Flexibility assessment of Canada’s electricity system for deep decarbonization

by

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Abstract

In accordance with the Paris Climate Agreement, Canada has committed to reaching net-zero greenhouse gas (GHG) emissions by 2050, necessitating decarbonization across various sectors, including the electrical grid. The widespread deployment of variable renewable energy (VRE) sources holds the potential for a carbon-free electrical grid. However, the variable nature of VRE can result in technical challenges such as network frequency fluctuations, requiring a highly flexible power network to address these issues. Both the demand side and generation side can contribute to network flexibility. Generation-side flexibility can be provided by high ramping generators, such as hydro units, while demand response programs can incentivize customers to adjust their consumption patterns, offering demand-side flexibility.

This PhD dissertation seeks to investigate the decarbonization of Canada's electricity system through VRE integration, with a focus on flexibility assessment on both the generation and demand sides. The investigation of VRE integration in this study centres on employing the operation (optimal dispatch) model. The present study undertakes an examination of Canada's existing electrical system with a view to exploring its capability for the integration of VRE. The study commences by evaluating the generation-side flexibility and transmission network adequacy of the system. Thereafter, it examines two strategies aimed at enhancing the integration of VRE. The first strategy considers integrated operation of neighboring networks to leverage flexibility and enhance VRE integration in less flexible networks. The second strategy assesses the impact of demand-side flexibility in enhancing VRE integration. The findings demonstrate that Canada's hydro-dominated electrical network possesses significant potential for integrating VRE, which leads to a significant reduction in GHG emissions. Nonetheless, the current potential falls short of achieving net zero emissions, implying the need for further actions to reach this goal. The integration of neighboring electrical networks through integrated operation can enhance flexibility and VRE integration in networks that are less flexible. However, high flexible networks in Canada, dominated by hydropower, may have their flexibility provision capacity impacted by climate change. This implies that a range of flexibility resources must be taken into consideration to ensure secure and reliable VRE integration. Demand side flexibility can aid in facilitating VRE integration, however, its efficacy is contingent on consumer behavior and preferences, as well as incentives offered by the system operator. Additionally, the findings indicate that the transmission network holds a crucial role in achieving maximum flexibility on both the generation and demand sides. An inadequate transmission capacity can serve as a hindrance to achieving maximum VRE integration.

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This dissertation is based on following published papers:

1) **M. Saffari** and M. McPherson, “Assessment of Canada’s electricity system potential for variable renewable energy integration,” *Energy*, vol. 250, p. 123757, Jul. 2022, doi: 10.1016/J.ENERGY.2022.123757.
Contribution: Methodology, Software, Validation, Formal analysis, Investigation, Writing - Original Draft and revisions, and Visualization

2) **M. Saffari**, M. McPherson and Andrew Rowe, “Evaluation of flexibility provided by cascading hydroelectric assets for variable renewable energy integration”, Renewable Energy 211 (April): 55–63. https://doi.org/10.1016/j.renene.2023.04.052.
Contribution: Methodology, Software, Validation, Formal analysis, Investigation, Writing - Original Draft and revisions, and Visualization

3) **M. Saffari**, T. Cronshaw and M. McPherson, “Assessing the Potential of Demand-Side Flexibility to Improve the Performance of Electricity Systems under High Variable Renewable Energy Penetration.” Energy, vol. 272, p.127133, June. 2023. https://doi.org/10.1016/J.ENERGY.2023.127133.
Contribution: Methodology, Software, Validation, Formal analysis, Investigation, Writing - Original Draft and revisions, and Visualization

4) M. Miri, **M. Saffari** and R. Arjmand, and M. McPherson, “Integrated models in action: Analyzing flexibility in the Canadian power system toward a zero-emission future,” Energy, p. 125181, Aug. 2022, doi: 10.1016/J.ENERGY.2022.125181.
Contribution: Software development

5) M. McPherson et al., “Open-source modelling infrastructure: Building decarbonization capacity in Canada,” Energy Strateg. Rev., vol. 44, p. 100961, Nov. 2022, doi: 10.1016/J.ESR.2022.100961.

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Chapter. 1 : Introduction

In 2020, the electricity sector accounted for 8.4% of Canada's total net greenhouse gas (GHG) emissions (Government of Canada, 2021). To achieve net-zero emissions by 2050, it is necessary to decarbonize the electricity sector. One approach to achieve this is through the implementation of high levels of variable renewable energy (VRE) deployment. The effects and challenges associated with VRE are largely dependent on the extent of its deployment and the specifics of the power system context.

Power system flexibility refers to the ability of a power system to maintain stable and continuous service in the face of rapid and large changes in supply or demand. This includes the ability to quickly respond to unexpected contingencies such as plant and transmission outages, and to adapt to changes in the generation mix, including the integration of renewable energy sources. Flexibility is important for ensuring the reliability and stability of power systems, and is a key consideration in the planning and operation of power systems. As the proportion of VRE generation such as solar and wind power increases, power system flexibility becomes increasingly important. VRE generation is dependent on weather conditions and can fluctuate rapidly, making it more challenging for power systems to maintain reliability. Therefore, to accommodate higher VRE penetration, more flexibility investments such as demand response and grid upgrades are needed. Without sufficient flexibility, system operators may be forced to limit VRE output, which can result in significant amounts of curtailment. This can have negative consequences such as reducing project revenues and contract values, impacting investor confidence in VRE revenues, and making it harder to meet emissions targets. By improving system flexibility, the amount of curtailment is reduced, making investment in new VRE generation more attractive, and improving the integration of VRE into the power system. VRE curtailment reduces a plant's capacity factor and can negatively impact its revenue stream. As the proportion of VRE generation in the power system increases, the need for flexibility also increases to maintain stability and ensure reliable power supply. When decision makers inquire about the potential for adding more wind and solar generation to the electricity grid, the concept of flexibility is often brought up as a key factor in determining the amount of VRE that can be integrated without causing significant amounts of curtailment. A key objective for power networks is to minimize VRE curtailment by achieving a high degree of flexibility in the power system, through investments in demand response and grid upgrades. This allows for a higher penetration of VRE generation, which can help to meet renewable energy goals and reduce GHG emissions.

1.1. Operation model

The significance of power system operation has augmented as the electricity network faces decision-making under a high level of uncertainty in the behavior of electric vehicles, the integration of VRE, and diverse pricing mechanisms. By modeling intricate network operations under varying conditions, operation models can furnish crucial information to the electricity system planner, operator, and policy maker.

The operation model provides a detailed analysis of the power system by determining the optimal dispatch of the network with high temporal and spatial resolution and considering a comprehensive set of constraints. The high temporal resolution allows for the inclusion of the rapidly changing parameters, such as load, VRE capacity factor, and hydro capacity factor, which have a significant impact on network flexibility. The high spatial resolution contributes to a more realistic modeling of the scale of the electricity network. The comprehensive set of constraints allows for the accurate modeling of the behavior of electricity system components, which is crucial in ensuring the assessment of network flexibility is accurate.

Consequently, the operation model is capable of modeling the significant aspects of the electricity system in detail that impact network flexibility and curtailment of VRE. As a result, it serves as an effective tool for accurately determining the extent of VRE curtailment, which is a vital design objective in the integration of VRE sources.

1.2. Research objective

The present research endeavors to investigate Canada's electrical system decarbonization through the integration of VRE sources using an operational model. The study commences by refining and upgrading the existing Canadian operational model, Strategic Integration of Large-capacity Variable Energy Resources (SILVER) (McPherson and Karney, 2017). The research examines Canada's current electrical system with regards to generation side flexibility and transmission network to assess its potential for VRE integration. Subsequently, two strategies, namely integrated network operation and demand side flexibility, are explored to enhance flexibility and promote VRE integration.

In order to attain precise analysis of an electrical network and derive credible outcomes, it is crucial to model the network components with exactitude. The SILVER model is undergone refinement to precisely reflect the characteristics of Canada's electrical system. Given that Canada's electricity system is predominantly powered by hydropower, accurate modeling of this energy source is crucial for the effective operation of the network. To this end, the study improves the hydro modeling component of the SILVER model, taking into consideration the characteristics of hydropower in Canada. Additionally, to assess the impact of demand side flexibility, demand response programs, which are being implemented in Canada's electricity system, are incorporated into the SILVER model.

The current state of the electricity system, including its generation side flexibility and transmission network, is a crucial aspect in effectively planning for the future and integrating new technologies, such as renewable energy sources. In order to plan for the integration of VRE, decision-makers must evaluate the capacity of the existing infrastructure in order to identify the necessary measures to transition towards a zero-carbon electricity system. This is an important step in ensuring a smooth transition to a more sustainable and reliable electricity system. Chapter Two of the study carries out an assessment of Canada's existing electrical infrastructure, with a particular emphasis on its generation side flexibility and transmission network capacity for the integration of VRE. The generation-side flexibility plays a crucial role in demonstrating the suitability of a network for integrating VRE sources, as it reflects the network's ability to accommodate the fluctuating output of these sources. The transmission network is pivotal in promoting the integration of VRE by transmitting electricity from generation sites to demand locations. To ensure balance between energy generation and consumption, fluctuations in VRE generation must be compensated by other sources such as generators or storage. The electrical network comprises a decentralized network of generators. In cases where the capacity factor of VRE is low and falls below expected levels, power must be transferred from other parts of the network to load centers to guarantee security of power supply. A lack of sufficient transmission capacity can restrict the network's ability to counteract fluctuations in VRE. Even if there is enough generation capacity to compensate for VRE variation, a lack of transmission capacity can result in a power-demand imbalance. Therefore, transmission network capacity is a crucial consideration when integrating VRE into the electricity system.

To improve integration of VRE into electricity networks, an increase in network flexibility is required. Given the unequal distribution of hydro capacity, which possesses a considerable degree of flexibility, across Canada, integrated network operation concept, which allows neighboring networks to share their flexibility, can be implemented to enhance network flexibility of less flexible networks. This strategy allows for the sharing of flexibility across neighboring networks. This study assesses the potential for enhancing VRE integration and network flexibility through the integration of two neighboring electricity networks in Canada - British Columbia and Alberta. British Columbia boasts a highly flexible and clean electricity grid, primarily powered by hydropower, while Alberta primarily relies on gas and may require significant VRE deployment for decarbonization. Chapter Three investigates the feasibility of integrating the two grids to enhance Alberta's flexibility and VRE integration through the integrated network operation concept.

Demand side flexibility is another important factor that can contribute to VRE integration. Due to the variability in VRE output, shifting demand from periods of low capacity factor to periods of high capacity factor can help prevent VRE curtailment or power outages. Hence, demand side flexibility can play a crucial role in supporting VRE integration. Chapter Four delves into the implementation of demand response programs aimed at enhancing network flexibility. These programs incentivize customers to adjust their consumption patterns, thereby providing increased flexibility on the demand side, which can be leveraged to improve VRE integration. The fourth chapter evaluates the impact of these demand response programs on network flexibility and VRE integration.

The research objectives can be divided into four categories:

I) To improve/refine SILVER model according to Canada’s electricity network context.

II) Evaluation of the current Canada's electricity network with regards to its generation side flexibility and transmission network capacity for the integration of VRE.

III) Assessment of integrated operation of neighboring networks to enhance network flexibility and VRE integration in less flexible network.

IV) Evaluation of demand side flexibility impact on VRE integration.

Chapter. 2 Assessment of Canada’s electricity system potential for variable renewable energies integration

Abstract: Meeting Paris Agreement commitments will necessitate a transition in Canada's power system, including increased renewable generation. This study evaluates the current state of the Canadian electricity system in regard to its capacity to implement decarbonization strategies. Specifically, it assesses the ability of the system to integrate VRE sources. The SILVER operation model is refined to depict the impact of hydro resources and demand response programs, more accurately on the system. Using 2018 data, a SILVER network-constrained unit commitment (NCUC) is created for each of Canada's ten provinces for a one-year period. The results are analyzed to assess flexibility of the system, adequacy of the transmission network, and associated operational costs and emissions. The findings suggest that the hydro-dominated network in Canada, coupled with the capacity of the transmission network, has the potential to achieve an average VRE penetration rate of 54% with a VRE curtailment of less than 10%. However, relying solely on existing generation-side flexibility within the provincial networks will not result in net-zero emissions while reducing greenhouse gas emissions.

Keywords: Canada’s electricity system, decarbonization, VRE integration, network-constrained unit commitment (NCUC), network flexibility, demand response programs.

2.1. Introduction

Canada has pledged to decrease its greenhouse gas (GHG) emissions by 40% to 45% below 2005 levels by 2030 and to reach net zero emissions by 2050 (Goverment 2021). Despite the fact that Canada's electricity system is already dominated by low-carbon hydro assets, recent assessments indicate that fulfilling Canada's GHG emissions commitments will require a significant amount of variable renewable energy (VRE) capacity, such as solar and wind (Bataille 2015; Trottier 2016).

Operation models optimize the operation of generation and transmission assets with high temporal and spatial resolutions to minimize or maximize one or multiple objective functions while satisfying a comprehensive set of operational constraints. This type of model simulates the dispatch of an electricity system that encompasses generation units, VRE, the transmission network, and storage assets. Hence, operation models can be utilized to assess the operational aspects of decarbonization policies and plans. The importance of power system operations has increased as the electric grid confronts decision-making in a highly uncertain environment, characterized by the integration of variable renewable energy sources, the behavior of electric vehicles, and diverse pricing structures. By modeling complex network operations under various conditions, operation models can provide valuable insights to electricity system planners, operators, and policy makers.

Five operation models, ranging from small remote microgrids to provincial and national electricity networks, have been developed and applied in the Canadian context (McPherson and Karney 2017; Martinez et al. 2019, Olivares, Cañizares, and Kazerani 2014; Wong, Gaudet, and Proulx 2017; Wong, Gaudet, and Proulx 2017). Each considers different aspects of energy system operation. SILVER was designed to evaluate the high penetration of renewables into the bulk power system (McPherson and Karney 2017). The model has the capability to simultaneously simulate multiple flexible energy resources, enabling the assessment of their contribution to the integration of variable renewable energy. As a result, the model outputs can be utilized to determine the optimal trade-off between these resources in order to achieve decarbonization goals. Alternatively, Martinez et al. (2019) propose a control framework for evaluating wind energy integration with compressed air storage, with the goal of designing a wind-diesel system that can mitigate wind variability and facilitate integration.

In Canada, some remote regions possess electricity systems that are not integrated with the main grid. The management and operation of these isolated networks to accommodate the integration of variable renewable energy sources remains a persistent challenge that has been addressed through a multitude of modeling approaches and frameworks. Sauter et al. (2019) create a control framework for electric thermal storage (ETS) integrated into a microgrid energy management system (MEMS) to flatten heating demand and facilitate VRE integration onto the microgrid. Similarly, Wong, Gaudet, and Proulx (2017) propose an ETS control mechanism to achieve high VRE penetration on isolated networks, flatten heating demand, and reduce GHG emissions. Olivares, Cañizares, and Kazerani (2014) present a model predictive control-based centralised energy management system for remote microgrids. The model optimises storage unit operation to maximise VRE utilisation in the grid. In general, the three models under consideration aim to provide new control approaches for storage operation in the context of a smart grid in order to facilitate VRE integration. Another significant advantage of the models is their comprehensive formulations, which include three-phase alternating current power flow, active/reactive, and heating loads.

In addition to operation models, several models that encompass both expansion and operation decisions have been developed. These models are formulated with the aim of minimizing total system investment and operational costs. CREST (Dolter and Rivers 2018), CanESS (CanESS 2021) and IESD (Electricity Modeling - Navius Research, 2020.) have been designed specifically for Canada energy system. Furthermore, PLEXOS (PLEXOS 2020), OSeMOSYS (Howells et al.

2011), ENERGY 2020 (ENERGY2020 2020), ReEDS (Zinaman et al. 2015) and SWITCH (Nelson et al. 2012) have been applied to Canada’s energy sector.

A suite of literatures utilizes OSeMOSYS to investigate decarbonization policies in Canada. Keller et al. (2019) apply an integrated planning and operation model to investigate the effect of transportation electrification for the British Columbia under different decarbonization scenarios. Jeffrey English et al. (2020) use a hybrid expansion/operation framework in order to address VRE uncertainty in the planning level. Palmer-Wilson et al. (2019) investigate the effect of land-use requirements of increasing VRE penetration. J English et al. (2016) assess emission and cost decreases resulted from transmission line expansion between Alberta and British Columbia. Niet et al. (2017) investigate uncertainty of electricity generation emissions through a stochastic risk model. The purpose of the study is to determine the generation expansion scenario with the lowest risk.

Furthermore, the integration of VRE and decarbonization is a matter of ongoing investigation in several countries apart from Canada. Wyrwa et al. (2021) propose a novel planning framework to investigate decarbonization in Polish coal-dominated network. Ye, Lin, and Tukker (2019) analyze flexibility requirements for thermal units in order to assess future VRE integration scenarios in China. Hansen, Mathiesen, and Skov (2019) assess increasing share of renewables in Germany’s electricity network considering different policies including phasing out nuclear units. Finally, Syranidou et al. (2020) propose a new pan- European operation model considering contribution of responsive load programs to evaluate VRE integration.

To summarize, previous research in Canada has utilized operation models to explore the integration of VRE sources into the country's electricity grid. However, the current modeling framework has scope for improvement to reflect challenges and prospects more accurately for integrating VRE sources within the Canadian context. Specifically, the dominance of hydro power in Canada highlights the importance of accurately modelling hydropower operation. Improving the representation of hydro units, including cascading assets and categorizing by reservoir size, can enhance the accuracy of operation models. Additionally, considering the role of demand response programs in providing flexibility is critical for a comprehensive understanding of the potential for VRE integration.

Understanding the current state of the electricity system, including flexibility and network adequacy, is crucial for effectively planning for the future and integrating new technologies such as renewable energy sources. Decision makers must consider the potential of the existing network and identify requirements for integration of new technologies. This is an important step in ensuring a transition to a more sustainable and reliable electricity system. This study delves into the potential of Canada's existing power system for the integration of VRE sources. The variability and intermittency of VREs presents a major challenge in integrating them into the power system, hence the flexibility of power systems to manage VRE variability is crucial in determining their suitability for VRE integration. The study assesses VRE integration in Canada's electricity system through examination of the generation side flexibility and the transmission network adequacy. The generation-side flexibility plays a crucial role in demonstrating the suitability of a network for integrating VRE sources, as it reflects the network's ability to accommodate the fluctuating output of these sources. In order to sustain balance between generation and demand, the fluctuations in VRE must be compensated through alternative generators. The placement of generators is dispersed throughout the electrical grid, and the transmission network is responsible for transmitting generated electricity from the generation facilities to the sites of demand. When the capacity factor of VRE is inadequate, the power must be transferred from other areas of the network to meet demand, in order to ensure the security of the power supply. Although sufficient generation capacity may be present to compensate for VRE variability, a scarcity of transmission capacity can lead to imbalances in power supply. Consequently, the capacity of the transmission network is a critical aspect to be taken into account when integrating VRE into the electrical power system.

As such, in this paper, we:

1) Enhance the representation of hydro assets and demand response programs in the SILVER model in order to enhance its capacity to analyze the flexibility of the power system.
2) Conduct a comparative analysis of the generation side flexibility and transmission network adequacy of power systems across Canada with a focus on their potential for integrating VRE.

The subsequent sections of this paper are organized as follows. The second section outlines the improvement and validation of the SILVER model. The third section presents the methodology for the case studies. The fourth section presents the numerical results obtained from the study. The fifth section highlights the limitations of the study, and the final section concludes with a summary of the key findings.

2.2. SILVER improvement

In order to achieve accurate analysis of an electrical network and obtain trustworthy results, it is imperative to model the network components with precision. The SILVER model is refined to precisely reflect Canada's electrical system. Two key improvements are made to the SILVER model: the representation of hydro assets and demand response programs. The accuracy of the hydro modelling is particularly crucial for evaluating the generation side flexibility for VRE integration in Canada, where hydro power plays a dominant role. The implementation of DR programs has garnered significant attention in recent years as a crucial tool for improving the network's ability to integrate VRE sources. To examine the impact of demand-side flexibility on VRE integration in Canada, Time of Use (ToU) program, which is currently implemented in Alberta and Ontario, is integrated into the SILVER framework.

2.2.1. Hydro modelling

The SILVER model hydro modelling is improved to account for hourly, daily, and monthly category constraints (Note: the first version of SILVER (McPherson and Karney 2017) included a hydro module that only formulates hydro in terms of maximum output being limited by water flow availability).

$$P_{i,t} < P_i^{\max,\,hourly}, i \in \{hydro_{hourly}\} \tag{1}$$

$$\sum_{t=1}^{24} P_{i,t} < P_i^{\max,\,daily}, i \in \{hydro_{daily}\} \tag{2}$$

$$\sum_{t=1}^{720} P_{i,t} < P_i^{\max,\,monthly}, i \in \{hydro_{monthly}\} \tag{3}$$

Where Eq. 1 limits the hourly output of hydro hourly units, Eq. 2 limits the maximum output of daily units over a single day (24 hours), and Eq. 3 limits the maximum output of monthly units over a single month (720 hours).

The model of cascading hydro units has also been added to the SILVER framework. Based on (Wood and Wollenberg 1996), we used the following linear model of cascading hydro:

$$d^{\min} < d_{i,t} < d^{\max} \tag{4}$$

$$V^{\min} < V_{i,t} < V^{\max} \tag{5}$$

$$S^{\min} < S_{i,t} < S^{\max} \tag{6}$$

$$V_{i,t+1} = V_{i,t} - D_{i,t} - S_{i,t} + D_{i-1,t-\tau} + S_{i-1,t-\tau} + \kappa_{i,t} \tag{7}$$

$$P_{i,t} = A * \eta_i * D_{i,t} * \bar{H}_{i,t} \tag{8}$$

$$\sum_{t=1}^{N_t} P_{i,t} < P_i^{\max} \tag{9}$$

Eq. 4-6 ((Wood and Wollenberg 1996)) impose constraints of water discharge ($d_{i,t}$), storage volume ($V_{i,t}$) and water spillage ($S_{i,t}$). Eq. 7 ((Wood and Wollenberg 1996)) stipulates that the storage volume at next time ($V_{i,t+1}$) to be equal to the storage volume at the current time ($V_{i,t}$) plus inflow into the storage ($\kappa_{i,t}$), a constant parameter which depends on some other parameters (such as evaporation and rainfall), plus water discharge ($D_{i-1,t-\tau}$) and spillage ($S_{i-1,t-\tau}$) from upstream storage, where τ represents the delay time, minus water discharge ($D_{i,t}$) and spillage ($S_{i,t}$) of the storage. Eq. 8 represents storage's output power, where A is a constant, η_i is the energy conversion efficiency and $\bar{H}_{i,t}$is the average height of water in the storage. Finally, Eq. 9 imposes limitations on the permitted generation for unit i during N_t.

2.2.2. Demand response

In order to enhance the representation of demand response within SILVER, ToU demand response program is integrated into the model. The formulation for the ToU program is outlined as follows:

$$\Delta D_t = D_t \left(\sum_{\tau \in L} \sigma_{t,\tau} . \frac{(\varphi_t^L - \varphi_t)}{\varphi_t} + \sum_{\tau \in O} \sigma_{t,\tau} . \frac{(\varphi_t^O - \varphi_t)}{\varphi_t} + \sum_{\tau \in \mathrm{P}} \sigma_{t,\tau} . \frac{(\varphi_t^P - \varphi_t)}{\varphi_t} \right) \tag{10}$$

$$\sum_{t=1}^{N_t} \Delta D_t = 0 \tag{11}$$

$$A^D . D_t \leq \Delta \mathrm{D_t} \leq \mathrm{A^U} . D_t \tag{12}$$

$$\Delta\varphi_t^O \leq 0 \tag{13}$$

$$\Delta\varphi_t^P \geq 0 \tag{14}$$

$$\Delta\varphi_t^O \leq \Delta\varphi_t^L \leq \Delta\varphi_t^P \tag{15}$$

Where D_t is the electrical load at time t without a ToU response, and ΔD is the change in load with the ToU program; φ_t^L, φ_t^O, and φ_t^P represent prices prior to the implementation of the ToU program for the low peak, off-peak and peak periods, respectively; and $\sigma_{t,\tau}$ is the price elasticity of demand at time t in response to the price at time τ (i.e., $\mathrm{t} = \tau$ implies own-price elasticity, otherwise values are cross-price elasticities). According to Eq. 10, greater elasticity values cause greater load changes (ΔD), and vice versa. Eq. 11 (M.S. Misaghian et al. 2018) enforces a zero sum for load changes over all time periods (i.e., total load remains constant with ToU program implementation, only its distribution in time changes). A^{D} and A^{U} are constants constraining the range for load changes. $\Delta\varphi_t^L$, $\Delta\varphi_t^O$, and $\Delta\varphi_t^P$ indicate prices changes in the L, O, and P periods, respectively (with ranges constrained by Eq. 13-15).

2.3. SILVER validation

The validity of the SILVER model is established through five distinct evaluations. Firstly, the model's validation is performed based on power system principles. In fact, SILVER's results are investigated for meeting principles of power system. Secondly, the SILVER model's results are assessed for the fulfillment of constraints. Thirdly, a sensitivity analysis is conducted to investigate the anticipated output changes in response to parameters variations. Fourthly, the SILVER model's performance is compared against other literature results for the same data and case study. Finally, the SILVER model's results are compared against those of PLEXOS, a widely used commercial production cost model featured in numerous papers and theses worldwide.

The SILVER is tested against the RTS-GMLC system, a comprehensive system composed of 73 buses, 158 generator units, and 106 lines, as reported by Barrows et al. (2020). The SILVER DC unit commitment problem is employed to run the test system for a period of 14 days. The UC problem features hourly constraints, such as ramp rate, multi-hour constraints, such as generator minimum on/off time, and daily constraints, such as daily hydro. Thus, 14 days of operation are deemed adequate to assess the effectiveness of these constraints.

Although the results for some validation methods are presented for an arbitrary selection of components over a 24-hour period, they hold true for all components of the testing system for the duration of two weeks.

2.3.1. Theoretical assessment of results

This section presents a validation of the SILVER results in accordance with a power system principle. Power system operation principles encompass various parameters such as power system frequency, active power, reactive power, voltage angle, voltage magnitude, generator excitation current, etc. However, SILVER model employs DC unit commitment (DCUC) formulation that neglects essential constraints, such as voltage magnitude, reactive power, generator excitation system, and frequency. As a result, the only power system principle that can be evaluated by the SILVER model formulation is the one that associates active power to voltage angle. According to this principle, active power flows from the substation with a higher voltage angle to the substation with a lower voltage angle.

Table 1 presents the voltage angle values of the starting and ending substations of two arbitrary lines of RTS-GMLC system over the first 24-hour period of operation. The results indicate a consistent transfer of power from substations with higher voltage angles to those with lower voltage angles, demonstrating that the SILVER power flow constraints are in line with established power flow theories.

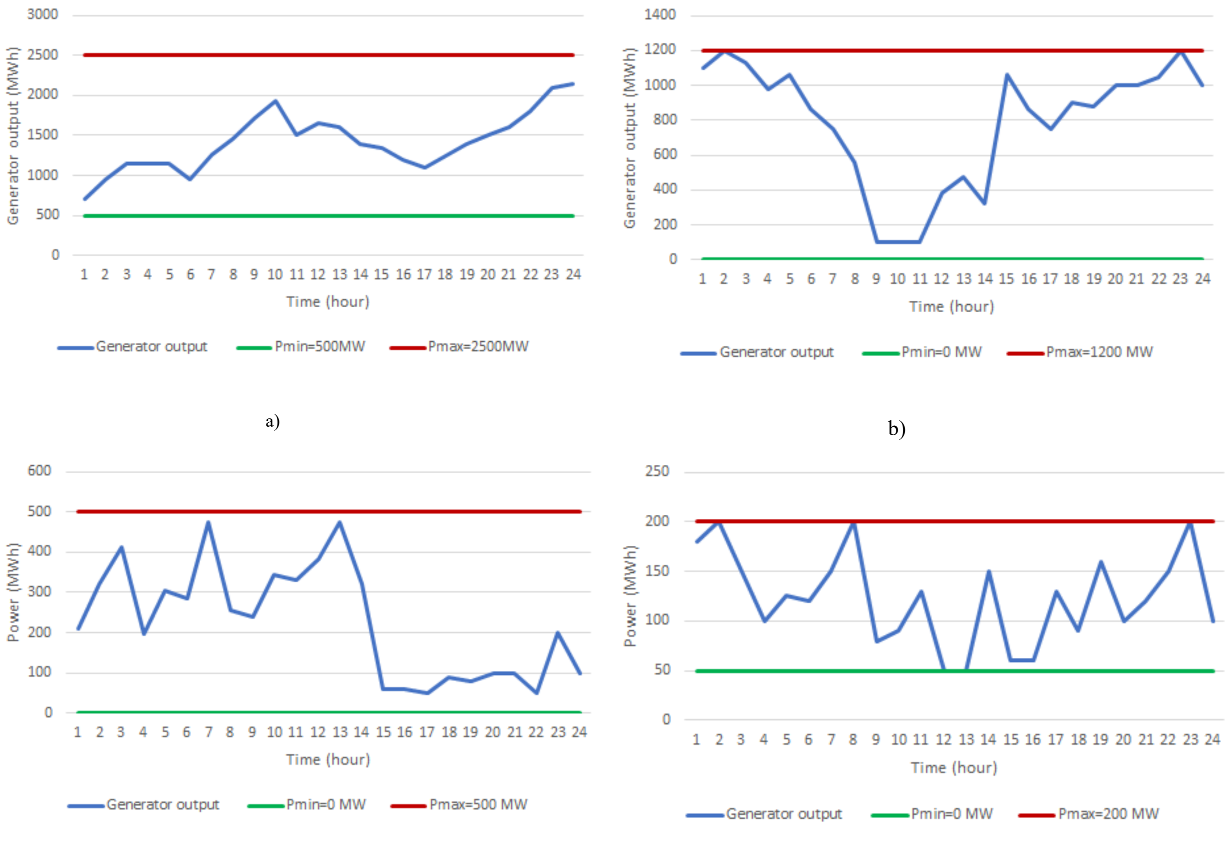
Table 1: Voltage angel and transferred power for two arbitrary lines

	Line1			Line2		
Time	Voltage angle (radian) (Starting substation)	Voltage angle (radian) (Ending substation)	Transferred power (MWh) from starting substation to ending substation	Voltage angle (radian) (Starting substation)	Voltage angle (radian) (Ending substation)	Transferred power (MWh) from starting substation to ending substation
1	2.12	1.1	1500	-0.3	0.1	-1400
2	2.06	1.3	780	-0.8	-0.2	-1730
3	2.86	1.1	1720	--0.32	0.3	-1650
4	2.01	1.33	1050	-0.1	0.9	-2140
5	2.55	1.3	1360	0.2	1.3	-2220
6	2.72	2.1	670	0.6	1.6	-26040
7	1.11	0.8	430	-0.2	0.5	-2950
8	1.98	1.1	1340	0.9	2.1	-3230
9	2.5	1.5	1550	1.3	2.5	-3950
10	3.01	2.4	1250	0.3	1.6	-3150
11	1.33	0.25	1800	-0.5	0.2	-1830
12	2.44	1.55	1370	-1.2	0.1	-2980
13	1.53	0.7	1230	-0.5	1.2	-1832
14	3.1	1.6	1000	-0.6	1.4	-1943
15	1.3	0.3	867	-0.2	1.1	-1500
16	2.1	1.8	895	-0.1	0.9	-1235
17	1.3	0.8.	823	-0.1	0.8	-960
18	2.2	0.3.	764	0.2	0.7	-943
19	3.1	0.5	678	-0.3	1	-1100
20	2.9	0.4	133	-0.9	1.9	-1740
21	2.8	3.1	-324	-1.2	2.3	-2202
22	1.8	2.5	-432	-1.3	2.5	-2390
23	1.6	1.9	-564	-1.5	2.6	-2500
24	0.5	2.2	-690	-1.8	3.1	-2876

2.3.2. Assessment of results in terms of meeting constraints

In this section, the conformity of the SILVER results to the constraints is analyzed. The constraints are the minimum and maximum output of the generator, which impose limits on the generator's output; the generator ramp rate, which limits the rate of ramping up or down to within the generator's maximum ramping capability; the minimum up and down time, which sets the minimum duration for generator up or down time; voltage angle, which imposes limits on the substation voltage angle within the range of -3.14 and +3.14; and power flow, which limits the line flow to its maximum allowable level; maximum discharge water, which restricts the maximum amount of water discharged from the reservoirs; reservoir maximum content, which limits the maximum capacity of the reservoirs; storage maximum charge/discharge, which restricts the maximum amount of charging or discharging allowed in the storage; and storage maximum content, which constrains the storage content to remain within its maximum limit.

The output power values for four arbitrary generators of RTS-GMLC system over the first 24-hour period is presented in Figure 1. The figure demonstrates that the SILVER results are in compliance with the generator's minimum and maximum output constraints.



a)

b)

c)

d)

Figure 1: Output power of four arbitrary generators over 24 hours; generator 1, b) generator 2, c) generator 3, d) generator 4

Figure 2 presents the ramping characteristics of four arbitrary generators od RTS-GMLC system across the first 24-hour interval. The data shows that ramping up is indicated by positive values, ramping down by negative values, and a stable output from the previous hour is denoted by zero. The analysis of the data in the figure indicates that the SILVER results comply with the ramp rate limitations.

a) b)

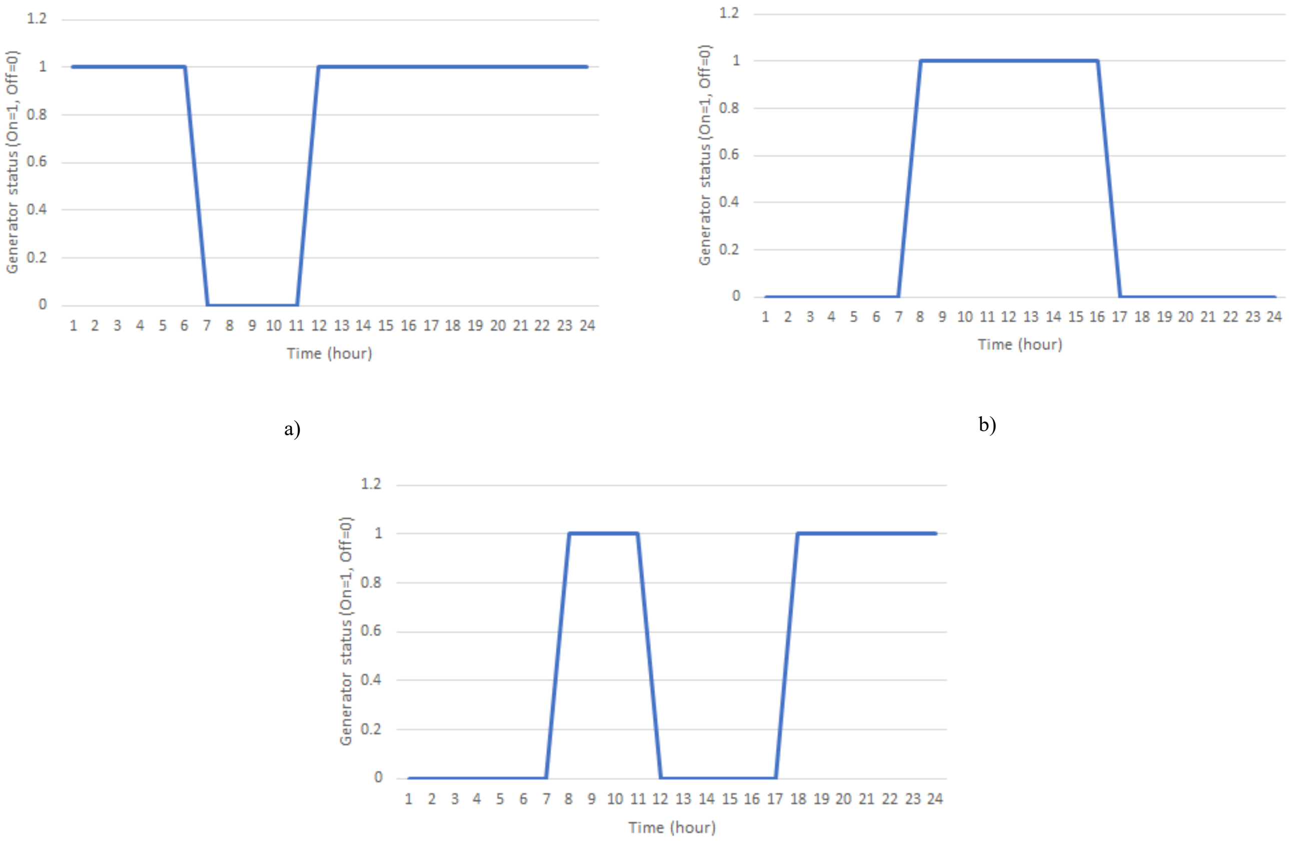
c) d)

Figure 2: Ramping values of four arbitrary generators over 24 hours; a) generator 1, b) generator 2, c) generator 3, d) generator 4

Table 2 illustrates the on and off times of three randomly selected generators from the RTS-GMLC system, exhibiting their adherence to the minimum up/down constraints. Moreover, Figure 3 provides a graphical representation of the generators' statuses over a 24-hour period, which can aid in evaluating their on and off times. As per the table, Generator 1 is running for 2 hours at time 1, and in accordance with its minimum on-time requirement of 4 hours, remains on until time 6, before turning off at time 7 after 5 hours of operation. The generator then remains off for a minimum of 4 hours, as per its minimum down-time requirement, before being reactivated. Similarly, Generator 2 is off for three hours at time 1 and cannot be reactivated before 8 hours, due to its minimum down-time of 8 hours. The generator is then reactivated at time 8 after being off for 9 hours. These results demonstrate that the SILVER model results adhere to the minimum up/down constraints.

Table 2: Up and down time of three arbitrary generators over 24 hours

	Generator 1		**Generator 2**		**Generator 3**	
Time	Up time (hour) Min_up_time=4	Down time (hour) Min_down_time=4	Up time (hour) Min_up_time=8	Down time (hour) Min_down_time=8	Up time (hour) Min_up_time=2	Down time (hour) Min_down_time=2
1	2	0	0	3	0	1
2	3	0	0	4	0	2
3	4	0	0	5	0	3
4	5	0	0	6	0	4
5	6	0	0	7	0	5
6	7	0	0	8	0	6
7	0	1	0	9	0	7
8	0	2	1	0	1	0
9	0	3	2	0	2	0
10	0	4	3	0	3	0
11	0	5	4	0	4	0
12	1	0	5	0	0	1
13	2	0	6	0	0	2
14	3	0	7	0	0	3
15	4	0	8	0	0	4
16	5	0	9	0	0	5
17	6	0	0	1	0	6
18	7	0	0	2	1	0
19	8	0	0	3	2	0
20	9	0	0	4	3	0
21	10	0	0	5	4	0
22	11	0	0	6	5	0
23	12	0	0	7	6	0
24	13	0	0	8	7	1



a)

b)

c)

Figure 3: Status of three arbitrary generators over 24 hours; a) generator 1, b) generator 2, c) generator 3

The results of voltage angle values for four arbitrary substations over a 24-hour period are presented in Figure 4. The voltage angle must fall within the bounds of -3.14 and +3.14, as indicated by the constraints. The results generated by SILVER, as indicated by the Figure 3, conform to these voltage angle limits.

a)

b)

c)

d)

Figure 4: Voltage angle of four generators over 24 hours; a) substation 1, b) substation 2, c) substation 3, d) substation 4

Figure 5 presents the line flow values for four arbitrary lines of RTS-GMLC system over the first 24-hour period of operation. The results indicate that the SILVER model adheres to the maximum line flow constraint, as evidenced by the values displayed in the figure.

a)

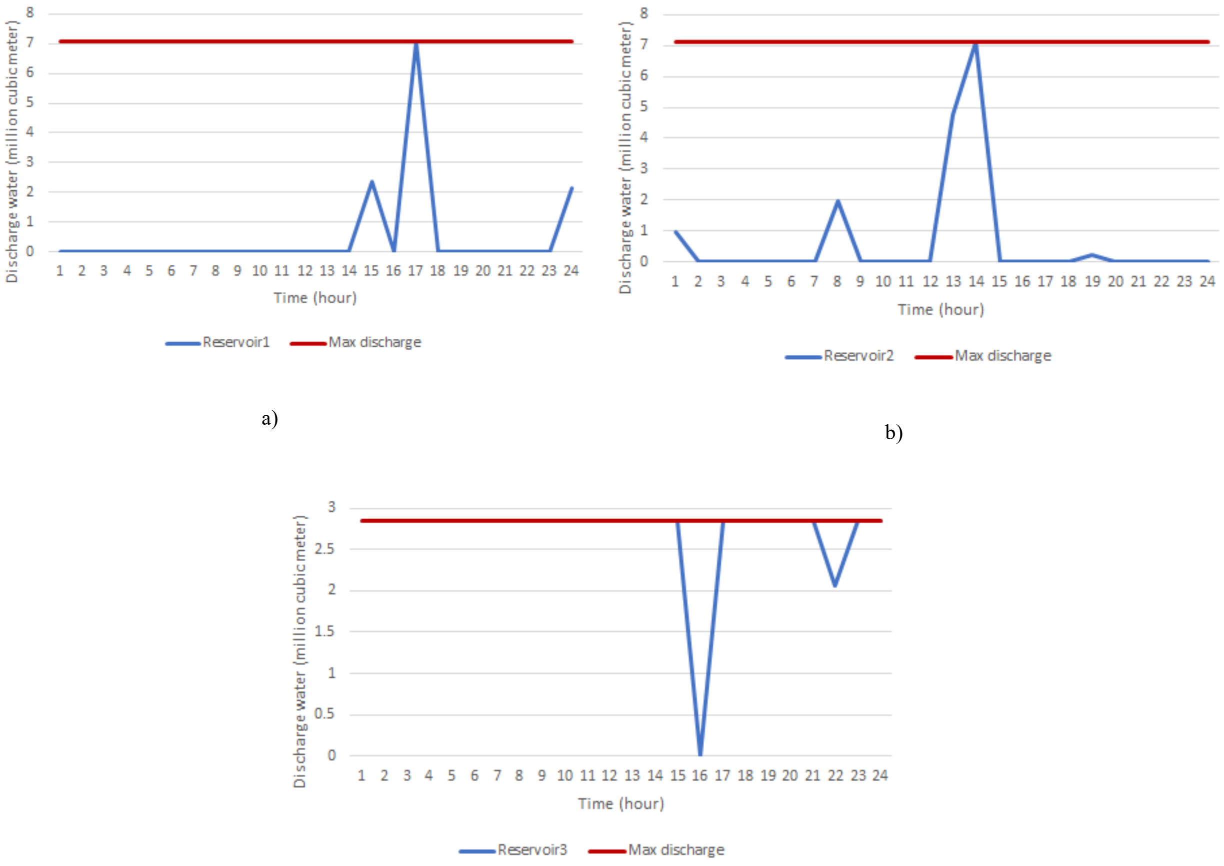
b)

c)

d)

Figure 5: Power flow of four arbitrary lines over 24 hours: a) line 1, b) line 2, c) line, d) line4

Figures 6 and 7 present the discharge water and reservoir content of three reservoirs in a cascade asset. It is evident from the findings that the SILVER model's results conform to the maximum discharge water and maximum reservoir content limitations.

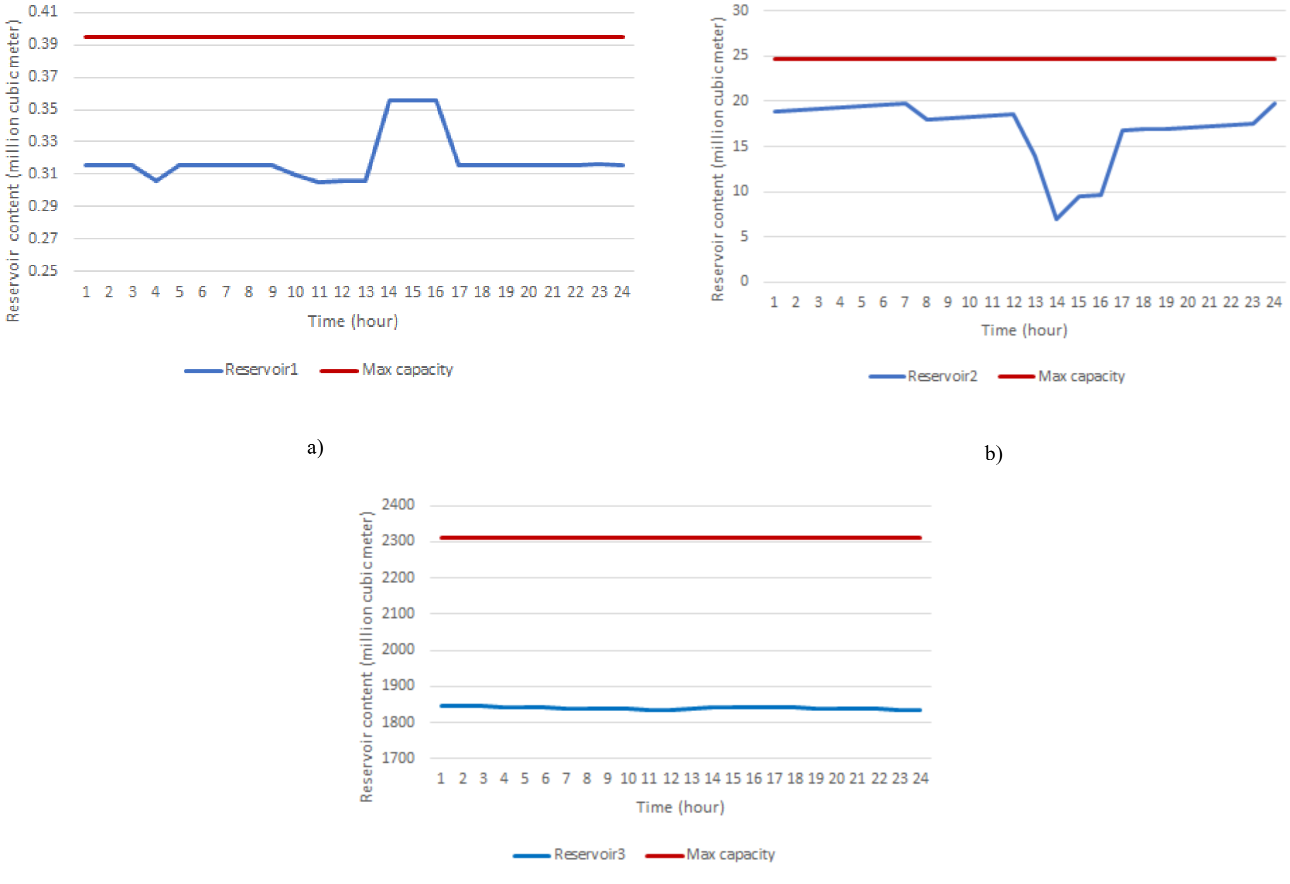


a)

b)

c)

Figure 6: Discharge water of three reservoirs over 24 hours, a) reservoir1, b) reservoir2, c) reservoir3



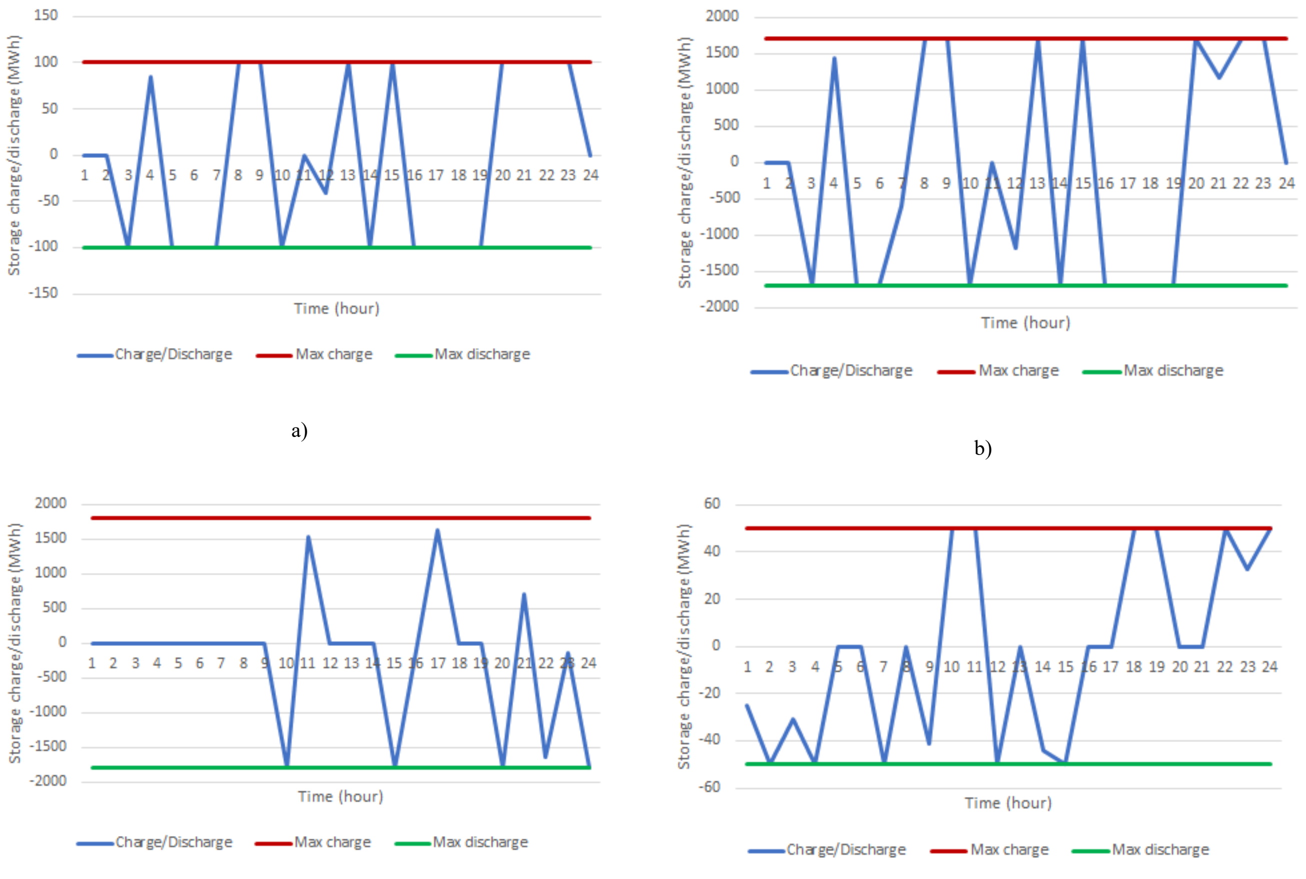
a)

b)

c)

Figure 7: Reservoir content of three reservoirs over 24 hours, a) reservoir1, b) reservoir2

Figures 8 and 9 depict the charge/discharge power and storage content of four energy storage systems. The results demonstrate that the SILVER model adheres to the maximum charge/discharge power and maximum storage content constraints.



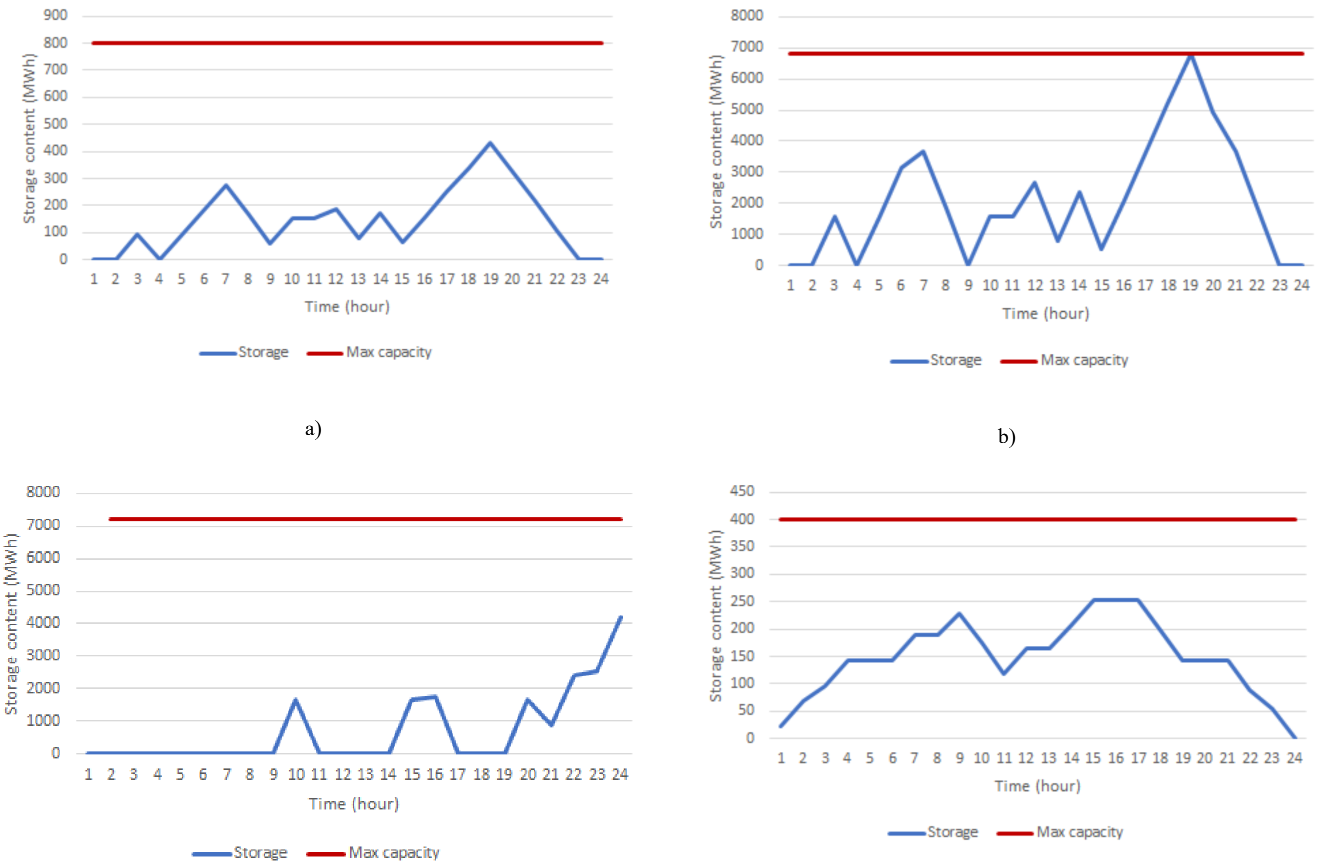
a)

b)

c)

d)

Figure 8: Storage charge/discharge of four storages over 24 hours, a) storage1, b) storage2, c) storage3



a)

b)

c)

d)

Figure 9: Storage content of four storages over 24 hours, a) storage1, b) storage2, c) storage3, d) storage4

2.3.3. Sensitivity analysis

This section presents a sensitivity analysis of various parameters, namely generator cost, generator maximum capacity, generator ramping rate, VRE capacity factor, line maximum power flow, and electricity demand. The aim is to evaluate whether variations in these parameters produce anticipated changes in the simulation results.

First, the sensitivity analysis is conducted to evaluate the impact of changes in generator cost on its output power. The objective of the analysis is to determine if variations in generator cost results in the expected changes in output power. The analysis is performed by altering the cost of generation for a single generator while keeping the costs of other generators constant. The results are presented in Table 3, which displays the percentage of output power for arbitrary generators under different cost scenarios over two weeks simulation. The findings indicate that an increase in generator cost leads to a decrease in output power and vice versa. This relationship is consistent with the objective of cost minimization in the SILVER model, which prioritizes generators with lower costs for dispatch, leading to a reduction in output power for higher cost generators.

Table 3: Price change vs output power change for three arbitrary generators over two weeks

	Generator 1	**Generator 2**	**Generator 3**
Price change scenario	Output power change	Output power change	Output power change
-20%	+5%	+2%	+8%
-10%	+2%	+1%	+5%
+10%	-4%	-5%	-7%
+20%	-11%	-13%	-16%

Given that the objective function is to minimize cost, generators with lower costs are given priority for dispatch. Therefore, an increase in the maximum generation capacity of a lower-cost generator should result in a corresponding increase in its power output, unless there are technical constraints such as transmission line capacity limits. Table 4 displays scenarios where the maximum capacity is changed, and their corresponding output power changes, for the generator with the lowest generation cost. The findings indicate that, in the first three scenarios, an increase in the maximum capacity of the lowest-cost generator leads to an equivalent increase in output power. However, in the final scenario, the increase in output power is less than the maximum capacity increase due to the transmission line's maximum capacity constraint.

Table 4: Maximum capacity change vs output power change for the lowest cost generator over two weeks

Maximum capacity change scenario	**Output power change**
+5%	+5%
+10%	+10%
+20%	+20%
+40%	+34%+

Electricity demand has a significant impact on generator dispatch, with higher demand resulting in increased generation by generators, and vice versa. Percentage change in generation versus the percentage change in demand over two weeks operation is presented in Table 5. The power balance constraint in the UC problem ensures that any change in demand is accompanied by an equal change in system generation.

Table 5: System generation change vs demand change over two weeks

Demand change scenario	System generation change
-20%	-20%
-10%	-10%
+10%	+10%
+20%	+20%

In this study, the cost of operating VRE sources is considered to be negligible. Consequently, when minimizing costs, VRE sources have the highest priority for dispatch. Therefore, increasing the capacity factor of VRE sources should result in a corresponding increase in their dispatched output power. However, the output power may be limited by constraints such as line maximum capacities. Table 6 presents a comparison of the relationship between changes in VRE capacity factors and changes in the corresponding VRE output power. As predicted, an increase in the capacity factor of VRE sources leads to an increase in their dispatched output power. Insufficient network flexibility, such as limited ramping capability of generators or transmission network capacity, can lead to a disparity between the percentage change of VRE capacity factor and VRE output power, resulting in reduced utilization of VRE.

Table 6: VRE output power vs VRE capacity factor over two weeks

VRE capacity factor change scenario	VRE output power change
+5%	+2%
+10%	+6%
+15%	+9%
+20%	+11%

Two sensitivity analyses are conducted to investigate the impact of generators' ramping rate and lines' maximum flow on VRE output power. The results are presented in Tables 7 and 8, respectively. Table 7 shows the percentage change in generator ramping rate versus the percentage change in VRE output power. The findings reveal that an increase in ramping rate leads to an increase in VRE utilization. Similarly, Table 8 demonstrates that an increase in lines' maximum flow results in an increase in VRE output power.

Table 7: Generators ramping rate vs VRE output power over two weeks

Generators ramping rate change	**VRE output power change**
+5%	+4%
+10%	+8%
+15%	14%
+20%	21%

Table 8: Lines maximum capacity vs VRE output power over two weeks

Lines maximum capacity change	**VRE output power change**
+5%	+4%
+10%	+7%
+15%	+11%
+20%	+15%

2.3.4. Results comparison with other literature

This section presents a comparison between the results of the SILVER model and those obtained from previous studies using a similar UC problem formulation.

Govardhan and Roy (2013) employ artificial bee colony algorithm (GABC) method to solve the UC problem for a 10-unit system over a 24-hour period. The generators' output is displayed in Figure 10. The generators' output obtained from the SILVER model for the same test system, input data, simulation period, and constraints (provided by Govardhan and Roy (2013)) are shown in Figure 11. Additionally, Table 9 presents the total output power by generators for 24 hours for both models. The results show that the output power of units 8 and 9 differs slightly between

Govardhan and Roy (2013) and SILVER runs, with a decrease in the operational cost in the SILVER model ($566,963.5 for Govardhan and Roy (2013) and $565,859.4 for SILVER). The differences in output occur at times 11, 12, 20, and 21.

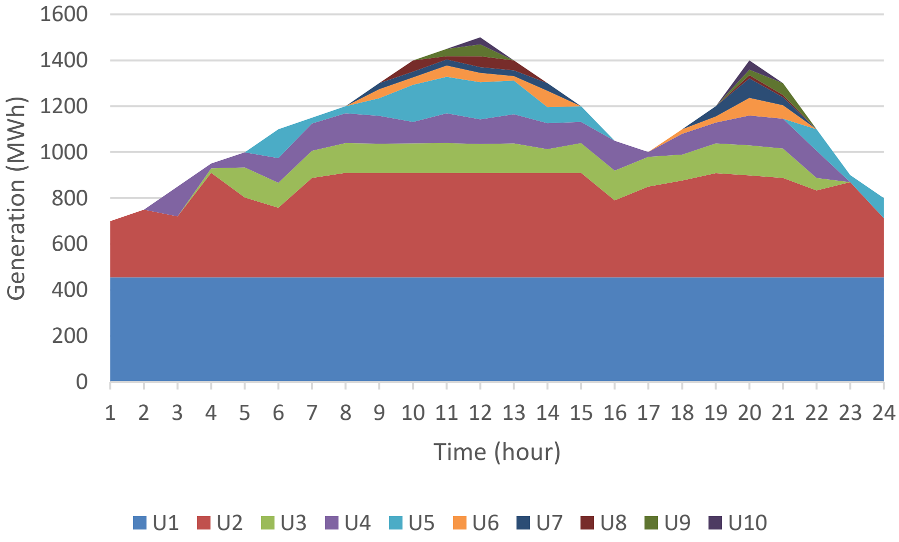


Figure 10: Results of UC problem using GABC algorithm (Govardhan and Roy 2013)

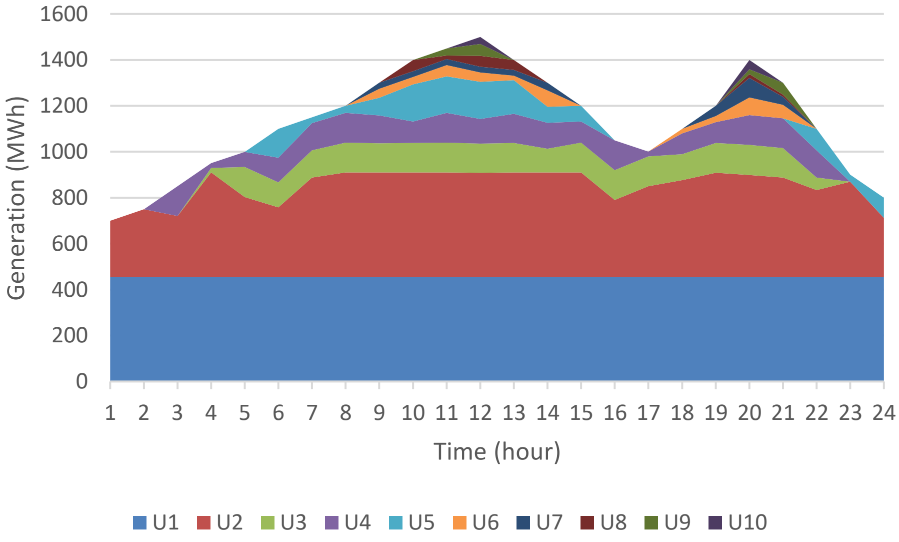


Figure 11: Results of UC problem using SILVER

Table 9: Output power by generators

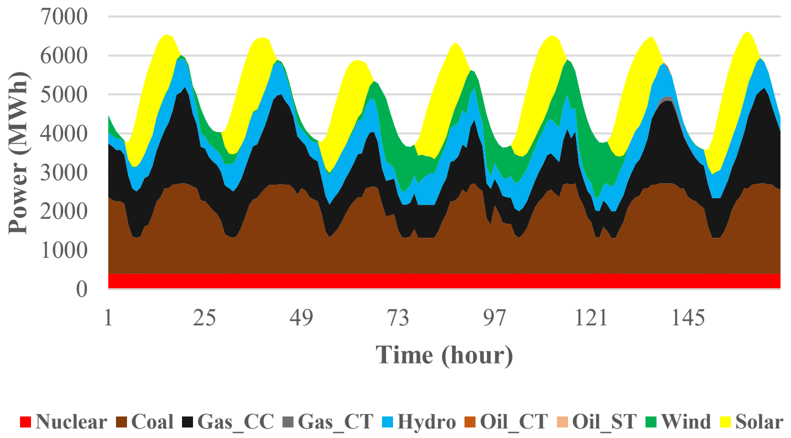
Generator	(Govardhan and Roy 2013) (MWh)	SILVER (MWh)
U1	10920	10920
U2	9514	9514
U3	2196.9	2196.9
U4	2063.1	2063.1
U5	1236.7	1236.7
U6	435	435
U7	323.5	323.5
U8	178.1	182.5
U9	158.3	153.9
U10	70.8	70.8

2.3.5. Comparing results with PLEXOS results

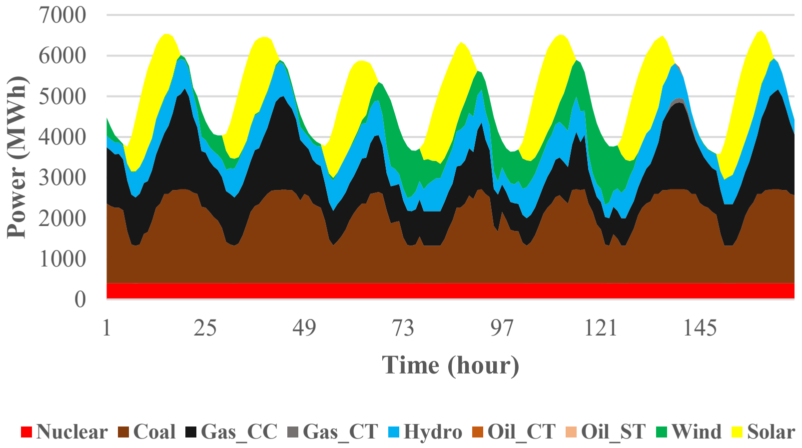
In this section, the SILVER model is compared to the commercially available PLEXOS model using the RTS-GMLC test system (Barrows et al. 2020) as the evaluation case study. The RTS-GMLC system, which has 73 buses, 158 generator units, and 106 lines, has been utilized in previous studies to assess a range of business models, including PLEXOS (Barrows et al. 2020). The results of this test system have been made publicly accessible in RTS-GMLC (2021). As a widely recognized and commonly used energy analysis model in power and energy system research globally, PLEXOS serves as a reliable benchmark against which to compare SILVER. Additionally, PLEXOS has been compared to other models, and the results of its application to an IEEE standard case study are publicly available.

The SILVER DC power flow UC problem is evaluated using the RTS-GMLC test system for a duration of 14 days. The problem is solved using the CPLEX solver with a set relative gap of 0.1% as stated by Barrows et al. (2020).

The SILVER results are compared with the PLEXOS results reported in RTS-GMLC (2021) with regards to operational costs and power production by generation type. The generation cost can serve as a valid evaluation criterion for the model's validity, as the objective function of the UC problem is to minimize cost. Figure 12a (PLEXOS) and 12b (SILVER) present the power generation for various generation types over the initial seven days of operation.



(a) PLEXOS



(b) SILVER

Figure 12: RTS-GMLC test system results-hourly power generation (a) PLEXOC (b) SILVER

Also, Table 10 shows the total generation over the two-week runtime for each generation type. The greatest disparity in generation between SILVER and PLEXOS throughout the operational period is noticed for coal generation and reaches 1.2%. The elevated coal generation in SILVER leads to a slightly higher operational cost as indicated in Table 11. Nevertheless, the total cost difference is approximately 0.18%, which is comparable to the solver gap of 0.1% predicted by Barrows et al. (2020).

Table 10: Output power by generation type

Generation type	**PLEXOS** (GWh)	**SILVER** (GWh)
Nuclear	134.2	134.2
Coal	570.3	576.2
Hydro	219.1	219.1
Gas	445.5	440.7
Oil	0.4	0.6
Wind	169.3	170
Solar	255.3	253.3

Table 11: Generation cost (PLEXOS vs SILVER)

	PLEXOS	**SILVER**
Startup/ shut down cost ($ million)	0.52	0.50
Fuel cost ($ million)	26.49	26.56
Overall ($ million)	27.01	27.06

Also, Figure 13 shows fuel cost over one week. According to the figures, fuel cost difference is less than 0.01% over 96% of simulation period.

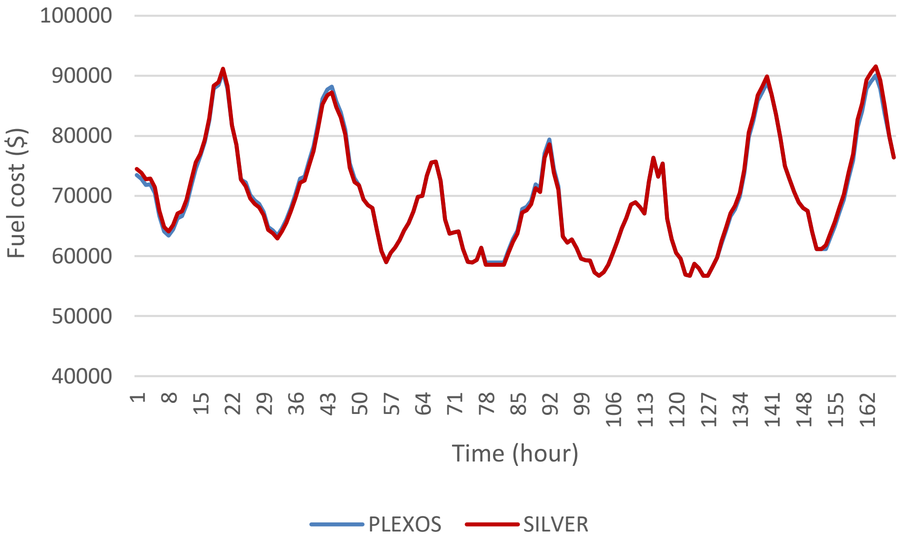


Figure 13: Generation cost, SILVER vs PLEXOS

In terms of wind and solar output power, there are some discrepancies between SILVER and PLEXOS (Figures 14 and 15). Comparing the wind and solar output power across each model, it is observed that for over 95% of the simulation period, the difference between models is below 0.01%.

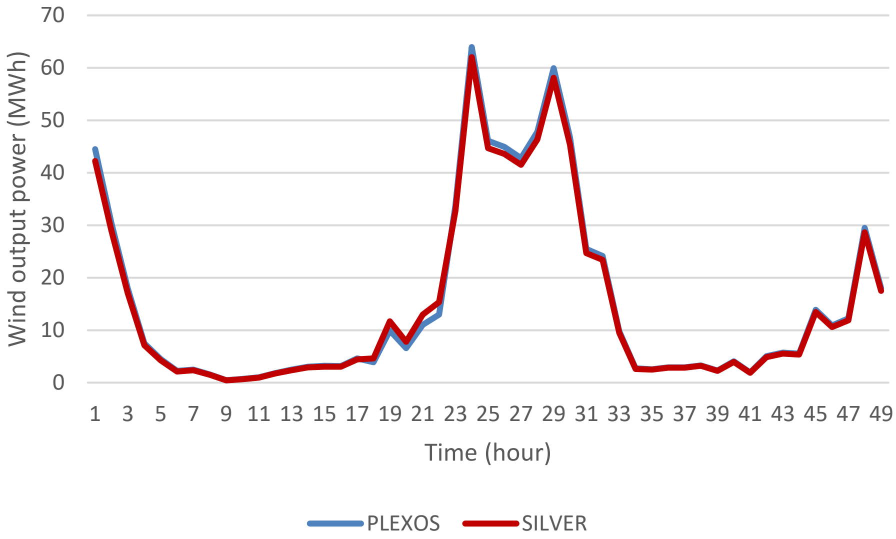


Figure 14: Wind output power, SILVER vs PLEXOS

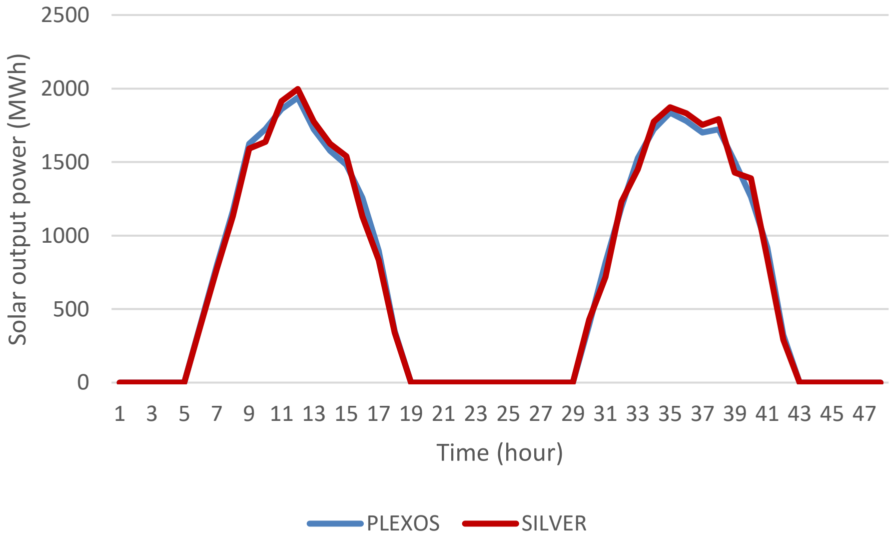


Figure 15: Solar output power, SILVER vs PLEXOS

Also, comparison between the two models in terms of line flow indicates that the difference is less than 0.01% for over 94% of the simulation period. The slight difference is caused by a minor difference in the generators output.

2.4. Modelling method

In order to analyze Canada's electricity system, a DC network-constrained unit commitment (DC-NCUC) problem is developed and implemented using the SILVER model for each of the Canadian provinces.

The NCUC problem is formulated as a mixed integer linear program (MILP) model, with the aim of minimizing cost while satisfying a set of operational constraints including generators, loads and network constraints. The objective function minimizes fuel and maintenance cost ($Cost^{gen}$), carbon cost ($Cost^{carbon}$) and generator startup/shutdown cost curve (Eq. 15).

$$Objective\ function\colon\ minimize\ (Cost^{gen} + Cost^{updn} + Cost^{carbon}) \tag{15}$$

The network constraints include the:

I) maximum flow of line,

$$Flow_{i,j,t} = \frac{\theta_{i,t} - \theta_{j,t}}{X_{i,j}} \leq Flow_{i,j}^{Max}\ \ \forall i,j,t \tag{16}$$

Where $Flow_{i,j,t}$ (MWh) and $Flow_{i,j}^{Max}$ (MWh) are the power flow and the maximum power flow between substation i and j at time t, respectively, $\theta_{i,t}$ (radian) is the voltage angle at substation i at time t, and $X_{i,j}$ (per unit) is the transmission line reactance between substations i and j.

II) voltage angle of substation

$$-\pi \leq \theta_{i,t} \leq +\pi\ \ \forall i,t \tag{17}$$

III) power balance constraint

$$\sum_{g=1}^{N_g} P_{g,t,i} - Demand_{t,i} = \sum_{j=1}^{N_L} Flow_{i,j,t}\ \ \forall t,i \tag{18}$$

Where $P_{g,t,i}$ (MWh) is the power output of generator g located at substation i at time t, $Demand_{t,i}$ (MWh) is the demand at substation i at time t, N_g is the number of generating units located substation i, and N_L is number of transmission lines connected to substation i.

The generators constraints include:

I) maximum and minimum output power

$$P_g^{min} \leq P_{g,t} \leq P_g^{max} \tag{19}$$

Where P_g^{min} and P_g^{max} are min and max output power of generator g, respectively.

II) maximum ramp up/down,

$$P_{g,t} - P_{g,t-1} \leq Ramp_g^{up} \ \forall g, t \tag{20}$$

$$P_{g,t} - P_{g,t-1} \geq Ramp_g^{dn} \ \forall g, t \tag{21}$$

Where RU_g and RD_g are the maximum ramp up and down rates in MWh for generator.

III) minimum up/down time

$$T_{g,t}^{up} \geq T_g^{\min\_up} \ \forall g, t \tag{22}$$

$$T_{g,t}^{dn} \geq T_g^{\min\_dn} \ \forall g, t \tag{23}$$

Where $T_{g,t}^{up}$ (hour) and $T_{g,t}^{dn}$ (hour) are actual up and down times of generator g at time t, and $T_g^{\min\_up}$ and $T_g^{\min\_dn}$ are minimum up and down times of generator g, respectively.

2.5. Data requirements

Building an operation model for Canada's electricity system requires a large amount of data from various sources, including generation and transmission data, electricity nodal load, storage data from hydro units, and power import/export data. This information can be obtained from utilities, such as BC Hydro, Quebec Hydro, Hydro One, Alberta Electricity System Operator, Manitoba

Hydro, Nova Scotia Power System Operator, New Brunswick System Operator, and the Independent Electricity System Operator. In cases where data is not publicly available, assumptions may need to be made based on the best available information from papers and electricity standards books. For example, assumptions for transmission line reactance and capacity can be based on information from IEEE transmission line reference books (such as (Dunlop, Gutman, and Marchenko 1979)).

Canada's total electricity demand was approximately 577 TW in 2018. Figure 16 shows the amount of demand for each province.

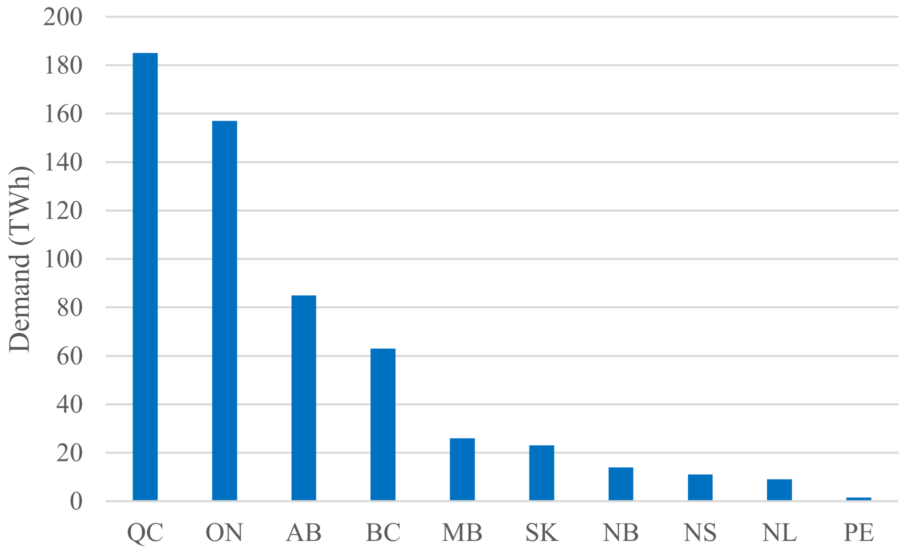
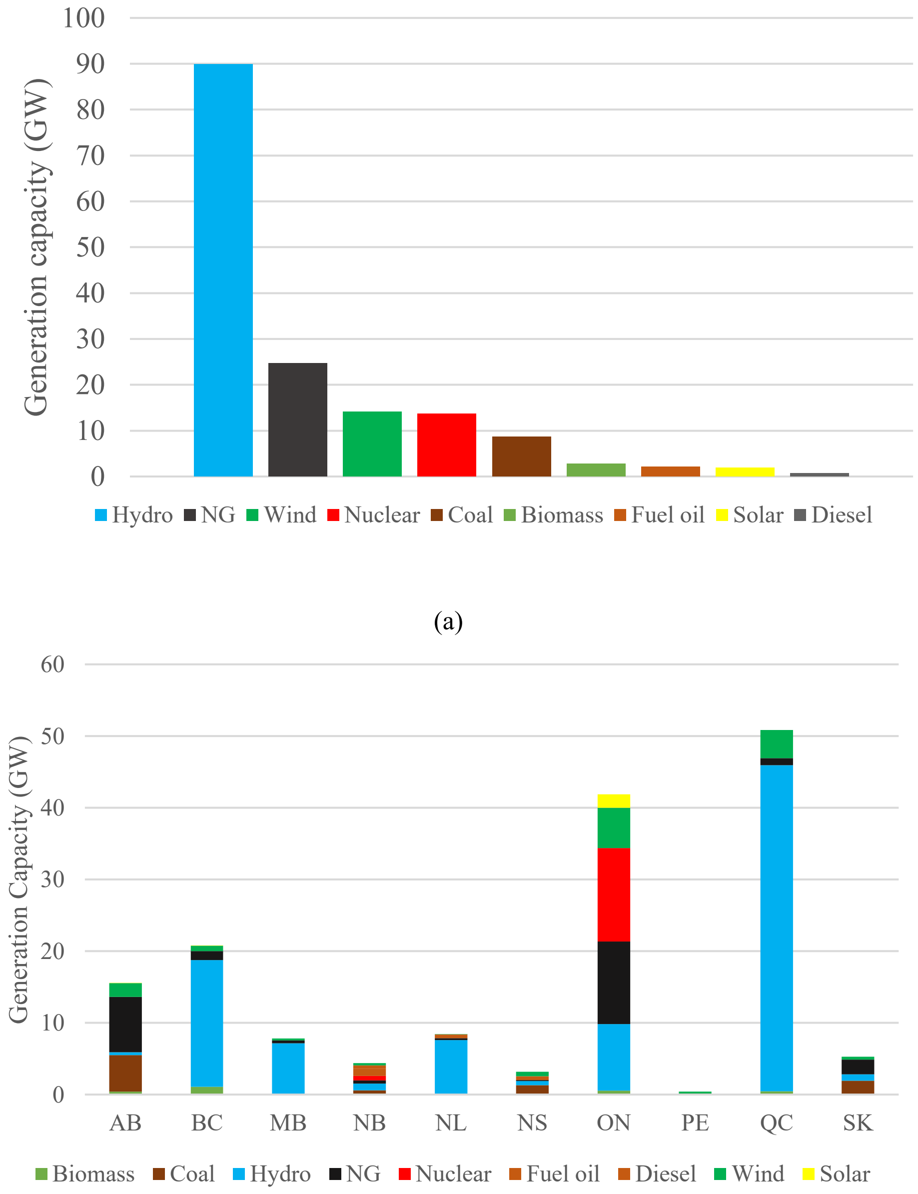


Figure 16: Canada's electricity system demand data

In 2018, the total installed generation capacity in Canada was estimated to be 158 GW. The distribution of capacity across different generation types is illustrated in Figure 17a. Figure 17b presents the generation capacity in each province, including the breakdown of different types of generation. Out of the total capacity, VRE accounted for roughly 10%, with wind energy accounting for 8.8% and solar energy contributing 1.2%. Apart from Prince Edward Island, the VRE penetration rate in all other provinces was less than 20%.



(a)

(b)

Figure 17: Canada’s electricity system data (2018) a) Generation capacity by generation type, b) generation capacity by province

2.6. Results and analysis

. This section examines Canada's existing electricity system from an operational standpoint to determine it potential in terms of generation side flexibility and transmission network for VRE integration. The objective is to determine the highest achievable rate of VRE integration in each province given the existing infrastructure.

The results of this study are derived from a one-year simulation of the NCUC, utilizing data from the year 2018. The one-year time frame has been chosen to reflect the influence of seasonal variations in demand, hydro capacity, and the capacity factors of VRE on the flexibility of the network.

2.6.1. Transmission network capacity analysis

This section examines the capacity of Canada's existing electricity system in order to evaluate its potential for accommodating the integration of VRE. Table 12 presents the utilization of the highest voltage level of transmission networks during peak load period over a simulation period of one year. The analysis focuses on the peak load period as this is when the highest quantity of power is generated and transmitted through the transmission network. Consequently, the amount of unused transmission capacity during the peak period serves as an indicator of the network's maximum available capacity. The results indicate that the average transmission line capacity utilization in peak load period is 63%, leaving an average of 37% of the power network capacity unused. This capacity within the transmission network offers promising potential for integrating VRE sources. Moreover, provinces like Ontario and Quebec boast particularly high levels of unused capacity in their transmission networks, providing ample opportunities for leveraging this capacity to support the integration of VRE.

Table 12: Transmission lines used capacity at peak time for each province resulted from SILVER run.

	AB	BC	MB	NB	NL	NS	ON	PE	QC	SK
Voltage level (kV)	240 & 500	500	230 & 500	230 & 345	230	230 & 345	500	138	735	230
Used capacity (%)	68	61	51	63	83	54	51	52	56	78

2.6.2. Flexibility assessment

Ma et al. (2013) define electricity system flexibility as "the ability of a power system to cope with variability and uncertainty in both generation and demand, while maintaining a satisfactory level of reliability at a reasonable cost over different time horizon". Both the generation and demand sides play a role in providing this flexibility. On the generation side, ramp rate of generators is a critical factor. Ramp rate capability varies among generation technologies, with nuclear units having low ramp rates and hydro units having high ramp rates. Generator ramp rates are a primary source of flexibility but may be restricted by various factors such as generator min/max output power. To gain a more comprehensive understanding of network flexibility and to make comparisons between different networks, a flexibility index has been defined by (Ma et al. 2013). The flexibility index, as described in Eq. 24 and 25, is an expanded definition that includes the generator ramp rate and the minimum/maximum capacity. This index quantifies the flexibility of the generation side of the network.

$$flex_j = \frac{0.5*R_j + 0.5(P_j^{\max} - P_j^{\min})}{P_j^{\max}} \tag{24}$$

$$Flex = \frac{\sum_{j=1}^{N_j} flex_j * P_j^{\max}}{\sum_{j=1}^{N_j} P_j^{\max}} \tag{25}$$

Where, $flex_i$ indicates flexibility of unit j, R_j is the ramp rate of unit j, $P_j^{\min}$and $P_j^{\max}$ are the minimum and maximum capacity of unit j, respectively and $Flex$ represents the flexibility of network.

The flexibility of provinces is quantified based on Eq. 24 and 25 and the resulting flexibility index is demonstrated in Figure18.

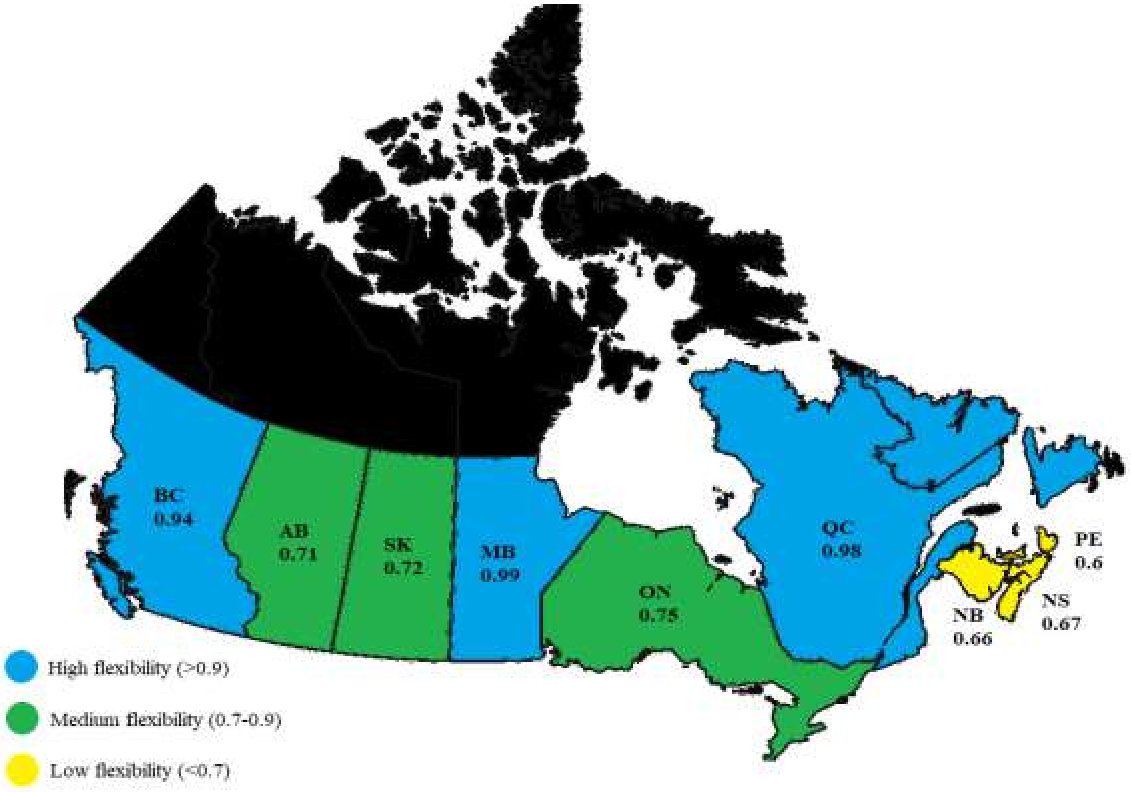


Figure 18: Value of the flexibility index for Canadian provinces

According to Figure 18, the flexibility of each province's electricity network can be categorized into three levels: low (<0.7), medium (0.7-0.9), and high (>0.9). Quebec, British Columbia, Manitoba, and Newfoundland and Labrador, with a high proportion of hydro capacity (89%, 85%, 91%, and 89% respectively), exhibit the highest network flexibility among Canadian provinces. Conversely, provinces with a lower flexibility index, dominated by less flexible sources such as coal and nuclear, show a lower potential for flexibility. The flexibility values of Canadian provinces, especially those with a high flexibility index, indicate that their networks possess a substantial potential for flexibility that can be utilized to facilitate VRE integration. These flexibility values can assist planners in assessing the current flexibility potential, enabling them to determine the required flexibility to attain the desired low-carbon network in the future.

2.6.3. VRE integration assessment

The flexibility index, as described in Section 2.3.3.3, is a measure of the flexibility on the generation side and incorporates the minimum and maximum capacity and ramp rate of generators. However, it does not account for other crucial factors that impact flexibility, such as the hydro capacity factor, water availability constraints, load profile, power import/export, transmission line capacity, minimum up/down time for generators, and capacity factor of VREs. These components all play a role in determining the system's overall flexibility and should be considered in a comprehensive evaluation of flexibility.

In our study of the viability of incorporating VRE into Canada's electrical system, we use the VRE curtailment rate obtained from the NCUC problem as a means of evaluating the network's flexibility. This approach is adopted because the NCUC problem considers all the technical restrictions that may influence the network's flexibility. It is assumed that the operating cost of VRE is zero, and as the objective function of the NCUC problem prioritizes cost minimization, VRE is given the highest priority in dispatch. If VRE is curtailed, it signifies those operational limitations, such as power import/export, transmission line capacity, and generator minimum up/down time, are impeding the dispatch of VRE, resulting in its curtailment. Hence, the VRE curtailment rate obtained from the NCUC problem provides a reflection of the network's flexibility. The acceptable range of VRE curtailment may differ based on the design of the network. However, a cost-efficient range for VRE curtailment would typically fall between 0% to 10% (Joos and Staffell 2018; Sinn 2017; Schill, and Kemfert 2018).

In the subsequent analysis, the maximum VRE penetration rate for each province is evaluated with the objective of attaining a certain curtailment. To achieve this, an NCUC problem is run for various VRE penetration scenarios to determine the maximum VRE penetration rate that corresponds to curtailment rates of 0.5%, 5%, and 10% (selected from cost effective range (0%-10%) for VRE curtailment (Joos and Staffell 2018; Sinn 2017; Schill, and Kemfert 2018)). The results of this analysis are shown in Figure 19.

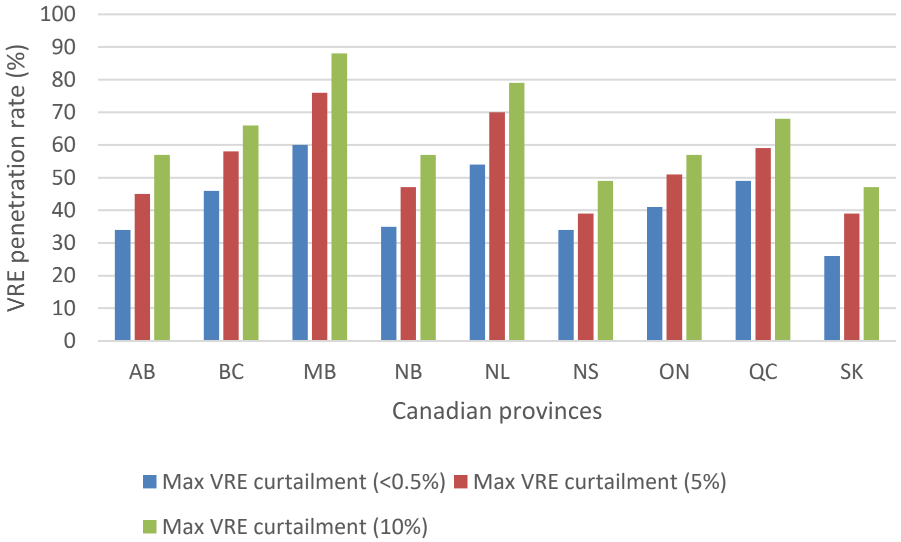


Figure 19: VRE penetration rate (% of installed capacity) for three scenarios of VRE curtailment rate

The findings indicate that the provinces of Canada possess a considerable potential for VRE integration. Provinces with a high flexibility index (ranging from 0.9 to 0.99), such as British Columbia, Manitoba, Newfoundland and Labrador, and Quebec, exhibit a higher potential for VRE penetration rates compared to provinces with a medium flexibility index (ranging from 0.66 to 0.75), such as Alberta, New Brunswick, Nova Scotia, Ontario, and Saskatchewan. The results demonstrate that Canada's electricity system has the flexibility to integrate an average of 35% VRE capacity with only 0.5% curtailment. Furthermore, it can accommodate 46% and 54% VRE penetration for 5% and 10% curtailment rates, respectively.

2.6.4. The impact of transmission network constraint on VRE integration

This section aims to determine the adequacy of current transmission capacity in Canada to reach the highest possible VRE integration. To this end, the NCUC problems are run under varying scenarios of VRE penetration rates to calculate the maximum VRE penetration that results in 0.5%, 5%, and 10% curtailment rates while the maximum capacity constraint of transmission lines is relaxed for this analysis and all other NCUC parameters and constraints remain unchanged. The findings of this analysis are presented in Figure 20. An evaluation of the results compared to Figure 19 shows that the existing capacity of Canada's electrical grid restricts the integration rate of VRE by 7%, 8%, and 10% respectively, for curtailment rates of 0.5%, 5%, and 10%. The capacity limitations of the transmission network, in fact, hinder the attainment of the maximum achievable flexibility. As such, there is a need to augment the transmission network capacity to achieve the maximum possible VRE integration rate.

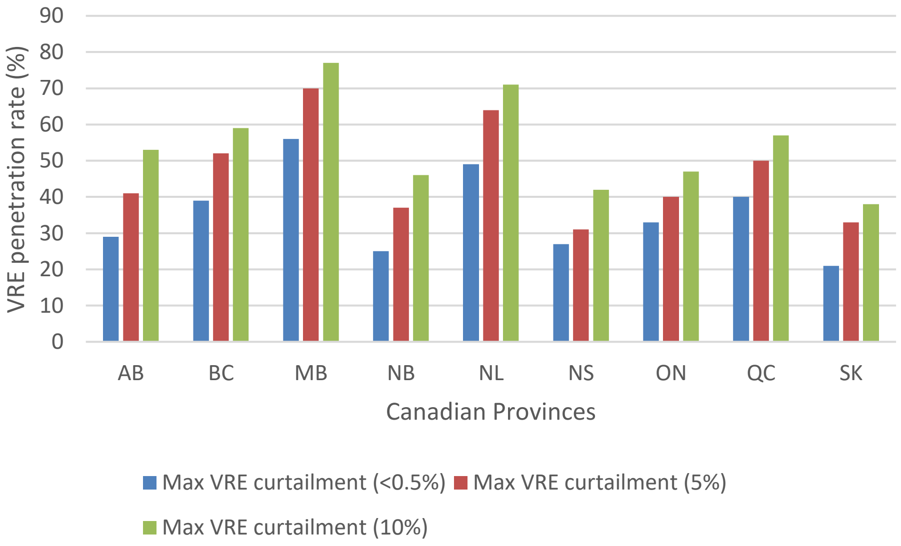


Figure 20: VRE penetration rate (% of installed capacity) for three scenarios of VRE curtailment rate with relaxed max flow constraint

2.6.5. Emission reduction resulted from VRE integration

This section endeavors to examine the emission reductions obtained through the integration of VRE, enabled by the current generation and transmission infrastructure. With the implementation of VRE penetration rates as depicted in Figure 19, Canada's electricity system emissions are found to have reduced from 74 Mt CO2e to 43 Mt CO2e, which constitutes a 42% decrease from the

2018 emissions levels. The emission reduction figures for each province are presented in Figure 21. The figure demonstrates that Alberta will experience the most significant reduction in GHG emissions, followed by Saskatchewan and Ontario. Furthermore, provinces such as Quebec, British Columbia, New Brunswick, and Manitoba exhibit a negligible level of GHG emissions reduction, as they primarily rely on clean hydroelectric power.

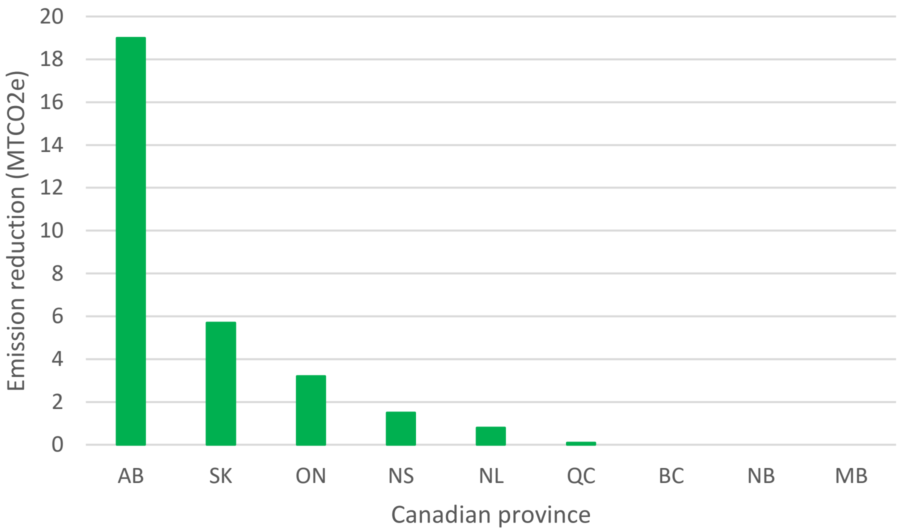


Figure 21: Emission reduction resulted by VRE penetration.

2.7. Limitations

In this paper, a significant challenge is posed by the limited availability of data. The data used in this analysis have been sourced from publicly accessible sources, and in instances where data was not readily available, reasonable assumptions had to be made. This includes assumptions regarding the capacity and reactance of transmission lines, nodal load, and the technical specifications of generators. Furthermore, the study utilizes historical data for solar and wind energy, which may not provide a comprehensive representation of future trends.

Due to limitations in data availability and also computational complexity, the transmission networks in the NCUC problems were simplified by only incorporating the highest voltage level.

Although transmission lines with the highest voltage level have the potential for the greatest power transfer capacity in the transmission network, this simplification may affect the precision of the obtained results.

To determine the upper bound of VRE penetration, VRE capacities were uniformly increased in 2018 VRE locations. However, the non-uniform increase of VRE can affect the maximum penetration rates. This analysis does not take into account new VRE locations, as they would require the addition of new transmission lines to the grid, thereby altering the transmission network configuration. The objective of the analysis is to determine the extent of additional VRE capacity that the existing transmission network can support.

In this study, historical solar and wind data were utilized, however, it is important to acknowledge that past trends may not necessarily be indicative of future performance. Additionally, it should be noted that the VRE installation was subject only to energy density limitations (MW per kilometer squared), without considering other constraints such as land-use limitations that may render certain areas infeasible for installation.

In this study, the modeling of network power flow was conducted using DC power flow. It should be noted that the primary operation of power systems is based on AC power flow. The mathematical representation of AC power flow, which incorporates sinusoidal and cosine functions, results in a non-linear model. The non-linear nature of this model presents a significant computational burden for optimization and the availability of free reliable non-linear solvers is often limited. In cases where the study is focused on a transmission network (as opposed to a distribution network), a DC power flow model, which is a linear power flow model, can be used as an alternative to the AC power flow model. The resistance to reactance ratio (R/X) in transmission networks (high voltage networks) is very low, which results in a very small phase angle in the current flowing through the network. A small phase angle results in a low current magnitude, which results in very low network loss. Therefore, AC non-linear power flow equations can be converted to DC linear power flow equations with little change in accuracy. The use of DC power flow for transmission networks is very common in power systems research.

2.8. Discussion

In recent years, there is a growing focus on the integration of VREs as a means of achieving deep decarbonization in electricity networks. The variable nature of VREs highlights the importance of conducting a network flexibility analysis to assess the flexibility of the existing network and identify the necessary requirements for ensuring sufficient flexibility for high penetration of VREs in the future.

The paper discussed the use of the SILVER model to assess the potential for integrating variable renewable energy sources, such as wind and solar power, into Canada's electricity system in order to meet decarbonization goals. The model is refined in two stages, which included modeling of hydro power and incorporation of demand response programs. The hydro modeling in the SILVER model is enhanced by incorporating different time scales, such as hourly, daily, monthly, and cascading, in order to improve the accuracy of simulating hydro facilities and their interactions with the power system. In addition, ToU program were added to the model to simulate the behavior of consumers in response to changes in electricity prices. The improved SILVER model, with these enhancements, is better able to analyze the generation and demand-side flexibility of the power system. The SILVER hydro model is now comparable to other models such as PLEXOS which have been used in studies to simulate Canada's hydro facilities.

The study presented in the paper indicates that Canada's hydro-based electrical grid holds a considerable potential for the integration of VRE. The findings of the research indicate that, with the aim of achieving a VRE curtailment rate ranging from 0% to 10%, the electrical grid can accommodate an average integration level of 38% to 56% VRE. Therefore, to attain the most ambitious curtailment rate of 0%, the power system can accommodate an integration level of 38% VRE. The study also highlights that an increase in VRE penetration results in a higher curtailment rate, which, in turn, diminishes the efficiency of the system. Therefore, to achieve a high penetration rate of VRE and reach net-zero emissions in an efficient manner, it is imperative to enhance the flexibility of Canada's electrical grid.

The existence of abundant hydro assets in provinces such as British Columbia and Quebec, which demonstrate high levels of network flexibility, highlights the substantial potential of these provinces in facilitating the integration of VRE sources. Despite this, as these provinces are already low emitting, they are less dependent on VRE integration as a means of decarbonization. Hence, linking the versatility of hydro-dominated systems with the expansion of VRE in adjacent provinces has the potential to offer a promising strategy for accomplishing decarbonization goals.

The transmission network in Canada benefits from free capacity, which can facilitate VRE integration. The provinces of British Columbia, Quebec, and Manitoba have the highest potential for VRE integration in Canada, with flexibility indices of more than 0.9 and free capacity on extra-high-voltage transmission lines (500 and 735 kV). However, the findings indicate that the current transmission capacity is insufficient to achieve the highest possible level of VRE penetration. The results suggest that, in the absence of transmission capacity constraints, maximum VRE integration can improve by 7% on average to meet a 10% VRE curtailment. This highlights the importance of transmission network capacity in achieving maximum generation side flexibility and improving VRE integration.

The results show that the maximum VRE penetration enabled by existing network capacity results in a 42% reduction in emissions (compared to 2018 emissions), significantly assisting Canada in meeting its Paris Agreement commitment. However, the Canadian electrical industry has committed to becoming net-zero by 2050. The study found that while relying solely on existing provincial generating side flexibility and transmission network capacity to integrate VRE reduces GHG emissions significantly, it does not result in net zero emissions. Therefore, additional activities and other technologies will be required to achieve the goal of net zero emissions.

Chapter. 3 Evaluation of flexibility provided by cascading hydroelectric assets for variable renewable energy integration

Abstract: The integration of a significant VRE capacity into Canada's electricity system is a crucial step towards decarbonization. Cascading hydro assets have been found to bolster the generation fleet with the flexibility necessary to mitigate VRE uncertainty and variability. The integration of British Columbia's cascading hydro-dominated system, known for its high flexibility, with Alberta's considerable wind and solar potential can create a hybrid hydro-VRE system with sufficient flexibility for aggressive VRE integration in Alberta. To examine this proposition, a flexibility metric is introduced into a unit commitment model to quantitatively assess network flexibility while account of pertinent operational and technical constraints. This study also analyzes changes to the effectiveness of cascading hydro assets for network flexibility and VRE integration under distinct climate change scenarios. Results indicate that the integration of the British Columbian and Albertan networks improves the flexibility index approximately two-fold, allowing a 13% increase in VRE penetration in Alberta. However, the study also highlights the significant impact climate change may have on cascading hydro operation and associated network flexibility, which could potentially challenge the capacity of these assets to provide the flexibility required for VRE integration.

Keywords: flexibility, unit commitment (UC), VRE integration, cascading hydro assets, hybrid hydro-VRE system, climate change

3.1. Introduction

Canada has committed to reducing its greenhouse gas (GHG) emissions by 40% to 45% below 2005 levels by 2030, and to achieve net zero emissions by 2050 (Government of Canada 2021). While low-carbon electricity generation already accounts for a significant portion of Canadian electricity generation, further decarbonization can be achieved through increased penetration of variable renewable energy (VRE). Obtaining high VRE penetration, on the other hand, can result in technical issues that must be addressed. One of the most difficult challenges for the integration of VRE resources is managing their variable and uncertain behaviour, which necessitates a high level of flexibility. The contribution that generation assets make to network flexibility can be approximated by their ramping capability. For example, hydro generation facilities have high ramping rates and, in many cases, reservoir storage, which makes them flexible assets; networks that are dominated by hydro generation (with storage) benefit from high inherent flexibility, which makes them promising jurisdictions for VRE integration.

Network flexibility is a measure of a network's ability to compensate for variations. Quantifying the flexibility of a network is essential in order to evaluate its current and future potential for integrating variable renewable energy. Several authors have created flexibility assessments and metrics to attempt this quantification. Some studies proposed a metric based on general generator characteristics (e.g., ramping up/down capability, minimum/maximum capacity) (Ma et al. 2013). Such metrics ignore network operational and technical constraints, which have a significant impact on system flexibility. Others have used VRE curtailment as a metric to assess the network's flexibility (Berahmandpour et al. 2019, Bashiri Atrabi et al. 2017). Berahmandpour et al. (2019) propose a conceptual flexibility index for studying wind power integration, calculated using the minimum and maximum capacities of generators as well as their ramping capability. This flexibility index is incorporated in economic dispatch (ED) as the second objective function (the first being operational cost) to evaluate the trade-off between operational cost and system flexibility under various scenarios. Bashiri Atrabi et al. (2017) define flexibility as the difference between the sum generation capacity maxima of hydro units and load, and then quantify the flexibility of the Columbia River system in the Pacific North-West region of the United States. According to the authors, estimating flexibility assists system operators in dealing with the unpredictability of energy supply (for example, due to wind/solar resource forecasting errors). In order to assess network flexibility, it is imperative to include all relevant technical and operational limitations in the quantification approach. Critically, some have noted that not all such constraints, such as transmission network capacities, are considered in current assessments of flexibility (Berahmandpour et al. 2019 ,Bashiri Atrabi et al. 2017), resulting in a less than comprehensive result from the system operation perspective.

As countries have adopted more ambitious climate targets, interest in VRE integration and power system flexibility has grown. Flexibility options span both demand and supply sides of power systems, market design, and inter-regional coordination. The role of hydro assets, including cascading hydro, in enabling VRE integration has emerged as a particularly salient conversation in Canada, where several provincial power systems are hydro-dominated. Part of the literature has modelled cascading hydro systems to analyze the benefits that improved coordination of hydro-wind systems could deliver. Abreu et al. (2012) propose a framework for coordinating cascading hydro (with storage) and wind power to maximise generating company (GENCO) revenues. The findings show that coordinating wind and cascading hydro reduces wind curtailment while increasing GENCO financial performance. An integrated wind-hydro model is proposed in Hamann and Hug (2016) to assess the potential of cascading hydro to facilitate wind integration. The results indicate the integrated model can improve wind curtailment by utilizing the ramping capabilities of hydro capacity. Similarly, Kern, Patino-Echeverri, and Characklis (2014) also propose an integrated hydro-wind model. The results of the model demonstrate that co-operation of hydro and wind units can achieve a 10% reduction in wind curtailment at 25% wind penetration.

An integrated thermal-hydro-wind model is proposed by Zhou, Geng, and Jiang (2016) to facilitate the integration of large wind farms into a electricity network. A coordinated cascading hydro-solar-pumped storage optimization framework is proposed by Huang et al. (2019) to maximize solar power utilization, with flexibility provided by a hydro reservoir and pumped storage improving economic benefits by 12% through decreased solar curtailment.

The results of these evaluations demonstrate the capacity of hydro, including cascading hydro, assets to mitigate VRE fluctuations and enhance the overall system flexibility. However, they do not take into account the potential impact of climate change on the flexibility provided by hydro assets. As the operation of hydro assets is contingent on water supplies, it is crucial to assess the effect of climate change, a global phenomenon, on the ability of cascading hydro to provide flexibility for VRE integration.

Hydropower constitutes a significant portion, over 60%, of Canada’s installed power generation capacity (Saffari and McPherson 2022). However, this capacity is not evenly distributed across the provinces, with some, such as Alberta, having limited hydropower production, while others, like British Columbia, heavily relying on it for electricity generation. To enhance the flexibility of provinces with minimal hydro, like Alberta, an integrated operation approach involving the coordination of two adjacent networks may present a viable solution.

The objective of this paper is two-fold. Firstly, we aim to assess the potential of utilizing the flexibility of British Columbia's hydro-dominant power grid to improve the integration of VRE in Alberta. Secondly, we examine the impact of different climate change scenarios on the operation of cascading hydro assets and network flexibility at varying levels of VRE penetration. The study focuses on investigating how climate change may impact the integration of VRE in Alberta when the required flexibility is provided through hydro facilities via integrated operation. To accomplish this, the paper formulates a flexibility index and incorporates it into a unit commitment (UC) problem to consider a wide range of factors and constraints that may affect the flexibility of the electricity network. Thus, the proposed UC can evaluate the influence of various constraints and parameters on network flexibility, which is used to assess the effects of climate change scenarios on cascading hydro operation and network flexibility in this study. The main contributions of this work are summarized as follows:

I) developing an index to quantify the flexibility of the electricity network and incorporating it into a UC problem to take into account of factors and constraints that may affect the flexibility of the electricity network;

II) analyzing the potential of using British Columbia’s electricity system flexibility to enhance VRE integration in Alberta through integrated operation;

III) investigating the impact of climate change scenarios on VRE integration.

The rest of the paper is organized as follows: section 2 presents the modelling method, section 3 presents the data a case study, section 4 details results and analysis, and finally, section 5 concludes the study.

3.2. Modelling method

This paper analysis is based on a UC problem whose objective function is cost minimization which includes both operation cost and shutdown/startup cost. Constraints of the UC problem are: network constraints, consisting of 1) maximum power flow of line, 2) voltage angle of substation, and 3) power balance constraint; and, generator constraints, consisting of 1) maximum and minimum output power, 2) maximum ramp up/down, 3) minimum up/down time, 4) VRE capacity factor, 5) availability of water in a reservoir (for hydro generation), and 6) water balance between reservoirs (for cascading hydro generation). The mathematical formulation of the constraints was already demonstrated in Chapter 2. Also, as parameters and constraints of cascading hydro assets are central to this work, the mathematical formulation of cascading hydro assets is elaborated as follow (Wood and Wollenberg 1996):

$$D_j^{\min} < D_{j,t} < D_j^{\max} \tag{1}$$

$$C_j^{\min} < C_{j,t} < C_j^{\max} \tag{2}$$

$$W_j^{\min} < W_{j,t} < W_j^{\max} \tag{3}$$

$$C_{j,t+1} = C_{j,t} - D_{j,t} - W_{j,t} + D_{j-1,t-\tau} + W_{j-1,t-\tau} + Y_{i,t} \tag{4}$$

$$P_{j,t} = K * \eta_j * D_{j,t} * \bar{H_j} \tag{5}$$

$$\sum_{t=1}^{N_t} P_{j,t} < P_j^{\mathrm{max} per\ month} \tag{6}$$

$$Perct_{Down} * C_{j,max} \leq C_{j,t(end)} \leq Perct_{Up} * C_{j,max} \tag{7}$$

Eq. 1-3 constrain values of water discharge ($D_{j,t}$), water volume ($C_{j,t}$), and water spillage ($W_{j,t}$) for reservoir j at time t. Eq. 4 serves as the dynamic water volume constraint for reservoir j in which $Y_{i,t}$ is water inflow at time t, dependent on the delay time τ and other parameters (such as temperature, precipitation, and evaporation). Eq. 5 gives the output power of a generating unit in MWh at reservoir j where η_j represents the energy conversion efficiency, $\bar{H_j}$ is the average height of water head in the reservoir, and K is a constant reflecting various other parameters, including gravity. Eq. 6 constrains the maximum monthly generation. Finally, Eq. 7 forces the water volume in the reservoir at the final operational time period to be in a range of its minimum and maximum value, preventing large fluctuations in reservoir water volume.

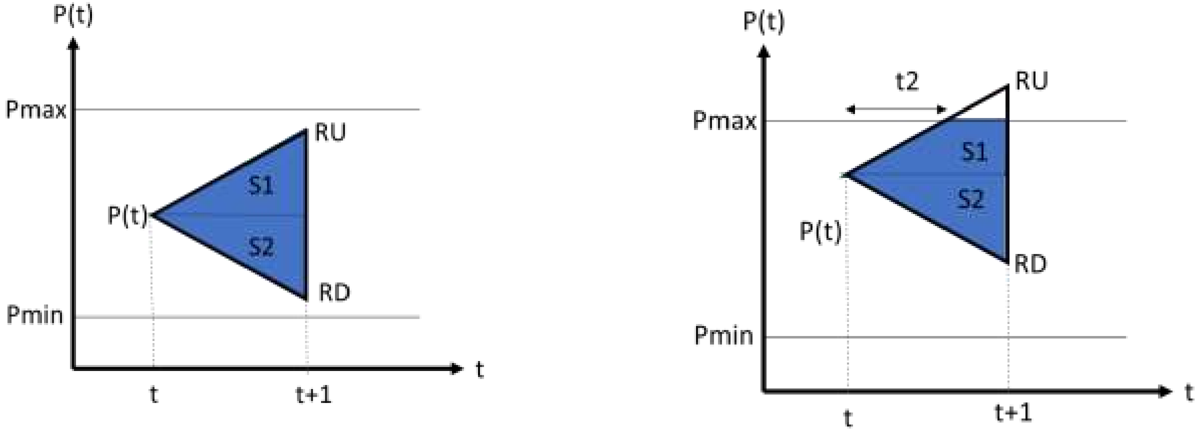
3.2.1. Electricity network flexibility

The illustration in Figure 22 conceptually depicts the flexibility of a generator at a specific operating point in three different scenarios. The capacity of a generator to ramp up or down reflects its flexibility, but this can be constrained by several factors such as the minimum and maximum output capacities of the generator, transmission network capacity, and the capacity factor of the generator, particularly for hydro units. The figure demonstrates how the minimum and maximum capacities of a generator can restrict its ramping capability (flexibility). Based on this visual representation of flexibility, a flexibility index is developed to consider additional factors in the UC problem, such as the capacity of the transmission network. In the figure, RU and RD are maximum ramp up and ramp down rates characteristic of the generator (in MW/h). Also, P_t, $P_{\min}$, and $P_{\max}$ denote output power at time t, and minimum and maximum output power, respectively. The areas labeled S1 and S2 illustrate potential changes in energy output that can be achieved between successive time steps.

In scenario (a), the generator is operating close to the center of its operational range (between $P_{\min}$ and $P_{\max}$), thereby allowing for full utilization of its ramping capabilities in both upward and downward directions in the subsequent time step; thus, the generator's maximum flexibility is achievable. In (b) and (c), the generator's operating point is closer to $P_{\min}$ and $P_{\max}$, respectively, and as a result, it cannot fully utilize its ramping capabilities. This implies that the generator's flexibility is limited in one direction due to its current operating conditions. It is important to note that the generator's flexibility is not only determined by its minimum and maximum capacities and ramp up/down characteristics, but also by its operating point, which can be impacted by the overall generation mix. Hence, the flexibility offered by a generator at any given time is contingent on its operating conditions.

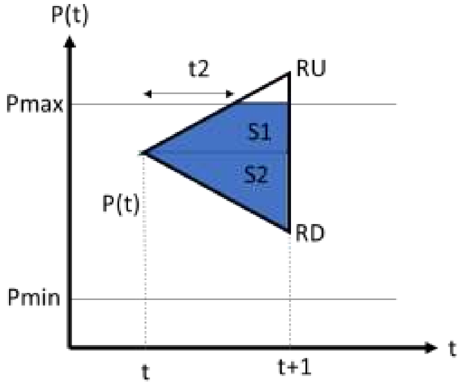
The flexibility of an electricity network is impacted by a multitude of factors, including the technical specifications of each generating unit, dispatch instructions sent by the system operator, the architecture of the transmission network, and the characteristics of its lines. The interplay between these factors, including the aggregation of generator attributes, network structure, line capacities, and merit order impacts, determines the system's overall flexibility. Our analysis seeks to incorporate these elements and their interaction. In the following sections, we calculate a flexibility metric for individual generators in real-time and then quantify system flexibility in aggregate by combining the metrics for all operational units. The dispatch choices reflected in the UC problem take into account the merit order and transmission limitations. Finally, system flexibility can be determined from hourly unit dispatch, thereby considering all previously mentioned factors.

We derive a flexibility metric for a single generating unit below. As shown, upward and downward flexibility can be calculated based on area of the blue-shaded regions in Figure 22 a, b, and c.



a) Upward/downward flexibility of a generator when the ramp up/down capability can be fully utilized.

b) Upward/downward flexibility of a generator when the ramp up capability cannot be fully utilized



c) Upward/downward flexibility of a generator when the ramp down capability cannot be fully utilized

Figure 22: Visualization of the flexibility concept

S1 and S2 in the Figure 22a are triangular regions whose areas are calculated according to the Eq. 8 and Eq. 9.

$$S1 = \frac{1}{2} * RU * \Delta t \tag{8}$$

$$S2 = \frac{1}{2} * RD * \Delta t \tag{9}$$

S1 in Figure 22b and S2 in Figure 22c are trapezoidal regions whose areas are calculated according to the Eq. 10 and Eq. 11

$$S1 = \frac{1}{2}(P_{\max} - P_t)(\Delta t + (\Delta t - t_2)) \tag{10}$$

$$S2 = \frac{1}{2}(P_t - P_{\min})(\Delta t + (\Delta t - t_1)) \tag{11}$$

Substituting $t_2 = \frac{P^{max} - P_t}{RU}$ and $t_1 = \frac{P_t - P^{min}}{RD}$ in the Eq. 10 and Eq. 11 gives:

$$S1 = \frac{1}{2}(P_{\max} - P_t)(2\Delta t - \frac{P_{\max} - P_t}{RU})) \tag{12}$$

$$S2 = \frac{1}{2}(P_t - P_{\min})(2\Delta t - \frac{P_t - P_{\min}}{RD})) \tag{13}$$

And, finally expressions for S1 and S2 can be expanded to Eq. 14 and Eq. 15.

$$S1 = (\Delta t * P_{\max} - \frac{P_{\max}^2}{2RU}) + (\frac{P_{\max}}{RU} - \Delta t)P_t + (-\frac{1}{2RU})P_t^2 \tag{14}$$

$$S2 = \left(-\Delta t * P_{\min} - \frac{P_{\min}^2}{2RD}\right) + \left(\frac{P_{\min}}{RD} + \Delta t\right)P_t + \left(-\frac{1}{2RD}\right)P_t^2 \tag{15}$$

The flexibility index for a generator at an arbitrary operation point is:

$$flex_t = flexup_t + flexdn_t \tag{16}$$

Where $flexup_t$ and $flexdn_t$ are defined as follow:

$$flexup_t = \begin{cases} \frac{1}{2}RU * \Delta t & if\ P_t \leq P_{\max} - RU \\ (\Delta t * P_{\max} - \frac{P_{\max}^2}{2RU}) + (\frac{P_{\max}}{RU} - \Delta t)P_t + (-\frac{1}{2RU})P_t^2 & if\ P_t \geq P_{\max} - RU \end{cases}$$

(17)

$$flexdn_t = \begin{cases} \frac{1}{2}RD * \Delta t & if\ P_t \geq P_{\min} + RD \\ (-\Delta t * P_{\min} - \frac{P_{\min}^2}{2RD}) + (\frac{P_{\min}}{RD} + \Delta t)P_t + (-\frac{1}{2RD})P_t^2 & if\ P_t \leq P_{\min} + RD \end{cases}$$

(18)

Finally, the flexibility of the entire system at time t is given by the summation of the flexibility of all generators in the system. To normalize the flexibility value, it is divided by demand at time t, as represented in Eq. 19

$$Flex_t = \frac{\sum_{i=1}^{N_i} flex_{i,t}}{Demand_t} \tag{19}$$

where $Flex_t$ indicates the flexibility of entire system at time t. The average flexibility of entire run time is defined as Eq. 20.

$$\mathrm{Flex} = \sum_{t=1}^{t=N_t} \mathrm{Flex}_t / N_t \tag{20}$$

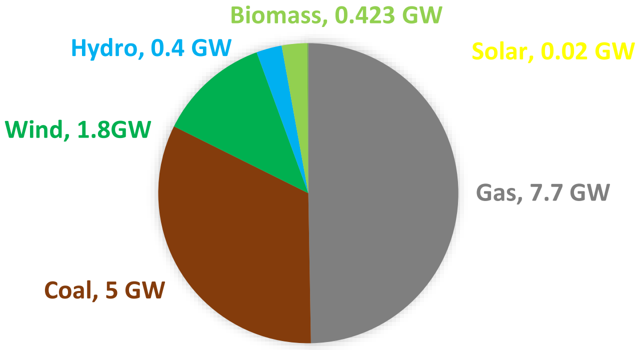
Where N_t is run time and $Flex$ is flexibility over entire runtime.

Incorporating the flexibility index equations and constraints to the UC problem, allows the quantification of network flexibility considering all operational and technical constraints that may affect the flexibility. To make and run the UC problem, the SILVER framework (McPherson and Karney 2017) is used.

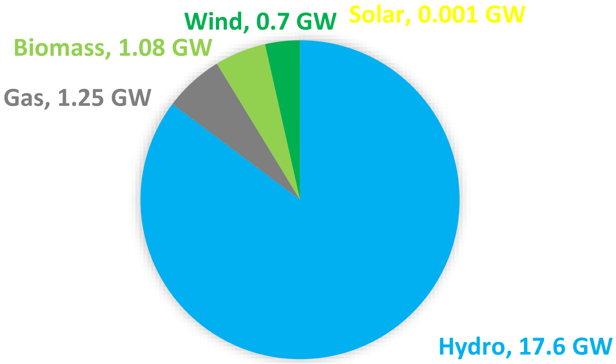
3.3. Data and case study

In this study, data from 2018 is used to analyze the electricity systems of Alberta and British In this study, 2018 data is used to analyze the Alberta and British Columbia electricity systems. The data includes the load curve, the capacity factor of renewable resources (for hydro, wind and solar), and the characteristics and capacities of generating units. This data is obtained from CODERS (Hendriks et al. 2021), a research database containing information about Canada's electricity system collected from various sources. For data used in this study, relevant sources include BC Hydro and the Alberta Electricity System Operator (AESO).

Figure 23a shows that Alberta's 2018 generation capacity totalled 13.6 GW, including approximately 50% gas-fired capacity and 13% VRE capacity. In comparison, Figure 23b depicts British Columbia's 2018 generation mix for approximately 20 GW total generation capacity, with 85% hydro generation and 4% VRE. In 2018, the total annual demand figures in Alberta and British Columbia were 85.3 TWh and 63.1 TWh, respectively.



a) Alberta



b) British Columbia

Figure 23: Alberta and British Columbia generation capacity mixes in 2018 (CER 2020)

3.4. Numerical results and analysis

This section investigates the potential of integrating the electrical systems of British Columbia and Alberta to improve VRE integration in Alberta. In addition, it assesses the impact of climate change scenarios on the operation of cascading hydro assets and VRE integration. The results are for one year of operation, formulated as the proposed UC problem. $Perct_{Down}$ and $Perct_{Up}$ are 0.5 and 1 in the base scenario of cascading hydro model, respectively. The flexibility values, which are normalized, are unitless. The values for VRE curtailment are expressed as a percentage of the total generated power.

3.4.1. Potential of integrated operation for VRE integration

In this section, the integrated operation of the Alberta and British Columbia electricity systems is studied to explore the potential of leveraging the flexibility of the British Columbia network to improve VRE integration in Alberta. To this end, the proposed UC formulation is utilized to analyze the operation of Alberta, British Columbia, and the integrated system with respect to flexibility. The potential of integrating the two systems to enhance VRE integration in Alberta is then explored. Finally, inter-provincial transmission network requirements for the integrated operation are investigated.

3.4.1.1. Flexibility analysis (standalone operation vs integrated operation)

The flexibility metric outlined in Section 3.2.1 is employed to quantify the flexibility of the power systems in British Columbia and Alberta, as well as the flexibility that can be achieved through their integration. The purpose of this analysis is to compare the flexibility of the power systems in the two provinces and to demonstrate how integrating the systems could result in shared flexibility that could be advantageous for Alberta. A higher flexibility value suggests a greater capacity for the network to alter its generation output, which is beneficial for mitigating fluctuations arising from the integration of variable renewable energy sources. Conversely, a lower flexibility value indicates a limited ability for the network to modify its generation.

The discrete distribution of flexibility value for one year operation is shown in Figure 24. This figure provides insights into the flexibility of the network which can be useful for comparing the case studies. As shown in the figure, the flexibility of British Columbia's system ranges from 0.66-1.85, and values between 1.09- 1.12 occur with the highest probability (11%). The flexibility of Alberta's system ranges from 0.15- 0.53, and the values between 0.34- 0.35 occur with the highest probability (6%). Comparing the distribution figures shows that British Columbia has a higher mean. Additionally, it has a higher variance as its distribution is wider in comparison to Alberta. The values shown in the figures reflect that British Columbia has higher flexibility in comparison to Alberta. As a result, British Columbia is better able to adapt to fluctuations from variable renewable energy sources. The integrated operation's flexibility range is 0.51- 0.88 in which highest probability (9%) is for range of 0.65- 0.66. Integrated operation increases variance by 0.0137, lower and upper bounds of flexibility range 0.36 and 0.35, respectively in comparison to Alberta (Table 13).

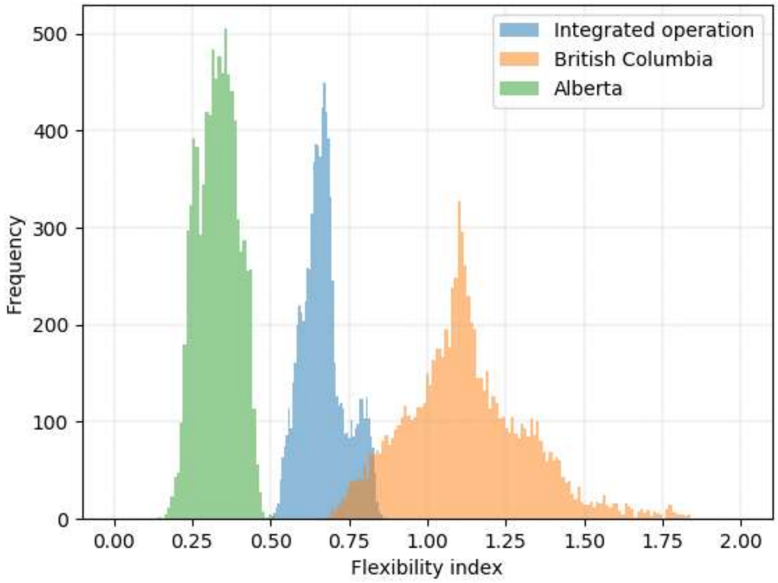


Figure 24: Discrete distribution of flexibility for Alberta, British Columbia and standalone operation resulted from UC problem over one year

Table 13: Results of UC for Alberta and British Columbia and integrated operation

	Cost ($ million)	Cost ($/MWh)	$Flex$	Variance
British Columbia	197	3.08	1.1	0.037
Alberta	7963	98.6	0.324	0.003
Integrated operation	4500	48.2	0.652	0.014

Table 13 also shows the average values of operation cost and flexibility index for British Columbia, and Alberta. As shown in the table, in comparison to the British Columbia system, Alberta's flexibility index is more than three times lower, and its operating costs are higher. The higher operating cost per MWh in Alberta is due to its gas-dominated network, as the operating cost of gas units in Canada is generally higher than that of hydro units. When the results are compared, the normalized flexibility index of integrated operation is roughly twice that of Alberta's network. These findings indicate that integrated operations have a greater potential for integrating VRE sources in Alberta.

3.4.1.2. VRE integration (standalone operation vs integrated operation system)

In this section, the feasibility of integrating VRE sources into the Alberta is evaluated through both standalone and integrated operations. To achieve this objective, the UC problem is employed to perform several scenarios ranging from 30% to 100% VRE penetration rate in 10% increments, with all other UC parameters and constraints remaining constant. The results, as shown in Figure 25, indicate that the curtailment rate increases as VRE penetration increases in both modes, but the slope of VRE curtailment increase is much lower in integrated operation, demonstrating its effectiveness in improving VRE curtailment. The effectiveness of integrated operation to reduce VRE curtailment is more significant as VRE penetration rate increases. The rate of VRE curtailment in Alberta with standalone operation stands at 15%, while it is lower at 9% (a 6% reduction) in the case of integrated operation, when the VRE penetration rate is 68%. Furthermore, when the VRE penetration rate reaches 100%, the curtailment rate in Alberta's standalone operation stands at 69%, while it is significantly lower at 31% (a 28% reduction) in the case of integrated operation.

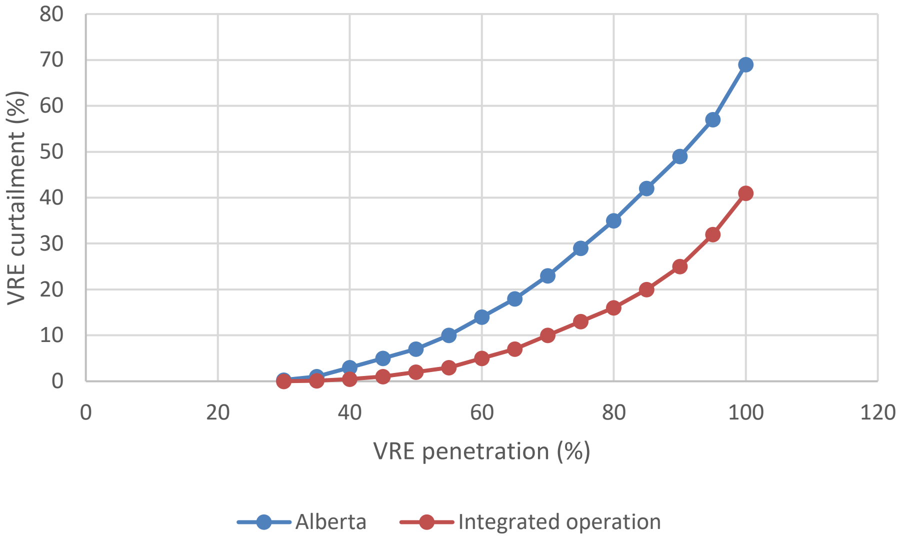


Figure 25: VRE integration vs VRE curtailment for Alberta and integrated operation system

3.4.1.3. Transmission network requirements for integrated operation system

This section aims to determine the maximum transmission line capacity necessary to support VRE integration within the framework of integrated operation. For this analysis, the UC problem of integrated operation is run for different scenarios of VRE penetration in Alberta, while all other parameters and constraints of the UC remain unchanged. Table 14 shows the inter-provincial transmission capacity requirements for various VRE penetration rates. The results indicate that as the penetration of VRE increases, there is a corresponding 1) increase in inter-provincial line capacity, 2) increase in power transfer between Alberta and British Columbia and vice versa, and 3) decrease in the utilization of transmission lines (The utilization rate for the transmission line is power transferred divided by the line capacity over one year). The outcomes can be attributed to the increased fluctuations in VRE output as VRE penetration increases. This leads to greater power transfer between provinces to manage the variability, necessitating a corresponding increase in transmission line capacity. Despite this, the maximum capacity is not utilized for a significant portion of hours, resulting in a decreased utilization rate of the transmission lines.

Table 14: Capacity of inter-provincial Transmission line vs VRE curtailment rate

VRE penetration rate (%)	Transfers from Albert to British Columbia (GWh)	Transfers from British Columbia to Alberta (GWh)	Max capacity of Transmission line (MW)	Utilization rate (%)
30	1723	2878	6631	78
40	2132	3128	6950	74
50	2635	3546	7485	68
60	3460	4295	8052	62
68	**4200**	**4978**	**8633**	**56**
80	5798	6483	9423	48
90	7009	7602	10286	40
100	8953	9476	11398	30

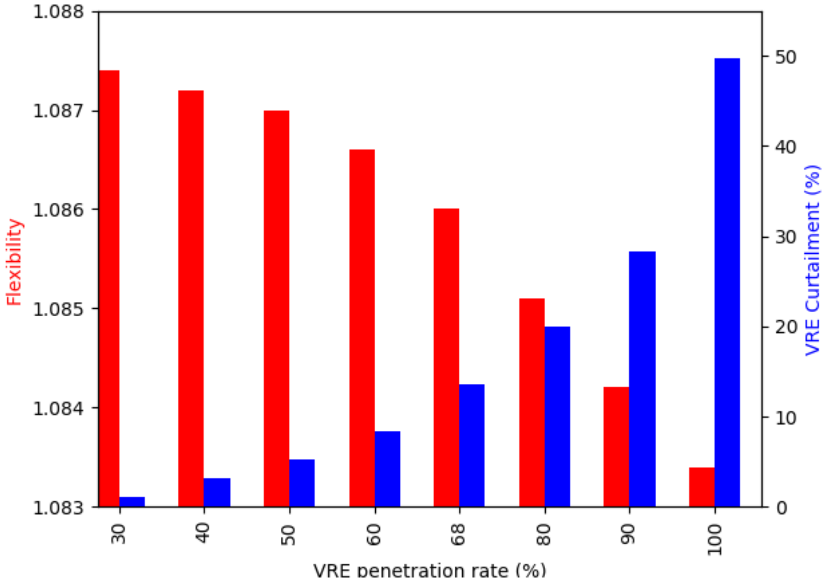
3.4.2. Impact of climate change on cascading hydro operation and network flexibility

This section evaluates the influence of climate change on the operation of cascading hydro assets and the VRE curtailment in the integrated operation. The analysis will focus on the impacts of climate change on water inflow values and environmental constraint.

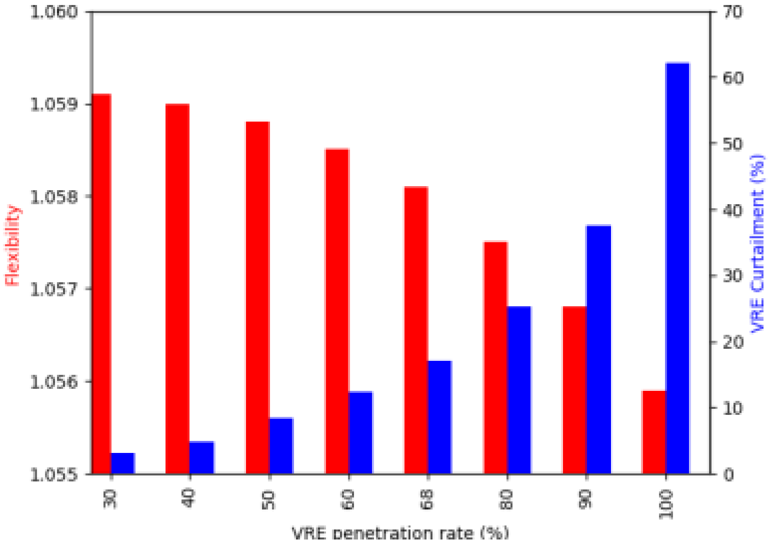
3.4.2.1. Water inflow

In this section, the impacts of changes in water inflow caused by climate change on the operation of hydro assets and VRE curtailment are analyzed. To achieve this, two different water inflow scenarios, freshet (enhanced snowmelt) scenario and drought scenario, are modeled and examined.

The freshet scenario represents an increase in water flow that typically occurs during the spring months (May, June and July). This scenario is used to model the impact of high-water inflow on system flexibility and VRE curtailment rates. The second scenario, the drought scenario, represents a reduction in water inflow into reservoirs, typically caused by a lack of precipitation. This scenario is used to model the impact of low water inflow on system flexibility and VRE curtailment rates. The results of this analysis are presented in Figure 26, which shows the effect of these water inflow scenarios on system flexibility and VRE curtailment rates at various VRE penetration rate in Alberta.



a) freshet scenario



b) Drought scenario

Figure 26: Flexibility parameter and VRE curtailment rate for various water inflow scenarios

The freshet scenario results in an overwhelming amount of water that cannot be stored and must be released immediately to generate power and avoid spillage according to the BC Hydro operation strategy. This results in a minimum generation/must-run constraint for reservoirs. The results show that this minimum generation constraint reduces network flexibility by 6.7% at 68% VRE penetration rate under the freshet scenario, compared to the base scenario (Figure 25). This leads to a 3.5% increase in VRE curtailment.

During drought conditions, the environmental constraint becomes closely linked to the water inflow parameter. When the environmental constraint parameter $Perct_{Down}$ exceeds 0.4, the system becomes infeasible as there is not enough water to meet the constraints. If the environmental constraint parameter $Perct_{Down}$ is lowered to 0.35 during a drought, the network flexibility is reduced by 9.2% at 68% VRE penetration rate compared to the base scenario. This reduction in flexibility results in a 7% increase in VRE curtailment.

The results indicate that the impact of climate change scenarios on network flexibility and VRE curtailment grows as the penetration rate of VRE increases. For instance, when analyzing freshet and drought scenarios, it is found that an increase in VRE penetration rate from 68% to 80% results in a decline of network flexibility by 6.4% and 8.2%, respectively.

3.4.2.2. Environmental constraint

The restriction on the amount of stored water in the final hour of operation is a critical factor in regulating the fluctuations of water volume in cascade hydro assets, particularly during freshet and drought conditions. It requires that the storage content in the last hour of operation must be greater than a given percentage ($Perct_{Down}$) of the maximum storage capacity, and less than a given percentage ($Perct_{Up}$) of the maximum storage capacity. The constraint is influenced by water availability, and it can have a significant impact on the operation and flexibility of cascading hydro assets. This section investigates the impact of various parameterizations of environmental constraint, arising from climate change, on the network's flexibility and the VRE curtailment. In this analysis, three scenarios of $Perct_{Up}$ and $Perct_{Down}$ are run for various VRE penetration rates in Alberta, while all other parameters and constraints of the UC problem remain unchanged. Table 15 shows the impact of various scenarios of the environmental constraint on the flexibility index and VRE curtailment in Alberta.

Table 15: Flexibility parameter and VRE curtailment rate for various scenarios of the environmental constraint

	$\mathrm{Perct}_{\mathrm{Donw}}$ = 0.45		**$\mathrm{Perct}_{\mathrm{Donw}}$ =0.55**		**$\mathrm{Perct}_{\mathrm{Up}}$ =0.95**	
VRE penetration (%)	**Flex**	**VRE curtailment rate (%)**	**Flex**	**VRE curtailment rate (%)**	**Flex**	**VRE curtailment rate (%)**
30	1.1041	<0.1	1.0973	<1	1.0919	<3
40	1.1040	<0.1	1.0973	1	1.0920	3
50	1.1038	0.5	1.0971	4.1	1.0922	6.3
60	1.1035	2.8	1.0968	7.3	1.0925	10.2
68	**1.1031**	**7.2**	**1.0962**	**12.5**	**1.0921**	**16.2**
80	1.1025	13	1.0956	18.4	1.0926	24.2
90	1.1017	21.2	1.0949	28	1.0919	34.5
100	1.1008	35.2	1.0940	39.2	1.0910	45.3

The minimum and maximum percentages of storage capacity, represented by $Perct_{Down}$ and $Perct_{Up}$ respectively, have a direct effect on network flexibility and VRE curtailment rates. By increasing $Perct_{Down}$, the usable storage capacity is limited, leading to a decrease in network flexibility and an increase in VRE curtailment rates. Conversely, decreasing $Perct_{Down}$ results in increased network flexibility. Also, decreasing $Perct_{Up}$ has a negative impact on network flexibility and VRE curtailment rates, as evidenced by changes in VRE curtailment rates. For instance, a 0.5 increase in $Perct_{Down}$ results in a 2.5% increase in VRE curtailment, while a 0.5 decrease in $Perct_{Up}$ leads to a 6.2% increase in VRE curtailment.

The results indicate that as VRE penetration increases, the impact of environmental constraint on network flexibility and VRE curtailment becomes more significant. This is demonstrated by the increase in the VRE curtailment rate in the scenario with $Perct_{Up} = 0.95$, which is 8% higher at VRE penetration rate of 80% compared to 68%.

3.5. Discussion

A UC problem formulation for the study of flexibility provided by cascading hydro assets was developed by formulating a flexibility index based on the concept of flexibility introduced by Berahmandpour, Kouhsari, and Rastegar (2019). The new model was found to be well suited to explore the integration of VRE. Relative to the results produced by formulations that did not comprehensively include operational constraints and asset characteristics (including cascading hydro) (Saffari et al. 2022), findings indicate that British Columbia's network flexibility increases by a factor of 3.3 greater than Alberta's. This highlights the importance of quantifying flexibility under operational conditions.

Results showed that British Columbia's cascading hydro-dominated network achieves high flexibility with low emissions, while Alberta's gas-dominated network has lower flexibility but ample potential for VRE deployment. The integrated operation of the two networks was found to enhance VRE integration in Alberta, allowing for 13% increase in the VRE capacity while maintaining a 10% curtailment rate. These results support the hypothesis that British Columbia's network can effectively smooth VRE fluctuations in Alberta. It can be inferred that the integrated operation strategy analysed here could be implemented in other regions in Canada with hydro-dominated networks, such as Quebec, neighbouring networks lacking this flexibility to improve VRE integration across the country.

In this study, the maximum capacity of inter-provincial transmission was determined with the goal of fully utilizing opportunities for co-ordination between Alberta's VRE capacity and British Columbia's hydro assets, thereby reducing VRE curtailment. In essence, this capacity corresponds to the highest capacity necessary to fully leverage interprovincial network co-ordination. However, this assumption may imply a low utilization rate of transmission capacity. For instance, to take full advantage of must-run generation during the freshet period, typically occurring during the summer, an increase in line capacity may be necessary despite the fact that it will only be used during this specific period. The economic implications of this low utilization warrant further study.

Additionally, as the VRE penetration rate rises, maximum interprovincial transmission capacity also increases and its utilization rate decreases. At a 68% VRE penetration rate in integrated operation, the maximum interprovincial transmission capacity and its utilization rate are 8600 MW and 56%, respectively. However, at a 100% VRE penetration rate, these values are 11300 MW and 30%, respectively. This dynamic calls for a careful consideration of the trade-off between the investment costs and operational cost savings from reduced VRE curtailment to determining the optimal interprovincial transmission capacity.

Results indicate that climate change scenarios can have a significant impact on the ability of hydro facilities to provide flexibility for VRE integration. In effect, this could lead to higher than expected VRE curtailment. As the VRE penetration rate increases, climate change-related impacts appear to worsen. At a 100% VRE penetration rate, the freshet and drought climate change scenarios exhibit 9.8% and 22.2% increases in VRE curtailment, respectively. Such outcomes may entail additional technical challenges, including frequency fluctuations and other power quality issues, if alternative sources of flexibility are not available.

3.6. Conclusion

In light of increasingly stringent decarbonization targets, the integration of larger shares of VRE into power systems has become a pressing issue. However, to achieve this integration effectively and minimize curtailment, the network must exhibit sufficient flexibility. Among the various types of generation assets, hydro units possess some of the highest ramping rates, making them crucial contributors to network flexibility. The role of hydro assets in enhancing network flexibility is significant in the context of decarbonization efforts, especially in Canada where hydropower plays a dominant role. Understanding the potential of hydro assets to contribute to network flexibility is crucial for charting effective decarbonization pathways.

This research undertook a technical analysis of the integrated operation of neighboring provinces in Canada with the aim of enhancing the flexibility and integration of VRE into less flexible power networks. The findings indicate that integrated operation between British Columbia, dominated by hydro power, and Alberta, a less flexible network, could facilitate improved VRE integration in Alberta. Nonetheless, this integration necessitates consideration of regulations and policies across provinces. For instance, Table 13 illustrates that the integrated operation results in a 50% reduction in electricity price per MWh for Alberta, while the price for British Columbia increases by more than ten times. Thus, the cost of power transfer between provinces must be taken into account to achieve a successful integration. Critical considerations for achieving successful integration include cost of transferred power between provinces, cost of new electricity transmission assets, inter-provincial transmission capacity, land use restrictions for inter-provincial line and VRE installation, and acceptable levels of VRE curtailment in relation to installed capacity. Addressing these considerations is crucial to obtaining more robust results in the integration process.

The flexibility of hydro assets, while substantial, is contingent upon water availability. The ongoing challenge of climate change has the potential to negatively impact the ability of hydro assets to provide much needed flexibility. Relying solely on hydropower as a source of flexibility would diminish the overall reliability of the power system, particularly with high VRE penetration rates which can cause imbalances between generation and demand, leading to power quality issues such as frequency fluctuations. To secure the integration of VRE into the power system, a diverse array of flexibility resources, such as energy storage and demand-side management, must be taken into account.

This study aimed to evaluate the hydro assets' flexibility contribution to VRE integration. It should be noted that there are potential methods to enhance the flexibility provision of hydro assets, such as retrofitting hydro systems with reverse hydro pumping. The effects of such retrofitting on network flexibility can improve VRE integration.

In order to achieve a comprehensive and resilient solution, it is imperative to consider significant aspects of energy transmission. Specifically, within the context of electricity systems in Alberta and British Columbia, the electrification of sectors beyond electricity, such as industry and transportation, as well as the decarbonization of technologies in sectors such as oil, predominantly powered by behind-the-fence generation, have the potential to significantly impact system demand. As a result, these factors must be accounted for in assessing the flexibility requirements for VRE integration.

Chapter. 4 : Assessing the potential of demand-side flexibility to improve the performance of electricity systems under high variable renewable energy penetration

Abstract: Increasing the deployment of VRE resources is a prominent option for decarbonizing Canada's electricity system. One of the most significant challenges with increasing VRE penetration is ensuring adequate network flexibility. This study examines the potential impact of demand-side flexibility on network flexibility in Alberta, Canada, using one demand response formulations. For this purpose, a coupled framework consisting of an electricity system operation model (SILVER) and a capacity expansion model (COPPER), both developed for the Canadian context, is used. In this framework, capacity expansion scenarios are identified using COPPER, based on Canada's decarbonization targets for 2050, followed by modeling using SILVER to investigate the effect of demand response programs on operational costs and VRE curtailment. Results indicate that demand response programs can decrease VRE curtailment by approximately 44-64% by 2050 in Alberta, alongside reductions in direct operational costs of $4-8 million per month. Notably, these results are considered robust due to the high spatial and temporal resolutions made possible by the coupled modelling framework.

Keywords: electricity system operation model (SILVER), capacity expansion model (COPPER), time-of-use (ToU), VRE integration, unit commitment.

4.1. Introduction

The Canadian federal government has committed to decrease domestic greenhouse gas (GHG) emissions to net-zero by 2050 (Government of Canada 2021). As a major emissions source, the electricity sector must be central to decarbonization plans, involving significantly increasing the share of supply from variable renewable energy (VRE) resources. However, achieving high VRE penetration in electric power systems requires infrastructural, operational, and behavioral adaptations if power quality and security of supply issues are to be avoided. Due to variable and unpredictable power output of VRE technologies, building network flexibility is one of the most important aspects of VRE integration – provided by both supply-side and demand-side interventions. Demand-side means include demand response (DR) programs, providing incentives for consumers to change their consumption patterns. As such, DR programs are considered a viable option for facilitating VRE integration and energy system decarbonization.

Several case studies in the literature investigate the contribution of DR programs to VRE integration and operating cost reductions using short-term system operation models of real-world networks. Dupont et al. (2014) propose a two-stage model including day-ahead UC and hourly real-time dispatch to assess the impact of residential DR programs on power system operation in Belgium. In the proposed model, the responsive behavior of white goods (dryer, dishwasher, and washing machine) is investigated, with results showing that by shifting only 20% of total consumption towards periods of excess generation, VRE curtailment can be reduced up to 41%. Dietrich et al. (2012) utilize a UC model to optimize the operation of a wind-dominated network with both controlled and uncontrolled responsive loads, finding that DR can enhance network flexibility and reduce operational costs by approximately 30%. Roos and Bolkesj (2018) apply a partial equilibrium linear programming model, BalmoREG, including reserve generation, demand shifting, and the optimal allocation between the spot market and reserve market in Germany. The authors conclude that the provision of reserves using demand flexibility can significantly reduce total costs, reduce VRE curtailment, and support VRE integration. Mansourshoar et al. (2022) develop a stochastic two-stage SCUC approach to studying system reliability featuring a price-based DR program, transmission line contingency, and wind power intermittency, simultaneously.

The authors found that shifting demand from the peak period to off-peak decreased the system operating cost by an average of 2.7% while significantly reducing wind curtailment.

Other research has investigated the impact of DR programs applied to IEEE case study networks. Falsafi et al. (2014) feature a stochastic model in which price-based DR acts as a reserve provider to manage variability in a wind-dominated power system. Results demonstrate that including DR programs in reserve scheduling will result in lower emissions and a 10% reduction in operating costs due to increased VRE utilization. Talari et al. (2019) propose a stochastic two-stage day-ahead and real-time operation model to compensate for wind power prediction errors using DR. Results indicate that DR can reduce wind curtailment by 10-35%. Finally, De Jonghe et al. (2014) investigate the effect of the demand elasticity of responsive load on the network flexibility that can be provided. In this study, various scenarios own-price[1] and cross-price[2] elasticity scenarios are applied to model price-sensitive load to evaluate effects on operational costs and wind curtailment. Result show that increasing own-price elasticity from 0.1 to 0.3 leads to a 10-20% cost reduction.

Aside from reductions in VRE curtailment, DR can also contribute to the resolution of other power system operation issues. An integrated gas-electricity operation model considering DR is proposed by Zhang et al. (2016), applying price-sensitive load to provide electricity network flexibility and decrease dependency on gas-fired generating units. Results show that DR programs can decrease wind curtailment and provide adequate network flexibility when gas-fired capacity is constrained by fuel availability. Zhao et al. (2014) use a network-constrained UC model to investigate the effectiveness of shifting load from peak to off-peak periods for VRE integration.

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[1] Own-price elasticity indicates the propensity of consumers to change their demand in response to changes in price at the time of consumption.

[2] Cross-price elasticity indicates the propensity of consumers to change their demand in response to changes in price in other time periods.

Results show that 10-50 MWh of load shifting can reduce operational costs by up to 15%. Yousefi et al. (2013) propose a DR strategy to smooth wind output variability using demand elasticities, penalties, and incentives within a network-constrained day-ahead optimization. Apart from the mitigation of wind fluctuations, results indicate that DR locations influence network congestion, with 20% DR load participation leading to a reduction in operational costs of approximately 14%. Olkkonen et al. (2018) construct a DR model linked with an existing model of the Finish energy system model, EnergyPLAN, finding that DR resources can improve the utilisation of wind capacity and reduce the need for thermal power generation and electricity imports during peak hours. McPherson and Stoll (2020) propose a suite of DR constraints for the PLEXOS model to realistically represent relevant operational limitations and apply this to a case study in Bangalore, India. The authors find that DR can enhance operational flexibility in the Indian electricity system, reducing both production costs and GHG emissions with benefits scaling in proportion with VRE penetration.

The above reviewed literature focusses mainly on the effectiveness of various DR programs to mitigate VRE fluctuations in short-term operation and dispatch contexts, including associated operational cost and emissions improvements. Notably, DR programs can be applied to overcome other power system operation issues, such as network congestion and maintaining network flexibility during gas supply shortages.

Another set of studies in the literature assesses the impact of DR on long-term expansion scenarios for the electricity system. De Jonghe et al. (2012) investigate the effect of a price-sensitive load (PSL) program on the future optimal electricity generation mix under technical constraints and varying demand elasticities. Results demonstrate that increasing demand elasticity allows the integration of greater quantities of installed wind capacity, while implementing a PSL program leads to reductions in required peak generating capacity. Jin et al. (2013) assess the impact of a PSL program on the expansion of thermal generating capacity under high wind penetrations using a stochastic optimization model. The results of the study show that DR decreases wind curtailment while lowering requirements for thermal capacity by 8%. Asensio et al. (2018) investigate the effects of applying a DR program with storage on network capacity expansion scenarios in the Canary Islands, Spain, under high VRE penetrations. The approach uses a stochastic optimization model considering distributed generation and network assets of varying size and location. Results indicate that the simultaneous operation of DR and storage can increase enhance VRE penetrations in low-voltage distribution networks and reduce the amount of additional capacity required, while also reducing total operational and capital costs by 5%. Kirkerud, Nagel, and Bolkesjø (2021) use the BALMOREL bottom-up energy system optimization model to analyse the potential of load shedding and load shifting in the northern European grid. They find that DR may contribute to a reduction in peak load of up to 18.6% by 2050 while bolstering energy security and delivering substantial economic benefit, although corresponding GHG emissions reductions are likely minor. Pina, Silva, and Ferrão (2012) utilize a model designed to optimize the deployment of DR technologies and behavioral changes in the domestic sector in conjunction with investment and operation of wind and hydro capacity in Flores Island in the Azores, finding that these options can significantly delay investments in new generation capacity while improving the operation of the existing capacity. Anjo et al. (2018) study the effect of DR implementation in the Portuguese electricity system using the OSeMOSYS model, finding decreases in the overall costs and installed capacity, an increase in VRE penetration, and a long-term decline in electricity prices due to avoided investment.

The studies reviewed in the capacity expansion area suggest that demand response programs have the potential to improve the flexibility of the power grid and facilitate the integration of VRE. However, many of these studies do not take into account the various operational and technical limitations that can impact both transmission networks and power generation assets, which can greatly affect the effectiveness of these programs. Additionally, these models often do not provide high levels of spatial and temporal resolution, making it difficult to fully evaluate the potential impacts of demand response programs.

To achieve high VRE penetrations in Canada’s electricity system in an effort to decarbonize energy supply, the consideration of network flexibility is essential. This study endeavors to explore the potential of demand-side flexibility to enhance VRE utilization in a VRE-dominant network. DR programs are widely recognized as a means to motivate consumers to modify their electricity consumption patterns, the design of such programs, including the incentives offered to consumers, can have a significant impact on consumption behavior and load curve alterations. The resultant changes to load curves can have far-reaching effects on various aspects of system operation, including operational costs, VRE curtailment, and network congestion. Therefore, it is imperative to carefully examine the impacts of various DR program formulations and parameterizations on system operation, to determine the optimal program design.

In order to effectively assess the impact of demand-side flexibility on Canada's electricity system as it moves towards decarbonization goals, such as net zero emissions, a robust modeling framework is necessary. This framework must have the capability to reflect future capacity expansion scenarios that align with relevant decarbonization policies and takes into account technical and operational constraints. In this study, a coupled framework, consisting of the system operation model SILVER (Saffari et al. 2022) and the capacity expansion model COPPER

(Arjmand et al. 2022), is employed to analyze Canada's electricity system. The utilization of high temporal and spatial resolutions in the framework allows for a more in-depth understanding of the interactions between DR implementation and VRE utilization, as well as the effects on operational costs and network impacts. The primary objective of this study is to investigate the impact of demand-side flexibility, facilitated through DR programs, on future VRE-dominated expansion scenarios in Canada with enhanced robustness.

Specifically, this study assesses demand-side flexibility provided by DR program formulations, with various parameterizations, as measured by changes in operational cost and VRE curtailment. ToU program is considered which currently being utilized in various jurisdictions, including Ontario, Canada (Angevine et al. 2007; Faruqui et al. 2020; Mcpherson 2022). One of the crucial parameters that determines the impact of responsive load on optimal system operation is the price elasticity of demand, which signifies the extent to which aggregate consumption patterns vary in response to changes in electricity prices. Thus, this parameter holds significant practical significance for system operators, as it is used to determine the optimal incentives required to elicit a desired level of demand response. The DR program formulations analyzed in this study take into account the demand elasticity, thereby modeling responsive consumption behaviors as functions of changes in electricity prices.

The remainder of this paper is organized as follows: section 4.2 details the modeling method including DR program formulations; section 4.3 presents and analyses results; section 4.4 discusses findings; finally, section 4.5 concludes the study.

4.2. Modeling method

The COPPER model is designed to project future electricity system capacity expansion scenarios for specified target years, incorporating various policy considerations such as carbon taxes, maximum VRE utilization, and greenhouse gas emission caps. The SILVER model, on the other hand, is optimized to determine the cost-optimal hourly operation of the network while taking into account technical and operational constraints. The outputs generated by SILVER include hourly power output of generating units, transmission line power flows, VRE curtailment, greenhouse gas emissions, and operational costs. In the coupled framework, the national scenario outputs from COPPER are utilized to populate the SILVER model, which is then run at the national level to evaluate inter-provincial transfers. Subsequently, the SILVER model is run again, this time focusing on the Alberta system, with and without the DR program formulation, to identify network-constrained hourly operation. The impact of demand-side flexibility is assessed in terms of operational costs and VRE curtailment (as shown in Figure 27).

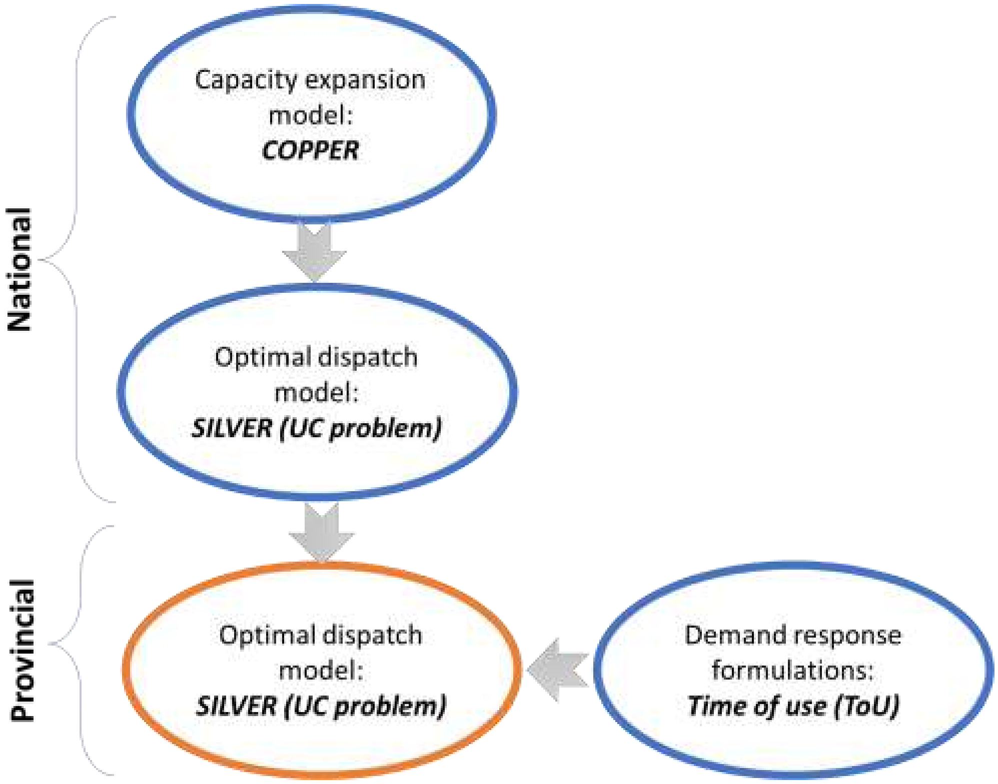

Figure 27: System operation and capacity expansion models constituting the coupled framework for the consideration of DR program

The COPPER model is a deterministic simulation of the Canadian electricity system over the period of 2020 to 2050, with a high degree of spatial resolution for wind and solar data. This model allows for the exploration of scenarios featuring a high penetration of renewable energy sources. The objective function of COPPER seeks to minimize the cumulative cost of planning and operating the system over the planning horizon, encompassing investments in transmission, generation, and storage infrastructure, as well as operational costs related to power production, carbon emissions, and the costs of fixed and variable operation and maintenance. As the model is dynamic in nature, the objective function takes into account costs incurred during all time periods from the start year to the target year. A set of constraints is employed to ensure that technical details and limitations are properly represented. The primary constraints include the following: the hourly balance of supply and demand in each balancing area; a minimum planning reserve margin in each balancing area; limitations on thermal units such as maximum generation, minimum and maximum capacity factor, and ramp rate; hydroelectric constraints for run-of-river, small, and large reservoir facilities, including operational and developmental limitations; maximum generation constraints for renewable energy sources and land-use restrictions; and constraints on transmission and energy storage.

The SILVER model is an object-oriented simulation tool developed using Python to address the unique requirements of analyzing Canada's electricity system. It features a comprehensive hydro modeling component, including cascading hydro, which is crucial for Canada's hydro-dominant electricity network. SILVER is formulated as a mixed integer linear programming (MILP) problem, based on a NCUC framework. The objective of the model is to minimize operational costs, including fuel, maintenance, and startup/shutdown costs. The NCUC problem utilizes a suite of technical and operational constraints:

- Generator constraints including 1) minimum/maximum output, 2) ramp rates (differentiating ramp up and ramp down), 3) minimum up/down durations, and 4) capacity factors for hydro and VRE units.
- Network constraints including 1) voltage angles for each bus, 2) maximum transmission line capacities, and 3) supply and demand balance constraints.

Mathematical formulation of the constraints was already represented in Chapter 2. Additional mathematical formulations applied in this study for the characterization of DR program are outlined in the following sections.

4.2.1. ToU mathematical formulation

The mathematical formulation for the ToU program used in this study is outlined as follows. The basic model is drawn from Liu and Tomsovic (2014):

$$\mathit{\Delta} D_t = D_t \left(\sum\nolimits_{\tau \in L} \sigma_{t,\tau} . \frac{(\varphi_t^L - \varphi_t)}{\varphi_t} + \sum\nolimits_{\tau \in O} \sigma_{t,\tau} . \frac{(\varphi_t^O - \varphi_t)}{\varphi_t} + \sum\nolimits_{\tau \in \mathrm{P}} \sigma_{t,\tau} . \frac{(\varphi_t^P - \varphi_t)}{\varphi_t} \right) \tag{1}$$

$$\sum\nolimits_{t=1}^{N_t} \mathit{\Delta} D_t = 0 \tag{2}$$

$$A^D . D_t \leq \Delta \mathrm{D_t} \leq \mathrm{A^U} . D_t \tag{3}$$

$$\mathit{\Delta} \varphi_t^O \leq 0 \tag{4}$$

$$\mathit{\Delta} \varphi_t^P \geq 0 \tag{5}$$

$$\mathit{\Delta} \varphi_t^O \leq \mathit{\Delta} \varphi_t^L \leq \mathit{\Delta} \varphi_t^P \tag{6}$$

Where D_t is the electrical load at time t without a ToU response, and $\mathit{\Delta} D$ is the change in load with the ToU program; φ_t^L, φ_t^O, and φ_t^P represent prices prior to the implementation of the ToU program for the low peak, off-peak and peak periods, respectively; and $\sigma_{t,\tau}$ is the price elasticity of demand at time t in response to the price at time τ (i.e., $\mathrm{t} = \tau$ implies own-price elasticity, otherwise values are cross-price elasticities). According to Eq. 1, greater elasticity values cause greater load changes (ΔD), and vice versa. Eq. 8 (M.S. Misaghian et al. 2018) enforces a zero sum for load changes over all time periods (i.e., total load remains constant with ToU program implementation, only its distribution in time changes). A^{D} and A^{U} are constants constraining the range for load changes. $\Delta\varphi_t^L$, $\Delta\varphi_t^O$, and $\Delta\varphi_t^P$ indicate prices changes in the L, O, and P periods, respectively (with ranges constrained by Eq. 4-6 (M.S. Misaghian et al. 2018). Eq. 1-6 are applied separately to each bus.

Own-price elasticity values for all periods are negative, implying changes in demand in the opposite direction to changes in price. Conversely, cross-price elasticity values are positive, implying changes in demand in the same direction to changes in price in other periods. For example, an increase in price in the peak period will encourage consumers to shift their demand to the low peak and off-peak periods.

4.3. The impact of demand-side flexibility on network operation

In this section, the modeled outcomes of the effect of enhanced demand-side flexibility on Alberta's electricity system in 2050 are presented. The capacity expansion scenario generated by COPPER model, which takes into account Canada's decarbonization policies, is used as the basis for the SILVER model run with the DR program as described in Section 4.2.1. The operational costs and the rate of VRE curtailment are selected as the primary measures of network flexibility for this study. The impact of the ToU program on network congestion is also assessed. Furthermore, sensitivity analysis is carried out for crucial parameters in the DR program.

The results presented for DR programs are based on a one-month simulation of the NCUC problem during the winter season (January) with a base case responsive load proportion of 50% applied at each bus. It is assumed, for modeling purposes, that the operational cost of VRE is zero. The limitations related to these modeling decisions are discussed in further detail in Section 4. 8.

4.3.1. Base COPPER scenario

In line with Canada's commitment to the Paris Climate Agreement, the government has established a national target of achieving net-zero GHG emissions by 2050. The COPPER model is utilized to run a suite of policies aimed at achieving this target. These policies include the implementation of a carbon tax, the establishment of performance standards for natural gas-fired and coal power plants, and the establishment of national emissions limits. The performance standards encompass restrictions on the emission intensity of natural gas-fired generation expressed in terms of emissions per megawatt hour (MWh) and the requirement for new units to utilize efficient technologies. Additionally, there is a mandate to phase out conventional coal-fired electricity generation facilities by the year 2030. The national emissions limits aim to achieve a 40-45% reduction in GHG emissions by 2030 from the 2005 level (equivalent to 11 MTCo2 of electricity sector GHG emissions by 2030) and net-zero emissions by 2050. The reference year for expansion is 2018 and the planning steps are on a 5-year basis, including 2025, 2030, 2035, 2040, 2045, and 2050. Additional information, such as input data and assumptions can be found in the Appendix.

The 2050 generation capacity mix for Alberta identified by COPPER based on this net zero emission policy is shown in Figure 28. In this scenario, Alberta carries out an extensive deployment of VRE capacity, with 13.25 GW (88.3%) wind and 1.33 GW (8%) solar photovoltaic (solar PV) capacity by 2050. It is important to note that the analysis of COPPER results is beyond the scope of this study as the examination of expansion results and policy implications has already been thoroughly explored and presented in Arjmand and McPherson (2022). However, it is noteworthy that the COPPER scenario utilized in this study features a significant amount of power imports into Alberta, which are considered exogenous variables with regards to the modeled effects of demand response implementation as presented by Miri et al. (2022).

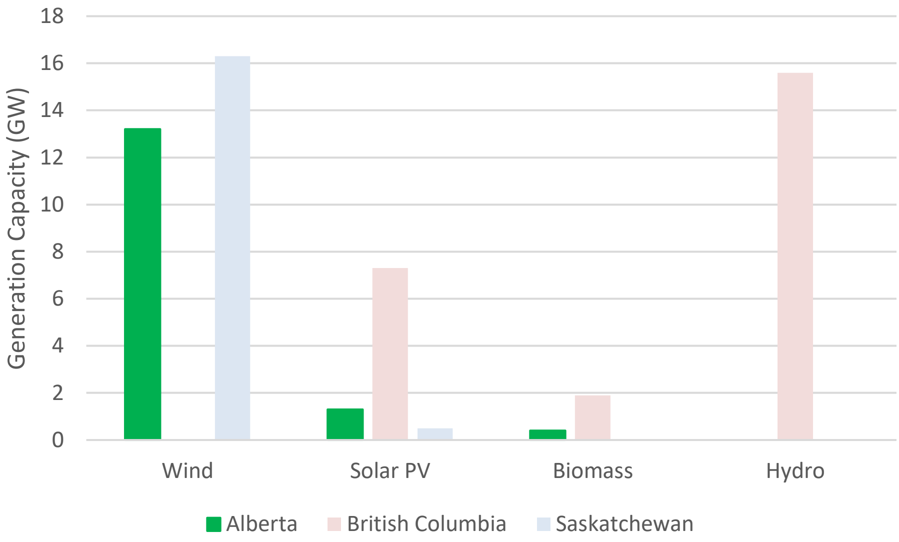

Figure 28: Modeled installed generation capacity in Alberta, British Columbia, and Saskatchewan in 2050

4.3.2. Optimal dispatch with ToU program

The default off-peak, low peak and peak periods used to represent the ToU program are 12 - 6 a.m. (6 hours), 6 a.m. - 4 p.m. (10 hours), and 4 p.m. - 12 a.m. (8 hours), respectively. Price elasticity of demand values are estimated based on the methods proposed by Kirschen et al. (2000) and Ton et al. (2013) using demand and electricity price data from the Alberta system operator (AESO), as summarized in Table 16.

Table 16: Estimated price elasticity of demand values for Alberta

	Peak	**Low Peak**	**Off Peak**
Peak	-0.22	0.0652	0.2481
Low Peak	0.0652	-0.0663	0.072
Off Peak	0.2481	0.072	-0.0517

Figure 29 illustrates the modeled load curve and VRE power output for an arbitrary week with and without ToU implementation. Table 17 summarizes modeled operational costs and VRE curtailment for Alberta in 2050.

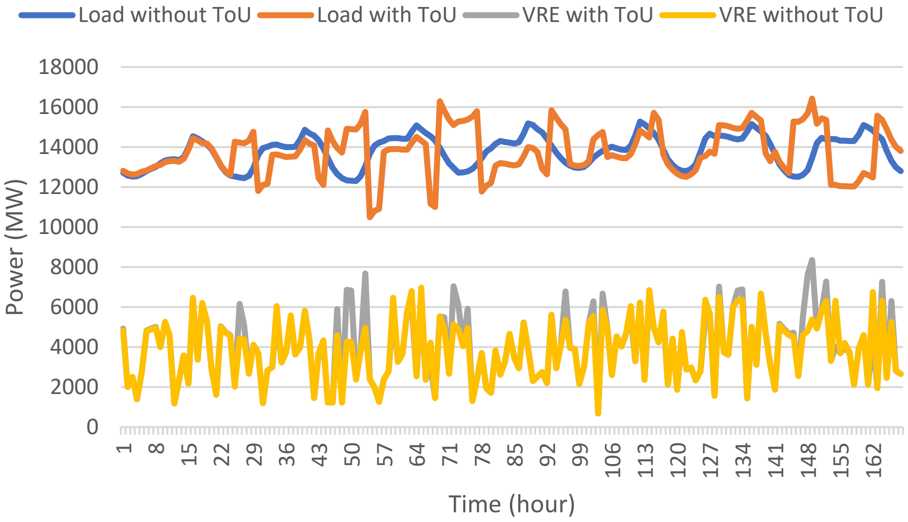

Figure 29: Example weekly load curve and VRE power output for Alberta in 2050, with and without ToU implementation

Table 17: Modeled network flexibility measures for Alberta in 2050, with and without ToU implementation

	With ToU	Without ToU
Operational cost ($ million)	26.6	30.1
VRE curtailment	5.9%	10.7%

Implementing the ToU program decreases modeled VRE curtailment by 44% (equating to 75.5 GWh more VRE output) leading to a 15.1% reduction in operational cost for the month. As can be seen in Figure 29, the ToU program causes greater fluctuations in net load in some periods. For example, in hours 48-55, 71-74, and 148-153, VRE output power and load both increase with the ToU program in place. Note, the difference between demand and VRE output is mostly supplied by imported power from neighboring networks (exogenous in this analysis).

4.3.3. Sensitivity analysis

4.3.3.1. The impact of demand elasticity

This section presents the outcome of a sensitivity analysis performed to evaluate the impact of own-price and cross-price demand elasticities ($\sigma_{t,\tau}$) on the operational costs and VRE curtailment rate of the Alberta electricity system in 2050. The aim of the analysis is to examine the role that demand elasticity, as a crucial customer characteristic, plays in affecting the flexibility provided by ToU implementation. The results of the sensitivity analysis of own-price elasticity are depicted in Table 18. The results show that a 10% increase in own-price elasticity leads to a 64%, 37%, and 49% decrease in VRE curtailment during peak, off-peak, and low-peak periods, respectively, along with a reduction in operational costs of 4.1, 2.7, and 3 $ million for the month. Conversely, similar decreases in magnitude are observed for decreases in own-price elasticity. The results are most sensitive to changes in the own-price elasticity during the peak period, as this period has a higher load, thus offering more potential for reducing VRE curtailment.

Table 18: Sensitivity analysis results for own-price demand elasticity, by ToU period

	Peak period		**Off-peak period**		**Low peak period**	
Own-price elasticity	Operational Cost ($ million)	VRE curtailment	Operational cost ($ million)	VRE curtailment	Operational cost ($ million)	VRE curtailment
-10%	29.8	9.5%	28.7	8.2%	29.2	8.7%
Base case	26.6	5.9%	26.6	5.9%	26.6	5.9%
+10%	22.5	2.1%	23.9	3.7%	23.4	3%

The sensitivity analysis results for cross-price elasticity are presented in Table 19. These results highlight that a 10% increase in cross-price elasticity between the low peak and peak periods leads to a decrease in VRE curtailment by 40%, and a reduction in operational costs by $3.3 million for the given month. Similarly, changes in the negative direction and between the off-peak and peak periods exhibit comparable magnitude. However, the impact of changes in cross-price elasticity between the low peak and off-peak periods is observed to be less significant. The results indicate that changes in cross-price elasticity are most sensitive to changes affecting the peak period as it represents a higher load and offers greater potential for reducing VRE curtailment. Additionally, the off-peak period is shorter in duration and has limited solar PV output, thus, offering limited potential for reducing VRE curtailment.

Table 19: Sensitivity analysis results for cross-price demand elasticity, by ToU period pair

	Between low peak and peak periods		Between off-peak and peak periods		Between low peak and off-peak periods	
Cross-price elasticity	Operational cost ($ million)	VRE curtailment	Operational cost ($ million)	VRE curtailment	Operational cost ($ million)	VRE curtailment
-10%	29.4	9.3%	28.9	9%	28.4	7.8%
Base case	26.6	5.9%	26.6	5.9%	26.6	5.9%
+10%	23.8	3.5%	24.6	4.3%	25.7	5.2%

4.3.3.2. The impact of peak, off-peak, and low peak period timing and duration

This section presents the outcome of a sensitivity analysis that explores the impact of timing and duration of peak, off-peak, and low-peak periods on operational cost and VRE curtailment. The aim of this analysis is to examine how adjustments to the ToU periods by system operation can influence system operation. Two scenarios are examined for this purpose:

- Scenario 1 - The off-peak period is defined as 9 p.m. to 9 a.m., the low peak period as 9 a.m. to 11 a.m. and 5 p.m. to 9 p.m., and the peak period as 11 a.m. to 5 p.m.
- Scenario 2 - The off-peak period is defined as 9 p.m. to 9 a.m., the low peak period as 9 a.m. to 4 p.m., and the peak period as 4 p.m. to 9 p.m.

Table 20 presents the results of the sensitivity analysis for two scenarios. The analysis reveals that modifications to the period timing and durations result in substantial reductions in VRE curtailment. Specifically, Scenario 1 exhibits a 47% decrease in curtailment, while Scenario 2 experiences a 74% decrease. Additionally, there is a decrease in operational costs by $2.8 million and $5.3 million in Scenario 1 and Scenario 2, respectively, for the given month. In Scenario 1, the low peak and peak periods have durations of 6 hours each, while in Scenario 2, the low peak and peak periods have durations of 7 hours and 5 hours, respectively. This comparison highlights the significant impact that small changes in period duration and timing can have on network flexibility. These results emphasize the criticality of proper design and parameterization of demand response programs.

Table 20: Sensitivity analysis results for peak, off-peak, and low peak durations

Scenario	**Operational cost ($ million)**	**VRE curtailment**
Base case	26.6	5.9%
1	23.5	3.1%
2	21.3	1.4%

4.3.4. Responsive load geographic distribution

In the base case scenario, it is assumed that the availability of responsive load is uniform across all substations, at a rate of 50%. The following analysis explores the impact of heterogeneous distribution of responsive load, where selected substations have a higher proportion of responsive load (more than 50%), while maintaining the same network-wide total quantity of responsive load as the base case (50% of the total). The objective of this analysis is to evaluate the influence of the geographical distribution of responsive load on the efficacy of ToU. Table 21 compares the results of this scenario with the base case scenario. The results indicate that a heterogeneous distribution of ToU load decreases network flexibility, as reflected by an increase in VRE curtailment and operational cost of 31% and 8.0%, respectively. This outcome is due to the limited transmission line capacities, which constrict the maximum possible changes in load at certain substations to a greater extent compared to the base case scenario.

Table 21: Impact of responsive load distribution

	Operational cost ($ million)	VRE curtailment
Base case (50% responsive load at all substations)	26.6	5.9%
Greater than 50% responsive load at selected substations (No change in total responsive load)	28.75	7.7%

4.3.5. Network congestion and constraints on ToU program effectiveness

This section presents an analysis of the impact of load alternation resulted from the ToU program on network congestion. As illustrated in Figure 29, the implementation of the ToU program leads to increased fluctuations and higher peaks in the load curve, resulting in implications for network capacity utilization and congestion. The study found that load variance values increased nearly 5-fold, from 724.4 GW to 3333.7 GW, for the analyzed month following the implementation of the ToU program. To quantify network congestion, the Alberta 500 kV and 240 kV transmission lines are considered for three selected days, including two days with significant load curve changes resulting from the ToU implementation and one day with a modest load curve change. A congestion factor is defined as the average percentage of transmission lines operating at their maximum capacities over all hours for each day, as per Eq. 13.

$$\text{Congestion factor (\%)} = \frac{\sum_{t=1}^{N_t} Number\ of\ lines\ at\ maximum\ capacity}{N_t * number\ of\ lines} \tag{13}$$

The results of the implementation of the ToU program on network congestion are presented in Figure 30. The graph compares the congestion factors for three selected days with and without ToU implementation. The results indicate a significant increase in network congestion, reaching up to 50%, as a result of ToU implementation. The changes in congestion factor are most pronounced for days with significant changes in the load curve (day 1 and day 2).

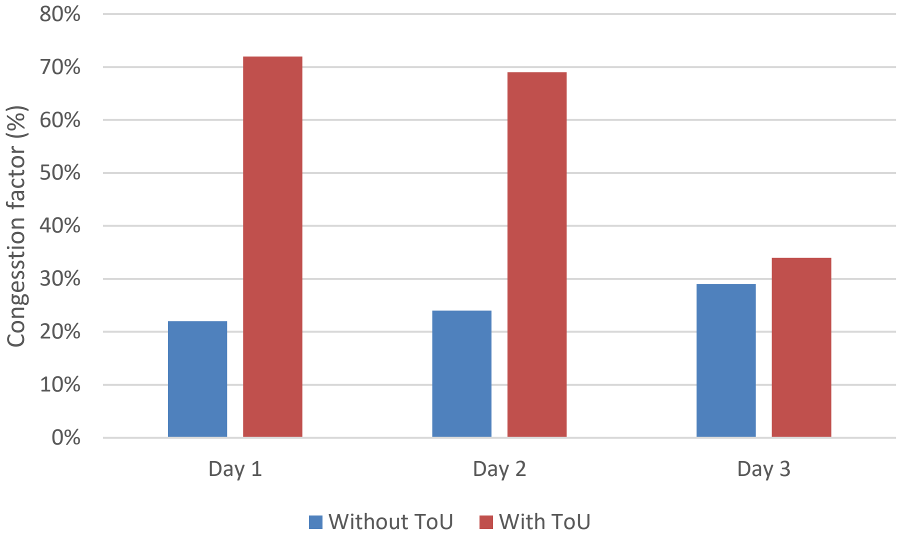

Figure 30: Network congestion factors for three selected days in Alberta in 2050, with and without ToU implementation

To determine the impact of transmission congestion more accurately on the effectiveness of ToU program, the 2050 scenario is run with relaxed transmission line capacities (with implementation of ToU program). The results indicated that a 16% increase in network capacity is needed to fully realize the benefits of demand response. Table 22 compares the operational cost and VRE curtailment between the relaxed transmission capacity scenario and the base case, revealing reductions of 11% and 48%, respectively.

Table 22: Network flexibility measures for Alberta in 2050, with and without relaxed transmission capacity

	Operational cost ($ million)	**VRE curtailment**
Base case (with ToU)	26.6	5.9%
Relaxed transmission capacity scenario	23.7	3.2%

Subsequently, a new COPPER solution was generated using the load profile produced from the scenario of relaxed transmission line capacities (with implementation of ToU program) (depicted in Figure 31 as installed generation capacities). Figure 32 shows the related reductions in generation capacity as a percentage of the base case scenario (without implementation of ToU program).

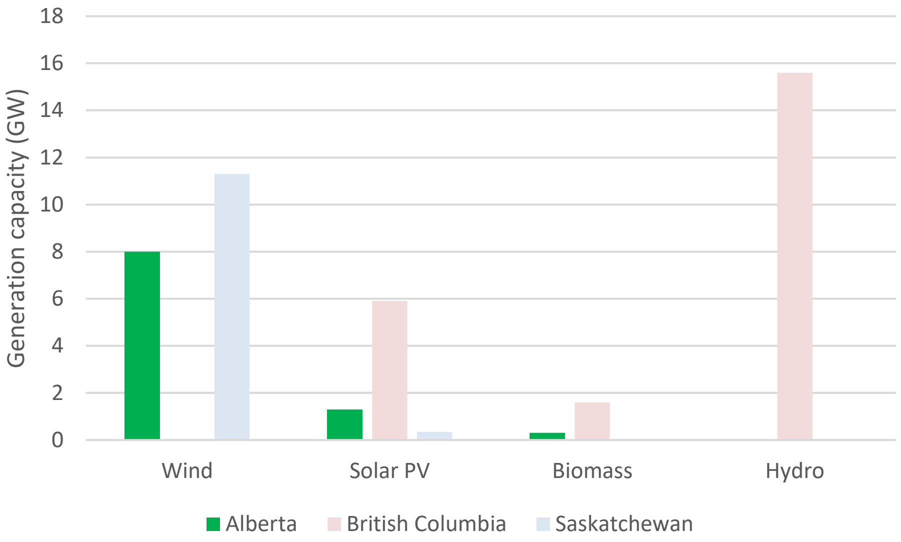

Figure 31: Installed generation capacities in Alberta, British Columbia, and Saskatchewan in Alberta in 2050 using COPPER with the relaxed transmission capacity scenario load profile

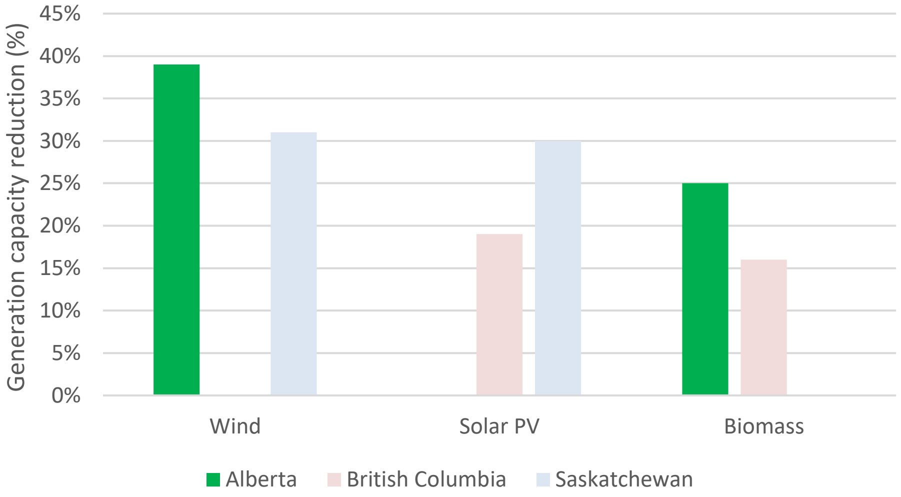

Figure 32: Percentage reduction in generation capacity by type for COPPER solve with the relaxed transmission capacity scenario load profile, relative to the base case with ToU

Figure 33 presents the capacities of the inter-provincial transmission lines between Alberta and its neighboring networks, which are modeled using the COPPER model for the solution of the relaxed transmission capacity scenario load profile (with implementation of ToU program) and the base case scenario (without implementation of ToU program).

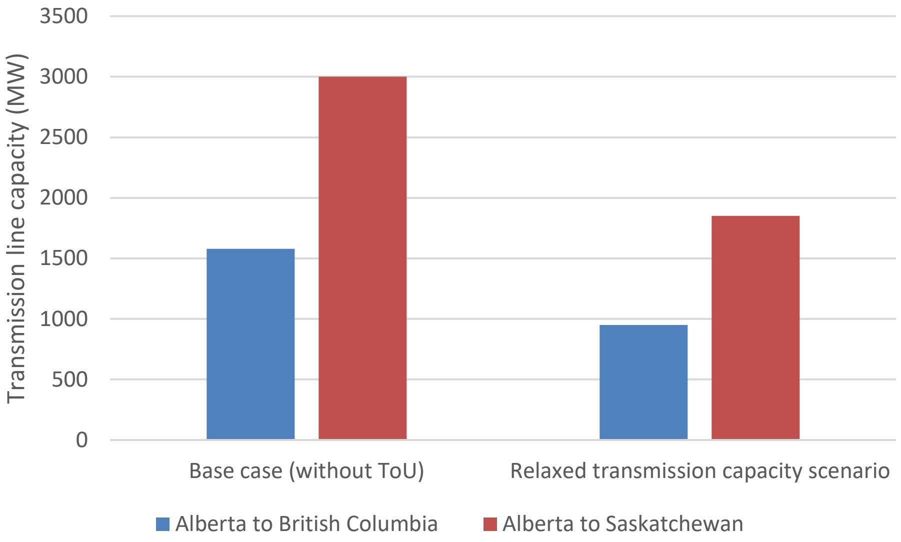

Figure 33: Inter-provincial line capacities in 2050 for COPPER solve with the relaxed transmission capacity scenario load profile and the base case without ToU

Maximizing the utilization of the ToU program in Alberta requires expanding the transmission network capacity by 16%, which leads to a reduction in capacity of inter-provincial links to British Columbia and Saskatchewan by 39% and 38% respectively, and a 27% reduction in total required generation capacity across these three provinces by 2050. Additionally, it results in reduced operational reliance on neighboring networks.

4.4. Limitations

This study modeled DR program using estimates from the literature, which are not specific to the Albertan context. ToU demand elasticities were modeled as constant for each period and thus did not take into account serial dependencies and weather-related effects.

Furthermore, this study is based on the 2018 Alberta Internal Load (AIL) profile, which represents the net demand. On the other hand, system demand is calculated as the total demand measured by the AESO plus the transmission network losses. The behind-the-fence (BTF) load represents the difference between AIL and system load. To create a projected demand profile for 2050, the 2018 AIL profile was scaled using a demand growth factor. It is assumed that the load will scale with a similar profile as 2018. However, considering the current dominance of industrial load in Alberta, it is highly probable that the load profile will change in the future.

The effect of decarbonization efforts in other sectors on BTF generation in Alberta may vary based on the rules and policies implemented. According to the AESO (AESO 2022), the relevant host industries are interlinked with the decarbonization of cogeneration assets. It can be assumed that the government will strive towards similar decarbonization objectives in other industries as well. In line with this assumption, other industries may adopt techniques and technologies, such as carbon capture and storage (CCS), post-combustion carbon sequestration, and pre-combustion carbon sequestration, to reduce their greenhouse gas emissions. Decarbonization of industrial sectors' BTF generation may have two significant impacts: 1) an increase in industrial BTF demand, and 2) a decrease in the power exported to the network from cogeneration assets. According to AESO (2022), the widespread deployment of CCS in cogeneration facilities would result in a 5% increase in Alberta's electricity load. However, the impact of decarbonization efforts in other industries on the expansion scenario is beyond the scope of the current study.

The COPPER model assumes that in a future net-zero scenario, the entire Alberta's load will be supplied by generation capacity dispatched by AESO, which means that industrial cogeneration capacity, particularly those governed by the oil industry, and distributed energy resources such as rooftop solar are not explicitly considered. These assumptions were made to focus on the capabilities of AESO to meet the net-zero target.

The inclusion of cogeneration capacity is acknowledged as having the possibility of affecting the results towards achieving net-zero emissions by 2050. However, as these assets are GHG emitter, they will eventually need to be phased out in the scenario considered, in the absence of any technological decarbonization, to reach the net-zero target.

It is important to recognize that the current study does not incorporate existing provincial plans for the expansion of VRE, including Alberta's goal to build 8 GW of solar power. The COPPER run was conducted with the aim of optimizing Canada's national electricity system and formulating a comprehensive national decarbonization plan. The results of the study indicate that Alberta's solar capacity is projected to remain at 1.3 GW in the 2050 expansion scenario. This is due to the more efficient approach of deploying VRE in other provinces and utilizing power transfer, as opposed to solely relying on VRE expansion within Alberta. This leads to the determination that a national-level strategy for decarbonization is likely to be a more advantageous approach as compared to regional or provincial level efforts, taking into consideration the optimization of the entire country, rather than provincial optimal conditions.

4.5. Discussion

Results of this study indicate that the implementation of DR programs in Alberta’s future VRE-dominated electricity system can produce improvements in network flexibility, measured in terms of both VRE curtailment and operational costs. The base case for the ToU program shows that reducing VRE curtailment by 35% and operational costs 9.4% is achievable. As such, while promoting supply-side flexibility cannot be seen as a singular solution for managing future supply variability in Alberta, it can make a material contribution.

Own-price and cross-price elasticities affecting the peak and off-peak periods, and also low peak and peak period timing and durations, have the most significant impacts on network flexibility. The effectiveness of the ToU program appears to be most dependent on consumer behavior within the context of seasonal and diurnal patterns. It is observed that minor differences in ToU period duration and timing can produce substantially different impacts on network flexibility in high VRE penetration scenarios.

In this study, the operational cost of VRE is modeled as zero (i.e., constant, unlike conventional generation). With high VRE penetration in electricity systems, VRE curtailment occurs during periods of high-power output. With a ToU program in place, demand will shift towards these periods to take advantage of power production at zero operational cost. As such, load will increasingly synchronize with VRE output power to the extent possible considering demand flexibility and network constraints. In other words, DR causes greater load variability as demand shifts to periods in which VRE curtailment would have otherwise occurred. Consequently, changes in demand elasticity will affect network flexibility as measured by both VRE curtailment and operational costs in VRE-dominated expansion scenarios. As demonstrated in Figure 29, this can result in greater net load fluctuations (an effect is also noted by Olkkonen et al. (2018)) and a greater degree of transmission network congestion.

Due to this network congestion effect, transmission network capacity appears to be a limiting factor for the advantages that DR programs can deliver in terms of reduced VRE curtailment and operational costs. However, the responsive load geographic distribution can change the implications of this limiting factor. A more uniform distribution of responsive load between substations appears to be beneficial. Furthermore, relieving this congestion and maximizing the utilization of DR resources through an expansion of provincial transmission capacity may offer multiple benefits, including 1) further improvements in operational cost and VRE curtailment, 2) a reduction in required inter-provincial transmission capacity and total generation capacity across Alberta and neighboring networks, and 3) reduced reliance of out-of-province actors and resources for the provision of adequate network flexibility.

Note that direct operational cost reductions identified in this study are more modest than those found by comparable studies in the literature, including Dietrich et al. (2012), De Jonghe et al. (2014), Zhao et al. (2014), and Yousefi et al. (2013). This difference is largely attributable to the higher spatial and temporal resolutions applied in the coupled COPPER-SILVER framework used in this study, allowing the detailed representation of operational and technical constraints affecting the utilization of VRE.

4.1. Conclusions

In recent years, there has been a growing focus in academic literature and policy circles on the role of DR programs in enhancing demand-side flexibility for the integration of VRE sources into the electricity grid. By incentivizing consumers to adjust their electricity consumption patterns in response to changes in electricity price, DR programs offer a cost-effective solution for managing the inherent variability of renewable energy resources. This research study conducted an analysis of the impact of demand-side flexibility on the integration of VRE in a hypothetical future expansion scenario for Alberta's electricity system. Specifically, the study evaluated the significance of ToU in contributing to network flexibility, including the implications for network congestion management.

The findings of this study demonstrate that ToU can be an effective means of enhancing network operation through reduced operational costs and reduced VRE curtailment rates. However, the success of ToU is contingent upon consumer willingness to modify their consumption patterns, as indicated by the price elasticity of demand and the extent of responsive demand. The temporal aspects of the load curve, which are influenced by consumer behavior, also play a critical role. As such, a thorough characterization of distinct consumer categories (e.g., residential, commercial, industrial, etc.) is imperative for the evaluation of DR potential under high VRE penetration scenarios. It is worth noting that these results provide more accurate estimates of the achievable DR potential for VRE integration compared to previous studies, as the coupled modeling framework used in this research provides high temporal and spatial resolution.

Transmission network capacity appears to be a limiting factor for delivering the maximal advantage of DR programs for VRE integration. This draws further attention to the economic trade-off between network capacity expansion and VRE curtailment identified in the literature, particularly regarding the relative merits of network expansion strategies aimed at local and regional scales.

Chapter. 5 : Conclusion

In this dissertation, we examined the feasibility of decarbonizing Canada's electricity system by incorporating a high share of VRE using power system operation model. In Chapter 2, we aimed to enhance the SILVER operation model through three key elements: hydro/cascading hydro modeling and demand response programs. Then, SLIVER validity was investigated through five different ways including comparison of the results with a commercial operation model, PLEXOS. The Chapter also assessed the potential of Canada' existing network for VRE integration in terms of flexibility and transmission network capacity. In Chapter 3, the examination of integrated operation of networks as a means of enhancing the integration of VRE in less flexible networks was conducted. A flexibility index was first established to quantify network flexibility while considering all technical and operational limitations. The chapter then evaluated the potential benefits of integrating the British Columbia cascading hydro-dominated network and the Alberta network to improve flexibility and VRE integration in Alberta. Furthermore, the impact of climate change scenarios on the ability of hydro units to provide flexibility is analyzed. Chapter 4 focused on the concept of demand-side flexibility. A linkage framework connecting the expansion model, COPPER, and the operation model, SILVER, was utilized to investigate the effect of demand response programs on the curtailment of VRE sources in a future scenario dominated by VRE in Alberta.

Due to the dominance of hydro generation in the existing Canadian electricity system, it has significant potential to provide generation side flexibility for the integration of VRE sources. Additionally, the transmission network capacity can facilitate high levels of VRE penetration. However, the existing transmission capacity is insufficient for realizing maximum possible VRE integration. While increased VRE penetration in each province based on its existing network capacity can significantly decrease GHG emissions, it is not enough to achieve net-zero emissions. Further actions are required to attain this goal.

Integrated operation of neighbouring networks would help to share flexibility of hydro-dominated networks, allowing for VRE integration improvement in less flexible networks. However, climate change has an impact on the flexibility provided by hydro assets. This effect calls into question the reliability of hydro facilities in providing flexibility for VRE integration under climate change considerations, particularly in high VRE penetration scenarios. This necessitates a variety of flexibility resources in order to secure reliable flexibility provision in order to meet the decarbonization target.

Another potential method to increase network flexibility is demand-side flexibility, which can be achieved through DR programs. The effectiveness of ToU program is influenced by two key factors: the program's parameterization by the system or market operator and customer behavior and preferences. On the system side, factors such as the timing and duration of off-peak, low-peak, and peak periods and the maximum allowed responsive load proportion on each substation are crucial. On the demand side, the demand elasticity and location play a significant role.

DR programs do not offer a comprehensive solution for managing high VRE penetrations in electricity systems. However, they can contribute to network flexibility, particularly for networks that lack supply-side flexibility and rely on neighboring networks for their effective operation. This is exemplified by Alberta's electricity system 2050 scenario.

Additionally, the capacity of the transmission network can act as a constraint that hinders the maximum flexibility of both the generation side and demand side. On the generation side, it may restrict the capability of power generators to accommodate fluctuations from VRE sources. On the demand side, it may limit the ability of demand to shift its consumption patterns. This emphasizes the significance of transmission network to facilitate high levels of VRE penetration while minimizing curtailment.

5.1. Limitations

The limitations and weaknesses of this thesis are as follows, and can be addressed or improved in future work to enhance the analysis:

1) In this thesis, an analysis of Canada's electricity system was conducted, taking into consideration its vast and extensive nature, necessitating the gathering of a significant amount of data. The majority of the data was obtained from publicly accessible sources. When data was not publicly available, reasonable assumptions were made. For instance, nodal load was estimated using population fraction and the maximum capacity of transmission lines was calculated using information from the Institute of Electrical and Electronics Engineers (IEEE) standard books.
2) In this thesis, VRE sources were modeled as a deterministic parameter. However, given the variable and unpredictable nature of VRE, it would be more appropriate to treat them as a stochastic parameter to accurately represent their behavior in the model.
3) In this thesis, it is assumed that ideal conditions exist for a transmission line between Alberta and British Columbia. The impact of ambient conditions such as temperature and solar irradiance have not been taken into account when determining the transmission line capacity under these ideal conditions. This means that the transmission line capacity calculations may not fully reflect the real-world performance of the transmission line, particularly in relation to how ambient conditions can affect the capacity of the line.

Appendix

COPPER data and assumptions

- Planning for the target year 2050 considering 2018 as the reference year

- modeled ['2025', '2030', '2035', '2040', '2045', '2050'] planning periods and ran 38 representative days in each period

- reserve margin = 0.15

- pumped hydro retrofit limit = 0.2

- Carbon price ($/MTCo2) =

{'2025': 95, '2030': 170, '2035': 220, '2040': 270, '2045': 320, '2050': 370}

Table 23: Provincial annual demand growth in percentage (Arjmand and McPherson 2022)

Provinces	2018–2025 (%)	2025–2030 (%)	2030–2035 (%)	2035–2050 (%)
British Columbia	0.73	0.95	1.36	1.59
Alberta	1.05	0.79	0.87	0.65
Saskatchewan	1.09	1.07	1.20	1.20
Manitoba	0.16	0.59	1.36	1.36
Ontario	0.10	1.10	0.77	0.61
Quebec	0.93	0.64	0.64	0.64
New Brunswick	0.07	0.43	0.47	0.33
Prince Edward Island	2.77	2.11	2.11	2.11
Nova Scotia	0.08	0.04	0.97	0.88
Newfoundland and Labrador	0.17	0.59	0.59	0.59

Table 24: Generation and storage technology data (Arjmand and McPherson 2022)

Type	Max CF (%)	Min CF (%)	Ramp-Rate (%)	Efficiency (%)	Fuel CO2 (kg/MWh)	Fixed O & M ($/KW/year)	Variable O & M ($/MWh)	Fuel price ($/GJ)	Annualized Capital cost ($/KW/year)
Coal	90	50	5	39	830	75	6	2.6	447
CoalCCS[b]	90	50	5	30	110	106	13	2.6	789
Diesel	95	5	10	39	664	19	19	16.6	86
GasCC	80	20	10	51	360	14	3.5	Local	154
GasCCS	80	20	10	45	33	46	9.5	Local	314
Nuclear	95	75	5	33	0	139	3.2	0.9	776
SMR	95	40	5	33	0	145	0	0.8	1548a
GasSC	30	20	100	28	650	16	9	Local	108
Biomass	90	20	5	39	0	154	7.7	2.8	550
Wind	N/A	N/A	N/C	N/A	0	48	0 0	0	212a
Solar	N/A	N/A	N/C	N/A	0	19	0 0	0	152a
Hydroelectric	N/A	N/A	N/C	N/A	0	55	5.8	0	Project-specific
PHS-new	N/A	N/A	N/C	80	0	9	0.9	N/A	201
PHS-retrofit	N/A	N/A	N/C	80	0	9	0.9	N/A	141
Lithium battery	N/A	N/A	N/C	85	0	0 34	0.9	N/A	216a

[a] Basic value and subject to change over time according to the technology evolution projections

[b] Coal with carbon capture and storage (CoalCCS).

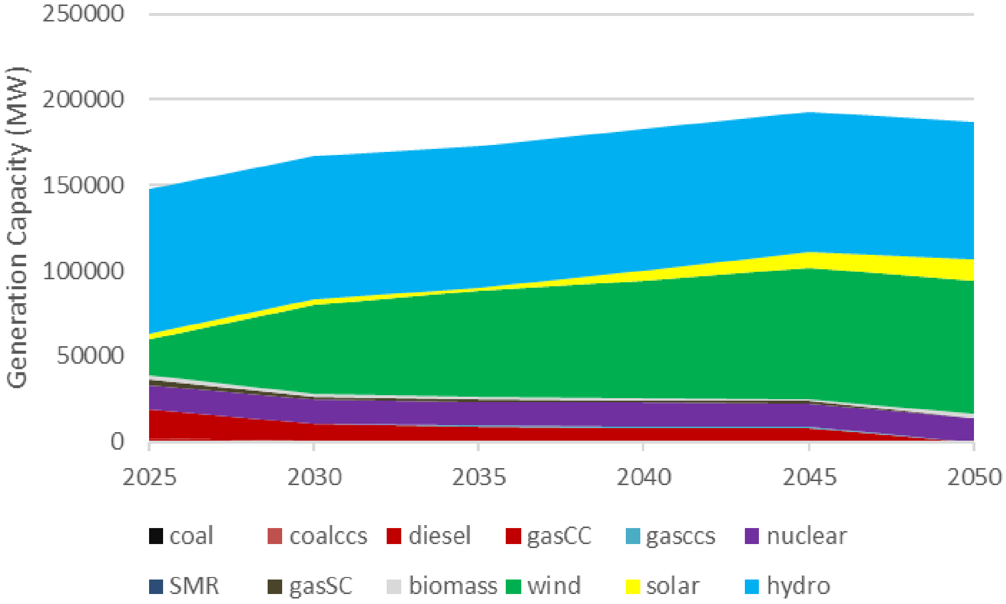

Figure 34: COPPER national results for net zero emission scenario from 2025 to 2050

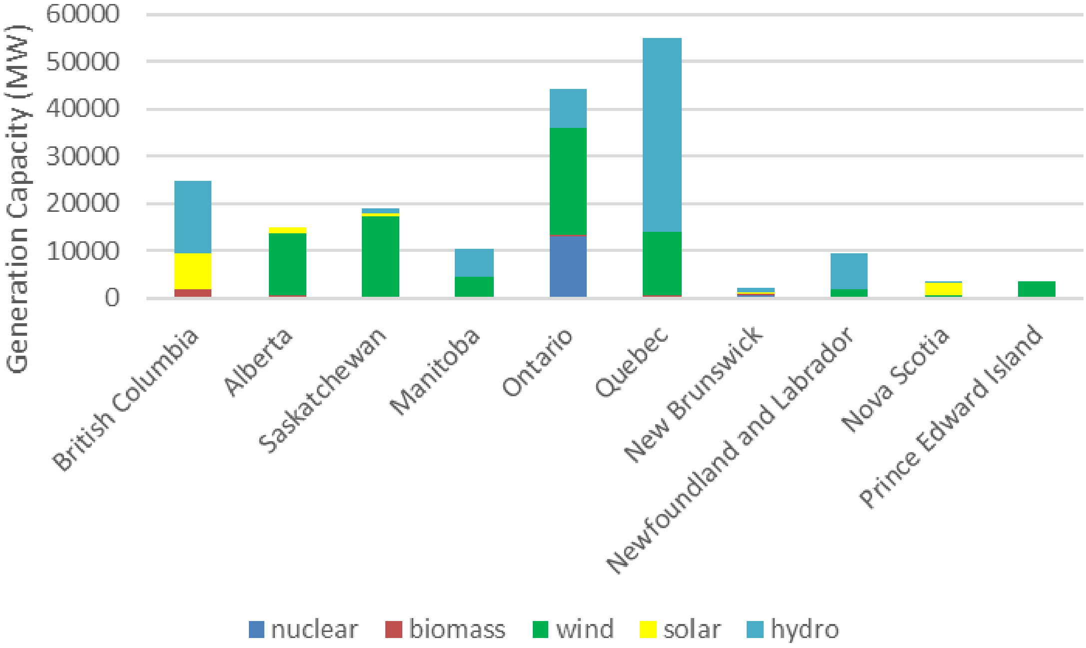

Figure 35: COPPER provincial results for 2050 net zero emission scenario

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