MIT Energy Initiative

ELECTRICITY SECURITY OF SUPPLY IN ICELAND

An MIT Energy Initiative project

In collaboration with IIT-Comillas

Principal Investigator

IGNACIO PEREZ-ARRIAGA

Professor, Electrical Engineering, Institute for Research in Technology, Comillas Pontifical University

Visiting Professor, MIT Energy Initiative

Research Team

PABLO DUENAS-MARTINEZ

Postdoctoral Associate, MIT Energy Initiative

SHWETA MEHTA

SM, Technology and Policy Program ('16), MIT

LUIS OLMOS

Associate Research Professor, Institute for Research in Technology, Comillas Pontifical University

ANDRES RAMOS

Professor, Institute for Research in Technology, Comillas Pontifical University

MICHEL RIVIER

Professor, Institute for Research in Technology, Comillas Pontifical University

KAREN TAPIA-AHUMADA

Research Scientist, MIT Energy Initiative

1. Executive Summary

How to ensure long-term security of electricity supply in an economic manner while preserving environmental goals is a relevant concern nowadays in Iceland. The country's unique characteristics increase the complexity of the challenge. First, almost one hundred percent of its electricity comes from renewable energy sources (primarily hydro and geothermal), and it has no nuclear, coal, or gas infrastructure. Second, Iceland nowadays is an isolated system with a transmission network disconnected from the rest of the world, which impedes any participation in electricity trade. In addition, the ageing transmission network frequently reaches its tolerance limits, as it must accommodate increasing loads from both the energy-intensive industry and the general demand.

According to the MILESECURE-2050 European project, a secure energy system evolves over time and achieves an adequate capacity to absorb uncertain events, so that the system is able to continue satisfying the energy service needs of its users with acceptable changes in their amounts and prices. Although the delivery of electricity takes place in real time, multiple decisions have to be adopted at different time scales (from several years to seconds before real time), by different agents (regulators, investors, systems operators, and producers and consumers), and involving diverse technologies and energy resources. Four dimensions of security of electricity supply have to be distinguished:[1]

1. **Strategic energy policy**, with a long- to very long-term decision horizon (5-10 years), determines the long-term availability of energy resources, including physical existence and reliable supply that meets environmental constraints; affordable price, and acceptable energy dependence of the country. This is the realm of the Master Plan and the Framework Program in Iceland.
2. **Adequacy**, with a long-term decision horizon (2-5 years), assures the existence of enough available capacity, both installed and/or expected, to meet the forecasted demand. This is the realm of the Annual Report published by Landsnet which includes a long-term energy balance.
3. **Firmness**, with a short- to medium-term decision horizon (within a year), 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. Firmness can be influenced by specific regulation established by the regulatory authorities and good practices mandated and coordinated by the system operator.
4. **Security**, involving real-time decisions, is achieved through the readiness of existing and functioning generation and network capacity to respond in real time to load requirements when needed. Security typically depends on the operating reserves and operational procedures that are prescribed and managed by the system operator. Specific regulation and rules established by regulators and system operators are essential.

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[1] I.J. Pérez-Arriaga, "Security of electricity supply in Europe in a short, medium and long-term perspective." European Review of Energy Markets, volume 2, issue 2, December 2007.

A reliable power supply results from a combination of security, firmness, and adequacy under the guidance of a strategic energy policy. We have analyzed the adequacy and firmness components[2] in Iceland from the regulatory (Part I: Regulatory Discussion) and economic (Part II: Economic Assessment) perspectives.

1.1. Part I: Regulatory discussion

Presently in Iceland, demand growth (including the possible arrival of additional large electricity consumers) and the time required to build new generation power plants are creating concerns about the future security of supply for the retail customers in the country. The price of electricity in the wholesale market that supplies retail customers has been typically higher than the electricity price of the intensive industries. However, this could change with new industrial contracts, increasing the risk of security of supply on the retail side.

In addition, we have identified three areas of concern within the Icelandic system that might compromise the security of supply:

1. **Adequate generation capacity and energy.** Presently, there is no shortage of capacity, but the lack of sound and clear investment signals and specific regulatory mechanisms concerning security of supply, as well as the increased emphasis on environmental protection, is discouraging required investments that are critical for the future.
2. **Adequate transmission capacity.** The Regional Ring Network is becoming obsolete. In 2014, inter-regional power flow exceeded security-monitoring limits 28% of the time. Moreover, the two main options under consideration for strengthening the main grid face environmental concerns.
3. **Firm generation capacity and energy.** Hydro accounts for 71% of total electricity generation and its firmness depends on hydro inputs, weather conditions, and reservoir management decisions. Shortcomings in regulatory instruments regarding firmness and adequacy commitments are creating concerns among participants.

These issues are the motivation behind this regulatory analysis. We want to help stakeholders initiate discussions about how to address existing practices that can compromise the electricity security of supply. We have first suggested the requirements for a future approach to address security of electricity supply, and then we have proposed regulatory measures to enhance security of electricity supply. Further study, out of the scope of this project, would be required in order to develop the necessary details.

1.1.1. Requirements for a comprehensive regulatory framework

A sound regulatory approach should:

1. Establish the roles and obligations of the agents, as well as their rights resulting from their remuneration and payments to the system.

[2] The project also embeds the strategic energy policy as determined by the projected demand and the different alternatives for reinforcing the network and expanding the generation capacity, among others.

2. Enable the regulatory authority to develop mechanisms that:
   - Result in a system with enough installed capacity in order to guarantee the adequacy of the system in the future, both in energy and capacity.
   - Guarantee the availability (i.e. firmness) of the existing firm capacity to provide sufficient energy and capacity to meet the demand requirements when needed.
3. Supply the regulatory authority with the necessary information and tools (with technical support by Landsnet, if necessary) for carrying out a comprehensive system-wide analysis of the electricity system, with the goal of providing an estimation of the mid- and long-term system performances followed by a proposal of the means and mechanisms needed to address any area of concern.

1.1.2. Proposed regulatory measures

In the case of Iceland, the regulation for security of supply should have the following objectives:

1. Guarantee that the demand for small and medium consumers (S&MC) is supplied with good reliability and at a cost-reflective/competitive price.
2. Make available sound economic signals that can guide the stakeholders' decisions and responses towards a more efficient and secure electric power system.
3. Make sure that the entry of new large consumers does not jeopardize the reliability of the existing consumers—the S&MC in particular. The new large consumers must also be supplied either with the same reliability standard as the S&MC or with the one that they privately agree upon with their supplier in a contract, if they choose this option.
4. Incentivize agents to comply with their committed energy schedules even when energy prices happen to be zero.
5. Facilitate the conditions to avoid deterioration of the quality of service for large consumers, both during the duration of the present long-term contracts and especially after the contracts expire.

However, as detailed in the study, given the specific characteristics of the present Icelandic system there are some significant challenges that have to be carefully accounted for when designing a sound regulatory approach to electricity security of supply. Based on these challenges and how they are addressed, we have proposed an approach that would have three key elements: (1) long-term firm contracts covering all demand; (2) annual auctions for guaranteeing reliability (adequacy and firmness) consisting of three products: annual committed energy, weekly firm energy, and firm capacity; and (3) computation of weekly wholesale electricity prices that can guide short-term decisions of the agents efficiently.

1.2. Part II: Economic assessment

The lack of reliability has a cost for industrial, commercial and residential consumers. Up to now, curtailments in Iceland are happening when the weather conditions are unfavorable to the filling of the reservoirs or due to contingencies. If new generation capacity does not accompany the expected future demand, curtailments could worsen. Given the current supply contract structure in Iceland, the industrial consumers face most of the energy scarcity by providing flexibility in the form of two types of negotiated curtailments: secondary and buyback energy. While curtailments of the household demand are in theory allowed, implementing such a measure is very unpopular. This translates into a very high cost of non-served residential demand; hence, the household demand curtailment is the last resource.

Our quantitative assessment has relied on a high-quality model of the Icelandic electric power system that has allowed representing the complex hydropower system in combination with the geothermal plants, portraying the main characteristics of the transmission network, and adding future expansions in generation and transmission in order to examine the various alternatives for the evolving Icelandic system. Among those alternatives, we have analyzed both the Highlands and Inter-regional options for transmission expansion; utilization of diesel backup in critical areas of the system; geothermal, hydro and wind generation expansion; natural gas power generation units; industrial demand response; and interconnection by a subsea cable to the UK.

1.2.1. Network reinforcements

We have looked into retrofitting the transmission network through the Highlands or the Inter-regional planned projects, or the possibility of installing diesel backup plants in critical nodes of the network. We have used a hypothetical year 2020 Icelandic system to understand the current transmission network limitations. Based on our assessment, we have concluded that:

1. The deployment of either the Inter-regional or the Highlands network plan is critical in order to guarantee a strong connection between the East and West halves of the island, because of the release of some relevant network congestions, especially when considering future demand growth. Curtailments under the Highlands reinforcement option seem to be marginally higher than under the Inter-regional option, although this difference could be within modeling error. The Inter-regional option annualized cost ($49.4 million per year) is halfway between the annualized costs of the AC ($33.1 million per year) and DC ($52.9 million per year) Highlands alternatives. The environmental impact assessment gains importance when deciding which option would be better as both options present environmental concerns.
2. The alternative of installing diesel groups in strategic points of the network by 2020 does not solve the network congestions. Since the diesel price is above the buyback energy price, the diesel stations could only be used for mitigating severe curtailments that would occasionally occur, although with great impact. The diesel stations may defer network investment, but stability problems and network congestions would remain.

1.2.2. Generation expansion

For this section, we have focused in year 2030, by which even after reinforcing the network, the existing generation capacity is clearly insufficient for the assumed demand. If no additional generation were installed before 2030, the capacity margin would be –7.4%, with 3,046MW peak demand and 2,821MW generation capacity. The underlying energy resources would not be able to cope with the additional 3.8TWh demand between 2020 and 2030. This would lead to relevant curtailments. Under this scenario, we evaluated the addition of domestic and clean generation such as hydro power plants, geothermal groups, or wind generation, considering the Highlands and Inter-regional network reinforcement options. We have observed that:

1. New hydro power plants are in general more competitive than the geothermal or wind technologies, although the optimal mix combines a portion of hydro and wind or of hydro and geothermal resources.
2. Wind turbines are as competitive as the geothermal or hydro power plants and result in a slightly better system performance than excluding this technology from both network reinforcement options. The wind option entails, however, more uncertainty on the level of security of supply as it substitutes, in part, the more predictable and controllable generation source that is geothermal.

1.2.3. Sensitivity analysis

The sensitivity analysis aimed at understanding the value of increasing demand response, that of gas-fired power plants, and the value of the subsea interconnector with the UK (IceLink) in providing security of supply to the system. Based on our assessment, we have found that:

1. Deploying additional demand response is marginally cheaper than building the most expensive hydro power plant (Blönduveituvirkjun, in our analysis). The stakeholders could consider the possibility of augmenting the buyback energy up to 2.4% (from 1.2%) of the total industrial demand. In contrast, we do not recommend the installation of gas power plants, as the Icelandic system seems less secure, more expensive, more pollutant, and dependent on foreign fuel source when installing these plants instead of building Blönduveituvirkjun.
2. IceLink seems to result in the largest increase of security of supply out of all the analyzed options. First, Iceland could import backup energy from the UK during times of scarcity. Second, Iceland should develop a relevant amount of domestic generation (around 600MW of geothermal capacity and 240MW of hydropower capacity) and some extra network reinforcements on top of the Highlands or the Inter-regional plans to serve the UK's demand for clean energy. Current water spillage could also provide part of this clean energy, around 650GWh. The additional costs due to the additional generation capacity, extra network reinforcements, and the interconnector is equivalent to 85%, almost $190 million per year of the interconnector cost. The current UK policy, which seeks improving its connectivity with neighboring countries and acquiring firm capacity and renewable energy, could favor the payment of a premium on the exported energy that could partially or fully cover the additional $190 million cost.

ELECTRICITY SECURITY OF SUPPLY IN ICELAND

PART I: REGULATORY DISCUSSION

Table of Contents

1. Introduction

This document discusses the regulatory framework currently in place in Iceland regarding electricity security of supply and proposes some alternatives to enhance it. These alternatives are described from a high level point of view. Further study, out of the scope of this project, would be required in order to develop the necessary details, once a choice is made on the direction to follow. The document focuses mainly on the adequacy and firmness dimensions of security of supply, where regulation usually plays a major role.[1] In addition to this discussion, we have performed a quantitative modeling-based evaluation of adequacy and firmness in Iceland which is presented in a parallel document.

According to the EU project MILESECURE 2050,[2] a secure energy system evolves over time and achieves an adequate capacity to absorb uncertain events, so that the system is able to continue satisfying the energy service needs of its users with acceptable changes in their quantities and prices. Although the delivery of electricity takes place in real time, multiple decisions have to be adopted at different time scales (from several years to seconds before real time), by different agents (regulators, investors, systems operators, and producers and consumers), and involving diverse technologies and energy resources. Four dimensions of reliability of electricity supply have to be distinguished:[3]

1. **Strategic energy policy**, with a long- to very long-term decision horizon (5-10 years), determines the long-term availability of energy resources, including physical existence and reliable supply that meets environmental constraints, affordable price, and acceptable energy dependence of the country. This is the realm of the Master Plan and the Framework Program in Iceland.
2. **Adequacy**, with a long-term decision horizon (2-5 years), assures the existence of enough available capacity, both installed and/or expected, to meet the forecasted demand. This is the realm of the Annual Report published by Landsnet which includes a long-term energy balance.
3. **Firmness**, with a short- to medium-term decision horizon (within a year), 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. Firmness can be influenced by specific regulation established by the regulatory authorities and good practices mandated and coordinated by the system operator.
4. **Security**, involving real-time decisions, is achieved through the readiness of existing and functioning generation and network capacity to respond in real time to load requirements when needed. Security typically depends on the operating reserves and operational procedures that are

[1] Note that Iceland will have to implement the Third EU Energy Package in 2017/2018. Provisions concerning security of supply and consumer protection are included in the Electricity Directive 2009/72/EC.

[2] Refer to http://www.milesecure2050.eu

[3] I.J. Pérez-Arriaga, "Security of electricity supply in Europe in a short, medium and long-term perspective." European Review of Energy Markets, volume 2, issue 2, December 2007.

prescribed and managed by the system operator. Specific regulation and rules established by regulators and system operators are of essence here.

A reliable power supply results from a combination of security, firmness and adequacy under the guidance of a strategic energy policy. Experience has shown that regulatory and policy intervention is sometimes required to achieve this goal.

In the case of Iceland—and any other country—long-term energy policies are needed. Iceland can adopt diverse paths to maintain and enhance energy security, as well as to choose a model of economic growth. Regarding electricity supply, these options include expanding clean energy capacity,[4] limiting new industrial demand installation, reinforcing the national transmission network, and interconnecting to the UK (and the rest of Europe) through a subsea cable or introducing fossil fuel power generation plants. The security of supply objective must not be separated from other goals, such as environmental targets, sustainability, competitiveness, economic growth, self-sufficiency and the connection and relationship with the European Economic Area. Governments and their regulatory bodies need to be proactive in ensuring acceptable levels of electricity security of supply, by enacting the required legislation and developing the secondary regulations, respectively.

Satisfactory levels of adequacy and firmness cannot be generally taken for granted in an electricity market environment, and therefore some regulatory intervention is required. 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 is the case in Iceland. The national government must create the legal framework that enables the regulatory authority to adopt and implement the mechanisms to ensure efficient and effective levels of adequacy and firmness, with the technical support of the system operator.

It is worth mentioning that there is a tradeoff between reliability improvement and system costs; i.e., better reliability means additional investments and therefore larger financial and environmental costs. However, the lack of reliability has the associated cost for industrial, commercial and domestic consumers of curtailments that directly impact their activities (known as unserved energy costs). The lack of reliability harms a country's economy in multiple ways.

The difficulties in properly assessing the cost of unserved energy often result in the adoption of some proxy, such as a target for some metric of the level of security of supply in the system that is easier to compute, estimate or measure. The best metric for a hydro-dominated system such as the Icelandic one is the volume of non-served energy.[5] Provided that the generation capacity is enough to satisfy peak demand, energy supply could be threatened by water scarcity. Mathematical tools that consider the uncertainty in water inflows can be used for computing both the expected non-served energy and the price associated with that expected non-served energy. We believe that this price (explained later on) provides an acceptable level of information about the existing and expected conditions of the energy

[4] In the "Master Plan", about 9 TWh of geothermal and 5.8 TWh of hydro production have been placed in the utilization category. The wind production potential is relevant, with a capacity factor above 40% for the already installed wind turbines.

[5] 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.

system, which could guide the decisions of the electricity consumers as well as the operation of the various reservoirs in such a manner that ensures that water is used in an optimal fashion. This being said, capacity problems (not only energy ones) may be expected in the future in Iceland, with the reason being twofold: first, if transmission expansion is not properly addressed and second, due to the role of geothermal plants within this system and the potential penetration of wind generation.[6] It is, therefore, plausible that a decrease over time of the power capacity of geothermal plants and intermittent availability of wind power production could lead to capacity shortages during peak demand periods.[7]

In summary, achieving reasonable levels of adequacy and firmness concerns the entire power sector and requires the choice of regulatory instruments that guarantee that enough energy exists and also incentivize that enough firm capacity is available when needed. Any regulatory instrument must be well adapted to the existing and preferred generation technologies and must be compatible with the adopted energy policy. The regulatory authority must be responsible for developing and monitoring the compliance of the secondary regulation that implements this policy in its adequacy and firmness dimensions.[8]

The document is organized as follows. First, the current situation of adequacy and firmness in Iceland is assessed and the main existing limitations of the system are identified. Second, several possible improvements and actions are proposed and discussed. Some final considerations close the main document. In addition, there are two annexes: the first one briefly refers to the present legislation in Iceland regarding security of electricity supply; the second one also concisely describes the method of reliability options, which has inspired the approach proposed in this document.

2. Assessment of the current situation

2.1. Background

The Icelandic primary energy needs are nowadays covered by geothermal and hydro sources, and oil. The utilization of geothermal resources (90%) and electricity (9%) for space heating plus a carbon-free electricity generation mix (70% hydro and 30% geothermal production) reduces oil consumption to less than 15% of total primary energy.

A distinguishing feature of the Icelandic electricity generation market is the dominant size (approximately 73%) of the publicly-owned company Landsvirkjun, which mostly generates with hydropower plants, while the remaining generators are geothermal.

Seven large international and energy intensive companies consume 80% of the electricity, with the remaining 20% being consumed by retail customers, which are supplied by six electricity retail companies.

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[6] Although investment in wind generation is not included in the current Master Plan, it has been repeatedly mentioned in conversations with local experts that wind could be a resource of future relevance in Iceland.
[7] Reduction over time of the output capacity of geothermal plants is to be expected and it might happen faster if the plants are not properly maintained. Note also that geothermal plants will be unavailable during scheduled maintenance periods. This indicates also the need to address capacity issues.
[8] Regulation should also look carefully at the real-time security dimension but it is not the object of this project.

There are six regional distribution companies, some of which share ownership with the retail companies. Landsvirkjun supplies 77% of the electricity consumed by the seven large industrial consumers and 55% of the consumption of the retail customers (all of it indirectly via the six retail companies).

Private ownership of electricity companies plays a minor role, with state and local municipalities having direct or indirect ownership of most companies.

Presently, in simplified terms, electricity is sold in Iceland under four different formats:

- Baseload power supplied to large industrial consumers under long-term contracts.
- Constant baseload power supplied to the wholesale market for the retailing companies.
- Flexible power to follow the demand curve, which is supplied by Landsvirkjun to the retail companies.
- Curtailable power, also provided by Landsvirkjun, which can be interrupted (even for weeks or months if necessary) depending on hydrology.

Demand growth, including the possible arrival of additional large electricity consumers, and the time required to build new generation power plants, is creating concerns about the future security of supply for the retailing customers. The price of electricity in the wholesale market that supplies retail customers has been typically higher than the electricity price of the intensive industries. However, this could change with new industrial contracts, increasing the risk of security of supply on the retail side.

2.2. Assessment on the basis of the quantitative analysis with models

Although the levels of adequacy and firmness seem reasonable in Iceland today, we have identified limitations within the system that might compromise the country's security of supply in the near future. We found three possible areas of concern that directly involve the transmission and generation infrastructures, *which have been analyzed in great detail in the quantitative assesment part of this project presented in a separate report:*

1. **Adequate generation capacity and energy**. Presently there is no shortage of capacity, but the lack of sound and clear investment signals, and specific regulatory mechanisms concerning security of supply, as well as the increased emphasis on environmental protection, is discouraging required investments critical for the future.
2. **Adequate transmission capacity**. The Regional Ring Network is becoming obsolete for transmission capacity requirements. The island is divided into five balancing zones due to congestions and in 2014, the inter-regional power flow exceeded security monitoring limits 28% of the time. Moreover, the two options[9] under consideration for strengthening the main grid face environmental concerns.
3. **Firm generation capacity and energy**. Hydro accounts for 71% of total electricity generation and its firmness depends on hydro inputs, weather conditions and reservoir management decisions.

[9] The Highlands solution crosses the island through the central plateau reinforcing the north-south connection. The Inter-regional solution retrofits the Regional Ring Network.

Deficiencies in regulatory instruments regarding firmness and adequacy commitments are creating concerns among participants.

2.3. Assessment on the basis of the analysis of the present regulation

Appendix A contains a summary of our review of the present electricity regulation in Iceland in reference to this study on security of supply. In this section we focus only on adequacy and firmness issues. Our evaluation separately addresses monitoring and analysis on one side, and wholesale market rules on the other. Based on this, we specify the requirements for a future approach to security of electricity supply.

2.3.1. System monitoring and analysis

The system operator (Landsnet) and the National Power Company (Landsvirkjun) already monitor the system's performance and analyze security of supply using advanced tools to examine adequacy and firmness.

Regarding adequacy, sophisticated hydropower simulation models are used for system expansion and operation planning, where both energy and capacity concerns are considered. A long-term Master Plan assesses and classifies power plant investment options, both hydroelectric and geothermal, "taking into consideration power generating capacity, feasibility and other macro-economic values…" The transmission system operator, Landsnet, is required to publish an annual report on the state of the system, mostly reflecting its operations, but an energy balance for the span of the study horizon is also discussed in it.

Regarding firmness's monitoring and analysis, all producers are required to send weekly production plans, down to hourly schedules, for each unit of the system. Landsnet manages an open application to plan the maintenance of all producers' units and the transmission system. In addition, regulation allows making bids in the balancing market. Landsvirkjun, which accounts for almost all hydropower generation in Iceland, runs hydropower simulations to plan the operation of its plants, and forecasts reservoir management and possible curtailments affecting the flexible load in the system.

In addition, every year Landsnet runs a comprehensive transmission study and publishes a Network Development Plan (Kerfisáaetlun), previous Orkustofnun's review and approval. One of the objectives of this plan is to ensure security of supply through the necessary improvements to the transmission system. A supplementary plan considers the environmental impact, although that plan is not subject to Orkustofnun's approval.

We may conclude that tools, methods and practices are in good condition regarding the monitoring and analysis of security of supply in its both dimensions of adequacy and firmness. However, based on our observations, those analyses are insufficient to ensure a satisfactory level of security of supply in the country. The roles and responsibilities of the actors regarding security of supply have not been clearly assigned, and the regulatory mechanisms currently in place not only to monitor and analyze, but also ensure security of supply seem to be insufficient.

2.3.2. Wholesale market rules and generation investment

The wholesale market is mostly based on bilateral contracts of different durations: up to 3 years for smaller consumers, and between 5 to 12 years, occasionally more, for large power intensive industries. These contracts incorporate curtailment clauses that are the main mechanism used to manage the system security of supply.

We have identified some limitations in the existing rules and practices, mostly related to the regulatory framework currently in place. Up to now, the system has exhibited an adequate behavior, with the cooperation of Landsvirkjun, which has voluntarily acted as default supplier of flexible generation, balancing services and security of supply at retail level. In our opinion, the existing regulation has become inadequate to comprehensively deal with security of supply in the mid- and long-terms, considering that adequacy and firmness issues may arise in the future. Below is a list of the shortcomings that we have identified:

- A precise legal definition of security of electricity supply is not clearly stipulated in the Electricity Act and subsequent regulations.[10] In practice, Landsvirkjun, along with Landsnet, play a major role. Responsibilities for all agents regarding adequacy and firmness should be clearly specified, beyond what is established in Regulation 1048/2004.
- A mid- and long-term indicative expansion plan related to the overall electricity energy model for Iceland (beyond the Network Development Plan by Landsnet) is not available for the agents, despite the existing regulation within the Electricity Act mandating the preparation of long-term plans for the utilization of energy resources (see Appendix A). This indicative plan could provide not only general guidelines on the future development of the electricity system, but also on how to maintain security of supply and the design of regulatory instruments to guarantee adequacy and firmness.
- There is no well-defined regulatory mechanism in place to guide the implementation of the resulting policy decisions or to provide the signals or instructions/guidelines to remedy possible problems regarding adequacy (investment decisions).
- Although all units must report to Landsnet their weekly and hourly schedules, this does not guarantee that enough production will be available on a real-time basis. We could not find a clear regulatory mechanism in place to ensure that enough energy and power will be readily available to meet online demand.
- Transparent economic signals are not being provided to consumers and generators to guide their responses and decisions. Since a spot market does not exist,[11] imbalances of production with respect to contracted commitments are not settled in a fair and efficient manner. Some companies may offer in their contracts more capacity than it is actually available without being

[10] Some provisions outline the role of some agents in general terms, as Article 9 - Obligations of the Transmission System Operator- and Article 28 - Regulation of the Quality of Electricity and Security of Delivery- in the Electricity Act No. 65/2003. However, a precise definition of electricity security of supply was not available on those documents. Regulation 1048/2004 provides definitions for quality of electricity and security of supply, but they should be clearer and more actionable.

[11] Landsnet has had plans to constitute one since 2008, but the economic crisis stopped this initiative and no progress has been made since then.

penalized for this,[12] with Landsvirkjun bearing the responsibility of providing backup for these contracts by default. A balancing market, run by Landsnet, does exist but it only concerns Landsvirkjun production.

- While long-term contracts are signed with large industrial consumers, shorter contracts are established for small general consumers. The result is that, once these short-term contracts end, the generation companies may decide to sign a new contract with a newcomer load (e.g., some large industrial demand). Therefore, it is implicitly assumed that the national power company will take care of abandoned consumers or leftover power. We could not find a regulatory provision that clearly defines the obligations of the supply agents under these circumstances, which is jeopardizing the adequacy of the system.
- In addition to energy constraints, capacity is also an ongoing concern. The system is becoming capacity-constrained because of three main reasons: i) network limitations, ii) higher role of geothermal production as base load, and iii) future possible presence of intermittent wind generation which, although it contributes to energy security, would require backup if it replaces geothermal or hydro in the future mix.

2.4. Required features for a sound approach addressing security of supply

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 will be available when needed. Any regulatory measure must be well adapted to the existing and preferred generation technologies and must be compatible with the energy policy chosen by the country. The legal framework must establish that the regulatory authority must be the institution responsible for designing, implementing, and monitoring the regulatory instruments that will guarantee a satisfactory level of reliability of electricity supply. This comprehensive regulatory framework should:

1. Establish the roles and obligations of the agents, as well as their rights resulting from their remuneration and payments to the system.
2. Enable the regulatory authority to develop mechanisms that:
   - Result in a system with enough installed capacity in order to guarantee the adequacy of the system in the future, both in energy and capacity.
   - Guarantee the availability (i.e. firmness) of the existing firm capacity to provide sufficient energy and capacity to meet the demand requirements when needed.
3. Supply the regulatory authority with the necessary information and tools (with technical support by Landsnet, if necessary) for carrying out a comprehensive system-wide analysis of the electricity system, with the goal of providing an estimation of the mid- and long-term system performances followed by a proposal of the means and mechanisms needed to address any area of concern.

[12] In this regard, we found that the Electricity Act No 65/2003 Article 19 - Obligations of Suppliers - specifies that suppliers should provide the electricity necessary to perform obligations under power contracts with Orkustofnun assessing whether these companies are meeting their obligation. However, it is not clear to us why in practice some companies are offering more capacity than available.

3. Proposed regulatory measures

This section details a proposed approach to enhance security of electricity supply in the Icelandic power system. First, we specify the objectives that the regulation should meet as well as the relevant existing challenges. Then, we delve into the suggested approach. We need to stress that this is a high level discussion, since the implementation of the suggested measures would require a more detailed analysis that exceeds the scope of the present document.

3.1. Objectives and challenges

Regulation for security of supply will have the following objectives:

1. Guarantee that the demand for small and medium consumers (S&MC) is supplied with good reliability and at a cost-reflective/competitive price.
2. Make available sound economic signals that can guide the stakeholders' decisions and responses towards a more efficient and secure electric power system.
3. Make sure that the entry of new large consumers does not jeopardize the reliability of the existing consumers—the S&MC in particular. The new large consumers must also be supplied either with the same reliability standard as the S&MC or, if they choose, with a standard privately agreed upon with their supplier in a contract.
4. Incentivize agents to comply with their committed energy schedules even when energy prices happen to be zero.
5. Facilitate the conditions to avoid deterioration of the quality of service of the large consumers, both during the term of duration of the present long-term contracts and especially after the contracts expire.

Given the specific characteristics of the present Icelandic system, there are some significant challenges that have to be carefully accounted for when designing a sound regulatory approach to electricity security of supply. How each challenge is addressed shapes the proposed approach to security of electricity supply that is presented later.

3.1.1. The lack of a short-term wholesale energy price

Despite the very special characteristics of the Icelandic power system, the advantages of having a short-term wholesale price that is directly related to the actual operating conditions of the system are beyond doubt. Market signals can be used for valuing energy trading, and they elicit an efficient response from consumers and producers alike. They also reduce barriers to entry by providing a transparent reference price. They can be used to settle any deviation from the contracted commitments. The volume of energy under this price might be small, but the economic signal (even when the price is zero) will be correct for demand response, for maintenance decisions, for geothermal generators failing to provide their committed energy, and so on.

The market in the case of Iceland is not a traditional day-ahead bid market, but rather a model-based multi-period centralized dispatch. In a mostly hydro system with significant storage capabilities, diversified hourly prices are not necessary, except perhaps on those occasions where network constraints and peak demands create local specific conditions.

Weekly prices[13] rolled over a year, could be a reasonable proposition. The computation of weekly prices would internalize the best available information regarding the stored energy in the reservoirs, the type of hydrological year, and other relevant factors such as the estimated demand, maintenance schedules, weather, etc.

As it is now the case, most of the electricity would continue being sold via long-term contracts. These long-term contracts are perfectly compatible with short-term economic signals that would incentivize efficient behavior regarding deviations with respect to any prescribed schedule, and that can respond to actual short-term power system operating conditions.

3.1.2. The need for a capacity remuneration mechanism and the protection of small consumers

To the best of our knowledge, in Iceland there is presently no obligation of contracting with small consumers and no centralized mechanism to guarantee that they are supplied at all times. Landsvirkjun is acting today as a backup provider for all these consumers. However, the laws and regulations do not assign this role to the national company, neither have they provided mechanisms to address this issue properly. This situation leaves small consumers exposed, for instance, to generation companies deciding to abandon them and signing contracts with new large industrial demands.

To address this problem, we propose that, in the same way that industrial demand is covered by long-term contracts, which include security of supply clauses with economic compensations for reliability failures, S&MC should also be covered with long-term contracts. These contracts would have multiple purposes. From the viewpoint of consumers, the price of the contracts would be obtained in a competitive fashion (an auction, see below) and would provide a hedge with respect to the volatility of the short-term market price. But, more important, if conveniently signed ahead of time, these contracts guarantee that there would be enough energy in the system to meet the S&MC demand, as well as any deficit that the long-term contracts of the industrial demand might have. From the viewpoint of generators, the contracts provide revenue predictability, which is particularly important for new entries.

Therefore, in order to address security of electricity supply in Iceland in a comprehensive and consistent way, we propose to launch a centralized auction for these contracts, which on the one hand are ordinary long-term energy contracts and, on the other hand, have features of "capacity remuneration mechanisms" or "capacity markets", but in the very specific Icelandic context. Here we face some challenges: the existence of long-term contracts for the majority of the demand, with built-in reliability clauses; and the multiple products that a "capacity remuneration mechanism" must cover in the case of Iceland: i) firm annual energy, ii) available energy when needed in critical periods, and iii) available capacity when required by specific transmission network conditions.

[13] These weekly prices could be obtained by an optimization model like the one used in the analytical part of this study.

This auction (including three products or services meant for security of supply, each one with its own price) will also determine the price of electricity for the fraction of demand not already covered by the existing long-term contracts. Capacity remuneration mechanisms are meant to enhance adequacy and firmness, which typically brings additional generation investment and depresses energy prices. The remuneration of generators should not suffer in well-designed approaches, as the deficit in energy prices is compensated by the remuneration of capacity.

This measure is meant to protect residential and other small consumers with less negotiating capability than industrial consumers. The use of auctions to provide electricity to S&MC is common in many systems around the world. Although this kind of mechanism has been typically used to guarantee affordable prices to household consumers rather than to provide energy security, here it can be used for both purposes simultaneously.

3.1.3. The need to handle short-term deviations from scheduled programs

A peculiar characteristic of systems with 100% of generation resources with zero variable production cost is that the energy price is based on the expectation and estimated cost of unserved energy. The value of one kWh consumed now is determined by the expected opportunity cost of storing this kWh and selling it at a later time to reduce unserved energy by one (minus storage losses) kWh.

In a power system like this, the energy price can be zero most of the time, since the regulation (see the previous point 3.1.2) is designed to strongly reduce the probability of power shortages. A practical problem arises during those many hours with zero energy price: who wants to produce at zero or quasi-zero price? It is necessary to create some priority criteria, some rules to determine the plants that will have to produce during these hours and to create incentives to prevent deviations from the program that could be understood as "free riding" of some plants on others.

3.1.4. The need to respect privacy conditions of long-term bilateral contracts

Long-term contracts with large industrial consumers obviously have much importance for the functioning of the wholesale market and cannot be ignored in whatever approach is finally chosen to improve the firmness and adequacy of the Icelandic electricity market. On the other hand, these are private contracts with terms (prices, quantities, penalties, etc.) that the parties may not want to make public.

In order to minimize the interference of any rules to enhance firmness and adequacy with the functioning and privacy of existing or future contracts with large consumers, we propose to bundle the supply to each large customer and the generator with the contract to supply it (which we know has reliability clauses with "penalties for failing to supply" which actually are equivalent to "costs of non-served energy") into one entity or "generator/consumer bundle" for all effects in what follows, with the generator being the speaker for the bundle. The generator will offer in the market (the auctions to be defined later) whatever surplus or deficit of adequacy/firmness the bundle has; this will be represented by a staircase function of quantity/price for firm energy (and also for firm capacity in special conditions of capacity scarcity).

3.2. The proposed approach to enhance adequacy and firmness

The major parties to which the proposed regulation applies are: (1) bundles of large consumers and their supplying generators, each bundle with some energy and/or capacity surplus or deficit; (2) the demand of the small and medium consumers S&MC, with a baseload component and a variable one, which in principle will grow; (3) new generators; and (4) new large demands.

The approach consists of the following three elements:

3.2.1. The need for all demand to be covered with long-term contracts

All demand has to be covered with a "firm contract". The bundles above defined have to declare how much surplus or deficit they have in firm energy & capacity. The S&MC will be covered in the annual auctions (to be defined later). The new large loads will have to sign a firm contract or enter in the annual auctions to get a contract. The same must be done when the existing contracts for large consumers expire.

Currently, large consumers have long-term contracts that contain curtailment (i.e., security of supply) clauses specifying the compensation that consumers must receive if curtailed beyond prescribed thresholds. The "bundle method" that was described above integrates the existing and future long-term contracts into the general proposed approach for all generators and demand, and preserves the privacy conditions of these contracts.

Landsnet, under the supervision of the regulatory authority, will take into account the declared surpluses and deficits of the "bundles" to determine how much firm capacity there is in the system and how much is needed in the reliability auctions (to be described next).

We propose not allowing the entry of new large demand that requires more firm energy and capacity than that existing in the system. Note that a new large entrant, by consuming energy when the risk is low, increases the probability of shortage later, deteriorating reliability for everybody in the future. If new large consumers come and cannot get a firm capacity contract, then they cannot be awarded a connection permit by Landsnet, which must deny the connection request "on grounds pertaining to the transmission capacity, security and quality of the system."[14] Therefore, before getting connected, we recommend requiring all new large consumers to obtain firm capacity from a generator that is not already committed, and/or obtain the firm capacity in the reliability auctions (see below). Specific zonal conditions might be required for these contracts.

3.2.2. Auctions for reliability products

The key instrument to guarantee reliability (adequacy and firmness, more specifically) is the annual auctions, with the following characteristics:

- Every year T an auction is run to cover the demand of year T+N. The value of N should be enough for new generation to be installed in the system, if necessary, for instance 2 to 5 years, depending

[14] Based on the Electricity Act No 65/2003 Article 9 Obligations of the Transmission System Operator.

on the technology.[15] The demand of year T+N consists of: i) the expected future demand of S&MC in year T+N; ii) the declared deficits of the bundles; iii) any large new demand that officially requests entry to the system (and pays a fee to enter the auction, or some other form of showing the commitment).

- This demand will have an estimated profile. Part of it will be baseload and the remaining part will be variable. The generators may specify in their bids how much of the firm energy that they bid is baseload or variable.[16]
- As indicated before, the auction must deal simultaneously with three products or services, which the generators will have to specify in their bids: annual committed energy, weekly firm energy, and firm capacity.
- The auction determines for each winning generator: i) the annual energy production of each generator for year T+N; ii) the weekly energy committed for those critical weeks when the short-term price of energy reaches a prescribed high value; and iii) the committed value of capacity that has to be sustained for a prescribed number of hours, when the SO declares that need. The auction also determines the per unit (marginal) price for items (i), (ii) and (iii). These three prices, in particular (i) and (ii), will determine the annual remuneration of the generators. The price for the consumers will result from covering the cost of the three products in the auction.
- In order for the auction to be attractive enough for a new potential generation investor (a longer term income guarantee is usually required to get financial support for the project), new generators participating in the auction will receive the marginal price of the auction for the year T+N during the interval (T+N, T+N+5).[17] In the case of existing generators, these will receive the marginal price of the auction during year T+N only, and the value for year T+N+1 will be determined by the next year's auction. New generators will become "existing generators" after 5 years. For both schemes to coexist, we propose:
    - For each new auction for year T+N, the amount of the demand already covered through these previous 5-year duration commitments should be removed from the auction.
    - The auction price actually applied to the whole demand at T+N will be calculated as a weighted average of all prices in force at T+N:
        - The new price at T+N resulting from the auction launched at year T to remunerate existing generators and,
        - The old prices resulting from the auctions launched from year T-5 to year T-1 to remunerate new generators, which will still be applicable at T+N.

Further details about the auctions of the three reliability products:

1. Annual committed energy

[15] In order to shorten this interval, the regulator might preselect some potential sites with all environmental permits and any other logistic requirements already cleared, which could be used by the new entrants.
[16] For instance, this belongs to the details that will have to be examined in the future if this approach is adopted.
[17] A five-year interval could provide sufficient income stability for a new generator to be bankable under reasonable financial conditions.

The generators and the "bundles" will bid a price-quantity stepwise function of annual energy that they are willing to provide. Landsnet will clear the auction using their best annual demand forecast for year T+N. The outcome will be a single price for all the energy cleared in the auction (marginal price) and a pre-set profile of hourly production for all generators during that year T+N.[18] Once the year T+N arrives, two kinds of deviations are possible and explicit penalties will be applied to each one: i) deficits of the annual energy actually produced during year T+N, as compared to the committed one will be heavily penalized, since this is the essential element for security of supply in this energy-based system;[19] ii) any deviation, on an hourly basis, of the physical delivery with respect to the scheduled production profile will be priced at the short-term weekly energy price computed by Landsnet (see below); however, to prevent possible gaming behaviors a light explicit penalty will be also applied. Since the price of electricity in most weeks will be zero, unless a small penalty is applied to deviations with respect to the scheduled hourly production, there will be no incentive to maintain the scheduled program and to avoid temptations of free riding. Still, a balancing market close to real time is needed to make sure that supply and demand are actually in balance.

There are some open issues to be resolved if this approach is adopted: i) the implementation of this complex auction; ii) the possibility that the auction could have a floor price, for instance based on the estimated annuity of a representative geothermal plant, or a function of price versus the amount of firm energy being offered, so that the price rises if the supply is tight; iii) the treatment of intermittent generation (wind), in particular regarding whether some special treatment of deviations is justified and how to design it; iv) the possibility of using secondary markets to trade these security of supply products (if this is the case, the incurred commitments and associated penalties should be transferred in the trade too); and v) the possibility for agents that own or manage several plants to bid either with each plant individually or as a portfolio (in principle portfolio bidding should be more efficient, but it can also facilitate the exercise of market power).

One hypothetical concern with this method is the possibility that the auction of annual commited energy to meet the demand not served by long-term contracts could be deserted, and this demand could be unserved. We do not consider this to be a real issue. In the first place, if there is no price limit and the auction is properly publicized, there should be (economically rational) bidders. Moreover, the bundles of generation / industrial demand can also bid, curtailing their loads so that the freed

[18] The major reason to compute and to enforce this hourly production profile for each generator is that we want to avoid the ambiguity that would exist if the auction only determines the annual amount of energy or the commitment during critical weeks, and leaves to the agents how much to produce in real time. It probably makes sense that this hourly profile of production is updated by Landsnet once year T+N is about to begin, using the best estimation of demand, hydrology, network status, etc. but keeping the same amounts of security of supply products that were allocated in the annual auction N years before. Another option is to let the generators specify the profiles at the beginning of year T+N and leave to Landsnet the responsibility of modifying them if necessary. Again, details will be decided in the future if this approach is adopted.

[19] Geothermal plants will try to reduce the forced, plus scheduled, total, and partial outage times. Hydro plants with storage will try to manage the reservoir level to maximize production. But this is not all that is needed. In order to maximize security of supply it is necessary that the maintenance of the geothermal plants is done when non-energy-limited plants can replace the plants on maintenance and that the production of hydro plants with reservoirs is not wasted at times when non-energy-limited plants can be used instead. The incentive to promote this second kind of behavior is provided by the auction of the weekly firm energy.

generation could meet the S&MC demand. Finally, if there are no bidders, or if the bids are unacceptably high, in the spirit of the EU Electricity Directive for the Internal Electricity Market,[20] the regulator could make sure that the auction has enough beneration bids to meet the demand, for instance, facilitating the permits and logistics at certain sites or instructing Landsvirkjun to participate.

2. *Weekly firm energy*

   In the annual auction, the generators will bid a price-quantity stepwise function for the amount of weekly energy that the generators commit to provide during those weeks when the short-term price of energy (which is calculated every week by Landsnet) is above a certain threshold value. Any failure in the firmness commitment during the critical weeks of energy scarcity will be also heavily penalized. These penalties will have an impact on the value of the bids. This applies to any generator or bundle (in this case the net production of the bundle is the one to be monitored to control the compliance with the commitment).

3. *Firm capacity*

   The generators will bid a price-quantity stepwise function for the amount of capacity that generators commit to provide for a given number of peak hours every day in situations of capacity scarcity determined by Landsnet on short notice. Any failure in the firmness commitment during the critical hours of capacity scarcity will be heavily penalized. This applies to any generator or bundle (in this case the net production of the bundle is the one to be monitored to verify the compliance with the commitment).

3.2.3. The computation of the short-term wholesale electricity prices

A wholesale energy price that can guide the short-term decisions of the agents efficiently is a necessity, despite the fact that most of the energy is traded via long-term contracts. The electricity market in Iceland is not a conventional day-ahead bid market, and the adopted solution must be adapted to its specific characteristics, which include that all generation units have a zero variable cost of production.

Although most of the relevant market information is in the hands of the national power company (Landsvirkjun), a “non-agent” like the system operator (Landsnet) should take care of the market-clearing process, where the hourly production for each plant for the next week, the actual (single) price for the next week, and the estimated prices for every week during the entire next year will be computed. Landsnet will take into account the amounts of firm energy and capacity committed in the reliability auction, as well as any new conditions declared by bundles, generators and load supply entities. As in any other wholesale market with a market operator, the hourly dispatch of the non-previously committed power plants will be decided by the system operator in the clearing process. Given that the variable cost of all the involved power plants may be zero, the clearing algorithm may include some priority classification and/or the owners of the power plants may have some freedom to manage their portfolio

[20] See article 8 of the Directive 2009/72/Ec Of The European Parliament And Of The Council of 13 July 2009 concerning common rules for the internal market in electricity.

of power plants introducing substitutions that do not interfere with the physical viability of the dispatch that was determined by the system operator.

Weekly market prices will depend on the probability of future (or the actual) energy curtailment in the system, with costs specified by the curtailment costs indicated in the bids of the bundles and, for the S&MC, by the cost of non-served energy established by the regulator. The wholesale market price is expected to be zero most of the time, except when curtailments actually happen or when they are anticipated to occur some time in the future.

Landsnet will compute every week[21] the short-term weekly energy price for every week in the following year starting at the present moment. These prices will have only indicative value, except for the immediately following week. The price for the following week: i) will determine if the scarcity condition (to be defined below) is triggered or not; ii) and will be used to value deviations of the actual production of each generator with respect to what was determined in the auction that took place N years before (or updated before year T+N starts). See below.

In addition to the weekly energy price, a short-term (hourly) balancing market must be used to price hourly deviations from the contract commitments. The present balancing mechanisms already in place involving Landsvirkjun and Landsnet could be extended to a system-wide hourly balancing price with zonal discrimination to account also for network-related constraints. Moreover, to highlight the relevance of honoring the commitments and to compensate the troubles and costs of third parties (presently Landsvirkjun) to meet the on-line balancing requirements, an explicit penalty for deviations is recommended.

3.3. One step beyond in pricing: the locational component and transmission investment needs

The following measures could help in tackling the network adequacy problems and promote efficient location of future generation and demand:

- **Provide locational signals through network charges for new generators and demand**. Generators, as well as consumers, should be charged the corresponding transmission tariffs. New generation capacity can create the need of or may defer transmission network reinforcements. An efficient design of network charges should internalize those impacts on system costs by providing locational signals for new generators and demand. Although this measure is already in place for large consumers in Iceland, it would be convenient to extend it to the expected new investments in wind generation, since these locational signals could make a significant difference in transmission and high voltage distribution network requirements.
- **Incentivize the fast development of critical network reinforcement**. Every other year the TSO should run a transmission study and determine: i) the critical reinforcements; ii) the cost and benefit and the estimated environmental impact of these investments; and iii) a proposed minimum cost transmission expansion plan where the environmental impact has been considered either as an additional

[21] By using a software similar to the MIT/IIT computer model.

estimated cost or as an environmental constraint. The regulator may establish higher regulated rates of return for the critical reinforcements, which could help speed up their development.

- **Balancing prices** (and maybe weekly energy prices also if necessary) could be zone-dependent to provide an additional locational signal to new investments with respect to network constraints.

4. Final considerations

While some of the measures proposed in this document may require changes in the present primary and/or secondary regulatory normative in Iceland, other measures would just follow from the application of the existing legislation.

We believe that a more transparent allocation of roles and responsibilities among the institutions is needed, as well as a more precise definition of the security of supply objectives. An indicative expansion plan of generation and transmission capacity, with some normative implications, should be available to the agents in the system, and this activity should be a major part of the biennial Energy Report required by article 39 of the Electricity Act.

The national government and the regulator should be proactive in ensuring that their citizens and the companies functioning in Iceland have acceptable levels of electricity security of supply. Clear guidelines and the means to implement them, with the technical support of the Transmission System Operator, should be given to the National Energy Authority for the design and implementation of the regulation that will ensure satisfactory levels of adequacy and firmness.

The system operator is in the best position to define the amount of firm commitments to be contracted in the system and Article 9 of the Electricity Act could be used as the basis for allowing the participation of the agents in the Icelandic market. It seems that additional legislative provisions will be needed if the role of the system operator has to be expanded to evaluate firm capacity and energy at a system-wide level. Additionally, in order for suppliers to "provide the electricity necessary to perform obligations under power contracts,"[22] additional provisions might be needed to increase the role of the National Energy Authority (with the technical help of the system operator) to request newcomers include firmness clauses in contracts with producers.

The existing bilateral contracts with large consumers already incorporate both security and firmness. Therefore, the easiest option to address a system-wide security of supply mechanism might be requiring all load serving entities, generators, and the "bundles"—which could be generators or consumers or both—to participate in the proposed reliability auction.

Complementary to the contracting approach that makes sure that there is an adequate level of security of supply is a proposed system of weekly energy prices, hourly prices to value any deviations of the agents with respect to their committed production or consumption profiles, and locational energy prices and network charges when necessary.

[22] Refer to Electricity Act No 65/2003 Article 19.

In any case, this overall regulatory proposal should be complemented with additional studies. We acknowledge that the ideas proposed in this document will introduce complexity in a system where competition is very limited, due to the size and the ownership structure of the power sector. But we also think that the proposed measures will enhance supply adequacy and firmness, will improve the overall operation efficiency, will be useful in the hypothetical interaction with other external systems and will create the foundation for a more competitive electricity market in the future, if this is the path that Iceland wants to follow.

5. Appendix A: Brief review of Icelandic regulation of electricity security of supply

We have reviewed the laws and regulations concerning Energy and Natural Resources as available by the Icelandic Ministry of Industries and Innovation[23] and Orkustofnun,[24] with particular focus on the following documents: Electricity Act No. 65/2003; Act amending the Electricity Act; Act amending various acts of law relating to natural resources and energy No. 58/2008; Act No. 87/2003 on the National Energy Authority in Iceland; and Regulation on the National Energy Authority in Iceland.

The Electricity Act mentions that a competitive environment should be ensured for the generation and trade of electricity, bearing in mind security of supply and specifying some of the obligations of the system operator to oversee it. However, we could not find a clear definition of what electricity security of supply entails under the particular characteristics of the Icelandic power system. There are frequent remarks to "security of the electricity supply system and consumer protection," but we consider the laws and regulations to have fallen short on providing a precise legal definition that stakeholders can use as a common framework for discussion.

It is crucial that the national government and pertinent regulatory bodies be proactive in ensuring that their citizens and companies have satisfactory levels of electricity security of supply. Therefore, a clear governing framework is needed to enable the National Energy Authority to adopt and implement the mechanisms necessary to ensure efficient and effective levels of adequacy and firmness, with the technical support of the Transmission System Operator.

Article 2 of Act No. 87/2003 requires that one of the main roles of the National Energy Authority is to prepare long-term plans on the energy utilization of Iceland and the development of energy resources and other mineral and water resources, on-land and off-shore. Article 39 establishes that the Minister shall submit a report on energy issues to the national parliament of Iceland every two years. The report shall contain an overview of the sale and use of electricity in the preceding four years; electricity needs and an overview of probable long-term trends on the basis of electricity forecasts and plans for energy-intensive industry and other activities not covered by the electricity forecast; research of energy resources and their preparation for the generation of electricity; electricity generation in light of electricity needs and the security of the electricity supply system; strengthening of the transmission system based on increased electricity needs; quality of electricity, with regard, inter alia, to delivery security; and the national importance of proposed electrical power developments and their effects on the economy and habitation in Iceland. This biennial Energy Report, could be used as a platform to develop and periodically update a comprehensive indicative (with normative implications) expansion planning, based on the present and future electricity needs in the country.

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[23] Refer to Laws and Regulations on Energy and Natural resources available at: https://eng.atvinnuvegaraduneyti.is/laws-and-regulations/energy-and-natural-resources/

[24] Refer to Acts and Regulations available at: http://www.nea.is/the-national-energy-authority/about-the-nea/acts-and-regulations/

The Electricity Act specifies in Article 9, "Obligations of the Transmission System Operator," "the Transmission System Operator is responsible for the secure management of the electricity supply system and shall ensure the security and quality of his delivery of electricity. Such system management includes coordinating supply and demand as regards electricity so that discrepancies between agreed purchase and actual use can be met, and entering into contracts with producers in connection therewith; and ensuring adequate supply of spinning reserves in the operation of the system." Article 28, "Regulation of the Quality of Electricity and Security of Delivery," states, "producers, the transmission system operator and distribution system operators shall establish internal controls on the quality of electricity and security of delivery." The role of Orkustofnun is mentioned several times in the Act and secondary regulation regarding the approval of security and reliabiity requirements proposed by the system operators, setting reliability targets, monitoring compliance and handling complaints regarding quality of service. Still, we believe that a more transparent allocation of roles and responsibilities among agents is needed.

Article 1 of the Electricity Act states that a "competitive environment shall be ensured," but there are no details or subsequent regulations that outline the creation of an electricity market that could provide economic signals to consumers and generators. Article 8 indicates that the Transmission System Operator "may operate an electricity market…", but we could not find further information regarding how the creation of this market should take place, and the rules to be followed by the agents. As we noted previously, the role of the transmission system operator is critical for the implementation and subsequent operation of this market, and further actions should be taken if a full-fledged electricity market is considered a plausible alternative for improving the transparency and efficiency of the existing system, as well as the possibility of establishing more advanced market instruments based on weekly and balancing prices.

Regarding protection to consumers, the Electricity Act (Article 1) clearly states that "…consumer protection shall be ensured" and additional text within the Act mentions that "regulation of the quality of electricity and security of delivery" is required. However, we could not find further guidelines for the requirements needed to implement this. It will have to be verified if some of the measures that are proposed later in this document—such as a centralized auction mechanism for small consumers—could be implemented under the existing regulatory framework.

Finally, regarding transparency of information, the Act, in Article 19 "Obligations of Suppliers in Electricity Trading," establishes that suppliers shall, inter alia, provide the electricity necessary to perform obligations under power contracts, and supply Orkustofnun with information necessary to assess whether the company is meeting its obligations.

6. Appendix B: A comprehensive approach to adequacy and firmness: Reliability Options

This appendix comments on the method of reliability options, which could be understood as the origin of the approach that has been proposed in this report to address adequacy and firmness concerns. Reliability options are powerful instruments for enhancing electricity security of supply, and they are currently in use or have been proposed already in several power systems around the world. For further information refer to Vázquez et al. (2002, 2003), Cramton at al. (2008, 2013).

Given the characteristics of the power system in Iceland, the original method of reliability options has to combine three different reliability products to cover the required services of security of supply. The first one is an annual energy commitment, the second one a weekly energy commitment and the third one is a capacity reliability option. All of them would possess the usual features of a time lag, a long commitment period, strike price, and penalty.

The **annual committed energy** is a commitment by a generator to produce some total amount of energy during a future year. Any production deficit will be heavily penalized. This is a necessary commitment from a reliability standpoint in Iceland, since the power system is energy-constrained in each annual cycle. However, as indicated in the main document, this annual commitment does not solve the firmness problem, i.e. the availability of a sufficient amount of energy to meet all the demand in those weeks where the power system might be short of supply. The second product solves this problem.

The **weekly energy commitment** consists of firm commitments by generators to deliver an agreed amount of energy in those weeks where the energy price exceeds a prescribed value, or strike price. The demand pays a fee (as the result of a centralized auction conducted by the regulatory authority) to guarantee the delivery of the weekly energy production at the strike price (i.e., in financial terms, the demand obtains a call option for a prescribed amount of energy in one week at an agreed strike price). Obviously the option would be only activated if the actual market price in that week exceeds the strike price. A penalty will be applied to those generators that do not honor their reliability option commitments. An alternative implementation would trigger the commitment by the generators when the system operator detects a system operating condition with a serious threat of scarcity of generation supply.

This mechanism is an investment and availability signal. The corresponding auctions must be called well in advance in order to consider the lag period in new investments and to allow the participation of potential new investments. All technologies can compete to sell firm energy through this reliability option mechanism. One issue of concern is the treatment of hydropower, since this technology is a key candidate and the lag period should be long enough to allow new hydro to participate. Some systems have implemented technology oriented auctions, which requires the regulator or the system operator to decide in advance the desired technology mix; note that combining these auctions is not straightforward. In addition to generation, the demand from the power intensive industry should be encouraged to participate in this type of energy reliability mechanism.

In case that the power system is also facing capacity problems, additional auctions based on a **capacity reliability** option mechanism will be needed. In this case, the auctioned product is the availability of producing a predetermined quantity of power when capacity is scarce and curtailments materialize. In this case, the triggering value can be either an hourly price (the price of the balancing market could be used for this purpose) or some capacity margin, which is calculated by the system operator. This value should be calculated as close as possible to real time conditions, for example, two hours, given the flexibility of the Icelandic system.

Both energy and capacity auctions should be called at the same time, because the results of one could affect the other. This is necessarily a complex process, as the agents do not know how to bid efficiently in one auction without knowing the result of the other one. Clearing both auctions at the same time while bearing in mind their interdependencies will be also complex.

In the context of Iceland, in addition to the pros and cons already mentioned above, other questions arise regarding the compatibility of the existing bilateral contracts with the proposed reliability options. Large consumers are already covered by these contracts, hence they should not pay double for reliability options, but they could benefit (and pay) for extra reliability or offer (and receive credit for) extra reliability to the system. This has been solved here by the proposed use of “bundles” of generators and large consumers.

Another issue arises with the installation of new large consumers into the Icelandic market. Given that impeding the installation and connection of new consumers may not be feasible, their arrival will not only compromise the system’s security but also have an impact on the generators’ operation. Their presence will cause the trigger condition to activate more frequently than previously expected, as it will not have been foreseen in the reliability options mechanism. Before getting the connection permit, we propose requiring the new consumers to sign an agreement that includes a firmness clause with a generator or portfolio of generators for firm capacity that is not already committed in the reliability option mechanism and to participate in the next reliability auction.

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ELECTRICITY SECURITY OF SUPPLY IN ICELAND

PART II: ECONOMIC ASSESSMENT

1. Table of Contents

2. 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 adverse impacts on business, schools, homes, finances, and telecommunications, and can also lead to public safety incidents. For example, the two day-long[1] power outage of 2003 led to around 50 million Northeastern US and 10 million Canadian residents losing power as well as an estimated economic loss of around $6.4 billion (Anderson & Geckil, 2003). Iceland has also experienced blackouts in the past. The most severe one took place in 2010 and left without power 200,000 inhabitants and two aluminum smelters, plus a third aluminum smelter that operated at its minimum.

Iceland has 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. Nowadays, Iceland is an isolated system with an independent transmission network disconnected from the rest of the world, which cannot participate in electricity trade. In addition, Iceland has an aging transmission network that frequently reaches its tolerance limits along with increasing load demands from both the energy-intensive industry and other general demand. Finally, Iceland is subject to severe weather conditions such as earthquakes and volcanic eruptions. For all of these reasons, Iceland is concerned about how to ensure long-term security of electricity supply in an economic manner while preserving its environmental goals.

The main goal of the project[2] is to assess the various alternatives that are currently under discussion in Iceland to achieve electricity security of supply in the most economical way for a 10-year time horizon. In addition, we have provided a separate document[3] for the stakeholders to initiate discussions about how to address existing practices that can compromise the electricity security of supply in the near term.

Critical for the accomplishment of the project goals is having a high-quality model of the Icelandic electric power system that can satisfactorily represent the complex hydropower system in combination with the geothermal plants and portray the main characteristics of the transmission network. Flexibility for adding future expansions in generation and transmission is also essential, as we have been examining various alternatives for the evolving Icelandic system. Among those alternatives, the project has analyzed the Highlands and Inter-regional options for transmission expansion; the utilization of diesel back-up in critical areas of the system; geothermal, hydro and wind generation expansion; natural gas power generation units; industrial demand response; and interconnection by a subsea cable to the UK. Assessing each alternative has provided insights on how the country could maintain and enhance electricity security of supply in the future, while choosing a model of economic growth.

[1] Complete power restoration was achieved after one week.

[2] The MIT Energy Initiative has elaborated the project in a joint collaboration with Instituto de Investigación Tecnológica – Universidad Pontificia Comilas.

[3] The authors refer the reader to Electricity Security of Supply in Iceland – Regulatory Discussion.

We have structured this report as follows. **Section 3** introduces the problem of security of supply with a particular focus on Iceland. **Section 4** describes the currently considered alternatives to improve security of supply in Iceland. **Section 5** focuses on the effects of reinforcing the network of a hypothetical Icelandic system in the near term, while **Section 6** looks at the consequences of the installation of additional generation assets in about a decade along. **Section 7** presents three sensitivity analyses: 1) additional demand response, 2) gas power plants and, 3) an interconnector with UK. Finally, **Section 8** concludes the report with a comparison of all the examined options, as shown in Figure 1.

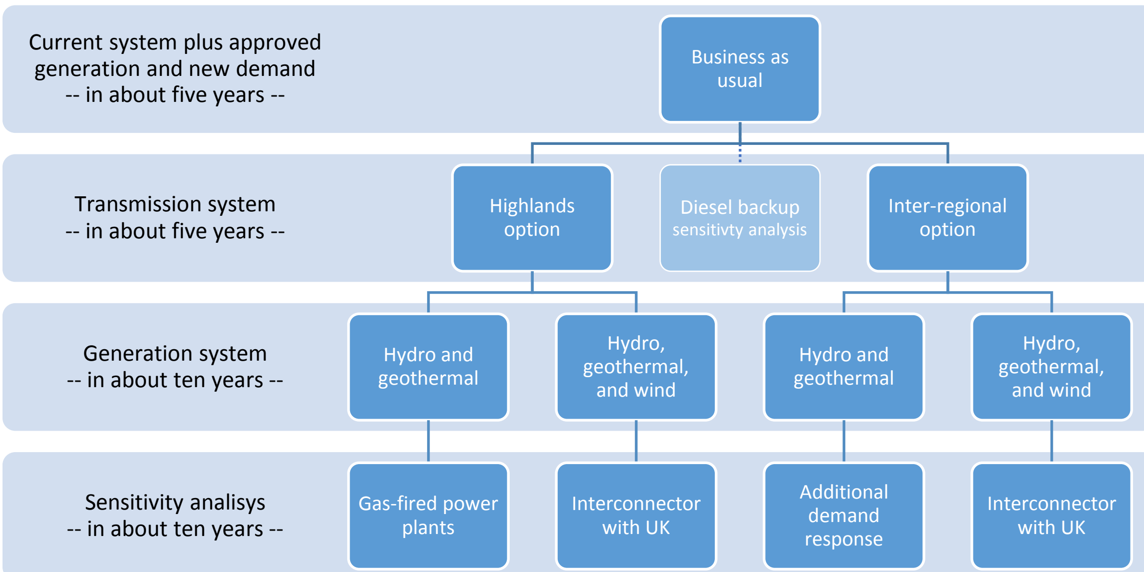

Figure 1: Map of cases analyzed in this study

3. Assessment of existing security of supply in Iceland

We have assessed the current situation of adequacy[4] and firmness[5] in Iceland and identified the main existing limitations of the system. The assessment also embeds the strategic energy policy[6] as determined by the projected future demand and the several analyzed future scenarios that portray several strategic options for the development of the system.[7] We have performed, and described in this document, a quantitative modeling-based evaluation of the performance of the system from a system security and economic point of view in the time horizon of the study.

Iceland has been performing satisfactorily regarding electricity security of supply. Iceland is almost energy independent. Specifically, Iceland is 99.9% independent in electricity (71% hydrothermal and 29% geothermal) and 99% in heating (9% electricity and 90% geothermal). As seen in Figure 2, in terms of

[4] Adequacy requires the existence of enough available capacity, both installed and/or expected, to meet the forecasted demand.
[5] Firmness requires that enough supply infrastructure is available when needed and mainly depends on the operation planning activities of the already installed capacity: maintenance schedules, reservoir management, etc.
[6] Strategic energy policy includes physical existence and reliable supply meeting environmental constraints, affordable price, and acceptable energy dependence of the country.
[7] Most of the options are part of the Icelandic Master Plan.

primary energy, as of 2015, geothermal accounts for 66%, mainly for heating and power generation; hydropower reaches 19%; oil represents 13% as the main transportation and back-up fuel; and a small amount of coal is still employed in the industry.

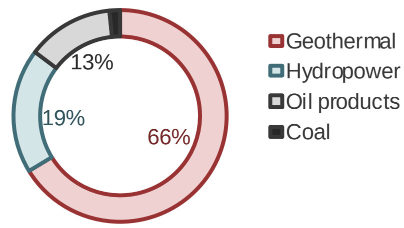

Figure 2: Primary energy sources in 2015. Source: Orkustofnun

Iceland has become energy independent while the energy consumption has grown. This is a great Icelandic success story. Iceland formerly obtained its energy from peat and imported coal. After the Second World War, Icelanders started to look for alternative ways of procuring energy. Slowly, geothermal increased its share in the generation mix, while oil replaced coal. The oil crisis of the 1970s boosted the use of domestic and renewable resources, such as geothermal and hydro, and displaced fossil fuels, as seen in Figure 3.

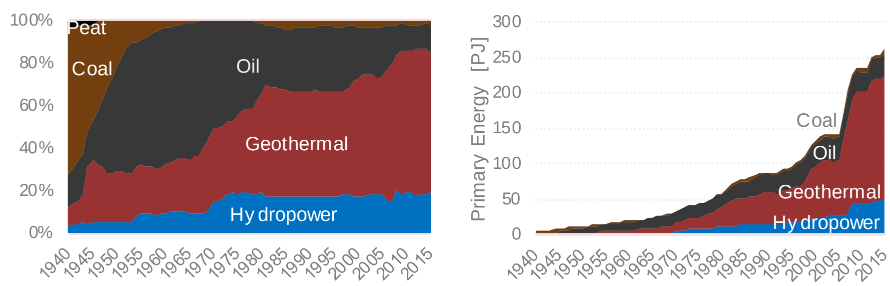

Figure 3: Historic primary energy mix (left) and use (right) in period 1940-2015

The large amount of domestically available hydro and geothermal resources have allowed Iceland to offer very low electricity prices that are very attractive for large power-intensive industrial consumers for the production of aluminum, silicon, and ferrosilicon, as well as for data centers. This dominant electricity demand by the energy intensive industry (left of Figure 4) has led the country to have the highest per capita electricity consumption worldwide (right of Figure 4).

Although the levels of adequacy and firmness seem reasonable in Iceland today, we have identified limitations within the system that might compromise Iceland's security of supply in the near future. This is particularly critical considering that the demand will most likely increase significantly from now until 2030. Under the demand scenario, used in this analysis, the non-intensive general electricity demand would grow annually at 2.76% until 2020, and the energy-intensive industry demand would increase by 2.5TWh. This growth of the energy-intensive industry is broadly in line with Orkustofnun projection, which only accounts for already committed power sales. From 2020 until 2030, the plausible demand scenario, used in this analysis, assumes that the non-intensive general electricity demand would grow annually at 2% and that additional consumption of energy-intensive industry would amount to 2.9TWh (Figure 5).

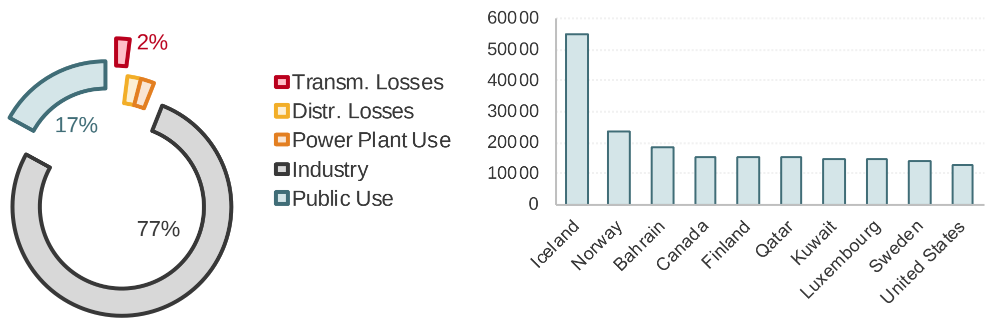

Figure 4: Power consumption by sector (left) and per capita (right). Sources: Orkustofnun and World Bank

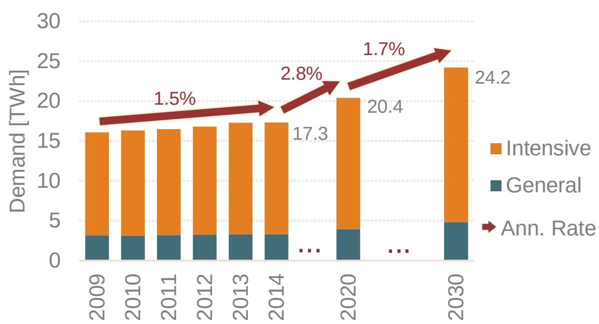

Figure 5: Historic power demand (2009-2014) and future scenarios. Source: Orkustofnun and Landsvirkjun

We have identified three possible areas of concern for the future, which directly involve the transmission and generation systems:

1. *Adequate generation capacity and energy*. Presently, there is no shortage of capacity, but the lack of sound and clear investment signals and specific regulatory mechanisms concerning security of supply, as well as the increased emphasis on environmental protection, is discouraging required investments that are critical for the future.

2. *Adequate transmission capacity*. The Regional Ring Network is becoming obsolete. In 2014, inter-regional power flow exceeded security-monitoring limits 28% of the time. Moreover, the two options[8] under consideration for strengthening the main grid face environmental concerns.

3. *Firm generation capacity and energy*. Hydro accounts for 71% of total electricity generation and its firmness depends on hydro inputs, weather conditions and reservoir management decisions. Shortcomings in regulatory instruments regarding firmness and adequacy commitments are creating concerns among participants.

The lack of reliability has a cost for industrial, commercial, and residential consumers. Curtailments directly affect their activities and harm the economy of the country in multiple ways. The difficulties in properly assessing the cost of unserved energy often result in the adoption of some proxy, such as a target

[8] The Highlands solution crosses the island through the central plateau reinforcing the north-south connection. The Inter-regional solution retrofits the Regional Ring Network.

for some metric of the level of security of supply that is easier to compute, estimate, or measure. The best metric for a hydro-dominated system such as the Icelandic one is the volume of non-served energy.[9]

For the purpose of this project, we have based our estimations of expected curtailments and the electricity prices associated with them, on a mathematical tool that considers the uncertainty in water inflows and the main characteristics of the Icelandic electricity system. Further details are available in **Appendix A**.

3.1. Curtailment and non-served energy

Curtailments and non-served energy (NSE) happen when the Icelandic weather conditions are unfavorable to the filling of the reservoirs.[10] If new generation capacity does not accompany the future demand, curtailments and non-served energy could worsen. Given the current supply contract structure in Iceland, the industrial demand faces most of the energy scarcity. While curtailments of the household demand are in theory allowed, implementing such measure is very unpopular. This fact translates into a very high cost of non-served residential demand; hence, the household demand curtailment is the last resource.

Based on the current structure of the contracts between the power intensive industrial demand and the power companies, we have distinguished two blocks of industrial demand that could potentially remain unserved: secondary energy and buyback energy. These two products, which have proved useful in the past in mitigating or solving conditions of energy scarcity, are expressed as a percentage of the energy that may remain unserved annually, and as a percentage of the power that may remain unserved at any moment. In addition, the requirement of secondary energy is also limited by a percentage of the average energy during a number of years that may remain unserved. Without loss of accuracy, we have calculated the average over all scenarios. We have considered any other curtailment, different from the previous categories, a severe curtailment that harms the security of supply.

Any curtailment has an associated cost. As the arranged price is private and confidential information, we have estimated the cost of the previous two products. We have estimated that the secondary energy price is close to the Icelandic price for the industrial demand as provided by Eurostat, about $25/MWh. Besides, we have assumed that the buyback energy price is 3.6 times the price of secondary energy. Within the model, the cost of severe curtailment is high enough to avoid incurring it unless strictly necessary.

Although the previous arrangements contemplate acceptable levels of curtailment at negotiated contract costs, for the purpose of this study, we have considered any curtailment that falls under the secondary energy category acceptable, whereas we have considered any other type of curtailment non-served energy. We have categorized the buyback energy as non-served energy due to its relative high cost in comparison to hydro and geothermal technologies. This categorization, however, must not lead to the perception that buyback energy has negative overtones. As described above, the buyback energy emerges from private agreements between the generation companies and energy-intensive industry, and is a

[9] 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.

[10] Non-served energy may also happen due to failures in the network and/or generation system. However, these situations that also affect the system security have not been assessed in this project, which focuses on the adequacy and firmness dimensions.

helpful resource in times of energy scarcity. Figure 6 illustrates the current contract structure and our categorization of acceptable curtailments and non-served energy.

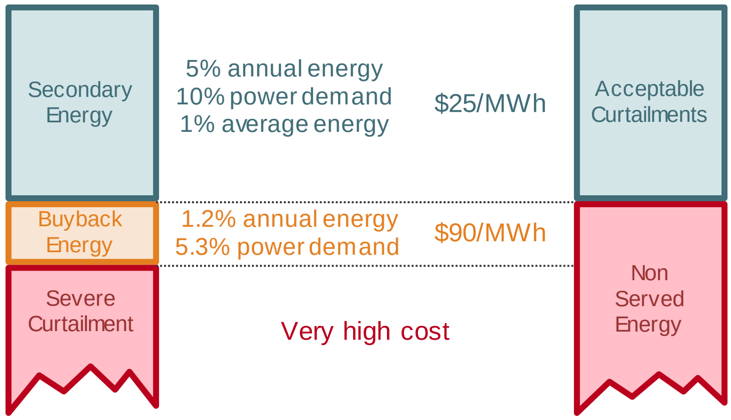

Figure 6: Structure of curtailment and non-served energy

3.2. Business as usual

In order to assess the near-term performance of Iceland regarding electricity security of supply, we have analyzed the case in which no new investment, on top of already approved generation assets and network reinforcements, happens either in the generation or in the network system. We have assumed that the following conditions apply to the Icelandic electric system:

- The geothermal generation portfolio as scheduled for 2020 (Figure 7) is expected to extend the current system with the development of a new project in Þeistareykir. We have determined the maintenance schedule according to historical data from May 2014 to October 2015.
- The hydro generation portfolio as scheduled for 2020 (Figure 8). With respect to the system of today, it includes a new power group in Búrfell.
    - The hydro uncertainty of the period 1951-2004 has been incorporated through a scenario tree that opens two branches the third week of October; two branches the second week of November; two branches the first week of April; two branches the first week of May; two branches the first week of June; and two branches the four week of July.
        - As there are fifty-four hydro historical years, which determine the probability of each scenario, ten out of sixty-four hydro scenarios result in zero probability.
        - Hydro operations decisions consider future hydro inflows uncertainty as modeled by the scenario tree.
    - In addition, we have fixed the initial reservoir levels to 95% at the start of the simulated time horizon, the second week of October, and we have imposed that the final reservoir levels must be greater than 95% one year later for all scenarios.
    - We have defined an equivalent basin model to replicate the Hálslón reservoir head effect and the Jökulsá diversion. Further details are available in **Appendix A**.

- The transmission network as of today (Figure 9). We have applied a clustering technique to the existing nodes, and reduced the system to twenty equivalent nodes. Although the model cannot capture the short-term dynamics of the system, we have included the three main transmission cuts (i.e., geographical borders crossed by power flows between two areas that are linked by one or more power lines) to account for stability constraints.

Figure 7: Geothermal generation portfolio as of 2020

Figure 8: Hydro generation portfolio as of 2020

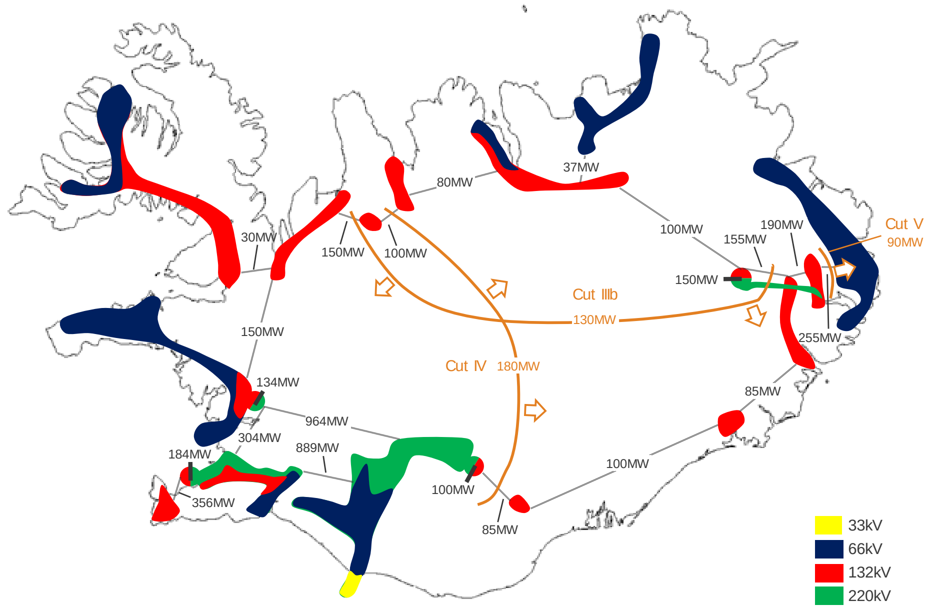

Figure 9: Transmission network as of today

Our analysis shows that under the business-as-usual case, in which the country does not implement any new development in either the transmission or the generation system, the secondary energy would be almost fully required in some scenarios leading to some instances of non-served energy. On average, existing secondary energy would be equal to 147GWh (0.9% of industrial demand) and non-served energy would be around 30GWh. Non-served energy would not only include buyback energy, i.e., Iceland would experience severe curtailments, around 50GWh, one out of eighteen years. As seen in Figure 10, the worst hydro conditions would lead to the almost full utilization of secondary energy during a single year. Non-served energy would show up every other year, and the worst hydrological conditions would cause non-served energy of 1.23% of industrial demand. When adding up the total curtailments, the secondary and the non-served energy would exceed 1% of the total demand in three out of five years. The worst hydrological condition would produce total curtailments of up to 5.19% of the industrial demand.

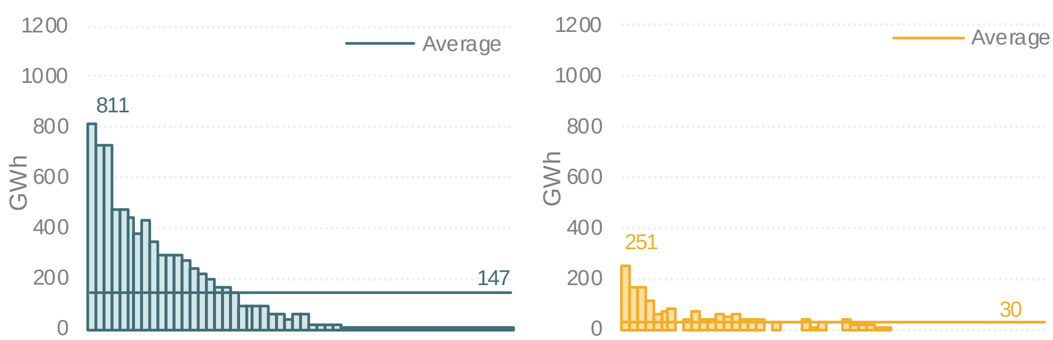

Figure 10: Secondary energy (blue) and non-served energy (orange) in the business-as-usual case for the 54 hydro scenarios

Analyzing the results by region, we observe that the Reykjavik area, with 10.5TWh of industrial demand—63% of total industrial demand—would be the most affected, representing 71% of the expected secondary energy utilization and facing 92% of the expected non-served energy as seen in Figure 11.

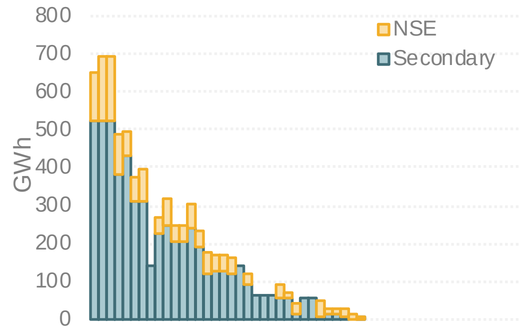

Figure 11: Curtailment in the Reykjavik industrial area in the business-as-usual case

The Reyðarfjörður industrial area, with 5TWh of demand, corresponding to 31% of industrial demand, would provide secondary energy and face non-served energy mainly during severe drought conditions, which have a particular impact in the East. In contrast, curtailments would slightly affect the Northern industrial areas, with 1TWh of demand, 6% of total industrial demand (Figure 12).

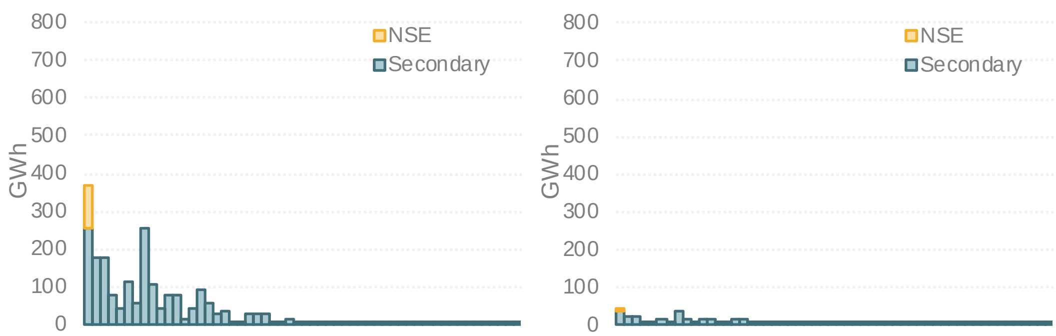

Figure 12: Curtailment in the Reyðarfjörður (left) and Northern industrial areas (right) in the business-as-usual case

The analysis suggests that, as early as 2020, the Icelandic power system would face all kind of curtailments, including extremely costly ones. The lack of action will increase the probability of additional curtailments and non-served energy in the future even if any new additional energy-intensive demand does not connect after 2020. As described in the following section, reducing the number of curtailments and increasing the security of supply might entail installing power generation, reinforcing the power transmission system, negotiating further buyback energy with the power intensive industry, and even building a subsea cable with the UK.

4. Alternatives to achieve security of supply

Several alternatives are currently under discussion. We have analyzed in this study the Inter-regional and the Highlands options that encompass plans to upgrade the existing 132kV lines, and construct new 132kV and 220kV lines with different topology layouts as outlined in the Landsnet 2015 Annual Report.[11] On the generation side, there are plans to incorporate carbon-free (hydro, geothermal, and wind) power plants into the generation portfolio at several possible locations (Figure 13).

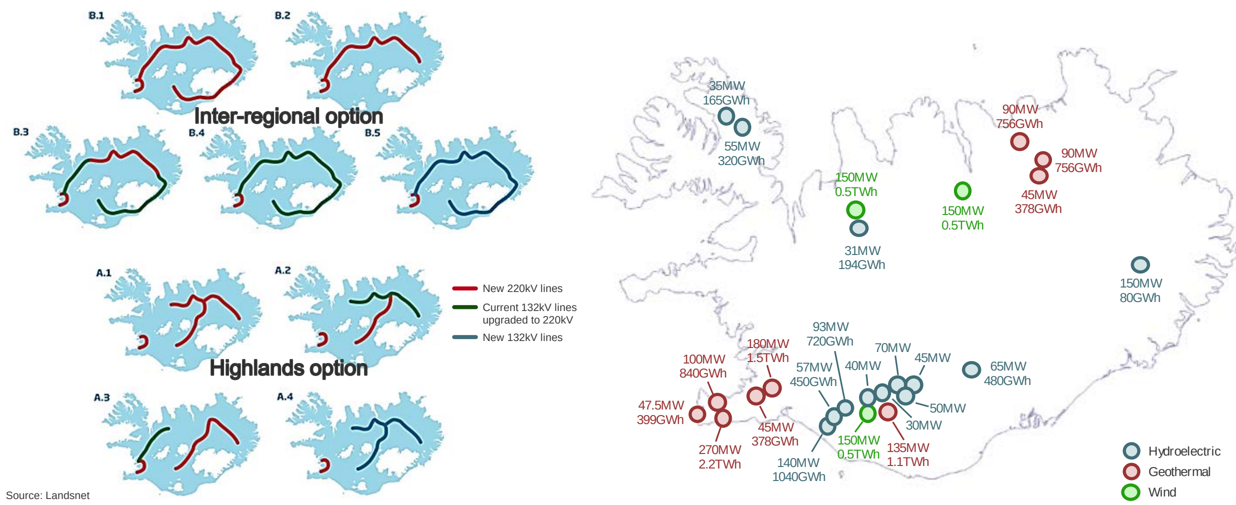

Figure 13: Alternatives in transmission (left side) and generation (right side) considered for achieving security of supply

Choosing the most economical of these alternatives to guarantee security of supply entails analyzing and comparing their level of curtailments, costs, and benefits. In particular, we have looked at the following options for the evolution of the system:

- The reinforcement of the transmission system offers two specific options:[12]
    - The *Highlands* option consists of either an AC overhead or a DC underground cable that would cross the island. The estimated upfront cost of the AC option amounts to $370 million, or $29.8 million of equivalent annualized cost,[13] while the DC option amounts to $616 million, or $49.6 million of equivalent annualized cost.[14]
    - The *Inter-regional* option retrofits the current Regional Ring network by building new lines in parallel. Most sections of the old network would keep working. The estimated upfront cost amounts to $575 million, or $46.3 million of equivalent annualized cost.[15]
- Three carbon-free generation technologies are available. All of them would use domestic energy resources. Mainly based on the Master Plan, the following projects are possible:
    - Six potential hydro repowering operations: Fljótsdalsstöð in Kárahnjúkar, and Vatnsfell, Sigalda, Hrauneyjafoss, Sultartangi, and Búrfell in Þjórsá.
    - Six hydroelectric projects: Blönduveituvirkjun in Blanda, Holtavirkjun, Hvammsvirkjun, and Urridafoss in Þjórsá; and Austurgilsvirkjun and Hvalárvirkjun in Westfjords.

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[11] Available online http://2015.landsnet.is/en/

[12] In addition, we have performed a sensitivity analysis to assess the costs and benefits of installing diesel stations at specific nodes of the system to alleviate partially or fully some of the transmission congestions.

[13] We assumed WACC 7.5%, lifetime 40 years, and O&M cost 1.5%.

[14] Ibid footnote 13.

[15] Ibid footnote 13.

- Seven geothermal projects in Reykjanessvæði, Hengilssvæði, Krafla, and Þeistareykir.

The levelized cost of electricity of the previous projects ranges from $25/MWh to$50/MWh (Figure 14).

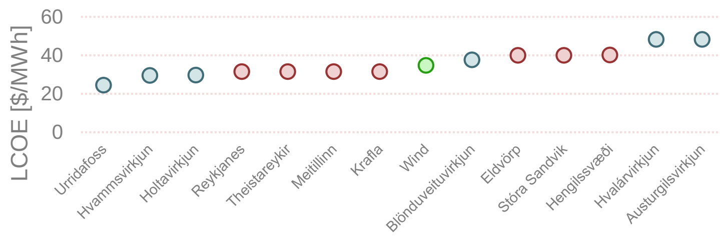

Figure 14: Levelized cost of electricity for new generation projects

In addition to the core cases, we performed three sensitivity analyses to look at other options:

- Interconnection to the UK through a subsea cable 1200km long with 1000MW capacity.
- Gas power plants potentially located in five specific nodes.
- Additional demand response in selected industrial sites.

The following section analyzes a hypothetical case in which Iceland could opt for and implement by 2020 one of the two options to reinforce the network. This hypothetical study allows understanding the role of the transmission network, and its possible reinforcements, in guaranteeing the security of supply. This section also includes a sensitivity analysis about the installation of diesel stations. In **Section 6**, the study extends to possible investments in the generation portfolio that are currently included in the Master Plan. **Section 7** describes the sensitivity analyses.

5. The role of the transmission network in achieving security of supply

For this analysis, which focuses on a plausible year 2020, we have analyzed the Highlands and the Inter-regional network reinforcement options. The Highlands option proposes reinforcing the network in a T-shape configuration, while the Inter-regional option proposes reinforcing the existing Regional Ring network (Figure 15).[16] Although fully implementing any of above network reinforcements before 2020 is unrealistic, this analysis allows understanding the limitations of the current transmission system.[17] In addition, we have performed a sensitivity analysis in which some diesel stations are located in strategic nodes of the system.

[16] Appendix A provides more details about the implemented reinforcements in different sections of the transmission system.
[17] We have considered both the Highlands and the Inter-regional network reinforcement alternatives fully implemented in the analysis of the next chapters for a 2030 horizon.

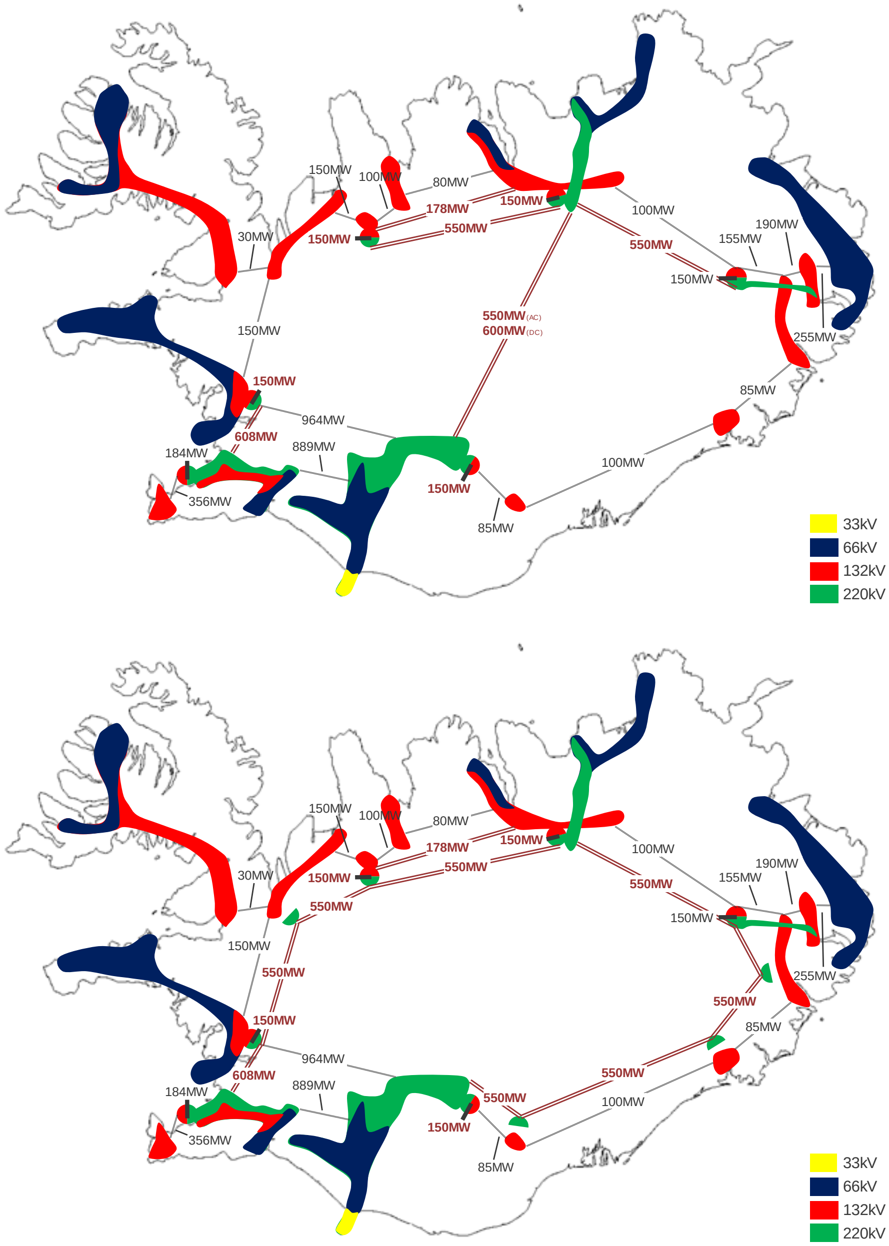

Figure 15: Highlands (top) and Inter-regional (bottom) network reinforcement options

5.1. Energy curtailments analysis

We have observed that the curtailments would significantly decrease with the network reinforcements in place. Both the Highlands and the Inter-regional options increase the transmission capacity between the Western and the Eastern halves of the system, and remove the non-served energy from all scenarios but one: buyback energy would only be required one out fifty-four years. Both alternatives would reduce the expected secondary energy utilization between 20% and 25%. Secondary energy curtailments would be required every other year, as shown in Figure 16.

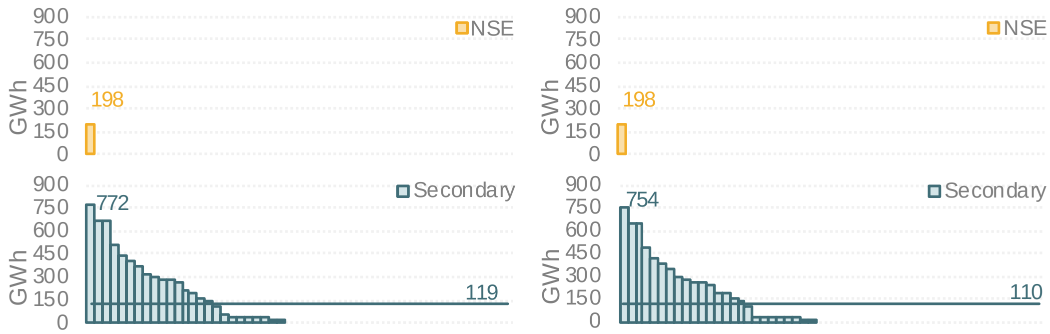

Figure 16: Total curtailments in 2020 after the Highland (left) and the Inter-regional (right) option.

At regional level, we observe that security gains from the network reinforcement favor more the Western region than the Eastern one. The industrial area around Reykjavik, with 10.5TWh of industrial demand—63% of total industrial demand—would reduce the non-served scenarios to just one, and secondary energy curtailments would be reduced by one third (Figure 17).

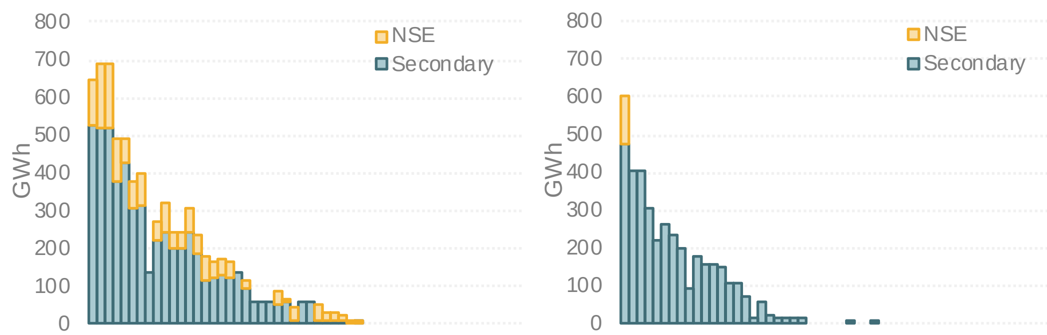

Figure 17: Total curtailments around Reykjavik before (left) and after (right) the reinforcement

In the Reyðarfjörður industrial area, with 5TWh of industrial demand, which represents 31% of the total industrial demand, non-served energy is reduced after reinforcement. Conversely, secondary energy curtailments could increase by up to 5% (Figure 18).

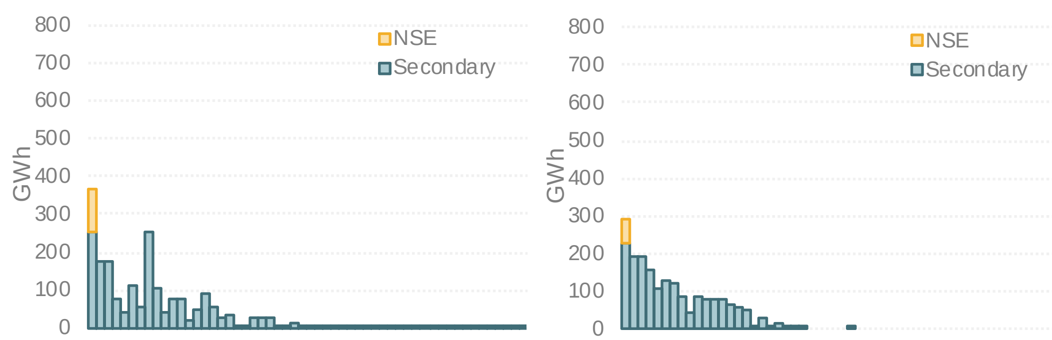

Figure 18: Total curtailments in the Reyðarfjörður industrial area before (left) and after (right) the reinforcement

The Northern industrial areas, with 1TWh of industrial demand—6% of total industrial demand—would experience an improvement in security of supply, as non-served energy would almost disappear, although secondary energy curtailments would remain.

When comparing both network options, a minor congestion under the Highlands option in the Prestbakki-Sigalda 132kV line makes this option slightly worse than the Inter-regional one (Figure 19).

Figure 19: Transmission congestion between Prestbakki and Sigalda under the Highlands alternative

5.1.1. Sensitivity analysis: Diesel backup

Since the diesel price is above $150/MWh and, hence, greater than the cost of buyback energy, the diesel stations can only help mitigate the severe curtailments. From the business-as-usual case (**Section 3.2**), we have identified that Iceland would experience severe curtailments one out of 18 years. The amount and duration of the curtailments, as shown in Figure 20, would always surpass 50MW, and could be above 550MW in the industrial area north of Reykjavik. The new diesel stations should be able to alleviate these curtailments and defer network reinforcements. The installation of diesel groups to address contingencies is out of the scope of this analysis.

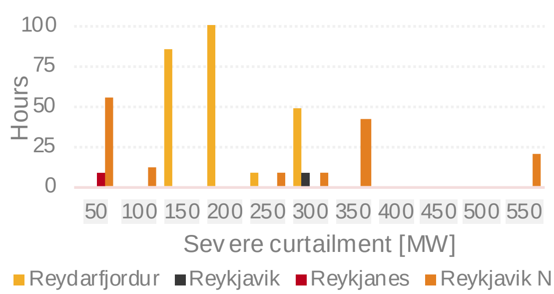

Figure 20: Amount and duration of severe curtailments in different areas

The cost of a 13.5MVA diesel station amounts to about $11 million. The maximum curtailment that would only affect the industrial demand could reach up to 97MW in Reykjanes, 331MW in Reykjavik, 340MW in Reyðarfjörður, and 588MW in the north of Reykjavik. Reducing these severe curtailments to zero would require a maximum of seven stations in Reykjanes, twenty-five stations in Reykjavik and Reyðarfjörður, and forty-four stations in the north of Reykjavik. However, we have assumed that the diesel stations in the Reykjanes, Reykjavik and the neighboring areas north of Reykjavik could solve the severe curtailments of any of the three areas. With this assumption in mind, the numbers reduce to forty-four diesel stations in Reykjavik and twenty-five stations in Reyðarfjörður. Therefore, 69 diesel stations could remove all severe curtailments. The total investment cost would exceed $750 million.

This high cost shows how expensive it is to use diesel stations to solve network congestions, or defer network reinforcements. The objective of a diesel station should be habitually maintaining a minimum power delivery or helping restore the service after a blackout.

Two additional reasons should discourage the installation of diesel groups to mitigate severe curtailments due to network transmission reinforcements:

1. The diesel stations are only required one out of eighteen years during less than 250 hours.[18]
2. The utilization of diesel recommends maintaining and paying a stock to avoid a deterioration of the Icelandic energy independence.

Finally, the requirements of secondary and buyback energy would be the same as in the business-as-usual case (Figure 21) because these two products are cheaper than the diesel price.

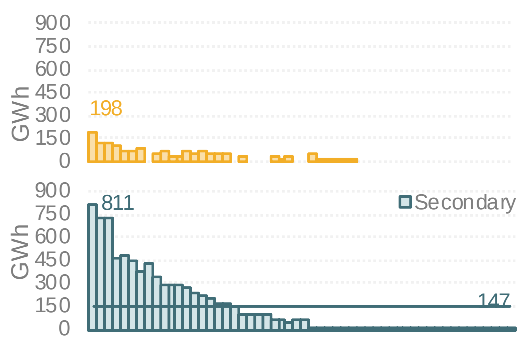

Figure 21: Buyback energy (top) and secondary energy (bottom) in 2020 after the installation of diesel stations

5.2. Network congestion analysis

The Highlands and Inter-regional network reinforcements would relieve major transmission congestion within the system. As shown in Figure 22, the flow in cut IIIb[19] hits its capacity limit during almost the whole year in the business-as-usual case. The flows in cut IV and cut V barely reach their limits. In all cases, these cuts would not limit the flows after the network reinforcements thanks to the strengthening of the East-West connection. Removing the cuts has a positive effect on the curtailments reduction.

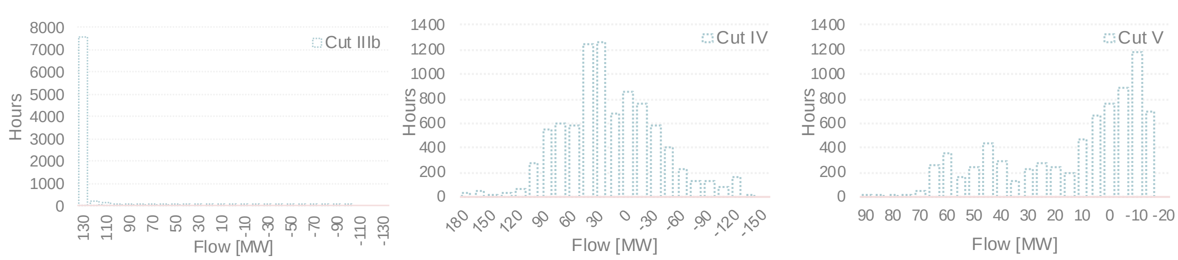

Figure 22: Flows across corridors in the business-as-usual case

[18] We recall that the installation of diesel stations to cope with contingencies is out of the scope of this analysis.

[19] Cut IIIb limits the flow, 130MW, from Northeastern to Southwestern Iceland—outflow from Blanda to Laxárvatn and Fljótsdalur to Hryggstekkur. Cut IV limits the flow, 180MW, from Western to Eastern Iceland—outflow from Blanda to Varmahlið and Sigalda to Prestbakki. Cut V limits the flow into the Eastfjords.

We have also observed that either the Highlands or the Inter-regional reinforcements would release the congestions, which occur in the business-as-usual case, in three transmission lines and two transformers. The figures below show the number of hours where the flow is above 90% of the capacity limit of each line or transformer in the business-as-usual case. The 100% mark shows those hours when the power flow reaches the maximum capacity. We have noticed that the 132kV/66kV transformer at Rangárvellir is at maximum capacity most of the time in all scenarios (Figure 23).

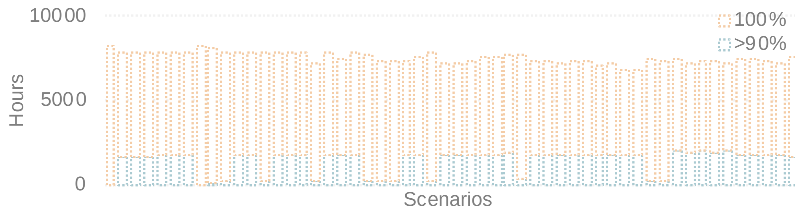

Figure 23: Flow above 90% of capacity for the Rangárvellir132kV/66kV transformer in the business-as-usual case

The 220kV/132kV transformer at Fljótsdalur and the 132kV lines Prestbakki-Sigalda, Teigarhorn-Hólar and Varmahlið-Rangárvellir seem less frequently congested with flows over 90% of capacity below 1000 hours in most scenarios (Figure 24).

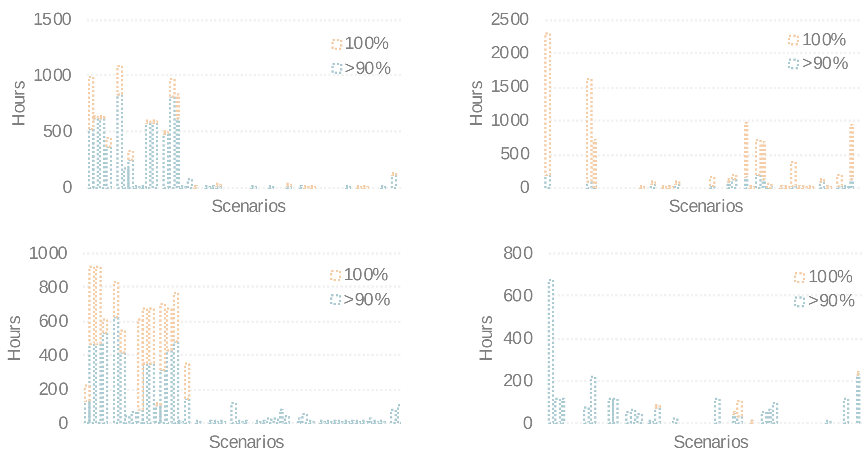

Figure 24: Flow above 90% of capacity for the Fljótsdalur 220kV/132kV transformer (top left), the line Prestbakki-Sigalda 132kV (top right), the line Teigarhorn-Hólar132kV (bottom left) and the line Varmahlið-Rangárvellir132kV (bottom right) in the business-as-usual case

In all these cases, the transmission congestions would disappear with either the Highlands or the Inter-regional network reinforcements. However, based on our analysis, a congestion would still be present in the Westfjords area. Although curtailments do not occur, flows into and out of the Westfjords area are effectively constrained during several hours along the year with power mainly flowing into the Westfjords (Figure 25). However, the Highlands or the Inter-regional options cannot help alleviate the problem since no reinforcement is planned for the Westfjords area. In fact, the transmission congestion in this area could worsen (Figure 26 and Figure 27). The capacity connecting the Westfjords area to the rest of the system is clearly insufficient.

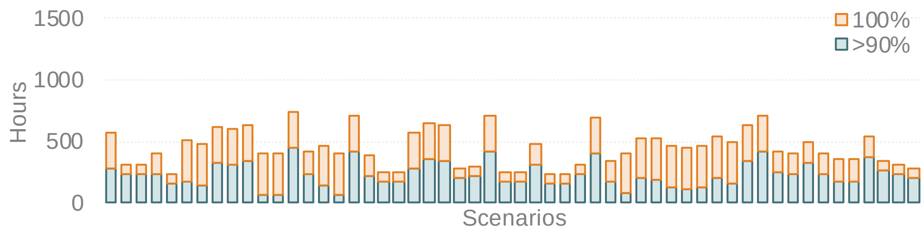

Figure 25: Transmission congestion in the Westfjords area for the business-as-usual case

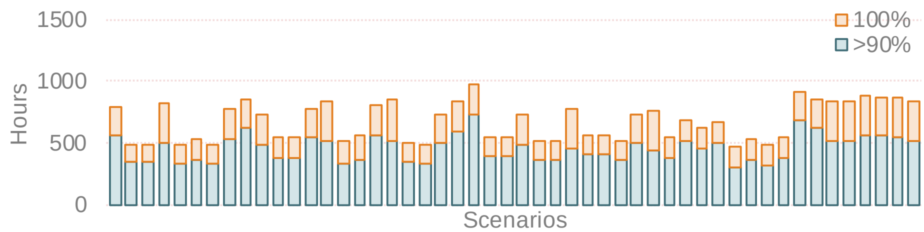

Figure 26: Transmission congestion in the Westfjords area for the Highlands alternative

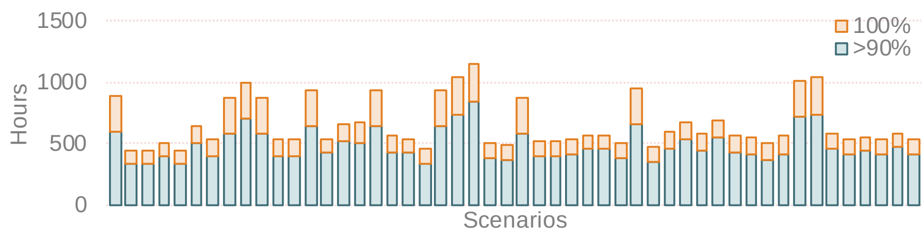

Figure 27: Transmission congestion in the Westfjords area for Inter-regional alternative

5.3. Capacity margin and water spillages analyses

By 2020, under the business-as-usual case, the capacity margin of the current generation portfolio would be 10.3%, with 2,557MW peak demand and 2,821MW generation capacity. The network reinforcements allow a better utilization of the hydro resources, which reduces the spilled energy (water) from 1.22TWh to 1.18TWh (Figure 28). In the next section, we have analyzed how an increasing demand affects the electricity security of supply in the system. We have looked at the alternatives that the country may pursue in order to achieve reasonable levels of security.

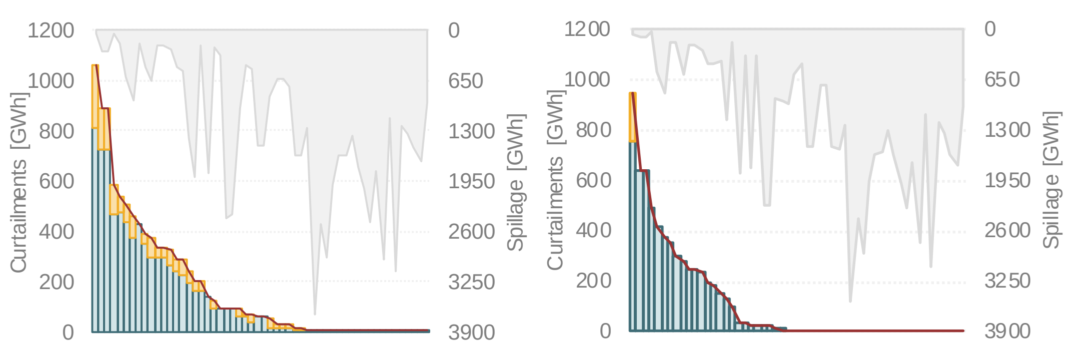

Figure 28: Spilled water before (left) and after (right) the network reinforcement in 2020

6. Generation capacity alternatives to achieve security of supply

In this section, we focus on year 2030, by which time, even after reinforcing the network, the existing generation capacity will be insufficient for the assumed demand. If no additional generation were installed before 2030, the capacity margin would be -7.4%, with 3,046MW peak demand and 2,821MW generation capacity. The underlying energy resources would not be able to cope with the additional 3.8TWh demand between 2020 and 2030. This would lead to relevant curtailments. However, as shown in Figure 29, curtailments and spilled energy may happen simultaneously. Although counterintuitive, the Icelandic system isolation, the hydro inflows uncertainty, the reservoir size, and the consumers' inflexibility would lead to spill water despite its scarcity. Connecting Iceland to the UK, increasing the reservoir capacity or making the demand more flexible would help reduce the 1.07TWh of spilled energy incurred.

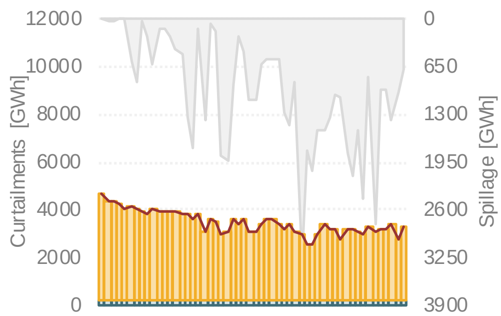

Figure 29: Non-served energy and spilled energy with network reinforcement for year 2030

In any case, Iceland would undoubtedly need generation investments to face the assumed 2030 demand. In this section, we consider the addition of domestic and clean generation such as hydropower plants, geothermal groups, or wind generation. The mathematical model optimizes the generation investments and provides the minimum-cost solution. We have run four cases that result from the combination of the two alternatives for reinforcing the network (Highlands and Inter-regional) with the possibility of installing wind generation (or not). In the next subsections, we describe the resulting new investments computed, which we have found are independent of the implemented network reinforcement. In the last subsection, we discuss the achieved levels of security of supply for these possible future system conditions and assess the cost of the alternatives by comparing its annualized costs.[20]

6.1. Hydro and geothermal investments without wind

In this case, the newly installed geothermal capacity would amount to 90MW in Þeistareykir with an expected generation of 725GWh, while the newly installed hydro capacity would amount to 321MW with an expected generation of 2.6TWh (Figure 30).

[20] We assume generation: WACC 7.9%; hydro lifetime 50 years, hydro O&M cost 1.5%; geothermal lifetime 35 years, geothermal O&M cost 3%; wind lifetime 25 years, wind O&M cost 4%; and transmission: WACC 7.5%; lifetime 40 years, O&M cost 1.5%.

This combination would result in a weighted average levelized cost of electricity of $28.39/MWh.[21] The investment generation cost would amount to $1.09 billion in hydro and geothermal technologies. The annualized cost, including the network investment cost, would amount to $126 and $146 million for the Highlands case for its AC and DC alternatives, respectively, and $143 million for the Inter-regional case.

Figure 30: Generation investments in hydro and geothermal technologies in the year 2030

6.2. Hydro and geothermal investments with wind

We also analyzed wind generation in combination with hydro and geothermal generation investments. We observed that it could achieve similar levels of security of supply at comparable costs. The newly installed wind capacity would amount to 450MW with an expected generation of 1.5TWh. The newly installed hydro capacity would scale down to 233MW with an expected generation of about 1.9TWh (Figure 31), and the geothermal technology would be fully avoided.

This combination would result in a weighted average levelized cost of electricity of $28.82/MWh.[22] The upfront cost of this combined hydro-wind option would amount to 1.14 billion dollars. The annualized cost, including the annualized network investment costs, would amount to $153 million for the Inter-regional case, and $136 and $156 million for the Highlands case in its AC and DC alternatives, respectively.

[21] Hydro: Urridafoss $21.33/MWh | Holtavirkjun $27.57/MWh | Hvammsvirkjun $29.02/MWh | Blönduveituvirkjun $39.03/MWh. Geothermal: Þeistareykir $32.76/MWh.

[22] Hydro: Urridafoss $21.33/MWh | Hvammsvirkjun $29.02/MWh. Wind: $34.68/MWh.

Figure 31: Generation investments in hydro and wind technologies in year 2030

6.3. Comparison of curtailment levels among alternatives

We have observed that curtailments remain at reasonable levels within all the possible future evolutions of the system just defined. The *Inter-regional network reinforcement with wind* option (left of Figure 32) leads to the use of buyback energy in one out of 54 years under the worst-case scenario. The required amount of buyback is equal to 1.20% of the total industrial demand. Secondary energy is required every year, and its average utilization reaches 0.93% of the total industrial demand. Required secondary energy, under the worst-case scenario, amounts to 4.64% of the total industrial demand, which is below its agreed maximum value in any year (i.e., scenario), which corresponds to 5% of industrial demand.

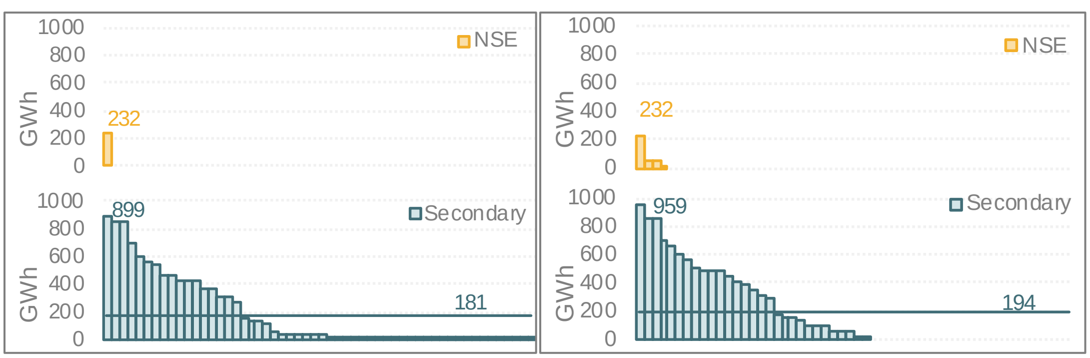

Figure 32: Curtailment levels by year 2030 under the Inter-regional reinforcement with wind (left) and without wind (right)

The *Inter-regional network reinforcement without wind* option (right of Figure 32) leads to a utilization of buyback energy that keeps under the worst-case scenario at 1.20% of the total industrial demand, but augments its frequency of use in comparison to the *with wind* option to one out of 14 years. Despite secondary energy only being required every other year instead of every year, its average requirement grows from 0.93% to 0.99% of the total industrial demand. Its requirement also increases under the worst-case scenario from 4.64% to 4.95% of the total industrial demand.

The Inter-regional reinforcement, including wind, leads to a lower utilization of buyback energy and a lower requirement of secondary energy in average and under the worst-case scenario than when the generation portfolio excludes the wind technology. Moreover, the wind option is cheaper, as evidenced by the annualized cost ($147 million vs. $161 million). On the other hand, the wind option would entail the requirement of secondary energy every year.

The *Highlands network reinforcement with wind* option (left of Figure 33) requires the use of buyback energy under the worst-case scenario at a level of 1.20% of the total industrial demand. The use of buyback energy happens one out of 18 years. Secondary energy is required every year. Its average utilization reaches up to the set upper limit, and in the worst-case scenario, its utilization increases from 4.68% to 4.82% of the total industrial demand.

The *Highlands network reinforcement without wind* option (right of Figure 33) provide similar results to the Inter-regional case. The buyback energy utilization under the worst-case scenario stays at 1.20% of the total industrial demand. This frequency of use in comparison to the wind option increases, however, to one out of 14 years. Secondary energy is only required every other year, instead of every year, and its average requirement slightly decreases from 1% to 0.99%. In contrast, under the worst-case, the secondary energy requirement grows from 4.82% to 4.95%.

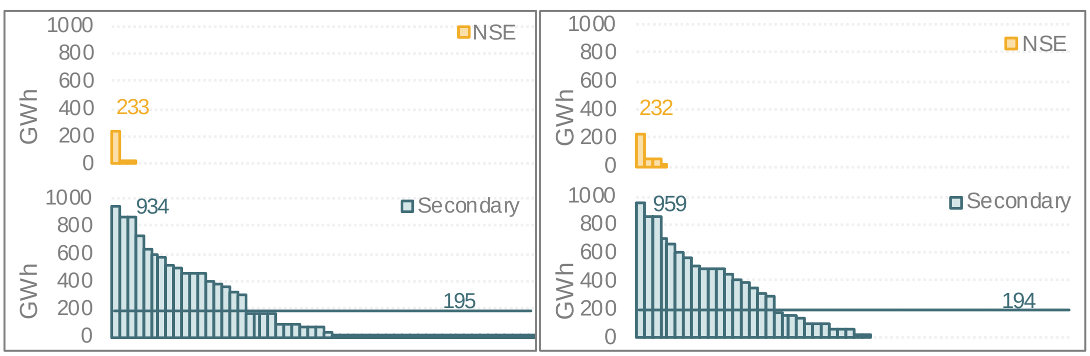

Figure 33: Curtailment levels by year 2030 under the Highlands reinforcement with wind (left) and without wind (right)

Under the Highlands reinforcement option, the benefits of including wind in the generation portfolio are more difficult to justify than under the Inter-regional option. Actually, including and excluding wind in the generation portfolio would result in very similar requirements of buyback energy and secondary energy, under both the average and worst-case scenarios. The factor that may tip the scale in favor of wind is the annualized cost. When the generation portfolio includes wind, the annualized cost is $13 million lower for both the AC and the DC network alternatives than when the generation portfolio excludes wind.

If we look at the regional level, we observe that the level of curtailments in each region approaches its demand share, but differences still occur. In 2020, in both the Inter-regional and the Highlands options, each area faces curtailments that are approximately proportional to its own demand, i.e., 63% in the West region, 31% in the East region and 6% in the North region (Figure 34).

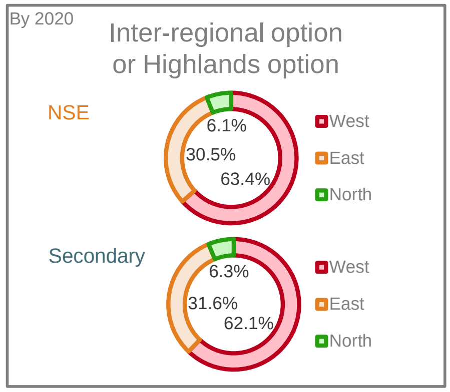

Figure 34: Curtailments per region under Inter-regional or Highlands option by year 2020

The *Inter-regional network reinforcement with wind* is the option with the lowest level of curtailment by 2030, and is the one in which the buyback energy distributes proportionally to the demand of each area. The secondary energy is, however, required asymmetrically: the West and North are favored at the expense of the East, which provides more secondary energy (top of Figure 35).

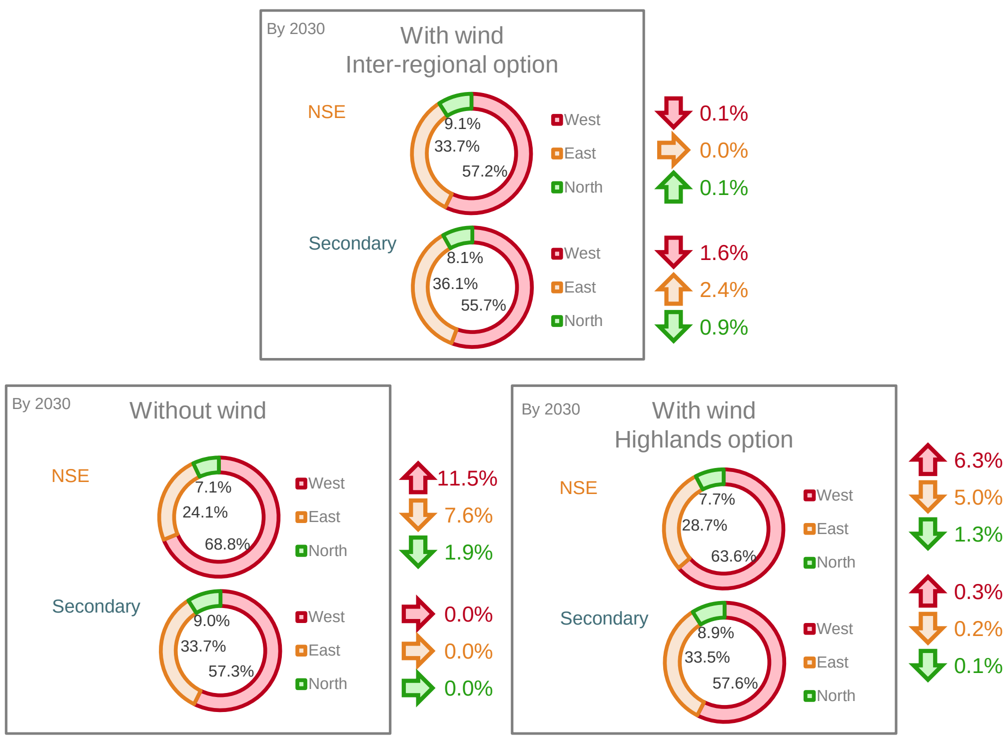

Figure 35: Curtailments per region under Inter-regional reinforcement with wind (top), under any reinforcement without wind (bottom left) and under the Highlands reinforcement with wind (bottom right) by year 2030f[23]

The second-best options with respect to the level of curtailments by 2030 correspond to the options 1) in which the generation portfolio excludes wind generation and the transmission system adopts any type of

[23] The arrows denote the difference between regional curtailment and demand: positive means contributions above demand, negative means contributions below demand.

network reinforcement, and 2) the *Highlands network reinforcement with wind*. In both cases, the West provides more buyback energy than the other regions, although the West unbalance is more noticeable in the first case (bottom left of Figure 35) than in the second case (bottom right of Figure 35). Moreover, when the generation portfolio excludes wind, the secondary energy curtailments distribute proportionally to the demand of each area (bottom left of Figure 35).

In summary, the comparison of the four options, which result from combining the two options related to the wind dichotomy and the Highlands and Inter-regional options to network development, lead to the conclusion that the level of curtailments and, hence, of security of supply is similar for all possible combinations, although the Inter-regional alternative with wind slightly outperforms the rest. Economically speaking, when the generation portfolio includes wind, the annualized cost decreases, while the level of curtailments reduces (Inter-regional) or maintains (Highlands). The Inter-regional alternative with wind is most likely the most secure option as it improves the connection between the Eastern and Western halves of Iceland, and wind reveals itself as a reliable and economical source of clean and domestic energy. Although not specifically addressed in this study, the wind option entails however more uncertainty on the level of security of supply as it substitutes in part a more predictable and controllable generation source as the geothermal one.

7. Sensitivity analysis on other resources to achieve security of supply

This section presents three sensitivity analysis-on-the-run cases to assess security of supply by 2030. The sensitivity analyses aim at understanding the value of increasing demand response; that of gas-fired power plants; and the value of the subsea interconnector with the UK in providing security of supply to the system. In the former two cases (i.e., demand response and gas-fired power plants), we substituted the most expensive installed power plant with the alternative whose impact we are analyzing. In the interconnector case, we allow the model to invest in additional generation capacity to minimize the overall incremental generation investment plus variable operation cost.

7.1. Additional demand response

For this purpose, we substitute Blönduveituvirkjun with additional demand response. Blönduveituvirkjun is a hydropower plant with 31MW capacity, expected to generate 187GWh. Its investment cost amounts to $89 million, and its levelized cost of electricity is equal to $37.63/MWh. Blönduveituvirkjun is chosen as the most expensive power plant. Our analysis indicates the following:

1. The secondary energy is still fully required on average, and the only variations among scenarios occur as shown in the left-hand side of Figure 36.
2. The use of buyback energy is partially required in two out of each five years, and highly required in one out of each five years (right of Figure 36).The maximum required buyback energy must increase from 1.2% to 2.4% to minimize the incurred costs.

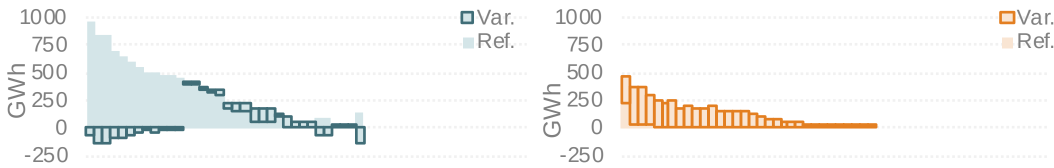

Figure 36: Secondary energy (left) and buyback energy (right) requirement variation with additional demand response with respect to Inter-regional case without wind by 2030[24]

We conclude that implementing additional demand response is slightly cheaper than Blönduveituvirkjun power plant. Blönduveituvirkjun upfront cost would amount to $89 million, while the net present value of the additional incurred costs due to the additional buyback energy during Blönduveituvirkjun's lifetime, 50 years, would amount to $86 million. In annual terms, the incurred cost due to additional demand response is about $6.9 million, while the Blönduveituvirkjun annualized cost is equal to $7.3 million.

7.2. Gas power plant and floating storage regasification unit

For this purpose, we substitute the Blönduveituvirkjun 31MW hydroelectric plant with an equivalent gas-fired power plant. We assume that its associated floating and storage regasification unit would be located in the Reykjavik area where most of the consumption and curtailments take place (Figure 37).

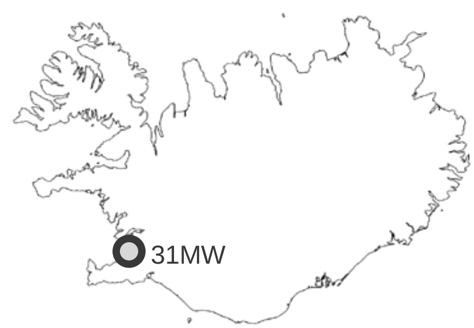

Figure 37: Possible location for a gas floating storage and regasification unit.

The cost of this regasification unit plus the gas-fired power plant investment cost would amount to $60 million.[25] The operation cost would amount to $125/MWh, while the CO_2 emission cost would be around 30$/ton. Based on this information, our analysis indicates the following:

1. The system requires full secondary energy in average, and the only variations among scenarios occur with respect to the base case (left of Figure 38).
2. As the gas price, $125/MWh is higher than the buyback cost, $90/MWh, the buyback energy is fully required one out of each two years, and some is required in five out of each seven years (right of Figure 38).

[24] Var. shows the variation after Blönduveituvirkjun is removed from the system; Ref. shows the case 2030 without wind after any reinforcement option.
[25] Data provided by Landsvirkjun for a 100MW project.

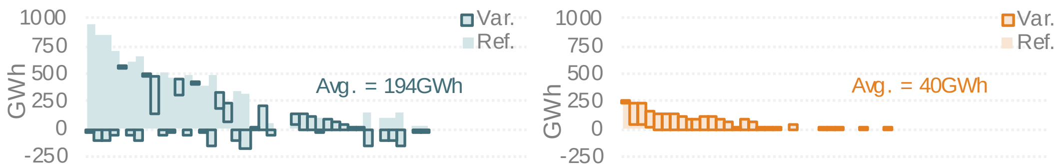

Figure 38: Secondary energy (left) and buyback energy (right) requirement variation when installing a gas plant with respect to the Highlands case without wind by 2030[26]

Given the abovementioned assumptions, we conclude that having the Blönduveituvirkjun power plant in place is still a cheaper option, with lower curtailments and no emissions, than building a gas power plant. The expected cost of demanding additional buyback energy, \$8.9 million, plus the variable production cost of the gas-fired power plant, \$0.35 million, when this plant replaces Blönduveituvirkjun, amounts to \$9.2 million per year, which adds up to the \$60 million extra investment cost. The present cost of all these would amount to \$165 million, which is greater than Blönduveituvirkjun's investment cost of \$89 million. In annual terms, the annualized cost[27] of the gas-fired power plant plus the additional required buyback energy is equal to \$14.8 million, while the Blönduveituvirkjun annualized cost is equal to \$7.3 million. As noted from the results, unless the gas price drops below the buyback energy cost, the gas-fired power plant will not be cost-competitive. Even if the Icelandic gas price decreases, the Blönduveituvirkjun power plant would still be a competitive option until the gas prices (plus the CO_2 price) reduces to around \$25/MWh, which is a price very close to secondary energy cost. This is equivalent to a gas price of about \$3.65/MMBtu with no price on carbon. Each dollar per ton of CO_2 increase in CO_2 price would require an additional decrease of \$0.1/MMBtu in the gas price.

7.3. Interconnection to the United Kingdom

This subsection focuses on the construction of an interconnection with the UK (IceLink) with a capacity if 1000MW in both directions. This is another alternative to enhance security of supply, and although IceLink is expected to enhance the security of supply, it requires further consideration due to the implications to the country of future development.

IceLink would allow for both exporting the excess of electricity production, e.g., by reducing water spillages, and importing electricity when a deficit of available local production has compromised the security of supply. However, the large investment costs related to the whole project might only be economically justified if enough exports from Iceland to the UK took place, and if Iceland and the UK signed some type of bilateral contract to price those exports at a reference price that allowed satisfying the investment costs. Increasing the amount of exports to the economically optimal level would require an expansion of the generation capacity in Iceland. Moreover, it would also require an additional reinforcement of the Icelandic network on top of the already planned Highlands or Inter-regional reinforcements. We have analyzed the IceLink case considering both the Inter-regional reinforcement and the Highlands reinforcement.

[26] Ibid footnote 24.

[27] We assume WACC 7.9%, lifetime 30 years, and O&M cost 4%.

7.3.1. IceLink case for the Inter-regional transmission expansion option

Results show that, in general, IceLink provides additional security to Iceland and a good level of exports. IceLink would export above 800MW of power about 64% of the time and above 900MW about 47% of the time. Net exports are expected to vary between 6.9TWh and 4.2TWh, depending on the hydrological year considered, with an expected average net export totaling 5.9TWh. In order to achieve this level of exports, Iceland would need to expand the generation capacity and reinforcing the network. The optimization model has allowed us to obtain the most economical generation investments leading to these exports. In contrast, we have obtained the network reinforcement by performing a sensitivity analysis in which the different reinforcement options potentially increasing exports into the UK were manually included into the model. Without additional reinforcements on top of the already planned ones, the Icelandic network would limit the amount of flow within the system, and, in particular, from West to East, reducing the level of exports as described below.

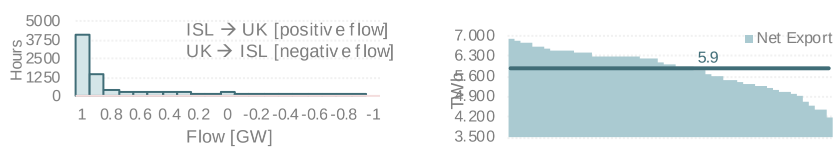

Figure 39: Expected distribution of the hourly level of flow (left) and cumulative net expected exports per scenario, or year, (right) of the IceLink for the Inter-regional transmission expansion option

Although the introduction of IceLink might incentivize parties to rethink how much secondary energy is required, we assume that the secondary energy cost would remain at $25/MWh. In addition, we assume that the UK price is always below the buyback energy cost to avoid simultaneous exports and buyback curtailments. Based on the results from the model, which provides the economically optimal operation of the system, we have observed that the average requirement of secondary energy is similar to that without the interconnector. However, the use of secondary energy approximately spreads uniformly over the years. When we compare each region demand with its secondary energy requirement, we observe that each region contributes with an amount of secondary energy that is proportional to its demand (Figure 40). Finally, the Icelandic system does not require buyback energy, as it would first resort to UK imports.

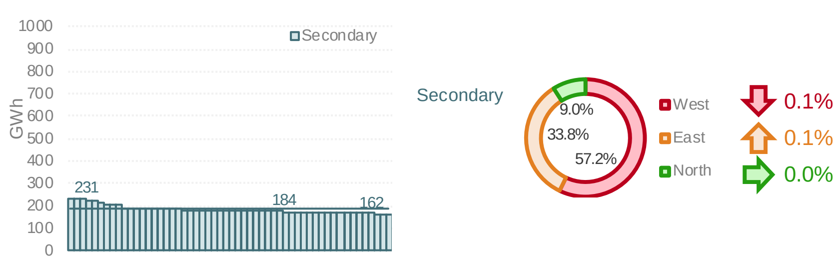

Figure 40: Expected secondary energy (left) and its distribution per region (right)[28]

[28] Ibid footnote 24.

We note that our analysis shows that IceLink would require additional generation investments in hydro and geothermal resources within Iceland. New geothermal generation needed would amount to 630MW, while new hydropower generation would total 238MW (Figure 41). These new generation investments would provide almost 6.5TWh of extra electricity production.

If the network is appropriately reinforced, an improved exploitation of the hydro resources would provide part of the exported energy. Specifically, the pre-existing hydropower plants plus the Fljótsdalsstöð repowering would reduce water spillage by 658GWh:

- In the Sog, Laxá and Blanda regions, the water spillage would be reduced down to 25GWh. The previous spillage amounted to 59GWh.
- In the Þjórsá region, the water spillage decreases by 77GWh, although still amounts to 43GWh.
- Kárahnjúkar power plants could use additional 547GWh of spilled water. The water spillage would still reach up to 421TWh.

The overall upfront cost of all these generation investments would amount to about $2.6 billion, with the levelized cost of electricity of each new plant ranging between $21/MWh and $39/MWh.[29] Conspiring all the expansion plants together, the weighted average levelized cost of electricity produced by new plants would amount to $32.11/MWh.

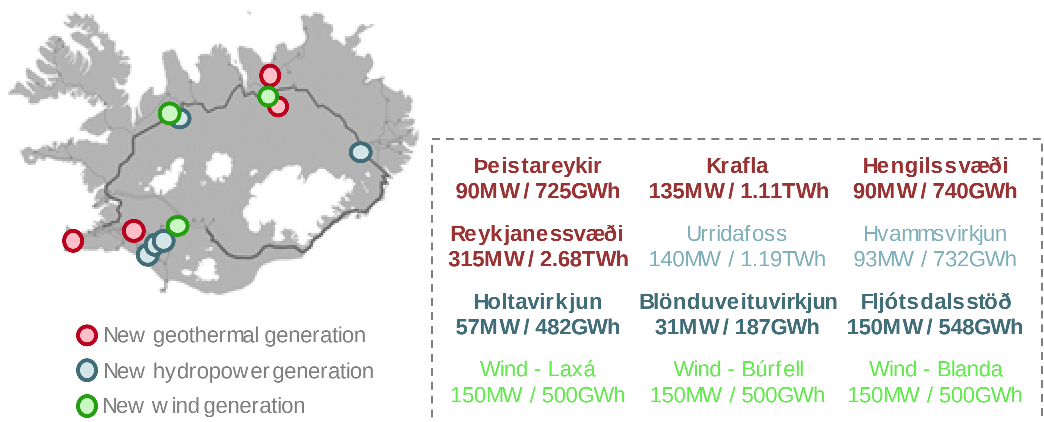

Figure 41: New generation investment (in bold) required in the IceLink case for the Inter-regional network reinforcement

Regarding the transmission system, the installation of IceLink requires some additional reinforcements within the Icelandic network beyond the ones included in the Inter-regional expansion plan of the local network to get exports to reach a satisfactory level that could maximize net revenues for the Icelandic system. This satisfactory level ranges between 5.0TWh and 5.6TWh of annual exports, on average, over the 50 hydrological years considered. As shown in Figure 42, without these additional local network reinforcements, the expected average annual exports would be below 3.5TWh, while when these

[29] Geothermal: Reykjanessvæði $31.25/MWh| Krafla $32.19/MWh| Þeistareykir $32.76/MWh| Hengilssvæði $34.30/MWh. Wind: $34.68/MWh. Hydro: Fljótsdalsstöð $22.53/MWh | Holtavirkjun $27.57/MWh | Blönduveituvirkjun $39.03/MWh.

additional local reinforcements are undertaken, annual exports would increase by 3.4TWh. The overall cost of those additional local network expansions would be about $85.3 million.

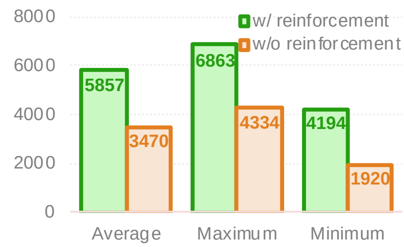

Figure 42: Expected net exports through the IceLink with and without additional local reinforcements of the Icelandic network beyond those included in the Inter-regional network expansion plan

Figure 43 shows the required set of additional local network reinforcements that would alleviate congestion and increase the level of exports beyond those in the Inter-regional expansion plan. We have identified these reinforcements through a sensitivity analysis that considered several possible network configurations.[30] Specifically, on top of the Inter-regional expansion plan, the system would benefit from additional transforming capacity in the substations in Laxá, Hamranes, and Blanda, and from the opening of the 220kV/132kV transformer in Sigalda. We have also noticed that the new Laxá-Fljótsdalur line included in the Inter-regional plan would need further reinforcement.

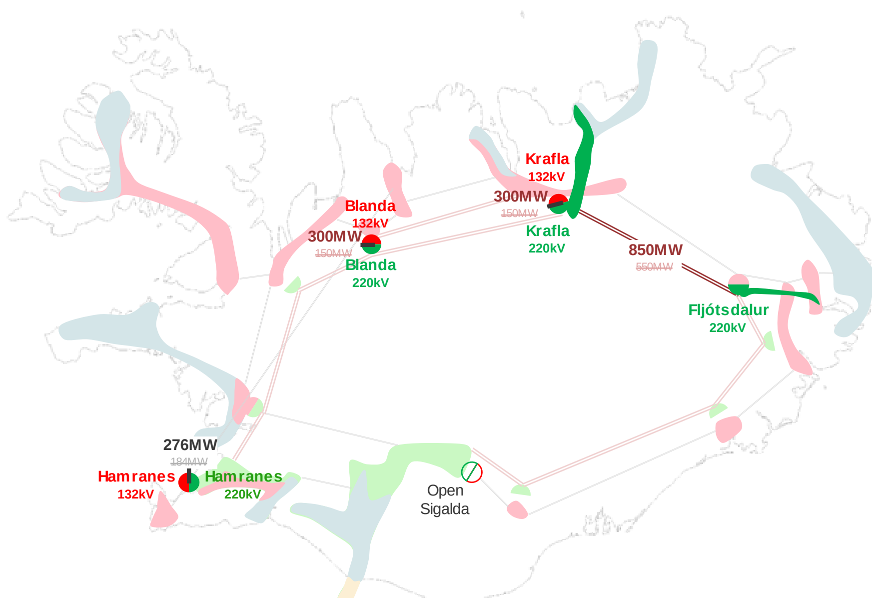

Figure 43: Additional network reinforcements needed on top of the Inter-regional expansion plan with the IceLink in place

According to Figure 44, there would be a predominant export flow from Iceland into the UK in the IceLink. Despite the variability of the hydro conditions in Iceland and the UK, most of the uncertainty of the exports happens when these are below 800MW. The uncertainty duration is below 3500 hours, which leads us to

[30] Some of these reinforcements may not be in line with Landsnet policy for the expansion of the grid.

foresee a stable cable utilization. On a weekly basis, Icelandic imports under the worst hydrological conditions would occur at the beginning of summer.

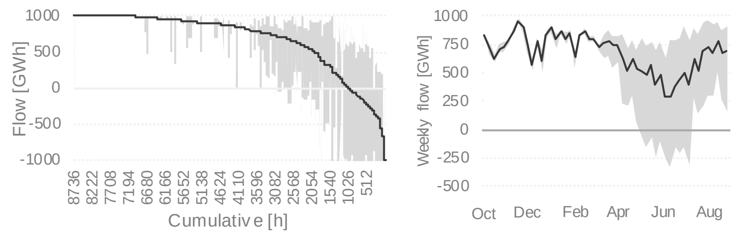

Figure 44: Energy flow through IceLink on an hourly (left) and weekly (right) basis (average level and range variation)

Finally, we observe that, after putting in place all these reinforcements, some congestion in the network may prevent additional exports from taking place. The 132kV line connecting Varmahlið and Rangárvellir is heavily congested across all the scenarios (Figure 45). In several hours during the years considered, the energy flow in this line would be at 100% of the capacity limit of the line (orange shaded area in the graph).

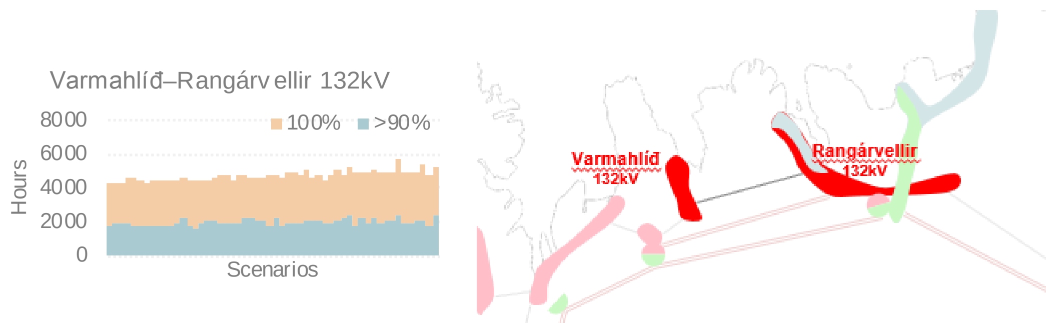

Figure 45: Number of hours in each year when the energy flow of the line connecting Varmahlið and Rangárvellir is at 100% (orange) and above 90% (blue) of its capacity limit

7.3.2. IceLink case for the Highlands transmission expansion option

In this case, we have also observed that IceLink would provide additional security to Iceland and a good level of exports. Under this alternative, IceLink would allow exports above 700MW for about 70% of the time, and between 700MW and 900MW for about 60% of the time. Net exports, depending on the considered hydrological year, would vary between 6.4TWh and 3.9TWh, with an average net export of about 5.5TWh. As in the previous case, to achieve this level of exports, Iceland requires expanding the generation capacity and reinforcing the network. The use of the optimization model has allowed us to obtain the most economical generation investments leading to an appropriate level of exports and minimum generation investment plus variable production costs. In contrast, we have determined the required network reinforcements by performing a sensitivity analysis in which the different reinforcement options were manually included into the model. Without additional reinforcements on top of the already planned ones, the Icelandic transmission network would limit the amount of power flows within the system, and, in particular, from West to East reducing the level of exports (Figure 46).

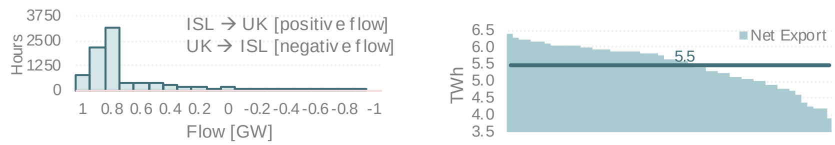

Figure 46: Expected distribution of the hourly level of flow (left) and cumulative net expected exports per scenario, or year, (right) of the IceLink for the Highlands transmission expansion option.

As in the Inter-regional case, although the introduction of IceLink might incentivize parties to rethink how much secondary energy is required, we assume that the secondary energy cost would remain at $25/MWh. In addition, we assume that the UK price is always below the buyback energy cost to avoid simultaneous exports and buyback curtailments. Based on the results from the model, which provides the economically optimal operation of the system, we have observed that the average requirement of secondary energy is similar to that without the interconnector. However, the use of secondary energy approximately spreads uniformly over the years. When we compare each region's demand against its secondary energy requirement, we observe that each region contributes an amount of secondary energy that is proportional to its demand, as Figure 47 shows. Finally, the Icelandic system does not require buyback energy, as it would first resort to UK imports.

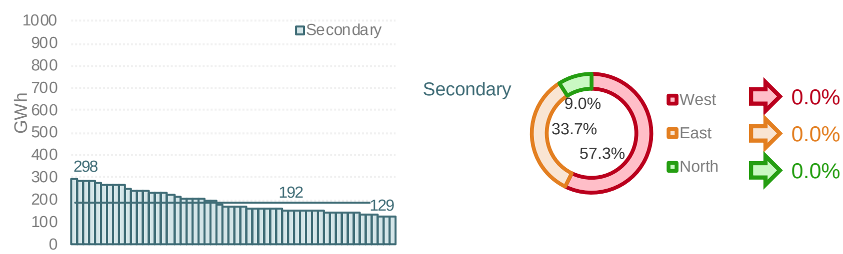

Figure 47: Expected secondary energy (left) and its distribution per region (right)[31]

Results for this alternative also suggest that building IceLink would require developing new generation investments to make the most of the use of this link. New geothermal and hydropower is required, totaling 585MW and 238MW, respectively (Figure 48). This new generation investment would provide almost 6.1TWh of additional energy production.

If the network is appropriately reinforced, an improved exploitation of the hydro resources would provide part of the exported energy. Specifically, the already existing hydropower plants plus the Fljótsdalsstöð repowering would allow reducing water spillage by 653GWh:

- In the Sog, Laxá and Blanda regions, the water spillage would be reduced down to 35GWh, while the previous spillage amounted to 59GWh.
- In the Þjórsá region, the water spillage decreases by 83GWh, although it still amounts to 37GWh.

[31] Ibid footnote 24.

- Kárahnjúkar power plants could use additional 546GWh of spilled water. The water spillage would still reach up to 422TWh.

The upfront cost of all these investments amounts to $2.3 billion. While the levelized cost of electricity for the new plants to build ranges between $21/MWh and $39/MWh, the weighted average levelized cost of electricity considering all of these plants is about $31.73/MWh.[32]

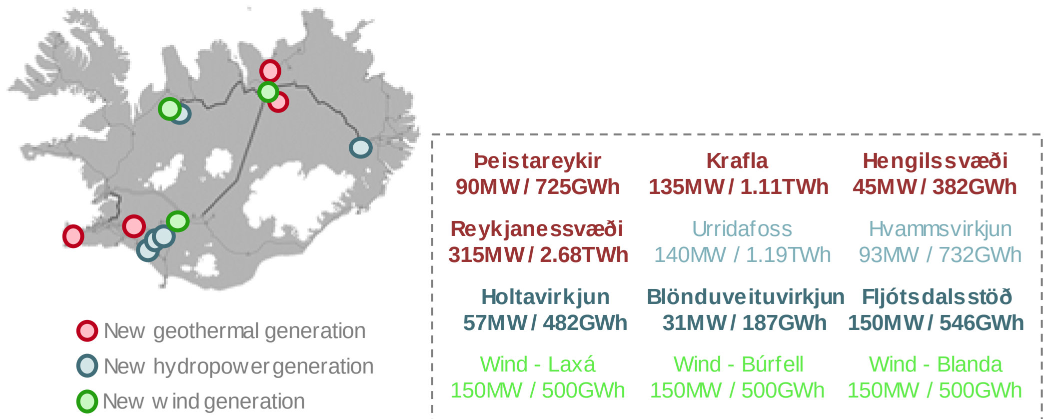

Figure 48: New generation investments (in bold) required in the IceLink case for the Highlands transmission expansion option

Regarding the transmission system, similar to what occurs for the Inter-regional network expansion option, the installation of IceLink requires some additional reinforcements within the Icelandic network, beyond the ones included in the Highlands expansion plan of the local network, to get exports to reach a satisfactory level that maximizes net revenues for the Icelandic system. This satisfactory level ranges between 5.0TWh and 5.6TWh of annual exports, on average, over the fifty hydrological years considered. As shown in Figure 49, without these reinforcements in place the expected average annual export would be below 3.2TWh, while after undertaking these additional reinforcements, the exports would increase by 2.3TWh, reaching 5.5TWh. The overall cost of those additional local network reinforcements is estimated to be about $97.3 million.

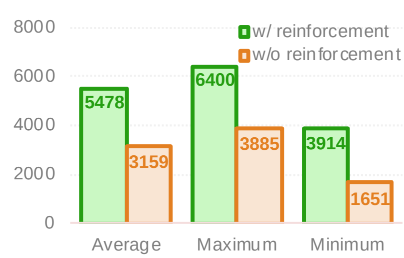

Figure 49: Expected net exports through the IceLink with and without the additional local network reinforcements besides those included in the Highlands network expansion option.

Figure 50 shows the required set of additional local network reinforcements that would alleviate congestion and increase the level of exports beyond those in the Inter-regional expansion plan. We have

[32] Geothermal: Reykjanessvæði $31.25/MWh| Krafla $32.19/MWh| Þeistareykir $32.76/MWh| Hengilssvæði $34.30/MWh. Wind: $34.68/MWh. Hydro: Holtavirkjun $27.57/MWh | Fljótsdalsstöð $22.53/MWh | Blönduveituvirkjun $39.03/MWh.

identified these reinforcements through a sensitivity analysis that considered several possible network configurations.[33] Specifically, on top of the Highlands expansion plan, the system would benefit from additional transforming in the Hamranes substation, while opening the 220kV/132kV Sigalda transformer. Besides, the newly built Laxá-Fljótsdalur line would need reinforcement, as well as the already existing 132kV Krafla-Fljótsdalur line.

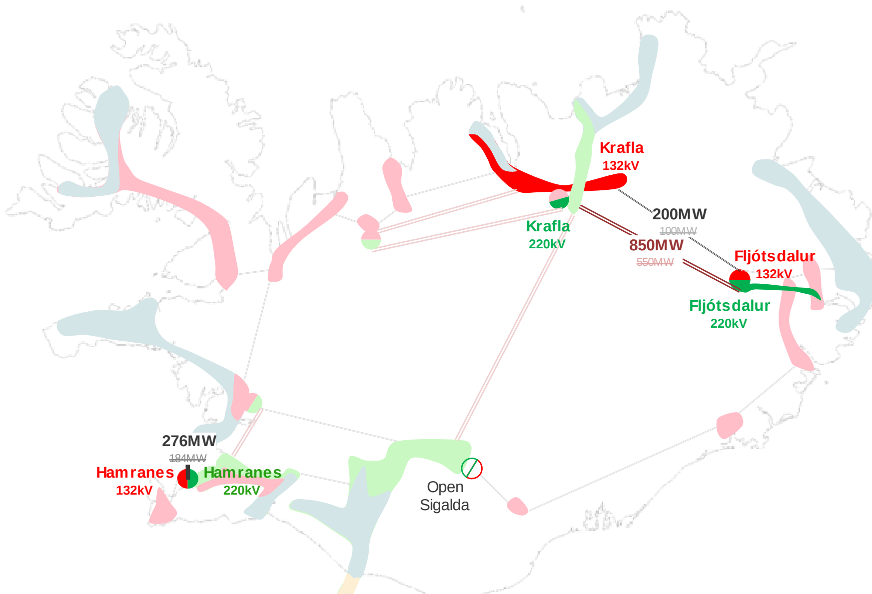

Figure 50: Additional network reinforcements needed on top of the Highlands expansion plan with the IceLink in place

According to Figure 51, a predominant export flow would take place from Iceland into the UK also for the Highlands network expansion option. Despite the variability of the hydro conditions in Iceland and the UK, most of the uncertainty of the exports happens when these are below 700MW. The uncertainty duration is below 3000 hours, which leads us to foresee a stable cable utilization. On a weekly basis, Icelandic imports of energy from the UK in the worst hydrological conditions would occur at the beginning of summer.

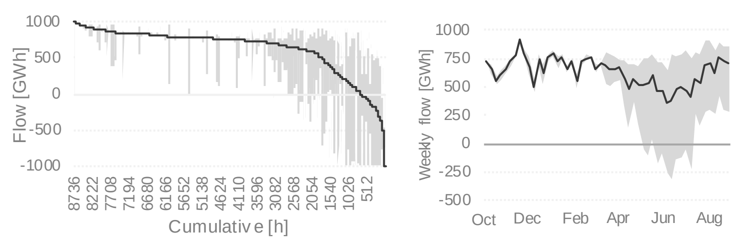

Figure 51: Energy flow through IceLink on an hourly (left) and weekly (right) basis (average level and range variation)

Finally, we observe that, after putting in place all these reinforcements, some congestions in the network still prevent additional exports from taking place. Based on our analysis, we observe that the transformers

[33] Some of these reinforcements may not be in line with Landsnet policy for the expansion of the grid.

Krafla 220kV/132kV and Blanda 220kV/132kV, and the 220kV lines Krafla–Fljótsdalur and Krafla–Sigalda are congested (Figure 52).

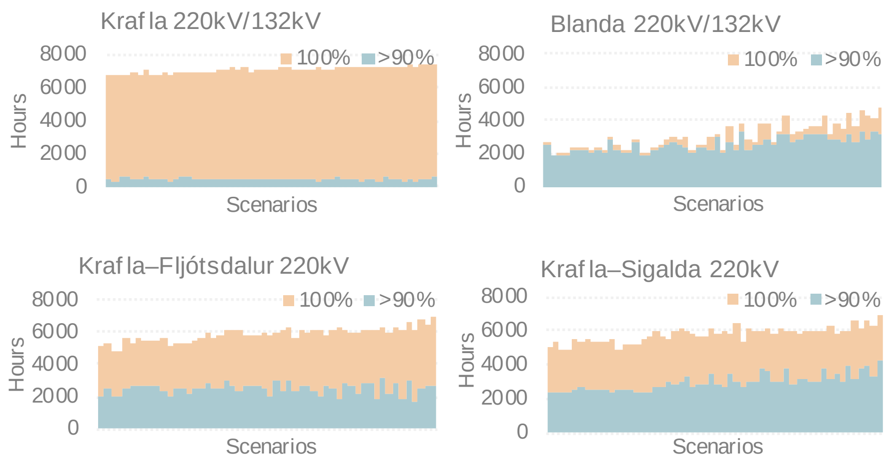

Figure 52: Number of hours in each hydrological year when the energy flow in each line or transformer reaches 100% of the capacity of the corresponding element (orange) or 90% (blue).

7.3.3. Summary

The interconnector option increases the energy security in the Icelandic system, since it behaves as backup in situations of scarcity and requires an expansion of the local generation capacity. However, the technical and economic challenges need to be understood by all stakeholders in order to consider this alternative a plausible one to enhancing security of supply. The challenges involve recovering the cost of the interconnector itself, which could amount to $2.7 billion; the need to reinforce the onshore network from $85 million to $100 million on top of the Inter-regional or Highlands reinforcement cost; and the development of several hydro, geothermal, and wind power plants, for an amount of around $2.5 billion. Even when the UK energy policy seeks improving its connectivity with neighboring countries, and acquiring the renewable energy and firm capacity that Iceland could provide, the project financing requires further analysis, which is out of the scope of this project.

		Inter-regional	Highlands
Net export [GWh]	Avg.	5857	5478
	Max.	6863	6400
	Min.	3853	3914
Secondary energy [GWh]	Avg.	184.0	192.0
	Max.	231.5	297.8

Table 1: IceLink summary of results for net exports and secondary energy use.

Table 1 summarizes the results for the interconnector option. We observe that IceLink, with either the Inter-regional or the Highlands local network reinforcement, produces similar results in terms of the net exports into the UK and secondary energy usage, although the Inter-regional option allows a slightly larger level of exports. Despite the fact that the use of secondary energy is a useful tool to avoid harsh curtailments, the UK cable could offer this service, maybe at a higher cost than today.

[M$/year]	Inter-regional	Highlands AC / DC
Net export income[(a)]	265.02	244.56
Generation investment[(b)]	(227.01)	(211.88)
Network investment[(b)]	(6.87)	(7.84)
IceLink investment[(b),(c)]	(218.67)	(218.67)
Secondary energy cost	0.31	0.53
Total	**(187.22)**	**(193.30)**

Table 2: Comparison of the economics of IceLink against the corresponding reinforcement case by 2030. Notes: (a) The net export profit results from the expected UK market prices; i.e., the calculation does not include any premium. (b) Annualized investment costs. Generation: WACC 7.9%; hydro lifetime 50 years; geothermal lifetime 35 years. Transmission: WACC 7.5%; lifetime 40 years.

Table 2 shows a summary of the economics of the interconnector when compared to the case without it for the three main network reinforcement options: the Inter-regional option, the Highlands option using AC technology, and the Highlands option using DC technology.[34] As we noted in the previous sections, exporting large amounts of energy through IceLink requires extra generation investments and network reinforcements. The interconnector itself is an expensive investment that would cost about $2.7 billion,[35] although it would report between $245 and $265 million annually when considering the UK price as the expected export price. Finally, we observe that the reduction in costs due to the decrease on the amount of secondary energy used with respect to the case without the interconnector is small when compared to the other figures. Exporting large enough amounts of energy through IceLink brings about additional costs, mainly investment ones, that net export income and cost savings related to the reduction in the use of secondary energy achieved though IceLink cannot offset. This difference in net system costs between the case with and without the interconnector in place amounts to around $190 million per year. A premium over the UK market price, which the UK could pay for its imports, could offset this deficit.

The level of security of supply achieved for the interconnector option is almost perfect (still, some extreme events like the unavailability of the link during a very long period coinciding with a dry year may lead to some unserved energy). Indeed, two factors would be enhancing security of supply in the considered case study: first, the interconnector would provide large back up support; and, second, additional generation

[34] Under the Highlands alternative, we have considered both the AC overhead line and the DC underground cable.
[35] As shown indicated in “Interconnector between Iceland and Great Britain, cost-benefit analysis and impact assessment” by Kvika and Pöyry.

capacity having been built to allow large enough net exports into the UK to take place would provide further back up capacity when the supply of load in Iceland is compromised.

8. Conclusion

The project focuses on a quantitative assessment of the security of supply implications and the cost of the various options available to Iceland to enhance its electricity security of supply within the following decade. We have divided the analysis into three parts. The first part has allowed us to assess the impact of reinforcing the network by considering the retrofit of the transmission network through the Highlands or the Inter-regional planned projects, or the possibility of installing diesel backup plants in critical nodes of the network. In this analysis, we have considered a hypothetical Icelandic system by 2020 to understand the current transmission network limitations. The second part has evaluated the generation expansion plan –as composed of hydro, geothermal and wind resources– by comparing, for each possible option, the costs of installing new generation assets plus that of requiring secondary energy and buyback energy. In this analysis, we have made use of a plausible demand and representation of the Icelandic system by 2030. The third part has delved into the economics of three alternatives to the base case just described that are currently being considered. Analyzing these involves performing a sensitivity analysis on the cases of the second block. These alternatives include: 1) deploying extra demand response 2) installing gas power plants, and 3) building a subsea interconnection with the UK. We have based our analysis on the results of a hydrothermal optimization model of the Icelandic system (**Appendix A**).

From the first part, we conclude that deploying either the Inter-regional or the Highlands network plan is critical in order to guarantee a strong enough connection between the East and West halves of the island, as shown by the release of some relevant network congestions (**Section 5.2**), especially when considering future demand growth. By year 2020, the curtailments under the Highlands reinforcement option seem to be marginally higher than under the Inter-regional option, although this difference would be within the modeling error (Table 3). The Inter-regional option annualized cost ($49.4 million per year) is halfway between the annualized costs of the AC ($33.1 million per year) and DC ($52.9 million per year) Highlands alternatives. The environmental impact assessment gains importance when deciding which option would be better (if any) as the Highlands option would cross virgin lands, while the Inter-regional option follows the current line course, including the Jökulsárlón narrow pass.

We have also analyzed the possibility of installing diesel groups located at strategic points of the network by 2020. Since the diesel price is above the buyback energy price, the diesel stations could only be used for mitigating the severe curtailments that would occur one out of eighteen years. In order to reduce any severe curtailment to zero, the investment cost of the required number of diesel station would be equal to or exceed that of the planned Highlands or Inter-regional reinforcements. The buyback energy and secondary energy curtailments would remain at similar levels as in the business-as-usual case. Although a low number of diesel stations may defer network investments, this option does not solve the network congestions.

	Business-as-usual	Inter-regional reinforcement	Highlands reinforcement	Backup Diesel generation
Secondary Energy Average	147GWh / 0.89%	110GWh / 0.66%	119GWh / 0.71%	147GWh / 0.89%
Secondary Energy Maximum	811GWh / 4.91%	754GWh / 4.57%	772GWh / 4.68%	811GWh / 4.91%
Secondary Energy Frequency	54 / 54 years	25 / 54 years	25 / 54 years	54 / 54 years
Buyback Energy Average	28 GWh / 0.17%	-	-	28 GWh / 0.08%
Buyback Energy Maximum	194 GWh / 1.18%	198GWh / 1.20%	198GWh / 1.20%	198 GWh / 1.20%
Buyback Energy Frequency	27 / 54 years	1 / 54 years	1 / 54 years	27 / 54 years
Severe Curtailment Maximum	57 GWh / 0.35%	-	-	-
Severe Curtailment Frequency	3 / 54 years	-	-	-
Annualized Costs	$9.3 million / year	$49.4 million / year	AC:$33.1 | DC:$52.9 million / year	$82.7 million / year

Table 3: Comparison of network reinforcement alternatives in year 2020

	Inter-regional w/o wind	Inter-regional w/ wind	Highlands w/o wind	Highlands w/ wind
Secondary Energy Average	181GWh / 0.93%	194GWh / 1.00%	194GWh / 1.00%	194GWh / 1.00%
Secondary Energy Maximum	899GWh / 4.64%	959GWh / 4.95%	934GWh / 4.82%	959GWh / 4.95%
Secondary Energy Frequency	54 / 54 years	27 / 54 years	54 / 54 years	27 / 54 years
Buyback Energy Maximum	232 GWh / 1.20%	232GWh / 1.20%	232GWh / 1.20%	232 GWh / 1.20%
Buyback Energy Frequency	1 / 54 years	4 / 54 years	3 / 54 years	4 / 54 years
Annualized Costs	$143 million / year	$153 million / year	AC:$126 | DC:$146 million / year	AC:$136 | DC:$156 million / year
	Sensitivity analysis			
	Additional demand response	*Interconnector with UK*	*Gas power plants*	*Interconnector with UK*
	The maximum buyback energy augments up to 2.4%.	The maximum secondary energy drops to 232GWh.	The maximum buyback energy is required 27 out of 54 years.	The maximum secondary energy drops to 298GWh.
	The buyback frequency increments to 32 out 54 years.	The buyback frequency decreases to zero.	The buyback frequency increments to 39 out 54 years.	The buyback frequency decreases to zero.
	The annualized costs decrease $385,000 per year.	The annualized costs increase $187 million per year.	The annualized costs increase $7.5 million per year.	The annualized costs increase $193 million per year

Table 4: Comparison of the considered generation expansion options and sensitivity analysis by 2030

From the second part, we have evaluated the new generation capacity plans by 2030, which expects to expand the portfolio of hydro, geothermal and wind resources available. We observed that including wind generation investments may result in a slightly better system performance than excluding this technology for both network reinforcement options (Table 4). Wind would also prove to be more economical to achieve the required level of security of supply. The small curtailment and cost differences in any case do not allow us to conclude that including wind outperforms using only hydro and geothermal technologies. Actually, the results indicate that wind turbines are as competitive as the geothermal or hydropower plants.

The sensitivity analyses of the third block have also contributed to the security of supply discussion. As indicated in Table 4, deploying additional demand response is marginally cheaper than building the most expensive hydropower plant, which in this analysis is Blönduveituvirkjun. The stakeholders could consider the possibility of augmenting the buyback energy up to 2.4% of the total industrial demand. In contrast, we suggest discarding the installation of gas power plants, as the Icelandic system seems less secure, more expensive, more polluting, and dependent on foreign fuel source when installing these plants than when building the Blönduveituvirkjun power plant.

Building an interconnector with UK shows up as the option that would result in the largest increase of security of supply. First, Iceland could import back-up energy from the UK during times of scarcity. Second, Iceland should develop a relevant amount of domestic generation (around 600MW of geothermal capacity and 240MW of hydropower capacity) and some extra network reinforcements on top of the Highlands or the Inter-regional plans to serve the UK demand of clean energy. Current water spillage could also provide part of this clean energy, around 650GWh. The additional costs due to the aforementioned additional generation capacity, extra network reinforcements, and the interconnector is equivalent to 85%, almost \$190 million per year, of the interconnector cost. Put differently, the incomes from the net exports to the UK may finance the additional domestic generation and the network reinforcements, but not IceLink. The current UK policy, which seeks improving its connectivity with neighboring countries, and acquiring firm capacity and renewable energy, could favor the payment of a premium on the exported energy that could partially or fully cover the additional cost of \$190 million.

9. References

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Appendix A: Summary description of the Icelandic power system

This section summarizes the main considered features in the Icelandic power system representation for the purposes of this project.

Network

We have defined a simplified model of the Icelandic transmission network based on the allocation of real nodes to equivalent nodes. We have also defined twenty-one equivalent transformers and power lines that connect the equivalent nodes. We have computed the characteristics of each equivalent transformer or power line (resistance *R*, reactance *X*, and total transfer capacity *TTC*) by the aggregation of the original physical transformers or power lines that link the equivalent nodes, which are, in actuality, groups of real nodes. Table 5 and Figure 9 show the equivalent transmission network.

			R [p.u.]	X [p.u.]	TTC [MW]
Sigalda 220	-	Hamranes 220	0.004	0.030	889.2
Hamranes 220	-	Hamranes 132	0.002	0.064	184.1
Hamranes 132	-	Fitjar 132	0.008	0.037	356.0
Hamranes 220	-	Brennimelur 220	0.009	0.053	304.0
Sigalda 220	-	Brennimelur 220	0.004	0.047	963.9
Brennimelur 220	-	Brennimelur 132	0.003	0.091	134.0
Brennimelur 132	-	Laxárvatn 132	0.086	0.394	150.0
Laxárvatn 132	-	Blanda 132	0.015	0.074	150.0
Blanda 132	-	Varmahlíð 132	0.015	0.075	100.0
Varmahlíð 132	-	Rangárvellir 132	0.086	0.214	80.0
Rangárvellir 132	-	Fljótsdalur 132	0.108	0.485	100.0
Fljótsdalur 132	-	Fljótsdalur 220	0.002	0.080	150.0
Fljótsdalur 132	-	Hryggstekkur 132	0.013	0.050	155.0
Hryggstekkur 132	-	Hólar 132	0.064	0.292	85.0
Hólar 132	-	Prestbakki 132	0.078	-0.008	100.0
Prestbakki 132	-	Sigalda 132	0.033	0.179	85.0
Sigalda 132	-	Sigalda 220	0.002	0.108	100.0
Laxárvatn 132	-	Mjólká 132	0.000	0.000	30.0
Rangárvellir 132	-	Laxá 66	0.286	0.808	37.0
Hryggstekkur 132	-	Eastfjords IN	0.001	0.001	190.0
Eastfjords IN	-	Eastfjords OUT	0.001	0.001	215.0

Table 5: Equivalent network model

In addition to the equivalent transmission network, the network reinforcements that are under discussion include two options: the Inter-regional and the Highlands options (Figure 15). The equivalent network reinforcements, both transformers and power lines, for the Inter-regional option are shown in Table 6, while those for the Highlands option are shown in Table 7.

			R [p.u.]	X [p.u.]	TTC [MW]
Laxá 220	-	Fljótsdalur 220	0.011	0.109	550
Fljótsdalur 132	-	Fljótsdalur 220	0.002	0.080	150
Fljótsdalur 220	-	Hryggstekkur 220	0.005	0.044	550
Hryggstekkur 220	-	Hólar 220	0.007	0.067	550
Hólar 220	-	Prestbakki 220	0.016	0.152	550
Prestbakki 220	-	Sigalda 220	0.007	0.069	550
Laxá 132	-	Laxá 220	0.050	0.120	150
Hamranes 220	-	Brennimelur 220	0.004	0.027	608
Brennimelur 220	-	Laxárvatn 220	0.009	0.086	550
Laxárvatn 220	-	Blanda 220	0.010	0.094	550
Blanda 132	-	Rangárvellir 132	0.056	0.250	178
Blanda 132	-	Blanda 220	0.050	0.120	150
Blanda 220	-	Laxá 220	0.010	0.095	550
Sigalda 132	-	Sigalda 220	0.002	0.108	150

Table 6: Inter-regional reinforcements

			R [p.u.]	X [p.u.]	TTC [MW]
Laxá 220	-	Fljótsdalur 220	0.011	0.109	550
Fljótsdalur 132	-	Fljótsdalur 220	0.050	0.120	150
Laxá 132	-	Laxá 220	0.050	0.120	150
Hamranes 220	-	Brennimelur 220	0.004	0.027	608
Blanda 132	-	Rangárvellir 132	0.056	0.250	178
Blanda 132	-	Blanda 220	0.050	0.120	150
Blanda 220	-	Laxá 220	0.010	0.095	550
Sigalda 220	-	Rangárvellir 220	0.016	0.160	550

Table 7: Highlands reinforcements

Demand

We have broken down the hourly electricity demand into general (i.e., residential) and power-intensive industry (i.e., industrial). We have used historical data from January to December 2014.

We have collapsed the residential demand from 8760 hours to 520 load levels, i.e., fifty-two weeks that distinguish between weekdays and weekends, each with five load levels. We have looked for two super peak hours, two peak hours, fourteen base load hours, three off-peak hours, and three super off-peak hours for every day of a week. Because the Reykjavik area accounts for 43% of total residential demand, and presents high correlation (around 80%) with the load profiles of other residential nodes in the system, the Reykjavik area profile has been used for allocating the hours into load blocks (Figure 53).

By using the same hourly allocation in every equivalent node as for the Reykjavik area, we have obtained the average demand levels for every load block for all the nodes of the system. In contrast, the industrial demand is considered constant throughout the year.

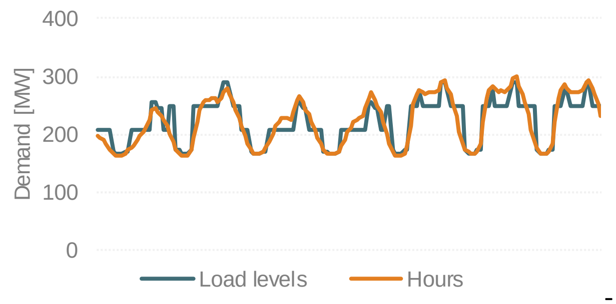

Figure 53: Comparison between real demand and simplified demand in Reykjavik for one week.

Hydro System

We have modeled the hydropower plants that are situated in five different watersheds, namely Sog, Laxá, Þjórsá, Blanda, and Kárahnjúkar. We have also aggregated the several small hydropower stations into four equivalent medium-size power plants. Table 8 shows the topology, the output capacity and production function of each power plant, and the reservoir volume of each considered watershed.

	Output [MW]	Production function [kWh/m³]	Volume [hm³]			Output [MW]	Production function [kWh/m³]	Volume [hm³]
Sog	90.0	0.1810			**Blanda**			
Laxá	27.5	0.1556			Blöndulón			400
Þjórsá					*Blönduveituvirkjun*	31.0	0.1400	
Hágöngulón			320		Gilsárslón			20
Þórisvatn			1512		Blönduvirkjun	150.0	0.6830	
Vatnsfell	90.0	0.1576			**Kárahnjúkar(*)**			
Sigalda	150.0	0.1690	80		Kelduárlón			60
Hrauneyjafoss	210.0	0.2130	16		Ufsarlón			5
Búðarháls	95.0	0.0924	30		FljótsdalsstoðA	43.0	0.1600	
Sultartangi	134.0	0.1150	110		Hálslón			2088
Búrfell	388.0	0.2860	5		FljótsdalsstoðB	647.0	1.2900	
Hvammsvirkjun	93.0	0.0728			**North**	13.3	0.5000	
Holtavirkjun	57.0	0.1598			**East**	14.5	0.5000	
Urridafoss	140.0	0.3488			**Westfjords**	19.0	0.5000	
					West	15.2	0.5000	

Table 8: Icelandic hydropower system representation. Potential new power plants are in *italics*

The Jökulsá diversion at Kárahnjúkar has been considered by artificially defining two independent power plants whose total capacity is equal to the real one. The first group is only fed by the small reservoirs upwards of Hálslón reservoir. In addition, the Hálslón reservoir head effect has been considered by correcting the output capacity. The minimum output capacity is 553MW. This value increases with the stored water level multiplied by a factor of 0.045MW/hm^3. We have obtained the linear approximation by fitting the output surface (Figure 54) to a plane that depends on the head, the Jökulsá diversion flow, and the inlet flow.

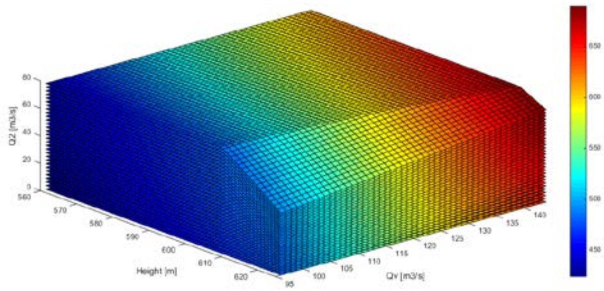

Figure 54: Output surface with respect to head, Jökulsá diversion flow, and inlet flow.

Based on the historical natural inflows series from 1951 to 2004, we have generated a scenario tree by performing a multivariate clustering approach of the original series to a predefined tree structure (Latorre et al., 2007). We have captured most of the hydro uncertainty with a tree that opens two branches at the beginning of the following weeks:

- Third week of October.
- Second week of November.
- First week of April.
- First week of May.
- First week of June.
- First week of July.

We have established the beginning of the hydrological year at the second week of October when we have estimated and fixed the initial reservoir levels at 95%. We have also set that at the end of the simulated period, fifty-two weeks, the reservoir levels must be equal or greater than 95% for each scenario.

Mathematical formulation

We have used a medium-term hydrothermal model that optimizes the operation and generation capacity expansion. The model has been adapted to the particularities of the Icelandic power system, which has mainly entailed, first, modifying the geothermal formulation to represent must-run baseload plants with scheduled maintenance periods and, second, extending the hydro formulation to incorporate the above-mentioned Hálslón reservoir head effect.

We have formulated a stochastic optimization model that is solved as a mixed integer linear programming problem. The objective function minimizes the expected operation and generation investment costs for the entire scope of the model. The operation costs term includes the generation costs (negligible in the case of Iceland), the curtailment costs, and some minor penalties to incentivize a balanced utilization of all reservoirs. The investment generation costs term include the annualized capital cost of the new power plants. The formulation also includes several linear constraints such as balance of generation and demand, spinning reserves, linear transmission losses, hydro reservoir inventories, DC load flow for existing lines, flow limit for each cut, among others. The investment decisions are represented through binary variables. Further details are available at https://www.iit.comillas.edu/aramos/starnet.htm.

Appendix B: Assumption on the Interconnector

By using as input a forecast of the hourly profile of energy prices in the UK, we have run the optimization model to determine both the generation investment decisions in Iceland and the economic use, imports, and exports, of IceLink. We have not considered a reference price of a hypothetical bilateral contract that could apply to exports, imports, or both and condition the incomes, generation investment, and operation decisions. Therefore, we have obtained an amount of exports and imports that results from a purely economic analysis. This analysis may, however, be used by interested stakeholders for computing the reference price of a potential contract for differences with the UK to make this option economically viable. The base scenario for Iceland is that of 2030.

The objective of this analysis is twofold:

1. Providing the economically optimal amount of expected annual net exports, i.e., exports minus imports, from Iceland to the UK given the UK electricity price and the Icelandic system.
2. Providing the investments in new generation assets in Iceland that are economically justified and selected out of a set of candidate generation projects.

Based on previous studies on the interconnector, we have represented IceLink as a 1200km-long 1000MW HVDC link. From our experience, we have assumed power losses in the link at 5% of the power flow. We have also hypothesized that the cable lands at Reyðarfjörður, as previous studies has already considered this location due to its "proximity" to the UK. Furthermore, we have assumed that the link is fully available all the time.

The considered UK hourly electricity prices correspond to a naïve-model forecast for 2030 extracted from 2015 data. We have represented a unique set of UK prices has all hydro scenarios as we have assumed that there is no correlation between Iceland hydrological conditions and the UK electricity prices.

We have imposed that the Icelandic system cannot resort to buyback curtailments to the power intensive industry or any curtailment to the residential consumers to increase exports through the interconnector. Exports shall therefore be as small as needed to avoid such curtailments. Put differently, the Icelandic power supply has priority over exports. Accordingly, we have increased the buyback price to $100/MWh, which is the highest observed UK electricity price throughout the chosen year. In contrast, the secondary energy requirement still depends on strict economic criteria and, hence, helps obtain the most efficient system operation. Since the secondary energy price is usually smaller than the considered UK prices, this product is required up to the maximum allowed level to maximize the exports.

Finally, we have considered both the Inter-regional and the Highlands network reinforcement options. We have identified some network reinforcements, in addition to the planned ones in both options, which are required to facilitate an amount of exports (between 5.0TWh and 5.5TWh) that allows Iceland to contemplate IceLink as an option.[36] We have performed a systematic analysis of the congestions that occur in the network to identify the required reinforcements to reach that level of net exports.

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[36] This level of exports results from economic considerations.