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Impact of Variable Renewables Through Market Coupling on Day-Ahead Prices in NO2

A panel quantile approach

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NORWEGIAN SCHOOL OF ECONOMICS

Abstract

This thesis investigates the impact of European variable renewables on the distribution of electricity prices in Norway through market coupling. When examining the effect from variable renewables we assess day-ahead prices in the Norwegian bidding zone NO2 and variable renewable generation in Germany, Great Britain, Denmark, and the Netherlands. We exploit hourly data from October 2021 throughout 2022 and employ a panel quantile regression. A quantile approach enables us to estimate the variable renewables effect on various price quantiles while the panel structure allows us to control for market dynamics through hourly-specific effects. In the model, we also control for various other factors known to impact electricity prices. The variable of particular interest is the penetration of variable renewables, constructed by dividing the variable renewable generation by the total generation in each respective country.

The results imply that an increasing penetration of variable renewables in all countries have a negative effect on day-ahead prices in NO2, suggesting that the merit-order effect occurs through market coupling. An increasing penetration of wind and PV generation in interconnected countries decreases domestic electricity prices. The result implies that the impact from variable renewables is strongest in the right-tail of the price distribution, indicating stronger impact during peak demand. Nonetheless, the result signals signs of transmission congestion which diminish the price contagion from the variable renewable penetration in the interconnected country, obstructing the merit-order effect originally seen through market coupling. The model is unable to capture this effect given a confidence of 95 percent. Hence, we cannot adequately conclude that this result is due to congestion.

Keywords *– Electricity Markets, Electricity Prices, Variable Renewable Energy, VRE, Market Coupling, Merit-Order, Interconnectors, Congestion, NO2, Europe, Panel Quantile Regression*

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Norwegian School of Economics

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Contents

List of Figures

List of Tables

List of Abbreviations

CACM	Capacity Allocation and Congestion Management
DE	Germany
DK	Denmark
EPEX SPOT	European Power Exchange
EU	European Union
EUR	Euro
GB	Great Britain
GBP	The British pound sterling
GME	Gestore Mercati Energetici
GWh	Gigawatt hours
HenEx	The Hellenic Energy Exchange
HVDC	High-Voltage Direct Current
MW	Megawatts
MWh	Megawatt hours
NEMO	Nominated Electricity Market Operator
NGNSL	National Grid NSL Limited
NL	The Netherlands
NO2	Southern Norway
NVE	The Norwegian Water Resources and Energy Directorate
OLS	Ordinary Least Square
PCR EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
PCR	Price Coupling of Regions
PV	Photovoltaics
PX	Power Exchange
SDAC	Single Day-Ahead Coupling
TSO	Transmission System Operator
TWh	Terrawatt hour
VRE	Variable Renewable Energy

1. Introduction

Electricity markets are gaining increasing importance in both the European and global energy scene. The International Energy Agency suggests that electricity demand will rise by 25 to 30 percent by 2030 (IEA, 2022). At the same time, The European Commission's goal to cut greenhouse gas emissions by at least 55 percent below 1990 levels by 2030 sets Europe on a responsible path to becoming completely climate neutral by 2050 (European Commission, 2020). The transition to variable renewable energy (VRE) sources such as wind and photovoltaic power (PV) is vital in this process. The importance of understanding the implications of VRE is increasing as their influence continues to accelerate. Nevertheless, a challenge that arises from VRE is that the supply of electricity from these sources is not continuously available (Action Renewables, 2019). Electricity interconnection enables countries to better utilize their resources by leveraging comparative advantages and facilitate the transition to VRE, thereby achieving decarbonisation targets. The European Commission has long been pursuing the establishment of an integrated electricity market across Europe. Consequently, Norway has become integrated with other Nordic countries and the European continent through both physical interconnectors and market coupling. This study investigates the extent to which electricity prices in Norway are influenced by VRE sources from other countries.

In 1960, the first interconnection between Norway and Sweden was established in response to concerns about the energy supply in the region of Trøndelag. Since then, a total of 17 cross-border connections have been established, consisting of seven subsea cables and ten above sea cables to Sweden, Russia, and Finland (Statnett, NVE, 2021). The Nordic countries have gradually progressed from operating individually, to complete integration, and more recently with a broader part of the European continent. In 2021, operation of the two most recent interconnectors started, from the NO2 bidding zone in Norway to Germany and Great Britain. These two cables increased cross-border transmission capacity by close to 50 percent (NOU 2023: 3, p. 165). Subsequently, Norwegian electricity prices have surged and experienced unprecedented levels of volatility through the fall and winter of 2021 and throughout 2022.

The discussion surrounding the closer integration to the European market remains a highly debated cause for the staggering electricity prices. Some state that the Norwegian electricity price always has been correlated with European prices due to cross-border cables being installed as early as in 1960. Hence, some argue that the two most recent interconnectors to Germany and Great Britain have a limited effect and put more emphasis on the current situation with scarce gas supply all over Europe (Kampevoll et al., 2022). On the other hand, Volue Insight claims in a report that the two new interconnectors contribute to a 25 percent increase in spot prices alone (2022).

The purpose of this thesis is to contribute to the current discussion in Norway by examining the domestic price impact from VRE sources through market coupling. In other words, how day-ahead electricity prices in Norway are affected by PV and wind generation abroad. This does not mean that Norway directly imports electricity from wind and PV generators in for example Germany or Great Britain. Once uploaded to the grid, one electron is indistinguishable from another. The short-term impact domestically is caused by the increased influx of VRE with zero short-run marginal cost, and consequently, the EUPHEMIA algorithm shifts the merit-order curve to the right (Keppler et. al., 2016). As critics argue Norway see spiking electricity prices much due to the installation of NordLink and North Sea Link, advocates point to the current European energy crisis and argue that our long history of cross-border interconnection demonstrate that they in isolation have a very limited effect on the Norwegian market. The Norwegian system operator, Statnett, states that interconnectors allow Norway to absorb low-priced residual wind and PV, consequently reducing domestic prices. This thesis investigates how electricity generation in interconnected countries impact day-ahead prices in NO2, with a special focus on VRE, as this is the envisioned future of European electricity. Therefore, our main research question is as follows:

How does an increasing share of variable renewable energy in Europe impact the day-ahead price in NO2 through market coupling?

To investigate how the day-ahead price in bidding zone NO2 and the interconnected markets converge according to the merit-order effect from VRE, we examine the fundamental variable VRE penetration which is further elaborated below. The research question pertains to the law of one price, which states that electricity prices should converge as market restrictions, specifically transmission capacity, are reduced. In this regard, our study aims to examine the impact on day-ahead prices in NO2 as they converge in concordance with the merit-order effect. Additionally, we aim to evaluate how the intermittent nature of wind and PV feeds, and the resulting interconnection congestion, may influence this effect. To assess the price effect of VRE, we employ the Linear Quantile Regression model, using data spanning from the opening of the North Sea Link in October 2021 throughout 2022. Given that day-ahead prices are determined the day before operation, we treat the data as hourly panels.

Studying the consequences of cross-border electricity interconnection is relevant and important for various reasons. Predictions suggest that Norway's energy consumption will surpass future generation capacity (Kirkerud et al., 2022). This raises the question whether increasing cross-border interconnection capacity is a sustainable solution to maintain Norway's power balance in the future compared to alternatives, and what the appropriate level of capacity is. This thesis aims to contribute to develop a better understanding of the market integration to countries with interconnected VRE in combination with flexible Norwegian hydropower. VRE generation is unpredictable in nature and not correlated with consumption, unlike hydropower, which is more predictable. As a result, we hypothesize that the relationship between interconnected VRE and day-ahead prices are mediated by Norwegian demand patterns, with VRE having a greater price impact during peak demand hours as the supply becomes more sensitive to changes. In addition to off-peak demand hours due to the occurrence of negative bids. Moreover, congestions and consequently a diminishing merit-order effect are less likely to occur in peak demand hours as excess VRE is more likely absorbed locally.

The remainder of this paper is structured as follows. Chapter 2 describes the electricity mix in each country. In Chapter 3, relevant theory is explained. Chapter 4 presents existing literature on pertinent topics. Further, Chapter 5 presents the data utilised in our model, while Chapter 6 describes the methodology. Results are presented in Chapter 7. Limitations of our thesis and the conclusion are finally covered in Chapter 8 and 9, respectively.

2. Background

The purpose of market coupling is to enhance social welfare and efficiency in electricity markets. Market coupling enables countries to better utilize their resources and improve societal welfare by leveraging comparative advantages. Therefore, the country specific electricity mix suggests that Norway trades differently with, for instance, Germany than with Great Britain. In that respect, the impact of VRE should be assessed based on the respective electricity mix and transmission capacity for each individual country. This chapter provides an overview of the history of market coupling, followed by a description of the distinctive electricity mix of each country.

2.1 History of Deregulation and Market Coupling

The deregulation of the European electricity market began in 1990 when integrated monopolies were dismantled, and a uniform competition model was imposed in England and Wales. Only a year after the deregulation in Great Britain, the Norwegian market transitioned to open market-based solutions. Other Scandinavian nations soon followed, including Finland and Sweden, which underwent transitions in 1995 and 1996, respectively (Katic & Shikoski, 2002). The old power system model consisted of vertically integrated and regulated monopolies compromising all three parts of the system: generation, transmission, and distribution. With deregulation, these parts were treated separately, which introduced competition and the possibility for private market participation. Prior to the deregulation, cross-border interconnectors were limited. Throughout the 1980s, excess production from Norway's hydropower system could not be utilized domestically, resulting in a motivation to pursue exports of the surplus through cross-border interconnectors (Bolton, 2022). Norway already had a two-decade-old cross-border interconnection to Sweden; however, further interconnection would increase interdependencies requiring a well-functioning framework for electricity exchange. Nord Pool (then Statnett Marked) was established in 1993 as an independent company, and two years later, the framework for an integrated Nordic power market was made and delivered to the Norwegian Parliament. Along with Nord Pool's license for cross-border trading given by The Norwegian Water Resources and Energy Directorate (NVE), the report laid the foundation for spot trading at Nord Pool (Nord Pool, n.d.-a). As the

Nordic market became increasingly more integrated, several European countries also extended cross-border transmission capacity through interconnectors, and continuously do so to this date. Thus, electricity flows through countless of borders in both the Nordics and the rest of the European continent.

Today, Norway is directly connected to seven countries: Sweden, Finland, Denmark, Germany, the Netherlands, Great Britain, and Russia. The transmission capacities range from 3 695 MW between Norway and Sweden to 50 MW between Norway and Russia. The capacity to the other Nordic countries accounts for approximately 60 percent of Norway's total cross-border transmission capacity. Thus, the Nordic countries are closely linked through both interconnectors as well as a joint financial market. Nord Pool is the exchange for physical power trade for the Nordic countries. The Nordic electricity market consists of various marketplaces: the day-ahead market, the intra-day market, and the balancing markets. The day-ahead market, Elspot, is where most of the trading is conducted. In both physical and financial terms, the joint Nordic market is also connected with the rest of Europe's power market, where the physical power trading takes place on the European Power Exchange, EPEX SPOT (EPEX SPOT, n.d.).

Europe is continuously taking further steps to increase the integration of the internal energy market. A total of 24 countries are interlinked by the European market coupling, covering approximately 90 percent of the European electricity consumption (Ministry of Petroleum and Energy, 2022). Norway's most recent interconnections to Europe opened in 2021, NordLink and North Sea Link, to Germany and Great Britain, respectively. In addition, Norway is also connected to the Netherlands and Russia. However, the latter has in recent years very rarely been active and capacity was thus set to zero in 2022 (Statnett, 2022a). All active cross-border interconnectors between Norway and non-Nordic nations are currently connected to the southern part of Norway, or bidding zone NO2. Norway has a total of five bidding zones, as the power situation differs from one region of the country to another. The bidding zones account for congestion in the grids as power is imported from one area with surplus to another area with deficit. The NO2 bidding zone is also connected to Denmark through four interconnectors, making this the preeminent bidding zone in Norway for cross-border transmission capacity. Our thesis investigates the impact of VRE generation in countries connected to Norway through bidding zone NO2, thus limiting our study to countries connected through High Voltage Direct Current (HVDC) transmission cables:

Interconnection	**To**	**Opening year**	**Capacity**
Skagerrak 1, 2, 3 & 4	Denmark	1976, 1977, 1993, 2014	1700 MW
NordNed	The Netherlands	2008	700 MW
NordLink	Germany	2021	1400 MW
North Sea Link	Great Britain	2021	1400 MW

Table 2.1: Subsea cross-border interconnections from the NO2 bidding zone as of May 2023, Source: Statnett (2021), TenneT (2015) & Delebekk (2022).

Further, we will briefly present the electricity mix in Norway as well as each of the other countries connected to bidding zone NO2. It is important to specify that electricity mix is not equivalent to the energy mix, as its only one of three components of the total energy mix, the other two being transport and heating (Ritchie et. al., 2022).

2.1.1 Norway

Before the Norwegian power market was deregulated in 1991 following the Energy Act, the market functioned as a cost-reimbursement system. Power producers acted as local monopolies which supplied power to nearby areas. There was no connection between price and investment costs or operation costs. This led to inefficient investments in capacity, in which it eventually exceeded demand considerably (Aune et al., 2005). Hence, the Energy Act was implemented which introduced competition for electricity production and trade. Transmission lines are natural monopolies and were organized accordingly. The Norwegian government created two new entities, Statkraft SF and Statnett SF (NVE, 2021a). Statkraft SF was responsible for the production while Statnett SF was responsible for transmission. In addition, the power market Statnett Marked AS was established which is known as Nord Pool today (Ministry of Petroleum and Energy, 2022).

The annual domestic electricity generation in a normal year is approximately 155 TWh. As displayed in Figure 2.1, in 2021, this consisted of 88 percent hydropower, 10 percent wind power and 2 percent thermal power. Norwegian production is characterised by the large share of hydropower, enabling storage of up to 70 percent of annual demand in reservoirs. It is mainly water inflow and capacity that determine the annual hydropower generation. In years with drought, the inflow may be reduced by 65 TWh (Ministry of Petroleum and Energy, 2021).

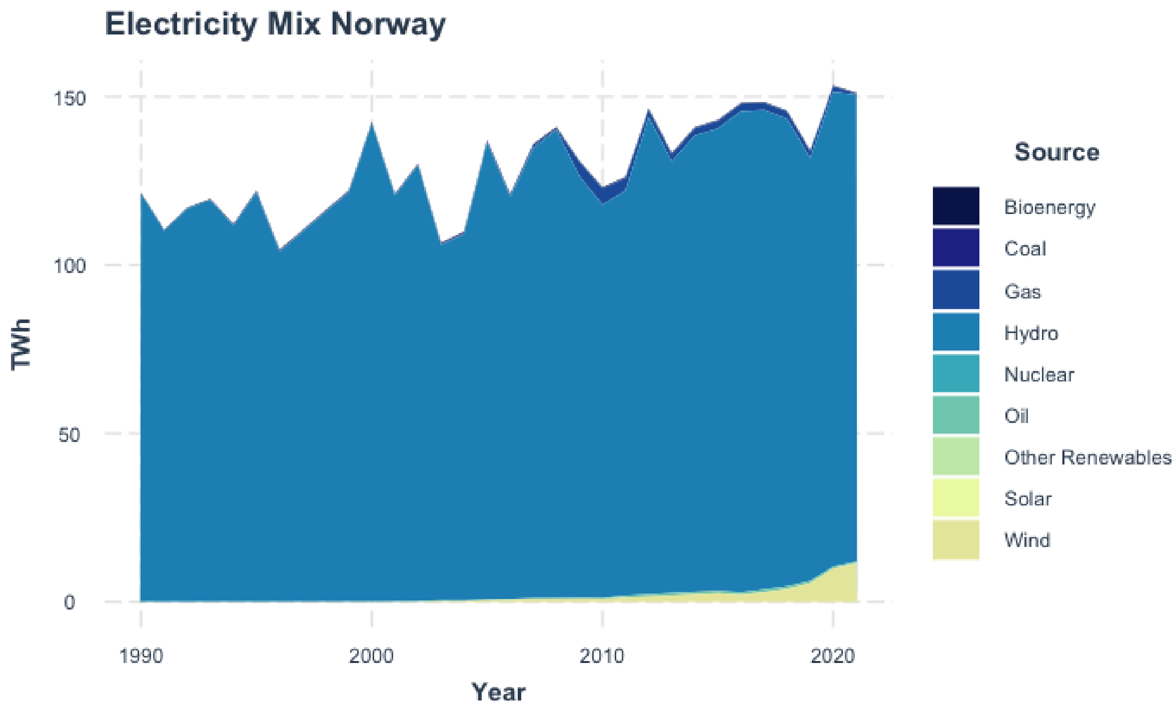

Figure 2.1: Electricity mix in Norway. Source: Our World in Data (2022)

2.1.2 Germany

The German electricity market was liberalized in 1998. Prior to this, the market consisted of vertically integrated utilities with area monopolies. Electricity customers were not given the choice of selecting their supplier, and retail rates were regulated. As the liberalisation started to arise in the 1990s, mergers and acquisitions began to form, resulting in four different utilities owning approximately 80 percent of the generation capacity. The market is still dominated by four generation companies and four transmission companies. At the time, electricity from VRE did not play an important role. However, in 1990 the first regulation on feed-in of VRE was enforced (Agora Energiewende, 2019).

Today, Germany is the largest energy consumer in Europe followed by France and the UK. Germany is currently undergoing a transition from a dominance of coal, oil, and nuclear power to renewable energy sources. In 2011, the so-called "Energiewende", a long-term energy and climate strategy was announced by the German government. The goal was originally to reduce the amount of fossil fuels from 80 to 20 percent of the supply by 2050. However, the target was toughened after the Paris Agreement and in 2050 the goal is to be completely climate neutral in the electricity sector (Renn & Marshall, 2020).

The annual gross electricity production in Germany was 588.1 TWh in 2021. The share of electricity generated from renewable energy sources was 39.7 percent (AG Energiebilanzen, 2022). Generation from onshore and offshore wind accounted for 19.4 percent, PV for 8.5 percent and biomass for 8.6 percent. Hydropower and other renewable energy sources accounted for the remaining 3.2 percent. Germany has seen a significant growth in VRE, as the proportion has increased more than six times since the year 2000 (Agora Energiewende, 2022).

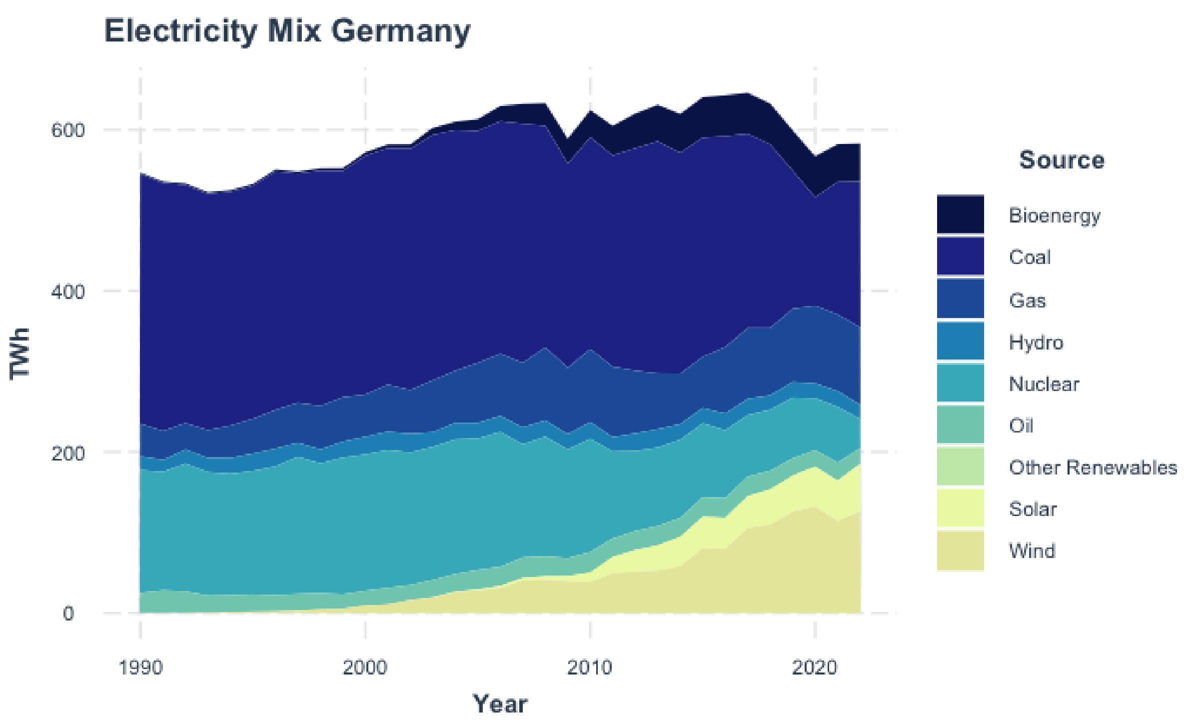

Figure 2.2: Electricity mix in Germany. Source: Our World in Data (2022)

2.1.3 Great Britain

The liberalization experience in the Great Britain started with the adoption of The Electricity Act in 1989. Before this, the Central Electricity Generating Board served as the controlling body for the generation and transmission of electricity in Great Britain, which was a state-owned monopoly (Rotaru, 2013). The 1989 Electricity Act sought to restructure the market by separating supply, generation, distribution, and transmission companies to privatise the electricity industry. In 2008, Great Britain´s government announced the Climate Change Act, setting a goal to cut all of greenhouse gas emissions by 2050 (The UK Government, 2023a). Great Britain is already the global leader and the frontrunner of the development of offshore wind power capacity. Their ambition is clear, with more than half of their renewable generation being wind by 2030. They also target a five time increase in PV capacity before 2035 (The UK Government, 2023b).

The annual gross domestic electricity generation in the Great Britain was 308.1 TWh in 2021. Following 2020, Great Britain experienced its first year in which electricity was primarily generated by renewable sources. In 2021, there was a decline as a result of unfavourable weather. Renewables accounted for 39.7 percent of the electricity generation, with 24.9 percent stemming from wind and PV. Great Britain has seen an even more substantial increase in VRE compared to Germany, from a share of 5.9 percent in 2010 (The UK Government, 2022). Note that Figure 2.3 is the electricity mix for the United Kingdom which also includes the electricity mix in Northern Ireland.

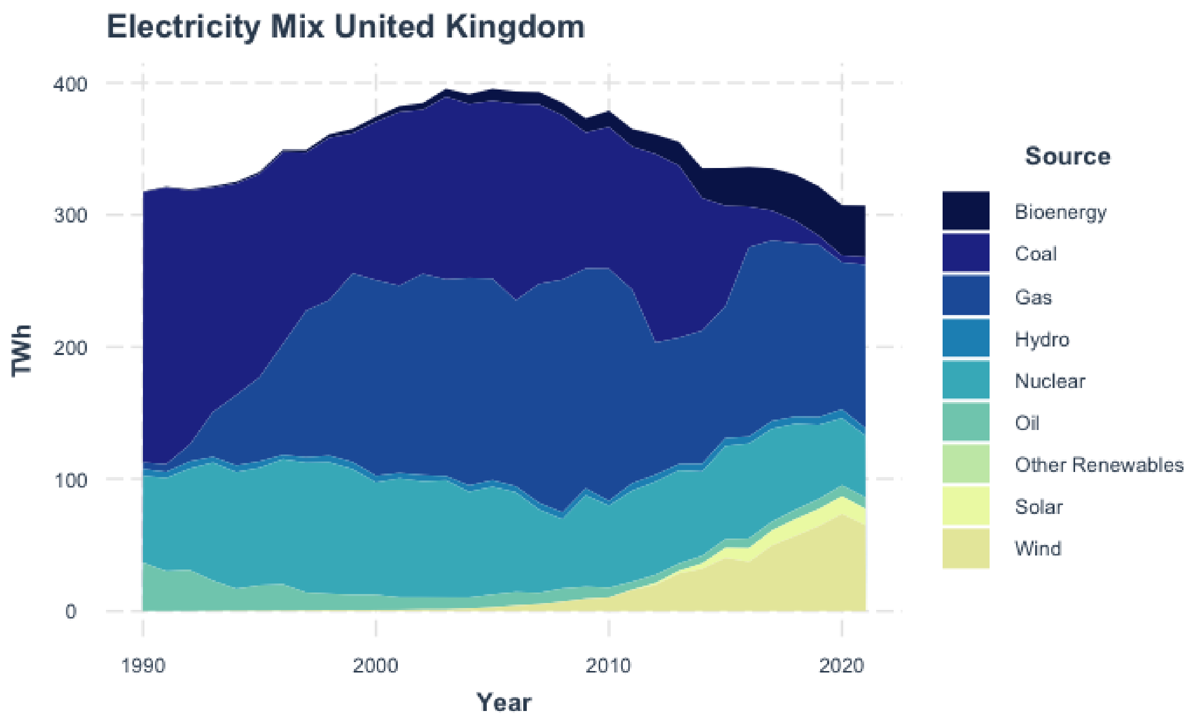

Figure 2.3: Electricity mix in the UK. Source: Our World in Data (2022)

2.1.4 The Netherlands

The Dutch electricity market was deregulated and fully opened for competition in 2004, leading to the entry of several vertically integrated European companies. The previously national generation and distribution companies were purchased by private companies, as the Netherlands aimed to completely split network owners from power generators (Deloitte, 2015). In 2019 The Climate Act framework was passed in the Netherlands, mandating the country to reduce its total greenhouse gas emissions by 95 percent compared with 1990 levels in the long run, and have a completely carbon neutral electricity sector by 2050. Already in 2030, the framework requires the country to reduce emissions by 49 percent, also here with 1990 levels as a baseline (Climate Laws, 2019).

In 2021, the annual gross domestic electricity generation in the Netherlands was 121.6 TWh. Of the total electricity generation, wind and PV accounted for 14.8 percent and 9.5 percent, while bioenergy combined with hydropower covered 9 percent. In total, renewables comprised 33.3 percent of the domestic electricity generation (Ritchie et. al., 2022).

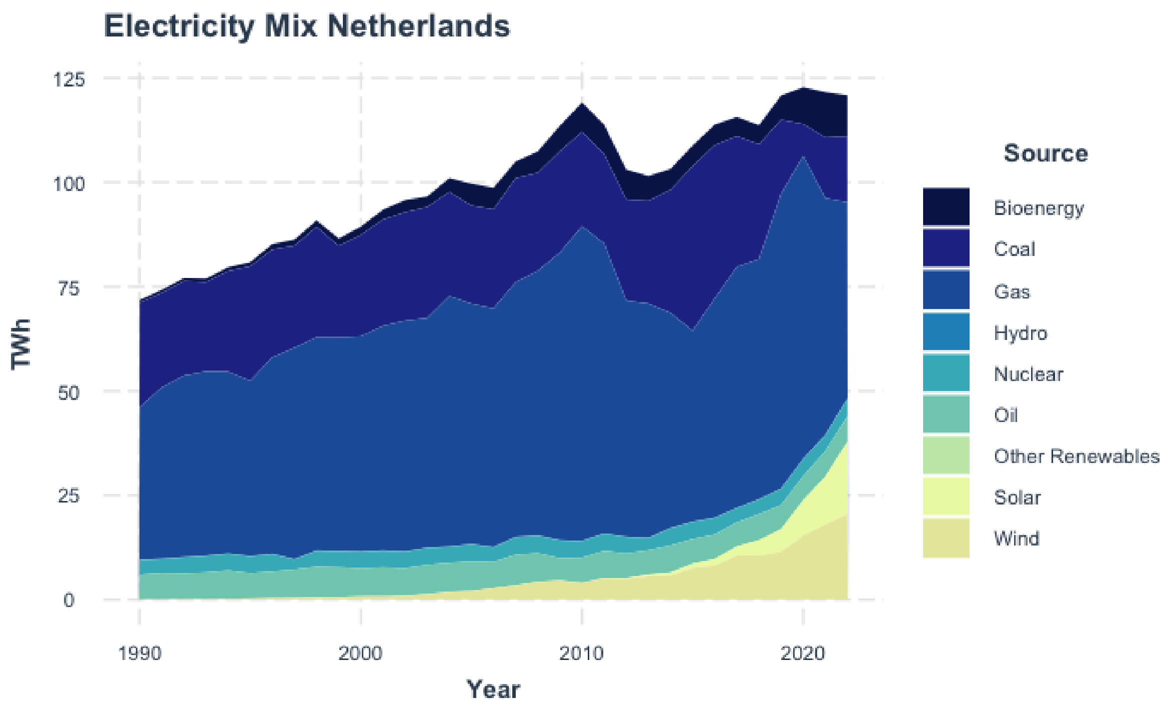

Figure 2.4: Electricity mix in the Netherlands. Source: Our World in Data (2022)

2.1.5 Denmark

The motivation behind the deregulation of the Danish electricity sector was the development seen in Norway and Sweden, as well as EU's focus on an internal European market. The process started in 1996, removing the local monopolies, giving third party access to the grid, and establishing a transmission system operator (TSO). Denmark joined Nord Pool three years later, in 1999, and all transmission capacity was then allocated to Nord Pool for the day-ahead market. The deregulation of the Danish electricity market was one of the initiatives that helped the country become one of the global leaders in VRE (Danish Energy Agency, 2020).

In 2020, Denmark set a target to reduce their greenhouse gas emissions by 70 percent by 2030 compared to levels in 1990 as well as a goal to become completely climate neutral by 2050. Denmark had a gross domestic electricity generation of 33.1 TWh in 2021. Wind is the major source of electricity, with 16.05 TWh equivalent to 48.5 percent. Bioenergy is the second largest electricity source, with 26.2 percent. Including PV and hydropower, renewables composed more than three quarters of the domestic electricity generation in Denmark, totalling 78.9 percent.

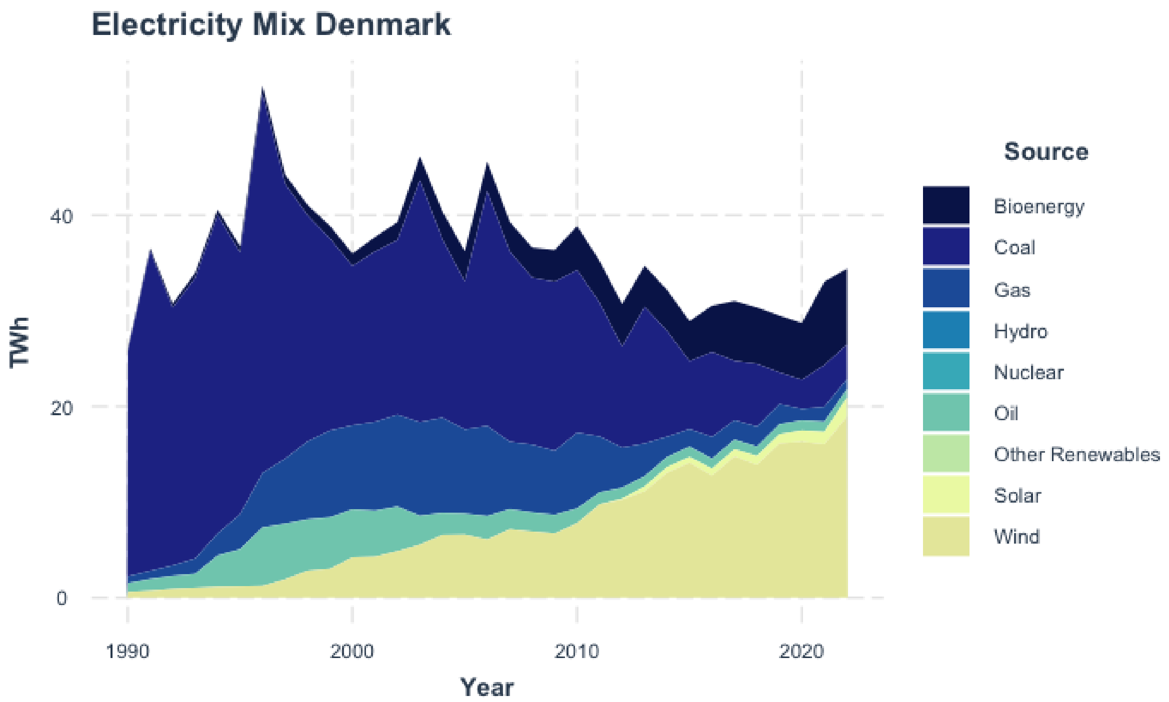

Figure 2.5: Electricity mix in Denmark. Source: Our World in Data (2022)

3. Theory

In this chapter we will elaborate on the relevant theories necessary to understand the varying price impact of VRE. Apart from the electricity mix, there are other structural factors impacting the day-ahead price such as the auction process, price coupling algorithm, and congestion. By examining these theories, we aim to shed light on the complex interactions between VRE and other market forces, ultimately contributing to a more nuanced understanding of the challenges and opportunities posed by the integration of VRE in the electricity grid.

3.1 Drivers of the Electricity Price and the Merit-Order Curve

The deregulation of the European power industry started about three decades ago, removing price controls and thus introducing competition (Katic and Shikoski, 2002). Following the restructuring of the power industry, distinct dynamic properties in electricity prices was introduced, considerably different from those of financial assets (Kyritsis et al., 2017). The deregulation provoked fundamental changes, as electricity prices started seeing phases with high volatility and other periods with low and stable prices (Kyritsis et al., 2017). As VRE are increasingly infiltrating the global energy scene, electricity prices are progressively further influenced by their low marginal cost according to the merit-order curve.

Most restructured electricity markets set market spot prices through an auction; hence the equilibrium price is set where supply meets demand. The supply curve, also known as the merit-order curve, is derived from ordering the supplier bids according to ascending marginal cost (Deane et al., 2015). The merit-order curve is composed of all electricity-generating energy sources and their capacities, as well as their marginal cost of generation, ranked from the lowest to the highest. The intersection of this merit-order curve and the demand curve is known as the market clearing price, in other words the electricity spot market price. Electricity sources with lower marginal cost will be prioritised up until demand is not filled and the demand curve shift to the right to electricity sources with higher marginal cost, increasing the market clearing price. In other words, electricity prices are set by the variable cost of the marginal plant, that is the most expensive plant that is required to meet demand (Hirth, 2022). The purpose of this system is to economically optimize the electricity supply. An illustration of this is shown in Figure 3.1. VRE sources such as wind and PV have extremely low marginal cost, therefore entering near the bottom of the supply curve (Krohn et. al., 2009). As the VRE generation increases, the merit-order curve will shift to the right, changing the marginal plant utilized to meet demand. This is referred to as the merit-order effect, illustrated by the change from the dark blue line to the light blue line in the figure. The figure shows that the marginal plant shifts from coal to nuclear, which has a lower marginal cost of generation.

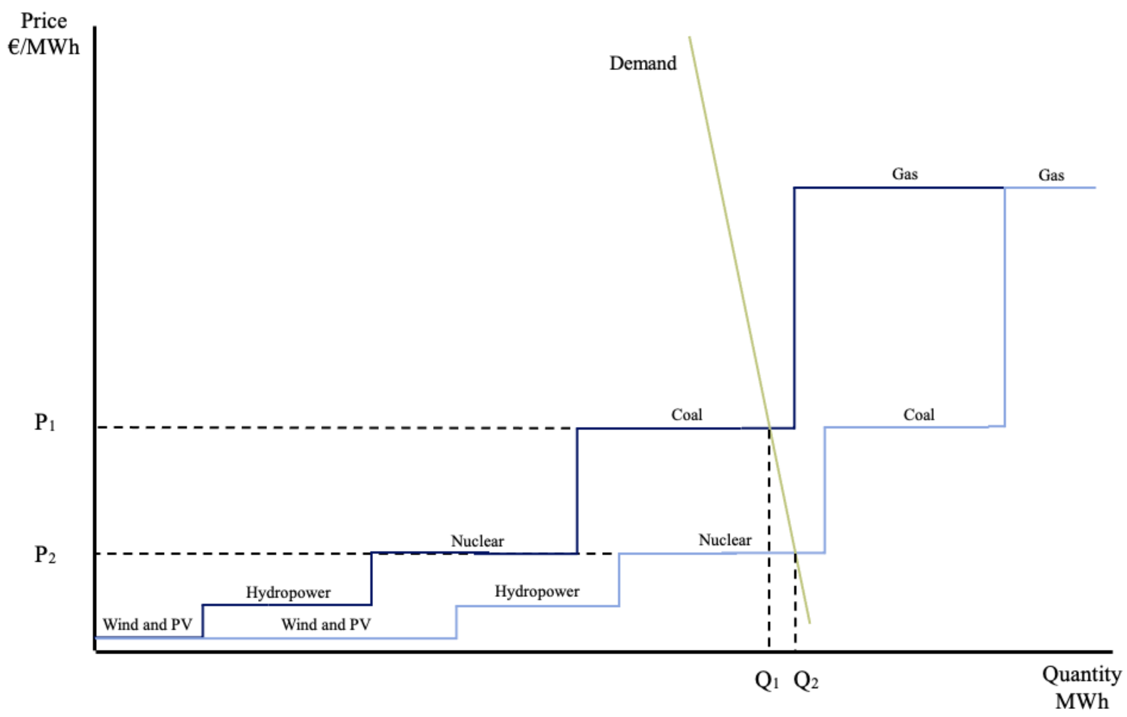

Figure 3.1: The merit-order effect

Electricity demand curve is steep and highly inelastic in the short term, as consumers have limited ability to alter their consumption patterns (Kyritsis et al., 2017). The instantaneous nature of electricity consumption and the inelastic supply leads to frequent price changes as either the supply or demand varies. The demand for electricity varies based on several components. However, it is both expected and crucial that demand is continuously fulfilled. It is a uniform and homogeneous good for consumers, meaning that the final product serves the same function no matter how it was produced, and only the price paid for it is affected by its origin. The demand varies from instant to instant, hour to hour, day to day, and from season to season. Demand for electricity is higher during the day than during the night, so-called peak, and off-peak hours. We also see seasonal variations in demand. For instance, electricity demand in Nordic countries typically peak during the winter, while the opposite is true for southern Europe, where peak demand and thus prices are seen during the summer (Econ, 2007).

These pricing mechanisms reflect the dynamics of electricity prices, and the behaviour of electricity prices differ from that of other commodities predominantly as mentioned because electricity is non-storable. Inventories cannot be used to arbitrage prices across time (Knittel and Roberts, 2015). However, one could argue that Norway as a highly hydro-reliant country is in a unique position. With reservoirs capable of storing up to 85 TWh of water, the Norwegian system exhibits considerable flexibility. Each hydropower producer faces the problem to decide when its most profitable to use the water given a long-term planning horizon. The water value is assessed by estimating the opportunity cost, which is calculated based on the potential revenue that would be foregone because the water is not accessible for future use. This problem is illustrated in Figure 3.2 for two periods. The length of the X-axis is the total amount of water in GWh available in both periods. In period 2, the inflow is depicted as a thinner line flowing from the right side to the left side. The demand curve for this period is also plotted on this axis, which is the opposite direction compared to the demand curve in period 1 (Green, 2021).

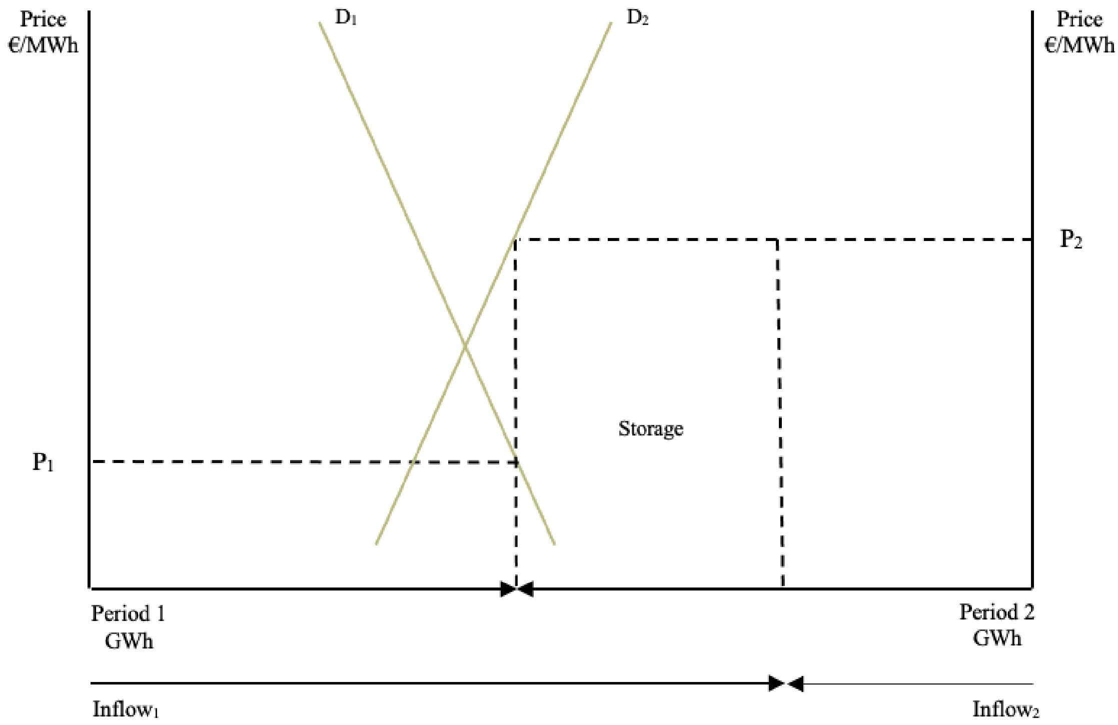

Figure 3.2: Reservoir management for two periods with storage. Source: Green (2021)

The social optimum without capacity constraints would be to conserve water from one period to the next so that prices would be equal in both periods. In this case, we have a hydro reservoir with maximum capacity denoted by the dashed lines which gives unequal prices during the planning horizon. We assume no discounting between periods as each period is typically one week. Demand in period 1 is lower compared to period 2 which allows inflow to be stored to the next period. Since the reservoir is constrained, more water has to be released in period 1 relative to the demand in period 2 which lowers the price in that period. When incorporating interconnector capacity into this model, the overall generation capacity expands. This enables the possibility of either saving more water during import hours or releasing more water during export hours. Essentially, Norway can arbitrage between domestic production costs, prices and imports of inexpensive electricity when interconnected countries have an excess supply of VRE. Therefore, on the longer-term, availability of water could be enhanced during periods of scarcity, leading to a decrease in the value of water and, consequently, lower electricity prices. Nevertheless, if the additional conserved water obtained through imports is utilized for exports, it will offset the price dampening effect (NOU 2023: 3, p. 139). Hence, the complete price impact from a merit-order effect on the longer term is not only dependent on imports, but also water conservation and exports. In other words, whether Norway has net export or net import over the planning horizon, will in large parts reflect if the price contagion is positive or negative. However, this long-term effect is not directly captured by our model as we focus on the instantaneous impact from a shift in the merit-order on day-ahead prices, and not how VRE impact day-ahead prices indirectly through changes in the water value.

3.2 Price Coupling and EUPHEMIA

Electricity interconnection between various European nations have been designed largely to promote security of supply, enabling areas with a shortage of supply to import power from an area with surplus (Jacottet, 2012). In more recent times, the European Commission has encouraged market coupling, which has started to take place in large parts of Europe. Market coupling is a technique to integrate various energy markets into one coupled market. With market coupling, demand and supply orders in one market are no longer restricted to the local territorial, only limitation being the electricity grid constraints (NEMO Committee, 2019). Before market coupling was introduced, cross-border capacity and electricity had to be purchased separately, meaning a trading party had to reserve cross-border capacity before buying the electricity (EPEX SPOT, 2020). Market coupling uses implicit auctions where participants do not individually receive allocations of cross-border capacity, instead, prices and flows are simultaneously calculated between areas in the day-ahead market. Market participants can make bids and offers hourly for the next 24 hours, and do not need to reserve grid capacity in advance (Ministry of Petroleum and Energy, 2022). Power Exchanges (PXs) then consider the available cross-border capacity and aim to minimize the price difference in the coupled market areas (EPEX SPOT, 2020).

Today, large parts of Europe are part of the Single Day-ahead Coupling (SDAC), which allocates cross-border transmission capacity between different regions. The goal of SDAC is to create a single pan European cross zonal day-ahead electricity market, as it is believed to improve efficiency and maximise welfare. The initiators of SDAC are the Transmission System Operators (TSOs) and the Nominated Electricity Market Operators (NEMOs) (ENTSOE, 2021). PCR, short for Price Coupling of Regions, is the supplier to Single Day-

Ahead Coupling, and has been since June of 2021. PCR is a project by a group of European PXs to develop a single price coupling system to calculate electricity prices across Europe, integrating the European electricity markets. It is an initiative of eight central European PXs: Nord Pool, EPEX SPOT, GME, HEnEx, OPCOM, OMIE, TGE, and OTE. These PXs cover 26 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, Sweden, Greece, and Bulgaria (Madani, 2021).

The main advantage of market coupling is an increase in market liquidity, which has the positive side effect of making electricity prices less erratic. Market players are no longer required to purchase transmission capacity rights to conduct cross-border exchanges; they only need to submit a single order in their market. The order will further automatically be matched with competitive orders in either the same or other coupled markets, while the network constraints simultaneously are evaluated (NEMO Committee, 2019).

The algorithm developed to deal with coupling of day-ahead markets in the Price Coupling of Regions is called PCR EUPHEMIA (Pan-European Hybrid Electricity Market Integration Algorithm, hereafter referred to as just EUPHEMIA). EUPHEMIA has been used since 2014, calculating electricity allocation and prices across the European PCRs. For all the periods of a single day, EUPHEMIA matches energy supply and demand while accounting for both market and network constraints. The goal of the algorithm is to maximise social welfare while it returns the market clearing prices, the matched volumes, and net position of each bidding zone with the flow through the interconnectors (NEMO Committee, 2019). The algorithm is highly efficient and complex, requiring inputs from the involved NEMOs and TSOs, such that each area's price is constructed. A highly detailed description of EUPHEMIA and its mathematical formulation is excessive to answer our research question. On that account, to briefly summarize EUPHEMIA and its characteristics:

- EUPHEMIA calculate the energy allocation and electricity prices across the European PCRs. All orders by all market participants are collected, with no limit on either the number of orders, markets, or network constraints. All bids and offers are treated exactly equally.

- The goal of the algorithm is to maximise the overall welfare. That is, the total market value of the day-ahead auction expressed as the sum of consumer surplus, producer surplus, and congestion rent across all involved areas is maximised.

- The algorithm increases the transparency of both the computation of prices and flows. It returns the matched volumes, the market clearing prices, and the net position of each bidding zone as well as the flow through the different interconnectors.

3.3 Congestion Management

The procedures for determining how much capacity market participants can utilize on cross-border interconnectors without jeopardizing system security are set forth in the guideline on Capacity Allocation and Congestion Management (CACM). Additionally, it harmonizes how European cross-border markets work to boost competition and promote the use of renewable energy sources. CACM is the foundation of a single European market for electricity (ENTSOE, 2021). The CACM provide the rules and regulations for both the implementation and the operation of the European market coupling of day-ahead electricity prices. The rules and regulations apply to NEMOs, TSOs, and regulatory authorities in each market area. To make capacity computation as transparent and efficient as possible for market participants, TSOs coordinate their capacity. Through the CACM regulation, TSOs can offer the right amount of cross-zonal capacity for market allocation. The NEMOs manage the intraday coupling as continuous trading with several implicit auctions as well as the day-ahead coupling as an implicit auction collecting all bids and offers from the different bidding zones. Exchanges of electricity between bidding zones are constrained by cross-zonal capacity, while exchanges inside one bidding zone is unrestricted. Bidding zones are important to avoid structural congestions within one zone. If the current bidding zone arrangement is ineffective, TSOs must assess the design and recommend a more efficient one. The physical congestions are managed by the TSOs (ACER, n.d).

If the power flow through a transmission cable exceeds its thermal limit, congestion is detected. The overload could potentially threaten the security and network reliability. When production through VRE sources reaches ample amounts compared to consumption or exceeds the transmission capacity, excess electricity results in curtailment of renewables. That is, production of electricity from the VRE sources is purposefully reduced as either demand or transmission capacity essentially become bottlenecks. In this scenario, one might experience negative electricity prices, as producers are faced with the economical decision to either stop production and restart it later, which is costly, or essentially pay to give away the electricity. The ability to export excess generation to where it is needed most can prevent or reduce the curtailment of renewables (National Grid, 2022). Thus, interconnectors serve the option to transfer excess generation in one area to other areas, instead of curtailing the renewable production.

3.4 Nord Pool

The leading electricity market in Europe is Nord Pool, which provides day-ahead and intraday trading, clearing, settlement, and related services across 16 different European nations. The countries trading on Nord Pool are the countries in the Nordic and Baltic regions, Great Britain, Austria, Belgium, France, Germany, Luxembourg, the Netherlands, and Poland. All the countries trading through Nord Pool are connected through the PCR (Nord Pool, n.d-b).

The intraday market on Nord Pool is named Elbas, and the day-ahead market is called Elspot. Due to limitations for the transmission between the regions, Nord Pool is separated into bidding zones with varying prices. If these bottlenecks did not exist, the price would be the same in all bidding zones, which is reflected in the hypothetical system price. The day prior to delivery, prices for the consecutive day are determined after bids and offers are received from participants by 12:00 CET. In 2022 a total of 1077 TWh was traded through Nord Pool. The majority of the volume traded at Nord Pool takes place on Elspot, accounting for approximately 96.5 percent total volume. From 10:00 CET available interconnector capacities are published, and market participants have until 12:00 CET to submit their bids and offers to a blind auction for all hours in the next day. The orders are then matched to maximize social welfare while also considering the capacity constraints between each bidding zone. The calculation of each bidding zone price is done by EUPHEMIA. (Nord Pool, n.d-c).

3.5 EPEX SPOT

The European Power Exchange (EPEX SPOT) operates the most liquid day-ahead and intraday markets in Europe and is an approved NEMO in all its coupled countries. Today, EPEX SPOT is operating across 13 different countries: Austria, Belgium, Denmark, Germany, Finland, France, Luxembourg, the Netherlands, Norway, Poland, Sweden, Great Britain, and Switzerland. For a long time, EPEX SPOT has been one of the main drivers in market coupling initiatives for Europe. All the countries trading through EPEX SPOT are, similarly to Nord Pool, connected through the PCR.

Very much like Nord Pool, the day-ahead price is settled in the trading period, an hour-long period during which all market participants submit bids and offers by 12:00 CET. All orders are logged in by the market participants, and EUPHEMIA compute the market clearing price for each hour of the consecutive day taking grid constraints and capacities into consideration. The market clearing price reflects the intersection between the supply and demand, which apply to all buyers and sellers. In 2022, a total of 611 TWh was traded on EPEX SPOT. Approximately 78 percent of the trading took place on the day-ahead market and 22 percent on the intraday market (Enerdata, 2023).

3.6 North Sea Link Auction

Due to Brexit, the interconnector between NO2 and Great Britain, North Sea Link, cannot be included in any solution within the European energy market. Hence, a separate system for day-ahead auctions have been developed between NO2 and Great Britain. Statnett and the National Grid NSL Limited (NGNSL), the certified TSO and interconnector licence holder are responsible for the North Sea Link day-ahead market auction. This is an implicit auction mechanism within the day-ahead timeframe which are coupling the day-ahead markets of NO2 and Great Britain. The implicit auction process is ran using an algorithm developed and maintained by NGNSL's appointed power exchange, much like the EUPHEMIA algorithm (Stortinget, 2022). This implicit auction process is allocating the North Sea Link interconnector capacity in combination with physical power orders. North Sea Link's capacity will not be directly accessed by or available to the market participants. Due to Great Britain and Norway trading in different currencies, respectively GBP and EUR, in cross-border matching, an external daily foreign exchange rate is used (National Grid, 2021).

On the Norwegian side, every customer of Nord Pool can participate in NSL auctions in line with the requirements for participating in the SDAC. On the British side, NSL is integrated into Nord Pool's British spot auction (Statnett, 2021). All participants of the NSL auction must have physical generation or consumption in bidding zone NO2, or alternatively place a price-independent bid in SDAC that corresponds to a possible commitment from the NSL auction. This is required to ensure balance in both markets, and thus makes it more complex and riskier to participate in the NSL auction (Statnett, 2021).

4. Literature Review

The effect of VRE sources on electricity price dynamics is a widely recognised and extensively studied subject. This also applies to the price effects from transmission interconnector installations. However, there is no distinct research on the isolated price effects of cross-border transmission of electricity from VRE in Norway. Given that Norway is a highly flexible hydro-dependent country with expanding transmission capacity to countries with a more variable electricity mix, the topic is of high importance to investigate. In this chapter, we present the pertinent existing findings as well as the inconsistencies we have found in the literature.

4.1 Renewable Energy Sources and Their Effect on Electricity Prices

Extensive research has been conducted on the connection between the price of electricity and the output of VRE. The merit-order suggests that the increase of low marginal-cost electricity generation, such as wind and PV, should decrease prices. Numerous previous studies on this topic support this theory and find that VRE generation has a price-dampening effect on electricity prices (e.g., Sensfuß et al., 2008; Ketterer, 2014; Cludius et al., 2014; Clo et al., 2015). These findings are consistent across several different markets and countries. However, the focus in earlier studies is on individual countries' domestic implementation of VRE and its price effects. There is inadequate research on how VRE affect prices in another area through market coupling, even though both cross-border transmission capacities and the share of renewables are drastically increasing.

To our knowledge, the earliest study on the price impact of VRE generation was conducted by Sensfuß et. al on the German market. In their study from 2008 they concluded that in the year 2006 the increasing share of VRE reduced the unweighted average price by 7.8 EUR/MWh. These findings were later supported by research from both Ketterer (2014) and Cludius et. al (2014). The latter showing that electricity generation from VRE sources reduced the spot market prices by 6 EUR/MWh and 10 EUR/MWh in Germany in 2010 and 2012, respectively. Clo et. al (2015) examined the impact of VRE generation on national wholesale electricity prices in Italy, finding empirical evidence that an increase of 1 GWh in the hourly average of daily generation from VRE on average reduced wholesale electricity prices by respectively 2.3 EUR/MWh and 4.2 EUR/MWh in the period between 2005 to 2013. Cevik et al. investigated the impact of VRE on both the volatility and level of wholesale electricity prices in 24 European countries from 2014 to 2021 (2022). They discovered that the wholesale electricity prices in Europe were significantly reduced, with an average reduction of 0.6 percent for each percentage point increase in the share of VRE. In their study, they also found evidence that the relationship between the share of VRE in the energy mix and electricity prices was non-linear.

Tselika investigated the impact of VRE generation on the distribution of electricity prices and their variability in both Denmark and Germany by a novel panel quantile approach on hourly prices from 2015 to 2020 (2022). The use of hourly-specific effects combined with a quantile approach allowed for estimation of the VRE impact on various price quantiles while at the same time controlling for market dynamics. The results suggest that the merit-order effect occurs in both countries, as both wind and PV generation have various effects on the electricity price distribution on three separate demand levels: low, intermediate, and high. The paper exhibits a contrast in the effect from wind- and PV generation in Germany, as wind generation show a stronger impact in the lower price quantiles while PV more prominently impacts the upper price quantiles.

The price-dampening effect of VRE stems from changes in the supply curve, as described under Section 3.1. Due to the fact that wind and PV have close to zero marginal cost they constitute the far left of the merit-order curve. Findings from the studies referred to above conducted on the German, Danish and Italian market displays that an increase in VRE capacity causes the merit-order curve to shift to the right.

4.2 Cross-border Interconnections and Their Effect on Electricity Prices

Considerable research has been conducted on the relationship between the price dynamics of electricity and installation of cross-border transmission interconnectors (e.g., Keppler et. al., 2016; Vágner, 2019; Mevatne & Michel, 2022). The literary interest has especially surged in recent years as the coupling of the European power market has increased. Domestic price effects from the installation of one of the more recent interconnectors from Norway, NordLink has been broadly researched the last couple of years. Research on earlier interconnector installations between Norway and other countries, such as the Skagerrak project to Denmark and NorNed to the Netherlands has not been as widespread. The same is true for the most recent interconnector to Norway, the North Sea Link to Great Britain. The conducted studies found that prices between originally separate markets tend to converge after the installation of electricity interconnectors. Nonetheless, past research focus on the aggregate price effects of such interconnector installations.

Myrvoll and Undeli recently conducted a study of the NordLink interconnector between Norway and Germany and its effect on day-ahead electricity prices in both NO2 and Germany (2022). Their research is conducted using a quantile regression approach on time series data for both price areas, while also controlling for several other variables which are known to affect day-ahead prices. Their result indicate that NordLink has had a price-reducing effect in Germany and price increasing effect in Norway. In other words, their study shows that prices between the two countries have converged after the NordLink installation.

Mevatne and Michel (2022) investigated the consequences of a hypothetical scenario where Norway is decoupling from the European electricity market. They analysed the three interconnectors: NordLink, NorNed and North Sea Link. Their research is conducted with an optimisation model, with data from 17 different European price areas over a 60-day period in 2022. Their simulations suggest that hourly prices in the south of Norway, price area NO2, decrease by 9% on average if all three interconnectors were disconnected at once.

In a study by Vágner (2019) the price effects from an expansion of transmission capacity between Norway and both Germany and Great Britain are modelled. The research was done prior to the installation of NordLink and North Sea Link while they both where under construction, using historical data on supply and demand curves for day-ahead market between 2015 and 2018. Their result show that an increase in transmission capacity from Norway to both countries would cause an increase in domestic electricity prices. The price increase from the NordLink cable was estimated to be roughly 1 EUR/MWh, while their research showed that North Sea Link would lead to a twice as big price spike at around 2 EUR/MWh.

Keppler et. al. investigated the impacts of VRE and market coupling on the convergence of French and German electricity prices (2016). Their research is conducted on a sample of 24-hourly day-ahead prices in both France and Germany over three and a half years. Their result suggests that VRE generation in Germany has a strong positive impact on the price divergence between the two countries, as it decreases the price in Germany. However, the implementation of market coupling has the opposite effect, mitigating the price divergence stemming from VRE. Such research is yet to be conducted in Norway, even though we see an increasing transmission capacity to European countries with an abundant amount of electricity generation from VRE sources.

5. Data

Within this chapter, we introduce a comprehensive dataset comprising dependent, fundamental, control, and fixed effects variables. Additionally, we employ descriptive statistics as a means to examine the dataset and explore the relationship between the day-ahead price in NO2 and VRE.

5.1 The Dataset

Our data sample consists of hourly day-ahead prices in bidding zone NO2 with a total of 10,968 observations, equivalent to 457 calendar days. The first observation is October the 1st 2021 due to North Sea Link having its first trading hour on this date, and the last observation is the final trading hour of December 31st, 2022. Since we are modelling the hourly prices that were determined the day prior, we will resample the data into 24 panels containing observations for each hour. The main argument being that all these prices were determined with the same information and hence should be treated as panel data (Pham, T., 2019; Tselika, K., 2022). The same argument is made by Keppler et. al., as the 24 separate hours are all determined simultaneously the day prior with respect to the exact same information, not generating a single time series with continuously updated information (2016). In addition, Huisman et al., state that hourly electricity prices mean revert around the hourly specific price level rather than following a time series process (2007). Furthermore, Tselika K. argues that the hourly specific effect may vary extremely when looking at interconnections, as transmission flows may be diverse throughout the day (2022). Another point made by Keppler et al. is that VRE sources have certain features, such as the fact that PV generation always is highest around noon, which favours the hourly panel structure (2016). Table 5.1 gives an overview of the variables with unit of measurement, resolution, transformation, and source.

Variable	Units	Resolution	Day-ahead	Shifted	Source
Price NO2	EUR/MWh	Hourly	x		ENTSO-E (n.d.-a)
VRE penetration DK	Percent	Hourly	x		ENTSO-E (n.d.-b)
VRE penetration NL	Percent	Hourly	x		ENTSO-E (n.d.-b)
VRE penetration DE	Percent	Hourly	x		ENTSO-E (n.d.-b)
VRE penetration GB	Percent	Hourly		x	Elexon (2022), Sheffield Solar (n.d.)
Demand	MWh	Hourly	x		ENTSO-E (n.d.-c)
Reservoir levels NO2	Percent	Weekly		x	NVE (n.d.)
Temperature	Celsius	Daily		x	MET Norway (n.d.)
Price of Natural Gas	EUR	Daily		x	Bloomberg (n.d.) EGTHDAHD
Electricity Certificates	EUR	Daily		x	Macrobond (n.d.) ELCSEKD

Table 5.1: Overview of the variables used in our model, with their respective unit, transformations, and source. Data sources can be found in the reference list.

To reduce potential issues of endogeneity in the model we ensure that day-ahead orders are used, and not actual values. All values are then based upon the individual choices and trading strategies done by all market participants given the available information at that point in time. However, many offers may be a result of earlier data, which may reduce the exogeneity of the variables. Further, variables that are not determined in the day-ahead market are shifted by one day to reflect the information at that point. In addition, the VRE penetration variables are created based on the total generation within the respective countries. The VRE penetration variable for Denmark, the Netherlands, and Germany is calculated with the total generation data from ENTSO-E (n.d.-d), while for Great Britain, we use total generation data from the BMRS API from Elexon (2022).

5.2 Dependent Variable

5.2.1 Price in NO2

Day-ahead prices for bidding zone NO2 in Norway is obtained from ENTSO-E´s Transparency Platform. Price levels are expressed in EUR/MWh, and the time resolution is hourly. We do not perform any transformations on the price data, partly due to some points in the sample having negative values. A potential solution would be to change the negative prices to positive values. However, the negative outliers are of interest since our analysis is concerned with VRE generation, which is likely to have a negative price impact in the tails of the distribution. In addition, a transformation could potentially obscure important data characteristics and incur error effects (Karakatsani et al., 2010). Further argumentation for our data transformation decisions can be read in Chapter 6.0 Methodology.

The day-ahead price is hourly contracts between producers and consumers determined in blocks for each hour of the following day. As mentioned above, these prices may be negative, which is one of the aspects that make electricity prices different from that of other financial assets or commodities. Since electricity is non-storable, there needs to be a constant balance between consumption and generation. When low demand coincides with high inflexible electricity generation, typically from VRE sources, negative prices can occur (Geman and Roncoroni, 2006). The system inflexibility pressures conventional power plants to bid in negative prices when it is more cost-efficient for the producers than shutting down and restarting production later (Tselika, 2022). Table 5.2 displays the negative prices in our dataset.

Date	**Price EUR/MWh**
2021-10-03 01:00:00	-0.03
2021-10-03 02:00:00	-1.02
2021-10-03 03:00:00	-1.91
2021-10-03 04:00:00	-1.97
2021-10-03 05:00:00	-1.01

Table 5.2: Datapoints with negative electricity price

Another characteristic about electricity prices mentioned by Geman and Roncoroni, is a mean reversion toward a level that represents marginal cost and may be constant, periodic, or periodic with a trend (2006). However, they argue that this is the case driven by seasonal effects and thus typically patterns seen over a few years horizon. Electricity prices typically have more frequent price changes around the average trends as demand and supply varies given its instantaneous nature and consumers limited ability to react to price changes through adjusting their consumption in the short run (Kyritsis et al., 2017). Geman and Roncoroni also mention a third and intrinsic feature in what they call spikes, namely, one or multiple upward jump shortly followed by a steep downward move (2006). This can be explained by shocks in supply or demand as it is not possible to smooth such instances away by inventories.

5.3 Fundamental Variables

5.3.1 Forecasted VRE Penetration

Generation from VRE sources is one of the fundamental variables that is likely to explain some of the variation in price. For each interconnected country, data on day-ahead forecasted VRE generation is used. Although there could be differences between wind and PV generation (e.g., Tselika, 2022), this thesis investigates the aggregated generation because the effect from an interconnected country through market coupling is likely to be significantly smaller than price effects from domestic generation. Following the work done by Rai & Nunn (2020), Sakaguchi & Fujii (2021), Johnathon et. al. (2021), Jaraite et. al. (2019) and Owolabi et. al. (2023) we create a new variable referred to as VRE penetration. The variable is the share of electricity supplied by VRE generation in each country for each hour. In other words, the variable is the sum of all VRE generation divided by the sum of all electricity generation:

$$VREpenetration_{i,d,c} = \frac{\sum_{s \epsilon S} VRE_{i,d,c,s}}{Total\ electricity\ generation_{i,d,c}} \tag{I}$$

Where *VRE* is the sum of all VRE generation sources *s (S=onshore wind, offshore wind, solar PV).* The notation *i* represents the hour of the day (*I=1,2,3….24),* and *d* is denoting the day *(D=1,2,3…457)*, while *c* is a subscript for the country *(C=DE, GB, DK, NL)*. This variable will always take values between 0 and 100, as it would equal zero if the generation from VRE sources is non-existent in the respective hour, and 100 if all electricity generation is covered by VRE sources. Since VRE generation is independent from demand, it will capture both supply and demand effects within each country. For instance, when demand increases, the electricity supply from fossil fuelled sources must increase which will increase the denominator in the VRE penetration equation.

5.4 Control Variables

5.4.1 Fuel Prices

Gas-powered electricity generation makes up a large portion of the electricity mix in Germany, Great Britain, and the Netherlands, as shown in Figure 2.3, 2.4 and 2.5. Coal is mostly used in Germany, making up a smaller portion of the mix in Great Britain and the Netherlands. However, due to the small amount of thermal power in Norway, fuel prices such as coal and crude oil are not included. In addition, by including all these variables the model would suffer from multicollinearity. Therefore, only gas prices are included because it is serves as a determinant for the water value (Statnett, 2022b). Since fuel plants have high marginal cost, considering the merit-order curve, we anticipate a positive impact on electricity prices. Fuel prices have historically been shown to significantly increase day-ahead prices, especially in peak hours due to the short ramp-up time (e.g., Paraschiv et al., 2014; Bunn et al., 2016). As we have seen under Section 2.1.1, gas was not included in Norway's electricity mix in 2021 and thus only would affect electricity prices in Norway through the water value and market coupling. Due to this, we anticipate our result to show a smaller effect than papers examining more heavily fossil-based countries. The futures markets are closed on weekends and therefore data is interpolated for both Saturday and Sunday using the last observed value.

5.4.2 Electricity Certificate Price

The joint Norwegian-Swedish electricity certificate program aims to increase the generation of renewable electricity in both nations as producers receive one certificate for every MWh they produce. These certificates are sold in a market where the supply and demand determine the price, such that producers of renewable energy receive additional income, both from selling electricity and selling the certificates. Buyers are required to acquire an amount of electricity certificates based on their sales or consumption of energy. Thus, this is paid by the customers as the cost of the certificates is added to the final cost of electricity (NVE, 2021b).

It is reasonable to assume that the price of electricity certificates affects the price of electricity negatively, as a surge in the price of certificates reflect a strong demand for renewable electricity generation with close to zero marginal cost. Electricity certificates essentially subsidize increased generation of renewable energy resulting in a decrease in the electricity price (Aune et. al., 2005). Hence, we suggest that an increase in the price of electricity certificates will decrease the overall price of electricity.

The market for electricity certificates is closed during weekends and is updated only whenever the price of the certificate change. Data is thus interpolated for missing values using the last observed value.

5.4.3 Demand Forecast

Demand is known to have a positive relationship with day-ahead prices. Demand is considered quite inelastic in the short term, as previously explained under Section 3.1. In addition, demand has shown to affect how VRE impacts the electricity price (Ketterer, 2014; Maciejowska, 2020; Tselika, 2022). Ketterer (2014) found that the forecasted VRE generation divided by forecasted load has a negative impact on electricity prices. Tselika (2022) used three subsets of the data based on three demand levels, where the effect of VRE was shown to be greater in the upper price quantiles when demand was high and lower price quantiles when demand was low. In addition, according to Bunn et al. we could expect the demand to increase non-linearly together with the quantiles (2016). Since the demand variable is demand bids with an hourly resolution, we also expect this variable to capture the more fine-grained demand patterns such as the time of the day. Less frequent patterns are expected to be captured by the dummy variables that will be discussed below. Also note that we are using the forecasted demand for bidding zone NO2 only.

5.4.4 Reservoir levels

Hydropower is clearly the prominent source for electricity in Norway. The key question in hydropower generation is the time pattern of the use of the water in the reservoirs, as the water used to generate electricity today alternatively can be used tomorrow (Førsund, 2007). This operational decision whether to produce electricity now or later is based on opportunity cost considerations, also known as the water value. A generator will profit from withholding generation if the electricity price is lower than the water value, and vice versa. A detailed forward-looking computation of the opportunity cost is complicated, as it essentially represents a solution to a stochastic programming problem (Jahns et al., 2019). Producers would also want to sell when reservoir levels are high to prevent potential overflow, in addition to counter the decrease in water value when the reservoir level increases.

Cross-border interconnectors allow producers to sell electricity abroad when reservoir levels are high, which could increase domestic electricity prices even though reservoir levels are high. However, in periods with high VRE generation, the NordLink interconnection facilitates for potential import of cheap electricity due to the low marginal cost, while water levels in reservoirs are preserved. Prices in Norway might not necessarily reflect the prices the day of import from Germany as domestic producers withhold water (NOU 2023: 3, p. 155). Nonetheless, as water has been saved in the period of import, it can be used to generate electricity later and thus contribute to lower prices in the medium- to long-term as mentioned under Section 3.1. The relationship between reservoir levels and electricity prices have become somewhat more complex as cross-border transmission capacity has increased the last couple of years. However, we do expect a negative relationship between reservoir levels and electricity prices, with increasing reservoir levels leading to lower electricity prices. As reservoir levels data are updated on a weekly basis, we have linearly interpolated the data from weekly to hourly data.

5.4.5 Temperature

Temperature is an important predictor of electricity price because it affects demand and indicates seasonal patterns such as hydropower production and reservoir levels. When temperature increases in the summer, the demand for electrical heating is reduced. This is at least generally true for Norway but might not be the situation in other countries where we see very warm summers and mild winters, and demand for electrical cooling accordingly increases during the summer. Huisman et al. (2007) found that the probability of day ahead price spikes increased when the temperature deviated from its mean. Temperature may also influence market expectations as this information is more accessible than for example load, demand, and capacity data. Hence, it is expected that day ahead prices will be reduced when temperature increases. Temperature may also capture longitudinal seasonality patterns. In the winter, precipitation comes as snow and delays the reservoirs inflow until the spring. To capture the effect of temperature on day ahead prices in NO2, the daily mean temperature for NO2 is collected and averaged. We use data from 39 weather stations from the Frost API by The Norwegian Meteorological Institute. The list of weather stations can be found in Appendix A.1.

5.4.6 Price Dynamics and Adaptive Behaviour

A 24-hour price lag is included to capture short-term price dynamics in the day-ahead market. Higher prices tend to reinforce higher prices. Repeated gaming is likely to occur in the higher price quantiles as the market becomes less competitive (Bunn et al., 2016). In addition, price lags have shown to be the best predictor for the Nord Pool markets. Kamperud and Sator found that a one-day price lag had a significant effect in off-peak hours and lower distribution tails (2016). Hence, we expect a one-day price lag to have a positive effect on current day-ahead prices and especially for the high and low-price quantiles.

5.5 Fixed Effects Variables

We construct various fixed effects variables to control for systematic differences among variables that are not captured by the control variables. These may be more fine-grained seasonal and cyclical patterns in demand and supply. The large amount of hydropower in Norway makes electricity supply dependent on precipitation or inflow. Time dummies will therefore be able to control for variations in inflow given different seasons. Monthly dummies are created for February to December which are equal to 1 in the respective month. January is omitted due to dummy variable trap and will be interpreted as the base month. Demand is also different during weekends and expected to be less on Saturdays and Sundays. Therefore, a weekend dummy is included which is equal to one if it is a Saturday or Sunday. Further, public holidays may have a similar effect on demand which is likely to impact peak hours. We add a dummy for each public holiday in Norway where an overview over each date could be found in Appendix A.5. If the public holiday is during the weekend, it is not included in this list. In addition, the dependent variable is detrended by a dummy variable that are increasing by 1 for each individual day and hour.

Variable	**Type**
Month	Binary {1,0}
Weekend	Binary {1,0}
Holidays	Binary {1,0}
Time trend	Continuous {0, 457}

Table 5.3: Fixed effects variables and their type

5.6 Descriptive Statistics

As will be discussed under the limitations section, the period of analysis includes some events that is clearly displayed in Figure 5.1. Firstly, during the spring of 2021, hydropower producers in Norway expected a wet season which triggered high generation and exports that drained the reservoirs. This prediction was later shown to be wrong and reservoir levels did not reach average levels during the summer and fall. Further, in the end of 2021, Russia started to cut its gas supply to Europe. When the war started in February of 2022 the supply was cut completely.

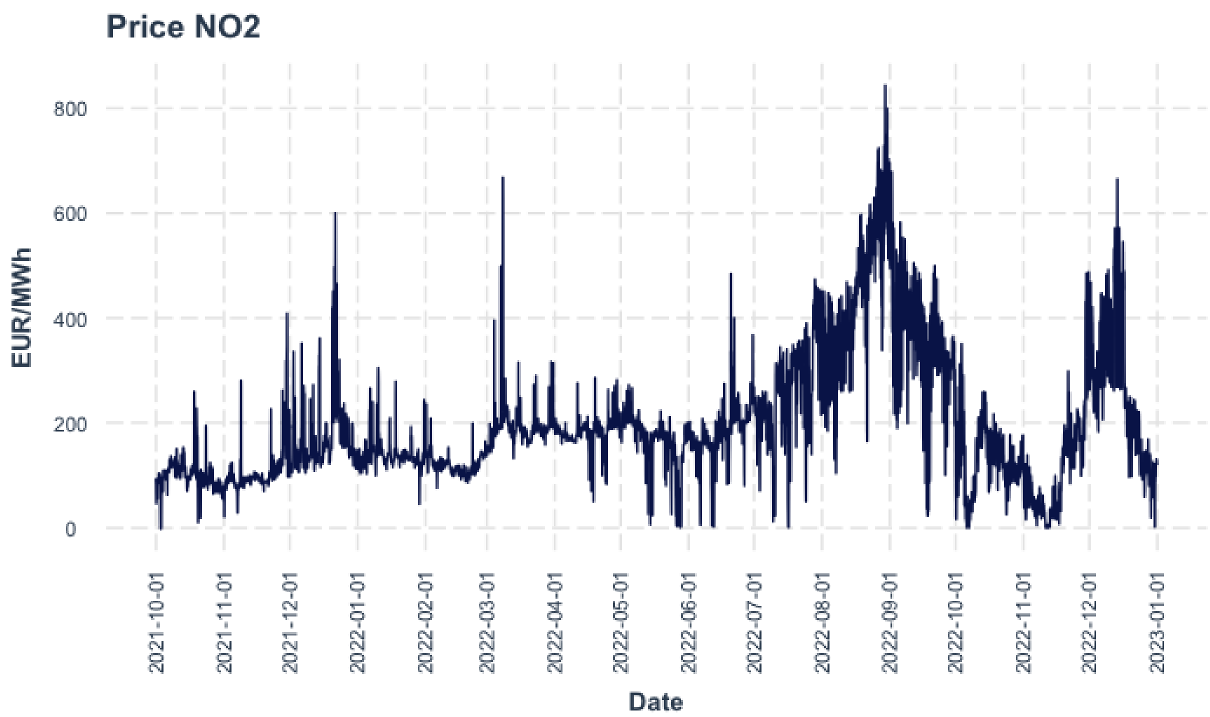

Figure 5.1: Hourly day-ahead prices for NO2 in EUR/MWh between 01.10.2021 and 31.12.2022

During the period, prices have had some significant spikes. In the winter 2021, the price reached 600EUR/MWh which could be explained by the scarce situation in Norway combined with Russia starting to decrease their supply of gas. The next spike around March 2022 could be explained by the war in Ukraine where the gas supply from Russia was cut completely. The following period from July 2022 to October 2022 reflects the situation in which all countries were dependent on fossil-fuelled sources to meet electricity demand while the gas price reached extreme levels. Further, the hourly distribution of day-ahead price is shown in Figure 5.2.

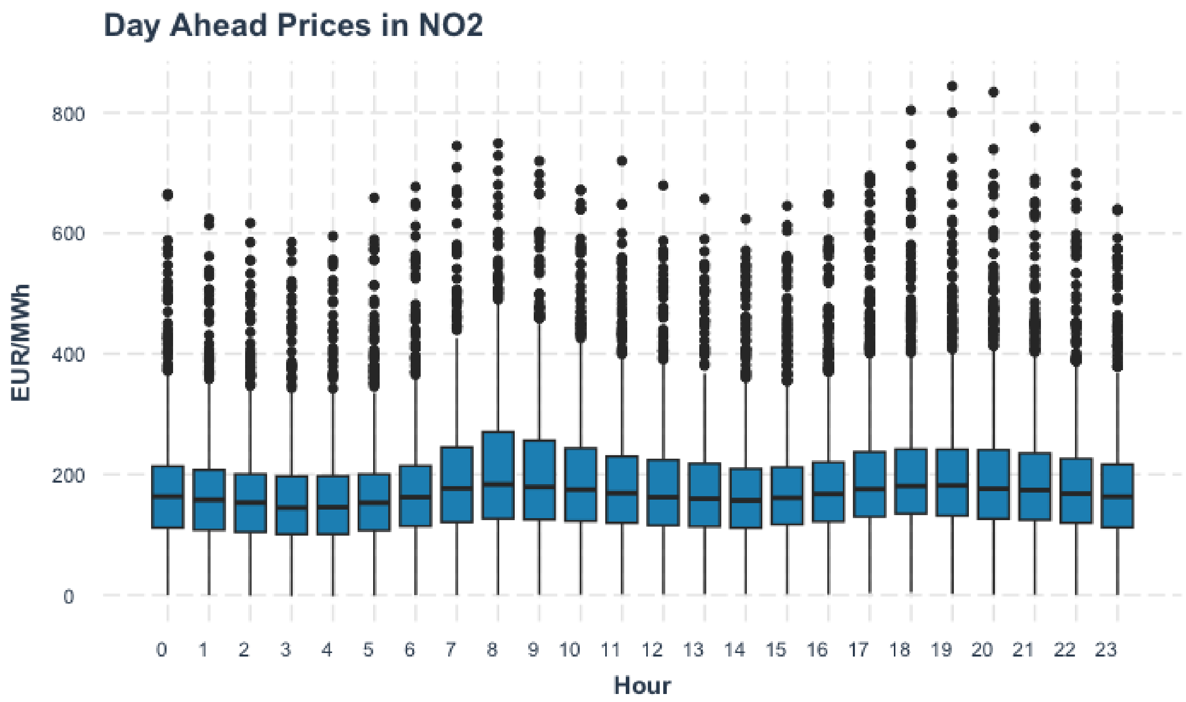

Figure 5.2: Boxplot with median, quantiles and outliers for day-ahead prices in NO2 for each hour

The peak demand in NO2 is found in the morning between 07:00 and 11:00, and in the evening between 17:00 and 19:00 (NOU 2023: 3, p. 89). Accordingly, Figure 5.2 shows that day-ahead prices peak in the morning between 07:00 and 10:00, and in the evening between 18:00 and 22:00. On average, prices tend to be lowest during the night, especially between 02:00 and 05:00. There are also some significant outliers ranging between 400 EUR/MWh and 800 EUR/MWh. The greatest outlier is found in hour 19 with a day-ahead price of 844 EUR/MWh. In the following tables, descriptive statistics is displayed for hour 12:00 and 17:00 which are considered an off-peak hour and a peak hour, respectively.

Variable	Mean	Sd	Median	Min	Max	Skew	Kurtosis
Price NO2	189,22	113,35	162,42	1,48	679,20	1,37	2,01
Demand	15938,79	2884,23	15627,00	10472,00	22623,00	0,25	-1,11
Reservoir	70,69	17,03	76,10	36,78	92,50	-0,63	-0,94
Gas price	124,88	49,63	106,65	64,87	339,20	1,46	2,26
El-certificate	1,28	0,47	0,99	0,81	3,45	0,97	0,94
Temperature	5,36	7,80	5,60	-17,90	21,30	-0,24	-0,50
VRE DE	45,29	14,34	47,31	9,23	75,76	-0,49	-0,41
VRE GB	30,91	13,72	29,47	3,22	68,72	0,33	-0,51
VRE NE	35,53	12,59	36,85	4,79	62,50	-0,35	-0,54
VRE DK	63,75	18,58	66,96	11,14	92,83	-0,75	-0,22

Table 5.4: Table with descriptive statistics for the hour 12:00 to 13:00

Variable	Mean	Sd	Median	Min	Max	Skew	Kurtosis
Price NO2	210,80	128,18	175,85	3,69	694,95	1,51	2,10
Demand	16122,00	2966,14	15786,00	11313,00	23015,00	0,24	-1,20
Reservoir	70,69	17,03	76,08	36,79	92,50	-0,63	-0,94
Gas price	124,88	49,63	106,65	64,87	339,20	1,46	2,26
El-certificate	1,28	0,47	0,99	0,81	3,45	0,97	0,94
Temperature	5,36	7,80	5,60	-17,90	21,30	-0,24	-0,50
VRE DE	32,28	14,30	32,49	2,11	71,59	0,01	-0,63
VRE GB	23,75	11,73	22,70	0,90	63,31	0,38	-0,22
VRE NE	25,74	13,51	26,02	0,47	58,46	0,11	-0,68
VRE DK	58,28	20,92	61,31	4,16	92,58	-0,66	-0,34

Table 5.5: Table with descriptive statistics for the hour 17:00 to 18:00

According to Table 5.4 and 5.5, prices tend to be higher in the peak hour at 17:00 than off-peak hour at 12:00 with a median price of respectively 210 EUR/MWh and 189.22 EUR/MWh. The minimum value in hour 12:00 is 1.48 EUR/MWh which is less than 3.69

EUR/MWh in hour 17:00. Additionally, in terms of mean and median demand, hour 17:00 has a greater demand than hour 12:00. This further indicates that prices tend to increase with demand. The range between the minimum and maximum demand in hour 12:00 and 17:00 is respectively 12151 MWh and 11702 MWh which illustrates how demand varies throughout the year. The price distribution is leptokurtic and positively skewed, given the kurtosis and skewness. This shows that the majority of outliers are located above the median and in the right distribution tails. Gas price also has a leptokurtic distribution, while the other variables seem to have a mesokurtic distribution except for demand which is moderately platykurtic. Further, VRE penetration is less at 17:00 compared to 12:00 which is expected due to a greater PV generation in this hour. Lastly, the VRE penetration in Great Britain is lower on average compared to the other countries. The average VRE penetration is further explored in Figure 5.3.

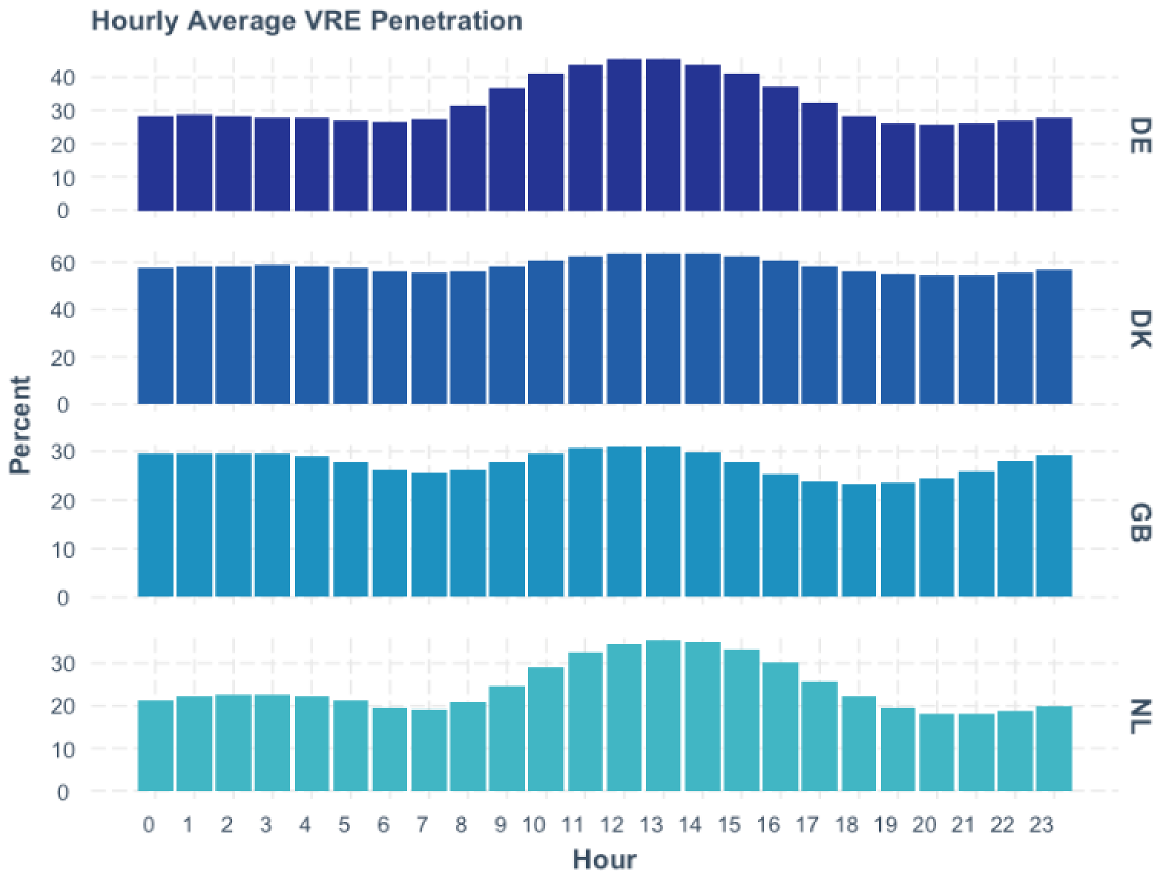

Figure 5.3: Hourly VRE penetration in percent for each hour and country

For all countries, there seems to be an increasing share of VRE during the afternoon which is likely explained by peaking PV generation (Tselika, 2022). In Germany, there appears to be less VRE during the night and evening, with a VRE penetration of approximately 30 percent. In Denmark, the average VRE penetration is more stable during the period but slightly lower during the evening. In Great Britain, there is less VRE during peak hours and the greatest amount during the afternoon and night on average. Lastly, the Netherlands has the greatest share of VRE during the afternoon and least during the night, early morning, and evening. In periods with a low share of VRE, the residual demand must be covered by other sources, which are likely to be fossil fuelled. Therefore, it is expected that day-ahead price in NO2 will show a decreasing pattern when the VRE share increases due to the merit-order.

Figure 5.4: Boxplots with day-ahead price in NO2 for each VRE share and country

In Figure 5.4, boxplots of day-ahead prices in NO2 are displayed, given the share of VRE in each country. All countries display a decreasing pattern in the day-ahead price when the share of VRE increases. However, there are no observations for a VRE penetration greater than 81 percent in Germany, 81 to 90 percent in the Great Britain and 71 to 90 percent in the Netherlands. In Denmark, prices seem relatively stable until the VRE penetration reach 60 percent. In Great Britain and Germany, the magnitude of the price decrease seems to flatten out after a VRE penetration of 40 percent. The negative relationship between the VRE penetration and day-ahead price in NO2 is further explored using Kendall correlation coefficients in Figure 5.5 for the 0.05 quantile. We use Kendall's rank coefficient due to its robustness against outliers and its nonparametric nature that does not assume a linear relationship between the variables. In contrast, Pearson's correlation is sensitive to outliers and may produce spurious results (Puth et al., 2015).

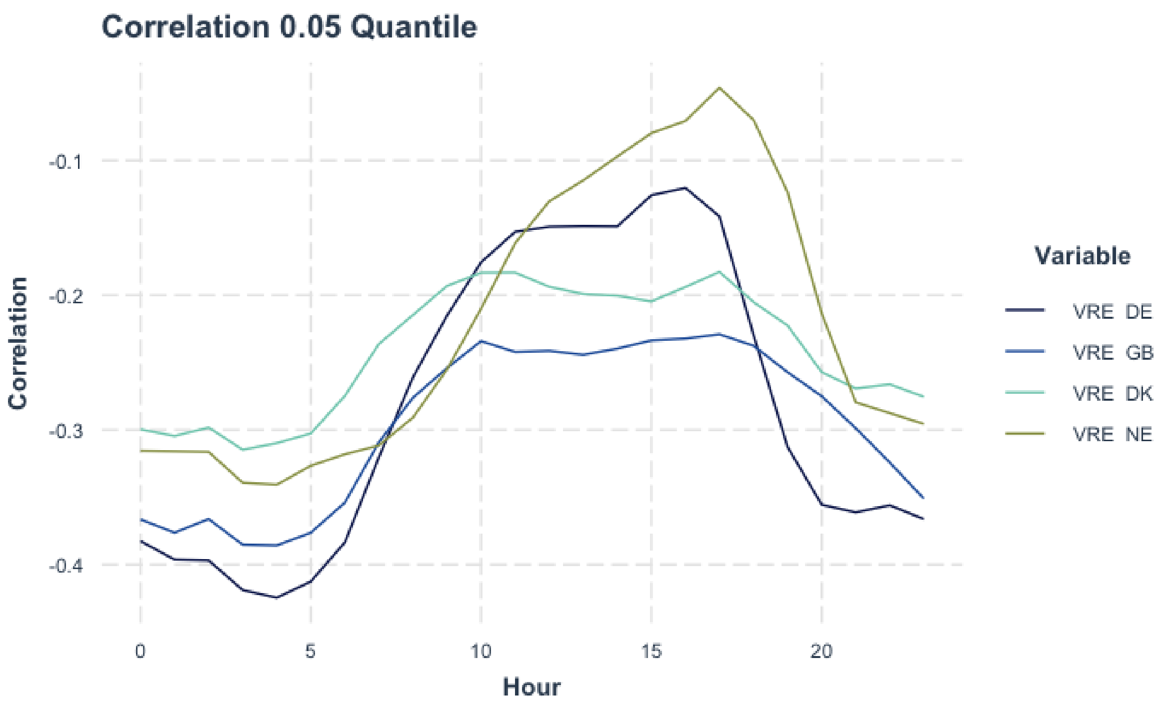

Figure 5.5: Kendall correlation for fundamental variables on price in NO2 for all hours and the 0.05 quantile

VRE penetration seems to have the greatest negative correlation during the night and evening for the lower distribution tails. Surprisingly, the relationship weakens during the day when VRE penetration peaks – see Figure 5.5. Germany and Great Britain have the greatest negative impact overall and especially during the night. However, Great Britain has a slightly more stable impact than Germany during the day. Denmark has the least variance throughout the period, with a slightly weaker impact between 08:00 and 19:00. The Netherlands displays a negative correlation of approximately 0.35 during the night and evening. However, during the day it reaches approximately 0.05 which could indicate congestion. Based on Figure 5.3 and 5.5, the relationship seems to weaken when VRE penetration is approaching 35 percent in the Netherlands, indicating that after a certain point, an increase in VRE penetration in the Netherlands essentially weakens its relationship with the day-ahead price in NO2.

6. Methodology

In the following chapter we present the methodology of the linear quantile regression model using the Frisch-Newton interior point method for the 0.05, 0.25, 0.5, 0.75 and 0.95 quantile. The research design is presented which is mainly based on the auction process in Nord Pool's Elspot market for the day-ahead price formation. In addition, we discuss some topics related to data transformations, stationarity, and multicollinearity. Lastly, we present our main hypotheses that will form the basis for the discussion and conclusion. The empirical model is computed in R and the script can be found here.

6.1 Quantile Regression

The concept of quantile regression was first introduced in 1978 by Koenker and Bassett. The method is an extension of standard ordinary least square (OLS) and is preferred when the assumptions of OLS are violated or when a more comprehensive understanding of the relationship between variables is desired. While standard OLS regression models the relationship between the independent factors and the conditional mean of the dependent variable, quantile regression quantifies the relationship of explanatory factors on each quantile of the conditional distribution (Cevik and Ninomiya, 2022). This enables a closer examination of each distribution and thus allows for interpretation of the relationship between the variables outside of the mean of the data. As seen in Figure 5.1, 5.2 and Table 6.1, the day-ahead price varies a lot throughout our sample period, supporting the use of a quantile regression method. Table 5.4 and 5.5 also show a significant deviation between the maximum and minimum price and that the distribution is moderately skewed. Hence, outliers and extreme values are not uncommon in our sample. Quantile regression can produce good and reliable estimates even in the presence of extreme outliers as it minimizes the weighted sum of absolute residuals (Onyedikachi, 2015). Additionally, it does not make any assumptions about the distribution which is preferrable due to the skewness, excess kurtosis and heteroskedasticity (LaFevor and Pitts, 2022; IBM, 2022).

To confirm our assumptions regarding the quantile approach rather than an OLS, we compute a Joint Test of Equality of Slopes using the Wald Test on each model for the five specified quantiles and panels. This evaluates whether there are significant differences in the coefficient estimates across the quantiles, assuming the null hypothesis that all coefficient estimates are equal. The result can be found in Appendix A.7 where the F-statistic and corresponding P-value indicate that we can reject the null hypothesis in all panels. Therefore, we find evidence suggesting that the coefficient estimates vary significantly across the quantiles, supporting the notion that the relationships between the variables differ at different quantile levels given a confidence level of 99 percent.

We can express our model by the general quantile regression approach by Koenker and Bassett:

$$Q^q\left(P_{i,d} \middle| X_{i,d}\right) = \alpha^q + \beta_i^q X_{i,d} + \epsilon_{i,d}^q \qquad \textit{(II)}$$

Where q represent the quantile, $0 < q < 1$. $P_{i,d}$ represent the day-ahead price with the subscript i expressing the hour of the day and d the day. The constant term at each quantile is denoted by α^q. The predictor variables are denoted by $X_{i,d}$ with corresponding coefficients β_i^q for each quantile. A random example of the quantile regression is illustrated in Figure 6.1 given a dependent variable P and covariate X conditioned on five different quantiles q.

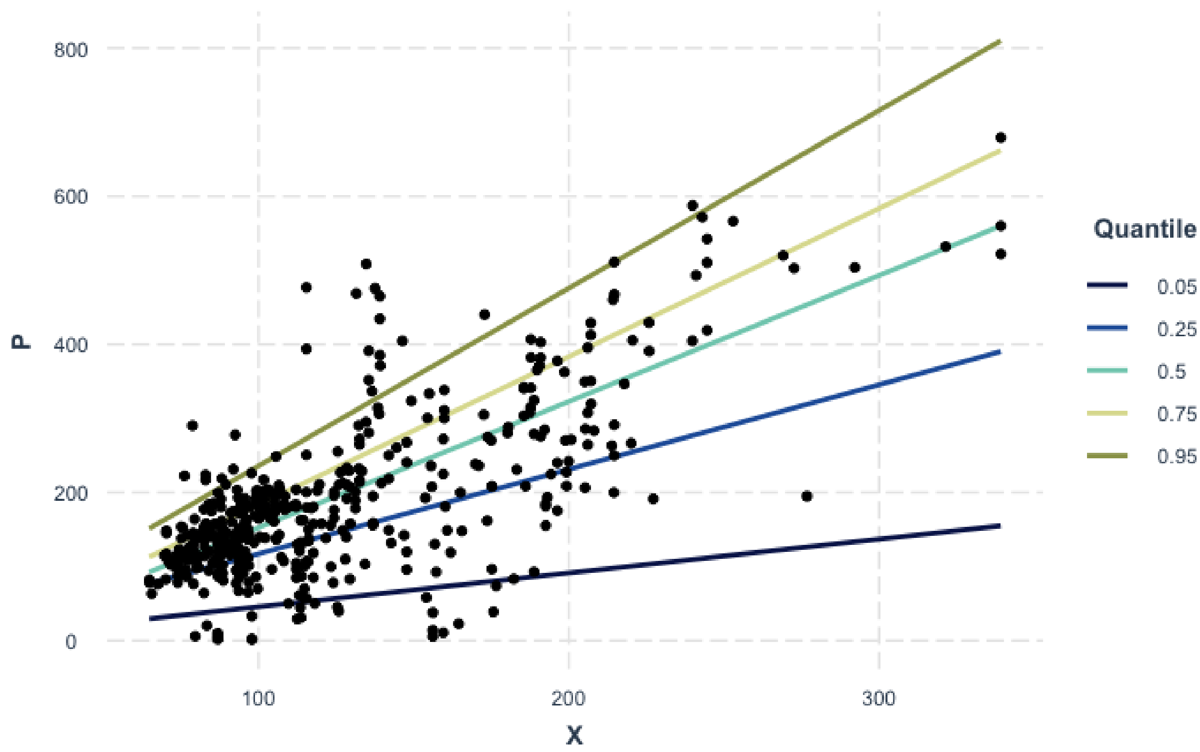

Figure 6.1: Illustration of quantile regression using random variables P and X and quantiles 0.05, 0.25, 0.5, 0.75 and 0.95

There are several different algorithmic methods used to estimate the quantile regression coefficients. We use the Frisch-Newton interior point method as it is advantageous for high-dimensional data and when modelling complex relationships (Koenker and Portnoy, 1997). This method solves the following minimization problem:

$$\min_{\alpha_i^q,\beta_i^q} \sum_{d=1}^{D} \left(q - 1_{P_{i,d} \leq \alpha_i^q + X_{i,d}\beta_i^q}\right)\left(P_{i,d} - \left(\alpha_i^q + \beta_i^q X_{i,d}\right)\right) \qquad (III)$$

$$\text{Where } 1_{P_{i,d} \leq \alpha_i^q + \beta_i^q X_{i,d}} = \begin{cases} 1, if\ P_{i,d} \leq \alpha_i^q + \beta_i^q X_{i,t} \\ 0, otherwise \end{cases}$$

Our model implements five quantiles and the 24-hourly panels, which gives a total of 120 models (24x5). The model includes the fundamental-, control- and fixed effects variables presented below. The quantile regression implements the 0.05, 0.25, 0.5, 0.75 and 0.95 quantile.

Fundamental variables (γ^q):

$$\gamma^q = \beta^q VREpenetration_{i,d,c} \tag{IV}$$

Where *i* denotes each different time period of the day, *d* denotes the day, and *c* denotes each of the different countries.

Control variables (λ^q):

$$\begin{aligned}\lambda^q = {} & \beta^q NaturalGasPrice_{i,d} + \beta^q ElCertificatePrice_{i,d} + \beta^q Demand_{i,d} \\ & + \beta^q ReservoirLevels_{i,d} + \beta^q Temperature_{i,d} \\ & + \beta^q RiskAversion_{i,d}\end{aligned} \tag{V}$$

Where *i* denotes each different time period of the day and *d* denotes the day.

Fixed effects variables (θ^q):

$$\theta^q = \beta^q Month + \beta^q Weekend + \beta^q Holiday + \beta^q TimeTrend \tag{VI}$$

The associated standard errors are obtained through bootstrapping. This is a statistical method used to estimate the sampling distribution of an estimator such as for example standard errors by sampling with replacement. The bootstrapping approach do not require any assumptions and is more accurate than using the standard intervals obtained through sample variance (Cline, 2021). According to Angrist and Pischke (2009), the bootstrap method treats potential heteroskedasticity and serial correlation in the data.

6.2 Empirical Quantiles

Hour	.05	.25	.50	.75	.95
0	57,98	111,50	163,41	213,63	425,34
1	50,73	107,93	157,81	207,33	389,79
2	46,11	104,27	153,28	200,34	376,98
3	27,63	101,07	144,74	196,93	374,10
4	33,73	101,15	145,51	197,43	364,99
5	42,85	107,22	152,99	200,20	391,65
6	60,02	114,09	162,46	214,23	419,96
7	74,04	121,00	177,00	245,21	484,66
8	82,41	126,66	183,51	270,36	500,52
9	72,80	125,11	179,06	256,07	476,79
10	66,57	122,65	174,75	243,43	459,58
11	62,13	119,63	168,91	229,98	444,72
12	58,05	115,38	162,42	224,04	430,54
13	49,92	113,48	159,64	218,11	424,72
14	42,57	111,23	156,82	209,36	433,67
15	59,94	117,09	161,13	211,96	437,02
16	63,28	121,89	167,62	219,93	450,89
17	78,51	129,79	175,85	237,29	487,23
18	84,23	135,15	180,58	241,98	486,47
19	81,75	131,49	181,64	241,64	503,98
20	78,58	126,36	176,47	240,81	490,51
21	75,71	124,37	173,97	234,92	454,25
22	71,57	119,67	168,17	226,19	450,75
23	63,97	112,01	163,21	216,64	422,49

Table 6.1: Overview of the empirical quantiles used in the quantile regression model

The quantile regression model implements the 0.05, 0.25, 0.5, 0.75 and 0.95 quantile for each hour and is displayed in Table 6.1. This demonstrates the wide distributional spread in the price variable and attests to the applicability of the quantile regression approach.

6.3 Research Design

Our research method is designed according to the market structure. As mentioned above, the market participants submit their bids and asks including a volume in MWh and price in EUR/MWh between 10.00 CET and 12.00 CET. Producers and consumers use the available information about the market to estimate orders with price levels that are likely to be accepted. For instance, if a producer submits a price that is too high the order is less likely to get accepted. Similarly, if consumers submit a price that is too low the order is less likely to get accepted. Therefore, all final orders that are submitted to EUPHEMIA should reflect this information. This process is summed up in Figure 6.2.

Figure 6.2: Three-step illustration of the electricity market process and research design

First, available information is assessed by market participants and forms the basis for the bids and asks which later are submitted by the market participants. Second, orders are submitted, and EUPHEMIA performs the price calculations according to the merit-order. Third, the final day-ahead price for NO2 is published. The model does not control for the Available Transmission Capacity (ATC) due to these values being arguably constant throughout the year and close to the maximum transmission capacity. Therefore, the model assumes price coupling effects independent of whether there is available capacity on the interconnector or not. In addition, actual transmission flows are also irrelevant because they are determined by the day-ahead prices and therefore not exogenous.

6.4 Transformation of Variables

As we examine the day-ahead prices it is crucial that variables are transformed such that they reflect the information available to the participants submitting bids in the day-ahead auction. Thus, several variables need to be shifted by 24 hours. This applies to the all the fuel prices, the price of the electricity certificates, and the average temperature in bidding zone NO2. The reservoir level is shifted 72 hours to reflect the day when the information was published. Further, utilizing logarithmic prices provides a notable benefit, as it has the capability to alleviate the skewness of a distribution and make it more normal. However, the quantile regression model does not impose any underlying assumptions about the distribution, and thus it is not necessary to address this issue. Furthermore, using logarithmic variables may only provide an advantage in the interpretation of coefficients as elasticities, but this advantage is not required since our fundamental variables are expressed as percentages. Lastly, our model does not have any instances of collinearity among covariates. However, there exist some correlation between temperature and demand which is shown in the correlation matrix in Appendix A.3 but is considered to be non-problematic.

6.5 Stationarity

According to Tselika (2022), it is observed that day-ahead prices tend to be stationary. Although hourly panels are treated as individual time series, the reliability of unit root testing can be improved by testing the panels collectively. Levin et al. (2002) has shown that there is an increase in test power when unit root testing is performed on the pooled panel data, as opposed to each individual time series. Therefore, the pooled panel data approach is used where an Augmented Dickey-Fuller (ADF) test is applied. The results, which can be found in Appendix A.2, show that the test statistic for all variables rejects the null hypothesis that the series contain a unit root, given a lag order selected by minimizing the Akaike Information Criterion.

6.6 Hypotheses Development

When the electricity market went from explicit auction to implicit auction (market coupling), the flow directions through the interconnectors became determined by the relative prices given by the aggregated order book for all participating countries. Without implicit auction, problems such as booking unnecessary transmission capacity or imports from the high-cost country arise. Implicit auction incorporates EUPHEMIA which calculates the optimal prices in respect to the order book and ensures that the transmission flows do not violate these conditions. Therefore, import or export flows will always move from the low-cost country to the high-cost country which will result in price convergence. Price convergence relates to the law of one price where day-ahead prices should converge between markets when capacity limitations are reduced. This means that day-ahead prices in NO2 should increase when prices in Germany, Great Britain, Denmark, or the Netherlands is greater than the price in NO2, and vice versa.

Historically, electricity prices in Europe have been greater than in NO2 due to the comparatively higher share of thermal power. The marginal cost of generating hydropower in Norway should be considered when examining the electricity mix in each country. The generation sources with lower marginal cost than hydropower is wind and PV. As explained previously, when there is a high share of VRE generation such as wind and PV, the merit-order curve shifts to the right which is called the merit-order effect. The degree to which the curve shifts depend on the overall electricity mix. In Germany and Denmark, the share of VRE is relatively high compared to that of Great Britain and the Netherlands. Consequently, it is likely that our result will show a more negative price impact from these countries. However, Germany, Great Britain, and the Netherlands also have a greater share of fossil fuelled generation. Therefore, it is expected that these countries will have somewhat lower price impact compared to Denmark. Great Britain and the Netherlands have the lowest VRE penetration and therefore most likely to display the least negative price impact. In summary, we expect that the merit-order effect is present in our result which means that regression coefficients are negative across all price quantiles.

A well-known consequence of VRE is interconnection congestion (Keppler et al., 2016). Wind and PV feeds the market whenever there is availability, and this inconsistency can cause trouble in the grid. In periods when generation is high and demand is low, the residual VRE can become trapped within the region if there is not enough transmission capacity. In periods when the demand is high, more VRE generation becomes absorbed locally and interconnections are consequently less likely to become congested. Hence, in off-peak hours when there are residual generation, prices converge up until the transmission capacity is reached. After this, prices may start to diverge which cause the opposite effect than the merit-order effect. Therefore, the result should be evaluated based on the amount of VRE within the respective hour and the local demand. We expect that signs of congestion are most likely to occur during off-peak hours for the left-tail price distribution. Illustrated in Figure 5.3, VRE penetration is highest in off-peak hours, and the left-tail price distribution typically reflect low demand. This can potentially obscure the result from a negative to a positive price impact. Considering transmission capacity, this is most likely to appear for the Netherlands.

During peak hours, the electricity supply is more elastic, and fossil fuel plants are likely to act as price setters, increasing day-ahead prices. Consequently, a unit increase in VRE during peak hours is expected to have a greater impact than during off-peak hours. This sensitivity in supply is expected to manifest as a more negative price impact between 07:00 and 11:00, and 17:00 and 21:00 for the higher price quantiles. Thus, reflecting the increased marginal cost of supplying electricity during peak hours. Conversely, when VRE penetration occurs during periods of low electricity demand, the inflexibility of the system can exert pressure on conventional power plants. In response, these plants may submit bids with negative prices as it becomes more cost-efficient to operate at a loss temporarily rather than incur the expenses associated with shutting down and subsequently restarting generation at a later time (Geman et al., 2006; Tselika, 2022). Hence, it is also expected that the greatest negative impact will be observed in the lower price quantiles in off-peak hours.

Our main hypothesis is based on the merit-order effect, where VRE should have a negative impact on day-ahead prices. However, there may be other factors that can obscure the result such as congestion following specific demand patterns. In addition, if VRE generation coincides with periods of high demand and low supply it may have a greater impact. Therefore, one should carefully evaluate the results based on the corresponding electricity mix and transmission capacity, but the main discussion will consider the following hypotheses:

Main hypothesis

Effect	**Expected result**
H_1: Merit-order effect	$\beta_{c,i} < 0$, *all quantiles*

Table 6.2: Main hypothesis

Sub hypotheses

Effect	Expected result
H_2: Congestion	$\beta_{c,i} \geq 0,\ q < 0.5$
H_3: Peak demand	$\beta_{c,i} < 0,\ q > 0.5$
H_4: Off-peak demand	$\beta_{c,i} < 0, q < 0.5$

Table 6.3: Sub hypotheses

7. Results

In the following section we present the empirical results from our model. We will first present and discuss the control- and fixed effects variables. The monthly and time trend variables are presented in Appendix A.4 and A.6, respectively. The results are presented with all price quantiles to examine the drivers throughout the whole price distribution for each hour during the day. Further, results of the fundamental variables for each different country are analysed and discussed. All the coefficients that are significantly different from zero at the 95 percent level are marked with points in the figures.

7.1 Control Variables

7.1.1 Demand

The coefficient estimates for the demand in NO2 are displayed in Figure 7.1. The coefficient estimates vary greatly, yet almost constantly positive. Despite the presence of negative coefficients, it is important to note that they are not significant at the 95 percent level. The results imply that demand and electricity price have a positive relationship. This could be described by the merit-order curve. As demand increases, the merit-order shifts to the right towards production with higher marginal cost in order to fulfil the consumption, increasing the price of electricity. There are no distinct dissimilarities between the quantiles, although the relationship seems to be slightly stronger in the upper and lower quantiles than around the median. Our result also indicates a peak around hour 09:00 to 11:00 for the upper quantile, which is the hours during the morning when demand typically surge.

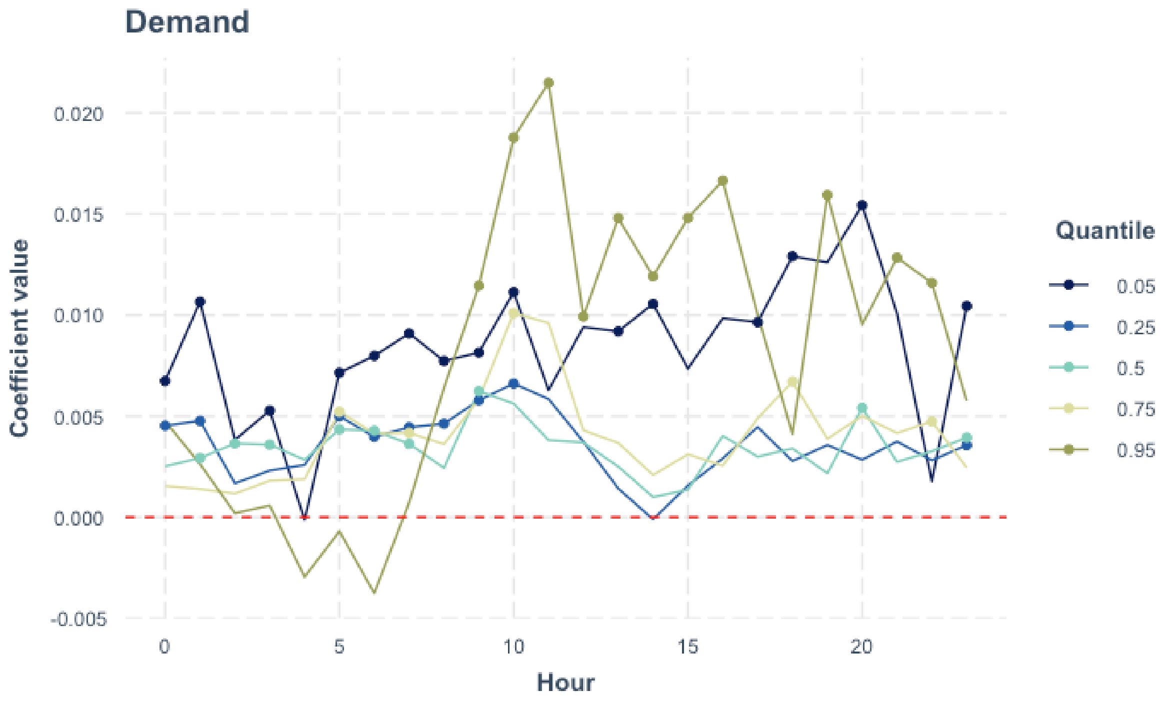

Figure 7.1: Coefficient estimates for the demand variable

7.1.2 Gas Price

The gas price is a strong driver for electricity prices in all of Europe, including Norway, as it is determinant for the water value (Statnett, 2022b). If the gas price increases, Norwegian producers could export electricity abroad to a higher price, which in turn increases the water value. An increasing gas price will lead to higher marginal costs for the fossil plants, which will increase its positive effect on electricity prices. We find gas far to the right on the merit-order curve, which means that other production sources will be prioritised until it no longer can meet demand. We see the highest coefficients around the peak-hours, where demand typically is highest during the 24-hour period. It is also within these hours production from sources far to the right on the merit-order curve are most likely to be required to fulfil the demand as VRE and other energy sources are unable to cover it. As seen in Figure 7.2, the positive price impact from gas prices peaks around hour 09:00 to 11:00 and 20:00 to 21:00. We also observe that the price impact is stronger in the upper quantiles. This could essentially be explained by the merit-order curve. The gas price can only to a large extent affect the electricity price at the right-tail of the price distribution, as gas is one of the most expensive production sources on the merit-order. The coefficients for the two upper quantiles, 0.95 and 0.75, are significant at the 95 percent level during almost all hours, except a few hours in the morning for the 0.75 quantile. This result shows that there is a positive relationship between the electricity price in NO2 and the gas price, which tends to peak during hours when demand peaks. The relationship is also stronger as the electricity price in NO2 increases, which could be explained by the fact that other electricity sources are prioritised before fossil plants are utilised for production of electricity. For the lowest quantiles, the coefficients are close to zero and negative in some hours for the bottom quantile. However, the coefficients are never significant for these price distributions. This result support the merit-order, as the gas price should not be an important driver for the electricity price in the left-tail of the price distribution.

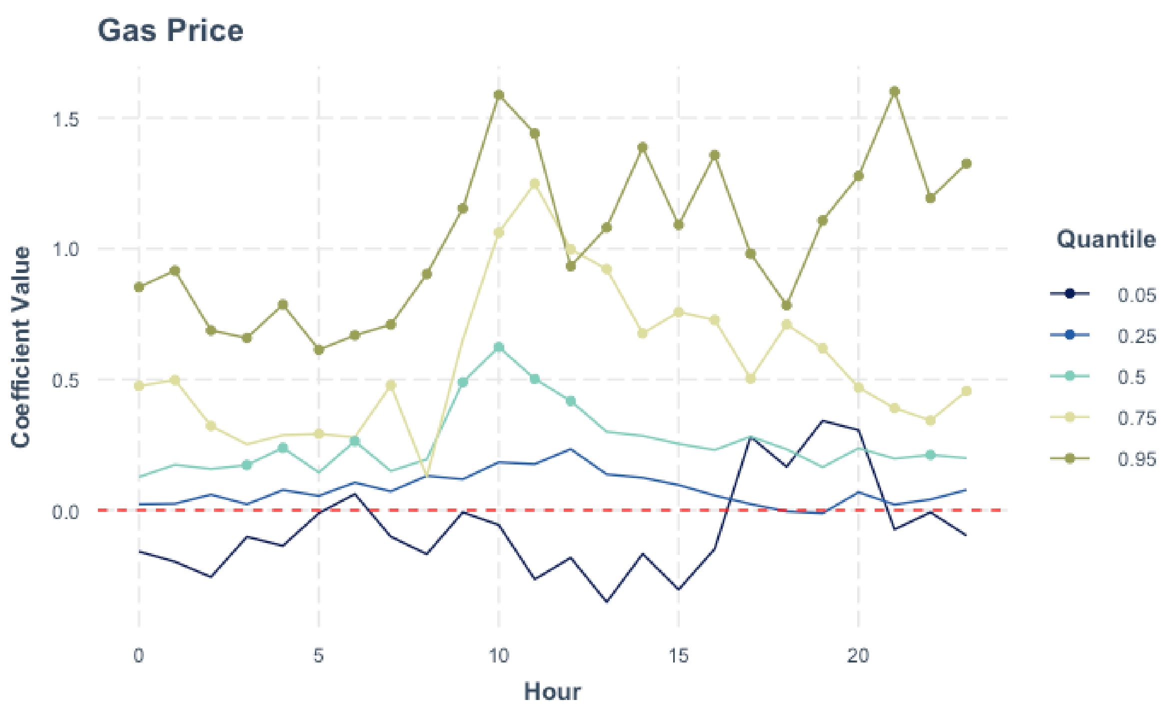

Figure 7.2: Coefficient estimates for the gas price variable

7.1.3 Temperature

In Figure 7.3 below, the coefficients and statistical significance of temperature is presented. Temperature is an important predictor of electricity price because it affects demand, and also indicate seasonal patterns for hydropower production and reservoir levels. It may also affect market expectations as the information is more accessible than for example data for load, demand, and capacity. The results show that the temperature has a slightly varying effect on the electricity price in NO2. In the hours with statistical significance, the coefficients are negative for the bottom two quantiles. That includes several hours during the night, in addition to the upper quantile during the hours 19:00 and 22:00. This could simply capture the effect from a reduction in demand due to higher temperatures, as the need for heating is reduced. One should also note that there are some hours with positive coefficients. However, these are not significant at the 95 percent level.

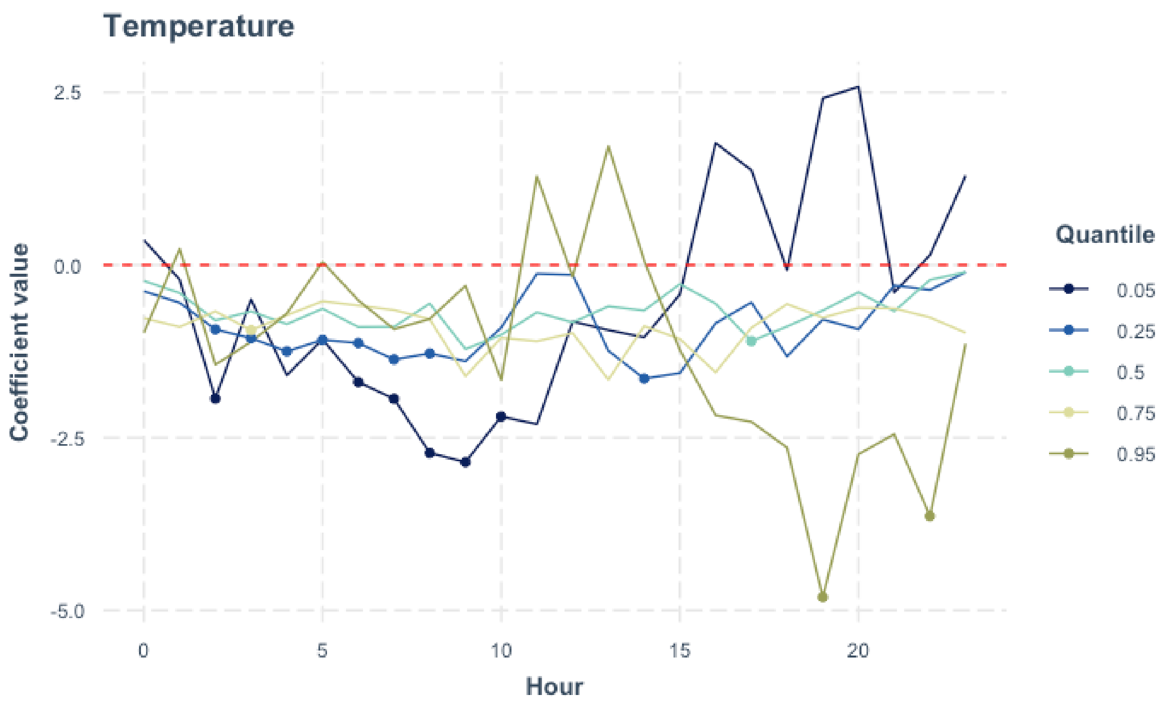

Figure 7.3: Coefficient estimates for the temperature variable

7.1.4 Price Lag

The coefficient estimates and significance for the one-day lagged day-ahead price are presented in Figure 7.4. The coefficients are always positive and significant for all quantiles in all hours. The results suggest that yesterday's price has a significant impact on the day-ahead price, particularly when the price is around the median quantile. The coefficients for the median quantile are consistently more positive in most hours, indicating that yesterday's price is a significant driver of the day ahead price. Additionally, there are a few hours where the coefficients are slightly stronger for the 0.25 quantile. This could reflect trading periods with predictable demand and supply, as today's price typically reflect yesterday's price when the price is around its median, indicating that it is less disturbed by shocks in either demand or supply. Both for the lowest and highest quantile, the impact is less throughout the day. As mentioned under Section 3.1, electricity prices are influenced by the instantaneous nature of electricity consumption combined with the inelastic supply which could lead to frequent and large price changes in both directions. The result show that such instances could to a lesser degree be explained by yesterday's price, which is possibly the most notable part of the result from this variable. Our result also indicates, as previously found by Bunn et. al. (2016), that high prices tend to be followed by high prices. This could potentially be due to market power initiating opportunities for repeated gaming, as mentioned under Section 5.4.6.

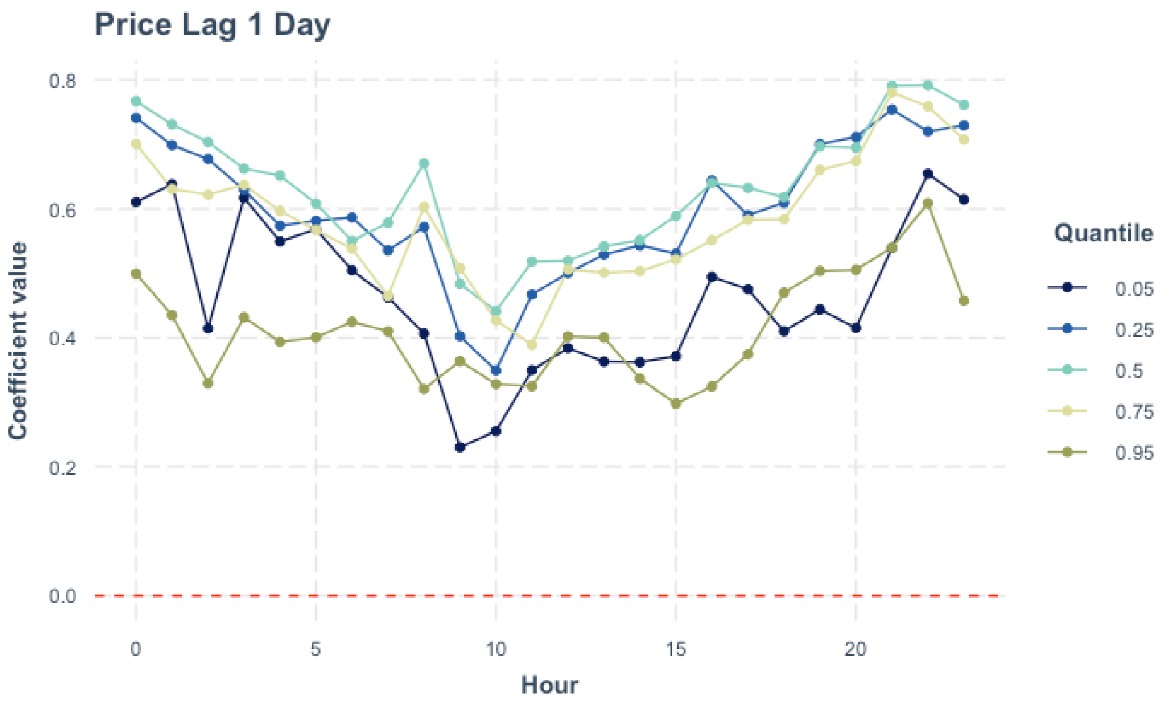

Figure 7.4: Coefficient estimates for the price lag variable

7.1.5 Electricity Certificates

Coefficients of the electricity certificates can be seen in Figure 7.5. The result shows that the relationship between electricity certificates and prices in NO2 tend to vary quite a lot, however, the coefficients are not significant at the 95 percent level for any hour on the price distribution. Our model thus implies that the price of electricity certificates is not a significant driver of the electricity price.

In the 0.05 quantile, there is a positive relationship between the price of electricity certificates and the electricity price for almost all hours. However, in the 0.95 quantile, the relationship is slightly negative in several hours. This could possibly be due to explanations presented in Section 5.4.2. An increase in the price of electricity certificates imply an increase in demand for renewable production, which in return will reduce the electricity price through the merit-order effect. On the other hand, the results show that if the price of electricity is in the lower quantiles, an increase in the price of electricity certificates in fact increase the day-ahead price of electricity. One possible explanation for this is that a reduction in price from the increase in demand for renewable production do not offset the increase in the price directly caused by the electricity certificates. As described and illustrated, there are no significant coefficients. Hence, we can't rely on the results for this variable.

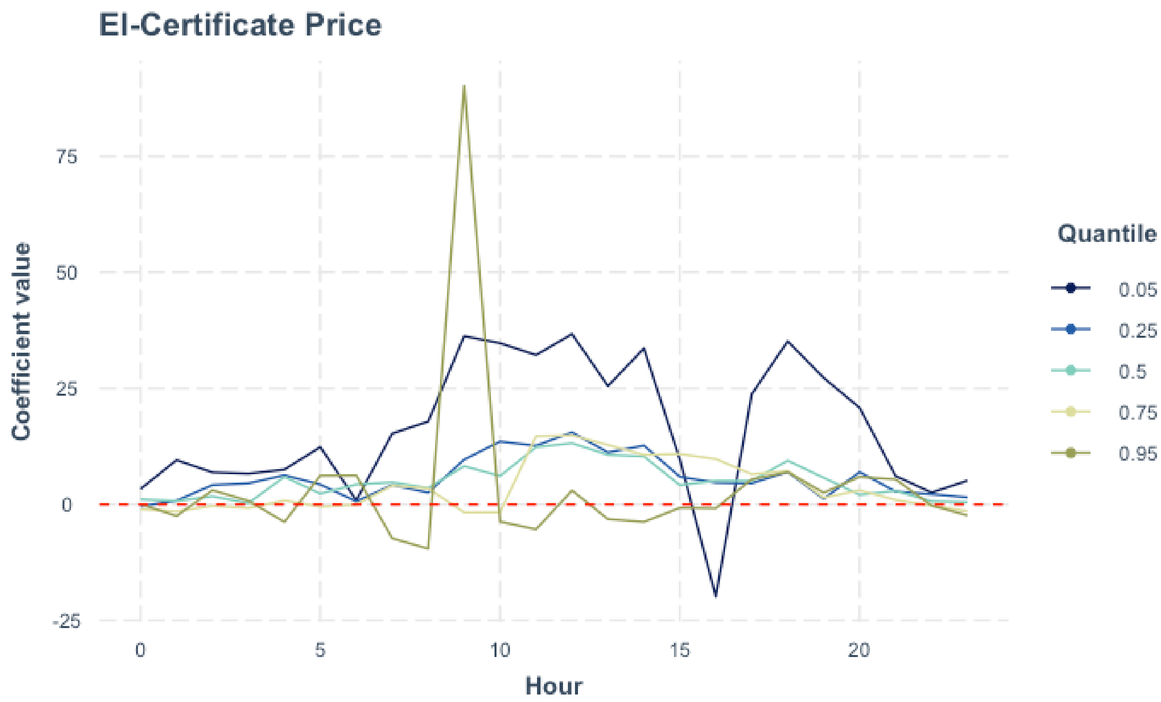

Figure 7.5: Coefficient estimates for electricity certificate price

7.1.6 Reservoir Levels NO2

In Figure 7.6 the coefficient estimates of reservoir levels in NO2 are presented. Surprisingly, the coefficients tend to vary a lot. However, only the negative coefficients are significant at the 95 percent level. Thus, the statistically significant coefficients indicate that an increase in reservoir levels will decrease the day-ahead price. However, even though the coefficients are insignificant, the result imply a positive impact in some hours, most notably for the highest price quantile. As mentioned under Section 5.4.4, the operational decision whether to produce electricity now or later is determined by the water value. The water value is highly determined by the gas price. Expectations of a decrease in the gas price will induce producers to drain the reservoirs and sell electricity for a high price now, or vice versa if the gas price is expected to later increase. Thus, the coefficient estimates might be stirred by more long-term estimations of the water value, even though it should be emphasised the positive values are insignificant. The significant coefficient estimates are mainly in two lowest price quantiles, for some hours during the day and night, illustrated in Figure 7.6.

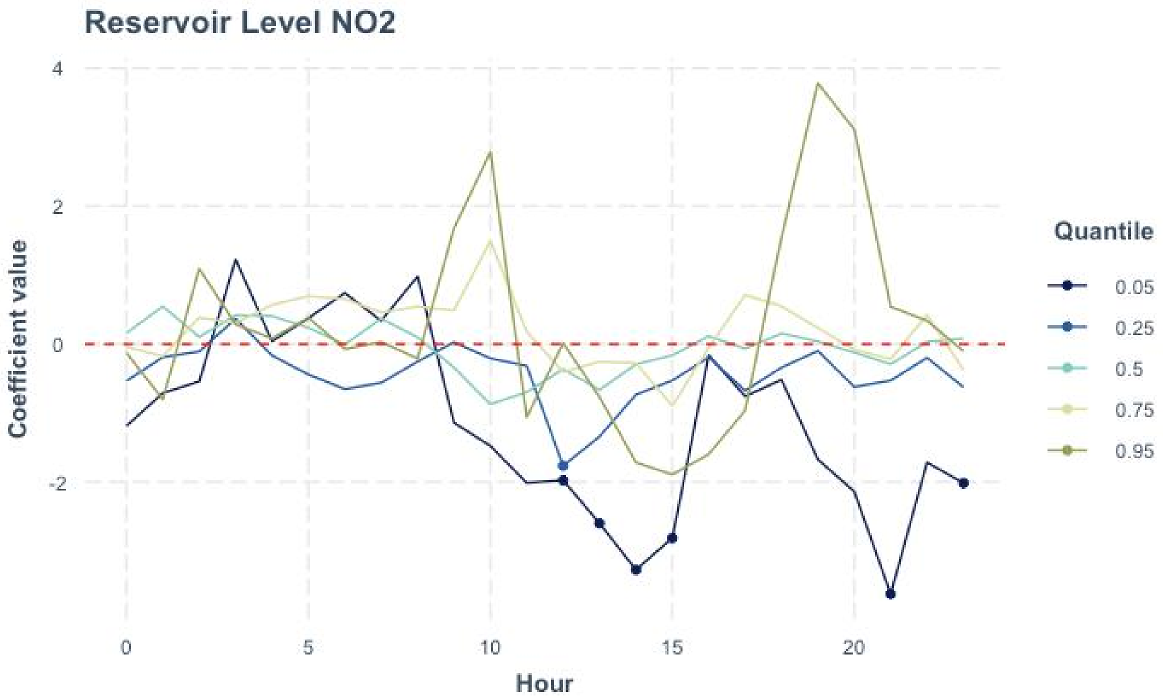

Figure 7.6: Coefficient estimates for reservoir levels in NO2

7.1.7 Holiday

Holiday is a binary variable created to capture price effects from public holidays in Norway. As public holidays are likely to impact demand patterns, it is plausible that it will affect the price throughout the day. The coefficient estimates for the holiday variable are presented below in Figure 7.7. As seen, there is clearly a negative relationship between public holidays and day-ahead prices in NO2, where prices tend to decrease during public holidays. The relationship seems to be strongest from 11:00 to 15:00. This could potentially reflect that during holidays, consumption of electricity decrease as less people are at work and businesses are less operational. This will dampen the electricity demand affecting the merit-order curve as it is less likely to require input from plants with high marginal cost to fulfil the consumption. The result shows that during the night, price is less affected by public holidays, which could be explained by the fact that the demand during the night already is relatively low outside of the public holidays. Further, there seems to be a greater negative relationship for the lower price quantiles. Additionally, the higher price quantiles are rarely statistically different from zero given a 95 percent confidence level.

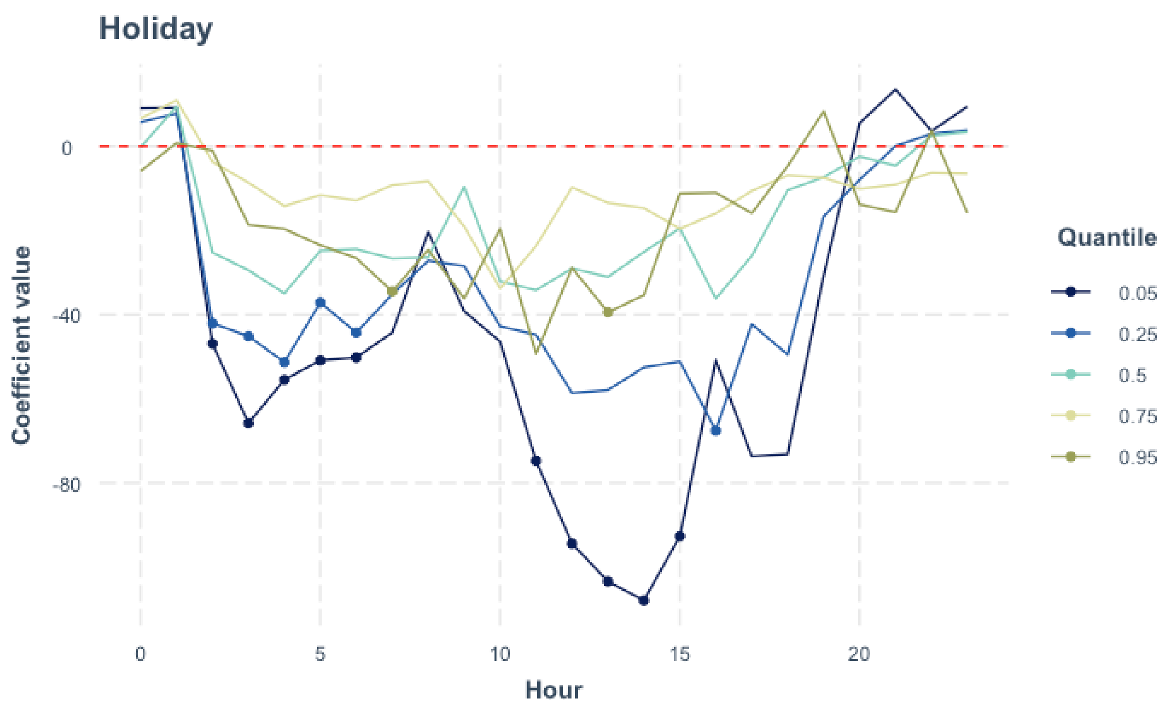

Figure 7.7: Coefficient estimates for holiday

7.1.8 Weekend

Weekend is a binary variable capturing the weekly seasonal impact on day-ahead price from Saturdays and Sundays. It is reasonable to assume that peak hours will change during the weekend, as demand and electricity consumption patterns change. Figure 7.8 displays the results from our model. As observed, weekends have a negative effect on the day-ahead price in NO2. The effect is clearly strongest in hour 11:00 and 16:00. This is likely capturing the effect from the change in electricity consumption patterns during the morning, and that offices and factories in high electricity industries are closed or at least less occupied during these days. There also seem to be a greater negative impact in the left-tail price distribution.

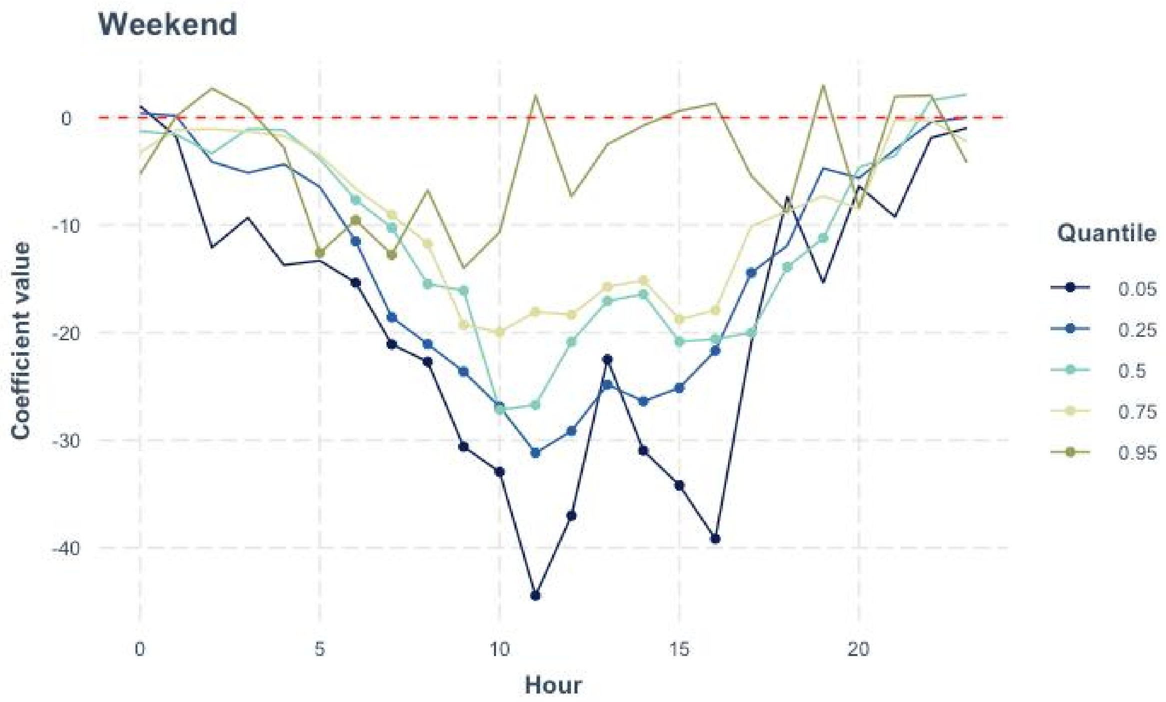

Figure 7.8: Coefficient estimates for weekend

7.2 Fundamental Variables

The results from each fundamental variable for each country will be discussed and compared jointly in the following section. Results for the 0.05, 0.25, 0.50, 0.75, and 0.95 quantile are included to examine the impact of VRE on the total price distribution for each hour of the day. The coefficients that are statistically different from zero given a confidence level of 0.95 are represented as points in the figure.

7.2.1 VRE Penetration

The coefficient estimates of VRE penetration in Germany, Great Britain, Denmark, and the Netherlands are presented in Figure 7.9, 7.10, 7.11 and 7.12. The estimated coefficients are nearly always negative, implying that an increasing share of VRE in all countries will decrease day-ahead prices in NO2. Hence, the results imply that the merit-order effect indeed occurs through market coupling between the respective country and NO2. Overall, the impact is relatively greater during the day compared to the evening and night. The result for Great Britain is less significant relative to the other countries, implying that VRE penetration from Great Britain is a weaker price driver for the day-ahead price in NO2.

In Germany, during the day (from 06:00 to 17:00), the effect from VRE penetration is amplified, which possibly could be due to PV, as the impact declines during the night. Comparing Figure 2.2 to the other countries' electricity mix, Germany has the highest generation capacity of PV. From 10:00 to 11:00, the negative impact peaks with the greatest coefficient of –2.47 EUR/MWh. This means that a 1 percent increase in VRE penetration between 10:00 and 11:00 decreases the day ahead price in NO2 by 2.47 EUR/MWh. This confirms our hypothesis that an increase in VRE during peak hours has a greater price impact for higher price quantiles than lower price quantiles. Coefficient estimates tend to be greater with an increasing VRE penetration and therefore we cannot confirm congestion in any hour. In summary, hypothesis H_1 and H_3 concerning the merit-order effect and peak demand are supported, while we do not find any evidence supporting H_2 and H_4 in Germany.

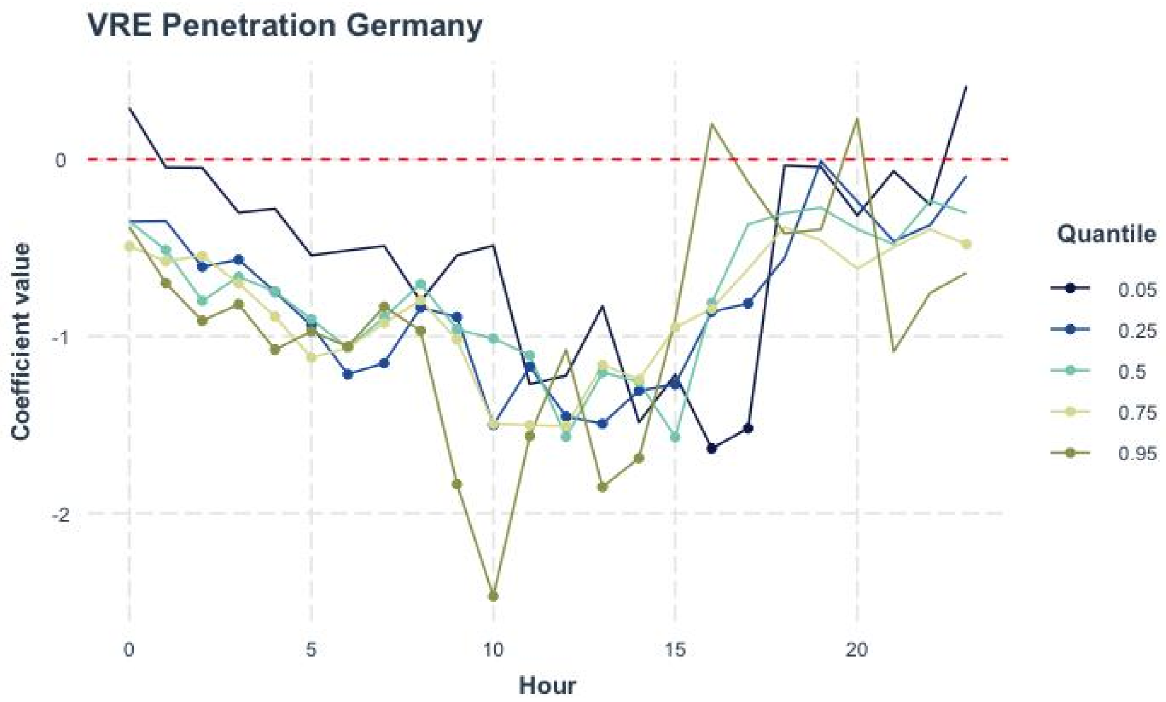

Figure 7.9: Coefficient estimates for VRE Penetration in Germany with points indicating 95 percent significance

The coefficient in hour 08:00 for Great Britain suggests that a 1 percent increase in VRE penetration decrease the day-ahead price in NO2 by 1.15 EUR/MWh. For the right-tail of the price distribution, the result implies approximately half the price impact, with negative coefficients in hour 04:00 and 07:00 suggesting a decrease of 0.4 EUR/MWh and 0.6 EUR/MWh, respectively. A few coefficients from 16:00 to 18:00 are also significant, suggesting a negative price impact of approximately 0.4 to 0.5 EUR/MWh for the three intermediate price quantiles. Coefficients also seems to move towards zero in those hours when VRE penetration peaks. That is the hours between 10:00 and 15:00, as can be seen in Figure 5.3. However, these coefficients are not significant and therefore we cannot claim that this result stems from congestion. In summary, we find evidence supporting H1 stating that an increase in VRE penetration in Great Britain has a negative price impact in NO2 in terms of the merit-order effect.

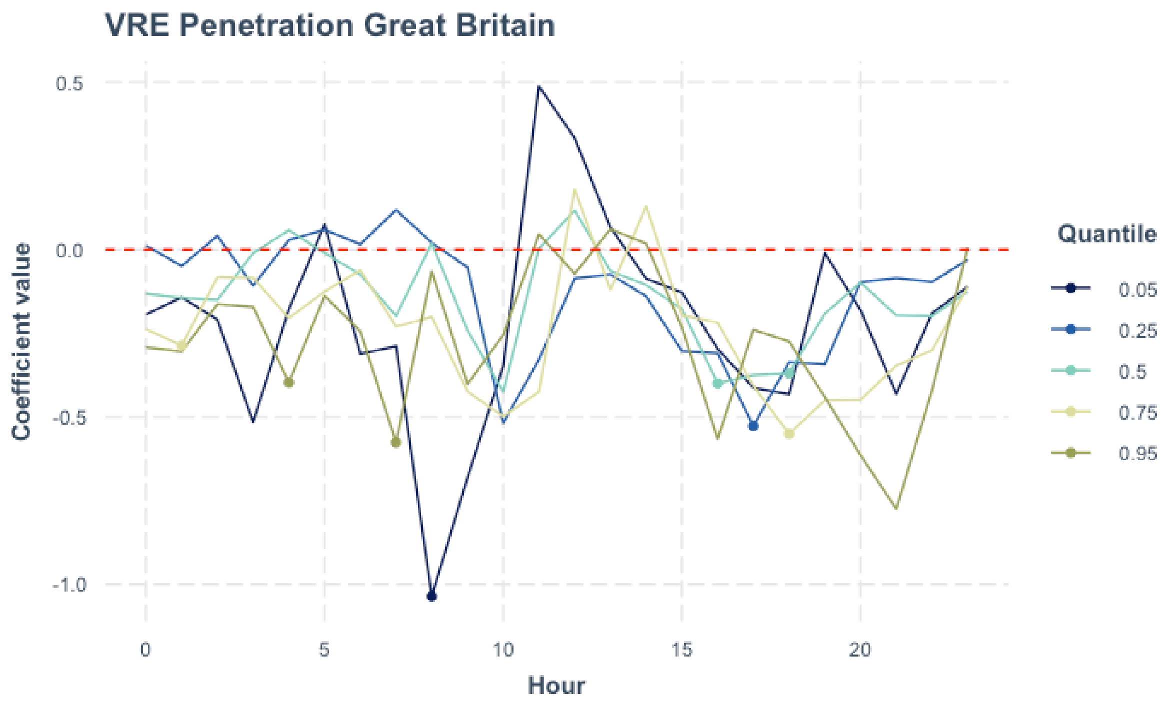

Figure 7.10: Coefficient estimates for VRE Penetration in Great Britain with points indicating 95 percent significance

In Denmark, one observes an increasingly non-linear impact as the quantile increases. Thus, the impact from VRE peaks in the right-tail of the price distribution during peak hours, supporting the hypothesis concerning a greater price impact for the higher quantiles during peak demand. In the hours 16:00 and 20:00 a 1 percent increase in VRE penetration in Denmark decreases the day-ahead price in NO2 by approximately 1.1 EUR/MWh. Considering the single positive coefficient is insignificant, there is no statistically significant indication of congestion. As described in Table 2.1, the transmission capacity to Denmark is largest. The assumption of less likely congestion is further supported through Figure 5.5, showing that the correlation between VRE penetration and prices in NO2 is relatively stable throughout the day, compared to the other countries. In summary, we find support for H_1 and H_3, but not H_2 and H_4 in Denmark.

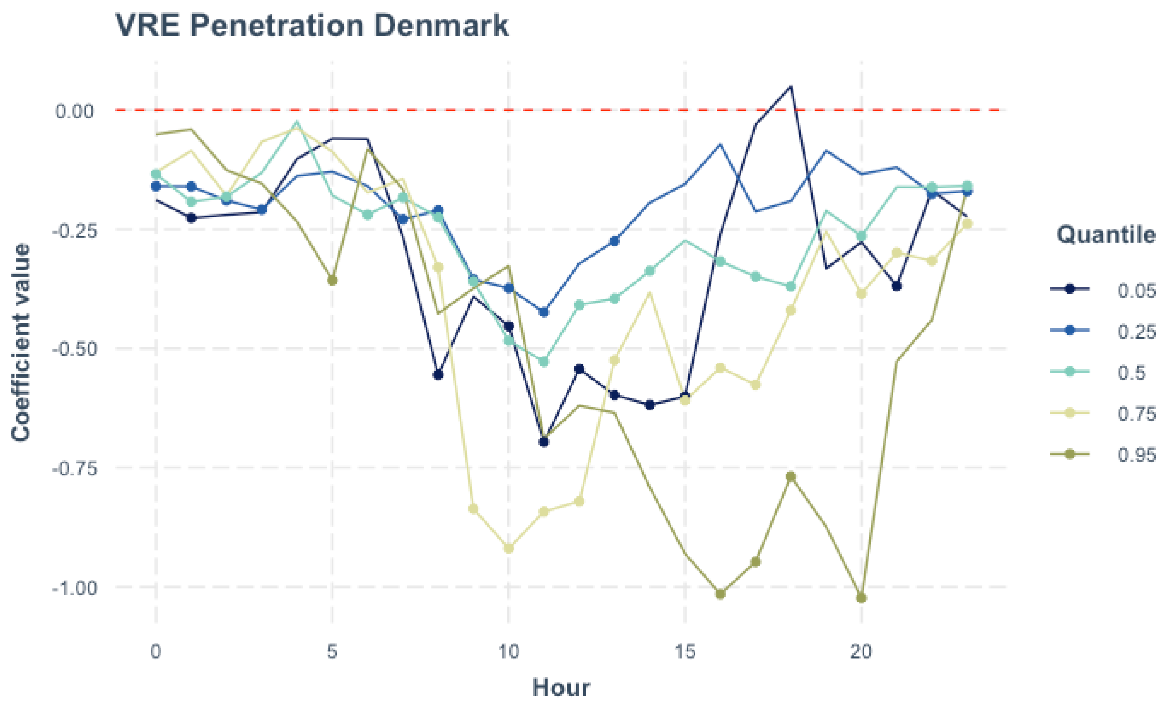

Figure 7.11: Coefficient estimates for VRE Penetration in Denmark with points indicating 95 percent significance

The result for the Netherlands implies that the negative price impact during the night (from 20:00 to 10:00) is lower than during the day. This is perhaps due to the fact that output from VRE sources decreases during the night (as seen in Figure 5.3), and consequently, the price impact in NO2 is relatively low. However, the impact is greater for the lower price quantiles during these off-peak hours, supporting our hypothesis regarding off-peak demand. On the other hand, during the day (from 12:00 to 19:00), we see a stronger negative impact for the right-tail of the price distribution. This supports our hypothesis regarding a greater negative price impact when VRE coincides with peak demand hours. A 1 percent increase in VRE from the Netherlands at 18:00, decreases the day-ahead price in NO2 by 2.1 EUR/MWh.

However, the coefficient estimates for the bottom three quantiles in the Netherlands are positive or around zero during the day. This arguably stems from congestion, but the coefficient estimates are only significant at the 85 percent level. Therefore, we cannot state that this result is due to congestion given a 95 percent confidence level. As seen in Figure 5.5, the negative correlation between VRE penetration in the Netherlands and prices in NO2 increases towards zero during the day, strengthening the assumption of congestion. The VRE penetration in the Netherlands is highest during the day. However, in the left-tail distribution, demand is likely low, resulting in abundant electricity generated by VRE sources. Thus, the increase in VRE penetration during the day when demand is low do not decrease the price in NO2, as is the case during the day when demand is high, i.e., in the right-tail price quantiles. Congestion is most likely to occur in the Netherlands, considering the transmission capacity is considerably lower compared to the interconnectors to Germany, Great Britain, and Denmark, as described in Table 2.1. In summary, we find evidence supporting H1, H3 and H4 in the Netherlands. We find some support for H2 but cannot state that congestion occurs given a confidence of 95 percent.

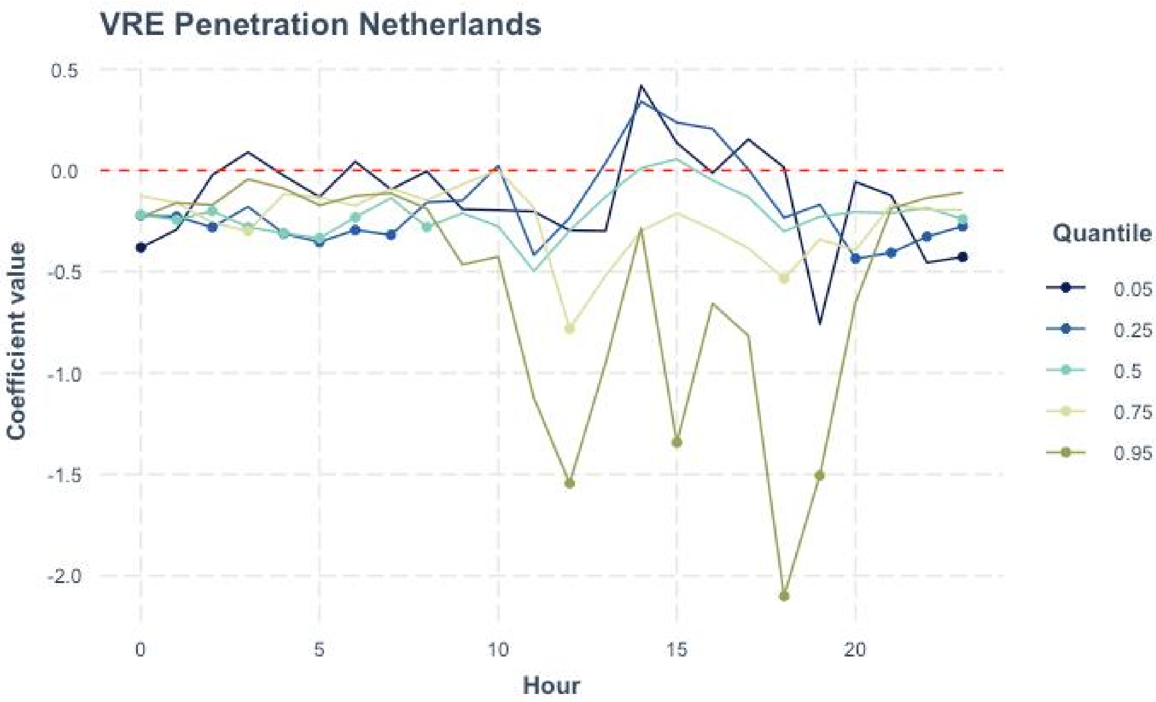

Figure 7.12: Coefficient estimates for VRE Penetration in the Netherlands with points indicating 95 percent significance

A summary of our result is displayed in Table 7.1. For all countries, the merit-order effect is present with the greatest negative impact being from VRE penetration in Germany between 10:00 and 11:00. The results in Germany, Denmark and the Netherlands also support our third hypothesis regarding the impact being greater in the higher price quantiles when demand is high. However, one does not observe this result for Great Britain and coefficients are generally less statistically significant. As discussed under Section 3.6, the day-ahead auction process between NO2 and Great Britain is unlike others, which could rationalise a less significant price effect through market coupling. The significant price impact is strongest for the bottom quantile in hour 08:00, in other words, during a morning peak-hour. However, we would expect the price impact to be greatest in the higher price quantiles when demand is high. Thus, this result is rather unexpected. In the Netherlands one also observes that the impact is greater in the lower quantiles in the hours when demand is low and supports our fourth hypothesis H_4.

Hypothesis	**H_1**	**H_2**	**H_3**	**H_4**
Germany	Supported	-	Supported	-
Great Britain	Supported	-	-	-
Denmark	Supported	-	Supported	-
Netherlands	Supported	-	Supported	Supported

Table 7.1: Summary of supported and unsupported hypothesis

8. Limitations

In this section we will discuss the limitations of our thesis and the implications they may have had for our analysis and result.

As mentioned earlier in the thesis, we choose to start our sample on the 1st of October 2021 as this was the first operational day for the most recent cross-border interconnection to NO2, North Sea Link. We ended our sample on the last trading hour of the consecutive year, 31st of December 2022. During this 15-month period Europe has seen staggering electricity prices with occurrences of record-high gas prices as well as record low reservoir levels in Norway. Hence, it is worth noting that assessing the price impacts from transmission of electricity stemming from VRE sources over a longer time-period could lead to other results as well as strengthening our findings.

During our sample period, on April 15, 2022, Germany completely phased out their last electricity production from nuclear power plants (Clifford, 2023). However, later in August of 2022, the closure was disrupted by Russia's invasion of Ukraine which led them to open up previously closed plants in an attempt to stop the staggering electricity prices and ensure security of supply (Hovland, 2022). It is worth noting that this might also affect our results, as they have deliberately phased out nuclear in the last couple of years, which lately has been disturbed by the ongoing geopolitical tensions.

Our model does not capture long-term price effect stemming from Norway's high hydro storage capacity as described in Section 3.1. Import of electricity allows for saving water in hydro reserves. Consequently, the price is potentially affected later as well, not only during the day of import. Thus, we emphasise that the long-term price impact from VRE sources abroad is likely not captured through solely evaluating day-ahead prices.

This thesis utilizes a flexible model which assumes cross-sectional independence that allows for estimating separate time series equations for each panel. As mentioned above, there might be events during the sample period that have induced common shocks that our fixed effects variables have not controlled for. If these shocks impact each panel differently, this unobserved heterogeneity might lead to cross-sectional dependence due to correlation among the errors. Hence, a comparison between our model and a pooled panel regression could have been conducted to assess the level of consistency in the coefficients (Coakley et al., 2006).

We have also made some notable modifications to part of the control variables in our sample. As mentioned under the data section, some variables have been interpolated due to missing values, namely fuel prices, reservoir levels, and prices for electricity certificates. The models explanatory power could potentially be increased if hourly data was available for these variables and interpolation thus would be avoided. In addition, one could have included the Available Transmission Capacity variables for each country. However, as Keppler et al. argues, it is unlikely that these would provide any additional explanatory power due to them being quite constant throughout the year and very similar to the maximum transmission capacity (2016). One could also have controlled for other production sources such as other renewables and fossil fuelled sources. However, this would potentially lead to perfect multicollinearity, due to the fact that such a combination essentially would make up 100 percent of demand.

9. Conclusion

This thesis contributes to the area of research on interconnectors and coupling of electricity markets by assessing the merit-order effect in Norway from VRE in Europe. Electricity markets are currently undergoing vast changes, as Europe becomes increasingly integrated and VRE sources are on the forefront of the energy transition. This research could provide valuable insight for future decision making. We employ a Linear Quantile Regression model to assess price effects appropriately. Considering previous research and their pertinent findings, we develop applicable hypotheses, covering the merit-order effect, congestion, off-peak and peak demand patterns. The results from our model are analysed and explained in accordance with relevant theory and reasons for possible differences between each country is discussed.

Our results show that an increase in VRE penetration in all countries, that is, Germany, Great Britain, Denmark, and the Netherlands, decrease prices in NO2. This provides evidence that the merit-order effect occurs through market coupling, as an increasing share of low marginal cost VRE abroad will decrease prices domestically. However, the results suggest different degree of impact from each country, considering their respective electricity mix and the varying transmission capacities. A greater transmission capacity will allow for more excess VRE to flow from the low-price area to the high-price area. In addition, if capacity is reached, congestion might occur, creating a situation in which the merit-order effect diminishes. The results indicate signs of congestion in hours when demand is low and VRE penetration peaks, most notably from the Netherlands. However, the model is unable to capture this effect at a 95 percent statistically significant level. Thus, we cannot conclude that this is caused by congestion. The results also imply that the merit-order effect varies on the price distribution. For the higher price quantiles, we find a greater VRE impact during peak demand for Germany, Denmark, and the Netherlands. The results indicate the opposite effect from Great Britain, as the impact is strongest towards the left-tail of the price distribution. For the lower price quantiles, we do not find strong evidence indicating that the impact of VRE is greater during off-peak hours except for the Netherlands. Our findings are displayed in Table 7.1. We control for possible underlying causes of our result by including variables known to affect electricity prices. The results of these variables coincide with applicable theory and previous research, indicating expected electricity price effects.

In terms of future research, we suggest exploring the price convergence between each interconnected country and NO2 to evaluate market efficiency and congestion. Price convergence is calculated as the price difference between the two bidding zones. Each model would require variables that are tailored to the specific countries to reduce omitted variable bias which is likely to occur due to the complexity of the electricity market. Such research could also include data from a longer time period. Considering NordLink and North Sea Link started operating relatively recently, such a study could potentially strengthen or change our results. In addition, the dependent variable would arguably be better at capturing effects from congestion as prices would display divergence. We also suggest future research on how interconnectors affect the security of electricity supply in Norway, by focusing on for instance futures prices, exports, imports, and reservoir levels. Due to the distinct differences in flexibility from hydropower to VRE, such a topic would be highly interesting and potentially give valuable guidance in future decision making.

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Appendix

A.1 Weather Stations

Name	Station ID	Name	Station ID
Arendal Lufthavn	SN36330	**Laudal - Kleiven**	SN41175
Blåsjø	SN40510	**Lindesnes Fyr**	SN41770
Byglandsfjord - Neset	SN39750	**Lista Fyr**	SN42160
Bykle - Kultran	SN40420	**Lyngdal**	SN41825
E18 Haslestad	SN36010	**Lyngør Fyr**	SN35860
E18 Inntjorheia	SN38150	**Mandal Iii**	SN41090
E18 Studevann	SN38250	**Nelaug**	SN36560
E39 Fidjane	SN39212	**Oksøy Fyr**	SN39100
E39 Osestad	SN41795	**Rv41 Åmli**	SN37070
E39 Regevik	SN42700	**Rv9 Bykle**	SN40405
E39 Suvatnet	SN41005	**Rv9 Dalehefte**	SN39450
E39 Vatland	SN41990	**Rv9 Hekni**	SN40005
Fv42 Haddelandsheia	SN42490	**Rv9 Hovden**	SN40905
Fv45 Hunnedalen	SN44985	**Rv9 Moisund**	SN39520
Fv76 Østerholtheia	SN35110	**Sirdal - Sinnes**	SN42940
Gjerstad	SN35210	**Sirdal - Smøleheiknuden**	SN42930
Hovden - Lundane	SN40880	**Torungen Fyr**	SN36200
Kjevik	SN39040	**Valle**	SN40250
Sømskleiva	SN39150	**Åseral**	SN41480
Landvik	SN38140		

Table A.1: Overview of weather stations used to calculate the average temperature in NO2

A.2 Augmented Dickey-Fuller Test Results

Variable	Dickey-Fuller	Lag order	P-value
Price NO2	-14,21	22	0,01
VRE DE	-11,93	22	0,01
VRE GB	-15,12	22	0,01
VRE DK	-18,22	22	0,01
VRE NL	-11,71	22	0,01
Demand	-6,96	22	0,01
Reservoir	-10,49	22	0,01
El-certificate	-30,49	22	0,01
Gas price	-19,89	22	0,01
Temperature	-7,59	22	0,01

Table A.2: Results from the ADF-test on the pooled panel data

A.3 Kendall Pairwise Correlation

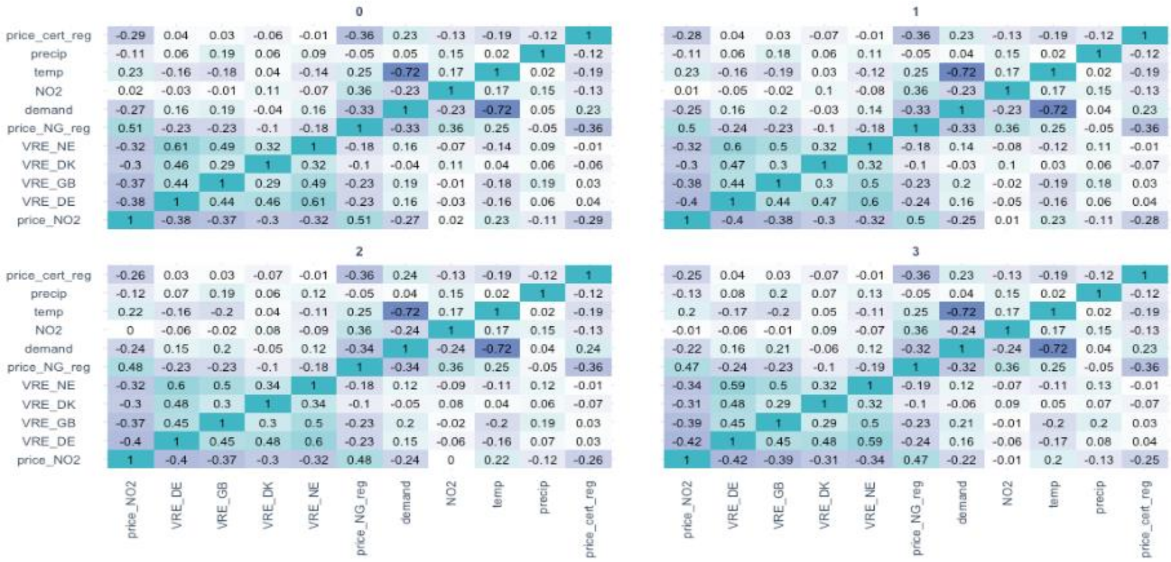

Figure A.1: Kendal Pairwise Correlations for each variable in hourly panels 0-3

Figure A.2: Kendal Pairwise Correlations for each variable in hourly panels 4-7

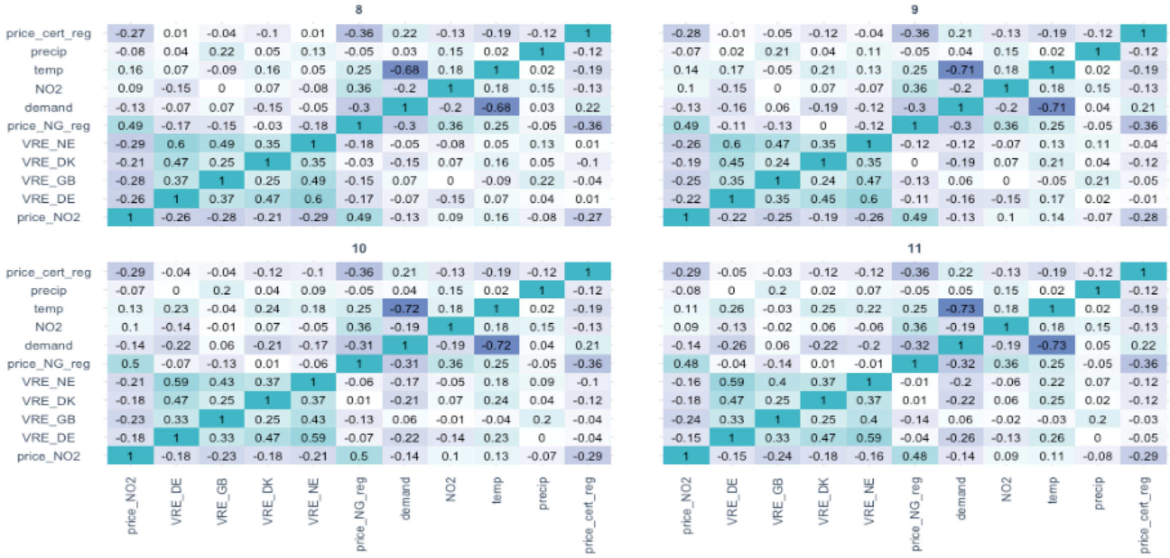

Figure A.3: Kendal Pairwise Correlations for each variable in hourly panels 8-11

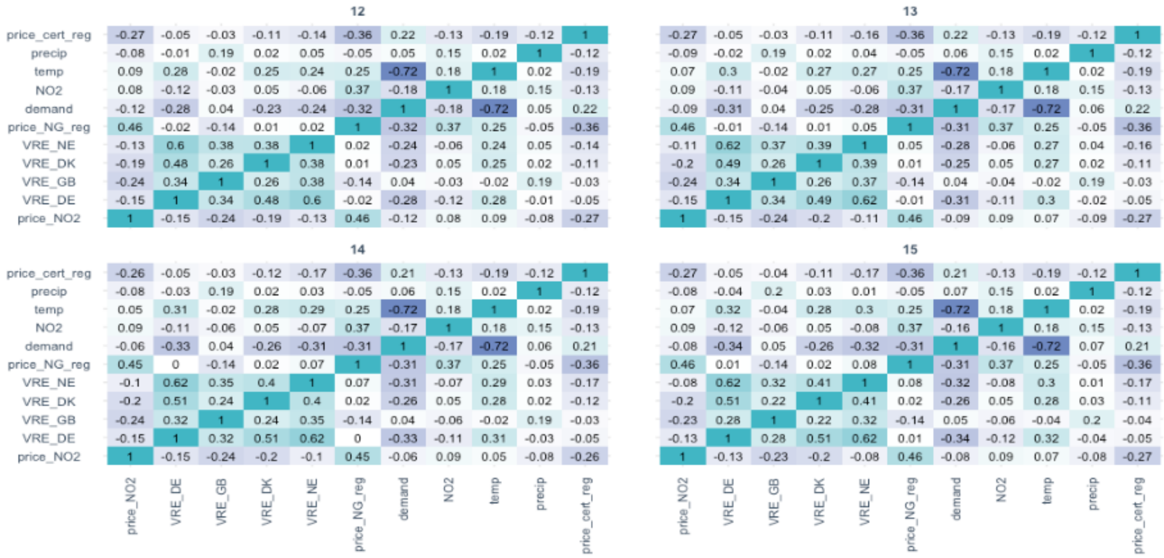

Figure A.4: Kendal Pairwise Correlations for each variable in hourly panels 12-15

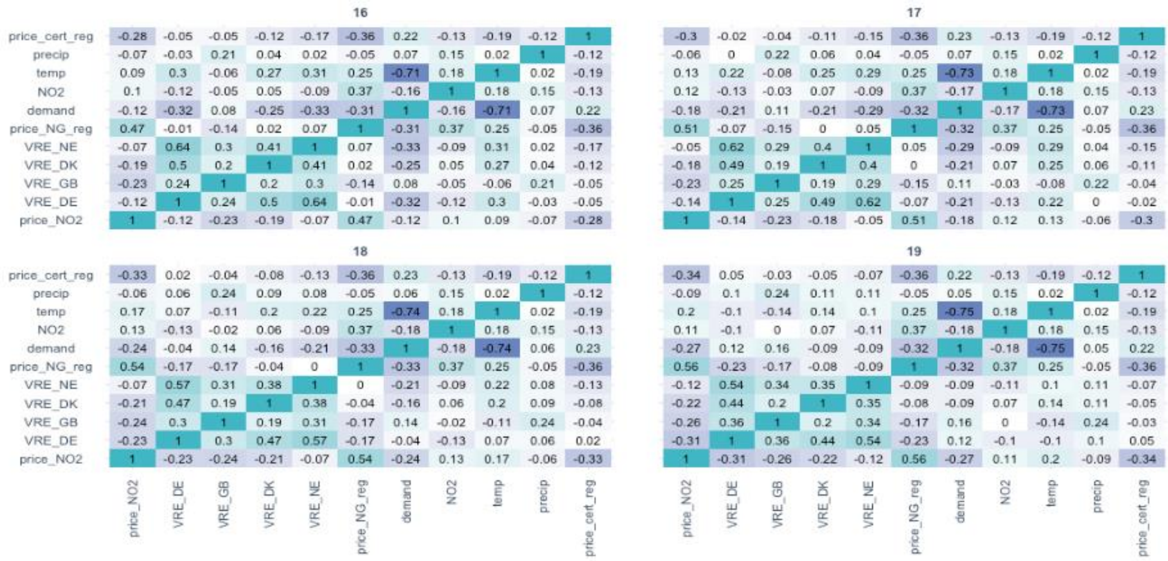

Figure A.5: Kendal Pairwise Correlations for each variable in hourly panels 16-19

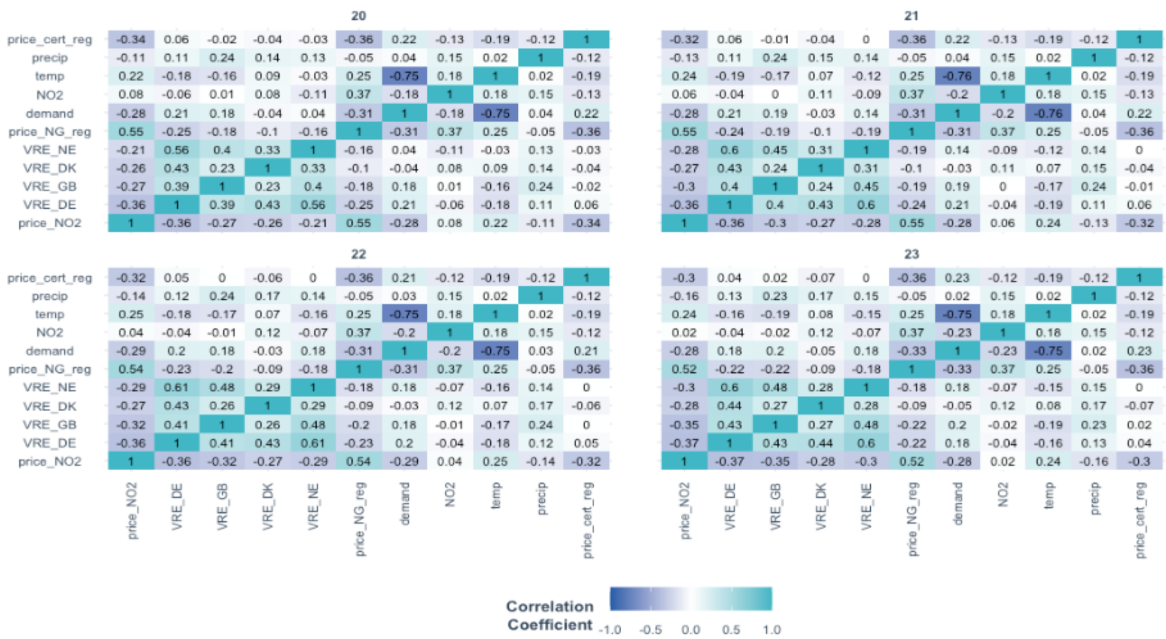

Figure A.6: Kendal Pairwise Correlations for each variable in hourly panels 20-23

A.4 Month Coefficients

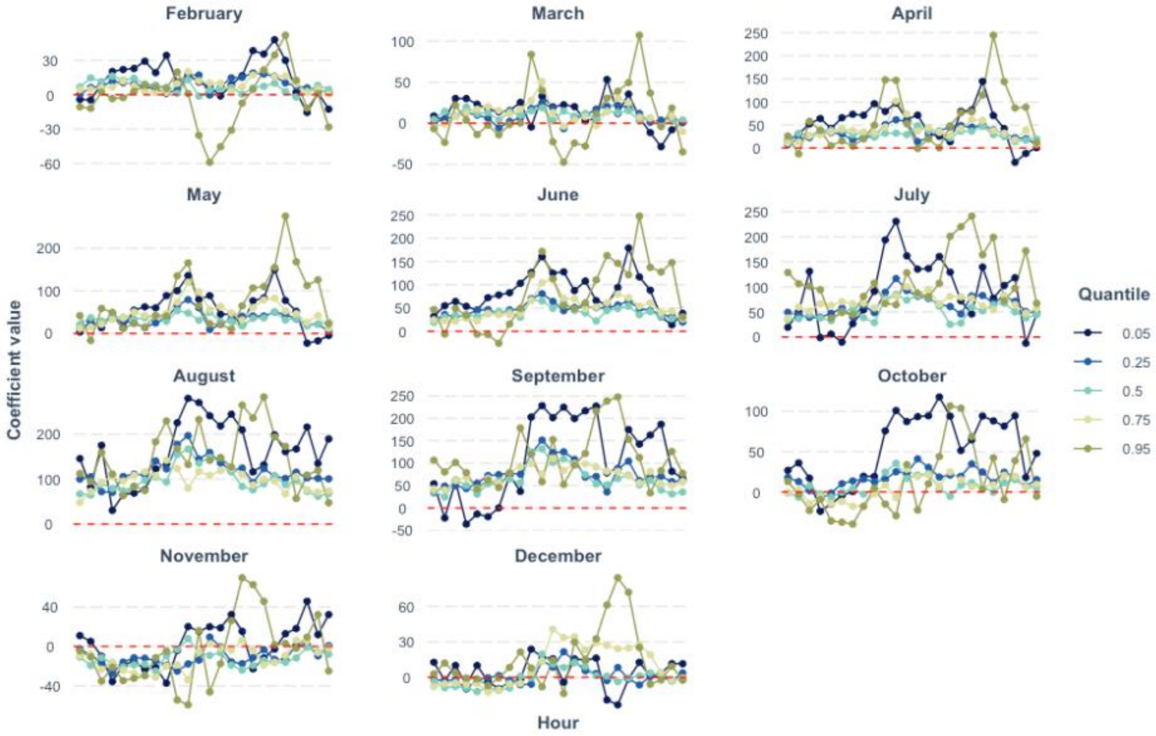

Figure A.7: Coefficient estimates for the monthly dummy variable excluding January

Monthly dummies must be interpreted as the impact on price in NO2 compared to January that is omitted due to dummy variable trap. The most notable part of the result is the fact that the coefficients from April to September are close to constantly positive, indicating that the electricity price during our sample were higher in spring and summer months compared to January. Evaluating this result to our sample set in our R code, this is in fact true. However, monthly seasonality is controlled for by the monthly dummies.

A.5 Public Holidays

Holiday	Date	Weekday
Christmas Eve	24.12.2021	Friday
Maundy Thursday	14.04.2022	Thursday
Good Friday	15.04.2022	Friday
Easter Monday	18.04.2022	Monday

Norway's national day	17.05.2022	Tuesday
Ascension Day	26.05.2022	Thursday
Second day of Pentecost	06.06.2022	Monday
Boxing Day	26.12.2022	Monday

Table A.3: Overview of public holidays used to calculate the holiday dummy variable

A.6 Time Trend

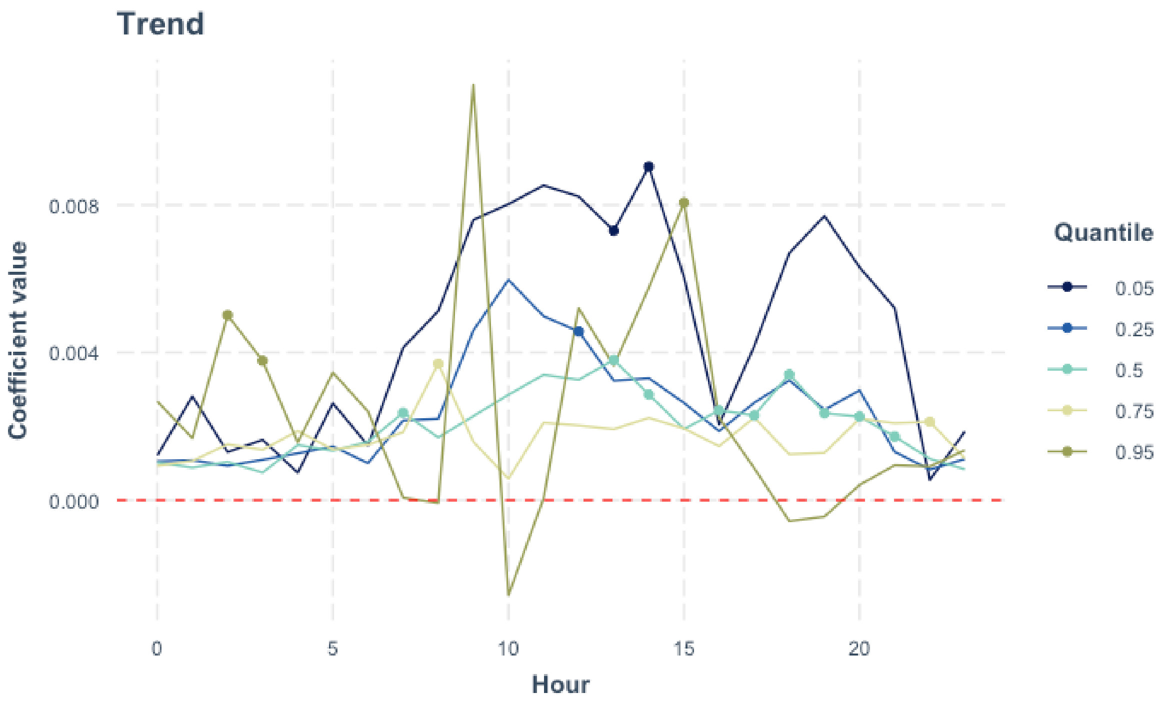

Figure A.8: Coefficient estimates for the time trend variable

A.7 Joint Test of Equality of Slopes

Hour	F-value	P-value
0	5.4381	< 2.2e-16 ***
1	5.1458	< 2.2e-16 ***
2	11.437	< 2.2e-16 ***

3	8.7976	< 2.2e-16 ***
4	5.1455	< 2.2e-16 ***
5	5.1913	< 2.2e-16 ***
6	4.5514	< 2.2e-16 ***
7	4.1833	< 2.2e-16 ***
8	2.8003	< 2.2e-16 ***
9	14.436	< 2.2e-16 ***
10	6.8922	< 2.2e-16 ***
11	8.2611	< 2.2e-16 ***
12	24.131	< 2.2e-16 ***
13	7.6797	< 2.2e-16 ***
14	10.303	< 2.2e-16 ***
15	7.1474	< 2.2e-16 ***
16	13.117	< 2.2e-16 ***
17	4.397	< 2.2e-16 ***
18	10.153	< 2.2e-16 ***
19	4.0775	< 2.2e-16 ***
20	10.606	< 2.2e-16 ***
21	4.9082	< 2.2e-16 ***
22	5.4623	< 2.2e-16 ***
23	4.7425	< 2.2e-16 ***

Table A.4: Results from the Joint Test of Equality of Slopes using Wald on each panel