Norwegian School of Economics
Bergen, Spring 2022

NEXIT:

A Norwegian Decoupling Scenario in the European Power Market

Implications of removing interconnector capacity

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Master thesis, Economics And Business Administration

Majors: Business Analysis and Performance Management & Economic Analysis

NORWEGIAN SCHOOL OF ECONOMICS

Acknowledgements

As our time at NHH draws to a close, there are some people we would like to extend a particular appreciation to. First of all our supervisors, Professor Endre Bjørndal and Professor Mette Helene Bjørndal at the Department of Business and Management Science at the Norwegian School of Economics (NHH). Your enthusiasm and support during this semester has been invaluable, as well as your suggestions for research topics and methodology.

We also appreciate those who offered their time to help us along the way. We need to thank Ellen Skansaar and Harald Endresen at NVE for their introduction to the Nordic electricity market, and input on how to model it. We are also grateful to Johan Olav Botnen at Volue and Fabian Rønningen at Rystad Energy for giving us insight and data on the Nordic electricity market. A major challenge has been the construction of Norwegian bid curves. Special thanks in this regard goes to Vegard Kyllingstad at Lyse Energi for his help and feedback concerning this issue.

Further, we would like to thank the small city of Ronda, Spain for providing an excellent scenery for a writing bootcamp. Finally, our deepest gratitude goes to friends and family for their support during the semester.

Norwegian School of Economics

Bergen, May 2022

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Abstract

This thesis investigates the consequences of "NEXIT", the decoupling of Norway from the European electricity market, as a contribution to the current electricity market debate in Norway. Impacts on prices, social surplus, power flows and electricity market stakeholders are illuminated. The analysis is conducted through an optimisation model, using data from 17 selected European price areas over a 60 day time period in early 2022. By looking at three distinct interconnectors to Germany, Great Britain and the Netherlands, different NEXIT scenarios are compared and contrasted. This thesis is inspired by similar investigations done on British decoupling, and analyses from Statnett on the impacts of interconnectors.

Findings from this thesis suggest that NEXIT leads to a reduction of the total Norwegian and European social surplus. Southern Norwegian price areas experience lower and more stable prices, while Western Europe sees a price hike and increases in price variations. Hourly prices in the south of Norway are simulated to fall €12/MWh or 9% on average if all interconnectors are disconnected simultaneously. This causes a similar drop in southern Swedish prices. In Western Europe, Great Britain and the Netherlands are the most affected, with a price hike of 15%. Consumers in the south of Norway benefit from the lower prices, but this is outweighed by losses to Norwegian producer surplus and congestion rent, causing an hourly net loss of €124 000 in social surplus on average. Overall for Europe, the impact of disconnecting all three interconnectors amounts to an hourly average loss in social surplus of €240 000. Congestion in the Nordic power grid isolates the effects of NEXIT to the southern price areas in Norway and Sweden. A key limitation of the thesis is assessed through a sensitivity analysis accounting for changes to water-values. The sensitivity analysis suggests that the NEXIT impact on water values significantly affects results on prices and social surplus. Results are contingent on the current power mixes, which are likely to change in the future. A Norwegian exit from the European electricity market would nevertheless be expected to have far ranging consequences on prices and social surplus in Norway and Europe.

Keywords – NEXIT, European Power Market, Interconnectors, Decoupling, Social Surplus, Congestion Rent, Electricity Prices

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List of Abbreviations

AC	Alternating Current
ATC	Available Transfer Capacity
BE	Belgium
CS	Consumer Surplus
CR	Congestion Rent
DAM	Day-Ahead Market
DE	Germany
DK1	Western Denmark
DK2	Eastern Denmark
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
FBMC	Flow-Based Market Coupling
FI	Finland
FR	France
GB	Great Britain
HVDC	High Voltage Direct Current
kWh	Kilowatt Hours
LNG	Liquified Natural Gas
MW	Megawatt
MWh	Megawatt Hours
NC	NorthConnect
NEMO	Nominated Electricity Market Operator
NIQ	Net Injection Quantity
NL	The Netherlands
NLK	NordLink
NLP	Nonlinear Programming
NN	NorNed

NO1	Eastern Norway
NO2	Southern Norway
NO3	Central Norway
NO4	Northern Norway
NO5	Eastern Norway
NSL	North Sea Link
NTC	Net Transfer Capacity
NVE	Norwegian Water Resources and Energy Directorate
NXT	NEXIT
PCR	Price Coupling of Regions
PS	Producer Surplus
SDAC	Single Day-Ahead Coupling
SE1	Northern Sweden
SE2	Central Northern Sweden
SE3	Central Southern Sweden
SE4	Southern Sweden
SS	Social Surplus
TRM	Transmission Reliability Margin
TSO	Transmission System Operator
TTC	Total Transfer Capacity
TWh	Terawatt Hours
UK	United Kingdom
WV	Water Value
XBID	Cross-Border Intraday Market Project

1 Introduction

Energy prices in Norway have soared during the fall and winter of 2021 leading into 2022. The Norwegian Water Resources and Energy directorate predicts high energy prices for the remainder of 2022 (Tjoflot et al., 2022). The unusually cold winter of 2020/2021 contributed to a high energy consumption both in Norway and generally in Europe. Combined with a low influx of water into reservoirs caused by a lack of precipitation, and a lack of energy sources such as gas in Europe, energy was in high demand (Birkelund et al., 2021).

Nordic countries have gone from isolated individual markets in the 1990s towards full integration with each other and, more recently, with European countries (Ciucci, 2021). Closer integration involves the construction of interconnector cables, facilitating more electricity trade between countries.

The most widely debated cause of high energy prices in Norway has been the addition of two such interconnector cables, linking Norway closer to Europe. First, a 1400 MW cable, NordLink, was opened between Norway and Germany in March 2021 (Statnett, 2021c). Then, in October 2021, the North Sea Link connecting Great Britain and Norway became operational (Statnett, 2021a). Norway's efforts towards closer European market integration have been questioned in light of these high electricity prices. This has led to the government rejecting to grant permission to build the planned 1400 MW NorthConnect cable to Scotland (E24, 2021).

The aim of this thesis is to contribute to the ongoing debate in Norway, by exploring what a Norwegian disconnection towards Europe would entail. Critics argue that Norway imports higher energy prices through the interconnectors, and that Norway would benefit from disconnecting them (Skårdalsmo and Solheim, 2021). This thesis investigates the validity of such claims, by answering the following research question:

How would a Norwegian exit from the European power market affect consumers, producers and power flows in Norway and Europe?

The research question is answered by constructing an optimisation model recreating the northern European electricity market, calculating power flows, prices and social surpluses. A Norwegian exit, hereafter referred to as "NEXIT", is simulated by removing interconnector capacity from Norway towards Europe.

Studying NEXIT is relevant for several reasons. Firstly, existing literature on European market decoupling is scarce, and primarily focuses on the consequences of Brexit. It is therefore relevant to investigate the topic of market decoupling in a Nordic context. The potential consequences of a Norwegian Exit will be estimated by analysing changes in prices and social surplus. Secondly, Norwegian consumers are experiencing higher electricity prices than ever seen before, and the debate revolves around Norway's position as a major electricity exporter. As the European markets become more closely integrated, a step in the opposite direction is particularly interesting to study. Lastly, by adding more renewable energy in the coming decades, Europe is in the middle of transforming its electricity market (Rystad Energy, 2022). It is therefore relevant to examine how electricity is traded within Europe.

The remainder of the thesis is organised in the following manner. First, the background in Chapter 2 introduces key features of the electricity market before relevant academic work is review in Chapter 3. The methodology in Chapter 4 then describes the construction of the optimisation model used to simulate NEXIT. The model covers the key Northern-European price areas, and results are analysed to illuminate the consequences of a Norwegian exit from the European power market. The analysis and discussion section is found in Chapter 5, where a particular emphasis is placed on investigating impacts in the south of Norway. Finally, concluding remarks summarising findings and suggestions for future research are made in Chapter 6.

2 Background

This chapter is composed of five sections explaining concepts later used in Chapter 4 and Chapter 5. The first section introduces key stakeholders in the market. In the second, supply and demand in the electricity market is described. Subsequently, the organisation of the power exchange is explained. The next section presents the issue of congestion, how it is solved in the power market, and finally the concept of congestion rent. It focuses on the Net Transfer Capacity (NTC) solution used for the analysis. The final section presents recent developments, giving relevant context on the current situation in the power market.

2.1 The Power Market and Its Stakeholders

The electricity market facilitates the process where electricity is provided from the producers to the end users. For some businesses and most households, the electricity is supplied by power retailers operating on the power exchange (Energy Facts Norway, 2022), which is the market of interest in this thesis. Four main stakeholders in the market can be identified: Consumers, producers, the state, and facilitators & regulators.

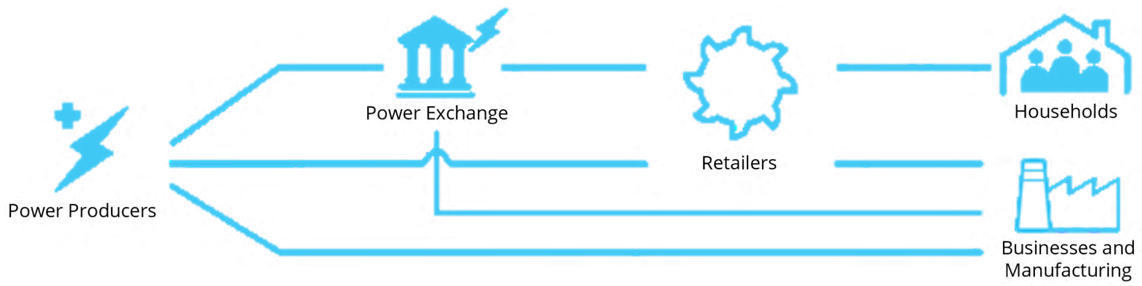


Figure 2.1: Overview of Actors In the Electricity Market. Adapted From Energy Facts Norway (2022)

2.1.1 Producers

Producers create the electricity supplied to the market. The electricity can be produced through different energy sources, which have different marginal costs per Megawatt hour (MWh). The marginal cost of energy sources is further elaborated on in Section 2.2. In Norway the main electricity producer is the state owned company Statkraft, and their largest power station is Ulla-Førre with a capacity of 7.8 Terawatt hours (Statkraft, 2013).

There are other smaller producers owned either by municipalities (Lyse, Eviny) or private actors (Clemens Kraft).

2.1.2 Consumers

In Norway, households can choose to have a flexible (spot) price for their electricity or a fixed price in addition to various tariffs (Energy Facts Norway, 2022). 96% of households have a flexible price making them directly affected by the power market price (Dagbladet, 2021). The demand of individual households and businesses is aggregated by the retailers and traded on the power exchange. In this thesis, retailers and businesses receiving electricity through the power exchange are regarded as consumers. As shown in Figure 2.1 end-users like households buy electricity from retailers such as Agva and Tinde Energi. Some electricity producers, like Lyse, also act as retailers in the Norwegian market.

2.1.3 The State

The Norwegian state, through the company Statnett, is the owner of the interconnectors, receiving part of the income they generate. In Norway, the state is a major electricity producer and sometimes also a retailer (Energy Facts Norway, 2022). With the aim to maintain a healthy market, the government can intervene to help specific stakeholders. Examples include subsidies for producers, tax reductions or financial aid to consumers. Additionally, the state is involved in the operations of market facilitators and regulators described below (Energy Facts Norway, 2022).

2.1.4 Facilitators & Regulators

The Norwegian producers and consumers primarily participate in the Nord Pool power exchange. Recently, trade on the European Power Exchange (EPEX SPOT) has also been made possible (EPEX SPOT, 2022). Both are Nominated Electricity Market Operators (NEMOs), who are parts of the system responsible to coordinate European power trade through a common marketplace (NEMO Committee, 2022).

Overseeing and supporting this market are Transmission System Operators (TSOs) and regulators. TSOs are in charge of ensuring system stability, while regulators set rules and oversee the functioning of the market. The Norwegian TSO is Statnett, accompanied by

Energinet in Denmark, Fingrid in Finland and Svenska Kraftnät in Sweden (Energinet et al., 2021). An example of a regulator is The Norwegian Water Resources and Energy Directorate (NVE). NVE plays an active role in developing network regulation, providing market access for customers, and ensuring security of supply in the Norwegian market (Flataker and Nielsen, 2019).

2.2 Supply & Demand in the Electricity Market

Supply and demand bids from market participants belonging to the same bidding area are aggregated into a single curve (an aggregated curve) defined for each hour of the day (Nord Pool Group, 2022g). Demand bids from retailers are sorted from highest to lowest, while supply bids from producers are sorted from lowest to highest price. In this section, only the characteristics of supply in the electricity market is explained in detail. Features of the electricity supply provide important context for the methodology chapter. An aggregated supply and demand curve is illustrated in Figure 2.2 for first hour in Germany on the 16th of February 2022.

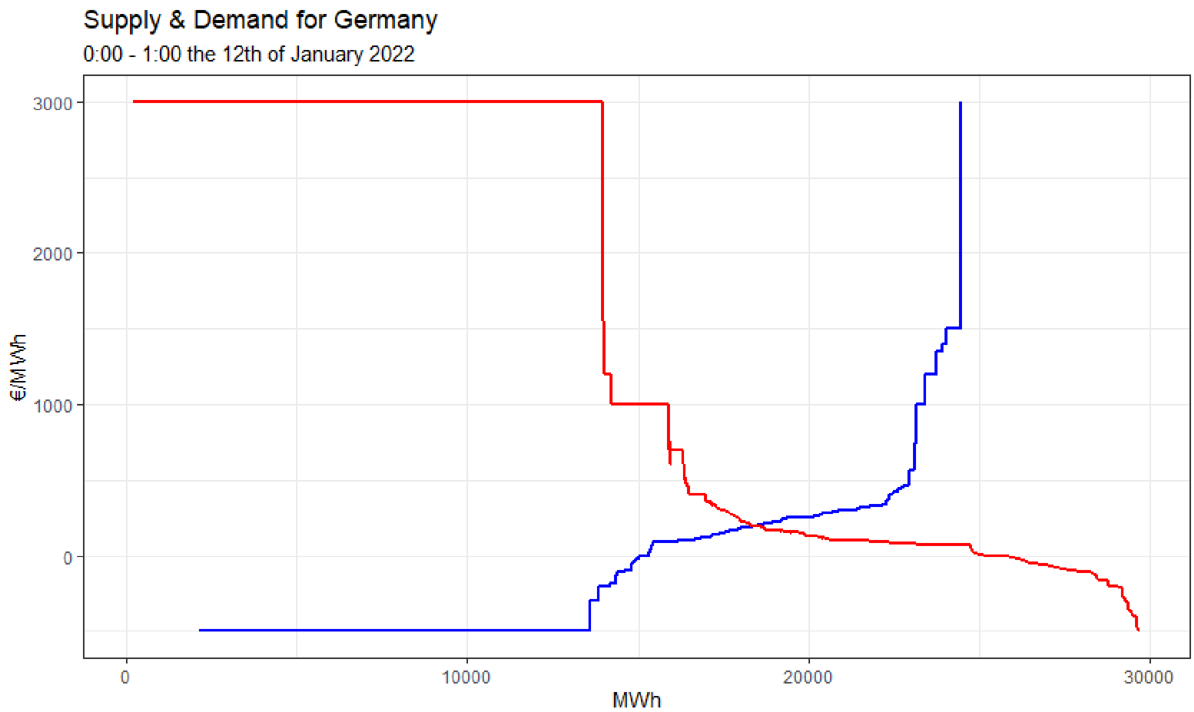


Figure 2.2: Aggregated German Bid Curves. Based on Daily Published Data From EPEXSPOT (2022a)

2.2.1 Supply Bids

The most common supply bid, and the emphasis of this thesis, are hourly bids made for individual hours, with a corresponding price and volume supplied. Actors may also submit all-or-nothing block bids, which must be fulfilled in full and accepted for a block of hours. Finally there are flexible hourly bids, which are sell-bids for the hours with the highest prices (Bjørndal, 2013). Block bids and flexible bids are not included in our model and will not be elaborated further.

2.2.2 Marginal Cost

The supply curve shows the marginal production costs of power in ascending order. Energy from suppliers with low marginal costs, like run-of-river hydro, nuclear, and wind power can be offered at the lowest price and are found to the left in the supply curve (Ministry of Petroleum and Energy, 2013). Hydro-reservoirs also have a low production cost, but bids are based on opportunity cost as explained in the following section. In Norway, hydro power accounts for 90% of all power generation (Ciucci, 2021), and so precipitation volume and influx to reservoirs are decisive for the power price and its fluctuations throughout the year (Ministry of Petroleum and Energy, 2013). To the right in the supply curve are technologies with higher marginal costs like biopower, coal and gas (Ministry of Petroleum and Energy, 2013). In Figure 2.2 there is a clear merit order supply bid structure, coming from Germany's different energy sources, seen in Figure 2.3.

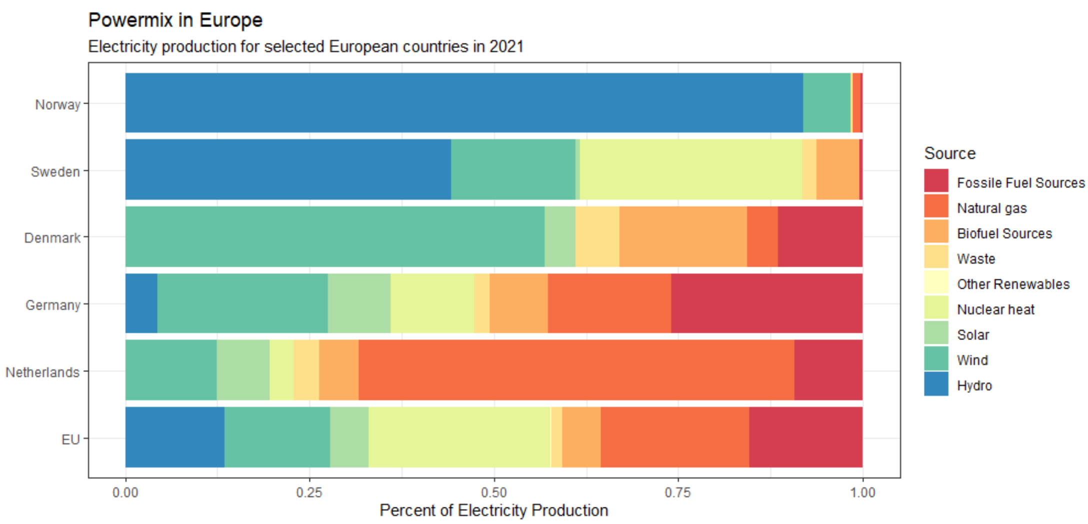


Figure 2.3: Share of Electricity Production by Energy Source. Adapted from Eurostat (2022)

The Figure shows the power mix for selected European countries, in shares of total production. Hydro power is a large part of the Norwegian and Swedish power mix, while other European countries rely more on wind power and fossile fuels.

2.2.3 Hydro-Reservoir Opportunity Cost

The supply bids from water reservoirs are based on the opportunity cost of water (Aasgård et al., 2016). Hydro power producers using water reservoirs can opt to produce electricity now or later. This makes the water in the reservoir a scarce resource, and the producer will be incentivised to distribute the production of electricity over time so that the cumulative income is as large as possible. If they expect higher electricity prices at a later time, it is profitable to withhold water in the reservoirs. The expected value of saving the water is called the water value, and determines hydro producers' bid price. If the electricity price is lower than the water value, the producer will profit from withholding production. When the electricity price is higher than the water value, it is profitable to produce hydro power (The Norwegian Water Resources and Energy Directorate, 2021).

2.3 Market Organisation

2.3.1 The Nord Pool Power Exchange

Norway is part of a joint Nordic power market with Sweden, Denmark and Finland, which in turn is connected to the European power market through interconnector cables to Germany, The Netherlands, Poland and Russia (Ministry of Petroleum and Energy, 2013). In 2021 Norway increased its market integration towards Europe, with the introduction of two 1400 MW cables: The North Sea Link (NSL) to Great Britain (Statnett, 2021a) and The NordLink (NL) cable to Germany (Statnett, 2021c) .

The Nordic electricity market originates from the early 1990s, when the Nordic countries deregulated their power markets. They brought their individual markets into a common Nordic market, with the Nord Pool market opening in 1996 (Nord Pool Group, 2022i). Today, Over 360 customers from 20 countries operate in the Nord Pool markets (Nord Pool Group, 2022f).

The key actors are Norway, Sweden, Denmark and Finland, but Estonia, Latvia and Lithuania all joined in the period between 2010-2013 (Nord Pool Group, 2022i). Deregulation of an electricity market entails that the state cedes control over running the market, and instead introduces free competition (Nord Pool Group, 2022i).

The goal of deregulating electricity markets is to improve efficiency and increase exchange of power and security of supply among the Nordic countries. Power capacity can be exploited more efficiently in a large market, and integrated markets improve efficiency and productivity (Nord Pool Group, 2022i). Electricity is an unconventional good in that it cannot be stored easily, and so once it has been produced it must generally be consumed (Ministry of Petroleum and Energy, 2013). It is critical that there is an exact balance between production and consumption. The power market plays an important role in this regard, where prices provide a planned balance between generation and consumption for the hours in the following day (Ministry of Petroleum and Energy, 2013).

2.3.2 The Day Ahead Market Clearing

The wholesale electricity market can be divided into separate markets that fulfil different purposes. The day-ahead market and the intra-day market can be found on the Nord Pool exchange, while the balancing market is run by Statnett as part of its TSO duties (Energy Facts Norway, 2022). The day-ahead market is the main market for electricity trading in the Nordics. The largest volumes are traded on the Nord Pool exchange, where 500 TWh is traded on a yearly basis (Nord Pool Group, 2022a).

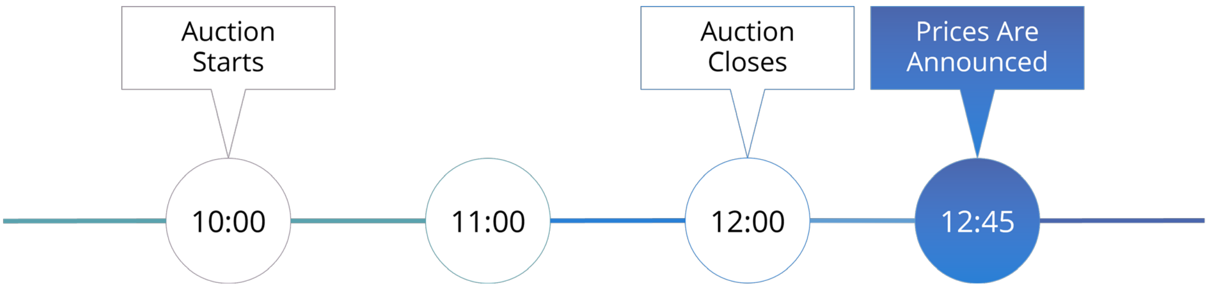


Figure 2.4: The Day Ahead Market Timeline (Nord Pool Group, 2022b)

At 10.00 CET, available power transmission capacities are published by the TSOs, and buyers and sellers have until 12.00 CET to submit their bids. Bids are submitted to Nord Pool who conducts an auction for delivery in 1-hour slots for the next day. Supply and demand bids are matched in the European market coupling process – the Single

Day-Ahead Coupling (SDAC) – through an algorithm called EUPHEMIA (Nord Pool Group, 2022a). Hourly prices are then announced to the market at 12.45 CET or later (Nord Pool Group, 2022a).

2.3.3 EUPHEMIA

The EUPHEMIA algorithm is part of the Price Coupling of Regions (PCR) project led by the European Power Exchanges. The project is managed by nine Power Exchanges: EPEX SPOT, GME, HenEx, Nasdaq, Nord Pool, OMIE, OPCOM, OTE and TGE (EPEXSPOT, 2022b). The goal is to develop a single day-ahead price coupling solution to calculate electricity prices in Europe, while considering the transmission constraints in the power grids. This is intended to increase liquidity, efficiency and social welfare in the markets. The EUPHEMIA name is an acronym of Pan-European Hybrid Electricity Market Integration Algorithm (EPEXSPOT, 2022b).

EUPHEMIA is the algorithm currently being used to solve the Day-Ahead Market (DAM) coupling problem in Europe. It matches energy supply and demand while considering market and network constraints. EUPHEMIA gives the market clearing prices, corresponding volumes and the net position (difference between local supply and demand) of each bidding zone, in addition to the flow through the interconnectors(Nominated Electricity Market Operators Committee, 2019).

The main objective of the algorithm is to maximize social surplus, i.e the sum of producer and consumer surplus and the congestion rent. The consumer surplus is calculated by multiplying the difference between the limit price of a bid and the market clearing price with the executed volume of the order. Similarly, the producer surplus is the difference between the minimum amount required to supply an order and the market clearing price multiplied with the executed volume of the order (Nominated Electricity Market Operators Committee, 2019).

The EUPHEMIA algorithm serves as a theoretical background for the model used in this thesis. A more elaborate explanation can be found in Nominated Electricity Market Operators Committee (2019).

2.4 Congestion Management

This section focuses on the issue of congestion, and how it is managed in the European electricity markets. The concept of price areas is introduced, before congestion management methods are elaborated on. A special emphasis will be placed on the NTC model, as this is the base for the model employed in this thesis.

2.4.1 Price Areas

The prices published by Nord Pool each day include a system price, in addition to area prices covering specific regions. The system price is for the entire Nordic market as a whole, and reflects the overall generation and consumption. If there were no capacity limitations between the price areas, the price in all Nordic price areas would equate to the system price. Due to capacity restrictions that are often referred to as bottlenecks, Nord Pool provides area prices which take these into account. Differences that arise between price areas in the Nordics are in other words a result of specific bottlenecks restricting the power flow from one area to another (Ministry of Petroleum and Energy, 2013).

In Figure 2.5, the Nord Pool price areas are shown. The current zone configuration in Europe mainly corresponds with national borders, except for Scandinavia and Italy who have multiple price-zones (Plancke et al., 2016). Price differences between price areas create income for the owners of interconnectors, called congestion rent. TSOs collect this revenue, which is normally used for investments in the power grid (Statnett, 2021b). The congestion rent equals the number of MW sent on an interconnector multiplied with the price difference between the two bidding areas (Nominated Electricity Market Operators Committee, 2019). The Nordic congestion income is typically shared in equal proportions for the TSOs on each side of the interconnector (Fingrid, 2022). Congestion income is calculated as follows, where I denotes all connections for a price area:

$$Congestion\ Income = \sum_{i \in I} \frac{Commercial\ Power\ flow_i \times Area\ price\ difference_i}{2}$$

The underlying cause of bottlenecks and differing power prices between areas is that regions have different power situations. Power must be imported to areas which have a

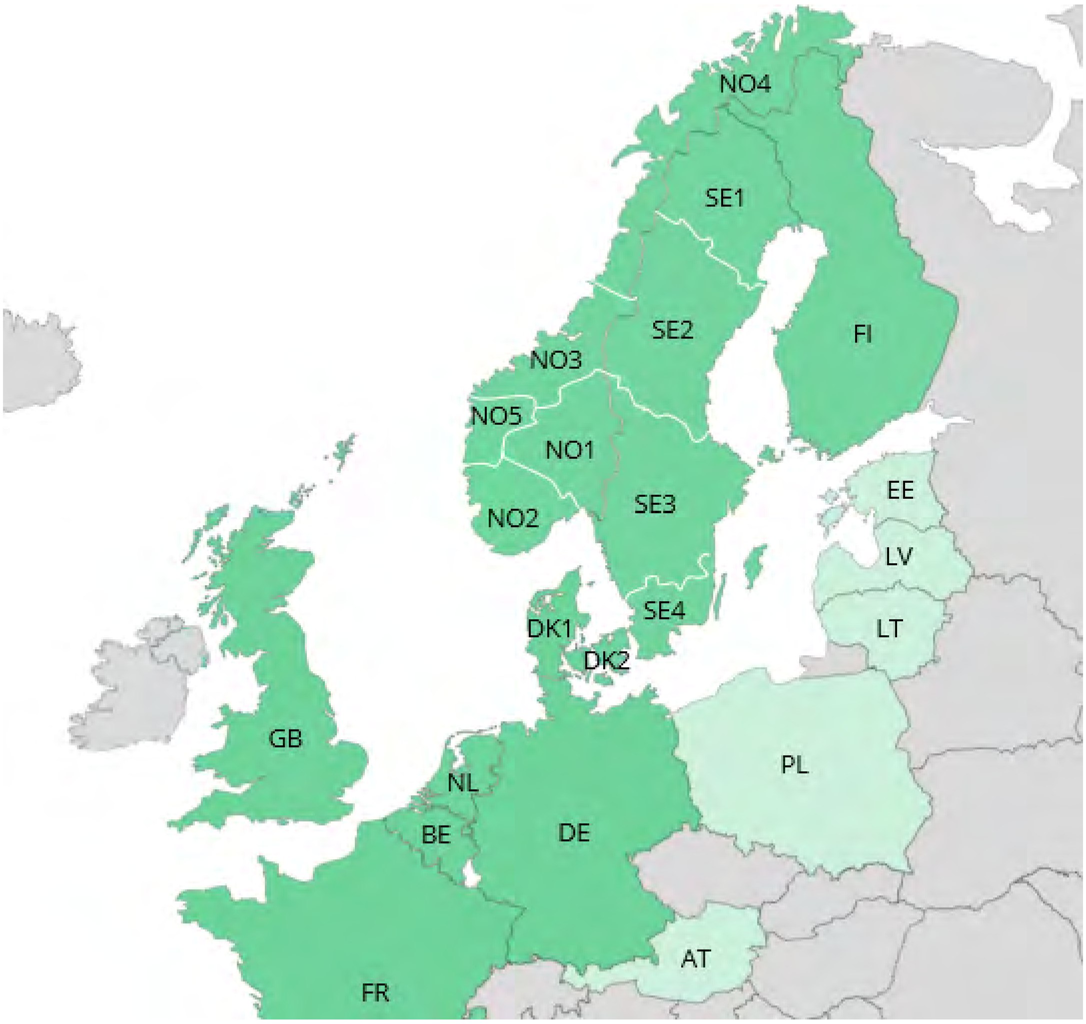


Figure 2.5: European Price Areas. Adapted From Nord Pool Group (2022e)

deficit, and exported from areas with a surplus (Ministry of Petroleum and Energy, 2013). If the transmission capacity is insufficient, bottlenecks occur between the areas. Such constraints can be incorporated into the market coupling process by defining a market area on each side of the bottleneck. The area with a deficit will naturally have a higher price than the area with a surplus. The power will therefore flow from the low-price area to the high-price area, alleviating the need for power supply. The prices also help shape behaviour, as generation is increased, and consumption decreased in areas with scarcity of power. Additionally, the area prices serve as a long-term signal to help identify where to place new generators or add new major consumption (Ministry of Petroleum and Energy, 2013).

2.4.2 Congestion Management Methods

The efficient allocation of scarce transmission capacities is one of the main tasks of congestion management, which comprises all measures taken to handle network access when there is congestion (Krause, 2005). Cross-border electricity trading fundamentally requires coordination between capacity calculation and allocation. Coordination between bidding zones is essential because power flows are not restricted by commercial agreements but must adhere to the laws of physics. When Germany exports electricity to France, part of this power flow will travel through the Netherlands and Belgium instead of following the direct path between the countries. This means that the transaction between France and Germany also impacts the remaining interconnector capacity available at the Dutch and Belgian borders (Plancke et al., 2016).

Congestion management can be split into two categories; capacity allocation and capacity alleviation. Capacity allocation methods are aimed at allocating transmission capacity before the physical delivery of the energy takes place. This can be methods such as zonal or nodal pricing, or explicit auctioning. Capacity alleviation are corrective methods, aimed at relieving congestion immediately. This can be done through redispatching or buybacks and countertrades (Krause, 2005). Capacity alleviation methods are not the emphasis of this thesis, as they occur after the day-ahead market clearing, and so only capacity allocation methods will be explained in detail.

2.4.2.1 Nodal Pricing

A nodal pricing method calculates the price at each power generating node. Each producer is paid in accordance with the local price at the node where it is located (Sarfati et al., 2019). A key feature of nodal pricing is that nodal prices typically become higher the further away generation is located from demand. Consequently, price signals in a nodal system are "sharper" than in a zonal system (Pettersen et al., 2011). Optimal Nodal prices give optimal dispatch and congestion management, and allows for optimal exploitation of the energy generation and the grid (Pettersen et al., 2011). However, the costs of implementing such a pricing method in many European countries would, at least in the short term, likely outweigh the benefits. A restructuring of cross border trading would be needed, implying significant IT and procedural changes (Sarfati et al., 2019).

2.4.2.2 Zonal Pricing

The pricing method most favoured in Europe is zonal pricing. The method entails aggregating nodes into zones with uniform prices for each price area. There are two different zonal pricing methods. Zonal pricing with Available Transmission Capacity (an ATC model) and a Flow Based Market Coupling (FBMC) (Sarfati et al., 2019).

The model used in this thesis is an NTC model. The ATC value which is used in an ATC model is found by also subtracting long-term cross-border nominations from the NTC value (Plancke et al., 2016). These expressions are used rather interchangingly. In the following sections, the original sources may refer to an ATC model or value. To avoid confusion, the model and its characteristics will be referred to as NTC-values.

The NTC model is currently used in the Nordic market. The method entails ignoring intra-zonal transmission constraints in the day-ahead market. The power flow is only limited by a pre-defined value: the available transmission capacity. Since transmission constraints are ignored for *intra*-zonal flows and approximated for *inter*-zonal flows, some transmission lines may be overloaded. This issue is handled through the redispatching stage, where overloaded lines must be relieved (Sarfati et al., 2019). Accurately representing the transmission network using a zonal pricing method is difficult. The size of the zones, as well as the transmission capacity amongst them needs to be well-defined (Plancke et al., 2016).

Central-European countries are increasingly implementing FBMC, which means partly incorporating physical constraints of the network directly into the market clearing. FBMC considers constraints on a set of representative transmission lines called critical branches in the day-ahead market stage. Zonal pricing with FBMC may in some case give a better representation of transmission constraints than zonal pricing with NTC. Since critical branches are determined before the day-ahead market clearing, a redispatch stage is still needed in zonal pricing with FBMC (Plancke et al., 2016).

2.4.3 Net Transfer Capacity Model

The net transfer capacity (NTC) between two zones is a measurement of how much power that can be transferred between two prize zones, without overloading the transmission grid.

These capacities are set by each Transmission System Operator (TSO) and represent how much power exchange is available for trading between zones (Nord Pool Group, 2022h). The net transfer capacity is defined as the following:

$$NTC = TTC - TRM$$

The Total Transfer Capacity (TTC) is the maximum possible power exchange between two areas compatible with operational and security standards. The TTC between two areas is jointly determined by the TSO on both sides of the interconnection. If the values from the TSOs differ, the lowest value is used. The objective for the TSOs is to allow for as high capacity for market trading as possible, while considering outages and other faults in the network. Simulations are made to determine how much power can be transmitted through different "transmission corridors" between the areas before thermal overloads, voltage collapse and other instabilities occur (Nord Pool Group, 2022h). This means that some internal constraints are considered as well.

The Transmission Reliability Margin (TRM) is a security margin that accounts for uncertainties related to the computation of the TTC, which may arise from unintended deviations of physical flows during operations, due to the physical functioning of load-frequency regulation. Included in these security margins are security standards such as the N-1 criterion. The N-1 criterion states that the power system should be able to handle the loss of any single component (a production unit, grid line, transformer etc) (Nord Pool Group, 2022h). For some specific power-connections, there is no need for a TRM. This is the case for High Voltage Direct Current (HVDC cables). HVDC cables are well-suited for large-scale long-distance transmission, as the voltage and current waves don't change direction like they do in Alternating Current (AC) cables. The heat loss from transmission is therefore significantly reduced (Circuit Globe, 2022). The thermal capacity (TTC) for HVDC cables is normally used as the NTC value in both directions, and there is no need for any margin (Nord Pool Group, 2022h).

NTC values between all price areas are given to Nord Pool Spot for day-ahead trading, in the Elspot market. The TSO guarantees that the capacities offered for trading are physically viable to implement, and the remaining cross-border transmission capacity available under the actual operational conditions are offered to the intra-day market XBID (Nord Pool Group, 2022h).

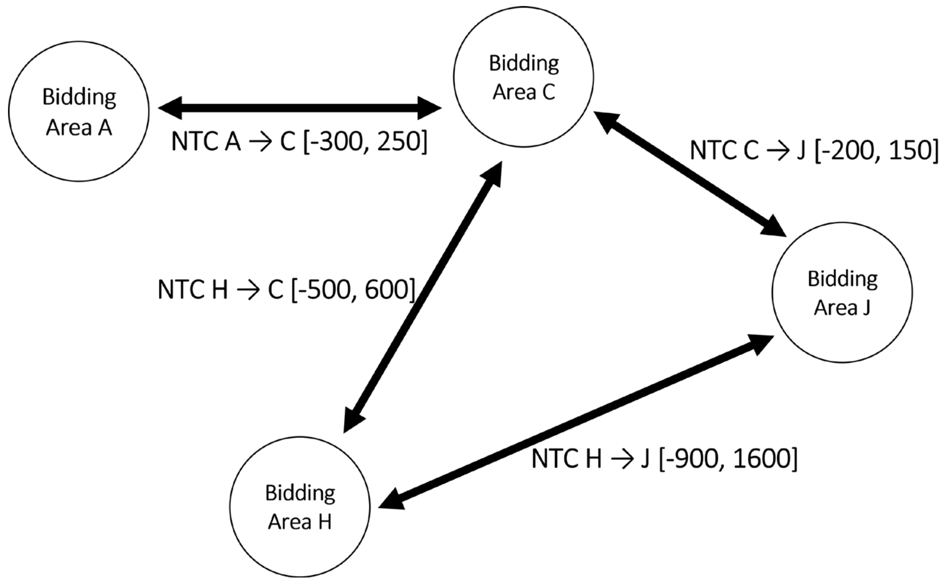


Figure 2.6: An NTC Model. Adapted From (Nominated Electricity Market Operators Committee, 2019, p. 7)

In Figure 2.6, a simple NTC model is shown. The bidding zones are linked by interconnectors. The power flow from a bidding zone to a neighbouring zone can only flow through these lines and is limited by the NTC capacity. The lines are oriented from a source bidding zone (A) to a sink bidding zone (C). A positive value of the flow on the line between them therefore indicates a flow from A to C. Correspondingly, a negative value indicates a flow from C to A. The net transfer capacity can be different per period and direction of the line. NTC limits can also be negative. For example, an NTC value of -250 on the line of AC is implicitly indicating that the flow is forced to go in one direction (from C to A) (Nominated Electricity Market Operators Committee, 2019).

The power flow through interconnectors may be subject to losses and tariffs. Interconnector losses mean that part of the energy injected from one side is lost on the way, and the received power is less than the energy sent. An illustration of this is found in Figure 2.7.

Bidding area B injects 1000 MWh on the line to bidding area A, but only 950 MWh reaches area A. Power may be lost along the way in the form of heat (Circuit Globe, 2022), and so 50 MWh is consumed on the line.

In an NTC model, the direct current cables may have operators who levy a cost per MWh passing through the cable. In the NTC model, this is represented as flow tariffs. The flow

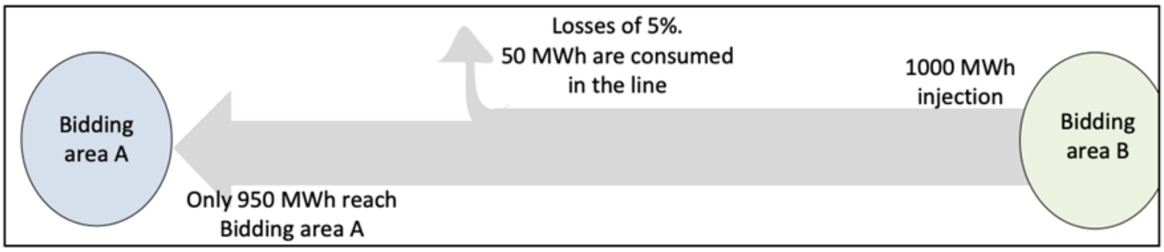


Figure 2.7: Power Transfer Between Interconnectors (Nominated Electricity Market Operators Committee, 2019, p. 8)

tariff is incurred as a loss with regard to the congestion rent. If the difference in price between areas is less than the tariff, the flow will be zero. Once the price difference exceeds this tariff, the operator collects a congestion rent. Losses in power during transmission do not impact congestion rent but, should an interconnector implement tariffs, the congestion rent would be reduced by the tariff rates multiplied with the flow calculated by EUPHEMIA (Nominated Electricity Market Operators Committee, 2019).

Calculation of Available Capacity

Two days before delivery, the TSOs create a forecast for congestion in their part of the grid. The forecast contains information on anticipated outages of grid components, generation units and their expected output levels, as well as forecasts for load and renewable generation (Plancke et al., 2016). For Central Western Europe, all of these forecasts from the TSOs are merged by the coordinator Coreso, which creates the base-case. Coreso is responsible for the coordination amongst TSOs, while the TSOs themselves remain responsible for operation (Plancke et al., 2016).

In an NTC model, each TSO determines a net-transfer capacity for each direction on the borders of its control area. The NTC value can be interpreted as "the maximum allowable commercial exchange between two zones that push at least one critical network element to its physical limit" (Plancke et al., 2016). TSOs of neighbouring zones coordinate bilaterally to align NTC values, generally selecting the lowest NTC value proposed (Plancke et al., 2016).

2.4.4 Flow-Based Market Coupling

Many studies have in the last years investigated how a more integrated European energy market would affect social surplus. As part of the development towards closer integration of European energy markets and climate targets the FBMC design was implemented in 2015. This market coupling method superseded the NTC approach in central western Europe in 2015 (Voswinkel et al., 2019). The aim was to get a better representation of the physics of the electricity grid, and to increase transparency of the market results and procedures (Voswinkel et al., 2019). The following section describes the FBMC method currently being used in many European countries.

Calculation of Available Capacity

The flow-based methodology does not give fixed commercial capacities on aggregated zonal interfaces, but rather formulates constrains which reflect the physical limits of the grid (Plancke et al., 2016). A simplified network model is constructed, represented by a combination of nodes and lines. The combined input from all of the TSOs give a set of restrictions for all Critical Branches within or between zones. Each of these constraints limits the combined effect of all zonal net exchange positions, so that no CB exceeds its available flow (Plancke et al., 2016).

Review of Flow-Based Market Coupling

The relationship between the different congestion management methods (Nodal, FBMC and NTC) is illustrated by Bjørndal et al. (2018). They use a 3-node example, where the nodes are connected in a triangle with lines sharing the same thermal capacity and admittance. The network of nodes is separated into two different zones. They then simulate the feasibility of the solutions offered by the FBMC and NTC model under different base loads, compared to the optimal nodal pricing. Bjørndal et al. (2018) find that it may be difficult to identify the relevant critical branches in a FBMC model, because it requires TSOs to accurately predict the directions of power-exchange across borders. If the Critical Branches are not correctly defined, higher social-surplus in the day-ahead market may be offset by higher redispatching cost due to the infeasibility of the solutions offered. Additionally, they find that FBMC does not necessarily outperform an NTC model with regards to alleviating congestion and utilising the resources in the network.

When given an idealised setting with unlimited trade, the overall performance of FBMC comes close to that of a theoretically optimal solution (i.e nodal pricing), realising around 87% of the possible welfare gains (Voswinkel et al., 2019). This picture changes dramatically when conditions are not ideal. In a realistic setting where intra-zonal bottlenecks are commonplace, FBMC only attains 59% of the theoretically possible welfare. Voswinkel et al. (2019) conclude that FBMC generally has the capability of performing reasonably well, but that its problems arise from intra-zonal bottlenecks. FBMC is ineffective at handling intra-zonal congestion, because the main cause of this congestion – intra-zonal trade – is not supervised by the market clearing process (Voswinkel et al., 2019). Intra-zonal bottlenecks are however to some degree accounted for in both the NTC and FBMC methodologies, in identifying critical branches or available transmission capacities.

Although used in many European countries, FBMC is not currently being used in the Nordics and is as such not a part of the model used in this thesis. All European countries are instead modeled by using the NTC method.

2.5 Recent Developments in the Power Market

Several forces have caused the high prices in Southern Norway in 2021 and 2022. There are structural limitation in the Nordic grid, as well as major changes in power generation and demand. These factors are important to consider when discussing present and future consequences of decoupling the interconnectors. This section presents context on structural challenges in the Nordic power grid, as well as recent developments causing high prices.

2.5.1 An Unbalanced Nordic Power Grid

The northern part of the Nordics (NO4 and SE1) is a large surplus area, accounting for roughly 30% of Nordic annual power production, but only 15% of consumption (Energinet et al., 2021). The power surplus in the north of Sweden has especially grown in the last 5 years, due to more wind capacity being built there (Bloomfield, 2021). The western part of Norway (NO5) also has a considerable power surplus, with an electricity balance in 2020 of +15 TWh. The main power flows in the Nordic system are therefore from electricity surplus areas in the north, to the electricity deficit areas in the south and further down to the European continent (Energinet et al., 2021). There is also a west-to-east power flow, due to the NO5 surplus. The Nordic TSOs Statnett, Energinet, Fingrid and Svenska Kraftnät conducted an analysis of future power flows in the Nordics (Energinet et al., 2021). Figure 2.8 shows realised market flows in 2020 and projected power flows in 2040, with the implementation of intermittent renewable energy sources.

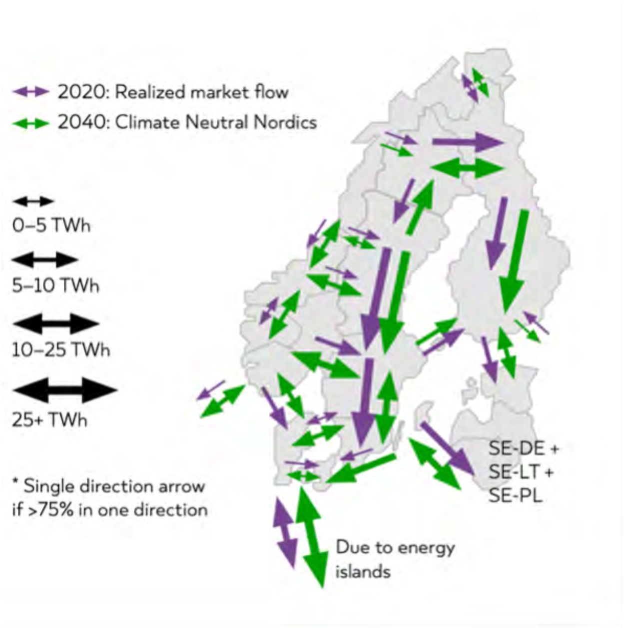


Figure 2.8: The Nordic Power Grid (Energinet et al., 2021, p. 17)

Towards 2040, high consumption growth combined with a higher share of intermittent production will affect flow patterns as well as price differences between bidding zones (Energinet et al., 2021). More consumption is expected to be situated in the northern part of the Nordics, in particular the north of Norway and Sweden. Consumption in this part of the Nordics is expected to rise to 25% of the total, compared to a share of 15% today. Production in the northern areas will not be able to supply all of this, and so the surplus in the north decreases and the annual north-south flow will be reduced compared to today. A higher share of intermittent production from renewables also means that flows may more often go in the opposite direction than today, depending on wind power production. In periods with high wind production in the south of Norway and Sweden, the power flow may more often go from NO3 to NO4 and from SE2 to SE1 (Energinet et al., 2021).

The Nordic region is also expected to increase its export and imports towards Europe, with an expansion of interconnector capacity and higher share of intermittent production capacity in central Europe and the United Kingdom (UK). Increased trade will generally increase the bottlenecks and in turn hour-by-hour price differences across Nordic price areas if no investments in the grid system are made. The TSOs therefore indicate a need for increased grid investments towards 2040, and cooperation between the Nordic TSOs is needed to better understand the changing flow patterns in the interconnected grid (Energinet et al., 2021).

2.5.2 Swedish Nuclear Power Shutdown

Nuclear energy has been a controversial topic in Sweden, with the government initiating a halt to the expansion of nuclear power capacity in the 1980s (Duxbury, 2021). All powerplants were expected to be shut down by 2010. However, the decision was repealed due to a higher electricity demand and greater awareness of the need for emission-free power. Still, a tax specifically targeting electricity from nuclear plants has limited their profitability. In 2019 and 2020, the energy producer Vattenfall shut down two nuclear powerplants in Ringhals, in the SE4 area of Sweden (Duxbury, 2021).

Nuclear energy is of great importance to Sweden and Finland, but also the entire Nordic power system. Nuclear power, with its steady and predictable generation, contributes to the security of supply, stable market prices and system stability in the Nordic power system (Statnett, 2019). A phase out of nuclear energy would have major consequences not only for the south of Sweden, but the whole Nordic region. As fossil-fueled plants are on a planned decline as well, this reduces the available capacity of powerplants where generation is administrable (Statnett, 2019).

A major theme in the Nordic power mix is therefore, like in the rest of Europe, the replacement of controllable power production with the implementation of green weather-dependent sources like wind, solar and hydro power. With no nuclear power production, the power deficit in the south of Sweden would widen. This is especially the case during periods of low intermittent production and high consumption. In such periods, the south of Scandinavia will depend more on imports in order to cover consumption. Contrastingly, increased wind and solar energy production will entail several hours where intermittent production alone exceeds consumption (Statnett, 2019). How strong the impact on grid development will be is linked to production type, volume and location of the new energy sources. The renewable energy sources are often located far away from consumption centers, and this adds to the need for grid development. The longer the distance between production units and consumption, the more grid investments are needed (Statnett, 2019)

The decommissioning of Ringhals 1 and 2 is one of three major recent changes, which has led to new transfer patterns. The two others are increased wind power in the north of Sweden, and the new cross-border interconnectors between Norway and Europe. These changes have led to congestions between SE2 and SE3. In addition, increased electricity flows from southern Finland to SE3 and from SE3 to NO1 and DK1 has caused east-to-west congestions in the Swedish grid. To avoid compromising operational security, Sweden has restricted capacity between NO1 and SE3 for extended periods. The congestions were expected to be amplified due to increased Finnish nuclear power (Statnett, 2019).

Reduced capacity in the corridor between NO1 and SE3 has affected power prices in the entire Nordic system. This, in combination with reduced SE2 and SE3 capacity, has led to very high price differences between the southern and northern parts of Norway and Sweden. The major congestions in the Nordic grid are exacerbated by the currently ongoing supply crunch in the EU (Energinet et al., 2021).

2.5.3 Energy Supply Crunch in the EU

The current energy crisis is a result of what the European Union Institute for Security Studies name a "perfect storm of mutually reinforcing negative forces", caused by both global and local issues (Popkostova, 2022). The global interconnectedness of markets means that problems in one geographical region ripple throughout the world.

An unusually cold 2020/2021 winter season in both Asia and Europe, the two main markets competing for liquified natural gas (LNG), has pushed energy prices upwards (Popkostova, 2022). Additionally, US LNG shipments to Europe and Asia were severely restricted, due to extreme cold in Texas in February 2021, which led to a contraction of supply. Supply issues were further exacerbated by summer heatwaves across the US, Asia and Europe leading to a surge in demand for air conditioning (Popkostova, 2022). Gas prices are typically lower during the summer due to lower demand, and more gas goes to storage. However, this did not happen last year (Buli, 2022).

In Latin-America droughts led to a reduction in hydro power generation, causing even more LNG cargoes to be diverted from Europe. In addition, scarcity of shipping capacity triggered by the Covid-19 pandemic pushed LNG spot shipping rates to all-time highs in the beginning of 2021 (Popkostova, 2022). The increased demand combined with severely limited supply meant that Europe entered the winter of 2021/2022 with gas storage at its lowest level for at least 10 years (Buli, 2022).

Internally in the EU, wind generation has been limited by poor wind conditions in Northern Europe. Wind power constitutes as much as a fifth of German and Dutch power generation. Reduced wind generation in combination with Germany phasing out nuclear energy has further increased demand for gas and coal in the EU (Popkostova, 2022).

What may escalate the situation from an energy crunch to an energy crisis is a termination of gas exports from Russia to European countries, following the invasion of Ukraine (Thomas and Race, 2022). This has happened to Poland and Bulgaria in April 2022, causing a significant rise in gas prices (Elliott and Griffin, 2022). Russia says it may close the gas pipeline Nordstream 1, and Germany froze the certification of the newly built pipeline Nordstream 2 in February 2022 (Thomas and Race, 2022). The European Union (EU) may also decide themselves to block gas exports as part of sanctions against Russia. The EU gets about 40% of its gas supplies from Russia, and gas supplies are difficult to replace as they must travel through fixed pipelines from country to country. Should exports be stopped, energy intensive industries may need to shut down to ration energy (Thomas and Race, 2022). The European Energy situation in 2022 is severely strained, strongly affecting the Nordic power market. In the following section we delve into the specifics of the Nordic power situation.

2.5.4 The Nordic Power Situation in 2022

Coinciding with the high continental prices, the Nordic region had a very dry summer in 2021. The European supply crunch caused large exports of electricity to the continent, through heavy use of the interconnectors from the NO2 price area to Germany, the Netherlands and Denmark. This meant high production and exports in NO2 despite decreasing reservoir levels (Bloomfield, 2021). In the fall of 2021, the North Sea Link interconnector to the United Kingdom was also opened, further increasing exports (Birkelund et al., 2021). The northern part of Norway and Sweden experienced a normal influx to water reservoirs, giving low prices despite low levels of wind production (Bloomfield, 2021). The table below displays the Norwegian water reservoirs' hydro balance in the spring of 2022 compared its historical mean.

Elspot Area	Week 12(%)	Mean Week 12
East-Norway (NO1)	13.4%	17.1%
South-West Norway (NO2)	25.7%	44.7%
Mid-Norway (NO3)	31.3%	25.8%
North-Norway (NO4)	48.1%	44.2%
Western-Norway (NO5)	18,7%	30.4%
Norway	29.2%	38.6%

Table 2.1: Water Reservoir Filling Levels 2022. Adapted from The Norwegian Water Resources and Energy Directorate (2022)

In week 12, during March 2022, NO3 and NO4 had relatively normal reservoir filling levels. This was however not the case in NO2 and NO5. In September 2021, the Norwegian TSO Statnett designated the power situation in these areas as "tight" due to the low reservoir filling levels. Their most recent assessment in November 2021 was that the situation is normal, citing that increased precipitation in combination with import capabilities means low likelihood of energy shortage (Statnett, 2022b).

The recent years have seen very low prices in 2020 and very high prices in 2021 and 2022. The yearly Nord Pool system price had in previous years varied between 20 and 44 Euros per MWh. In 2020 the price plummeted to 11 €/MWh, before a sharp increase to 62 €/MWh in 2021. The unusually high prices have carried into 2022 with a current year-high system price of 144,79 €/MWh in March 2022. The monthly system prices in 2022 have surpassed all prices in the last 10 years, with the exception of December 2021. Due to the congestion in the Nordic power grid, the high price have not been felt by all regions in Norway. NO1 has seen average day-ahead prices of 192,27 €/MWh in March 2022, while NO4 had average prices of 15,53 €/MWh in the same period (Nord Pool Group, 2022b).

3 Literature Review

This section will provide an overview of literature studying uncoupling of electricity markets, and the impact of interconnectors. Firstly, relevant academic work on the topic of European market uncoupling will be explored. Subsequently, literature on the impact of interconnectors will be examined, supplemented by technical reports from market actors such as Statnett.

3.1 European Market Coupling

Existing literature on decoupling electricity markets is scarce, and mainly revolves around the recent Brexit scenario. Coupled electricity markets involve a simultaneous calculation of prices and electricity flows between areas in the day-ahead market (Geske et al., 2020). Market participants do not need to reserve capacity on interconnectors in advance, and can simply make bids and offers for the next 24 hours (Energy Facts Norway, 2022). Following the Brexit decision in 2016, Britain disconnected from the common European electricity market. Geske et al. (2020) study the cost of bilaterally uncoupling Britain and the EU; they name this event "Elecxit". A company wishing to trade power across an interconnector, must first reserve capacity on the cable. Subsequently, it must buy power in one market and sell power in the other. Geske et al. (2020) look at the costs of Elexcit, using historical data on prediction errors in capacity reservation. They find that market uncoupling in combination with the abandonment of planned interconnectors would raise generation costs by €700m (2%) a year, compared to staying in the internal energy market. Their results are affected by how British and French electricity systems develop over the next decades. If France keeps its low marginal-cost nuclear energy, economic losses would be 4 times greater at €2700m. Should the UK weaken its decarbonisation ambitions, losses would be greatly reduced as lower carbon prizes would subsidize UK electricity generation, allowing prices to converge with those in France. However, in three out of four scenarios Geske et al. (2020) study, British prices rise, while French prises sink.

The UK left the EU integrated electricity market on 31/12/2020, and with it the access to the Single Day Ahead Market Coupling that clears local and cross-border trades jointly (Guo and Newbery, 2021). The replacement "multi-region loose volume coupling" was scheduled to be introduced before April 2022, but progress stagnated and the solution is not yet implemented (Paul, 2022). In the meantime, Great Britain conducts its own explicit auction for interconnector capacity and a British day ahead market before the SDAC auction in the EU. Guo and Newbery (2021) measure the risks in taking positions in each market separately, and the costs of uncoupling GB's interconnector trade. In this scenario, traders are exposed to the risk that their ex-ante market position and interconnector purchases may lock them into unprofitable trades, and so they attach a risk discount to their price forecasts. Trading on the IFA interconnector to France is risky, as inflexible French nuclear generation and highly weather-sensitive demand makes prices (and flow patterns) hard to predict. This leads to a quite high bid discount of about €2 per MWh. The less volatile market in the Netherlands results in a lower bid discount on the BritNed interconnector of under €1 per MWh.

Mathieu et al. (2018) also discussed potential consequences of Brexit, arguing that Brexit has no upside for the energy sector, and will make decarbonisation more complex and costlier. Day-ahead market coupling increased the percentage of available cross-zonal capacity used in the "right direction", in the presence of price differentials above €1, from 60% in 2010 to 86% in 2016. Social welfare losses in the absence of market coupling was in 2016 estimated at €58 million for the GB-IE (Ireland) border, and €45 million for the GB-NI (Northern Ireland) border (Mathieu et al., 2018). Mathieu et al. (2018) mention interconnectors as a tool to help compensate for any shortfall in renewable energy production, and allowing surplus output to be exported during periods where supply exceed what can safely be injected into the grid at a domestic level. Another potentially negative consequence are higher project costs, if UK interconnectors no longer were eligible to receive EU funding. Additionally, trading efficiency and social welfare suffers, as the number of hours with full saturation (full utilisation) on the interconnectors would drop markedly in a full Brexit with market decoupling. Suspension of plans to build new interconnectors would also disproportionately harm the UK as a net importer of electricity. As an example, building the planned VikingLink interconnector between Denmark and Great Britain is expected to generate gains for UK consumers, and producers in Denmark, Sweden and Northern Germany. Norway and the Netherlands should on the other hand experience minor losses due to revenue cannibalisation on the BritNed and North Sea Link connections (Mathieu et al., 2018).

3.2 Impact of Interconnectors

Before Elexcit was implemented, Newbery et al. (2019) examined the efficiency and value of uncoupled and coupled trading for the four direct current interconnectors to GB, over different timescales ranging from year-ahead to intra-day. They found that market coupling created efficient trading at the day-ahead stage both on the IFA interconnector to France, and on the BritNed interconnector to the Netherlands. They estimate the commercial value of IFA and BritNed together to be at €500 million/yr, including contributions to security of supply.

SEM Committee (2011) attempts to estimate the potential social costs of not coupling two interconnectors between GB and the single electricity market (SEM) on the island of Ireland. The cables have an import capacity of 950/910 MW and an export capacity of 580 MW. The social welfare gains of coupling were estimated to be around €30M per year with an average import capacity of 930 MW, with the estimates including €5/MWh to allow for various losses and transmission access charges. Increased imports of electricity into Ireland will result in lower wholesale price of electricity in Ireland, all else being equal. Consumers in Ireland were expected to benefit from these prices, while producers will lose out because less infra-marginal rent (their revenues in excess of their variable costs) is earned. Increased exports of electricity from Ireland will result in higher wholesale prices of electricity in Ireland, all else being equal. Irish producers would then make more infra-marginal rent, but consumers would lose out. The sum of these two different movements is equal to the change in social welfare.

Malaguzzi Valeri (2009) studies the impact on social welfare and competition in the Irish electricity market, when adding additional interconnection between Ireland and Great Britain. She finds Irish consumers stand to gain the most from increased interconnection, while Irish producers lose out. This corresponds to the scenario mentioned by SEM Committee (2011), with increased imports of electricity into Ireland. Malaguzzi Valeri (2009) also finds that the total social welfare for Ireland and Great Britain increases with closer interconnection, although at a decreasing rate.

Skar et al. (2016) study the role of transmission in the future, where renewable energy will be a significant portion of the power system. They examine a simulated 2050 scenario with no, limited and high expansion of transmission capacity between European countries. Results from the scenarios with no expansion of transmission capacity shows that the cost to the electricity sector would be very high, potentially in the hundreds of billions of euros.

The most prominent analyses of Norwegian interconnectors have been conducted by the Norwegian TSO Statnett. Before the implementation of NordLink and North Sea Link, Statnett (2013) attempted to estimate the impact of the interconnectors on social welfare in 2020. Their estimate, including congestion rent, producer and consumer surplus, is that each interconnector provides around €120 to €160 million euros per year. The utility for the Nordic is even higher, as especially Sweden benefits from the cables. Furthermore, Statnett estimated smaller price differences between Norway and Germany/Great Britain, but continuing cases of bottlenecks and large price differences between the countries despite the added capacity. They concluded that the interconnectors would add stability to prices on a yearly basis, but that they would entail increased short-term volatility (Statnett, 2013).

Statnett conducted a similar analysis to this thesis in March 2022. Their analysis estimates that the NordLink and North Sea Link interconnectors only explain around 10% of the average price in South-Norway in 2021, compared to a situation without these cables (Døskeland et al., 2022). A smaller impact on prices can also be found in the north of Norway.

The general theme in the literature reviewed argues that losses in social welfare is to be expected in a scenario where power markets are decoupled. Geske et al. (2020) show that losses occur when traders must reserve capacity on transmission lines in advance. Similarly, Mathieu et al. (2018) argue that day-ahead market coupling increased the percentage of available cross-zonal capacity used in the "right direction". Guo and Newbery (2021) measure the risks in taking positions in the EU and GB markets separately, causing traders to add a risk discount to their price forecasts. SEM Committee (2011) and Newbery et al. (2019) compare uncoupled and coupled trading on interconnectors, to Ireland and the Netherlands respectively. Both studies find that the interconnectors positively impact social welfare. SEM Committee (2011) elaborates on this by arguing that consumers and producers stand to gain or lose, depending on if the country is a net importer or exporter.

Malaguzzi Valeri (2009) supplements this point of view by arguing that Irish consumers would stand to gain the most by adding additional interconnection between Ireland and Great Britain, while Irish producers lose out. Skar et al. (2016) highlights the role of transmission in the future, where renewable energy will be a significant portion of the power system. Finally, technical reports from Statnett (2013) and Døskeland et al. (2022) specifically look at the impact from two of the interconnectors studied in this thesis; the NordLink cable to Germany and the North Sea link to Great Britain. Statnett (2013) emphasises large gains in social welfare, but warns of possible short-term volatility in prices. Døskeland et al. (2022) addresses public outcry that the interconnectors have skyrocketed Norwegian electricity prices, by showing that the estimated price-effect of the interconnectors only was around 10% in 2021.

Insights from the literature review leads suggests that disconnecting the interconnectors to GB, NL and DE will likely have a negative impact on total social welfare for all countries involved. Several studies show, however, that this does not necessarily mean that consumers or producers in some countries are not better off. Prices are expected to diverge in a decoupling scenario, contrasting the price convergence seen when adding capacity between countries.

4 Methodology

This chapter describes the process and challenges in calculating the results presented in the analysis and discussion chapter. A special emphasis is put on the bid curves used, as well as assumptions and simplifications used in the NTC-model.

4.1 Choice of Method

The aim of building the NTC-model is to reflect the current market clearing mechanism for selected Nordic and European countries. The accuracy of the model is measured by comparing the base case prices with the prices seen in the real world. After constructing a realistic base case, simulations will be conducted where capacity on specific interconnectors is set to zero. Simulations are conducted involving the NorNed cable to the Netherlands, the NordLink to Germany and the North Sea link to Great Britain. Differences in prices, power flows and the decomposed social surplus can then be shown under the selected scenarios.

The model comprises the 17 European price areas in Figure 4.1, colored in dark green, in order to capture impacts on countries affected by the interconnectors. Combinations of time limitations, lack of available data and data size are the main reasons for assumptions and simplifications taken to construct the optimisation model. The optimisation model used is an NTC model. This is considered the most suitable option, as it is the model used to calculate prices and power flows in the Nordics (Nord Pool Group, 2022h). The interconnectors studied are HVDC cables, meaning that power only flows in one direction at a time (Circuit Globe, 2022). This aligns well with how power flows are modeled in an NTC model.

For simplification purposes the model is constructed as if GB is still a part of EUPHEMIA. Additionally, due to the diminishing impact of price zones located further away from the Norwegian price areas, the bid curves from Poland, the Baltics and Austria have not been included. This is a measure to reduce the data quantity and run-time of the model, but bid curves affected by excluding these areas are adjusted for imports and exports. The adjustment is made in the data cleaning process, where the import and export volume is added or removed from the lower end of the domestic supply curve.

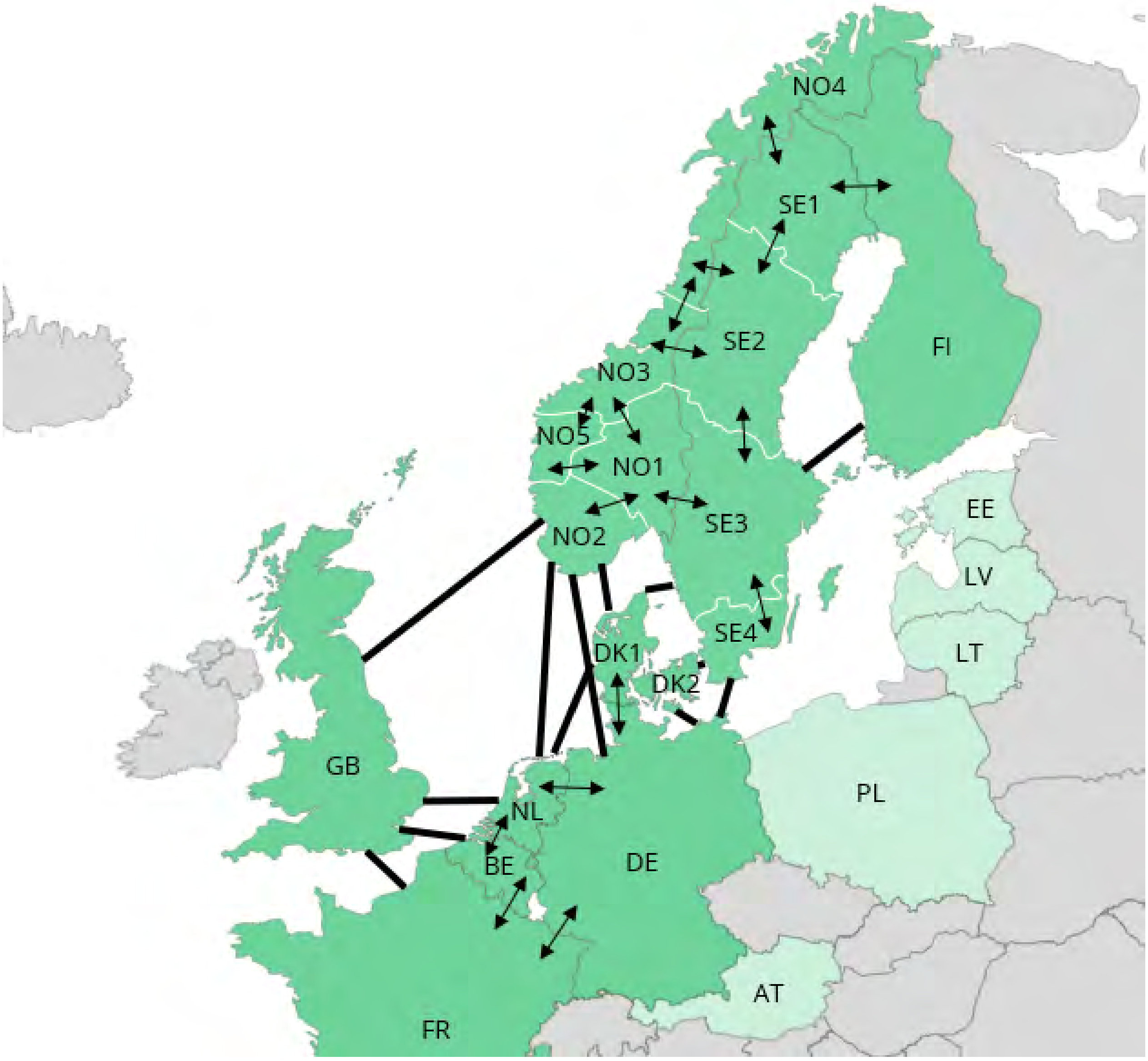


Figure 4.1: Price Areas and Trade Connections in the Optimisation model. Adapted From Nord Pool Group (2022e)

4.2 Data Sources

Bid curve data from EPEX SPOT (EPEXSPOT, 2022a) and NordPool's FTP Server (Nord Pool Group, 2022d) serves as the data foundation. The time period of the data is between the 14th of January and the 15th of March 2022. For the Norwegian price areas, information on wind- and hydropower generation is retrieved from the European Network of Transmission System Operators for Electricity (ENTSO-E) (ENTSO-E, 2022). ENTSO-E provides hourly data on power production, split on generation sources. Other datapoints required for the optimisation have been collected on an hourly granularity from Nord Pool (Nord Pool Group, 2022e).

4.3 European Bid Curves

The bid data from EPEX SPOT and Nord Pool is stored as .csv files per country, and contains information on the date, hour, volume and price of the bids. This is sorted from lowest (highest) to highest (lowest) bid for supply (demand) bids on a per-hour basis.

Hour	Zone	Bid Number	Volume (MWh)	Bid Price (€)
1	NO2	1	200	-100
1	NO2	2	143	-5
1	NO2	3	111	70
1	NO2	4	60	100
1	NO2	5	222	170
1	NO2	6	65	195
1	NO2	7	57	230

Table 4.1: Simplified Example of Supply Bid Data

Hour	Zone	Bid Number	Volume (MWh)	Bid Price (€)
1	NO2	1	400	300
1	NO2	2	40	200
1	NO2	3	11	150
1	NO2	4	99	120
1	NO2	5	50	50
1	NO2	6	100	15
1	NO2	7	150	-10

Table 4.2: Simplified Example of Demand Bid Data

Tables 4.1, 4.2 and Figure 4.2 represents a simplified example of how data is structured in the model. The actual bid data consists of several hundred bids per hour. Bid numbers are counted per zone per hour. Bid prices usually start at €-500, but the graph is truncated for illustrative purposes. The input in the table is illustrated in Figure 4.2. The bid curves are linearised to calculate the market clearing price and social surplus. This is the same procedure used in the EUPHEMIA algorithm (Nominated Electricity Market Operators Committee, 2019).

The EPEX SPOT bid data can, after data cleaning in Python, be used directly as input to the optimisation model for the countries that only have a single price area. This is the case for Germany (DE), The Netherlands (NL), Belgium (BE), Finland (FI), France (FR)

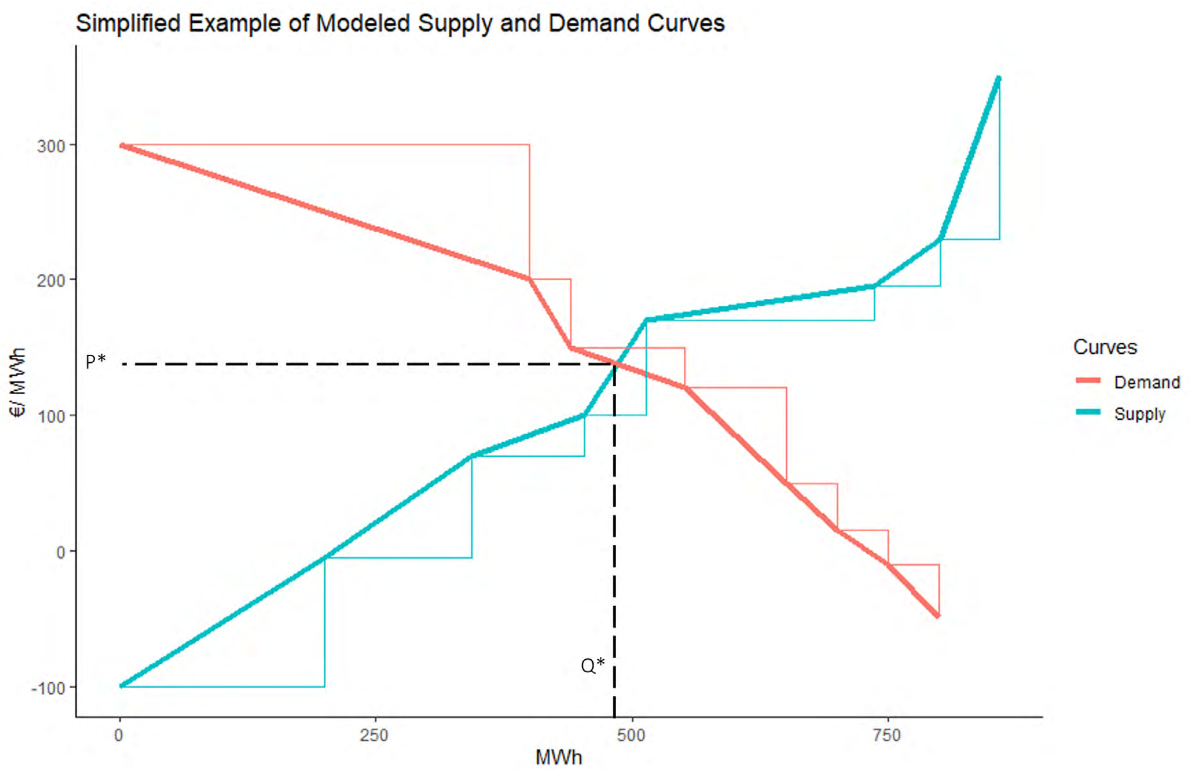


Figure 4.2: Example Supply and Demand - With Equilibrium Price and Volume

and Great Britain (GB). The data cleaning involves normalising the bid curves for trades, by adjusting for imported or exported volume in the bid data from EPEX SPOT. For the Scandinavian countries, disaggregation of the bid curves is needed.

4.4 Scandinavian Bid Curves

EPEX SPOT only provides bid curves on a country-aggregated level. For the Scandinavian countries, the data is challenging to use, as they are separated into different price areas. The country aggregated data is not directly applicable to use in the model, especially in the current situation with highly varying prices between the northern and southern price areas in the Nordics. The Scandinavian countries' bid curves must therefore be disaggregated to a price-area level.

To disaggregate the Danish bid curve into DK1 and DK2, bids are divided based on Danish buy and sell volumes from Nord Pool Group (2022e). This method is also applied to the Swedish price areas (SE1, SE2, SE3, SE4). The method works reasonably well for DK and SE, but gives inaccurate elasticities and prices for SE3 and SE4 during hours where prices are not uniform across Sweden. For example on the 16$^{\text{th}}$ of February between

8:00 and 9:00, the prices in SE1 and SE2 are €16.52/MWh while the southern areas have a price of €105.09/MWh (Nord Pool Group, 2022e). Using the country level aggregated curve from Nord Pool, the model gives all Swedish areas the same supply curve elasticity, causing a uniform price of €95/MWh. This is a drawback of disaggregating bid curves based on volume, because it implies a uniform elasticity across all price areas. In Norway, this is rarely the case, as different price areas have different price-sensitivities and water values.

When analysing a NEXIT scenario, it is important that the bid data used in the optimisation model has a realistic elasticity, to ensure that the model reacts realistically to changes in transmission capacities. The bid data used for Norway in the model is, as a result of this, not based on the EPEX SPOT data. Rather, the bid-curves are constructed from the bottom up using price data from Nord Pool Group (2022b) and volume data from ENTSO-E (2022). The construction of the bid-curves is described in the following section. The method is currently being used by Norwegian power analysts (V. Kyllingstad, personal communication, May 12, 2022), utilising the fact that the power mix in Norway is mainly composed of wind- and hydropower . This is not the case in Sweden and Denmark, making such an approach infeasible for constructing the SE and DK bid curves.

4.4.1 Constructing Norwegian Supply Curves

When constructing the Norwegian supply curves, the Norwegian production is split into two main sections: Energy production with a very low marginal production cost (wind and run-of-river hydro), and hydro electricity production from water reservoirs. As can be seen in Figure 2.3, this is a reasonable approximation considering that the power mix in Norway mainly consists of hydro- and wind power. Other energy sources in Norway are regarded as negligible.

All of the low marginal cost energy production is added into a single bid of € –500, where its size marks the start of the hydro reservoir electricity production in the bid curve. This is the same value given by Nord Pool to the lowest bids in the aggregated bid curves for Norway, as can be seen in Figure 4.5. Hydropower bids of 50MW are added up until the maximum production capacity. Maximum capacity is calculated by allocating the total Norwegian maximum production capacity, found in the aggregated Nord Pool curve, based on production shares. The hydropowers bids are based on a regression between the sold electricity volume and the respective prices during a day. When the supply reaches maximum capacity the price breaks vertically. The water values in the price areas can be inferred by looking at the price of electricity in a given hour. The last supply bid to be accepted originates from the least efficient hydropower producer, with the highest water value. Prices and volumes for each hour during a day can then be used to indicate the elasticity of supply. The constructed hydropower bids used for the Norwegian price areas increase at a slope given by a regression up until the determined maximum capacity.

This method ensures that the slope of the supply curve around the price is more realistic than disaggregating Nord Pool curves based on production volume. Errors in determining the maximum capacity for production in the model can lead to severe inaccuracies in estimating the prices. If the market clearing during an hour is at a volume around the maximum capacity, the deviation in prices may be very large if modeled and real maximum capacity deviate. As seen later in Figure 4.5, small discrepancies in volume around the maximum capacity give large deviations between real and modeled prices. Situations like these are not accurately represented by the optimisation model. The corresponding volume to the prices is however rarely set close to the maximum offered supply volume, reducing the impact of this limitation.

Limitations of utilising a regression between prices and volume

	Estimate	Std. Error	t value	Pr(>|t|)
Intercept	62.2511	10.4398	5.96	0.0000
Variable	0.0278	0.0061	4.59	0.0001

Table 4.3: Regression Output for the 16$^{\text{th}}$ of February

Figure 4.3 and Table 4.3 shows the relationship between the volume sold in NO1 and its prices. February 16$^{\text{th}}$ is used as an example date, but the regression is run for all days in the time period studied. Significant values for both the intercept and the dependent variable can be observed, indicating a correlation between the volume and prices. This correlation is assumed to give a realistic representation of the elasticity of the hydro-reservoir bids.

Utilising a regression like this may potentially be problematic. Every datapoint in the regression represents a different market clearing, with its own price and volume. The dataset may be prone to "noise", distorting the accuracy of the datapoints. For instance,

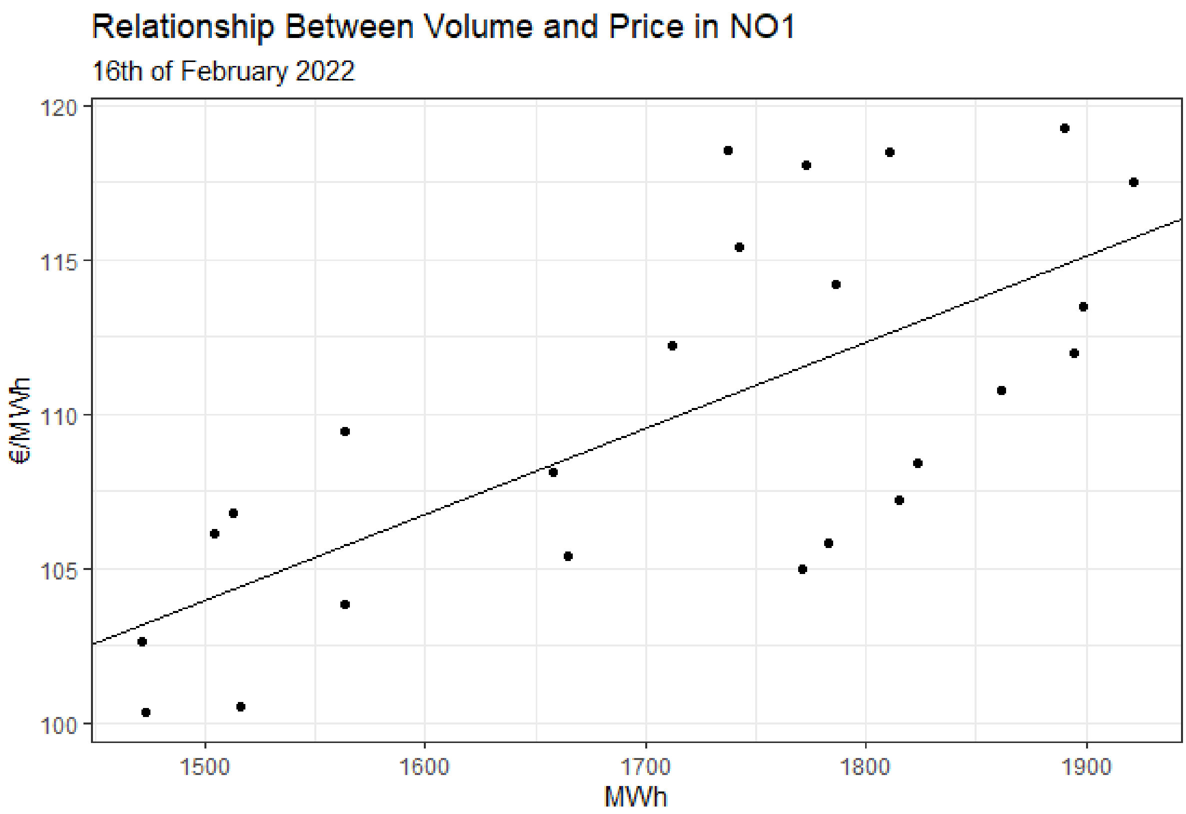


Figure 4.3: Regression of Prices and Volume in NO1

the volume offered to the market may change. Some powerstations planning to be operational during a certain time window, may need to shut down due to unforeseen circumstances. This signifies that the market intersection suddenly is shifted, distorting the regression coefficient indicating the elasticity of supply. These are however random events, and do not contribute to a structural bias in the data. The method is therefore deemed appropriate, and the noise in the data is regarded as negligible for the purposes of this thesis.

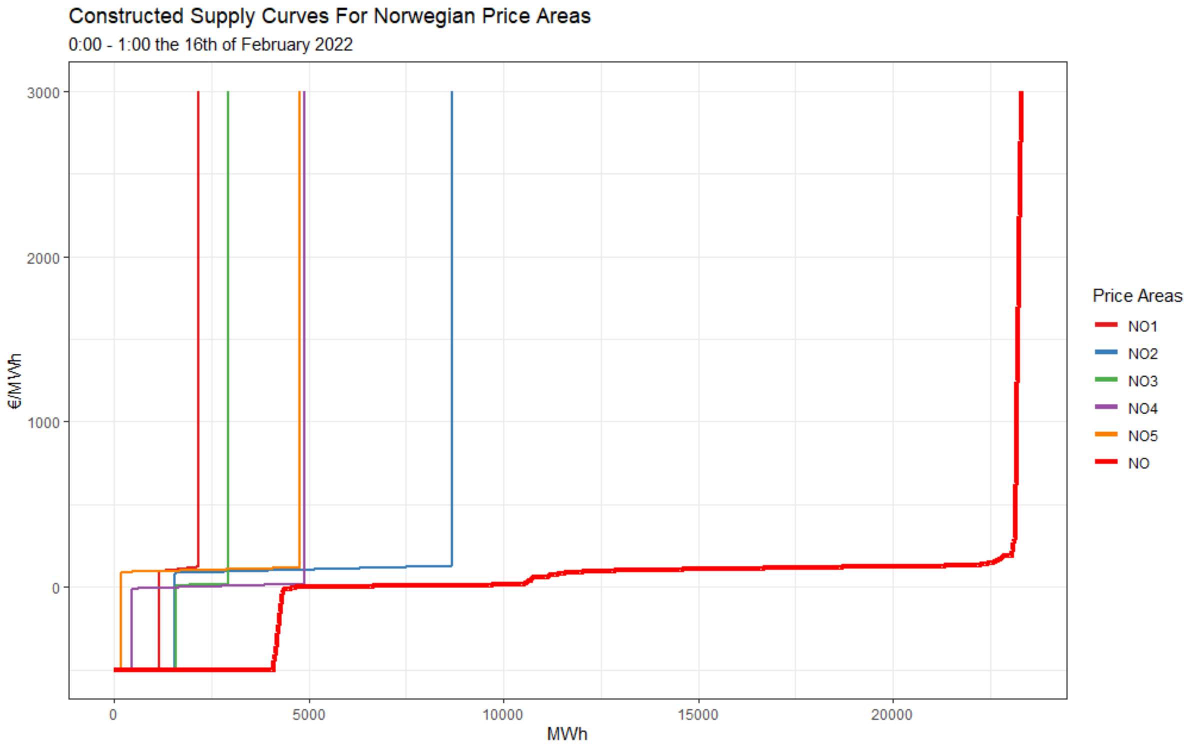


Figure 4.4: Constructed vs Nord Pool Bid Curve

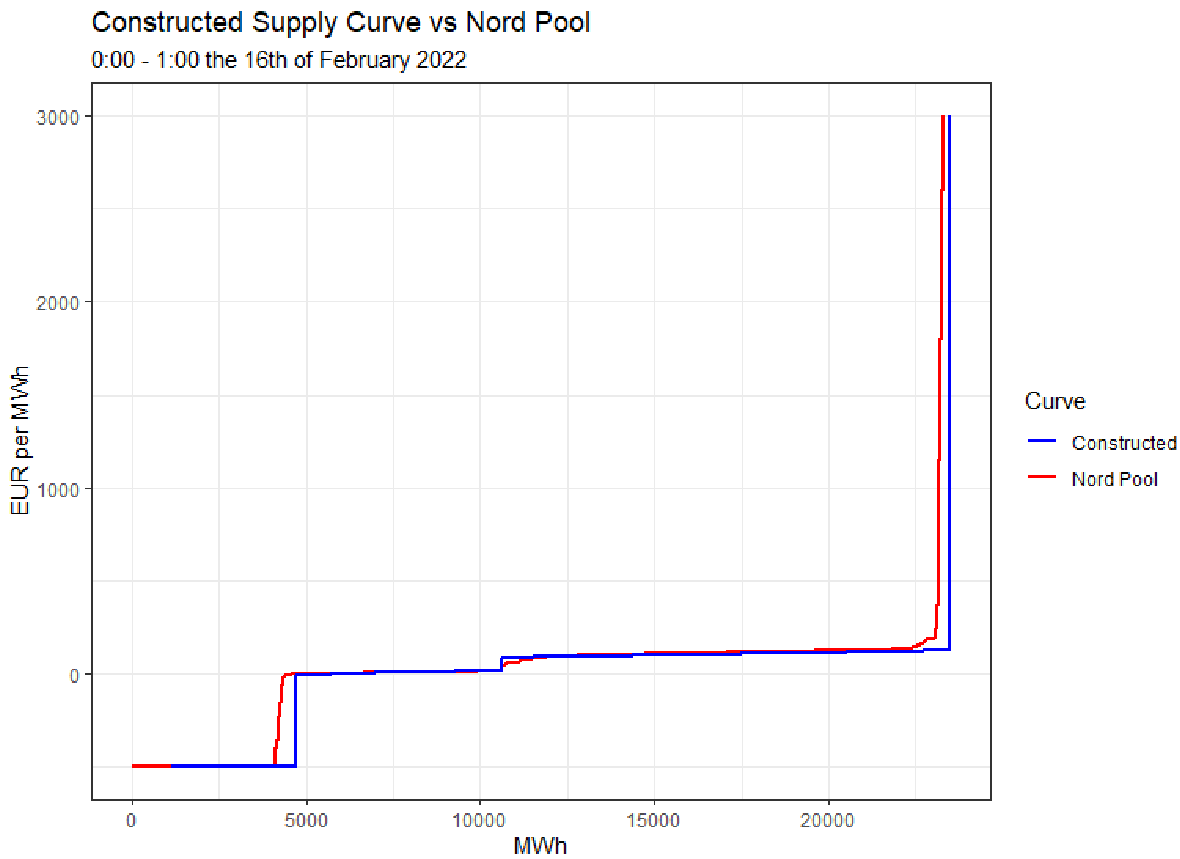


Figure 4.5: Aggregated Constructed Norwegian Curves vs Nord Pool Bid Curve for Norway

The regression can subsequently be used to construct the supply bid curves for the Norwegian price areas, represented in Figure 4.4. The red curve shows the aggregated bid curves published by NordPool. Inaccuracies caused by features such as conditional bids in the aggregated curves mean that there are discrepancies of +/- 200MWh in the aggregated volumes. These discrepancies can be observed in 4.5. Conditional bids may be flexible hourly bids or block bids (Bjørndal, 2013). The volume adjustments described later in section 4.7.2 compensate for this deviation.

4.4.2 Disaggregation of Supply Curves for DK and SE

Constructing a supply curve like the one used for Norway requires the assumption that the area prices have a positive relationship with the volume produced. Secondly, all hourly price equilibriums have to be located within the hydropower section of the supply curve. If the last accepted bids determining the price are not from hydropower producers, it will distort the regression of the hydropower bids.

These assumptions are consistently violated in the case of Denmark, and often violated for Sweden. In Denmark all bids are in theory linked to the marginal cost of production, as the power mix consists mainly of wind, biofuels and coal. In Sweden where the power mix includes hydro, nuclear and wind, the regression approach is suitable for northern Sweden (SE1, SE2). However, it does not work in the southern part, where there is a negative relationship between prices and volumes in roughly 50% of the days studied. Using the regression approach is thus not valid for the price areas in Sweden and Denmark.

4.4.3 Disaggregation of Demand Curves for Scandinavia

In the absence of available data on the demand elasticities of distributors per price area, the Scandinavian demand elasticities are assumed to be uniform within each country. This implies that demand patterns across the country are similar. In reality, this assumption does not hold due to weather conditions, factory locations and household patterns. Electricity demand is highly inelastic in the short run (Csereklyei, 2020), reducing the consequences of errors caused by this assumption. Using this assumption, demand curves can be disaggregated based on the share of consumption.

4.5 The NTC Optimisation Model

The model is constructed in the optimisation software AMPL. This is supplemented by code in Python, preparing data files and running a loop of optimisations through AMPL. The model is a non linear optimisation problem due to quadratic expressions in the objective function. The problem is solved with the MINOS solver. A mathematical explanation of the optimisation model is found below.

Sets

Z : zone

$\mathrm{D}_{t,z}$: Bids from consumers

$S_{t,z}$: Bids from producers

T: Time period

Links : Connections between different zones

Parameters

TP : Number of time periods

$\mathrm{PD}_{t,z}$: Demand Bid Prices

$PS_{t,z}$: Demand Bid Prices

$QD_{t,z}$: Quantity Demand

$QS_{t,z}$: Quantity Supply

$NTC\ Max_{t,z,zz}$: Net transfer capacities in cable direction, ex: BE to DE

$NTC\ Min_{t,z,zz}$: Net transfer capacities in the opposite direction ex: DE to BE < 0

Positive Variables

$\mathrm{d}_{t,z}$: Variable for accepted demand bids

$s_{t,z}$: Variable for accepted supply bids

Variables

$\mathrm{LF}_{t,z,zz}$: Line flow

$NIQ_{t,z}$: Net injection quantity

Objective function

$$\sum_{t\in T,z\in Z}\left[(PD_{t,z,1}*d_{t,z,1})+\sum_{i=2}^{D_{t,z}}\left((PD_{t,z,i-1}*d_{t,z,i})+0,5*\frac{(PD_{t,z,i}-(PD_{t,z,i-1})}{(QD_{t,z,i})}*(d_{t,z,i})^2\right)\right]$$
$$-\sum_{t\in T,z\in Z}\left[(PS_{t,z,1}*s_{t,z,1})-\sum_{i=2}^{S_{t,z}}\left((PS_{t,z,i-1}*s_{t,z,i})+0,5*\frac{(PS_{t,z,i}-(PS_{t,z,i-1})}{(QS_{t,z,i})}*(s_{t,z,i})^2\right)\right] \tag{4.1}$$

Constraints

$$NIQ_{t,z}=\sum_{i\in S_{t,z}}s_{t,z,i}-\sum_{i\in D_{t,z}}d_{t,z,i}\quad\forall\quad t\in T,z\in Z \tag{4.2}$$

$$NIQ_{t,z}-\sum_{\substack{zz\in Z\setminus\{z\}\\(z,zz)\in L}}LF_{t,z,zz}+\sum_{\substack{zz\in Z\setminus\{z\}\\(z,zz)\in L}}=0\quad\forall\quad t\in T,z\in Z \tag{4.3}$$

$$\sum_{z\in Z}NIQ_{t,z}=0\quad\forall\quad t\in T \tag{4.4}$$

$$Ntc\ Min_{t,zz,z}<=LF_{T,z,zz}<=Ntc\ Max_{t,z,zz}\forall\quad(z,zz)\in L,t\in T \tag{4.5}$$

Equation 4.1 is the objective function. It subtracts the integral of the demand curve from the integral of the supply curve in order to calculate the social surplus. The objective function then maxmises the combined sum of social surplus for all price areas. This refers to the sums of the areas between the supply and demand curve seen in Figure 4.2. The optimisation problem is to maximise the total sum of social surplus across all price areas given a set of constraints.

The first constraint says that the net injection quantity is equal to the volume supplied minus the volume demanded in a zone for a given hour.

The second constraint ensures that the net injection quantity for each zone ± the lineflow in and out of the zone is equal to zero. Similarly to the first constraint, this ensures that there is no surplus energy at a local level in the price areas. If the supply in a zone exceeds the demand, the net of lineflows must transport this energy out of the zone.

The third constraint says that the sum of net injection quantity in all zones in the model must be equal to zero. This reflects the concept of energy balance, which says that all electricity produced must also be consumed. The condition must be met in all hours. This can be illustrated in an example with 2 price zones, Norway and Sweden. If the net injection quantity in Norway is 500MWh (i.e Norway produces 500 MWh more than it consumes), the net injection quantity in Sweden must be -500MWH. This constraint ensures that imports and exports in all zones sum to zero, meaning that all produced electricity is consumed.

The final constraint limits the amount of capacity available to transfer between zones. The lineflow must not exceed the NTC capacities given by the TSOs. This constraint is the subject of our analysis, as the simulation manipulates what transfer capacities are available from NO2 to GB, NL and DE.

4.6 Calculating Results

The optimisation model optimises the social surplus across all zones modeled. The corresponding electricity prices are derived from the shadow price of the constraint in Equation 4.2.

In order to analyse the impact that NEXIT has on the market participants, the output from the optimisation is used to calculate the consumer surplus, producer surplus and the social surplus for each individual zone.

Consumer Surplus

The consumer surplus for a price area is calculated using the following formula:

$$CS_{t,z} = \left[(PD_{t,z,1} * d_{t,z,1}) + \sum_{i=2}^{D_{t,z}} \left((PD_{t,z,i-1} * d_{t,z,i}) + 0,5 * \frac{(PD_{t,z,i} - (PD_{t,z,i-1})}{(QD_{t,z,i})} * (d_{t,z,i})^2 \right) \right] - AP_{t,z} \times \sum_{i \in D_{t,z}} d_{t,z,i}$$

Producer Surplus

The producer surplus is calculated using the following formula:

$$PS_{t,z} = AP_{t,z} \times \sum_{i \in S_{t,z}} s_{t,z,i} - \left[(PS_{t,z,1} * s_{t,z,1}) - \sum_{i=2}^{S_{t,z}} \left((PS_{t,z,i-1} * s_{t,z,i}) + 0,5 * \frac{(PS_{t,z,i} - (PS_{t,z,i-1})}{(QS_{t,z,i})} * (s_{t,z,i})^2 \right) \right]$$

Congestion Rent

The congestion rent is calculated by taking the price difference between the prices in two zones that are connected, and multiplying this by the amount of MW sent between the zones. This is expressed mathematically below. In the calculations used for the analysis it is divided by two, and split between the two connected price areas.

$$CR_{t,z,zz} = LF_{t,z,zz} \times \Delta Price_{t,z,zz}$$

Social Surplus

The social surplus in each individual zone is the sum of the congestion rent, consumer and producer surpluses.

$$SS_{t,z} = CS_{t,z} + PS_{t,z} + \frac{\sum CR_{t,z,zz}}{2}$$

4.7 Model Adjustments

In order to facilitate more realistic simulations from the model, some adjustments to the input data need to be made. The following section outlines methodological challenges encountered, and describes how they are accounted for in the model.

4.7.1 NTC Values in Cases of Missing Values

Many European countries have switched to an FBMC method, and do not post NTC values as such between them and their neighbouring countries. This is for instance the case for Germany and France, where there is no available NTC capacity to use as input for the model. In such cases, an approximation is made by making the assumption that if the two countries have unequal prices, the physical flow between them is equal to the NTC capacity. This is based on the fact the prices would be fully converged if the power flow was beneath the NTC value. In cases where the prices between two countries with no available NTC values are equal, an NTC value is inserted to allow for power flows in the model. NTC values are in such cases based on the median powerflow on the interconnector during hours with price difference, in the time period studied (January-March 2022).

4.7.2 Adjusting Prices

When running the initial optimisation in AMPL, there are incidences of large price discrepancies between real and simulated prices. This is mainly the case for SE3, SE4 and GB. The Swedish price discrepancies are present during hours where there is a major price difference between northern and southern price areas, which also affects DK2. These are due to the assumption and simplifications made in the construction of the model.

To correct such errors and have a good outset for the simulation, the supply curves are adjusted to fit with real hourly prices. The adjustment of the supply curve is achieved through manipulating the first bid, until the price is within a ± €1.1 range.

Table 4.4 shows the modeled mean prices before and after the supply adjustments. In order to compare the initial fit of the model, a column showing prices without supply adjustment is also included. In many cases, the model produces reasonably correct prices even without the supply-adjustment.

Zones	Real Price	Not Adjusted	Adjusted
BE	210.15	204.56	209.49
DE	180.38	180.06	179.57
DK1	151.61	151.83	151.68
DK2	139.79	117.18	139.95
FI	91.67	59.79	92.76
FR	237.38	246.48	237.10
GB	244.27	231.52	243.80
NL	209.00	193.11	207.25
NO1	143.13	144.04	142.77
NO2	143.13	144.04	142.78
NO3	16.98	27.41	17.21
NO4	16.05	15.20	16.26
NO5	142.32	144.04	142.00
SE1	20.68	38.92	20.98
SE2	20.68	38.92	20.98
SE3	94.47	40.63	94.59
SE4	103.17	40.63	103.33

Table 4.4: Mean of Real, Not Adjusted and Adjusted Prices Between the 14^{th} of January and 14^{th} of March 2022. Values are in €/MWh

5 Analysis and Discussion

This chapter presents the results from the model, looking at five different scenarios where interconnector capacity from Norway to Europe is removed. In most scenarios the capacity is set to zero, but in the case of NorthConnect the capacity is doubled. The interconnectors are discussed separately, before Scenario 4 simulates disconnecting North Sea Link (NSL), NordLink (NLK) and NorNed (NN) simultaneously. Findings on prices and social surplus is subsequently reviewed in light of academic work, before price variations are discussed. A sensitivity analysis of results is then conducted, where the impact of water values on results is illuminated. Finally, the chapter includes an outlook towards 2030, and outlines the limitations of the thesis.

Scenario	GB	DE	NL
Base Case	1	1	1
Scenario 1 - North Sea Link	0	1	1
Scenario 1a - NorthConnect	2	1	1
Scenario 2 - NordLink	1	0	1
Scenario 3 - NorNed	1	1	0
Scenario 4 - North Sea Link & NordLink & NorNed	0	0	0

Table 5.1: Scenarios. 0 = cut, 1 = base case, 2 = Double Capacity

Table 5.1 is an overview of the scenarios used in the thesis. The base case represents the situation today, with the interconnectors to NL, DE and GB all operating.

5.1 Base Case

The time period investigated in the analysis ranges from the 14$^{\text{th}}$ of January until the 15$^{\text{th}}$ of March. The base case scenario is the implementation of the model shown in Chapter 4, with no changes made with regards to capacities. 17 price areas are included, reflecting selected bidding areas on the Nord Pool power exchange. As mentioned in Section 4.1 Great Britain is assumed to be cleared simultaneously. Table 5.2 shows the modeled mean of prices and social surplus (SS) for the price areas included in the simulation, shown in Figure 2.5. Prices are in €/MWh and the remaining columns are in €/hr.

As explained in Section 2.5.4, electricity prices were unusually high in the time period studied, with large price differences between price areas. The Norwegian prices are however

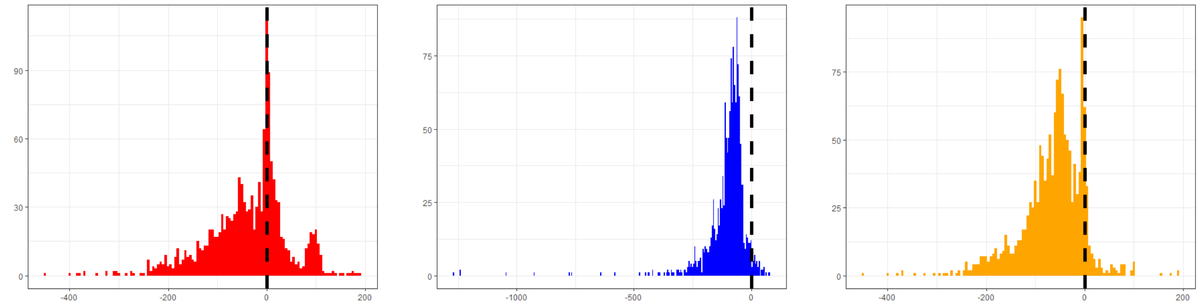
Zones	Base Price	SS	CS	PS	CR
BE	209.49	9 368 786	7 109 310	2 180 511	78 964
DE	179.57	78 845 341	65 034 056	13 604 088	207 196
DK1	151.68	6 132 579	5 197 915	852 695	81 967
DK2	139.95	3 648 765	3 365 836	245 625	37 303
FI	92.76	25 458 655	22 929 094	2 468 282	61 278
FR	237.10	37 519 801	31 308 500	60 698 075	141 494
GB	243.80	23 926 476	22 065 372	1 740 360	120 743
NL	207.25	14 117 272	11 574 251	2 451 085	91 936
NO1	142.77	13 562 284	12 810 234	709 059	42 990
NO2	142.78	13 884 658	12 573 153	1 173 627	137 876
NO3	17.21	10 797 057	9 833 439	933 333	30 284
NO4	16.26	7 193 150	6 899 726	291 253	2 170
NO5	142.00	5 891 470	5 624 211	254 631	12 627
SE1	20.98	4 778 911	3 548 114	1 174 673	56 123
SE2	20.98	7 695 625	5 339 510	2 106 703	249 411
SE3	94.59	32 466 620	29 468 117	2 691 591	306 911
SE4	103.33	8 994 124	7 941 608	986 118	66 397

Table 5.2: Base Case Mean Results

relatively moderate in the time period studied, compared to countries in central western Europe. The effects of the north-south congestion in the Nordics, explained in section 2.5.1, is also clearly shown, with average prices in SE1/SE2 and NO3/NO4 far below the southern price areas.

The absolute values for the consumer, producer and social surplus in Table 5.2 should be read with caution. Large parts of the consumer surplus is caused by the maximum bid value of €3000, set by Nord Pool. It is difficult to determine if this limit reflects consumers true willingness to pay. Most households would probably not be willing to pay €3000/MWh for their electricity, so the absolute value of the consumer surplus is perhaps not a very useful statistic. The same logic applies to producer surplus, with the minimum bid value of €-500. Therefore, in the following sections, only absolute changes in consumer, producer and social surplus are analysed.

The consumer surplus (CS), producer surplus (PS) and congestion rent (CR) sum to the social surplus (SS) in the model. Especially interesting is the distribution of congestion rent. Naturally the NO2 area, connected to Europe via North Sea Link, NordLink and NorNed, collects the most congestion rent of the Norwegian areas. A more surprising result is that the Swedish area SE3 collects by far the most congestion rent, more than countries like Germany and Great Britain. This is due to SE3 receiving and selling large volumes to Finland, SE2 and NO1, where the price differences are often large.



(a) NO2 minus DE **(b)** NO2 minus GB **(c)** NO2 minus NL

Figure 5.1: Histogram of Price Differences

The histograms above show the difference in prices between NO2 and DE, GB and NL, where the dashed line represents zero price difference. The histograms tend to skew towards the left, meaning Norway has lower prices, and is thus a net exporter to these price areas. However, for DE one can observe more observations on the right side than for GB and NL. This signifies that the price relationship between NO2 and DE is more balanced. Additionally the most frequent value in both 5.1a and 5.1c is 0, meaning that prices equal each other more often than with GB (shown in 5.1b).

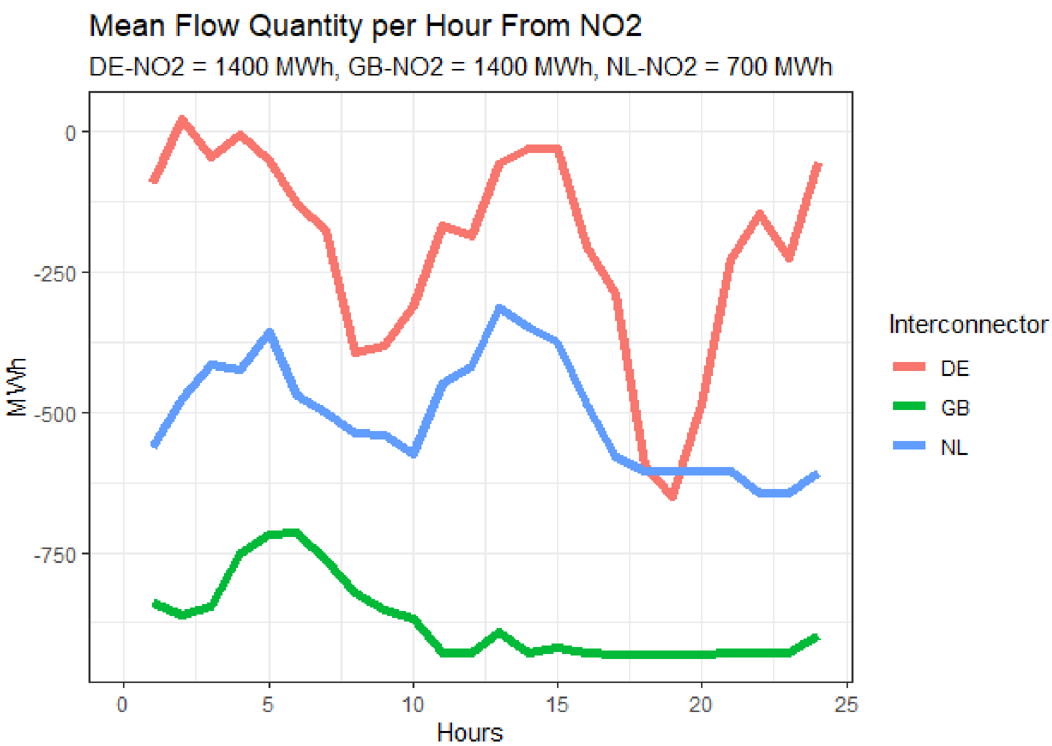


Figure 5.2: Average Flows on the NO2 Interconnectors

Figure 5.2 shows average flows from the model in a base case scenario. A negative value signifies that NO2 is exporting electricity and a positive value represents imports. The Figure displays that during most hours of the day, NO2 on average is an exporter of electricity to DE, GB and NL. Only for a very small period early in the day does Germany export to Norway. Great Britain receives more than 750 MW on average on the Interconnector to Norway during an hour. The exports are at their highest levels during the peak demand hours in the morning and evening. Germany has several hours during the day where it is close to being an exporter to Norway on average.

5.2 Disconnecting the Interconnectors

This section consists of three distinct analyses, investigating the impact of disconnecting the interconnectors. The interconnectors are discussed in reverse chronological order, starting with the newly implemented North Sea Link, followed by NordLink and NorNed. In the North Sea Link analysis, a subsidiary analysis is conducted in which the NorthConnect interconnector is included.

5.2.1 North Sea Link

In the first scenario, the effect of disconnecting the North Sea Link cable between GB and NO2 is investigated. As mentioned in the introduction, this is a 1400 MW interconnector that became operational in October 2021. In the simulation, the capacity of the cable is set to zero. The following sections show the impacts on prices and social surplus in Norway as well as Europe. Additionally, when investigating prices the planned NorthConnect capacity of 1400MW is added.

Prices

For Norway, the price impact of disconnecting the North Sea Link cable is largest in the southern price areas. This is expected, as they are the most closely linked to Europe through the interconnectors in NO2. The north-south congestion means that the price decrease in NO3 and NO4 is negligible. NO3 was already sending electricity southwards at maximum capacity, which is still the case after the capacity to GB is removed. This means that the change does not alter the export from NO3 and NO4, and so the price

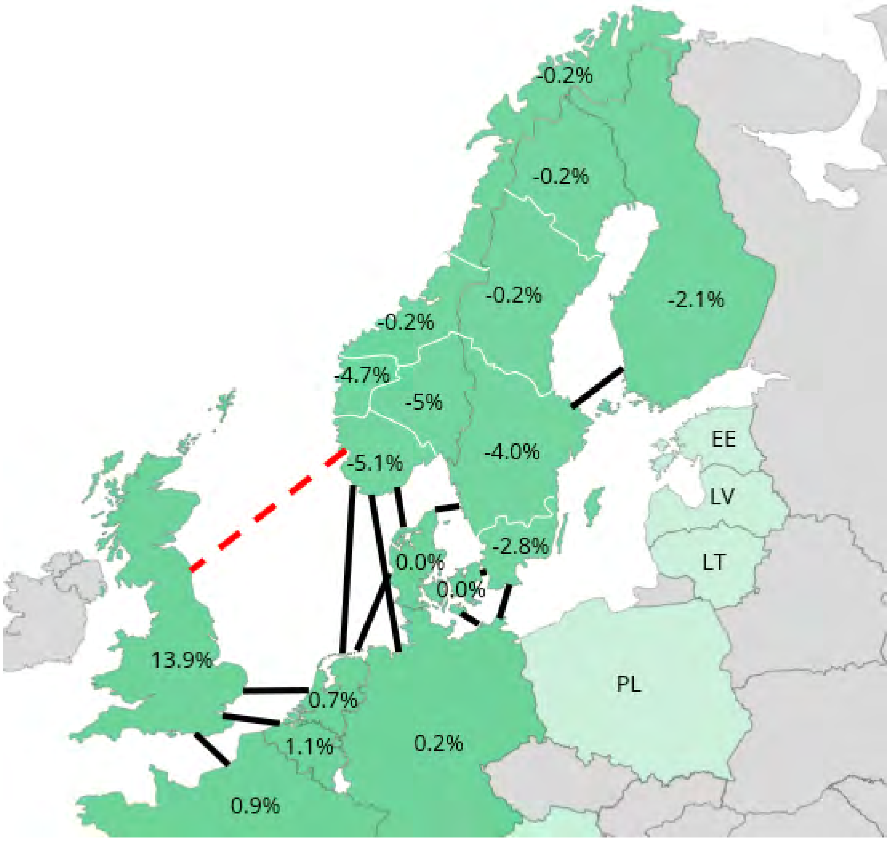


Figure 5.3: Mean per cent Changes per Hour in Prices for Scenario 1

remains similar to the base case. NO1, NO2 and NO5 on the other hand, experience a relatively similar price decrease of about 5%. All three price areas had similar prices in the base case during the period, meaning that the disconnection of North Sea Link shaved about €7/MWh in absolute terms. The results shown in table 5.3 show mean values. A more detailed comparison of variations in prices will be shown in section 5.5.

The simulation shows that the mean hourly prices in GB rise by €33/MWh (13%). Disconnection of the North Sea Link is also shown to have ramifications for the countries connected to GB. Prices rise in FR, NL and BE. This happens because the model simulates increased exports from these countries in hours where there previously were equal prices. The Norwegian price decrease also affects other Scandinavian price areas. NO1 and SE3 frequently experience price equalisation. This means that SE3 benefits from the lower price in NO1, as price effects are distributed through changes in power flows. The effect of this spreads throughout Scandinavia, with small price decreases seen in Finland and SE4.

Zones	Price Base	Price S1	Δ Price	% Δ Price
BE	209.49	211.71	2.21	1.06
DE	179.57	179.87	0.29	0.16
DK1	151.68	151.71	0.04	0.02
DK2	139.95	140.01	0.06	0.04
FI	92.76	90.81	-1.96	-2.11
FR	237.10	239.29	2.19	0.92
GB	243.80	277.76	33.95	13.93
NL	207.25	208.70	1.45	0.70
NO1	142.77	135.64	-7.13	-4.99
NO2	142.78	135.44	-7.34	-5.14
NO3	17.21	17.18	-0.03	-0.15
NO4	16.26	16.23	-0.03	-0.17
NO5	142.00	135.31	-6.68	-4.71
SE1	20.98	20.95	-0.04	-0.18
SE2	20.98	20.95	-0.04	-0.18
SE3	94.59	90.77	-3.81	-4.03
SE4	103.33	100.47	-2.86	-2.77

Table 5.3: Mean Prices per Hour in Base Case vs Scenario 1

Social Surplus

Overall social surplus in Norway is reduced by €58 000 per hour on average, as a consequence of disconnecting the North Sea Link. Across all price areas, consumers are better off while producers lose out. This is a result in line with Malaguzzi Valeri (2009), as Norway is a net exporter to GB. Figure 5.4 shows changes in producer surplus (blue), consumer surplus (yellow) and congestion rent (beige) for Scenario 1. This colour coding also applies for subsequent social surplus illustrations.

Surprisingly, the NO1 area has an increase in social surplus. This is due to consumers benefiting from lower prices, while the negative impact on producers is not as large as in NO2 and NO5. The simulation estimates a net positive benefit for NO1 of €18 800 per hour. In NO1 and NO2, the gains in consumer surplus are similar. This is expected as NO1 and NO2 account for about 22% and 27% of consumption in Norway respectively (Nord Pool Group, 2022c). However, the difference in producer surplus is due to large losses in producer surplus for NO2. NO2 producers are the most directly impacted, and lose a large amount of export that would normally go to GB. Impacts in NO3 and NO4 are similarly to the findings in prices relatively modest.

All price areas in Norway also see a reduction in congestion rent. Naturally, the largest

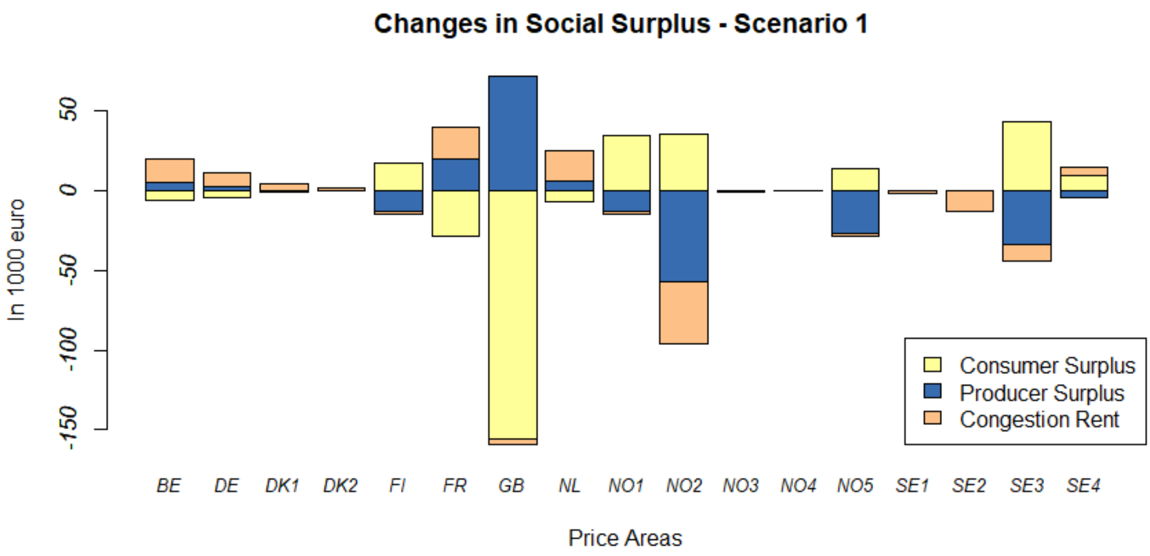


Figure 5.4: Mean Changes per Hour in Social Surplus for Scenario 1 (Data from appendix A0.1)

effect is seen in NO2 where the North Sea Link is located. NO2 experiences a 27.42% reduction in congestion rent, equating to €38 700 per hour. The congestion rent in NO1 is reduced as a result of lower prices, narrowing the price difference between NO1 and SE3/NO3.

The net effect on social surplus in Europe is negative. Some countries, like Belgium, Germany, France and the Netherlands see an increase in social surplus. This is due to the increase in congestion rents and producer surplus offsetting any losses in consumer surplus caused by higher prices. Congestion rent previously divided between GB and NO is now dispersed between GB and BE, NL, FR, through increased exports from these countries. The net impact on Europe is however negative, as any gains made by these countries are dominated by a significantly larger loss to social surplus in GB and NO areas. Changes in consumer and producer surplus are linked to the price changes seen in the European countries. Countries who see a reduction in prices, like FI and SE, gain a larger consumer surplus. Contrastingly, in countries like FR, GB and NL, where prices rise as a result of the North Sea Link being disconnected, the consumer surplus shrinks.

5.2.1.1 Scenario 1a: NorthConnect

This subscenario examines the repercussions of the Norwegian government's decision to abandon the planned 1400MW NorthConnect interconnector. An additional 1400MW is added to the capacity between NO2 and GB, for a total capacity of 2800MW.

Zones	Price Base	Price S1a	Δ Price	% Δ Price
BE	209.49	207.48	-2.01	-0.96
DE	179.57	179.75	0.17	0.10
DK1	151.68	152.71	1.03	0.68
DK2	139.95	140.57	0.62	0.44
FI	92.76	94.71	1.94	2.09
FR	237.10	235.08	-2.02	-0.85
GB	243.80	222.69	-21.11	-8.66
NL	207.25	206.28	-0.98	-0.47
NO1	142.77	159.56	16.79	11.76
NO2	142.78	159.93	17.15	12.01
NO3	17.21	17.24	0.04	0.21
NO4	16.26	16.28	0.02	0.13
NO5	142.00	158.76	16.77	11.81
SE1	20.98	21.04	0.06	0.27
SE2	20.98	21.04	0.06	0.27
SE3	94.59	100.64	6.05	6.40
SE4	103.33	107.07	3.74	3.62

Table 5.4: Mean Prices per Hour in Base Case vs Scenario 1a

Table 5.4 indicates that increasing the capacity between GB and NO2 would have the opposite effects of disconnecting the North Sea Link, with a higher electricity price in Norway. Prices in NO1, NO2 and NO5 would increase by €17 in absolute terms, or about 12% compared to the base case. For Great Britain, the price decreases by €21 euros, or 8.7 %. The price effect of the NorthConnect interconnector is larger than the North Sea Link for Norway, but smaller for Great Britain. As was the case with the North Sea Link, price effects from the interconnector spread to Sweden and Finland through Norway.

The overall effect of added capacity is a reduction in congestion rent for the countries close to GB. This finding is expected, as the added capacity alleviates the congestion in the grid. In NO2 and NO5 the added producer surplus from NorthConnect dominates the loss in consumer surplus and congestion rent, giving a net gain in social surplus. For NO1 this is not the case, as consumers lose more than producers gain. In GB, consumers benefit from lower prices causing the consumer surplus to dominate losses in producer

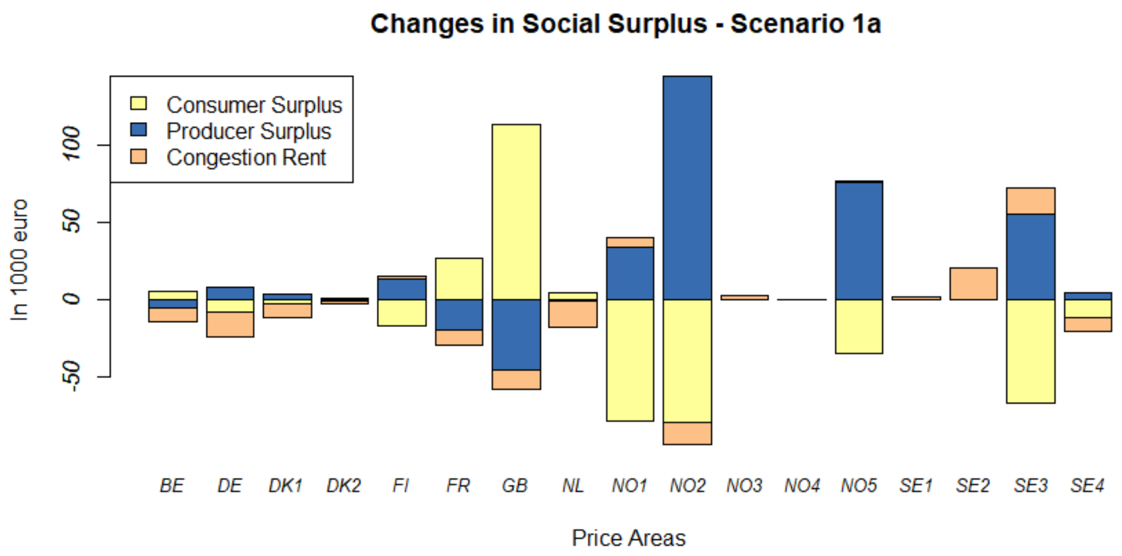


Figure 5.5: Mean Changes per Hour in Social Surplus for Scenario 1a(Data from appendix A0.2)

surplus and congestion rent. The net effect from NorthConnect on social surplus is positive for both NO and GB. The subscenario suggests that the Norwegian government did not have a social surplus maximising perspective in mind, with the abandonment of the planned NorthConnect interconnector. However, impacts are not distributed equally among stakeholders, nor across price areas.

5.2.2 NordLink

In the second scenario, the effect of disconnecting the 1400 MW NordLink cable between DE and NO2 is investigated. Similarly to the previous scenario the interconnector's capacity is set to zero and the tables show the impact on prices and social surplus in Norway as well as Europe.

Prices

Similarly to the North Sea Link scenario, disconnecting the cables has a decreasing effect on Norwegian prices. The impact is however smaller than what is experienced when disconnecting the North Sea Link interconnector. The price effect of NordLink is smaller, because the ratio of imports to exports is more balanced for NO and DE than it is between NO and GB. In other words, in the time period studied, Norway frequently has hours

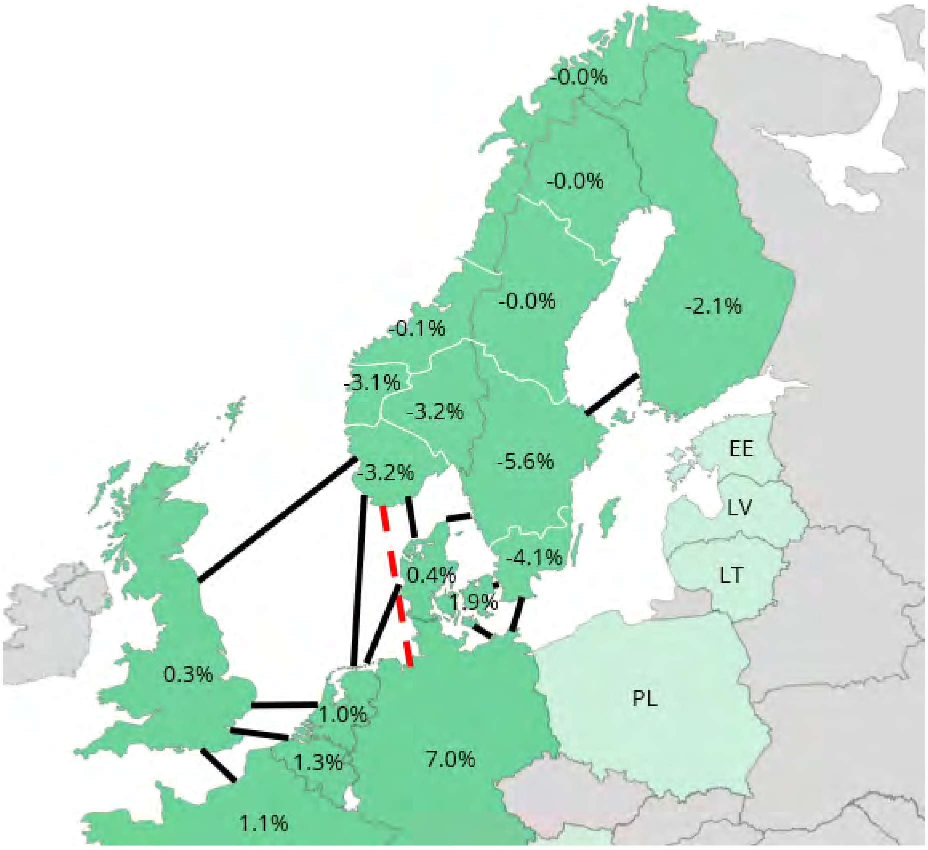


Figure 5.6: Mean per cent Changes per Hour in Prices for Scenario 2

where the NordLink cable imports electricity from Germany. In cases where Norwegian prices are affected by German prices, this also generally happens at a lower price than what is the case for GB. The same dynamics described in Section 5.2.1 apply, meaning that the prices in NO3 and NO4 are almost unaffected.

Germany is naturally impacted the most by the removal of the NordLink interconnector. Hourly prices rise by 7% on average, equating to €13/MWh. This has knock-on effects to DK1 and DK2, giving small increases in mean price. This effect is also seen in FR, NL and BE. Interestingly, SE3 and SE4 see larger price reductions than any Norwegian price areas, which also affects the Finnish price. Once again, north-south congestion in the Nordics ensure that SE1, SE2, NO3 and NO4 do not see any price reduction.

That the knock-on effect from Germany dominates the effect from lower Norwegian prices in DK1 and DK2 is surprising. Initially one would expect Danish prices to fall as well from price effects in Norway and Sweden. Indeed the median change in danish prices is negative, but extreme values cause the mean of prices to increase in the time period studied.

Zones	Price Base	Price S2	Δ Price	% Δ Price
BE	209.49	212.14	2.65	1.26
DE	179.57	192.21	12.64	7.04
DK1	151.68	152.23	0.55	0.36
DK2	139.95	142.67	2.72	1.94
FI	92.76	90.54	-2.23	-2.40
FR	237.10	239.80	2.70	1.14
GB	243.80	244.59	0.79	0.32
NL	207.25	209.38	2.13	1.03
NO1	142.77	138.18	-4.59	-3.22
NO2	142.78	138.15	-4.63	-3.24
NO3	17.21	17.23	0.02	0.11
NO4	16.26	16.25	-0.00	-0.02
NO5	142.00	137.66	-4.34	-3.06
SE1	20.98	20.99	0.01	0.02
SE2	20.98	20.99	0.01	0.02
SE3	94.59	89.28	-5.31	-5.61
SE4	103.33	99.14	-4.20	-4.06

Table 5.5: Mean Prices per Hour in Base Case vs Scenario 2

Something peculiar also happens in SE3 and SE4 when disconnecting NordLink. Prices fall even more sharply than they do in Norway. This is due to a power flow pattern involving Norway, Sweden and Germany. In the hours where Germany previously exported electricity to Norway, the power flow is now redirected to SE4. During the hours where Norway would export electricity to Germany, the power flow between SE4 and DE is usually already at maximum capacity, or price effects are mitigated through power flows involving Norway. SE4 therefore benefits from the hours with cheap German electricity, but does not suffer greater losses in hours with high prices.

This dynamic in power flows is demonstrated in Figure 5.7 and 5.8. The blue curve represents the flow from DE to NO2; NO2 exports when values are negative. The red curve in Figure 5.7 shows the change in power flows after disconnecting the NordLink interconnector. The curve demonstrates that there are increased exports or less imports from DE to SE4 after NordLink is disconnected, as flow changes are positive. In Figure 5.8 the changes in power flows between NO1 and SE3 after disconnecting NordLink are shown by the green curve. NO1 exports more or imports less to SE3, as can be inferred by the fact that the changes in power flows primarily negative.

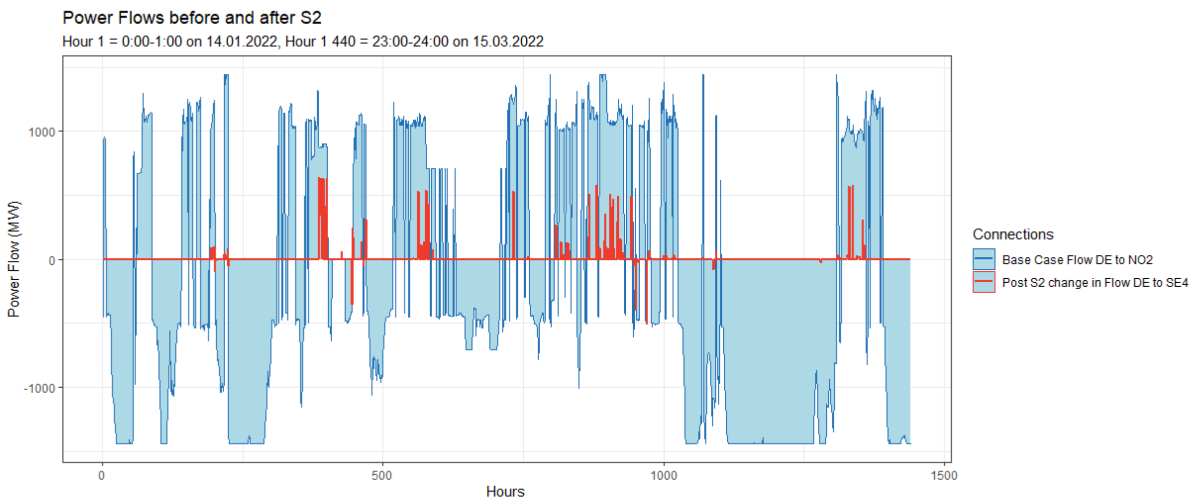


Figure 5.7: Changes in Power Flows From DE to SE4 After Scenario 2 Compared to Base Case Power Flows Between DE and NO2

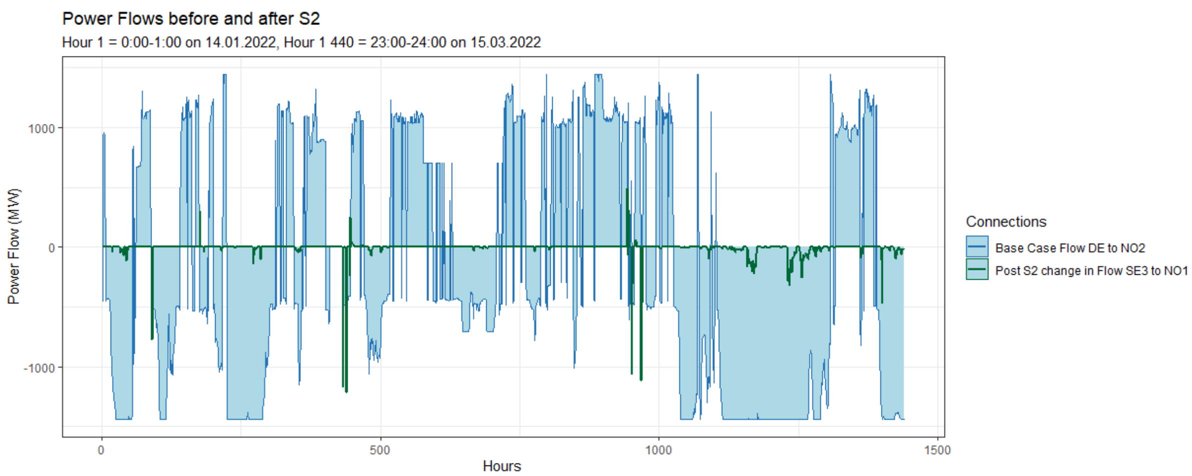


Figure 5.8: Changes in Power Flows From SE3 to NO1 After Scenario 2 Compared to Base Case Power Flows Between DE and NO2

Social Surplus

Overall, hourly social surplus is similarly to Scenario 1 reduced by €45 000 on average. The gain in consumer surplus is smaller for NO1 and NO2, but the producer surplus change in NO2 is also smaller. The changes in congestion rent are different from Scenario 1, except for NO2 being impacted the most. Losses in congestion rent are generally smaller compared to scenario 1, which is expected when the price decrease is smaller. The explanation lies in power flows between NO and DE being more dynamic and variable than between NO and GB. The model simulates an average flow of about 200MW from NO2 and DE compared to 800MW from NO2 to GB. Germany has hours with large

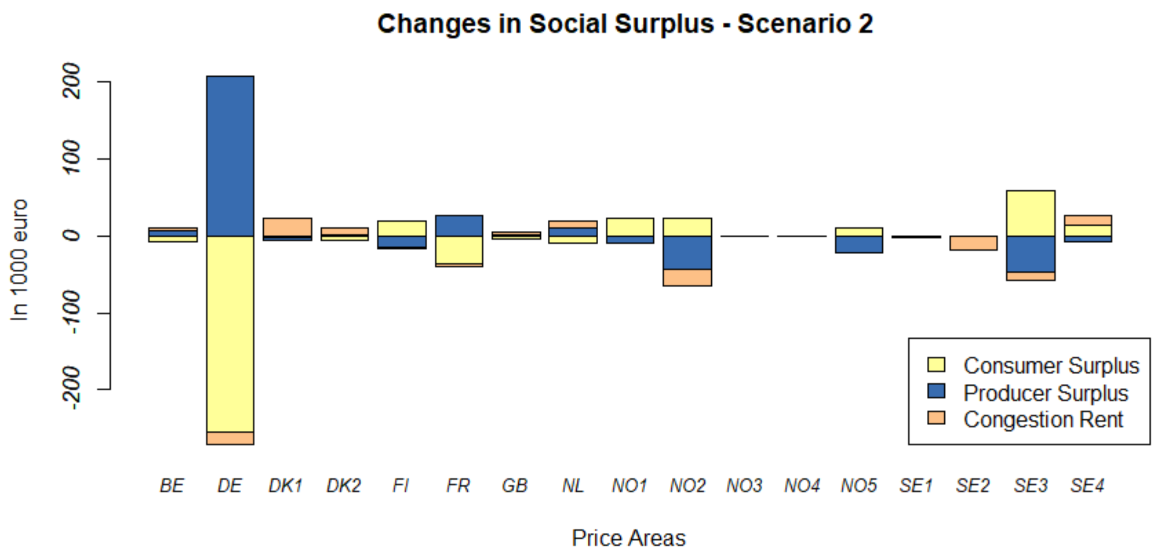


Figure 5.9: Mean Changes per Hour in Social Surplus for Scenario 2 (Data from appendix A0.3)

amounts of wind generation, giving large imports of electricity to Norway on the NordLink interconnector.

As was the case for GB in Scenario 1, social surplus sharply decreases in DE. This is mainly due to consumer surplus sinking as a result of higher prices. Nearby areas like BE and NL benefit from this by gaining more in producer surplus and congestion rent than they lose in consumer surplus. The price decrease in SE3 has negative consequences for SE2 which experiences a loss of €20 000 in social surplus, due to loss of congestion rent caused by smaller price differences. In SE3, this effect is offset by the increase in consumer surplus. Additionally, SE4 experiences an increase in social surplus due to an increase in consumer surplus but also higher congestion rent, as it is connected to DE which now has higher prices.

Surprisingly, DK1 indicates that on average both consumer and producer surplus decreased, even if there is on average a slight increase in price. The histogram and descriptive statistics for the price change in DK1 is shown below in Figure 5.12 and Table 5.6. Due to extreme values on the right side of the histogram, the mean is higher than the third quartile and the median which are both 0. Additionally, the model simulates a total decrease of 27 548 MW supplied in the time period studied for DK1 in scenario 2. These factors explain how the change in average producer surplus can be negative while the average price, shown in

Table A0.3, increases.

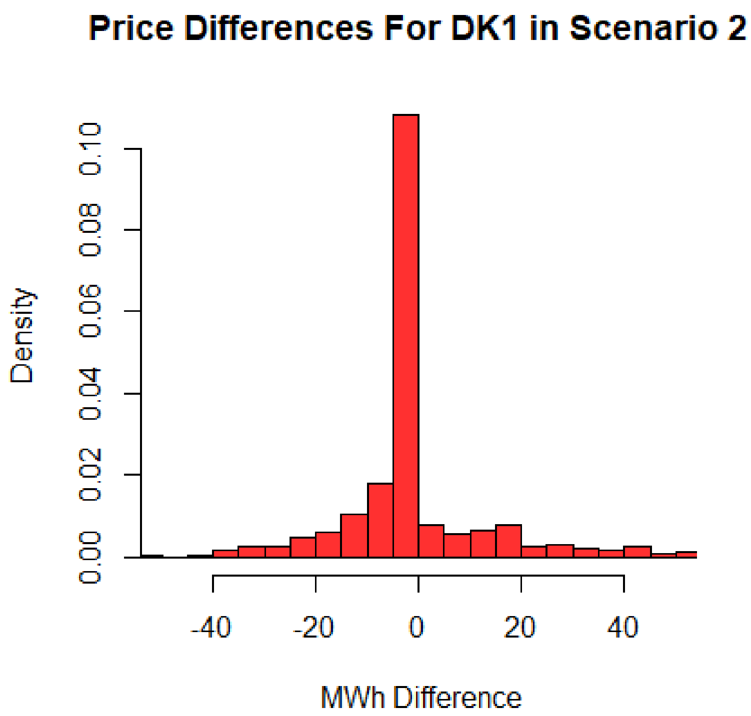


Figure 5.10: Histogram of Price Changes Compared to Base Case for Scenario 2 in DK1

Min.	1st Qu.	Median	Mean	3rd Qu.	Max.
-64.270	-4.497	0.000	0.866	0.000	289.380

Table 5.6: Descriptive Statistics for DK1 Price Change
The table shows summary statistics for the histogram

5.2.3 NorNed

The NorNed interconnector is different from the NSL and NLK interconnectors in that the capacity is only 700MW. Like in Scenario 1 and 2, capacity is set to zero, and implications for prices and social surplus is examined.

Prices

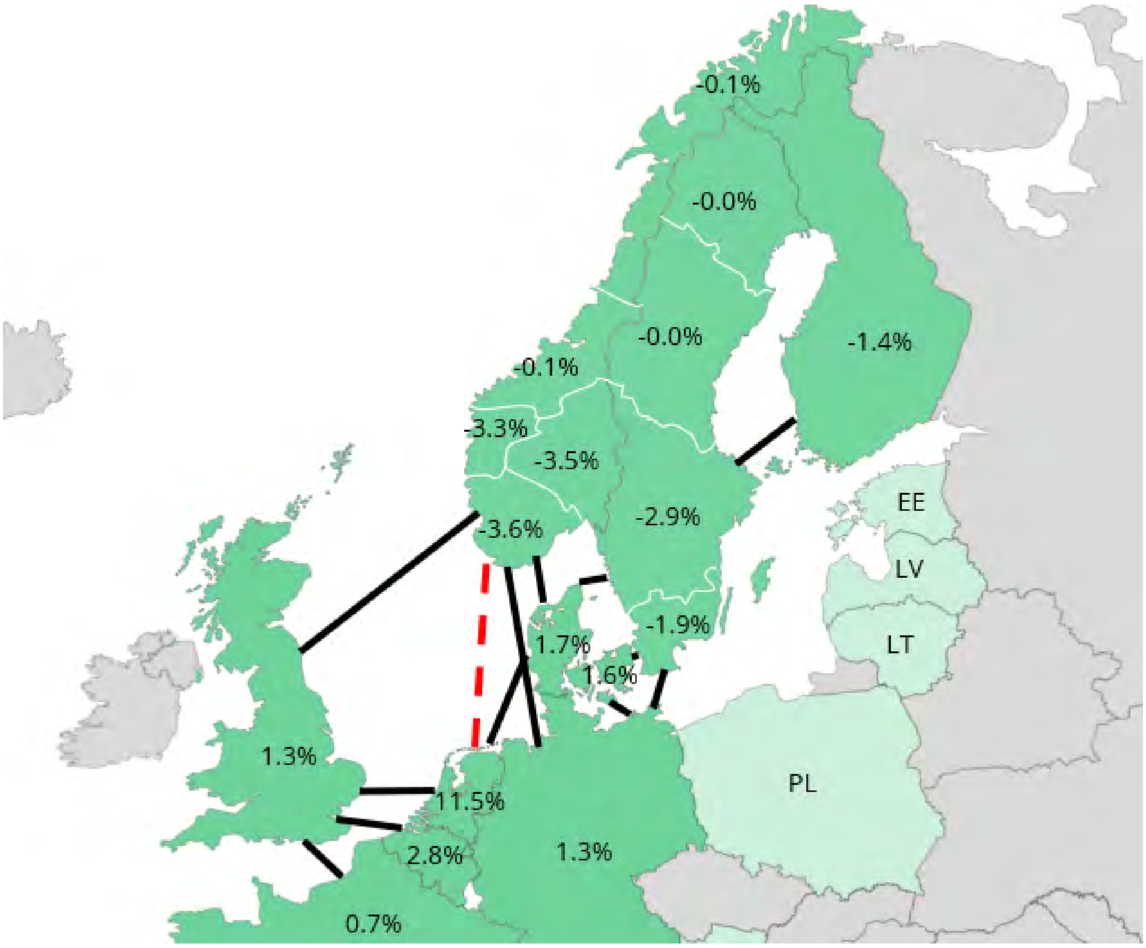


Figure 5.11: Mean per cent Changes per Hour in Prices for Scenario 3

Zones	Price Base	Price S3	Δ Price	% Δ Price
BE	209.49	215.39	5.90	2.81
DE	179.57	181.85	2.28	1.27
DK1	151.68	154.23	2.56	1.69
DK2	139.95	142.17	2.22	1.59
FI	92.76	91.47	-1.29	-1.39
FR	237.10	238.66	1.56	0.66
GB	243.80	246.95	3.14	1.29
NL	207.25	231.13	23.88	11.52
NO1	142.77	137.75	-5.02	-3.52
NO2	142.78	137.61	-5.17	-3.62
NO3	17.21	17.20	-0.01	-0.05
NO4	16.26	16.25	-0.01	-0.06
NO5	142.00	137.35	-4.64	-3.27
SE1	20.98	20.98	-0.01	-0.04
SE2	20.98	20.98	-0.01	-0.04
SE3	94.59	91.87	-2.72	-2.88
SE4	103.33	101.42	-1.91	-1.85

Table 5.7: Mean Prices per Hour in Base Case vs Scenario 3

As expected, the simulation shows a smaller impact on Norwegian prices compared to Scenario 1 and 2. Price decreases are however relatively similar in Scenarios 2 and 3, despite the capacity on NorNed only being half of NordLink's. Power flows on the NorNed cable are predominantly exports from Norway to the Netherlands in the time period studied, which amplifies the price reduction compared to NordLink. As was the case in Scenario 1 and 2, NO3 and NO4 are not significantly impacted.

The model simulates a relatively large price increase in the Netherlands of 11.5%, or about €24/MWh on average. This surpasses the effect seen in GB and DE, in percentage price rise. Other European prices are not significantly affected except for a €6/MWh price hike in BE. The NorNed cable has a relatively strong price impact on NO and NL, but fewer of the knock-on effects seen in Scenarios 1 and 2.

Social Surplus

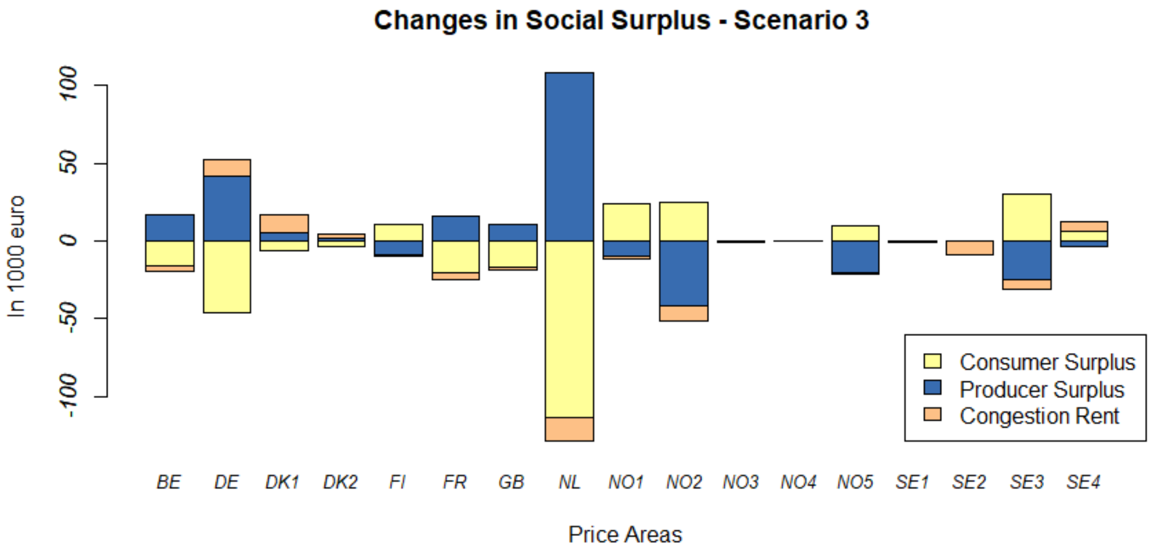


Figure 5.12: Mean Changes per Hour in Social Surplus for Scenario 3 (Data from appendix A0.4)

The changes in social surplus by disconnecting the NorNed cable are similar to the North Sea Link. NO1 increases its social surplus due to the decrease in price causing the consumer surplus to be greater than producer surplus and congestion rent combined. However the opposite effect is again found in NO2 and NO5. The model simulates a decrease in total Norwegian social surplus of about €26 000 which is lower than both North Sea Link and NordLink. This is likely because the interconnector has less available capacity.

The changes in social surplus for Europe are small compared to the previous scenarios. Table 5.7 shows small price changes for most countries except the Netherlands, leading to similar findings for social surplus. The change in DK1 and DE mean social surplus is positive, mainly due to the price increase in NL. The largest mean change after NO2 is therefore NL, due to the loss in consumer surplus and congestion rent. The impact on other European countries is quite limited.

5.3 Full NEXIT

This scenario investigates the consequences of a full NEXIT, where all three interconnectors are disconnected. The results presented shows changes in prices and social surplus that are simulated by the optimisation model. The total reduction in interconnector capacity is 3500 MW.

5.3.1 Prices

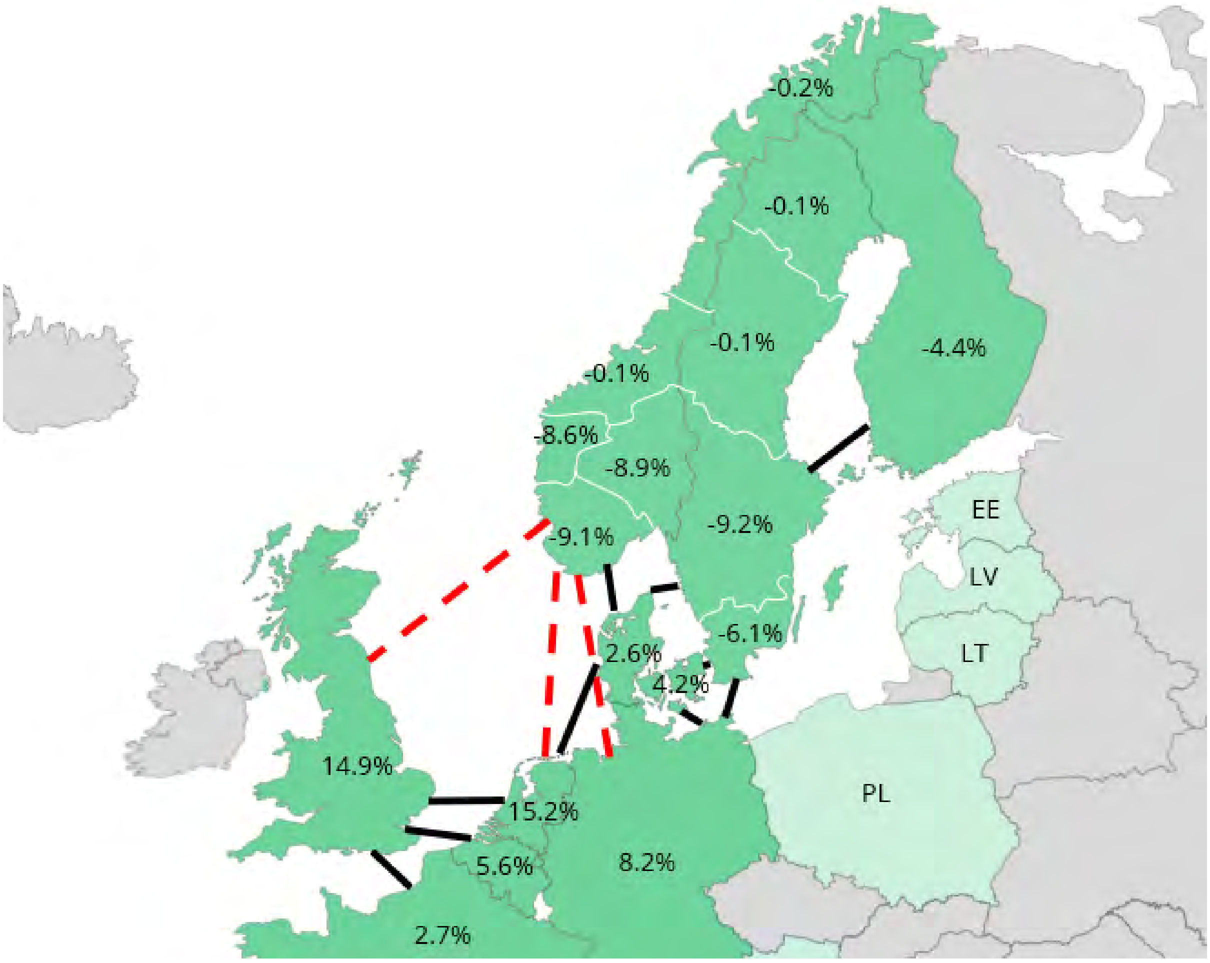


Figure 5.13: Mean per cent Change in Price for Europe. Only dark green countries are included in the optimisation problem.

Figure 5.13 shows the price impacts of a full NEXIT, while Table 5.8 reports prices when disconnecting the interconnectors cumulatively. The difference between the base case and after disconnecting is as discussed earlier mainly felt in southern Norway. For NO3 and NO4, there is a much smaller impact as discussed in the preceding sections. As discussed in Section 5.2.1, disconnecting the North Sea Link causes prices in NO1, NO2 and NO3

Zones	Price Base	NSL	NSL & NL	NEXIT	Δ Price	% Δ Price
BE	209.49	211.71	214.39	221.22	11.73	5.60
DE	179.57	179.87	192.73	194.33	14.76	8.22
DK1	151.68	151.71	152.29	155.62	3.95	2.60
DK2	139.95	140.01	142.82	145.76	5.81	4.15
FI	92.76	90.81	89.32	88.65	-4.11	-4.43
FR	237.10	239.29	241.86	243.40	6.30	2.66
GB	243.80	277.76	278.35	280.03	36.23	14.86
NL	207.25	208.70	211.11	238.82	31.57	15.23
NO1	142.77	135.64	132.91	130.03	-12.74	-8.92
NO2	142.78	135.44	132.84	129.83	-12.95	-9.07
NO3	17.21	17.18	17.19	17.19	-0.02	-0.12
NO4	16.26	16.23	16.23	16.22	-0.04	-0.22
NO5	142.00	135.31	132.57	129.86	-12.14	-8.55
SE1	20.98	20.95	20.95	20.96	-0.02	-0.12
SE2	20.98	20.95	20.95	20.96	-0.02	-0.12
SE3	94.59	90.77	87.09	85.88	-8.70	-9.20
SE4	103.33	100.47	97.57	97.05	-6.28	-6.08

Table 5.8: Mean Prices When Disconnecting Interconnectors Cumulatively

to fall by approximately €7/MWh. Disconnecting both NSL and NLK cause prices to fall by a further €3/MWh. The NorNed cable has a similar effect, giving a total price decrease in a full NEXIT scenario of €14/MWh. The decrease is 8.9%, 9% and 8.6% for NO1, NO2 and NO5 respectively.

Prices generally rise in Europe, while they sink in the Nordics. Especially large are the effects for the three European countries involved: Great Britain, The Netherlands and Germany. The Netherlands is directly impacted by the disconnection of all three cables, and consequently sees the largest rise in electricity price. Price hikes in Great Britain, The Netherlands and Germany in turn affect neighbouring countries like Belgium and France.

Price areas in the north of Norway and Sweden are exporting at maximum capacity southwards in all scenarios investigated. This entails that they do not see any price decrease from the disconnection of NSL, NLK and NN.

5.3.2 Social Surplus

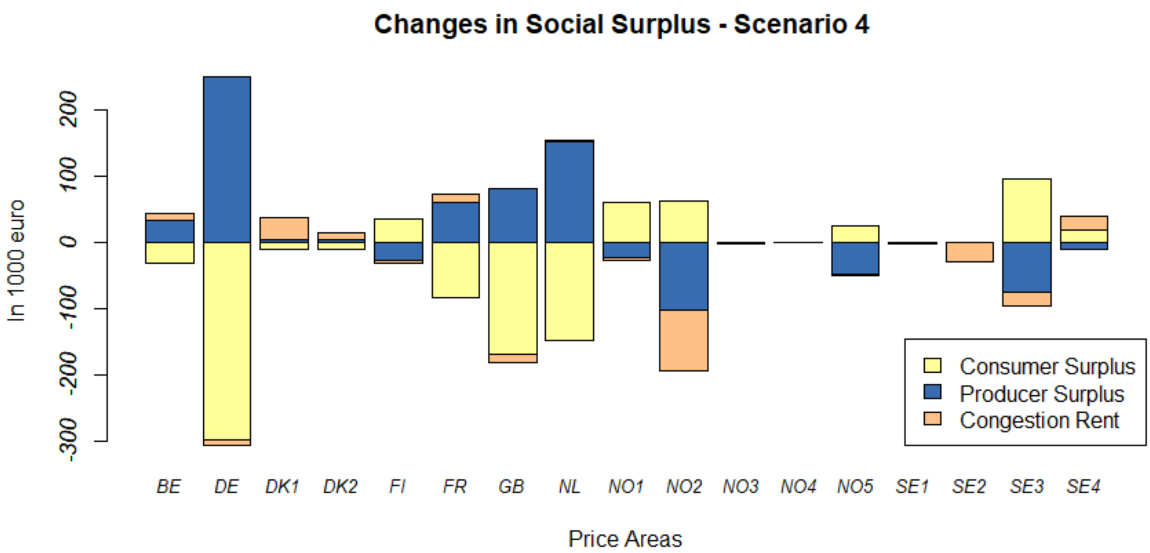


Figure 5.14: Mean Changes per Hour in Social Surplus for Scenario 4 (Data from appendix A0.5)

Figure 5.14 shows the mean hourly decomposed changes in social surplus in a full NEXIT scenario. Figure 5.15 and 5.16 display the mean aggregated changes of social surplus and congestion rent on a country level. The trends are similar to Scenario 1, but the losses in social surplus are larger. The overall average loss in social surplus for all Norway is estimated at about €124 000/hr, as observed in Figure 5.15. This includes a €99 000 loss in congestion rent. 75% of NO2's and 43% of the total Norwegian congestion rent is lost when the interconnectors are removed.

The largest losers in Europe in terms of social surplus are Great Britain and Germany, followed by France and Sweden. Surprisingly, the Netherlands is overall less affected, as the gain in producer surplus compensates for the 14% price increase's impact on consumer surplus.

Denmark is, together with Belgium, the only country which significantly gains in social surplus in a full NEXIT scenario. Belgium gains more in producer surplus and congestion rent than it loses in consumer surplus. For Denmark, the congestion rent is the dominating factor, exceeding losses to consumer surplus caused by higher prices. DK1 experiences the largest positive change in congestion rent, while prices in DK1 only increase by 2.4%.

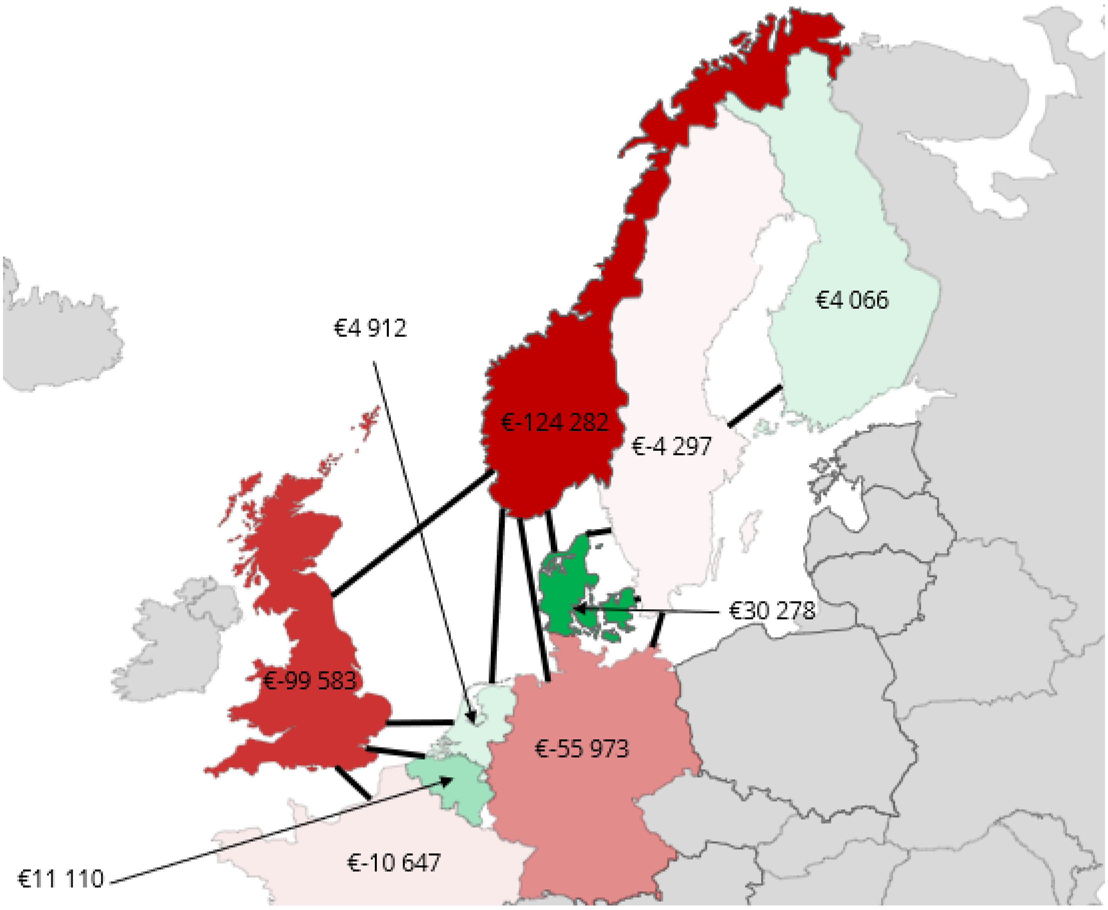


Figure 5.15: Mean Hourly Social Surplus Changes in a Full NEXIT Scenario

Additionally, SE3 and Finnish consumers benefit greatly from the price reduction in SE3. Consequently the SE3 and Finnish producers are, together with NO2, the largest losers when it comes to producer surplus. In summary Europe is worse off, as disconnecting the interconnectors is a deviation from the optimal total social surplus calculated by the EUPHEMIA algorithm. This amounts to a simulated hourly loss of €240 000 in social surplus on average.

Zones	Base Supply	Δ Supply (MWh)	Average Δ Supply %
NO1	1670.77	-166.21	-9.95
NO2	6610.32	-777.40	-11.76
NO3	4184.76	-2.66	-0.06
NO4	3914.47	-3.97	-0.10
NO5	3599.36	-569.40	-15.82

Table 5.9: Change in Supply in a Full NEXIT Scenario

The Table 5.9 shows the changes in produced volumes in a full NEXIT scenario. Even if such a scenario entails a 3500MW interconnector reduction, this only amounts to a

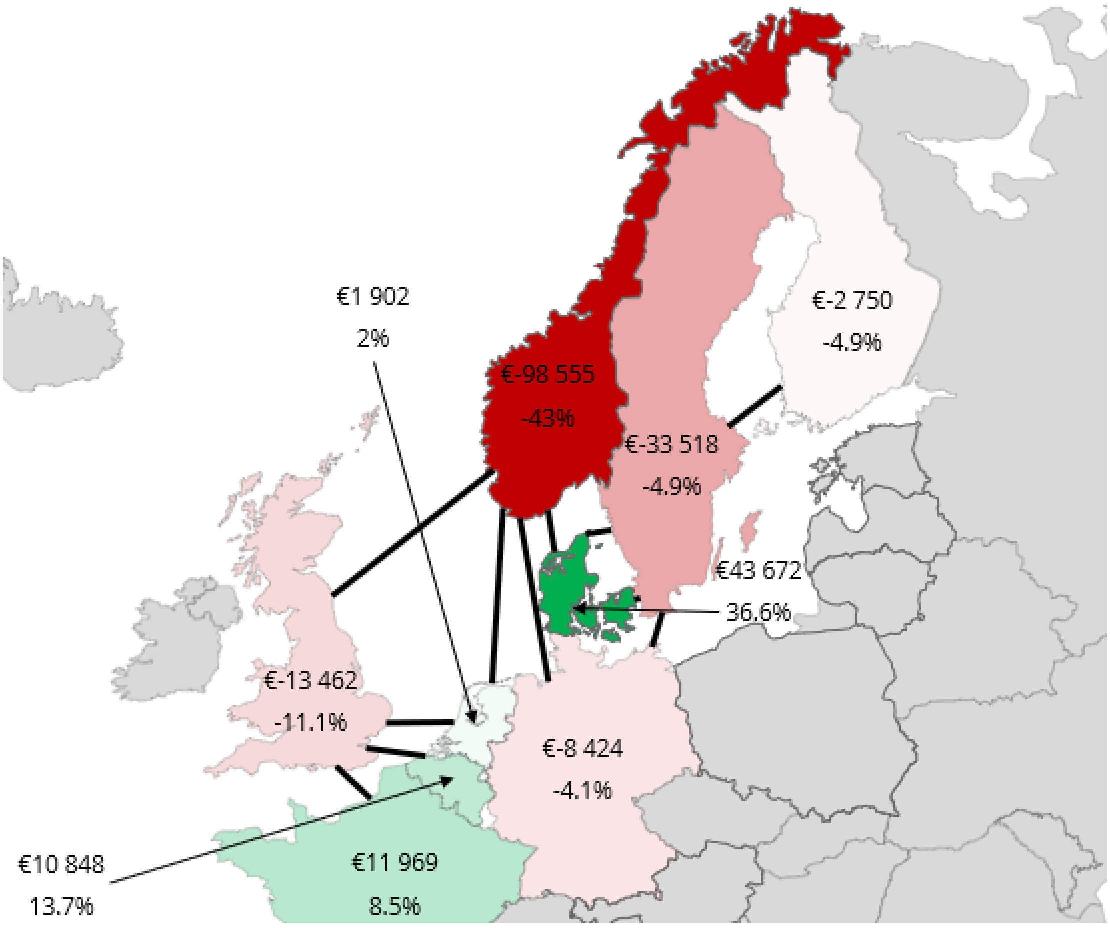


Figure 5.16: Mean Hourly Congestion Rent Changes in a Full NEXIT Scenario

reduction of 1 500MW on average. This is due to increased exports to Scandinavia, higher local demand caused by lower prices, and that the capacity was not fully utilised before NEXIT. The per cent reduction in supply is greater than the 8.8% price decrease indicating supply price-elasticity in the Norwegian market. However, in this simulation, the NEXIT impact on water values which would likely alter the Norwegian supply curves is not accounted for.

Base case results from the model show that Norwegian consumers face some of the lowest electricity prices in Europe in the time period studied. This is a nuancing circumstance to take heed of in the Norwegian debate, as Norway is less affected by the energy crisis than its central western European counterparts. Norway also has amongst the worlds highest electricity consumption per capita (Index Mundi, 2022), significantly above peer countries like Canada, Sweden and Denmark (Index Mundi, 2022). In this regard, high prices may serve as a signal to reduce consumption levels. As mentioned in Section 4.4.3, demand is strongly inelastic. Consumption levels are therefore not strongly affected by the surge in electricity price. This is seen in the Table 5.10, where the average increase in Norwegian demand is small when the prices fall as a result of the removal of the interconnectors. In response to an average reduction of 8.8% in prices, the average demand only rises by 0.28% in NO1.

Zones	Base Demand	Change demand	Average Change Demand
NO1	4669.45	13.11	0.28
NO2	4583.48	13.33	0.29
NO3	3566.93	0.06	0.00
NO4	2503.03	0.03	0.00
NO5	2049.51	5.88	0.29

Table 5.10: Change in Demand in a Full NEXIT scenario

5.4 Review of Findings

The following section compares and contrasts the findings in the analysis section with academic work described in chapter 3.

5.4.1 Prices

Døskeland et al. (2022) estimate that the NordLink and North Sea Link interconnectors only explain around 10% of the average price in southern Norway in 2021, compared to a situation without these interconnectors. This thesis finds that the impact of removing the NorNed interconnector in addition to these two would lower Norwegian prices by around 9% in the time period studied in early 2022. As can be seen in Table 5.8, the cumulative effect from disconnecting both the NordLink and the North Sea Link is estimated at around €10 or 7%. This is slightly lower than Statnett's estimate for 2021, but Statnett's analysis covers a different time period and likely accounts for changes in water values.

5.4.2 Social Surplus

As mentioned in Section 5.1, the absolute values for social surplus should be read with caution. Nevertheless, the general trend of social surplus losses in both Norway and Europe fits well with Geske et al. (2020), Newbery et al. (2019) and Mathieu et al. (2018). Overall changes in social surplus correlate well with the hypothesis and findings in the

Literature Review, although the analysis shows that some countries and areas are better off in a NEXIT scenario.

In line with findings by SEM Committee (2011) and Malaguzzi Valeri (2009), consumers gain while producers lose out in a NEXIT scenario. Another expected result is that price areas in the south of Norway and Sweden are affected more than the northern areas. Surprisingly, NO1 actually gains in social surplus in a full NEXIT scenario. A similar result is found for SE4.

5.4.3 Congestion Rent

Calculations of congestion rent in the base case scenario can be corroborated by comparing the modeled values with official numbers published by Statnett (2022a). Only February is captured in full in the model, so comparisons are made with the official numbers listed as congestion rent collected by Statnett in February 2022. Modeled and real congestion rent align fairly well in February, signaling a satisfactory model fit for this metric. The North Sea Link contributes the most to congestion rent in the period studied, reflecting the importance of this interconnector for the Norwegian state and producers. A summary of real and modeled congestion rent in the period is found below.

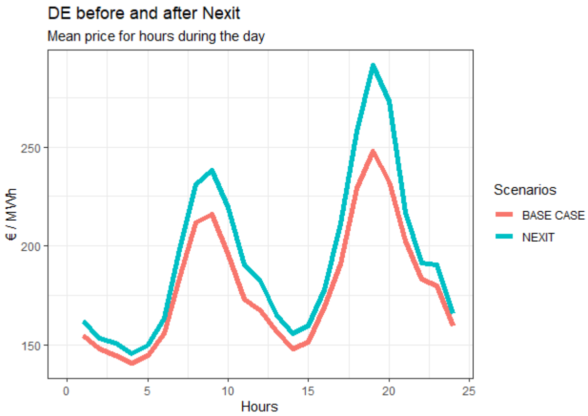
	LINK	Statnett (€ mln)	Simulated (€ mln)
1	DE NO2 (NordLink)	9.9	10.2
2	DK1 NO2	11.7	12.7
3	GB NO2 (North Sea Link)	22.9	24.0
4	NL NO2 (NorNed)	9.5	9.4
5	NO1 SE3	17.8	17.1
6	Internal Flows	35.4	34.5

Table 5.11: Comparison of Real and Modeled Congestion Rent (Statnett, 2022a)

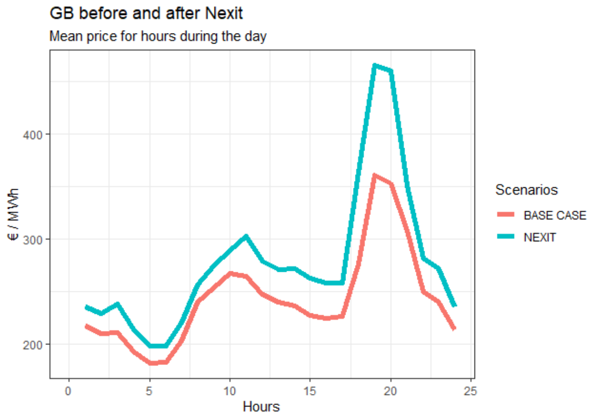
5.5 Price Variations

The analysis shows that most countries stand to lose following a disconnection of Norwegian interconnectors. A NEXIT would constitute a break with recent developments in the European markets, which are generally moving towards closer integration. NEXIT's potential impact on social surplus is covered the analysis. This sections focuses on another feature of Norwegian interconnectors: Their stabilising effect on European electricity prices.

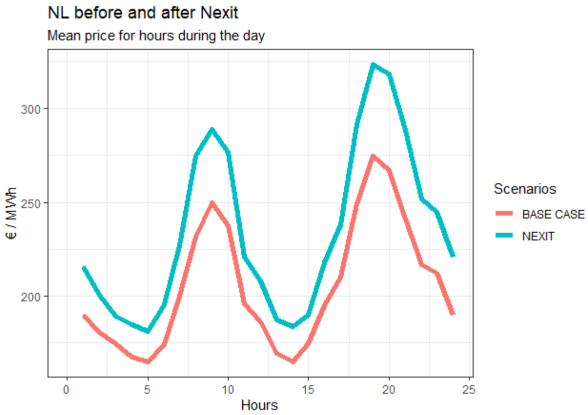
5.5.1 Price Variation



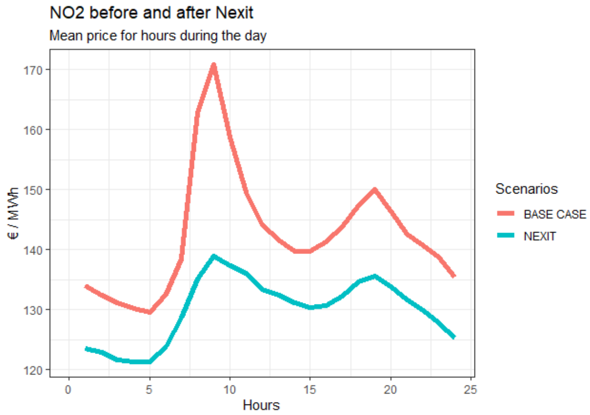
(a) DE



(b) GB



(c) NL



(d) NO2

Figure 5.17: Mean Price Per Hour for DE, GB, NL and NO2

Figures 5.17a, 5.17b , 5.17c and 5.17d show mean prices per hour for DE, GB, NL and NO2. The blue line represents the full NEXIT scenario and the red line the base case. Two main price peaks are observed during the day. The first in the morning and the second around 20:00. For NO2 and Norway the morning peak is the most dominant in contrast to especially GB, but also DE and NL where the evening peak is the largest.

5.5.2 Standard Deviation

Scandinavia, in particular Norway and northern Sweden, have some of the smallest price variations in Europe. This is due to the flexible nature of hydropower production from water-reservoirs (Office of Energy Efficiency & Renewable Energy, 2017). This production is easily regulated at a low cost. Standard deviations in price during the period studied is shown in Figure 5.18.

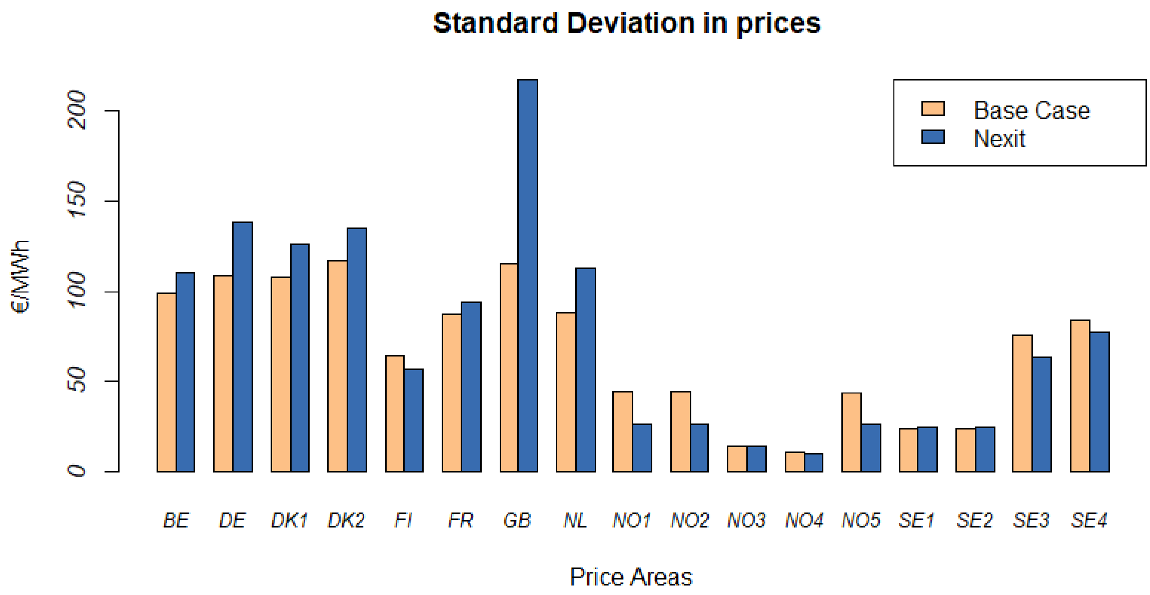
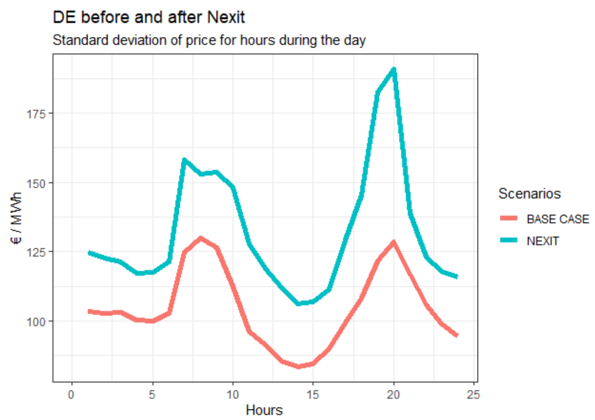


Figure 5.18: Standard Error of Prices Across Price Areas

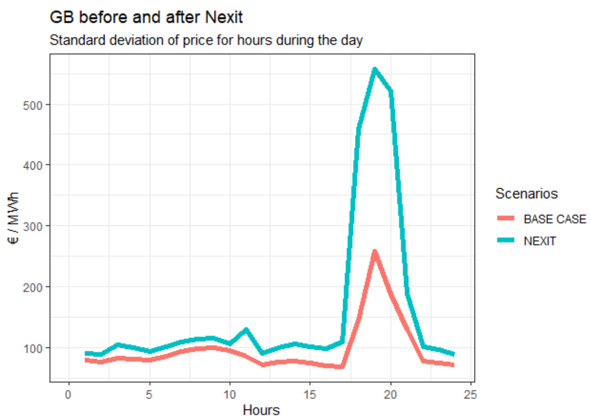
Figure 5.18 shows standard deviations price in the base case compared to the full NEXIT scenario. The stabilising effect is illustrated by European price variations growing in the full NEXIT scenario. Contrastingly, Norwegian, Swedish and Finnish prices stabilise in the time period studied. Higher shares of intermittent energy production i Europe accentuates the benefits of interconnectors as a stabilising element.

The Figures 5.19a, 5.19b, 5.19c and 5.19d show hourly mean standard deviation of price before and after NEXIT. The standard deviation after NEXIT is higher for DE, GB and NL during all hours. However, there is a significant increase during the evening in DE and GB. While there is a significant increase in standard deviation during the day in the NL price area. The effect for NO2 is the opposite, as standard deviation decreases in a NEXIT scenario. In the base case, significant increases in standard deviation in the morning hours compared to after a NEXIT can be observed. The stabilising effect of the interconnectors is particularly large in the peak-hours during the morning and the evening.

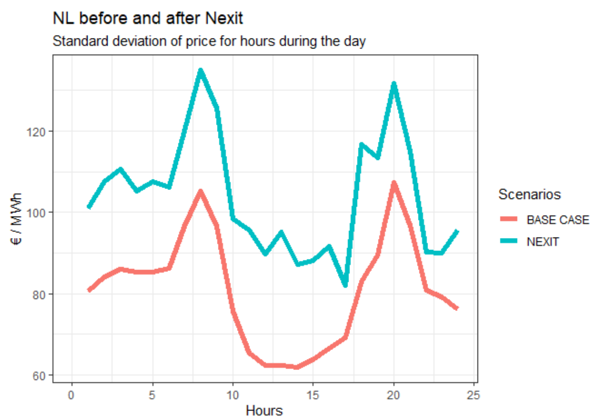
Central western European countries face more variable electricity prices as a result of



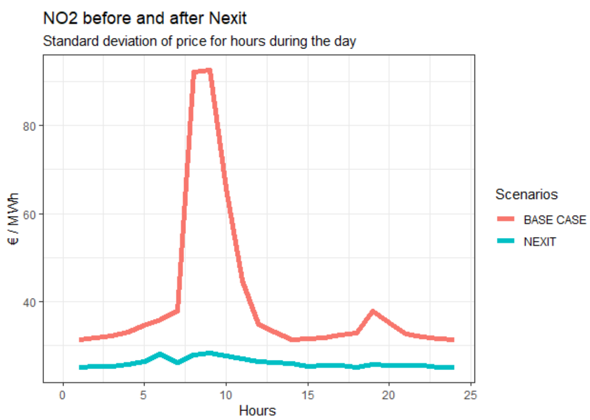
(a) DE



(b) GB



(c) NL



(d) NO2

Figure 5.19: Mean Standard Deviation of Prices per Hour

their power mix. In this context, access to Norwegian electricity is key. In hours with low production from intermittent energy, countries like Germany and The Netherlands can benefit from flexible Norwegian hydropower. Price volatility in the electricity market is likely to pose an even greater challenge in the years to come. Increasing shares of weather-dependent power sources add variability to electricity prices.

5.6 Sensitivity Analysis

In order to gain an understanding of how the high water-values have affected the results in the analysis, a sensitivity analysis is conducted. Lower water-values can be simulated by simply reducing the price of bids. The amount offered does not change, but the opportunity cost of water is reduced, and so the bid prices offered are lower. The sensitivity analysis uses data for the full time period studied, from the 14$^{\text{th}}$ of January to the 15$^{\text{th}}$ of March in 2022. Only a sensitivity analysis on prices is conducted, as this is a key driver for changes in social surplus.

Table 5.12 shows the total price effect of a full NEXIT with lower water values. Notice that the "Price Base" and "Full NEXIT" columns are identical to the full NEXIT scenario shown in 5.3.1. In the columns to the right, the price effects of a NEXIT scenario are shown, with declining water values in intervals of 10%. All values except the Price Base are in per cent.

$$\frac{Water\ Value_{NXT} - Price\ Base}{Price\ Base}$$

Zones	Price Base	Full NEXIT	-10% WV	-20%WV	-30%WV
BE	206.51	5.82	5.82	5.80	5.75
DE	177.36	6.91	6.75	6.40	5.78
DK1	163.26	3.26	1.99	0.41	-1.66
DK2	152.61	5.05	4.08	2.86	1.31
FI	89.41	-5.93	-7.76	-9.73	-12.03
FR	235.63	3.35	3.36	3.36	3.36
GB	241.06	12.04	12.05	12.05	12.04
NL	206.81	13.40	13.53	13.50	13.48
NO1	144.24	-9.89	-17.94	-26.53	-35.20
NO2	144.24	-9.95	-18.12	-26.69	-35.34
NO3	17.40	-0.21	-0.54	-0.73	-0.82
NO4	16.11	-0.37	-0.47	-0.52	-0.53
NO5	143.66	-9.69	-17.65	-26.29	-35.00
SE1	21.94	-0.14	-0.60	-0.96	-1.26
SE2	21.94	-0.14	-0.60	-0.96	-1.26
SE3	95.11	-11.70	-15.64	-20.26	-25.60
SE4	105.78	-7.95	-10.48	-13.57	-17.26

Table 5.12: Mean Hourly Prices of a Full NEXIT, With Lower Water Values in NO1, NO2 and NO5

Lower water values also give lower equilibrium prices in southern Norway. A NEXIT with a 30% decrease in water values brings a 35% decrease in prices for NO1, NO2 and NO5, according to the simulation. This shows that changing water values would have a significant effect on prices in Norway. As seen when disconnecting the interconnectors, SE3 and SE4 are often impacted by price changes in NO1,NO2 and NO5. This is also the case when altering the water values. However, for GB, changes in water values seem to have no effect on prices. GB generally has higher prices than Norway, with power flows at maximum capacity. Increasing the price gap between NO2 and GB with lower water values therefore has little effect on GB prices. DK1, DK2 and FI are slightly impacted, while the remainder of Europe is more of less unaffected.

The results represent the impacts of a full NEXIT in combination with lower water values. Both of these features pull in the direction of lower electricity prices in the south of Norway. In the two following tables, the results from Table 5.12 are decomposed, demonstrating the impact from NEXIT and lower water values separately.

Zones	Price Base	-10% WV	-20%WV	-30%WV
BE	206.51	-0.03	-0.13	-0.30
DE	177.36	-0.50	-1.36	-2.44
DK1	163.26	-1.44	-3.49	-5.89
DK2	152.61	-1.05	-2.53	-4.32
FI	89.41	-1.80	-3.52	-5.26
FR	235.63	0.02	0.01	-0.01
GB	241.06	-0.01	-0.06	-0.14
NL	206.81	-0.16	-0.51	-0.95
NO1	144.24	-8.29	-16.81	-25.30
NO2	144.24	-8.33	-16.81	-25.29
NO3	17.40	-0.35	-0.56	-0.64
NO4	16.11	-0.17	-0.23	-0.23
NO5	143.66	-8.24	-16.83	-25.31
SE1	21.94	-0.56	-0.94	-1.26
SE2	21.94	-0.56	-0.94	-1.26
SE3	95.11	-3.88	-8.25	-13.10
SE4	105.78	-2.50	-5.53	-9.09

Table 5.13: Mean Hourly Change in Prices With Lower Water Values in NO1, NO2 and NO5

Table 5.13 decomposes the price changes from Table 5.12, by returning the isolated water value effect before a NEXIT. Values are calculated in the following manner:

$$\frac{Water\ Values_{PB} - Price\ Base}{Price\ Base} =$$

Lowering the Norwegian water values has a decreasing effect on prices all over Europe. Table 5.13 demonstrates the effect lower Norwegian prices has on Europe today. Lowering water values by 10% in NO1, NO2 and NO5, causes an 8% reduction in NO1,NO2 and NO5 prices. In turn, this causes a 3.9% and 2.5% decrease in SE3 and SE4 respectively, while German prices fall 1.4%. When lowering the water values further, the area prices appear to fall in an approximately linear trend. GB and DE prices are less impacted by the decrease in Norwegian prices than SE3. This is likely due to the interconnector flow direction between the price areas. Lower Norwegian prices do not help GB and DE in the instances where powers flows are already sent from Norway at maximum capacity. As the flow direction between GB and NO2 is most frequently from NO2 to GB, GB would not experience a significant price reduction. SE3, and to a smaller extent DE, frequently experience price convergence with Norwegian price areas. Price convergence often means that power flows are not at maximum capacities, allowing the price effects of lower water values in Norway to benefit these price areas.

The effect on the Norwegian prices also appears to follow a linear trend, falling around 8% per 10% change in water value. It may also be interesting to study the effects of altering water values *after* the NEXIT scenario is implemented. Table A0.6 in the appendix shows that the water value effect is similar in Norway, but the impact on other price areas is reduced as there are less interconnectors after NEXIT to distribute the effects of lower NO1, NO2, and NO5 prices.

	Zones	Price Base	Full NEXIT	-10% WV	-20%WV	-30%WV
1	BE	206.51	5.82	5.85	5.92	6.05
2	DE	177.36	6.91	7.25	7.76	8.22
3	DK1	163.26	3.26	3.43	3.89	4.24
4	DK2	152.61	5.05	5.14	5.39	5.62
5	FI	89.41	-5.93	-5.97	-6.22	-6.78
6	FR	235.63	3.35	3.35	3.35	3.37
7	GB	241.06	12.04	12.05	12.10	12.18
8	NL	206.81	13.40	13.69	14.01	14.42
9	NO1	144.24	-9.89	-9.65	-9.72	-9.91
10	NO2	144.24	-9.95	-9.78	-9.88	-10.05
11	NO3	17.40	-0.21	-0.19	-0.17	-0.18
12	NO4	16.11	-0.37	-0.30	-0.29	-0.30
13	NO5	143.66	-9.69	-9.41	-9.46	-9.69
14	SE1	21.94	-0.14	-0.04	-0.02	-0.00
15	SE2	21.94	-0.14	-0.04	-0.02	-0.00
16	SE3	95.11	-11.70	-11.76	-12.01	-12.50
17	SE4	105.78	-7.95	-7.98	-8.04	-8.16

Table 5.14: Isolated Impact of a Full NEXIT on Mean Hourly Prices, With Different Water Values in NO1, NO2 and NO5

Table 5.14 decomposes the price changes from Table 5.12, by returning the isolated NEXIT effect after changes in the waters values. Results are calculated in the following manner:

$$\frac{Water\ Values_{NXT} - Water\ Values_{PB}}{PriceBase}$$

Interestingly, the percentage impact of NEXIT on price only slightly increases or decreases in the 10, 20 and 30% decreased water value scenarios. The changes in the different scenarios are quite small, indicating that the isolated effect of disconnecting the interconnectors is fixed, regardless of water value.

The sensitivity analysis is an attempt to elucidate the implications of high water values in Norway, in the time period studied. The sensitivity analysis shows that the price impact of NEXIT could vary depending on associated changes to water values. Nevertheless, the direct price impact of the interconnectors appears to be quite robust.

5.7 Outlook 2030

In the coming decade, several European countries will add large amounts of renewable energy to their power mix. Table 5.15 shows projections of added renewable energy sources for selected countries in 2030. The data on future capacity is collected from Rystad Energy and adjusted for seasonal patterns for both wind and solar production based on data from ENTSO-E (2022). The table shows the increase in average hourly added MW to the market, without adjusting for hourly patterns.

Countries	Adj Wind	Adj Solar	Other RE	Total Capacity
NO	1 100	65	0	1 169
DK	1 960	255	0	2 222
SE	1 949	81	0	2 030
FI	2 629	39	338	3 006
DE	7 818	5 412	-4 291	8 939
BE	1 306	342	-2972	-1 322
FR	7 109	2 398	-4 993	4 514
GB	12 315	1 043	-1 844	11 515
NL	1 865	1 010	0	2 876

Table 5.15: Estimated Hourly Addition of MW Renewable Energy in 2030

GB, DE and FR all add several thousand megawatts renewable energy, mainly wind and solar, while reducing their nuclear power production. Towards 2030, Norway is one of the countries adding the smallest amount of renewable electricity (Rystad Energy, 2022). An boost in wind generation will likely affect power flows on the interconnectors.

On the demand side, consumption of electricity is expected to grow by 21% in Norway, 17% in Sweden and 26% in Denmark (Birkelund et al., 2021). In central western Europe, consumption is only expected to grow by 11% in GB (Department for Business, Energy Industrial Strategy, 2022), 8% in DE (Hladik et al., 2020) and 5% in FR (RTE, 2022). In other words, the energy deficit in Europe is projected to narrow in the coming decade, altering the potential consequences of NEXIT.

Figure 5.2 shows that Norway is already close to being a systemic importer of electricity in hours where the German supply of wind-power is high. Based on the projections for supply and consumption, this trend is likely to continue and strengthen in the coming years. The import to export ratio on the NordLink cable might be more leveled for Norway and Germany. As mentioned by Malaguzzi Valeri (2009), increases in import of electricity would mean lower prices for Norway than what would otherwise be the case. Current gains in Norwegian consumer surplus from disconnecting NordLink could be significantly lower or even be reversed to losses in the future. Should DE, GB and NL add several thousand MW per hour to the electricity market, and projected consumption patterns materialize, Norway could become a net-importer in several hours. The analysis conducted in this thesis only reflects the current circumstances. As conveyed in this section, the findings may not hold true in future conditions. This is only one of the limitations of the thesis, elaborated on in the following section.

5.8 Limitations of the Thesis

In this section, limitations and assumptions are elucidated.

A key limitation of the thesis is that the data only ranges from the 14$^{\text{th}}$ of January until the 15$^{\text{th}}$ of March. This is typically a period with lower water-levels in the water reservoirs. This was especially the case in 2022. The model does not capture that the interconnectors helped exacerbate this problem, by increasing exports from Norway during the fall of 2021. Low water levels caused in part by the interconnectors has been a contributing factor to the high electricity prices seen the spring of 2022. This occurred before the first datapoint used in the model, but has a large effect on bids from the south of Norway. Norway is normally importing more than normal during this time of the year (Statnett, 2022b). Ideally the data would be for an entire year, in order to not be colored by such seasonality effects. The data is also influenced by the fact that it is collected during an energy crisis affecting all of Europe. Prices have been unusually high, which may have caused the model to overestimate the impact of the interconnectors. The results only reflect the current situation, which may change in the future. The discussion around the 2030 scenario is an attempt to shed light on how a NEXIT scenario would look like in the future with different power mixes. An interesting avenue for further research could be to simulate NEXIT using future power mixes and transmission capacities.

The sensitivity analysis has some limitations, as it only looks at three alternative scenarios with diminishing water values. This makes it difficult to conclude about trends when water values are changed. Ideally, a more thorough sensitivity analysis would be conducted, also including possible elevations in water values.

The same bid curves are used for the base case and the NEXIT simulation. The only change made is the capacity available for transfer between Norway and Germany, Great Britain and the Netherlands. If an actual NEXIT happened, hydropower producers would immediately alter their bids to reflect the new situation. Water values would decrease, reflecting the lack of opportunities for producers to sell their electricity to the European market. Such fundamental changes to bid curves are difficult to model, and would require detailed information on water values and bidding strategies. This reduces the validity of the results, but they are still useful to indicate trends in prices, social surplus and power flows caused by disconnecting the interconnectors. Although the full extent on social surplus and prices is not captured by the model, the marginal impact of cutting transmission capacity is illuminated.

Assumptions and simplifications have also been made with regards to data sources and model construction. Bid curves for Norwegian price areas have been constructed based on a regression between volume and prices. This gives a useful approximation of hydropower producers' water values, but is inferior to Norwegian price areas' actual bid curves. Access to accurate data on a price-area level would elevate the accuracy of the model, and improve the validity of findings from the simulated scenarios. Block-bids and flexible hourly bids are not included in the model. Such bids provide an entirely new dynamic, and can cause bigger shifts in the location of the market clearing price and volume.

The NTC model used requires Net Transfer Capacities between all price areas sharing a border or connected through an interconnector. Missing NTC values have been replaced by looking at mean power flows in hours where powers flows are assumed to be at maximum capacity for a given border or interconnector. The challenge of missing NTC values stems from most Central European countries employing a flow-based market coupling model. It is a simplification measure to treat these countries as if they are using an NTC model. This naturally affects the validity of the simulations, as a flow-based model might give different responses to a restriction of interconnector capacity. A particular emphasis is put on Norway in this thesis, giving priority to the use of an NTC model rather than a flow-based market coupling.

Estimates of social surplus are prone to mistakes from the calculation method. Consumer surplus is for instance strongly affected by the maximum value set for a demand bid. Should this be set at €2 000 or €1 000 instead of €3 000, this would significantly reduce the base case consumer surplus. This means that the absolute values for social surplus are potentially problematic to interpret at face value. Estimates for congestion rent do hold up to scrutiny, but are subject to weaknesses in the simulated power flows. The model rarely returns accurate power flows between price areas in cases where their prices are equal. The interconnectors of interest in this thesis mostly have power flows on maximum capacity, reducing the impact of this weakness. Power flows are also restricted by tariffs, and power flow between two price areas is only initiated so long as their price difference exceeds the tariff (Nominated Electricity Market Operators Committee, 2019). Such a rule is not employed in the model used in this thesis, which could give discrepancies in real and modeled prices and power flows. These simplifications mean that the full impact of a NEXIT scenario is not covered.

A more general limitation is the definition used for NEXIT. Rather than simply restricting interconnector capacity, an actual NEXIT could entail a two-step market process like the one described by (Geske et al., 2020). Alternate ways of defining NEXIT are potential areas to investigate in further research on the topic.

The intra-day market is not included in this analysis. The day-ahead market is by far the largest, but the importance of the intra-day market may grow in the years to come. A full decomposition of NEXIT implications would also include redispatching costs and intra-day market effects.

6 Conclusion

This thesis aims to contribute to the ongoing Norwegian electricity market debate. Critics argue that the costs of the interconnector cables to Central Europe outweigh the benefits. The thesis investigates this claim by analysing the consequences of a Norwegian Exit from the European electricity market. A particular emphasis is placed on Norwegian stakeholders. An optimisation model including 17 selected price areas is constructed, reflecting the European market's clearing process. In order to facilitate analysis and discussion, relevant context and academic work is explored.

The main data-sources are from EPEX SPOT and Nord Pool, which include bid curves, prices and transmission capacities. This data is used to replicate the current prices and power flows in an optimisation model. Subsequently, four potential NEXIT scenarios are simulated, where interconnector capacity is removed. This allows for an analysis of changes in prices, social surplus and interconnector flows across price areas over time. The validity of results is reflected upon with a sensitivity analysis on water values, and an outlook towards the coming decade with different power mixes in Europe.

The thesis finds that critics citing the price increasing impacts in Norway from the interconnectors are corrects in their assessments for the time period studied in early 2022. However, claiming that Norway would be better off does not hold up to scrutiny according to results from the simulation.

Findings suggest that removing the NorNed, NordLink and North Sea Link decreases hourly prices in southern Norway by 9%. In Europe, Great Britain and the Netherlands experience the largest increase in prices at around 15%. The simulation finds that the social surplus for Norway as a whole decreases in the different variations of NEXIT. The interconnector with the greatest effect on Norwegian prices and social surplus is the North Sea Link to Great Britain. Losses to social surplus are not distributed equally among stakeholders, with Norwegian consumers benefiting while producers lose out.

For Europe, the consequences of a NEXIT are negative overall; social surplus decreases, and the interconnectors' stabilising effect on prices is lost. The total hourly loss to European social surplus in a full NEXIT scenario is €240 000 on average. The largest absolute losses are incurred by German, British and Dutch consumers, and Norwegian producers in the southern parts of Norway. Contrasting this, some price areas, like the NO1 area in eastern Norway, benefit from NEXIT. Other benefactors are the SE3, SE4 and DK1 areas in Sweden and Denmark. The Swedish consumers benefit from the lower Norwegian prices, while DK1 gains significantly in congestion rent. In fact, Denmark is significantly better off, as the gains in congestion rent outweigh losses to consumer surplus. Northern areas in Sweden and Norway are largely unaffected, due to congestion in the Nordic grid.

The model simulates that NEXIT reduces the Norwegian price variation significantly during the morning peak, while increasing variation in mainland Europe and Great Britain. The British price area is on average the most affected due to an extreme increase in variation during evening peak hours. However, it only experiences a relatively small added variation the remainder of the day. The NEXIT effect on German price variation is more stable throughout the day. In contrast, for Norway NEXIT removes the morning peak in price variations.

The sensitivity analysis shows that incorporating water value changes in the analysis would further decrease prices in Norway with knock-on effects to all connected price areas except GB. It also demonstrates that the direct impact on prices from interconnectors is constant, but associated impacts on water values from NEXIT remain unknown.

Forecasts show that Europe, in particular Great Britain and Germany, will have significantly more renewable generation capacity. Some countries may add several thousand MW each hour to their average production. This may be enough to alter power flows in Europe towards Scandinavia in the future, but is beyond the scope of this thesis.

Further research on this topic could estimate changes in water values as a response to events in the power market. Research could also look further into avenues not explored in this thesis. An interesting topic to study is the impact of improving the Nordic North-South congestion. NEXIT could be also be studied in the context of the conditions mentioned in the 2030 outlook.

A Norwegian exit from the European power market would have detrimental effects on both the Norwegian and the European social surplus. Consumers in Norway would be better off due to lower prices and less price variation, while Norwegian producers and

Central European consumers lose out. Such a scenario would affect prices, social surplus and power flows through all of Europe, but the impacts may be different in the future depending on the power mix in European countries.

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Appendix

Zones	Change SS	Change CS	Change PS	Change CR	Base CR	% CR
BE	13 271	-6 289	5 153	14 407	78 964	18.25
DE	6 309	-4 391	2 650	8 049	207 196	3.88
DK1	3 186	-209	-385	3 780	81 968	4.61
DK2	1671	-151	-130	1 952	37 304	5.23
FI	1598	16 753	-13 532	-1 623	61 278	-2.65
FR	11 630	-28 252	19 567	20 315	141 494	14.36
GB	-87 443	-155 974	71 402	-2 871	120 743	-2.38
NL	17 983	-7 008	5 801	19 189	91 936	20.87
NO1	18 840	34 100	-13 258	-2 001	42 990	-4.66
NO2	-61 562	34 874	-57 205	-39 231	137 877	-28.45
NO3	-1 248	99	-88	-1 259	30 284	-4.16
NO4	-52	77	-127	-2	2 171	-0.10
NO5	-14 300	14 079	-27 202	-1 178	12 627	-9.33
SE1	-1 548	59	-140	-1 467	56 123	-2.61
SE2	-12 865	84	-239	-12 701	249 412	-5.10
SE3	-1 620	42 679	-33 947	-10 351	306 911	-3.37
SE4	10 150	9 216	-4 344	5 278	66 398	7.95

Table A0.1: Mean Changes in Social Surplus When Disconnecting the North Sea Link Interconnector (Scenario 1). Values are in €/hr

Zones	Change SS	Change CS	Change PS	Change CR	Base CR	% CR
BE	-8 638	5 450	-5 877	-8 210	78 964	-10.40
DE	-15 818	-7 707	8 095	-16 206	207 196	-7.82
DK1	-8 579	-2 452	3 205	-9 332	81 967	-11.39
DK2	-2 119	-1 056	999	-2 062	37 303	-5.53
FI	-1 226	-16 777	13 596	1 953	61 278	3.19
FR	-2 215	26 996	-19 780	-9 432	141 494	-6.67
GB	55 445	113 543	-45 827	-12 270	120 743	-10.16
NL	-13 789	4 595	-1 361	-17 023	91 936	-18.52
NO1	-38 818	-78 754	34 249	5 687	42 990	13.23
NO2	51 150	-80 263	144 937	-13 523	137 876	-9.81
NO3	2 635	-139	149	2 625	30 284	8.67
NO4	56	-58	95	19	2 170	1
NO5	41 879	-35 089	76 390	578	12 627	4.58
SE1	1 580	-83	206	1 457	56 123	2.60
SE2	20 500	-126	346	20 280	249 411	8.13
SE3	5 017	-67 766	55 151	17 142	306 911	5.59
SE4	-15 872	-11 568	4 635	-8 939	66 397	-13.46

Table A0.2: Mean Changes in Social Surplus When Adding the NorthConnect interconnector (Scenario 1a). Values are in €/hr.

Zones	Change SS	Change CS	Change PS	Change CR	Base CR	% CR
BE	2 505	-7 088	6 813	2 779	78 964	3.52
DE	-63 688	-254 452	206 361	-15 598	207 196	-7.53
DK1	16 853	-3 392	-2 446	22 692	81 967	27.69
DK2	3 974	-5 248	1 389	7 833	37 303	21.00
FI	2 386	18 779	-15 073	-1 319	61 278	-2.15
FR	-14 405	-36 220	25 770	-3 954	141 494	-2.80
GB	495	-3 737	1 861	2 371	120 743	1.96
NL	10 221	-9 010	9 894	9 337	9 1936	10.16
NO1	12 258	22 705	-10 179	-266	42 990	-0.62
NO2	-42 220	22 779	-44 250	-20 750	137 876	-15.05
NO3	-373	-82	165	-456	30 284	-1.51
NO4	56	1	9	46	2 170	2.12
NO5	-13 027	9 475	-21 610	-892	12 627	-7.07
SE1	-1 553	-38	159	-1 674	56 123	-2.98
SE2	-17801	-86	69	-17 784	249 411	-7.13
SE3	-821	58 026	-46 381	-12 466	306 911	-4.06
SE4	18 650	12 871	-7 384	13 163	66 397	19.83

Table A0.3: Mean Changes in Social Surplus When Disconnecting the NordLink Interconnector (Scenario 2). Values are in €/hr.

Zones	Change SS	Change CS	Change PS	Change CR	Base CR	% CR
BE	-2 471	-16 329	17 083	-3 226	78 964	-4.08
DE	6 846	-45 873	41 439	11 280	207 196	5.44
DK1	10 585	-5 994	5 140	11 439	81 968	13.96
DK2	1 017	-3 446	1 820	2 643	37 304	7.09
FI	1 069	10 988	-8 834	-1 085	61 278	-1.77
FR	-8 429	-20 574	16 097	-3 951	141 494	-2.79
GB	-7 848	-17 059	10 474	-1 263	120 743	-1.05
NL	-20 107	-113 319	107 930	-14 717	91 936	-16.01
NO1	13 220	24 252	-9 669	-1 364	42 990	-3.17
NO2	-26 726	24 783	-41 877	-9 632	137 877	-6.99
NO3	-865	32	-31	-867	30 284	-2.86
NO4	-9	26	-43	7	2 171	0.36
NO5	-11 182	9 837	-19 892	-1 127	12 627	-8.93
SE1	-965	8	2	-976	56 123	-1.74
SE2	-9 182	-3	-43	-9 136	249 412	-3.66
SE3	-502	30 437	-24 480	-6 458	306 911	-2.10
SE4	9 104	6 197	-3 131	6 039	66 398	9.09

Table A0.4: Mean Changes in Social Surplus When Disconnecting the NorNed Interconnector (Scenario 3). Values are in €/hr.

Zones	Change SS	Change CS	Change PS	Change CR	Base CR	% CR
BE	11 110	-32 312	32 574	10 847	78 964	13.74
DE	-55 973	-296 149	248 601	-8 424	207 196	-4.07
DK1	26 075	-11 534	4 311	33 297	81 967	40.62
DK2	4 202	-10 044	3 873	10 373	37 303	27.81
FI	4 065	34 618	-27 802	-2 749	61 278	-4.49
FR	-10 646	-83 249	60 634	11 968	141 494	8.46
GB	-99 582	-167 477	81 356	-13 461	12 0743	-11.15
NL	4 911	-14 7699	15 0708	19 02	91 936	2.07
NO1	34 512	60 949	-23 842	-2 594	42 990	-6.04
NO2	-13 1572	61 665	-101 341	-91 896	137 876	-66.65
NO3	-2 025	67	-20.49	-2 072	30 284	-6.84
NO4	5	91	-137	51	2 170	2.39
NO5	-25 202	25 628	-48 788	-2 043	12 627	-16.18
SE1	-2 994	2	83	-3 081	56 123	-5.49
SE2	-29 257	-44	-111	-29 101	249 411	-11.67
SE3	-1 426	94 628	-75 695	-20 359	306 911	-6.63
SE4	29 381	19 096	-10 780	21 066	66 397	31.73

Table A0.5: Mean Changes in Social Surplus in a Full NEXIT (Scenario 4). Values are in €/hr.

Zones	Price Base	-10%WV	-20%WV	-30%WV
BE	206.51	0.00	-0.02	-0.07
DE	177.36	-0.17	-0.51	-1.14
DK1	163.26	-1.26	-2.85	-4.91
DK2	152.61	-0.97	-2.19	-3.75
FI	89.41	-1.84	-3.81	-6.11
FR	235.63	0.01	0.01	0.01
GB	241.06	0.00	0.00	0.00
NL	206.81	0.13	0.11	0.08
NO1	144.24	-8.05	-16.64	-25.31
NO2	144.24	-8.17	-16.75	-25.39
NO3	17.40	-0.33	-0.52	-0.61
NO4	16.11	-0.10	-0.15	-0.16
NO5	143.66	-7.96	-16.60	-25.31
SE1	21.94	-0.46	-0.82	-1.12
SE2	21.94	-0.46	-0.82	-1.12
SE3	95.11	-3.95	-8.56	-13.90
SE4	105.78	-2.53	-5.62	-9.31

Table A0.6: Post NEXIT Water Value Change (Values are in per cent Change of Price Base.

Zones	Price Base	Δ NXT -10%WV	Δ NXT -20%WV	Δ NXT -30%WV
BE	206.51	5.85	5.92	6.05
DE	177.36	7.25	7.76	8.22
DK1	163.26	3.43	3.89	4.24
DK2	152.61	5.14	5.39	5.62
FI	89.41	-5.97	-6.22	-6.78
FR	235.63	3.35	3.35	3.37
GB	241.06	12.05	12.10	12.18
NL	206.81	13.69	14.01	14.42
NO1	144.24	-9.65	-9.72	-9.91
NO2	144.24	-9.78	-9.88	-10.05
NO3	17.40	-0.19	-0.17	-0.18
NO4	16.11	-0.30	-0.29	-0.30
NO5	143.66	-9.41	-9.46	-9.69
SE1	21.94	-0.04	-0.02	-0.00
SE2	21.94	-0.04	-0.02	-0.00
SE3	95.11	-11.76	-12.01	-12.50
SE4	105.78	-7.98	-8.04	-8.16

Table A0.7: NEXIT Effect Post Water Value Change. (Values are in per cent Change of Price Base)