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Strategies to Ensure Sufficient Inertia in the Norwegian Power System

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Preface

This master thesis completes the Master of Science (M.Sc.) degree within Energy and Environmental Engineering at the Norwegian University of Science and Technology (NTNU). It has been written in the fall of 2017 at the Department of Electric Power Engineering.

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Abstract

Having a stable system frequency is vital for safe operations of a power system. A small change in frequency is adjusted for by the system inertia. Inertia is the ability of the rotating masses of a synchronous machine to resist a change in frequency. The system inertia has the important ability that it helps maintain a stable frequency. The consequence of an unstable frequency can in the worst case be a blackout.

The Nordic power system is changing, and it is expected that these changes will lead to more occurrences of low inertia situations. Low inertia situations must be avoided as they lead to a more unstable frequency. To avoid low-inertia situations it is necessary to introduce measures to increase the inertia in the Nordic power system.

Three strategies to ensure sufficient inertia in the Norwegian power system will be evaluated based on their socioeconomic costs and their effectiveness in providing sufficient inertia. The aim of the thesis was to find a cost-effective strategy for the Norwegian power system. To analyze the effect of the strategies, a market model of the Northern European power system was used.

Defining a minimum production level for the hydro generators proved an effective strategy in ensuring sufficient inertia. The socioeconomic costs related to this strategy were however, high. Extending the strategy to only apply on days with low inertia gave satisfying results: the inertia was increased on the days it was needed and the costs of the strategy were reduced. Reducing the capacity on an HVDC link gave lower socioeconomic costs. The strategy has a positive effect on the system inertia, as long as there is import on the HVDC link when the capacity is reduced. The best economic outcome was estimated to come from load reduction by disconnecting the pumps for hydro storage. This strategy has however limited availability.

The results show that low inertia situations in the Norwegian power system can be avoided by taking necessary measures. Imposing a minimum production level on days with low inertia proved an effective strategy to increase the system inertia. Looking at the cost-effectiveness, load reduction by disconnecting the pumps for hydro storage or reducing the capacity of an HVDC-link are better options. However, the capability of these latter strategies to provide the inertia depend on external factors giving them a somewhat limited applicability.

Sammendrag

En stabil systemfrekvens er nødvendig for stabil og sikker drift av kraftsystemet. Hvis systemfrekvensen endrer seg vil dette bli korrigert for av tregheten i systemet. Et systems treghet er definert ved evnen systemets roterende masse har til å motstå endringer i frekvens. Systemets treghet er viktig fordi den opprettholder frekvensen på et stabilt nivå. En ustabil systemfrekvens kan i verste fall føre til strømbrudd.

Det nordiske kraftsystemet er i endring, og det forventes at disse endringene vil føre til flere situasjoner med lav treghet i det kraftsystemet. Lav treghet i kraftsystemet gir en ustabil frekvens og må derfor unngås. For å unngå situasjoner med lite treghet i det nordiske kraftsystemet er det nødvendig å iverksette tiltak.

I denne oppgaven evalueres tre strategier som alle har som mål å sikre tilstrekkelig rotasjonsenergi i det norske kraftsystemet ut ifra på deres samfunnsøkonomiske kostnad, og evne til å bidra til systemets treghet. Oppgaven har som mål å finne en kostnadseffektiv strategi for det norske kraftsystemet. For å analysere effekten av de ulike strategiene, vil en markedsmodell over det nord-europeiske kraftsystemet bli brukt.

Å definere et minimumsproduksjonsnivå for alle vannkraftgeneratorer viste seg å være en effektiv strategi med tanke på å øke systemets treghet. Denne strategien viste seg å ha høye samfunnsøkonomiske kostnader. Å utvide denne strategien til kun å gjelde når tregheten i systemet er lav ga tilfredsstillende resultater: tregheten i systemet økte og kostnadene gikk ned. Å redusere kapasiteten på en HVDC kabel resulterte i lavere samfunnsøkonomiske kostnader. Strategien hadde en positiv effekt på tregheten så lenge kabelen importerer strøm når kapasiteten blir redusert. Strategien med det beste økonomiske resultatet var lastutkobling ved utkobling av pumpene til pumpekraftverk. Ulempen med denne strategien er at den har begrenset tilgjengelighet.

Resultatene viser at situasjoner med lav treghet i det norske kraftsystemet kan unngås så lenge nødvendige tiltak blir iverksatt. Å definere et minimumsproduksjonsnivå for vannkraftgeneratorer på dager hvor tregheten i systemet er lav, er en svært effektiv strategi for å øke systemets treghet. Når det kommer til kostnadseffektiviteten, er lastutkobling ved utkobling av pumpene til pumpekraftverk og reduksjon av kapasiteten på en HVDC kabel, bedre alternativer. De sistnevnte strategienes evne til å bidra med treghet til systemet er avhengig av utvendige faktorer, noe som gir dem en noe begrenset tilgjengelighet.

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Abbreviations

ECSA	European Continental Synchronous Area
EMPS	EFI's Multi-area Power-market Simulator
ENTSO-E	European Network of Transmission System Operators for Electricity
HVDC	High-Voltage Direct Current
MRC	Multi-Regional Coupling
NTC	Net Transfer Capacity
PCR	Price Coupling of Regions
PV	Photovoltaics
RES	Renewable Energy Sources
ROCOF	Rate of Change of Frequency
TSO	Transmission System Operator
VSG	Virtual Synchronous Generator
XBID	The Cross-Border Intraday Market Project
s.t.	Subject to
B&B	Branch and Bound

Nomenclatur

Sets

A	Set of balancing areas
T	Set of time periods
R	Set of balancing regions
Γ	Set of planning periods
G, G_a	Set of thermal units, and of thermal units in area a
H, H_a	Set of hydro units, and set of hydro units in area a
A_r	Set of balancing areas in region r

Indices

a, b	Balancing area
r, s	Balancing region
g	Thermal unit
h	Hydro unit
τ	Planning period
t	Time period within τ
x	Reservoir segments

Parameters

$\overline{P}_{a,g}, \underline{P}_{a,g}$	Maximum and minimum generation capacity of a thermal unit g in area a (MW)
$\overline{P}_{a,h}, \underline{P}_{a,h}$	Maximum and minimum generation capacity of a hydro unit g in area a (MW)
$\overline{P}^{s}_{a,\tau,t}$	Maximum solar power generation in area a at time t (MWh/h)
$\overline{P}^{w}_{a,\tau,t}$	Maximum wind power generation in area a at time t (MWh/h)
$MC_{a,g}$	Marginal costs of unit g in area a (EUR/MWh)
$WV_{a,h,x,\tau}$	Water value of a reservoir connected to unit h in area a at reservoir level x at τ (EUR/MWh)
$SC_{a,g}$	Start-up costs of a thermal unit g in area a (EUR)
$FC_{a,g}$	Fixed costs of a thermal unit g in area a (EUR)
VLL	Rationing costs (EUR/MWh)
$Mg^{prev}_{\tau,a,h}$	Previous period reservoir level in area a of hydro unit h (MWh)

Variables

$\delta_{a,g,\tau,t}$	Online status of a thermal unit g in area a at t, $\in$ 0,1
$u_{a,g,\tau,t}$	=1 if unit g in area a is started up in time step t, =0 otherwise
$p_{a,g,\tau,t}$	Output of each thermal unit g in area a at time t (MWh/h)
$p_{a,h,\tau,t}$	Output of each hydro unit h in area a at time t (MWh/h)
$p^{s}_{a,\tau,t}$	Solar power output in area a at time t (MWh)
$p^{w}_{a,\tau,t}$	Wind power output in area a at time t (MWh)

$p^{cur}_{a,\tau,t}$	Load curtailed in area a at time t (MWh/h)
$ep^{A}_{a,b,\tau,t}$	Energy exchange from area a to b at t (positive is export from a) (MWh/h)
$p^{st}_{a,h,\tau,t}$	Storable inflow into hydro unit h in area a at time t (MWh)
$p^{ns}_{a,h,\tau,t}$	Non-storable inflow unto hydro unit h in area a at time t (MWh)
$Mg_{a,h,\tau}$	Reservoir level of hydro unit h in area a (MWh)
$Of_{a,h,\tau}$	Overflow from a reservoir connected to unit h in area a at τ (MWh)

1 Introduction

1.1 Thesis Motivation

In the coming years the Nordic power system is expected to experience structural changes. Within the Nordic power the share of renewable energy sources (RES) are increasing, and more power generation will in the future come from distributed and small-scale power plants. Denmark and Finland will be shutting down fossil fuel plants, and Sweden is decommissioning their nuclear power plants [6]. In addition several interconnections to the European Synchronous Area (ECSA) are planned. Norway is planned to have an HVDC-interconnection to Germany, and and HVDC-interconnection to Great Britain in operation by the end of 2020 and 2021. Closer market coupling between the Nordic power market and the European power markets is expected to increase in the coming years.

Inertia is important for the frequency stability of the power system. In a power system inertia is defined as the ability of a system to oppose changes in frequency due to resistance provided by the kinetic energy of the rotating masses of synchronous generators. In a power system the generation and the consumption of power should be equal at all times. If the generation and consumption does not equal each other, this will lead to a small change in frequency. The inertia in the power system limits how large the change in frequency will be. A large change in frequency can in the worst case develop into a blackout. How much change in frequency a power system can handle depends on the amount of inertia present in the power system.

A generation unit that is connected to the grid via a synchronous machine contributes with inertia through the rotating masses of the machine. Renewable energy sources and HVDC-links are connected to the grid via power converters that do not have the ability to contribute with inertia. With the increase in RES and power imported from HVDC-links it is expected that the Nordic power system will experience an increase in low-inertia situations.

1.2 Problem Definition

As inertia is of critical importance to the power system, situations with low inertia must be avoided. The master thesis aims to find a cost-effective strategy to ensure sufficient inertia in the Norwegian power system.

To find a cost-effective strategy to ensure sufficient inertia in the Norwegian power system, three different strategies will be evaluated and compared based on their effectiveness in providing the power system with inertia, and their socioeconomic cost. A market model of the Northern European power system implemented in GAMS IDE is used to analyze the effect of the strategies. The market model is a linear optimization model of the day-ahead market. The input data is a case study from 2010. It is important to bear in mind when analyzing the results that the case study is from 2010, and the power system as it is today may differ from how it was in 2010.

The first strategy modifies the model by defining a minimum production level for the hydro units of 20 % of maximum production. This strategy has been given the main focus in the analysis. To ensure that the hydro reservoirs are not emptied due to the first strategy, an additional restriction regarding the size of the reservoir is is implemented in the model. The first strategy is extended to only apply on days with low inertia to improve the cost-effectiveness.

To get an impression of the socioeconomic cost related to the first strategy, two other strategies have been used for comparison. These two strategies are perceived by the Nordic TSO's as the two most promising mitigation measures when it comes to ensuring sufficient inertia in the Nordic power system. Reducing the import/export on an HVDC link is one of them. Nord Link is the chosen HVDC link that is implemented in the model, and reduced on days with low inertia.

Increasing the system inertia by reducing the load is the other promising mitigation measure. One of the loads that are proposed as a possible to disconnect is the pumps used for pumped hydro storage. The costs of this strategy will be estimated based on research literature and results of the survey conducted among some Norwegian hydro producers.

Contribution

- Implement the first strategy in a valid market model in a viable way. Extend this strategy to only apply on days with low inertia.

- Illustrate the effectiveness and costs of reducing the capacity on an HVDC link between Norway and Germany. Provide an indication of the effects of this in 2020.

- Map the general pumping pattern of pumped hydro storage systems. Define a cost estimation.

- Compare the three strategies based on their socioeconomic costs and inertia contribution.

The results of my contribution are described in section 6.

1.3 Previous Work

The Nordic Analysis Group (NGA) have written two reports on the topic of inertia in the Nordic power system. The first report, *Future System Inertia* [5], estimated the total kinetic energy in each Nordic country, and found a relationship between how the frequency behaves during a disturbance and how this relates to external factors. In the follow-up report from 2017, *Future System Inertia 2* [6], one of the objectives was to develop mitigation measures to avoid low inertia situations. The two mitigation measures that were found the most promising in the report are used as strategies in this thesis.

The master thesis of Karsrud [14] analyzed the socioeconomic cost of two strategies to ensure sufficient inertia in the Nordic power system, using the relationship between the behavior of frequency and the power imbalance found in the first NGA report. The KUBE report [15], was written as part of a student project at Statnett, studied possible market designs of a market for inertia that could be introduced for the Nordic power system. The masters thesis of Brekke [16], analyzed the effect of one of the inertia markets presented in the KUBE report, on medium-term hydropower scheduling. Inertia in the European power system has just been briefly touched upon in this thesis. Thiesen et al. [7] assessed the need for a market for inertia for the European synchronous area. The challenges the Irish power system is facing was addressed by Flynn et al. [17].

Gebrekiros et al. [10] and [18] highlights the mathematical formulations behind the power market in the simulation model and provides relevant information about the case study used as input into the model. To account for the cost of change in the hydro units reservoirs level, the method developed and used in The TradeWind Project, *Integrating Wind* [19], will be used.

The theory part of this masters thesis is based on the authors specialization project, *Literature Study: An Ancillary Service Market for System Inertia* [20].

1.4 Thesis Structure

Chapter 1 will present the motivation behind the topic of the thesis and define the problem the thesis aims to answer.

Chapter 2 provides a general overview of the basic theory relevant for understanding the objectives of this masters thesis. This chapter is based on the authors specialization project.

Chapter 3 provides the reader with a thorough understanding of the model used in the simulations. The mathematical formulation of the day-ahead market and the implementation of the Northern European power system in the model will be described.

Chapter 4 describes how the inertia and the costs are estimated, and the simplifying assumptions that have been taken. The implementation of the two first strategies are explained, and the results of the survey concerning the last strategy presented.

Chapter 5 presents the original data set used for the analysis.

Chapter 6 presents the main results of the simulations. The chapter is structured according to the strategies, and the results are compared with the original data set.

Chapter 7 evaluates the results presented in the sixth chapter. A comparison of the three strategies will be presented; the main focus being on their socioeconomic costs and their effectiveness in providing sufficient inertia. The chapter will include a validation of the assumptions that has been made in the thesis and a brief discussion on the limitations of the model.

Chapter 8 provide concluding remarks on the thesis' objectives and suggestions for further work.

Part I

Theory

2 Theory

This chapter presents the basic theory relevant for understanding the objective of this master thesis. The theory presented is based on the author's specialization project concerning the same topic [20].

2.1 Structure of Power Systems

2.1.1 Synchronous area

A synchronous area is an interconnected area consisting of one, or more, countries that all share the same steady-state frequency. A synchronous area is balanced if the production of power in the synchronous area equals the consumption of power. The US has three synchronous areas, and Europe has five synchronous areas where the the European Continental Synchronous Area (ECSA)[1] is the biggest of them with 24 member countries. Norway, Sweden, Finland and Eastern Denmark form the Nordic Synchronous Area. Both ECSA and the Nordic Synchronous area operate at a synchronous frequency of 50 Hz. Figure 2.1 shows the different synchronous areas in Europe [21].

2.1.2 Balancing area

A balancing area is an area within a synchronous area where only one transmission system operator (TSO) is responsible. The role of the TSO is to ensure that both the balancing area and the synchronous area are balanced. The balancing area and the synchronous area are balanced when the system frequency is at its nominal value (50 Hz), and when the net import and export of power to and from the balancing area is at its scheduled value [21], [22].

A balancing region is a region containing several balancing areas. The balancing areas within a balancing region all help trying to maintain the frequency at its nominal value. This means that if there is a power imbalance in Norway, this can be corrected by a generator in Sweden, but the Norwegian TSO is responsible for fixing the fault if it lasts for a long time.

[1] The ECSA is previously known as Union for the Coordination of the Transmission of Electricity (UCTE).

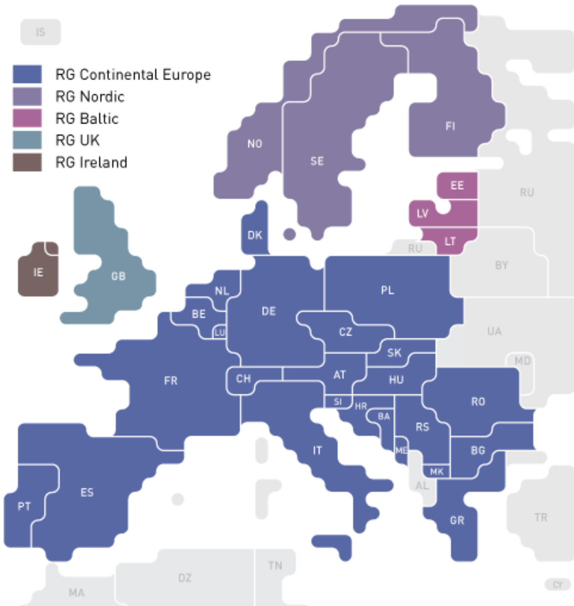


Figure 2.1: The five different synchronous areas in Europe. RG Continental Europe stands for ECSA [1].

2.2 Structure of Power Markets

A power market is a liberalized market where power is the product that is being traded. Today most countries have a liberalized power market. The Nordic countries are joined in a common electricity market, Nord Pool, which will be further explained in this section.

2.2.1 Price calculation

The price of electricity is set when demand equals production in a specified price area. The power plants bid their planned production at a certain price, and the buyers (typically a utility) bid their demand at a certain price. The bidding curve is then sorted according to the marginal price of the generation units, and the price is set when demand equals production. Figure 2.2 shows a typical demand and supply curve.

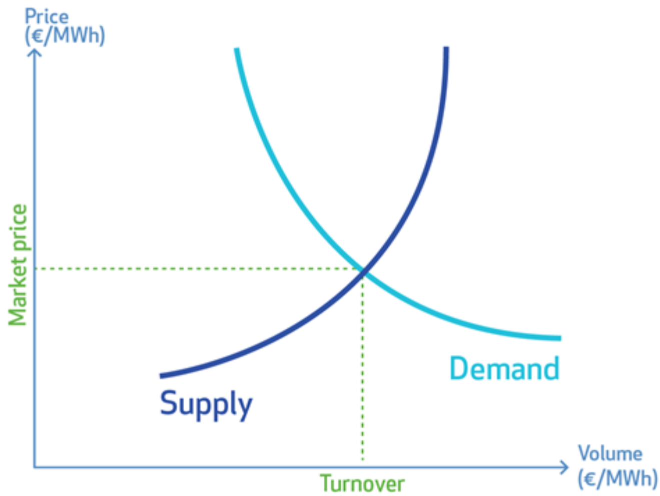


Figure 2.2: Supply and demand curve illustrating how the system price of electricity is decided in the Nordic day ahead market, Elspot [2].

2.2.2 The merit order

In liberalized power markets the bidding curve is, as mentioned in the previous section, sorted after the marginal cost of the generation units. The generation units with the lowest marginal costs are placed first, and the other follow in ascending order. The generation units with the lowest marginal costs are wind, photovoltaics (PV) and run-of-river hydropower plants[2]. These generation units have almost no operating costs, and no way to store energy so they will bid in at a low price. When these generation units bid into the market, the supply curve will be shifted to the right, lowering the electricity price, and pushing the generation units with higher marginal cost to the left. Consequently some of the more expensive generation units can be pushed out of the market, this effect is often referred to as the merit order effect.

2.2.3 The Nordic power market

In the 1990s the Nordic countries deregulated their markets, and brought their individual markets into a common electricity market, called Nord Pool. From 2010-2013, Estonia, Latvia and Lithuania deregulated their power markets, and joined Nord Pool power market [23]. The Nordic power market consists of three

[2]Run-of-river hydropower plants are hydro power plants without reservoir. When the river is running, the hydropower plant will be running.

markets: the day-ahead market (Elspot), the intraday market (Elbas) and the financial market.

The day-ahead market

The Day-Ahead Market, called Elspot, trades electricity one day ahead of physical delivery. Elspot has 360 members buying and selling electricity. The prices are determined through a double auction[3] for each hour of the day [24]. The system price is based on the assumption that there are no transmission restrictions in the grid and is referred to as the unconstrained price in Elspot. The system price is the reference price for financial trade in the Nordic Market [24].

Each Nordic country is divided into bidding areas[4], decided by the local TSO. In Norway there are five bidding areas (this number can vary). Denmark is always divided into two bidding areas: Eastern Denmark and Western Denmark. Sweden is divided into four bidding ares, while Finland, Estonia, Lithuania and Latvia constitute one bidding area each [12]. Bidding areas have the functionality that they indicate constraints in the transmission system, and ensure that the regional market conditions are reflected in the price. The different bidding areas can have different prices due to bottlenecks[5] in the transmission system. The price for each bidding area is calculated for every hour of the following day [12]. On the day-ahead market, more than 80 % of the total power consumption in the Nordic countries is traded. The deadline for submitting a bid is 12.00.

The intraday market

The Intraday market, also known as Elbas, covers the Nordic countries, the Baltic countries, UK and Germany. The intraday market supplements the day-ahead market and helps secure the necessary balance between supply and demand in the power market for Northern Europe [25]. In Elbas the participants have the opportunity to adjust their power balance close to real time [24]. The bids can be placed up to an hour before physical delivery. Prices are set based on a first-come, first-served principle, where the best price comes first; highest buying price and lowest selling price [25].

The financial market

The financial market is a market where financial contracts are traded. The duration of the contracts may be up to six years. The financial contracts are mainly used for price hedging and risk management. The system price is used as the reference price for the financial market [26]

[3] Double auction is an auction with supply and demand participation.

[4] Bidding areas are also referred to as price areas.

[5] A bottleneck occurs when the transmission grid is not able to transmit sufficient power

2.2.4 Connection to other power markets

The Nordic power market is connected to the European power markets through HVDC links. The interconnections from the Nordic system to the European continent are expected to increase with 5-6000MW by 2030. The motivation behind the increase in HVDC interconnections is better use of the different power sources, a more climate friendly energy sector, more secure energy supply, and an economically favorable export in the summer months when there is surplus energy in the Nordic power system [3]. The Nordic countries, the UK, the Baltic countries and Germany all participate in Nord Pool's intraday market. Figure 2.3 shows the existing and planned HVDC interconnections from the Nordic power system.

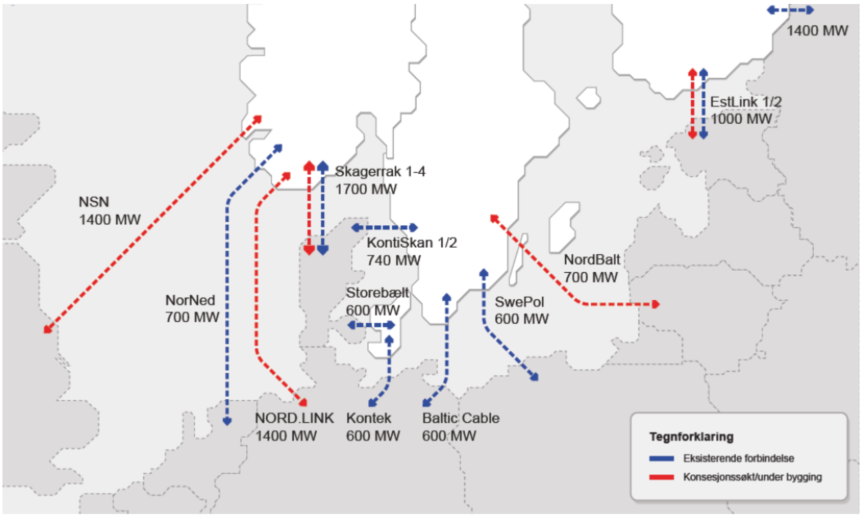


Figure 2.3: Existing (blue line) and planned (red line) HVDC interconnections in the Nordic power system in 2014 [3].

The following HVDC interconnections are planned to be built by 2020

- A new HVDC connection between Norway and Germany is planned to be built by 2018. The HVDC connection, called Nord Link, will have a capacity of 1400MW.
- A new HVDC connection between Norway and England, called NSN, is planned to be built by 2020. The HVDC link will have a capacity of 1400 MW [3].
- The Cobra cable will be a HVDC connection between western Denmark and the Netherlands. It is planned to be commissioned by 2019 and will have a capacity of 700MW [27].

In addition a HVDC connection between western Denmark and Great Britain are being planned. The connection is named Viking Link and is planned to have a capacity of 1400MW [27].

Market coupling of European power markets

The EU wants a harmonized European power market. In order to realize this European power exchanges has initiated two projects: Price Coupling of Regions (PCR) and Cross-Border Intraday Market Project (XBID).

PCR is a single price coupling algorithm that calculates the day-ahead electricity prices across Europe. It was developed by European Power Exchanges. Today PCR is used to couple the following countries: Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Hungary, Italy, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden and UK [28].

The Cross-Border Intraday Market Project (XBID) aims to create a joint European intraday market, and to increase the efficiency of intraday trading. The XBID will have a common IT system with one Shared Order Book, a capacity Management Module and a Shipping Module. As the amount of fluctuating renewable energy sources are increasing, the importance of the intraday market is expected to increase. The XBID was initiated by the Power Exchanges: EPEX SPOT, GME, Nord Pool and OMIE together with TSOs from 11 different countries [28].

2.3 Inertia in the Power System

This section will introduce the fundamental equations concerning inertia in the power system. For a deeper understanding, it is recommended to see [29]. This section will lead up to two important equations, equation 2.5 and 2.6 that will be used later in the thesis. The function of inertia in the power system, and which generation units has the ability to provide inertia will be presented.

2.3.1 Inertia

The term inertia is defined as the resistance of any physical object to resist change in its state of motion. In a power system inertia is defined as the ability of a system to oppose changes in frequency due to resistance provided by the kinetic energy, E_k [J], of rotating masses in individual turbine-generators [5]. This kinetic energy can be expressed as

$$E_k = \frac{1}{2} J \omega_m^2 \tag{2.1}$$

where J [kg/m^2] is the moment of inertia and ω_m [mechanical radians/s] is the rotor shaft velocity.

A synchronous machine contributes with inertia if it rotates synchronously with the grid, meaning that its rotational speed equals the frequency of the grid. The correlation between the system frequency f [Hz] and the rotational speed of the machine is

$$f = \frac{\omega_m p}{120} \tag{2.2}$$

where p is the number of poles of the machine[30].

The rotating masses of a synchronous machine is stored as kinetic energy and referred to as inertia. When there is a change in the system frequency, the machine will automatically adjust its rotational speed to try and maintain the system frequency. This can be seen in Newton's second law

$$J \frac{d\omega_m}{dt} + D_d \omega_m = \tau_t - \tau_e \tag{2.3}$$

where τ_t [Nm] is the torque produced by the turbine, τ_e [Nm] is the counteracting torque and D_d [Nms] is the damping torque coefficient. An unbalanced torque acting on the rotor will result in acceleration or deceleration of the rotor according to equation 2.3 [29].

$M_m = J\omega_{sm}$ is the angular momentum at synchronous speed, and is referred to as the inertia of the machine. Newton's second law leads to a fundamental equation concerning the rotor dynamics, namely the *swing equation*

$$M_m \frac{d^2 \delta_m}{dt^2} = P_m - P_e - P_D \tag{2.4}$$

The swing equation shows the relationship between the inertia of the machine M_m, the rotor angle δ_m, the change in frequency $\Delta\omega = \frac{d\delta_m}{dt}$, the mechanical power P_m, the electrical power P_e and the damping power P_D [29].

Since the synchronous machine rotates synchronously with the grid, the frequency of the grid will equal the rotational speed of the machine. In a power system the production and consumption of power should be equal at all times. If there is a change in the electrical or mechanical power there will be a change in the rotational speed of the machine, and thus also a change in the frequency of the power system. The change in frequency depends on the system inertia and the change in electrical power.

The inertia of a generator is often described through the inertia constant H. Similar generators will all have the same inertia constant. The inertia constant is defined as the stored kinetic energy in [MJ] at synchronous speed, ω_{sm}, divided by the machine rating S_n in [MVA]

$$H = \frac{J\omega_{sm}{}^2}{2S_n} \tag{2.5}$$

The inertia constant is given in seconds. It states how many seconds it will take a generator to provide an equivalent amount of electrical energy when the generator is operated at a power output equal to the machine rating. In other words, knowing the inertia means knowing how large frequency deviations the system can handle [29].

System inertia

The system inertia is defined as the sum of inertia in the power system. The inertia of a power system is given by the following equation

$$H_{sys} = \frac{\sum_{i=1}^{N} S_{ni}H_i}{S_{n,sys}} \tag{2.6}$$

where S_{ni} is the rated power of generator i and H_i is the inertia constant of generator i [5].

Artificial inertia

Inertia that is not provided from a synchronous machine is often referred to as artificial inertia, synthetic inertia or virtual inertia. The terms are not always used consistently in research literature, but it is possible to detect some difference between the terms based on the control theory behind it [31].

Synthetic inertia is the inertial response imitated by a adding an extra control function to the controller [5]. Synthetic inertia can be produced by wind turbines and HVDC-links. By adding additional control functions to the wind turbine, the wind turbine can use the rotational energy stored in the turbine to deliver more power during under-frequency events [32]. An HVDC-link can be controlled to provide synthetic inertia if needed. For an HVDC-link to contribute with inertia it requires that the connecting power system has available active power that can be utilized. The way it produces synthetic inertia is simply by transferring more active power through the link [33]. Provision of synthetic inertia through an HVDC-link has been successfully tried in the Caprivi Link project in southern Africa [34].

Production units that do not have any form of rotating mass can produce virtual inertia via a virtual synchronous generator (VSG). The virtual synchronous generator (VSG) is a control scheme applied to the inverter or converter of a generating unit to support the power system stability by imitating the behavior of a synchronous machine. Photovolatics and fuel cells are two generation units that could be possible providers of virtual inertia [35]. It can also be possible for energy storage systems to provide virtual inertia [36], and electric vehicles to provide vehicle-to-grid services via a VSG [37].

Hereinafter, the term artificial inertia will be used for both synthetic and virtual inertia. It must be specified that artificial inertia represents a possible way to provide inertia, but it is not commonly used today and must not be confused with the conventional inertia provided by synchronous machines.

2.3.2 Inertial response

The frequency response to a power imbalance describes how the power system will change if the frequency changes due to a power imbalance. The frequency response can be divided into: inertial response (fast primary response), governor response (slow primary response), automatic generation control (secondary control) and tertiary control [38]. The inertial response is the first to handle a change in frequency.

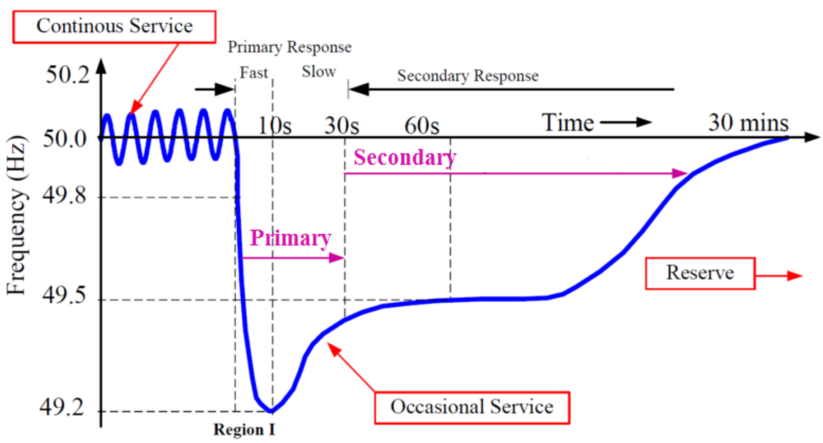


Figure 2.4: Frequency response to a power imbalance for a general power system [4].

The function of inertia is that it prevents the frequency in the power system from dropping too low through its contribution to inertial response. Inertial response is defined as a system's ability to withstand a drop in frequency. More specifically, inertial response corresponds to how much change in the total rotational energy the system is able to handle. How much change in the rotational energy the system can handle depends on the system inertia. How much a generation unit contributes to the system inertia, depends on how much frequency change the generation unit can handle until its rotational energy changes. Subsection 2.3.3 showed the inertia constants of different generation units. A big inertia constant means the generation unit contribute with more rotational energy to the system inertia, making the inertial response able to withstand larger drops in frequency [38].

2.3.3 Providers of inertia

Today inertia is provided through production by synchronous machines. The production units that provide inertia are nuclear power, thermal power, hydropower, and small-scale hydropower. Table 2.1 shows the inertia constant H for the different production units. Calculations of the inertia in the current thesis will be done exclusively from these generation units.

Production Type	**H(s)**
Nuclear	6.3
Other thermal	4
Hydropower conventional	3
Hydropower small-scale	1

Table 2.1: Inertia constants for different generation units [5]

2.3.4 Strategies to increase the inertia in the power system

Reduce the load by disconnection of pumps for hydro storage

Instead of increasing the inertia in the power system, the need for inertia can be reduced. By reducing the load, the amount of inertia needed to stabilize the frequency is reduced. The swing equation (see equation 2.4) presents the theoretical background for this. If the mechanical power is reduced due to a loss of a generation unit, the frequency will change. But if the electrical power is also reduced the frequency change will be smaller.

In [6] various options for the load reduction are presented. One of these is load reduction by disconnecting the pumps for hydro storage. When the pumps pump water up into the reservoir, they represent a load. According to [6] Norway has 13 pumps of 9 hydro storage plants. These 9 plants represent approximately 3 GWs of inertia and a load of around 1 000 MW. If there is low inertia in the system, and this corresponds to when the pumps are in use, this strategy proposes to disconnect one or more of the pumps. The pumps are usually located between two reservoirs. The upper reservoir is often a big reservoir with low inflow, while the lower reservoir is a smaller reservoir but with large inflow.

Reduce the planned import/export on an HVDC link

If there is low inertia in the power system, an option presented in [6] is to reduce the planned import or export on an HVDC link. The capacity of an HVDC link often corresponds to the dimensioning incident of a power system. The dimensioning incident is the largest change in active power that a power system can handle. If the amount of power being consumed, produced or transferred via an HVDC link is reduced, the impact of a frequency change can be limited [6].

This can easily be done by limiting the capacity of the HVDC link in the day-ahead market. Another proposed option is to limit the capacity in real-time in the balancing market. Due to the day-ahead market being a bigger market, it is better if the actors in the day-ahead market find an optimal solution for the situation.

An ancillary service market for inertia

An ancillary service market for system inertia is a market where inertia [kgm^2] is the product being sold, and the providers of inertia gets paid in [€/kgm^2] to deliver it. An ancillary market for inertia is an option if today's market solutions fail to provide the system with sufficient inertia. The market will be an ancillary market, meaning that it will only be activated if there is a need for inertia. The advantage with such a market is the possibility that it encourages investment in technology that provides inertia in a cost-efficient way. It is unknown how a market for inertia will influence the existing power markets.

In [15] several possible market designs for a inertia market is discussed, and a joint Nordic day-ahead market clearing after Elspot is found to be the best option. In such a market, the TSO estimates the expected amount of inertia in the system with information from Elspot, and uses this to estimate the amount of inertia that needs to be required through a market for inertia. The market will only be activated if there is a need for inertia.

Investing in new providers of inertia

Generation units that are attached to the grid through power converts can contribute with artificial inertia if they are designed to do so. As mentioned above, it is possible for HVDC-links, fuel cells, electric vehicles, energy storage systems, wind turbines and photovoltaics to provide artificial inertia. Other strategies to provide conventional inertia is to operate the synchronous machine of a hydropower unit or a nuclear unit to be able to run as a synchronous condenser.

2.4 The Present and Future Situation for Inertia

This section will present the situation for inertia in the Nordic power system, in ECSA and in Ireland. The situation for inertia in Ireland is interesting to study due to Ireland having a high penetration of wind generation in their power system.

2.4.1 The Nordic power system

The situation for inertia in Nordic power system is described in two reports written by the Nordic Analysis Group [5], [6].

The present situation

The Nordic Analysis Group is a group consisting of representatives from the Nordic TSOs. They initiated a project called *Future System Inertia* [5] to study the impact of future production and consumption changes on inertia. The group estimated the kinetic energy in the Nordic system using the circuit breaker positions of different generation units. The total kinetic energy capacity in the Nordic system was estimated to be 390 GWs. Table 2.2 shows the kinetic energy capacity in each Nordic country.

Area	**Kinetic Energy Capacity [GWs]**
Sweden	170
Norway	100
Finland	90
Eastern Denmark	30

Table 2.2: Kinetic energy capacity of each country's power system [5]

To observe how the kinetic energy developed from 2009 to 2015, the group used retroactive calculation. The kinetic energy in Norway, Sweden and Finland from 2009 to 2015 was observed. Denmark was not included due to lack of data. The kinetic energy can be seen in figure 2.5 to be higher during the winter. The lowest kinetic energy measured was 115 GWs during the summer of 2009. The highest kinetic energy measured was 275 GWs during the winter of 2012 [5]. During summer, the demand for electricity is low, giving low electricity prices. This often results in less inertia in the system due to low production of hydropower, and more import from fluctuating renewable energy sources. The uncertainties in the estimation are related to the accuracy of the inertia constants.

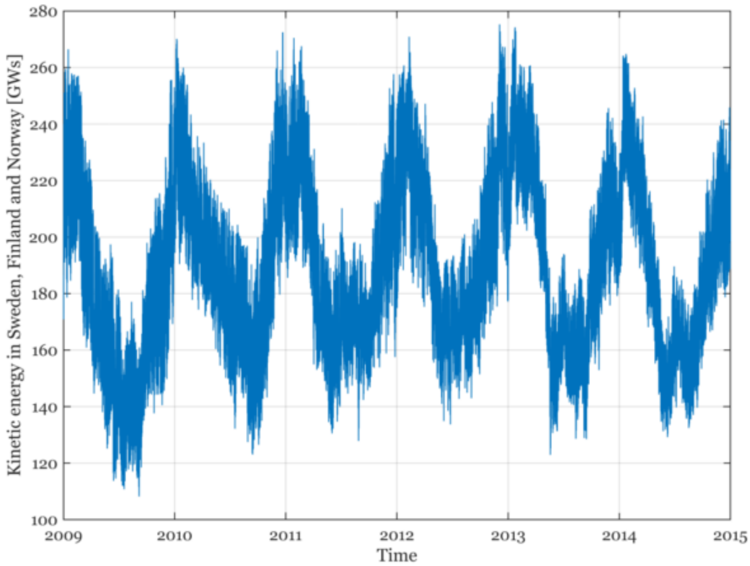


Figure 2.5: Estimated kinetic energy in Sweden, Finland and Norway from 2009-2015 [5].

The future situation

The Nordic Analysis group implemented a follow-up project finishing in 2017. The project is called *Future System Inertia 2* [6]. The objective of the project was to develop a proper forecasting tool to anticipate low inertia situations, and to develop mitigation measures to avoid low inertia situations. The project conducted a future kinetic energy estimation for the years 2020 and 2025. The results of the estimation done in [6] will be presented below.

Low inertia situations are defined as situations when the inertia in the system is below 120 GWs. The scenarios for 2020 and 2025 has been defined by the Nordic TSOs and used for input in a market simulator. The forecast resulting from this has been matched with the individual generators where the inertia constant is known making it possible estimate the kinetic energy in the system.

In 2020 it is expected that there will be some significant changes in the Nordic power system. New HVDC connections of in total 1 800 MW are expected to be in place and four Swedish nuclear reactors are expected to be decommissioned. Additionally, the demand is expected to increase with two percent compared to in 2015 and the installed capacity of wind and solar power will be increasing. Figure 2.6 shows the expected portfolio mix of 2020 and 2025.

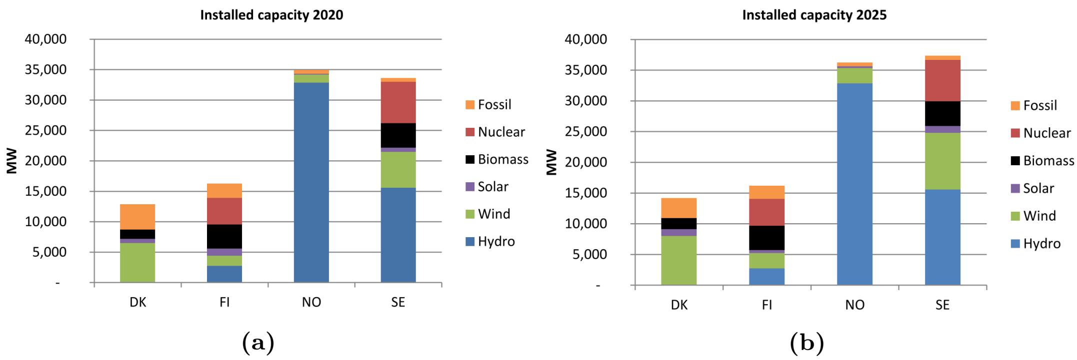
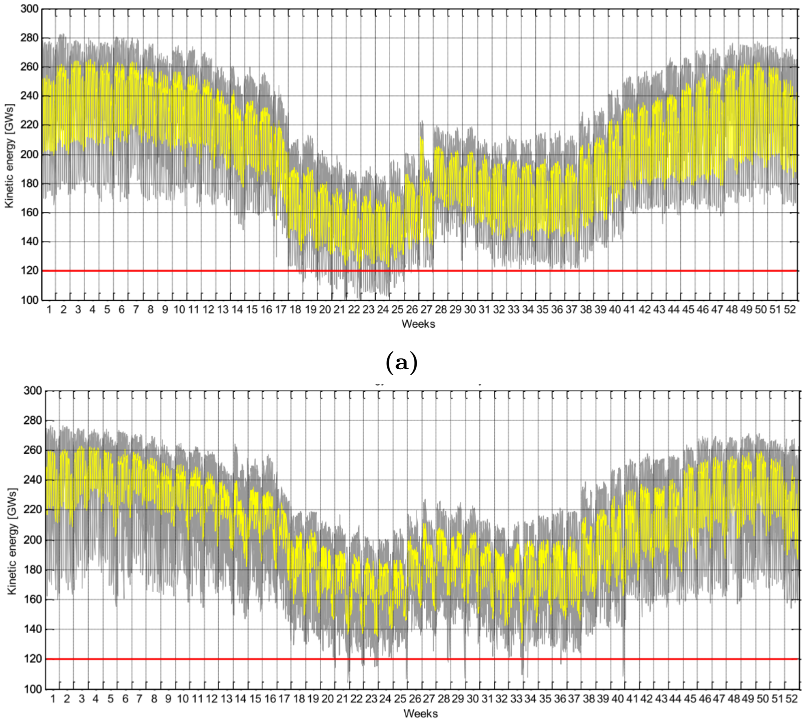


Figure 2.6: Expected installed capacity in a) 2020, and in b) 2025 [6].

In 2025 Sweden is expected to have reached 9 GW of installed wind capacity. The demand is expected to increase with six percent compared to the demand in 2020. New HVDC connections are planned to be in operation by 2025: the Hansa PowerBridge (700 MW) between Germany and Sweden and North Sea Link (1 400 MW) between Norway and England.

The estimated kinetic energy in the Nordic power system for 2020 and 2025 can be seen in figure 2.7. The yellow curve represents the average value of the simulated years, and the grey curve shows the minimum and maximum values. The red line emphasize the 120 GWs value. When the kinetic energy is below 120 GWs, this is referred to as low inertia. The power system of 2020 has more occurrences of low inertia situations than the power system of 2025. This is because the load is expected to be higher in 2025, and the kinetic energy from nuclear power plants is expected to be higher, even though the installed nuclear capacity will be the same.



(a)

(b)

Figure 2.7: Kinetic energy estimation conducted in [6] of the year a) 2020 and for the year b) 2025.

Requirements for inertia

In the Nordic power system today, low inertia situations are not a problem and it is therefore no set requirement for inertia. In the future (year 2020) power system it is expected that low inertia situations will occur. Low inertia situations are defined in [6] to be when the kinetic energy is below 120 GWs. The Nordic TSOs consider it necessary take measures when the kinetic energy in the future Nordic power system is below 130 GWs.

2.4.2 The European Continental Synchronous Area (ECSA)

The power generation mix in ECSA is currently dominated by conventional energy sources. The generation mix is expected to shift to more renewable energy sources (RES) in the coming years. Figure 2.8 shows the power generation mix in ECSA in 2015. A small amount of the power generation comes from RES providing inertia (hydropower and biomass), and another small amount of the power generation comes from RES that do not provide inertia, while a large share of the power generation comes from conventional generation units [7].

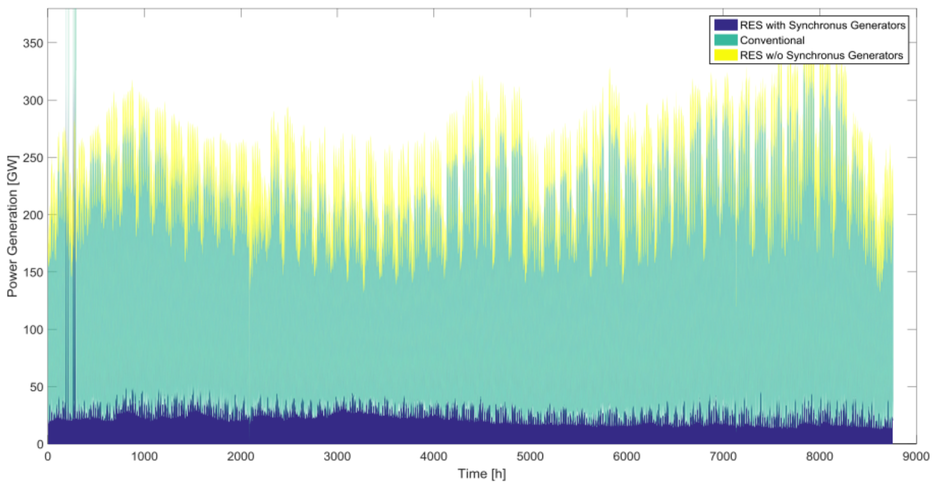


Figure 2.8: Power generation mix in the ECSA in 2015 [7].

Requirements for inertia

The ECSA has no formal requirement for inertia, but they do however have a requirement for the rate of change of frequency (RoCoF). In [39] the European Network of Transmission System Operators for Electricity (ENTSO-E) evaluated the frequency stability in the ECSA. This was done by analyzing the impact reduced system inertia will have on system operation. The main parameter that ENTSO-E used when analyzing this was the rate of change of system frequency (RoCoF). The RoCoF is given as

$$RoCoF = \frac{df}{dt} = f_n \frac{P_m - P_e}{2E_{rot}} \tag{2.7}$$

where, $\frac{df}{dt}$ is the change in frequency, f_n the nominal frequency, P_m represents the mechanical power, P_e represents the electrical power, and E_{rot} represents the rotational energy.

Today the continental European power system is able to withstand a RoCoF of 1 Hz/s. Market simulations conducted in the ENTSO-E report showed that the future continental European power system system must be able to withstand a RoCoF equal to 2 Hz/s. The increase in the RoCoF is a result of future system expansions, higher power exchanges and future power generation technologies [39].

A decrease in inertia will cause higher RoCoF in the continental European power system, making it more difficult to meet the requirements to the RoCoF. Given the power generation mix in the ECSA, this can prove a problem for the ECSA. As a result the ECSA might have to rely on synthetic inertia provision [7].

2.4.3 Ireland

The synchronous system of Ireland has a high penetration of renewable energy sources. In 2002 installed wind generation in Ireland was 145 MW. By 2014, installed wind generation had increased to 2825 MW. This number is set to increase over the coming years and it is expected that Ireland by 2020 will have a total wind generation of 6 GW. In 2014, 21,4% of the demand was covered by wind generation. Through national and European targets Ireland aims to have 40 % of the country's electricity generation delivered by renewable energy sources. When addressing the issue of inertia and the need for an ancillary market for system inertia, the situation in Ireland is important to study because Ireland are facing these issues in the near future [40], [17].

As a response to the national and European targets, the TSOs of Ireland and North-Ireland launched the DS3 program. The program aims to find a secure way to operate the Irish power system today and in the future [40]. A focus of the program is related to the delivery of new ancillary services, and synchronous inertial response being one of them. Introducing inertia related constraints in the Irish power market is considered an option. As a first step in this direction, Ireland has installed an inertia monitor in the control room of the TSO to warn operators if the inertia available from synchronized generators drops below a pre-determined level [17].

Requirements for inertia

The Irish TSOs, EirGrid and SONI, have set an operational limit for RoCoF and inertia. The limit represents the normal intact transmission network limit and can vary from time to time due to changing system conditions [41]. The operational limit for RoCoF is ≤ 0.5 Hz/s. The operational limit for inertia is ≥ 20 000 MWs, meaning that the inertia in the Irish power system must be over 20 000 MWs. According to [6] Eirgrid does not consider low inertia to be an issue today, but the future trends indicate that inertia will decline as the penetration of non-synchronous renewable generation increases further.

2.5 Optimization

This section will give an introduction to the optimization theory relevant to understanding the model that will be used in this master thesis. The optimization problem is a linear programming problem with mixed integer constraints. To solve the optimization problem, the branch and bound algorithm is used. This section will explain integer programming and the branch and bound algorithm.

2.5.1 Integer programming

Integer programming is a method within optimization where one or several variables are restricted to integer values. The problem is usually a linear programming problem. A linear programming (LP) problem is a problem where all functions describing the objective function and the constraints are linear functions. It is possible to have non-linear integer programming problems, but it is not common and few solution methods exist to solve non-linear integer programming problems. This is due to the complexity of these problems. A general formulation of a linear integer programming problem is

$$\min \ z = \sum_{j=1}^{n} c_j x_j \tag{2.8a}$$

$$\text{s.t.} \quad \sum_{j=1}^{n} a_{ij} x_j \ \leq \ b_i, \ \ i = 1, .., m \tag{2.8b}$$

$$x_j \ \geq \ 0, \ \ \text{integer}, \ \ j = 1, ..., n \tag{2.8c}$$

where z is the objective function, the objective function coefficient for variable x_j is c_j, a_{ij} is the constraint coefficient for variable x_j in constraint i, and b_i represents the right-hand side coefficient in constraint i [8].

The feasible area of a integer programming problem is non-convex and consists of a set of discrete points. The optimal solution can be anywhere within the feasible region. Figure 2.9 shows the feasible region of an integer programming problem. The feasible region is the set of all possible solutions to the optimization problem that satisfy the problems constraints. There are two main reason for applying integer variables in a model. The first reason is when the integer variables are natural integers. The second reason to use integer variables is when they represent decisions and are logical, or binary variables [8].

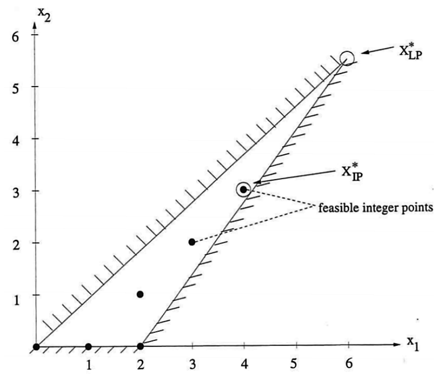


Figure 2.9: Example of an integer programming problems feasible region [8].

LP relaxation

LP relaxation is a way to simplify the integer programming problem into a LP problem. This is done by removing the integer requirements on the constraints and solve the problem as a LP problem. When an optimal solution is found the constraints are rounded up or down to the nearest integer value.

Mixed integer programming

A special case of integer programming is mixed integer programming. Mixed integer programming means that only some of the variables in the optimization problem are required to have integer values [42]. This means that the optimization problem can contain both integer and continuous variables.

2.5.2 The Branch & Bound method

The branch and bound (B&B) method is a method for solving integer programming problems. The idea behind the B&B method is to split the problems feasible region into smaller regions with corresponding subproblems. In each subproblem a relaxed (simplified) problem is solved.

The problem is branched into subproblems by either adding one or several constraints, or by fixing the value of one or several variables. To keep track of the new constraints a search tree is created. The subproblems are represented in the search tree as nodes. The edges represent the new constraints that are added, or fixed, to form new subproblems. In each subproblem the algorithm finds an optimal solution with a pessimistic bound and an optimistic bound. These bounds are explored into new branches. If a better solution is found, the branch is cut away [8].

Part II

Methodology

3 Model

The model is based on the work described in [10], which will also be used for reference in this chapter, and was originally developed at NTNU by Yonas Gebrekiros in his PhD. This master thesis uses a modified version of Gebrekiros' model. The model is based on linear integer programming, and is implemented in GAMS IDE[1]. The solver used for the optimization is Cplex[2], and it uses a Branch & Bound algorithm explained in section 2.5.2 to solve the optimization problem.

3.1 Mathematical Formulation

This section will explain the mathematical formulation behind the model used in the thesis. The objective is to minimize the total costs from the day-ahead market within a specified planning period, and to find the optimal transmission capacity allocation between the balancing areas included in the model [10].

The following power units are included in the model: gas, oil, oil and gas regulating generators, hard coal units, nuclear power plants, miscellaneous renewables, wind power, solar power and hydropower.

3.1.1 Thermal unit

The power units: gas, oil, oil and gas regulating generators, hard coal units, nuclear power plants, miscellaneous renewables and lignite coal power plants are all modelled the same way and denoted thermal units for the rest for the section. Miscellaneous renewables are all renewable energies except from solar and wind (most of it is biomass).

Binary variables

The optimization problem is a mixed integer programming problem due to its binary variables. The binary variables in the model represent the start up status of a unit, $\delta_{a,g,\tau,t}$, or the start-up transition of a unit, $u_{a,g,\tau,t}$. The planning period is denoted τ.

$$\delta_{a,g,\tau,t} = \begin{cases} 1, & \text{if the thermal unit } g \text{ in area } a \text{ at time } t \text{ is on,} \\ 0, & \text{otherwise.} \end{cases}$$

[1]The GAMS is an optimization tool, and GAMSIDE adds the ability to monitor the compilation of GAMS models [43]

[2]Cplex solves LP problems by using different algorithms [43]

$$u_{a,g,\tau,t} = \begin{cases} 1, & \text{if thermal unit } g \text{ in area } a \text{ is started up at time } t, \\ 0, & \text{otherwise.} \end{cases}$$

Day-ahead costs

The day-ahead costs of a thermal unit consist of fuel costs, start-up costs and fixed costs. The constraint associated with the day-ahead costs are related to the maximum and minimum capacity of the units generator. The total day-ahead costs of a thermal unit are described by equation 3.1. The output of each thermal unit is restricted by the maximum and minimum generation capacity of the unit. The set of thermal units are denoted G, T is the set of time periods, Γ is the set of planning periods.

$\forall g \in G, t \in T, \tau \in \Gamma, a \in A$

$$\sum_{a \in A} \sum_{t \in T} \sum_{g \in G_a} (p_{a,g,\tau,t} \cdot MC_{a,g} + u_{a,g,\tau,t} \cdot SC_{a,g} + \delta_{a,g,\tau,t} \cdot FC_{a,g}) \tag{3.1}$$

$$\text{s.t.} \qquad p_{a,g,\tau,t} \geq \delta_{a,g,\tau,t} \cdot \underline{P}_{a,g} \tag{3.2}$$

$$p_{a,g,\tau,t} \leq \delta_{a,g,\tau,t} \cdot \overline{P}_{a,g} \tag{3.3}$$

where $\overline{P}_{a,g}$ and $\underline{P}_{a,g}$ is the maximum and minimum generation capacity, $MC_{a,g}$ is the marginal costs, $SC_{a,g}$ is the start-up costs, and $FC_{a,g}$ is the fixed costs of a thermal unit g.

3.1.2 Hydro unit

Each hydro unit is modelled as a unit with a generator and a reservoir. The inflow into the reservoir is divided into storable inflow and non-storable inflow (often referred to as spillage). Figure 3.1 shows a typical hydropower system.

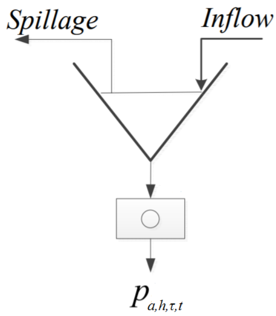


Figure 3.1: Representation of a hydropower system [9].

The total production from a hydro unit, h, is the sum of the production from storable inflow, $p^{st}_{a,h,\tau,t}$, and the production from the non-storable inflow, $p^{ns}_{a,h,\tau,t}$. The production is restricted by the maximum and minimum generation capacity of each unit hydro unit; $\overline{P}_{a,h,\tau}$ and $\underline{P}_{a,h,\tau}$. The set of hydro units are denoted H.

$\forall h \in H, t \in T, \tau \in \Gamma, a \in A$

$$p_{a,h,\tau,t} = p^{st}_{a,h,\tau,t} + p^{ns}_{a,h,\tau,t} \tag{3.4}$$

$$\text{s.t.} \qquad p_{a,h,\tau,t} \leq \overline{P}_{a,h,\tau} \tag{3.5}$$

$$p_{a,h,\tau,t} \geq \underline{P}_{a,h,\tau} \tag{3.6}$$

The reservoir of a hydropower unit has storeable and non-storable inflow. The reservoir balance of a reservoir depends on the previous period reservoir level, the storable inflow, the spillage and the production of power from the storable inflow. The reservoir of a hydro unit is subject to a constraint regarding the magasin parameters, $\overline{mg}_{a,h,x}$, that is a preset size.

$\forall h \in H, t \in T, \tau \in \Gamma, a \in A$

$$Mg_{a,h,\tau} = Mg^{prev}_{\tau,a,h} + Q^{stor}_{a,h,\tau} - \sum_{t \in T} p^{st}_{a,h,\tau,t} - Of_{a,h,\tau} \tag{3.7}$$

$$\text{s.t.} \qquad Mg_{a,h,\tau} \leq \overline{m}g_{a,h,x} \tag{3.8}$$

where $Mg_{a,h,\tau}$ represents the reservoir balance, $Mg^{prev}_{\tau,a,h}$ the previous period reservoir level, Q_{stor} the storable inflow, and $Of_{a,h,\tau}$ is the overflow from a reservoir connected to hydro unit h.

Day-ahead costs

The total cost of a hydro unit is defined as the water value, $WV_{a,h,x,\tau}$, of the sum of the overflow from a reservoir and the storable inflow into the reservoir.

$\forall h \in H, t \in T, \tau \in \Gamma, a \in A$

$$\sum_{a \in A} \sum_{h \in H_a} \left(Of_{a,h,\tau} + \sum_{t \in T} p^{st}_{a,h,\tau,t} \right) \cdot WV_{a,h,x,\tau} \tag{3.9}$$

3.1.3 Solar unit and wind unit

The renewable energies solar power and wind power are modelled with zero costs in the day-ahead market. The cost of production is zero, and they are therefore not included in the objective function. The production output of these two renewable energy sources are restricted by the capacity of the power plant they are connected to.

$\forall t \in T, \tau \in \Gamma, a \in A$

$$p^{s}_{a,\tau,t} \leq \overline{P}^{s}_{a,\tau,t} \tag{3.10}$$

$$p^{w}_{a,\tau,t} \leq \overline{P}^{w}_{a,\tau,t} \tag{3.11}$$

where $\overline{P}^{s}_{a,\tau,t}$ is the maximum solar power generation, and $\overline{P}^{w}_{a,\tau,t}$ is the maximum wind power generation.

3.1.4 Load shedding

If demand is not equal to production a load shedding generator is activated. The generator produces power at a higher price than the normal generators do, and are therefore only activated in times where it is needed. The day-ahead costs of load shedding is often referred to as rationing costs. The total costs of load shedding within a planning period is given in equation 3.12.

$\forall \tau \in \Gamma$

$$\sum_{a \in A} \sum_{t \in T} (p^{cur}_{a,\tau,t} \cdot VLL) \tag{3.12}$$

where $p^{cur}_{a,\tau,t}$ is the curtailed load, and VLL is the rationing costs.

3.1.5 Transmission restrictions

The model is a net transfer capacity model, meaning that the energy exchange between the different balancing areas is restricted. The restriction is based on the capacity of the cables and overhead lines. The energy exchange, $ep^A_{a,b,\tau,t}$, is restricted by the net transfer capacity, $NTC_{a,b}$, between the balancing areas a and b.

$\forall a, b \in A, t \in T, \tau \in \Gamma$

$$ep^A_{a,b,\tau,t} \leq NTC_{a,b} \tag{3.13}$$

$$ep^A_{b,a,\tau,t} \leq NTC_{b,a} \tag{3.14}$$

3.1.6 Load balance

The load balance is given in equation 3.15. The load must at all times be equal to the difference between the power generated and the power exported. The dual value [3] of the load balance is the spot price. The load balance, $PL_{a,\tau,t}$ per area a at a given day τ in a given hour t, is given by the following equation.

$\forall a \in A, t \in T, \tau \in \Gamma$

$$\begin{aligned}\sum_{g \in G_a} p_{a,g,\tau,t} + \sum_{h \in H_a} p_{a,h,\tau,t} + p^s_{a,\tau,t} + p^w_{a,\tau,t} \\ - \sum_{b \in A} ep^A_{a,b,\tau,t} + p^{cur}_{a,\tau,t} = PL_{a,\tau,t}\end{aligned} \tag{3.15}$$

3.1.7 Objective function

The objective is to minimize the expected total costs from the day-ahead market within a planning period, τ. The objective function is found by combining the equations for the day-ahead costs of the different power units: 3.1, 3.9, 3.12.

$\forall \tau \in \Gamma$

$$\begin{aligned}\min \quad & \sum_{a \in A} \Bigg\{ \sum_{t \in T} \Bigg[\sum_{g \in G_a} (\, p_{a,g,\tau,t} \cdot MC_{a,g} + u_{a,g,\tau,t} \cdot SC_{a,g} + \delta_{a,g,\tau,t} \cdot FC_{a,g}) \\ & + p^{cur}_{a,\tau,t} \cdot VLL \Bigg] + \sum_{h \in H_a} \Big(Of_{a,h,\tau} + \sum_{t \in T} p^{st}_{a,h,\tau,t} \Big) \cdot WV_{a,h,x,\tau} \Bigg\}\end{aligned} \tag{3.16}$$

[3]The dual value represents the change in the objective function if the constraint is relaxed with one unit.

3.2 System Model

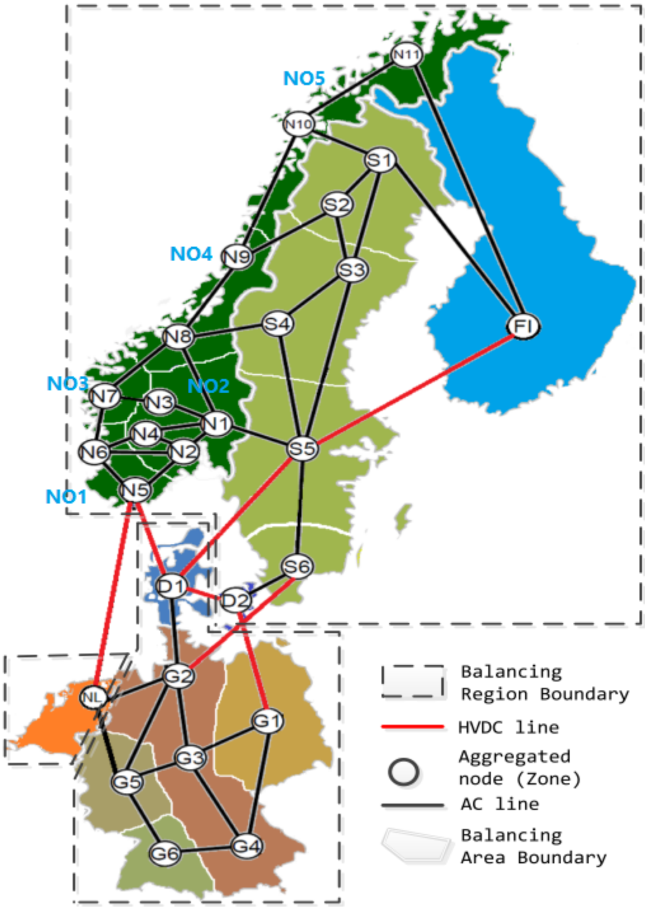


Figure 3.2: Northern European system modelled in the model [10]. The white lines indicate the price areas.

The model is a simplified model of the one described in [10] using the same input data. The input data is a case study from 2010. The simulation model represents the North European power system in 2010. The system consists of 17 balancing areas, and three balancing regions. Within each balancing area, there is one or more price areas. These are described in figure 3.2 as aggregated nodes. The balancing regions represented in the model are the Nordic Region, Germany and the Netherlands. Figure 3.2 shows the system modelled. The Norwegian bidding areas of 2010 are labelled in the figure.

Figure 3.2 shows an interconnection between Norway and Finland. This interconnection is disregarded in the model due to the capacity on the interconnection being small (around 50 MW) compared to the other interconnections.

3.2.1 Generation units

All generation units are modelled as ideal generation units. This means that a capacity range of 0-100% is assumed possible.

Thermal units

The data for the thermal units are taken from [44]. The thermal units modelled are: gas, oil, hard coal, nuclear power, lignite coal and miscellaneous renewables. The simulation model takes in the maximum capacity [MWh] of each thermal unit on each day in the simulation period. The model also takes in minimum capacity [MWh], the fixed costs [EUR], the start-up costs [EUR] and the marginal costs [EUR/MWh] of each thermal unit. As mentioned above, the units are assumed ideal and the minimum capacity of the thermal units is zero.

Hydro units

The water values for the hydro units are collected from the EFI's Multi-area Power-market Simulator (EMPS). The EMPS model is a multi-area model developed for optimization and simulation of hydrothermal production of the Nordic power system. It is divided into two phases: a strategy phase where the water values are calculated and a simulation phase. The water values in the case study are collected from the EMPS model and used as marginal costs of the hydro units. The inflow scenario used is the median hydro inflow scenario from the EMPS model [45].

The hydro units are restricted by the size of their reservoirs [MWh]. It is also possible that the hydro units are run-of-river hydro units, meaning that they do not have a reservoir. The maximum and minimum production [MWh] of each hydro unit is given per day. The marginal cost of each hydro unit is the water value of each hydro unit [EUR/MWh].

Wind and solar units

The production of wind and solar per area are modelled with maximum production output equal to the available wind or solar capacity in an area for a given hour [MWh]. The data for the wind and solar series are collected from the COSMO EU model [46].

3.2.2 Demand

The demand in each area is given per hour for each day in the simulation period [MWh]. The data for the demand is collected from [47] which is a part of the *EU FP7 TWENTIES project*.

3.2.3 Transmission

The model is a net transfer capacity (NTC) model, meaning that the transmission capacity limits the amount of power transferred between different price areas. The net transfer capacity between the balancing areas in the model are collected from European Network of Transmission System Operators for Electricity (ENTSO-E) [48]. The NTC between the balancing areas are used as exchange constraints in the optimization [10].

Interconnections

The model is based on a case study from 2010, and all interconnections installed after 2010 are therefore not included in the model. Since then the HVDC connection between Norway and Denmark has been increased with 700MW. Table 3.1 shows the total transmission capacity of the interconnections from Norway in the 2010 simulation model. The interconnection to Finland, is as mentioned earlier, neglected in the simulation model.

Table 3.1: Transmission capacity of the interconnections between Norway and the other countries in the model.

Sweden [MW]	3 600
Denmark [MW]	1 000
The Netherlands [MW]	700

4 Method

The model presented in the previous section will be used to quantify the costs of three different strategies that aims to increase the inertia in the power system. This section will explain how the inertia is estimated, how the socioeconomic costs are quantified and how the different strategies are implemented in the model.

4.1 Estimation of Inertia

Equation 2.1 defines inertia in relation to the kinetic energy of the rotating masses. The amount of inertia in the Norwegian power system will in this master thesis indirectly be defined through the amount of rotational energy in the Norwegian power system.

4.1.1 Calculation of the rotational energy

The rotational energy in the scenarios studied can be found by rewriting equation 2.6 to express the rotational energy in the system instead of the system inertia. The rotational energy in the Norwegian power system can then be expressed as

$$E_{rot,sys} = \sum_{i=1}^{N} S_{ni} H_i \text{ [MWs]} \tag{4.1}$$

The 2010 data set only contains information about the rated active power. To be able to use equation 4.1 a *power factor* on 0,9 is assumed. The rotational energy of one power plant is then calculated by

$$E_{rot} = \frac{P \cdot H}{0,9} \text{ [MWs]} \tag{4.2}$$

where H is the inertia constant of the power plant and P is the rated active power of the power plant.

The inertia constant is specific for each power plant. The 2010 case study does not contain information about the inertia constant of each power plant, and general values for the inertia constants, presented in table 2.1, are therefore used.

To calculate the rotational energy in a power system for a given day, the sum of the rotational energy contribution from all the power plants is found (see equation 4.1). It is only assumed that the power plants that deliver rotational energy through a synchronous machine contribute with rotational energy. Synthetic inertia providers are not included when calculating the rotational energy.

4.1.2 Simplifying assumptions

- The inertia constant is assumed to be constant for all hydro generators. In reality each generator has an individual inertia constant.

- The hydro generators are assumed to be ideal, meaning it is assumed that they can deliver 0-100 %. In reality this would not be the case. The turbines have an operating range that limits their minimum and maximum production point. Figure 4.1 illustrates the operating range for the different turbine types. The turbines that are the most common in Norway today are Francis, Kaplan and Pelton. Taking the operating range into account would result in lower rotational energy values.

- A power factor of 0.9 has been assumed, due to lack of information regarding the rated power of each generator. To find an accurate power factor, information about the rated power of each synchronous machine must be known.

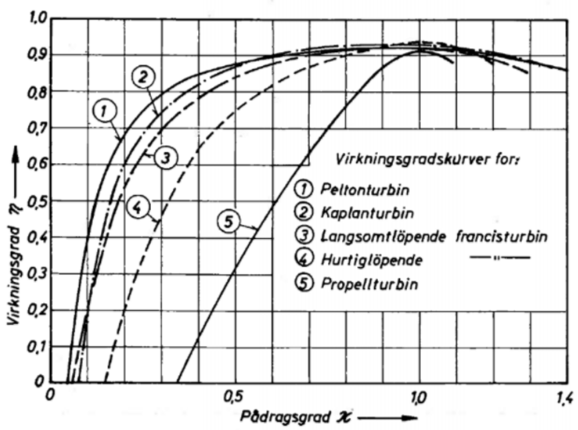


Figure 4.1: Typical hydraulic efficiency types for five different turbine types: 1 - Pelton, 2 - Kaplan, 3 - Francis (slow running), 4 - Francis (quick running), 5 - Propeller. The factor κ is defined as discharge relative to best efficiency discharge [11].

4.2 Costs

The costs of the different strategies are measured by the weighted average price of electricity, the total socioeconomic cost of electricity in the simulation period and the potential cost of change in reservoir levels.

4.2.1 The weighted average price

The weighted average price, often referred to as the system price, is defined as the average price a Norwegian electricity consumer have to pay for electricity in a given hour. The weighted average price of a given hour in Norway is

$$\overline{MP}_{w,t} = \frac{\sum_{a=1}^{5} MP_{a,t} \cdot D_{a,t}}{\sum_{a}^{5} D_{a,t}} \text{ [EUR/MWh]} \tag{4.3}$$

where $MP_{t,a}$ is the price of electricity in area a in hour h, and $D_{t,a}$ is the electricity demand in the same area at the given hour.

The yearly average system price is the average price of electricity that the Norwegian consumers paid in one year. It is defined as

$$\overline{MP}_{w,year} = \frac{\sum_{t=1}^{8760} \overline{MP}_{w,t}}{8760} \text{ [EUR/MWh]} \tag{4.4}$$

4.2.2 The cost of change in reservoir level

If the reservoir level at the end of the simulation period differ from the reservoir level at the beginning of the simulation period, this indicates that there will be less water in the reservoirs next year. This can potentially lead to higher electricity prices due to higher water values. The costs of change in reservoir level represents an estimate of how much more the consumers will have to pay for electricity in the following year. This cost is estimated as

$$C_{res} = \sum_{t=1}^{8760} \sum_{a=1}^{5} (MP_{t,a}^{Sim.2} - MP_{t,a}^{Sim.1}) \cdot D_{t,a} \text{ [EUR/year]} \tag{4.5}$$

where $MP_{t,a}^{Sim.1}$ is the market price of electricity in the first simulation, and $MP_{t,a}^{Sim.2}$ is the market price of electricity in the second simulation. The second simulation has been run using the reservoir values of the last day of simulation 1 as start-value for the reservoirs.

4.2.3 Total socioeconomic costs

The socioeconomic costs can be defined as the total cost of electricity for the electricity consumers in Norway in the simulation period. The total socioeconomic costs are found by

$$C_{consm} = \sum_{t=1}^{8760} \sum_{a=1}^{5} MP_{t,a} \cdot D_{t,a} \text{ [EUR/year]} \tag{4.6}$$

4.2.4 Simplifying assumptions

- The cost of change in reservoir level is found by using the reservoir level at the end of the simulation period as input into the model. There are several uncertainties related to this simplification; the inflow for the next year is not known, the demand is unknown and the generation of sun and wind power in the connected power systems are not certain. All of this can influence the size of this cost.

4.3 Strategies

Three strategies are proposed to ensure sufficient inertia in the Norwegian power system. The first strategy is to set a minimum production level for the hydro units, the second strategy is to change the power transfer to an HVDC link and the third strategy is load reduction by disconnecting the pumps for pumped hydro storage. The two first strategies are implemented in the model, while the last strategy has been evaluated using information from the hydro producers and through a cost estimation.

4.3.1 Strategy 1: Define a minimum production level for hydro generators

As described in section 3.2.1 all generation units are assumed ideal. This implies that they can choose not to produce if they want to. The first strategy defines a restriction on the minimum production level of the hydro units. The idea is that if there is a restriction stating that the hydro generators always have to produce at a certain output, there will always be inertia in the power system. The strategy will be extended to only apply on days where the rotational energy in the power system is below a certain value.

The restriction is formulated to be that the hydro unit must produce at a minimum of 20 % of their maximum power. Equation 3.6 presented in the section 3 is modified to the following

$$\underline{P}_{a,h} = 0.2 \cdot \overline{P}_{a,h} \tag{4.7}$$

Implementation of strategy 1

To implement this strategy into the simulation model, a restriction regarding the reservoir level in the reservoirs of the hydro units was required to be added. For the reservoirs to not be emptied a constrained is set regarding the amount of water available in the reservoirs.

This is done by evaluating the reservoir level of the hydro units reservoir on the previous day. If 2,5 % of the size of the reservoir on the previous day is larger than the restriction presented in equation 4.7, the reservoir is assumed to be big enough to be "forced" to produce power, and the restriction regarding the minimum production on 20 % of the rated power output applies. If not $\underline{P}_{a,h}$ is set to its original value, zero. Mg_{prev} [MWh] represents the previous period reservoir level.

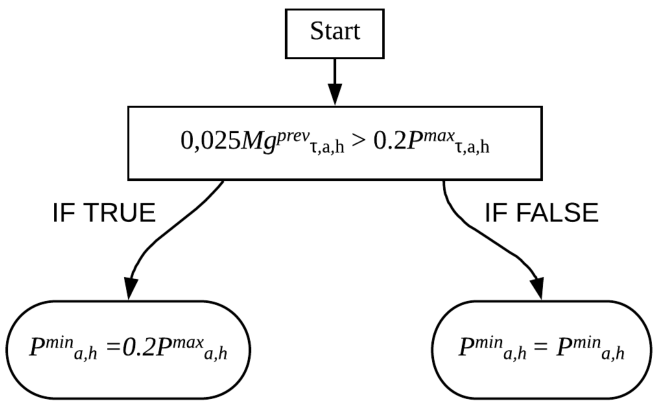


Figure 4.2: The method used with the H_{min}-strategy.

Quantification of costs

The total consumer costs of the first strategy are the total costs of electricity plus the cost of change in reservoir level. Equation 4.6 explained how the increased costs for the consumers in the second simulation year are calculated. The difference between this value for the Base Case scenario and for strategy 1 is how much more the consumers have to pay for the electricity in the second simulation year with strategy 1. This value is added to the total costs of strategy 1 and denoted ΔC_{res}.

$$C_{consm} = \sum_{t=1}^{8760} \sum_{a=1}^{5} MP_{t,a} \cdot D_{t,a} + \Delta C_{res} \text{ [EUR/year]} \tag{4.8}$$

Extending strategy 1 to only apply on days with low rotational energy

The first strategy is extended to only apply on days where the rotational energy in the power system is below a certain value. This value should be the minimum wanted level of rotational energy that should be present in the power system at all times. Due to limitations in the model, a safety margin should be added to the minimum value to make sure it applies to all happenings of low rotational energy.

Figure 4.3 shows the extended strategy 1. $E^{rot,min}$ is the preset minimum value, $E^{rot}_{\tau,a}$ is the rotational energy on a given day, τ in a given area a, and ϵ is the safety margin. The model includes the rotational energy from the original data set, and compares this to the specified minimum value. If the total rotational energy on a given day is below $E^{rot,min}$ and the reservoir level on the previous day fulfills the restriction set for it, the Hmin-restriction applies. If not $\underline{P}_{a,h}$ is set to its original value, zero.

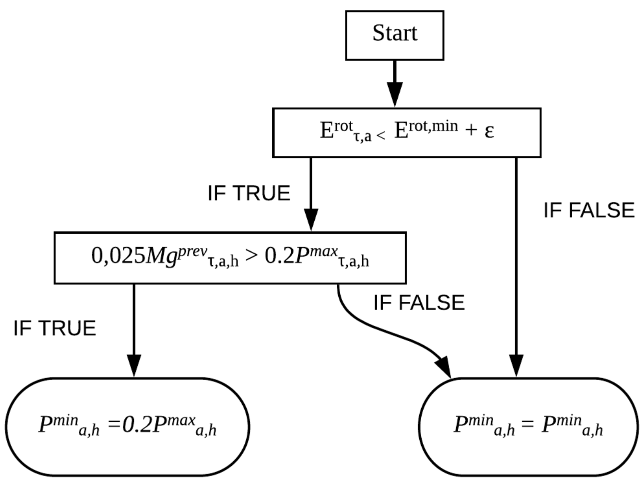


Figure 4.3: The method used with the extended H_{min}-strategy.

4.3.2 Strategy 2: Reduce the planned import/export on an HVDC link

The year 2020 is assumed to be the year when the Nordic power system will experience problems with inertia. One of the things that cause low inertia situations are the new HVDC links. This strategy proposes to change the capacity on the planned interconnection between Norway and Germany, Nord Link. Nord Link will be installed by 2020 and have a capacity of 1 400 MW. The original data set is from 2010. To get an impression of the effect of Nord Link in 2020 a simplified 2020 scenario is developed and used as comparison for the results.

Simplified 2020 scenario

This scenario is a simplified estimate of how the generation mix might be in 2020 in Germany and Norway. The Norwegian generation portfolio is assumed to be approximately the same (see figure 2.7 and table 5.1)[1], while the German generation mix is assumed to have an increase of the wind and sun generation. According to Fraunhofer the generation of wind and sun is expected to increase with around 50 % or more in Germany by 2020 [49]. In this simplified 2020 scenario, the data set of Wind and sun generation is increased with 50 % in all of Germany. The remaining parameters of the 2010 data set remains the same.

Implementation of strategy 2

The capacity will be reduced if the rotational energy in the Norwegian power system is below a certain limit. This limit is set to be 35 GWs. This is a fictional minimum limit set for simulation purposes in this master thesis. It is influenced by the minimum rotational energy limit used for the simulations in [6] and the amount of rotational energy in the Nordic countries found in [5]. If the rotational energy in the Norwegian power system is below 35 GWs on a given day in the simulation period, the capacity of the HVDC link will be reduced from 1 400 MW to 1 000 MW on this day.

The days with low rotational energy is found by running a simulation with the original capacity of the HVDC link. When the days with low rotational energy are found, the capacity of Nord Link is changed to 1 000 MW for these days. A new simulation is then conducted with the new values of Nord Link for some days. The electricity market is left to figure out the generation mix with the reduced capacity. The method is illustrated in figure 4.4.

[1]The wind generation in Norway is expected to increase by 2020, but this increase is not big enough too have an impact on the results in this scenario

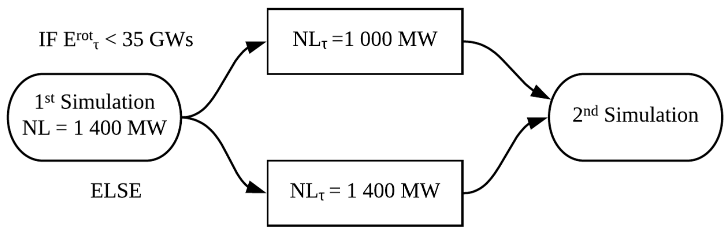


Figure 4.4: The method used to reduced the import/export on an HVDC link.

Simplifying assumptions

The uncertainties in the cost estimation and the effectiveness of this strategy is related to the simplifications made in the implementation of the second strategy in the model.

- The minimum limit of 35 GWs is an estimate. If the limit is in reality higher, there will be more occurrences of low-inertia situations and the capacity will have to be reduced more often which will give a higher cost. If this limit is set too high, it will be the other way around.
- The capacity is reduced for the whole day if the rotational energy is low. To get a more accurate estimate the capacity should be reduced only on certain hours with low rotational energy. The simplification of reducing the capacity on a daily basis gives a higher price than if it was on an hourly basis.
- Due to limitations in the model, the capacity is reduced based on already calculated rotational energy values. Calculating the rotational energy per hour in the simulation of the model would be more accurate.
- The capacity is reduced with 400 MW for all days with low rotational energy. Basing the size of the reduction on how low the rotational energy is would give a better estimate of the total socioeconomic costs.

4.3.3 Strategy 3: Reduce the load by disconnection of pumps for hydro storage

The third strategy is proposed to activate in times where the inertia in the power system is low. When the inertia is low, the power system cannot handle a big change in frequency. If a generation unit is lost, there is less inertia available to stabilize the frequency. By disconnecting the pumps used in pumped hydro storage systems the system load will be decreased. When pumped hydro storage systems pump water up into their reservoirs they consume power and represent a load.

The hydro producers follow two patterns when they pump water up into their reservoirs, and their willingness to turn the off pump if it is needed depends on which of the pumping pattern they follow:

1. If there is danger of overflow from the below reservoir the hydro producers pump water up to the reservoir above. In this situation they are in general not interested in turning their pumps off.

2. The other situation where the hydro producers pump water up to a reservoir occurs if there is low prices of electricity, and prospects of higher electricity prices at a later point. An example of this is that the hydro producers want to pump the water up at night, when the price is low, and sell it again later when the price is higher. Due to the start/stop costs of the pump they usually do not pump for less than 5-8 hours. In this pumping situation some of the hydro producers will be willing to turn off their pumps as long as they are remunerated.

Due to restrictions in the pumping system, some hydro producers only follow the first pumping pattern, while some follow both depending on the season. In Norway there exists different pumped hydro storage systems. The flexibility of the hydro storage depends on how it has been designed. If the pumping system has only been designed for pumping when there is danger of overflow from the lower reservoir, the pumps are not designed for fast start/stop of the pump, and they only utilize the first pumping pattern. Other pumping systems are installed with reversible pumps that run synchronously with the grid. When they run they provide the system with rotational energy. These pumping systems follow both pumping patterns.

A short survey was conducted among the hydro producers that have a pumped hydro storage to map their pattern of pumping and whether they were interested in disconnecting their pumps if they were remunerated for it. Table 4.1 shows the result of this survey. The hydro producers that answered maybe reasoned that they thought it would be too expensive to remunerate, and/or they felt it would not be relevant for their pumped hydro storage [50], [51], [52], [53].

Hydro producer	Follow pumping patterns	Interested
Statkraft	1 + 2	Yes
E-CO	1 + 2	Maybe
Hydro	1	Maybe
Lyse/Sira-Kvina	1 + 2	Yes

Table 4.1: Result of the survey conducted among some of the Norwegian hydro producers with pump storage.

Disconnection of load

How big of a load that needs to be disconnected depends on how low the systems' rotational energy is. When defining a minimum limit for the systems rotational energy, all values below that is regarded as low inertia situations. In this thesis the minimum limit for the rotational energy in Norway is set to be 35 GWs. The size of the load that needs to be disconnected can be found by rearranging equation 4.2.

$$\Delta P = \frac{\Delta E_{rot} \cdot 0,9}{H} \text{ [MWs]} \tag{4.9}$$

where ΔP is an estimate of the load that needs to be disconnected to bring the rotational energy up to 35 GWs, ΔE_{rot} is the difference between the minimum set limit of 35 GWs and the measured rotational energy, and H is the inertia constant. For the pumps of the hydro storage this is the same as for a hydro plant, 3 s.

Estimation of costs

Most of the pumps are easy to stop. It is only relevant to disconnect the pumps when the pumps follow the second pumping pattern. The costs associated with the disconnection of the pumps are the lost income in the spot market and maintenance costs related to start/stop of the pumps. The lost income in the spot marked depend on the price of electricity when the pumps are pumping water up, the efficiency loss of the pumping process and the possible selling price.

$$C_{pump} = \Big[(1-\eta) \cdot MP_{sell} - MP_{buy}\Big] P_{pump} \cdot t + 2 \cdot C_{start/stop} \qquad \text{[EUR]} \tag{4.10}$$

where C_{pump} is the total cost of disconnecting the pump, η is the efficiency of the pump, MP_{sell} is the selling price [EUR/MWh], MP_{buy} is the buying price [EUR/MWh], P_{pump} represents the load of the pump [MW] and $C_{start/stop}$ is the maintenance costs related to starting and stopping the pump.

MP_{buy} is found by taking the average market price during the night on the days with low inertia. The night is in this thesis estimated to be from midnight until eight in the morning. The average selling price, MP_{sell}, is found by taking the average of the highest market prices in the simulation period. The amount of market prices that is averaged depends on how many days with low rotational energy that occur; if the pump can be turned off all days it is 104 and if it can only be disconnected on certain days it is 48 for the original data set. If ΔP is bigger than the size of the pump, more pumps need to be disconnected in order to get the rotational energy at the desired level.

Simplifying assumptions

Several simplifications has been done in the estimation of the socioeconomic costs related to this strategy. The socioeconomic cots can not be seen as an accurate number, it is merely an upper estimate.

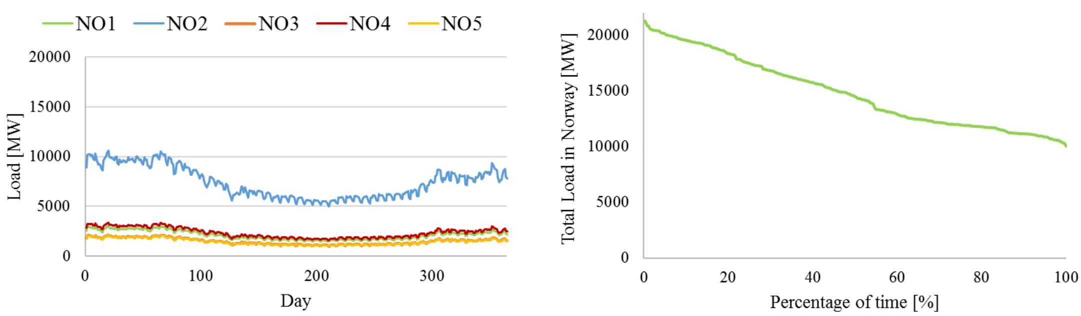
- The start/stop costs depends on the size of the pump, the condition of the pump, how long it is until next maintenance and the labour costs of the maintenance work. An estimate of the start/stop costs found in [54] for a pump of 110 MW with five years to next maintenance due to start/stop has been used. For a more accurate estimation of the start/stop costs it is advised to use [54].
- Every start/stop increases the maintenance costs. This increase has not been accounted for and represents an uncertainty.
- How long the pumps are planning to be in operation varies. In this thesis it is assumed to be 8 hours, but the duration can be longer or shorter, and the costs would be smaller or larger depending on this.
- If the pumps are available for disconnection depend on the inflow season. If the inflow is high, the pumps are not available for disconnection. The time frame of the inflow season is depends on where in Norway the pumps are located. This has not been taken into account.
- The cost estimation is based on a minimum limit of 35 GWs in the Norwegian power system. This limit might in reality be smaller or higher, reducing or increasing the need for pumps to be disconnected. The disconnection of pumps will most likely be a mitigation measure for the Nordic power system, which will give a different minimum rotational energy limit.

5 Data Set

The data set used as input in the model is a 2010 case study presented in section 3.2. The simulations with this data set will be denoted "Base Case" and will be used to analyze the effect of the strategies to ensure sufficient inertia in the Norwegian power system. The simulation period is one year.

5.1 Original Data Set

5.1.1 Load



(a) (b)

Figure 5.1: The load in NO1, NO2, NO3, NO4 and NO5 in the simulation period (a) and a duration curve of the total load (b).

The load in the simulations are fixed throughout the whole simulation. Figure 5.1a shows the load in the five Norwegian price areas. Figure 3.2 shows the location of the price areas in 2010. The load in NO2 is the highest. The load fluctuates on a weekly basis; it is often higher in the week days than on weekends. The load in NO2 has bigger fluctuations than the other price areas, and there is a bigger difference between the peak load and the low load. The load is highest the three first months of the year (up to day 100), and the last months of the year (from day 300-365). During the summer months the load is low. NO3 has almost the same load as NO1, and NO3 is therefore hard to spot. NO5 has the lowest load. The lowest load that appears in one price area is around 1 GW and happens in NO5 during the summer. The highest load in a price area is in NO2 and happens during the winter.

Figure 5.1b shows the duration curve for the total load in Norway for the given year and the total load in Norway. The peak load in Norway is around 21 GW, and the lowest load in Norway is around 10 GW. Comparing the two figures shows that the load in NO2 has a big influence on the total peak load and the total low load.

5.1.2 Prices

Figure 5.2 shows that the spot price is higher during the winter months than in the summer months. The spot price is at its highest from around day 60 (the end of February) to around day 110 (the mid of April). The price areas NO2, NO4 and NO5 all have high spot prices in this period compared to the rest of the year.

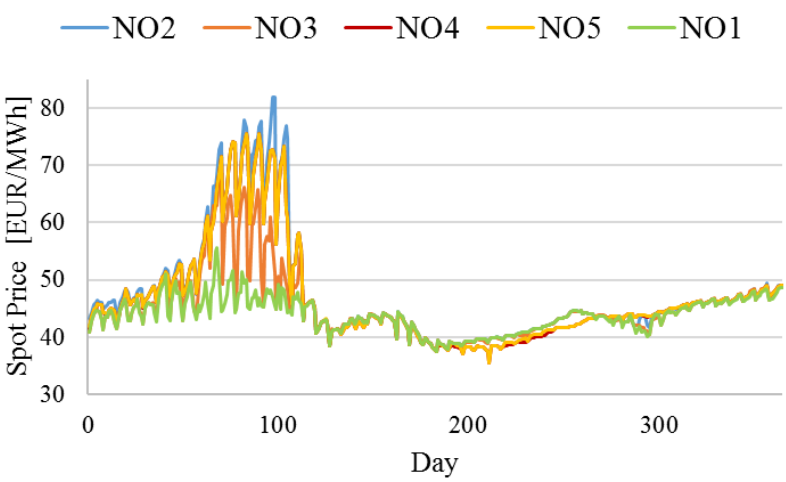


Figure 5.2: The spot price in NO1, NO2, NO3, NO4 and NO5.

NO2 has in general the highest spot price throughout the year, and NO1 has the lowest spot price throughout the year. NO4 and NO5 have almost the same spot price making the spot price of NO4 hard to see in figure 5.2. NO1 have a more stable spot price throughout the year due to its HVDC connections to the European continent.

From the figures 5.2 and 5.1 a correlation between high load and high spot price can be interpreted. When the load in Norway is high, the spot price in Norway is also high. When the load is low the price of electricity is also low.

Weighted average price

The average system price per day in the simulation period follows the same path as the spot price in the NO2 and NO5 price areas. Figure 5.3 shows the average system price in Norway. It is high in the winter months, especially in the beginning of the year and low in the summer months. The weighted average price in Norway for the whole year is: $\overline{P}_{w,year} = 45,5$ EUR/MWh.

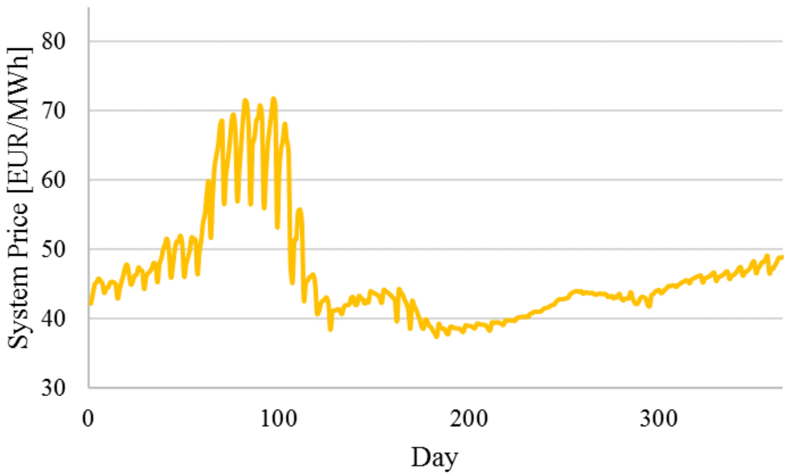


Figure 5.3: The system price for the Base Case scenario.

5.1.3 Inflow

The storable inflow is defined as the inflow of water that the hydro reservoirs have capacity to store, while the non-storable inflow cannot be stored. The highest inflow in Norway is when the snow is melting in the spring and summer. Figure 5.4 shows that this is from around day 140 (the mid of May) until around day 200 (the end of June).

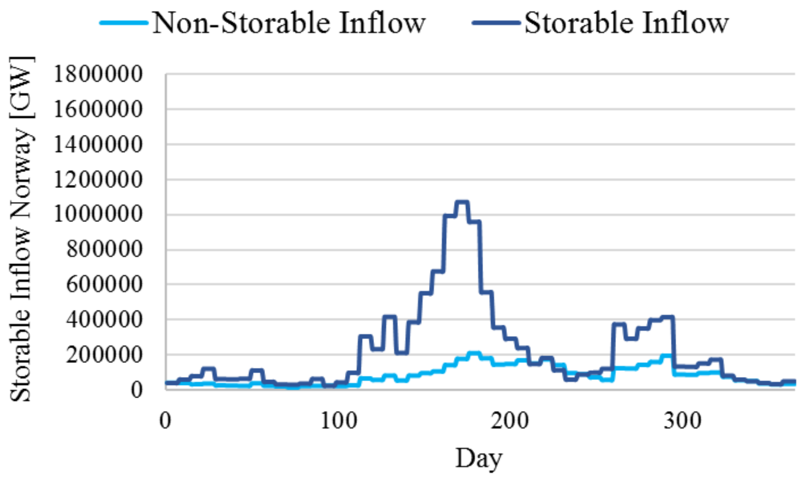


Figure 5.4: The storable and non-storable inflow in Norway during the simulation period.

5.1.4 Reservoir level

Figure 5.5 shows the reservoir level in the Norwegian price areas in the simulation period.

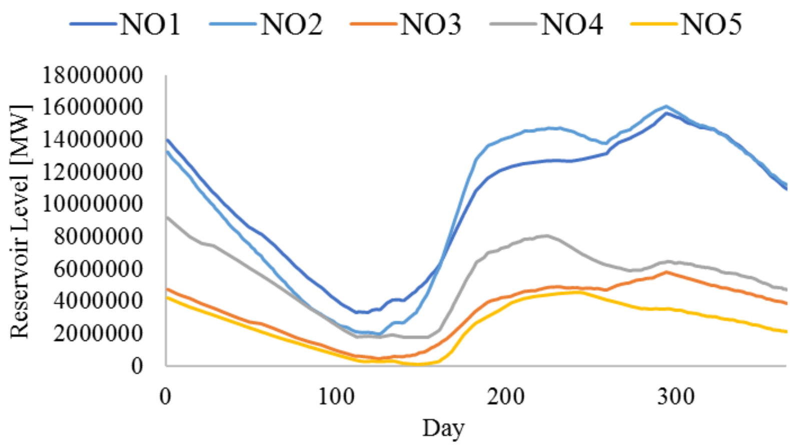


Figure 5.5: The reservoir level in the Norwegian price areas in the simulation period.

The reservoir levels vary with the season; the highest inflow is during snow-melting.

Snow-melting is in the spring and summer, depending on where in Norway the reservoirs are. Figure 5.5 shows that the lowest reservoir level is from around day 100 to around day 140, which corresponds to the mid of April to mid of May. After this the reservoir level rises through the spring and summer months with a peak at the end of July (around day 210 in the figure). The reservoir level increases a little bit more in the fall months, this is mainly inflow from rain. The hydro producers wish to produce when the spot price is high. Therefore the hydro producers wish to save as much water as possible in the summer and fall months when the spot price is low, and produce when the spot price is higher.

5.1.5 Production

Table 5.1: The production mix in Norway and in Germany.

	Norway [%]	Germany [%]
Wind	0,1	2
Sun	-	39
Thermal	-	54
Hydro	99,9	2

Norway's generation mix consist of hydropower production and a small share from wind. Table 5.1 shows the Norwegian and the German generation mix. The German generation mix is presented due to it being relevant to understanding the results of one of the strategies to ensure sufficient inertia. When looking at the production in Norway for the rest of the thesis, it will only be on the hydro production. All price areas in Norway have hydropower production.

Figure 5.6 shows the duration curve of the total hydro output in the different price areas. NO2 has the highest production in the simulation period, and the most hydropower units. NO3 and NO5 has the smallest share of the hydro production compared to the other price areas. They produce on a more even output. NO5 and NO3 has small hydro generators compared to the other price areas.

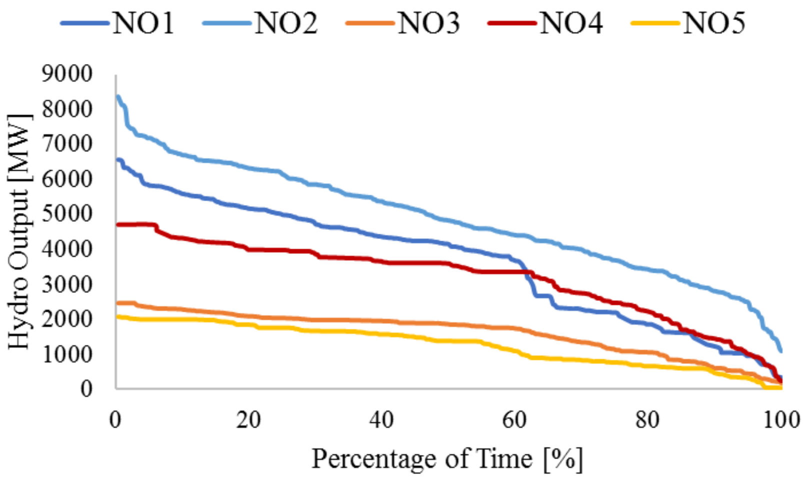


Figure 5.6: Duration curve of the total hydro output on NO1, NO2, NO3, NO4 and NO5.

Figure 5.7 shows the total hydro production in Norway and the total load in Norway. Note that the y-axis of figure 5.7 and figure 5.6 has different maximum bounds. The total hydro production fluctuates more than the load, and it often exceeds the load implying that power is exported. The load is most of the year covered by the hydro production.

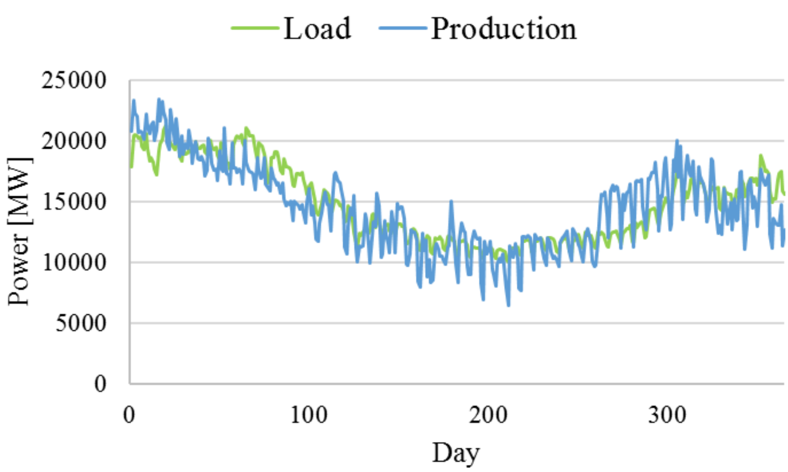


Figure 5.7: The total load, and the total production of power in Norway.

5.1.6 Import and export

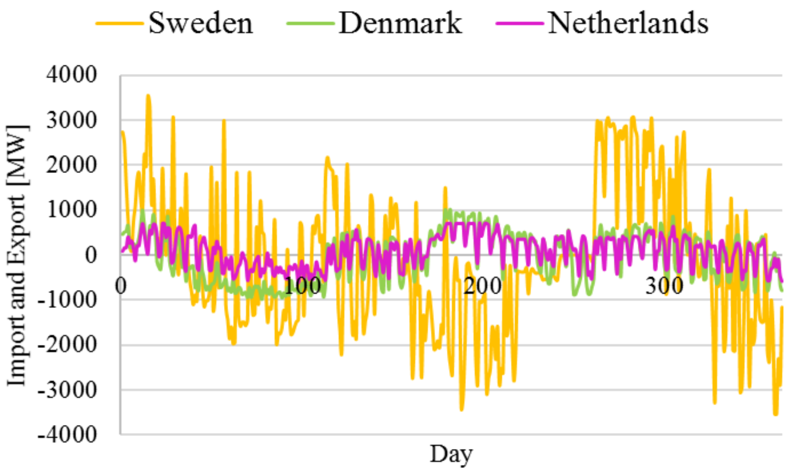


Figure 5.8: The import (-) and export (+) of power from Norway.

In the 2010 data set Norway is interconnected with Sweden, Denmark and the Netherlands. Import of power often happens if there is need for power in Norway, or if cheap power can be imported. Export of power happens if there is a need for power in any of the interconnected countries or if the power can be sold at a higher price.

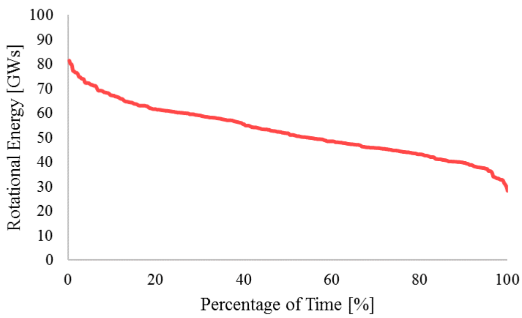
Sweden is the country Norway has the most import and export with, as it is the country Norway has the largest transmission capacity to (see table 3.1). From around day 150 to day 250, Norway exports power to the Netherlands and Denmark while importing power from Sweden. The reason for this is often related to market speculations; that the price of power is cheap in Sweden, but more expensive in the Netherlands and Denmark, so Norway sells some of the imported power to make a profit. When the price of power is the most expensive in Norway (around day 60 to around day 110) there is more import of power. In the summer months the water values of the reservoirs are often higher than the spot price, leading to higher import of power.

5.1.7 Rotational energy

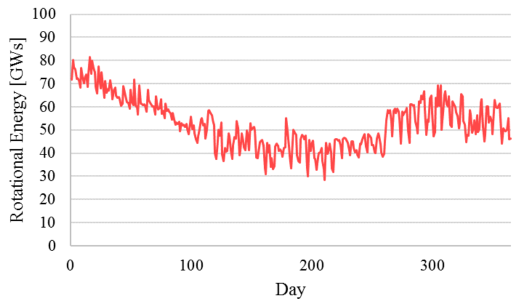
The rotational energy in the Norwegian power system is highest in the beginning and at the end of the year. The highest rotational energy value is observed in the middle of January. The rotational energy is lower in the summer months, with the lowest rotational energy value is observed at end of July.

This correlates well to the information about the load in the Norwegian power system, when the load is high, the production is high and then also the rotational energy. The close correlation between production of power and rotational energy is especially strong in Norway due to Norways large share of hydropower. In the beginning of the year the spot price is also at its highest in Norway, making it profitable for the hydropower producers to produce power. In the summer months, when the spot price is low, the water value is often higher than the spot price resulting in less hydropower production and more import of power.

Figure 5.9 shows a duration curve of the rotational energy in the simulation period. The minimum rotational energy present in the base case scenario is 28,5 GWs. The average value is 51,9 GWs and the maximum value is 80 GWs.



(a)



(b)

Figure 5.9: Duration curve of the rotational energy in the original data set in (a) and the rotational energy throughout the simulation period in (b).

Part III

Analysis

6 Results

This chapter presents the main results of the simulations conducted, and the results of the different strategy scenarios. The results of the simulations will be compared with the Base Case scenario explained in chapter 5.

6.1 Strategy 1: Define a Minimum Production Level for Hydro Generators

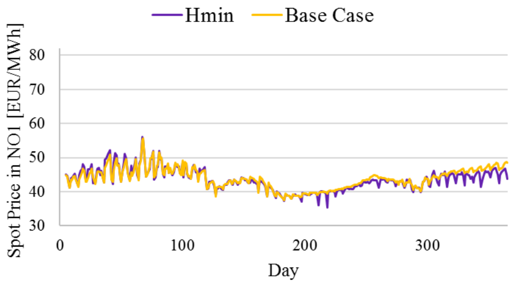
This section will show the results of simulations with a restriction regarding the minimum production level of a hydro unit, referred to as strategy 1 and explained in section 4.3.1.

6.1.1 Prices

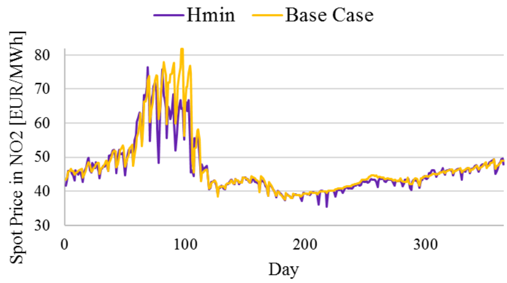
Spot Price

Figure 6.1 compares the spot price in the Norwegian price areas with the Hmin restriction, to the spot price in the corresponding price area for the Base Case scenario. NO4 and NO5 have the same spot price, therefore only NO4 is shown in the figure. The general trend is that the Hmin restriction gives lower spot prices. Since the restriction sometimes forces the hydro units to produce, this is a result of a cheaper hydro unit producing power, that normally would not produce.

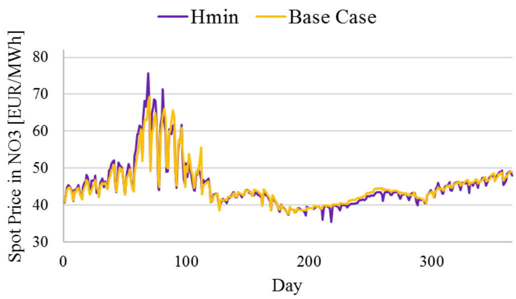
In the beginning of the year, the restriction does not change the spot price in NO1 noticeably. The spot price is almost the same for the two scenarios. From June until the end of the year, the spot price is in general lower with the Hmin restriction. In NO2, NO4 and NO5 the restriction gives lower spot prices from the mid of March (around day 75). From mid of June (around day 200) the price profile of the two scenarios are similar, but with lower minimum points on some days for the Hmin restriction. In NO3 the Hmin restriction gives higher spot prices in the beginning of the year and lower from the summer until the end of the year. In NO3 the spot price of the two scenarios follow an almost identical profile, only that the Hmin restriction has a little bit higher price peaks and a little bit lower price dips.



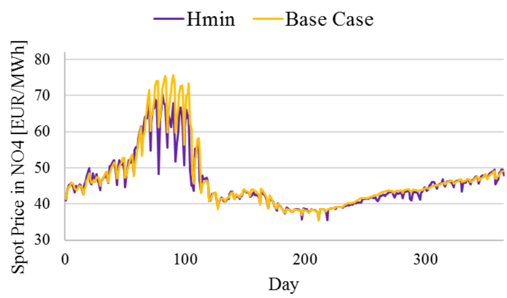
(a) Spot price in NO1



(b) Spot price in NO2



(c) Spot price in NO3



(d) Spot price in NO4

Figure 6.1: Spot Price of Electricity in NO1, NO2, NO3 and NO4. NO4 and NO5 share similar plots for the spot price, therefore only NO4 is shown in this figure.

Weighted average price

Figure D.4 shows the system price of electricity in Norway during one year, with and without the restriction regarding the hydro output.

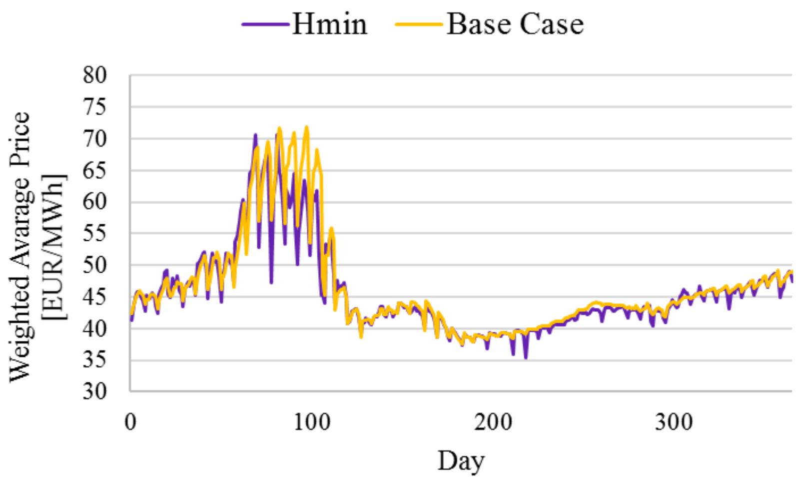


Figure 6.2: Weighted average price of the two scenarios in one year.

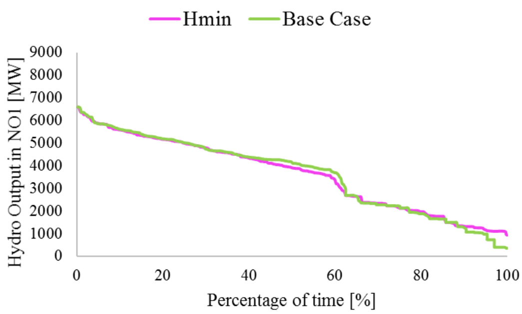
The graph in figure 6.2 resembles the graph of the spot price in NO2, NO4 and NO5 showed in figure 6.1. Since NO2 has the highest load, it can be assumed that the spot price in NO2 has the most influence on the weighted average price in Norway. The yearly average system price of electricity in the simulated year can be seen in table 6.1. The average price is lower with the Hmin restriction compared to the average Base Case price.

Table 6.1: Average system price of electricity, $\overline{P}_{w,year}$ in Norway in one year.

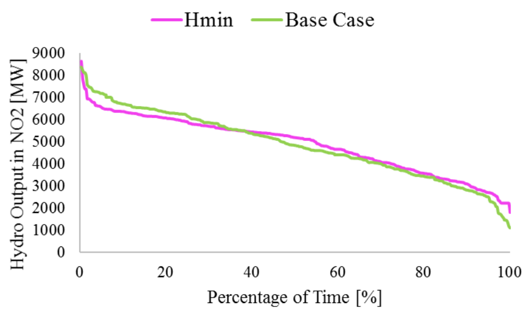
	Base Case	Hmin Restriction
$\overline{P}_{w,year}$ [EUR/MWh]	46,50	45,75
Difference: Hmin Restriction - Base Case [EUR/MWh]	0,75	

6.1.2 Hydro output

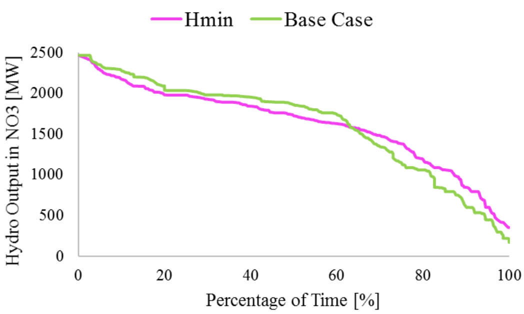
Figure 6.3 shows duration curves of the hydro output in four of the five price areas. NO4 has only a small difference in the hydro output with the Hmin restriction and is therefore not included in the figure. In general the hydro output is higher with the Hmin restriction in all the price areas from 60-100 % of the time. In all price areas, the 100 % value is higher with the Hmin restriction. The maximum output is the same. NO3 has the biggest difference in hydro output between the two scenarios of the price areas.



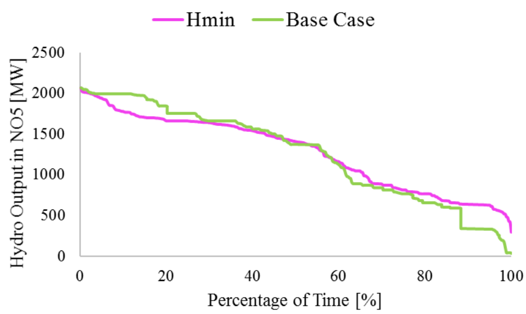
(a) NO1



(b) NO2



(c) NO3



(d) NO5

Figure 6.3: Hydro Output Duration Curve for NO1, NO2, NO3 and NO5. Note that the two upper figures have different maximum bound on the y-axis than the two lower figures.

Table 6.2 shows the 50 % value of the hydro output duration curve for the five price areas. The 50 % value is the hydropower production that is produced 50 % of the time, and is referred to as the median.

Table 6.2: The median hydro output (the 50 % value) in the five different price areas in Norway for the Base Case scenario and with the Hmin restriction.

	Base Case	Hmin restriction
NO1 [GW]	4,159	3,899
NO2 [GW]	4,841	5,192
NO3 [GW]	1,852	1,725
NO4 [GW]	3,610	3,458
NO5 [GW]	1,370	1,407
Total for: NO1, NO2, NO3, NO4 and NO5 [GW]	14,43	14,57

For the total hydro output the median is 0,14 GW higher with the Hmin restriction than with the Base Case Scenario. The median is also higher with the Hmin restriction in NO2 and NO5. In the other Norwegian price areas the median is lower. Since the load in both scenarios is the same, the increase in the total hydro output with the Hmin restriction indicates an increase in export of power.

Change in output power for the hydro units

The Hmin restriction changes the output of the hydro units. Table 6.3 shows the difference in hydro output between the two scenarios. The numbers showed in table 6.3 is the difference in sum of production between the two scenarios. A negative number means the hydro unit produces less with the Hmin restriction. Two generators in NO2 are not included in the table. These two generators had a minimal change in the total output compared to the other generators in NO2 and were excluded due to space limitations.

Table 6.3: Sum of the difference in hydro output between Hmin restriction and Base Case. Values shown in tabular are Hmin-Base Case.

Hydro Unit	h1	h2	h3	h4	h5	h6	h7	h8	h9
NO1 [MW]	-2363,4	-2237,9	-2078,8	-2204,5	2135,5	1367,3	1937,3		
NO2 [MW]	4081,8	3175,6	4179,1	4278,8	599	-1910,7	-1997	203,3	-1984,4
NO3 [MW]	159,5	115,6	387,5						
NO4 [MW]	535,1	526,0	577,3	1131,0	1475,5	773,5			
NO5 [MW]	957,1	1247,0	912,0	-579					

In NO1 four of the five generators produce less with the Hmin restriction. In the other price areas most of the generators produce more with the restriction. The hydro unit with the biggest change in output power is shown in table 6.3 to be h4 in price area NO2.

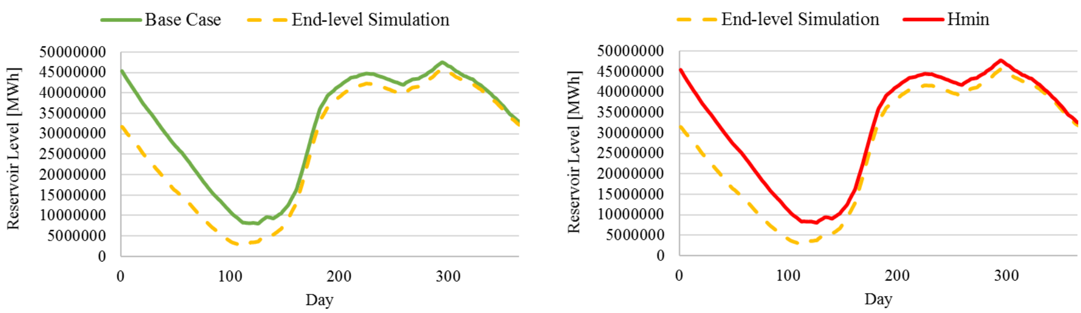
6.1.3 Reservoir level

Table 6.5 shows the total reservoir level in Norway at the last day of the simulation period (day 365) in the Base Case and Hmin scenario.

Table 6.4: Reservoir level at the end of the simulation period for both scenarios, and the cost of change in reservoir level.

	Base Case	Hmin Restriction
Reservoir level day 365 [GWh]	32890,7	32501,1
Difference: Hmin Restriction - Base Case [GWh]		-389,6

When adding a Hmin restriction 389,7 GWh more is produced by the hydro units in Norway. This means, that in the following year there will be 389,7 GWh less available water in the reservoirs. Less water in the reservoirs means higher water values which again will lead to higher electricity prices and higher socioeconomic costs. Figure 6.4 shows the reservoir level of the first simulation (solid line) and the reservoir level using the reservoir level at the end of the simulation period as input into a new simulation (dotted line). The reservoir level has the same value at the end of the simulation period for both simulations.



(a) Base Case (b) Strategy 1

Figure 6.4: Reservoir level with the original input data (solid line), and the reservoir level using the reservoir level at the end of the simulation period as input into a new simulation (dotted line).

Change in reservoir level for one hydro unit

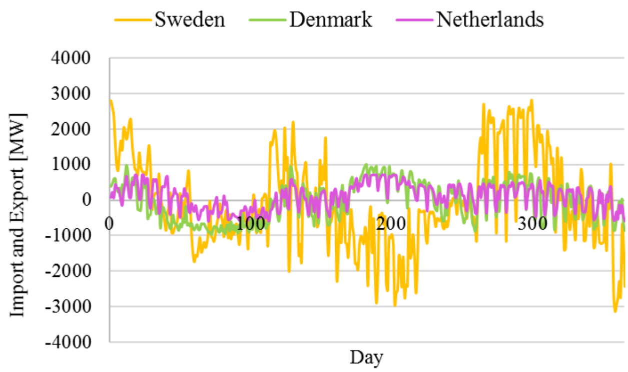
The hydro unit h4 in NO2 experiences the biggest change in output power with the Hmin restriction. Table 6.5 shows the change in reservoir level on the last day of the simulation period for the original simulation, and for the second simulation using the reservoir level of the last day of the original simulation.

Table 6.5: Reservoir level at the end of the simulation period for hydro unit h4 in NO2.

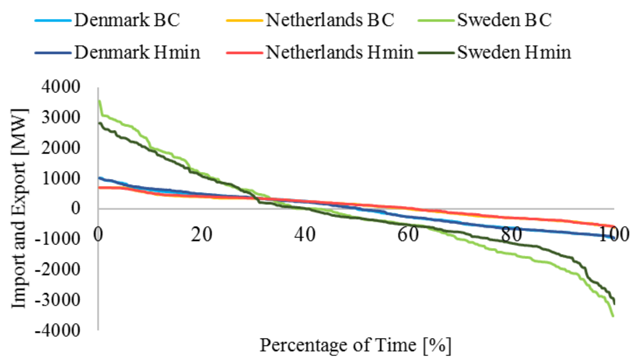
	Base Case	Hmin Restriction
Simulation 1 Reservoir level day 365 [GWh]	488,9	386,3
Simulation 2 [GWh]	475,4	382,7
Difference: Simulation 1 - Simulation 2 [GWh]	13,5	3,6

6.1.4 Import and export

Figure 6.5 shows the import and export to and from Norway after implementing the first strategy.



(a)



(b)

Figure 6.5: Import (-) and export (+) of power from Norway with the Hmin restriction (a) and presented as a duration curve (b).

In the beginning of the year (from day 0 to around day 40), the export to Sweden increases. The rest of the year the import and export from Norway follow the same pattern as in the Base Case scenario. The import/export to Netherlands and Denmark does not change by implementing the first strategy. The import from Sweden increases slightly while the export to Sweden decreases slightly with the Hmin restriction.

6.1.5 Rotational energy

The Hmin restriction leads to a significant increase in the rotational energy in the Norwegian power system. Figure 6.6 shows the duration curve of the rotational energy in the Norwegian power system with and without the Hmin restriction.

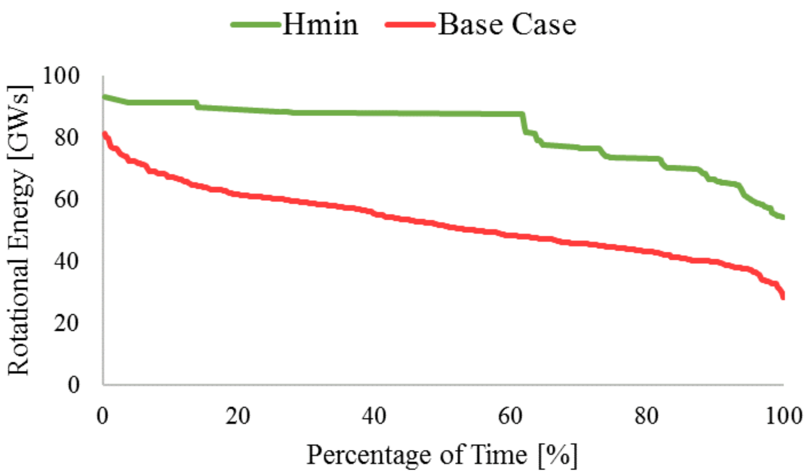


Figure 6.6: Duration curve of the rotational in the Norwegian power system in the two scenarios.

The rotational energy with the Hmin restriction has several equal measurements giving a more step-wise curve for the rotational energy than the Base Case curve that consists of several different values for the rotational energy. It can be interpreted that the Hmin restriction leads to more generators producing at times where they would not produce without the Hmin restriction.

Table 6.6 shows the minimum value and the median of the rotational energy with and without the Hmin restriction. The minimum rotational energy in the Norwegian power system with the Hmin restriction is 54,4 GWs. This is almost twice the value of the minimum rotational energy in the Base Case. The median of the rotational energy is also significantly higher with the Hmin restriction.

Table 6.6: Minimum value and the median of the rotational energy in the Norwegian power system in the simulation period.

	Base Case	Hmin Restriction
Minimum value [GWs]	28,5	54,4
The median [GWs]	51,9	87,7

6.1.6 Costs

Cost of change in reservoir level

Table 6.7 shows the cost of change in reservoir level for the Base Case scenario and the Hmin scenario. Table 6.4 showed when adding a Hmin restriction 389,7 GWh more is produced by the hydro units in Norway. The 389,7 GWh less available water in the reservoirs for the next simulation year corresponds to a cost of 1,25 billion euros, that can be seen as an additional cost for the Norwegian consumers.

Table 6.7: The cost of change in reservoir level with the Hmin restriction.

	Base Case	Hmin Restriction
Cost of change in reservoir level [EUR]	7 443 885 496	8 696 801 038
Difference: Hmin - Base Case [EUR]	1 252 915 542	

Total socioeconomic costs

Table 6.8 shows the total socioeconomic costs of the Hmin restriction compared to the Base Case scenario. The increased costs of change in reservoir level is adjusted for. With the Hmin restriction the total costs of electricity is 1,17 billion euros higher than in the Base Case scenario.

Table 6.8: The total socioeconomic costs of the Hmin restriction compared to the Base Case scenario.

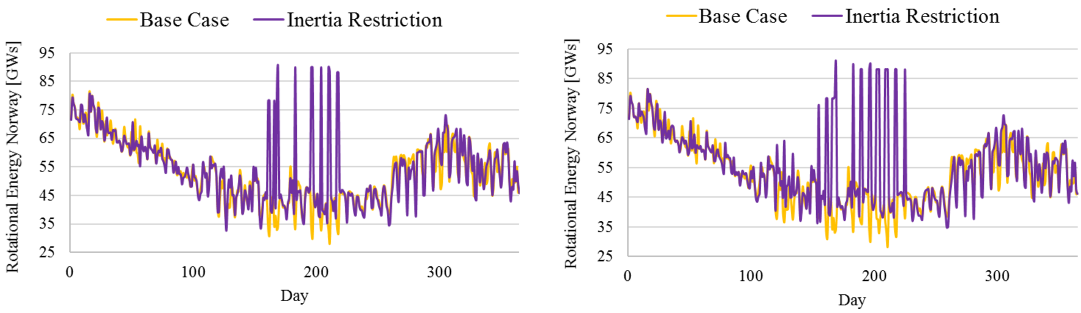
	Base Case	Hmin Restriction
Total price of electricity in Norway [EUR]	6 183 712 544	6 103 332 970
With the cost of change in reservoir level [EUR]	6 183 712 544	7 356 248 512
Difference: Hmin - Base Case [EUR]	1 172 535 968	

6.1.7 Rotational energy restriction

Strategy 1 is extended to only activate when the rotational energy in the Norwegian power system is below a certain value.

Rotational energy

By defining 35 GWs as the minimum limit for the amount of rotational energy in the Norwegian power system, the base case scenario has 13 occurrences where the total rotational energy in the system is below 35 GWs. The Hmin restriction has no occurrences where the rotational energy is below 35 GWs. By extending the restriction regarding the minimum production level from hydro units to only apply when the inertia is below 35 GWs, the total socioeconomic costs are significantly reduced. The occurrences of low-rotational energy situations are reduced from 13 to 3 occurrences.



(a) (b)

Figure 6.7: The rotational energy in the Base Case scenario and with the rotational energy restriction of a) 35 GWs and b) 38 GWs.

Figure 6.7 shows the rotational energy in the Base Case scenario, and with the inertia restriction (dentoted "Inertia Restriction" in the figure). The occurrences of rotational energy occur from around day 150 to day 250. The spikes visible in figure 6.7 around this time is when the Hmin restriction is activated. Figure 6.7a shows that the rotational energy with the 35 GWs limit still has 3 occurrences of low inertia situations. By adding a margin of 3 GWs and increasing the limit to 38 GWs there are no occurrences of low rotational energy situations as visualized in figure 6.7b.

Costs

The average yearly system price in the first simulation year is presented in table 6.9. The system price is reduced compared to the Base Case scenario, but higher compared to the original Hmin restriction.

Table 6.9: Average system price of electricity, $\overline{P}_{w,year}$ in Norway with the rotational energy restriction.

	$\overline{P}_{w,year}$
Base Case [EUR/MWh]	46,50
Hmin Restriction [EUR/MWh]	45,75
35 GWs Limit [EUR/MWh]	46,21
38 GWs Limit [EUR/MWh]	46,18

The total socioeconomic costs of the Hmin restriction is significantly reduced when the restriction is extended to only apply on days with low inertia. Table 6.10 shows the total socioeconomic costs with the two limits. The future cost of change in reservoir level has been adjusted for.

Table 6.10: The total socioeconomic costs of the extended Hmin restriction taking the cost of change of reservoir level into account.

	Hmin	35 GWs Limit	38 GWs Limit
Total Socioeconomic Costs Norway [EUR]	7 356 248 512	6 292 841 097	6 363 078 994
Difference: Strategy 1 - Base Case [EUR]	1 172 535 968	109 128 553	179 366 459

6.2 Strategy 2: Reduce the Planned Import/Export on an HVDC link

6.2.1 Prices

Average system price

Table 6.11 shows the average system, $\overline{P}_{w,year}$, price with Nord Link for the 2010 data set and for the simplified 2020 scenario with and without the reduced capacity.

Table 6.11: Average system price of electricity, $\overline{P}_{w,year}$ in Norway (NOR) and Germany (GER) with Nord Link.

	$\overline{P}_{w,year,NOR}$	$\overline{P}_{w,year,GER}$
Base Case [EUR/MWh]	46,50	45,36
Nord Link 2010 Data Set [EUR/MWh]	46,96	45,39
Simplified 2020 Scenario [EUR/MWh]	46,26	43,41
2010 Reduced Capacity [EUR/MWh]	46,98	45,38
2020 Reduced Capacity [EUR/MWh]	46,56	44,49

In Norway, the average system price increases when Nord Link is implemented, and decreases in the 2020 scenario compared to the Base Case scenario. The average system price in Germany remains close to unchanged after the implementation of Nord Link. When the capacity is reduced, the average system price increase in both Germany and Norway. Figure 6.8 shows the average system price in Norway and Germany with the 2010 data set.

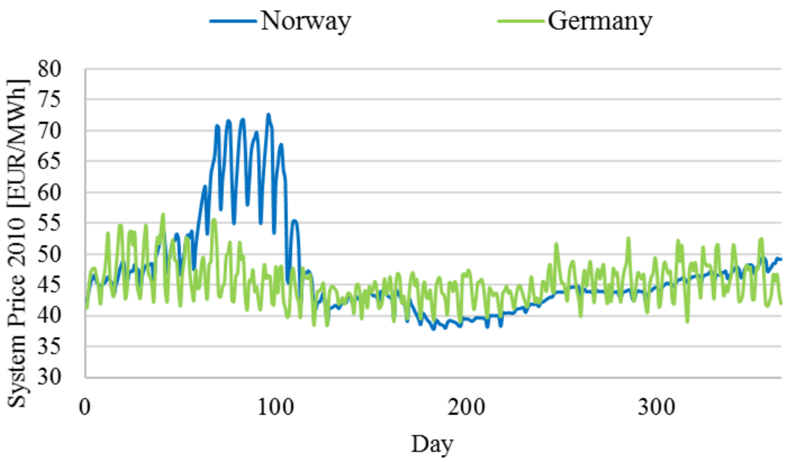


Figure 6.8: The average system price in Norway and Germany in the 2010 Data Set. The system price follow the same pattern when the capacity on Nord Link is reduced.

6.2.2 Import and export

Figure 6.9 shows the import and export from Norway with Nord Link. By implementing Nord Link, Norway has a HVDC connection to Germany.

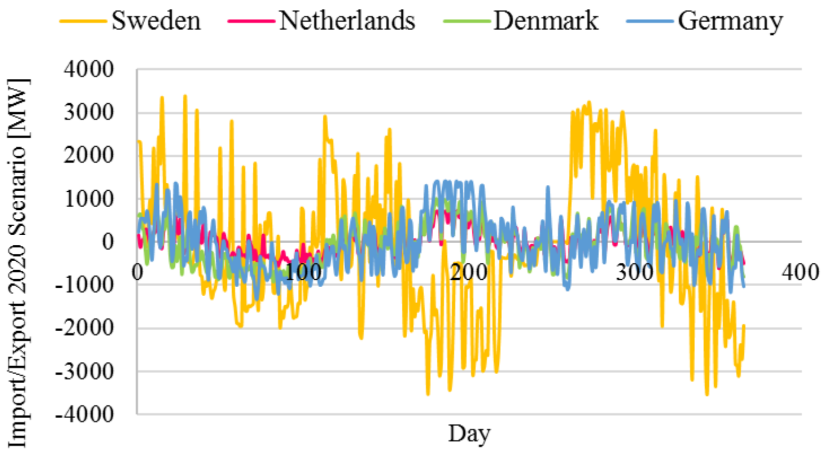
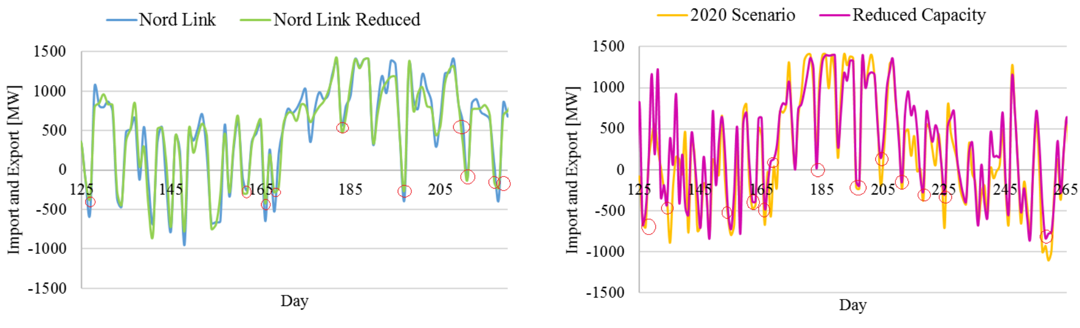


Figure 6.9: The import (-) and export (+) from Norway with Nord Link.

The first one and a half months of the year, power is exported from Norway to Germany. From mid of February to the beginning of April power is imported from Germany to Norway. In the last months of the simulation period the import and export of power from Norway to Germany fluctuates. Norway has large import from Sweden during the summer, and export of power in the winter.

Reducing the planned import/export on Nord Link

Figure 6.10 shows the import and export of power between Norway and Germany with and without reduced capacity on Nord Link. The figure shows the spring and summer months (day 125 to day 260) as this is the time period where the low rotational energy days occurs. The days where the capacity has been reduced is marked with a red circle in figure 6.10. Most of the days with low rotational energy are when Norway is importing power. The capacity reduction leads to a smaller drop.



(a) Original Data Set

(b) 2020 Scenario

Figure 6.10: The import (-) and export (+) in Norway. The red circles marks the days where the capacity on Nord Link is reduced. The figure is zoomed in on the days the capacity is reduced.

When comparing the original data set to the 2020 scenario, it can be seen from the figures that the import and export fluctuates more in the 2020 scenario. The reduction in capacity also leads to a bigger change in the import/export on some days in the 2020 scenario compared to the original data set.

Figure 6.11 shows the duration curve of the import/export from Norway to Germany through Nord Link.

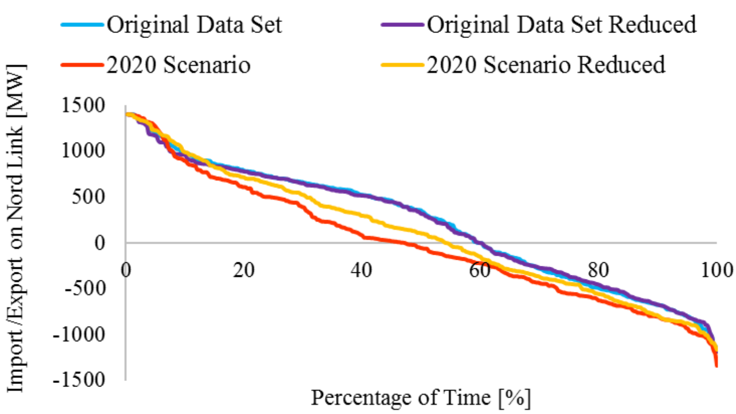


Figure 6.11: Duration curve of the import (-) and export (+) from Norway with Nord Link.

For the original data set almost 60 % is export from Norway. The duration curve is close to the same for the original data set with and without reduced capacity on Nord Link. The 2020 scenario gives a more even distribution of the import and export between Norway and Germany: approximately 55 % of the power transmitted on Nord Link is exported to Germany. Reducing the capacity on Nord Link in the 2020 scenario leads to less export from Norway and more import from Germany. Table 6.12 presents the import/export distribution on Nord Link in the different scenarios.

Table 6.12: Percentage of time that there is import/export on Nord Link to/from Norway.

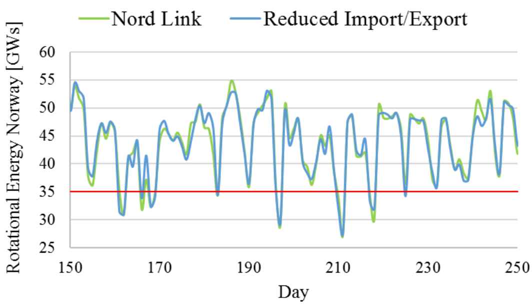
	Export	Import
Original Data Set [%]	60	40
Reduced Import/Export Original Data Set [%]	60	40
2020 Scenario [%]	55	45
Reduced Import/Export 2020 Scenario [%]	48	52

6.2.3 Rotational energy

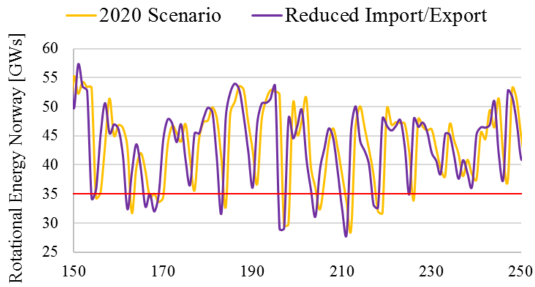
The rotational energy in the Norwegian power system follow the same pattern as in the Base Case scenario. The implementation of the cable does not change the rotational energy significantly. The occurrences of low-rotational energy situations increases from 13 to 17 in the 2020 Scenario. In the original data set the implementation of Nord Link leads to a decrease in occurrences of low rotational energy situations from 13 without Nord Link to 11. Low rotational energy situations are still defined as when the rotational energy is below 35 GWs.

Reducing the import/export on Nord Link

Figure 6.12 shows the rotational energy in the Norwegian power system with Nord Link, and with reduced import/export on Nord Link. Figure 6.12a shows the effect of reducing the capacity on Nord Link in the original data set, and figure 6.12b presents the effect in the 2020 simplified scenario.



(a) Original Data Set



(b) 2020 Scenario

Figure 6.12: The rotational energy with and without reduced capacity. The figure is zoomed in on the days the capacity is reduced.

When reducing the capacity on Nord Link the occurrence of low rotational energy is 11 for the original data set and 16 for the 2020 scenario. When reducing the capacity on Nord Link the rotational energy has slightly smaller fluctuations, but the rotational energy is not changed enough to see a significant change.

6.2.4 Costs

The socioeconomic costs related to this strategy is presented in table 6.13. The table presents the costs of the 2020 Scenario and the costs with the original data set. In both cases the total socioeconomic costs increase when reducing the capacity on Nord Link. With the original data set from 2010 the total socioeconomic costs increase with 1,7 million euros in the simulation period. With the simplified 2020 scenario this number has increased to 37,3 million euros. When analyzing these numbers it is important to bear in mind that the capacity was reduced 11 times in the original data set and 17 times in the simplified 2020 scenario.

Table 6.13: The total socioeconomic costs in Norway with reduced capacity on Nord Link

	Original Data Set	2020 Scenario
Nord Link [EUR/year]	6 252 419 929	6 159 805 627
Reduced Import/Export on Nord Link [EUR/year]	6 254 119 361	6 197 147 513
Cost of reduced Import/Export [EUR/year]	1 699 432	37 341 886

6.3 Strategy 3: Reduce the Load by Disconnection of Pumps for Hydro Storage

The third strategy has not been implemented in the model. The following is results of an estimate of the costs related to this strategy based on the information from [51], [33], [52], [53], [6].

6.3.1 Correlation between the rotational energy and the system price

When analyzing the correlation between the periods of low rotational energy and low system price, it can be seen from figure 6.13 that on they correlate on several occasions. It is on these occasions that the third strategy proposes to disconnect the pumps for hydro storage if there is a need for it.

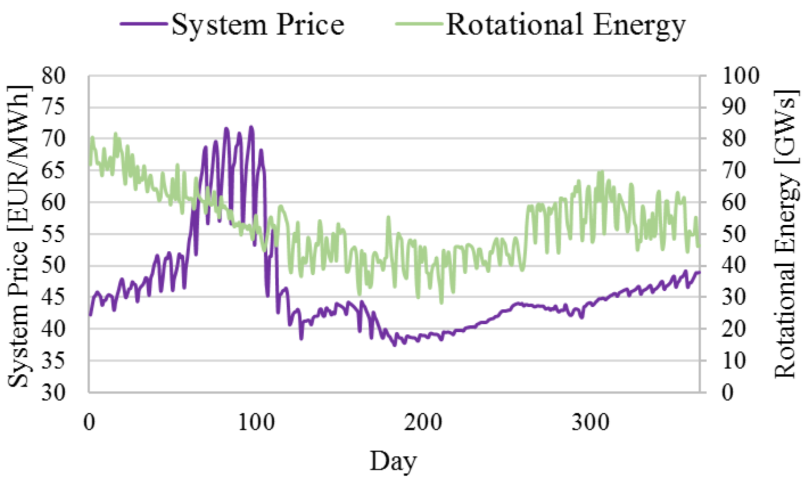


Figure 6.13: The average system price in Norway vs. the rotational energy in Norway in the Base Case scenario.

6.3.2 Correlation between the inflow and the rotational energy

Figure 6.14 shows the correlation between the inflow and the rotational energy in the Base Case scenario. After the highest inflow is over there is still occurrences of low rotational energy values.

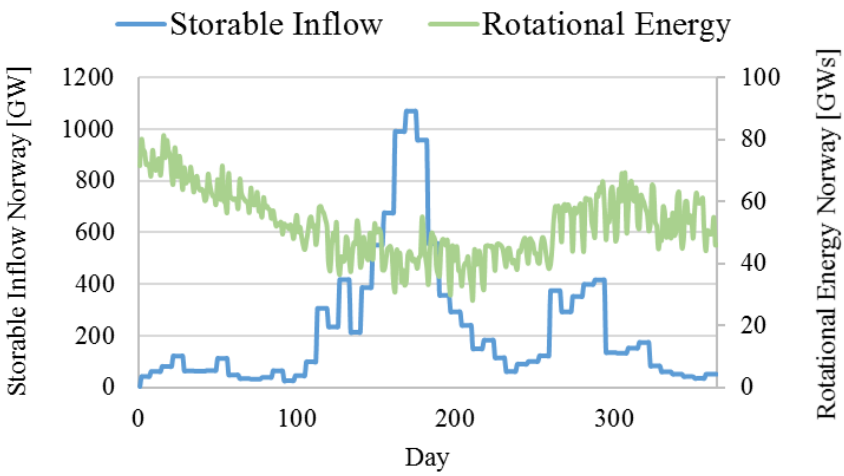


Figure 6.14: The rotational energy in Norway vs. the storable inflow in the Base Case scenario.

6.3.3 Estimation of costs

When assuming a pump of efficiency of 30%, and that the hydro producers plan to sell the water during the winter at a high market price. Based on SINTEF's [54] the start/stop costs of pumps can vary from 400 - 1 400 EUR. Assuming a pump of 110 MW, the start/stop cost related to this pump is set to be 530 EUR. This is based on an estimation done in [54] for a hydro generator of that size. Once a pump is turned on in pumping pattern two, it pumps for at least 6-7 hours.

$\eta = 30$ %
$t = 8$ h
$P_{pump} = 110$ MW
$C_{start/stop} = 530$ EUR
$MP_{sell} = 69{,}6$ EUR/MWh

The cost estimation is found for two scenarios. The first scenario assumes that the pumps can be turned off on all 13 days with rotational energy below 35 GWs. The total costs of the third strategy is then estimated to be 0,83 million euros. The second scenario assumes that the pumps can only be turned off when the inflow is low. As figure 6.14 shows, the inflow is the highest in Norway from day 147-197. It can be assumed that in this time-interval the pumps will be used for pumping to avoid overflow. If the pumps only can be turned off outside of the time-interval with high inflow, this leaves 6 days where the pumps can be turned off, and an estimated total socioeconomic costs of 0,66 million euros. Table 6.14 shows the total socioeconomic costs of the third strategy.

Table 6.14: The total socioeconomic costs of disconnecting the pumps for hydro storage.

	Cost [EUR]	Total Costs [EUR/year]
Pumps can be turned off all days	837 426	6 184 549 970
Pumps can be turned off at certain days	660 850	6 184 373 394

7 Discussion

This section will discuss the main results presented in section 6, the limitations of the model and the simplifying assumptions. The relation between the main results and previous work will be introduced and discussed.

7.1 Quantification of Costs

7.1.1 Prices

Strategy 1

In the first strategy the spot price and the average system price decrease. The hydro units are forced to produce power through the Hmin restriction resulting in more hydro units producing even if their water value is lower than the spot price. When bidding into the market, the hydro producers will bid in with a lower price, pushing the supply and demand curve shown in figure 2.2 to the right, and lower the price of electricity due to the merit order (see section 2.2.2).

Strategy 2

The implementation of Nord Link leads to a higher average system price of electricity in Norway, while the average system price in Germany remains unchanged. Germany is a bigger power system than Norway, supplying a bigger load. Norway will therefore be influenced by the German electricity prices. Figure 6.8 shows that the German electricity prices do not fluctuate as much as the Norwegian prices, making it possible to export power to Germany when the electricity price in Norway is low and sell it for a higher price on the German market. Reducing the capacity on Nord Link gives a marginally higher system price of electricity in both Norway and Germany.

In [3] the benefits of HVDC links are described to be better use of the available power sources and economically favorable export. In the 2020 simplified scenario this effect can be observed. Both the average system price in Norway and Germany decrease in 2020 compared to the original data set. The increase in sun and wind generation gives cheaper production that both Norway and Germany benefits from. Reducing the capacity on Nord Link in the 2020 simplified scenario increases the average system price. Comparing the increase in average system price when the capacity is reduced for the two scenarios, the increase is bigger in 2020. The increase in sun and wind has economically beneficial effects; they push the supply and demand curve shown in figure 2.2 further to the right and lower the price of electricity. This effect is more visible in the 2020 scenario, due to it having a higher share of wind and sun in the German power system.

Strategy 3

The results of the third strategy does not show a change in market prices as it has not been simulated in the model.

Comparison of strategies

The first strategy decreases the spot price, and the average system price, due to a higher level of production. The second strategy has the opposite effect; it results in a slight increase in the average system price when the capacity on Nord Link is reduced as the economically beneficial effects of the HVDC link is not used to its full potential.

7.1.2 Socioeconomic costs

Strategy 1

When comparing the total socioeconomic costs of the different strategies, the first strategy is the most expensive one. In [6] different mitigation measures to handle future low rotational energy situations were evaluated. To "start up generators and run them on low output" was found to be too expensive. The first strategy is comparable to this mitigation measure as it forces generators to start up by restricting their minimum output, and it is the most expensive strategy. Strategy 1 is also inefficient as it turns on more generators than what is needed. When the first strategy is extended to only apply on days where it is needed, the socioeconomic costs are reduced.

Since the first strategy turns on more generators, more power is produced. To account for the change in reservoir level it is important to get a view of the actual socioeconomic costs of the first strategy. The method of calculating the potential cost of change in reservoir level assumes that the inflow and demand are the same for the following year. There are uncertainties regarding this assumption. If the inflow in the next simulation year is higher, the cost of the first strategy will be lower. If the inflow is lower the costs will be higher. It is reasonable to assume that the demand does not change significantly from year to year.

In [15] different options for a market for rotational energy is evaluated. The first strategy is comparable to one of the markets presented; to remunerate all generation units that provide the grid with inertia a fixed price so they do not shut off due to low prices in the spot market. The assumptions was that this market type would result in high costs for the TSO but also ensure sufficient inertia, which is what the results of this thesis showed.

Strategy 2

Reducing the capacity on an HVDC link is in [6] expected to give high socioeconomic costs compared to disconnecting load, but also to be an effective measure to increase the system inertia. Compared to the third strategy, the socioeconomic costs of reducing the capacity on an HVDC link is high and this number is expected to increase in the future. Increased interconnection between European countries, and closer coupling between European power markets increases the cost of reducing the capacity on an HVDC link. The change in total socioeconomic costs from 2010 to 2020, presented in table 6.13 gives an indication of this. The socioeconomic costs of the second strategy was higher in the 2020 scenario due to it having more occurrences of low rotational energy values than the original data set. When analyzing the numbers it is important to bear in mind that the capacity was reduced on a whole day each time, while in reality it would be a couple of hours that the capacity would need to be reduced.

Due to the simplifications made regarding the size of the HVDC link, the total socioeconomic costs are most likely too high. Had the size of the reduction been based on the amount of inertia in the power system, it would be reduced with less than 400 MW on certain days. The socioeconomic costs of the second strategy should be seen as an upper estimate.

In [14] reducing the dimensioning fault was analyzed as a strategy to ensure sufficient inertia in the Nordic power system. When Nord Link is implemented in the Norwegian power system, the capacity of Nord Link will correspond to the dimensioning fault. The thesis compared the strategy of reducing the dimensioning fault to increasing the number of hydro units running. The first strategy analyzed in this section is comparable to increasing the number of hydro units running. The results of [14] showed that reducing the dimensioning fault was the most cost-effective of the two strategies.

Strategy 3

The third strategy is in [6] evaluated to be one of the most promising mitigation measures in terms of cost, potential and effectiveness. The estimated cost of the third strategy is the lowest of the three strategies. As this cost is an estimation and has not been simulated in the model, the accuracy in the comparison to the other two strategies is limited. Section 4.3.3 presents the main uncertainties related to the cost estimation. The biggest uncertainty is regarding the start/stop of each generator and the increase in maintenance cost due to more start/stop. The cost estimation of strategy 3 should therefore only be used as an indication.

Comparison of strategies

The third strategy has the best economic outcome. The most expensive one, is as estimated, the first strategy. Table 7.1 shows the socioeconomic costs of the three strategies using the 2010 data set and a limit of 35 GWs as the minimum rotational energy limit. When the first strategy is extended to only apply on days with low inertia the socioeconomic costs are reduced, but the total socioeconomic costs are still high compared to strategy 2 and 3.

Table 7.1: The socioeconomic cost of the three strategies.

Strategy 1: Restricting the minimum hydro output level [EUR]	1 172 535 968
Extended Strategy 1: Rotational energy restriction [EUR]	109 128 553
Strategy 2: Reduce the planned import/export on an HVDC link [EUR]	1 699 432
Strategy 3: Disconnection of pumps for hydro storage [EUR]	837 426

7.2 Effectiveness in Ensuring Sufficient Inertia

7.2.1 Ability to provide sufficient inertia

Strategy 1

The first strategy leads to a higher minimum production from the hydro generators, and the median of the total production in Norway increases with strategy 1, indicating that the generators produce on a higher level overall. The increase in production leads to more export to Sweden in the beginning of the year. The more hydro generators that are on, the more inertia is produced as presented in equation 2.6.

The reservoir level at the end of the simulation period has decreased with 389,6 GWh with the Hmin restriction. Conducting a second simulation, referred to as simulation 2 in the results, using the reservoir level at the end of the first simulation as input, shows that the reservoir level at the end of both simulations are unchanged (see figure 6.4). Analyzing the reservoir level at the end of the simulation period for the hydro unit with the biggest change in output power (see table 6.5) shows that the change in reservoir level from simulation 1 to simulation 2 is bigger for the Base Case scenario than the Hmin restriction. This indicates that adding a restriction regarding the size of the hydro reservoirs limits the change in reservoir level and ensures that the reservoirs are not emptied due to strategy 1. As long as there is water in the reservoirs, the first strategy has the ability to provide the system with the inertia that is needed.

Strategy 2

Figure 7.1 shows the correlation between the rotational energy with Nord Link and the import/export to Germany in the simulation period. The rotational energy is low between day 150 until day 250. In the beginning of this time period there is export from Norway. This means that reducing the capacity leads to less power generation in Norway. The strategy to reduce the capacity on an HVDC link will only lead to more rotational energy in the Norwegian power system if there is import to Norway when the capacity is reduced. If there is export, reducing the capacity will lead to less power production in Norway, which again might lead to hydro generators turning off.

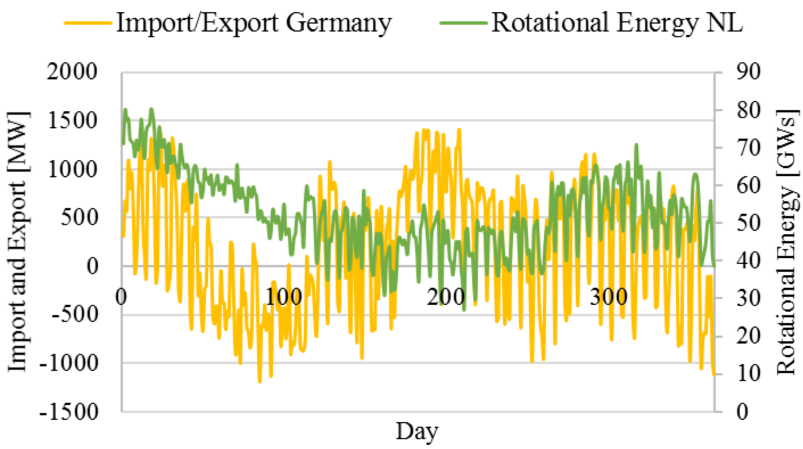


Figure 7.1: The correlation between the rotational energy with Nord Link and the import/export to Germany.

Strategy 3

The third strategy has reduced availability in ensuring sufficient inertia. The third strategy is therefore not always available to be used. The information provided by the hydro producers ([50], [53], [51], [52]) specified that disconnection of pumps can only be done when there is no danger of overflow from the lower reservoir. When comparing the inflow, the system price and the rotational energy in the Norwegian power system (shown in figures 6.13 and 6.14) some of the low rotational energy occurrences are around the same time that the inflow in Norway is high. In this time period, disconnecting the pumps is not an option. In the simulations conducted the Base Case scenario had 13 days with low rotational energy. On 7 of these days there is high inflow and it is reasonable to assume that the pumps are not available for disconnection.

Comparison of Strategies

The first strategy has the ability to provide the inertia needed as long as there is water in the reservoirs. The second and third strategy has more limited availability. The second strategy should only be used when Norway is importing power thorough Nord Link. The third strategy depend on the inflow, if the inflow is high it is not available.

7.2.2 Effectiveness in ensuring sufficient inertia

Strategy 1

The first strategy is effective when it comes to providing more inertia. It indirectly forces more hydro generators to be on, increasing the system inertia described through equation 2.6. When the strategy is extended to only apply on certain days, the system inertia is still increased. Section 2.3.2 described the importance of inertial response in the power system. The inertial response corresponds to how much system inertia there is in the power system.

Strategy 2 and 3

Both the second and third strategy aims to decrease the need for inertia in the Norwegian power system. Their effectiveness is therefore not as easy to measure as for the first strategy. When the capacity is reduced on Nord Link on the days where Norway imports power, the reduction leads to less import. This is visualized in figure 6.12.

Comparison of strategies

As the second and third strategy aims to decrease the need for inertia, it is difficult to compare their effectiveness to the first strategy. The first strategy is effective in increasing the system inertia.

7.3 Validation of Assumptions

Minimum production level of 20 %

The minimum level used for the first strategy is 20 %. If this limit is increased, the socioeconomic costs increase with it. The inertia in the power system does not change significantly, since it depends on whether the generators are on or not. By increasing the limit to 30 and 40 % the socioeconomic costs increase, and the rotational energy remains unchanged. Appendix A shows the costs and the rotational energy when the limit is increased.

It is assumed that the hydro units are ideal. In [14] an estimate of the minimum production level of the hydro units in Norway was made based on the distribution of turbines in Norway. An average minimum production level of a Norwegian hydro generator was found to be 27,5 %. If this limit was applied in the model, the amount of inertia would be reduced, but the effect of the strategies would be the same.

Low rotational energy value

The low-rotational energy limit is set to be 35 GWs based on table 2.2 and [6]. The limit is an upper estimate[1]. In [6] a limit of 120 GWs is set to be the minimum limit for the Nordic power system in 2020, and 134 GWs is set to be the minimum limit for the Nordic power system in 2025. In [14] and [16] a minimum limit of 90 GWs and 100 GWs for the Nordic power system was used. Due to the data set being a 2010 case study, a limit of 35 GWs for the Norwegian power system might be a too high estimate. If this is the case, the 35 GWs limit will give a higher socioeconomic cost for the extended strategy 1, strategy 2 and strategy 3.

When the first strategy is extended to only apply on days with low inertia, two limits were used; 35 GWs and 38 GWs. When the limit implemented in the model was increased to 38 GWs, there was no occurrences of rotational energy below 35 GWs.

Power factor

Due to lack of data, a power factor of 0,9 has been assumed for the thesis. In [29] typical power factors for different loads are presented. Industrial loads have a power factor of 0,8-0,9. If the power factor is in reality higher than assumed, the rotational energy would be lower than the results of the thesis show. If the power factor is in reality lower than assumed, the rotational energy would be higher than the results show.

[1]The limit in Norway is found by multiplying Norway's share of inertia with a limit of 130 GWs; $\frac{100}{396} \cdot 130 = 33,33 \approx 35$ GWs

Inertia constant

The inertia constant depends on the machines' ratings and the angular velocity of the rotor. These are not known in the data set used in this masters thesis. Based on the average inertia constant values from [5] this was set to be 3 for all hydro generators. In reality each generator has its own specific inertia constant, depending on how long the generator is able to supply a load of equal size to the generator. If the specific inertia constant of the machine is higher than the average constant, the rotational energy would be higher. If the specific inertia constant is lower than the average inertia constant, the rotational energy would also be lower.

7.4 Limitations of the Model

The model is based on linear integer programming. As described in section 2.5 the feasible area of an integer programming problem is non-convex and consists of a set of discrete points. It is made up by the constraints of the objective function. As every constraint limits the problems' feasible area, adding a constraint to the optimization problem can complicate the problem. If the constraint leads to other constraints not being fulfilled, or it limits the feasible area to such a degree that no optimal solution can be found, the problem is found unfeasible.

Due to this, it was difficult to implement the rotational energy as a variable in the model with a corresponding constraint. The constraint limited the problems' feasible area to such a degree that no solution could be found. The solution was to calculate the rotational energy contribution from one simulation, and then use these values as input. The result would however be more accurate if the rotational energy were calculated in the model for every hour. This could have decreased the cost of the extended first strategy, and the second strategy.

8 Concluding Remarks

The objective of this master thesis has been to evaluate three different strategies to ensure sufficient inertia in the Norwegian power system. The strategies have been evaluated based on their socioeconomic costs and their effectiveness in ensuring sufficient inertia. A market model of the Northern European power system is used to evaluate two of the strategies. The model is based on linear integer programming and uses the Branch & Bound algorithm to solve the optimization problem. The data set is a case study from 2010. The socioeconomic costs of the last strategy have been estimated using research literature, and by conducting a survey among Norwegian hydro producers.

8.1 Conclusion

The first strategy has the ability to produce the inertia needed as long as there is water in the hydro reservoirs. It is necessary to extend strategy 1 to only apply when the reservoir level is over a certain limit. The first strategy is the most effective strategy when it comes to ensuring sufficient inertia in the Norwegian power system. Defining a minimum production level for hydro generators leads to more generators turning on, and to an increase in the system inertia. A minimum limit of 20 % for an ideal hydro generator was found to be a satisfying limit.

The second strategy proposes to reduce the capacity on an HVDC link in order to increase the system inertia. This strategy only makes sense if Norway is importing power at the time when the capacity is reduced. If the capacity is reduced when Norway is exporting power, this might lead to Norwegian generators turning off and hence there will be less rotational energy in the Norwegian power system.

The third strategy has limited availability of ensuring sufficient inertia. The pumps are only available for disconnection when there is no danger of overflow from the lower reservoir. When the pumps are used for market purposes the hydro producers are willing to disconnect their pumps if they are properly remunerated for it.

Of the mitigation measures proposed to increase the system inertia in the Nordic power system in [6], disconnecting the pumps for hydro storage has the best economic outcome. The first strategy is in the report viewed expensive compared to the two other strategies. This is confirmed by the results of this thesis.

Looking at the total socioeconomic costs, disconnecting the pumps shows economic prospects. It still has several uncertainty factors in the estimation of the total socioeconomic cost, and including the question of whether the hydro producers are willing to disconnect their pumps. Since the third strategy has limited availability it is not certain that it will always be available to provide the system with the inertia needed.

The second strategy has higher socioeconomic costs than the third strategy. In the 2020 simplified scenario the socioeconomic costs increased significantly. The more occurrences of low rotational energy, the higher the socioeconomic costs. The socioeconomic costs must serve as an upper estimate, as it is possible that the reduced capacity has been set too high.

The first strategy is the most expensive strategy. When the strategy is extended to only apply on days with low inertia the socioeconomic costs are reduced. Results show that a safety margin needs to be added to get rid of all occurrences of low rotational energy in the Norwegian power system.

If the main objective is to have an option to activate when the inertia in the Norwegian power system is low, defining a minimum production level for the hydro generators is the most effective of the strategies presented. However, if the motivation is to have a cost-effective alternative, the other two strategies are better options. Both the costs and the effectiveness of the strategies are difficult to accurately compare due to the uncertainties in estimation of strategy 2 and 3. It can however be concluded that strategy 1 reduces the low-inertia situations in the Norwegian power system, but it has a high socioeconomic cost. The cost of a black out, which is the worst consequence of a system with low inertia, will most likely have a bigger socioeconomic cost.

A minimum limit of 35 GWs for the Norwegian power system has been used. It is possible that this limit is set too high, giving higher socioeconomic costs. The generators have been assumed ideal. Average inertia constants and a power factor of 0,9 are assumed for the calculation of the rotational energy.

8.2 Recommendations for Further Work

One recommendation for further work is to implement a variable in the model that calculates the rotational energy continuously for every hour of the day. The restriction regarding the minimum output of a generator can then be activated if the rotational energy is measured to be too low. As this proved to be difficult in the linear model used in the thesis, a suggestion for further is to consider using a non-linear model. The complexity of the problem would increase, but it might give more freedom in implementing certain variables and may prove a better fit.

The second strategy is implemented using previous simulated values of the daily rotational energy. If the rotational energy was calculated on an hourly basis, the capacity of the HVDC-link could also be reduced on an hourly basis. The decision of whether the capacity should be reduced or not needs to be made in advance, so the day-ahead market can be notified. A natural next step in the development of this strategy would be to find an easy way to estimate how much the capacity should be reduced when the rotational energy is expected to be low. The size of the reduction should depend on the expected amount of rotational energy in the power system.

It would be interesting to calculate the socioeconomic costs of both the first and the second strategy using a 2020 case study of the Northern European power system. This would require an update in the data set used.

The simulations have been conducted on the Norwegian power system. A natural next step would be to run simulations on the Nordic power system.

The topic of securing sufficient inertia in a power system is a topic of continuing research, and there are several other strategies that could be discussed and compared. Investing in new providers of inertia is mentioned in section 2.3.4. The investment cost related to enabling HVDC links and wind power plants to provide artificial inertia is expected to be low. Analyzing the costs and effect of artificial inertia provision from these possible providers of inertia would be interesting to see the results of.

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A Increased Minimum Production Level of Strategy 1

The minimum production level is increased from 20 % to 30 and 40 %.

Total consumer costs

Table A.1 shows that the socioeconomic costs increase when the limit is increased. The cost of change in reservoir level has not been accounted for. The total reservoir level on the last simulation day is showed in figure A.2. It is lower for the increased limit, implying that the potential cost of change in reservoir level would be higher than with the 20 % limit.

Table A.1: The socioeconomic costs of increasing the limit for the minimum hydro production.

	Total price of electricity in Norway [EUR]
Hmin=0.2Hmax	6 103 332 970,3
Hmin=0.3Hmax	6 108 794 918
Hmin=0.4Hmax	6 105 614 066

Reservoir level

Table A.2: The reservoir level at day 365.

	Reservoir level day 365 [GWh]
Hmin=0.2Hmax	386,3
Hmin=0.3Hmax	271,8
Hmin=0.4Hmax	273,2 0

Rotational energy

The rotational energy does not change significantly when the limit is increased. An increase in the minimum limit leads to more power being produced, but not to more generators turning on compared to the 20 % restriction.

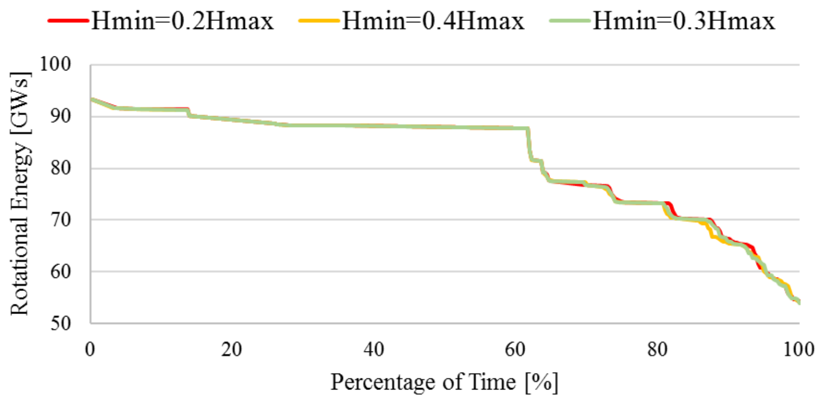

Figure A.1: Duration curve of the rotational energy with different limits to the minimum output.

B General Strategy for the Branch & Bound Algorithm

The solution strategy for the branch and bound algorithm can be divided into four steps: Relax, Branch, Prune and Search.

1. Relax
In the first step, each subproblem is relaxed and solved.

2. Branch
The feasible region of every subproblem is divided into smaller areas. It is often divided into two areas, but it can be more. It is important that each feasible solution only exists in one of the subproblems. To guarantee that a new optimal solution is generated, the optimal solution found in the previous subproblem must be removed in the new subproblem.

3. Prune
If any of the following cases occur after solving the relaxation of a subproblem, the search in a search tree must stop. If none of the cases occur, the search can continue into new subproblems. It is assumed that the problem is a minimization problem. The search in a search tree must stop if:

- The problem has no feasible solution.
- The problem has an optimal solution with $z \geq \overline{z}$, where $\overline{z}$ represents the best feasible solution so far.
- The problem has a solution which is also feasible in the original problem. In this it is implied that the search area cannot provide a better solution than the one found, and it is therefore no need to search for alternative solutions.

4. Select
A search strategy is a strategy that defines which subproblems to solve next. It must be clearly defined in the method. The standard search strategies are: depth first, breadth first and best first. In the search strategy depth first the subproblem that has been branched the most times are chosen as the next subproblem to solve. The breadth first strategy searches all subproblems on a given level of the search tree, before moving down to the level below. The best first strategy searches the subproblems that are created from the nodes with the most optimistic bound. This search strategy need a pre-defined termination criterion.

Illustrative example

This example will show the basics of the branch and bound method. Given the following minimization problem

$$\begin{aligned} \min\ z &= 7x_1 + 12x_2 + 5x_3 + 14x_4 \\ \text{s.t.} \quad 300x_1 + 600x_2 + 500x_3 + 1600x_4 &\geq 700 \\ x_1, ..., x_4 &\in \{0, 1\} \end{aligned}$$

In each subproblems, the binary variables are fixed to either 0 or 1. The first step is to solve the LP relaxation. This gives the solution $(x_1, x_2, x_3, x_4) = (0,\ 0,\ 0,\ 0.4375)$ with the objective function value z = 6.12. This solution gives x_4 as a fractional number, and the solution is therefore not feasible. This first subproblem is denoted P0. The subproblem branches into two new subproblems by fixing the value of x_4 to be 1 and 0. These two new nodes are named P1 and P2. In P1 x_4 = 1 giving the solution of the LP relaxation to be $(x_1, x_2, x_3, x_4) = (0,\ 0,\ 0,\ 1)$ with the objective function value z_{P1} = 14. This solution is feasible and is the pessimistic bound of the subproblem. In P2 x_4 is set to zero, and the solution found to be (x_1, x_2, x_3, x_4) $=$ (0, 0, 0.33, 0). The objective function value is z_{P2} = 9 which is the optimistic bound of the subproblem. Since the objective function value in P2 is better than in P1, the search in P1 is terminated. The search in P2 continues until the optimal solution is found. The optimal solution is found in P8 with the objective function value $z*$ = 12. Figure B.1 illustrates the search tree.

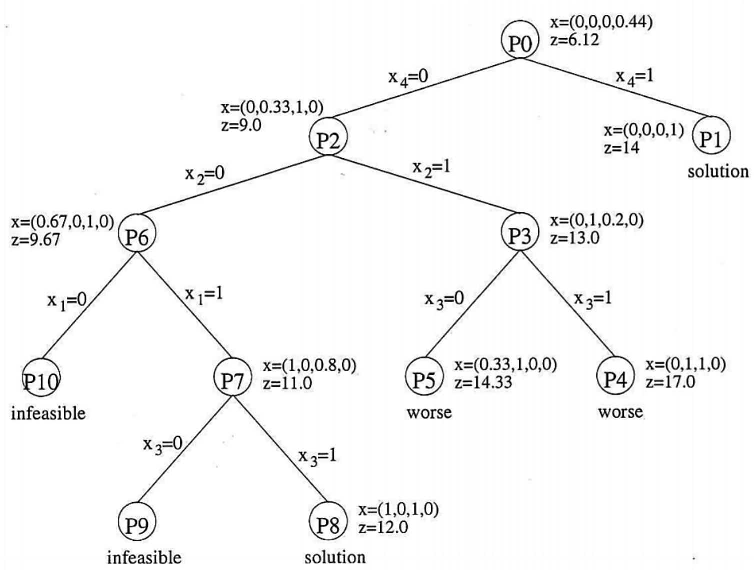

Figure B.1: The Branch and Bound search tree of the illustrative example [8]

C The Nordic Balancing Markets

Figure C.1: The different bidding areas in the Nordic power market today [12]

C.1 Balancing markets

Balancing markets are ancillary markets run by the TSO. The point of a balancing market is to ensure a stable system in real time. The power production in the power system is planned on the basis of assumed demand in the system. If demand is not equal to production, or an unforeseen event occurs, an imbalance will occur. The term imbalance refers to that the system is not in equilibrium, meaning that the production of electric power does not equal the consumption of electric power in the power system. To avoid an imbalance, the balancing market activates it's reserves. These will be activated in sequence depending on the duration of the imbalance.

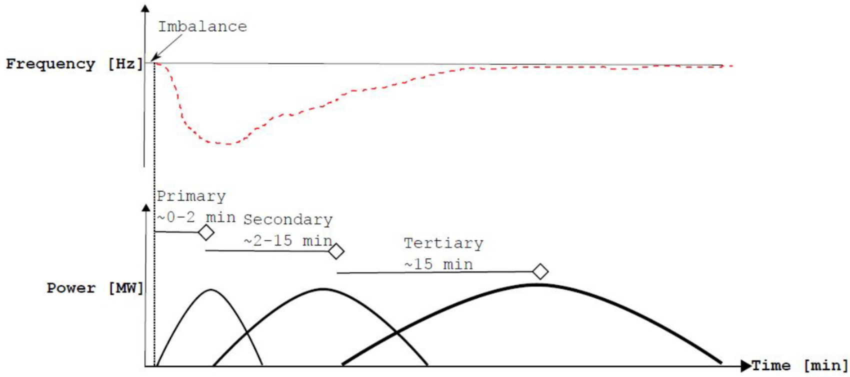

Figure C.2: Activation sequence of reserves after an imbalance. Long term reserve is also known as tertiary reserve [13]

C.1.1 The Nordic balancing markets

Frequency Containment Reserves (FCR)

The Frequency Containment Reserves, also called primary reserves, are the first to be activated when there is a change in frequency. The activation of FCR is an automatic function. It is necessary that there is enough reserves in the system and that they are evenly distributed throughout the grid. In the Nordic system the TSOs demand hydro generators bigger than 10MVA to have a maximal droop setting of 12% (and 6% during the summer months) to ensure enough available primary reserves.

In the Nordic system FCR is divided into two products that are both traded in the primary reserve market: Frequency Containment Reserves - Normal for normal operations, and Frequency Containment Reserves - Disturbance for disturbances. FCR-N is activated when the frequency is between 49.9 Hz - 50.1 Hz. FCR-N responds within 5 seconds, and is fully activated within 30 seconds. The requirement for available FCR-N is 600 MW in the Nordic system, and the requirement in Norway is 210 MW. When the frequency is lower than 49.9Hz, FCR-D is automatically activated. The FCR-D should have a up regulating time of 2-3 minutes. The requirement for available FCR-D is 1200MW in the Nordic system of which 350MW is provided by Norway [3].

Primary reserves are traded in the primary reserve market. The primary reserve market consists of a daily and a weekly marked. The producers have the option to choose to participate in one of the markets, or both markets. The weekly market only trades FCR-N. In the weekly market bids are given per price area, and per time period for the coming week. The weekly marked is divided into six time periods; weekdays night: 00.00-08.00, weekdays day: 08.00-20.00, weekdays evening: 20.00-24.00, weekends night: 00.00-08.00, weekends day: 08.00-20.00, and weekends evening: 20.00-24.00. The weekly market is run before the Elspot market. In the daily market both FCR-N and FCR-D are traded. It is run after the Elspot market has been cleared to cover remaining demand. The bids are given per hour, and per price area of the next day. The minimum quanta to bid is 1MW. The primary reserve market is cleared with marginal pricing. Local conditions and distribution of primary reserves after market clearing may lead to contracts being given at a higher price than the marginal price [55], [56].

Frequency Restoration Reserves – Automatic (aFRR)

The Frequency Restoration Reserves – Automatic (aFRR), also called secondary reserves or Load Frequency Control (LFC), are activated if the imbalance lasts longer than a couple of minutes. The purpose of aFRR is to bring the frequency back to 50,0Hz and, at the same time, release the primary reserve. aFRR is automatically activated by the TSOs. If there is a need for aFRR, the TSOs sends a signal to a suppliers control system, and the supplier will then automatically adjust its production, or demand. The activation time is 120-210 seconds after the signal is received.

In the Nordic system the Nordic TSOs decides collectively what volumes of secondary reserves to buy and when to use them. The secondary reserves are then bought in separate national markets [57]. The Norwegian and the Swedish TSOs are currently working on a project called The Hasle Pilot, aiming for aFRR to be traded between Norway and Sweden.

Frequency Restoration Reserves – Manual (FRR-M)

Frequency Restoration Reserves – Manual (FRR-M), also called tertiary reserves, have two areas of application: frequency regulation to reduce imbalance and handling of regional bottlenecks between price areas [16]. Tertiary reserves are manual reserves that have a response time of 15 minutes. In the Nordic system all subsystems are obliged to have tertiary reserves equal to the dimensioning fault in their subsystem. Dimensioning fault is the value of the biggest loss or fall-out of production station that the power system have to withstand. In Norway the dimensioning fault is 1200MW. In addition Statnett has decided that it is necessary to have an additional 500MW of tertiary reserves available in the system [58].

Tertiary reserves are traded on the Regulating Power Market (RK). The Regulating Power Market is a joint balancing market for the Nordic power system where both consumption and production is traded. The bids from the Nordic countries are listed in a joint list. This list is sorted according to price so the bid offered at the lowest price is activated first. The bid for a coming hour must be placed 45 minutes before the hour of operation.

The Regulating Power Options Market (RKOM) is a capacity market where the Norwegian power producers are paid to guarantee their participation in RK. The regulating power options are traded in a weekly market, RKOM-weekly, and a seasonal market, RKOM-seasonal. In the RKOM-seasonal, options are bought for the entire winter season (October to April). The bid must be placed by the 1st of October. Bids in the RKOM-weekly depend on the power situation in the following week, and must be placed by Friday at 12.00 for the following week [59].

C.2 Comparison of the Bidding Areas in 2010 and 2018

Figure C.1 shows the bidding areas in the Nordic power system today. The Norwegian bidding areas today differ from the bidding areas in 2010 that the analysis of this masters thesis is based on. Table C.1 shows the difference between the bidding areas today and the bidding areas used in this masters thesis.

Table C.1: Comparison of the Norwegian price areas in 2010, and the price areas today

2010	2018
NO5	NO4
NO4	NO3
NO3 + parts of NO2	NO5
NO2	NO1
NO1	NO2

D Additional Results of Strategy 1

D.1 Costs

Spot Price

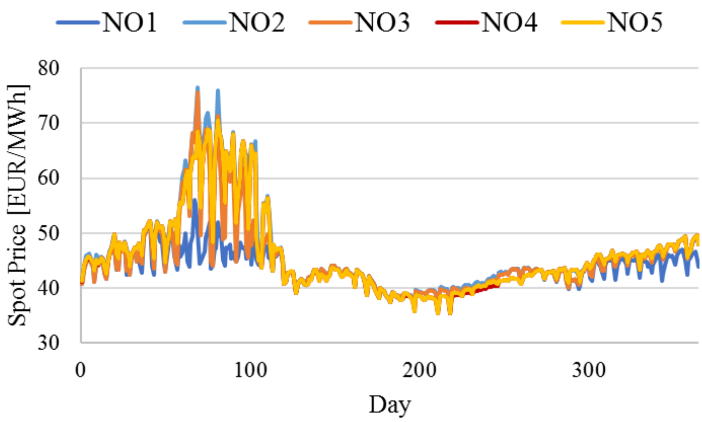

Figure D.1: Total spot price in Norway in the simulation period.

Hydro Output

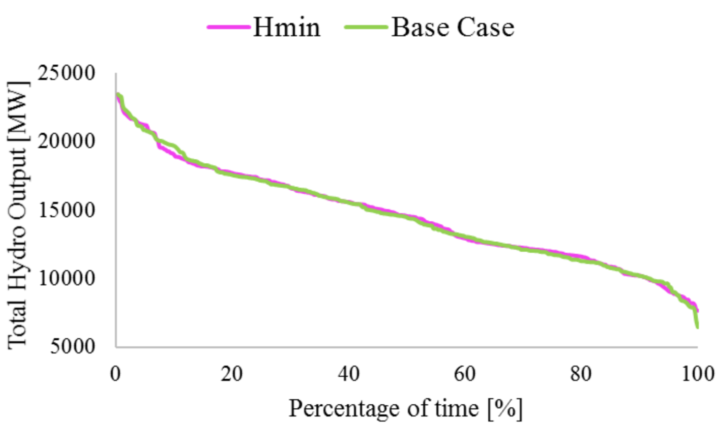

Figure D.2: Total hydro output in Norway in the simulation period.

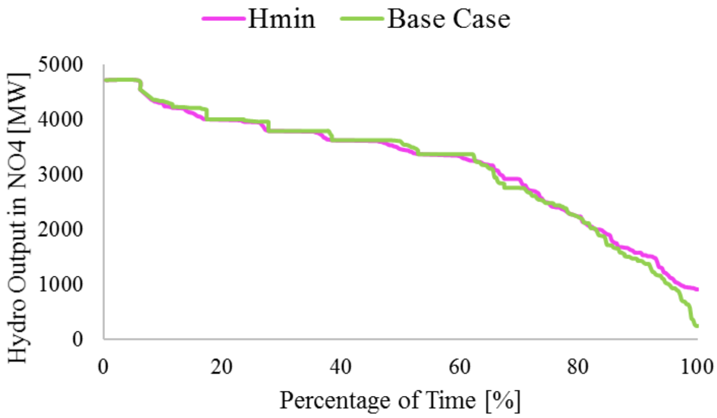

Figure D.3: Total hydro output in NO4 in the simulation period.

Change in reservoir level

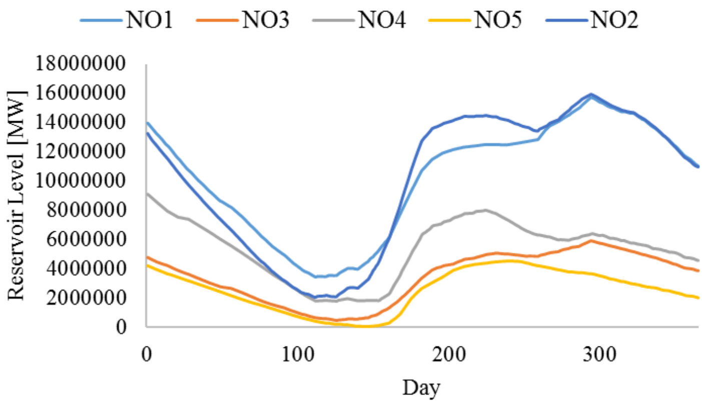

Figure D.4: The reservoir level in the Norwegian price areas with the Hmin restriction.