Engineers

BAU – business as usual

CES – Clean Energy Standard

CWEEDS – Canadian Weather Energy and Engineering Datasets

DR – demand response

DRA – demand response aggregator

EV – electric vehicle

GHG – greenhouse gas

GRETA – Global Renewable Energy Timeseries and Analysis

GSHP – ground source heat pump

HVAC – heating, ventilation, and air conditioning

kW – kilowatt

kWh – kilowatt-hour

LCOE – levelized cost of energy

MW – megawatt

MWh – megawatt-hour

OCED – Organization for Economic Co-operation and Development

NG – natural gas

PHS – pumped hydro storage

PV – photovoltaic

UCC – utility-controlled charging

VRE – variable renewable energy

Author Contributions

This dissertation is comprised of three manuscripts which were all submitted, or are intended to be submitted, to journals. All written as lead author. The author contributions of each manuscript are described below.

Chapter 2: Madeleine Seatle (MS), Lauren Stanislaw (LS), and Robert Xu (RX) completed the modelling work and wrote the original draft of the manuscript. MS performed final analysis of results. Madeleine McPherson (MM) revised the manuscript. All authors contributed to conception and design of the study, and read and approved the final version. Submitted and published in *Frontiers in Sustainable Cities*.

Chapter 3: MS developed the model, collected the data, analyzed results, and wrote the original draft of the manuscript. MM provided model guidance and revised the manuscript. All authors contributed to conception and design of the study, and read and approved the final version. Submitted to *Energy*.

Chapter 4: MS completed the modelling work, collected the data, analyzed results, and wrote the original draft of the manuscript. MM provided model guidance and revised the manuscript. All authors contributed to conception and design of the study, and read and approved the final version. Prepared for submission to journal.

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1 Introduction

An argument can be made that cities are the lowest hanging fruit in term of decarbonization from the energy standpoint; cities occupy only 2% of the global landmass, yet they are responsible for over two-thirds of energy consumption and produce over 70% of global GHG emissions (Conroy & Hoika, 2020). When looking at Canadian cities, there are some equally disproportional statistics. As of the end of 2020, the Partners for Climate Protection program, a network of Canadian cities who voluntarily committed to reducing their GHG emissions, has over 500 cities active on their platform; this number represents 70% of the national population (Partners for Climate Protection, 2023). It has been calculated that municipal governments in Canada have the ability to reduce their GHG emissions by 40-50%, though many are not close to that level (Torrie, 2015). Based on these numbers, it is clear that the problem is not a lack of willingness, but a lack of city-scale resources available for cities to actually carry out these commitments or monitor their progress (Torrie, 2015).

This lack of resources available at the city-scale is made evident by the fact that most decarbonization policies in Canada are implemented at the provincial or federal level (McPherson, 2021), with very few being implemented by specific cities (ex. Toronto providing homeowners with low-interest loans for energy efficiency improvements (City of Toronto, 2017)). As most large-scale energy infrastructure is owned provincially or, in some cases, federally, these policies have made sense; however, as technologies continue to improve and cities are more willing to develop their own decarbonization plans, there is more opportunity for the ownership of electricity generation infrastructure to shift to homeowners (e.g., rooftop solar) or municipalities.

What has to be kept in mind as city-scale policy makers approach creating local decarbonization policies is that the process is far from “one-size fits all”, and is instead based on several factors that vary significantly from city to city (Conroy & Hoika, 2020). For example, Vancouver and Regina have both committed to being 100% renewable cities, yet their plans on how to do so vary significantly. Vancouver has very little solar or wind capacity, but incredible hydro resources, which is contrary to Regina’s lack of hydro but abundance of solar and wind (Global Wind Atlas, 2019; Government of Canada et al., 2020).

Another thing to consider is how behavioural patterns affect demand. For example, transportation patterns in Toronto, where public transit utilization is high (VandeWeghe & Kennedy, 2007), will vary drastically from transportation patterns in Regina, where public transit utilization is low (Xu et al., 2023). This means that between the two cities, the respective impacts of personal vehicle electrification and public transit electrification will be substantially different. Similarly, building electrification will be impacted drastically by the climate and typical heating demand, such as the differences in heating demand between Regina and Victoria (Conroy & Hoika, 2020).

These intricacies of decarbonization pathways in Canadian cities lends itself well to energy modelling. Additionally, since different sectors are often so interlinked in urban environments, the potential to utilize linked energy models is promising. Linked energy models can generate insights that would not be possible when running models separately, as the user is allowed more control over the type and scope of decarbonization techniques being modelled without drastically increasing the computational burden of running the model (McPherson et al., 2022; Miri et al., 2022).

As the electricity sector is moving towards decarbonization, energy modelling is becoming increasingly relevant. Two major changes that are being seen in the electricity sector are especially relevant to my research: VRE integration and electrification.

Historically, VRE sources have made up only a small portion of electricity grids, but recently that has been changing (McPherson & Karney, 2017). Global wind capacity increased 9% from 2021 to 2022 with projected 13% year-on-year growth to 2030 (Hutchinson & Zhao, 2023). Similarly, global solar capacity accounts for two-thirds of 2023's projected renewable growth when accounting for utility-scale solar projects and distributed generation (i.e., residential and commercial solar PV) (IEA, 2023).

For cities, electrification is mainly focused on electrifying the building and transportation sectors. As much research about large-scale electrification is theoretical, there is debate about what effects it will have on demand. It has been found by Keller et al. (2019) that electrifying the entire road vehicle fleet in British Columbia will require a 60% generation capacity increase. Similarly, Talebian et al. (2018) found that reducing road transportation emissions in British Columbia by 64% will require a 40% increase in generation capacity. The electrification of building heating in California was found by Tarroja et al. (2018) to increase electricity demand by just over 30%. In a review of electrification projections in the US and UK, Blonsky et al. (2019) found many projections showed that "very significant" increases in generation capacity are needed to accommodate a transition to heat pumps, with one study notably projecting that demand would nearly double. However, it was found in the same review that there are significant opportunities to use electrification to smooth the demand curve, even while the overall annual demand still increases. This was reiterated by Stewart et al. (2018) that even though electrification will likely lead to significant increase in electricity demand, there are opportunities to "soften" this increase through various strategies, such as increasing energy efficiency and implementing DSM techniques.

In a traditional electricity system, electricity supply reacts to demand, as traditional electricity generation sources have been fuel driven and are able to be turned on at will. In electricity systems with high levels of VRE generation, this control of the electricity supply is not always possible. An option to make supply more reliable is to implement utility-scale energy storage, though is not always possible to the extent needed due to geographic, technologic, and/or cost barriers (Kebede et al., 2022). However, another option for balancing variable energy supply is DSM programs, such as DR. DR is a technique where electricity consumers alter their electricity usage based on some external stimulus (McPherson & Stoll, 2020). This can be done through several different types of programs, though the focus of this research is utility-controlled DR programs, where consumers allow the grid operator to modify their consumption for an agreed upon incentive.

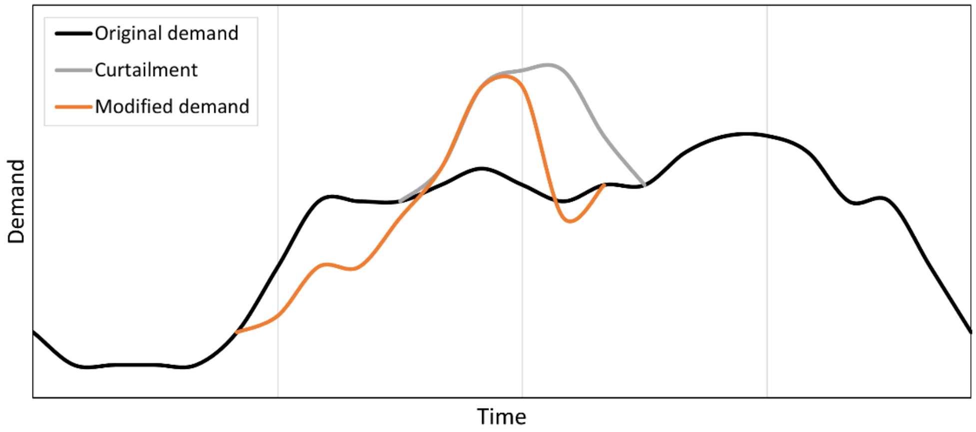
The aim of this dissertation is to present two novel approaches to DR modelling, iterative and non-iterative, for the purpose of determining the viability of DR in city-scale decarbonization targets. Both the modelling approaches utilize linked sector-specific models with an electricity system model, enabling analysis of DR from the grid operator's perspective. Though both these modelling approaches are meant to represent the same type of DR programs, the modelled representation is different. A theoretical example of how the application of DR programs differ between these two modelling approaches can be seen in Figure 1.

Note that the "iteration" refers to iterations of model runs (i.e., results are passed back and forth between the demand-side models and the electricity system model until an acceptable solution is reached). Therefore, the non-iterative approach requires only one run of all models (i.e., only one pass between demand-side models and electricity system model is required).

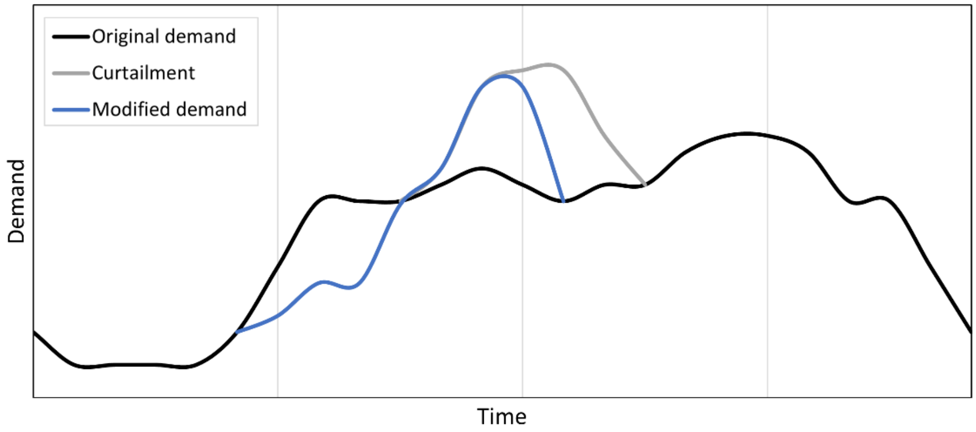
A main difference between the modelling approaches is the optimality of the results, specifically the global optimality of the optimization period. The iterative modelling approach is able to find a solution that cannot be confirmed as the global optimal solution for DR dispatch, with the end point of the iteration being determined by the user based on external metrics. In contrast, the non-iterative modelling approach can determine an optimal solution for DR dispatch, meaning the maximum theoretical benefits of DR to both the grid and to the consumer can be determined.

This is due to the application of the DR program to modify demand. The iterative modelling approach shifts demand load by rerunning demand-side models for the sole purpose of reducing curtailment by giving priority to periods of excess VRE production (discussed further in Chapter 2). It should be noted that even though the solution is not globally optimal, it may be suitable in meeting the needs of the user (e.g., assessing feasibility of a renewable energy target). The non-iterative approach differs significantly, as it is self-contained within the electricity system model and is able to shift demand to reduce overall operational costs (discussed further in Chapter 3). As maximizing VRE utilization both reduces curtailment and reduces operational costs, the non-iterative results may appear similar to the iterative approach (Figure 1B); however, as the non-iterative approach considers more variables than the iterative approach, the strategy employed to reduces operational costs may result in a much different demand curve (Figure 1C).

A) DR program application with iterative approach



B) Potential DR program application with non-iterative approach



C) Alternative DR program application with non-iterative approach

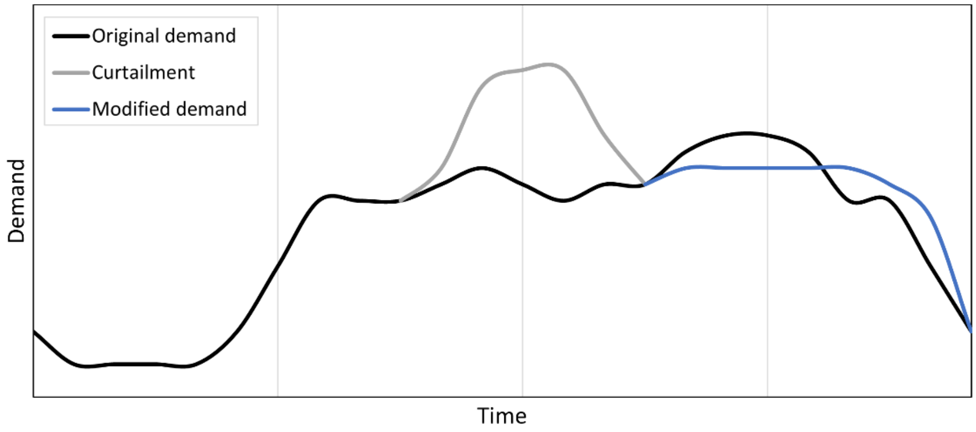


Figure 1: Comparison of DR program applications between modelling approaches. Iterative approach finds non-optimal solution by reducing curtailment (top). Non-iterative approach finds optimal solution by maximizing VRE utilization (middle) or reducing peak demand (bottom).

The dissertation is organized as follows:

Iterative DR modelling (Chapter 2): A novel model linkage of building and transportation demand models are linked with an electricity system model in order to determine the feasibility of a city-scale renewable target at various scopes.

Non-iterative DR modelling (Chapter 3): A novel application of linear DR constraints is applied to an electricity system model in order to determine the theoretical benefits of residential building DR programs on various electricity grids.

Multi-sector, non-iterative DR modelling (Chapter 4): The same modelling approach from Chapter 3 is applied to a variety of sectors (residential buildings, personal transportation, and industrial facilities) by leveraging the linked models from Chapter 2.

Though the focus of my research has been Canadian focused, the model linkage and the approaches to modelling DR found within my research can, and hopefully will, be applied globally.

2 Integrated transportation, building, and electricity system models to explore decarbonization pathways in Regina, Saskatchewan

2.1 Introduction

In Canada, end-use energy demand in the transportation and building sectors relies heavily on carbon-intensive sources. These sectors, which are collectively responsible for approximately 40% of Canada's GHG emissions, mainly use motor gasoline and NG for fuel and heating (Natural Resources Canada 2019). Some cities in North America have recognized this and committed to becoming renewable cities (Zuehlke 2017; Eaton and Enoch 2020). In 2018, the City Council of Regina, Saskatchewan made this decision as well, committing to using 100% renewable energy by 2050 (Tink and Folk 2019). Though the decision was unanimous, City Council lacked clarity on the scope of the commitment, as well as an official plan for how to achieve it. More recently, three novel definitions of scope have been suggested by Bartdutz and Dolter (2020):

- Scope 1 would encompass electricity used only by City owned buildings and operations;
- Scope 2 would encompass all electricity used by the City of Regina, including private residents; and
- Scope 3 would encompass all energy used by the City of Regina.

City Council has not yet finalized the scope of the commitment (Peterson 2020). However, in October 2020, Regina City Council decided to move forwards with the development of an Energy and Sustainability Framework and Action Plan. This would include "details on how City and municipal wide action plans, with specific and aggressive timelines, could forward the commitment of a transition towards a 100% community-wide renewable Regina by 2050." This suggests the city is interested in investigating pathways to reaching the Scope 3 target (Regina City Council 2020). Meeting Regina's target would require increased use of renewable energy, likely including VRE such as wind and solar. When introducing uncertainty and variability inherent to VRE generation on the supply side, flexibility on the demand side becomes a necessary ingredient to maintaining cost-effective grid reliability. Without demand side flexibility, integration of large-scale VRE generation can be challenging and result in undesirable outcomes, such as inability to meet demand and high curtailment rates (McPherson et al. 2018). Electrification, or a shift away from traditional fuel sources towards electricity powered technologies, can provide demand side flexibility when combined with management strategies (Mathiesen et al. 2015). With proper load management, technologies such as EVs, electric space heating, and other electric appliances are able to time-shift their demand to match spikes in VRE generation (Dennis 2015). If carefully designed and managed, there could be a positive feedback loop when electrification and VRE integration are implemented together: low-carbon on the supply side could power the decarbonization of demand sectors, while responsive loads could provide much needed flexibility to facilitate VRE integration.

DR programs can operationalize this positive feedback loop by changing consumers' electricity consumption patterns (McPherson and Stoll 2020). This can be done through user-controlled electricity reduction, typically for industrial-scale electricity consumers (SaskPower 2019; Hydro-Québec 2020; Alberta Electric System Operator 2019); time-of-use electricity pricing (Ontario Energy Board 2021); or grid control of appliances, typically with financial incentives (Holy Cross Energy 2016).

Regina is an ideal candidate for coupling electrification with VRE integration for several reasons: it currently relies on carbon-intensive electricity generation but has immense potential for electrification and exceptional renewable resources. Saskatchewan has the second-highest emitting electricity grid in Canada, due to its reliance on coal generation (Canada Energy Regulator 2020). Meanwhile, the EV penetration in Saskatchewan is near zero, while electric space and water heating are used in less than 10% of households (Natural Resources Canada 2020). Electrification of the transportation and building sectors powered by renewable generation is possible due to Regina's location in one of the highest solar (Figure 2A) and wind (Figure 2B) potential areas in Canada (Canada Energy Regulator 2020).

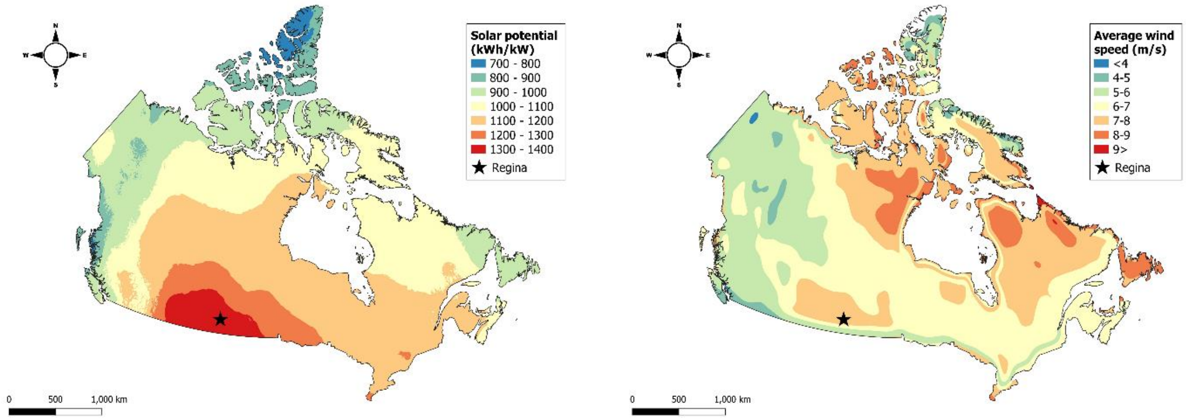


Figure 2: (A) Solar potential map (Government of Canada et al. 2020) (left) and (B) wind potential map (Global Wind Atlas 2019) (right)

To investigate how a city such as Regina might meet an energy target such as their goal to be 100% renewable by 2050, it was necessary to have control over the types and scopes of policies that are able to be modelled; this is done by employing a novel integrated modelling paradigm. Energy transition models in Canada typically take a macroeconomic approach (Vaillancourt et al. 2014), which have simplistic specifications for energy demand, as well as being spatially and temporally aggregate. A general tendency within the formulation of macroeconomic models is the focus on the decision-making process of individual actors, thus the trade-off in the detail of energy, spatial, and temporal data. However, these simplifications and aggregations mean that highly variable, spatially, or temporally, constraints are not able to be assessed at the level of detail needed. Within city-scale energy modelling, there are models that are able to represent a city at a high spatial resolution, but do not provide the temporal resolution necessary to accurately model an electricity system with high VRE integration (Zuehlke 2017; Crockett et al. 2019). There are also load models, which can model at the adequate temporal resolution for electricity systems but lack the ability to model the electricity system at the same spatial resolution (Salama et al. 2019). On the other end of the spectrum are micro-grid models (HOMER Energy 2021), which are typically restricted in the size of the system they can model, thus making them unable to model the electricity grid for an entire city.

To capitalize on the strengths of multiple models, model linkage is a common practice, especially between load models and operational models. Within this space, there have been studies showing the value in model linkage between two sectors. Szinai et al. (2020) found that the linkage of a transportation model and an electricity system model was able to provide insights on the operational implications of the increased EV penetration and VRE utilization. It was found that on a solar dominant electricity grid, “smart” charging (DR program used to control charging time to provide the grid the most benefit) can reduce VRE curtailment and reduce grid operating costs (compared to unmanaged EV charging). Additionally, Deane et al. (2015) found that the linkage of a building model and an electricity system model can more accurately measure the capabilities of an electricity system to manage a more highly electrified load. The linking of the models was proven to leverage the strength of each model and provide complimentary insights that would not have been seen otherwise. However, even with the proven benefit of mode linkage between two sectors, there has yet to be a model that links the transportation, building, *and* electricity sectors at a high enough resolution to fully assess the co-benefits of electrification and VRE integration. As all three sectors are key in meeting Regina’s energy target and, more generally, Canada’s deep decarbonization goals, a linkage of models between these sectors is a current gap in the research field.

This paper combines the strengths of multiple approaches via a novel integrated model of the transportation, building, and electricity sectors, with a bidirectional linkage allowing DR strategies to be modelled at high degree of temporal and spatial resolution. SILVER, an electricity system model, currently operates at a high temporal resolution and has the ability to model highly granular spatial boundaries; however, linkages with individual transportation and building models can allow for further spatial granularity while keeping SILVER’s computation time reasonable.

2.2 Methods

With Regina’s potential for additional VRE generation and demand side electrification, there is a broad exploration space for future configurations of its energy system. Uncertainty can be explored by changing variables such as the electrification level, VRE capacity, storage, and DR.

With the novel linkage between transportation, building, and electricity system models, these variables can be explored at a high temporal and spatial resolution.

2.2.1 Integrated model formulation

Reducing emissions related to energy use is a main objective behind Regina's renewable energy goal. Evaluating the effect of demand side electrification on emissions requires the demand side models to pass information to the electricity system model. Investigating DR based on VRE generation requires information to be passed from the electricity system model to the demand side models. VRE curtailment is an indicator of system efficiency and design because lower curtailment indicates more demand is being met by VRE. Since VRE is non-polluting, bidirectional linkage is implemented by using curtailment reduction as a proxy for emissions reduction.

Figure 3 illustrates the novel linkage process; the solid arrows represent the linkage from the building and transportation sector models to the electricity system model, while the dashed arrows represent the linkage from the electricity system model to the demand side models. Once a scenario is selected, the building and transportation models - outlined in detail in the following sections - are run concurrently and output demand load curves. These are combined with a baseline demand to represent the total electrical load for Regina, which is then input directly into the electricity model. Although these models interact with each other while running a scenario, they are decoupled and individual insights are able to be drawn from each model individually, as well as from the linked outputs.

After the electricity model is run, the amount of VRE curtailment is assessed. DR is modelled to occur through utility control over EV charging and building temperature setpoints, allowing the utility to time-shift loads during periods of curtailment to take full advantage of VRE generation. Constraints are placed upon utility control to minimize the disruption to the customers. For example, EVs must charge if needed to get to their next destination, even if curtailment is not occurring. Similarly, the utility can only allow the temperature within a building to drop to a certain degree before allowing the heater to turn on. It is assumed that all electrified vehicles and buildings participate in DR.

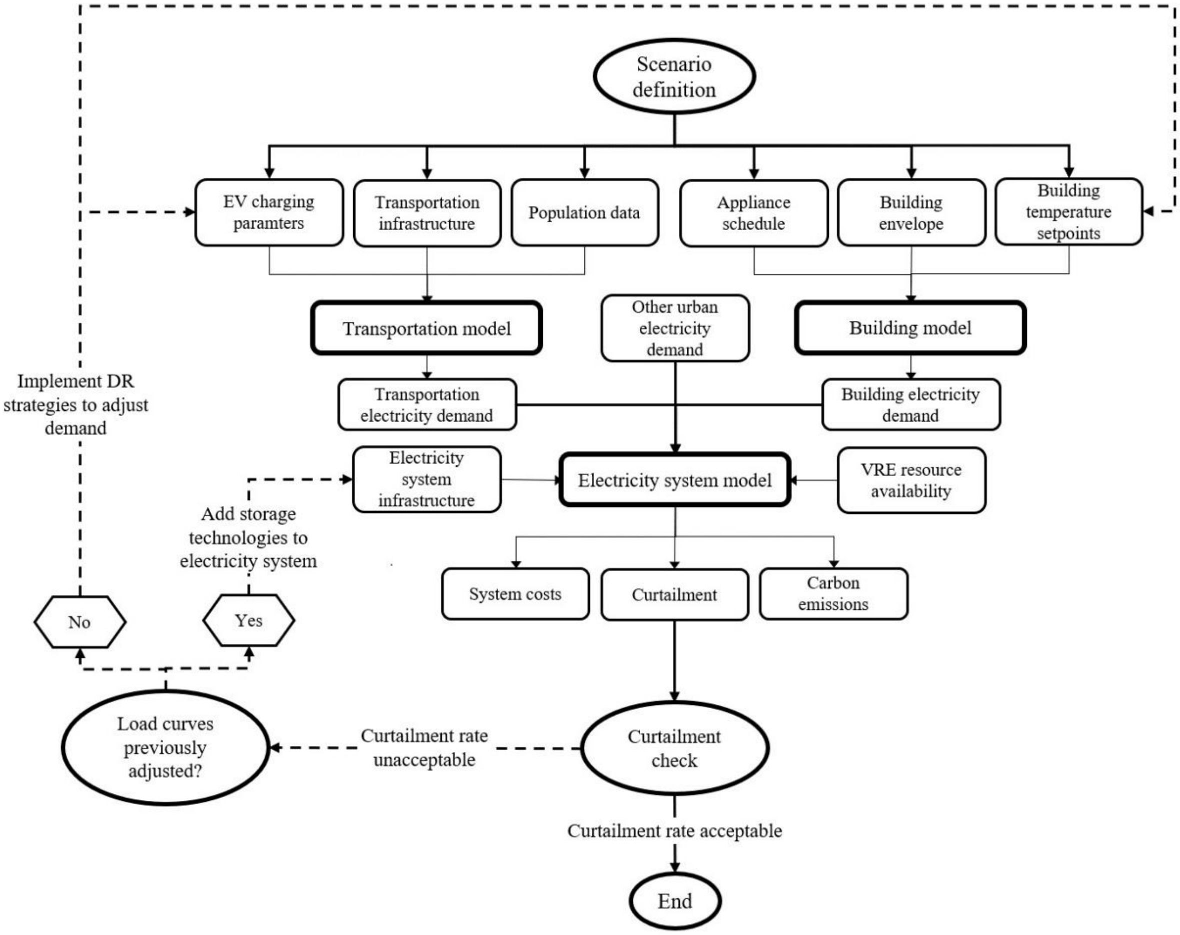


Figure 3: Bidirectional model framework with key inputs and outputs

The utility would decide how to allocate DR load to the building and transportation sectors; for simplicity, as it makes no difference to the overall system which sector uses electricity, every EV is charged until there is either no curtailment, or no remaining vehicles available to charge. The setpoints of all electrified buildings are then changed until there is either no curtailment, or all buildings have reached their maximum setpoint. This results in curtailment being minimized for that scenario. If the curtailment is still at unacceptable levels after the setpoints of all possible buildings have been changed, and the renewable target is not met, SILVER is rerun with storage technologies added.

2.2.1.1 Transportation model

To predict EV charging, the travel and charging behavior of individual vehicles are simulated. By understanding when and where individual vehicles are travelling, the spatiotemporal distribution and flexibility of EV charging can be estimated by aggregating the charging of individual vehicles.

TASHA, an activity scheduling model developed and maintained at the University of Toronto (Miller and Roorda 2003), is used to model vehicle schedules. It is currently being used to forecast travel patterns and test policy decisions in the Greater Toronto Area (Miller et al. 2015). Selected for its ability to consider spatiotemporal and resource constraints, such as vehicle availability, TASHA is able to use this information to predict EV demand within the integrated model platform. A complete daily travel schedule is generated for each household resident in a synthetic population, but commercial and freight transportation is not considered. This and other limitations regarding the transportation model are elaborated in Section 3.4.4. Detailed steps for creating and calibrating a TASHA implementation are documented by the University of Toronto Travel Modelling Group (Travel Modelling Group 2020).

The data sources and processing flows for the Regina transportation and EV charging model are shown in Figure 4, where the output of TASHA is used as an input into the charging model. Without DR, EVs are assumed to charge as soon as they arrive to their destination, and this strategy is modelled for scenarios without DR. Charging is modelled by processing each vehicle's trip schedule in temporal order: when a vehicle departs from an activity, its battery level is updated based on the trip distance and depletion rate.

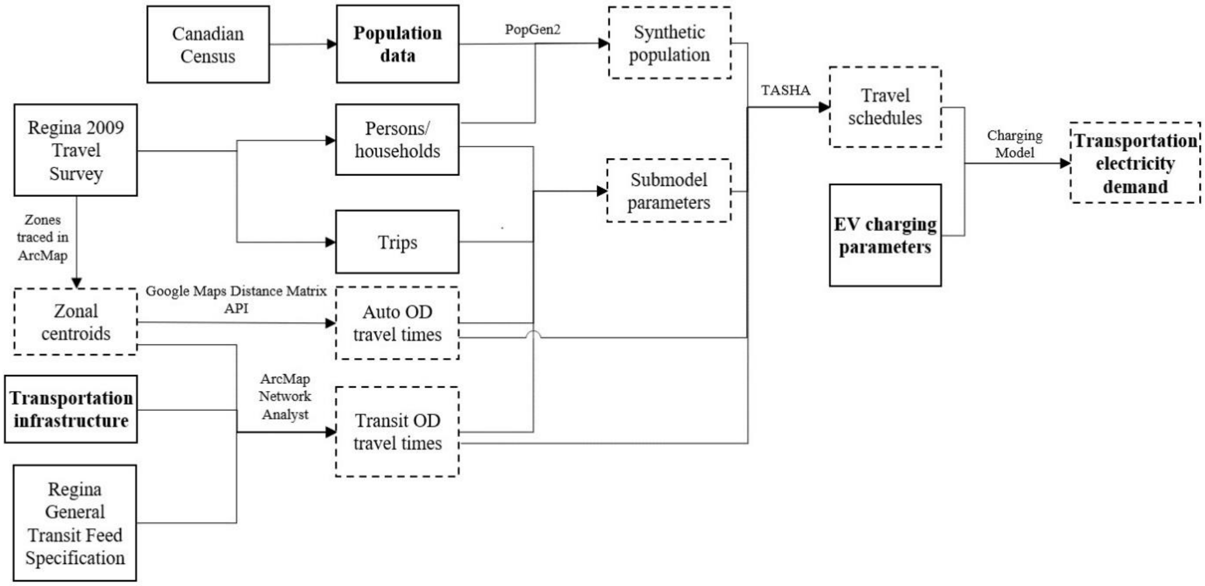


Figure 4: Transportation model processes, with solid boxes representing raw data inputs and dashes boxes representing a processed output. Note that bold text represents a direct tie-in to Figure 3.

DR implementation is modelled for EVs as UCC, where the utility can control the charging status of individual vehicles. When DR is modelled, it is assumed that all EVs participate in DR and are required to communicate the following with the utility: time of next trip departure, desired battery state of charge at time of departure, and charging status (i.e., vehicle plugged in, vehicle charging). With UCC, participating vehicles follow the same travel schedules as with uncontrolled charging but modify their charging behaviour. Instead of charging immediately, EVs delay charging until the last possible moment such that the total energy charged during the activity is the same that would be charged without UCC. Because of this delay, the utility can charge EVs with excess renewable energy if it occurs. As previously mentioned, the VRE curtailment output from SILVER is used to guide UCC within the charging model; specifically, the utility tries to charge as many vehicles as possible (when curtailment occurs) to minimize curtailment and maximize use of VRE.

2.2.1.2 Building model

A detailed representation of the relationship between building characteristics and the resulting energy usage is needed to investigate the effects of retrofit policies on building energy use. However, it is also necessary to keep data and computational requirements to a manageable level. Therefore, electrification of the residential building sector is modeled using an archetype-based engineering model, similar to that employed by Ballarini et al. (2014).

Under this modelling framework, heat exchange between individual buildings and their environment is calculated using EnergyPlus, a detailed thermodynamics simulator. For this, building properties relevant to heat transfer are specified, which include building shape, building size, construction materials, size and location of windows, and the living patterns of occupants (Swan and Ugursal 2009). A large population of varied buildings are modelled by specifying these characteristics for a small number of archetypes, whose properties are representative of the population as a whole (Reinhart and Davila 2019). Building policies are then simulated by changing specific details in each of the archetypes. For example, insulation retrofits in houses built before a specified date are modelled by changing the construction materials of the relevant archetype within the EnergyPlus simulation.

The process flows and data sources used within Regina specifically can be seen in Figure 5. Archetypes were defined based on census data for the city, and archetype annual load curves were aggregated up to a city scale by multiplying by the number of houses represented by each archetype. The simulation was then verified by visual comparison to historical load curve data.

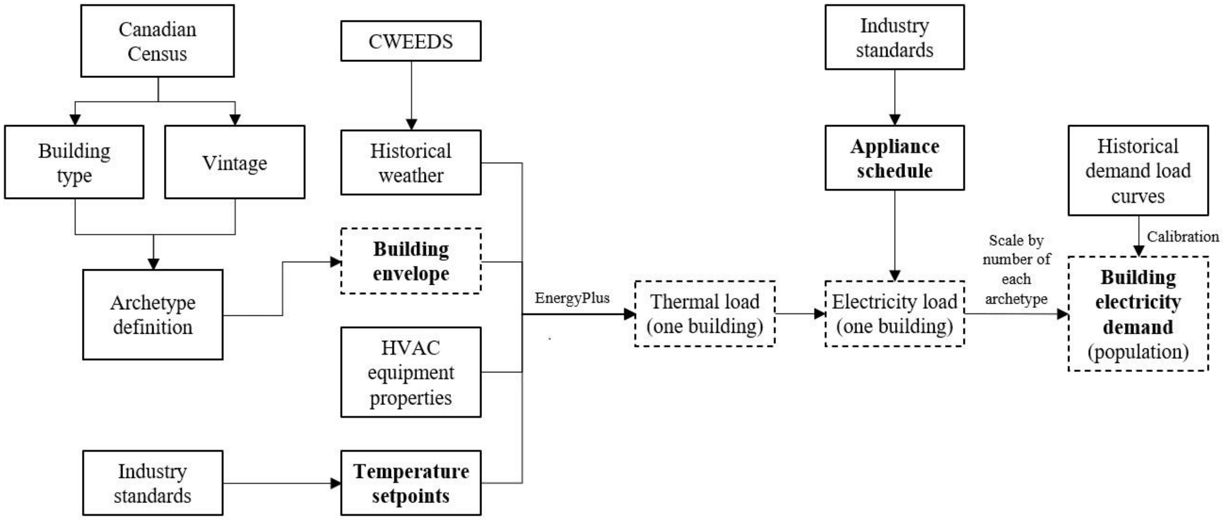


Figure 5: Building model processes, with solid boxes representing raw data inputs and dashes boxes representing a processed output. Note that bold text represents a direct tie-in to Figure 3.

DR was implemented in the model by manipulating the building setpoints for each hour based on whether VRE curtailment was occurring in that period. When the model is run without DR, all buildings are kept at a constant setpoint of 19°C for heating and 27°C for cooling. In contrast, when DR is applied, building setpoints vary depending on if there is curtailment occurring, so that the buildings can be used as heat storage for the otherwise curtailed electricity. When curtailment is *not* occurring, setpoints relax to 18°C for heating and 28°C for cooling (i.e., lessening the electricity demand). During periods of curtailment, the heating and cooling setpoints change to the more restrictive values of 21°C and 26°C, respectively (i.e., increasing the electricity demand).

2.2.1.3 Electricity system model

To effectively model a renewable city, it is crucial to develop a city-scale electricity system model. SILVER, a production-cost model (McPherson and Karney 2017), was chosen as the electricity system model for the following reasons. First, though originally developed for analyses at the provincial level, it can also be applied at a city-scale (McPherson et al. 2018). Second, SILVER models an electricity system as defined by the user, including generation and transmission assets; generation operational constraints, costs, and carbon-intensity; VRE characteristics; and electricity demand. These inputs are then validated through transmission congestion checks, generation capacity checks, and flexibility checks before proceeding to the optimization module, which determines the least-cost dispatch of the electricity system (generation and transmission assets) needed to satisfy demand at every node and each timestep of the simulation (McPherson and Karney 2017). Third, SILVER is conducive to DR implementation within the model linkage by synthesizing multiple load curves into one overall demand load and quantifying curtailment.

SILVER utilizes optimization software to determine optimal grid dispatch. For these scenarios, the relative uncertainty inherent to the determined solution is 0.1%.

An overview of the data sources and model processes can be seen in Figure 6. In summary, the available electricity demand data came from SaskPower, the electricity distributor for most of the province of Saskatchewan; census population data came from the Canadian Census (Statistics Canada 2017), and neighbourhood boundary data came from the City of Regina (City of Regina 2017b). Boundary resolution and VRE resource analysis are discussed in detail in the Appendix (Section 6.1), while the processes within SILVER are outlined in more detail by McPherson and Karney (2017).

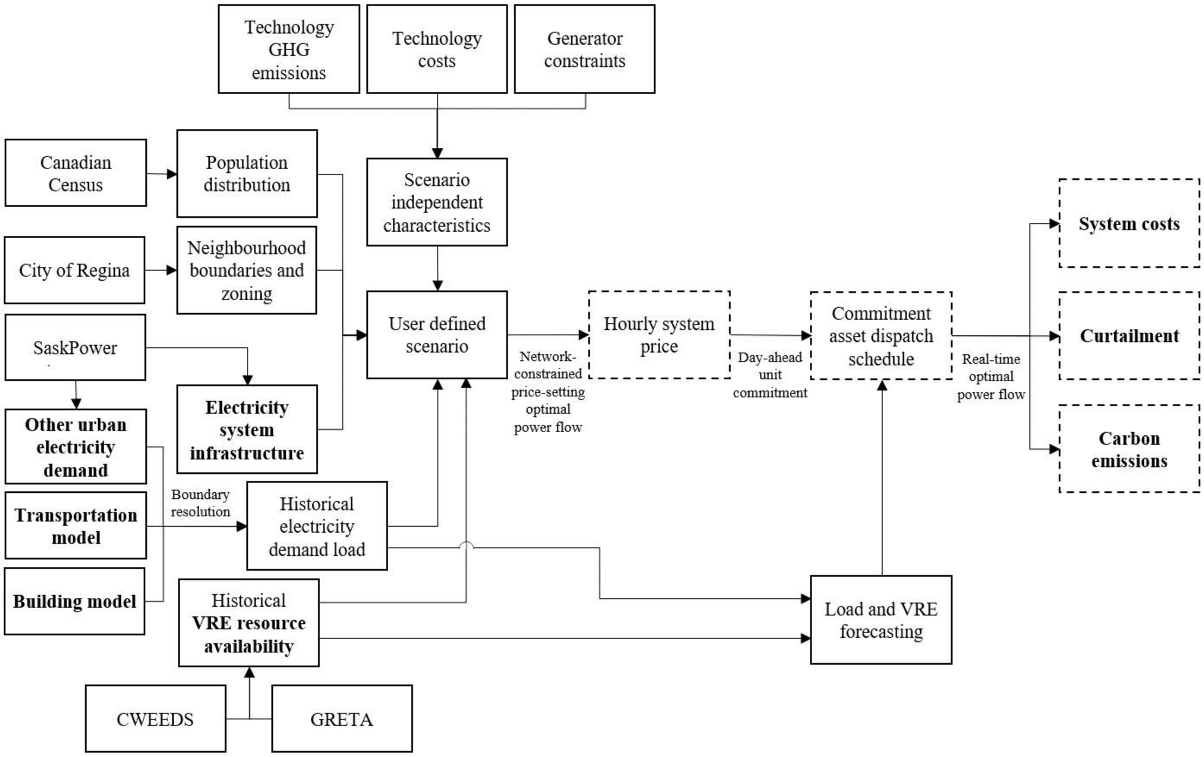


Figure 6: Electricity model processes, with solid boxes representing raw data inputs and dashes boxes representing a processed output. Note that bold text represents a direct tie-in to Figure 3.

For city-scale analysis, resolving spatial boundaries across data sources is a key priority; the high spatial resolution inherent to SILVER makes this especially important. As city-scale data is typically adopted from larger-scale data collection, there are discrepancies in spatial boundaries between data sets, as well as between the transportation and building model spatial boundaries. A detailed description of the assumption made within boundary resolution for Regina can be found in the Appendix (Section 6.1).

Due to Regina's high solar and wind potential, this analysis considers rooftop solar and wind. The hourly generation profiles are derived on a nodal level through capacity factor values. The wind capacity factor values were taken from the GRETA online tool (McPherson et al. 2017). Due to the intricacies of solar capacity factor calculations in relation to rooftop solar and shading variabilities, the calculations were done based on local weather station data and the capacity factor procedure outlined by Masters (2004) and the GIS-work procedure outlined by Latif et al. (2012). Additionally, seasonal changes in sun position and rooftop slopes are accounted for by average annual rooftop shading factors. The related weather data came from CWEEDS (Environment and Climate Change Canada 2015), while applicable GIS surface cover data came from various sources (City of Regina 2017b; Natural Resources Canada 2020).

2.2.2 Scenario development

Regina currently draws its power entirely from the SaskPower grid, which is heavily dependent on coal (30% of generation capacity) and NG (43% of generation capacity) (SaskPower 2021). The electricity demand on the grid is primarily commercial, industrial, and residential plug-load, with very little residential heating being electrified, nor significant EV load. With the current grid composition, electrifying residential building and transportation loads would lead to an increase in overall emissions. However, with an increasing share of VRE generation, the effects of electrification would allow for an overall reduction in city-wide emissions.

Utilizing the novel methodology, the simultaneous implementation of VRE integration and electrification is explored. In order to assess the feasibility of Regina's energy target, ten different scenarios were developed (Table 1). Each scenario is run in three stages, where curtailment and system cost are evaluated at each stage: Stage A models the naive load curve as a result of the transportation and building electrification scenarios with renewable generation infrastructure added; Stage B adjusts the transportation and building demand by enacting DR strategies when renewable energy would otherwise be curtailed; and Stage C adds storage technologies, reducing curtailment while still maintaining high VRE implementation on the grid. Note that Stage B has the same parameters as Stage A, but a different model architecture.

Table 1: Scenario parameters

	Stage A/B			*Stage C*
Scenario number	**Electrification level**	**Rooftop solar capacity (MW) / Share of viable rooftops covered**	**Wind farm size (MW)**	**Maximum storage size (MW) / Maximum storage capacity (MWh)**
Current system	Transportation: 0%; Buildings: 10%	0 / 0%	0	0 / 0
1	50%	353 / 25%	0	0 / 0
2	100%			0 / 0
3	50%	705 / 50%	0	0 / 0
4	100%			0 / 0
5	50%	1,410 / 100%	0	225 / 900
6	100%			200 / 800
7	50%	1,410 / 100%	100	250 / 1,000
8	100%			250 / 1,000
9	50%	1,410 / 100%	200	325 / 1,300
10	100%			325 / 1,300

As future electrification rates are highly uncertain, electrification levels were chosen to explore as broad a space as possible to align with Regina's ambitious decarbonization goal. Levels of 50% and 100% electrification balance the computational burden of running multiple scenarios with representing pathways to Regina's target.

Electrification of the transportation sector focuses on the switch from combustion engines to battery EVs, which run exclusively on electricity. It should be noted that electrification of the building sector refers to both replacing NG-powered furnaces with electric GSHPs, and upgrading window, wall, and roof insulation levels to match the highest tier of the BC Step Code (Robinson 2018). The insulation upgrades support electrification by reducing the energy demand of affected buildings, making it more feasible for electrification to be powered by renewable sources.

Within the scenarios, transportation and building electrification levels are assumed to change concurrently[1]; an electrification level of 50%, as in Scenario 1, means that 50% of households use exclusively EVs, 50% of households switch to GSHP, and 50% of households increase their level of insulation. For simplicity, it is assumed that policies for these variables would be implemented at similar times, resulting in similar electrification levels across sectors. This allows for a greater focus on how electrification as a whole will affect the electricity grid, rather than the effect of specific sectors.

Regardless of the adoption level, there are several assumptions in the EV charging model which remain constant across scenarios:

- EVs charge at every destination (home, work, shopping, and other activities) and have a battery capacity of 40kWh;
- EV adoption occurs uniformly distributed across Regina households;
- Charging occurs with a power of 2kW and the battery depletion rate is a function of external temperature;
- Temperature is sampled monthly using average temperatures from (Environment Canada 2020); and
- Battery depletion rate was estimated using the online tool provided by Geotab (2021), where a 2019 Nissan Leaf with a 40kWh battery is assumed.

Building model parameters varied slightly based on the adoption level. For the fully electrified scenario, all homes were assumed to receive both GSHP and insulation upgrades. For the 50% electrification scenario, all buildings received one of the two upgrades, and each upgrade was performed on exactly half of the building stock. Upgrades were strategically distributed to reduce energy consumption as much as possible, resulting in the following distribution among the types of buildings modeled:

- Buildings constructed before 1975, and a portion of those constructed in 1975, received insulation upgrades, as they are assumed to have poorer insulation.
- Buildings constructed after 1975, and the remaining portion of those constructed in 1975, received GSHP, as they are assumed to consume more energy due to their larger floor area.

Rooftop solar integration is reflective of both residential and commercial implementation and is based on the percentage of usable[2] rooftop space covered with PV panels. Rooftop solar

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[1] Unless otherwise indicated, i.e., Current system scenario.

[2] Usable rooftop space is defined as an area where the average annual solar capacity factor is at least 10% for a minimum of 25.5 m^2, which is equivalent to a 5 kW PV array (Solar Calculator 2020).

integration levels were taken based on recent residential opinion survey conducted in Regina (Bardutz and Dolter 2020):

- 25% of residents are willing and able to install rooftop solar without any financial incentives;
- 50% of residents are willing and able to install rooftop solar with financial incentives;
- And 100% rooftop solar integration, though not directly taken from the survey data, relates to a best-case scenario of residents willing and able to install rooftop solar.

Though this data reflects only residential interest in rooftop solar, it is assumed to be consistent across commercial and industrial building owners as well.

Wind farms are assumed to be installed outside city limits, for which there is significant support (Bardutz and Dolter 2020). A wind farm is assumed to be introduced into the generation mix in conjunction with 100% rooftop solar implementation scenarios. This was done so that scenarios with a wind farm could be directly compared. Currently, the largest wind farm in Saskatchewan[3] is 200 MW, which was taken as the upper bound for the modelled wind farm. To explore the space further, scenarios were also modelled with a 100 MW wind farm.

Storage was introduced to six scenarios (Scenarios 5 through 10) that were identified as having the potential to meet the renewable target if curtailment was decreased further than found in the previous stage. This was based on the amount of curtailment and progress towards the target renewable usage after the DR strategy was implemented (further discussion can be found in Section 2.4). The storage technology was assumed to be lithium-ion batteries with a 4-hour discharge duration. The maximum capacity of the storage technology (equivalent to the storage size multiplied by the duration of the battery) was assumed to equal the maximum curtailment within each scenario.

2.3 Results

Electrification of private vehicles and building heating, DR, and storage each have different effects on system cost, VRE curtailment, and the ability of Regina to meet its renewable energy target. In this section, detailed results from all three stages are discussed. Figures that are referred to across subsections are various generation mixes (Figure 7) and a comparison of annual average curtailment levels for each scenario in each stage (Figure 8).

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[3] Golden South Wind Project is currently in the progress of being constructed and should be operational by 2021 (SaskPower 2018).

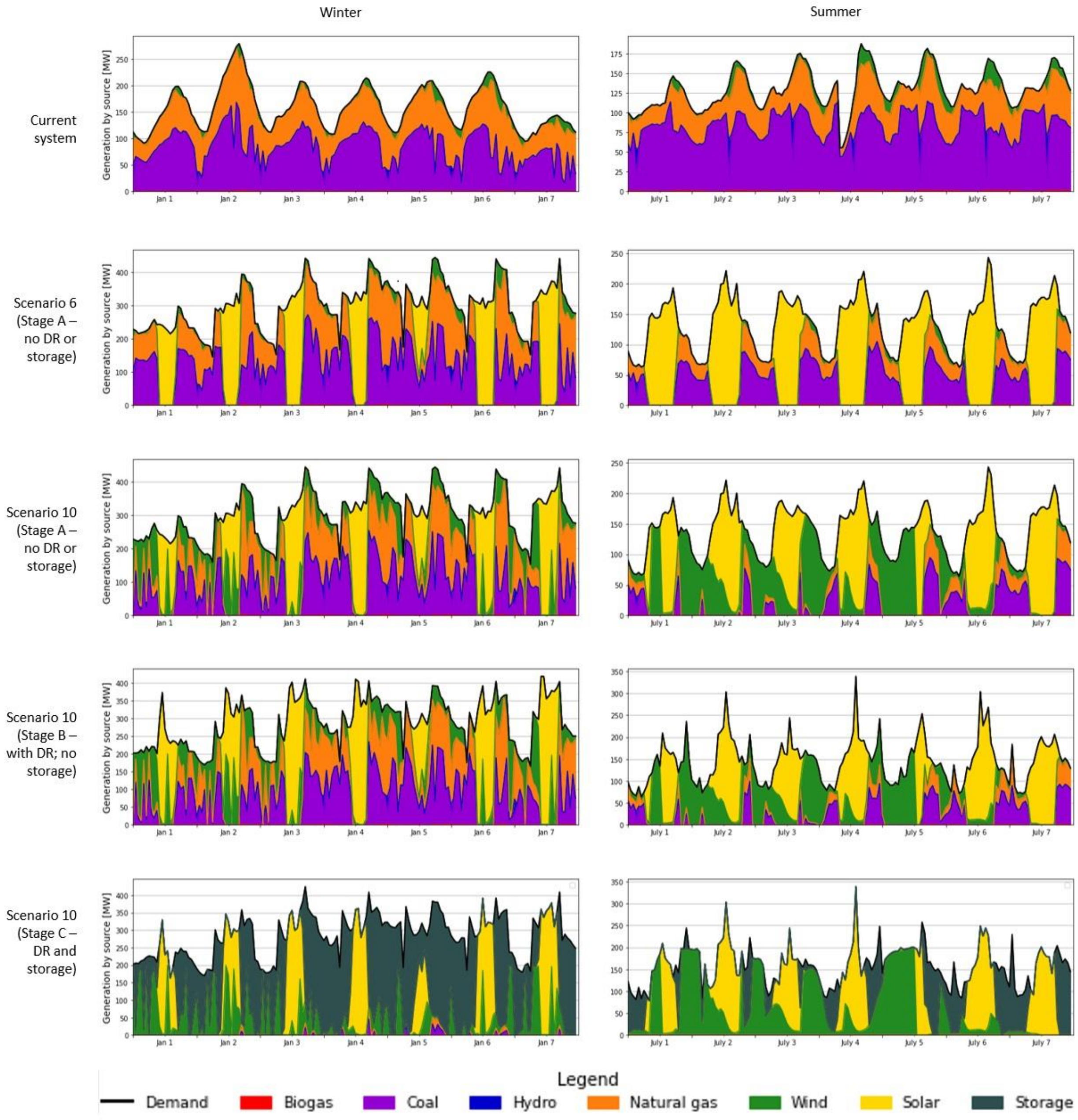

Figure 7: Generation mixes of various scenarios. Winter generation is seen from January 1-7 (left column) while summer generation is seen from July 1-7 (right column). As previously outlined, Scenario 6 has added rooftop solar capacity, and Scenario 10 has added rooftop solar and wind capacity.

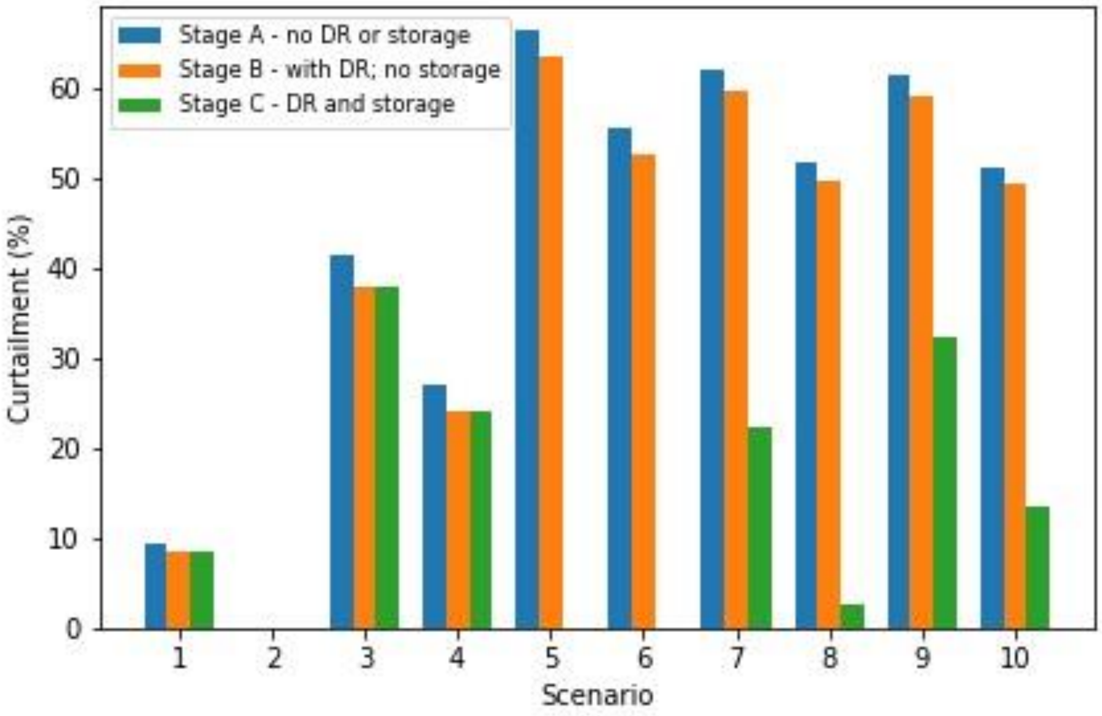

Figure 8: Annual average curtailment value across all scenarios and stages. Curtailment in Stage C of Scenarios 1 through 4 is identical to Stage B, as there is no storage capacity added to the system. Note that if scenarios appear to not have values for a particular stage it is due to that value being zero or near zero.

Scenarios are evaluated on two key criteria: LCOE (Lazard 2020; International Renewable Energy Agency 2020) and ability to meet Regina's renewable target (Figure 9). Additionally, as these scenarios are looking ahead to 2050, when Regina's target is set to be achieved, the cost is also evaluated based on a carbon tax of 170CAD, as per the federal carbon tax guidelines (Tasker 2020; Canada Energy Regulator 2020). It should be noted that LCOE is only reflective of the cost of electricity and future analysis should include comparison to the cost of other energy sources. The costs reported here may not be representative of overall energy costs in any given scenario, as discussed further in Section 2.4.1. Additionally, it should be noted that the uncertainty in all the presented results is 0.1%.

2.3.1 Stage A: Electrification impact

Electrification increases the annual peak demand by almost 50%, though the effects on overall electricity consumption varies by electrification level. An electrification level of 50%, along with building retrofits to make consumption more efficient, was found to decrease consumption by almost 18%, while an electrification level of 100% was found to increase consumption by 15% (Table 2). Buildings were shown to be the more significant source of the changes in consumption, with transportation contributing under 5% of the total for both 50% and 100% EV penetrations.

Table 2: Modelled annual electricity consumption by sector based on electrified share of personal vehicles and residential building heating

	BAU electricity consumption (GWh) / Contribution to total consumption	50% electrified electricity consumption (GWh) / Contribution to total consumption	100% electrified electricity consumption (GWh) / Contribution to total consumption
Transportation	0 / 0%	29 / 2%	58 / 3%
Building	921 / 49%	562 / 37%	1157 / 54%
Other urban loads	947 / 51%	947 / 62%	947 / 44%

The addition of rooftop solar allows Regina to be powered entirely by solar generation for periods in the summer (comparing Figure 7: Current system to Figure 7: Scenario 6A). Further, the deployment of wind allows for renewables to contribute to the generation mix at night (Figure 7: Scenario 10A), which is especially important in the winter electrification contributes significantly to overnight demand.

However, without DR or storage, Regina is unable to meet their target of 100% renewable energy across for the entire energy system. Only 65% of the energy demand is sourced from renewable energy, even when 100% of roofs are covered with solar PV (1,410 MW) and 200 MW of wind is installed, when DR and storage do not contribute to the grid balancing. In this scenario, 60% of the renewable energy is curtailed, which not only impedes reaching the target, but also indicates that the system is being operated inefficiently. Compared with the current system (composed of primarily not electrified loads), electrification of private vehicles and building heating and cooling results in a 7% -33% higher LCOE (Figure 9). Assuming an LCOE of $40/MWh for wind and $126.5/MWh for rooftop solar, the addition of a wind farm tends to decrease the overall LCOE, as seen in the clustering of Scenarios 7A, 8A, 9A, and 10A in Figure 9.

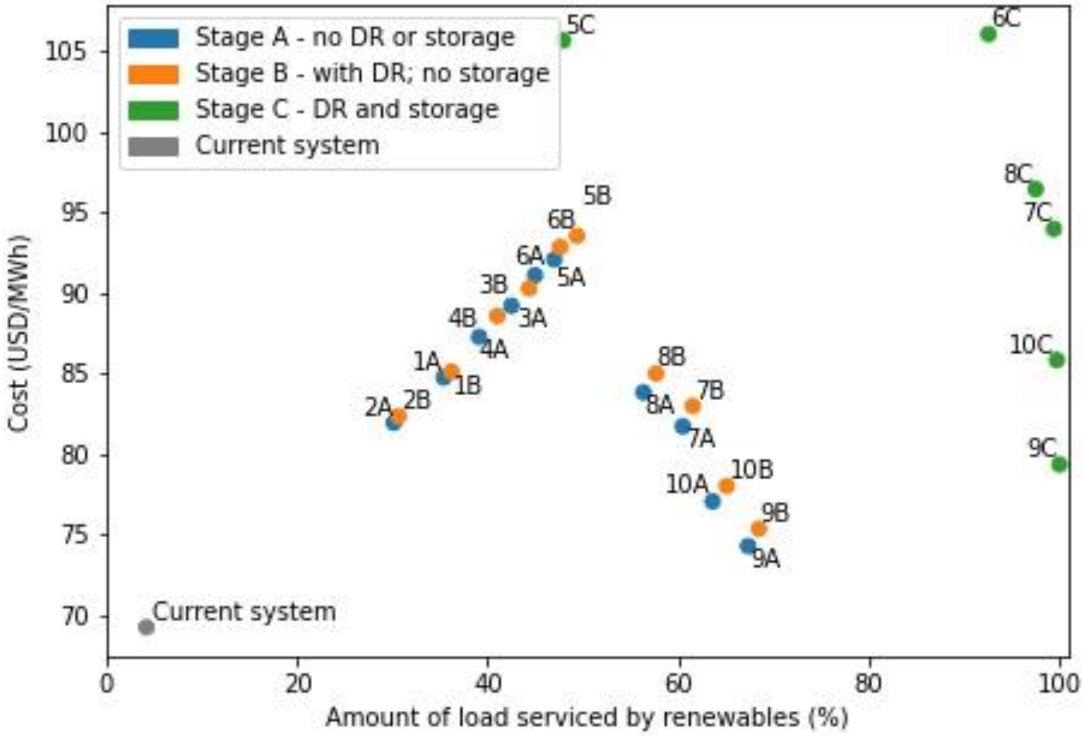

Figure 9: Modelled cost of electricity system per unit energy compared to ability to meet Regina's renewable target with a carbon tax of 170CAD. As previously outlined, odd numbered scenarios have 50% electrification levels; even numbered scenarios have 100% electrification levels; and Scenarios 7 through 10 have additional wind capacity along with rooftop solar.

As expected, curtailment in Stage A scenarios, when DR and storage are excluded from the system mix, is the highest. Curtailment peaks at almost 70% in Scenario 5A (refer to Figure 8) when there is 50% electrification and 100% rooftop solar penetration. In general, since electricity demand is higher in 100% electrification than 50% electrification scenarios, curtailment decreases between 9% and 15%, across all VRE penetrations. Without DR, EV charging demand follows a similar pattern day to day, when holding temperature constant. Lower efficiency in the winter results in longer charging events - because EVs arrive at their destinations with more depleted batteries than in the summer - and therefore a larger peak demand, as shown in Figure 10A. Temperature dependent efficiency was the only seasonal variation accounted for, but different seasonal travel patterns may also affect charging patterns and were not investigated. By disaggregating the EV charging curve by load type, it is seen that charging at work and home charging are responsible for the two peaks observed in EV charging (Figure 10B). However, it was assumed in this work that EV charging could take place at any location (i.e., work, home, shopping areas, etc.)– which would require widespread charging availability throughout the network. Such a scenario would result in infrastructure costs that were not quantified in this work.

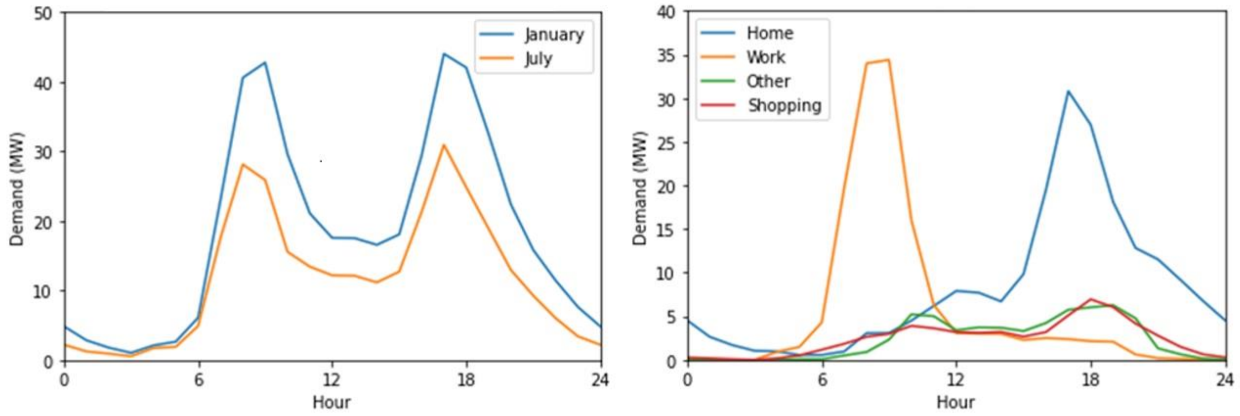

Figure 10: (A) EV charging demand load at 50% EV penetration compared seasonally (left) and (B) winter EV charging demand load for 50% EV penetration disaggregated by trip activity (right)

The building model also uses markedly more energy in the winter than the summer. As seen by comparing Figure 11A and Figure 11B, winter peak loads are almost three times higher than summer peaks, while winter troughs are approximately equal to summer peaks. The magnitude of this seasonal variation underscores that Regina's climate is heavily heating-dominated, and that it is important to choose envelope retrofits that help retain heat and HVAC systems that are optimized for efficient heating.

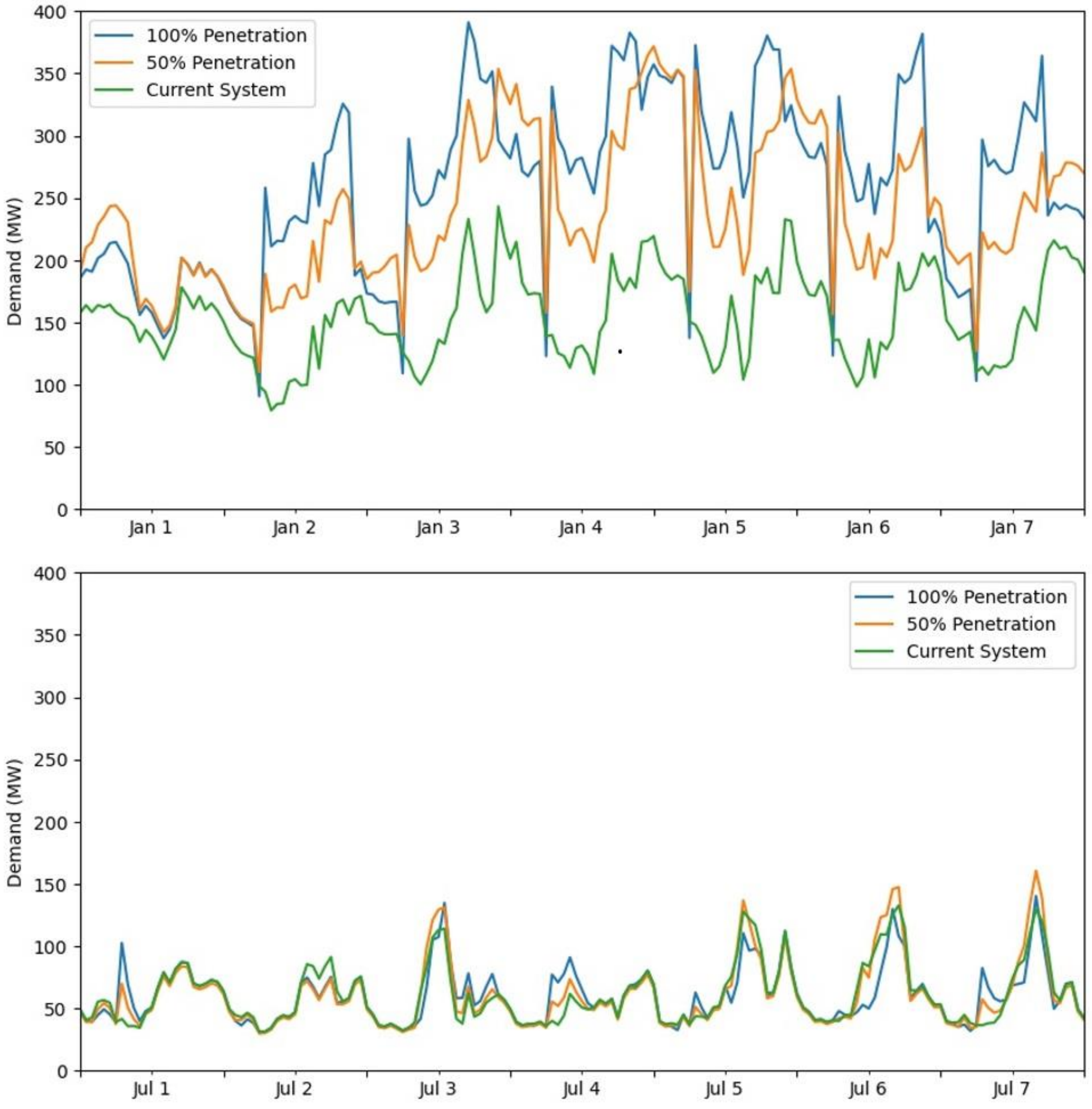

Figure 11: Building demand load in 50% and 100% penetration scenarios in (A) winter (top) and (B) summer (bottom).

Comparison between winter load curves in the 50% penetration scenario and the 100% penetration scenario (Figure 11A) shows that the two display a different temporal shape. In the 50% scenario, some of the electrified homes are powered by less-efficient electric heating systems, which are left over from the current system. This results in the 100% penetration scenario only using 20% more electricity over the course of the year, despite having twice as many homes contributing to the thermal load curve. From that, it can be seen that replacing gas-powered HVAC systems with more efficient systems can have a significant impact in terms of energy savings.

2.3.2 Stage B: DR impact

Implementing DR had a noticeable but small effect on VRE curtailment, which allowed for an increase in the percent of load serviced by renewable energy, as shown in Figure 9. Seen in Figure 8, the DR results in only a 1-3% reduction in curtailment. This is largely due to the dual effect of decreased energy requirements and increased solar generation in the summer overwhelming the ability for DR to meaningfully decrease VRE curtailment. Additionally, the implementation of DR continued to see scenarios with 50% electrification having consistently more curtailment than those with 100% electrification, as seen in Stage B scenarios in Figure 8.

As the LCOE of rooftop solar is higher than non-renewable generation, DR results in a marginal increase of overall LCOE. However, even in the best-case scenario (Scenario 9B with 50% electrification, 100% rooftop solar, and 200MW wind farm), curtailment rate was 60%, impeding the contribution that renewables could make. Though 70% of the load was serviced with renewable energy; this is only marginally better than that achieved without DR (Scenario 9A).

Though it was seen that 50% electrification scenarios are better able to service their electricity demand from renewables (Figure 9), this is mainly due to the overall lower electricity demand when compared to 100% electrification scenarios. It should be noted that 50% electrification scenarios may be representing a different pathway to meeting the renewable target than 100% electrification scenarios, as other renewable energy needed to meet Scope 3 are not accounted for in this modelling work. To meet Regina's Scope 3 target, the 50% electrification scenarios must be implemented in conjunction with additional decarbonization strategies for the remaining energy sources.

Implementing DR on the demand-side transportation model causes EV charging demand to shift towards the beginning of the curtailment period. A visual comparison of EV demand and VRE curtailment shown in Figure 12 shows that no matter how DR is implemented, the amount of curtailment may be so large that fulfilling 100% of EV charging with excess VRE would still result in curtailment. This is shown in Figure 12 for Scenario 3B (50% rooftop solar penetration) in the winter and summer.

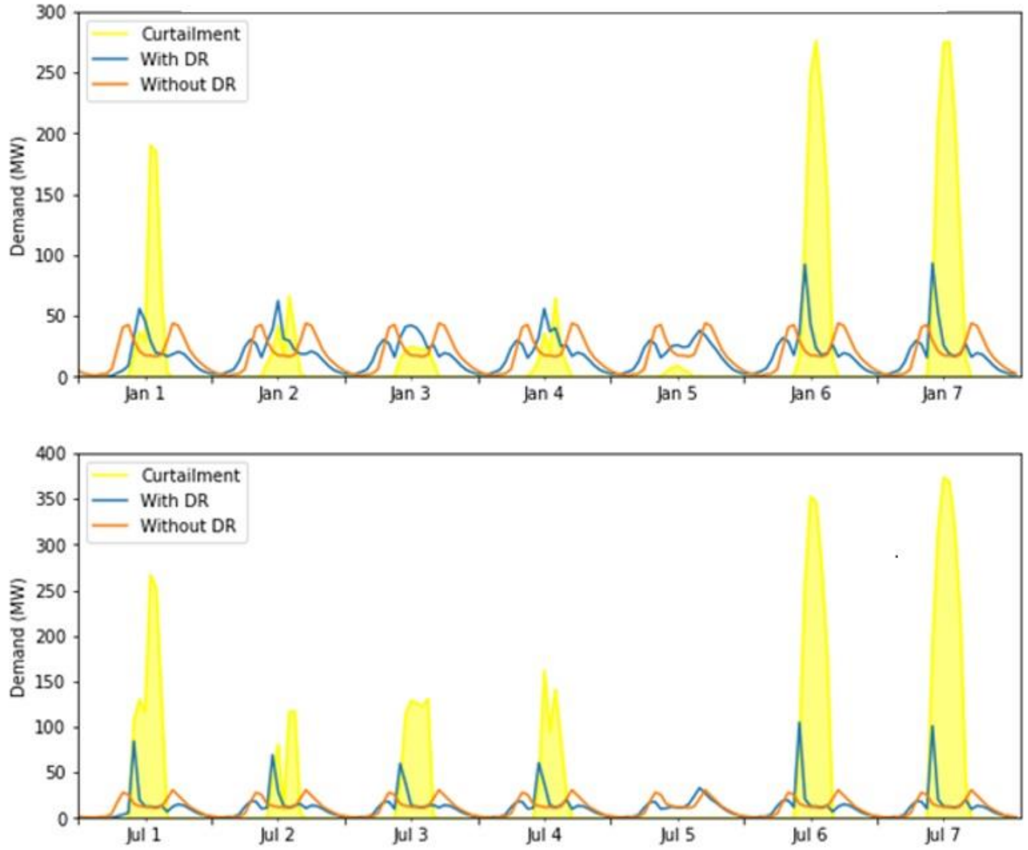

Figure 12: Time-shifting of EV demand load due to curtailment within Scenario 3B in the (A) winter (top) and (B) summer (bottom)

As an EV is simulated to charge to its maximum capacity before every departure, there is charging occurring at times when there is no curtailment. As a result, not all EV charging is fulfilled by VRE generation (Figure 13). Alternative charging strategies, such as those where a vehicle is not charged until it reaches a certain battery level, could potentially be used to further shift EV charging and utilize more excess VRE. As the focus of this work was on electrification, space of EV charging behaviour was not explored. Implementing DR successfully for EVs also requires that the infrastructure for DR exists where vehicles are during curtailment times. This can be seen in Figure 13, which shows EV charging load in Scenario 3B for select days in the winter, disaggregated by activity. Work related charging experiences the greatest increase during curtailment times, suggesting that most vehicles are parked at work when curtailment occurs.

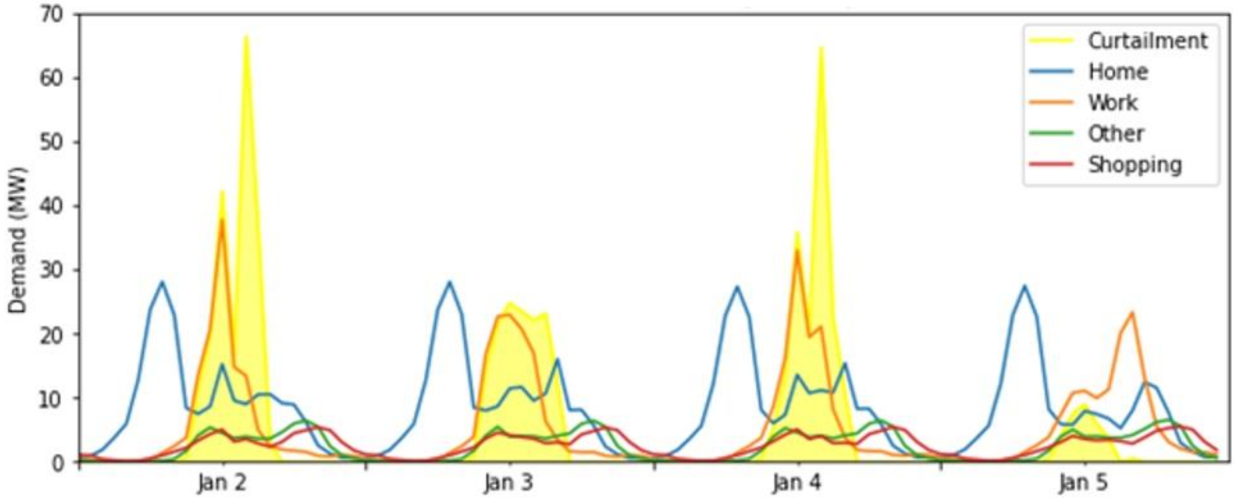

Figure 13: Time-shifting of EV demand load due to curtailment within Scenario 3B disaggregated by trip activity for select dates with low curtailment in the winter

Similarly, the underwhelming effect of DR on building load shifting, as seen by the proximity of the curves in Figure 14, can be explained by the nature of the DR strategies investigated. Even in the winter (Figure 14A) when the thermal load is much higher, additional activities such as lighting, appliance usage, and water heaters contribute to the total electric load of buildings. Effective load-shifting on the building side therefore requires comprehensive DR programs that include as many electricity-consuming activities as possible. It is also worthwhile to investigate the inclusion of industrial and commercial buildings in these programs.

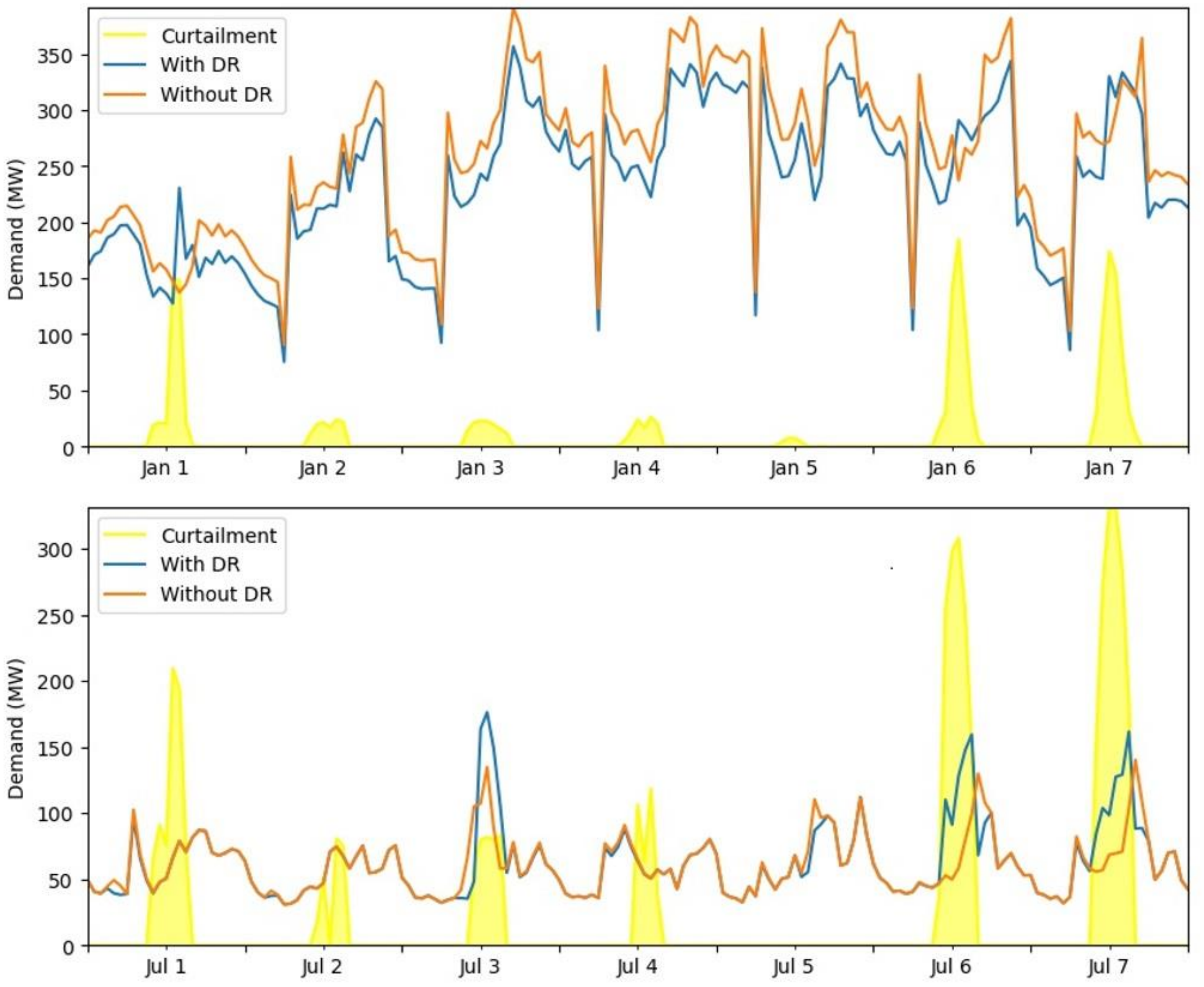

Figure 14: Time-shifting of building demand load due to curtailment within Scenario 3B in the (A) winter (top) and (B) summer (bottom)

2.3.3 Stage C: Storage impact

As seen in Figure 7: Scenario 10C, the introduction of VRE storage changes the generation mix significantly. The ability to store renewable generation leads to a decrease in curtailment in all scenarios (Figure 8). Notably, adding storage to scenarios with 100% rooftop solar penetration but no added wind capacity (i.e., Scenarios 5C and 6C) reduce their curtailment to near zero. Though there is still curtailment within some of these scenarios (ex. Scenario 9C), the level falls within an acceptable range considering the amount of demand being met by renewables.

As seen in Figure 8, adding storage technology to the grid is the most successful strategy in reducing curtailment. Overall, reducing curtailment directly correlates to Regina's ability to meet their target, but there are scenarios that have significant curtailment even when the target has been met (i.e., Scenario 9C). This indicates that there is excess renewable generation within this scenario, meaning increasing storage capacity would not necessarily increase

Regina's ability to meet their target. In this situation, excess VRE generation unable to be stored can be exported to the provincial grid and potentially used as a renewable credit towards the renewable target, which is discussed further in the Section 2.4.

As can be seen comparing Figure 9, the current system will continue to be the least expensive option in terms of LCOE due to the relative low cost of carbon intensive generations, though it is comparable to scenarios that have 100% rooftop solar penetration and a 200MW wind farm (i.e., Scenarios 9C and 10C) are able to meet over 99% of their demand load with renewables. However, there is potential for cost reduction in the method of renewable penetration chosen; rooftop solar had a significantly higher LCOE than utility scale solar or wind, the latter of which can be seen in the cost difference between Scenarios 6C and 10C. Both these options would be viable and realistic ways to decrease the cost of integrating large-scale renewables.

2.4 Discussion

The integrated model platform developed was used to investigate the feasibility of electrifying private vehicles and homes to run on renewable energy from a system operation perspective. With the high spatial and temporal resolution of the operational perspective, the feasibility of future planning decisions can be evaluated, and insights from the operational model can be used to inform planning in the building, transportation, and electricity sectors.

Though it was shown that DR within the transportation and residential buildings sectors only slightly reduces curtailment levels (1-3%), they are comparable to results within other literature. On the transportation side, though it was not quantified, Wolinetz et al. (2018) found that UCC of EVs alone may not be effective for integrating additional VRE into the generation mix. However, the authors only simulated capacity additions to the electricity system that would not result in excess VRE generation, while this analysis assumed fixed VRE capacity. In the building sector, Pedersen et al. (2017) noted that thermal DR strategies could shift roughly 30-47% of peak residential building load in a cold climate. This is consistent with the Stage B results showing 11-60% of peak load was reduced in winter curtailment events.

This analysis found that electrification and renewable energy integration could not meet Regina's target without adding a significant amount of energy storage. 250 MW could fully power Regina with renewable energy in the fully electrified scenario. While this level of storage is technically feasible, the scale is more consistent with utility-scale energy storage projects such as Sir Adam Beck Pump Generating Station (174 MW) (OPG 2021) and Hornsdale Power Reserve (150 MW) (Hornsdale Power Reserve 2021). These projects serve entire provinces, which may raise the question of whether such a large-scale storage system is reasonable for a single city. Nonetheless, (Solomon et al. 2017) found that to integrate large-scale VRE into an electricity system, the optimal storage size is roughly equivalent to the daily average demand. Comparing storage size found within the scenarios to winter daily average demand shows that storage sizing is in line with these results, though it is over-sized in relation to summer demand.

Though not possible with battery storage alone, the fact that there are higher curtailment levels in the summer, paired with higher electrified demand loads in the winter, indicate that long-duration electricity storage may be beneficial in creating more reasonably sized storage systems (Albertus, Manser, and Litzelman 2020; Dowling et al. 2020). However, the logistics of this would prove complicated in regard to Regina specifically; the traditional long-duration electricity storage system is PHS (Albertus, Manser, and Litzelman 2020), though Regina is not located close enough to a major waterway to feasibly utilize PHS. This means that other long-duration electricity storage options would need to be considered (such as power-to-gas-to-power (Dowling et al. 2020)) or constructed where SaskPower grid resources would be needed to reach it. As SaskPower currently does not have any utility-scale storage technology on its grid (SaskPower 2021), this option may not be feasible for Regina in the near future, though should be kept in mind for a time when long-duration storage plants are more accessible.

A possible alternative or complement to energy storage is exporting excess VRE to the provincial grid; this would allow for the City of Regina to act as a net generator at specific times of the day and create a revenue stream through the sale of excess electricity. This could contribute to Regina's target as a "renewable credit" to offset any non-renewable generation utilized. This option may be necessary if Regina's renewable target is at odds with the provincial utility grid's capacity expansion plan, resulting in Regina's generation mix being less carbon-intensive than the provincial mix. Adding capacity at a provincial-scale would be less expensive due to economies of scale but adding them at a city-scale may be required if the province and city have opposing views on renewable generation. Other options such as the use of renewable NG in the building sector and clean fuel standards in the transport sector may play a role in the energy future of Regina (Government of Canada 2017b). The latter is explored in more detail in the Section 2.4.2.

2.4.1 Current limitations

This study has limitations within the results presented, the linkage architecture, as well as in the individual models. Firstly, LCOE results are only indicative of electricity and do not consider the cost benefits of offsetting gasoline and NG use in transportation and building sectors. Excluding these cost benefits has potentially overreported the relative costs of meeting Regina's renewable target.

Currently the integrated model platform is unable to model either the electrified load or the DR capabilities of commercial and industrial sectors. This may have resulted in an under-representation of the effectiveness of DR. However, an area of inconsistency is that rooftop solar was assumed to be installed on commercial and industrial buildings in addition to residential.

Based on how the curtailment values are passed to the building and transportation models, the time-shifting of loads in DR adjustments may, with certain configurations, create new periods of curtailment. Though this did not occur within the scenarios analyzed, it can be addressed in future scenario configurations by changing the types of data passed from the electricity system model to the transportation and building models.

Finally, a limitation to the scenarios considered was that that they do not aim to capture the long-term planning and evolution of any of the systems modelled. Instead, the scenarios aimed to capture a snapshot of the system as it could optimally operate. This means that the degradation and replacement of equipment (EV batteries, HVAC equipment, etc.) was not considered within any costs or associated emissions.

A limitation of the transportation model is that it does not include a traffic assignment step. This may have affected the accuracy of travel and activity scheduling, resulting in different EV charging patterns. Similarly, the assumption that travel patterns of EV drivers are the same as non-EV drivers may limit accuracy of results. Further exploration of different charging strategies, including not charging at every activity, could improve the potential for UCC to improve the use of VRE in EV charging.

As previously discussed, the archetype-based approach to constructing the building model under-represents the diversity actually seen in the building stock, which may lead to the model predicting higher peaks, lower troughs, and more fluctuations in the building load than would be observed in real life.

The electricity system model is assumed to import electricity from the provincial grid when it is unable to meet demand from local generation assets, but the hourly generation mix of the provincial grid may change if Regina is able to supply a significant amount of their peak demand. A linkage between a provincial electricity system model and a city-scale electricity system model would allow for these changes to be explored in more detail.

2.4.2 Suggested further research

This study developed a baseline for evaluating Regina’s ability to meet their Scope 3 renewable target through various pathways, but there is still potential for future research. Some suggestions can be seen below:

- As previously mentioned, the exploration of meeting the Scope 3 renewable target through renewable energy sources other than electrification can be done in conjunction with the 50% electrification scenarios evaluated. This may include increased demand side management strategies to reduce overall energy usage, as well as the introduction of renewable fuels into the transportation and building sectors.
- Further analyzing the ability of Regina to meet the Scope 3 renewable target may involve electrifying commercial and industrial buildings, as well as electrification of commercial transportation.

- As mentioned, the system was analyzed as it currently exists. Connecting this work to a capacity expansion model would give the justification to explore scenarios that have drastically different system configurations to meet energy targets.
- Finally, on the economic side, there are several avenues to be explored pertaining to rooftop solar panels or wind farm ownership. This may include, but not be limited to, city ownership; resident ownership (referring to rooftop solar panels) with or without net metering; or a combination of the two.

2.5 Conclusions

Several conclusions can be drawn from this exploration of the feasibility of Regina's energy target, ranging from immediately actionable results, to results that indicate further research is needed to fully understand what the impacts will be on the electricity system. The impacts of this study have a wide-range of applications within Regina, as well as the potential to be leveraged by other cities with similar VRE resources and/or are currently drawing electricity from a high-emitting grid.

It is feasible for Regina to meet Scope 3 of their renewable energy target, by considering electrification of private vehicles and households and integrating VRE.

Results from the integrated model platform show that Scope 3 of Regina's renewable energy target can be achieved through large-scale implementation of VRE capacity and storage technology. By adding 100% rooftop solar on residential, commercial, and industrial rooftops (equal to 1,410 MW of solar capacity), 100 MW of wind capacity, and 250 MW of storage, 95% of Regina's electricity demand could be met with renewable energy, even with 100% electrification of private vehicles and thermal residential building load.

Meeting the renewable target will slightly increase LCOE, but this does not capture savings from fuel switching.

Though some scenarios have comparable costs to the current system, there would still be an overall increase (15-50% cost increase across Stage C results) in the net cost of operating the electricity system. That given, scenarios with higher VRE and storage implementation had lower costs than those with lower VRE integration, indicating that it is more economical to commit to large-scale penetration strategies. Additionally, there is significant potential for further reduction in costs of scenarios that can meet Regina's renewable target through switching from rooftop solar to utility-scale solar, as well as increasing the wind capacity.

The addition of storage capacity was necessary when utilizing utility-controlled DR to reduce curtailment.

In lower VRE penetration scenarios, DR can help reduce curtailment to acceptable amounts, though this is due to the lower initial curtailment values (27% to 24% in Scenario 4). In higher

VRE penetration scenarios, DR does not meaningfully reduce curtailment, making energy storage necessary to reduce curtailment and meet Regina's target. As the current demand trends exist within the building and transportation sectors, it is unlikely that the implementation of DR strategies alone would allow Regina to meet their target.

Implementing DR for EVs hinges on adequate charging infrastructure at work locations.

Particularly in scenarios with a significant amount of solar energy, charging at work is found to experience the greatest shift when DR is implemented. This indicates that many vehicles in Regina are parked at work when solar curtailment occurs. DR with large amounts of wind energy, which is less predictable, could potentially be implemented through charging infrastructure at home.

For buildings, utility-controlled thermal load shifting does not have a large impact on overall curtailment reduction.

Building thermal DR is found to be largely ineffective in the summer due to the low cooling load of Regina. In the winter, although clear differences can be seen before and after the implementation of DR, these changes are small compared to the total building load. This indicates a need for more comprehensive DR strategies that include additional loads such as water heating, appliances, or lighting.

3 Residential demand response program modelling to compliment grid composition and changes in energy efficiency

3.1 Introduction

A significant headline from the *Canada's Changing Climate Report* (2021) is that Canada is warming two times faster than the global average. As human-driven climate change continues to increase the temperature, the effects will be felt through an increase of extreme weather events, higher risk of water shortages, and coastal flooding, to name a few (Warren & Lulham, 2021). As is made apparent in the report, Canada can not procrastinate decarbonization efforts.

Following the Paris Agreement in 2015, the *Pan-Canadian Framework* (2016) was released, which outlined how Canada would meet its 2030 goal of 30% greenhouse gras (GHG) emissions reduction from 2005 levels. However, this plan was incomplete as the last 77 Mt of GHG emission reduction was unaccounted for (Environment and Climate Change Canada, 2021b). This, along with the fact that Canadian emissions were continuing to rise even after the release of the Pan-Canadian Framework (Callison & Tindall, 2017), indicated the need for a redesigned policy. In an updated climate plan, *A Healthy Environment and a Healthy Economy* (2021a), Canada committed to exceeding the original 2030 GHG emissions reduction target by 8 Mt (Environment and Climate Change Canada, 2021b). Two of the proposed strategies to accomplish this are to decarbonize the electricity system, and to improve building energy efficiency (Environment and Climate Change Canada, 2021b).

Ambitious decarbonization policies require a shift away from carbon intensive on- or off-site fuels (Dennis, 2015). Electrification refers to the transition from traditional fossil fuel sources to electricity for end use applications. In Canada, like many countries with relatively decarbonized power systems (Canada Energy Regulator, 2020), the path forward is heavily reliant on electrification (Stewart et al., 2018).

The building sector is responsible for 18% of Canada's total emissions and typically heavily reliant on on-site fuels, which makes it a prime sector that would benefit from electrification (Natural Resources Canada, 2022c). Electrification in the building sector would require technologies that use on-site fuels, such as natural gas (NG) powered space heaters and water heaters, to be converted to electric technologies. Depending on the climate and physical characteristics of the building, this could be ground source heat pumps, air source heat pumps, or electric baseboard heating.

There is debate about the extent of the effects that large-scale electrification will have on demand. The electrification of building heating in California was found by Tarroja et al. (2018) to increase electricity demand by just over 30%, with a key issue being the mismatch of electricity demand and variable renewable energy (VRE) supply. A review of electrification projections in the US and UK found that many projections showed “very significant” increases in generation capacity are needed to accommodate a transition to heat pumps, with one study notably projecting that demand would nearly double. However, it was found in the same review that there are significant opportunities to use electrification to smooth the demand curve, even while the overall annual demand increases. This was reiterated by Stewart et al. (2018) that even though electrification will likely lead to significant increase in electricity demand, there are opportunities to “soften” this increase through various strategies, such as increasing energy efficiency and implementing demand side management techniques. These findings are complimented by the results from Seatle et al. (2021) where electrification of the residential building and transportation sectors (with building retrofits to improve energy efficiency) had a 15% increase in electricity demand. These findings indicate that electrification may be a feasible method to consider for decarbonization.

Additionally, electrification offer opportunities to increase grid flexibility. Historically, electricity supply responds to demand, since conventional electricity generation sources have been fuel driven and flexible. In electricity systems with high levels of VRE generation, this control of the electricity supply is not possible, since it is subject to the availability of the demand side resource. Demand response (DR) is a demand side management technique in which electricity customers change their consumption patterns in response to an external stimulus (McPherson & Stoll, 2020). It has been shown that DR programs are able to increase the amount of VRE generation that a grid can accommodate due to strategic changes of demand peaks (Aghaei & Alizadeh, 2013; O’Connell et al., 2014). Examples of DR programs include: exposing customers to varying electricity price, such as through tiered, time-of-use pricing; incentive programs, where customers are paid to reduce consumption at key times; or “smart” technologies, that are able to communicate with the utility companies to have some control over consumption patterns (Mathiesen et al., 2015; McPherson & Stoll, 2020).

DR programs have been shown to aid power system operations by reducing peak load, postponing transmission upgrades, and facilitating VRE integration. Reducing peak load and smoothing demand has been shown to not only allow for greater renewable integration, but can also reduce overall strain on the electricity system (Strbac, 2008). In a review of several DR studies, Bergaentzlé et al. (2014) found that various DR pricing policies can result in up to a 50% decrease in peak load. Further, these effects have shown to be not only economically beneficial, but environmentally beneficial as well; typically carbon-intensive electricity generators are turned on to meet peak load, meaning that the reduction in peak load values disproportionally reduce overall electricity grid GHG emissions (Bergaentzlé et al., 2014). In some cases, DR programs are able to reduce peak load to the extent that grid capacity expansion was postponed (Aghaei & Alizadeh, 2013). Another strategy for DR deployment is to use it to increase VRE penetration, as it allows for more reliable utilization of variable power supplies (Jordehi, 2019). In a study based on power systems of the Pacific Northwest, USA, it was found that shifting 10% of the demand load through DR programs led to an 11% decrease in wind curtailment (Bitaraf & Rahman, 2018). Similarly, Seatle et al. (2021) found that DR was able to be utilized to decrease both solar and wind curtailment by 3% in a high-solar scenario, and likely even more in a balanced-VRE scenario. These finding indicate that DR is an effective strategy at aiding grid operations, especially when used in conjunction with electrification.

Despite it being widely seen in literature that DR programs are beneficial to the grid, there are only three DR programs offered in Canada (Table 3). These programs are all quite similar: they target large consumers and are operated at a provincial level, require voluntary and/or involuntary electricity demand reduction at specific times dictated by the program administrator. Ontario allows participation from smaller consumers in the capacity auction, although the most successful participants are typically large and medium-sized consumers (IESO, 2022).

Table 3: Current DR programs in Canada (McPherson, 2021)

Location	Program name	Administrator	Availability	DR parameters	Compensation
Ontario	Capacity auction	IESO	Available to everyone	Varies	$60/MW-day (winter); $265/MW-day (summer)
Quebec	Demand response	Hydro Quebec	Available to consumers who can reduce load by 200 kW	3-4 hours, up to 100 hours/year	$46-66/kW of effective interruptible power
Saskatchewan	Demand response	SaskPower	Available to consumers who can reduce load by 5 MW	4 hours, up to 15 times/year	$20,000/MW-year + $150/MWh reduced; or $70,000/MW-year

Though DR programs exist in Canada, they are not accessible to all consumers. Residential buildings represent almost a third of national electricity demand (Canada Energy Regulator, 2021b), which is expected to increase with building electrification. The building sector, and specifically the residential portion of it, is an underutilized resource in meeting Canada's emission reduction targets.

Canada has called for "evidence-based decisions" to be made in the fight against climate change (Warren & Lulham, 2021); however, there is no "one-size fits all" solution. As Canada's electricity system is controlled at a provincial level, there are a wide variety of electricity grid configurations across the country (Canada Energy Regulator, 2021a). Additionally, as building continue to become more energy efficient, the amount of flexible electricity may change.

Several existing studies on residential DR programs have largely been focused on the implications of DR programs for the program participant through utilizing detailed building models. Basnet et al. (2019) predict the likelihood of a residential household to participate in DR programs based on socioeconomic factors and the predicted incentives, while specific benefits to grid operations are not discussed. Pallonetto et al. (2020) conduct a review on residential DR modelling and implementation, though there is more focus on smart control technologies of the DR implementation than on grid performance optimization. Muratori et al. (2014) focuses more on grid-related utilization by using residential DR program modelling to assess how it can aid in "market-related problems of electricity grids", though the specifics of the electricity grid composition are not discussed. On the other hand, Yan et al. (2018) evaluate the effect of various residential DR programs on grid operations, thought here is no discussion on the effect of grid composition plays a role in program effectiveness. McPherson & Stoll (2020) found that larger-scale studies of DR programs tend to oversimplify the program by representing DR as purely a peak load reduction, or by focusing on solely power constraints (as opposed to temporal ones as well); this in turn does not truly represent how real-world DR programs operate.

This study aims to determine how residential building DR programs impact grid operations on different archetypical electricity grids. Additionally, various demand profiles are constructed to mimic changes in building stock efficiencies. Energy modelling will be used to provide evidence for how residential building DR programs are able to contribute to Canada's decarbonization efforts.

The rest of the paper is organized as follows. Section 2 establishes the methodology, including the formulation used to represent real-world residential DR programs and the configuration of the theoretical grids and demand profiles used within the model. Section 3 presents the results and determines the drivers that suggest successful DR program utilization. The conditions for success include reduction in cost, reduction in GHG emissions, and utilization of DR capacity. Finally, Section 4 compares these results to real-world electricity grid structures and the feasibility of introducing residential DR programs is discussed.

3.2 Methodology

This section outlines the formulation of DR within an energy system model, the proposed scenario matrix, and the input data, including the grid configuration, building stock efficiency, demand profiles, and DR potential.

The energy system model used to determine the effects of residential building DR programs on the grid is the SILVER model developed by McPherson and Karney (2017). SILVER is written in Python, open-source, and developed specifically for the Canadian electricity system and has been previous benchmarked against PLEXOS using the RTS-GMLC case study (Saffari & McPherson, 2022). It should be noted that the benchmarked scenario uses a relative uncertainty of 0.1% for the optimization solution gap, whereas a relative uncertainty of 1% is used in this study. This is done for computational feasibility, as the introduction of demand response into the SILVER model significantly increases computational demand of the optimization problem. Relevant previous applications of the SILVER model include modelling the province of Ontario (McPherson & Karney, 2017), determining the feasibility of the City of

Regina meeting their renewable target (Seatle et al., 2021), and investigating renewable pathways for Canada (Miri et al., 2022; Thomas & Green, 2022).

Modelling residential building DR programs can be done at many scales, though individual buildings must be aggregated when larger scales are modelled to maintain computational tractability. Balancing the detail gained from a smaller scale with broader grid-scale impacts, the city-scale is the scale chosen to model residential building DR programs. An overview of key inputs into SILVER for this analysis can be seen in Figure 15.

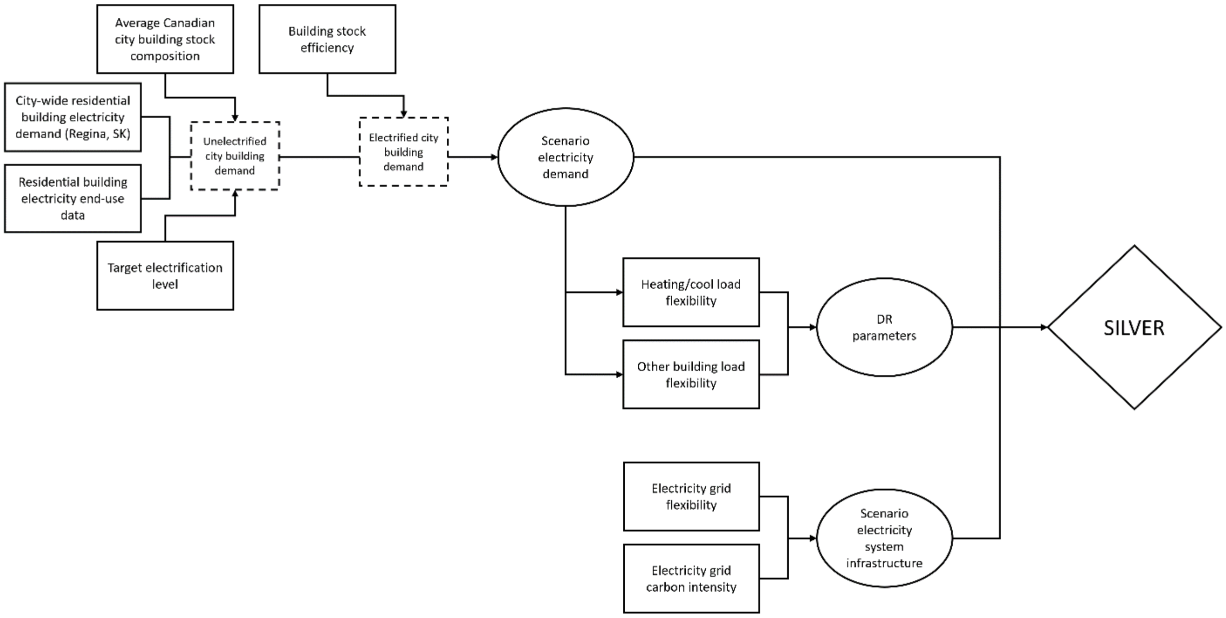

Figure 15: Overview of key inputs into SILVER. Raw data is in rectangles, intermediate data is in dashed rectangles, and inputs into SILVER are in ovals.

3.2.1 SILVER formulation

Within SILVER, DR is conceptualized as a virtual generator-storage object. This allows for "generation" to occur when a DR program is reducing electricity demand and "storage" to occur when the DR program is recovering the shifted energy (McPherson & Stoll, 2020). DR generators are parameterized with typical generator constraints (ramping limitations, minimum down time, etc.), but are further constrained by limits that are specific to DR programs. One benefits of this formulation is that it is able to include temporal constraints on DR programs, including subdaily recovery constraints. Additionally, DR potential is able to be utilized at the times it is most beneficial to the system, as opposed to limiting DR utilization to peak load reduction. This DR formulation is representative of a real-world DR program contract and has been previously used to model the DR potential for Bangalore, India.

Five constraints are adapted from McPherson and Stoll (2020) and can be formulated as such:

1. Dispatch power limitation: maximum demand that can be reduced from input demand profile at each timestep

$$P_{g_e,t} \leq P_e \tag{1}$$

$P_{ge,t}$: power generation for end use e at timestep t

P_e : power available for end use e (timeseries)

2. Recovery power limitation: maximum rate that power can be recovered/stored at each timestep

$$P_{P_e,t} < max_{h\in y}[P_e] - P_e \tag{2}$$

$P_{Pe,t}$: pumping load for end use e at timestep t

P_e : power available for end use e (timeseries)

3. Subdaily energy limitation: maximum time a DR event can occur for

$$\sum_{t\,\in\,I} G_e \leq P_{e,a} \cdot T_e \tag{3}$$

G_e : available generation (energy) of end use e

I : recovery interval

$P_{e,a}$: average power availability for the given hour of the day and season

T_e : maximum up time of end use e per call

4. Daily energy limitation: maximum number of daily DR events

$$\sum_{t\,\in\,D} G_e \leq P_{e,m} \cdot T_e \cdot S_e \tag{4}$$

G_e : available generation (energy) of end use e

D : each day (24 hours)

$P_{e,m}$: maximum average power availability for the given end use in each month

T_e : maximum up time of end use e per call

S_e : maximum number of starts per day

5. Recovery schedule: maximum time before recovery from DR event must occur

$$V_h = V_i \tag{5}$$

V_h : energy in DR storage unit in hour h (where $h \in DR_j$)

DR_j : *DR recovery schedule (equal to start time of the DR event plus the sum of the maximum up time and the maximum time before recovery must occur)*

V_i : *initial energy in DR storage unit*

Further detail on these constraints is described in McPherson and Stoll (2020, pp. 3–5).

Additionally, to give the user more control of how the DR program is implemented, the daily energy limitation is modified into a sixth constraint:

6. Monthly energy limitation: maximum number of monthly DR events.

$$\sum_{t\,\in\,M} T_{gen} \leq\ T_{max} \cdot S_M \qquad (6)$$

T_{gen}: *time the DR generator is generating*

M: *each month (30 days)*

T_{max}: *maximum duration of DR event*

S_M: *maximum number of starts per month*

These six constraints allow the user to customize the modelled DR availability through a series of user inputs: generation cost, recovery cost, maximum duration of DR event, maximum time before recovery must occur, maximum starts per day, and maximum starts per month. Additionally, dispatch and recovery power can be inputted hourly, subdaily, daily, monthly, or seasonally. Smaller timesteps allows for finely-tuned DR modelling, but larger timesteps allow for DR programs to be studied when hourly data is costly and/or difficult to collect.

3.2.2 Scenario matrix

The DR formulation can be used to validate the effectiveness of residential building DR, as well as to determine how the value DR programs will be impacted by grid configurations, building efficiency, and policy packages. As various electricity grids have vastly different characteristics, including differences in flexibility and carbon intensity, scenarios are run on four different grid configurations (discussed further in Section 2.2.1). The level of flexibility is expected to heavily influence the utilization of DR programs, while the carbon intensity is expected to heavily influence the immediate benefits of DR programs.

Determining the value of DR programs is done in two parts: first, the effectiveness of DR on different electricity grids is compared to scenarios without DR programs (Table 4); second, the impact of building efficiency on DR effectiveness is investigated (Table 5) (discussed further in Section 2.2.2). For the *No DR* and *DR baseline* scenarios to be comparable, the efficiencies of these scenarios were kept equal.

Table 4: Scenario matrix investigating DR effectiveness

	No DR	DR baseline
Grid 1	NO_1	BASE_1
Grid 2	NO_2	BASE_2
Grid 3	NO_3	BASE_3
Grid 4	NO_4	BASE_4

Table 5: Scenario matrix investigating effect of building efficiency

	Less efficient buildings	DR baseline	More efficient buildings
Grid 1	LESS_1	BASE_1	MORE_1
Grid 2	LESS_2	BASE_2	MORE_2
Grid 3	LESS_3	BASE_3	MORE_3
Grid 4	LESS_4	BASE_4	MORE_4

3.2.2.1 Grid configurations

The grids considered in the scenario matrix are categorized as either high or low flexibility, and either high or low carbon intensity (Table 6). These broad categorizations of the electricity grid allow for an insight into how different electricity grids across Canada may benefit from a DR program. The four grid configurations chosen are based on the actual grid configurations in Canada's provinces (Canada Energy Regulator, 2021a).

Table 6: Grid configuration summary

Name	Flexibility	Carbon intensity	Real-world example
Grid 1	High	Low	BC 2030
Grid 2		High	SK 2030
Grid 3	Low	Low	SK 2050
Grid 4		High	AB 2020

As seen in Figure 16, Grid 1 is composed mainly of hydro generators, making it flexible and low-emitting. Grid 2 has some hydro, but is mostly composed of NG generators, making it flexible, but more carbon-intensive compared to Grid 1. Grids 3 and 4 are less flexible, being composed largely of VRE (Grid 3) or composed of coal generators (Grid 4).

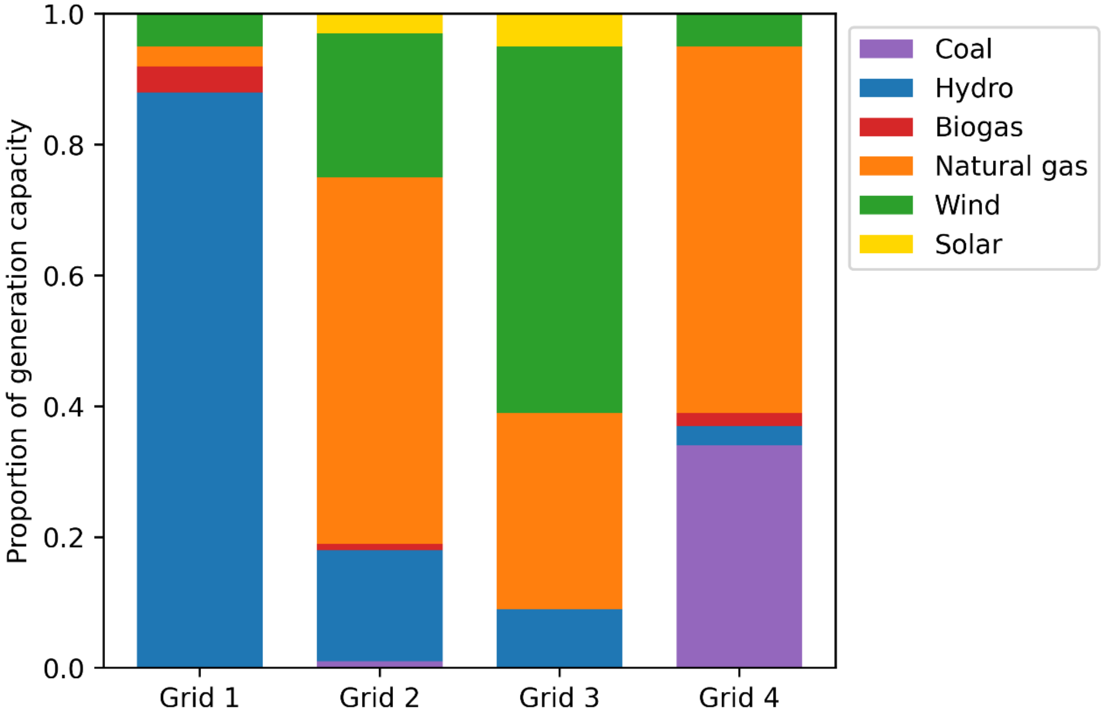

Figure 16: Comparison of grid composition

3.2.2.2 Building demand

As technology advances, building envelope improvements (Natural Resources Canada, 2022b) and technological developments (Natural Resources Canada, 2020; Pomeroy, 2022), are expected to improve the overall building stock efficiency. For the *DR baseline* scenario, the building stock was assumed to be 40% more efficient than today's levels (Martin, 2022; United States Department of Energy, 2022). The inefficient building stock was assumed to be only 10% more efficient than today's levels (City of Regina, 2022), while the efficient building stock was assumed to be 70% more efficient than today's levels (Martin, 2022).

Demand profiles are constructed using historical data and simulated building electricity end-use. City-wide residential building hourly electricity demand is taken from Regina, SK, a mid-sized city in Canada. To disaggregate the residential building demand by end-use, scaling factors from a dataset of aggregated model runs is used (National Renewable Energy Laboratory, 2021). The building profiles are taken from ASHRAE zone 6A to ensue compatibility with the majority of Canadian cities (Government of British Columbia, 2014). The building stock composition by building type is scaled to match that of a generic Canadian city (Statistics Canada, 2022).

The overall demand varies by the building stock efficiency, which is assumed to apply uniformly over every hour of the year. The heating portion of the electricity demand is scaled based on the portion of building stock heated by electricity (Natural Resources Canada, 2019b, tbl. 5; U.S.

Energy Information Administration, 2020, tbl. EIA-457A). A target electrification level of 75% for residential building heating is consistent across all scenarios to match the target set by the City of Regina (City of Regina & Sustainability Solutions Group, 2022). It is assumed that this electrification will occur through a transition to heat pumps in order to remain consistent with DR availability estimates (discussed further in Section 2.2.3) (Chassin et al., 2015; Pallonetto et al., 2020). A sample of the disaggregated demand profile can be seen in Figure 17.

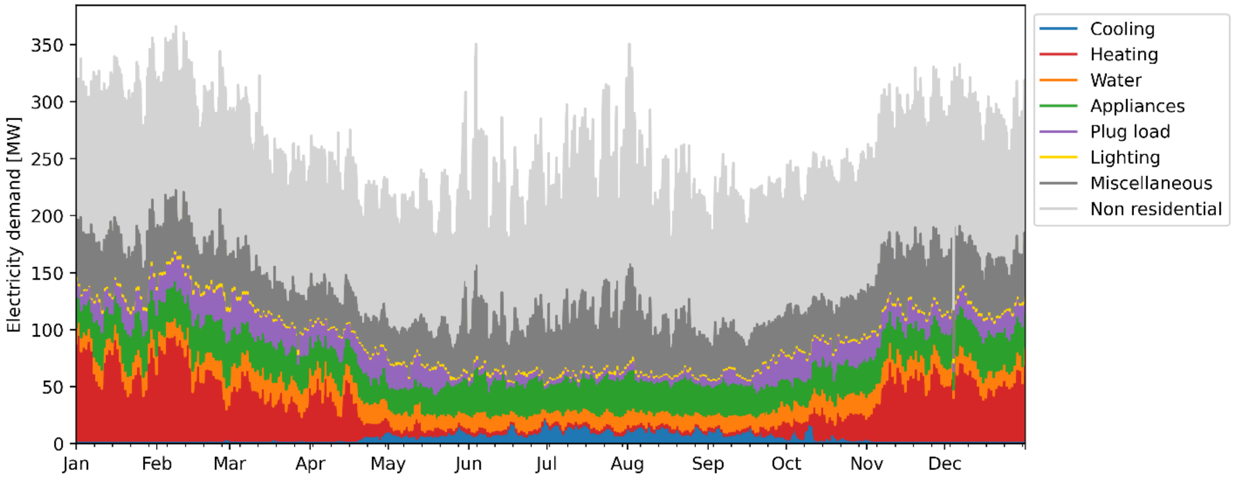

Figure 17: Electricity demand by end-use for DR baseline scenario

3.2.2.3 Demand response formulation

DR potential is calculated on and hourly basis from values found in the literature. Potential shiftable load represents the maximum dispatchable power that is available in the DR program. As per Pallonetto et al. (2020), it is assumed that 18% of the heating and/or cooling load of a residential building can be shifted during a DR event. Additionally, 48% of other residential building loads are assumed to be able to be shifted during an event (Pallonetto et al., 2020). The average hourly DR potential from this calculation can be seen in Table 7. As the net amount of electricity used should not change, the recovery power is equal to total dispatch power over the period of the DR event.

Across different building stock efficiencies, the proportion of the total electricity demand available for DR shifting remains relatively constant, even though the average hourly DR potential decreases as the buildings become more efficient.

Table 7: Calculated electricity demand available for DR programs city-wide by scenario

Scenario	Average hourly DR potential (MW)	Average portion of electricity demand (%)
Less efficient buildings	48.16	19.578
DR baseline	44.43	19.665
More efficient buildings	40.70	19.765

There is significant variation in DR programs, and thus the parameterization of the DR program modelled must be assumed. The selected parameterization balances benefits to grid operations with convenience for program participants. These parameters include:

- A maximum duration of four hours per DR event,
- Energy must be recovered within two hours after the end of the DR event,
- One DR event is allowed per day, and
- Each DR event can occur every day in a month (i.e. 30 DR events per month).

Note that in some cases it may be seen that if a DR event occurs for less than the maximum duration, additional DR events may occur that day until the maximum DR event duration is reached. Within SILVER, DR programs are aggregated to the building stock level for computation feasibility, meaning that the building stock as a whole may have multiple DR events happening, though no more than the daily limit would ever occur at any one building.

3.3 Results

Anticipating the benefits of DR programs prior to implementation is valuable for both grid operators and programs participants, as well as to motivate DR programming. These benefits are found to vary significantly based on key characteristics of both the grid they are implemented on, as well as the efficiency of the building stock. This section will outline the impact of DR programs based on these factors in Section 3.3.1 and Section 3.3.2, respectively. It should be noted that all presented results have a relative uncertainty of 1%, as previously discussed in Section 3.2.

3.3.1 Effect of grid composition on DR utilization

The timing and magnitude of DR utilization is driven primarily by the grid composition. The changes to the demand curves resulting from building DR implementation is shown in Figure 18. In all cases, DR is dispatched to minimize system costs. How DR accomplishes that though depends on the flexibility of the grid in question.

In a highly flexible and low-emitting grid (i.e., Grid 1), building DR programs are used to reduce demand at non-peak times. This resulted in a spike in demand just before demand began to rise, but this spike was located at marginally cost-optimal times (i.e., times with small amounts of VRE utilization). In contrast, in an inflexible and carbon-intensive grid (i.e., Grid 4) the DR programs shift demand away from peak times, reducing the need for expensive and carbon-intensive peaking generation.

In addition to flexibility, DR program utilization is impacted by the amount of VRE generation. This can be seen in both the flexible and carbon-intensive and the inflexible and low-emitting grids (i.e., Grid 2 and Grid 3, respectively). In high VRE grids, building DR programs maximize

VRE utilization, resulting in a more erratic demand profile that minimizes system costs (due to the low operational costs of VRE generation).

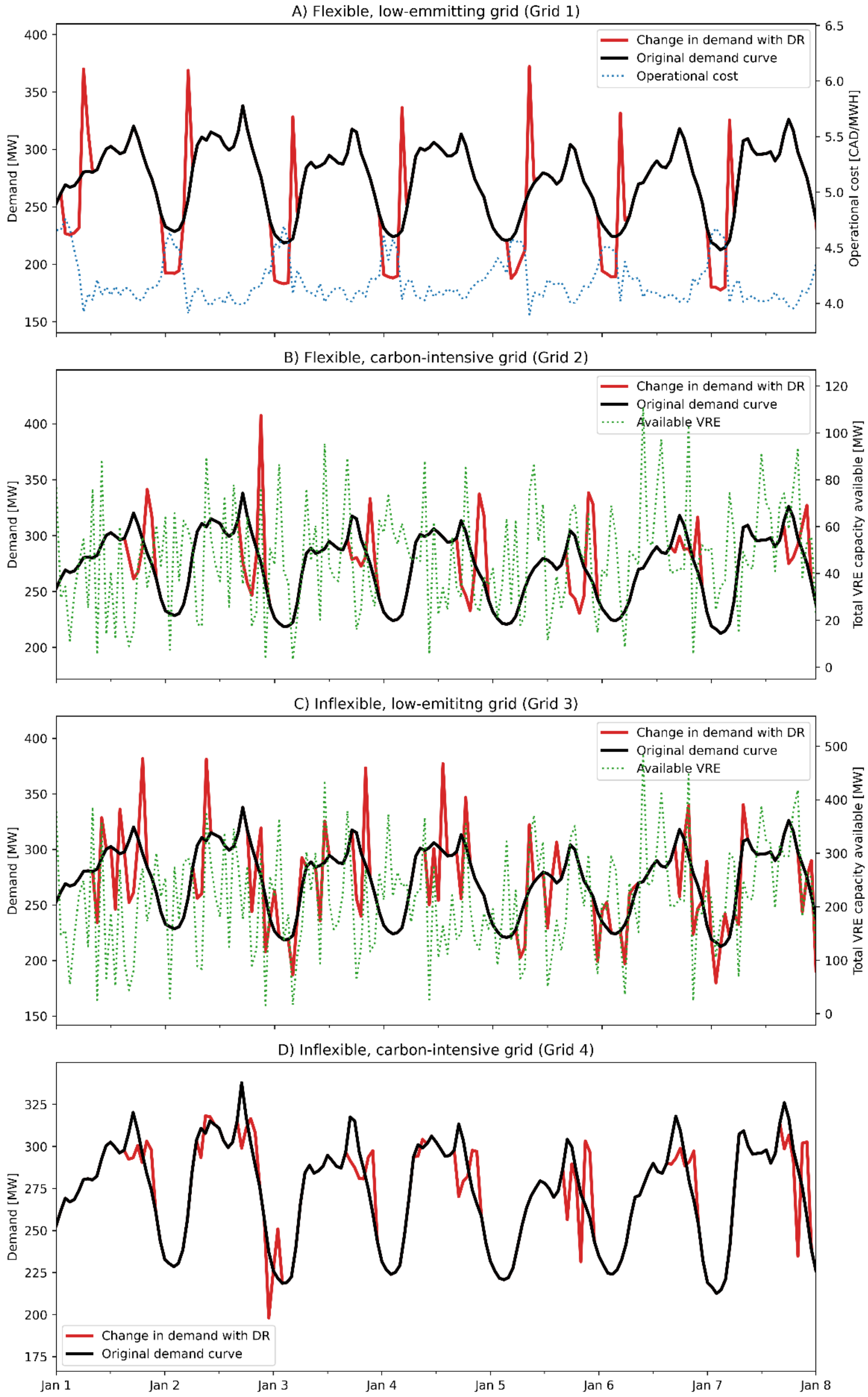

Figure 18: Change to demand profiles due to DR in DR baseline scenario

This DR utilization can be further characterized by how much curtailment is able to be reduced with DR programs (Table 8). The total amount of curtailment reduction compared to the average curtailment reduction when curtailment is occurring can indicate how frequently DR is able to be utilized in curtailment reduction; a lower average curtailment reduction than total curtailment reduction may speak to an opportunity to further reduce curtailment by relaxing the constraints on the DR program (i.e., longer up time for DR event, shorter downtime for DR event, higher frequency of DR events, etc.). The total DR utilization for curtailment reduction is the total amount of DR potential used, while the average DR utilization indicates how much DR potential is used when a DR event is occurring; a high average DR utilization with a low total curtailment reduction may indicate that increasing total DR potential can further reduce curtailment.

Table 8: Analysis of curtailment as a driver of DR utilization on high VRE grids

	Grid 2	Grid 3
Total curtailment reduction	20.8%	4.6%
Average curtailment reduction when curtailment occurring	15.5%	1.0%
Total DR utilization for curtailment reduction	13.0%	14.6%
Average DR utilization for curtailment reduction when DR occurring	76.9%	86.3%

Generation infrastructure utilization remained somewhat consistent with and without DR programs, though an increase of VRE utilization was seen on grids that had significant VRE generation present: flexible, carbon-intensive (i.e., Grid 2), and inflexible, low-emitting grids (i.e., Grid 3). Generation expansion was not delayed due to the DR program. However, this may be able to be investigated further in future work using a capacity expansion model as done in Miri et al. (2022).

3.3.2 Effect of building stock efficiency on DR utilization

Though the available DR in dispatched in all scenarios, the flexible and low emitting grid (Grid 1) dispatched DR to the greatest extent, followed by the inflexible and low-emitting grid (Grid 3), the flexible and carbon-intensive grid (Grid 2), and finally the inflexible and carbon-intensive grid (Grid 4). These values can be seen in Table 9.

The average DR usage on flexible grids, and inflexible and low-emitting grid (Grids 1-3) is very comparable across different building stock efficiencies. However, inflexible and carbon-intensive grids (Grid 4) with an inefficient building stock have a higher DR utilization compared to when it has an efficient building stock. As the inflexible, carbon-intensive grid is the only grid that has coal, an expensive form of generation, the DR program is primarily used to reduce coal usage on this grid. Since peak demand is significantly reduced as the building stock becomes more efficient, the utilization of the DR program decreases as the efficiency increases. Note that DR utilization is not directly correlated with benefits of DR programs.

Table 9: Average proportion of available DR utilized during event

	Grid 1	Grid 2	Grid 3	Grid 4
Less efficient buildings	0.954	0.735	0.830	0.920
DR baseline	0.968	0.769	0.863	0.727
More efficient buildings	0.938	0.753	0.829	0.511

Across all scenarios, DR decreased the grid's operational costs by as little as 0.5% (Grid 1) and as much as 5.1% (Grid 3) (Table 10). It should be noted that these operational costs do not take carbon tax increases into effect, and may show different usage of DR programs, if the carbon tax is to increase as planned (Environment and Climate Change Canada, 2022b).

GHG emissions decreased on both inflexible grids (Grid 3 and Grid 4), and flexible and carbon-intensive grids (Grid 2) but increased slightly on flexible and low-emitting grids (i.e., Grid 1) (Table 11). This is because the demand profiles show larger peaks and lower valleys with DR programs in place, compared to without DR, which allows for NG generators to stay on or off more consistently. Since NG generators have start up costs, while hydro and VRE generators do not, running NG generations consistently reduces the overall cost to the grid, while GHG emissions increase.

Table 10: Change in average operational costs due to DR

	Grid 1	Grid 2	Grid 3	Grid 4
Less efficient buildings	-0.53%	-0.61%	-3.19%	-0.59%
DR baseline	-0.50%	-2.09%	-4.71%	-0.62%
More efficient buildings	-0.53%	-4.04%	-5.10%	-0.60%

Table 11: Change in average GHG emissions with implementation of building DR programs

	Grid 1	Grid 2	Grid 3	Grid 4
Less efficient buildings	0.08%	-0.64%	-3.18%	-0.65%
DR baseline	0.07%	-2.21%	-4.70%	-0.68%
More efficient buildings	0.07%	-4.27%	-5.08%	-0.66%

Since a less efficient building stock has more load available for shifting, one might expect reduced benefits of DR programs as the building stock efficiency improves. However, flexible and carbon-intensive grids (Grid 2) decrease operational costs and GHG emissions as the building stock becomes more efficient. As previously discussed, when there is a significant amount of VRE on the grid, DR programs produce a more erratic load profile to maximize VRE usage. As can be seen in Figure 19, when this strategy implemented on a more efficient grid allows for a proportionally larger amount of demand to be met with cost-effective generation.

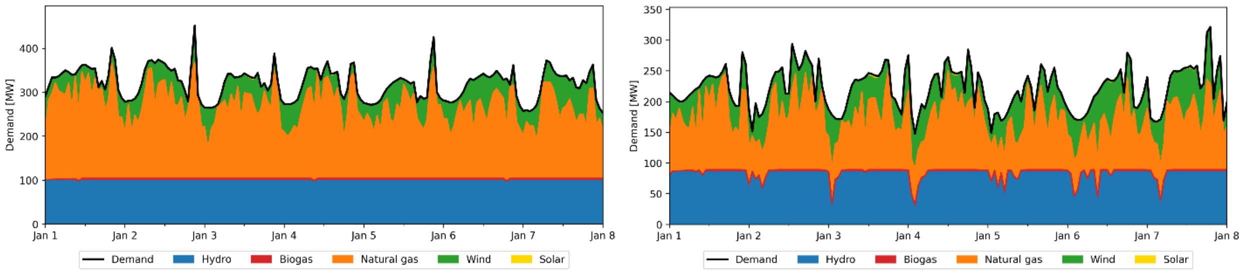

Figure 19: Grid 2 generation mix with a less efficient building stock (left), and more efficient building stock (right)

Additionally, the overall lower demand from more efficient buildings allows for fewer NG generators to be running at any time. In this case, the flexibility of the grid is what allows for this DR utilization strategy to be successful, as the minimum generation constraint that governs NG generators is less constraining with more efficient buildings.

Inflexible and low-emitting grids (i.e., Grid 3) display the same trend of decreasing costs and GHG emissions as building stock efficiency increases. Since Grid 3 is composed of majority VRE generators, this trend is expected based on results from Grid 2. Since VRE is innately non-flexible, but cost-effective, the flexibility offered by DR programs means that the most benefits in both operational costs and GHG emissions can be seen on grids with high VRE penetration. Furthermore, these benefits increase as building stocks become more efficient.

3.4 Discussion

Due to their complex nature, the modelling community has struggled to implement residential building DR programs in system models, despite evidence suggesting their benefits by literature. Through this modelling approach, the insights gleaned in this paper can influence real-world DR programs. We have quantified the value of DR programs based on cost savings for the grid and to DR programs participants. Comparing the results to future projections of grid composition and/or electrification levels quantifies the value of DR programs over time, which could facilitate smart investments.

3.4.1 Value of DR programs

In Canada, provincial electricity grid operators offer DR contracts for large consumers that are able to reduce their electricity demand (Table 3 in Section 3.1). However, there are no programs that allow residential buildings to participate individually in DR. This is likely due to the added difficulty of aggregating residential DR contracts.

The large consumer DR contracts are structured to target large reductions to electricity demand several times a year. In contrast, residential DR programs, as structured in this modelling work, entail smaller reductions in electricity demand with greater frequency. As opposed to a minimum load reduction of 200 kW per hour (such as required by the Hydro Quebec DR contract), grid-controlled DR programs would be able to shift an average of 0.60 kW per residential building per hour[4], making DR programs much more accessible to the general public.

Existing DR programs are structured such that large consumers are paid out per unit of power reduced. This effectively treats these DR contractors as if they were peaking generators on standby. With residential DR programs, as the demand reduction would be grid-controlled, a more logical structure would be to be paid per unit of energy reduced. The value of residential DR programs to the grid, represented per unit of energy, ranges from $0.80/MWh to $67.82/MWh depending on the grid configuration and building stock efficiency as shown in Table 12. This value includes both operational cost savings, as well as value of GHG emission reduction based on a carbon tax of $200/tonne CO_2e.

Table 12: Value of DR program to grid per MWh

	Grid 1	Grid 2	Grid 3	Grid 4
Less efficient buildings	$0.81	$11.64	$34.70	$23.41
DR baseline	$0.80	$38.57	$45.34	$28.11
More efficient buildings	$0.82	$67.82	$53.63	$33.11

Though there is small value to DR programs on flexible and low-emitting grids (i.e., Grid 1), it is generally not an effective strategy. However, DR programs on flexible and carbon-intensive grids, or inflexible and low-emitting grids (i.e., Grids 2 and 3, respectively), especially with more efficient buildings, is a strategy worth considering. Inflexible and carbon-intensive grids (i.e., Grid 4) would also benefit from DR programming, though building efficiency does not play as much of a role in the effectiveness of the DR programs.

The value of a residential DR programs to the participant must also be considered. Assuming a participation rate of 75% and that all savings from the DR program go back to participants, the total annual cost savings for DR programs participants is calculated (Figure 20). On a flexible and carbon-intensive grid (i.e., Grid 2), cost savings would be as high as 2.7% of a typical Canadian electricity bill[5]. In contrast, on a flexible and low-emitting grid (i.e., Grid 1), annual cost savings would be inconsequential.

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[4] Based on values from Table 7 and assuming 100,000 residential buildings in a city (median number of residential buildings in a city (Statistics Canada, 2022))

[5] Based on an average usage of 800 kWh/month at an electricity rate of $0.179/kWh

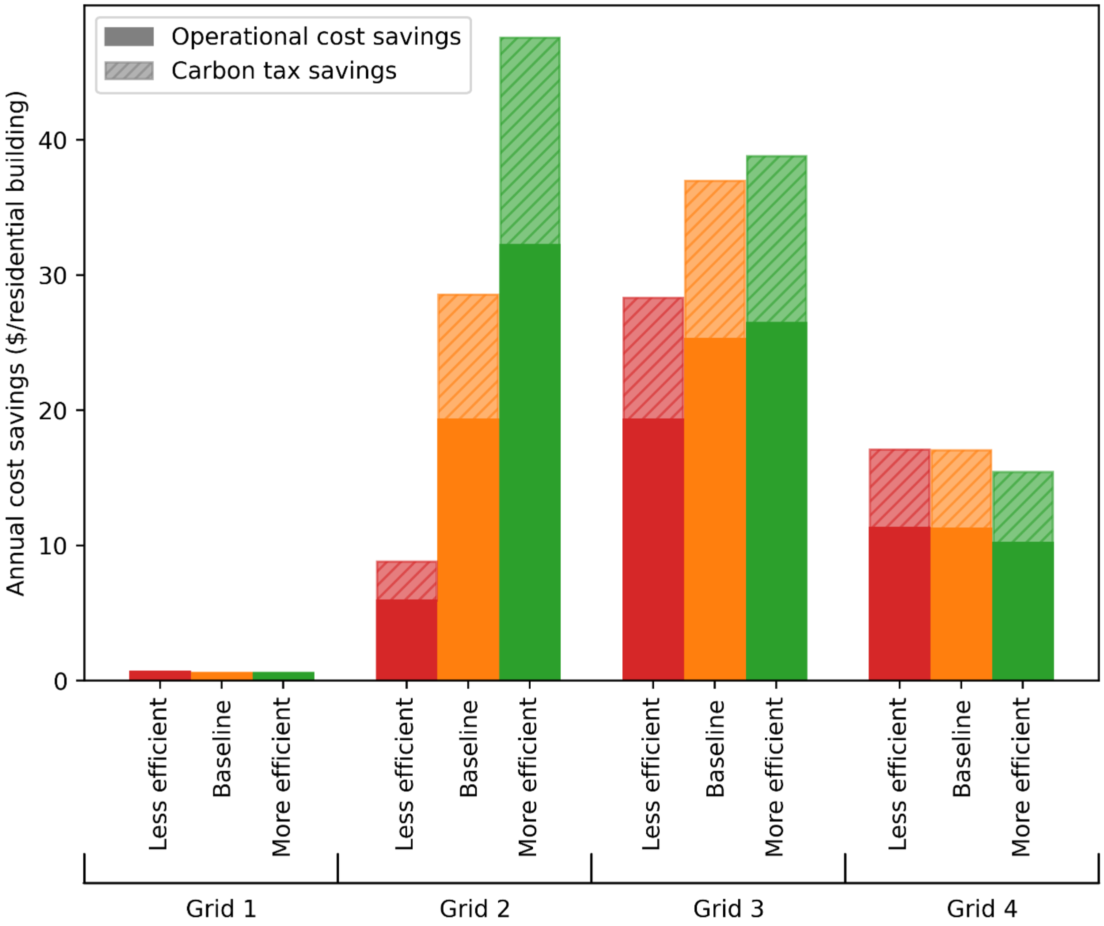

Figure 20: Cost savings for a DR program participant

Though the savings are small, the incentive may be enough to encourage participation. Studies in the midwestern United States found that just under 50% of residents were willing to participate in DR programs with annual incentives as low as $10 (Morton et al., 2021). Over 85% of survey respondents to a Chinese survey were willing to participate in residential DR programs for the equivalent of $14/MWh of load reduction (Wang et al., 2020). In addition to monetary benefits, consumers may be enticed to participate for environmental reasons. In a Canadian context, residents of Regina, Saskatchewan indicated a willingness to pay higher property taxes (or rent) to meet city-wide sustainability goals (Bardutz & Dolter, 2020).

3.4.2 Canadian applications

Basing future grid configurations on the 2050 *Evolving Policies* projections in the *Canada's Energy Futures* report (Canada Energy Regulator, 2021a), provinces can be broadly categorized as follows:

- Flexible and carbon-intensive grids, and inflexible and low-emitting grids would benefit from residential DR program (particularly in scenarios with an efficient building stock);

- Inflexible and carbon-intensive grids would somewhat benefit; and
- Flexible and low-emitting grids would see inconsequential benefits.

From these conclusions, the geographical benefits of residential DR programs across Canada can be seen in Figure 21.

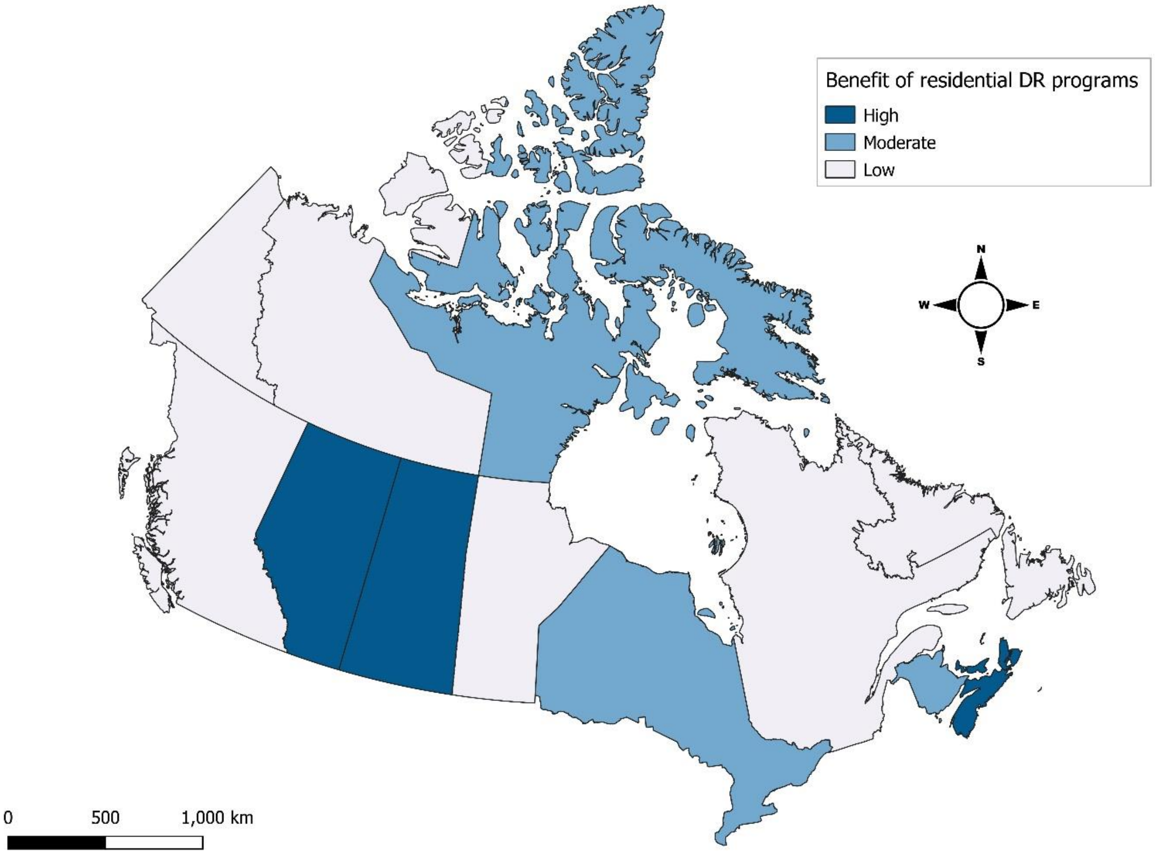

Figure 21: Benefits of residential DR programs based on projected provincial electricity grid composition

Future building codes and the resulting building stock efficiency will play a role in the future effectiveness of residential DR. On the grids with DR program benefits, increasing building efficiency resulted in higher cost savings due to DR. Furthermore, increased building efficiency will lead to lower overall electricity demand, which has its own associated cost benefits.

On grids with moderate DR program benefits, cost savings from DR decreased slightly with a more efficient building stock, though this may not be a universal result. In these cases, a more nuanced approach may be required when implementing DR programs. Leveraging local climate data, attitudes of potential DR programs participants, and the nature of the electricity market (see Section 3.4.3) will help to make an informed decision regarding the extent of DR program implementation.

3.4.3 Role of the electricity market

How a grid operates plays a large part in how cities will be able to enact residential DR programs. In Canada, most provinces and territories are governed by provincial public utilities; Ontario and Alberta have energy markets. These two provinces have several smaller electricity distributors providing electricity to consumers, rather than electricity being both generated and distributed by the provincial utility (Christian & Shipley, 2019). Both grid structures present different challenges for residential DR programs. For Alberta and Ontario, DRA that participate in the energy markets are the most likely path forward. This would mean that a third party would be involved with their own profitability concerns, which may reduce cost savings of the actual DR program participant (Lu et al., 2020; Ponds et al., 2018). Without DRA involvement, the possibility of residential DR programs going into effect would be lowered, as it would effectively be many very small DR "generators" that the utility would oversee. Though a DRA may be able to participate in large-scale DR contracts, the same issue of narrowing the cost-saving margins would continue to play a role.

However, there are examples of DRAs being an effective method of enabling small DR contributions. In Ontario, the capacity auction allows bids from DRAs (IESO, 2022), though many will not work with smaller (i.e., residential) contributors (Edgecom Energy, 2021; Voltus, 2021). On the other hand, California operates their electricity grid as an energy market and allows for participation from DRAs. In this case, several of the DRAs do allow for residential contributors (CPUC, 2022).

3.4.4 Limitations

There are three major limitations of this modelling work. Firstly, the demand input data was heavily based on Regina, SK, due primarily to data availability. However, Regina does not accurately represent all Canadian cities. Large cities in Canada (i.e., Toronto, Vancouver, Montreal) or cities with vastly different climates (i.e., Victoria, Iqaluit) likely display significantly different electricity demand patterns. Such variations would likely impact the results and should be kept in mind if attempting to apply the findings of this research to Canadian cities with significantly different characteristics. Secondly, as this study focuses on how an electrified building stock as a whole can be used as a means of flexibility for grid operations, some detail is lost on the impact of DR programs at the building level. Specifically, we've made assumptions about consumer participation in these scenarios and did not include detail about participant thermal comfort, though this behavioural level data may influence real-world consumer participation. Finally, the DR parameters that were used for the modelling work were chosen primarily to explore the upper potential of residential DR programs. Specifically, the frequency parameter in the modelling work is much higher than that of existing DR programs. Thus, the results presentation herein should be used as a starting point to motivate further research.

3.5 Conclusions

By exploring how residential DR programs would impact grid operations on various electricity grids and with various building stock efficiencies, the benefits of these programs can be seen. The value of residential building DR programs have to both the grid and program participants was able to be quantified and the Canadian provinces where these programs would be most beneficial was determined. From this, three main conclusions can be draw:

1. *Grid composition plays a significant role in the effectiveness of a residential DR program.*

   Grids that have significant VRE compositions, whether composing of the majority of generation capacity or in conjunction with high-emitting generators, dispatched building DR programs much more effectively than low-VRE grids. These grids also exhibited significant reductions in GHG emissions due to higher utilization of available VRE generation, making DR programs beneficial for meeting climate change mitigation goals. Grids composed of inflexible, high-emitting generators were able to use building DR programs to some extent but did not to the degree as those with more significant VRE resources. Grids that were already flexible and low-emitting (i.e., hydro dominated) exhibited only marginal costs-savings benefits of building DR programs, and incurred an increase in GHG emissions, making building DR programs detrimental to meeting climate change mitigation goals.

2. *In cases where residential DR programs were highly beneficial to the gid, increasing the efficiency of the building stock led to DR being more effective.*

   Grids categorized as flexible and high-emitting, or inflexible and low-emitting showed the DR program implementation was highly beneficial. In such grids, more efficient building stocks increased costs savings and GHG emissions by 4.4% and 3.7%, respectively, compared to less efficient building stocks. This translates to a DR valuation difference of $56/MWh.

3. *Modelling building DR with this formulation allowed for exceptional user control of DR parameters and the ability to assess various aspects of DR program implementation.*

   Allowing for variable DR potential, as well as specific event duration and recovery time allows for more accurate modelling of DR programs. This formulation, applied to the SILVER model in this work, can be applied to other production cost models.

4 Capitalizing on electrification: The potential of multi-sector demand response

4.1 Introduction

Canada's current climate mitigation goal targets the reduction of GHG emissions to 30% below 2005 levels by 2030. Many traditional sources of GHG emissions can be attributed to on-site fuel burning, due to its convenience and the outdated assumption that it reduces emissions (Dennis, 2015), which can be seen in the transportation sector (i.e., gasoline and diesel cars) and the residential building sector (i.e., wood, propane, or NG space heating). However, as the power sector decarbonizes, electrifying these sectors can now prove to be beneficial to GHG reductions as it allows for the use of low-emitting fuel sources that may not be portable (i.e., solar, wind, hydro) (Dennis, 2015; Roelofsen et al., 2020). Electrification is beneficial if the carbon intensity of electricity generation is below that of the on-site fuel being used. In practice, this means that electricity grids must be significantly decarbonized before electrification becomes a viable option for emission reduction strategies.

Canada is fortunate to have significant hydro resources, allowing its carbon intensity for electricity generation to be only a third of the OECD country average (Canada Energy Regulator, 2023). There are currently nation-wide policies in place under Canada's CES to continue to reduce carbon intensity within the electricity sector, such as a coal phase out and carbon pricing (Environment and Climate Change Canada, 2016, 2022a). Future electricity grid configurations range from BAU scenarios, which consider currently in-place policies, to scenarios where policies are expected to continue evolving; broadly speaking, such evolving policies would leverage underutilized VRE resources to decarbonize the electricity grids. These predictions mean that electrification would be an impactful strategy for decarbonization across Canada (Environment and Climate Change Canada, 2022a).

To complement nation-wide policies targeting electricity system decarbonization, there are several policies targeted at individuals (McPherson, 2021). These policies are typically focused on rebates for proactive actions, such as switching from NG space heating to a heat pump, or purchasing an EV; many of these policies specifically target the transportation and building sectors, which are two of the highest emitting sectors in Canada due to their reliance on carbon based fuels (making up approximately 40% of all national GHG emissions) (Natural Resources Canada, 2019a). This alone is not enough; even with plans to phase out coal, the Canadian electricity sector still has significant progress to make before being completely decarbonized. The CES currently recognizes that fuel switching from coal will result in higher NG generation, which is recognized as a necessary step towards full decarbonization (Environment and Climate Change Canada, 2022a); however, for the electrification of the transportation and building sectors to drastically affect Canada’s overall emissions, the electricity sector must continue to work to phase out emitting generation sources.

These building and transportation sector policies are mostly implemented at the federal or provincial level and only a few are implemented by specific cities (e.g., Toronto providing homeowners with low-interest loans for energy efficiency improvements (City of Toronto, 2017)). However, as technologies continue to improve, there is more opportunity for the ownership of electricity generation infrastructure to shift to municipalities.

Cities, when given the proper resources, are able to implement more proactive policies that have a greater impact on emission reduction (Abergel et al., 2017; The World Bank, 2010). Further, municipal governments have the ability to reduce their overall GHG emissions by 40-50% (Torrie, 2015) and, within Canadian cities, roughly 70% have made a commitment to reduce their GHG emissions (Partners for Climate Protection Program, 2020). There are limited resources available for cities to carry out these commitments or monitor their progress (Torrie, 2015), which is further complicated by the fact that long-term emissions reduction plans involve the cooperation of several different sectors. Still, some cities have been able to exert more control over their electricity system by owning and operating their own electricity distribution system, such as EPCOR in Edmonton, Alberta (EPCOR, 2023) and Saskatoon Light & Power in Saskatoon, Saskatchewan (City of Saskatoon, 2023).

Large-scale electrification of electricity grids may present opportunities for grid operators, as DR programs can be beneficial for both grid operations and decarbonization efforts. DR is a DSM technique: a means for electricity grids to balance supply and demand by influencing the consumption patterns of electricity customers (McPherson & Stoll, 2020). As electricity grids decarbonize through increasing the share of VRE capacity, there is less flexibility on the supply side; DR programs are a means of regaining that flexibility through modifying demand to increase VRE utilization (Aghaei & Alizadeh, 2013; O’Connell et al., 2014). However, implementing comprehensive DR programs has proven to be difficult due to the complex nature of sector-specific demand interactions and VRE generation (McPherson, 2021). Being able to investigate the impacts of DR programs in a holistic way through energy modelling would help to quantify the benefits of DR for system operators, which in turn may motivate them to consider DR programs as a viable option in decarbonization plans.

The benefits of energy modelling being used to aid in policy development is well documented (McPherson et al., 2022), but Canada has been advised to invest more into building out their energy modelling capacity (IEA, 2016). Recently, the Energy Modelling Hub has been introduced to fill this purpose (EMH, 2023), though there is still a need to continually develop relevant modelling capabilities. This study, through electricity system modelling, introduces a method for modelling DR strategies in various sectors for the purpose of determining the full impact of city-scale DR programs on the electricity grid. A case study is used to introduce methods of leveraging transportation and building model outputs to use as inputs for the electricity system (Section 4.2). The results of different combinations of DR strategies are compared, focusing on the interactions of the sector-specific DR strategies (Section 4.3). The feasibility of these scenarios, outside of modelled constraints, is discussed, as well as the applicability of the case study to other cities based on key characteristics (Section 4.4). Finally, the findings of this modelling work are summarized, and future work is suggested (Section 4.5).

4.2 Methodology

This section introduces the models and the case study used to assess DR impacts and interaction between various sectors. The DR potential calculations for various sectors are introduced and the scenarios constructed for this analysis are outlined.

There are three models used within this modelling work: a transportation model, a building model, and an electricity system model. The building model used is the building thermodynamics simulator, EnergyPlus (Crawley et al. 2001; United States Department of Energy 2020), which was chosen for the extensive control the user has in defining building construction and technologies. Building archetypes are modelled and the resulting building load is scaled up to represent city-wide building stock. The transportation model used is the activity-based model, TASHA (Roorda et al., 2008), which was chosen for the high temporal granularity of the output of passenger travel demand profiles. These profiles are then used to determine city-wide EV charging load and to calculate DR potential, which is discussed further in Section 4.2.2. Finally, the electricity system model used is the production cost dispatch model, SILVER (McPherson & Karney, 2017), which was chosen for the high temporal granularity and the resulting ability to model VRE utilization with a high degree of accuracy.

DR programs were represented within SILVER as a storage-generator object, adapted from the formulation created by McPherson and Stoll (2020) and used previously to assess the impact of DR programs on various electricity grid configurations (Seatle & McPherson, 2023). This formulation optimizes DR program utilization at the grid level, allowing for the added demand flexibility to be utilized in the most cost-optimal way. It should be noted that the specific representation of the DR programs within this study are simply illustrative values; with this DR formulation, DR parameterization is flexible and values can be changed depending on the jurisdiction and the available data. The relative uncertainty to the optimization of the DR dispatch is 1%.

4.2.1 Case study

The case study is focused on the City of Regina, Saskatchewan, which can be characterized as:

- A small urban settlement (population between 100,000 and 300,000 inhabitants) (Statistics Canada, 2022; United Nations, Department of Economic and Social Affairs, Population Division, 2019);

- Warm summer continental climate (Dfb) Köppen climate classification (Arnfield, 2023);
- Car-dependent; and
- Located on an electricity grid with the potential for significant VRE resources (Seatle & McPherson, 2023).

Regina has committed to become 100% renewable by 2050 (Bardutz & Dolter, 2020; Regina City Council, 2020). The current framework for meeting this target includes significant electrification of both the building and transportation sectors (City of Regina & Sustainability Solutions Group, 2022). This includes:

- Electrifying current residential building through a switch from NG furnaces to heat pumps when current heating systems reach end-of-life;
- Increasing residential building energy efficiency by 50%; and
- Electrifying the transportation sector through all new personal vehicles sales being EVs by 2030.

Though "demand management" strategies are mentioned in the framework, there is no specific mention of DR programs being implemented. Regina would be a good candidate for widespread DR program implementation in conjunction with its electrification plans, provided that its electricity grid continues to build capacity as expected with "evolving policies"[6] (i.e., increasing VRE penetration); though Regina's electricity generation is currently dominated by NG, the dominant generation source is expected to transition to wind by 2050 under evolving policies (Figure 22) (Canada Energy Regulator, 2021a).

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[6] "Evolving policies" refers to the scenario name developed by Canada Energy Regulator (2021a)

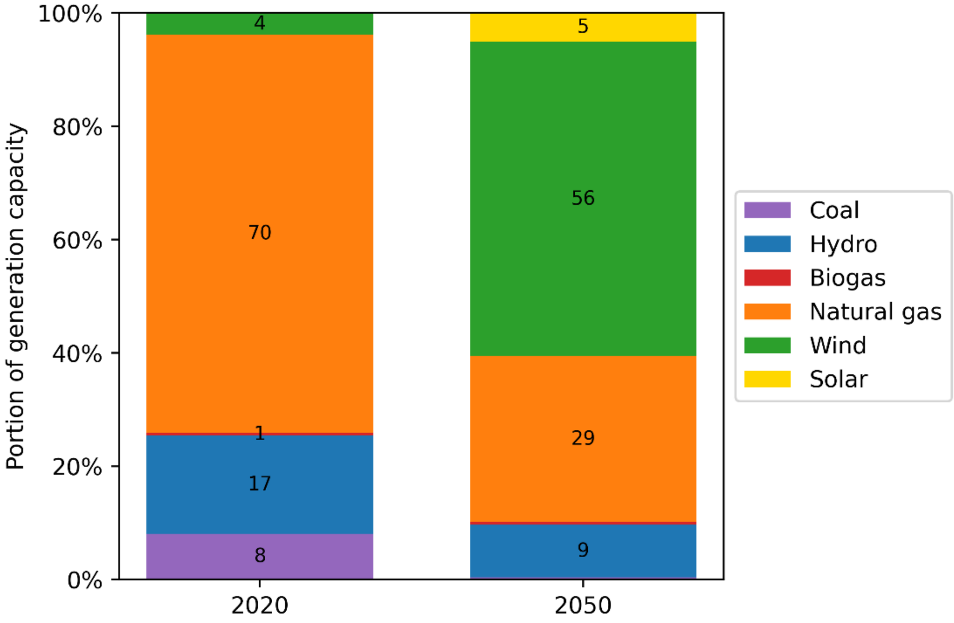

Figure 22: Change in Regina electricity grid composition with evolving policies. Note that these policies include a Canada-wide transition to 95% non-emitting electicity sources, though this transition is not required to be met by individual provinces (Canada Energy Regulator, 2021a).

In order to avoid overestimating the impact of DR programs for Regina, a conservative prediction for 2050 is created based on the current framework targets. This prediction includes:

- 50% of residential building will have transitioned to using GSHP;
- 50% of residential buildings will have been retrofitted to increase energy efficiency by 50%; and
- 50% of the personal vehicle fleet will have transitioned to be composed of EVs.

It should be noted it is assumed that the remaining residential buildings and personal vehicles will remain unchanged.

These changes all have an impact on Regina's demand curve, which can be seen in Figure 23. The transportation sector increases the load, as EV charging is an additional load. For this case study, two distinct scenarios for EV charging are considered: a "home charging only" scenario, where EVs are only plugged in at home; and a "charge anywhere" scenario, where EVs are plugged in at any location where they were stationary for five hours or longer. It is assumed that EV home charging uses a type I charger (charging speed of 2kW) while outside the home charging uses a type II charger (charging speed of 4kW). The building sector has a more variable impact on the demand curve, as it both increase and decrease electricity demand at different times. This is due to simultaneous electrification and energy efficiency improvements of the residential building stock.

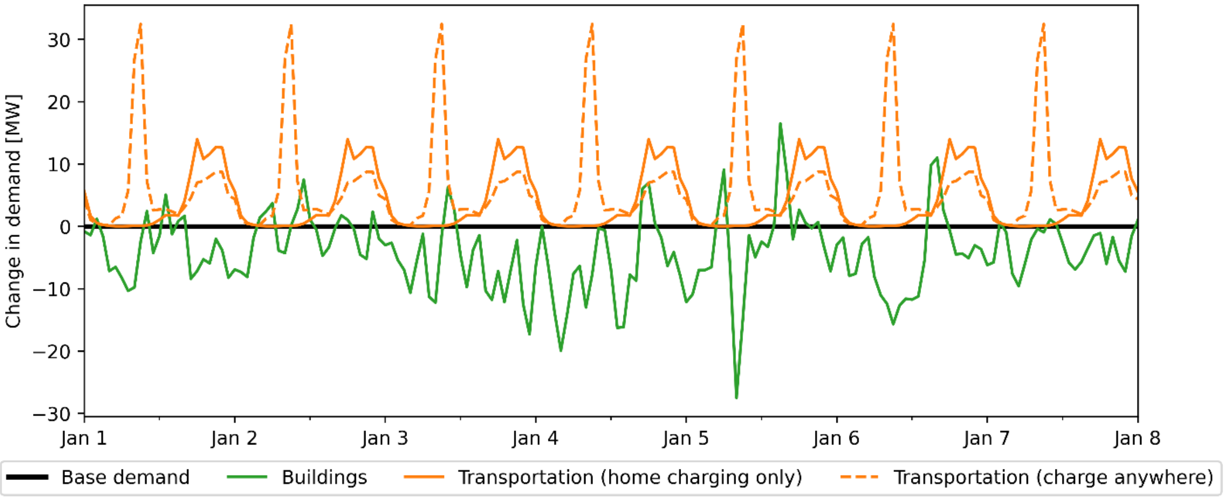

Figure 23: Change in Regina demand from current (baseline) amount with electrified residential building and transportation sectors. Building electrification includes energy efficiency retrofits. Transportation electrification is considered with home charging only or with unlimited public charging infrastructure.

In addition to the sector specific changes to demand, the base electricity demand curve is scaled based on the projections of Saskatchewan’s annual change in electricity demand in an evolving policies scenario (Canada Energy Regulator, 2021a).

4.2.2 Demand response potential

DR potential was calculated for three distinct sectors: residential buildings, light-duty transportation, and industrial facilities.

For residential building DR programs, it is assumed that all residential buildings that had heat pumps installed also had retrofitting to increase energy efficiency. It is further assumed that all these buildings are enrolled in DR programs. Building DR potential is modelled by modifying the heating set point (i.e., reducing the heating load for a set time period before returning to the original set point), which shifts the demand load to a later time. The hourly DR potential is found by running the EnergyPlus model at the normal building set point, rerunning it at the modified building set point, and taking the hourly difference in energy consumption between those two values. This varies based on physical building characteristics, which is quantified using six different archetypes based on Regina’s current building stock: four archetypes for freestanding houses and two archetypes for apartments. The resulting load is then scaled based on the building stock composition of Regina (Statistics Canada, 2022). Residential building DR potential is calculated hourly for a representative day in every month, which can be seen in Figure 24. Using a representative day for a month removes the possibility of an outlier day skewing DR utilization, as well as for computational ease.

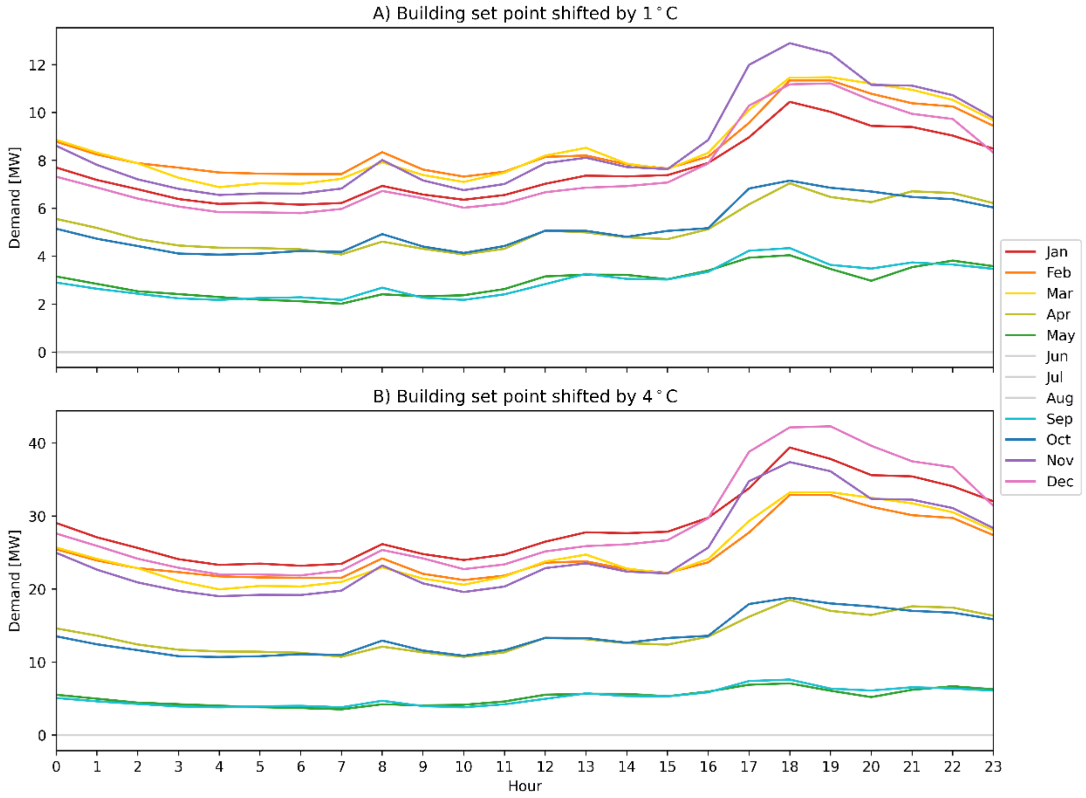

Figure 24: Daily building DR potential for a representative day over each month. Note that there is no building DR potential in June, July, and August as there are no heating days within those months in Regina.

For transportation DR programs, it is assumed that all EVs are enrolled in DR programs. DR potential for EVs is modelled by shifting the charging load and also being able to use stored electricity within EV batteries when they are plugged in (also known as vehicle-to-grid). TASHA is used to model daily vehicle trips throughout the city, with key outputs being trip length (i.e., distance travelled), trip duration, and trip purpose. This allows for a detailed account of where EVs will be and for what length of time.

In contrast to building DR programs, where DR potential is always available but there is a consistent maximum length of DR events, transportation DR is not always available as EVs are not always plugged in. Instead, transportation DR potential is calculated based on how long an EV is plugged in, which results in variable maximum length of DR events. In this analysis, transportation DR falls into one of two categories: DR, which is the shifting of EV charging load (Figure 25); or storage, which is the utilization of the stored energy in EV batteries (Figure 26). Within these two categories, three set lengths of potential DR events were set: short, where the EV is plugged in between five and nine hours; medium, where the EV is plugged in between nine and 13 hours; and long, where the EV is plugged in for 13 hours or more. As EV technology is assumed to improve by 2050, EV battery capacity is assumed to be 40 kWh and have a range of 480 km.

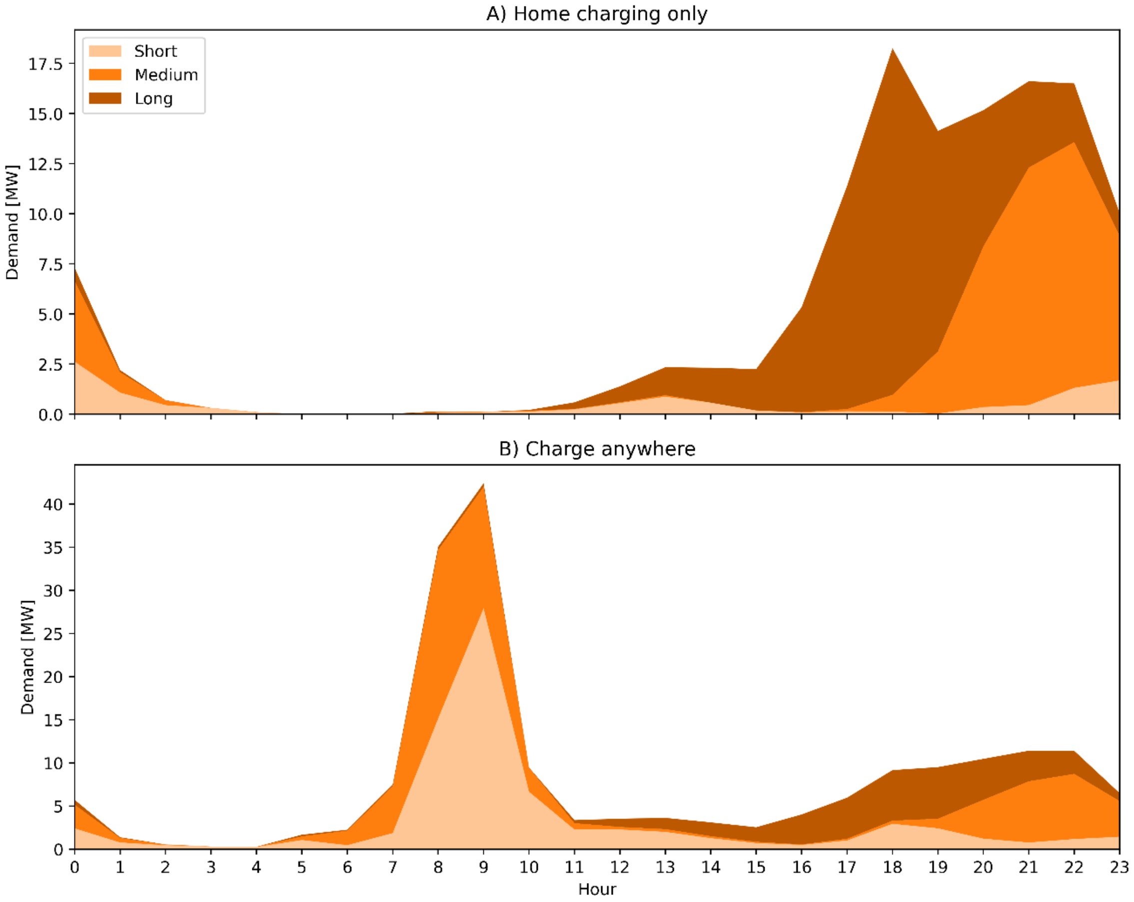

Figure 25: Daily transportation DR potential for a representative day

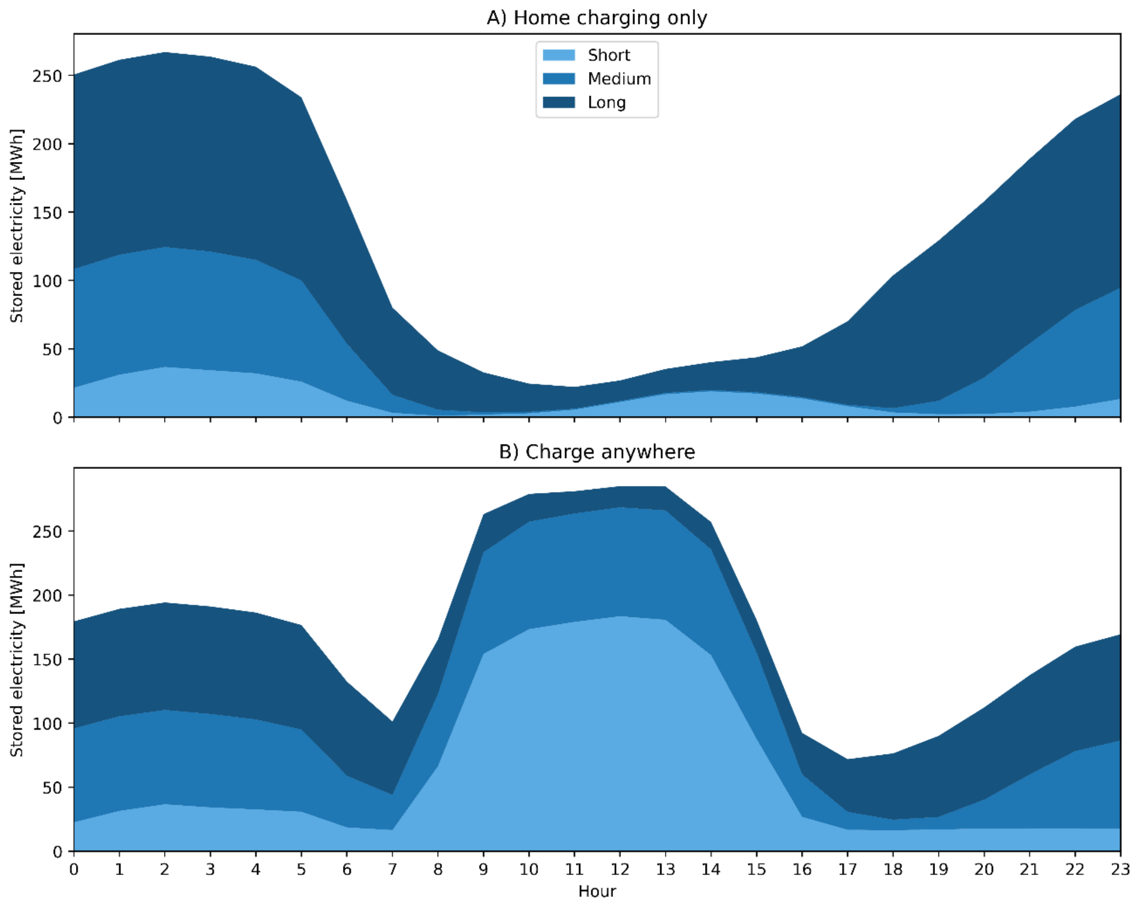

Figure 26: Daily EV battery potential for a representative day

Industrial DR potential is based off of the DR program that is currently offered by the provincial grid operator, SaskPower (SaskPower, 2019). This program is only effectively open to industrial consumers and consist of load reduction as opposed to load shifting. As this is the only DR program to currently be in effect, there are fewer assumptions that are made about the structure of the program; the modelled parameters for electricity reduction are taken from the existing program and the DR potential is scaled based on Regina's predicted electricity demand.

4.2.3 Scenario matrix

The scenarios used in this analysis encompass a range of DR program formulations across different sectors. The purpose of this is to explore different levels of "invasiveness" to the consumer that the DR program would require. All the scenarios can be seen in Table 13, with invasiveness of building DR programs increasing from left to right and invasiveness of transportation DR programs increasing from top to bottom.

For building DR programs, invasiveness is measured by the number of degrees the building heating set point is lowered and the frequency at which a DR event is allowed to occur. B1 scenarios lower the building heating set point by only one degree Celsius, while B4 scenarios lower it by four degrees Celsius. For both $B1_{infqt}$ and B4 scenarios, a DR event is able to occur 15 times per month, or once every other day on average. For $B1_{fqt}$ scenarios, a DR event is able to occur 30 times per month, or once every day. For transportation DR programs, invasiveness is measured by where DR events could occur. T_{home} scenarios assume that EVs are only plugged in at home, as opposed to $T_{anywhere}$ scenarios which assume the EVs are plugged in at any location in which the duration of the stay is five hours or longer. Industrial DR program are able to occur once a month and are consistent across all scenarios.

Table 13: Scenario matrix

	No building DR	Lower 1 degree (infrequently)	Lower 1 degree (frequently)	Lower 4 degrees (infrequently)
No transportation DR	BAU	$B1_{infqt}$	$B1_{fqt}$	B4
	BAU*	$B1_{infqt}$*	$B1_{fqt}$*	B4*
Home charging only	T_{home}	$B1_{infqt}/T_{home}$	$B1_{fqt}/T_{home}$	$B4/T_{home}$
Charge anywhere	$T_{anywhere}$*	$B1_{infqt}/T_{anywhere}$*	$B1_{fqt}/T_{anywhere}$*	$B4/T_{anywhere}$*

Note that on all scenarios marked with an asterisk (*), the demand profile for the scenario use the “charge anywhere” transportation demand, while the scenarios without an asterisk use the “home charging only” transportation demand (Figure 23).

4.3 Results

This section discusses the overall trends observed on grid operations across the previously introduced scenarios. DR programs are analyzed based on operational cost savings, reduction in GHG emissions, reduction of VRE curtailment, and conflicting DR usage between DR streams. Inconsistencies within these trends are explored. It should be noted that the relative uncertainty of all presented results is 1%.

4.3.1 System impacts

A primary factor in determining the benefit of DR programs on the grid is operational cost. Scenarios that have transportation DR have significantly greater operational cost savings than those that used just building DR (Figure 27). However, within scenarios that use just building DR, the more invasive but infrequent programs (i.e., B4 scenarios) decrease operational costs much more than less invasive programs (i.e., B1 scenarios). For scenarios with transportation DR, the ability for EVs to be available for DR throughout the city (i.e., $T_{anywhere}$ scenarios) provides noticeable benefits compared to when EVs were just available when plugged in at home (i.e., T_{home} scenarios).

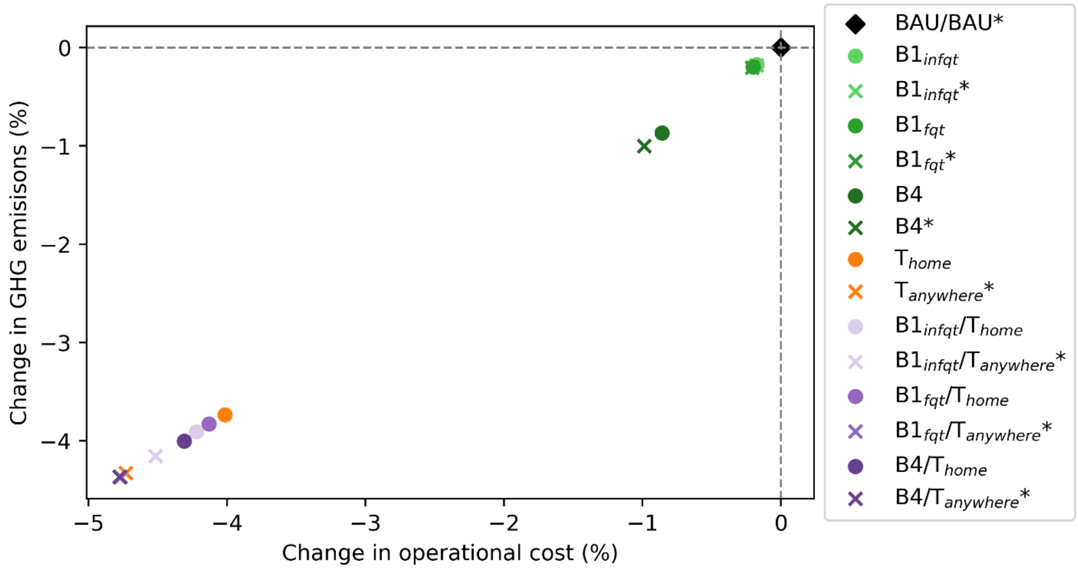

Figure 27: Change in operational costs vs. change in GHG emissions for all scenarios modelled

Change in curtailment levels, another key factor in determining the benefit of DR programs, is also considered. Figure 28 shows that making *both* building and transportation DR programs available reduces operational costs beyond single-sector DR programs in almost all cases. The exception is scenario B1$_{\text{infqt}}$/T$_{\text{anywhere}}$*, where the operational cost is not reduced to the level of T$_{\text{anywhere}}$*. The available DR programs in these scenarios cannot capitalize on VRE generation in the same way that other scenarios can, as can be seen by the higher amount of VRE curtailment.

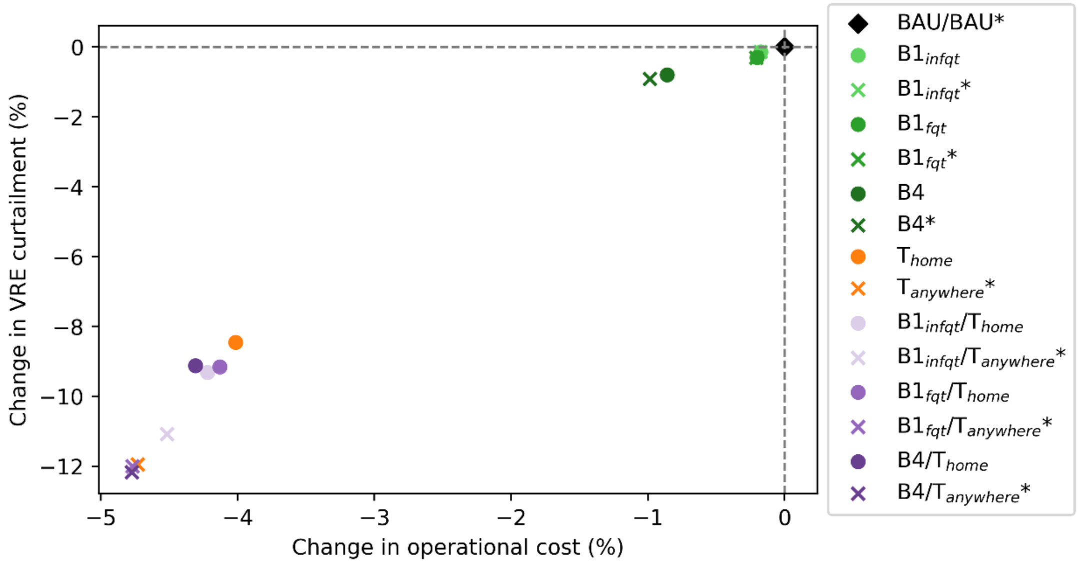

Figure 28: Change in operational costs vs. change in VRE curtailment for all scenarios modelled

The difference in DR utilization for the purpose of minimizing curtailment can be seen more clearly in Figure 29, where the scenarios $B1_{infqt}/T_{anywhere}*$, $B1_{fqt}/T_{anywhere}*$, and $B4/T_{anywhere}*$ are compared. As the transportation DR potential is consistent throughout these scenarios, the difference is the building DR potential. This indicates that either having a greater amount of DR potential (scenario $B4/T_{anywhere}*$) or the flexibility of being able to use DR more frequently (scenario $B1_{fqt}/T_{anywhere}*$) allows for greater VRE utilization. Further, due to the recovery constraints on building DR programs specifically, limiting the frequency (i.e., $B1_{infqt}$), and thus the flexibility, of building DR utilization can result in building DR programs being a hindrance to grid operations.

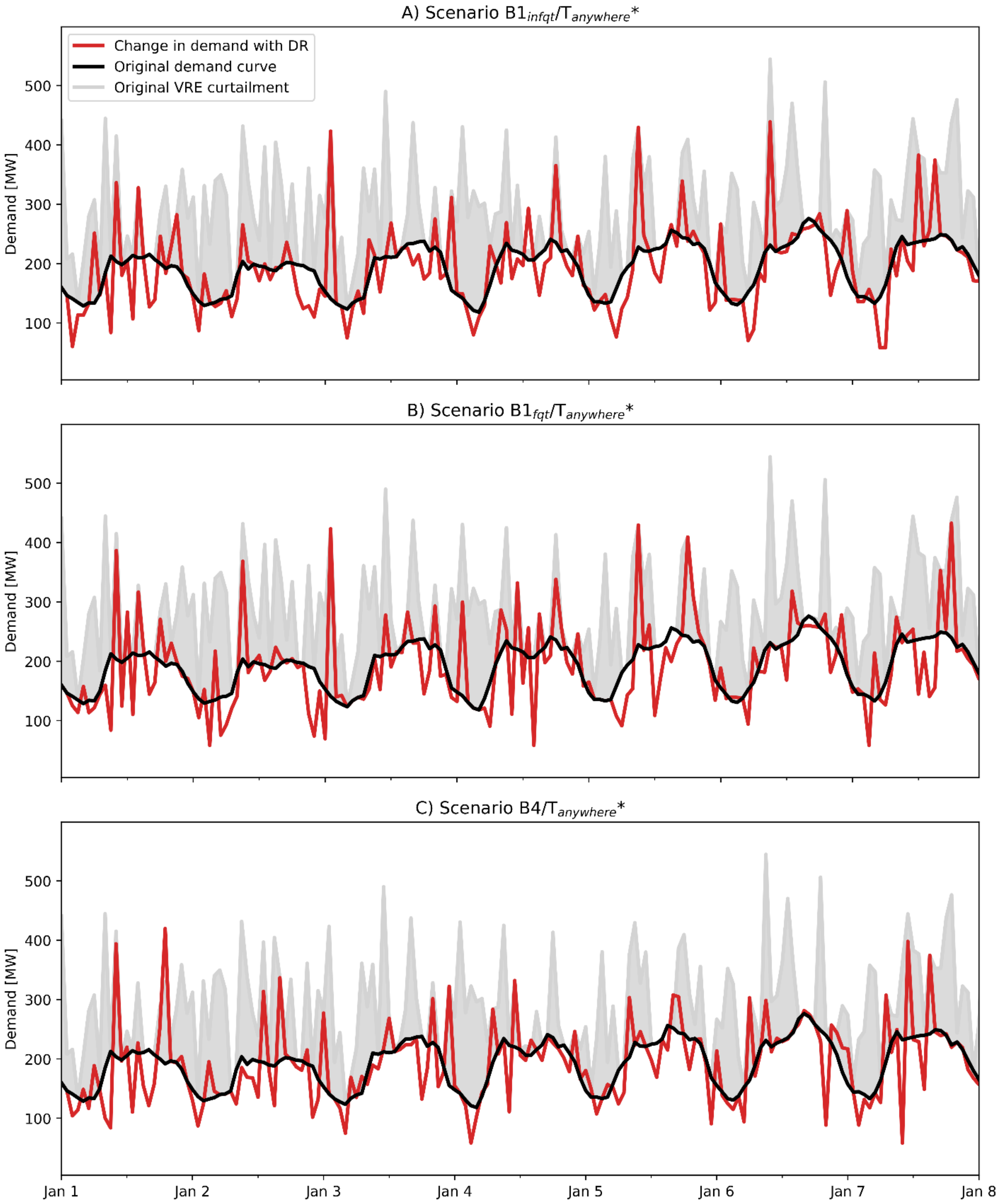

Figure 29: Comparison of DR impact on curtailment for all B/T$_{anywhere}$ scenarios*

The ability to fully utilize available VRE does not coincide with the amount of DR utilization. The building DR utilization of scenario B1$_{infqt}$/T$_{anywhere}$* (Figure 30A) is actually higher than that of all other B/T$_{anywhere}$* scenarios. Similarly, the transportation DR utilization is higher than all B/T$_{anywhere}$* scenarios, even compared to the T$_{anywhere}$* scenario that does not have any building

DR capacity. This, along with the analysis of DR impact on curtailment, indicates that there is an optimal amount of DR utilization on the grid which may be lower than the projected amount of DR available.

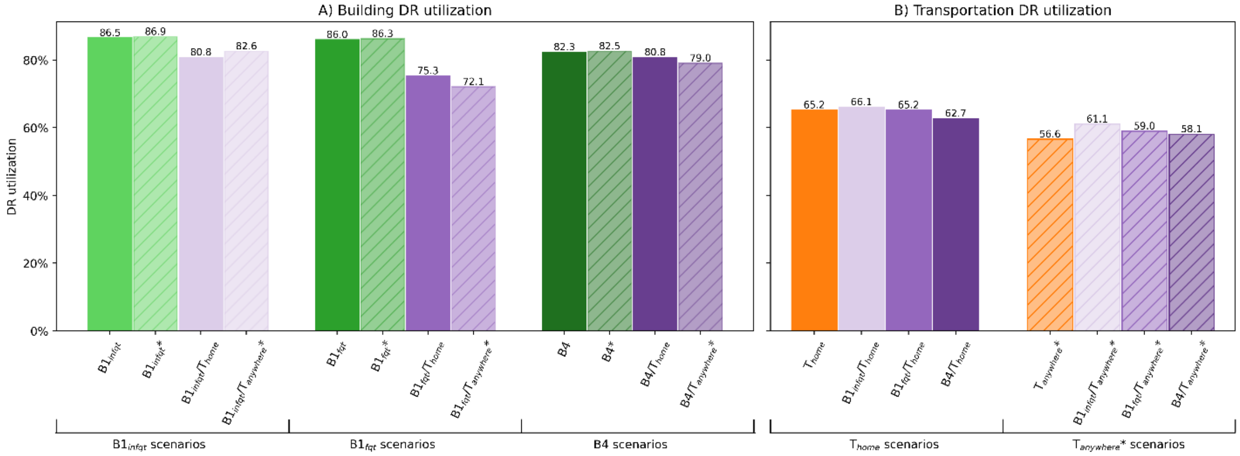

Figure 30: DR utilization across scenarios by building DR programs (left) and transportation DR programs (right)

4.3.2 Utilization characteristics

Transportation DR has a much larger impact on the change in demand profiles than building DR. Within the transportation DR streams, the battery capabilities of EVs are utilized more than shifting charging loads, which can be seen in Figure 31C. This is due to the scale of the battery potential compared to both the transportation and building load shifting potential. Industrial DR contributes very little benefit to the grid across all scenarios.

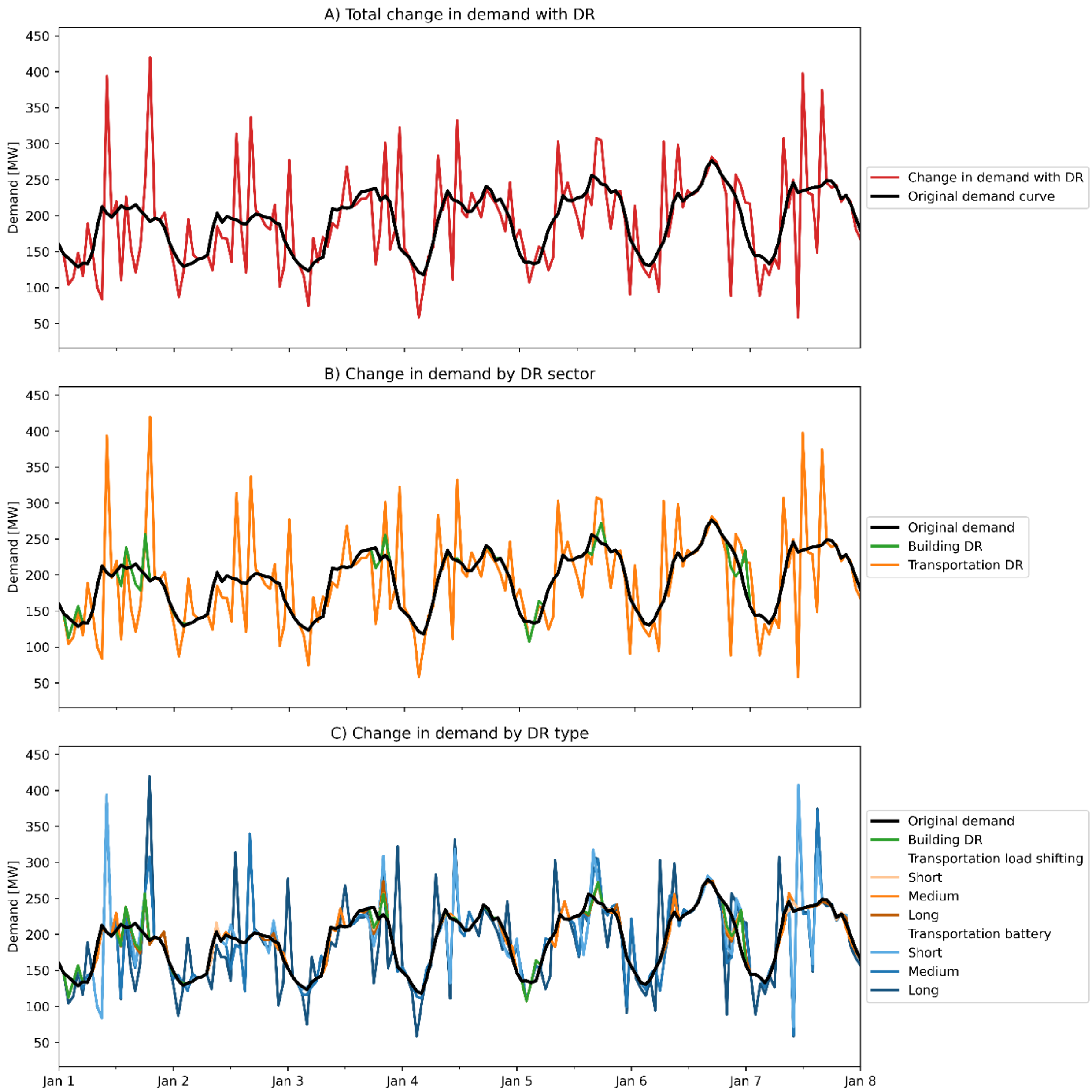

Figure 31: Change in demand with DR programs for scenario B4/$T_{everywhere}$ overall (top), grouped by sector (middle), and divided into specific DR streams (bottom)*

The way that different DR types, even within the sector, impact the overall demand curve can be seen Figure 31. Mostly the different DR types complement each other by being utilized simultaneously to either further reduce or further increase demand (i.e., Figure 31C; late January 3rd), but there are instances where the DR types are "conflicting", or one type is reducing load at the same time that one is increasing load (i.e., Figure 31C; midday January 2nd, or late January 5th). This can be attributed to the different recovery constraints on the DR types; for example, long EV battery storage (transportation battery long) can be used for up to 12 hours at a time, while building DR can only shift load for up to four hours at a time. This indicates that if there's a period where load would optimally be reduced for over four hours, such as when there is very little VRE production, building DR may be used at the beginning of that period, but has to recover after four hours, while long EV battery storage is able to be used for another eight hours before recovering.

Overall, scenarios that utilize "charge anywhere" charging strategies for transportation DR have more DR conflicts than those that only charge at home (Figure 32). As well, scenarios with higher building DR potential have more DR conflicts than those that have lower building DR potential, regardless of the frequency of the building DR utilization. However, the trend cannot conclusively be summarized as more invasive policies lead to more conflicting DR usage, as $B1_{infqt}/T_{home}$ has more conflict than $B1_{fqt}/T_{home}$, and $T_{anywhere}$* has more conflict than both $B1/T_{anywhere}$* scenarios.

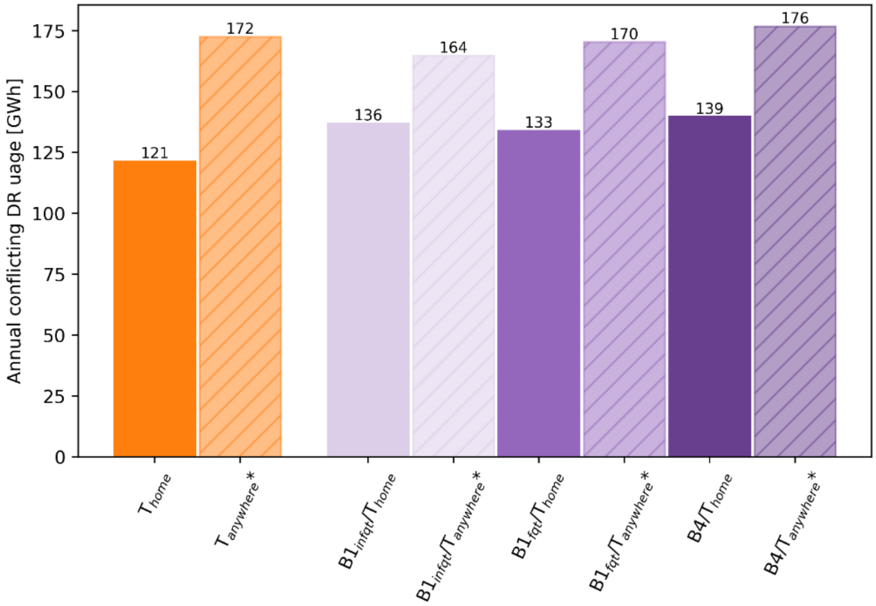

Figure 32: Annual conflicting DR utilization across scenarios with transportation DR

DR conflicts with just transportation DR programs in place come from different transportation DR streams being used simultaneously (Figure 33A). Figure 32 shows that reducing building DR potential decreases DR conflicts when "charge anywhere" strategies are used (such as scenario $B1_{infqt}/T_{anywhere}$*) but increases conflicts when higher potential building DR programs were introduced (i.e., scenario $B4/T_{anywhere}$*). $B1_{infqt}/T_{anywhere}$* reduces the amount of transportation load shifting and utilizing more of the energy stored within EV batteries (Figure 33B). Conversely, scenario $B4/T_{anywhere}$* utilized more transportation load shifting then the baseline $T_{anywhere}$* scenario, along with building DR, resulting in more conflicting DR usage (Figure 33C). However, it should be noted that there does not seem to be a correlation between DR program benefits and DR conflicts, as can be seen when comparing effectiveness of scenarios in Figure 27 and Figure 28. This indicates that conflicting DR utilization may be used within the optimization of grid dispatch, as recovery of a DR stream during an ongoing DR event may be used as a form of ramping or smoothing of the demand curve.

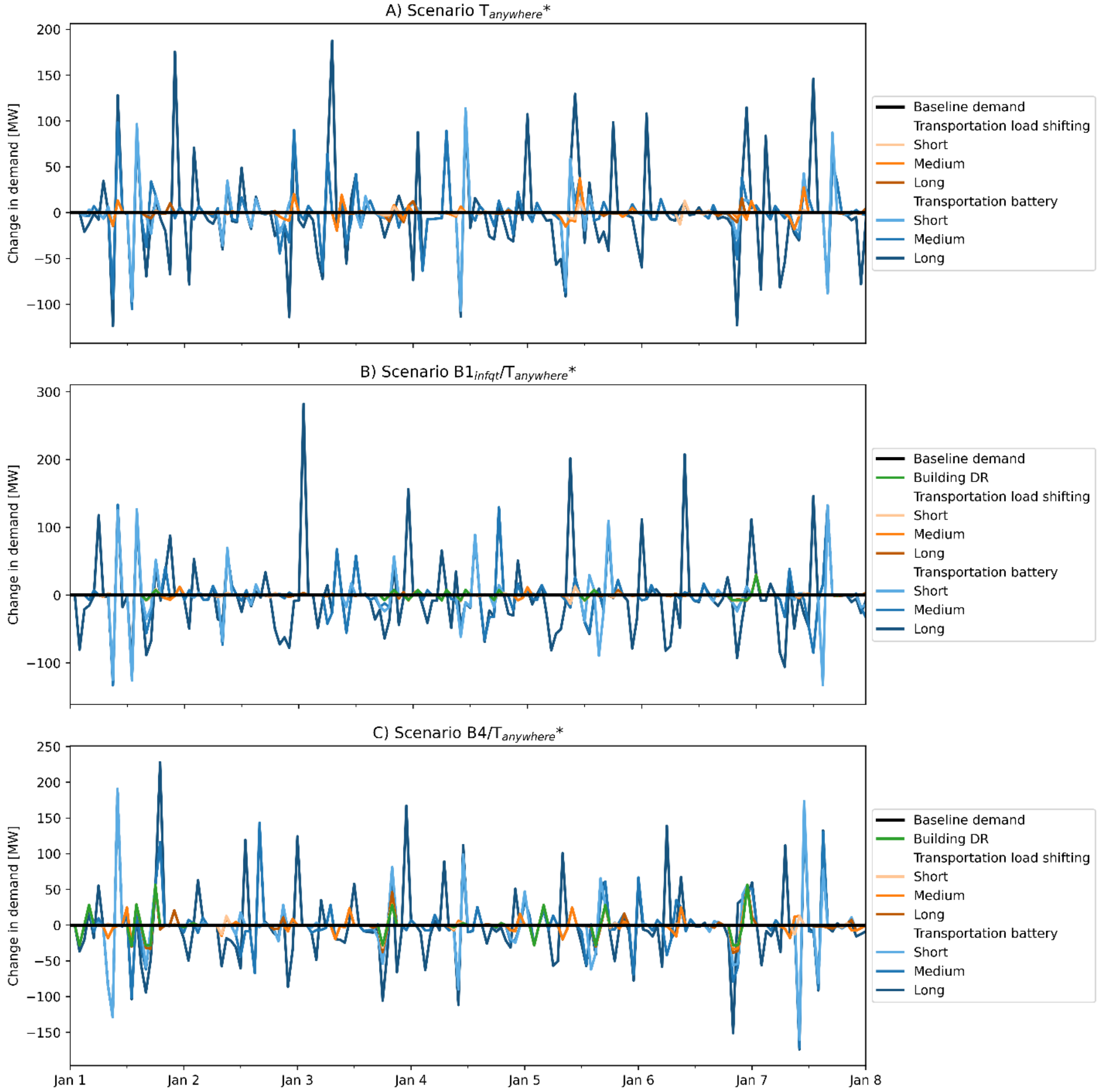

Figure 33: Comparison of DR stream utilization with just transportation DR programs (top), with transportation DR programs and less invasive building DR programs (middle), and with transportation DR programs and more invasive building DR programs (bottom)

This unpredictable nature of conflicting DR usage, and its variability in the relation to the overall benefits of DR programs, may need to be evaluated on a case-by-case basis, as the interactions between different DR types on different demand profiles cannot necessarily be predicted by DR invasiveness or overall DR potential.

4.4 Discussion

This section compares the results of this study to literature. As well, the feasibility of the scenarios modelled, specifically as they relate to public infrastructure investments needed is discussed, and key characteristics of Regina that may be useful in creating city-level archetypes to be used in climate action plan development are identified.

The results of our study, namely the plateauing utility of DR utilization, is consistent with McPherson and Stoll (2020) finding that when incrementally increasing DR availability to the grid, the first introduction of DR provides the most benefit and benefits decrease for each increment afterwards. However, previous studies have found that industrial DR is more beneficial to the grid than residential and commercial DR programs (which are typically presented and structured similarly to the residential DR programs modelled here), which is inconsistent with our findings. Jang et al. (2015) found that industrial DR programs are more than twice as effective as commercial DR programs for reducing peak loads; however, the composition of the electricity grid was not discussed and may have contributed to the difference in findings. Similarly, Logenthiran et al. (2012) found that industrial DR programs were able to double the operational cost reduction compared to residential DR programs. Again, the composition of the modelled electricity grid was not discussed, but the benefits of maximizing VRE utilization was mentioned, indicating that the grid may bear resemblance to Regina's. Despite the potential differences in electricity grids to account for the different results in our study, the potential discrepancy in results is discussed further in Section 4.4.1.

Though these scenarios leverage several changes that are already laid out in Regina's city plans, many components require additional changes that are not explicitly stated. First and foremost, additional public EV charging infrastructure is necessary to facilitate scenarios that use a "charge anywhere" approach to transportation DR. The amount of EVs plugged in to public infrastructure is the highest at noon, with just over 42,500 EVs plugged into public charging infrastructure (Figure 34). Further, the majority (91%) of these are when EVs are parked at work, while the remainder are when EVs are parked at other locations (school, shopping centers, or other miscellaneous locations).

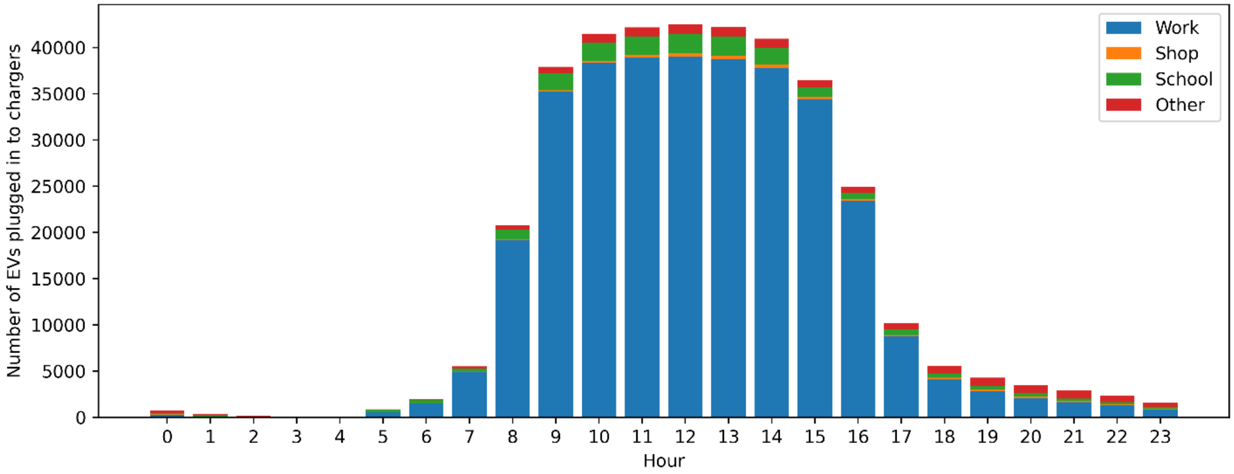

Figure 34: Number of EVs plugged in every hour of the day to facilitate transportation "charge anywhere" DR scenarios

Though plugging in at work may be using public charging infrastructure, many traditional work locations provide parking on private property (e.g., large office buildings). This indicates that for cities to leverage that most benefit out of transportation DR, subsidies can be offered on installing EV charging infrastructure to the property owners of large office buildings.

The location of other charging infrastructure may be more difficult to place in such a way that everyone has access to them, though there may be opportunities to centralize public EV chargers as EVs replace traditional gasoline-fuelled vehicles. Due to various economic factors, including modal shift to EVs, it has been estimated that 43% of European gas stations will shut down by 2050 (Hecquet & Lebouteiller, 2021). Going further, it has been estimated that with substantial EV market share, up to 80% of gas stations world-wide will be unprofitable by 2050 (Rubeis et al., 2019). Placing EV charging stations at gas stations is a well documented prediction (Chen & Hua, 2014; Funke et al., 2019; Huang & Kockelman, 2020, 2020; Liu, 2012); as there are currently over 50 gas stations in Regina (GEOFABRIK, 2023) and if 80% are decommissioned, this represents up to 41 potential EV charging station locations. Additionally, land that has previously been used as a gas station may require substantial environmental assessment to be rezoned for residential, or even commercial usage, but EV charging stations may be able to be built immediately (Lewis, 2022; Tobias, 2022). If cities strategically utilize this land for public EV charging lots, greenfield development is avoided and there is more opportunity for EVs to participate in transportation DR.

The probability of installing over 40,000 public chargers in Regina under current policies is a high estimate but is within the range of possibility with progressive policies. Currently there are only 22,500 public EV chargers in Canada, with under 60 of them located in Regina (Natural Resources Canada, 2022a). However, it has been estimated that if EVs reach 90% penetration within the national vehicle fleet by 2050, the number of public EV chargers in Canada must increase by a factor of 1,215 (Dunsky Energy + Climate Advisors, 2022). Based on the current EV distribution, and scaling to only 50% EV penetration as per the modelled scenarios, the predicted number of EV chargers in Regina under progressive policies would be just over 40,000. By prioritizing investment in transportation DR and making new EV charging infrastructure beneficial to the operation of the electricity grid, the prediction of 42,500 chargers in Regina is within reason.

Globally, over 200 cities have made a similar commitment as Regina to being 100% renewable on a city-wide scale (Conroy & Hoika, 2020). Though this case study is focused on Regina, other cities across Canada, and even globally, may find these results useful. Other cities that share similar characteristics[7], and could display similar trends in optimal DR application, are Portland, Maine, USA; Kushiro, Japan; and Potsdam, Germany. Identifying cities with these same characteristics is important when considering options for climate change mitigation, as it can guide modellers and policy makers in the scenario creation stage. Though the cities listed do not currently have climate action plans, developing these city archetypes on the national and global scale can aid smaller cities, perhaps without the same resources to run detailed models, in creating realistic climate action plans.

4.4.1 Limitations

As we cannot capture all aspects of the real world within models, there are a few limitations to note.

Firstly, as discussed previously in Section 4.4, the results of industrial DR having negligible impact on grid operations is inconsistent with literature. Though this is explained by different electricity grid compositions being modelled in other studies, it may also indicate that this DR formulation is not as accurate at representing load reduction (i.e., the modelled industrial DR program) as opposed to load shifting, which it was developed for. Additionally, this DR formulation may be unnecessarily complicated at representing industrial DR programs due to the infrequency of their events. Likely, a better representation of industrial DR programs is the original DR module within SILVER (McPherson & Karney, 2017).

Secondly, due to data availability, all DR potential is assumed to be the same whether it is a weekday or weekend. This would have an impact on both the building heating habits, as well as the location of EVs, particularly in the “charge anywhere” scenarios. Factoring in building heating habits may show an overall reduced demand from buildings on weekends, meaning that there may be less DR potential available for shifting. Factoring in weekend travel habits may result in more erratic travel schedules and locations, particularly locations where trips are typically taken for shopping and other miscellaneous activities may need a higher allocation of public EV chargers to be able to facilitate the similar level of DR potential during the weekend.

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[7] Key characteristics of Regina were outlined in Section 4.2.1.

Additionally, EV battery depletion rates are assumed to be consistent annually, despite it being shown that EV range is reduced up to 45% in cold weather (Delos Reyes et al., 2016). However, the impacts of this omission may not be significant to the total scenario impact since transportation DR considers both the stored energy in the battery as well as the energy used to charge the EV. Though this may only marginally affect the overall amount of transportation DR utilized, it would impact the type of transportation DR utilized (i.e., load shifting or battery).

Finally, the base electricity demand curve (not considering additional demand from building electrification and EV charging) is scaled uniformly with no consideration to the potential change in the shape of the demand curve as electricity consumption habits change. As this is a difficult change to predict, the impact on the results is also difficult to predict, though it is expected that it would change the times of DR utilization. However, it would be expected that similar trends would persist in that DR utilization would be used to reduce VRE curtailment, though generation profiles, and the resulting generator schedules, may differ from modelled scenarios.

4.5 Conclusions

This paper determined that multiple DR programs are beneficial to the operations of the electricity grid. These benefits can be summarized in three main conclusions:

Transportation DR has a much greater impact on electricity system operations than building DR.

Scenarios with only building DR are only able to reduce operational costs by up to 1%, while scenarios with only transportation DR can reduce costs by almost 5%. This is generally tied to the invasiveness of the program, as more invasive programs result in greater benefit to the electricity grid and vice versa. Within the transportation DR streams, the battery capabilities of EVs are often much more utilized than the shifting of charging loads, though this is assumed to be since there much more energy stored in EV batteries as opposed to shiftable from charging. Scenarios where EVs can charge anywhere are much more beneficial to electricity grid operations than scenarios where only home charging is available.

With multiple DR streams, there is significant conflicting DR utilization due to recovery constraints. However, it is unclear if conflicting DR utilization is detrimental or beneficial to grid dispatch.

As the driving factor behind DR utilization is reduction in VRE curtailment, DR streams with shorter recovery constraints must recover shifted energy (i.e., increase load) at times when DR streams with longer recovery constraints are still reducing demand. During longer periods of high VRE potential, DR streams that can recover over a long period of time are more beneficial to the electricity grid than DR streams that must recover quickly after a DR event. However, there does not seem to be a correlation between DR program benefits and DR conflicts, meaning that DR conflicts may be being utilized as a form of ramping or smoothing of the demand curve.

Even in the scenarios with the most DR utilization, the amount of DR utilized during DR events is never above 90% of the available amount.

Additionally, the benefits of DR (i.e., operational cost reduction, GHG emission reduction, and/or VRE curtailment reduction) in a scenario does not coincide with the amount of DR utilization. From this, it can be concluded that there is an optimal amount of DR utilization on the grid which may be lower than the projected amount of DR available, though this may vary with different grid configurations.

4.5.1 Future work

There is further research that should be done to complement this research. For example:

- More detailed research into the optimal amount of DR on the grid, and how it related to dispatch uncertainty, would allow for a quantifiable conclusion about at what point DR programs begin to see diminishing returns.
- A study of optimal public EV charger locations would enable a more accurate prediction of the transportation DR potential at any given hour. This would also allow for behavioural modelling in regard to public EV charger utilization, in a similar way that predicted public transit utilization may be based on the “first and last mile” problem.
- Further research into the technological advancements concerning vehicle-to-grid connection viability, specifically in terms of battery strain, would either prove the worth of transportation DR or show a need to pivot away from this solution.
- As 2050 is still far enough into the future that behavioural predictions can vary widely, various scenarios for cities can reasonably be considered. For example, drastically increase public transit ridership may limit EV DR potential, but may present an opportunity for electric public transit vehicles to be included in DR programs. On the other end of the spectrum, an increased presence of autonomous cars may have a sweeping impact on vehicle scheduling and, thus, change the transportation DR potential.

5 Conclusions

In the preceding chapters, two novel approaches to DR modelling were presented. Both these approaches contribute to Canadian modelling capacity, but both are useful for different situations. The iterative approach in Chapter 2 is a viable option for situations where scenario feasibility is being assessed, though the solution may end up being non-optimal. In contrast, the non-iterative approach introduced in Chapters 3 and further discussed in Chapter 4 is a viable option for assessing the value of DR to the grid and to the consumer as the optimal solution for the scenario is determined.

The iterative approach was able to determine some key insights into the City of Regina's proposed decarbonization target. It was found that Regina is able to meet the most ambitious scope of their target through electrification of the residential building and transportation sectors in conjunction with DR programs and energy storage. It was determined that non-optimal application of DR resulted in building DR programs have only marginal impact on curtailment reduction and that transportation DR programs were only effective if extensive amount of EV chargers were publicly available.

The non-iterative approach was able to better utilize DR potential due to the optimization of DR dispatch. It was found that this approach allowed residential buildings to contribute more to grid dispatch optimization through DR programs, as well as gave the user greater control of specific DR program parameters (Chapter 3). It also allowed transportation DR to be better utilized by including vehicle to grid battery utilization within DR programs (Chapter 4). Additionally, it allowed the analysis of the interactions between DR programs from different sectors (Chapter 4).

It was found in all three chapters that DR programs were beneficial for grid operations, though the value did vary based on the scenario being assessed and the metric being utilized. In Chapter 2, DR was able to help in achieving a 100% renewable grid, but the inclusion of large-scale storage on the grid drastically overshadowed DR's contribution. In Chapter 3, DR programs were able to reduce operational costs and GHG emissions by up to 5%, though that did vary based on the grid it was being simulated on. Chapter 4 found similar findings to Chapter 3, with DR programs allowing for operational cost and GHG emission reductions of up to 5% and 4.5%, respectively.

Though these numbers indicate that DR programs are not the lowest-hanging fruit in regards to achieving net-zero targets, they are still able to contribute. For example, the Canadian government's new Clean Energy Regulations are the most progressive policy to date with the goal of achieving national net-zero emissions (Government of Canada, 2023). However, the need for flexibility in the electricity system is recognized and there are still exceptions for backup emitting generation, which has been noted as being an issue for reaching a net-zero electricity grid (Net-Zero Advisory Body, 2023); this is where DR programs may be most beneficial. On a mostly decarbonized grid, DR programs may be able to provide the flexibility needed to remove lingering emitting generation, though the flexibility would be on the demand side as opposed to the supply side. Additionally, DR programs are well suited later on in decarbonization timelines, as the potential for load-shifting from DR programs drastically increases with large-scale electrification and smart-grid implementation.

5.1 Levers for DR effectiveness

Like most decarbonization strategies, there is no “one-size fits all” solution; it can be seen throughout the chapters that there are certain characteristics, or levers, of the electricity grid and DR potential that allow for DR programs to be more impactful on both operational costs and GHG emissions (i.e., successful).

Three primary levers for DR program success can be observed throughout the chapters:

1. Inflexible electricity grid due to high VRE penetration;
2. DR programs allowing for frequent DR events with a significant shiftable load; and
3. Significant midday DR potential.

As can be seen in Chapter 3, inflexible electricity grid (due to high VRE penetration or otherwise) benefit from the added demand-side flexibility that DR programs introduce. However, if we classify a DR program as being successful only when it significantly reduces GHG emissions, a DR program is more successful the more VRE is present on the grid. As Canada works towards its net-zero target, VRE generation will likely become more incentivized; in areas with high VRE resource and adoption levels, DR programs should also be incentivized since they will be particularly beneficial.

Chapter 4 was able to display the benefit of DR program parameterization where large and frequent DR events were allowed. These two parameters play hand-in-hand, as having a large amount of DR potential on the grid allows for more frequent load shifts at a grid level (assuming each DR events shifts below the maximum potential), even if the DR program does not allow for frequent shifts at a consumer level. Additionally, this difference in perspective (i.e., frequent shifts from the grid operator’s perspective and infrequent shifts from the consumer’s perspective) make for a more mutually beneficial DR program design.

Also seen in Chapter 4 was the benefit of midday DR potential, when comparing scenarios where EVs are only available when plugged in at home versus when they are plugged in at every major stop throughout the day. This increased DR potential in the middle of the day corresponds to reduction in VRE curtailment, most predictably from solar generation. However, there is still significant reduction in wind curtailment when there was increased midday DR potential.

Although the formulation of DR programs was essentially unconstrained in Chapter 2, and thus the impact of DR parameterization cannot be assessed, it was seen based on when DR was utilized that midday flexibility was necessary to reducing curtailment (particularly solar curtailment). This supports midday load shifting potential as a primary lever in DR program success.

5.2 Uncertainty within the model results

The SILVER model that is used throughout my research, though tested and benchmarked for accuracy, is not immune to uncertainty. Each chapter had a scenario matrix designed specifically for the research question being asked but there are still parameters that may have been inadvertently affecting the results. Though too many parameters are varied in scenarios between chapters, some conclusions on the impact of major parameters can be drawn by comparing SILVER outputs. For example, the demand profiles in Chapter 2 were quite a bit less smooth than the demand profiles in Chapters 3 and 4 due to the much higher electrification of the building sector. This in turn seems to have led to much spikier demand curves with the addition of DR. However, this difference in DR application is likely due to the way DR was modelled in Chapter 2, since the major consistency throughout the chapters is that it implemented in a way to minimize curtailment of VRE generation. Additionally, the utilization of available VRE generation, with and without DR, still follows the same trends as it does within Chapters 2 and 3. This all to say that inaccuracies in the shape of the projected demand profiles throughout chapters may not have contributed significant uncertainty to the relevant results.

Another area that uncertainty may have arisen is within the operational costs of various generation types. As SILVER is a production cost model, it optimizes for the least cost solution. Since VRE generation is already the least expensive generation type to operate, it is always prioritized and there is very little change to the amount of VRE used no matter how non-VRE operational costs change. However, what can be seen is the difference of utilization between non-VRE generation when those prices fluctuate. In test scenarios without any carbon pricing, SILVER selected coal generators to be run over natural gas simple cycle generators. This flipped when carbon pricing hit \$150/tCO_2e and GHG emissions were penalized to the point that it became less optimal to operate coal generators. This indicates that there may be uncertainty in the results due to the projected operational costs of different generation types; this is also a parameter that is difficult to forecast as macroeconomics, fuel availability, and policies may play a large role in operational costs.

Besides operational cost, changes in ramping parameters may contribute to uncertainty in the results. As generators are constrained by the speed that they are able to turn on and off, this may affect the amount of VRE being utilized as it is unpredictable in its availability. This is especially pertinent to scenarios with high VRE penetration, as it tends to make up a significant part of the operational generation mix. In test scenarios where generators have longer ramping rates (i.e., able to turn on/off slower), VRE utilization is lower and VRE curtailment is higher. However, as technologies improve, it is unlikely that ramping rates will become longer; if anything, ramping rates will likely shorten and allowed for even better VRE utilization. Though there is uncertainty in projected ramping rates, the affect is probably an understatement of the benefits of DR programs.

Finally, the parameterization of DR potential is a source of uncertainty within the research presented. Though all attempts were made to accurately simulate the amount and schedule of DR potential, it is likely that by 2050 demand will change in ways that we are unable to predict. One way that DR potential is able to be modelled within the building model resulted in a larger amount of shiftable load than needs to be recovered (i.e., DR programs would allow for load shifting *and* load reduction). Running SILVER with this projected DR potential had a marginal effect on the operational cost and GHG emission reductions compared to DR potential without load reduction potential. However, the larger difference was in the prioritization of when DR events happened: SILVER attempted to minimize operational costs by ignoring periods of high VRE availability and instead focusing on utilizing DR when it was able to recover less than was shifted. Though this did not significantly change the operational cost reduction, it would have drastically changed the conclusions that were drawn from observing the adjusted demand curve. Due to the less granular timesteps used with this version of DR potential scheduling, it was ultimately not used in any of the research presented within these chapters; however, it does lead to uncertainty by raising the possibility that incorrect assumptions around DR potential schedule creation may have affected the findings of this research.

5.3 Future work

As decarbonization targets and the policies surrounding them are progressing, future applications of DR are constantly in flux. To keep up with these changes, it is important for us to continuously improve modelled representations of DR programs. When using linked models, ensuring all individual models are up to date ensures the most up to date analysis of the benefits of DR programs. However, to maximize the potential of this research, it is important for these modelling results to be included in policy discussions. If cities continue to be able to pass more progressive policies than larger governments, implementing DR programs at the city-scale may be hugely impactful to national decarbonization targets.

Potential future research related to the work presented here includes expanding the linked model network to include behavioural models. Much of the assumptions made about DR program enrollment is based on policy, though survey results were utilized in Chapter 2; however, linking a behavioural model, such as an energy economy model, can validate any claims made about DR program enrollment. It would also be useful when justifying high VRE penetration scenarios, especially ones that would be implemented at the household level (such as rooftop solar panels). Though the research presented within this dissertation is Canadiancentric, future work will hopefully leverage the approaches to DR modelling presented here and apply them to other cities, provinces, or countries.

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6 Appendix

6.1 Chapter 2 boundary resolution assumptions

The service area for each electrical substation defines one immutable spatial boundary. The analysis uses boundaries that are recognized by the City of Regina, so that the ensuing results are meaningful. Slight spatial modifications were made to neighbourhood boundaries to keep them consistent with the substation service areas, including splitting neighbourhoods into their subsidiary subdivisions and joining neighbourhoods that were serviced together. Land that was not part of a neighbourhood recognized by the city was grouped into “outskirts” neighbourhoods. Census tract data was attributed to each neighbourhood through proportional overlap with residential buildings. As Regina is considered as a whole within the integrated model platform, none of these boundary manipulations have any effect on the results; if the electricity system were considered at a community-scale, these boundaries would need to be further verified to ensure that they are consistent between all data sources.

Based on the granularity of the electricity demand data, each substation service area is modelled as a region within SILVER, each with their own hourly demand load. The same substation service areas are also modelled as buses, or nodes, to preserve the granularity of the transmission infrastructure data. An additional bus for the connection to the provincial electricity grid is included to allow for electricity from provincial generation infrastructure to still be utilized when necessary. Neighbourhoods are modelled as demand centers within Regina, with the spatially resolved population data being used to estimate the demand within each substation attributed to each neighbourhood.

Demand loads from the transportation and building models also involve boundary resolution. The transportation model zones vary significantly from neighbourhood boundaries used within SILVER. These boundaries are spatially resolved by dividing the transportation electricity demand by the preceding trip purpose and land use zoning to determine which neighbourhood the EV charging occurs in.

For example, assume transport zone (TAZ) A overlaps with two SILVER zones (zone 1 and zone 2). SILVER zone 1 has 80% commercial buildings and 20% residential buildings, based on building footprint, while SILVER zone 2 has 90% residential buildings and 10% commercial buildings (Table A 1). We can then assume that a trip is going to TAZ A with the purpose of work or shopping, it has an 89% chance of going to SILVER zone 1 and an 11% chance of going to SILVER zone 2 (resolved so that the total likelihood is 100%). Similarly, if there is a trip to TAZ A with the purpose of going home, it has an 18% chance of going to SILVER zone 1 and an 82% chance of going to SILVER zone 2 (Table A 2). This means that any charging occurring in TAZ A when the trip purpose was work would have 89% of the load attributed to SILVER zone 1 and 11% of the load attributed to SILVER zone 2.

Table A 1: SILVER zone composition within TAZ A

	Residential	Commercial
SILVER zone 1	20%	80%
SILVER zone 2	90%	10%

Table A 2: Share of load attributed to SILVER by zone by trip purpose

	SILVER zone 1	SILVER zone 2	Total load
Work	89%	11%	100%
Shopping	89%	11%	100%
Home	18%	82%	100%

Building electricity demand loads are spatially resolved through building type distribution. The process for attributing the load to different neighbourhoods within SILVER is done by multiplying the output for each archetype modelled by the number of that type of building within each neighbourhood.