THE POTENTIAL CONTRIBUTION OF SMALL HYDROELECTRIC GENERATION TO MEETING ELECTRICAL DEMAND ON VANCOUVER ISLAND

by

Matthew T. Schuett
B.A.Sc., University of Waterloo, 2001

A Thesis Submitted in Partial Fulfillment
of the Requirements for the Degree of

MASTER OF APPLIED SCIENCE

in the Department of Mechanical Engineering

SUPERVISORY COMMITTEE

THE POTENTIAL CONTRIBUTION OF SMALL HYDROELECTRIC GENERATION TO MEETING ELECTRICAL DEMAND ON VANCOUVER ISLAND

by

Matthew T. Schuett
B.A.Sc., University of Waterloo, 2001

Supervisory Committee

Dr. Peter Wild (Department of Mechanical Engineering)
Supervisor

Dr. Andrew Rowe (Department of Mechanical Engineering)
Departmental Member

Dr. Karena Shaw (School of Environmental Studies)
Outside Member

ABSTRACT

Supervisory Committee

Dr. Peter Wild (Department of Mechanical Engineering)
Supervisor

Dr. Andrew Rowe (Department of Mechanical Engineering)
Departmental Member

Dr. Karena Shaw (School of Environmental Studies)
Outside Member

This work focuses on the electrical contribution small hydro generation can make to meeting Vancouver Island's electrical demand, today, and as further development proceeds. A hydrologic assessment of Vancouver Island was undertaken for the period of 1999 to 2005. Eight regional areas were identified that exhibited temporally similar specific discharge runoff patterns, termed flow area curves (FACs). A small hydro generation MATLab model was developed and the FACs used as input to represent available generation flow. The model was used to calculate temporally accurate generation values from 175 small hydro facilities under four development scenarios for the seven year period. Generation results from each scenario were compared to electrical demand on Vancouver Island during that time period to determine the contribution provided by small hydro facilities. Results demonstrated that small hydro facilities are unable to offer dependable capacity, but are capable of meeting a portion of Vancouver Island's electrical demand.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

ACKNOWLEDGEMENTS

There are a number of people who were instrumental in the completion of this thesis that deserve more thanks than mere words can express.

A special and heartfelt thanks goes to Jennie, my soon to be wife, whose unwavering belief in my abilities and delicate application of pressure ensured this work was completed before we were to be wed. Her grammatical advice and uncanny ability to summarise my long explanations in short concise statements, greatly improved my writing and ensured the readability of this work.

Thank you to my supervisor, Dr. Peter Wild, who meticulously reviewed each chapter and ensured my use of colloquial terms was kept to a bare minimum. Any errors or colloquialisms that remain are the fault of the author.

I would like to express my gratitude to Lawrence Pitt, IESVic's Research Director, for the direction and advice he provided throughout the development of this work. His vast knowledge of the operation of the electrical network and its various components was invaluable and his open door policy (I treated it that way anyway) was greatly appreciated.

I would also like to thank my parents, Barb and Brian Schuett, for their encouragement throughout my pursuit of a higher education and giving me a kick in the pants every now and then to keep me going.

Lastly, I would like to acknowledge the financial contribution made by WorleyParsons Komex and the Natural Science and Engineering Research Council of Canada (NSERC) in the form of an Industrial Postgraduate Research Scholarship. Without these funds, this work would not have been possible.

NOMENCLATURE

A	drainage area (km^2)
c	calculated value
CF	capacity factor (%)
CFR	capacity factor result (%)
d	pipe diameter (m)
E!	model efficiency (%)
g	acceleration due to gravity (9.81 m/s^2)
H	head (m)
h_f	head loss due to friction (m)
i	interest (area or flow)
j	index
L	characteristic length (m)
m	mean flow of dataset (m^3/s)
n	number of observations
NR	normalised result (%)
o	observed value
P	power (kW)
P_{cu}	copper losses (kW)
P_{core}	core losses (kW)
P_{design}	nameplate capacity (MW)
P_{field}	magnetic field losses (kW)
P_{mech}	mechanical losses (kW)
PF	power factor
Q	flow (m^3/s)
R	coefficient of determination (%)
s	standard deviation of dataset
t_i	time increment (variable)
U	storage volume (m^3)
VA_{out}	power output (kVA)
V	velocity (m/s)

GREEK LETTERS

ΔP	change in power generating capacity
f	Darcy friction factor
η	system efficiency (%)
η_g	generator efficiency (%)
η_t	turbine efficiency (%)
η_p	penstock efficiency (%)
ρ	density of water (kg/m^3)

UNITS OF POWER

1 kilowatt (kW)	= 1000 watts (W)
1 megawatt (MW)	= 1000 kilowatts (or 1 000 000 watts)
1 gigawatt (GW)	= 1000 megawatts (or 1 000 000 000 watts)

UNITS OF ENERGY

1 kilowatt hour (kWh)	= 1000 watts for 1 hour
1 megawatt hour (MWh)	= 1000 kWh
1gigawatt hour (GWh)	= 1000 MWh

ABBREVIATIONS

AC	Alternating Current
BC	British Columbia
BCH	British Columbia Hydro and Power Authority
BCMEMPR	British Columbia Ministry of Energy, Mines, and Petroleum Resources
BCTC	British Columbia Transmission Corporation
BCUC	British Columbia Utilities Commission
CF	Capacity Factor
CFT	Call for Tenders
DEM	Digital Elevation Model
DFO	Department of Fisheries and Oceans
ELC	Electronic Load Controller
EPA	Energy Purchase Agreement
ESHA	European Small Hydro Association
FAC	Flow Area Curve
FDC	Flow Duration Curve
GDC	Generation Duration Curve
GIS	Geographic Information System
HDPE	High Density Polyethylene
HVDC	High Voltage Direct Current
IEA	International Energy Agency
IMP	Integrated Method for Power Analysis
LMM	Lowest Monthly Median
MAD	Mean Annual Discharge
MIP	Maximum Instantaneous Penetration
NSERC	Natural Science and Engineering Research Council of Canada
RP	Resource Penetration
RRA	Regional Runoff Area
SH	Small Hydro
uPVC	Unplastified Polyvinyl Chloride
WSC	Water Survey of Canada
VFF	Variable Fish Flow
VI	Vancouver Island

1 INTRODUCTION

Increasing public concern over the environmental costs associated with traditional forms of electrical generation has led many governments to mandate that a certain percentage of new generation be renewable (i.e., non-fossil fuel based). Within Canada, matters associated with the generation and transmission of electrical energy are under the jurisdiction of the provincial governments. In 2002, the Province of British Columbia (BC) adopted an energy policy that set the most aggressive targets for renewable energy development in Canada, stipulating that 50% of new generation be produced by green renewable sources [1]. In 2007, the new energy policy; A Vision for Clean Energy Leadership, stipulated that *clean* or *renewable* sources of generation continue to account for 90% of total generation [2]. The terms *clean* or *renewable* refer to resources that are constantly renewed by natural processes.

The BC government also set out a mandate that the Province be self sufficient in terms of energy generation by 2016 [2]. BC Hydro (BCH), however, is limited in the contribution to new capacity that it can make due to legislation that prohibits it from developing new resources beyond efficiency improvements and capacity additions to existing heritage assets [1]. Therefore, to meet growing electrical demand, BCH has turned to independent power producers (IPPs) in the private sector and has issued multiple calls for tenders (CFTs) to construct additional generation in the Province. CFTs issued in 1999, 2001, 2003 and 2005 have been answered by IPPs proposing to generate electricity using wind, biomass, natural gas, coal and, most prominently, small hydro. Capacity additions since 2002 have been from two sources: small hydro accounting for 91% and landfill gas accounting for 9% [3]. Small hydro producers also dominated the latest CFT securing 28 of the 38 Energy Purchase Agreements (EPAs) awarded by BCH. These 28 EPAs involve the construction of 35 facilities and represent a total nameplate capacity addition of 525 MW. An additional 196 MW run-of-river hydro project was also awarded an EPA but does not fit the definition of small hydro [4].

BCH defines small hydro facilities as those having a nameplate capacity of between 2 MW and 50 MW. Those with a nameplate capacity rating of less than 2 MW are considered micro hydro sites [5]. The majority of small hydro facilities are also operated as run-of-river facilities. This means they operate using a watercourse's natural available flow and do not store water using a dam like traditional hydro developments. Without the ability to store water, generation from small hydro facilities is governed directly by the available flow in the watercourse and is subject to natural variability. This makes small hydro an intermittent generation source. Introducing intermittent generating resources into an electrical grid increases the complexity of matching generation with demand while ensuring system stability. Many studies have assessed the impact of intermittent generation, most frequently wind [6, 7], on electrical supply systems. However, the literature is devoid of studies involving the impact of small hydro. This may be due to the relatively small incremental capacity addition that small hydro facilities typically contribute to a larger system. However, when considered on a cumulative basis, the future impact of small hydro facilities may be significant.

Vancouver Island is located in the southwest corner of BC. It is mountainous and yearly precipitation exceeds 2000 mm over most of the Island [8] making it an ideal location for small hydro development. Small hydro resource assessments completed for BCH identified 159 potential small hydro sites between 100 kW and 5 MW on Vancouver Island [9]. Current on-island generation is capable of supplying only a portion of the Island's electrical demand with 70% supplied from the mainland via submarine transmission cables [10]. BCH is interested in increasing on-island generation to reduce the Island's reliance on the ageing submarine transmission cables. With the large number of potential small hydro sites identified on the Island, small hydro may appear to be the obvious choice for future development. However, the intermittent nature of the resource means that it may not be capable of offering dependable capacity.

The primary objective of this study was to determine the contribution small hydro generation could make to the Vancouver Island electrical demand and what, if any, dependable capacity could be realized by distributing small hydro generators around the Island. Secondary objectives were the characterisation of the intermittent nature of small hydro resources on the Island and an assessment of the implications of incorporating a large number of small hydro facilities into the Vancouver Island electrical grid. These objectives were addressed as follows:

- Characterisation of flows available for generation;
- Small hydro site identification and model development;
- Assessment of modelled small hydro generation; and,
- Characterisation of resource intermittence.

Further development of small hydro resources on Vancouver Island would increase the amount of generation situated on the Island and could decrease reliance on transmission from the mainland.

This work begins with an overview of a small hydro facility and a review of research completed on assessing potential small hydro facilities in Chapter 2. Chapter 3 includes an assessment of the hydrologic resources on Vancouver Island and presents the method used to represent flow for all streams on the Island. In Chapter 4, the supply and demand of electricity on Vancouver Island is discussed as well as the forecasted growth in electrical demand. Chapter 5 provides a detailed description of the small hydro generation model used in this work. Results of the generation model, assessment of small hydro's ability to meet Vancouver Island demand, and an intermittence analysis are presented in Chapters 6 through 8, respectively. This is followed by sensitivity analyses in Chapter 9 that demonstrate how changes to key assumptions used in the model could influence the findings. Chapter 10 presents the conclusions of the study and outlines potential future work that could be completed to improve the generation model.

2 SMALL HYDRO OVERVIEW

Flowing water has the power to carve canyons, change landscapes and was one of the first natural resources harnessed to electrify nations. This chapter introduces the major components that comprise a small hydro facility and provides background on small hydro resource assessment techniques. The mathematical expression of the potential energy in a flowing stream of water is presented. Modifications and simplifications to this expression that have been developed to approximate the amount of potential energy that can be converted to electrical energy are discussed. The components of a small hydro facility that are responsible for the conversion of this potential energy are presented and ongoing research into the improvement of these components is reviewed.

A number of national-level and regional small hydro assessments have been performed that estimate the potential for development in terms of potential capacity. The methods used in these assessments are reviewed and their merits discussed. Using the results of these assessments, a small hydro developer may further investigate a site through specialised assessment software. Information regarding this software is provided and some available models reviewed. Finally, a brief economic overview of small hydro development is presented.

2.1 EXTRACTABLE POWER

To estimate the power output from a small hydro site requires two key pieces of information: elevation drop (head) and the flow available for generation. All sources of hydroelectric generation rely on the potential energy of water at height. The power associated with this water is expressed by the following equation:

$$P = \rho g Q H \,, \qquad [2.1]$$

where:
- P power (W);
- ρ density of water (kg/m^3);
- g acceleration due to gravity (9.81 m/s^2);
- Q flow (m^3/s); and,
- H head (m).

As with any energy conversion there are losses intrinsic to the process. For this reason, equation [2.1] must be modified to account for equipment inefficiencies:

$$P = \eta \rho g Q H, \qquad [2.2]$$

where: η system efficiency (%).

System efficiency incorporates the combined efficiency of all major components that make up a small hydro facility and influence generation. Some of these components are the turbine (η_t), generator (η_g), and penstock (η_p). Power output from utility-scale generation facilities is typically expressed in terms of kilowatts (kW) or megawatts (MW).

Within the literature, constants of gravity and density are often combined and a fixed operating efficiency is assumed [9, 11-13] or efficiency is neglected completely [14]. As a rule of thumb, the European Small Hydro Association (ESHA) uses the following equation to approximate the power available in kW [11-13]:

$$P = 7 \times QH\ . \qquad [2.3]$$

This equates to a 70% fixed system operating efficiency. In work completed by Sigma Engineering in 2000, this value was increased to 80% using a multiplier of 7.83 [9] in equation [2.3]. Fixed efficiency values can result in an overestimate of the energy supplied from a site by not taking into account system operating constraints [15]. For this reason, variable system efficiency values and specified operating constraints were used in this study.

2.2 COMPONENTS OF A SMALL HYDRO FACILITY

The following discussion provides an overview of the components that are involved in a small hydro facility and recent advances that have occurred in the field. Figure 2.1 shows the major components of a small hydro facility and a typical layout. The main generating components (turbine, generator and load controller) are located in the power house.

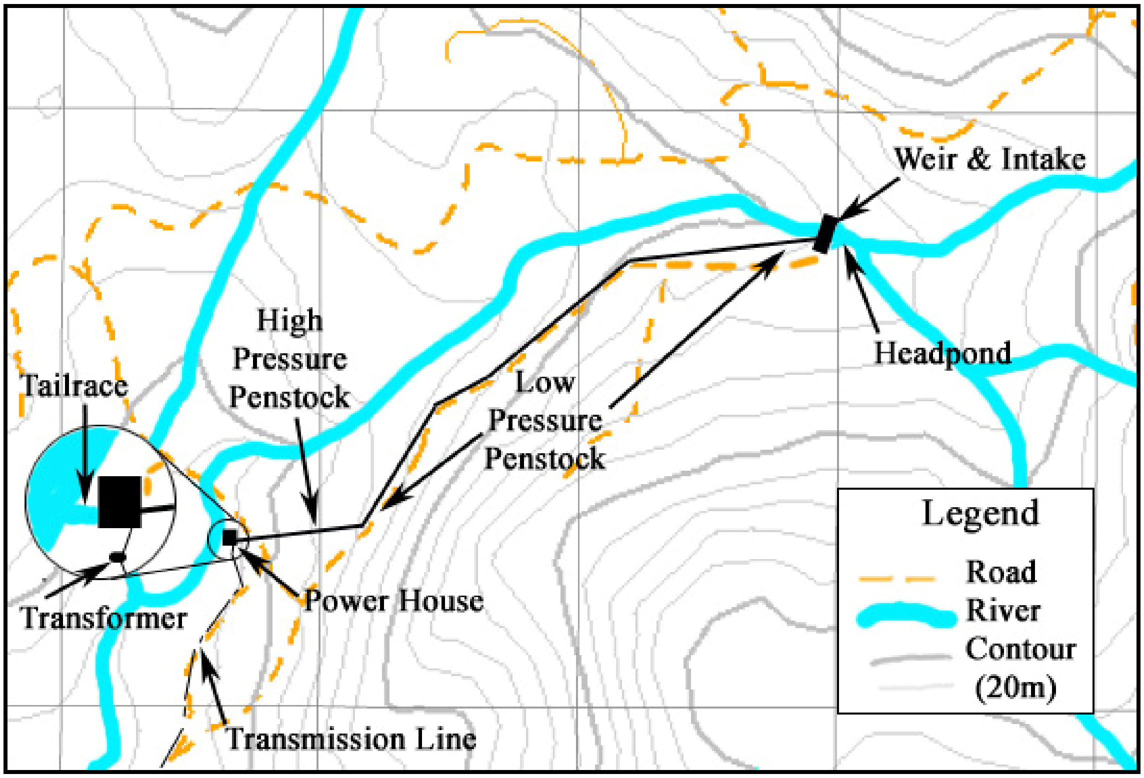

Figure 2.1: Layout of a small hydroelectric facility

A small hydro facility operates by using a portion of a watercourse's natural flow. To divert a portion of flow from the watercourse, a low head weir is usually constructed to form a small head pond. The weir ensures a certain water level is maintained in the head pond so that water can be drawn into the intakes without introducing significant quantities of air into the system. Penstocks are used to transport water from the upstream weir and intake site to the power house. On high head schemes, both low and high pressure penstocks are often used to reduce costs and decrease head losses. Once at the power house, the potential energy of the water is converted by a hydraulic turbine which is connected to an electrical generator. After imparting its energy to the turbine, the water is returned to the watercourse via the tailrace. The tailrace is usually a short channel, as depicted in Figure 2.1, from the power house to the watercourse. Electrical output from the generator must be closely controlled for use in modern electrical systems.

This is accomplished by controlling the rotational speed of the generator through a load controller. Generation typically takes place at lower voltages than are required for efficient electrical transmission. A transformer, therefore, is employed to step up the voltage to transmission levels. The transformer is typically situated immediately adjacent to the power house building.

In competitive electrical generation markets, the search for and assessment of cost effective site development strategies, structural materials, generators and turbines is particularly relevant. For example, the addition of inflatable rubber dams to the market substantially reduced the cost of civil works for small projects and provides another hydraulic control tool to the engineer [12, 15-17]. According to Gordon [18, 19], weirs of this type can deflate allowing the stream to pass heavy sediment loads during flood events while also allowing a small hydro facility to continue to operate. At high head facilities on rivers with high sediment loads, this can result in lower maintenance requirements and substantially improved turbine runner life.

When water is drawn from the head pond to the penstock, it must be screened at the intake to prevent debris from damaging the turbine runner [12, 15-20]. A low maintenance screening solution mentioned by Draisey [20] is Aquashear™. Aquashear™ is an intake that employs the Coanda effect [21]. As a result, this type of intake is able to exclude debris larger than 1 mm in diameter and is self cleaning, resulting in decreased maintenance downtime and increased runner life. Paish [16] notes many advances in this area and provides a good overview of the function these systems provide but does not give details on the systems themselves.

Advances in plastics (unplastified polyvinyl chloride [uPVC] and high density polyethylene [HDPE]) as well as fibreglass pipe manufacturing have permitted another means of improving small hydro design and development while decreasing costs [12, 15, 17]. uPVC and HDPE are ideal for low pressure penstocks, while fibreglass pipe can be used in place of steel in high pressure penstocks. Corrosion concerns associated with ductile iron or steel are also diminished, permitting more installation alternatives [18, 22].

While larger capacity turbines (> 2 MW) have achieved efficiencies upwards of 90%, there are still large improvements to be made to smaller units [12, 19]. Turbines fall into two categories: impulse and reaction [15, 22-24]. Impulse turbines convert the water's pressure energy to kinetic energy in the form of a high speed jet. The jet impacts the buckets mounted on the periphery of the turbine runner and induces rotation. Turbines of this type operate under atmospheric pressure. Alternatively, reaction turbines utilize water pressure acting on the face of the turbine blades which diminishes as it passes through the turbine. Turbines of this type are fully immersed in water and must withstand significant pressure differences between the spiral case, where water is introduced, and the draft tube, where water exits, during operation. Axial and Francis are the two major types of reaction turbines. Typically, impulse turbines have excellent partial flow efficiency, are less expensive than their reaction turbine counterparts, and require less sophisticated systems to control and operate them [15-17, 22, 25].

As a rough turbine selection guide, charts similar to that depicted in Figure 2.2 are employed to select a turbine type, based on head and flow combinations [15].

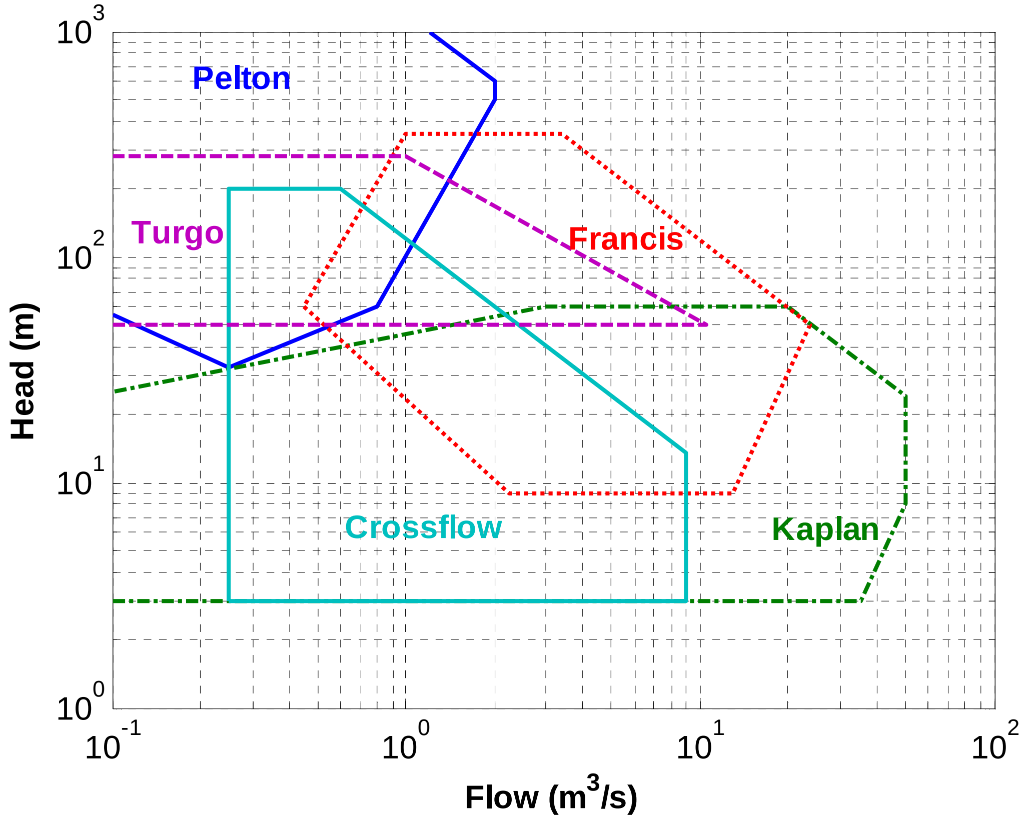

Figure 2.2: Effective head and flow combinations for typical turbine types

Charts such as these allow developers to focus on a manufacturer specializing in the type of turbine required for the site conditions.

An electrical generator is required to convert the mechanical energy of the rotating turbine shaft to electrical energy. Efficiencies of 96-99% are commonly achieved using modern synchronous generators [17, 22, 26, 27]. Asynchronous (induction) generators are also used for power generation, but typically have efficiencies that are 2-4% lower and do not operate as well under partial load [28, 29]. Synchronous generators combine a DC excitation system with a voltage regulator and, as such, are able to provide voltage, frequency and phase angle control [15, 19, 24, 27, 28]. As these generators are self exciting, they can also operate in isolation from the grid, making them useful in remote areas or in islanding situations. Islanding is a term used to describe a generator disconnected from the main electrical grid, but continuing to supply power to the local electrical grid.

In the absence of a strong grid tie to hold a synchronous generator to the correct frequency (50 or 60 Hz), an effective speed controller or a means of maintaining a load is required [16]. Older load controllers used sophisticated mechanical systems which employed servo motors to modulate the flow entering the turbine, thereby controlling the resulting rotational speed of the generator [23]. The advent of low cost Electronic Load Controllers (ELCs) in the 1980s dramatically improved the reliability and feasibility of many small hydro sites. Even with these devices, the cost, complexity and operating maintenance of a synchronous generator can be prohibitive for small installations [17, 24, 28].

2.3 SMALL HYDRO RESOURCE ASSESSMENTS

Assessments of small hydro potential have been completed in several countries throughout the world [14, 30, 31]. A synopsis of small hydro development potential in many countries is available on the International Small Hydro Atlas website [32]. Using information from these national studies, small hydro developers may use one of several small hydro assessment software packages to gain a better perspective of the nuances of specific sites. Both regional and site specific assessment procedures are discussed below.

2.3.1 Regional Assessments

When small hydro assessments are completed on national and regional levels, numerous simplifications and assumptions are made in an attempt to quantify the resource potential. In a recent study completed by the United States Department of Energy, for example, system operating efficiency was disregarded entirely (η=100%) [14, 33]. As stated previously, ESHA advocates a fixed efficiency in their rule of thumb calculation to quantify the resource [12]. The mean stream flow is also typically used to determine the size of a potential facility with modifications made to account for the residual flow that must remain in the stream [11, 13, 14, 34]. A study completed by Sigma Engineering supports the use of mean stream flow [35]. In this study, Sigma found that a small hydro facility should be sized such that 80% to 120% of the mean annual flow is used. Once the assessments are completed, the results are typically presented in terms of total capacity in MW rather than the total energy in GWh they can provide [14, 32, 36]. This is somewhat deceiving as small hydro facilities, especially those operating as run-of-river facilities, can not provide this level of generation continuously.

In Canada, assessments have been conducted at both the national and provincial levels [9, 11, 13, 17, 24, 37]. During the 1980s, under the direction of Environment Canada and the provincial ministries, several regional small hydro assessments were conducted in BC, Ontario, and Atlantic Canada [13, 35, 37, 38]. Sigma Engineering has been responsible for all utility scale small hydro studies conducted in BC [9, 13, 35, 39]. On Vancouver Island, 190 sites were identified in the first study [35]; however, this number was subsequently reduced to 159 during later studies that incorporated residual flow requirements [9]. In these assessments, the potential nameplate capacity of each site was determined based on mean annual flow, costs were approximated, and average expected generation was calculated. A constant system efficiency of 70% [35] and then 80% [9] was assumed and no operating flow constraints were employed. Any sites that were operating or under development at the time the assessment was completed were excluded. While the studies do provide an approximation of the total generation potential, no information is provided regarding the variability of generation that should be expected. The accurate representation of the timing of generation and its variation are major objectives of this work.

2.3.2 Individual Site Assessment

There are numerous software packages available to assist developers in assessing the generation potential of a small hydro site. Wilson [40] completed a thorough review of many of these packages for the International Energy Agency (IEA) and summaries are provided on the IEA small hydro website [34]. Unfortunately, the majority of the software was developed to assess individual sites and is not conducive to conducting regional assessments. Many of the software programs are also written specifically for the country where the software was produced [32, 33, 40]. Two programs written in Canada intended for world wide application [24, 41] were reviewed by the author.

Retscreen (Renewable Energy Technology Screening Software) is an Excel based analysis tool capable of assessing a project from both physical and financial perspectives [24]. From discussions with a small hydro operator and developers in BC, the program does not accurately reflect runoff conditions prevalent in BC, limiting its use in the Province [42]. However, the program does incorporate generic turbine efficiency equations that describe the dynamic performance of a turbine within its operating range [24], a characteristic not found in any of regional assessments conducted by Sigma Engineering [9, 13, 35]. These equations were incorporated into the small hydro generation model developed in this work.

IMP (Integrated Method for Power Analysis) is a small hydro assessment program that uses meteorologic and topographic inputs to model generation flow on an hourly or daily basis [41]. The major benefit of IMP is the ability to assess available generation flow and determine generation using a full runoff hydrograph. This is a departure from most other assessments [9, 13, 24, 35, 40] that rely on flow duration curves (FDCs) to size a facility and determine generation. The IMP method preserves the temporal aspects of flow and, therefore, the timing of generation, which are integral to this work. Further discussion on the differences between a FDC and full runoff hydrograph, including how they are developed, is provided in Section 3.3.

2.4 SMALL HYDRO ECONOMICS

The strong and continued development of small hydro resources throughout the world demonstrates the favourable economics of small hydro facilities. In a techno-economic evaluation of small hydro facilities in Greece, Kaldellis et al. [43] found that small hydro facilities operating in Greece with a capacity factor exceeding 30% could expect a 10 year and 15 year IRR of 13.5% and 14%, respectively. Other studies have been completed that demonstrate the economic viability of small hydro [9, 44] or ways of improving the economics even further through optimisation [45] or life cycle analysis [46] such that more development may be realised.

Montanari [46] conducted a detailed economic comparison of the capital costs associated with the purchase of a propeller turbine (a type of axial turbine) and a crossflow turbine (a type of impulse turbine) and the expected generation over their lifetimes. As flows become more variable, the crossflow turbine exhibited superior performance, because it was able to operate over a much greater range of flows.

Sigma Engineering approximated installation costs and the cost per unit of energy produced ($/kWh) in their 2000 small hydro assessment [9] for each site assessed. The capital costs were based on a combination of experience curves, cost curves, and unit price data. A site factor was then applied, based on the travel time from a large urban center to reflect the increased cost of remote sites. An example of a capital cost calculation is provided in the Sigma report.

2.5 SUMMARY

In this chapter, the equations used to determine the power of flowing water were presented. Common simplifications made to these equations for purposes of regional assessment and the pitfalls associated with using them were discussed. The techniques used to conduct regional assessments were reviewed and small hydro assessment software was presented. Positive and negative aspects of the assessment software that were incorporated into the modelling completed by this study were outlined. Finally, the economics of small hydro development was reviewed and select studies summarised.

3 HYDROLOGIC RESOURCE

Hydrology is the study of the movement, quality, and distribution of water around the earth. The movement and distribution of surface water, in particular, pertain directly to the development of small hydro sites as the sizing, location, and operation of a small hydro facility depend on the amount of water available for electrical generation. According to Wagener et al., characterizing and predicting streamflow at ungauged sites remains one of the fundamental challenges hydrologists face today [47]. The Water Survey of Canada maintains flow gauges to quantify runoff on Vancouver Island but gauge distribution is sparse and the majority of streams identified as having small hydro potential are ungauged. The approximation of runoff flows was therefore an important aspect of this work as it was needed to determine generation output.

This chapter begins with a basic discussion of hydrology and the forces responsible for runoff generation with particular focus on attributes pertaining to Vancouver Island. Methods of modelling runoff are reviewed and regionalization techniques used to generate flow time-series are discussed. Methods employed on Vancouver Island to define regional areas and generate flow time-series for this study are then presented. In-stream flow requirements and the influence they have on runoff flows available for generation are discussed. Finally the flow time-series used to represent available generation flow are validated using visual comparisons as well as statistical measures.

3.1 THE HYDROLOGIC CYCLE

The hydrologic or water cycle is driven by solar radiation. Solar heating of water on the earth causes evaporation (liquid water to water vapour), transpiration (plant respiration to water vapour) and sublimation (snow and ice to water vapour), moving water from the surface to the atmosphere. This water vapour condenses to form clouds at altitude. When clouds become saturated, water molecules collide to form water droplets which, when overcome by gravity, fall back to the surface as precipitation. Upon contact with the earth’s surface, the precipitation can accumulate as snow, pool in depressions (puddles, ponds, and lakes), infiltrate (enter porous ground), be taken up by plants, or simply runoff over the earth’s surface. Surface water runoff accumulates to form watercourses of varying sizes that direct the accumulated runoff, known as streamflow in a watercourse, downhill towards the oceans. Streamflow and the embedded energy inherent in it are the focus of this work. Figure 3.1 shows the water cycle, described above, graphically.

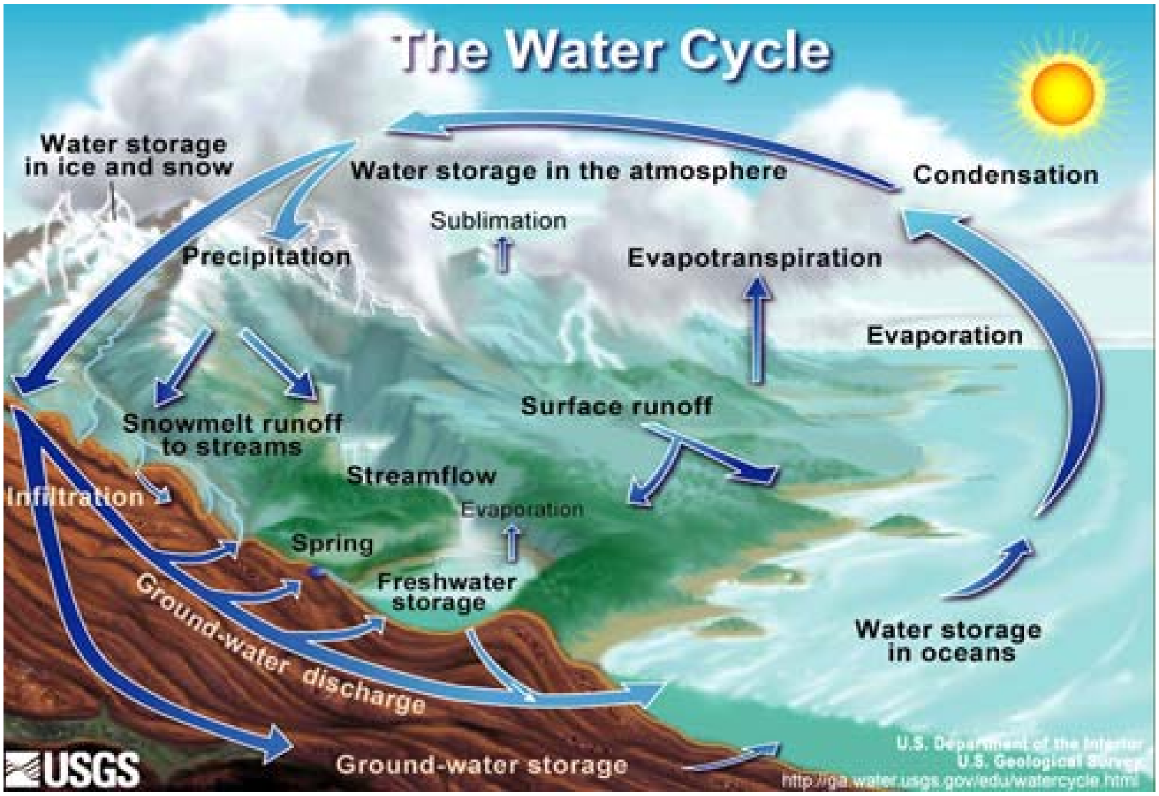

Figure 3.1: The hydrologic cycle [48]

3.2 HYDROLOGY OF VANCOUVER ISLAND

Vancouver Island is the largest island on the west coast of North America at 460 km long and up to 80 km wide with a total land area of 32 134 km^2. It is located just off the south west coast of mainland British Columbia, Canada from which it is separated by the Strait of Georga (south), Johnston Strait (mid), and Queen Charlotte Strait (north). The Strait of Juan de Fuca separates the Island from the state of Washington to the south. The west and north coast of the island border the open Pacific Ocean.

The mountains forming the Vancouver Island Ranges trend in a north-westerly direction dividing the Island into east and west; reaching their highest elevation of 2200 m in the central region of the Island. These mountains are largely responsible for the heavy precipitation that Vancouver Island receives, being the first obstacle encountered by moisture laden Pacific Ocean air masses.

In excess of 3200 mm of precipitation fall yearly on the west coast of Vancouver Island, making it one of the wettest places in Canada [8]. The east coast of the Island receives considerably less precipitation, measuring between 1000 mm to 2500 mm, owing to the rain shadow influence of the Vancouver Island Ranges and the Olympic Mountains of the state of Washington. Most of this precipitation (75%) occurs during the months of November to March in the form of rain with a notable snowfall component occurring at altitude. This heavy precipitation leads to high surface water runoff volumes that accumulate to form watercourses (streams, creeks, rivers, etc.). The form of precipitation dictates the runoff response the intercepting watercourse will have. A runoff hydrograph is a graphical representation of this response and is composed of runoff flow plotted in terms of time. There are three major types of runoff hydrograph defined by the cause of the peak runoff event [49]:

- Rainfall dominated – maximum runoff values result from rain storms
- Snowmelt dominated – maximum runoff values result from melting snowpack
- Hybrid – both rainfall and snowmelt are significant runoff contributors.

Figure 3.2 shows average monthly rainfall, snowmelt, and hybrid runoff hydrographs found in British Columbia expressed in terms of specific discharge.

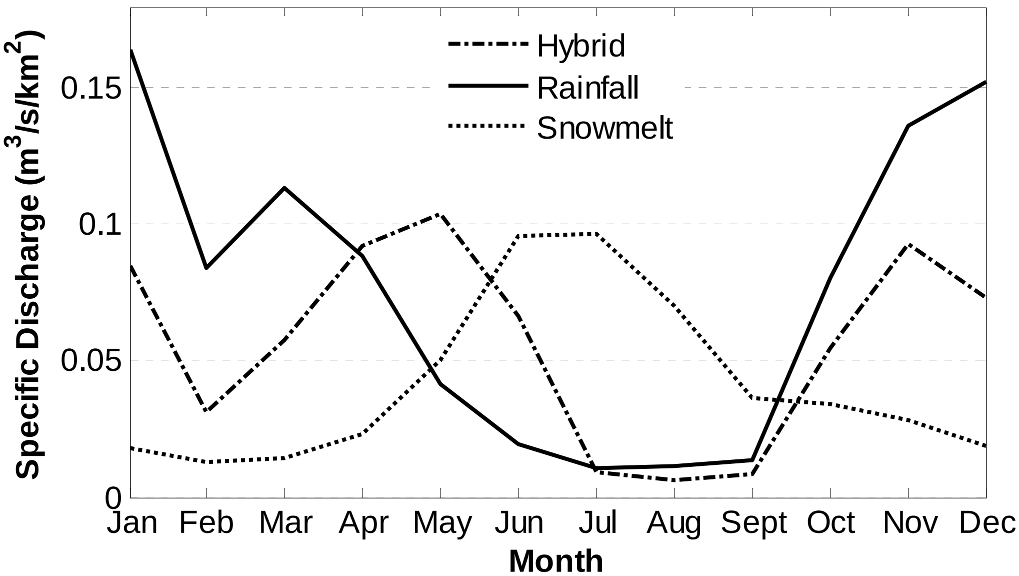

Figure 3.2: Major categories of runoff hydrograph found in BC

Based on data collected from the Water Survey of Canada (WSC) runoff hydrographs on Vancouver Island tend to be rainfall dominated in the south and far north with a notable snowfall component occurring during some years. The central Island is most accurately represented by a hybrid runoff hydrograph reflecting the influence of altitude on precipitation type.

3.3 Regional Hydrologic Modelling

Regional hydrologic models are typically developed to characterize the major hydrological conditions that dominate a region [47, 50]. This information can be used to simulate flows in the absence of measured data for flood prediction [51], power generation [52], water resource feasibility studies [37], and climate modelling [49]. Sites that have been instrumented with hydrometric flow gauging equipment form the basis of the regionalization process. These gauged streams are also used to validate the flow predictions generated by the models and calibrate the parameters describing regional hydrological conditions [53]. Once a satisfactory representation has been attained, the models may be employed to simulate flow in ungauged watercourses for the purposes noted above. Regional models have met with limited success depending on the application and the size of the regional area represented. All authors on the subject agree that the simulation of runoff flows for ungauged streams remains a major challenge for hydrologists [47, 53]. In an effort to address this challenge, the largest and oldest hydrological association, the International Association of Hydrological Sciences (IAHS), initiated Prediction in Ungauged Basins (PUB) in 2003, aimed at reducing uncertainty in hydrological practice [54]. This initiative has spurred research in model development, model improvement, error quantification, and new predictive approaches [53].

Beven [55] points out that the inherent difficulty in predicting runoff hydrograph responses for ungauged watersheds is due to every watershed being unique in topography, soil type, bedrock presence, vegetative cover, and anthropogenic modification. To address this uncertainty, several studies focusing on resource assessment and feasibility studies have employed the flow duration curve (FDC). A FDC is produced by sorting flow values in a hydrograph from greatest to least and expressing them on the x-axis as a probability that a flow value is equalled or exceeded. Once prepared, FDCs are easily compared, lend themselves to correlation assessments and are relatively easy to interpret for purposes of water resource planning. Yu and Yang [56] obtained promising results using specific discharge FDCs to identify regional runoff patterns in Southern Taiwan. Specific discharge is a measure of flow per area drained and has units of $m^3/s/km^2$.

While FDCs are useful for demonstrating the availability and variability of flow, they fail to capture the temporal aspect of the traditional runoff hydrograph [37, 56]. For this analysis, the temporal information embedded in a runoff hydrograph was required to maintain the focus of the study. Regional hydrographs were developed for Vancouver Island based on runoff information collected from 31 WSC gauging stations situated on the Island, over a seven year period (1999-2005). Specific discharge information from these 31 gauging stations was used to identify eight dominant runoff hydrographs on Vancouver Island. The runoff hydrographs selected to represent each Regional Runoff Area (RRA) were amalgamated to form a specific discharge Flow Area Curve (FAC). These FACs offer a simple method of describing flow in any watercourse on the Island within the seven-year time-series noted earlier. The particulars of how this was achieved are discussed in further detail in the following sections.

3.3.1 Vancouver Island Regional Runoff Development

Every watershed is unique in terms of rainfall, area drained, vegetation coverage, elevation range, and countless other aspects. Of the numerous watersheds identified as being suitable for small hydro development on Vancouver Island, most do not have hydrometric flow gauging stations. This posed a problem as time and resources did not permit the extensive field work or data mining required to determine the characteristics of numerous potential sites.

The WSC currently maintains 59 flow based hydrometric stations on Vancouver Island. Of these, 37 are situated on watercourses that are not directly regulated through means of flow control structures. These natural run sites were used to identify areas exhibiting a homogeneous runoff response pattern. An area influenced by the observed runoff pattern will be referred to as a RRA. Three to six gauged streams were used to represent each RRA. The aerial extent of each RRA was defined by regional topography, precipitation zones, the WSC's gauge locations, and watershed extent. In total 31 hydrometric stations were used, 28 natural, two regulated, and one inactive (retired in 2002), to define eight RRAs. The two regulated hydrometric stations employed as a representative watercourse used to define an RRA were naturalized. This means the measured flow was corrected to account for the portion of flow added to or diverted from the natural watercourse upstream of the measurement location. Figure 3.3 illustrates the eight RRAs and the location of hydrometric stations on Vancouver Island.

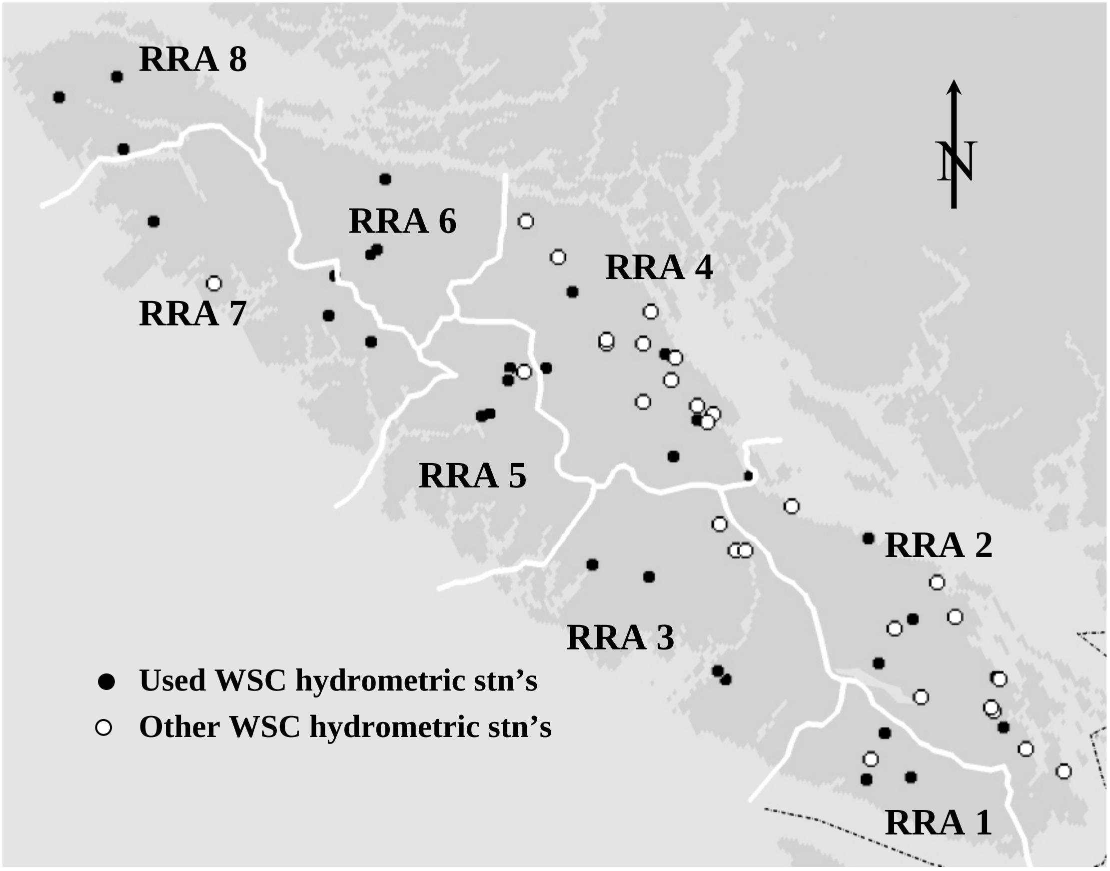

Figure 3.3: WSC gauging station locations on Vancouver Island

WSC hydrometric station data, representing several watersheds within each RRA, were compared and the watersheds were found to contribute to stream flow on the basis of specific discharge. When used in the context of surface water hydrology, specific discharge is a measure of flow per unit area having units of $m^3/s/km^2$. The finding noted above means that each unit area within a given RRA contributes approximately the same amount of runoff volume to a watercourse within that RRA. This finding is further investigated in Section 3.4 using visual and statistical analysis methods.

Flows measured at a hydrometric gauge at a particular location in a watershed can be used to approximate flows in any other part of that watershed. This approximation is based on the assumption that specific discharge is the same throughout a watershed. For the watershed shown in Figure 3.4, this approximation can be made using the following equation:

$$Q_i = \frac{A_i}{A_{gauge}} \times Q_{gauge}, \qquad [3.1]$$

where: Q flow (m^3/s);
A drainage area (km^2);
i interest (flow and area); and,
$gauge$ gauge (flow and area).

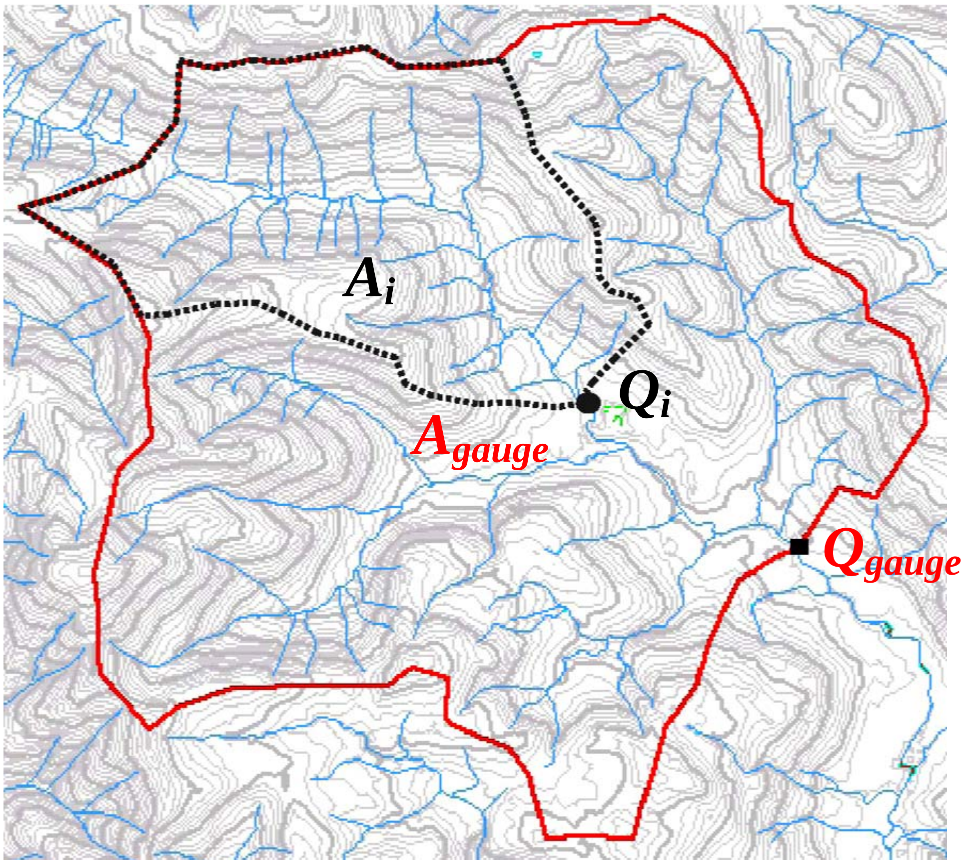

Figure 3.4: Flow adjustment diagram

A separate analysis was completed to validate the assumption that specific discharge provides a reasonable means of approximating flow within any part of a watershed. The methods used to conduct this analysis and the results are presented in Section 3.4.1.

Using regionally defined specific discharge permits the approximation of flows for similar watersheds in relatively close proximity to one another [52, 56]. Daily runoff data from the 31 WSC hydrometric stations for the period of 1999 to 2005 were used to develop a specific discharge hydrograph for each RRA. To define this hydrograph, daily flow values from each gauge were divided by the area drained. This resulted in a specific discharge hydrograph for each gauge in the RRA. Figure 3.5 illustrates the three specific discharge hydrographs that are within RRA 5. Each hydrograph tends to follow the same pattern indicating each watershed is responding similarly to precipitation events.

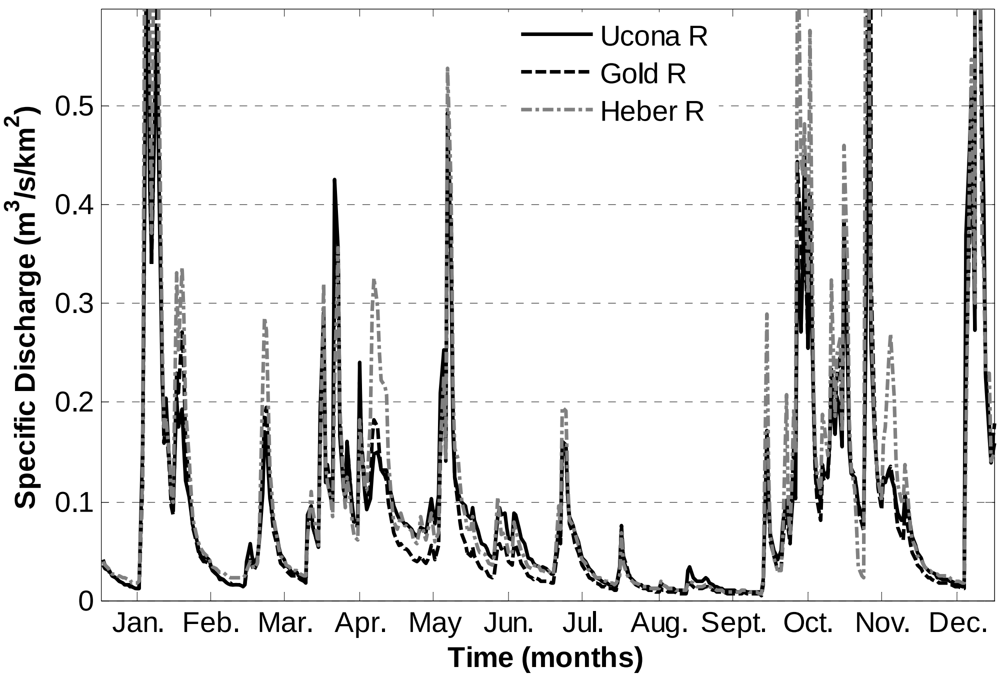

Figure 3.5: 2005 RRA 5 specific discharge hydrograph comparison

A single composite hydrograph was created for each RRA by taking the median of all specific discharge hydrographs used to represent the RRA. This single hydrograph was called a FAC and was used to define the flow of any watercourse in a RRA based on the area drained. The hydrometric stations used to develop the FACs were chosen on the basis of location, data quality, the existence of a potential small hydro site in the watershed, and the drainage area. Statistical measures commonly applied to hydrometric models are discussed and used to quantify the applicability of the FAC in Section 3.4.2. Appendix A contains a table of all gauging stations on Vancouver Island that were considered in the construction of the FACs, including information regarding those sites that were excluded.

3.3.2 In-stream Flow Requirements

In an effort to maintain watercourse ecosystems, in-stream flow requirements have been prescribed by the Province and the Department of Fisheries and Oceans [DFO]. These residual flows define the minimum flow that must be maintained at all times directly downstream of the point of diversion when the plant is generating. In 2004, the BC Ministry of Water, Land and Air Protection together with the Ministry of Sustainable Resource Management commissioned a study that produced updated “working” in-stream flow guidelines. The guidelines are “working” meaning they are still under development and have not yet been fully legislated as of May, 2007. Prior to these guidelines, in-stream flows were set to a minimum of 10% of the mean annual discharge (MAD) of the watercourse. Therefore, the old 10% MAD criteria were used to model in-stream flow requirements for all small hydro sites that were under development prior to 2007. The MAD for each FAC was determined using the entire 1999-2005 daily flow dataset. The 10% MAD was then subtracted from each FAC value to ensure the in-stream flow was maintained. When the 10% MAD flow requirement was greater than the daily FAC value, a zero value was used, indicating that no flow was available for generation.

Undeveloped small hydro sites were modelled using the new guidelines. These guidelines stipulate that, for non-fish bearing streams, minimum flow shall meet or exceed the median flow for the lowest flow month of the year [57]. In this document, this criterion will be referred to as the Lowest Median Month (LMM) criterion. A fluctuating minimum flow requirement has been proposed in the guidelines for fish bearing streams, but when this Variable Fish Flow (VFF) criterion will apply has not been clearly defined. The intakes of many small hydro sites are situated at or above natural fish barriers. It was, therefore, assumed all identified small hydro streams were non-fish bearing over the impacted portion of the watercourse. A sensitivity analysis was completed to gain perspective of how fish bearing status might affect generation output from undeveloped small hydro facilities and is discussed further in Section 9.3.

To model in-stream flow requirements at undeveloped sites, the LMM flow value was calculated using the entire seven year dataset. This value was then subtracted from each

FAC value to ensure residual in-stream flows were maintained. When the in-stream flow requirement was greater than the daily FAC value, a zero value was used, indicating that no flow was available for generation.

3.4 FAC VALIDATION

Validation is an integral part of model development, required to give confidence in the outputs derived from modelled data. Validation of modelled flows was completed using both visual and statistical methods. The visual method involved plotting the FAC and comparing it to the actual river runoff hydrographs in a RRA [58]. Statistical methods used to test the runoff representation of the FAC were the coefficient of correlation (R), coefficient of determination (R^2) and model efficiency (E!) suggested by Nash and Sutcliffe [59]. The correlation coefficient is defined as:

$$R = \frac{\frac{1}{n}\sum_{j=1}^{n}\left(Q_o^j - m_o\right)\left(Q_c^j - m_c\right)}{s_o s_c}, \qquad [3.2]$$

where:	Q	flow (m^3/s);
	m	mean flow of dataset;
	s	standard deviation of dataset;
	o	observed value;
	c	calculated value; and,
	n	number of observations.

The correlation coefficient and the coefficient of determination do not account for bias and demonstrate only that the modelled and observed data can be described by an arbitrary linear relationship, not the 1:1 relationship typical of an accurate model [60]. They were, therefore, employed as a measure of how well the FAC related to the observed data on a temporal basis only. To assess the FAC modelled flow on both a temporal and volumetric basis, thereby accounting for the bias intrinsic to R, Nash-Sutcliffe's model efficiency described by equation [3.3] was employed:

$$E! = 1 - \frac{\sum_{j=1}^{n}(Q_o^j - Q_c^j)^2}{\sum_{j=1}^{n}(Q_o^j - m_o)^2}. \quad [3.3]$$

For reference, a value of one, for all statistical measures represents a perfect representation. The implementation and results of these tests and the area of interest they pertain to is described below.

3.4.1 Inter-watershed Analysis

To test the assumption that watersheds on Vancouver Island have a homogeneous response to runoff events characterised in terms of area drained, an inter-watershed analysis was completed on the Salmon River watershed. The headwaters of the Salmon River are located in the northern portion of Strathcona Provincial Park west of the town of Campbell River on Vancouver Island. The river flows north and enters Johnstone Strait at the town of Sayward. Four active WSC gauges are situated on the river (08HD015, 08HD020, 08HD007 and 08HD006) representing increasingly larger drainage areas. The WSC gauge 08HD020 monitors the quantity of water diverted into the Campbell River watershed and was used to correct the downstream Salmon River flow gauges such that natural flows were represented. Figure 3.6 depicts the gauged portion of the Salmon River Drainage Basin and the location of each of the WSC gauges within the watershed.

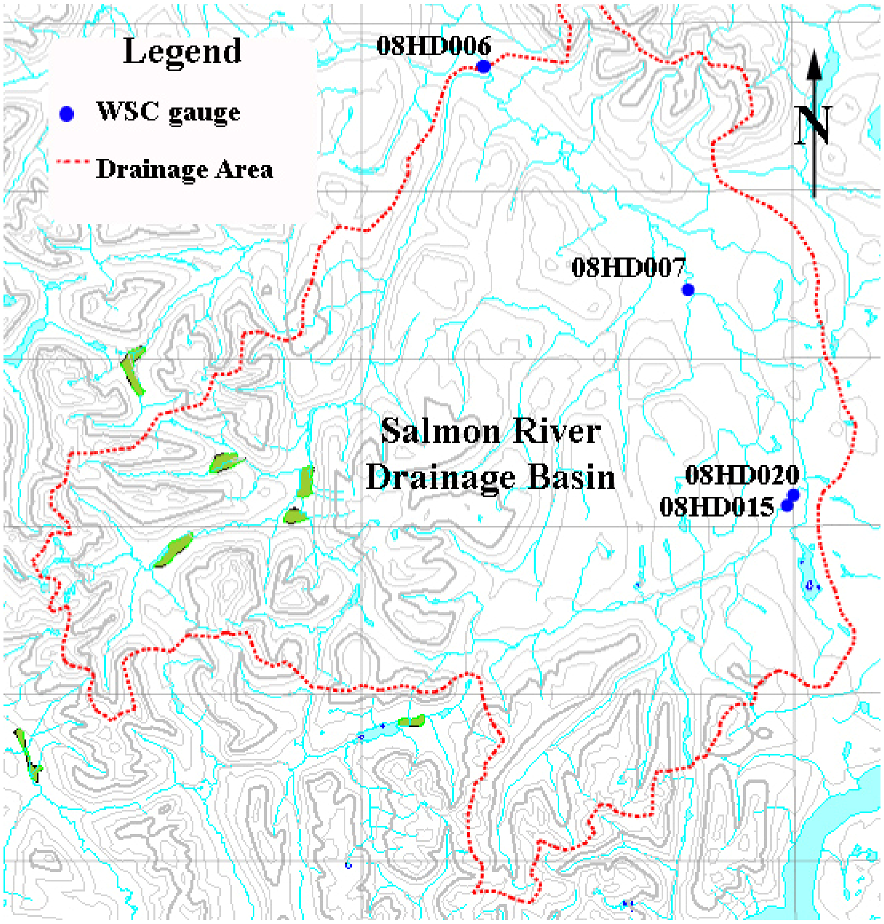

Figure 3.6: Salmon River Drainage Basin and WSC gauge locations

To compare the inter-watershed runoff response on a specific discharge basis, runoff values from each WSC gauge were divided by the drainage area upstream of their respective gauge. An aggregate watershed FAC was created using the median flow-area value of the three gauging locations. To determine the goodness of fit provided by the aggregate watershed FAC, validation techniques described at the beginning of this section were employed. Table 3.1 lists the characteristics of each gauging location and the calculated R^2 and E! from upstream to downstream. The WSC gauge 08HD020 was excluded from the comparison as it measures the quantity of flow diverted out of the Salmon River basin only.

Table 3.1: Salmon River WSC gauging location characteristics

WSC Gauge	Drainage Area (km^2)	MAD (m^3/s)	R^2 (%)	E! (%)
08HD015	268	13.29	97.64	97.1
08HD007	439	19.05*	98.23	95.98
08HD006	1210	66.86*	97.86	96.69

Note*: Values corrected to account for water diverted upstream

The coefficient of determination and model efficiency show that the FAC accurately predicts both temporal and volumetric flow characteristics on the Salmon River at all gauging locations. The small difference between the measures demonstrates that little bias exists. Figure 3.7 shows the runoff hydrographs of each site represented in terms of specific discharge as well as the aggregate FAC they form.

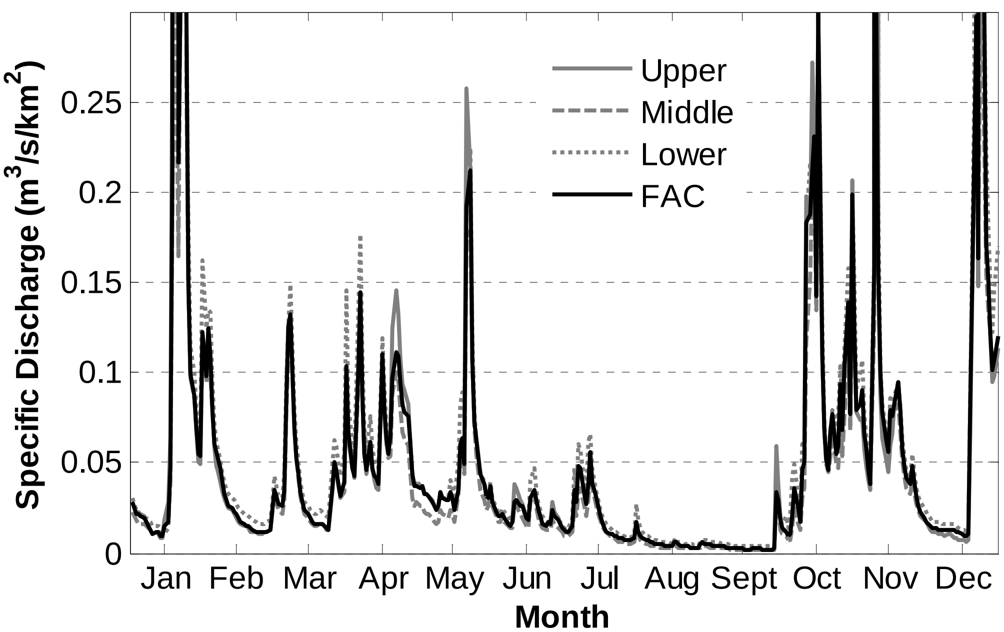

Figure 3.7: Salmon River inter-watershed specific discharge comparison

A visual comparison of the specific discharge at each gauging location demonstrates a very close correlation in terms of runoff response. The FAC provides an accurate representation of specific discharge at all locations. Subtle variations do occur due to the flow attenuation that results from larger drainage areas and longer river lengths. Both visual and statistical validations of the estimated Salmon River FAC support the assumption that Vancouver Island watersheds have a homogeneous response to runoff events characterised in terms of area drained.

3.4.2 Synthesised Flow Values

The FACs were developed to provide synthesised flows for any watershed within a given RRA. Correlation coefficients and Nash-Sutcliffe model efficiency values were calculated for each gauged stream representing a RRA by comparing FAC flows to directly measured values as described at the beginning of this section. A coefficient of determination in excess of 75% was required for a river to be included in a RRA. Table 3.2 contains the summarised results of this analysis in terms of median R^2 and E! values of each RRA.

Table 3.2: Median statistical results for each RRA

RRA	R^2 (%)	E! (%)
1	92.93	89.87
2	83.09	80.70
3	87.64	80.30
4	89.69	83.40
5	97.44	96.98
6	93.79	92.93
7	91.17	79.21
8	91.42	91.00

Significant differences between the correlation of determination and model efficiency denote the presence of conditional or unconditional bias at one or more of the gauged streams within the RRA. The bias usually takes the form of under or over estimation of stream flows at a particular site. This is discussed further below. Figure 3.8 and Figure 3.9 show visual comparisons of gauged flow and calculated flow on the Chemanus River and Carnation Creek, respectively. These rivers represent the best (97.4%) and worst (41.7%) fit, as determined by the model efficiency calculation.

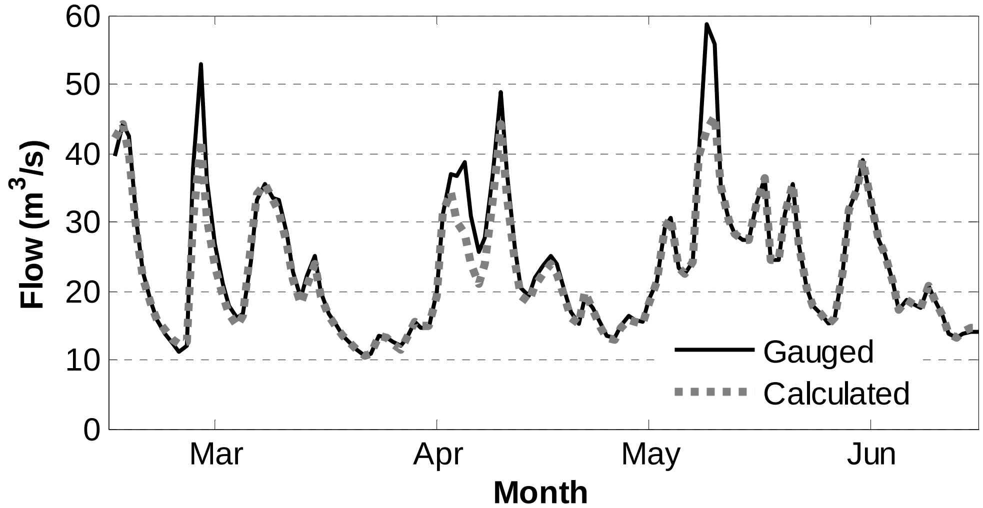

Figure 3.8: Chemanus R. gauged flow compared to FAC calculated flow

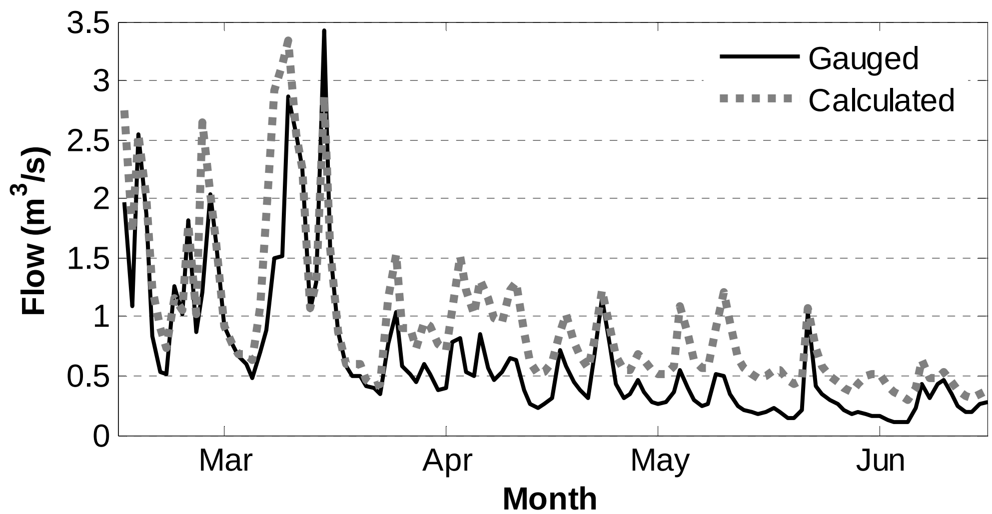

Figure 3.9: Carnation Ck. gauged flow compared to FAC calculated flow

The March to June 1999 time period was chosen for the figures due to the clear depiction of several runoff events of varying size. The y-axis was scaled to the 95th gauged flow percentile calculated over the entire 1999-2005 time series. In both cases, the temporal aspects of the calculated flows match closely with the gauged runoff responses. However, in Figure 3.9 the calculated flow values overestimate gauged values by 100% in some instances. A possible reason for this is Carnation Creek's location and the shape of its drainage basin. The creek originates 7 km inland from its mouth on Barkley Sound and drains the easterly (leeward) side of two small mountains. The drainage basin is very narrow with a maximum width of only 2 km. The other streams representing RRA 3 have broad catchment areas that extend well inland and are able to take advantage of orographic precipitation effects.

Carnation Creek represents an anomaly in terms of calculated model efficiency values. Only two other E! values were calculated to be below 70%. Both of these cases also preserved the temporal aspects of their gauged counterparts indicating that the FACs are well suited to the intended purpose of this work in terms of assessing the timing of flow availability. These anomalous results also demonstrate the importance of conducting site specific studies to quantify the flow resource using actual measurements. Overall, the results summarised in Table 3.2 demonstrate that the FACs provide a sound starting point from which to assess flow availability and calculate generation on a regional basis. Therefore, FACs will be used to represent available generation flow to calculate the contribution small hydro can make in meeting Vancouver Islands electrical demand.

3.5 SUMMARY

This chapter reviewed the hydrologic cycle and introduced the reader to regional hydrologic modelling. The methods used to identify eight areas exhibiting homogeneous runoff patterns on Vancouver Island, called RRAs, were described. Gauged watersheds within each RRA were used to develop regional hydrographs known as FACs. Flows described by a FAC require adjustment to account for minimum flow requirements prior to being used to define available generation flow. Methods used to determine these minimum flow requirements for non-fish bearing watercourses were explained. Finally, the flow values calculated by the FACs were validated using visual and statistical measures. Results of the validation demonstrated that FAC calculated flows were representative of natural flows occurring within the RRA the FAC represented.

4 VANCOUVER ISLAND ELECTRICITY SUPPLY AND DEMAND

The energy of British Columbia's rivers and streams has been instrumental in the economic and industrial development of the Province. Electrical generation using small hydro in particular was responsible for furnishing many early saw mills and towns with mechanical and electrical power needed for economic growth [61]. On Vancouver Island, small hydro facilities and local steam generators supplied the majority of electrical demand until 1953 when the 120 MW John Hart Project was completed. Further development of on-island hydroelectric resources continued through the 1950s, however these hydro resources were inadequate to meet growing demand. In 1956, the Vancouver Island and mainland electrical grids were connected with a high voltage submarine transmission cable ending Vancouver Island's electrical independence [62].

Vancouver Island continues to rely on generation from the mainland to supply the bulk of electrical demand. On-island generation currently accounts for less than 35% of peak electrical demand. When all on-island generating resources operate at 100% of nameplate capacity, these sources are unable to meet even the minimum demand. Unmet demand is supplied by generation from the mainland which is transmitted hundreds of kilometres, incurring transmission losses and, as demand increases, further taxing a system that is already close to capacity. Figure 4.1 provides an estimated breakdown of Vancouver Island's electricity supply during the peak demand of 2004 and the average summer demand of 2003. All BCH facilities and Independent Power Producers (IPPs) are assumed to be operating at their nameplate capacity during these periods. This is very unlikely to occur during the summer months but has been presented as a best case scenario.

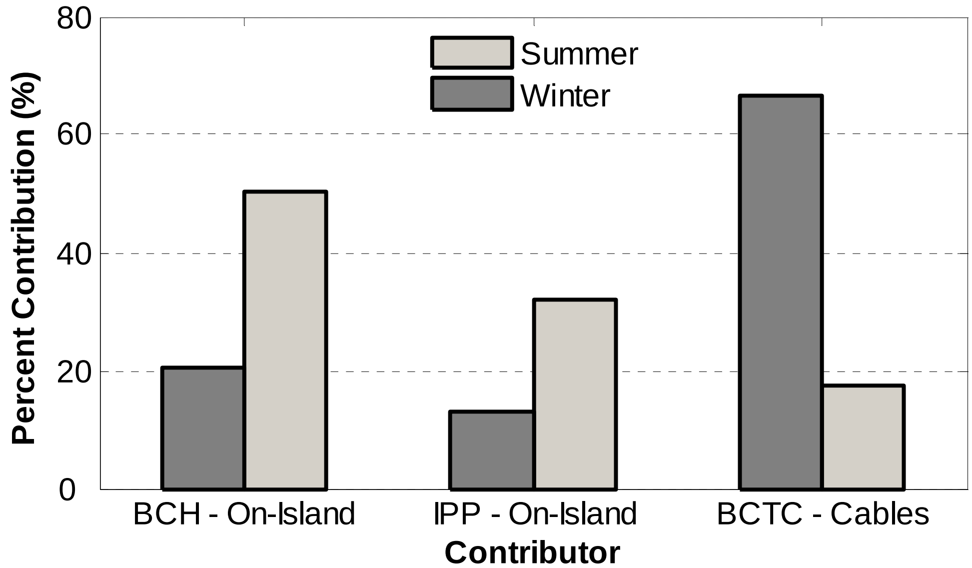

Figure 4.1: Vancouver Island electricity supply scenarios

BCH is the main power producer and only power distributor on Vancouver Island. BC Transmission Corporation (BCTC) is the main power supplier to the Island during peak demand periods via submarine transmission cables which connect the island to the mainland electrical grid. This chapter identifies the characteristics and capacities of these generating / transmission means of electrical supply to Vancouver Island. Electrical demand on Vancouver Island is then reviewed, followed by a final section on forecasting electrical demand growth.

4.1 VANCOUVER ISLAND ELECTRICAL SUPPLY

BCH facilities account for the majority of generating capacity on Vancouver Island. Their generating capability is derived from six large hydro facilities with a total generation capacity of 459 MW and one 44 MW diesel generation site. IPPs are developing an increasing presence on the Island, currently accounting for 285 MW of generation.

Each of the hydro facilities operated by BCH has the ability to store water in an upstream reservoir for future power generation if the incoming flows exceed generation requirements. Hydro facilities of this type also have the ability to ramp up and down quickly, as electrical demand changes, allowing them to act as electrical load levellers that stabilise the Island's electrical grid. Table 4.1 lists the location and nameplate capacity of BCH's hydroelectric facilities on Vancouver Island [63].

Table 4.1: BC Hydro large hydro facilities on Vancouver Island

Facility Name	Capacity [MW]	River System
Jordan	170	Jordan River
Ash River	28	Ash River
Puntledge	24	Puntledge River
John Hart	126	Campbell River
Ladore	47	Campbell River
Strathcona	64	Campbell River

While the on-island hydro facilities have a total capacity of 459 MW they have a *dependable capacity* of 450 MW and this level of generation can only be sustained for 3 hours per day during the winter period [64]. *Dependable capacity* refers to the reliable nameplate capacity available at any time. Reliable means the named dependable capacity will be available a high proportion of the winter demand period that extends from November through March.

BCH's Keogh facility, the 44 MW diesel generator, is located between Port McNeill and Port Hardy on the northern reaches of Vancouver Island. This generator is used exclusively for emergency power supply during transmission disruptions to the northern tip of the island. For this reason it was excluded from further analysis in this work.

Independent power producers generate power that BCH purchases according to electricity purchase agreements (EPAs). As of 2006, 10 IPPs were operating on Vancouver Island at 12 different locations, adding an additional 285 MW of generation capacity to the Island's electrical grid. Future IPP developments currently underway could add an additional 188 MW to the existing capacity.

4.1.1 IPP - Cogeneration

Calpine's Island Cogen Facility in Duncan Bay, north of Campbell River, supplies 240 MW to BCH while supplying low-pressure steam to Catalyst Paper's Elk River Pulp and Paper mill for process heat. As a result of this dual duty, the Cogen facility operates in a continuous generation mode, providing electricity, regardless of demand, to the Vancouver Island electrical grid throughout the year while the mill is operating.

4.1.2 IPP - Run-of-River Hydro

Currently there are 10 small hydro plants operating on Vancouver Island, eight of which are run-of-river facilities. These eight facilities generate their nameplate capacity only when suitable water flow conditions allow. During the rest of the year they are forced to run at a portion of their full capacity or shut down entirely due to insufficient flows. It is for this reason that these plants tend to operate on a *must run* basis, providing power to the electrical grid when they can and not necessarily when it is needed. This characteristic forces other generation sources to buffer the effect of both changes in demand as well as changes in intermittent generation from these *must run* sources. Given the current low level of grid penetration of intermittent *must run* systems, there is little problem in assimilating these sources into the existing generation matrix. However, as these systems become more prevalent, grid instabilities may result.

4.1.3 Future IPP Activity on VI

CFTs for new IPP generation issued by BCH have resulted in increased IPP activity on Vancouver Island. During the last CFT, BCH awarded EPAs to seven IPPs on the Island. In addition, four IPPs are currently still in the development process from the previous CFT. Table 4.2 gives a list of projects that have outstanding EPAs with BCH [4, 65]. These new sources represent a 188 MW addition to the Vancouver Island electrical grid in the near future with 30% of this capacity from intermittent sources. Those sites with storage are only able to store limited quantities of water (storage volume is much less than BCH facilities). Once storage has been exhausted they operate as run-of-river facilities.

Table 4.2: EPAs generation type and nameplate capacity

Name	Generator Type	Nameplate Capacity [MW]
Green Island Energy	Steam	90
Barr Creek	Run-of-River Hydro	2.5
Franklin River	Run-of-River Hydro	6.6
McKelvie Creek	Run-of-River Hydro	3.4
Raging River 2	Run-of-River Hydro	4.0
Tsable River	Run-of-River Hydro	4.5
Ucona River	Run-of-River Hydro	26.0
Victoria Lake	Run-of-River Hydro	9.5
Clint Creek	Storage Hydro	5.8
Songhees Creek	Storage Hydro	14.5
Zeballos Lake	Storage Hydro	21.8

4.1.4 Transmission Cables

BC Transmission Corporation is responsible for high voltage electrical transmission in BC, connecting distant generators to the load centres of the lower mainland and Vancouver Island. The Island is tied into this transmission network at two points: Dunsmuir, where the AC cables contribute a maximum of 1300 MW (2-hour circuit rating at this level); and, Duncan, where the Vancouver Island Terminal can invert up to 240 MW of High Voltage DC (HVDC). The HVDC cables are at the end of their useful lifespan and, as of the fall of 2007, will be downgraded to a reliable transmission capacity of 0 MW [66]. BCTC was in the design and public consultation phase of the Vancouver Island Transmission Reinforcement (VITR) Project during the writing of this document. The VITR Project will bring the installation of a 237 kV AC transmission line adding 500 MW of transmission capacity [10].

The VITR Project was accepted only after BCH had attempted to increase firm on-island supply through the development of a natural gas generating facility. The development of this facility would have decreased the Island's reliance on generation from the mainland and allowed the HVDC to be retired without the immediate need for a replacement. The plant was originally to be sited in Port Alberni with the natural gas supplied by the Georgia Strait Crossing (GSX) natural gas pipeline [67]. On October 22, 2001 the Port

Alberni City Council voted against a re-zoning amendment required for the project to proceed [68]. Interestingly, around the same time in 2001 the BC Legislature passed Bill M 203. The Bill ensured that Vancouver Island residence and businesses were not charged higher electricity rates than other areas of BC [69]. With the cancellation of the Port Alberni project, BCH needed to secure another means of ensuring power to Vancouver Island and, once secured, Bill M 203 meant costs could not be recovered directly from Island customers.

In October of 2003, BCH issued a CFT for generation sited on Vancouver Island [70]. The call required the facility have a high dependable capacity effectively excluding most sources of renewable generation. The CFT awarded an EPA to Duke Point Power Limited Partnership and on February 17, 2005 the British Columbia Utilities Commission (BCUC) approved a plan to construct a 265 MW natural gas generator [71]. Repeated appeals to the BCUC by Island residents, industry and lobby groups forced the cancellation of the project on June 17, 2005 by BCH on the grounds of the delay causing an unacceptable risk of the facility not being operational by the date required [70].

The transmission of electricity over long distances is subject to significant resistance losses. These losses are reduced by transmitting power at higher voltages or generating power close to its point of use. The former loss reduction strategy is prevalent in BC, where 80% of electricity generated is produced at hydroelectric facilities on the Peace and Columbia River systems. Power generated at the major sites in these systems (Columbia River: Revelstoke – 1840 MW and Mica – 1730 MW; Peace River: GM Shrum - 2730 MW and Peace Canyon - 695 MW) travel approximately 950 km to 1350 km when used to supply Vancouver Island. BCTC's transmission scheduling rates stipulate that all transmission transactions will incur 6.28% transmission losses calculated at the point of receipt [72]. Assuming the 6.28% transmission loss rate applies to the transmission of electricity to Vancouver Island regardless of generation origin, this represents losses of 95 MW during the peak demand.

BCTC is also responsible for intra-island transmission, bringing electricity generated in or delivered to the central part of the Island to demand centres in the south. Figure 4.2 gives an overview of the Vancouver Island electrical transmission grid including the connections with the mainland [73].

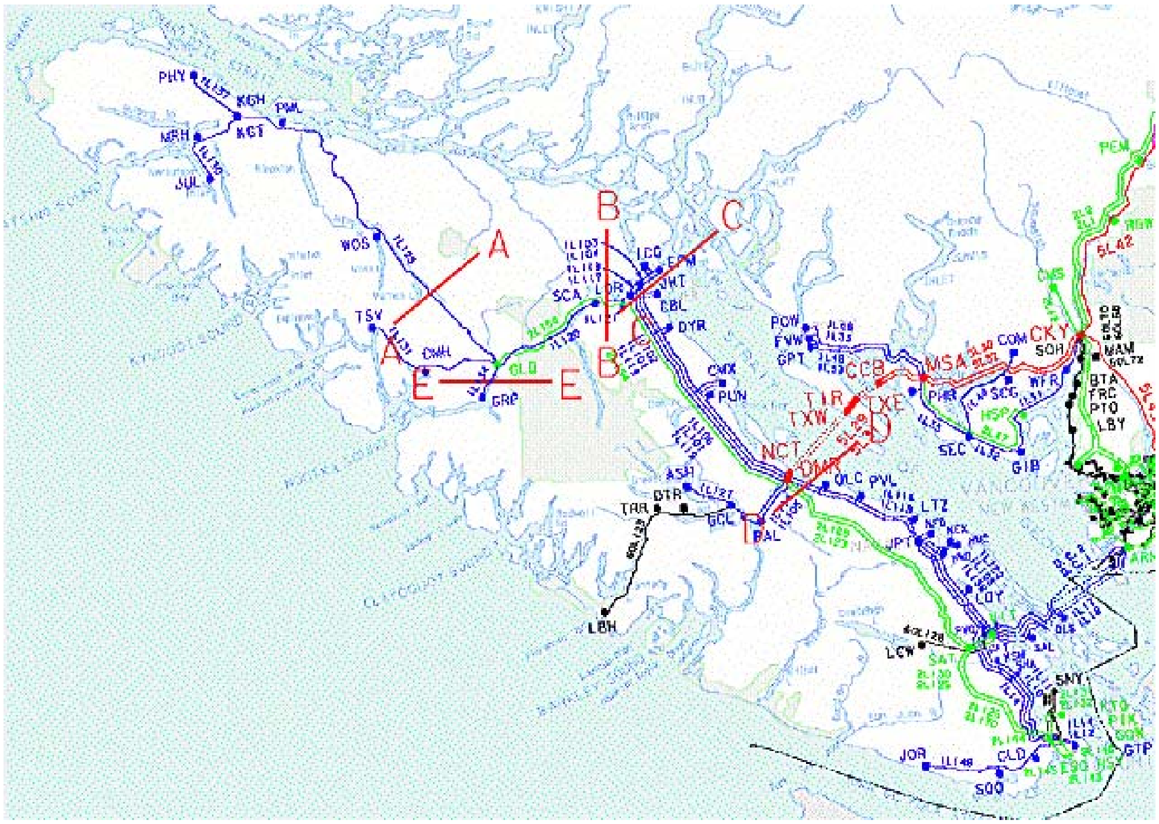

Figure 4.2: Vancouver Island electrical transmission grid [73]

Current transmission capabilities of these high voltage lines limit the amount of new generation that can be pursued in the northern reaches of Vancouver Island. The most up to date transmission limits for the forecast 2008/2009 winter peak and 2009 summer conditions demonstrate that cut planes B and C, shown in Figure 4.2, are the areas that may require upgrades if new generation were to be developed north of these points [73]. This is based on the assumption that the VITR project is completed and functioning. If this assumption is incorrect then cut plane D, just south of the Dunsmuir AC interconnection, would be the critical bottleneck in the system [73].

4.2 VANCOUVER ISLAND ELECTRICAL DEMAND

Peak daily and hourly electrical demand data for Vancouver Island was acquired from BCTC for the period of January 1, 2000 through February 9, 2004. Peak daily electrical demand was also provided for 1999. Figure 4.3 shows a representative example of daily peak demand.

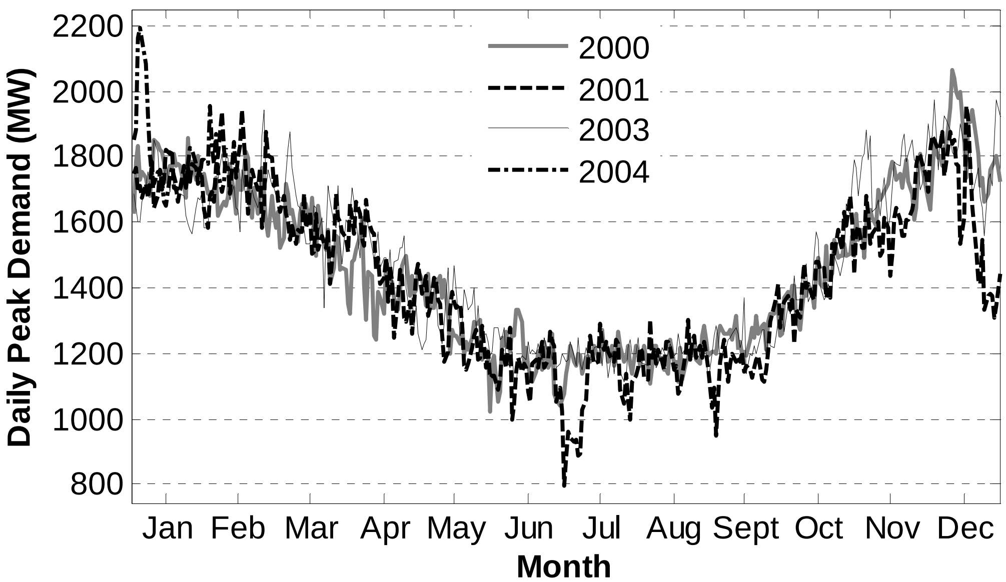

Figure 4.3: Vancouver Island peak daily demand for selected years

On-island generating resources can supply a maximum of 744 MW which is represented by the minimum value on the y-axis in Figure 4.3. At no time during the period assessed were on-island generating resources capable of meeting peak demand. The years 2000, 2001 and 2004 have been plotted in bold and demonstrate significant deviation from the normal peak demand patterns as represented by the 2003 data. The deviations occurring during these years can be explained by events occurring at the time the deviation occurred. In July of 2001, for example, low demand for pulp and paper products forced many of the Island's mills to shut down or reduce output [74]. This resulted in a peak reduction of more than 200 MW compared with normal peak demand for the period. In December of the same year, three of the Island's pulp and paper mills curtailed operations, again due to poor market conditions, reducing electrical demand by 400 MW for an extended period [68]. The forestry industry comprises the majority of Vancouver Island's industrial sector and global demands for many of its products are declining. Industrial consumers account for 40% of the total electrical demand on Vancouver Island [68], making the Islands electrical demand very sensitive to fluctuations in global markets, as was demonstrated above.

Another demand deviation occurred in December, 2001 when the Island's 500 kV AC electrical transmission connection to the mainland was interrupted due to a severe wind storm and subsequent icing of the transmission lines [74]. This forced BCH to use automatic load shedding measures which were implemented after a system upgrade study completed by Keeney in 1995 [75]. These measures permitted 300 MW of load to be shed by the Island's large industrial users. However, manual load shedding of non-essential areas was still required to maintain system stability [76]. Supply was met exclusively by on-island generation and the HVDC transmission connection to the mainland during this time. In December of the following year, this scenario was repeated when a landslide destroyed a section of the transmission network in the vicinity of Sechelt Creek [64]. Island demand was met by using alternate routing circuits until icing of the AC cables to the Island caused a fault, again severing the Island's main source of electricity. These incidents demonstrated the fragility of Vancouver Island's electrical supply situation and the need for greater on-island generation capability.

Referring back to Figure 4.3, the demand profile illustrates that Vancouver Island (like the rest of BC) is winter peaking, meaning that maximum electrical demand occurs during the winter months. Interestingly, Vancouver Island's population accounts for 21% of BC's population but residential demand on the Island represent 26% of BC's total residential demand [66]. This is driven largely by domestic heating requirements that are predominantly satisfied on Vancouver Island by electrical heaters. Natural gas was only introduced to the Island in 1991 and has been slow to gain widespread usage. This is in part due to the higher price of natural gas on Vancouver Island compared to other parts of the Province [66].

The peak electrical demand on Vancouver Island is highly susceptible to inclement winter weather due to the prevalence of residential electrical heating on the Island. The bold lines representing the year 2000 in Figure 4.3 and the beginning of 2004 demonstrate how inclement cold weather (in December and January, respectively) on Vancouver Island influences electrical load. The 2005 BCH forecast notes that sustained periods of cold weather on the Island may increase peak demand by as much as 11% [66]. Variable weather is also the reason that peak demand does not increase every year as forecasts would suggest. BCH and BCTC must, however, prepare for a worst case scenario resulting in forecasts that predict constantly increasing peak demand.

Peak demand lasts only for a period of minutes to hours and then declines. Peak and hourly demand data for the same 1999-2004 period shows that demand exceeded 2000 MW on Vancouver Island for a total of 39 hours, 31 of which occurred over 4 days in 2004. The low number of total hours at this level can be partially explained by daily usage patterns on the Island. Figure 4.4 shows one week of hourly demand data on Vancouver Island for the peak demand period of January 1 through 7, 2004 and summer demand period of July 5 through 11, 2003.

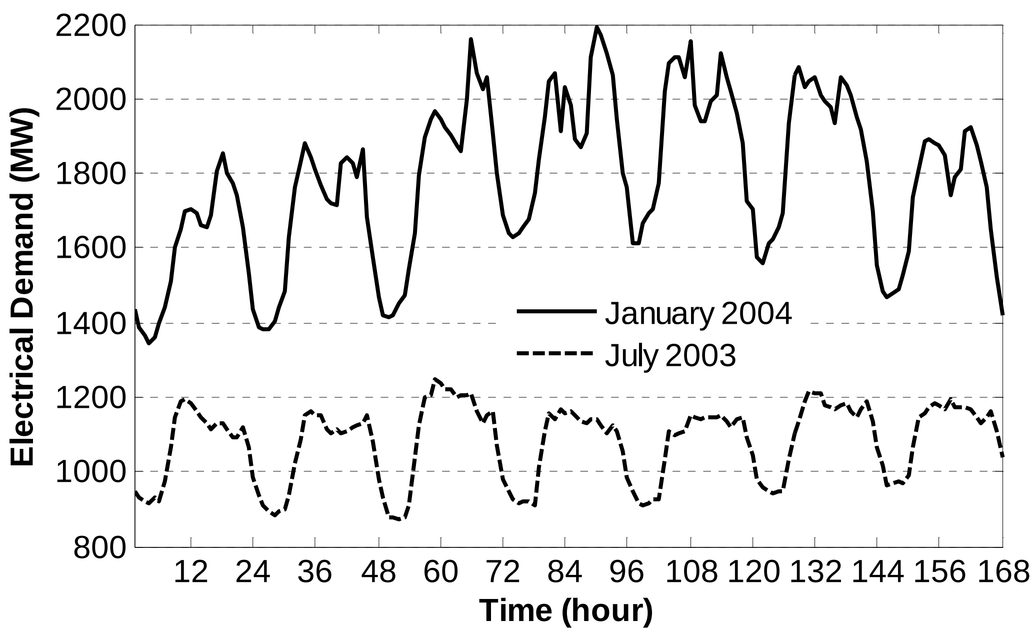

Figure 4.4: Hourly Vancouver Island electrical demand for one week periods in July 2003 and January 2004

This figure illustrates typical daily load cycles under both summer and winter conditions. As noted above, the daily peak, especially in winter is short lived and usually occurs in the morning or evening, with a notable demand reduction occurring at night. The increased difference between peak and minimum daily demand occurring in the winter can be attributed to the increased demand from the residential and commercial sectors on the Island. This illustrates the effect of lighting requirements due to low light conditions prevalent in the winter and again the influence of a high heating load on the system. Demand from the industrial sector, however, does not exhibit the high degree of weather sensitivity of the other sectors. Therefore, if the proportion of demand from the industrial sector declines significantly, this variability could increase in both summer and winter periods. During the summer months the difference between the daily peak and minimum demand is significantly reduced due to less demand from the residential and commercial sectors.

4.3 FUTURE LOAD FORECAST

BCH and BCTC are constantly forecasting future demand to plan short, mid and long term developments that are required to maintain the capability and reliability of the system. In the short term, to ensure electrical resources are available to meet Vancouver Island demand, eight day demand forecasts for the Island are prepared daily, based on temperature data from Victoria International Airport and historic Vancouver Island demand data [66]. These demand forecasts are quite accurate owing to the short time period, relative certainty of outcomes and low probability of major changes.

To match supply with demand, accurate information regarding the availability of different generators is also vital to BCH. Intermittent forms of generation functioning under *must run* conditions and unable to provide relatively accurate output forecasts would, therefore, be a challenge to integrate while maintaining system stability and efficiency. For planning purposes, BCH, therefore, gives all intermittent forms of generation a dependable capacity of 0 MW until proven otherwise by the facility operator [36]. This is one way of decreasing uncertainty in an already complex system.

Each year BCH completes a 20-year forecast that predicts growth based on housing starts, the status of current and expected global markets, as well as British Columbia's current and projected gross domestic product (GDP). In the short term these forecasts have proven relatively accurate, but over the long term they have proven to be quite inaccurate. This is demonstrated in Table 4.3, where forecast and actual peak demand from three BCH forecasts are compared [62, 66, 77].

Table 4.3: Vancouver Island peak demand forecast and actual values

Year March 31 – March 31	Vancouver Island Peak Demand		Difference[2] (%)	Time from forecast (years)	Actual Change [3] (%)
	Forecast (MW)	Actual (MW)			
1997/1998	2730 [1]	1661	64.3	20	-
1998/1999	2850 [1]	1971	44.6	21	18.7
1999/2000	2970 [1]	1856	60.0	22	-5.8
2000/2001	3090 [1]	2065	49.6	23	11.1
2001/2002	2039	1955	4.3	1	-5.3
2002/2003	2089	1944	7.5	2	-0.6
2003/2004	2121	2193	-3.3	3	12.8
2004/2005	2146	2202	-2.6	4	0.4

1.estimates assuming natural gas supply to the island in 1982 [62].
2. difference between forecast and actual electrical demand.
3. change in electrical demand from one year to the next.

As an electrical system must be sized to meet maximum demand, long-term planners rely on peak demand forecasts to give an indication of when system additions are required. The first four entries in Table 4.3 clearly show the difficulty of relying on these forecasts especially over the long term given the amount of uncertainty associated with electrical demand. To complicate matters further, BCH has now begun to produce demand forecasts with and without the projected influence of Demand Side Management (DSM) initiatives. This additional variable, which is in itself a forecast, increases the uncertainty with which long-term planners must deal.

The inaccuracy of long-term forecasts can be linked to the uncertainty associated with variables that are central to their calculation. For example, Vancouver Island's industry is largely forestry based and therefore heavily influenced by the demand for pulp and paper and building materials. In the previous Section, the influence of low demand for pulp and paper products in 2001 manifested itself in an electrical demand reduction. The under-performance of the industrial sector is partially responsible for the huge discrepancy between the 1978 estimated 1998/1999 peak demand (2730 MW) and the actual value (1661 MW). At the time, BCH had nine large industrial consumers on the island that represented 49% of the total energy sales. Forecasts completed for 1977/1978 to 1997/1998 assumed that the industrial load on Vancouver Island would increase at a rate of 2% annually [62]. Today, one of the mines which was in operation in 1978 has closed as well as one of the major pulp and paper mills based in Gold River. In 2001, electrical sales to the industrial sector had declined to 40% of demand [68]. The following year, this value declined even further [74] demonstrating the influence of global markets on the industrial sector on Vancouver Island.

Other events that may adversely affect the accuracy of demand forecasts include: an increase in interest rates that could reduce demand for new houses, slowing load growth in both the residential and commercial sectors; a series of warm winters that would reduce demand on Vancouver Island significantly; or cold winters which could sharply increase demand. Due to the significant uncertainty associated with forecasted demand, past Vancouver Island load data has been used to assess the contribution that small hydro generation could make to meeting the Island's demand.

4.4 SUMMARY

On-island generation is unable to meet demand and as a result Vancouver Island relies on the mainland to make up the shortfall. Vancouver Island demand was presented for 1999-2004 and perturbations to demand trends were discussed. The uncertainty associated with forecasting future Island electrical demand was then presented using past forecasts to demonstrate the difficulties that can be associated with future forecasts. Due to the significant uncertainty associated with forecasting, this work focused on demand during the period for which Vancouver Island demand data were available (1999-2005).

5 SMALL HYDRO SIMULATION MODEL

This chapter explains the criteria used to identify 175 potential small hydro installations on Vancouver Island and the means of determining the electrical generating capability of these sites over the 1999-2005 study period. Using individual site characteristics and regional FACs, the methods used to determine design flow and plant size are explained. These values represent the nameplate capacity of a site, but poorly describe how it will operate under fluctuating flow conditions. To determine this, information regarding turbine type and system efficiency is required. Criteria used to select the type of turbine(s) at each site and how the selection process was implemented within the model is explained. This is followed by a section on the method used to determine the overall operating efficiency of a facility by accounting for turbine, generator and penstock efficiencies.

Most facilities in this study are modelled as run-of-river plants; however, in a few rare cases, storage must also be taken into account. For these cases, a simple storage model was developed and the modes of operation are explained within this chapter. The detailed generation equation is presented using all information gathered on both storage and run-of-river facilities. Calculations using this equation were categorised into four modelling development scenarios that are explained. Finally, an assessment of FAC accuracy, when used to calculate generation, is conducted and the results are discussed.

5.1 SITE IDENTIFICATION

In 1982, the BC Ministry of Energy and Mines commissioned a map study to identify promising sites for small hydro development using 1:125 000, 1:126 720, 1:100 000 and 1:50 000 scale maps with contour intervals of 200 feet, 100 feet, 50 m and 100 feet, respectively [13]. In 2000, this study was revisited by Sigma Engineering on behalf of BCH to create an inventory of undeveloped small hydro sites in the Province [9]. In the inventory, Sigma Engineering also adjusted the design flows found in the previous study to reflect newly adopted best management practices for in-stream fish flows.

The current study includes small hydro sites identified by both of these previous assessments and builds on the inventory by incorporating developed sites or those sites under development that were not identified in the original studies. All duplicate or misidentified sites have been removed. Each site has been revisited and the head and catchment area updated based on 1:20 000 maps with a 20 m contour interval. Additional sites have also been identified using the 1:20 000 maps, taking into account improved road access as well as electrical grid extensions that have occurred since the original studies were completed. A total of 175 sites were identified and are included in the current study. Each site has a nameplate capacity in excess of 100 kW but below 50,000 kW. These sizes fall within BCH's definition of small and micro hydro and are large enough to function at a utility level. Figure 5.1 illustrates the location of the small hydro sites included in this study. Appendix B contains information regarding each site.

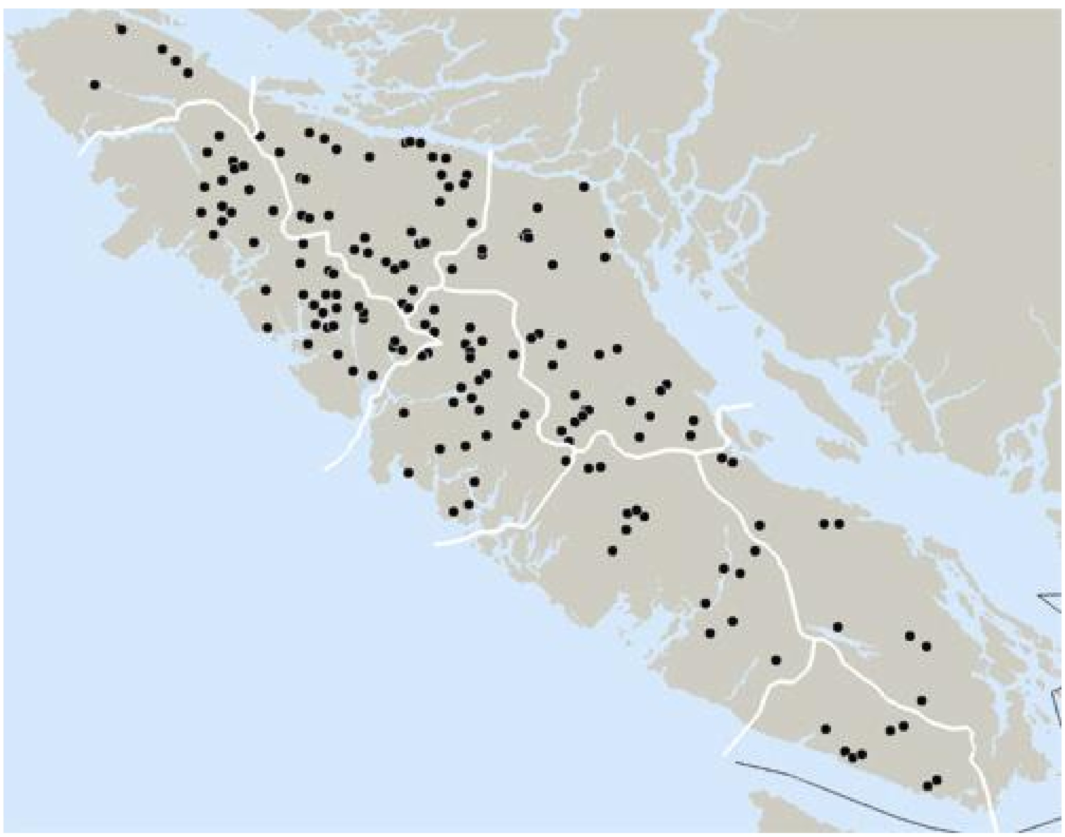

Figure 5.1: Potential small hydro sites on Vancouver Island

This study used a river gradient selection criteria used by previous studies [9, 39] to identify undeveloped sites. These criteria are:

- the steepest portion of the watercourse must have a minimum gradient of 10% in areas where electricity is provided by the electrical grid; and,
- the steepest portion of the watercourse must have a minimum gradient of 5% in areas where electricity is provided by diesel generators.

New and quantitative proximity criteria for the distance to existing roads and connection to the nearest load centre or transmission system were selected for this study to replace qualitative measures employed in previous studies [9, 39]. To be considered for development within this study, the following proximity criteria were required:

- the site is within 20 km of existing logging roads or other roadways (waterways were included as viable transportation means when considering remote communities);
- the site is within 50 km of existing transmission or distribution lines; and/or,
- the site is less than 25 km from a remote community currently supplied by diesel generation.

Proximity criteria used in previous studies were based on a "reasonable distance" that was determined by approximating an economic travel and transmission distance to the point of interconnection. As the economic aspects of generator interconnection are beyond the scope of this work, a quantitative distance was chosen based on a proximity review of sites identified by past studies.

5.2 Site Characteristics

The required input data for both turbine selection and operation modelling are design flow, gross head, and drainage area. For sites currently under development, the water license flow was adopted as the design flow. At undeveloped sites, design flows were approximated based on the site drainage area at the point of diversion and the FAC for the RRA in which it is located. A detailed discussion of the methods used to make this approximation can be found in Section 3.3.

The gross head at an undeveloped site was determined using the Land Information BC – Make a Map online mapping tool [78]. This tool is capable of 1:20 000 scale map detail with 20 m contour intervals. For sites under development, gross head was determined in one of three ways:

- provided by the developer;
- calculated by manipulating the general power equation [2.2] outlined in Section 2.1, using the site's water license flow and the nameplate capacity of the plant assuming an 80% efficiency; or,
- where the first two options were not available, using the 1:20 000 mapping software mentioned above.

Drainage area determination was completed for all sites using the aforementioned mapping software. The online software area calculation tool was used to determine the aerial extent of each watershed above the assumed intake point from user defined drainage boundaries. The boundaries were defined using the topographic features depicted on the maps, most notably ridge lines. This is an improvement over past studies that employed overlay grids and planimeters to determine approximate drainage areas using less detailed map scales [9, 13, 39]. A table listing all sites and their respective characteristics is provided in Appendix B.

5.3 DESIGN FLOW DETERMINATION

Small hydro plants currently operating in BC typically have a capacity factor (CF) between 40% and 60%. Independent power developers often use a 50% CF as a rough measure of whether a project is worth pursuing or not [4]; therefore, the model used this CF value to approximate design flows for all undeveloped sites within a region.

The nameplate capacity and associated design flow corresponding to a 50% CF was determined for each FAC through an iterative process in which power output (P) was calculated based on the available generation flow (Q) for the entire FAC time series using the power equation outlined in Secton 2.1. Values of head and system efficiency, required for the calculation of P, were fixed at 100 m and 80%, respectively. When the available generation flow (Q) was less than 20% of the design flow (Q_d), the generated power (P) was assumed to be zero. The reason for this will be explained further in Section 5.5.1. Initial values of Q_d were set to the mean flow value of the FAC time series. CF was calculated using the following formula:

$$CF = \frac{\sum_{j=1}^{n}(P_j \times t_j)}{P_{design} \times \sum_{j=1}^{n} t_j} \times 100\% \,, \qquad [5.1]$$

where:

	P_i	Generated Power (kW);
	P_{design}	Nameplate Capacity (kW);
	t	time (s);
	j	index; and,
	n	total number of measurements.

Iterations continued until a P_{design} and Q_d were found that satisfied CF equal to 50%.

Sites currently under development used the licensed flow listed on the BC Ministry of Environment – Water License Query website as the design flow value [79]. The resulting design flows for each undeveloped site can be found in Appendix B.

5.4 TURBINE SELECTION

The characteristics of a site (i.e., head, flow range and design flow) govern the types of turbine(s) that can be considered. The turbine selected for installation determines the operating characteristics and constraints of a small hydro plant. As a result, turbine selection is often an iterative process in which the advantages and disadvantages of each option are weighed, projected generation calculated and costs tallied until a suitable design is determined. Table 5.1 outlines some advantages and disadvantages of the three types of turbines considered in the model.

Table 5.1: Turbine attributes [15, 23]

Turbine	Advantages	Disadvantages
Impulse	• simple operation • excellent part load efficiency • broad operating range • lowest excavation cost	• reduced effective head • larger generator requirement due to slow rotational speed • lower peak efficiency
Francis	• greater generation output for a given diameter • high peak efficiency • inexpensive	• poor part load efficiency • cavitation risk • rough operation at low flows
Kaplan (Axial)	• low head operation • smaller generator required due to high rotational speed • high efficiency over a broad range of flows	• very expensive • complex operation • high maintenance • backwater influence • cavitation risk

To select a turbine for an identified site, metrics of efficiency and operating range were used to maximise potential generation for that site's unique characteristics. Figure 5.2 illustrates the range of head and design flow values over which each turbine type is typically used [15, 23].

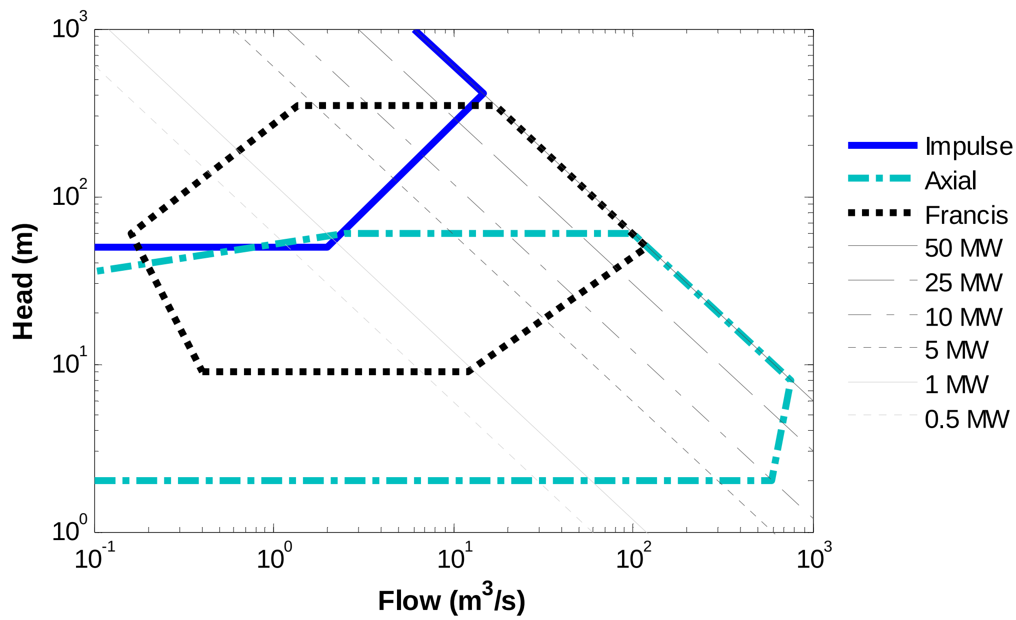

Figure 5.2: Turbine application ranges and generation potential

In general, impulse turbines are used in high head, low flow applications, axial turbines in low head, high flow applications and Francis turbines for mid range heads and flows. The turbine selection program was set up such that impulse turbines were selected over the whole range represented in Figure 5.3, axial turbines for heads less then 50 metres and Francis turbines for site characteristics not yet covered by the other two. Dual Francis turbines were employed when the plant design flow exceeded 3 m^3/s. Figure 5.3 shows the turbine selection range used by the model.

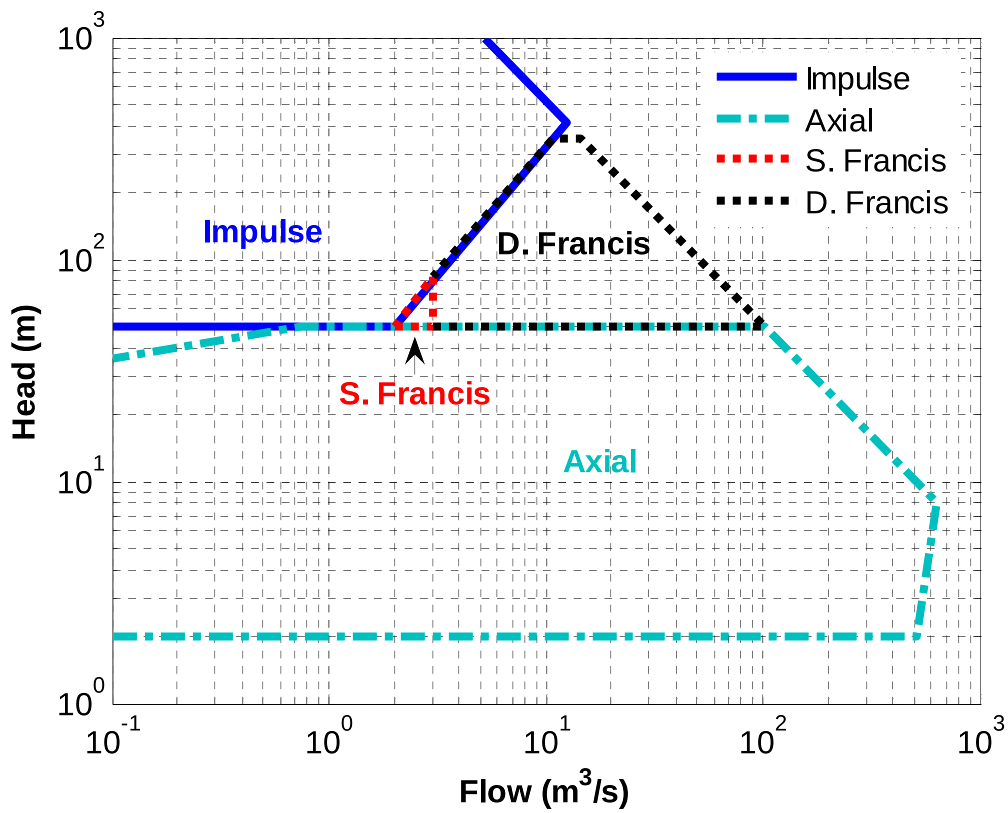

Figure 5.3: Turbine application range used in model turbine selection

Turbines having large operating ranges (Pelton, Axial and D. Francis) were preferentially selected to maximise contribution time from each small hydro site. Reasons for this were presented earlier in Section 2.2 and are explained further in the following section on system efficiency.

5.5 SYSTEM EFFICIENCY

Turbine and generator combinations operate most efficiently at a fixed operating point, usually corresponding to a plant design flow. However, run-of-river hydroelectric systems operate over a wide range of flows making the design and accurate modelling of these systems difficult. The turbine selected for a site determines the flow range over which a small hydro plant can operate. As flows decrease in relation to the design flow an efficiency penalty will be incurred. In an attempt to capture the effect of variable flows on the operation and output of a small hydro plant, turbine, generator and penstock efficiencies were calculated over the flow operating range and incorporated into the model. This is an improvement over past studies that assumed a fixed system efficiency value over the entire operating range [9, 35].

5.5.1 Turbine Efficiency

Turbine efficiency curves were calculated to simulate the dynamic efficiency of an operating plant. Generic turbine efficiency equations derived from industry data by the developers of RETScreen [24] were used to model turbine efficiency values for each site. Table 5.2 provides the minimum operating flow (Q_{min}), peak efficiency flow (Q_{peak}) and associated peak efficiency of each turbine setup.

Table 5.2: Turbine types

Turbine	Q_{min} (% Q_d)	Q_{peak} (% Q_d)	Peak Efficiency
Impulse	~ 15	~ 88	90%
Kaplan (Axial)	~ 25	~ 90	93%
S. Francis	~ 45	~ 80	93%
D. Francis	~ 20	~ 80 , ~ 40	93%

The Q_{min} value represents the lowest minimum flow at which a turbine can be reasonably operated. Below this minimum flow value, inconsistent output and excessive vibration may occur causing premature system failure. This minimum flow corresponds to a turbine efficiency of approximately 75%. Therefore, when turbine efficiencies fall below 75%, the plant is considered to be outside of its operating parameters and is shut down. Note that Single Francis (S. Francis) turbines have a limited range of operation. They are only able to operate from 45% to 100% of design flow. The other alternatives are capable of functioning from 25% to 100% of design flow.

To illustrate turbine efficiency over the full operating range, four different small hydro sites having characteristics suited to the four turbine types are presented below. Table 5.3 contains the characteristics of the four sites selected.

Table 5.3: Site characteristics of four example sites

Name	Turbine	Head (m)	Q_d (m^3/s)	Flow Range (% Q_d)	Capacity (MW)
Big Tree Cr.	Impulse	140	1.8	16 – 100	2.0
Leiner R.	Kaplan (Axial)	40	9.0	28 – 100	3.0
Teihsum R.	Single Francis	60	2.8	45 – 100	1.4
Browns R.	Dual Francis	75	5.5	20 – 100	3.4

Figure 5.4 provides calculated efficiency curves for each site and turbine type (Kaplan, impulse, S. Francis) used. A curve for a Dual Francis (D. Francis) installation is also included as this illustrates a common method of achieving operation over a wide range of flows.

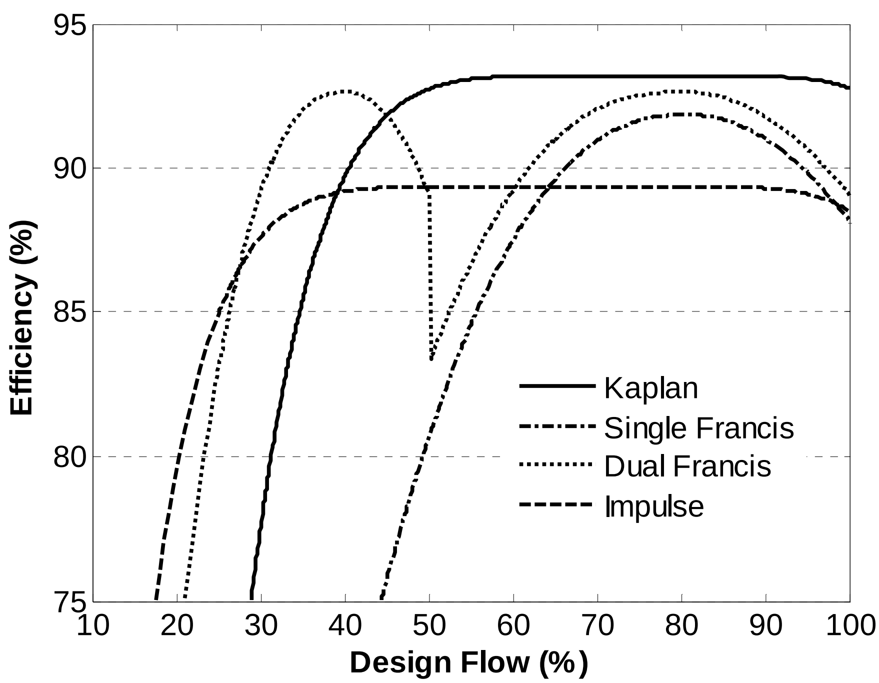

Figure 5.4: Turbine efficiency curves

Figure 5.4 and Table 5.3 show that sites having highly variable flows (i.e., flow variations from 30% to 100%+ of design flow) tend to favour multiple turbines or impulse and Kaplan (a type of axial turbine) turbines that have flatter efficiency curves. Conversely, if flows are relatively constant (i.e., always above 50% of design flow) a S. Francis turbine would be well suited. Streams on Vancouver Island tend to have very large flow variations making D. Francis, impulse and Kaplan turbines better suited to the development of these potential sites. For this reason, these turbines were selected for modelling.

5.5.2 Generator Efficiency

Hydroelectric generators convert the mechanical energy provided by the turbine to electrical energy. To model the influence of variable input on generation, two generic generator efficiency curves were developed and used in the model. To develop the curves, a synchronous generator was assumed due to high operating efficiency, BCH preference [80] and stand alone capability. The efficiency of a generator is determined as follows [81, 82]:

$$\eta_g = \frac{VA_{out} \times PF}{VA_{out} \times PF + P_{cu} + P_{core} + P_{field} + P_{mech}} \times 100, \qquad [5.2]$$

where:

η_g generator efficiency (%);
VA_{out} power output (kVA);
PF power factor;
P_{cu} copper losses (kW);
P_{core} core losses (kW);
P_{field} magnetic field losses (kW); and,
P_{mech} mechanical losses (kW).

Typically, generator efficiencies are between 96.8% and 98.6% [26]. According to Emanuel [81], in a synchronous generator, “the mechanical, core and field losses are relatively constant. The copper loss, however, varies with load.”. Therefore, to determine efficiency over the expected operating range of a generator, all losses were calculated for the nameplate capacity and then copper losses recalculated as the output changed. A power factor of 0.9 was assumed due to a BCH surcharge on generators operating at lower power factors [83].

The average plant capacity for the 175 identified sites was determined to be 4.4 MW. To simplify calculations in the power output model, this nameplate rating was used to develop a generic generator efficiency curve, expressed as a percentage of design flow that was then applied to all sites. A best fit trend line was used to determine the equation representing generic generator efficiency as a function of design flow. This exercise was repeated for sites having two turbines and two generators. The resulting equations expressed in terms of normalised flow ($Q^* = Q / Q_d$) are:

- single generator over full operating range or two generators operating above 50% design flow ($R^2 = 0.9987$):

$$\eta_g = -0.9025(Q^*)^4 + 2.6519(Q^*)^3 - 2.9111(Q^*)^2 + 1.4814(Q^*) + 0.6324; \quad [5.3]$$

- single generator operating below 50% design flow ($R^2 = 0.9992$):

$$\eta_g = 1.8824(Q^*)^3 - 2.4369(Q^*)^2 + 1.1337(Q^*) + 0.7587. \quad [5.4]$$

Appendix C lists the values required by equation [5.2] to derive these equations. Figure 5.5 depicts the generic generator efficiency curves based on these equations.

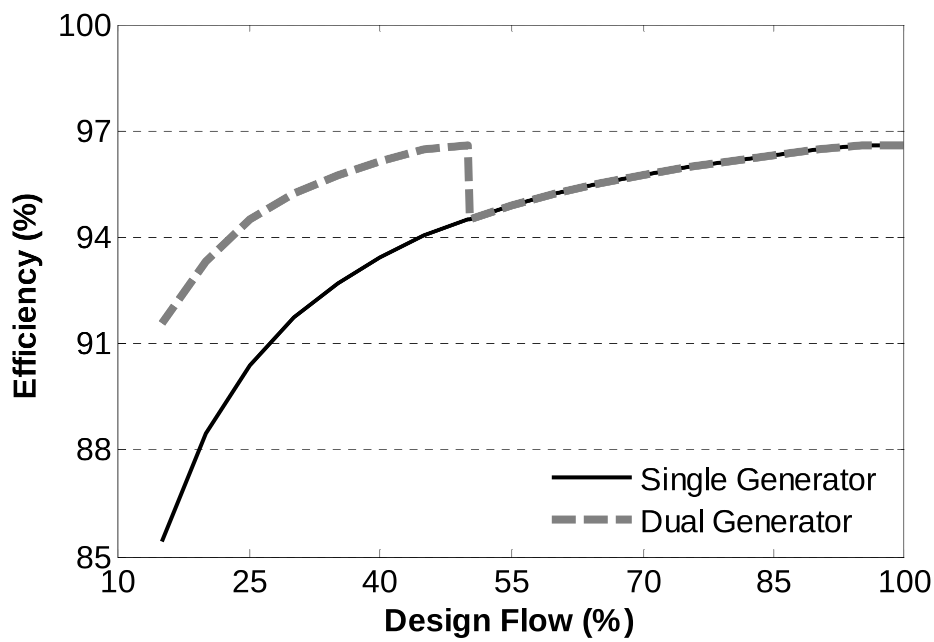

Figure 5.5: Generic generator efficiency curves

The curve representing the dual generator case overlays the single generator curve when flows are above 50% of design flow because both generators operate in parallel at their respective part load efficiencies. This parallel operation is assumed to match the part load efficiency of a similar sized single generator. When flows decrease below 50% design flow in the case of dual generators, one generator is shut down while the other continues to operate at its design load.

5.5.3 Penstock Efficiency

To incorporate losses attributed to fluid flow in a penstock, a frictional loss curve was developed for the entire operating range of a typical small hydro plant. The curve was developed using generic site characteristics assuming a penstock constructed of equal lengths of steel and HDPE. The Darcy-Weisbach equation was used to calculate major losses for the generic case assuming turbulent pipe flow [84]:

$$h_f = f \frac{L}{d} \frac{V^2}{2g}, \qquad [5.5]$$

where:
- h_f head loss due to friction (m);
- f Darcy friction factor (unitless);
- L characteristic length (m);
- d pipe diameter (m);
- V velocity (m/s); and,
- g acceleration due to gravity (m/s^2).

The Darcy friction factor was calculated for both penstock materials and a weighted average based on length used in equation [5.5]. Pipe roughness values used in the calculation of the Darcy friction factor were 0.002 mm for steel and 0.0015 mm for HDPE. Pipe diameter was chosen such that frictional losses resulted in ~4% head loss under design flow conditions.

Head losses calculated using the Darcy-Weisbach equation were expressed as a percentage of the head and subtracted from 100%. This allowed the resulting percent gross head values to be incorporated directly into the power output model as penstock efficiency. To ensure the curve's applicability to all sites, losses were expressed in terms of normalised flow to develop the equation used in the model. The equation that represents this curve is:

$$\eta_h = \left[-0.0352\left(Q*\right)^2 - 0.0026\left(Q*\right) + 1.0002\right] \times 100 . \qquad [5.6]$$

Figure 5.6 illustrates the curve.

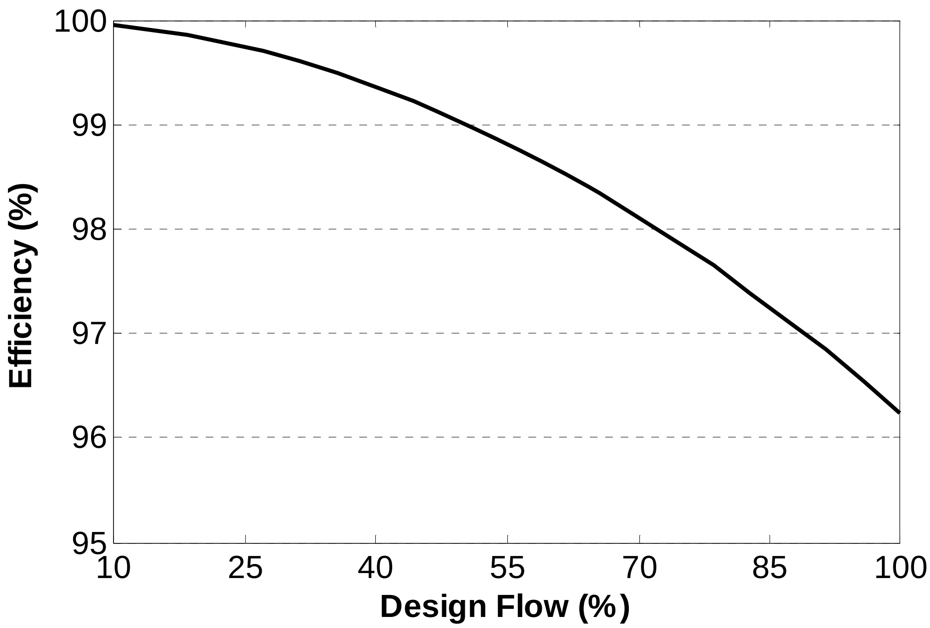

Figure 5.6: Penstock efficiency curve

Decreasing flows in a penstock improve its efficiency due to decreased frictional losses over the penstock length. The variable values and equations used to derive [5.6] are contained in Appendix D.

5.6 STORAGE MODELLING

While the majority of small hydro developments on Vancouver Island are run-of-river, seven are licensed to store water for use during periods of low flow. Storing small volumes of water during times of excess runoff allow a small hydro facility to offer dependable capacity to the electrical network. The amount of storage available and the period of time between runoff events will determine how the facility is operated and what fraction of the nameplate capacity can be offered dependably. For modelling purposes, a fixed mode of operation was adopted that maximised generation time. This was achieved by selecting a generation flow (Q_{gmin}) that coincided with the peak, second turbine, efficiency for facilities employing D. Francis turbines (2 sites) and a quarter of the design flow for sites employing an impulse turbine (5 sites).

To model the fluctuating storage volume the following equation was used:

$$U_n = (Q_{in} - Q_{out})t_n + U_{(n-1)} , \qquad [5.7]$$

where:

U	storage volume (m^3);
U_{max}	licence storage volume (m^3);
U_{min}	zero storage volume remaining;
Q_{in}	flow into the reservoir (m^3/s);
Q_{out}	flow out of the reservoir (m^3/s);
t	time (s); and,
n	interval;

subject to: $U_n \leq 1.1 \times U_{\max}$ and $U_n \geq U_{\min}$.
If either of these constraints are violated: $U_n = U_{(n-1)}$.

The model assumes a reservoir-full starting condition and five states of operation:

1. *Storing:* inflows to the reservoir exceed plant design flow (Q_d) and add volume to the reservoir if licence capacity exists ($Q_{out} = Q_d$, $Q_{in} > Q_d$);

2. *Spilling:* reservoir licence capacity is exceeded ($U_n \geq U_{max}$) and inflows, beyond what can be used for generation, are spilled to the downstream watercourse ($Q_{out} > Q_d$, $Q_{in} > Q_d$);

3. *Normal Generation:* reservoir level is maintained and generation is occurring such that inflow matches outflow similar to the operation of a true run-of-river plant ($Q_{out} = Q_{in}$);

4. *Generation from Storage:* inflows have fallen below the minimum pre-set level corresponding to low flow peak turbine efficiencies and storage is used to maintain generation at this lower level($Q_{out} = Q_{\mathrm{gmin}}$, $Q_{in} < Q_{\mathrm{gmin}}$); and,

5. *Plant Off:* when the storage reservoir has been depleted ($U_n = U_{min}$) and inflows are below the minimum operating point the plant is shut off ($Q_{out} = Q_{\mathrm{gmin}}$).

The storage model output was expressed in terms of available generation flow that was used to calculate system efficiencies and generation output from the site as discussed below.

5.7 Generation Modelling

To model generation output from a small hydro plant, the following equation was used:

$$P = \eta_t \cdot \eta_g \cdot \eta_h \cdot \rho g Q H \, , \qquad [5.8]$$

where:
- P electrical generation (W);
- η_t turbine efficiency;
- η_g generator efficiency;
- η_h penstock efficiency; and,
- ρ density of water (kg/m^3) .

Site specific design flow (Q_d), head (H) and RRA were imported into MATLab from Excel. The MATLab program, developed by the author, then calculated daily generation flow and system efficiencies for each individual site. This information was then used to calculate daily power output using equation [5.8]. Figure 5.7 illustrates schematically the processes used to calculate daily generation output incorporating each of the quantities explained in the previous sections.

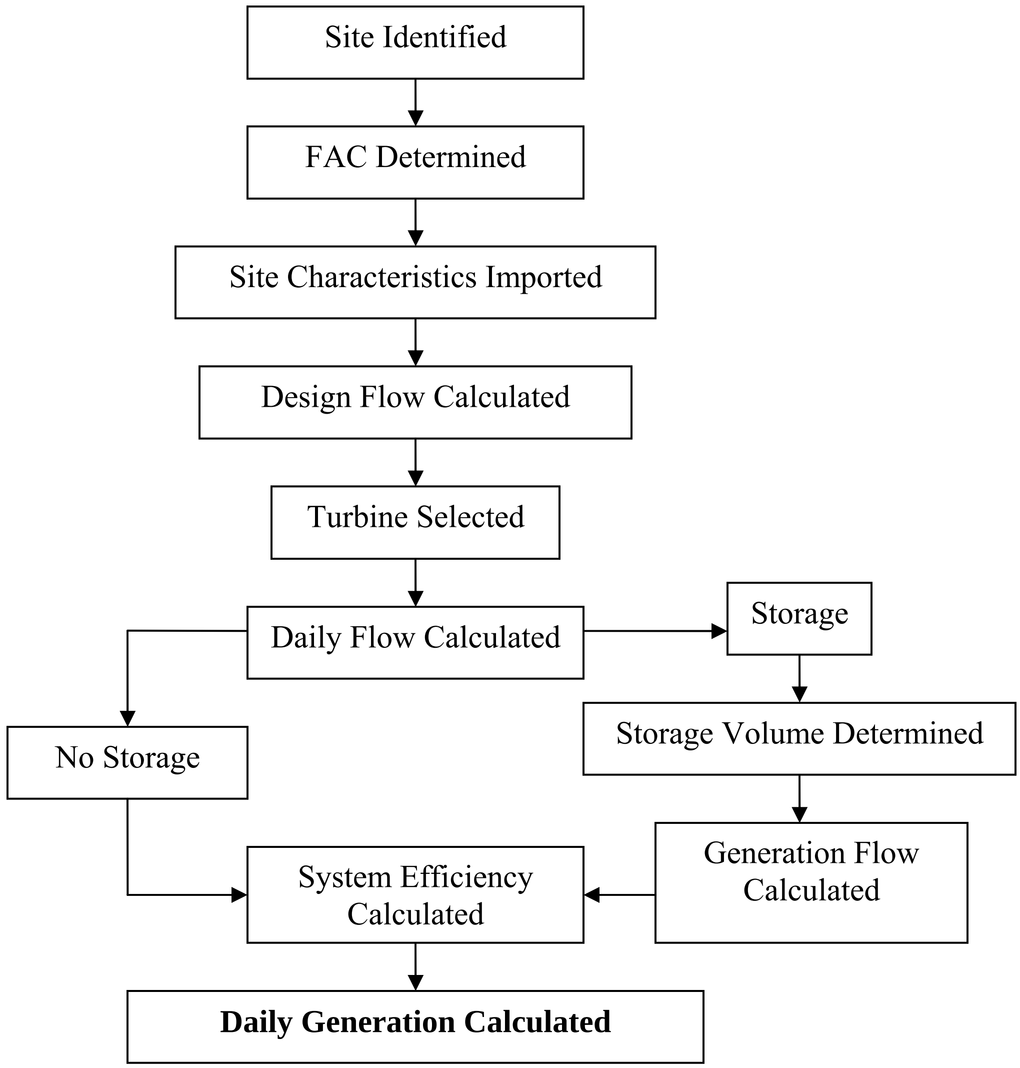

Figure 5.7: Model calculation schematic

5.8 MODELLED DEVELOPMENT SCENARIOS

To gain insight into the contribution small hydro is capable of making to the Vancouver Island power grid, a summation of daily generation from each site was taken for each modelling development scenario. The four modelling development scenarios are outlined below:

- *Operating*: currently operating small hydro plants;

- *Phase 1 Development:* all operating sites plus small hydro developments that have obtained an Energy Purchase Agreement (EPA) from BCH;

- *Phase 2 Development:* Phase 1 developments plus small hydro sites for commercial power production in the process of obtaining a water license; and,

- *Full Development:* Phase 2 developments plus all other currently identified small hydro sites that have not yet begun development.

Results of each of these modelling development scenarios and the cumulative generating potential they represent are presented in the following chapter.

5.9 ACCURACY OF FACS IN PREDICTING GENERATION

The FACs were derived from real flow values and demonstrate the climatic fluctuations that occurred during the seven year time period of 1999 to 2005. Therefore, generation calculated using these FACs should accurately reflect the generation from a small hydro facility. To determine the accuracy of using daily flow and FAC data, a comparative analysis was completed using hourly generation data as the control. Hourly generation was calculated at four sites using hourly flow data sets that were acquired from WSC hydrometric stations located near potential small hydro intake sites. Close proximity to an identified intake site avoided any data adjustments to correct for drainage area differences, permitting the use of directly measured flow values to model site generation.

Hourly flow values from these sites were used to calculate plant generation for 1999-2004. Where hourly data was unavailable due to station malfunction, daily values were substituted to complete the dataset. The hourly generation results were then compared to generation results calculated using daily average flow data as well as FAC derived data for each site. To make direct comparison possible, daily average flows were assumed constant for 24 hour periods. A cumulative generation comparison was then made on the basis of average yearly output. The results for each stream are summarized in Table 5.4.

Table 5.4: Total generation values calculated from hourly WSC flow data, daily WSC flow data and FAC generated flow data

Stream Name	Hourly Generation (GWh)	Daily Generation (GWh)	Hourly/ Daily (%)	FAC Generation (GWh)	Hourly/ FAC (%)
Browns R	7.4	7.5	98.2	7.8	94.9
McKelvie Cr	11.1	11.6	96.1	10.7	103.7
Salmon R	21.2	21.5	99.0	22.4	94.6
Tsable R	18.2	18.4	98.2	19.4	93.8

The use of daily flow values to calculate potential generation consistently overestimated the potential generation calculated using hourly flow data. Total generation output calculated using daily flow values differed from that calculated using hourly flow values by less than 4%. Therefore, daily flow data are accurate for the purposes of approximating generation output.

FAC generation totals were both above and below hourly flow generation totals. These apparently inconsistent total generation results are due to the amalgamation of datasets used to create the FAC. As the FACs are intended to represent generation from a region it is not expected that any one stream would be represented perfectly. Total generation calculated using FACs was within 7% of that calculated using hourly flows. These results demonstrate that FACs produce an accurate approximation of the total generation available from these sites. To check the timing of the predicted generation, a time series graphical comparison was completed. Figure 5.8 illustrates the time series comparison results completed on Browns River for a two month period in 2002.

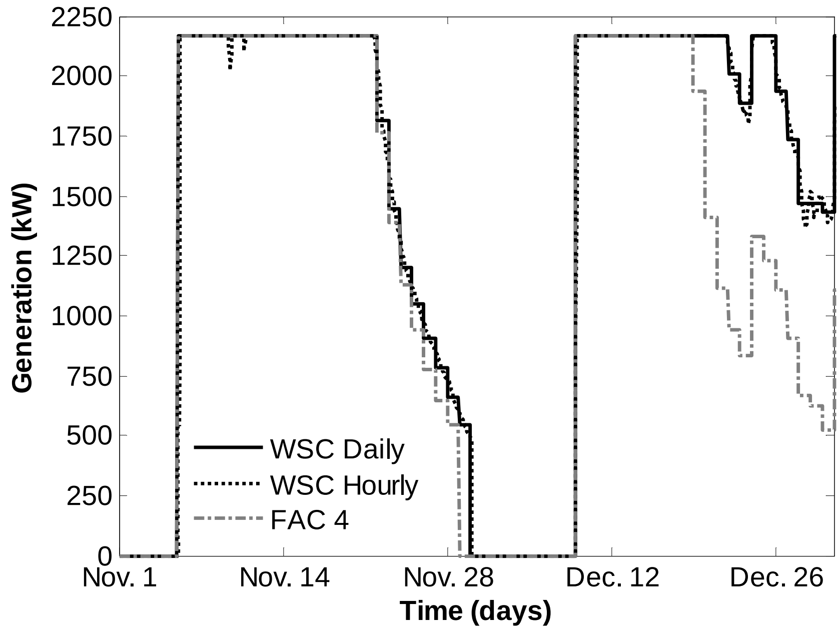

Figure 5.8: Browns River generation comparison, Nov. 1 – Dec. 31, 2004

The two months of data depicted in Figure 5.8 comprise two significant generation periods, each lasting in excess of 20 days. The pattern describing the first generation period occurring from early November to the beginning of December was followed closely by all of the input flows used. The only discrepancies in generation are the slight dip in hourly flow not captured by the other flow measures due to the influence of averaging and the FAC result leading the receding phase of the generation period. The pattern describing the second generation period beginning in early December and lasting for the duration of the year was followed by all flow measures until December 20. Again, the FAC flow measure diverged from the hourly and daily calculated generation leading the receding phase of the generation period. The FAC remained distinct from the other measures while maintaining the generation pattern for the remainder of the year. As was previously mentioned, the FAC represent flows (and indirectly power generation) in a region (*i.e.,* RRA 4) as opposed to flow in a particular stream and therefore does not have the accuracy of the gauged values. This deviation suggests that the Browns River Watershed has a greater natural storage capacity than the regional median or that more rain fell in this particular watershed then elsewhere within the region.

In the case above, generation calculated over the two month period using the FAC was, on average, within 170 kW of the generation calculated using daily flows and 69% of the time there was zero difference between them. From this result, it is concluded that for purposes of regional analysis, the FACs adequately depict generation flow trends and provide good representation in terms of generation availability.

5.10 SUMMARY

This chapter introduced the criteria used to select a small hydro site and how nameplate capacity and design flow values were determined. Turbine selection methodology was explained followed by a discussion of system efficiency that illustrated how turbine, generator and penstock efficiencies were calculated for each time series step. To account for those systems licensed to store water for later generation use, a simple storage model was introduced and the modes of operation were explained. The detailed small hydro generation calculation was presented and the four modelled development scenarios were explained. Finally, the accuracy of using FACs to calculate generation was assessed and found to be suitable for the purposes of this work.

6 MODEL GENERATION RESULTS AND DISCUSSION

Daily flow values for each watershed, calculated using the FACs, were used to determine the nameplate rating as well as daily generation for each of the 175 small hydro sites. These 175 sites were grouped by RRA. The total nameplate capacity was then calculated for each RRA and for each development scenario. Daily generation for the 175 sites were aggregated for each development scenario and are presented for the entire 1999-2005 time period. The generation occurring over the time series was further analysed to produce maximum, minimum and median plots to demonstrate the variability of small hydro generation. These results are discussed in terms of changes to generation capability and geographic distribution for each development scenario.

6.1 REGIONAL DISTRIBUTION

Currently, 10 small hydro facilities are operating on Vancouver Island. Developments beyond these operating facilities were assessed using the development scenarios outlined in Section 5.8. Table 6.1 lists the total number of sites represented by each scenario and the total addition to nameplate capacity.

Table 6.1: Small hydro development summary

Development Scenario	Number of Sites	Nameplate Capacity (MW)	Cumulative Capacity (MW)
Operating	10	43.5	43.5
Phase 1 (EPA)	11	98.2	141.7
Phase 2 (WL)	21	151.8	293.5
Undeveloped	133	153	446.5
Total	**175**	**446.5**	**446.5**

Figure 6.1 illustrates the number of sites installed per RRA for each development scenario, while Figure 6.2 shows the nameplate capacity associated with each RRA.

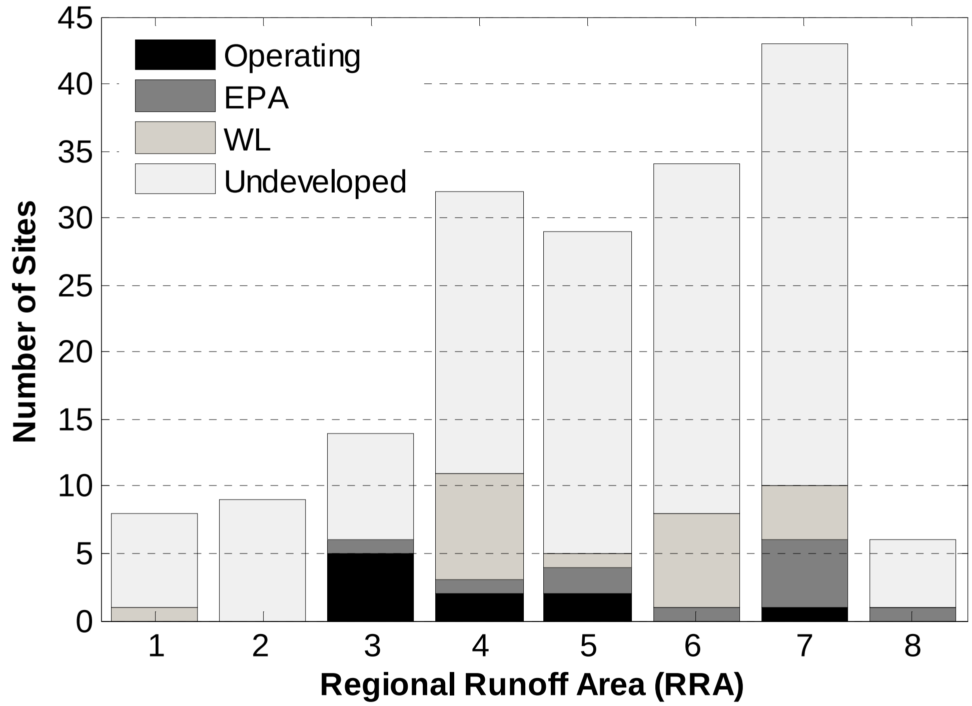

Figure 6.1: Number of small hydro sites by RRA

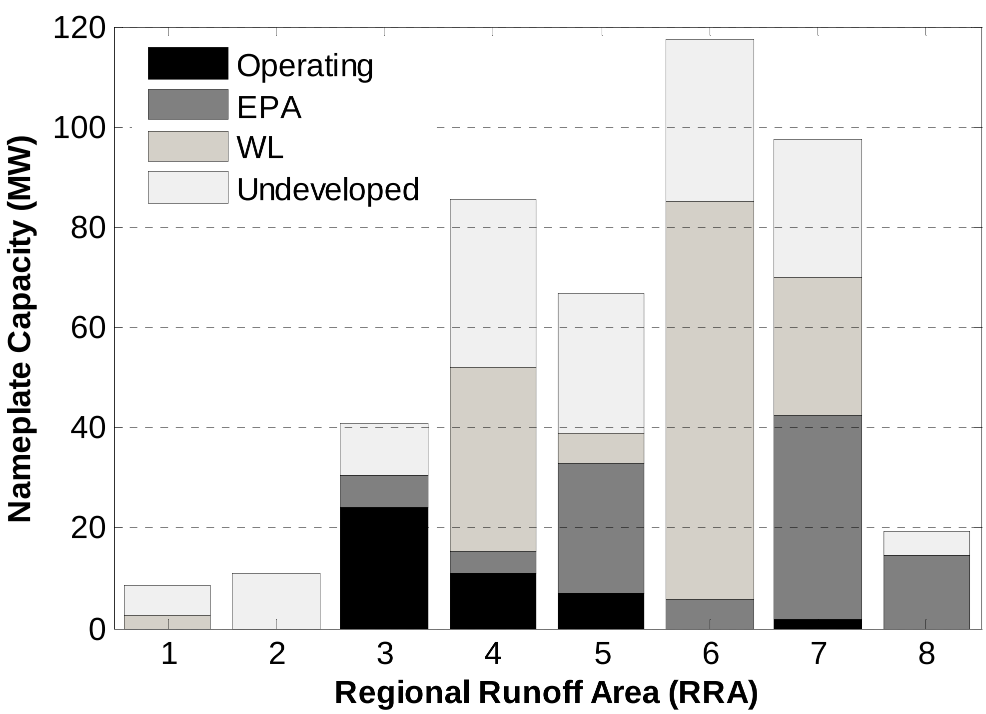

Figure 6.2: Nameplate capacity of small hydro sites by RRA

Figure 6.3 shows small hydro locations on a map of Vancouver Island and the boundaries of the RRAs. Each small hydro location is identified with a symbol that represents its stage of development.

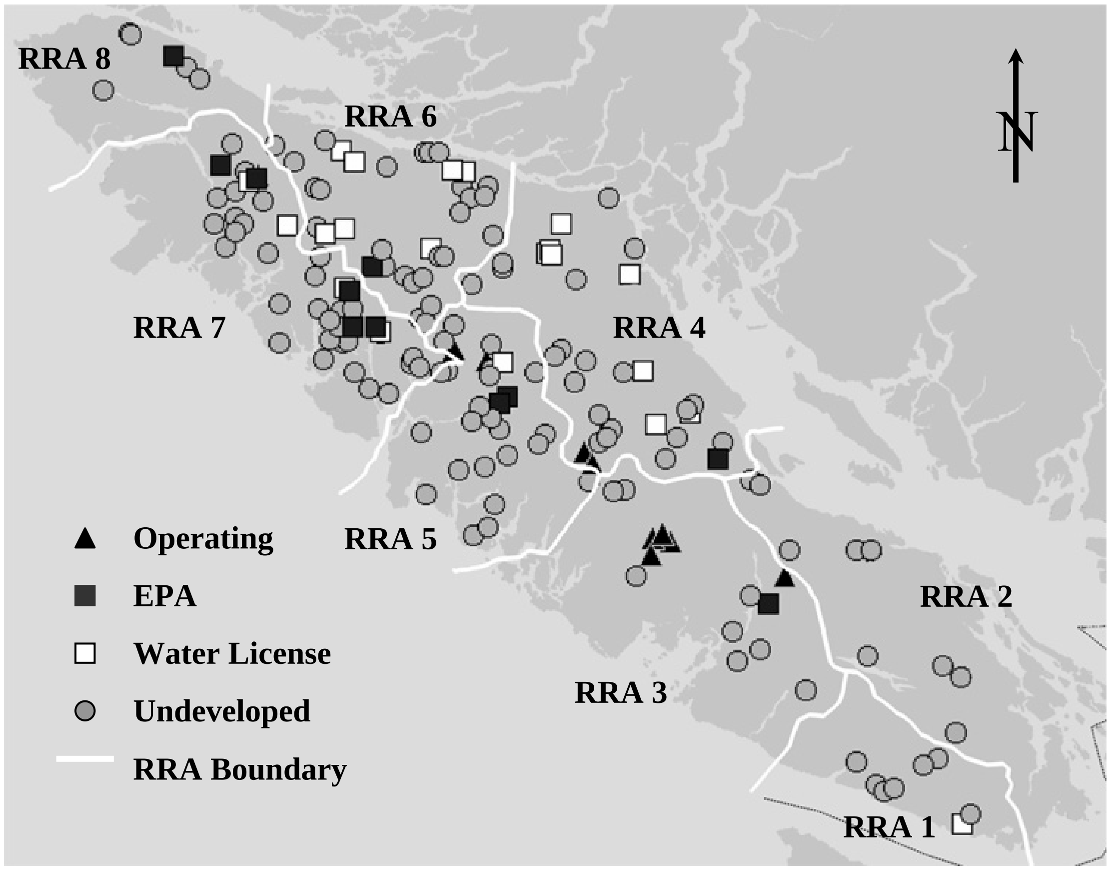

Figure 6.3: Status and location of small hydro developments

The geographic distribution of operating small hydro developments on Vancouver Island is currently limited to four out of eight RRAs, with the majority of sites situated in RRA 3. As further development proceeds and this geographic distribution increases, more reliable generation capacity may be realised. To assess the influence of geographic distribution, cumulative output from each development scenario was normalised by dividing the total daily generation by the aggregate nameplate capacity. Figure 6.4 shows the normalised output for each development scenario for 1999.

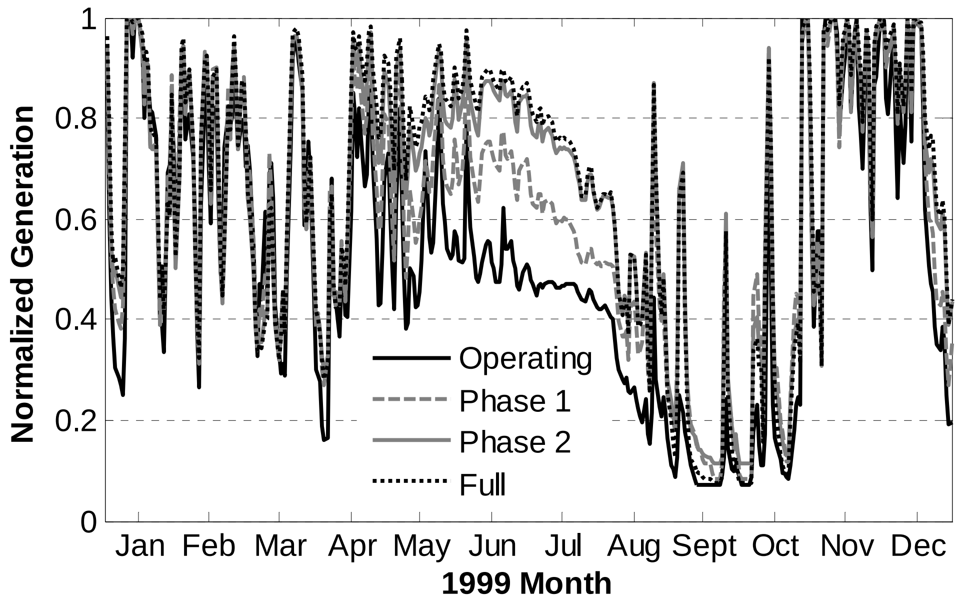

Figure 6.4: 1999 normalized generation comparison

1999 was chosen due to heavy snowfalls that occurred in that year which resulted in generation outputs that clearly illustrate the differences between scenarios during the spring snowmelt period. Differences in RRA flows are the reason for the differences between development scenarios. Figure 6.5 demonstrates flow differences in the form of average monthly FACs.

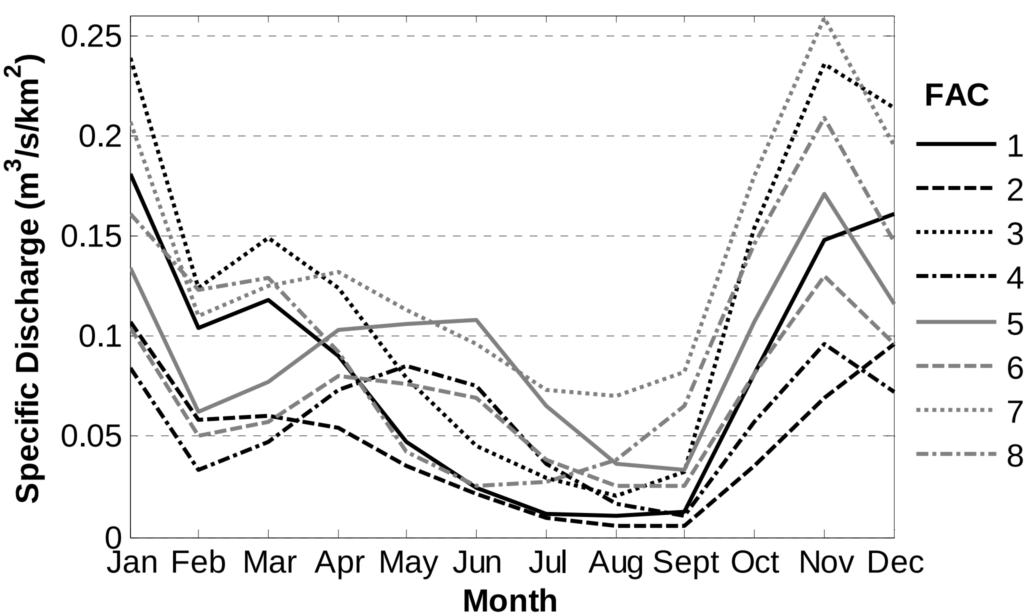

Figure 6.5: Monthly average FAC values

While Figure 6.5 does not demonstrate generation output directly, the FACs depict trends in the amount of water available for generation in each RRA. As these FACs apply to a RRA regardless of development scenario, they are well suited to illustrating geographic influence.

6.2 Generation by Development Scenario

To demonstrate the cumulative impact of small hydro development on generating potential, the 175 sites were categorised into four distinct development scenarios and modelled. The scenarios were introduced in Section 5.8 and represent current and potential facilities at various stages of development. In the following section, the generating results are presented for the entire seven year time period.

6.2.1 Currently Operating Facilities

There are currently 10 small hydro facilities operating on Vancouver Island having a total nameplate capacity of 43.5 MW. These facilities operate in RRAs 3, 4, 5 and 7. Two of these facilities have small storage reservoirs and were modelled as outlined in Section 5.7. Figure 6.6 shows the total generation output from these sites for the 1999 – 2005 study period. The y-axis has an upper bound of 450 MW to allow for direct comparison between the development phases illustrated in the subsequent figures.

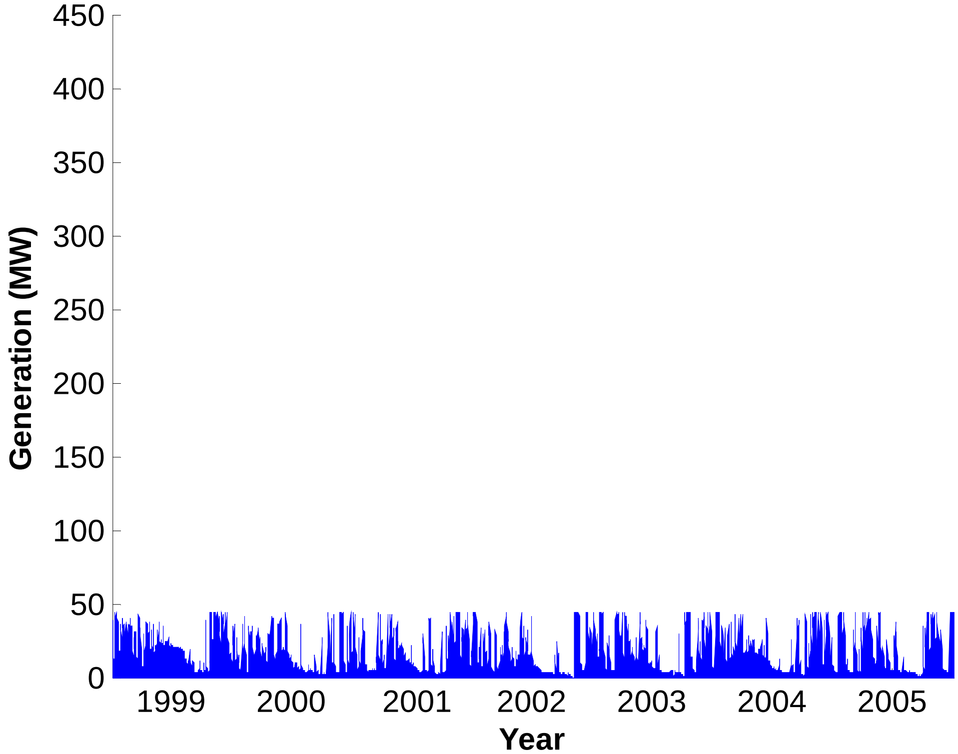

Figure 6.6: Operating daily generation output, 1999-2005

To illustrate the variability of generation output over the course of the study period, maximum, minimum and median values were determined for each day of the year. Figure 6.7 shows the range of generation output from all operating sites (maximum and minimum), while Figure 6.8 shows the median generation output.

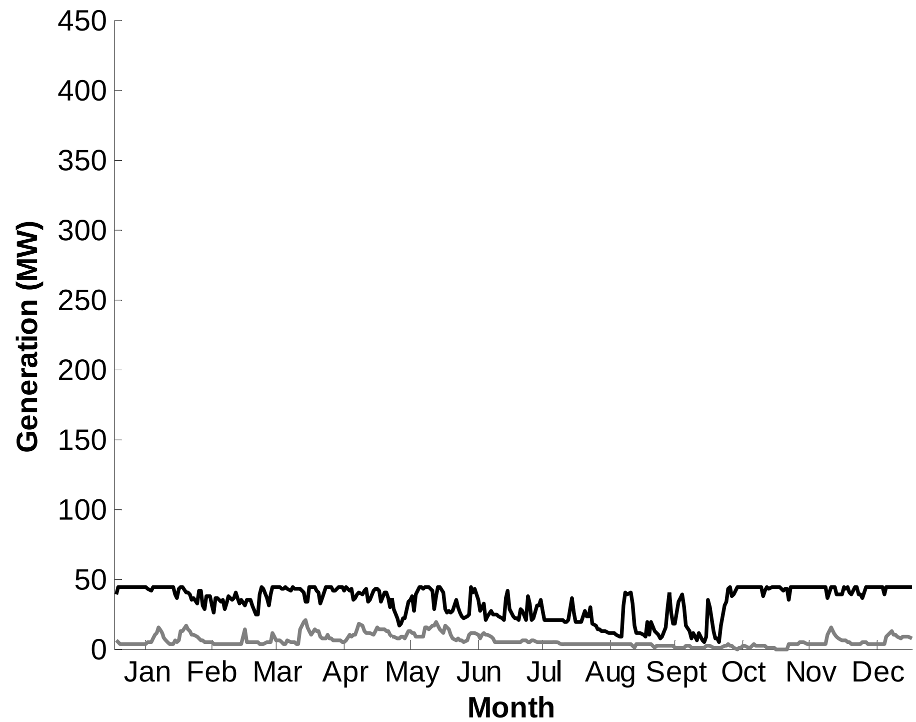

Figure 6.7: Maximum and minimum daily generation from Operating facilities

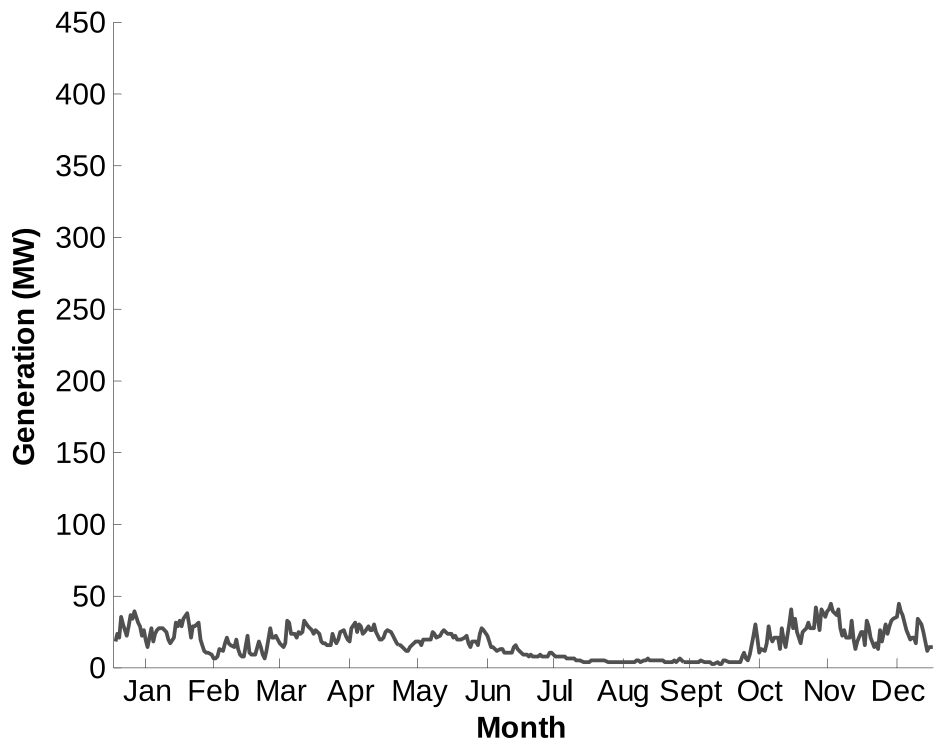

Figure 6.8: Median daily generation from Operating facilities

6.2.2 Phase 1 Development

BCH has recently signed 11 EPAs with IPPs on Vancouver Island that will add 98.2 MW of nameplate capacity to the system. These facilities operate in RRAs 3 through 8. Three of these facilities, accounting for 41.5 MW of nameplate capacity, incorporate storage reservoirs into their design and have been modelled as per Section 5.7. Figure 6.9 shows how the addition of these generating units to those units currently operating will influence generation for the same 1999-2005 study period.

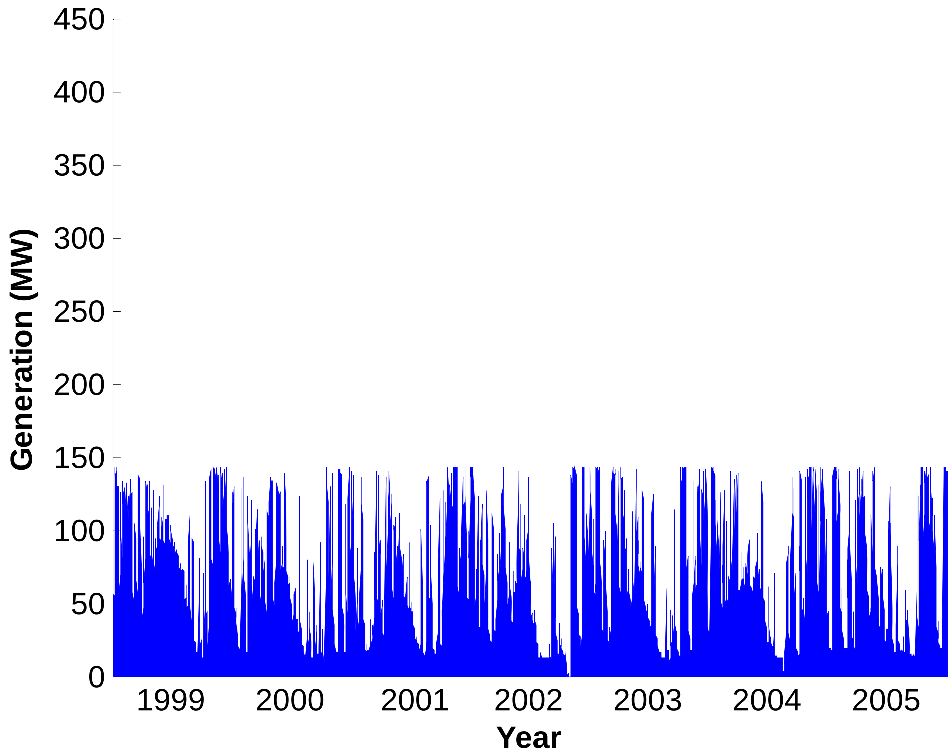

Figure 6.9: Phase 1 daily generation output, 1999-2005

Maximum, minimum and median values were again determined for each day of the year for the study period to illustrate the variability of generation output. Figure 6.10 shows the range of generation output from all operating sites (maximum and minimum), while Figure 6.11 shows the median generation output.

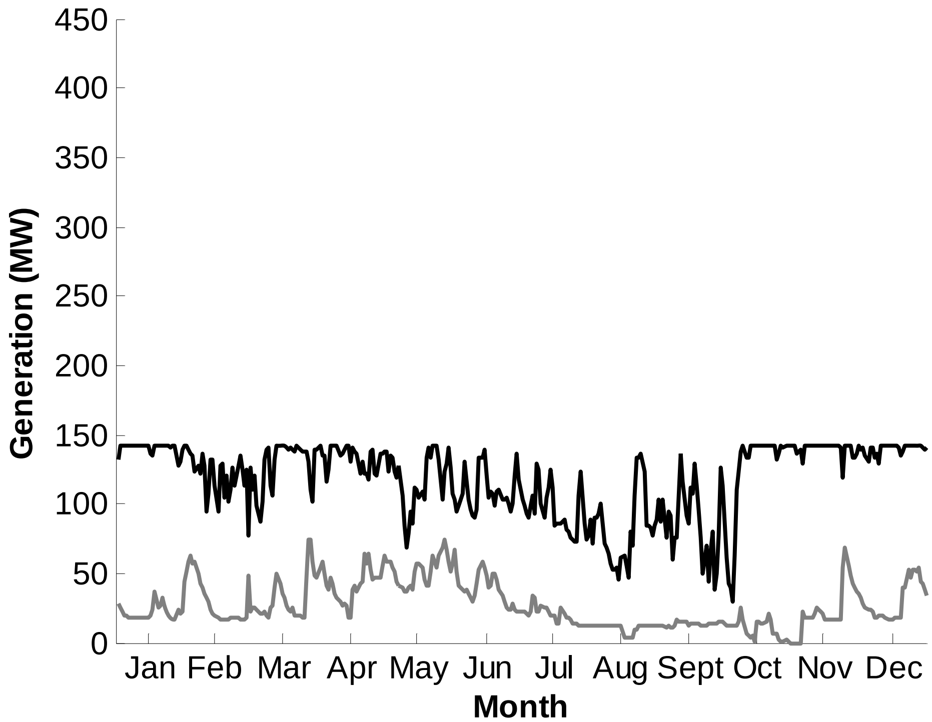

Figure 6.10: Maximum and minimum daily generation for Phase 1 development

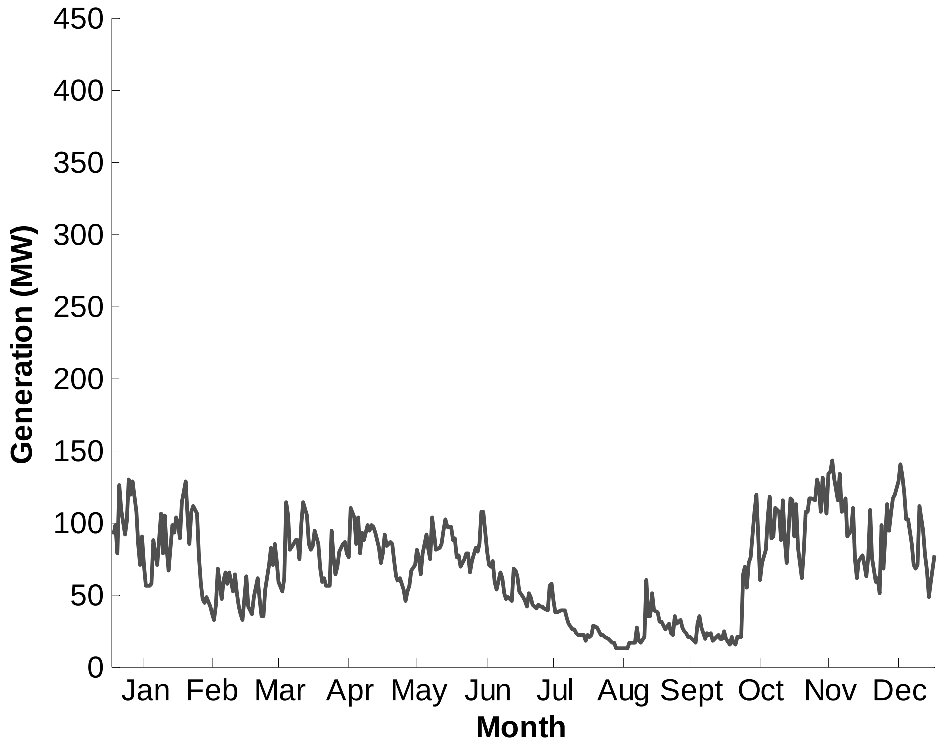

Figure 6.11: Median daily generation for Phase 1 development

6.2.3 Phase 2 Development

Small hydro developers have obtained or are in the process of obtaining water licences for 21 small hydro facilities that have the potential to add 151.8 MW of nameplate capacity in addition to that provided by Phase 1 developments. Results from this section account for all sites that were in the process of obtaining a water license at the end of 2006. These facilities operate in RRAs 1 and 3 through 7. Three of these facilities, accounting for 48.4 MW of nameplate capacity, incorporate storage reservoirs in their designs and have been modelled as outlined in Section 5.7. Figure 6.12 shows how the addition of these generating units to the Phase 1 facilities will influence generation for the same 1999-2005 study period.

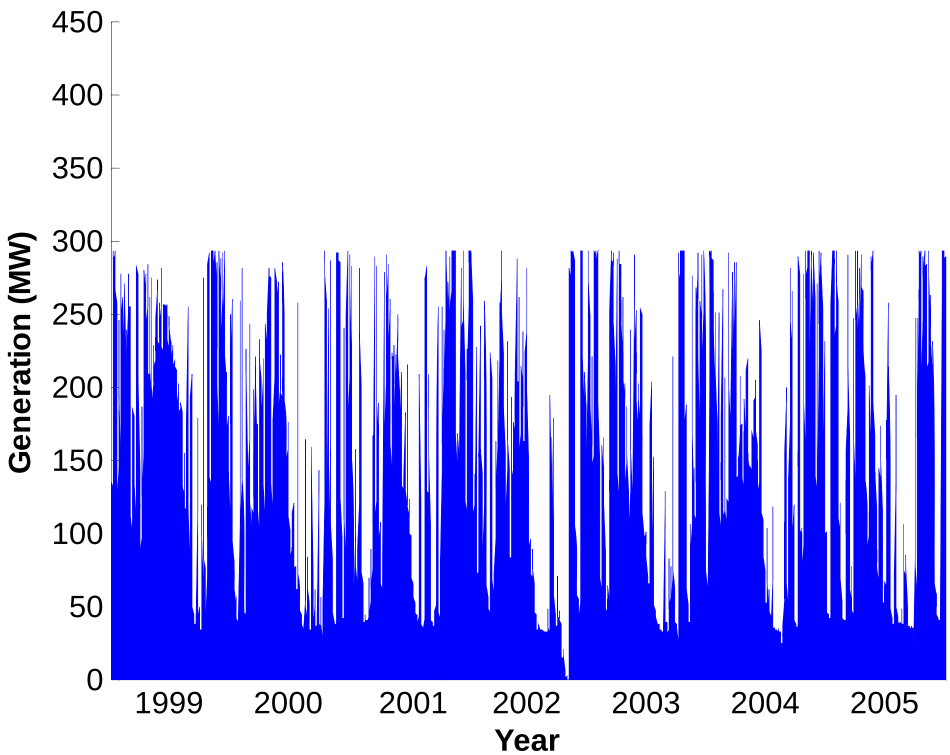

Figure 6.12: Phase 2 daily generation output, 1999-2005

Maximum, minimum and median values were again determined for each day of the year for the study period to illustrate the variability of generation output. Figure 6.13 shows the range of generation output from all operating sites, while Figure 6.14 shows the median generation output.

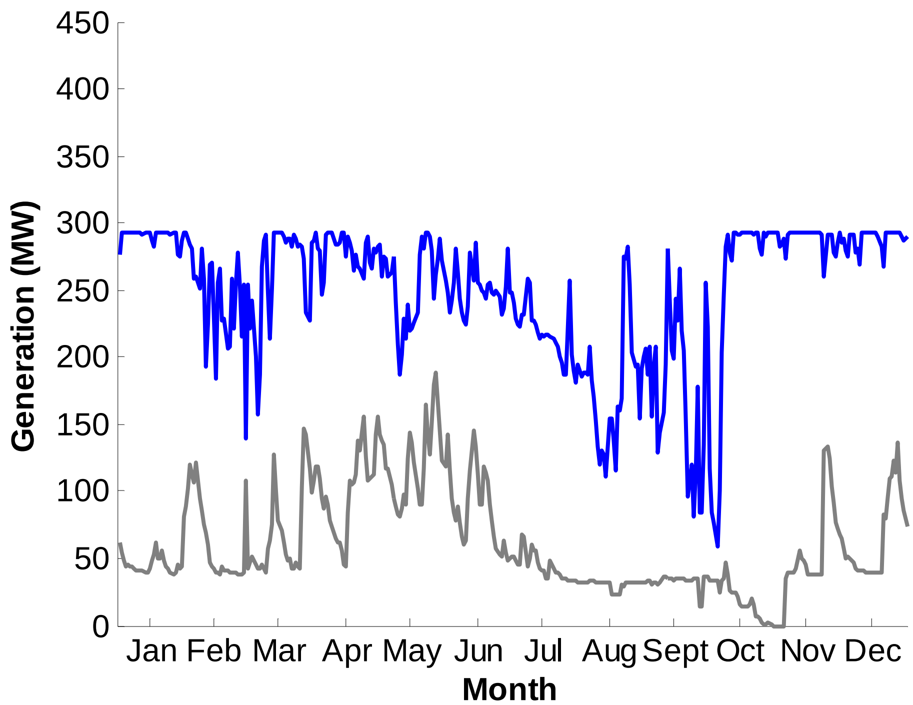

Figure 6.13: Maximum and minimum daily generation for Phase 2 development

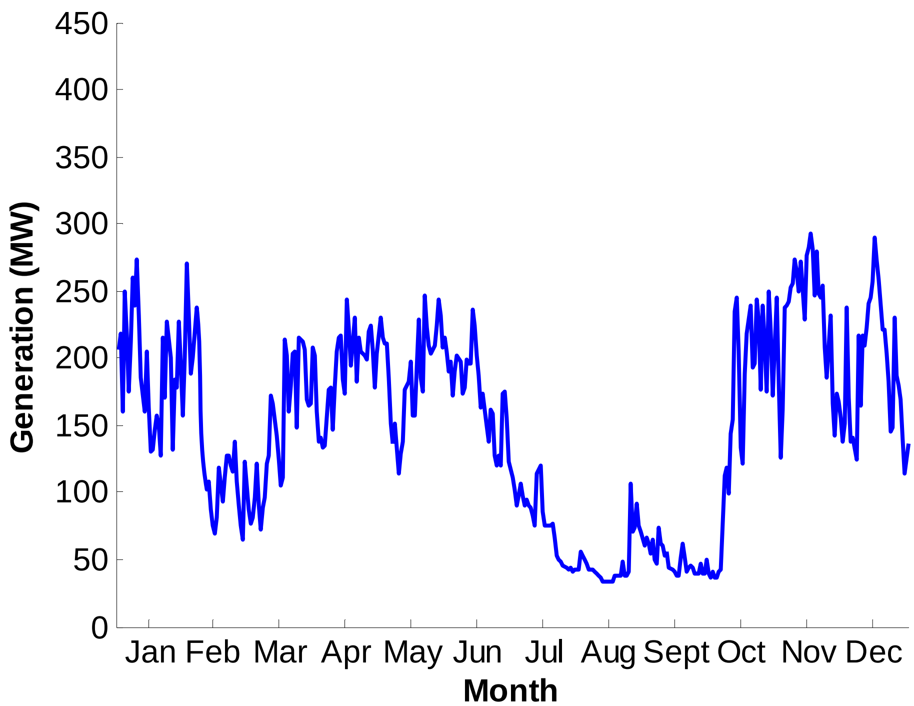

Figure 6.14: Median daily generation for Phase 2 development

6.2.4 Full Development

An additional 133 sites have been identified on Vancouver Island as having small hydro potential. This represents a potential nameplate capacity addition of 153 MW on top of that produced by Phase 2 developments using a 50% CF sizing criteria. Site specific studies may demonstrate that larger generating units are feasible. Sites that have been identified as having small hydro potential, but are currently undeveloped, occur in all RRAs. Figure 6.15 shows how the addition of these generating units to the previous Phase 2 facilities will influence generation for the same 1999-2005 study period.

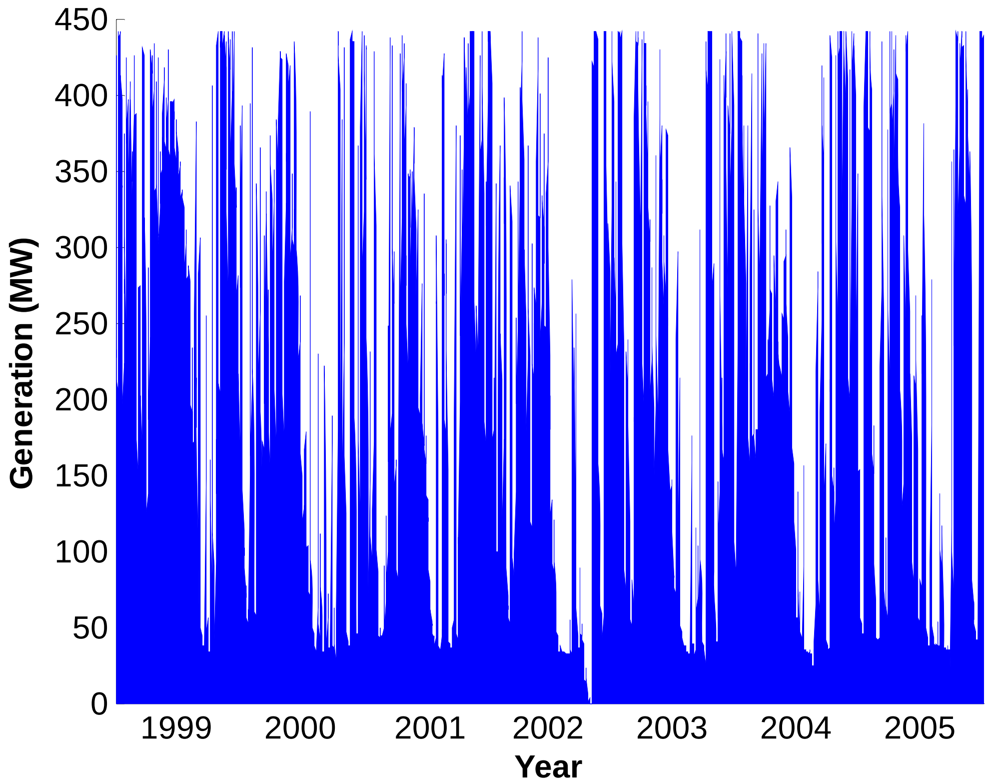

Figure 6.15: Full development daily generation output, 1999-2005

Maximum, minimum and median values were again determined for each day of the year for the study period to illustrate the variability of generation output. Figure 6.16 shows the range of generation output from all operating sites (maximum and minimum), while Figure 6.17 shows the median generation output.

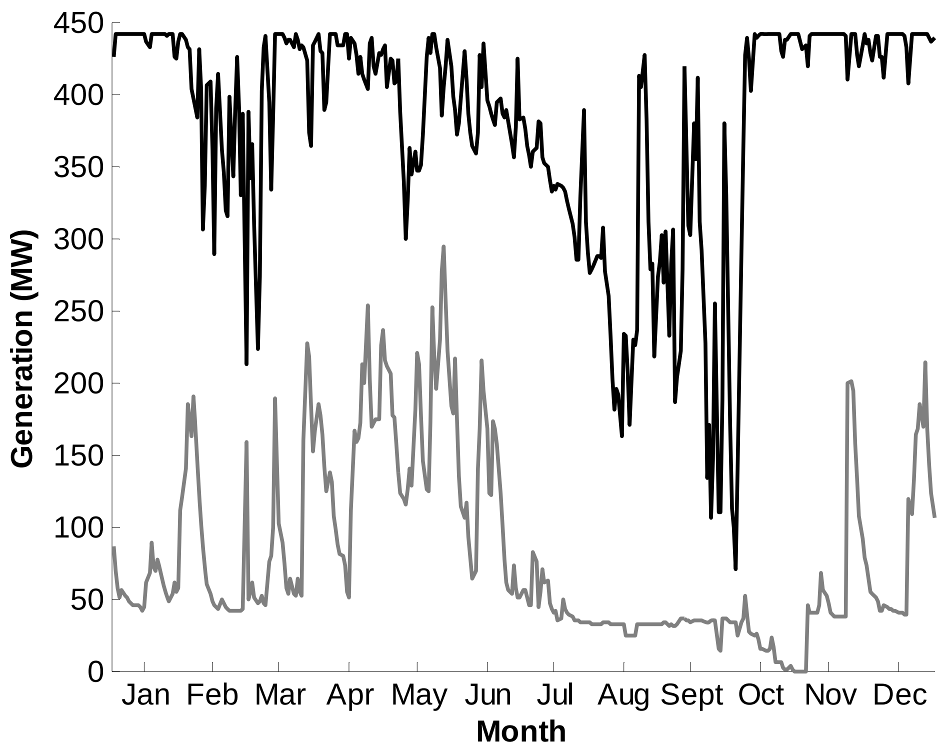

Figure 6.16: Maximum and minimum daily generation for Full development

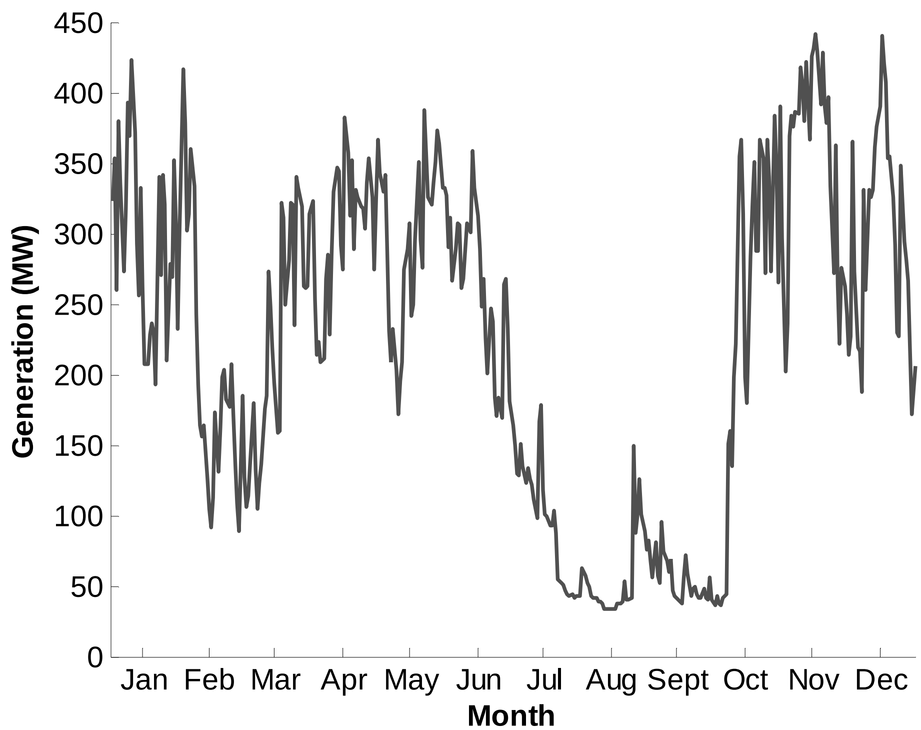

Figure 6.17: Median daily generation for Full development

6.3 DISCUSSION OF MODELLED SMALL HYDRO GENERATION RESULTS

In Section 6.1, the total number and aggregate nameplate rating for each development scenario was presented. For facilities under development, a trend of greater output per site is evident with the average rising from a current rating of 4.4 MW/site to 8.9 MW/site and 7.2 MW/site for Phase 1 and 2 developments, respectively. By comparing Figure 6.2 and Figure 6.6, it is evident that a small number of large developments cause this anomaly. Figure 6.18 illustrates the effects of this trend directly by comparing the number of sites in a capacity category to the total capacity supplied by those sites.

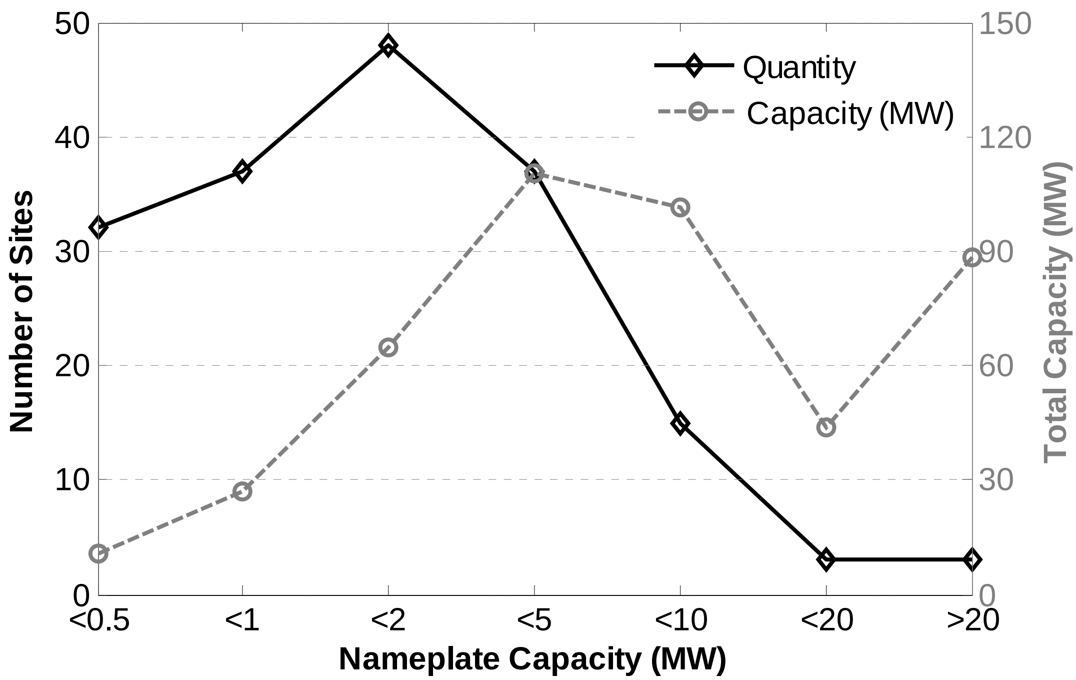

Figure 6.18: Number of sites and total capacity as a function of nameplate capacity

While sites having a nameplate capacity of less then 2 MW account for the majority of identified sites, the total capacity contribution made by these sites represents only 10% of the total. The most notable large-scale installations occur during Phase 1 development in RRAs 5, 7 and 8 and Phase 2 development in RRA 6. The undeveloped sites offer a noticeably smaller average contribution of 1.15 MW/site that may be attributed to less detailed site information. This also suggests that the most lucrative sites are developed first leaving only marginal sites for further development.

In terms of geographic location, Figure 6.2 and Figure 6.3 clearly demonstrate that the majority of small hydro opportunities are situated on north-central Vancouver Island, with RRAs 4 through 7 accounting for more than 80% of potential development capacity. These areas currently account for less then 50% of the developed capacity. Future development in these areas may be limited by transmission constraints outlined in Section 4.1 unless upgrades are completed by BCTC.

It is a widely held belief that moisture laden winter storms affecting Vancouver Island from late fall until spring sustain high river flows. Average Vancouver Island river flows, presented on BCH's map of green electricity resources of BC [85], do little to dispel this belief. As generation output is directly governed by flow availability, it follows that generation should also be sustained and remain relatively constant through the winter months. The generation output results presented for each development scenario clearly show that while generation is greater during the winter than in the summer it is far from constant. The figures illustrating median daily generation experienced over the 1999-2005 time period further support this finding.

Median plots, Figures 6.8, 6.11, 6.14 and 6.17, demonstrate "normal" generation patterns that can generally be expected. Using these plots to interpret generation trends through the course of a year demonstrates that a generally high level of generation is attained early in the year. This is followed by a significant reduction in generation in February and early March. Spring storms and snowmelt runoff beginning in mid March increase generation outputs throughout the spring until mid June. This generational period is punctuated by several notable generation reductions possibly associated with decreased storm size and sporadic snow pack runoff that influence individual RRAs. During the summer and early fall, generation is dominated by facilities having storage capabilities and is a fraction of total nameplate capacity. The return of inclement weather in mid October brings generation output from small hydro facilities to a significant portion of total nameplate capacity right through until the following year. These major trends are evident in all development scenarios, but the difference in generating output between highs and lows increases dramatically with increasing development. The maximum – minimum plots frame this difference in terms of extremes experienced during the time series.

The increase in daily minimum generation values seen in the progression from Figures 6.4, 6.7, 6.10 and 6.13 can be largely attributed to the addition of small hydro sites that employ storage. Only during one period in October 2002, after an exceptionally dry summer/fall period, does the level of generation provided by storage facilities fail completely. A wider geographic distribution of sites in future development scenarios also contributes to increasing minimum generation values, but this influence is most notable during the spring melt period. This is clearly demonstrated in Figure 6.4 where the greatest divergence between scenarios occurs during the spring/summer melt period. Referring to Figure 6.2 and Figure 6.5, the reasons for this trend become evident as significant future development in RRAs 4, 5 and 6 occur where few currently operating facilities exist. These RRAs are dominated by hybrid runoff hydrographs, which means they derive significant runoff contribution from snowmelt (as discussed in Section 3.2).

6.4 SUMMARY

The greatest potential for future small hydro development on Vancouver Island is in the north-central parts of the Island. Even partial development of this area will require transmission upgrades as current transmission capacity is limited. Successive small hydro development on the Island can increase the installed nameplate capacity by almost an order of magnitude from the current level. The last Section outlined generation trends experienced over the time period assessed but described little about the influence of this generation in terms of meeting Vancouver Island's electrical needs. The following chapter addresses this in terms of capacity and total yearly electrical demand.

7 SMALL HYDRO CAPABILITY TO MEET DEMAND

On Vancouver Island, 70% of the electrical demand is met by generating facilities on the mainland [10]. A network of transmission lines and submarine cables currently link mainland generators to the Island electrical grid ensuring reliable service. However, some of the transmission components are at the end of their service life and Vancouver Island's reliance on mainland generation places significant stress on the aging system during maximum demand periods.

Peak daily electrical demand data were acquired for Vancouver Island from BCTC and used to assess the availability of small hydro facilities during times of maximum yearly demand. Vancouver Island hourly demand data were also acquired from BCTC and used to assess the electrical contribution small hydro facilities could potentially make towards meeting the Island's demand. Daily generation values calculated for the four small hydro development scenarios discussed in the previous chapter were used for both analyses. To determine the total energy generated, it was assumed calculated daily output values were maintained for 24 hours. The results of both analyses are presented and discussed.

7.1 CAPACITY FROM SMALL HYDRO

Maximum electrical demand periods on Vancouver Island are met by submarine electrical transmission cables connecting the Island to generators on the mainland, as on-island generation capacity is insufficient to meet demand. Daily peak demand data for Vancouver Island were acquired from BCTC for the period of January 1, 1999 to February 9, 2004. Maximum yearly demand on Vancouver Island usually occurs during the winter months of December through February. The following analysis focuses on this maximum demand period. This time period was selected as it is during this time that the greatest strain is placed on the current system. Figure 7.1 shows the peak daily electrical demand on Vancouver Island during 2000 and the contribution of existing on-island generation including operating small hydro facilities. On-island generation, other than small hydro, was assumed to be operating at 100% dependable capacity for the analysis. The existing 744 MW of on-island generating capability was discussed in Section 4.1. Also shown are each of the small hydro development scenarios.

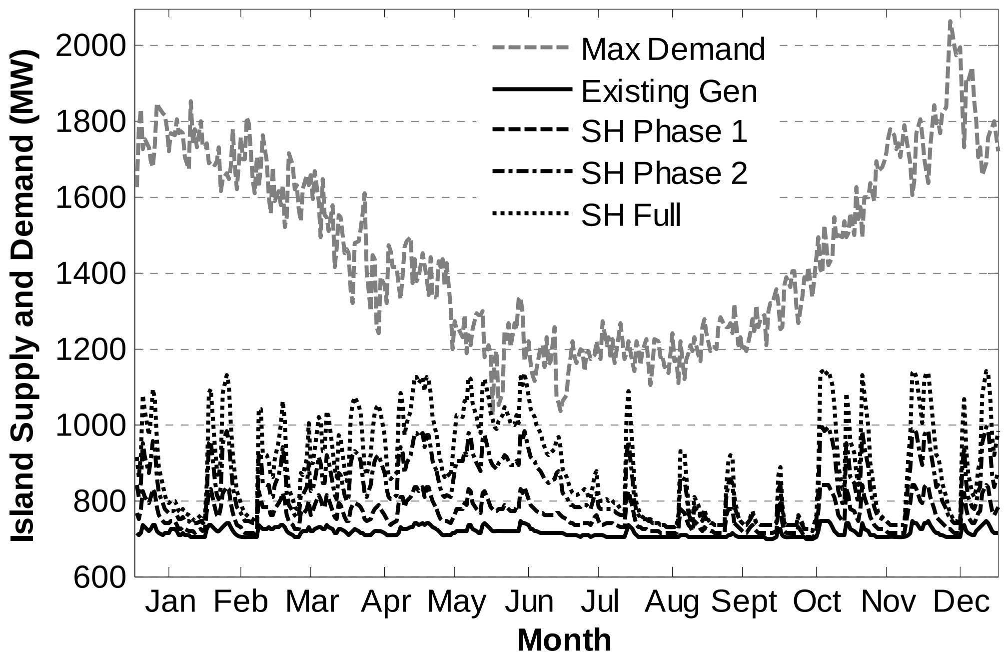

Figure 7.1: Vancouver Island Supply and Demand for 2000 with the addition of stepped small hydro development

The available nameplate capacity of small hydro during the maximum demand period was assessed and is referred to as availability in this section. At no time during this maximum demand period is on-island generation capable of meeting peak daily demand. Daily generation capacity values were normalized by the total nameplate capacity for each development scenario. Figure 6.4 in Section 6.1 demonstrated the divergence between development scenarios that occurs during the spring melt period. This figure also shows that during other times of the year normalized outputs between scenarios are similar. Based on this finding the output from all sites can be represented by a single normalized availability curve during the December to February maximum demand period. Table 7.1 summarizes the results of this analysis for the demand peak that occurred each year from 1999-2004.

Table 7.1: 1999-2004 capacity summary

Maximum Demand Period (Dec. – Feb.)	1999 - 2000	2000 – 2001	2001 - 2002	2002 – 2003	2003 – 2004
Day of Peak	Dec. 13	Dec. 11	Dec. 17	Feb. 25	Jan. 4
Max. Load (MW)	1862	2065	1955	1944	2193
Availability (%)*	96.0	15.9	100.0	16.5	13.2
Operating (MW)	40.8	3.7	44.2	5.9	3.1
Phase 1 (MW)	136	22.8	142.3	25.5	18.8
Phase 2 (MW)	281.7	56.1	292.5	54.1	43.9
Full (MW)	430.9	69.3	441.8	66.2	50.7

Note*: median operating availability of all scenarios, actual value may be different

Note that during the 2001 – 2002 peak demand, small hydro output is 100% of potential output yet is only capable of supplying 2.2% to 22.5% (44.2 MW to 441.8 MW) of the demand, depending on the development scenario.

To demonstrate the variability of small hydro availability over the entire maximum demand period, daily demand values were normalized by the maximum demand occurring in a given year, found in Table 7.1. All values were expressed as a percent of maximum for illustrative purposes. For reference, an ideal generator would exhibit 100% availability throughout the maximum demand period. Figure 7.2 to Figure 7.4 represent the maximum demand periods of 1999-2000, 2001-2002 and 2003-2004, respectively. The analysis of the 2003-2004 maximum demand period was cut short due to data being unavailable after February 9, 2004.

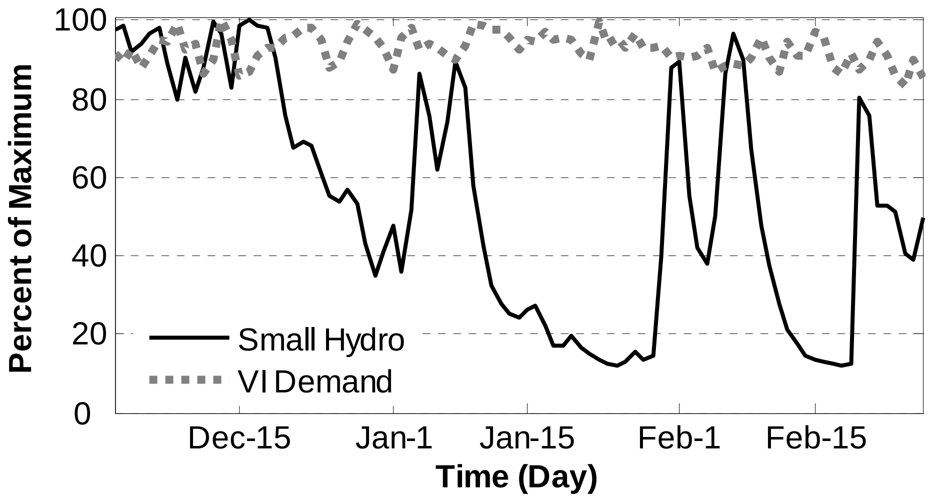

Figure 7.2: Small Hydro capacity and VI demand, Dec. 1999 – Feb. 2000

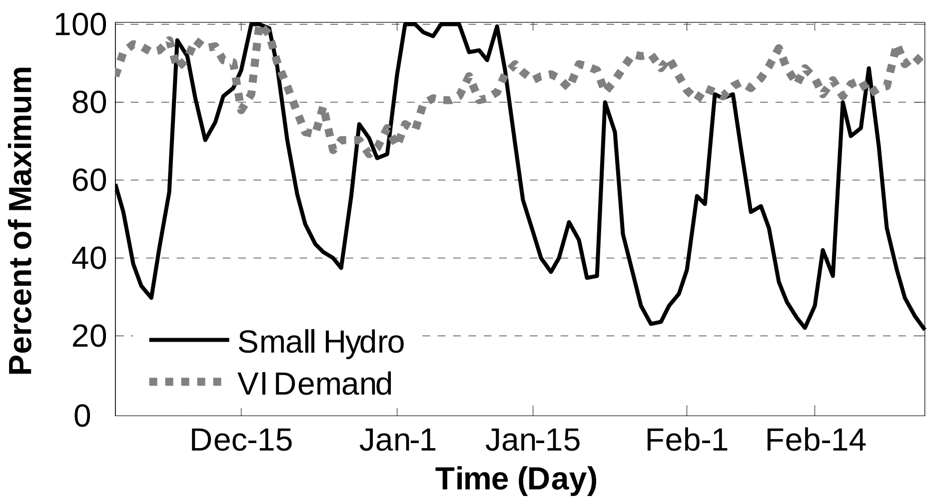

Figure 7.3: Small Hydro capacity and VI demand, Dec. 2001 – Feb. 2002

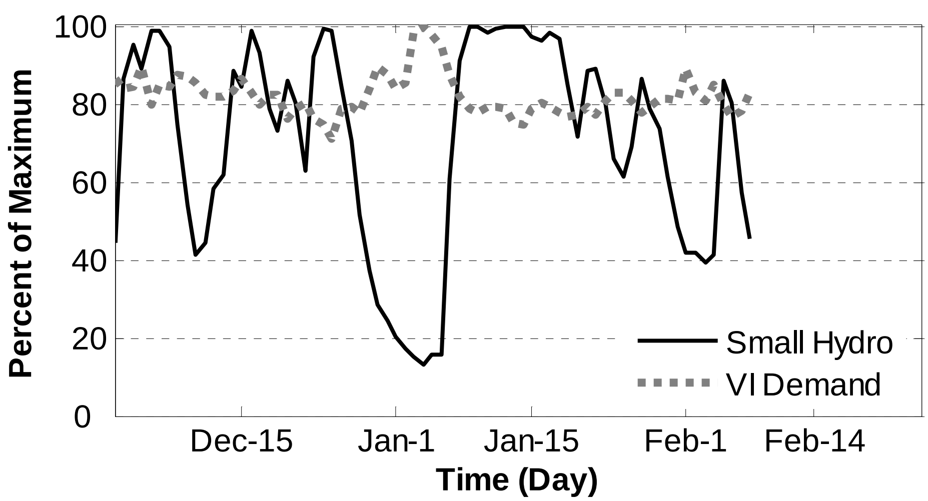

Figure 7.4: Small Hydro capacity and VI demand, Dec. 2003 – Feb. 2004

Figure 7.2 to Figure 7.4 illustrate the high degree of year-to-year variability in the availability of small hydro during the maximum demand period. At peak demand times in both 1999-2000 and 2001-2002, small hydro contributes 96% and 100% of its maximum generation potential, respectively. During the peak demand in 2000-2001, 2002-2003 and 2003-2004, however, generation contribution from small hydro was only 15.9%, 16.5% and 13.2% of its maximum potential, respectively. These results demonstrate the fallibility of relying on intermittent resources alone for power generation.

These figures also show significant demand fluctuations during the maximum demand period, both within the same year and from one year to the next. While the normalized demand depicted in the figures appears relatively constant, a change of 20% represents demand fluctuations of 372 MW, 391 MW and 439 MW for each depiction, respectively. In this context, daily peak demand is more volatile than the output from small hydro generators. Figure 7.3 and Figure 7.4, in particular, show prominent peak demand values that are well above the other demand values within the period. These anomalous peak values were found to be the result of inclement or cold weather events according to archived weather data [86].

Historical weather records could also be used to predict the availability of small hydro during these peaks based on whether inclement (*e.g.,* low pressure systems bringing precipitation) or clear and cold (*e.g.,* high pressure systems bringing no precipitation) weather was expected. In the case of the former, small hydro availability would be expected to be high, while low availability would result from the latter. This type of forecasting, if proven accurate, could be invaluable to the system operator.

7.2 Energy from Small Hydro

The analyses demonstrate that, while the availability of small hydro sites is far from constant, some capacity is always available. Thus on an Island-wide scale, small hydro facilities are consistently meeting some of the demand. Hourly Vancouver Island electrical demand data for the years 2000 to 2003 were acquired from BCTC. The monthly sums of this hourly data were used to determine total energy consumption.

Figure 7.5 shows the total monthly energy demand for Vancouver Island each year. To clearly represent monthly differences the y-axis begins at a value of 700 GWh. From year to year, total energy demand on a monthly basis is relatively constant with a median monthly discrepancy of 60 GWh. Energy requirements during December in 2000 and 2001 show the greatest discrepancy of 134 GWh.

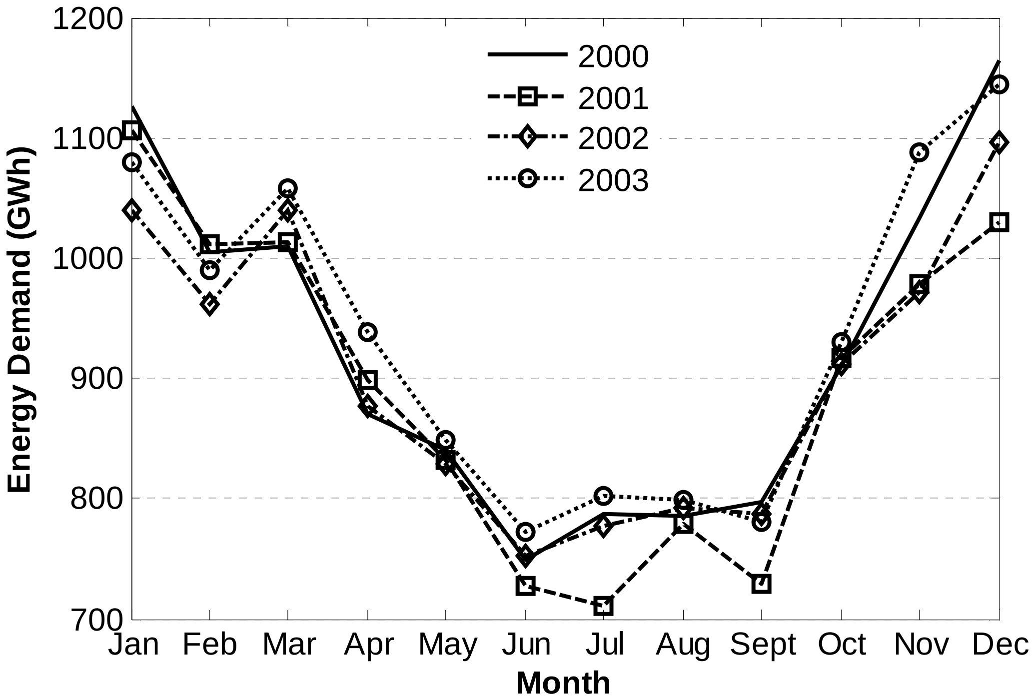

Figure 7.5: Vancouver Island monthly energy demand, 2000-2003

The notable yearly differences in energy demand can be attributed to weather and industrial activity on Vancouver Island. The effects of weather on electrical demand are most notable during the winter months when there is high demand for space heating. The influence of industrial activity is particularly evident during the summer of 2001. During this period, low pulp and paper prices forced many mills to drastically decrease output or shut down entirely, dramatically reducing the demand for electricity.

The total energy contribution for each small hydro development scenario was calculated and compared to Vancouver Island's electrical demand. Figure 7.6 shows the total monthly generation from small hydro for the Phase 2 development scenario. While an annual trend is clearly evident, significant monthly variations exist. These differences are most prevalent in the fall when exceptionally dry (*e.g.,* in 2003) or wet conditions (*e.g.,* in 2001) persisted.

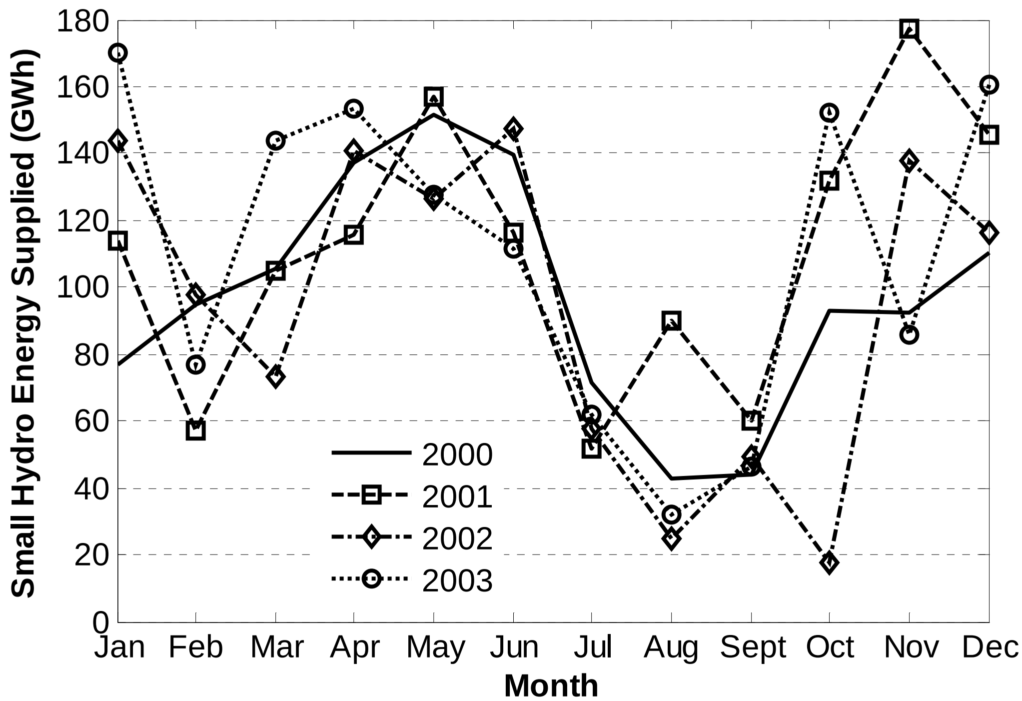

Figure 7.6: Phase 2 development energy contribution, 2000-2003

To illustrate the portion of Vancouver Island electrical demand small hydro generation could provide, generation totals were compared to demand on a monthly basis. This was completed for each development scenario. Figure 7.7 shows the monthly percentage of energy supplied by small hydro in terms of Vancouver Island's total demand during the year 2000.

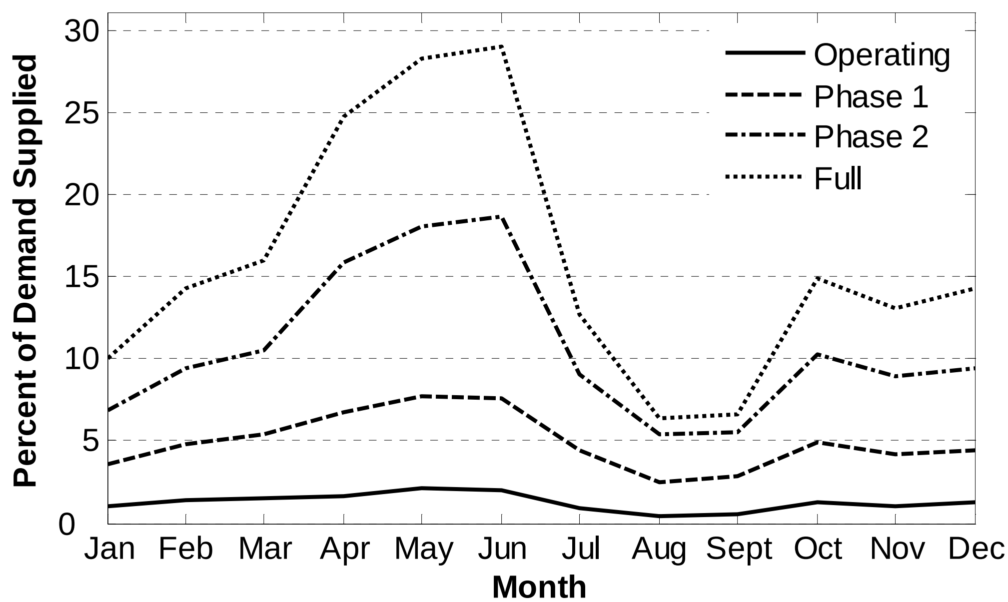

Figure 7.7: Small hydro contribution to Vancouver Island demand in 2000

Figure 7.7 captures the volatility of both monthly electrical demand and small hydro supply. During periods of high electrical demand small hydro is capable of meeting appreciably less of the overall percentage of demand. This can be attributed to both the inconsistency of flows available for generation and the smaller proportion of total demand met by small hydro during these times, due to high electrical demand. During the spring and early summer as high demand subsides, available generation flows become more consistent allowing small hydro to contribute a greater proportion of the total demand. During the low flow period, experienced in most years from July to September, flow available for generation is scarce while electrical demand is increasing. This results in a very low level of contribution from small hydro generators. This contribution level would be even lower were it not for sites that incorporated storage into their designs. The influence of these storage sites is discussed in Section 9.4.

On the basis of energy supplied, small hydro generators can make a valuable contribution to Vancouver Island demand. As seen in Figure 7.7 the greatest contribution from small hydro generators occurs during the spring shoulder season. However, it is also evident that small hydro is capable of meeting a portion of the Island demand in every month of the year. Table 7.2 contains the percentage of energy supplied by small hydro for each year and for each development scenario.

Table 7.2: Energy supplied by small hydro and the percentage of Vancouver Island demand met, 2000 to 2003

Year	Demand (GWh)	Operating		Phase 1		Phase 2		Full	
		(GWh)	(%)	(GWh)	(%)	(GWh)	(%)	(GWh)	(%)
2000	11074	140.0	1.27	541.1	4.90	1160.3	10.50	1730.9	16.67
2001	10734	152.8	1.42	612.2	5.70	1321.1	12.31	1959.0	18.25
2002	10835	136.5	1.26	526.5	4.86	1132.6	10.45	1679.2	15.5
2003	11232	165.6	1.47	624.6	5.56	1321.7	11.77	1956.0	17.41

During the 2000-2003 assessment period, the energy contribution from small hydro generation remained relatively constant. A longer survey period would be helpful in determining long term trends with greater confidence. Interestingly, while demand was at its highest in 2003, small hydro was able to meet a greater proportion of this load due to favourable flow conditions that occurred in that year. This demonstrates the capability small hydro has to meet a portion of Vancouver Island's demand.

7.3 SUMMARY

High generating capacity from small hydro facilities on Vancouver Island does not dependably coincide with peak demand on the Island. Throughout the maximum demand period, the amount of capacity small hydro can offer varies considerably meaning other sources of generation must make up the difference. From an energy perspective, small hydro sites situated on the Island are capable of meeting a portion of Vancouver Island's electrical demand every month of the year. The total contribution small hydro is capable of making to yearly demand depends on both available generation flows and electrical demand on the Island. This inherent variability will be examined further in the following chapter on intermittence.

8 INTERMITTENCE

Intermittence influences the assimilation of any renewable resource into the generation mix. When the contribution of intermittent sources compared to the rest of the electrical network is small, these sources are easily assimilated into the network. However, if the contribution of intermittent sources comes to represent a significant portion of total generating capacity, the challenge of maintaining network stability increases. For this reason, an assessment of small hydro intermittence was undertaken.

In this chapter, the intermittence of small hydro is assessed in terms of daily generation change and the level of penetration small hydro attains within the Vancouver Island grid. The influence of storage on intermittence is then discussed. A comparison between generation from wind and small hydro facilities on southern Vancouver Island concludes the chapter.

8.1 SMALL HYDRO INTERMITTENCE

Run-of-river facilities are unable to store water for later use and must reduce output or shut down during low flow periods resulting in intermittent output. However, watersheds naturally attenuate, store and concentrate rainfall runoff, making stream flows relatively stable from day to day. As a result, intermittence from small hydro facilities tends to be relatively predictable with major changes to generating capacity taking place over a time period of hours to days. To demonstrate this, the daily change in generating capacity was calculated over the entire 1999 to 2005 study period for each development scenario and expressed as a percent change of the nameplate capacity using the following equation:

$$\Delta P(\%) = \frac{\left(P_n - P_{n-1}\right)}{P_{\max}} \times 100\% \,. \qquad [8.1]$$

A histogram of $\Delta P(\%)$ (Figure 8.1) was created to illustrate the size and frequency of generation changes for the entire 1999-2005 time-series (2556 observations). Only the full development scenario is presented, as similar fluctuations in generation were found to occur in all scenarios.

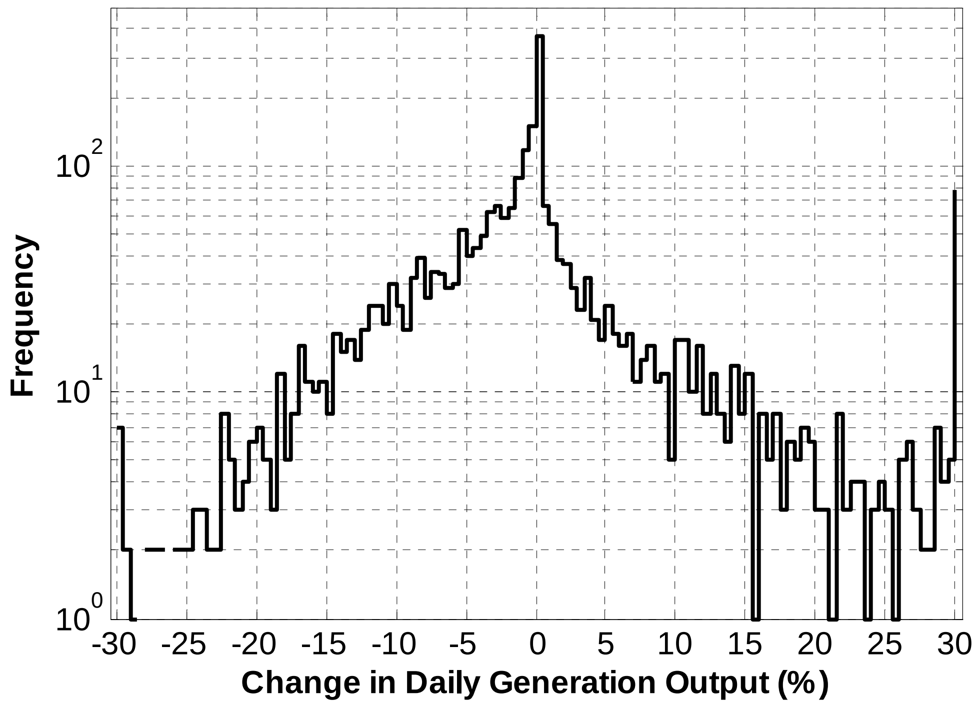

Figure 8.1: Histogram of percent change in daily generation output for full development scenario (441 MW)

The y-axis of the histogram has been displayed in log scale to clearly show the infrequent large fluctuations. Figure 8.1 is asymmetric about 0%, with changes to generating capacity more frequent in the range of 0% to –15%, than changes in the range of 0% to +15%. This asymmetry is the result of a watershed's ability to attenuate runoff which, in Figure 8.1, is clearly represented by the gradual reduction in generation. Less than 10% of the data exhibits a daily change in generation greater then ±15% (66.3 MW) with the majority of occurrences being positive. These large positive changes in generation can be attributed to large volume precipitation events typical of Pacific weather systems. Large amounts of precipitation occurring over a short period tend to exceed a watershed's infiltration rate leading to greater amounts of runoff. This runoff accumulates in watercourses, rapidly increasing the amount of flow available for generation. As the weather system passes, flows subside leading to less generating flow. The negative fluctuations in daily generation occur predominantly in increments of 5% (22.1 MW) or less. This supports the point made earlier regarding a watershed's ability to attenuate runoff.

8.2 Level of Penetration

The generating capacity available from a single resource type in a larger generating system is referred to as that resource's level of penetration (RP). The method of calculating RP is demonstrated by the following equation:

$$RP = \frac{P_{resource}}{P_{system}} \times 100\% , \qquad [8.2]$$

where: RP = Resource penetration;
$P_{resource}$ = Nameplate capacity of resource (kW); and,
P_{system} = Total generating capacity of the system (kW).

Table 8.1 represents the level of penetration small hydro attains in terms of nameplate capacity at each development phase in relation to Vancouver Island's current on-island generating capacity.

Table 8.1: Small hydro level of penetration in relation to Vancouver Island's total generating capacity

Development Phase	Total On-Island Generation (MW)	Small Hydro Contribution (MW)	Small Hydro Penetration (%)
Current	742.2	44.2	6.0
Phase 1	840.3	142.3	16.9
Phase 2	990.5	292.5	29.5
Full	1139.8	441.8	38.8

It should be noted that Vancouver Island's electrical grid is an extension of the much larger British Columbia electrical grid. In this larger context the contribution of Vancouver Island's small hydro generation at full development represents only 4% of total generating capacity of the Provinces generation. Future developments of other generation sources are likely to make this contribution even smaller.

Maximum instantaneous penetration (MIP) is another measure of penetration. In this case, the level of penetration is measured based on the amount of demand a resource is capable of meeting during a low demand period. This relationship is expressed by:

$$MIP = \frac{G\{t_{D-low}\} \bullet P_{resource}}{D\{t_{D-low}\}} \times 100\% \,, \tag{8.3}$$

where:
- MIP Maximum instantaneous penetration (%);
- G Instantaneous resource generating capacity (%);
- D Instantaneous electrical demand (kW); and,
- $t_{D\text{-low}}$ Time of lowest demand.

The MIP in a year is attained when high resource generation coincides with a low demand. This measure is relevant to intermittent resources that operate on a *must run* basis. Table 8.2 lists the MIP small hydro resources would have attained for each development scenario for each year from 2000 to 2003. Occurrences of MIP are the result of disruptions to the transmission system connecting the Vancouver Island grid to the mainland grid, with the exception of the 2000 case.

Table 8.2: Small hydro maximum instantaneous level of penetration

Minimum Demand Period (Year)	2000	2001	2002	2003
Day of Occurrence	June 14	Dec. 15	June 18	Mar. 22
Min. Load (MW)	813	707	507	558
Level of Penetration				
Operating (%)	5.3	5.0	6.4	7.9
Phase 1 (%)	17.1	18.1	21.3	25.4
Phase 2 (%)	35.1	36.3	46.5	52.3
Full (%)	53.45	55.18	73.9	79.05

Had small hydro facilities been constructed and able to contribute, the minimum load may have been adjusted accordingly. For this reason it is unlikely that future development scenarios will ever attain the levels of penetration noted above.

As MIP in the year 2000 was not caused by a transmission disruption, it will be used as a representative example. The MIP of small hydro during 2000 occurred during the spring snowmelt season when small hydro facilities are capable of dependably providing some capacity to the grid. Therefore, MIP during this time of year would only be a concern if a low snowpack situation occurred and the MIP was caused by a short lived spring runoff event. In this case, the high contribution of small hydro to the grid would be short lived and other means of generation required to ensure reliable electrical service would be maintained. It is unlikely that this would be an issue until development exceeded the Phase 1 scenario due to the low MIP level. Development scenarios beyond Phase 1 may result in the export of power from the Island or require other sources to be manipulated to maintain system stability.

8.3 Influence of Storage

There are seven small hydro facilities representing 105 MW currently operating or under development on Vancouver Island that incorporate storage into their designs. The addition of storage enables flows to be regulated and thereby reduces the quantity of water spilled. In addition, flow regulation increases dependable capacity by taking water out of storage when natural flows are low [37]. BCH defines dependable capacity as the maximum output a generating plant can reliably produce when required, assuming all units are in service. The reliability of production is associated with generation capacity coincident with times of system peak demand.

Storage sites were modelled with and without their licensed storage volume to demonstrate the influence of storage on generation capacity and the total amount of electrical power produced. The amount of dependable capacity a storage site is able to provide is directly related to how the stored water is utilised. For the storage case, the simple storage model outlined in Section 5.6 stores water to maximize long term generating capacity while adhering to the licensed storage volume and minimum flow constraints. Future work could focus on the optimization of storage for alternative operating scenarios. For the natural flow case, available generation flows were modelled as run-of-river. Generation output from storage and natural flow sites was calculated using their respective available flows. Generation values were then normalised based on a total nameplate capacity of 105 MW. Figure 8.2 demonstrates the influence of storage during the 2004-2005 maximum demand period.

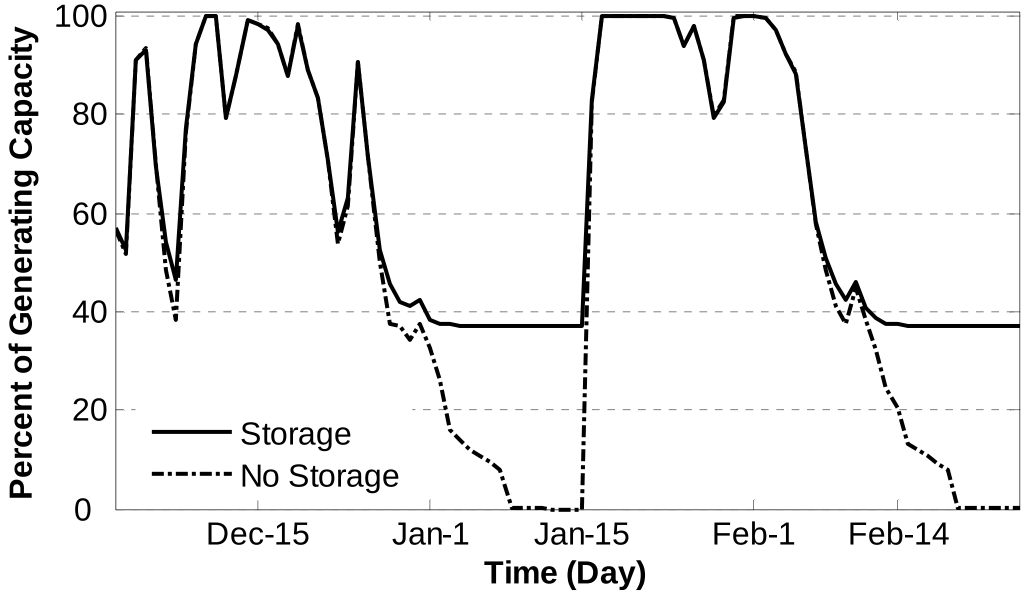

Figure 8.2: Influence of storage on generation output, 2004-2005 maximum demand period

In the example depicted in Figure 8.2, sites modelled with storage have a dependable capacity of 38% (~40 MW) of their nameplate capacity during the maximum demand period. Again, this is a function of how stored water was utilised to satisfy the simple storage model constraints. If storage use were optimized, the level of dependable capacity could potentially be much higher. When the same sites are modelled under natural flow conditions, low flows result in no or significantly reduced levels of generation. From these observations it can be concluded that storage sites are responsible for the dependable capacity realised during the maximum demand period.

During the maximum demand period, storage sites have been shown to have a significant influence on generation during periods of low flow. This influence continues into the summer months when storage sites can continue generating and meeting demand. Figure 8.3 shows the generation duration curve for storage and non-storage scenarios for the entire 1999-2005 time series.

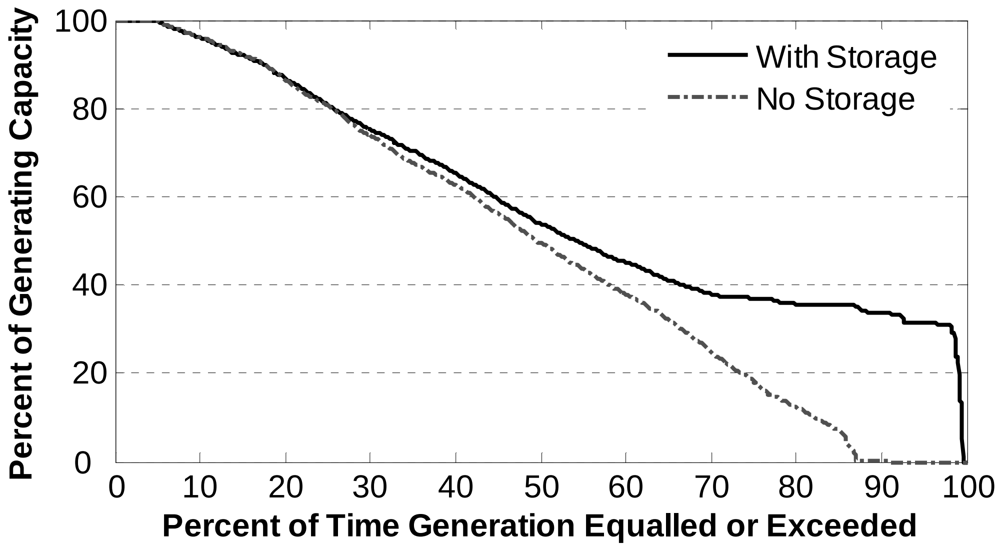

Figure 8.3: Generation duration curve of storage vs. non-storage facilities

On average, the use of storage increased generation by 92 GWh/year beyond what would have been generated under run-of-river operation using the current storage operating criteria. The time during which nameplate capacity is attained remains unchanged in both cases due to the operating criteria of the storage facilities. The lines depicting available generation diverge at approximately 30% of the time that generation is equalled or exceeded. There is a discontinuity in the rate of divergence at approximately 70% because, beyond this point, all storage facilities are using stored water. The irregularities along the storage generation line represent facilities reducing output as storage is exhausted.

8.4 Comparison to Wind

While wind farm development in Canada continues at a brisk pace, British Columbia has yet to incorporate wind generation into its electrical grid. The reasons for this are unclear considering the growing demand for green sources of generation and British Columbia's energy policy that 50% of new generation be green [1]. In comparison, small hydro generation, another renewable green resource within British Columbia, has been growing rapidly, accounting for 91% of new capacity added to the system since 2002 [3]. Although small hydro is intermittent, like many green generation sources, including wind, its development has been favoured. To demonstrate the differences between these two renewable means of generation, a simple analysis was completed using Vancouver Island data. Generation from both wind and small hydro resources were modelled on an hourly basis and the results compared.

To model wind generation, a single Enercon E70 turbine [87] was employed. The turbine has a nameplate capacity of 2.3 MW at a wind speed of 15 m/s. It has a cut-in wind speed of 2.5 m/s and a cut-off wind speed of 31 m/s. The turbine was modelled using a hub height of 113 m and swept blade area of 3959 m^2. Measured wind speed data was corrected to reflect winds occurring at hub height using the following equation [88]:

$$V_{hub} = V_{data}\left(\frac{H_{hub}}{H_{data}}\right)^{\alpha}, \qquad [8.4]$$

where: V_{hub} wind velocity at hub height (m/s);
V_{data} wind velocity at measurement height (m/s);
H height (m); and,
α shear component (0.14 most typical shear component value).

The power curve for the Enercon E70 was obtained from the company's product manual [87] and a simple look-up table was used to interpolate for the instantaneous power output at a given wind speed.

In 2000, BCH initiated a wind monitoring program on Vancouver Island. Eight sites were monitored, but a year of continuous data was only acquired from three locations: Port Alice, Great Central Lake and Jordan Ridge situated in Northern, Central and Southern Vancouver Island, respectively. Wind data was obtained from these monitoring stations at 10 minute resolution taken at 30 m above ground level [89]. Average hourly wind speeds for each location were calculated using this data and used for this analysis. A preliminary assessment demonstrated that all three sites exhibited poor CF characteristics as noted below:

- Port Alice, 2001 data, 12.1% capacity factor;
- Great Central Lake, 2002 data, 7.2% capacity factor; and,
- Jordan Ridge, 2001 data, 14.3% capacity factor.

As Jordan Ridge had the highest CF, it was selected as the site that would be used for further analysis and comparison to small hydro.

A small hydro site situated on the Fleet River was selected for the analysis. This site was chosen due to its close proximity to Jordan Ridge and similar nameplate capacity to the E70 wind turbine. Hourly flow data was acquired for the San Juan River from the WSC for 2001. The Fleet River is part of the same watershed allowing for a specific discharge correction to be made as outlined in Section 3.3. The Fleet River site is currently undeveloped and the design flow was selected on the basis of a 50% CF. This flow was determined to be 4.47 m^3/s and the head at the site was measured to be 50 m. The site output based on the aforementioned design flow and head was determined to be 1.88 MW. All hourly efficiency values and generation output were calculated using the methods discussed in Sections 5.5 and 5.7.

To compare resource generation directly, all output values produced by the model were normalised by dividing hourly generation by the site nameplate capacity. The change in hourly generation was used to illustrate the fluctuating nature of both renewable resources. Figure 8.4 is a histogram of hourly change in generation assessed from –25% to 25% at 0.5% increments. The data is displayed using a log scale in the vertical direction to clearly show the less frequent fluctuations.

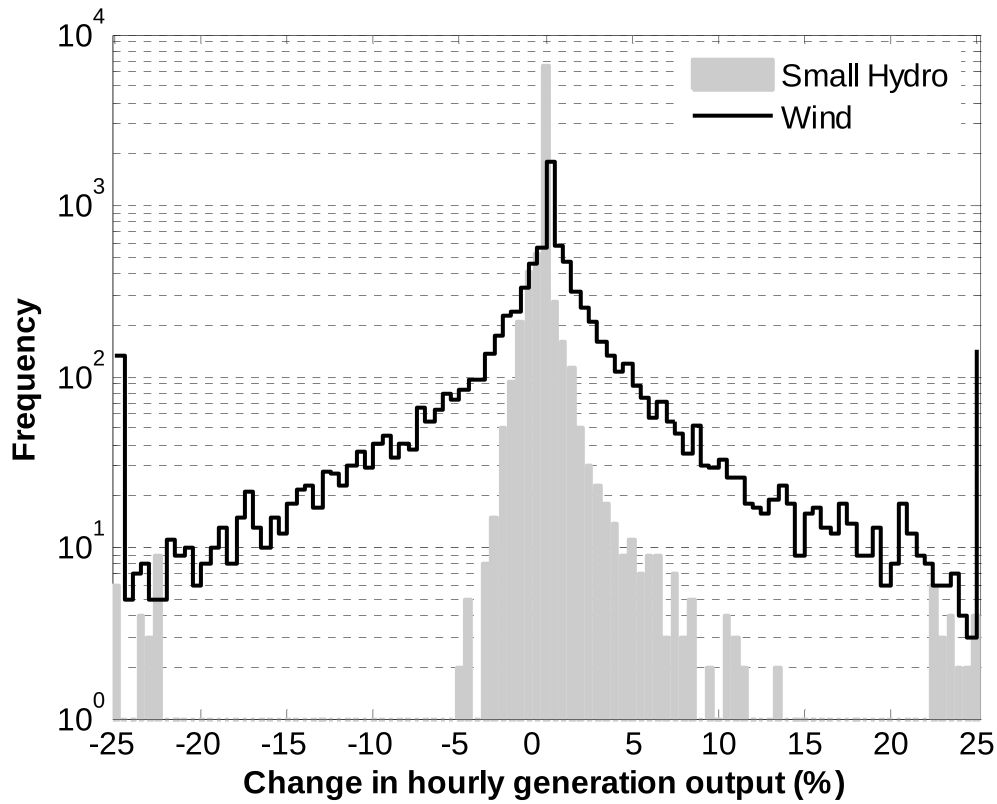

Figure 8.4: Histogram of hourly percent change in generation, small hydro vs. wind

It is evident from the data that large changes in hourly generation are more prevalent for wind generation. Hourly changes in small hydro generation are almost all within ±5%. The changes in excess of ±20% seen in the small hydro data can be attributed to the 75% turbine efficiency constraint discussed in Section 5.5. Spikes seen in the wind data at ±25% represent changes in generation output equaling or exceeding 25%.

Figure 8.5 shows the normalized hourly output from both the wind and small hydro resources for December 2001. December was chosen due to its coincidence with the Vancouver Island maximum demand period. It clearly demonstrates the occurrence of large fluctuations in the wind output during the maximum demand period while small hydro output remains relatively constant.

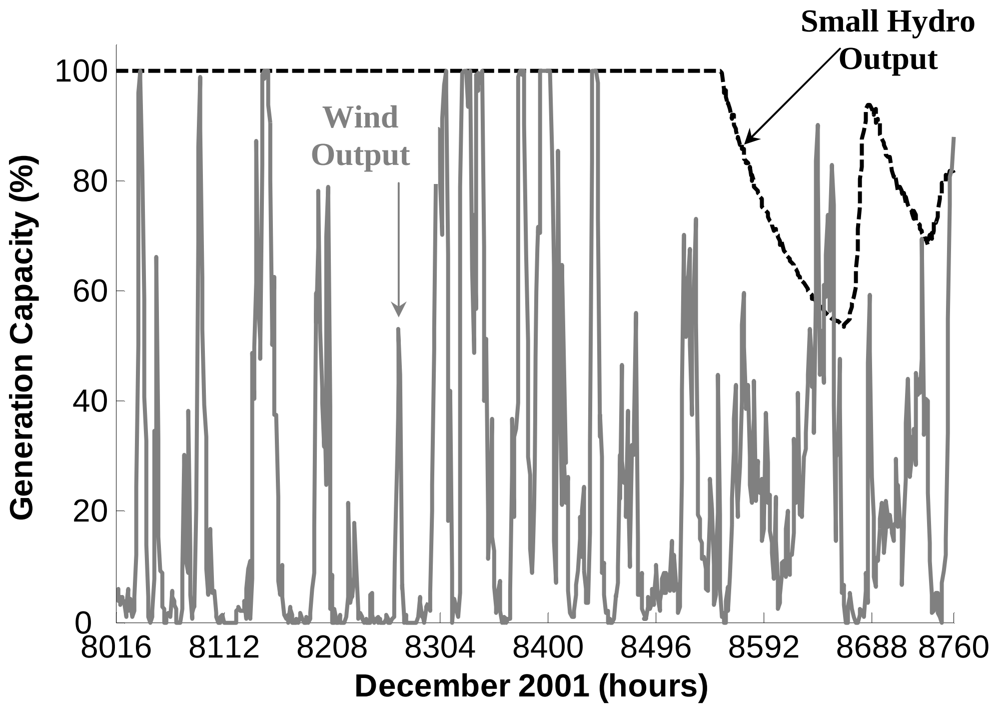

Figure 8.5: Hourly generation capacity of a wind turbine on Jordan Ridge compared to a small hydro installation on the Fleet River

For wind and small hydro generation having these characteristics, ensuring stable operation of an electrical grid incorporating small hydro generation would present fewer challenges than incorporating wind generation. This intrinsic volatile characteristic of wind generation can be attributed to the wind resource itself and its method of capture. Air has a low density (1.275 kg/m^3) necessitating a large surface area to capture the energy of its movement (*i.e.,* wind). The influence of wind is also diffuse increasing the difficulty of extracting energy from its flow using a wind turbine. Small hydro facilities benefit from water's higher density (1000 kg/m^3) which allows much smaller equipment to be used to extract energy from its flow for an equivalent nameplate capacity. A watershed upstream of a small hydro facility also acts as a natural runoff collector, concentrating flow and delivering it to the point of generation. The modelled generation outputs demonstrate how the attributes of both resources manifest themselves. Figure 8.6 shows a generation duration plot.

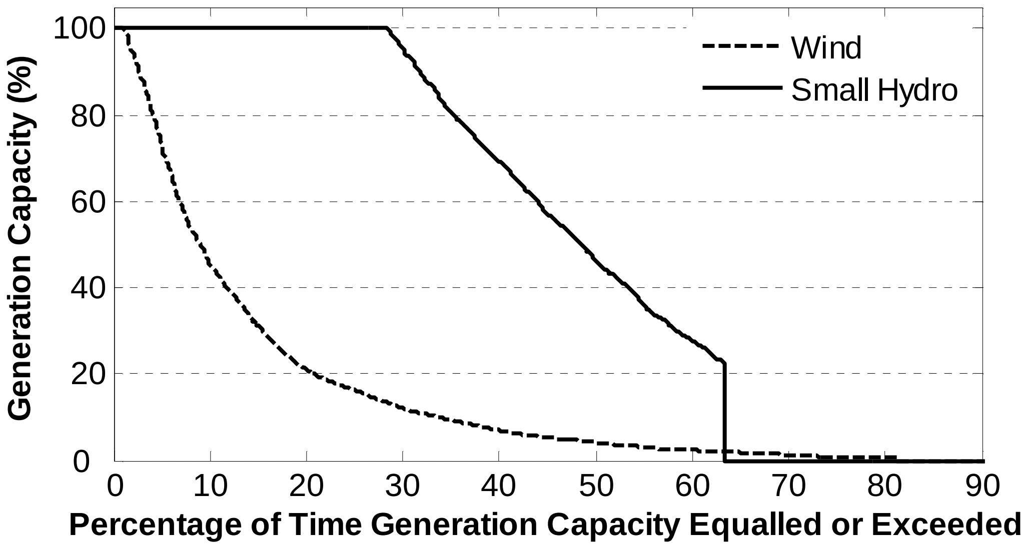

Figure 8.6: Generation Duration Curve for a wind turbine located on Jordon Ridge and a small hydro facility located on the Fleet River

Note the relatively long period that small hydro sustains 100% of generation capacity. Flows in excess of that required for generation are redirected along the natural watercourse. These high flows result from the watershed collecting and concentrating runoff as mentioned above. Without this concentrating mechanism, a wind generator on Jordon Ridge rarely operates at 100% of generation capacity.

The discontinuity that occurs along the small hydro curve, at 25% generating capacity, is the result of the 75% turbine efficiency operating constraint mentioned earlier. The E70 wind turbine used to model wind output employs a variable speed generator, capable of functioning at wind speeds as low as 2 m/s. As a result, this trend can not be seen at the scale presented above.

8.5 SUMMARY

In this chapter small hydro intermittence was assessed and the change in daily generation output was quantified. The intermittence analysis demonstrated that changes in daily generation tend to be small and could be easily absorbed by other generators within the system. A comparison between the intermittence of wind and small hydro generating resources was also assessed for sites on southern Vancouver Island. The results of this comparison demonstrated that small hydro intermittence is much lower than wind and, therefore, would be much easier to assimilate into the current generating system.

The level of penetration was assessed using two measures, RP and MIP. This analysis demonstrated that early development scenarios will have little influence on the operation of Vancouver Island's electrical grid due to low levels of penetration. Later development scenarios have the potential to change grid operation as these levels of development may result in Vancouver Island being able to export electricity during portions of the year. The RP attained by small hydro is totally dependent on the development of other generation resources on the Island.

The affect of incorporating storage sites was quantified. The analysis demonstrated that storage sites are responsible for the majority of dependable capacity offered during the maximum demand period.

9 SENSITIVITY ANALYSIS

The results presented in the preceding chapters are sensitive to the time step used for analysis, the representative nature of the time-series used, flow availability and general plant design. Changes in these variables can affect the upper limit that small hydro could ultimately contribute to the Vancouver Island electrical grid.

In this chapter, sensitivity analyses are discussed that qualify the influence of these variables on the results of this work. The time increment used for analysis was assessed by averaging hourly data from the Browns River over increasing time intervals. These average flow values were then used to evaluate the potential for small hydro development on the Browns River. Differences between the small hydro potential found using hourly data and the averaged data were compared.

The WSC hydrometric gauge having the longest period of record in each RRA was used to assess how representative the 1999-2005 flow time series was in terms of expected generating flow conditions on Vancouver Island. A 1960-2005 MAD time series was created and the 1999-2005 MAD flows were compared to historical flows.

The susceptibility of small hydro facilities to changes in generating flow availability caused by natural variability as well as human mandated causes was analysed. The influence of natural variability was determined by assessing total generation in each year of the 1999-2005 time series. Hypothetical changes to in-stream flow requirements were used to demonstrate the influence of human mandated flow changes on the generating capabilities of small hydro facilities on Vancouver Island.

Every effort was made to accurately depict the operating characteristics of small hydro facilities in this work, however every design is different. The sensitivity of results to changes in CF, available head, and efficiency multipliers was assessed.

9.1 SENSITIVITY TO ANALYSIS TIME INCREMENT

When calculating power output from an intermittent resource, the shortest possible time increment should be used to accurately capture the resource's fluctuations. Unfortunately, computing power, time and cost constraints often dictate the increment used for analysis. In this section, the sensitivity of modelling results to time step is assessed.

Hourly, daily, weekly, bi-weekly and monthly flow datasets were compiled for Browns River on Vancouver Island for 2000-2004. Each flow dataset was calculated as the average of the hourly flows during a given time step. All gauged flows were used in the calculation of the average and high flow values were not truncated. The minimum required residual flow was set at 0.554 m^3/s based on in-stream flow requirements discussed in Section 3.3.2 and applied to all flow datasets to determine the amount of flow available for generation. For each time step, this available flow was then used to calculate generation based on a 50 m head and turbine, generator and penstock efficiencies of 92%, 95% and 96%, respectively. Nameplate capacity and design flow were calculated for each dataset based on a 50% CF using methods outlined in Section 5.3. At flow values of less than 20% of the design flow, generation was modelled to cease. It was assumed that modelled generation corresponding to a given flow value remained constant for the duration of the time step increment. Table 9.1 summarises the results.

Table 9.1: Yearly energy output (GWh) and nameplate capacity based on different time increments of analysis

Year	Hourly	Daily	Weekly	Bi-weekly	Monthly
2000	6.20	6.36	8.28	10.21	11.63
2001	5.82	5.98	7.52	9.13	11.17
2002	6.58	6.74	8.58	10.73	15.36
2003	7.08	7.29	9.58	11.88	18.20
2004	8.26	8.44	10.66	12.45	16.16
Nameplate Capacity (MW)	1.55	1.59	2.05	2.47	4.12

Trends in year to year energy generation are preserved for all cases with the exception of the monthly average time interval for 2003. The hourly power calculation used directly measured flow values making it the most accurate assessment of yearly generation. Based on this, it is evident that increasing the time step results in overestimation of nameplate capacity and energy production. While this discrepancy remains small (~2.5%) as the time increment is increased from hourly to daily, further increases quickly magnify the resulting discrepancy (+30% using a weekly time increment). The high level of discrepancy between values can be partially attributed to the 50% CF sizing method used. As the average flow available in each time step was calculated based on hourly flows without truncation, very high flow events increased the supposed available flow and resulted in higher nameplate sizes. This demonstrates the sensitivity of the sizing method to the time step used.

Repeating the analysis completed above but limiting the nameplate capacity and, therefore, the design flow, to that determined using an hourly time increment also results in overestimation of energy production for longer duration time steps. This is again the result of very large flow events increasing average flow over larger time steps. These large flow events are typically induced by large frontal weather systems such as those experienced during the winter storm season on Vancouver Island. The runoff hydrograph for the Browns River WSC gauge shows that the watershed's response time is on the order of hours to days depending on the size of the storm. By averaging flows over longer time periods a greater number of these large events are captured making it appear that more flow is available than is actually the case. To demonstrate this effect, CF was calculated using the hourly nameplate rating and design flow with the flows predicted by each time interval.

Recall that CF is the ratio of actual generation to the maximum possible. A higher CF therefore means that the design flow is available more often. Figure 9.1 shows the CF calculated for each time interval.

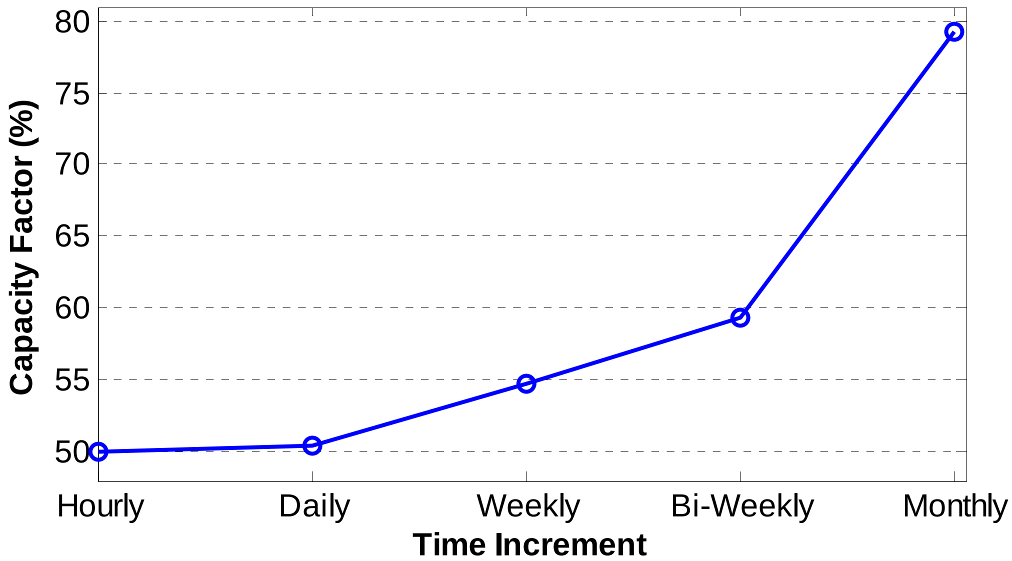

Figure 9.1: Capacity factor for Browns River site as measured using different time increments for assessment (design flow of 3.79 m^3/s)

Once again, values determined using a daily time increment are relatively close to those found for the hourly increment. This supports the earlier statement about the response time of a watershed to a storm event. Averaging flows over periods of a week or more produces misleading results that do not accurately represent potential generation.

9.2 Time Series Representation

The modelling completed in this work used a flow time-series based on WSC flow data for the period of 1999-2005. This time-series was chosen based on data availability. It was assumed to provide a representative example of flows that could be expected on Vancouver Island. If this assumption is in error then the contribution from small hydro, calculated using this dataset, could over or under estimate the potential contribution.

Flows that occurred from 1999-2005 were compared to historical flows on Vancouver Island. Historical flows were based on the longest continuous flow time-series in each RRA. The mean discharge of each continuous record and the mean annual discharge (MAD) were calculated. Table 9.2 lists the watercourses having WSC gauges that were used in the analysis.

Table 9.2: Long term runoff records for each RRA

RRA	Watercourse	Mean Discharge (m^3/s)	Period of Record	Total Years
1	San Juan R	47.75	1960 - 1993, 1997 - 2005	43
2	Koksilah R	9.62	1960 - 2005	46
3	Sarita R	19.10	1977 - 2005	29
4	Tsable R	7.83	1961 - 2005	45
5	Ucona R	17.73	1960 – 1981, 1984 - 2005	44
6	Tsikita R	22.34	1977 - 2005	29
7	Zeballos R	24.26	1971 - 2005	35
8	San Josef R	7.88	1994 - 2005	12

For each river, the MAD was normalised by the mean discharge to show high and low water years in each RRA. By averaging the normalised MAD from each RRA, a composite Vancouver Island normalised MAD was determined which represented typical runoff for each of the past 46 years (1960 – 2005). Figure 9.2 shows the variation of MAD compared to the long term mean for all of Vancouver Island.

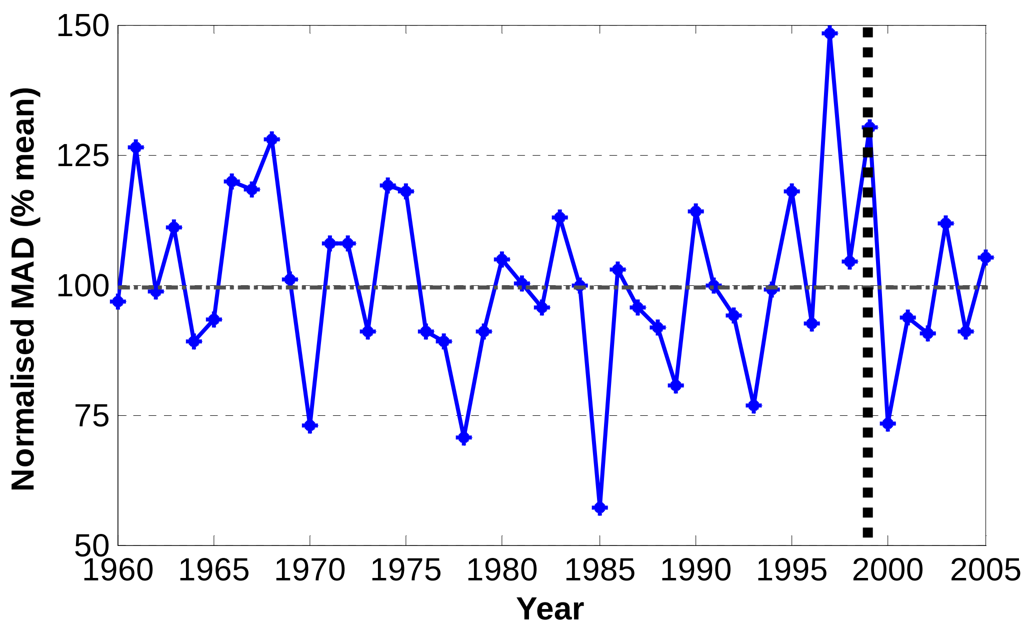

Figure 9.2: Vancouver Island mean annual runoff comparison 1960 – 2005

The vertical line on the far right of Figure 9.2 represents the year 1999 which was the first year of flow data used in the 1999-2005 flow time-series. The mean discharge is represented by a horizontal line at 100% yearly flow. During the period of record shown in Figure 9.2, the year 1999 had the second highest MAD while the year 2000 had the fourth lowest MAD. All other years provide information between the 1999 high and 2000 low MAD. Averaging normalized MAD for 1999-2005 results in a time-series mean discharge of 99.4%. While close to the mean discharge calculated for 1960-2005, this result suggests the findings of this work may be slightly conservative. Overall, however, this analysis demonstrates that the seven years used to model small hydro generation potential represent the full spectrum of flow scenarios.

9.3 AVAILABILITY OF FLOWS

A watershed's hydrologic response to a storm event and its natural/anthropogenic storage characteristics determine the amount of flow available for generation and the length of time that generation can be maintained. Variations in the amount of generation flow available may be caused by natural phenomenon (*e.g.,* a low rainfall year or a very mild winter resulting in a small snowpack) or by changes to in-stream flow requirements. The sensitivity of results to both of these influences is presented below.

9.3.1 Natural Flow Variation

Year to year natural flow variability can cause significant changes to the generation output from a small hydro facility. To demonstrate this variability, a hydrograph was produced for a 100 km^2 watershed in RRA 4 during 1999 and 2000, the wettest and driest years modelled, respectively (Figure 9.2). FAC 4 was used to generate the synthetic hydrograph for both years. A generation hydrograph was then created by deducting the minimum in-stream flow and then capping runoff at the generating design flow (8.27 m^3/s). Figure 9.3 shows the resulting generation hydrograph.

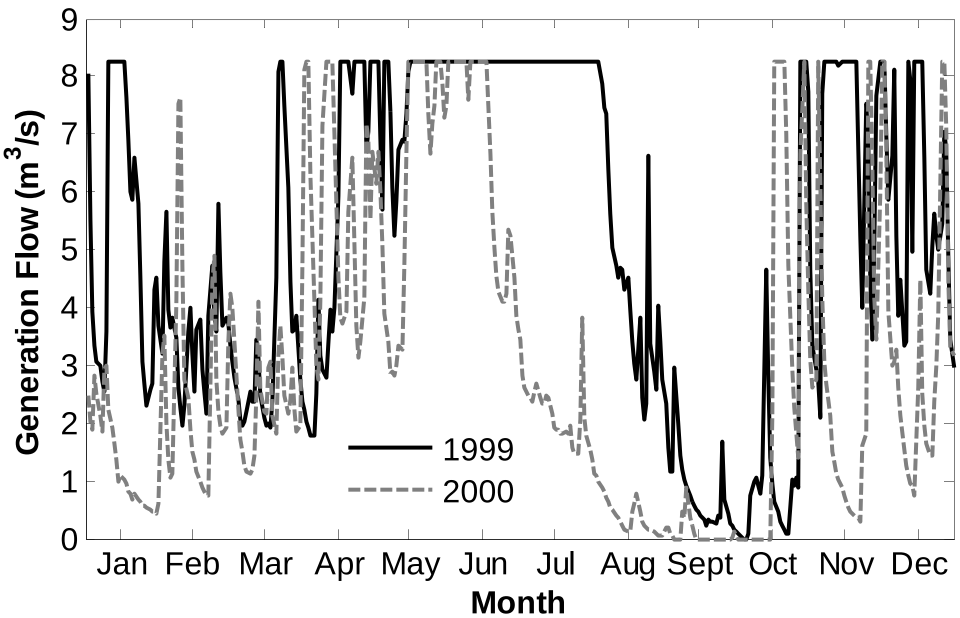

Figure 9.3: Generation hydrograph for a 100 km^2 watershed in RRA 4 1999 and 2000

Note the sustained runoff extending well into the summer months in 1999. This sustained runoff can be attributed to heavy snows that occurred during the winter of 1998/1999. Snow offers a means of natural storage in a watershed by attenuating runoff from large winter storms through partial capture as snow and ice as a snowpack. During spring and early summer, snowmelt from the snowpack provides higher flows downstream, enabling more generation to occur. Generation flows for 2000 demonstrate that very few periods of sustained design flow are attained, even during the spring snowmelt, leading to significantly decreased generation.

The maximum development scenario was chosen to demonstrate the influence of natural flow variability on small hydro generation on Vancouver Island as a whole. A comparison of yearly generation was used to demonstrate this. Figure 9.4 shows the year to year variation in total generation by comparing yearly cumulative generation.

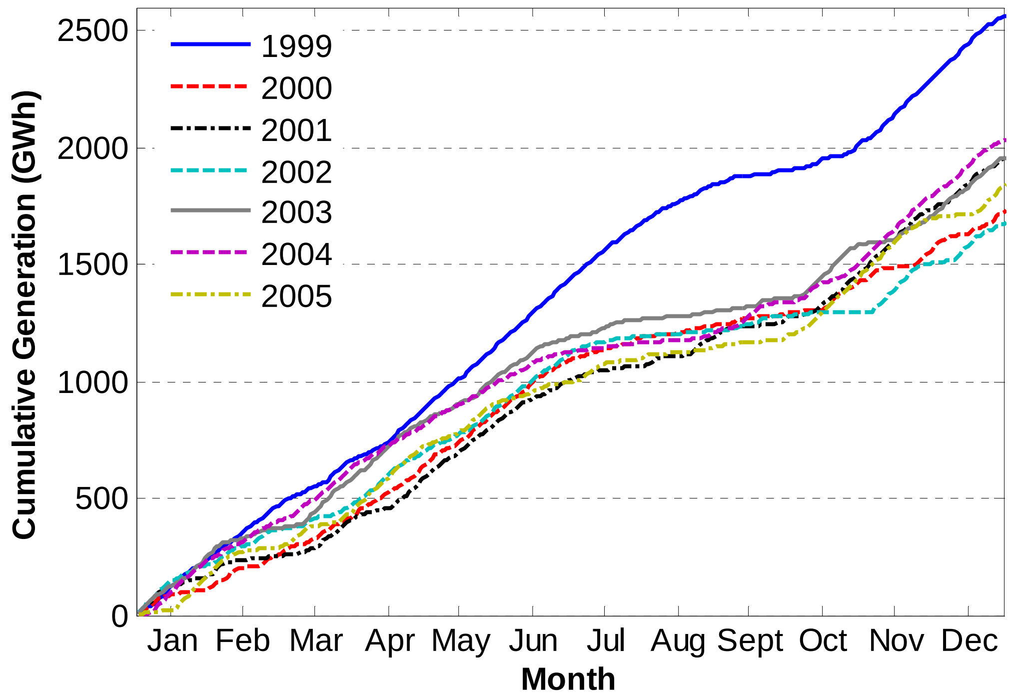

Figure 9.4: Cumulative generation for each model year using the full development scenario, 1999 - 2005

A period of reduced slope in the cumulative generation line for a given year indicates lower generation output for sustained periods. From Figure 9.4, 1999 is by far the best generation year (2564 GWh) due to a large snowpack and long melt period. While 2000 may have had the lowest MAD, 2002 had the lowest cumulative generation total (1679 GWh) due to a long dry summer and fall. This is demonstrated along the cumulative generation line by the shallow slope from late September to early November. Recall that 2002 was the only year in which storage facilities were forced to shut down (Figure 6.15).

The differences between the extremes of 1999 and 2002 can be seen more clearly in Figure 9.5.

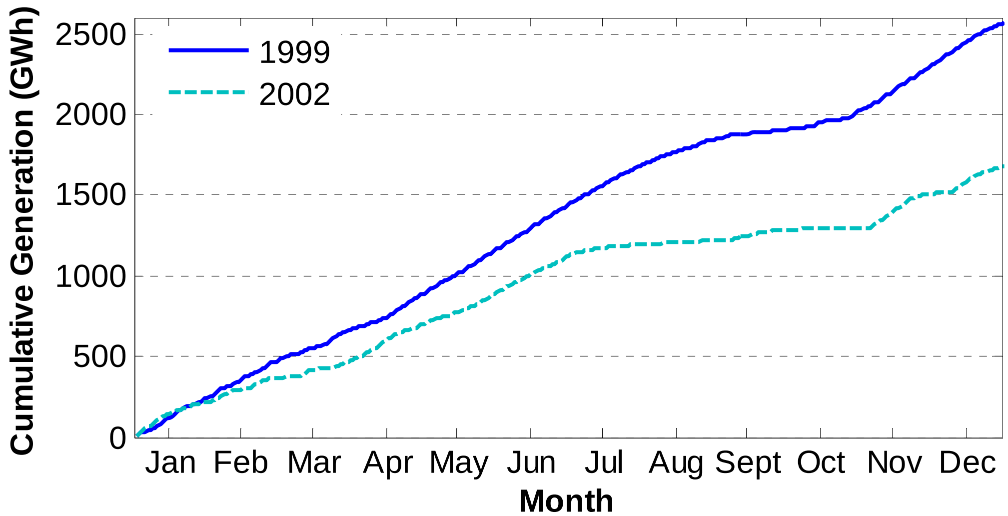

Figure 9.5: Cumulative generation for 1999 and 2002 model years

This shows that the variation in total generation is dependent on the timing and amount of runoff in a given year. It also demonstrates that total generation may be more sensitive to the timing of runoff as opposed to the amount of runoff (*e.g.,* the year 2002).

9.3.2 Minimum Flow Requirement

To maintain the pre-development ecosystem of a stream, regulating bodies have mandated that a minimum flow be maintained while generating. The implementation of minimum flows in the model was discussed in Section 3.4. Changes to current minimum flow requirements are likely to influence only those sites that are completely undeveloped when new regulations are passed. This is because water licenses, for power production, are granted for 40 year periods [90]. For this reason, only those sites that are currently undeveloped were used in this assessment.

Generation was modelled over the entire 1999-2005 time period using minimum flow values of 10%, 15%, 20% and 25% of MAD as well as a variable fish flow (VFF) as described in the British Columbia In-stream Flow Guidelines for water uses [57]. The VFF criteria sets monthly minimum flow requirements based on statistical analysis of the time period over which flow data exist (the ideal is 20 years). The variability is intended to mimic natural variation to maintain or enhance fish habitat. The entire 1999-2005 time-series was modelled. The total resulting generation for each minimum flow criterion was then compared to the generation determined using the lowest median month (LMM) criterion, described in Section 3.3.2. Comparisons were completed for all of Vancouver Island as well as for individual RRAs. Figure 9.6 shows the total energy output for each minimum in-stream flow value in terms of percent of LMM generation.

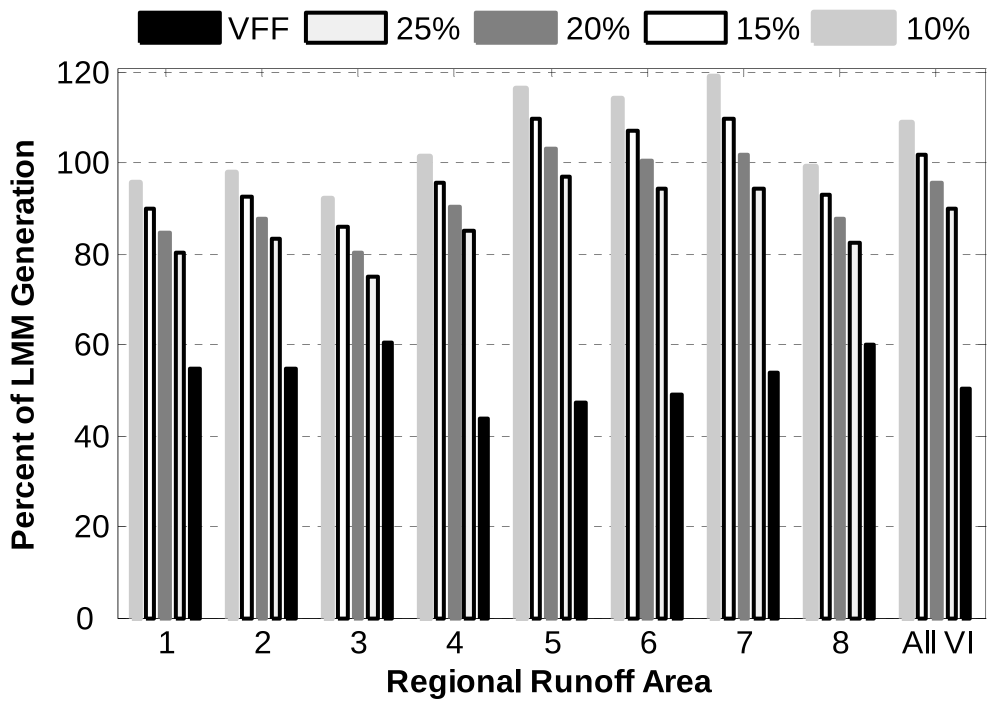

Figure 9.6: Influence of minimum in-stream flow requirements on generation as compared to lowest monthly median (LMM) result

Differences in regional flows resulted in significantly different responses to in-stream flow requirements. The largest differences are between RRA 3 and RRA 7. Figure 9.7 and Figure 9.8 help to demonstrate the reasons for these differences.

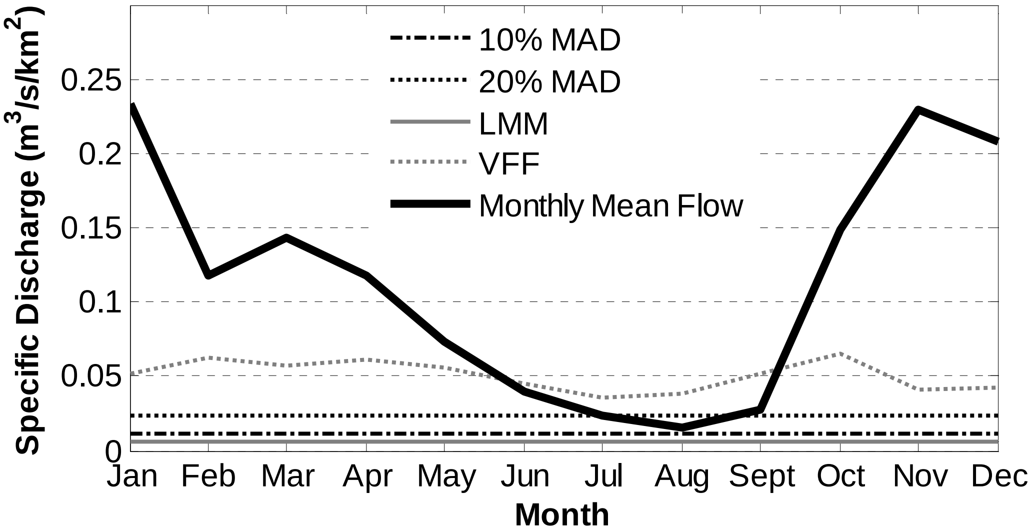

Figure 9.7: In-stream flow analysis results, RRA 3

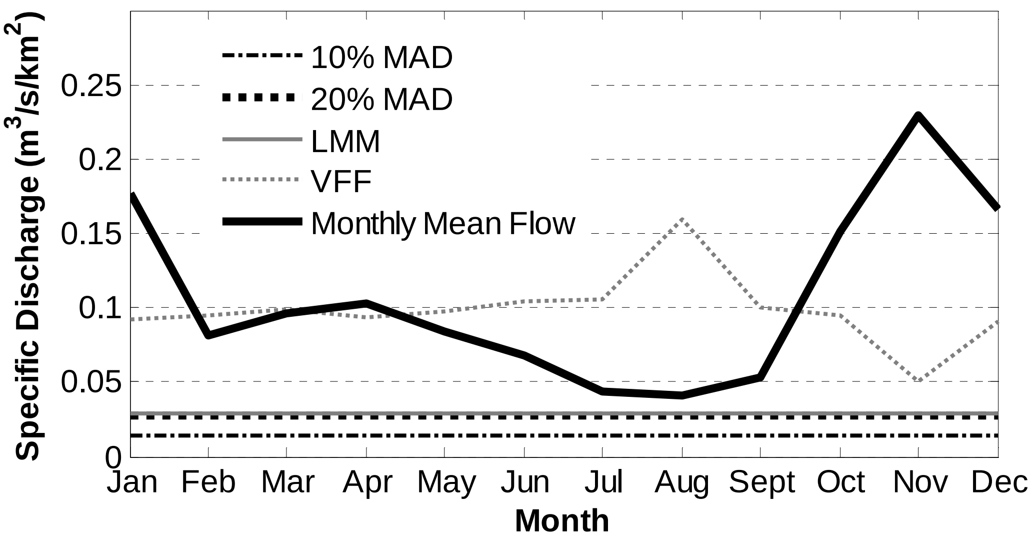

Figure 9.8: In-stream flow analysis results, RRA 7

The response of generation in RRA 3 to different in-stream flow requirements depicted in Figure 9.6 can be attributed to very low summer flows in RRA 3, permitting lower flows under the LMM criterion than any of the MAD criteria (Figure 9.7). Using any of the MAD criteria therefore results in less total generation. Flows in RRA 7 are much higher than those in RRA 3 during the summer dry period (Figure 9.8). Under the LMM criterion, high in-stream flows are required that are not exceeded by the MAD criteria until 20% MAD is surpassed. Therefore, if the 20% MAD criterion or less were to be adopted a greater amount of generation would result. A mixture of variations on the two trends can be seen in the other RRA results.

The cumulative impact of the different in-stream flow requirements on small hydro output around Vancouver Island is shown in Figure 9.6. The cumulative result demonstrates that greater generation would result from using MAD criteria up to 15% when compared to LMM criteria. As analyses of RRAs 1-4 and 8 do not support this finding, it can be concluded that a high proportion of projects are located in RRAs 5-7. The geographic analysis completed in Section 6.1 supports this conclusion.

The most significant effect of in-stream flow requirements occurred for the VFF criteria. The total generation, as compared to LMM criteria, was reduced by between 39.5% (RRA 3) and 56% (RRA 4). On an Island-wide basis, total generation was reduced by approximately 50%. This again demonstrates the susceptibility of small hydro facilities to changes in generation flows.

9.4 SENSITIVITY TO DESIGN ATTRIBUTES

Several assumptions were made regarding the design and operation of small hydro facilities in an effort to model "real" generating characteristics. These assumptions had the greatest impact on undeveloped sites, owing to the limited amount of information available pertaining to these sites. For this reason the sensitivity to design attributes is assessed for undeveloped sites only.

9.4.1 Changes in Capacity Factor

Generation from undeveloped sites was based on a 50% CF. However, if a developer is required to meet higher CF criteria (i.e., BCH dependable capacity incentives) or the price of electricity continues to climb, favouring larger installations (lower CF), the potential generation would change. To address this, undeveloped sites were modelled using nameplate capacities and the associated design flows that equated to CFs of 40% to 75% at 5% intervals. Results of each CF modelled were normalized to the results of the 50% CF base case according to the following equation:

$$NR = \frac{CFR_{CF}}{CFR_{50}} \times 100\% , \qquad [9.1]$$

where: NR normalized result (%);
CFR capacity factor result (MW or GWh); and
CF capacity factor.

Figure 9.9 presents the results of this analysis relative to the 50% CF results.

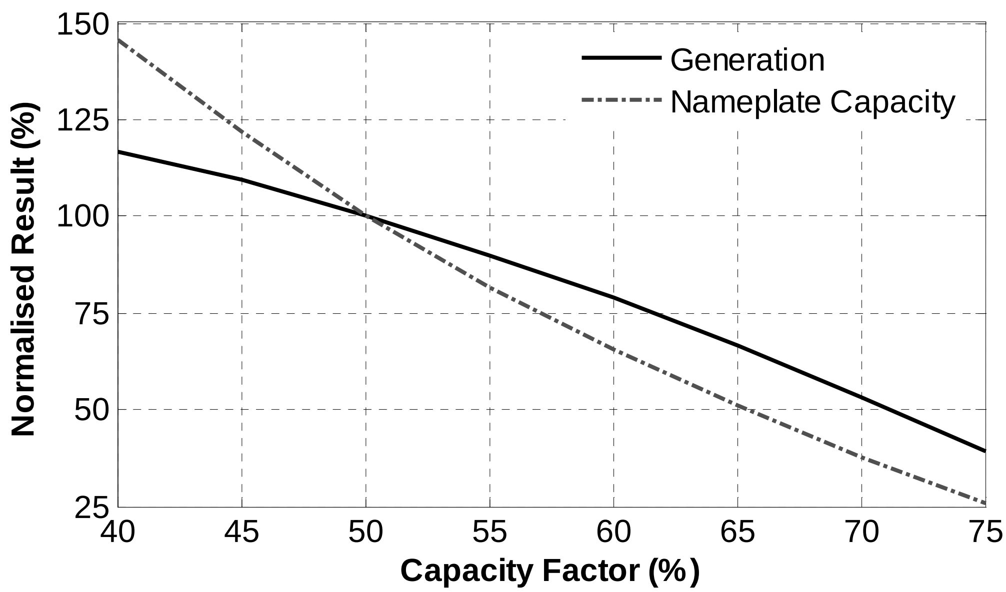

Figure 9.9: Changes to nameplate capacity and generation as a function of capacity factor

Figure 9.9 shows the sensitivity of nameplate capacity and generation to changes in CF when compared to the 50% CF base case. From this plot it can be concluded that nameplate capacity exhibits greater sensitivity to CF than generation. An example is used to illustrate this. If a facility were to be constructed with a 40% CF, the nameplate capacity would be ~145% greater then the 50% CF result. However, the total generation from the site would only be ~117% of the 50% CF result. Alternatively, if the facility were to be constructed with a 60% CF, the nameplate capacity would be ~65% and the generation ~79% of the 50% CF result. From this analysis it can be concluded that changes in CF could significantly alter the findings of this work, especially nameplate capacity. For reference, the average CF for projects awarded EPAs in the F2006 CFT was 46.9%. This demonstrates that the 50% CF used in this work is relatively accurate in terms of assessing the contribution of small hydro.

9.4.2 Influence of Available Head

Several previously undeveloped sites identified in other resource assessments [9] had begun the development process at the onset of this work. These sites offered some insight into the development process. Developers of these sites proposed higher heads than were identified by previous resource assessments. This may be attributed to more detailed site information becoming available or due to the fact that a higher head site can generate the same output with less flow. Table 9.3 shows a few examples of this occurring on Vancouver Island.

Table 9.3: Examples of identified sites being developed using higher heads

Watercourse	Head (m)		Flow (m^3/s)		Capacity (MW)	
	Identified	Developed	Identified	Developed	Identified	Developed
Barr Cr	30	130	3.5	2.3	0.8	2.5
Browns R	50	75	6.4	5.5	2.5	3.4
Piggott Cr	50	300	5.3	3.79	2.1	9.5
Pinder Cr	90	120	3.0	1.5	2.1	1.45
Thelwood Cr	100	385	2.9	2.55	2.3	7.9

For every percent increase in head there can be a corresponding percent decrease in the amount of flow required for a given nameplate rating. If the decrease in flow due to the decrease in watershed area were less than the corresponding gain in head, a higher nameplate capacity would result. If the increase in head resulted in a corresponding decrease in flow due to drainage area reduction, capacity would be maintained. This situation is denoted as percent head equivalent (H.E.). By maximising head, equipment size requirements are reduced and less reliance is placed on high flows to sustain generation. There are also economic factors to consider that are beyond the scope of this work.

To demonstrate the influence of design head, a simple analysis was undertaken. A site identified originally as being capable of generating 1.48 MW at a design flow of 3.1 m^3/s and 60 m head was reassessed. For each assessment scenario the amount of watershed area was reduced by 2.5%, 5%, 7.5%, 10% and H.E., for every increase in head. The head was increased in increments of 10 m from 60 m to 180 m.

If topography permits, tripling the head results in only a third of the flow required to generate the same nameplate capacity. This makes obtaining environmental permits easier and, with less reliance on flow, may increase the generating ability of a site as well as the amount of total generation. Figure 9.10 shows the influence of head on nameplate capacity for given changes in flow.

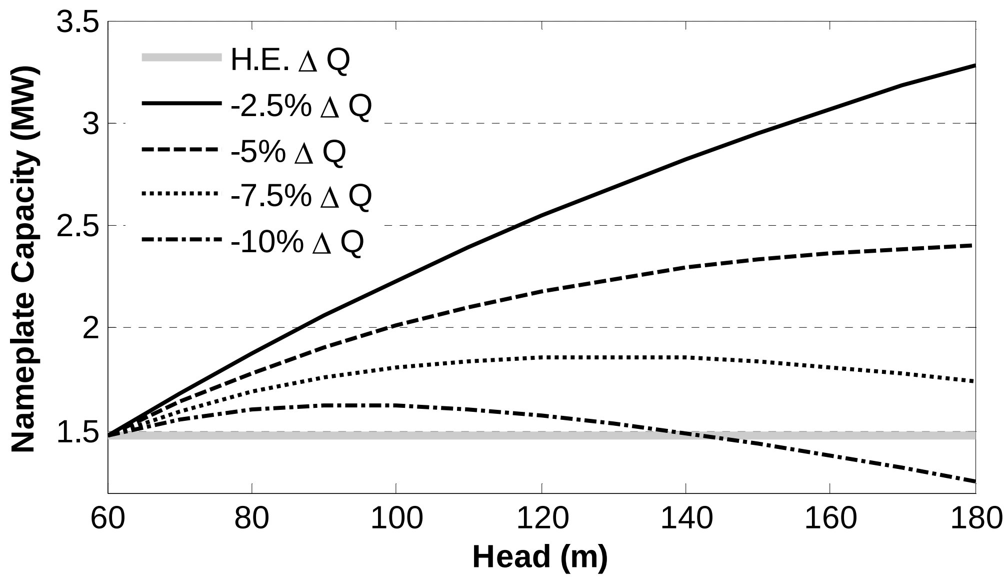

Figure 9.10: Nameplate capacity resulting from increasing head while decreasing flow requirement

From this simple analysis it is clear that maximising head can reduce reliance on flow and/or permit the installation of a larger generator. The declining nameplate capacities for watershed area reductions of 7.5% and 10% are caused by reduction in flow associated with each increasing head increment. It also demonstrates that nameplate capacity and, indirectly, generation are sensitive to changes in head on an order similar to that of flow.

9.4.3 Influence of Penstock Head Losses

In the model, frictional losses in the penstock were assumed to cause a 4% loss in operating head at the design flow. This value may increase as the result of different penstock construction materials (*e.g.,* HDPE, steel or ductile iron), economic constraints (*e.g.,* smaller pipe is cheaper) or corrosion within an installed penstock (*e.g.,* increases the internal friction of the penstock). To determine the sensitivity of the results to penstock losses under all flow conditions, penstock efficiency curves having design flow penstock losses of 6%, 8% and 10% were calculated and modelled. Figure 9.11 shows penstock efficiency curves over the full flow range encountered.

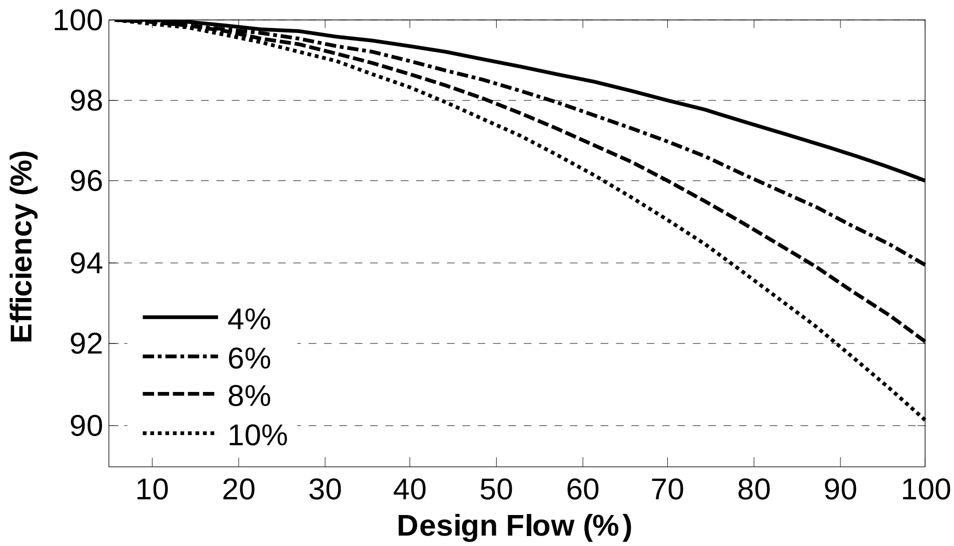

Figure 9.11: Penstock efficiency curves

From Figure 9.11 it is evident that the effect of penstock efficiency on generation will depend on the amount of time small hydro facilities operate at or away from their design flow. The influence of decreasing penstock efficiency on nameplate capacity is expected to be equivalent. The efficiency curves in Figure 9.11 were modelled to determine total generation and nameplate capacity for each RRA and compared to the 4% base case. Figure 9.12 shows the outcome of this analysis.

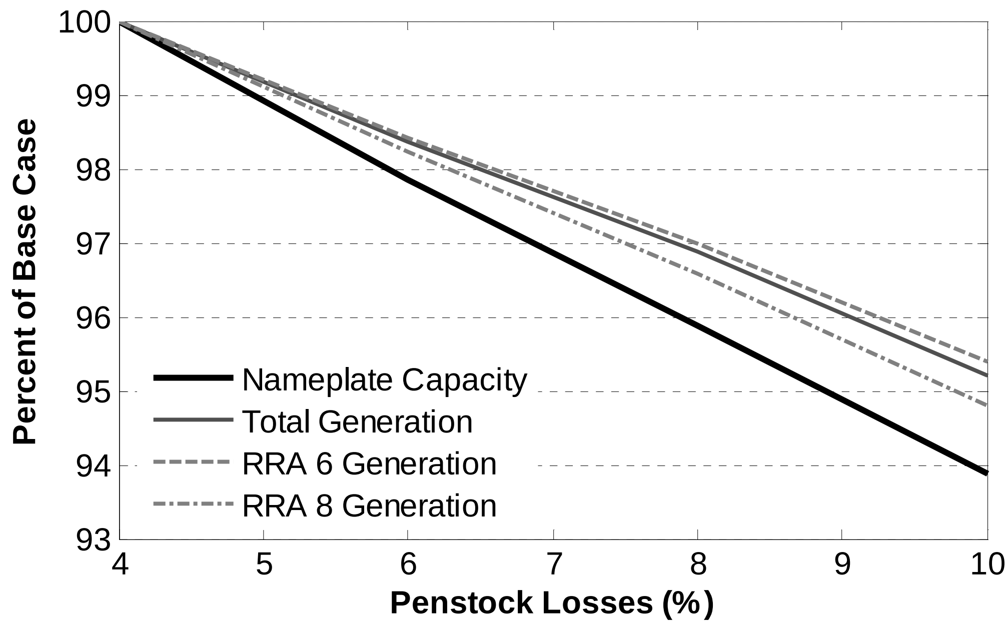

Figure 9.12: Sensitivity of nameplate capacity and total generation to penstock losses

As expected, nameplate capacity was influenced by an amount equivalent to the change in penstock efficiency. Interestingly, the change in total generation appears to have an almost linear response of approximately 0.8% per percent change in penstock losses for the Vancouver Island average case. The response was also found to vary depending on RRA but maintained a similar profile for all cases. In Figure 9.12, RRA 6 and RRA 8 were plotted to represent the upper and lower bound of this variance, respectively. The variance can be attributed to differences in flow regimes found in each RRA as discussed above.

9.4.4 Influence of Efficiency

Variable turbine, generator and penstock efficiencies were used in the model to reflect operating characteristics of small hydro facilities and to determine the amount of generation they could provide. Past studies completed for BCH and BCMEMPR used fixed efficiency values to approximate the total generation from small hydro sites [9, 13]. To quantify the sensitivity of nameplate capacity (NPC) and total generation (Gen.) to fixed versus variable efficiency values, the following analysis was undertaken. A fixed efficiency for each small hydro component was modelled with all other efficiency values maintained in their variable configuration. This was completed to demonstrate the influence of each of the variables independently.

Each of the small hydro components: turbine, generator and penstock were assigned fixed efficiency values of 90%, 96% and 96%, respectively. The variable efficiency model employed a 75% turbine efficiency low flow shutdown constraint (*i.e.,* generation ceased when turbine efficiency was at or below 75%). The fixed turbine efficiency scenario was modelled with and without the low flow shutdown constraint. The results of these analyses are listed in Table 9.4 by the headings of Turbine 1 and Turbine 2, respectively. The low flow constraint, used in the Turbine 1 assessment, was set at 20% of the design flow. The value of 20% design flow was selected based on the turbine efficiency analysis completed in Section 5.5. Simulations that combined fixed efficiency values were also modelled with and without this low flow constraint. In Table 9.4, the results of these analyses are termed All 1 and All 2, respectively. Table 9.4 shows the results of the analysis.

Table 9.4: Sensitivity of nameplate capacity and total generation to fixed and variable efficiency values

Fixed Efficiency (%)	Nameplate Capacity (MW)	Nameplate Capacity (% Var)	Total Generation (GWh)*	Generation (% Var)
Variable	149.25	100	4544.18	100
Generator (96)	148.3	99.36	4549.88	100.13
Penstock (96)	148.88	99.75	4492.56	98.86
Turbine 1 (90)	150.24	100.66	4617.47	101.61
Turbine 2 (90)	150.24	100.66	4763.9	104.84
All 1 (82.9)	148.91	99.77	4570.02	100.57
All 2 (82.9)	148.91	99.77	4730.05	104.09

Note*: generation calculated based on entire 1999-2005 time-series

Differences in nameplate capacity can be directly attributed to the different efficiencies used under design flow conditions for variable and fixed scenarios. Turbine efficiency in the variable case was determined by site characteristics and differed from one location to another. The similar nameplate capacity found using a fixed turbine efficiency demonstrates that a turbine efficiency of 90% reasonably estimates the composite efficiency of all turbine types used at undeveloped sites.

Varying degrees of sensitivity were noted in terms of total generation when each component was changed. The model was least sensitive (less then 0.5% difference) to the use of fixed or variable generator efficiency values as long as the fixed efficiency chosen (96%) remained close to the variable generator efficiency at design flow (96.662%). Fixing the penstock efficiency at the variable design flow value resulted in a notable decrease (greater then 1%) in total generation. This is the result of a variable penstock efficiency capturing the improved penstock operating efficiency when flows are less than the design flow (Figure 9.11), while a fixed value fails to capture this subtle change. Interestingly, if generator and penstock efficiency curves were combined a nearly constant value would result. For this reason a fixed value could be used to approximate these two components.

How accurately fixed turbine efficiency reflected the variable turbine efficiency result depended greatly on the use of a low flow constraint. Under a low flow constraint, the increase in generation could be attributed mainly to the increase in nameplate capacity throughout the generating range. Without a low flow constraint, generation was modelled to continue until no generation flow was available (minimum in-stream flow requirement reached). This resulted in a 3.2% increase in total generation above that already caused by the fixed turbine efficiency alone. This trend was also seen when all components were modelled using fixed efficiency values. When the low flow constraint was applied to the All 1 scenario, total generation was found to be very close to the variable efficiency result. Therefore, all future work conducted at this level of detail could forgo the complications of including variable efficiency values provided a low flow constraint was applied. The low flow criteria should accurately represent the operating range of small hydro facilities. In this analysis, a low flow criteria of 20% design flow proved to be representative.

9.5 SUMMARY

Sensitivity analyses were completed on many different aspects of this work in an attempt to quantify how different assumptions incorporated directly or indirectly into the model influenced the results. The selection of a time increment for analysis was found to be very important to the accurate prediction of available generation flow. Hourly and daily flow data were found to accurately demonstrate the availability of flows, while longer time increments exaggerated what was actually feasible.

This work utilized a seven year dataset (1999-2005) that fortuitously incorporated a representative mixture of flow years on Vancouver Island as measured by MAD. The representative nature of the dataset gave greater confidence in the results and demonstrated the high yearly variability that exists in natural systems. The impact of this variability was further examined in terms of flow from two perspectives: naturally induced variability and human mandated variability. From these analyses the availability of generating flow was, not surprisingly, shown to be the parameter of greatest importance when locating a small hydro facility.

When analysing the sensitivity of design attributes at undeveloped sites the importance of flow was demonstrated again in an assessment of sizing based on CF. The sensitivity of the nameplate capacity to variations in head was shown to be as sensitive as the availability of generating flow at undeveloped sites. Analysis of variable versus fixed efficiency values demonstrated that using fixed values with a low flow constraint simplifies modelling and achieves similar accuracy.

10 CONCLUSIONS & FUTURE WORK

The primary objective of this study was to determine the contribution small hydro generation could make to Vancouver Islands electrical supply and what, if any, dependable capacity could be realised by distributing small hydro generators around the Island. Secondary objectives involved the characterisation of the intermittent nature of small hydro resources on the Island and assessment of the implications of incorporating a large number of small hydro facilities into the Vancouver Island electrical grid.

To demonstrate the influence of variable generating flow on the generating output of small hydro facilities required the development of a simple regional flow model. This model was developed using data from 38 of 59 stream gauges maintained by the WSC on Vancouver Island. Measured flow from each of the gauged watercourses was expressed in terms of specific discharge and compared to identify regions exhibiting similar discharge characteristics. Eight such regions (RRAs) were identified. Each RRA was represented by three to six watercourses. The median specific discharge from these representative watercourses was used to define an FAC specific to each RRA. These FACs were used to model watercourse flows in each RRA based on a watercourse's drainage area.

A survey of past small hydro resource assessments and the British Columbia water license database identified 165 potential and operating small hydro sites on Vancouver Island. An additional 10 sites were identified by the author over the course of this study based on selection criteria outlined within. These 175 sites were categorised, based on a site's current level of site development, into four development scenarios. The cumulative generation from potential and operating small hydro sites was modelled for each of the development scenarios using MATLab code developed by the author. The small hydro generation model incorporated dynamic efficiency curves representing penstock, turbine and generator efficiencies as a function of flow. The FACs representing available flow were used by the small hydro generation model to calculate generation time-series data. A simple storage model was also developed to demonstrate the influence of the few identified sites that incorporated storage into their designs on generating capability.

The contribution of small hydro to meeting Vancouver Island electrical demand was assessed on both an energy and peak demand capacity basis. Total energy contribution for each development scenario was assessed by calculating the cumulative generation from all small hydro sites and comparing it to the total Vancouver Island demand. Small hydro facilities' contribution to peak demand was assessed by evaluating the timing of small hydro generation relative to Vancouver Island maximum demand periods.

The intermittence of the small hydro resource on Vancouver Island was characterised by calculating the daily change in generating capacity as a percent of the total nameplate capacity. The magnitude of this change was evaluated on the basis of occurrence frequency and plotted using a histogram. This was also completed on an hourly timescale for an individual small hydro facility. The hourly timescale was used in an analysis comparing the intermittence of wind and small hydro resources on Vancouver Island.

10.1 Contributions and Conclusions

The major contributions and conclusions of this work are presented below in the categories under which the objectives were addressed. Those conclusions that do not pertain directly to the objectives are recorded in a "general conclusions" category.

10.1.1 Flow Characterization

The approximation of available generation flow is integral to determining the contribution small hydro can make. Past small hydro resource assessments have used flow duration curves (FDCs) to accomplish this; however, the temporal aspects of the runoff hydrograph are lost in the creation of a FDC. This work sought to improve upon these assessments by using complete hydrographs to depict available generation flow. This approach preserves temporal features of the flows, allowing real time simulation of available generation flows. Conclusions from the characterization of flows on Vancouver Island are as follows:

- Watercourses on Vancouver Island identified as suitable for small hydro development exhibit regional runoff characteristics that can be closely approximated using specific discharge. This allowed large regional areas to be represented using a representative specific discharge runoff hydrograph. The area drained is then the only input required to determine available generation flow at an individual site.

- Daily flow values are adequate to characterize available generation flow. The differences between results obtained using daily and hourly flows were less than 4%. This approach reduces computational requirements and simplifies analysis.

- FACs provide a tool for simulating available generation flows in watercourses on Vancouver Island in real time. Their use in determining small hydro generation permits direct comparison to electrical demand, something not possible using other methods.

10.1.2 Site Identification and Model Development

This work determined the small hydro generation potential for 175 operating and undeveloped sites that have been identified on Vancouver Island. While these sites can be considered representative of the small hydro potential that exists on the Island, an exhaustive site identification search was not undertaken. The model developed to calculate the output from all of the small hydro sites improved upon past efforts by incorporating FACs and dynamic efficiency variables to represent the major generating components. These improvements accurately represented facility operation and facilitated direct comparison between generation and electrical demand on Vancouver Island. Conclusions related to development of the small hydro generation model and site identification are presented below:

- Incorporating only dynamic turbine efficiency while maintaining fixed efficiency values representing the penstock and generator is adequate for site assessments. This is due to the offsetting effect of dynamic penstock and generator efficiencies. This method simplifies the model structure and reduces the number of variables required in the code.

- Incorporating a low-flow cut off in the model provides similar results to using dynamic efficiency curves for the major components. Sensitivity testing determined that total energy output using fixed efficiencies with a 20% low flow cut off criteria predicted the variable efficiency result to within 1%. This method further simplifies the model.

10.1.3 Small Hydro Generation

The cumulative generation contribution of the 175 modelled small hydro sites was assessed in terms of ability to meet part of the Vancouver Island demand. The conclusions of this assessment are summarised below:

- During the maximum demand period (December – February) the Phase 2 and Full development scenarios demonstrated meagre dependable capacities of 2.92 MW and 4.41 MW (~1% of their design capacities), respectively, without the addition of storage. These two development scenarios represent the largest geographic coverage of small hydro facilities on the Island. The very low dependable capacity achieved in these scenarios demonstrates that a larger geographic distribution of small hydro facilities on the Island does not appreciably improve small hydro's ability to offer dependable capacity during the maximum demand period. This finding also supports BCH's policy of assigning small hydro facilities a 0 MW dependable capacity rating unless the facility operator can demonstrate otherwise.

- Dependable capacity during the maximum demand period (December – February) is increased by incorporating storage into small hydro facilities. The addition of the identified storage sites into each development scenario resulted in dependable capacity ratings of 3.1 MW, 16.2 MW, 35.2 MW and 35.2 MW, respectively. Dependable capacity from storage sites could be further increased by optimising the use of storage, which was not completed in this work.

- A greater geographic distribution of small hydro facilities improves the dependable capacity during the spring shoulder season (April 1 – June 15). This finding reflects the influence of more consistent runoff prevalent during the spring melt period. The dependable capacities for each development scenario, listed in order of development progressing from Operating to Full, are 4 MW, 18 MW, 44.6 MW and 50.1 MW, respectively. This demonstrates that during this period of the year, dependable capacity from small hydro can be realised.

- The total energy contribution that small hydro could make to meeting the Vancouver Island demand was found to be notable. Currently operating small hydro facilities supply 1.2% of the Island's demand. If all of the sites that have been awarded an EPA are constructed, this value will rise to more than 5%. On-island generation sources are needed and this demonstrates that small hydro facilities could contribute to meeting a portion of Vancouver Island's electrical demand. However, because small hydro offers little dependable capacity other generating resources would be required to meet demand when generation from small hydro was unavailable.

10.1.4 Intermittence of Small Hydro

The conclusions of the small hydro intermittency analysis are presented below:

- Intermittence from small hydro facilities is low. During the 1999-2005 analysis period, the daily generation change from all small hydro facilities was less than ±15% of the total scenario capacity 90% of the time. When an individual site was assessed on an hourly basis the generation change was less than ±1.2% of the nameplate capacity 90% of the time. The intermittence of wind generation was also assessed on an hourly basis. The hourly generation change found was less than ±12.6% of the nameplate capacity 90% of the time. This is an order of magnitude greater than the small hydro result. This demonstrates that small hydro facilities could be easily assimilated into the existing Vancouver Island electrical grid.

- Further development and greater geographic distribution of small hydro facilities does not appreciably change the characteristic intermittence of small hydro. This demonstrates that all watersheds on Vancouver Island have a similar response to precipitation events. It also shows that dominant weather patterns influencing the Island are on the scale of the island itself. Therefore, a larger distribution of small hydro facilities throughout BC, rather than just Vancouver Island, would be required to appreciably change the pattern of intermittence.

10.1.5 General Small Hydro Conclusions

General conclusions based on the work conducted are as follows:

- Transmission limitations may hinder the full development of small hydro resources. The north-central regions of Vancouver Island (RRAs 4, 5, 6 and 7) have the greatest small hydro development potential, but current transmission limitations around Campbell River would require upgrading for even partial development to be realised.

- The use of historic flow and demand data provides a realistic assessment of the contribution that small hydro facilities can offer Vancouver Island. Significant uncertainty was alleviated by employing actual flow data in the small hydro generation model. Actual electrical demand data was also used, alleviating the considerable uncertainty associated with forecast demand. By comparing modelled generation to demand permitted an appraisal of generation timing and allowed a yearly contribution assessment to be made directly.

10.2 FUTURE WORK

This thesis presents a small hydro resource assessment that demonstrates the real-time contribution that small hydro facilities could make to meeting Vancouver Island's electrical demand. The small hydro generation model could be improved and stochastically generated flow values used to assess future 'what if' scenarios. This would permit the study of various flow scenarios that may occur under changing climatic conditions and the impact that this may have on small hydro generation. Work on the influence of climate changes on river flows in the Georgia Basin (of which Vancouver Island is part of) and other mountainous regions has been completed [49, 91] and could be used to facilitate further small hydro generation studies.

The work presented here could be used as a starting point for the development of a real time monitoring program for small hydro facilities on Vancouver Island. Collection of model input parameters from all operating facilities would allow calibration of the small hydro generation model to their generation characteristics. Incorporating the information of multiple operating plants would provide an in-depth perspective on their contribution to and interaction with the Vancouver Island electrical grid. This study could also include factors that may limit facility operation such as the influence of tail water during high flow periods. The optimisation of storage to maximise generation during peak demand periods could also be completed. This type of study may also facilitate an economic assessment of different types of small hydro developments and means of sizing and operating them such that maximum return is attained. The economics of selling electricity generated to buyers other then BC Hydro and the policy implications of doing so could also be assessed.

Future studies could focus on the environmental impact of constructing potentially hundreds of small hydro facilities. This area of research was beyond the scope of this work but deserves the attention only direct study can offer. For example, a cumulative impact assessment of developing small hydro facilities could be conducted and the results compared to the impacts caused by a few larger sites providing the same benefits.

The small hydro generation model was developed to assess the impact of small hydro generation using Vancouver Island as a manageable assessment area. With further hydrologic analysis, the model could be used to assess the influence of small hydro development throughout BC. According to the IPP Association of British Columbia, there is currently 359 MW of installed small hydro in BC [92]. BC Hydro has recently entered into EPAs with small hydro developers that are now in the process of constructing an additional 1067 MW [92]. These new facilities represent almost 10% of BC's current generating capacity and may assist BC in becoming self sufficient by 2016. However, the impact they may have on system operations and potential electricity opportunities remain to be seen.

REFERENCES

1. Government of British Columbia, *Energy for our Future: A Plan for BC - Executive Summary, Introduction, Background*. 2002, Ministry of Energy, Mines and Petrolium Resources. p. 1-16.
2. Government of British Columbia, *The BC Energy Plan*, M.a.P.R. Ministry of Energy, Editor. 2007, Government of British Columbia.
3. BC Hydro, *Green Power News*. 2007.
4. BC Hydro. *CFT Results: F2006 Call for Power*. F2006 Open Call for Power 2006 July 27, 2006 [cited May 28, 2007]; Available from: http://www.bchydro.com/info/ipp/ipp47608.html.
5. BC Hydro. *Small and Micro Hydro Energy*. 2005 September 23, 2005 [cited 2007 June 2, 2007]; Available from: http://www.bchydro.com/environment/greenpower/greenpower1751.html.
6. Decarolis, J.F. and D.W. Keith, *The Economics of Large-scale Wind Power in a Carbon Constrained World.* Energy Policy, 2006. **34**: p. 395-410.
7. Rosen, J., I. Tietze-Stockinger, and O. Rentz, *Model-based Analysis of Effect from Large-scale Wind Power Production.* Energy, 2007. **32**: p. 575-583.
8. Canada Department of Fisheries and the Environment, *Annual Precipitation*, in *Hydrologic Atlas of Canada*. 1975, Canada, Department of Fisheries and the Environment: Ottawa.
9. Sigma Engineering Ltd., *Inventory of Undeveloped Oppourtunities at Potential Micro Hydro Sites in British Columbia*. 2000, BC Hydro and Power Authority.
10. Jacques Whitford Limited, *Vancouver Island Reinforcement Project - Application for Envirionmental Assessment Certificate and Environmental Screening*. 2006, British Columbia Transmission Corporation: Vancouver.
11. Oprisan, M. and S. Pneumaticos. *Potential for Electricity Generation from Emerging Renewable Sources in Canada*. 2006.
12. Lorenzoni A. et al, *Strategic Study for the Development of Small Hydro Power in the European Union*. 2001, European Small Hydro Association.
13. Sigma Engineering Ltd., *A Small Hydro Technology and Resource Assessment*. 1982, British Columbia Ministry of Energy, Mines and Petrolium Resources.
14. Hall, D.G., et al., *Feasisibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectrical Plants*, in *Wind and Hydropower Technologies Program*. 2006, U.S. Department of Energy. p. 68.
15. Penche, C., *Layman's Handbook on how to Develop a Small Hydro Site*. 2 ed, ed. E. Wilson. 1998, Madrid: European Small Hydro Association.
16. Paish, O., *Small hydro power: Technology and Current Status.* Renewable & Sustainable Energy Reviews, 2002. **6**(6): p. 537-556.
17. Natural Resources Canada, *Micro-Hydropower Systems: A buyers guide*. 2004, Government of Canada,: Ottawa.
18. Gordon, J.L., *High Head Small Hydro*, in *Hydrovision - Workshop on International Small Hydro Oppourtunities*. 2002: Portland Oregon.
19. Gordon, J.L., *Small Hydro Workshop: Dissertation on site development and costs*, in *Waterpower XII*. 2001: Salt Lake City, Utah.

20. Draisey, I., *Working together: Understanding the effects of small hydropower*, in *Refocus*. 2002. p. 58-59.
21. Wahl, T.L., *Hydraulic performance of Coanda-effect screens.* Journal of Hydraulic Engineering-Asce, 2001. **127**(6): p. 480-488.
22. International Energy Agency, *Renewables for Power Generation: Status and Perspectus*. 2003, Paris: OECD / IEA.
23. ASME Hydro Power Technical Committee, *The Guide to Hydropower Mechanical Design*. 1996, Kansas City: HCI Publications.
24. Retscreen International, *Clean Energy Project Analysis: Small Hydro Project Analysis Chapter*. 2001, National Resources Canada.
25. Davis, S., *Microhydro: Clean Power from Water*. 2003: New Society Publishers.
26. Clemen, D.M., *Hydro Plant Electrical Systems*. 1999, Kansas City: HCI Publications.
27. IEEE, *IEEE Guide for Control of Small Hydroelectric Power Plants*. 1998, IEEE: New York.
28. Wang Y.C. et al. *Dynamic Analysis of a Grid Linked Small Hydro Induction Generation System*. in *IEEE Melecon*. 2004: IEEE.
29. Ekanayake, J., *Induction generators for small hydro schemes.* Power Engineering Journal, 2002. **16**(2): p. 61-67.
30. Punys, P. and B. Pelikan, *Review of small hydropower in the new Member States and Candidate Countries in the context of the enlarged European Union.* Renewable and Sustainable Energy Reviews, 2007. **11**(7): p. 1321-1360.
31. Balat, H., *A renewable perspective for sustainable energy development in Turkey: The case of small hydropower plants.* Renewable and Sustainable Energy Reviews, 2007. **11**(9): p. 2152-2165.
32. International Energy Agency. *International Small Hydro Atlas*. Implementing Agreement for Hydropower Technologies and Programmes 2007 [cited 2007 June 8]; Available from: http://www.small-hydro.com.
33. Idaho National Laboratory. *Hydropower Evaluation Software*. 2006 Dec. 5 [cited 2007 June 7]; Available from: http://hydropower.inl.gov/resourceassessment/software/.
34. International Energy Agency. *Assessment Tools and Methodologies*. International Small-Hydro Atlas 2000 [cited 2007 June 7]; Available from: http://www.small-hydro.com/index.cfm?Fuseaction=planning.tools.
35. Sigma Engineering Ltd., *Small Hydro Power Resource in the Provincial System*. 1983, British Columbia Ministry of Energy, Mines and Petrolium Resources: Vancouver.
36. Power Supply Engineering, *Executive Report on the Green Energy Study for British Columbia. Phase 1: Vancouver Island*. 2001, BC Hydro.
37. Judge, D.G., J.E. Anderson, and B.I. McClennan, *Hydrologic Design methodologies for Prefeasibility Studies of Small-Scale Hydro at Ungauged Sites.* Canadian Journal of Civil Engineering, 1988. **15**: p. 289-298.
38. Charles Howard & Associates Ltd., *Hydrologic Design Methodologies for Small-Scale Hydro at Ungauged Sites in British Columbia - Integrated Method for Power Analysis*. 1989, Energy, Mines and Resources Canada and Envirionment Canada: Victoria.

39. Sigma Engineering Ltd., *Small Hydro Projects and Potential Sites in British Columbia*. 1986, British Columbia Ministry of Energy, Mines and Petrolium Resources: Vancouver.
40. Wilson, E.M., *Assessment Methods for Small-Hydro Projects*, in *Implementing Agreement for Hydropower Technologies and Programmes*. 2000, International Energy Agency.
41. Powell Group Inc., *User Manual for IMP 5.0 (Integrated Method for Power Analysis)*. 2004, Natural Resources Canada: Victoria.
42. Croft, S., *Operation of Doran-Taylor Small Hydro Facility*, M. Schuett, Editor. 2006, Personal Communication.
43. Kaldellis, J.K., D.S. Vlachou, and G. Korbakis, *Techno-economic evaluation of small hydro power plants in Greece: a complete sensitivity analysis.* Energy Policy, 2005. **33**(15): p. 1969-1985.
44. Forouzbakhsh, F., S.M.H. Hosseini, and M. Vakilian, *An approach to the investment analysis of small and medium hydro-power plants.* Energy Policy, 2007. **35**(2): p. 1013-1024.
45. Hosseini, S.M.H., F. Forouzbakhsh, and M. Rahimpoor, *Determination of the optimal installation capacity of small hydro-power plants through the use of technical, economic and reliability indices.* Energy Policy, 2005. **33**(15): p. 1948-1956.
46. Montanari, R., *Criteria for the Economic Planning of a Low Power Hydroelectric Plant.* Renewable Energy, 2003. **28**: p. 2129-2145.
47. Wagener, T. and H.S. Wheater, *Parameter estimation and regionalization for continuous rainfall-runoff models including uncertainty.* Journal of Hydrology, 2006. **320**(1-2): p. 132-154.
48. Evans, J.M. *The Water Cycle*. 2005 Oct. 6, 2006 [cited 2007 May 28]; Available from: http://ga.water.usgs.gov/edu/watercyclehi.html.
49. Whitfield, P.H., et al., *Modelling Streamflow in Present and Future Climates: Examples from the Georgia Basin, British Columbia.* Canadian Water Resources Journal, 2002. **27**(4).
50. Merz, R. and G. Bloschl, *Regionalisation of catchment model parameters.* Journal of Hydrology, 2004. **287**(1-4): p. 95-123.
51. Quick, M. and A. Pipes, *U.B.C. Watershed Model.* Hydrological Sciences Bulletin, 1977. **22**(1): p. 153-161.
52. Mimikou, M. and S. Kaemaki, *Regionalization of flow duration characteristics.* Journal of Hydrology, 1985. **82**(1-2): p. 77-91.
53. Goswami, M., K.M. O'Connor, and K.P. Bhattarai, *Development of regionalisation procedures using a multi-model approach for flow simulation in an ungauged catchment.* Journal of Hydrology, 2007. **333**(2-4): p. 517-531.
54. International Water Management Institiute. *Predictions in Ungauged Basins*. 2006 [cited 2007 May 31, 2007]; Available from: http://www.cig.ensmp.fr/~iahs/.
55. Beven, K.J., *Uniqueness of Place and Process Representations in Hydrologic Modelling.* Hydrology and Earth System Sciences, 2000. **4**(2): p. 203-213.
56. Yu, P.-S. and T.-C. Yang, *Synthetic Regional Flow Duration Curve for Southern Taiwan.* Hydrological Processess, 1996. **10**: p. 373-391.

57. Hatfield, T., A. Lewis, and D. Ohlson, *Development of instream flow thresholds as guidelines for reviewing proposed water uses*, British Columbia Ministry of Sustainable Resource Management and British Columbia Ministry of Water Land and Air Protection, Editors. 2003.
58. Micovic, Z. and M.C. Quick, *A rainfall and snowmelt runoff modelling approach to flow estimation at ungauged sites in British Columbia.* Journal of Hydrology, 1999. **226**(1-2): p. 101-120.
59. Nash, J.E. and J.V. Sutcliffe, *River flow forecasting through conceptual models part I -- A discussion of principles.* Journal of Hydrology, 1970. **10**(3): p. 282-290.
60. Weglarczyk, S., *The interdependence and applicability of some statistical quality measures for hydrological models.* Journal of Hydrology, 1998. **206**(1-2): p. 98-103.
61. ROBINSON, J.L., *British Columbia - Energy*, in *The Canadian Encyclopedia*. 2007, Historica Foundation of Canada.
62. BC Hydro and Power Authority, *Vancouver Island Power Supply*. 1978, BC Hydro and Power Authority.
63. BC Hydro, *Quick Facts for the year ended March 31,2006*. 2006, BC Hydro: Vancouver p. 2.
64. BC Hydro, *BC Hydro Annual Report 2003*. 2003, BC Hydro: Vancouver p. 134.
65. BC Hydro. *Green IPPs*. 2005 [cited 2007 May 28, 2007]; Available from: http://www.bchydro.com/info/ipp/ipp958.html.
66. BC Hydro, *Electric Load Forcast 2005/06 to 2025/26*, M. Forcasting, Editor. 2005, BC Hydro.
67. BC Hydro, *Port Alberni Generaion Project Major Capital Project Plan*. 2001, BC Hydro. p. 1-4.
68. BC Hydro, *Third Quarter Report*. 2001, BC Hydro. p. 1-28.
69. Government of British Columbia, *Bill M 203 --2001 Vancouver Island Electrical Rate Stabilizaton Act*. 2001, Queen's Printer.
70. BC Hydro. *Continued appeals force BC Hydro to abandon Duke Point Power Project*. 2005 June 17, 2005 [cited 2007 June 2, 2007]; Available from: http://www.bchydro.com/news/2005/jun/release24839.html.
71. British Columbia Utilities Commission, *A Filing by British Columbia Hydro and Power Authority Call for Tenders for Capacity on Vancouver Island Review of Electricity Purchase Agreement*, British Columbia Utilities Commission, Editor. 2005, Queens Press.
72. British Columbia Transmission Corporation. *Losses*. Transmission Scheduling 2007 June 4, 2007 [cited June 4, 2007]; Available from: http://www.bctc.com/transmission_scheduling/tariff_pricing/losses.htm
73. British Columbia Transmission Corporation, *Vancouver Island Transfer Capability Limits*. 2006, British Columbia Transmission Corporation
74. BC Hydro, *BC Hydro's Annual Report 2002*. 2002, BC Hydro,. p. 94.
75. Keeney, R.L., T.L. McDaniels, and C. Swoveland, *Evaluating Improvements in Electric Utility Reliability at British Columbia Hydro.* Operations Research, 1995. **43**(6): p. 933-947.

76. British Columbia Transmission Corporation, *Emergency Manual Load Shedding - Vancouver Island Region*, B.C.T. Corporation, Editor. 2005, British Columbia Transmission Corporation.
77. BC Hydro, *Electric Load Forcast 2001/02 to 2021/22*, B.H.M. Forcasting, Editor. 2001, BC Hydro.
78. Land Information BC. *Land and Resource Data Warehouse Calalogue*. Make a Map 2007 [cited 2007 June 8]; Available from: http://maps.gov.bc.ca/imf50/imf.jsp?site=lrdw_catalog_ext&crumb=B.C.+Home*Land+Information+BC&crumburl=%2Fhome.do*%2FkeyInitiativeHome.do%3Faction%3DlandInfoBCUser.
79. Ministry of Environment. *Water Licences Web Query*. 2007 March [cited 2007 June 9]; Available from: http://www.elp.gov.bc.ca:8000/pls/wtrwhse/water_licences.input.
80. BC Hydro, *Handbook for Developing Microhydro in British Columbia*, J. Croockewit, Editor. 2004, BC Hydro - Green and Alternative Energy Division. p. 1-69.
81. Emanuel, P., *Motors, Generators, Transformers and Energy*. 1985, Englewood Cliffs: Pretence-Hall, Inc.
82. Sawhney, A.K., *A Course in Electrical Machine Design*. 5 ed. 2005, Delhi: Dhanpat Rai & Co.
83. BC Hydro, *Power Factor*, in *Guides to Energy Management*. 1999, BC Hydro,. p. 8.
84. Street, R.L., G.Z. Watters, and J.K. Vennard, *Elementary Fluid Mechanics*. Seventh ed. 1996, Toronto: John Wiley & Sons.
85. Skoda, L., *Green Electricity Resources of British Columbia - Small Hydro*. 2002, BC Hydro & Power Authority and Canadian Cartographics: Victoria.
86. Environment Canada. *National climate Data and Information Archive - Hourly Data Report*. 2007 April 6, 2005 [cited 2007 May 30, 2007]; Available from: http://www.climate.weatheroffice.ec.gc.ca/climateData/hourlydata_e.html.
87. Enercon, *Product Overview - E70*, in *Enercon Wind Turbines* 2007, Enercon GmbH: Aurich. p. 1-8.
88. Patel, M.R., *Wind and Solar Power Systems*. 1999, Boca Raton [Fla.]: CRC Press.
89. BC Hydro. *Wind Monitoring*. Green Technologies 2004 Dec. 22, 2004 [cited 2007 June 5]; Available from: http://www.bchydro.com/environment/greenpower/greenpower1764.html.
90. BC Ministry of the Environment, *Water Act*, Province of British Columbia, Editor. 1996, Queens Printer.
91. Jong, C.d., D. Collins, and R. Ranzi, eds. *Climate and Hydrology in Mountain Watersheds*. 2005, John Wiley & Sons Ltd.: West Sussex.
92. Knight Piesold Ltd. and Willis Energy Services Ltd., *IPP Projects in BC*. 2007, Independent Power Producers Association of British Columbia.

APPENDIX A

WATER SURVEY OF CANADA HYDROMETRIC GAUGING STATIONS ON VANCOUVER ISLAND

WSC Gauging Stations used in the development of the FACs

Station name	Status	Latitude	Longitude	RRA	Notes
SAN JUAN RIVER NEAR PORT RENFREW	Active	48.57611	-124.31111	1	
GARBAGE CREEK NEAR THE MOUTH	Active	48.57833	-124.10444	1	
HARRIS CREEK NEAR LAKE COWICHAN	Active	48.71833	-124.22611	1	
CHEMAINUS RIVER NEAR WESTHOLME	Active	48.87917	-123.70194	2	
KOKSILAH RIVER AT COWICHAN STATION	Active	48.72750	-123.66972	2	
ENGLISHMAN RIVER NEAR PARKSVILLE	Active	49.31667	-124.28278	2	
SOUTH NANAIMO RIVER NEAR JUNCTION	Active	49.07028	-124.07944	2	
COTTONWOOD CREEK HEADWATERS	Active	48.93389	-124.25000	3	
CARNATION CREEK AT THE MOUTH	Active	48.91556	-124.99778	3	
TOFINO CREEK NEAR THE MOUTH	Active	49.24944	-125.58056	3	
SARITA RIVER NEAR BAMFIELD	Active	48.89278	-124.96500	3	
MARION CREEK NEAR UCLUELET	Active	49.20583	-125.31750	3	
TSABLE RIVER NEAR FANNY BAY	Active	49.51750	-124.84167	4	
BROWNS RIVER NEAR COURTENAY	Active	49.69250	-125.08528	4	
CRUICKSHANK RIVER NEAR THE MOUTH	Active	49.57917	-125.20083	4	
OYSTER RIVER BELOW WOODHUS CREEK	Active	49.89389	-125.23833	4	
SALMON RIVER ABOVE CAMPBELL LAKE DIVERSION	Active	50.09167	-125.67222	4	
ELK RIVER ABOVE CAMPBELL LAKE	Active	49.85556	-125.80500	4	corrected for Diversion influence
HEBER RIVER NEAR GOLD RIVER	Active	49.81528	-125.98639	5	corrected for Diversion influence
HEBER DIVERSION NEAR GOLD RIVER	Active	49.85444	-125.97222	5	used to correct flows in the Elk River
GOLD RIVER BELOW UCONA R	Active	49.70583	-126.10611	5	

UCONA RIVER AT THE MOUTH	Active	49.70889	-126.09778	5	
TSITIKA RIVER BELOW CATHERINE CREEK	Active	50.43694	-126.57417	6	
NIMPKISH RIVER ABOVE WOSS RIVER	Active	50.21528	-126.60917	6	
GOLD CREEK NEAR WOSS	Discontinued	50.21833	-126.61667	6	incomplete dataset for full period of analysis
KLASKISH RIVER NEAR KLASKINO INLET	Active	50.29500	-127.68833	7	
MCKELVIE CREEK ABOVE INTAKE	Active	49.93333	-126.63333	7	
ZEBALLOS RIVER NEAR ZEBALLOS	Active	50.01444	-126.84250	7	
ZEBALLOS RIVER AT MOOK PEAK	Active	50.13694	-126.81917	7	
SAN JOSEF RIVER BELOW SHARP CREEK	Active	50.66972	-128.16417	8	
PUGH CREEK NEAR NAHWITTI LAKE	Active	50.73500	-127.88306	8	
SIMPSON CREEK NEAR KOPRINO HARBOUR	Active	50.51194	-127.84306	8	

WSC gauging stations omitted from FAC development for reasons noted

Station name	Status	Latitude	Longitude	RRA	Notes
RENFREW CREEK NEAR PORT RENFREW	Active	48.63694	-124.29194	1	omitted due to clear cut condition of watershed
BONSALL CREEK NEAR THE MOUTH	Active	48.87722	-123.67889	2	incomplete dataset
BINGS CREEK NEAR THE MOUTH	Active	48.78944	-123.72444	2	lowland drainage not typical of a SH stream
COWICHAN RIVER AT LAKE COWICHAN	Active	48.82611	-124.05194	2	regulated
COWICHAN RIVER NEAR DUNCAN	Active	48.77278	-123.71222	2	regulated
NANAIMO RIVER NEAR CASSIDY	Active	49.06861	-123.88694	2	regulated
SANDHILL CREEK AT PAT BAY HIGHWAY	Active	48.58028	-123.39722	2	regulated
SHAWNIGAN CREEK NEAR MILL BAY	Active	48.65806	-123.56889	2	regulated
MILLSTONE RIVER AT NANAIMO	Active	49.17722	-123.96778	2	Urban drainage not conducive to small hydro development
JUMP CREEK AT THE MOUTH	Active	49.03667	-124.16528	2	regulated
NILE CREEK NEAR BOWSER	Active	49.41889	-124.64222	2	regulated
ASH RIVER BELOW MORAN CREEK	Active	49.36944	-124.98278	3	regulated
SOMASS RIVER NEAR ALBERNI	Active	49.28528	-124.86667	3	regulated
SPROAT RIVER NEAR ALBERNI	Active	49.28972	-124.91028	3	regulated
TSOLUM RIVER BELOW MUREX CREEK	Active	49.81278	-125.20278	4	Low gradient watershed not conducive to small hydro development
CREST LAKE NEAR HIGHWAY 28	Active	49.84111	-125.90500	4	influenced by the hebre river diversion
QUINSAM DIVERSION NEAR CAMPBELL RIVER	Active	49.94333	-125.50806	4	omitted due to modulating lake effect and diversion structures upstream

Station name	Status	Latitude	Longitude	RRA	Notes
LITTLE OYSTER RIVER AT YORKE ROAD	Active	49.88417	-125.18917	4	partial record only - seasonal measurement
DOVE CREEK NEAR THE MOUTH	Active	49.73694	-125.08333	4	poorly defined drainage boundary in upper reaches of drainage. Poor runoff hydrograph fit.
PIGGOTT CREEK AT MOUNT WASHINGTON	Active	49.75000	-125.34028	4	regulated
PUNTLEDGE RIVER AT COURTENAY	Active	49.68806	-125.03250	4	regulated
QUINSAM RIVER AT ARGONAUT BRIDGE	Active	49.93139	-125.50917	4	regulated
QUINSAM RIVER BELOW LOWER QUINSAM LAKE	Active	49.92972	-125.33778	4	regulated
QUINSAM RIVER NEAR CAMPBELL RIVER	Active	50.02917	-125.29861	4	regulated
SALMON RIVER ABOVE MEMEKAY RIVER	Active	50.19889	-125.74583	4	regulated
SALMON RIVER DIVERSION NEAR CAMPBELL RIVER	Active	50.09583	-125.66667	4	regulated
SALMON RIVER NEAR SAYWARD	Active	50.30667	-125.89722	4	regulated
TSOLUM RIVER NEAR COURTENAY	Active	49.70722	-125.01139	4	regulated
CLANNINICK CREEK AT HEADWATERS	Active	50.10222	-127.39556	7	atypical location not representative of sites within area

APPENDIX B

IDENTIFIED SMALL HYDRO SITES ON VANCOUVER ISLAND

Watercourse Name	Latitude	Longitude	Flow (m^3/s)	Head (m)	Power (kW)	RRA	Area (km^2)	Development Scenario
Fairy Cr.	48.5947	-124.3587	0.65	50	270	1	10.2	Full
Fleet R.	48.5833	-124.0500	4.47	50	1,880	1	70	Full
Gain Cr	48.5122	-124.1911	1.04	120	1,050	1	16.3	Full
Noyse Cr	48.5020	-124.2340	0.49	160	660	1	7.6	Full
San Juan R.	48.6000	-123.9833	3.61	50	1,510	1	56.5	Full
Sombrio R.	48.5214	-124.2700	0.60	50	250	1	9.4	Full
Tugwell Cr.	48.4261	-123.8314	0.66	50	280	1	10.3	Full
Muir Cr.	48.4081	-123.8731	5.92	50	2,480	1	49.5	Phase 2
Cameron R.	49.2500	-124.6667	3.33	50	1,400	2	77.6	Full
Chipman Cr	48.8875	-123.9486	2.33	50	980	2	54	Full
Englishman R.	49.2500	-124.3500	6.30	50	2,640	2	147	Full
Fellows Cr.	48.6781	-123.8958	0.49	80	330	2	11.4	Full
Rosewell Cr.	49.4500	-124.8000	1.73	100	1,450	2	40.4	Full
Solly Cr	48.8511	-123.8672	1.12	80	750	2	26.1	Full
S. Englishman R	49.2500	-124.2833	3.11	100	2,610	2	72.5	Full
Wardropper CR	48.9186	-124.2986	0.24	120	240	2	5.6	Full
Wilfred Cr.	49.4667	-124.8500	0.90	50	380	2	20.9	Full
Franklin R.	49.0939	-124.7678	8.00	106	6,650	3	53.7	Phase 1
China Cr.	49.1678	-124.6925	5.20	157	6,400	3	46.9	Op
Klitsa Cr.	49.2775	-125.2289	1.00	293	2,300	3	4.4	Op
Marion 3 Cr.	49.2361	-125.3181	0.99	553	4,300	3	4.3	Op
South Sutton Cr.	49.2886	-125.3133	2.00	344	5,400	3	10.1	Op
Doran-Taylor	49.3000	-125.2667	1.10	630	5,580	3	8	OpS
Canoe Ck	49.1697	-125.3844	0.46	315	1,170	3	5.0	Full
Drinkwater Cr.	49.4333	-125.5000	2.74	50	1,150	3	29.2	Full
Four Mile Cr.	48.8161	-124.5972	0.87	65	470	3	9.3	Full
Handy Cr.	49.0000	-124.9333	3.04	100	2,550	3	32.4	Full
Mactush Cr.	49.1108	-124.8500	2.41	50	1,010	3	25.7	Full
Margaret Cr.	49.4370	-125.4458	2.46	50	1,030	3	26.2	Full
Sarita R.	48.9064	-124.9111	8.55	28	2,010	3	91	Full
Sarita R Tributary	48.9419	-124.8081	0.70	140	820	3	7.6	Full
Tsable R.	49.5400	-125.0000	8.20	70	4,500	4	111	Phase 1
Tennent Cr.	49.5522	-125.6383	0.48	750	3,030	4	3.5	Op
Thelwood Cr.	49.5181	-125.6008	2.55	385	7,900	4	29.9	OpS
Adrian Cr.	49.8000	-125.4500	2.43	50	1,020	4	40.0	Full
Beech Cr.	49.6000	-125.2000	0.99	50	420	4	16.3	Full
Browns R. #1	49.6833	-125.1500	5.23	50	2,190	4	86.0	Full
Cervus Cr.	49.8500	-125.7833	3.41	100	2,860	4	56.1	Full
Comox Cr.	49.5333	-125.2500	1.60	50	670	4	26.3	Full
Headquarters Cr.	49.7000	-125.1167	1.23	50	520	4	20.2	Full
Henshaw Cr #1	49.6000	-125.5333	2.27	50	950	4	37.3	Full
Moakwa Cr.	50.1167	-126.0333	2.21	90	1,670	4	36.4	Full
Myra Cr. @ falls	49.5833	-125.5667	4.31	50	1,810	4	70.9	Full
Nora Cr.	50.1333	-126.0333	0.81	152	1,030	4	13.3	Full
Phillips Cr.	49.6667	-125.5667	4.85	50	2,030	4	79.7	Full
Pye Cr.	50.3344	-125.5232	5.23	60	2,630	4	86.1	Full
Ralph R.	49.6223	-125.5038	1.78	50	750	4	29.3	Full
Salmon R.	50.0833	-125.6833	14.60	50	6,120	4	240	Full

Watercourse Name	Latitude	Longitude	Flow (m^3/s)	Head (m)	Power (kW)	RRA	Area (km^2)	Development Scenario
Shepherd Cr.	49.6207	-125.5168	2.84	50	1,190	4	46.7	Full
Tlools Cr.	49.8667	-125.7500	3.15	60	1,590	4	51.8	Full
Trent R.	49.5833	-124.9833	1.86	50	780	4	30.6	Full
Unnamed Cr.	50.0667	-126.1833	0.33	80	220	4	5.4	Full
Unnamed Cr.	49.8333	-125.6333	1.30	60	650	4	21.3	Full
Unnamed Cr.	50.1833	-125.4000	1.17	100	980	4	19.2	Full
Unnamed Cr.	49.7667	-125.6833	2.07	200	3,480	4	34.1	Full
Bigtree Cr.	50.2675	-125.7586	1.78	140	2,090	4	29.6	Phase 2
Browns R. #1	49.6839	-125.1375	5.47	75	3,440	4	73	Phase 2
Cruickshank R.	49.6483	-125.2944	6.51	120	6,560	4	67.7	Phase 2
Memekay R.	50.1694	-125.8006	6.10	75	3,840	4	96.6	Phase 2
Middle Memekay R. #1	50.1833	-125.8053	6.10	75	3,840	4	96.2	Phase 2
Middle Memekay R. #2	50.1739	-125.8208	2.10	120	2,110	4	93.6	Phase 2
Mohun Cr.	50.1086	-125.4244	3.80	160	5,100	4	64.2	Phase 2
Piggott Cr.	49.8144	-125.3594	3.79	300	9,550	4	84	Phase 2
Ucona R.	49.7317	-126.0069	7.20	100	6,040	5	77.8	Phase 1
Ucona R.	49.7128	-126.0456	16.00	150	20,130	5	158.9	Phase 1
Cypress Cr.	49.8300	-126.1100	1.70	232	3,100	5	10.4	Op
Mears Cr.	49.8667	-126.2667	1.40	346	3,800	5	11.3	Op
Ahamingas Cr.	49.6911	-126.1334	0.85	200	1,430	5	9.5	Full
Bancroft Cr.	49.5733	-125.8547	3.35	100	2,810	5	37.1	Full
Bedwell R.	49.4597	-125.6119	2.59	50	1,080	5	28.6	Full
Black Cr.	49.6553	-126.0789	1.00	60	510	5	11.1	Full
Burman R	49.6058	-125.8233	6.17	50	2,590	5	68.3	Full
Butterwort/Elk Cr	49.7944	-125.8761	3.01	50	1,260	5	33.3	Full
Gold R	49.8811	-126.0883	19.62	30	4,940	5	217	Full
Hesquiat Pt Cr.	49.4169	-126.3842	1.56	40	520	5	17.3	Full
Matchlee Cr.	49.6194	-126.0433	1.47	40	490	5	16.3	Full
Megin R.	49.5392	-126.0011	3.23	40	1,080	5	35.7	Full
Mooyah R.	49.6056	-126.4092	1.55	40	520	5	17.2	Full
Muchalat R.	49.8883	-126.3119	1.86	60	940	5	20.6	Full
Oktwanch R.	49.9408	-126.2653	1.52	30	380	5	16.8	Full
Pretty Girl L.	49.4939	-126.2331	1.63	80	1,090	5	18.0	Full
Tabolt Cr.	49.5042	-126.1100	1.37	40	460	5	15.2	Full
Tlupana R.	49.7917	-126.3278	2.32	90	1,750	5	25.7	Full
Tlupana R @ falls	49.7986	-126.2969	1.69	80	1,130	5	18.7	Full
Unnamed Cr.	49.2931	-126.1594	0.75	40	250	5	8.3	Full
Unnamed Cr.	49.3867	-126.0583	0.69	80	460	5	7.6	Full
Unnamed Cr.	49.3178	-126.0922	0.37	80	250	5	4.1	Full
Unnamed Cr.	49.4942	-126.2331	1.64	80	1,100	5	18.1	Full
Upana Cr.	49.8067	-126.0872	5.46	30	1,370	5	60.4	Full
Ward Cr.	49.7872	-126.0875	0.71	60	360	5	7.9	Full
Wilson Cr.	49.6431	-126.1700	1.41	90	1,060	5	15.6	Full
Saunders Ck	49.8378	-126.0297	3.79	180	5,730	5	29.4	Phase 2
Clint Cr.	50.1253	-126.6631	2.50	288	5,790	6	12.4	Phase 1 S
Atluck Cr.	50.2328	-126.9292	2.81	30	710	6	43.2	Full

Watercourse Name	Latitude	Longitude	Flow (m^3/s)	Head (m)	Power (kW)	RRA	Area (km^2)	Development Scenario
Catherine Cr	50.4225	-126.5975	2.88	90	2,170	6	44.2	Full
Kilpala R.	50.4333	-127.0500	3.36	60	1,690	6	51.7	Full
Kinman Cr.	50.3500	-126.9167	1.44	90	1,090	6	22.1	Full
Kiyu Cr.	50.0889	-126.5067	1.07	90	810	6	16.5	Full
Kunnum Cr.	50.2856	-126.2406	3.01	91	2,300	6	46.3	Full
Maquilla Cr.	50.0833	-126.4167	2.77	90	2,090	6	42.6	Full
Montague Cr.	50.3333	-126.2000	2.30	152	2,940	6	35.4	Full
Naka Cr.	50.4703	-126.4217	3.23	60	1,630	6	49.7	Full
Newcastle Cr.	50.3692	-126.1078	2.21	90	1,670	6	33.9	Full
Sebalhall Cr.	49.9417	-126.3961	1.46	30	370	6	22.36	Full
Swah Cr.	50.0006	-126.3756	0.91	70	530	6	14	Full
Tlatlos Cr.	50.3697	-126.2342	2.02	182	3,090	6	31.1	Full
Unnamed Cr.	49.9589	-126.4264	1.18	30	300	6	18.2	Full
Unnamed Cr.	50.2167	-126.0833	0.71	55	330	6	10.9	Full
Unnamed Cr.	50.3536	-126.9433	1.16	120	1,170	6	17.9	Full
Unnamed Cr.	50.1167	-126.6000	0.40	120	400	6	6.1	Full
Unnamed Cr.	50.5000	-126.9000	1.41	60	710	6	21.6	Full
Unnamed Cr.	50.1519	-126.3178	0.94	90	710	6	14.5	Full
Unnamed Cr.	50.0833	-126.4167	1.48	60	750	6	22.8	Full
Unnamed Cr.	50.4717	-126.3461	0.56	180	840	6	8.6	Full
Unnamed Cr.	50.1667	-126.6167	1.13	90	850	6	17.3	Full
Unnamed Cr.	50.1508	-126.3428	0.59	244	1,200	6	9	Full
Unnamed Cr.	50.3406	-126.1219	1.67	120	1,680	6	25.6	Full
Unnamed Cr.	50.4728	-126.3956	1.38	152	1,760	6	21.2	Full
Yookwa Cr.	50.0667	-126.4667	2.04	30	510	6	31.3	Full
Adam R.	50.4214	-126.2194	27.50	50	11,530	6	384	Phase 2
Cain Cr.	50.1875	-126.3814	0.75	160	1,010	6	9.4	Phase 2
Kaipit Cr.	50.2383	-126.7950	11.69	80	7,850	6	63.6	Phase 2
Kokish R.	50.4458	-126.7600	6.30	140	7,400	6	68.7	Phase 2
Palmerston Cr.	50.4281	-126.2850	3.00	130	3,270	6	23.8	Phase 2
Kokish R.	50.4800	-126.8236	26.50	220	46,940	6	414.8	Phase 2 S
Pinder Cr.	50.2236	-126.8956	1.50	120	1,450	6	36.5	Phase 2 S
Barr Cr.	49.9375	-126.7489	2.30	130	2,510	7	15.4	Phase 1
Mckelvie Ck	49.9436	-126.6408	3.75	116	3,400	7	20.6	Phase 1
Raging R. 2	50.3906	-127.2267	8.00	60	4,000	7	108	Phase 1
Victoria Lake	50.4278	-127.4070	12.60	90	9,500	7	116.3	Phase 1
Zeballos Lake	50.0500	-126.7700	10.00	263	21,180	7	61	Phase 1 S
Raging R.	50.3900	-127.2200	3.82	58	1,750	7	108	Op
Artlish R.	50.1444	-126.9161	3.54	60	1,780	7	36.3	Full
Brodrick Cr.	49.8256	-126.8869	0.98	120	980	7	10	Full
Canton Cr.	49.8348	-126.4567	1.03	30	260	7	10.5	Full
Canton Cr.	49.8167	-126.4667	2.66	30	670	7	27.2	Full
Canton Cr. W	49.8260	-126.4685	1.62	30	410	7	16.6	Full
Ciriaco Cr.	49.9269	-126.8189	0.38	90	290	7	3.9	Full
Cluxewe R.	50.4833	-127.1478	2.09	60	1,050	7	21.4	Full
Ehatisaht Cr.	49.8858	-126.8564	1.20	60	600	7	12.3	Full
Friend Cr.	49.9800	-126.8064	0.27	90	210	7	2.8	Full
Hectate L.	49.8778	-126.7961	0.69	40	230	7	7.1	Full
Hoiss Cr.	49.7233	-126.5683	0.96	60	480	7	9.8	Full
Kaouk R.	50.0833	-126.9367	2.76	60	1,390	7	28.3	Full

Watercourse Name	Latitude	Longitude	Flow (m^3/s)	Head (m)	Power (kW)	RRA	Area (km^2)	Development Scenario
Kashult Cr.	50.2100	-127.3264	2.05	60	1,030	7	21	Full
Kauwinch R.	50.2403	-127.2833	1.43	120	1,430	7	14.6	Full
Kendrick Cr.	49.7381	-126.6672	1.45	50	610	7	14.9	Full
Lutes Cr.	49.8833	-126.7667	1.19	60	600	7	12.2	Full
Malksope R.	50.1650	-127.3672	1.59	60	800	7	16.3	Full
Mamat Cr.	49.9814	-126.9117	0.48	60	240	7	4.9	Full
Marble R.	50.2575	-127.3242	0.54	60	270	7	5.5	Full
Narrowgut Cr.	49.9942	-127.1014	1.69	30	420	7	17.3	Full
Ououkinsh R.	50.2367	-127.4286	1.13	120	1,140	7	11.6	Full
Perry R.	49.9100	-126.6144	3.84	30	970	7	39.3	Full
Teihsum R.	50.3378	-127.3292	2.83	60	1,420	7	29	Full
Unnamed Cr.	49.7892	-126.7392	1.13	60	530	7	11.6	Full
Unnamed Cr.	49.8719	-127.0931	1.18	60	550	7	12.1	Full
Unnamed Cr.	50.1478	-127.1636	2.83	30	660	7	29.0	Full
Unnamed Cr.	49.9486	-126.8603	0.28	122	270	7	2.9	Full
Unnamed Cr.	49.8069	-126.4225	1.05	60	490	7	10.8	Full
Unnamed Cr.	50.3125	-127.1956	1.17	90	820	7	12.0	Full
Unnamed Cr.	50.4833	-127.3500	2.04	90	1,430	7	20.9	Full
Utluh Cr.	50.3167	-127.4167	1.84	60	920	7	18.8	Full
Wady Cr.	50.4000	-127.2833	1.29	180	1,950	7	13.2	Full
Little Zeballos R.	49.9833	-126.7500	1.89	175	2,780	7	19.4	Full
Craft Cr.	50.3766	-127.2684	2.49	125	2,610	7	14.1	Phase 2
Leiner R.	49.9283	-126.6189	9.00	40	3,020	7	60.8	Phase 2
Tahsish R.	50.2481	-127.0717	15.01	143	18,000	7	88	Phase 2
Zeballos R.	50.0592	-126.7914	6.80	70	3,990	7	44	Phase 2
Songhees Ck	50.7572	-127.6494	6.50	277	14,480	8	61.6	Phase 1 S
Dick Booth Cr.	50.6833	-127.5167	1.48	120	1,490	8	22.2	Full
Peggattem Cr.	50.6333	-127.9833	1.36	30	340	8	20.5	Full
Shushartie R.	50.8167	-127.8667	4.37	30	1,100	8	65.7	Full
Tsulquate R.	50.7164	-127.5814	2.56	40	860	8	38.5	Full
Ursie Cr.	50.8117	-127.8558	1.19	100	1,000	8	18	Full

APPENDIX C

DERIVATION OF GENERATOR EFFICIENCY CURVES

Approximation of the Generator Efficiency Curves

Values used in the derivation of equations [5.3] and [5.4]

VA_{out} = 4900 kVA

Phase = 3

PF = 0.9

Freq. = 60 Hz

P_{cu} = Copper Loss + Stray Loads

P_{core} = Iron Loss

P_{field} = Excitation Loss

P_{mech} = Friction & Windage Loss

$$\eta_g = \frac{VA_{out} \times PF}{VA_{out} \times PF + P_{cu} + P_{core} + P_{field} + P_{mech}} \times 100$$

Op. Point [1] (%)	1 phase copper (kW)	Copper Loss [2] (kW)	Stray Loads [3] (kW)	Iron Loss (kW)	Friction & Windage [4] (kW)	Excitation Loss (kW)	Total Losses (kW)	Total Generation (kW)	Part Load Efficiency (%)	Two Turbines (%)	Part Load Efficiency (%)
100%	10.40	31.20	1.56	46	34.3	26.3	149.76	4559.8	96.72%	100%	96.62%
95%	9.88	29.64	1.48	46	34.3	26.3	147.60	4337.1	96.60%	95%	96.60%
90%	9.36	28.08	1.40	46	34.3	26.3	145.44	4114.4	96.47%	90%	96.47%
85%	8.84	26.52	1.33	46	34.3	26.3	143.29	3891.8	96.32%	85%	96.32%
80%	8.32	24.96	1.25	46	34.3	26.3	141.13	3669.1	96.15%	80%	96.15%
75%	7.80	23.40	1.17	46	34.3	26.3	138.97	3446.5	95.97%	75%	95.97%
70%	7.28	21.84	1.09	46	34.3	26.3	136.81	3223.8	95.76%	70%	95.76%
65%	6.76	20.28	1.01	46	34.3	26.3	134.65	3001.2	95.51%	65%	95.51%
60%	6.24	18.72	0.94	46	34.3	26.3	132.50	2778.5	95.23%	60%	95.23%
55%	5.72	17.16	0.86	46	34.3	26.3	130.34	2555.8	94.90%	55%	94.90%
50%	5.21	15.63	0.78	46	34.3	26.3	128.22	2337.6	94.51%	50%	94.51%
50%	5.20	15.60	0.78	46	34.3	26.3	128.18	2333.2	94.51%	100%	96.72%
45%	4.68	14.04	0.70	46	34.3	26.3	126.02	2110.5	94.03%	90%	96.47%
40%	4.16	12.48	0.62	46	34.3	26.3	123.86	1887.9	93.44%	80%	96.15%
35%	3.64	10.92	0.55	46	34.3	26.3	121.71	1665.2	92.69%	70%	95.76%
30%	3.12	9.36	0.47	46	34.3	26.3	119.55	1442.5	91.71%	60%	95.23%
25%	2.60	7.80	0.39	46	34.3	26.3	117.39	1219.9	90.38%	50%	94.50%
20%	2.08	6.24	0.31	46	34.3	26.3	115.23	997.2	88.44%	40%	93.33%
15%	1.56	4.68	0.23	46	34.3	26.3	113.07	774.6	85.40%	30%	91.58%

Notes: (1) Losses at 100% load are based on scaled data from the detailed design data of a 3 MW unit found in [82].

(2) P_{cu} varies linearly with load while all other loss factors remain constant [81,82].

(3) stray loads approximated as 5% of total copper losses [82].

(4) friction and windage approximated as 0.7% of kVA rating [82].

APPENDIX D

DERIVATION OF PENSTOCK EFFICIENCY CURVE

Approximation of a Penstock Efficiency Curve

Values used to derive equation [5.6]

Water @ 10°C

L =	380	m
h =	85	m
g =	9.81	m/s^2
ρ =	1000	kg/m^3
μ =	1.3070E-03	$(N*s)/m^2$
v =	1.3070E-06	m^2/s
d =	1.25	m
e =	0.002	(mm) steel
e =	0.0015	(mm) HDPE
e/d =	0.0000016	steel
e/d =	0.0000012	HDPE

Equations used:

Reynolds Number:

$$\boxed{\mathrm{Re}_d = \frac{\rho V d}{\mu}}$$

Darcy Friction Factor:

$$\boxed{\sqrt{\frac{1}{f}} = -1.8\log\left(\frac{6.9}{\mathrm{Re}_d} + \left(\frac{e/d}{3.7}\right)^{1.11}\right)}$$

Darcy-Weisbach Equation:

$$\boxed{h_f = f\,\frac{L}{d}\frac{V^2}{2g}}$$

Flow (m^3/s)	V (m/s)	Re_d	f steel	f HDPE	h_f (m)	Head Loss (%)	Penstock Efficiency (%)
5.82	4.743	4.5357E+06	0.00919	0.00917	3.2007	3.77%	96.23%
5.75	4.686	4.4812E+06	0.00921	0.00919	3.1296	3.68%	96.32%
5.5	4.482	4.2863E+06	0.00927	0.00925	2.8816	3.39%	96.61%
5.25	4.278	4.0915E+06	0.00933	0.00931	2.6433	3.11%	96.89%
5	4.074	3.8967E+06	0.00940	0.00938	2.4146	2.84%	97.16%
4.75	3.871	3.7018E+06	0.00947	0.00945	2.1955	2.58%	97.42%
4.5	3.667	3.5070E+06	0.00954	0.00952	1.9862	2.34%	97.66%
4.25	3.463	3.3122E+06	0.00962	0.00961	1.7866	2.10%	97.90%
4	3.259	3.1173E+06	0.00971	0.00969	1.5969	1.88%	98.12%
3.75	3.056	2.9225E+06	0.00980	0.00979	1.4172	1.67%	98.33%
3.5	2.852	2.7277E+06	0.00990	0.00989	1.2474	1.47%	98.53%
3.25	2.648	2.5328E+06	0.01002	0.01000	1.0877	1.28%	98.72%
3	2.445	2.3380E+06	0.01014	0.01013	0.9382	1.10%	98.90%
2.75	2.241	2.1432E+06	0.01027	0.01026	0.7990	0.94%	99.06%
2.5	2.037	1.9483E+06	0.01043	0.01042	0.6702	0.79%	99.21%
2.25	1.833	1.7535E+06	0.01060	0.01059	0.5519	0.65%	99.35%
2	1.630	1.5587E+06	0.01080	0.01079	0.4443	0.52%	99.48%
1.75	1.426	1.3638E+06	0.01104	0.01103	0.3476	0.41%	99.59%
1.5	1.222	1.1690E+06	0.01132	0.01131	0.2619	0.31%	99.69%
1.25	1.019	9.7417E+05	0.01166	0.01166	0.1874	0.22%	99.78%
1	0.815	7.7934E+05	0.01211	0.01210	0.1246	0.15%	99.85%
0.75	0.611	5.8450E+05	0.01273	0.01272	0.0736	0.09%	99.91%
0.5	0.407	3.8967E+05	0.01368	0.01368	0.0352	0.04%	99.96%