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Effects of Uncoupling the North Sea Link

An empirical analysis of risks and premiums in the two day-ahead auctions in bidding area NO2

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Abstract

In this thesis, we study the impact of the current auction solution on the North Sea Link (NSL), an interconnector between the electricity systems of Great Britain (GB) and Southern Norway (NO2). Due to Brexit, interconnector capacity is allocated through an implicit day-ahead auction, which closes before the regular NO2 (SDAC) auction. Consequently, traders in NO2 can decide to participate in two consecutive auctions.

To address this decision problem, we develop a forecast model to predict day-ahead NO2 (SDAC) prices. Using these forecasts, we approximate the premium that the marginal trader requires to take positions in the first auction (NSL). Contrary to initial expectations, we find that traders are, on average, pricing in a positive premium in the NSL auction. This results in a systematic difference between the NO2 and NSL prices.

We further examine the drivers behind the premium to determine when and why it arises. Our findings indicate that when traders have less confidence in their NO2 price forecasts, they demand a larger premium for trading with the NSL. On average, the marginal trader in our model requires a €0.22/MWh higher premium for each incremental increase in the prediction interval of the point forecast. In an efficient market with risk-neutral traders, such premiums would not exist as the traders would increasingly take advantage of the arbitrage opportunity. Therefore, we argue that traders in the NSL auction are risk-averse.

The risk premium comes with a commercial cost for the interconnector owners. We find that Statnett has lost €27 million in congestion revenues since the opening of the NSL on the 1st of October 2021 to the 15th of January 2023. This amounts to approximately 10% of the total congestion revenues accumulated during the period.

Overall, we find that the implicit auction solution on the NSL leads to a redistribution of socio-economic welfare from the interconnector owners to the traders in the form of a systematic risk premium. We argue that this finding should be acknowledged in future research on the socio-economic welfare gains from the NSL and in future projects considering the use of an implicit auction to connect uncoupled markets.

Keywords – North Sea Link, Integrated electricity markets, Interconnector, Day-ahead market, Implicit auction, Forecasting, Risk premium, Congestion revenues

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List of Abbreviations

ARIMA Autoregressive Integrated Moving Average
ARX Autoregressive Models with Exogenous Variables
BEIS Department of Business, Energy and Industrial Strategy
CACAM Capacity Allocation and Congestion Management
CACM Capacity Allocation and Congestion Management Regulation
CCU Commercial Cost of Uncoupling
CET Central European Time
CR Congestion revenue
DA Day ahead
DAM Day Ahead Market
EU European Union
EUPHEMIA Pan-European Hybrid Electricity Market Integration Algorithm
GB Great Britain
GMT Greenwich Mean Time
GW Gigawatt
HVDC High Voltage Direct Current
IEM Internal Energy Market
MAE Mean Absolute Error
MAPE Mean Absolute Percentage Error
MC Market Coupling
MW Megawatt
MWh Megawatt-hour
NEMO Nominated Electricity Market Operator
NO2 Norwegian price area NO2
NSL North Sea Link
NVE The Norwegian Water Resources and Energy Directorate
PCR Price Coupling of Regions
PX Power exchange
RME Norwegian Energy Regulator
RMSE Root Mean Squared Error
RSI Residual Supply Index
SDAC Single Day-Ahead Coupling
SLR Simple Linear Regression
SN Seasonally Naïve Forecasting Method
TSO Transmission System Operator
TWh Terrawatt-Hour

1 Introduction

Electricity has been crucial in the development of modern society and is today a necessity for both households and industry. In the transition towards a low-carbon energy system, increased cross-border transmission capacity is seen as a pivotal factor in enabling closer integration of electricity markets. Expected benefits from further market integration include improved competition and socio-economic welfare, as well as more efficient electricity generation and increased security of supply. This becomes even more important as the share of intermittent renewable energy production increases.

Following the process of deregulating European electricity markets in the 1990s, considerable developments have been seen in the markets over the past decades. In 2015, the European Union (EU) implemented the Energy Union to achieve a secure, sustainable and competitive energy system through a fully integrated European electricity market (Energy Facts Norway, 2019b). In the years following, Norway has become even more integrated with European electricity markets with the introduction of two new interconnectors, NordLink (2020) and North Sea Link (2021), linking Norway to Germany and Great Britain (GB), respectively.

Trading on both interconnectors was originally planned to happen under the European Internal Energy Market (IEM) arrangements. Through the Single Day Ahead Coupling (SDAC), all members of the integrated market submit their bids and offers to the EUPHEMIA EU-wide Day Ahead Market (DAM) auction platform. The EUPHEMIA algorithm then finds the optimal solution of generation and consumption that maximises the socio-economic welfare, subject to potential constraints in transmission capacity. However, following UK's decision to leave the EU, the British electricity market is no longer a part of the European market coupling. Consequently, a separate auction on the NSL was organised to connect the bidding areas NO2 and GB by implicitly allocating the available transmission capacity.

Market players in NO2 are currently in a situation where they can trade electricity in two auctions: the regular NO2-SDAC (NO2) auction and the separate NO2-N2EX (NSL) auction. The two auctions, NSL and NO2, are operated by Nord Pool and close at 10:50 and 12:00, respectively. Due to the time lag of the auctions, traders are forced to forecast the NO2 price before submitting bids into the NSL auction to prevent losses. According to Statnett (2021a), there should, over time, be no systematic price difference between the two auctions, and traders should be indifferent between trading electricity in the NSL auction or in the NO2 auction. However, significant price differences between the auctions can be observed, and an empirical analysis could give valuable insight into the trading efficiency on the NSL.

The thesis aims to answer the following research questions:

> *To what extent do traders in NO2 require a premium for participating in the NSL auction? Why does this premium arise, and what are the socio-economic consequences?*

The thesis quantitatively estimates the impact of the current trading arrangement on the trading efficiency and the costs and revenues of the owners and traders. To address the decision problem market players in NO2 face by taking positions in each market separately, we develop a forecasting model to predict the day-ahead NO2 prices ahead of the NSL auction closing. Using the forecasted prices, we calculate the premium marginal traders require to participate in the NSL auction. Further, potential drivers behind the premium are examined to understand when and why it arises. Lastly, we calculate the commercial cost of a separate auction for the NSL.

With this thesis, we provide the first academic research on the effects of the implicit auction solution on the North Sea Link. The interconnector has been in operation for a year and a half, and while there are studies on the projected implications of the separate auction, little has been done on the historical effects. Studying the impact of uncoupled interconnector trade is relevant for several reasons. Firstly, engaging with key stakeholders revealed ongoing debates regarding the effects of this auction. Secondly, most studies have been done on the implications of coupled interconnectors, such as NordLink, leaving a scarcity of literature on decoupled interconnector trade. Moreover, the socio-economic benefits derived from integrated electricity markets are crucial drivers for further integration. Therefore, it is interesting to study how the separate trading solution affects the distribution of socio-economic welfare.

In total, this thesis aims to shed light on the mechanisms and consequences of the separate auction solution, addressing the research gap and enhancing our understanding of the interconnector's functioning in the energy market.

The remainder of the thesis is structured as follows. Chapter 2 outlines the electricity market structure in Norway and GB. Chapter 3 reviews relevant literature, while Chapter 4 outlines the theoretical framework relevant to the thesis. Chapter 5 describes the methodology used to answer the research questions. Chapter 6 presents the data used to forecast electricity prices and includes a description of the price data and the variables included in the analysis. Chapter 7 presents the results and discussion before conclusive remarks are given in Chapter 8.

2 Background

2.1 The Electricity Market

The electricity market is an important tool to facilitate a cost-efficient delivery of electricity from producer to end user (Energy Facts Norway, 2022). When production is located far from consumption, the electricity grid enables the transmission of power produced over long distances and even across borders. The electricity grid is consequently a central part of securing the electricity supply and can be divided into two types of networks. The transmission network carries electricity at high voltages over long distances. It is a nationwide system connecting different regions and countries. Further, the distribution network runs at lower voltage levels and connects households, businesses and industry to the electricity grid.

The Norwegian electricity market has been connected to Europe since the 1960s and is today part of an integrated Nordic and European power market. Following the deregulation of European electricity markets in the 1990s, the market organization went from vertically integrated monopolies to market-based competition for the production and exchange of electricity. This deregulation ensured effective use of resources and reasonable electricity prices (Energy Facts Norway, 2022).

The integration of the electricity systems has been important to secure flexibility in the electricity market. Electricity differs from other traded goods as it cannot be stored easily. This entails equal generation and consumption at all times and is referred to as the instantaneous balance. Increased integration allows regions to import power when their production is low and to export power when production exceeds domestic demand. The characteristics of different countries' generation mixes vary, and further integration and market coupling will thus make it easier to secure efficient delivery of electricity (Norsk Klimastiftelse, 2023). As the share of intermittent renewable energy sources in the generation mix increases, this becomes increasingly more important.

In the following sections, an introduction to the Norwegian and British electricity markets and the interconnection between the two markets will be given. Further, a description of the Nord Pool power exchange will be presented. Lastly, the implications of Brexit and

Great Britain's decoupling from the European electricity market are discussed.

2.1.1 The Norwegian Market

The Norwegian electricity market was deregulated in 1991 through the Norwegian Energy Act (NVE, 2021). An important principle of the deregulation was the distinction between operations suitable for competition and monopoly operations. While production and exchange of electricity is market-based, transmission and distribution are strictly regulated as natural monopolies. With the deregulation, the goal was to avoid overproduction and high electricity prices (Norsk Klimastiftelse, 2023).

In 2022, the total electricity consumption amounted to 126 TWh, representing a decrease from 140 TWh in 2021 (Elhub, 2023). Elhub points to the record high electricity prices, specifically in Southern Norway, as an explanation behind the decrease in consumption. According to Statnett (2023a), future energy consumption is, however, expected to increase to a total of 220 TWh by 2050. Important drivers for the increased consumption is the electrification of transportation, petroleum installations and new industry (NVE, 2021). Changes in both the production capacity and the electricity grid will be necessary to meet this increased demand.

According to Elhub (2023), the electricity production also experienced a decrease in 2022, where total production went from 157 TWh in 2021 to 146 TWh in 2022. Even though production from both solar and wind were record high, lower production from hydropower gave a net decrease in total electricity supply. In their projections of future electricity production, The Norwegian Water Resources and Energy Directorate (NVE) estimates that the annual generation will increase to a total of 185 TWh by 2040 (NVE, 2021). This increase will come from new installation of both offshore and onshore wind, solar plants and increased hydropower production. However, due to the extensive licensing process for such projects, large increases in new power production is not expected until after 2030. According to Statnett's long-term market analysis, Norway might face a power deficit already in 2027, leaving Norway more dependent on import capacity to secure the energy balance (Statnett, 2023a).

A special feature of the Norwegian power supply system is the dominant share of hydropower, making the resource base for production highly dependent on the precipitation each year (Energy Facts Norway, 2021). An overview of the Norwegian generation mix can be found in Table 2.1. In 2022, hydropower accounted for 88.2% of the total Norwegian power production (Elhub, 2023). With the high storage capacity of hydropower, more than 75% of the total Norwegian production capacity is considered flexible (Energy Facts Norway, 2021). This implies that production rapidly can be increased or reduced as needed, at a low cost. The power system's flexibility to secure balance between production and consumption is especially important as the share of intermittent production increases. Over the past decades, the share of both wind and solar has increased, with a total installed capacity of 4 700 MW for wind and 299 MW for solar at the end of 2022 (NVE, 2022b, 2023). In addition, Norway also has a limited share of thermal power generation with an installed capacity of 640 MW (NVE, 2022c).

Production type	**Share**
Hydropower	88.2 %
Wind	10.2 %
Thermal power	1.6 %

Table 2.1: Generation mix in Norway in 2022 (Elhub, 2023)

The state-owned company Statnett is the designated transmission system operator (TSO) and owns most of the transmission grid in Norway (Energy Facts Norway, 2019a). Statnett is responsible for maintaining the instantaneous balance in the electricity system and ensuring satisfactory quality of supply. The income of Statnett is regulated through an income cap decided by the Norwegian Energy Regulator (RME) each year (Statnett, 2022c). If the revenues from grid tariffs and congestion revenues exceed the income cap, the additional revenue must be passed on to the electricity consumers through reduced grid tariffs.

As of 2022, Norway has a total of 19 cross-border lines[1], where seven of these are high-voltage direct current (HVDC) interconnectors. The total capacity of the HVDC interconnectors is 9 000 MW, and they connect the Norwegian electricity market to Denmark, Germany, the Netherlands and GB (Innst. 220 S, 2020). The level of import and export changes between seasons and is highly weather dependent, with the water inflow to the reservoirs being the main factor. Historically Norway has been a net exporter.

[1]A map of the interconnectors is found in Appendix A1.1

2.1.2 The British Market

The process of deregulating the British electricity market started with the Electricity Act of 1989, with the first privatizations happening in 1990 (Green, 2006). The goal was to implement a free-market policy to stimulate competition within generation, transmission, distribution and retail (Liu et al., 2022). A fundamental part of the deregulation was the separation of activities along the supply chain. Prior to the deregulation all activities of the power market were controlled by state-owned monopolies in Scotland, England and Wales. Since 2005 the electricity systems of England, Wales and Scotland have been integrated under the British Electricity Trading and Transmission Arrangements (BETTA) (Hagfors et al., 2016). Today the number of producers, distributors, and retailers is significantly higher, securing a more diversified system of power supply.

Following the deregulation, the Office of Gas and Electricity Markets (OFGEM) was established as the independent energy regulator on behalf of the government. Its goal is to protect the interest of consumers by promoting competition where appropriate. Further, it issues licenses for companies to carry out activities in the electricity sector, sets a cap on potential return for the monopoly transmission company and decides on changes to the market rules (Energy UK, nd).

In 2021, total demand in the British electricity market was 334 TWh, representing an increase of 1.2% from 2020. According to the Department of Business, Energy and Industrial Strategy (BEIS), the increase primarily was a result of the response to the Covid-19 pandemic, where the restrictions on businesses and industry had a smaller effect in 2021 (BEIS, 2022a). In 2022, BEIS published a report with energy and emission projections for GB between 2021 and 2040. In the reference scenario, they estimated total electricity demand in 2040 to be 399 TWh (BEIS, 2022).

Total production in 2021 amounted to 309 TWh, which was a record low according to BEIS (2022a). Even though the demand for electricity increased in 2021, this was met by increased levels of import and not domestic generation. In the reference scenario of the energy and emission projections, BEIS predicts that total electricity production will be 390 TWh by 2040 (BEIS, 2022).

An overview of the British power supply system can be found in Table 2.2. GB's power generation is characterized by a high share of thermal power, with natural gas being the main source of electricity accounting for 38.5% of the total production in 2022. In line with GB's goal to reach net zero by 2050, the share of renewable energy is increasing and 2020 marked the first year where electricity predominantly came from renewable energy sources. When looking at onshore and offshore wind combined, wind power makes up the largest share of renewable energy with a total installed capacity of 25.5 GW at the end of 2022 (RenewableUK, 2022). In 2022, GB also experienced the first time with over 20 GWh of wind production in a day, accounting for 70% of the electricity generated that day (National Grid ESO, 2023).

Production type	**Share**
Gas	38.5 %
Wind	26.8 %
Nuclear	15.5 %
Biomass	5.2 %
Coal	1.5 %
Solar	4.4 %
Imports (mixed source)	5.5 %
Hydropower	1.8 %
Energy storage	0.9 %

Table 2.2: Generation mix in GB in 2022 (George, 2023)

The British transmission grid is operated by the National Grid. Similar to Statnett, National Grid is responsible for balancing the system and ensuring that generation always meets demand. As of 2022, GB has eight HVDC interconnectors with a total capacity of 8.4 GW. They connect the British electricity market with France, Belgium, the Netherlands, Norway and the Republic of Ireland (BEIS, 2022b). The interconnectors help balancing the grid and as the share of intermittent renewable energy sources increases they become an increasingly more important component of GB's electricity system. Historically, GB has been a net importer of power, however, in 2022 GB was a net exporter of energy for the first time in many years (Day et al., 2023). Towards 2030, the British Government has set an ambition of 18 GW in total interconnector capacity (BEIS, 2022b). The new interconnectors will connect GB to Germany and Denmark.

2.1.3 Interconnector Capacity Between Norway and GB

With the commitment to reduce carbon emissions by 55% by 2030 and the goal of Net Zero by 2050, Norway and other European countries are implementing ambitious actions to become more climate neutral (The European Council, 2023). The interconnection of electricity markets is essential in establishing a single European market, where increased transmission capacity between regions gives more transmission-level flexibility and thus improves resource utilization.

The NordLink and the North Sea Link cables were launched in December 2020 and October 2021, connecting the Norwegian power market to Germany and GB. Statnett argues that increased interconnection will improve the security of supply and better facilitate the integration of renewable energy across regions (Statnett, 2021b). For this thesis, the trading arrangement on the NSL is the topic of interest and the following section will, therefore, only focus on the NSL.

The North Sea Link is a subsea interconnector linking the Norwegian and British electricity markets directly for the first time. With a total length of 720 kilometres, it is the world's longest subsea interconnector, stretching from NO2 in Norway to the Newcastle area in GB (North Sea Link, nd). The construction of the NSL had a total cost of €1.6 billion, and Statnett and the British National Grid own 50 percent of the cable each (Statnett, 2021c). The NSL interconnector consists of two parallel HVDC cables and has a total capacity of 1 400 MW. Trial operation on the cable started on the 1st of October 2021, with regular operation starting one year after.

The different but complementary electricity systems have been central in rationalizing the coupling of the Norwegian and British electricity markets. With Norway's high share of flexible hydropower and GB's growing share of intermittent renewable energy from wind, the interconnection will give greater security of supply for both countries. In situations with high wind power production in GB, Norway can import the excess power at a price lower than the one in the Norwegian market and therefore conserve the water in the hydropower reservoirs. In situations with little wind and greater demand in GB, the situation is the other way around. GB can then import hydropower from Norway at a lower price and, through this, secure the supply of power. With the transition towards more intermittent renewable energy, Statnett argues that the interlinked markets will give more predictable supply situations and prices, both throughout the year and from year to year (Statnett, nd). Lastly, integration is argued to create a greater market for power producers when there is a surplus of power in the domestic market.

2.2 The Nord Pool Power Exchange

Nord Pool is a pan-European power exchange (PX) that serves as the common marketplace for electricity trade in both the day-ahead market, Elspot, and the intraday market, XBID. Nord Pool operates in the Nordic and Baltic regions, Germany, Poland, France, the Netherlands, Belgium, Austria, Luxembourg, and GB, making it one of the leading power exchanges in Europe.

Nord Pool was established in 1993 following the Norwegian parliament's decision to deregulate the market for trading of electrical energy. With the integration of Sweden in 1996, it became the world's first multinational exchange for electricity (Wangensteen, 2012). As Finland and Denmark joined in respectively 1998 and 2000, the creation of a fully integrated Nordic marketplace was complete. Estonia, Latvia and Lithuania later deregulated their power markets and joined the Nord Pool market between 2010 and 2013.

In January 2010, Nord Pool and Nasdaq OMX Commodities launched the GB market N2EX aiming to establish a liquid and transparent British power market. Four years later, in 2014, Nord Pool took sole ownership of the N2EX and the responsibilities for the short-term physical market. As a result, Nord Pool now operates the largest exchange for power in both the Nordic region, Baltic region and GB (Nord Pool, 2014).

In 2021, a total volume of 963 TWh of power was traded with Nord Pool. That included trading in the Nordic and Baltic day-ahead markets of 722 TWh. GB day-ahead achieved 147 TWh traded. Meanwhile, Nord Pool achieved a total of 68 TWh of power traded in the remaining European day-ahead markets (Nord Pool, 2021).

2.2.1 The Day-Ahead Market

The majority of volume traded at Nord Pool is settled in the day-ahead market Elspot. In 2021, day-ahead markets accounted for 97% of the volume traded at Nord Pool, with 75% occurring in the Nordic and Baltic regions (Nord Pool, 2021). The day-ahead market follows a uniform price periodic double auction, as the buyers and sellers submit their bids in a closed auction the day before delivery for each hour the following day. After the publication of available capacities and interconnectors in the grid at 10:00 CET, market participants submit their orders specifying the volumes they are willing to buy and sell at given price levels until the deadline at 12:00 CET. After the deadline, submitted orders are matched through the EUPHEMIA algorithm, which constructs the aggregated supply and demand for a particular area. The area prices are then calculated for all 24 hours in the upcoming day and are announced at 12:45 CET.

Trading in the day-ahead market is based on four different order types where customers can either use one or construct a combination of all order types to meet their requirements. The largest share of day-ahead trading is matched based on single hourly orders. In this case, the participant specifies the sales and/or purchase volume for each hour in a day which could both be price dependent or price independent. Alternatively, market participants can submit block orders with a specified volume and price for a certain number of consecutive hours on the same day. Regular block orders have an "all-or-nothing" condition such that they must be entirely accepted or rejected and are particularly useful for power stations or energy-intensive consumers wishing to minimize start-up costs. Furthermore, block bids can also be submitted in clusters, out of which only one block can be activated, called an exclusive group. Finally, one can submit flexible orders, which are bids that may be accepted in an hour, given that price conditions are met (Nord Pool, ndc).

2.2.2 The Intraday Market

Market participants can adjust their balance closer to real-time in the intraday market (XBID). XBID enables trading around the clock every day of the year, covering individual hours up to one hour before delivery, thereby securing the necessary balance between supply and demand. In total, 3% of the volume traded at Nord Pool is traded at the intraday market, but this share is expected to grow with the increasing intermittent renewable production (Nord Pool, 2021).

The results from the day-ahead market are used as a baseline for planning the next 24-hour period, with additional changes realized in XBID or TSO's balancing power markets. Balancing power markets regulate production or consumption to maintain balance when the market experiences disturbances within a specific hour of operation.

2.2.3 Bidding Areas

Most European countries, including GB, operate with a single bidding area corresponding to national borders. Transmission constraints are therefore not reflected in the electricity price, and the wholesale price of electricity clears as a uniform price across the entire geographical area of the market (National Grid ESO, nd). For each trading period, a single price is provided for both demand and supply, regardless of their location in the network.

For the Nordic countries, the market is, however, divided into multiple bidding areas to better handle regional market conditions (Nord Pool, ndb). The Nordic bidding areas are shown in the map in Figure 2.1. The Norwegian power market currently operates with five price areas decided by Statnett: NO1 (Oslo), NO2 (Kristiansand), NO3 (Trondheim), NO4 (Tromsø), and NO5 (Bergen). In situations where the capacity of at least one transmission line is binding, it will restrict the power flow between areas (Boury, 2015). When these capacity constraints are taken into consideration, this will give different area prices between the bidding areas, as seen in Figure 2.1. Through the EUPHEMIA algorithm, the electricity price of each bidding area is calculated for each hour of the following day.

The organization of bidding areas is done by the relevant TSO and is based on the expectations of long-lasting capacity limitations in the electricity grid (NVE, 2022a). In the market coupling process, price areas can be defined on each side of a bottleneck, and each area will consequently have its own supply and demand curve. To best capture regional market conditions, these areas can be changed and adjusted over time.

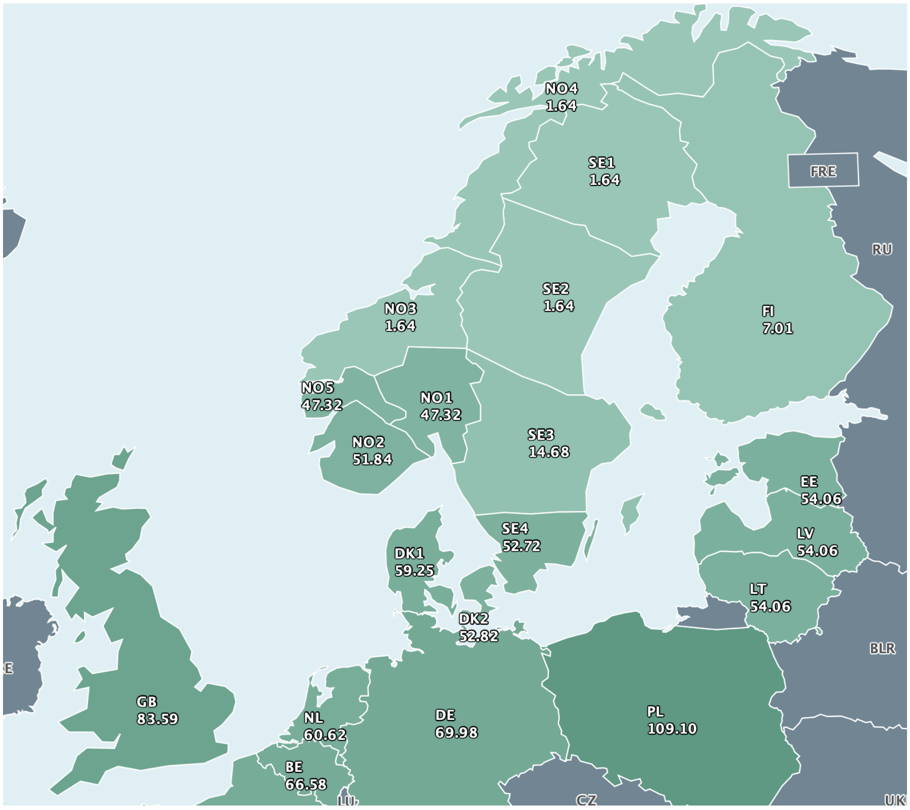


Figure 2.1: Bidding areas and corresponding area prices in Norway and GB (26th of May 2023) (Nord Pool, 2023)

2.2.4 European Market Integration

The EU has been a driving force behind the development of market coupling in Europe. In 2011 the European Council set a clear deadline for the completion of an internal energy market by 2014, underlining that no EU Member State should remain isolated from the European gas and electricity networks after 2015. The European Internal Energy Market (IEM) aims to create a single, integrated energy market across the EU member states, covering both day-ahead (SDAC) and intraday (SDIC) trade. The IEM is based on the principles of free movement of energy, non-discrimination, and transparency, and it aims to ensure that energy can flow freely across borders without any obstacles or restrictions. The IEM covers electricity, gas, and oil and is regulated by a range of EU legislation and directives (General Secretariat of the European Council, 2011).

The IEM has brought significant benefits to the EU energy sector, including increased competition and security of supply (European Parliament, 2022). One of the key developments within this framework has been the creation of the Price Coupling of Regions (PCR) project (NEMO Committee, 2020).

2.2.5 PCR EUPHEMIA

The PCR project aims to create a single European day-ahead market for electricity trading (SDAC). The project currently involves eight power exchanges (PXs), including EPEX SPOT, GME, HEnEx, Nord Pool, OMIE, OPCOM, OTE and TGE, and it is open to other European Power Exchanges wishing to join. By integrating these PXs, PCR is used to couple the following European countries: Austria, Belgium, Czech Republic, Croatia, Denmark, Estonia, Finland, France, Germany, Hungary, Italy, Ireland, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain and Sweden, i.e., about 75% of European power consumption (NEMO Committee, 2020). We display a map of the SDAC member countries in Figure 2.2.

Figure 2.2: SDAC member countries (Madani, 2021)

One of the key achievements of the PCR project is the development of a single price coupling algorithm called EUPHEMIA (acronym of Pan- European Hybrid Electricity Market Integration Algorithm). Since February 2014, EUPHEMIA has been progressively used to calculate energy allocation and electricity prices across Europe, maximizing the overall welfare and increasing the transparency of the computation of prices and flows (NEMO Committee, 2020).

First, the PXs collect all the orders and submit them to EUPHEMIA. The algorithm then has to determine which orders are to be executed and which orders are to be rejected such that the overall welfare (consumer surplus + producer surplus + congestion rent across the regions) is maximized. Further, it secures that the power flows induced by the executed orders do not exceed the capacity of the relevant network elements (NEMO Committee, 2020). Market coupling of the day-ahead market (SDAC) is regulated through the Capacity Allocation and Congestion Management (CACM) rules. The CACM regulation aims to provide maximum cross-border capacity within the operational security limits and includes rules on capacity calculation, allocation and management (DNV, 2019).

2.3 Decoupling the British Market

UK's decision to leave the EU in the referendum in 2016 had significant implications for various aspects of its economy, including its energy sector. The energy sector was one of the areas most affected by Brexit, as the British energy policy was closely linked to the EU's energy policy through the IEM.

Brexit led to GB's departure from the IEM and the SDAC on the 1st of January 2021. This posed many challenges for the British electricity market. Before Brexit, the European Power Exchange SE (EPEX) and Nord Pool AS were designated by The Gas and Electricity Markets Authority as Nominated Electricity Market Operators (NEMOs). The electricity prices were determined through the EU market coupling regime for EPEX and Nord Pool's respective GB Day-Ahead markets. However, following Brexit, EPEX and Nord Pool are now operating fully separated day-ahead markets, settling and clearing at different and independent prices at different times (UK Government, 2021). Today, the Nord Pool platform has the largest market share in GB, accounting for around 70% of the exchange-traded day-ahead volumes with larger and more well-established participants (Nord Pool, 2020b). EPEX has about a third of the trading volume, and the participants tend to be small traders and asset providers (Reierson and Morison, 2021).

The IEM facilitated the free movement of electricity and allowed GB to trade electricity seamlessly with other EU countries. Before UK's decision to leave the EU, it was agreed that trade on the NSL would be a part of the European market coupling. However, with Brexit, a separate auction solution had to be designed to ensure efficient cross-border trade with neighbouring countries still a part of the IEM.

2.3.1 The North Sea Link Auction Design

The separate trading solution for the NSL had to be designed in such a way that compliance with the CACM rules was not jeopardized. Only implicit or explicit auctions with automatic nominations could make the auction results compliant with ramping constraints (DNV, 2019). In an auction with automatic nomination, accepted bids would be physically binding for both the TSOs and the market participants.

An explicit NSL auction would mean an auction for the transmission capacity on the interconnector itself. This is the current auction design on the other uncoupled GB interconnectors (IFA1, IFA2, Nemo Link, BritNed). With an explicit auction, cross-border trade between NO2 and GB could only be performed by market participants that acquired cross-border capacity on the NSL. Moreover, an explicit NSL auction would only be open for market players who could arrange balance responsibility in both NO2 and GB (DNV, 2019). Due to these disadvantages, an explicit auction was not chosen as a trading arrangement. Instead, Statnett and National Grid chose an implicit auction to manage trade on the NSL (Statnett, 2021a).

An implicit auction means a separate day-ahead auction between NO2 and GB, illustrated by "NSL" in Figure 2.3. This auction is independent of the EUPHEMIA price calculation for NO2 and the rest of SDAC. Participants deliver bids and offers for every hour on the Norwegian and British sides of the interconnection, respectively. These are then coupled over available capacity on the NSL with an algorithm similar to EUPHEMIA. Consequently, there are two prices in NO2; one NO2 price in the regular NO2(SDAC) auction and one in the separate NSL auction. An implicit auction results in a more leveled playing field for smaller market players in NO2 in competition for export and import possibilities as they only need to arrange balance responsibility in NO2. On the British side, NSL is integrated into Nord Pool's British spot auction. (DNV, 2019).

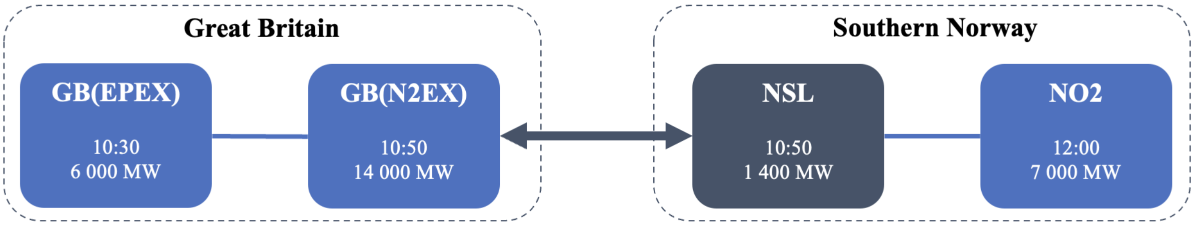


Figure 2.3: The implicit NSL auction setup with respect to closing time and hourly volume traded

With the chosen implicit auction, Nord Pool (2020a) has argued that there are good chances of developing a well-functioning market. However, the overall market efficiency in the NSL auction would depend on two factors: (i) sufficient liquidity in the NSL auction and (ii) active trading patterns by the market participants in both the NSL and NO2 auctions.

2.3.2 Auction Timing

To accommodate the decoupling from IEM, EPEX Spot's Day-Ahead auction was moved up from 12:00 GMT to 10:20 CET – allowing market participants to quickly react to the results of the daily interconnector explicit capacity auctions. The timing of the N2EX Day Ahead auction aligns with the NSL auction, closing half an hour later, at 10:50 CET. For market participants, this means that only the results from explicit auctions on the other GB interconnectors and the EPEX GB day-ahead clearing are available at the closing of the NSL auction. With this auction timing, the participants know their NSL positions before bids are given to SDAC. Participants in the NSL are therefore forced to forecast the NO2 price to prevent submitting unprofitable bids on the NSL auction. Moreover, if the forecasted prices in NO2 are lower than in GB, the participants will place sell bids on the NSL auction. Opposite, the participant will place buy bids when the forecasted prices in GB are lower than in NO2.

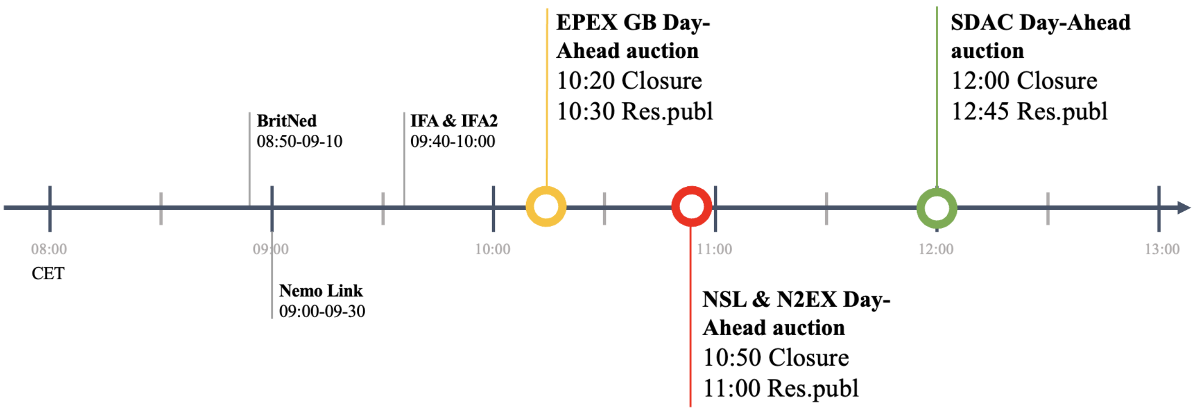


Figure 2.4: Auction timeline for the Norwegian and British electricity markets

2.3.3 Access Rules and Participants

Currently, the auction is only available to market participants with a trading license at Nord Pool. EPEX Spot has long been dissatisfied with the fact that Nord Pool has an exclusive license for organising trade on the NSL and has lodged complaints about the set-up to the Norwegian authorities and the Efta Surveillance Authority (ESA). The Norwegian Energy Regulator (RME) is now considering shared order books on the 1.4 GW capacity. Such a solution is, however, unlikely to be implemented before 2026 (Mollestad, 2023).

To become a Nord Pool customer, the applicant must (i) be financially sound, (ii) have registered with a VAT register, and (iii) hold a balancing agreement with the TSO in the requested bidding area. The last point induces that the player must have balance responsibility themselves or have an agreement with a balance responsible who handles the actor's imbalance against the TSO (Nord Pool, nda). This means that also players without production in NO2 can trade on the NSL as long as they have a balancing agreement in NO2 and are able to cover their obligations through trade. As Nord Pool accepts customers from all jurisdictions, there should be low barriers to participate in the NSL auction.

Today, there are around 15 different players participating in the NSL auction. Since individual bid information is concealed by Nord Pool, it is difficult to determine exactly who these players are. However, we can divide them into three groups: producers, consumers and financial traders.

Firstly, the producers include companies with electricity generation in NO2. For them, the NSL auction simply offers an alternative trading venue to the SDAC auction. The largest producers are Statkraft and Å Energi. DNV argues that there could be at least two different motivations for determining which venue a producer would use (DNV, 2019). In case of inconsistent prices between the NSL auction and the NO2 auction, they could seek profits from exploiting these price differences by selling in the auction with the highest price and thus gaining higher profits. Further, they could be splitting their bids between the NO2 and NSL auctions in order to reduce the risk of inaccurate price forecasts.

Secondly, the consumers include retailers and energy-intensive companies that are using the NSL as an alternative trading venue. Similar to the producers, the NSL auction only represents a way to secure better electricity prices.

Lastly, the financial traders include both domestic and foreign companies with and without physical production in NO2. Examples of such companies are Axpo from Switzerland and Centrica Energy Trading from GB. These companies still need a balancing agreement in NO2 to participate on the NSL auction. However, instead of having their own production in NO2, many of them operate as the balancing responsible for smaller power generators located in the price area. Most of the financial traders participate in the NSL auction to exploit any price differences based on advanced forecasting methods and trading strategies.

2.3.4 Market Power Potential

Even though there are low barriers to entering the market, there is a risk of price impacts because of market power exertion in NO2 (DNV, 2019). The hydropower production in NO2 is 47 TWh in a normal year, which equals 35% of total Norwegian hydropower production. NO2 thus has the biggest production of the five Norwegian bidding zones and is the biggest flexibility provider. In total, there are more than 200 owners of hydropower production in NO2, but ownership is highly concentrated as illustrated in Table 2.3 (if partnerships are divided among the owners and consolidated companies are attributed to the parent company).

If NO2 was an isolated market, it would be considered a market with poor competition. However, the competition in NO2 is enhanced by interconnectors to NO1, NO5, NL, DK1, DE and GB. Figure 2.5 from Nord Pool illustrates the actual cross-border interconnection

Company or group	Share of normal production
Statkraft	45.7 %
Å Energi	15.8 %
Hydro	13.9 %
Lyse	13.8 %
Sunnhordaland Kraftlag	4.1 %
More than 200 other owners	6.7 %

Table 2.3: Market shares of production capacity in NO2 (DNV, 2019)

capacity (in MW) to the Nordic and European bidding zones in hour 11 on the 11th of April 2023. The actual power flow, which is the achievable transfer capacity at a specific time, can differ from the nominal capacity, which is the optimal capacity for a specific interconnector. The capacity on the interconnector is decided by the TSOs on each side of the cable, and as seen in Figure 2.5, the capacity for the different directions on the same interconnector can differ. However, to ensure optimal utilization of an interconnector a good balance between capacity for import and export is important, and the TSOs often work closely together when setting the capacity in both directions.

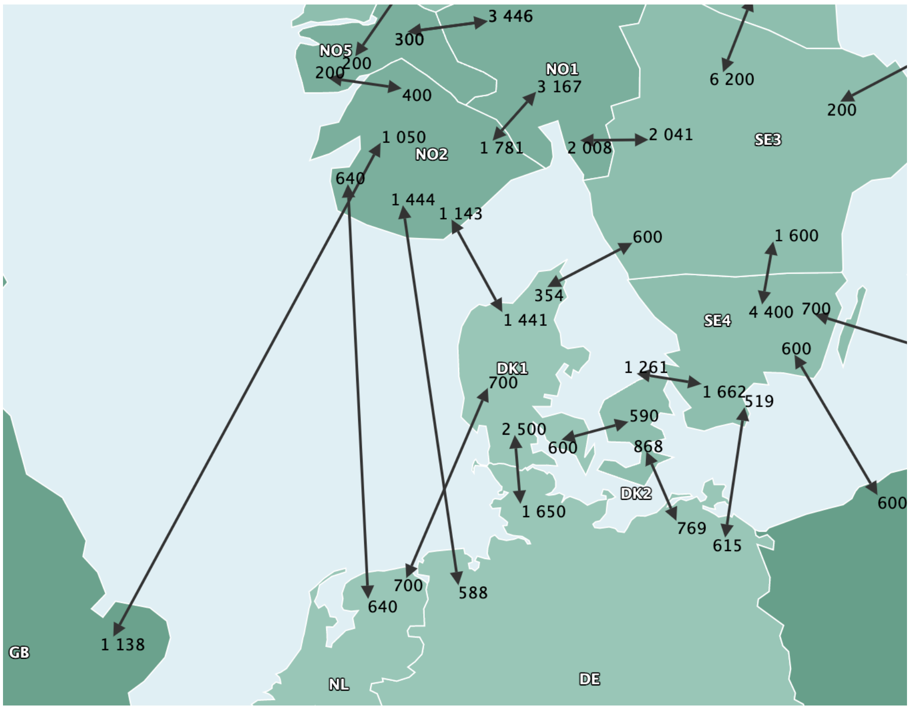


Figure 2.5: Cross-Border capacities from NO2 (11th of April 2023, 11:00-12:00) (Nord Pool, 2023)

3 Literature Review

The following chapter gives an overview of relevant literature on the integration of electricity markets. Literature concerning the decoupling of markets, systematic price differences and the impact of interconnectors will be covered. The literature review will serve as a basis for the thesis and help place our thesis in the literary landscape.

3.1 Decoupling of Markets

Before the coupling of European electricity markets, different market closing times forced traders to commit to cross-border trading volumes based on forecasted electricity prices (Geske et al., 2020). This often led to interconnector capacity being under-used and situations where power flowed from high-price to low-price areas. Following UK's decision to leave the EU in 2016, Geske et al. (2020) developed a model to study the cost of bilaterally uncoupling GB and EU electricity markets. Naming the event "Elecxit", they found that the uncoupling would give a less efficient market and that some planned interconnectors would be abandoned. This would raise GB's generation costs by €700 million a year compared to remaining in the Internal Energy Market in the EU (Geske et al., 2020).

Mevatne and Michel (2022) conducted a similar analysis in their master thesis, where they studied the impact of a potential Norwegian decoupling from the integrated European electricity market. In the study, they estimated the effects a decoupling would have on power flow, electricity prices and socio-economic welfare. Comparing different decoupling scenarios in their analysis, they found that a full "NEXIT", where all interconnector capacity was cut, would lower the average electricity price by €12/MWh in the Southern Norwegian price areas. This would increase the Norwegian consumer surplus. However, the increase would be outweighed by the loss in producer surplus, causing an hourly net loss of €124 000 in socio-economic welfare on average (Mevatne and Michel, 2022).

In 2021, Guo and Newbery conducted a similar analysis to our master thesis, looking at the consequences of trading on interconnector capacity outside the European market coupling. Following the end of UK's transition period of exiting EU on the 1st January 2021, they studied the effect of GB leaving IEM and, with it the access to the SDAC auction, where local and cross-border trades are cleared jointly. While waiting for the implementation of the "multi-region loose volume coupling" replacement, where cross-border flow is implicitly allocated and prices determined in a subsequent step, the interconnector capacity has been allocated through an explicit day-ahead auction that clears before the EU SDAC auction.

In the paper, Guo and Newbery (2021a) measured the risk traders face when taking positions in the two markets separately. Under the present timings of the auctions, the traders would have to forecast the price difference between the separate auctions, exposing them to the risk that their ex-ante market positions and interconnector purchases may lock them in unprofitable trades. The traders would therefore attach a risk premium to their forecasted prices and discount their bids in the explicit interconnector auction. Trading on the interconnector to France (IFA) gave the highest risk premium of €2/MWh due to the inflexibility of nuclear and highly weather-sensitive demand. Further, the interconnector to the Netherlands (BritNed), which is a less volatile market, resulted in a lower risk premium of 1€/MWh.

Guo and Newbery (2021a) also calculated the resulting commercial costs of uncoupling GB from interconnector trade. They estimated a total loss in congestion revenue of around €31 million per year, which would equal 13% of total congestion revenue generated under market coupling. Further, the social cost of uncoupling GB's interconnectors was calculated to be €28 million per year, representing the increase in generation cost caused by the reduced exports from the low-cost country.

3.2 Systematic Price Differences

Before the NSL was put into operation, DNV conducted a study to assess the consequences of a separate trading solution. In the study, DNV (2019) concluded that as long as the NSL auction results in the same power flows, there would be no systematic difference in the NO2 prices independent of whether trading on the NSL was within the SDAC auction or in a separate auction. The issue of efficient reservoir management in NO2 would still be the same, with precipitation, demand and interconnection capacities and prices in connected bidding areas being the key parameters when determining the NO2 price.

DNV argued that in the case of hourly price differences, this should be interpreted as a forecast error. Given clever and rational market players, situations with unexpected deviations between the two auctions would 'immediately' cause traders to take advantage of the arbitrage opportunity so that the systematic difference would disappear (DNV, 2019). Consequently, the expected net forecast error over time would be zero. Further, DNV also found little risk of price impact from the use of market power because of the extensive interconnection between NO2 and other bidding zones even before NordLink and the NSL were taken into operation. If NO2, on the other hand, was an isolated market, it would be considered to have poor competition, with Statkraft having 45.7% of the production capacity (DNV, 2019).

The effect of a separate auction was also studied by Nord Pool in their application process for a marketplace license on the GB-NO2 auction. In the case of a systematic difference, it could appear profitable for market players to apply arbitrage strategies between the two separate markets (Nord Pool, 2020a). Under perfect competition, such a strategy would, however, contribute to price convergence and, therefore, efficient allocation on the NSL. In line with DNV (2019), Nord Pool also stated that NO2 is a liquid area. However, they argued that there could still be market players with significant market power, so that there is a risk that some may abuse a dominant position and impact the prices on the auctions (Nord Pool, 2020a).

3.3 The Impact of Interconnectors

According to Spiecker et al. (2013), market coupling and cross-border transmission capacity between electricity markets have several positive effects. The most important are reduced generation costs and generation investments, increased system security and reduced market power potential. In their study on interconnector investments, Spiecker et al. (2013) developed a method to evaluate grid extensions in a competitive European market with a growing share of intermittent renewables. They found that increased transmission capacity would improve flexibility, where linking separate markets could compensate for fluctuations in domestic wind and water production. The additional cross-border transmission capacity would consequently generate higher socio-economic welfare. Spiecker et al. (2013) also found that the Nordic countries would gain less from the interconnection compared to other European countries. Seeing that the Nordic electricity market traditionally has been a low-price area, the interconnection would lead to higher prices. This would, in turn, lower the price spread between the Nordic market and other European countries, generating a lower congestion rent for the TSOs.

The impact of increased cross-border transmission capacity between countries has also been studied by Zakeri et al. (2018). In their paper, they studied the direct interconnection of the Nordic and British electricity markets and how it would affect the social welfare and integration of renewable energy. They found that the interconnection would increase the Nordic socio-economic welfare by €108 million per year, with Norway acquiring the largest share. Most of the socio-economic welfare gain would come from the price gap between the countries, and Zakeri et al. (2018) estimated the generated congestion rent to be approximately €200 million per year, given the current electricity systems in Norway and GB. However, in a scenario with increasing shares of wind energy, especially in GB, the price gap between Norway and GB will be reduced, giving a lower congestion revenue in several hours a year.

In 2013, the Norwegian TSO, Statnett, conducted a socio-economic analysis on the impact of additional Norwegian interconnector capacity. The study was part of the license application for the NordLink and North Sea Link cables. The expected total socio-economic benefit from each interconnector was estimated to be between €120 and €160 million per year (Statnett, 2013). Further, Statnett estimated a lower price spread between Norway and Germany/GB and an isolated growth in Norwegian electricity prices of approximately €4 per MWh in 2030. At the same time, they found that despite the increased trading capacity, there would still be congestion and significant price differences most of the time, contributing to the socio-economic welfare. The study concludes with more stable electricity prices throughout the year but also more short-term price volatility when Norway's interconnection to other markets increases (Statnett, 2013). Increased price stability will be caused by higher prices in periods which previously had the lowest prices. Further, the short-term volatility is expected to increase due to greater differences in the opportunity cost of water in each reservoir and more hours with full stop in regulated power production during the summer (Statnett, 2013).

In an analysis from 2022, Statnett found that the introduction of NordLink and North Sea Link only explains 10 % of the average price in Southern Norway, compared to a situation without the cables (Statnett, 2022b). In the analysis, Statnett argues that the effect of the cables will vary over time, depending on factors such as future power surplus, gas, oil and CO2 prices and increased implementation of intermittent renewable energy sources in neighbouring countries.

Myrvoll and Undeli (2022) studied the impact NordLink has had on the day-ahead prices in NO2 and Germany. In their master thesis, they found evidence of price convergence between Norway and Germany after the implementation of the NordLink cable in 2020. The Norwegian market has experienced a price increase, where the gas and EUA prices are shown to have a stronger effect on electricity prices after the implementation of NordLink. Further, the downward pressure renewables have on electricity prices is shown to be strengthened by NordLink in both Norway and Germany.

4 Theory

In this chapter, the theoretical framework relevant to the thesis will be outlined. The chapter starts with an explanation of how the merit order determines the supply of electricity and how electricity prices are established. Further, the concept of congestion management will be presented, followed by a description of the socio-economic welfare in electricity markets, with specific regard to the introduction of an interconnector. In the last part, traders' risk when trading on an uncoupled interconnector will be explored.

4.1 The Merit Order Effect

For each bidding area, the supply and demand bids from all market participants are aggregated into single curves for all hours of the day, giving each market its unique supply and demand curve (Nord Pool, ndd). The market clearing price is then set in the equilibrium between supply and demand, where the electricity price equals the marginal price of the last unit of electricity produced. In Figure 4.1, the price formation in the electricity market is illustrated under the copper-plate assumption, where transmission constraints are disregarded.

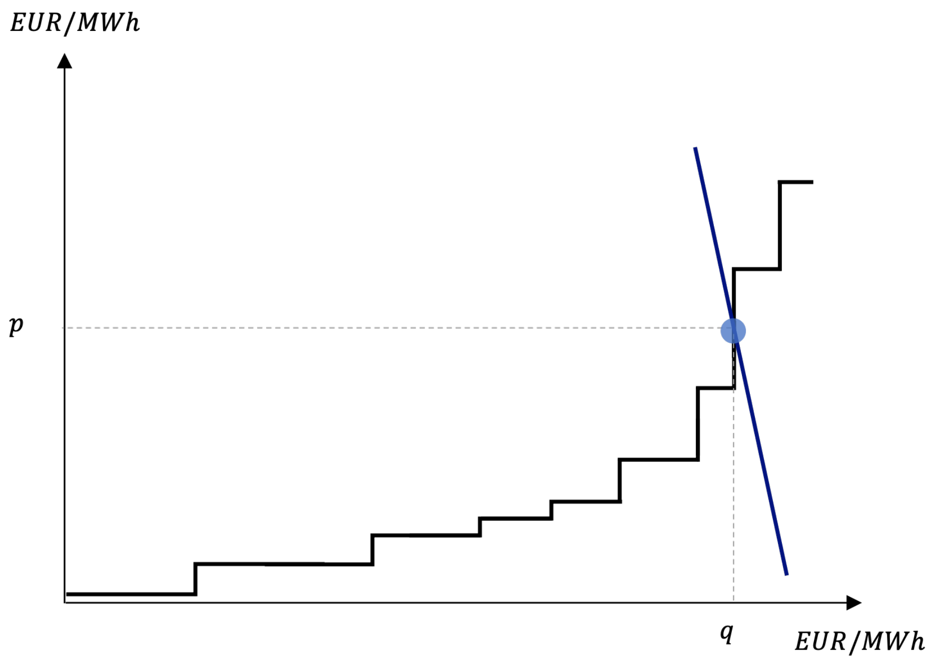


Figure 4.1: Merit order curve

Electricity can be produced using different energy sources and technologies, and power plants will consequently have different cost structures. In the electricity price formation, the goal is to minimize the costs of providing the electricity (Cretì and Fontinha, 2019). The supply bids are therefore ranked in ascending order according to the marginal cost of production and the volume offered within each price segment. This is called merit order dispatching, and in Figure 4.1, the supply curve is represented by the merit order curve of electricity (Cretì and Fontinha, 2019). Bids from wind, solar and nuclear are usually found to the left in the figure due to their low marginal costs. Coal, gas and oil have higher generation costs and are therefore located further to the right on the supply curve. Hydropower is also able to generate electricity at a low cost. However, their bids fluctuate more due to changes in the opportunity cost of water. The opportunity cost is determined based on several factors including reservoir levels, expected inflows, demand, transmission capacities and marginal costs of other generators. If a hydropower producer expects higher electricity prices in the future, the opportunity cost of withholding the water in the reservoir will be higher compared to producing today.

In the absence of trade between markets, each electricity market will have an equilibrium price set by a unique supply curve determined by its specific merit order. In markets where the share of low-cost generation is high, the electricity price will, therefore, usually be lower than in markets with a higher share of high-cost generation capacity. Further, the composition of different energy sources and technologies in a market will affect the steepness of the supply curve. If the share of renewables is dominant, such as in the Norwegian energy mix, little wind can be balanced with low-cost hydropower, and the price will remain stable at a lower level. However, in a market with high shares of both renewables and fossil fuels, such as the GB electricity market, little wind must be balanced with high-cost gas, which might lead to more volatile electricity prices.

The demand curve is ranked in descending order from the highest to the lowest bids. The downward-sloping demand is characterized by its inelasticity to short-term changes in electricity prices, implying that price changes have a limited effect on the demand (Csereklyei, 2020). Electricity is a necessity in modern society, and as the electrification of society continues, it will become even more important.

With the steepness of the demand curve, potential changes to the supply curve might give significant alterations to the equilibrium price. When additional generation capacity is introduced in a power system, either through investments in new generation or increased transmission capacity between markets, the supply curve may change its shape depending on the initial shape of the curve and the type of capacity that is added. If high-cost generation capacity is added and its marginal cost is higher than the current price equilibrium, this would have no impact on the electricity price. However, adding capacity with a lower marginal cost could give a right shift in the supply curve, as can be seen in Figure 4.2 (Maciejowska, 2020). The share of renewable energy sources is increasing in most power markets, and with a marginal cost close to zero, the number of low-cost bids will increase. This will give a shift in the supply curve where the bids from the new generation capacity would replace the more expensive ones. This change in the market equilibrium between supply and demand would lead to lower power prices and is known as "The Merit Order Effect" (Maciejowska, 2020). In addition, Figure 4.2 illustrates how an increase in intermittent renewable energy could give more volatile electricity prices due to its intermittent nature and volatility in production.

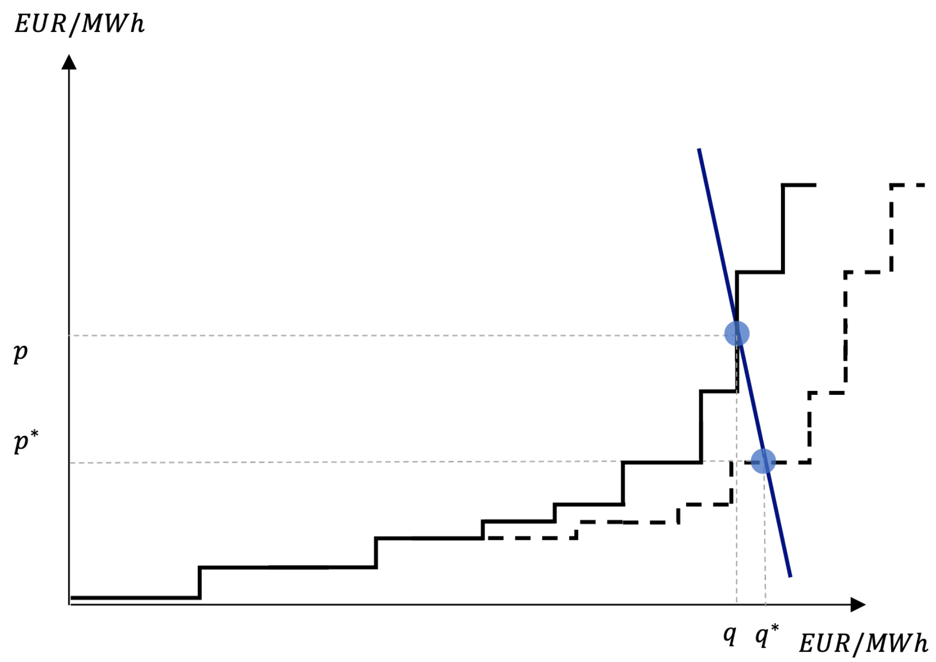


Figure 4.2: The Merit order effect from an increased share of renewables in the supply curve

4.2 Congestion Management

As depicted in Figure 2.1, the European electricity market is divided into several bidding areas, where the Nordic countries operate with several bidding areas within the country. When there is a difference in the power situation between the bidding areas, the transmission of power is useful to secure that demand is met in both areas. The deficit area will have a higher price, and through market coupling electricity will flow towards the high-price area (NVE, 2022a). If the transmission of power is within the capacity limits, this will give identical area prices. However, available transmission capacity may be restricted creating so-called bottlenecks or congestion. This will hinder full price convergence and bidding areas will consequently have different area prices. Different consumption patterns and variations in the generation mixes between the bidding areas are central drives for the price difference.

Congestion management is important to alleviate bottlenecks in the grid and secure efficient use of transmission capacity. Zonal pricing, where several generation nodes are aggregated, giving each zone a uniform price, is the most applied method to manage congestion in Europe (Cai, 2018). In the short term, the main objective is to utilize the grid capacity so that social welfare is maximized. In the longer term, the differences in area prices can help shape the behaviour within a bidding area, with increased generation and decreased consumption in areas with insufficient power and the opposite in areas where the power supply is sufficient (NVE, 2022a). Over time it can also serve as a signal as to where investments in new production or consumption should be placed.

When electricity is traded between areas with different prices, an income is generated for the owners of the transmission line (NVE, 2022a). The income, called congestion revenue, is collected by the local TSOs. The congestion revenue is typically used to cover a part of the network costs and reduces other grid tariffs if the grid companies' revenues are regulated (Bjørndal et al., 2013). For interconnectors, the revenue is usually shared equally between the TSOs on each side of the line.

4.3 Socio-Economic Welfare

The fundamental source of economic value for an interconnector derives from the increase in the economic efficiency of the electricity market (Pöyry, 2014). Through better utilization of the production capacities on both sides of the interconnector, cross-border transmission capacity is expected to generate higher socio-economic welfare. According to ENTSO-E (2022) there are two approaches for calculating the change in socio-economic welfare when considering a transmission project. The first is the generation cost approach, which compares the generation costs for both markets with and without the interconnector. In the second approach, the focus is on the total surplus for consumers and producers in both markets as well as the generated congestion rent, with and without the project. For this thesis, we will focus on the second approach as we want to address how different stakeholders' surpluses are affected by a separate auction arrangement for an interconnector.

When looking at the electricity market, the socio-economic benefit is defined as the aggregated surpluses of consumers, producers, and owners of the transmission grid (ENTSO-E, 2022). The consumer surplus equals the difference between the consumers' willingness to pay and the actual price they pay. For producers, the surplus equals the difference between the price received for each unit of electricity and the marginal cost of producing the unit. The interconnector welfare, being the surplus for the transmission line owners, equals the congestion rent less the construction and operation costs of the interconnector (Pöyry, 2014). In the short run after the investment, construction and operation costs are, however, not considered.

In Figure 4.3, the supply curves of high-price market (A) and low-price market (B) are represented by the merit order curves S^A and S^B, which have different shapes. The demand levels in the two markets are also different, and they are both considered inelastic in the short run of the example. With no transmission capacity between the markets (TC0), each market serves its own load, and significant differences in generation costs arise. This would give different prices P_0^A and P_0^B, and a theoretical welfare loss equal to area ADE because the overall generation cost is higher than it theoretically could be. If, on the other hand, the transmission capacity between market A and market B was unlimited, this would lead to full price convergence and a homogeneous price P^* in both markets. This optimal situation with a uniform price level is, however, not reached in Figure 4.3.

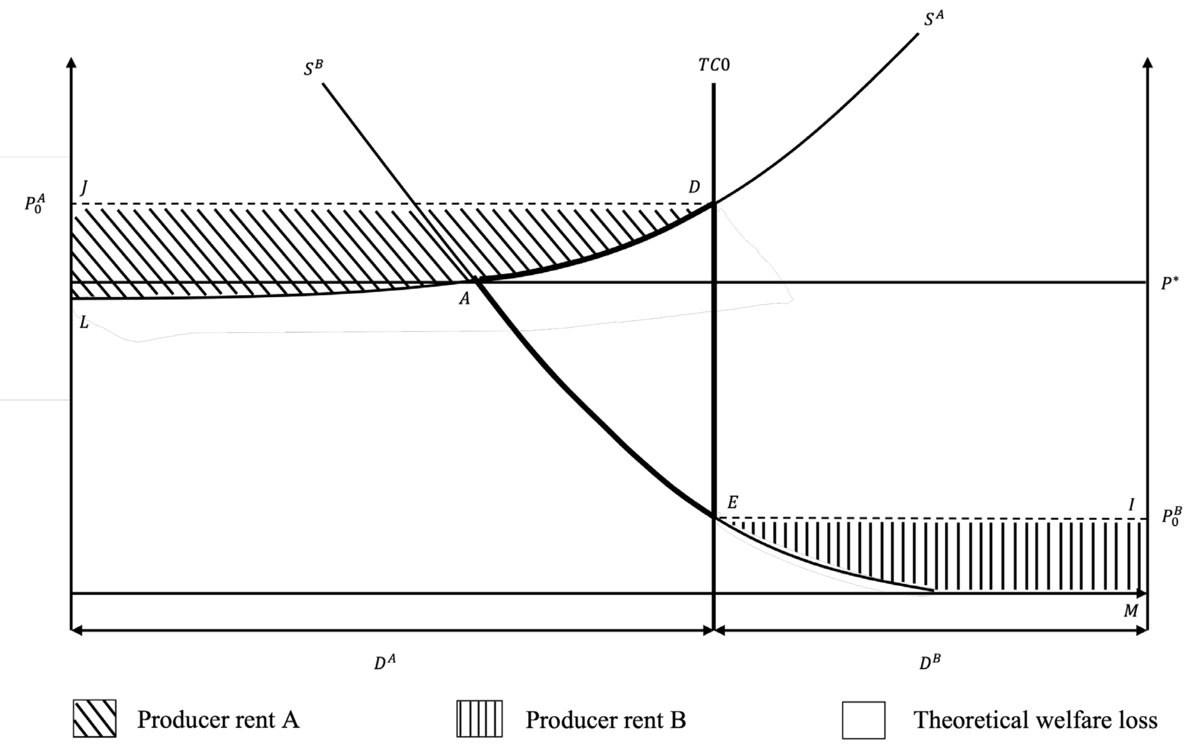


Figure 4.3: Welfare implications of interconnection, based on figure by Spiecker et al. (2013)

In Figure 4.4, the interconnector capacity is increased to TC1. The optimal price level is still not reached, but the introduction of transmission capacity between the markets gives a significant reduction in the theoretical welfare loss ABC. This results in a welfare gain equal to area $BDEC$. The effects of the welfare gain will vary among the stakeholders, also within the same market. In high-price market A, increased supply due to imports reduces the price level from P_0^A to P_1^A. The producer surplus decreases with $JDBK$, while the consumer surplus increases with $JDGK$. This gives a redistribution of socio-economic welfare from producers to consumers as well as a net effect in welfare gain for consumers equal to DGB.

In low-price market B, the opposite happens. The interconnector capacity increases the electricity price from P_0^B to P_1^B because of increased demand. This increases the producer surplus with $CHIE$ and reduces consumer surplus with $FHIE$, giving a redistribution effect from consumers to producers and a net effect in welfare gain for producers equal to CFE.

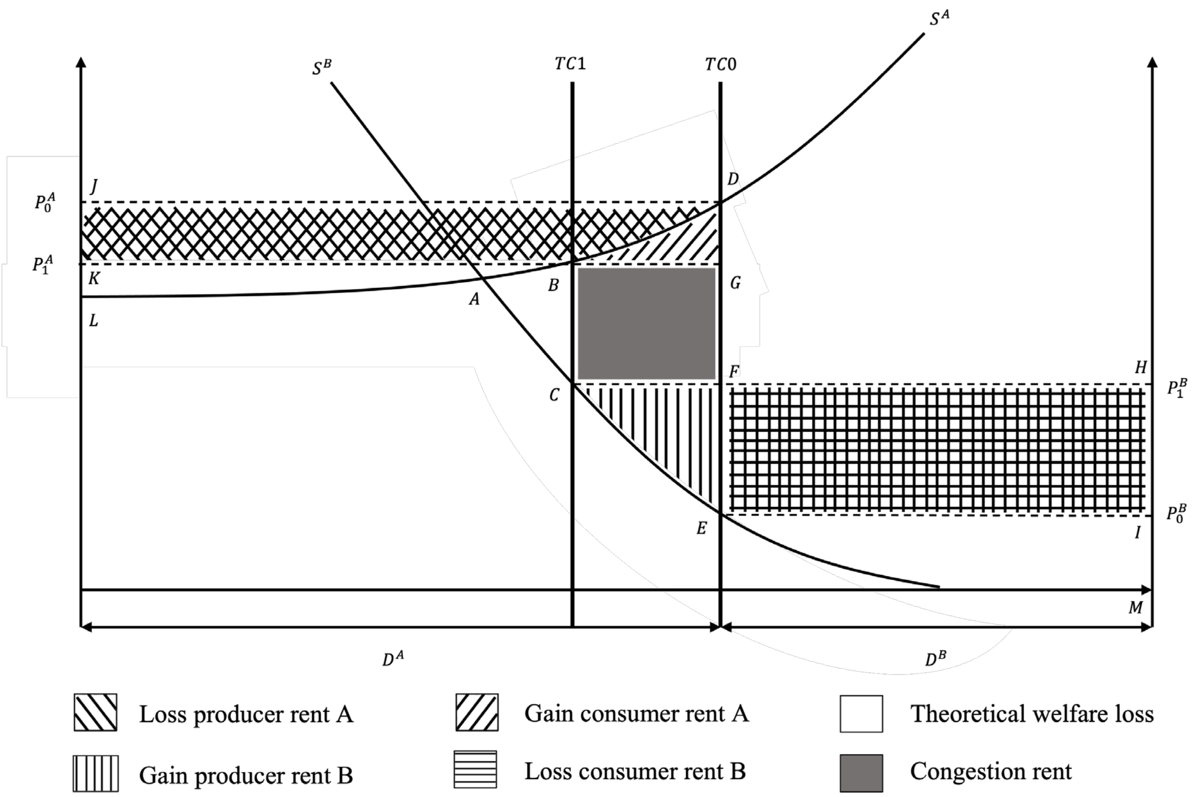


Figure 4.4: Welfare implications of interconnection investments for different stakeholders, based on figure by Spiecker et al. (2013)

If the optimal situation with a uniform price level is met, the welfare gain would go to the consumers in market A and producers in market B, with no income generated for the owner of the transmission line. However, because of the limitations in the transmission capacity ($TC1$), congestion occurs, and an income for the TSO is generated. In Figure 4.4, the congestion rent equals area $BGFC$. An important point when looking at the example illustrated in Figure 4.4 is the cost of increased interconnection capacity. Through the cannibalization effect, the introduction of a new interconnector may have an impact on the revenue from already existing interconnectors. The additional interconnector may lead to smaller congestion revenue on other interconnectors because there will be a further price convergence between the markets (Pöyry, 2014).

For a non-regulated TSO the marginal welfare gain decreases with increased transmission capacity and so the optimal transmission capacity is not necessarily the one that avoids all welfare losses of congestion but the one where the avoided welfare losses equal the investment cost of newly built lines (Spiecker et al., 2013). However, in markets where the revenues of the TSO is regulated, it could be optimal to build interconnector capacity so that the price difference disappears and all of the socio-economic welfare is captured by producers and consumers. This because the congestion revenue through incentive regulation is passed on to domestic customers and is not part of the TSO's profits. The regulated TSO will therefore make no profit from the congestion revenue.

4.4 Risks from the Trader's Perspective

Spot electricity prices exhibit sudden and large jumps, a phenomenon usually attributed to unexpected increases in demand, unexpected shortfalls in supply and failures of transmission infrastructure. The spikes reflect the fact that the market needs to rely on the bids from the generators with high marginal cost of production in order to satisfy demand (Christensen et al., 2012). Once an interconnector is uncoupled and two auctions are established in the same market, market participants must forecast these price fluctuations to maximize profits. The level of risk faced by traders will depend on their portfolio of assets, commitments and financial resources (Guo and Newbery, 2021a).

To understand the risk profiles of different traders, it may be helpful to examine trading scenarios involving three types of agents: a generator in NO2 without any captive customers, a financial trader that only holds balance responsibility in NO2 and a producer in NO5. We assume that the agents are placing a price-dependent single hourly order of 10 MW in the same hour.

Producer in NO2

First, consider an agent with generation capacities in NO2. The forecasted GB price in an hour is €170/MWh, and the corresponding forecasted NO2 price is €120/MWh. On the Norwegian side, a generator will then expect export on the cable. We assume that the generator is indifferent between the trading venues and places a selling bid of 10 MW at €120/MWh in the NSL auction before it closes at 10:50.

Suppose now that the generator is the marginal bidder and that the NSL auction settles at €120/MWh. The generator then has to deliver 10 MW the next day to the NSL auction and can fulfil this commitment by either selling 10 MW of its own production or reversing the bid in the NO2 auction at 12:00. Suppose that the generator satisfies its commitment through production and that the NO2 price clears as forecasted at €120/MWh. In this case, the generator has not earned any premiums on its trade with the NSL, and the market is fully efficient.

Now, let's consider the generator trading under high uncertainty, where the NO2 price can clear within an expected price interval. Suppose that the time is 11:00 and that the generator has committed to deliver electricity in the NSL auction at the predetermined price of €120/MWh. Assume that the subsequent NO2 price unexpectedly settles at €150/MWh. If the generator's bid exceeds the marginal cost of production, it receives a positive cash flow as long as the bid is accepted. However, the generator incur an opportunity cost of €30/MWh because it could have made a larger profit by selling to the NO2 auction. With a trade of 10 MW, this lost profit amounts to a total of €300. In the opposite case, where the NO2 price unexpectedly settles at €90/MWh, the generator avoids a loss of €30/MWh by trading with the NSL.

Consequently, the generator risk losing out on potential profits and is incentivised to split its bids between the NO2 and the NSL auction (DNV, 2019). However, by only trading with the NSL, the generator will make a revenue of €1 200 in all cases as he has no exposure to NO2 price fluctuations. We display the trading revenue for the producer under the different NO2 price scenarios in the first column in Table 4.1.

Financial Trader

While fundamental participants aim to sell power at the highest price, trading participants seek to exploit potential price differences between the two auctions. In the second scenario, consider an agent without physical production in NO2 trading 10 MW with the NSL. Suppose that the forecasted NO2 price remains at €120/MWh. In this case, the trader could submit both a buying and a selling bid close to the forecasted price, aiming to exploit any significant price differences regardless of the direction of the flow.

Suppose now that the NSL price clears at €120/MWh such that the selling bid of the financial trader is accepted. Since accepted bids on the interconnector auction entail a commitment to the delivery of electricity the following day, the bid has to be reversed in the subsequent NO2 auction. If the NO2 price clears as expected at €120/MWh, the trader has not earned any trading revenue. However, if the NO2 price instead settles at €150/MWh, the financial trader is forced to buy 10 MW at €150/MWh in the NO2 auction and sell at a price of €120/MWh in the NSL auction, representing a loss of €30/MWh. The total loss in that particular hour is €300. Opposite, if the NO2 price settles at €90/MWh, the trader earns €300 from the arbitrage. Consequently, the risk exposure is to the possibly onerous charges of unwinding the NSL position. The trading revenue for the financial trader is displayed in the second column in Table 4.1.

Producer in NO5

In the third scenario, we consider a generator in NO5, with balance responsibility in NO2, aiming to exploit the price differences in the NSL auction. As the agent has no fundamental connection to NO2, the trading risk is the same as for a financial trader. However, in this case, the producer will also sell 10 MW of generation in NO5. This is the reality for many of the financial traders, who act as the trading arm of vertically integrated utilities in other price areas (Guo and Newbery, 2021a). Suppose that the agent commits to selling 10 MW to the NSL at a price of €120/MWh. Without production in NO2, the bid has to be reversed in the NO2 auction at 12:00. Assume first that the NO5 price is independent of the NO2 price and clears at €120/MWh. If the NO2 price settles at €150/MWh, the producer loses €300 on the NSL bet but still makes a revenue of €1 200 with the independent sale in NO5. The net effect for the producer in this particular hour is €900. Opposite, the producer earns a trading revenue of €1 500 if the NO2 price clears at €90/MWh. The trading revenue for the producer in NO5 is displayed in the third column in Table 4.1.

In a more realistic scenario, the NO2 and NO5 prices would be closely linked due to the transmission capacity between the bidding areas. An unexpected price jump to €150/MWh in NO2 would spill over to NO5. In this case, the producer in NO5 would sell its generation to €150/MWh in NO5 while losing €30/MWh from the unprofitable bet on the NSL-NO2 price spread. This gives a net trading revenue of €120/MWh or €1 200 in total. Opposite, a sudden drop in NO2 and NO5 clearing prices to €90/MWh means that the producer would sell its generation in NO5 to €90/MWh while earning €30/MWh from the profitable bet on the NSL-NO2 spread. This also gives a net trading revenue of €120/MWh or €1 200 in total. Moreover, if the agent were a hydropower producer with storage capacities, he could withhold the power in the low price hours by placing a price-dependent order, thereby avoiding the downside in the €90/MWh price scenario. Consequently, the NSL auction offers an opportunity to hedge against electricity price fluctuations, also for producers in NO5.

In summary, we find that while fundamental market participants face the risk of missing out on potential revenues, financial traders risk making a negative cash flow.

	Producer NO2	**Financial trader**	**Producer NO5**
$P_{NO2} = 150$	1 200	-300	900
$P_{NO2} = 120$	1 200	0	1 200
$P_{NO2} = 90$	1 200	300	1 500

Table 4.1: Trading revenue for different agents from selling 10 MW in the NSL auction with clearing price at €120

5 Methodology

The following chapter introduces the methodology used to answer the research questions of the thesis. We seek to investigate whether traders require a premium to participate in the NSL auction. With the current timeline of the two auctions, traders can forecast the NO2 price to mitigate the risk of submitting unprofitable bids in the NSL auction. First, we will therefore apply different forecasting methods and compare their forecast accuracy. The best forecasting method is then used to approximate the premium that a marginal trader requires for participating in the NSL auction. The premium will be found by comparing the forecasted NO2 prices with the actual NSL price. In case of a systematic price difference, this could be considered a premium added by the traders when they bid into the NSL auction. Further, we will examine the drivers behind the premium to better understand when and why it arises in the market. Lastly, we want to assess the socio-economic consequences of uncoupling the NSL. This will be done by calculating the commercial cost of uncoupling.

The methodology chapter is structured in different sections. The first section outlines methods to forecast electricity prices, and time series analysis and short-term electricity price forecasting will be discussed. The most common econometric forecasting methods will then be explored, including a Seasonally Naïve Method, Simple Linear Method, ARIMA and ARX method. Further, we describe the forecasting process and the error measures, which are used to evaluate the forecasting accuracy of the models. Finally, we propose a method to calculate the premium required by the traders as well as a method to calculate the commercial cost of uncoupling.

5.1 Time Series

Time series are a set of observations y_t, that is measured over a set of times $t = 1, \ldots, N$ and may have continuous or discrete sample spaces. These models assume that the observations are time-dependent, be it daily, weekly, monthly or yearly. Analysis of time series is commonly used in financial markets but increasingly also in deregulated electricity markets. Time series analysis involves analyzing the patterns and trends in historical data and extrapolating them to predict future values.

5.2 Short-Term Electricity Price Forecasting

Short-term electricity price forecasting is a critical area of research in the energy industry, as it enables market participants to make real-time decisions about production, consumption, and trading in the day-ahead market. Accurate short-term forecasts are essential for the efficient operation of power systems, risk management, and market trading.

Short-term electricity price forecasting poses several challenges due to the volatility and complexity of electricity markets. These challenges include the unpredictability of renewable energy sources, weather conditions, demand fluctuations, transmission constraints and unexpected outages. To address these challenges, various modelling techniques have been developed, ranging from traditional econometric models to advanced machine learning methods (Shah et al., 2020). Machine learning methods are able to handle large and complex data sets, capture non-linear relationships, and adapt to changing market conditions. However, Guo and Newbery (2021a) found that these methods generate greater forecast errors than the standard econometric methods on day-ahead prices in GB and France.

In this thesis, we compare the most common econometric methods for one-day-ahead forecasting with a naïve method to investigate the decision problem of a marginal trader bidding in the NSL auction.

5.2.1 Seasonally Naïve Forecasting Method (SN)

According to Hyndmand and Athanasopoulos (2021), it is a good practice to have some simple forecasting methods as a comparison to make sure that the method you are choosing to use is actually better than some simple comparative method.

The Seasonally Naïve Forecasting Method is applied to highly seasonal data and sets each forecast equal to the last observed value from the same season. The day-ahead (DA) electricity prices in NO2 exert a strong daily seasonality, and we therefore set the forecast of the DA hourly prices equal to prices one-day (24 hours) earlier.

$$y_{t,h} = y_{t-1,h} + e_{t,h} \tag{5.1}$$

Where $y_{t,h}$ denotes the DA price for an hour h on day t, and $e_{t,h}$ are forecast errors. Sometimes the simple methods will be the best forecasting method available, but in many cases, these methods will serve as benchmarks rather than the method of choice.

5.2.2 Simple Linear Regression (SLR)

Fezzi and Mosetti (2020) found that Simple Linear Regression (SLR), with only two parameters, performed unexpectedly well in the Nord Pool market if estimated on extremely short samples.

$$y_{t,h} = \alpha_0 + \alpha_1 q_{t,h} + e_{t,h} \tag{5.2}$$

Where α_0 is a constant, $q_{t,h}$ is the DA forecast of electricity demand, and α_1 is the corresponding coefficient.

When using simple linear regression, we implicitly make assumptions about the variables in Equation (5.2). First, we assume that the model is a reasonable approximation to reality; that is, the relationship between the forecast variable and the predictor variable satisfies this linear equation. Secondly, we make three assumptions about the errors: (i) they have mean equal to zero, (ii) they are not autocorrelated, and (iii) they are unrelated to the predictor variables.

The linear model has limitations. Electricity prices are highly persistent, meaning that a price shock in a certain hour will carry over to the next hour. In addition, the prices exert both a daily, weekly and monthly seasonality. Both of these attributes mean that electricity prices tend to be non-stationary. This issue will be handled by the more sophisticated models.

5.2.3 ARIMA Model

Autoregressive Integrated Moving Average (ARIMA) is a time series forecasting method that has been widely used in electricity price forecasting (Contreras et al., 2003). It is a powerful technique that can capture complex patterns and trends in time series data and provide accurate predictions for future values. ARIMA is a combination of three components: Autoregression (AR), Integration (I), and Moving Average (MA), which makes it a flexible and robust forecasting model.

ARIMA model types are listed using the standard notation of ARIMA(p,d,q) and (P,D,Q) are their seasonal counterparts. The autoregressive term (p) represents the number of autoregressive orders in the model. Autoregressive orders specify which previous values from the series are used to predict the current values. The difference (d) specifies the order of differencing applied to the series before estimating the model. Differencing is necessary when trends and seasonality are present and is used to make the time series stationary. Moving average (q) refers to the number of moving average orders in the model. Moving average orders specify how deviations from the series mean for previous values are used to predict current values (Jakasa et al., 2011). Within the seasonal ARIMA model (SARIMA), the forecasted NO2 price on day t and hour h is given by the equation:

$$\begin{aligned} y_{t,h} = c + \phi_1(y_{t,h-1} - \mu_p) + \cdots + \phi_p(y_{t,h-p} - \mu_p) + \theta_1 e_{t,h-1} + \cdots + \theta_q e_{t,h-q} + \\ \phi_S(y_{t-S,h} - \mu_S) + \cdots + \phi_{pS}(y_{t-pS,h} - \mu_{pS}) + e_{t,h} \end{aligned} \tag{5.3}$$

Where $\phi_1, \ldots \phi_p$ is the autoregressive coefficients of the non-seasonal part of the model of order p and $\mu_1, \ldots, \mu_p$ is the mean values of the non-seasonal part of the model at order p. $\theta_1, \ldots, \theta_q$ is the moving average coefficient of the non-seasonal part of the model of order q. We define the daily seasonal period S. The equation forecasts the future prices $y_{t,h}$ by estimating the model parameters through maximum likelihood and predicting the future values of the error term e_t.

Based on the discussion in Appendix A2, we specify two ARIMA models: an $ARIMA(0,1,3)(0,1,1)_{24}$ and an $ARIMA(3,1,0)(0,1,1)_{24}$, both of which passes the required checks. Furthermore, when forecasting day-ahead prices with ARIMA, Conejo et al. (2005) argue that it could be necessary to use different notations of the model for nearly every week. Accordingly, ARIMA models turn out to be very unstable in their predictive power over time. Especially when the volatility was very high, the ARIMA models provided poor results. Consequently, we also include an automatically selected model. In this case, R uses a stepwise approach to find the model with the lowest Akaike Information Criterion (AIC) for each estimation window. AIC quantifies the balance between the goodness of fit of a model and its complexity so the model with the lowest value is considered to have the best trade-off between accuracy and simplicity.

Univariate ARIMA models allow for the inclusion of information from past observations of a series but not for the inclusion of other information that may also be relevant. For example, the effects of forecasted demand, renewable production, gas prices, or other external variables that may explain some of the historical variations and may lead to more accurate forecasts. On the other hand, the simple linear regression model allows for the inclusion of a relevant predictor variable but does not allow for the subtle time series dynamics that can be handled with ARIMA models. Therefore, we now consider how to extend the autoregressive model in order to allow other information to be included.

5.2.4 ARX Model

Autoregressive Models with Exogenous Variables (ARX) are extensively used for electricity spot price forecasting. The simple autoregressive structure with an exogenous variable was originally proposed by Misiorek et al. (2006) and later used in several electricity price forecasting studies (Nowotarski et al., 2014; Maciejowska et al., 2016; Marcjasz et al., 2019). Within this model, the forecasted NO2 price on day t and hour h is given by:

$$y_{t,h} = \beta_{0,h} + \sum_{i=1}^{m} \beta_{i,h} y_{t-i,h} + \sum_{j} \theta_{j,h} X_{j,t,h} + e_{t,h} \tag{5.4}$$

Where m represents the AR lags, $X_{j,t,h}$ contains exogenous variables, including DA forecasts of domestic electricity demand and wind infeed, gas prices, as well as a weekend indicator variable. The parameters $\beta_{i,h}$ and $\theta_{j.h}$ represents the coefficients associated with the AR lags and exogenous variables, respectively, while $e_{t,h}$ denotes the error term. This forecasting model facilitates the use of more recent price information and is expected to improve forecasting accuracy, especially for hours following the NSL auction closing. Even though many other exogenous variables were considered, we chose to include those who together maximized the accuracy of the forecast. The variables are further described in Chapter 6.

Equations (5.1)-(5.4) provide forecasts of DA prices in NO2. The forecast of the day-ahead clearing prices from the N2EX auction in GB, that together with the prices in NO2-NSL determines the flow on the NSL, is set equal to the clearing prices from the EPEX Spot auction. The EPEX Spot auction price is a strong indication of the clearing price on the N2EX and is able to provide a better estimation than any attempted fundamental forecasting method (Guo and Newbery, 2021b).

5.3 Forecasting Process

We perform an ex ante forecast of the NO2 day-ahead prices each day, from the opening of the NSL, on the 1st of October 2021, to the 15th of January 2023, resulting in 470 iterations. When forecasting over multiple iterations, parameter instability is considered a critical issue. An additional problem is that the optimisation of the parameters becomes more time-consuming because of the number of observations involved (Hyndmand and Athanasopoulos, 2021).

To deal with these issues, we employ a rolling window in all the forecasting models. The size r of the rolling window is set to 7 days, meaning that each forecast is fit on the previous 168 hours. A rolling window of one week is applied to capture the weekly seasonality while managing demand fluctuations and minimising the computational power (Amjady and Hemmati, 2006).

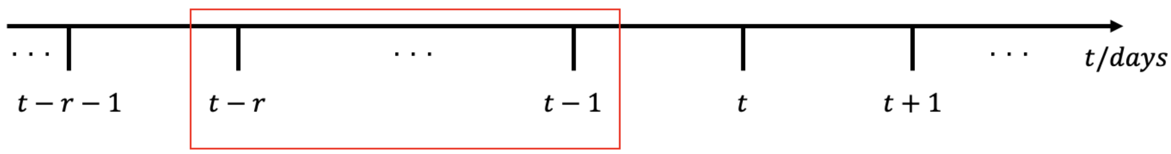


Figure 5.1: Illustration of the rolling window

Following the timing of the EPEX Spot auction in GB and the NO2 auction in Norway, seen in Figure 2.4, traders want to forecast the NO2 prices as close to the closing of the NSL at 10:50 CET as possible to utilize the most recent market information. As a result, we utilize the previous day-ahead prices up until 10:00 to forecast the day-ahead prices from 00:00-23:00 in t+1.

Unexpected events such as power plant outages, weather changes or transmission constraints can cause extreme prices driven by high demand and/or low supply. Extreme prices cannot be predicted by conventional econometric methods, instead, probability methods are preferred (Hagfors et al., 2016).

Janczura et al. (2013) found that including extreme prices as predictive variables can distort the values of the estimated coefficients, resulting in poor forecasting accuracy.

Consequently, we calibrate our models from raw prices to transformed data. For electricity markets with only positive prices, the logarithm is the most popular choice for variance stabilizing. However, since the NO2 data set exhibits hours with negative prices, as seen in Table 6.2, we follow Guo and Newbery (2021a) and stabilize the input data variance by constraining the allowed z-score of the DA prices entering the regression. The z-score represents the number of standard deviations that a data point deviates from the mean of the time series. The bounds are set at a z-score of four, meaning that any prices deviating more than four standard deviations from the sample window mean is replaced by the upper and lower bounds.

5.4 Error Measures

There are several ways to evaluate the performance of forecast models. It makes a lot of sense to look at how the model fits within the estimation sample, but a perfect fit can always be obtained by using a model with enough parameters. An over-fitted model will not necessarily forecast well. We are, therefore, more interested in the out-of-sample forecast performances.

The forecast error $e_{t,h}$ is the difference between an observed value and its forecast. The error is not necessarily a mistake but rather the unpredictable part of an observation. We want to minimise the absolute values of the forecast errors. The forecast accuracy can be measured by summarising the forecast errors in different ways. In this thesis we focus on the most commonly used scale-dependent measures which are based on the mean absolute errors (MEA) and the root mean squared errors (RMSE).

When comparing forecast methods applied to a single time series, or several time series with the same units, the MAE is popular as it is easy to understand and compute. A forecasting method that minimises the MAE will lead to forecasts of the median while minimising the RMSE will lead to forecasts of the mean (Hyndmand and Athanasopoulos, 2021). Denoting the forecasting error as $e_{t,h}$, the error measures are:

$$
\begin{aligned}
MAE &= \frac{1}{HT}\sum_{h=1}^{H}\sum_{t=1}^{T}|e_{t,h}|, \\
RMSE &= \frac{1}{HT}\sum_{h=1}^{H}\sum_{t=1}^{T}\sqrt{(e_{t,h})^2}.
\end{aligned}
\tag{5.5}
$$

In our case, $T = 30$ is the total number of days for our out-of-sample validation and $H = 24$ is the total numbers of hours in a day.

5.5 Prediction Intervals

The volatility in the energy market data is posing challenges for auction participants in the studied time period. More volatility means more uncertainty, which reduces the reliability of the point forecasts of the day-ahead NO2 price. Uncertainty can be expressed by a prediction interval, which is a region within which we expect the forecast to lie with a specified probability. With each forecast of the NO2 price, we follow Hyndmand and Athanasopoulos (2021) and include 80% prediction intervals within which we expect the forecast $y_{t,h}$ to lie. Assuming forecast errors are normally distributed, then an 80% prediction interval is defined as:

$$y_{t,h} \pm 1.28\sigma \tag{5.6}$$

Where σ is an estimate of the standard deviation of the forecast distribution.

The prediction interval is wider when the observed DA prices are farthest from the mean. For most models, prediction intervals also get wider as the forecasting horizon increases. Moreover, we argue that the calculated prediction intervals are too narrow due to unaccounted uncertainty. This includes both model uncertainty and measurement uncertainty. The model uncertainty relates to uncertainty regarding the reliability of the forecasting model based on the out-of-sample criterion. Measurement uncertainty refers to uncertainty in the observed data used to build the forecasting model. For the out-of-sample forecast, we feed in forecasted values from external sources of the exogenous variables into the model. The width of the resulting prediction intervals will be understated as the uncertainty of these forecasts is not accounted for. On the other hand, the calculated prediction interval is probably still wider than the interval obtained by traders with more sophisticated forecasting methods. In total, we believe that the calculated interval will provide a sufficient measurement for how certain traders are in their hourly NO2 price forecast.

5.6 Premium

The premium that a marginal trader would bid into the NSL auction can be calculated algebraically. We denote the premium a marginal trader requires in the NSL auction in a particular hour π, the actual GB EPEX price as p_{GB}, the forecasted NO2 price as $\hat{p}_{NO2}$ equal to $y_{t,h}$, and the observed NSL price as p_{NSL}.

We define the ex-ante export premium as the price spread between p_{NSL} and $\hat{p}_{NO2}$ when export is forecasted ($p_{GB} > \hat{p}_{NO2}$). Similarly, the ex-ante import premium in a particular hour is defined as the price spread between $\hat{p}_{NO2}$ and p_{NSL} when import is forecasted ($p_{GB} < \hat{p}_{NO2}$). Consequently, in export scenarios, the premium is positive as long as the marginal selling bid that settles the price on the NSL is higher than the marginal trader's NO2 price forecast. Opposite, the premium is positive in import scenarios as long as the marginal buying bid is lower than the NO2 price forecast. Algebraically, we calculate the premium in a given hour as follows:

$$\pi = \begin{cases} p_{NSL} - \hat{p}_{NO2}, & \text{if } p_{GB} > \hat{p}_{NO2} \\ \hat{p}_{NO2} - p_{NSL}, & \text{if } p_{GB} < \hat{p}_{NO2} \end{cases} \tag{5.7}$$

We model that a marginal trader does not bid in a premium π when $p_{NSL} = \hat{p}_{NO2}$. The trader's loss comes from forecasting the wrong price in NO2 and thus placing the wrong bids in the NSL or NO2 auction. The underlying assumption is that our point forecasts are representative of what the marginal trader faces in the market. Consequently, the premium reflects the required rate of return (RRR) a marginal trader expects from participating in the NSL auction.

The traditional econometric forecasting methods have limited ability to capture the impact of unexpected events. We see that extremely cold winter days or power plant outages can give large jumps in the actual NO2 price. As we are unable to capture these dynamics, the ex-ante premium we find will be overstated in terms of the true premium achieved by the market. The problem is best illustrated through an example. Suppose that there is a power plant outage that creates a price jump in the market. The econometric forecasting method is not able to properly capture this dynamic and predicts a NO2 price of €100/MWh while the actual NO2 price clears at €110/MWh. Consider an export scenario where the NSL auction clears at €115/MWh. A trader will, in this case, achieve a premium of €5/MWh, while our econometric model finds that he requires a premium of €15/MWh. This means that we will model a higher premium than what is actually achieved in the market. The opposite is also true for sudden drops in prices. Despite the inaccuracy, we argue that the ex-ante premium is a more interesting measure since it reflects how a marginal trader bids on their ex-ante information.

5.7 Commercial Cost of Uncoupling

The commercial cost of uncoupling (CCU) is the loss in congestion revenue relative to the total congestion revenue under market coupling (Guo and Newbery, 2021a). Thus, the lost congestion revenue is equal to the difference between the obtained congestion revenues under the current implicit auction scheme and the congestion revenue that would arise if only determined by the NO2-GB price spread through coordination in EUPHEMIA.

Given the observed values of net flow from NO2 to GB V, the GB price p_{GB}, the NSL price p_{NSL}, and the NO2 price p_{NO2}, the lost congestion revenue from the separate NSL auction is calculated as follows for a given hour:

$$CCU = V * (p_{GB} - p_{NSL}) - V * (p_{GB} - p_{NO2}) \tag{5.8}$$

The equation estimates the lost congestion revenues on the basis of the cost of the premiums required by the traders on the NSL. It does not consider that coupling the auction would change the flow and the prices in both markets.

6 Data

The following chapter gives a description of the data used in the thesis. Table 6.1 gives an overview of the relevant data with regards to their unit, frequency and source from which it is gathered. The first seven rows in the table present data used to forecast the NO2 price and will be further described in the first section of this chapter. The last three rows present data on the NSL cable used to analyse the forecasting results. The NSL data will be described in more detail in the last section of the chapter. All observations are collected from the first trading day of the North Sea Link on the 1st of October 2021 to the 15th of January 2023. In total, there are 12 048 observations in our data set, including 29 missing values that we interpolate linearly.

Variable	**Unit**	**Daily**	**Hourly**	**Source**
Day-ahead NO2(SDAC) price	€/MWh		x	ENTSO-E
Day-ahead NO2(NSL) price	€/MWh		x	ENTSO-E
Day-ahead GB(N2EX) price	€/MWh		x	Nord Pool (N2EX)
Day-ahead GB(EPEX) price	€/MWh		x	EPEX SPOT
Norwegian load forecast	MW		x	ENTSO-E
Norwegian wind forecast	MW		x	ENTSO-E
Day-ahead UK NBP gas price	€/MWh	x		NBPGDAHD Index
Auction volumes	MW		x	Nord Pool (N2EX)
Market coupling capacity	MW		x	Nord Pool (N2EX)
Cross-border physical flow	MW		x	ENTSO-E

Table 6.1: Overview of data provided in the thesis with regards to unit, frequency and source

6.1 Forecasting Data

This section provides an overview of the data used in the forecasting process. First, we describe the day-ahead spot price data. Second, we present the exogenous variables used in the multivariate forecasting models.

6.1.1 Day-Ahead Spot Prices

Historical data on day-ahead spot prices for NO2(SDAC) and NO2(NSL) have been collected from ENTSO-E´s transparency platform. Further, GB day-ahead prices have been collected for GB(N2EX) and GB(EPEX) through Nord Pool's FTP server and EPEX SPOT, respectively. The spread between GB(N2EX) and GB(EPEX) is found to be relatively small[2]. Since the GB(EPEX) auction clears before the NSL auction, market participants will therefore know the GB price when bidding into the NSL auction and only have to forecast the NO2 price.

The data is observed with an hourly granularity, and the NO2 prices are measured in €/MWh while the GB prices are measured in £/MWh. For the forecasting, all price data should be given in the same currency, and so the GB prices are converted to euros using the daily exchange rates from the Nord Pool FTP server.

The day-ahead spot price series for NO2(SDAC) and GB(EPEX) is presented in Figure 6.1 and Figure 6.2. Short-term jumps and spikes in positive and negative directions can be seen for both NO2 and GB. Further, the electricity prices show levels of mean reversion, indicating that the electricity price in the longer-run returns to the long-term average related to the generation costs of electricity. The GB price data shows higher levels of both spikes and mean reversion. Figure 6.1 and Figure 6.2, also show situations with small random movements around the average trend, representing temporary imbalances of supply and demand. The curves exhibits signs of volatility clustering, where small changes tend to be followed by small changes and large changes are followed by large changes.

[2]The spread between the GB(N2EX) and GB(EPEX) is found in Appendix A3.2

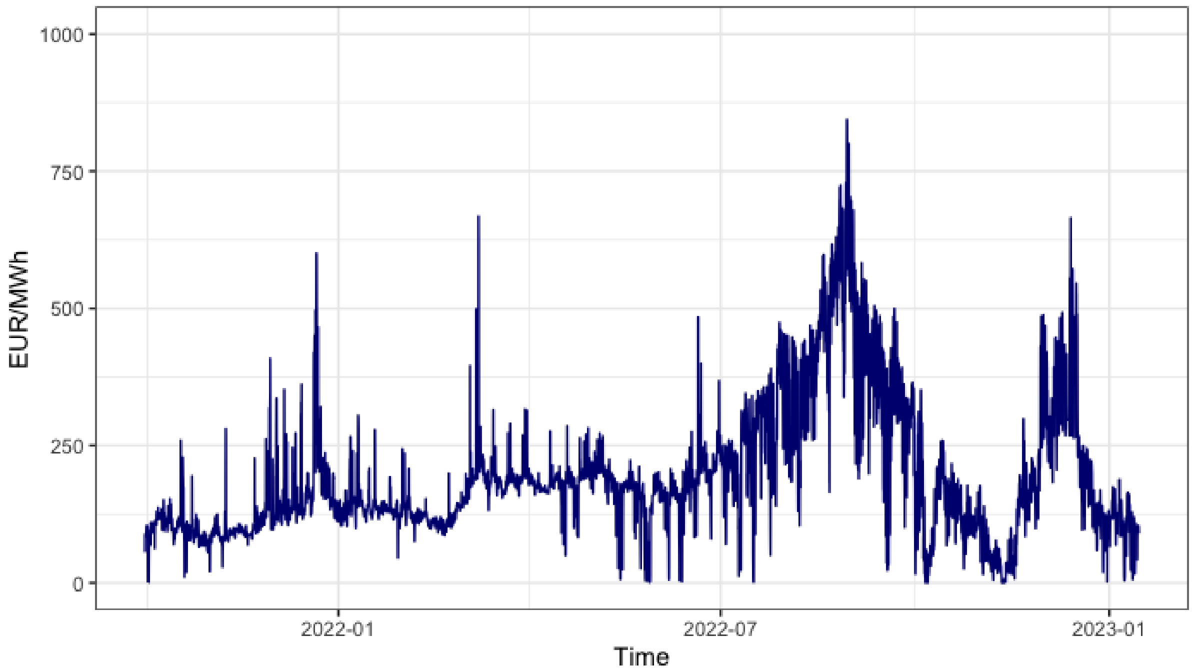


Figure 6.1: Day-ahead spot prices for NO2, 1st of October 2021 to 15th of January 2023

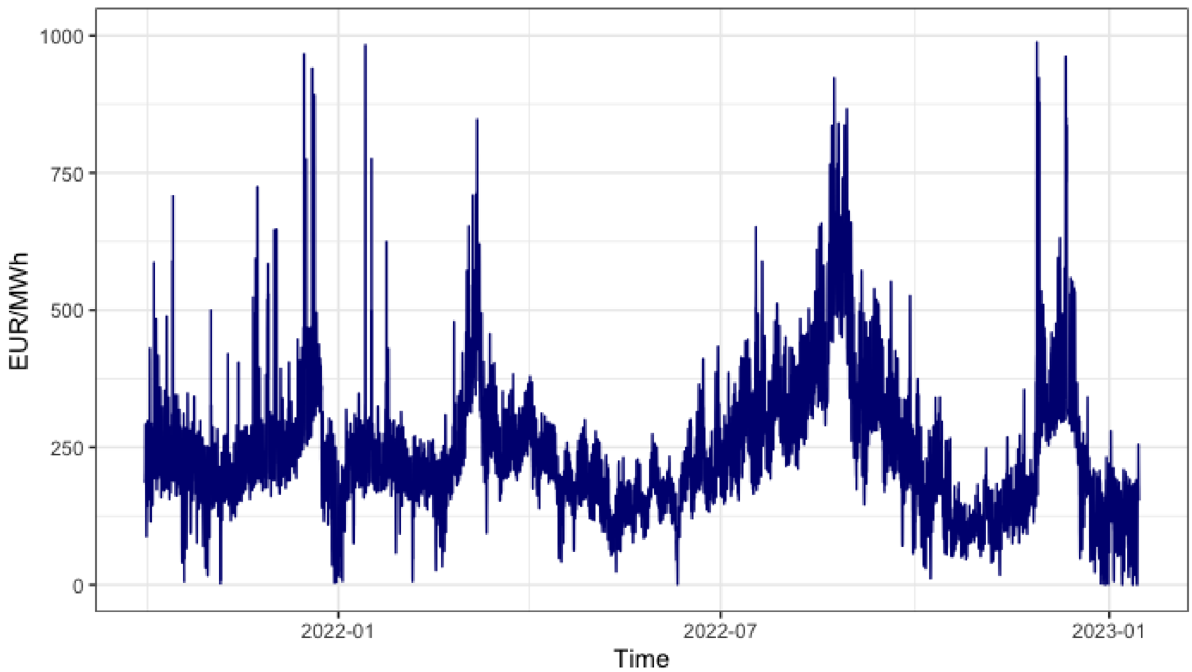


Figure 6.2: Day-ahead spot prices for GB (EPEX), 1st of October 2021 to 15th of January 2023

The basic descriptive statistics of the electricity prices for both NO2 and GB are presented in Table 6.2. In the succeeding section, the summary statistics of NO2(SDAC) and GB(EPEX) will be further discussed. With means of €234.74/MWh and €186.08/MWh for GB and NO2, respectively, GB evidently has the highest mean price. Further, both markets have a median price below the mean, indicating a central tendency for both the GB and NO2 prices to be positively skewed to the right, where most of the prices are lower than the average.

Variable	**Mean**	**Median**	**Sd**	**Min**	**Max**
NO2(SDAC) price	186.07	155.98	117.66	-1.97	844.00
NO2(NSL) price	188.28	160.07	115.19	-2.69	809.89
GB(EPEX) price	236.73	211.15	136.65	-29.60	3,012.68
GB(N2EX) price	234.73	209.77	134.88	-59.59	2,933.76

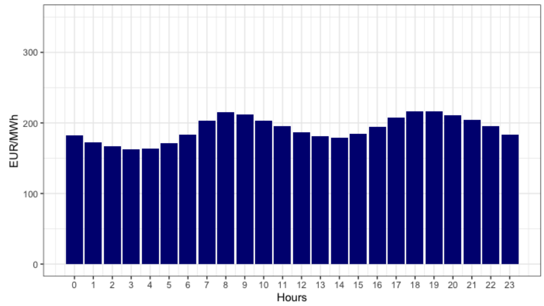
Table 6.2: Summary statistics of NO2 and GB day-ahead prices

The occurrence of negative prices is one of the aspects differentiating electricity prices from other commodities and financial assets. Negative prices often occur in situations with low demand and high production from inflexible or intermittent energy sources. Both GB and NO2 experience hours with negative prices, with GB having the lowest minimum price of -€29.60/MWh, compared to -€1.97/MWh for NO2. When considering the maximum price, there is an even greater difference between the two markets, with GB´s maximum price of €3,012.68/MWh being almost 3.5 times as high as the NO2 maximum price of €844.00/MWh. With both the lowest minimum price and highest maximum price, GB noticeably has the largest price range of the two markets.

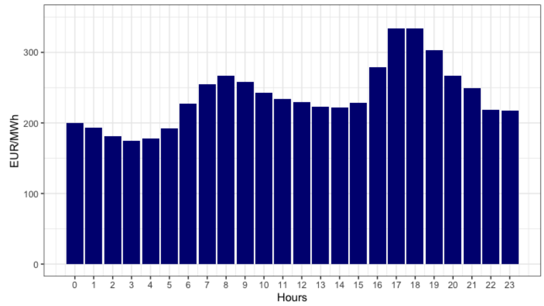
The standard deviation is high for both markets, with €136.65/MWh for GB and €117.6/MWh for NO2. This supports the volatile characteristics of electricity prices in both markets. The GB price is slightly more volatile, which could be explained by its larger share of intermittent renewable energy sources and dependency on carbon-intensive generation through high-cost technology, giving a higher market clearing point.

Figure 6.3 shows the average day-ahead prices for each week and all hours in NO2 and GB from 2018 to 2023. The subfigures indicate seasonality in the electricity prices both on a daily and weekly level. The daily prices show a clear pattern of peaks in the morning and evening hours for both NO2 and GB. However, the variations throughout the day are found to be greater for the GB price. The electricity price also exhibits some seasonality on a weekly level, with the prices going slightly down during the weekend in NO2. For

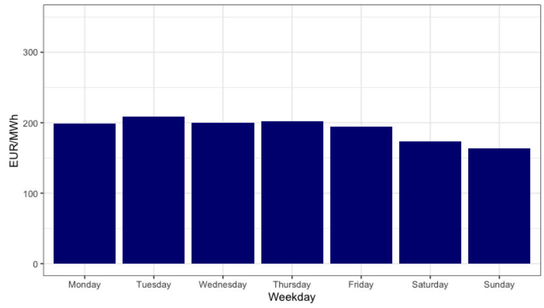
GB the weekly pattern is slightly different, with lower levels on Friday and Saturday but higher levels on Sunday.



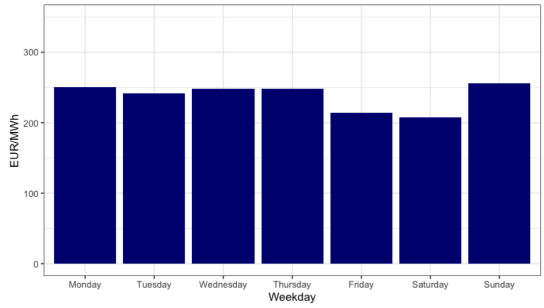
(a) Average prices for each trading period in NO2



(b) Average prices for each trading period in GB



(c) Average prices for each weekday in NO2



(d) Average prices for each weekday in GB

Figure 6.3: Day-Ahead price averages in NO2 and GB

6.1.2 Exogenous Variables

The day-ahead price is influenced by several fundamental drivers that should be considered in the forecasting process. These factors include domestic and foreign renewable production, demand, weather, as well as fossil fuel prices and permits. We chose to include the variables that together minimized the MAE and RMSE of the multivariate forecasting models in the sample period. The high share of hydropower in the Norwegian electricity system makes the electricity price very dependent on the weather and reservoir levels. Note that we choose not to include hydrological data as we do not have sufficient granularity on the reservoir filling levels. The filling levels are reported once a week, while we fit our model on a 7-day window. This means that we would have to forecast based on only one filling level observation for each iteration.

Table 6.3 provides an overview of the descriptive statistic for the chosen exogenous variables. In the following section, these factors and the impact they have on the day-ahead prices will be described.

Variable	Mean	Median	Sd	Min	Max
Norwegian load	15,376.13	15,028.00	2,881.47	9,992.00	25,194.00
Norwegian wind production	1,682.87	1,581.00	900.37	37.00	7,088.00
UK NBP gas price	17.91	16.26	9.79	2.13	40.59

Table 6.3: Summary statistics of exogenous variables

Load Forecast

The electricity price is highly dependent on the load or demand. Even though it is close to inelastic, there are still variations in the demand depending on the time of the year, day of the week and hour of the day. During the colder winter months, demand is usually higher compared to the warmer summer months. These seasonal variations in electricity demand can be seen in Figure 6.4. Further, industrial loads are usually high during weekdays but significantly lower during weekends. For households, on the contrary, the load is usually higher during weekends compared to the weekdays. To account for the seasonality, the time series is made stationary by decomposition in the multivariate models[3].

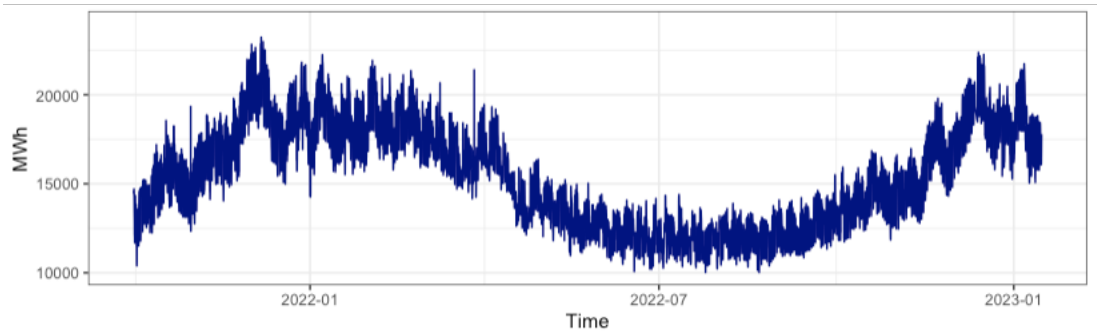


Figure 6.4: Plot of the expected demand in the studied period

Wind Production

Following the merit order effect, renewables are known to have a downward pushing effect on electricity prices due to their low operational costs. At the same time, the intermittent nature of many renewable energy sources makes the electricity price more volatile and dependent on the weather conditions. In both NO2 and GB, wind power constitutes a considerable share of the generation mix and is a central price driver in both markets. The fluctuating nature of wind power generation can be seen in Figure 6.5. In situations

[3]The seasonal decomposition of the load is found in Appendix A2.8

with little forecasted wind production, costlier generation technologies might have to be used to meet demand, resulting in a higher electricity price. The thesis is focused on performing ex ante forecast of the day-ahead electricity price. Since the traders do not have data on the actual generation from wind for the next day, we use the forecasted generation instead.

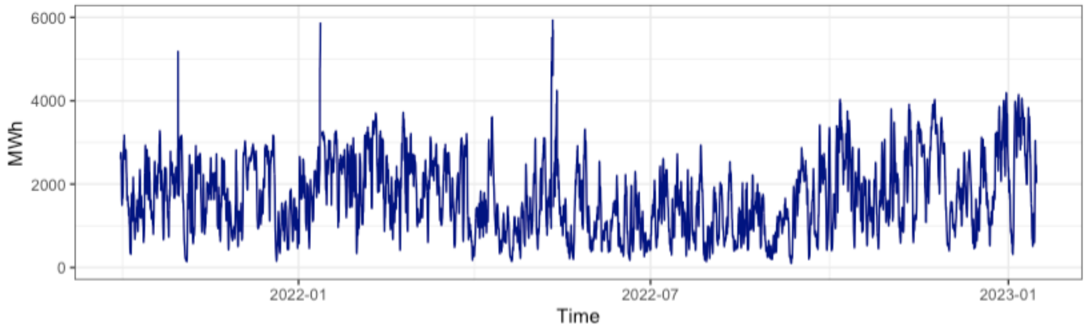


Figure 6.5: Plot of the forecasted wind power generation in the studied period

Gas Prices

Even though the share of fossil fuels in the Norwegian electricity system is limited, the gas price can still have an impact on the market clearing price in NO2. This could either happen directly when there are imports of electricity from e.g. Germany through the NordLink cable or indirectly because the gas price affects the opportunity cost of water for hydropower producers. The UK National Balancing Point (NBP) gas price is used as a proxy for the cost of generating electricity from gas in Europe. The data is observed on a daily level in £/thm, but is converted to €/MWh in order to be used in the forecasting. Furthermore, we interpolate the daily values by assigning the daily price to each hour on that day. The day-ahead UK NBP gas price is announced to the market at 17:30 CET, meaning that players are only informed on historical price developments in their ex-ante bidding on the NSL. Figure 6.6 shows the historical developments of the NBP gas prices over the time period of the data set, showing a peak in gas prices in the late summer of 2022. The record-high gas prices reverted close to average levels throughout the fall as the European gas storages were filled up.

Figure 6.6: Plot of the day-ahead gas prices in the studied period

6.2 North Sea Link Data

The following section describes the North Sea Link-specific data that we use in the analysis of the forecast results. First, we present the hourly auction volume data, which denotes the cumulative buying and selling bids submitted in the auction. Then, we present the data of the actual flow and capacity before displaying the interaction between the flow and price data.

Auction Volumes

We are using the N2EX day-ahead auction volumes to investigate the hourly liquidity in the NSL auction. The NSL auction volumes are collected from Nord Pool's (N2EX) FTP server. Figure 6.7 displays the volumes sold and purchased on the NSL in the first week of January 2023. The bids are subject to the direction of the flow (GB(N2EX)-NSL price spread) and the relevant interconnector capacity on the interconnector. At the most, in February 2022, there was 3 496 MW of selling bids submitted into the auction. The submitted selling bid volume is generally larger than the buying bid volume, and the volumes bid are generally larger than the available capacity. The average selling bid volume was 1 438 MW in the period, while the average export capacity was 977 MW. Moreover, the average buying bid volume was 1 022 MW, while the average import capacity was 876 MW. We also see that there is a volume bid in each direction every hour. A reason can be that generators and retailers always submit a base volume of selling and buying bids or that financial traders place opposite bids to make a profit regardless of the direction of the flow. The bids that are accepted constitute the flow on the NSL.

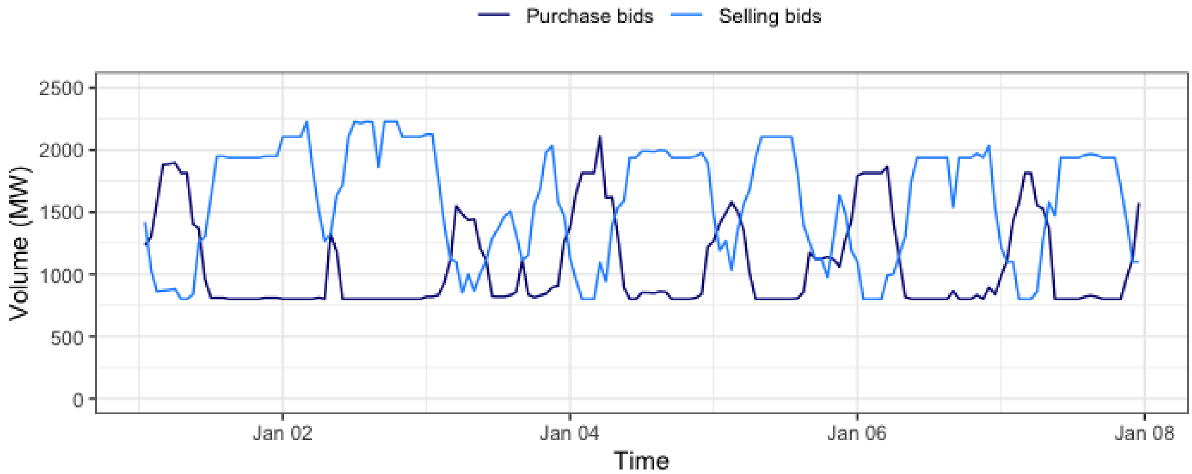


Figure 6.7: NSL day-ahead auction volumes in the first week of January 2023 (complete time series plot in Appendix A3.3)

Capacity and Flow

Data on cross-border transmission capacity and flow on the NSL is needed to calculate the congestion revenue. The capacity and flow data is collected from Nord Pool's FTP server and the ENTSO-E transparency platform. Regarding the flow on the interconnector, it should be noted that for the first year of operation, the cable was in a trial phase with a capacity of only 700 MW. In total, for the whole time period studied, the line was congested in 62% of the total hours, and there was export 72% of the time[4]. Figure 6.8 displays the flow and capacity during the first week of January 2023. The negative values constitute the import capacity and flow.

Furthermore, Figure 6.9 shows the total hours of import and export for each hour of the day. We see that most import is happening during night-time. Over the period, NSL exports have accumulated to 6 406 824 MW while imports have accumulated to 1 766 721 MW, giving a net export of 4 640 103 MW. Given the tendency of GB prices to usually be above the NO2 price, more hours of export are natural as the power will flow from the low-price area to the high-price area when the markets are connected.

[4]For complete time series plot see Appendix A3.4

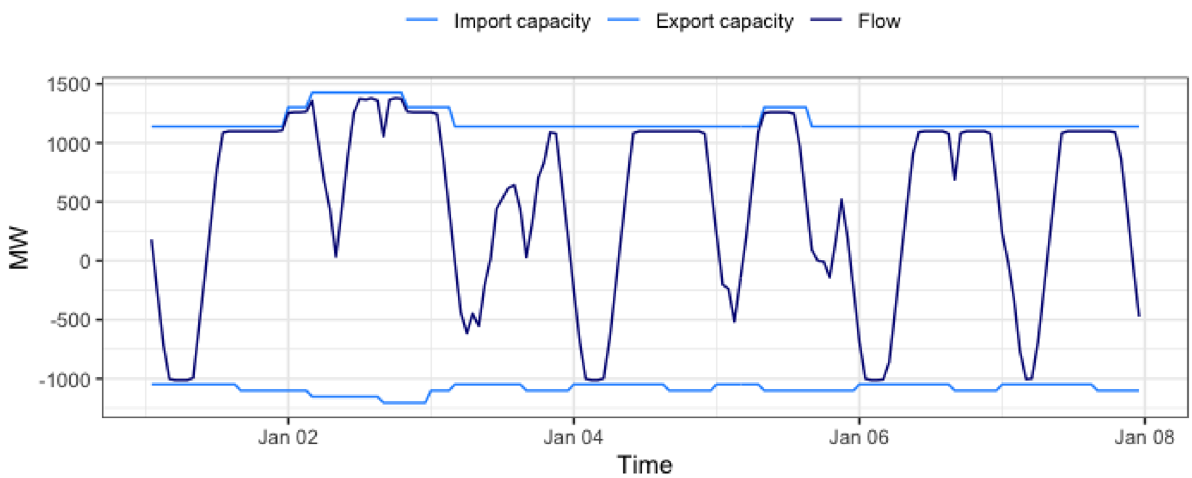


Figure 6.8: Cross-border capacity and flow on the North Sea Link in the first week of January 2023 (complete time series plot in Appendix A3.4)

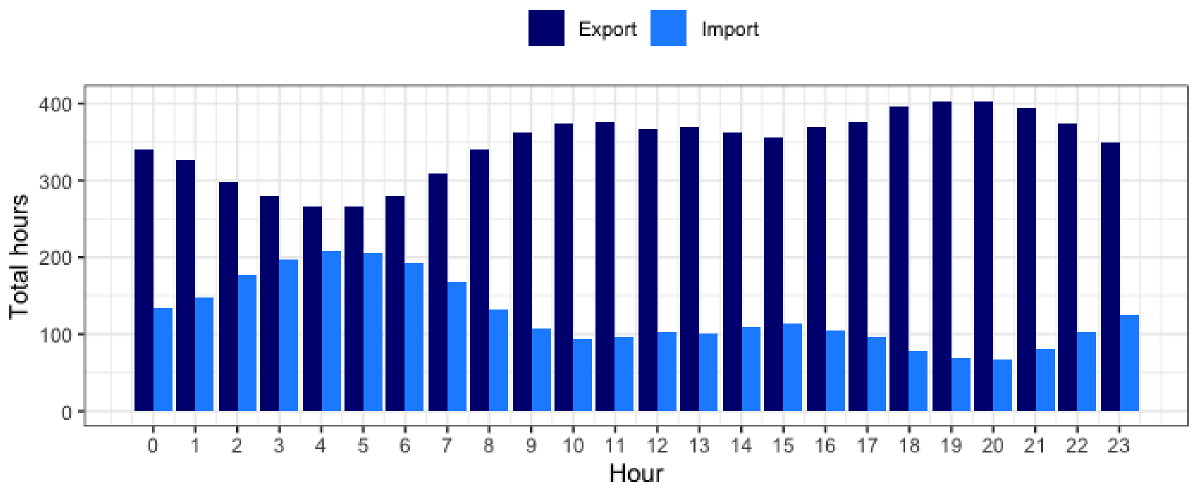
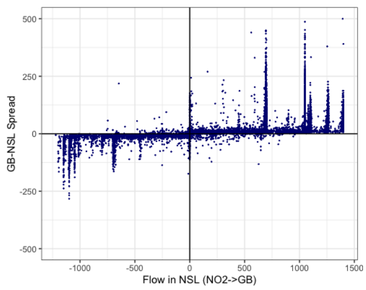


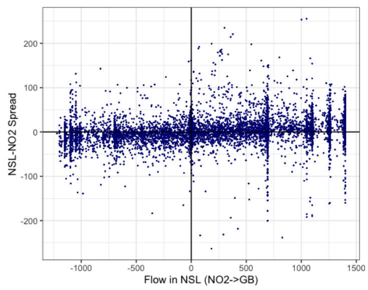
Figure 6.9: Hours of import and export on the NSL from NO2

Flow and Price Differences

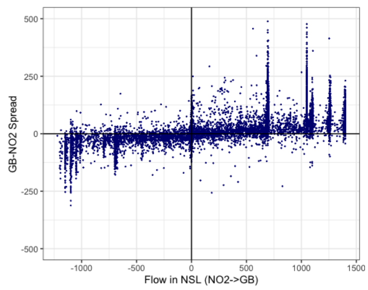
The flow on the NSL is determined by the GB(N2EX)-NSL spread, illustrated by Figure 6.10a. The observations in the second and fourth quadrants are inefficiencies caused by the 308 MW/h ramping constraint on the interconnector and make up 4.5% of the total hours. This is not the case in Figure 6.10b, which displays the flow against the NSL-NO2 price spread. The observations in the second and fourth quadrants make up 32.1% of the total hours and represent the hours where the traders make an incorrect judgement of the sign of the price difference. This means that traders in the NSL auction are losing every third hour with their bets in the North Sea Link auction. The most extreme consequence of this speculation is a flow against the GB(N2EX)-NO2 price spread. This occurs in 10.4% of the total hours, represented by the observations in the second and fourth quadrants in Figure 6.10c. As only 4.5% of these observations can be explained by ramping constraints, 5.9% of the flow against the price difference must be caused by the implicit auction solution. In the next chapter, we will investigate how this inefficiency is related to a trading premium and thereby answer the research questions of this thesis.



(a) GB-NSL price spread and flow



(b) NSL-NO2 price spread and flow



(c) GB-NO2 price spread and flow

Figure 6.10: Spread/flow diagrams

7 Results and Discussion

This chapter gives a presentation and discussion of the results achieved. Firstly, the optimal forecasting method for DA NO2 prices will be determined based on its performance on the reported error measures. Further, the calculated premiums a marginal trader would bid into the NSL auction are presented, and the underlying mechanisms that drive the premiums will be identified and discussed. Lastly, we analyse the impact this premium has on the congestion revenues of the interconnector owner by calculating the commercial cost of uncoupling.

7.1 Identifying the Optimal Forecast

Table 7.1 presents the error measures of the forecasting results on the NO2 DA prices from the 8th of September to the 8th of October 2021. Among the six proposed econometric methods, ARX substantially outperforms the others on all reported accuracy measures, followed by the automatic ARIMA model. A MAE of 9.58 indicates that the ARX forecasts, on average, are off by €9.58/MWh. Even though this is high compared to the mean, we consider this an acceptable measure due to the strong volatility in electricity prices in the period. Consequently, we employ the ARX method to model the premium bid in the NSL auction by a marginal trader.

Model	Type	MAE	RMSE
ARX	Test	9.58	15.05
autoARIMA	Test	10.60	18.06
SLR	Test	11.37	18.24
ARIMA013011	Test	11.43	19.23
ARIMA310011	Test	11.81	20.10
SN	Test	11.99	20.92

Table 7.1: Forecast error measures by time series cross-validation

The coefficients from the ARX model in Table 7.2 confirm the expected dynamics and may explain why it is able to forecast the NO2 price better than the SLR and univariate models. It shows how the first day-ahead forecast on the 1st of October 2021, is affected by the variables from the previous seven days. Even though this regression output only displays 1 of 470 different windows, we can interpret the direction and strength of the linear relationships. The positive first-order autoregressive coefficient (ar1) indicates a strong positive linear relationship between the current value and its immediately preceding value, meaning that an increase in the past price would lead to an increase in the current price. This aligns with our assumption that electricity prices are highly dependent time series. Furthermore, we see that increasing load (no_load) and UK NBP gas prices (uknbp_price) are related to higher prices, while increased wind (no_wind) and weekends (day_type1) are related to lower prices. The lower prices due to increased wind follow the assumptions of the merit order effect. The p-value associated with each estimated coefficient is a measure of the evidence against the null hypothesis that the true value of the coefficient is zero. A value less than 5% indicates that the variable has no effect on the outcome. Consequently, for the first iteration, we see that wind power and weekends have a limited effect on the day-ahead forecast.

Term	Estimate	Std.Error	p-value
ar1	0.729	0.052	0.000
no_load	0.002	0.001	0.005
no_wind	-0.003	0.002	0.076
day_type1	-0.483	1.752	0.783
uknbp_price	2.419	0.908	0.008
intercept	35.667	20.929	0.090

Table 7.2: ARX fit on a sample window

7.2 Premium Required by Traders

We assume that marginal traders make forecasts using the ARX method. Using Equation 5.7, we find that marginal traders are, on average, bidding a premium of €17.78/MWh into the NSL auction over the forecasted NO2 price[5].

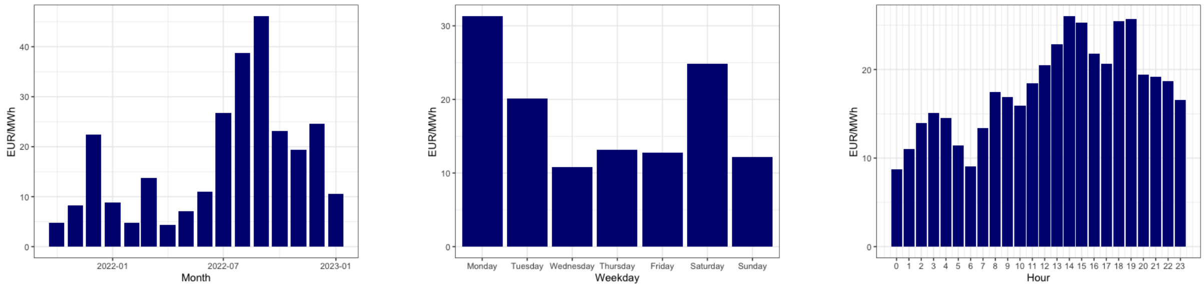
First, we present the monthly average modelled premiums in Figure 7.1a. Since the opening of the NSL, the premiums required by the marginal traders have varied significantly, with the highest premium observed in September 2022 at €46/MWh. Following the high levels during Q3 2022, the premium decreased slightly towards Q4 2022. Nevertheless, it still remained at a considerable level, with premiums above €10/MWh in the last month of observation. The premium observed in the last month is twice the size of the premium

[5]The distribution of the modelled premiums is found in Appendix A4.2

observed in the first month. This contradicts the expectation that NO2 and NSL prices would converge through increased competitive trading on the price difference.

Further, the modelled average premium per day of the week in the period is calculated and presented in Figure 7.1b. We see that the daily premium exhibits significant spikes on Mondays and Saturdays. We hypothesise that the large premium observed on Mondays can be explained by the nature of a normal work week. As the day-ahead bids for Monday are submitted into the NSL auction at 10:50 each Sunday, many traders are on leave from the office at the time of auction closing. Consequently, the competition for the available capacity is not as intense as during the weekdays[6]. This indicates that a lack of competition can be one of the drivers behind the premiums.

Lastly, we present the modelled average premium per hour in Figure 7.1c. We observe the lowest premiums in the hours following the NSL auction closing. This could indicate that uncertainty about the forecasted NO2 price is what drives the premium, as the hours closest to the auction closing are more certain. The night-time hours are also the hours with the lowest load during the day, which could contribute to lower uncertainty with regard to demand in the given hours.



(a) Average premium each month

(b) Average premium each day

(c) Average premium each hour

Figure 7.1: Plots of the average modelled premiums

7.3 Potential Drivers of the Premium

For a competitive NSL auction, the assumption is that prices will be driven to marginal costs. Any deviations from this should be attributed to forecasting errors. However, our empirical evidence suggests that there is not only a significant but also a systematic price difference between the two auctions that cannot only be explained by forecasting errors.

[6]The average liquidity each day is displayed in Appendix A3.1

Given the presence of a dominant player in NO2 production and the observation of the largest premiums on Mondays, our first hypothesis is that the premium is a result of market power. Furthermore, we see that the premiums correlate with periods of high uncertainty, and our second hypothesis is, therefore, that traders are risk-averse.

7.3.1 Market Power Exertion

An implicit assumption in all models attempting to analyze market power is that the departure from marginal cost pricing is due to some form of general or locational market share concentration (Oren, 1997). When applying for an extended market license, Nord Pool (2020a) identified a risk that the abuse of a dominant position could contribute to systematic differences between the two auctions. We investigate the potential for market power use in the NSL auction by first investigating the dominant producers in NO2. Then, we look at the NSL auction liquidity to determine whether enough players are participating in the NSL auction.

Market Power Potential by a Dominant Producer

In an oligopoly, dominant market players will have incentives to divert their bids from the marginal cost in order to increase their profits. With Statkraft controlling 45.7% of the production in NO2, there is a risk of price impacts if it is poor competition in the bidding area (DNV, 2019). Here, the emphasis is on Statkraft's potential to engage in price manipulation on the NSL auction to capture congestion rents that otherwise would be claimed by the interconnector owner (Ea Energy Analyses, 2008).

We limit our analysis to the residual supply index (RSI), used in multiple other studies of electricity market concentration (Swinand et al., 2010). The RSI was originally proposed by Sheffrin (2001) to monitor the Californian electricity market, but it has also been applied to investigate market power in Norway by McDermott (2020) and DNV (2019). The RSI is formally defined as:

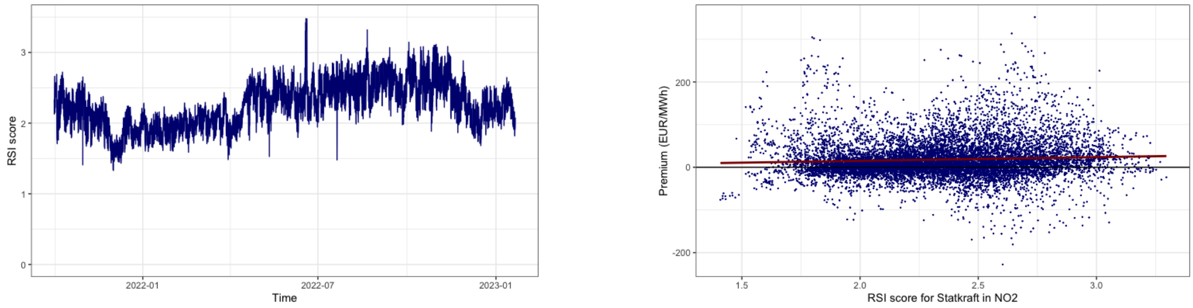
$$RSI_f = \frac{\text{Total capacity - Firm } f\text{'s capacity}}{\text{Total demand}} \tag{7.1}$$

Where the total production capacity is the total regional supply capacity plus the sum of hourly import capacities, and the total demand is the hourly consumption plus an assumed reserve capacity.

A precise calculation of RSI requires hourly information on actual production capacities from the producers. In the absence of bid information in the day-ahead market, we follow DNV (2019) and predict a rough RSI for Statkraft in the following way. For each hour in the time period, we use the actual NO2 consumption and the actual NO2 import capacities given to the day-ahead market on NordNed, North Sea Link, Skagerrak, NO1NO2 and NO5NO2. Furthermore, we assume a total installed production capacity of 13 000 MW in NO2 (ENTSO-E, 2023). Since RSI is a measure of short-term adequacy, we assume a 90% availability during all hours for the producers in NO2 and that Statkraft operates 45.7% of the total capacity. We also assume that a maximum of 750 MW production in NO2 is needed as a reserve for system services. Moreover, we assume that firm ownership of reservoirs and the total installed capacity remains constant over the review period. RSI thus captures the extent to which supply can meet demand, absent the supply of the dominant firm. It is measured inversely to market power, such that a smaller RSI indicates greater market power. Similarly, an RSI of less than 1 implies that a firm is pivotal (Hellmer and Wårell, 2009).

The simplifications of the dynamic market setting, that is the hydro-based electricity system in NO2, can distort the RSI scores. We note that the assumption of constant short-term availability of production at 90% is an oversimplification. The storability of water means that producers will have a dynamic availability that is low in hours of high water values or low reservoir levels. In fact, the average capacity factor of hydropower plants is closer to 50%, meaning that the true market power potential is understated in many of the observed hours. Thus, the calculated RSI should be interpreted with caution.

The graph in Figure 7.2a displays the calculated RSI for Statkraft in NO2 for all of the 12 048 hours in the data set. The average RSI is 2.22, which is far above the threshold of a pivotal supplier. The lowest RSI observed is 1.34 and occurs in hours 9 and 10 on the 1st of December 2021, when the peak load in the period in NO2 coincides with hours of reduced import capacities because of grid maintenance and disturbances. Possible low RSI in hours with low availability of production from other companies in NO2 is missing in the figure as we do not have access to individual bid data given to the day-ahead market. The



(a) Rough RSI score for Statkraft in NO2 **(b)** RSI score and modelled premiums

Figure 7.2: Market power potential and premiums

conclusion drawn from the RSI calculation is that Statkraft normally has a low potential to use market power in NO2, although its market share is 45.7% in NO2 production. The competition is enhanced by the extensive interconnectors between NO2 and other bidding areas. However, the potential to use market power is higher in peak load hours or in hours with very small import capacities. The potential is also increased in hours with low availability in the plants of other producers in NO2.

In Figure 7.2b, we plot the hourly predicted RSI score against the modelled premiums in the NSL auction to investigate whether Statkraft has exerted market power to capture congestion rents. One would expect to see decreases in the RSI value to be correlated with increases in the premium. We regress the hourly premiums bid in the market on the RSI score and find that an increase in the RSI score of 1 is related to a 7.48 increase in the premium we observe, significant at a 5% level[7]. The scatter plot shows that even in the hours when Statkraft has the highest potential to use market power, with an index close to 1 in NO2, they are not able to impact the premium on the NSL auction price. Assuming the RSI is a sufficient measure of short-term market power potential in hydro-dominated power systems, the result contradicts our expectations and shows that the premiums are not a direct result of market power among producers in NO2.

One explanation lies in the relative size of the NSL auction. The NSL has a maximum capacity of 1 400 MW, while the total production capacity in NO2 is around 13 000 MW. This effectively means that it is impossible to exert market power with the current auction timing as long as participants in the NO2 auction are actively and aggressively participating in the NSL auction. If, however, the auction closing was after SDAC, then

[7]The output from the linear regression is displayed by regression (1) in Appendix A4.1

producers could risk locking in too much production in the SDAC auction resulting in lower liquidity and a higher potential for market power in the subsequent NSL auction. However, this potential is also further undermined by the possibility of speculators trading on the price difference.

Furthermore, there is a risk that producers will exert any market power on the NO2 price directly instead of in the NSL auction. Theory tells us that dominant hydropower firms will reallocate their water resources away from periods with relatively inelastic demand for electricity to periods with relatively elastic demand. This would allow them to recoup higher profits by restricting supply when consumers are least responsive to the resulting price increase (McDermott, 2020). These effects would not be captured by the auction premium calculated by Equation 5.7.

In summary, these finding rules out market power exertion by Statkraft as an explanation of the observed premium but has highlighted the importance of active participation in the NSL auction. To be able to rule out competition issues as a driver of the premium, we have to investigate the liquidity of the auction.

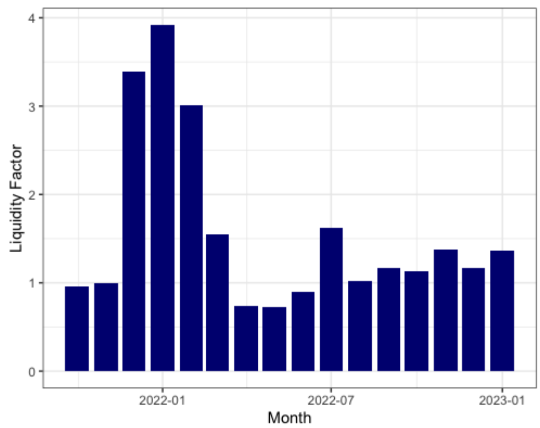
Auction Liquidity

In this section, we calculate the liquidity factor in the NSL auction. We define the liquidity factor as the hourly volume bid[8] over the available capacity[9] on the forecasted direction. A large liquidity factor means that there is strong competition for the available capacity on the NSL. Liquidity equal to or less than 1 means that there is no competition on the capacity, and all matched bids are accepted. Figure 7.3a displays the monthly average liquidity factor in the NSL auction. The average liquidity factor in the studied period is 1.63. The lowest liquidity was observed during April, May and June 2022. In these months, the average liquidity factor was below 1, corresponding with reduced capacity and low utilization on the interconnector[10]. Moreover, it seems like the auction liquidity has increased since the full capacity of 1 400 MW was made available to the market in June 2022.

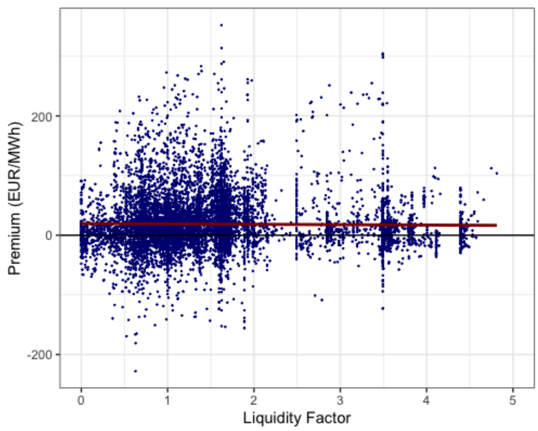
We would expect the hours of low liquidity in the NSL auction to increase the premium

[8] The hourly auction volume is displayed in Appendix A3.3
[9] The hourly available capacity is displayed in Appendix A3.4
[10] The monthly utilization on NSL is displayed in Appendix A3.6

achieved in the market, assuming that the participants are competitively trading. In Figure 7.3b, we plot the hourly liquidity factor against the modelled premiums. It is difficult to determine any relationship between the variables. A linear regression finds no statistically significant relationship between the auction liquidity and the observed premium[11]. This result contradicts the assumption that NO2 and NSL prices would converge through increased participation, indicating that the trading is not competitive enough. It seems like the participation is sufficient to lower the premium to at least the expected value of the player's risk. This result aligns with the previous finding that Statkraft was unable to exert market power in the NSL auction.



(a) Monthly average liquidity factor in the NSL auction



(b) Liquidity factor and modelled premiums

Figure 7.3: Auction liquidity and premiums

In summary, we do not find any evidence of market power exertion that could explain the observed premiums. More than that, it seems like the participants are not good enough at exploiting the price differences between the two auctions. In the next section, we will therefore investigate the participants' willingness to take risks.

[11]The output from the linear regression is displayed by regression (2) in Appendix A4.1

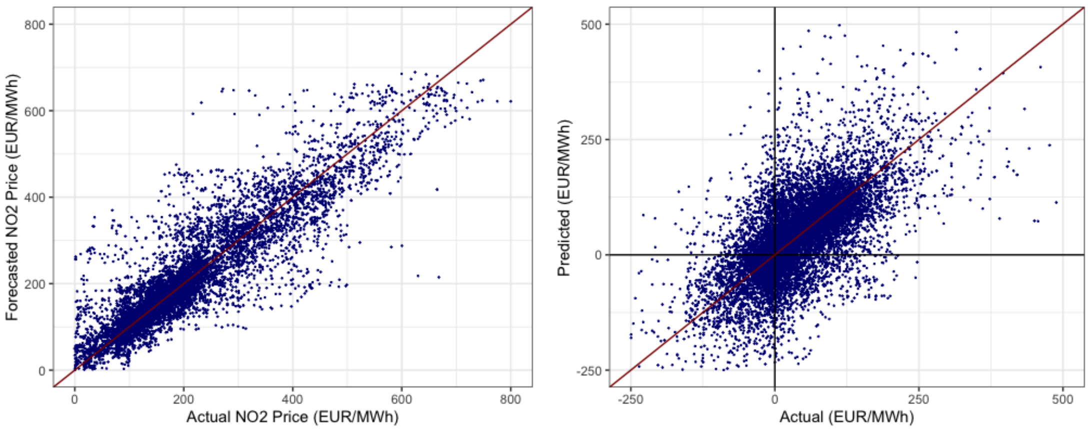
7.3.2 Risk Aversion

In an efficient market, risk-neutral traders would seek to take advantage of an arbitrage opportunity and eliminate any price differences between the two separate auctions. As we see systematic price differences, the second hypothesis is that the premium arises because traders are risk-averse. We begin by defining risk aversion as if a trader, for any arbitrary risk, prefers the sure amount equal to the expected value of the risk to the risk itself (Menezes and Hanson, 1970). Effectively, this means that the marginal trader will insure against a higher risk by requiring a higher premium.

Risk and Uncertainty

With the separate NSL auction closing before the regular NO2 auction, traders are exposed to the risk that their ex-ante market positions and NSL bids may lock them into unprofitable trades if their projections of the NO2 prices are wrong. Figure 7.4a illustrates the difficulties in forecasting accurate NO2 prices. The observations left of the 45-degree line represent the hours where a marginal trader would forecast a higher NO2 price than what is actually observed. The plot shows that the inaccuracy in NO2 price forecasts increases as the price increases. This supports the expectation that the econometric ARX method is unable to accurately predict the NO2 price in sudden high-price hours. Trading on the NSL based on forecasts far from the 45-degree line puts a player at risk of severely losing on their bets.

Figure 7.4b displays a scatter plot of the actual GB-NO2 spread against the forecasted price spread using the ARX method. We see that most of the observations are relatively evenly spread along the 45-degree line, indicating that in most situations, we are able to forecast the price spread accurately. However, there are also points located in the second and fourth quadrants, representing the hours when the traders make an incorrect judgement of the sign of the price difference. For instance, in quadrant four, the points represent situations where the traders are forecasting export when it actually becomes import on the interconnector. In total, we find that a trader using the ARX method will misjudge the sign of the price difference in 18.4% of the total hours.

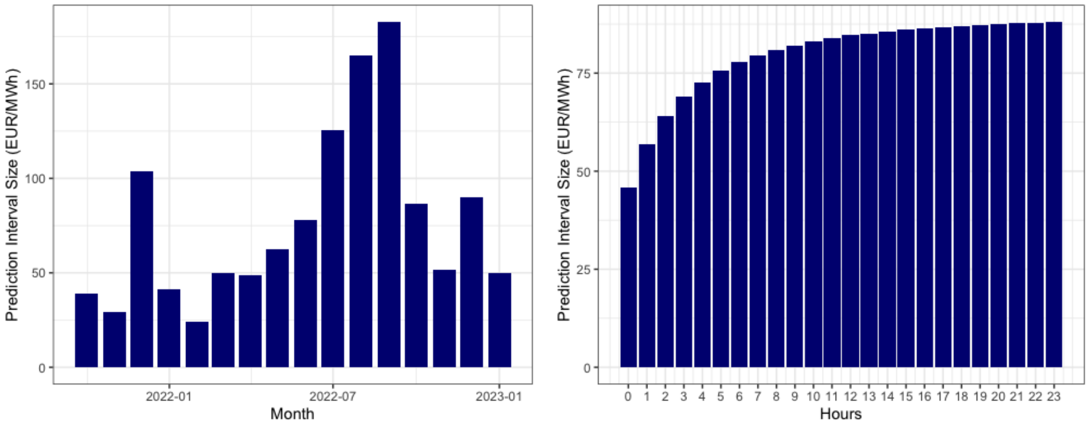


(a) Actual vs forecasted NO2 price **(b)** Actual vs forecasted GB-NO2 price spread

Figure 7.4: Forecasting accuracy

In Figure 7.5a and Figure 7.5b, we represent the uncertainty by the width of the 80% prediction interval from the ARX forecast of NO2 prices. Figure 7.5a shows how the uncertainty has changed considerably over the studied time period. We observe the lowest uncertainty during February 2022, with an average prediction interval size of €23.9/MWh. Meanwhile, the width of the prediction intervals increased significantly in Q3 2022, reaching €182.6/MWh during September. In these months, Europe experienced the worst parts of the energy crisis. Record high gas prices, geopolitical tensions, drought and critically low hydrological balance in Norway contributed to skyrocketing NO2 price volatility. While traders are able to easily forecast seasonal variations, short-term volatility, especially when caused by a combination of several factors, is much more difficult to predict (Statkraft, 2023). After Q3 2022, the energy market started to cool down, and we see that the forecasting uncertainty has dropped to its previous levels.

Figure 7.5b shows the average prediction interval for each hour. The smooth logarithmic increase over the span of the day-ahead period is based on the feature that the prediction interval width increases with the forecast horizon. The further away we forecast, the more uncertainty is associated with the accuracy of the forecast (Hyndmand and Athanasopoulos, 2021). It displays that traders using the ARX method, on average, believe with an 80% certainty that NO2 prices will clear within a €45.8/MWh interval in the first day-ahead-hour. In the last trading hour, however, the average prediction interval width of the trader has grown to €88.0/MWh. Overall, these graphs display how difficult it is to be certain in the prediction of day-ahead electricity prices. For traders participating in the NSL auction, increased uncertainty in NO2 price forecasts corresponds to a greater risk when taking positions in the NSL auction.



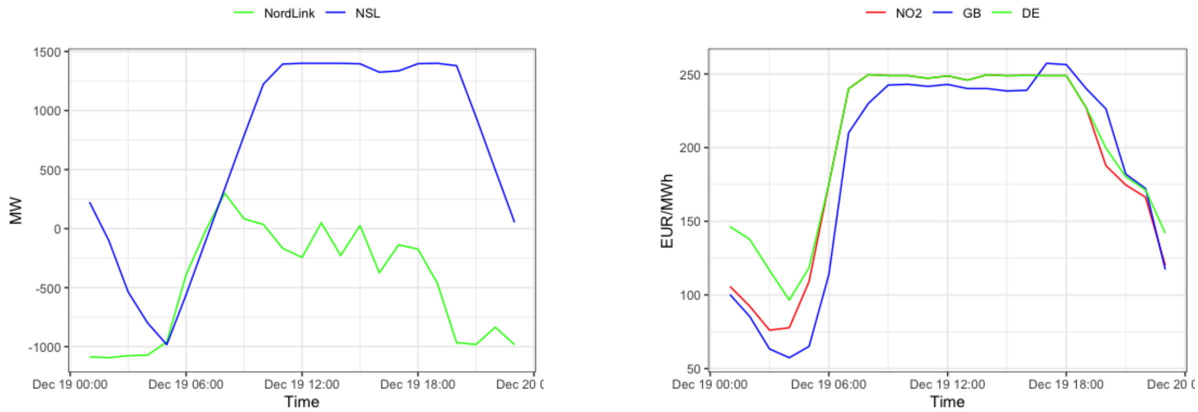
(a) Price uncertainty in each month **(b)** Price uncertainty in each trading period

Figure 7.5: Uncertainty in forecasting NO2 prices

The special market conditions in 2022 also made the NO2 price more dependent on the NSL auction clearing. The problem occurred as a result of the auction timing. In normal hours the GB/DE/NL price is above the NO2 price[12]. Consequently, in most hours, full export was determined on the NSL at 10:50. The problem was, however, that the production capacity in Southern Norway was strained. Producers would, in some hours, lock in too much production to GB, to the extent that they were unable to meet the export capacity on the other interconnectors. For instance, this happened on the 19th of December 2022, illustrated by Figure 7.6a and 7.6b. Producers locked in maximum export on the NSL at daytime and were therefore unable able to fulfil the capacity on NordLink, even though the DE price cleared above the GB price. As a result, the NO2 price coupled with the DE price from 06:00 to 19:00, and Norway exported electricity against the GB-NO2 price spread. This shows that the NO2 price in some hours depends on whether the NSL is within the SDAC auction or handled separately. The implicit auction has the power to alter the flow on the interconnectors, thereby diverting the NO2 price from the SDAC optima. The marginal traders were, in these hours, unable to forecast the coupling with Germany and lost on their bets with the NSL.

As illustrated in Chapter 4.4, fundamental bidders and financial traders will respond to

[12] Average hourly prices in connected bidding areas can be seen Appendix A3.1



(a) Hourly flow on the interconnectors **(b)** Hourly prices in the bidding areas

Figure 7.6: Inefficient flow and price coupling, 19th of December 2022

uncertainty differently. In the absence of individual bid data, we hypothesise that a base level of the trade on the NSL is provided, regardless of the uncertainty, by fundamental bidders in NO2 who see the NSL auction as a possibility to diversify risks (DNV, 2019). In addition to the possibility of hedging bets with the generation, there is an information asymmetry in the auction that favours producers in NO2. By knowing their marginal costs, water values and capacities, producers also have insights into the aggregated bid curve and the potential price clearing in the regular NO2 auction.

For financial traders, on the other hand, the NSL auction poses an increasing risk as the uncertainty in the NO2 price forecasts increases. For a higher uncertainty, they risk locking in a bid into the NSL that has to be reversed in NO2 auction at a highly uncertain price. Even though financial traders are trying to exploit these price differences, they are bounded by strict rules and regulations, as well as company-specific limitations that are in place to restrict the individual trader's appetite for risk (Statkraft, 2023). A financial trader may therefore look elsewhere for attractive investment opportunities in hours of high uncertainty. This hypothesis is supported by the findings of Geske et al. (2020) in their study on uncoupled interconnector trade. They found that financial traders would scale back their desired quantities to reduce the variance of their profit. As competitive trading in the NSL auction is mostly provided by financial traders, price differences should increase if they opt out in hours of high uncertainty.

In total, this shows that risk-averse traders can react to higher uncertainty in two ways: either by requiring a higher premium or by choosing to scale back the desired quantities.

Regardless of the reaction, the result should be the same: a higher observed premium in the hours of high uncertainty.

Risk and Premiums

We explore the hypothesis that the premium is risk-related by plotting the hourly prediction interval sizes against the modelled premiums in Figure 7.7 below. We see that, apart from two intervals, the premium required by the marginal trader is monotonically increasing. When traders are most certain in their NO2 price forecast, they are, on average, requiring a premium of €3.9/MWh. On the other hand, in the largest uncertainty span, they require a premium as large as €52.9/MWh. By regressing the hourly prediction interval size on the premium[13], we find a significant coefficient of 0.22, confirming our hypothesis that a larger forecasting uncertainty is related to a higher premium. The coefficient reveals that traders, on average, require a €0.22/MWh higher premium for every incremental increase in the prediction interval size. According to Menezes and Hanson (1970), the risk premium can be interpreted as a general measure of risk aversion, where the premium reflects the required rate of return. By this view, Figure 7.7 strongly suggests that the marginal trader in the NSL auction is risk-averse, requiring an almost linear premium to the modelled forecasting uncertainty.

The observation of a risk premium in the NSL auction contradicts the predictions from DNV (2019) and Statnett (2013). Along with Guo and Newbery (2021a), they argue that in a market with competitive trading, the premium added by marginal traders would disappear so that the price over time would be the same for the NSL and NO2 auctions. The traders' losses would offset the wins so that the average profits would drive towards zero, giving a null-sum game. However, we see that the traders are not able to exploit the price difference in hours with high uncertainty. Instead, they address the increased risk by more cautious bidding, adding a premium to the forecasted NO2 price. By adding the premium, they account for the uncertainties in their forecasts and possible market changes in the hour between the closing of the NSL auction and the NO2 auction. The risk-averse behaviour in the NSL auction causes a market imperfection that comes with a large cost for the relevant stakeholders. In the following section, we will discuss the consequences of attaching a risk premium to the NSL price.

[13]The output from the linear regression is displayed by regression (3) in Appendix A4.1

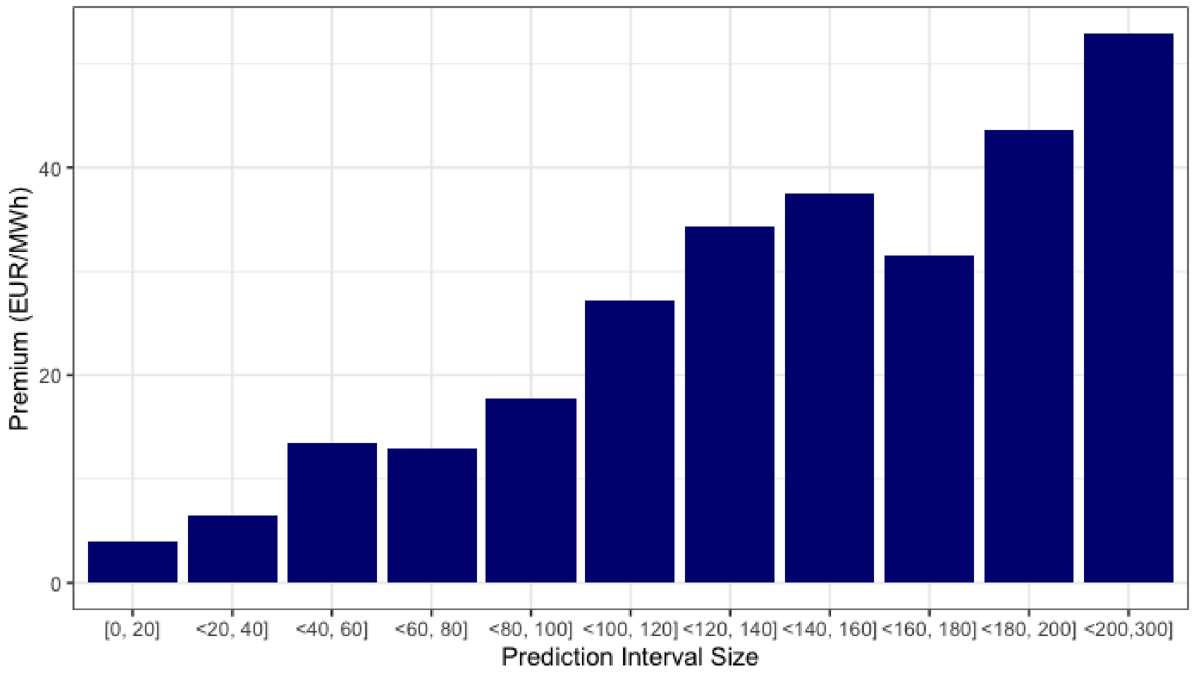


Figure 7.7: NO2 price uncertainty and premiums. The number of observations in each interval is found in Appendix A4.4.

7.4 The Cost of Uncoupling

The socio-economic benefit generated from an interconnector is a central driver for further integration between electricity markets. We find that the traders' risk aversion results in a cost for the relevant stakeholders and a redistribution of the socio-economic welfare gains from cross-border trade. In the following section, we will elaborate on the short-term and long-term consequences of the observed NSL premium.

7.4.1 Short-Term Effects

DNV (2019) argued that the expected congestion revenue under uncertainty would be about the same as the congestion rent without uncertainty. However, when traders require a risk premium, this will undoubtedly not be the case. Using Equation 5.8, we find that the commercial cost of uncoupled trade has accumulated to over €27 million over the studied time period. The commercial cost equals the lost congestion revenue for Stanett and corresponds to over 10% of the congestion revenue they have collected from the NSL in the same time period. Figure 7.8 illustrates how both the congestion revenues (CR) and the commercial cost (CCU) have increased over time after the opening of the NSL in

October 2021. Greater increases are seen following the summer months of 2022 as the capacity on the cable also increased.

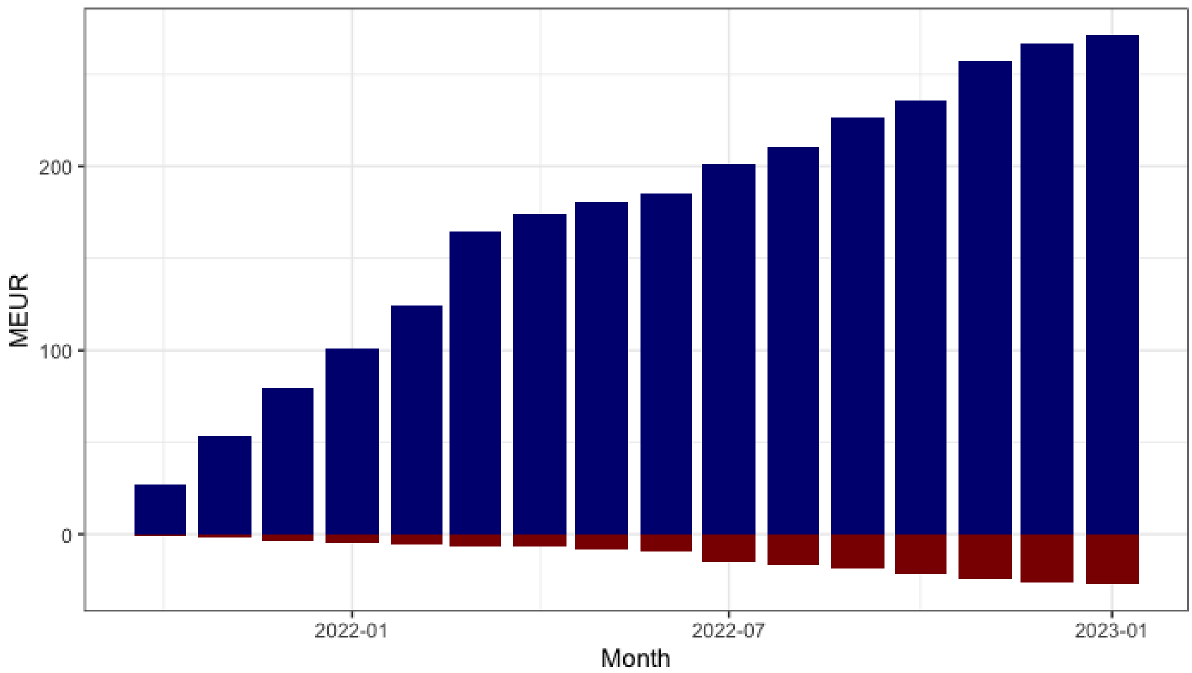


Figure 7.8: Statnett's accumulated CR (Blue) and CCU (Red) from NSL

We find that the uncoupling has led to a redistribution of socio-economic welfare generated from the interconnector. When traders bid a premium on the NSL price, this premium takes shares of the congestion revenues that, in theory, should go to the interconnector owner. However, for a regulated transmission system operator (TSO) like Statnett, the loss of congestion revenue will not affect their overall profits as any excess revenue is used to reduce grid tariffs for Norwegian customers. Statnett's revenue cap in 2022 was set to NOK 13.4 billion or around €1.12 billion (NVE, 2023). In the same year, the congestion revenue reached a record high level of €2.17 billion and €94 million was returned to consumers through lower grid tariffs (Statnett, 2023b).

Hence, the TSO would be indifferent between receiving its income through grid tariffs from consumers or congestion revenues from interconnectors. If there were no commercial costs of uncoupling, Statnett's additional congestion revenue would be redistributed to the consumers in the form of a lower grid tariff. However, as traders are able to grab 10% of the theoretical congestion revenue on the NSL, the consumers miss out on this potential welfare benefit. Effectively, the regulated TSO passes on its welfare loss to the consumers. This means that the systematic risk premium obtained in the implicit auction, in reality, leads to a redistribution of socio-economic welfare from consumers to the auction participants.

7.4.2 Long-Term Consequences

The inefficiencies of the current trading arrangement could, in addition to the short-term effects, have long-term consequences.

Uncertainty and volatility in the energy markets and NO2 prices are expected to increase as the share of intermittent renewable energy increases. Even without a war and energy crisis, the long-term uncertainty is expected to be high. As seen by the results from the analysis and the following discussion, an efficient operation of the separate auction solution is dependent on accurate forecasts. When looking at the future energy situation in Norway, Schäffer et al. (2020) expects an increase in the hourly power price volatility as a result of more solar and wind production. The volatility increase will materialize by 2030 and be further amplified by 2050. In addition, the power prices will attribute a stronger seasonality and become even more weather dependent. All else equal, higher uncertainty will result in higher premiums for the market participants. This implies that without better forecasting methods, Statnett will risk losing an even larger share of their congestion rents in the future. This will again increase the costs for the consumers and decrease their consumer surplus.

From a socio-economic perspective, investments in interconnector capacity could be made so that the bottleneck between NO2 and GB disappears and there is full price convergence between the markets. This would increase the socio-economic welfare generated from the interconnector and there would no longer be a theoretical welfare loss. With the increased transmission capacity, all of the socio-economic surplus would be captured by the producers and consumers, and no congestion revenue would be generated for the TSO. However, given an income-regulated TSO such as Statnett, this should make no difference in their willingness to invest in increased transmission capacity.

Although the commercial cost and loss in congestion revenue have no implications for Statnett's profits, the additional coordination that a separate auction requires could make further investments in cross-border transmission capacity between Norway and GB less attractive. Even though the two electricity markets are highly complementary, Statnett might find it more attractive to connect the Norwegian electricity market to other countries that are part of the European IEM.

When analysing trading efficiency and available transmission capacity in the US, Oren (1997) found that in the long run, price distortion from the marginal price could misplace investment incentives by encouraging more generation at the supply node. This could potentially also apply to the NO2 bidding area if producers find it attractive to place their production in NO2 based on the potential of higher profits rather than the demand profile in the price area. However, with the option to participate in the auction without physical production, we see this as unlikely. But, with several interconnectors to other electricity markets with higher prices, additional production capacity in NO2 should become more attractive in general.

7.5 Possible Measures to Improve Trading Efficiency

In the following section, possible measures to improve the trading efficiency in the NO2 bidding area are proposed. We see that with regard to the socio-economic welfare generated from the NSL, the optimal solution to improve the efficiency would be to re-admit GB into the European IEM arrangements and let trade on the NSL be part of the regular NO2 auction. This would give a single auction in NO2 where the NSL price would clear together with the rest of the market. Consequently, there would be no commercial cost or redistribution effect between the interconnector owner and traders.

We recognize that the topic of readmitting GB into the IEM arrangements is stymied by politicians in both the EU and GB and that it is unlikely to happen in the nearest future. This does, however, not hinder measures to be taken to improve the efficiency on the NSL auction specifically. With the current trading arrangement, Nord Pool is the only power exchange managing trade on the NSL. While we do not find any evidence of market power exertion in the NSL auction, there is an evident lack of competitive trading in hours of uncertainty. If it was opened for other power exchanges to manage trade on the NSL, the auction would become more accessible to speculators that could trade on the price difference between the NO2 and NSL prices. EPEX Spot has been clear on their discontent with the current trading solution with only one power exchange (Mollestad, 2023). The Norwegian Energy Regulatory Authority (RME) has proposed a solution where one power exchange is responsible for managing the trading on the cable but where other power exchanges can share their order books to access the NSL. Such a solution might increase the participation of financial traders. While Statnett has shown positive indications, they have also stated that they see limited benefits from such a solution until after 2026, when the current trading agreement with Nord Pool is ended.

7.6 Limitations of the Thesis

In this section, limitations and assumptions that may affect the results and validity of the thesis are elucidated. The most important limitations are the length of the studied time period, the use of only one forecast method for all marginal traders, the disregard of unexpected and extraordinary events and omitted variables.

A key limitation is the length of the time period studied, with the data only ranging from the 1st of October 2021 to the 15th of January 2023. Even though this is over a year with data, this also includes the first year of operation, where the cable in the beginning operated with limited capacity. The time frame also included periods of special market conditions, including a war in Ukraine and an energy crisis that significantly impacted the dynamics of the European energy market. Studying the trade on the NSL over a longer time period, with more hours after the trial period, could strengthen the validity of the results we have found in this thesis or lead to other results. We hypothesise that the effect of uncertainty in our model has overshadowed the potential impact of the other variables. A longer time frame, with more stable prices, could give a better explanation of the more subtle changes in the premium.

In the 'real' world, each trader chooses their own forecasting method, and traders will therefore end up with slightly different NO2 prices in their respective predictions. However, for the thesis, we have assumed that the marginal trader uses the ARX method, giving them the same forecasted NO2 price. Further, we acknowledge that the traditional econometric forecasting methods have limited ability to capture the impact of unexpected events and that this gives overstated premiums. As we are actively modelling out the price spikes by constraining the allowed z-score, we get a better average forecast but fail to predict the outliers.

Moreover, the ARX method performed best with only three exogenous variables, including wind infeed, demand, gas price and a weekend indicator variable. This means that there are many omitted variables that can affect the electricity price that we fail to account for. Our model is a simplified model compared to the advanced models used by professional agents in the market. By using more sophisticated forecasting methods in the analysis, we could improve the accuracy of the forecasted prices and thereby provide more exact estimations of the required premiums.

8 Conclusion

This thesis aims to contribute to the research on interconnectors in deregulated electricity markets. Following Brexit and GB leaving the IEM, a separate trading solution had to be established on the NSL. Market players in NO2 are currently in a situation where they can trade electricity in two different auctions, the regular NO2 auction and the separate NSL auction. With the NSL auction closing before the NO2 auction, traders have to forecast the NO2 price when submitting bids into the NSL auction to prevent losses.

We address the decision problem of a marginal trader by developing a forecasting model to predict the day-ahead NO2 prices ahead of the NSL auction closing. We find that the ARX model provides the best forecasting accuracy among the proposed econometric methods. This model facilitates the modelling of subtle time series dynamics and the inclusion of exogenous variables. In our model, we find that the inclusion of forecasted electricity demand, wind generation, gas prices and a weekend indicator variable positively contributes to the accuracy of the point forecasts.

We use the ARX forecast to calculate the ex-ante premium as the flow-dependent spread between the actual NSL price and the predicted NO2 price. In export scenarios, the premium is positive as long as the marginal selling bid that settles the price on the NSL is higher than the marginal trader's NO2 price forecast. Opposite, the premium is positive in import scenarios as long as the marginal buying bid is lower than the NO2 price forecast. As a result, the premium reflects the required rate of return a marginal trader expects from participating in the NSL auction.

Our results show that traders, on average, require a premium of €17.78/MWh to participate in the auction. The highest premiums are observed during Q3 2022, and the average premium observed in the last month is twice the premium observed in the first month. In addition, the premiums seem to increase over the day-ahead hours and in periods of high volatility in NO2 prices.

We further examine the drivers behind the premium to uncover why it arises. Given the presence of a dominant player in NO2 production and premiums correlating with periods of high uncertainty, we formulate two hypotheses: i) the premium arises because of market power exertion, and ii) the premium arises because traders are risk-averse. We explore the first hypothesis by calculating a rough RSI for Statkraft. However, we find little evidence that their dominant position in NO2 production has contributed to the systematic price difference between the two auctions.

On the other hand, we do find clear evidence that the premium is linked to the uncertainty in the NO2 price forecasts. On average, the marginal trader in our model requires a €0.22/MWh higher premium for each incremental increase in the 80% prediction interval of the point forecast. In an efficient market with risk-neutral traders, such premiums would not exist as the traders would increasingly take advantage of the arbitrage opportunity. Therefore, we argue that the traders in the NSL auction are risk-averse.

This risk premium comes with a commercial cost for the interconnector owners. We find that the commercial cost of uncoupling, which refers to the lost congestion revenues by Statnett, has accumulated to €27 million in the period from the opening of the NSL in October 2021 to mid-January 2023. This amounts to approximately 10% of the total congestion revenues accumulated in the period. In total, we find that the implicit auction solution on the North Sea Link leads to a redistribution of socio-economic welfare from the regulated interconnector owners, and thereby the consumers, to the participants in NO2 in the form of a systematic risk premium.

We argue that the efficiency of the cable could be improved if GB is readmitted into the IEM. However, the topic has been clearly stymied by politicians in both the EU and GB and changes to the current trading arrangements are unlikely to happen in the nearest future. Meanwhile, a proposed solution would be to open up shared order books on the NSL auction to increase the participation of speculators.

With regard to future research, we believe that it could be interesting to utilize more advanced forecasting models (e.g. by Volue, DNV or THEMA) to backtest trading strategies in this market. Our findings suggest that risk-takers should be able to generate large profits; for instance, by participating in high-uncertainty hours. Future research could also benefit from studying the auction solution over a longer time period. Additionally, we believe that our methodology can be applied to study similar market uncouplings, such as the separate day-ahead EPEX and Nord Pool auctions in Great Britain. Lastly, we note that future research on the socio-economic welfare gains from the NSL should include the CCU and redistribution effects highlighted in this thesis.

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Appendix

A1 Figures

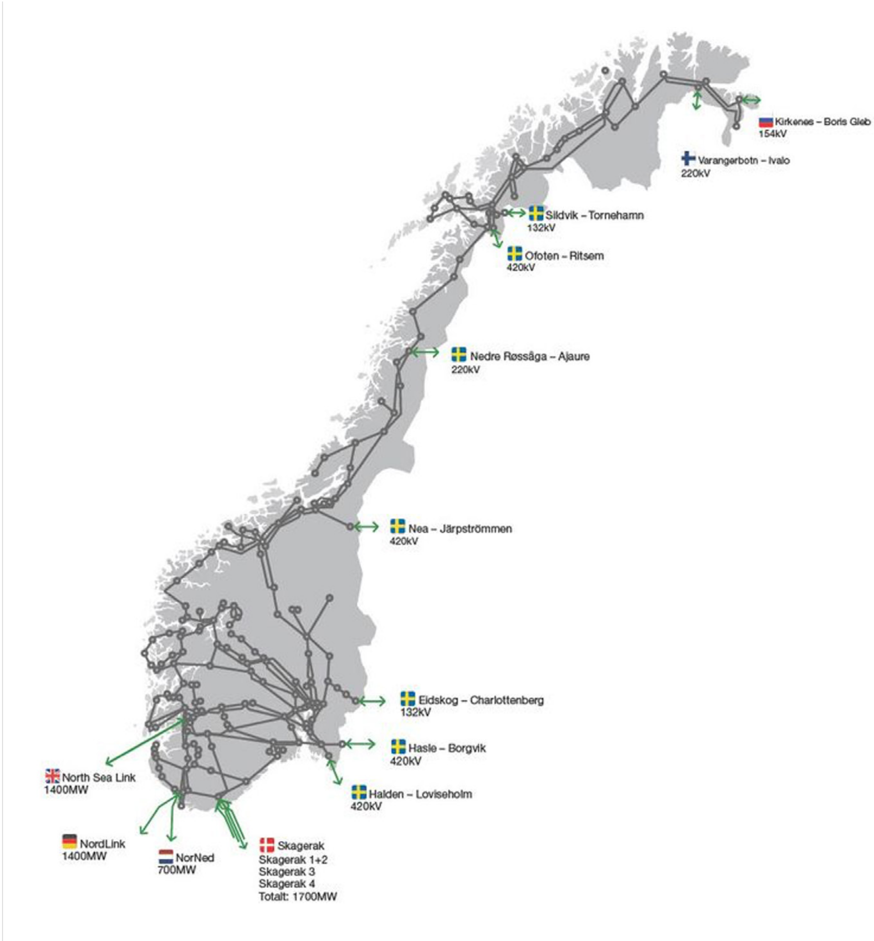
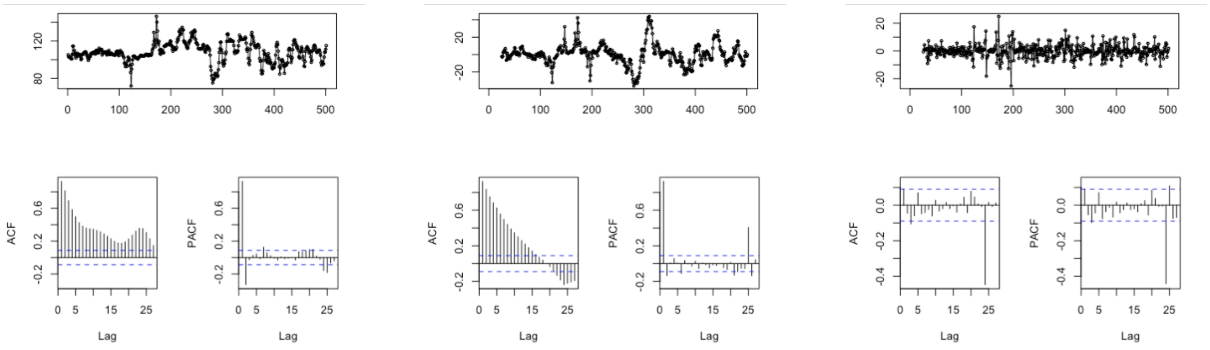


Figure A1.1: Installed capacity on the cross-border interconnections between Norway and the Nordics/Europe (Statnett, 2022a)

A2 Methodology



(a) No differencing **(b)** Seasonal differencing **(c)** Double differencing

Figure A2.1: Identifying the best ARIMA specifications

We base the appropriate ARIMA specifications on the autocorrelation function (ACF) and partial autocorrelation function (PACF) of the NO2 price series in Figure A2.1. Looking at the non-differenced series in Figure A2.1a, the ACF plot shows significant autocorrelation values at higher lags, suggesting the presence of non-stationarity in the data. Also the seasonal differenced series in Figure A2.1b indicates a dependency on past observations, suggesting that the statistical properties of the time series may vary over time. We therefore take an additional difference of the NO2 price. The ACF and PACF of the double-differenced NO2 price series is shown in Figure A2.1c. The significant spike at lag 3 in the ACF suggests using a non-seasonal MA(3) component. The significant spike at lag 24 in the ACF suggests using a seasonal MA(1) component. Consequently, we begin with an $ARIMA(0,1,3)(0,1,1)_{24}$ model, indicating a first-difference, a seasonal difference, and a non-seasonal MA(3) and a seasonal MA(1) component.

If we had started with the PACF, we might have selected an $ARIMA(3,1,0)(0,1,1)_{24}$ model – using PACF to select the non-seasonal part of the model and ACF to select the seasonal part of the model. The residuals from the model is found in Appendix A2.2 and show one small but significant spike at lag 4 out of 36, but this is still consistent with white noise. To be sure, we use a Ljung-Box test, being careful to set the degrees of freedom to four to match the number of parameters in the model. The p-value of 0.101 confirms that the residuals are not significantly different from white noise (Hyndmand and Athanasopoulos, 2021). Thus, we now have a seasonal ARIMA model that passes the required checks and is ready for forecasting.

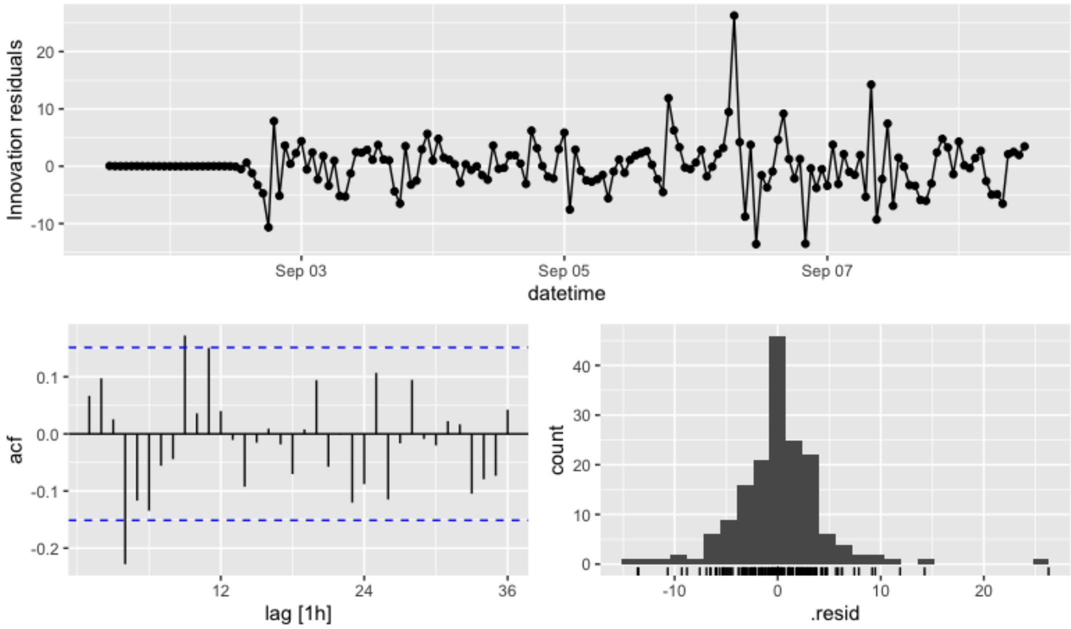


Figure A2.2: Residuals from the $ARIMA(0,1,3)(0,1,1)_{24}$ model

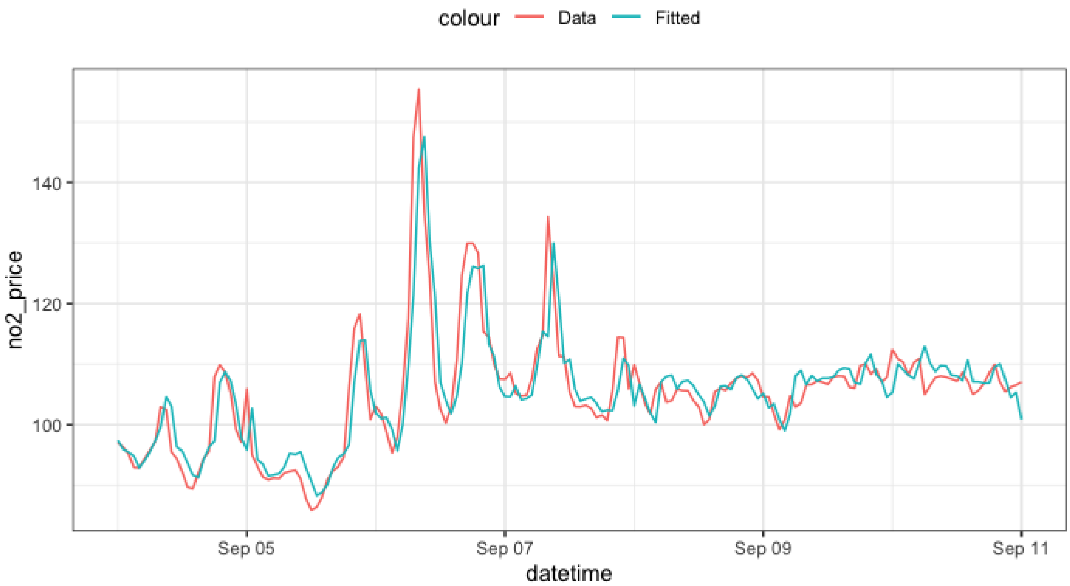


Figure A2.3: The ARX fit on a sample window

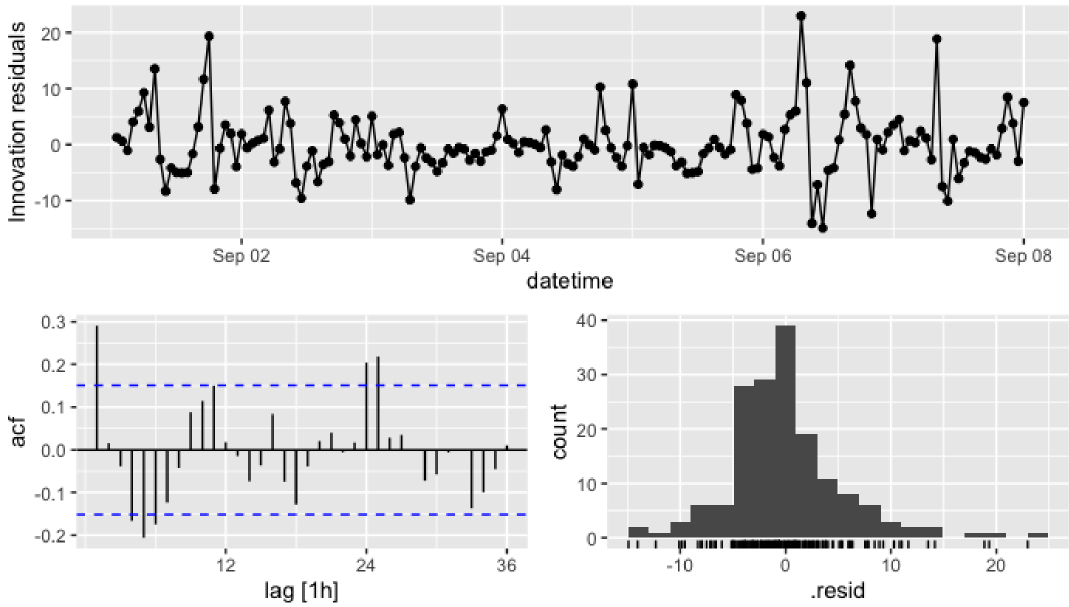


Figure A2.4: Residuals from the ARX model

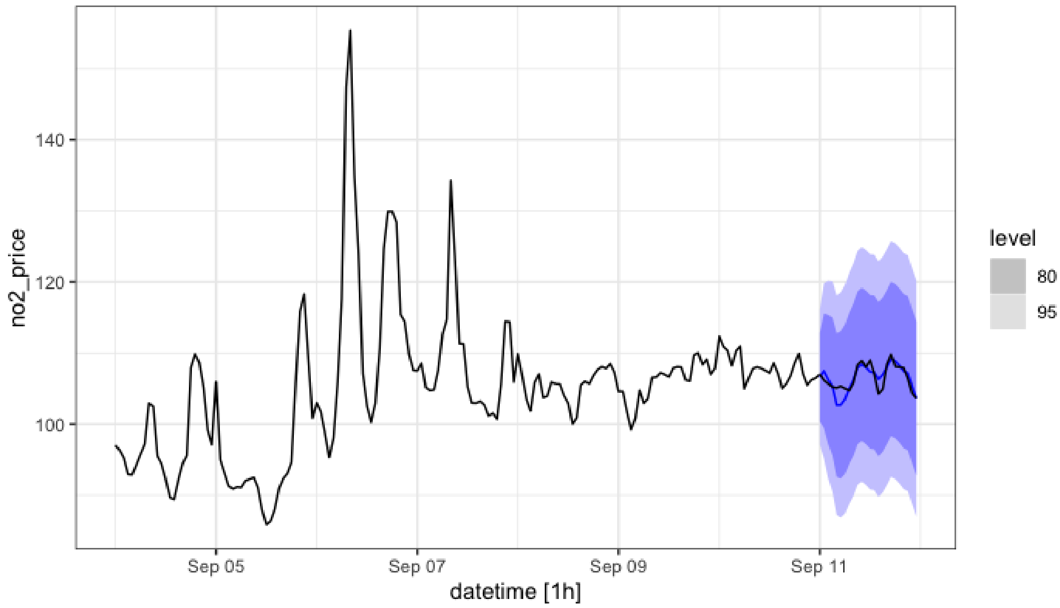


Figure A2.5: ARX forecast accuracy and prediction intervals

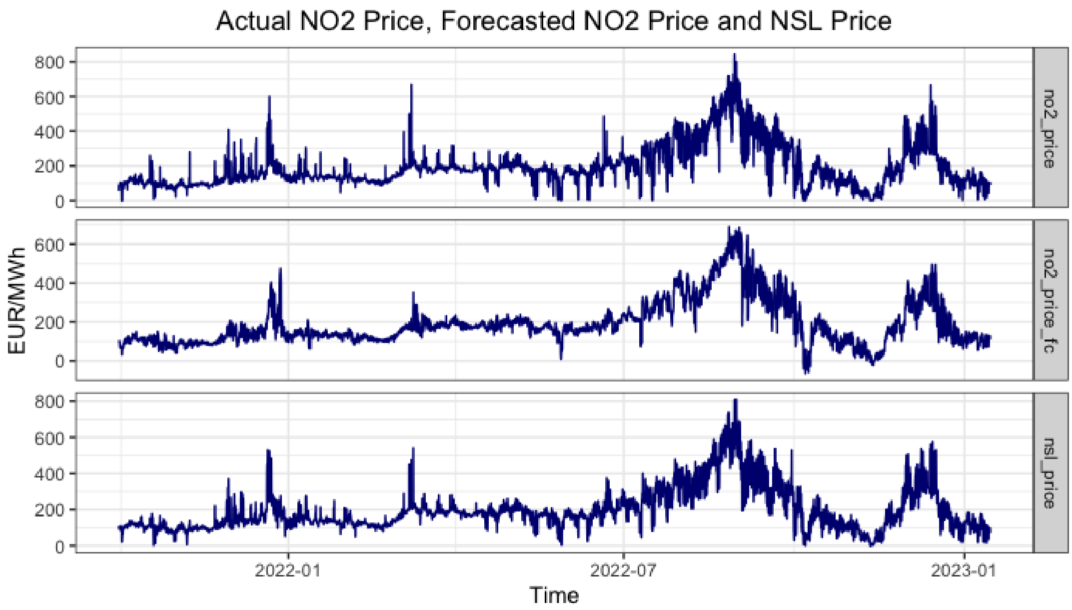


Figure A2.6: Actual NO2 price, forecasted NO2 price and actual NSL price

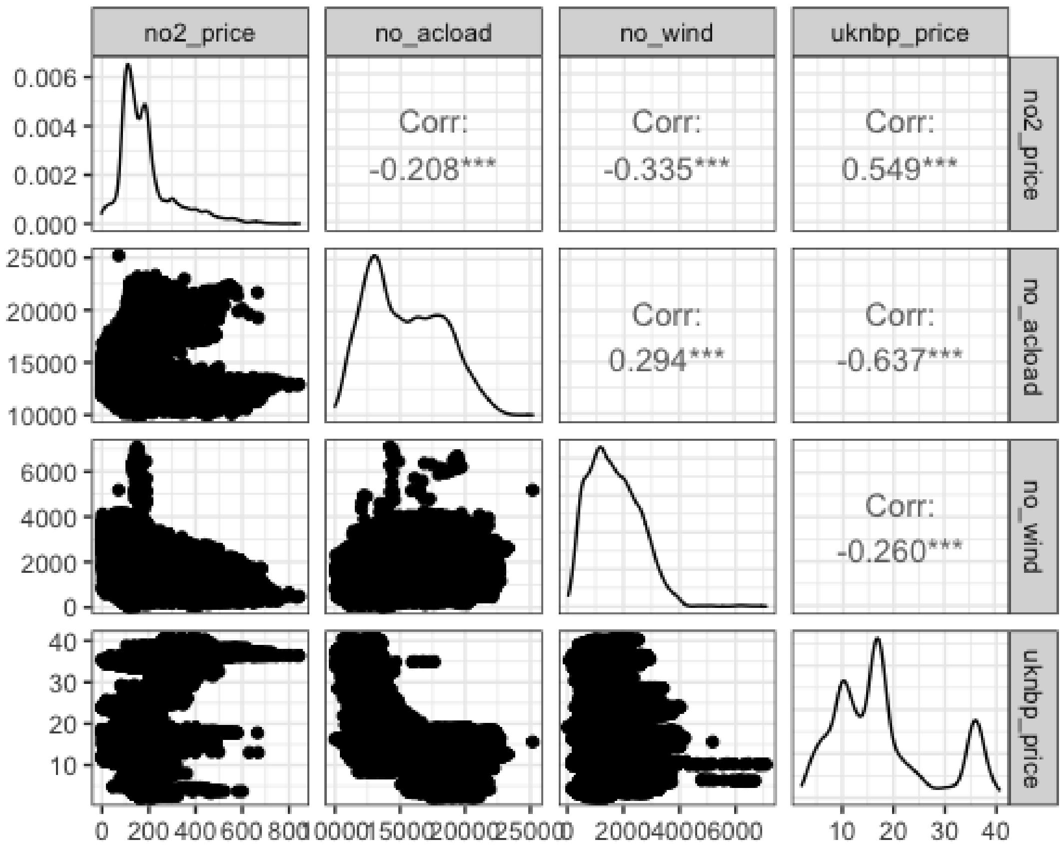


Figure A2.7: Correlation plot of the exogenous variables

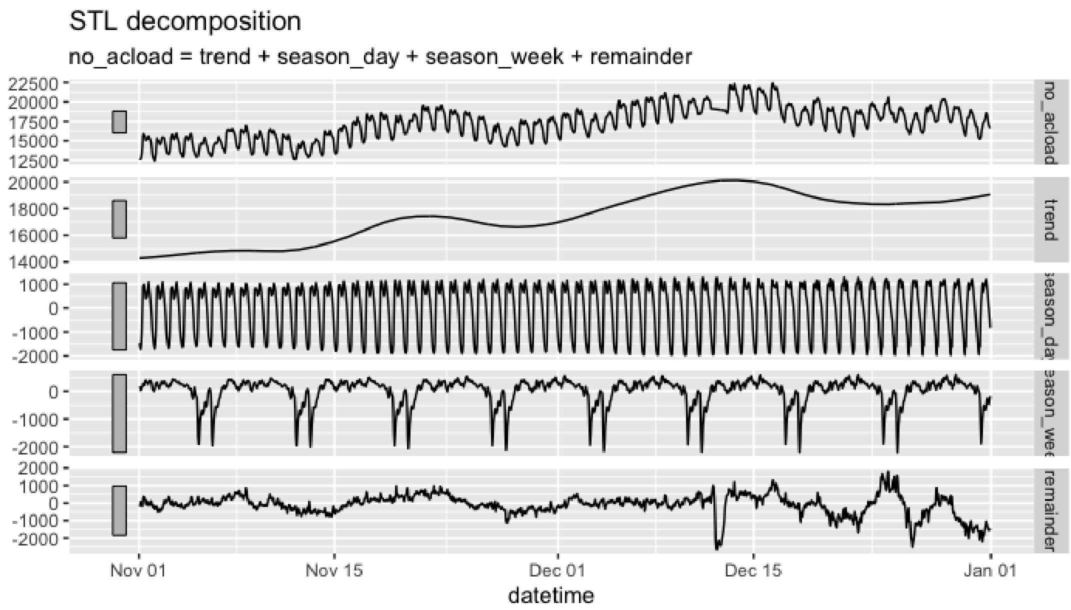


Figure A2.8: STL decomposition of actual Norwegian load

A3 Data

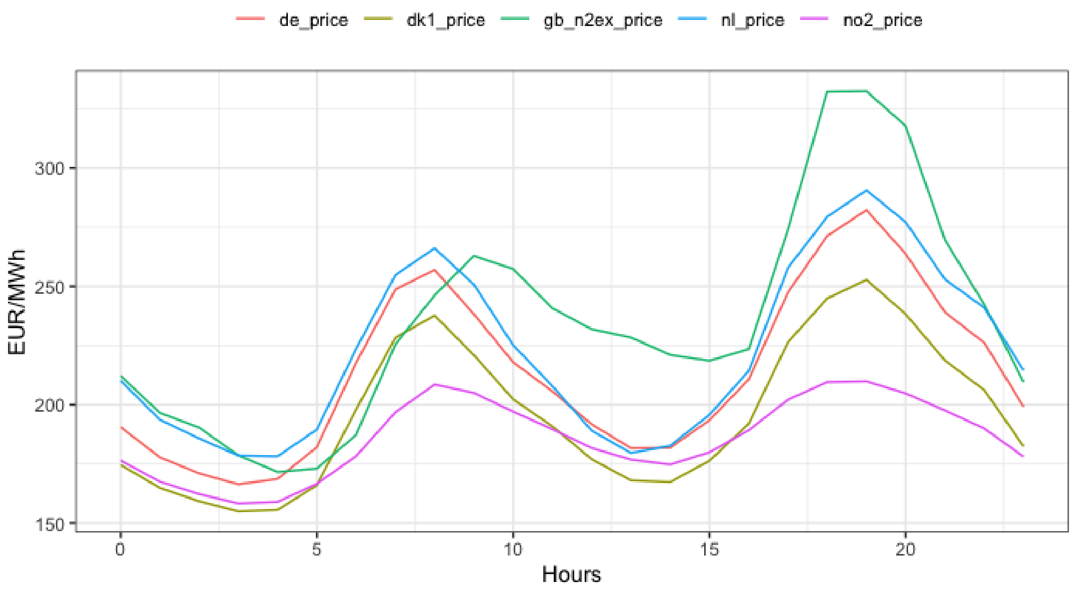


Figure A3.1: Average hourly prices for foreign NO2-connected bidding zones

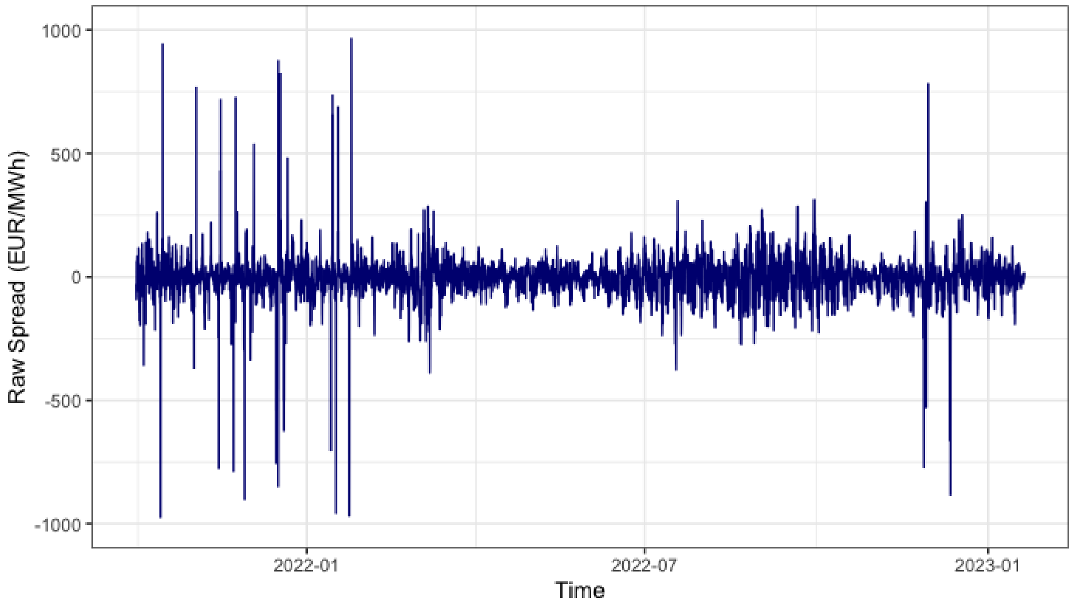


Figure A3.2: Spread between GB(N2EX) and GB(EPEX) prices

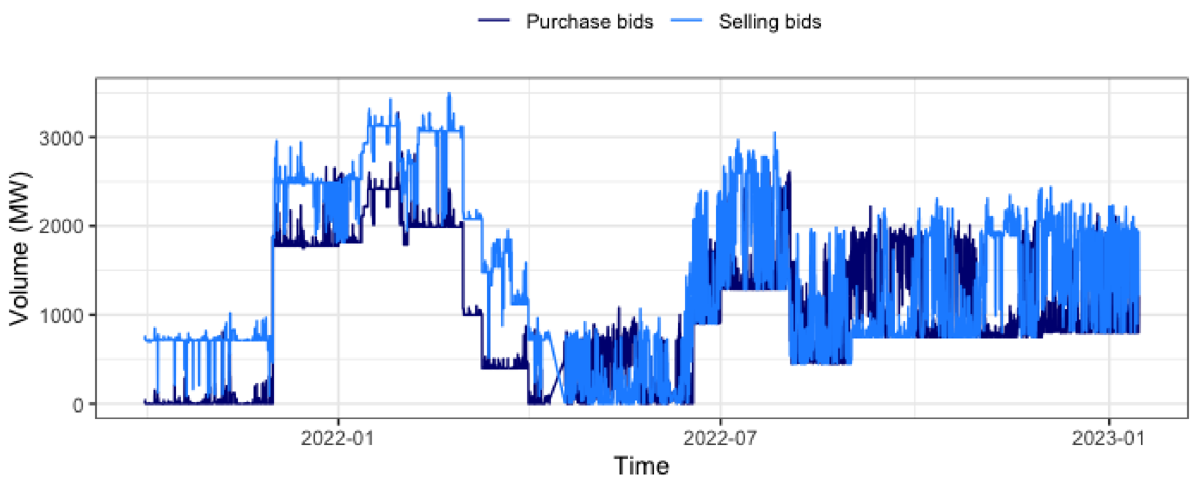


Figure A3.3: NO2(NSL) day-ahead auction volumes

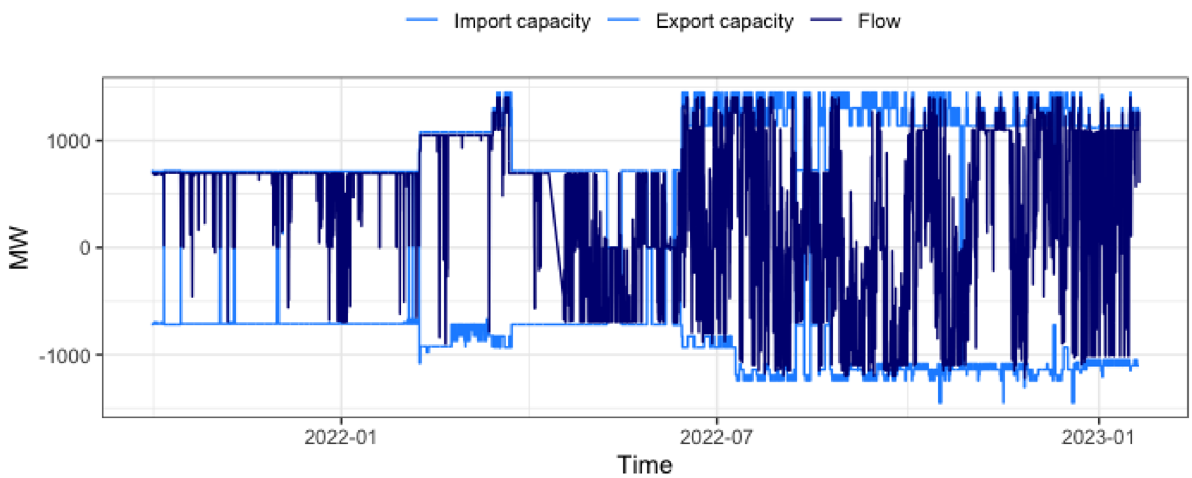


Figure A3.4: Cross-border capacity and flow on the NSL

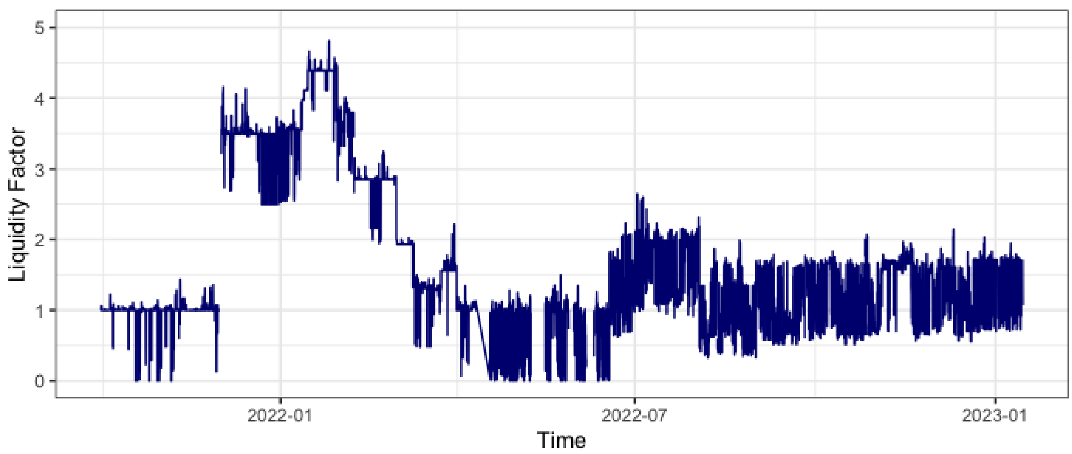


Figure A3.5: Plot of the liquidity factor on the NSL

Day	Liquidity Factor
Monday	1.601647
Tuesday	1.629522
Wednesday	1.639916
Thursday	1.680950
Friday	1.643271
Saturday	1.603856
Sunday	1.589810

Table A3.1: Daily average liquidity factor

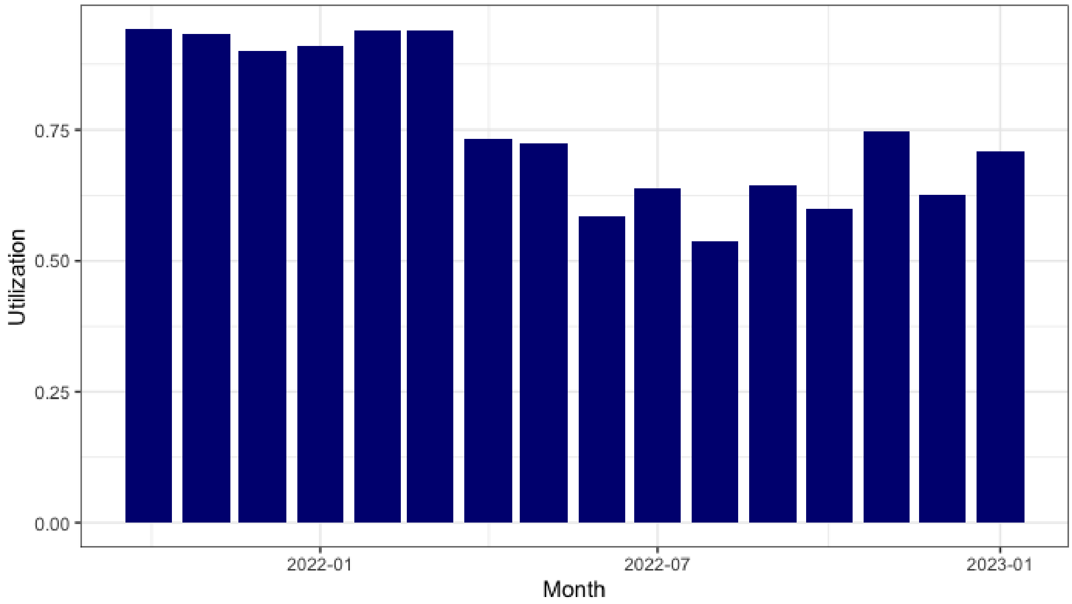


Figure A3.6: Utilization on the NSL

A4 Premium

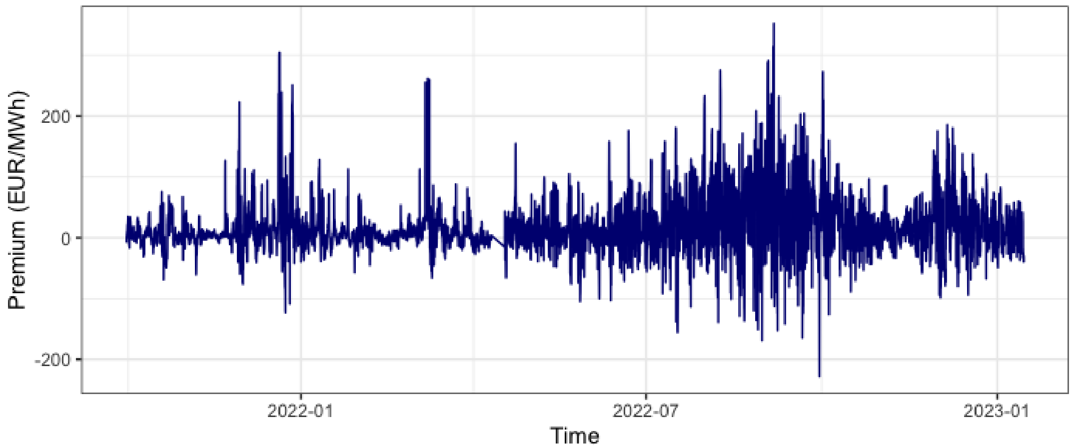


Figure A4.1: Time series plot of the premium

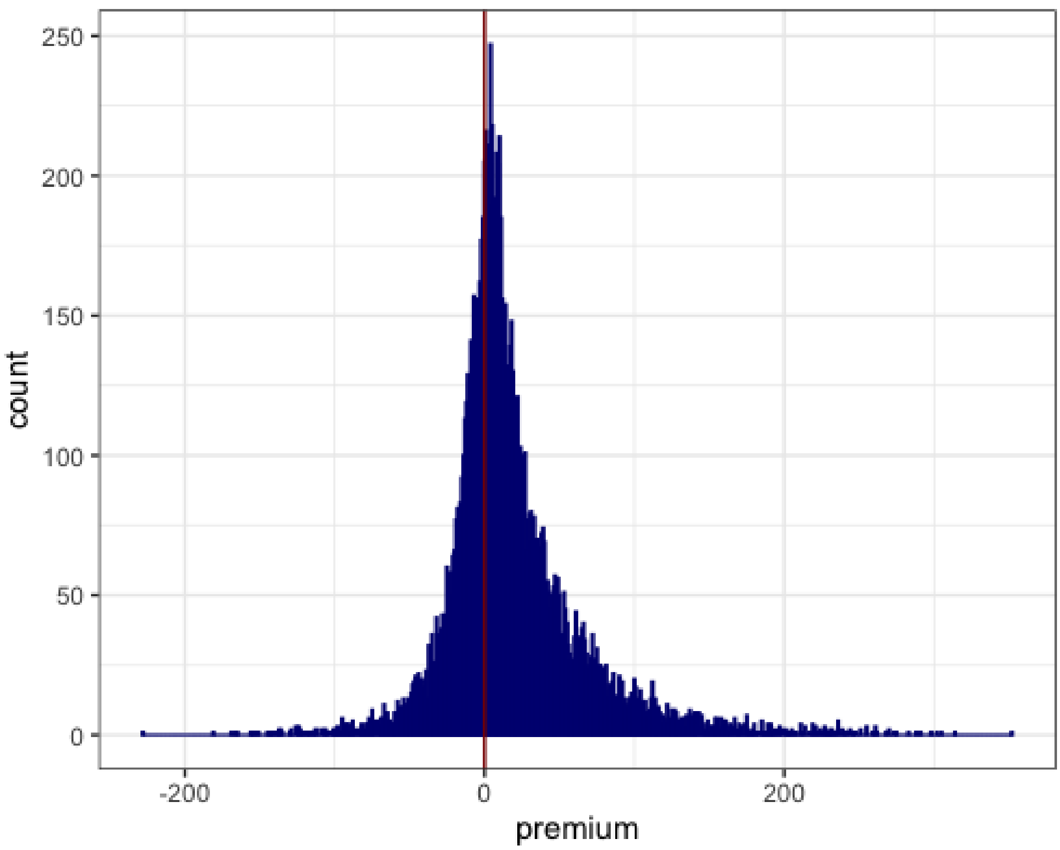


Figure A4.2: Histogram of the modelled premiums

	Dependent variable:		
	Premium		
	(1)	(2)	(3)
RSI Score	7.3335***		
	(1.2394)		
Liquidity Factor		-0.6855	
		(0.4029)	
Prediction Interval Size			0.2249***
			(0.0073)
Constant	0.7482	19.6327***	0.0682
	(2.9194)	(0.7836)	(0.7024)
Observations	11,406	11,024	11,406
R^2	0.0031	0.0003	0.0774
Adjusted R^2	0.0030	0.0002	0.0773
Residual Std. Error	44.8301 (df = 11404)	45.0754 (df = 11022)	43.1269 (df = 11404)
F Statistic	35.0099*** (df = 1; 11404)	2.8947 (df = 1; 11022)	956.3875*** (df = 1; 11404)
Note:			*p<0.05; **p<0.01; ***p<0.001

Table A4.1: Linear regression analyzing the relationship between RSI, liquidity, uncertainty and the premium

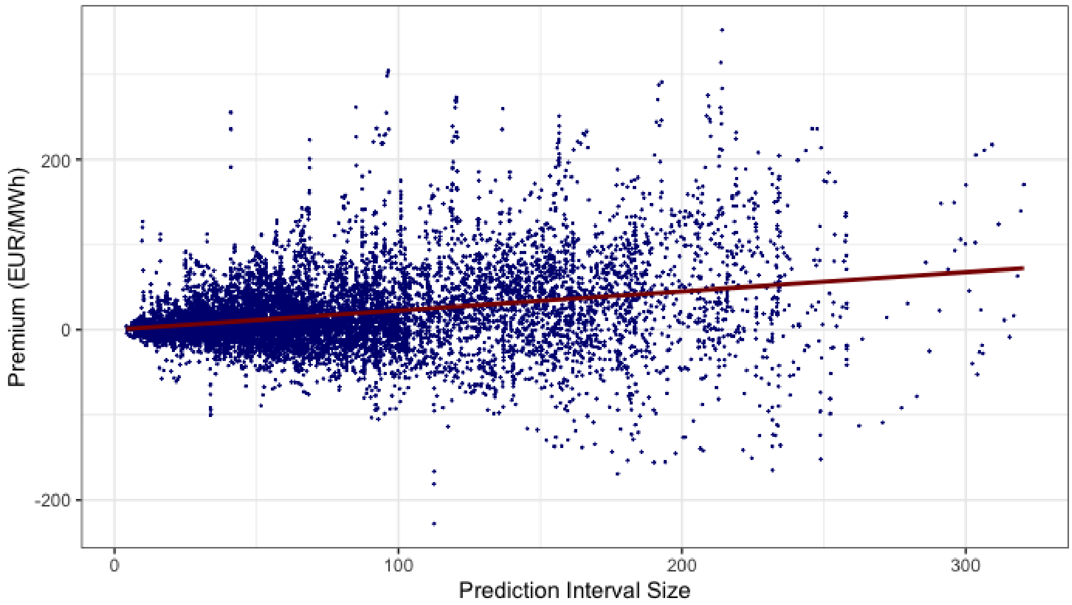


Figure A4.3: NO2 price uncertainty and premium

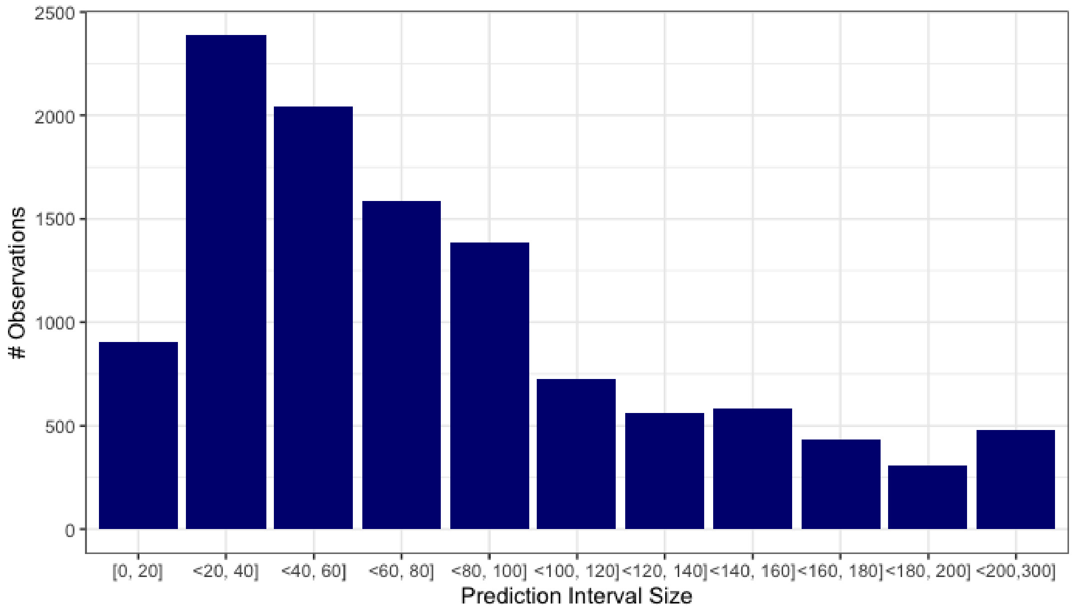


Figure A4.4: Number of observations within each prediction interval size

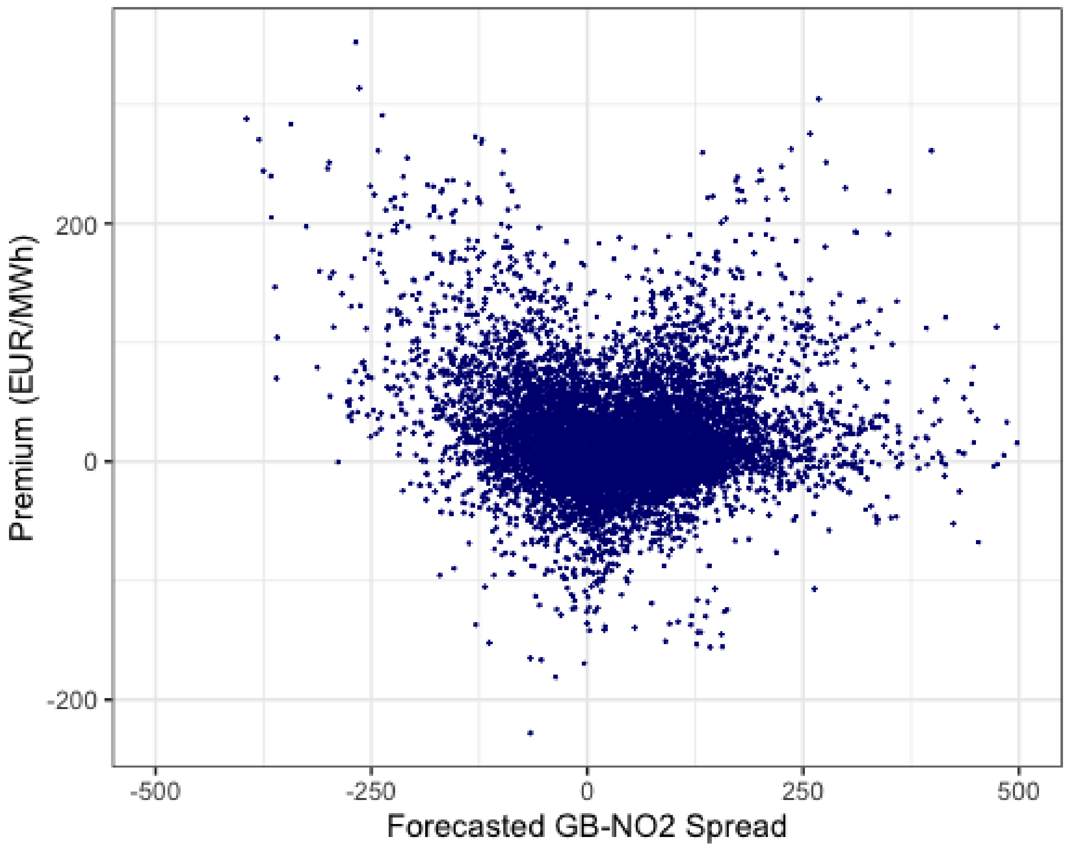


Figure A4.5: Flow direction uncertainty and premiums

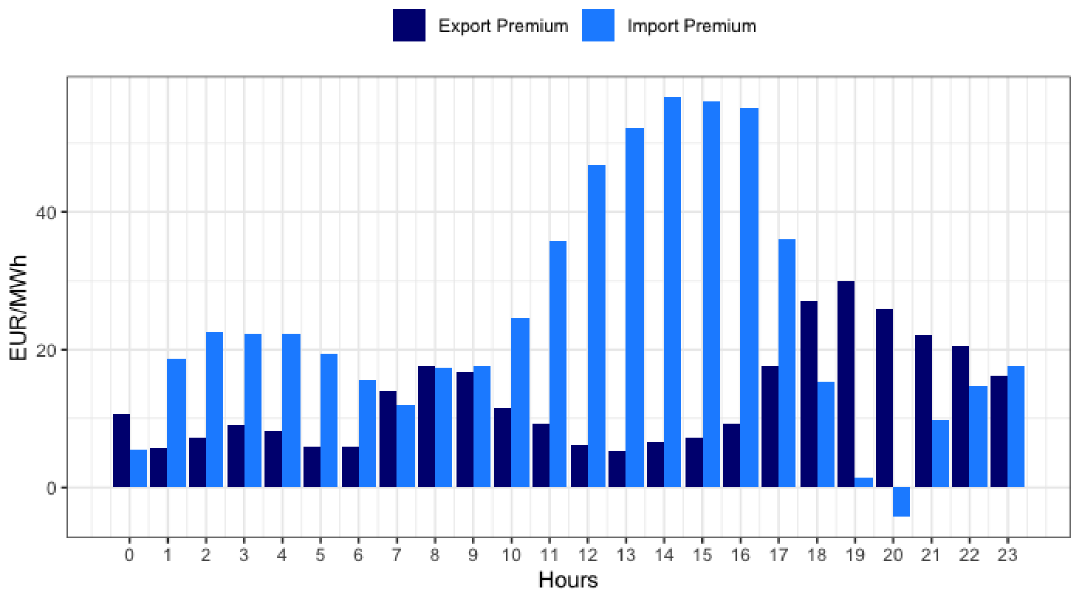


Figure A4.6: Hourly import and export premium

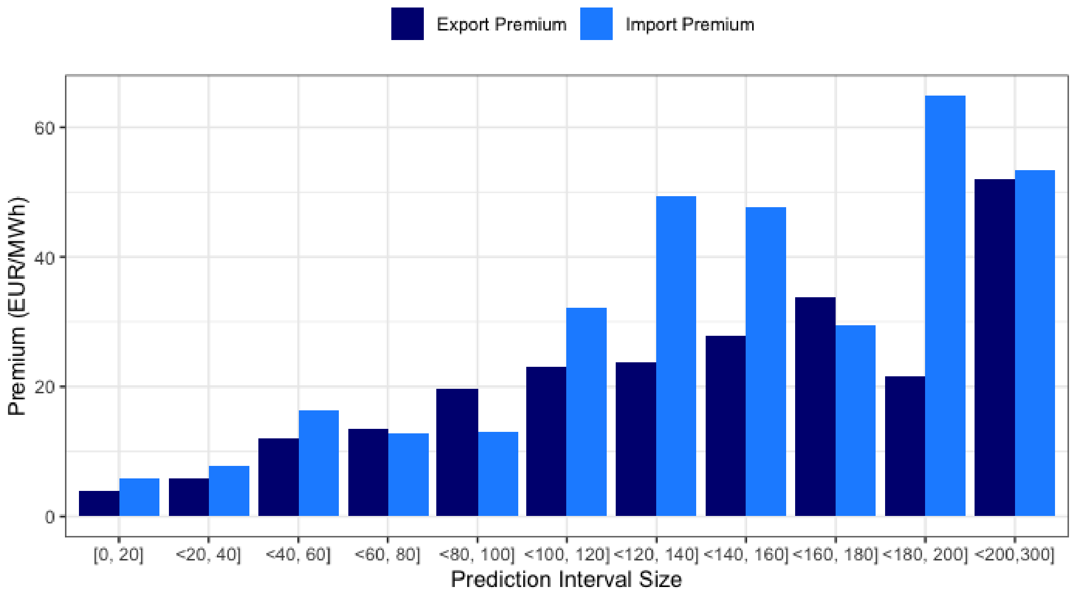


Figure A4.7: NO2 price uncertainty and import and export premiums

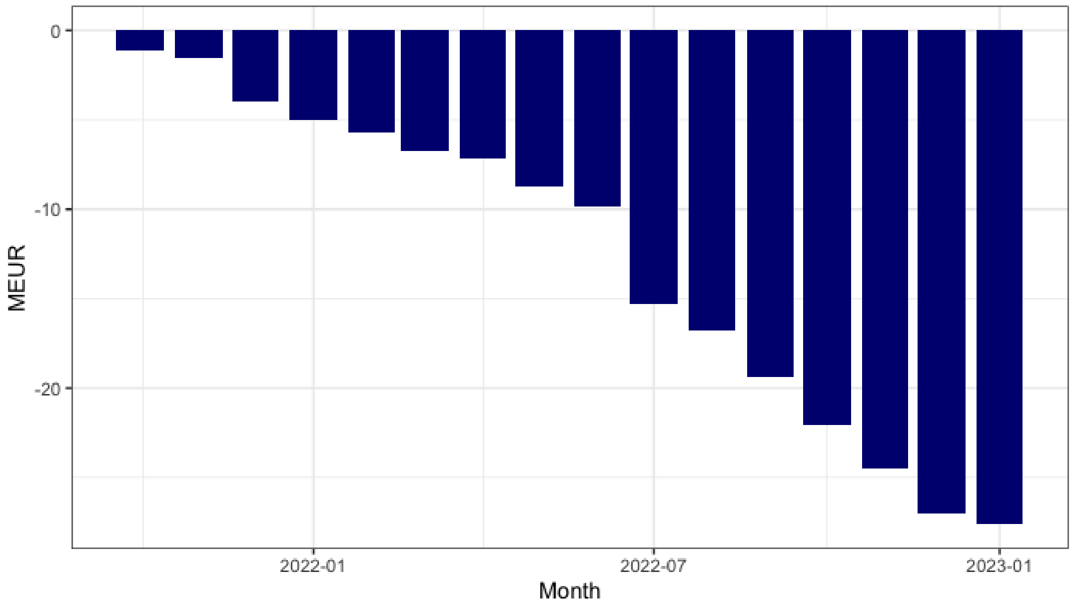


Figure A4.8: Cumulative CCU