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Market effects of increased electricity demand in the Norwegian industry sector towards 2050

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Renewable energy

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Abstract

Norway aims to become a low-emission society by 2050. This transition will require a major electrification of the country's industry sector leading to a largely increased demand for renewable energy in the electricity market. This study explores the potential effects of such large-scale industrial development on Norway's electricity market by 2050 and considers if it is possible to supply all new grid capacity requests for industry projects in Norway by 2050. Furthermore, it analyzes what such a development would entail for electricity production, transmission and electricity prices. This study utilizes the Balmorel energy system model to analyze four scenarios with consumption input from varying combinations of existing and new industries. The industries included in the analysis are power-intensive industries, data centers, green hydrogen production, battery production, and mining and petroleum activities.

The findings reveal a projected rise in electricity production by 50 to 115 percent by 2050 across all scenarios. As new production from both onshore wind power and hydro power is limited, offshore wind becomes the primary technology for new electricity generation after 2030. Increased demand coupled with limited new production capacity leads to rising electricity prices in all scenarios and in all Norwegian price zones. The sensitivity analysis highlights increased transmission capacity as a measure to limit price growth.

The study concludes that a large-scale electrification of the existing industry and petroleum sectors, and development of new industries in Norway, will depend on large investments in offshore wind power production. The necessary level of scale-up in production varies largely depending on how many industry categories are included in the consumption input. It is uncertain whether a large-scale consumption and production growth to such an extent as analyzed in this study is necessary from a climate perspective, and whether it is socially and environmentally acceptable. However, prioritization of electricity for some industries or projects at the expense of others can largely reduce the need for new production and limit the growth in electricity prices to some extent.

Sammendrag

Norge har som mål å bli et lavutslippssamfunn innen 2050. Denne omstillingen vil kreve en stor elektrifisering av landets industrisektor som fører til en sterk økning i etterspørsel etter fornybar energi i kraftmarkedet. Denne studien undersøker de potensielle effektene av en slik storstilt industriutvikling på Norges elektrisitetsmarked innen 2050 og vurderer om det er mulig å bygge ut alle nye forespørsler om nettkapasitet for industriprosjekter i Norge innen 2050. Videre analyseres konsekvensene av en slik utvikling for kraftproduksjon, -overføring og -priser. Denne studien bruker energisystemmodellen Balmorel for å analysere fire scenarier med forbruk fra varierende kombinasjoner av eksisterende og nye industrier. Næringene som inngår i analysen er kraftintensiv industri, datasentre, grønn hydrogenproduksjon, batteriproduksjon, og gruve- og petroleumsvirksomhet.

Funnene viser en anslått økning i elektrisitetsproduksjonen med 50 til 115 prosent innen 2050 på tvers av scenariene. Ettersom ny produksjon fra både landbasert vindkraft og vannkraft er begrenset, blir havvind primærteknologi for ny kraftproduksjon etter 2030. Økt etterspørsel kombinert med begrenset ny produksjonskapasitet fører til stigende strømpriser i alle scenarier og i alle norske prissoner. Sensitivitetsanalysen fremhever økt overføringskapasitet som et tiltak for å begrense prisveksten.

Studien konkluderer med at en storstilt elektrifisering av eksisterende industri- og petroleumssektor, og utvikling av nye næringer i Norge, vil avhenge av store investeringer i vindkraftproduksjon til havs. Nødvendig oppskalering i produksjonen varierer mye avhengig av hvor mange industrikategorier som inngår i forbruket. Det er usikkert om en storstilt forbruks- og produksjonsvekst i en slik grad som analysert i denne studien er nødvendig i et klimaperspektiv, og om det er sosialt og miljømessig akseptabelt. Prioritering av elektrisitet til enkelte bransjer eller prosjekter på bekostning av andre kan imidlertid i stor grad redusere behovet for ny produksjon og begrense veksten i elektrisitetsprisene til en viss grad.

Contents

Acknowledgements .... **i**

Abstract .... **ii**

Sammendrag .... **iii**

List of figures .... **vi**

List of tables .... **vii**

1. Introduction **1**

1.1. Background 1

1.1.1. Paths to a low-emission society 1

1.1.2. Greenhouse gas mitigation in the industry sector 2

1.2. Objective and scenarios 3

1.3. Literature review 5

2. Theory and method **7**

2.1. The Nordic electricity market 7

2.1.1. Spot price zones 8

2.1.2. Price determination 8

2.1.1. Drivers of supply and demand 9

2.2. Balmorel 10

2.2.1. Energy system modelling 10

2.2.2. Spatial and temporal resolution 10

2.3. Input data 11

2.3.1. Scenario input 11

2.3.2. Assumptions 15

2.3.1. Levelized Cost of Energy 16

2.3.2. Short-run marginal costs (SRMC) 17

2.3.3. Fuel costs 18

2.3.4. CO_2-prices 18

2.4. Constraints 19

2.5. Sensitivity 19

3. Results **21**

3.1. Production 21
3.2. Power transmission 23
3.3. Electricity prices 26
3.3.1. High average prices in NO1 28
3.3.2. Price development in NO2 diverges from NO5 in 2050 in scenario 1 29
3.4. Sensitivity analysis 33
3.4.1. Sensitivity in wind power production and capacity 33
3.4.2. Sensitivity in power transmission capacity 39
4. Discussion 43
4.1. Energy system modelling 43
4.2. Temporal resolution 43
4.3. Energy efficiency and flexibility 43
4.4. Environmental and social impacts 44
4.5. Levels of production and consumption 45
4.6. Prices and sensitivity 47
4.7. Paths to a low-emission society 47
5. Conclusion 50
6. References 52

Appendix 1: Total demand per price zone 54
Appendix 2: Total production per technology and price zone 57
Appendix 3: Net transmission flow per price zone 60
Appendix 4: Yearly price variation graphs per scenario 65
Appendix 5: Electricity prices with wind power sensitivity 67
Appendix 6: Electricity prices with transmission capacity sensitivity 69

List of figures

Figure 1: Nordic electricity production (TWh) in 2022 ... 7
Figure 2: Total demand for electricity (TWh) per scenario. ... 15
Figure 3: LCOE values (EUR/MWh) for onshore wind power ... 17
Figure 4: LCOE values (EUR/MWh) for offshore wind power ... 17
Figure 5: Total production in Norway per technology graph (TWh) ... 21
Figure 6: Net transmission flow graph (TWh) in 2030 ... 24
Figure 7: Net transmission flow graph (TWh) in 2050 ... 24
Figure 8: Combined production, transmission and consumption graph (TWh), scenario 1 ... 25
Figure 9: Combined production, transmission and consumption graph (TWh), scenario 2 ... 25
Figure 10: Electricity price development graph (EUR/MWh), scenario 1 ... 26
Figure 11: Electricity price development graph (EUR/MWh), scenario 2 ... 27
Figure 12: Electricity price development graph (EUR/MWh), scenario 3 ... 27
Figure 13: Electricity price development graph (EUR/MWh), scenario 4 ... 28
Figure 14: Yearly price variation graph (EUR/MWh), NO1, NO2, NO5 and SE3 ... 29
Figure 15: Price duration curves graph (EUR/MWh), NO2, NO4 and NO5 in 2040 ... 30
Figure 16: Price duration curves graph (EUR/MWh), NO2, NO4 and NO5 in 2050 ... 30
Figure 17: Combined yearly production variation (MWh) and yearly price variation (EUR/MWh), NO2... 31
Figure 18: Combined yearly production variation (MWh) and yearly price variation (EUR/MWh), NO4... 32
Figure 19: Yearly price variation graph (EUR/MWh), NO2, DK1, DE4-N, UK and NL ... 32
Figure 20: Total production per technology graph (TWh), Low Wind, Base and High Wind ... 33
Figure 21: Electricity prices (EUR/MWh), NO1, Low Wind, Base and High Wind ... 34
Figure 22: Yearly production variation graph (MWh), NO1, Base ... 35
Figure 23: Yearly production variation graph (MWh), NO1, High Wind ... 35
Figure 24: Yearly price variation graph (EUR/MWh), NO1, Low Wind, Base and High Wind ... 36
Figure 25: Total production per technology (TWh), NO4, Low Wind, Base and High Wind ... 36
Figure 26: Electricity prices (EUR/MWh), NO4, Low Wind, Base and High Wind ... 37
Figure 27: Yearly price variation (EUR/MWh), NO3, NO4, SE1 and SE2, Base ... 38
Figure 28: Yearly price variation (EUR/MWh), NO3, NO4, SE1 and SE2, High Wind ... 39
Figure 29: Net transmission flow (TWh), NO4, NO3, SE1 and SE2, Base and High Wind ... 39
Figure 30: Electricity prices (EUR/MWh), NO1, Base, 50% increase and 100% increase ... 40
Figure 31: Total production per technology (TWh), Base, 50% increase and 100% increase ... 41
Figure 32: Net transmission flow (TWh), NO1, Base, 50% increase and 100% increase ... 41
Figure 33: Combined yearly transmission variation (MWh) and yearly price variation graph (EUR/MWh), NO4, NO2, NO3, NO5 and NO3, Base ... 42
Figure 34: Combined yearly transmission variation (MWh) and yearly price variation graph (EUR/MWh), NO4, NO2, NO3, NO5 and NO3, 100% increase ... 42

List of tables

Table 1: Reserved capacity (MW) 12
Table 2: Queued capacity (MW) 12
Table 3: Other active cases (MW) 12
Table 4: Hours of use in a year per industry consumption category 13
Table 5: Description of scenarios 14
Table 6: Fuel price input (EUR/MWh) 18
Table 7: CO_2-price input (EUR/ton-CO_2) 18
Table 8: Production (TWh) and installed capacity (GW), Low wind, Base and High Wind 20
Table 9: Transmission capacity levels (GW) between price zones 20
Table 10: Total national production and consumption (TWh) 46
Table 11: Average prices (EUR/MWh) 47

1. Introduction

The Norwegian industry and petroleum sectors are grappling with the need to decarbonize production over the coming decades, in accordance with ambitious climate targets and stringent regulations and expectations. Such a transition is expected to demand large amounts of fossil-free energy, both for existing and new emerging industries. This entails electrification of the power-intensive industry sector and the petroleum sector, coupled with the establishment of industries such as battery production, data centers and hydrogen production. The demand for renewable electricity is thus expected to increase largely. However, while all long-term power market analyses project an increase in electricity demand in Norway, the quantity of the increase varies greatly. While NVE's base scenario projects a consumption level of 191 TWh in 2040 (NVE, 2023b), Statnett projects a consumption level of 210 TWh and 220 TWh in 2040 and 2050 in their base scenario, but plan based on a high consumption scenario of 260 TWh in 2050 (Statnett, 2023a).

This study will use the energy system model Balmorel to analyze different scenarios of development in the industry and petroleum sectors in Norwegian, and how they will affect the electricity market. The analysis provides results displaying how variations in demand might affect production technologies, transmission flows and market prices. The analysis can provide an increasing understanding for the challenges the Norwegian electricity market and industry and petroleum sectors are facing, while also providing solutions with the lowest socio-economical costs.

1.1. Background

The world is facing the threat of climate change as a consequence of human activity. In response to this, countries of the world have committed themselves, through the Paris agreement of 2015, to reduce or readjust activities that negatively affect the global climate. This implies that all countries are obliged to work towards stabilizing the global temperature below an increase of 2 degrees Celsius compared to preindustrial levels, and should simultaneously work to keep the increase below 1.5 degrees (UNFCCC, 2024). In order to achieve this, close to all greenhouse gas (GHG) emissions must be removed by 2050. In accordance with the Paris agreement, Norway has committed to reducing its GHG emissions with 55 percent by 2030 and 90-95 percent by 2050 compared to the reference year 1990 (Miljødepartementet, 2021).

1.1.1. Paths to a low-emission society

Future development and transition to a more climate friendly economy is expected to be dependent on large amounts of new fossil free energy, like renewable electricity production. However, natural resources and access to areas are to a growing extent being considered limited. New developments of both hydro power, wind power and other energy sources are therefore restricted by considerations of natural habitats and social acceptance, as well as by grid access, profitability in the power market and other technical restrictions.

While there exists a general agreement in Norway to work towards the low-emission society target in 2050, there is still uncertainty of how to achieve the goal. The 2050 Climate Change Committee of 2023 defined two main paths towards a low-emission society; a high-energy society and a low-energy society

(Committee, 2023). A high-energy society involves few limitations on new production of renewable energy, facilitating a situation where all new energy consuming projects can be developed. In such a situation, production will largely follow the demand. A low-energy society is a situation where new energy production will be limited, and access to energy will need to be prioritized between projects.

As a country with historically low electricity prices and a surplus of renewable energy, the main political perception between shifting governments has been to proceed with a high-energy society in order to sustain a high level of social welfare and high activity in the economy. This is, for instance, explicitly expressed in the mandate of the Energy Commission of 2023. The report presented by the Commission concludes that there is a "massive need for more renewable power" in order to meet the climate targets by way of the high-energy society path. It specified goals for 40 TWh new renewable energy and 20 TWh saved energy through energy efficiency measures by 2030 (Commission, 2023).

The report presented by the 2050 Climate Change Committee in 2023 recommends, in contrast to the Energy Commission, to prioritize a low-energy society path towards a low-emission society in 2050. The Committee expresses a need to acknowledge resources like energy, area and nature as limited to a larger extent, and pricing the resources accordingly (Committee, 2023). The choice between the low- and high-energy society pathways is a choice between two very different situations for both energy producers and consumers, including for the industry sector.

1.1.2. Greenhouse gas mitigation in the industry sector

During the next 26 years, most activities in the industry and petroleum sectors that depend on fossil energy today must either decarbonize to a large extent or cease in order to meet the 2050 climate target. The industry sector is characterized by activities with high demand for energy and other resources and is responsible for 23.5 percent of the national GHG emissions in Norway. Within the sector, most activities can be defined as either metallurgical production, oil refineries, cement production, petrochemical industry or production of mineral fertilizer. The products are generally produced for a global market. The production process itself usually provides large single points of emission, either from combustion or from other industrial processes like reduction. The main political goal for these sectors today is to decarbonize the activities, and the main Norwegian strategy to achieve this goal has been to be a part of the Emission Trading System (ETS) in the EU (Miljødirektoratet, 2023).

In order for firms to transition from fossil energy-based activities, the demand for new fossil free energy will be high. Phasing out fossil energy from the electricity production sector is therefore, in contrast to much of the EU, not a main objective in Norway because the production is already close to 100 percent renewable. However, when considering the total use of energy, including non-electric energy, the share of renewable energy is much lower. This energy use will need to be mitigated by either removing or changing the activity. Changing activities therefore entails an increased need for renewable power for electrification of activities in most sectors, including petroleum and industry.

Mitigating emissions from existing industry processes in Norway is expected to largely increase demand for renewable energy. Industrial firms will either need to change or substitute their production processes or remove the GHG emission output from the process. Changing the process will often imply changing the energy carriers and reduction agents from fossil-based to renewable-based, like clean electricity, hydrogen, bioenergy, or biochar. In the cases where the process cannot be changed or substituted, carbon capture and storage (CCS) will be needed. This is expected to be the case for waste incineration and cement production, as well as for gas refineries where CCS can be used to convert natural gas to blue hydrogen (Miljødirektoratet, 2023). As the industrial firms will need to reduce their own emissions, demand for existing and new products is simultaneously expected to increase as new low-emission technologies are put into use to mitigate emissions in other sectors.

New industries, like green and blue hydrogen production, battery production and data centers, are expected to be developed all over the world over the coming decades. In Norway, there are a few, large battery and data center projects under development today, and multiple hydrogen production projects. Establishing low emission battery production is a prerequisite for prevalence of electric vehicles, as well as for developing large scale power storage solutions to balance electricity markets with an increasing share of intermittent renewable power production. Hydrogen can be used as an energy carrier in multiple sectors, including transportation and industry, in cases where electrification and batteries are insufficient (Fiskeridepartementet, 2023). It can also be used as a reduction agent in some industries. Data centers is another growing industry, as the need for computing resources and network and storage infrastructure is growing. Since data centers consume large amounts of energy, locating the centers in areas with clean energy production can limit a potential growth in global GHG emissions as the industry grows (Cisco, 2024).

The petroleum sector in Norway is mainly an offshore operation, and while the sector has similarities with the land-based industry, both public governance and GHG accounting of the two sectors are separated. The petroleum production in Norway is the country's single largest GHG emitting sector, with 24.5 percent of the national emissions (Miljødirektoratet, 2023). The strategy prioritized by the government for reducing greenhouse gas emissions from this sector, regardless of the governing parties, has involved the electrification of the platforms producing oil and gas and of onshore refineries. This approach aims to transition offshore petroleum operations from relying on energy from own-produced fossil fuels to operate the platforms, to using electricity generated from renewable sources. Electrifying production platforms will depend on new renewable power production, either from land or from offshore wind power produced closer to the platforms. Thus, Norway can significantly reduce emissions associated with offshore oil and gas extraction from the national GHG accounting. However, this method is dependent on new renewable electricity, while simultaneously inducing a risk of carbon leakage by selling the surplus gas for use in other countries.

1.2. Objective and scenarios

Norway has over time enjoyed a power surplus in the electricity market in normal years. This situation is expected to change before 2030 as a consequence of increased demand for electricity in order to meet climate targets, both in the industry sector and other sectors. The planned development of new electricity production is, however, much lower than the expressed need for access to new grid capacity and thus for access to more electricity (Statnett, 2023c). It is therefore relevant to look at how growth in the industry sector, with increased demand in both existing and new productions, can affect the electricity market in the future. The objective of this study will therefore be to analyze the energy market based on the following question:

How will the electricity market in Norway be affected by new industry projects developed before 2050?

The objective of this study will be analyzed through four different scenarios, which will look at different combinations of new demand from various types of industrial production. This includes new demand within the existing power-intensive industry sector in Norway, electrification of the energy use in the petroleum sector, as well as the three new industry demand categories; hydrogen production, battery production and data centers. The objective is not to create projections and assumptions about what the most likely development in the electricity sector is. The purpose is rather to analyze what could happen if all projects in different planning phases registered in the statistics of grid connection processes provided by Statnett were to be developed.

Four different scenarios are created in order to analyze whether there are competing needs between the five different industry demand categories. The five categories are Power-Intensive Industry (PII), Data Centers (DC), Green Hydrogen Production (HYD), Battery Production (BAT) and Mining and Petroleum (MIPE). These will be further described in chapter 2.3. The four scenarios include different combinations of the demand categories and will be used to analyze effects on the electricity market due to prioritization of electricity for different purposes.

Scenario 1: All Industries

The first scenario will analyze a market situation where all potential new projects in all the five industry demand categories are developed by 2050.

Scenario 2: Existing Industries

The second scenario will analyze a situation where only new projects within the two existing categories, Power-Intensive Industries (PII) and Mining and Petroleum (MIPE), will be developed. This is to simulate a market where energy is prioritized for further development of existing productions, rather than introducing new productions.

Scenario 3: Petroleum Phase-out

The third scenario will analyze a situation where all industry demand categories are included, but the electricity demand in the Mining and Petroleum (MIPE) category is facing a gradual phase-out towards zero electricity use in 2050. This is to simulate a market where the national petroleum production is phased out rather than developed and electrified.

Scenario 4: Reference

The fourth scenario will simulate the effects of NVE's Long Term Power Market Analysis as a reference to compare with the previous three scenarios.

1.3. Literature review

Driven by national targets and international agreements to reduce greenhouse gas emissions, the energy sector in Norway and Europe is set to undergo a large-scale transition in both the energy sector and the industry sector. Elements of this expected transition have been explored in a variety of previous studies modelling energy markets based on different objectives. This section will review some studies to present previous findings relevant for the research objective of this study.

Several studies have utilized energy system models to analyze different future market scenarios, primarily in light of a fossil fuel phaseout in Europe. This includes the models Balmorel (Jåstad et al., 2022; Nagel et al., 2023; Wiese & Baldini, 2018), TIMES (Damman et al., 2021), EMPIRE (Durakovic et al., 2024) and LEAP (Malka et al., 2023). Malka et al. (2023) Nagel et al, (2023), and Jåstad et al. (2022) all examine how Norwegian and Nordic electricity markets can be affected by policies and risk factors emerging from the green transition. Durakovic et al. (2024) and Damman et al. (2021) specifically analyzes the hydrogen industry and its role in decarbonization.

Malka et al. (2023) analyzed the potential effects on security and diversity in the Norwegian energy market when approaching the 2050 climate target. The study considers how becoming a low-emission society in 2050 can affect demand for energy in Norway, including in the industry sector. Expected demand in the industry sector by 2050 is mapped based on national statistics on fuel and energy consumption, projected GDP development and assessments of individual power-intensive industrial plants. The objective of the study is to use demand-side data to project efficient climate mitigation measures and alternative fuel use. Consequently, effects on the electricity market beyond consumption levels such as effects on electricity production, transmission and prices, are not analyzed.

Both Nagel et al. (2023) and Jåstad et al. (2022) used the Balmorel model in their studies. Nagel et al. (2023) analyzed how the European Green Deal's policies on phasing out fossil energy by use of carbon pricing in combination with other policies can impact Nordic electricity prices and production. Jåstad et al. (2022) investigated the influence of various risk factors on future power prices and renewable energy market values. Jåstad et al. (2022) combined the model with a Morris screening approach to rank price drivers and risk factors on both the demand and supply side in the Norwegian electricity market. Both studies provide findings on how consumption, production and prices in the electricity market can develop over the coming decades. However, while the industry sector is included as a main cause for consumption growth, and a subject to climate policies and other risk factors, it is not a main objective in either study.

Within the industry sector, multiple studies model production and consumption of hydrogen specifically. Durakovic et al. (2024) and Damman et al. (2021) both explore the role of hydrogen in decarbonization pathways. The study by Durakovic et al (2024) used the energy system model EMPIRE to optimize hydrogen both as an output produced from electricity and natural gas, and as an input in the industry, heat and power sectors. Damman et al. (2021) considers Norway specifically and analyzes the utility of hydrogen as input in various sectors in a transition to a low-emission society.

The study of Wiese & Baldini (2018) focuses directly on the industry sector but does not conduct a full energy system analysis, like the earlier mentioned studies. Instead, the study proposes a new method to analyze the interaction between the energy and industry sectors in the energy system model Balmorel. Their approach allows for a more detailed breakdown of industrial energy consumption, including electricity demand, heat demand at different temperatures, and fuel usage. According to the study, the new approach will enable a more precise investigation of how changes in industrial processes can affect the entire energy system, including potential for CO_2 reduction strategies. However, as both the service and agricultural industries are included in this study, the industry sector is more widely defined than the industry sector normally is in the Norwegian energy and greenhouse gas emissions statistics.

As presented, there exist multiple recent studies exploring developments in the Norwegian, Nordic and European energy markets. While multiple studies present results on market effects, there is a large variety in the assumptions made and no previous study specifically analyzes the effect on the electricity market from increased demand in the industry sector in Norway. Thus, by drawing on this literature, this study will examine how the development of new industry projects will affect the Norwegian electricity market in the coming decades.

2. Theory and method

This chapter contains a theoretical and methodical background presenting the Nordic electricity market and the energy system model used in this study, as well as a description of the input data and constraints used when optimizing different market situations. In describing the input data, it will be distinguished between the scenario input and other input assumptions. In the scenarios, the demand input varies between the industry categories. The remaining input data covers the demand input for all non-industry sectors in Norway, as well as all sectors within all other countries in the model. In the end of the chapter, constraints imposed on the model are covered.

2.1. The Nordic electricity market

The Nordic electricity market operates in a liberalized market model interconnected through transmission grids and common market mechanisms. 98 percent of the Norwegian electricity production is based on renewable energy sources, with 88 percent being hydro power (Energifakta, 2024). In recent years, development of wind power plants has occupied an increasing share of the mix of power production. The share of wind power production has increased from around zero to 10 percent of the total production within a period of 20 years (Energifakta, 2024). Both Finland and Sweden have power systems consisting of large shares of hydro and wind power production, but these systems, in contrast to Norway, also include nuclear power and other thermic power production. The Danish power system does not have hydro or nuclear power production, but the system consists of a larger share of both onshore and offshore wind power production, as well as other thermic power production and some solar power (NVE, 2023b).

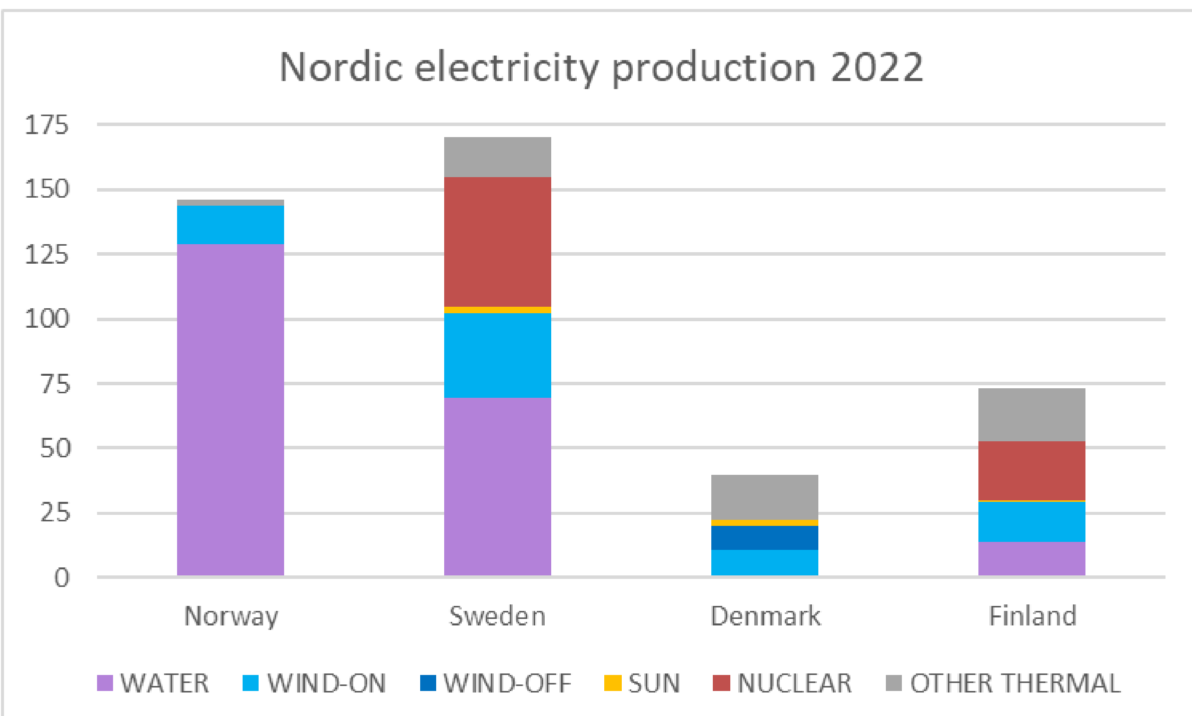

Figure 1: Nordic electricity production (TWh) in 2022 by production technology (NVE, 2023b)

2.1.1. Spot price zones

The Nordic countries are separated into spot price zones depending on the flow of electricity within a region and between different regions. Each price zone is a market where the combined effects of internal demand and supply and transmission with bordering price zones result in a common price for the area. Norway consists of five price zones referred to as NO1-NO5. Three of the price zones have transmission capacity to three out of four price zones in Sweeden, and the southernmost Norwegian price zone, NO2, has transmission capacity to main-land Denmark (DK1), as well as Germany (DE), the Netherlands (NE) and the United Kingdom (GB). There is also some transmission capacity between NO4 and both Finland and Russia, but the Russian connection is currently not in operation (Statnett, 2024).

The size of a spot price zone depends on the capacity of the transmission grid, the geography of existing bottle necks in the grid, and characteristics of the production and demand in the region. Price differences between price zones occur when there is congestion in the grid reducing transmission between regions and causing bottle necks. Thus, creating a best possible border for a price zone requires a balance between the objectives of increasing competition between producers and reducing efficiency loss in grid dispatching (Cretì & Fontini, 2019).

2.1.2. Price determination

Electricity prices are determined in the market by the effects of the available supply and demand at any given time. Prices represent the current market value of electricity and provide important market signals to both producers and consumers. The price level is an important factor in determining whether to produce and use electricity in the short run, and whether to invest in new production, electricity dependent technologies or energy efficiency measures, for instance, in the long run.

Short-run market prices in the electricity market are determined by a merit order dispatching principle, where the power plants with the lowest marginal cost of production are dispatched first. All plants producing power at a marginal cost lower than or equal to the system marginal cost will be dispatched, making up the total load in the market at any given time. The market price is the system marginal cost, defined as the cost of increasing production by one more unit (Wangensteen, 2007). This price is found in the market equilibrium where the supply curve, made up of the merit order curve, meets the demand curve, which is the consumers' willingness to pay for electricity at any given time. Any consumer with a marginal utility of consuming electricity higher than or equal to the system marginal cost in a given market situation will consume electricity (Cretì & Fontini, 2019).

The merit order dispatching system of pricing is a form of uniform auction, which is used in the physical electricity markets in northern Europe. The international power exchange, Nord Pool, is responsible for market transactions in the physical electricity market in Norway, as well as the other Nordic countries, the Baltics and parts of western Europe. Uniform auctions are used both in the day-ahead-market and the intraday market. In the day ahead auctions, expected consumption load is matched with expected production from the producers choosing to bid. This clears the market, providing the system marginal costs for the next day in every price zone (Nordpool, 2024a). Auctions in an intraday market are used to balance out the market based on the information available closer to the physical delivery (Nordpool, 2024b).

In energy markets, the difference between long-run and short-run is the ability to make investments in order to adapt to a long-run market trend (Wangensteen, 2007). Long-run marginal cost for a power producer is approximately the same as the Levelized Cost of Energy (LCOE) for a power producer. This is defined as the total life-time production cost for a power producer, where the production cost is divided by the total amount of energy produced throughout the economic lifetime of the power plant. This measure does not take into account the income of the power plant, but considers the plant's profitability by comparing the LCOE with the long-run market prices. Equal to the case of short-run market prices and dispatch, all plants with an LCOE lower than or equal to the long-run market price are, in theory, profitable investments (NVE, 2023a).

2.1.1. Drivers of supply and demand

The Nordic electricity market depends on a large share of renewable electricity production, with an increasing amount of intermittent production, making the electricity system relatively weather dependent. 75 percent of the hydropower production in Norway is regulated reservoir power (Energifakta, 2024). The availability of water for production, and thus the water value, is therefore a major driver in influencing electricity prices from the supply side. There are seasonal differences in water inflow to hydro power water ways and reservoirs, as well as variations between years. Thus, the water resource is more valuable in some seasons and years than others. In the Nordics, the combined effect of less water inflow and higher electricity demand for heating generally results in higher prices during the winter months than in the rest of the year.

In coming years, climate and energy policies, as well as the development of prices on natural gas, are expected to be major driving forces affecting the electricity price on the supply side of the market. European countries prepare for a gradual increase in carbon prices within the EU ETS in order to gradually phase-out fossil fuels. This transition is expected to increase the share of intermittent renewable electricity production in all of Europe at the expense of high-emission electricity production, like coal. A phase out of coal, both in the Nordics and in other larger northern and western European countries, is expected to increase demand for natural gas (Nagel et al., 2023). This is both because natural gas is less carbon intensive and is thus affected less by the increasing carbon prices than coal, and because more intermittent energy provides a growing need for balancing energy like natural gas.

Power production from natural gas generally has a high marginal cost compared to renewable energy technologies, nuclear energy and energy production from coal, causing high electricity prices when natural gas is included in the electricity mix. The prices on natural gas in Europe have increased further after 2020, due to less availability as a consequence of Russia holding back substantial amounts of their pipeline gas deliveries to Europe (IEA, 2022). The Norwegian electricity system depends neither on coal nor gas power. Thus, trends of higher electricity prices in Europe due to less availability of natural gas and increased carbon pricing affect Norway only indirectly by price contagion through power transmission.

Electricity demand is expected to rise in the long term due to growth in the economy and in the population, alongside a growing need for electrification in existing and emerging sectors. Policy interventions or market shifts can give way to energy efficiency enhancements, countering some of the demand surges driven by economic growth and increased electrification. Additionally, taxes, subsidies, regulations and political priorities can influence demand dynamics, either strengthening or weakening some of the effects expected to increase demand.

2.2. Balmorel

For this study, the Balmorel model has been used to simulate developments in the Norwegian electricity market when demand in the industry sector increases. This section will describe what type of energy system model the Balmorel model is, with the advantages and disadvantages associated with it, as well as defining the model resolutions used for this study.

2.2.1. Energy system modelling

The Balmorel model is an energy system model developed to study the electricity and heating sectors in northern Europe. It is a linear programming energy system optimization model, seeking to minimize total system costs and maximize socio-economic surplus while satisfying various constraints and objectives. Energy system optimization involves finding the most economically efficient way to allocate resources, technologies, and infrastructure while considering technical, economic, and regulatory constraints. The model has a bottom-up approach, analyzing the system based on disaggregated activity data as input. The methods provide insights into the behavior of specific technologies and sectors, but require extensive data inputs (Wiese et al., 2018).

Balmorel is a partial equilibrium model, focusing on optimizing the operation and investment decisions of the energy system. Demand and supply are met in a market equilibrium where the social economic costs are minimized. The market price for electricity and heating is provided in this equilibrium. This allows for a detailed examination of supply-demand dynamics, price formation, and investment decisions within the modeled sectors. However, in a partial equilibrium framework, the scope of the model is limited to the market of the specific sector. Thus, the optimizations do not consider how changes in other sectors impact the electricity and heating sectors and vice versa. As the modelling approach excludes broader macroeconomic interactions, simplifications and abstractions are made, which may overlook aspects of the real-world energy systems (Wiese et al., 2018).

2.2.2. Spatial and temporal resolution

The spatial and temporal dimensions in the Balmorel model are divided into three hierarchical levels each, but the units and scope of the levels can be adjusted according to the needs of a given project. The spatial resolution consists of three layers of geographical entities *Country*, *Region*, and *Area*. The *Country* layer allows for inclusion of general economic inputs and policy measures in the model, while the *Region* layer focuses on power transmission limitations, electricity demand and market pricing. *Areas* represent individual geographical characteristics within a *Region*, defining climate conditions, power generation, and heat demand (Wiese et al., 2018). In this study, the predefined resolutions have been utilized, dividing *Countries* into *Regions* based on the nationally determined price zones. When modelling the Norwegian electricity market, this implies modelling for each of the five Norwegian spot price zones. The spot price zones are created to provide realistic price signals within and between zones separated by physical bottlenecks in the transmission grid.

The temporal resolution in Balmorel is structured using the three layers *Year*, *Season*, and *Term*. The temporal hierarchy allows for flexibility in representing different time scales and durations, enabling the assessment of investments and policy measures over multiple years. *Seasons* capture seasonality within a *Year*, while *Terms* represent the smallest unit of time for optimal heat and power dispatch (Wiese et al., 2018). The temporal layers used in this study are divided into three *Years*, four *Seasons* and 36 *Terms*. The three *Years*, 2030, 2040 and 2050, represent the endings of the three next decades. All three are relevant to analyze in light of global and national climate goals affecting both the electricity and industry sectors. The *Seasons* are divided into four, winter, spring, summer and fall, represented by the four weeks S04, S17, S30 and S43 respectively. The Terms are given as 36 out of 168 hours in a week, from T002 to T168, including every other hour between T002 and T047, and every other hour between T146 to T168.

2.3. Input data

This chapter describes the input data used in the Balmorel model, including descriptions of the scenarios created for the study, the data gathering and processing methods, and the limitations of the methods. The main input parameter used in this study is nominal annual electricity consumption excluding electricity losses. This includes both the relevant data input for defining the four different scenarios in this study, as well as data assumptions concerning consumption in other countries, non-industry sectors, and historic consumption for all countries and sectors. There has been established seven categories for use in the Balmorel model in order to sort the demand input data and separate the different scenarios:

- RESE – Residential and Service
- PII – Power-Intensive Industry
- OTHER – Other Demand Categories
- DC – Data Centers
- HYD – Green Hydrogen Production
- BAT – Battery Production
- MIPE – Mining and Petroleum

The RESE sector consists of the user categories Housing, Vacation Homes and Service. The OTHER sector consists of all the user categories that are not covered by either RESE or any industry categories, but does not include grid loss. The model also includes a category for smart charging of electric cars. This can provide some flexibility in the system, but the category is not analyzed further. All of the industry related categories, meaning all categories except RESE and OTHER, have been given the same hourly demand profile as the preexisting profile for the PII category. Thus, all industry production categories are here assumed to be energy intensive and consequently have a demand profile with little variation over time.

2.3.1. Scenario input

There have been established four different scenarios in order to analyze the effects of increased demand for electricity in the industry sector. The data necessary to establish the different scenarios has been obtained from Statnett and NVE. Statnett provides statistics from their grid connection process, showing where in Norway there is demand for new capacity, including both new demand and new supply. The statistics show how much grid capacity is indicated for each sector and in each price zone. This is divided into three categories; *Reserved capacity*, *Queued capacity* and *Other active cases*.

Table 1: Reserved capacity (MW) per price zone and industry consumption category (Statnett, 2023c)

Reserved capacity (MW)					
Demand groups	**NO1**	**NO2**	**NO3**	**NO4**	**NO5**
Power-Intensive Industry	209	1166	134	653	20
Data Centers	279	613	241	119	30
Green Hydrogen Production	-	920	352	430	-
Battery Production	-	455	-	-	-
Mining and Petroleum	-	332	276	350	368
SUM	*488*	*3486*	*1003*	*1552*	*418*

Table 2: Queued capacity (MW) per price zone and industry consumption category (Statnett, 2023c)

Queued capacity (MW)					
Demand groups	**NO1**	**NO2**	**NO3**	**NO4**	**NO5**
Power-Intensive Industry	54	16	576	118	-
Data Centers	271	500	23	25	-
Green Hydrogen Production	-	-	463	181	-
Battery Production	-	-	100	-	-
Mining and Petroleum	-	59	180	-	-
SUM	*325*	*575*	*1342*	*324*	*-*

Table 3: Other active cases (MW) per price zone and industry consumption category (Statnett, 2023c)

Other active cases (MW)					
Demand groups	**NO1**	**NO2**	**NO3**	**NO4**	**NO5**
Power-Intensive Industry	1061	2105	1118	896	603
Data Centers	662	2027	247	257	170
Green Hydrogen Production	125	811	904	3647	724
Battery Production	370	466	545	150	-
Mining and Petroleum	-	-	459	125	-134
SUM	*2218*	*5409*	*3273*	*5075*	*1363*

Reserved capacity implies that a customer has been assured access to the grid for a specific project, and thus has the security to start developing the project. *Queued capacity* is when a request for grid access for a specific project has been made, but the customer must wait for the grid operator to find available capacity. The category *Other active cases* refers to cases where customers have notified the grid operator about a potential future grid access request, but have not yet made the official request (Statnett, 2023b).

Grid capacity access statistics have been used to establish the first three out of the four scenarios used for simulations in this study. The statistics do not include information about which projects the grid capacity has been requested for or the time frame of the projects. However, the grid operator, which is

Statnett for the transmission grid and local grid companies for the regional and distribution grids, are responsible for granting and revoking reservations. Large scale industry projects are oftentimes connected directly to the transmission grid due to the need for high power output from the electrical grid at one single spot. Projects granted a capacity reservation can lose the reservation or be forced to reapply if a project is delayed compared to the agreed timeframe of the reservation. The reservation will be given to the next mature project in the queue (Statnett, 2022).

It is not possible to know for certain when and if a project with reserved capacity is going to be established. Both project development and grid extension take time. According to Statnett, new grid extensions take between 4 to 12 years, depending on the type of extension and scope. Based on this, it is possible to assume that most projects with reserved capacity by the beginning of 2024 are expected to be finished within a twelve-year time period (Statnett, 2022). For this study, it has been assumed all capacity reserved by the beginning of 2024 will be connected to the grid by 2030. Thus, for all industry categories in all price zones for scenarios 1-3, the 2030 consumption level is the reserved capacity multiplied with the expected number of hours of consumption within a year for each category. The number of hours of consumption used for this study is the estimations made by NHO and LO in their joint report, "Kraftløftet", from the end of 2023 (NHO, 2023).

Table 4: Hours of use in a year per industry consumption category (NHO, 2023)

Demand group	Time of use
Power-Intensive Industry	7 000
Data Centers	7 000
Green Hydrogen Production	4 500
Battery Production	7 000
Mining and Petroleum	8 000

Using all *Reserved capacity* in 2030, while being a simplification, is done for two main reasons. One reason is because it is difficult to divide this category into different time periods, as there are no timeframes connected to the available data. The other reason is to create scenarios that analyze what would happen if industry projects were developed in accordance with the haste associated with reaching the 2030 climate goal.

All capacity demand included in the statistics categories *Queued capacity* and *Other active cases* combined is summed up for each industry category and distributed equally between the years 2040 and 2050. The capacity is multiplied with hours of consumption in the same way as for the 2030 consumption. This implies that the increase in electricity demand is equal in absolute numbers in the two periods 2031-2040 and 2041-2050 within each industry category. By using this method of distributing the demand for new grid access, it is ensured that the situation analyzed includes the sum of all reserved, queued and notified cases of grid access by 2050, while also obtaining an even increase from 2031 to 2050.

Out of the four scenarios established for this study, the scenarios *All Industries*, *Existing Industries* and *Petroleum Phase-out* are based on the Statnett statistics for indicated future grid capacity demand. The three scenarios differ in which industry categories are included in the analysis. *Petroleum Phase-out* diverges from *All Industries* by phasing out the electricity demand in the MIPE sector linearly between 2020 and 2050. The fourth scenario, *Reference*, is based on the projected market development from NVE's Long-Term Power Market Analysis 2023 (Langsiktig kraftmarkedsanalyse 2023) (NVE, 2023b).

All four scenarios have the same starting point, based on historical electricity consumption at a total of 127 TWh in 2020 as a base level of consumption. The historic data is corrected for temperature. Provided by NVE, it is divided into ten different user categories within each of the five spot price zones in Norway. This data has been summarized into the four superordinate sector categories RESE, PII, OTHER and MIP. Historic data is also used as a base level in the *Reference* scenario, because the numbers for electricity use in 2020 provided by the market analysis are lower than real historical numbers. All values after 2020 in this scenario are shifted in accordance with the growth in the market analysis.

Table 5: Description of scenarios

Scenario		**Description**	**Categories**
1.	***All Industries***	All demand indicated within all industry categories	PII, DC, HYD, BAT and MIPE
2.	***Existing Industries***	Demand within the industry categories currently existing in the Norwegian market	PII and MIPE
3.	***Petroleum Phase-out***	Demand within all categories, but a gradual phase out of the electricity demand in the category MIPE	PII, DC, HYD, BAT and MIPE
4.	***Reference***	Demand as presented in NVE's Long Term Power Market Analysis 2023	PII, DC, HYD, BAT and MIPE

Figure 2 illustrates the differences in demand between the scenarios, showing that *All Industries* and *Petroleum Phase-out* generally have higher levels of demand than *Existing Industries* and *Reference*. The high demand in *All Industries* and *Petroleum Phase-out* compared to *Existing Industries* and *Reference* is attributed to the inclusion of all projects within the new industry categories currently in queue or expressing interest in grid access within these scenarios. This divide is especially significant in NO2 and NO4, as shown in Appendix 1. In NO2, the demand in 2050 for scenarios 1 *(All Industries)* and 3 *(Petroleum Phase-out)* is considerably larger than can be observed in all other scenarios and price zones. It is also worth noticing that the demand in 1 *(All Industries)* and 3 *(Petroleum Phase-out)* look equal in NO1 because the values of MIPE are small enough compared to the other demand categories to not make an impact on the total demand.

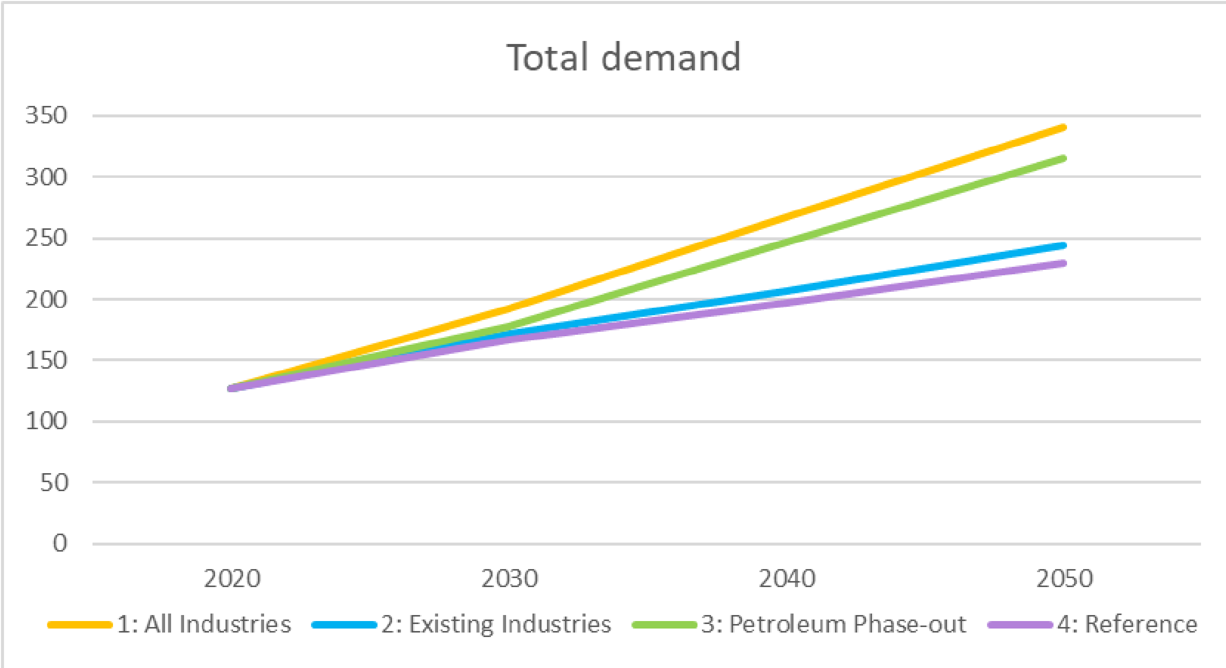

Figure 2: Total demand for electricity (TWh) per scenario

2.3.2. Assumptions

Input data covering sectors and countries aside from the scenario-specific data presented in 2.3.1, has been gathered from NVE's Long-Term Power Market Analysis 2023. This has been done by using three different methods. The choice of method depends on the data that is available and on the necessary accuracy for the electricity consumption in different categories and for different countries.

The first method for data acquisition is the data used for assumed future electricity use in the sectors RESE and OTHER in Norway, as well as both historic and assumed future electricity use in the Nordic countries Denmark, Finland and Sweden. The data for the years 2030 and 2040 has been acquired from NVE's Long-Term Power Market Analysis 2023 (Langsiktig kraftmarkedsanalyse 2023). Because the RESE and OTHER sectors are not the subjects of the analysis in this study, using existing projections has been considered sufficient, rather than preparing projections specifically for this analysis. However, as the precise historic data used in the first acquisition methods is available also for RISE and OTHER from the year 2020 in Norway, this has been used for all Norwegian consumption in 2020.

For Denmark, Finland and Sweden, data for all years and sectors has been acquired from NVE's Long Term Power Market Analysis from 2020 and 2023. The data for the year 2020 has been acquired from the 2020 edition of the Power Market Analysis, while the data for 2030 and 2040 has been acquired from the most recent edition, which is the Power Market Analysis from 2023. The data in the Power Market Analysis is given as sector specific but is not divided into spot price zones like the data in the Balmorel model is. Therefore, the data that existed in the model previous to the work on this study has been used to calculate a share of the total demand that can be distributed to each of the price zones in each of the sectors in the Nordic countries. The data gathered from the Long-Term Power Market Analysis has been used for all categories.

Data for Germany, the Netherlands, the United Kingdom and France has been gathered from the two Long-Term Power Market Analyses made by NVE, similar to the data for the Nordic countries. However, rather than being divided into consumption categories, like the data for the Nordic countries, this data is presented as the estimated total sum of consumption in each country for 2020, 2030 and 2040. The expected consumption in each sector is therefore derived from the change in the total consumption given in the Power Market Analysis and compared to the sum of consumption presented in previous Balmorel data. This percentage change is multiplied with demand in all sectors.

None of the Long-Term Power Market Analyses made by NVE provides projections for energy consumption in 2050. It has therefore been necessary to make a rough estimate of how consumption in non-industry sectors and in other countries will develop by 2050. For this study, this estimation has been done by extending the trend of consumption growth from the period between 2031 and 2040 to the period between 2041 to 2050. In other words, the difference between 2031 and 2040 consumption in absolute numbers has been added to the estimated 2040 consumption to obtain a value for 2050 consumption.

2.3.1. Levelized Cost of Energy

Levelized Cost of Energy (LCOE) is a method of measuring the costs of a power plant investment over the economic lifetime of the plant. This is the method used in the Balmorel model in order for the model to make investment decisions. The LCOE is calculated as the total discounted cost of a plant over its economic lifetime divided by the total discounted amount of electricity sold from the plant (Cretì & Fontini, 2019). This formula can be written as follows:

$$LCOE = \frac{\sum_{t=1}^{n} \frac{Capital\ Expenditure_t + Operations\ and\ Maintenance_t + Fuel\ Costs_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{Electricity\ Production_{i,t}}{(1+r)^t}}$$

The Balmorel model contains data covering both capital expenditure costs, operation and maintenance costs and fuel costs per MWh produced for a great variety of production technologies in both the electricity and heating market. The LCOE-values used for onshore and offshore wind power technologies in this study are presented in figures 3 and 4. The values are specified for each price zone and each year in the model, as one technology will have different costs and levels of production in different regions. They do not change between scenarios. For onshore wind power technologies LCOE-values fall within the range of 17 and 35 EUR/MWh. For offshore wind power technologies, the values vary between 34 and 42 EUR/MWh, and the values are reduced somewhat from 2030 to 2050.

Estimations of LCOE values for different technologies are based on representative production plants from the given regions. While it varies between technologies when the data in the model was last updated, all data has been gathered within the time period from 2016 to 2023.

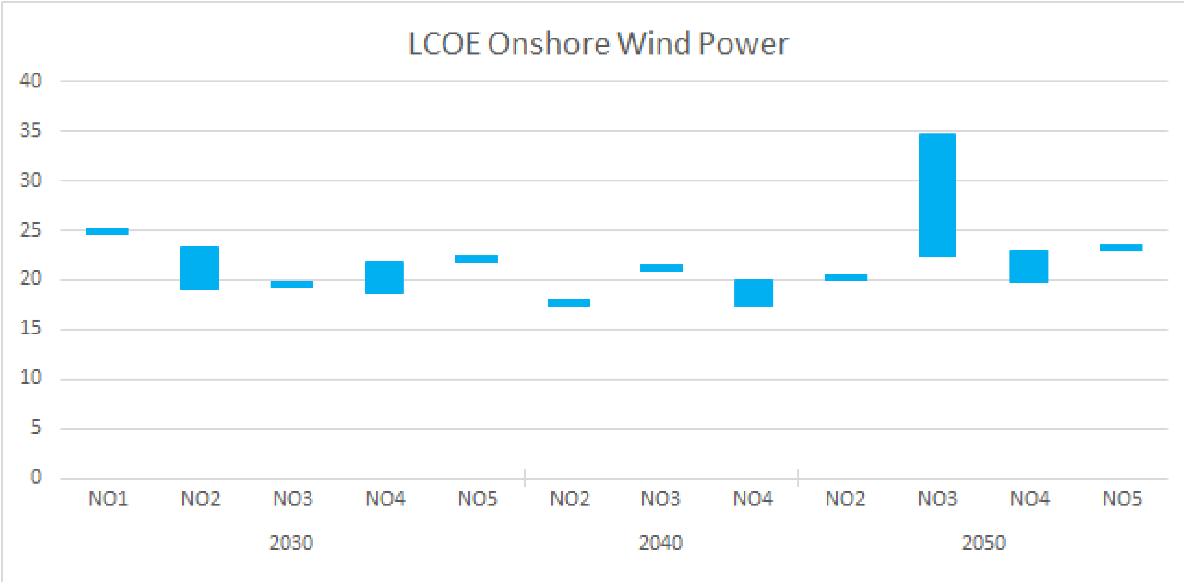

Figure 3: LCOE values (EUR/MWh) for onshore wind power technologies for each price zone in 2030, 2040 and 2050

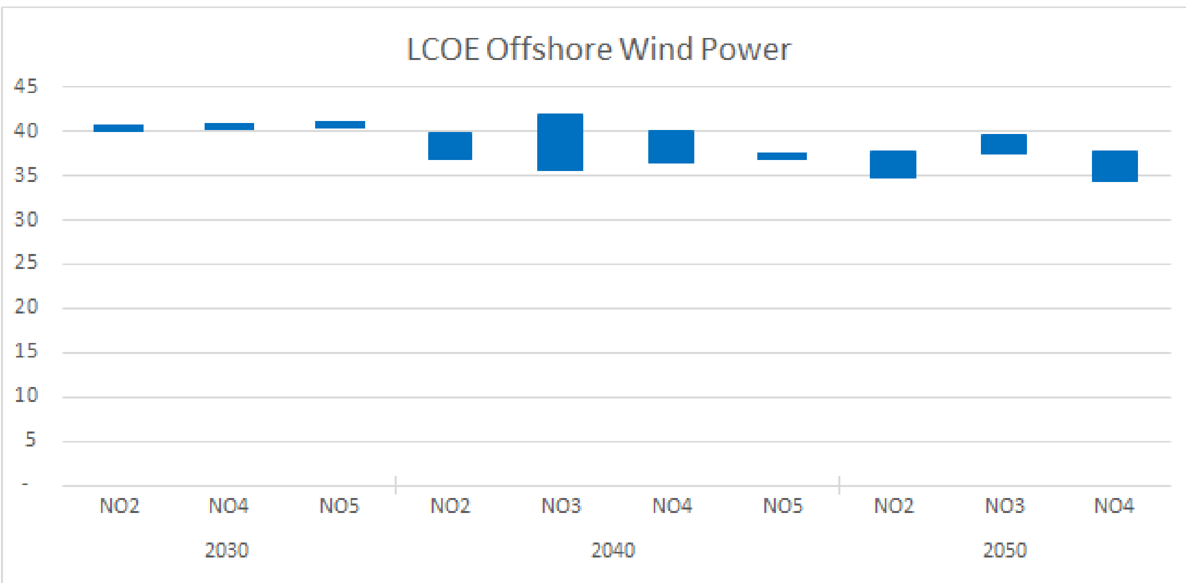

Figure 4: LCOE values (EUR/MWh) for offshore wind power technologies for each price zone in 2030, 2040 and 2050

2.3.2. Short-run marginal costs (SRMC)

The Balmorel energy system model utilizes Short-Run Marginal Cost (SRMC) to determine the economic dispatch of electricity generation technologies, including onshore and offshore wind. SRMC reflects the variable cost of producing one additional unit of electricity from a specific technology. Onshore wind has a somewhat lower SRMC compared to offshore wind because onshore plants typically have lower operation and maintenance costs due to easier accessibility. In the model, these costs vary between 1.22 EUR/MWh and 1.47 EUR/MWh for onshore technologies, and between 2.06 EUR/MWh and 2.65 EUR/MWh for offshore technologies. The variations occur due to small differences between price zones and years. For offshore wind power technologies, the costs are somewhat reduced from 2030 to 2050.

2.3.3. Fuel costs

The Balmorel energy system model factors in fuel prices for a variety of technologies as an input in order to value both their short-run and long-run costs. In the short term, fuel prices directly impact a technology's short-run marginal cost (SRMC), determining which existing technology should be dispatched in the market. In the long run, fuel prices influence a technology's levelized cost of energy (LCOE), and thus which technologies will be developed over time. Table 6 contains the fuel price input in the Balmorel model for energy carriers used as fuel in the Northern European electricity market. The four fuel-types *straw*, *woodchips, woodpellets* and *woodwaste* make up the fuels of the category mainly referred to as BIO in this study.

Table 6: Fuel price input (EUR/MWh) in the Balmorel model per energy carrier in 2030, 2040 and 2050

	2030	**2040**	**2050**
NUCLEAR	0.21	0.21	0.21
NATURAL GAS	1.19	1.17	1.14
COAL	0.56	0.49	0.43
MUNIWASTE	-0.91	-0.91	-0.91
STRAW	1.63	1.70	1.77
WOODCHIPS	1.99	1.99	2.07
WOODPELLETS	2.45	2.50	2.55
WOODWASTE	0.18	0.18	0.18

2.3.4. CO_2-prices

The Balmorel energy system model incorporates CO_2-prices as an input factor. This means that the model considers the economic cost of releasing greenhouse gases when modelling future energy scenarios. The CO_2 prices are based on emission quota prices in the EU Emission Trading System (ETS), which are expected to rise steadily in the years leading up to 2050 as an incentive to shift towards cleaner energy sources. As CO_2 prices rise, the economic competitiveness of fossil fuel technologies will decline in comparison to non-fossil energy sources like renewable and nuclear power production. This allows the Balmorel model to project how future energy landscapes might evolve under increasing pressure to reduce carbon emissions. Table 7 contains the CO_2-prices used in the Balmorel model for the three years analyzed.

Table 7: CO_2-price input (EUR/ton-CO_2) in the Balmorel model in 2030, 2040 and 2050

YEAR	**PRICE**
2030	85
2040	150
2050	500

2.4. Constraints

Constraints can be incorporated in order to reflect economic or political goals or regulations considering resource allocation, market prices or environmental considerations, amongst other things. They can also reflect technical and practical boundaries in real-world market operations. For the optimizations in the Balmorel model used for this study, maximum capacity and production constraints have been placed on onshore wind power production, hydro power production and power transmission capacity.

The maximum production level of onshore wind power production allowed in the model in 2030 for all the four scenarios in the study is 22 TWh. This level is increased to 25 TWh in 2040 and 2050. These constraints have been placed in order to reflect a level of available capacity and future investments that appear realistic based on current trends and technical limitations. At the start of 2023, the wind power production in Norway reached 16.9 TWh, marking an annual increase between 1 and 4 TWh since 2018 (Energifakta, 2024). While the number of new investments in wind power production is expected to decrease compared to the last five years, there are still new projects in planning and development.

Hydro power production is, similarly to onshore wind power production, constrained by a maximum level of production each year. However, while the constraints on wind power production are strict numbers, the constraint on hydro power is formulated to limit production to the 2013 weather year. The constraint results in a production level of around 134 TWh, but the total production value can vary somewhat each year in the optimizations depending on variations in factors like storage and pumping. This implies that no new production can be developed compared to the 2013 level and power plant upgrades are not included in the model. The constraint is placed to reflect the political intention of not developing new large hydro power plants in Norway. However, new small-scale production and upgrades on existing power plants are also not included in the model despite political support. This is a consequence of limitations in the model, rather than constraints implemented to reflect real-life trends, and can affect the results. Also, potential future change in weather and inflow to existing reservoirs due to climate change is not included in the simulations.

For all scenarios, transmission of power is constrained by the capacity of the current transmission grid. Thus, no new investments in the transmission network are permitted for any of the four scenarios. This includes both transmission within a price zone and between. Limited transmission capacity can cause bottlenecks. This can affect the results as the bottlenecks can enhance the price differences between price zones and limit the options for how to ensure access to power in order to meet changes in demand.

2.5. Sensitivity

The results of any optimization carried out will be limited by the input parameters, constraints and limitations of the model. It is therefore relevant to use sensitivity analysis as a tool for assessing the impacts of uncertainties and variations in input parameters and constraints. In this study, the input parameters have been varied by creating four different scenarios with variations in demand, providing a *Base* situation. The constraints on output described in chapter 2.4, on the other hand, have been fixed in all scenario optimizations. This study will analyze how sensitive energy market prices are to variations in the maximum constraints on investments in wind power production and on transmission capacity.

In order to test sensitivity within all Norwegian price zones, two new situations have been optimized for all the four scenarios to be compared to the *Base* situation. One situation is a *Low Wind* situation, where the production and installed capacity is limited to the 2023-level. This is done to analyze what would happen if no new onshore wind power installations were allowed after 2023. The second situation is a *High Wind* situation, where the level of new onshore wind power production allowed is doubled compared to the *Base* scenario. The constraints for each situation are presented in Table 8.

Table 8: Production (TWh) and installed capacity (GW) for the constraints in the three sensitivity situations Low wind, Base and High Wind in 2030, 2040 and 2050

	2030		*2040*		*2050*	
	Production (TWh)	**Capacity (GW)**	**Production (TWh)**	**Capacity (GW)**	**Production (TWh)**	**Capacity (GW)**
Low Wind	17	5	17	5	17	5
Base	22	6.5	25	7.5	25	7.5
High Wind	44	13	50	15	50	15

The *Base* situation for optimizing the four scenarios in this study has been constrained by limiting new investments in the transmission network to zero. It is therefore relevant to analyze whether this constraint has affected the optimal market solution in any of the scenarios. To compare with the *Base* situation, which is described in Table 9, two new situations have been modelled. The first is a *50% increase* situation, entailing optimizations where the total level of installed transmission capacity allowed in the market is a 50 percent increase compared to the *Base* situation. The second situation, *100% increase,* is a market where a doubling in the level of installed transmission capacity is permitted compared to *Base.*

Table 9: Transmission capacity levels (GW) between price zones in, and bordering to, Norway in the Base situation

PRICE ZONES			**CAPACITY (GW)**
NO1	↔	NO2	2.85
NO1	↔	NO3	0.50
NO1	↔	NO5	2.25
NO1	↔	SE3	2.12
NO2	↔	DE4-N	1.40
NO2	↔	DK1	1.64
NO2	↔	NL	0.70
NO2	↔	NO5	1.55
NO2	↔	UK	1.40
NO3	↔	NO4	0.80
NO3	↔	NO5	0.90
NO3	↔	SE2	0.80
NO4	↔	SE1	0.65
NO4	↔	SE2	0.28
		SUM	***26.69***

3. Results

This chapter presents the energy market optimizations of four scenarios run with the Balmorel model. Each scenario has been run for the years 2030, 2040 and 2050, and the results are separated into countries and price zones. While the model provides results for all countries and price zones, only the Norwegian price zones will be presented in this chapter as Norway is the focus of the research objective. In this chapter, the optimized development in production, transmission and prices will be presented in subchapters 3.1., 3.2 and 3.3. respectively. The chapter also includes sensitivity analysis for price development when restrictions on onshore wind and transmission capacity are adjusted presented in subchapter 3.4.

3.1. Production

This section outlines the anticipated electricity generation output from various energy-producing technologies resulting from the optimizations conducted with Balmorel. The Balmorel optimizations for the Norwegian energy market (Figure 5) estimates a general trend of stable levels of hydro, solar and onshore wind power production, while offshore wind power covers the larger variations of demand between regions, years and scenarios. There is no change in total production of hydro power over time, and a slight increase in total solar and onshore wind power production after 2030. This is equal in all scenarios. The overall total power production, on the other hand, varies between scenarios in 2040 and notably so in 2050. This variation is covered by larger variations in offshore wind power production. The results show some offshore wind power production in 2030, but the significantly largest amounts in the scenarios 1 *(All Industries)* and 3 *(Petroleum Phase-out)* in 2050.

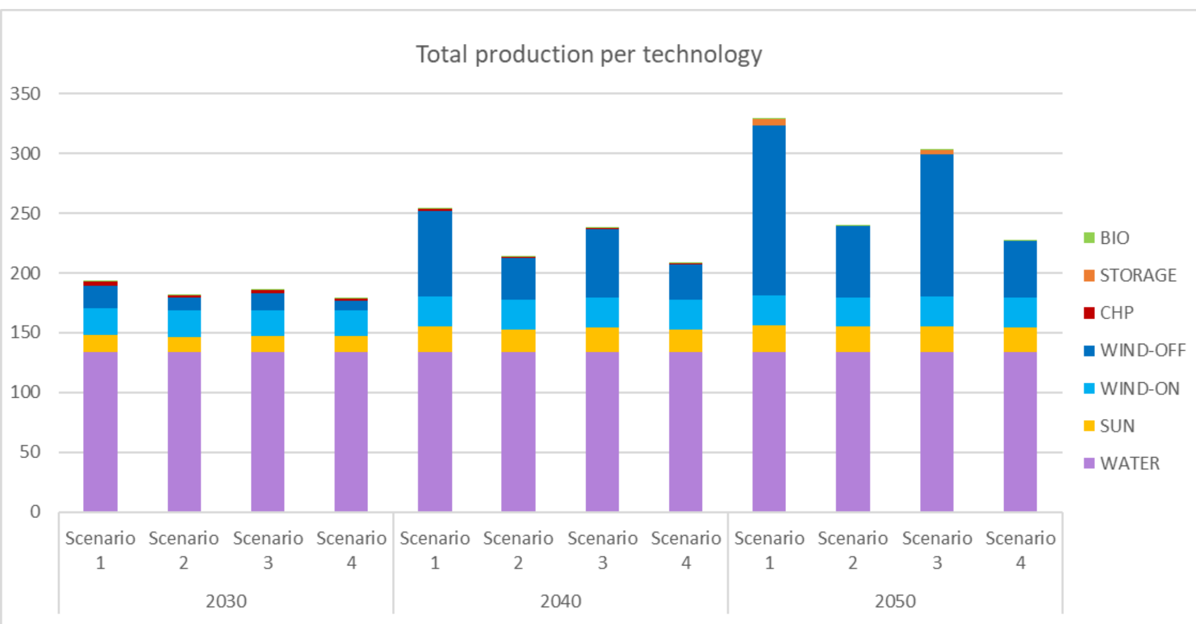

Figure 5: Total production in Norway per technology graph (TWh) for each scenario in 2030, 2040 and 2050

The model optimizations show that all hydro and onshore wind power available is used, and that offshore wind power, as the more expensive technology, is first put into production after the other technologies are maximized. The total national production for hydro power and onshore wind power is maximized within the constraints applied in the model. As all scenarios utilize the maximum level of available onshore wind power, the production increases with approximately 15 TWh from the 2020-level of 10 TWh to 25 TWh in 2050 in all scenarios. In total, the production of all technologies is estimated to double from the 2020 level of 154 TWh by 2050 in the two scenarios 1 (*All Industries)* and 3 (*Petroleum Phase-out)* and increase by around 50 percent in the 2 (*Existing Industries)* and 4 (*Reference)* scenarios.

The variation in production technologies between years and scenarios is more noticeable when studying the results within each of the five price zones in Norway (Appendix 2). Similarly to the national trend, both hydro and solar power technologies provide electricity production with little variation, both between years and between scenarios, in most price zones. The only prize zone where the production of solar power seems to be varying between scenarios is in NO4. In NO4, there is no solar power production in 2030 in any scenario nor in scenarios 2 *(Existing Industries)* and 4 *(Reference)* in 2040. There is also lower production in scenarios 2 *(Existing Industries)* and 4 *(Reference)* compared to scenarios 1 *(All Industries)* and 3 *(Petroleum Phase-out)* in 2050.

Power production from onshore and offshore wind varies notably between price zones, scenarios and years. In NO1, the simulations show less than 1 TWh production from wind power in all scenarios and a slight reduction in total production due to some reduced production from combined heat and power (CHP) technologies. The optimizations of NO2, on the other hand, display a large production in offshore wind power in all scenarios. The production in this price zone diverges from the four others by being the only price zone, except scenario 1 *(All Industries)* for NO5, with offshore wind power production in 2030. While the production of offshore wind power increases in all scenarios for NO2, the increase is higher in scenarios 1 *(All Industries)* and 3 *(Petroleum Phase-out)*, with production of 80 TWh and 75 TWh respectively, compared to 37 TWh in scenario 2 *(Existing Industries)* and 30 TWh in scenario 4 *(Reference)*. The wind power production in NO2 also diverges from the other price zones by having a negative trend for onshore production from 2030 to 2050 for all scenarios. Only scenario 4 *(Reference)* shows onshore wind power production in 2050 in this price zone.

In the price zones NO3 and NO4, the Balmorel optimizations show stable onshore wind power production and increasing offshore wind power production from 2030 to 2050. The production of onshore wind power is around 6 TWh in all years and scenarios in NO3. In NO4, it is slowly increasing from around 10-11 TWh in 2030 to 16-18 TWh in 2050, with the production in scenario 4 *(Reference)* being somewhat lower than the other three scenarios. For offshore wind, most of the production in NO3 is expected to come in 2050, except for scenario 1 *(All Industries)* in 2040. In 2050, this production varies from around 8 TWh to almost 32 TWh between the scenarios, with scenario 1 *(All Industries)* having the highest production and scenario 4 *(Reference)* having the lowest. Production from offshore wind power in NO4 is higher than in NO3 for scenarios 1 *(All Industries)* and 3 *(Petroleum Phase-out)* in 2040, but lower in 2050. For scenarios 2 *(Existing Industries)* and 4 *(Reference)*, the offshore wind power production in NO4 is close to zero in all years.

In NO5, the onshore wind power production is close to zero in all scenarios and years, while the production of offshore wind power is stable from 2040 to 2050. The optimizations show production of around 2 TWh offshore wind power in scenario 1 *(All Industries)* and 2 TWh onshore wind power in scenario 4 *(Reference)* in 2030. In 2040, the optimizations show offshore wind power production around 10 TWh, and a reduction of 1-2 TWh by 2050 for all scenarios.

With a total national level of onshore wind power production constrained to 22 and 25 TWh a year, the model prioritizes more than half of the available production to NO4. New investments are made in both NO2, NO3 and NO4 in 2030, where the technology has the lowest LCOE. In 2040, all new onshore wind power investments occur in NO4 despite NO2 and NO4 having an equally low LCOE. NO2 and NO5 covers demand beyond what hydro and solar power can provide by mainly producing offshore wind power. This suggests that onshore wind power is relatively more available and competitive compared to offshore wind power in NO4 compared to NO3 and NO5. Onshore wind power production being prioritized for NO4 rather than NO2, however, cannot be explained by LCOE alone. This can, for instance, be a result of differences in electricity prices between the two price zones. By 2050, all new investments are in offshore wind power production.

3.2. Power transmission

This section describes the trends in electricity transmission in each price zone, displaying the main trends in the power transmission development. The results (Figures 6 and 7) show a generally increasing net transmission flow in each price zone between 2030 and 2050, except NO4. In NO2, scenarios 1 *(All Industries)* and 3 *(Petroleum Phase-out)* experience growth of around 10 TWh in net export from 2030 to 2050. This is a change from scenarios 1 *(All Industries)* and 3 *(Petroleum Phase-out)* having a lower level of net export than scenarios 2 *(Existing Industries)* and 4 *(Reference)* in 2030 to having a higher level of net export in 2050. Net exports in scenarios 2 *(Existing Industries)* and 4 *(Reference)*, on the other hand, change little between 2030 and 2050.

In all scenarios, NO2 experience increased import from bordering countries simultaneously as export to other Norwegian price zones increases. There is a shift from NO2 being a net exporter to Germany, Denmark, and the United Kingdom in 2030 to being a net importer from the same countries in 2050. In this period, exports from NO2 to NO1 and NO5 increase (Appendix 3). For the price zones NO3 and NO4, the results show relatively stable transmission flows with little variation over time. NO3 is a net importer in all scenarios, with a somewhat higher level of net import in 2050 than 2030, and NO4 is a net exporter with some reduction in exports from 2030 to 2050. NO4 is mainly exporting to NO3. NO3 also imports electricity from SE2, while it varies whether NO3 is a net importer or exporter with NO5 (Appendix 3).

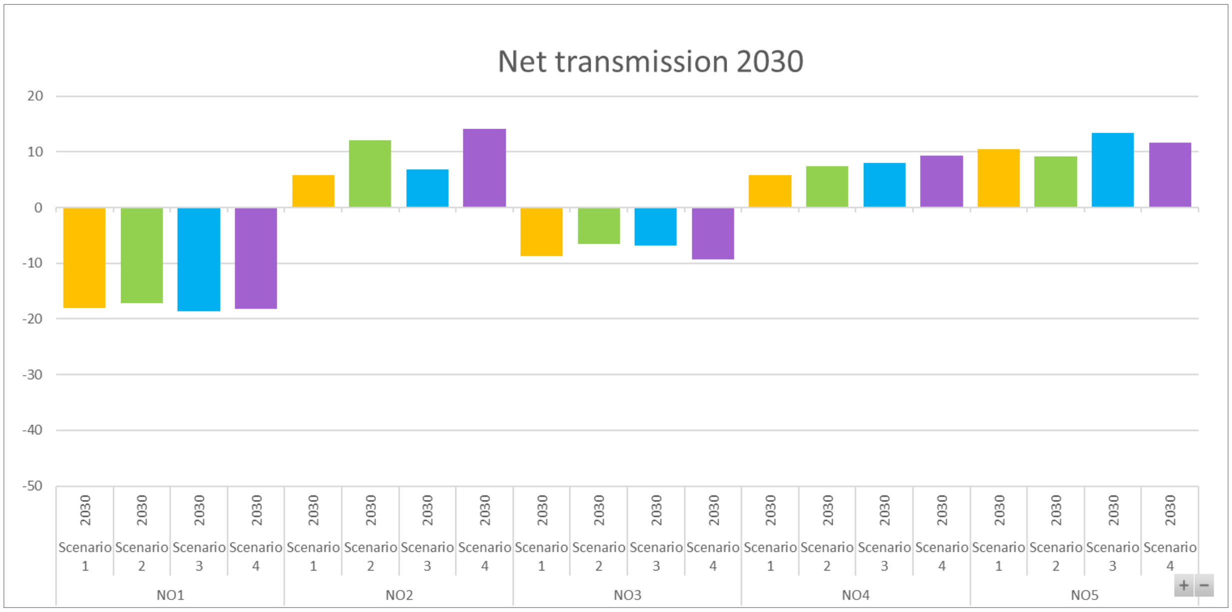

Figure 6: Net transmission flow graph (TWh) for each scenario and price zone in 2030

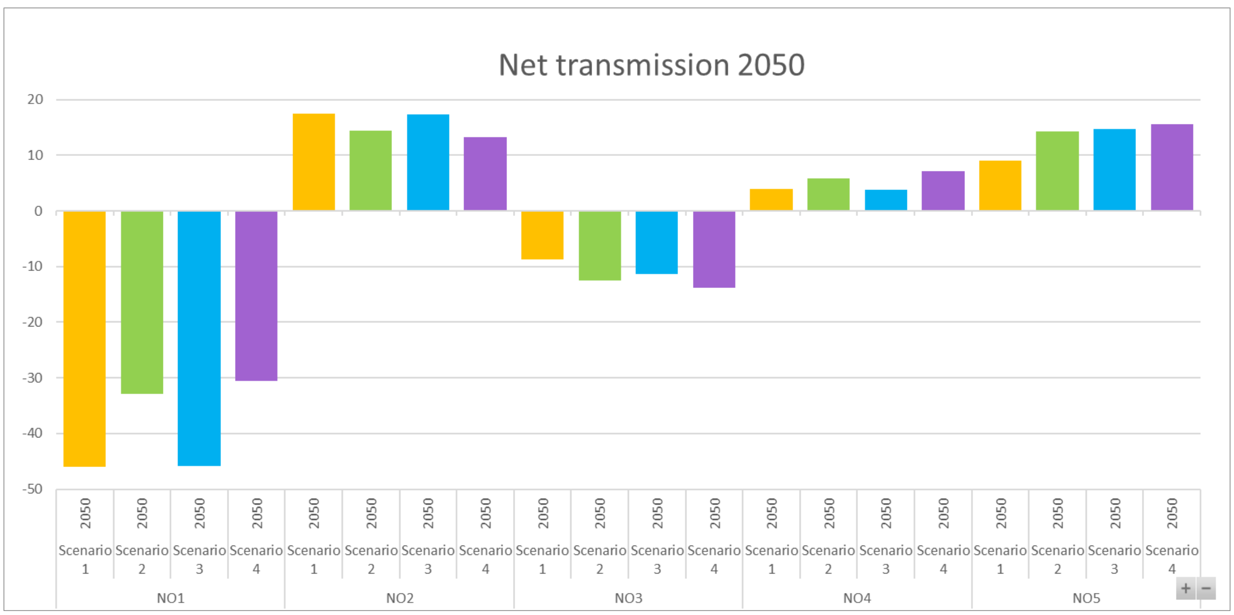

Figure 7: Net transmission flow graph (TWh) for each scenario and price zone in 2050

The increase in transmission is especially notable in NO1, where the net import grows from around 18 TWh in all scenarios in 2030 to between 30 and 45 TWh in 2050. There is also a shift from NO5 being the largest exporter to NO1 in 2030 and 2040, to NO2 being the largest exporter in 2050 (Appendix 3). Both NO5 and NO2, however, are expected to increase export to NO1 significantly from 2030 to 2050. This corresponds with the demand input as well as the results in 3.1. There is increasing demand in NO1 in the period between 2030 and 2050, while the production results indicate a slight decrease in production in the same price zone. The graphs combining production and transmission displayed in Figures 8 and 9 show how the increase in demand is covered only by power imports in NO1.

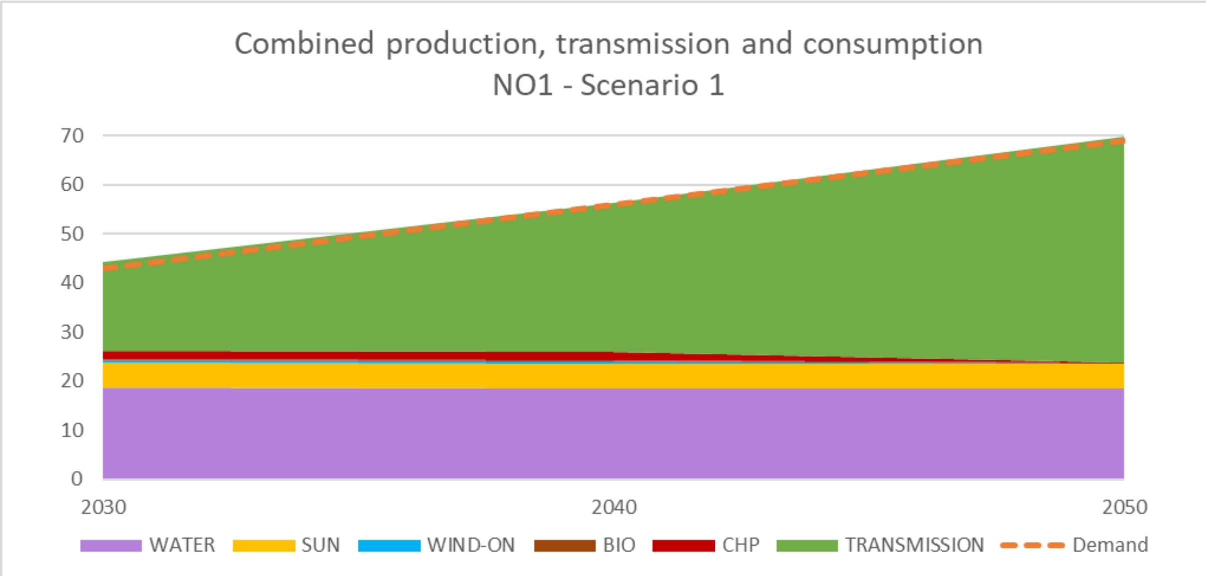

Figure 8: Combined production, transmission and consumption graph (TWh) in NO1, scenario 1 (All Industries), for 2030, 2040 and 2050

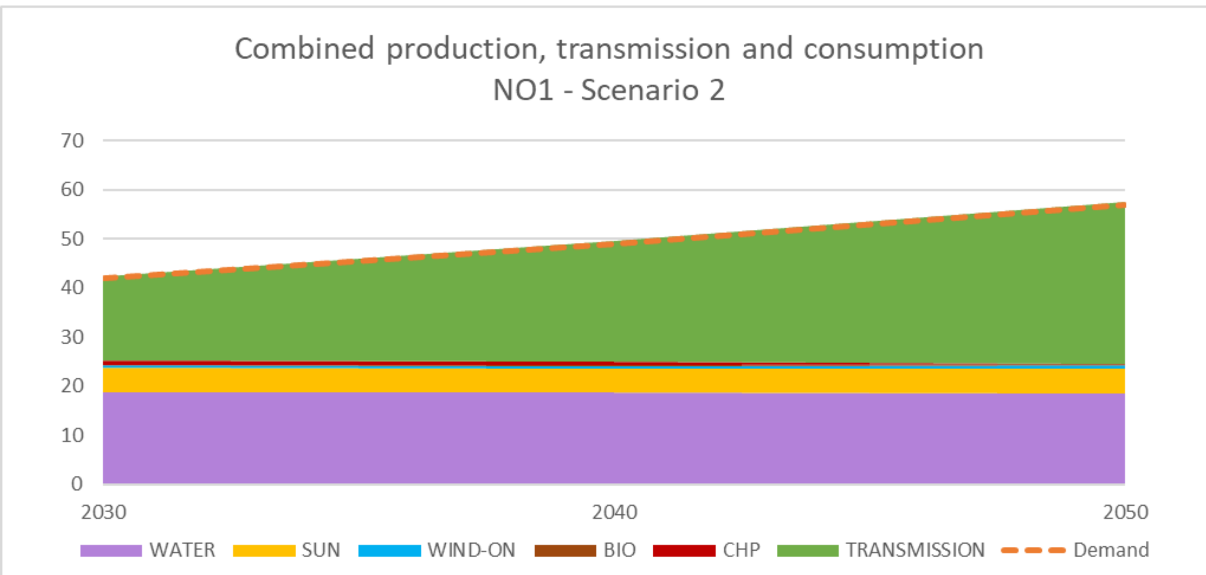

Figure 9: Combined production, transmission and consumption graph (TWh) in NO1, scenario 2 (Existing Industries), for 2030, 2040 and 2050

3.3. Electricity prices

In this section, the estimated development of the electricity prices in Norway from 2030 to 2050 is presented. The price graphs in Figures 10-13 compare the average price estimations for the five different price zones within all scenarios. For all scenarios, there is an increase in prices from 2030 to 2050. While the level of the prices varies between the scenarios, the ranking of the price zones with, from highest to lowest price levels, remains mostly consistent.

The optimizations estimate generally higher prices in the two high-demand scenarios, 1 *(All Industries)* and 3 *(Petroleum Phase-out)*, than in scenarios 2 *(Existing Industries)* and 4 *(Reference)*. The difference between the highest and the lowest price in each scenario in 2050 is similar, being between 12 and 16 EUR/MWh. With the 2030 level being almost equal in all scenarios, this shows a generally steeper increase in scenarios 1 *(All Industries)* and 3 *(Petroleum Phase-out)* in all price zones than in scenarios 2 *(Existing Industries)* and 4 *(Reference).* This is a response to higher demand towards 2050 in the two former scenarios. NO4 experiences a similar development trend to the other price zones, but with a generally lower price level than the other price zones for all years.

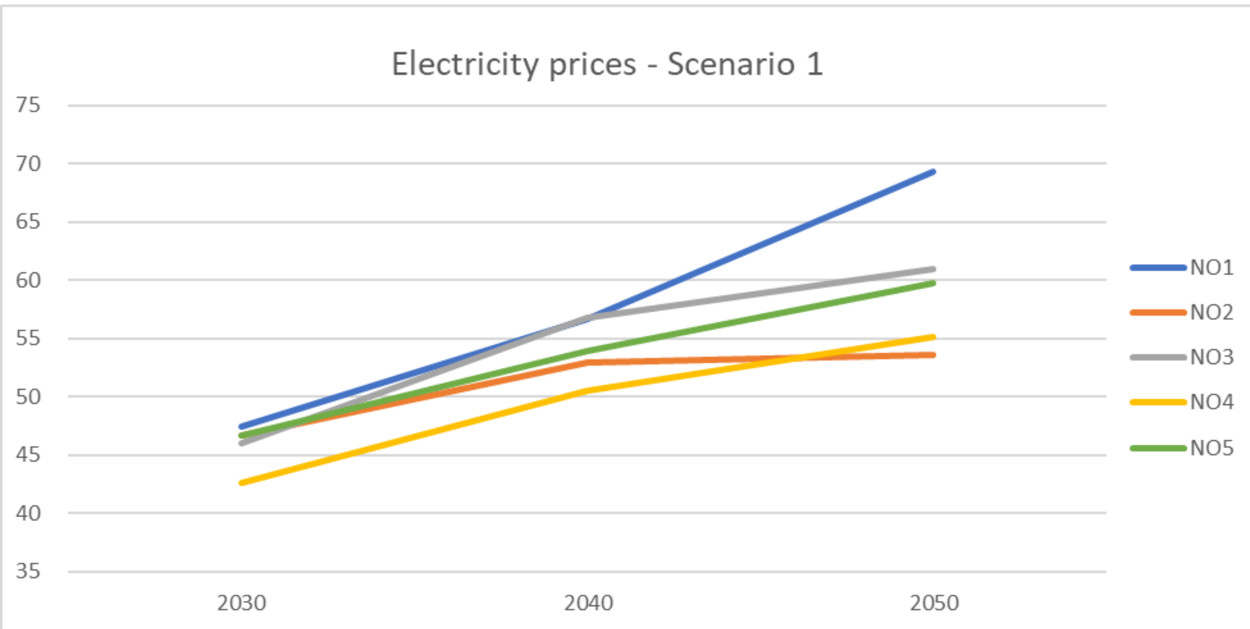

Figure 10: Electricity price development graph (EUR/MWh) in scenario 1 (All Industries) per price zone in 2030, 2040 and 2050

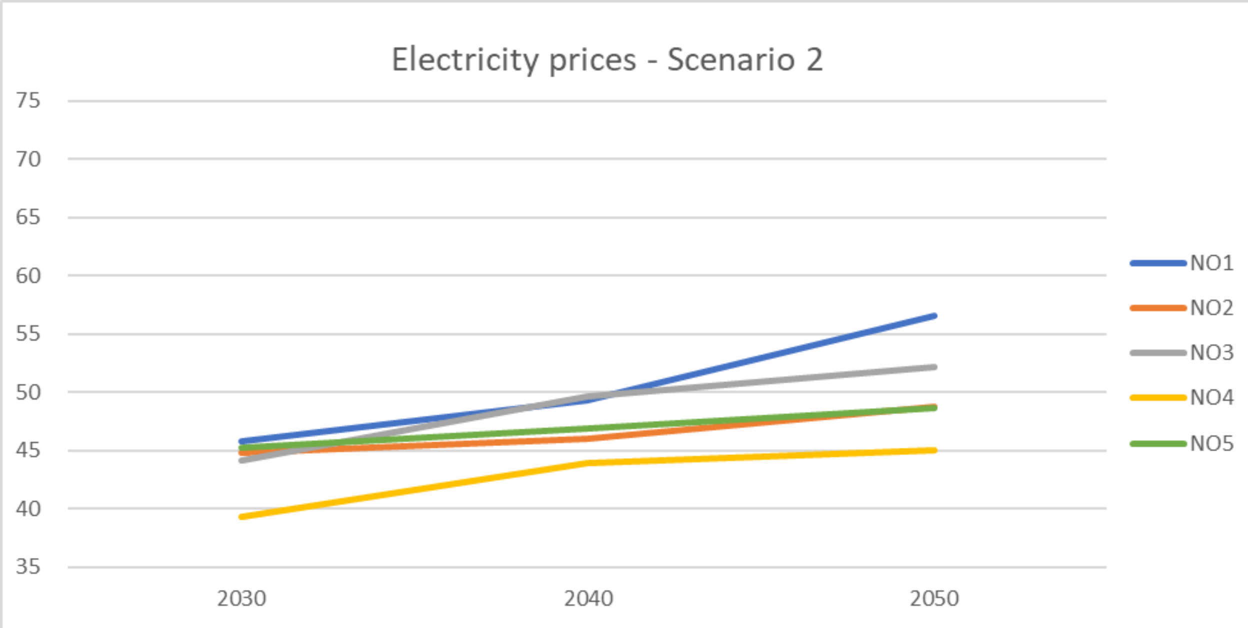

Figure 11: Electricity price development graph (EUR/MWh) in scenario 2 (Existing Industries) per price zone in 2030, 2040 and 2050

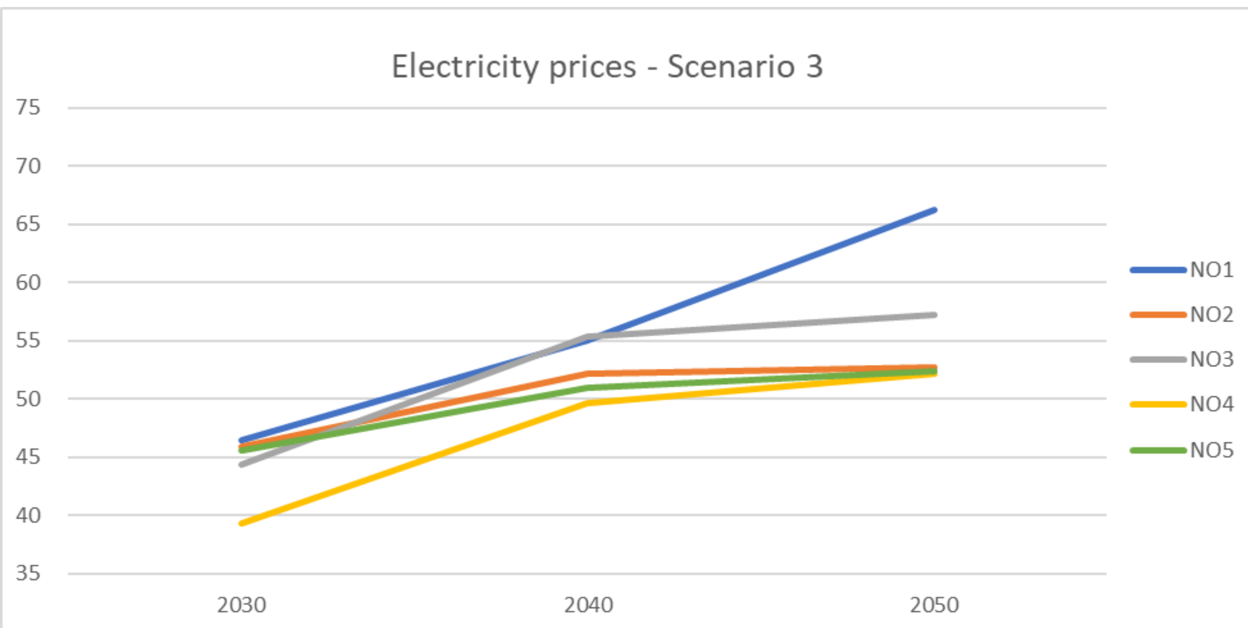

Figure 12: Electricity price development graph (EUR/MWh) in scenario 3 (Petroleum Phase-out) per price zone in 2030, 2040 and 2050

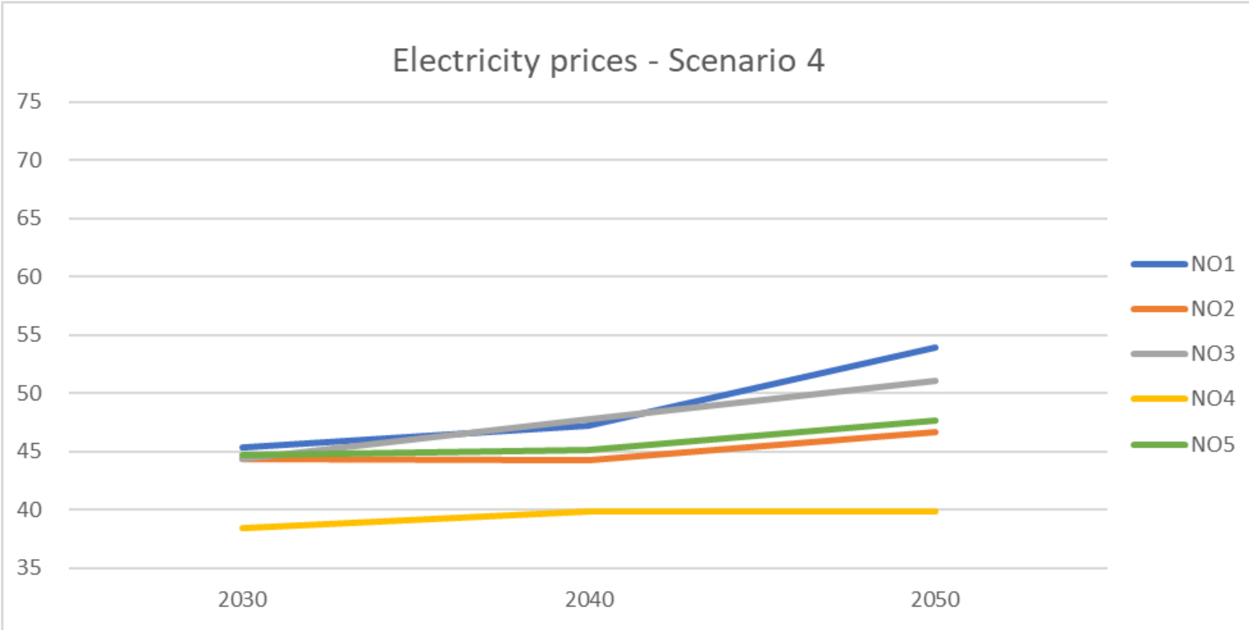

Figure 13: Electricity price development graph (EUR/MWh) in scenario 4 (Reference) per price zone in 2030, 2040 and 2050

3.3.1. High average prices in NO1

NO1 is estimated to have the highest average price in 2050 in all scenarios, while NO4 generally experiences the lowest average price with the exception of in 2050 in scenario 1 *(All Industries)*. The price in NO1 reaches prices of 69 EUR/MWh and 66 EUR/MWh in 2050 in scenario 1 *(All Industries)* and 3 *(Petroleum Phase-out)* respectively, which are the highest for any price zone and scenario. The high prices in NO1 and the low prices in NO4 reflect the differences in production within the two price zones. The first area has low production compared to demand and the second area has high production compared to demand. The demand in NO1 increases towards 2050 in all scenarios and is somewhat higher than in NO4. However, while the production in NO4 adjusts when own demand changes by 2050, no new production is established in NO1, prompting the price zone to import electricity from other price zones to cover the growing demand.

While the prices in NO1 develop equal to NO3 in all scenarios before 2040, a price gap occurs between the two price zones in 2050. This is the result of a corresponding divergence in own production between the two price zones in 2050. NO1 and NO3 have corresponding consumption profiles, from a 2030 consumption level of 42-43 TWh in NO1 and 31-35 TWh in NO3 to a 2050 consumption level between 50 and 70 TWh. The 2050-levels in each scenario are similar across the two price zones. Equally, both price zones have own power production somewhat lower than 30 TWh in 2030 and 2040. In 2050, however, NO3 experiences a large growth in offshore wind power production in all scenarios, thus increasing total own production. Production in NO1, on the other hand, is slightly decreased, while electricity imports from NO2, NO5 and SE3 are largely increased.

The price profiles (Appendix 4) through a year in NO1 and NO3 are essentially equal in 2030 and 2040 but diverging in 2050. In 2030, all scenarios in all price zones have a higher frequency of shorter price fluctuations than later years. In 2040, there is less price variation throughout the year, leaving the price during summer evenly close to zero and the price during the rest of the year between 60 and 100 EUR/MWh. In 2050, there are more seasonal fluctuations in both price zones. While NO3 has the highest single event peak price of around 350 EUR/MWh, NO1 has longer periods of higher prices, with prices reaching 180 EUR/MWh over time during the fall season.

The graphical comparison of the yearly price variations in NO1, NO2, NO5 and SE3 (Figure 14), using scenario 1 *(All Industries)* as an example, clearly illustrates how prices in NO1 correspond with the prices in the bordering price zones. The hourly prices in NO1 align with the prices in the bordering price zone with the highest prices in most hours during the year. Thus, the dependency on electricity imports in NO1 in 2050 leads to a significant price contagion effect, which increases the average price to a level distinguished from the other price zones.

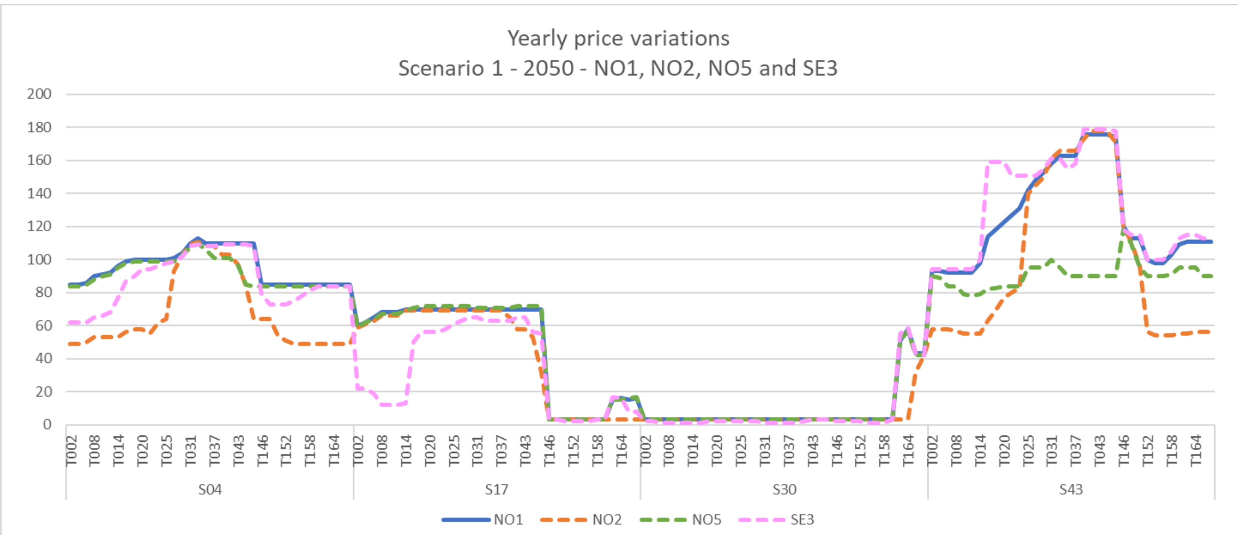

Figure 14: Yearly price variation graph (EUR/MWh) with hourly prices in NO1, NO2, NO5 and SE3 within the four weeks S04, S17, S30 and S43 in 2050, scenario 1 (All Industries)

3.3.2. Price development in NO2 diverges from NO5 in 2050 in scenario 1

The price levels in NO2 and NO5 develop similarly to each other in all scenarios, with the exception of scenario 1. In scenario 1, there is little change in average prices in NO2 between 2040 and 2050 while the average prices in NO5 increase by 6 EUR/MWh from 2040 to 2050 (Figure 10). The price duration curves in Figure 15 illustrate this division occurring after 2040. NO2 and NO5 have resembling price duration curves throughout the year in 2040, but the price duration curves deviate from each other in 2050. NO5 has less price fluctuations over the year than NO2 and does not experience price peaks above 120 EUR/MWh, in contrast to NO2, which reaches peak prices of 180 EUR/MWh. However, during most hours of the year in 2050, when neither price zone experiences peaks of prices above 100 EUR/MWh nor prices close to zero, the price duration curves of NO2 and NO5 show parallel trends, but with an average price difference of 20 EUR/MWh.

When NO2 diverges from the same average price development trend as NO5 after 2040 in scenario 1 *(All Industries)* (Figure 10), it becomes the only scenario where NO2 experiences the lowest average price out of the five price zones. The price level in NO4 is generally the lowest in most years and scenarios but reaches a level close to NO2 and NO5 by 2050 in scenario 3 *(Petroleum Phase-out)* and bypasses NO2 in scenario 1 *(All Industries)*. This is due to NO4 experiencing higher peak prices than NO2 during the high-price hours in 2050 (Figure 16). The opposite is true in 2040, where NO2 experiences some hours with prices close to 200 EUR/MWh, while NO4 has no hours with prices above 86 EUR/MWh (Figure 15). Hence, which region experiences the lowest average price shifts from NO4 in 2040 to NO2 in 2050.

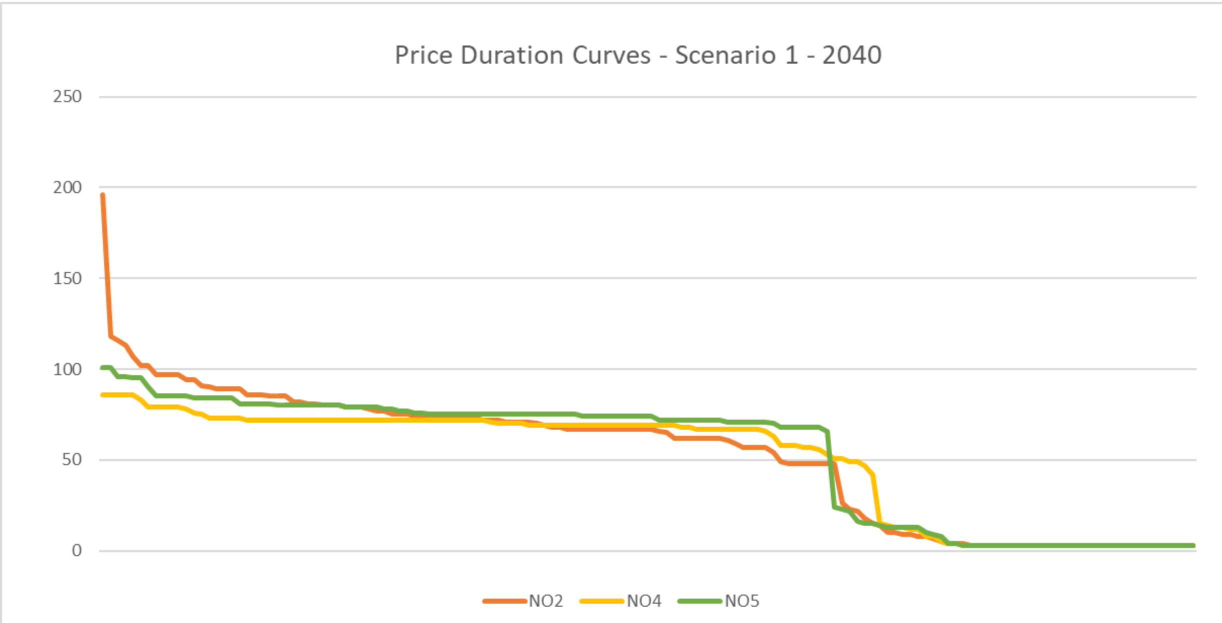

Figure 15: Price duration curves graph (EUR/MWh) for NO2, NO4 and NO5 in 2040, Scenario 1 (All Industries)

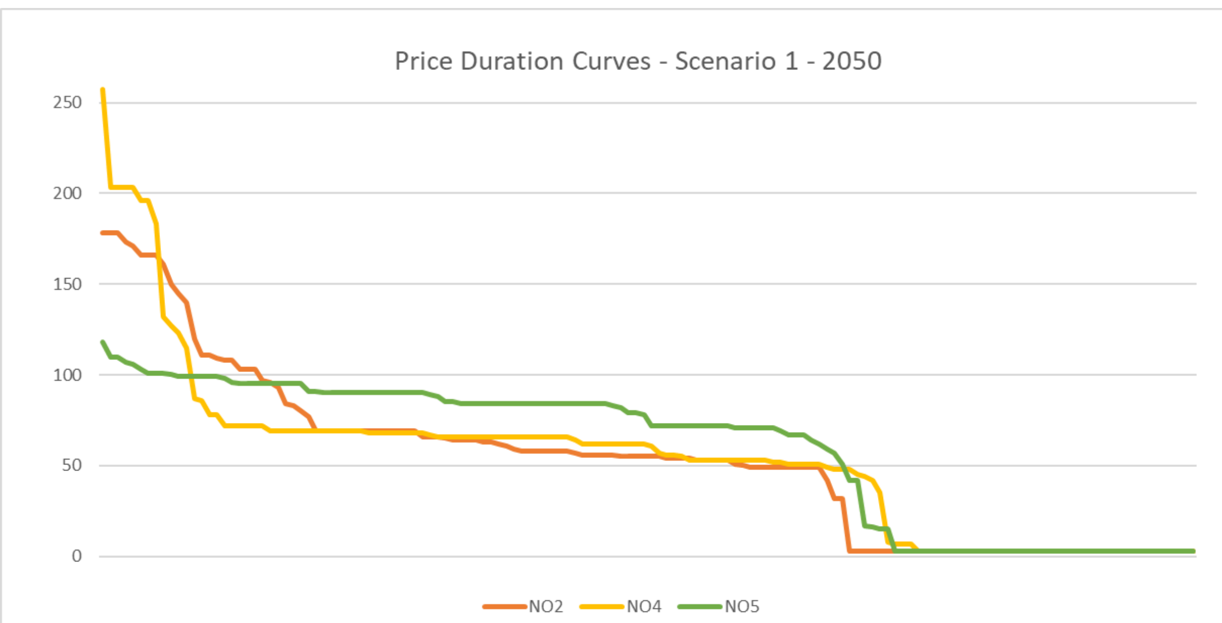

Figure 16: Price duration curves graph (EUR/MWh) for NO2, NO4 and NO5 in 2050, Scenario 1 (All Industries)

Both NO2 and NO4 have positive power balances within the price zones and are net exporters of electricity in all years. However, while the power surplus in NO2 increases from 2030 to 2050 with increased consumption and production, the power surplus in NO4 is reduced. The combined yearly production and price variation curves (Figures 17 and 18) for NO2 and NO4 in 2050 in scenario 1 *(All Industries)* show that both prices and hydropower production spike in periods when wind power production is low. This includes offshore wind power production in NO2 and both onshore and offshore wind power production in NO4. In some of the periods with high prices, energy from storage technologies is also dispatched.

As prices in both NO2 and NO4 seem to follow the same pattern as hydro power production, it can indicate that hydro power is generally the marginal producing technology determining the market price. In the cases where prices spike, especially during the fall season (S43), storage technologies are dispatched as marginal producing technology and it can be assumed that power import from neighboring price zones are included in the power mix to cover demand. While hourly prices in NO2 does not follow the prices in the neighboring price zones notably throughout the year, the prices in NO2 during price peaks match price levels of Denmark and Germany (Figure 19).

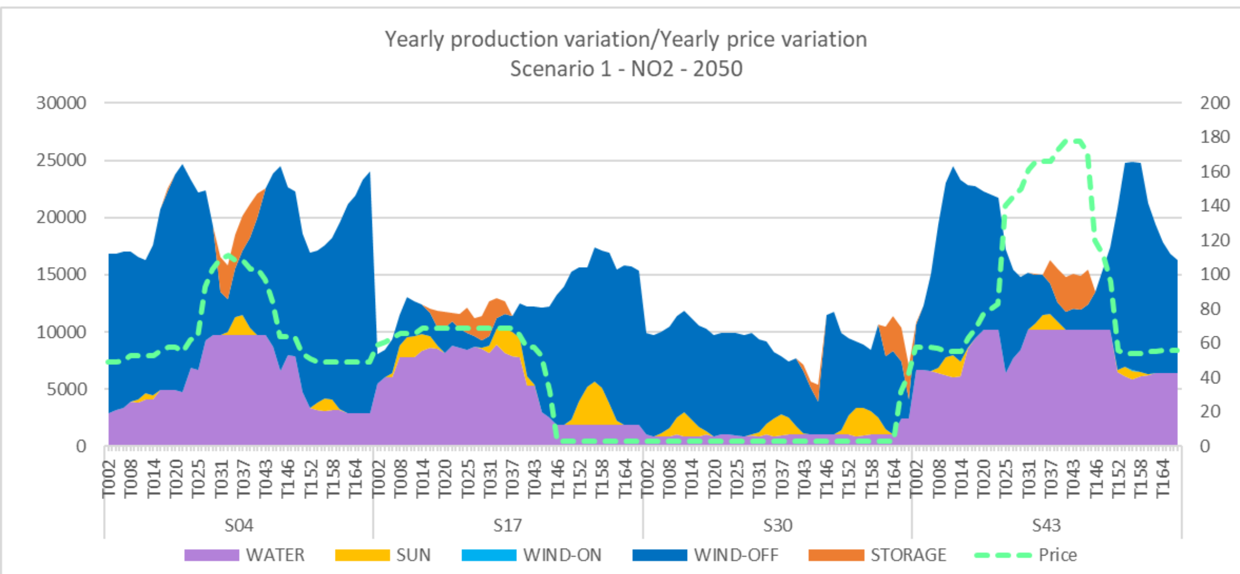

Figure 17: Combined yearly production variation (MWh) and yearly price variation graph (EUR/MWh) in NO2 within the four weeks S04, S17, S30 and S43 in 2050, scenario 1 (All Industries)

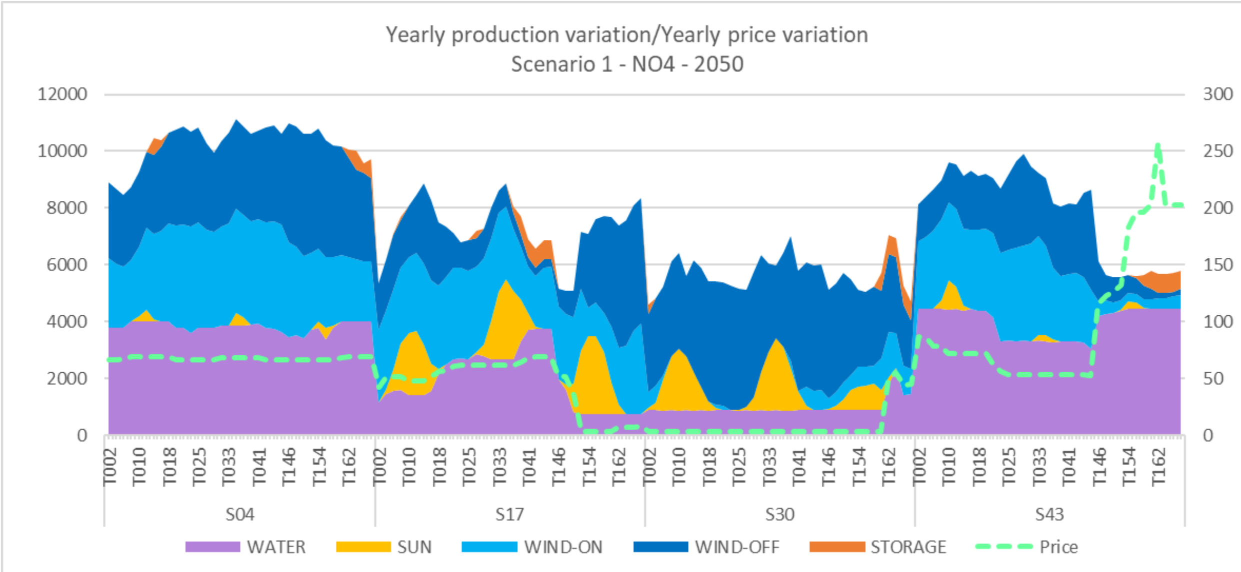

Figure 18: Combined yearly production variation (MWh) and yearly price variation graph (EUR/MWh) in NO4 within the four weeks S04, S17, S30 and S43 in 2050, scenario 1 (All Industries)

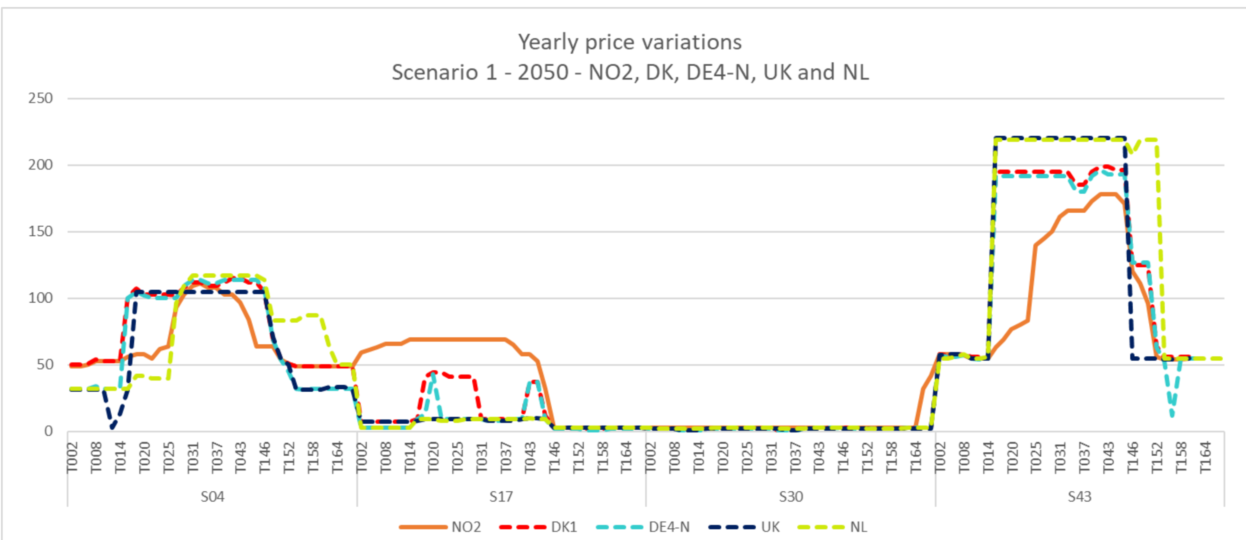

Figure 19: Yearly price variation graph (EUR/MWh) with hourly prices in NO2, DK1, DE4-N, UK and NL within the four weeks S04, S17, S30 and S43 in 2050, scenario 1 (All Industries)

3.4. Sensitivity analysis

This chapter presents how electricity prices in the four different scenarios are affected by variations in the allowed volume of new investments in wind power production and capacity and in transmission capacity.

3.4.1. Sensitivity in wind power production and capacity

Increasing and decreasing the maximum constraints on onshore wind power production changes the national production from this technology accordingly. In all scenarios, with the slight exception of the *High Wind* situation in scenario 4 *(Reference)* in 2030, production is maximized within the constraints (Figure 20). In 2030, changing the production of onshore wind power changes the total power production. Thus, the total national power production is higher in the *High Wind* situation than in the *Base* and *Low Wind* situations.

There is some replacement of power production from offshore wind in the High Wind situation compared to *Base* and *Low Wind* in all scenarios, but the replacement effect on power production from other technologies is subtle. In 2040 and 2050, the replacement effect is more significant. After 2030, changes in onshore wind power production does not change the total production in any scenario. Rather, the share of onshore wind power in the total production increases at the expense of offshore wind power when the maximum constraints on onshore wind power production are increased.

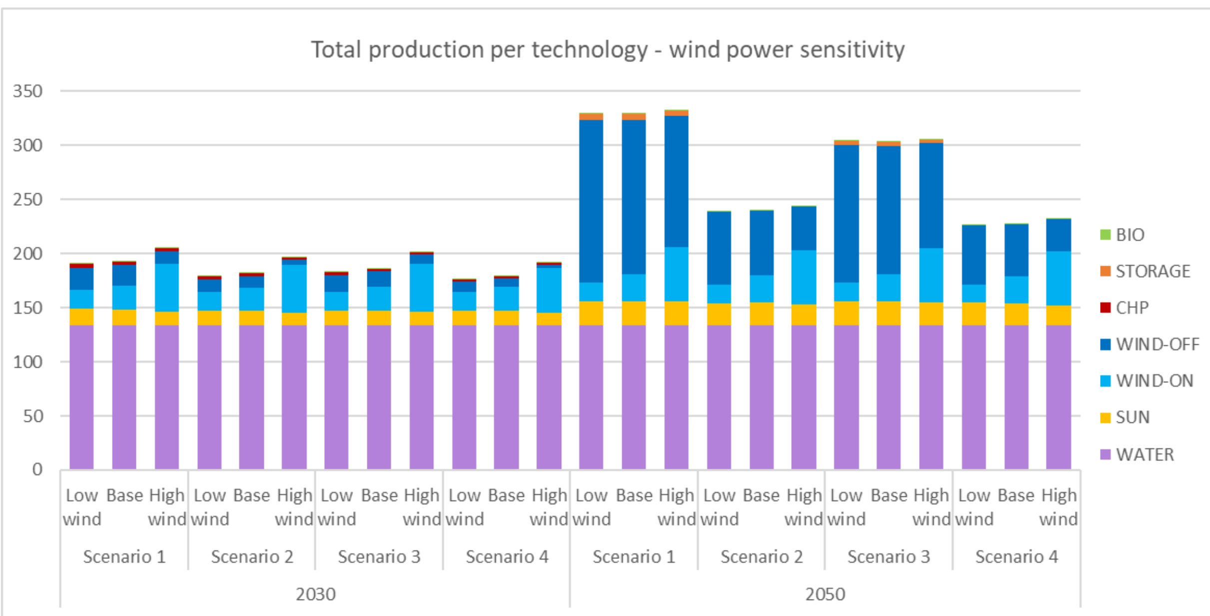

Figure 20: Total production in Norway per technology graph (TWh) for each scenario in 2030 and 2050 in the Low Wind, Base and High Wind situations

The results from running the additional optimizations for the *Low Wind* and *High Wind* situations show one main price trend for all the price zones, with the exception of NO4 (Figure 26). In all scenarios, there is little difference in the yearly average prices for NO1 (Figure 21), NO2, NO3 and NO5 (Appendix 5). In all these optimizations, the *Low Wind* situation results in a marginally higher price than the *Base* situation, and the *Base* situation equally has a marginally higher price than the *High Wind* situation. The price differences between the situations vary from 0 to 4 EUR/MWh. As demand does not change between *Low Wind*, *Base* and *High Wind*, it is necessary to look at changes in production and transmission to explain the changes.

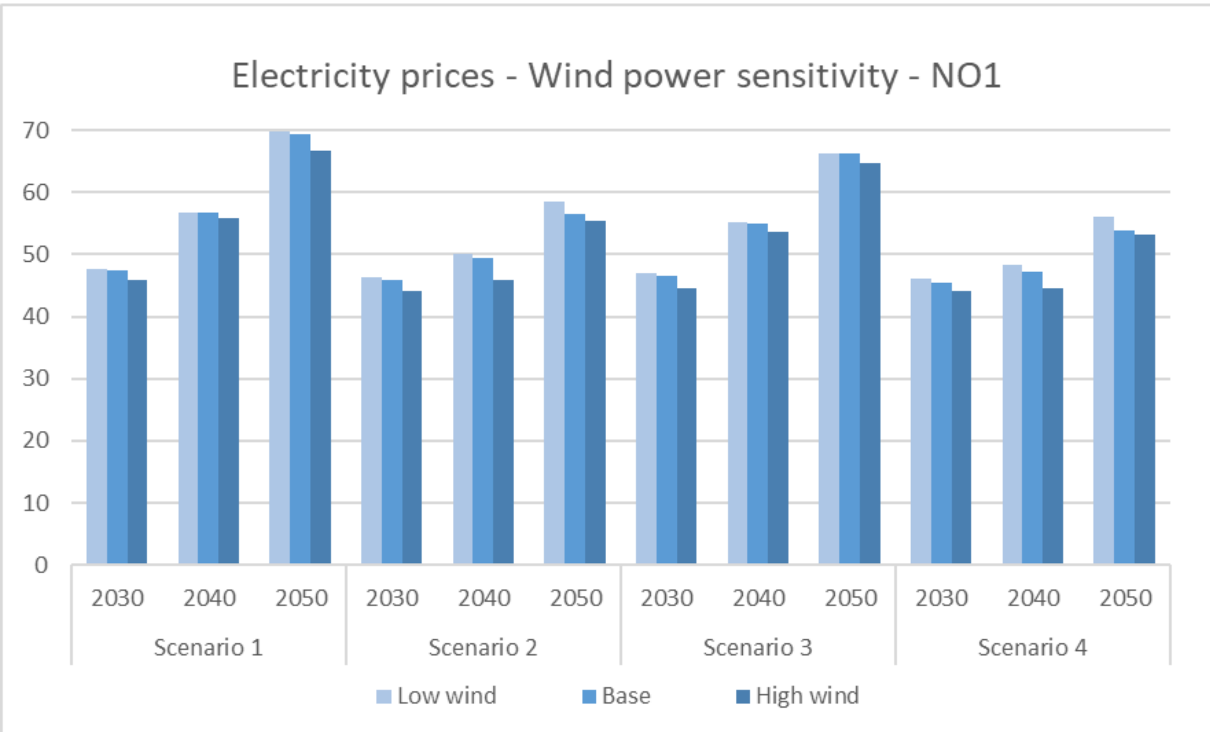

Figure 21: Electricity prices (EUR/MWh) in NO1 for each scenario in 2030, 2040 and 2050 in the Low Wind, Base and High Wind situations

The trend of a marginally lower price with more onshore wind is the result of onshore wind replacing more costly production or import in some hours during the year, reducing the yearly average price somewhat. This effect is visible when comparing the *High Wind* and *Base* situations in NO1 in 2050. Using scenario 1 *(All Industries)* as an example, Figures 22 and 23 show that increasing the allowed amounts of investments in onshore wind power production from a *Base* level to a *High Wind* level does not replace production from other technologies in NO1. Rather, it increases the total production within the price zone in some periods. Increased total production in NO1 reduces the need for electricity imports to a certain extent during those periods, and thus reduces the hourly prices somewhat (Figure 24).

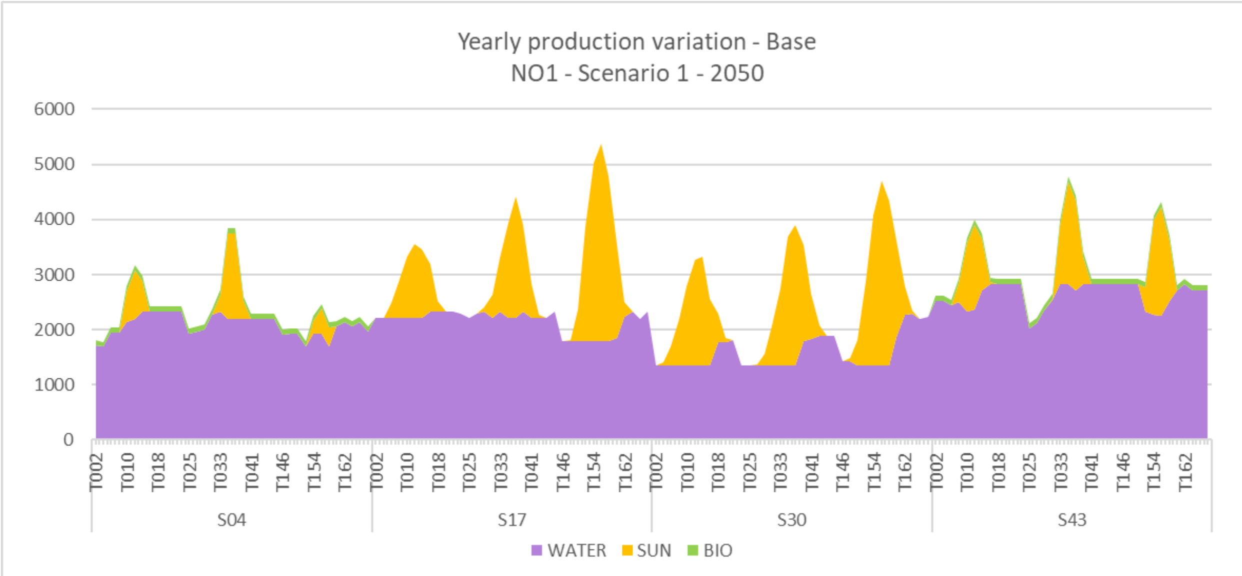

Figure 22: Yearly production variation graph (MWh) in the Base situation in NO1 within the four weeks S04, S17, S30 and S43 in 2050, scenario 1 (All Industries)

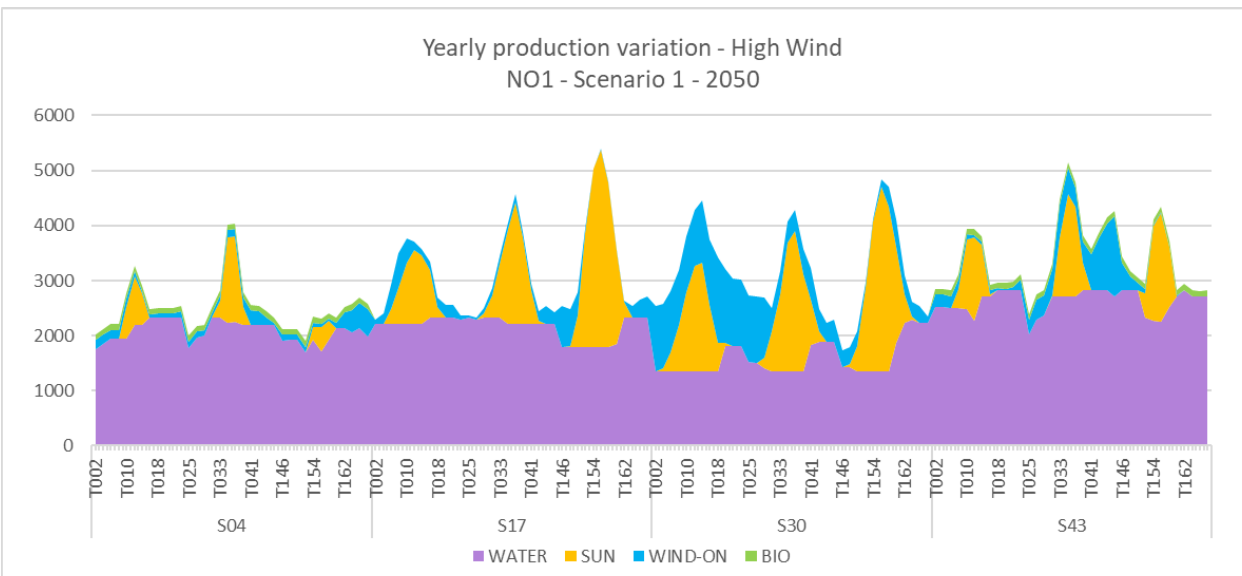

Figure 23: Yearly production variation graph (MWh) in the High Wind situation in NO1 within the four weeks S04, S17, S30 and S43 in 2050, scenario 1 (All Industries)

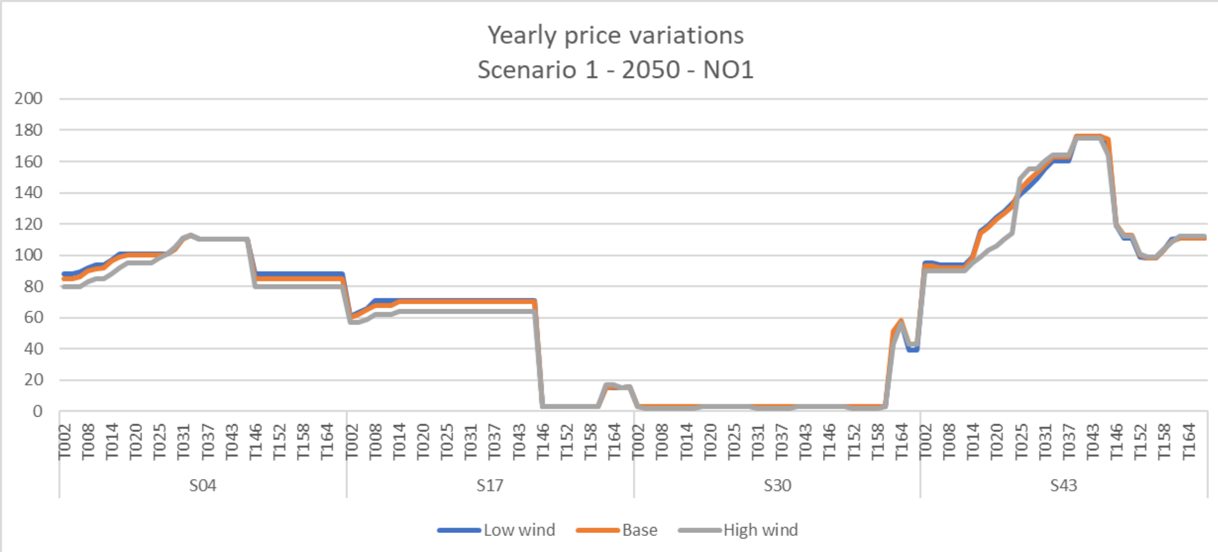

Figure 24: Yearly price variation graph (EUR/MWh) with hourly prices in NO1 in the Low Wind, Base and High Wind situations within the four weeks S04, S17, S30 and S43 in 2050, scenario 1 (All Industries)

Allowing a *High Wind* situation affects the results in NO4 significantly more than in any other price zone. This is especially noticeable in 2030 for all scenarios and 2040 for scenarios 2 (Existing Industries) and 4 (Reference), where prices are reduced from around 40 EUR/MWh in *Base* to around 25 EUR/MWh in *High Wind*. The impact on production from varying the amount of onshore wind power in NO4 is illustrated in the production graph in Figure 25. They show notable differences in onshore and offshore wind power production between the three situations.

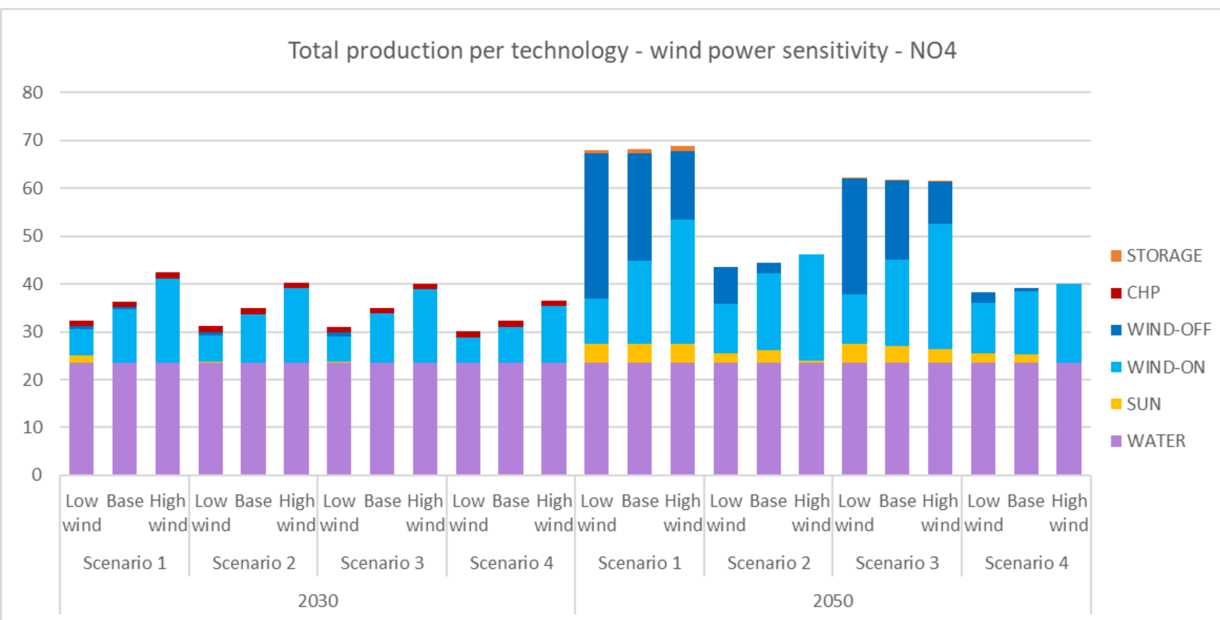

Figure 25: Total production per technology graph (TWh) for each scenario in NO4 in 2030 and 2050 in the Low Wind, Base and High Wind situations

In 2030, as well as in scenarios 2 *(Existing Industries)* and 4 *(Reference)* in 2040, there is no offshore wind power production in NO4, but the total production in the price zone varies. The total production is higher in the *High Wind* situation than in the *Base* and *Low Wind* situations. In 2030, the total production is increased from around 30 TWh in the *Low Wind* situation to around 40 TWh in the *High Wind* situation. The difference in total production is all due to increases in onshore wind power production. In scenarios 1 *(All Industries)* and 3 *(Petroleum Phase-out)* in 2040 and all scenarios in 2050, the total production is mostly the same between the three situations *Low Wind, Base* and *High Wind*. However, the share of the production coming from onshore and offshore wind power varies. The *Low Wind* situation depends on a larger utilization of offshore wind power to reach the same level of production as the two other situations.

The changes in production observed in the three situations demonstrate a trend of lower prices when there is more wind power production available. Decreasing prices correspond with higher total production in a year within an area. Whether the increase in wind power production stems from onshore or offshore technologies does not seem to affect prices notably. This is because the short-run marginal cost (SRMC) of producing one more unit of power from an existing wind power plant will be low for both onshore and offshore technologies. Both technologies have no fuel costs and have operational costs between 1-3 EUR/MWh. While this difference affects which of the two technologies will be dispatched first, neither technology will be the marginal producer in most hours in a hydro power dominated electricity market. The more significant differences in prices observed for some scenarios and years in NO4 are thus likely attributable to increased electricity imports.

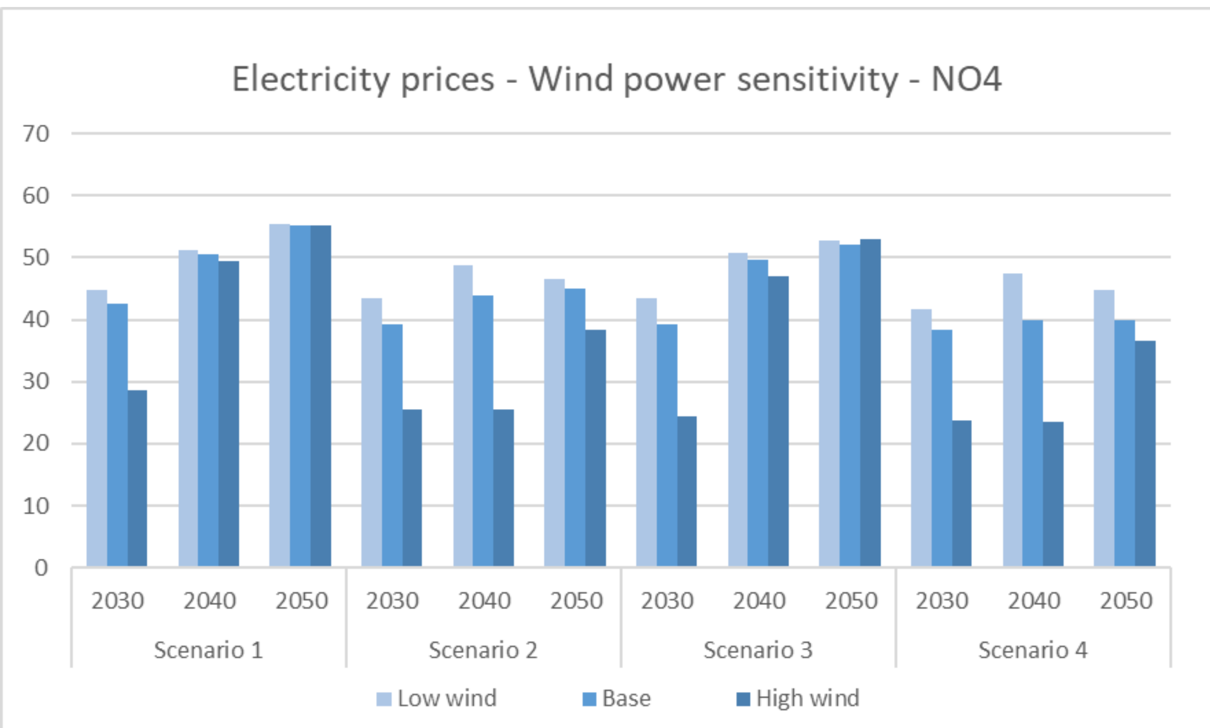

Figure 26: Electricity prices (EUR/MWh) in NO4 for each scenario in 2030, 2040 and 2050 in Low Wind, Base and High Wind situations

More local production of onshore wind power in NO4 reduces the need for import of higher priced energy into the region to cover electricity demand. NO4 has transmission capacity to the price zones NO3, SE1 and SE2. The *Low Wind* and *Base* situations show higher prices in NO4 in 2030 than what the *High Wind* situation does. Figures 27 and 28, using scenario 1 *(All Industries)* as an example, show how the yearly price variations of 2030 in NO4 in the *Base* situation follows price variations in the neighboring price zones significantly more closely than in the *High Wind* situation. The prices throughout the year in 2030 in the *High Wind* situation are generally lower than in the neighboring price zones. In addition, Figure 29 shows more net export of electricity from NO4 in 2030 in the *High Wind* situation than in the *Base*. In 2050, net export from NO4 is lower than in 2030 and there is little difference between the *Base* and *High Wind* situations. The results thus suggest that the effect of price contagion to NO4 is significantly stronger and more decisive in determining the price in the *Base* situation, when own production is lower, than in the *High Wind* situation.

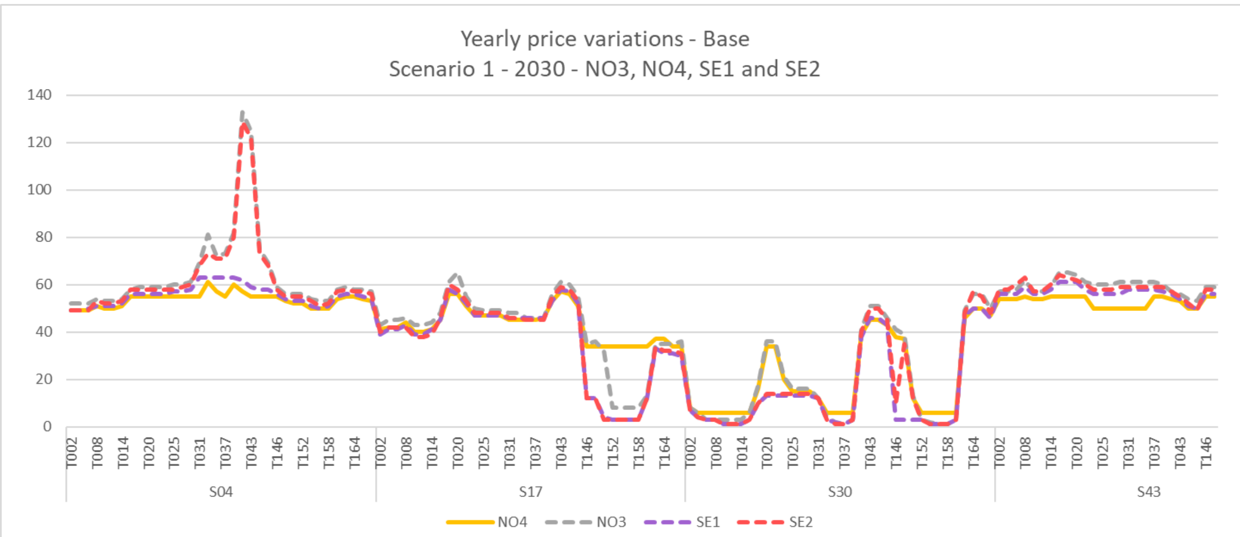

Figure 27: Yearly price variation graph (EUR/MWh) with hourly prices in the Base situation in NO3, NO4, SE1 and SE2 within the four weeks S04, S17, S30 and S43 in 2030, scenario 1 (All Industries)

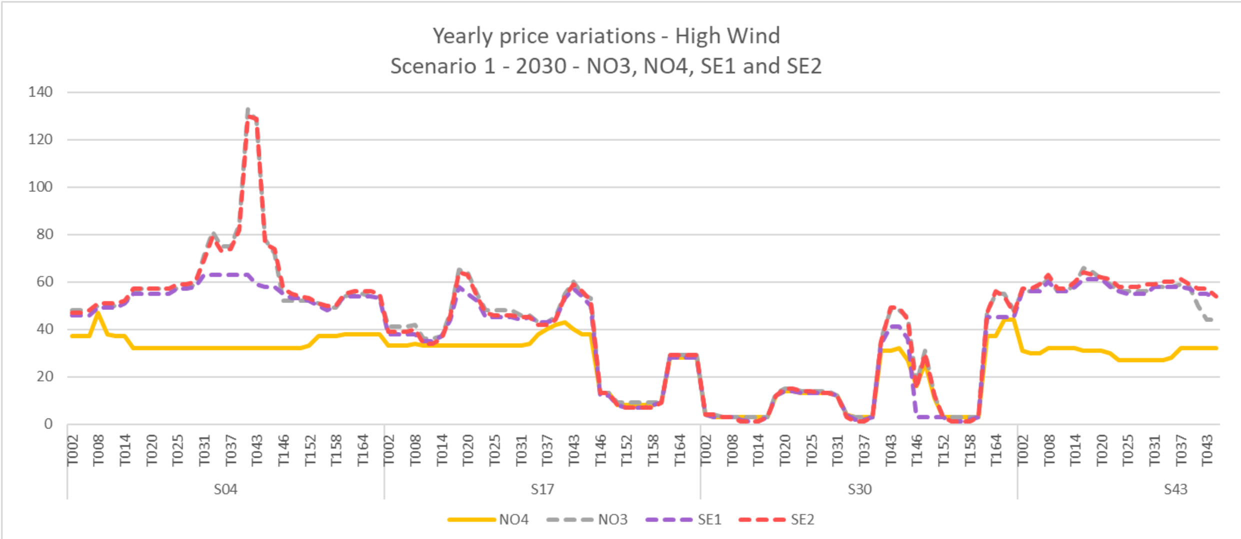

Figure 28: Yearly price variation graph (EUR/MWh) with hourly prices in the High Wind situation in NO3, NO4, SE1 and SE2 within the four weeks S04, S17, S30 and S43 in 2030, scenario 1 (All Industries)

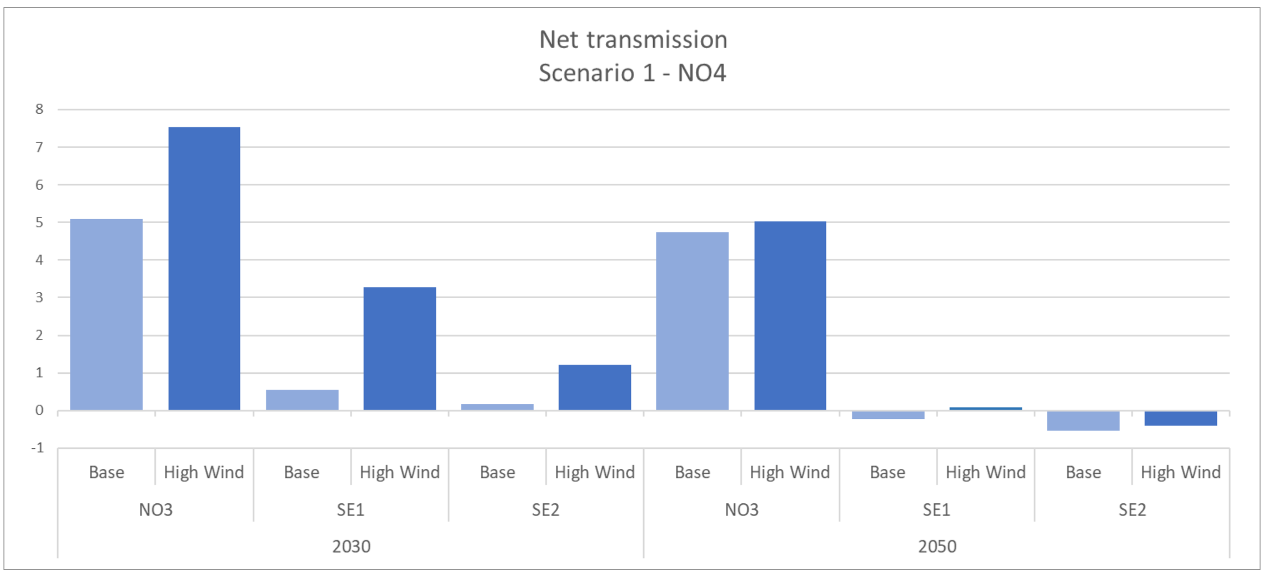

Figure 29: Net transmission flow graph (TWh) between NO4 and neighboring price zones NO3, SE1 and SE2 in the Base and High Wind situations in 2030 and 2050

3.4.2. Sensitivity in power transmission capacity

This section will analyze how the electricity price is affected by allowing the Balmorel model to increase transmission capacity between price zones in the market. Increasing the constraints on allowed investments in transmission capacity in accordance with the *50% increase* and *100% increase* situations increases the transmission capacity to, from and within Norway to 46,05 GW and 53,63 GW respectively in 2050. The *50% increase* situation leads to an increase of 73 percent to, from and within Norway. This is because the constraints apply to all countries in the Northern European electricity market included in the Balmorel model. Thus, the optimizations distribute a larger share of the total new investments in transmission capacity in this situation to Norway at the expense of other countries in the market.

The results of the sensitivity analysis show a tendency for price reduction as time progresses when the permitted level of investments in transmission capacity is increased (Figure 30, Appendix 6). The tendency for prices to be highest in the *Base* situation and lowest in the *100% increase* situation is thus stronger in 2050 than in 2040. The significance of the trend varies between scenarios and price zones. This trend is generally stronger in scenarios 1 *(All Industries)* and 3 *(Petroleum Phase-out)*, and especially notable in NO1. There are no differences in prices in 2030 in any scenario or price zone because the model does not allow for new investments in transmission capacity before after 2030.

The results from varying transmission capacity suggest that allowing larger amounts of transmission capacity investments can limit the electricity price growth described in chapter 3.3. Allowing for a *100% increase* situation has the potential to restrict the electricity price growth somewhat after 2030. As this effect is most notable in scenario 1 *(All Industries)* in NO1, this scenario and price zone will be analyzed further as an example.

Figure 30: Electricity prices (EUR/MWh) in NO1 for each scenario in 2030, 2040 and 2050 in Base, 50% increase and 100% increase situations

Increasing the total allowable investment in transmission capacity results in a situation with somewhat increased power production in the overall Norwegian electricity market in 2050 compared to the *Base* situation. This increase in production mainly stems from new offshore wind power production in NO2 and NO4. Simultaneously, NO3 experiences a reduction in production equal to the increase in NO4. The strongest reduction in prices from the *Base* situation to *100% increase* occurs in the three price zones, NO1, NO3 and NO5, that does not experience an increase in own production. Thus, there is no direct connection between changed own power production and changes in prices when the amount of transmission changes.

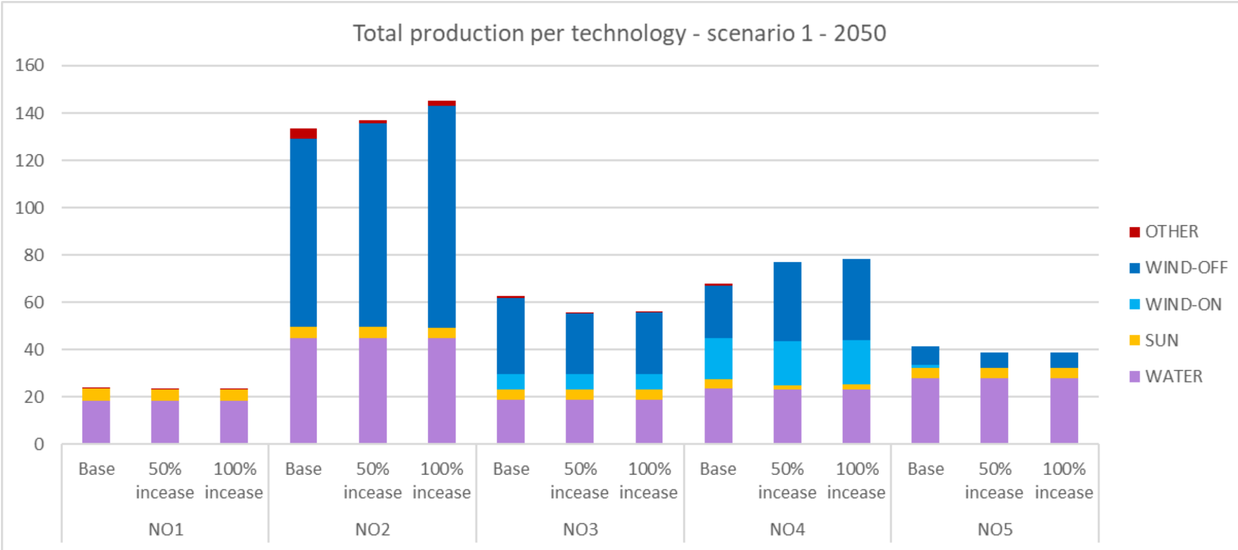

Figure 31: Total production per technology graph (TWh) for each price sone in scenario 1 (All Industries) in 2030 and 2050 in the Base, 50% increase and 100% increase situations

When analyzing the total net transmission flow from and to NO1, the results show that the net flow does not change between the *Base, 50% increase* and *100% increase* situations. However, there is a gradual growth of 4-5 TWh in both exports and imports from and to NO1 from the *Base* to the *100% increase* situation. Thus, there is more total flow of electricity to and from the price zone in the *100% increase* situation, indicating more flexibility and less barriers in the grid.

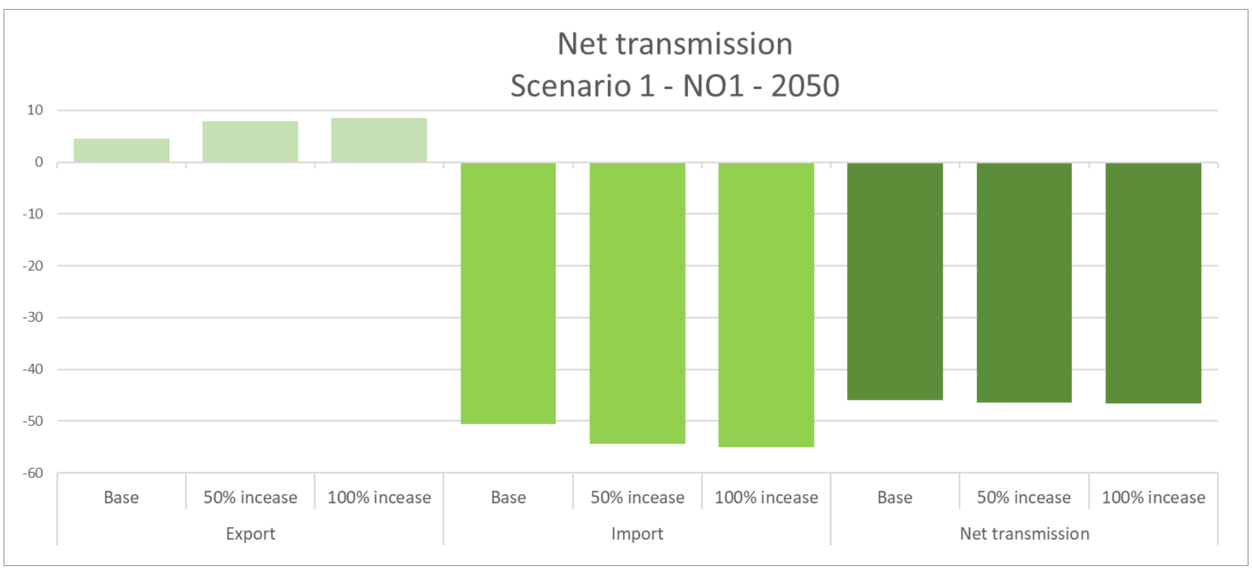

Figure 32: Net transmission flow graph (TWh) to and from NO1 in scenario 1 (All Industries) in 2050 in the Base, 50% increase and 100% increase situations

The graphs in Figures 33 and 34, combining the yearly import variation to NO1 from its neighboring price zone with the yearly price variation in 2050 in scenario 1 *(All Industries),* show lower hourly prices and more fluctuations in the import flow. The price profile of the *Base* situation (Figure 33) has higher hourly prices than the *100% increase* situation (Figure 34) in most hours of the year. There are simultaneously larger volumes and more fluctuations in the imports during the winter (S04), spring (S17) and fall (S43) in the *100% increase* situation than in the *Base* situation. The changes in total volumes of electricity flow to and from NO1 provide more available electricity to meet short term fluctuations in consumption and production within the price zone. This, in turn, reduces hourly prices.

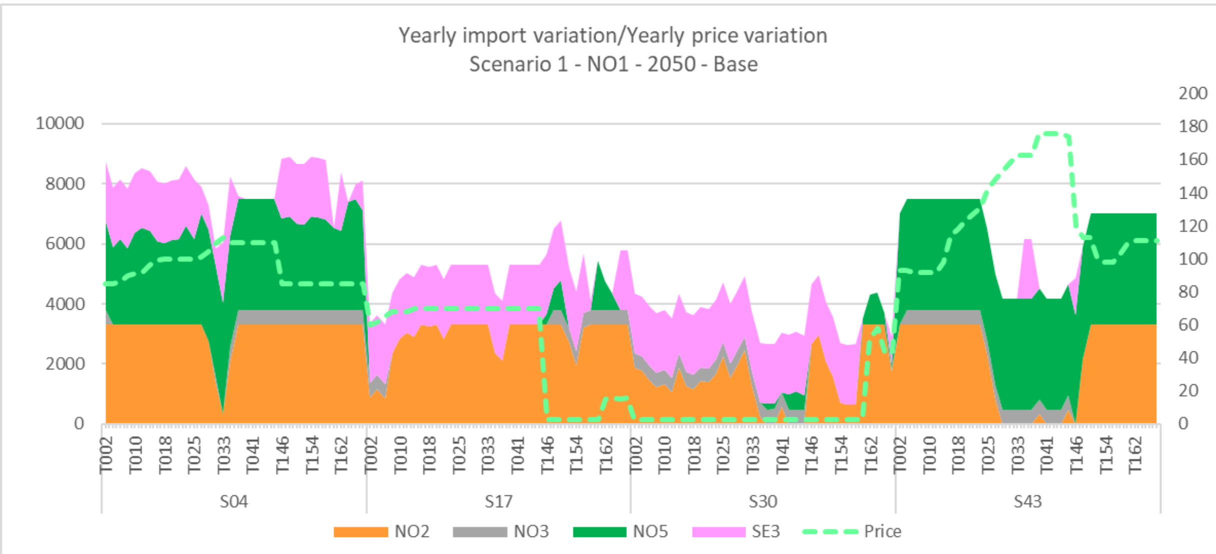

Figure 33: Combined yearly transmission variation (MWh) to NO4 from the neighboring price zones NO2, NO3, NO5 and NO3 and yearly price variation graph (EUR/MWh) within the four weeks S04, S17, S30 and S43 in 2050, scenario 1 (All Industries), in the Base situation

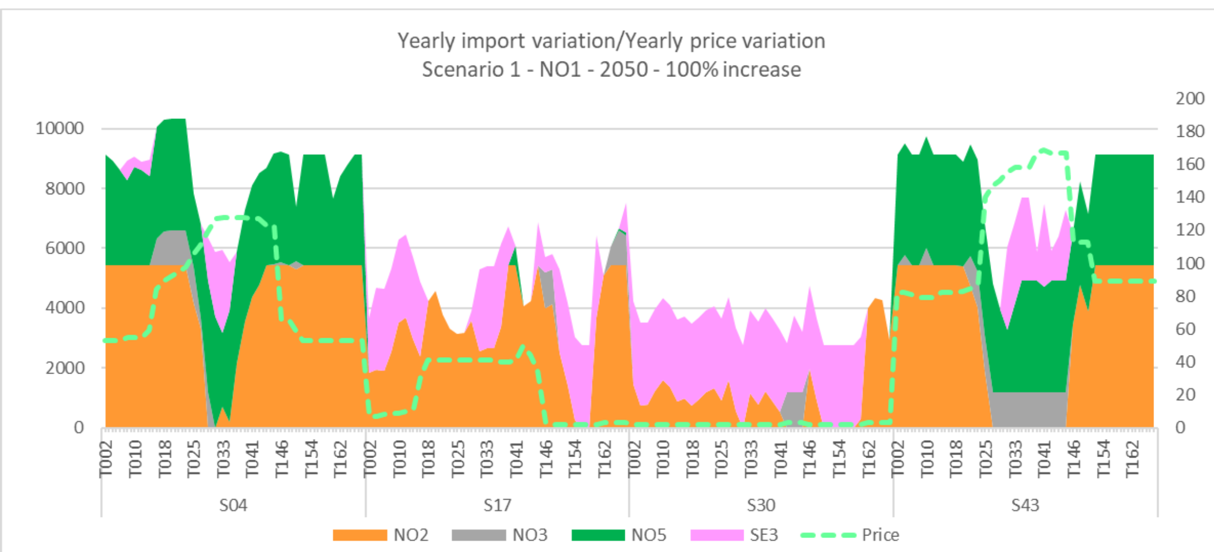

Figure 34: Combined yearly transmission variation (MWh) to NO4 from the neighboring price zones NO2, NO3, NO5 and NO3 and yearly price variation graph (EUR/MWh) within the four weeks S04, S17, S30 and S43 in 2050, scenario 1 (All Industries), in the 100% increase situation

4. Discussion

This chapter will discuss the methodology and results, considering how assumptions and choices in methodology can affect the results. The discussion will consider advantages and disadvantages with the methods used in this analysis, and whether the assumptions and constraints made are suitable in answering the research objective. The results will be compared to other studies and analyses, and the realism and utility of the results will be discussed.

4.1. Energy system modelling

Energy market models serve as tools to gain insight into potential developments and trends in the real world by optimizing the socio-economic surplus in the market based on a set of input and constraints. Such models will thus have limitations as they will always be a simplification of the dynamics in the real-world market. This section will discuss the limitations and uncertainties occurring when trying to model the Nordic electricity market using a partial equilibrium model.

A partial equilibrium model like the Balmorel model optimizes the socio-economic surplus when modelling the electricity market. They are characterized by ignoring interactions with other sectors, assuming perfect information and ignoring externalities. Thus, both market effects in sectors interacting with or dependent on the electricity sector, as well as non-market factors like environmental impacts and social equity considerations, are not accounted for in the optimization. Some of these effects can, to some extent, be considered in the model based on the choice of input data and the constraints implemented.

4.2. Temporal resolution

The temporal resolution used in this analysis is divided into four *Seasons* and 36 *Terms* within a year, which is a low resolution. It provides results for 144 hours during a year, which is 1.6 percent of a full year. While the hours and weeks used in the model are chosen to be representative of weekly and seasonal variation, only a small selection of the year is analyzed. This can affect the results of production, transmission and prices as parts of a week and the year may not be properly represented. There will normally be variations in supply and demand between weeks within a season, which can be quite different from the one week modeled to represent the season.

When modeling with a low temporal resolution, single occurrences can have a disproportionate impact on the outcomes. One week experiencing a price peak does not imply that all weeks within that season will experience the same peak. Thus, this one peak can increase the average price significantly more than if more weeks within the season were modelled. Both extreme low and high single occurrences will have a higher impact on the results when the scenarios are modelled with few hours in a year. Whether this affects the results in a notable way is uncertain. However, as the scenarios are modelled with the same preconditions, using the same weeks and hours, the results from the different scenarios should be comparable.

4.3. Energy efficiency and flexibility

The Balmorel model lacks energy efficiency measures and waste heat utilization due to model limitations. Utilizing energy more efficiently is a relevant measure for sustainability and can affect the need for new power production. In the case of power-intensive industries, the utilization of waste heat might be especially relevant, as energy intensive production processes release large amounts of heat that can for instance be used for heating in residential and commercial buildings. This can further reduce the need for electric heating which could, theoretically, free electricity for new industry projects. Integrating these measures, however, would require complex modeling and data inputs, which would be a comprehensive research project on its own.

Production and use of hydrogen differs from the other industry categories analyzed in this study in both hours of production and purpose of use. All industry categories have been modelled based on one common hourly demand profile, as well as being considered production technologies only. For traditional power-intensive industries, petroleum production, battery production and data centers, it is reasonable to assume a generally stable production, and thus energy use, both in a day and throughout a year. This is reflected in high values for hours-of-use in these industries, as well as little variation in the hourly demand profile. In the case of hydrogen production, on the other hand, this is not as likely to be the case. The hours-of-use utilized for hydrogen production for the model input was significantly lower than for the other industries, as green hydrogen is a flexible and costly production which is likely to mainly operate when electricity prices are low. Thus, the hourly demand profile for hydrogen is expected to be more volatile than the profile used in the modelling. However, such a profile has not been available.

Hydrogen is an energy carrier that can be used as a fuel in sectors like transportation and industry, but it can also be used for electricity production. Thus, it has the additional property of being a potential energy storage solution. While this study has only modelled hydrogen as an output in the electricity market, it can also function as an input. This can provide increased flexibility in the market and be a solution compatible with more intermittent renewable electricity production. This dual production and consumption property would be relevant to include in long term electricity market modelling but has not been possible to implement within the scope of this study.

4.4. Environmental and social impacts

The Balmorel model does neither take into account environmental impacts of new power production or transmission installations, nor does it consider social support and opposition to development in the sector. These non-quantified effects can and has affected the power market in Norway and are likely to be a continuing factor in political decision making in the power sector. After 2019, as a result of local opposition to onshore wind power development, national and local regulations on developing new wind power have become increasingly strict, providing more regulatory power and profit shares to local governments (Energidepartementet, 2020). Simultaneously, knowledge and awareness about the effects of degradation of nature has become more widespread, and indigenous peoples' rights have become an important point of attention (Energidepartementet, 2024b; Leiren et al., 2020). Thus, the available areas for new power production on land have become increasingly limited.

While the model does not include environmental and social effects directly, the constraints on wind power production have been imposed to represent the described barrier to developing new onshore wind power production. The constraints in the *Base* situation have assumed a growth in wind power production from 17 TWh in 2023 to 22 TWh in 2030. Wind power investments are expected to slow down compared to the years before 2020 due to increased taxes and stricter regulations aimed at ensuring more local acceptance and stronger focus on environmental protection. However, a pipeline of projects at various development stages continues to move forward. An increase of 5 TWh in onshore wind power production is in accordance with estimations made by the Energy Commission of 2023, which considered a realistic increase to be in the order of 5-10 TWh higher in 2030 than 2023 (Commission, 2023).

Equally to the constraints on onshore wind power production, the constraint on hydro power production in the model is implemented due to a political intention to reduce new intervention in nature. While few new large scale hydro power projects have been developed in Norway during the last 30 years, and few are planned, hydropower production capacity has increased by 0.5 to 1 TWh each year. In 2022, hydro power technologies in Norway had ha combined average annual production around 137 TWh (NVE, 2024b). This is 3 TWh higher than the constraint used in the model.

According to NVE, there are registered hydro power projects in different stages of development with the ability to provide an additional 5 TWh new production (NVE, 2024a). The Energy Commission of 2023 also considered 5-10 TWh new production by 2030 from hydro power to be realistic (Commission, 2023). Thus, the constraint on hydro power production of 134 TWh used for modelling can be considered somewhat low. However, there is uncertainty in whether new projects will be developed, and among the projects that will be developed, a large portion are expected to come from upgrades of existing power plants. Such upgrades are a form of energy efficiency measure of various nature, where resources in already regulated waterways are more efficiently utilized, which is difficult to model. Thus, a simplification has been made by implementing the constraint as relatively fixed and somewhat low.

4.5. Levels of production and consumption

The results in this analysis indicate that power production will reach levels between 227 and 329 TWh in 2050 in order to meet a consumption level between 230 and 341 TWh (Table 10). These results provide a generally higher level of production and consumption than other analyses. NVE’s Long-Term Power Market Analysis projects a level of production and consumption of 203 and 191 TWh respectively in 2040 (NVE, 2023b). This is 5-6 TWh lower than the results in scenario 4 *(Reference)*, which is the scenario based on the very same projections made by NVE. The difference is due to a change in the 2020 level in scenario 4 *(Reference)*, shifting the projections to ensure all scenarios are based on the same historic 2020-consumtion level. As scenario 4 *(Reference)* experiences the lowest supply and demand levels out of the four scenarios, all scenarios have higher production and consumption than the projections made by NVE. In the case of scenario 1 *(All Industries)*, this difference is 51 TWh on the supply side and 76 TWh on the demand side.

The Long-Term Market Analysis made by Statnett consists of four consumption scenarios for 2050 named *Low*, *Base*, *High* and *Extra High*. They reach 2050 consumption levels of respectively 190 TWh, 220 TWh, 260 TWh and 300 TWh (Statnett, 2023a). In the *Base* scenario, the consumption level is higher than scenario 2 *(Existing Industries)* by 6 TWh in 2030 and 3 TWh in 2040. There is, however, a lower growth in consumption from 2040 to 2050 in all the Statnett scenarios than in the scenarios of this study, thus reaching lower 2050 consumption levels. In all the scenarios in this study, Norway moves towards a negative power balance in 2050, and reaches this situation already by 2040 in scenarios 1 *(All Industries)* and 3 *(Petroleum Phase-out)*.

Most of the increase in power production in both NVE's Long-Term Power Market Analysis and Statnett's *Base*, *High* and *Extra High* scenarios after 2030 comes as offshore wind power and hydro power. The onshore wind power production levels are similar to the constraints imposed on the Balmorel model. The hydro power production grows to levels of 145 TWh in the NVE analysis and 151 TWh in the Statnett *Base* scenario in 2040, which is 11-17 TWh higher than the hydro power constraint in the model. On the other hand, the Statnett analysis only includes a third of the solar power production used in the Balmorel analysis. In the Balmorel analysis, the production of offshore wind power varies between 47 TWh in scenario 4 *(Reference)* to 142 TWh in scenario 1 *(All Industries)* in 2050. This variation is on the scale of what is considered feasible production levels in the Statnett analysis, lying between 40 and 140 TWh. The high production scenarios are also close to the goal set by the Norwegian Parliament of assigning areas for installation of 30 GW offshore wind power by 2040 (Energidepartementet, 2024a).

Statnett's Long Term Market Analysis bases the variation between their scenarios on the level of available power production in the market, rather than the level of consumption, arguing that the level of consumption will adjust according to production and prices. While some of the increase in consumption will be little price sensitive, the potential new consumption, especially within the industry sector, is expected to be almost inexhaustible. This is a major difference compared to the analyses made in this study, where production and transmission levels are the result of the consumption level input.

It is not realistic that all future capacity indicated in the statistics from Statnett's grid connection process will be developed and dispatched, as many will never reach the necessary level of maturity. Many industry projects will never be developed due to dependency on low electricity prices to ensure profitability. As this analysis projects increasing prices, reaching average prices close to 70 EUR/MWh in 2050 in some scenarios, it would render even more projects unprofitable. There is also a question of whether there will be available capacity on the grid in time for the development of a project, which is a question that has not been explored in this analysis. Both the Statnett and the Balmorel analysis indicate that a large-scale development of offshore wind power production will be a prerequisite in order to produce enough electricity for large-scale industry electrification. This analysis is used to illustrate what would be the consequences in the electricity market of developing all indicated new projects. However, the amounts of new projects dispatched on the demand side will be dependent on the break-even point of the projects in question, as well as the development of the LCOE of offshore wind power production.

Table 10: Total national production and consumption (TWh) in Norway for each scenario in 2020, 2030, 2040 and 2050

	Scenario 1		*Scenario 2*		*Scenario 3*		*Scenario 4*	
	Supply	**Demand**	**Supply**	**Demand**	**Supply**	**Demand**	**Supply**	**Demand**
2020	154	127	154	127	154	127	154	127
2030	193	192	182	172	186	178	179	167
2040	254	267	214	207	238	246	208	197
2050	329	341	239	244	303	315	227	230

4.6. Prices and sensitivity

In all scenarios and price zones in this analysis, price levels increase from 2030 to 2050, experiencing a trend reverse to that of most prognoses for the Norwegian electricity market. With the exception of NO4, prices in all price zones grow from a level between 44 and 47 EUR/MWh in 2030, to level between 47 and 69 EUR/MWh in 2050 (Table 11). While 2050-prices are much higher in some price zones and scenarios than others, prices increase in every case. Statnett's Long-Term Power Market Analysis operates with 2030-prices close to those of this analysis in the *Base* scenario. Statnett's *High Price* scenario, as well as NVE's analysis, on the other hand, projects prices in 2030 to be between 70 and 80 EUR/MWh. Both prognoses, however, agree that prices are likely to stabilize around 40 EUR/MWh after 2040 in Norway.

Both Statnett's and NVE's analyses project prices in Europe to be reduced as they become less dependent on fossil fuels. Statnett expects prices in northern Europe to converge with the Norwegian prices in 2050. This is also true for the Balmorel analysis, where prices in Norway reach the same levels as the neighboring price zones, however, at price levels 10-20 EUR/MWh higher than what Statnett projects.

Results from the Balmorel model analysis show that both increasing wind power production and transmission capacity levels reduce prices in 2040 and 2050 compared to the *Base* situation. In the case of increased transmission capacity, a doubling reduces prices in 2050 significantly in all scenarios and price zones. A doubling of transmission capacity also ensures a decrease in prices from 2040 to 2050 in NO2 and NO3. This measure results in price trends more similar to those of the market analyses made by NVE and Statnett. While increasing transmission capacity has a more notable effect than increasing wind power production, the two measures cannot be compared directly. The increase in capacity is much larger in transmission than in wind power production, with an increase of up to 26,95 GW in 2050 in the *100% increase* situation compared to *Base,* while wind power production capacity is only increased by 7.5 percent in 2050 in the *High Wind* situation.

Table 11: Average prices (EUR/MWh) in every Norwegian price zone for all scenarios in 2030 and 2050

	Scenario 1		*Scenario 2*		*Scenario 3*		*Scenario 4*	
	2030	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**
NO1	47	69	46	57	46	66	45	54
NO2	47	54	45	49	46	53	44	47
NO3	46	61	44	52	44	57	44	51
NO4	43	55	39	45	39	52	38	40
NO5	47	60	45	49	46	52	45	48

4.7. Paths to a low-emission society

Facing the transition to a more climate friendly economy depends on electrification of many of the activities our society is dependent on today. In this analysis, all scenarios have been developed in line with a high-energy society pathway to a low emission society in 2050. While the three first scenarios, 1 *(All Industries)*, 2 *(Existing Industries)* and 3 *(Petroleum Phase-out)*, consider electricity use for different combinations of industry categories, they all consider high consumption within the specific categories. Also, in scenario 4 *(Reference)*, NVE assume a significant growth in electricity consumption and production to be likely and necessary in order to reduce GHG emissions in all sectors and to keep up with population growth. However, the high levels of consumption and production analyzed in this study might not be necessary in order to reach the targets for GHG mitigation through electrification or possible due to social or environmental considerations.

While there is a certain necessity for using electrification as a GHG measure in Norway, to what extent this measure is used could be a question of prioritization. This study shows that prioritizing which purposes electricity is used for results in a difference of more than 100 TWh in both consumption and production between scenarios in 2050. Prioritizing electricity consumption only for power-intensive industries and the petroleum sector, as in scenario 2 *(Existing Industries),* would secure a continuation of the operations of existing industrial companies in Norway. It would also ensure electricity for the purpose of reducing GHG emissions from the two sectors, and thus help in reaching the national climate targets. There is, on the other hand, a discussion in Norway on whether the use of electricity, as a limited resource, should be prioritized for the petroleum sector, as the future demand for the petroleum goods is uncertain as a consequence of climate efforts.

Reducing emissions from existing industries in Norway can contribute to reducing emissions in other sectors somewhat. However, technologies like batteries and hydrogen can be necessary to reduce emissions from sectors like transportation, construction and agriculture, for instance. Scenario 3 *(Petroleum Phase-out)* analyzes a situation where GHG emissions from the petroleum sector are mitigated through phasing out the production rather than electrifying the process, while including development of existing and new onshore industries. This can contribute to both direct and indirect economic development and emission reductions in most sectors in Norway, as well as in other countries through export of products. However, such a scenario would demand 70 TWh more electricity than that of scenario 2 *(Existing Industries)*. Similarly, scenario 1 *(All Industries)*, where there is no prioritization between purposes for use of electricity, 100 TWh more electricity is needed compared to 2 *(Existing Industries)*.

This analysis shows that developing large numbers of new industry projects in Norway will result in a strongly increased demand for new electricity production, but there are large variations between consumption and production depending on which industries are prioritized. Largely increasing electricity demand for industry will cause a dependency on both offshore wind power production and electricity import to a larger extent than today. An increased dependency on electricity import will also make the Norwegian market more sensitive to changes in other countries. It can increase competition for the power available if other countries simultaneously choose to increase consumption by such an extent as Norway does in this analysis.

Increasing consumption and production to the levels analyzed in this study result in a growth in electricity prices from 2030 to 2050, leading to price levels between 50 and 100 percent higher than the historic average in Norway before 2021. Consumers in Norway, both in households, businesses and industry, have adapted to low electricity prices over time by using electricity for a larger variety of purposes than consumers in most countries, including for heating. Thus, variable costs of consumers in Norway in general are relatively more affected by changes in electricity prices than in most other countries (Energidepartementet, 2022). Situations with long-term average prices higher than the historic normal can thus be socially and politically challenging, as experienced in 2021 and 2022, when prices reached levels above 100 EUR/MWh over time.

Developing new electricity production is a long-run solution for reducing high prices, but this measure has received negative political reactions over time in Norway. This has both been the case for hydro power development and, more recently, onshore wind power development (Energidepartementet, 2022). Negative reactions are results of increased awareness considering environmental impacts, focus on visual impact and a need for local communities to receive more benefits from hosting new power plants (Energidepartementet, 2020; Leiren et al., 2020). These trends reduce the opportunities for developing new onshore wind power and hydro power plants. However, it is still uncertain whether offshore wind power developments will experience the same social opposition as onshore technologies have. The environmental effects of developing offshore wind power plants are also less explored. As the scenarios in this study mostly depend on large amounts of new offshore wind power production by 2050, the realism of the analyses will depend on how this technology is received over time.

The scenarios explored in this study primarily focus on high-energy electrification to achieve climate targets. However, an alternative approach worth considering is a low-energy society with a focus on significant reductions in overall electricity demand. This could involve a shift towards more energy-efficient technologies and infrastructure across all sectors, alongside behavioral changes that promote reduced energy consumption. While electrification would still play a role in decarbonization efforts, it might be targeted towards specific sectors where alternative solutions are limited. This approach could potentially minimize the need for large-scale new infrastructure development, potentially mitigating social and environmental concerns surrounding extensive wind power projects. However, like the high-energy scenarios, it could lead to a price increase as electricity becomes a more limited resource.

It is uncertain whether a truly low-energy society situation is possible while still developing existing power-intensive industries in Norway over time. Further research into the feasibility and potential impacts of a low-energy pathway in the Norwegian context could provide valuable insights for a more comprehensive and sustainable energy transition strategy. It is important to acknowledge that not all projects included in this analysis, particularly those in scenario 1 *(All Industries)*, may be necessary to reach Norway's climate targets. Both consumption and prices can be reduced somewhat compared to this analysis by including energy efficiency measures and increased flexibility in the energy mix. A focus on strategic and prioritized electrification alongside robust energy efficiency efforts can pave the way for a sustainable and secure energy future for Norway.

5. Conclusion

This analysis looks at how consumption growth in the industry and petroleum sectors affects the electricity market in Norway towards 2050. The objective has been analyzed by the use of the energy system model Balmorel. Four different scenarios have been modelled, analyzing consumption form different combinations of industry categories, including existing Power Intensive Industry (PII), Data Centers (DC), Green Hydrogen Production (HYD), Battery Production (BAT) and Mining and Petroleum (MIPE). The different scenarios consist of different input consumption levels, varying from 230 TWh in scenario 4 *(Reference)*, as the lowest, to 341 TWh in scenario 1 *(All Industries)* as the highest in 2050.

The results from this analysis show that Norway's electricity production will increase with between 50 and 115 percent by 2050 when faced with the input consumption levels of the four scenarios. In 2030, new production comes mainly from onshore wind power production and some solar power production. After 2030, however, offshore wind power production is the main source of new production as onshore wind power production is constrained to 22 TWh in 2030 and 25 TWh in 2040 and 2050. Hydropower is similarly constrained, resulting in no new electricity production from this technology. The analysis thus shows that high consumption scenarios in Norway, like that of large-scale electrification of the industry sector and development of new industries, will be highly dependent on development of offshore wind power production. It is also clear that prioritizing for which purposes electricity is used can significantly impact consumption and production levels.

Electricity prices increase in all scenarios due to the increasing demand for electricity and the limited supply of new generation capacity. The price growth is especially strong in NO1, where no new production occurs to face the increased demand, resulting in a strong dependency on electricity imports from NO2 and NO5. On the other end of the scale, NO4 experiences generally lower price levels, as a net exporting price zone with high levels of onshore wind power production.

The sensitivity analysis investigated how changes in wind power production and transmission capacity affected electricity prices in the four scenarios. Doubling the allowed investments in onshore wind power production resulted in marginally lower prices compared to the *Base* situation. The price reduction effect of doubling the transmission capacity was more significant, limiting the price growth from 2030 to 2050 displayed in the *Base* situation, and reducing 2050 prices to levels close to 2030. The effects of doubling onshore wind power production and doubling transmission capacity cannot be compared because there is a large difference in the volumes of installed capacity. However, the results show that increased transmission capacity can be used as a measure in addition to new electricity production to reduce electricity prices in high consumption scenarios.

Both increasing electricity consumption and developing new electricity production in Norway would likely face challenges due to social and environmental concerns. Large-scale consumption growth as analyzed in this study would increase prices to a level that could be socially and politically undesirable. Simultaneously, increasing power production in Norway can result in local resistance. This is particularly true for onshore wind power development, while the reception of offshore wind power is currently uncertain. An alternative approach to a high-energy electrification pathway is a low-energy society that focuses on reducing overall electricity demand, which could reduce the pressure on nature, but does not necessarily reduce prices compared to the scenarios in this study. Thus, it is uncertain which pathways would experience the least resistance and be most efficient in reducing GHG emissions according with national climate targets.

The scope of this study has been to explore the effects on the electricity market if electricity consumption grew significantly as a result of new industry projects in Norway. When limiting the scope, some properties of the industries and the markets analyzed have been disregarded. This includes the inclusion of energy efficiency measures in the industry sector and the versatile functions of the energy carrier hydrogen. Implementing these objectives into analyses about the effects of industrial electricity demand on the electricity market could be of interest in future research.

Future research could consider what volume of the electricity demand assumed in this analysis would be necessary in order to reach the climate targets in the respective sectors in Norway and further. In addition, given the high prices resulting from this analysis, it is probable that many projects in the planning and development stages, as well as existing industrial plants, would become unprofitable. It would therefore be relevant to analyze how many of the industry projects in planning in Norway today would be developed given certain electricity market prices.

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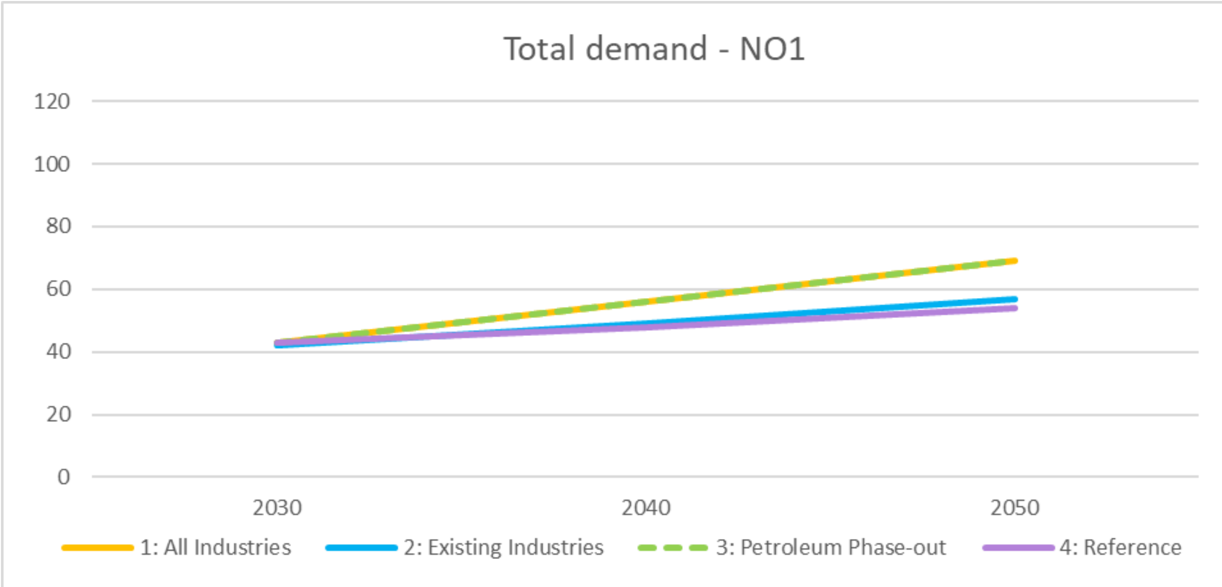
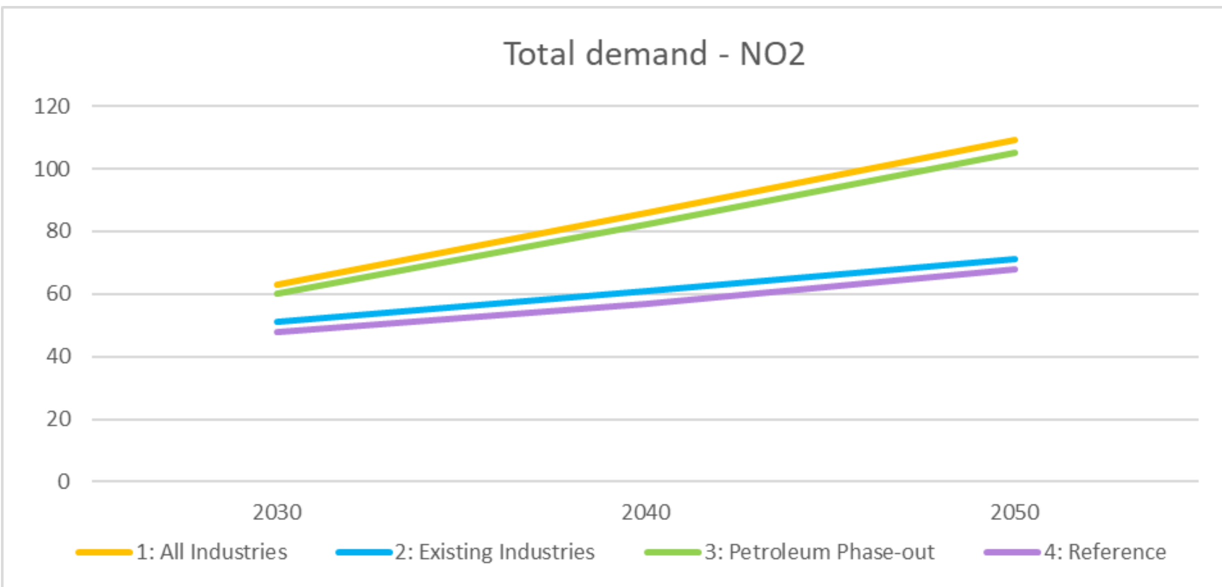
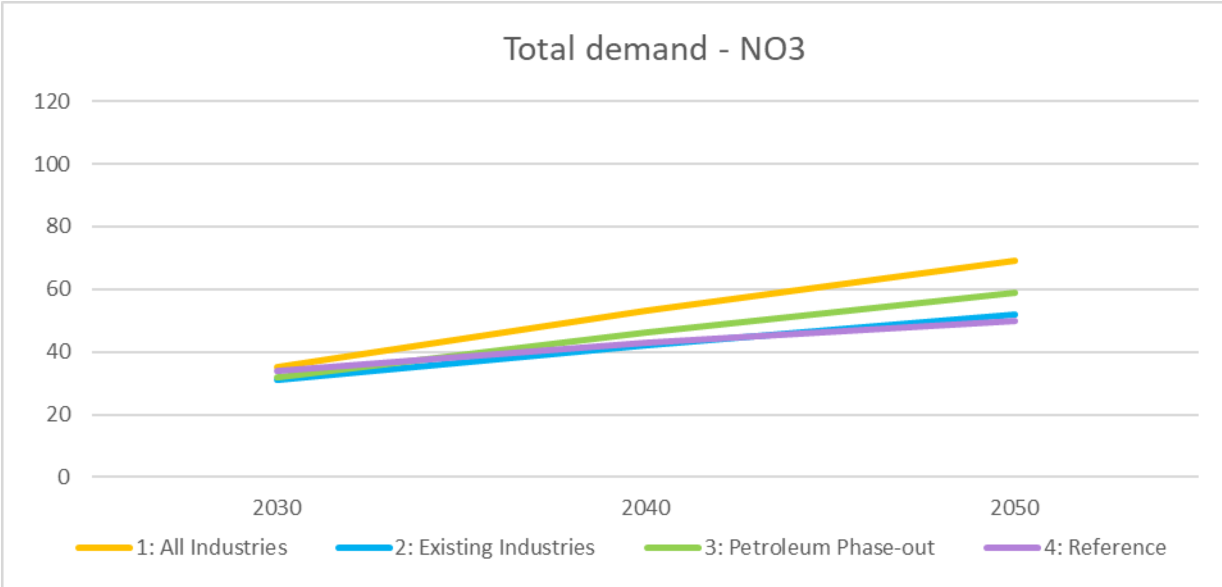
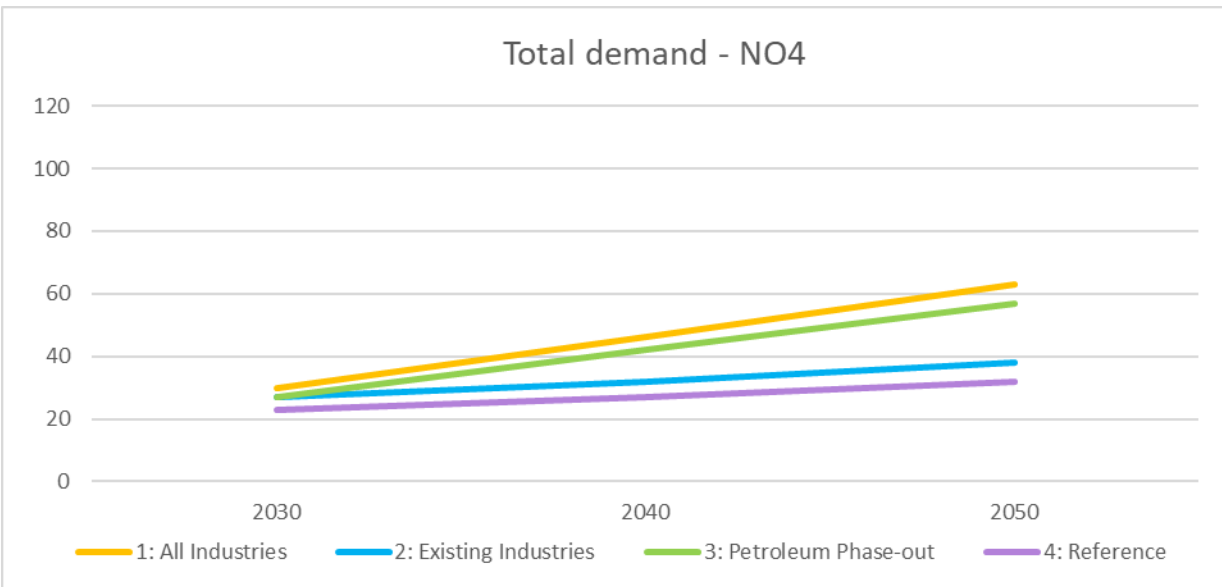
Appendix 1: Total demand per price zone

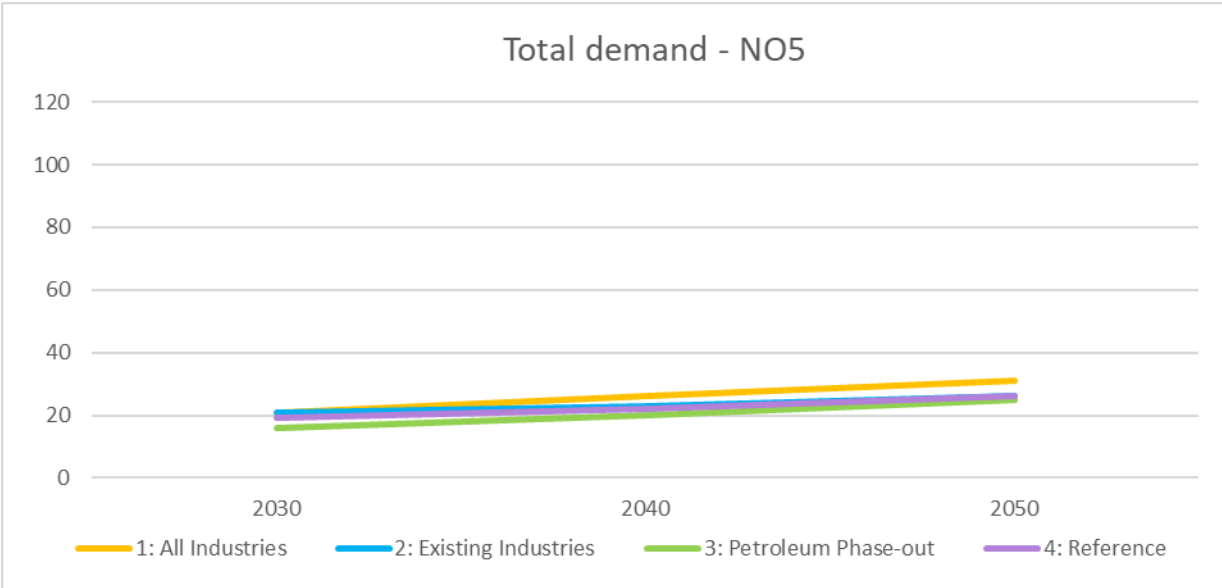
Total demand for electricity (TWh) per price zone and per scenario.





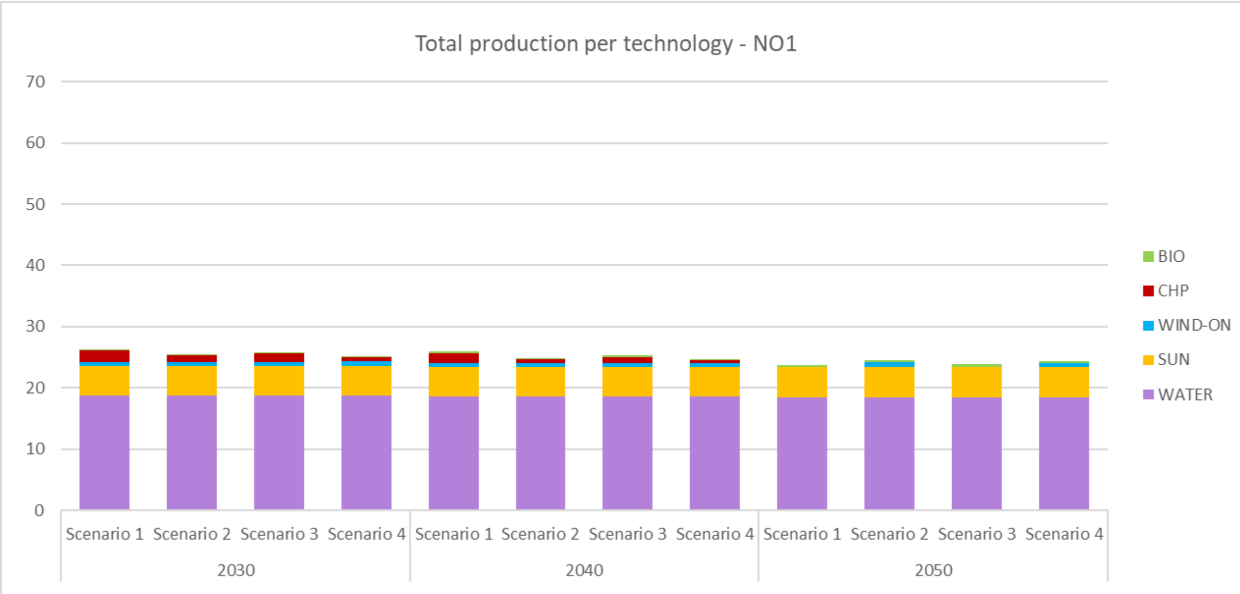

Total demand - NO3
120
100
80
60
40
20
0
2030
2040
2050
1: All Industries
2: Existing Industries
3: Petroleum Phase-out
4: Reference

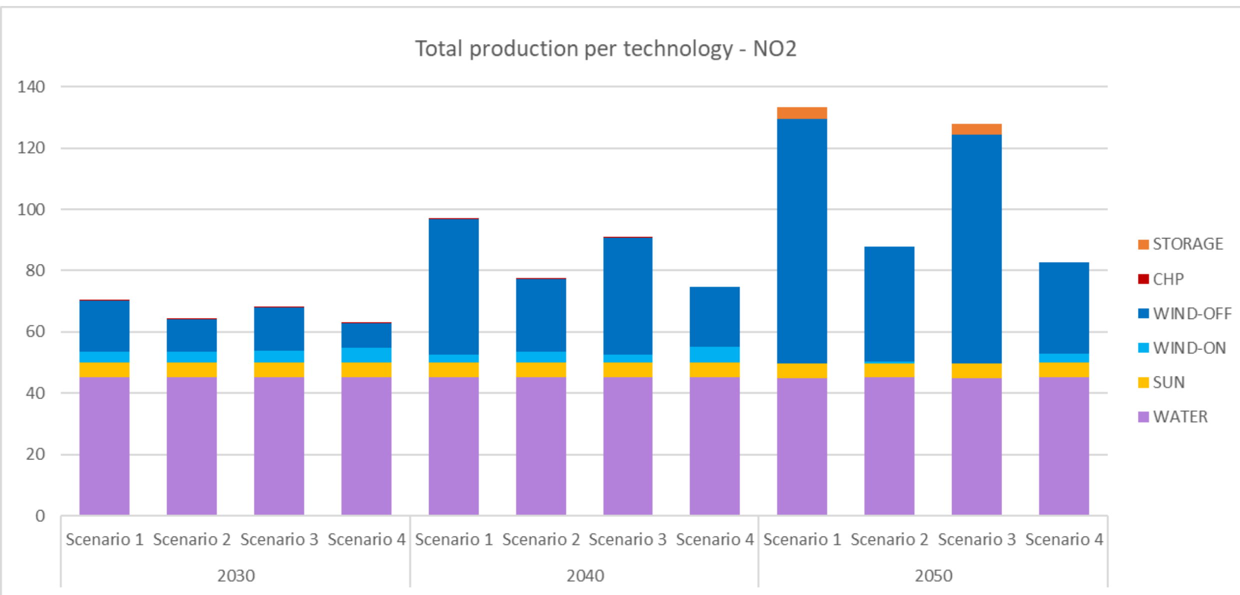

Total demand - NO4
120
100
80
60
40
20
0
2030
2040
2050
1: All Industries
2: Existing Industries
3: Petroleum Phase-out
4: Reference

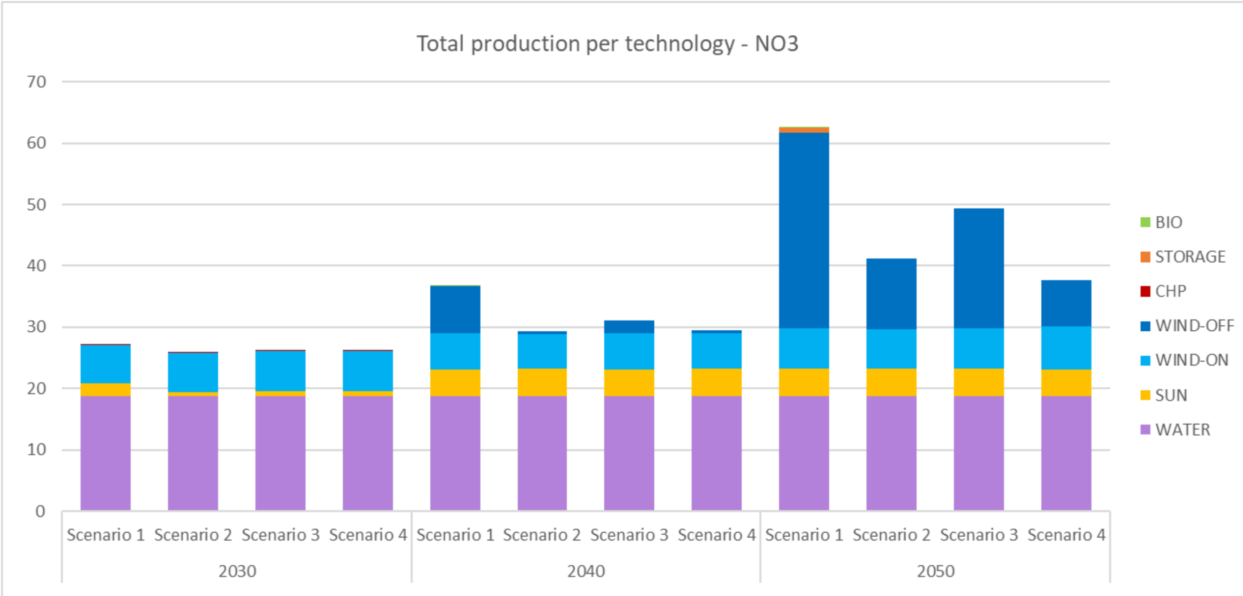

Total demand - NO5
120
100
80
60
40
20
0
2030
2040
2050
1: All Industries
2: Existing Industries
3: Petroleum Phase-out
4: Reference

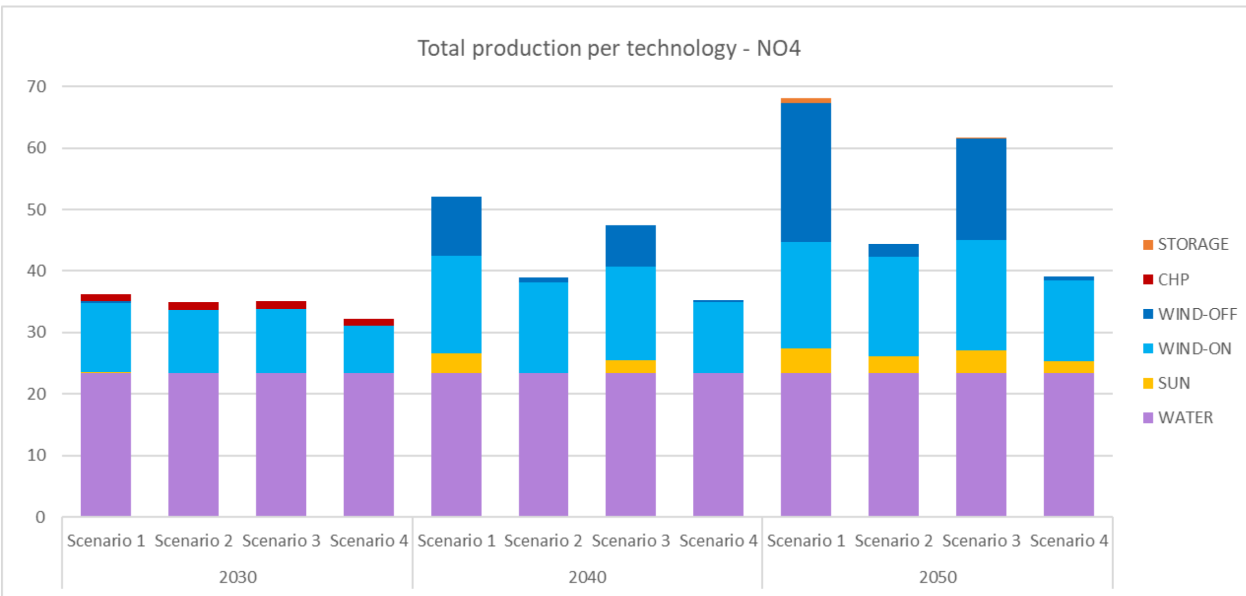
Appendix 2: Total production per technology and price zone

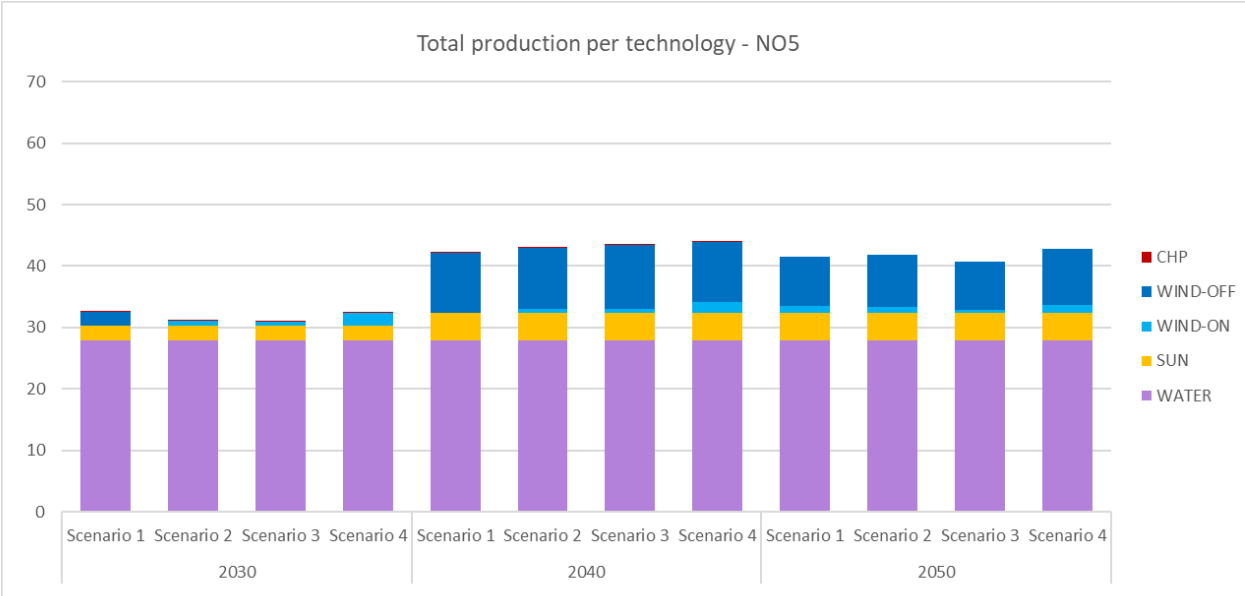
Total production per technology (TWh) for each price zone and scenario in 2030, 2040 and 2050.





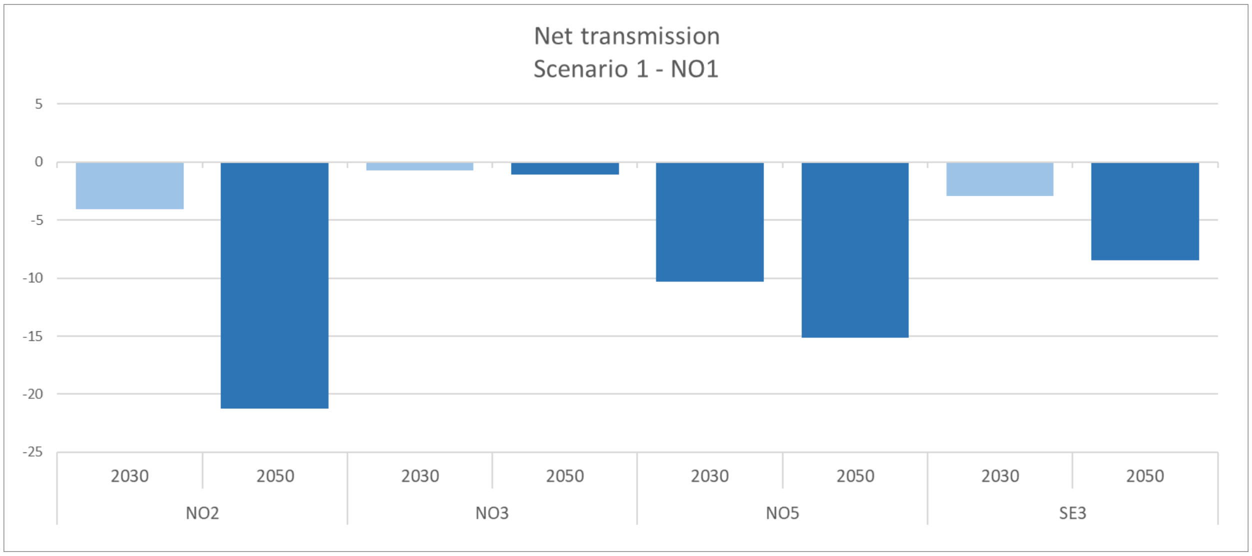

Total production per technology - NO3
70
60
50
40
30
20
10
0
Scenario 1
Scenario 2
Scenario 3
Scenario 4
2030
2040
2050
BIO
STORAGE
CHP
WIND-OFF
WIND-ON
SUN
WATER

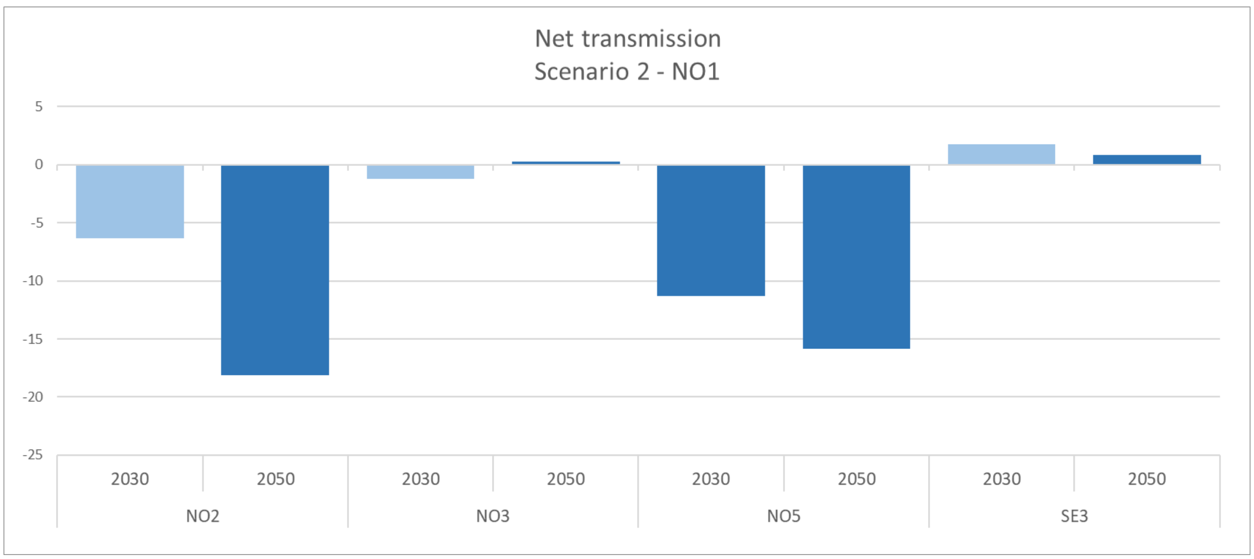

Total production per technology - NO4
70
60
50
40
30
20
10
0
Scenario 1
Scenario 2
Scenario 3
Scenario 4
2030
2040
2050
STORAGE
CHP
WIND-OFF
WIND-ON
SUN
WATER

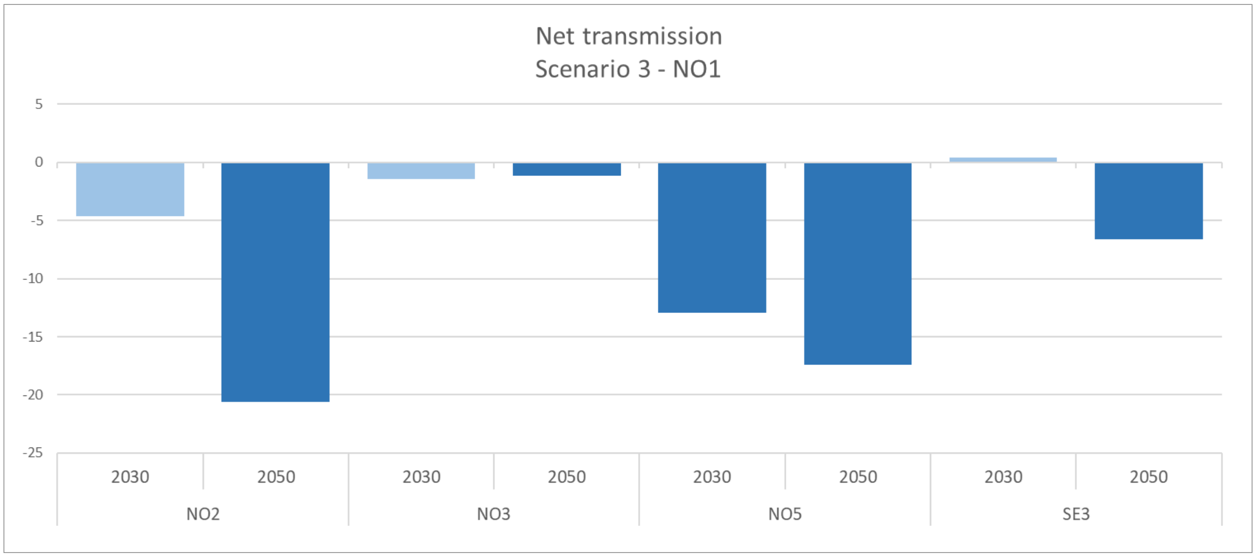

Total production per technology - NO5
70
60
50
40
30
20
10
0
Scenario 1
Scenario 2
Scenario 3
Scenario 4
2030
2040
2050
CHP
WIND-OFF
WIND-ON
SUN
WATER

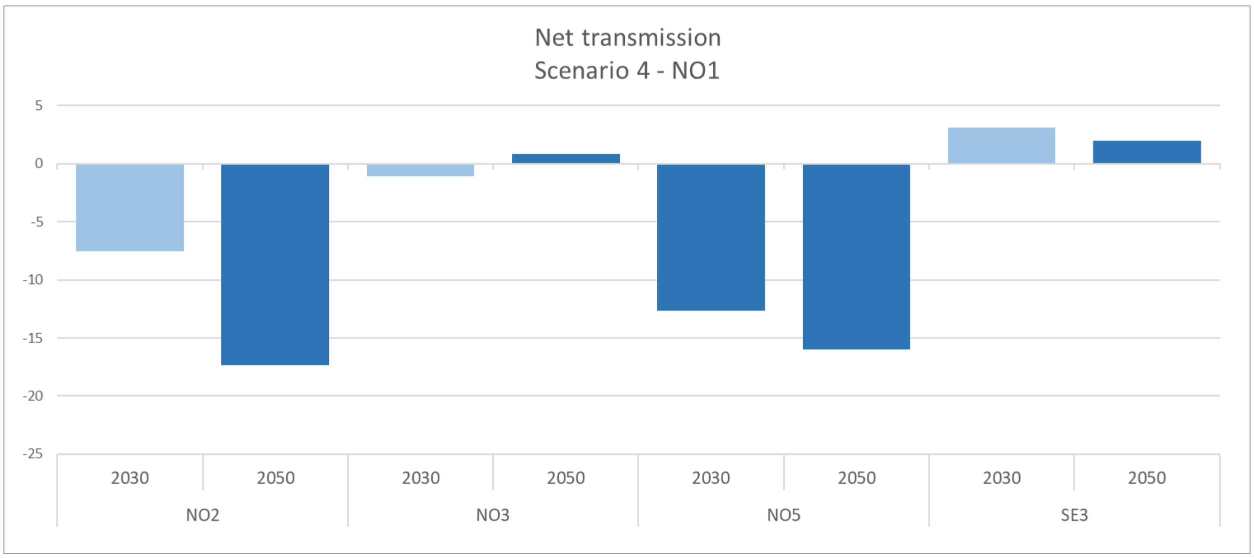
Appendix 3: Net transmission flow per price zone

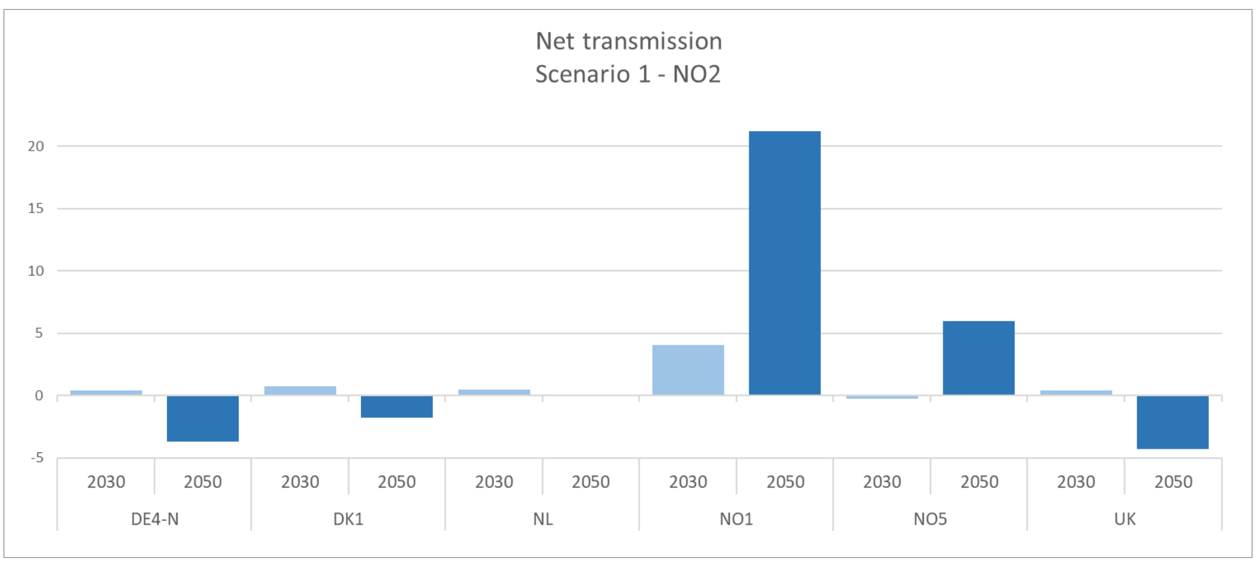
Net transmission flow graphs (TWh) to and from neighboring price zones for NO1, NO2 and NO3 in 2030 and 2050 for each scenario.

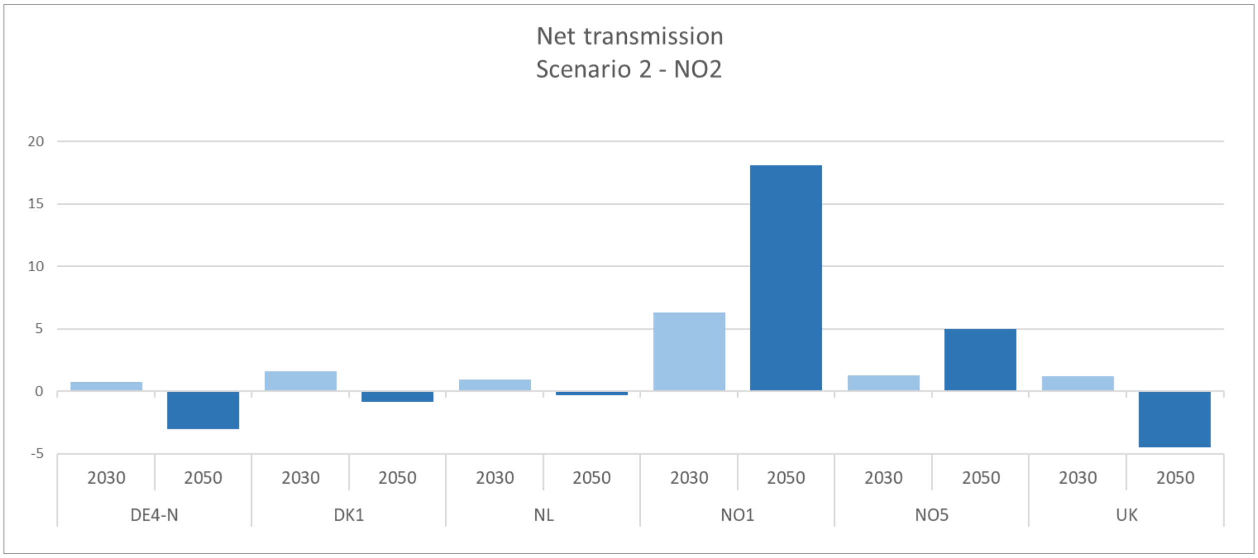


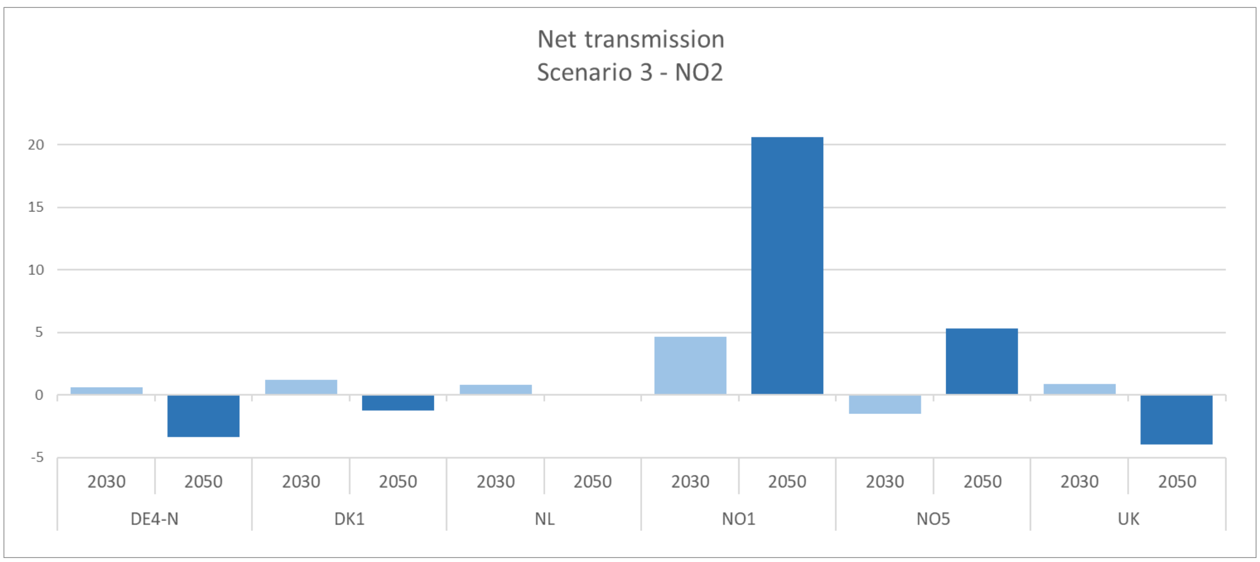


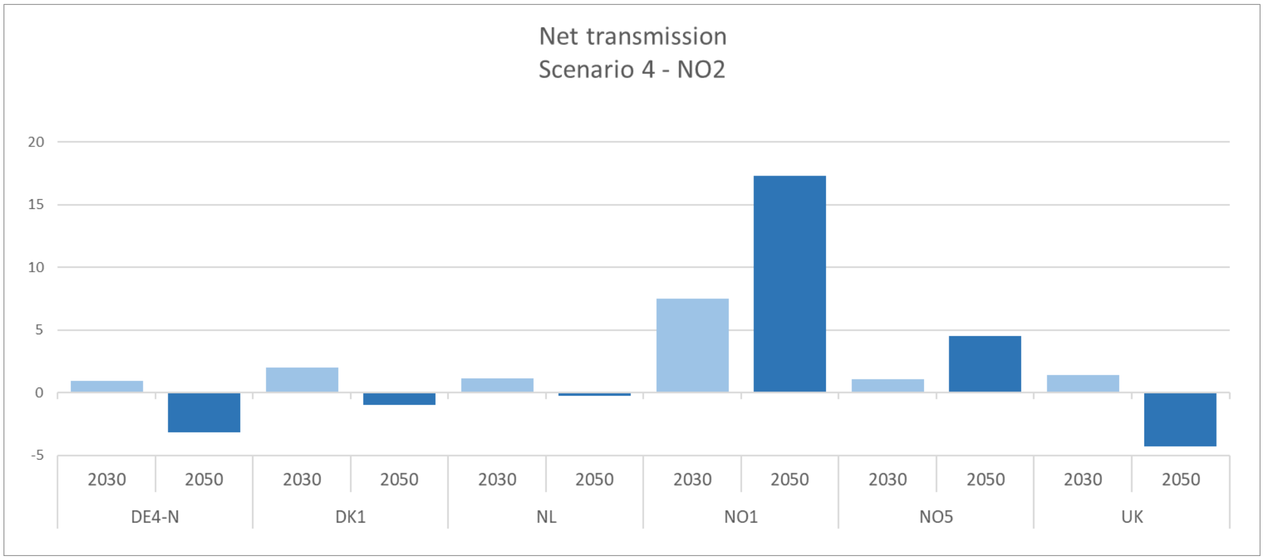

Net transmission
Scenario 3 - NO1
5
0
-5
-10
-15
-20
-25
2030
2050
2030
2050
2030
2050
2030
2050
NO2
NO3
NO5
SE3

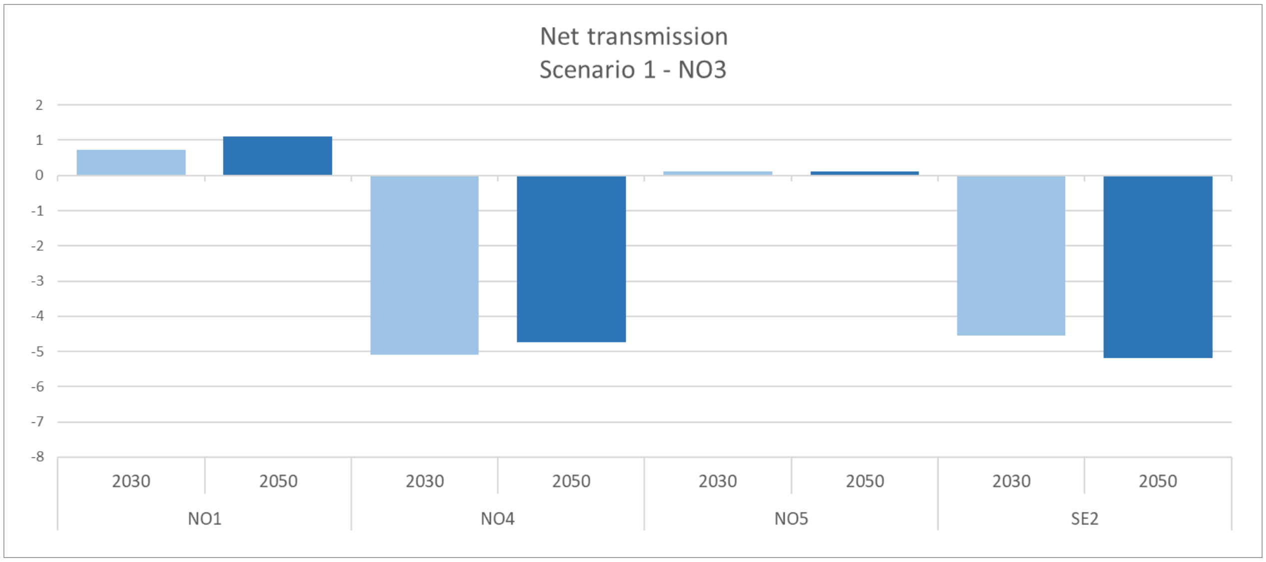

Net transmission
Scenario 4 - NO1
5
0
-5
-10
-15
-20
-25
2030
2050
2030
2050
2030
2050
2030
2050
NO2
NO3
NO5
SE3

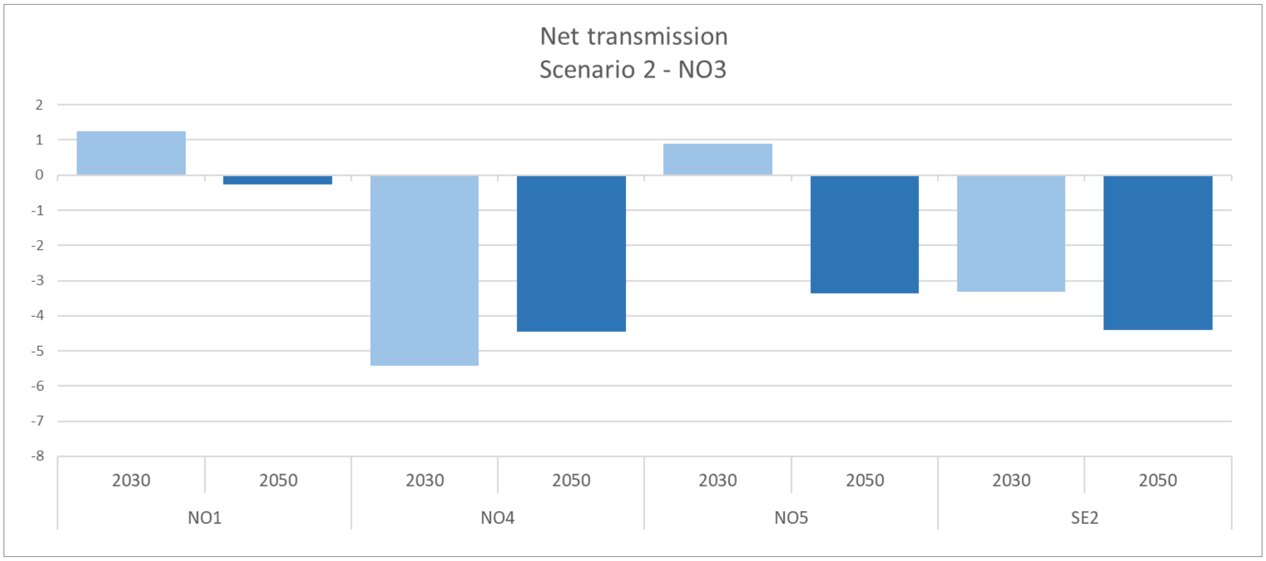

Net transmission
Scenario 1 - NO2
20
15
10
5
0
-5
2030
2050
2030
2050
2030
2050
2030
2050
2030
2050
2030
2050
DE4-N
DK1
NL
NO1
NO5
UK

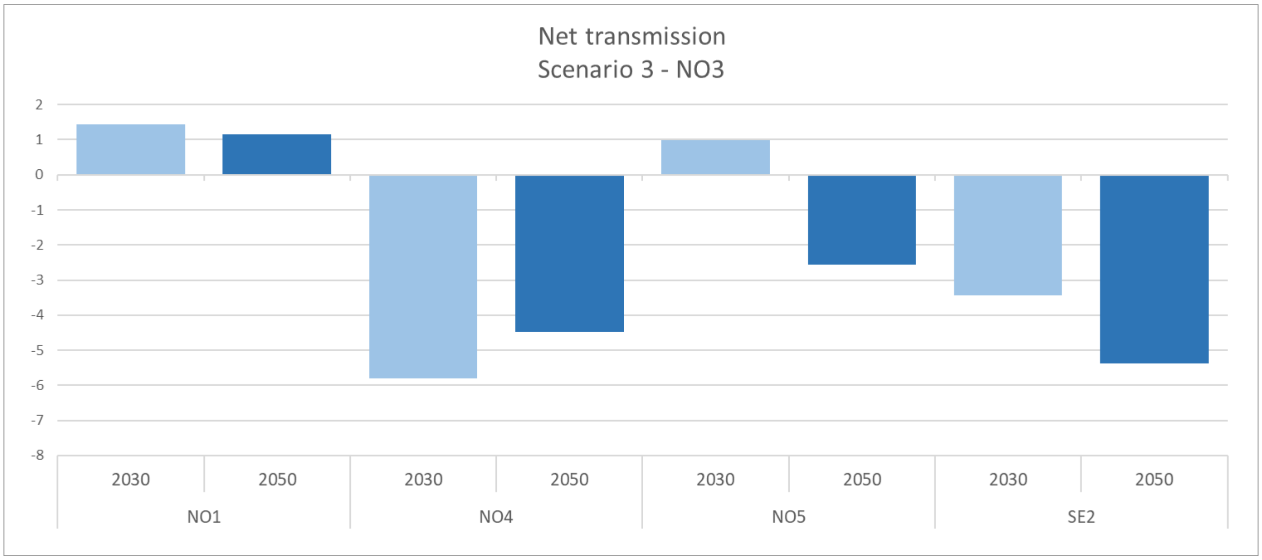

Net transmission
Scenario 2 - NO2
20
15
10
5
0
-5
2030
2050
DE4-N
DK1
NL
NO1
NO5
UK

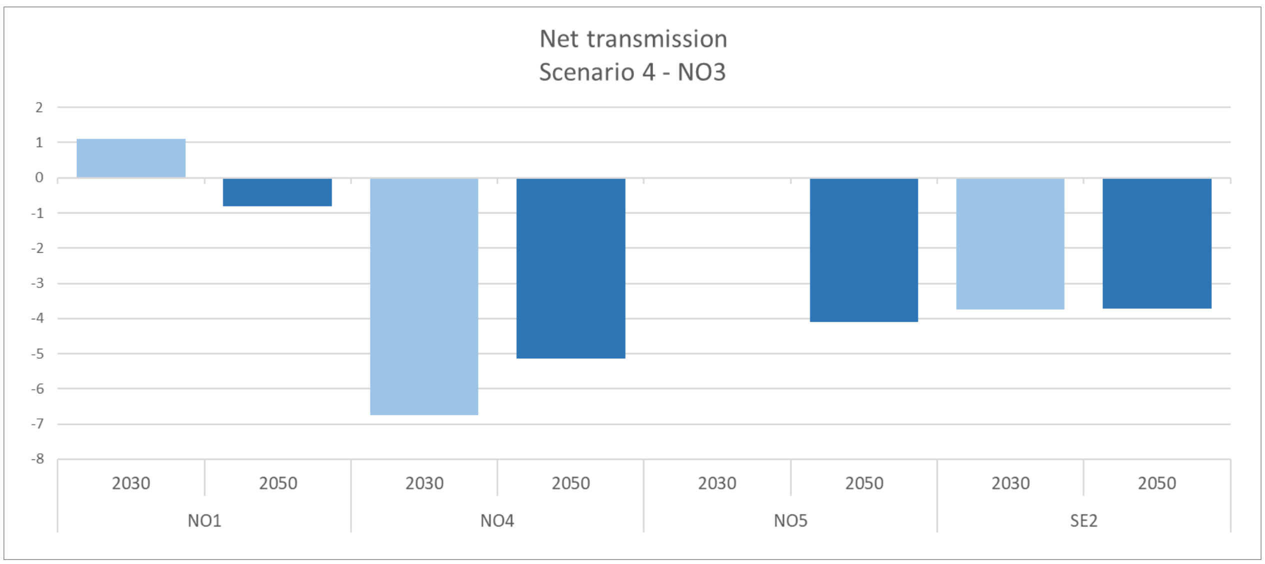

Net transmission
Scenario 3 - NO2
20
15
10
5
0
-5
2030
2050
DE4-N
DK1
NL
NO1
NO5
UK


Net transmission
Scenario 4 - NO2
20
15
10
5
0
-5
2030
2050
DE4-N
DK1
NL
NO1
NO5
UK


Net transmission
Scenario 1 - NO3
2
1
0
-1
-2
-3
-4
-5
-6
-7
-8
2030
2050
NO1
NO4
NO5
SE2

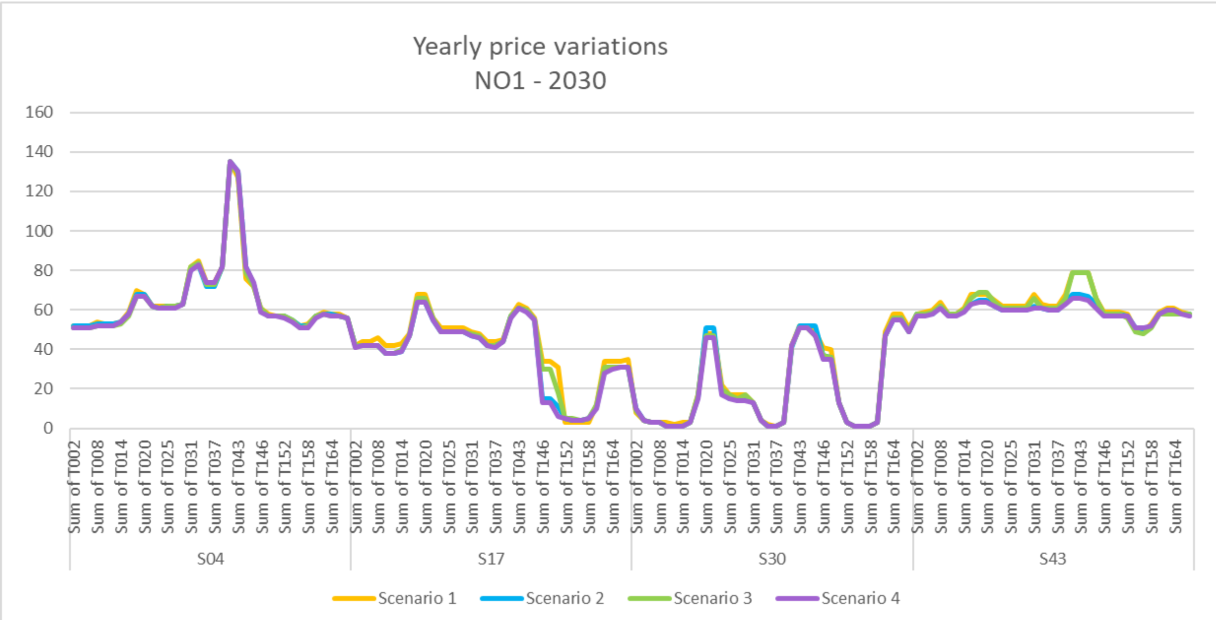

Net transmission
Scenario 2 - NO3
2
1
0
-1
-2
-3
-4
-5
-6
-7
-8
2030
2050
NO1
NO4
NO5
SE2

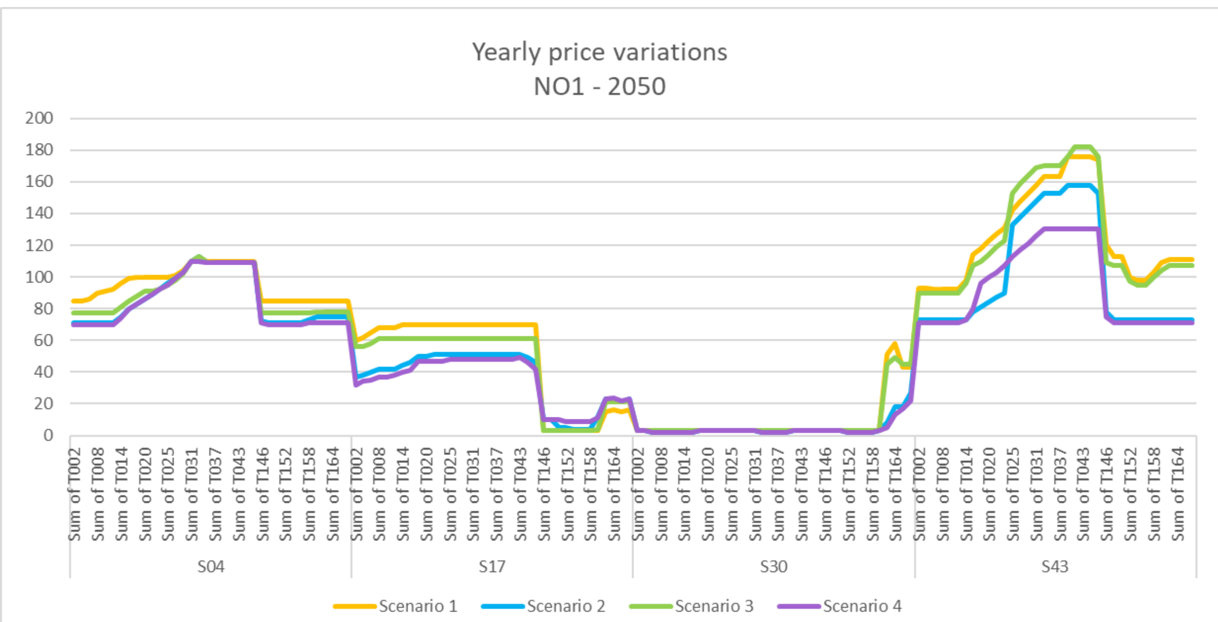

Net transmission
Scenario 3 - NO3
2
1
0
-1
-2
-3
-4
-5
-6
-7
-8
2030
2050
2030
2050
2030
2050
2030
2050
NO1
NO4
NO5
SE2

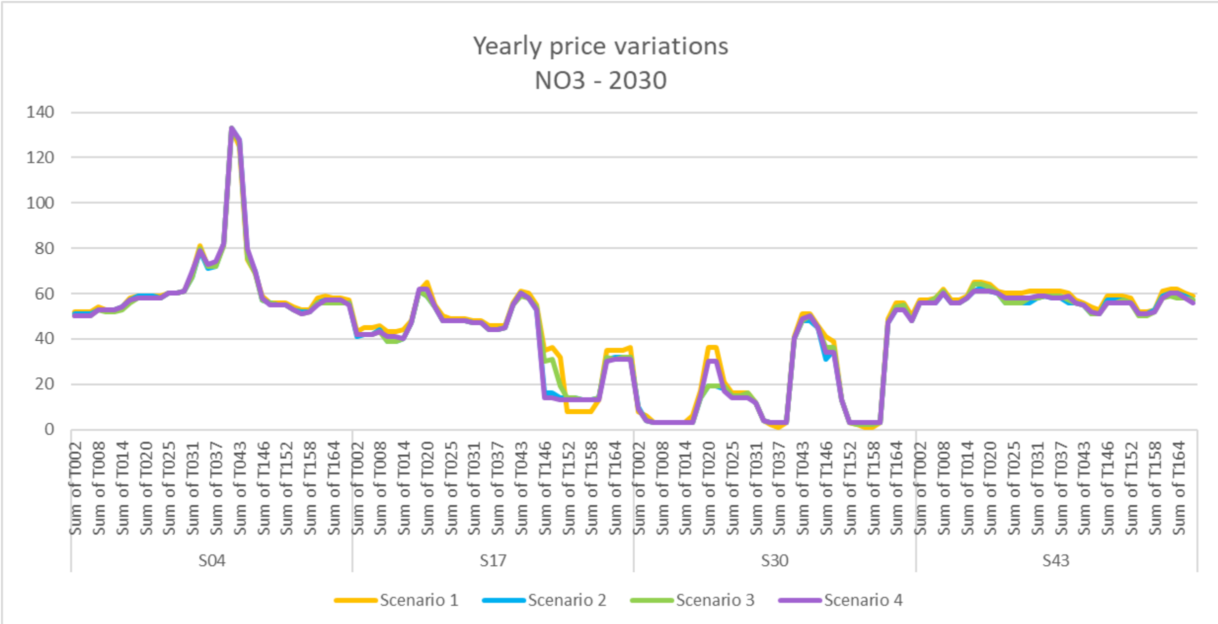

Net transmission
Scenario 4 - NO3
2
1
0
-1
-2
-3
-4
-5
-6
-7
-8
2030
2050
2030
2050
2030
2050
2030
2050
NO1
NO4
NO5
SE2

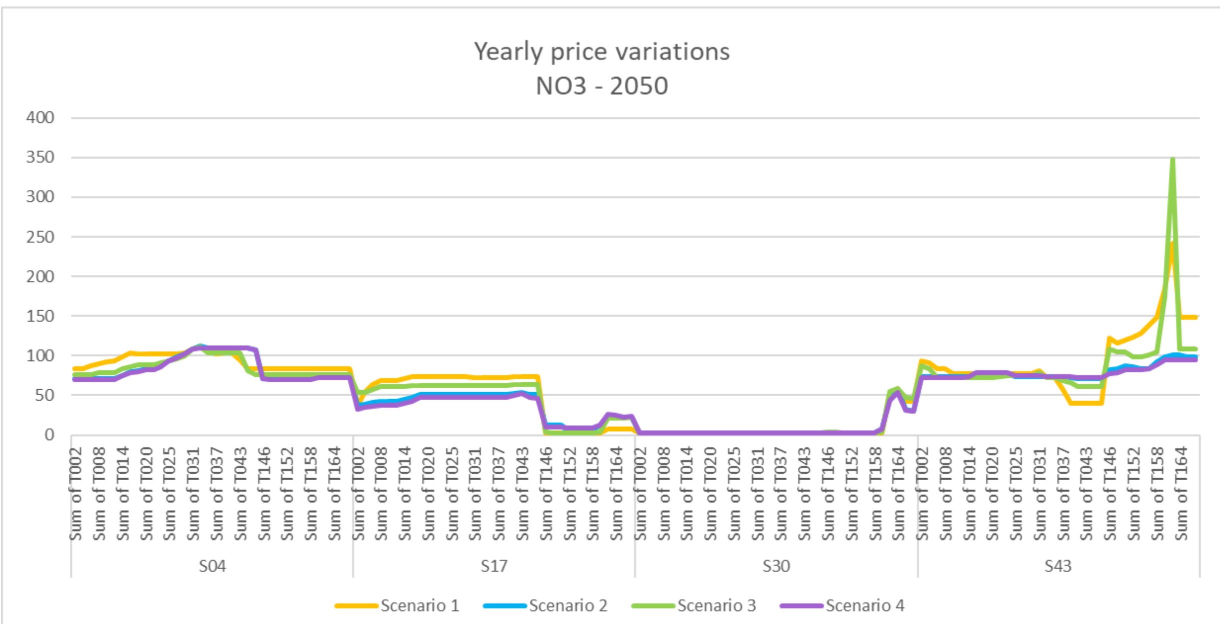
Appendix 4: Yearly price variation graphs per scenario

Yearly price variation graph (EUR/MWh) with hourly prices for all scenarios in NO1 and NO3 within the four weeks S04, S17, S30 and S43 in 2030 and 2050.



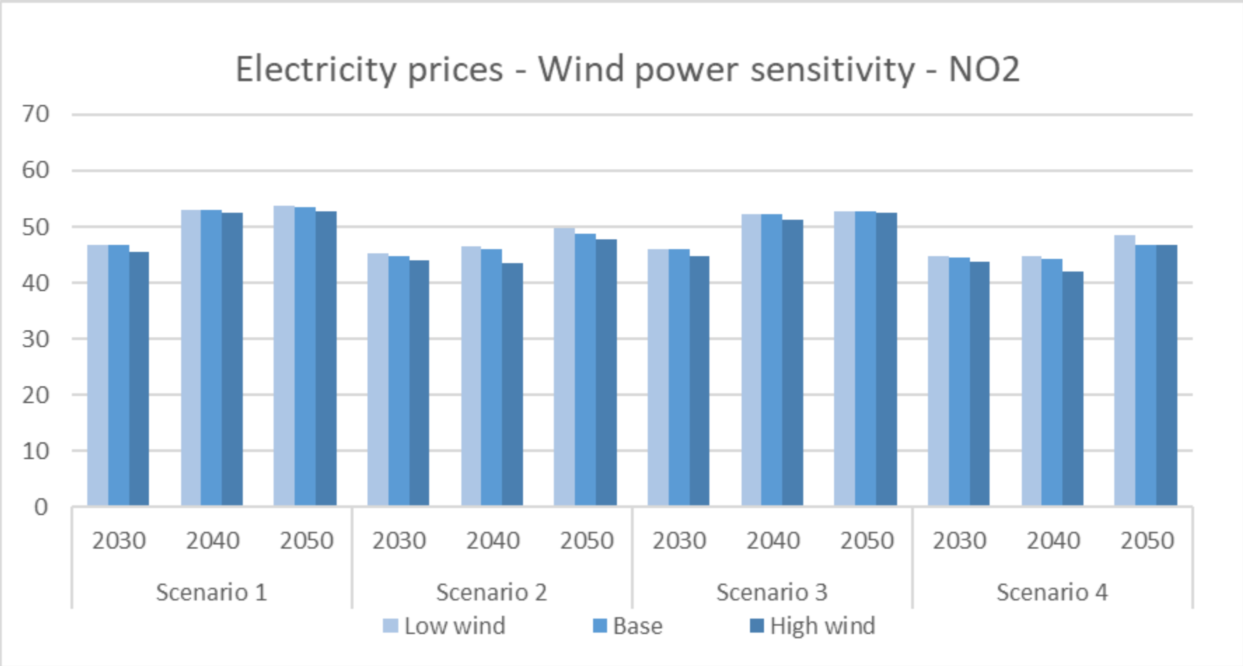


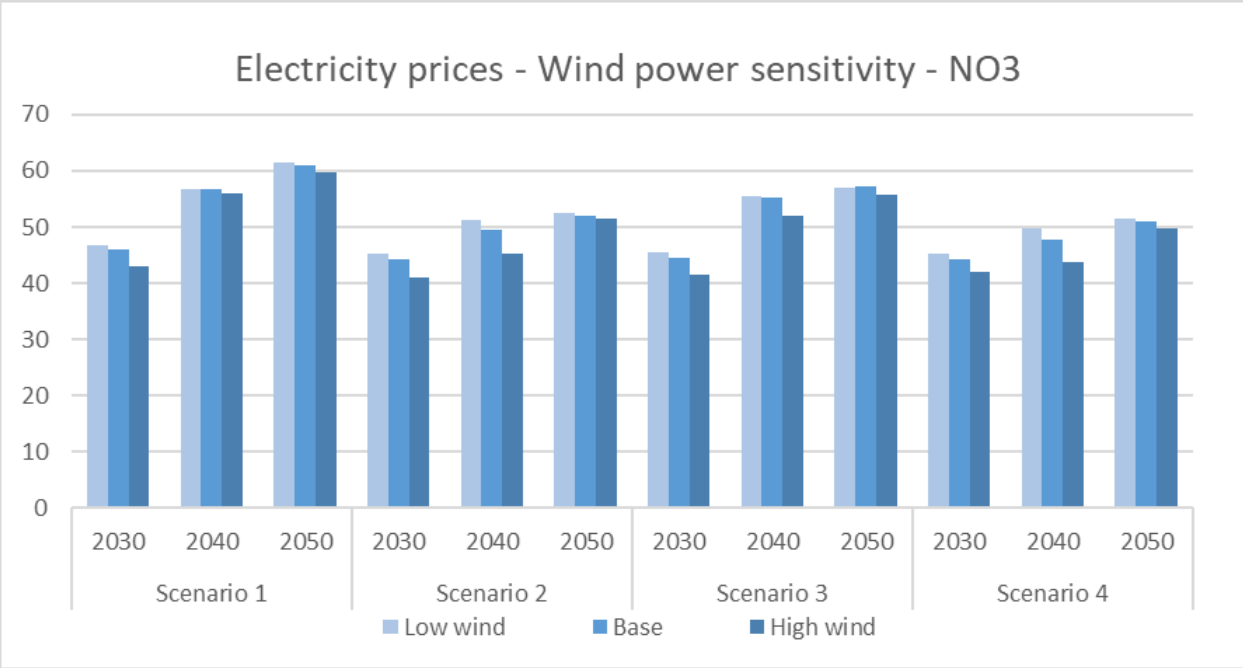

Yearly price variations
NO3 - 2030
140
120
100
80
60
40
20
0
Sum of T002
Sum of T008
Sum of T014
Sum of T020
Sum of T025
Sum of T031
Sum of T037
Sum of T043
Sum of T146
Sum of T152
Sum of T158
Sum of T164
S04
S17
S30
S43
Scenario 1
Scenario 2
Scenario 3
Scenario 4

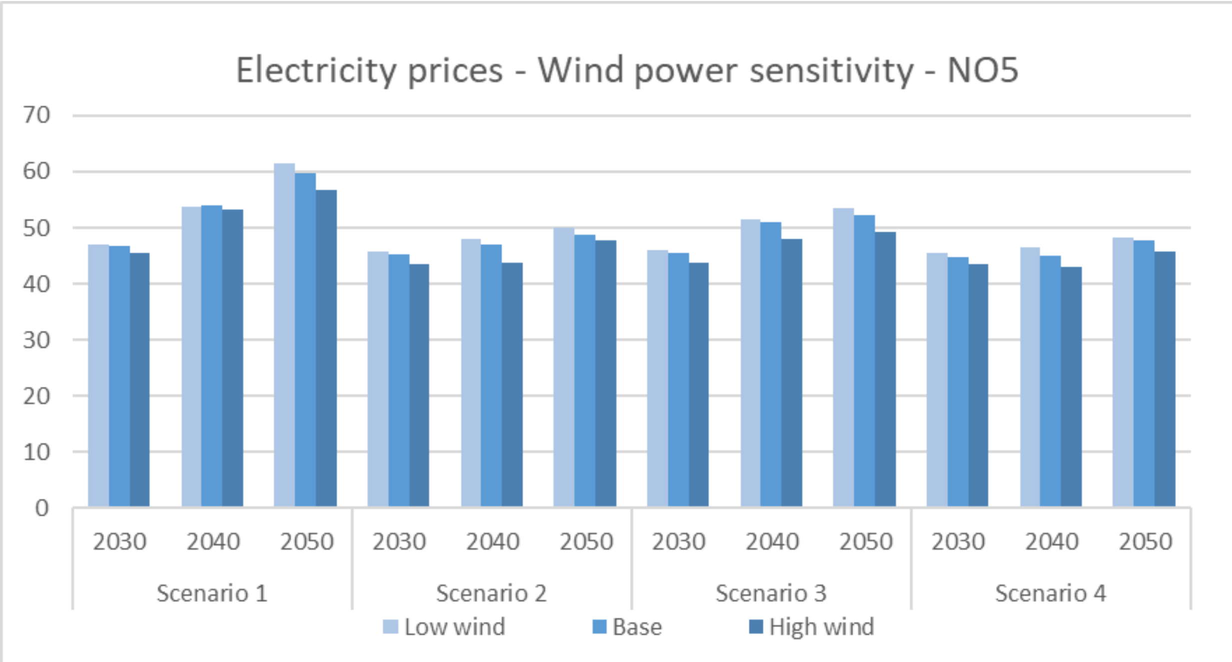

Yearly price variations
NO3 - 2050
400
350
300
250
200
150
100
50
0
Sum of T002
Sum of T008
Sum of T014
Sum of T020
Sum of T025
Sum of T031
Sum of T037
Sum of T043
Sum of T146
Sum of T152
Sum of T158
Sum of T164
S04
S17
S30
S43
Scenario 1
Scenario 2
Scenario 3
Scenario 4

Appendix 5: Electricity prices with wind power sensitivity

Electricity prices (EUR/MWh) in NO2, NO3 and NO5 for each scenario in 2030, 2040 and 2050 in Low Wind, Base and High Wind situations.

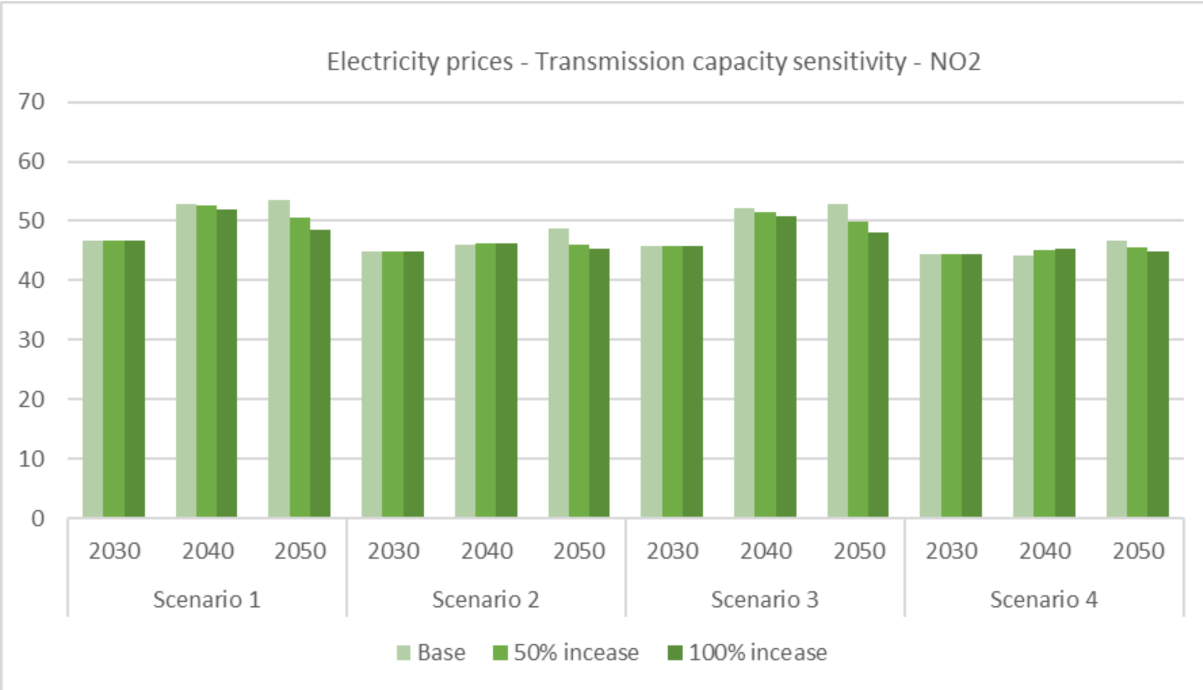





Electricity prices - Wind power sensitivity - NO5
70
60
50
40
30
20
10
0
2030
2040
2050
Scenario 1
Scenario 2
Scenario 3
Scenario 4
Low wind
Base
High wind

Appendix 6: Electricity prices with transmission capacity sensitivity

Electricity prices (EUR/MWh) in NO2, NO3, NO4 and NO5 for each scenario in 2030, 2040 and 2050 in Base, 50% increase and 100% increase situations.




Electricity prices - Transmission capacity sensitivity - NO4
70
60
50
40
30
20
10
0
2030
2040
2050
2030
2040
2050
2030
2040
2050
2030
2040
2050
Scenario 1
Scenario 2
Scenario 3
Scenario 4
Base
50% incease
100% incease


Electricity prices - Transmission capacity sensitivity - NO5
70
60
50
40
30
20
10
0
2030
2040
2050
2030
2040
2050
2030
2040
2050
2030
2040
2050
Scenario 1
Scenario 2
Scenario 3
Scenario 4
Base
50% incease
100% incease

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