

Implications of distributed solar PV on the flexibility of hydro-dominant power systems

by

McKenzie April Fowler
B.Sc.E., University of Massachusetts Lowell, 2016

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of the Requirements for the Degree of

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Abstract

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Solar photovoltaic power generation will play a dominant role as jurisdictions around the world move toward a future decarbonized economy. For decarbonised power systems that rely on variable renewable energy, flexibility will be one of the most valued services needed by the greater electricity system. This thesis presents the modelling approach and results of a production cost model of British Columbia to examine the implications of large penetrations of rooftop solar PV on the electricity system. The modeling approach focuses on accurate modelling representations of hydro system flexibility, with differentiation made between storage hydro and run-of-river hydro assets. Current literature gives little attention to the exact representation of hydro-dominant system flexibility as it is often assumed to be almost completely flexible.

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List of Acronyms and Symbols

Acronyms

AB	Alberta
AESO	Alberta Electric System Operator
BAU	Business as usual
BC	British Columbia
CA	Census agglomeration
CAISO	California Independent System Operator
CCGT	Combined cycle gas turbine
CCS	Carbon capture and sequestration
CLP	Climate Leadership Plan
CMA	Census metropolitan area
cumec	A unit of flow equal to 1 cubic meter of water per second
E_i	Energy of i
EIA	U.S. Energy Information Administration
FIT	Feed-in tariff
GW	Unit of power in gigawatts
GWh	Unit of energy in gigawatt-hours
IEA	International Energy Agency
IPP	Independent power producer
kW	Unit of power in kilowatts
MR	Must-run
MW	Unit of power in megawatts
OCGT	Open cycle gas turbine
OECD	Organisation for Economic Co-operation and Development
PV	Photovoltaic
RCS	Renewable City Strategy
RE	Renewable Energy
ROR	Run-of-river
RPS	Renewable portfolio standard
SCGT	Simple cycle gas turbine

VRE Variable renewable energy
WUP Water use plan

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Chapter 1 - Introduction

1.1 Motivation

The burning of coal, oil, and natural gas for electricity and heat is the largest source of global GHG emissions - roughly 25% of global greenhouse gas emissions [1]. To decarbonize the electricity and heating sectors, conventional heating systems must be electrified, and cleaner electricity generation sources must be utilized [2]. A prime candidate to aid in this task is the deployment of distributed solar photovoltaic (PV) electricity generation; a clean and modular technology.

Jurisdictions around the world, including most Canadian provinces, US states, and EU countries, focused on the increased deployment of both solar PV and wind have established various methods of increasing the deployment of renewable technologies. These include feed-in tariffs (FITs), tax incentives, subsidies, and renewable portfolio standards (RPS), and net metering, all which help to support the buildout of these technologies. FITs are a contract offering payment typically based on the cost of generation. Net metering is the option to send surplus energy generated back to the grid to receive electricity bill credits. Global solar PV electricity production has grown at an average annual rate of 43.3% from 1990 to 2016, greater than that of any other renewable technology, while wind electricity production has grown at a rate of 21.4%. Though solar PV and wind are growing at an impressive rate, hydroelectric generation continues to be the dominant source of renewable energy and was responsible for 54.2% of renewable electricity production in 2016. However, large hydro generation has seen the lowest growth rate of all renewable technologies as it has reached its capacity limit in most OECD countries [3].

In a future leaning increasingly toward higher variable renewable penetrations, with little ability for the buildout of additional of large hydro, it is expected that much of this energy will come from solar PV generation. Solar PV is an intermittent generator meaning it is dependent upon resource availability which changes over time. In certain circumstances, renewable energy including solar PV and hydro resources can also be thought of as generating ‘must-take’ energy. Must-take energy has no flexibility in generation due to various system constraints and must be taken by the grid. Variable renewable energy (VRE) generators, lacking generation flexibility, cause the system to look to other resources to balance the system.

In transitioning to highly renewable power systems, flexibility, or the ability of a power system to respond rapidly to change in load and variable generation, will be one of the most valued services needed by the greater electricity system. Common system flexibility management technologies include: flexible generators, such as open cycle (OCGT), combined cycle gas turbines (CCGT), and hydro; transmission expansion and battery storage; and demand-side resources, such as demand response and storage. Each of these valuable management technologies come with challenges. OCGT and CCGT are both CO₂ emitting technologies. Transmission expansion and battery storage are two of the most costly options used to increase system flexibility, meaning large-scale investments are needed in order to fully integrate more variable renewables via these technologies [4]. While demand response could play a large role in future flexibility of a fully electrified system, currently its full potential is unknown.

In many previous works, hydroelectric generators are often treated as more operationally flexible than is realistic [5]. Their flexibility is often overestimated in operational dispatch

models due to a variety of reasons including resource aggregation, lack of computational resources, modeling time required with complex models, or a lack of data [5]. Though thermal dominant power systems have undergone many variable renewable energy (VRE) integration studies [6]–[12], fewer studies have been conducted on the integration of distributed rooftop solar PV to a hydroelectric dominant system. Solar PV and other intermittent generation may see declining value as penetration levels increase due to resource and load timing along with the limited flexibility available to manage the variability. In hydro-dominated systems, one major limitation on system flexibility is the concept of minimum generation levels which are driven by generator ramp rates and minimum flow limits on hydro units [13], [14]. Minimum generation is the minimum level at which a generator must operate to satisfy all operational and regulatory constraints. This work aims to add depth to the study of minimum generation constrained hydro-dominant system operation when paired with large penetrations of solar PV. Specifically, solar PV penetration benefit limits are explored along with fossil fuel displacement potential. In conjunction, the transmission intertie with Alberta is studied to examine impacts of large solar PV penetrations on electricity trade between the provinces. Finally, the flexibility of the current hydro system is explored when combined with solar PV in terms of the nexus of solar curtailment versus spilled water.

1.2 Background

1.2.1 Solar PV

Installed global capacity of solar PV has seen recent growth from approximately 200 GW in 2015 to approximately 360 GW in 2017. Much of this growth can be attributed to policy support and falling module costs [15]. Capacity growth of solar PV from 2015 to 2017 can

be seen in Figure 1.1 for top installing countries [16]–[18]. Residential solar PV total system costs have decreased from between 47-78%, depending on location, between 2007 and 2017 [19].

Leaders in capacity growth, China and the United States, remain fossil fuel dominant regions. China’s electricity generation is dominated by coal [20] whereas the United States is dominated by natural gas [21]. Within the US, much of the solar PV capacity additions have taken place in California. By comparison, Canada currently plays a small role in solar PV capacity deployment, with a total installed capacity of approximately 2.9 GW in 2017.

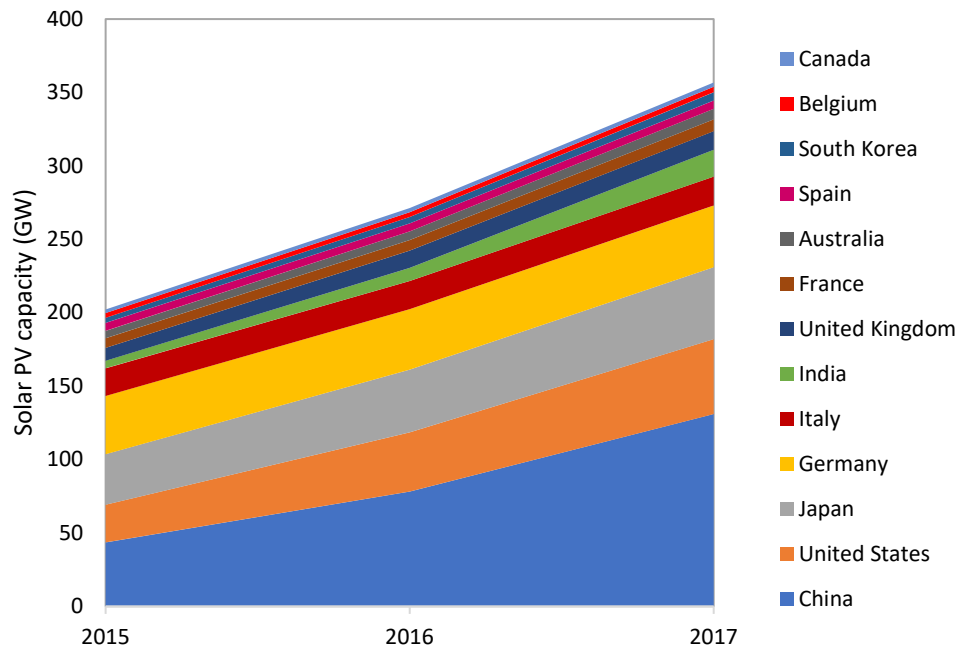


Figure 1.1: Stacked solar PV installed capacity by leading countries from 2015 to 2017. Data available from the IEA [16]–[18].

The California Independent System Operator (CAISO) has set a target of 60% renewable energy penetration by the year 2030 and 100% RE penetration by the year 2045 [22]. California has already seen a large buildout of utility scale solar PV due to their renewable

portfolio standard (RPS). Though CAISO does not count rooftop solar PV toward the RPS, California already has a sizable capacity of rooftop (distributed) solar PV, estimated at 6,605 MW in December 2017 [23], and has recently mandated that all new homes and multi-family residences must be built with solar PV installed [24] by 2020. California's ambitious renewable targets have created flexibility, over generation, and curtailment challenges for system operators. In California, the generation mix is predominantly natural gas fired, with a capacity penetration of approximately 54%, which is responsible for much of the flexibility that allows for high penetrations of solar PV [25].

California has struggled with daily operational challenges in the form of the net load 'duck curve', seen in Figure 1.2 [26]. This figure is referred to as the duck curve due to the 'belly' of the duck when solar PV is generating and feeding into the grid at midday.

The duck curve has created various new operating conditions for the system including short and steep ramps, overgeneration risk, and decreased frequency response. A ramp is a large change in electric load which happens over a short period of time, most often due to a change in VRE production, seen in Figure 1.2 between 4 PM and 9 PM. Other generation resources must be able to respond to this net load variation thus requiring them to be flexible in operation. Overgeneration is when more electricity is generated than demanded, creating an imbalance within the system which results in curtailment of electricity generation. Frequency response helps to maintain the balance between electric load and generation at every second and is responsible for management of any grid disturbances. The duck curve causes decreased frequency response due to less resources operating and available to adjust their generation output. To maintain reliability of this variable grid due

to the addition of solar PV, more flexible resource options are required to manage ramping and frequency response.

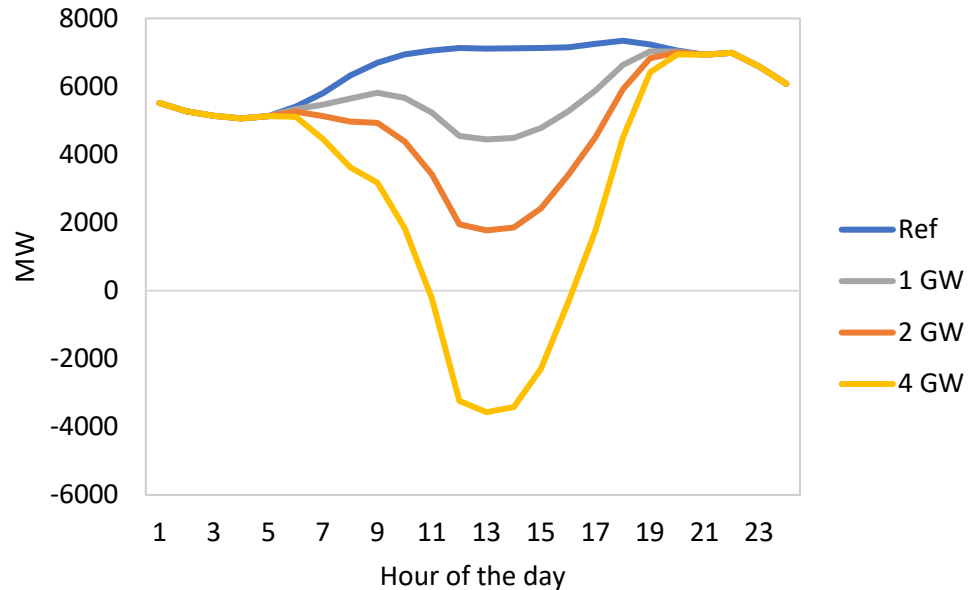


Figure 1.2: An example duck curve using British Columbia 2016 load data and simulated PVWatts solar data [27], [28].

1.2.2 VRE integration to electric systems

Previous studies of flexibility impacts of variable renewables have focused largely on thermal based systems [29]–[33]. A study of this type focused on finding certain time frames in which different impacts would occur [34]. These time categories are: Long-term (months-years), mid-term (hours-days), short-term (sub-hourly), super short-term (instantaneous). Long-term generation choices include a shift toward low-carbon baseload technologies, such as nuclear, geothermal, and carbon capture and sequestration (CCS), all which have limited operational flexibility. Mid-term impacts focus mostly on the deterioration of generation units due to increased cycling, or frequent start-ups, to manage VRE output. Unit deterioration can lead to higher maintenance costs and longer unit outage

periods. Short-term impacts focus on increased ramping requirements, increased reserve needs, and minimum output limits. Super short-term impacts include power and voltage control. Short-term impacts, modeled down to hour intervals, will be the focus of this study.

There have been few studies of renewable integration to hydro-based systems due to the complexity of the associated hydro system modelling. The completed studies have focused on wind integration [35], [36], using the hydro system to balance a greater area [37], and utilizing pumped hydro as a system balancing mechanism [38], [39].

Olauson et al. [40] investigate net load variability of VRE including solar PV, wind, wave, and tidal on the Nordic hydro dominant system where net load is the difference between electric load and VRE generation. The study found PV to be the most variable resource due to its seasonal and diurnal patterns. However, focusing on net load variability only, Olauson et al. fail to examine the realistic flexibility of the hydro system being modelled by not investigating the deployment of balancing plants and storage.

Huertas-Hernando et al. [41] reviewed hydro power flexibility for systems with large VRE penetrations and found that many studies using aggregated system models do not capture all aspects of hydro power plant operations, including geographically detailed descriptions of hydro power systems, cascading river systems, reservoirs, grid connection, and congestion which is needed to properly assess the real flexibility potential of hydro power and its storage value. The information noted as important in capturing these details are the correct marginal cost of hydro power generation and the incorporation of geographical details of hydro reservoirs, river coupling of power plants, and detailed representation of the transmission grid. Their study also found that the time scales important in studying hydro power variability, which is seasonal, are different from the

variability timescales of VRE, days to weeks, calling for models operating on multiple timescales. Recommendations for future model improvement included the representation of transmission constraints, hydrological details between major areas with hydro dominant systems, and treatment of VRE uncertainty.

Denholm et al. [14] recently studied the importance of quantifying minimum generation levels for the integration of VRE in CAISO. Varying levels of minimum generation and the associated affects on VRE curtailment were examined, as shown in Figure 1.3. As minimum generation levels increase, the curtailment of VRE increases showing the necessity of these studies to be considered for long term planning purposes. This case study is valuable yet is still focussed a thermal dominant system. Minimum generation levels will be a limitation on the continued deployment of VRE due to its infringement on total system flexibility.

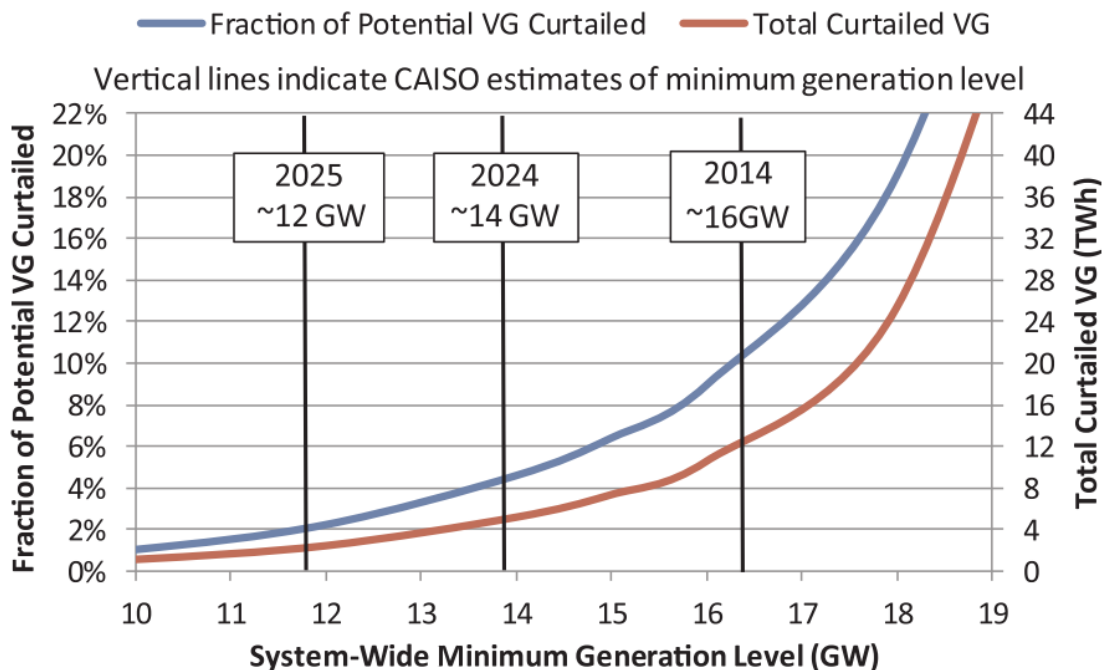


Figure 1.3: Curtailment as a function of assumed minimum generation in California with a 50% RPS. Figure from Denholm et al. [14]

The complexity of hydroelectric modelling is due to the host of constraints and variations of operation. These constraints include water flow and availability, variations of rainfall and snowmelt, the operational effects of cascading hydro networks, power purchase agreements, water use agreements, and operational constraints of individual hydro dam systems. These constraints contribute to a ‘minimum’ generation level for each storage hydro dam and run-of-river hydro dam, as described in more detail in Section 2.1.1. As large penetrations of VRE are integrated to hydro dominant systems, there is an increased need for the study of minimum generation and cascaded system operation.

This work aims to add depth to the study of minimum generation constrained hydro-dominant system operation when paired with large penetrations of solar PV. Specifically, solar PV penetration benefit limits are explored along with fossil fuel displacement potential. In conjunction, the transmission intertie with Alberta is studied to examine impacts of large solar PV penetrations on electricity trade between the provinces. Finally, the flexibility of the current hydro system is explored when combined with solar PV in terms of the nexus of solar curtailment versus spilled water.

1.2.3 Modeling hydropower system constraints in energy system models

The analysis of hydropower system operation can be conducted using several types of models, each with different strengths and weaknesses. These include production cost models (PCM), capacity expansion models, and watershed models [42]. Production cost models, examples of which are PLEXOS and PROMOD, are used to simulate hourly to sub-hourly operation of a given system to analyse the operation, emissions, and resource

adequacy as well as to analyze the value of new technology additions [43]. PCMs typically model both generation and transmission assets.

Capacity expansion models, examples of which include OSeMOSYS, MARKAL, and PLEXOS, simulate generation, and sometimes transmission, capacity investment given forecasts for future electricity load, fuel prices, technology costs and performance, as well as policy and regulation assumptions. Typically, these models are used in integrated resource planning to find the optimal generation capacity build necessary to meet load [44].

Watershed models, an example of which is RiverWare, are used to simulate the water system rather than the power system [45]. These model detailed flow rates, water availability, environmental impacts, as well as detailed evaporation, runoff, soil-water interactions, pollutants, and aquifers. These models are particularly adept at accurate modeling of the interactions between a cascaded system and water accounting over time [46].

Hydropower system modelling constraints fall into three different categories: Environmental, Operational, and Regulatory [5]. Environmentally, hydropower systems are dependent upon, and have a direct effect upon, utility scale storage water systems. As a result, constraints must be put on operation of these systems to ensure minimal effects on environment quality. Environmental constraints typically appear in modeling practices as minimum water release, reservoir level restrictions, and flow rate requirements. Prolonged water storage can also introduce thermal stratification of the reservoir, possibly effecting downstream species. Additionally, it is expected that climate change will have significant impacts on future hydrological conditions – potentially adding further constraints to the system [47], [48].

Operationally, hydropower is limited by the maximum and minimum amount of power than can be generated due to both turbine capability and reservoir water planning. Turbines have optimal ranges of operation and operation outside of these ranges can have negative impacts on performance and life expectancy [49]. Hydropower operation is impacted by water inflows, both from upstream generation, in cascaded systems, as well as natural inflows. This water must be managed over time periods, ranging from hours to years depending on the size of the reservoir. Head also influences how much power can be generated. Turbines also have limited ramp rates although this is usually not a limiting factor at the hourly scale [50].

Regulatory constraints, including water rights, use of water, flood control, power regulations, and power purchase agreements should also be considered when specifying hydro modeling constraints. These tend to be specific to the region in question, and therefore are not always applicable.

1.2.4. Canadian applications of production cost modelling

This work focuses on production cost modelling using western Canada as a case study. There have been other production cost modelling studies of Canadian provinces used to examine a variety of questions, mostly based in variable renewable energy integration. McPherson et al. [51] examine balancing strategies for high penetrations of VRE in Ontario, Canada. This study utilizes the SILVER electricity system production cost model to examine the implications of high CRE penetrations in a 100% renewable scenario including analysis on storage, demand response, electric vehicles, and transmission expansion. McPherson et al. show the operational differences between the balancing

options studied and the challenges faces by system planners in Ontario to integrate VRE in a nuclear dominant system.

Multiple studies based in thermal dominant Alberta, Canada have examined modeling of policy and regulatory changes in the integration of VRE. MacCormack et al. [52] developed a reduced model of the Alberta electric system to study how variations in market structure may impact system operation, electricity prices, and long-term supply reliability. Knight et al. [53] model dispatch operations of energy storage facilities in the Alberta wholesale electricity market. The operation and economic dispatch study focused on modeling of transmission connected energy storage systems using GAMS (General Algebraic Modeling System) to examine hourly dispatch over 260 weeks. The study examined models of energy arbitrage options for energy storage participation in Alberta's energy only market. Results showed that storage occurs at low demand periods and discharges at periods of high demand.

1.3 Scope and contributions

This work aims to add depth to the study of minimum generation constrained hydro-dominant system operation when paired with large penetrations of solar PV. Specifically, solar PV penetration benefit limits are explored along with fossil fuel displacement potential. In conjunction, the transmission intertie with Alberta is studied to examine impacts of large solar PV penetrations on electricity trade between the provinces. Finally, the flexibility of the current hydro system is explored when combined with solar PV in terms of the nexus of solar curtailment versus spilled water.

Existing literature examines the integration of VRE to typical thermal energy systems, however much less focus has been given to integration of VRE to hydro-dominant systems.

Of the literature that has investigated VRE in hydro-dominant systems [37], [41], [51], little attention has been given to the effects of distributed solar PV. Current research also often overestimates the flexibility of hydro-dominant systems [5], [14].

The main contributions of this work are:

1. This study shows that after a 50% penetration of all residential buildings, which is an approximate installed capacity of 5 GW, it is not clear that much system benefit is seen in terms of additional PV generation utilized by the grid.
2. The addition of large penetrations of solar PV have the ability to displace electricity generated via thermal resources such as natural gas and biomass.
3. The resource timing of solar PV does not align with the freshet which does little to reduce the dependence upon AB imports under normal load growth conditions. Imports are traditionally needed from AB predominantly during non-freshet months.
4. The modelling of minimum generation constraints in energy system production cost models is important to accurately predict flexibility constraints of future hydro-dominant systems. Without imposed minimum generation constraints and allowed flexible operation, a disparity is seen in modelled water energy spilled.
5. Allowing for flexible operation of ROR units results in no PV curtailment across all load growth scenarios by greatly increasing system flexibility. Annual water spill across all load growth scenarios is also reduced, resulting in higher energy balances, meaning less energy waste.
6. While the flexible operation of IPPs result in less water energy wasted, as well as better management of solar PV generation, it does not diminish the need for electricity trade with Alberta, especially the need for imports in non-freshet months.

7. Total BC energy self sufficiency, though possible under certain load growth conditions, would result in either large amounts of unserved energy in BC or in significant energy waste which could otherwise be sold via exports.

1.4 Overview

This thesis is structured as follows:

Chapter 2 presents details on the electricity systems of British Columbia and Alberta, Canada. Chapter 3 outlines the examination of distributed solar PV potential in BC and the modelling techniques used to examine BC's electricity system under various penetrations of distributed solar PV. Chapter 4 presents the results of study scenarios and discusses insights obtained. Chapter 5 details the conclusions of the study based on results obtained and presents a proposal for future work.

Chapter 2 - The Electricity System of Western Canada

2.1 British Columbia's electricity system

British Columbia (BC) currently meets over 90% of its electrical load with hydroelectric generation [55]. Typical winter peak loads occur between 4 to 8 PM on weeknights and range from 9,300 to 10,000 MW [56]. The record winter peak load is 10,126 MW recorded in January 2017 [44]. Average system load in 2017 was 7,304 MW¹. The typical daily load profile sees a demand peak in late afternoon for both summer and winter days. Typical historical summer and winter load profiles are shown in Figure 2.1 using 2017 BC load data [27].

The vast majority of installed generating capacity is large scale storage hydro. Total 2017 installed generation capacity share, including IPPs, is seen in Figure 2.2. Installed capacity values are detailed in Table A.1 of Appendix A. Cascaded systems, account for approximately 77% of the installed generation capacity in 2017 [57]. This is followed by run-of-river hydro at 11% of installed capacity, and relatively small installed capacities of gas fired thermal, wind, biomass, and other generation (includes solar, biogas, energy recovery generation, and municipal solid waste). Approximately 30% of total BC generating capacity is in the form of contracts with independent power producers (IPPs), including all run-of-river (ROR) hydro, wind, and 'other' capacity along with additional gas fired thermal and storage hydro capacity [58].

¹ Calculated from BC Hydro 2017 Balancing Authority Load data [27]

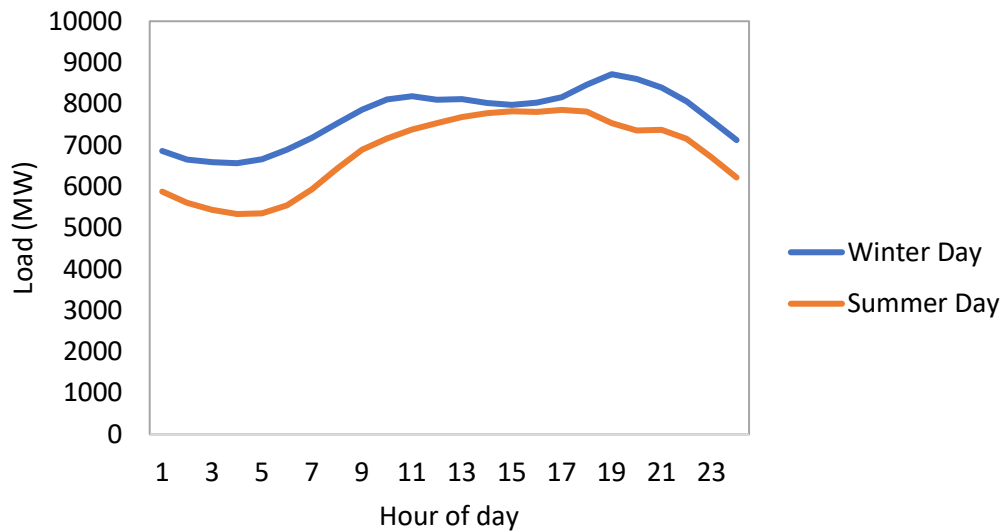


Figure 2.1: Typical summer and winter load days in British Columbia. Data available from BC Hydro

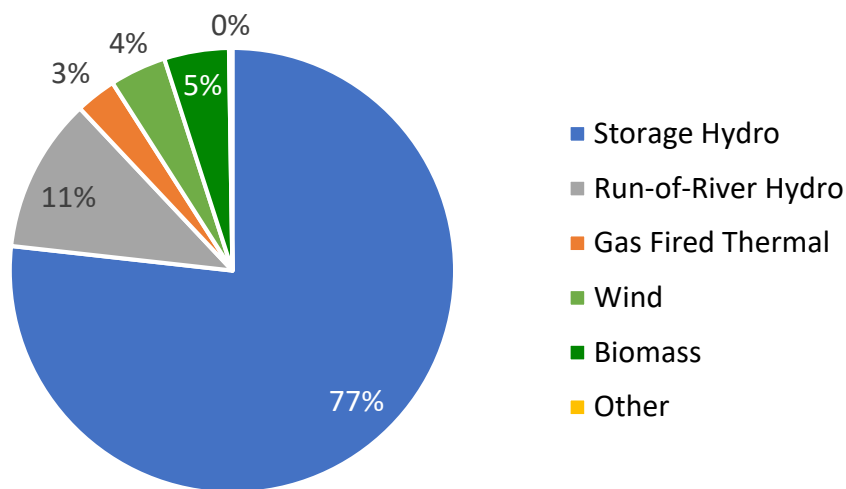


Figure 2.2: Installed generation capacity share by generation type in British Columbia, Canada as of 2017. Data available from BC Hydro [57], [58].

2.1.1 The freshet and minimum generation requirements

British Columbia has a hydro dominant electricity generation mixture with 13,155 MW capacity of storage hydro and 1,924 MW capacity of run-of-river hydro. These hydro resources, both storage hydro and run-of-river hydro, face seasonal energy oversupply during the *freshet*. The freshet occurs when snowmelt increases river flows in the spring months, typically between April and June. Approximately one-half of total annual river inflows in British Columbia occur during this period. Storage reservoirs are used to capture these inflows as possible. Coincidentally, spring and summer are also periods of lowest system electricity load.

All hydro generation plants face minimum generation requirements which limit their operational flexibility. These minimum generation requirements are due to a variety of reasons, including safety, regulatory and social obligations, present and future power load, hydrological conditions, minimum river flow conditions, etc. Average system minimum energy generation requirements for British Columbia from storage hydro and run-of-river hydro resources are detailed in Figure 2.3.

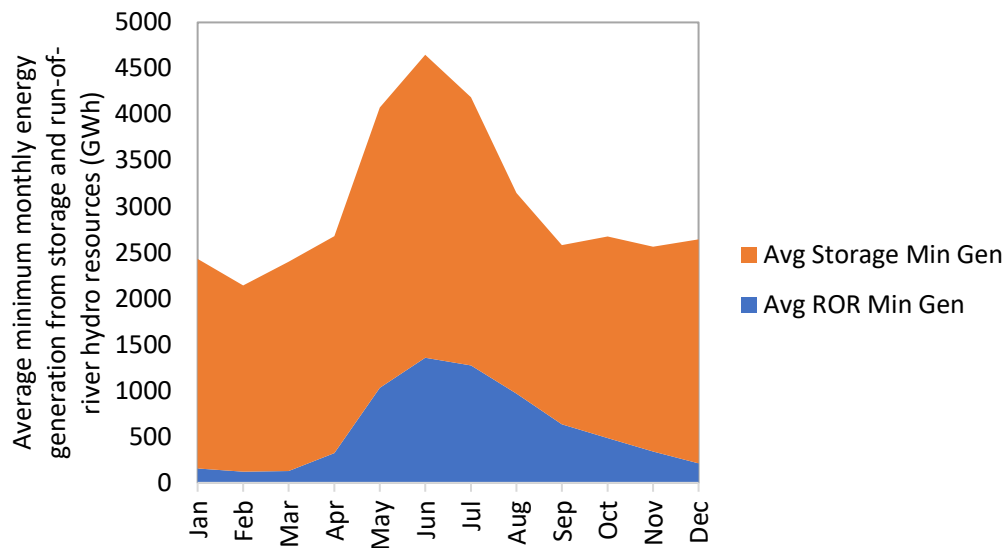


Figure 2.3: Stacked average minimum energy generation from storage hydro and run-of-river hydro resources over the course of a year in British Columbia, Canada [13]

The freshet typically spans the months of April to June as snow melt into waterways resulting in increased minimum generation levels. This occurs at a time of low electric load. The system sees lower hydro minimum generation requirements in the winter when load is higher and would more easily accommodate the increased constraints.

British Columbia has increased its portfolio of run-of-river hydro assets to meet its energy planning criteria under expected load growth. Addition of these generation assets has led to an increase in minimum generation during the freshet of approximately 3000 GWh, between 2006 to 2018, with little to no increase in freshet load [13]. Forecast IPP generation, due to run-of-river resource additions, is compared to electric load forecast in Figure 2.4.

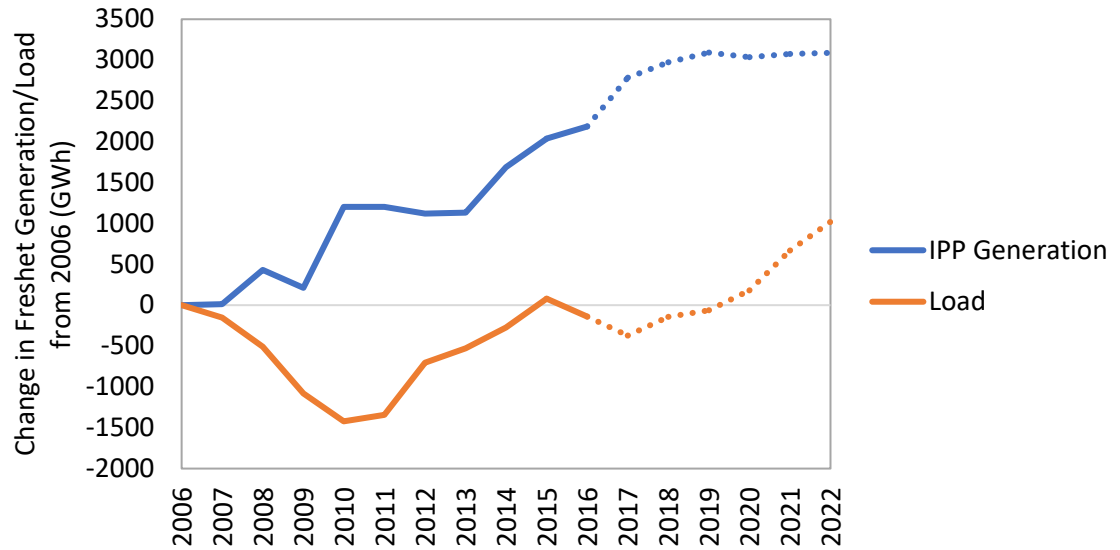


Figure 2.4: Change in May-July freshet energy volumes from 2006 for EPA purchases and BC Hydro integrated system May-July freshet load. Historic data in solid lines and forecasted data in dashed lines. Forecasted IPP generation is net of IPP energy that can be economically turned down during the freshet. This represents all must-take IPP energy and economic IPP energy [13].

Figure 2.4 shows minimum generation compared to load for 2006 and forecasted for 2018. Examining this figure, we can see stress events in 2018 freshet months due to the increasing amount of minimum generation energy. Load has not changed substantially between 2006 and 2018 forecasts; however, minimum generation levels have increased due to the addition of ROR IPPs. These stress events will be exacerbated by the uncertainty around additions of solar PV; either commercially or residentially.

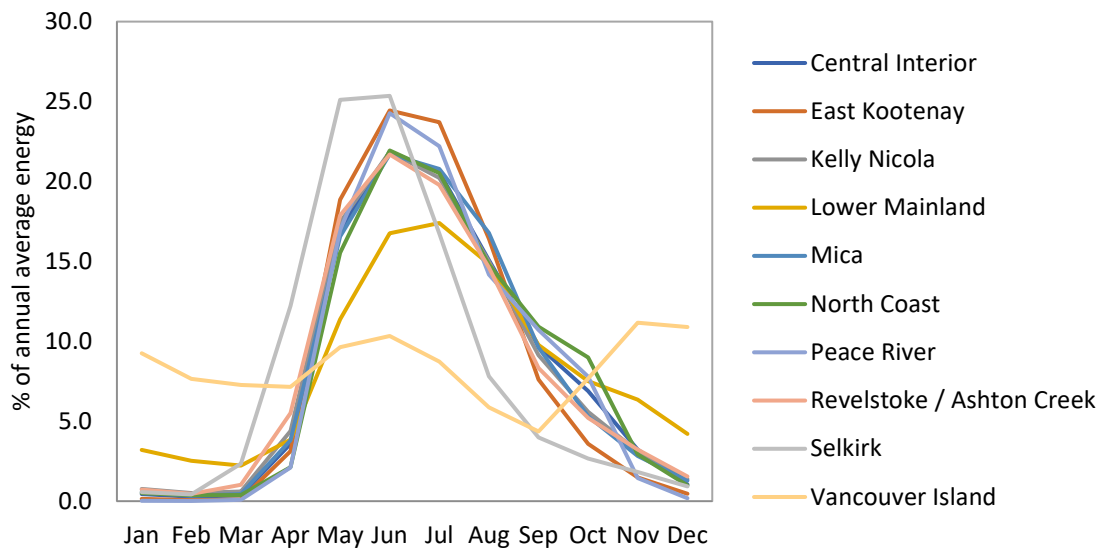


Figure 2.5: Monthly energy profiles of run-of-river hydro as a percentage of annual average energy potential at various locations in British Columbia. Data from BC Hydro [59].

Figure 2.5 shows the expected generation profiles of run-of-river hydro as a percentage of the total annual average energy from BC Hydro's transmission planning regions. While most locational profiles follow the freshet, Vancouver Island sees a flatter profile with a winter peak. River systems on Vancouver Island are driven more by year-long rainfall than by freshet snow melt, with the heavy rain season occurring mainly in fall and winter [60].

2.1.2 The future of British Columbia's electricity system

BC's Integrated Resource Plan shows growing load with little ability to increase capacity of hydro reservoir storage and generation [61]. Any increase in hydro generation will likely be from run-of-river plants, thus further increasing minimum generation levels and limiting the flexibility of the overall hydro system. Generation capacity by type for the year 2030 is shown as a merit order curve in Figure 2.6, which here uses variable operation and maintenance values to determine merit order. Additional figures and tables detailing

expected generation capacity by type for the year 2030 are shown in Appendix A as Figure A.1 and Table A.2. In the model, installed generating capacity in BC for the year 2030 is assumed to stay constant after the addition of the Site C Dam project. IPP contracts assumed to stay constant after the addition of the Site C Dam project. IPP contracts assumed to stay constant after 2018 additions. The ‘other’ generation category is not modelled as it accounts for less than 1% of IPP contract installed capacity.

Historic load data for British Columbia was obtained from BC Hydro [62]. BC load is winter peaking due to the high load for winter space heating. Historic electricity load is scaled to 2030 load using the BC Hydro Electric Load Forecast future peak load data and shown in Figure 2.7 [63].

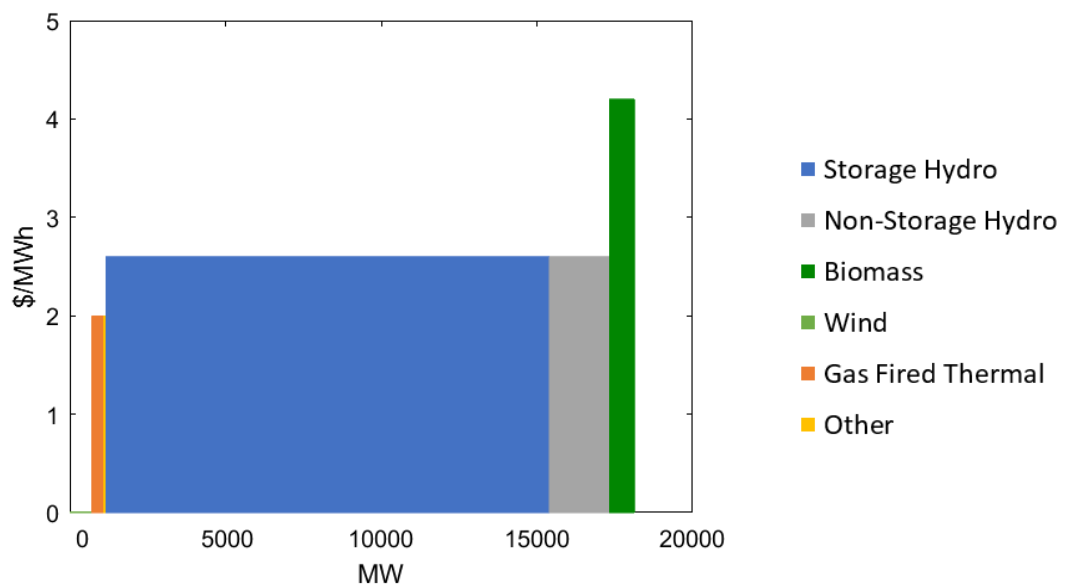


Figure 2.6: Merit order curve for British Columbia in 2030

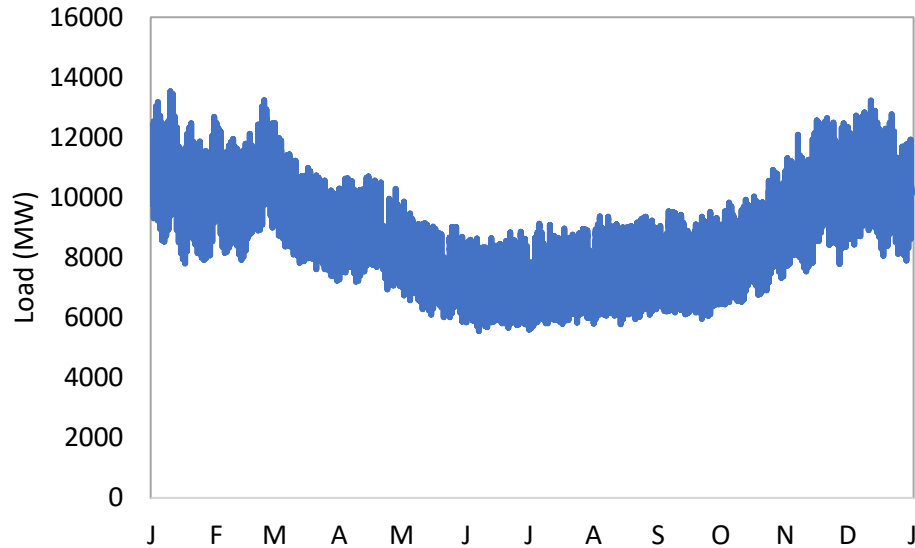


Figure 2.7: BC load data scaled to 2030 values

Additionally, British Columbia has mandated an energy self-sufficiency target, meaning the system may not rely on other jurisdictions for any energy needs [64]. This adds additional complexity and opportunity into the system.

2.1.3 Energy planning in British Columbia

British Columbia's recent energy and policy actions include the 2007 BC Energy Plan, the 2010 Clean Energy Act, the 2013 BC Integrated Resource Plan, and the 2016 BC Climate Leadership plan, all of which are outlined in this section. The BC Energy Plan, released in 2007 [64], created policy actions to shape the future of the BC energy system. The most important aspects of the plan in application to this thesis, are:

1. All new electricity generation projects will have zero net greenhouse gas (GHG) emissions
2. Clean or renewable electricity must continue to account for at least 90% of total generation

3. No nuclear power
4. Achieve electricity self-sufficiency by 2016

As of 2018, BC typically meets the self-sufficiency target though it fluctuates between being a net importer and net exporter of electricity depending on the yearly conditions [65].

The 2010 Clean Energy Act requires generating at least 93% of all electricity from clean or renewable sources in BC, ensuring rates remain among the most competitive of those charged by public utilities in North America, meeting at least 66% of the expected increase in electricity load through conservation and efficiency by 2020, using clean or renewable resources to help achieve provincial GHG reduction targets, fostering the development of First Nations and rural communities through the use and development of clean or renewable resources, as well as an updated Integrated Resource Plan at least every 5 years [66]. The subsequent 2013 Integrated Resource Plan, from BC Hydro, sets out the long-term plan to meet the Clean Energy Act goals. This includes analysis of the load-resource balance in BC, electric load forecasts, future resource options analysis, and resource planning framework and outcomes [61].

In 2016, British Columbia instituted the Climate Leadership Plan (CLP) which sets a target for all new buildings to be net-zero emissions ready by 2032 [67]. Additionally, the City of Vancouver's Renewable City Strategy (RCS) mandates that all new buildings must reach net zero emissions by 2030, including energy use for heat and electricity. The RCS also mandates that all energy consumed in Vancouver must come from renewable sources by 2050, including the energy to heat buildings [68].

The result is that BC energy plans will likely lead to widespread electrification of building heating systems and increased demand for on-site renewable electrical energy. The decreasing capital cost and modular nature of solar photovoltaics (PV) makes it a prime candidate to meet this increasing demand [69].

2.2 Alberta's electricity system

Alberta's electricity mixture consists predominantly of coal and natural gas fired generation. In 2015, Alberta emitted 38% of Canada's total GHG emission, the highest of any province [70]. Alberta's 2017 generation capacity distribution is shown in Figure 2.8 and generation capacity detailed in Table 2.1. Average electricity load in AB has seen consistent growth from 2008 to 2017 with a record peak load of 11,473 MW in 2017 and an average system load of 7,220 MW [71].

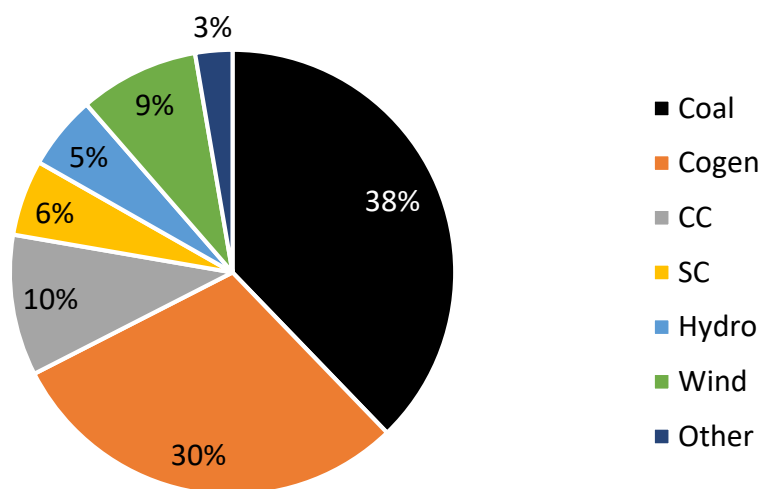


Figure 2.8: Installed generation capacity share by generation type in Alberta, Canada as of 2017.

Data available from the Alberta Electric System Operator [71].

Table 2.1: Installed generation capacity (MW) in Alberta, Canada as of 2017. Data available from the Alberta Electric System Operator [71].

Generation Type	2017 Installed Capacity (MW)
Coal Fired	6,283
Cogeneration	4,936
Combined Cycle Gas Turbine	1,703
Simple Cycle Gas Turbine	916
Hydro	894
Wind	1,445
Other	449

Currently, BC and AB benefit from electricity trade via an intertie with an approximate transfer capability of 1000 MW from AB to BC, and 800 MW from BC to AB [72]. Historic annual intertie energy transfers from 2013 to 2017 are shown in Table 2.2. Alberta also has interties to Saskatchewan with a flow of approximately 153 MW and Montana with a flow of approximately 300 MW [73]. Due to their smaller flow capacity and to maintain manageable model complexity, these other interconnections are not modelled in this thesis.

Table 2.2: Historic annual energy transfers between BC and AB (GWh). Data available from AESO [71].

Year	Imports from BC (GWh)	Exports to BC (GWh)	Net Imports from BC (GWh)
2013	1,902	223	1,679
2014	1,311	384	926
2015	732	460	273
2016	283	556	-273
2017	1,038	580	459

2.2.1 The future of Alberta's electricity system

Alberta's 2017 Long Term Outlook calls for 6445 MW of wind capacity and 700 MW of solar capacity by 2032 [74]. Assuming this generation capacity to be in place by the year 2030 the capacity share is presented as a merit order curve in Figure 2.9. Additional figures and tables detailing assumed installed capacity are included in Appendix A as Figure A.2 and Table A.3.

As the focus of the study is BC's electricity system with some attention given to the intertie between AB and BC, AB's system has been simplified and modeled as one node. All capacity planned for 2030 as outlined in the 2017 Long Term Outlook is aggregated as generator types and included in the model [74]. The intertie between AB and BC is modeled to represent an approximate transfer capability of 1000 MW from AB to BC, and 800 MW from BC to AB [72].

Historical load data for Alberta was obtained from the Alberta Electric System Operator (AESO) [75]. The historical load is scaled to 2030 load using the AESO 2017 Long Term Outlook and shown in Figure 2.10 [74]. Alberta load is winter peaking but overall is flatter than that of its neighbor, British Columbia. This is due to the high industrial activity responsible for a large portion of load in Alberta.

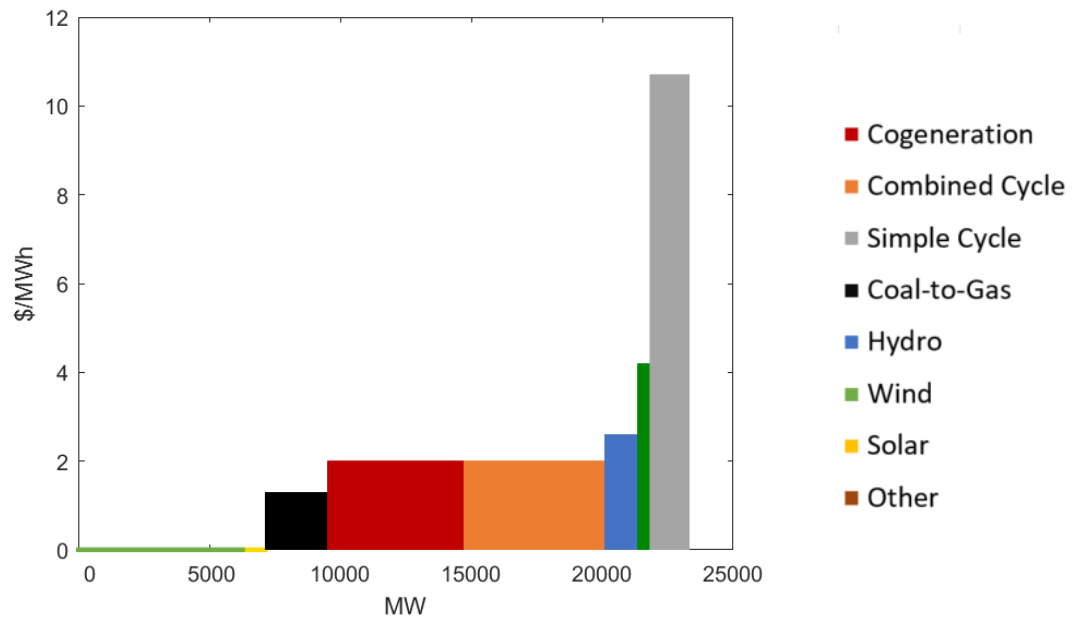


Figure 2.9: Merit order curve for Alberta in 2030

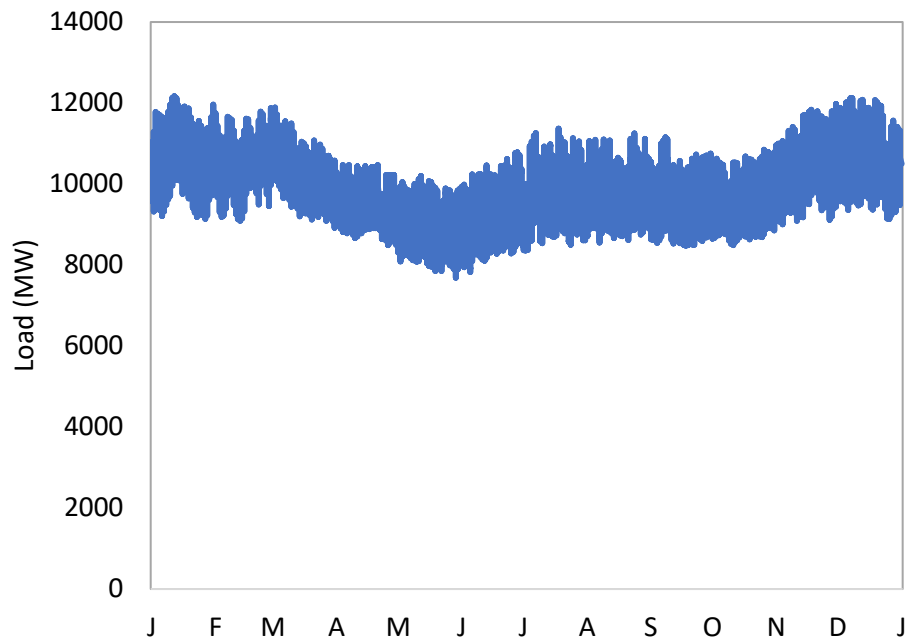


Figure 2.10: Alberta load data scaled to 2030

2.2.2 Energy planning in Alberta

To combat their high carbon intensity, the province of Alberta (AB) announced their Climate Leadership Plan in 2015. The plan includes a carbon levy, the phase out of coal-fired generation by 2030, capping oil sands emissions, reducing emissions, and the development of a generation portfolio that will provide 30% of Alberta's electricity via renewables by 2030. Alberta's 2017 Long Term Outlook calls for 6445 MW of wind capacity and 700 MW of solar capacity by 2032 [74].

Chapter 3 - Methods

3.1 Introduction

This chapter details the methodology used to create a production cost model of British Columbia's electricity system with interconnection to Alberta. The nodal architecture of the model is described along with the methods applied to model various generation types including: storage hydro, run-of-river hydro, and distributed solar PV. The optimization scheduling of the production cost model is described in detail. Generator input assumptions are shown followed by limitations of the model. The chapter concludes with a discussion of the scenarios presented for study.

3.2 Model architecture

To accurately represent solar and hydro resources, spatial and temporal resolution must be captured as well as the ability to model both generation and transmission assets. This study uses the PLEXOS® Integrated Energy Model, an industry standard software capable of both long term and short term modelling applications [43], [76], [77]. PLEXOS is well suited to represent the geographic resource and load distribution of British Columbia.

This thesis uses the short-term simulation application of PLEXOS which is a production cost planning tool with an objection function of total system cost minimization. PLEXOS is a mixed-integer linear programming power system model that simulates hourly power generation over the course of the year 2030. The year 2030 is selected for study to align with proposed climate plan targets set in the province [67].

3.2.1 Nodal depiction of the PLEXOS model

A PLEXOS model was built to represent BC electricity generation and transmission. A spatially explicit map of the model is shown in Figure 3.1 with node definitions and generation types given in Table 3.1. The region of focus, British Columbia, is modelled as 11 nodes, and Alberta is modeled as a single node. All major hydroelectric generators, storage reservoirs, and waterways are modeled as well as all thermal and VR generation.



Figure 3.1: Map of British Columbia PLEXOS model showing nodes, transmission lines and intertie Alberta (AB). Original map under creative commons.

In total, the model includes 28 hydro generation dams, 26 hydro storage reservoirs, eight aggregated run-of-river locations, four aggregated biomass generating units, one gas plant, and one wind farm in British Columbia. All Alberta generation is aggregated as representative generation types and applied to a single node to simulate the limited energy trade between regions. The interconnection between British Columbia and Alberta is always available to import and export within the defined limits of 1000 MW import to BC and 800 MW export to AB.

Load is split between nodes by examining forecast residential, commercial, and industrial loads from the BC Hydro Electric Load Forecast and using this to create *load participation factors* [63]. A load participation factor is a percentage of total system load assigned to be met at the node in question. Load participation factors are assigned to each node, which gives the load split shown in Figure 3.2. Load participation factors are listed in Table 3.1. As Alberta is a single node, its load participation factor is unity.

Table 3.1: PLEXOS node definitions, generation types, and load participation factors modelled at node

Node acronym	Node definition	Generation types at node	Load Participation Factor
NC	North Coast	ROR hydro	0.08
VI	Vancouver Island	Storage hydro, ROR hydro, Cogeneration, Wind, Biomass	0.1
LM	Lower Mainland	Storage hydro, ROR hydro, Biomass	0.42
KL	Kelly Lake	Storage hydro, Biomass	0.06
CI	Central Interior	ROR hydro, Biomass	0.06
PR	Peace River	Storage hydro	0.02
NI	Nicola	No generation at node	0.11
AC	Ashton Creek	Storage hydro, ROR hydro	0.03
MI	Mica	Storage hydro, ROR hydro	0.02
SL	Selkirk	Storage hydro, ROR hydro	0.05
EK	East Kootenay	Storage hydro, ROR hydro	0.05
AB	Alberta	CCGT, SCGT, Cogen, Coal to Gas, Wind, PV, Small hydro	1

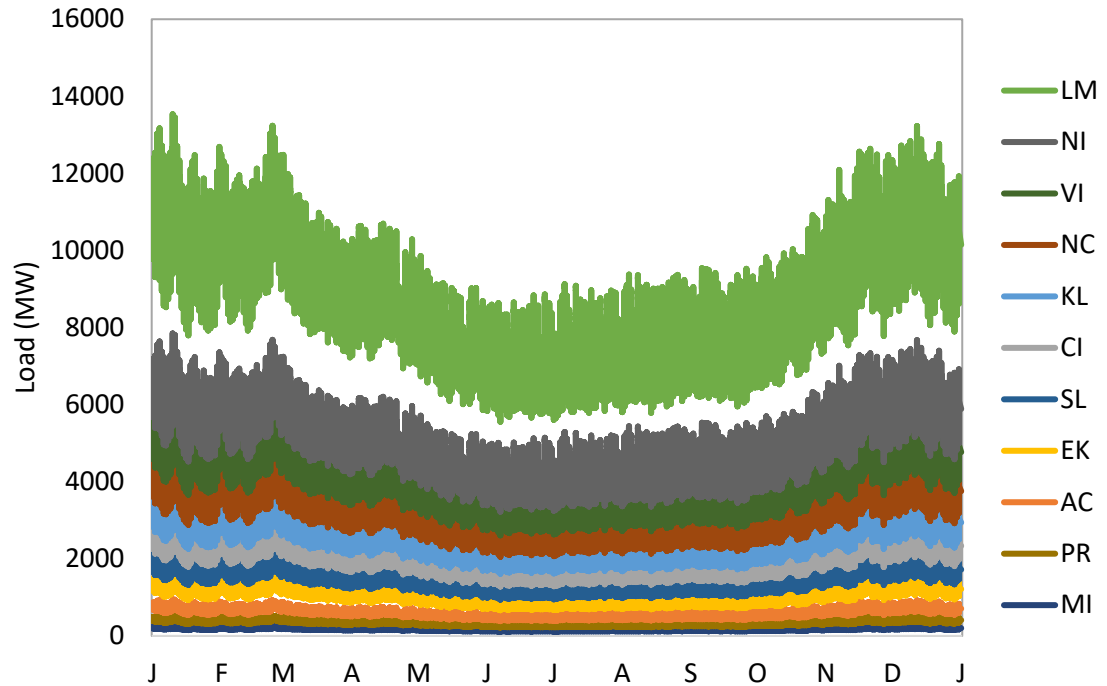


Figure 3.2: Stacked 2030 scaled BC load split between nodes to represent approximate load share based on historic transmission planning region load [62]. LM (Lower Mainland), NI (Nicola), VI (Vancouver Island), NC (North Coast), KL (Kelly Lake), CI (Central Interior), SL (Selkirk), EK (East Kootenay), AC (Ashton Creek), PR (Peace River), MI (Mica).

3.2.2 Hydrological year data

Historical hydrological inflows for each hydro facility are obtained from BC Hydro Water Use Plans (WUP) [78]. The WUPs detail historic inflows to reservoir and dam systems for minimum, mean, and maximum monthly inflows in cumec, a unit of flow equal to $1 \text{ m}^3/\text{s}$. It is vital to perform sensitivity analysis for each scenario with min, mean, and max hydrological year information.

3.3 Storage hydro modelling

In the model, cascaded systems are connected so that generator release and spill release from each reservoir travels downstream to the following dam. For example, and as shown

in Figure 3.3, on the Columbia River system the Kinbasket Reservoir and associated Mica generating station flow into Revelstoke Reservoir and the associated Revelstoke dam, which then flows into the Arrow Lake project. Arrow Lake also receives flows from the Whatshan project and the Walter Hardman project. The head system, Mica, is located at the MI node with all other systems in the cascade located at the AC node.

Storage reservoir bounds use a 'level' approach where each reservoir has prescribed maximum and minimum levels. The level approach approximates a total reservoir size, defined by its level and area, as well as operational constraints (levels within which the reservoir may operate). The reservoirs are tied to historic reservoir natural inflows for max, mean, and min hydrological years. This monthly average data is converted to hourly flow profiles in cumec (m^3/sec) and modeled for every reservoir. To maintain sustainable operation, final and initial storage levels are constrained to be equal at the start of the year and the end of the year, where flows-in-transit recycle back to the beginning of the optimization.

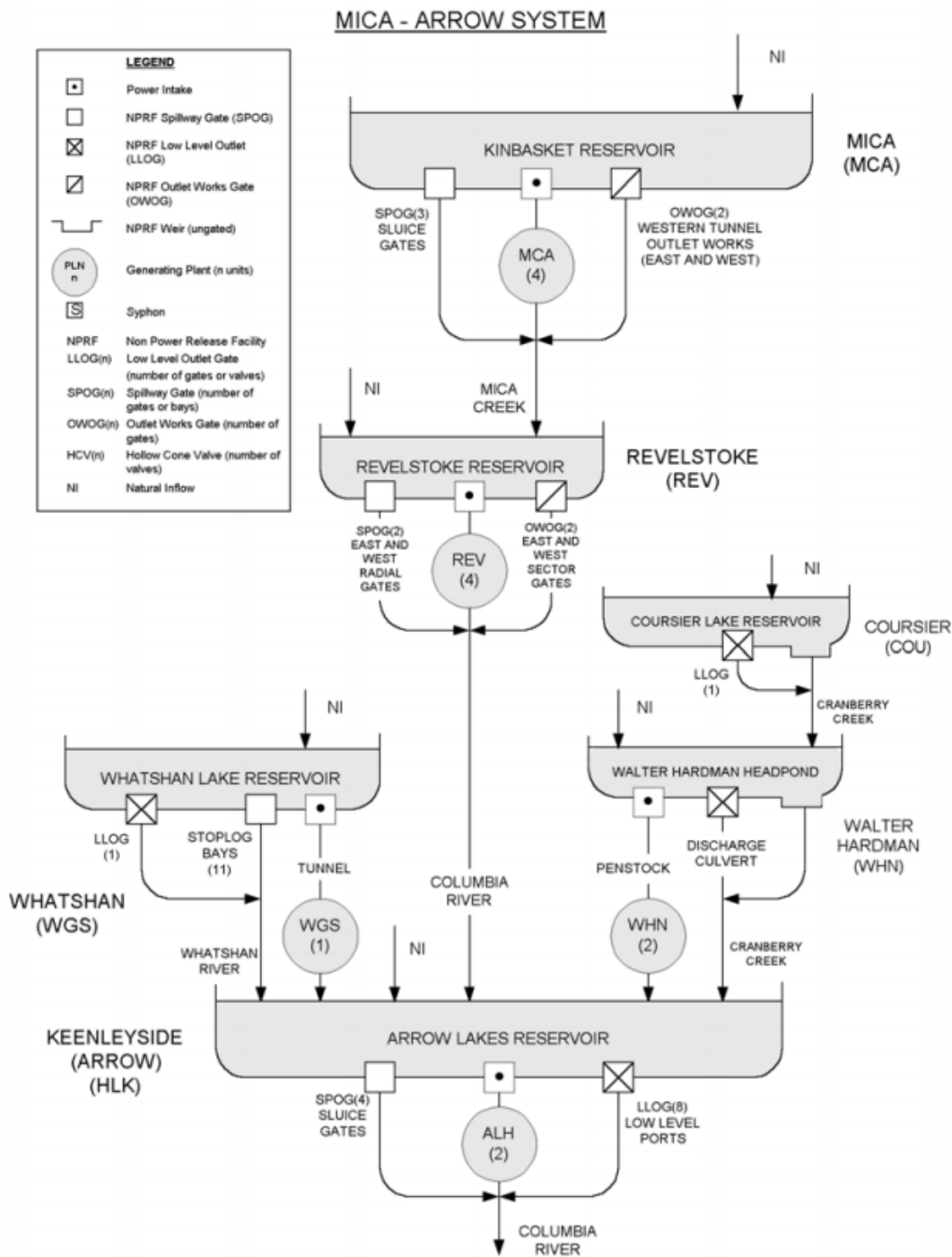


Figure 3.3: Schematic of the Columbia River system. Figure obtained from the BC Hydro Columbia River Water Use Plan [79].

The publicly available historic monthly minimum generation data is defined only for the aggregated storage hydro system [13], the total average monthly minimum generation for storage hydro is distributed to dominant dams. These selected dams have large associated reservoirs and/or dams with high natural inflows. Minimum generation for various hydro dams is set by creating generators with defined generation in each month of the year corresponding to the available data. These minimum values are distributed over selected units according to generator capacity.

Beyond the minimum generation levels and operational capacity constraints, hydro generation is flexible in operation. Details of the selected dams are detailed in Table 3.2. Calculated minimum generation profiles for selected storage hydro dams can /be seen in Figure 3.4.

Table 3.2: Information on selected storage hydro generating stations for associated minimum generation profiles

Generating Station Abbreviation	Generating Station Name	Associated River System	Associated Reservoir	Dam Nodal Location	Installed Capacity (MW)
LAJ	La Joie	Bridge	Downton Reservoir	KL	25
BRI	Bridge River 1 & 2	Bridge	Carpenter Reservoir	KL	478
STR	Strathcona	Campbell	Buttle and Upper Campbell Lake	VI	64
SEV	Seven Mile	Pend d'Oreille	Seven Mile Reservoir	SL	805
ALL	Alouette	Stave	Alouette Lake	LM	9
STA	Stave Falls	Stave	Stave Reservoir	LM	91
GMS	G.M. Shrum	Peace	Williston	PR	2,730
STC	Site C	Peace	Site C Reservoir	PR	1,100

MIC	Mica	Mica Creek / Columbia	Kinbasket Reservoir	MI	2,746
REV	Revelstoke	Mica Creek / Columbia	Revelstoke Reservoir	AC	2,980

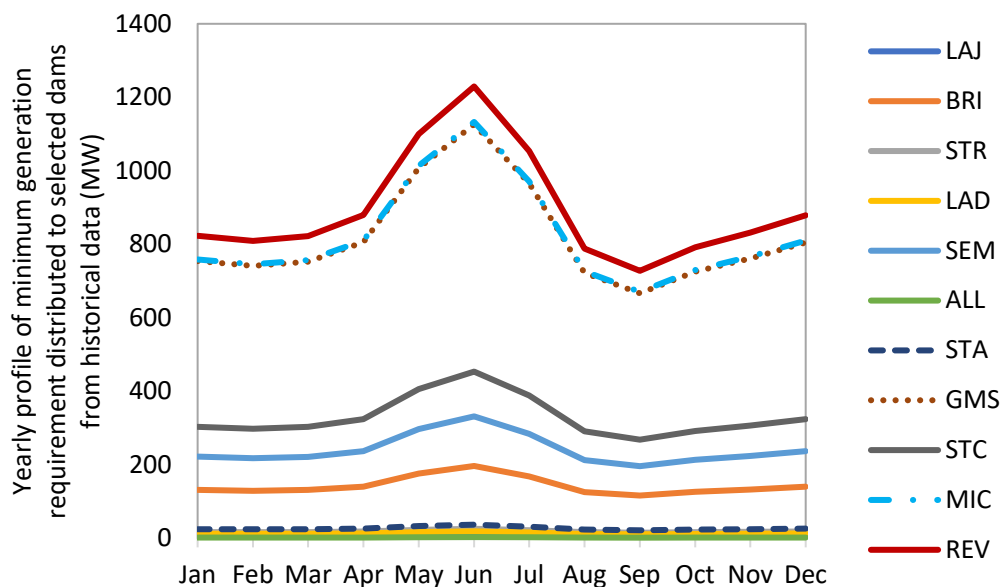


Figure 3.4: Minimum generation profile for selected storage hydro generating stations based on historical aggregated system minimum generation data

Model validation was performed to compare 2016 forecast energy production for five major generating facilities [80] to modeled 2030 energy production for a business as usual mean hydrological year scenario. Historical generation data is not readily available and therefore forecast data is used for validation purposes. Validation values are detailed in Table 3.3. Differences in energy production can be attributed to a variety of circumstances and assumptions including hydrological year and the model limitations discussed in Section 3.8.

Table 3.3: Model validation to compare 2016 forecast energy production with 2030 business as usual energy production for a mean hydrological year [80]

Facility	2016 Forecast Energy Production (GWh)	2030 BAU Energy Production (GWh)
GM Shrum	14,300	13,548
Revelstoke	7,900	8,284
Mica	6,900	7,600
Peace Canyon	3,500	3,145
Seven Mile	3,400	3,175

3.4 Run-of-river hydro modelling

The installed capacities, energy production and locations of run-of-river hydro generation units in BC are taken from [58]. This is compared with the regional monthly energy profile for small hydro potential from BC Hydro showing potential of percent of annual average energy in each month of the year in BC Hydro regions [59]. These are combined to give an approximate minimum generation profile for run-of-river hydro locations over the course of the year. Due to the lack of spatially explicit information as well as the small nameplate capacity of most ROR units, ROR systems are aggregated to represent nodes using this information. The final calculated generation profiles for aggregated run-of-river hydro can be seen in Figure 3.5. Most ROR profiles follow the normal freshet profile with snow melt occurring from April through June, causing increased river flows and an increase in minimum generation levels. Vancouver Island has a minimum generation profile driven more by year-round rainfall due to the temperate climate and geography which causes it to maintain a relatively flat level.

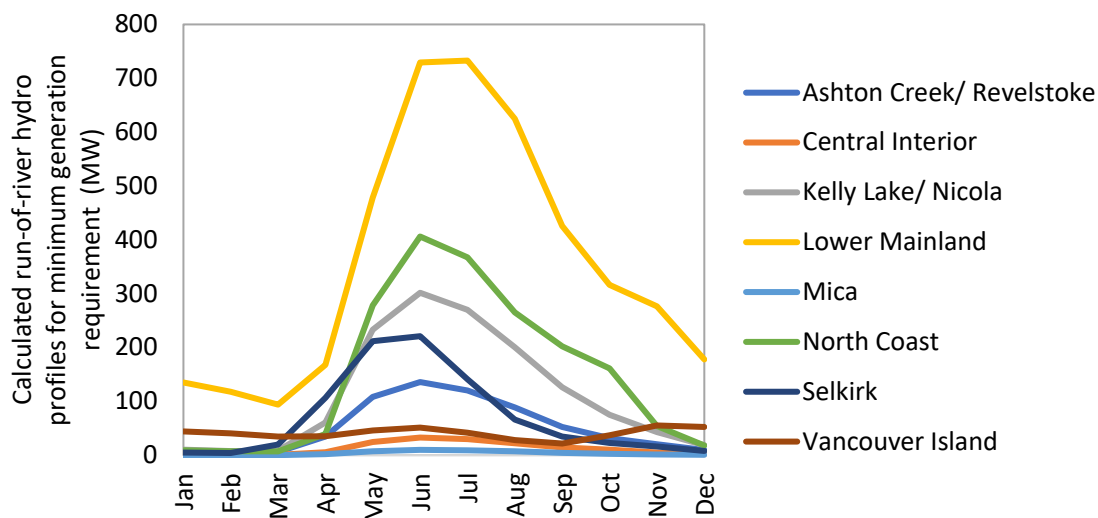


Figure 3.5: Calculated run-of-river hydro minimum generation profiles over the course of a year

As a result of policy agreements, run-of-river generation is designated as must-take energy, therefore necessitating these minimum generation profiles. This thesis examines scenarios where ROR generation is either must-take, or when it is taken as cost effective. The latter scenario reflects the policy option which could be available upon renegotiated renewal of IPP contracts when made available.

3.5 Distributed solar PV modelling

The spatial distribution of solar PV is determined by examining Statistics Canada 2016 Census of Population Program data [81]. Given that much of the Canadian population resides around major cities, this study examines four major census metropolitan areas (CMAs) in British Columbia that may see future buildouts of solar PV [81]. The CMAs selected for study are Vancouver, Victoria, Kelowna, and Prince George². The census data

² Prince George does not qualify as a CMA, and therefore CA (Census Agglomeration) data is used for study

reports the number of total occupied private dwellings and reports this total subdivided by dwelling type.

BC has a net metering program for all clean or renewable grid connected systems with a nameplate capacity of less than 100 kW [82]. For reference, the average residential solar PV system size in the United States is 5 kW [83]. As this average system size falls within the net metering program size range, we use this installation size for our study.

This thesis focuses on all occupied private dwellings including single-detached homes, apartment buildings, row houses, and semi-detached homes, as these would be most likely to see residential solar PV. The census data examined in this study is detailed in Table 3.4. Studying private dwellings in the 4 selected cities accounts for approximately 66% of all private residential dwellings in British Columbia. In this study, *penetration* refers to the number of total homes which have a 5 kW rooftop solar panel installed. For example, the 25% PV penetration scenario means that 25% of all private dwellings in the four major metropolitan BC cities have rooftop solar panels.

Table 3.4: Statistics Canada 2016 Census of Population Program data for study selected cities reported as total number of private dwellings and number of single detached homes subset [81].

Installed solar PV capacity at various single detached home installation penetration rates.

City	Node	Number of private dwellings	PV capacity at 25% penetration (MW)	PV capacity at 50% penetration (MW)	PV capacity at 75% penetration (MW)
Vancouver (CMA)	LM	960,890	1,201	2,402	3,603
Victoria (CMA)	VI	162,720	203	407	610
Kelowna (CMA)	AC	81,380	102	203	305
Prince George (CA)	CI	35,095	44	88	132

All 4 selected cities	-	1,240,085	1,550	3,100	4,650
All of BC totals ³	-	1,881,970	2,352	4,705	7,057

Simulated solar PV generation in British Columbia is generated with PVWatts, developed by the National Renewable Energy Lab (NREL), to provide a common reference point between data for all cities [28]. All generated data is for fixed roof mounted panels. Panel assumptions for PVWatts generated data is detailed in Table 3.5.

Table 3.5: Solar PV assumptions for PVWatts data [28]

Array type	Fixed roof mount
Module efficiency	15%
System losses	14%
Inverter efficiency	98%
Array tilt	Location latitude
Azimuth	180° (South facing)

This work examines 5 kW solar PV systems, the average installed residential system size in the US, at various deployment penetrations of single detached housing stock in BC. Installed solar PV capacity levels examined at 25%, 50%, and 75% penetration rates of single detached homes in the four selected cities is detailed in Table 3.4. Scenarios where solar PV generation may be curtailed and where generation is must-take energy are examined.

³ This row of all BC totals is provided as a reference only. Study is not conducted for this scenario.

3.6 Production cost model optimization scheduling

The PLEXOS model is an hourly unit commitment model which optimizes for least-cost dispatch. Within the PLEXOS model, the constraints associated with each generator are captured by first running the model with a medium term (MT) schedule followed by a short term (ST) hourly schedule. The MT reduces the number of simulated periods by combining hourly dispatch intervals into 12 blocks per day and optimizing decisions over the then reduced chronology. After the MT optimization, a ST hourly unit commitment optimization is run to determine detailed system operation under constraints from the MT schedule. A graphic of these optimization steps is shown in Figure 3.6.

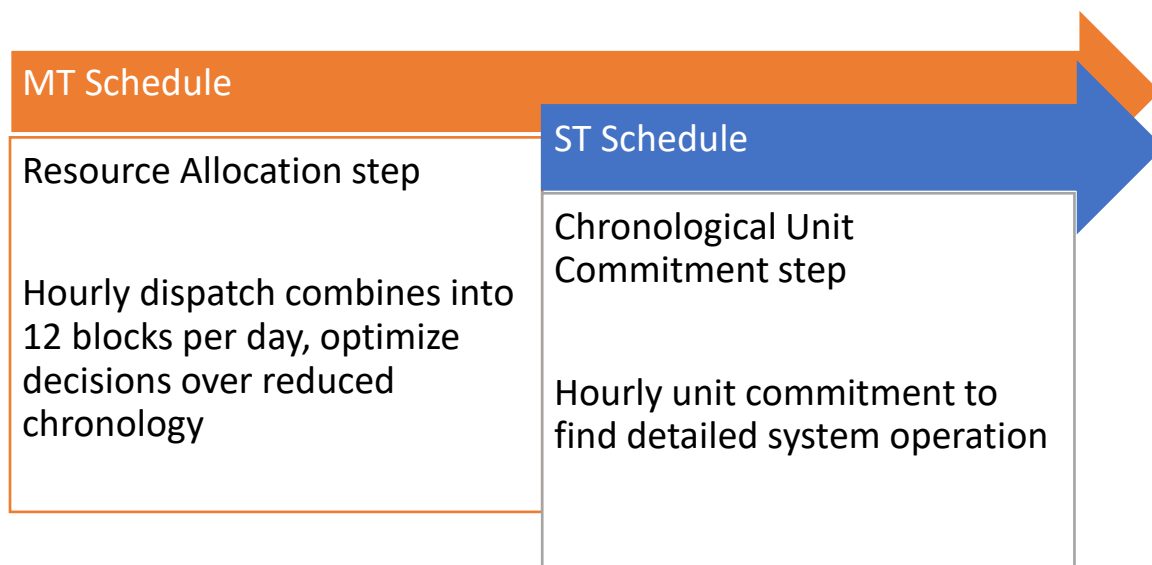


Figure 3.6: PLEXOS model optimization steps for hourly unit commitment modelling

3.7 Power plant characteristic and cost data

Cost assumptions for BC hydro power variable operation and maintenance costs are based on BC government water license rental rates for power production [84]. All other assumed generating plant characteristics and operating and maintenance costs are from the U.S. Energy Information Administration (EIA) and detailed in Table 3.6 [85], [86]. Cogeneration is assumed to have the same characteristics and costs as CCGT. This study assumes that costs for distributed residential type solar PV are covered by the owner and therefore modeled as a zero cost. Costs are in 2012 USD values.

Table 3.6: Estimates of power plant characteristics and operating and maintenance costs

Generator type	Heat rate (Btu/kWh)	Fixed O&M (\$/kW-yr)	Variable O&M (\$/MWh)
Biomass	13,500	110	4.2
Cogeneration	6,300	10	2
Combined cycle gas turbine	6,300	10	2
Simple cycle gas turbine	9,800	6.8	10.7
Coal-to-gas	10,300	22	1.3
Storage hydro	0	14.13	2.6
Run-of-river hydro	0	14.13	2.6
Alberta small hydro	0	14.13	2.6
Wind	0	39.7	0
Residential solar PV	0	0	0
Solar PV – tracking	0	21.8	0

3.8 Model limitations

While this thesis makes all efforts possible to model all assets as accurately as possible, some limitations must be noted for clarity. Limitations of this model include:

- *No interconnection modeled to the US.*

In the interest of model simplicity, energy trade with the US, which is a significant trading partner of British Columbia, is not included in this study.

- *Sub-hourly modelling is not applied.*

Sub-hourly modelling analysis would allow for better examination of the effects of solar PV, a highly variable resource, on the minute-to-minute flexibility of BC's hydro resources. However, this study lacks adequate temporal resource data to properly inform such an exercise.

- *Solar PV data is simulated from typical meteorological year data via PVWatts.*

Solar PV data for this study is simulated data from a typical mean year using PVWatts analysis. This means that solar PV resource data for various locations is not from the same year but rather from a typical meteorological year which aims to give annual averages consistent with long-term locational averages.

- *Hydro turbine efficiency is assumed to be constant.*

Due to the lack of publicly available data on the efficiencies of hydro turbines at the dams in BC, this study calculates efficiencies that remain constant throughout turbine operation.

- *Water traversal time between cascaded hydro dams is not modeled.*

Water is assumed to reach the next reservoir in the cascade within the same hour that it leaves the previous dam as traverse time data is not available.

- *Model lacks details which could be provided by coupling a watershed model with current production cost model.*

The coupling of a watershed model would help to more accurately model the environmental effects as well as the waterflow between cascaded hydro systems. However, this adds significant modelling complexity which was outside the bounds of this study.

- *Calculated minimum generation profiles are not linked to hydrological years.*

This study lacks data to link the calculated minimum generation profiles to hydrological years – this data is not publicly available. Therefore, these are assumed constant for minimum, mean, and maximum hydrological year studies which effects the results of the sensitivity analysis.

3.9 Technical and policy scenarios

Using the PLEXOS model and methodology described in Chapter 3, various scenarios studying possible technical and policy impacts, and the associated implications for the BC electricity system are explored.

Decarbonisation of the BC energy system may lead to widespread electrification of building heating systems and increased demand for on-site renewable electrical energy. The decreasing capital cost and modular nature of solar photovoltaics (PV) makes it a prime candidate to meet this increasing demand. In this chapter, study results are presented based upon the impacts of large penetrations of distributed solar PV on a flexibility-constrained BC electricity system, tied to minimum hydro generation constraints, with a modelled inertia to AB for a mean hydrological year. Sensitivity analysis is subsequently performed for maximum and minimum hydrological years.

The technical and policy scenarios examined in this study are outlined in Table 3.7. Each scenario is examined for the mean hydrological year, with a subsequent sensitivity analysis performed for reference load growth, low load growth, and no-load growth scenarios. Results are presented for all load growth scenarios and the implications of hydrological years are discussed. In this study, *penetration* refers to the number of total homes which have a 5 kW rooftop solar panel installed. For example, the 25% PV penetration scenario refers to a scenario in which 25% of all private dwellings in the four major BC metropolitan cities have rooftop solar panels.

Table 3.7: Scenarios for study

Scenario name	Scenario type	Load growth	Solar PV penetration ⁴	Storage hydro constraints imposed? ⁵	ROR hydro constraints imposed? ⁶	AB intertie modelled?
BAU	Technical	Normal, Low, None	0%	Yes	Yes	Yes
25% PV	Technical	Normal, Low, None	25%	Yes	Yes	Yes
50% PV	Technical	Normal, Low, None	50%	Yes	Yes	Yes
75% PV	Technical	Normal, Low, None	75%	Yes	Yes	Yes
Flexible Hydro	Technical	Normal	50%	No	Yes	Yes
IPP Non-Renewal	Policy	Normal, Low, None	50%	Yes	No	Yes
Energy Independence	Policy	Normal, Low, None	50%	Yes	Yes	No

⁴ See Table 3.4 for penetration assumptions

⁵ Storage hydro constraints are detailed in sub-section 2.1.1 and Section 3.3

⁶ Run-of-river hydro constraints are detailed in sub-section 2.1.1 and Section 3.4

The business as usual (BAU) scenario represents the BC electricity system in 2030 as if it were to maintain current growth trajectory. In this scenario, there is no installation of distributed solar PV, all minimum generation constraints are imposed on storage and ROR hydro, and the current BC-AB intertie capacity is maintained.

The 25%, 50%, and 75% PV housing stock penetration scenarios examine the implications of extreme distributed solar PV buildout by the year 2030, at varying penetrations of all BC residential buildings. These scenarios see all minimum generation constraints imposed on storage and ROR hydro, and the current BC-AB intertie capacity.

The flexible hydro scenario models the 50% PV penetration scenario without minimum generation constraints imposed on storage hydro or ROR hydro. This scenario represents the practice of modeling of hydro-dominant systems as completely flexible, with the aim of quantifying the implications of more realistic hydro modeling approaches.

In the policy scenario, IPP Non-Renewal, IPP contracts are withdrawn and ROR projects are flexible generators without minimum generation constraints. In this scenario, ROR hydro is modelled with the same hourly energy limits tied to the minimum generation profile, however allowed to operate flexibility within this limit. The 50% solar PV penetration scenario is modelled to examine if more flexible generation options could reduce ‘wasted’ energy via curtailment and water spillage.

The Energy Independence policy scenario aims to explore the impacts of the self-sufficient British Columbia policy, as described in Section 2.1.3. In this scenario, the Alberta intertie is eliminated, and a 50% solar PV penetration scenario is modelled to see if this could replace the existing transmission intertie.

Chapter 4 - Results and Discussion

4.1 Introduction

This chapter presents results for all technical and policy scenarios. The chapter concludes with a discussion of result implications of large penetrations of solar PV on the case study region of British Columbia.

4.2 25%, 50%, and 75% PV Scenarios

4.2.1 Generation to meet load

The BC generation profile, for a mean hydrological year and normal load growth condition, is shown in Figure 4.1, as a stacked plot showing generation by aggregated river systems and generation types. As seen, the Peace and Columbia river systems contribute the majority of the generated energy. Run-of-river generation, largely freshet dominated, plays a predominant role in May through June generation to meet load.

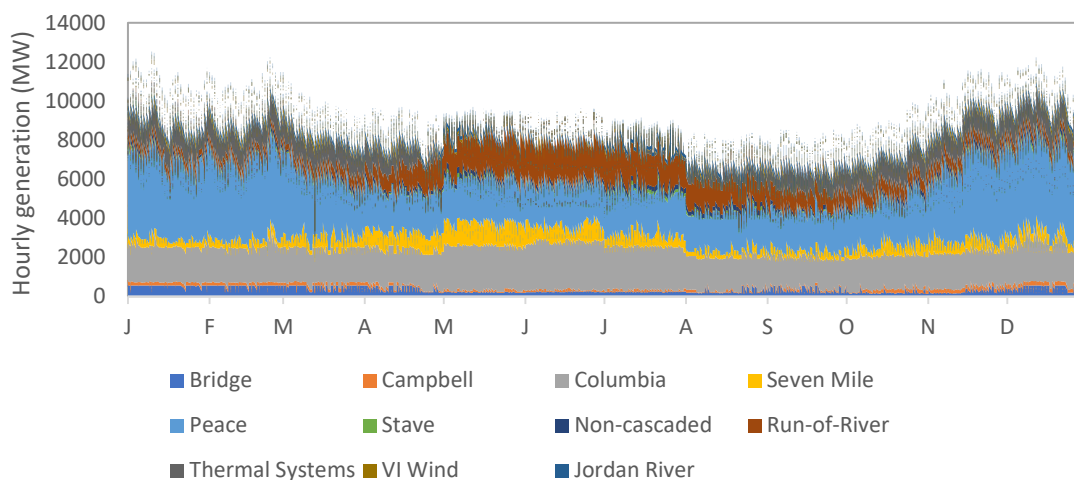


Figure 4.1: Stacked BC generation to serve load for BAU normal load growth scenario grouped by river systems and generation types. The discontinuity in August is due to generation aggregation to create this figure and MT scheduling optimization.

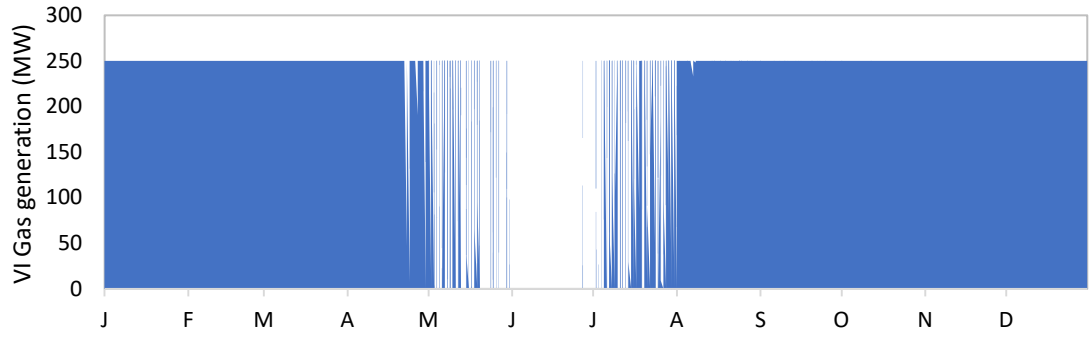
Figure 4.2 shows the annual generation profile for the VI natural gas plant for normal load growth and no-load growth sensitivities of the BAU scenario and the 75% PV scenario. For both normal load growth scenarios, the natural gas plant is seen to operate at max capacity during non-summer months to help meet load. The gas plant turns off during the freshet and operates intermittently during the shoulders of the freshet, noting the need for flexibility during these times.

Figure 4.3 shows typical daily generation profiles of the VI natural gas plant for both BAU and 75% PV no load growth scenarios. While typical summer days are the same between both scenarios, the BAU winter day shows greater utilization of the gas plant than the 75% PV scenario. However, due to the lack of ramping requirements both winter days do show intermittent operation.

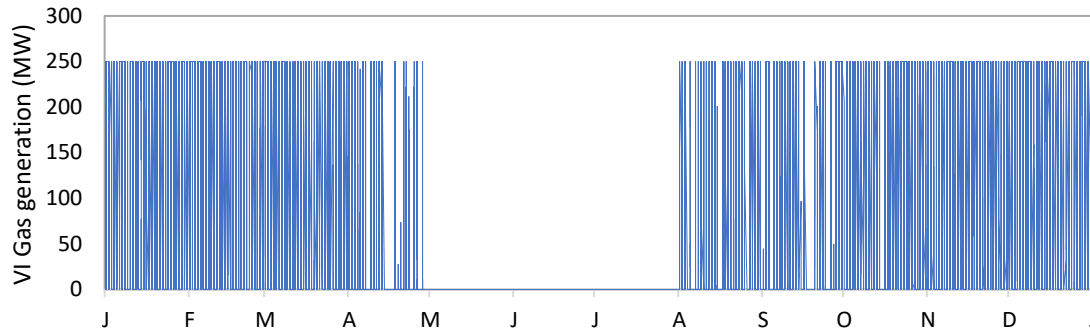
The annual generation profiles for the no-load growth scenario of both BAU and 75% PV show the plant shut off period extended further past the freshet as PV penetration increases. As the generators are not constrained to hourly ramp rates, more frequent ramping cases are seen as the plant is used to manage system variability. While the 75% PV no-load growth scenario does see more intermittency in operation in shoulders of the freshet, dependency on the flexible gas plant driven more by demand than by need for solar PV ramping management.

Figure 4.4 shows annual generation for the natural gas plant for all PV scenarios compared to the BAU scenario. A slight decrease in natural gas annual generation is seen as the PV penetration level increases, which is then exacerbated by decreasing load scenarios. As previously noted, decreasing dependency on the natural gas generation in

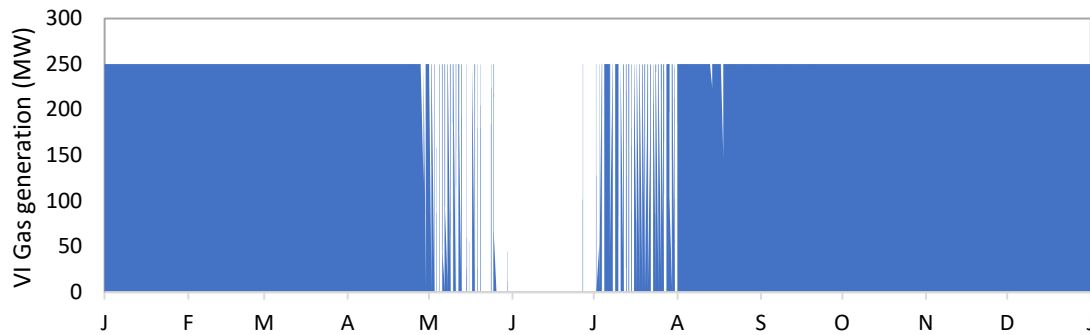
question is driven by diminishing load scenario requirements rather than by solar PV ramping management.



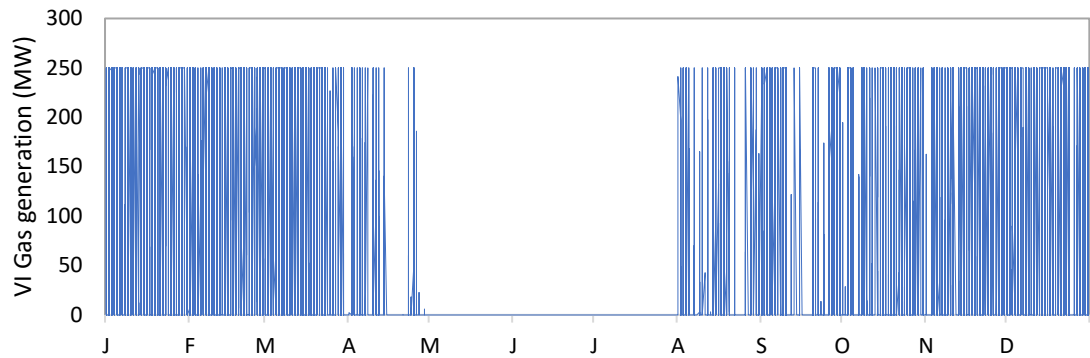
(a)



(b)



(c)



(d)

Figure 4.2: Annual VI natural gas generation for (a) BAU normal load growth scenario, (b) BAU no load growth, (c) 75% PV normal load growth, (d) 75% PV no load growth

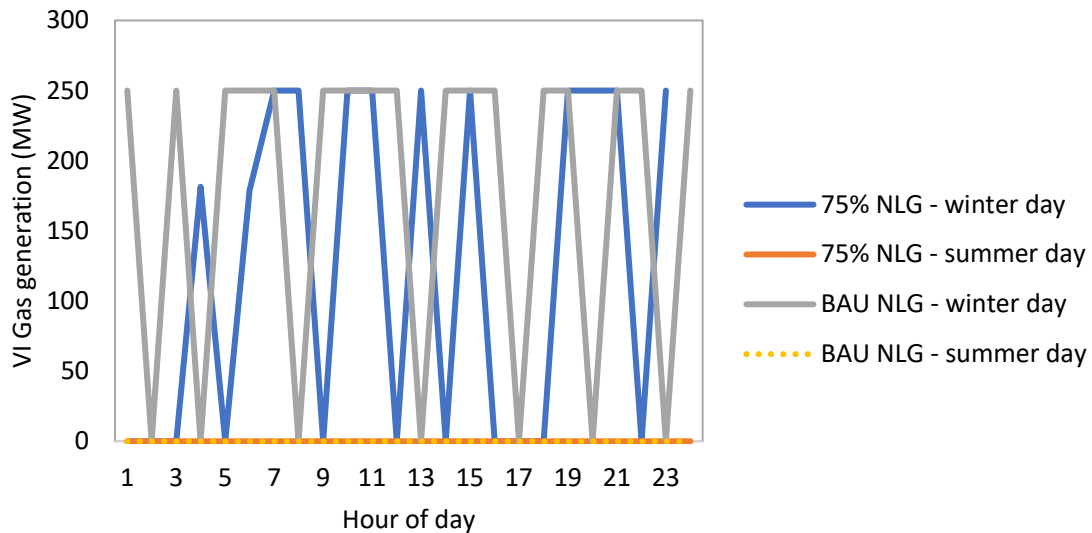


Figure 4.3: Daily VI gas generation for a typical winter day and summer day for both the BAU and 75% PV no load growth scenarios

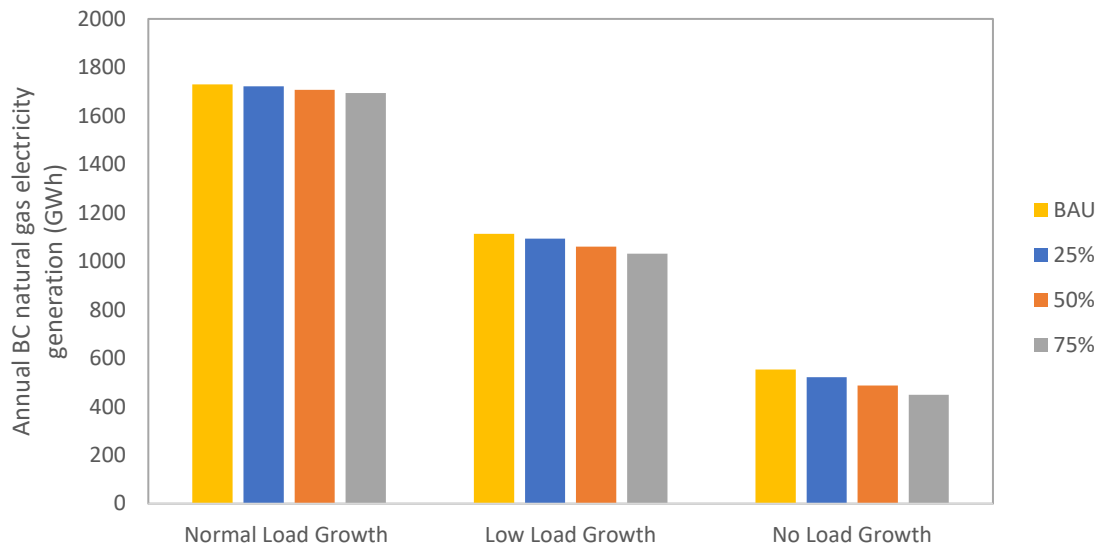


Figure 4.4: Annual 2030 BC natural gas electricity generation for solar PV penetration scenarios

Figure 4.5 shows the annual generation profile for the aggregated biomass plants. Like the natural gas plants, the biomass plants do not generate during the freshet due to the

oversupply of hydro generation. The ‘Biomass other’ aggregated generator is located on the VI node, and thus can be seen to operate further into the shoulders of the freshet. because VI generation is not governed by the freshet effect. This is also due to the limited transmission capacity to the island node, which prefers to serve load at the node before importing from other nodes.

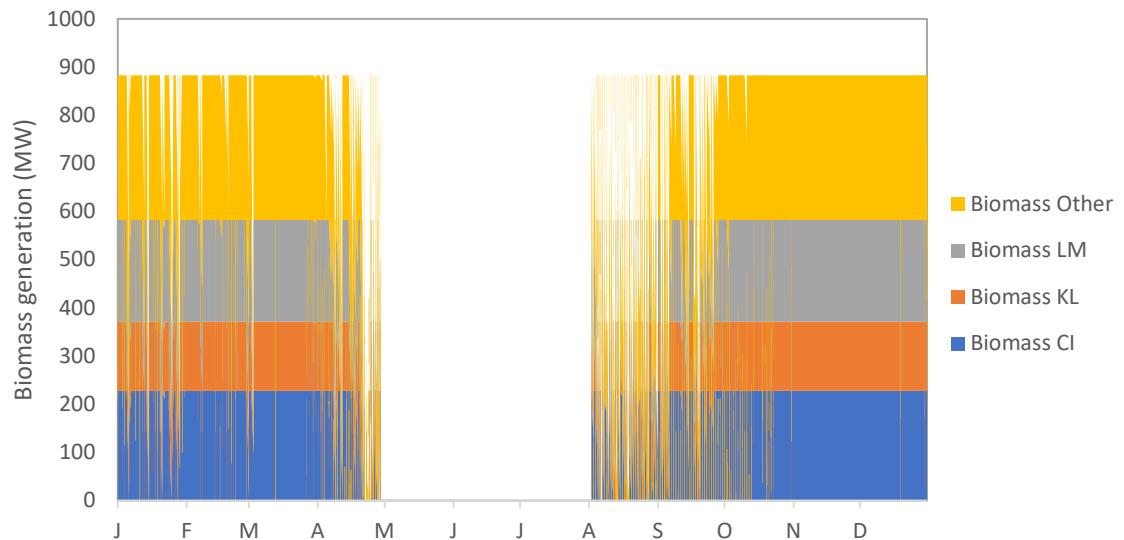


Figure 4.5: Stacked aggregated biomass generation for the BAU normal load growth scenario

Figure 4.6 shows annual generation from the biomass plants for all PV penetration scenarios across the load sensitivities. As expected, generation is seen to decrease slightly as PV penetration increases and displaces the need for some of this energy by approximately 12%, between BAU and the 75% Scenarios for a normal load growth year. However, in both the low load growth and no-load growth sensitivity studies, all biomass generation is seen to completely shut off year-round for all scenarios, including BAU. Solar PV, which does not emit greenhouse gasses, is able to displace the need for biomass

generation, which does emit CO₂. With decreasing load and increasing solar energy penetration, especially in the summer months, biomass plants are not needed to meet load and due to their higher fixed and variable O&M costs, are forced out of operation.

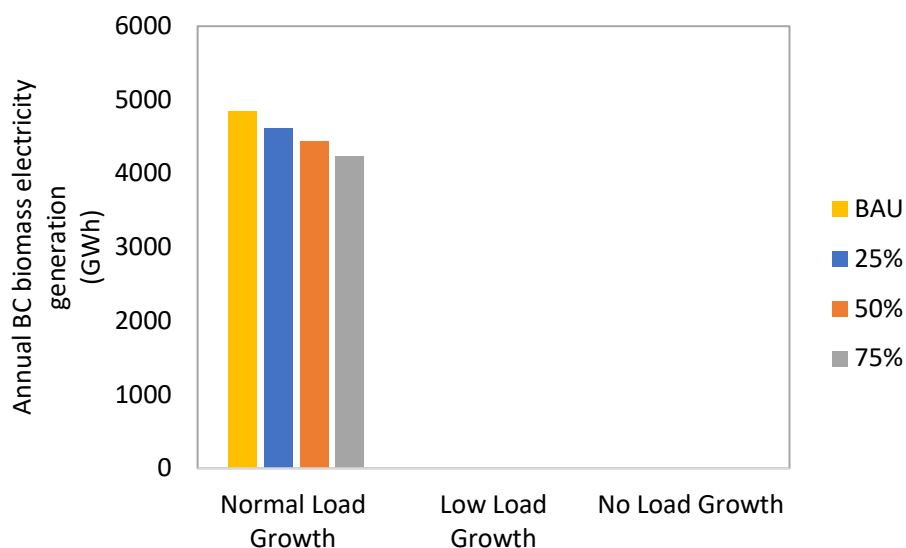


Figure 4.6: Annual 2030 BC biomass electricity generation for solar PV penetration scenarios

Table 4.1 details annual thermal energy generation values presented above.

Table 4.1: 2030 thermal energy generation for BAU normal load growth scenario

Generation Type	Scenario	Thermal Energy Generation (GWh)		
		Normal Load Growth	Low Load Growth	No Load Growth
Natural Gas	BAU	1,730	1,114	554
Biomass		4,843	0	0
Natural Gas	25% PV	1,722	1,093	522
Biomass		4,618	0	0
Natural Gas	50% PV	1,707	1,061	488
Biomass		4,444	0	0
Natural Gas	75% PV	1,694	1,031	449
Biomass		4,242	0	0

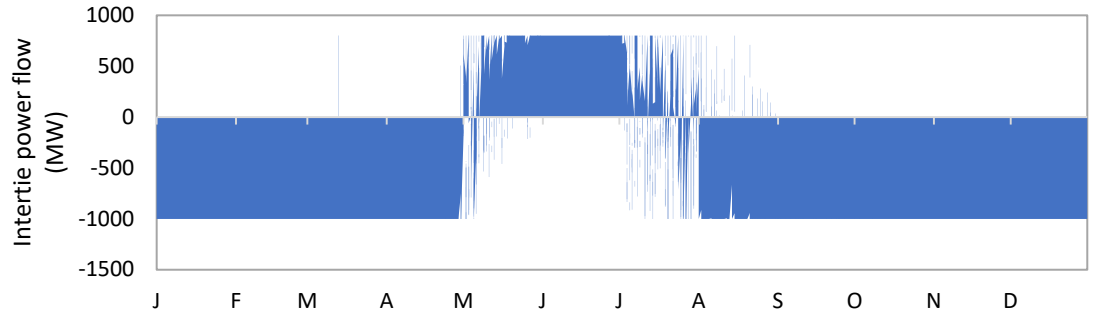
4.2.2 Imports and exports

Electricity trade between BC and AB is typically driven more by necessity from BC rather than AB, due to oversupply during the freshet and undersupply in late winter when reservoir levels are low. Power flow from BC to AB is limited to 800 MW and flow from AB to BC is capped at 1000 MW.

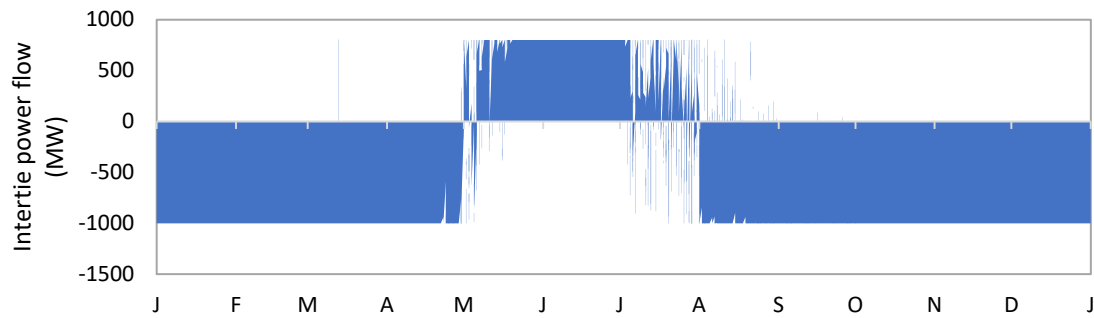
The annual 2030 profile of electricity trade, shown as intertie power flow, can be seen in Figure 4.7 for a reference load growth year where positive flow is from BC to AB and negative flow is from AB to BC.

As expected, in the BAU normal load growth scenario, (a), BC exports to AB during the freshet and imports during the rest of the year. It is important to note that this study does not model an intertie to the US, which may somewhat alter these results. In the business as usual case, BC relies more heavily on imports due to the lack of adequate capacity and energy and, as a result, does not meet the self-sufficiency requirements by the year 2030. However, when examining the 75% PV normal load growth scenario, (d), an almost identical electricity trade profile is seen to the BAU scenario, (c). As evidenced by Figure 4.7 (b) and (d), solar PV, even at large penetrations, will not allow for self sufficiency due to the resource timing of the freshet with peak solar resource levels and low winter reservoir levels with minimal solar potential.

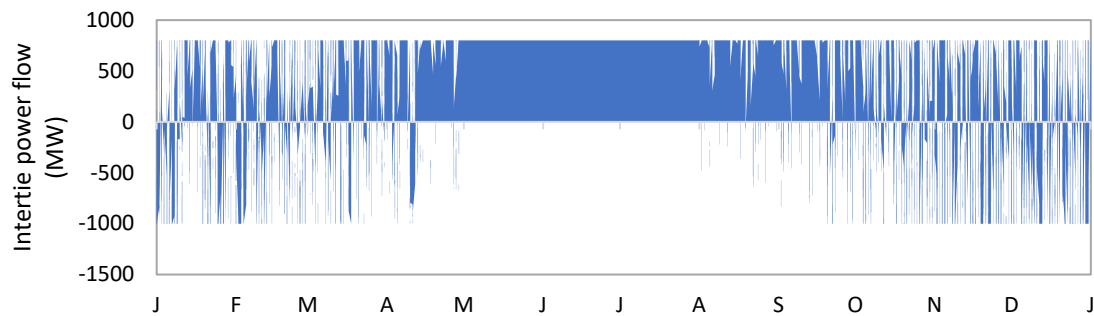
However, both the BAU and the 75% PV no load growth sensitivities show BC exports during most of the year and maxed out intertie line capacity during the freshet and summer months when hydro generation is least flexible and solar PV generation is at its peak. BC still maintains imports from AB, however, to a lesser degree than as seen in the normal load growth sensitivities.



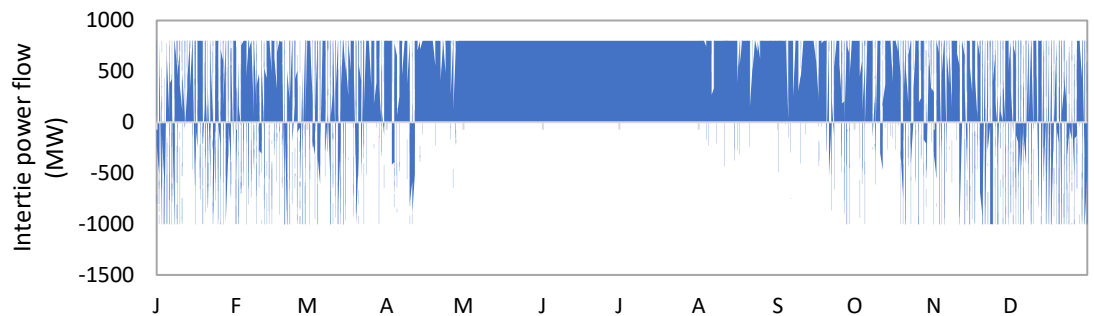
(a)



(b)



(c)



(d)

Figure 4.7: Annual 2030 electricity trade between BC and AB shown as power flow with positive flow representing flow to AB and negative flow representing flow to BC for scenarios (a) BAU normal load growth, (b) 75% PV normal load growth, (c) BAU no load growth, (d) 75% PV no load growth

Figure 4.8 shows annual energy flow between BC and AB for the BAU and PV penetration scenarios where positive flow is from BC to AB and negative flow is from AB to BC. As solar PV penetration levels increase, a slight increase of approximately 7% - 11% depending on the scenario is seen in exports from BC to AB. However, a much greater increase in exports, 250% for the BAU scenario, is seen as load decreases and BC finds itself with excess energy. As PV penetration levels increase, a slight decrease of between 2% - 23% depending on load growth scenario is found in needed imports from AB. This is due to the resource timing of solar PV which does not align with demand for imports from AB during non-summer months. However, as load decreases, a large drop is seen in imports from AB (i.e. 84% and 87% drop for the BAU and 75% PV scenarios respectively) which aligns with the increase seen in BC exports.

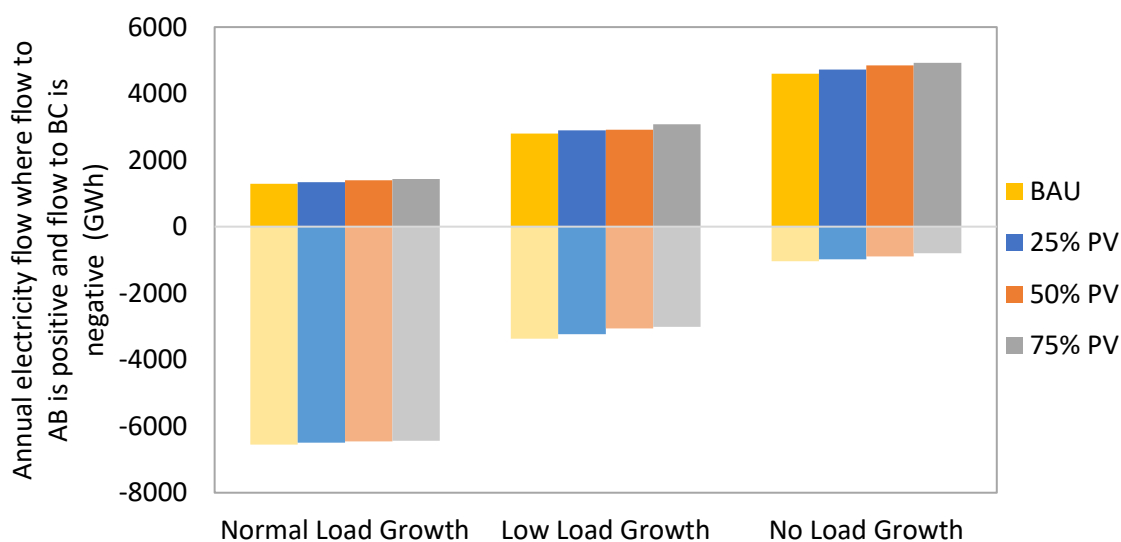


Figure 4.8: Annual energy flow between BC and AB in GWh for solar PV penetration scenarios where flow to AB is positive and flow to BC is negative

Table 4.2 details annual energy trade values for BAU and PV penetration scenarios.

Table 4.2: Annual energy trade between Alberta and British Columbia for the BAU scenario

Flow to	Scenario	Annual Energy Trade (GWh)		
		Normal Load Growth	Low Load Growth	No Load Growth
Alberta	BAU	1,292	2,799	4,600
British Columbia		6,556	3,373	1,043
Alberta	25%	1,336	2,891	4,727
British Columbia		6,491	3,233	983
Alberta	50%	1,394	2,915	4,848
British Columbia		6,454	3,064	900
Alberta	75%	1,433	3,076	4,930
British Columbia		6,435	3,012	797

4.2.3 Spilled and curtailed generation

High freshet inflows combined with reduced electricity load results in water spillage from dam and reservoir systems during early summer months in BC. To examine this water spillage in a comparable way, water spilled is converted into equivalent energy, based on estimated generator efficiencies for each dam. In the BAU scenario, spillage does occur over the course of the year, as seen in Figure 4.9 for a normal load growth year. Dams that see spillage are spread among most major cascaded systems, including Dinosaur, Diversion, Seven Mile, Walter, Downton, and Stave, and thus spread across various nodes. Most spillage is focused around the freshet timeframe. However, water spillage at Jordan Diversion dam, located at the VI node, is driven more by year-round rainfall on the island rather than the freshet, which dictates spillage at mainland dams. Diversion generates at maximum capacity throughout much of the year and with smaller relative storage ability when compared to mainland dams, results in spilling throughout much of the year.

Yearly energy spilled from the systems in question is detailed in Table 4.3. Interestingly, some dams are more impacted than others by decreasing load growth. Stave, Downton,

Walter, and Diversion all see small change in spill compared to Seven Mile and Dinosaur. These are both located in larger cascaded systems with larger respective generation capacities at 805 MW and 700 MW, respectively.

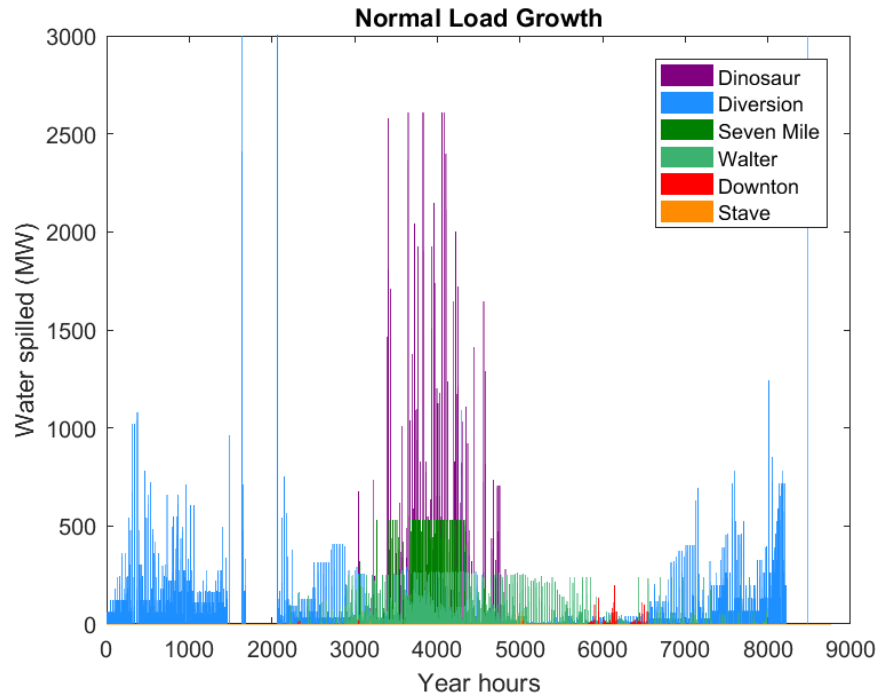


Figure 4.9: Annual BAU water spillage in MW from applicable reservoirs for a normal load growth scenario

Table 4.3: Annual BAU water spillage in terms of energy (GWh) by reservoir

Reservoir	Associated Node	Spilled energy (GWh)		
		Normal Load Growth	Low Load Growth	No Load Growth
Downton	KL	2	11	16
Walter	AC	64	69	72
Seven Mile	SL	106	362	496
Dinosaur	PR	101	221	340
Stave	LM	0	5	12
Diversion	VI	255	255	283
Total	-	527	923	1,219

As shown, water spillage is to be expected, even without the addition of variable generating resources. In 2030, under a normal load growth scenario, average yearly energy load in BC is expected to be approximately 78,000 GWh. Under BAU scenarios, spilled energy is approximately 1% of expected energy demand.

Figure 4.10 shows annual water energy spilled from cascaded hydro systems for the solar penetration scenarios compared to the BAU scenario. The difference between BAU spill and the 75% PV scenario spill is 19%, 18%, and 10% for the normal, low, and no-load growth scenarios, respectively. However, the differences in water spilled between various load growth scenarios, is on the order of 50%. As demonstrated, annual energy spilled is impacted more by load growth scenarios than by solar penetration. However, increasing solar PV penetration scenarios do show a reinforcing negative impact on increased spilled energy.

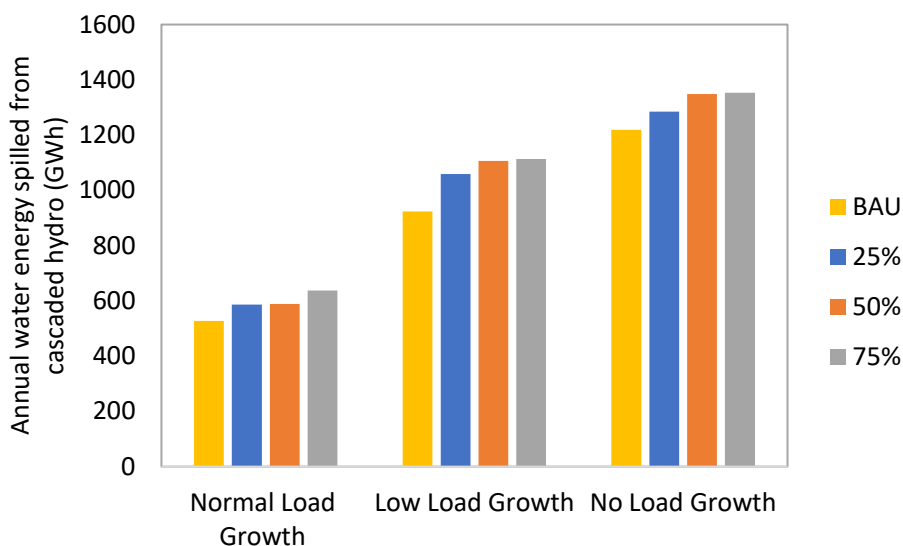


Figure 4.10: Annual water energy spilled from cascaded hydro systems for solar PV penetration scenarios

Figure 4.11 shows annual solar PV generation and subsequent curtailment for solar PV penetration scenarios. Curtailment increases as load growth decreases. Maximum

curtailment seen is in the 75% PV no-load growth scenario, where approximately 5% of PV generation is curtailed.

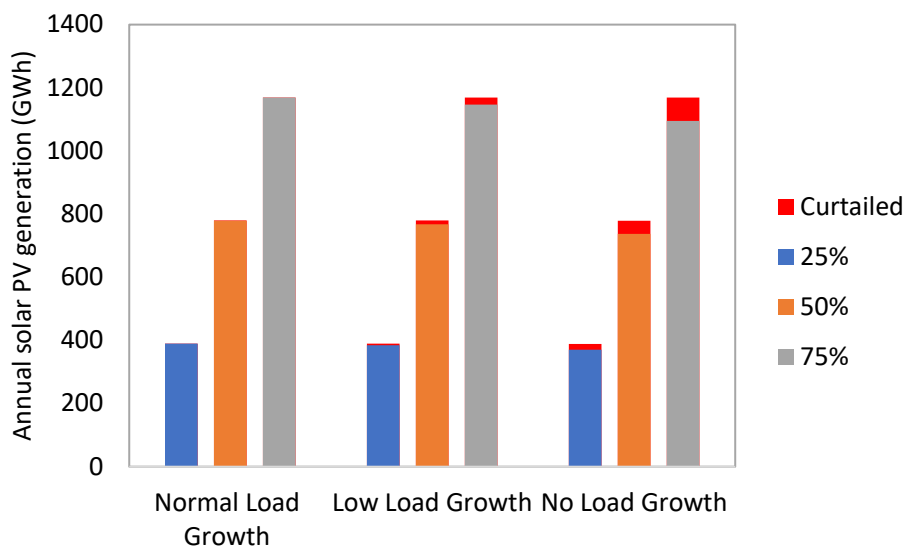


Figure 4.11: Annual solar PV generation and curtailment for solar PV penetration scenarios

Figure 4.12 shows daily water spilled and PV curtailed during a period of the freshet from May 27th to June 27th for the 75% PV no-load growth scenario. Each stacked bar represents one day, with hourly details represented in each bar. As shown, the majority of water energy spilled in this period is from the Dinosaur reservoir/ Peace Canyon Dam, located at the PR node. The closer generation occurs to load, the more economic the process. At this time of year, PV generation is increasing while load is decreasing. As expected, generation at the PR node must decrease while water flow ramps up as it is located furthest from all demand centered nodes. The PV location showing most curtailment is Vancouver. While PV generation is essentially “free” to the economic dispatch, it cannot always be utilized mostly due to minimum flow requirements of hydro systems and to a lesser degree due to ramping restrictions on other generation assets to

manage the variability. Daily water spilled, and PV generation curtailed can be seen for a longer period of time during the freshet in Figure A.3 of Appendix A.

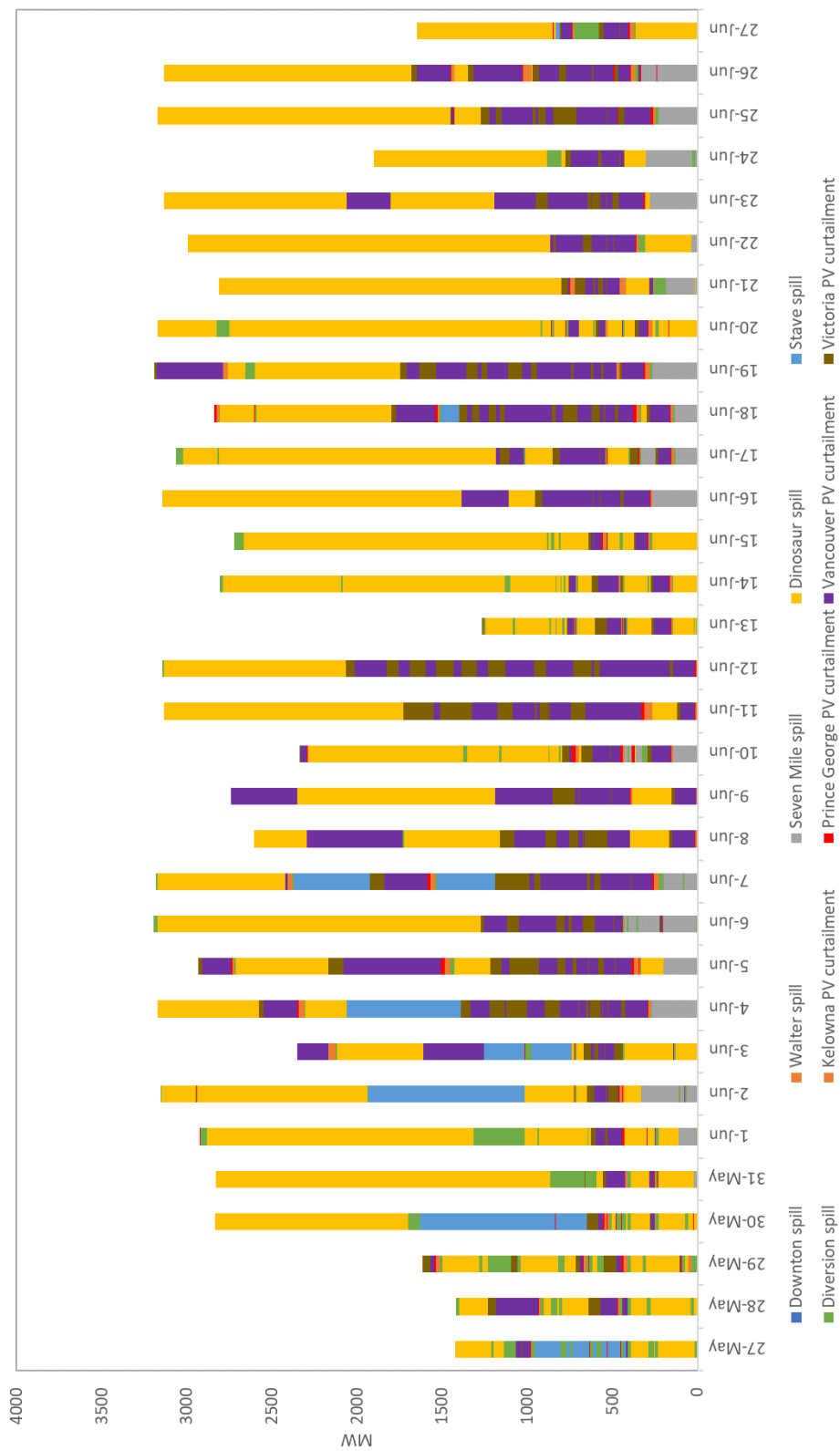


Figure 4.12: Freshet period water spill and solar PV curtailment by location for 75% PV no load growth scenario. The y-axis shows spill occurrence by location from hour 1 to 24, in order.

Annual energy balance ($E_{balance}$) of solar PV generation (E_{PV}), PV curtailment ($E_{PVcurtailed}$), water energy spilled (E_{spill}), and BAU water energy spilled ($E_{BAUspill}$) is detailed in Equation 4.1.

$$E_{balance} = E_{PV} - E_{PVcurtailed} - E_{spill} + E_{BAUspill} \quad (4.1)$$

Figure 4.13 shows the annual energy balance of solar PV generation to PV curtailment and water energy spilled with accounting for BAU spill by removing this from the equation. With accounting for the expected BAU spill and subtracting it from the equation, the addition of solar PV shows an annual positive energy balance for all scenarios. As more PV penetrates the system, the energy balance diminishes marginally. Figure 4.13 shows that while the addition of solar PV does show system-wide benefit, there seems to be a cap on acceptable penetration levels. As a system, the total PV capacity factor is 15% without curtailment. While curtailment for PV is typically minimal, in both the 50% PV and 75% PV no-load growth scenarios, the capacity factor of solar PV decreases to 14% due to curtailment alone. It is not clear that after a 50% penetration of all residential buildings, which is an approximate installed capacity of 5 GW, there is much system benefit. It is important to note that installed location does play a role in examining the advantage of solar PV, with more value potential possible in locations located farther from nodes with significant minimum generation requirements.

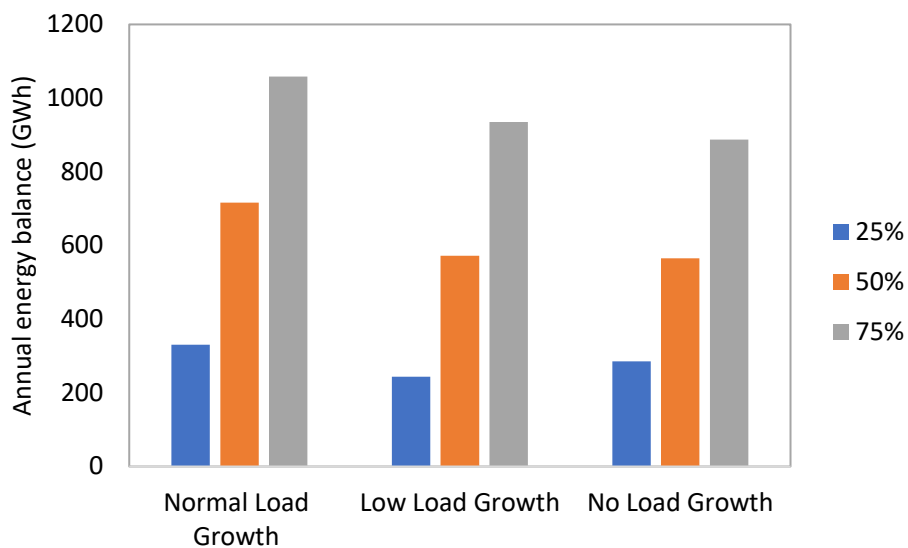


Figure 4.13: Annual energy balance of solar PV generation and curtailment to water energy spilled in GWh with accounting for BAU spill

Table 4.4 details annual solar PV generation, PV curtailment, and water energy spilled for each scenario.

Table 4.4: Annual solar PV generation, curtailment, storage hydro water spillage, and the resulting energy balance for the 25% PV scenario

Factors in annual energy balance	Scenario	Normal Load Growth	Low Load Growth	No Load Growth
Total water energy spilled (GWh)	BAU	527	923	1,219
Total PV curtailed (GWh)	25%	0	5	19
Total PV generation (GWh)		390	385	370
Total water energy spilled (GWh)		586	1,059	1,285
Energy balance (GWh)		331	244	285
Solar PV capacity factor		15%	15%	15%
Total PV curtailed (GWh)	50%	0.4	12	42
Total PV generation (GWh)		779	768	737
Total water energy spilled (GWh)		589	1,107	1,349
Energy balance (GWh)		717	572	565

Solar PV capacity factor		15%	15%	14%
Total PV curtailed (GWh)	75%	0.5	22	74
Total PV generation (GWh)		1,169	1,147	1,095
Total water energy spilled (GWh)		637	1,113	1,353
Energy balance (GWh)		1,059	935	887
Solar PV capacity factor		15%	15%	14%

4.2.4 Hydrological years

Though this thesis does not present the results for different hydrological years, analysis was performed for both minimum and maximum hydrological rain years with a normal load growth sensitivity. For minimum rain years, unserved energy was found in both the BAU as well as all PV penetration level scenarios. This is possibly due to the lack of modeled US intertie capacity which would allow for additional imports in these years. For maximum rain years, as expected, water spillage increases along with year-round exports to Alberta. Hydrological year results are not presented as minimum generation profiles are not tied to hydrological years and obtainable only for a mean hydrological year. It was found that the study of load growth sensitivities made for a more interesting and potentially more beneficial study to stakeholders.

4.3 Flexible hydro scenario

The flexible hydro scenario models the 50% PV penetration scenario without minimum generation constraints imposed on storage hydro. This scenario aims to examine the common practice modeling of hydro dominant systems as completely flexible, with the hopes of quantifying the implications of more realistic hydro modeling approaches.

Table 4.5 details annual spilled energy by reservoir system for the flexible hydro scenario and the 50% PV scenario with imposed minimum generation constraints, respectively. As shown, without imposed minimum generation constraints and allowed flexible operation,

a disparity is seen in modelled water energy spilled. Most dams which are allowed to operate flexibly see little to no spill apart from Diversion dam at the VI node. As previously noted, Diversion dam sees water spill year-round due to the rainfall conditions and therefore spill would be expected regardless of operational flexibility.

Table 4.5: Annual spilled energy in GWh by reservoir system for Flexible Hydro scenario and 50% PV Scenario, both for normal load growth year

Reservoir	Associated Node	Flexible Hydro Scenario spilled energy (GWh)	50% PV Scenario spilled energy (GWh)
Downton	KL	0	2
Walter	AC	61	63
Seven Mile	SL	0	107
Dinosaur	PR	0	132
Stave	LM	0	1
Diversion	VI	283	283
Total	-	343	589

4.4 IPP non-renewal scenario

The purpose of this scenario is to study the operational implications of altering agreements for the renewal of run-of-river independent power producer (IPP) contracts. Currently, the addition of ROR IPPs add to minimum generation levels, therefore constraining system operational flexibility. This scenario studies the potential benefits of allowing for flexible operation of ROR, or purchase of energy as needed by the system. ROR generation is modelled to run within the calculated generation profiles, however there are no minimum generation requirements imposed. In this scenario, water not utilized by ROR units is spilled. The 50% solar PV penetration scenario is modelled to examine if more flexible generation options could reduce ‘wasted’ energy via curtailment and water spillage.

Figure 4.14 shows annual water energy spilled for the IPP non-renewal scenario in comparison to results from the 50% PV scenario. Flexible operation of ROR units results in no PV curtailment across all load growth scenarios. Flexible operation of ROR increases the systems ability to manage PV generation rather than spilling cascaded systems instead. Annual water spill across all load growth scenarios is reduced, resulting in higher energy balances, meaning less energy waste. Ultimately, this results in better management of cascaded reservoir systems. Detailed water energy spill values are shown in Table 4.6.

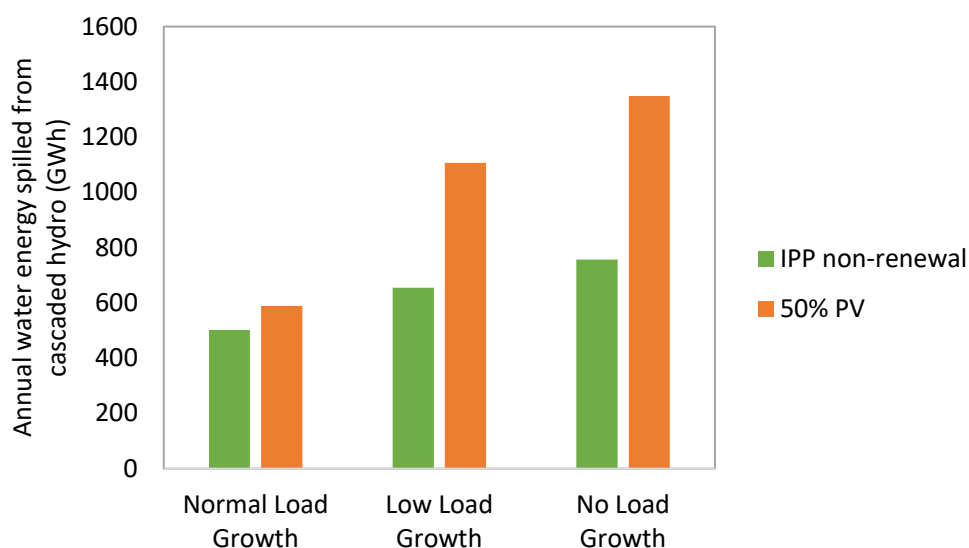


Figure 4.14: Annual water energy spilled from cascaded hydro systems of the IPP Non-Renewal Scenario compared to the 50% PV Scenario

Table 4.6: IPP Non-Renewal Scenario annual PV curtailment and generation, total water energy spilled, and subsequent energy balance

IPP Non-Renewal Scenario	Normal Load Growth	Low Load Growth	No Load Growth
Total PV curtailed (GWh)	0	0	0
Total PV generation (GWh)	779	779	779
Total water energy spilled (GWh)	502	655	757
Energy balance (GWh)	277	125	22

Examining Figure 4.15, weekly generation for ROR locations for the IPP Non-Renewal normal load growth scenario, the locations curtailed most significantly are the North Coast, Kelly Lake, and the Lower Mainland. The North Coast has minimal electricity load and occasionally benefits during the freshet from reduced generation as all balancing must be performed over a single transmission line from the CI node. Kelly Lake and the Lower Mainland, however, have more significant loads and are well connected to other nodes. These nodes see more significant curtailment during the freshet raising the question whether this generation capacity would potentially be better suited in a different location, such as VI which sees minimal ROR curtailment, limited transmission capacity, and a significantly large electricity load.

Flexible operation of ROR plants results in reduced spillage at large storage dams, shown in Figure 4.16 for the IPP Non-Renewal normal load growth scenario and in Figure 4.17 for the 50% PV normal load growth scenario. Though peak spill events are not greatly impacted, significantly less energy spillage is seen in the shoulders of the freshet and during the freshet season as well as reduced occurrences of spill. This change would potentially be a cost saving measure for energy purchase from ROR IPPs if water could be spilled or if alternate flexible generation resources could be found that did not have the same minimum generation profile coinciding with the freshet.

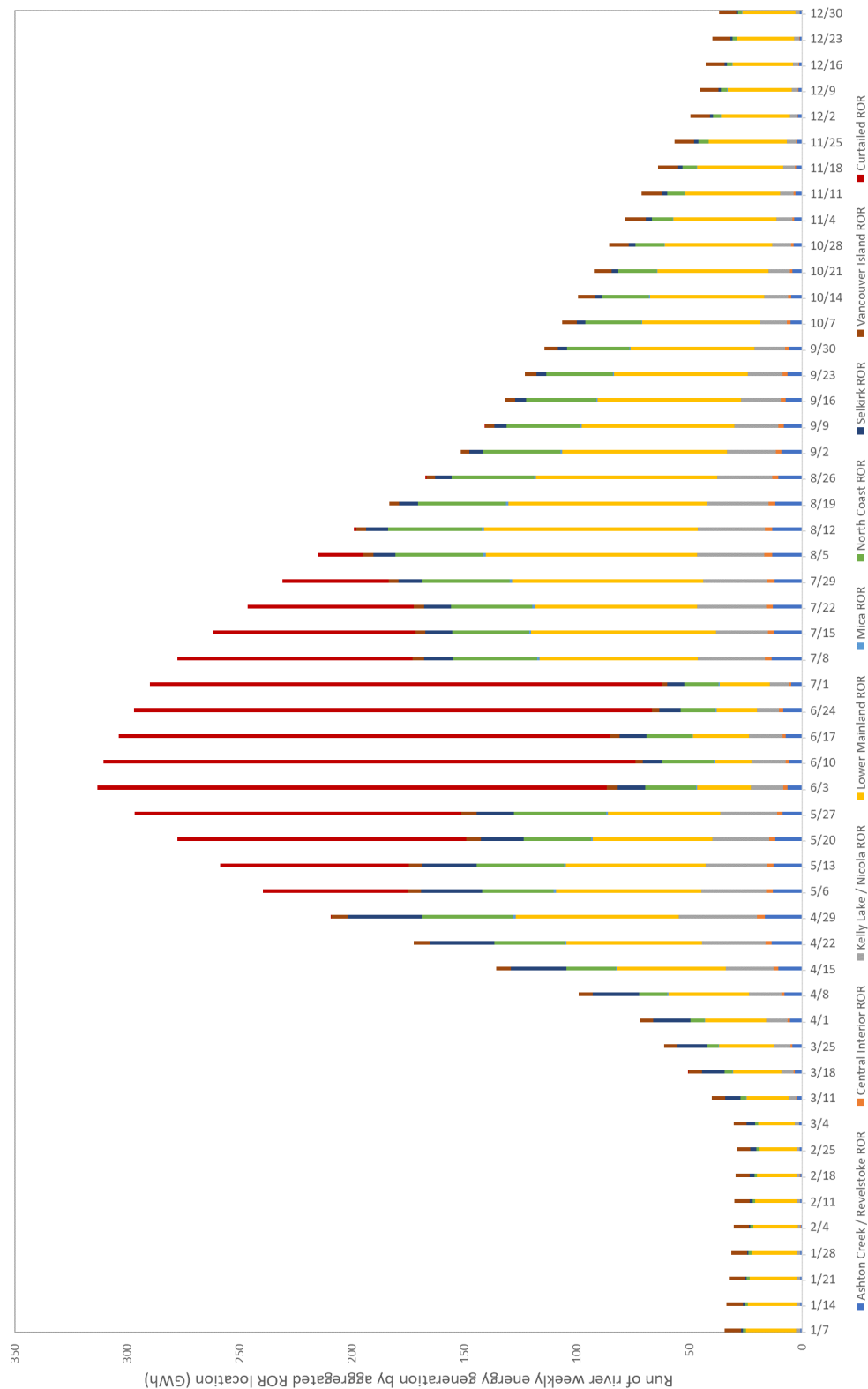


Figure 4.15: Run of river weekly generation by aggregated ROR location for the IPP Non-Renewal normal load growth scenario

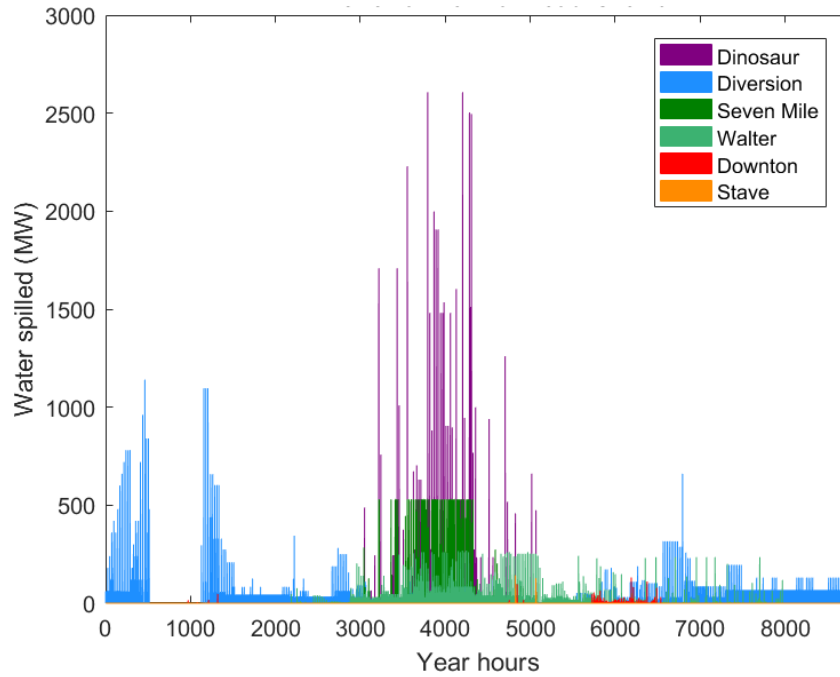


Figure 4.16: Water energy spilled by reservoir for IPP Non-Renewal normal load growth scenario

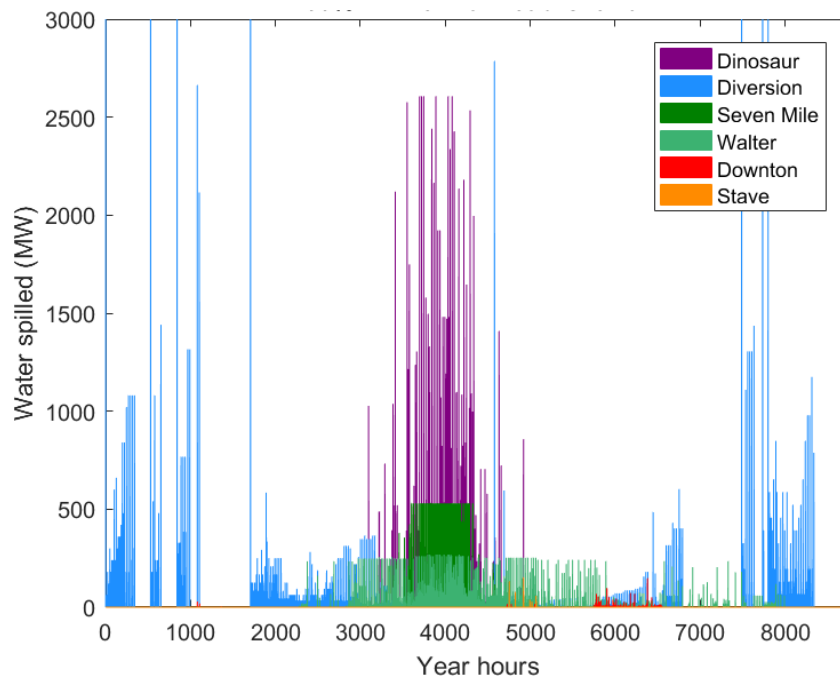


Figure 4.17: Water energy spilled by reservoir for the 50% PV scenario

Table 4.7 details annual energy trade between BC and AB for the IPP non-renewal scenario. When compared to annual energy trade for the 50% PV scenario, energy trade shows less than a 2% change across all load growth scenarios. While the flexible operation of IPPs result in less water energy wasted, as well as better management of solar PV generation, it does not diminish the need for electricity trade with Alberta, especially the need for imports in non-freshet months.

Table 4.7: IPP Non-Renewal Scenario annual energy trade

Flow to	Scenario	2030 Energy Trade (GWh)		
		Normal Load Growth	Low Load Growth	No Load Growth
Alberta	IPP Non-Renewal	1,370	2,930	4,755
British Columbia		6,456	3,097	909
Alberta	50%	1,394	2,915	4,848
British Columbia		6,454	3,064	900

4.5 Energy independence scenario

The Energy Independence policy scenario aims to explore the impacts of a completely self-sufficient British Columbia, as described in Section 2.1.3. The Alberta intertie to BC is not modelled and the 50% solar PV penetration scenario is modelled to see if this could replace the existing intertie capacity.

When the intertie to Alberta is ‘cut’, BC suffers large levels, totaling 5,204 GWh, of unserved energy for a normal load growth scenario, as shown in Figure 4.18. The LM and VI nodes suffer the largest share of unserved energy as they are responsible for the largest portion of load and farthest away via transmission from the large generation resources in the North. A small amount of unserved energy is seen at the other nodes which are closer to or located with generation assets. This creates even larger impacts on downstream nodes LM and VI.

In this scenario, BC is not capacity limited, but energy limited, meaning that while there is enough installed generating capacity serve load if all assets were run, there is not enough energy (water) available at times of need due to resource variability.

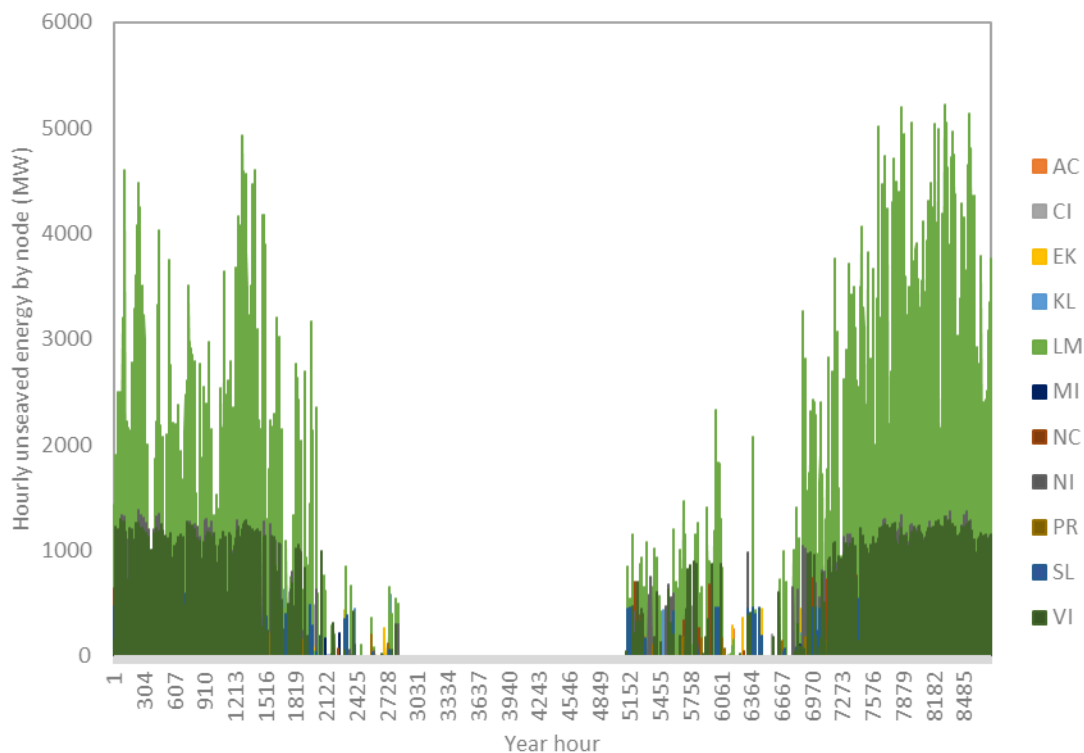


Figure 4.18: Hourly unserved energy by node for energy independence normal load growth scenario

Under the low load growth and no-load growth scenarios, there are no events of unserved energy, meaning that a future independent BC may be possible. This would simply result in large volumes of wasted energy which would need to be curtailed or spilled, when otherwise could be sold via exports. Ultimately, the results of this scenario only further justify other findings which show the benefit of more strongly interconnected systems [87], [88].

4.6 Discussion

The addition of large penetrations of solar PV have the ability to displace energy generated via thermal resources such as natural gas and biomass. However, the resource timing of solar PV does not align with the freshet and ultimately does not allow for BC self-sufficiency. This is when imports are traditionally needed from AB during non-freshet months, doing little to reduce dependence upon AB imports under normal load growth conditions. It is not clear that after a 50% penetration of all residential buildings, which is an approximate installed capacity of 5 GW, there is much system benefit in terms of added generation from PV. Greater benefit potential is possible in locations located farther from nodes with significant minimum generation requirements which inhibit system flexibility.

Load growth plays a larger role in water spill and alternate energy generation than the addition of solar PV. The low load growth and no-load growth scenarios reduce natural gas generation by approximately 33% and 66%, respectively, on the normal load growth scenario. Biomass generation is reduced by 100% in both the low load and no-load growth scenarios. Annual energy spilled via water is impacted more by load growth scenarios than by solar penetration. Between the normal load growth and the no-load growth scenarios, annual water spill increases by an approximate factor of 2.3. This is due to the freshet oversupply that now is not able to be utilized for electricity generation and therefore must be spilled instead. However, water spillage at Diversion dam, located at the VI node, is driven more by year-round rainfall on the island rather than the freshet which dictates spillage seen at mainland dams.

The modelling of minimum generation constraints in energy system production cost models is important to accurately predicting flexibility constraints of future hydro-dominant systems. Without imposed minimum generation constraints and allowed flexible

operation, a disparity is seen in modelled water energy spilled. Most dams which operate flexibly see little to no spill apart from Diversion dam at the VI node, where spill is expected regardless of operational flexibility. If not modeled correctly in the system planning stage, future systems could see disastrous implications from the additions of large penetrations of VRE with unexpected inability to manage them via the greater system.

Allowing for flexible operation of ROR units results in no PV curtailment across all load growth scenarios by greatly increasing system flexibility. Annual water spill across all load growth scenarios is also reduced, resulting in higher energy balances, meaning less energy waste. Additional benefit in less water spilled at cascaded hydro systems is seen as load growth decreases in size. In the no-load growth sensitivity, approximately 50% less cascaded water spill is seen, when compared to the same scenario with ROR constraints imposed, due to the increased system flexibility. The IPP non-renewal scenario would potentially be a cost saving measure for energy purchase from IPPs if water could be spilled or if alternate flexible generation resources could be found that did not have the same minimum generation profile coinciding with the freshet. While the flexible operation of IPPs result in less water energy wasted, as well as better management of solar PV generation, it does not diminish the need for electricity trade with Alberta, especially the need for imports in non-freshet months.

Total BC energy self sufficiency, though possible under certain load growth conditions, would result in either large amounts of unserved energy in BC or in significant energy waste which could otherwise be sold via exports. When the intertie is 'cut' to Alberta, BC suffers drastically large levels of unserved energy in for a normal load growth scenario, totaling 5,204 GWh. The LM and VI nodes represent the largest share of unserved energy

as they are responsible for the largest portion of load and farthest away via transmission from the large generation resources in the North. The BC system in 2030 is not capacity limited, but energy limited, meaning that while there is enough installed generating capacity serve load if all assets were run, there is not enough energy (water) available at times of need due to resource variability.

Chapter 5 - Conclusions and Future Work

5.1 Conclusions and policy implications

BC energy plans will likely lead to widespread electrification of building heating systems and increased demand for on-site renewable electrical energy. The decreasing capital cost and modular nature of solar photovoltaics (PV) makes it a prime candidate to meet this increasing demand. This thesis reviews the buildout trajectory of solar PV and the possible implications of the daily and seasonal variability of solar PV on a hydro-dominant power system, such as those found in certain Canadian provinces and Scandinavian countries. Specific attention is paid to the modeling practices of hydro-dominant systems via minimum generation requirements to accurately model power system flexibility. As a case study, this work examines the current electricity system of Western Canada and the possible future of British Columbia if large residential solar PV buildout is to take place with both technical questions and Canadian applicable policy questions addressed.

Motivation for this work was initiated by the lack of such studies in hydro-dominant jurisdictions. Though many studies have been performed to assess system flexibility in the integration of VRE, very little of this has looked at hydro-dominant systems. This work, which analyzed the addition of distributed solar PV to British Columbia's hydro electricity system, found that the addition of large penetrations of solar PV do little to reduce BC's dependency on imports under normal load growth conditions. This is because the resource timing of solar PV aligns with the freshet when very little additional energy is needed. Energy is typically needed in non-freshet months. When planning the future of the BC electricity system, it is important to keep resource timing of additional generating capacity in mind. The BC system in 2030 is not expected to be capacity limited, but energy limited, meaning that while there is enough installed generating capacity serve load if all assets

were run, there is not enough energy (water) available at times of need due to resource variability. This study shows that after a 50% penetration of all residential buildings in the four major metropolitan cities of Vancouver, Victoria, Kelowna, and Prince George, which is an approximate installed capacity of 5 GW, it is not clear that much system benefit is seen in terms of additional PV generation utilized by the grid. However, the penetrations of solar PV examined in this work do have the ability to displace electricity generated via thermal resources such as natural gas and biomass.

Currently, additional generation capacity in BC is expected to come from the additional independent power producer run-of-river assets. The future of independent power producer run-of-river generation in British Columbia was examined via the study of flexibly operation of IPP ROR units. Allowing for flexible operation of ROR units results in no PV curtailment across all load growth scenarios by greatly increasing system flexibility. Annual water spill across all load growth scenarios is also reduced, resulting in higher energy balances, meaning less energy waste. While the flexible operation of IPPs result in less water energy wasted, as well as better management of solar PV generation, it does not diminish the need for electricity trade with Alberta, especially the need for imports in non-freshet months. This change would potentially be a cost saving measure for energy purchase from ROR IPPs if water could be spilled or if alternate flexible generation resources could be found that did not have the same minimum generation profile coinciding with the freshet.

Energy independence was examined to coincide with energy planning as discussed in Section 2.1.3. Typically, energy self-sufficiency refers to whether BC is a net importer or exporter of energy throughout the year. This study examines total BC energy self-

sufficiency via eliminating power flow between BC and AB. Total BC energy self sufficiency, though possible under certain load growth conditions, would result in either large amounts of unserved energy in BC or in significant energy waste which could otherwise be sold via exports. Results justify other findings which show the benefit of more strongly interconnected electricity systems rather than self-sufficiency targets.

From a modeling perspective, this work examines the implications of modeling minimum generation constraints on hydro-dominant power systems. The modelling of minimum generation constraints in energy system production cost models is important to accurately predict flexibility constraints of future hydro-dominant systems. Without imposed minimum generation constraints and allowed flexible operation, a disparity is seen in modelled water energy spilled. When planning the future of the power system, including new generation and transmission assets, accurate modelling of the current hydro system is vital to ensuring system efficiency and least-cost impact to the ratepayers within the province.

5.2 Recommendations for future work

To complement the work presented in this thesis, the author suggests that the current production cost model be updated to address the model limitations outlined in Section 3.8 which include: no intertie modeled to the United States, a lack of sub-hourly modeling, simulated solar PV data rather than measured data, hydro turbine efficiency curves were not modeled, water traversal time is not modeled, and the minimum generation profiles are for an average year and not tied to hydrological years. Future work could examine the implications of using average typical mean year solar PV data versus historical PV data if available. This analysis would most likely see more significant ramping events that may

not be captured in typical mean year data. Most significantly, the current model lacks details which could be provided by coupling a watershed model with the current production cost model. The coupling of a watershed model would help to more accurately model the environmental effects on water systems as well as the waterflow between cascaded hydro systems.

Additional energy storage solutions, specifically battery storage coupled with solar PV systems, were not explored in this work. While it is not clear that battery storage would solve the seasonality issues found in the results of this work, results could be interesting when coupled with sub-hourly analysis of freshet period system operation.

A survey of public interest in residential solar PV could be conducted to gain a better social understanding of what currently prevents the buildout of rooftop PV and what incentives would be necessary to begin to see penetration levels as studied in this thesis.

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Appendix A

Table A.1 shows installed generation capacity in British Columbia, Canada as of 2017.

Table A.1: Installed generation capacity in MW in British Columbia, Canada as of 2017. Data available from BC Hydro [57], [58].

Generation Type	2017 Installed Capacity (MW)
Storage Hydro	13,155
Run-of-River Hydro	1,924
Gas Fired Thermal	508
Wind	702
Biomass	807
Other	65

Figure A.1 and Table A.2 detail installed generation capacity share by generation type in British Columbia, Canada as expected in 2030.

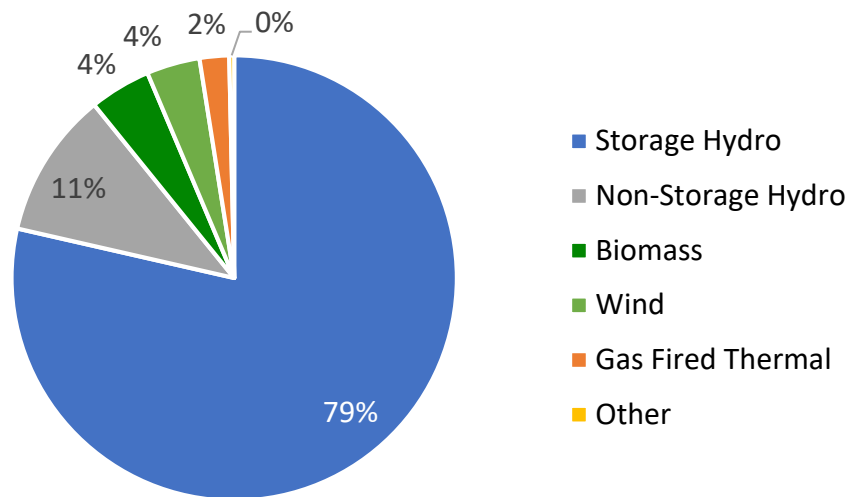


Figure A.1: Installed generation capacity share by generation type in British Columbia, Canada as expected in 2030 [61].

Table A.2: Installed generation capacity in British Columbia, Canada as expected in 2030 including the addition of Site C [61].

Generation Type	Installed Capacity (MW)
Storage Hydro	14,247
Non-Storage Hydro	1,924
Biomass	807
Wind	702
Gas Fired Thermal	389
Other	65

Figure A.2 and Table A.3 show expected 2030 installed generation capacity for Alberta, Canada.

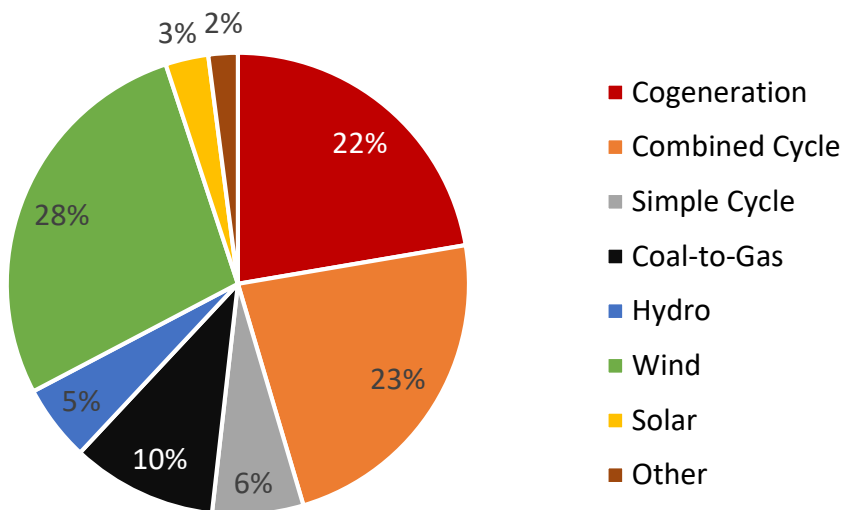


Figure A.2: Installed generation capacity share by generation type in Alberta, Canada as expected in 2030

Table A.3: Installed generation capacity in Alberta, Canada as expected in 2030.

Generation Type	Installed capacity (MW)
Cogeneration	5,204
Combined Cycle	5,386
Simple Cycle	1,486
Coal-to-Gas	2,371
Hydro	1,244
Wind	6,445
Solar	700
Other	479

Figure A.3 shows an extended view of Figure 4.12 for the 75% PV no load growth scenario.

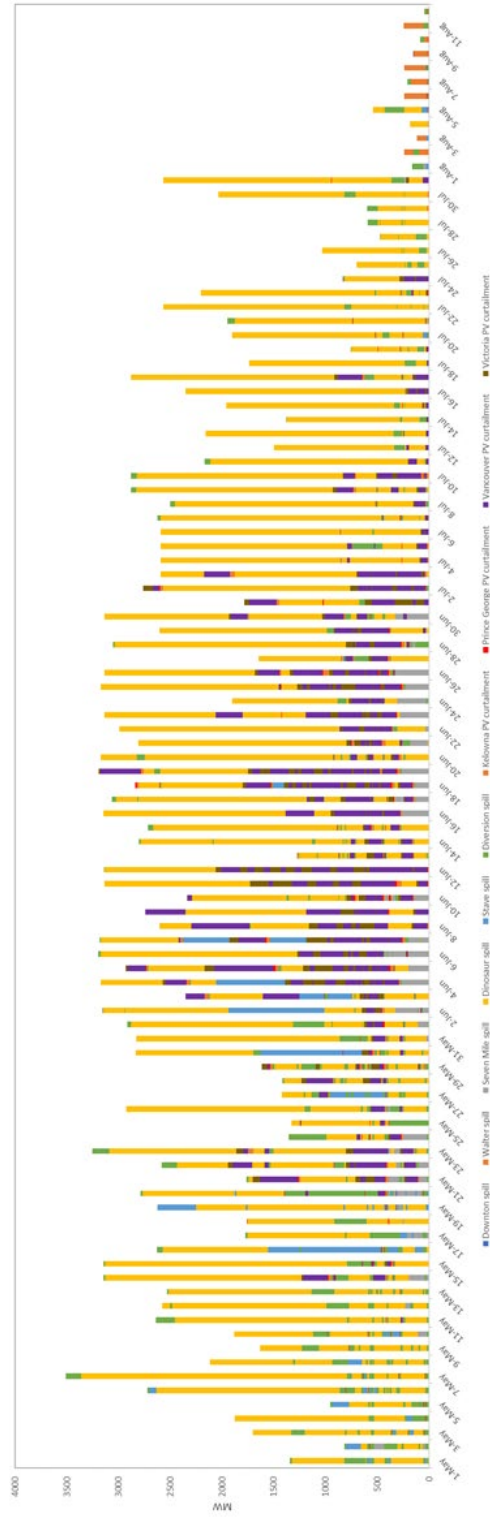


Figure A.3: Extended freshet period view of water spill and solar PV curtailment by location for 75% PV no load growth scenario.