Short Term Hydropower Planning in the Icelandic System

Pjörsá- and Tungnaá River System

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Master’s Degree Project

September 2009

XR-EE-ES 2009:014

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Abstract

This master thesis contains my work of studies of a short term planning model, with the time span of one week, or 168 hours. The models are based on the future hydropower system in Pjórsá- and Tungnaá- river system, located in the south part of Iceland.

The purpose of this thesis is to formulate and develop one week operation schedules for this future power generation system, which for a given inflow- and load forecast returns a good schedule for each power stations in the system.

The planning problem is formulated as a mathematical programming problem. The models used to describe and implement the system under study are a piecewise linear models. For piecewise linear models the breakpoints of the model are the local best-efficiency points. The objective is to return operation plan for each power station in the system, where the the volume of stored water in the end of the planning period is maximized through optimal discharge plans. It is needed to supply contracted load, regulation- and balance power for each hour during the planning period under study.

Two test cases are made for each model in this thesis. The former case describe winter operation, with high consumptions and lower natural inflow to the reservoirs. In the latter case the consumption is low and river inflow high and is meant to describe summer time operation.

Obtained results shows that piecewise linear model gives more realistic results when the load consumption is high and the inflow is low. During summer time, with low load and high inflow, the piecewise linear models schedule more often discharge not on local best-efficiency points. This behavior can be decreased by inserting a penalty cost of discharge changes.

Keyword: Short term planning, hydropower, electrical generation.
Acknowledgements

This masters thesis cover my work carried out at Electric Power System (EPS), Department of Electrical Engineering, Royal Institute of Technology (KTH) in Stockholm, Sweden.

First I would like to thank my supervisor at EPS, Magnus Olsson for all his support, patience and guidelines during my thesis work. I also want to thank Professor Lennart Söder at EPS for his support and for approving this project as this master’s thesis work.

Within Landsvirkjun I would like to to thank my contact person Eggert Guðjónsson, head of generation planning, for his support and for giving my access to all the system data needed for this master thesis. Also for approving this idea and giving me an opportunity to do this internal thesis.

Within Landsvirkjun Power I want to thank Guðlaugur V. Pórarinsson, project manager, for giving my access to all the project planning reports for the new hydropower stations in lower river of Pjórsá.

Stockholm, September 2009
Guðmundur Björnsson
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<th>Variables:</th>
<th>Explanation:</th>
</tr>
</thead>
<tbody>
<tr>
<td>( P_i(k) )</td>
<td>power production in power station ( i ), hour ( k )</td>
</tr>
<tr>
<td>( x_i(k) )</td>
<td>contents of reservoir ( i ) at the end of hour ( k )</td>
</tr>
<tr>
<td>( s_i(k) )</td>
<td>spillage past power station ( i ) during hour ( k )</td>
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<td>( u_i(k) )</td>
<td>discharge in power station ( i ) during hour ( k )</td>
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<tr>
<td>( u_{i,j}(k) )</td>
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<td>( Z )</td>
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<td>( \underline{s}_i(k) )</td>
<td>minimal spillage by power station ( i )</td>
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<tr>
<td>( \lambda_f )</td>
<td>expected future electricity price</td>
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<td>( \tau_{j,i} )</td>
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<td>( n_i )</td>
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<td>( \mathcal{P}_i )</td>
<td>installed capacity in power station ( i )</td>
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<td>( P_c )</td>
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<td>( P_{p} )</td>
<td>contracted primary power / spinning reserve</td>
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<tr>
<td>( P_R )</td>
<td>total reserved power</td>
</tr>
<tr>
<td>( \rho_i )</td>
<td>penalty cost of discharge changes, power station ( i )</td>
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### List of Notations

<table>
<thead>
<tr>
<th>Sets</th>
<th>Explanation</th>
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<tbody>
<tr>
<td>$\mathcal{K}_i$</td>
<td>set of neighboring power stations directly upstream of power station $i$</td>
</tr>
<tr>
<td>$\mathcal{N}_i$</td>
<td>set of indices for all power stations downstream of reservoir $i$, including station $i$ itself</td>
</tr>
<tr>
<td>$\mathcal{I}$</td>
<td>set of all power stations in the system</td>
</tr>
<tr>
<td>$\mathcal{K}$</td>
<td>time duration in the planning period</td>
</tr>
</tbody>
</table>
List of Abbreviations

Explanation:
AGC Automatic Generation Control
GAMS General Algebraic Modeling System
GDX GAMS Data Exchange
GL Gigaliter
LN Landsnet
LP Linear Problem
LV Landsvirkjun
TSO Transmission System Operator

Power stations:
VAF Vatnsfell power station
SIG Sigalda power station
HRA Hrauneyjafoss power station
BUD Búðarháls power station
SUL Sultartangi power station
BUR Búrfell power station
HVA Hvammur power station
HOL Holt power station
URR Urðafoss power station
STE Steingrímsstöð power station
LJO Ljósifoss power station
IRA Írafoss power station
BLA Blanda power station
LAX Laxá power station
KRA Krafla power station
BJA Bjarnarflag power station
KAR Kárahnjúkar power station

Icelandic letters in the thesis:
P / þ Defined as Th / th in english
D / ð Defined as D / d in english
Chapter 1

Introduction

1.1 Background

Renewable energy sources are becoming more and more important at same time as the threats of climate changes are increasing due to pollution. An important benefit of renewable energy sources like wind-, hydro- and geothermal power is that it is clean and does not contribute to pollution.

Iceland is small country compared to other nations, where the population is in excess of three hundred thousand and due to that the public electricity consumption is very low. The Icelandic power system is not connected to other grids in other countries and has no opportunity to transport electricity cross borders like many other countries.

Iceland have large potential in hydro- and geothermal power and only a part of the capacity, which technically can be harnessed, have been harnessed today. Due to this large potential in environmental friendly power sources, many production companies have shown their interests to invest in energy in Iceland. Such companies are for example aluminium smelters and companies in the field of data banks centers and a producers of solar cells.

Because of increased energy requests, many power companies in the country have started their preparation process for planning new power stations, who might be build in nearest future, both in the field of geothermal and hydropower.

The national power company of Iceland - Landsvirkjun has recently started operation of a 690 MW power station, at Kárahnjúkur in the eastern part
of Iceland, mainly build to cover electrical consumption in new aluminium smelter. To be able to meet increased energy request during coming years, Landsvirkjun is planning to expand its generation capacity within hydropower in south part of Iceland.

1.2 The aim of the thesis

The purpose with this project is to obtain knowledge of the upgraded power- and river system in the south part of Iceland. In the area, named after the two main rivers, Þjórsá and Tungnaá, total four new hydropower stations are planned to be built in the future.

Three of these new hydropower stations will be located in the lower part of Þjórsá river and these three stations will all be in series most downstream in the river. The fourth station is planned to be built in the middle of the river system. That station would harness water from Tungnaá river and its location is the fourth most downstream in the present system.

The aim of the thesis is to formulate and develop one week operation schedules for the future power generation system in the south part of Iceland, which for a given load- and inflow forecast produce a good schedule of the power stations in the system where the objective function is to operate the stations as often on their local best-efficiency points and by that maximize the value of stored water in the end of the planning period.

Furthermore the aim is to run different cases with different numbers of hydropower stations, reflecting the new system in southern Iceland. These different cases are studied for different situations in load and inflow to the system, with the aim to reflect summer- and winter time situations in the future system.

The aim is also to study how the stations participate in supplying contracted load during the planning period for each case. Further to investigate if the balance- and primary power is fulfilled, and how great surplus of secondary reserve power are left in the area when all requirements are fulfilled.
1.3 Scope of thesis

The scope of this thesis is to study short term hydropower planning with the timescale of one week of the hydropower system in Pjósá- and Tungnaá river area in south part of Iceland. Time period for longer time than one week will not be under study here therefore seasonal planning or such questions are therefore not considered in this thesis.

The model of the power generation characteristics in this thesis is piecewise Linear Programming\(^1\) modeling approximation of the discharge-generation curve. Another way and also interesting when study multi machine hydropower system is to modeling the system as Mixed Integer Linear Programming\(^2\) problem, but such problem is not within the scope of this thesis and will not be considered here.

Combinations of units which are on-line or off-line is therefore not studied. Questions regarding how the primary control reserve is shared between online units can therefore not be calculated where no binary variables which presents combination of on-line units are in use. Due to this limitation the total surplus of power in each power station every hour is therefore only considered in total, but not how the power surplus is divided down to on-line units.

With same reasoning, start-up and shut-down costs of units or minimum start- and stop times can not be taken into account, where only LP-model is used in this thesis. Units starts and stops are therefore outside the scope of the thesis.

1.4 Overview of the thesis

Chapter 2 contains a presentation of the whole Icelandic electric power system. An introduction to the history of electrification and development of hydropower production in Iceland is given. Also introductions to the development in the electric consumption are presented.

Chapter 3 contains an overview over the Icelandic electricity market, its participants, the transmission system operator, producers, grid owners and consumers in Iceland.

\(^{1}\)LP
\(^{2}\)MILP
Chapter 4 contains an overview over the transmission system in Iceland, its structure and its characteristics feature is explained briefly.

Chapter 5 contain descriptions of theory regarding different planning periods, expansion-, seasonal- and short term planning. Power system operation is presented and introduction to frequency-, primary- and secondary control is given.

Chapter 6 contains the theoretical part of the thesis. This chapter contains the theory behind modeling of hydropower systems. Not only the theory used in the thesis, but also the theory that might be used to develop and improve the work already done in a later stage and in future work.

Chapter 7 contains short description of Landsvirkjun, the National power company of Iceland. Introduction is given to each of Landsvirkjun’s power stations in the present and future systems in the area under study. How the system is modeled, how the problem is formulated and how the theory and the ideas from chapter 6 are used during that work is presented in detail.

Chapters 8 contains presentations of test cases, the summer and winter time simulations as well as introduction to how the penalty cost is implemented. The layout of all the four models models are presented.

Chapter 9 contains selected part of obtained results of the considered cases in the models under study.

Chapter 10 contains discussions about obtained results and what conclusion might be drawn from obtained results.

Chapter 11 contains some ideas and suggestion about how the models can be developed and improved in the further work to return better results.
Chapter 2

The Icelandic Hydro System

This chapter contains a presentation of the Icelandic hydro electrical system. Introductions of the power production, as well as the electric consumption are presented. An overview over the historical stages of electrification in Iceland are given.

2.1 Electric energy system in Iceland

Total installed capacity in the Icelandic power system in 2008 was 2.574 MW. The share of hydropower in total installed power is 1.879 MW, 575 MW comes from geothermal power and 120 MW from fuel power stations, but fuel power are mainly used as back-up stations around the country [2].

Total electric energy production in Iceland in 2008 was 16.467 GWh, which is equally to yearly consumption of barely 52 MWh per inhabitant in Iceland. Between the years 2007 and 2008 the electrical generation increased about 27% mainly due to increased energy consumption in the aluminium industry, where new aluminium smelter started operation. In 2008 around 75% of the electricity was generated with hydropower and 25% with geothermal power in Iceland [2].

2.2 Hydropower in Iceland - historical overview

The history of electrification in Iceland can roughly be divided to three periods. In 2006 total 235 hydropower stations are recorded and registered in Iceland. Almost 80% are smaller than 100 kW and used as private generators on the country side [5]. Table 2.1 gives overview over installed hydropower in Iceland in 2006.
2.2.1 The first period 1904-1934

The first period lasted from 1904 to 1934, but the first hydropower turbine came on stream in December 1904. This was a small hydropower station which electrified a carpenters workshop and manage to electrify 12 other houses in nearest surroundings as well. This small hydropower station had installed capacity of 6 kW and located in Hafnarfjörður close to Reykjavik [27].

The first hydropower station with alternating current generation was built in Seyðisfjörður, in the east part of Iceland in 1913. In the beginning, the power station named Fjarðarselsvíkjun, had an installed capacity of 55 kW and supplied the town and its closest surroundings. This was the first power station who managed to electrify a municipality on its own. Today this is the oldest power station still in operation and have been upgraded to 172 kW [27].

The largest hydropower station built within the period was 1.1 MW station, built 1919-1921, owned and operated by city of Reykjavik. The station became the largest one in sixteen years and was built with the aim to electrify Reykjavik and was located on the outskirts of the town. Today this station is still in operation but has been upgraded to 3.2 MW.

2.2.2 The second period 1935-1964

During the years from 1935 to 1964 which can be defined as the second period, a larger hydropower stations were built to meet increasing population density in the south west and north part of the country. In the beginning of the period the consumption increased mainly because of general use of

<table>
<thead>
<tr>
<th>Installed capacity [MW]</th>
<th>Number of stations</th>
<th>Total installed capacity [MW]</th>
<th>Average annual generation [GWh/year]</th>
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<td>985</td>
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<tr>
<td>&gt; 100</td>
<td>5</td>
<td>900</td>
<td>5,520</td>
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<tr>
<td>Total:</td>
<td>235</td>
<td>1,167</td>
<td>7,015</td>
</tr>
</tbody>
</table>

Table 2.1: Total number of hydropower stations in Iceland in 2006, installed capacity and average annual generation.
electrical equipment at homes, but during the years 1953-1964 the power intensive industry took larger share of the total electrical consumption. Main intensive industry at this time was a fertiliser- and a cement factory.

During the second period, the city of Reykjavik started the Sog Power Company. The company build three hydropower station in the area of Sog, close to Reykjavik. The power stations came on stream the years 1937, 1953 and 1959. The stations are owned and operated by Landsvirkun since 1966, when Reykjavik city incorporated the stations into Landsvirkjun as part of the owner's founding contribution.

To meet the increased consumption due to increased population density, the town of Akureyri started the Laxá Power Company, who build three hydropower stations in the river of Laxá in the north east part of Iceland. The aim was to electrify the town of Akureyri and its nearest surroundings. From 1983 this stations have been owned and operated by Landsvirkun, when the town of Akureyri incorporated the stations into Landsvirkjun as part of the owner’s founding contribution.

2.2.3 The third period 1965 to present days

At the beginning of the sixties a discussions took place about how it would be possible to utilize the country’s energy resources and at same time to increase the exports from Iceland, which at this time were almost only based on fish products.

The government founded a committee with the aim to investigate the possibilities to start up power intensive industry in Iceland. Where the aluminium process is very energy consuming industry, and the aluminum industry through the world was growing at this time it was an attractive idea to start up aluminium smelter as an option to utilize the energy resources for electrical generation.

In 1965 the national power company of Iceland - Landsvirkjun was established. The role of Landsvirkjun at this time was to build and operate new power stations with the aim to supply the futures power intensive industry. The discussions between the committee and foreign power intensive companies resulted in an agreement for a construction of an aluminium smelter. The first aluminum smelter, then owned by ISAL and Landsvirkjun’s first hydropower station Búrfell started operation 1969 [1][24].
Figure 2.1: The development of the Icelandic electricity system from 1960-2007

From 1969, Landsvirkjun has built total eight hydropower stations. Five are located in the south part of Iceland, in the Pjórsá- and Tungnaá river, one in the north part and the new hydropower station in Kárahnjúkár area in the east part of Iceland, who started operation in November 2007. These power stations were more or less built parallel to new consumers within the intensive industry, such as aluminium- and ferrosilicon smelters.

From 1965 to 2008 the electrical generation in Iceland have increased about 96% and about 73% during the twenty years period, from 1988 to 2008. In figure 2.1 it can be seen how the power system has developed through the years and how the system has been build up during the period from 1960 to 2007.
Chapter 3

The Icelandic Electricity Market

This chapter contains a short introduction of the Icelandic electricity market. A presentation of the Icelandic transmission system and its structure is given.

3.1 Reformed electricity market

The Icelandic electricity market became reformed and effective in stages from July 2003, when all companies in the field of power intensive industry could choose its supplier. In January 2005, all final consumers who were power measured could choose their own suppliers. The third and the last stage became effective in the middle of the year 2006 when all users were able to choose their supplier of electricity [22].

The purpose of the new Electricity Act is to contribute to an economical electricity system and to enable competition in the sales of power, by separating the production and sale of electricity from the transmission and distribution part of the power system, which will remain a monopoly.

3.2 Participants in the electricity market

The participants on the electricity market have been gaining their experience in a free market environment the last couple of years. Compared to electricity markets in other countries, the structure of the Icelandic market is different. The market contain no spot market and the transmission system is isolated from other countries, so no cross border trading with electricity is possible.
with other countries.

When the electricity market was formed, the structure and layout of markets in other countries were taken into consideration, but the market is though partly custom-made to Icelandic context and will be under construction and development as participants gain their market experience [10].

3.2.1 Transmission system operator

The transmission system operator (TSO) is responsible for constantly keeping all technical requirements in the power system within limits, such as voltages and to maintain the frequency requirements by keeping the momentary balance between production and consumption in the power system. The system operator has also the responsibility for keeping the spinning reserve in the system within limits to be able to supply primary power when it is needed.

The system operator is also a consumer on the market, where he is responsible for buy power to cover the losses in the transmission system.

The system operator in Iceland is Landsnet. The owners of Landsnet are three power companies, Landsvirkjun- The National Power Company, RARIK-Iceland State Electricity, Orkuveita Reykjavikur (Reykjavik Energy) and Westfjord Power Company, which all put their distribution system and all its equipment into Landsnet as equity.

All power intensive consumers and the distributors are connected to Landsnet’s transmission system as well as all power stations with seven megawatts of installed capacity and higher. Further, it is also a part of Landsnet’s rule to manage the power trading on the balancing market and maintain enough primary reserve power for secured operation of the power system.

3.2.2 Producers

The producers on an electricity market are those who own and operates the power stations and produce the electricity.

Landsvirkjun produce electricity for the power intensive industry and for the wholesale market. The time span of power contracts within the power intensive industry deviate between 20-40 years. No spot market is in operation in Iceland today. The producers sells therefore all its generation through
long term contracts. The time span of contracts today with other producers or retailers, where the electricity is sold to the local households, is in form of one, three, seven or twelve years contracts.

In addition to Landsvirkjun, there are two other large producers on the Icelandic market. These are Reykjavík Energy and Suðurnes Heiding, which operate a geothermal power stations. Additionally four other participants are on the Icelandic electricity market today. Three of them are local power companies, located in the West-fjords, north part and east part of Iceland and one which are located all around the country. These participants also operates their own power stations, but in small scale and buy energy on wholesale for a resale within their local area.

3.2.3 Balance responsibility

It can never be known in advance how much electricity each consumer consume and therefore at same time how much electricity each producer is producing time to time. In general, the deviation in consumption and production between expected and real time consumption is covered by the players on the marked which are balance responsible or balance provider.

The transmission system operator is responsible for the safety and stability of the power system. In order to compensate for the deviation between planned generation and real time generation, the TSO therefore needs to buy balance power on the balancing market to cover the difference.

This balance power is bought from Landsvirkjun, who is the only producers who has contracts with Landsnet as a balance provider. The minimum requirements for the volume of balance power in Iceland is set to ±40 MWh/h for upward- and downward regulation.

Primary power reserve is also needed in the system. Where Landsvirkjun is the only large producer with hydropower, the company has signed a long term contract with Landsnet for having total 100 MWh/h of primary reserve power in the whole country. This power is distributed and located in the south, north and east part of the island and explained in chapter 4.

3.2.4 Grid owners

The main role of the grid owners is to maintain and operate the grid in their own local network. The grid owner is also responsible for measuring the
power inflow and power outflow in the grid. Where some losses occur in the system, the grid owner is responsible to cover these losses and need therefore to buy electricity to cover these losses in his own system.

3.2.5 Consumers

Consumers are all from normal households to large consumers, like power intensive industries. All consumers have to sign a contract with the producer they want to buy the electricity from. Further this same consumers have to sign a contract with the grid owners to be connected to his network and get the electricity distributed.
Chapter 4

The Transmission System in Iceland

4.1 The transmission lines

All main electrical transmission lines in Iceland is operated by Landsnet. The main transmission system consists of lines with voltage level between 132 kV and 220 kV. Landsnet also operates few lines on lower voltages such as 66 kV and 33 kV which also are part of the transmission system [10].

The total length of transmission lines in Iceland is 2,911 km. Total length for each voltage level can be seen in table 4.1. The highest transmission voltage in Iceland is 220 kV, but the most recent lines are built for 400 kV voltage to be able to meet increased consumption in the future. This lines are though currently operated at 220 KV. The round connection around the country is operated at 132 kV.

<table>
<thead>
<tr>
<th>Length of transmission lines at specific voltage level</th>
<th>km</th>
</tr>
</thead>
<tbody>
<tr>
<td>220 kV</td>
<td>612</td>
</tr>
<tr>
<td>132 kV</td>
<td>1,244</td>
</tr>
<tr>
<td>33 kV and 66 kV</td>
<td>1,055</td>
</tr>
<tr>
<td>Total length of transmission lines:</td>
<td>2,911</td>
</tr>
</tbody>
</table>

Table 4.1: Length of transmission lines at specific voltage levels.
4.2 The structure of the transmission system

The transmission system as it looks today is presented in figure 4.1. As mentioned all power stations above seven megawatts of installed power are connected to the transmission system. Total 19 such connection points for inflow of power are in the system today. The connection points where energy is taken out from the transmission system today is on 57 places and connection points for power intensive industry have four connection points to the system. Landsnet’s transmission system is shown in figure 4.1, where the system is divided up to five areas round the country [11].

![Image](image_url)

**Figure 4.1**: The transmission system in Iceland 2008.

Area one - the south part, includes large amount of hydropower station and approximately 40% of installed power in the Icelandic system. The transmission network is strong in this area and consists of meshed 220 kV lines. The production is dominant in area one and therefore a high share of the power is transmitted to south west part, where the main consumption in Iceland is located. Total primary power reserve in the area is 60 MWh/h and is located in the power stations at Pórsá- and Tungnaá river area [11].

Area two - the area surrounding Reykjavík, includes the highest consump-
tion in the system and most of the largest consumer, Reykjavik city and surrounding towns, as well as three of four companies within the power intensive industry. The power stations in this area are mostly geothermal power stations with approximately 20% of total installed power in the system. Large volume of imported power is needed to supply the consumption in the area. This power is transmitted from the south part\(^1\) and north part\(^2\) through the west part of Iceland [11].

Area tree - the west part of Iceland and the west fjords includes quite weak transmission system with long 132 kV as well as 66 kV lines. This area has small share of energy production, therefore it is needed to import largest share of consumed power to the area from north part of Iceland, from area four [11].

Area four - the north part of Iceland contains long 132 kV transmission lines which is a part of the round-connected lines round the island. In the north part, the consumption is low compared to the generated power in the area. Installed power in the north part of Iceland is approximately 10% of installed power in the system, where 7% is hydropower and 3% is geothermal power. Surplus of power in area four is transmitted out from the area and even to the west- and/or east part of Iceland. Total primary power reserve in the area is 10 MWh/h and is located in the hydropower station Blanda [11].

Area five - the east and southeast part of Iceland consist of long 132 kV which form part of the round connection round Iceland. Also 220 kV lines from the new Fljótshlíðar station to the aluminium smelter in the east part, around 50 km distance. Approximately 30% of installed power in the Icelandic system are located in this area. The majority of generated power is supplied to the Aluminium smelter, but also it is transmission to- and from the north- and south part if Iceland. Total primary power reserve in the area is 30 MWh/h and is located in the new hydropower station at the Kárahnjúkar area [11].

Compared to total supplied power to the transmission system in 2008, the total losses in the transmission system became 400 GWh or 2,4% of transmitted power [2].

\(^1\)Area one in figure 4.1
\(^2\)Area four in figure 4.1
Chapter 5

System Planning

This chapter contains introduction of different planning periods used when operation of power systems are planned. The idea behind the theory regarding system operation and frequency control is given.

5.1 Production planning

When power stations are operated, it may be one of the most important task for the owner and the operator, to run the units in such a way that natural resources are utilized in as optimal way as possible. By doing that the power station owner maximize its income at same time, which must be one of the main issue.

When production plans for hydropower systems are made, where many stations and many local inflow rivers are included, many parameters needs to be taken into account to make reliable, efficiency and useable production plan.

Many parameter like inflow and consumptions are not known in advance. Therefore some uncertainties occur in each made schedule, which lead to that planning schedules are needed to be made over and over again, when new and more reliable data are accessible.

By updating important parameters constantly with new information give the planner opportunity to make as reliable production plan as possible though it will never be perfect.

Different planning periods and planning methods can be defined in at least three groups:
• Expansion Planning
• Seasonal Planning
• Short Term Planning

5.1.1 Expansion planning
The time horizon within expansion planning can be years or even decades. Within the time horizon of expansion planning, power producers makes a schedule for futures projects like building new power stations. When consider expansion planning the uncertainty is obvious where the planning have to consider the future growth in electrical consumption, the environmental impact as well as development of investment and operational cost [20].

5.1.2 Seasonal planning
The time horizon within seasonal planning is between 6-12 months. The aim with seasonal planning is to make schedule for the water storage within the time horizon and make decisions about appropriate time of large maintenance work in the power stations [25]. The main uncertainties in seasonal planning are the river inflow, availability of power stations and the load.

5.1.3 Short term planning
The time horizon within short term planning is from one week down to 24 hours. The aim of short term planning is to make schedule for the power stations under study. The schedule has to fulfil contracts about sold electricity as well as the requirement regarding reserved power and other physical requirements. In short term planning, more detailed descriptions of the power stations are needed as well as the hydrological couplings between the stations have to be well known to make reasonable production and discharge plan for the whole system.

In short term planning the uncertainties are mainly the same as in seasonal planning. But where short term planning schedules are made daily and even several times per day, when and if new and more reliable data appears, the variation of the uncertainties are not as large as for larger planning horizons [20].

In addition it may be needed to take the conditions in the transmission
system into account. If there is any bottlenecks due to a maintenance work in the transmission system on specific area. If that is the case it may effect the operation of the power stations in the nearest surrounding.

5.2 System operation

Electrical energy can not be stored. Due to that reason, all electrical energy need to be generated at same time as it is consumed. The transmission system operator is responsible to keep momentarily balance between the generation and consumption in a power system and maintain secure operation of the system.

5.2.1 Frequency control

To keep the momentarily balance between the production and consumption in a power system it is necessary to have automatic control system which can respond within few seconds to deviation between generation and consumption. Such automatic control system is called primary regulation and its aim is to stabilize the frequency in the power system.

When disturbances occur in a power system, where loss of load or loss of generation occur, the new stable frequency will deviate from the nominal value. The new frequency will be higher - for the case with loss of load, or lower - in the case of loss of generation.

When the primary control reserve has been used to stabilize the frequency in the power system after disturbances, an additional control is needed to reset the frequency to its nominal values. To do that, secondary control is used to regain the primary control back, which then can be used again during next disturbances.

5.2.2 Primary control

Primary control determines the capacity of the power system to meet unexpected load- or generation changes. Primary power is automatic control system with the aim to keep the momentary balance between generation and consumption. The total primary power in multi machine hydropower system, are defined as the sum of difference between the maximum generation capacity for the combination of units scheduled on line and their present generation [21].
In a synchronous power system, the deviation between production and consumption occurs in frequency deviation in the system. The nominal value of the frequency can vary between power systems and countries. In North and South America the nominal value is usually 60 Hz, whereas in the Nordic countries, Europe and most of the remaining world uses 50 Hz [26].

As mentioned before, energy can not be stored in a power system, but there is a large rotational mass stored in the system, so called moment of inertia - rotating. This mass is stored in all the rotating synchronous rotors and their turbine shafts.

Assume loss of generating unit in a synchronous power system. From other generators point of view, loss of generation is equal to increase in load. Right after the failure in this generating unit, there is a shortage of power in the system.

Since the generation and the consumption always need to to be in balance, the deficit of power is compensated by using the rotational energy in the rotors and their shafts, which lead to decrease in rotational speed of all the rotating machines in the system.

Where there is a strong connection between rotor speed and electric frequency in synchronous machines, the reduced rotor speed results in a frequency decrease in the grid.

To response to the falling frequency in the grid, frequency sensitive equipment, located on some of the primary control units in hydropower stations, give a signal to increase the opening of the guide vane of the turbines to increase the discharge through the turbine, and at same time the power output from the generator.

When participating generators in the primary control have increased their generation to compensate for the lost unit, the frequency stop decreasing and stabilize again, but at frequency lower than the nominal frequency. Balance has been obtained between generation and consumption again.

Similar courses of events appears in the case of load decrease or generation increase. Then only difference is that the frequency increases, which results in need of decrease the generation in units participating to the primary regulation.
5.2. System operation

How much each generators participate in the primary control depends on their installed frequency sensitive equipment. Generally, the minimum requirements of speed droop characteristics is set by the transmission system operator in each country.

The Icelandic TSO has set minimum requirements regarding the volume of speed droop characteristics to 400 MW/Hz. As described in Chapter 4, the spinning reserve requirements is now set to total 100 MWh/h in the whole country. Additional minimum balance power needed to be available for upward- and downward regulation on the balancing market is ±40 MWh/h for secondary response control.

Since the Icelandic system is small compared with the power system in other countries, all the dynamical swings happen very fast. Therefore the need of systems such as fast and well tuned fault breakers and frequency sensitive equipments are of grate important.

5.2.3 Secondary control

The primary control only stabilize the frequency in the power system. It does not restore the system frequency to the nominal frequency again.

After the frequency in the power system is stable, a part of its system reserve has been used up to maintain the balance between generation and consumption. In such condition, the system is not able to withstand another fault or changes in the system in form of lost generation or increased load.

It is therefore important to restore the frequency to its nominal value, to release the primary control reserves and by that prepare the system to be able to withstand another fault and frequency deviation.

To solve these kind of problems the secondary control is used. The secondary control is slow response control and can be activated within few minutes. In the Nordic countries all secondary control is controlled manually from the control rooms of the system operators, which call for up- or down regulation from the balance providers on the electricity market.

In some power systems, where the Icelandic system is among them, the secondary control is managed with automatic generation control (AGC), to restore the frequency to nominal value and to regain back the primary control
reserves.
Chapter 6

Modeling of Hydropower Systems

_This chapter contains the theoretical part of the thesis - the theory behind modeling a hydropower system. A part of the theory introduced in this chapter are then used to built the simulation models studied in the test cases._

6.1 Hydropower generation

Hydropower generation utilizes the difference in potential energy between the headwater surface and the tailwater surface for power production. The layout and design of hydropower stations are largely influenced by local natural conditions and the generation capacity is usually expressed in kilowatts (kW) for small power generation or megawatts (MW) for large power generation. The selection is based on a careful evaluation of several important parameters, i.e. the gross head and the discharge. The gross head is the difference in elevation between the the headwater surface, and the tailwater surface.

In the process when delivering the water from the intake gate, down the penstock into the turbine losses occurs resulting in decreased gross head. With increased discharge through a hydropower station the gross head decrease where the headwater surface lowered a bit and in same way the tailwater surface rise. Also the losses will increase in the penstock with increased discharge. The losses are therefore a function of the head- and tailwater surface level or up- and downstream reservoirs levels. The generation in a hydropower station will therefore be a function of up- and downstream reservoir level as well as the discharge through the turbines [23],[21].

The losses has an impact on the station’s efficiency often called station or
plant efficiency [23]. The plant efficiency describes how large share of the potential energy stored in the water in the reservoirs can be converted to electrical energy.

The main losses in a hydropower station, effecting the station efficiency are in form of losses in a water ways, turbine and generator. Where no two power stations have neither the same layout nor the same design, their station efficiency are different. For each power station the efficiency, \( \eta_{\text{tot}} \), is a constant and can be defined as [23]:

\[
\eta_{\text{tot}} = \eta_w \cdot \eta_t \cdot \eta_g
\]  
(6.1)

where \( \eta_w \) is the efficiency in a waterways, \( \eta_t \) is turbine efficiency and \( \eta_g \) the efficiency in the generator. Normal values of these efficiencies can be around \( \eta_w \approx 0.90 \), \( \eta_t \approx 0.93 \) and \( \eta_g \approx 0.98 \) [23].

The power output of a hydropower station is proportional to the product of the head and discharge and within the station efficiency it can be expressed as:

\[
P = \rho \cdot g \cdot H \cdot u \cdot \eta_{\text{tot}}
\]  
(6.2)

where

- \( P \) = power production [kW]
- \( \rho \) = water density [\( \text{kg/litre} \)]
- \( g \) = acceleration due to gravity [\( \text{m/s}^2 \)]
- \( H \) = gross head [m]
- \( u \) = discharge through the station [\( \text{m}^3/\text{s} \)]

The total energy production, over a time period can then be calculated as:

\[
E = \int P(t) \, dt \quad \text{[MWh]}
\]  
(6.3)

### 6.2 Efficiency and discharge

One of the characteristics for hydropower system is limitation amount of energy. The energy is stored in the reservoirs, in form of water, and can be used for electrical production in the future. Where this energy is limited it is desirable for the electrical producers to utilize their hydro system in as
optimal way as possible.

To be able to operate a hydropower system in efficiency way a model is needed to describe the couplings between different parts of the system such as reservoirs and the rivers as well as the power stations located in the system. For short term planning problems it is important to obtain as detailed representation of the power stations as possible where the output of the short-term planning schedule will be used to operate the system during the upcoming planning period.

To determine a generation in a power station it is necessary to obtain data about its generation characteristics which describes the generation as a function of the discharge through the station and data about the station's efficiency.

Few concepts are needed to describe a characteristics for a power station. This concepts have to be clear in mind and well defined when modeling and calculating the power generation in a hydropower station. These concepts are the production equivalent, marginal production equivalent and efficiency or relative efficiency.

### 6.2.1 Hour equivalent of water

In following sections within this chapter the water discharge, water spillage and reservoir contents are all defined in the equations as hour equivalents [HE]. One HE corresponds to the volume of 1 m³/s water discharged during one hour, which means 3600 m³ [26].

### 6.2.2 Production equivalent

The production equivalent is the quota between energy generation and the discharge through the turbines and is different for different discharge. The production equivalent is here denoted by \( \gamma \) and measured in MWh/HE. Obtaining data for a generation and discharge, the production equivalent for power station \( i \) at the discharge \( u \) can be calculated by [26]:

\[
\gamma_i(u) = \frac{P_i(u)}{u} \quad \text{[MWh/HE]} \quad (6.4)
\]
6.2.3 Constant production equivalent

The constant production equivalent, for power station \( i \) at the discharge \( u \) can be defined as the constant:

\[
\bar{\gamma}_i = \frac{P_i}{u} \quad \text{[MWh/HE]}
\]  

(6.5)

where \( P_i \) and \( \bar{\gamma} \) are installed capacity for power station \( i \) and maximal discharge through the station respectively.

6.2.4 Marginal production equivalent

To measure how much the power generation will deviate for a small change in discharge the marginal production equivalent is introduced. The marginal production equivalent is declared as:

\[
\mu = \frac{d}{du} P(u) \quad \text{[MWh/HE]}
\]  

(6.6)

6.2.5 Relative efficiency

The relative efficiency is a measure of how much energy can be extracted from each m\(^3\) of water compared to the maximal possible, i.e. it measure the production equivalent for some discharge compared to the maximal production equivalent obtained for the power station.

The relative efficiency is presented as \( \eta \) and is measured in per cent. Having access to data showing production equivalent as a function of the discharge, the relative production equivalent can be calculated as:

\[
\eta(u) = \frac{\gamma(u)}{\gamma_{\text{max}}} \quad \text{[\%]}
\]  

(6.7)

where \( \gamma_{\text{max}} \) is the maximal production equivalent obtained for the station [26].

If the main object of a short-term planning schedule was only to consider the energy generation, without taking other constraints into account, then the power stations would always been operated at their maximal efficiency. For a station with more than one unit, it can be preferable to share the discharge between the units in such a way that the efficiency is maximized, where for each combination of units, there will be a local best-efficiency point [21].
Figure 6.1: An example of a generation characteristics. Power generation as a function of discharge through a station.

Figures 6.1 and 6.2 shows a generation as a function of discharge and the relative efficiency curve respectively for one of the power station under study. As can be seen in figure 6.2 a local best-efficiency point appear for each combination of units. When the discharge reach the local best-efficiency point with highest discharge the efficiency decrease fast.

During high load periods, or during spring floods and summer time when large inflow is into the system, power stations might be operated above their local best-efficiency point with highest flow to avoid spillage.

6.3 Modeling hydropower generation

Where the relation between power generation, discharge and head is a non-linear or non-concave relationship, it is somehow needed to approximate this relations to be able to modeling the power generation as a linear programming problem. Several models are concave approximations of this non-linear or non-concave relationships as the power generation is. The most simplest and common models for the generation characteristics are a linear model and a piecewise linear model.

6.3.1 The linear model

In a linear model the generation is proportional to the discharge and have only one segment. It is easy and fast to solve as a linear programming prob-
lem.

On the other hand, using linear model have several disadvantages. In a linear model the solution may often contain operation points far away from the local best efficiency points, resulting in low efficiency solutions points.

Also it is not possible to consider costs for start-ups or shutdowns in power stations nor forbidden discharge intervals. To be able to take this point into account mixed integer linear programming has to be considered with binary integers to present the unit status in the power stations [20],[21], but will not be considered in this thesis.

### 6.3.2 The piecewise linear model

In the piecewise linear model, shown in figure 6.3, the generation as a function of the discharge is divided into one or more segments. The breakpoints between the segments are located to those discharges where local maxima appears in the efficiency. This is one of the main advantages with the piecewise linear model, because these discharges are then more likely to appear in the solution for scheduled discharge. The marginal production equivalent

![Generation vs. Discharge](image1)

![Relative Efficiency vs. Discharge](image2)

Figure 6.3: A piecewise linear model of one of the station under study
6.3. Modeling hydropower generation

for station $i$ and in each segment $j$ is approximated by the constant $\mu_{i,j}$, according to figure 6.3 and also in equation (6.6) [26].

But it is however possible that the model give solution, where scheduled power stations are not operated close to their local best-efficiency points. In figure 6.3 it can be seen that if the discharge is between the local best-efficiency points the power generation will be overestimated. On the other hand, if scheduled discharge is planned between the local best-efficiency point with highest discharge and maximal discharge through the station, the generation will be underestimated [21],[20].

So the model work properly the marginal production equivalent have to be decreasing with increased number of segments. That is, generation in the first segment have to be more profitable than the second segment, second segment has to be more profitable than the third and so on.

Here, profitable means that more electric energy can by subtracted out of each HE of water. To fulfill this requirements following have to be valid $\mu_{i,j} > \mu_{i,k}$ if $j < k$. Here $\mu_{i,j}$ is the marginal production equivalent in power station $i$ and segment $j$ [26].

### 6.3.3 Total discharge and power generation

Where the marginal production equivalent is approximated by a constant in each segment, the total discharge through power station have to be divided in one variable per segment. For the power station $i$, the total discharge through the power station can mathematically be expressed as:

$$u_i(k) = \sum_{j=1}^{n_i} u_{i,j}(k)$$  \hspace{1cm} (6.8)

$u_i(k) =$ discharge through power station $i$, during hour $k$.

$u_{i,j}(k) =$ discharge in power station $i$, segment $j$, during hour $k$.

$n_i =$ number of segments in power station $i$.

The total power generation in a power station can then be expressed as:

$$P_i(k) = \sum_{j=1}^{n_i} \mu_{i,j} u_{i,j}(k)$$  \hspace{1cm} (6.9)

$P_i(k) =$ power generation in power station $i$, during hour $k$.

$\mu_{i,j} =$ marginal production equivalent in power station $i$, segment $j$. 

6.4 River inflow

To be able to make reliable production plans for a hydropower system and operate the system in an optimal manner, it is important to have as reliable inflow forecast to each power station and reservoir in the system as possible. In this thesis the river inflow to power station \(i\) during hour \(k\) is expressed as \(w_i(k)\). Weather conditions such as rain, temperature and snow melting have great effect on the river inflow. However it can be very difficult to make a good forecast where the weather forecasts is not always reliable.

For a short term planning, which normally span the time scale from one day to one week, it is common approximation to consider the forecasts for the river inflow and the electrical consumptions as perfect and reliable forecasts. When new forecasts are available for the river inflow or consumptions the schedules are updated.

6.5 Reservoirs

Where the electrical consumption is high during periods when natural flow in the rivers are low, like during winter time, reservoirs are needed to store the water, which then can be used for energy generation later in the future.

Many reservoirs are often located in the same river system, with different contents volume and different role from the system operation point of view. The reservoirs with largest volume contents in a river system are normally located in the upper part of the system, while the smaller reservoir are located in the lower part.

6.5.1 Seasonal reservoirs

Some reservoirs have large storage volume in order to store water from the spring flood to the winter when the consumption is high. These type of reservoirs are normally located in the upper part of the river system, as previously mentioned, and are normally used for long term or seasonal energy storage. If there is no rivers connected to the system downstream, these reservoirs can be acting as a source for the whole system downstream.
6.5.2 Short term reservoirs

Reservoirs used for water storage on weekly and daily basis are normally located in the lower part of the river system. These kind of reservoirs are often used for short term operation such as weekly or daily operation of a power stations and are normally located in the lower part of the river system.

6.5.3 Reservoirs operation

Reservoir with a power station downstream may have some requirements regarding how much the water level in a reservoir can variate up and down from some specific normal level time to time. Often the normal operation level for a reservoir is defined from the situation when all units for the power station under study are in operation. These requirements may be set due to environmental or technical reasons and can variate for different periods and different season of the year.

From a electrical producer point of view it is also important to keep the reservoir level within specific limits to obtain and maintain good generation efficiency.

6.5.4 Reservoir constraints

For a power station $i$, with the reservoir storage contents $x_i$, it may be desirable to keep the reservoir level within some upper and lower limits, defined here as $\bar{x}_i$ and $\underline{x}_i$ respectively. Preferable operation level of a reservoir for a power station $i$ can then be be defined as:

$$\underline{x}_i(k) \leq x_i(k) \leq \bar{x}_i(k)$$

(6.10)

Requirements regarding how fast the water surface can be regulated up and down can also be found in some reservoirs. Normally this can be found in those reservoirs where the reservoirs contents are quite small or where the reservoirs water level is sensitive due to inflow, discharge or spillage.

Such constraints can also be found where large and high discharging hydro power station is located with many units. These stations are often able to discharge large volume of water through the turbines during short period of time.
6.6 Spillage

The spillage is the volume of water flowing from a reservoir, by a power station without flowing through the turbines. Here, the spillage, defined as \( s \), in power station \( i \) hour \( k \) is expressed as \( s_i(k) \).

Spillage can be controlled and uncontrolled. Controlled spill can have lower limit \( s_l \) and an upper limit \( s_u \).

\[
 s_l(k) \leq s_i(k) \leq s_u(k) \tag{6.11}
\]

6.6.1 Uncontrolled spillage

Uncontrolled spillage can appear during spring floods when river inflow is large and all the reservoirs in the system are full and can not store more water. During such situation the water flows normally over the specially designed overflow spillways on the dam and down its natural riverbed.

6.6.2 Controlled spillage

Controlled spillage is the contents of water flowing through a controllable gates. Due to environmental reasons it may be stated by special water- or environmental court that it may be needed to spill some minimum flow of water past a power station, down natural riverbed which otherwise would be dry.

It may also be needed to spill water during maintenance periods to fulfill minimum required inflows to downstream power stations, where some power stations do not have any natural inflow. How such power stations are operated from hour to hour, depends on how the closest power station upstream are operated at same time and the spillage from that power station.

6.7 Hydrological coupling between power stations

Hydropower stations can form quite complicated system when they are located in the same river with many reservoirs, different in size and with different role in the system. Cascaded power stations form a coupled system where the operation of the power stations located in the upper part of the river can effect how other stations are operated downstream in same river,
6.7. Hydrological Coupling between Power Stations

as mentioned in section 6.6.2.

The hydrological balance in a river system have to be fulfilled for each hour or other time-step used in the planning schedule. In general, the hydrological coupling can be formulated in words as:

\[
\text{New reservoir contents} = \text{Old reservoir contents} - \text{Water outflow} + \text{Water inflow} \quad (6.12)
\]

This formulation has to be valid for each reservoir, or power station having reservoir, in the system. Mathematically it can be described as:

\[
x_i(k) = x_i(k-1) - u_i(k) - s_i(k) + \sum_{j \in K_i} u_j(k) + \sum_{j \in K_i} s_j(k) + w_i(k) \quad (6.13)
\]

where,

- \(x_i(k)\) = contents of reservoir \(i\) at the end of hour \(k\) [HE]
- \(u_i(k)\) = discharge in power station \(i\) during hour \(k\) [HE]
- \(s_i(k)\) = spillage past power station \(i\) during hour \(k\) [HE]
- \(K_i\) = set of neighbouring power stations directly upstream of power station \(i\)
- \(w_i(k)\) = water inflow to reservoir \(i\) during hour \(k\) [HE]

### 6.7.1 Delay time between power stations

It may be interesting, important and even necessary from operational point of view, for a power company with many hydropower stations in operation in the same river, to consider the time it takes for the river to pass next power station downstream, after the water is discharged from the closest upstream power station.

Considering equation (6.13) again, now with the delay time \(\tau_{ji}\), which is the delay time for the water between station \(j\) and the closest downstream station \(i\) in hours:

\[
x_i(k) = x_i(k-1) - u_i(k) - s_i(k) + \sum_{j \in K_i} u_j(k-\tau_{ji}) + \sum_{j \in K_i} s_j(k-\tau_{ji}) + w_i(k) \quad (6.14)
\]

The delay time between two power stations can be a quite complex function and depend on seasonal condition in the river, the water flow and the reservoir levels in the nearest upstream and downstream reservoirs if there is one. The content of water, situated between two station, is negligible compared to the
total volume in the reservoirs.

However, in some situations it may be important and necessary to know when water discharged from one station reach the next station downstream, particularly if the hydro system contains many reservoirs with small volume which may be sensitive for the inflow.

If it is assumed that the delay time between power station \( j \) and station \( i \) is \( H_j \) hours and \( M_j \) minutes, independent of the discharge, season or the condition in the riverbed, the delay time for the discharge \( u_j \), can be expressed mathematically as weighted average of the discharge \( H_j \) and \( H_j + 1 \) hours earlier, i.e.:

\[
  u_j(k - \tau_{ji}) = \frac{M_j}{60} u_j(k - H_j - 1) + \frac{60 - M_j}{60} u_j(k - H_j)
\]  

(6.15)

The spillage in the system can be formulated with same reasoning and explanation.

### 6.8 Reserve requirements

As discussed in section 5.2.2, spinning power is needed to meet the deviation between the power generation and consumption. This spinning power is called primary reserve and its aim is to stabilize the system frequency during and right after disturbances.

To reset the system frequency to nominal value again, the secondary power is used in addition to the primary reserve.

#### 6.8.1 Primary control reserve

Where it is not known in advance how much each consumer will consume, primary control reserve is needed to meet deviation in load demand during a planning period. The primary control reserve margins are needed to be kept within required limits. These limits are often set by the system operator, who define the volume of power needed to control the system.

The maximum generation capacity for a hydropower station can be calculated as

\[
  \overline{P} = \sum_{i=1}^{I} \sum_{j=1}^{n_i} \mu_{i,j} \overline{u}_{i,j}
\]

(6.16)
The total volume of reserved power needed to be available at any time is here defined by $P_R$. In the case of loss of load, it has to be possible to decrease the generation to balance the generation and consumption. To do that, following load balance constraint has to be valid:

$$\sum_{i=1}^{I} \sum_{j=1}^{n_i} \mu_{i,j} u_{i,j}(k) \geq P_R, \quad \forall k \in \mathcal{K} \quad (6.17)$$

In the case of loss of generating units on line, it has to be possible to increase the generation immediately. To be able to do so, following load balance constraint has also be fulfilled and valid:

$$\sum_{i=1}^{I} \sum_{j=1}^{n_i} \mu_{i,j} u_{i,j}(k) \leq \mathcal{P} - P_R, \quad \forall k \in \mathcal{K} \quad (6.18)$$

How the total reserved power, $P_R$, within these load balance constraints are defined for the Icelandic system under study in this thesis can be seen on page 54.

### 6.8.2 Secondary control reserve

As described in section 5.2.3, a hydro units participating in the secondary reserve do not have to be on line. Where this kind of reserver is normally defined as a a slow responding control they can be started up if it is needed to reset the frequency in the system, and to reset the primary reserve needed in the system to acting in next disturbance.

### 6.9 Penalty cost on discharge changes

Generally, the operation and therefore the discharge through a hydropower station should be as stable within each hour as possible. Large changes in discharge, such as starts and stops should be avoided as much as possible. In [3] and [21], start-up and shot-down costs have been studied.

When generators are started-up and taken off line very often it reduces its lifetime and causing costs which is in form of loss of water during the start up and shut down process, wear and tear of the windings due to temperature changes and as well wear and tear of mechanical equipment during start- and stop processes.

The start-ups and shut downs should be avoided where it is more likelihood
that malfunctions in the control equipment will increase with increased number of start-ups. To avoid such discharge changes and unnecessary start-ups and shut-downs in hydropower stations, penalty costs on discharge changes can be used.

In [20] penalty costs on discharge changes in hydropower stations is introduced. When working with piece-wise linear model, a costs in start-ups and shut-downs can be treated implicitly through these costs.

\[
\delta_i^+(k) = \text{Discharge increase in power station } i \text{ between hour } k - 1 \text{ and hour } k. \text{ (if the discharge is increasing between these hours then } \delta_i^+(k) > 0, \text{ otherwise } \delta_i^+(k) = 0) \\
\delta_i^-(k) = \text{Discharge decrease in power station } i \text{ between hour } k - 1 \text{ and hour } k. \text{ (if the discharge is decreasing between these hours then } \delta_i^-(k) > 0, \text{ otherwise } \delta_i^-(k) = 0)
\]

For each power station and each hour, we need to add discharge change constraints to take care of that these variables are given correct value:

\[
u_i(k) - u_i(k - 1) = \delta_i^+(k) - \delta_i^-(k) \tag{6.19}
\]

We also need to add limits which prevents the discharge changes from becoming negative

\[
0 \leq \delta_i^+(k) \tag{6.20} \\
0 \leq \delta_i^-(k) \tag{6.21}
\]

Together, equations (6.19), (6.20) and (6.21), work in such way that if the discharge in hour \( k \) is larger than in hour \( k - 1 \), that is if the discharge has increased, then \( \delta_i^+(k) \) must be greater than zero, due to that fact that negative values of \( \delta_i^-(k) \) is not allowed, and vice versa.

When we introduce a cost for each discharge change it will become optimal to keep the sum of all changes as small as possible. The total cost of all discharge changes can be presented with

\[
\sum_{i=1}^{I} \sum_{k=1}^{K} \rho_i \left( \delta_i^+(k) + \delta_i^-(k) \right) \tag{6.22}
\]

where \( \rho_i \) is the cost of discharge change for station \( i \).
6.10 Short-term planning problem

6.10.1 Formulation in general

When power producer makes production plan for the system he runs, for upcoming planning period, the aim is to operate the system in such a way that the income during the period is maximized. The total profit is as large as possible when the total income minus the total cost is maximized.

At same time the requirements are that the system fulfills all physical, technical, economical, legal or any other limitation who may appear in the system. In general the formulation can be defined as in (6.23).

Maximise: \( (\text{The income during the planning period + future income}) - (\text{the cost during the planning period + future cost}) \) \hspace{1cm} (6.23)

Subject to: Physical, technical, economical and legal limitation etc.
Chapter 7

The System Under Study

This chapter gives presentation on the system under study. An overview is given on Landsvirkjun - the national power company of Iceland, as well as the power stations in present system- and in the future system under study. The data handling, problem description and problem formulation of the project are introduced with references to the theoretical part introduced in chapter 6.

7.1 The National Power Company

The system under study are owned and operated by Landsvirkjun, the national power company of Iceland. The company was founded on 1 July 1965 and was originally owned by the State of Iceland and the City of Reykjavík. In 1983, the town of Akureyri became third owner. On 1 January 2007, the Icelandic State took over the shares of Reykjavík and Akureyri. Since then, Landsvirkjun is a State-owned company.

Today Landsvirkjun owns and operate total 11 hydropower stations. Eight stations are located in southern part of the country in two different areas. Sog's area, located close to the National park Þingvellir where three stations are located, and the river system in the south part of Iceland, called Æða/Bakagísl and Tungná river system with five hydropower stations. Three stations are in the northern part, also in different areas and the newest and biggest one, 690 MW in Fljótsdalsá river in the east part of Iceland.

Total installed hydropower is 1797 MW. The company also operates two geothermal power stations in the north part of Iceland and two backup power stations driven by fuel and gas, located in the north- and south west part.
In 2008 the Landvirkjun's share in total electrical generation in Iceland was 75%. Country-wide, Landvirkjun has 95% share of electrical generation within hydropower and around 12% share in geothermal power. Considering only Landvirkjun, its total generation in 2008 became 12.345 GWh, where share of hydropower was 96% and 4% from geothermal power. Landvirkjun's growth in electrical generation became 45% between 2007 and 2008 [14].

The company sell electricity only in whole sale, to other power companies and to power intensive industry, which today is mainly aluminum smelters. Landvirkjun is also the only balance provider on the electricity market.

### 7.2 The power stations in present system

The system under study consists of nine hydropower stations, located in south part of Iceland in the rivers of Fjörsá- and Tungnaá. Today there are five hydropower stations in operation in this area and can be seen in figure 7.1, marked with black dots. The four stations marked with the red color are planned to being built in the near future.

The five hydropower stations already in operation in the area have installed capacity of 870 MW. In 2007 these stations produced around 5,900 GWh or approximately 70% of Landvirkjun's total generation that year [13], but after 690 MW Fjótsdahur station in the east part came on stream late year 2007, this share of generation in this five stations has decreased down to 45% in 2008 [14].

#### 7.2.1 Vatnsfell

Vatnsfell is the most upstream power station. It is the newest station in the area and came on stream 2001 after 2 years in construction. Vatnsfell is the sixth large-scale hydropower station built by Landvirkjun. It utilizes the head in the diversion canal between Lake Þórisvatn and Krósklón, the Sigakla station reservoir. Water is carried from the intake in two penstocks, down 67 m of utilized head to two Francis turbines in the powerhouse which drive the generators with a capacity of 45 MW each. A tailrace canal leads from the station to Krósklón reservoir. Because of Vatnsfell's location in the system, it is designed and figured as a peak load station and for maintain the requirements of spinning reserve during summer time if needed. The target is to fill the lake of Þórisvatn, which is a seasonal reservoir, in the end of each
summer. Because of this the operation of Vatnsfell is minimized and only used as a spinning reserve station if possible.

### 7.2.2 Sigalda

Construction of Sigalda, Landsvirkjun’s second large scale hydropower station began in 1973. The station went on stream in 1977-1978 with its three units. The river Tungnaá is dammed to build Sigalda’s reservoir Krókslón, which is around 14 km² and 140 GL of usable storage.

The operation of Sigalda station depends on the local inflow from Tungnaá river and from nearest upstream power station - Vatnsfell. Water is carried from the intake in three penstocks, down 74 m of utilized head to three Francis turbines in the powerhouse with a generators of 50 MW capacity each. A tailrace canal leads from the station to the Hrauneyjafoss reservoir, directly downstreams.

In real live operation Sigalda station contribute to the load deviation within the day and required spinning reserve margins in the area.
7.2.3 Hrauneyjafoss

Construction of Hrauneyjafoss, Landsvirkjun’s third hydropower station began in 1977. The station went on stream in 1981-82. Until Kárahnjúkar hydropower station started its operation with six 115 MW units, Hrauneyjafoss power station had the most powerful generators in the Icelandic electricity system. Three Francis turbines drive 70 MW generating units in the station.

Water is carried from the intake in three penstocks, down 88 m of utilized head to the turbines. The tailrace channel, just over 1 km in length enters the old course of the River Tungnaá.

Where local inflow to Hrauneyjafoss station is almost negligible compared to the discharge through Sigalda’s turbines the reservoir contents of Hrauneyjafoss is determined by the operation of Sigalda power station next upstream and Hrauneyjafoss station itself. These two stations therefore needs to be closely synchronized in operations. Hrauneyjafoss reservoir is around 8.8 km² and 33 GL of usable storage and is operated normally as few days regulation reservoir.

Just like Sigalda power station, Hrauneyjafoss station contribute to the load deviation within the day and where the station is not a base load station the spinning reserve is kept within margins to maintain the power system security.

7.2.4 Sultartangi

Sultartangi is the fifth large-scale power station built by Landsvirkjun. The construction started in 1997 and the station went on stream in 2000. The water through the turbines is utilized from Sultartangi reservoir, which is around 20 km² with 109 GL of usable storage. Utilized head is 44.6 m, where the water is carried in two penstocks down to the powerhouse where two 66 MW generators driven by a Francis turbines are running.

Today, water from three sources meets in Sultartangi reservoir. Discharge through Hrauneyjafoss station, as well as the local inflow from the Þjórsá river and Kaldakvísl river end up in the reservoir.

Due to this large access of water from this inflow sources, Sultartangi station can be operated as a base load station during the largest part of the year. During normal operation the station do not contribute much to load varia-
tions within the day, summer as well as winter time.

During the spring and summer flood, when the inflow is so high that it is impossible to discharge it all through the station, it is quite common that water is spilled through the bottom outlet of Sultartangi dam. This is done to avoid overflow over the spillway of the dam.

It happen also every winter that water need to be spilled through the gates at Sultartangi station, to avoid that too much of ice will end up in the intake reservoir at Bürfell station, next downstream. That has and might cause operational problem in Bürfell due to its small reservoir volume.

7.2.5 Bürfell

Bürfell is the first power station built by Landsvirkjun and most downstream in present system at Bjórsá- and Tungnaá river system. The construction began in 1966 and the power station started operation in 1969, then with installed capacity of 105 MW but expanded to 210 MW in 1972. During the years 1997-1998, Bürfell station was expanded to 288 MW [12]. Bürfell utilizes the water discharged from the next upstream station, Sultartangi.

Where the Bürfell’s reservoir is very small, around 3,6 G.L of usable storage and local inflow is negligible compared to the discharge from next upstream station these two station have to be as close synchronized in discharge as possible. If Sultartangi station is operated at installed power, Bürfell power station can also be operated at installed power, where the station discharge through Sultartangi is very similar as the station discharge through Bürfell station.

Water is carried from the intake down 115 meters of utilized head to the power hose where six Francis turbines drive the generators with a capacity around 48 MW each.

Bürfell station is normally and quite often operated as a base load station, that is, during normal operation the station do not contribute to load variations within the day and run close to its installed capacity.

As mentioned, during winter time it happens that water need to be spilled by Bürfell power station, to avoid to much and to thick ice bits in Bürfell’s reservoir. Ice pieces can by controlled down the spillway at Bürfell by controlling the gates in the river, located in the intake of the reservoir. In such
way it can be controlled that the water flows in to the reservoir but the ice
down its natural river bed.

7.3 The power stations in the future system

Since it is expected that electricity consumption will increase during next
years, total four new hydropower stations have been planned in south part of
Iceland. These stations can be seen in figure 7.1 market with red color. Total
installed power in these three stations are around 350 MW, with expected
total annual generation capacity around 2.645 GWh [15].

The annual average discharge at lower Pjórsá river is around 340 m³/s, which
is close to design discharge for these stations. Due to this reason these sta-
tions will more or less be considered as a base load stations in the Icelandic
power system [8].

The three new stations in lower river or Pjórsá will have minor environmental
effects on its surroundings area. This is due to the fact that the operation on
the stations is based on already regulated inflow from the existing upstream
reservoirs.

The three small reservoir in the lower river of Pjórsá will be up to 90% located in the existing riverbed. No new power lines are needed and the sta-
tions will either be underground or designed in harmony with the landscape
in the area.

7.3.1 Búðarháls

Búðarháls power station is the furthest upstream of the four new power sta-
tion planned. The station is located between Hrauneyjafoss and Sultartangi
power station.

Búðarháls is planned as approximately two 45 MW units power station, to-
tal around 90 MW of installed capacity. Búðarháls utilizes the water from
the river of Tungnaá, after it has been utilized in Sigalda and Hrauneyjafoss
power station. The name of the Búðarháls reservoir, Sporðalda reservoir
will be formed by a dam over the river Kaldakvísl, little downstream where
the intersection of Kaldakvísl and the tailrace canal of Hrauneyjafoss station
cross each other.
From the intake reservoir, about 4 km long tailrace tunnel will transfer the water through Búðarháls mountain, down gross head of 40 meters to the turbines, from which the water will run through 300 meters long tailrace canal into Sultartangi reservoir.

In normal operation the water level in Sporðalda reservoir will be around 337.0 m.a.s.l. with usable storage volume of approximately 32 GL or 7 km² in area [7].

### 7.3.2 Hvammur

The Hvammur power station is located approximately 20 km downstream of Búrfell. The layout in the south Iceland can be seen in figure 7.1. The installed capacity of Hvammur will be approximately 80 MW. The intake reservoir for Hvammur power station, which will be named Hagálón, will be formed by a dam over Pjórsá river and its layout figure is shown in figure 7.2. In normal operation the water level will be in 116 m a.s.l. with volume of approximately 15.5 GL of useable storage volume or 4.6 km² in area [31].

The powerhouse will be underground. A headrace tunnel approximately 400 m long will lead from the intake structures at Hagálón to the power station, from which the water will run through an underground tunnel and then an open canal to Pjórsá river. Figure 7.2 shows the layout for Hvammur power station in lower Pjórsá river before and after the constructions.

![Image](a) Before Hvammur power station  ![Image](b) After Hvammur power station

Figure 7.2: The layout before and after Hvammur power station and Hagálón reservoir have been built.
7.3.3 Holt

The Holt hydropower station is downstream of Hvammur power station. The installed capacity of Holt power station will be approximately 50 MW. The intake reservoir of Holt power station, to be named Árneslón, will be made by a dam over Árneskvísl river. During normal operation the water level will be in 71 m a.s.l. with volume of approximately 13.6 GL of useable storage volume or 4.8 km² in area [29]. Figure 7.3 shows the layout for Holt power station in lower Þjórsá river before and after the constructions.

![Before Holt power station](image1)
![After Holt power station](image2)

Figure 7.3: The layout before and after Holt power station and Árneslón reservoir have been built.

7.3.4 Urriðafoss

Urriðafoss power station is the most downstream in lower Þjórsá river. Urriðafoss will have a capacity of approximately 130 MW. The intake reservoir for this power station, which will be named Heiðarlón, will be formed by a dams over the Þjórsá river and by dykes lying along the west banks of the river. In normal operation the water level in the intake pond will be in 50 m a.s.l. with volume of approximately 17 GL of useable storage volume or around 9 km² in area [8]. Figure 7.4 shows the layout for Urriðafoss power station in lower Þjórsá river before and after the constructions.

More detailed information about the power stations under study are listed up in table 7.1.
7.4 The model of the system

In this section the method and the theory introduced in chapter 6 will be partly used to modeling a simulation models to study the power stations, described in sections 7.2 and 7.3, as well as make a generation schedule.

7.4.1 The data used

All obtained data used to make the model in GAMS, for the power generation, came from Landsvirkjun. Most of the data for the stations already in operation was in form of Excel- files and in a system description report [16],[18] and [19].

The data for the future stations in the area were mostly in forms of project planning reports. These reports gave information about approximately in-

<table>
<thead>
<tr>
<th>Power station</th>
<th>Started operation</th>
<th>Installed capacity [MW]</th>
<th>Turbine type</th>
<th>Gross head</th>
<th>Head-nesses</th>
<th>Reservoir storage</th>
<th>Average annual production</th>
</tr>
</thead>
<tbody>
<tr>
<td>VAF</td>
<td>2001</td>
<td>90 (2x45)</td>
<td>Francis</td>
<td>65 m</td>
<td>160 m$^3$/s</td>
<td>3.2 Gt</td>
<td>300 GWh</td>
</tr>
<tr>
<td>SIG</td>
<td>1977</td>
<td>150 (3x50)</td>
<td>Francis</td>
<td>71 m</td>
<td>132 m$^3$/s</td>
<td>140 Gt</td>
<td>750 GWh</td>
</tr>
<tr>
<td>HRA</td>
<td>1981</td>
<td>210 (3x70)</td>
<td>Francis</td>
<td>88 m</td>
<td>154 m$^3$/s</td>
<td>33 Gt</td>
<td>1100 GWh</td>
</tr>
<tr>
<td>SUL</td>
<td>2000</td>
<td>132 (2x66)</td>
<td>Francis</td>
<td>45 m</td>
<td>316 m$^3$/s</td>
<td>109 Gt</td>
<td>950 GWh</td>
</tr>
<tr>
<td>BUR</td>
<td>1969</td>
<td>288 (6x48)</td>
<td>Francis</td>
<td>115 m</td>
<td>260 m$^3$/s</td>
<td>3.6 Gt</td>
<td>2200 GWh</td>
</tr>
<tr>
<td>BUD</td>
<td>2017</td>
<td>90 (2x45)</td>
<td>Kaplan</td>
<td>35 m</td>
<td>200 m$^3$/s</td>
<td>3.2 Gt</td>
<td>575 GWh</td>
</tr>
<tr>
<td>HVA</td>
<td>2017</td>
<td>80 (2x40)</td>
<td>Kaplan</td>
<td>32 m</td>
<td>310 m$^3$/s</td>
<td>31.6 Gt</td>
<td>670 GWh</td>
</tr>
<tr>
<td>HOL</td>
<td>2017</td>
<td>50 (2x25)</td>
<td>Kaplan</td>
<td>18 m</td>
<td>330 m$^3$/s</td>
<td>27.2 Gt</td>
<td>420 GWh</td>
</tr>
<tr>
<td>URR</td>
<td>2017</td>
<td>130 (2x65)</td>
<td>Kaplan</td>
<td>41 m</td>
<td>370 m$^3$/s</td>
<td>27 Gt</td>
<td>980 GWh</td>
</tr>
</tbody>
</table>

Table 7.1: The power stations in Pjörsá- and Tungnaá river area in the south part of Iceland, in present system and expected future system.
stalled power, harnessed discharge, reservoir volumes as well as number and type of turbines [7],[8],[9],[29],[30],[31],[32].

These reports were then used to make some approximation for the operational curves for the generation characteristics for the new stations.

7.4.2 Power generation model

When dealing with short term planning problems it might be interesting, as well as necessary in some cases, to take as detailed model as possible into account. It is though always some trade of between sufficient results obtained and acceptable solution and calculation time, but as normally it takes longer computation time as more detailed the simulation model is.

The model used to describe the power stations in this thesis, is a piecewise linear model. As previously mentioned and explained in section 6.3.2, page 28, this model will overestimate the generation in all points except the local best efficiency points and the part between the local best efficiency point with highest discharge and maximum flow.

7.4.3 Contracted load to supply

The period under study have a time span of one week - or 168 hours. Two different time of the year are under consideration, a summer time\(^1\) with a low load and winter time\(^2\) with high load.

How the load is defined is shown in equation 7.1. The total load curve, for the whole consumptions to be covered for the winter and summer cases can be seen in figures 7.5(a) and 7.5(b) respectively. The solid line is the base load and other are additional load, according to different case studies.

The load \(D_{add}\) is here assumed to be close to constant load, planned as a long term contract load, sold to power intensive industry or similar industry with close to constant power consumptions.

The real time generation data, outside the area in the south part of Iceland, during the time under study can be seen in figures 7.5(c) and 7.5(d) for the winter- and summer cases respectively. The hydropower stations in Sog’s

\(^1\)The week under study is from Saturday to Friday, 22.07.2006 to 28.07.2006
\(^2\)The week under study is from Saturday to Friday, 27.01.2007 to 02.02.2007
area and the geothermal stations in the north part of Iceland are a base loads stations, where Blanda are following the load outside the area. Subtracting this generation from the total consumption, contracted to Landsvirkjun, the load curve to be fulfilled in the Pjórsár- and Tungnaár area are found, for all cases and are shown in figures 7.5(e) and 7.5(f) for the winter and summer planning period respectively.

\[
D_{\text{tot}}(k) = (D(k) + D_{\text{add}}) - P_{\text{out,gen}}(k) \tag{7.1}
\]

where,

\[
\begin{align*}
D_{\text{tot}}(k) &= \text{The load used in the simulations.} \\
D(k) &= \text{Contracted load, real time data} \\
D_{\text{add}} &= \text{Assumed as constant load. Additional power intensive industry.} \\
P_{\text{out,gen}}(k) &= \text{The power generation in other power stations outside the area under study.}
\end{align*}
\]

### 7.4.4 The inflow data to the system

Landsvirkjun get inflow forecast once a day for next five upcoming days. This inflow forecast is generated from a software which include the history of the river flow into the area under study. Additionally to this inflow history, weather forecast for next five days are taken into a count. By using the inflow history, the weather forecast as well as parameters such as thickness of the snow drifts on the highlands and mountains, this software returns a expected inflow forecast for the areas and rivers where Landsvirkjun is operating its hydropower stations.

As mentioned in section 6.4, page 30, the river inflow to the system is needed for every station, every hour of the planning period. A history of inflow data used for weakly planning, was imported from Excel to GAMS. This was done by using the syntax `gdxin` in GAMS, and described in Appendix A.1.1, page 86.

The inflow to the system, in the considered models, vary between days, but remain stable within each day. The average inflow for each day are used as input to the model and defined as \( \omega_i(k) \)
Figure 7.5: The total load profiles in the system, the generation contribution from other stations outside the area and the load under study during the planning period.
7.4. THE MODEL OF THE SYSTEM

7.4.5 Delay time between power stations under study

Delay time between the hydropower stations in the system under study was not taken into account in this thesis. Introduction and the theory about the delay time was given in section 6.7.1, page 33.

The delay time in the upper part of present river system are very short or around thirty minutes between each reservoir. This is valid for all the hydropower stations from the most upstream station Vatnsfell down to Súltartangi, assuming the new station Búðarháls in the system as well.

On the other hand, the delay time between the stations in the lower part of the river system, i.e. from Súltartangi down to Urriðafoss power station is longer. The delay time in this part of the river system is also more dependent on the condition of the riverbed during winter time. The delay time between each station below Súltartangi is around two to three hours.

The total delay time from most upstream hydropower station to the station most downstream in lower river of Pjórsá can be assumed around twelve hours. Further discussions about the delay time in present and future system can be found in the discussions, section 10.1, page 73.

7.4.6 The reservoirs in the system under study

According to the definitions of the reservoirs in subsections 6.5.1 and 6.5.2, the reservoir in the system under study consist of one seasonal reservoir - Þórisvatn lake and the rest of the reservoirs are short term reservoirs - used from daily and up to a weekly regulations.

All of the reservoirs have some required regulation limits, upper- and lower limits. These limits can deviate between summer and winter time, where in summer time it is needed to regulate the reservoirs at lower water level to avoid spill or overflow if suddenly changes will occur in the inflow, possible caused by heavy rain. Such situation can also occur during winter time when a lot of snow is in the mountains and on the highland. In heavy wind or rain, with temperature over zero degrees the snow can smelt on very short time, and caused heavy inflow to the reservoirs.

In reality it is though hard to avoid spill during summer times in Súltartangi reservoir, which has not enough storing volume to keep all the water coming in. Due to this high inflow from Pjórsá river during summer, it is
necessary to open gates in Sultartangi and spill water to protect the dam. Spilled water in Sultartangi, passes next down stream power station, Búrfell, without being harnessed.

During winter time it may be more preferable to keep the water level high to avoid problems when the river bed or the nearest surrounding of the reservoirs are icy and to maintain higher efficiency. It may happen for a short time period that the inflow from Tungnaá river, to Sigalda station is not enough to keep the reservoir level in accurate water level to maintain secure operation level for the station. It might therefore be needed to run the uppermost station, Vatnsfell, to contribute to the inflow into Sigalda reservoir.

7.5 Problem formulation

As mentioned, the aim is to study present power system described above with this three new hydropower station located in lower river of Bjórsá and the new station, Búðarháls located between the stations Sultartangi and Hrauneyjar. The aim is to make generation plans for the system, fulfilling contracted load, requirements regarding primary- and regulation power every hour as well as taking other constraints into account.

As mentioned in section 3.2.2 no spot market is in operation in Iceland so far. Therefore no opportunity is for producers to sell the electricity into a spot market within the day. Therefore the question - "Should the electricity be generated now and sold into the spot market, or generated later for higher price?" - is not valid question in the Icelandic system today. All the electrical energy generation is sold through long term contracts, with more or less fixed price as described in section 3.2.2. The electricity price might though vary between type of contracts and summer and winter time.

According to this, the generation planning of the hydropower stations in the system run upon to operate the power stations in as efficiency way as possible. The water itself is free but not unlimited. Therefore it is important to operate the hydropower stations is such a way that they generate as much energy from as low amount of water. To maximize stored water in the end of planning period and to avoid spill in the system.

According to equation 6.23, page 37, the problem we want to solve can be formulated in words as following:
Maximise: \( z_1 = \lambda_f \cdot \sum_{i=1}^{T} X_i(T) \cdot \sum_{i=1}^{T} \gamma_i \)  \( \) (7.3)

The expected future electricity price \( \lambda_f \) is set to a price which can reflect some average price of electricity and is set equal to 2500 kr/MWh in the simulated cases.

Where it is not known in advance if it might be possible to schedule the stations in the system on their local best-efficiency points, the production equivalent \( \gamma_i \), appearing in the objective function, is set equal to constant production equivalent \( \bar{\gamma}_i \). Constant production equivalent is presented in equation 6.5, page 26.

Objective function with penalty cost on discharge changes

To avoid unwanted discharge changes in the power stations, a penalty cost was added to the objective function for some of considered cases. This kind of penalty cost was presented and discussed in section 6.9 page 35.

\( z_2 = \lambda_f \cdot \sum_{i=1}^{T} X_i(T) \cdot \sum_{i=1}^{T} \gamma_i - \sum_{i=1}^{T} \sum_{k=1}^{K} \rho_i (\delta_i^+(k) + \delta_i^-(k)) \)  \( \) (7.4)

The basic idea regarding how the penalty cost was distributed between the stations in the systems is as following: During the summer time, the five
most downstream power stations, in Landsvirkjun’s future system, have high inflow to their reservoirs. Therefore, operation at installed capacity to avoid spill situation in the system is preferable in these stations. Therefore no penalty cost is added to the five most downstream stations in the system, where it should not cost to reschedule the operation if the river inflow is hight and if changes is for spilling situation to occur.

Where the target is to lay up water in Pórisvatn lake during the summer time, it is preferable to add highest penalty cost on the most upstream station during the summer time, because it is not preferable to start-up the station under such condition and all start-ups of units should be avoided.

The remaining two stations Sigaldar and Hrauneyjafoss, have to be operated in such a way that it is verified that they meet the remaining load and give most of the the slack in generation in the lower river part, to the five most downstream station in the river area where the inflow is highest. Therefore penalty cost on discharge changes is added to this stations.

### 7.5.2 Constraints

Following constraints have all been presented in detail in chapter 6. Following constraints were considered in the models: Hydrological balance in the system, load constraints - total generation has to be equal to contracted load each hour. Downward regulation as well as upward regulation has to be available and within limits. The last constrains are set to fulfill the penalty cost function.

\[
x_i(k) = x_i(k - 1) - u_i(k) - s_i(k) + \sum_{j \in K_i} u_j(k) + \sum_{j \in K_i} s_j(k) + w_i(k) \quad (7.5)
\]

\[
\forall k \in K, \quad \forall i \in I
\]

\[
\sum_{i=1}^{I} \sum_{j=1}^{n_i} \mu_{i,j} \cdot u_{i,j}(k) = D_{tot}(k), \quad \forall k \in K, \quad (7.6)
\]

\[
\sum_{i=1}^{I} \sum_{j=1}^{n_i} \mu_{i,j} \cdot u_{i,j}(k) \geq P_R, \quad \forall k \in K, \quad (7.7)
\]

\[
\sum_{i=1}^{I} \sum_{j=1}^{n_i} \mu_{i,j} \cdot u_{i,j}(k) \leq \overline{P} - P_R, \quad \forall k \in K, \quad (7.8)
\]

\[
u_i(k) - u_i(k - 1) = \left( \delta_i^+(k) - \delta_i^-(k) \right), \quad \forall k \in K, \quad \forall i \in I \quad (7.9)
\]
7.5. Problem formulation

The total reserved power, $P_R$, within the load balance constraints in equations (7.7) and (7.8) is here defined as the total volume of the power, which Landsvirkjun can not sell. That is, power which has been sold to Landsnet as a primary reserved power ($P_r$) and as balance power on the balance market ($P_b$) in this area under study in south part of the country.

As already described in sections 3.2.3 and 4.2, the sum of primary reserved power and balance power, together form the volume of the total reserved power $P_R$ defined as:

$$P_R = P_r + P_b = 100 \text{ MWh/h} \quad (7.10)$$

This total reserved power is needed to be taken into consideration in the problem formulation.

7.5.3 Limits

Following limits have all been presented in chapter 6 and are used in the problem formulation in this project: discharge, spill, reservoir contents and limits for the penalty cost.

$$0 \leq u_{i,j}(k) \leq \pi_{i,j}, \quad \forall i \in I, \quad \forall k \in \mathcal{K}, \quad j = 1, \ldots, n_i \quad (7.11)$$

$$0 \leq \pi_i(k), \quad \forall i \in I, \quad \forall k \in \mathcal{K}, \quad (7.12)$$

$$\underline{x}_i(k) \leq x_i(k) \leq \overline{x}_i(k), \quad \forall i \in I, \quad \forall k \in \mathcal{K}, \quad (7.13)$$

$$0 \leq \delta^+_i(k), \quad \forall i \in I, \quad \forall k \in \mathcal{K}, \quad (7.14)$$

$$0 \leq \delta^-_i(k), \quad \forall i \in I, \quad \forall k \in \mathcal{K}, \quad (7.15)$$
Chapter 8

Simulated Cases

This chapter contains descriptions of the models used to study the future hydropower system. Different test cases for winter and summer case for inflow and consumption are introduced.

In chapter 7 the hydropower system in Pjórsár- and Tungrnaár river area, in the south part of Iceland were introduced. Presentation was also given on how the system was modeled, and how the theory from the theoretical part of the thesis in chapter 6 was taken into account during that work.

Total four models were made and studied. For each of these models, data for both summer- and winter time cases were used. An short overview over the models and different cases can be seen in table 8.1.

<table>
<thead>
<tr>
<th></th>
<th>Inflow $w_i(k)$</th>
<th>Load $D(k)$</th>
<th>Added load $D_{add}$</th>
<th>New hydro stations</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Model 1</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Summer case</td>
<td>High</td>
<td>Low</td>
<td>0 MW</td>
<td>-</td>
</tr>
<tr>
<td>Winter case</td>
<td>Low</td>
<td>High</td>
<td>0 MW</td>
<td>-</td>
</tr>
<tr>
<td><strong>Model 2</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Summer case</td>
<td>High</td>
<td>Low</td>
<td>80 MW</td>
<td>BUD</td>
</tr>
<tr>
<td>Winter case</td>
<td>Low</td>
<td>High</td>
<td>80 MW</td>
<td>BUD</td>
</tr>
<tr>
<td><strong>Model 3</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Summer case</td>
<td>High</td>
<td>Low</td>
<td>300 MW</td>
<td>URR, HOL, HVA</td>
</tr>
<tr>
<td>Winter case</td>
<td>Low</td>
<td>High</td>
<td>300 MW</td>
<td>URR, HOL, HVA</td>
</tr>
<tr>
<td><strong>Model 4</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Summer case</td>
<td>High</td>
<td>Low</td>
<td>380 MW</td>
<td>BUD, URR, HOL, HVA</td>
</tr>
<tr>
<td>Winter case</td>
<td>Low</td>
<td>High</td>
<td>380 MW</td>
<td>BUD, URR, HOL, HVA</td>
</tr>
</tbody>
</table>

Table 8.1: Introduction to the different simulation cases for each model
8.1 Model 1 - Introduction

Model one contains present system in operation in Pjórsá- and Tungnaá river area, where total five hydropower stations are in operation. The hydro chain layout of model one can be seen in figure 8.1. The numbers within the brackets are numbers of units in each station. The stations in this model have total 16 generating units with installed capacity of 870 MW.

![Hydro system layout](image)

Figure 8.1: Model 1 - Hydro system layout

As earlier mentioned, in section 7.2, the stations in model one can be divided in three groups in real live operation, depending on how they participate in the power generation, i.e. base load station, stations who follows the load more than the others and top load station.

Two most downstream power stations, Búrfell and Sultartangi are planned most of the time of the year, as a base load stations in this system. Two next up-streams stations, Hrauneyjafoss and Sigalka, follows the load within the day more than the other stations and the most upstream station, Vatnsfell, can be defined as a top load station during.

The two most downstream stations are normally operated close to their installed capacity and therefore they do not participate as much in spinning reserve or balance power. This is due to that fact that the inflow to Sultartangi station from Pjórsá river as well as the discharge from Hrauneyjafoss is high. The discharge through Sultartangi close to its installed capacity is plentiful to operate Búrfell at installed capacity as well.
8.2 Model 2 - Introduction

Model two contains present power stations described in section 8.1. The hydro chain layout for the system is shown in figure 8.2. As shown in the figure one new power station has been added to the previous system. This is Búðarháls power station located between Sultartangi and Hrauneyjafoss. Búðarháls station will most likely be built first of these four planned stations, if new power station is going to be built in the area. The stations in this model have total 18 generating units with installed capacity of 960 MW.

![Model 2 - Hydro system layout](image)

The inflow to Búðarháls reservoir is from Káldakvísl river and the outlet discharge from Hrauneyjafoss power station. Compared to the discharge through Hrauneyjafoss power station, the river inflow from Káldakvísl river is very low, or on the scale 3-5% of the discharge through Hrauneyjafoss station [7]. Due to that reason, and due to that fact that usable storage volume at the intake reservoir at Búðarháls is quite small, it is preferable that the discharge through Búðarháls and Hrauneyjafoss is similar. These two stations therefore needs to be operated in synchronous way.

In model two it is assumed that increase in consumption is around 80 MWh/h of constant load, due to expected increase in electrical consumption within power intensive industry or new high-tech industry such as data bank centers or solar cell production.
8.3 Model 3 - Introduction

Model three contains present power stations described in sections 8.1. Additionally to the system are the three power stations in lower river of Pjórsá. These stations were introduced in sections 7.3.2 to 7.3.4. The hydro chain layout for the system is shown in figure 8.3. The stations in this model have total 22 generating units with installed capacity of 1130 MW.

![Figure 8.3: Model 3 - Hydro system layout](image)

Three new hydropower stations are planned down stream of Búrfell station in lower river of Pjórsá. This is Urriðafoss-, Holt- and Hvammur power stations.

In model three it is assumed that increase in consumption is around 300 MWh/h of constant load. This constant load is assumed to be located in south- or southwest part of Iceland due to expected increase in electrical consumption within power intensive industry or new high-tech industry such as data bank centers or solar cell production.
8.4 Model 4 - Introduction

Model four contains present system in operation, with the four additional stations already presented in sections 8.2 and 8.3. The stations in model four have total 24 generating units with installed capacity of 1220 MW.

![Model 4 - Hydro system layout](image)

**Figure 8.4: Model 4 - Hydro system layout**

In model four it is assumed that increase in consumption is around 380 MWh/h of constant load and assumed to be located in south- or southwest part of Iceland due to expected increase in electrical consumption within power intensive industry or new high-tech industry such as data bank centers or solar cell production.
Chapter 9

Results

*This chapter contains presentation of obtained results from the simulated cases presented in chapter 8. The results which are presented in this chapter are only a part of obtained results from the simulations. These results presented here were selected with the aim to describe the main difference between models and selected simulation cases.*

9.1 The layout of the chapter

The results presented in this chapter are only a part of obtained results from the studied cases in Chapter 8. The main part of presented results will focus on the generation plans and how the stations are participating in the generation to fulfill contracted power.

The main object in the results presentations are to study what effects new hydropower station might have on the generation plans in other stations already in operation in Pjorsá- and Tungnaá river area. It is also studied what changes appear in the operation plans for the power stations when penalty cost is added to the objective function.

Further important information from the hydropower operational point of view like how the discharge through stations changes during the planning period, the fluctuation in the reservoir contents etc. can be seen in form of figures in Appendix B for studied cases.

It is worth to mention that obtained results gives only a clue about how the system will behave for this specific planning period and specific input data. By doing some changes on the input data such as the load curves,
generation in station outside the area under study, the inflow profiles or any other approximations - may change the obtained results in the end. Therefore, with this in mind, any detailed and straightforward conclusions have to be taken with little care.

9.2 Generation planning schedules

Figure 9.1 presents generation planning schedules for three different models under study, during a winter time. The figures on the left hand side, shows the total load profile needed to supply in each case. In same figure it can be seen how each station participates to the total load. The figures on the right hand side presents the scheduled generation plan for each power station in that system.

Present system, introduced in section 8.1, can be seen in figures 9.1(a) and 9.1(b). As normally in the reality the two most downstream stations, Búrfell and Sultartangi are scheduled as a base load stations, operating close to their installed capacity with few exceptions and close to their local best efficiency points. The two most upstream stations, Vatnsfell and Sigalda are scheduled in steady operation during the weekend\(^1\), but participating in the load deviation during working days. As seen on the generation plan for Hrauneyjafoss, that station is giving its largest contribution to the load deviation within the week under study.

Adding the new station Búðarháls to the system and increase contracted load about 80 MWh/h, results in the stations contributions to the load as shown in figures 9.1(c) and 9.1(d). As before, the two most downstream stations are operated at installed capacity the whole planning period. The two most upstream stations have similar generation plans as before, steady operation with more contribution to the load deviation within the day at workdays than weekends.

The new station Búðarháls is together with Hrauneyjafoss participating in the load variation within the day. Of all the stations, these two are participating the most in the load deviations between day and nights. By comparison between figures 9.1(b) and 9.1(d) it can be seen that the generation plan for Hrauneyjafoss has flatten out after Búðarháls was added to the system. This shows that Búðarháls is taking pressure of Hrauneyjafoss and giving large share in electrical generation during peak power hours.

\(^1\) During the first 48 hours or so
In figures 9.1(f) the generation schedule can be seen when the three new stations, Urriðafoss, Holt and Hvannmúr are added to the system, as well as 380 MWh/h of constant load. The total load needed to supply is shown in figure 9.1(e).

With the new stations in lower river of Æjörn added to the system, all the five most downstreams power stations - that is the two stations already in operation, Súltartangi and Búrfell - as well as the three new power stations are operated close to their installed capacity during the whole planning period as seen in figure 9.1(f). All the four most upstream stations are giving contribution to the load variation within the day.

## 9.3 Surplus of power in the system

To give even more clear picture of how close to installed capacity the power stations are operated in each case, the surplus of power in the system can be studied. Surplus of power in each station is equal to the station’s installed power minus generated power each hour.

The figures on the right hand side in figure 9.2, presents the surplus of power in each station and case under study. The figures on the left hand side in figure 9.2 presents the total surplus of power in the whole system for each case study - or equally - the sum of the surplus power in all stations on the right hand side of same figure.

If the figures on the right hand side of figure 9.2 are examined, it can be seen that those stations that are most downstream in the river system for each case study, are most often operated at installed capacity. This is due to that fact that the inflow to that part of the hydro system is very high. To avoid spill situations in the lower river part the stations is operated at installed power most of the time.

The stations which are located more upstream in the river system are more or less operated with the aim to store as much water as possible in their reservoir in the end of the planning period. Therefore these power stations, located more upstream in the system are synchronized operated.

On the left hand sides figures in figure 9.2 the total surplus of power is presented. The power reserved as primary- and balance power is shown in
Figure 9.1: Winter Case study: Model 1, model 2 and model 4 - Load curves and generation plans schedules.
9.3. Surplus of power in the system

Figure 9.2: Winter Case study - Model 1, model 2 and model 4: Surplus of power in the system.
these figures as dotted line at 100 MWh/h and defined as $P_{\text{res}}$, defined and explained in equation 7.10 on page 55.

As seen in the figures, the surplus power above $P_{\text{res}}$ which can be sold or used to take generators off lines for maintenance decreases with increased load, even though numbers of power stations in the system increases. For the case studies in model 1 and model 2, shown in figures 9.2(b) and 9.2(d), the surplus power during the peak load periods is around 60 MW, while in figure 9.2(f), presenting model 4, the surplus is around 20 MW during peak load hours during winter time.

### 9.4 Penalty cost on discharge changes

During the summer time studies, when the load was low, inflow high and access to power in the power station was good, many unwanted discharge changes appeared in the operation schedules for the power stations. To avoid such schedules, a penalty cost for discharge changes was added to the objective function, presented in section 6.9, which effected the planning schedules.

Adding penalty cost on discharge changes can be seen in practice as equality to forcing the models to minimize the movements on the gate vanes located on the water wheels. Minimizing movements on the gate vanes might also decrease the wear and tear of the stations control equipments.

This section presents how the theory and the idea behind the penalty cost effected the results. Model four was selected for the comparison, where model four has all the futures power stations planned in Pjörsá- and Tungnaá area. The aim here is more to show what impacts it have on the results to add the penalty cost function, than to present precise numerical results.

Figure 9.3 shows the generation schedule for the summer case under study. The figures on the right hand side present the generation in each station, and the remaining two on the left had side presents the total load needed to supply and how the station participate in the electrical generation.

The two figures on the left hand side presents clearly how the generation plans changes by adding the penalty cost on the discharge changes. As can be seen on figure 9.3(a) the discharge fluctuates very much in each power station which cause unstable power generation.
By running same case again, now with penalty cost on the gate vanes movements, obtained results for station discharges and power generations in each station are much more stable as can be seen on figure 9.3(c). All the large fluctuations are smoothen out. The same can be seen by comparison the two figures on the right hand side on figure 9.4 which present the surplus of power in the stations for same cases.

As can be seen by comparison in the figures, it has good effects on operational schedules to avoid to many discharge changes through the stations. In reality, as already mentioned, it may also decrease the wear and tear of the stations equipments which might decrease needs of maintenance work.

Figure 9.3: Model 4 - Summer case: Generation contribution with and without penalty cost
Where the penalty cost stabilized the operational plans in the stations, which again leads to smoother and higher average discharge over a long period of time, the spillage in the system also decreased for the cases with active penalty cost. At same time the reservoir contents in the smallest reservoirs became more stable within the planning period.

Table 9.1 presents lost energy due to spillage in every station for the models under study. By comparing the two right most columns, for model four in the table, it can be seen that the average spillage decreased with the penalty cost active. The right most column, $\text{Sum}_p$, presents the spillage in MWh when the penalty cost is active and the columns $\text{Sum}$ shows calculated spillage with no discharge changing cost. Same behavior can be seen by study the spillage for model three in the table.

On the other hand this behavior seems to be strange. To get decreased spill in the system after adding penalty cost to the objective function and additional constraints is something which might be needed to study little further. All such detailed study on the spillage were left out of the scope of this thesis.

<table>
<thead>
<tr>
<th>Average spillage in MWh in the system during the planning period</th>
</tr>
</thead>
<tbody>
<tr>
<td><img src="image" alt="Table 9.1" /></td>
</tr>
</tbody>
</table>

Table 9.1: Average spill in the system in MWh: Win = winter case study, Sum = summer case study and $\text{Sum}_p = $ summer case with penalty cost.
Figure 9.4: Model 4 - Summer case: Surplus of power in the system with and without penalty cost
Chapter 10

Discussions and Conclusions

This chapter contains some discussions about the models and the assumption made when the models were implemented. Some general conclusion built on obtained results from chapter 9 are presented.

10.1 Discussions

This thesis presents four models for the future power stations system in the south part of Iceland. All the models are implemented as a piecewise linear. These models includes between five to nine hydropower stations with between 18-24 generators with total installed capacity on the scale 870 MW to 1225 MW.

The purpose of the models was to make generation schedule for each station. Where it could be seen how each station participate in energy production to given load and inflow profiles. The stations should also be operated as often on their local best efficiency points and by that maximizing the reservoir contents in the end of the planning period and spill situations should be avoided if possible.

The contracted load should be fulfilled at same time as the secondary power had to be greater than reserved power for spinning reserve and balance power requirements. Furthermore, the computation time for the models had to be short.

The models and the solution method are tested for high and low inflow to the system. The inflow data were aimed to reflect summer and winter time inflow. All the four models were tested for both summer and winter time
cases. An overview of the model statistics is summarized in table C.1.

For the winter time simulations, when the inflow to the system was low and the energy consumption high, the piecewise linear model gave the most realistic solution. Most of the station were scheduled most of the time on their local best efficiency points and discharge changes did not occur often.

The piecewise models did not work as smooth and in as realistic way for the summer time studies, where inflow was high and low load. Discharge changes occur very often in such cases, the power stations were more often scheduled with operation point between the local best efficiency point, which lead to frequently discharge changes and increased spill situation in the system for stations with small reservoir.

This unwanted behavior was highly decreased and minimized by inserting penalty costs on each discharge changes in the power stations. Resulting in more realistic schedule during the summer time study, with similar operation behavior as for the winter time models.

One of the assumptions made when the models for the power stations and river system were modeled was to assume no delay time between power stations. As mentioned in section 7.4.5, page 51, the delay time in the upper part of the river system are very short or approximately around thirty minutes between each station, for all the stations from the upper most station Vatnsfell down to Sultartangi, assuming the new station Búðarháls in the system as well. The total delay time between Vatnsfell and Sultartangi can therefore be assumed around two hours.

On the other hand, the delay time between the stations in lower part of Pjórsá river are greater. Between Sultartangi and Búrfell is approximately two hours delay time during normal condition when the river bed is not icy. The delay time between Búrfell down to the stations in lower river of Pjórsá can be assumed as three hours between each station or around nine hours from Búrfell to Urriðafoss. The total delay time between Vatnsfell, the hydropower station most upstream in the river system, down to Urriðafoss the most downstream power station can be assumed as twelve hours during normal conditions in the riverbed of Pjórsá.

Búrfell station is though most often scheduled as a base load station with constant discharge. Therefore the river flow in lower part of the river system is not fluctuating that much within the week. That is, the inflow to the
system below Búrfell is almost neglecting volume compared to the discharge through the stations itself. It would though be interesting to take the delay time into account in the whole system.

For the summer cases, when the load was low, the inflow high, a spill could be found in the system and large surplus of power was in the stations where the spill occur. Under that situation GAMS returned a discharge plan, where the power stations changed their discharge through the turbines very often and the discharge varied from low to high discharge constantly at same time water was spilled by the stations. Similar problems, where given solution in GAMS is not obviously close to optimal have also occur in [28] and [4].

10.2 Conclusions

As mentioned in and discussed in page 57, all detailed and narrow conclusions should be taken with little care. Obtained results in this thesis are output results compared to the input data used in the model and the assumptions made for simplification. By changing some of the used input data e.g. the load- or inflow profiles or the power generation in other station outside the area might give some other results. Therefore these results can be seen as a snapshot for this particular data and for all used approximations.

The main conclusions regarding the future river system in Þjórsá- and Tungnaá river can be drawn as following:

- For all studied models and cases the power stations Búrfell and Sultartangi are in all simulation scheduled as a base load stations, operating majority of the time on installed power.

- When the three new power station in lower river of Þjórsá, Urriðafoss, Holt and Hvammur have been added to the system, most of their operation plans are scheduled as a base load stations.

- When the new power stations, Búðarháls, has been added to the system it will more or less be scheduled synchronized with next upstream station Hrauneyjafoss, where the delay time between these stations is very short or and within one hour. Búðarháls station will therefore most often be scheduled to follow the load deviations during day and night within the planning period.

- The primary- and the balance power will mostly be scheduled in the power station located in the station upstream of Sultartangi. At same
time, the stations downstream of Sultartangi, with the station itself included, are frequently scheduled as a base load stations.

- The energy production in Urriðafoss station, the most downstream station in the future system can be expected to be similar to the energy production in Sultartangi station.

- During summer time, when the inflow is high, the spill may occur mostly in the lower part of Þjórsá river. Spill occur more frequently in Búrfell due to its small reservoir volume and below Búrfell during summer time when the inflow is high.

- The spillage in the system decreased when penalty cost on discharge changes was taken into account. It is though needed to study the spillage further but was left out for further work.
Chapter 11

Future Work

In this chapter some ideas and suggestions regarding future work is presented. This will be done in two parts. In the former part interesting improvements on the models presented in this thesis will be discussed. In the latter part of this chapter it is discussed how the models could be developed parallel to the development on the Icelandic electricity market.

11.1 Mixed integer linear model

By developing the models as a mixed integer linear program (MILP-model) a lot of interesting features can be taken into count. One of the advantages with mixed integer liner models is that the station will only be scheduled on their local best-efficiency points, where the discharge is only allowed at a finite numbers of values and one linear segment from the local best efficiency point with highest discharge to the end of the segment - to maximum discharge.

Following features can be taken into account when implementing the models as a MILP-model:

11.1.1 Spinning reserve

Spinning reserve can be taken into account. To be able to calculate the primary power reserve or the spinning reserve in the system, it has to be known which units are on-line and which units are off-line. With MILP model it is easy to include the station’s units status with integer variables.
11.1.2 Forbidden discharge

Forbidden discharge for stations can be implemented with integer variables. There will be local best-efficiency points for each combination of units online. When units are scheduled far from these points means that the units are operating on lower efficiency. In some cases it can also cause risk of cavitation and vibration in the turbines.

11.1.3 Start-up and shut-down costs

Start-up and shut-down costs could be taken into the study with MILP model. Each start and stops are defined with binary variables for each unit. It should be avoided to start-up and shut-down units to often, where such operation can increase likelihood on malfunctions and wear and tear in equipments.

11.1.4 Minimum start- and stop time

Minimum start and stop time could be included in the model. In Landsvirkjun’s system there is a requirements regarding how long time units should be offline if it is shut down. If units are taken off-line, the unit should be off-line for at least four hours. The same requirements is valid for if units are started. In general, total numbers of start- and stops should be minimized in hydropower stations where each start and stop decrease the lifetime of units [21,3].

For the cases where the aim is only to supply given load, and the model only have load constraints to fulfill and e.g. no price variation on electrical market to consider, MILP simulations may have some disadvantages. When having a model where the discharge is only allowed in numbers of operation points, and the aim is only to fulfill given load, it might be difficult for such model to find solution were allowed operation points fulfill the load needed to supply.

11.2 Delay time between power stations

The water delay time for discharged and spilled water between hydropower stations in the system under study, and described in section 6.7.1, page 33, may be interesting when studying short term planning problems. Where the delay time in the lower river of Björnsá is longer than in the upper part of the river it would be interesting to take the delay time into account for the future system.
11.3 Further developments of the project

11.3.1 Short term planning for the whole system

It is known that operation of other power stations in other parts of Iceland, located outside the area under study may have effects on the operation of the hydropower stations in Pjórsá- and Tungnaá river area. To be able to handle the whole system, operated by Landsvirkjun, it would be interesting to take the whole system in Iceland into account.

11.3.2 Cost of balance power in hydropower systems

Cost of balancing power and what causes costs of balance power in hydropower systems - were one of the aims when the proposal for this theses was first made. On later stage of the project work it was decided to leave this part out, due to that fact that this subject was quite complicated and could be enough for separated and independent master’s thesis.

However, in the meantime similar project with the subject title An investigation of the cost of primary regulation was made as a master’s thesis within EPS at KTH. Such investigations would be interesting to study for the Icelandic system. One of the conclusions drawn in this thesis was that cost of primary regulation depends e.g. on reservoir storage volume, inflow to the system, prices on the spot market and expected water value. One factor that is influencing the cost, but do not exist in the Icelandic system are the spot-price on electricity. For further information see [4].

Related to this, and also very interesting project for further work is to investigate and develop method to find out how it would be most profitable to send in bits volumes on the balancing market for up- and down regulations. Master’s thesis with the Swedish title Strategi för utvecklande av reglerbrud has been written about this project, at the department of EPS in KTH. This object would be interesting to study and implement as a further work for the Icelandic system. For further information see [6].
Bibliography


Appendix A

GAMS

This chapter contain overview over the software used to modeling the system in the thesis. A short presentation on General Algebraic Modeling System - GAMS is given.

A.1 General Algebraic Modeling System

The software General Algebraic Modeling System (GAMS) was used to model the system under study and solve the optimization problem. The reason of using GAMS in the thesis is that GAMS is easy to work with and the only software I knew in brief and had seen before used in optimization problems. The program allow the user to concentrate on the modeling of the problem. No special type or very deep knowledge in programming is required to implement and setting up problems in GAMS.

When the software from GAMS is used, there is no need for complex subroutine linkage, storage assignments and flow control. All data are also entered in one file with the form filename.gms. This file is build up in familiar list and table form, and the models can be described as algebraic statements which is easy to read. By that, the possibilities for mistakes when defining the problem is minimized and it gives good opportunity to make some changes and redefine the problem without spending a lot of time on it.

Another very good property by using the GAMS software is the reason that lot of useful information, such as manuals and solution technique can be found on the GAMS on-line homepage free of charge.
Other useable programs to use to solve optimization problems are e.g. Excel from Microsoft [17] and Matlab from Math Works [33]. Using optimization programming in Matlab, quite deep programming knowledge is required. Excel can also be used to solve simple optimization problems. Visual Basic can though be used to solve complex optimization problems if the data are presented on an Excel sheets, but with lot of programming skills in Visual Basic.

A.1.1 Import and export of data

All the majority data needed as input in the models were imported from Excel in to GAMS by using the GAMS Data Exchange (GDX). This was data such as production and efficiency curves for the power stations, the inflow to the system and the load curves.

The GDX property can both be used to import data from external software, to use in the models including GAMS for calculation and simulation. After running the model, the results can be written out to Excel sheets by using .gdxtw, where it is possible to work with obtained data and obtained results.

One of the disadvantage by using GAMS is how complex the solution file is. The solution file is defined with the form filename.lst. In the GAMS version used in this thesis, it took quite a long time to examine the filename.lst file to investigate obtained results, even though the data were exported over to a Excel-Sheet for further study. Good graphical interface within the GAMS software would have been good for quick examination of obtained solution, but was missing.

GAMS includes though very good error code generator. This error code gives detailed information where the errors are located in the programming file if any are found during running stage. This error code contains information in what line in the filename.gms the error is located, and what kind of error it is e.g. undefined variable etc. This given informations are easy to follow and fix.
Appendix B

Figures from Simulated Cases

This Appendix contains obtained results from the models and case studies from Chapter 9. The results is presented in form of figures for all studied cases. Figures B.1 to B.8

For each model, the main presentation is in form of one figure, and discussions for selected cases and presented in Chapter 9. Following figures, from figure B.1 to figure B.8, located on pages 88 to 95, contains six sub-figures, where each sub-figure, with the name from (a) to (f) presents the following:

- Contracted load curve and contribution to the generation in each power station.
- Reservoir contents for each reservoir.
- Discharge plan for each power station.
- Generation plan for each power station.
- Total surplus and reserved power in the system.
- Surplus of power in the power stations.
Figure B.1: Model 1 - Winter: Load curve and generation contribution, reservoir contents, discharge and generation plan, reserved power and surplus of power in the power stations
Figure B.2: Model 2 - Winter: Load curve and generation contribution, reservoir contents, discharge and generation plan, reserved power and surplus of power in the power stations.
(a) Load curve and generation contribution in each power station

(b) Generation in each power station

(c) Reservoir contents

(d) Stations discharge

(e) Reserved- and total surplus of power

(f) Surplus of power in each station

Figure B.3: Model 3 - Winter: Load curve and generation contribution, reservoir contents, discharge and generation plan, reserved power and surplus of power in the power stations
Figure B.4: Model 4 - Winter: Load curve and generation contribution, reservoir contents, discharge and generation plan, reserved power and surplus of power in the power stations
Figure B.5: Model 3 - Summer: Load curve and generation contribution, reservoir contents, discharge- and generation plan, reserved power and surplus of power in the power stations
Figure B.6: Model 3 - Summer, with penalty cost on discharge changes: Load curve and generation contribution, reservoir contents, discharge, and generation plan, reserved power and surplus of power in the power stations.
Figure B.7: Model 4 - Summer: Load curve and generation contribution, reservoir contents, discharge- and generation plan, reserved power and surplus of power in the power stations.
Figure B.8: Model 4 - Summer, with penalty cost on discharge changes: Load curve and generation contribution, reservoir contents, discharge and generation plan, reserved power and surplus of power in the power stations
Appendix C

The Models Statistics

In table C.1 below the model statistic is presented. These information, here called model statistic was given by GAMS and appear in the command window after each run.

The table presents number of iteration for each simulated case, the time it took to run the simulations, and the objective value for each case.

<table>
<thead>
<tr>
<th>$\lambda_f$ = 2500 kr/MWh</th>
<th>Number of iterations</th>
<th>Time [seconds]</th>
<th>Obj. value M kr.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Model 1</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Winter case</td>
<td>10.329</td>
<td>45.726</td>
<td>3.434,311</td>
</tr>
<tr>
<td>Summer case</td>
<td>6.532</td>
<td>69.320</td>
<td>3.592,826</td>
</tr>
</tbody>
</table>

| **Model 2**              |                     |                |                  |
| Winter case              | 12.652              | 37.494         | 3.811,743        |
| Summer case              | 8.531               | 63.582         | 3.992,123        |

| **Model 3**              |                     |                |                  |
| Winter case              | 10.475              | 34.530         | 4.250,298        |
| Summer case              | 5.877               | 52.456         | 4.481,151        |
| Summer case (with penalty cost) | 18.347        | 59.145         | 4.481,135        |

| **Model 4**              |                     |                |                  |
| Winter case              | 13.793              | 32.897         | 4.647,130        |
| Summer case              | 7.784               | 60.217         | 4.896,300        |
| Summer case (with penalty cost) | 33.586        | 64.853         | 4.896,143        |

Table C.1: The models statistics: Number of iteration, computation time and the objective value for each case study
Appendix D

Figures of lower river of Þjórsá

Following four figures within figure D.1 shows the layout for the future’s three new hydropower station in lower Þjórsá:

Figure D.1: Layout figures of lower river of Þjórsá. The location of the three new power station in lower Þjórsá