Impact of Cascaded Hydro Operational Constraints on Power System Flexibility Requirements for Variable Renewable Energy Integration

By

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Abstract

Variable renewable energy resources will play an increasingly prominent role in electricity systems as global economies pursue ambitious decarbonization and electrification targets. Power system flexibility will become a valued asset as more variable renewable energy resources are integrated into energy systems. The extent to which power systems can provide flexibility services to accommodate increased net load variability depends considerably upon the constraints of the existing energy resources in the generation mix. Jurisdictions whose electricity supply is predominantly hydroelectric operate within a unique set of operational, environmental, and regulatory constraints specific to large storage hydro systems. The constraints associated with large hydro systems may limit the extent to which hydro-dominant electricity systems can accommodate VRE resources. This thesis presents a model for cascaded hydro generation resources that is compatible with the SILVER production cost model and presents a case study of future VRE integration into the British Columbia electricity system. Modelling results indicate that a fully decarbonized BC electricity system is feasible assuming that hydro generation assets have a high degree of operational flexibility and adequate transmission capabilities.

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Contributors

The author acknowledges the main contributors to the research presented in this thesis. The primary contributor is Mohammadali Saffari, who was responsible for overseeing the cascaded hydro generator class implementation into the SILVER model, and for writing all code relevant to integrating the cascaded hydro generator class with the model framework. The author also acknowledges Dr. Jacob Monroe, Madeleine Seatle, and Tamara Knittel for their contributions to improving and ensuring the functionality of the cascaded hydro generator class. The SILVER production cost model used for this research was originally developed by Dr. Madeleine McPherson [1].

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List of Acronyms

AWY	Average Water Year
BAU	Business-as-usual
BCH	BC Hydro
CCGT	Combined cycle gas turbine
EPA	Electricity Purchase Agreement
EV	Electric Vehicle
GHG	Greenhouse Gas
GRETA	Global Renewable Energy Time series and Analysis
HWY	High Water Year
IPP	Independent Power Producer
IRP	Integrated Resource Plan
LWY	Low Water Year
MERRA	Modern-era Retrospective Analysis for Research and Applications
OCGT	Open Cycle gas turbine
OPF	Optimal Power Flow
PCM	Production cost model
RoR	Run of River
SILVER	Strategic Integration of Large-capacity Variable Energy Resources
UC	Unit Commitment
VRE	Variable renewable energy
WECC	Western Electricity Coordinating Council
WSCC	Western Systems Coordinating Council

List of Nomenclature

Symbol	**Description**	**Unit**
C	Operational cost of a generator	\$/MWh
P	Power output of a generator	MW
L	System load	MW
C_s	Shutdown cost of a generator	\$/MWcap
u	On/off status of a generator	{1, 0}
C_{GHG}	Cost of GHG emissions	\$/kgCO2e
Q_{spill}	Reservoir spill rate.	m^3
C_{Spill}	Spill cost	\$/MWh
ρ	Mass density of water	kg/m^3
g	Acceleration due to gravity	m/s^2
η	Hydroelectric turbine efficiency	
Q_{dam}	Dam discharge rate	m^3/h
h	Dam head	m
V	Reservoir storage volume	m^3
Q_{spill}	Dam spill rate	m^3/h
Q_{ex}	Exogenous natural reservoir inflow rate	m^3/h
E	Total annual energy generation	MWh
P_{av}	Average power generation	MW

Acknowledgements

I sincerely thank the Pacific Institute for Climate Solutions for funding my research. Thank you to my supervisors Dr. Peter Wild, Dr. Andrew Rowe, and Dr. Madeleine McPherson for their guidance and insight during the course of this research. Many thanks to the brilliant colleagues whose generous help and advice made this research possible, including Jacob Monroe, Mohammadali Saffari, Kevin Palmer-Wilson, Madeleine Seatle, Tamara Knittel, Victor Keller, Cameron Wade, Seán Collins, and Mackenzie Fowler.

Most of all, thank you to my family for their unwavering love, support, and humour. A special thank you to my dear friend Jocelyn Pettit whose “accountability chats” kept me on track and inspired!

Chapter 1 – Introduction

1.1 Motivation

The ongoing problem of climate change resulting from human activities has provided a strong incentive to transform energy systems and reduce greenhouse gas (GHG) emissions on a global scale. In response to increasing environmental and geopolitical instability, governments seek to accelerate development of lower-emission, renewable energy sources for their energy supply and independence. Many countries also aim to electrify fossil-fuel intensive services such as transportation and industrial processes. Global emissions reduction targets set by many of the world's largest economies at the most recent COP26 in Glasgow (2021) aim for net zero emissions by 2050, and that 100% of vehicles sold globally will be zero emission by 2040 [2]. In the private sector there is a strong movement towards all-electric, environmentally sustainable industrial operations to meet environmental, social and governance criteria [3]. As a result, industries such as mining and natural resource extraction are turning to clean electricity in place of diesel to fuel their operations. These trends emerging from both the public and private sectors result in a rapidly increasing demand for clean, reliable electricity on a global scale [4].

Electricity generation resources vary substantially across geographical regions, depending on the natural resources available and inter-regional transmission capabilities. Within Canada, electricity systems and generation resources differ considerably from one province to another. In the context of the global push towards electrification and adoption of renewable, low-emission electricity sources, some jurisdictions may be better positioned to facilitate a clean energy transition due to the suite of energy resources at their disposal. Hydroelectricity-rich provinces such as British Columbia have access to low-emission, renewable baseload electricity generation and the seasonal storage capabilities of large hydro dams. The abundance of storage hydro in BC allows the province to generate over 87% of its electricity from hydropower annually, as shown in Figure 1 [5]. As a result, the province does not rely on emissions-intensive thermal generators or nuclear power for baseload generation or grid balancing services.

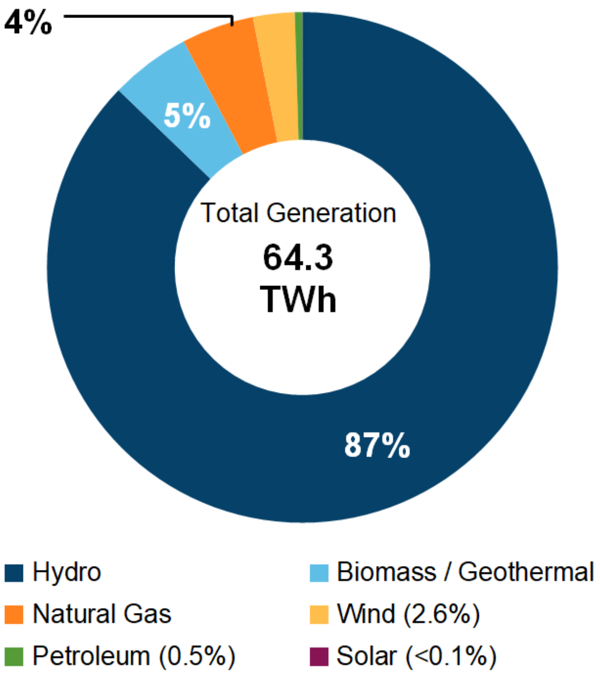

Figure 1: British Columbia electricity generation by source (2019) [5].

Despite its advantages, large hydro capacity has seen the slowest growth rate of any renewable energy source; development of additional facilities has plateaued in BC and most OECD countries [6]. Construction of large storage reservoirs has been shown in many instances to arouse significant public opposition due to the environmental impact of flooding surrounding areas and disruption to aquatic ecosystems [7], [8]. However, electricity demand is projected to increase both in BC and globally due to multiple factors, including widespread electrification, population growth, rising living standards, and increased cooling demand due to a rise in global average temperature [4]. Within BC electricity demand is projected to grow by approximately

25% over 2022 levels by 2041, as forecast by the BC Hydro 2021 Integrated Resource Plan (IRP). This exceeds the system's current generation capacity [9]. At the same time government policy, as outlined in the CleanBC 2030 Roadmap [10], is aligned with the global IEA target of achieving net zero emissions by 2050 [10]. In addition to meeting its own needs, BC's electricity resources will be in demand to support decarbonization in neighbouring jurisdictions such as Alberta and the United States via the Western Interconnection. With fewer large hydro projects under development other forms of renewable energy will likely be required to meet future demand in BC and adjacent jurisdictions.

Integration of variable renewable energy (VRE) resources such as wind and solar PV into electricity grids introduces variability into a system's net load, which is defined as the difference between total system demand and the available generation from VRE sources [11]. Significant variability in net load requires that the remaining generation sources provide both baseload generation and balancing services to maintain grid frequency. Power system flexibility can be achieved by installing sufficient dispatchable generator capacity, such as open cycle gas turbines (OCGT), combined cycle gas turbines (CCGT), or hydro generators. Other non-generator balancing strategies include expanding transmission capabilities, investing in storage technologies, or load shifting via demand-side management [1], [12].

VRE integration into existing power systems has been studied extensively in energy systems modelling literature, however the majority of studies focus on regions with thermal-based power systems [13 – 19]. The studies which focus on the Canadian and Western Canadian power system suggest that hydropower resources will play a key role in providing balancing services to support increased VRE penetration, especially in provinces with thermal-based power systems [20 – 22]. However, these studies typically employ a simplified representation of hydro generation facilities that does not incorporate many of the operational, environmental, and regulatory constraints related to the management and distribution of water in reservoirs. A full description of hydropower constraints is provided in Section 1.2.1, and techniques for modelling hydropower is discussed in Section 1.2.3.

When modelling hydro-dominant regions, a reduced approximation of hydropower generation facilities contributes uncertainty to modelling results and may lead to missed opportunities for understanding its role in supporting VRE deployment. Ibanez et al. demonstrated that using a detailed representation of the Columbia River hydropower facilities with the RiverWare model resulted in a decreased operational cost and reduction in variable generation curtailment in a dispatch modelling study of the United States Western Interconnection [23]. Farahmond et al. captured the impact of variable reservoir inflows in a model of Norway's hydropower resources and demonstrated that the Nordic hydro system can provide significant flexibility to European power grids under high VRE penetration scenarios, assuming expanded transmission capacity [24]. Saffari and McPherson demonstrated, using the same cascaded hydro model presented in this work, that operational and regulatory constraints in the SILVER production cost model of the Canadian electricity system improved system operation by 4% on average in scenarios of increased VRE penetration with fixed curtailment rates [25]. These studies suggest that models employing a more detailed representation of hydropower generators, specifically those that capture reservoir inflow variability and cascaded hydro (where applicable) in their generator representation, allow for a more complete understanding of the extent to which hydro resources can support VRE integration in an electricity system. Moreover, it appears that electricity system models which include a cascaded hydro generator representation find that these resources may have a greater capability to provide balancing services, reduce VRE curtailment, and decrease operational costs than studies which omit the cascaded feature from their hydropower generator model. The results of [23], [24], and [25] motivate the use of a cascaded hydro generator model that captures reservoir inflow variability when modelling the BC electricity system, where over 80% of power is generated from cascaded hydro resources [26]. In particular, [25] suggests that the SILVER cascaded hydro model used in this study can help to identify the full potential of cascaded hydro resources in facilitating VRE integration.

1.2 Background

1.2.1 Hydropower in the British Columbia Context

The majority of hydro facilities in BC exist within natural watersheds and must operate in a way that meets the demands of the power system while maintaining the hydro-climatic ecosystem in which they are situated; often while complying with additional regulations related to Indigenous water rights, and agricultural and recreational water use [27]. This is a complex, dynamic task for hydro utility operators who must plan for seasonal and annual fluctuations in reservoir inflows and changes in electricity system demand, while optimizing storage to ensure sufficient operational reserves. As an additional complication, it is common in hydro-rich geographical regions to have multiple storage hydro facilities operating on the same river system or on a series of interconnected lakes, known as cascaded hydro. In cascaded hydro systems, facility operators must also account for inflows from upstream reservoirs and the impact of discharging water into downstream reservoirs when planning storage and generation schedules. In the context of studying VRE integration into hydro-dominant regions, using a simplified approximation of hydropower operational constraints may incorrectly estimate the amount of water available for dispatchable generation, and, therefore, the extent to which hydro can provide grid balancing services [28]. The purpose of this work is to assess the impact of increased VRE installed capacity in the BC electricity system using a production cost model that includes a comprehensive representation of cascaded hydro generator constraints and reservoir inflows based on historical utility data. The model aims to assess the extent to which hydropower can provide grid balancing services to facilitate VRE integration in an operational dispatch study of the BC electricity system.

Hydropower harnesses the potential energy of water associated with elevation changes along the course of a river to generate electricity. It remains one of the most economical, low-carbon energy sources despite rapid development in other renewable energy technologies. Hydropower regimes fall into three categories: storage hydro, run-of-river, and pumped storage. Storage hydro facilities consist of a water reservoir held behind a dam, which releases water through a system of one or more turbines to generate electricity. Typically a generating station will be proximally located to a reservoir-dam system. Storage hydro is the most flexible of hydropower generation types due to its ability to store water during high-inflow periods that can be made available during high demand and low-inflow periods. Depending on physical constraints of the reservoir some facilities may be able to store several years’ worth of inflow, providing significant flexibility to the power system being served.

Run-of-River (RoR) hydropower, equivalently known as non-storage hydro, is generated from water flowing through an elevation change in a river. Running water is diverted down a channel or penstock to be passed through turbines which drive an electricity generator. As the name implies, RoR facilities have limited storage capabilities (pondage) but this is typically limited to use within the same day. This type of generation clearly has limited flexibility in comparison to storage hydropower, however they are generally considered to have a smaller environmental impact as they do not disrupt river flows to the extent of large storage hydropower [29].

There is just over 2GW of non-storage hydro capacity in the BC Hydro System. These facilities are independent power producers (IPPs) that are contracted by BC Hydro by way of Electricity Purchase Agreements (EPAs) to provide power to the utility over the course of several years. BC Hydro currently has EPAs with 70 independent non-storage hydro facilities, and 125 in total with other generator types including biomass, solar, wind and thermal generators [30]. Due to their limited flexibility and contractual standing, energy generated by RoR hydro IPPs constitutes ‘must-take’ energy within the BC Hydro system, meaning that it is energy that cannot be stored at the facility for later use. These resources contribute to non-flexible minimum generation levels and can challenge the hydro system’s storage capacity during seasons when precipitation and surface runoff are particularly high. This occurs consistently during the freshet, which is defined as the period from May to July when the winter snowpack melts and provincial demand is low relative to the winter months [31]. Figure 3 shows the forecast balance between provincial electricity demand and system inflows for average hydrological conditions, indicating a significant energy surplus during the spring and early summer months. During this period, substantial surface runoff from snow and glacier melt increases must-take energy from RoR IPPs while reservoirs simultaneously approach the upper limits of their storage capacity; this can lead to spill events from storage hydro facilities that are prevented from discharging sufficient water

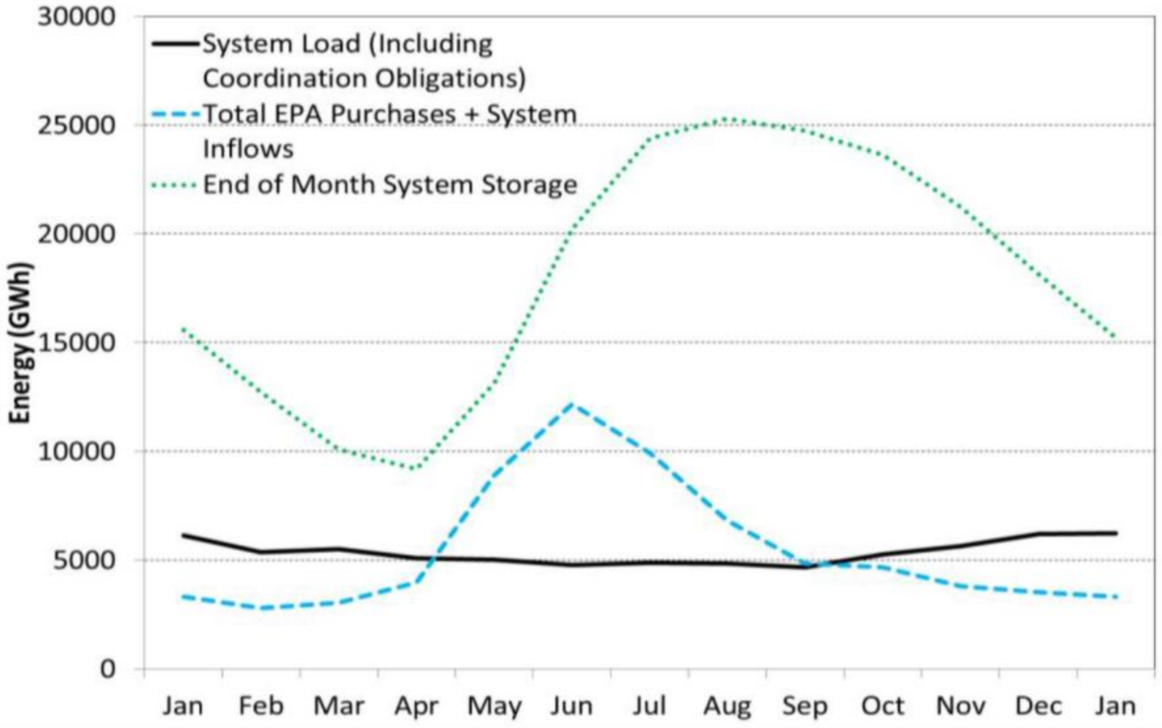

Figure 2: Forecast 2018 monthly provincial electricity load in comparison to system inflows, including system inflows into storage reservoirs and non-storage hydro EPA purchases [31].

to generate electricity. This seasonal supply-demand imbalance is an annual feature of BC Hydro's system operations and may pose challenges and opportunities for future VRE integration in BC and neighbouring jurisdictions.

BC Hydro forecasts a growth in capacity requirements of approximately 3500MW over 2022 levels over the next two decades to meet anticipated provincial demand, as shown in Figure 3 [9]. Since there are currently no plans to construct additional large storage hydro facilities during this period, this demand increase would be met by EPAs with a combination of renewable energy sources including non-storage hydro, wind, solar, and biofuels. It is reasonable to assume that fossil fuel-based thermal generation would not be prioritized in the capacity supply mix during this time-frame due to the province's 2050 net-zero target; however, it is likely that thermal power generation will continue to play a role in BC within the next two decades due to the province's substantial natural gas reserves [32].

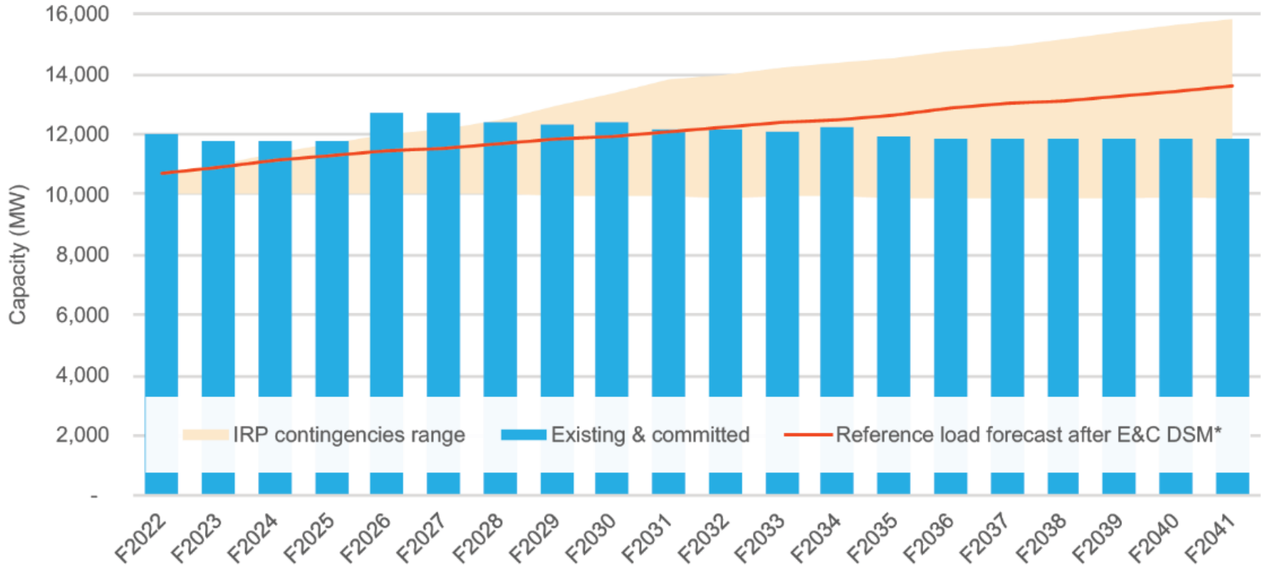

Figure 3: BC Hydro Load Resource Balance for the load forecast projected in the 2021 Integrated Resource Plan (IRP) [9].

1.2.2 Production Cost Models for Studying VRE Integration

The global energy transition has necessitated the development of a wide range of modelling platforms for simulating the operation and integration of various energy sources in power grids. Computational models are invaluable tools for policy makers, utilities, and energy system planners to expand and operate energy resources in a way that meets policy objectives such as emissions targets or sustainable growth goals. Models also help to identify unintended consequences of potential policy decisions, such as carbon taxes or renewable energy expansion projects.

Due to the highly interdisciplinary nature of the field, energy system models vary widely on the scope and breadth of modelling capabilities. Modelling tools differ by their mathematical structure, geographical and sectoral coverage, as well as their time horizon and temporal resolution [33]. Production cost models (PCM) simulate electricity system operations by minimizing the cost of unit commitment and dispatch of a fleet of generators subject to a given electricity system demand. This approach is optimal for studying electricity system grid dynamics over a short time period with a high level of detail in the representation of generation and transmission technologies. PCMs generally simulate over a time horizon of one week to one year with an hourly or sub-hourly time step [34]; they are useful for identifying time-sensitive inefficiencies or opportunities in power system operations, such as excess curtailment or load balancing strategies. This class of models answers the question: what is the least cost dispatch of a set of generation resources to reliably meet electricity system load across a defined network of demand centres? Model outputs typically include unit generation, power flow, CO_2 emissions and curtailment in intervals of the given time step.

1.2.3 Methods for Modelling Cascaded Hydro in PCMs

The SILVER (Strategic Integration of Large-capacity Variable Energy Resources) production cost model is an open-source software tool based in the Python programming language. It seeks to address several limitations of previously developed PCMs, particularly with respect to modelling scenarios with high penetrations of variable renewable energy (VRE) resources. In contrast with many commercial PCM platforms, the open-source nature of SILVER provides transparency to the user with respect to model operations and mathematical structure. This allows for greater autonomy and flexibility to adjust the technology and market assumptions of the model to suit the study purpose.

The SILVER model seeks to incorporate all key elements necessary for comprehensive operational dispatch studies involving increased VRE integration. These include linkage to a global renewable energy resource database, representation of all power system flexibility and balancing strategies, and a mixed-integer formulation to fully represent generator constraints. Variable energy resource availability is obtained in SILVER by dynamically linking with multiple meteorological databases to obtain location-specific historical wind and solar time series data. This feature allows the SILVER model to access VRE generation data for any given location at a high spatial and temporal resolution suitable to the precision required of production cost dispatch modelling studies. In addition, SILVER aims to represent all known balancing options that have been proposed to facilitate VRE integration. These include transmission expansion, electricity storage (battery, pumped hydro, and hydrogen storage), demand response, electric vehicles (EV). The flexible mixed-integer formulation of the model allows the user to fully define constraints for generators of any type, both VRE and non-VRE, such as startup/shut-down costs, minimum up/down times, ramping limitations, and minimum generation.

This thesis documents the integration of a cascaded hydro model into the SILVER framework. The SILVER cascaded hydro representation includes a set of operational and regulatory constraints of storage hydro facilities based on a review of the modelling literature described in Section 1.2.3, as well as the ability to model reservoir inflows at a high temporal resolution. A full description of the SILVER cascaded hydro framework is presented in Chapter 2. In addition to model validation, the SILVER cascaded hydro model will be employed in an operational dispatch study of BC involving expanded VRE and RoR hydro capacity to supply future energy and capacity demands.

1.3 Scope of Research

The aim of this work is to investigate the implications of increased VRE installed capacity in the BC power system using the SILVER cascaded hydro model to represent the province's cascaded storage hydro facilities. This study addresses the future energy and capacity supply gap in the year 2041, as outlined in the BC Hydro 2021 IRP, and will consider the following scenarios where demand is met by:

1. Business-As-Usual (BAU) IPP supply mix: Increased capacity and energy demand is met by an IPP supply mix, such that the ratio of generation resource types is consistent with the current (2022) IPP supply mix, as shown in Figure 4 [30].

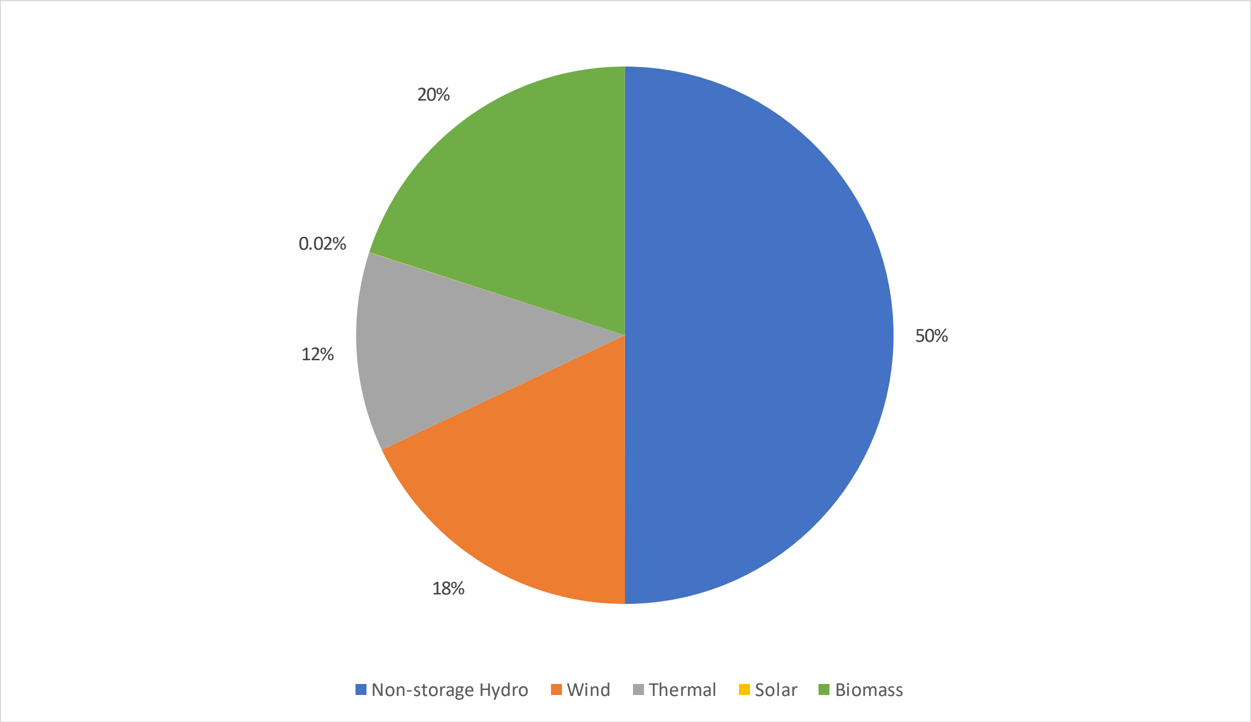

Figure 4: BC Hydro 2022 IPP capacity mix showing percent of capacity by resource type [30].

2. Fully decarbonized IPP supply mix: Increased capacity and energy demand is met by an IPP supply mix consisting only of non-storage hydro, wind and solar generators. This scenario will explore the case of an IPP supply mix consisting of 60% RoR, 30% wind, and 10% solar.

The main contributions of this thesis are:

1. Development and validation of a cascaded hydro model integrated into the SILVER production cost model framework. Validation of the model will be performed against a 2021 BC power system reference scenario.
2. A case study of the cascaded hydro-dominant BC electricity system under future load growth conditions. Scenarios will explore the benefits and tradeoffs of meeting future demand with moderate and high penetrations of VRE generation resources.

Chapter 2 – Methods

2.1 Introduction

This section describes the model architecture of the SILVER production cost model, the implementation of a cascading hydro generator model in the SILVER framework, and the methodology used to create a model of the BC electricity system. Section 2.2 details the SILVER optimization framework, representation of generation and transmission technologies, and strategies for modelling VRE resources and balancing strategies. Section 2.3 describes the formulation of the cascading hydro generator class. Section 2.4 describes the data inputs and structure for representing the BC electricity system in SILVER, including all of the province's cascaded hydro facilities. Section 2.5 describes the implementation of a spill cost. Section 2.6 concludes with a description of the scenarios performed for this study and Section 2.7 details the limitations of the model.

2.2 The SILVER Model

The SILVER production cost model is an optimization platform which minimizes the cost of unit commitment and dispatch of a fleet of generators. SILVER is a mixed-integer linear program that simulates hourly power system operation for time periods of up to one year. This framework was designed to assess of the impact of high penetrations of renewables into a power system, with an emphasis on identifying key balancing strategies to facilitate renewables integration.

SILVER seeks to address limitations of previously developed production cost models with respect to VRE and hydro generator representation [1]. Rather than limiting VRE analysis to a specific geographic area, SILVER dynamically links to a global renewable resource database, allowing it to access hourly wind and solar generation for any given location. To provide a complete assessment of VRE integration strategies, SILVER incorporates all known grid balancing options, including transmission expansion, electricity storage, demand response, and electric vehicles. VRE forecasting error is modelled explicitly using probability distribution functions specifically formulated for wind and solar PV facilities [65] [66]. Finally, the mixed-integer formulation allows for flexible definition of generator constraints, such as ramping limitations, minimum up/down times, startup and shut-down costs, efficiencies, and other resource-specific constraints [1].

2.2.1 Model Framework

SILVER consists of four sequential modules: (i) the long-term scenario planning framework, (ii) the day-ahead network-constrained price-setting dispatch, (iii) day-ahead unit commitment, and real-time optimal power flow (OPF) dispatch. The fourth OPF stage is not included in this study and therefore is not described below. Figure 5 depicts the overall flow of operations within the model.

(i) Long-term scenario planning module

In the long-term scenario planning module the user inputs are defined and a scenario feasibility assessment is performed to ensure that certain minimum operational constraints are met. The model inputs include generation assets (distinguished as VRE or non-VRE generators), storage assets, electric vehicle fleet characteristics, demand response availability, demand centre nodes, and transmission infrastructure. The complete set of model inputs is detailed in Table 1. The objective of this module is to ensure that the user inputs constitute a feasible electricity system scenario by checking that the following constraints have been met:

1. There is sufficient dependable capacity to meet peak demand plus a reserve margin. Generation types that are considered to provide 100% firm capacity include all thermal generators, nuclear, and hydro.
2. There is sufficient flexible generation to meet the minimum operating reserve constraint. Each generator type is assigned an operating reserve coefficient, which allocates a certain percentage of its electricity generation to spinning reserves.
3. There is sufficient installed and transmission capacity to meet demand at each node.
4. The VRE installed capacity does not exceed the total land area in each grid cell. Each VRE technology type is assigned a maximum power density, which is 65 DC MW/km^2 for solar PV [67] and 5 MW/km^2 for wind [68].

Table 1: SILVER Model Inputs.

SILVER Model Inputs	**Description**
Generator Costs	- Fixed and variable O&M cost - Transmission investment - Startup/shutdown cost - GHG emissions cost
Generator technology characteristics	- Efficiency - GHG emissions intensity - Min/max ramp rate - Min up/down time - Capacity - Transmission bus - Storage capacity (if applicable) - VRE lat/long coordinates
Transmission system	System of demand centres/transmission buses and lines for distributing electricity.

System load	Total hourly system load is allocated to each demand centre according to the population fraction at the node.
Electricity imports and exports	Hourly imports and exports are assigned to a single transmission node. Imports are treated as positive generation at the node whereas exports are treated as a negative demand on the node.
Hydro inflow conditions	Hourly volumetric water inflows into storage hydro reservoirs from exogenous sources (rivers, surface runoff, precipitation).

(ii) Network-constrained price-setting economic dispatch

The model inputs defined in the long-term scenario planning module are subsequently passed into the first optimization stage, the network constrained price-setting economic dispatch. This stage of the algorithm solves for the 24-hour day-ahead system marginal price based on the forecasted load schedule and generation profiles of each VRE asset. The model objective is to minimize the total cost of generation for a fleet of N generators:

$$min \sum_{i=1}^{N} C_i(P_i)$$

Equation 1: Network-constrained price setting economic dispatch objective function.

Where C_i is the cost of generator i, a function of its power output P_i. The objective function is subject to the constraint that the power balance at each node is satisfied, namely

$$L_n(t) + P_n(t) = 0, \qquad 1 \leq t \leq 24\ hours$$

Equation 2: Network-constrained price-setting economic dispatch power balance constraint.

Where $L_n(t)$ is the load in hour t at demand centre n, and $P_n(t)$ is the power supplied to the demand centre, either by generation directly at the node or via transmission by connected nodes.

As discussed in the introduction, SILVER accesses VRE generation profiles by linkage to a global renewable resource database. Hourly wind and solar generation data are obtained from the Global Renewable Energy Time series and Analysis (GRETA) [69]. GRETA applies various mathematical modelling approaches to derive hourly wind and solar energy generation potentials from a dataset of global historical wind and solar weather observations. GRETA accesses the NASA-developed Modern-era Retrospective Analysis for Research and Applications (MERRA) dataset, which provides the necessary weather observations to compute hourly wind and solar generation on a global 0.5º by 0.7º latitude-longitude grid, from the year 1979 to within two months of the present [69]. GRETA calculates solar generation potentials assuming a PV power curve equal the average of First Solar FS 395, Canadian Solar CS6X-P, and the Astroenergy CHSM6610P [1]. Similarly, wind generation profiles are calculated from historical wind speeds interacting with a turbine at a height of 100m, and with a technology power curve equal to that of the Vestas-112-3.0 [1].

(iii) Day-ahead unit commitment (UC)

The day-head UC builds upon the network-constrained price-setting economic dispatch by minimizing the objective function with the addition of several costs associated with specific technology parameters. The additional costs include startup and shutdown of generators within the 24-hour optimization cycle, the consumption of power by storage assets and electric vehicle fleets at the system marginal price (set by the highest-cost generator dispatched in the 24-hour period), the GHG emissions costs, and the cost of spillage from cascaded hydro reservoirs. The objective function in this module is expanded as shown in Equation 3, for a fleet of N generators,

$$min\sum_{t=1}^{24}\left(\sum_{i=1}^{N} C_i(P_i(t)) + C_{s,i}\cdot|u_i(t)-u_i(t-1)| + \sum_{i=1}^{N} C_{GHG}((P_i(t)) + \sum_{i=1}^{H} Q_{spill,i}(t)\cdot C_{Spill}\right)$$

Equation 3: Day-ahead UC objective function.

where,

C_i - Operational cost of generator *i*

$P_i(t)$ - Power generated by generator *i* at time *t*

$C_{s,i}$ - Shutdown cost of generator *i*

$u_i(t) = \{0, 1\}$ - On/off status of generator *i* during time step *t*

C_{GHG} - Cost of GHG emissions (\$/kg CO_2e) as a function of power produced by generator *i*.

$Q_{spill,i}(t)$ - Spill volume (m^3) of cascaded hydro reservoir/generator *i* during time step *t*

C_{Spill} - Spill cost (\$/m^3 dam spill)

H - Total number of cascaded hydro generators

The scenarios implemented for this study do not include storage assets or EV fleets, therefore the costs associated with these technologies are not included in the objective function for the day-ahead UC stage.

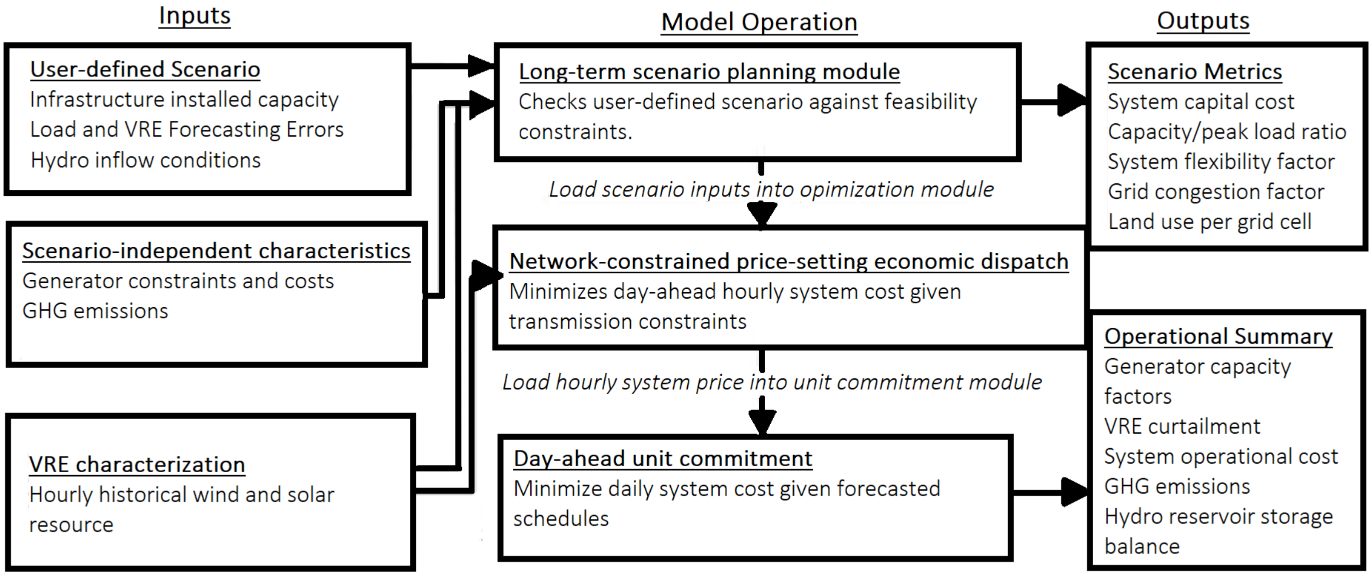

Figure 5: Flow diagram of SILVER model operations [1].

2.3 The SILVER Cascading Hydro Model

This section describes the cascading hydro generator class in the SILVER framework, which was developed to improve the representation of large cascaded hydro systems in the model. Cascaded hydro facilities consist of storage reservoirs connected in series, such that water discharged for electricity generation and spilled from an upstream dam flows into a downstream reservoir. In addition to upstream dam inflows, cascaded hydro reservoirs receive natural water inflows from rivers, precipitation, and surface runoff. In order to accurately represent storage hydro dynamics, the model tracks hourly reservoir inflows and storage while optimizing for dam discharge and spill during the day-ahead UC stage. This approach aims to bridge the gap between the detailed representations of water systems found in watershed models, and the power system optimization capabilities of PCMs, as described in Section 1.2.3.

Storage hydro facilities (including cascaded hydro) are subject to numerous constraints related to water distribution for the purpose of facility maintenance and ecosystem management. Each reservoir's storage volume is constrained within minimum and maximum bounds to maintain adequate storage levels and prevent dam overflow. Water discharged for electricity is limited to the maximum discharge capacity of the dam turbines and is often required to be maintained at a minimum threshold to support ecosystem activities such as fish spawning [70]. When reservoirs risk of exceeding their maximum storage levels due to excessive inflows and insufficient dam discharge, they may release water via spill. Spill is constrained to a maximum flow rate determined by the size of the spillway and to minimize damage to the surrounding facilities [71, 72]. In BC Hydro system operations spill is avoided unless it is necessary for maintaining reservoir water levels, therefore in the SILVER model a spill cost is added to the objective function to minimize spill events. The addition of the spill cost will be discussed further in Section 2.5.

Hourly inflows to hydro reservoirs from rivers, precipitation and surface runoff are added in the long-term scenario planning module as part of the model's data inputs. For this study of the BC Hydro system, historical monthly average inflow rates for each cascaded hydro reservoir were obtained from BC Hydro Water Use Plans [71]. These data are provided for low, average, and high-water years which refer to the annual inflow volumes historically observed at BC Hydro facilities. A sensitivity analysis is performed by running scenarios with minimum, mean, and maximum inflow conditions to capture the range of typical hydrological years.

2.3.1 Mathematical Formulation of the Cascaded Hydro Generator Class

Electric power generated by a dam is given by the rate of change of potential energy of water falling from a height h multiplied the efficiency of the turbine system:

$$P = \rho g h \eta Q_{dam}$$

Equation 4: Electrical power generated by a hydroelectric facility.

where ρ = 997 kg/m^3 is the mass density of water, g = 9.81 m/s^2 is the acceleration due to gravity. The turbine efficiency η is assumed to by 90% for all generators in this study according to the peak efficiency curve of Francis turbines, which are the most commonly used technology at BC Hydro facilities [27]. Q_{dam} is the rate at which water is discharged from the dam in m^3/s.

The power generation of a hydroelectric facility is a nonlinear relationship with the dam discharge rate, since the dam head is proportional to the volume of water stored in the reservoir. To maintain linearity in the SILVER model, the water release height h is assumed to the mean reservoir water level according to the BC Hydro WUP reservoir stage-storage curves [71]. As discussed in Section 1.2.3, the linear approximation of head-dependent generation efficiency reduces model accuracy, however it is necessary for compatibility with the overall SILVER model framework. This distinguishes the SILVER cascading hydro class from more detailed, non-linear cascaded hydro models which are applied to STHUC problems.

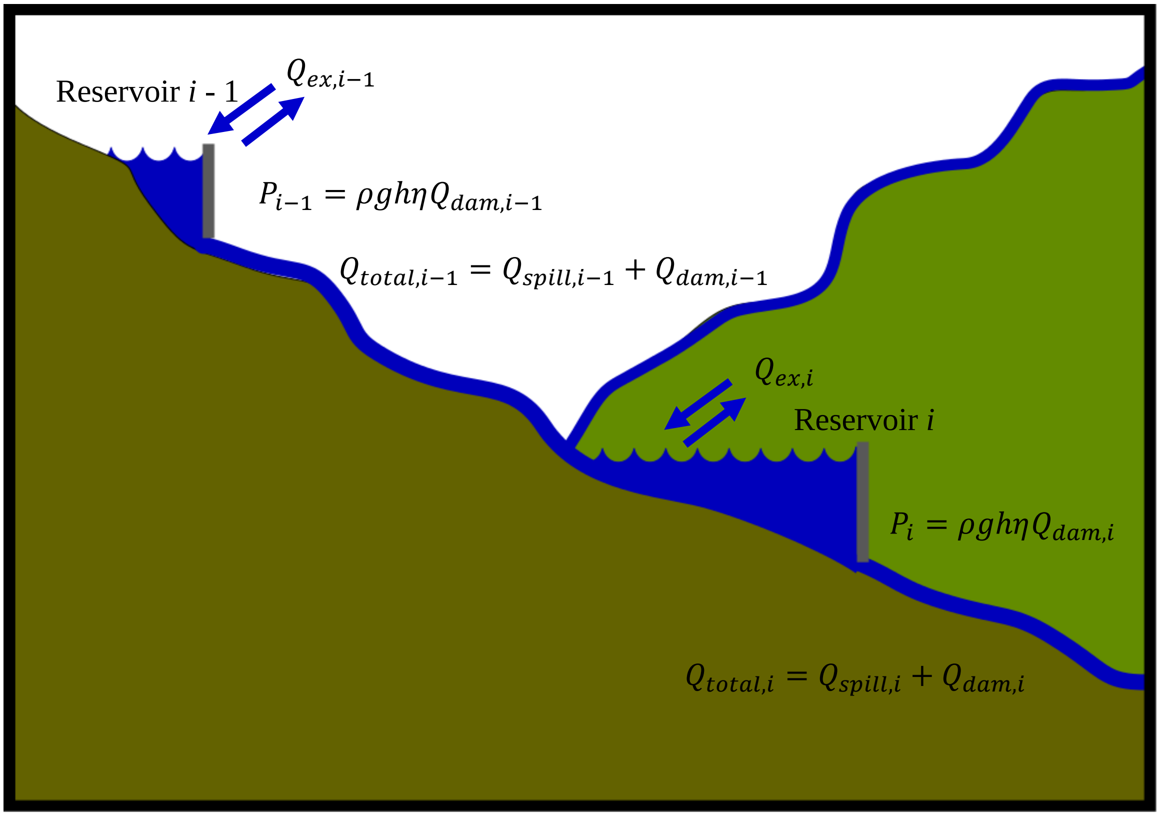

Figure 6: Demonstration of water mass balance between two cascaded hydro facilities.

Given a set of *N* cascaded reservoirs, the change in storage volume V_i of water stored in the i-th reservoir, $1 < i <$ N, during time step *t* is the difference of its inputs and outputs, as depicted in Figure 6. The storage balance equation (for the i-th reservoir in Figure 6) is given by

$$V_i(t) = V_i(t-1) + \Delta$$

where,

$$\Delta = Q_{dam,i-1}(t) + Q_{spill,i-1}(t) + Q_{ex,i}(t) - Q_{spill,i}(t) - Q_{dam,i}(t), \qquad 1 < i < N$$

Equation 5: Storage balance equation for a cascaded hydro reservoir.

Q_{ex} represents the net inflows due to surface runoff, precipitation, and river flowing into the reservoir, as well as evaporation from the reservoir. Q_{dam} is dam discharge through turbines for power generation, and Q_{spill} is water released as spill (and does not contribute to power generation). The uppermost reservoir in a cascade receives no upstream dam input, therefore the storage balance is formulated as in Equation 6, which is equivalent to Equation 5 for i = 1. The formulations Equation 5 and Equation 6 assume that water released from an upper reservoir takes less than one hour to enter a downstream reservoir, in contrast to the detailed methodologies for water delay times described in Section 1.2.3. Delay times are not included in this model formulation due to a lack of data on delay times greater than one hour documented for BC Hydro's cascaded facilities [71], [64]. It may be the case that cascaded reservoirs in the province are sufficiently close together that the transit time for water travelling between reservoirs can be considered negligible, however more data is necessary to confirm this.

$$\Delta = Q_{ex,i}(t) - Q_{spill,i}(t) - Q_{dam,i}(t), \qquad i = 1$$

Equation 6: Storage balance equation for the top reservoir in a cascade.

In the cascading hydro generator class, each facility is assigned a "cascade group name" and "number", indicating the river system it belongs to and its position in the cascade sequence. For example, if a reservoir is the furthest upstream facility in a cascaded system, it is assigned the number one ("Reservoir 1"). The downstream reservoir that receives the discharge and spill of Reservoir 1 is assigned the number two, and so on. In this example both reservoirs would be assigned the same "cascade group name", indicating that they are part of the same cascaded system. Figure 7 depicts the example of a three-reservoir cascade system.

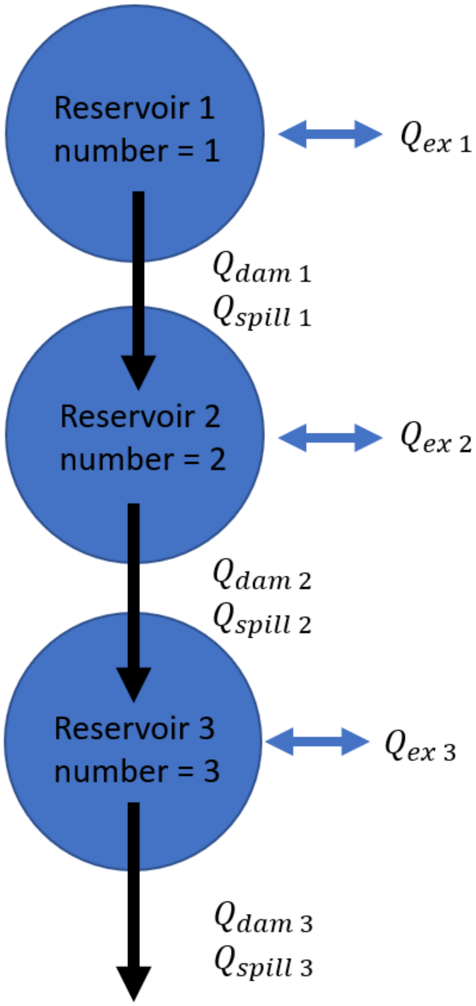

Figure 7: Three-reservoir cascade group indicating order and water flow.

In some instances, reservoirs may have more than one upstream dam discharging water into its storage volume, as depicted in Figure 8. This is the case of the Arrow Lakes reservoir in the Columbia River System in southeastern BC, depicted in Figure 9. Arrow Lakes is preceded by three upper dams, Revelstoke, Walter Hardman, and Whatshan, all of which discharge into the Arrow Lakes reservoir. Of the three dams upstream of Arrow Lakes, only Revelstoke receives the discharge and spill of a further upstream dam (Mica). Whatshan Lake Reservoir and

Walter Hardman, on the other hand, have no upstream dams (Coursier Lake is a storage reservoir whose dam was decommissioned in 2003) [73]. To address this type of situation, each cascade generator is assigned a “code” as follows, for reservoir number i in the cascade:

$$\text{code} = \begin{cases} 1, & \text{if } i > 1, \text{but does not receive inputs from reservoirs numbered } i-1 \\ 0 & \text{otherwise} \end{cases}$$

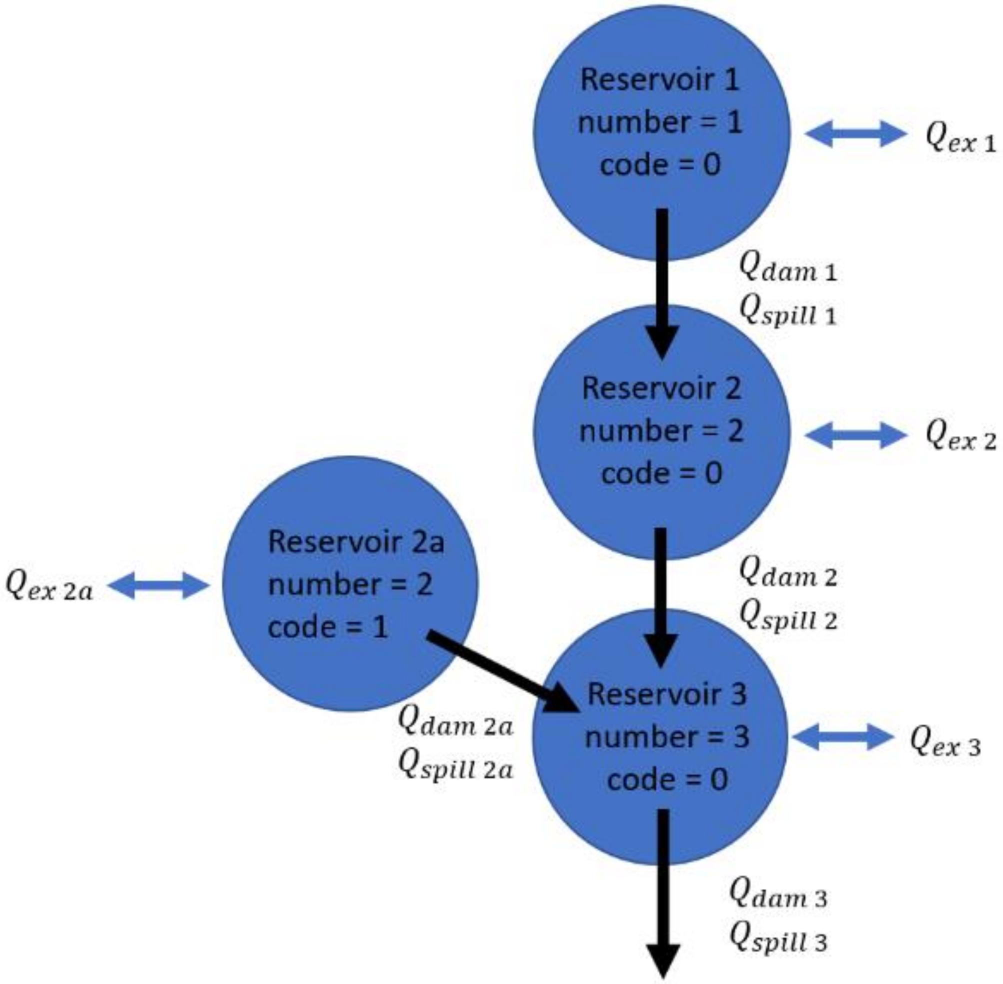

Figure 8: Four-reservoir cascade group with multiple upstream dams.

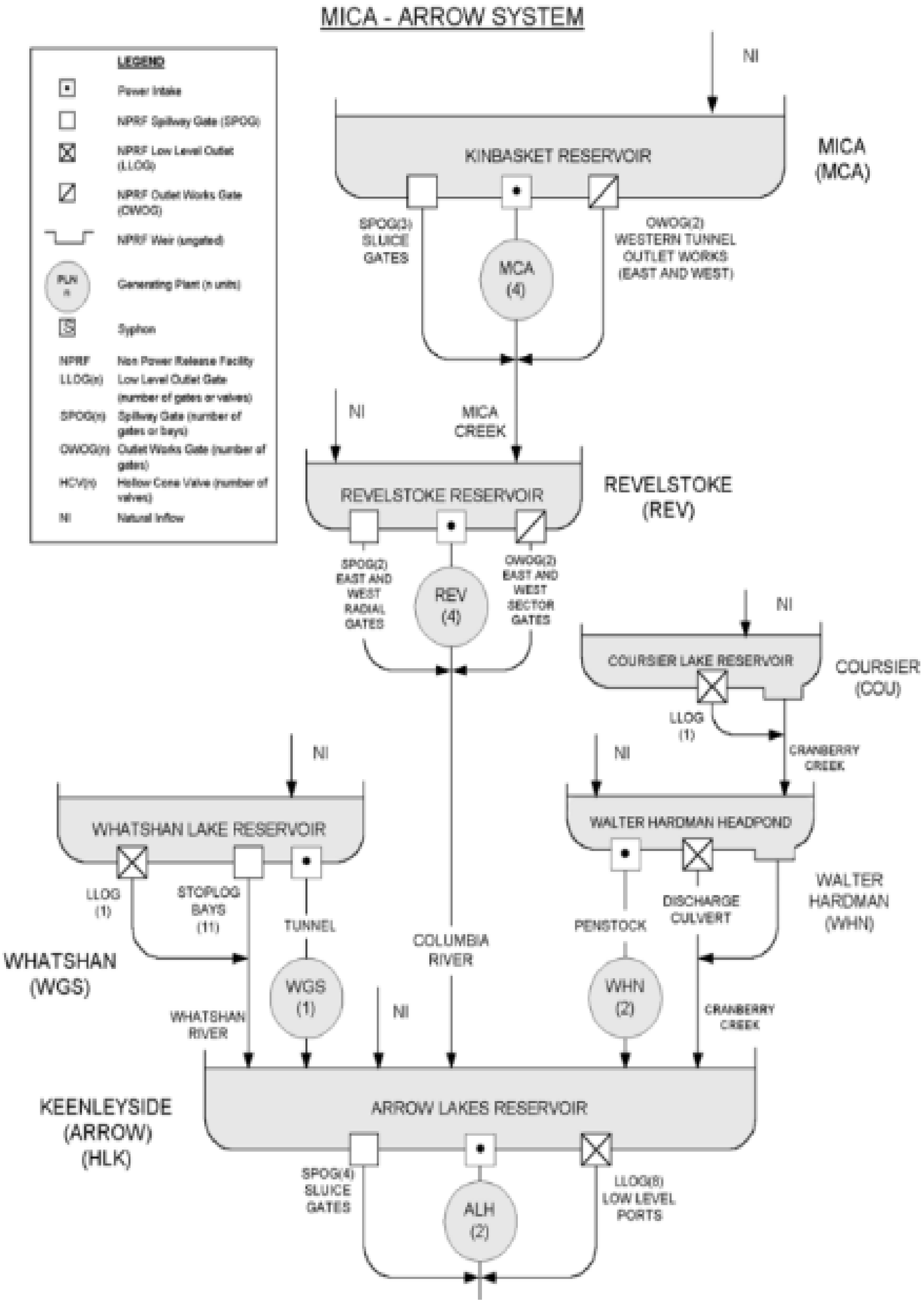

Figure 9: Flow diagram of the Columbia River System [17].

Table 2: List of Columbia River cascade generators with corresponding group, number, and code.

Cascaded Hydro Generator Name	**Cascade Group Name**	**Number**	**Code**
Arrow	Mica/Columbia	2	0
Mica	Mica/Columbia	1	0
Revelstoke	Mica/Columbia	3	0
Walter Hardman	Mica/Columbia	2	1
Whatshan	Mica/Columbia	2	1

Table 2 lists the group name, number, and code values for the Columbia River system hydro facilities, depicted in Figure 9, to illustrate how the classification scheme is integrated into the SILVER model inputs.

As discussed in Section 2.3, each cascade generator is subject to the following constraints:

1. *Storage volume constraint*

$$V_{min} \leq V(t) \leq V_{max}$$

where V_{min}, V_{max} are the minimum and maximum storage volume (m^3) of the reservoir and $V(t)$ is the storage volume during time step *t.*

2. *Discharge constraint*

$$Q_{min} \leq Q(t) \leq Q_{max}$$

where Q_{min}, Q_{max} are the minimum and maximum hourly discharge volume (m^3) of the dam and $Q(t)$ is the hourly discharge volume during time step *t.*

3. *Spill constraint*

$$0 \le Q_{spill}(t) \le Q_{spill,max}$$

Where $Q_{spill,max}$ is the maximum hourly spill volume (m^3) and $Q_{spill}(t)$ is the spill volume during hour *t*.

4. *Storage volume boundary condition*

$$(1-\alpha)\cdot V(t_0) \le V(t_{final}) \le (1+\alpha)\cdot V(t_0)$$

Where t_0, t_{final} are the initial and final time step of the simulation and α is a constant that enforces the final storage volume of the reservoir to fall within a certain percentage of its initial storage content. In this study $\alpha = 0.05$.

2.4 BC Electricity System Model

A model of BC's electricity generation assets, transmission and demand centres was developed for the SILVER model which characterizes all BC heritage hydro facilities using the cascaded hydro generator model described in Section 2.3. As depicted in Figure 10, the BC electricity system is modelled as 11 aggregated nodes representing generation and demand centres. This model is derived from the bulk provincial transmission system [74] by aggregating clusters of substations and transmission lines to reduce computation time and complexity. The interconnection between BC and Alberta is modelled as a single node (AB) with imports and exports defined exogenously during the long-term scenario planning stage. Each generator in the model is assigned a node to which it provides electricity, which can also be transmitted to other nodes within the constraints of the transmission lines. Each node is assigned a share of the total system demand according to its population fraction listed in Table 3, with the exception of the BC-AB interconnection which is assigned a demand share of one [75].

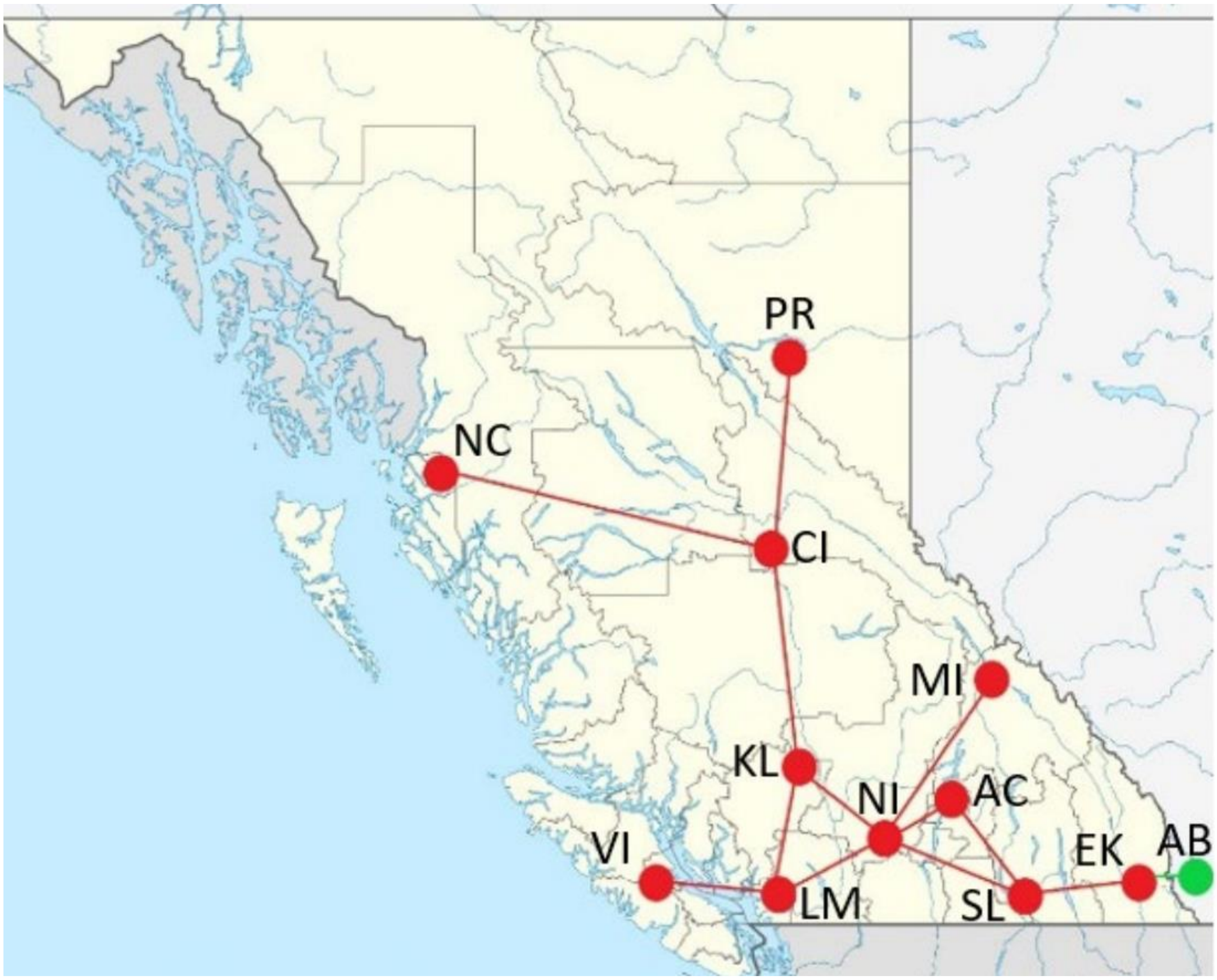

Figure 10: Nodal depiction of BC generation and demand centres [76].

Table 3: List of transmission nodes/demand centres by geographical region and their corresponding share of total system electricity demand [75].

Node	**Region**	**Share of Total System Demand/Provincial Population**
NC	North Coast	0.08

VI	Vancouver Island	0.1
LM	Lower Mainland	0.42
KL	Kelly Lake	0.06
CI	Central Interior	0.06
PR	Peace River	0.02
NI	Nicola	0.11
AC	Ashton Creek	0.03
MI	Mica	0.02
SL	Selkirk	0.05
EK	East Kootenay	0.05
AB	Alberta	1

System load is obtained from historical Balancing Authority Load Data for the year 2021, which is used in the baseline scenario [77]. To model load growth in 2041, an additional 10.76TWh of energy demand is added to the 2021 load profile according to forecasts from the 2021 IRP [9]. The 10.76TWh increase is scaled according to a normalized 2021 hourly load profile. Equation 7 demonstrates the calculation of hourly demand in the year 2041, P_{2041} , in time step *t*:

$$P_{2041}(t)\ [\mathrm{MW}] = \frac{P_{2021}(t)}{\sum_{i=0}^{8760} P_{2021}(i)} \cdot (10.76 \times 10^{6}\ \mathrm{MW})$$

Equation 7: Calculation of hourly load in 2041 model scenarios.

Where $P_{2021}(t)$ is the hourly demand at time t in 2021 according to BC Hydro Balancing Authority Load data.

To represent must-take energy requirements from IPPs, hourly generation from non-storage hydro, wind, solar, biofuel, and thermal units is subtracted from the system demand. The remaining demand after subtracting IPP generation is therefore met by the cascaded storage hydro generators. Figure 11 plots the 2021 hourly adjusted system demand, which is the load remaining after generation from IPP sources, plus hourly generation from non-storage hydro, wind, solar, biofuel, and thermal IPPs for an average water year.

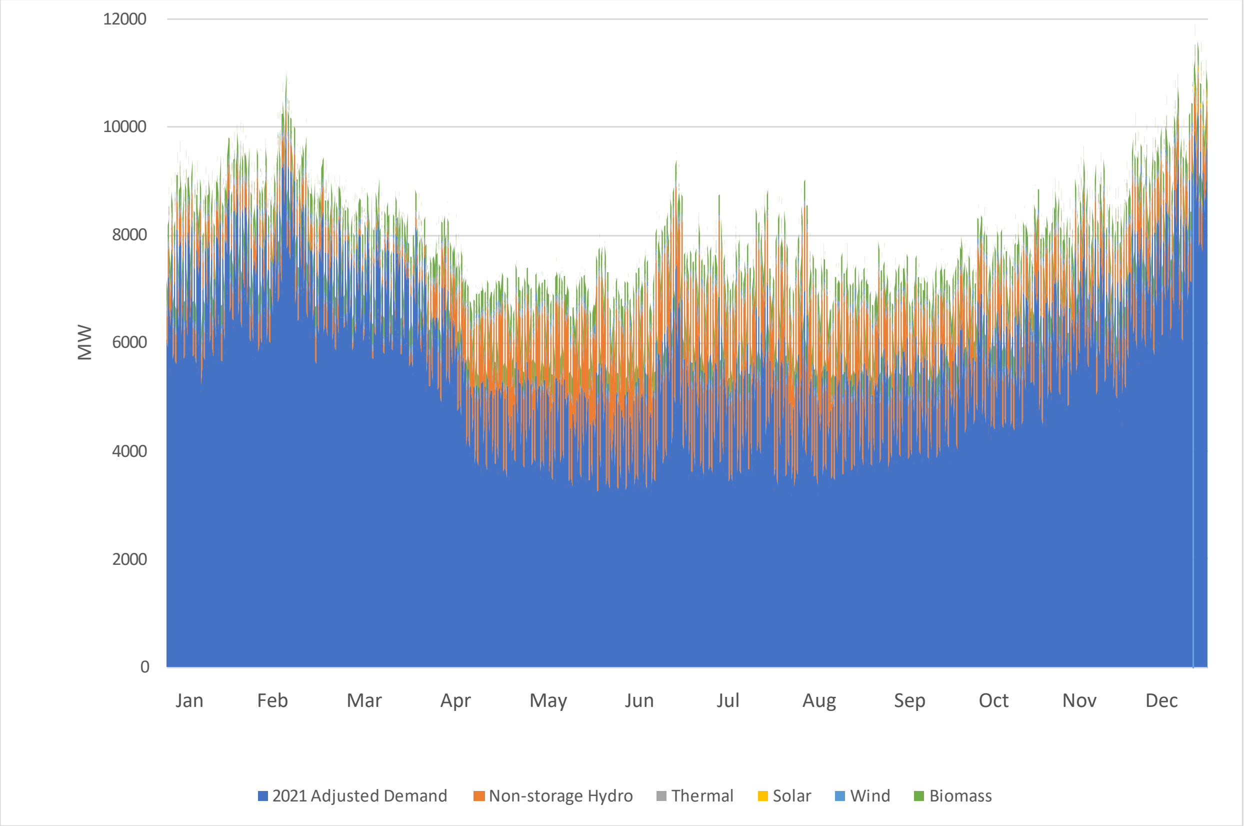

Figure 11: Hourly 2021 adjusted system demand stacked with generation from IPP sources (AWY) [38].

Hourly generation from biofuel and thermal generators is approximated by using a constant average value calculated from the total annual energy generation of these facilities listed in the IPP supply list [20]. The average power output of these units is calculated in Equation 8.

$$P_{av}(t)\ [MW] = \frac{E\ (MWh)}{8760h}$$

Equation 8: Average power generation of thermal and biofuel generators.

Where E is the total cumulative generation of the aggregated biofuel or thermal generator. The generation profile and average generation values and for each biofuel and thermal generator is detailed in Appendix C.

The generation assets in the system include 25 cascaded hydro generators categorized into 12 cascade groups; six of these generators are isolated storage hydro facilities and therefore form a cascade group of one. The aggregated thermal generation assets include one combined-cycle natural gas generator and four biomass generators. Run-of-river generation is modelled as eight aggregated units and will be discussed further in Section 2.4.1. VRE generators in the model baseline scenario include ten wind farms and one solar farm corresponding to the 2022 IPP Supply List of wind and solar facilities providing power to BC Hydro. Figure 12 displays the total installed capacities of the baseline BC System model by resource type [30, 71]. Generator costs and characteristics are listed in Appendix D.

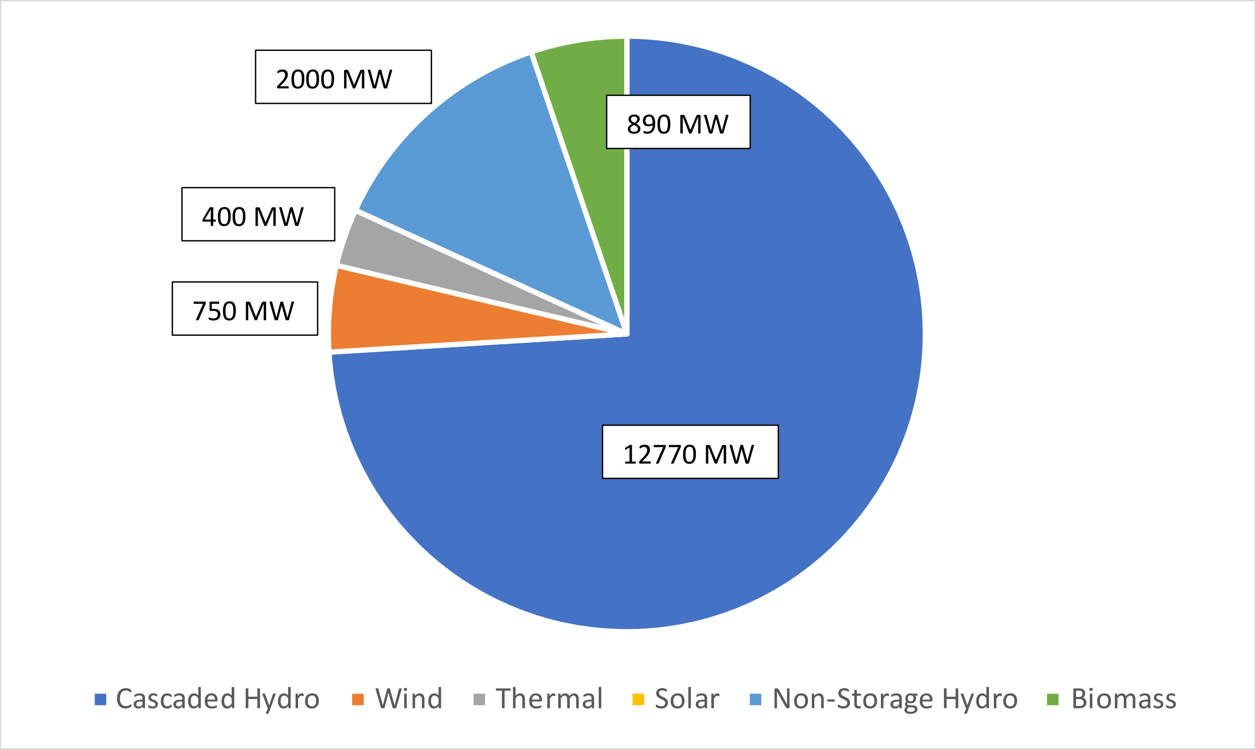

Figure 12: Installed generator capacities by resource type for the BC system baseline model [30, 27].

2.4.1 Run-of-River Hydro Modelling

Hourly energy generation from RoR hydro facilities is defined exogenously for aggregated generator units, which represent regional clusters of small hydro facilities with hourly storage capability. The 2022 IPP Supply List provides the location, installed capacity, and annual energy generation (for average water years) of RoR generation units. Hourly generation profiles are then extrapolated from the monthly profiles shown Figure 13 [78]. In the case of low and high water years, RoR generation profiles are scaled corresponding to the monthly change inflow volume for the storage hydro system, as provided in BC Hydro Water Use Plans. Figure 14 plots the differential between monthly average inflows for high and low water years relative to an average water year. High water years represent approximately a 132% cumulative increase in inflows to reservoirs relative to an average water year, however the change is most pronounced during the winter months from November to February. Low water years, on the other hand, represent a 39% cumulative decrease in annual inflow volume [27], but the change is more evenly distributed

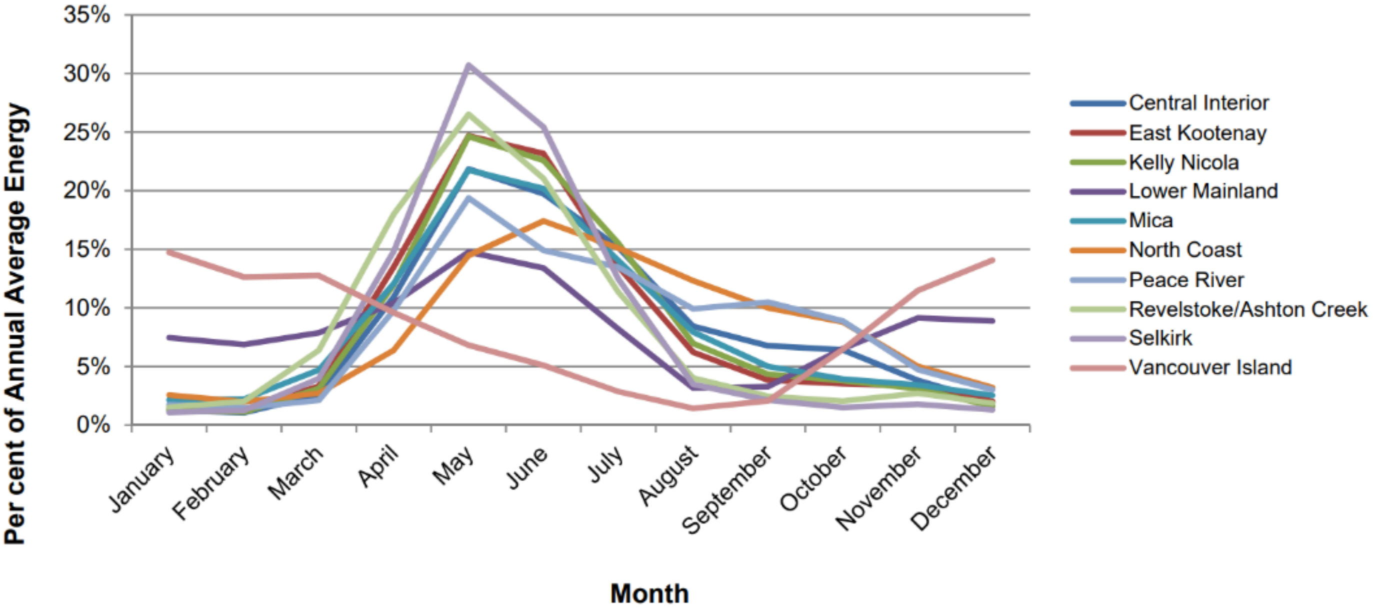

Figure 13: Monthly energy profiles - small hydro potential by transmission region [38].

across the year. The monthly differences in inflow volume are applied to RoR generation profiles shown in Figure 13 when modelling high and low water years to capture monthly variability in

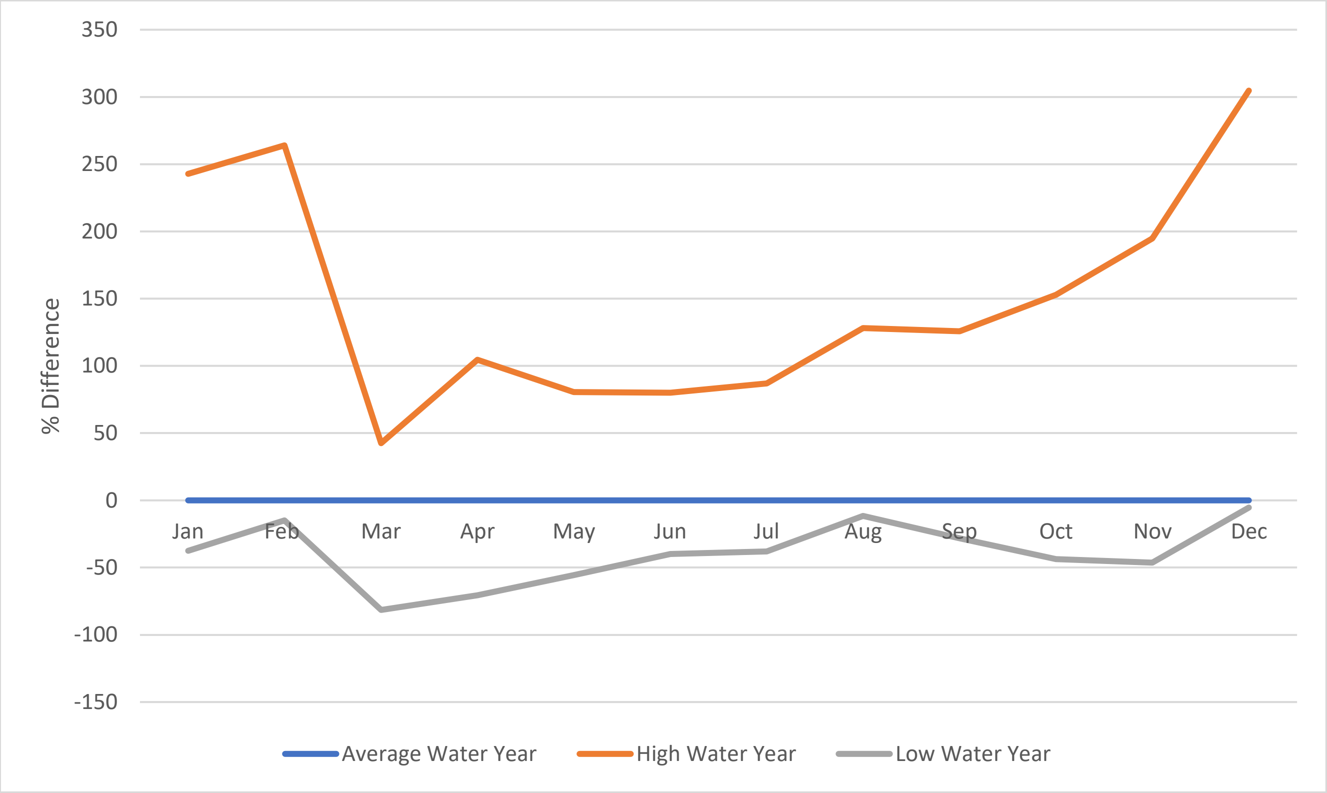

Figure 14: Average difference in monthly inflow volume of high and low water years relative to an average water year [27].

inflow conditions. The net monthly generation profile for non-storage hydro is plotted in Figure 14. While this approach neglects variations between regional hydrological systems, it serves as approximation for monthly changes to river flow volumes for non-storage hydro facilities.

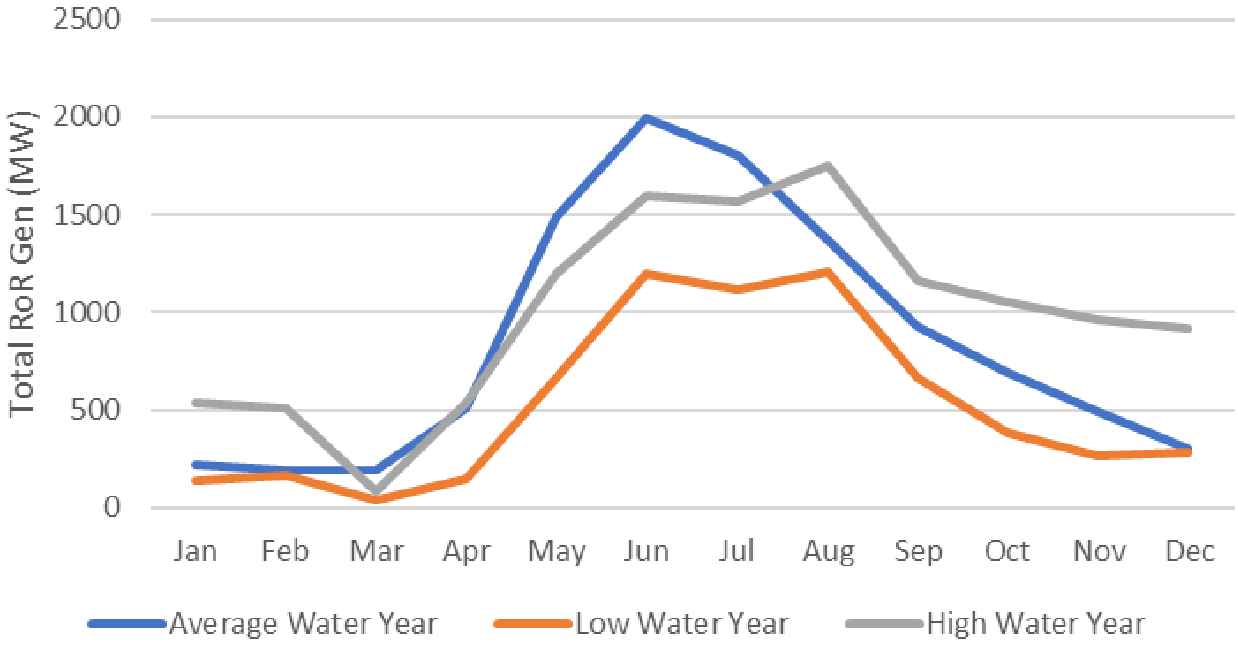

Figure 15: Net monthly generation from RoR facilities for average, low, and high inflow conditions [78, 27].

2.4.2 Cascaded Hydro Inflows

As discussed in previous sections, hydro reservoirs receive natural inflows from rivers, precipitation and surface runoff. The cascaded hydro model requires reservoir inflow data at an hourly resolution in order to optimize for discharge and spill rates. Hourly inflow data was approximated for the reservoirs in the model from monthly average inflow rates provided in BC Hydro WUPs for average, low, and high water years. Thus, the model assumes a constant hourly inflow rate for each month of the year, for all reservoirs in the system. The hourly inflow volumes for each cascaded hydro system is plotted in Figure 16. This approach neglects any sub-monthly variation that occurs in reservoir inflow rates and this limitation of the model is discussed in Section 2.7. As described previously, each scenario is modelled for average, high, and low inflow years as a sensitivity analysis. Figure 17 presents the cumulative inflows for each cascaded hydro system in the model for average, high, and low water years, demonstrating significant regional variability in inflow conditions for each cascaded hydro system.

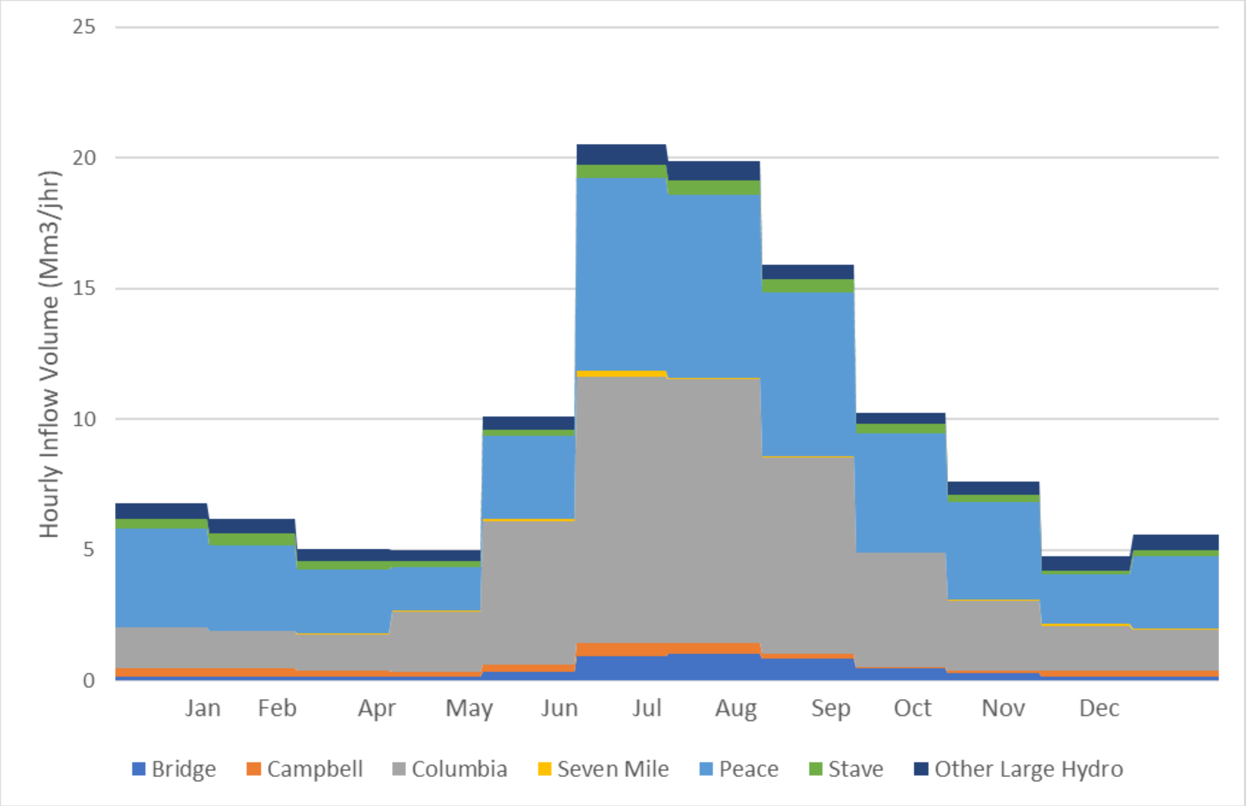

Figure 16: Stacked hourly inflow volumes for each cascaded hydro system (average water year) [17].

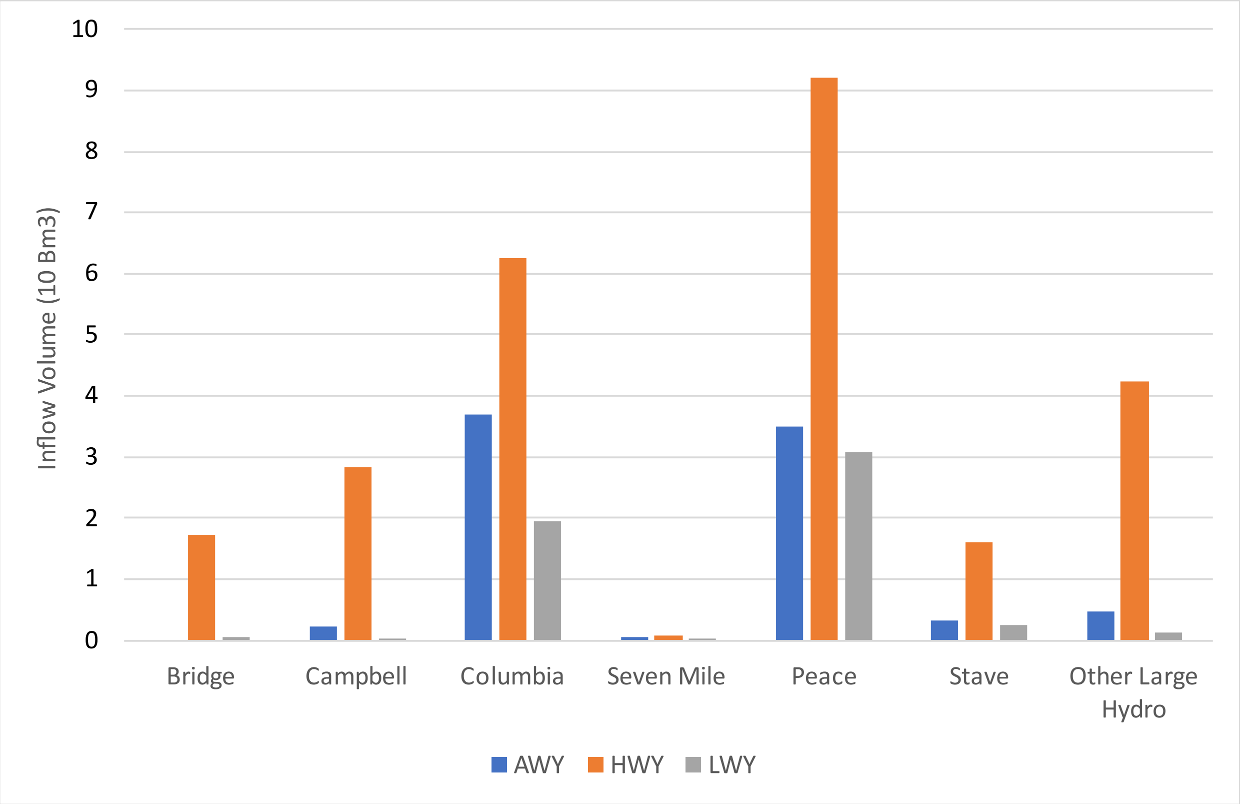

Figure 17: Annual cumulative inflows for each cascaded hydro system for average, high, and low water years [17].

2.4.3 Imports and Exports

Electricity trade between BC and Alberta is modelled as a single node representing the BC-AB interconnection, and hourly imports and exports are fixed for all scenarios. The BC-AB interconnection was built to provide an operating transfer capability of 1200MW from BC to AB and 1000MW from AB to BC, however actual ratings on the Intertie are typically lower. Imports from AB to BC range from 0 to 600MW and exports to Alberta do not exceed 800MW [79].

Hourly transmission data from the year 2021 is used to represent electricity trade between the two provinces in each modelled scenario [80]. Although interprovincial trade may expand in future decades to support increased VRE penetration in both provinces, values are fixed at 2021 levels for all scenarios to limit the scope of study [21]. For the same reason electricity trade with the US is not included in the model although it is a significant trading partner with the province. Figure 18 plots hourly electricity trade between BC and AB for the year 2021, with positive values indicating exports from BC to AB, and negative values representing imports from AB to BC.

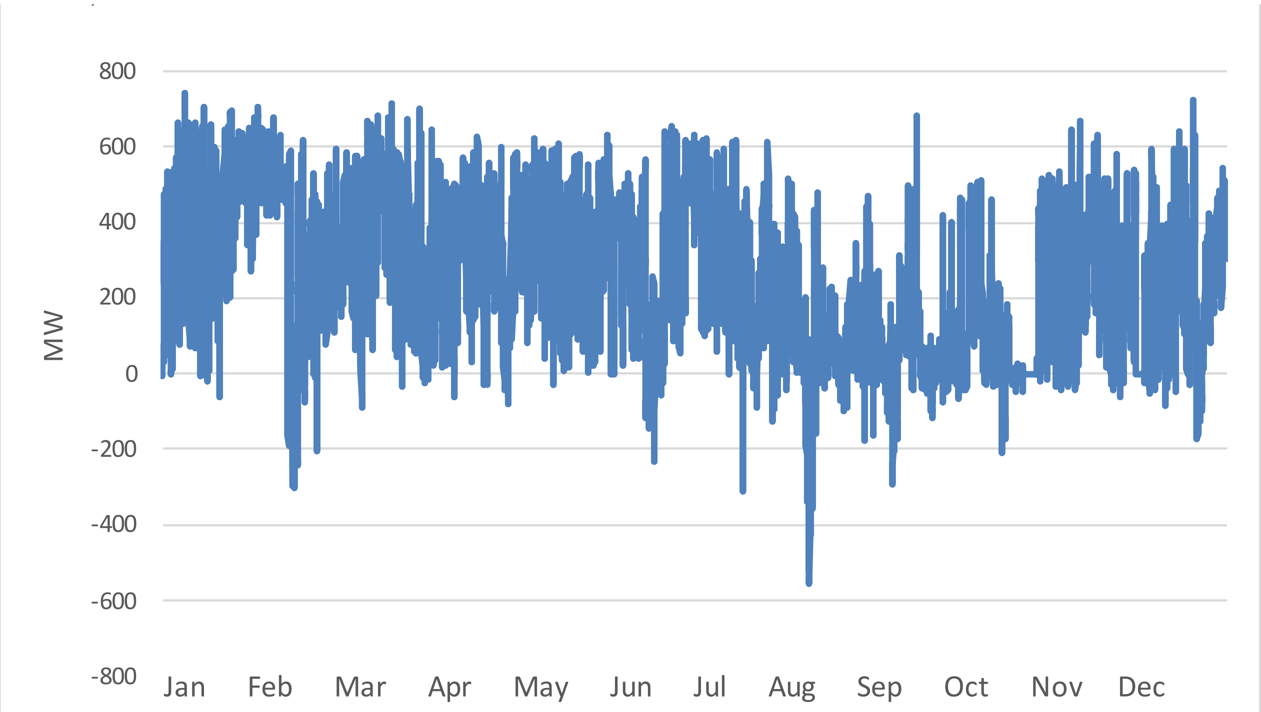

Figure 18: 2021 BC-AB electricity trade [79].

2.5 Spill Cost Implementation

As described in Section 2.2.1, the objective function includes a spill cost to minimize spill from cascaded hydro units in the model. In reality a storage facility will only spill if it risks exceeding its maximum storage capacity and is used as a last resort measure to maintain water levels within appropriate bounds [27]. It was found during the course of the SILVER cascading hydro implementation that spill events occurred in the model when the cascaded hydro units are not approaching maximum storage levels due to the arbitrary nature of the spill variable in Equation 5. This motivated the addition of a spill cost to the objective function. Figure 19 demonstrates the impact of a range of spill costs on total spill volume for all cascaded hydro generators in the baseline model scenario, indicating that a spill penalty of 0.01 \$/MWh is sufficient to reduce the spill volume by approximately half, and no further reduction is achieved for spill costs at higher orders of magnitude. However, at higher spill costs changes are observed for the generation mix of the model, as shown in Figure 20. It appears that increasing the spill cost leads to an increase in the share of generation from cascaded hydro units and reducing the share of generation from RoR in the absence of must-take energy requirements. This trend is not representative of the true BC electricity system which is required to accommodate generation from RoR IPPs. This conclusively indicates that a spill penalty on the order of 0.1 \$/MWh or less is suitable for reducing spill without shifting the model's generation mix excessively.

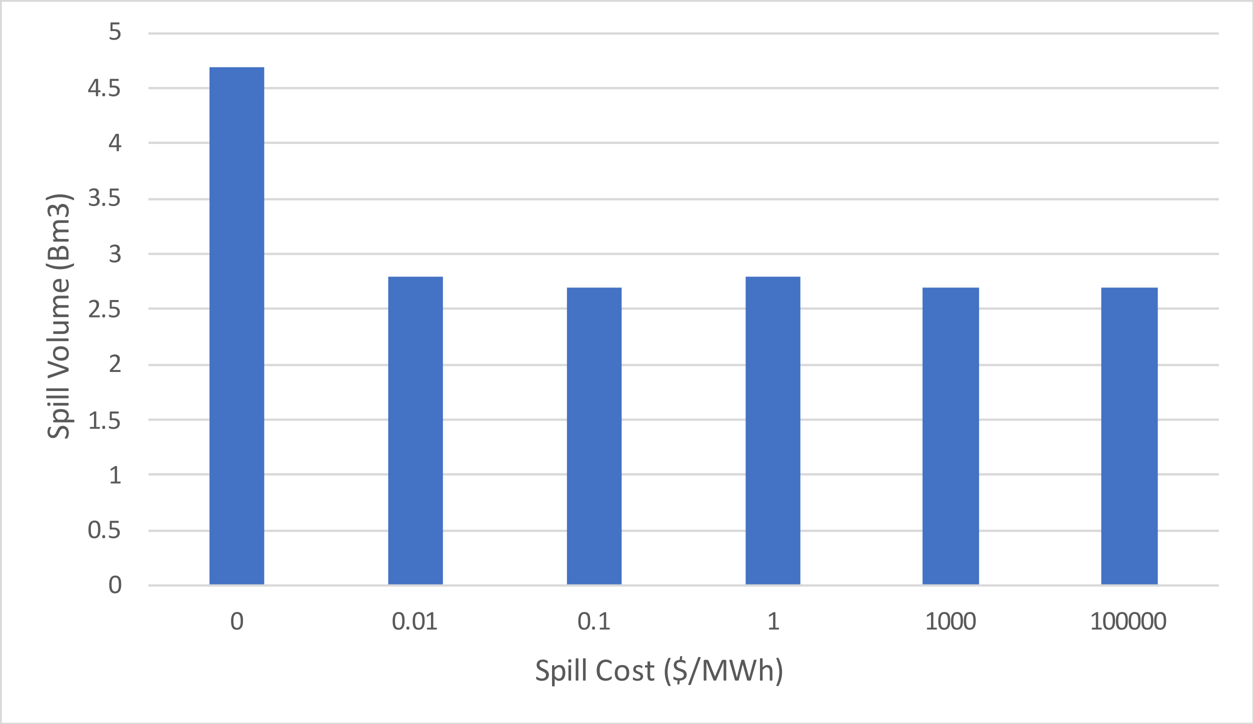

Figure 19: Cumulative spill volume (all cascaded hydro) for the range of spill costs tested on the baseline scenario (AWY).

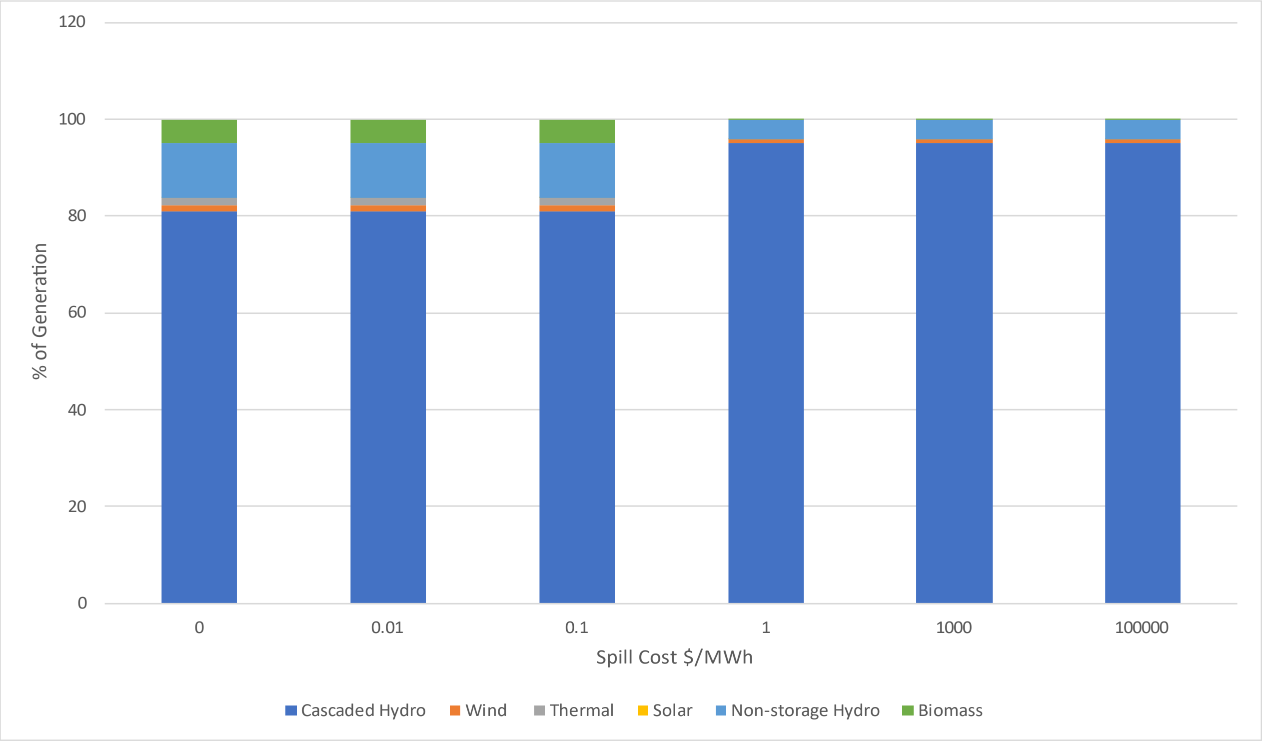

Figure 20: BC model generation mix for all tested spill costs.

2.6 Scenarios for study

Table 4 presents the scenario matrix which will serve to validate the model and explore future one-year scenarios in which the BC electricity system meets increased demand, as forecasted in the 2021 IRP, with a BAU IPP supply mix or with a fully decarbonized IPP supply mix with significantly increased VRE installed capacity. The baseline scenario serves as validation of the BC System Model and SILVER cascading hydro generator class described in Section 2.3 and 2.4, subject to the 2021 Balancing Authority Load [81]. The BAU scenario investigates the BC System under reference load growth conditions forecasted for the year 2041, with the IPP supply mix matching current ratios of non-storage hydro, thermal, biomass, wind, and solar installed capacities. The third scenario investigates the same load growth conditions as Scenario 2, but with a fully decarbonized IPP supply mix of 60% RoR, 30% wind, and 10% solar PV installed capacity. These ratios were chosen to be representative of a future decarbonized IPP supply mix in the province, which would likely continue to be dominated by smaller-scale hydropower projects due to its availability in the province. GIS assessments have suggested that there may by as much as 12GW of potential small hydro capacity that could be developed in BC, therefore non-storage hydro may play a key role in meeting future provincial energy and capacity needs [82]. Increased VRE capacities are modelled by adding additional capacity to existing VRE generators in Scenario 1. In all three scenarios heritage hydro capacity remains fixed in accordance with the absence of any planned large hydro development in the province’s near future [9]. Each scenario is performed with an additional sensitivity analysis for average, high, and low water years. The system generation mix, curtailment rates, and spillage is compared between the scenarios as indicators of system flexibility.

Table 4: Scenario matrix.

Scenario #	System Load	IPP Capacity Mix	Purpose of Scenario & Quantified Results
1. Baseline	2021	50% RoR 12% Thermal 20% Biomass 18% Wind 0.02% Solar	- Model validation - Generation mix - Curtailment - Spill
2. BAU	2041 Reference Load Forecast	2021 IPP Supply Mix with 1789MW added capacity over 2021 levels 50% RoR 12% Thermal 20% Biomass 18% Wind 0.02% Solar	Flexible but higher emission scenario to compare with Scenario 2: - Generation mix - Curtailment - Spill
3. Fully decarbonized IPP Supply Mix	2041 Reference Load Forecast	Fully decarbonized IPP Supply Mix with 1789MW added capacity over 2021 levels 60% RoR 30% Wind 10% Solar	Inflexible but fully decarbonized scenario to compare with Scenario 1: - Generation mix - Curtailment - Spill

2.7 Model Limitations

- *Seasonal storage not included in optimization*

SILVER UC optimizes within a 720-hour period for multi-month or year-long scenarios, and therefore only has perfect foresight with respect to input data for 30 days at a time. This prevents the model from accounting for future inflows to cascaded hydro reservoirs beyond the month it is optimizing unit commitment. In large hydro systems storage is optimized initially on a seasonal or annual basis according to forecasted inflow conditions. Once seasonal storage is established for a given study year, more granular power system optimizations may be performed at a higher temporal resolution. Future adjustment to the SILVER cascaded hydro model that would accommodate for seasonal storage optimization will be discussed in Chapter 4.

- *Reservoir inflows approximated from monthly averages*

The hourly inflow volumes to cascaded hydro reservoirs are derived from monthly average rates given in BC Hydro WUPs for average, high and low inflow conditions. This approximation does not reflect the daily or hourly variability in exogenous inflows from rivers and precipitation into reservoirs.

- *Climate changes to hydrological inflow conditions not included*

The modelled scenarios do not incorporate future changes to reservoir inflows due to climate change. Climate change models forecast significant seasonal changes to the quantity and type of precipitation, changes to average temperatures, and with significant regional variability within BC [83]. This may affect water storage volumes and inflow conditions for BC Hydro reservoirs in future decades.

- *Seasonal changes to minimum discharge rates not included*

Minimum dam discharge rates are maintained at many storage hydro facilities for ecosystem management and to prevent thermal stratification in reservoirs. Typical minimum discharge rates change throughout the year according to a schedule prescribed for wildlife or hydrological ecosystem maintenance [27]. In the model minimum discharge rates are fixed at a constant representative value where applicable.

- *Cascaded hydro dam power generation assumed to be linear*

As discussed in Section 2.3.1, water discharge height from dams is taken to be the average dam head, rather than a changing function of storage volume. Turbine efficiency curves are also a function of dam head, however in this study they are assumed to be constant.

- *Thermal and biofuel hourly must-take energy assumed to be constant.*

Due to a lack of data on must-take energy requirements for thermal and biofuel IPPs, generation from these sources are assumed to be a constant average value based on the annual energy contribution from these generation types [20].

- *Delay times not included.*

Due to a lack of data on inter-reservoir delay times for BC cascaded hydro systems, delay times are assumed to be less than one hour for all river systems.

- *Regional variability in RoR inflow conditions not included*

Inflow conditions for RoR facilities are derived from net changes to the BC heritage hydro facilities and therefore do not account for regional variability in streamflow rates between low, average, and high water years.

- *Aggregated representation of generation and transmission units*

The aggregated representation of demand centres, transmission infrastructure, RoR facilities, and biomass generators reduces the model's accuracy with respect to technology infrastructure.

- *BC-AB intertie fixed for future-year scenarios*

Electricity imports and exports via the BC-AB interconnection remain fixed for future scenarios incorporating reference load growth conditions, and no additional transmission capacity included in the model. In reality it is possible that BC will continue to support expanded VRE deployment in thermal-dominant jurisdictions such as Alberta, potentially by way of expanded transmission capacity [21].

- *US interconnection not included*

Although a significant energy trading partner, interconnection to the US is not included in order to reduce model complexity.

Chapter 3 - Results and Discussion

3.1 Introduction

This section presents the results and analysis for the scenarios described in Sections 1.3 and 2.6. Scenario 1 (Baseline) demonstrates the operation of the cascading hydro generator class in the context of a present-day BC electricity system. This scenario serves to validate the model and identify inconsistencies between model results and actual BC Hydro system operations. Scenario 2 (BAU) models the 2041 BC electricity system under normal load growth conditions, with an addition of 1789MW of IPP installed capacity from a “business-as-usual” supply mix consisting of 50% non-storage hydro, 12% thermal generation, 20% biomass, 18% wind and 0.02% solar. Heritage hydro capacity remains constant across all scenarios. Scenario 2 represents an expansion of the current IPP supply mix, but it does not strongly align with the province’s 2050 net-zero target which may require less thermal generation capacity by 2041 [84]. Scenario 2 serves to contrast the results of a fully decarbonized IPP capacity portfolio, modelled in Scenario 3. Scenario 3 (fully decarbonized IPP supply mix) models the 2041 BC system under the same load growth conditions as Scenario 2, however increased demand is met by a fully decarbonized BC Hydro system, consisting of existing heritage hydro assets plus an IPP supply mix consisting of 60% non-storage hydro, 30% wind, and 10% solar. As in Scenario 2, the IPP installed capacity is expanded by 1789MW as projected in the BC Hydro 2021 IRP [9]. As a sensitivity analysis each scenario is run for average, high, and low water years.

Section 3.2 presents model validation results, Section 3.3 presents generation to meet load for each scenario, Section 3.4 presents VRE curtailment and capacity factors, and Section

3.5 presents cascaded hydro spill rates observed in scenarios. Section 3.6 concludes the chapter with a discussion of the results.

3.2 Model Validation

Validation of the model is performed by comparing typical forecast energy production for cascaded hydro generating facilities with SILVER UC results for Scenario 1. Historical generation data is available for ten out of 25 cascaded hydro generators in the model from BC Hydro WUPs. Table 5 compares baseline scenario generation results with BC Hydro mean annual generation for ten cascaded hydro facilities. Average annual generation for the Site C facility (not yet in operation) is based on Site C project forecasts rather than historical averages [85]. Differences in energy production may be due to a multitude of factors discussed in Section 2.7: Model Limitations. These include differences in provincial demand (BC provincial demand has increased steadily in previous decades according to population and economic growth, therefore historical averages may not reflect 2021 energy demands [9]), differences in reservoir inflow volumes, transmission constraints, must-take energy requirements for IPPs, and the fact that electricity trade with the US is not accounted for in the model.

Table 5: Comparison of SILVER scenario 1 generation results with BCH mean annual generation for ten cascaded hydro facilities.

Cascaded Hydro System	**Facility**	**BCH Mean Annual Energy Production [27] (GWh/yr)**	**SILVER Scenario 1 Energy Production – AWY (GWh/yr)**
Campbell River	Strathcona (STR)	225	1191

	Ladore (LAD)	230	405
	John Hart (JHT)	775	552
Columbia	Walter Hardman (WAL)	37	23
	Whatshan (WHA)	121	155
Seven Mile	Seven Mile (SEM)	3200	5676
	Waneta (WAN) [86]	2680	4232
Peace [85]	Site C (STC)	5100	3371
Cheakamus	Cheakamus	590	1364
Wahleach	Wahleach	245	236

Additional validation of the model is demonstrated by comparing regional shares of cascaded hydro generation with model results. The BC Hydro system consists of four regions: Columbia, Peace, Lower Mainland and Coast, and Vancouver Island. Table 6 compares the share of generation by region from Scenario 1 - AWY results with BCH historical averages, indicating strong agreement between model results and typical regional shares of generation in the BC Hydro system. The share of generation is proportional to the amount of installed hydro capacity in each geographical region.

Table 6: Share of total hydro generation by region - comparison of SILVER results with BCH mean annual generation.

BC Hydro Region	Share of Total Hydro Generation – BCH [26] (%)	Share of Total Hydro Generation – SILVER (%)
Columbia River	48	49
Peace River	38	41
Vancouver Island	4	6.5
Lower Mainland and Coast	9.3	8

3.3 Generation to Meet Load

3.3.1 Scenario 1 – Baseline

Figure 21 presents the generation mix in the baseline scenario for each set of inflow conditions in comparison with the 2019 BC generation mix [5]. The Scenario 1 generation mix indicates that cascaded hydro generation represents a greater share of total electricity generation (between 76% and 83%) in comparison to the 2019 BC system, in which storage hydro contributes approximately 75% to the province's total generation. Thermal generation makes up a slightly larger share of generation in the model, in comparison with the observed 2019 energy mix. This discrepancy may be due to the approximation method used to represent thermal generation using an average value due to a lack of data on hourly must-take IPP energy for these generator types. Since there is zero VRE curtailment in Scenario 1, differences in VRE generation between the model results and actual data may be attributed to differences in capacity factors derived from wind and solar generation profiles in the model. Table 7 summarizes the share of generation by resource type.

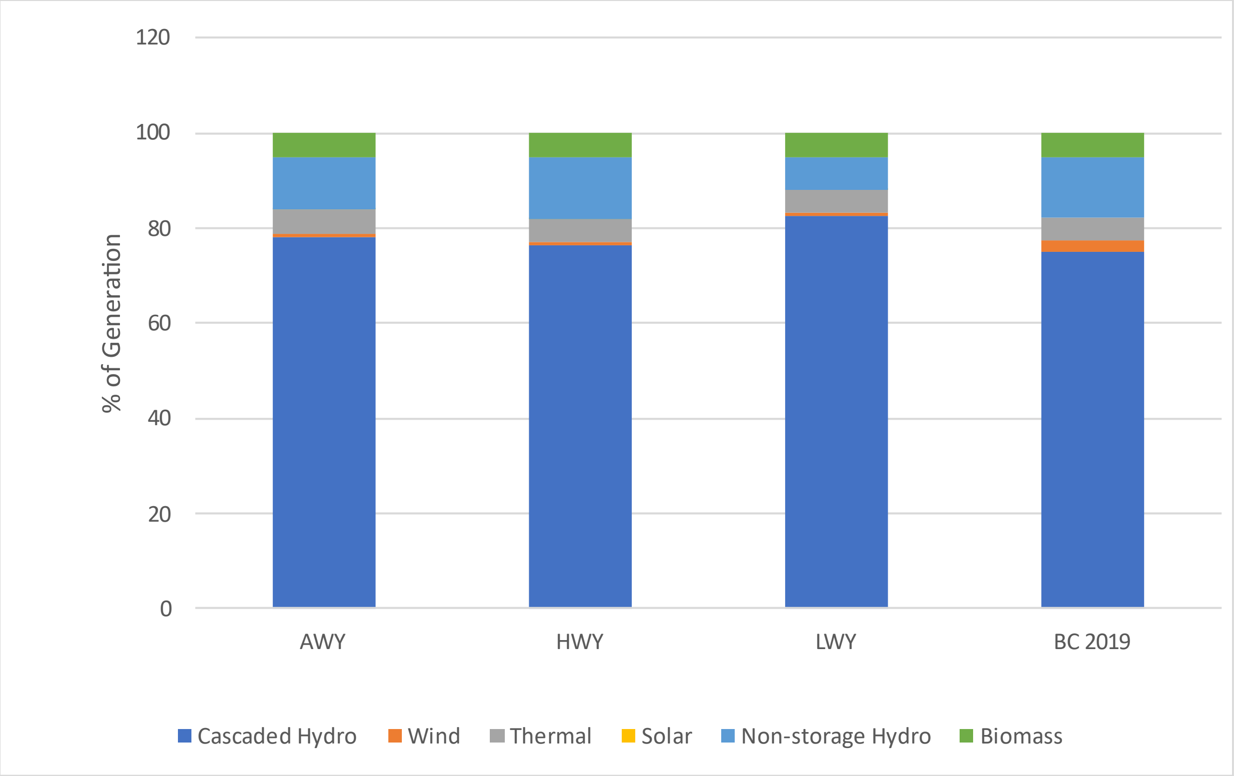

Figure 21: Summary of generation by resource type in comparison to BC 2019 generation mix.

Table 7: Percentage of electricity generation by resource type (summary of Figure 21).

	Cascaded Hydro (%)	**Biomass (%)**	**Thermal (%)**	**Non-storage Hydro (%)**	**Wind (%)**	**Solar (%)**
AWY	78	5	5	11	1	< 0.1
HWY	76	5	5	13	1	< 0.1
LWY	83	5	5	7	1	< 0.1
BC 2019	75	5	4.5	12	2.6	< 0.1

Figure 22 demonstrates the impact of varying inflow conditions on the generation mix and share of generation by each cascaded hydro system. Average and high water years utilize effectively the same mix of generation sources, however, during low water years the share of generation from non-storage hydro drops by approximately 40% in favour of cascaded hydro generation (other generation sources remain the same). This is due to reduced inflows in run-of-river facilities necessitating increased use of cascaded hydro facilities for electricity generation.

During low water years the share of generation from the Columbia River system increases by approximately 95% over average and high inflow years. In contrast, almost all other cascaded hydro systems reduce their electricity generation during low inflow years. As presented in Section 2.4.2, the Columbia River inflow volumes during low water years are approximately one-third of the Peace River system, and the Columbia River reservoirs have collectively less than half of the active storage volume of the Peace River reservoirs (see Appendix A for reservoir storage volumes). Given the fact that the Peace River has comparable generation capacity to the Columbia Region, and the absence of any transmission constraints in the model, it is unclear why the generation mix shifts in favour of the Columbia River facilities substantially during low water years.

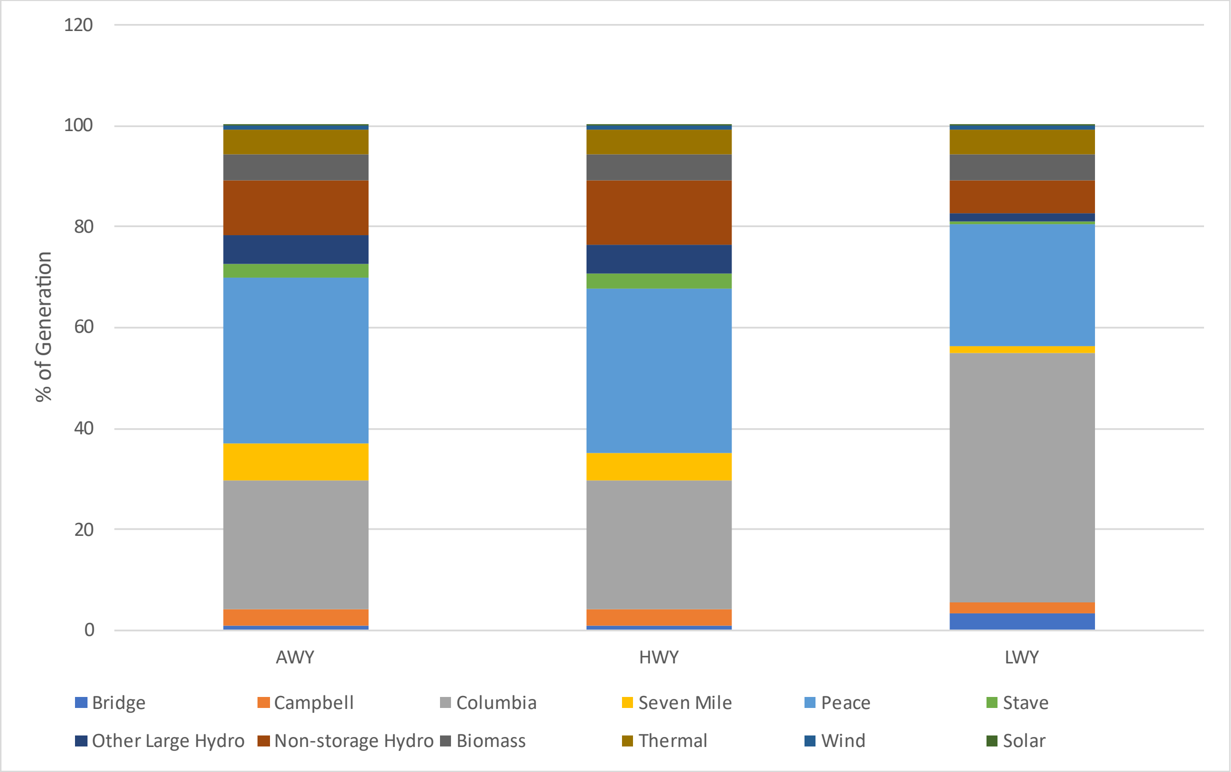

Figure 22: Scenario 1 generation mix for average, high, and low water years by cascaded hydro system and resource type.

3.3.2 Scenario 2 – 2041 BAU

Figure 23 presents the generation mix for Scenario 2. This scenario includes 1789MW of added capacity to existing IPP generators in the baseline model, and 10.76TWh of additional system electricity demand. As demonstrated in Figure 23, the generation mix of Scenario 2 closely resembles that of Scenario 1, with a modest increase in share of generation from non-storage hydro. Run-of-river generation is consistently higher during average and high water years due to increased inflows, and reduced river flow in low water years necessitates increased cascaded hydro electricity generation. The generation mix shown in Figure 23 suggests that there will be sufficient hydro capacity in the system to meet future electricity demands, assuming IPP contract renewals include adequate run-of-river and small hydro capacity.

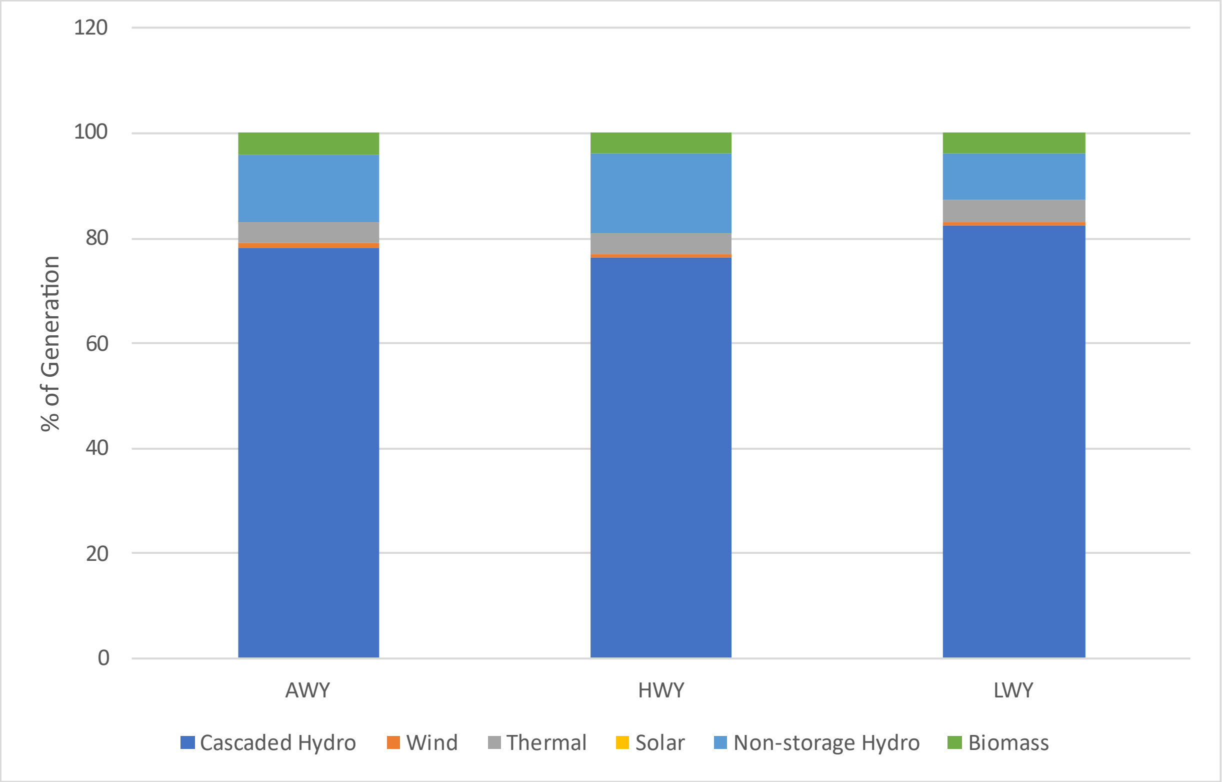

Figure 23: Scenario 2 generation mix for average, high, and low water years.

Figure 24 presents the share of generation by cascaded hydro system and generation resource type. As in the baseline scenario, electricity generation from cascaded hydro systems is dominated by the Columbia and Peace River systems, in proportion to their share of generating capacity. Scenario 2 exhibits the same shift in cascaded hydro generation under low inflow conditions seen in previous scenarios, where the Columbia River system increases its share of generation by approximately 50% while all other cascaded hydro systems decrease their share of generation in low water years. Conversely, during the high water year Peace River generation increases to 31% of total electricity production, while the Columbia facilities decrease to 26%. These results indicate that changing inflow conditions prescribed for cascaded hydro reservoirs will shift the ratios of the generation mix in the absence of any transmission constraints. However, these changes do not appear to be correlated with energy availability in cascaded hydro reservoirs.

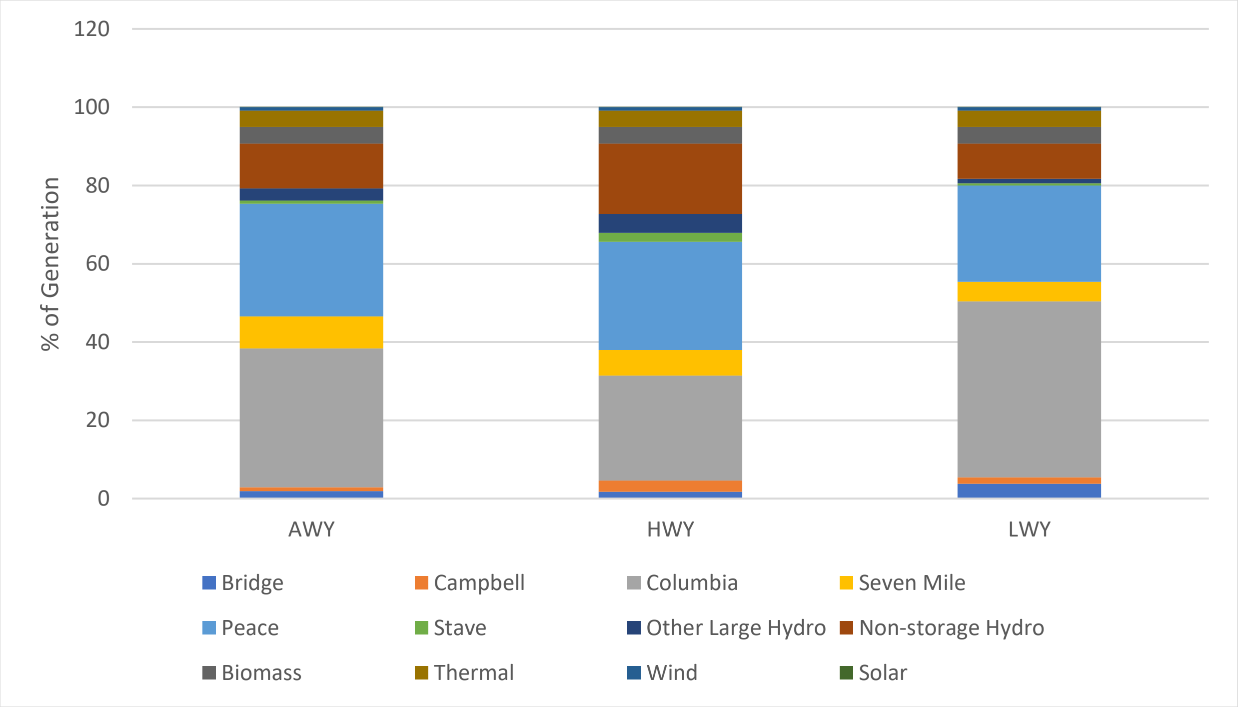

Figure 24: Scenario 2 generation mix by cascaded hydro system and generation type.

3.3.3 Scenario 3 – Fully decarbonized IPP supply mix

Scenario 3 addresses the case of a future BC electricity system that has fully decarbonized, where the increased demand of 10.76TWh is met with existing large hydro assets plus an IPP supply mix consisting of only non-storage hydro, wind, and solar generators. Figure 25 plots the generation mix for average, high, low water years for the fully decarbonized generation portfolio. The share of generation from cascaded and non-storage hydro remains consistent with Scenario 2. Wind penetration increases by approximately 60% over Scenario 2, as a result of 180MW of additional wind capacity, however overall wind and solar generation contribute just 2% and 0.3% of total generation respectively. VRE generation will be discussed in detail in Section 3.4. No significant changes were observed in the share of generation by each of the cascaded hydro systems between Scenarios 2 and 3, indicating that the existing hydro system can provide sufficient capacity to support a fully decarbonized IPP supply mix under all inflow conditions, assuming adequate transmission capabilities and Run-of-River IPP capacity.

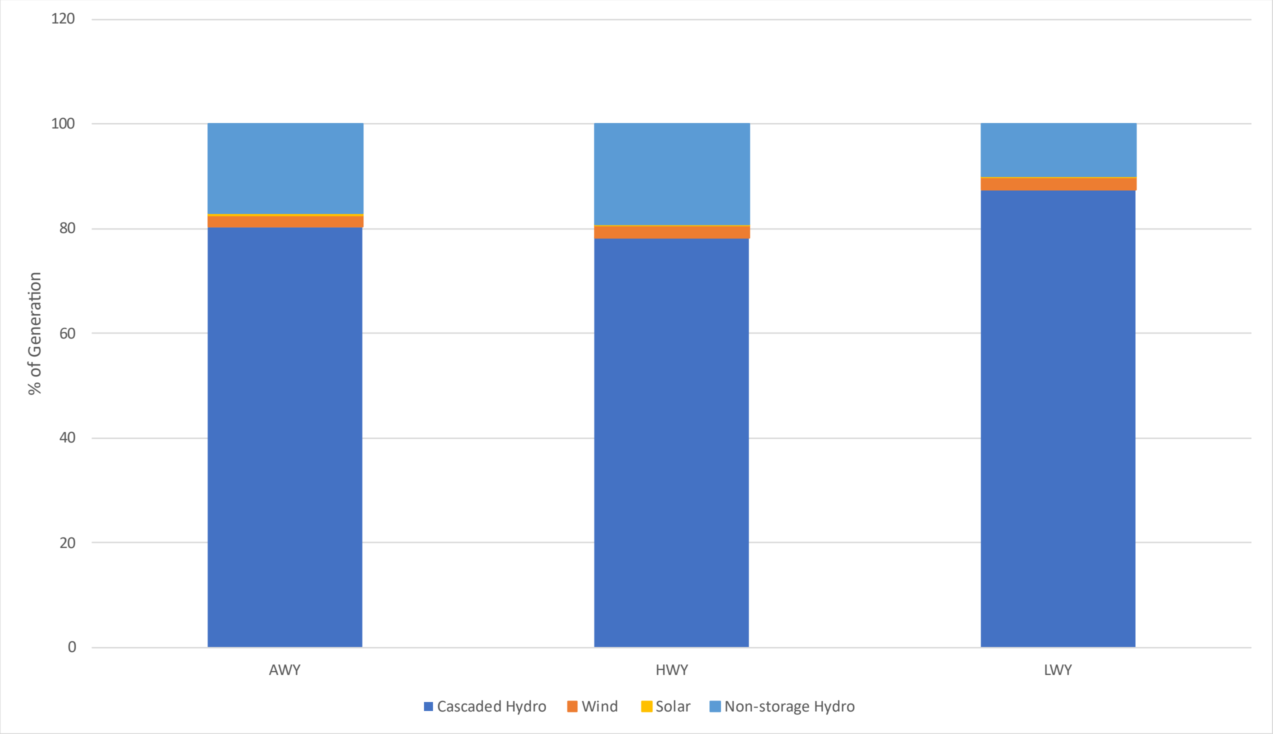

Figure 25: Scenario 3 generation mix for average, high, and low water years.

3.4 VRE Performance

In Scenarios 2 and 3, expanded wind and solar capacity is modelled by adding capacity to existing VRE units in the baseline BC electricity system model; the set of VRE generators is listed in Table 8. Scenario 2 adds a total of 322MW of wind capacity to the IPP supply mix, equally divided among the ten wind farms, and 0.4MW of solar (over baseline installed capacities). Scenario 3 adds 1240MW of wind and 180MW of solar capacity.

Table 8: List of VRE generators and their capacities in each model scenario.

VRE Generator	**Scenario 1 Capacity (MW)**	**Scenario 2 Capacity (MW)**	**Scenario 3 Capacity (MW)**
Dokie Wind	144	176	268
Sukunka Wind Energy Project	15	47	139
Zonnebeke Wind Energy Project	15	47	139
Bear Mountain Wind Park	102	134	226
Cape Scott Wind	99	131	223
Shinish Creek Wind Farm	15	47	139
Meikle Wind	185	217	308
Quality Wind	142	174	266
Moose Lake Wind	15	47	139
Pennansk Wind Farm	15	47	139
SunMine	2	34	126

Zero curtailment occurs and capacity factors for VRE units remain constant across all modelled scenarios. Figure 26 presents the capacity factors of each VRE generator in the model in comparison with capacity factors for the actual wind and solar farms, derived from the 2022 IPP Supply List [30]. With the exception of the SunMine solar farm, all VRE capacity factors in the model are between 4 to 10 times lower than those obtained from the IPP supply list. The difference between the model results and actual data may be due to discrepancies between VRE generation profiles in the model, which are based on historical weather observations in the MERRA dataset [69], and actual energy available on-site at wind and solar farms in the province. The difference in capacity factors may also be due to the technology assumptions embedded in the wind generation profiles used in SILVER, which calculate wind generation for a single turbine type (Vestas-112-3.0) at a fixed height (as discussed in Section 2.2.1) [1]. This turbine type and height differs from those used at the wind farms represented in the model, which include turbines such as the Vestas 100 (Cape Scott), Vestas 90 (Dokie), to Enercon E115 turbines (Sukunka and Zonnebeke) [87 – 89].

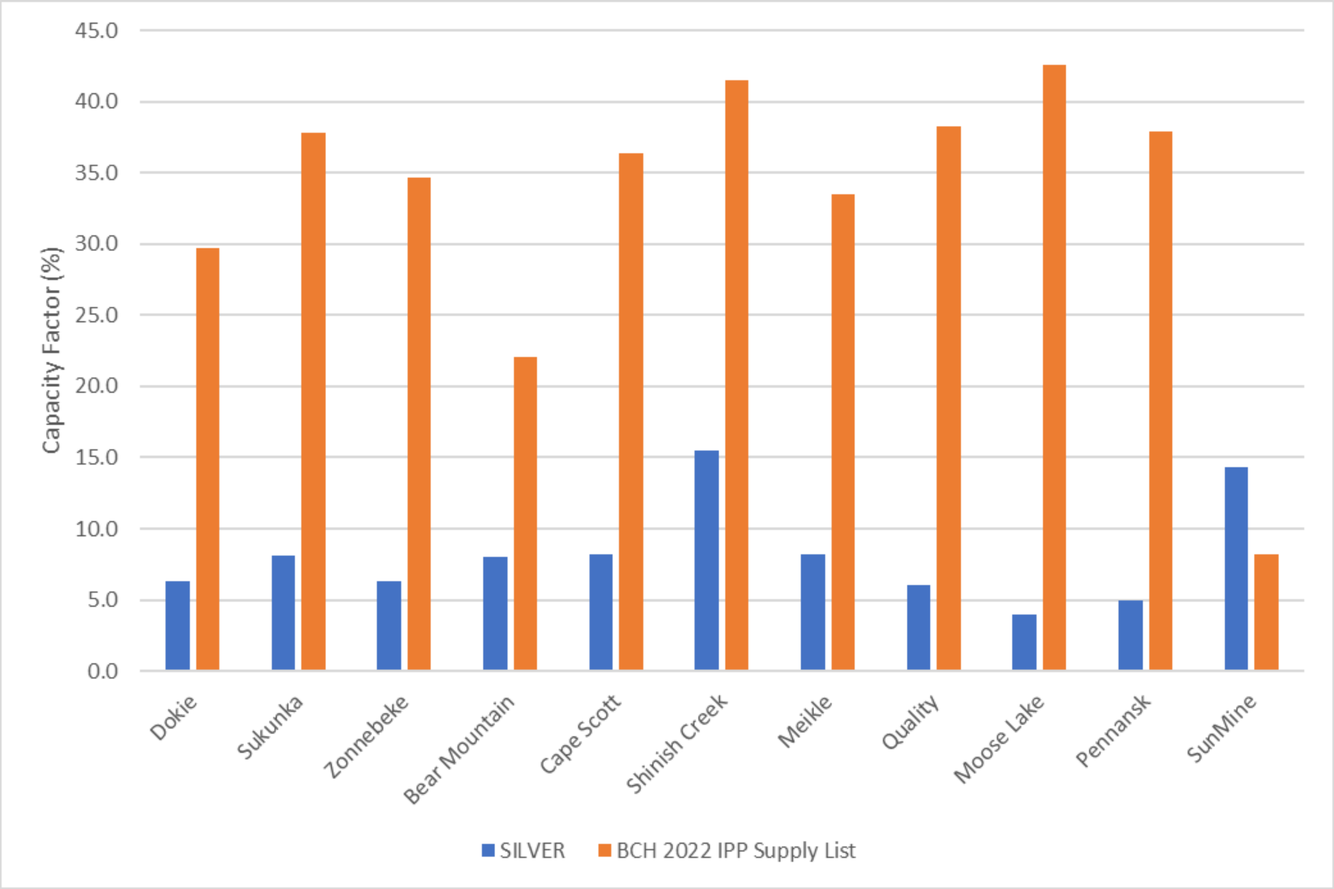

Figure 26: Comparison of capacity factors of VRE generators for modelled scenarios in comparison with capacity factors derived from the 2022 IPP Supply List.

3.5 Spill Volume

As described in Chapter 2, a cost is imposed on cascaded hydro spill events to prevent arbitrary water spill from reservoirs. As demonstrated in Chapter 2, a spill cost of 0.01 \$/MWh reduces spill volume in the baseline scenario by approximately 50%, and higher spill costs do not appear to reduce reservoir spill volumes any further. Figure 27 plots the hourly reservoir spill for cascaded hydro generators in Scenario 1 (AWY), indicating that large spill events occur frequently at the majority of reservoirs in the model, throughout the course of the year-long simulation. A similar number of spill events occur for Scenarios 2 and 3, and the magnitude of spill is roughly proportional to the volume of reservoir inflows, as shown in Figure 28. Scenario 3 shows a noticeable difference in spill volumes during average and low water years, where spill increases by 20% and 80% respectively relative to the same inflow conditions of Scenarios 1 and 2. Increased spill in Scenario 3 may be due to reduced flexibility of the electricity system as a result of greater VRE installed capacity. In the fully decarbonized scenario, the least cost solution to the UC problem may require spilling excess cascaded hydro energy in order to avoid curtailment of VRE generation. The increased spill observed for average and low water years in Scenario 3 suggests that increased must-take energy from VRE generators in future decades would reduce overall system flexibility and may increase the volume and frequency of spillage required at BC Hydro facilities. In actual BC Hydro system operations spill events occur relatively infrequently, and only occur when reservoirs risk exceeding their storage capacity or for wildlife ecosystem management purposes [64], [90].

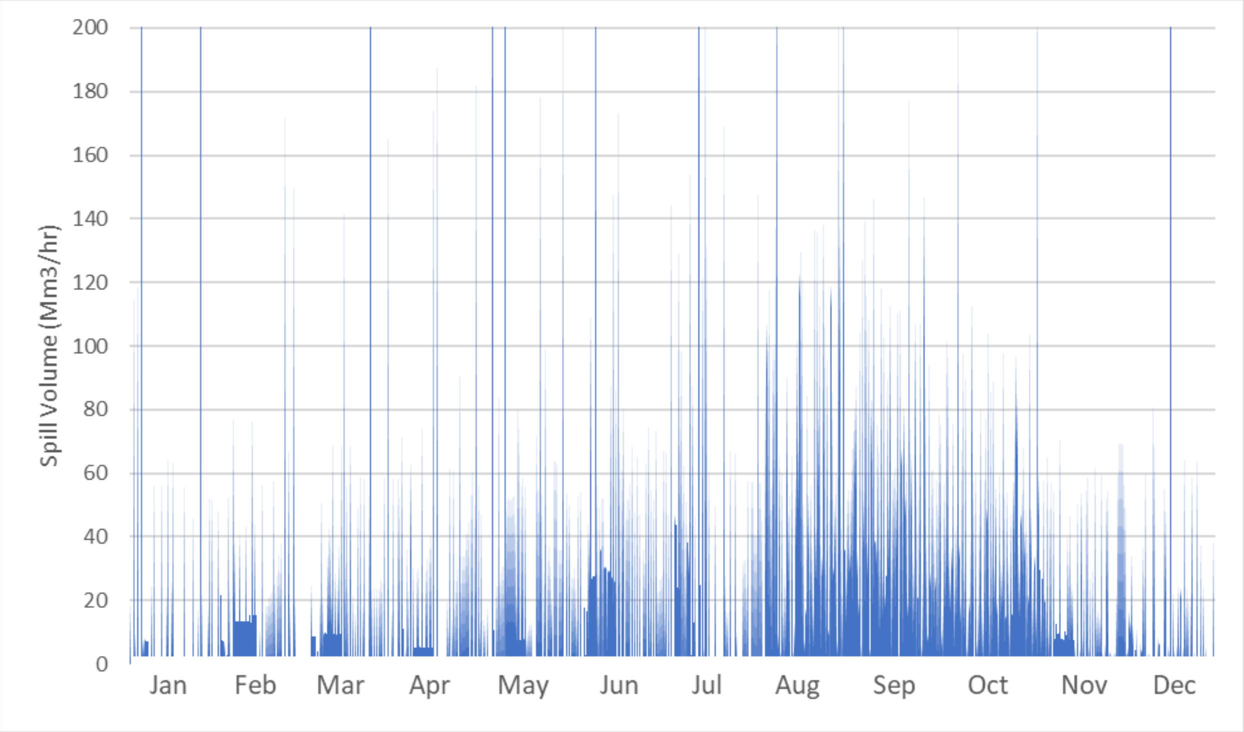

Figure 27: Hourly cumulative spill volume (all reservoirs), Scenario 1, AWY.

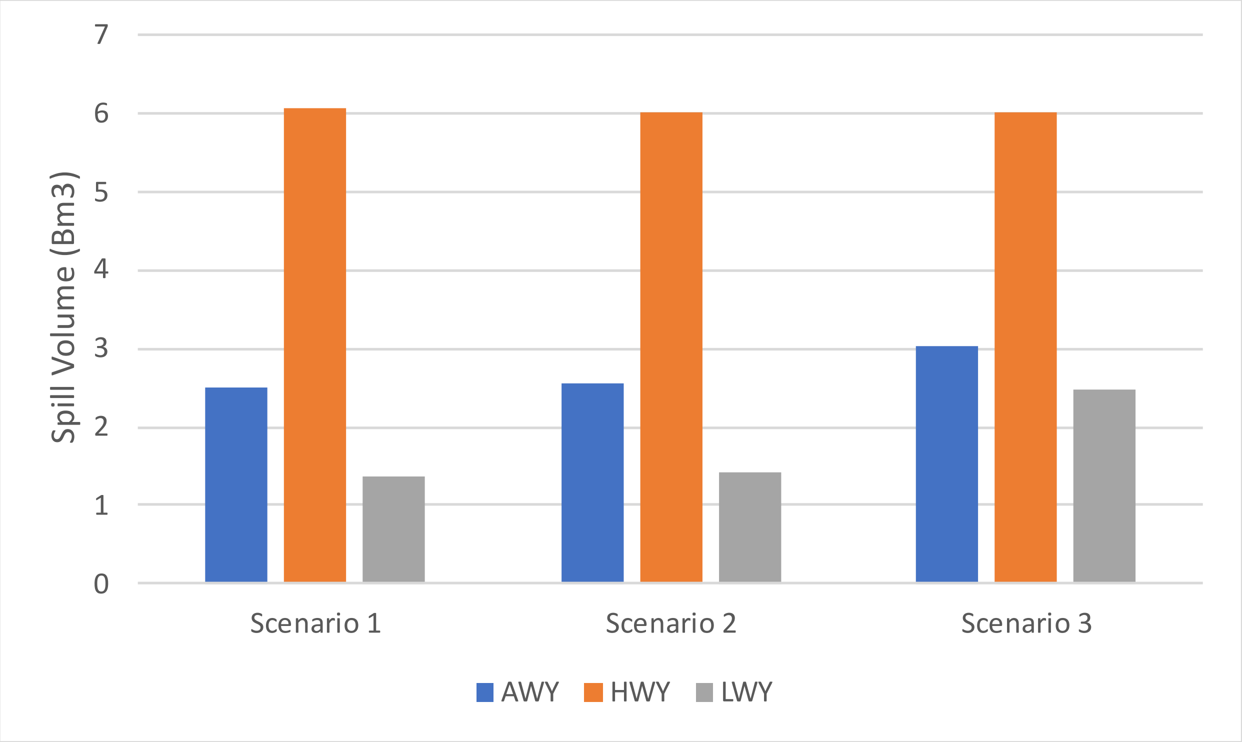

Figure 28: Annual cumulative spill volumes for each scenario (all reservoirs).

Figure 29 demonstrates that many reservoirs in the model approach their maximum storage volume consistently throughout the simulation, and therefore require spill to maintain their storage within the bounds of the maximum storage constraint. Thus, it does not appear that the cascaded hydro generators in the model spill any more water than necessary to maintain storage constraints. More data on spill event frequency and magnitude at BC Hydro reservoirs is required to determine the extent to which spill volumes generated in the cascaded hydro model exceed those observed at actual BC Hydro projects.

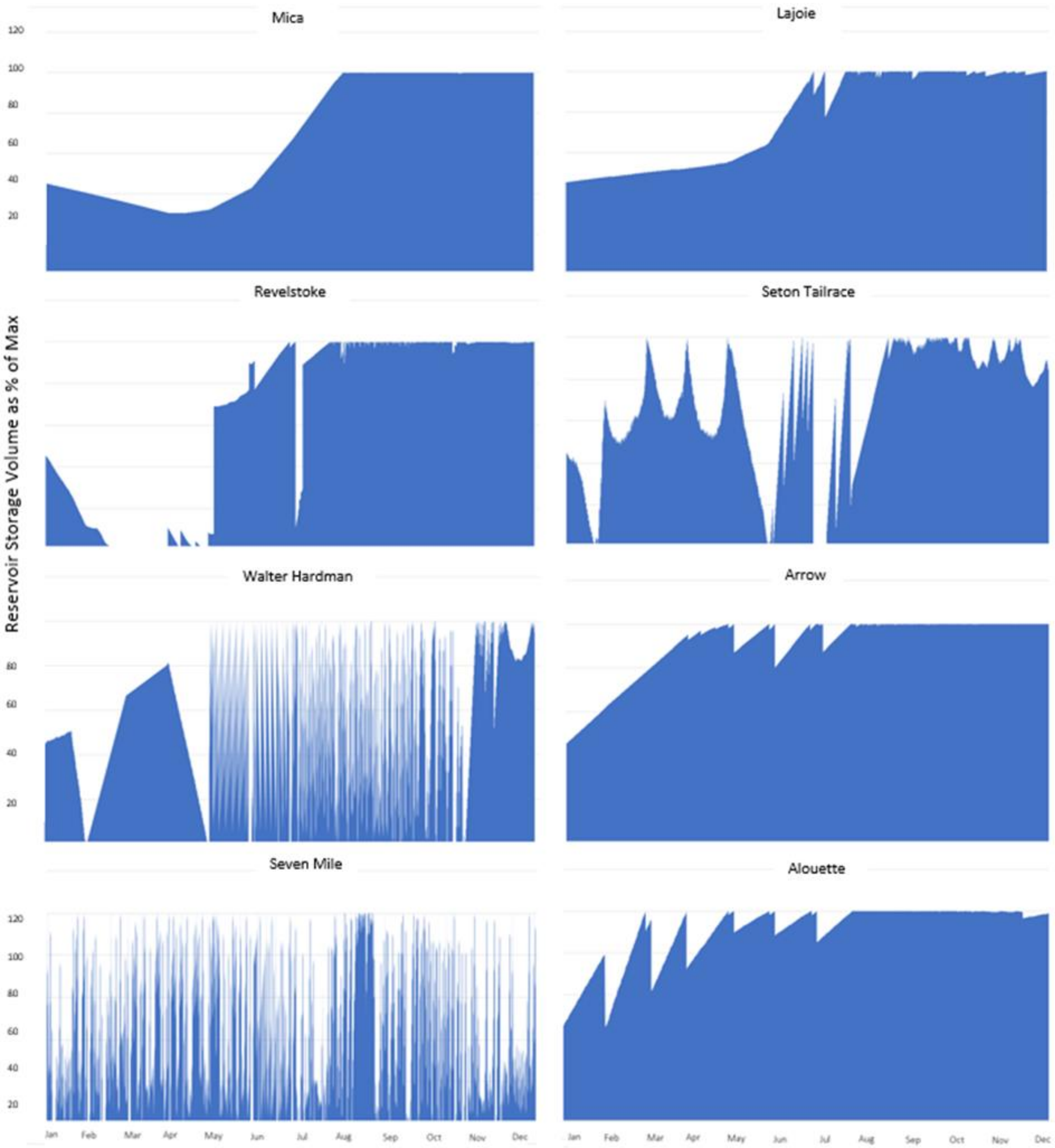

Figure 29: Hourly reservoir storages as a percent of maximum storage volume, Scenario 1, AWY.

Figure 30 presents total spill rates observed at the Wahleach Project for the decade from 1987 to 1997 [91]. In comparison, the SILVER model results for spill rates at the Wahleach Project in Scenario 1 are shown in Figure 31 for average, high, and low water years. During average and low water years spill rates in the model are comparable to actual spill rates at the

Wahleach Project. However, during the high water year, spill rates in the model are several orders of magnitude higher than any spill event observed at Wahleach in the decade between 1987 and 1997, and occur with much higher frequency. Although annual spill rates are not available for all storage hydro projects, comparison of Figure 30 and Figure 31 suggest that under certain inflow conditions, spill rates determined in the model may significantly exceed actual spill rates typically observed at BC Hydro facilities.

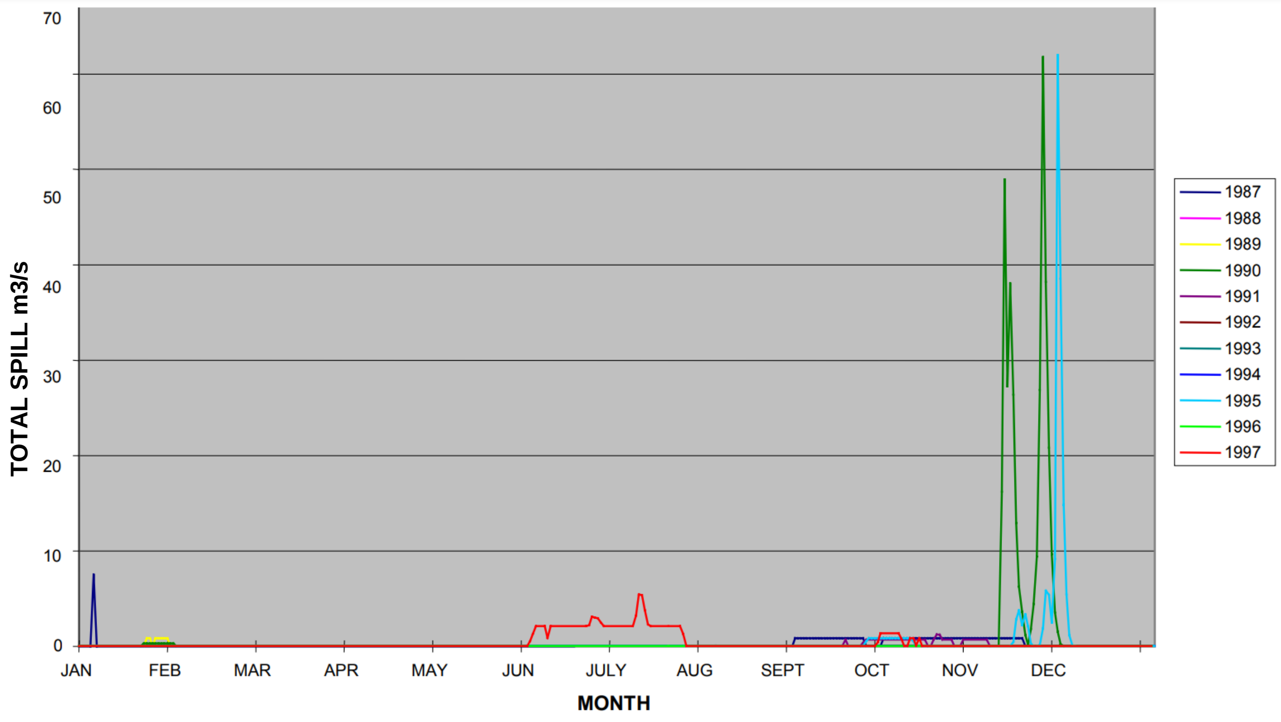

Figure 30: Spill rates at Wahleach Project (1987 to 1997) [91].

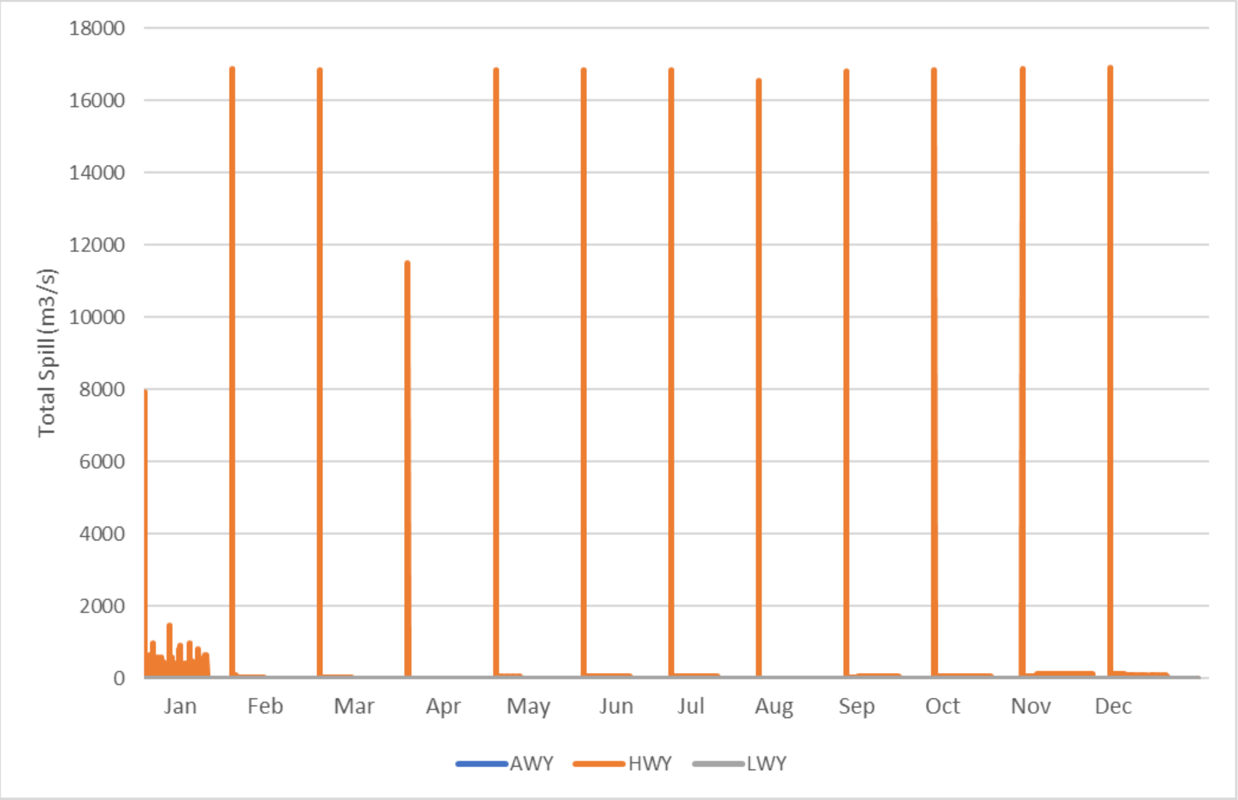

Figure 31: Spill rates at Wahleach Project for Scenario 1 (AWY, HWY, and LWY).

The discrepancy between the model spill results and actual BC Hydro operations may be due to the approximation method for reservoir inflows, which potentially over-estimate the actual inflow volume into reservoirs, and require increased spill to maintain maximum storage levels. Excessive spill rates may also be due to the monthly optimization periods used in the SILVER UC framework. Model variables (and therefore cascaded hydro storage) are optimized in one-month intervals, and the model has zero foresight from one optimization period to the next. As a result, the model cannot anticipate future changes to reservoir inflows or system demand, both of which are highly seasonal in the BC electricity system. Figure 31 demonstrates that large spill events of similar magnitude and duration occur regularly at the beginning of each optimization period (the beginning of each month) at the Wahleach Project during high water years. These spill events are not physical and would not be feasible in actual storage reservoirs which plan controlled spill releases over the course of several hours or days [90, 92, 93]. The spill dynamics observed in the model results indicate that the monthly optimization periods used in the SILVER framework may contribute to unrealistic spill rates from cascaded hydro generators. Due to the highly seasonal nature of large hydro system operations, the monthly optimization cycle may not be suitable for modelling large hydro facilities with seasonal or multi-year storage capabilities.

3.6 Discussion

The objective of presenting these results is two-fold: first, to demonstrate the operation of the cascaded hydro generator class in the context of a BC electricity system model and identify discrepancies between simulation results and BC Hydro system operations. The results point to the successes of the model and the remaining challenges of accurately representing cascaded storage hydro facilities in a production cost modelling framework. The second objective is to evaluate the flexibility of the hydro-dominated BC electricity system to accommodate increased VRE installed capacity in the IPP supply mix under future load growth conditions.

Model validation (Scenario 1) results indicate that the shares of hydro generation by geographical region determined by the SILVER UC are in strong agreement with those typically observed in the BC Hydro system. Cascaded hydro generation is dominated by the Columbia and Peace River systems, followed by the Lower Mainland and Coast, and Vancouver Island facilities. Shares of hydro generation are proportional to the amount of installed capacity in each region, with the Columbia River facilities contributing the greatest amount of hydro capacity, followed by the Peace, Lower Mainland and Coast, and Vancouver Island regions. The regional allocations of electricity generation indicate that, in the absence of transmission constraints, the SILVER UC prioritizes generation from cascaded hydro facilities in proportion to the amount of installed hydro capacity at a given transmission node, which is in strong agreement with the shares of regional generation observed in the BC Hydro system.

A sensitivity analysis of Scenario 1 is performed for high and low water years. No meaningful change to the generation mix is observed in years with high inflow conditions, however during low water years the Columbia River cascaded hydro facilities contribute significantly more to total electricity generation relative to higher inflow scenarios. Generation from the Columbia system increases by approximately 95% during the low water year, whereas shares of generation from all other major cascaded systems decrease. A similar shift is observed in Scenarios 2 and 3, although the increase in generation from Columbia facilities is less pronounced in the latter two scenarios. As discussed in Section 3.3, generation from other major cascaded hydro systems such as the Peace River and Seven Mile decrease by approximately 25% and 27% respectively during low water years. As Figure 17 demonstrates, Peace River reservoirs collectively receive over seven times the inflow volume in comparison to the Columbia River System during low water years. In addition, Peace River hydro reservoirs have collectively nearly twice the storage capacity as the combined storage of the Columbia River reservoirs (see Appendix A for active storage capacities). Thus, it is unclear as to why generation from the Columbia River increases dramatically during low water years. Particularly considering that it receives lower inflow and has less capacity to store water than the Peace River system, which has a similar generating capacity. Due to a lack of data on BC Hydro generation during low and high water years, it is not possible to compare how ratios of generation from cascaded hydro facilities shift in response to varying inflow conditions.

The generation mix observed in Scenario 1 (Figure 21) demonstrates that cascaded hydro facilities contribute the majority (76% or greater) of annual electricity generation in model simulations, which is slightly higher than the typical share of large hydro generation observed in the BC Hydro system (storage hydro contributes approximately 75% of total generation). The 2019 BC generation mix shown in Figure 21 indicates that thermal generators contribute approximately 4.5% to the province's total electricity generation respectively [5], which is slightly lower than the amount of thermal generation prescribed in the model. This discrepancy may be due to differences in assumptions about the annual generation of thermal facilities from the BC Hydro IPP supply list and the Canada Energy Regulator.

Sensitivity analyses of Scenario 1 performed for high and low water years indicates that during low water years, generation from non-storage hydro is reduced by as much as 50% relative to average and high inflow conditions; no meaningful changes are observed for any other generation types as a result of changing inflow conditions. The shift in RoR generation during low water years reflects the reduced water available for non-storage hydro generation, which necessitates the increased use of cascaded hydro facilities for electricity production. On the other hand, during high water years the hydro system has an excess of energy flowing into reservoirs, and therefore cascaded hydro dams must continue discharging water to prevent exceeding their maximum reservoir storage levels and spill. Thus, years with high inflow conditions can pose a significant operational challenge if inflows exceed reservoir storage capacities. Under these circumstances in the actual BC Hydro system, significant and profitable energy trade with the US is possible due to the excess of energy stored in large hydro reservoirs [94]. As discussed in Chapter 3, trade with the US is not included in this particular model, however future extensions of this work would benefit from including a representation of BC-US energy trade.

Scenarios 2 and 3 address a hypothetical “2041” BC electricity system scenario which incorporates the future load and capacity requirements forecasted in the 2021 BC Hydro IRP. System energy demand in both scenarios is increased by 10.76TWh over 2021 levels, and IPP installed capacity increases by 1789MW. Scenario 2 considers a “business as usual” case in which the increased IPP capacity consists of non-storage hydro, biomass, thermal, wind and solar generators in ratios consistent with the current IPP supply list [30]. Cascaded hydro installed capacity remains fixed at 2022 levels for all scenarios. The resulting generation mix in Scenario 2 shows no meaningful difference from that of Scenario 1. In spite of increased demand, the residual load continues to be met primarily by cascaded hydro and non-storage hydro generation. This indicates that, provided sufficient non-storage hydro EPAs are renewed in future decades, the current set of heritage hydro assets (with the addition of Site C) will have adequate capacity and flexibility to meet increased demand and accommodate modest increases in VRE installed capacity.

Scenario 3 tests the flexibility of a future BC electricity system with a fully decarbonized IPP capacity mix, consisting of 60% non-storage hydro, 40% wind, and 10% solar generation capacity. This scenario introduces 1280MW of additional wind and 180MW of solar capacity, which vastly exceeds current levels of installed VRE capacity. The resulting generation mix for Scenario 3, however, does not differ dramatically from Scenarios 1 and 2. Electricity production continues to be dominated by similar percentages of cascaded hydro and non-storage hydro, and VRE generation contributes less than 2% of total generation. Given that curtailment is zero across all scenarios, it appears that the hydro assets in the Scenario 3 capacity mix can provide sufficient flexibility to accommodate increased VRE penetration to the extent explored in Scenario 3.

It is evident in Scenarios 2 and 3 that VRE penetration does not scale with increases in VRE installed capacity. In Scenario 3, VRE assets account for 13% of total capacity, but contribute just 2.5% of annual electricity production. Zero curtailment indicates that all available VRE generation is used for electricity in the model, therefore low VRE penetration rates can be attributed to the notably low capacity factors observed for wind and solar generators in the model. Indeed, the capacity factors of the wind and solar farms represented in the SILVER model are between 4 and 10 times lower than those listed for the corresponding generators in the 2022 BC Hydro IPP supply list [30]. This discrepancy may be due to the method for approximating wind and solar generation availability, as discussed in Section 3.3. Higher capacity factors from VRE generators in the model would most likely increase net load variability, and therefore increase the demand for flexible generation from the hydro system. Thus, it is essential that available VRE generation is derived accurately in order to obtain a reasonable assessment of the flexibility requirements for the electricity system. It is unclear whether the hydro system in Scenarios 2 or 3 could provide sufficient flexibility to accommodate VRE generators if their capacity factors were higher than those observed in the model simulations.

Spill is a measure of flexibility (or lack thereof) in an electricity system dominated by storage hydro. Spill indicates that energy in reservoirs must be wasted rather than stored for future electricity generation. In all model scenarios spill volumes from hydro reservoirs are relatively uniform and proportional to the volume of reservoir inflows, with the exception of the fully decarbonized capacity mix explored in Scenario 3. In Scenario 3 spill volumes increase by 20% and 80% during average and low water years respectively, relative to the same inflow conditions for other scenarios. This indicates that the increase in VRE installed capacity in Scenario 3 reduces the flexibility of the hydro system, leading to increased spill from cascaded hydro. Reservoirs may be forced to spill water, rather than discharging it to produce electricity, to avoid curtailment of VRE generation. It is unclear, however, as to why the increase in spill in Scenario 3 is observed only for low and average water years, and not during the high water year.

The addition of a spill cost effectively reduces the number and volume of spill events from cascaded hydro generators in the model. When comparing cascaded hydro storage volumes with the timing of spill events in model scenarios, it is evident that spill events occur only when reservoirs risk exceeding their maximum storage volume. However, a case study comparing the historical spill rates at Wahleach Project with those observed in Scenario 1 demonstrates that, under high inflow conditions, spill rates in the model vastly exceed those observed at the Wahleach Project over the course of a decade. Additional data on spill rates at other BC Hydro projects would be necessary to understand the extent to which spill rates in the model exceed those observed historically at reservoirs. Discrepancies between spill rates in the model results and actual spill rates may also be due to the approximation of reservoir inflows from rivers, streams, and precipitation. Reservoir inflows are derived from monthly average flow rates for each hydro reservoir, and therefore do not account for any hourly or daily variability in inflow rates. This approximation method may over-estimate inflow volumes during high water years, leading to excess spill rates observed in model results.

The monthly optimization period used in the SILVER UC framework may also impact dynamics of cascaded hydro spill, and potentially lead to unrealistically high spill rates. In the case study of the Wahleach Project in Section 3.5, it is clear during high water years that extremely large spill events of similar magnitude and duration occur at the beginning of each optimization period in the simulation. This suggests that the model's lack of foresight beyond the current month of optimization leads to spill dynamics which are unphysical both in their magnitude and duration, and have a clear monthly pattern that coincides with the optimization periods of the simulation.

Longer optimization periods of several months or up to a full year may be better suited modelling seasonal aspects of cascaded hydro operations, such as reservoir storage and generation levels. One way to address the incompatibilities in the model framework would be to perform a separate optimization stage exclusively for large hydro units in which monthly reservoir storage levels, and minimum and maximum generation levels for cascaded hydro generators are optimized at a coarser temporal resolution over longer time periods. The outputs of this initial optimization stage could then be defined in the main SILVER UC framework, thereby mitigating some of the challenges associated with modelling seasonal generation units in monthly optimization cycles. This two-stage optimization process is similar to the iterative modelling approach used by BC Hydro system operators, as described in Chapter 1 [64].

Chapter 4 - Conclusions and Future Work

4.1 Summary

BC provincial and global decarbonization targets will require widespread electrification and integration of VRE generation resources into existing power systems in future decades [95] [2]. These shifts will greatly increase the value and need for flexible generation sources in electricity systems to accommodate increased net load variability. Storage hydro has been identified as a zero-emission electricity source that can provide important grid balancing services to support increased VRE penetration in Canada and in other countries with large hydro generation capacities [20 – 22]. While many energy system modelling studies have identified hydro as playing a key balancing role in facilitating future VRE integration, models of hydro facilities vary widely in their representations of generator technology and reservoir constraints, cascaded hydro systems, and reservoir inflow variability. It was determined from a review of available production cost models that current approaches to modelling cascaded hydro generators were not sufficiently accurate for electricity systems dominated by cascaded hydro generation. This motivated the development of a cascaded storage hydro model that is compatible with the SILVER framework and accounts for the many of the operational, regulatory, and environmental constraints unique to these generators. The SILVER cascaded hydro model is applied in a case study of the BC electricity system to evaluate the flexibility of the hydro system in scenarios involving increased VRE installed capacity. Important conclusions can be drawn in relation to modelling cascaded hydro facilities in production cost models, as well as to the real-world implications of expanded VRE integration in hydro-dominant electricity systems.

4.2 Implications for Production Cost Modelling

The SILVER cascaded hydro model aims to represent all constraints related to electricity generation, water flows, and water storage in reservoirs. Rather than prescribing minimum and maximum generation levels for hydro assets, the approach used by most electricity system-scale production cost models, the SILVER cascaded hydro model optimizes hourly dam discharge and spill while taking into account system demand and hourly reservoir inflows from rivers, precipitation, surface runoff, and upstream dams in the case of cascaded hydro systems. While this approach more accurately reflects the distribution of water resources in actual cascaded hydro systems, there are challenges associated with integrating this formulation into a production cost model that utilizes monthly optimization periods for unit commitment scheduling. The unphysical dynamics of the spill variable under certain inflow conditions is a clear indicator of the challenge associated with the model's lack of foresight. Significant differences are observed between spill rates of cascaded hydro generators in the model and those of operational BC Hydro facilities. Since spill is an important indicator of flexibility for hydro-dominant electricity systems, it is crucial to ensure that spill events occur at a similar frequency and magnitude to those observed at actual hydro facilities under similar inflow conditions. Although data on spill rates from BC Hydro projects is sparse, it appears that the current formulation of the cascaded hydro model can result in excessively high spill rates from reservoirs experiencing high inflow conditions. This may be due in part to the use of monthly optimization periods for unit commitment scheduling, which may not be well suited for planning seasonal generation and storage requirements of large hydro facilities. Due to a lack of foresight beyond the current month of optimization, the model cannot plan for future seasonal inflow changes, such as the freshet snowmelt, dry summer months, or a rainy winter season; nor can it anticipate seasonal changes to system demand. The monthly optimization structure may contribute to the unphysical spill dynamics observed in scenario results, because cascaded hydro reservoirs cannot anticipate future storage requirements in subsequent optimization periods.

The high spill rates observed in model results may also be due to excessive reservoir inflows defined in the model inputs. This highlights the need for higher resolution data on reservoir inflow volumes than is currently available for BC Hydro reservoirs. The approximation method used in this study does not capture any sub-monthly variation in reservoir inflows, and may over or under-estimate the actual volume of inflows into hydro reservoirs.

4.3 Implications for VRE Integration in Hydro-dominant Electricity Systems

This work explores future scenarios of the BC electricity system subject to forecast load growth for the year 2041, with increased installed capacity from independent power producers [9]. Results indicate that a fully decarbonized IPP supply mix consisting of only non-storage hydro, wind, and solar generation sources is feasible under all inflow conditions, with zero curtailment of VRE generation. While this suggests that the large hydro assets in the BC system have sufficient flexibility to accommodate increased in VRE installed capacity, it should be noted that capacity factors of VRE generators in the model were substantially lower than those observed at wind and solar farms at equivalent locations in the province [30]. Further calibration of wind and solar capacity factors in the SILVER model is necessary to ensure an accurate assessment of the flexibility requirements for the levels of VRE installed capacities explored in each scenario.

It appears that the province’s storage hydro assets, in combination with sufficient RoR generation, can successfully accommodate increased VRE capacity in the BC electricity system with zero curtailment. However greater shares of VRE capacity in the IPP supply mix appears to result in increased spill volumes from cascaded hydro generators. This suggests that the hydro system may have limited flexibility to accommodate additional VRE installed capacity, as indicated by the increased spill volumes observed in the fully decarbonized electricity system scenario. Increased generation from VRE units may force cascaded hydro generators to spill rather than discharge water in order to maintain their reservoir storage constraints and avoid curtailment. This suggests that there may be a limit to the amount of additional VRE IPP capacity that can be added to the BC Hydro system without consequences for hydro facility operations.

4.4 Future work

The cascaded hydro model described in this work represents the first iteration of a collaborative process, which the author hopes will yield successively improved representations of cascaded hydro generators in the SILVER model framework. As described previously, the paucity of quality data for reservoir inflow and spill rates is a significant source of uncertainty in the model results. It is recommended that future users of the model continue to seek out higher resolution data to model reservoir inflow rates, reservoir characteristics, and to calibrate spill rates of BC Hydro projects represented in the model.

As discussed in previous sections, the monthly optimization periods utilized in the SILVER framework may not be suitable to the seasonal planning requirements of large storage hydro facilities. Future development of the cascaded hydro model could involve a separate optimization stage exclusively for cascaded hydro generators, which would optimize minimum and maximum generation levels and reservoir storage levels using multi-month or full-year optimization periods. The outputs of this stage could then be prescribed as model inputs in the main SILVER UC framework. This approach would greatly simplify the computational requirements for cascaded hydro generators in the main UC stage, and could potentially mitigate the previously described model inconsistencies resulting from the current monthly optimization structure.

As described in the model limitations, the model uses an approximation method to represent the constraints imposed by EPAs on the BC Hydro system for biofuel and thermal generators. It would be valuable to improve the temporal resolution of must-take generation requirements for all generator types to fully represent the flexibility limitations enforced by IPP contracts on the BC Hydro System.

The outputs of many climate models project that hydrological inflow regimes in future decades will be significantly altered from their historical patterns [83]. As described in the model limitations, this study only accounts for three sets of inflow conditions, which are based on historical observations at BC Hydro facilities. However, these inflow conditions do not account for projected future changes resulting from warmer average temperatures, increased glacier and snowpack melt, and changes to annual seasonal precipitation distribution. Future work with the cascaded hydro model could assess the impact of forecasted changes to inflow regimes on the BC Hydro system using projections from various climate change models [83].

Other limitations of the model include the aggregated representation of transmission nodes, and aggregated run-of-river, biomass, and thermal generation resources. While this approach improves computation time and tractability, model accuracy could be improved by representing all generators, substations, and transmission lines individually. A final limitation of the model is the exclusion of energy trade with the US, which is a significant trading partner of British Columbia via the Western Interconnection [96]. Incorporating BC-US electricity trade into future model scenarios would provide a more accurate representation of the import-export demands placed on BC Hydro system.

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Appendix A - Cascaded Hydro Generator Characteristics

gen name	reservoir name	cascade group name	number	code	capacity (MW)	k-value (MW/m3/s) [64]	Mean annual inflow (m3/s)
LAJ - Lajoie	Downton Lake	Bridge	1	0	25	0.49	42
BRI - Bridge	Carpenter Lake	Bridge	2	0	478	3.15	52
SON - Seton Tailrace	Seton Lake	Bridge	3	0	48	0.4	17
JHT - John Hart	John Hart	Campbell	3	0	138	1.03	0
LAD - Ladore	Lower Campbell Lake	Campbell	2	0	47	0.28	10.2
STR - Strathcona	Upper Campbell Lake	Campbell	1	0	64	0.32	77.5
ARR - Arrow	Arrow Lakes	Mica/Columbia	3	0	185	0.45773	355
MIC - Mica	Kinbasket	Mica/Columbia	1	0	2746	1.49	577
REV - Revelstoke	Lake Revelstoke	Mica/Columbia	2	0	2480	1.15	236
WAL - Walter Hardman	Walter Hardman Headpond	Mica/Columbia	2	1	8	1.82	
WHA - Whatshan	Whatshan Lake	Mica/Columbia	2	1	50	1.6	9.3
SEM - Seven Mile	Seven Mile	Seven Mile	1	0	805	0.53	
WAN - Waneta	Waneta	Seven Mile	2	0	490	0.51	
GMS - GM Shrum	Williston	Peace	1	0	2730	1.43	1075
PEC - Peace Canyon	Dinosaur	Peace	2	0	694	0.34	9
STC - Site C	Site C	Peace	3	0	1100	0.52815	
ALL - Alouette	Alouette Lake	Stave	1	0	9	0.34	21
RUS - Ruskin Tailrace	Hayward Lake	Stave	3	0	105	0.28	7
STA - Stave River	Stave Lake	Stave	2	0	91	0.28	112
Aberfeldie	Aberfeldie	Aberfeldie Headpond	1	0	24	0.65	
Ash	Elsie Lake	Elsie	1	0	28	1.96	

Cheakamus	Daisy Lake	Daisy	1	0	158	2.52	
Clowhom	Clowhom Lake	Clowhom	1	0	33	0.41	
Wahleach	Jones Lake	Jones	1	0	65	4.84	
Jordan River	Jordan Diversion Reservoir	Elliott	1	0	170	2.58	

Contd.

gen name	**active storage (m3)**	**min storage (m3)**	**max storage (m3)**	**initial storage (m3)**	**min water discharge (m3/h)**
LAJ - Lajoie	7.06E+08	0.00E+00	7.06E+08	4.94E+08	20520
BRI - Bridge	1.01E+10	0.00E+00	1.01E+10	7.09E+09	0
SON - Seton Tailrace	1.48E+07	0.00E+00	14800000	10360000	18000
JHT - John Hart	2.04E+07	2.43E+07	4.47E+07	31290000	14400
LAD - Ladore	3.10E+08	6.40E+06	3.16E+08	2.21E+08	0
STR - Strathcona	879640000	1.58E+09	2.46E+09	1.72E+09	0
ARR - Arrow	8757708000	0.00E+00	8.76E+09	6.13E+09	0
MIC - Mica	8634360000	6.17E+09	1.48E+10	1.04E+10	0
REV - Revelstoke	1850220000	0.00E+00	1.85E+09	1.30E+09	509688
WAL - Walter Hardman	459350	2.41E+05	700000	490000	0.1
WHA - Whatshan	122000000	0	1.22E+08	85400000	0
SEM - Seven Mile	6.05E+07	0.00E+00	60500000	42350000	0
WAN - Waneta	6.05E+07	0.00E+00	60500000	42350000	0
GMS - GM Shrum	3.95E+10	0.00E+00	3.95E+10	2.76E+10	0
PEC - Peace Canyon	2.47E+07	0.00E+00	24690000	17283000	835920
STC - Site C	1.65E+08	2.15E+09	2.31E+09	1.62E+09	0

ALL - Alouette	1.94E+08	4.65E+06	1.99E+08	1.39E+08	10692
RUS - Ruskin Tailrace	4.20E+07	0.00E+00	42000000	29400000	0
STA - Stave River	4.70E+08	0.00E+00	4.70E+08	3.29E+08	0
Aberfeldie	510000	0.00E+00	510000	357000	3600
Ash	78000000	0.00E+00	78000000	54600000	12600
Cheakamus	5.50E+07	0.00E+00	5.50E+07	38500000	10800
Clowhom	4.66E+07	0.00E+00	4.66E+07	32585000	0
Wahleach	6.05E+07	0.00E+00	6.05E+07	42350000	504
Jordan River	1.82E+07	3.50E+06	21700000	15190000	900

Contd.

gen name	**max water discharge (m3/s)**	**max spill (m3/s)**	**Turbine type**	**Turbine Number**	**Mean Gen (GWh/yr)**
LAJ - Lajoie	50.6	127	Francis	1	
BRI - Bridge	160	585.6		8	
SON - Seton Tailrace	142.76	359.4	Francis	1	
JHT - John Hart	124	1238	Francis	6	775
LAD - Ladore	167.9	1266	Francis	2	230
STR - Strathcona	197.4	577	Francis	2	225
ARR - Arrow	530	10500		2	
MIC - Mica	1590	4290		6	
REV - Revelstoke	1325	7110		5	
WAL - Walter Hardman	4.33	11			37
WHA - Whatshan	34.4	278.6	Francis		121
SEM - Seven Mile	1473	2300		4	3200
WAN - Waneta	838	100000000		4	2680
GMS - GM Shrum	1968.02	9200		10	

PEC - Peace Canyon	1982.2	10280			
STC - Site C	792.967	10280		6	5100
ALL - Alouette	23.8	1257	Francis	1	
RUS - Ruskin Tailrace	348	4430	Francis	3	
STA - Stave River	296.5909	2100	Kaplan	2	
Aberfeldie	40	923	Francis	3	
Ash	15.01	1370	Francis	1	
Cheakamus	65	100000000			590
Clowhom	100	1153		1	
Wahleach	1.33E+01	10000000			245
Jordan River	30	2500			

Appendix B – Derivation of Initial Storage Levels for Cascaded Hydro Generators

Forecast end-of-month system storage levels for the BC Hydro system are obtained from [21]. This forecast indicates that reservoir storage levels reach peak capacity in August. Thus, the initial storage levels in the model are calculated from the end-of-December system storage as a percentage of the peak system storage in August. At the end of December the hydro system is at 70% of its peak storage capacity, therefore initial storage levels for each reservoir are assumed to be 70% of their maximum storage volume listed in Appendix A.

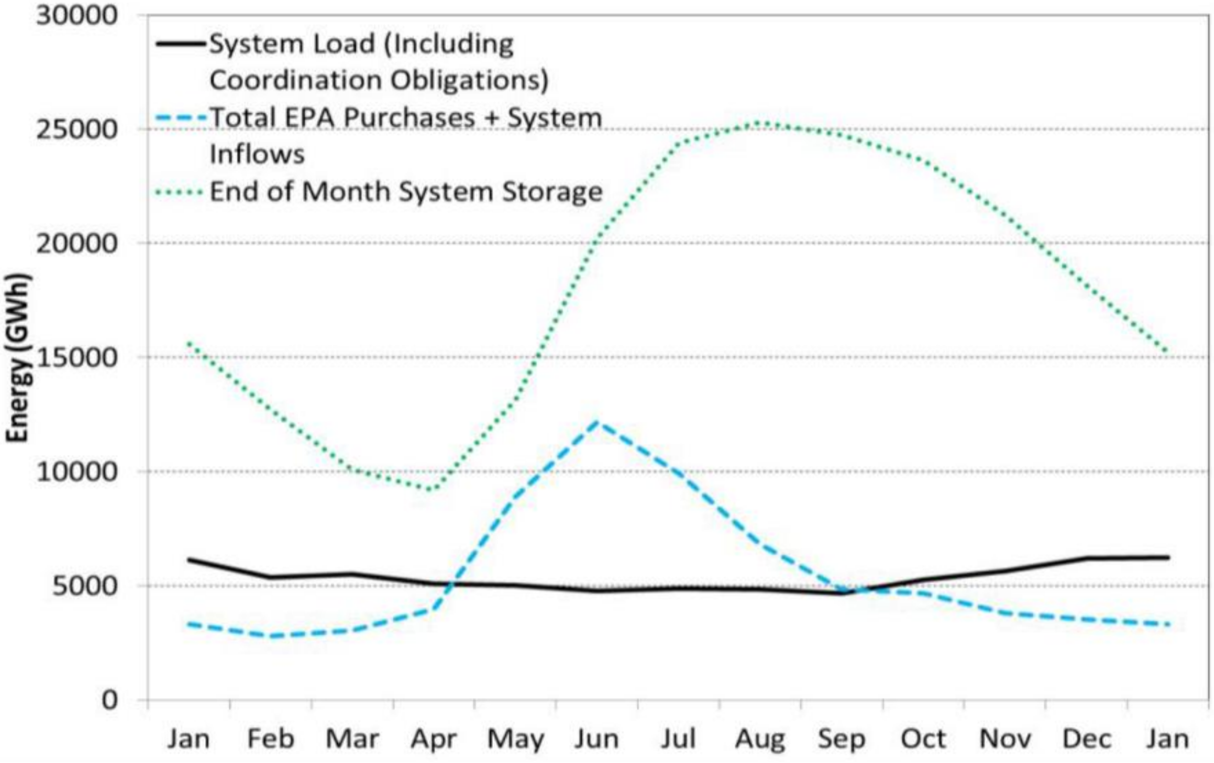

Figure 32: Monthly system storage levels, monthly system inflows plus EPA purchases, and system load forecast for 2018 [21].

Appendix C – Thermal and Biofuel IPP Generation

Generation from biofuel and thermal units is assumed to be a constant average value based on the IPP energy generation listed in the BC Hydro IPP supply list [20]. The model represents IPP thermal generators as one aggregated unit of 404MW capacity and four aggregated biofuel units each with a capacity of 222.5MW.

	Capacity (MW)	**Energy (MWh)**	**Average Power Generation per Facility (MW)**
Thermal	404	3204700	366
Biomass	890	3185700	91

Appendix D – Generator Costs and Characteristics

Cost and operational characteristics for each generator type in the model [97].

Generation Type	**Fixed O&M Cost (\$/MWh)**	**Variable O&M Cost (\$/MWh)**	**Startup/ Shutdown Cost (\$/MW$_{cap}$)**	**Ramp rate (MW/h per MW$_{cap}$)**	**Efficiency**	**Min up/down (hrs)**
Cascaded Hydro	5.00	1.46	0	0.25	0.90	<1hr
RoR Hydro	5.00	1.46	0	1	0.90	<1hr
NG-CC	1.68	2.67	66	0.25	0.55	8/4
Biomass	15.03	5.06	54	0.05	0.23	1
Wind	3.15	0	0	0	N/A*	<1hr
Solar	1.82	0	0	0	N/A*	<1hr

* See Section 2.2.1 for description of efficiency power curves.