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Energy and hydrology modelling of hydropower in Eastern Canada

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Abstract
Canada is plentiful in resources and the fourth largest producer of hydropower in the world. The province of Quebec stands for about 52% of Canada's total hydropower production, and the Quebecois energy market is totally dominated by hydropower: 96% of the electricity produced in Quebec is hydro. In hydro dominated deregulated energy markets, a correlation can often be found between the water inflow to the hydropower reservoirs, i.e. the potentially available energy, and the price of electricity. Predictions on how the water inflow will vary are thus attractive information for many actors in the energy market. This master thesis, conducted as degree project at the program in environmental engineering at Lund University, was made in collaboration with the company Thomson Reuters. In the study it is investigated whether the conditions in eastern Canada qualifies to be applied to the Scania-HBV model, with the purpose to produce forecasts of the energy inflow to the hydropower system. A literature study is performed and models for the hydropower complexes Churchill Falls in Newfoundland and Labrador and La Grande Rivière in Quebec are constructed. From the literature study, it is concluded that the energy market in Quebec is regulated and that the electricity price thus is fixed and indifferent to external influences. The export to the deregulated US markets are however of significant importance, and in this context the energy inflow prognoses might be of interest. In order to construct Scania-HBV models it is of utmost importance to have reliable and extensively available data. As a rule, such data are unfortunately seldom obtainable, and this was also the case concerning the modelling of eastern Canada. However, based on the available data, the models are evaluated as reasonable, and the modelled results as very good. For further studies and model constructions it is recommended to try and find data on the hydropower reservoir capacities and how the reservoirs are regulated.

Sammanfattning

Kanada är väldigt rikt på energiresurser och fjärde största vattenkraftproducenten i världen. Provinsen Quebec står för omkring 52% av Kanadas totala vattenkraftsproduktion, och energimarknaden Quebec domineras fullständigt av vattenkraft: 96% av elen genereras där av vattenkraft. I avreglerade vattenkraftdominerade energimarknader är det vanligt att det finns ett samband mellan vatteninflödet till kraftverksreservoarerna, dvs mellan den potentiellt tillgängliga energin, och elpriset. Förutsägelser om hur vatteninflödet kommer att variera är därmed hett åtråvärd information för många aktörer på elmarknaderna. Denna mastersuppsats, som genomförts som examination på civilingenjörsprogrammet i ekosystemteknik på Lunds tekniska högskola och i samarbete med företaget Thomson Reuters, utreder förutsättningarna för att upprätta Scania-HBV-modeller för områdena i östra Kanada, i syfte att producera prognoser på energiinflödet till vattenkraftssystemen. En litteraturstudie om den kanadensiska elmarknaden utförs och modeller för vattenkraftskomplexen Churchill Falls i Newfoundland och Labrador och La Grande Rivière i Quebec upprättas. Av litteraturstudien framkommer att elmarknaden i Quebec fortfarande är reglerad och att elpriset därmed ligger fast och utan synlig påverkan från yttre faktorer. Dock förekommer en betydande export till de öppna marknaderna i USA, och i denna kontext kan inflödesprognoser vara intressanta. För upprättandet av Scania-HBV-modeller är det av yttersta vikt att ha utförlig tillgång till tillförlitliga data. Som regel är dessa data dessvärre svåråtkomliga, och så var även fallet i modellerandet av östra Kanada. Baserat på de data som fanns tillgängliga, bedöms dock modellerna som rimliga och modellresultaten som mycket goda. För fortsatta studier och modellkonstruktioner rekommenderas att försöka finna data för hur stor kapacitet som ryms i kraftverksreservoarerna och hur dessa regleras.

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Acronyms

CF – Churchill Falls
CFSR – Climate Forecast System Reanalysis
CPCp – Climate Prediction Center, precipitation
FERC – Federal Energy Regulatory Commission (US)
HBV – Hydrologiska Byråns Vattenbalansavdelning
HQ – Hydro-Québec
IPP – Independent Power Producer
LG – La Grande (La Grande Rivière hydropower complex)
NEB – National Energy Board (Canada)
NERC – North American Electric Reliability Corporation
NL – Newfoundland and Labrador
NOAA – National Oceanic and Atmospheric Administration
NRCan – Natural Resources Canada
OATT – Open Access Transmission Tariff
ON – Ontario
OPG – Ontario Power Generation
PPA – Power Purchase Agreement
QC – Quebec
RTO – Regional Transmission Organisation

Abbreviations

MW/h/ – Megawatt /hour/; mega = 10^6 = 1 000 000
GW/h/ – Gigawatt /hour/; giga = 10^9 = 1 000 000 000
TW/h/ – Terawatt /hour/; tera = 10^{12} = 1 000 000 000 000

Q – discharge, water runoff, normally measured in cubic meters per second, but in this thesis most often in energy units (gigawatt hours)

Power – work per unit of time, or in this context: electricity, flow of energy, measured in watts, W = J/s

Energy – measured in joules, J, or, equivalently, kilowatt hours, kWh.
1 kWh = 1000 (J/s)h * 3600s/h = 3.6 MJ

1. Introduction

The North American energy market has gone through radical changes during the last couple of years, mostly due to new technologies for exploiting gas and oil resources. However, as a total, the fraction of fossil fuels has decreased in relation to the renewable energy sources, which are steadily on the march. Increasing regulations of green house gas emissions and heavy metals impede the usage of fossils, and since the accident in Fukushima, the International Energy Agency, IEA, has noticed that the nuclear power has decreased generally in the world (NEB, 2013). During these times of climate change, with peak oil approaching at the same time as an increasing societal demand for energy, it is of outmost importance to promote renewable energy sources, such as hydropower.

Electricity differs from other market commodities in that it is more or less indispensible for everyday life. This fact rules out much of the customers normal abilities to respond to the market fluctuations. Since electricity cannot be stored in appreciable quantities and since demand does not vary with the price, the production must rise and fall in synchronization with the demand. The production costs normally increase with the demand, causing the electricity price to be highest during the peak demands. As a consequence of this, all actors in the energy wholesale markets keep miniscule observation on all factors that can be used to forecast the energy supply as well as the power demand (FERC, 2012).

Thomson Reuters is a company that supplies a spectrum of information services within a wide field. One of these services is to produce forecasts for the potential hydropower generation within an area, which becomes a valuable tool for improving the chances of profitability when trading with hydropower generated electricity. It is Thomson Reuters' ambition to provide this service on a global scale, and the work is in constant progress to expand and locate new areas to invest in. The forecast is in form of a hydrograph simulated by a rainfall-runoff model, which requires many pieces of information about the region being modelled. A hydrograph describes a discharge curve over time, normally expressed in natural flow units such as e.g. cubic meters per second. Figure 1.1 shows an example of a hydrograph with a curve typical for an area with Nordic climate: low discharge during the colder months, when the precipitation accumulates as snow, and then a large peak due to the spring flood when the snowpack melts. Notice that the x-axis of the figure starts and ends in November, thus following the hydrological year and not the calendar year. The start of the hydrological year varies from place to place, but is defined as just before the snow starts to fall, in order to not divide the snow pack for one season over two different years. Discharge is generally measured in cubic meters per second (m^3/s) and is typically denoted as Q in hydrological contexts.

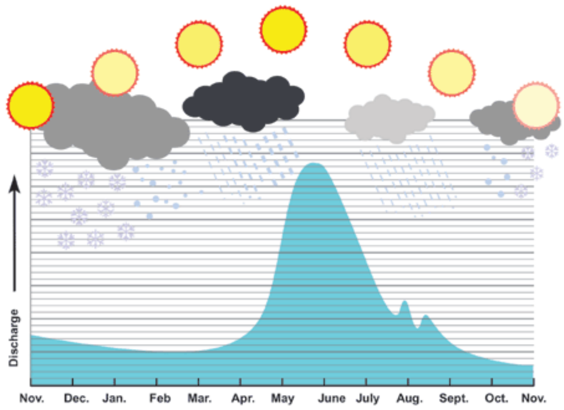

Figure 1.1 A typical river hydrograph for Nordic and Canadian climates. Discharge from the river varies with the seasons, with a characteristic peak in the spring due to the snow melt (Environment Canada, 2010).

In the Thomson Reuters rainfall-runoff model, the discharge is converted into energy units (gigawatt hours), in order for the forecast to be directly compatible with the electricity spot price market.

In this master thesis, which is made in collaboration with Thomson Reuters, an evaluation is made of whether the Eastern parts of Canada are suitable for future forecasting projects. The study includes a résumé of the Canadian climate and (hydro)energy market, a collection of relevant input data, and calibration and evaluation of the rainfall-runoff model.

1.1. Objectives

The overall objective of this master thesis is to investigate whether the conditions in Eastern Canada qualifies for future forecasting projects. Expressed as milestones the objectives are to

- Describe the mechanisms of the Canadian energy market in general, and the price areas in the regions around Quebec especially
- Evaluate which areas that are most interesting to calibrate for modelling
- Collect and process the data required to build rainfall-runoff models for the selected regions
- Calibrate and run models for the selected regions
- Evaluate the reliability of the calibration and the input data provided to the model
- Discuss the possibilities for Thomson Reuters to proceed with a project to make reliable forecasts of the evaluated areas

1.2. Method

A literature study was performed on the state and mechanisms of the Canadian electricity market, with primary focus on Quebec.

Overview information regarding climate, geology and hydrology for Quebec was also gathered, along with data about the hydropower system of the provinces Quebec, Ontario and, to some extent, Newfoundland and Labrador.

A rainfall-runoff model requires meteorological input data in form of time series of precipitation and temperature which are fed directly to the model. This meteorological data was taken from the NOAA CPCp and CFSR data sets (Söderberg, 2015). The model also has a set of parameters that represent the physical conditions of the modelling area. In order to choose the best and most reasonable values of these parameters, information about the climate trends and geological and hydrological conditions in the area is helpful, but most important is to have a valid observed discharge series, a Q-target, to calibrate the model against. For a more detailed description of the hydrological concepts and the mechanisms of the model, see section 3.1.1.

Considering a modelling area of the great size for which the Thomson Reuters rainfall-runoff model is normally applied, the Q-target series cannot be directly measured as discharge in a specific outflow point from a catchment. Instead it must be constructed from what information that can be found from the modelling area in question. Herein lays the biggest challenge with the whole project: the validity of the model highly depends on how trustworthy a Q-target series that could be constructed, and the information required to build the Q-target is almost never available. Since the hydrograph produced by the Thomson Reuters model is expressed in energy units (gigawatt hours), the Q-target series must also be in this unit. This requires information on how the hydropower plant system of the modelling area is operated over time, information which is most often internal matters that the operators do not share with outsiders. For each of the measured energy inflow series to the hydropower plant system, the Q-target series is derived and calculated from other data. The methods for these calculations vary depending on what information that is available for the region. Construction of the Q-target series employed for the models in this study is described in further detail in chapter 4.

Once a reasonable Q-target series is achieved, the model can be applied to the modelling areas by calibration of the model parameters. This calibration was done by iterative changes of the values of the parameters and the weights of the meteorological stations until the calculated hydrograph, Q_{calc}, was a sufficient match to the observed hydrograph, the Q-target, also called Q_{obs}. When the optimal parameter values were found for the calibration, the model was run for another period of time in the data series for validation. The performance of the calibration and validation were evaluated with quantitative indicators, for further details see section 3.1.2.

1.3. Limitations

Only power plants with a capacity of more than 100 MW have been taken into consideration when collecting data. When referring to "large" hydropower plants in this report, power plants with capacities of 100 MW or larger are intended.

Not all of Eastern Canada was modelled in this study. The accuracy of a model decreases with increasing area of the region that is being modelled, since a larger modelling area implies more simplifications and assumptions regarding the model parameters. Thus regions should preferably be divided into submodels to better match the local conditions. The areas modelled in this study were the basins of Churchill Falls River in Newfoundland and Labrador, and La Grande Rivière in Quebec.

It should be noted that a modelled result is only a simplification of the reality, burdened with many uncertainties due to assumptions made in the model structure and to the quality of the data provided to the model. Although the meteorological data from CPCp and CFSR are of secure quality, they are still based on modelled interpolations from measurements and not the real conditions themselves. Moreover, the Q-target series are not measured but artificially constructed, with many assumptions and simplifications in the process.

The next chapter, chapter 2, summarizes the literature study that was made regarding the Canadian electricity market(s). In chapter 3 the modelling areas and the rest of the data that was collected for the modelling process are presented. The results of the modelling are shown in chapter 5 and further discussed in chapter 6. Table 1.1 gives a quick comparative summary of the volumes of the hydropower systems in Canada, the province of Quebec in eastern Canada, the public utility Hydro-Quebec which governs the energy sector in Quebec, and, lastly, Sweden.

Table 1.1. Overview of the hydropower systems in all of Canada, the province of Quebec, the public utility Hydro-Québec and, lastly, for comparison for the Swedish reader, Sweden. For references, see the text.

	Canada	**Quebec**	**Hydro-Québec**	**Sweden**
Hydro inst cap	75 000 MW	38 400 MW	37 500 MW	16 000 MW
Hydro generation ; percentage of total electrical generation	370 TWh; 61%	190 TWh; 96%	165 TWh 99%	70 TWh; 45%
Number of hydro-power plants	475 larger plants, and about 200 smaller*	146	59	200 larger plants, about 2000 in total*
Reservoir capacity	- **	- **	170 TWh	33.7 TWh

Comments:
*Larger plants here refer to an installed capacity of about 50MW.
**Reservoir capacities are interesting pieces of information to include in this context, however the total capacity for the reservoirs in Canada could not be found, and neither the capacity in Quebec. However, regarding the reservoirs in Quebec, it can be assumed that the majority are owned and operated by the public utility Hydro-Québec, and that the capacity in the province is thus in the scale of about 170 TWh.

2. The Canadian energy market

2.1. Introduction to the North American electricity market

Electricity is a commodity that can be quantified and measured and is thus traded in largely the same ways as other commodities. However, electricity differs from other commodities in that it cannot be stored in large quantities and thus the purchased amount must be produced simultaneously as it is consumed. This means that the customers cannot buy large quantities when the price is low and store for usage when the price rises. Moreover, since electricity is indispensable and cannot easily be exchanged with some other product, the customers are less able to respond to extreme price fluctuations as compared to other retail markets (FERC, 2012).

The electric power supply can be subdivided into three components: generation, which is the production at a power plant; transmission, which is the transportation over great distances by high voltage lines; and distribution, which supplies the end-users with electricity through the low voltage grid. Often the power plants and transmission lines are mentioned as the bulk power system, and the transmission and distribution facilities are referred to as the power grid (NRCan, 2014; FERC, 2012).

In the dawn of the electricity era, scattered power plants were built and run by private actors, in Canada often by aluminum industries. As the electricity industry evolved, electric power became more of an indispensable commodity, and thus came the need to ensure supply and minimize costs and risks of blackout. To meet these needs, the transmission and regulation systems got more and more integrated, with centralized system operation and regulated electricity markets. In Canada, the provinces have historically been self-sustaining in energy and the provincial governments traditionally have jurisdiction over both the bulk power system and the power grid (FERC, 2012; NEB, 2013; NRCan, 2014).

During the last decade the electricity industry have been reorganized and gone through significant changes. The governmental monopoly has partly been set aside as many of the provinces have unbundled the supply chain and opened up for private actors to participate (NRCan, 2014). This is an international trend that has occurred in markets around the world to increase the efficiency of the systems: trading and sharing transmission lines keep the costs down and ensures that there is power supply when demands peak. Corporations have evolved to better ensure the reliability of the electricity distribution and the bulk power system. North American Electric Reliability Corporation, NERC, is a non-profit international authority which helps to coordinate the system operations in all of US and parts of Canada and Mexico. NERC analyzes causes of system failures and develops standards and policies on production, safety and management (NERC, 2013). Their standards are only mandatory in the US, but in Canadian provinces that implement their services, the governments usually use NERC policies in their regulations. This is the case for e.g. Quebec (Clermont, 2013; IEA, 2009). Figure 2.1 illustrates the NERC-regions in North America (FERC, 2012). Interprovincial and international transmission lines lie under the responsibility of the National Energy Board (NEB), which is an independent regulator that answers to the Canadian federal government (NEB, 2013).

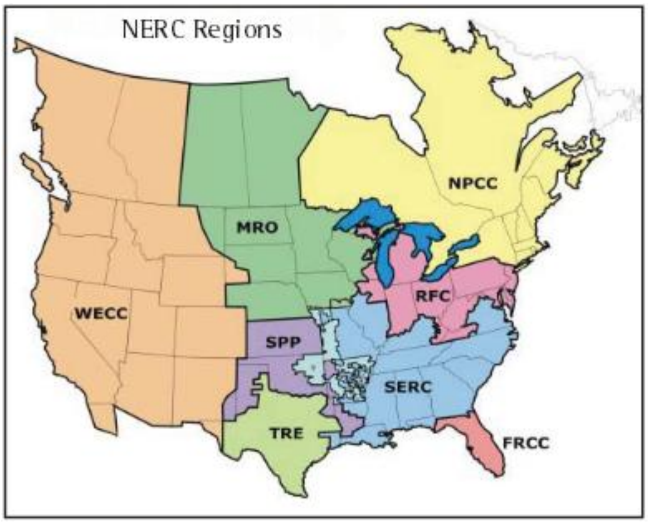

Figure 2.1. NERC regions. NPCC, Northeastern Power Coordination Counsil covers eastern Canada, including Ontario, Québec and Newfoundland and Labrador (FERC, 2012).

Electric markets comprise both physical and financial markets, where the physical market involves the infrastructure and the trading with and delivery of the actual commodity. The financial market is the trading with derived products, such as licences and agreements. The electricity market can also be divided into a retail market and a wholesale market, where retail is the trade to the end-use customers and the wholesale comprise much everything else, including business agreements between producers, distributors and industries (FERC, 2012).

2.2. The Canadian energy market

Canada is plentiful in energy production: in 2011 the country was ranked among the top producers in almost all energy sectors (Pineau, 2013), and each year Canada is third or fourth largest producer in the world when it comes to hydropower (CEA, 2013a; Renewable Facts, 2012a). The total production in 2009 amounted to 603 TWh, which with Canada's population of 35 million people corresponds to 18 MWh per capita, six times the world average production per capita. With these impressive facts, it would be natural for Canada to be a dominant player in the world market, but this is not quite the case. The reason for this is that the Canadian energy sector is fragmented into a myriad of subsectors with no centralized coordination and no common voice to emphasize their interests. There is a consensus that there would be lots of benefits (both economical and environmental) for all participants if the sector could be restructured into a more organized state, but at the moment there is no solution within reach to achieve this. The electrical market is representative for this description: according to the Canadian constitution, article 92A.1, each province has jurisdiction over its own electricity sector. Thus the Canadian electricity market is a mosaic of independent markets of very varying characters (Pineau, 2013).

The 10 provinces in Canada are among themselves unalike and with unique features, not least seen to the energy mix of each province, which highly affects the power prices. Figure 2.2 illustrates how the different energy resources add up to the installed capacity in each province. The total installed capacity of each province can be read directly from the figure and the accompanying pie chart shows the energy mix. As can be seen, similar provinces are situated far apart, further aggravating homogenization of the markets (Pineau, 2013).

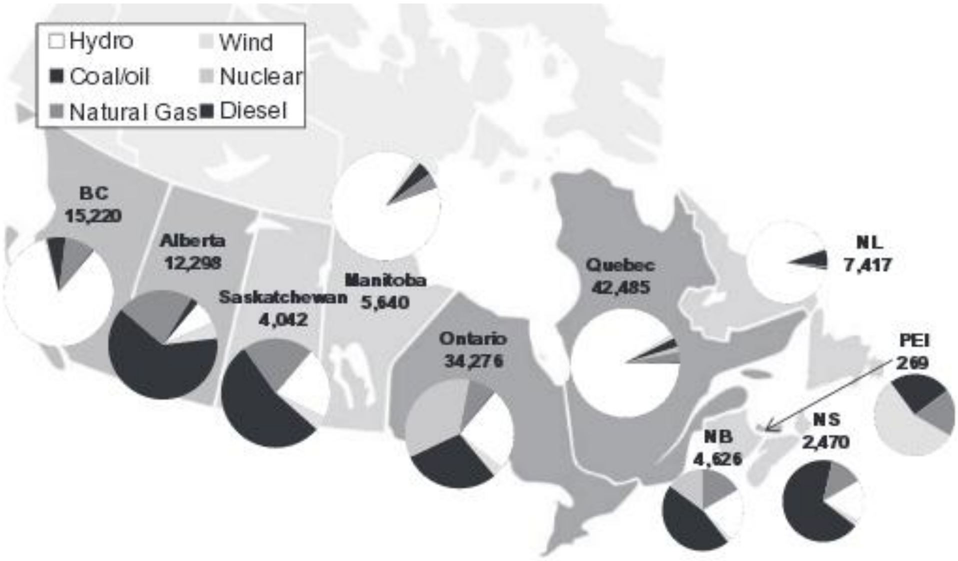

Figure 2.2. Installed capacity and energy mix in the Canadian provinces (by permission of Pineau, 2013).

In recent years, the respective electricity markets have opened up for interprovincial and international trading, although only Alberta and Ontario have deregulated their markets (NEB, 2013). The other provinces trade through bilateral agreements, and some of them, among others Quebec, have adopted the US FERC 1996 order 888 with Open Access Transmission Tariff, OATT, which gives the provinces possibility to trade outside their own jurisdiction. OATTs contain rates and terms of conditions for service of the power grid utilities as well as cost based prices, and are published online, freely available for all stakeholders. In this way the wholesale market is made available to both the public sector and the independent power producers, IPPs, who have the ability to make power purchase agreements (PPAs) with the distributors, or sell their electricity directly to the industry. However, the latter is mostly a formality and never takes place in practice, since the industry gets low tariffs from the distributors (see section 2.2.3) with which the IPPs cannot compete (FERC, 2012; Pineau, 2013).

In spite of the unique features of each province, Pineau (2013) points out that a pattern of characteristics can be noted and that the provinces can be divided into three groups according to their similarities:

1) Hydropower-dominated provinces, characterized by low production costs, dynamic export and public ownership. This group includes British Columbia, Manitoba, Quebec (QC) and Newfoundland and Labrador (NL).
2) Restructured provinces, which have deregulated their markets and implemented competitive wholesale markets. This group includes Alberta and Ontario (ON), and are stated to have high energy prices (although the high prices ought at least partly be explained by the energy mix in the respective province, see section 2.2.3 and figure 2.10 below)
3) Traditional provinces, highly dependent on fossil fuels (Pineau, 2013).

Before unfolding the market mechanisms further, a section on the hydropower situation in Canada follows below.

2.2.1. Hydropower in Canada

Canada is ranked among the top four hydropower producers after China, Brazil and the US. The country's total installed capacity amounts to 139 GW of which 75 GW is hydropower. 61% of the annual generation is from hydropower, of which 350 TWh is generated by about 475* hydropower plants, most of them situated in Québec and British Columbia. The largest, Robert-Bourassa, situated at The Grande River in Québec, is one of the largest hydropower plants in the world, and supplies 1.4 million people with electricity with its installed capacity of 5616 MW (Renewable facts, 2012a; Energy BC, 2012)

Canada has a 100 year history of hydropower production, which initially evolved rapidly but then stagnated somewhat due to environmental concerns and costly facilities. The country still only uses about half of its potential hydropower resources, but for environmental reasons, the priority is to firstly refurbish and upgrade existing plants rather than to build new facilities (Energy BC, 2012). However, the prognosis is that the energy consumption is bound to increase in the future (NEB, 2013). When demand is to be met, hydropower has many advantages, not least environmentally: a hydropower plant can convert more than 95% of the water flow into electrical energy, which is a significantly higher efficiency as compared to that of power plants driven by fossil fuels. Moreover, the hydropower is totally renewable by the hydrological cycle driving the water, and the facilities have long life times. For example, DeCew Falls 1 in Ontario was commissioned in 1898 and is still running today, and Beauharnois in Quebec recently celebrated 75 years of service (Canadian Hydropower Association, 2008). Renewable resources are popular with governments for goodwill reasons, but even more so since a system similar to the carbon credits that are traded on the European market is evolving in North America, the so called Cap-and-trade schemes/systems. So far, only California and Quebec have signed up for it, but more regulations of carbon emissions are emerging (NEB, 2013; Garrellek, 2013). All these factors favour the hydropower, and although many of the hydropower plants are more than 50 years old and rely on governmental funding for renovation, new projects also pop up around the country: newly installed plants include the Saint James project (The Grande River, e.g. the Eastmain-1-A-plant, Québec) and plants under construction are e.g. the Romaine project (1550 MW) and Petit Mécantina (1200 MW) in Québec and Muskrat Falls (824 MW) in Labrador. The annual hydropower production is expected to increase from 376 TWh in 2012 to 442 TWh in 2035 (Renewable facts, 2012a; Energy BC, 2012; Hydro-Québec, 2012a; NEB, 2013).

The National Energy Board concludes in their energy market assessment (NEB, 2013) that the electricity consumption will increase with about 1% per year until 2035, and that renewable resources including hydropower are in focus to cover this expansion, seen to both federal and provincial governments priorities.

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*Compared to the Swedish hydropower system with more than 2000 hydropower plants and yet an installed capacity (16 GW) much smaller than the Canadian (75GW), this number looks suspiciously small. However, many of the hydropower plants in Canada are many times larger than the largest hydropower plant in Sweden (Harsrprånget, 830 MW), and several sources agree to the number (authour's note) (Energimyndigheten, 2012; Energy BC, 2012; CDA, 2015; Canadian Hydropower Association, 2008).

Among the provinces in the country, Quebec is the largest in hydropower production. With 146 hydropower plants, 96% of the province's power production stems from hydropower, amounting to about 190 TWh, which corresponds to about 52% of Canada's total hydropower production. The total installed capacity in Quebec is 41 336 MW of which 38 400 MW is hydropower. (Centre for Energy, 2012a; Statistics Canada, 2014b) The government in the province promotes hydropower and has a plan of strategy laid out in which the number one priority is to expand the hydropower with additional 4500 MW (MERN, 2007).

The public company Hydro-Québec stands for a significant part of the energy production in Québec, with its 59 running hydropower plants. Solely their hydropower has an installed capacity of 37 500 MW and a yearly production of 165 TWh (Hydro-Québec, 2012b). The major facilities of Hydro-Québec can be seen in figure 2.3.

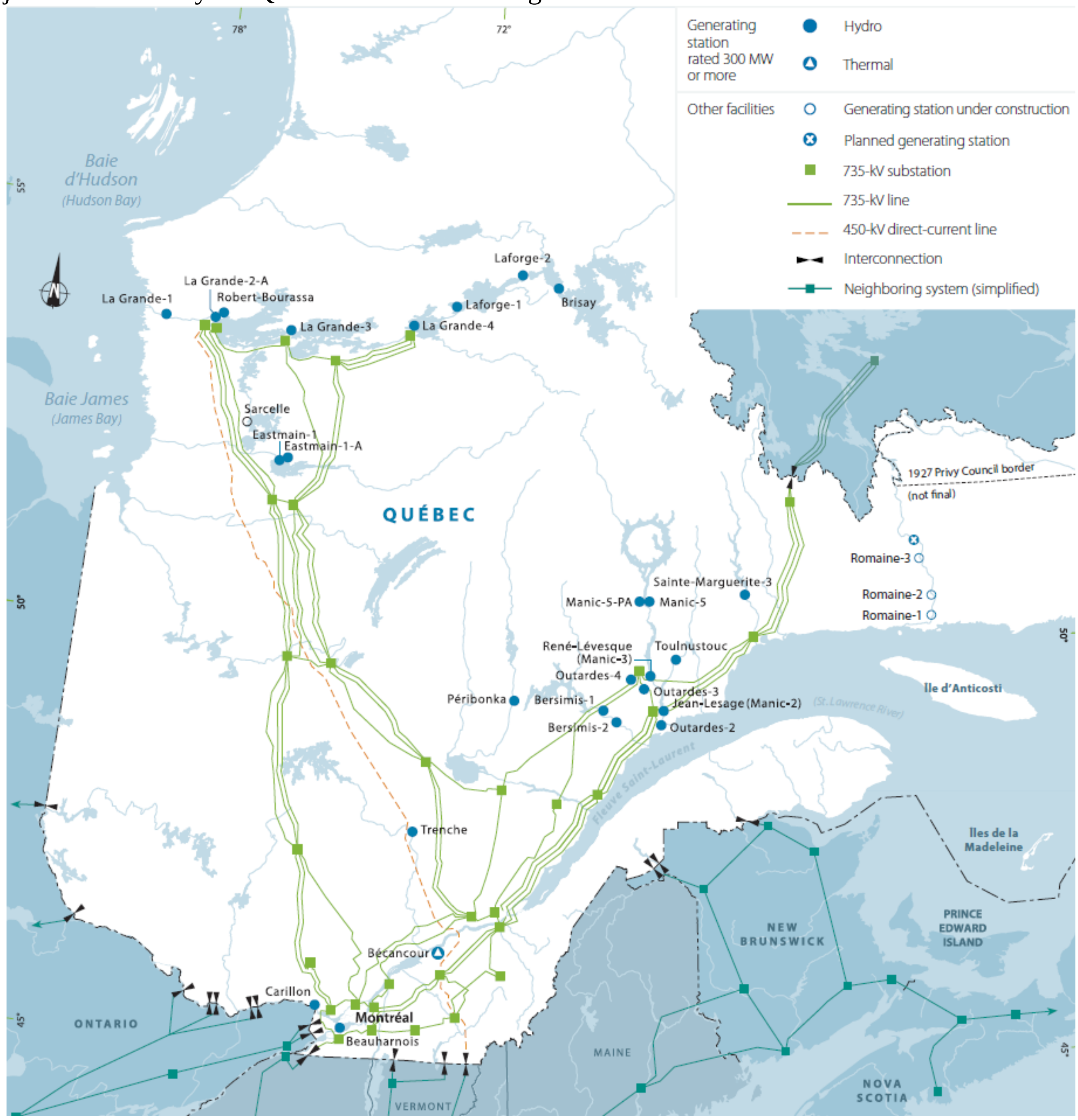


Figure 2.3. Major facilities of Hydro-Québec (Hydro-Québec, 2012a).

Apart from Hydro-Québec, there are lots of private actors (IPPs) on the hydropower market, however only a few with facilities of capacities larger than 100 MW. Those are Rio Tinto Alcan, owner of six large hydropower plants in the region Saguenay – Lac-Saint-Jean; Brookfield Renewable Energy Partners, international actor which owns two large power plants in Québec and also two in Ontario; and lastly Alcoa, which is co-owner to the hydropower plant McCormick (40%, Hydro-Québec 60%).

Ontario is comparably smaller (but still enormous) in energy production, with a total installed capacity of 33 771 MW, of which nuclear power and gas and oil are the major components. The hydropower stands for 24% of the total energy production, with an installed capacity of 8119 MW and an annual production of about 36 TWh (IESO, 2014). The public utility Ontario Power Generation (OPG) stands for a large part of the energy production in the province. The company has a total installed capacity of 16 000 MW and runs 65 hydropower plants. Their hydropower generation was 32.8 TWh in 2013, making them the main player in hydropower production in the province (OPG, 2013a).

Canada's second largest hydropower plant, Churchill Falls (5428 MW), is located in Labrador, northeast of Quebec. The enormous power plant is partly owned by the Newfoundland and Labrador crown corporation Nalcor (65.8%) and the rest is owned by Hydro-Québec. During the construction of Churchill Falls in the late 1960s, Hydro-Québec negotiated through a power contract with Nalcor, which entitles Hydro-Québec to buy almost 90% of the facility's produced energy for a paltry sum. The deal leaps until 2041 (NL Hydro, 2014).

The lower Churchill River, downstream the operating Churchill Falls facility, is evaluated as one of the most attractive undeveloped hydroelectric resources in North America, due to the heavy river flow and large drop in elevation. The area is mentioned as a key component for the province to fulfil a set of strategic goals, including augmenting the fraction of renewable energy. The government of Newfoundland and Labrador, with Nalcor and its subsidiary NL Hydro at the front, has already proceeded to the construction stage of phase 1 in the plans. Those plans include construction of two new hydropower plants and transmission lines, connecting both the new plants and Churchill Falls to the Island of Newfoundland for transmission to the Maritimes and the US markets. The two power plants will have a total installed capacity of 3000 MW and an average annual production of 16.7 TWh. The first one, Muskrat Falls, is already under construction and will be commissioned around 2017, and the construction of Gull Island will start in phase 2 of the plans, see figures 2.4 and 2.5 (Nalcor, 2015a).

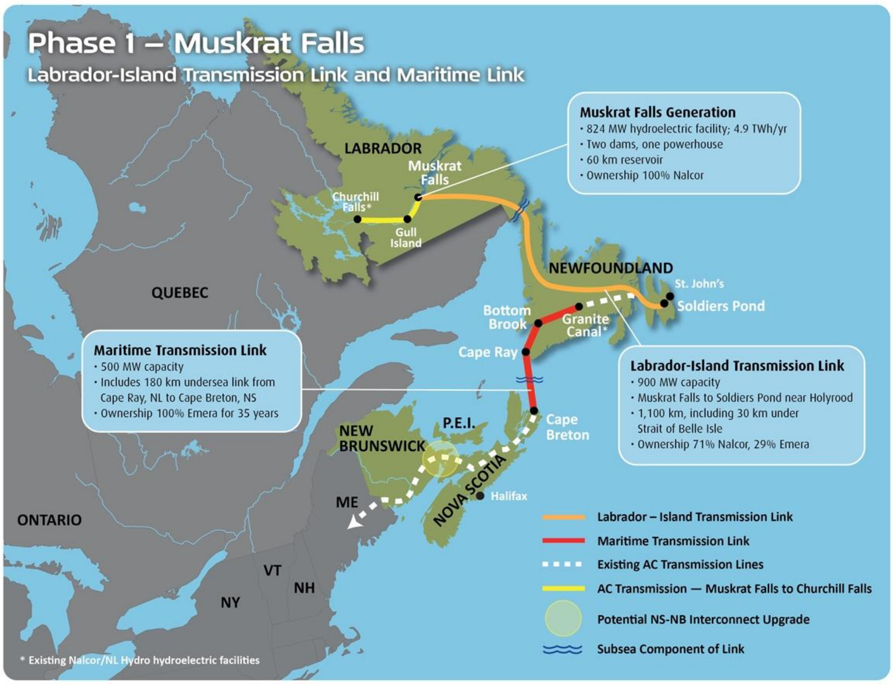


Figure 2.4. Phase 1 in the development plans for Lower Churchill River, including the construction of Muskrat Falls (824 MW and 4.9 TWh/year) and the transmission links to Island of Newfoundland and the Maritime. Construction of Muskrat Falls started in late 2012 and is expected to be completed around 2017 (Nalcor, 2015a).

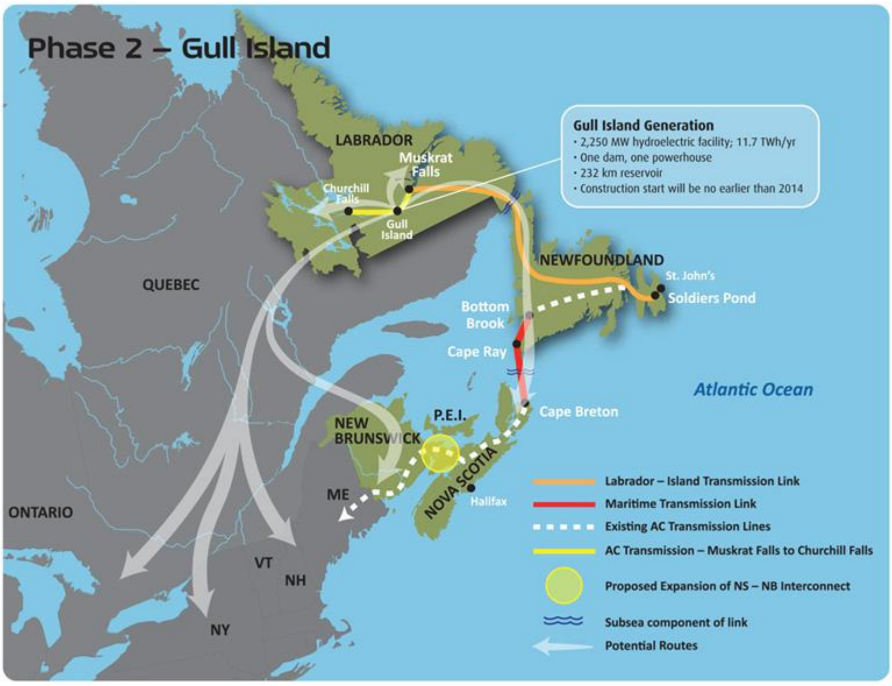


Figure 2.5. Phase 2 in the development plans for Lower Churchill River, with the construction of Gull Island (2250 MW and 11.7 TWh/year) (Nalcor, 2015a).

The electricity system in Newfoundland and Labrador is commonly referred to as two different systems: the Labrador interconnected system, which includes Churchill Falls, and the island interconnected system, on the Island of Newfoundland. The energy market in the province is regulated by the Public Utilities Board, PUB, and the market is dominated by the crown corporation and its subsidiaries. These companies have an installed capacity of 1626 MW of which 939 MW is hydropower (Nalcor, 2015b).

2.2.2. International and interprovincial trade

In North American deregulated markets, where the governments do not have the evident role of coordinating the bulk power system and power grid, regional transmission organizations, RTOs, have been created by the US Federal Energy Regulatory Commission, FERC. Those are mostly associated with the US market, but RTOs are also active to some extent in Canadian provinces: Alberta Electric System Operator (AESO) and Ontario Independent Electricity System Operator (IESO) have responsibility for the transmission and wholesale markets in the two provinces (there is also New Brunswick System Operator to regulate the transmission in New Brunswick, although their electricity market is still regulated) (FERC, 2012). An overview of the RTOs in North America can be seen in figure 2.6. For the Canadian provinces with regulated markets, international and interprovincial trade is possible through licence agreements (see section 2.2).

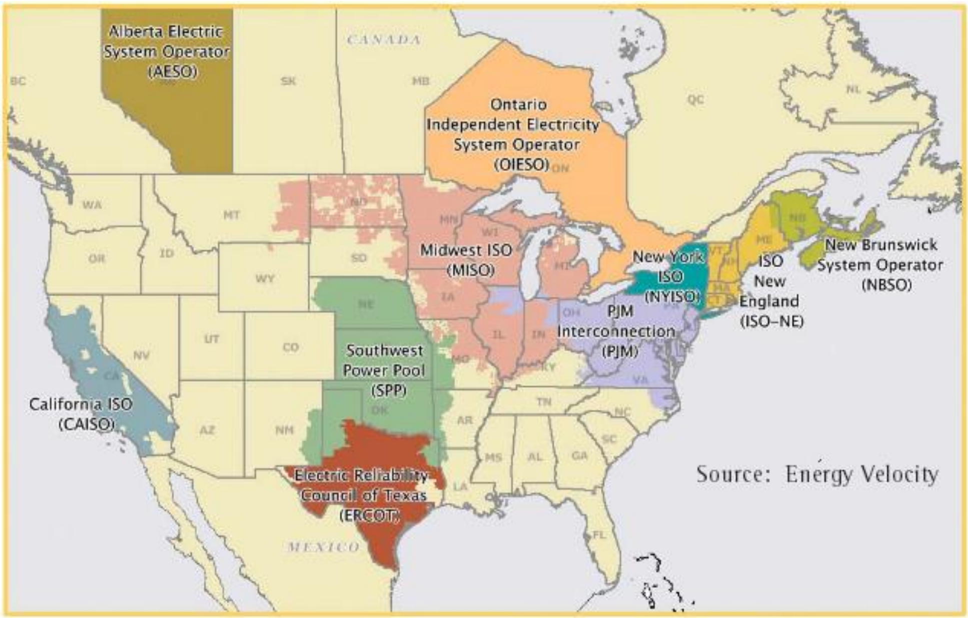


Figure 2.6. Regional Transmission Organizations in North America (FERC, 2012).

Canada is the largest electricity exporter to the US. For 2010 the export was valued to $76.27 billion, out of which the hydropower share amounted to about 2/3 (Energy BC, 2012). There is a clear correlation between high precipitation years (well supplied hydropower reservoirs) and large export of electricity (NEB, 2013). Otherwise, the two general factors that govern the North American energy trading is the rate of exchange between the US and the Canadian dollars, and the gas price. For example, the economic crisis in 2008-2009 caused the gas price to decrease 60% which affected the entire market (Hydro-Québec, 2009).

The Canadian annual export to the US amounts to about 58 TWh, with the export focused on the hydropower-dominated provinces, i.e. from Manitoba and eastern Canada, and the import is about 11 TWh per year (EIA, 2014a). The trading is important to reassure the reliability of the system and keep costs at a fair level. Even though a region might have installed capacity enough to cover its demands, all of the installed capacity is not available at all times. Typically it is profitable to export electricity during off-peak seasons and import during peak seasons. For Canada, peak demand often occurs during winter due to the cold climate, while peak season in the US often occur during summer, due to tourism and air conditioning. Thus the trading between Canada and the US at large matches the changes of seasons (NRCan, 2014). Pineau and Winfield (2014) criticise the provinces' trend to trade with the US rather than among themselves, a phenomenon that is an indication of the above mentioned malfunctions of the Canadian market.

Interprovincial trade of interest in the context of eastern Canada is the agreement between Quebec and Newfoundland and Labrador, which entitles Hydro-Quebec most of the production of Churchill Falls. There is also a fresh deal between Ontario and Quebec to trade 500 MW of electricity during the year: Ontario will supply Quebec during the winter time when Quebec is running low, and vice versa during the summer when Ontario normally has its peak demand (Clean Energy Canada, 2014).

2.2.3. Power consumption and electricity prices

The Canadian climate with cold winters and often warm summers, has in combination with the rich supply of clean and cheap energy, contributed to Canada being the seventh largest electricity consumer in the world in 2008 (CEA, 2013c). In an international perspective, the electricity in Canada is cheap, as can be seen in figure 2.7.

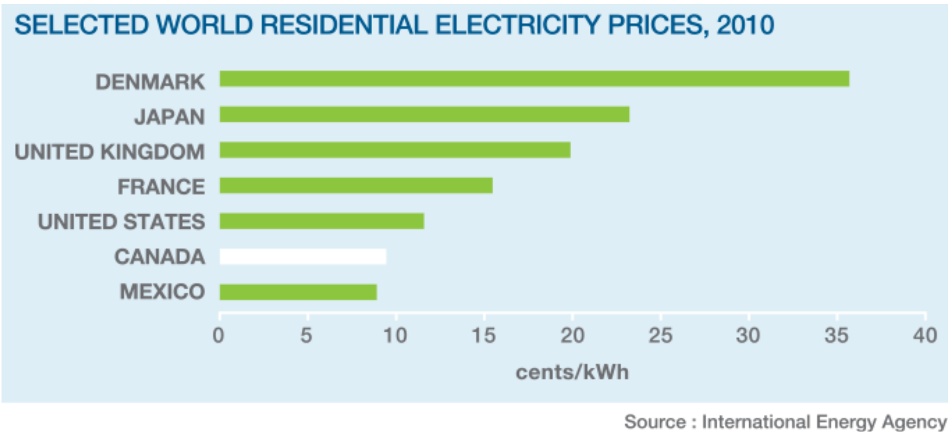


Figure 2.7. Comparison of electricity prices in cents/kWh in 2010 in selected developed countries (CEA, 2013b). Swedish residential prices correspond roughly to the Canadian (Eon charges about 0.90 SEK/kWh, which is about 10 US cents).

The electricity consumption is not constant but varies over the year, between weekdays (working days are different from week-ends) and on an hourly basis. The more or less steady consumption is called the base load and is cheaper to produce since it is easy to predict. More intense periods when the consumption increases drastically are called peak demand. During a day, peak demand is often in the afternoon, and during a year the peak demand is either in the winter or in the summer due to the climate at the location. The larger the peak demand, and the larger the frequency of deviations from the base load, the more expensive is the generation costs. This is due to the fact that power generation costs differently depending on what type of power plant that is run. Hydropower is typically low cost production, and as long as its capacity is sufficient to meet the demands the production costs are low. When the demand increases, more expensive plants, such as coal and gas plants, must be connected, causing both prices and environmental effects to increase (FERC, 2012).

Since electricity cannot be stored in meaningful quantities, the power generation must be able to meet the demands at all times. Figure 2.8 illustrates how the production and generation are interlinked over time. It can be seen from the figure that the demand peaks in January, when the monthly demand is about 55 TWh. The generation peaks with some margin above that number, at about 60 TWh. The baseload oscillates around 40 TWh (Statistics Canada, 2014a).

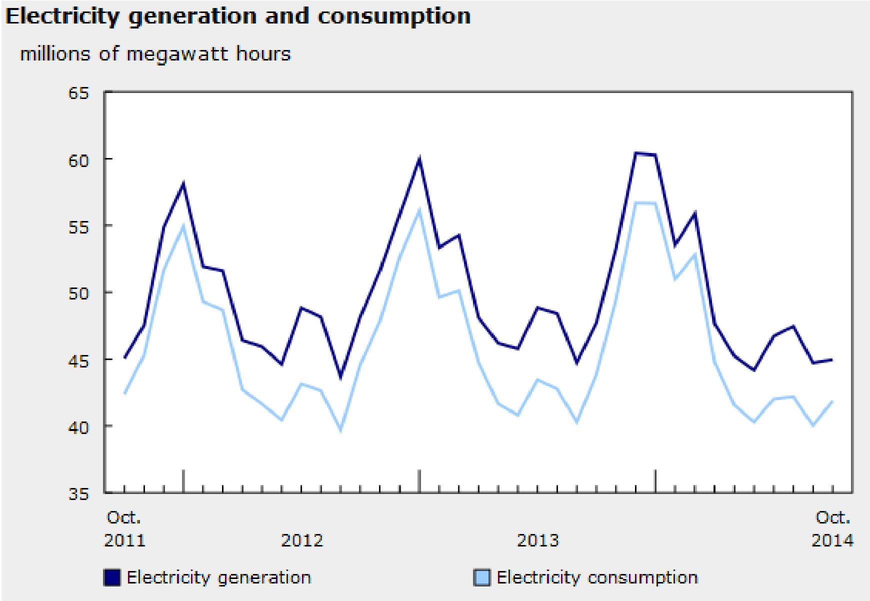


Figure 2.8. Total electricity generation and consumption (TWh) in Canada from October 2011 to October 2014 (Statistics Canada, 2014a).

The electricity consumers, often called the end-use customers, can be divided into four larger categories: the industrial sector (industries), the residential sector (households), the commercial sector (supermarkets, public buildings, etc) and the transport sector (trains) (NEB, 2013). In figure 2.9, the demand for each sector in Canada from 2005 to 2009 is shown. The transport sector is here included in “other” since it is such a small portion of the total electricity consumption. During the period, the demand declined slightly in all of the sectors, mainly because of the economic crisis in 2008. The industrial sector dominates with a demand of about 40% of the total, and the residential and commercial sectors each demand a 30% portion of the total (NRCan, 2014). The industrial sector benefits from lower electricity tariffs than the other sectors, due to the fact that their consumption has few peaks while being rather constant, and that they often can receive electricity through higher voltage distribution lines (FERC, 2012).

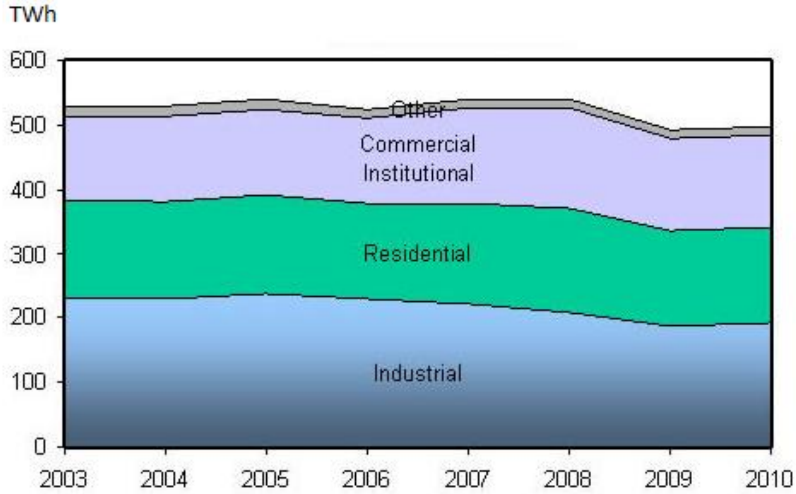


Figure 2.9. Demand for electricity in Canada by sector in 2005-2009. Total demand slightly declines from 538 TWh in 2005 to 503 TWh in 2009. All of the sectors electricity demand decreased during the period. The industrial sector represents about 40% of the demand, and the residential and commercial sectors are tied with each having a demand of about 30% of the total (NRCan, 2014).

The electricity prices vary due to many factors. In competitive markets the price is driven by economical mechanisms such as supply and demand, but in regulated markets the price is often based on production costs (FERC, 2012). The production costs vary due to the conditions in the province. Canadian Electricity Association (CEA, 2013b) summarized these circumstances into four posts:

- Geography: where is the customer located related to the power plant? Longer distances require more transmission lines, which means higher energy losses as well as construction and maintenance costs. Also, the population density matters: high population density diminishes the distribution cost per capita.
- Type of power plants in the energy mix: hydropower is low cost while fossil fuels are more expensive. Provinces with hydropower-dominated energy also have less fluctuating prices since hydropower provides a steady energy source, as compared to fossil fuel-dominated provinces, where the electricity price follows the fuel prices (Pineau, 2013). (For a recap of the energy mixes in the provinces, see figure 2.2 in section 2.2).
- Fixed and variable costs: the variable costs are due to the variation of demand. At peak demand electricity must be generated from more expensive sources.
- Age of the infrastructure: the older the infrastructure, the cheaper the generation. Particularly hydropower plants have long life time which means that lots of their generated power stems from so called heritage assets, for which construction costs have already been paid.

All these factors result in large price variations across Canada. Figure 2.10 depicts the energy consumption per capita along with the revenue per kilo-watt hour, which serves as a proxy for the electricity price, for all the provinces and the national average (Pineau, 2013). It is of interest to note that Quebec has the highest consumption per capita and also among the lowest costs. All of the hydropower-dominated provinces can be found in the low cost-section of the diagram, while the unregulated markets (Alberta and Ontario) have average cost along with the traditional provinces (see also section 2.2 above).

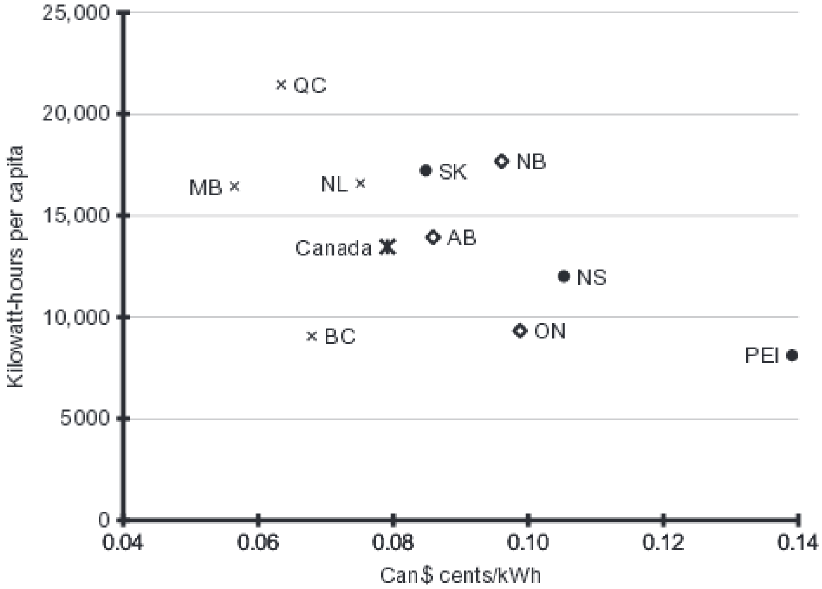


Figure 2.10. Consumption per capita and average revenue per kWh in the respective provinces in Canada in 2009 (by permission of Pineau, 2013).

The stability of the electricity prices can also be concluded to depend on the type of market in the province: in figure 2.11 the monthly power prices for Ontario, Quebec and Newfoundland and Labrador (Statistics Canada, 2015) from January 2009 to august 2014 have been plotted. The numbers are normalized with index 2009 = 100, which means that each monthly price has been divided with the average of 2009 of that province. The figure includes power consumption prices up to 5000 kW. For consumption >5000 kW, the price is slightly different, most often lower than the <5000 kW-price, but it follows largely the very same pattern. To make a more readable figure, those graphs were excluded, but all the data is freely available at the homepage of Statistics Canada. Please note that due to the normalization, the figure cannot be read as a comparison of prices between the provinces, but only illustrates the fluctuations of the price in each respective province.

From the figure the influence of the types of markets on the price becomes strongly visible. The markets in Quebec and Newfoundland and Labrador keep the price static by regulation, while in Ontario there are large variations due to the spot price variations on IESO (see figure 2.6 in section 2.2.2).

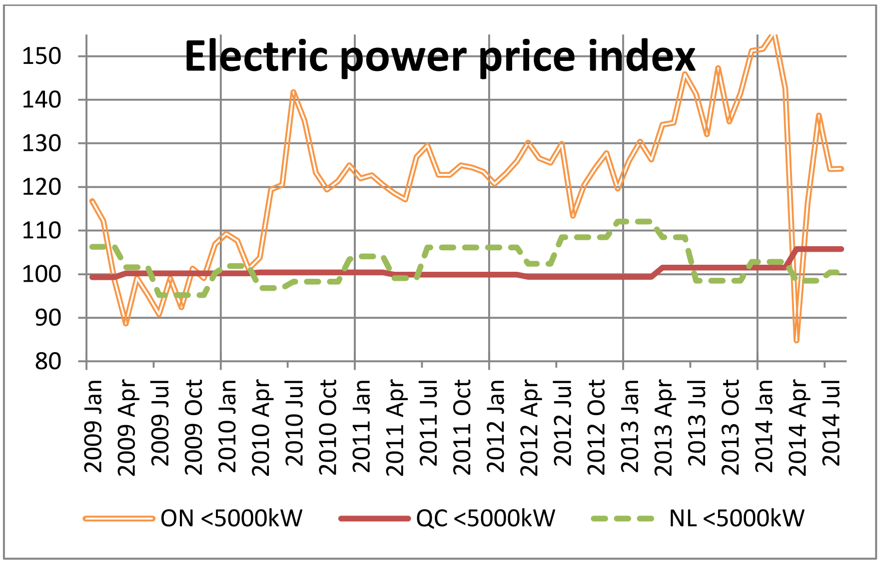


Figure 2.11. Monthly, non-residential electric power price indexes for Newfoundland and Labrador (NL), Quebec (QC) and Ontario (ON) from Jan 2009 to Aug 2014, index 2009 = 100 (Statistics Canada, 2015).

To conclude this energy market section, the key players and the market structures for Quebec, Ontario and Newfoundland and Labrador are summarized in table 2.1 (Pineau 2013, with additives). Acronyms can be found at page xi in the beginning.

Table 2.1. Structures and important actors in the electricity markets in Québec, Newfoundland and Labrador and Ontario (Pineau, 2013). Acronyms can be found at page xi.

Characteristics of energy market	**Restructured**	**Hydropower-dominated**	
Province	**Ontario**	**Quebec**	**Newfoundland and Labrador**
Generation (hydropower only, more actors in other energy sectors)	OPG, IPPs	HQ, IPPs	NL Hydro, IPPs
Total capacity (MW, 2009)	34,276	42,485 (or 47,913 including HQ's contracted fixed price rights over Churchill Falls which transmits to HQ's grid until 2041)	7,054 (or 1,626 excluding Churchill Falls) (Nalcor, 2015b).
Hydropower capacity (MW and percentage of total)	8,119; 24%	37,136 (or 42,564 including Churchill Falls); 90-95% (Centre for Energy, 2012a).	939 MW (Nalcor, 2015b) This number amounts to 57% of the total capacity of the crown corporations. However, hydro generation stands for about 80% if excluding the export from Churchill Falls,

			according to Department of natural resources (NL, 2014), indicating some extensive IPPs in the market.
Transmission	Hydro One, Great Lakes Power, Canadian Niagara Power, Five Nations Energy and Cat Lake Power Utility	HQ TransÉnergie	NL hydro and Newfoundland Power
Distribution	More than 60	HQ Distribution + 9 municipal distribution companies	NL hydro and Newfoundland Power
Ministry responsible	Energy	Natural Resources and Wildlife	Department of Natural Resources
Regulator	Ontario Utilities Board	Régie de l'énergie	Board of Commissioners of Public Utilities
System operator	Independent Electricity System Operator	HQ	NL Hydro and Newfoundland Power
Market design	Power pool for real-time energy market with bilateral contracts, PPAs and regulated tariffs. Start of marked May 1, 2002. Public reference price is Hourly Ontario Energy Price (HOEP)	Centrally managed model with bilateral contracts	
OATT since	-	1997	-

3. Model presentation and collection of secondary data

The Scania-HBV model employed by Thomson Reuters must be supplied with input data in order to be calibrated for the specific area of interest. This input data consist of two sets of time series in daily resolution, namely meteorological data and Q-target data. The meteorological data consist of precipitation and temperature time series for the modelling area, and those time series must be provided for all periods of time that the model is to be run for, i.e. including the simulation once the model has been calibrated. The Q-target data on the other hand, is only needed for calibration and validation of the model. Figure 3.1 gives a schematic overview of the direct and indirect inputs to the model, and the model output, Q_{calc}.

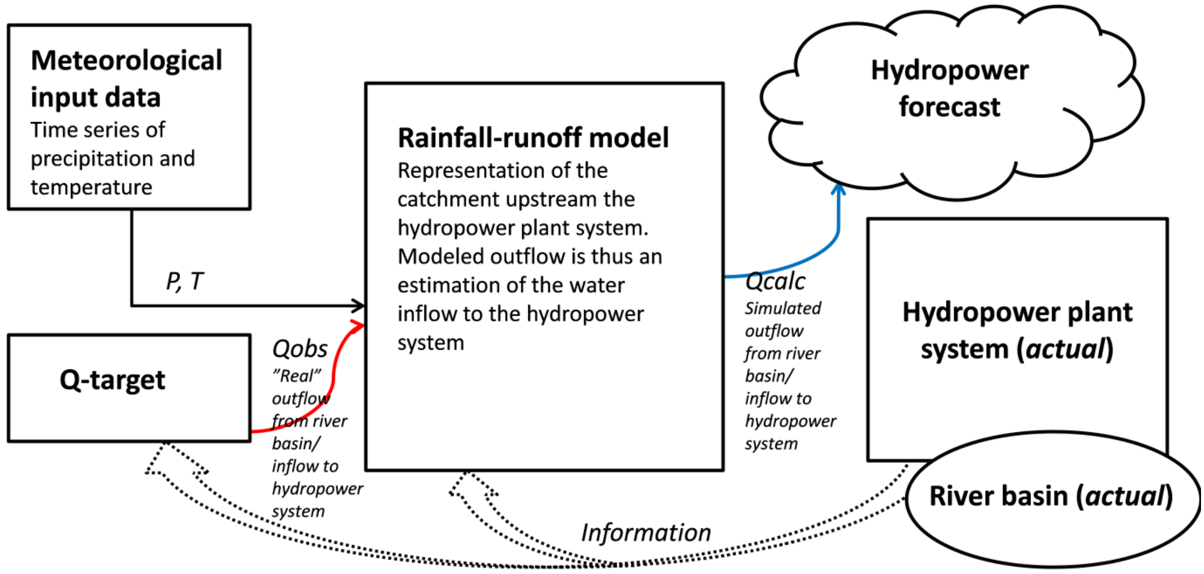


Figure 3.1. Schematic overview of the input data and the role of the model relative to the hydropower plant system. The discharge curve produced by the model represents the inflow to the hydropower system.

The construction of the Q-target and the analysis and processing of the meteorological data are described in chapter 4. This chapter summarizes secondary information of relevace for this project. In the following section, 3.1, a technical background to the Scania-HBV model is given. Section 3.2 presents the information that was collected about the hydropower systems in Quebec, and what information could be achieved for constructing the Q-targets. Lastly, sections 3.3. and 3.4 give an overview of the geological conditions and the climate in Quebec.

3.1. Technical background

The rainfall-runoff model employed by Thomson Reuters is very similar to the HBV-model, which was developed by the Swedish Meteorological and Hydrological Institute (SMHI) in the 1970ies. The first versions of these models were adapted for the Swedish conditions for usage in the Nordic countries, but since then the model has become a standard tool for runoff modelling and various versions have spread all over the world (Bergström, 1992). The version that Thomson Reuters has developed has simplified the area-elevation distribution and all flows and inputs (apart from the temperature) are recalculated into energy units (gigawatt hours) for practical reasons (Söderberg, 2015).

3.1.1. Model explanation

The HBV-model is based on the continuity equation, stating that the difference between inflows and outflows of a system equals the change in storage over time. For a catchment this can be expressed as

$$\frac{d}{dt}(SP + SM + UZ + LZ + Lakes) = P - E - Q \qquad (eq\ 1)$$

where left hand side describes total change in storage over time with

SP = snow pack
SM = soil moisture
UZ = upper groundwater zone
LZ = lower groundwater zone
Lakes = lake volume

and the right hand side describes difference in inflow and outflow with

P = precipitation
E = evaporation
Q = runoff (outflow)

The conceptual model of the storage is a set of boxes, one for each of the storages, with inflows and outflows moderated to simulate the natural mechanisms in that specific box. For clarity, the conceptual model is described by figure 3.2, with each subroutine described below.

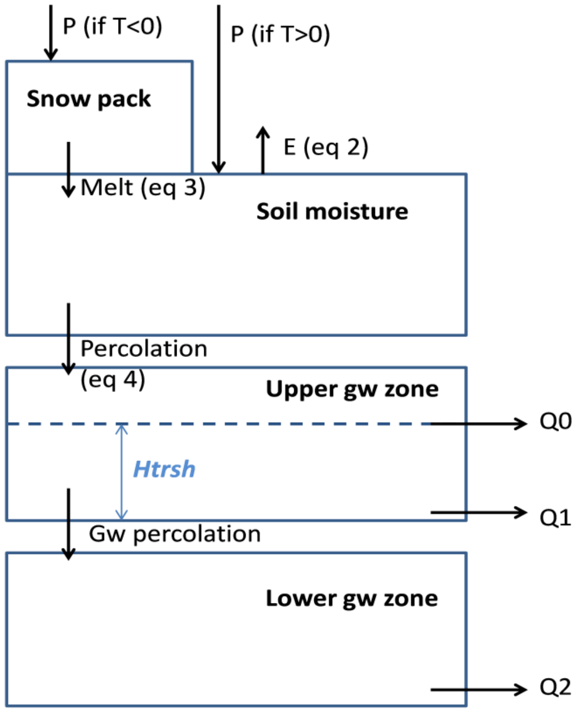


Figure 3.2. Conceptual sketch of the rainfall-runoff box model. The notations in brackets denote transport equations that are described below.

Apart from the temperature data, which are in degrees Celsius, all data and parameters in the model are expressed in energy units (GWh). Partly, this is for making the simulations more compatible with the market analysis tools, but moreover it is a way for the model to cope with the hydropower system that the model is set up to describe. Normally, hydrological parameters and water content are described in terms of millimetres (height of water per unit area), but in a hydropower system the same drop of water will have the ability to generate different amounts of energy depending on where in the system it falls: a drop of water far upstream in the system will pass through numerous hydropower plants and generate a lot more energy compared to a drop of water located downstream in the system. If the data was to be described in conventional units, the model would have to refine many of its mechanisms, e.g. its considerations of changes in elevation in the model area and the properties of each hydropower plant in the system. By expressing the data and parameters in the model readily in energy units, a simpler but still accurate model can be set up (Söderberg, 2015).

The amount of water that evaporates is primarily a function of the temperature, but also of how much water the soil already holds. Naturally, the more water that is available, the more water will evaporate. If the soil is saturated with water, then the evaporation, *e*, will be equal to the theoretical maximum evaporation, or the potential evaporation, *pe*, and otherwise, the evaporation will be proportional to the water content *h* in the soil compared to the amount, h_p, if the soil would be saturated:

$$e = \begin{cases} pe * \dfrac{h}{h_p}; & if\ h < h_p \\ pe & ; if\ h \geq h_p \end{cases} \qquad (eq\ 2)$$

If the temperature, *T*, is below 0^o (or rather a reference temperature T_{ref}), then the precipitation will fall as snow and accumulate in the snow pack. The melting of the snowpack is governed by the degree day method, where melt water is proportional to a snow melting coefficient, C_D, multiplied by the number of degrees that the temperature exceeds a certain reference temperature:

$$melt = C_D * \left(T - T_{ref}\right) \qquad (eq\ 3)$$

Percolation through the soil layer to the upper groundwater zone is highly dependent on the field capacity, *FC*, which encapsulates a set of properties such as hydraulic capacity of the soil, average gradient of the ground, etc, into one single model parameter. The amount of water inflow to the soilbox (i.e. the rain and the snow melt) that infiltrates the upper groundwater storage is thus proportional to the ratio between water content *h* already in the storage and the field capacity, *FC*, to the power of another field parameter *b*, which regulates the rate of the percolation:

$$percolation = inflow\ soil * \left(\frac{h}{FC}\right)^b \qquad (eq\ 4)$$

The porosity of the soil decreases with increasing depth, due to increasing pressure and decreasing biologic activity. Thus the responses of the respective groundwater zones are different due to the differing hydraulic conductivities. This is modelled by making the outflows Q_i proportional to different recession coefficients. The parameter *Htrsh* is a threshold value that activates the quickest outflow, Q_0, at when the model has a high water content (Bengtsson, 1996).

3.1.2. Calibration and validation

The calibration is performed in order to apply the model to a specific catchment area. In the process, the most suitable values of the model parameters are determined through an iterative process by running the model with different parameter values set and quantitatively evaluate the result against the target series. When the model is sufficiently calibrated, validation is performed by running the model with the unused part of the input time series.

A certain period of time is chosen for the calibration period and another period for the validation. For the validation to be reliable it is important that it is not performed with time series that was part of the calibration process, because then it will only tell how well the calibration performed and not how well the model performs in general.

For performing calibration and validation of the model parameters, it is necessary to have a set of meteorological data, with time series of temperature and precipitation, and corresponding time series of observed outflow from the system that can act as target.

Thomson Reuters' rainfall-runoff model is equipped with a set of objective functions that are used for the quantitative evaluation of the the performance of the calibration and validation. The functions adopted in this study for evaluation are presented in table 3.1. The table includes some versions of Nash- Sutcliffe's coefficient of determination, R^2. For good results, the R^2-value should approach 1. If $R^2 = 1$ the simulated values are identical to the target values. A reasonably good model has $R^2>0.7$. $R^2 <0$ indicates that the mean of the observed values is a better estimation than the model performance. The table also includes the accumulated error, which is the difference between observed and simulated outflow volumes. The accumulated error should be close to zero and if its graph is plotted over time, oscillation around zero indicates a well balanced model. If the graph on the other hand has an increasing trend it points to that too much water is put into the model, and vice versa with a decreasing trend.

Table 3.1. Objective functions for quantitative evaluation of the model performance

Name	Notation	Formula
Nash-Sutcliffe, daily inflow	R^2	$1-\frac{\sum(Q_{obs}-Q_{calc})^2}{\sum(Q_{obs}-Q_{obs,mean})^2}$
Nash-Sutcliffe, weekly inflow	R^2w	$1-\frac{\sum(Q_{obs,w}-Q_{calc,w})^2}{\sum(Q_{obs,w}-Q_{obs,mean})^2}$
Nash-Sutcliffe, monthly inflow	R^2m	$1-\frac{\sum(Q_{obs,m}-Q_{calc,m})^2}{\sum(Q_{obs,m}-Q_{obs,mean})^2}$
Accumulated error	Accdiff	$\sum(Q_{obs}-Q_{calc})$

The next section gives an overview of the information that was collected regarding the hydropower systems in eastern Canada, and what regions determined to be set up as models.

3.2. Hydropower data collection

Hydropower is a renewable resource that converts the movement of water through the hydrological cycle to electrical energy. The water is moved through the hydrological cycle by the sun and the gravitational force, and this energy is extracted by letting the water flow rotate the blades of the turbines in the hydropower plants. Hydropower is a very effective way to generate electricity: often the efficiency is up to 95%, to compare with many conventional fossil fuel plants that have an efficiency of about 30% (Canadian Hydropower Association, 2008).

There are a few different types of hydropower plants. A so-called run-of-river plant requires no modification of the river flow, but simply makes the turbine rotate by letting the water flow through the plant. Run-of-river plants are often smaller generating stations, and the electricity that they produce is directly proportional to the current flow in the river. Another common type of hydropower plants are storage, or reservoir, plants, which dam the water of the river. The larger the difference in water level between upstream and downstream the spillway of the reservoir, the more electricity can be produced. The generation in a reservoir plant can be regulated by storing the water in the dam. This storing capacity is a unique feature among energy sources, and since reservoir plants often are larger hydropower plants, their energy contribution provides reliability for the whole energy system. Lastly, there are the so called pumped storage plants, a less common type of hydropower station with a pump that can use its own hydro energy to pump the water back upstream during peak production and store it until demand rises (Canadian Hydropower Association, 2008).

The first step in this study was to collect information about the hydropower plants in eastern Canada, with the task set initially to focus on Quebec and Ontario. Those provinces are rich in energy production, but seen only to the hydropower, Ontario is comparably smaller than Quebec. When establishing this much, Ontario was excluded from further investigations in this study. However, connected to the Quebec transmission network is the second largest hydropower plant in all of Canada, Churchill Falls. Although located in the province Newfoundland and Labrador, it contributes with almost all of its production to Hydro-Québec's production, thus the Labrador region was also included in the study.

All hydropower plants with an installed capacity larger than 100 MW were listed and plotted in Google Earth, as shown in figure 3.3. As can be seen from the plot, the hydropower complexes in Quebec are clustered in a few marked out regions, their divisions loosely based on where the Hydro-Québec transmission lines have bottlenecks that put limits to the operations and thus create interfaces between the systems (NPCC, 2014). Table 3.2 presents the number of hydropower plants and the total installed capacity for each region.

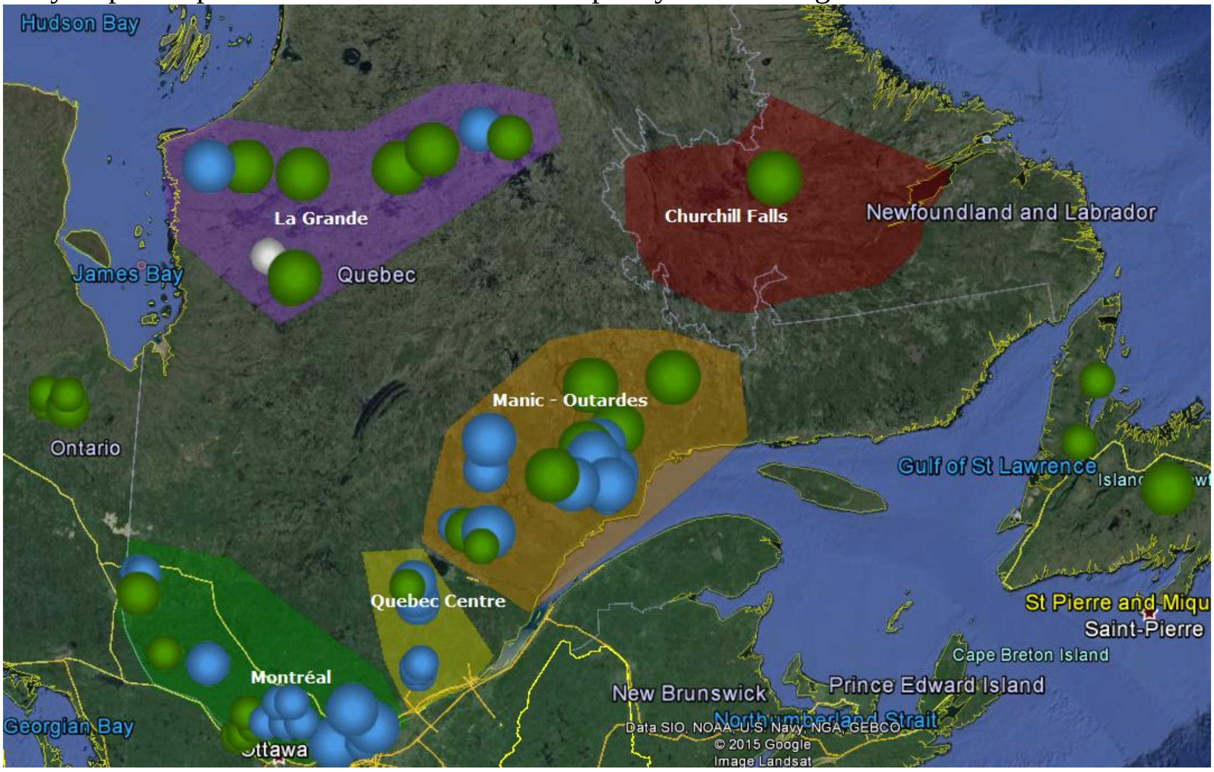


Figure 3.3. Plot in Google Earth of operational hydropower plants with an installed capacity of more than 100 MW. The complexes in Quebec are marked out and named, as well as Churchill Falls complex in Labrador. The size of the spheres that represents the hydropower plants is proportional to the installed capacity of the plants. Plants of reservoir type are plotted as blue spheres, and run-of-river plants are green. The white sphere in La Grande (the hydropower plant Sarcelle) is of unknown type.

Table 3.2. Number of operational hydropower plants with an installed capacity larger than 100 MW in Quebec. Churchill Falls in Newfoundland and Labrador is included since it is connected to the Hydro-Québec transmission network. Both publicly and privately owned facilities are included.

Name of complex	Number of plants	Installed capacity	Percentage of total
La Grande Rivière	11	17 418 MW	40%
Churchill Falls	1	5428 MW	13%
Manic-Outardes	20	14 329 MW	33%
Montréal	11	4191 MW	10%
Québec centre	8	1825 MW	4%
Total number of plants: 51		**Total installed capacity: 43 191 MW**	

To calibrate a Scania-HBV model for all of Quebec would not be optimal since the region is very large and heterogeneous in its production, climate and hydrological cycle. Besides, in this case it was not possible since information was lacking to construct a satisfactory Q-target series for calibration of the model. The regions chosen as models were Churchill Falls in Newfoundland and Labrador and La Grande complex in Nord-du-Québec. This choice of modelling regions was based on two factors: the installed capacity and production of the hydropower systems established in each basin, and the amount of information that could be found for these systems.

Energy inflow on annual basis was found for the Churchill Falls plant, for the years 1943 to 1996 (Bolgov et al, 2012), and thus the Churchill Falls model could be distinguished and modelled on its own.

Energy inflow data on annual basis, from 1943 to 2003, for all of Hydro-Quebec's facilities had been made available in a publication by request of Régie de l'Énergie (Hydro-Québec, 2004), and this could be used to construct the Q-target series for La Grande model. The estimation La Grande's part in the total system was made based on a pamphlet from Hydro-Québec, for want of more detailed information (Silver and Roy, 2010).

To refine the series into daily resolution, the data sets were combined with river discharge data from hydrometric stations in the region. Hydrometric stations are plentiful in all of Canada, and their data sets are freely available through the Internet (Wateroffice, 2015), although it is important to only use data from unregulated stations when building the Q-target. Else, if the hydrometric station is located in a river with reservoir hydropower plants, the discharge data will only show the regulation pattern. It is the natural flow in the catchment that is interesting to depict in the Q-target.

Information on the hydropower generation in every province is available in monthly resolution from Statistics Canada (2014). Generation corresponds to the outflow of the hydropower system, and can be used to build a Q-target, i.e. inflow to the system, if the changes in storage over time are known. Since no information on the reservoir levels or regulations in Quebec could be found, this information could not be used to build the Q-target. The generation data is however included in the analysis of the simulated results from the models, together with information on the electricity export (NEB, 2015), see section 5.3.

The next section, 3.3, presents the geographical conditions for Quebec in general. Note that a little extra focus on the modelling areas is also presented as respective introduction in the sections of the next chapter, 4.1 and 4.2, were the input data for each of the models also are further described and discussed.

3.3. Geography of Quebec

Canada is by geographical size the second largest country in the world, with an area of almost 10 million km^2. In 2006 the population amounted to almost 32 million people, with most inhabitants concentrated to the southern parts of Quebec and Ontario, where the capitol Ottawa is located, and southern central Canada. Vast areas of the geographically enormous country are scarcely populated (NRCan, 2010d).

Quebec is the largest province by area with its 1 542 000 km^2 (Sweden is 450 000 km^2) and the second most populated, with its 7.9 million inhabitants, most living in the southern areas around the cities Montréal and Québec City. Canada has more surface water than any other country in the world, and Quebec has even more lakes and rivers than the national average, water covering 12% of the province's surface. Among the largest rivers are La Grande Rivière in the north, with a string of enormous hydropower plants along it, and the Saint Lawrence river that runs from Montréal and Quebec City out to the Atlantic Ocean via the world's largest estuary. Northern Quebec is taiga, i.e. coniferous forest. The boreal shield covers the mid and south of Quebec, characterized by mixed forests, mostly spruce and pine (Environment Canada, 2013; National Geographic, 2015; Landguiden 2013; NRCan, 2010).

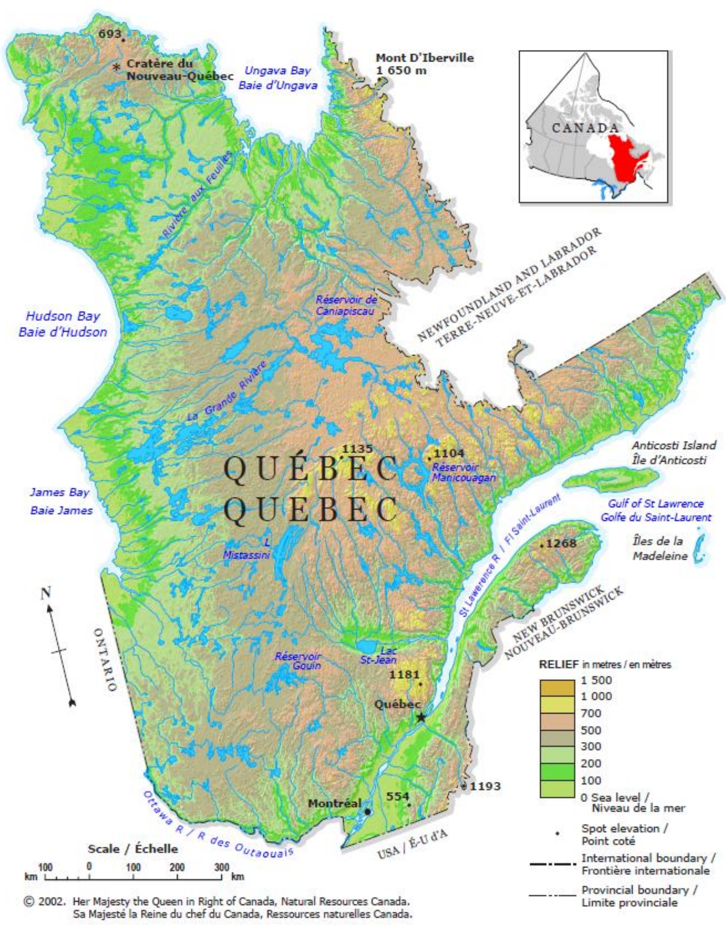


Figure 3.4 Hydrological and topographical map of Quebec. La Grande Rivière is found to the northwest, discharging into James Bay. Churchill Falls is situated in the blank area labeled Newfoundland and Labrador (NRCan, 2002)

Figure 3.4 illustrates the topography variations along with the larger lakes and rivers. The Canadian Shield is the bedrock fundament of the continent and covers almost half of Canada's surface. It is made up of Precambrian rock with undulating hills and valleys and an average elevation about 300 meters above sea level. The bedrock is mostly magmatic and rich in various metals, which explains the rich mining industry in Canada. In south east of Quebec, the Shield bounds with the St Lawrence platform, which is overlain by geologically younger material (NRCan, 2010a). On top of the bedrock the soil layer is made up of glacial deposits, very much like in Scandinavia. The surficial material map from Natural Resources Canada (2010b) shows that most regions are covered by till with eskers that have formed where the melt water made tunnels in the ice (in large parallel to the rivers). Till has low hydraulic conductivity, while the eskers, which have more assorted and larger grain sizes and thus higher porosity have higher hydraulic conductivity and are groundwater aquifers (Svensson, 2010).

Newfoundland and Labrador is the neighbouring province located to the northeast of Quebec, split in two parts by the mouth of Saint Lawrence estuary. The northernmost part of the province is the Labrador region, in which Churchill Falls, the second largest hydropower plant in all of Canada, is situated. Labrador covers the majority of the province’s total area of 405 000 km^2, while the island of Newfoundland hosts more than 90% of its population of 530 000 (Newfoundland Labrador tourism, 2015; Statistics Canada, 2014c).

3.4. Climate

Mean annual precipitation is 800-1200 mm in most parts of Quebec and Labrador, with the exception of the north western parts which have somewhat less precipitation. The average maximum snow depth is 1-2 meters in the regions around Manicouagan and Churchill Falls, while the area around Lac Saint-Jean has 50-100 cm (NRCan, 2010f). Lake evaporation in north east of Quebec is about 350 mm annually, most of which occurs during the four summer months (Environment Canada, 2015).

Overall Quebec has cold and snowy winters and mild summers, similar to the Scandinavian climate. Since the province is very large, the climate varies however, especially in north-south direction, but also with the distance to the nearest ocean. An overview of the annual temperature and precipitation can be seen in figures 3.5-7. Figure 3.5 is a calculated average of the climate normals from a set of stations at representative locations around Quebec, while figures 3.6-7 are direct illustrations of measuring data from stations in the two modelling regions. A summary on annual basis is presented in table 3.3.

Both the modelling areas are located to the north, and it can be concluded from the climate normal data that they are colder than the mean in Quebec, although Churchill Falls, which is located fairly close to the Atlantic ocean, is milder and with more precipitation than La Grande, which has vast areas of land around it with the relatively small and cold Hudson Bay as closest ocean. The precipitation pattern also differs a bit in La Grande region, with the larger rains concentrated a few weeks later as compared to the rest of Quebec.

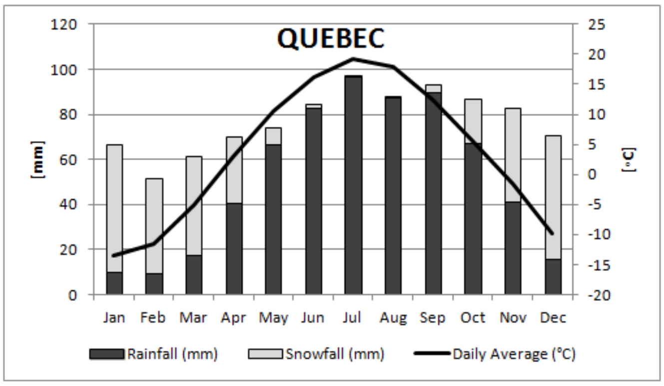


Figure 3.5. This figure represents an average temperature and precipitation in the whole province of Quebec. The figure was produced by taking the average from the climate normals 1981-2010 from a number of selected stations evenly spread over the province (inland, coast, north and south). Total annual precipitation is about 900 mm (Environment Canada, 2015).

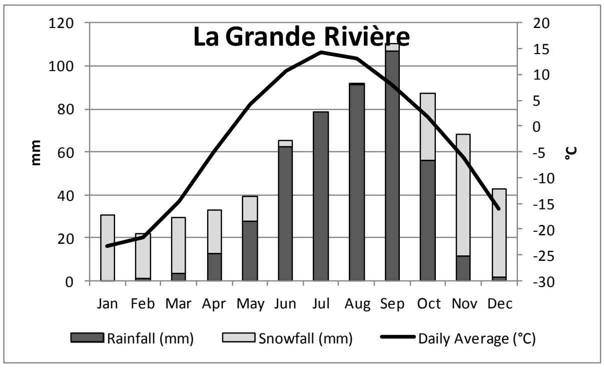


Figure 3.6. Climate normals 1981-2010 for La Grande Rivière A at 53.38 N, -77.42 (Environment Canada, 2015).

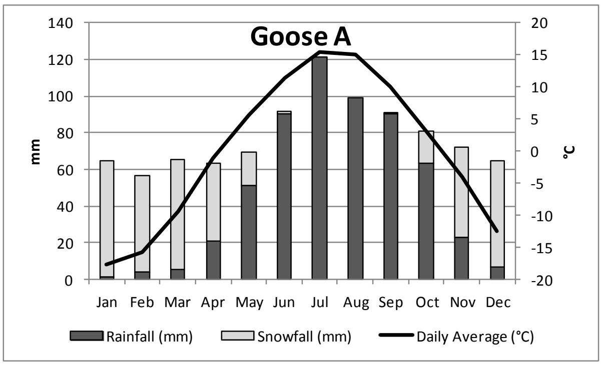


Figure 3.7. Climate normals 1981-2010 for Goose A at 53.32 N, -60.42, near the mouth of Churchill River (Environment Canada, 2015).

Table 3.3. Total annual precipitation and mean annual temperature for the Quebec average case, and at the stations La Grande Rivière A and Goose A.

	Quebec average	**La Grande Rivière**	**Churchill Falls at Goose A**
Total precipitation	926 mm	700 mm	940 mm
Snowfall	300 mm	243 mm	364 mm
Temperature	3.6 °C	-3 °C	0 °C

The meteorological input data used in the Scania-HBV model were data sets from National Oceanic and Atmospheric Administration, NOAA, provided by Thomson Reuters. The precipitation series were regression data produced from historical observations by the Climate Prediction Center (CPC), and the temperature series were reanalysis data from a meteorological model (CFSR) (Söderberg, 2015).

The CPCp and CFSR sets are tied to a polygon grid that covers the total surface of the Earth, each polygon with a resolution of 1 degree, equivalent to 61.3 km in latitudinal direction (west-east) and 110.2 km in longitudinal direction (north-south). NOAA collects information from meteorological stations situated around the world, and extrapolates the data so that the user can select polygons in any location on the planet and get information about the meteorological conditions at the site. It should however be noted that this data are not true observations but modelled results (Söderberg, 2015).

4. Input data to the models

4.1. Churchill Falls basin

Churchill Falls basin is located in the Labrador part of Newfoundland and Labrador, the neighbouring province to the northeast of Quebec. Churchill River runs from the Labrador Plateua, 856 km in eastward direction through a deep glacial gorge, and drains through Lake Melville at Happy Valley and Goose Bay into the Atlantic Ocean. The catchment area of the river is 79 800 km^2 and the average river flow 1620 m^3/s. The heavy river flow combined with the steep sloge give the river an enormous hydropower potential, although the remote location of the basin for a long time posed difficulties for the construction of hydropower plants in the region. It was not until 1969, when a deal had been made between the governments of Newfoundland and Quebec, that the construction of the Churchill Falls reservoir and powerhouse was initialized. The deal proclaims connection with Churchill Falls to Hydro-Québec's transmission network, and in exchange Hydro-Québec is entitled to buy 90% of the generated power, for a price corresponding to less than 5% of the commercial value. The deal leaps until 2041 and is a source of controversy between the two provinces, and the government of Newfoundland and Labrador claims that it is due to Quebec's unwillingness to cooperate that the hydropower potential of Churchill River is still not more exploited. However, in 2012, Newfoundland and Labrador proceeded with the plans to develop the lower parts of the river. Two new hydropower plants will be built, with a total installed capacity of about 3000 MW, and new transmission lines, connecting Labrador to the system of Island of Newfoundland, will be installed (see also section 2.2.1). The existing (upper) Churchill Falls was commissioned in 1971. When constructing the hydropower complex, Michikamau, Lobstick and hundreds of other small lakes in the area, were absorbed into the hydropower dam, renamed to Smallwood reservoir after the first premier in Newfoundland (although Google Earth still labels the area as Michikamau Lake). The reservoir has a capacity of 28 billion m^3 and is the tenth-largest lake in Canada (Marsh, 2006; NL Hydro, 2014; Matthews and Barron, 2010; MacCallum, 2006).

Figure 4.1 is a map over the Labrador region with the locations of the hydropower plant and the hydrometric stations that were used for construction of the Q-target, see section 4.1.2, and table 4.1 provides complementary information.

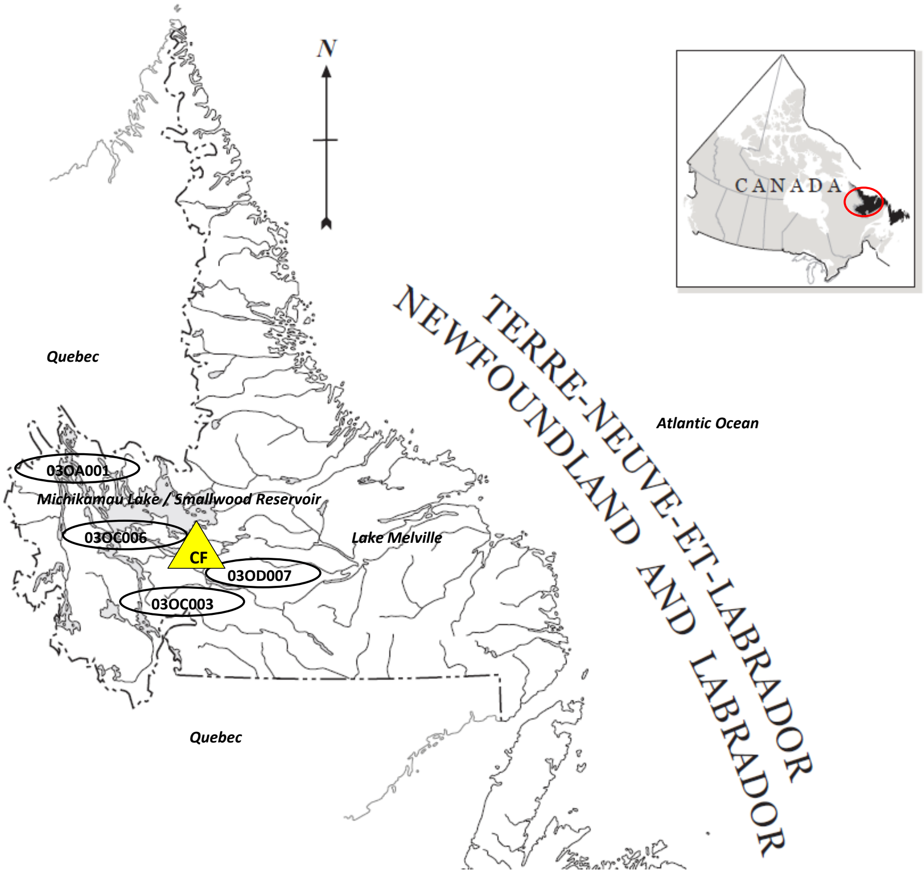


Figure 4.1. Map of the Churchill Falls basin in Labrador. The triangle marked CF is the hydropower plant (more information in table 4.1 below), and the ovals are some of the hydrometric stations in the area. The northernmost, 03OA001, was the one used in the regression analysis. Churchill River flows in a pendulum motion like form from Smallwood reservoir to Lake Melville and the Atlantic Ocean (Raw map from NRCan, 2012).

Table 4.1. Installed capacity and commissioning year for the hydropower plant in the Churchill Falls basin.

Map notation	Name	Installed capacity	Commissioning year
CF	Churchill Falls	5428 MW	1971

4.1.1. Meteorological input data

The temperature and precipitation data for the Churchill Falls model was received from CFSR and CPCp as described in section 3.4. Four polygons in the basin were selected as weather stations, and their data analyzed for calibration of the model. The analysis was made by plotting the data various ways, e.g. comparing the monthly averages of precipitation and the amount of precipitation over the years, to match the amount of water in the model at specific times. Most weight was put on the polygons west and southwest, i.e. upstream, of the power house.

4.1.2. Construction of energy inflow target data, Qobs

The Q-target for the Churchill Falls model was constructed using data for the energy inflow to the power house reservoir on annual basis (Bolgov et al, 2012), combined with discharge data in daily resolution from the unregulated hydrometric station 03OA001 north of Michikamau Lake.

Firstly, the hydrometric discharge data points were summed on annual basis, and then linear regression was made using the annual hydrometric sums as input and the annual energy inflow series as target.

$$CF\ regression\ series = coeffCF * hydrometric\ data_{annual\ sum} \qquad (eq\ 5)$$

CF regression series is the new data set that describes the energy inflow to the Churchill Falls reservoir on annual basis.The coefficient, *coeffCF*, is a number that is multiplied with each of the hydrometric annual sums in order to get as close as possible to the value of the matching energy inflow data point. The plot of *CF regression series* and the energy inflow series can be seen in figure 4.2. A quantitative evaluation between the energy inflow series and *CF regression series* gave a Nash-Sutcliffe, R^2, of 0.89, which indicates a good result of the regression. Thus the coefficient achieved from the regression analysis was used to convert the hydrometric daily discharge points (m^3/s) into daily energy inflow (TWh):

$$Q_{obs,daily} = coeffCF * hydrometric\ data_{daily} \qquad (eq\ 6)$$

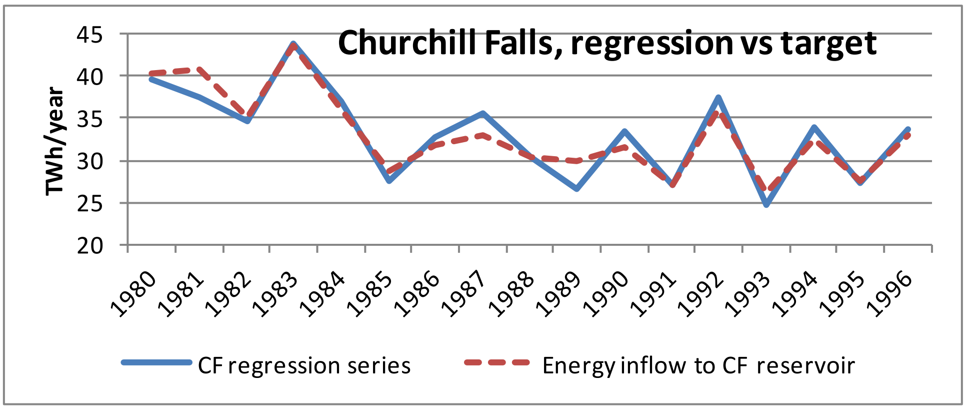


Figure 4.2. Evaluation of the Churchill Falls regression analysis. The quantitative evaluation between the two graphs gave an R2 of 0.89.

4.1.3. Data quality analysis

A Nash-Sutcliffe of 0.89 points to that the regression series is a very good match to the targeted energy inflow to the Churchill Falls reservoir. In figure 4.2 the fit of the regression series to the given energy inflow to the Churchill Falls reservoir is shown, visualizing that the largest deviations between the regression series and the target are in 1981, 1987 and 1989. The deviations for these years are 7-13%.

In this process it is assumed that the regression coefficient, *coeffCF*, derived on annual basis, is representative also on the daily basis, i.e. that the relation between the water flow in the hydrometric station and the energy inflow to the reservoir is constant also from day to day, not only from year to year. The daily variations in the discharge at the hydrometric station follow a natural flow pattern for the climate in the region, and those are the variations which are interesting to refine the energy inflow series with. The regression coefficient transfers those variations to the constructed $Q_{obs,daily}$ series, although there is no way to tell whether the inflow to the reservoir follows the same pattern as the discharge station.

Only one hydrometric station was used when constructing the Q-target series for Churchill Falls, which is not optimal. To begin with, station 03OA001 is located some distance from the Churchill Falls reservoir, upstream Michikamau Lake, at higher altitudes and with slightly different weather conditions. The discharge dynamics at 03OA001 will most certainly differ from the dynamics in the reservoir, but exactly in what manner they will differ is not possible to evaluate and account for. Moreover, if there are errors in the hydrometric data set, those errors will be directly transferred into the constructed Q-target series.

For these reasons the aim was to use more of the unregulated hydrometric stations in the vicinity of Churchill Falls in the regression analysis, some of which are marked out on the map in figure 4.1. However, most of the stations had no discharge series in the relevant time period, i.e. in the years 1980-1996, and could thus not be used in the regression. Only one other unregulated station in the area, 03OC006, had data for the relevant period, and this station was initially included in the regression, which then presented the result according to the following formula:

$$Reg\ series = coeff1 * 03OA001_{annual\ sum} + \ coeff2 * 03OC006_{annual\ sum} \qquad (eq\ 7)$$

This result gave a somewhat higher R^2 on the annual basis, but the shape of the hydrograph got an unnatural appearance on daily basis. The plot of the monthly averages of the three series can be seen in figure 4.3, and shows an abnormal mini-peak in February-March for station 03OC006, which has been transferred to the constructed series. This peak turned out to be impossible to simulate in the Scania-HBV. Analysis of the CPCp and CFSR data made it clear why: for all the weather polygons in the area the temperature was far below 0^{o}C, so there could not be any natural snow melt and all precipitation would accumulate as snow. A possible explanation to the behaviour of the 03OC006-hydrograph is that it is close enough to the Churchill Falls reservoir to be affected by the reservoir regulations. Normally, a hydropower reservoir will be emptied during these weeks before the spring flood, to sell off as much energy as possible before the storage will be refilled. In Quebec the peak demand also occurs around this time, which means further depletion of the energy reservoirs.

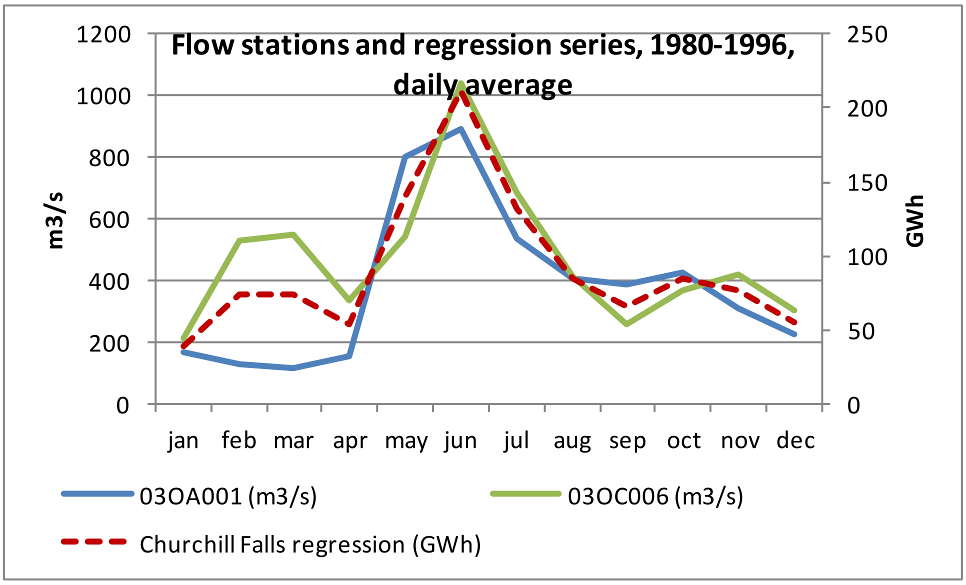


Figure 4.3. Plot of the daily average on monthly basis for 1980-1996, for the constructed series (legend Churchill_Falls) and the two hydrometric stations. 03OC006 has an abnormal small peak in February-March which is transferred to the constructed series.

To verify what the normal hydrograph in the region would look like, comparisons were made with discharge data from other unregulated hydrometric stations in the area situated at tributaries to Churchill River, namely 03OC003 (southeast of the powerhouse) and 03OD007 (southwest of the powerhouse). These could not be used in the regression analysis since they had too many gaps in their data sets in the years 1980-1996, but all the four stations had data for 1999-2010, and those data sets could be compared to see the natural flow pattern in the region. From figure 4.4, showing the average hydrographs for the stations, it can be concluded that 03OC006 shows an unnormal pattern as compared to the others, even though the other stations are further apart from each other (see figure 4.1). It can also be seen that the timing of the spring flood and the autumn rains is rather alike for 03OA001 and the tributaries, which strengthens the argument of using this station for building the Churchill Falls Q-target.

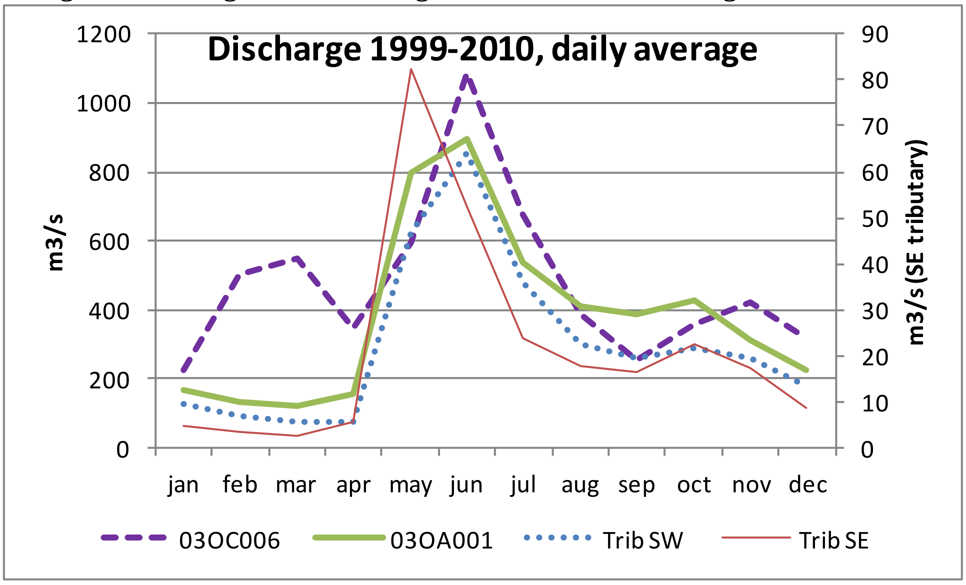


Figure 4.4. Comparison of the discharge data from the four hydrometric stations in the Churchull Falls basin.

The first run with the Scania-HBV model also gives an indication of the validity of the Q-target. When running the model with default parameters with the Q-target series produced from both the stations 03OA001 and 03OC006, the R^2 was around -70. When reconstructing the Q-target, only including 03OA001, the default run gave an R^2 around 0.60, which indicates that the new Q-target was reasonable. From there, the Churchill Falls model was calibrated to perfect the match, the results are shown in section 5.1.

4.2. La Grande Rivière basin

La Grande Rivière is one of the largest rivers in eastern Canada. Located in the taiga in the region Nord-du-Québec, the catchment area of the river covers 97 600 km^2. The river flows in westward direction, 800 km in length and dropping 376 m in elevation before it drains into James Bay. Just as the rest of these parts of Canada, the landscape is rich in surface water with thousands of glacial lakes and rivers, and many of these watercourses were greatly affected by the construction of the hydropower plants along La Grande Rivière, which commenced with phase 1 of the James Bay project in the early 1970s. The rivers Eastmain, Opinaca and Caniapiscau were diverted to dam the reservoirs of La Grande, increasing its average flow from 1700 to 3300 m^3/s, and the flow in Eastmain was reduced by 90% downstream the diversion in the process. The regulations of La Grande Rivière started in 1978 with filling up the dams, and the first hydropower plant, Robert-Bourassa, was commissioned the year after. The map in figure 4.5 shows the locations of the hydropower plants and some of the hydrometric stations in the area, and table 4.2 lists the hydropower plants in the order that they were commissioned along La Grande Rivière and Eastmain. Phase 2 of the James Bay project includes plans to dam and exploit La Grande Rivière de la Baleine north of La Grande, but these plans are put on hold for an indefinite period of time due to environmental and socioeconomic concerns (Hernández-Henríquez et al, 2010; Marsh, 2011).

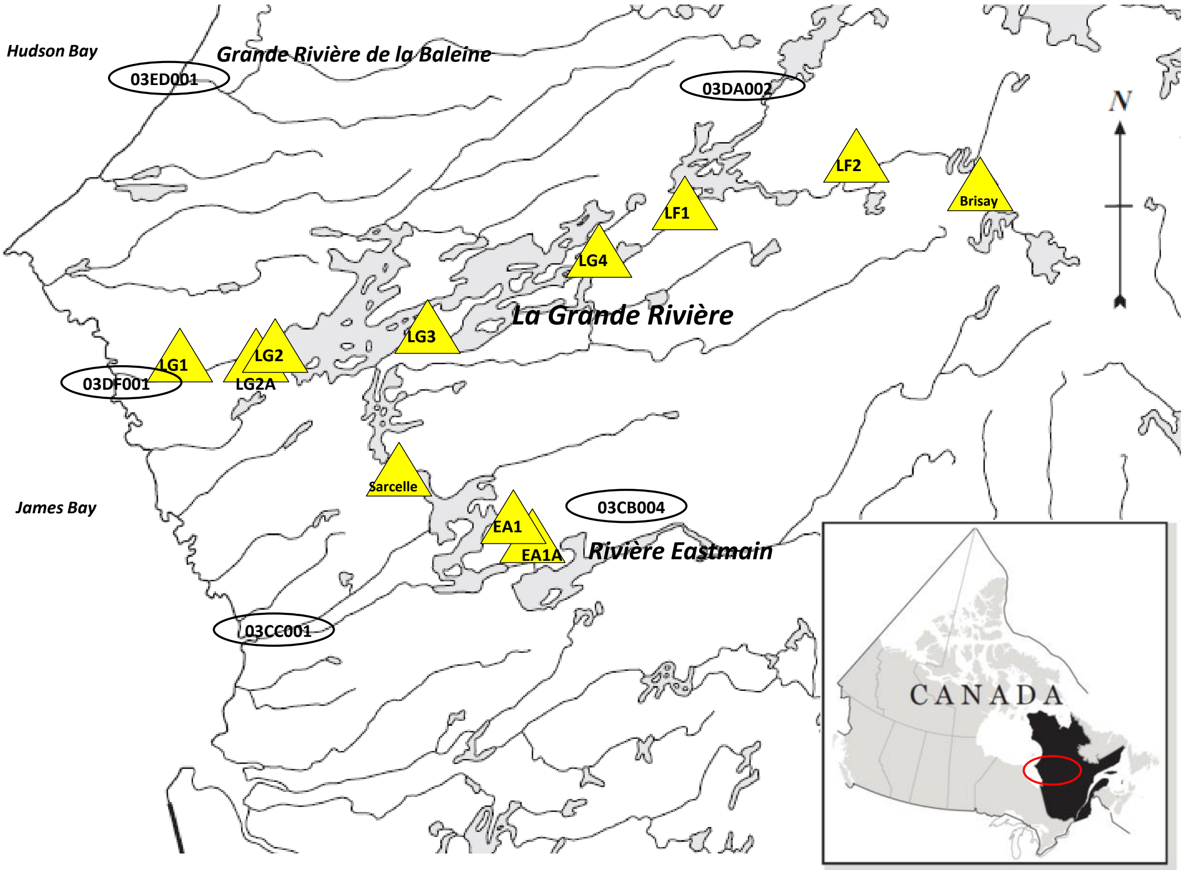


Figure 4.5. Map of La Grande Rivière basin in Nord-du-Québec. The triangles are the hydropower plants, and the ovals are some of the hydrometric stations in the area. 03ED001 at the mouth of Grande Rivière de la Baleine and 03CB004 upstream the hydropower plants at Rivière Eastmain were the stations used for the regression analysis. (Raw map from NRCan, 2012).

Table 4.2. List of the hydropower plants in La Grande complex, presented in the order that they were commissioned.

Map notation	**Name**	**Installed capacity (MW)**	**Commissioning year**
LG2	Robert-Bourassa	5616	1979-1981
LG3	La Grande-3	2417	1982-1984
LG4	La Grande-4	2779	1984-1986
LG2A	La Grande-2-A	2106	1991-1992
Brisay	Brisay	469	1993
LF1	LaForge-1	878	1993-1994
LG1	La Grande-1	1436	1994-1995
LF2	LaForge-2	319	1996
EA1	Eastmain-1	480	2006
EA1A	Eastmain-1-A	768	2011-2012
Sarcelle	Sarcelle	150	2012
Total number of power plants: 11		**Total installed capacity: 17 418 MW**	

4.2.1. Meteorological input data

The temperature and precipitation data for La Grande model was taken from CFSR and CPCp as described in section 4.4. Six polygons in the basin were selected as weather stations, and their data analyzed for calibration of the model. The analysis was made by plotting the data in various ways, e.g. comparing the monthly averages of precipitation and the amount of precipitation over the years to match the amount of water in the model at specific times. The meteorological data for La Grande region followed a predictable pattern: the temperature was lower the farther north and the farther from the sea that the polygons were located, and the amount of precipitation increased proportional southwards. Large spring floods and summer rains dominated the polygons farthest from the sea, while the polygons closer to the shore had larger autumn rains. A number of polygons scattered over the whole region where chosen as weather stations in the model, with much weight on polygons with much precipitation.

4.2.2. Construction of energy inflow target data, Qobs

The Q-target for La Grande model was constructed with linear regression just as the Q-target for the Churchill Falls model (see section 4.1.2), however no information on the energy inflow on annual basis to the La Grande complex was directly available as it was for Churchill Falls. Instead, this piece of information was derived from the annual energy inflow for all of Hydro-Québec's facilities (Hydro-Quebec, 2004), paired with the information that La Grande and Churchill Falls complexes represent 41% and 19% respectively of the total hydropower system of Hydro-Québec (Silver and Roy, 2010). An annual energy inflow series was thus constructed accordingly:

$$LG\ inflow_{annual} = (HQ\ tot.inflow_{annual} - \ CF\ inflow_{annual}) * \frac{0.41}{1 - 0.19} \qquad (eq\ 8)$$

By subtracting the Churchill Falls energy inflow, $CF\ inflow_{annual}$, whose annual variations are known (Bolgov et al, 2012), the level of accuracy is increased a bit. This energy inflow series was used as target for a regression analysis, using two hydrometric stations: 03ED001 at the mouth of Grande Rivière de la Baleine, and 03CB004 upstream the hydropower plants at Eastmain river. The reason for using these hydrometric stations at the neighbouring rivers, was that all stations in La Grande are regulated since the commissioning of the hydropower plants. The stations were carefully chosen among all the available stations, and the arguments and assumptions are further presented and discussed in section 4.2.3. The linear regression constructed a new series, *LG regression series*, as a fit to the *LG inflow* series, by matching the data points from the hydrometric stations with coefficients:

$$LG\ regression\ series = \\ coeffEA * 03CB004_{annual\ sum} + \ coeffB * 03ED001_{annual\ sum} \qquad (eq\ 9)$$

The plot of the series *LG inflow* and *LG regression* can be seen in figure 4.6. The largest difference between the series is in 1989, where the regression series differs with about 10% from the target. For the rest of the years the difference varies between 1 and 8%. Quantitative analysis of the series gave an R^2 of 0.70.

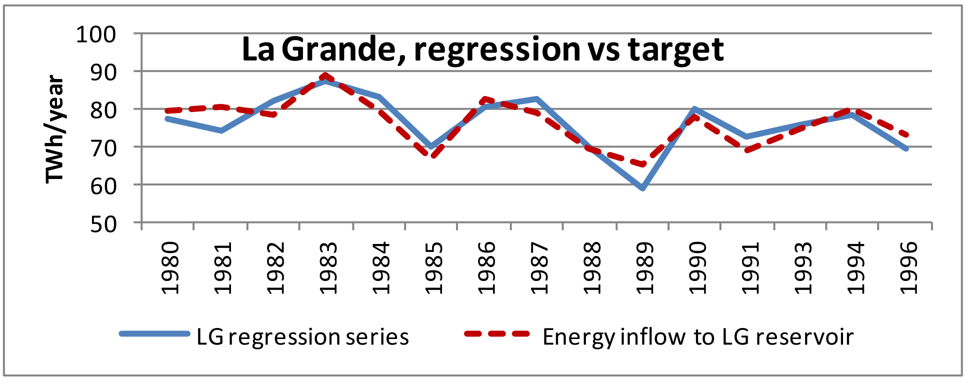


Figure 4.6. Evaluation of La Grande regression analysis. The quantitive evaluation between the two graphs gave an R2 of 0.70.

This regression was the best that could be achieved for La Grande, as further discussed in section 4.2.3, and the coefficients, *coeffEA* and *coeffB*, were used to convert the flows of the rivers Eastmain and Baleine (m^3/s) into Q_{obs}, i.e. energy inflow (TWh) into La Grande hydro-power complex:

$$Q_{obs,daily} = coeffEA * 03CB004_{daily} + coeffB * 03ED001_{daily} \qquad (eq\ 10)$$

4.2.3. Data quality analysis

The match between the annual energy inflow series for La Grande and the regression series merely amounted to an R^2 of 0.70. One possible explanation for this lies within the derivation of the annual energy inflow series. Since the energy inflow for only La Grande complex was available, this number had to be estimated from available information, and this was namely that La Grande makes up for 41% of the total hydropower complex of Hydro-Québec (Silver and Roy, 2010). This number is clearly an average over a longer period of time, and the fraction will differ from year to year. When comparing the energy inflow series between Hydro-Québec's total energy inflow and the energy inflow to Churchill Falls for the years 1943-1996, the fraction of Churchill Falls varied between 15-20%, however with an average of 18.5%. The fraction of La Grande will thus probably vary in a similar manner from year to year, but there is no available information to predict in what way. Therefore it is no surprise that the match between the natural river flows and the constructed energy inflow series was not better.

The hydrometric stations used in the regression analysis and for constructing the Q-target for La Grande were not located on La Grande river. The reason for this was that there are no unregulated hydrometric stations, since there are hydropower plants all along La Grande river. However, Hernández-Henríquez et al (2010). conducted a study in which they made a reconstruction of how the natural flow in La Grande would be without the regulations. In their analysis they made quality controls of the hydrometric stations in the whole region, and they based their simulation on the hydrometric stations at Eastmain and Baleine. They validated their simulated natural flow series against discharge data from La Grande-1 generating station, classified information that they received directly from Hydro-Québec, which confirmed that their simulation was trustworthy.

This present study employed the very same hydrometric stations as Hernández-Henríquez et al (2010). Initially, the regression analysis was made in two steps: one first step to make a simulation of the natural flow in La Grande, which was evaluated to Hernández-Henríquez et al's reconstructed flow series. The match between the two series had an R^2 of 0.97, which showed that the discharge data from the stations Eastmain and Baleine indeed matched the data used by Hernández-Henríquez et al. In the second step, another regression was made with the energy inflow to La Grande as target. This regression however, only got an R^2 of 0.66, which was not considered good enough to proceed with the Q-target construction.

In theory, the best result that possibly could be achieved would be regression using the natural flow in La Grande directly. Hydrometric data from 1961-1977, before the regulations started, were used in a regression to see this theoretically best result, which turned out to be R^2 0.40, i.e. far worse than using the neighbouring rivers. Possible explanations for this is that the drainage basin has changed too much since the regulation started to be accounted for as representative for an energy inflow based on the hydropower plant system of today.

In the end, the author thus settled for the above mentioned regression analysis with an R^2 of 0.70, which was made in one single step with the hydrometric stations from Eastmain and Baleine directly targeted at the energy inflow. The evaluated result of this regression turned out to be fairly good in the light of what analyses using the other available hydrometric stations showed. Based on figure 4.6, the deviations between data points on annual basis are estimated to be within an error margin of 10%.

As stated in section 4.1.2, this process includes the assumption that the regression coefficients, *coeffEA* and *coeffB*, derived on annual basis, also are representative on the daily basis. Thus the Q-target series will be refined with the daily variations of the hydrometric stations, assuming that these stations and the reservoirs follow the same hydrological dynamics. The possible differences in the flow patterns between the hydrometric stations and the reservoirs are in other words not accounted for in this analysis.

When running the Q-target series with the default parameters in Scania-HBV, the first run gave an R^2_daily of about 0.40, which confirms that the Q-target was a reasonable energy inflow estimation, in spite of the simplifications and assumptions made in the process.

5. Results

5.1. Churchill Falls

The Churchill Falls model was calibrated for a ten-year-period, starting in September 1986 and ending in December 1996. The reason for starting the period in September and not January is for not having to include the snow pack from the previous year when starting up the model. The model thus matches the hydrological year rather than the calendar year. The calibration ends in 1996 due to that the meteorological input data sets were available until this year only, initially. The period 1981 - 1996-08 was used as validation, and later on when longer meteorological data sets were available, the model was also validated for the period 1997 - 2010.

Figure 5.1 gives an overview of the resulting hydrograph for the total period with the calibration period and the respective validation periods marked.

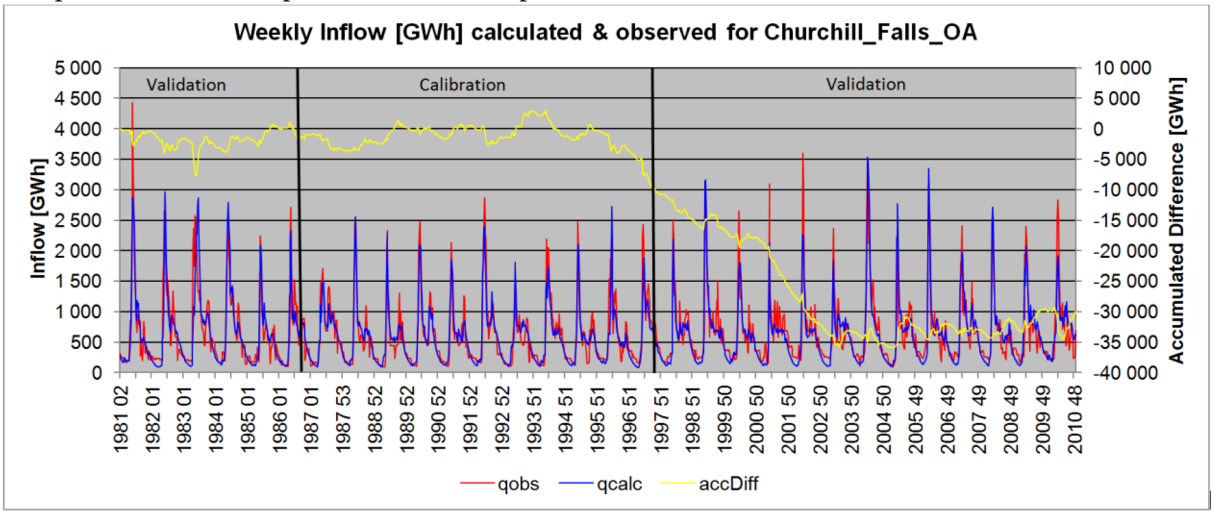


Figure 5.1. Modelled result for the whole period, sub periods used for calibration and validation are marked out. The red hydrograph is the Q-target, and the blue is the simulated runoff, Qcalc. Those two graphs are measured along the primary y-axis, which displays inflow in GWh/week. The yellow line which is measured along the secondary y-axis to the right is the accumulated difference, in total number of GWh, betweeen Q-target and Qcalc.

Inflow in gigawatt hours per week is presented on the primary y-axis of the figure. The secondary y-axis accounts for the accumulated error of the model, also in gigawatt hours, and shown in the figure as the yellow graph. The accumulated error oscillates around zero, until 1995 when this trend is interrupted and replaced with a decreasing trend until 2003, after which the trend once again is stabilized as more or less constant. The effect of the declining period results in an accumulated error of -30.2 TWh for the whole period, which corresponds to 3.1% relative to the total simulated runoff.

Simulation of the total period gave a Nash-Sutcliffe of 0.82 on a weekly basis. In table 5.1 the Nash-Sutcliffe values for the respective periods as well as the total periods on daily, weekly and monthly basis are presented.

Table 5.1. Summary of the Nash-Sutcliffe values for the Churchill Falls model for the calibration and validation periods on daily, weekly and monthly resolution, respectively.

Period in chrono-logical order	Validation 1981-01-01 - 1986-08-31	Calibration 1986-09-01 - 1996-12-31	Validation 1997-01-01 - 2010-12-31	Total period 1981-2010
R2 daily	0.76	0.81	0.77	0.78
R2 weekly	0.80	0.86	0.82	0.82
R2 monthly	0.87	0.92	0.89	0.89

From the data sets that are provided to the model, normals in terms of snowpack and hydrographs (both observed and calculated) are determined from the monthly averages for all of the years. Figure 5.2 summarizes the hydrological normals in the Churchill Falls basin in the period 1981-2010: The snowpack starts to accumulate in October, reaching its max in early April, after which it melts away in the spring flood during May and June. The normals of the observed and the calculated hydrographs give an overview of when the model tends to under- and overestimate the amount of water in the basin. The baseflow is a bit too low during the winter months, and the spring flood peak is also too low on average, however the runoff is a bit overestimated during the late summer months.

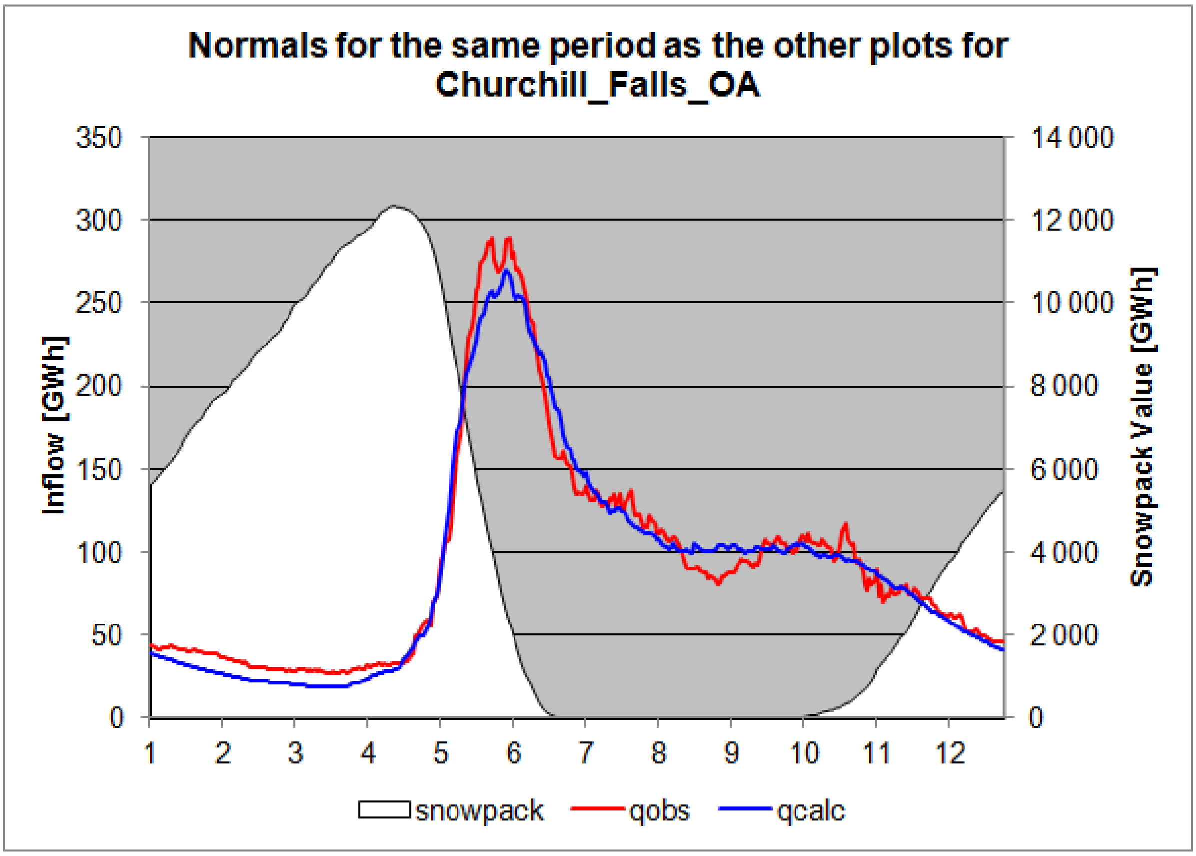


Figure 5.2. Normals for 1981-2010. The graphs qobs and qcalc are measured along the primary y-axis and express the average daily inflow (GWh/day) for target and simulation, for the years 1981-2010 in the Churchill Falls basin. The accumulated snowpack can also be seen in the figure and is measured on the rightmost y-axis.

The following sections display a closer look at the calibration and validation periods. Zoomed in hydrographs for each period are presented, as well as histograms of the total annual runoff, calculated (blue, left staple) and observed (red, right bar) respectively, along with the difference between the two.

5.1.1. Calibration

The calibration had a Nash-Sutcliffe value of 0.86 on a weekly basis. As can be read from the hydrograph in figure 5.3, the most apparent weaknesses was too much water flow during some of the summers and not enough water in some of the spring and autumn floods. The histogram with accumulated annual inflows, figure 5.4, shows the variation in inflow between the years. The accumulated annual inflow oscillates around 30 000 GWh, apart from 1986 since the model was commissioned that year in September, missing out the first 8 months. The accumulated difference oscillated around zero throughout the period.

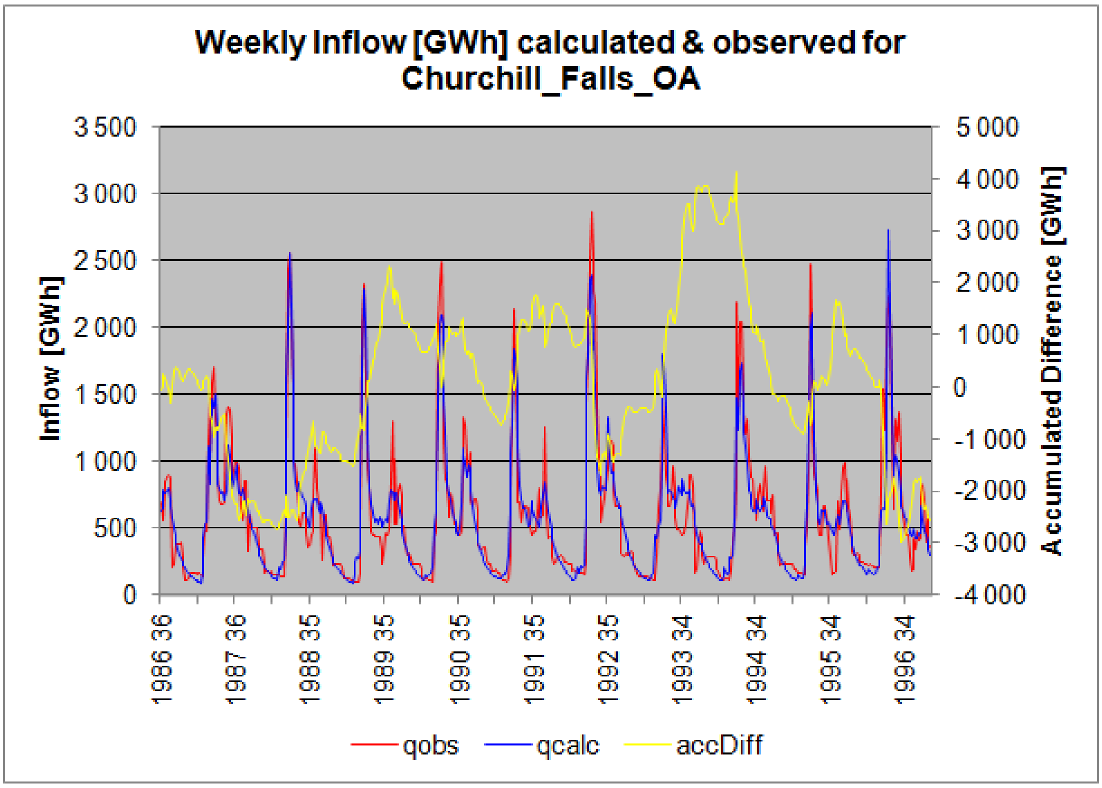


Figure 5.3. Modelled results for the calibration period, 1986-09-01 - 1996-12-31. Inflow in GWh/week on the leftmost y-axis. R2 weekly 0.86.

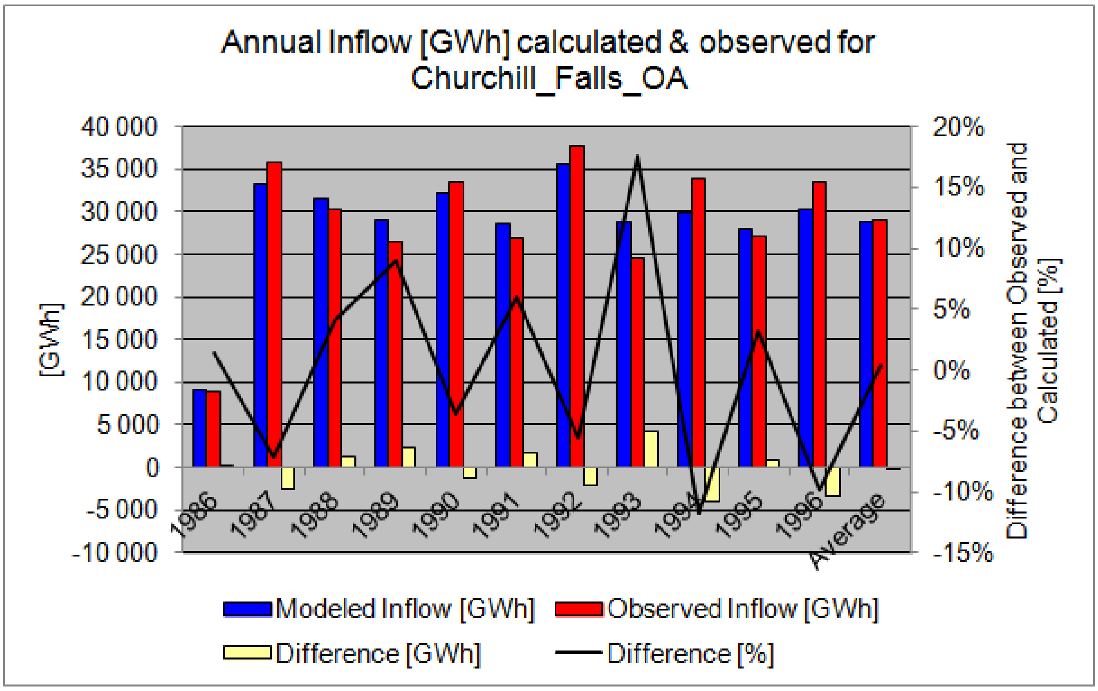


Figure 5.4. Histogram of accumulated annual inflow (GWh/year), modelled and observed respectively. The small yellow staples are the difference between the two, and the percentage of the difference to the total is the black line, measured at the second y-axis.

5.1.2. Validation periods

The validation period for the years 1981-1986 had a Nash-Sutcliffe value of 0.80 on a weekly basis. The zoomed in hydrograph in figure 5.5 shows that the most obvious differences between the observed and calculated flows are due to the extreme spring flood the first year, which had enormous amounts of snow, and a mismatch in the timing of the spring flood in 1983. The validation period is a bit too short to give an estimate of whether these two individual events are casualties due to unusual circumstances or if they are rather an indication of a structural problem with the calibration of the model. The accumulated difference still oscillates around zero, but with a lower frequency than as for the calibration period.

The late validation period, stretching from 1997-2001 and shown in figure 5.7, had a Nash-Sutcliffe value of 0.82 on a weekly basis. This period starts with a negative trend in the accumulated difference for a 6-year-period, i.e. an underestimation of the amount of water in the model. Primarily, there is not enough water during the autumn rains, and for the last three years of the negative period the spring floods are not sufficiently large. After 2003, the model performs better and the trend is once again stabilized and starts to oscillate around a constant value.

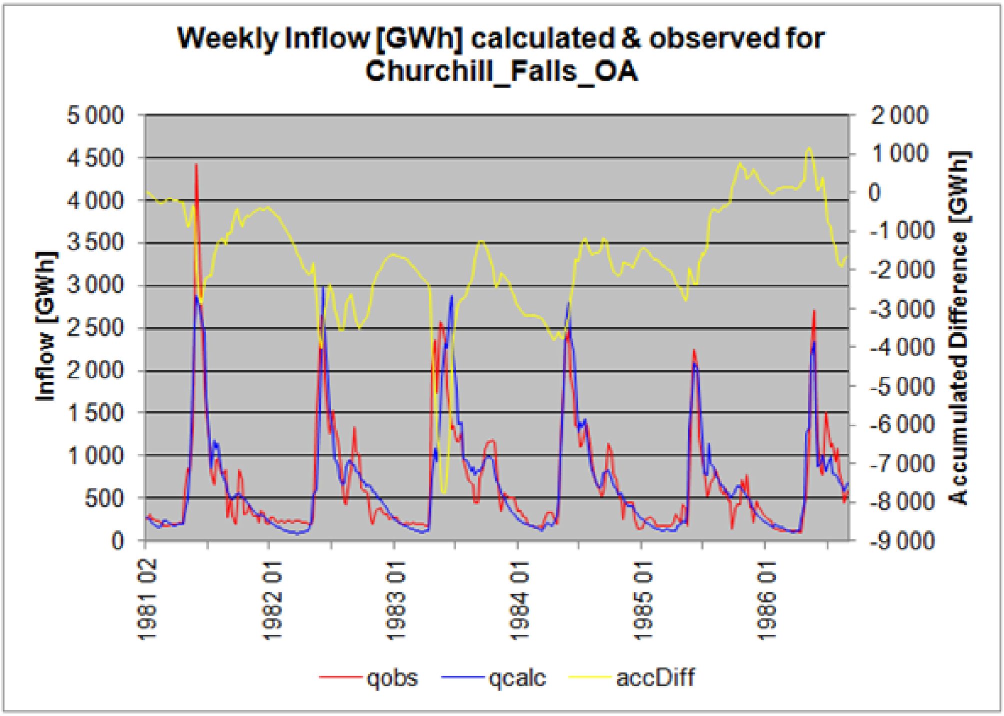


Figure 5.5. Modelled results for the early validation period, 1981-01-01 – 1986-08-31. Inflow in GWh/week on the leftmost y-axis. R2 weekly 0.80

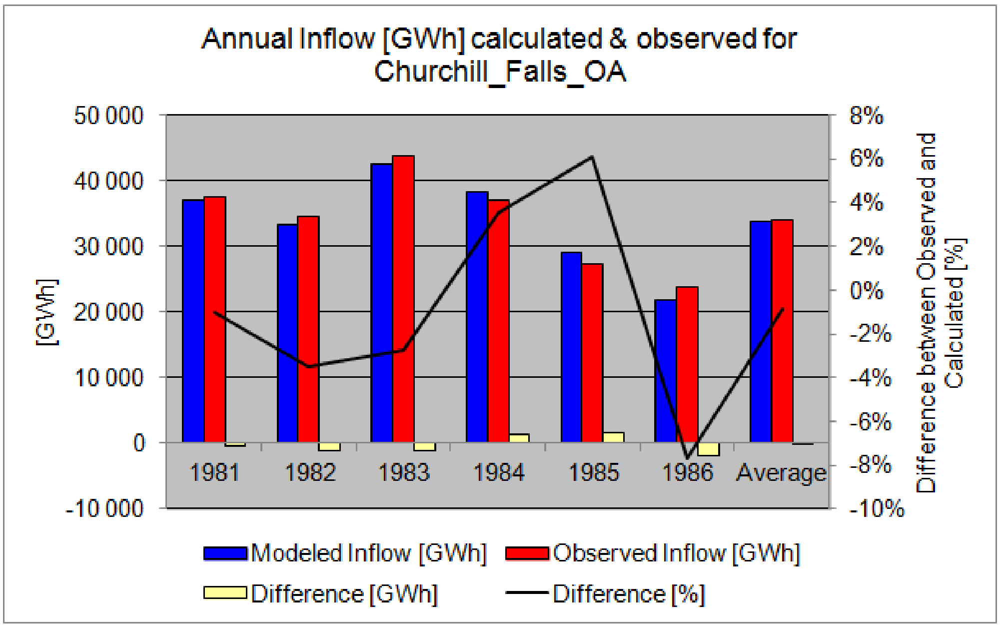


Figure 5.6. Histogram of accumulated annual inflow (GWh/year).

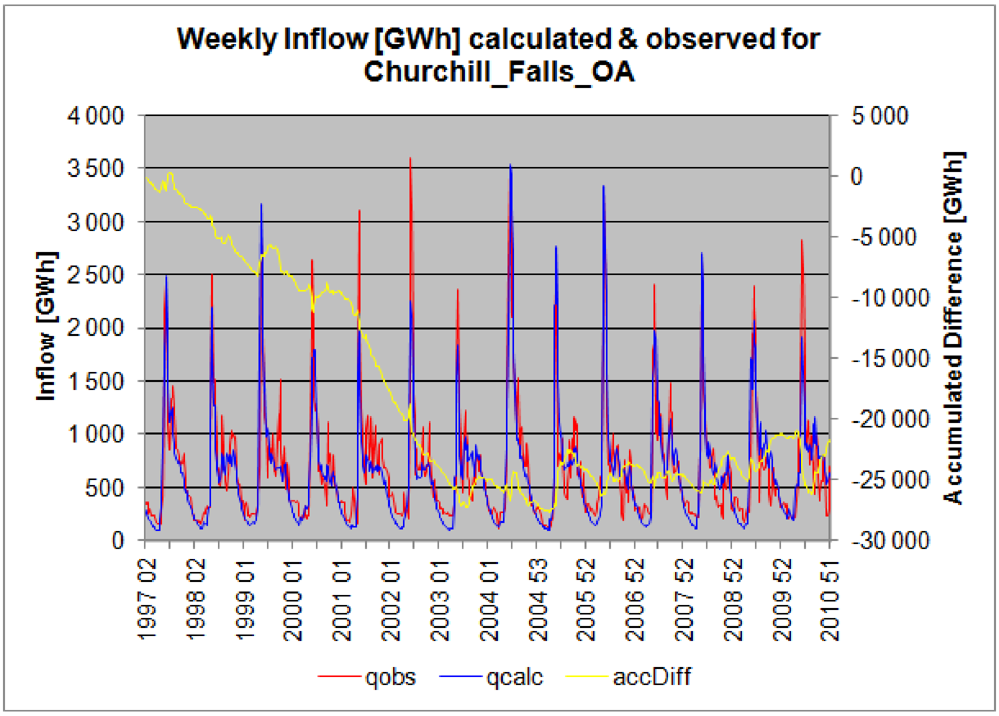


Figure 5.7. Modelled result för late validation period, 1997 – 2010. Inflow in GWh/week on the leftmost y-axis. R2 weekly 0.82.

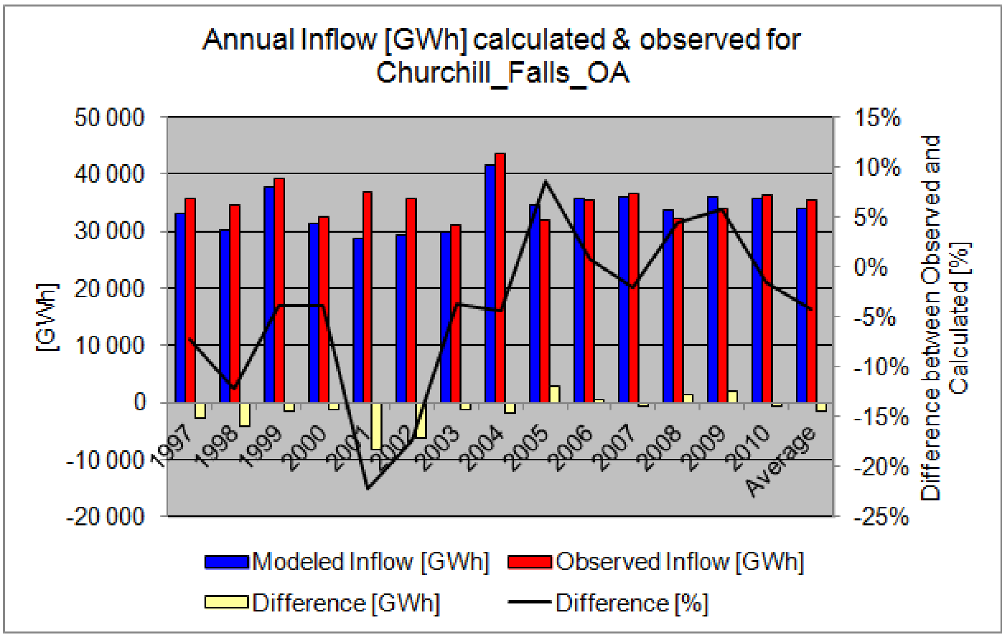


Figure 5.8. Histogram of accumulated annual inflow (GWh/year).

5.2. La Grande

La Grande model was calibrated for an eleven-year-period, starting in September 1981, matching the hydrological year as explained in section 5.1, and ending last of July 1992. From August 1992 to November the very same year, there was a gap in the Q-target data, and thus the calibration was ended before this gap. The period 1996-01-09 - 2001-08-31 was used as validation period.

Figure 5.9 gives an overview of the resulting hydrograph for the total period with the calibration, gap and validation periods marked.

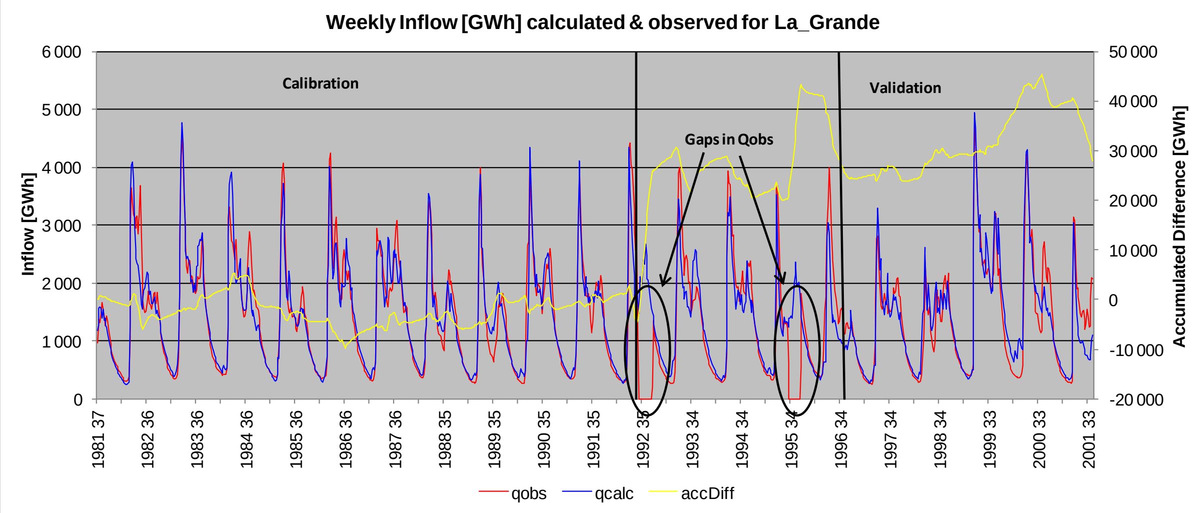


Figure 5.9. Modelled result for the whole period, subperiods used for calibration and validation are marked. The plot includes the period with gaps in the Q-target data. The gaps are marked out with circles. This period was excluded from calibration and validation due to the gaps. The primary y-axis describes the inflow in GWh/week for qobs and qcalc, and the secondary y-axis displays the accumulated difference between the two.

The graph of the accumulated difference shows a more or less constant trend throughout the total period, with exceptions for the two gaps in the Q-target, where the difference drastically increases for natural reasons. For the calibration period, the accumulated difference oscillates around zero as preferred, then the first gap in the Q-target, August-November 1992, causes an increase of about 30 000 GWh. After the first gap follows two exemplary years which are not quantitatively evaluated, and then there is the second gap from August to November in 1995, which further increases the accumulated difference. The spring flood of 1996 is underestimated by the model, and in the validation period the accumulated difference oscillates around 28 000 GWh, however with an inadvisably large amplitude for the last two years.

The gaps in the Q-target series reduced the Nash-Sutcliffe value to some extent when looking at the total period: total R2 was 0.77 on a weekly basis, low compared to the validation period, which had a weekly R2 of 0.85 even though the validation was quite unfit for the last years. In table 5.2 the Nash-Sutcliffe values for the respective periods as well as the total periods on daily, weekly and monthly basis are presented.

Table 5.2. Summary of the Nash-Sutcliffe values for La Grande model for the calibration and validation periods on daily, weekly and monthly resolution, respectively.

	Calibration 1981-09-01 - 1992-07-31	validation 1996-09-01 - 2001-08-31
R2 daily	0.88	0.84
R2 weekly	0.89	0.85
R2 monthly	0.92	0.87

From the data sets that are provided to the model, normals in terms of snowpack and hydrographs (both observed and calculated) are determined from the monthly averages. Figure 5.10 summarizes the hydrological normals in the La Grande basin in the period 1981-2001: The snowpack starts to accumulate in October, reaching its max in late March, after which it melts away in the spring flood during April and May. Compared to the Churchill Falls basin, La Grande is in other words approximately one month earlier with peak snow and spring flood. The normals of the observed and the calculated hydrographs give an overview of where the model tends to under- and overestimate the amount of water in the basin. To start with the baseflow is somewhat too high during the winter months. The peak of the spring flood is very well fitted in height and timing, although it should last longer in June. The baseflow during the late summer months should be lower, as well as the autumn rains in September and early October. However, the underestimation of volume in the spring flood and the overestimation of volume during the fall are approximately of the same quantities, and thus cancel each out in a longer time perspective.

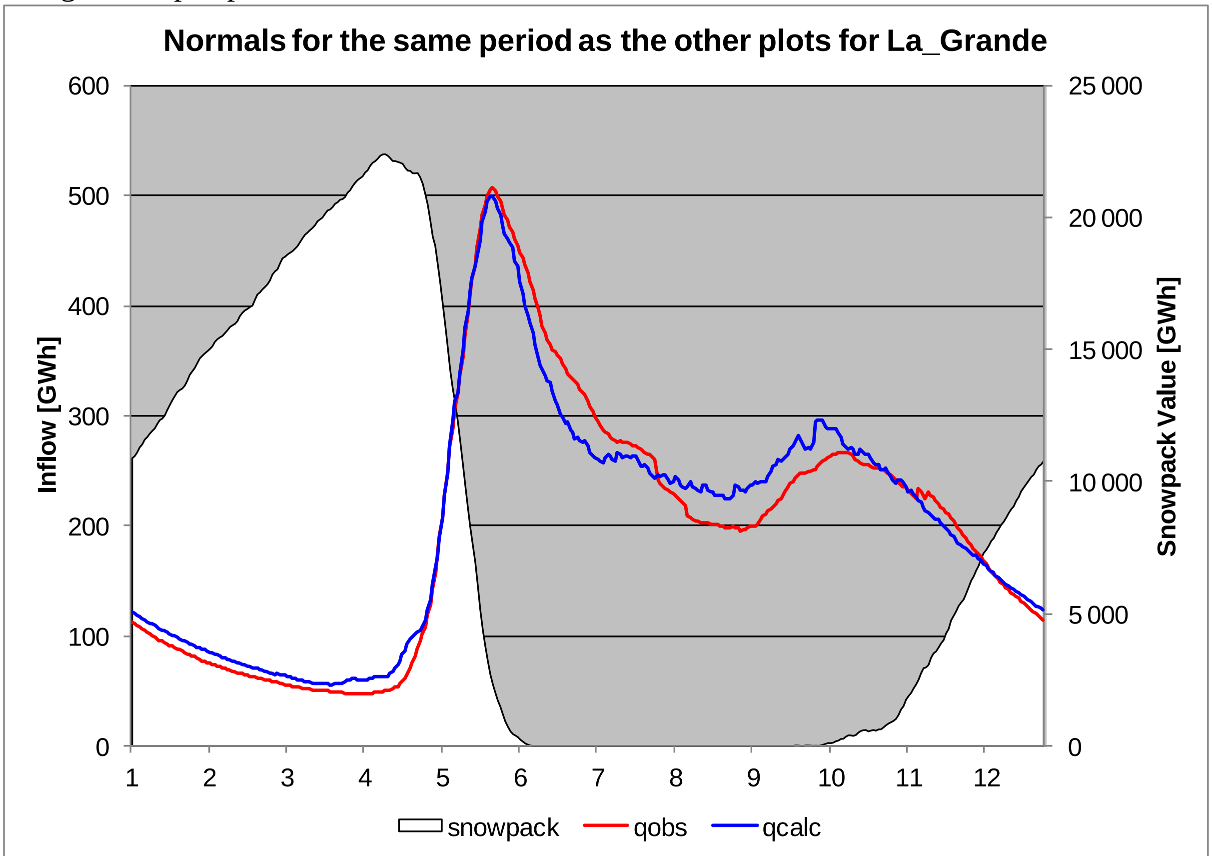


Figure 5.10. Normals for 1981-2001. The graphs qobs and qcalc are measured along the primary y-axis and express the average daily inflow (GWh/day) for target and simulation, for the years 1981-2010 in La Grande basin. The accumulated snowpack can also be seen in the figure and is measured on the rightmost y-axis.

The following sections display a closer look at the calibration and validation periods. Zoomed in hydrographs for each period are presented, as well as histograms of the total annual runoff, calculated (blue, left staple) and observed (red, right staple) respectively, along with the difference between the two.

5.2.1. Calibration

The calibration had a Nash-Sutcliffe value of 0.89 on a weekly basis. As can be read from the hydrograph in figure 5.11, the most apparent weaknesses were occasional under- and overestimations of the volumes in the spring and autumn floods. The histogram with accumulated annual inflows, figure 5.12, shows the variation in inflow between the years. The accumulated annual inflow oscillates around 70 000 GWh, apart from 1986 since the model was commissioned that year in September, missing out the first 8 months, and 1992, since the model only ran until last of July. The accumulated difference oscillated around zero throughout the period, with the overestimation in 1984 balanced by the underestimation in 1986.

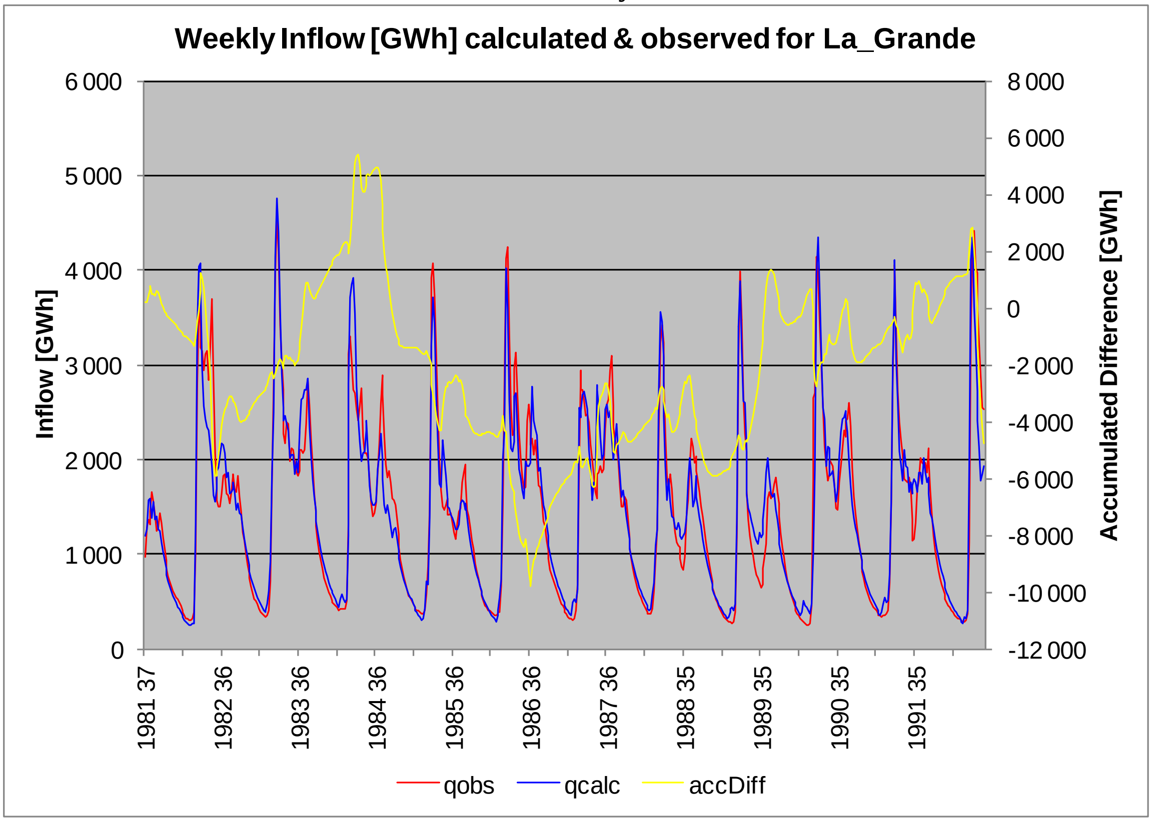


Figure 5.11. Modelled results for the calibration period, 1981-09-01 - 1992-07-31. Inflow in GWh/week on the leftmost y-axis. R2 weekly 0.89.

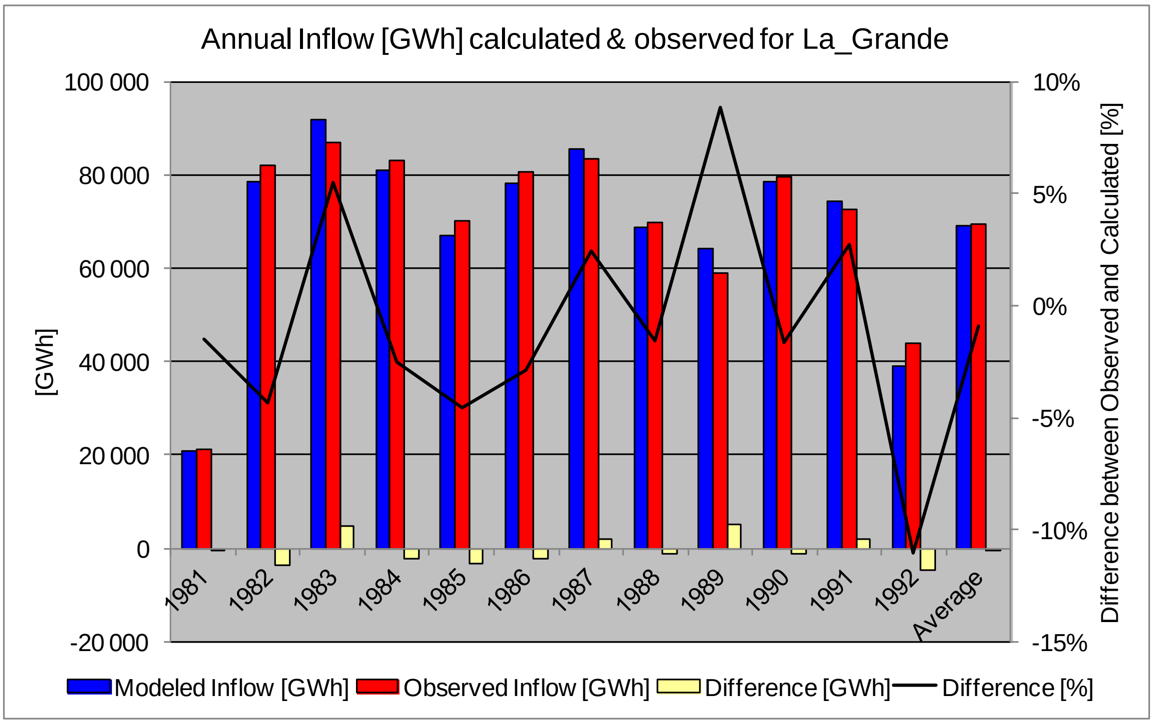


Figure 5.12. Histogram of accumulated annual inflow (GWh/year), modelled and observed respectively. The small yellow staples are the difference between the two, and the percentage of the difference to the total is the black line, measured at the second y-axis.

5.2.2. Validation period

The validation period for the years 1996-2001 had a Nash-Sutcliffe value of 0.85 on a weekly basis. The first three years are real good fits, but the last three are on the other hand considerably less good. It starts with an overestimation of the baseflow volume in the winter 1999-2000, which might be due to some occasional abnormalities in the meteorological data, deemed from the pointy look of the hydrograph, shown in figure 5.13. However, the autumn rains of the following years are underestimated with roughly 20 000 GWh altogether, which suggests that the chosen meteorological polygon weights are not optimal in representing La Grande basin in those later years.

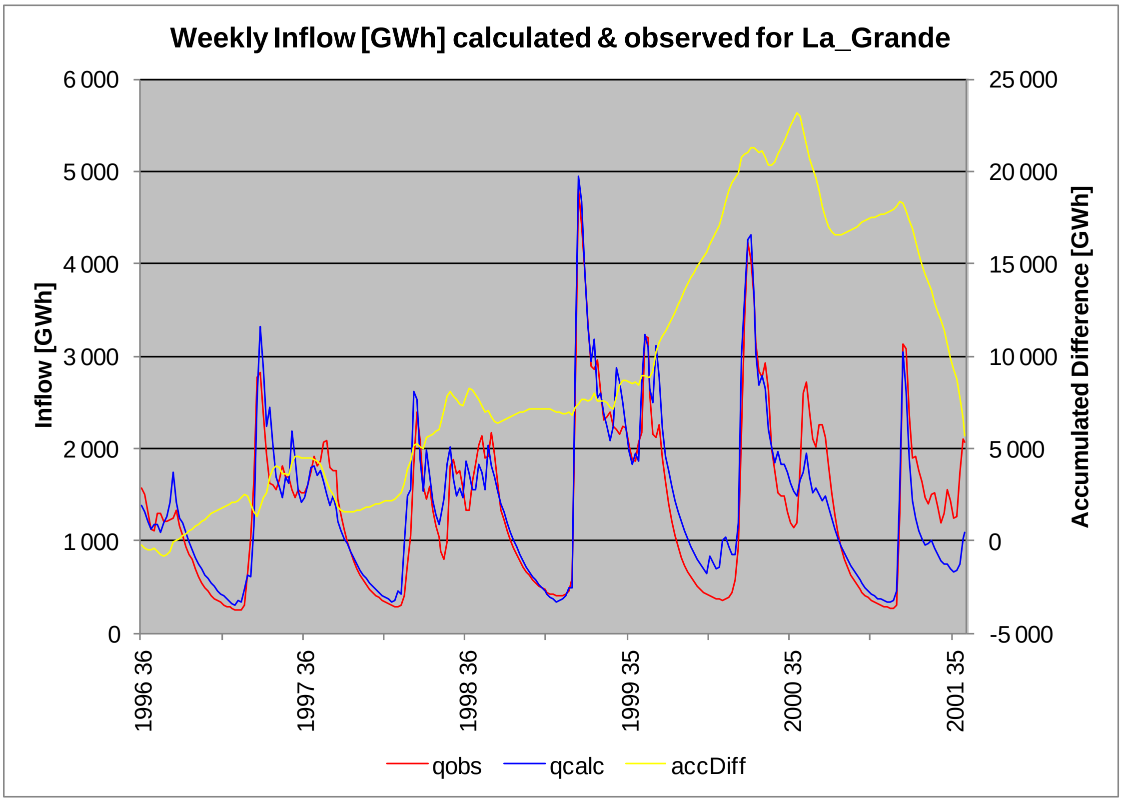


Figure 5.13. Modelled results for the validation period, 1996-09-01 – 2001-08-31. Inflow in GWh/week on the leftmost y-axis. R2 weekly 0.85

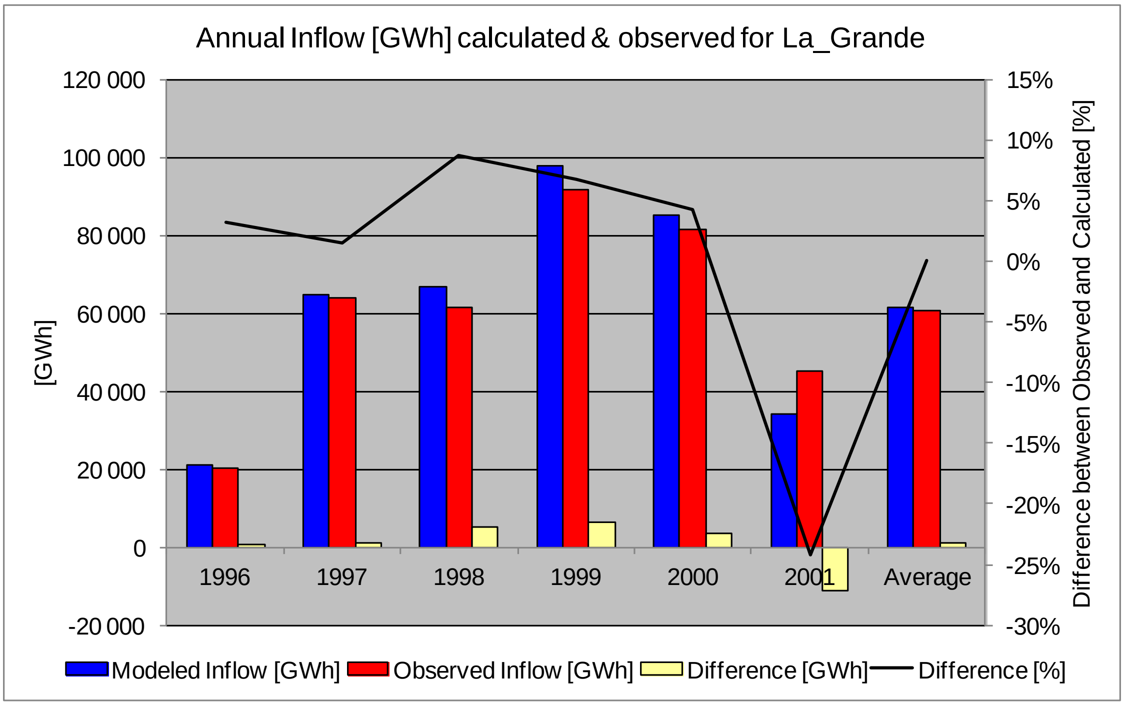
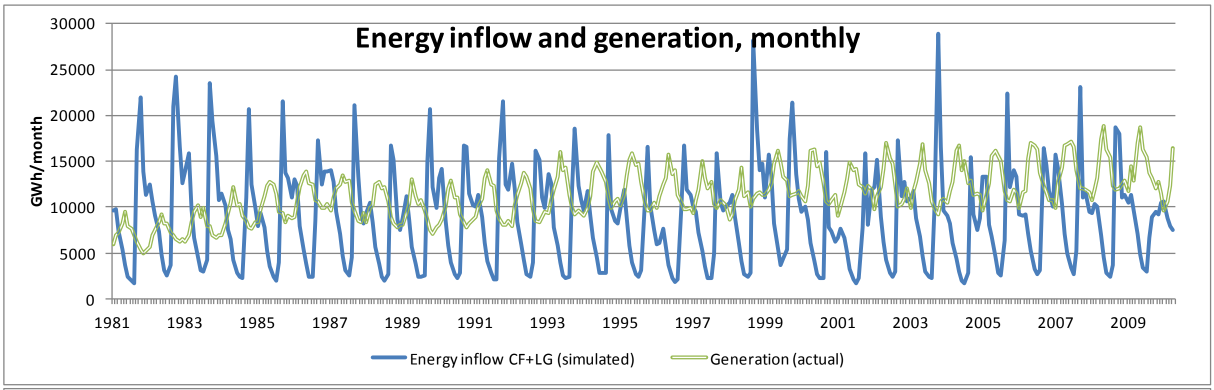


Figure 5.14. Histogram of accumulated annual inflow (GWh/year).

5.3. Comparisons of simulations and actuals

After calibration and validation, the models for Churchill Falls and La Grande were run in simulation mode for the total periods of available meteorological data, i.e. from 1981 until 2010. The simulated runoff series for the respective models were added together, thus representing 50-60%, roughly estimated, of Hydro-Québec's total energy inflow. The total runoff series (Churchill Falls and La Grande added together) were plotted along with the actual generation of Hydro-Québec, available from Statistics Canada (2014a). As can be seen in the upper part of figure 5.15, the plots in monthly resolution of the simulated energy inflow and the actual generation, mirror each other similar to a standing wave. In the lower part of figure 5.15, the same data are plotted on annual basis to visualize the trends over longer periods of time for the two data sets. Note that while the generation draws a growing trend, the simulated energy inflow series shows no growing trend but rather oscillates around a constant value. This does not depict how the real energy inflow has behaved over time, but is a consequence of the model being calibrated to a specific energy inflow target. For further discussion, see chapter 6.



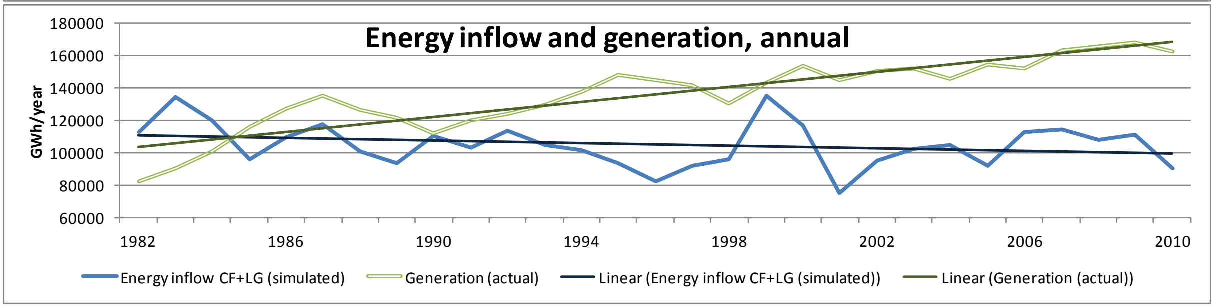


Figure 5.15. The simulated energy inflow, Qcalc, into the reservoirs of the complexes Churchill Falls and La Grande, plotted to the hydropower generation of public utilities (i.e. Hydro-Québec) (Statistics Canada, 2014a). The upper graph shows the plot on monthly basis, starting in September 1981 and ending in december 2010. The lower graph is a plot on annual basis, with trendlines, from January 1982 to December 2010.

Data on Hydro-Québec's electricity export and its value was downloaded from National Energy Board (NEB, 2015) and plotted in figure 5.16.

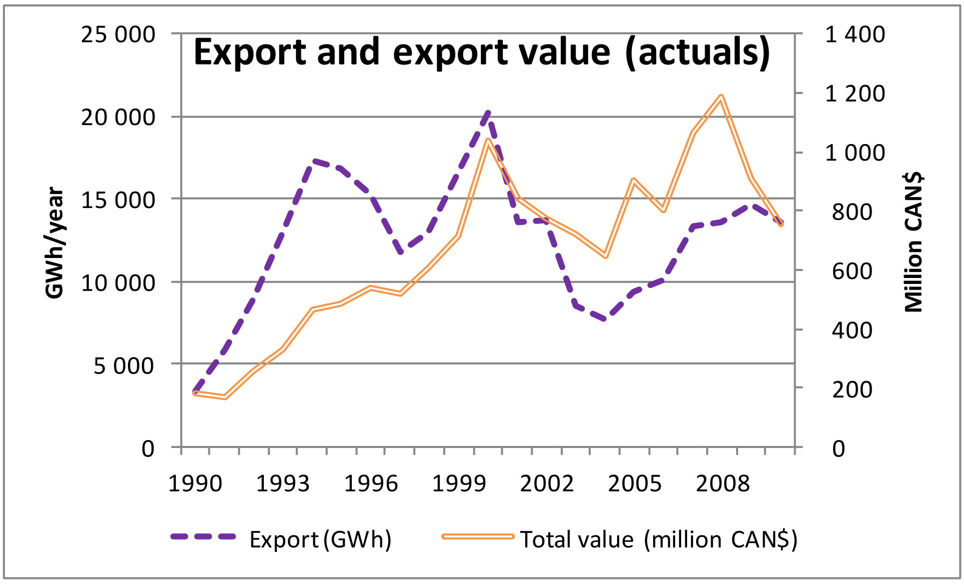


Figure 5.16. Hydro-Québec's electricity export from 1990-2010 on annual basis, and the value of the export in million CAN$ (NEB, 2015).

The export data was analysed in the context of the energy inflow data (the simulations) and the generation data (the actuals from Statistics Canada) with the aim to try and find a relation between the data sets, but the resolution of the data was too low to extinguish a clear pattern between all of the three data sets. A relation between the generation and the export could however be verified, as can be seen in the scatter point plot in figure 5.17. For further discussion on the result in this section, see chapter 6.

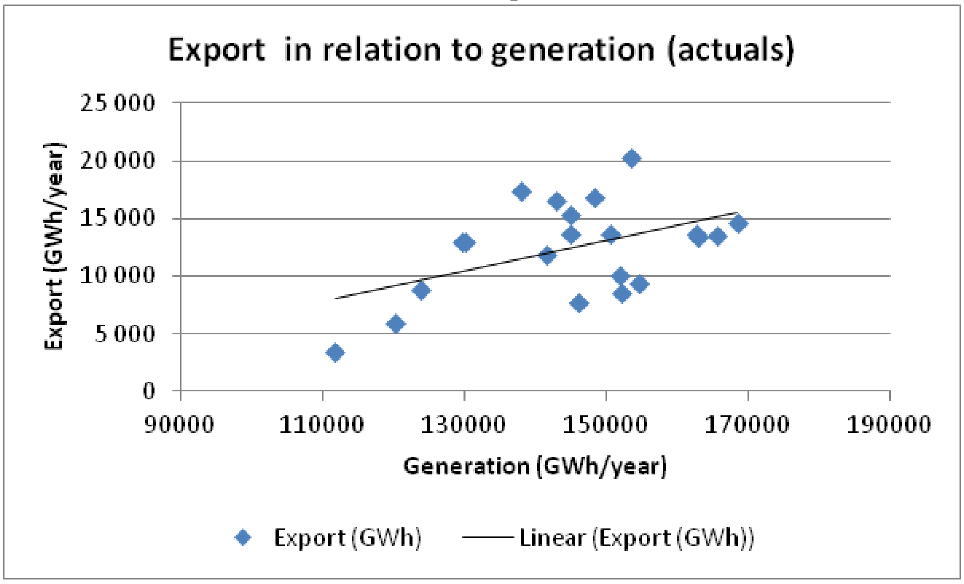


Figure 5.17. The relation between Hydro-Québec's hydropower generation on annual basis, and their export. A correlation can be concluded, although it is obvious that there are more factors than the generation that influence the amount of electricity exported.

6. Discussion

In this master thesis, Scania-HBV models have been built for two hydropower complexes in eastern Canada, namely Churchill Falls in Newfoundland and Labrador, and La Grande Rivière in Quebec. A literature study has also been conducted of the Canadian energy market in general and the Quebecois electricity market in particular. In this chapter, the model simulations are evaluated and discussed in relation to the actual hydropower generation, the Canadian energy market and the actual export.

6.1. Model evaluation

The results of the calibrations and validations of the models were analysed with the objective function Nash-Sutcliffe, R^2, and are presented in table 6.1 for recap on the weekly values:

Table 6.1. R2 weekly for the calibration and validation of the respective models.

Model	Calibration	Validation
Churchill Falls	0.86	0.80; 0.82
La Grande	0.89	0.85

Since a model is considered reasonably good if the Nash-Sutcliffe exceeds 0.7 (Söderberg, 2015), both models can be evaluated as satisfactory.

It is however important to keep in mind that modelled results are no better than the input data provided to the model, and that the model itself holds a set of simplifications and assumptions. The assumptions made for the Scania-HBV model are internal matters for Thomson Reuters, but all assumptions made related to the Q-target input data are presented in chapter 4, and discussed in detail in the respective data quality analyses, see sections 4.1.3 and 4.2.3. Based on the conclusions from those sections, both models' input data were evaluated as reasonable Q-targets.

6.2. Model simulations in relation to actual generation

When both models had been calibrated and validated, simulations were made for the energy inflows to the hydropower systems for the total period 1981-2010. In figure 5.15, the simulated results are added together as one series and plotted along with the actual hydropower generation. Note that the simulated inflow only represents about 50-60% of Hydro-Québec's total energy inflow, but the generation represents all public hydropower facilities in Quebec, and thus looks as if it is of greater magnitude than the inflow. The plot on monthly basis visualizes that the energy inflow and the generation totally mirror each other, making the plot of the two graphs resembles a standing wave. This points out that Hydro-Québec's hydropower reservoirs are heavily regulated: Often, a hydropower reservoir functions analogically to a natural lake with a certain attenuation effect, meaning that the shape of the outflow hydrograph will be smoother and with a later and lower peak as compared to the inflow, but the two curves will still shadow each other. In the case with the curves in the upper part of figure 5.15, one curve is at its maximum when the other is at its minimum. The reservoirs are emptied during the winter to meet the peak demand, that typically occurs during the winter in Quebec (NRCan, 2014), and to make room for the water from the spring flood that will take place a few months later. This causes the energy inflow hydrograph to drop to its trough, simultaneously as the generation (outflow) increases to its peak. As the reservoirs are refilled from the flowing spring flood and the energy inflow hydrograph reaches its annual maximum, the generation decreases to its annual minimum (see also figure 2.8 on the generation pattern).

The lower part of figure 5.15 is a plot of the two data sets, but on annual basis to emphasize trends over longer periods of time. The generation clearly increases over time, accordingly to the development of the hydropower systems and the prognosis of increasing demand (NEB, 2013). The energy inflow does not show an equivalent trend. This is due to that the models simulating the energy inflow series are calibrated after a Q-target that is based on a specific state of the hydropower system. Even though the energy inflow series (Hydro-Québec, 2004; Bolgov et al, 2012) describe the energy inflow for periods longer than 50 years, those are no actual numbers but calculated values that put the amount of water in the system in the context of how much energy every litre would correspond to in a specific hydropower system. For example, the energy inflow series for all of Hydro-Québec's facilities was based on the corresponding installed capacity in the system as it was in 2003, and this helps explaining the absence of a growing trend of the simulated inflow in figure 5.15. The simulated results are thus not really applicable over a longer period of time, but must be recalculated to match the developments of the hydropower system. New power plants might be commissioned or new units added to the existing power plants, and when this happens a new Q-target series must be constructed, else the model simulation will only describe the old system. For this reason, the calibration of a model is normally made for the latest possible period (Söderberg, 2015).

Seen to the total province of Quebec, the total installed capacity has increased since 2003, and thus that energy inflow series (Hydro-Québec, 2004) is not up to date with today's system. For the models constructed in this study, the installed capacity has increased with about 1400 MW in La Grande region due to the recent commissions of the Eastmain-plants and Sarcelle. For Churchill Falls, however, the system has been unchanged since 1979 when the last unit was installed, although changes are to be expected in a few years time due to the constructions of Muskrat Falls and Gull Island.

6.3. Model simulations in relation to the energy market and the export

In many energy markets where the hydropower has a significant contribution to the electricity supply, a clear correlation between the energy inflow to the systems and the spot price on electricity can be distinguished. The clearer this correlation for a specific market, the higher are the incentives for Thomson Reuters to proceed with calibrating a model for the market region (Söderberg, 2015). In the case of Quebec, the energy market is still regulated, and thus the price variations are insignificant, as can be seen in figure 2.11, section 2.2.3. The figure also illustrates the differences in the mechanisms of regulated and deregulated markets: while the regulated price for Quebec is constant over the years, the deregulated spot market price in Ontario heavily fluctuates. Seen in this context only, calibrating Scania-HBV models for the electricity market in Quebec seems rather pointless. However, chances are that it will not be long before the electricity markets in Canada open up and are restructured into deregulated markets. Regarding Quebec, the market has already been partly opened up in 1997, when the province adopted the OATT-system, US FERC 1996 order 888, making it possible to trade electricity outside their own jurisdiction (Pineau, 2013; FERC, 2012), see section 2.2.

As mentioned in section 2.2.2, the National Energy Board states a certain correlation between the amount of water in the hydropower reservoirs and the amount of electricity that is exported (NEB, 2013). This correlation could be verified, to a certain extent, by the data available in this study, when making a scatter plot of the annual export from Hydro-Québec (NEB, 2015) to the hydropower generation for public utilities in Quebec (Statistics Canada, 2014a), see figure 5.17. A correlation between the simulated inflows, produced by the models for Churchill Falls and La Grande, and the export data could however not be visualized. That does not necessarily mean that there is no correlation between the two, only that time resolution of the data in this study is not sufficiently high for it to show: Compare with the lower part of figure 5.15, showing the plot of the simulated energy inflow and the actual generation: The annual pattern between the two seems more arbitrary than interlinked, which is also explained by the time resolution and the difference between the calendar year and the hydrological year. Water that flows into a reservoir one year can be stored for generation until the next year. In Quebec, this seems to be rather rule than possibility since a lot of water is accumulated in the snowpack the last quarter of the year, and released for generation the next calendar year. This fact explains the difficulties to clarify the correlation between inflow, export and generation on the annual basis.

Additional factors are however involved in the pricing of electricity, other than the supply of water and the generation proportion. This can be concluded from figure 5.16, section 5.3, which illustrates a plot of the export and its corresponding financial value (NEB, 2015). As can be seen in the figure the two variables do not follow an interlinked predictable pattern: something else other than the exported amount does clearly influence the value. Possible factors are of course the demand, both in Quebec and in the export markets. Even if the demand in Quebec does not affect the provincial electricity price, it will affect the amount of power available for export; and in the deregulated export markets, the price is more directly connected to the demand. Moreover, the energy markets in the region are not as dominated by hydropower as the market in Quebec, and are thus influenced by the supply of other energy fuels, and particularly the gas price. The exchange rate between the US and Canadian currencies also have a great influence on the export value (Hydro-Quebec, 2009).

Although the above discussion points out difficulties with applying hydropower forecasts to the electricity market in Quebec, it should once again be noted that these difficulties also involves possibilities. Due to the regulations of the Quebecois energy market, the transparency is relatively low and information scarce. Chances are that these regions have not been modelled in a similar way before, that the field might still be unexplored, like a white map.

Sooner or later the energy market in Quebec will have to open up. This fact is emphasized by the relation between Quebec and its neighbouring province Newfoundland and Labrador, which is tense in the context of the electricity politics. To begin with, Newfoundlanders experience themselves robbed of the revenues from the Churchill Falls power generation, and the debate about the terms in the deal has been an infected controversy between the provinces for a long time. Quebec’s proceeding in its denial of letting Labrador connect more hydropower plants to the transmission network rendered the government of Newfoundland and Labrador to settle for the plans to build their own transmission lines over the sea to Island of Newfoundland and the Maritimes. The decision, and Quebec’s role in it, was commented in a news release from the government of Newfoundland and Labrador, May 12 in 2010, citing then premier Danny Williams:

“Today's ruling of the Régie de l'énergie (Régie), Québec’s energy regulator, on a transmission service request by Nalcor Energy once again demonstrates that province's arrogance and discriminatory business practices. [...] The absurdity of their decision is embarrassing to Quebec. What Quebec has done today is to tell the people of Canada and the United States that they will go to any lengths to ensure they have market dominance over electricity markets in northeastern North America.” (Matthews and Barron, 2010).

Newfoundland and Labrador are not alone in their critique of the Quebecois energy market politics. On a more general level, voices are raised to point out the mutual gains for all actors with a transparent and deregulated market. According to Pineau (2013) there is a broad consensus that there would be lots of benefits if the energy markets in Canada could be restructured into a more organized state with more centralized coordination (see section 2.2). How this would be achieved is still unresolved, but a reasonable speculation is that all the markets will tend to move towards deregulation. Ontario and Alberta have already proceeded with this, and many of the other provinces have taken steps in the direction, by opening up for interprovincial and international trading.

7. Conclusions and further studies

The overall objective of this master thesis was to investigate whether the conditions in Eastern Canada qualifies for future forecasting projects. This study shows that modelling of the region is possible, although the value of the forecasts is not easily proven in a straight forward manner at this point.

The hydropower complexes of Churchill Falls in Newfoundland and Labrador and La Grande in Quebec were successfully adapted to the Scania-HBV model. Reasonable Q-targets were built for both models, with an estimated error margin within 10-15% for the single data points. The results of the calibrations and validations were satisfactory. Nash-Sutcliffe values of the calibrations were 0.86 and 0.89, respectively and on weekly basis, for Churchill Falls and La Grande, and the validations amounted to Nash-Sutcliffe of 0.80-0.85.

Although the energy market in Quebec is still regulated and the amount of water inflow to the hydropower systems thus has no direct effect of the provincial power prices, the energy forecast is of interest in the context of electricity export to the US markets. Chances are also that the Quebecois energy market will open up internally in a not too distant future.

In this type of project, the data availability and quality of data are the most crucial factors for successful production of reliable results. In order to refine the models, and to make the construction of more models possible, the author wants to point out the necessity of finding information regarding the hydropower reservoir levels and regulations in Quebec, along with more detailed information about how much each of the respective hydropower systems in Quebec contribute to the total production. This information would simplify the construction of valid models for the rest of the hydropower systems that were not modelled in this study. Moreover, it could be of interest to keep an eye at the development in the Churchill River system, and in Newfoundland and Labrador as a whole. This province is also hydropower dominated and exporting to the US markets, and more transparent to its nature than Quebec.

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