# Electricity Security in a Hydro-Based Electric Power System: The Particular Case of Iceland

by

Shweta Mehta

B.S. Civil & Environmental Engineering
University of Michigan – Ann Arbor, 2009

M.S. Civil & Environmental Engineering
Stanford University, 2011

SUBMITTED TO THE INSTITUTE FOR DATA, SYSTEMS, AND SOCIETY
IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE DEGREE OF

MASTERS OF SCIENCE IN TECHNOLOGY AND POLICY
AT THE
MASSACHUSETTS INSTITUTE OF TECHNOLOGY

SEPTEMBER 2016



Signature of the Author: Signature redacted
Institute for Data, Systems, and Society
August 22, 2016

Certified By: Signature redacted
Ignacio Pérez-Arriaga
Visiting Professor, Sloan School of Management
Thesis Co-Supervisor

Certified By: Signature redacted
Karen D Tapia-Ahumada
Research Scientist, MIT Energy Initiative
Thesis Co-Supervisor

Certified By: Signature redacted
Pablo Duenas-Martinez
Research Scientist, MIT Energy Initiative
Thesis Co-Supervisor

Accepted By: Signature redacted
Munther Dahleh
William A. Coolidge Professor, Electrical Engineering and Computer Science
Director, Institute for Data, Systems, and Society
Acting Director, Technology and Policy Program

# ACKNOWLEDGEMENTS

These past two years at MIT have been astounding; filled with wonder, new learnings, and challenges. This is a special place, filled with even more special people who want to make the world a better place. My time here, more than ever, makes me believe that anything is possible if approached with hard work and honesty. I would like to thank several people for making this journey possible.

First of all, an immense gratitude to my wonderful advisor, Professor Ignacio Perez-Arriaga, who astounds and inspires me with his energy, intellect, and superhuman abilities. I thank him for giving me the opportunity to work in his research team and for being an ocean of knowledge. I would also like to thank Prof. Andres Ramos Galan, Prof. Michel Rivier, and Prof. Luis Olmos Camacho from IIT Comillas who contributed their time, expertise, hard work, but most importantly their humor on this project.

Words cannot express the gratitude I feel for Dr. Karen Tapia-Ahumada, and Dr. Pablo Duenas Martinez for working with me on a day-to-day basis on this project. I thank them for their unlimited support, unending teachings, infinite support, understanding, and for making this project such a fun experience for me. I deeply admire and am grateful to you both. MIT would not have been the same without you. This research team encompasses everything that I believe MIT stands for: extremely smart, passionate, and with a large heart and integrity.

Nothing is ever complete without a big thank you to my wonderful parents, Mr. Harshad Mehta and Mrs. Archana Mehta, as well as my fabulous sister, Shruti. I thank them for their constant support, encouragement, and faith in my abilities. If not for you, I would not be here. I would also like to thank my friends who are my support system: those from my past life (Adesh, Anjuli, Archana, Bhavna, Dhwani, Gautam, Genevieve, Lavanya, Miloni, Pooja, Puneet, Saaket, Siddharth, Wasay), from my Stanford days (Akhilesh, Arti, Michelle, Shrey, Vighnesh, and Vivek), San Francisco days (Hywel, Megan N., Min, and Shari) as well as my new friends from MIT (fellow TPP-ers: Aizhan, Neha, Kesiena, and Vivian; Junta gang: Ankit, Chai, Kairav, Saurabh, and Sami; and MITei folks: Ashwini, Charlene, and Jordan) for bringing so much joy, happiness, and laughter in my life. Thank you for being there through these past two years and for helping me through the good and hard times.

I would like to end saying a big blanket thank you to all the people who I encountered during my time at MIT- the teaching and administrative staff, caretakers, colleagues, and friends. Thank you for the thought-provoking conversations, the friendly banter, for all the dreams, and inspiration. My time at MIT comes to a close but I will leave with the hope of 'onwards and upwards to making this world a better place'.

# ACRONYMS

| | |
|---|---|
| % | percent |
| € | euro currency |
| $ | United States Dollar |
| AFRL | average final reserve level |
| DSO | distributed system operator |
| EEA | European Economic Area |
| EFC | Energy Forecasting Committee |
| EFRL | expected final reserve level (by scenario) |
| EII | energy intensive industry |
| ENSO | El Nino Southern Oscillation |
| EU | European Union |
| FRL | final reserve level |
| Gl | gigaliter |
| GWh | gigawatt-hour (1,000 MWh) |
| $hm^3$ | cubic hectometer |
| IEA | International Energy Agency |
| IIT | Instituto de Investigación Tecnológica |
| IRL | initial reserve level |
| ISK | Icelandic Krona |
| km | kilometer |
| kV | kilovolt |
| MP | Master Plan for Hydro and Geothermal Energy Resources |
| MFRL | minimum final reserve level |
| MRL | maximum reservoir level |
| MW | megawatt |
| MWh | megawatt hour |
| NEA | National Energy Authority |
| SDP | stochastic dynamic programming |
| SoES | security of electricity supply |
| TEPM | Transmission Expansion Planning Model |
| TSO | Transmission System Operator |
| TWh | terawatt-hour (1,000,000 MWh) |
| UK | United Kingdom |
| US | United States of America |

# GLOSSARY

**Key Players**

| | |
|---|---|
| Althingi | Icelandic Parliament |
| Landsnet | National Transmission System Operator (TSO) |
| Landsvirkjun | The largest public utility in Iceland |
| Orkustofnum | National Energy Authority (NEA) |

# TABLE OF CONTENTS

# LIST OF FIGURES

# LIST OF TABLES

# 1. INTRODUCTION

A secure energy system can be defined as one that is "evolving over time with an adequate capacity to absorb adverse uncertain events, so that it is able to continue satisfying the energy service needs of its intended users with 'acceptable' changes in their amount and prices" (Lombardi & Toniolo, 2015).

Access to a secure electricity supply is essential for a good standard of living in a modern society. Electricity outages can have severe impact on business, schools, homes, financial loss, telecommunications, as well as lead to public safety incidences. For example, the two day-long power outage starting on August 14, 2003 across several northeastern states in the United States of America (US) and parts of Ontario, Canada led to around 50 million US residents losing power as well as an estimated economic loss of around $6.4 billion (Anderson & Geckil, 2003). This number includes lost earnings for investors and worker wages, losses due to spoiled goods or wastage for consumers and industry, and the additional cost to government agencies and tax payers for emergency services and additional police staff (Anderson & Geckil, 2003). Similarly, a substation failure on January 2, 2001 led to the collapse of the entire northern grid in India and blackouts for over 12 hours. Around 250 million people were affected and losses to businesses were estimated at around $107.1 million (Hreinsson, 2016a). Another major blackout on July 30-31, 2012 in northern India due to weak infrastructure and overloading of transmission lines led to 600 million people temporarily having no electricity supply, and resulted in major disruptions in the transportation system, healthcare system, businesses, and even stranded coal miners (BRIEF, 2012). The International Energy Agency (IEA) and European Union (EU) estimate that EU countries need to invest Euro 1 trillion from 2012 to 2020 and an additional Euro 3 trillion till 2050 to ensure adequate electrical capacity (IEA, 2007).

In the case of Iceland, the country has very unique characteristics. Almost 100% of its electricity comes from renewable energy sources (primarily hydro and geothermal), and it has no nuclear, coal, or gas infrastructure. It is an isolated system with an independent transmission network that is disconnected from the rest of the world and hence cannot partake in electricity trade. In addition, Iceland has an ageing transmission network that frequently reaches its tolerance limits along with increasing load demands, especially from the ever growing energy-intensive industry. Finally, it is subject to severe weather conditions such as earthquakes and volcanic eruptions. Due to all these reasons, the country is concerned about how to ensure security of electricity supply in the long-term while maintaining its environmental goals (Hilmarsdóttir, 2015).

## 1.1 MOTIVATION AND OBJECTIVES

The goal of the thesis is to propose regulatory and technical measures to ensure electricity security in a non-intermittent, renewable energy-based power system using the Republic of Iceland (herein referred to as 'Iceland') as a case study. This type of a system is one that is predominantly operating on renewable, non-perishable sources of energy, which are fairly predictable and not dependent on climatic conditions in the short-time frame, such as hydro and geothermal. Solar or wind energy for instance are heavily dependent on atmospheric conditions, which can vary from very short to long-time frames. Reservoir hydropower is very dependent on climatic conditions such as the quantity of rainfall, and glacial melting, among others, which determines whether it is a wet or dry year. However, this dependency is on a seasonal level and does not vary significantly on a daily or even weekly basis.

In particular, this thesis will address the following topics:

1. Qualitative and quantitative analysis of the Icelandic power system to propose regulatory measures to ensure security of supply given uncertainty in future demand and hydro inflows.
2. Quantify the stored water value in the Icelandic power system in order to assess the opportunity cost and tradeoff of using the water now versus in the future. Since the Icelandic power system is primarily hydro-based, managing the water reservoirs and reserve levels plays a critical role in ensuring security of supply.

In order to respond to the proposed questions, the electric power system in Iceland was represented in a computer model that represents the country's generation mix, hydro inflows, and consumer demand. Linear optimization was used to better understand how drought conditions and expected demand growth would impact the supply of electricity in the system.

## **1.2** EXPECTED CONTRIBUTIONS

Given the particularities of the Icelandic power system, the main contribution of this work will be on better understanding the role that some critical factors have on impacting electricity security. The combination of non-flexible clean technologies, such as geothermal in this particular case, with uncertain renewable hydro resources poses several challenges such as the optimum management of the hydro reservoir system, as well as the economic signals that the agents should receive in order to properly operate the system to guarantee its security in the short and long term.

Accordingly, the audience interested in this work can be categorized in two groups:

1. Group one includes those entities that are directly related to this project. The National Energy Regulatory Authority (NEA) of Iceland, Orkustofnun, is most interested in the topic of energy security from a regulatory standpoint. The work would also directly impact and interest the Transmission System Operator (TSO) of Iceland, Landsnet, and the country's largest, public energy company, Landsvirkjun, among other energy companies, as well as the residents of Iceland. The work provides recommendations regarding the management of hydro reservoirs and generation capacity as part of the long-term electricity security planning.
2. Group two includes those that are interested in energy security in hydro- and geothermal systems from a more conceptual standpoint, or those power systems with similar characteristics. In particular, those systems that have a non-flexible, clean technology (i.e., geothermal, nuclear, coal with carbon capture and storage), combined with a renewable resource with long-term uncertainty (i.e., hydro, wind and solar with storage).

## **1.3** STRUCTURE OF THE THESIS

The structure of the thesis is as follows. **Chapter 2** gives a brief background on the current energy situation in Iceland as well as future expansion plans. **Chapter 3** presents a literature review focusing on the definition of electricity security. It also reviews electricity security in other countries that are primarily hydro power-based, including Iceland. **Chapter 4** discusses the modeling representation of the Icelandic power system. **Chapter 5** presents the mathematical formulation of the reference operational model as well as a methodology for the calculation of water value. **Chapter 6** presents the results of the reference model as well as the results from the modeling work on water value. Finally, based on the qualitative and quantitative analysis of the Icelandic power system, the regulatory measures for electricity security are presented in **Chapter 7,** along with a discussion of the insights of the value of water from hydro reservoir management, and future work.

# 2. OVERVIEW OF THE ENERGY SYSTEM IN ICELAND

Iceland is a small Nordic island country at the border of the North Atlantic and Arctic Ocean. With a population of 329,100 spread over 103,000 square kilometers, it has the lowest population density in all of Europe. Iceland sits atop the Mid-Atlantic Ridge which is a fault line where two of the Earth's tectonic plates are slowly drifting apart, resulting in a lot of volcanic and geothermal activity in the region. In addition, about 11 % of its land area is covered by glaciers, which provide ample glacial flows for hydropower. Due to its unique geography and location, it has abundant sources of renewable energy and has a standalone, independent electricity grid that is isolated from the rest of Europe.

## 2.1 COUNTRY ENERGY PROFILE

Energy use in Iceland is predominantly composed of space heating, and electricity. Space heating is provided almost entirely by geothermal resources (91%) and the remainder with electricity (9%) as seen in **Figure 1**.

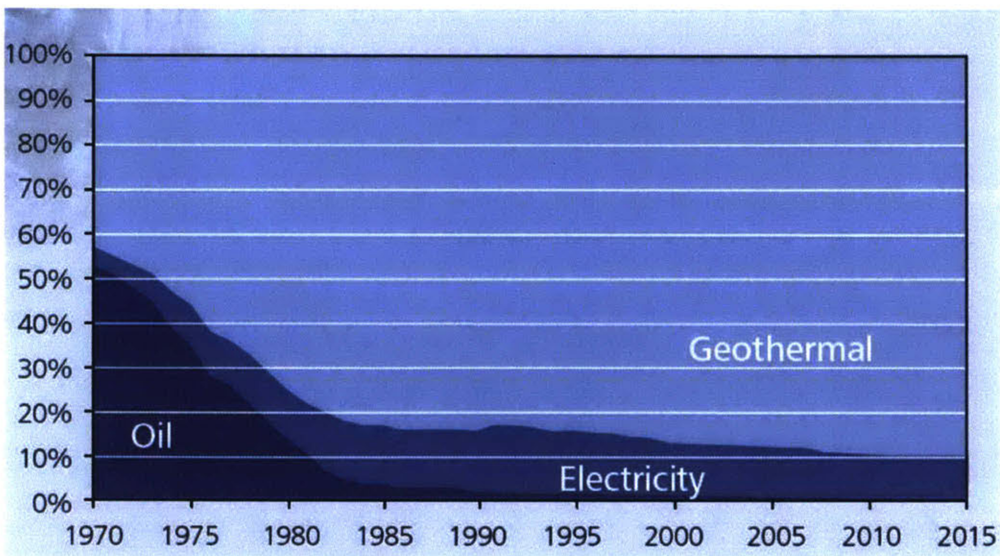


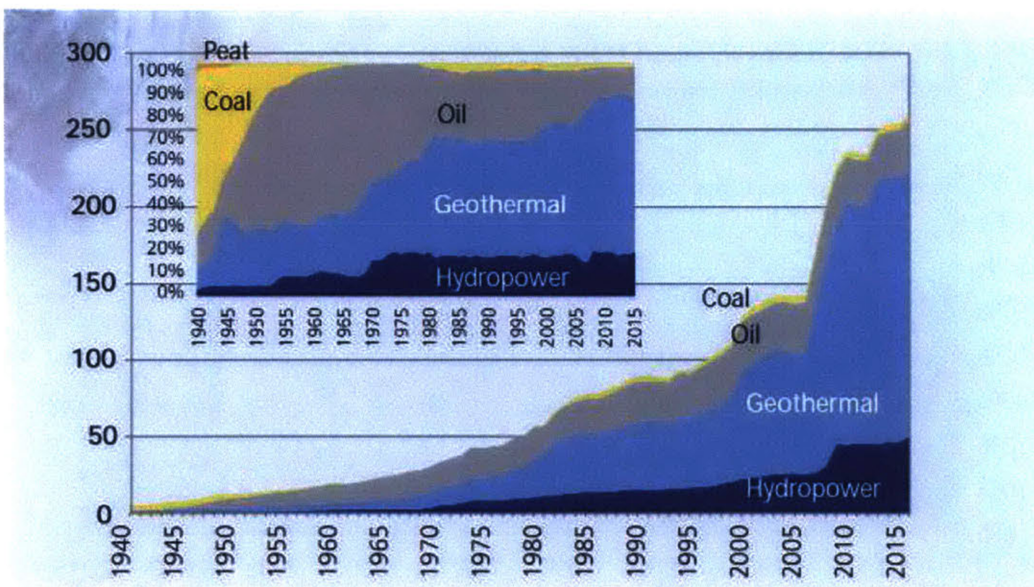

FIGURE 1: EVOLUTION OF FUEL MIX FOR SPACE HEATING (1940 – 2015) (Loftsdóttir et al., 2016)

Electricity generation (for general use and space heating) is composed of 73% hydropower and 27% geothermal power resulting in Iceland meeting almost 100% of its electricity demand from the aforementioned renewable resources, making its electric grid carbon-free as can be seen in **Table 1**.

| 2015 | Power Plant Installed Capacity | | Electricity Production | |
|---|---|---|---|---|
| | MW | % of Total | GWh | % of Total |
| **Hydro** | 1,986 | 71.7 | 13,780 | 73.3 |
| **Geothermal** | 665 | 24 | 5,003 | 26.6 |
| **Fuel** | 117 | 4.2 | 4 | 0 |
| **Wind** | 3 | 0.1 | 11 | 0.1 |
| **Total** | **2,771** | **100** | **18,798** | **100** |

**TABLE 1: POWER PLANT CAPACITY AND ELECTRICITY PRODUCTION IN 2015** (Loftsdóttir et al., 2016)

Oil contributes less than 15% of the primary energy use in Iceland and is mostly used for transportation. As can be seen from **Figure 2**, since the 1940's Iceland has moved from a predominantly fossil-fuel energy mix to a renewable energy-based one (Loftsdóttir et al., 2016). Future plans for electrifying its road and sea transportation will further reduce the dependence on oil for energy. Another factor that has led to developing Iceland's renewable energy potential is the expansion of the transmission grid, to reach remote areas with hydro, geothermal, and wind potential.




Source: Orkustofnun Data Repository OS-2016-T002-01

**FIGURE 2: CHANGE IN ENERGY FUEL MIX FROM 1940 – 2015**

Space heating will be secure due to the unlimited and abundant supply of geothermal energy, as long as it is harnessed in a sustainable fashion. Due to future electrification efforts for transportation (in addition to space heating), and a policy to use 100 % renewable sources for electricity, the discussion of *energy* security in Iceland pertains primarily to *electricity* security.

## 2.2 ICELANDIC POWER SYSTEM

Iceland has a unique power system. Firstly, most of its power is generated from local renewable energy sources: primarily hydro (73%) and geothermal (27%) energy. Secondly, it is an islanded power network, i.e. a standalone grid that is disconnected from the rest of Europe, leaving no scope for electricity import or export. Hence all of Iceland's demands must be met by local generation.

To lay the background for this thesis, a summary of the various components of the Icelandic power system, namely demand (energy consumers), electricity markets (wholesale and retail), transmission system, generation, and future expansion, are described below. There are six main actors on the Icelandic energy market (Hilmarsdóttir, 2015):

a. The energy production companies that produce electricity and feed it into the grid (wholesale market),
b. the transmission system operator, Landsnet, which receives electricity from the energy production companies and transports it to distributors,
c. the local distributors, who deliver electricity regionally to the end users,
d. energy-intensive industries (EII), which buy electricity in bulk and get it directly from the grid,
e. the energy sales or retail companies that sell electricity to other users (retail market), and
f. the National Energy Authority (NEA), whose main responsibilities are to advise the Government of Iceland on energy issues and related topics, license and monitor the development and exploitation of energy and mineral resources, regulate the operation of the electrical transmission and distribution system and promote energy research (Orkustofnun, 2016).

### 2.2.1 DEMAND

Total electricity demand in Iceland in 2015 was 18,659 GWh and is projected to grow between 0.3% - 0.7% each year till 2050 as can be seen in **Figure 3**.

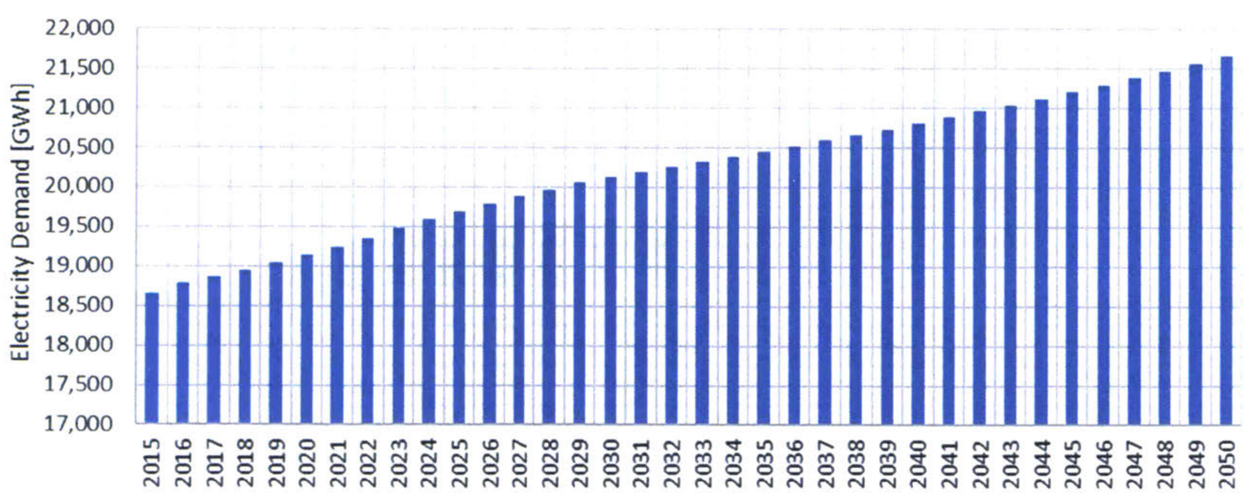



**FIGURE 3: TOTAL PREDICTED ELECTRICITY DEMAND IN ICELAND (2015 - 2050)** (Hreinsson, 2016a)

**Figure 4** shows the breakdown of the electricity demand by industry as of 2011. The abundance of renewable energy in Iceland at a low production cost, costs draws significant interest from the EII and data centers, which consume roughly 86% of total electricity, including 74% used by the aluminum industry alone in 2011 (Íslandsbanki, 2012).

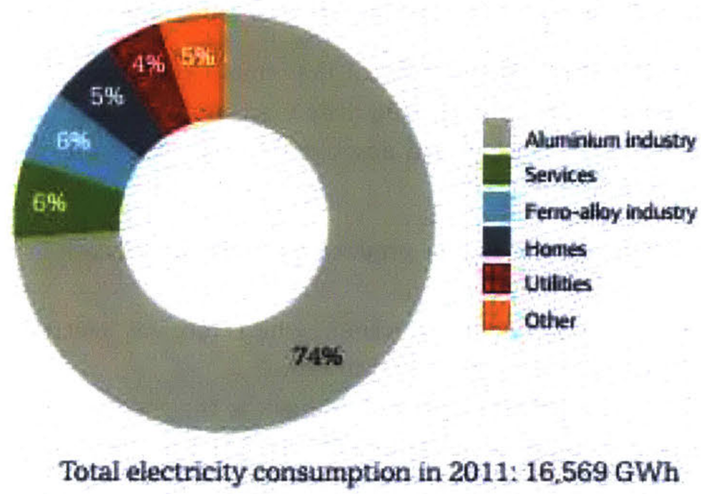



**FIGURE 4: BREAKDOWN OF ELECTRICITY DEMAND BY INDUSTRY (2011)** (Íslandsbanki, 2012)

Iceland has the highest per capita electricity consumption in all of Europe (Orkustofnum, 2012; WorldBank, 2016a) as seen in **Figure 5**. Landsvirkjun and Landsnet met the residential loads utilizing only 5% of total electricity generated (Íslandsbanki, 2012). This statistic is considered to be a misrepresentation inflated by the overwhelming electricity demand by the EII.

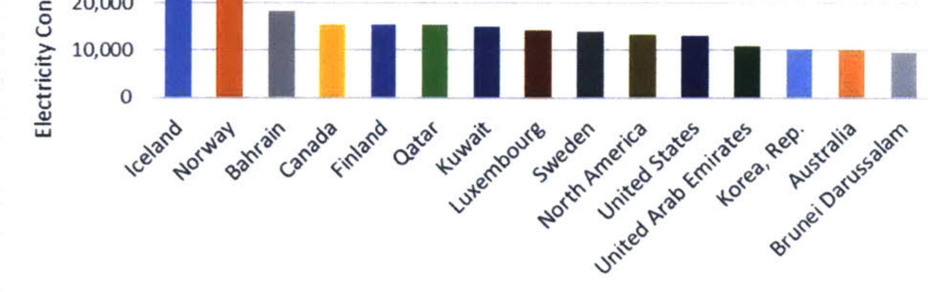



**FIGURE 5: ELECTRICITY CONSUMPTION PER CAPITA** (WorldBank, 2016a)

The main reason for the EII's high demand for electricity in Iceland is that Iceland has the lowest electricity prices when compared to the rest of the countries in Europe as seen in **Figure 6**.

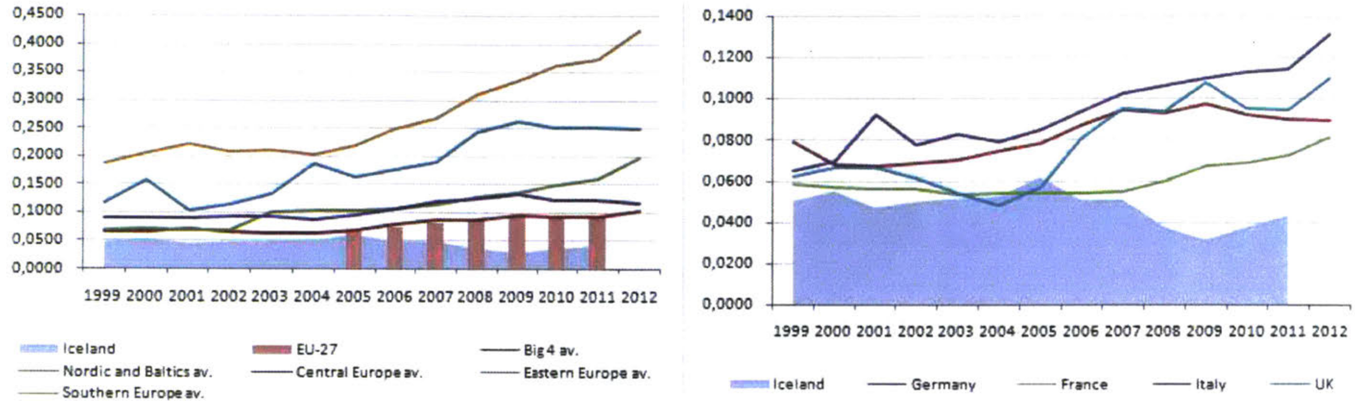



**FIGURE 6: ELECTRICITY PRICES FOR INDUSTRIAL CONSUMERS IN EUROPE** (Gudmundsson, 2012)

Residential demand is located primarily in the south-west and north-east areas of the country, as shown in **Figure 9** below. Whereas the industrial demand is located primarily in the eastern region, which is the place where a large aluminum smelter is located.

## 2.2.2 ELECTRICITY MARKETS

Competition occurs in three distinct ways in the Icelandic market: wholesale competition, retail competition and a competition for energy intensive industry (EII).

**Wholesale Market**

There are six major producers of electricity in Iceland; the national power company Landsvirkjun, Reykjavík Energy, HS Orka, Fallorka, Norðurorka, and Orkusalan. All of these companies are publicly owned except for HS Orka, which is owned by Magma Energy Sweden A.B. and Jarðvarmi slhf (Orkustofnum, 2012). Landsvirkjun, the dominant player produces about 73% of the total electricity and is considered the price-setting firm. The combined production of the three largest companies comprises about 97% of the generation as can be seen in **Figure 7**.

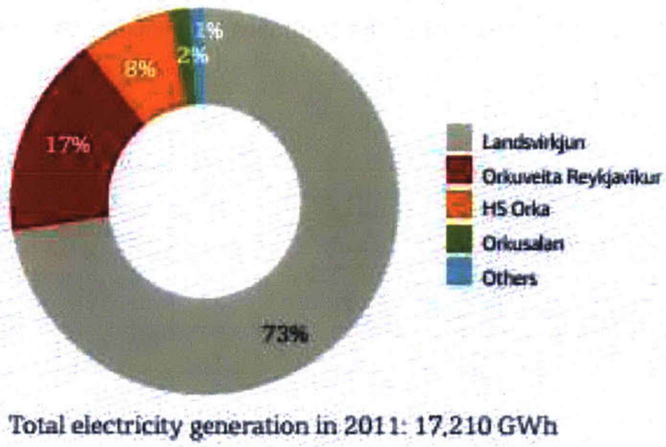



**FIGURE 7: DIVISION OF ELECTRICITY BY PRODUCER** (Íslandsbanki, 2012)

Although liberalization was introduced through the Electricity Act in 2003, retailers still purchase their supply through long-term contracts, as there is no power exchange for the wholesale electricity market yet. Most retailers are either producers themselves, or closely connected through ownership or history to a corresponding producer. Landsnet has been attempting to start a power exchange, which will allow retailers to purchase electricity directly from the market. However, its implementation has suffered several setbacks ranging from a lack of interest from the energy producers, and due to the 2008 financial crisis.

As mentioned, all major power producers enter into long-term power purchase agreements (i.e. bilateral contracts valid for over 10-20 years with a price fixed ahead of time) with EII clients and sales companies operating in the retail market. Hence, energy intensive companies are supplied electricity directly via the bilateral contracts and therefore never directly enter the wholesale market. The contracts are frequently structured on a long-term, "take-or-pay" basis. Under "take-or-pay" contracts the buyer (EII in this case) is obliged to purchase the contracted amount of electricity for the duration of the contract, even if its actual consumption is less (Svedman, Büchel, & Jónsdóttir, 2016). The advantage is that it provides revenue security to the supplier for the duration of the contract period, regardless of the business success of the EII (or changing needs of the buyer) (Svedman et al., 2016). The electricity sales price stipulated in such contracts is usually indexed to the output of the business in question, e.g., the price of aluminum. This results in power producers sharing in the risk/reward of the output market in question. Similarly, smaller power producers either sell directly to their own retail division or enter 7-10 year contracts with retail sales companies (Orkustofnum, 2012).

**Retail Market**

The electricity retail market has been open for all consumers to select a retail company since January 1, 2006. There were seven retail companies in year 2012[1], all of which were part of a DSO (prior to liberalization). All of them still maintain a dominant share of their original consumer base. Only three of the retail companies are active outside their old DSA area and participate in the retail market. The remaining four are very small, primarily serve in the local areas which were designated for them to operate in prior to liberalization, and are not competing in other areas (Orkustofnum, 2012).

Some characteristics of the retail market are the following:

a. ***Development of market concentration***. The top three sales companies supply 37%, 33%, and 17% of electricity to the general market (general market consists of all the consumers in the retail market albeit those EII who have entered into long-term contracts with the power producer).
b. ***Retail Price development.*** Electricity prices for Icelandic end-users are among the lowest in Europe. An indicative price (as advertised by a retail company in 2012) for domestic and mid-scale users, inclusive of distribution services, is in the range of 14.93 to 15.26 ISK/kWh (~0.11 €/kWh[2]) for urban areas and 20.75 to 21.09 ISK/kWh (~0.16 €/kWh[2]) for rural areas, for an annual consumption of 4,000 kWh.[3]

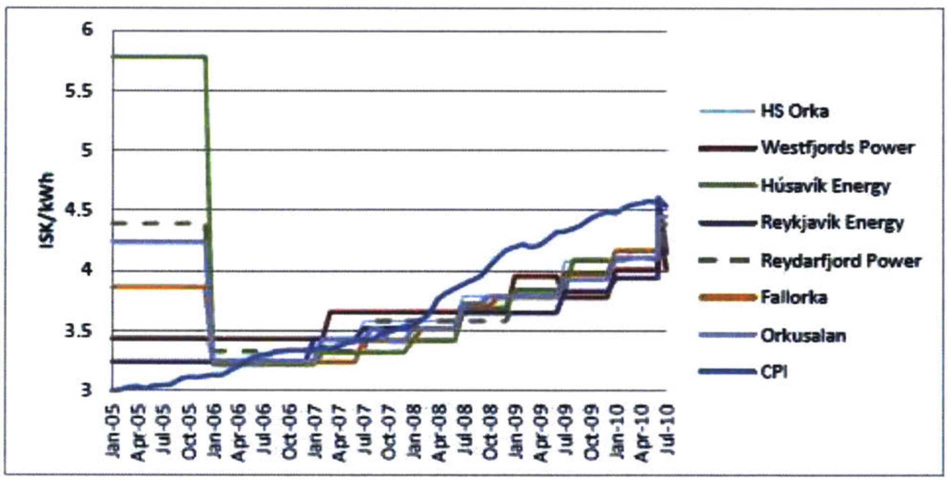



**FIGURE 8: SUPPLY PRICE FOR HOUSEHOLDS 2005-2010 FOR 4,500 KWH OF USE (EXCLUDING VAT)** (Orkustofnum, 2012)

[1] Reykjavík Energy, HS Orka hf., Fallorka, Orkusalan ehf., Westfjords Power Company (Orkubú Vestfjarða), Orkuveita Húsavíkur, Reydarfjord Electric Supply Company (Rafveita Reyðafjarða) and Eyvindartunga.

[2] Conversion between ISK to euro is based on August 2016 rates. Conversion rate used is 1 Euro = 132.03 ISK.

[3] As per https://www.stat.ee/57199, the 2012 electricity prices for medium-size households in Germany and the UK were 2.3 and 1.5 times that of Iceland, respectively.

Whereas the average price[4] calculated for households, services and light industry, was ISK 17.20 per kWh inclusive of VAT (25.5%) and energy tax of 0.12 ISK/kWh. This average price is split between distribution and retail vendor costs (including electricity generation) as 11.65 and 5.54 per kWh, respectively (i.e., 68% and 32%). No special measures have been taken to encourage competition, though a few signs of competition can be seen e.g. through online advertising of retail prices. NEA, in cooperation with the Consumer Agency, operates a price comparison website that compares available contracts of the market (Orkusetur, 2016). The customer can easily carry out an evaluation and make the choice of supplier using a price calculator. A large portion of electricity supplied by retailers is bought from Landsvirkjun which dominates the bulk market. The minimal price difference between retailers, as can be seen in **Figure 8**, results in a fairly dormant retail market.

c. *Development of switching*. Consumer switching to a competitive retail supplier is free of cost and yet has been very low since its inception (only 0.2% of residential customers, and 2.5% of the industrial and commercial customers switched suppliers in 2012). The majority of customers buy from the same retailer that was once the vertically-integrated utility in the area, prior to liberalization. The reason for the low switching rate might stem from the fact that the published prices are very similar between all the companies (Orkustofnum, 2012).

### 2.2.3 Electrical Transmission and Distribution System

The Icelandic transmission grid as seen in **Figure 9,** forms a ring around the island and has been rightly called the lifeline of the country. Iceland has a single defined transmission grid –owned by Landsnet who also serves as the transmission system operator (TSO)-- that transports electricity from producers to several regional distribution networks, which then transports the energy to the end users. These regional distribution networks are operated by six distribution system operators (DSO) licensed by the NEA to distribute electricity in their designated areas (Kerr, 2014). EII clients are fed electricity directly from the transmission system.

Landsnet began operations at the start of 2005 on the basis of the 2003 Electricity Act. It is the sole owner and operates all bulk transmission lines in the country. Landsnet is a public company owned by Landsvirkjun (64.73%), Iceland State Electricity (RARIK) (22.51%), Reykjavik Energy (6.78%) and the Westfjord Power Company (5.98%). It operates under a concession arrangement and is subject to regulation by the NEA, which determines the revenue cap on which its tariff is based (Landsvirkjun, 2015a).

The 3,200 kilometer (km) line transmission network includes lines with voltages of 33, 66, 132, and 220 kilovolt (kV), the latter being the highest operating voltage. Transmission lines in the south-west and east of Iceland were built as 420 kV lines but operate at 220 kV. All power stations with a capacity of 1

[4] The average price is calculated based on Reykjavik Electricity's tariff at the end of 2012. It is calculated based on the total price of electricity for household, services and light industry over a utilization time of 4,000 hours in a year.

megawatt (MW) and higher must be connected to the grid, into which power is fed at 20 locations. The grid then delivers the electricity to distributors at 59 locations around Iceland and to power-intensive users at six locations. Distributors then supply the energy onwards to the consumer via their own distribution networks (Landsnet, 2015a).

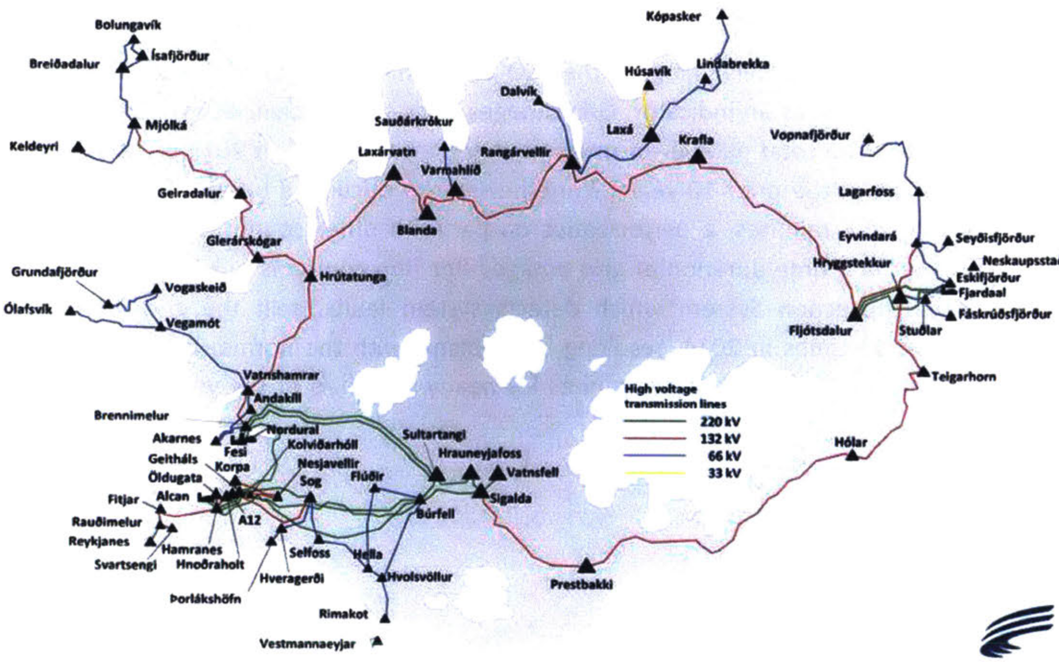



**FIGURE 9: THE TRANSMISSION NETWORK (2010)** (Landsnet, 2016)

The construction of the Regional Ring Network in 1972 to 1984 made a decisive difference for communities and economic development around Iceland. The power system in Iceland, as mentioned before, is dominated by hydro and geothermal power. The construction of the Regional Ring Network had a great impact on the environment since it allowed access to clean energy located in remote regions around Iceland, but it is also controversial as it crosses some areas of exceptional environmental interest. Greenhouse effects were dramatically reduced when cleaner, domestic energy generated by hydropower or geothermal facilities replaced generating stations powered by imported diesel oil.

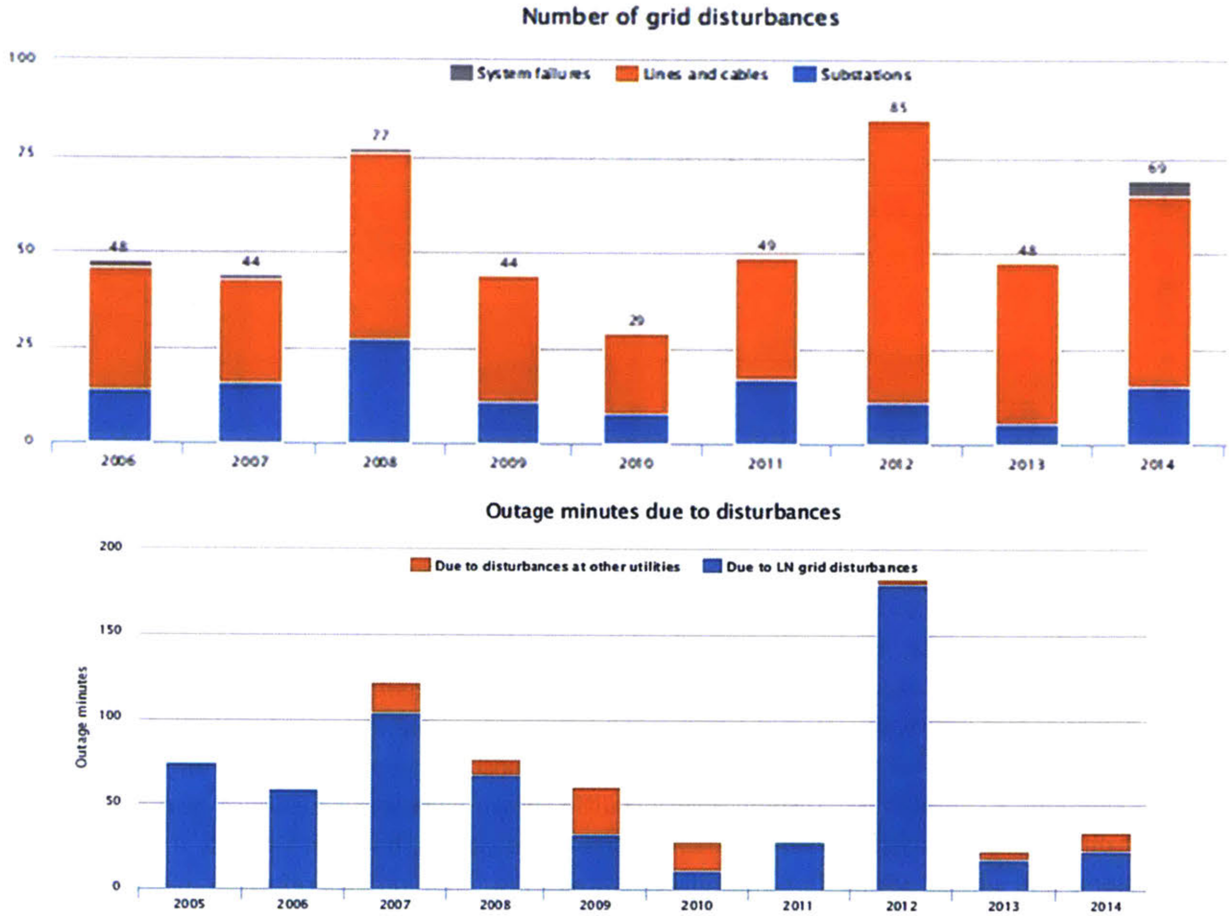
Currently, however, the network's operation is affected by transmission constraints and instability that impede development around the country. There are currently intense debates in Iceland on the topic of electricity security and future upgrades to the energy systems including generation capacity and the transmission network itself. For example, as of 2014, increased transmission through the grid coupled with system weaknesses have led to a rise in energy losses and growing operational risk. In addition, the network is also susceptible to harsh climatic conditions. In 2014 "there were frequent disturbances and infrastructure damage in East Iceland due to persistent north-easterly winds, with heavy icing conditions and high wind speeds right from the beginning of the year into March" (Landsnet, 2014). "In late winter, there were repeated disturbances in the West Fjords due to severe storms" (Landsnet, 2014). In such extreme conditions with high wind speeds, geological activity and snowstorms, it is very challenging to repair the transmission network and have it back up and running. This results in longer time periods of outages. In addition to the outages, there are costs associated with incident-related damage to assets such as electrical equipment, coordination operation of water reservoirs and business operations resorting to being powered by oil, leading to increased pollution. Landsnet projects that the macroeconomic costs of grid bottlenecks will run in to billions of Icelandic Krona (ISK) per every year if nothing is done to strengthen the grid (Landsnet, 2015a).

To gauge the reliability of the Icelandic grid, the TSO uses measurements of outage minutes due to unplanned grid interruptions as an indicator. Grid outages leads to inefficiencies for all consumers, and threatens grid security. The total number of unplanned grid interruptions in 2015 were 94, which was 50% above the average of the prior 10 years. Nonetheless, the calculated outage duration for priority consumers[5] was only 26.6 minutes, a performance on par with other countries in Europe. Historical values on the number and time duration of grid outages (for firm contracts only) is provided in **Figure 10**. The Wide Area Protection System[6] which detects system faults, split the grid into two island operations[7] a total of 11 times in 2014, resulting in problems with the normal operation of the grid. Interregional transmission exceeded security limits for nearly one-third of the year (Landsnet, 2015a), (Landsnet, 2014).

[5] Priority consumers are those who have entered into 'firm contracts' as opposed to 'non-firm contracts' with the TSO, Landsnet. Power transmitted to the 'non-firm contract' holders can be interrupted or entirely suspended without prior warning and under the discretion of Landsnet if the need so arises. The goal is to ensure the 'firm-contract' holders have reliable supply. Reserve power stations are activated as soon as possible if a grid disturbance occurs and there is possibility of disturbances for priority consumers. (Landsnet, 2015b)

[6] In addition to conventional protections, the Icelandic grid uses the Wide Area Protection System capabilities, which divide the grid into islands when operating conditions become difficult. This helps reduce the impact of disturbances by isolating them to one area of the grid (now islanded) instead of them percolating throughout the grid. These systems locate faults with more precision and are an important aspect of the grid's management with increasing load and the inter-regional transmission being near maximum levels for a large portion of the year. (Landsnet, 2015a)

[7] Island operation is the temporary operation of two or more sections of the grid that have been disconnected from each other and are therefore asynchronous. (Landsnet, 2015b)




*Curtailments to consumers on non-firm contracts are excluded here.*

FIGURE 10: HISTORICAL GRID DISTURBANCE AND OUTAGES (FIRM CONTRACTS) (Landsnet, 2015a)

If we include the duration of energy curtailments for non-firm contracts, it rises significantly from 26.6 minutes to 156.2 minutes in 2015 as shown in **Figure 11**. The use of curtailments to consumers on non-firm service contracts demonstrates a worrying trend and that the grid is overloaded in many places. As can be seen from the figure, there has been a marked increase in the use of reserve power during disturbances from 2013 to 2015. In the absence of reserve power and curtailment allowances, the grid's security of supply would currently be far below the reliability standards generally applicable to transmission systems. The grid's actual performance would then have measured at around 214 outage minutes in 2015, instead of 26.6 minutes (Landsnet, 2015a).

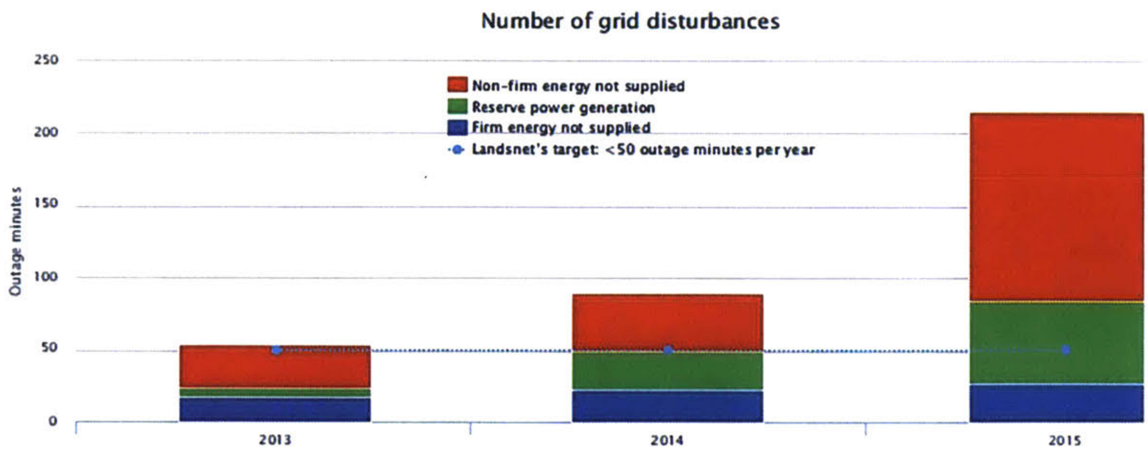



**FIGURE 11: HISTORICAL GRID DISTURBANCE AND OUTAGES (ALL CONTRACTS)** (Landsnet, 2015a)

Apart from operating the transmission system, Landsnet is in charge of forecasting future electricity needs and developing the grid accordingly for the long term. In addition, it also comes up with criteria for operational security. Landsnet operates a computer system to sense any deviation from normal flows and identify any breakdown within the grid. It can disconnect units from the system if it senses unusual activities that may badly affect the grid, and is required to analyze disruption within 0.1 seconds and react accordingly. A 24/7 watch is held over the grid to ensure its operational security. In general, Landsnet operates a so-called N-1 system, where shutting down units that experience disruption does not affect other units' ability to deliver electricity. Parts of the system, however --mostly the 66 kV and 33 kV systems and small systems-- are not fully operated as N-1 systems. Therefore, some disruptions can cause complete outage for the end users connected to these systems, if there is not enough backup power or local production to compensate (Hilmarsdóttir, 2015).

Statutory regulations require Landsnet to provide ancillary services to ensure supply meets demand at all times, as well as to ensure operational security. The portfolio of ancillary services for operational security include (Landsnet, 2015a):

- spinning reserves (for frequency control and disturbances),
- non-spinning reserves and
- instantaneous disturbance reserves.

In addition, Landsnet has to provide guaranteed regulating power to operate a balancing energy market. In order to meet its obligations, Landsnet purchases electricity from generating companies, and procures access to non-spinning reserves from distributors (Landsnet, 2015a).

The competencies of the TSO are stipulated in the Electricity Act 2003 no. 65. Chapter III. The TSO is responsible for the development of the transmission system in an economic manner, taking into account security, efficiency, reliability of supply and the quality of electricity. According to the Electricity Act, Article 9, the TSO shall (Landsnet, 2015a):

- Connect customers to the transmission system on request, provided they pay a connection fee according to the provisions of a tariff.
- Provide electricity in compensation for electricity losses in the system.
- Provide reactive power for the system to utilize transmission capacity and ensure voltage quality.
- Ensure reliability in the operation of the system.
- Ensure the availability of a forecast on the projected demand for electricity and a plan for the development of the transmission system.

The TSO is responsible for the secure management of the electricity supply system and is required to allow for the security and quality of delivery of electricity, including:

- Coordinating supply and demand of electricity so that discrepancies between the agreed purchase and the actual use can be met.
- Ensuring adequate supply of spinning reserves in the operation of the system.
- Determining processes of use where power measurements are not conducted.
- Measuring and documenting the delivery of electricity into and out of the transmission system in accordance with the applicable government regulation.
- Supplying public authorities, customers and the public with the information necessary to assess whether the company is performing its obligations and to ensure non-discrimination in trade in electricity.

In the event wherein a situation prevents the supply of electricity from meeting demand, the TSO shall take up rationing of electricity to distribution system operators and final customers, following government regulation.

### 2.2.4 Power Generators

As shown above in Error! Reference source not found. generation is composed of mainly hydro (~73%) and geothermal (~27%) power with small quantities of wind power as well. **Figure 12** power stations around Iceland.

The hydro power systems have a combined capacity of 1,986 MW. The biggest hydro power systems in Iceland are located in 5 different water sheds in the north (Blanda, and Laxa), north-east (Karahnjukar), south (Thjorsa), and south west (Sog). The largest hydroelectric stations utilize the flow of Iceland's glacial rivers, while numerous smaller hydropower plants are located in clear-water streams and rivers all around the country. All the major hydroelectric stations get their water from reservoirs, ensuring that these stations offer stable production year-round (Kerr, 2014).

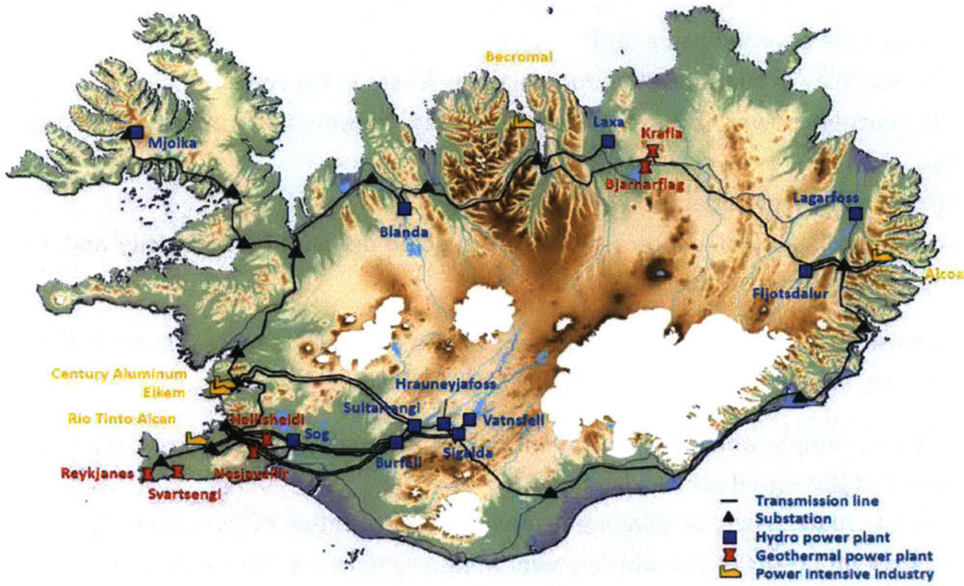



FIGURE 12: THE ICELANDIC POWER SYSTEM (Landsnet, 2016)

Iceland's geothermal power plants are located mainly in the north (Krofluvirkjun, and Bjarnarflag) and south west (Hellisheidi, Reykjanes, Nesjavellirm, Svartsengi) with a combined capacity of around 665 MW. They act as baseload power plants and are operational throughout the year.

### 2.2.5 FUTURE EXPANSION PLANS

At the moment, Iceland is considering several options for security of supply from a regulatory, generation capacity, and transmission perspective.

Iceland plans to upgrade or expand its current power system in order to meet its long-term needs. It has several objectives such as: meet the increasing load demand requirements, specifically arising due to the increasing EII sector; ensure security of electricity supply; upgrade its ageing and often overloaded transmission network; protect against extreme weather conditions; and yet maintain a clean energy mix for environmental reasons and to maintain independence from foreign supply of oil. Below is a discussion of some of Iceland's future plans:

**Generation**

As mentioned above, Iceland places a heavy emphasis on tapping its enormous renewable energy potential for environmental reasons (such as lower carbon emissions) and domestic production, both of which result in increased energy independence and less dependence on imported fossil fuels (Kerr, 2014).

So far only about 20-25% of Iceland's hydro- and geothermal energy resources have been harnessed (this number can be as high as 40-50% when environmental concerns are taken into account) (Kerr, 2014). To meet its every increasing electricity demand, a national-scale, Master Plan for Hydro and Geothermal Energy Resources (MP) in Iceland was initiated in the 1990's. The goal of the MP was to balance and reconcile the often competing interests of proposed power plant development: i.e., balancing energy efficiency, economic feasibility, environmental impact and impact to the cultural heritage. The MP includes participation and input from stakeholders such as political parties, power plant developers, experts, and citizens (Íslandsbanki, 2012), (ENR, 2015).

The plan, focusing on hydro and geothermal areas, is currently in this third phase and is due to be completed in 2017. (ENR, 2015) The end product will be a methodology to rank the assessed areas into utilization category (power plant options deemed fit for construction), on-hold category (power plants placed on-hold due to lack of data to make a decision, and energy generation licenses cannot be issued), and protected category (authorities will not issuing licenses for power plant generation or for the utilization of energy resources in such areas). Currently the energy utilization category has 2 hydro and 14 geothermal power plant options[8], and 22 hydro and 9 geothermal power plant options in the on-hold category. Finally, the protected category has 11 hydro and 9 geothermal power plant options. (Orkustofnum, 2015)

Landsvirkjun is working on improving the efficient utilization of its power stations as well as increasing production capacity with the expansion of the Búrfell Hydropower Station (Thjorsa system) by 100 MW. It is also looking at the continued development of a geothermal station at Þeistareykir by up to 200 MW, as well as the Krafla geothermal expansion, all in North East Iceland (Landsvirkjun, 2015a). Landsvirkjun's goal is to ensure that generating units are available 99.9% of the year, not accounting for routine maintenance periods (Landsvirkjun, 2015a).

In addition to hydro and geothermal, Iceland also plans to tap into its enormous wind energy potential. According to the categories established in the European Wind Atlas, the wind energy potential of Iceland is in the highest class. Although wind energy cannot be expected to replace hydro- and geothermal energy, it is being considered as a valuable addition (Kerr, 2014).

Solar is not considered a feasible option in Iceland due to its high latitude and relatively low insolation. However, Iceland is considering energy efficiency measures, especially for the industrial sector which consumed about 44.7% of total energy in Iceland in 2011 (Kerr, 2014).

**Transmission**

To strengthen the main grid and improve security of supply, Landsnet is looking at the long-term, overall picture. As part of their 2014-2023 Grid Plan (Landsnet, 2014), they have three possible ways of improving the connection throughout the country (see **Figure 13**).

- **Option A** is a "T-solution" with a connection across the Sprengisandur highland plateau and grid strengthening to the east and west.
- **Option B** is the construction of a new Regional Ring Network around the country.

[8] Hydro options in North Iceland (Blanda) and Westfjords (Hvalarvikjun). Geothermal options in the Reykjanes Peninsula area (Reykjanes among others), and North East Iceland (Bjarnarflag, Krafla expansion, and Þeistareykir).

- **Option C** is a connection over the interior highlands and strengthening to the east and in the west of the country.


**FIGURE 13: POTENTIAL OPTIONS FOR POWER SYSTEM UPGRADE** (Landsnet, 2014)

Iceland is also considering the option of building a 1,000 km high-voltage direct current (HVDC) line to connect to the UK system. The goal would be to ensure security of supply, since it would no longer be an isolated system and can tap into the additional capacity provided by the UK. It also has the potential of earning revenue by participating in electricity trading with the UK (especially since Iceland has among the lowest electricity rates). Although this plan has been conceptualized since the late 1990's, only recently has it started to become financially more feasible.

### 2.2.6 REGULATORY CONTEXT

To further understand the Icelandic power system, it is imperative to have an overview of the regulatory framework surrounding the power industry. NEA along with the Icelandic Parliament, Althingi, implemented a set of rules governing the internal market of electricity known as the Electricity Act No. 65/2003 (Act), in 2003 (Orkustofnum, 2012). The Act has been amended several times since its inception and contains a comprehensive legislation on the generation, transmission, distribution and supply (sale) of electricity, all as part of a competitive market.

The Act transposes the EU common rules for the internal market in electricity into the Icelandic legislation. It transforms a vertically integrated market structure into a fully liberalized market. Power generation and retailing was opened up, although the transmission and distribution portions of the industry remained natural monopolies. The Act fully opened the Icelandic electricity market to competition on January 1, 2006 and introduced third party access for transmission and distribution networks. Fees for transmission and distribution are based on published tariffs regulated by NEA. Furthermore, various acts and regulations in the field of environment apply to the construction and operation of electricity installations, such as the Planning Act No 123/2010, Act on Hygienic and Pollution Control No 7/1998 and Act on Environmental Impact Assessment No 106/2000 (Orkustofnum, 2012).

The role of the regulatory authorities is critical to better plan and promote a sustainable electricity system and significant changes are needed to overcome the current situation where the transmission infrastructure is in need of an upgrade since there is a high level of curtailments. The government is working on two important changes to Landsnet's operating environment: (1) an amendment to the Electricity Act for new procedures to be used in the preparation of the Grid Plan, and (2) a parliamentary resolution for the government to adopt a policy on undergrounding. Both are positive steps towards strengthening the transmission grid.

A stable regulatory and operating environment is a key requirement for all players involved in relation to electricity transmission and generation. The enactment of the 2011 Electricity Act aimed to strengthen the operating environment by determining the rate of return and thereby the revenue framework five years in advance at a time. The NEA determines the revenue cap for Landsnet based on historical operating expenses, allowed profitability (decided annually by the NEA), depreciation of fixed assets, and taxes. Based on the set revenue cap, Landsnet is then responsible for deciding a tariff for its services. At the start of 2015, however, a decision for the rate of return for the period 2011-2015 was not yet available, meaning major uncertainty for the revenue base. There is a failure on the part of the government to ensure timely decisions on the allowed rate of return and the revenue cap as stipulated by law. As a result, the TSO is unable to react to circumstances through appropriate measures, including tariff changes, at the start of each year. This can cause irregular tariff fluctuations, which is unacceptable for the customers (Landsnet, 2014).

A spot market was planned as per the Electricity Act of 2003. Landsnet has been attempting to start a power exchange, which will allow retailers to purchase electricity directly from the market, however the implementation of the market has been continuously postponed and there is still no market. Due to the lack of a market, the price formation is not transparent, but depends on a structure of bilateral contracts between the suppliers and the consumers.

In the particular situation of the Icelandic power market, Landsvirkjun is not only the main energy supplier with a market share which is above 70%, but also is the owner of the most relevant assets of the system, which are the water reservoirs. Landsvirkjun's strong market position and its close ownership and funding relationship to grid operator Landsnet is also a source of concern regarding monopolistic and price-setting behavior.

The uncertainty associated with the regulatory framework for the electricity industry is a key weakness. Because Iceland's Master Plan for Nature Protection and Energy Utilization is undergoing political debate, it brings a lot of uncertainty as to whether and how the country's energy potential will be fully exploited. Icelandic public opinion is skeptical about further expansion of the aluminum and energy sectors, mostly for environmental reasons. Uncertainty over government policy in this area has made new investment projects less predictable. Domestic politics are seen as playing an influential role in investment decisions, moving some energy projects forward while holding others back. Similarly, uncertainty has been increased by recent Supreme Court rulings about transmission upgrades and expansions. A frequently cited drawback of the Icelandic energy sector is the prevalence of long term

PPAs, leaving very little flexibility to establish transparent power trading through an exchange market. In this sense, the fact that three-quarters of the country's power output is consumed by fewer than 10 buyers can be considered a weakness (Christensen, 2016).

This makes the situation in Iceland especially interesting and fraught with regulatory challenges.

In summary the following problems can be highlighted (Christensen, 2016):

- The transmission grid is ageing and requires new investments and upgrades.
- Large parts of Iceland suffer from transmission capacity constraints, leading to lost opportunities in industry. This is especially true in the North, North-West, and South-East.
- Some regions in Iceland do not have (N-1) security of supply, making them vulnerable to blackouts following incidents.
- The lack of an extensive, reliable and authoritative central database on the energy industry and environmental affairs creates information asymmetry.
- The National Energy Authority has been criticized for being too weak.
- Geography places unusual stresses on the energy system. Frost and wind severely stress grid infrastructure. Exposure to the elements causes frequent breakdowns of regional transmission and distribution.
- The isolation of Iceland's power system means that reservoir management is suboptimal because of security of supply issues. In dry years, hydro facilities are at risk of water shortages. Conversely, in wet years, extra power generating opportunities are wasted due to lack of buyers.

# 3. SECURITY OF ELECTRICITY SUPPLY

This chapter will explore the definition of security of electricity supply (SoES) with the purpose of coming up with a comprehensive framework. The role of the regulator has to be examined to ensure SoES, if it is considered that the market does not guarantee the level of reliability that is required for the proper functioning of society. In particular, we conduct a literature review to understand how regulators in countries with a similar fuel mix to Iceland (i.e., primarily hydro-based), such as Brazil and Colombia ensure SoES. We present our current understanding of the measures taken in Iceland to ensure SoES, in particular hydro reservoir management. Finally, we discuss the definition of water value, prior to the development of a method for its computation.

## 3.1 DEFINITION

Security of energy can have several definitions in varying contexts. Several valid definitions were offered in (Arriaga, 2011): "guaranteed access to the diverse forms of modern energy that allow the satisfaction of the needs of the people at an affordable price, now and in the foreseeable future"; the "ability to meet the energy service needs, in a robust and reliable fashion, in the near-, medium- and long-terms"; the "continuous availability of energy in varied forms, in sufficient quantities and at affordable prices"; finally, the "availability of a regular supply of energy at an affordable price".

As per (OECD, 2010), "security of energy supply is the resilience of the energy system to unique and unforeseeable events that threaten the physical integrity of energy flows or that lead to discontinuous energy price rises, independent of economic fundamentals".

While there are several definitions capturing different aspects of SoES, the most comprehensive one defines a secure energy system as one evolving over time, with an adequate capacity to absorb adverse uncertain events, able to continue satisfying the energy service needs of its intended users with acceptable changes in their amount and prices (Lombardi & Toniolo, 2015). Although the delivery of electricity takes place in real time, several actions and measures must be performed in different time ranges (from years to seconds), by different agents (such as regulators, investors, systems operators), and involving different types of technology and investments.

The above definition leads to the four components of a reliable power supply (Pérez-arriaga, 2007):

1. **Strategic energy policy**, a long- to very long-term decision, determines the long-term availability of energy resources, which includes: physical existence and reliable supply meeting environmental constraints, affordable price, and acceptable energy dependence of the country.

2. **Adequacy**, a long-term decision, assures the existence of enough available capacity, both installed and/or expected, to meet the forecasted demand.

3. **Firmness**, a short- to medium-term decision, is defined as supply infrastructure that is available when needed. It mainly depends on the operation planning activities of the already installed capacity: maintenance schedules, fuel supply contracts and reservoir management, units cycling, etc.

4. **Security**, a real-time decision, is achieved through the readiness of existing and functioning generation and network capacity to respond in real time when they are needed to meet the actual load. Security typically depends on the operating reserves and operational procedures that are prescribed and managed by the system operator. As per the North American Electric Reliability Council it is defined as the "ability of the electrical system to support unexpected disturbances such as electrical short circuits or unexpected loss of components of the system" (Council, 1997).

The four dimensions of energy security are interrelated and cannot be decoupled from one another.

## 3.2 PROVISION OF SECURITY OF ELECTRICITY SUPPLY

The key question in power system reform is whether a competitive market can provide satisfactory security of supply at the power generation level or if there is a need to introduce additional regulatory mechanism; and if so then up to what level. A predominant belief is that there is a market failure to ensure SoES due to the inefficient allocation of risk among market players. Other issues which lead to a sub-optimal security of supply in a market situation are related to flawed regulatory rules which cap short-term signals, inefficient risk allocation, lumpy investment problems, economies of scale, and lack of short-term demand elasticity (Batlle & Rodilla, 2015). This market failure requires the need for regulatory measures to provide the incentives that are lacking in a free-market case to ensure a certain level of security of supply.

As a first essential step, the regulator has to decide whether or not to completely rely on the market to solve the security of supply problem. In this regard the regulator can adopt either one of two strategies:

1. Energy-Only Market approach (Do Nothing): This adheres to the belief that the market will provide an efficient long-term outcome. The regulator's lack of intervention would be mainly supported by the expectation that demand will (or will learn to in the end) manage the long-term risk involved in electricity markets (for example, by hedging and guaranteeing their future needs).
2. Regulatory-Intervention (Do something on behalf of the demand): This is the opposite mechanism to the previously mentioned 'Do Nothing' approach. In this case, the regulator designs a security of supply mechanism which entails the definition of a certain reliability-oriented product aimed to ensure system security of supply (i.e., avoid scarcities). For example, a reliability product can be provided by the generators, who receive in exchange the extra income or the hedging instruments they require to both proceed with efficient investments (adequacy) and make resources available when most needed (firmness). The other counterparty is either directly the demand, compelled to purchase the product by the regulator, or the regulator itself (i.e. the system, the tariff) acting on behalf of the demand. (Pérez-arriaga, 2013)

While some may claim that free-market can ensure SoES, in practice, as per (Batlle & Rodilla, 2015) it is hard to find a purely Energy-Only Market where the regulator completely restrains from making any interventions to ensure SoES, and demand is expected to manage the risk involved in electricity markets. The assertion is that, even in those markets where no explicit measures outlined by the regulator exist, such as ERCOT (Texas), UK (before the regulatory reform several years ago), Australia and Nord Pool, it can be argued that some sort of implicit mechanisms or conditions have been set in place to promote SoES. As per (Cramton & Stoft, 2008) no Energy-Only Market, even with ideal demand elasticity, can solve the adequacy problem. Following this dictum, the second approach, which is regulatory intervention, is required to ensure reliable power in the short- and long-term, as well as to protect consumers and industry from episodes of scarcity and high prices.

There are several options for ensuring SoES as discussed in detail in (Pérez-arriaga, 2013): from *price* mechanisms (such as "capacity payments"), to *quantity* mechanisms (such as "capacity obligations" and "strategic reserves"). In general, regulatory *price* mechanisms tend to compensate new and existing generators for providing firm capacity when needed by the system. This extra income provided to generators is to help recover their fixed investment costs that infra-marginal energy profits cannot recuperate. The goal is to induce more investment in generation capacity when such payments exceed the amortized cost of investment (Oren, 2005). On the other hand, in the *quantity* mechanism approach the regulator sets forth the desired amount of capacity required in the system and then allows the market to determine the price.

There is no single solution that can be recommended to ensure SoES in any electric power system, due to the different system's characteristics across countries, i.e., varying generator and fuel mix, or existing regulatory measures, and political climate. Below we discuss the mechanisms employed in Colombia and Brazil to ensure SoES. The reason for choosing Colombia and Brazil is because, similar to Iceland, these countries have a very high portion of hydro-based generation (approximately 80% in Colombia (Cramton & Stoft, 2007) and 85% in Brazil (Almeida Prado et al., 2016) as compared to 71% in Iceland in 2013 (WorldBank, 2016b)).

### 3.2.1 Colombian Experience

The Colombian power system experience is a pioneer regarding regulatory design of SoES mechanisms. As mentioned above, Colombia's energy mix is dominated by hydro generation (~69%) and it is significantly sensitive to the cyclical, macroclimatic period known as El Nino Southern Oscillation (ENSO), which implies suffering one severely dry year once out of five to eight years. Hence in this hydro-based system, the reliability adequacy constraint is defined as having "sufficient thermal resources and hydro reservoirs to provide firm energy during a scarcity period" (Cramton & Stoft, 2007). This scarcity period is the seasonal scarcity as the result of depleted hydro reservoirs and low inflows during dry periods, which causes high spot prices for electricity (an indicator for scarcity). The goal of the firm energy market is to provide suppliers with the right investment and operating incentives to build and operate the efficient quantity and quality of energy resources. Not only must the firm energy market reduce supplier risk and improve reliability, but also result in reliable electricity at minimum cost to consumers, hence protecting demand (Cramton & Stoft, 2007).

Colombia is an interesting case, as the incentives for adding capacity have been modified twice since deregulation, in an effort to adapt to shifting economic and market conditions. The 1994 power-sector reforms focused on changing a monopolistic, vertically-integrated, inefficient power system to a deregulated one. This resulted in a market with virtually no electricity interruptions, and with power companies in a better financial position (i.e., lower or no debt) (Olaya, Arango-Aramburo, & Larsen, 2016). One of the main objectives of the power sector reform was to attract new investment in generation to meet the growing demand needs. Hence separate payments for energy and capacity have always existed.

Capacity payments have been modified twice since 1994. Post deregulation of the power system, the first regulatory period (1996–2006) focused on resource adequacy where the mechanism was capacity payments (known as 'capacity charge'). The second regulatory period beginning in 2006, corresponded to reliability options (Pérez-arriaga, 2013).

The first incentives were aimed at reducing the electricity system's vulnerability (e.g., blackouts) during dry periods (such as ENSO). To counteract power outages during dry periods in a predominant hydro-based system, prior to 1994, a large investment was made in thermal generation. Not only did this turn out to be more expensive during regular periods, but the annual revenue would not support investment in future thermal power plants. Hence the regulators introduced a capacity charge, which rewarded the contribution of each generator to securing supply during dry periods. Capacity payments were proportional to the firm capacity contributed by a thermal generation plant (capacity charge). The reference value for estimating capacity charges was the cost of installing 1kW of an open-cycle gas generator (5.25 $/kW). Charges were collected from the energy pool. Each month, the capacity payments for each plant were calculated as the product of the capacity charge multiplied by the fraction of demand that each plant could supply in a critical hydro scenario, based on a market-model simulation (Olaya et al., 2016).

Average share of capacity payments for thermal and hydro power plants was approximately 30% to 70%, respectively, proportional to its generation share in the power system. This could be one reason for the increase in thermal generation from 1996 to 2000 as seen in **Figure 14** and attained the goal of having reliable supply (i.e., no blackouts) during the dry ENSO periods in this time frame.

The effectiveness of the scheme was called into question almost from the very beginning. It was argued that this system wherein the capacity payments remunerated generators based on their availability during the dry season led to inefficient reservoir management by hydro-power resources (Mastropietro, Rodilla, & Batlle, 2015). It was also argued that these payments did not send clear signals for expansion, they favored hydro generation instead of having a diverse mix, and the poor representation of the power system in the optimization model used by the regulatory agency. It was also argued that capacity charges were only a source of revenue and that reliability was not guaranteed.

The initial incentives (capacity charge) were modified in 2006 in order to provide signals for system expansion based on a commitment to provide firm energy when needed instead of just a payment for estimated available capacity. The approach that finally was chosen consisted in replacing the capacity payment by a quantity mechanism. The two major features of this proposal were the introduction of the so-called "reliability option" as the new reliability product and its acquisition through a centralized auction.

This new mechanism is called the reliability charge, and it is based on a forward market for firm energy, where firm energy is the capacity to deliver energy in a dry year. The regulator auctions off sufficient obligations to supply firm energy (OEFs) to satisfy the system's forecasted demand, three years ahead. The OEFs can be seen as a call option, backed by physical capacity. A generator receiving an OEF must supply a given quantity of energy if the spot price is above a previously defined scarcity price. A generator that supplies more than its share during scarcity periods receives the spot price, while a generator that supplies less is penalized. Therefore, there is an incentive for the generator to be able to deliver the agreed quantity as long as the penalty for not being able to deliver is severe enough. Contract length for new plants is currently 20 years. Simulation analysis indicates that the reliability mechanisms attract investment, lower market risk, and improve coordination in investment. This latter feature is desirable, since lack of coordination in investment has been related to undesired long-term cycles of over- and under-capacity (Olaya et al., 2016).

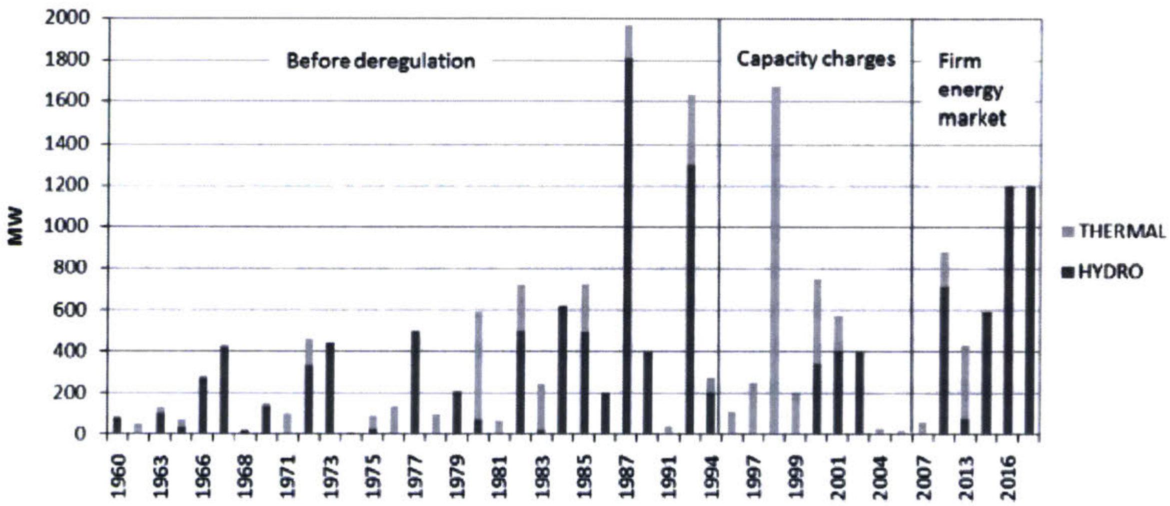



FIGURE 14: ANNUAL GENERATION CAPACITY ADDITION IN COLOMBIA BEFORE AND AFTER POWER SECTOR REFORM
(Olaya et al., 2016)

### 3.2.2 BRAZILIAN EXPERIENCE

Electrical energy in Brazil comes mainly from hydro-generation plants (around 80 – 85%) with multi-annual storage and planning of reservoirs. The first market-based design, which was in force from 1996 to 2004 was a centralized system marginal cost calculation to remunerate generating units, with added sort-of security of supply mechanism: regulated retailers were compelled to contract in the long-term 85% of their expected future energy needs and a floor price existed to overcome the fact that the market price is zero almost 80% of the time. This floor price has been also adopted in the subsequent redesign of the Brazilian market (Pérez-arriaga, 2013).

After the energy curtailment periods of 2001 and 2002, it was critical to ensure long-term security of supply. A thorough analysis resulted in the general conclusion that there were some imperfections regarding expansion and efficient contracting. This led to a proposal, that to some extent, was inspired in the above mentioned auction-based solution proposed years before for the Colombian system and that resulted in the mechanism currently in place (Pérez-arriaga, 2013).

The main differences from the Colombian case are (Pérez-arriaga, 2013):

- Different auctions are called for existing units and new entrants. In the first ones, the lag period and the contract duration are significantly shorter (1-year lag instead of 5, up to 15 years instead of up to 30).
- There are two different reliability products: i) a financial forward energy contract for hydro units and, ii) an "energy call option" (which in very general terms presents the characteristics of the reliability option previously described in the context of the Colombian case) for thermal plants.

The regulator has a backstop mechanism that allows the government to carry out specific energy auctions driven by energy policy decisions.

## 3.3 THE CASE OF ICELAND

**Current Situation in Iceland**

Iceland is a member state of the European Economic Area (EEA), which extends the internal market legislation of the EU to Iceland. Legislation in the member states of the EEA related to the energy market and environmental issues must comply with corresponding EU Directives. EU Directive No 96/92 applies to the electricity market, and the Icelandic Electricity Act No. 65/2003, enacted in mid-2003, implemented this EU legislation in Iceland (Íslandsbanki, 2012). As part of the Electricity Act (elaborated in **Section 2.2.3**), the TSO is required to ensure SoES by ensuring reliability in the system operation, and ensure adequate supply of spinning reserves.

There are "latent" security of supply mechanisms thanks to EU Directive 2005/89/EC, which states that 'the guarantee of a high level of security of electricity supply is a key objective for the successful operation of the internal market and that Directive gives the Member States the possibility of imposing public service obligations on electricity undertakings, inter alia, in relation to security of supply' (Pérez-arriaga, 2013). In addition, it recommends for appropriate levels of generation capacity via measures including but not limited to capacity options, or capacity obligations (Pérez-arriaga, 2013). Since Iceland is a member state of the EEA, it has to incorporate the above Directive and ensure SoES.

Based on the literature review it seems as though Iceland has a more 'Energy-Only Market' approach when it comes to ensuring SoES. That is, the regulator has a more hands-off approach regarding ensuring SoES, and there are no explicit mechanisms implemented such as capacity mechanisms or reliability options. However, it cannot be called a strictly 'Energy-Only Market' approach since there are signs of implicit regulatory intervention. Some of the measures include:

1. The regulator requires the TSO to take full operational control of the system during periods of scarcity. The TSO has full authority to implement actions such as voltage reductions, rolling blackouts, among others (Pérez-arriaga, 2013).
   As stated in (Hilmarsdóttir, 2015), "delivery security is synonymous with the reliability of electricity delivery. It is defined by the quality of voltage and frequency and the security of delivery through the transmission systems, along with communicating information to the end-users. It is assessed by comparing the number of disruptions that occur without notice, and the

scale of electricity outages that result, year against year within the firm and as between firms". The TSO is required to set its own goals for electricity security, which the NEA either approves, or changes if it deems them unrealistic. However, in practice electricity security is not the same everywhere in Iceland, with higher levels of reliability in the south-west portion of the country which is also where Reykjavik, the economic and population center is located. Outside the capital power disruptions are much more frequent, with the Westfjords having the lowest reliability levels.

2. The Electricity Act gives the TSO power to enter into long-term contracts for operational energy balance or for ancillary services and reserves to ensure SoES, as mentioned before in **Section 2.3.3**.

Finally, as per (Pérez-arriaga, 2013), horizontal concentration in the generation market may be one reason for the regulator to abstain from implementing an explicit SoES mechanism. A concentrated market would allow for generators to ensure the recovery of a 'reasonable' rate of return (Pérez-arriaga, 2013). Landsvirkjun, which is the dominant market player in the electricity generation market, is also heavily involved in capacity expansion planning and reservoir management to ensure long-term SoES. Especially since Iceland is predominantly a hydro-based power system, it is very imperative to be able to plan for the hydro storage and consumption given uncertainty and variability in electricity demand, climatic conditions, and hydro inflows. The reservoirs are required to end the water year[9] at 90% of the maximum or higher levels, irrespective of the weather predictions for next year. The reasoning for this risk averse approach is that if it is a dry subsequent year then a high level of water reserves in the prior year will minimize the curtailments. However, if it is a wet subsequent year then the reserves will be filled and some rain or glacier water will have to be spilled.

In summary, evaluating based on the comprehensive SoES framework represented in **Section 3.1**, as well as understanding the current mechanisms in place in Iceland for SoES, three areas of possible concern have been detected in the Icelandic power system:

1. **Firm generation capacity/energy**. Hydro accounts for 71% of total electricity generation and its firmness depends on hydro inputs and weather conditions. The high reservoir levels for operating purposes tends to be a risk averse approach, as the anticipated curtailments may have not been needed as subsequent hydro inflows would have filled reservoirs or maintained enough water volume for the following year. Geothermal maintenance schedules that are typically concentrated in summer may also create some firmness problems.

2. **Adequate generation capacity/energy**. Presently there is no shortage of capacity, but the lack of sound and clear investment signals and the strong environmental opposition may discourage required investments.

[9] In a hydropower dominated system a practical time period for planning purposes is known as the water year. The water year is defined to start on October 1 of each year and ends on September 31 of the following year. It arises from the dynamic nature of the seasonal reservoirs.

3. **Adequate transmission capacity**. The Regional Ring Network is obsolete for the current transmission capacity requirements. The island is divided into five balancing zones due to congestions. In 2014, inter-regional power flow exceeded security monitoring limits 28% of the time. Two main options are under study to strengthen the main grid, but the environmental opposition is strong.

As mentioned above the dominant player Landsvirkjun's role is crucial to the SoES in Iceland since it is in charge of most of the hydro-reservoir management in Iceland which is critical to the firm generation energy problem. The estimation of the value of the water stored in the hydro reservoirs at the end of the water year reflects an opportunity cost – balancing the tradeoff between immediate use and future curtailment of the water. Such an estimation of the water value (in hydro-dominated systems) will help with system planning, keeping operating costs low, and ensuring security of supply for the residential and industrial consumers. Hence the thesis will focus on quantifying the value of this water for future purposes to address the firmness aspect of SoES.

As per (Reneses, Barquín, García-González, & Centeno, 2016) the water value is defined as the substitution cost of the stored water that can be computed as the variation of the system's cost when an extra unit of hydraulic resources is available. This approach is normally called "dual approach." In this context, it is important to distinguish between the cost of hydro generation (which is almost zero) and its value, which is determined by the thermal generation that is being substituted by the hydro generation. Since Iceland has only geothermal generation (whose cost is also almost zero), and no traditional generation, the value is determined by the cost of the non-served energy.

Given the uncertainty and lack of a good methodology to estimate this water value, as well as a risk-averse outlook, causes the system operators to make very conservative, and hence more expensive operational decisions. In Iceland the reservoirs are required to end the water year at 90% of the maximum or higher levels, irrespective of the weather predictions for next year. The reasoning for this risk averse approach is that if it is a dry subsequent year then a high level of water reserves in the prior year will minimize the curtailments. However, if it is a wet subsequent year then the reserves will be filled and some rain or glacier water will have to be spilled. The objective is to avoid a situation with a large level of curtailments in case of a dry hydro year. In either case this is not properly accounting for the opportunity cost associated with spilling water in subsequent years or curtailing energy in the current year to end the year at maximum capacity. This approach sometimes achieves a high level of reserves at the end of the water year at the expense of energy curtailments if the year is drier than historical years. A retrospective analysis concludes that in most cases the anticipated curtailments may have not been needed as subsequent hydro inflows would have filled reservoirs or maintained enough water volume for the following year. This situation reflects a risk-averse operation and may indicate that water would be more valuable in the future than in the present. Therefore it is of great interest to infer the water value.

As per (Reneses et al., 2016), water value is defined in the context where each company manages its hydraulic resources in order to maximize its respective profits. Cost-based water value is defined as the substitution value for the company that owns the hydro resource. That is to say, the cost avoided by the company when hydro generation is unitarily incremented and the total generation for the company remains constant. Hence, cost-based water value is defined as the cost for the company when hydro resources are marginally substituted by thermal generation.

**How does Landsvirkjun compute water value?**

In a hydro and geothermal dominated system, such as Iceland, water reserves are equivalent to energy and hence can be equated to currency. At the end of a water year, the final water reservoir levels determine the expected energy that can be provided the following year and hence have a unit value attached to them. The lower the final energy reserve levels (at the end of the water year) equates to a higher probability for energy curtailment in future years and therefore results in higher operation costs in the following years. Similarly, the lower the initial reserve levels (at the start of the water year), the higher the value for current curtailment.

Therefore, the "water value represents the cost increase in electricity supply that the region would face if it had one less MWh of water in the reservoir. This opportunity cost is the value at which a hydro market player offers production into the market" (Unger, 2014).

Landsvirkjun estimates the value of water based on running a heuristic, two-step simulation in its proprietary long term reservoir modeling software, LpSim. First a stochastic dynamic programming (SDP)[10] algorithm is used to calculate the water value for the system by combining all reservoirs and hydroelectric stations into an equivalent three reservoir system (for ease of computation). To avoid the curse of dimensionality (i.e. a problem with too many dimensions) associated with dynamic programming, a simplified representation of the hydro-system is employed. The water value is the price of water expressed as a function of reservoir volume and time, and defines the strategy used for releasing water from the reservoirs. The water value is applied to all reservoirs and a simulation of system operation is performed for a period of N years with time resolution down to week-long timestamps. The second step is to recalculate the water value, but this time splitting the system into subsystems accounting for local load in each system as well as the import and export of energy to other sub-systems. Based on the new water values, system operation is simulated again (as before). This is repeated as long as the simulations result in better operation. Landsvirkjun's methodology to calculate the water value is described in detail in (Linnet, Grétar, & Sveinsson, 2012). This heuristic approach performs better than a regular dynamic programming approach but still has some of the original drawbacks such as simplification of the hydro system and long computation times.

The stochastic linear programming model that is used in this thesis, and the stochastic dynamic programming model that is used by Landsvirkjun should reach the same water value. Moreover, robust

[10] A multireservoir, multiperiod SDP model is formulated by considering the multiperiod optimization in stages. Each stage corresponds to one period. Release decisions are made to maximize the current benefits plus the expected benefits from future operation, which are represented by a recursively calculated cost-to-go function and a release policy decision rule for each time period as a function of the system state variables (Abdalla, 2007).

decisions are provided for the initial period in both cases[11]. The main difference is how the water value is obtained. In the former case, the water value is found as the dual variable of a constraint. In the latter case, the water value is an explicit variable. In addition, the solutions from both models could differ due to the considered level of detail, which may be lower in the dynamic programming model due to computational issues (known as 'curse of dimensionality'[12]) described above. The reasons to be using a linear programming model, when the dynamic one already exists, are: 1) recommendations should not be biased by the tool of a power company; 2) the linear programming model could serve in the future as benchmark of the dynamic one; and 3) the linear optimization algorithm is easier to understand by stakeholders (such as the regulator) who are not familiar with optimization techniques.

---

[11] Both models are equally used for taking a decision today –i.e. the initial period–. This decision is said to be robust since the decision considers all best-possible future information.

[12] The curse of dimensionality arises since optimization is performed for all discrete combinations of the state vector. In a multi-reservoir level if there are m-discretization steps and n-reservoirs then computation time and storage requirements are proportional to $m^n$ (Abdalla, 2007).

# 4. ICELANDIC POWER SYSTEM REPRESENTATION

One of the goals of this work is to address the question regarding energy security in Iceland in the near future, given the uncertainty in climate and hydro conditions, and uncertainty in future demand. As a first step, a representative model was created considering the main characteristics of the Icelandic power system. The reason for creating an independent model is to conduct an independent study where the results are not biased by the model of the power company;

Below we discuss the characteristics of the Icelandic power system (such as demand, power generation, inflows) as well as our methodology to represent them.

## 4.1 DEMAND

Landsvirkjun, the national power company, provided the historical hourly electricity demand in Iceland from January 2020 to December 2020. This demand was further broken down by general (herein referred to as 'residential') and energy-intensive industry (herein referred to as 'industrial') for every power electrical node in the system. The reason for dividing the demand into residential and industrial for modeling purposes is due to the differing energy contracts by user type (more details in **Section 4.2**).

The historical demand data was processed and categorized into multiple load blocks on a weekly basis in order to have a representative load level and duration for every node considered in the model. The goal of transforming hourly data into load blocks is to group together the super peak, peak, intermediate, off-peak, and super off-peak hours for each day and for every week of the year in order to simplify the representation of demand, yet maintaining the important patterns observed in the demand data. For each of the 52 weeks in the year and for every node in the system, there are 5 unique load blocks for weekdays and 5 blocks for the weekends –a total of 520 load blocks out of 8760 hours. **Figure 15** shows an example of the load blocks representation for the overall system's demand in Iceland for one particular week of the year.

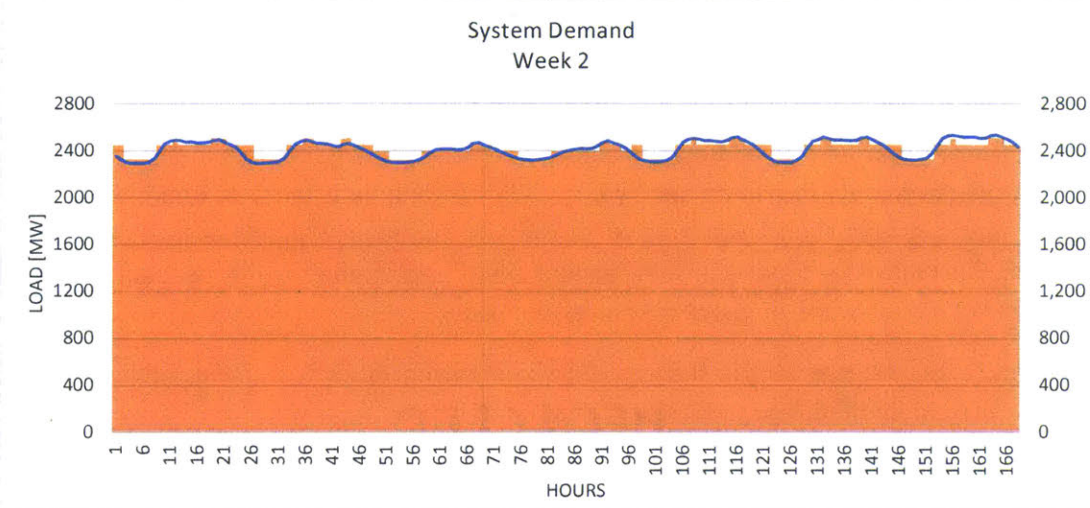



**FIGURE 15: COMPARISON BETWEEN OVERALL SYSTEM'S REAL DEMAND AND SIMPLIFIED DEMAND FOR WEEK 2.**

It was observed that the residential load profiles showed time-of-day and time-of-year variation given varying electricity consumption habits (i.e. the demand profile during a summer weekday would be much different from the one during a winter weekday). In contrast, the industrial load profile was fairly constant throughout the year with little to no-variation. Therefore, we decided to choose a residential node instead of an industrial node to represent the load block duration on a weekly basis due to this temporal variation. Based on this, we observed that the residential load profile at 'Reykjavik area' accounted for about 43% of the residential demand and had a high correlation of approximately 80% to the load profiles of other residential nodes in the system. Consequently, we selected the demand data for the Reykjavik area to determine the duration and load level of each block.

For the purpose of this project, the hourly demand data for the Reykjavik area was categorized by the week it belonged to and on whether it occurred during the weekend or weekday. Holidays in 2020[13] were also categorized as weekends, since they would have a demand profile reflective of a weekend consumption. For every day of a week, we looked for 2 super peak hours, 2 peak hours, 14 base load hours, 3 off-peak hours, and 3 super off-peak hours. Then, the average of the demand was taken over the hours of those groups with the purpose of obtaining the load level for each of the demand blocks for weekdays and weekends (see **Figure 16**). Finally, using the same hourly allocation from Reykjavik, we obtained the average demand levels for every load block for all the other nodes of the system.

[13] Public Holidays in Iceland for year 2020 were obtained from: http://www.feiertagskalender.ch/

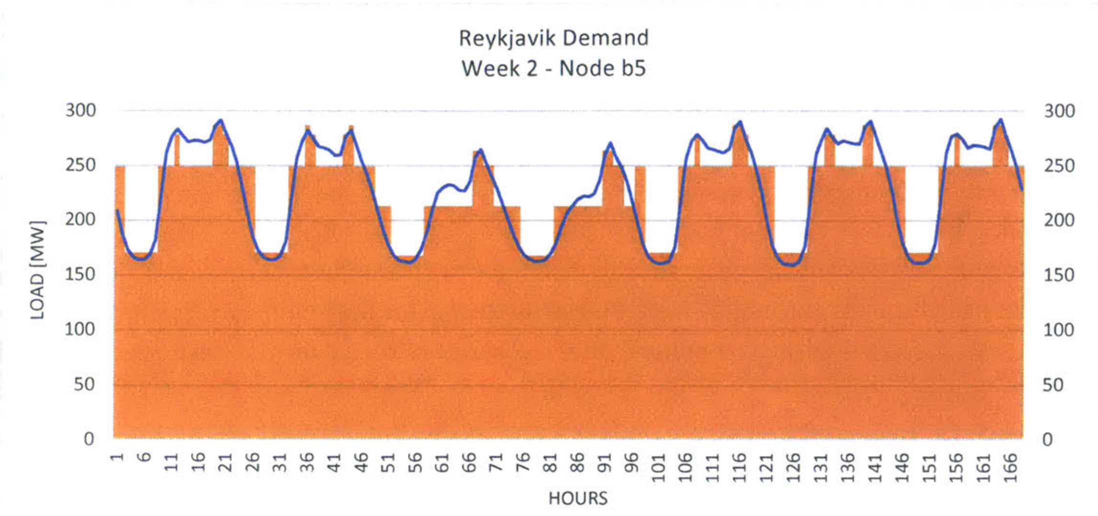



**FIGURE 16: COMPARISON BETWEEN REAL DEMAND AND SIMPLIFIED DEMAND IN REYKJAVIK FOR WEEK #2**

Based on this methodology, we were able to model the annual forecast demand for water year 2020 of 18,857 GWh ((Hreinsson, 2016b), (Hreinsson, 2016a)) with a very high accuracy (~100%) for the entire system in terms of energy. In terms of peak demand on a weekly basis, we were able to capture it within -0.14% and -1.9% of the actual peak. We realize that the real demand compared to the modeled one presents differences that our approximation does not fully capture (as can be seen from **Figure 16**). This could lead, for example, to underestimating some intermediate hours or overestimating some super off-peak hours of the day (as can be seen from **Figure 16**). However, we observed that these differences smoothen out when considering the aggregated overall system's demand as can be seen in **Figure 15**. Although our simplified single-node transmission model (see discussion on single-node model in **Section 4.7**) is not able to capture these differences at the nodal level (which may impact the start-up and shut-down of thermal plants), we recognize that most of those fluctuations will be absorbed by the system's hydro resources. In addition, we have validated our model results to the real operation of the Icelandic power system for year 2020 with satisfactory results.

Although the 2020 demand forecast was based on a regular calendar year (January – December) by the Energy Forecasting Committee (EFC), in a hydro-based system planning it is important to note that a more practical annual unit for planning purposes is referred to as a water year. The water year is defined to start on October 1 of each year and ends on September 31 of the following year. It arises from the dynamic nature of the seasonal reservoirs, which start to fill up during the start of the fall. The critical point in reservoir operation occurs in the winter period (approximately November to April), with continuous emptying of reservoirs due to frozen inflows and lack of incoming water to counteract the usage of water to generate electricity. Hence, based on this, a practical unit in planning has been chosen as the water year instead of the calendar year.

It is also important to note that the demand is provided on a nodal basis. However, for the purposes of this thesis a simplified network representation is used wherein we model the system as a single-node system (i.e. with no transmission constraints).

## 4.2 ENERGY NON SERVED

Based on the contract structure between the EII and the power companies, we defined 3 blocks for industrial customers and 1 block for the residential ones, each one with different level of curtailment (%) based on the maximum energy or power load. As the residential customer is expected to be curtailed in the last instance, the non-served energy cost is much greater than any block of the industrial demand. In the event when there is not enough generation to meet demand, the industrial consumers in block 1 are the first to face curtailments, since they have the lowest cost associated with curtailments. The power companies would be required to compensate these consumers based on the costs associated with curtailments.

The curtailment values adopted for each customer type and block are shown in **Table 2**.

| Energy Non Served by Customer | | | | | |
|---|---|---|---|---|---|
| | | | MaxPower [%] | MaxEnergy [%] | VarCost [€/MWh] |
| Industrial | . | Block1 | 10 | 5 | 16 |
| Industrial | . | Block2 | 3 | 1.5 | 75 |
| Industrial | . | Block3 | 87 | 93.5 | 229 |
| Households | . | Block1 | 100 | 100 | 972 |

**TABLE 2: NON-SERVED ENERGY BY CUSTOMER TYPE.** (Hreinsson, 2016b)

A shortage could happen because of two reasons: 1) lack of capacity; and/or 2) lack of energy. Lack of capacity is said to occur when, at a specific time, the total generation capacity is not enough to cover the total demand. For example, due to a combined maintenance of a hydropower plant plus a very dark day, the generation capacity lowers to 2000 MW while the demand increases to 2100 MW. Some demand must then be curtailed due to lack of capacity. In contrast, lack of energy is said to occur when, during a predefined period of time, the generated energy is not enough to satisfy the electricity consumption. For example, due to a severe winter, the reservoir levels are low, and the expected energy generation amounts to 14 GWh while the expected energy consumption is 14.3 GWh. Some demand must then be curtailed due to lack of energy. Obviously, any curtailment due to lack of capacity reduces the probability of another curtailment due to lack of energy since during the curtailment some energy has been saved. The opposite is not necessarily true.

## 4.3 HYDROPOWER SYSTEM

The various electric power plants (representation and characteristics) were modeled based on the information provided by Landsvirkjun, as well as other online sources (("Creating Kárahnjúkar," 2010; Hreinsson, 2016b; IAV, 2014; Landsvirkjun, 2012, 2015b, 2015c, 2015d, 2016a, 2016b; Wikipedia, 2016b, 2016a)). In total, 8 hydro systems were modeled including Landsvirkjun's and other companies' hydro plants. Landsvirkjun's hydroelectric power stations are situated in five different watersheds namely Sog, Thjorsa, Blanda, Karahnjukar, and Laxa as described below. **Figure 17** shows the geographical layout of the power plants. Information regarding the representation of a hydro-system for modeling purposes is provided in **Appendix A.**

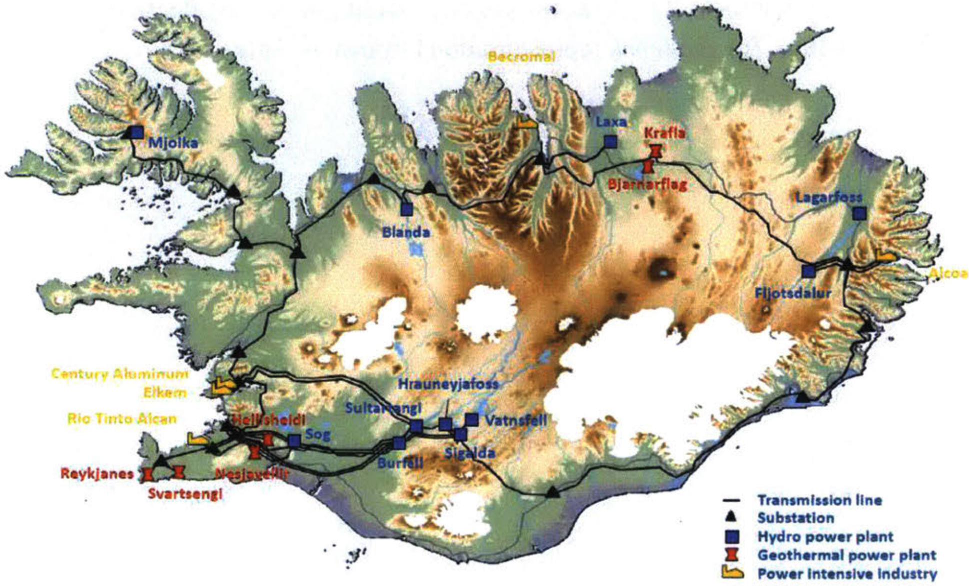



FIGURE 17: THE ICELANDIC POWER SYSTEM (Landsnet, 2016)

The Sog hydro-system comprises three run-of-river hydro plants in series (Steingrimsstod, Ljosifoss, and Irafoss), which for modeling purposes were combined and represented as one aggregated hydro plant (**Figure 18**). The total aggregated power capacity and production function is the sum of the individual capacity and production function of each power plant. The total capacity of the system is 86.2 MW (Hreinsson, 2016b) and production function is 0.169 kWh/m$^3$ (Hreinsson, 2016b).


FIGURE 18: SOG POWER PLANT SYSTEM

The Laxa hydro-system comprises three run-of-river hydro plants, namely Laxa I, Laxa II, and Laxa III. Laxa I and Laxa III, which are the upstream power plants, are in parallel and upstream to Laxa II. These two upstream power plants are aggregated by summing their individual capacity and averaging the production function. This combined system is in series with Laxa II. The entire system is aggregated by summing the capacity and production function of Laxa II with the aggregated upstream power plants. The total capacity of the system is 27.5 MW (Hreinsson, 2016b), with a production function is 0.167 kWh/m3 (Hreinsson, 2016b). The modeling representation is shown in **Figure 19**.

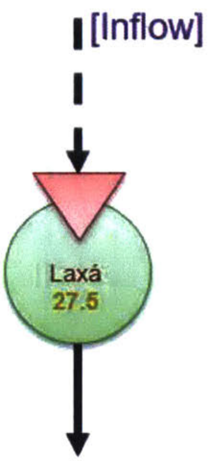



FIGURE 19: LAXA POWER PLANT SYSTEM

The three Laxá Stations harness a 70 m head on an 1800 m stretch of River Laxá to produce a total of 27.5 MW of electricity. The inflow to Lake Mývatn is mostly underground, through layers of lava, largely immune from seasonal fluctuations and ideal for harnessing hydropower. Laxá I and II are low head hydro stations that harness the natural flow of River Laxá. Station III, the latest addition, utilizes the same head as Laxá I but runs its water through a tunnel to the power station, 60 meters inside the rock (Landsvirkjun, 2015c).

The Blanda system comprises reservoir Blóndulón (400 $hm^3$ capacity (Landsvirkjun, 2016a)) upstream of hydro plant Blönduveituvirkjun, which in turn is upstream of reservoir Gilsarslon (20 $hm^3$ capacity (Landsvirkjun, 2016a)) and hydro plant Blanda. The plant Blönduveituvirkjun does not currently exist and may be built by year 2020. The total capacity of the system is 150 MW (Hreinsson, 2016b) and a production function is 0.683 $kWh/m^3$ (Hreinsson, 2016b). The modeling representation is shown in **Figure 20.**

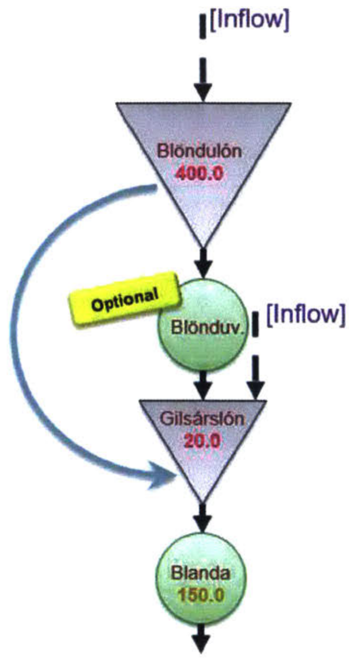



FIGURE 20: BLANDA POWER PLANT SYSTEM

The Thjorsa system is the largest hydro system in Iceland. The main reservoir is Thorisvatn, which is large enough to provide seasonal regulation. The existing total capacity of the system is 1,035 MW. The modeling representation is shown in **Figure 21**.

There are six hydropower stations in the catchment area of Rivers Thjórsá and Tungnaá: Búrfell, Sultartangi, Hrauneyjafoss, Vatnsfell, Sigalda, and Búdarháls, with a combined energy of 1,035 MW. Generation capacity and production function of each individual power plant is based on (Hreinsson, 2016b) and reservoir capacity is based on (IAV, 2014; Landsvirkjun, 2012, 2016b; Wikipedia, 2016a). Water for all the power stations is provided by three main reservoirs, Thórisvatn, Hágöngulón and Kvíslarveita, along with smaller reservoirs connected with each station.

Lake Thórisvatn, Iceland's largest lake, is the largest reservoir and an important part of Landsvirkjun's utility system. All water accumulated in Kvíslarveita and Hágöngulón reservoirs runs through Lake Thórisvatn. Lake Thórisvatn became a reservoir with the harnessing of River Thjórsá at Búrfell Mountain in 1970-1972. River Kaldakvísl was diverted into the lake at the northern edge of the lake and a controlled outflow constructed at the southern edge. A canal was dug from the lake and a concrete gate structure built in the canal to manage the flow rate. The canal is named the Vatnsfell Canal, and carries water from Lake Thórisvatn through the Vatnsfell Station into the Krókslón Reservoir above the Sigalda Station, and from there to other stations further down in the catchment area. Kvíslaveita Reservoir is the collective name for the dams, canals, bottom outlets and gate structures that manage the flow rate from the River Thjórsá and its tributaries into Lake Thórisvatn. The Háganga Reservoir was constructed in 1997–1999 and covers an area of 27 km$^2$. Its purpose is to increase the efficiency of the catchment area of River Kaldakvísl. During the summer months, water accumulates in the Hágöngulón Reservoir, with very little water flowing down the Kaldakvísl riverbed (Landsvirkjun, 2015d).

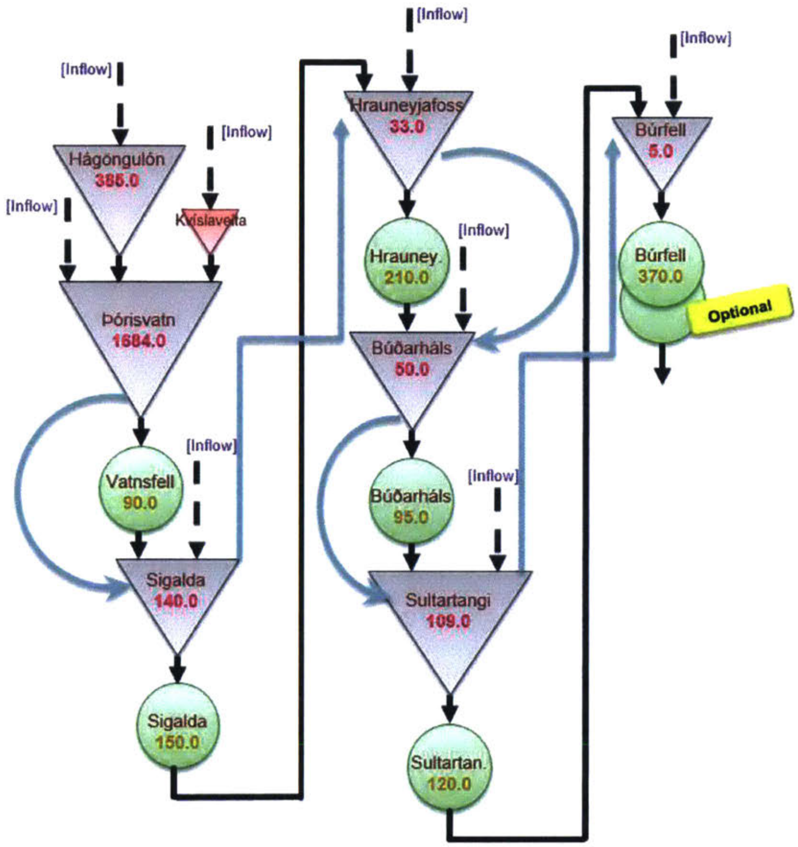



FIGURE 21: THJORSA POWER PLANT SYSTEM

Finally, Karahnjukar is the largest and most complicated hydro system in Iceland (**Figure 22**). Water from two glacial rivers (Jokla and Jokulsa) along with a direct run of river (Hraun) enters two separate tunnels before being combined at a tunnel junction. Hraun enters a small reservoir and Jokulsa enters an intake pond with little capacity, hence there is little regulation on the left side of the system. Jokla enters Halslon, which is a large reservoir of 2,088 Gl and it can provide storage in the winter months. The total drop of the water is approximately 600 meters. Based on the empirical equations and information provided by Landsvirkjun representing the flow of the Jokulsa river ($Q_u$ in **Figure 22**), the associated head losses ($H_h$ in **Figure 22**) as well as the estimated non-linear production function, we were able to establish a linear relationship between these variables to estimate the production as shown in **Figure 22**. Reservoir volumes are based on (Hreinsson, 2016b), ("Creating Kárahnjúkar," 2010) and generation capacity as well as the production function of the individual power plants are based on (Hreinsson, 2016b).

Concurrent with the construction work at Kárahnjúkar, an aluminum plant was built in Reydarfjördur. Most of the energy generated is sold to the Reydarfjördur plant (Landsvirkjun, 2015b).

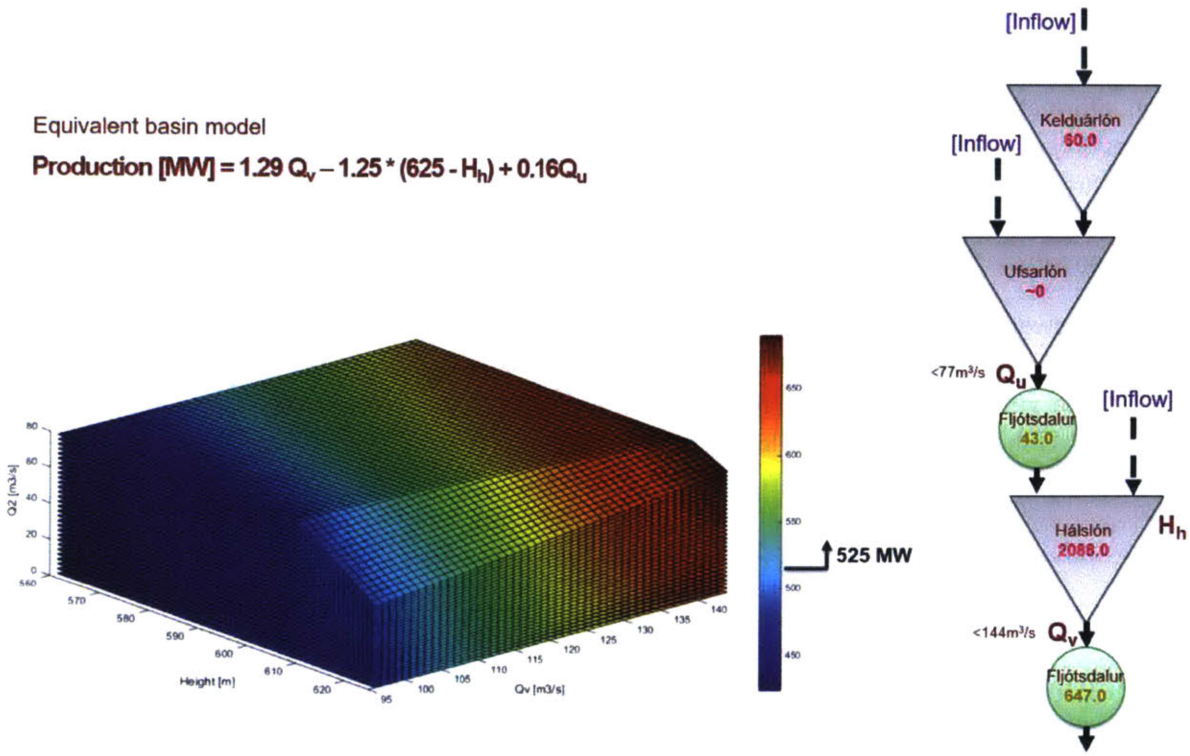



FIGURE 22: KARAHNJUKAR POWER PLANT SYSTEM

In addition, we modeled other smaller non-Landsvirkjun hydro systems as shown in **Figure 23**. Hydro systems in the North, East, West and West-fjords were aggregated and modeled as West, and Westfjords, with capacities of 8.5 MW, and 10.5 MW, respectively (Wikipedia, 2016b). In addition, there is a hydro power plant (Lagarfloss) downstream of Karahnjukar with a capacity of 27.5 MW (Wikipedia, 2016b).

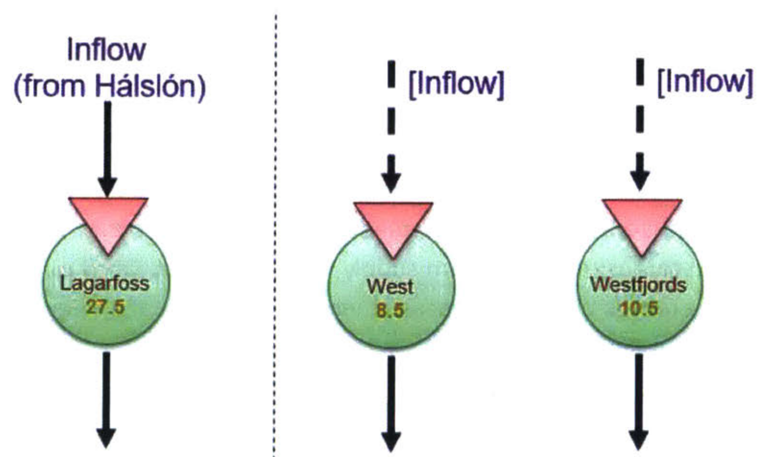



FIGURE 23: OTHER POWER PLANT SYSTEMS

## 4.4 GEOTHERMAL PLANTS

**Based on information provided by Landsvirkjun as well from (Hreinsson, 2016b), (Landsvirkjun, 2016b), and (Landsvirkjun, 2016c), 7 geothermal plants were modeled. Hellisheidi, Reykjanes, Nesjavellirm, Svartsengi, Krofluvirkjun, and Bjarnarflag were modeled to have a capacity of 303, 100, 120, 76.5, 60, and 3 MW, respectively. In addition to these ones, the 2020 scenario also included Theistrayekir with a capacity of 90 MW.**

**Geothermal power plants are assumed to be base-load, based on actual operation in Iceland and because of their physical characteristics they cannot regulate. They operate at maximum capacity throughout the year, unless they are down for maintenance. The maintenance schedule, based on historical data, is shown in Figure 24 below.**

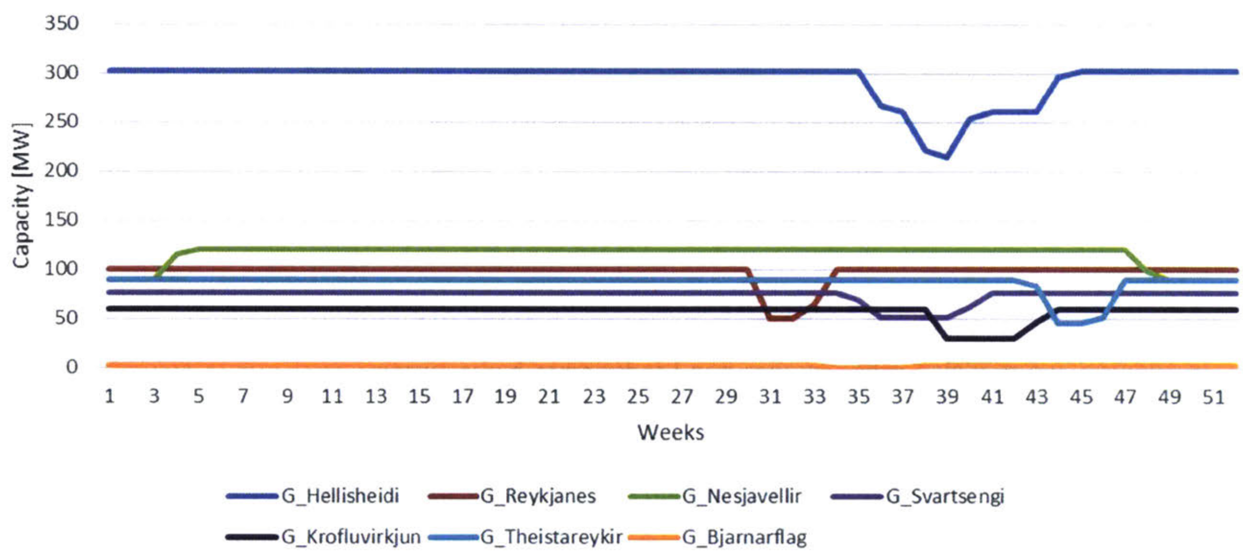



**FIGURE 24: MAINTENANCE SCHEDULE OF THE GEOTHERMAL PLANTS BY WEEK**

## 4.5 OPERATING RESERVES

**Landsnet is required by law to ensure the availability of sufficient spinning reserves (i.e., operating reserves that are connected to the grid and immediately available) at any given time to control frequency and voltage, and to ensure a minimum supply of regulating power (i.e., the power procured by Landsnet to balance differences between forecast energy use and actual energy use in the electricity system as a whole) in the regulating power market.**

**Long-term contracts with generating companies ensured the availability of 100 MW of spinning reserves in 2015 (Landsnet, 2015a). Operating reserves for 2020 were estimated to be 102 MW. This value was obtained by scaling the 2015 operating reserves based on the expected increase in energy demand between 2015 and 2020.**

## 4.6 INFLOWS

Based on the historical natural inflows series (years 1951 to 2004), a scenario tree is generated by performing a multivariate clustering of the original series to a predefined tree structure. For the purpose of this thesis, the "ARBOLES" tool was used based on this clustering method as detailed in Latorre et al. (2007)[14].

The multivariate scenario tree is obtained by a neural gas[15] clustering technique that simultaneously takes into account the main original series and their spatial and temporal dependencies. **Figure 25** shows a bidimensional clustering that obtains the bi-dimensional probability mass distribution (represented by black arrows) of the historical data (the yellow continuous probability density function). The centroids (red triangles) have the minimum distance to their corresponding points (blue dots). Their probability (length of the arrow) is proportional to the number of points represented by each centroid. The scenario tree is defined by the set of centroids (values of natural inflows) representing the best approximation to the original data series with a predefined branching structure for all the data series simultaneously. See reference Latorre et al. (2007) to understand in detail the method and its theoretical background.

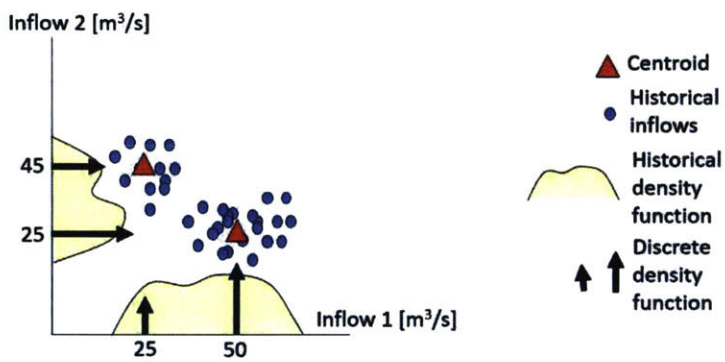



FIGURE 25: BI-DIMENSIONAL CLUSTERING

Some relevant options of the ÁRBOLES tool are:

1. The scenario tree can be created directly from historical data series. Alternatively, it can be based on synthetic data series that need to be generated out of the historical data series first, in order to determine the scenario tree.

---

[14] This tool has been developed at the Instituto de Investigación Tecnológica (IIT) of the Universidad Pontificia Comillas.

[15] The neural gas (https://en.wikipedia.org/wiki/Neural_gas) is a soft competitive learning method where all the scenarios are adapted for each new series introduced with a decreasing adapting rate.

2. The generation of synthetic series for each period is based on a Markov model that classifies the data into clusters and computes transition probabilities. Once this Markov model is determined, the synthetic series are generated following this procedure:
   - Sample of the Markov cluster
   - Sample of a historical data series from this cluster
   - Simulate using a kernel density estimation of the principal components of the original data
   - Sample a cluster for the following period taking into account the transition probability
3. The tool can generate either a normal tree or a recombining tree.
4. Different weights can be assigned to the original data series to allow flexibility in the definition of the distance. This weight multiplies the corresponding dimension when computing the multivariate distance.

$$d(x,y) = \sqrt{w_1(x_1 - y_1)^2 + w_2(x_1 - y_1)^2 + \cdots}$$

   A null coefficient means that this dimension is not taken into account for the distance. Nevertheless, the dimension is represented in the scenario tree as it is done for the others after doing the assignment of original data series to the centroids.
5. The centroids are distributed around the centered values of the data series. Those centroids can be complemented with very extreme scenarios that are artificially introduced with a very low probability. The extreme scenarios correspond to the year with the maximum/minimum natural inflows of all the years. This process is called contamination.

**Figure 26** and **Figure 27** show an example of the original data series of hydro inflows for 52 weeks, and its corresponding scenario tree.

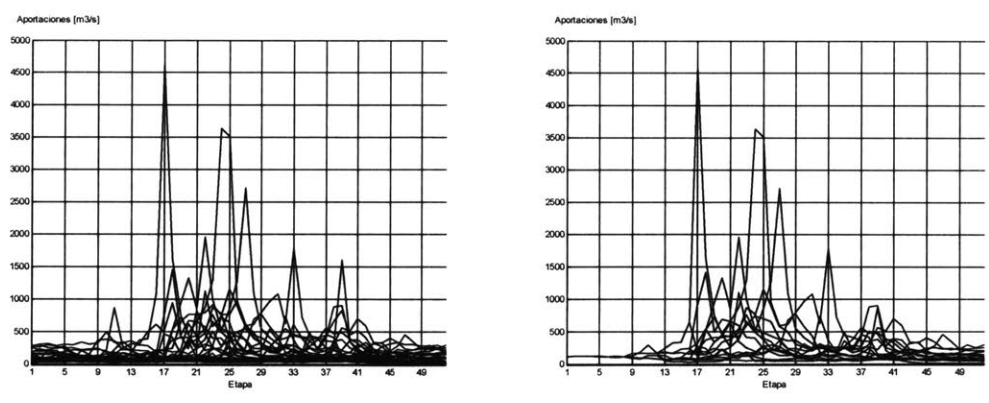



**FIGURE 26: ORIGINAL DATA SERIES AND SCENARIO TREE**

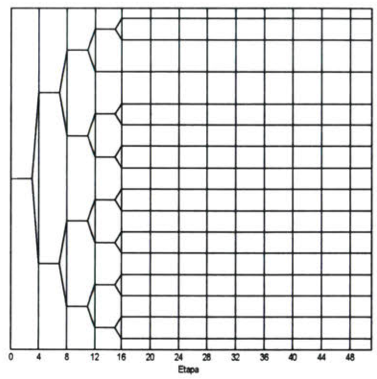



**FIGURE 27: SCHEMATIC REPRESENTATION OF THE SCENARIO TREE**

Our scenario tree starts in week 41 (1st week of October), since it coincides with the start of the water year, and it opens several braches at 6 different instances as follows:

- Branches at week 42, 2nd week of October
- Branches at week 45, 1st week of November
- Branches at week 14, 1st week of April
- Branches at week 18, 1st week of May
- Branches at week 22, 1st week of June
- Branches at week 26, 1st week of July

Over the course of the year, the branches of the scenario tree were selected to open in such a way that they capture the entire range of inflow volumes across all the scenarios.

For Hálslón, for instance, the following scenario tree is generated based on its natural inflows as shown in **Figure 28**.

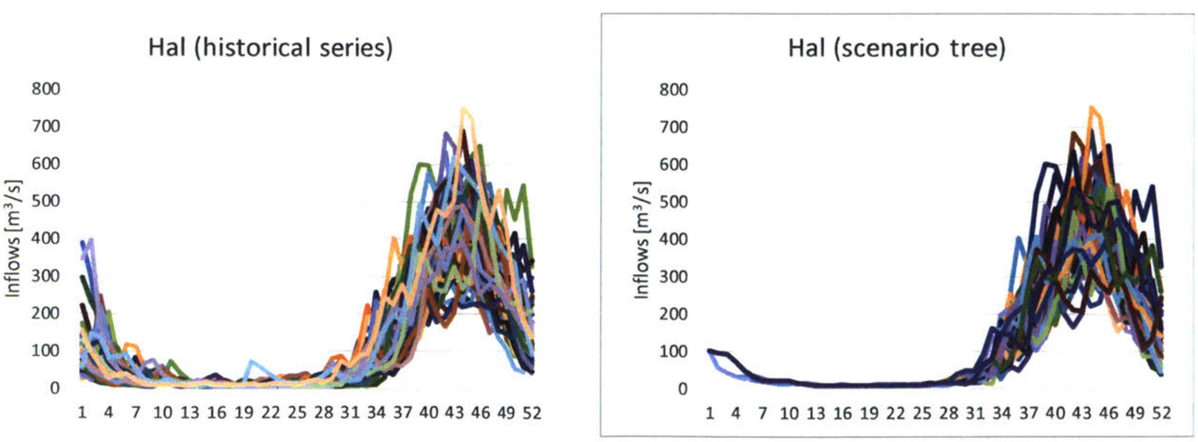



**FIGURE 28: HÁLSLÓN NATURAL INFLOWS VS. SCENARIO TREE**

## 4.7 NETWORK

While we represent the generation and demand as per the Icelandic power system, the generated output and demand is connected to a single bus for the sake of simplicity and data confidentiality. Therefore, transmission network characteristics, their constraints and losses are ignored for the purposes of this thesis.

The following section discusses the mathematical formulation of the single-node optimization model.

# 5. MATHEMATICAL FORMULATION

In order to model the Icelandic power system, a single-node, hydro-thermal operation model was used which has been developed and adapted to the particular characteristics of the Icelandic power system. Although this model is rooted in the TEPM model[16] (a mixed integer linear programming model that is typically used for defining the transmission expansion plan of a large-scale electric system at a tactical level), for this thesis the operational sub-part with no network representation was used in order to introduce sufficient level of detail of the Icelandic power system, along with stochastic short-term uncertainties (scenarios) related to natural hydro inflows of the system. The adapted model is formulated as a linear programming model.

In this section, a general description of the model formulation of the optimization problem solved by the hydro-thermal operation model is presented. **Appendix B: Hydro-Thermal Operation Model Formulation** presents the detailed formulation of the model with all the mathematical expressions for the objective function and related constraints.

**Objective Function**

The objective function of the model requires the minimization of the total costs of the system over the scope of one year. The total costs that are being minimized include expenses related to investment decisions on future power plants to build, as well as expected operating costs for power generation. In addition, the total costs include expected penalties for all the demand that is not met (in the form of annual non-served energy and hourly non-served power), an incentive to keep the reservoir levels high, and a penalty for reservoir levels below a percentage of a known final reservoir level.

**Operating Constraints**

The objective function is subject to several constraints, which represent the operational details of the power system. The operational variables and constraints can be split as inter-period or intra-period. The intra-period constraints are concerned with load and reserve balance, detailed hydro-basin modeling, and hydrothermal operation constraints. The inter-period constraints deal with the reservoir water storage and hydro scheduling, as well as water balance with stochastic inflows.

*Operating Constraints: Intra-Period*

Perhaps, the most important intra-period constraint is the energy load-balance one that requires the balance of demand and generation (hydro, and geothermal) at any given time [**Section 9.2.4, Equation 5**]. If there is not sufficient generation to meet demand, then the system can tap into operating reserves or even have some non-served energy with a corresponding associated penalty. Energy-non-served per customer and block is limited to a certain percentage, specified based on the power contracts existing in Iceland and information in **Table 2** above [**Section 9.2.4, Equation 4**].

The intra-period constraints require the operating capacity of the power plants must be within bounds, i.e. lower than the specified installed capacity. In addition, the maintenance schedule for the power

[16] The model has been developed at IIT Universidad Pontificia Comillas by Professor Andres Ramos. Details on how the model is used can be found in the 2016 Long-Term Transmission Expansion Planning Model (TEPM) User's Guide, prepared by IIT.

plants is also accounted for when deciding operating capacity. Hydro power is a function of the reservoir inventory (as defined below) [**Section 9.2.4, Equation 14**], production function, and follows the demand.

*Operating Constraints: Inter-Period*

Managing the hydro reservoir inventory and system is extremely important since it has a direct impact on the power production, or subsequently on energy curtailments. The hydro reservoir inventory is also known as the hydro-balance equation. It requires for the "reservoir volume at the beginning of the period, minus the reservoir volume at the end of the period, plus incoming natural inflows, minus spills from this reservoir, plus spills from upstream reservoirs, plus turbined water from upstream storage hydro plants, minus turbined and pumped water from this reservoir, plus pumped water from upstream pumped hydro plants, to be equal to zero" [**Section 9.2.4, Equation 10**].

**Reservoir Management Strategy**

The TEPM model gives great flexibility regarding simulating different management strategies for hydro reservoirs with various options regarding the initial and final reservoir levels. In addition, it can treat each reservoir individually, with a pre-specified value for the reservoir level or as a variable determined by the model. It can also allow for all the reservoirs to be treated similarly with a variable or known value common across all reservoirs. The different management strategies are outlined below:

- Initial reservoir volume or Initial Reserve Level (IRL) (depending on the chosen option) could be equal to a fixed initial volume, or to an initial-volume variable percentage, or to a unique variable percentage for all the reservoirs, or to a constant percentage for all the reservoirs [**Section 9.2.4, Equation 11**].
- Final reservoir volume or Final Reserve Level (FRL) (depending on the chosen option) could be greater or equal to a fixed initial volume, or to an initial-volume variable percentage, or to a unique variable percentage for all the reservoirs, or to a constant percentage for all the reservoirs [**Section 9.2.4, Equation 12**].
- Expected final reservoir volume or Expected Final Reservoir Level (EFRL) for all the scenarios (depending on the chosen option) could be greater or equal to the initial volume; or to an initial-reservoir variable percentage for each reservoir; or to a unique initial reservoir variable percentage for all the reservoirs; or to an initial constant reservoir percentage for all the reservoirs [**Section 9.2.4, Equation.13**].

In addition, the model also allows specifying the *expected value of the final reservoirs at the end of the year,* which could be either: i) greater than the initial reservoir level for every scenario, or ii) greater than the initial reservoir level for all scenarios.

The model also includes some additional bounds, as specified by the user, which require generation to be between the minimum and maximum output of the generator per period. The reservoir levels must also be between the minimum and maximum specified levels. [**Section 9.2.4, Equation 20**]

While the full version of the TEPM model has various additional constraints and features related to network modeling, such as direct-current flow in lines, network cuts, among others, for this work we have ignored the transmission system.

## 5.1 METHODOLOGY FOR DETERMINING THE VALUE OF WATER

The goal is to evaluate the value of the water reserves at the end of the water year. It is not possible to *explicitly* consider or compute the impact of water reserves levels at the end of the year on the operation of the system in subsequent years. The reason is due to the limitations of the model formulation, which optimizes the operation of the Icelandic power system on a single-year time frame. Hence, we need to *implicitly* simulate the impact of the water reserve levels on the operation of subsequent years by giving a value to the final energy reserves.

The model includes a scenario tree that captures the stochasticity of the historical hydro inflows. The start of the year coincides with the start of the hydrological year, while the branches of the scenario tree open over the course of the year so as to capture the variance in inflows. The water value for each branch, week, and load level is as a general rule equal to the dual variable of the hydro-balance constraint. As the Icelandic power system is composed by geothermal –baseload-type generation– and hydro generation with negligible variable cost, the water value will depend on the curtailment costs. The system allows four types of curtailments at different costs. Depending on the depth and accumulated duration of the curtailment, the curtailment cost amounts to P1, P2 and P3 for the industrial demand. The small consumer is curtailed at P4. The supply contract structure results in P4 > P3 > P2 > P1. The specific contract structure and the values of P1, P2, P3, and P4 are as shown in **Table 2.**

A major difficulty and peculiarity of the Icelandic system is the lack of fossil fuel generation, which habitually marks the water value. The difficulty lies in the need of having non-served energy to obtain the water value. However, non-served energy is an undesired situation that should be avoided by providing the correct value to the water before it is scarce. To do so, the thesis proposes two methodologies that should guide the reservoirs management and provide an economic value to the water before it is indeed scarce, which should be later sent to the consumers, so that they adjust their consumption level accordingly.

### 5.1.1 METHODOLOGY A

The Icelandic system operators tend to have a risk-averse approach to hydro reservoir planning. Given the uncertainty of the hydro conditions for future years, the final reservoir levels are maintained at 90% or greater. To substantiate this approach, we run the model with the following conditions:

1. The optimization model is set to minimize the objective function (which is the total cost). It attains this by minimizing the amount of NSE.
2. The average final reservoir level (AFRL) is set to be greater than or equal to the initial reserve level (IRL). Note that the average final reservoir level is calculated as a weighted average of the final reservoir levels of all scenarios. The weight is equal to the probability of each scenario.
3. The Initial Reservoir Level (IRL) and Final Reserve Level (FRL) are variables that are left open for the model to optimize based on minimizing the objective function. IRL and FRL can vary all reservoirs and scenarios and can range from any value between 0% to 100% of the maximum reservoir level (MRL).

In summary, the goal of this methodology is to give a conservative solution regarding management of the hydro reservoir levels. Because the expected reservoir levels should end at a level higher than what they started off (the model decides the start and end levels), this methodology provides the range of levels at which the reservoirs should start to guarantee that the expected end level is higher than the initial one. Put simply, the system will be in average recovering its hydro reserves. The solution is not unique, but can be controlled by, for example, incentivizing high reservoir levels throughout the year.

### 5.1.2 METHODOLOGY B

An alternate methodology to calculate the water value is presented here. It differs from the previous one mainly because the initial reservoir level is no longer a variable that is determined by the optimization model; instead it is specified by the user. Similar to the prior methodology, here also we require the final reserve level to be greater than the IRL. In particular, this methodology entails the following:

1. The IRL is specified by the user to be a certain fixed percentage of the MRL. It is common for all reservoirs.
2. The expected final reserve level (EFRL) in each scenario is set to be greater than or equal to the IRL. The EFRL is calculated as an average across all the final reserve levels for each scenario. The EFRL is calculated as a percentage of the MRL.
3. The AFRL is calculated based on the EFRL in each scenario as well as the corresponding weighted probability.
4. The next step is to run various iterations of the TEPM model using varying IRL's values till the trigger IRL is found. The trigger IRL corresponds to those levels where curtailments (i.e. non-served energy) appear in the system.

Under this methodology, the water value is the dual variable of the hydro-balance constraint of the reservoir when fixing its initial IRL. See **Section 9.2, Equation 10**

The goal of this methodology is to find out the minimum initial reservoir level, which is equal to the final reservoir level of the previous year, that is needed to secure the energy supply of the system. Furthermore, another relevant goal is providing an economic value to the decision of leaving the reservoir below the previous minimum initial reservoir. The reason for this methodology is to overcome the main issue identified with Methodology A: the risk aversion. A risk-averse agent is reluctant to empty reservoirs below a threshold that from their experience could compromise the security of supply. This behavior implies however a cost to the system. Future security is achieved at the expense of present curtailments. The main advantage of this methodology is helping assess the very complex decision of who should pay, either current or future consumers, and how much is then paid for curtailments.

Specifically, we ran the first iteration of the hydro-thermal operation model, initiating the IRL to be 40% of the maximum reserve level. The AFRL, and minimum final reserve levels (MFRL), average NSE, and the water value were evaluated for this run. If the NSE (and subsequently the water value) was a non-zero value, we ran another iteration of the run. In subsequent model iterations, the IRL was set to be closer to the MFRL of the pervious iteration. Hence several simulations were run, with the IRL ranging from 40% up to 70%. Finally, this iterative procedure is stopped when a model run concludes in zero NSE. At this point, the subsequent water value must be also zero.

# 6. MODEL RESULTS

This section will start off with a discussion on the results of the model, which was created to represent the current Icelandic power system and understand the impact of varying hydro conditions. Next, the modeling results that quantify the value of the water reserves will be presented. The results from Methodology B should help us understand the tradeoffs between curtailing energy in the present and storing the water for the future, or spending the water now so as to reduce the curtailments, but increasing the possibility of curtailments in the future.

## 6.1 OPERATION OF THE ELECTRIC SYSTEM

The Icelandic power demand is for the most part covered by hydro (70%) and geothermal (30%) power plants. Due to its technical characteristics, the geothermal generation capacity is utilized as a baseload technology. The hydro generation capacity must then satisfy the total power demand net of the geothermal production. This demand that is covered by the hydro power plants is referred as the net demand.

The net demand, and the potential and maximum energy production have been calculated for year 2020. According to the data, the total power demand is expected to amount to 18.9 GWh. Since the geothermal generation will reach up to 6 GWh, the net demand is expected to reach 12.9 GWh.

During a year, the water inflows that are received by the hydraulic system come from the snow and glacier melting, rain, and some natural springs. Any inflow (i.e., water volume) is equivalent to a quantity of energy that can be obtained by multiplying the water volume [$m^3$] by the production function or efficiency of the power plant [$kWh/m^3$]. However, a water drop at the headwaters of the Þjorsa river basin (e.g., Hágöngulón reservoir) does not present the same energy potential as compared to a water drop at the end of the Þjorsa river basin (e.g., Búrfell pond). The drop in head as the water droplet traverses the system also corresponds to a drop in its potential energy and hence ability to generate electricity. For this reason, cumulative production functions have been obtained for all the hydro power plants as the sum of all production functions downstream of an inflow (**Appendix C: Cumulative Production Function (By Generator)**). Simply put, the idea is to produce the total energy that a water drop could potentially produce by multiplying the inflow by its respective cumulative production function.

Nevertheless, that water drop cannot typically produce all that energy due to the hydropower system constraints, such as the maximum power output or the maximum reservoir level. In order to compute the maximum energy production, we have used the model in a new mode in which the annual energy production is maximized. This way, we obtain the maximum hydropower generation when the technical constraints are considered.

In order to conduct a probabilistic study on the expected non-served energy (**Figure 29**) probability function for the potential (blue line) and the maximum (red line) power generation out of the real inflow time series (1951-2004) is evaluated. That is, the blue line represents the potential hydro-production if every water droplet from the inflows could be converted to energy without any other constraints. The red line considers reservoir limits as well as the maximum power output of the generators. The green line represents the demand net of the geothermal production. At first sight, we can observe that for 10% of the years the inflows themselves are not enough to cover the net demand (green line). When the hydropower technical constraints are considered, curtailments are expected in one out of four years.

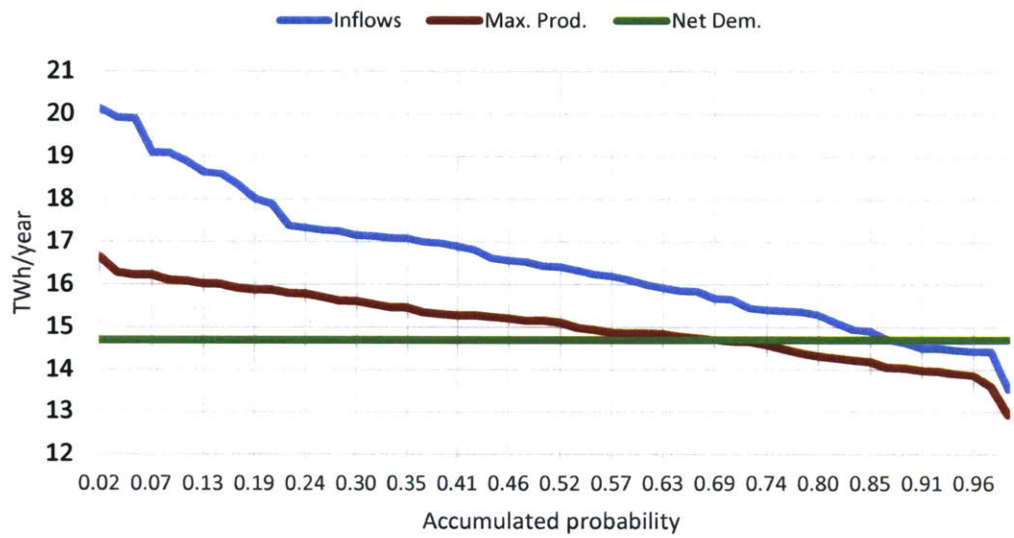



**FIGURE 29: CUMULATED PROBABILITY FUNCTION FOR THE POTENTIAL (BLUE LINE) AND MAXIMUM (RED LINE) POWER GENERATION BASED ON REAL INFLOW TIME SERIES.**

Regarding the operation of the plants in the system, it is observed that the geothermal power plants are fully operating in all cases, except for the time they are down for scheduled maintenance. **Figure 30** shows the geothermal power plant production via box-and-whisker plots. The plots represent the statistical distribution of the geothermal power production across all the considered scenarios (i.e. hydrological conditions). The box shows the 1$^{st}$ quartile, median, and 3$^{rd}$ quartile power production, whereas the whiskers show the minimum and maximum production per plant and across all the modeled scenarios. These values are compared against historical production values found on online sources ('Website') as well as the theoretical annual maximum production minus scheduled maintenance ('Theoretical'). As can be observed in **Figure 30**, the geothermal power plants produce at levels that are very close to the calculated theoretical maximum.

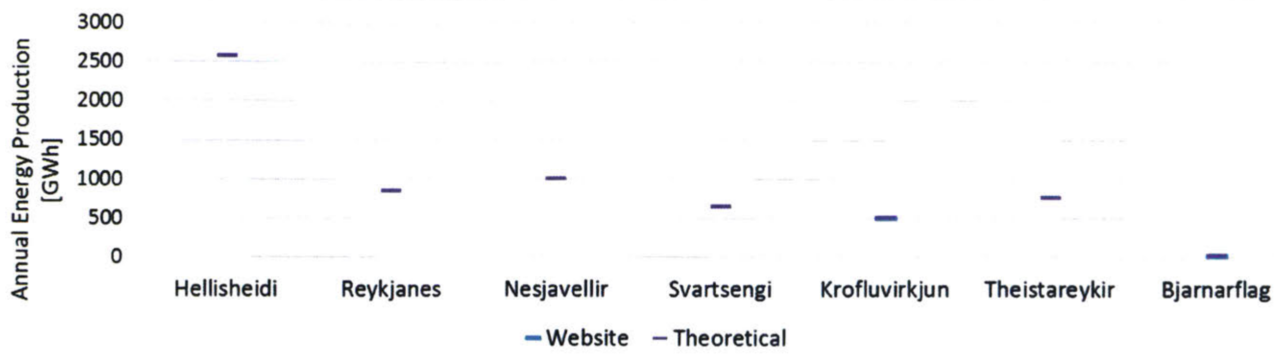



FIGURE 30: GEOTHERMAL GENERATION PER PLANT ON AN ANNUAL BASIS

In contrast, the hydropower generation slightly varies for each plant depending on the scenario. **Figure 31** shows the hydropower plants production with box-and-whisker plots. Noteworthy, almost all power plants are expected to produce close to their historical values (blue line).

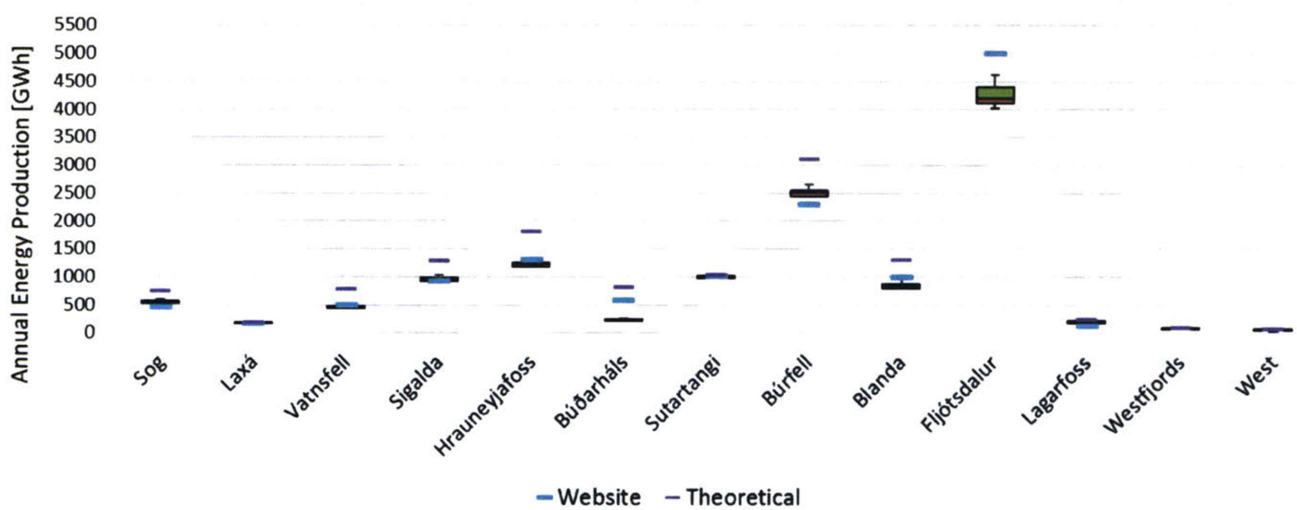



FIGURE 31: HYDROPOWER GENERATION PER PLANT ON AN ANNUAL BASIS.

The reservoir utilization follows similar patterns, as shown for the two major water reservoirs Hálslón and Þórisvatn (see **Figure 32** and **Figure 33**). Each line in the figures represents a particular hydrological year that was modeled (based on historical data) and the behavior of the reservoir levels in response to those hydrological conditions. The reservoirs were modeled to start and end the water year at 90% of their maximum water volume based on a conservative reservoir management approach by the Icelandic authorities. The reservoirs are full at the start of the winter and continue to deplete during the winter months as the water in the reservoirs is used to produce hydroelectricity. However, the reservoir levels are not replenished because the inflows freeze during the cold winter months. In the spring months the inflows are at their maximum and we notice a subsequent rise in the reservoir levels.

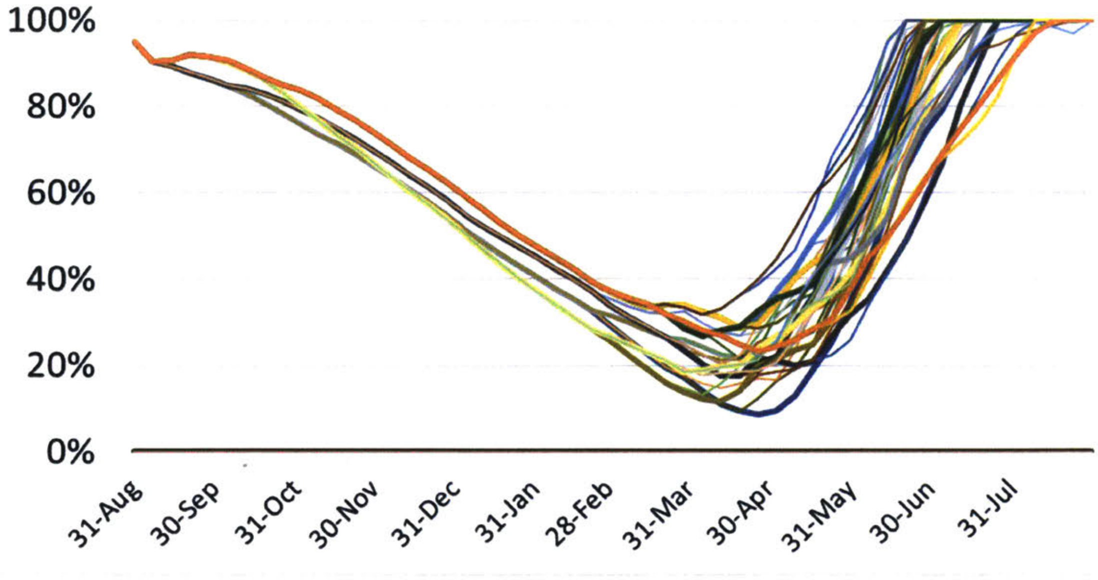



**FIGURE 32: HÁLSLÓN RESERVOIR UTILIZATION BASED ON RESERVOIRS LEVELS THROUGHOUT THE YEAR**

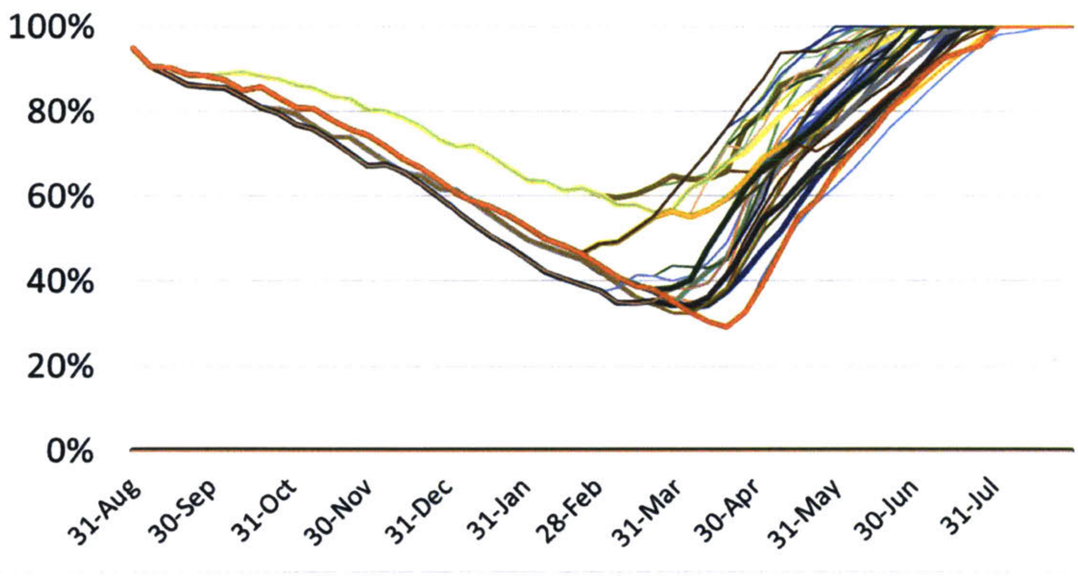



**FIGURE 33: ÞÓRISVATN RESERVOIR UTILIZATION BASED ON RESERVOIRS LEVELS THROUGHOUT THE YEAR**

Without considering for network or local constraints, there is no NSE when the reservoirs are managed with a conservative approach, and required to start the water year at 90% of their maximum reservoir level and end the water year at a level 90% or higher. *The question arises that in the future, with an increasing load demand and constraints of the actual transmission network, what is the best strategy that must be employed to manage the reservoirs to ensure security of supply? Is the system operator justified using its current extremely risk-averse approach?* To answer this question, we run our model to determine the value of the water in the reservoirs when they start and end at varying levels in order to understand the impact of employing different hydro reservoir management strategies in the Icelandic system.

## 6.2 SENSITIVITY TO RESERVOIR LEVELS

Based on **Methodology A**, a run of the model provides the following results:

- Initial reservoir level is set to be 99.4% for all the reservoirs across all the scenarios.
- Average final reservoir level, weighted across all the scenarios, is determined to be 99.5%.
- The range of final reservoir level (across all scenarios) is 97.2% - 100%. Thus, across all the scenarios that we considered, the driest year would deplete the reservoir level from an initial starting point of 99.4% to 97.2% at the end of the water year. Whereas the wettest year would raise the level of the water from 99.4% to 100%.

The key point to note is that the average final reservoir level is 99.5%; that is, the repetition over time of different hydrological conditions is expected to leave the reservoirs full up to 99.5%. Even with the driest year which could lower reservoir levels to 97.2%, the expected hydro inflows of the subsequent years recover the reservoirs level to the average level of 99.5%. The same applies to wet years, as the expectancy will reduce the reservoirs level to the average. In short, this methodology is taking advantage of the regression toward the mean property of natural phenomena[17].

The main disadvantage of this methodology is the risk of facing a series of consecutive dry years. Since we observe that the minimum final reservoir level is lower than the initial reservoir level, it entails that each year the reservoir level would be lower than the previous year. Although improbable, a risk-averse agent will not wait-and-see if the reservoir level will recover on its own, without any type of intervention. In this situation, curtailments are expected in the current year, since the current operating conditions do not allow for the desired initial reservoir level of the subsequent year to be achieved. As mentioned before, the desired initial reservoir level will be lower than the level at the start of the current year.

Based on **Methodology A**, the model sets the AFRL to be at 99.5% of the maximum reservoir levels (MRL). The minimum final reservoir level (MFRL), corresponding to the driest year, is 97% of the MRL. Based on the results it seems that the model picked a very conservative solution given an entire range of optimal solutions. Moreover, the decay of the final reservoir level with respect to the initial one could lead one to think that a series of dry years could cause scarcity situations, since the reservoirs levels would be continuously decreasing. However, when the initial reservoir level is set at 90%, the minimum reservoir level across all scenarios is again 97%, which is contradictory with the previous statement. Hence we needed to come up with an alternate methodology.

Based on **Methodology B,** it is observed now that irrespective of the starting IRL, the corresponding AFRL and minimum final reserve level are always greater. As the IRL increased, the corresponding NSE and water value decreased (results shown in **Table 3)**.

---

[17] Climate change could alter the foundations of this methodology as the mean may be also altered.

It is observed that the average NSE decreases as the IRL in increased (**Figure 34)**. When the IRL's are 70% or greater, then the expected NSE or energy curtailments are negligible.

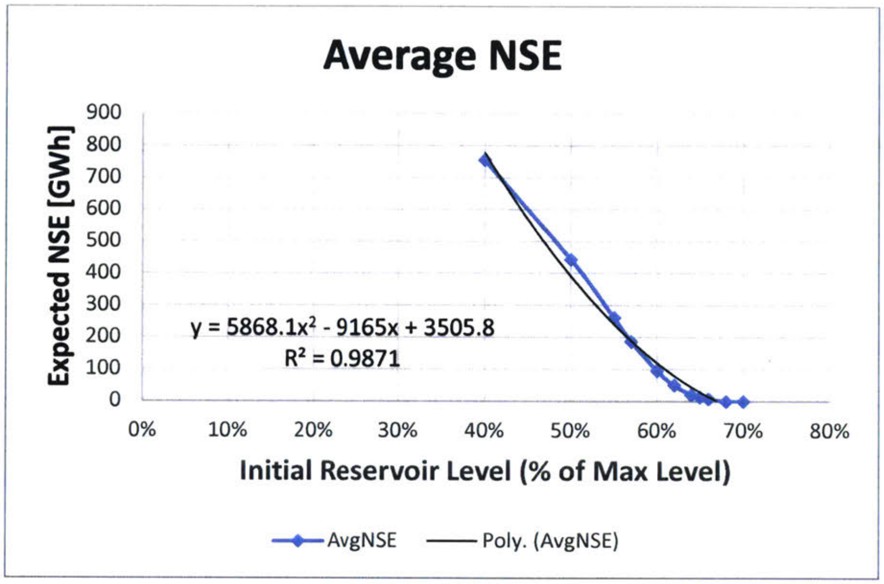



FIGURE 34: INCREASE IN AVERAGE NSE WITH A DECREASE IN INITIAL RESERVOIR LEVEL

The model evaluates two water values as can be seen in **Table 3.** The first water value in €/hm$^3$ is the reservoir-specific value of a unit of water. It reflects the opportunity cost of utilizing a single cubic hectometer of water for each reservoir. The other water value, given in €/MWh, is a system-wide cost per unit generation, i.e. it reflects the marginal cost of water in the reservoir required to generate one MWh of electricity. Here the cumulative production function is used to evaluate the generating capacity of a drop of water as it passes through the system of reservoirs and power plants.

As observed in **Figure 35,** the water value increases as the IRL diminishes. Intuitively this makes sense since the lower the initial level of water reserves, by the end of the year, each unit of water will be even more valuable since it will have a higher opportunity cost. The water value follows a similar trend as the average NSE. When the IRL is 70% or larger, we expect to have zero curtailments and hence the water value to be zero. Conversely, for IRLs that are below 70% of the maximum reservoir level, the water value is non-zero.

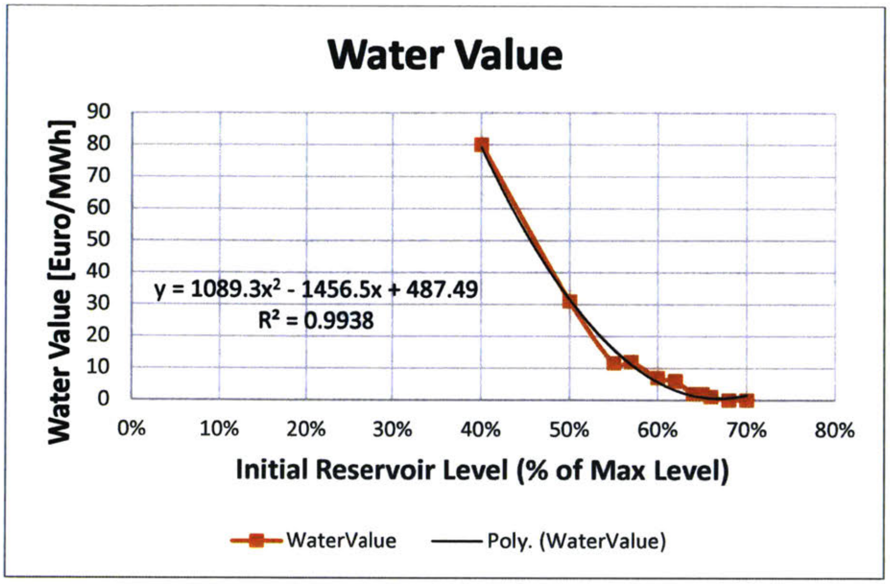



FIGURE 35: INCREASE IN AVERAGE WATER VALUE [€/MWH] WITH A DECREASE IN INITIAL RESERVOIR LEVEL

**Figure 36** clearly demonstrates that the minimum final reserve level (MFRL, yellow line) and AFRL (gray line) are always greater than the corresponding IRL. To illustrate, if at the start of the water year the IRL is at 40% of the maximum reservoir levels, then the corresponding MFRL and AFRL at the end of the water year across all hydro scenarios will be 57% and 88%, respectively. Hence even in the driest hydro scenario the water reserves will end the water year at a minimum level of 57%. Iterating the model with an IRL of 57%, this results in the MFRL and AFRL at the end of the water year to be 61% and 90%, respectively. Results are presented in **Table 3** for various initial reservoir levels.

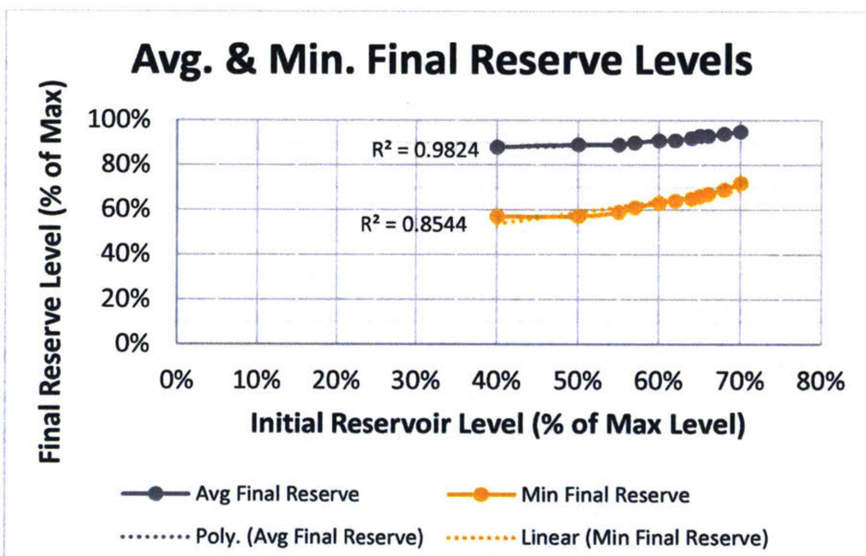



FIGURE 36: DECREASE IN AVERAGE FINAL RESERVE LEVEL AND MINIMUM FINAL RESERVE LEVEL WITH A DECREASE IN INITIAL RESERVOIR LEVEL

Since the hydro conditions (wet, dry, or average) for the following year is not known ahead of time, the Icelandic system operators, who are risk averse to droughts and high levels of curtailments, tend to end the water year with reservoir levels of at least 90% of the maximum level. This could result in potentially higher levels of curtailments for the current year. Depending on the hydro conditions for the next year, especially if it is wet, there could be spillage of water. An important take away from **Figure 36** is that even with an IRL as low as 40%, the AFRL is close to or greater than 90%. This is very close to the desired final reservoir levels as maintained in the risk-averse, current Icelandic system. To attain these desired final reservoir levels (of around 90%) the system operator does not need to start with high initial levels. Also the system operators may allow final reservoir levels to drop below 90%. However, the risk-averse behavior could be justified if a severe drought during a critical moment of the year or any other water contingency could result in compromising curtailments[18]. Therefore, the importance of providing periodical, probably weekly, price signals to the consumers, so they can react to hydro power restrictions.

To compute the weekly price signals to the consumers as mentioned above, the model that has been described in this thesis could be used. For example, the model could be run in a weekly basis by the regulator or the system operator with the best available information for the next 52 weeks. The stochastic tree would incorporate all this information, and provide a weekly price for the current week. The price would be the shadow price of the energy balance equation for each load block, consumer type, weekday, and weekend scenario. This weekly price could later become the price cap of an auction in which the consumers could response by reducing their demand. These prices should also correspond to our calculations of the value of the stored water in the reservoirs, as in both cases the prices will depend on the costs associated to the curtailment contracts existing the Icelandic system for the various types of consumers.

In summary, the series of runs show the monetary impact of various hydro reservoir management strategies. From the results we infer that initial reservoir levels below 70% result in costs for the Icelandic system given the risk of curtailments for customers. This information is key in the event of having dry hydrological year. The operator will know that the initial reservoir levels could be lower than 90% without having the risk to curtail power. Also the operator will know that the reservoirs in average will be able to increase their final levels by the end of the year given the system's high inflows contributions after spring.

We realized that accounting for the transmission system could have an impact on our results. Because of stability limits, for instance, the Icelandic system could be split into regions whose operation need to be monitored and maintained within specific limits. In addition, the thermal limit of some corridors could raise local energy problems as for example a particular location could have more demand than its nearby generating resources and imported power flows. In addition, we would expect to see an increase in NSE due to the transmission constraints, and a subsequent increase in the water value for the same IRL. This is the result of the losses in the transmission network and a higher energy production would be

[18] The cost of shutting down and starting up an aluminum smelter is exceptionally high.

required to meet the same level of demand. Hence one unit of water would have a higher opportunity cost associated with it leading to a higher water value.

| Initial Reservoir Level (IRL) [$hm^3$] | | 70% | 68% | 66% | 65% | 64% | 62% | 60% | 57% | 55% | 50% | 40% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Reservoir** | **Volume** | **Volume-based Water Value [€/$hm^3$]** | | | | | | | | | | |
| **Hágöngulón** | 302 $hm^3$ | 0 | 0 | 18 | 25 | 25 | 61 | 67 | 95 | 95 | 279 | 711 |
| **Þórisvatn** | 1512 $hm^3$ | 0 | 0 | 18 | 25 | 25 | 61 | 67 | 95 | 95 | 279 | 711 |
| **Sigalda** | 80 $hm^3$ | 0 | 0 | 18 | 25 | 25 | 62 | 68 | 96 | 96 | 283 | 722 |
| **Hrauneyjafoss** | 16 $hm^3$ | 0 | 0 | 18 | 26 | 26 | 63 | 69 | 98 | 98 | 288 | 734 |
| **Búðarháls** | 30 $hm^3$ | 0 | 0 | 19 | 26 | 26 | 64 | 71 | 100 | 100 | 294 | 749 |
| **Sultartangi** | 110 $hm^3$ | 0 | 0 | 19 | 26 | 26 | 65 | 71 | 100 | 100 | 295 | 751 |
| **Búrfell** | 5 $hm^3$ | 0 | 0 | 19 | 27 | 27 | 65 | 72 | 101 | 101 | 298 | 759 |
| **Blöndulón** | 400 $hm^3$ | 0 | 0 | 18 | 26 | 26 | 63 | 69 | 97 | 97 | 287 | 731 |
| **Gilsárslón** | 20 $hm^3$ | 0 | 0 | 18 | 26 | 26 | 63 | 69 | 97 | 97 | 287 | 731 |
| **Kelduárlón** | 60 $hm^3$ | 0 | 0 | 17 | 24 | 24 | 59 | 65 | 91 | 91 | 269 | 684 |
| **Ufsarlón** | 5 $hm^3$ | 0 | 0 | 17 | 24 | 24 | 59 | 65 | 91 | 91 | 269 | 684 |
| **Hálslón** | 2088 $hm^3$ | 0 | 0 | 17 | 24 | 24 | 60 | 66 | 92 | 92 | 273 | 694 |
| **Cost-based Water Value [€/MWh]** | | **0** | **0** | **1** | **2** | **2** | **6** | **7** | **12** | **12** | **31** | **80** |
| **Expected NSE [GWh]** | | **0** | **0** | **7** | **13** | **20** | **50** | **95** | **187** | **261** | **444** | **756** |
| **Average Final Reserve Level (AFRL)** | | **95%** | **94%** | **93%** | **93%** | **92%** | **91%** | **91%** | **90%** | **89%** | **89%** | **88%** |
| **Minimum Final Reserve Level (MFRL)** | | **72%** | **69%** | **67%** | **66%** | **65%** | **64%** | **63%** | **61%** | **59%** | **57%** | **57%** |

TABLE 3: EXPECTED NSE AND FINAL RESERVE LEVELS WITH VARYING INITIAL RESERVE LEVELS

# 7. DISCUSSION AND SUMMARY

Based on our understanding and analysis of the issues and characteristics pertaining to the Icelandic electricity market and power system presented above, this chapter will provide a discussion on proposed regulatory measures to address the aforementioned issues.

## 7.1 VALUE OF WATER

The best metric for a hydro-dominated system is the volume of non-served energy[19]. Limitations in transmission capacity may lead to local-capacity problems. Provided that the installed generation capacity is enough to satisfy the peak demand, energy supply may be compromised by water scarcity. As explored throughout this thesis, expected non-served energy provides an acceptable level information about the existing and expected conditions of the energy system, which could guide the operation of the various reservoirs in such a manner that ensures water being used in an optimal fashion in order to satisfy current and future needs while ensuring security of supply.

Water value was said to represent the cost increase in electricity supply that the region would face if it had one less MWh of water in the reservoir. This opportunity cost is the value at which a hydro market player offers production into the market (Unger, 2014).

Based on our analysis in **Section 6.2**, it can be seen that a risk-averse approach of maintaining reservoir levels (at the end of the water year) at 90% of the maximum levels was not required. In the event of a dry year, it is acceptable for the water reserves to end at a lower level than 90% of the maximum. This would be acceptable to ensure there were no curtailments required for any kind of consumer, residential or industrial. Curtailments result in social and economic costs. The model indicates that curtailments may be avoided since, irrespective of the initial levels of the reserves, the end reserve levels are always higher than the initial. For water reserve levels ending as low as 68%, the NSE and corresponding water value for the following year would be zero. Hence it is advisable to allow for the reserves to drop as low as 70% to ensure no curtailments in the present and future years.

The incumbent company, still publicly owned and responsible for the reservoirs management, could even empty the reservoirs to a greater level during a drought period. However, risk aversion has a great impact on its operation and preventive curtailments occur. The lack of short-term market signals due to the OTC structure and bilateral contracting impedes the consumers' voluntary reaction while the former incumbent company must exercise the flexible portion of the supply contracts at its best, but discretionary, rationale. Therefore, the appropriate scarcity costs must be transmitted to the consumer to ensure SoES. Due to the lack of fossil fuel generation, the scarcity cost, or water value, is the opportunity cost of not fulfilling the supply contract and partially curtailed the power delivery. The

[19] Other metrics, such as the frequency, duration and cost of outages, can also be used for complementing the security of supply analysis, in particular, when failures of units and/or lines are considered.

consumers must be exposed to this market signal, i.e., to the expected curtailment cost, which can be obtained with the model that has been presented in this thesis.

## 7.2 REGULATION

The discussion on the water value and the reservoir management is of extreme importance for the Icelandic power system. However, a qualitative discussion on other aspects related to SoES is equally needed as other concerns have been identified in **Section 3.3**.

A reliable power supply results from a combination of security, firmness and adequacy under the guidance of the strategic energy policy. Regulatory experience based on other systems has shown that some regulatory and policy intervention is required. However, the important question is up to what level is regulatory intervention required (Batlle & Rodilla, 2015).

Countries need to establish long-term policies. In the case of Iceland, several options exist for maintaining and improving energy security and choosing a model of growth. An exhaustive list includes expanding clean energy capacity options[20], allowing or impeding new industrial demand installation, reinforcing the national transmission network, interconnecting to the UK (and the rest of Europe) through a subsea cable, or exploring and putting into production offshore oil and gas fields. The security of supply objective must not be separated from other goals, such as sustainability, competitiveness, economic growth, self-sufficiency and the connection and relationship with the European Economic Area members.

As mentioned before, an electricity market environment does not guarantee satisfactory levels of adequacy and firmness. This is particularly true when there is a very strong horizontal concentration in generation and the variable production costs cannot provide proper economic signals, as in the case of Iceland. Adequacy and firmness are extremely important and a precondition for attracting large industrial consumers, but some regulatory intervention is required with a clear allocation of responsibilities. Relying on a publicly owned power company leads to an ambiguous situation, which hardly coexists with market conditions. The adoption of a regulatory mechanism is a direct responsibility of the regulatory authority, with the technical support of the system operator. It is worth mentioning that there is a tradeoff between reliability improvement and cost; i.e., better reliability means additional costs.

Achieving reasonable levels of adequacy and firmness concerns the entire power sector and requires the choice of regulatory instruments that guarantee that enough firm capacity exists and incentivize that enough firm capacity will be available when needed. Any regulatory instrument must be well adapted to the existing and preferred generation technologies and must be compatible with the decided energy policy. However, in the case of Iceland, limitations in the current market rules and the behavior of some

[20] According to the Master Plan, about 9 TWh of geothermal and 5.8 TWh of hydro production could be deployed with minor environmental impact. The wind production potential is relevant, with a capacity factor above 40% for the already installed wind turbines.

agents indicate that the system is moving away from the goal. A non-exhaustive list of problems includes:

1) some private companies may offer more capacity than available;
2) some private companies may dump its excess power production in the power system; or
3) the national power company implicitly takes care of abandoned consumers or leftover power.

Some discussion on how to achieve energy security is then needed. The regulatory recommendations will be guided by the following criteria:

- Small consumers must be protected against poor quality of service and non-affordable prices.
- Existing large consumers must be protected against deterioration of quality of service when new (industrial) demand enters the system.
- Sound economic signals must guide the stakeholders' decisions towards a more efficient and secure operation of the power system.

The regulatory authority must be the institution responsible for designing, implementing and monitoring the activities necessary to improve the overall reliability level. Measures in this direction include:

**A. A pricing system that improves operation efficiency of generation and demand.**

The advantages of having a short-term price signal that is directly related to the actual operating conditions of the power system are beyond manifold, in particular eliciting efficient response by consumers and producers alike. In a mostly hydro system with significant storage capabilities, differentiating prices by the hour does not make sense, except perhaps in those occasions where network constraints and peak demands create local specific conditions. Weekly prices, obtained by an annual operation optimization model that is rolled over a year every week could be a reasonable proposition. Based on our model, we can compute these prices based on the shadow price of the demand-generation balance equation per load block, weekday and weekend and scenario. These prices should also correspond to our calculations of the value of the stored water in the reservoirs, as in both cases the prices will depend on the costs associated to the curtailment contracts existing the Icelandic system for the various types of consumers. The calculation can be done on a week-ahead basis and this information should be made available to the market participants. Hence, the computation of weekly prices would internalize the best available information regarding the hydrological year and other variables (demand, maintenance schedules, weather, etc.).

Most of the electricity would continue being sold via long-term contracts. This is perfectly compatible with shorter term economic signals that would incentivize efficient behavior regarding deviations with respect to any prescribed schedule responding to actual short-term conditions taking place in the power system.

**B. Regulatory support to adequacy and firmness.**

It is proposed the adoption of a proactive stance of the regulatory authority regarding the guarantee of adequacy and firmness in the Icelandic power system, with participation of supply and demand, taking into account its very specific characteristics. In principle the regulatory mechanism to be adopted could consist of energy (and also capacity, in specific areas, perhaps only temporarily) auctions. One possible approach could be the use of reliability options (with the usual features of a time lag, a long commitment period, strike price and penalty) with weekly energy commitments if the energy price for the week exceeds a threshold value. Details regarding the design of this proposal would require further discussion with the various key stakeholders of the Icelandic system.

**C. Consumer protection.**

In addition to any regulatory measures that try to ensure a satisfactory level of security of supply, it may be decided to guarantee the supply of electricity for the following year(s) for non-industrial consumers at affordable prices. This can be achieved by annual auctions with participation of all generators. This should be seen as a complementary measure to be coordinated with the regulatory measures for security of supply presented in bullet D below. This measure is meant to protect residential and other small consumers with less negotiating capability than industrial consumers. The outcome of the auction would determine the energy component of the electricity tariff for small consumers. Since a surplus of supply is available (see bullet B above), despite the prevalence of already established long-term contracts, it is expected to have enough competition for this supply, guaranteeing competitive prices. A floor price or a price cap could be added, if deemed convenient. Some coordination with the mechanism to ensure adequacy and firmness may be necessary.

Existing large consumers with contracts that are about to expire should be also ensured enough supply, in particular taking into account the potential entry of new large consumers. A possible measure, in addition to what has been proposed in bullet B above on adequacy and firmness, is requiring any new large consumers that want to connect to the power system to have contracts of a minimum duration of a number (to be determined) of years with any of the generators that is not yet committed in the adequacy and capacity mechanisms.

**D. Locational signals to promote efficient siting of generation and demand.**

The following two measures could promote efficient location of future generation and demand:

- **Create locational signals for new generators and demand.** Generators, as well as demand, should be charged the corresponding transmission tariffs. New generation capacity can create the need or, on the contrary, may defer transmission network reinforcements. This proposal is in particular oriented to the expected wind generation deployment which could make a significant difference in transmission and high voltage distribution network requirements. At least the new large demand should also be subject to these locational signals.
- **Incentivize fast development of critical network reinforcement.** Every other year the TSO should run a transmission study and determine: 1) the critical reinforcements; 2) the cost and benefit of these investments; and 3) a proposed minimum cost transmission expansion plan.

The regulator may establish higher regulated rates of return for the critical reinforcements, which could help speed up their development.

The security of supply concern is in continuous discussion as electric power systems are continuously evolving. The partial or full implementation of this group of recommendations will for sure improve the security of supply in Iceland by 1) providing transparent and adaptive (to water scarcity) power prices to consumers; 2) making use of regulatory instruments to incentivize investments in generation capacity; 3) creating locational signals to incentivize investments in transmission capacity; and 4) protecting small and established large consumers from arriving new large consumers.

**E. Vertical Separation between the TSO and the National Power Company**

In 2003, with the passing of the Directive No. 65/2003, the Icelandic electric industry went through a major restructure. The vertically integrated market structure was transformed into a fully liberalized market. Power generation and retailing were opened up to competition, while transmission and distribution remained as natural monopolies and were heavily regulated.

The basic rule for separating or unbundling activities in the new regulatory environment is that no single agent should be allowed to conduct a regulated activity (such as transmission or distribution) and an activity open to competition (such as generation or retailing) simultaneously. The reason for unbundling is the appearance of conflicts of interest when a player engages in both a monopolistic and a competitive activity. In other words, monopoly power may be used to distort competition in the monopolist's favor in the liberalized activity (Pérez-arriaga, 2013).

As mentioned in **Section 2.2.3** the National power company, Landsvirkjun, which is also the dominant market player has a majority ownership of the TSO, Landsnet. The latter is also dependent on funding from Landsvirkjun. This ownership structure could potentially give Landsvirkjun a competitive advantage in the market as compared to the other energy producers. It is important that grid-associated activities must be independent of competitive businesses such as generation and retailing (Pérez-arriaga, 2013). Hence it is important that the TSO and power generator must be completely separate in legal and economic terms with a full financial separation between the two companies. Landsnet could obtain its funding through the financial markets – for example, by issuing bonds (Christensen, 2016).

**F. Reduce Horizontal Concentration in the Power Generation Market and Set up Power Exchange**

As mentioned in **Section 3.3**, a horizontal concentration in the power generation market would allow for generators to ensure the recovery of a 'reasonable' rate of return and may be one reason for the regulator to abstain from implementing an explicit SoES mechanism (Pérez-arriaga, 2013).

Landsvirkjun, the dominant market player with around 70% of the energy production could be split and its assets sold to competing power companies or new entrants. Such a scheme would clearly promote competition in the market and lead to efficiencies.

One outcome of splitting up Landsvirkjun would probably be the need for a power exchange which Landsnet has been in the process of implementing, but facing several roadblocks. An active power exchange market would potentially result in more transparent electricity prices. The current system has primarily bilateral contracts between the generator and consumer which leads to the potential of exercising market power for profits as well as lower transparency in the setting of energy prices. Another advantage of establishing a power exchange is it could allow for trading in energy futures and options, making it significantly easier for energy consumers to hedge against volatile prices.

## 7.3 FUTURE WORK

The goal of this thesis was to provide regulatory recommendations regarding ensuring SoES in Iceland based on a qualitative and quantitative analysis of the Icelandic electricity market and power system. There are a number of ways to enhance and expand the work presented in this thesis.

The thesis focuses on the management of hydro-resources to manage long-term SoES using stochastic linear programming. Future work would include exploring other modeling techniques such as stochastic dynamic programming, or even machine learning techniques such as reinforcement learning to verify our results (Abdalla, 2007).

Next steps could also focus on refining and expanding the existing hydro-thermal operation model to include the transmission network. Doing so would help model a spatial distribution of the demand and generation, as well as any associated energy losses due to network constraints as well as the system cuts. Modeling the transmission network would highlight the existing weakness in the current transmission network and also provide insight to help evaluate alternate options for energy security. Some of these options include reinforcing the current transmission grid to reduce losses and ensure system stability, as well as building an HVDC interconnector, between Iceland and the UK to ensure additional source of generation capacity.

We could also explore the role of non-hydro generation to provide SoES. For this purpose, the model could include and evaluate a variety of other generation such as intermittent renewable energy (e.g. wind). This would be interesting, since Iceland has a large potential for wind energy and it would fall in line with ensuring it remains fossil-free and energy independent. In addition, the model could also expand to include power plants that are likely to be built in the long term as part of the MP. The model could also include the potential for demand-response to help provide SoES.

Based on further modeling and discussions with the Icelandic authorities a proposal for ensuring SoES based on the recommendations in **Section 7** could be developed.

# 8. BIBLIOGRAPHY


Abdalla, A. E. (2007). *A Reinforcement Learning Algorithm for Operations Planning of a Hydroelectric Power Multireservoir System*. The University of British Columbia. Retrieved from https://open.library.ubc.ca/cIRcle/collections/ubctheses/831/items/1.0063269

Almeida Prado, F., Athayde, S., Mossa, J., Bohlman, S., Leite, F., & Oliver-Smith, A. (2016). How much is enough? An integrated examination of energy security, economic growth and climate change related to hydropower expansion in Brazil. *Renewable and Sustainable Energy Reviews*, *53*(August), 1132–1136. http://doi.org/10.1016/j.rser.2015.09.050

Anderson, P. L., & Geckil, I. K. (2003). Northeast Blackout Likely to Reduce US Earnings by $6.4 Billion. *Anderson Economic Group Working Paper 2003-2.* Lansing, MI: Anderson Economic Group. Retrieved from http://www.andersoneconomicgroup.com/Portals/0/upload/Doc544.pdf

Arriaga, I. P. (2011). What really matters in security of energy supply ? (pp. 1–3). Madrid. Retrieved from http://intranetnet.upcomillas.es/Centros/bp/Documentos/Actividades/Foro/2011/Intro_Perez-Arriaga.pdf

Batlle, C., & Rodilla, P. (2015). A critical assessment of the different approaches aimed to secure electricity generation supply. *Energy Policy*, *38*(11), 7169–7179. http://doi.org/10.1016/j.enpol.2010.07.039

BRIEF. (2012). Bureau of Research on Industry & Economic Fundamentals (BRIEF) Empowering Growth: Lack of Affordable & Quality Power: Shackling India's Growth Story. New Delhi: Federation of Indian Chambers of Commerce & Industry. Retrieved from http://ficci.in/sedocument/20218/power-report2013.pdf

Christensen, L. (Markets & M. A. (2016). *Our Energy 2030: Efficiency, competitiveness and transparency in the Icelandic energy sector*. Copenhagen. Retrieved from http://www.si.is/media/orku-og-umhverfismal/Iceland-Energy-2030.pdf

Council, N. A. E. R. (1997). North American Electric Reliability Council.

Cramton, P., & Stoft, S. (2007). Colombia Firm Energy Market. In *Proceedings of the Hawaii International Conference on System Sciences*. Retrieved from http://www.cramton.umd.edu/papers2005-2009/cramton-stoft-colombia-firm-energy-market.pdf

Cramton, P., & Stoft, S. (2008). Forward reliability markets: Less risk, less market power, more efficiency. *Utilities Policy*, *16*(3), 194–201. http://doi.org/10.1016/j.jup.2008.01.007

Creating Kárahnjúkar. (2010). Retrieved August 6, 2016, from http://www.waterpowermagazine.com/projectprofiles/projectprofilescreating-k-rahnj-kar-/

ENR. (2015). Environment and Natural Resources Ministry (ENR): Iceland Master Plan for Nature Protection and Energy Utilization. Retrieved August 9, 2016, from http://www.ramma.is/english

Gudmundsson, N. (2012). Iceland and EU electricity prices 2011. Retrieved August 18, 2016, from https://icestat.wordpress.com/2012/11/01/iceland-eu-electricity-prices-2011/

Hilmarsdóttir, P. (2015). *Electricity Security in Iceland: Security awareness in the Icelandic electricity sector, and its implications for society*. Reykjavik, Iceland. Retrieved from http://skemman.is/stream/get/1946/20893/48074/1/PollyH_Electricity_Security.pdf

Hreinsson, E. B. (2016a). Electric Load Forecasting in a Hydro- and Renewable Based Power System. In *13th International Conference on the European Energy Market (EEM)* (pp. 1–6). Porto, Portugal. http://doi.org/10.1109/EEM.2016.7521230

Hreinsson, E. B. (2016b). Optimal Long Term Hydro Scheduling Linked to Average Electricity Market Prices. In *13th International Conference on the European Energy Market* (pp. 1–7). Porto, Portugal. http://doi.org/10.1109/EEM.2016.7521244

IAV. (2014). Hagongur water diversion. Retrieved August 5, 2016, from http://www.iav.is/dk/konstruktion/faerdige-projekter/anlaegsprojekter/hagongur-water-diversion/

IEA. (2007). *Tackling Investment Challenges in Power Generation in IEA Countries*. Paris: OECD Publishing. http://doi.org/10.1787/9789264030084-en

Íslandsbanki. (2012). The Icelandic Energy Market, (September). Retrieved from https://www.islandsbanki.is/library/Skrar/Geothermal-Reports/Íslenski-Orkumarkaðurinn-SkyrlsaENSKAN_2.pdf

Kerr, D. (2014). Iceland (2013). Retrieved August 8, 2016, from http://www.reeep.org/iceland-2013

Landsnet. (2014). *Annual Report 2014*. Reykjavik. http://doi.org/10.1016/j.parkreldis.2015.02.017

Landsnet. (2015a). *Landsnet: Annual Report 2015*. Reykjavik.

Landsnet. (2015b). Landsnet: Operation of the Grid. Retrieved August 16, 2016, from http://2015.landsnet.is/en/operation-of-the-grid/

Landsnet. (2016). Landsnet: Transmission and Market. Retrieved August 8, 2016, from http://landsnet.is/english/transmissionandmarket/

Landsvirkjun. (2012). *Hydro and Geothermal Energy*. Reykjavik. Retrieved from https://issuu.com/hugsmidjan/docs/stodv_030212_02

Landsvirkjun. (2015a). Landsvirkjun: Annual Report 2015. Retrieved August 6, 2016, from http://annualreport2015.landsvirkjun.com/energy-generation/energy-generation/#Thethreemainpillarsofenvironmentallyfriendlyenergy

Landsvirkjun. (2015b). Landsvirkjun: Fljótsdalur Power Station. Retrieved August 10, 2016, from http://www.landsvirkjun.com/Company/PowerStations/FljotsdalurPowerStation/

Landsvirkjun. (2015c). Landsvirkjun: Laxa Power Station. Retrieved August 10, 2016, from http://www.landsvirkjun.com/company/powerStations/laxapowerstationl/

Landsvirkjun. (2015d). Landsvirkjun: Sigalda Power Station. Retrieved August 10, 2016, from http://www.landsvirkjun.com/Company/PowerStations/SigaldaPowerStation/

Landsvirkjun. (2016a). Landsvirkjun: Blanda Power Station. Retrieved August 5, 2016, from http://www.landsvirkjun.com/Company/PowerStations/BlandaPowerStation

Landsvirkjun. (2016b). Landsvirkjun: Power Stations. Retrieved August 5, 2016, from http://www.landsvirkjun.com/Company/PowerStations/

Landsvirkjun. (2016c). Theistareykir Geothermal Power Project. Retrieved August 6, 2016, from http://www.lvpower.com/Projects/TheistareykirGeothermalPowerProject/

Linnet, Ú., Grétar, Ó., & Sveinsson, B. (2012). Longterm hydro and geothermal reservoir operation. In

Orkustofnum (Ed.), *SIMS 2012 : The 53rd Scandinavian conference on simulation and modeling*. Reykjavik. http://doi.org/001251218

Loftsdóttir, Á., Guðmundsson, Benedikt Ketilsson, J., Georgsdóttir, L., Jónsdóttir, R., Hjaltason, S. E., Guðmundsdóttir, M., & Guðmundsson, J. Á. H. og J. R. (2016). *Energy Statistics in Iceland 2015*. Reykjavik. Retrieved from http://os.is/gogn/os-onnur-rit/orkutolur_2015-enska.pdf

Lombardi, P., & Toniolo, J. (2015). The challenge of the human factor and energy security, up to 2050. In *EU Low Carbon & Energy Security Milesecure - 2050*. Rome. Retrieved from http://www.enea.it/it/comunicare-la-ricerca/events/milesecure/Toniolo_workshop_milesecure2050.pdf

Mastropietro, P. (IIT C., Rodilla, P. (IIT C., & Batlle, C. (IIT C. (2015). The Need For Non-Performance Penalties In Capacity Mechanisms: Conceptual Considerations And Empirical Evidence. *Economics of Energy & Environmental Policy*. Retrieved from http://www.iit.comillas.edu/batlle/Publications/2015 Capacity mechanisms and performance incentives _ Mastropietro et al.pdf

OECD. (2010). The Security of Energy Supply and the Contribution of Nuclear Energy. *Nuclear Energy, 28*(2), 171. Retrieved from http://www.oecd-nea.org/pub/secure-energy/

Olaya, Y., Arango-Aramburo, S., & Larsen, E. R. (2016). How capacity mechanisms drive technology choice in power generation: The case of Colombia. *Renewable and Sustainable Energy Reviews, 56*, 563–571. http://doi.org/10.1016/j.rser.2015.11.065

Oren, S. S. (2005). Generation adequacy via call options obligations: Safe passage to the promised land. *Electricity Journal, 18*(9), 28–42. http://doi.org/10.1016/j.tej.2005.10.003

Orkusetur. (2016). Electricity Price Calculator. Retrieved August 21, 2016, from http://orkusetur.is/reiknivelar/raforka/raforkuverd/

Orkustofnum. (2012). *National Report to the Agency of Cooperation of Energy Regulators and to the European Commission*. Retrieved from http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National_Reporting_2013/NR_En/C13_NR_Iceland-EN.pdf

Orkustofnum. (2015). Orkustofnun: Master Plan for Hydro and Geothermal Energy Resources in iceland. Retrieved August 17, 2016, from http://www.nea.is/hydro-power/master-plan/

Orkustofnun. (2016). Orkustofnun. Retrieved August 21, 2016, from http://www.nea.is/the-national-energy-authority/

Pérez-arriaga, I. J. (2007). Security of electricity supply in Europe in a short, medium and long-term perspective. *European Review of Energy Markets, 2*(2), 1–28.

Pérez-arriaga, I. J. (Ed.). (2013). *Regulation of the Power Sector*. Madrid: Springer. http://doi.org/10.1007/978-1-4471-5034-3

Reneses, J., Barquín, J., García-González, J., & Centeno, E. (2016). Water value in electricity markets. *International Transactions of Electrical Energy Systems, 26*, 655–670. http://doi.org/10.1002/etep

Svedman, S. E., Büchel, F. J., & Jónsdóttir, H. (2016). EFTA Surveillance Authority Decision On The Sale Of Electricity To Thorsil (Iceland). *EFTA Surveillance Authority*. Brussels: EFTA Surveillance Authority. http://doi.org/10.1017/CBO9781107415324.004

Unger, B. (2014). *Near-Term Interconnector Cost-Benefit Analysis : Independent Report*. Retrieved from https://www.ofgem.gov.uk/sites/default/files/docs/2014/12/791_ic_cba_independentreport_final.pdf

Wikipedia. (2016a). Búðarháls Power Plant. Retrieved August 5, 2016, from https://en.wikipedia.org/wiki/Búðarháls_Power_Plant

Wikipedia. (2016b). List of Power Plants in Iceland. Retrieved August 16, 2016, from https://en.wikipedia.org/wiki/List_of_power_stations_in_Iceland

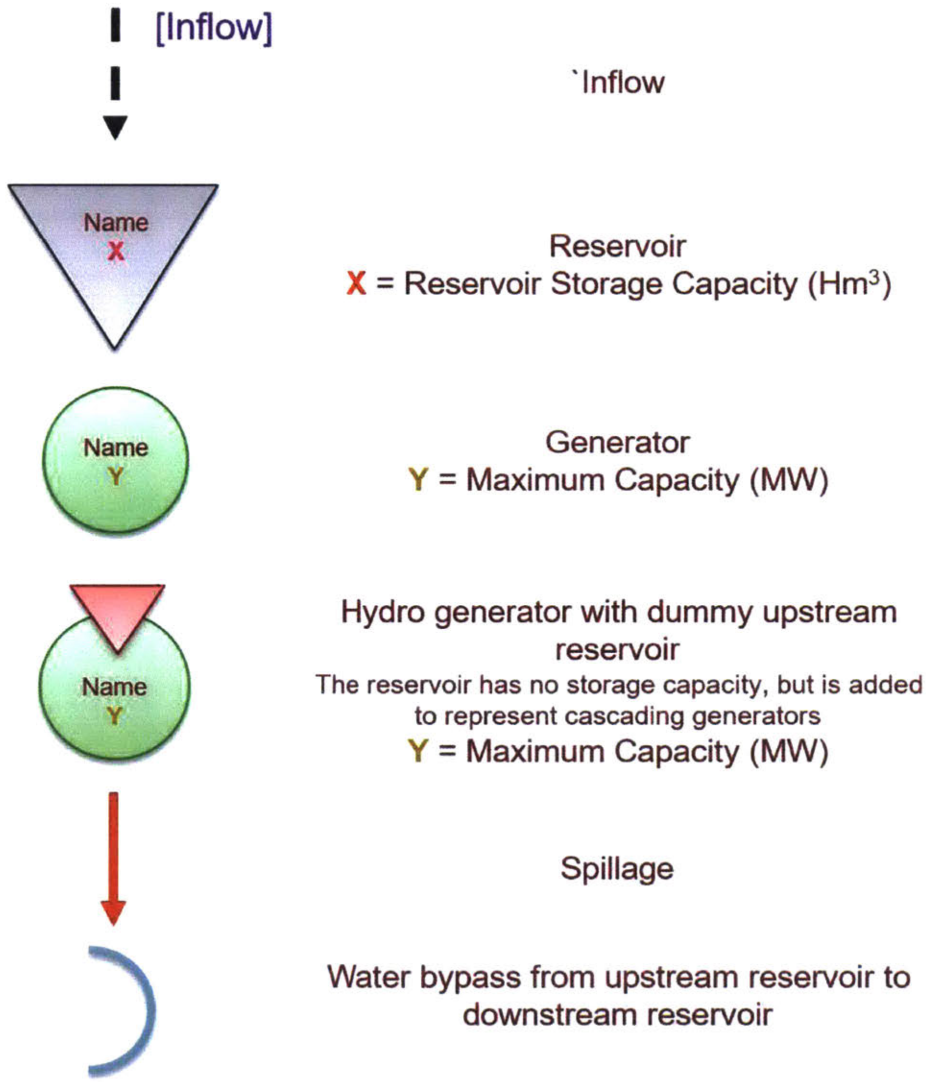
WorldBank. (2016a). Electric power consumption (kWh per capita). Retrieved August 7, 2016, from http://data.worldbank.org/indicator/EG.USE.ELEC.KH.PC?year_high_desc=true

WorldBank. (2016b). Electricity production from hydroelectric sources (% of total). Retrieved August 16, 2016, from http://data.worldbank.org/indicator/EG.ELC.HYRO.ZS?year_high_desc=true

# 9. APPENDIX

## 9.1 APPENDIX A: SYMBOLS USED FOR THE REPRESENTATION OF THE HYDRO-POWER SYSTEMS

**A key (with symbols) to illustrate the different parts of a hydro-power system. Based on this key, the symbols assist in representing the hydropower in this thesis.**



# 9.2 APPENDIX B: HYDRO-THERMAL OPERATION MODEL FORMULATION

## 9.2.1 INDICES

| | |
|---|---|
| $y$ | Year |
| $p$ | Period |
| $s$ | Sub-period |
| $n$ | Load level |
| $g$ | Thermal unit, hydro plant or intermittent generator |
| $t$ | Thermal generator |
| $h$ | Storage hydro or pumped-storage hydro plant |
| $\omega$ | Hydro scenario |
| $i, j, d$ | Node |
| $c$ | Type of customer |
| $b$ | Block of ENS |
| $ij$ | Line |
| $k$ | Cut |
| $E, C$ | Sets of existing and candidates lines |

### 9.2.2 PARAMETERS

| | | |
|---|---|---|
| | ***Demand*** | |
| $D_{psndc}$ | Demand for each type of customer in each node | MW |
| $d_{psn}$ | Duration | h |
| $I_y$ | Cumulative yearly demand growth | MW |
| $R_{ps}$ | Operation reserve | MW |
| $CENS_{cb}$ | Cost of not served energy per block and type of customer -- Value of Lost Load (VoLL) | €/MWh |
| $M_{cb}$ | Maximum energy not served per customer and block | p.u. |
| $CPNS$ | Cost of not served power | €/MW |
| | ***Generation System*** | |
| $\underline{GP}_{gp}, \overline{GP}_{gp}$ | Minimum load and maximum output of generator per period | MW |
| $\overline{GC}_{hp}$ | Maximum consumption of a pumped-storage hydro per period | MW |
| $FCG_t, VC_t$ | Fixed & variable cost of generator. Variable cost includes fuel, O&M and emission cost | €/h, €/MWh |
| $SU_t$ | Startup cost of thermal unit | € |
| $\eta_h$ | Efficiency of pumped-storage hydro plant | p.u. |
| $I_h$ | Inflows of hydro reservoir | $hm^3$ |
| $\underline{R}_h, \bar{R}_h$ | Minimum and maximum reservoir levels | $hm^3$ |
| $RI_h, RF_h$ | Initial and final reservoir levels | $hm^3$ |
| $RI', RF'$ | Initial and final reservoir proportions | p.u. |
| $a_h, b_h$ | Slope and intercept of the hydro output as a function of the reservoir volume | $MW/hm^3$, MW |
| $\alpha$ | Pointedness factor for hydro output following the demand | p.u. |
| $\rho_h$ | Downstream cumulative production function | $MWh/hm^3$ |
| $RL_h$ | Threshold energy to penalize values of final reservoir energy below this threshold | MWh |
| $W_h$ | Penalty to values of final reservoir energy below this threshold | €/MWh |
| | ***Transmission System*** | |
| $FCT_{ij}$ | Annualized fixed cost of a transmission line | € |
| $LC_{ij}$ | Loss coefficient of a transmission line | p.u. |

| | | |
|---|---|---|
| $\bar{F}_{ij}$ | Transfer capacity of a transmission line. In the operational scenarios, the net transfer capacity is used (total transfer capacity reduced by the security coefficient). In the reliability scenarios, total transfer capacity is used | MW |
| $\bar{F}_k$ | Transfer capacity of a cut | MW |
| $\bar{F}'_{ij}$ | Upper bound of the constraint of a transmission line | MW |
| $R_{ij}, X_{ij}$ | Resistance and reactance of a transmission line | p.u. |
| $S_B$ | Base power | MW |

### 9.2.3 VARIABLES

| | | |
|---|---|---|
| | **Demand** | |
| $ens^{\omega}_{ypsnicb}$ | Energy not served | MW |
| $pns^{\omega}_{yps}$ | Power not served | MW |
| | **Generation system** | |
| $gp^{\omega}_{ypsng}, gc^{\omega}_{ypsng}$ | Generator output and pump consumption | MW |
| $dh^{\omega}_{ypsnh}$ | Deficit of hydro production | MW |
| $u^{\omega}_{ypst}, su^{\omega}_{ypst}, sd^{\omega}_{ypst}$ | Commitment, startup and shutdown of thermal unit [0,1] | p.u. |
| $r^{\omega}_{yph}$ | Hydro reservoir level | hm³ |
| $rl^{\omega}_{yph}, ru^{\omega}_{yph}$ | Final hydro reservoir energy below and above the threshold | MWh |
| $ri_h, rf_h$ | Initial and final hydro reservoir proportion for each reservoir | p.u. |
| $ri', rf'$ | Initial and final hydro reservoir proportion for all the reservoirs | p.u. |
| $s^{\omega}_{yph}$ | Water spillage | hm³ |
| | **Transmission system** | |
| $ic_{yij}$ | Indicator of cumulative installed capacity of candidate line in each year {0,1} | p.u. |
| $f^{\omega}_{ypsnij}$ | Flow through a line | MW |
| $l^{\omega}_{ypsni}$ | Half of the ohmic losses of the node | MW |
| $\theta^{\omega}_{ypsni}$ | Voltage angle of a node | rad |

### 9.2.4 EQUATIONS

The objective function (OF) of the problem minimizes of total costs for the scope of the model (for all the years). The overall expression can be broken down into transmission and generation costs, expected penalties for non-served energy and power, an incentive for keep the reservoirs levels high, and penalty for reservoir levels below a percentage of a known final reservoir level. The OF is subject to several restrictions as outlined below.

1. *Transmission investment cost.*

$$\sum_{yij} FCT_{ij}(ic_{yij} - ic_{y-1ij}) \tag{1}$$

2. *Generation operation cost.*

$$\begin{aligned}&\sum_{ypsnt\omega} DUR_{psn}VC_t gp^{\omega}_{ypsnt} + \sum_{ypsnt\omega} DUR_{psn}FC_t u^{\omega}_{ypst} + \sum_{ypst} SU_t su^{\omega}_{ypst} + \\ &+CENS\sum_{ypsnicb\omega} DUR_{psn} ens^{\omega}_{ypsnicb} + CPNS\sum_{yps\omega} pns^{\omega}_{yps} + \\ &+\varepsilon\sum_{ypsnh} dh^{\omega}_{ypsn} - \varepsilon\sum_{yph\omega} r^{\omega}_{yph} + \varepsilon\sum_{yph\omega} s^{\omega}_{yph} + \sum_{yh\omega}\left(RL_h - rl^{\omega}_{yPh}\right)W_h\end{aligned} \tag{2}$$

3. *Final hydro reservoir energy split in below and above a threshold*

$$rl^{\omega}_{yPh} + ru^{\omega}_{yP} = \rho_h r^{\omega}_{yPh} \quad \forall yh\omega \tag{3}$$

4. *Energy-not-served per customer and block limited to a certain percentage.*

$$\sum_{psni} ens^{\omega}_{ypsnicb} \leq M_{cb}\sum_{psni} DUR_{psn}D_{psnic} \quad \forall ycb\omega \tag{4}$$

5. *Balance of generation and demand for each node.*

$$\sum_{g\epsilon i} gp^{\omega}_{ypsnt} - \sum_{h\epsilon i}\frac{gc^{\omega}_{ypsnh}}{\eta_h} + ens^{\omega}_{ypsnicb} = D_{psndc} + l^{\omega}_{ypsni} - \sum_j f^{\omega}_{ypsnji} + \sum_j f^{\omega}_{ypsnij} \quad \forall ypsni\omega \tag{5}$$

6. *Linear ohmic losses for each node.*

$$l^{\omega}_{ypsni} = \frac{1}{2}\left(\sum_j LC_{ji}\left|f^{\omega}_{ypsnji}\right| + \sum_j LC_{ij}\left|f^{\omega}_{ypsnij}\right|\right) \quad \forall ypsni\omega \tag{6}$$

7. *Non-linear losses for each node.*

$$l^{\omega}_{ypsni} = S_B\left[\sum_j\left(1 - cos(\theta^{\omega}_{ypsnj} - \theta^{\omega}_{ypsni})\right)\frac{R_{ji}}{R_{ji}{}^2 + X_{ji}{}^2} + \sum_j\left(1 - cos(\theta^{\omega}_{ypsni} - \theta^{\omega}_{ypsnj})\right)\frac{R_{ij}}{R_{ij}{}^2 + X_{ij}{}^2}\right] \quad \forall ypsni\omega \tag{7}$$

8. *Reserve margin for the first load level.* Intermittent generation does not contribute to the reserve margin.

$$\sum_t \overline{GP}_t u_{ypst}^{\omega} + \sum_h \overline{GP}_h + pns_{yps}^{\omega} \geq \sum_{dc} D_{psndc} + R_{ps} \quad \forall ypsω \tag{8}$$

9. *Commitment, startup and shutdown status.* Only startup of units in the transition from weekend to working days and shutdown of units from the working days to the weekend are considered.

$$u_{yps+1t}^{\omega} - u_{ypst}^{\omega} - su_{yps+1}^{\omega} + sd_{yps+1}^{\omega} = 0 \quad \forall ypst\omega \tag{9}$$

$$u_{ypst}^{\omega} - u_{yp-1s+1t}^{\omega} - su_{ypst}^{\omega} + sd_{ypst}^{\omega} = 0 \quad \forall ypst\omega \tag{10}$$

10. *Hydro reservoir inventory,* given by "reservoir volume at the beginning of the period – reservoir volume at the end of the period + natural inflows – spills from this reservoir + spills from upstream reservoirs + turbined water from upstream storage hydro plants - turbined and pumped water from this reservoir + pumped water from upstream pumped hydro plants = 0".

$$r_{yp-1h}^{\omega'} - r_{yph}^{\omega} + I_{ph} - s_{yph}^{\omega} + \sum_{h' \in up(h)} s_{yph'}^{\omega} + \sum_{sn} DUR_{psn}\left[gp_{ypsnh}^{\omega} - gc_{ypsnh}^{\omega}\right] = 0$$

$$\forall yph\omega, \omega' \in a(\omega) \tag{11}$$

11. *Initial reservoir volume* (depending on the chosen option) could be equal to an initial volume, to an initial volume variable proportion, to a unique variable proportion for all the reservoirs, or to a constant proportion for all the reservoirs.

$$r_{y0h}^{1} = \begin{Bmatrix} RI_h \\ \bar{R}_h ri_{yh} \\ \bar{R}_h ri' \\ \bar{R}_h RI' \end{Bmatrix} \quad \forall yh \tag{12}$$

12. *Final reservoir volume* (depending on the chosen option) could be greater or equal to a fixed initial volume, to an initial volume variable proportion, to a unique variable proportion for all the reservoirs, or to a constant proportion for all the reservoirs.

$$r_{yPh}^{\omega} \geq \begin{Bmatrix} RF_h \\ \bar{R}_h rf_{yh} \\ \bar{R}_h rf' \\ \bar{R}_h RF' \end{Bmatrix} \quad \forall yh\omega \tag{13}$$

13. *Expected final reservoir volume for all the scenarios* (depending on the chosen option) could be greater or equal to the initial volume; to an initial reservoir variable proportion for each reservoir; to a unique initial reservoir variable proportion for all the reservoirs; or to an initial constant reservoir proportion for all the reservoirs.

$$\sum_{\omega} prob_{\omega} r^{\omega}_{yPh} \geq \begin{Bmatrix} RI_h \\ \bar{R}_h ri_{yh} \\ \bar{R}_h ri' \\ \bar{R}_h RI' \end{Bmatrix} \quad \forall yh \tag{14}$$

14. *Hydro production* as a function of the reservoir inventory.

$$gp^{\omega}_{ypsnh} \leq a_h r^{\omega}_{yph} + b_h \quad \forall ypsnh\omega \tag{15}$$

15. *Hydro production* following the demand.

$$gp^{\omega}_{ypsnh} - gp^{\omega}_{ypsn+} \quad e^{\alpha \, ln\left(\frac{\sum_{dc} D_{psndc}}{\sum_{dc} D_{psn+1dc}}\right)} + dh^{\omega}_{ypsnh} \geq 0 \quad \forall ypsnh\omega \tag{16}$$

16. *DC Load flow for existing and candidate lines.*

$$f^{\omega}_{ypsnij} = (\theta^{\omega}_{ypsni} - \theta^{\omega}_{ypsnj}) \frac{S_B}{X_{ij}} \quad \forall ypsnij\omega, ij\epsilon E \tag{17}$$

$$\left| f^{\omega}_{ypsnij} - (\theta^{\omega}_{ypsni} - \theta^{\omega}_{ypsnj}) \frac{S_B}{X_{ij}} \right| \leq \bar{F}'_{ij}(1 - ic_{yij}) \quad \forall ypsnij\omega, ij\epsilon C \tag{18}$$

17. *Transfer capacity in existing and candidate transmission lines.*

$$\left| f^{\omega}_{ypsnij} \right| \leq \bar{F}_{ij} \quad \forall ypsnij\omega, ij\epsilon E \tag{19}$$

$$\left| f^{\omega}_{ypsnij} \right| \leq \bar{F}_{ij} ic_{yij} \quad \forall ypsnij\omega, ij\epsilon C \tag{20}$$

18. *Flow limit for each cut.*

$$\sum_{ij\in k} f^{\omega}_{ypsnij} - \sum_{ji\in k} f^{\omega}_{ypsnji} \leq \bar{F}_k \quad \forall ypsnk\omega \tag{21}$$

19. *Relation between indicators of installed capacity in consecutive years.*

$$ic_{yij} \leq ic_{y'ij} \quad \forall yy'ij, ij\epsilon C, y' > y \tag{22}$$

*20. Bounds on variables.*

$$\underline{GP}_{gp} u^{\omega}_{ypsg} \le gp^{\omega}_{ypsng} \le \overline{GP}_{gp} u^{\omega}_{ypsg} \quad \forall ypsng\omega \tag{23}$$

$$0 \le gc^{\omega}_{yps} \quad \le \overline{GC}_{hp} \quad \forall ypsnh\omega \tag{24}$$

$$\underline{R}_{h} \le r^{\omega}_{yph} \le \bar{R}_{h} \quad \forall yph\omega \tag{25}$$

$$0 \le ens^{\omega}_{ypsnicb} \le D_{psnic} \quad \forall ypsnicb\omega \tag{26}$$

$$rl^{\omega}_{yPh} \le RL_{h} \quad \forall yh\omega \tag{27}$$

### 9.2.5 RESERVOIR MANAGEMENT

| Identifier | Description | | Default |
|---|---|---|---|
| pOptAverageRve | Indicator for introducing that the average value of the final reserves for all the scenarios is equal to the initial value, that will depend on the pOptIniReserve | {0,1} | 0 |
| pOptIniReserve | Initial reserve equal to the initial numerical input values from IniReserve column in Generation sheet (0), a variable for each reservoir (1), a variable unique for all the reservoirs (2) and a unique numerical input value (pIniReserveUnique) for all the reservoirs (3) | {0,1,2,3} | 0 |
| pOptFinReserve | Final reserve equal to the initial numerical input values from FinReserve column in Generation sheet (0), a variable for each reservoir (1), a variable unique for all the reservoirs (2) and a unique numerical input value (pFinReserveUnique) for all the reservoirs (3) | {0,1,2,3} | 0 |
| pIniReserveUnique | Initial reserve unique | p.u. | 1 |
| pFinReserveUnique | Final reserve unique | p.u. | 1 |
| pAlpha | Knee point to penalize reservoir levels below this p.u. of the maximum reserve | p.u. | 0.8 |
| pWtrVal | Water value of the reservoir level below pAlpha p.u. of total final reservoir | €/MWh | 0 |

TABLE 4: RESERVOIR MANAGEMENT OPTIONS INTRODUCED IN THE MODEL.

# 9.3 APPENDIX C: CUMULATIVE PRODUCTION FUNCTION (BY GENERATOR)

| | Cumulative production function [kWh/m$^3$] |
|---|---|
| Sog | 0.169 |
| Laxá | 0.167 |
| Blöndulón | 0.683 |
| Gilsárslón | 0.683 |
| Hágöngulón | 0.968 |
| Kvíslaveita | 0.968 |
| Þórisvatn | 0.968 |
| Sigalda | 0.809 |
| Hrauneyjafoss | 0.640 |
| Búðarháls | 0427 |
| Sultartangi | 0.388 |
| Búrfell | 0.273 |
| Kelduárlón | 1.340 |
| Ufsarlón | 1.340 |
| Hálslón | 1.196 |
| Lagarfoss | 0.039 |
| West | 0.500 |
| Westfjords | 0.500 |

TABLE 5: VALUE OF CUMULATIVE PRODUCTION FUNCTION (BY GENERATOR).