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Offshore wind and its effect on the Nordic power market

Adding power generation from Sørlige Nordsjø II and Utsira Nord

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Abstract

An increasing share of renewable energy sources, such as offshore wind power, is expected in the future power markets. Several authors have found that power prices tend to decrease and fluctuate more when integrating offshore wind. This results from the merit order effect and the intermittent nature of wind power generation. The thesis aims to investigate how deployment of offshore wind power at Sørlige Nordsjø II and Utsira Nord will impact the Nordic day-ahead market. The optimization model used assumes that both sites are connected directly to the Norwegian mainline grid in NO2 and NO5. Adding offshore wind results in declining power prices for all three operating hours accounting for seasonal fluctuations in water reservoir levels. The level of price convergence in the initial baseline prices seems to impact the number of affected bidding areas. With low seasonal water level, all Nordic bidding areas expect for Finland are affected by the additional generation from offshore wind power, whereas only NO1, NO2 and NO5 are affected in the average- and high- seasonal water level scenarios. Moreover, generation increases in the bidding areas with the added capacity and decreases in other affected areas. Overall, the thesis illustrates trends of increasing price differences and price fluctuations when integrating offshore wind.

Keywords – Electricity markets, Renewable energy sources, Offshore wind power, Hydropower, Utsira Nord, Sørlige Nordsjø II

Contents

List of Figures

List of Tables

1 Introduction

The Nordic power market has undergone fundamental changes in the past, leading up to the integrated and efficient market operating today. Moving forward substantial changes are yet to be made in light of climate change and the role of electricity markets. The European Union has a target of becoming the first carbon-neutral continent by 2050 (European Commission, 2019). As the energy sector stands for the largest greenhouse gas emissions in Europe, mitigating climate change through decarbonizing the electricity sector will be of importance. Thus, both the European and Nordic power market will encounter substantial changes when moving towards a low-carbon, climate-friendly electricity sector in the years to come. In this transition a successful integration of renewable energy sources will be crucial.

Through climate policies and an increasing demand for electricity higher levels of variable renewable energy sources enters the market. Renewable energy sources, such as wind- and solar power, are characterized by their low marginal costs and intermittent nature (Zalzar et al., 2020). As their generation depends on weather conditions rather than demand conditions, short-term fluctuations in power prices are expected. These interesting aspects of renewable energy implementation have caught the attention of several researchers, as a substantial increase in the installed renewable energy capacity is expected in the upcoming years. Statnett (2020c) expects a growth of 275 TWh of wind power in the Nordics by 2050, where 80 TWh is expected from offshore wind. As such, offshore wind will be an essential part of how Europe can become carbon-neutral (The International Energy Agency, 2020).

Norway has a beneficial coastline with high and steady wind speeds, a prerequisite for offshore wind power (NVE, 2012). In 2020, the Norwegian government opened two offshore wind sites for further development; Utsira Nord and Sørlige Nordsjø II (Norwegian Ministry of Petroleum and Energy, 2020). As of January 2021, licence applications can be submitted for offshore wind projects on the two sites.

Still, Norway remains a hydropower dominated electricity supplier (SSB, 2019). As many hydropower plants have the unique feature of storing water in reservoirs to delay electricity production, the Norwegian and Nordic power market, is characterized by great flexibility

(NordREG, 2019). Whether to produce or to delay, depends on the value of using the water today as opposed to saving it for later production. With increasing penetration of intermittent renewable energy sources, creating a larger balancing need to mitigate short term fluctuations in supply, this flexibility will be valuable.

The objective of this thesis is to investigate the implications of integrating offshore wind power in the Nordic day-ahead market through the Norwegian mainland grid. Attention is brought to the hydropower dominated power supply in Norway and the implications of fluctuations in the water reservoirs levels. Moreover, a particular emphasis is placed on areas where the offshore wind capacity will be added, which is from Sørlige Nordsjø II to NO2 and from Utsira Nord to NO5. In light of this, the following research question will be investigated:

How will offshore wind deployment, connected to the hydropower dominated Norwegian mainland grid, impact the Nordic power market?

To encounter the above-mentioned question of interest, an optimization model for the Nordic power market has been constructed. The purpose of the model is to make a realistic comparison of power prices and the level of congestion in the Nordic area with and without the increased capacity added from offshore wind power. Moreover, to draw attention to the fluctuations in water levels in the hydropower reservoirs, three baseline scenarios have been modelled. As such, a discussion can be made on whether initial water levels in the hydropower reservoirs will have an impact on the integration of offshore wind in Norway. These three baseline scenarios are based on operating hours on the same date from three different years with low-, average- and high seasonal water levels. This is to avoid different forecasts of future consumption and precipitation patterns, reflected in the value of water.

There are several reasons why the topic of this thesis is of importance. Offshore wind, and renewable energy sources in general, will be a fundamental part of the transition towards a carbon-neutral European electricity market. Norway, together with other Nordic countries, will give licenses for offshore wind projects in the upcoming years. This implies that the Nordic power market will need to handle the implications of new renewable electricity sources. Moreover, Norway's position as a large hydropower supplier can be beneficial when integrating offshore wind power.

In the following chapters the research question will be explored, and an assessment of how offshore wind connected to the Norwegian mainline grid will affect the Nordic power market will be provided. The second chapter will present the context of this thesis by introducing the Nordic wholesale market and the changing power market towards renewable energy sources, with an particular emphasis on offshore wind in Norway. Thereafter, the third chapter will review existing literature on the Nordic power market and the integration of wind power, as well as the combination of hydropower and offshore wind. The fourth chapter will explain the theoretical aspects of this thesis, focusing on the merit order effect, power price impacts from seasonal fluctuations in hydropower and existing congestion management methods. In chapter five an overview of the chosen methodology with the assumptions and simplifications made will be presented. The sixth chapter will interpret and discuss the simulation results. Lastly, in chapter seven a conclusion will be made and limitations impacting the robustness of the conclusion will be discussed.

2 Background

This chapter will elaborate on the relevance of our chosen research question in light of the present and future electricity markets. First, by describing the Nordic wholesale market, presenting how it functions and who participates. Then, by looking into the changing power markets and the entrance of renewable energy sources. Lastly, opportunities from offshore wind will be presented, focusing on the Norwegian case.

Electricity has become an important part of our daily lives both at work and home (Nord Pool Group, 2020j). As such, there has been an extended use of electricity, implying higher production and transmission capacities. For that reason, having an efficient and secure power market has become crucial. Today, we see a dynamic market where electricity can be bought and sold across countries and areas. Transmission of electricity between countries ensures the maintenance of an efficient power flow (Energi Norge, 2020). However, power markets differ from other commodity markets as electricity cannot easily be stored (Norwegian Ministry of Petroleum and Energy, 2019). Therefore, the amount produced and consumed must balance at all times. However, as will be seen, there are flexible generation technologies, such as hydropower, which currently is and will be an important part of future electricity markets. Furthermore, the transmission of electricity is restricted by the capacity limitations on the connections in the grid. These characteristics of electricity have implications for how power markets are constructed.

2.1 The Nordic wholesale market

The Nordic countries have an integrated power market where electricity flows between countries (Mundaca et al., 2013). The integration ensures efficient trade between the countries, reduces costs and facilitates the integration of more renewable energy sources (Energi Norge, 2020). The transmission network ensures that there is a sufficient level of electricity available to meet demand across borders. Each of the Nordic countries has their own combination of electricity generation technologies supplying power to the Nordic wholesale market. In Norway, hydropower is the dominating source of electricity, producing 95% of the electricity generation portfolio (SSB, 2019). Also in Sweden, hydropower represents a significant share of the generation portfolio with more than 50% (Svenska

Kraftnät, 2020). They also have a large share of nuclear power. In Finland, the generation portfolio consists of a combination of hydro-, nuclear- and combined heat and power (The European Commission, 2020a), whereas in Denmark, wind power is the main generation source (Energinet, 2020).

The Nordic power market is divided into several bidding areas, also called pricing zones, because of physical constraints in the transmission grid (Nord Pool Group, 2020b). The division of the Nordics into bidding areas ensures that regional market conditions are reflected in the price. Thus, different areas can have dissimilar prices if the physical constraints limit full price convergence. The term congestion is used to refer to situations when the power flow is constrained. The division of the Nordic power market into bidding areas is a method of handling congestion. A more detailed description of congestion management is given in section 4.3. Currently there are five bidding areas in Norway, four in Sweden, two in Denmark and one in Finland. The regional coupling of electricity together with interconnectors within the Nordic countries has been a major success factor for the Nordic power market, as cooperation increases the security of supply and lowers system costs (Nordic Energy Research, 2018).

Furthermore, the Nordic power market is integrated in the wider European market through transmission connections. The system for price coupling of regions (PCR) uses a common European algorithm, Euphemia, to calculate prices across Europe (Nord Pool Group, 2020l). The intended outcome is to allocate cross-border capacity to optimize social welfare and increase transparency. The physical integration of power between the Nordics and the rest of Europe is provided by interconnectors to the Netherlands, Germany, the Baltics, Poland and Russia (Norwegian Ministry of Petroleum and Energy, 2019). In the Nordic countries, physical trade of power is ensured by the power exchange Nord Pool.

Since electricity must be consumed and produced at the same time, the Nordic wholesale market is divided into i) the day-ahead market, ii) the intraday market, and iii) the balancing markets (Norwegian Ministry of Petroleum and Energy, 2019). This is to ensure balance at all times. The day-ahead market, Elspot, and the intraday market, Elbas, are currently operated by Nord Pool, which as of today is the only power market in the Nordic region (Nord Pool Group, 2020a). In the day-ahead market contracts are made for delivery of power hour-by-hour for the next day, whereas in the intraday market contracts are made in the time frame between the Elspot market closing and one hour before power delivery. Thus, if the market participants are not able to deliver on their commitment from the Elspot market, they have the possibility to trade themselves into balance in the intraday market. As events disturbing the balance can occur within the hour before delivery, balancing markets regulate either consumption or production to maintain an instantaneous balance. In this thesis, the day-ahead market is of focus.

2.1.1 Market participants

In the Nordic electricity market, there are several actors with different responsibilities and purposes (Nord Pool Group, 2020i). The various functions of the wholesale market can be divided between five main actors:

Transmission system operators (TSOs) are responsible for the security of the power supply, as well as they own and run the transmission grids (Ma et al., 2016). These responsibilities include ensuring operational security, e.g., that the physical power balance is upheld, and formulating market rules. Each Nordic country has their own state-owned TSO which is the respective owner of the main national grid, namely Statnett in Norway, Fingrid in Finland, Svenska Kraftnät in Sweden and Energinet in Denmark. The TSOs are assigned to conduct projects related to the security of electricity and energy targets by its national government (Unger et al., 2018).

The producers are responsible for the power production (Nord Pool Group, 2020i). The electricity generated is sold directly to suppliers or indirectly through Nord Pool. The producers also sell electricity to the TSOs on the regulating market if the power balance is not upheld.

Suppliers either buy electricity through Nord Pool or directly from producers, and resell it to the end-users (Nord Pool Group, 2020i). In the Nordic and Baltic countries there are approximately 380 suppliers, and the competition among them is high within each country.

Traders own the power when the trading process takes place, whereas *brokers* act as an intermediary in the power market (Nord Pool Group, 2020i).

The end-users are households, commercial and industrial users of electricity (Nord Pool

Group, 2020i).

2.1.2 Nord Pool and the day-ahead market

Nord Pool is the leading power market in Europe, with 360 companies from 20 different countries trading on their power exchange (Nord Pool Group, 2020a). They offer services of trading, clearing and settlement in both the day-ahead and the intraday market, with a transparent and trustworthy power price as their product. In 2019 a total of 494 TWh of power traded through the exchange in the Nordic, Baltic and UK day-ahead market, as well as in the intraday market. The majority shareholder is Euronext, with an ownership share of 66%, and the resulting 34% is owned by 7 Nordic and Baltic TSOs. They are licensed by the Norwegian Water Resources and Energy Directorate (NVE) to operate a marketplace for trading power, and by the Norwegian Ministry of Petroleum and Energy to ease power exchange across borders. Nord Pool's main responsibilities are to ensure efficient trading, liquidity and security in the electricity market.

In the day-ahead market, Elspot, power is traded for delivery the next day (Nord Pool Group, 2020d). The market focuses on planned energy demand and delivery, with a market clearing set to maximize social welfare. Figure 2.1 illustrates the market clearing procedure for the day-ahead market where prices are calculated hour by hour for the next day. Since the transmission grids have physical limitations, constraints in the transmission capacities must be taken into account in the price coupling algorithm. Under the current Net Transfer Capacity (NTC) approach, the TSOs must send in the available transmission capacities on the grid for the next day before 10:00 CET. Between 08:00 and 12:00 CET buyers and sellers can submit their bids and offers into the trading system to the Nominated Electricity Market Operator (NEMO) (Nordic RSC, 2018). Currently, Nord Pool is the only NEMO in the Nordic countries. After the bids and offers are submitted, the NEMO forwards the orders to the European market coupling function (MCO). Here, prices in each bidding area are calculated using the price coupling algorithm Euphemia that optimizes social welfare. Thereafter, a system price for the Nordic region is calculated locally at Nord Pool using the same orders as Euphemia (Nord Pool Group, 2020k). The system price is a reference price for the entire Nordic region, calculated without any capacity constraints.

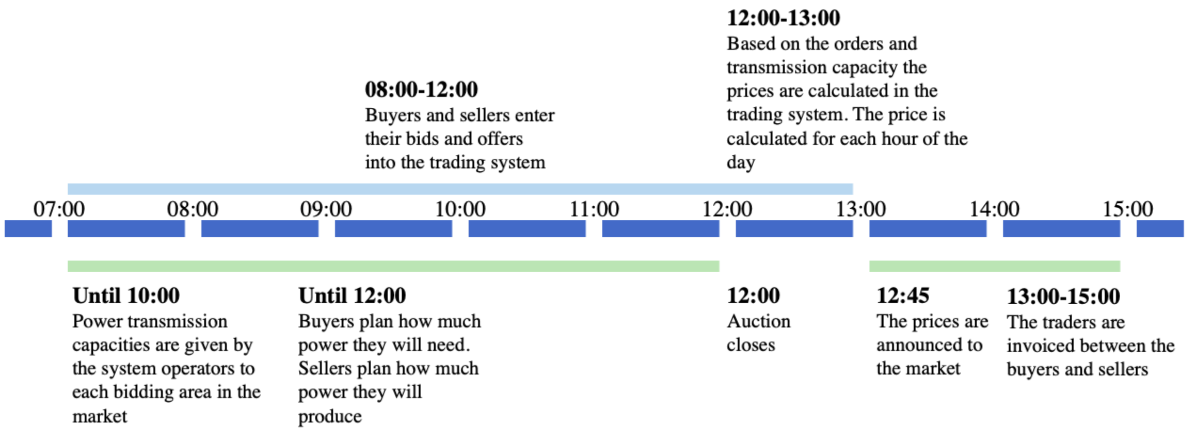

Figure 2.1: The day-ahead market clearing procedure (Sutter, 2014).

Euphemia is part of the Price Coupling of Regions (PCR) project, as noted above. The PCR project and the guidelines on Capacity Allocation and Congestion Management from the European Commission are considered to be outside the scope of this thesis and will not be further explained.

2.2 Changing power markets

The last decades, climate change has captured the public's attention and is now a vital part of the political agenda in many countries. As the energy sector stands for approximately 75% of the emissions in the European Union (EU), mitigating climate change and moving towards a low-carbon, energy efficient power sector is of importance (The International Energy Agency, 2020). In response, the EU's Energy Union was established in 2015 in order to increase efficiency and sustainability in the European electricity sector (European Commission, 2019). The Union works for an integrated continent-wide energy system and a sustainable, low-carbon and climate-friendly economy.

Decarbonising the European energy sector implies that all use of energy within transport, industry, construction, households and power systems must be emission free (Statnett, 2020c). The electrification of the economy results in increased demand for electricity. In line with this, Statnett (2020c) estimates that the electricity consumption will double within 2050. The left part of figure 2.2 illustrates their rising demand forecast in the EU11 countries, which stands for 70% of the European power consumption. The development in the Nordic countries follows the same trend as in Europe. Electrification of the transport sector and several industry processes, as well as the establishment of data centers are drivers of the trend. By 2040, Statnett (2020c) assumes that the Nordic demand will rise by 40% from today's level. In Norway and Sweden it is expected that the electrification of the economy is completed by 2040, but for Finland and Denmark further increases in the electricity consumption could occur until 2050.

At the same time as demand for electricity rises, the phase out of fossil fuels and thermal power plants is expected. The combination of increased demand and climate policies highlights the need to transform the production-, distribution- and utilization of power across Europe. As the new generation must be emission free, renewable energy sources will play a crucial part in the future European and Nordic power markets.

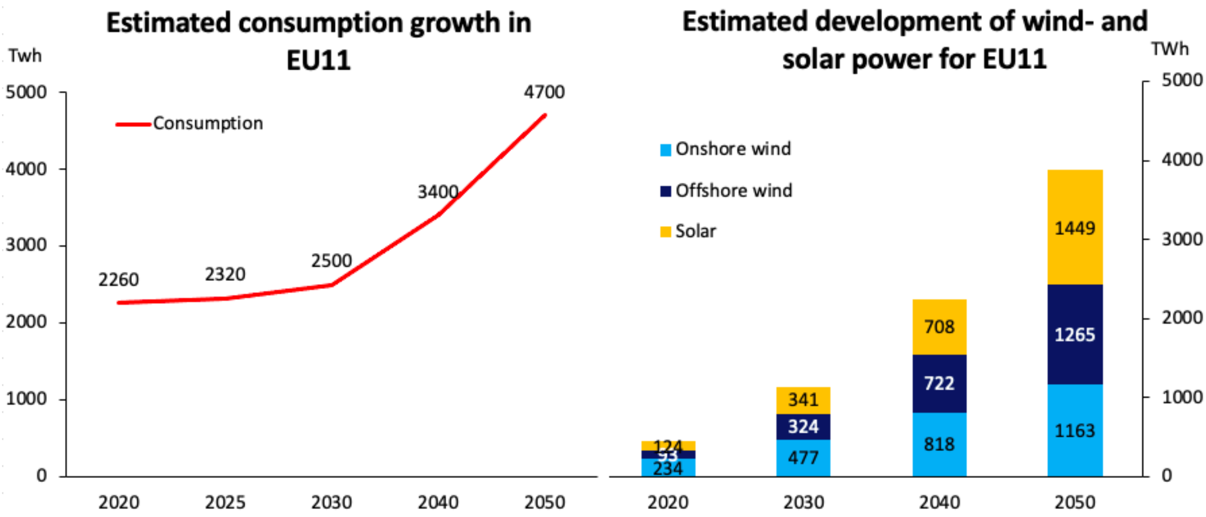

Figure 2.2: Statnett's (2020c) estimates for consumption and development of wind- and solar power in the EU11 countries until 2050.

2.2.1 The entrance of renewable energy sources

With robust energy policies from the European Union, large investments have been made in order to integrate renewable energy sources in electricity markets (The International Energy Agency, 2020). As a result, the installed capacity from renewables in the European market has doubled in the last ten years (IRENA, 2020), implying a share of 32% renewables in 2018 (The International Energy Agency, 2020). Thus, the transition towards a low-carbon power market has already started. Nonetheless, with ambitious policy targets for integration of renewable energy sources in the European electricity market by 2030 and 2050, the EU and its Energy Union requires further actions (European Commission, 2020).

Among renewable energy sources solar- and wind power has strengthened their position as the generation sources with highest cost-efficiency and lowest emissions (Statnett, 2020c). As such, Statnett (2020c) expects that solar- and wind power will be the main generation sources in the future low-carbon European energy market. They predict that that present generation will tenfold within 2050, as seen in the right part of figure 2.2, implying that 86% of the total electricity production will result from variable solar- and wind power generation. Between the two, wind power will account for the highest share. This is in line with the expectations of the European Union of wind power becoming the largest generation source in the upcoming years (The International Energy Agency, 2020). The transition will in large part be driven by investments on the field of offshore wind, where the EU is at the forefront in the development. In fact, as illustrated in figure 2.2, for the EU11 countries Statnett (2020c) expect that offshore wind will account for more than 50% of total wind production by 2050. One of the areas where the EU aims to exploit the potential benefits from offshore wind power is in the North Sea.

In the Nordic power market, hydropower currently accumulates for over half of the generation, making the Nordic countries one of the areas with the highest share of renewable energy sources in Europe (NordREG, 2019). Already in 2017, the Nordic countries had shares of renewable energy exceeding their 2020 targets from the European Union (Nordic West Office, 2019). As such, the Nordic countries are currently recognised as frontrunners in the transition towards a low-carbon energy supply. However, in order to remain forerunners and adjust to the rising demand for electricity, they must continue making efforts to integrate more renewable energy sources. Statnett (2020c) expects an increased share of renewable energy sources across the Nordic market, primarily resulting from wind power. In total, they expect a growth of 275 TWh of wind power from both onshore and offshore sites by 2040. The deployment will contribute to assure supply in light of the increasing demand and the reduced nuclear power production in Sweden. A significant part of 80 TWh is expected to come from offshore wind power.

2.2.2 Development and current state of offshore wind power

Offshore wind uses the same technology as traditional onshore wind to generate power by capturing the kinetic energy resulting from airflows (The European Commission, 2020b). However, there are several benefits from deployment of wind farms at sea compared to on land, such as the higher and steadier wind speed, the large unexploited offshore wind resources and the low environmental impact on citizens (Wilson, 2020).

Typically offshore wind has required high capital expenditure costs and system integration costs, making the cost difference between offshore and onshore wind farms substantial (Statnett, 2020c). However, with increasing attention to the potential at sea, the industry is quickly evolving. Better wind conditions, technology developments and the lower environmental impact on citizens, have also increased the size of turbines available for offshore wind farms relative to onshore wind farms. Hence, more energy per turbine can be extracted offshore compared to onshore. As a result, the cost difference between offshore and onshore wind farms has decreased. Only in the last five years the investment costs have been reduced by half, and are expected to decline even further in the upcoming years. Nonetheless, as of today, feed-in tariffs and renewable obligation certificates have been essential to ensure investments as offshore wind is not yet profitable (GWEC, 2020; Statnett, 2020c).

20 GW of offshore wind was installed in Europe in 2019 (Wind Europe, 2019). This covers approximately 1.5% of the annual electricity demand. Each year the installed capacity increases. Still, to become carbon-neutral Europe will need to accelerate deployment. With Europe being a frontrunner on the field of offshore wind with some of the world's prime wind resources, Wind Europe (2019) indicates that a total of 450 GW of offshore wind capacity is feasible to deploy within 2050. With this magnitude of offshore wind deployment, the industry can potentially meet 30% of European electricity demand. Of this capacity 212 GW are envisioned in the North Sea, with 30 GW on the Norwegian continental shelf.

The more realistic expectation of Statnett (2020c), as mentioned above, is that 80 TWh will be generated from offshore wind power in Nordic region by 2040. For Norway they expect that offshore wind will be deployed from 2030 and onwards. The expectation for

2030 is a yearly generation of 4 TWh, which will increase to 15 TWh and 20 TWh in 2040 and 2050.

2.2.3 Offshore wind in Norway

With a long coastline and good wind resources, Norway has the prerequisite for deploying offshore wind power (NVE, 2010). However, water depths and wave heights have made deployment in the Norwegian waters challenging. As such, the actual deployment of offshore wind power has been located in other countries. Nonetheless, as costs continue to decrease, offshore wind power can pose great opportunities for Norwegian businesses as well (Norwegian Ministry of Petroleum and Energy, 2020). The Norwegian service and supply industry has developed cutting-edge technologies and prime expertise for offshore petroleum activities (Rystad Energy, 2018). Thus, possible synergies from existing knowledge on offshore operations can give Norwegian suppliers an edge and potentially a dominant position in the rapidly evolving market for offshore wind (NVE, 2012). As of today, several Norwegian companies work with development of offshore wind projects. Equinor is currently developing the world's largest floating offshore wind farm, Hywind Tampen, that will supply electricity to the offshore oil and gas fields Snorre and Gullfaks (Equinor, 2020). The project will be of great benefit for developing floating offshore wind technology and for further cost reductions. In the long-run this will be essential for deployment of offshore wind in Norway due to the challenging water depths. Furthermore, it emphasizes the Norwegian offshore supply and service industry's beneficial existing knowledge, and offers new industrial opportunities for Norway in a rapidly developing global offshore wind market.

As the development in offshore wind technologies has evolved, so has the attention from the Norwegian government. In 2007 the Ocean Energy Act was established, and as a result resources have been devoted to investigate potential offshore wind sites on the Norwegian continental shelf (Norwegian Ministry of Petroleum and Energy, 2020). The Norwegian Water Resources and Energy Directorate (NVE) did a comprehensive analysis of 15 potential areas for offshore wind deployment in 2012. Of these, the areas "Sørlige Nordsjø II" and "Utsira Nord" were opened for offshore renewables in June 2020, in accordance with the Ocean Energy Act (Norwegian Ministry of Petroleum and Energy, 2020). This implies that from January 2021 companies can submit license applications for offshore wind power projects on these sites. The reasoning behind choosing Sørlige Nordsjø II and Utsira Nord was their technological and economic suitability for offshore wind deployment. The expected national value creation is between 60 and 63 million NOK/MW over the lifetime of the wind farms at each site. The locations of the two sites are shown in figure 2.3.

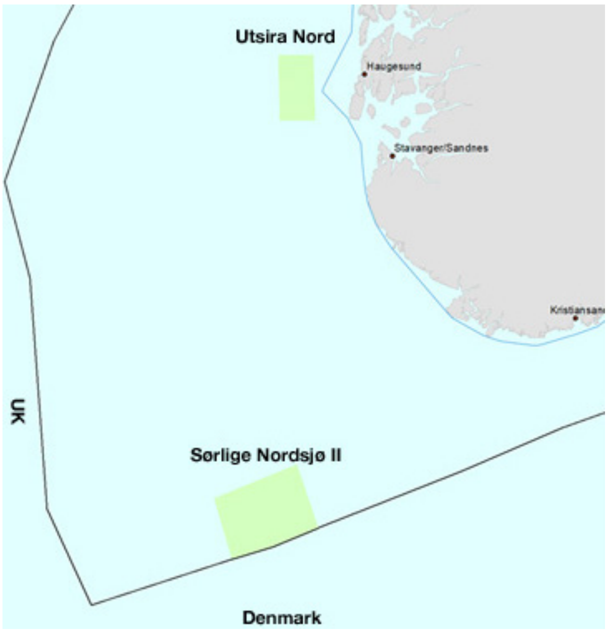

Figure 2.3: Location of Sørlige Nordsjø II and Utsira Nord (NVE, 2019)

Sørlige Nordsjø II is located 140 kilometers from shore and borders the Danish part of the North Sea, east of the Ekofisk- and Tor petroleum fields (NVE, 2012). Because of the long distance to shore, the site must be connected to the grid through a high voltage direct current (HVDC) cable. Statnett (2020b) states that the most rational would be to connect Sørlige Nordsjø II to several countries and not necessarily to the closest onshore connection point. This will require investments, technological development and standardisation to enable a system that functions across distributors. The long-term perspective is that grid developments should facilitate and enable a system that could be connected to the European offshore grid. The first step in this process is to connect Sørlige Nordsjø II to the Norwegian mainland grid.

In contrast to Sørlige Nordsjø II, Utsira Nord has a shorter distance to shore as it is located around 22 kilometers outside of Haugesund. Thus, the site will likely be connected to the Norweigan mainland grid through an alternating current (AC) cable. As Haugalandet is a deficit area, and as there is a large number of energy-intensive industries currently creating an overloaded grid, the area is well suited for extentions in the installed capacity (Statnett, 2020b; NVE, 2012). Currently, it is possible to connect an installed capacity from offshore wind deployment of 500 MW without making notable adjustments to the existing grid. However, for larger extensions transfer capacities need to be increased. According to Statnett (2020b), Gismarvik is considered to be an important connection point to integrate the extended generation from offshore wind farms at Utsira Nord.

The above-mentioned expected deployment of 4 TWh of offshore wind in Norway by 2030 is based on deployment at Sørlige Nordsjø II and Utsira Nord. At Sørlige Nordsjø II, NVE assumes an installed capacity of 1008 MW with small deployment and 3000 MW with large deployment. The installed capacity estimates for Utsira Nord are somewhat lower of 504 MW and 1512 MW.

2.3 Integrating offshore wind power

To successfully integrate offshore wind power and other renewable energy sources, power markets needs to consider how new generation sources will impact the market equilibrium and generation patterns. Firstly, offshore wind power has low marginal costs (Unger et al., 2018). As such, with the entrance of higher shares of offshore wind, the aggregate power supply curve will shift to the right and impact the market schedules by replacing thermal units. This could potentially result in a lower equilibrium price between supply and demand in the power market, an effect commonly known as the merit order effect. This will be further described in section 4.1. Secondly, offshore wind power depends on weather conditions rather than demand conditions (Unger et al., 2018). As such, there will not always be optimal wind conditions to generate power in line with the installed capacity. The Centre for Environmental Design of Renewable Energy (CEDREN), finds that there can even be operating hours where actual wind power generation only accounts for 2% of the installed capacity on the site (Charmasson et al., 2018). Thus, the intermittent nature of wind will create both uncertainty and variability in the short-term power supply.

The European and Nordic power market will need to adapt and encounter these challenges to successfully integrate offshore wind power. Thus, the need for grid developments and storage capacity to potentially decrease price sensitivity towards weather conditions will be of importance (Wind Europe, 2019).

2.3.1 The need for grid development in the Nordics

A robust power grid will enable offshore wind power and other renewable energy sources to enter the market (Statnett, 2019). As the intermittent nature of offshore wind will create price differences between and within countries, new grid capacity will benefit the power market. With a rapidly changing market, planning for grid development requires coordination to facilitate cross-border power flows. This implies development of both the onshore and offshore grid. In their long-term market analysis, Statnett (2020c) assumes a stepwise development of the offshore grid in the North Sea. The first step of the offshore grid development process is to connect the sites to the mainland grid (Statnett, 2020b). At the same time, Statnett (2020c) highlights the need to develop the onshore grid as transmission of power will be even more important when the wind conditions implies lower generation quantities. This will increase the socioeconomic surplus. In further steps of the grid development process one envisions the introduction of offshore hubs, which will imply independent offshore bidding areas where several countries can be connected (Statnett, 2020b).

However, it is important to emphasize that the immediate need for grid development within the Nordic countries comes from the transition towards renewable energy in general. The nuclear power plants that will be phased down are located in southern Sweden, whereas the new onshore wind power farms are located mainly in the northern part of Sweden, Finland and Norway (Statnett, 2019). Since the largest consumption centers are in the south, this strengthens the need for developments in the power flow from north to south. However, Statnett (2020c) expects offshore wind deployments of 45 TWh in Norway and Sweden by 2040. As these will mainly be located in the southern part, the expansion in power generation in the north will be somewhat compensated in the future (Statnett, 2020c; Swedish Wind Energy Association, 2019)

2.3.2 The value of flexible generation sources and storage capacity

Increasing shares of intermittent renewable energy sources causes more variability in the production as the generation is dependent on weather conditions. As consumption and production always must equal in the power system, this causes a higher need for balancing from controllable and flexible power generation, as well as energy storage (Charmasson et al., 2018). In contrast to wind- and solar power, where the resource must be utilized immediately to generate electric energy, water resources can be stored in hydropower reservoirs for later utilization. With the large storage capacity in Norwegian reservoirs of 85 TWh as of 2018, the flexibility in power supply plays an important role in the Nordic market (Nordic West Office, 2019). As the Norwegian and Swedish hydropower plants are already used as the main source for balancing the variable wind power generation in Denmark, their importance will further increase with the increasing shares of intermittent wind- and solar power in the future power markets.

Still, Statnett (2020c) states that the most important factor in balancing variable power generation in the future European power market will be adjustments in the demand. As they emphasize, the power market will need to transition from a system where the production adapts to consumption, to a system where the consumption adapts to the variable production from intermittent renewable energy sources. Thereafter, new energy storage possibilities, such as hydrogen and batteries, will play a part. As this thesis investigates the impacts of offshore wind generation in Norway using historical data, these possibilities will not be discussed further.

3 Litterature overview

In the following section, an overview of existing literature on the topic of this thesis will be presented. There is a wide range of academic work of interest on the integration of wind power from both Norway, the Nordics and Europe. First an introduction to current findings on integration of both onshore- and offshore wind power will be given. Then, relevant literature on hydropower will be presented and lastly, studies on the beneficial combination of hydro- and wind power will be reviewed.

3.1 Increasing shares of wind power in the generation mix

3.1.1 Onshore wind power

Førsund et al. (2008) studied the effects of integrating wind power in Finnmark County in Norway, by using EFI's Multi-area Power-market Simulator (EMPS)[1]. The region has many operating hours with constrained connections to the rest of the Nordic power market. By looking at two scenarios of 1500 GWh/year and 2500 GWh/year, they find that increasing the share of wind power leads to higher network congestion, lower hydropower production and a substantially lower price level in Northern Norway.

Cludius et al. (2014) studied the merit order effect of wind and photovoltaic electricity generation in Germany. Using time series regression analysis, they estimate that the merit order effect of wind on German spot prices from 2008 to 2012 were between -0.97 €/MWh to -2.27 €/MWh. In the period, the average hourly generation from wind power was between 4.4 GW and 5.8 GW. Looking at the minimum and maximum values of the wind power generation, the hourly production varied from 0 GW to 25.2 GW. They argue that higher merit order effects occur in times with high fuel and CO2 prices, as this indicates that the marginal costs of other generation sources are higher, resulting in a steeper merit order curve.

For the case of Western Denmark, Jónsson et al. (2010) looked into the effect of wind

[1]EMPS is the so-called "Samkjøringsmodellen" in Norwegian.

power forecasts on spot prices in the day-ahead market. At the time of the analysis, the pricing area (DK1) had the largest share of wind power in the world, accounting for more than 20% of the area's annual consumption. On average, the spot price was shown to decline with increased predicted wind power penetration. In addition, with the current market structure of marginal bidding, they found that with growing wind power generation, the frequency of hours with a spot price of zero increased. This implies increased price volatility, created by weather dependent patterns. Furthermore, they found that wind power penetration has some non-linear effects on prices, which indicate that it will not be accurate to scale the current market situation for analysing future impacts.

Spodniak et al. (2019) argues that as power generation moves towards having a higher share of variable renewable energy sources, the trading activity is shifting from the traditionally dominating day-ahead market to the intra-day and regulating markets. As such, they investigated price spreads in the day-ahead, intraday and regulating power markets in Denmark, Sweden and Finland from 2013 to 2017. Within these countries, they used the variation in shares of wind power in each bidding area to look at the effect on intraday and regulating markets. They found that in areas with a large share of wind power, making errors in forecasting affects all price spreads studied. On the contrary, in areas with modest levels of wind power forecasting errors have no statistically significant effect on price spreads. Overall, their results suggest that when increasing the shares of wind power, shorter term markets become more important.

For Great Britain, Green and Vasilakos (2009) studied how the generating capacity would change if large deployment of variable renewable energy sources was introduced. Their findings suggest that if all generators were to bid their marginal costs, the changes in generation mix are much larger than the changes in the distribution of prices over time. With extra wind capacity, the thermal generation capacity falls less than the increase in wind, such that the total capacity rises significantly. For the pattern of prices over time, they find relatively small changes from adding higher wind capacities. Moreover, they find that wind generation tends to be higher in high-demand hours than in low-demand hours on average.

3.1.2 Offshore wind power

Ederer (2015) did a simulation looking at onshore and offshore wind power with the objective of quantifying differences and looking into benefits of offshore wind. He studied the market value of offshore wind and found that even though the effect on spot prices for offshore and onshore wind are relatively equal, there is a difference between the two types of utilizing wind power in terms of variability imposed on the electricity spot market. As offshore wind tends to be steadier than onshore wind, risks of negative market prices, unwanted peaks and the need for increased reserve capacities are lower. Even though offshore wind has the drawback of higher levelized cost, it also has lower variability compared to onshore wind, which can be of compensation.

Leuthold et al. (2008) used a nodal pricing model to estimate the effect on German electricity prices when adding offshore wind energy to nodes in Northern Germany. Looking at the German market individually, they found an average nodal price decline of 10% when adding a capacity of 7.9 GW from offshore wind parks. In this scenario, the additional offshore wind capacity only affects the nodes in Northern Germany, whereas the nodes in Southern Germany are nearly unaffected. This results from the initial situation with a high level of congestion in the grid. Leuthold et al. (2008) also studies the effect of offshore wind parks in Northern Germany with an expanded market containing Denmark, France, Switzerland, Austria and the Benelux. Compared to the scenario of 7.9 GW, the average price decreases about 2.5% in the case of the extended grid and 13.3 GW of added offshore wind. Also in this case, they found that Northern Germany is affected the most by the added offshore wind. Moreover, they found that when adding wind capacity of 13.3 GW, prices in the Northern part of the Netherlands actually increased due to congestion on the interconnector between the Netherlands and Germany. Hence, they illustrate that adding offshore wind in Northern Germany can increase congestion both in Germany and in neighbouring countries.

3.2 Hydropower

Electricity spot prices exhibit seasonal patterns, price peaks and large volatility. Bühler and Müller-Merbach (2009) presents a model for how the spot prices depend on the deviation from the median reservoir water level, which will be described in section 4.2.

When looking at these two variables in the time period between 1999 and 2004, they found a correlation of -75.9%. This implies that when the water level is seasonally high, the spot price tends to be lower, and when the water level is seasonally low, the spot price tends to be higher.

Graabak et al. (2017) used an stochastic optimization and simulation model to assess how using Norwegian hydropower reservoir capacity for balancing power markets in Europe will impact Norwegian hydropower's production patterns, reservoir levels and water values. The analysis is based on 75 years of stochastic wind, temperature, solar radiation and inflow data. Their scenarios assume an initial reservoir capacity of 31 GW, increasing to 42 GW and 50 GW. The results show that the water values increase with higher reservoir capacity in all Norwegian regions. However, they emphasize that the calculation of water values are complex, and hence, the explanation for why the water values are changing is difficult to find. As for the aggregated reservoirs levels in the four regions they analyse, they find that the water values increase with greater capacity in three of the regions (VestSyd, Sorlandet and Telemark), whereas for the fourth region (VestMidt) it remains almost equal. Furthermore, for the average price year, the three capacity scenarios show significant changes in production patterns. Interestingly, it also indicates that the extra capacity in the reservoirs is not fully utilized. Moreover, when assuming large transmission capacities between Norway and Germany, the Netherlands, UK and France, they show that prices in these countries are reduced up to 20% in the case where the reservoir capacity is at 50 GW.

3.3 The benefits of combining wind and hydropower

Matevosyan et al. (2009) studied how one could tackle the uncertainty in wind power forecasts and showed the positive benefits of hydro- and wind power coordination. For the Norwegian and Sweden case, they found that congestion could be reduced with more coordination between wind- and hydropower generation. Due to hydropower reservoirs ability to delay the electricity generation in times of high wind power generation, overloads on the transmission system can be reduced. In periods with high wind power generation and low electricity prices due to the low marginal costs of wind, hydropower producers could lower their generation. In opposite situations when the wind generation is low, they could convert more of the water in the reservoirs into electric energy when prices are higher.

Hirth (2016) assesses the market value of power systems where hydropower plants with large reservoirs prevail. He uses the case of Sweden where hydropower supplies half the electricity demand and looks at how this opens for flexibility when taking wind power into account. His results imply that wind power can benefit from hydropower, as hydropower plants can compensate for the fluctuating output of offshore wind power. When increasing the share of wind power from 0% to 30%, he finds that 1 MWh of electricity from wind is worth 18% more in Sweden than in Germany. This is explained by the flexibility of hydropower in Sweden mitigating the value decrease by a third. The benefits of flexible hydropower do not increase after 20% share of wind power. Hirth (2016) also brings attention to the case of locating wind parks where net benefits are greatest. He suggests that wind parks should be located in areas where hydropower is present, as the reservoirs can contribute to a high value of wind power despite its variable nature.

The research project CEDREN HydroBalance (2013-2017) investigated the feasibility of using Norwegian hydropower for balancing and energy storage of the European energy system (Charmasson et al., 2018). As the Norwegian reservoir storage capacity already accounts for 50% of the total storage capacity in Europe, Norwegian hydropower has potential for providing significant parts of the flexibility needed in the future European power market. The research project's calculations show that with the forecasted increase in intermittent renewable energy sources in West-Central Europe by 2050, the region could have an hourly balancing need up to 300 GW in the months with the lowest production from wind- and solar power. Their simulations of the future European power market, with large shares of production from intermittent energy sources such as wind and solar, showed that increasing the hydropower capacity in Norway by 11-19 GW will significantly reduce the peak and average prices in neighbouring countries like Germany, the UK and the Netherlands.

4 Theory

This chapter will give a brief overview of the theoretic foundation for the thesis. Firstly, the merit order effect on prices will be explained. Then, the marginal cost of hydropower and its relationship to the seasonal water levels will be described. Lastly, the theoretical aspects of mitigating congestion will be explained, through the nodal and zonal pricing approaches, as well as the Net Transfer Capacity method.

4.1 The merit order effect

Electricity has become an essential part of our daily life and can be generated from several technologies with various marginal costs. This has implications for the market and the shapes of the supply and demand curves, as illustrated in figure 4.1.

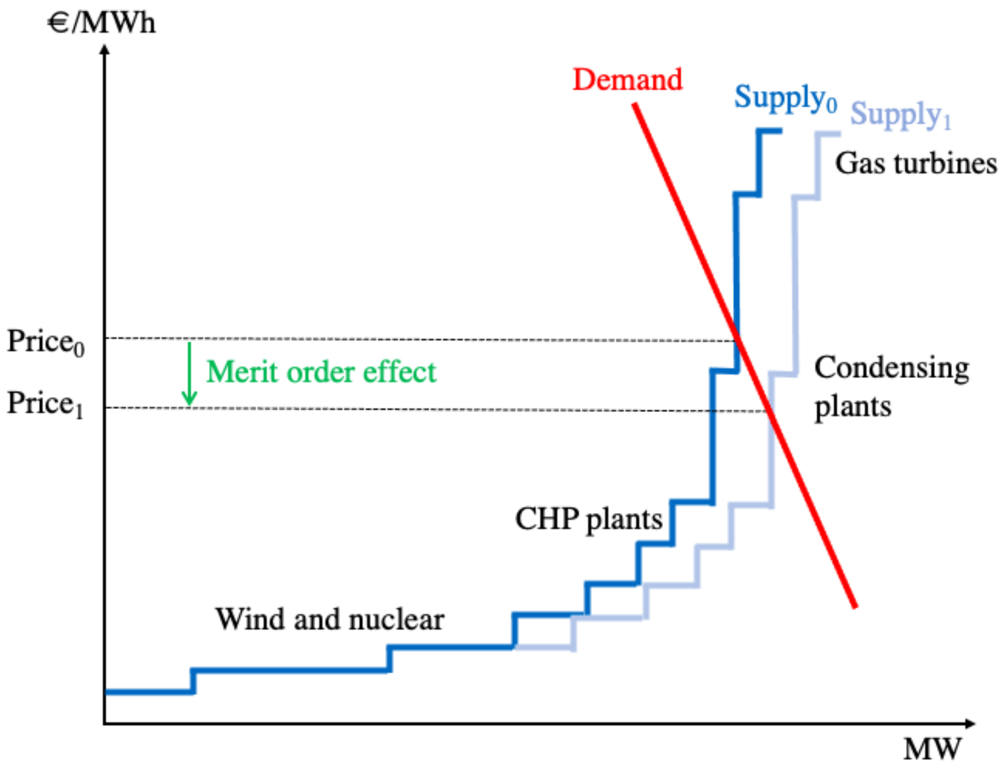

Figure 4.1: The merit order effect (EWEA, 2010).

In general, the ordering of supply bids from each producer depends on the volume supplied and to which marginal cost (EWEA, 2010). The curve presents the least expensive bids first and then the more expensive ones, reflecting both volume and cost. The result, as illustrated in figure 4.1, is a rising supply curve representing different types of generation technologies with various marginal costs. The figure uses a stepwise approach to make a theoretical illustration of the slope. There are several generation technologies constructing the supply bid curve, such as wind- and nuclear power, combined heat and power plants, condensing plants and gas turbines. As a result of having various power technologies, the shape of the supply curve will vary according to generation volumes offered within each price segment. This will have impacts on the power price. Another common source of electricity, not illustrated in the figure, is hydropower. As hydropower producers often have flexibility in when to generate power, their bids can be both in the lower and higher part of the supply bid curve depending on the value of water.

Electricity is considered a commodity to be traded (Kirschen, 2003). Consumers will demand electricity up to a certain level where the price they pay equals the marginal benefit they receive from consumption. A higher (lower) price will imply a lower (higher) demand. As such, the aggregate demand curve declines. The downward sloping demand curve is characterized by its inelasticity, since electricity is a necessity in today's society. This implies that in the case of electricity, changes in price makes for an almost unchanged demand (EWEA, 2010).

The steepness of the demand curve makes for changes in the supply curve to have significant impacts on the equilibrium between supply and demand. In a changing power market, the supply curve would potentially have another combination of generation volumes offered within each price segment. In light of the entrance of renewable energy sources, often with low marginal costs, the number of less expensive bids might increase, shifting the supply bid curve to the right, as illustrated in figure 4.1. As the least expensive bids are cleared before the more expensive ones, bids from producers with higher marginal costs would be replaced. As such, the intercept between supply and demand would shift, resulting in lower power prices. This result is commonly known as "The Merit Order Effect".

4.2 Marginal cost of hydropower and water reservoir level

Hydropower is generated in hydroelectric power plants, often located near rivers, streams or canals (Chakraborty et al., 2015). The idea behind this generation source is to utilize the energy from flowing water. Inside power stations, the water flow turns the turbine blades around creating mechanical energy which is transformed to electrical energy through a generator. One of the special features of this process is that the water used to generate electricity can be stored in reservoirs, making hydropower a flexible electricity generation source (Statkraft, 2020).

Through hydropower reservoirs, the water used to generate electricity today, can also be utilized tomorrow. As such, there exists a shadow price or an alternative cost associated with utilizing the water resource today (Førsund, 2015). This shadow price is referred to as the value of water. It depends on several factors, such as expectations for future demand and inflows of water, as well as the current water level in the reservoirs. The water levels exhibit a repeated pattern because of seasonal precipitations, as well as expected melting and freezing phases during the year (Bühler and Müller-Merbach, 2009). As such, the inflow varies to a large degree. This affects the flexibility characteristic of reservoirs, as there are limits to how low and how high the water levels can be. In the winter, when the water reservoir levels are low, the value of water is high and so are typically prices. In contrast, in the summer the water reservoir levels are higher and prices are typically lower, as the value of water is low (Botterud et al., 2002). Ultimately, the value of water determines how much the hydropower generators will choose to supply.

Using a dynamic equilibrium model one can show that there exists a relationship between the seasonal fluctuations in the water reservoir level and the electricity spot price (Bühler and Müller-Merbach, 2009). Assumptions of a competitive market, where the spot price is equal to the marginal cost, and an exponential marginal cost function are made. The water reservoir level is assumed to exhibit a deterministic pattern. However, deviations from the median, or expected, seasonal water reservoir level will occur. To avoid water shortages and failure to deliver on obligations, the hydropower producers will meet deviations from the expected seasonal water level with an immediate reduction or extension of the generation in the hydropower plant. The objective is to level the total upcoming production.

Since deviations from the median seasonal water level will cause changes to the water value, the deviations will have implications for the marginal cost of hydropower generation. The adjustment to the marginal cost function is defined by D^*, which is referred to as the reservoir corrected production quantity of electricity:

$$D_t{}^* = D_t + \gamma^* WRD_t \tag{4.1}$$

D_t denotes the produced quantity of electricity with no deviations from the median water level, whereas WRD_t denotes the difference between the median water reservoir level and the actual. The parameter γ^* translate the WRD_t into additional or reduced production capacity. If WRD_t is positive the actual water level is lower than the median, and there is a lack of stored potential energy. This translates into missing production capacity.

The marginal cost function is defined as:

$$C'(D_t) = exp(c_0 + c_1 D_t + \gamma WRD_t), \qquad \gamma = \gamma^* c_1 \tag{4.2}$$

The relationship between the deviation from the median water level and the marginal cost of hydropower is illustrated in figure 4.2. The y-axis represent the marginal cost, $C'(D_t)$, and the x-axis represent the reservoir corrected production quantity, D^*.

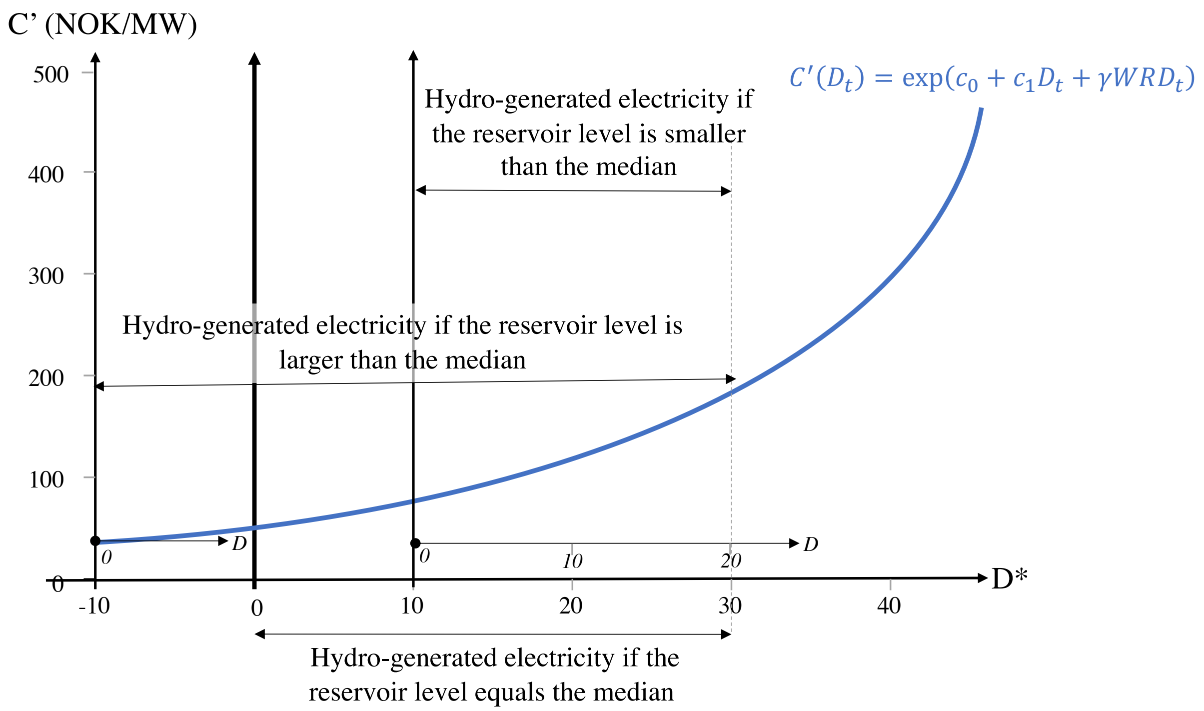

Figure 4.2: Relationship between the deviations from the median seasonal water reservoir level and the marginal cost of hydropower (Bühler and Müller-Merbach, 2009).

When the water reservoir level is above the median, the reservoir corrected production quantity, D^*, will be lower than the production quantity with median seasonal water level. This results in a lower marginal cost than obtained if the water level had been equal to the median. Opposite, if the water level is below the median, D^* will be higher, and the marginal cost will be higher. The figure shows how the marginal cost of hydropower will depend on the deviation from the median water reservoir level.

4.3 Congestion management

In the day-ahead market clearing procedure, each bidding area has its own set of supply and demand curves (Nord Pool Group, 2020d). As generation and consumption differs between bidding areas, transmission of power is necessary to meet demand. However, because of the physical limitations in the grid, the power flow could be prevented, causing price differences between bidding areas. This is referred to as congestion, which describes situations where the volume needed to meet demand is bottlenecked as a result of constrained transmission capacity in the grid. To mitigate such bottlenecks and to utilize the transmission capacity efficiently, congestion management is of importance (Androcec and Wangensteen, 2006). In the short term, the main objective of congestion management is to utilize the network capacity and the generation resources to maximize total welfare. In addition, congestion management aims to provide incentives for investments in the transmission network and generation capacity in the areas of need, and to manage risk reducing the uncertainty of trading electricity between countries.

4.3.1 Nodal and zonal pricing approaches

There are several methods attempting to mitigate congestion (Unger et al., 2018). The applied congestion management method in Europe and the Nordic countries today is zonal pricing (Tosatto and Chatzivasileiadis, 2019). As Leuthold et al. (2008) uses a nodal pricing model, and their results will be discussed in chapter 6, a brief introduction to nodal pricing will be given before looking into zonal pricing in more detail.

The nodal pricing approach defines each node in the grid as a single price zone (Leuthold et al., 2008). A node is a physical location on the transmission network. The price at each node reflects the location value of energy and is determined by matching offers from generators to bids from loads. This process takes place at specific time intervals at both input and exit nodes in the grid. Furthermore, the nodal prices may reflect both losses and constraints in the system. In accordance with the required security of the system, generators are dispatched by the TSO. Nodal pricing is said to be a more transparent reflection of the actual situation in the grid as it accounts for allocation signals between nodes.

In the zonal pricing approach, the market is divided into geographical bidding areas (price zones), with each of them being connected to other bidding areas through cross-border transmission connections (Zalzar et al., 2020). As each bidding area represents an aggregation of nodes with a uniform price, intra-zonal congestion is neglected under this price scheme (Bjørndal et al., 2013). Thus, zonal pricing is viewed as a simplification of nodal pricing. As the representation of the simplified transmission network can differ, several versions of the zonal pricing scheme can be considered.

4.3.2 Zonal pricing with Net Transfer Capacity

As of the fall of 2020[2], the applied congestion management method in the Nordic countries is zonal pricing with Net Transfer Capacity (NTC) (Nordic RSC, 2018). This method involves two stages, i) a day-ahead market stage, and ii) either a re-dispatch, market splitting, or counter-trading stage (Bjørndal et al., 2017). Prior to the first stage, the TSOs determine the NTCs between bidding areas. In the first stage, the market price in each area is calculated and the power flow between bidding areas is only constrained by the NTC values (Sarfati et al., 2019). Since the inter-zonal NTC values are approximated and the transmission constraints within bidding areas are ignored, some transmission lines may be overloaded. Thus, in the second stage, these lines need to be relieved. If the transmission capacity between bidding areas is not adequate to reach full price convergence, price differences between bidding areas will occur.

The NTC value represents the maximum potential transmitted capacity between two bidding areas and is submitted by the TSOs on an hourly basis for the next day in the day-ahead market (Ruksans et al., 2014). The capacities, which are set for both directions

[2] In light of the Commission Regulation (EU) 2015/1222 of 24 July 2015 on establishing a guideline on Capacity Allocation and Congestion Management (CACM), the Nordic TSOs have proposed to implement a Flow Based capacity calculation approach for the day-ahead market timeframe (Nordic RSC, 2018).

of the connection by the TSOs, are based on historical data, possible loop flows, seasonality and a security margin (Leuven, 2015). The capacity calculation is a legal obligation for the TSOs (Statnett, 2020a).

The Net Transfer Capacity (NTC) is defined as the Total Transfer Capacity (TTC) less the Transmission Reliability Margin (TRM), and can be represented by the following equation:

$$NTC = TTC - TRM \tag{4.3}$$

The TTC is the maximum exchange capacity that is compatible with the operation security standards at each system (Ruksans et al., 2014). Thus, it is the maximum amount of power transferred between two systems without any network constraints if the future network condition was known in advance. The calculation of TTC is done by coordinating network models taking into account a wide range of operational parameters, where three of these will be amplified (Nord Pool Group, 2020m). Firstly, there are thermal limits, which are based on heating of conductors of the transmission overhead lines, resulting in a maximal current to avoid damage on components. Secondly, there are voltage limits, which are based on international standards trying to avert cases such as blackouts. Thirdly, there are stability limits, to prevent collapses in the largely interconnected system. Still, there are uncertainties associated with the computation of TTC values since they are calculated for the future based on historical parameters and values (Nord Pool Group, 2020m). Such uncertainties can arise from deviations in the physical flow of electricity during operations, power exchanges between the TSOs due to unexpected imbalances in real-time, or inaccurate data collection and measurement. The Transmission Reliability Margin (TRM) adjusts the TTC for such uncertainties. The TRM on each connection is agreed upon in the System Operation Agreements.

The NTC value is found by subtracting the TRM from the TTC (Nord Pool Group, 2020m). Thus, the NTC is the maximum capacity that can be transmitted between two areas compatible to the security standards, taking into account the uncertainties for the future network conditions.

4.4 The European grid

As of today, the European electricity transmission and distribution network largely consists of Alternating Current (AC) cables (Europacable, 2020b). On AC cables, the flow of electrons can go in both directions and the directions change on a regular basis (GreenFacts, 2020). In Europe the standard current is 50 cycles per second. Another type of current is a Direct Current (DC), an electrical current which only flows in one direction.

For transporting power over longer distances, high voltage direct current (HVDC) transmission lines are often used (Europacable, 2020b). There are two types of HVDC land transmission technologies. The first one carries high power over 200 kilometres through overhead lines, while the second one carries medium to high power over 50 kilometres through underground lines. The technologies can be combined and require a small number of cables. The HVDC technology has also been applied in the subsea cables systems, transferring electricity from wind farms or connecting offshore platforms to the European grid (Europacable, 2020a).

5 Methodology

In this chapter, the methodology used to approach the research question of how offshore wind on the Norwegian continental shelf will impact the Nordic power market will be presented. The offshore wind sites studied are Sørlige Nordsjø II and Utsira Nord. The chapter will bring attention to the reasoning behind the choice of operating hours and show an overview of the applied solution model of the Nordic power market. A particular focus will also be placed on the processing of data and the modelling approach.

5.1 Choice of operating hour

Since hydropower accounts for 95% of the Norwegian electricity production (SSB, 2019), the hydrological situation in Norway plays a crucial part in determining power prices. As such, the operating hours chosen to model the effect of offshore wind capacity from Sørlige Nordsjø II and Utsira Nord are based on the hydrological situation. To evaluate this, data on water levels in the Norwegian hydropower reservoirs from NVE (2020) were used. The water levels vary considerably both within and between years. Moreover, high and low water levels do not necessarily imply different generation from the hydropower producers. An important factor in determining the generation from hydropower producers is the value of water. As this is the alternative cost of using the the water resource for generation today, it depends on forecasts of future consumption and precipitation patterns, as well as the water levels in the reservoirs. Since forecasts of future consumption and precipitation patterns are greatly affected by the time of year, the three chosen operating hours are on the same day and month. The reasoning being that differences in the value of water will mainly be caused by the fluctuations in seasonal water levels. However, it is important to emphasize that the actual water values the hydropower producers calculated for the three specific operating hours were not available.

For all three operating hours chosen the date is set to 28th of September. This is typically a time where the water level is at its highest. Since Nord Pool only has bid curves published as of 2014, the chosen operating dates are after this point. Table 5.1 shows that the water level on 28th of September in the years between 2014 and 2019 have similar statistics as in the years between 2000 and 2019. However, the minimum observation is much lower for the extended period. For the period between 2014 and 2019, the chosen operating dates represent the minimum, average and maximum water levels. Thus, the chosen operating dates are 28th of September 2018, 2017 and 2015. Table 5.2 highlights the water levels for these three dates.

Years	**Min.**	**1st Qu.**	**Median**	**Mean**	**3rd Qu.**	**Max.**
2000-2019	62.25 %	77.92 %	82.52 %	82.31 %	89.16 %	93.96 %
2014-2019	76.82 %	79.38 %	82.73 %	83.27 %	85.45 %	92.72 %

Table 5.1: Descriptive statistics of water reservoir levels in week 39 (NVE, 2020).

Water levels in the reservoirs	
Low seasonal water level (28/09/2018)	76.82%
Average seasonal water level (28/09/2017)	83.12%
High seasonal water level (28/09/2015)	92.72%

Table 5.2: Water levels in the reservoirs on the chosen operating hours (NVE, 2020).

The chosen operating hour of the day is between 07:00 AM and 08:00 AM for all dates. This is an hour with relatively high private consumption of electricity.

5.2 Solution model for the Nordic electricity market

To calculate the impact on power prices with additional capacity from Sørlige Nordsjø II and Utsira Nord, an optimization model is solved. The model contains the following variables and parameters:

Sets

$i, j \in Z$	Set of price zones
$l \in L$	Set of consumer bids
$p \in P$	Set of producer bids
$L^i \subseteq L$	Consumer bids in zone i
$P^i \subseteq P$	Producer bids in zone i

Parameters

a_p^S	Constant term for supply bid curve

b_p^S	Slope of supply bid curve
$\overline{Q}_p^S$	Generation (MW) upper bound
a_l^D	Constant term for demand bid curve
b_l^D	Slope of demand bid curve
$\overline{Q}_l^D$	Consumption (MW) upper bound
$\overline{ntcmax}_{ij}$	NTC maximum from zone i to zone j
$\overline{ntcmin}_{ij}$	NTC minimum from zone i to zone j

Positive variables

Q_p^S	Quantity (MW) supplied by producer p
Q_l^D	Quantity (MW) consumed by consumer l

Variables

NI_i	Net injection quantity (MW) in zone i
F_{ij}	Power flow from zone i to zone j

The supply and demand bid curve parameters for each zone are based on the system price bid curves retrieved from the Nord Pool Group (2020o). The maximum and minimum net transfer capacities between price zones are retrieved from Nord Pool Group (2020e).

The market clearing solution in the model is found by maximizing the social economic welfare subject to several constraints. The optimization problem is based on the zonal NTC model used by Brose and Haugsbø (2019). The optimization problem is defined as:

Objective function:

$$max \sum_p (a_p^S \cdot Q_p^S - 0.5 \cdot b_p^S \cdot (Q_p^S)^2) - \sum_l (a_l^D \cdot Q_l^D + 0.5 \cdot b_l^D \cdot (Q_l^D)^2) \tag{5.1}$$

Subject to:

$$\sum_i NI_i = 0 \tag{5.2}$$

$$0 \leqslant Q_p^S \leqslant \overline{Q}_p^S \qquad \forall p \tag{5.3}$$

$$0 \leqslant Q_l^D \leqslant \overline{Q}_l^D \qquad \forall l \tag{5.4}$$

$$\overline{ntcmin}_{ij} \leqslant F_{ij} \leqslant \overline{ntcmax}_{ij} \qquad \forall i, j \tag{5.5}$$

$$NI_i = \sum_{p \in P^i} Q_p^S - \sum_{l \in L^i} Q_l^D \qquad \forall i \tag{5.6}$$

$$NI_i - \sum_{j \neq i} F_{ij} = 0 \qquad \forall i \tag{5.7}$$

The optimization problem was solved using the optimization software GAMS, as an NLP optimization problem with the MINOS solver.

5.3 Data sources and implementation

The market players in the Nordic power market are relatively restrictive in their data sharing procedures. As such, the availability of data has created a need for some simplifications relative to the market clearing algorithm used at Nord Pool.

5.3.1 Disaggregation of bid curves

The system bid curves includes a large number of data points. To decrease the computation time of the model parameters and the optimization problem, the number of data points was reduced by approximately 77% and 82% for the supply and demand curves. As the objective was to not affect the shape of the system bid curves, points with both similar price and quantity were removed. The impact on the shapes of the supply and demand curves is considered marginal.

Nord Pool only publishes bid curves for the aggregated load demanded and capacity supplied in the entire Nord Pool area. As the bids must be allocated to each pricing area, a disaggregation of the system price curves has been completed to further utilize the data. There are several approaches to do a disaggregation, which all have different implications for the precision of the model. The disaggregation method in this thesis is to use the production and consumption shares in each bidding area for the respective operating hours. Figure 5.1 illustrate the proportional shares of the Nordic bidding areas for one of the operating hours. A table of the production and consumption shares for the three specific operating hours can be found in Appendix A1.

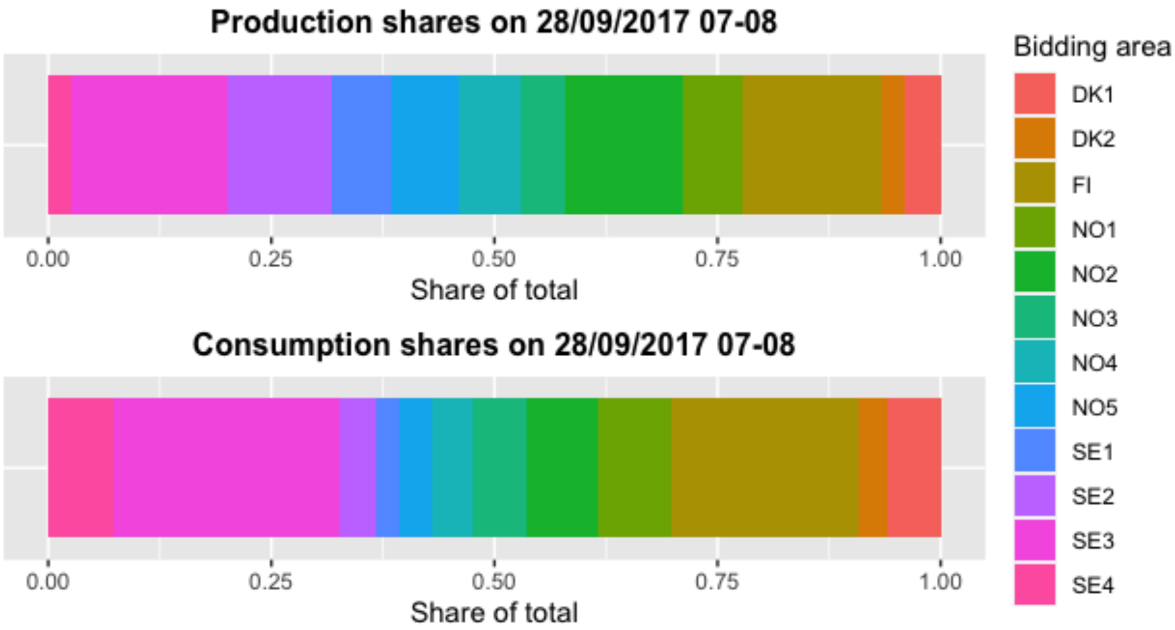

Figure 5.1: Production and consumption shares for the Nordic bidding areas on 28/09/2017 07-08 AM.

One of the main issues with the disaggregation method described above is that each bidding area will have the same price sensitivity. Various generation sources have different price sensitivities and marginal costs, and the differences in generation sources in each bidding area will in reality affect the shape of the supply curve. As seen in figure 5.2, the disaggregation method used implies that all bidding areas have the same relative price sensitivity. Thus, it is important to emphasize that the supply curves for each bidding area used in the model are simplifications of the actual supply curves for the three operating hours.

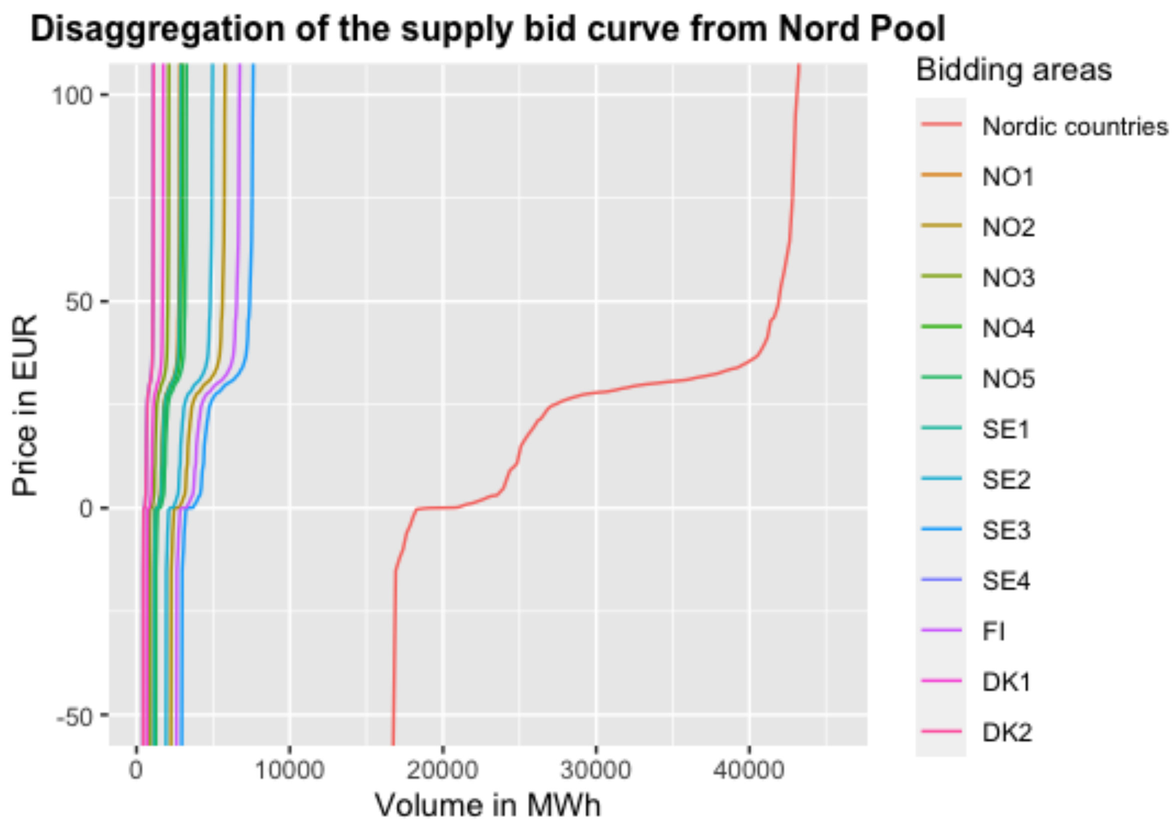

Figure 5.2: Disaggregation of supply bid curves, illustrating with 28/09/2017 07-08 AM.

5.3.2 Network and power flow constraints

For the transmission capacity constraints between bidding areas, data on the maximum and minimum NTC values for each connection is used (Nord Pool Group, 2020e,h). These are the same capacity constraints used in the day-ahead market coupling algorithm at Nord Pool. In the model, AC and HVDC connections are modelled similarly. Figure 5.3 shows the connections between bidding areas in the model.

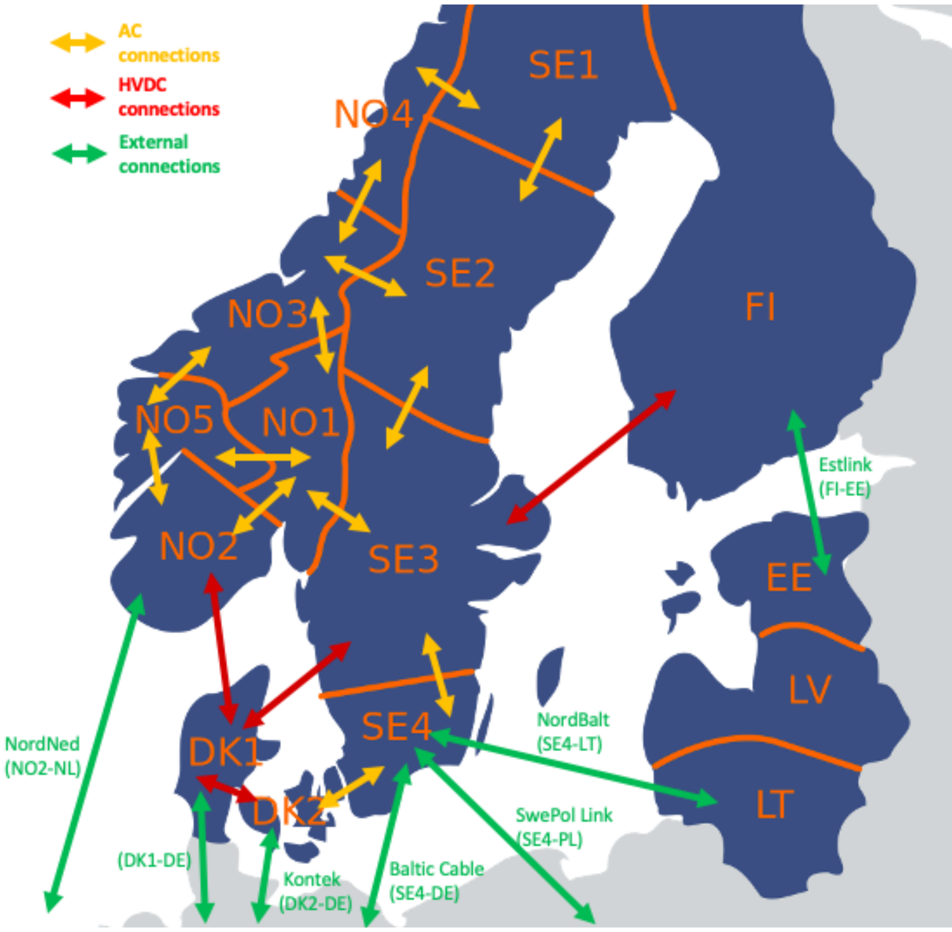

Figure 5.3: Connections between bidding areas in the model.

Since the model is restricted to the Nordic countries, bids from external bidding areas connected to the Nordic countries are not modelled. Thus, in all simulations the power flow on the green connections in figure 5.3 is equal to zero. As the system price bid curves do not account for import and export, a manual adjustment has been done by using the exchange connections data retrieved from the Nord Pool Group (2020g). For example, for the operating hour on 28/09/2017, the power flow from DK1 to Germany was -376 MW, implying that DK1 received power from Germany. To adjust for this, 376 MW is added to the supply curve in DK1. In bidding areas that exported power to other bidding areas outside the Nordic countries, the adjustment was done by removing megawatts in the supply curve. It should be highlighted that the basis for the adjustment was the actual flows appearing on the operating hour and not the market coupling flows from the Nord Pool Group (2020f). However, comparing the market coupling flows from Nord Pool and the power flows from the simulation model without adding offshore wind, the flows aligns well. For the three operating hours, the model simulated the same flows as the market coupling flows in minimum 84% of the cases.

5.3.3 Adding electricity from offshore wind

To simulate power prices with offshore wind from Sørlige Nordsjø II and Utsira Nord, the added capacities are based on the estimated deployment scenarios from NVE (2012) and mail correspondence with their Energy Department to receive up to date estimates for both small and large deployment at each site. These estimates are shown in table 5.3.

	Small deployment	**Large deployment**
Sørlige Nordsjø II	1008 MW	3000 MW
Utsira Nord	504 MW	1512 MW

Table 5.3: Estimated deployments for Sørlige Nordsjø II and Utsira Nord (NVE, 2012).

The estimates for the two deployment scenarios are based on turbines with a maximal installed capacity per turbine of 10 MW and a given number of turbines at each site. A more detailed explanation of the calculations are given in Appendix A2.

According to Statnett (2020b) the first step in integrating offshore wind farms is to connect the two sites to the mainline grid. As such, the capacity from deployment at Sørlige Nordsjø II and Utsira Nord is assumed to be connected directly to the Norwegian mainline grid. Specifically, capacity from offshore wind is added to the supply bid curves from Utsira Nord in NO5 and from Sørlige Nordsjø II in NO2, to a marginal cost of zero. This implies that potential negative bids resulting from subsidies are not taken into account. As explained in section 5.3.2, whether it is a HVDC cable or an AC cable that is used to connect the sites to the mainland grid will not affect the model implementation.

For all operating hours small and large deployment scenarios are modelled both individually to each site, as well as to both sites at the same time. The added capacity is assumed to be equal to the installed capacity. This implies that a capacity factor equal to 1 is assumed. However, according to Energiomstilling Vest (2020) the capacity factor for offshore wind is typically at 0.5. This implies that only half of the full capacity over the year will be utilized to generate electric energy. As such, the magnitude of the price decline for the respective capacities from the estimated deployment scenarios represent what could happen in hours where the utilization of the wind farms is at its maximum. Therefore, scenarios with only half of the estimated deployment capacities are also modelled. These scenarios can be said to represent hours where the utilization of the installed offshore wind capacity is only 50%. In addition, scenarios with added capacity in intervals of 500 MW up to 4500 MW for each site are also modelled.

6 Simulation Results and Discussion

This chapter will present and discuss the simulation results from the modelled scenarios of the Nordic power market with and without offshore wind generation in Norway. Firstly, a comparison of the simulated prices from the baseline scenarios without added offshore wind generation and the actual Elspot prices will be made. Then, the magnitude of the volumes of offshore wind power added to the baseline scenarios will be discussed and the simulation results when including wind power will be presented. Thereafter, main findings will be highlighted and discussed. In particular, a closer look will be given to the descending price trend, the impacts and implications on congestion in the grid, and lastly the changes in generation among the affected bidding areas.

6.1 Baseline scenarios

The operating hour on the 28th of September is characterized by its higher water levels in the hydropower reservoirs compared to other seasons. Even so, seasonal variations can cause water levels in the reservoirs to fluctuate for the same time period between years. The three chosen baseline scenarios represent and illustrate this within season variation and its effect on power prices. The operating hours in 2018 and 2015 represent days with abnormally low and high seasonal water levels when compared to the same date in other years. The average seasonal water level is represented by the operating hour in 2017. Table 6.1 compares the actual Elspot prices with the baseline prices resulting from the simulation model of the Nordic power market.

	Low water level (28/09/2018)		**Average water level (28/09/2017)**		**High water level (28/09/2015)**	
	Elspot prices	Baseline prices	Elspot prices	Baseline prices	Elspot prices	Baseline prices
DK1	44.44	44.55	34.61	35.48	53.33	54.80
DK2	44.44	44.55	49.21	49.57	53.33	54.80
FI	70.47	70.63	45.96	46.76	58.02	59.75
NO1	44.44	44.55	30.57	31.56	15.12	15.46
NO2	44.44	44.55	30.57	31.56	15.12	15.46
NO3	44.44	44.55	34.61	35.48	20.71	20.93
NO4	44.44	44.55	31.13	35.48	20.71	20.93
NO5	44.44	44.55	30.57	31.56	15.12	15.46
SE1	44.44	44.55	34.61	35.48	20.71	20.93
SE2	44.44	44.55	34.61	35.48	20.71	20.93
SE3	44.44	44.55	34.61	35.48	20.71	20.93
SE4	44.44	44.55	34.61	35.48	20.71	20.93

Table 6.1: Elspot prices and simulated baseline prices (in €/MWh).

Looking at the table, prices for the three operating hours have different degrees of price convergence. The average (2017) and high (2015) seasonal water level scenarios, have baseline prices that vary to a large degree between bidding areas. These differences in prices are caused by limitations in the transmission capacities between bidding areas, preventing price convergence between certain areas. In contrast, the low (2018) seasonal water level scenario have similar prices for all bidding areas expect for Finland. In fact, the price in Finland stands out in all operating hours caused by a deficit in the power balance. This results in the power flows from SE1 and SE3 to Finland to be constrained. The combination of low nuclear power generation and constrained connections from Sweden causes Finland to be decoupled from the other Nordic bidding areas.

Overall, simulated baseline prices for all three operating hours appear to align fairly with the actual Elspot prices. The exception is the 2017 price in NO4. In contrast to the actual Elspot price of 31.13 €/MWh, the simulated price of 35.48 €/MWh is equal to the price in the Swedish bidding areas, NO1, NO2 and DK1. In the market coupling algorithm at Nord Pool, all connections from NO4 to other bidding areas was constrained in the hour. In particular, the maximum amount of power, given by the NTCs, was transmitted from NO4 to NO3, SE1 and SE2. This is also the case in the simulated model except for the power flow from NO4 to SE1 which was not constrained. This enabled price convergence between NO4 and other bidding areas, and is likely caused by the disaggregation method used. Nonetheless, by comparing the market coupling flows and the baseline flows from the simulation model, it becomes apparent that NO4 would not be affected by adding offshore wind in NO2 or NO5 in this specific operating hour.

Moreover, table 6.1 also illustrates the relationship between water levels and power prices in hydropower dominated bidding areas found by Bühler and Müller-Merbach (2009). Taking the deviation from the median seasonal water level and the baseline prices in the hydropower dominant bidding areas in table 6.1, a correlation coefficient of -98.5% is calculated. In comparison, when looking at the period between 1999 and 2004, Bühler and Müller-Merbach (2009) found a correlation between the deviation from the median seasonal water level and the spot price of -75.9%. Thus, in accordance with their findings, the baseline prices in this thesis vary according to water levels. With high seasonal water levels the baseline prices in Norway and Sweden lie between 15 €/MWh and 21 €/MWh, which is lower than the prices for the median (average) seasonal water level at around 31 €/MWh to 36 €/MWh. In contrast, with a low seasonal water level the prices are around 44 €/MWh, which is higher than the median water level prices.

6.2 Offshore wind in the model

The implementation of offshore wind from Sørlige Nordsjø II and Utsira Nord is modeled by adding generation bids with a marginal cost of zero to the supply curves in NO2 and NO5. NVE has estimated two scenarios for deployment at Utsira Nord and Sørlige Nordsjø II. With small and large deployment at Sørlige Nordsjø II, they estimate an installed capacity of 1008 MW and 3000 MW. At Utsira Nord their estimates are lower with an installed capacity of 504 MW and 1512 MW. For all operating hours, small and large deployment on each site are modelled, both individually and for both sites at the same time.

A small deployment at both sites would imply a total installed offshore wind power capacity of 1512 MW. This translates to 8.4%, 10.0% and 11.1% of the initial Norwegian generation without wind for the low- (2018) , average- (2017), and high (2015) seasonal water level scenarios. Furthermore, in all three scenarios, small deployment at both sites accounts for around 3.6% of the Nordic generation. With a large deployment at both sites a total wind power capacity of 4512 MW is installed. This accounts for 25.0%, 29.9% and 33.0% of the Norwegian baseline generation in the low-, average- and high seasonal water levels scenarios. In the Nordic context, this translates to approximately 10.5% of the generation in all scenarios. As both the magnitudes of small and large deployment can be considered substantial in light of total generation volumes, changes in power prices are expected.

In comparison, according to NVE's (2012) estimated service time at Utsira Nord and Sørlige Nordsjø II, large deployment at both sites will result in a yearly production equal to 19.2 TWh[3]. This accounts for approximately 13.0% of the yearly Norwegian generation, and 4.0% of the aggregated Nordic production. The same shares for small deployment at both sites are around 4.5% of the Norwegian generation and 1.4 % of the Nordic generation. Thus, the estimates of yearly power production from the two sites are lower than for the specific operating hours studied in this thesis. This can be explained by the assumption that generation from both sites is equal to the installed capacity. In reality, the actual wind power generation will vary depending on the wind speed. In particular, the estimated service time from NVE (2012) assumes that the actual production will only equal 49.5% and 46.9% of the installed capacity over the year for Sørlige Nordsjø II and Utsira Nord, respectively. As such, the scenarios using the installed capacity estimates from NVE, represent price impacts that could happen in operating hours where the wind production is at its highest. However, as the wind speed is not always optimal, and downtime or repairs on the turbines could occur, the actual production will in many hours be less than the installed capacity.

The tables below present the simulated results when adding capacities based on small- and large deployment of offshore wind power from the two sites[4]. Depending on the utilization of the wind farms, the tables also show the results from adding 50% of the deployment estimates to illustrate effects on prices with suboptimal wind conditions. The tables will only present the bidding areas where prices are affected by the added offshore wind power capacities.

[3]Calculations of the service time can be found in Appendix A2.

[4]Tables of all modelled scenarios, including the ones for small and large deployment on both sites at the same time, can be found in Appendix A3.

6.2.1 Deployment at Sørlige Nordsjø II

Low seasonal water level (28/09/2018) - Sørlige Nordsjø II					
		Small deployment (1008 MW)		Large deployment (3000 MW)	
	Baseline prices	50% utilization	Installed capacity	50% utilization	Installed capacity
DK1	44.55	43.41	41.29	38.91	25.01
DK2	44.55	43.41	42.77	42.77	42.77
FI	70.63	70.63	70.63	70.63	70.63
NO1	44.55	43.41	41.29	38.91	25.01
NO2	44.55	43.41	41.29	38.91	25.01
NO3	44.55	43.41	42.77	42.77	42.77
NO4	44.55	43.41	42.77	42.77	42.77
NO5	44.55	43.41	41.29	38.91	25.01
SE1	44.55	43.41	42.77	42.77	42.77
SE2	44.55	43.41	42.77	42.77	42.77
SE3	44.55	43.41	42.77	42.77	42.77
SE4	44.55	43.41	42.77	42.77	42.77

Table 6.2: Simulated prices (in €/MWh) for low seasonal water level on 28/09/2018 07-08 AM with capacities added from Sørlige Nordsjø II to NO2.

Table 6.2[5] shows the price impact from adding offshore wind capacities to the low seasonal water level scenario. The results show that in the case of 50% utilization of installed capacity with small deployment the prices decline by 1.14 €/MWh in every bidding area except for Finland. Moreover, with increasing levels of capacities the prices in DK1, NO1, NO2 and NO5 are to a larger degree affected and decline more than other affected bidding areas. With the highest installed capacity of 3000 MW and 100% utilization, prices in NO2, where the wind capacity is added, declines by 43.85%. This represent a substantial price decline of almost 20 €/MWh.

[5]The 50% utilization of large deployment of 3000 MW at Sørlige Nordsjø II scenarios are modelled with 1512 MW. More accurately this represent 50.4% of 3000 MW.

Average seasonal water level (28/09/2017) - Sørlige Nordsjø II					
		Small deployment (1008 MW)		Large deployment (3000 MW)	
	Baseline prices	50% utilization	Installed capacity	50% utilization	Installed capacity
NO1	31.56	30.55	29.76	28.42	18.83
NO2	31.56	30.55	29.76	28.42	18.83
NO5	31.56	30.55	29.76	28.42	18.83

Table 6.3: Simulated prices (in €/MWh) for average seasonal water level on 28/09/2017 07-08 AM with capacities added from Sørlige Nordsjø II to NO2.

In contrast to the low seasonal water level scenarios, table 6.3 show that only the baseline prices in NO1, NO2 and NO5 are affected by the added offshore wind capacities in the scenarios with the average seasonal water level. Interestingly, with 50 % utilization of the small deployment scenario, the prices in these areas only decrease by 1.01 €/MWh. In comparison, the price decline for the low seasonal water level was 1.14 €/MWh. On the contrary to what might be expected, this illustrates that adding the same volumes of offshore wind capacities do not necessarily imply a higher absolute price decline when fewer bidding areas are affected. Moreover, the price declines by 12.73 €/MWh when adding 3000 MW to NO2. This implies a relative price change of 40.33%, which is of somewhat similar magnitude as when adding the same volume for the low seasonal water level scenario.

High seasonal water level (28/09/2015) - Sørlige Nordsjø II					
		Small deployment (1008 MW)		Large deployment (3000 MW)	
	Baseline prices	50% utilization	Installed capacity	50% utilization	Installed capacity
NO1	15.46	13.71	11.79	9.85	2.45
NO2	15.46	13.71	11.79	9.85	2.45
NO5	15.46	13.71	11.79	9.85	2.45

Table 6.4: Simulated prices (in €/MWh) for high seasonal water level on 28/09/2015 07-08 AM with capacities added from Sørlige Nordsjø II to NO2.

Table 6.4 shows the price impacts on the baseline prices with high seasonal water level. Similarly as in the average seasonal water level scenario, only NO1, NO2 and NO5 are affected by the added offshore wind capacities in these scenarios. For 50% utilization of small deployment, prices in these bidding areas decrease by 1.75 €/MWh, whereas they decrease by 13.01 €/MWh for full utilization of large deployment. This makes the absolute price decline only marginally higher in the high water level scenario compared with the average water level scenario. However, due to lower initial baseline prices, the relative magnitude of these price changes is much higher. In particular, the price decline in this case is twice as high as for the similar scenarios with low and average water levels. For large deployment and full utilization, the new price of 2.45 €/MWh implies a price reduction of 84.15%.

6.2.2 Deployment at Utsira Nord

Low seasonal water level (28/09/2018) - Utsira Nord					
		Small deployment (504 MW)		Large deployment (1512 MW)	
	Baseline prices	50% utilization	Installed capacity	50% utilization	Installed capacity
DK1	44.55	44.13	43.41	42.78	38.91
DK2	44.55	44.13	43.41	42.78	42.77
FI	70.63	70.63	70.63	70.63	70.63
NO1	44.55	44.13	43.41	42.78	38.91
NO2	44.55	44.13	43.41	42.78	38.91
NO3	44.55	44.13	43.41	42.78	42.77
NO4	44.55	44.13	43.41	42.78	42.77
NO5	44.55	44.13	43.41	42.78	38.91
SE1	44.55	44.13	43.41	42.78	42.77
SE2	44.55	44.13	43.41	42.78	42.77
SE3	44.55	44.13	43.41	42.78	42.77
SE4	44.55	44.13	43.41	42.78	42.77

Table 6.5: Simulated prices (in €/MWh) for low seasonal water level on 28/09/2018 07-08 AM with capacities added from Utsira Nord to NO5.

The price impacts when adding capacities from Utsira Nord to NO5 in the low seasonal water level scenario are presented in table 6.5. As seen, all bidding areas expect for Finland are affected with the same marginal price decline up to an installed capacity of 750 MW, representing 50% utilization of large deployment[6]. After this point, only prices in DK1, NO1, NO2 and NO5 continues to decline. This results from the additional offshore wind

[6]The 50% utilization of large deployment of 1512 MW at Utsira Nord scenarios are modelled with 750 MW. More accurately this represents 49.6% of 1512 MW.

generation preventing further power flow from these areas. With full utilization of an installed capacity of 1512 MW, the prices in these bidding areas decline by 5.64 €/MWh, representing a relative price reduction of 12.66% from the baseline prices.

By comparing the simulated prices for the low seasonal water level scenario for both Sørlige Nordsjø II and Utsira Nord, one feature is apparent. For the same volumes of offshore wind added, the price decline is the same regardless of whether the capacity is added in NO2 or NO5. For example, by adding 504 MW to Utsira Nord results in prices of 43.41 €/MWh in all bidding areas expect for Finland. For the same volume of 504 MW, resulting from 50% utilization of small deployment at Sørlige Nordsjø II, identical prices are found. This feature applies for all three operating hours, and can imply that the same production volume at Sørlige Nordsjø II and Utsira Nord will impact prices similarly. However, this is not necessarily the case for the scenarios when adding higher capacities of offshore wind, which are presented in Appendix A3. Not surprisingly, this indicates that the feature only applies as long as there is free transmission capacity on the connections between the affected bidding areas.

Average seasonal water level (28/09/2017) - Utsira Nord					
		Small deployment (504 MW)		Large deployment (1512 MW)	
	Baseline prices	50% utilization	Installed capacity	50% utilization	Installed capacity
NO1	31.56	30.91	30.55	30.17	28.42
NO2	31.56	30.91	30.55	30.17	28.42
NO5	31.56	30.91	30.55	30.17	28.42

Table 6.6: Simulated prices (in €/MWh) for average seasonal water level on 28/09/2017 07-08 AM with capacities added from Utsira Nord to NO5.

Table 6.6 shows that only NO1, NO2 and NO5 are affected by the added offshore wind capacity to NO5 in the average seasonal water level scenario. This is similar to what is seen for the same operating hour when adding capacities from Sørlige Nordsjø II, but to a smaller extent because of the lower installed capacities. With full utilization of large deployment, prices in NO1, NO2 and NO5 declines by 3.14 €/MWh, representing a decline of 9.93% from the baseline prices.

High seasonal water level (28/09/2015) - Utsira Nord					
		Small deployment (504 MW)		Large deployment (1512 MW)	
	Baseline prices	50% utilization	Installed capacity	50% utilization	Installed capacity
NO1	15.46	14.67	13.71	12.76	9.85
NO2	15.46	14.67	13.71	12.76	9.85
NO5	15.46	14.67	13.71	12.76	9.85

Table 6.7: Simulated prices (in €/MWh) for high seasonal water level on 28/09/2015 07-08 AM with capacities added from Utsira Nord to NO5.

The results from adding offshore wind capacity to NO5 for the high water level scenario is shown in table 6.7. Also in this case, only NO1, NO2 and NO5 are affected by the added capacities. With full utilization of the large deployment scenario of 1512 MW, the prices in these bidding areas decrease by 5.61 €/MWh, representing 36.27% of the baseline price.

6.3 A descending price trend

Overall, the simulation results show a descending price trend when adding capacities from potential offshore wind farms at Sørlige Nordsjø II and Utsira Nord. The trend is seen regardless of seasonal water level. Figure 6.1 uses the operating hour in 2017 to illustrate the aggregate supply and demand curves in the Nordic power market and the changing intercept between the two when supply bids from offshore wind power are included. As seen in the figure, the supply curve shifts to the right when adding higher capacities from offshore wind generation. In combination with the highly inelastic demand curve, the equilibrium price declines. This illustrates the merit order effect.

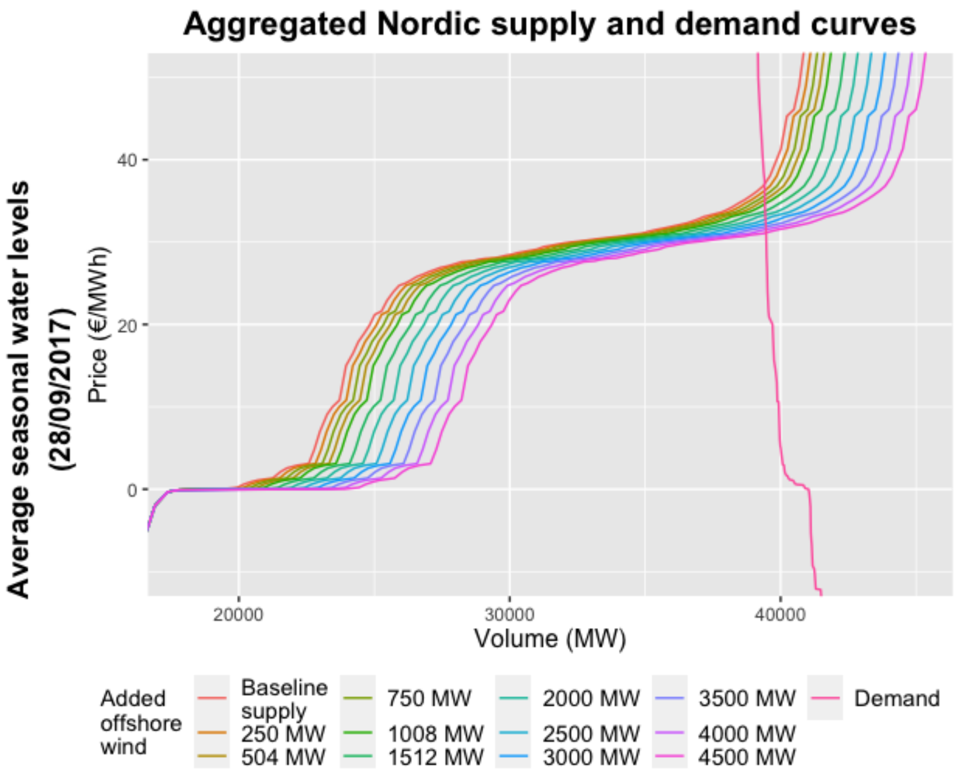

Figure 6.1: Aggregated Nordic supply and demand curves with added offshore wind capacities on 28/09/2017 07-08 AM.

As the figure is aggregated on a Nordic level and does not account for transmission capacity constraints, the price impact in each bidding area individually will vary. This is seen in the simulated results. In particular, the Norwegian bidding areas are the most affected when adding offshore wind power capacities.

6.3.1 Relative price changes

Figure 6.2 illustrates the relative price changes from the baseline price in NO2 and NO5 when including offshore wind power from Sørlige Nordsjø II and Utsira Nord. The three slopes represent the operating hours for the three seasonal water levels. Not surprisingly, the relative price change from the baseline price both in NO2 and in NO5 increases with higher capacities of offshore wind added. Up to 2000 MW added to either site, the price changes in each seasonal water level slope appear similar regardless of adding the capacity to NO2 or NO5. Thereafter, the slope characteristics varies to a larger degree between each part of the figure. In particular, for the low seasonal water level, increasing the added capacity from 2000 MW to 2500 MW from Utsira Nord makes for a substantial decline in price. As such, the slope is steeper between these capacities compared to the same capacities added from Sørlige Nordsjø II. This can be explained by the limited transmission capacity in the grid, causing only the price in one bidding area to be affected by capacities higher than 2000 MW. This finding will be further emphasized in section 6.4.1.

Another detail to notice is that the blue, high seasonal water level, slope for Utsira Nord never fully declines to -100%. This results from the cleared consumption being equal to the maximum demand in the three bidding areas affected when adding offshore wind capacities above 3500 MW to NO5. This implies that the price in NO1, NO2 and NO5 stops declining after it reaches 0.36 €/MWh.

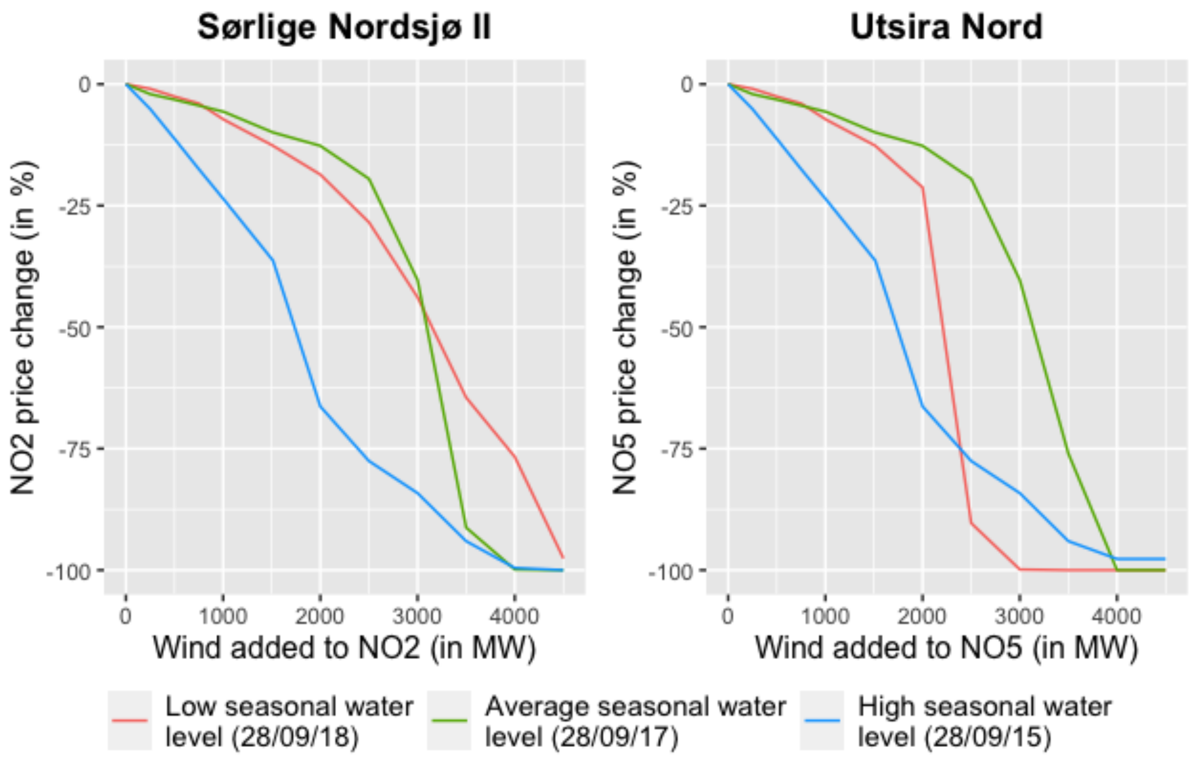

Figure 6.2: Relative price changes when adding offshore wind capacities from Sørlige Nordsjø II and Utsira Nord to NO2 and NO5 on 28/09/2017 07-08 AM.

The relative price change depends on the initial baseline price and the level of the absolute price change. As such, these will impact the pattern of the slopes illustrated. There is already established an almost perfectly negative relationship between the baseline prices and the deviation from median (average) seasonal water level of -98.5%. This implies that higher seasonal water levels will have lower baseline prices than the median and that lower seasonal water levels will have higher baseline prices than the median. As such, the relative price changes for the same absolute price decline would be higher for the high seasonal water level scenario and lower for the low seasonal water level scenario. The average seasonal water level should have relative price changes placing the slope in between the two others. The reasoning aligns fairly with the high seasonal water level scenarios which have high relative price changes up to a certain level of added capacities both to NO2 and to NO5. However, there is no clear pattern supporting the relationship between seasonal water levels, reflected in baseline prices, and relative price changes when looking at the slopes for the low and average seasonal water level scenarios. As a result, the level of the baseline prices alone does not seem to explain the variations in relative price changes.

This can be the result of relative price changes also depending on the absolute price changes, which could be affected by the level of price convergence in the baseline prices for each seasonal water level. The market coupling algorithm is set to maximize social welfare and will try to level out price differences between bidding areas. As a high level of price convergence implies that there is enough transmission capacity to level out these differences, one could be tempted to think that a high level of price convergence would imply a higher number of affected bidding areas when adding offshore wind capacities to either NO2 or NO5. This is exactly what is seen for the low seasonal water level scenario where all bidding areas except for Finland are affected by the added offshore wind power. For a lower level of convergence in the initial baseline prices fewer bidding areas appears to be affected by the additional offshore wind capacities. This is the case for the average- and high seasonal water level scenarios. One might think that the number of bidding areas affected would impact the absolute price change in each bidding area. As such, the low seasonal water level scenarios should have lower absolute changes, because many areas are affected. The opposite would be the case for the average- and high seasonal water level scenarios with higher absolute price changes. However, as highlighted in section 6.2.1, the simulated results show that the absolute price changes do not necessarily vary according to the number of bidding areas affected.

Overall, there do not seem to be a single clear explanation for why the relative price changes in the bidding area where the offshore wind capacity is added differs for the three seasonal water level scenarios. It is likely that a combination of factors will impact the relative price changes, among them the level of baseline prices and the absolute price changes, but also supply and demand characteristics in each affected bidding area.

6.3.2 Changes in power prices in the Nordics versus in Germany

The descending price trend found aligns fairly with previous research on adding offshore wind to other European countries. In a German study, Leuthold et al. (2008) found an average nodal price decline of 10%, when adding an offshore wind capacity of 7.9 GW to the Northern part of Germany. This accounted for 10% of the consumption in their model of the German market. To compare, table 6.8 shows the average price decline[7] across all Nordic bidding areas resulting from adding a capacity of 4500 MW to either NO2 or NO5. This capacity translates to 10% of the Norwegian consumption for the three operating hours.

Average price declines when adding 4500 MW of offshore wind capacity			
	Low water level 28/09/2018	Average water level 28/09/2017	High water level 28/09/2015
NO2	31.6%	18.9%	13.6%
NO5	14.4%	14.9%	13.3%

Table 6.8: Average price declines when adding 4500 MW to NO2 and NO5.

The results vary across initial baseline scenarios. For the two high seasonal water level scenarios, the average price declines found are at the same level as the findings made by Leuthold et al. (2008). This is also the case when adding capacity to NO5 with both the low and average seasonal water level. In contrast, the average price decline is much higher in the low and average water level scenario with added capacity to NO2. As such, the results show a similar average price decline as Leuthold et al. (2008) in over half of the comparable cases. The larger average price declines for the low seasonal water level when adding capacity to NO2 of 31.6% can be explained by the fact that all bidding areas in the Nordics except Finland are affected in the model, whereas only the nodes in Northern Germany were affected in the study made by Leuthold et al. (2008).

[7] The average price decline is calculated as $\sum_i (Price_i^{Baseline} - Price_i^{Wind}) / \sum_i Price_i^{Baseline}$

There are differences between the approaches used in this thesis and the German study that could result in the different magnitudes of price declines. Still, the comparison does give an indication of the magnitude of the findings being in line with previous studies. The changes in both this thesis and the study from Germany are based on historical supply and demand curves, only accounting for changes in supply when adding capacities from offshore wind power. As such, the results illustrate the substantial impact the introduction of offshore wind power could have on the electricity market. However, without accounting for changes in other fundamental aspects of the market, such as increased consumption, the price changes does not necessarily reflect future power prices.

6.3.3 Can the simulated results represent future Nordic power prices?

As development of offshore wind projects take time, it is not likely that the offshore wind farms at Sørlige Nordsjø II and Utsira Nord will supply the Nordic market with electricity in the next years. According to Statnett (2020c) deployment of offshore wind farms in Norway will generate electricity as of 2030. As such, a question that rises is whether the simulated results based on historical supply and demand curves with added capacities from offshore wind power could be a fair representation of future Norwegian power prices.

In their long-term analysis Statnett (2020c) studies the market developments of the European and Nordic power market. By accounting for expectations of increasing consumption and generation of electricity, as well as the transition towards a zero emission European energy sector, they forecast future power prices. For the period between 2030 and 2040 they find a sample set for the Norwegian power prices to be between 30 €/MWh and 55 €/MWh. This calculation is based on assumptions of a yearly Norwegian offshore wind power generation of 4 TWh and 15 TWh in 2030 and 2040. This accounts for 2.3% and 7.8% of the total Norwegian production in 2030 and 2040. To compare their forecast of future power prices with the findings in this thesis, table 6.9 shows the simulated results when adding capacities equal to full utilization of small and large deployment at both sites to the historical bid curves for the three operating hours.

	Adding offshore wind generation at both sites					
	Low water level (28/09/2018)		Average water level (28/09/2017)		High water level (28/09/2015)	
	Small deploy.	Large deploy.	Small deploy.	Large deploy.	Small deploy.	Large deploy.
NO1	38.92	1.05	28.42	0.38	9.85	0.00
NO2	38.92	1.05	28.42	0.38	9.85	0.00
NO3	42.77	42.77	35.48	35.48	20.93	20.93
NO4	42.77	42.77	35.48	35.48	20.93	20.93
NO5	38.92	1.05	28.42	0.38	9.85	0.00

Table 6.9: Simulated prices in Norway when adding offshore wind capacities to NO2 and NO5 equal to the small and large deployment estimates for Sørlige Nordsjø II and Utsira Nord.

Small deployment at both sites would imply a total installed offshore wind power capacity of 1512 MW. As mentioned in section 6.2, this translates to between 8% and 11% of the Norwegian generation in the model. As such, the generation equal to small deployment at both sites is closest to the yearly estimates made by Statnett (2020c). In the low and average seasonal water level hours, the prices obtained aligns fairly with the sample set of Statnett (2020c). In contrast, the high seasonal water level prices are much lower. The case of large deployment at both sites implies an installed capacity of 4512 MW, which account for between 25% and 33% of the Norwegian generation in the model. As seen in table 6.9, for all operating hours full utilization causes the power price to decline substantially to almost zero in all cases. Thus, the differences between the forecasted prices of Statnett (2020c) and the estimated prices when adding offshore wind in this thesis are substantial.

As mentioned, the simulations of Statnett (2020) accounts for expected increases in demand, mainly resulting from the electrification of the economy. In contrast, this thesis bases the simulation on historical demand for the specific operating hours analyzed, implying that increases in demand are not accounted for. With current deployment plans and expectations of offshore wind supplying the Nordic market in 2030, it is likely that demand will have increased significantly before offshore wind power enters the Nordic market. As such, the impacts on power prices found in this thesis may not reflect the level of future power prices. Still, there are several trends found in the simulated results that are in line with the expectations from the long-term market analysis from 2020.

In particular, Statnett (2020c) expects that the future power market will experience larger price differences hour by hour between the Norwegian bidding areas when higher shares of intermittent renewable energy sources enters the market. This aligns fairly with the findings of this thesis, where especially in the scenarios with higher installed capacities price differences between NO1, NO2 and NO5 and the rest of the Norwegian bidding areas increases. Furthermore, in the scenarios with low seasonal water level where offshore wind is added to NO5, the higher additional capacities result in price differences between NO1, NO2 and NO5. This case will be discussed in section 6.4.1. Likewise, Statnett (2020c) finds that there will be more operating hours with bottlenecks internally in the Southern part of Norway, mainly resulting in differences between the price in the same bidding areas. They also find that for all countries connected to the Norwegian grid, price differences will increase, which also fairly align with the simulated results.

6.4 Levels of congestion

The three sets of baseline prices have different levels of price similarities among bidding areas. As price differences occur as a result of congestion in the grid, the level of congestion will determine how many bidding areas that are affected by the additional generation in either NO2 or NO5 from the two offshore wind sites. As previously emphasized, the low seasonal water level scenario is characterized by baseline prices that are highly converged. As there are non-constrained connections that enables power flow such that price differences between bidding areas are prevented, generation from offshore wind power in either NO2 or NO5 causes the prices in all bidding areas expect for Finland to decline. Still, with increasing volumes of added generation, the magnitude of the price change in the affected areas varies. This is because the additional generation causes changes to the power flows between bidding areas and the combination of constrained connections in the grid. Since all connections from the NO1, NO2 and NO5 to other bidding areas becomes constrained after a certain point of additional generation from offshore wind, levelling out price differences will not longer be possible and the price in these bidding areas will decline more. As such, adding offshore wind causes more congestion in the low seasonal water level scenario. This aligns well with what Leuthold et al. (2008) found when adding offshore wind capacities in Germany.

For the average and high seasonal water level scenarios, the case is somewhat different. These hours are characterized by a larger degree of congestion and price differences between bidding areas occur. For both scenarios the price in NO1, NO2 and NO5 are decoupled from the rest of the Nordic bidding areas, and since the power flow from these bidding areas to neighbouring areas are constrained, these are the only ones affected. Since the connections between these bidding areas still enable price convergence, all these three bidding areas are affected similarly by the added offshore wind in NO2 or NO5. These cases are similar to what they found in the German study where offshore wind capacity only affected nodes in Northern Germany and not in Southern Germany because of high initial levels of congestion. As offshore wind capacities up to large deployment for each site do not constrain any additional transmission connections, the level of congestion in the Nordic market do not seem to increase. Still, when increasing the capacities above the large deployment scenarios, the connections between NO1, NO2 and NO5 becomes constrained in both the low and average seasonal water level scenario, causing increasing price differences and congestion in the Nordic market.

6.4.1 A substantial price decline in only one bidding area

An interesting findings when looking at congestion is the case where the additional capacity from offshore wind after a certain point isolates the effect on price to one bidding area. This occurs in three of the modelled scenarios. For the average seasonal water level scenario, additional capacity beyond 3000 MW in NO2 and 3500 MW in NO5, only causes changes to the price in the bidding area where the offshore wind capacity is added[8]. The same feature occur for additional capacities beyond 2000 MW in NO5 for the low seasonal water level scenario. Table 6.10 highlights the last mentioned case by illustrating the price changes in the bidding areas experiencing the highest price decline when capacities are added to NO5.

[8]See table A3.3 and A3.4 in the Appendix.

Low seasonal water level (28/09/2018) Added capacities to NO5 in MW									
	Baseline prices	250	504	750	1008	1512	2000	2500	3000
DK1	44.55	44.13	43.41	42.78	41.29	38.91	36.58	36.58	36.58
NO1	44.55	44.13	43.41	42.78	41.29	38.91	36.58	36.58	36.58
NO2	44.55	44.13	43.41	42.78	41.29	38.91	36.58	36.58	36.58
NO5	44.55	44.13	43.41	42.78	41.29	38.91	35.08	4.31	0.06

Table 6.10: Simulated prices (in €/MWh) in the bidding areas that experiences the highest price decline for low seasonal water level on 28/09/2018 07-08 AM.

The table shows that when adding capacities up to 1512 MW, DK1, NO1, NO2 and NO5 are affected the same. With an added capacity of 2000 MW, the price decline is marginally larger in NO5 than in the other affected bidding areas. However, additional capacities beyond 2000 MW causes the connection between NO1 and NO5 to become constrained, resulting in an immediate price drop in NO5. As such, a substantial price difference between NO5 and all other Nordic bidding areas occur. At Utsira Nord, the large deployment plan implies an installed capacity of 1512 MW. As such, the increased congestion illustrated here, resulting in the immediate price decrease in NO5 when adding 2000 MW, can be considered of less importance. Still, the case could illustrate what would happen in other operating hours with similar combinations of power flows and constrained connections. Moreover, one should not neglect the possibility of increasing capacity estimates should there be other offshore wind sites in the area opened for deployment in the years to come. On that note, grid developments will be of importance and the Nordic TSOs are moving in the right direction with several projects under construction.

6.4.2 The need for interconnectors

With the increasing volume from weather dependent generation sources, there will be a higher level of volatility in the power prices in the years to come (Statnett, 2020c). As the simulated results show, regardless of initial baseline prices, adding offshore wind has a substantial impact on the power prices. In some scenarios all bidding areas are affected, whereas in other cases only some of the Nordic areas are affected. Due to the transmission capacities in the grid, baseline prices in NO1, NO2 and NO5 are decoupled from the other bidding areas in the average and high seasonal water level scenarios. As such, adding offshore wind can cause substantial price differences between these bidding areas and the other parts of the Nordic market. To prevent such price differences, one would benefit from new grid capacity.

Moreover, with a higher share of weather dependent generation, bidding areas could experience larger fluctuations in their production volumes. As this will affect the power balance in each bidding area, it could cause large variations in the power flow between areas. Bidding areas with large shares of intermittent renewable energy would in times of high wind speed export power, whereas they in times of low wind speed would need to import power. The two arguments of larger price differences and changing power flows both suggests that grid development will be important when integrating variable energy sources. Increased grid capacity could prevent large price differences between bidding areas and ensure that the power flow is sufficient to meet the demand in all areas. However, as the Statnett (2019) emphasizes it is not socioeconomically beneficial to develop grid capacity to the extent of removing all price differences even though grid improvements can be of importance to prevent bottlenecks.

On the other hand, increased demand will shift the demand curve outwards. As such, some or all of the generation from the offshore wind farms could potentially be consumed in the same bidding area where it is added. As this thesis does not take increases in demand into account, this could suggest that the need for increased transmission capacities between bidding areas is smaller than implied above. Nonetheless, both the European Commission (2019) and Statnett (2020c) emphasize that the main challenge to integrate offshore wind in Norway results from the need to increase connections with Europe and within the Nordics.

6.5 Changing generation patterns

Adding offshore wind capacity directly to the grid in NO2 and NO5, causes changes to the net generation[9] both in these bidding areas and in other affected areas. In particular, generation increases in the bidding areas where the offshore wind capacity is added, whereas it decreases in other bidding areas with a descending price trend. As seen throughout the analysis, the effects of adding offshore wind to Sørlige Nordsjø II and

[9] Net change in generation = Added offshore wind generation - reduction in other generation sources

Utsira Nord for the average (2017) and high (2015) operating hours have similar results. This also applies when looking at the changes in generation as illustrated in figure 6.3 and figure 6.4.

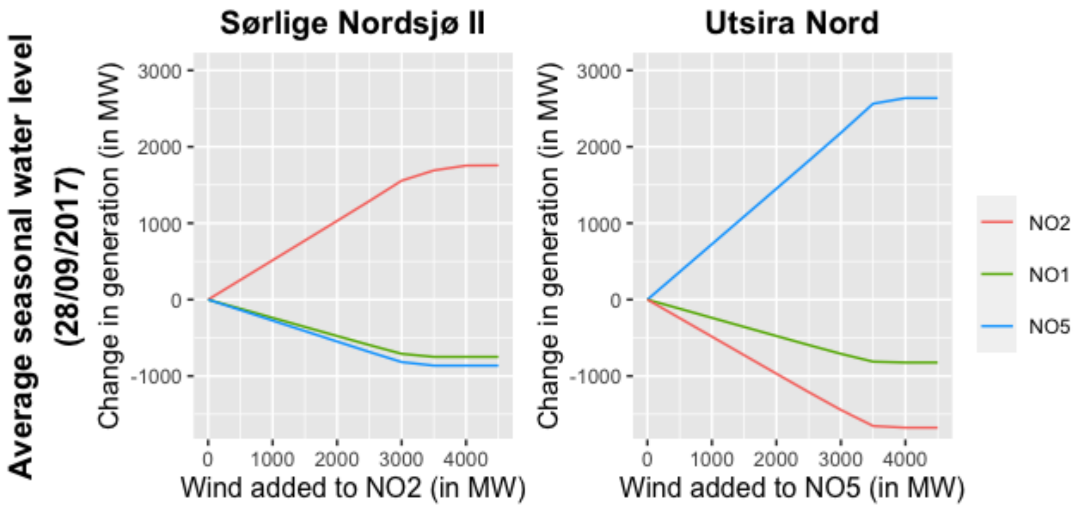

Figure 6.3: Changes in generation when adding offshore wind on 28/09/2017 07-08 AM.

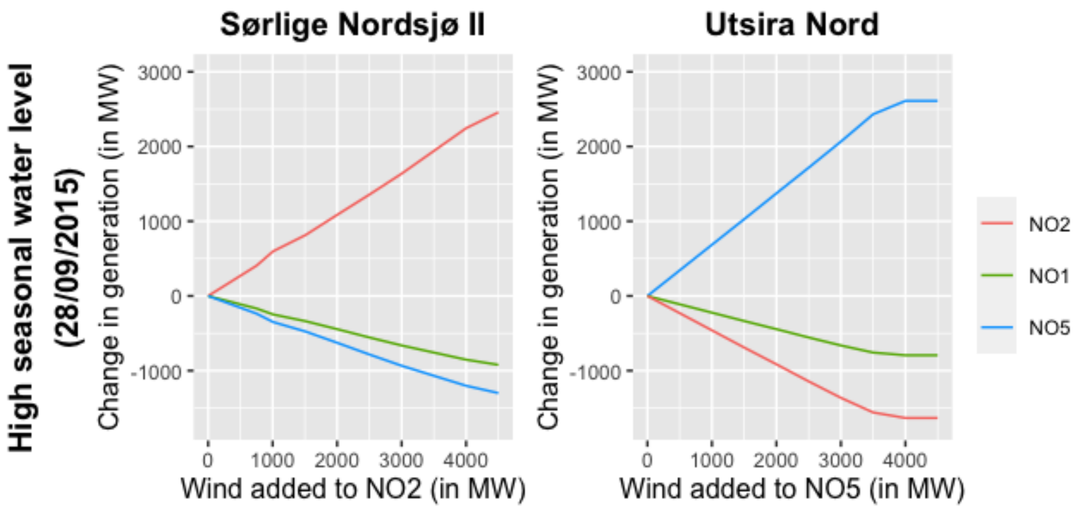

Figure 6.4: Changes in generation when adding offshore wind on 28/09/2015 07-08 AM.

Until the added offshore wind capacity from Sørlige Nordsjø II reaches 3000 MW there are similar changes to generation for the two seasonal water level scenarios, as shown in the left part of the figures. For the average seasonal water level, additional capacity above 3000 MW cannot be transferred to other bidding areas, and the price in NO2 declines much faster towards zero. Thus, only minor changes to the generation in NO2 occur after this point. On the other hand, for the operating hour with high seasonal water level the changes to generation continues for all added wind scenarios modelled. This is because the price decreases to zero at a higher volume of added offshore wind capacity, respectively at 4500 MW. Nonetheless, the same pattern in generation changes, as for the average case, is expected to occur for scenarios with added wind above the level that causes the price to decrease to zero. This implies that after 4500 MW only minor changes to generation are expected. As seen in the right part of figure 6.3 and 6.4, the changes in generation resulting from deployment at Utsira Nord are similar for the average and high seasonal water level scenarios.

In contrast to figure 6.3 and 6.4, adding offshore wind in the low seasonal water level scenarios affect the generation in all bidding areas except for Finland. Figure 6.5 shows that the increased generation in NO2 and NO5, depending on which site the added capacity results from, follow the same pattern for volumes up to 2000 MW. This applies for the decreasing generation in the remaining bidding areas affected, as well. However, for Utsira Nord, additional capacities above this level only causes changes to the generation in NO5. At this point, the changes in generation are very small, resulting in a line that appears horizontal in the right part of figure 6.5. As for Sørlige Nordsjø II, only generation volumes in NO1, NO2 and NO5 continue to change throughout all scenarios as these bidding areas are the ones that experience the price decline for all added capacities.

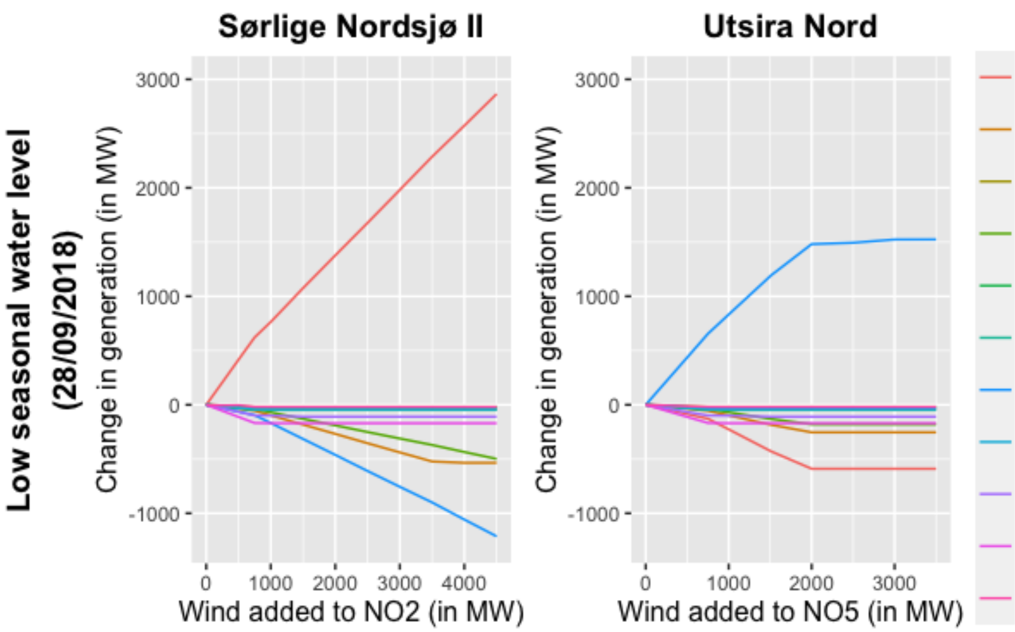

Figure 6.5: Changes in generation when adding offshore wind on 28/09/2018 07-08 AM.

All three figures illustrate the common feature of the aggregate net change in generation in the Nordics being smaller than the added offshore wind capacity. To illustrate, an example from the high seasonal water level scenario will be presented. When adding offshore wind generation of 3000 MW to NO2 from Sørlige Nordsjø II, generation cleared in the bidding area increases by 1636 MW. At the same time the generation quantities in NO1 and NO5, which are the bidding areas experiencing the same price decline, decreases by 663 MW and 934 MW. As such, there is only an additional 39 MW cleared in the market with adding bids from offshore wind generation in NO2 of 3000 MW, compared to the baseline case. As the least expensive generation bids will be cleared before the more expensive ones, this implies that producers of more expensive generation sources clear 2961 MW less than they did initially. This feature is caused by the inelasticity of demand and the merit order effect.

As mentioned previously, the simulation results are based on historical demand for the chosen operating hours. Since it is expected that offshore wind will not generate power to the Norwegian market in the nearest future, it is likely that when it does so, the demand has increased. Thus, when offshore wind power is integrated, changes to generation would likely be different than what the figures suggests. With increasing demand, it is likely that the aggregated net changes in generation will increase accordingly to the added capacity from offshore wind power as both the supply and demand curves will shift to the right. Furthermore, demographic patterns and placement of new energy intensive industries, such as data centers, will also be of importance for future generation of electricity and the decisions on how to distribute power generated from offshore wind farms to end users.

6.6 Implications for hydropower producers

As seen above, regardless of the initial baseline scenario, deployment of offshore wind power implies that the generation from other power producers decreases. As the wind speed will fluctuate, the power production from offshore wind sites will vary accordingly. This suggests that with offshore wind power penetrating the Nordic power market, existing power producers with flexible generation sources, such as hydropower producers, might want to respond to this change.

The response from hydropower producers when adding offshore wind will be of importance to the price behavior as hydropower is the dominating electricity source in the Nordic market. In general, hydropower producers decide how much to supply based on the value of water. For that reason, one could argue that they would not change their supply bid curve, as it is determined by the long-term value of water. As such, the entrance of wind power would have to impact the water value in the long-run for hydropower producers to respond. If the water value is not affected one would not see any changes to the hydropower supply. However, the intermittent nature of wind power makes for large fluctuations in generation patterns. Thus, one could claim that the increasing share of unpredictable power supply, would make for hydropower producers to gain more from trading in the shorter-term markets, where flexible generation is valued.

The intermittent nature of wind power production causes increasing balancing needs. Hydropower reservoirs offer the possibility to store electricity in times of high utilization of offshore wind turbines and lower electricity prices, and to release it in times when the utilization from wind is lower and prices are higher. As wind production is a function of weather conditions rather than demand conditions, this ability to regulate the hydropower production up and down with low additional costs will be important to meet demand. Thus, with increasing shares of intermittent renewable energy sources, such as offshore wind, the flexibility of hydropower production plays an even more prominent role in the shorter-term markets.

On the other hand, as Bühler and Müller-Merbach (2009) writes, deviations from the median seasonal water level can affect the hydropower generators flexibility. With high unexpected deviations from the median seasonal water level, hydropower producers will increase the hydropower generation with the goal to smooth total future production. In these scenarios, abnormally high or low seasonal water levels can reduce the flexibility of hydropower plants. As such, there could be situations where the water levels could prevent the hydropower producers from being able to balance out short term fluctuations in wind power production by adjusting their supply bid curves.

The intermittent nature of renewable energy sources, such as offshore wind, will also have implications for other power producers. With the increasing penetration of these energy sources in the Nordic market, higher short-term fluctuations in power prices are likely to occur. Thus, forecasting of future revenues can become challenging as it will be difficult to predict the supply from intermittent renewable energy sources and how this will affect the market equilibrium.

7 Conclusion

7.1 Concluding remarks

In line with the objective of the thesis, implications from adding offshore wind capacities to the Nordic power market through the Norwegian mainland grid have been discussed. Through bringing attention to the relevance of hydropower production in Norway and the fluctuations in water level in the hydropower reservoirs, the research has attempted to give a realistic picture of how offshore wind power will impact the market. Moreover, an emphasis has been placed on the areas where the offshore wind sites will be connected to the Norwegian mainland grid, namely NO2 and NO5. Based on the the simulated results and the discussion of these, the following main features have been found to answer the research question.

A descending price trend is found throughout all scenarios. This is in line with the merit order effect and aligns fairly with previous studies on wind power and its impact on power prices. Absolute price changes are found to be of substantial magnitudes. The results from the low-, average- and high seasonal water level scenarios with a large deployment at Sørlige Nordsjø II and an installed capacity of 3000 MW, show absolute price declines of 19.54 €/MWh, 12.73 €/MWh and 13.01 €/MWh, respectively. The similar results with a large deployment at Utsira Nord and an installed capacity of 1512 MW, show price declines of 5.64 €/MWh, 3.13 €/MWh and 5.61 €/MWh in the low-, average- and high seasonal water level scenarios. As such, the merit order effect of descending power prices is present and significant, but the magnitude of the price changes varies across the different seasonal water level scenarios.

By accounting for seasonal fluctuations in water levels, the results show that the number of bidding areas in the Nordics affected depend on the level of convergence in the initial baseline prices. In the low water level scenario with highly converged prices initially, every bidding area except for Finland is affected by added offshore wind capacities to various degrees. The opposite seems to be the case with average and high seasonal water level and congested initial baseline prices, causing only the prices in NO1, NO2 and NO5 to be affected. Nevertheless, the results also show that fewer bidding areas affected do not necessarily imply larger absolute price changes than when many bidding areas are affected.

Comparing the relative price changes when including offshore wind power generation across seasonal water levels, the results show no clear patterns. Even though the relationship between seasonal water levels and baseline prices was established, the level of baseline prices alone could not explain the differing relative price changes when adding offshore wind generation. Furthermore, neither the number of affected bidding areas gives a clear explanation.

However, a clear relationship is found in the generation patterns across all modelled scenarios. The results show that generation in the bidding area with the added capacities increase, but not as much as the volume of offshore wind added would imply. At the same time, the generation in the other bidding areas also affected by the added wind capacities decrease.

Overall, the thesis shows that deployment of offshore wind at Sørlige Nordsjø II and Utsira Nord will impact the Nordic power market and that the largest implications are seen in NO1, NO2 and NO5. However, as the simulated results are based on historical demand and supply, they do not necessarily reflect future power prices. Nonetheless, they do illustrate trends of increasing price differences between bidding areas and price fluctuations, that will affect the power market in the years to come.

7.1.1 Limitations

One of the main limitations of this thesis is that the disaggregation method used implies that all bidding areas have the same relative price sensitivity. As such, the model do not account for differences in power sources between bidding areas. It is likely that the simulation results would have been different if actual bid curves from each bidding area were used.

Another factor is that the modelling is limited to consider only one date and one operating hour. Even though water level differences are accounted for within seasons by looking at three different years, it cannot be said that the results would have been similar for another season or another operating hour. Moreover, the implication of only considering Norway, taking no notice of the potential changes in capacities supplied by other Nordic countries, limits the reliability of the results.

Furthermore, the model does not consider how the hydropower generators will respond to the entrance of bids from offshore wind generators as the model uses historical bid curves when adding capacity from offshore wind. This is an important shortcoming of the model, as hydropower producers with their flexible generation source, most likely will respond to the change in supply.

Lastly, by not accounting for the increasing consumption of electricity, the magnitude of the price changes could be considered a less fair representation of the actual impacts when offshore wind power is supplied from Sørlige Nordsjø II and Utsira Nord.

7.1.2 Stepping forward

In this final section, some of the many interesting aspects touched upon while writing this thesis will be mentioned. The intermittent nature of wind causes challenges to the power market. As such, it would be interesting to study how increasing balancing needs would play out in the intraday and balancing markets. Another interesting aspect would be to look at whether the results would have been of similar magnitude looking at other seasons. As this thesis does not account for changes in demand, it would have been intriguing to look at price impacts from additional offshore wind capacity when accounting for higher consumption as well. In addition, it would also be of interest to look into the impact including the offshore wind capacity estimates from other Nordic countries. Lastly, the many possibilities for how to connect the offshore wind farms to the grid are intriguing. As such, further research on price changes could have been done accounting for grid development plans of interconnectors and potentially offshore wind hubs. This thesis has shown that substantial changes in the electricity market are yet to be resolved to integrate renewable energy sources and that the final impact on the Nordic power market from developing offshore wind remain uncertain.

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Appendix

A1 Production and consumption for the three operating hours

Table A1.1 shows the production and consumption shares for the three operating hours. The shares are based on production and consumption data retrieved from Nord Pool Group (2020c,n). As the system price curves also include the bids in the Baltic countries, the shares in the table do not summarize to 100%.

	28/09/2015		28/09/2017		28/09/2018	
	Produc.	Consump.	Produc.	Consump.	Produc.	Consump.
DK1	3.20%	5.44%	3.85%	5.87%	5.93%	5.25%
DK2	1.23%	3.25%	2.496%	3.38%	2.15%	3.05%
FI	16.17%	20.29%	14.80%	20.79%	15.51%	20.31%
NO1	6.01%	8.41%	6.24%	8.29%	4.20%	8.85%
NO2	12.37%	8.21%	12.71%	7.95%	13.78%	8.62%
NO3	3.97%	5.19%	4.64%	6.07%	5.07%	6.43%
NO4	5.18%	4.39%	6.65%	4.46%	3.25%	4.53%
NO5	8.47%	4.30%	7.19%	3.67%	10.22%	3.97%
SE1	7.28%	2.44	6.37%	2.48%	4.66%	2.17%
SE2	10.76%	3.91%	10.91%	4.18%	10.60%	3.77%
SE3	18.31%	21.31%	16.73%	25.18%	18.01%	20.31%
SE4	1.07%	6.05%	2.42%	7.34%	2.07%	5.70%

Table A1.1: Production and consumption shares for the Nordic bidding areas used in the disaggregation of bid curves

A2 Offshore wind capacity estimates: calculations from NVE

NVE has calculated capacity estimates for each site considered in their Strategic Impact Assessment, among these the capacity estimates used in this thesis for small and large deployment at Utsira Nord and Sørlige Nordsjø II (NVE, 2012). To calculate these estimates for each site with small and large deployment, they have used effect curves from two different turbines. The first one is the Vestas V164 7MW turbine with a rotor of 164 meters in diameter. The second one is the RePower 6MW Offshore LM615P2 Evolution which has a somewhat lower rotor diameter of 126 meters, but has been tested offshore and can generate power with wind speed up 30 meters per second. Wind turbines are designed with an expected theoretical level of power production for each given wind speed resulting in effect curves. The yearly service time on each site depends on the installed effect from each turbine and the annual wind power generation:

Service time = Annual wind power generation (MWh) / Installed turbine effect (MW)

There are several factors interfering with the theoretical level of wind power generation, that creates generation losses and must be taken into consideration when calculating capacity estimates for each site. Firstly, wake losses vary between 5 and 13% from site to site. Thus, in the calculations the turbines are located as to optimize power production. Secondly, NVE has evaluated the possible impact of icing resulting from the Nordic climate limiting generation of wind power. However, their evaluation does not show implications of importance for the calculations. Thirdly, the estimates take the wave climate on the Norwegian continental shelf into consideration which impacts the possibility to do maintenance and repairs.

The uncertainty in the estimates made by NVE ranges from 4 to 13%. Both the calculations of power generation and of power losses result from several uncertain estimates, such as wind speed, wake losses, expected downtime, electrical losses and the effect curve from the developing 7 MW turbine.

The service time estimates we have used in the discussion on the magnitude of the capacity added is showed in the table below:

	Installed capacity	Service time	Yearly power production (GWh)	Yearly power production (TWh)
Utsira Nord	1512	4107	6210	6.21
Sørlige Nordsjø II	3000	4334	13002	13.00

Table A2.1: Yearly offshore wind power production calculations

A3 Simulated results

	Low seasonal water level scenario (28/09/2018)											
	Added capacity to NO2 in MW											
	Baseline prices	250	504	1008	750	1512	2000	2500	3000	3500	4000	4500
DK1	44.55	44.13	43.41	42.78	41.29	38.91	36.26	31.89	25.01	15.82	10.39	10.39
DK2	44.55	44.13	43.41	42.78	42.77	42.77	42.77	42.77	42.77	42.77	42.77	42.77
FI	70.63	70.63	70.63	70.63	70.63	70.63	70.63	70.63	70.63	70.63	70.63	70.63
NO1	44.55	44.13	43.41	42.78	41.29	38.91	36.26	31.89	25.01	15.82	10.39	1.08
NO2	44.55	44.13	43.41	42.78	41.29	38.91	36.26	31.89	25.01	15.82	10.39	1.08
NO3	44.55	44.13	43.41	42.78	42.77	42.77	42.77	42.77	42.77	42.77	42.77	42.77
NO4	44.55	44.13	43.41	42.78	42.77	42.77	42.77	42.77	42.77	42.77	42.77	42.77
NO5	44.55	44.13	43.41	42.78	41.29	38.91	36.26	31.89	25.01	15.82	10.39	1.08
SE1	44.55	44.13	43.41	42.78	42.77	42.77	42.77	42.77	42.77	42.77	42.77	42.77
SE2	44.55	44.13	43.41	42.78	42.77	42.77	42.77	42.77	42.77	42.77	42.77	42.77
SE3	44.55	44.13	43.41	42.78	42.77	42.77	42.77	42.77	42.77	42.77	42.77	42.77
SE4	44.55	44.13	43.41	42.78	42.77	42.77	42.77	42.77	42.77	42.77	42.77	42.77

Table A3.1: Simulated prices (in €/MWh) for low seasonal water level on 28/09/2018 07-08 AM when adding capacities from Sørlige Nordsjø II to NO2.

	Low seasonal water level scenario (28/09/2018)									
	Added capacity to NO5 in MW									
	Baseline prices	250	504	1008	750	1512	2000	2500	3000	3500
DK1	44.55	44.13	43.41	42.78	41.29	38.91	36.58	36.58	36.58	36.58
DK2	44.55	44.13	43.41	42.78	42.77	42.77	42.77	42.77	42.77	42.77
FI	70.63	70.63	70.63	70.63	70.63	70.63	70.63	70.63	70.63	70.63
NO1	44.55	44.13	43.41	42.78	41.29	38.91	36.58	36.58	36.58	36.58
NO2	44.55	44.13	43.41	42.78	41.29	38.91	36.58	36.58	36.58	36.58
NO3	44.55	44.13	43.41	42.78	42.77	42.77	42.77	42.77	42.77	42.77
NO4	44.55	44.13	43.41	42.78	42.77	42.77	42.77	42.77	42.77	42.77
NO5	44.55	44.13	43.41	42.78	41.29	38.91	35.08	4.31	0.06	0.00
SE1	44.55	44.13	43.41	42.78	42.77	42.77	42.77	42.77	42.77	42.77
SE2	44.55	44.13	43.41	42.78	42.77	42.77	42.77	42.77	42.77	42.77
SE3	44.55	44.13	43.41	42.78	42.77	42.77	42.77	42.77	42.77	42.77
SE4	44.55	44.13	43.41	42.78	42.77	42.77	42.77	42.77	42.77	42.77

Table A3.2: Simulated prices (in €/MWh) for low seasonal water level on 28/09/2018 07-08 AM when adding capacities from Utsira Nord to NO5.

		Average seasonal water level scenario (28/09/2017)										
		Added capacity to NO2 in MW										
	Baseline prices	250	504	1008	750	1512	2000	2500	3000	3500	4000	4500
DK1	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48
DK2	49.57	49.57	49.57	49.57	49.57	49.57	49.57	49.57	49.57	49.57	49.57	49.57
FI	46.76	46.76	46.76	46.76	46.76	46.76	46.76	46.76	46.76	46.76	46.76	46.76
NO1	31.56	30.91	30.55	30.17	29.76	28.42	27.55	25.41	18.83	15.50	15.50	15.50
NO2	31.56	30.91	30.55	30.17	29.76	28.42	27.55	25.41	18.83	2.76	0.04	0.00
NO3	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48
NO4	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48
NO5	31.56	30.91	30.55	30.17	29.76	28.42	27.55	25.41	18.83	15.50	15.50	15.50
SE1	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48
SE2	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.4	35.48	35.48
SE4	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48

Table A3.3: Simulated prices (in €/MWh) for average seasonal water level on 28/09/2017 07-08 AM when adding capacities from Sørlige Nordsjø II to NO2.

	Average seasonal water level scenario (28/09/2017)											
		Added capacity to NO5 in MW										
	Baseline prices	250	504	1008	750	1512	2000	2500	3000	3500	4000	4500
DK1	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48
DK2	49.57	49.57	49.57	49.57	49.57	49.57	49.57	49.57	49.57	49.57	49.57	49.57
FI	46.76	46.76	46.76	46.76	46.76	46.76	46.76	46.76	46.76	46.76	46.76	46.76
NO1	31.56	30.91	30.55	30.17	29.76	28.42	27.55	25.41	18.83	7.55	5.81	5.81
NO2	31.56	30.91	30.55	30.17	29.76	28.42	27.55	25.41	18.83	7.55	5.81	5.81
NO3	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48
NO4	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48
NO5	31.56	30.91	30.55	30.17	29.76	28.42	27.55	25.41	18.83	7.55	0.00	0.00
SE1	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48
SE2	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.4	35.48	35.48
SE4	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48	35.48

Table A3.4: Simulated prices (in €/MWh) for average seasonal water level on 28/09/2017 07-08 AM when adding capacities from Utsira Nord to NO5.

	High seasonal water level scenario (28/09/2015)											
		Added capacity to NO2 in MW										
	Baseline prices	250	504	1008	750	1512	2000	2500	3000	3500	4000	4500
DK1	54.80	54.80	54.80	54.80	54.80	54.80	54.80	54.80	54.80	54.80	54.80	54.80
DK2	54.80	54.80	54.80	54.80	54.80	54.80	54.80	54.80	54.80	54.80	54.80	54.80
FI	59.75	59.75	59.75	59.75	59.75	59.75	59.75	59.75	59.75	59.75	59.75	59.75
NO1	15.46	14.67	13.71	12.76	11.79	9.85	5.21	3.47	2.45	0.92	0.07	0.00
NO2	15.46	14.67	13.71	12.76	11.79	9.85	5.21	3.47	2.45	0.92	0.07	0.00
NO3	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93
NO4	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93
NO5	15.46	14.67	13.71	12.76	11.79	9.85	5.21	3.47	2.45	0.92	0.07	0.00
SE1	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93
SE2	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93
SE3	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93
SE4	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93

Table A3.5: Simulated prices (in €/MWh) for high seasonal water level on 28/09/2015 07-08 AM when adding capacities from Sørlige Nordsjø II to NO2.

High seasonal water level scenario (28/09/2015)												
	Added capacity to NO5 in MW											
	Baseline prices	250	504	1008	750	1512	2000	2500	3000	3500	4000	4500
DK1	54.80	54.80	54.80	54.80	54.80	54.80	54.80	54.80	54.80	54.80	54.80	54.80
DK2	54.80	54.80	54.80	54.80	54.80	54.80	54.80	54.80	54.80	54.80	54.80	54.80
FI	59.75	59.75	59.75	59.75	59.75	59.75	59.75	59.75	59.75	59.75	59.75	59.75
NO1	15.46	14.67	13.71	12.76	11.79	9.85	5.21	3.47	2.45	0.92	0.36	0.36
NO2	15.46	14.67	13.71	12.76	11.79	9.85	5.21	3.47	2.45	0.92	0.36	0.36
NO3	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93
NO4	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93
NO5	15.46	14.67	13.71	12.76	11.79	9.85	5.21	3.47	2.45	0.92	0.36	0.36
SE1	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93
SE2	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93
SE3	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93
SE4	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93	20.93

Table A3.6: Simulated prices (in €/MWh) for high seasonal water level on 28/09/2015 07-08 AM when adding capacities from Utsira Nord to NO5.

Added small (1512 MW) and large (4512 MW) deployment to both sites									
	Low seasonal water level (28/09/2018)			Average seasonal water level (28/09/2017)			High seasonal water level (28/09/2015)		
	Baseline prices	1512	4512	Baseline prices	1512	4512	Baseline prices	1512	4512
DK1	44.55	38.92	10.39	35.48	35.48	35.48	54.80	54.80	54.80
DK2	44.55	42.77	42.77	49.57	49.57	49.57	54.80	54.80	54.80
FI	70.63	70.63	70.63	46.76	46.76	46.76	59.75	59.75	59.75
NO1	44.55	38.92	1.05	31.56	28.42	0.38	15.46	9.85	0.00
NO2	44.55	38.92	1.05	31.56	28.42	0.38	15.46	9.85	0.00
NO3	44.55	43.41	42.77	35.48	35.48	35.48	20.93	20.93	20.93
NO4	44.55	43.41	42.77	35.48	35.48	35.48	20.93	20.93	20.93
NO5	44.55	38.92	1.05	31.56	28.42	0.38	15.46	9.85	0.00
SE1	44.55	43.41	42.77	35.48	35.48	35.48	20.93	20.93	20.93
SE2	44.55	43.41	42.77	35.48	35.48	35.48	20.93	20.93	20.93
SE3	44.55	43.41	42.77	35.48	35.48	35.48	20.93	20.93	20.93
SE4	44.55	43.41	42.77	35.48	35.48	35.48	20.93	20.93	20.93

Table A3.7: Simulated prices (in €/MWh) when adding small and large deployment of offshore wind from Sørlige Nordsjø II and Utsira Nord at the same time.