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How Do the EU's Climate and Energy Policies Affect Norwegian Electricity Prices and the Outlook for Profitable Wind Power Development in 2030?

A grid parity analysis of onshore wind in Norway under different scenarios for the future power market in Northwestern Europe

by

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Abstract

In this study, I conduct a scenario analysis of the power market in Northwestern Europe in 2030 to assess how different trajectories towards achieving the EU's energy and climate objective affect the Norwegian electricity prices and thereby the market value for onshore wind. Due to the close integration of the European electricity markets, the EU's long-term transition to a low-carbon and energy-efficient economy has vast implications for the levels and structures of the wholesale electricity prices in Norway, which in turn determine the revenues for Norwegian wind power projects. Following the Norwegian government's decision to withdraw Norway from the electricity certificate market after 2021, the long-term development of the wholesale electricity price and the costs of wind projects will solely determine whether it becomes profitable to develop onshore wind in Norway in 2030. I find that the EU's climate and energy policies lead to higher and more volatile electricity prices in Norway under all scenarios, which particularly favors the development of wind power in Norway. In the Base Scenario of this analysis, Norway's average electricity price increases to 44 €/MWh in 2030, while the market value factor of onshore wind is 101 % in all Norwegian bidding zones. By comparing the volume-weighted electricity prices for onshore wind with my estimates of the levelized cost of electricity for 25 onshore wind power projects in Norway, I find that onshore wind reaches grid parity in 2030. Finally, I find that the wind value factors in Norway range from 99 % to 103 %, for wind shares between 5.8 % and 16 % of the Norwegian electricity mix across the four scenarios for 2030. This stands in stark contrast to the wind value factors in Sweden, Denmark and Germany, which drop to 94 %, 93 % and 82 % respectively in the scenario with high renewable energy development and low carbon prices in Europe. The study concludes that the Norwegian power market is particularly well suited for increased wind power development due to the high share of flexible hydropower generation, the correlation between demand peaks and wind power generation, and the limitations in cross-border transmission capacity that upholds price differences.

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Abbreviations

AEA	Annual emission allocation
COP	Conference of the Parties to the UNFCCC
CO_2	Carbon Dioxide
EC	European Commission
EEA	European Economic Area
EED	The 2012 Energy Efficiency Directive
ETS	Emission Trading System
EU	European Union
EUA	European Union Allowance
GDP	Gross Domestic Product
GHG	Greenhouse Gases
GWh	Gigawatt-hour
Gt	Gigatonne
IEM	Internal Energy Market
INDC	Intended Nationally Determined Contributions
IPCC	Intergovernmental Panel on Climate Change
kWh	Kilowatt-hour
LCOE	Levelized Cost of Electricity
MSR	Market Stability Reserve
Mt	Megatonne
Mtoe	Million tonnes of oil equivalents
MW	Megawatt
MWh	Megawatt-hour
NVE	Norwegian Water Resource and Energy Directorate
OECD	Organisation for Economic Co-Operation and Development
RED	The 2009 Renewable Energy Directive
RES	Renewable Energy Source
RES-E	Electricity from Renewable Energy Sources
STMC	Short-term Marginal Cost
TWh	Terawatt-hour
TSO	Transmission System Operator
UK	United Kingdom
UNFCCC	United Nations Framework Convention on Climate Change
VoLL	Value of Lost Load
WACC	Weighted-average cost of capital

1. Introduction

Driven by the EU's energy and climate policies, the European power markets are undergoing an unprecedented transition towards a low-carbon power system, which will have significant implications for the Norwegian power market due to the regional market integration. In this study, I seek to find how the EU's climate and energy policies affect Norway's electricity prices in 2030, and which implications they have for the profitability of Norwegian wind power projects. I use the TheMA model, which is an advanced power market model over Northwestern Europe, to project how Norway's price levels and price structures could develop depending on the progress made towards achieving the EU's climate and energy objectives. Through this scenario analysis, I also seek to identify how the development of the power market in Northwestern Europe affect the revenues for Norwegian wind power projects in particular. By estimating the levelized cost of electricity (LCOE) from 25 Norwegian wind power projects with construction licenses that currently await funding, and conducting sensitivity analyses of the LCOE estimates, I seek to give a realistic picture of the cost development of onshore wind in Norway towards 2030. Finally, I want to investigate whether onshore wind in Norway could reach grid parity in 2030 by comparing my LCOE estimates for onshore wind with the revenues received by wind power plants under the different scenarios.

Against the backdrop of the 2015 Paris Agreement, the EU and Norway embark on a long-term transition towards decarbonization, which will have profound implications for both the supply side and the demand side of the European power market. By 2030, the EU targets a 40 % cut in greenhouse gas emissions compared to 1990 levels, at least a 27 % share of renewable energy consumption and at least 27 % energy savings compared with the business-as-usual scenario. The measures used and progress made to achieve these targets will largely affect the long-term development of the power markets in Northwestern Europe. In particular, the price development depends on the effects from the energy efficiency measures, the renewable energy incentives and the restrictions on coal power generation in EU Member States, along with the revisions of the EU Emission Trading System (ETS).

Meanwhile, the Norwegian government has recently laid out its long-term climate and energy policies through the 2015 White Paper *New emission commitment for Norway for 2030 – towards joint fulfillment with the EU* and the 2016 White Paper *Power for Change –*

an energy policy towards 2030 (Norwegian Ministry of the Environment, 2015; Norwegian Ministry of the Petroleum and Energy, 2016*)*. The latter highlights profitable renewable energy production as one of the key focus areas, and states the government's aim for a long-term development of profitable wind power in Norway (Norwegian Ministry of the Petroleum and Energy, 2016). The 2016 White Papter also reflects the government's decision to withdraw Norway from the joint electricity certificate scheme with Sweden from December 31, 2021, with no signals to replace it with another support mechanism for renewable energy. This motivates a study of whether it will indeed be profitable to develop wind power in Norway without subsidies in 2030 under the EU's envisioned energy transition.

Over the next five to ten years, the International Energy Agency (IEA) (2016a) expects the wholesale power prices to provide little incentive for market-based investment in new capacity in the Nordic power market, as the price is currently below long-term marginal cost of most power-producing technologies. This leads to the question of whether the electricity prices in the long term will develop towards levels that are sufficiently high to spark investments in the wind power sector. As the EU's policies overarch the development of the European power sector, which affects Norwegian prices through the high interconnectivity of the electricity markets in Northwestern Europe, the main research question of the thesis is the following:

> *How do the EU's climate and energy policies affect Norwegian electricity prices and the outlook for profitable wind power development in 2030?*

To answer which implications the EU's climate and energy policies have for the development of onshore wind in Norway, I must look at both the revenues and the costs for Norwegian wind power projects in 2030. Since the intermittency of wind power generation affects the income that wind power plants receive from the spot market, I study how Norwegian wind power plants perform in the wholesale market relative to a constant source of electricity. According to the IEA (2016a), the first Megawatt (MW) of wind power capacity usually have a relatively high value, often even higher than the average wholesale market price, since wind turbines normally produce more during the winter when power prices tend to be higher. However, as the wind share increases within a power system, wind drives expensive power plants out of the market, which reduces the market price of electricity in hours of high wind generation. I therefore estimate the volume-weighted electricity price for onshore wind (hereafter referred to as the wind price) under each scenario, to study how the EU's climate and energy policies affect the Norwegian wind power sector through their effect on price levels and price structures. To find a comparable metric for the costs of generating electricity from onshore wind in 2030, I estimate the levelized cost of electricity (LCOE), which represents the expected lifetime costs of producing a Megawatt hour (MWh) of electricity from a given technology (World Energy Council, 2013). By comparing the costs and revenues for Norwegian wind power projects on a unit cost basis, I study whether onshore wind reaches grid parity in Norway under four scenarios for the long-term development of the European power market. As I base my analysis on project-specific data for all Norwegian wind power projects with construction licenses that currently await funding, my grid parity analysis also provides implications for the net additions in Norway's annual wind power generation under different price levels.

This paper consists of seven chapters that together provide a comprehensive assessment of how the Norwegian electricity prices may develop towards 2030 depending on the EU's energy and climate policies, and the corresponding outlook for developing profitable wind power in Norway. **Chapter One** offers insight into the relevance of the study and provides a literature review of topics related to the scope of this analysis. It serves to place this study in the literature on how measures to achieve the EU's climate and energy objectives affect the electricity prices in the long term and in turn the profitability of onshore wind power projects.

Chapter Two provides a more detailed background to the study and offers insight into the policies and mechanisms that affect the future development of the electricity prices in Norway. It broadly covers the climate and energy policies in the EU and Norway, and their relation to each other and international climate agreements, as well as the policy mechanisms that affect the European electricity market as a whole and the Norwegian electricity market in particular. The chapter lays the foundation for the analysis in chapter five where the policies are translated into four outlooks for the power market in Northwestern Europe in 2030.

Chapter Three provides theoretical insight into power market economics, including how the intersection between the demand curve and the merit order curve determine the equilibrium price. With the fundamentals of the power market as a basis, the chapter then describes how different policy measures, such as carbon pricing and support mechanisms for renewables, affect the wholesale electricity price and the overall welfare.

Chapter Four presents the methodological approach used in the analysis. First, the chapter provides a detailed description of the TheMA model, which is the key tool for modeling the power market in Northwestern Europe. Subsequently, it outlines the storyline and main assumptions behind each scenario that is modeled in the TheMA model. The chapter then explains the levelized cost of electricity, which is the methodology used for estimating the costs of generating electricity from onshore wind. Finally, the chapter provides the methodology used for calculating the revenues for wind power plants. Together, these parts serve to give the reader a profound understanding of the methodology applied in this analysis, before chapter five presents the results.

Chapter Five constitutes the key analysis of how the EU's climate and energy policies affect the Norwegian electricity prices, and which implications they have for the development of onshore wind in Norway in 2030. It begins with an analysis of the long-term cost development of the Norwegian wind sector that includes estimates for the levelized cost of electricity for 25 Norwegian wind power projects. Against this backdrop, the chapter then presents the long-term development of the electricity prices in Northwestern Europe under the four scenarios for 2030. The scenario analysis covers how the EU's climate and energy policies affect the price structures and price levels in Norway and the market value for onshore wind in Scandinavia and Germany. Building on the four scenarios, the next part analyzes whether onshore wind reaches grid parity in Norway under different outlooks for the power market in Northwestern Europe in 2030. The chapter ends with illustrating how increased wind penetration in Norway affects the Norwegian electricity prices through the merit order effect under each scenario.

Chapter Six discusses the results from the analysis in a broader perspective and consists of three parts. The first part discusses the implications of the EU's energy and climate policies on Norwegian electricity prices. The discussion focuses on the effects of the EU's 2030 targets for reduced greenhouse gas emissions, increased renewable energy consumption and increased energy efficiency, and the interdependency between the EU's energy and climate policies. The second part of the chapter argues that the Norwegian power market is particularly well suited to wind power development. Finally, the chapter discusses the outlook for wind power development in Norway in the long term.

Chapter Seven provides the overall conclusion of the study and summarizes the key findings of how the EU's climate and energy policies affect the Norwegian electricity prices, and their implications for the long-term development of wind power in Norway. The chapter also includes suggestions for future research.

1.1 Literature Review

This section gives an overview of the main published work on how the EU's climate and energy policies affect the Norwegian power market towards 2030 and on the profitability of Norwegian wind power in the future. It also serves to place this analysis among the literature that has already been published on this topic. First, this section provides a review of relevant long-term power market analyses, which include either analyses of the EU's energy and climate policies or projections for the Norwegian power market in 2030. Subsequently, the section moves on to review literature on the profitability of the Norwegian wind power sector in the future, which includes studies of both the revenue side and the cost side. In particular, the revenue side is covered through a review of the main literature on historic and projected wind prices in Scandinavia. The cost side is covered through a review of the key literature on the levelized cost of electricity for onshore wind in Norway around 2030, which are presented towards the end of this section.

Table 1.1 summarizes the literature review of long-term power market analyses that are relevant for this analysis. Under a broad analysis of the European power market in 2030, Flues et al. (2014) analyze how the EU's climate and energy policies interact with each other in relation to the power market. In particular, they analyze the implications of overlapping regulation from the EU energy and climate policy portfolio for 2030 under different levels of electricity demand. They find that the EUA price is always lower if the EU ETS is combined with a minimum renewable energy share, and deem this a costly and unintended interaction between the two policy measures. Flues et al. (2014) further conclude that the decline in the EUA price is particularly low if the electricity demand decreases.

The Nordic Council of Ministers (2015) finds that RES subsidies cause the Nordic electricity prices to decline due to a combination of the merit order effect and a decline in the EUA price. When renewable energy becomes more competitive with fossil fuels, a lower EUA price is required to meet the EU's emission reduction targets, which causes the short-term marginal costs of coal and gas to decrease (The Nordic Council of Ministers, 2015). Furthermore, the Nordic Council of Ministers (2015) concludes that the different policy measures used to achieve the EU's climate and energy targets are interdependent. Hence, the EUA price declines if the RES share increases, the investments in coal power generation are banned or the electricity demand is reduced.

Table 1.1: Review of Long-Term Power Market Analyses with Implications for Norway

Author	Scope	Model	Relevant analysis	Key takeaway
Flues et al. (2014)	Europe in 2030	Unnamed (partial equilibrium electricity system model)	Implications of overlapping EU regulation under different levels of electricity demand	The EUA price is particularly low if the EU ETS is combined with a minimum RES share and low electricity demand
The Nordic Council of Ministers (2015)	Nordic countries in 2030	Balmorel (partial equilibrium energy system model)	Impact of EU energy and climate policy measures on the Nordic electricity markets in 2030	RES subsidies cause the Nordic electricity prices to decline due to a combination of the merit order effect and a decline in the EUA price
Zakeri et al. (2016)	Germany and Nordic countries in 2030	Enerallt (simulation-based energy system model)	The impact of Germany's energy transition (energiewende) on the Nordic power market	The energiewende slightly increases the prices and particularly benefits Norwegian hydropower producers
Statnett (2016)	Norway and Northwest Europe. 2020-2040	Samlast/Samnett (load flow models) and BID (fundamental market model)	Trends in the European power market towards 2030 and impact on Norway's price levels and price structures	The Nordic countries get higher and more volatile prices towards 2030, though these trends are stronger on the continent
IEA (2016a)	Nordic countries. 2020-2050	Balmorel (partial equilibrium energy system model)	Integration of RES into the Nordic power market	The Nordic countries become strong electricity exporters in 2030, with Norway as the main export hub

The insight from Flues et al. (2014) and the Nordic Council of Ministers (2015) has been applied when developing the storylines behind the four scenarios of this analysis. The scenarios Base and Green Nations assume that there is little market intervention. Consequently, the EUA price falls in the Green Nations scenario as the renewable energy share increases relative to the Base scenario. In contrast, the Decarbonization Scenario assumes that the EU ETS is revised further, which allows for the EUA price to increase relative to the Base Scenario despite the high RES share. Similarly, the Moderation Scenario assumes that the EU ETS is revised so that the EUA price increases despite the reduction in electricity demand relative to the Base Scenario.

Zakeri et al. (2016) analyze the impact of Germany's energy transition (known as the Energiewende) on the Nordic power market towards 2030 while taking the planned interconnector between Norway and Germany into account. Their results indicate that the average electricity price slightly increases in the Nordic power market after Germany's energy transition. This causes the consumer surplus in the Nordic region to diminish, while the producer surplus increases (Zakeri et al., 2016). The study concludes that Norwegian hydropower producers would receive the highest economic gain among the Nordic power producers because of Germany's energy transition. The study also finds that the wind curtailment in Denmark increases as the renewable energy share in Germany and the Nordic region increases. However, the study does not analyze the impact on wind power producers in Norway in particular, which illustrates the gap in literature on this field.

In terms of long-term power market analyses including Norway, Statnett (2016) provides a detailed scenario analysis of the Nordic and European power markets towards 2040, while the IEA (2016a) analyzes the Nordic electricity system towards 2050. Statnett (2016) and the IEA (2016a) expect the Norwegian prices to increase along with the prices on the continent, albeit at a lower price level. The electricity price increase is attributed to increased prices for gas and CO_2, combined with an increased tendency for gas power plants to set the prices on the continent as more coal power plants and nuclear power plants become decommissioned (Statnett, 2016; IEA, 2016a). In the base scenario, Statnett (2016) projects the prices in Northwestern Europe to average 40-50 €/MWh. In comparison, the IEA (2016a) envisions a steeper increase in the electricity price in the Nordic countries between 2020 and 2030, with the power prices in Sweden, Norway and Finland averaging slightly above 50€/MWh in 2030. The gap between the electricity price forecasts can above all be attributed to different assumptions regarding the CO_2 price in 2030. While Statnett (2016) assumes the EUA price to reach 20€/tCO_2 in the base scenario for 2030, the IEA (2016a) expects the EUA price to reach 100€/tCO_2 in 2030 in the Carbon Neutral Scenario (CNS) scenario. The relatively large discrepancies in the assumptions, and thereby the results, provided by Statnett and the

IEA call for further analyses of how the EU’s climate and energy policies will affect the Norwegian power market in the long term.

In terms of price structures, Statnett (2016) forecasts increased short-term price fluctuations after 2020, which are driven by the increased RES share, the decommissioning of thermal power plants and the increased fuel prices. As the renewable energy production increases, the electricity price increase also leads to more short-term price fluctuations in Northwestern Europe (Statnett, 2016). However, the IEA (2016a) finds that Nordic hydropower absorbs the fluctuations in the system in 2030 by reducing their generation when there is plenty of wind and vice versa. Given the uncertainty regarding the future development of the power markets in Norway and Northwestern Europe, this study contributes to the literature by analyzing Norway’s electricity prices under different assumptions than the IEA and Statnett apply.

Moving on to the profitability of Scandinavian wind power, the IEA (2016a) and Statnett (2016) compare the wind prices to the levelized cost of electricity for onshore wind in Denmark and Norway respectively. Together with the Norwegian Water Resources and Energy Directorate (2015a) and Hirth (2013; 2016), these sources provide some of the key analyses of the wind power sector in Scandinavia. Table 1.2 summarizes the key takeaways from the literature review of the costs and revenues for wind power plants in Norway, Sweden, Denmark and Germany.

Statnett (2016) compares the wind power price and the average electricity price in Norway and Germany for the years 2020 and 2040, while the IEA (2016a) projects the difference between these two prices (the price drop) in the Nordic countries in 2050. However, neither analysis covers the wind power price in Norway in 2030. In contrast, this analysis includes an in-depth study of how wind power producers in Norway perform relative to those in Sweden, Denmark and Germany under different degrees of wind penetration in the respective countries.

Hirth (2016) estimates the wind value factor in Sweden and Germany under different wind market shares. He finds that the market value drops in both countries as the wind share increases, although the drop is less pronounced in Sweden. Hirth (2016) concludes that the Nordic hydro flexibility helps securing the wind value in the long term, as higher system flexibility mitigates the value drop. In another study of the market value of variable renewables, Hirth (2013) finds that the wind value factors were 103 % in Norway, 101 % in Sweden, 99 % in Eastern Denmark, 96 % in Western Denmark and 94 % in Germany in 2010. Building on the insight from these contributions, this analysis goes further into detail by analyzing how gradual increases in the wind share affect the wind power prices in specific bidding zones in Scandinavia and in Germany.

Table 1.2: Review of Publications Covering the Wind Power Sector in Scandinavia

Author	Analysis	Region	Time Horizon	Key takeaway
Statnett (2016)	Wind power prices	Norway and Germany	2020 and 2040	Price drop of wind in 2020 and 2040 is 16 % and 34 % in Germany and 3 % and 7 % in Norway
	Projected LCOE	Norway	Long-term	LCOE declines to 30-45€/MWh
IEA (2016a)	Historic and projected wind power prices	Nordic	2050	In 2050 the price drop is 40 % in Denmark, 19 % in Norway, 17 % in Sweden and 13 % in Finland
	Projected LCOE	Nordic	2013, 2030, 2050	The LCOE declines to 56-79 USD/MWh by 2030
NVE (2015a)	Historic and projected LCOE	Norway	2011-2013, 2014 and 2035	The LCOE for onshore wind declines by 15 % from 2014 to 2035
Hirth (2016)	Projected wind value factor	Sweden and Germany	Unspecified	For each percentage point increase in the wind market share, the wind value factor drops by 0.8 points in Germany, but only 0.5 points in Sweden
Hirth (2013)	Historic wind value factor	Scandina via and Germany	2009-2010	The wind value factors averaged 93 % in Germany and 101 % in Sweden and Norway

In addition, this analysis estimates the levelized cost of electricity (LCOE) for onshore wind in Norway, and compares it to the wind power prices under different scenarios. Statnett (2016), the IEA (2016a) and the Norwegian Water Resources and Energy Directorate (2015a) expect the levelized cost of electricity (LCOE) for onshore wind to decline over the next decades. Statnett (2016) presumes the LCOE of onshore wind power in Nordic to range from 30€/MWh to 45€/MWh in the long-term, and expects profitable development of wind power in Nordic without subsidies, especially in the scenarios with high electricity prices. In the Balmorel model, the IEA (2016a) assumes the LCOE of onshore wind in the Nordic region to decline to 56-79 USD/MWh in 2030. However, neither publication estimates the LCOE for onshore wind in Norway in 2030 in particular. The Norwegian Water Resources and Energy Directorate (2015a) goes further into detail by estimating the LCOE of Norwegian, onshore wind power in 2011-2013 and 2035 based on their project-specific information from license applications. NVE (2015a) projects the LCOE for onshore wind to fall to 37€/MWh (0.34 NOK/kWh) by 2035, which corresponds to a 16 % reduction from current levels. Building on NVE's in-house dataset, this analysis provides updated LCOE estimates for onshore wind in Norway in 2030. In particular, this analysis calculates the LCOE for all the Norwegian wind power projects that currently await funding and possess construction licenses. While NVE's publication focuses on the cost of generation from different energy sources in Norway, it does not cover the revenue side of electricity generation. Hence, this analysis differs from previous literature by combining in-depth studies of both the revenue side and the cost side for onshore wind in 2030.

To sum it up, this analysis brings novel insight to the literature in three ways. First, it provides a long-term market analysis of Norway and Northwestern Europe under a brand new set of assumptions for the electricity mix, electricity demand and fuel prices in Europe. Given the uncertainty regarding each of these factors, this analysis contributes to enhancing the understanding of how the EU's energy and climate policies can affect these power markets in the future. Second, this analysis provides estimations for the wind prices in Scandinavia and Germany under different outlooks for the European power market. This contributes to highlight how the electricity mix, the demand levels and the fuel prices affect the market value of wind. It also provides a more in-depth analysis of Norwegian wind prices than previous literature by estimating the relative and absolute market value of wind in different bidding zones under various scenarios. Third, this analysis provides new LCOE estimates for onshore wind, which particularly reflect the conditions for the Norwegian market in 2030. The dataset used for the LCOE calculations consists of all Norwegian wind power projects that the Norwegian Water Resources and Energy Directorate have granted construction licenses and that await decision investments as of January 2017. As these projects have not been profitable to develop under the current market conditions, they serve as a relevant representation of the wind projects that investors will evaluate around 2030.

2. Background

The main objective of this chapter is to provide the reader with a general understanding of the policies and mechanisms that affect the Norwegian power sector, and particularly the future development of electricity prices. This chapter further lays the foundation for the scenario analysis that is presented in Chapter Five. The Norwegian electricity market is highly integrated with the European electricity market through cross-border interconnectors and market coupling. Consequently, it is essential to make assumptions for the future development of the electricity markets in Norway's adjacent countries and main trading partners, in addition to the domestic market, when projecting the long-term development of the Norwegian electricity prices. The electricity markets in European countries are affected by climate and energy policies on an international, EU-wide and national level. Hence, the chapter begins by outlining international climate policies, which serves as a backdrop for the climate and energy policies in the EU and Norway.

The second section of the chapter outlines the EU's climate and energy policies, which directly and indirectly affect the Norwegian electricity market, before the chapter gives an overview of the EU's Target Model for electricity. The chapter then describes the EU ETS, which is the EU's key tool for achieving its emission reduction target (EC 2016a). The next section narrows down the scope to Norway and outlines the country's climate and energy policies and the electricity certificate market, which is Norway's support mechanism for renewable energy. Finally, the chapter describes the Norwegian electricity market, in terms of key regulation and market structure. In particular, it provides an overview of the power exchange, Nord Pool, and the day-ahead market, Elspot, as they are essential to understand how the wholesale electricity price is determined in Norway.

2.1 International Climate Policy

International climate agreements lay the foundation for regional and national climate policies in Europe, which have motivated efforts to reduce greenhouse gas emissions from the power sector. This section thus gives a broad overview of how international climate policies have developed from the beginning of the 1990s to date. Within this context, the targets and results of two essential international climate agreements are highlighted, i.e., The 1997

Kyoto Protocol to the United Nations Framework Convention on Climate Change (the Kyoto Protocol) and the Paris Agreement.

There is scientific consensus that anthropogenic climate change is occurring now, and poses a growing threat to society (NASA, n.d.). While the Earth's climate has changed throughout history, the observed global warming since the mid-20th century is outstandingly significant because human influence has been the dominant cause of the temperature increase (the Intergovernmental Panel on Climate Change [IPCC], 2014). In particular, anthropogenic GHG emissions are causing the climate to change, which increases the risk of severe and in some cases irreversible detrimental consequences for natural and human systems (IPCC, 2014). In order to limit the climate change risks and reduce the associated increase in global, average temperature adaptation and mitigation strategies are needed. The historic effects and future implications of climate change are well documented by the IPCC's Assessment Reports, which are the most comprehensive scientific reports about climate change produced globally (IPCC, n.d.). In the First Assessment Report, the IPCC (1990) stated that they are certain that GHG emissions resulting from human activities are resulting in an additional warming of the Earth's surface. The First Assessment Report then played a major role in the creation of the United Nations Framework Convention on Climate Change (UNFCCC) in 1992. According to the UNFCCC (n.d.-a), "The ultimate objective of [the UNFCCC] is to stabilize greenhouse gas concentrations in the atmosphere at a level that will prevent dangerous human interference with the climate system." In 1995, the signatories to the UNFCCC started negotiations at the first Conference of the Parties (COP), which has since been held annually (UNFCCC, n.d.-b).

2.1.1 The Kyoto Protocol

The Kyoto Protocol was adopted under COP3, and entered into force on February 16, 2005 (UNFCCC, n.d.-c). Building on the general commitments of the UNFCCC, the Kyoto Protocol outlined GHG emission reduction obligations and the Kyoto mechanisms (UNFCCC, n.d.-c). It established legally binding obligations for reductions in GHG emissions for 38 Annex I parties (i.e. industrialized countries that were members of the OECD in 1992 and the Economies-in-Transition Parties listed in Annex B. Most of the Annex I countries, including the EU-15, were given an emission limitation equivalent to an 8 % reduction relative to 1990 for the first commitment period, which lasted from 2008 to 2012 (Kyoto Protocol, 1997). The Kyoto Protocol adopted a market-based approach to emission reductions, where tradable permits were used as the main policy instrument for Annex B parties to meet their emissions reduction targets. However, the alleged emission reductions from different Kyoto mechanism projects have been widely criticized as hot air, i.e., free surplus that was treated as emission reductions in the emission market although no true abatement had occurred (Morel & Shishlov, 2014; Schneider, Rosencranz & Niles, 2002). In addition to the concern for the environmental integrity of the Kyoto credits, the effectiveness of the Kyoto Mechanisms in incentivizing emission reductions have further been challenged by the low trading prices of Kyoto credits.

These issues have also posed a challenge to the EU ETS, as participants in the EU ETS are permitted to use Kyoto credits to fulfill parts of their obligations until 2020, with the limit being set to 50 % of the EU-wide reductions over the period 2008-2020 (European Commission, n.d.-b). Kyoto credits have thus represented a cheap alternative to buying EUAs under the EU ETS, and contributed to the prevailing challenge of European Emission Allowances (EUAs) trading at low prices (IETA, 2015; EC, 2016a). While participants in the EU ETS will be prohibited from using Kyoto credits from 2020 according to the European Commission (2016b), the low price stemming from an oversupply of allowances may continue to challenge the emission trading system towards 2030.

Although the global Kyoto target for 2008-2012 was overachieved, Morel and Shishlov (2014) argue that the overachievement can largely be attributed to hot air, the non-participation of the US and Canada, and the international economic crisis that decreased GHG emissions. Following the limited participation in the Kyoto Protocol and the lack of agreement under COP15 in Copenhagen in 2009, the Parties agreed in 2012 to adopt a universal climate agreement by 2015 and started negotiating towards COP21.

2.1.2 The Paris Agreement

The 2015 Paris Agreement aims to hold “the increase in the global average temperature to well below 2 °C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 °C above pre-industrial levels,” (UNFCCC, 2015a). According to UNFCCC (n.d.-d), the Paris Agreement was a landmark, being the first global agreement to bring “all nations into a common cause based on their historic, current and future responsibilities”. The Paris Agreement is a hybrid of legally binding and nonbinding provisions, according to the United Nations (2015). While the core agreement that governs the international process will be binding for the Parties, other elements such as the intended nationally determined contributions are not part of the legally binding agreement.

The Paris Agreement requires all Parties to set "nationally determined contributions" (NDCs), which will be updated on a five-year basis (UNFCCC, 2015a). The NDCs revisions are intended to raise mitigation targets further as the countries gain experience and as technology costs decline (IEA, 2016b). According to Carbon Brief (2015), 162 intended nationally determined contributions (INDCs) had been submitted to UNFCCC by December 24, 2015, reflecting 189 countries and accounting for 99.1 % of global GHG emissions. However, the Paris Agreement notes with concern that the estimated aggregate GHG emission levels from the INDCs fall short of reaching the least cost 2 °C scenarios for 2100 (UNFCCC, 2015a). Both the EU and Norway have put forward a binding, economy-wide target to reduce their GHG emissions by at least 40 % below 1990 levels by 2030 through their INDCs (UNFCCC, n.d.-e). Moving forward, the level of ambition in the revised NDCs undertaken by Norway and its adjacent countries will have indirect implications for the power sector through the policies that are implemented to support the achievement of these emission reduction targets. In particular, the NDCs will provide the backdrop for the overall cap of the EU ETS, various measures to decarbonize the supply side of the power market, and energy efficiency and electrification measures on the demand side.

2.2 Climate and Energy Policies in the EU

This section serves to give a broad overview of the current climate and energy policies in the EU, including the objectives for 2020 and 2030, and the long-term objective of decarbonization. While the backdrop for the EU's climate policies were outlined in the previous section, this section begins by describing the triple objective that overarches the EU's energy policies. Subsequently, the targets for GHG emission reduction, renewable energy and energy efficiency are described while their implications for the power sector are emphasized. Finally, the EU's Energy Union strategy is described, including the vision of an internal electricity market.

The EU's current energy policies are driven by three main objectives; namely energy independence, competitiveness and sustainable development (the "triple objective") (EC, 2016c). The three objectives were first proposed in 2006 by the European Commission in the green paper "A European strategy for sustainable, secure and competitive energy", before being translated into EU legislation through the "Climate and Energy Package" in 2009 and the "European Energy Security Strategy" in 2014 (EC, 2006; 2010; 2016d). The European Commission (2016c) states that the first objective, energy independence, arise from the EU's current status as a net energy importer, whose imports correspond to more than half of its energy consumption at a cost of €350 billion per year. Furthermore, many EU countries are heavily reliant on a single supplier, in particular on Russia for their natural gas, which leaves them vulnerable to supply disruptions, such as political and commercial disputes, and infrastructure failure (EC, 2016d). The second objective of the EU's energy policies, competitiveness, reflects the EU's ambition to ensure that energy providers operate in a competitive environment that facilitates affordable prices for its citizens and competitiveness of the European industry (EC, 2016c). Finally, the sustainable development objective reflects the union's targets of lowering GHG emissions, pollution and fossil fuel dependence, (EC, 2016c). Sustainable development has been included as a fundamental target of the EU since 1997, when it was incorporated as a principal objective of EU policies in the Treaty of Amsterdam (EC, 2016e). Driven by the motivation to mitigate climate change, the EU aims to decarbonize its economy towards 2050.

2.2.1 Targets for GHG emission reductions, renewable energy and energy efficiency

In 2007, the European Council first adopted the so-called 20-20-20 targets: to reduce GHG emissions by 20 % relative to 1990 levels, to increase the share of renewable energy to 20 % and to make a 20 % improvement in energy efficiency by 2020 (EC, 2016c). The targets were translated into legislation in 2009 through the 2020 climate and energy package, and supported by the 2009 Renewable Energy Directive (RED) and the 2012 Energy Efficiency Directive (EED). The RED established an overall policy for the production and promotion of renewable energy sources (RES) in the EU. Although the RED demanded the submission of National Renewable Energy Action Plans by each member state by 2020, the states are free to choose which regulatory or supporting policies to use to achieve their national RES target (Fruhmann & Tuerk, n.d.). Two years later, the European Council further committed to the long-term objective of turning the EU into a low-carbon economy through cutting its domestic emissions by 80 to 95 % relative to 1990 levels by 2050 (EC, 2011).

Building on the 2020 climate and energy package, the European Council adopted the 2030 Framework for Climate and Energy in 2014. By 2030, the EU targets a reduction in GHG emissions by 40 % compared to 1990 levels, as later reflected in the EU's INDC for COP21 in 2015 (EC, 2016f; UNFCCC, n.d.-e). The EU intends for all emission reductions to occur within the EU member states, which implies that other international climate policies will not be accounted for (THEMA Consulting Group [THEMA], 2015a). Hence, the EU Member States will no longer be able to use Kyoto credits from Clean Development Mechanism and Joint Implementation projects to fulfill their commitments after 2020. The European Commission (2016f) further notes that in order to achieve the 40 % emission reduction target for 2030, the ETS-sectors will have to decrease their emissions by 43 %, while the non-ETS sectors must reduce their emission by 30 % relative to 2005-levels.

The objective for the non-ETS sectors, which include transport, buildings, agriculture, waste and land use and forestry sectors, is to be translated into national, binding targets for each member states through the Effort Sharing Decision. On July 20, 2016 the European Commission (2016g) proposed the Effort Sharing Regulation, which suggests binding GHG emission reduction targets for each Member State. The national targets for 2030 are expressed as a percentage reduction from 2005 emission levels, and range from 0% to -40% depending on the Member States' Per capita Gross Domestic Product (GDP). The proposal also sets a limit for each year in the ten-year period up to 2030, according to a decreasing linear trajectory. However, to allow for a cost-effective achievement of the target, in particular for higher income Member States, the European Commission (2016g) proposes flexibilities through which Member States can reduce emissions jointly, across several sectors and over time. The new one-off flexibility allows eligible Member States to reach their national targets through covering some emissions in the non-EU ETS sectors with EUAs. The maximum annual flexibilities are given as a percentage of 2005 emissions, and range from two to four percent for the nine high-income Member States that are eligible.[1] On an EU-wide level, the use of this flexibility is however limited to 100 million tonnes of CO_2 over the period 2021-2030. The amount of EUAs that is transferred from the EU ETS sector to the non-EU ETS sectors will have direct implications for the price of EUAs through the supply side (THEMA, 2015a). The proposed Effort Sharing Regulation also maintains the existing flexibility of banking, borrowing, buying and selling Annual Emission Allocations (AEAs). The European Commission (2016g) argues that the banking and borrowing of

[1] Proposed flexibilities: Austria (2%), Belgium (2%), Denmark (2%), Finland (2%), Ireland (2%), Luxembourg (4%), Malta (2%), the Netherlands (2%), Sweden (2%)

AEAs from previous or subsequent years respectively provide flexibility to cope with annual fluctuations in emissions due to weather or economic conditions. The AEAs can also be traded between Member States, which allows for the targets to be met in a cost-effective manner according to the European Commission (2016g).

In addition to the GHG emission reduction target, the targets for 2030 are to increase the share of renewable energy consumption to at least 27 % and to obtain at least 27 % energy savings compared with the EU's business-as-usual scenario (EC, 2014a). The targets for 2020 and 2030, which are summarized in Table 2.1, serve as milestones for the EU's long-term objective of becoming a low carbon economy.

Table 2.1: *The EU's Energy and Climate Targets for 2020, 2030 and 2050*

	2020	2030	2050
Reduction in GHG emissions *	20 %	40 %	80-95 %
Share of renewable energy	20 %	27 %	TBD
Increase in Energy Efficiency	20 %	27 %	TBD
Emission trading system (ETS) **	21 %	43 %	TBD
Non-ETS Sectors **	10 %	30 %	TBD

Note: *Relative to 1990 levels. ** Relative to 2005 levels. *Source:* Adapted from the European Commission, 2016c.

The energy efficiency target is due to be reviewed in 2020, having in mind a 30% EU-level target (EC, 2016c). The EU level target for energy efficiency is not legally binding at the national level or EU level (Jacobsen & Crisp, 2014). Furthermore, each member state no longer have binding RES targets at the national level under the 2030 climate and energy framework, as opposed to the 2020 climate and energy package. Each EU MS is free to choose its own regulatory or supporting mechanisms to contribute to the EU-wide RES targets for 2020 and 2030. The EU's RES targets can be met through increases in the shares of renewable energy in both the electricity sector (RES-E) and the heating sector. The European Commission (2014b) expects the share of electricity generated by renewable energy to reach up to 50 % by 2030. Since electricity generation is covered by the EU ETS, while heat production is not, the share of the 2030 RES target that is met by the ETS-sectors and the non-ETS sectors respectively will affect the electricity price directly through the merit order effect and indirectly through the EUA. The higher the share of RES-E, the more zero-carbon generation is added to the EU ETS and the more EAU prices will be suppressed price (Pöyry Management Consulting, 2014).

2.2.2 Towards an Energy Union

In 2015, the European Commission (2015a) adopted "A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy" (The Energy Union Framework Strategy) to ensure that Europe has secure, sustainable and competitive energy. The EU's Energy Union serves as a new umbrella that unites the elements of the abovementioned energy strategies into one coherent, integrated approach. Consequently, it consists of five mutually reinforcing dimensions: supply security; energy efficiency; emissions reductions; a fully integrated internal energy market; and research and innovation for climate (EC, n.d.-a). In particular, energy efficiency will play a role in all five dimensions under the EU's "energy efficiency first" approach for the energy union (European Council for an Energy Efficient Economy, n.d.).

The fourth dimension of the Energy Union, a fully-integrated Internal Energy Market (IEM), targets free flow of energy, in particular gas and electricity, across the EU – without any technical or regulatory barriers (EC, n.d.-b). The final objective, for the internal electricity market in particular, is to create a pan-European market with closer connection of power markets to improve the efficient use of energy across countries. The European Commission has gradually put in place the IEM since 1996, through Directive 96/92/EC, 2003/54/EC and 2009/72/EC (IEA, 2014). The last legislative package, i.e. "The third Energy Package" from 2009, set objectives for 2015, including optimal use of transmission network capacity, achieving reliable prices and liquidity in the day-ahead market and achieving efficient forward market and intraday market (Auverlot et al., 2014).

One of the key priorities in implementing the Energy Union Strategy are completing the infrastructure links still missing for a truly integrated IEM, and facilitating the necessary investments for this to be achieved (EC, 2015b). Consequently, the European Council called for all member states to achieve interconnection of at least 10 % of their installed electricity production by capacity by 2020, and is looking into increasing the target to 15 % by 2030 (EC, 2015b). Following the EU's liberalization of energy markets and the Energy Union Strategy, interconnectors now play a vital role in completing the IEM and reaching the triple objective of energy security, affordability and sustainability. In parallel, implicit allocation, i.e., electricity market coupling, has been implemented to optimize the use of cross-border capacities, thus leading to a larger harmonization of electricity prices throughout the interconnected countries (Auverlot et al., 2014). Under this approach, electricity prices are computed simultaneously for different power exchanges while taking cross-border transmission capacity into account. The integration of day-ahead markets across Europe yields numerous benefits including increases in liquidity, transparency, efficiency and social welfare (Price Coupling of Regions [PCR], 2016a). In 2014 full price coupling between 12 European countries was achieved through the market coupling of the South Western Europe and North Western Europe day-ahead electricity markets (PCR, 2016b).

2.2.3 Revision of the Target Model for Electricity

The current Target Model is due to be redesigned towards 2030 in order to cope with the challenges related to achieving the energy union strategy while transitioning the EU to a decarbonized economy. Balancing energy security, affordability and sustainability, the three overall objectives of the EU's energy policies, has proved to be challenging. While investments in renewable energy are needed to meet the EU's target for 2030, the intermittent nature of technologies such as wind power and solar power also requires relatively high levels of flexibility. The carbon price derived from the EU ETS has however failed to provide sufficient long-term price signals for setting the EU on a cost optimal path to decarbonization. On top of that, European wholesale prices for electricity have declined to levels that are insufficient to drive needed investments in new generation capacity. The decline in wholesale prices have been attributed to multiple factors including the strong expansion of RES, a low EUA price, a reduction in coal prices due to the shale bonanza, and a relatively lower electricity demand in Europe in wake of the financial crisis (Auverlot et. al., 2014; IEA, 2014; Statnett 2016).

As opposed to the wholesale prices, retail prices for both household and industry have however increased throughout the EU in recent years (EC, 2015c). The increase in retail prices is mainly caused by the costs of renewable support mechanisms that are externalized from the electricity market and passed on to end-consumers through levies and taxes (Auverlot et. al., 2014). The increase in retail prices poses a challenge to the competitiveness of the European industry, and stands in sharp contrast to the affordability target of the EU's triple objective for the energy sector.

In response to the abovementioned challenges, some EU Member States have implemented different national reforms, including capacity mechanisms to guarantee security of supply and additional carbon pricing mechanisms such as carbon taxes and price floors. The EU has also recognized that a redesign of the European electricity market is necessary to cope with the challenges.

2.2.4 The EU Emission Trading System (ETS)

The objective of this section is to give the reader a profound understanding of the EU ETS, and the factors that determine the price of allowances. The EU ETS has particularly significant implications for the electricity prices in thermal-dominated power systems, and these prices affect the Norwegian electricity market as well due to the close market integration. First, the section provides an overview of the design of the EU ETS and how the system is related to the EU's climate and energy objectives. The next part analyzes the market for European Union Allowances (EUAs) and serves to explain the price development of the EU ETS and the persisting oversupply of allowances. The last part covers the latest revisions of the EU ETS, including the Market Stability Reserve that will be introduced in 2019 to correct for the market imbalance in the EU ETS.

The EU’s key tool for reducing GHG emissions is the EU ETS, which is built on the cap-and-trade principle (EC, 2016a). The EUA price is an important driver for the electricity prices in Europe as it affects the marginal cost of fossil fuel-fired power generation. Historically, an increase in the EUA price of one €/tCO_2 has given rise to an increase in power prices of 0.6 to 0.7 €/MWh (THEMA, 2015a). In the EU ETS, a cap is set on the total amount of GHG emissions that can be emitted by each installation, and the corresponding allowances that the companies buy or receive can then be traded within the system. By the end of each year, each participant must surrender a number of allowances corresponding to its emissions; otherwise, fines are imposed. One EUA corresponds to one tonne of CO_2 equivalents, and the market price for the EU ETS emission allowances (carbon price) is determined by supply and demand. The EU ETS is currently in its third phase; following two major revisions since it was launched in 2005 as the world’s first international carbon market. Operating in 31 countries, the EU ETS covers approximately 45% of the EU’s GHG emissions that are released from more than 11,000 heavy energy-using installations (i.e., power stations and industrial plants) and airlines operating between the countries (EC, 2016a).

As a policy instrument, the EU ETS is supporting all three of the EU's climate and energy targets for 2020 and 2030: reducing the annual level of GHG emissions, improving the energy efficiency and increasing the share of RES. However, while a carbon price is aligned with the sustainability objective of the EU's energy strategy, the EU ETS has caused concern for the second objective of the strategy, namely competitiveness. Additionally, the imposed carbon price raised concerns for carbon leakage, i.e., the relocation of production and corresponding GHG emissions from Europe to other regions with lower carbon costs (Ecofys, 2014). In order to protect the global competitiveness of the European industry and to prevent carbon leakage almost all allowances were allocated to business for free in the first phase (2005-2007). In the current phase however, auctioning is set as the default option for allocating allowances, as opposed to widespread use of free allocation in the previous phases (EC, 2016a).

Oversupply of EAUs resulting in low prices

Since the end of the first phase, the EU ETS has been structurally oversupplied, resulting in sustained low market prices for EUAs. Several factors have attributed to the surplus of allowances, which amounted to 2 billion EUAs by the end of phase II in 2012 and increased further to 2.1 billion as the EU ETS entered into its current phase in 2013 (EC, 2016a). Firstly, the economic stagnation in Europe reduced the demand for allowances, as lower industrial activity caused emissions to decline more than expected (EC, 2016a; IETA, 2015; OECD, 2016). Secondly, the supply of allowances increased through a system of transferable credits leading to high imports of Kyoto credits from the first commitment period of the Kyoto Protocol (EC, 2016a; IETA, 2015; OECD, 2016). In addition, IETA (2015) and OECD (2016) cite overlapping climate policies and subsidies to RES within the EU as a supplementary cause of the surplus of allowances.

As the banking provision of EU ETS allowed firms to bank allowances from Phase II and use them in Phase III, the oversupply of allowances, which corresponded to a year's worth of emissions, was carried over to the current phase (Van der Werf, Verdonk, Vollebergh & Brink, 2014). From the beginning of phase III to June 2016, the EUA prices have fluctuated between three and eight €/tCO_2. As of December 18, 2016, the EUA price had averaged 5.34 € in 2016 (Investing.com, 2016). The observed prices are thus well below the 30 €/tCO_2 anticipated when the ETS directive was adopted (EC, 2008).

Van der Werf et al. (2014) argue that the large oversupply reflected in the low price is not problematic for reducing emissions, as the cap ensures that cumulative emissions will not exceed cumulative supply of EUAs. However, the main cause of concern is that the low carbon price provides insufficient incentive to invest in low carbon technologies, which could make it costlier and more challenging for the EU to meet its 2050 emission reduction target (Van der Werf et al., 2014). The EUA prices are much lower than the price needed to trigger a fuel switch from coal to gas, which is one of the cheapest sources of emission reductions according to Ecofys (2015).

Measures to correct the market imbalance in the EU ETS

The EU ETS was revised in several ways in the 2030 climate and energy package. First, the linear reduction factor of the annual issuance of allowances was increased from 1.74% in Phase III (2013-2020) to 2.20% in Phase IV (2021-2029) to meet the 43 % target for the EU ETS-sector by 2030 (EC, 2016j). This factor thus determines the pace of emission reductions in the EU ETS, as a reduction of the annual issuance of allowances gradually decreases the overall cap. In addition, the use of Kyoto credits from the first commitment period was banned from exchange in the EU ETS from March 31, 2015 (IETA, 2015).

As a short-term measure to correct the market imbalance, the European Commission implemented a back-loading mechanism in the EU ETS in 2014, with the intention of postponing the auctioning of 900 million EAUs in the period 2014-2016 (EC, 2016a). As a long-term solution, the European Commission established a Market Stability Reserve (MSR) in 2015 that will start operating in 2019. The European Commission then decided that the 900 million allowances that were back-loaded in 2014-2016 would be transferred to the MSR instead of being auctioned in 2019-2020. The MSR is a rule-based mechanism that facilitates flexible supply in response to demand changes. Its purpose is to address the current imbalance in the EU ETS and to make the EU ETS more resilient to imbalances caused by significant unexpected shocks in the future (Ecofys, 2015). In February 2016, a senior Commission official stated that the European Commission will not propose further measures to address the oversupply or low carbon prices in the EU ETS before 2020 (Carbon Pulse, 2016a).

Several studies conclude that the proposed MSR will reduce the surplus and increase the price of EUAs (Jalard et. al, 2015; Ecofys, 2015; Bloomberg New Energy Finance, 2015).

Jalard et al. (2015) estimated that implementing the MSR in 2019 could gradually decrease the surplus until it reaches 500 MtCO_2 by 2030, as illustrated in Figure 2.7. According to their modeling results, the MSR would limit the EUA surplus to two Gigatonne (Gt) CO_2 in 2020, relative to 3 Gt CO_2 without the MSR. Ecofys (2015) also argues that the MSR has potential to increase carbon prices in the long term and stimulate abatement, although they consider it more limited than a price corridor in providing a stable low-carbon price signal in the long term. Furthermore, Bloomberg New Energy Finance (2015) concludes that the MSR will almost certainly result in carbon prices sufficiently high to achieve the policy goal for which they were designed, namely transitioning Europe to a low-carbon economy.

2.3 Climate and Energy Policies in Norway

This section serves to provide the reader with an overview of the climate and energy policies in Norway, which affect the electricity market through both the supply side and the demand side. The section first draw parallels to the EU's policies, before outlining the current energy policy as laid out in the 2016 White Paper. The next section describes the Norwegian climate policy, including its relation to international climate agreements and the EU's climate policies.

As a member state of the European Economic Area (EEA) and the European Free State Association (EFTA), Norway's climate and energy policies are largely aligned with those of the EU (European Free Trade Association, 2015). As part of the EEA Agreement, Norway participates fully in the EU's internal energy market and the EU ETS. Emission trading under the EU ETS and carbon taxation are the main instruments of Norwegian climate policy, which combined cover more than 80 % of Norwegian emissions (Norwegian Ministry of the Environment, 2015). Norway has also adopted the EU's Renewable Energy Directive (RED) under the EEA agreement. The RED sets an overall target for Norway to increase the share of energy generated from renewables to 67.5% of gross final energy consumption by 2020 (Norwegian Ministry of Petroleum and Energy, 2015). The directive also encompasses renewable energy targets for Norway in 2020 in three sectors. The objectives are to generate 114% of Norway's electricity demand, 10 % of the transport demand and 43 % of heat consumption from renewable energy sources. The key tool for Norway to reach its RES commitment for 2020 is the electricity certificate system, which is a joint market with Sweden. As of 2016, Norway has not set any specific post-2020 RES target. Since the EU's 2030 climate and energy framework is only binding on a EU-wide level, it is currently unclear which implications this will have for Norway through EEA (Gullberg & Aakre, 2015).

2.3.1 The 2016 White Paper on Energy Policy

On April 15, 2016, the Norwegian government published the first White Paper on Energy Policy in 17 years, *Power for Change – an energy policy towards 2030* (Report no. 25 to the Storting) (*Energimeldingen)* (Norwegian Ministry of Petroleum and Energy, 2016). One of the key focus areas in the White Paper is *profitable renewable energy production*. The government aims for a long-term development of profitable wind power in Norway. At the same time, the government wants to ensure the profitability of existing renewable power production in its hydropower-dominated system. A great share of the hydropower plants in Norway was built in the second half of the 20th century and requires significant upgrades and reinvestments in the years to come. In order to avoid further depression on wholesale prices through additional renewable power generation, the government has decided not to extend its current policy support mechanism for renewable energy past the 2020 target. Hence, the white paper reflects the decision to withdraw Norway from the joint electricity certificate scheme with Sweden from December 31, 2021. The white paper highlights that lower electricity prices results in reduced values of existing renewable production, in particular hydropower, and weakened incentives for technology development and energy efficiency improvement.

Another key focus area in the White Paper is *effective utilization of profitable renewable natural resources*, which involves enhancing Norway's role as a producer of renewable energy in Europe. The government relates this to the expected increase in demand for flexible power generation in the Nordic and European power markets. Consequently, it may be applicable to establish more cross-border interconnectors after the planned interconnectors to the UK and Germany have been constructed (Norwegian Ministry of the Petroleum and Energy, 2016). The government argues that competition can result in a more cost-effective construction of interconnectors, and will therefore allow other players than the state-owned TSO, Statnett, to own and operate interconnectors. In addition, the government proposes to set a national objective to reduce the energy intensity (the ratio of gross domestic energy consumption to GDP) by 30 % by 2030.

2.3.2 Norwegian climate policy

In the period up to 2020, Norway commits to cut global GHG emissions equivalent to 30 % of Norway's emissions in 1990 (Norwegian Ministry of the Environment, 2012). Norway has also committed to become carbon-neutral in 2050 through a combination of domestic reductions and international offsetting (Regjeringen, 2014b). Meanwhile, Norway's climate policy towards 2030 is due to be negotiated with the EU, according to the white paper *New emission commitment for Norway for 2030 – towards joint fulfillment with the EU (*Report no. 13 to the Storting) (Norwegian Ministry of the Environment, 2015).

The 2015 white paper proposes that Norway reduces GHG emissions by at least 40 % by 2030 relative to 1990-levels, which is also reflected in Norway's INDC for COP21. The white paper states that Norway will enter into dialogue with the EU on joint fulfillment of the objective. A joint agreement with the EU would imply that the EU's climate policies for the non-EU ETS sectors also become relevant for Norway (THEMA, 2015a). Given that the Effort Sharing Regulation is based on GDP per capita, the EU would be likely to place Norway among the countries with the highest percentage reduction targets.[2] According to THEMA (2015a), there is reason to believe that a joint agreement with the EU would require a significant tightening of Norwegian climate policies for the non-EU ETS sectors. The white paper further states that it is essential for Norway that such an agreement is negotiated as a bilateral agreement, and not incorporated into the EEA Agreement. Table 2.2 summarizes Norway's current objectives for energy and climate.

Table 2.2: *Norway's Energy and Climate Targets for 2020, 2030 and 2050*

Year	**Cut in GHG emissions relative to 1990 levels**	**Share of Gross Energy Consumption from RES**	**Improvement in Energy Intensity**
2020	30 %	67.5%	-
2030	40 %	-	30 % (relative to 2015)*

Note: * Proposed target. *Sources:* Norwegian Ministry of Petroleum and Energy, 2013; Norwegian Ministry of the Petroleum and Energy, 2016; UNFCCC, 2015b.

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[2] The proposal on emission reduction targets for 2030 from the European Commission (2016g) sets Sweden and Luxembourg on top with 40 % reductions relative to 2005 emission levels, followed by Denmark and Finland with targets of 39 %.

2.4 The Norwegian Electricity Market

This section provides an overview of the main characteristics of the Norwegian electricity market, and serves to give the reader an understanding of the backdrop for wind power development in Norway in 2030. The first section outlines Norway's current electricity mix and describes Norway's current support mechanism for renewable energy, which lays the foundation for the development of Norway's electricity mix towards 2030. The next section covers the regulation and structure of the market. In particular, the power exchange, Nord Pool, and the day-ahead market, Elspot, are key for understanding how the electricity prices are determined and how wind power generators are remunerated.

2.4.1 Norway's electricity mix

The Norwegian electricity market is dominated by hydropower and is therefore subject to annual and seasonal fluctuations depending on precipitation levels and inflow to reservoirs. In 2014, Norway generated 96 % of its annual power production of 142 TWh from hydropower, while gas-fired power plants and wind power plants generated 3.5 TWh and 2.2 TWh respectively (Statistics Norway [SSB], 2015). With a net consumption of 117 TWh, Norway was a net exporter of electricity in 2014, as tends to be the case in normal years and wet years (SSB, 2015). Norway's remaining hydropower potential that is not protected against development is estimated to 33.8 TWh/year in a normal year (Norwegian Ministry of Petroleum and Energy, 2015). The country's wind power potential is also large, with the average speed of 7-9 m/s providing good conditions for development.

Since 2012, Norway has supported investments in new renewable energy projects through the Norwegian-Swedish electricity certificate scheme. The ultimate target of the joint system is to increase renewable energy production in the two countries by 28.4 TWh by 2020 (NVE, 2016a). Norway is responsible for financing 13.2 TWh and Sweden 15.2 TWh, regardless of where the new generation is located. Electricity certificates are a technology-neutral policy mechanism, and the scheme is thus identical for all new RES-E generation. An electricity certificate is an electronic document certifying that electricity corresponding to one MWh was produced from renewable sources (Regjeringen, 2014a). Power producers that build new renewable power generation and start operating before December 31, 2021 are entitled to electricity certificates for a maximum of 15 years (NVE, 2016a; Regjeringen 2014a). The power producers can either sell the issued electricity certificates in the market or bank them in order to sell them later. Electricity certificates thus provide a second revenue stream for renewable power producers, in addition to the revenue generated from sales of electricity in the spot market. The system will be phased out in Norway in 2035 when end-users will no longer be obligated to buy electricity certificates. While the Norwegian government has decided not to continue the electricity certificate scheme beyond the 2020 target, the Swedish government announced in June 2016 that they would extend the scheme towards 2030 with an additional 18 TWh (Regeringen, 2016). By the end of 2015, the electricity certificate market had contributed to 13.9 TWh of electricity generation capacity from new RES, with 2.3 TWh being installed in Norway and 11.6 TWh in Sweden (NVE, 2016a).

2.4.2 Market structure

Norway was the first Nordic country to deregulate and liberalize its power market, with the approval of the Energy Act in 1990. The Energy Act unbundled generation and transmission into separately price commodities, while establishing third-party access. Norway's Energy Act further laid the foundation for the subsequent deregulation in the other Nordic countries in the mid-1990s. In 1996, Nord Pool ASA was established as a joint Norwegian-Swedish power exchange, in response to the liberalization process. Finland joined Nord Pool ASA in 1998, and in 2000, the Nordic market became fully integrated with Denmark joining the exchange (Randen, 2013).

The market participants in the wholesale market are power producers, power suppliers, brokers, energy companies and large end-consumers. In Norway and the other Nordic countries, these players can trade electricity bilaterally or on the power exchange, Nord Pool (former Nord Pool ASA). As of 2016, Nord Pool serves as the Nominated Electricity Market Operator across thirteen European power markets (Nord Pool, n.d.-b). Nord Pool is an energy-only market where the price formation is based on marginal price setting through the merit order principle. As Nord Pool operates a decentralized system, the market-clearing price and traded quantity is determined by the intersection point between supply and demand, which is represented by the aggregated sales and purchase bids (Wangensteen, 2005). Nord Pool operates a day-ahead spot market with regional hourly prices (Elspot), and an intraday market with continuous power trading up to 30 minutes one hour before delivery (Elbas). As illustrated in Figure 2.1, the subsequent market timeframes, Elbas and the balancing market, enable adjustment close to the operational hour. Financial contracts are traded through Nasdaq commodities, which uses Nord Pool's system price as a reference price for the financial market.

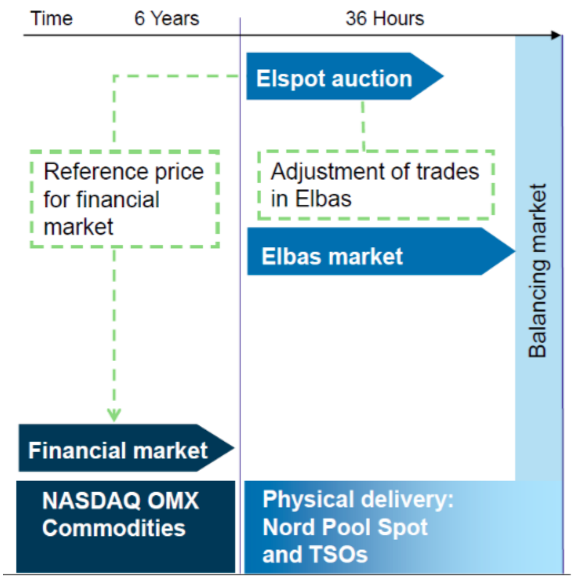

Figure 2.1: The Nordic wholesale market – timeframes
Source: Reprinted from Randen (2013)

Elspot is an auction-based exchange where power is traded for physical delivery the next day (Randen, 2013). It is the most liquid day-ahead market in Europe and produces a robust and credible system price. Elspot is characterized as an unbundled market and designed as a non-mandatory power exchange, where physical forward contracts are allowed alongside the organized spot exchange. The Nord Pool markets are divided into several bidding areas, which are decided by the local TSOs. When all Elspot members have submitted their orders, the supply and demand curves are constructed by making a linear interpolation of volumes between each adjacent pair of price steps. Nord Pool then calculates a system price based on all orders disregarding available transmission capacity between different bidding areas (Nord Pool, n.d.-c). The system price is used as the reference price for trading and clearing of most financial contracts in the region. Subsequently, Nord Pool calculates a price for each bidding area for every hour of the following day. The prices may vary between different bidding areas due to bottlenecks in the transmission system that restricts the electricity to flow freely. The power and market situation of each area will then determine which direction the power flows between the Elspot areas as the power will flow from low-price areas to areas of higher prices (Statnett, 2013).

3. Theory

The theory chapter serves to give an overview of power market economics, with an emphasis on how different policy measures affect the electricity price and the overall welfare. Since the application of economic theory to electricity markets must reflect the specific features of electric power, the chapter begins by providing an overview of the main characteristics that set electricity apart from other commodities. Subsequently, the chapter outlines the mechanisms behind demand for and supply of electricity. It then describes how the market equilibrium is determined in an energy-only market such as Nord Pool. With the fundamentals of the power market as a backdrop, the chapter then illustrates how the merit order effect, carbon pricing and cross-border trade affect the market equilibrium. This provides the reader with a theoretical understanding of how the EU’s climate and energy policies affect the Norwegian electricity market.

3.1 Electricity Features

Power is the rate of flow of energy and this holds true for any form of energy. In terms of electricity, power is the rate of which electrical energy is transformed to another form of energy, such as motion, heat or electromagnetic field (Stoft, 2002). The standard unit for power is Watt (W), where one watt equals one Joule (J) per second. Capacity is the potential to deliver power and the size of a generator is therefore also measured in Megawatt (MW). Electrical energy is usually measured in Megawatt-hours (MWh), which is the power or capacity of one MW operating for an hour. Although a unit of electricity is a homogenous good from a physical perspective, it is not homogenous from an economic point of view (Erdmann, 2015). Since electricity currently cannot be stored in significant quantities in an economic manner it is considered to be a non-storable good. Furthermore, bottlenecks in transmission and distribution grids hamper electricity price conversion between regions. Wholesale electricity prices are therefore subject to significant fluctuations over time and between regions. The associated non-homogeneity of electricity is the basis of the following economic analysis of electricity markets.

Since electricity flow is continuous, the generation and consumption of the commodity are also continuous (Wangensteen, 2005). Due to the non-storability feature, of electricity production must always equal consumption (Stoft, 2002). The balance between supply and demand must be instant at all times, since electricity is also generated and consumed at the same time. Consequently, electricity pricing must either occur ahead of real time (ex ante) or after real time (ex post), as the price mechanism cannot work fast enough to balance generation and consumption in real time. The price of electricity is also affected by consumption variability, which constitutes a characteristic demand pattern. Furthermore, the metering and billing system must be adapted to the non-traceability feature of electricity, i.e. that a unit of electricity delivered cannot physically be traced back to the original producer. Moreover, electricity is characterized by its essentiality to modern society. This can be expressed by the Value of Lost Load (VoLL), which is a measure of the costs associated with electricity disruptions (Wangensteen, 2005). A breakdown of the system can therefore have massive economic consequences. The risk is enhanced by the fact that a breakdown can hit an entire area, and not only individuals, due to the technical characteristics of a power supply system.

3.2 Electricity Demand and Electricity Supply

This section explains the fundamentals behind supply and demand for electricity, which lays the foundation for understanding how the market price is determined. The first part outlines the main drivers for electricity demand, and its particular characteristics, while the second part outlines how the supply curve for electricity is derived in a competitive market.

3.2.1 The demand for electricity

Electricity demand is characterized by annual, seasonal, weekly, daily and hourly fluctuations. The demand for electricity can be described by a load-duration curve that plots demand against duration, as illustrated by Figure 3.1. The load-duration curve measures the number of hours per year the total demand (load) is at or above any given level of demand (Stoft, 2002). Total load is the demand for a flow of power and is measured in MW. A load-duration curve can be constructed for any given region by measuring the total load at hourly intervals for each of the 8760 hours in the year, and illustrating them as a downward sloping curve ranging from the maximum load to the minimum load in the year. The first hour is the maximum load in the peak hour of a given year, while the minimum load represented by hour 8760 is the most off-peak hour. Duration also has a natural interpretation, as the probability that load will be at or above a certain level. In the example illustrated below, the probability of load being 20 GW or greater in a randomly selected hour is 50 %.

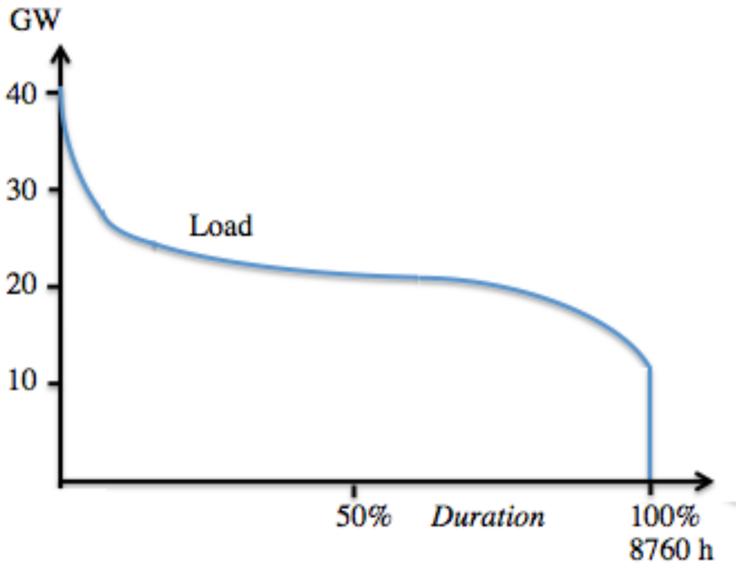

Figure 3.1: Load duration curve
Source: Author's own illustration based on figure from Wangensteen (2005)

Like other goods, the demand for electricity can also be illustrated by a demand curve that indicates the relationship between price and quantity demanded. In the short term, electricity demand is almost completely unresponsive to price, since customers do not respond directly to real-time market prices and as such, no willingness-to-pay value is available (Stoft, 2002). Consequently, the short-term demand for electricity can be considered as inelastic, which would be illustrated by a vertical demand curve. In contrast, the demand curve for electricity in the day-ahead market can be illustrated by a steep, downward sloping demand curve. In the day-ahead market, the customers place hourly purchase bids in an auction that is held the day before physical delivery. Each customer selects its hourly bid from a range of price steps, which are then aggregated to a demand curve by the power exchange (Nord Pool, n.d.-d).

The daily demand for electricity can be divided into peak-hours and off-peak hours. During peak-hours, which are defined as the hours from 8am to 8pm by Nord Pool (2011), the demand for electricity is higher. The main seasonal drivers for electricity demand are weather and temperature (Wangensteen, 2005). In Northern regions where a large share of electricity consumption is used for heating, the load will increase with decreasing temperature and the winter peak is thus higher than the summer peak. The opposite holds true for Southern regions where air conditioning is a bigger driver for electricity demand. The non-price fluctuations in demand can be illustrated by shifts in the demand curve. Figure 3.2 illustrates two demand curves for electricity, which correspond to different demand situations in a winter-peak system. The demand curve to the left illustrates electricity demand at a given time during the summer. During the winter, the demand for electricity is higher, which is illustrated by a shift to the right in the demand curve.

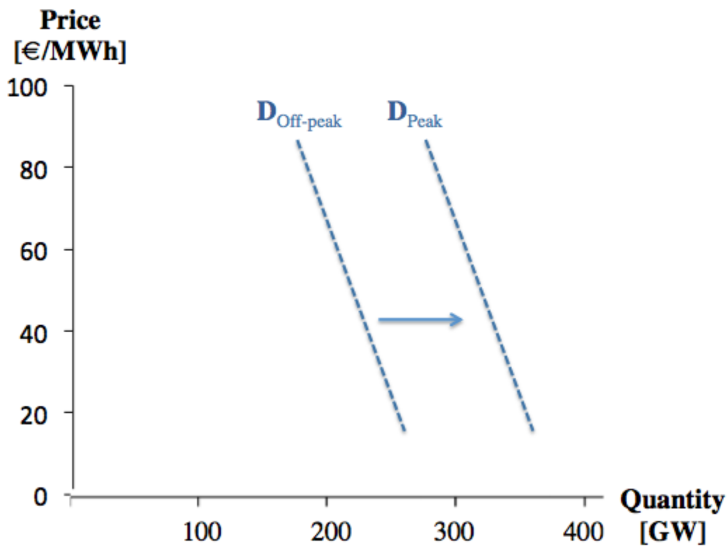

Figure 3.2: Demand curves for electricity in a winter-peak system
Source: Author's own illustration.

3.2.2 The supply of electricity

Under perfect supply competition, a power plant operator seeking to maximize profits will generate electricity as long as the short-term marginal cost of the power plant is lower than the market price (Erdmann, 2015). An individual supplier's profit, $\Pi(Q)$, equals its total revenues, $\bar{p} \cdot Q$, subtracted for its total economic costs, $C(Q)$.

$$\Pi(Q) = \bar{p} \cdot Q - C \cdot (Q) \qquad (1.1)$$

Assuming the individual supplier seeks to maximize its profit, the solution is found by setting the derivate of the profit function with respect to the produced quantity Q equal to zero.

$$\frac{d\Pi}{dQ} = \frac{d(p \cdot Q)}{dQ} - \frac{dC}{dQ} = \bar{p} - \frac{dC}{dQ} = 0 \rightarrow \frac{dC}{dQ} = \bar{p} \qquad (1.2)$$

Thus, assuming atomistic competition, the supplier should set its production Q so that the short-term marginal cost (STMC) is equal to the fixed sales price $\bar{p}$. STMC can be defined as the cost of increasing the production of electricity by a marginal unit (one kWh) at a given instant of time. Depending on the type of power plant, the STMC can consist of fuel costs, carbon costs, and operation and maintenance costs.

While the fuel cost can be nonexistent in the case of renewable energy, it can constitute a large share of the marginal cost for thermal power plants, particularly for those using fossil fuels. There is a clear ranking based on thermal efficiencies of power plants using the same fuel (Erdmann, 2015). The efficiency of the heat engine is defined as the ratio of net work output, W, to the heat supplied at high temperature, Q_h. The heat that cannot be used to do work is exhausted in the cold reservoir, Q_c.

$$\eta = \frac{W}{Q_h} = \frac{Q_h - Q_C}{Q_h} \tag{1.3}$$

Increasing fuel efficiencies results in a ceteris paribus decrease in fuel cost per unit of electricity produced (Erdmann, 2015). Consequently, modern high-efficiency power plants have a cost advantage over older, less efficient systems, as they use less fuel and emit less CO_2 to produce the same amount of electricity. In the absence of carbon costs, the short-term marginal cost (STMC) of a fossil-fired power plant is given by the ratio between fuel costs (C_f) and the efficiency of the plant (η).

$$\text{STMC}=\frac{c^{fuel}}{\eta} \tag{1.4}$$

In the European power market however, power plants running on fossil fuels are subject to carbon pricing through the EU ETS. Hence, their marginal costs also depend on the carbon cost (c^{CO_2}), i.e., the price of European Union Allowances multiplied by the quantity of CO_2 emitted per MWh of electricity. The latter is given by the ratio between the emission factor (EF) and the fuel efficiency (η) (Chevallier, 2011).

$$\text{STMC}=\frac{c^{fuel}}{\eta} + \frac{EF}{\eta} * c^{CO_2} \tag{1.5}$$

Since thermal power plants must burn fuel to heat up the boiler before being able to generate electricity, the bid of a thermal power plant may also be affected by ramp-up costs if the plant is not already running (Castro et al., n.d.). The ramp-up cost may thus elevate the variable average cost to produce the first few MWh of electricity. Thermal power plants will not have an incentive to initiate production unless the market price covers the ramp-up expenses. Hence, this constitutes an exemption to the rule that power plants will generate electricity as long as the short-term marginal cost of the power plant is lower than the market price.

In contrast to the fuel costs, the operation and maintenance (O&M) costs can be relevant to all energy technologies (Narbel, Hansen & Lien, 2014). With the exception of biomass, power plants fueled on renewable energy sources still have marginal costs close to zero (Erdmann, 2015). However, while the use of water in hydropower plants is basically free, it is subject to a big opportunity cost since there is limited amount of water available in the reservoirs (Narbel et al., 2014). This is particularly true for hydropower plants with storage facilities, which tend to be used for intervals and selective peak-load generation (Erdmann, 2015). The instant STMC for a hydropower plant is thus set by the water value, which is the estimated value of a marginal unit of water given present reservoir levels, expected future inflow and future demand (Wangensteen, 2005). In essence the water value reflects the alternative costs of generation on the margin, i.e. the cost of replacing hydropower generation with other conventional generation (THEMA, 2011). The water value is therefore not determined and bid into the market according to short-run marginal costs, but according to the alternative cost of generation in the market.

3.2.3 The merit order curve

For an individual power plant, the optimal supply strategy is to offer electricity at short-term marginal cost (Erdmann, 2015). Hence, in the aggregate supply curve (the merit order curve), the supplier bids are ranked based on ascending short-run marginal costs of generation. The production with the lowest marginal cost is dispatched first, which minimizes the overall electricity system costs to consumers (Auverlot et al., 2014). Due to their negligible marginal costs, hydro, wind and solar power are at the beginning of the merit order dispatch, usually followed by nuclear, as illustrated in Figure 3.3. The order of coal plants and natural gas plants may vary depending on the respective fuel and carbon costs, while oil-based power plants have the highest marginal costs.

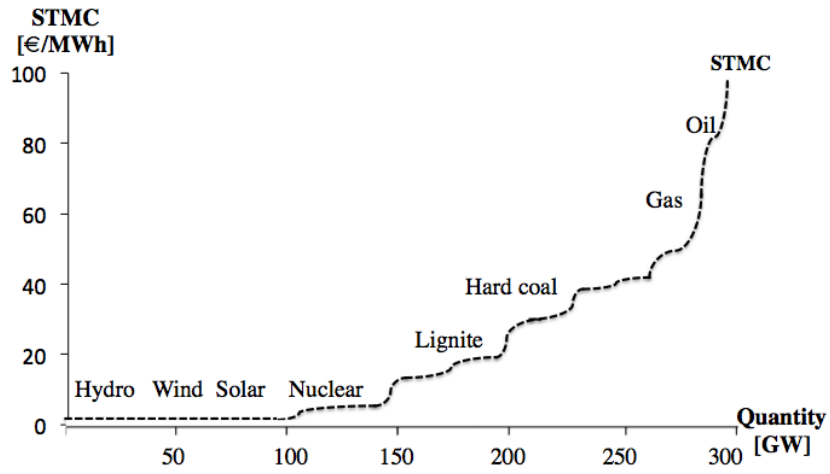

Figure 3.3: Merit order curve in a power system
Source: Author's own illustration based on figure from Erdmann (2015).

3.3 The Energy-Only Market

This section begins by describing how the electricity price is determined in an energy-only market like Nord Pool, and how increased renewable energy affects the electricity price. Subsequently, the concept of producer surplus is introduced, in order to describe how power producers earn profits from generating electricity. After having introduced this concept, the effects of carbon pricing on the electricity price, the merit order curve and the producer surplus are then described. This serves to explain how the EU ETS and other forms of carbon pricing affect the profitability of different power generation technologies.

In energy-only electricity markets cost recovery is derived from energy and operating reserves and not capacity. The market equilibrium is determined by the intersection of the supply curve and the demand curve (Wangensteen, 2005). The equilibrium price thus represents the price at which the quantity supplied is exactly equal to the quantity demanded of the good. In the day-ahead market, this translates into the intersection of demand bids and supply offers, which determines a uniform market-clearing price (the system price). Figure 3.4 illustrates two wholesale electricity market equilibriums corresponding to different demand situations under the same merit order curve. The demand curve to the left illustrates electricity demand at a given time during off-peak hours. During peak hours, the demand for electricity is higher, which is illustrated by a shift to the right in the demand curve. In the merit order curve, the production with the highest marginal cost is dispatched last. The market-clearing price is thus determined by the marginal costs of the last producer (the marginal plant) brought on line to satisfy the demand (Collins et al., 2015). In Figure 3.4, hard coal is the marginal producer in the equilibrium where the off-peak demand curve intersects with the merit order curve. The plant's marginal cost of 40 €/MWh thus sets the market price in this equilibrium. During peak hours however, costlier generation must be dispatched in order to meet the increased demand, which results in a higher market-clearing price (Erdmann, 2015). In Figure 3.4, the market clearing price of 60 €/MWh is set by a gas power plant that serves as the marginal plant in the peak-load hour.

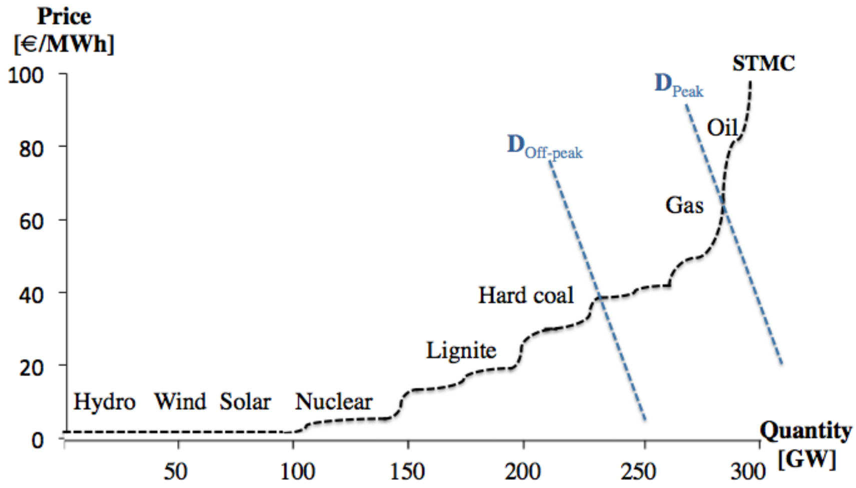

Figure 3.4: Market equilibriums in a wholesale electricity market
Source: Author's own illustration based on figure from Erdmann (2015).

3.3.1 The merit order effect

If more renewable energy capacity with low marginal costs is added to the market, the merit order is shifted to the right, as illustrated in Figure 3.5. This shift moves the intersection between the merit order curve and the demand curve, and as a result, the marginal clearing price will decrease for a given demand of electricity. The reduction in wholesale prices when renewable energy capacity is added to the market is termed the merit-order effect. In the example below, coal becomes the new marginal plant in the new equilibrium, while gas power plants are pushed out of the market since their marginal costs are no longer competitive at this given hour.

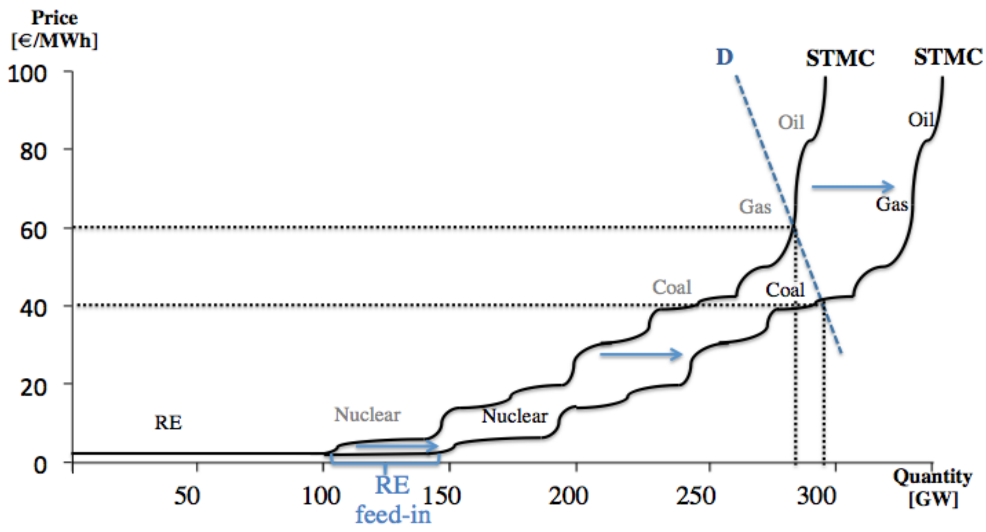

Figure 3.5: The merit-order effect
Source: Author's own illustration

Figure 3.6 illustrates the infra-marginal rent that producers derive from the wholesale electricity market. Since the marginal plant determines a uniform electricity price for the wholesale market, all producers with relatively lower marginal costs will receive a rent above their marginal costs of production. The infra-marginal producers thus earn a rent equal to the market price minus their marginal cost, as illustrated by the blue area in Figure 3.7. This rent, termed the infra-marginal rent or quasi-rent, contributes to recover fixed costs for the production, including interest on the invested capital (Genoese et al., 2015; Wangensteen, 2005).

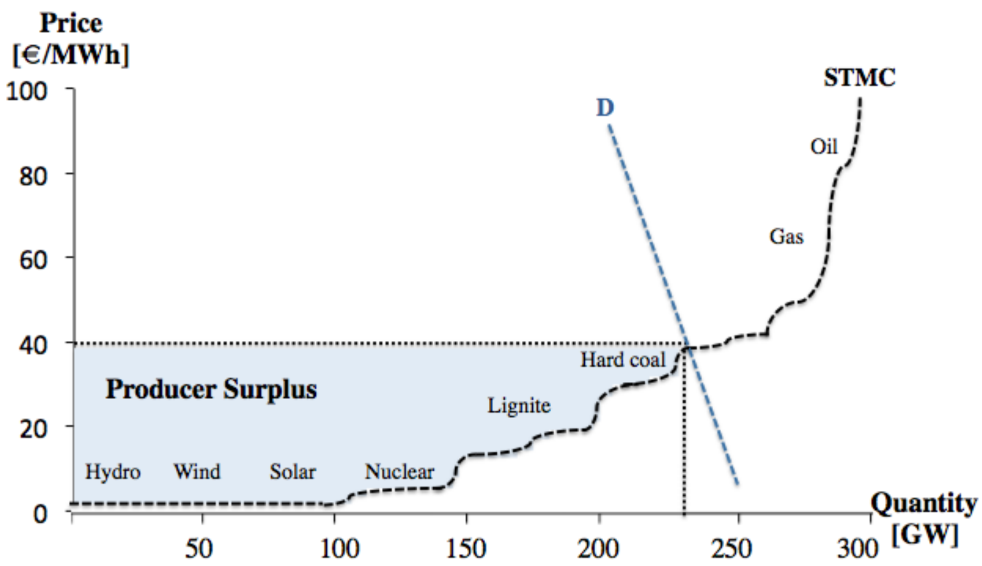

Figure 3.6: Infra-marginal rent
Source: Author's own illustration based on figure from Genoese et al. (2015), Stoft (2002).

In some peak hours where the margin between available capacity and demand is inelastic, electricity prices will rise above marginal operating costs to include a scarcity rent. During these occasions of capacity shortage, the prices may rise to extremely high levels, potentially up to the Value of Lost Load (VoLL). In power system economics, scarcity rents can be defined as actual revenue less the highest revenue earned before total generation becomes scarce (Stoft, 2002). Since peak generators are dispatched infrequently, scarcity rents are necessary for them to cover their fixed costs. In energy-only markets, there exists a long-term equilibrium where all generators, including the last generator, recover their fixed costs (Hirth & Ueckerdt, n.d.). It follows that the scarcity rents in the long-term equilibrium will be just high enough to cover the fixed costs of the last generator (Stoft, 2002). Furthermore, the corresponding amount of capacity and technology mix are welfare-optimal in this equilibrium. Assuming there are no market failures, energy-only market will thus provide an optimal level of investment in generating capacity through the market prices for electricity and ancillary services (Agency for the Cooperation of Energy Regulators, 2013).

3.3.2 *Effect of carbon pricing on the merit-order curve*

A carbon cost can be introduced in the wholesale electricity market through tradable permits or carbon taxation. This would modify the competitiveness of power plants, as the carbon price becomes a component of the STMC of fossil-fired power plants and make them relatively more expensive than carbon-free power generators. Furthermore, a carbon price may change the dispatch merit order, as gas-fired power plants are less CO_2-intensive than coal-fired power plants (Chevallier, 2011). The switching point between a gas-fired power plant and a coal-fired power plant may be calculated as the carbon cost that leads to equal short-term marginal costs ($STMC_{\mathbf{gas}}$= $STMC_{\mathbf{coal}}$), and depends on each plant's fuel cost (C^{fuel}), efficiency (η) and emission factors (EF):

$$C_{swith}^{CO_2} = \frac{(\eta_{coal} * C_{gas}^{fuel}) - (\eta_{gas} * C_{coal}^{fuel})}{(\eta_{gas} * EF_{coal}) - (\eta_{coal} * EF_{gas})} \quad (1.5)$$

If the carbon price is higher than the switching point, gas-fired power plants will be dispatched before coal-fired power plants. Figure 3.7 illustrates the effect of a carbon price on the wholesale electricity market when the carbon price is sufficiently high to trigger a fuel-switch between coal and gas. The carbon price increases the STMC for fossil-fired power plants from STMC' to $STMC_C$, which corresponds to a shift upward in the merit order curve for the mid-merit and peak-merit plants. In the new equilibrium, the demand is reduced from Q' to Q_C while the market price for electricity has increased from P' to P_C.

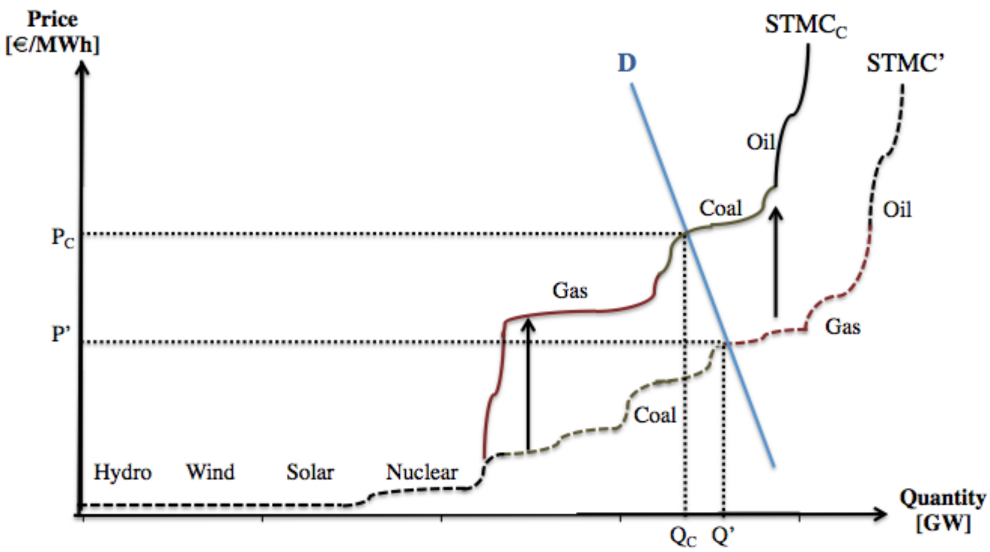

Figure 3.7: Fuel switch on the merit order curve
Source: Author's own illustration

The introduction of a carbon price will also have implications for the infra-marginal rent that the power producers derive from the wholesale electricity market. Carbon pricing is a technology-neutral instrument, with the marginal carbon price remunerating all low-carbon investors through its influence on the wholesale price (Pöyry Management Consulting, 2014). Consequently, carbon pricing provides substantially higher infra-marginal rents to carbon-free generators with low marginal costs such as hydropower, wind power, solar power and nuclear power. Figure 3.8 illustrates the changes in producer surplus after a carbon price is introduced. In the absence of carbon pricing, the infra-marginal rents are given by the difference between the electricity price and the short-term marginal costs (P' – STMC') multiplied by the quantity Q'. The producer surplus is thus equivalent to area A, B and C. In the carbon price equilibrium, the infra-marginal rents are given by the difference between the electricity price and the short-term marginal costs (P_C - $STMC_C$) multiplied by the quantity Q_C.

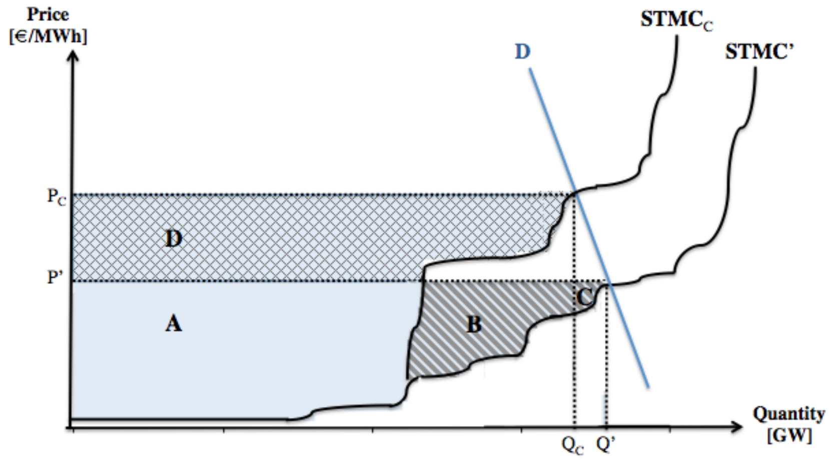

Figure 3.8: Change in producer surplus under carbon pricing
Source: Author's own illustration

The increased electricity price thus causes the infra-marginal rents to increase by area D, which especially benefits generators with low STMC. At the same time, the infra-marginal rents are reduced by areas B and C due to the increased STMC and reduced quantity sold respectively. The net effect of a carbon price on the infra-marginal rents, or the producer surplus (PS), is summarized in Equation 1.7:

$$\Delta PS = D - B - C \qquad (1.7)$$

3.3.3 The gains of trade

Economic theories suggest that allowing for trade will increase the overall welfare and hence the efficiency of the market for a given good (Kling, 2008). In electricity markets, overall welfare is calculated as the sum of producer surplus, consumer surplus and congestion revenues (Ku Leuven Energy Institute, 2015). The producer surplus equals the total net benefit to producers from selling a good at a market price that is higher than the least that they would be willing to sell for (i.e., the marginal cost) (Pindyck & Rubinfield, 2009; Ku Leuven Energy Institute, 2015). The consumer surplus corresponds to the total benefit that consumers receive from purchasing a good at a price lower than the highest price they would be willing to pay (Pindyck & Rubinfield, 2009). Congestion revenues are the product of the price difference between two price areas (P_H- P_L) and the constrained energy exchanged between them (E). The economic benefit of allowing for trade between electricity markets is illustrated by a two bidding zone example in Figure 3.9.

The graph to the left represents a low-price area with an electricity surplus, whereas the graph to the right illustrates a high-price area where electricity is scarce. When trade of electricity is introduced, the power will flow from the area with low prices to the area with high prices. In the exporting region, the increase in producer surplus will exceed the decrease in consumer surplus. The net-effect for the exporting region is illustrated by the blue triangle in the graph to the left. Analogously, the increase in consumer surplus will be larger than the decrease in producer surplus in the importing region, resulting in a net gain equal to the green triangle. Finally, the overall welfare increases by the congestion revenue represented by the grey area in the Figure 3.9. The congestion revenues are normally granted to the TSOs. As a result of the trade, the prices between the two areas converge. If there are no limitations in transmission capacity, the prices will converge until the price is the same in both areas.

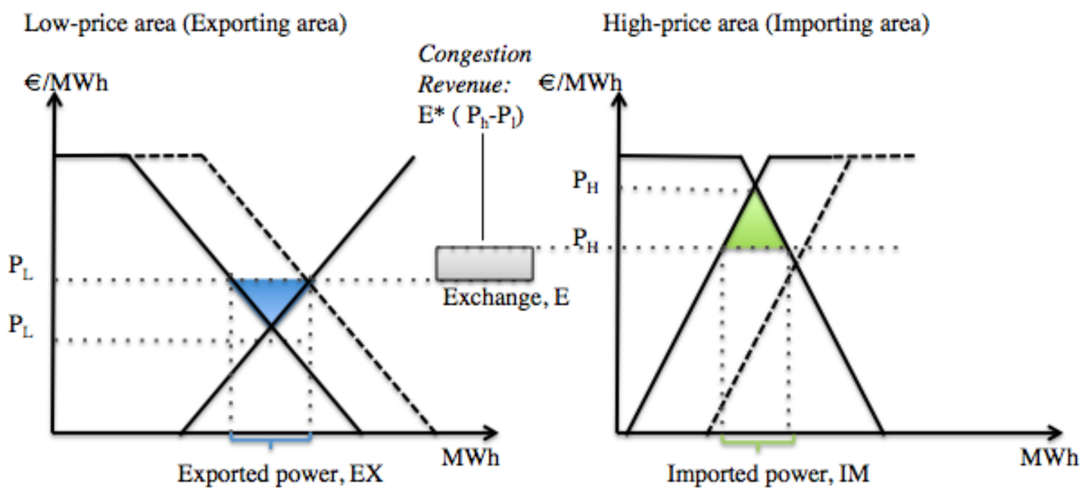

Figure 3.9: Welfare effect from allowing for trade of electricity
Source: Author's own illustration based on figure from Energinet.dk, Svenska kraftnät, Fingrid and Statnett (2013).

In the day-ahead market for electricity, the power exchange first calculates an unconstrained market-clearing price without taking capacities between bidding areas into account. The Nordic power exchange Nord Pool (n.d.-d) terms this the system price and calculates it based on the intersection of the aggregate supply and demand curves that represent all bids for the entire Nordic and Baltic region. However, if congestions arise in the grid, indicating that there is an active capacity constraint, the Nordic area is divided into several price areas. The members' bids in the bidding areas are then aggregated into supply and demand curves in the same manner as in the system price calculation. Consequently, new equilibriums are determined in each bidding area, giving rise to a higher price in the deficit area and a lower price in the surplus area. The zonal pricing procedure will then follow the principles illustrated by the example above, with prices flowing from low-price bidding areas to high-price bidding areas.

4. Methodology

This chapter serves to give an overview of the methodology used to estimate the electricity prices, the wind prices and the levelized costs of electricity for onshore wind in 2030 in this study. The first section explains the methodological approach used to conduct the respective analyses. The chapter then describes the TheMa model, which is the key tool used for conducting the scenario analysis and estimating the electricity prices. Subsequently, the chapter explains the storyline and main assumptions behind each scenario for the power market in Northwestern Europe in 2030. The next part covers the levelized cost of electricity, which is the measure used for estimating the cost of electricity produced by onshore wind power plants in Norway in 2030. Finally, the last section explains the methodology for estimating the market value of onshore wind.

4.1 Methodological Approach

This section provides the reader with an understanding of the overall methodology applied in this study of the electricity prices and the profitability of wind power generation in Norway in 2030. As illustrated in Figure 4.1, the main building blocks of this study are an analysis of the levelized costs of electricity of onshore wind in Norway, a scenario analysis of the power market in Northwestern Europe and an analysis of the wind prices in Scandinavia and Germany. The first step behind both the LCOE analysis and the scenario analysis was to analyze NVE's in-house dataset of licensed wind power projects in Norway. Projects identified as being under construction or having secured funding were taken into account in the assumptions for Norway's installed wind power capacity in 2030 in the scenario analysis. Building on this insight, each scenario assumes that Norway's wind power generation increases to 8.6 TWh in 2030. The remaining projects, which await funding as of December 2016, lay the foundation for the estimated LCOE curve for onshore wind in Norway in 2030. The LCOE analysis applies the project-specific data on the investment costs and the load hours of these 25 projects. In addition, a literature review and discussions with wind experts in NVE form the basis for the assumptions regarding the real discount rate, the lifetime of the projects and the cost development of onshore wind towards 2030.

To analyze the effect of the EU's energy and climate policies on Norwegian electricity prices and in turn the wind prices, this study develops four scenarios for the power market in

Northwestern Europe in 2030, as further described in section 4.3. The scenario analysis serves to capture some of the uncertainty regarding how the Norwegian electricity prices may develop, both in terms of price level and price structure. Building on the output from the scenario analysis, this study then estimates the wind prices in Scandinavia and Germany under the different outlooks for the power market in Northwestern Europe. These prices represent the average electricity prices received by wind power plants in each scenario for 2030, and take the generation profiles and the hourly price fluctuations throughout the year into account.

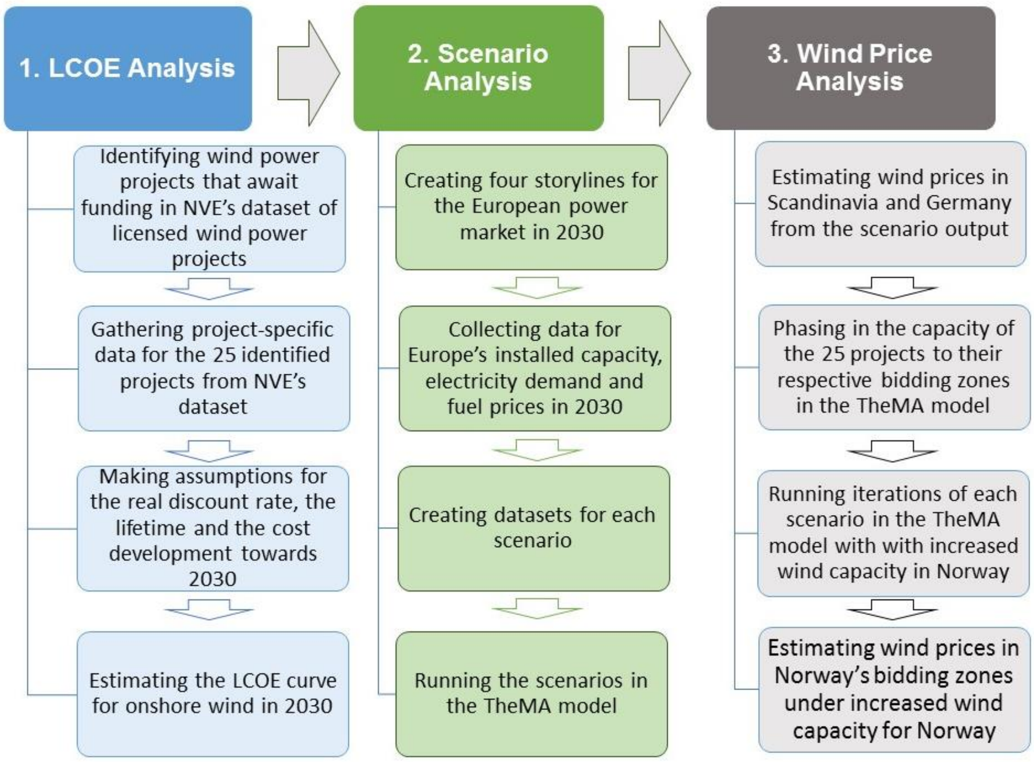

Figure 4.1: Flow diagram of the methodology applied in this analysis
Source: Author's own illustration

To assess whether onshore wind power reaches grid parity in 2030, this study compares the LCOE estimates to the wind prices from the different scenarios. While the wind price from the scenario analysis represents the remuneration for the first additional wind power project, the wind prices would gradually decline as Norway deploys more wind power due to the merit order effect. To take this into account, the capacity of the 25 wind power projects are gradually phased in under each scenario to compute the wind prices under increased wind penetration in Norway, as further explained in section 4.6.

4.2 The Market Analyzer (TheMA) Model

This section serves to provide the reader with an understanding of the TheMA model, which is the main tool for modeling the scenarios and estimating the electricity prices in Norway in 2030 in this analysis. TheMA is an advanced model for power market simulations that comes with a full dataset for Northwestern Europe for the time horizon 2014-2040 (THEMA, 2015b). The model, which was developed by THEMA Consulting Group, is widely used in projects for power producers, the EU commission, European TSOs, regulators, and traders. The actual optimization is performed in GAMS (the General Algebraic Modeling System), using CPLEX (IBM ILOG CPLEX Optimization Studio). The model simulates all hours of a year, while taking intertemporal constraints and restrictions into account. The hourly time resolution allows for capturing the price volatility in different markets and further improves the model estimates of trade patterns and water values. The TheMA model is a fundamental market, which means that it minimizes generation costs under a set of constraints. Hence, the model mimics perfectly competitive markets, and the market outcome is then equivalent to a cost-minimizing solution (THEMA, 2013). General outputs from the model include power prices, power balances, trade flows, welfare indicators, generation by plant, and CO_2 emissions. The hourly electricity price in a bidding zone is defined as the shadow price of demand and given in the unit of €/MWh. The model can be interpreted as representing an energy-only market without capacity payments, where the price represents the market-clearing zonal spot price in a deregulated wholesale electricity market.

The power plants in the dataset can be modeled on an individual basis with specific profiles and characteristics. For thermal plants, the model takes start-up costs, part-load efficiencies and minimum load restrictions into account (THEMA, 2014). Solar, wind and other renewable power generation are modeled with full hourly time resolutions, in order to reflect the volatile and intermittent nature of these technologies. Furthermore, the hydro reservoirs are characterized by reservoir size, installed capacity, inflow and inflow profiles, allowing for the calculation of implicit water values for hydropower plants. The TheMA model can model each reservoir individually in order to address the constraints in a hydro system. This increases the accuracy compared to the modeling approach of aggregating hydropower reservoirs into larger super-reservoirs, as super-reservoirs have a much higher flexibility than individual reservoirs (THEMA, 2012).

The transmission lines in TheMA are also modeled on a line-by-line basis with transmission losses and availability. Each transmission line is specified in both directions because the export capacity is not necessarily equal to the import capacity and the characteristics may change with the direction (THEMA, 2014). The trade between two bidding zones can either have a fixed profile or be subject to minimum and maximum constraints. For instance, the trade between Russia and Finland can be set as a fixed trade profile, expressed in percent of installed capacity. Unless a fixed profile is specified, a maximum profile is applied to the transmission line such that trade is constrained by the bounds from available installed capacity (THEMA, 2014).

To account for the high integration of power markets in the region, all relevant markets in Northwestern Europe are represented in the model. Hence, the default set-up includes endogenous modeling of Norway, Sweden, Denmark, Finland, Estonia, Latvia, Lithuania, Germany, Poland, the Netherlands, Belgium, France, Switzerland, Austria and the Czech Republic. In addition, Russia, Italy, Spain, Hungary and Slovenia are included as exogenous bidding zones in the model. The exogenous bidding zones are modeled endogenously through virtual plants (THEMA, 2014). The trading with these zones is modeled via implicit auctions, according to specified transmission capacities between the external price zones and the endogenous zones.

While national borders define most of the endogenous bidding zones, Norway is divided into seven bidding zones, Sweden into four and Denmark into two in the default set-up. The model's division of bidding zones in Sweden and Denmark correspond to the current setup of bidding areas in Nordpool. In contrast, the model has a finer granularity for Norway than the current setup in the Nordpool market where Norway has five bidding zones. By dividing the Scandinavian countries into multiple bidding zones, the model takes into account intra-national bottlenecks that may cause price divergences between the bidding zones. Each bidding zone is modeled with its own demand profile, which allows for taking seasonal, daily and hourly demand fluctuations into account.

The overall cost function can be described as minimizing the variable costs and the startup costs over all hours for all power plants while correcting for part-load efficiencies from thermal generating plants, as given by Equation (4.1):

$$Min \sum\nolimits_{hours,plants} \begin{pmatrix} generation * [fuel\ costs + carbon\ costs + variable\ operating\ costs] \\ +startup\ costs + corrections\ for\ partload\ generation \end{pmatrix} \quad (4.1)$$

The variable cost of a power plant depends on its technology, and is calculated by multiplying the MWh of electricity generated in a given hour with the variable generation costs per MWh. For power plants running on intermittent renewable energy sources, such as solar and wind, the variable costs are determined exogenously in terms of €/MWh. These power plants are modeled with fixed generation profiles that are given as a percentage of installed capacity.

The variable costs of thermal power plants are determined by the variable operating costs, the fuel costs, and, in the case of fossil-fired power plants, the carbon costs. The carbon price in a region is set exogenously in terms of €/tCO_2. The estimated carbon cost for a fossil-fired power plant takes into account the regional carbon price, the efficiency rate of the power plant and the emission factor of the fuel. A lower efficiency rate, a higher emission factor or a higher carbon price will increase the carbon cost and thus the marginal cost of a fossil-fired power plant.

The variable operating costs are given exogenously for each thermal power plant. In contrast, the fuel costs are calculated based on the fuel price, the hourly generation, and the efficiency rate of the power plant. The annual average price of a fuel, for instance the price of coal, is set exogenously in terms of €/MWh in the model. In addition, each fuel has a price profile that defines the hourly fuel prices throughout the year. Consequently, if this value is set equal to one, the fuel price in the given hour will correspond to the annual average price, while a value below one would imply that the hourly price is lower than the annual average. This allows for modeling price variations throughout the year, such as the tendency of gas prices to drop over the summer (THEMA, 2014). The TheMA model's linearized approach to thermal modeling is based on Weber (THEMA, 2014). The approach optimizes the power plants' costs while taking account for start-up costs, part-load efficiencies and minimum load restrictions (See THEMA, 2014, or Weber[3], 2004, for a more detailed description of the linearized approach).

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[3] Weber, C. (2004). *Uncertainties in the electric power industry: methods and models for decision support*. New York, the US: Springer. http://dx.doi.org/10.1007/b100484

For hydropower plants, the variable costs can either be given by explicit or implicit water values in the model (THEMA, 2015b). When the water values are set implicitly, they are determined by reservoir capacity, installed effect, inflow and inflow patterns. Hence, the variable cost of a hydropower plant is given by the variable operating costs and the water value for a hydropower plant in a given hour. When implicit water values are applied, the TheMA model serves as a perfect foresight model that optimizes the utilization of water in the reservoirs simultaneously. It should be noted that since the model knows the water inflow for hydropower plants in the model year, it might optimize water utilization better than what is the case in reality. The model also allows to use explicit water values as a function of reservoir filling and model imperfect foresight.

The power balance, which is given by Equation 4.2, is the central constraint of the TheMA model. In any given hour, the demand side must be equal to the supply side of the power balance for each bidding zone in the model.

$$\begin{aligned}&\mathit{Conventional\ demand} + \mathit{pumping\ demand} = \\ &\mathit{generation} - (\mathit{exports} - \mathit{imports} * (1 - \mathit{transmission\ losses}))\end{aligned} \tag{4.2}$$

The left-hand side of the power balance represents the demand side and consists of conventional demand and pumping demand. The latter takes into account hydropower plants with pumped storage and represents the amount of reservoir water that is pumped instead of being spent in the given hour. The right hand side of the power balance represents the supply side and corresponds to the aggregated generation in the bidding zone subtracted for its net exports in the given hour. In particular, a bidding zone's net exports are given by the difference between the exports and the imports corrected for transmission losses.

To sum it up, TheMa is a sophisticated power market model for Northwestern Europe. The model is licensed to a wide range of market participants in Europe, including the Norwegian Water Resources and Energy Directorate, whom this analysis is written in cooperation with. Its application includes short-term modeling, medium-term trade support, long-term forecasting and scenario modeling (THEMA, 2015b). This analysis uses the TheMA model as the main tool for forecasting the power market in Northwestern Europe in 2030 under different scenarios. Subsequently, iterations of each scenario are run to analyze how gradual increases in Norway's wind power capacity affect the market value of onshore wind.

4.3 Modeling of the Scenarios

This section explains the storyline and the main assumptions behind the four scenarios that have been developed to represent different outlooks for the Northwestern European power market in 2030. The first part outlines the four scenarios and gives a broad overview of the four variables that differentiate them. Subsequently, this section illustrates the geographical scope of the scenario analysis, before it outlines the storyline behind each scenario.

4.3.1 Outline of the scenarios

The four scenarios represent different paths and progresses towards achieving the EU's climate and energy objectives. Four variables represent the different trajectories for the power market in Northwestern Europe; namely, the installed generation capacity, the electricity demand, the carbon price and the price of natural gas imported to Europe.

In the Base Scenario, more renewable energy is developed in Europe towards 2030, although the development is lagging behind the envisioned energy transition of the EU. In this scenario, the RES-E development, the EUA price and the natural gas price are moderate, while the electricity demand is relatively high. In the Moderation Scenario, the EU is making stronger efforts towards meeting its energy efficiency objective. While a relatively high EUA price supports the transition towards a low-carbon economy, the development of renewable energy is moderate. In contrast, a high renewable energy share is the EU's main achievement towards the 2030 targets in the Green Nations Scenario. The energy transition is mainly driven by national subsidies, as the EUA price remains low in this scenario. Finally, the Decarbonization Scenario represents a scenario where the EU is on track towards meeting its decarbonization objective while making significant efforts both in terms of increasing the renewable energy share and improving the energy efficiency in Northwestern Europe. In this scenario, the EUA price remains relatively high despite the strong development of renewable energy and reduced GHG emissions, which occurs as a result of further revisions of the EU ETS. In addition, the Decarbonization Scenario assumes that the price of natural gas imported to Europe decreases as the demand for natural gas is significantly reduced in all sectors, including the industry, residential& commercial, transport and other sectors. Figure 4.2 illustrates how the assumptions for these variables are combined in the four scenarios.

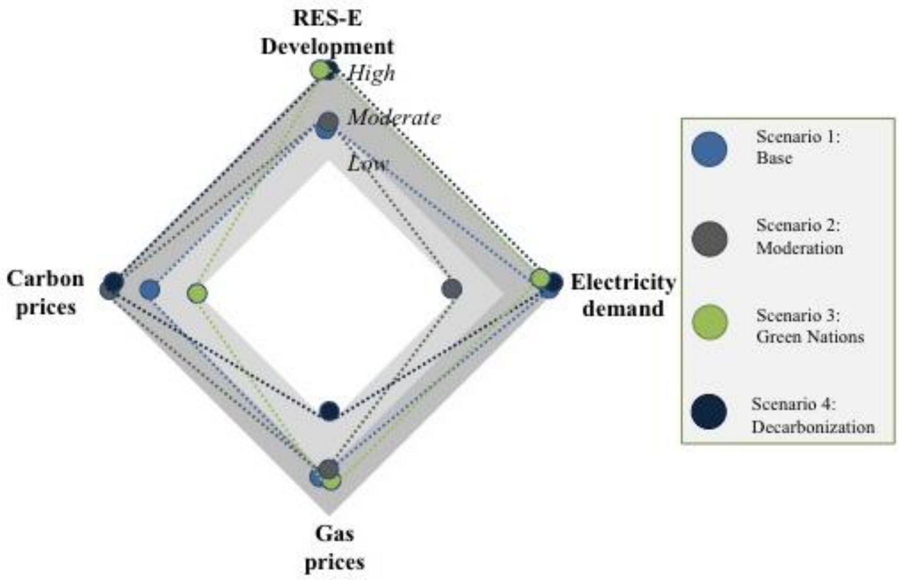

Figure 4.2: Overview of the four scenarios
Source: Author's own illustration

Figure 4.3 illustrates the assumptions for installed capacity and annual electricity demand in Northwestern Europe under the four scenarios for 2030. While the same levels of annual electricity demand are applied to the scenarios Base, Green Nations and Decarbonization, the Moderation Scenario represents a low-demand scenario where the energy efficiency measures materialize in reduced electricity consumption. The scenarios Base and Moderation represent a trajectory with moderate RES-E development towards 2030, while this is high in the Green Nations and Decarbonization scenarios. In all scenarios, wind power is assumed to surpass gas as the energy source with the highest installed generation capacity in the region by 2030, leaving gas as the energy source with the second largest generation capacity. Although the assumptions for installed capacity of nuclear power are held constant throughout the four scenarios, solar power surpasses nuclear power as the third largest energy source in terms of installed capacity in the scenarios Green Nations and Decarbonization. However, the most significant differences between the scenarios with moderate renewable energy development and the scenarios with high renewable energy development are the increase in wind power capacity and the reduction in coal power capacity. In addition, the scenarios Green Nations and Decarbonization have a higher installed capacity of solar power, hydropower, biomass power and gas, while the installed capacity of lignite is lower than in the Base and Moderation scenarios. As the additional installed capacity of renewable energy is larger than the decommissioned capacity of fossil fuels in the scenarios Green Nations and Decarbonization, there is a net increase in the installed capacity in Northwestern Europe relative to the scenarios Base and Moderation. While the installed capacity in Northwestern Europe amounts to 667 GW in the Base and Moderation scenarios, it increases to 746 GW in the Green Nations and Decarbonization scenarios. For further details, Appendix A.1 illustrates the assumptions for the installed capacity by country under the four scenarios. In terms of the aggregated electricity demand in the region, the assumptions range from 2250 TWh in the Moderation Scenario to 2475 TWh in the other scenarios.

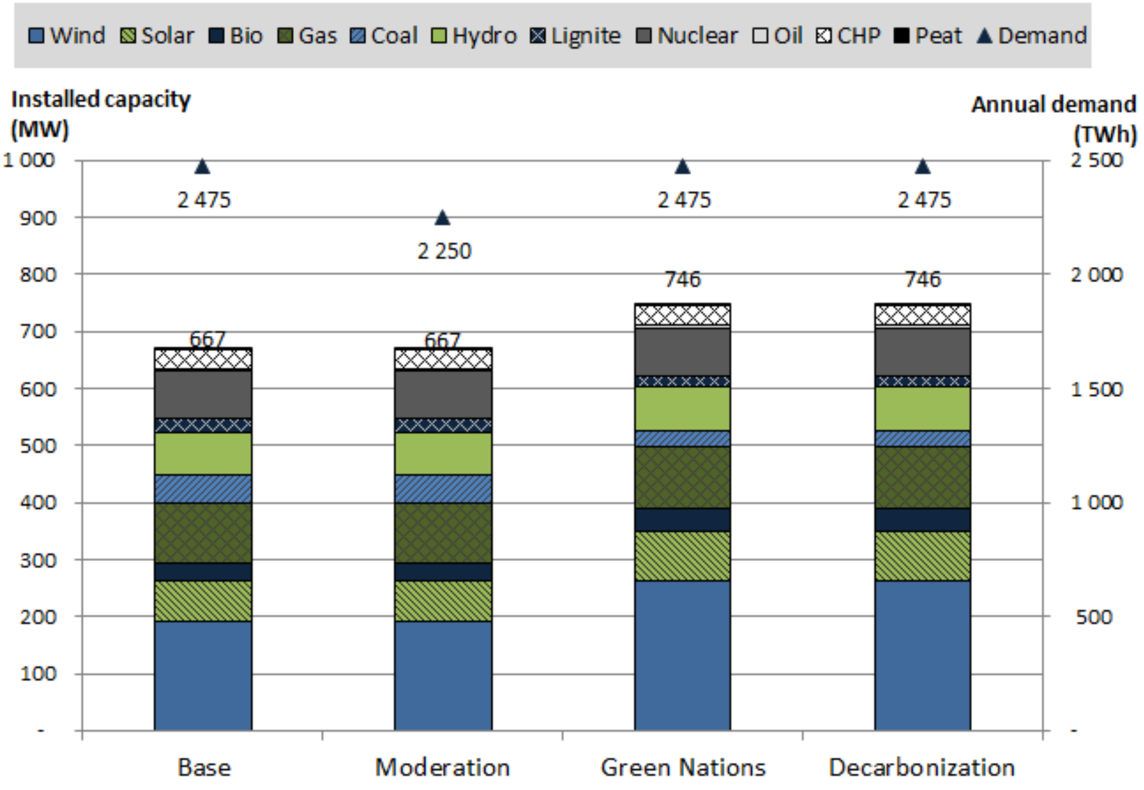

Figure 4.3: Scenario assumptions for the installed capacity and the electricity demand in Northwestern Europe

Note: The data illustrates aggregated installed capacity and annual electricity demand for Norway, Sweden, Denmark, Finland, Germany, the UK, the Netherlands, Poland, Latvia, Estonia, Lithuania, France, Belgium, Austria, Switzerland and the Czech Republic. *Source*: Author's own illustration.

4.3.2 Geographical scope of the scenario analysis

By 2030, Norway has transmission capacity to Sweden, Denmark, Finland, Russia, the UK and the Netherlands. In addition, other Nordic countries have transmission capacities to the Baltic countries and Poland, which affect Norway indirectly since the Nordic power market is highly integrated. The strongest emphasis is therefore placed on the Nordic countries and their main trading partners in this scenario analysis. Towards 2030, the cross-border transmission capacity within the Nordic region and between the Nordic countries and the continent increases, which implies that the development in this region will have stronger implications for the Norwegian electricity prices. This analysis bases the assumptions for the cross-border transmission capacity in Europe in 2030 on ENTSO-E's 2016 ten-year development plan (see Appendix A.2 for a list of the new cross-border interconnectors in Northwestern Europe towards 2030).

As illustrated in Figure 4.4, the assumptions for the carbon price, the gas price, the installed capacity and the electricity demand in Northwestern Europe vary throughout the four scenarios. In terms of installed capacity, two different trajectories are envisioned for Norway's adjacent countries and their main trading partners, i.e., Sweden, Denmark, Finland, Germany, the UK, the Netherlands, Poland, Latvia, Estonia and Lithuania. In particular, the renewable energy development in this region towards 2030 is moderate in the scenarios Base and Moderation while it is high in the scenarios Green Nations and Decarbonization. In contrast, the assumptions for installed capacity in Austria, Belgium, France, Switzerland and the Czech Republic are held constant throughout the scenario analysis. The development of renewable energy in these countries is considered out of scope for this analysis, due to the markets' relative remoteness from the Norwegian power market.

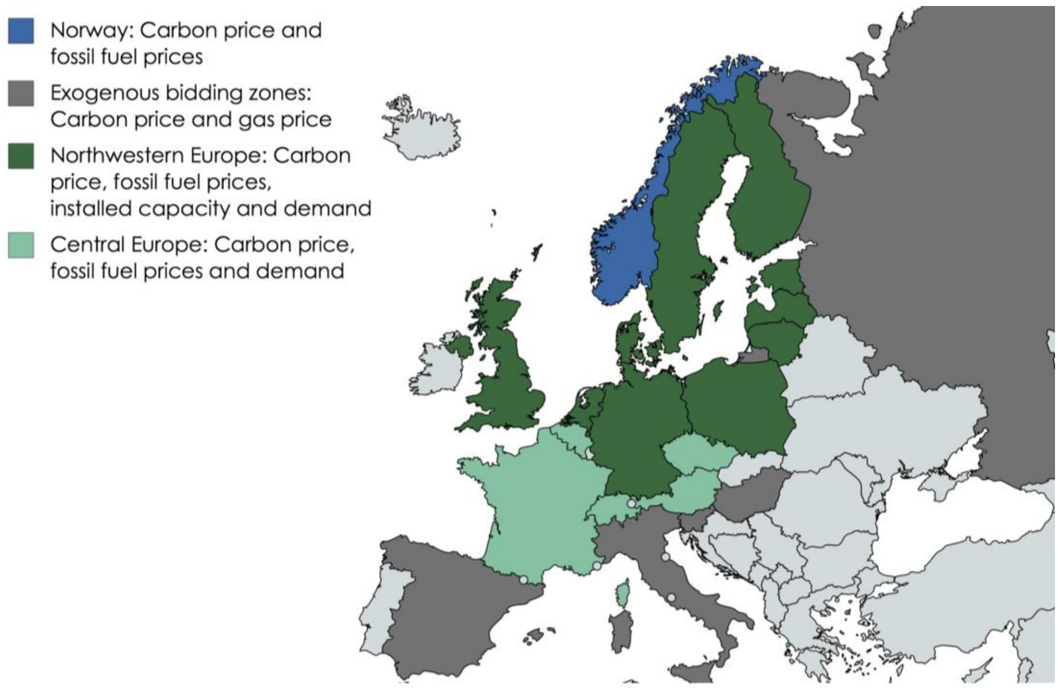

Figure 4.4: Geographical scope of the scenario analysis
Source: Author's own illustration created with mapchart.net (2016)

While the same demand assumptions are applied to three out of four scenarios, the Moderation Scenario assumes that the electricity demand in Europe is reduced through strong energy efficiency measures. The electricity demand is then relatively low for all countries that are modeled endogenously in the model, with the exception of Norway. The assumptions for the installed capacity and electricity demand in Norway are purposely held constant to isolate the effect of the European development on Norwegian electricity prices. Furthermore, all countries that are modeled endogenously are affected by the assumptions for the carbon price and the fossil fuel prices. In addition, Russia, Italy, Spain, Hungary and Slovenia are modeled as exogenous bidding zones in the model. For these countries, the assumptions for the gas price and the carbon price determine the electricity prices and net exports under the different scenarios run in the TheMA model.

4.3.3 The Base Scenario

The Base Scenario assumes that the development of the European power sector towards 2030 is mainly driven by national efforts and market signals. In this scenario, the countries in Northwestern Europe are making gradual progress towards achieving the EU's climate and energy objectives. Although the share of renewable energy in the electricity mix increases for all of the countries in Northwestern Europe, the energy transition and the decarbonization of the economy are taking place at a slower pace than in the other scenarios in this analysis. In the Base Scenario, the EUA price is expected to gradually increase from current levels, to reach 26€/tCO_2 by 2030. The carbon price neither triggers a fuel switch from coal to gas nor provides sufficient investment signals for new capacity in the power sector. As the relatively low wholesale price and the gradual phase-out of national subsidies provide an unfavorable investment environment, older power plants are kept online when possible, in order to ensure energy security. In addition, some member states introduce capacity remuneration mechanisms to provide incentives for investments in new capacity. This enhances the economic viability of some peak power plants, although the gas-fired power plants are still struggling to be profitable.

Although the regional cooperation on energy and climate policies is low in comparison to the scenarios Moderation and Decarbonization, some member states still pursue ambitious efforts towards a green energy transition. However, the increase in installed capacity of renewable energy is largely dominated by technologies that are commercially viable and have reached grid parity by 2030. In Northern Europe, onshore wind thus represents the vast share of new renewable energy projects, although significant amounts of solar power are deployed in the UK, France and Germany.

The annual electricity demand is assumed to grow moderately from 2016 to 2030, which is overall reflecting moderate economic growth in the Member States. While some energy efficiency measures are introduced, the increase in energy efficiency is limited due to a lack of strong political will and regulatory support. At the same time, the process of electrifying the heating and transport sector is slow, and does not cause large increases in the electricity demand in the region.

4.3.4 The Moderation Scenario

In the Moderation Scenario, energy efficiency is considered the corner stone of the EU's climate and energy objectives. Efforts to reduce energy consumption are driven by strong regulation on an EU-wide level, which ensures that each Member State moderates their energy consumption. The energy savings are predominantly achieved through significant reductions in energy consumption from the industry and the buildings sector, which reduces the overall electricity demand from the EU. Although there is some energy substitution to electrical power in the transport sector and the heating and cooling sector, the overall energy efficiency savings still outweigh the increased electrical usage in these sectors. The Moderation Scenario assumes that the electricity demand in the EU increases towards 2020, as a result of economic growth, before decreasing in the following decade due to the abovementioned energy efficiency measures. The annual electricity demand in the region is therefore closer to current levels under the Moderation Scenario than in the other scenarios where the demand is higher. As the electricity demand decreases from 2020, new investments in renewable energy are partly directed towards renewable heat projects, although the renewable power capacity still increases from current levels. Hence, the Moderation Scenario and the Base Scenario apply the same assumptions for installed power generation capacity. However, the share of renewable energy consumption is expected to be higher in the Moderation Scenario due to the increase in renewable heating and cooling.

The shift to an energy-efficient economy is further supported by a well-functioning EU ETS, which is no longer characterized by an oversupply of allowances. In the Moderation Scenario, the EUA price is assumed to increase sharply by the end of the 2020s, to reach 45€/MWh in 2030. Despite the low electricity demand, the EUA price remains high in this scenario for 2030, as there is strong political will to use carbon pricing as the key tool for decarbonizing the European economy. The Moderation Scenario thus presumes that the EU member states agree to revise the EU ETS further, such as by tightening the cap or introducing a carbon price floor, which facilitate a high EUA price.

4.3.5 The Green Nations Scenario

In the Green Nations Scenario, the EU's energy transition is primarily driven by ambitious national efforts, which particularly includes economic and regulatory support for developing renewable energy. While large investments in renewable energy have been undertaken in the period towards 2030, most coal-fired power plants have been decommissioned. Hence, the installed power generation capacity provides a higher share of renewable energy in the Green Nations Scenario than in the Base Scenario and the Moderation Scenario. The EUA price is assumed to remain low at 10€/tCO_2 in 2030 in the Green Nations Scenario, since the high renewable energy development reduces the EUA price in the absence of a carbon price floor. The relatively low carbon price is insufficient to drive investments in renewable energy towards 2030, the EU Member States continue to provide subsidies for renewable energy in order to reach their renewable energy objectives. On the demand side, the Green Nations Scenario assumes that more energy efficiency measures are implemented than in the Base Scenario. At the same time, there is a larger energy substitution to electricity in the transport sector and the industry sector than in the Moderation Scenario. Consequently, the overall electricity demand is assumed to be similar to that of the Base Scenario, although the demand composition would differ slightly.

4.3.6 The Decarbonization Scenario

In the Decarbonization Scenario, the EU is on track towards its long-term objective of becoming a decarbonized economy by 2050. Low-carbon investments are above all driven by strong price signals from the EU ETS and further supported by regulatory measures. In the period towards 2030, the EU leaders are committed to let the EU ETS play its intended role, and undertake additional revisions of the system in order to increase the EUA price significantly. The wholesale electricity price increases because of the high carbon price, which provides stronger price signals for investments in new generation capacity. In particular, the profitability of investments in renewable energy technologies increases significantly compared to present levels, which allows most of the countries in the region to phase out their renewable energy subsidies. Most coal power plants are decommissioned by 2030 due to a combination of political and economic decisions, as gas power plants become more competitive than coal.

While the EUA price causes the short-term marginal cost of coal to increase more than the short-term marginal cost of gas increases, the competitiveness of gas-fired power plants is further enhanced by the low gas prices in Europe in this scenario. The Decarbonization Scenario assumes that Europe's demand for fossil fuels decreases significantly due to electrification measures and structural changes to Europe's economy that reduces the consumption of fossil fuels in all sectors. Since the gas market is a regional market, a significant decline in demand would cause the price of natural gas imported to Europe to decrease. The price of gas is therefore assumed to be 15€/MWh in the Decarbonization Scenario. In contrast the assumptions for coal prices and oil prices are held constant for all scenarios. Since coal and gas are traded in global markets, a reduced consumption in Europe would have less effect on the global price of oil and coal than on the price of natural gas imported to Europe. This scenario thus assumes that the EU's share of the global markets for coal and oil is not large enough to affect the global prices of these commodities, for the sake of simplicity. Towards 2030, the IEA (2016c) indeed expects the EU to account for a decreasing share of the global demand for coal and oil, which would further reduce the EU's impact on these global markets. In the IEA's main scenario (i.e., the New Policies Scenario), the EU's share of global demand for coal decreases from 6.8% in 2014 to 3.8% in 2030, while the EU's share of global demand for oil is reduced from 14.5% to 8.2 %, which supports this assumption.

While significant efforts are taken to decarbonize all sectors of the economy, the electricity demand is affected by two opposing trends in the Decarbonization Scenario. On the one hand, a large-scale implementation of energy efficiency measures is assumed to decrease the electricity demand, all else being equal. On the other hand, the electrification of sectors such as transport, heating and industry contribute to growth in the annual electricity demand. Overall, the two effects are assumed to balance each other out relative to the Base Scenario.

4.4 Scenario Assumptions

The subchapter covers the key assumptions for the scenario analysis and provides the reader with an overview of the sources that were used to create the dataset for each scenario. It begins by outlining the assumptions for Norway's installed generation capacity and electricity demand in 2030, before providing a detailed overview regarding the assumptions for electricity demand, installed capacity, fossil fuel prices and carbon prices in Northwestern Europe.

4.4.1 Norway's power market in 2030

This analysis bases the assumptions for Norway's electricity demand in 2030 on estimates made by NVE in relation to the 2016 White Paper *Power for Change – an energy policy towards 2030.* While the gross electricity consumption was 126 TWh in Norway in 2014 (Statistics Norway, 2015), NVE (2016b) expects this figure to increase to 143 TWh in 2030. NVE (2016b) identifies population growth as the most important driver for energy consumption, and expects additional electrification in the heating sector, the transport sector and the industry, with the transport sector accounting for the largest increase in electricity consumption towards 2030

Furthermore, this analysis uses NVE's in-house dataset for 2030 as a basis for the assumptions for Norway's installed capacity. Building on this, the assumptions further include all licensed wind power projects that have secured funding as of December 2016. In all scenarios, Norway's installed capacity is expected to increase to 38 906 MW by 2030, of which 35 649 MW is hydropower, 2 685 MW is wind power, 330 MW is gas power and 242 MW is CHP. The installed capacity of wind power is expected to increase the most towards 2030, as the capacity more than doubles from the current levels of 2 685 MW. With Norway's annual generation of electricity amounting to 148.4 TWh while the electricity demand is equal to 143.71 TWh, Norway remains a net exporter of electricity in the four scenarios for 2030.

4.4.2 Electricity demand assumptions for Northwestern Europe

Figure 4.5 illustrates the assumptions for the electricity demand in 2030 by country for the different scenarios. While the assumptions for Norway are held constant throughout the scenario analysis, two different trajectories are envisioned for the demand in the other European countries that are modeled endogenously in the TheMA model. For the scenarios Base, Green Nations and Decarbonization, a relatively high electricity demand is envisioned in Europe in 2030, which is aligned with most of the visions developed by ENTSO-E (2015) and the IEA's New Policy Scenario from the 2016 World Energy Outlook. In contrast, the

European electricity demand is lower in the Moderation Scenario where energy efficiency measures cause the demand to decline.

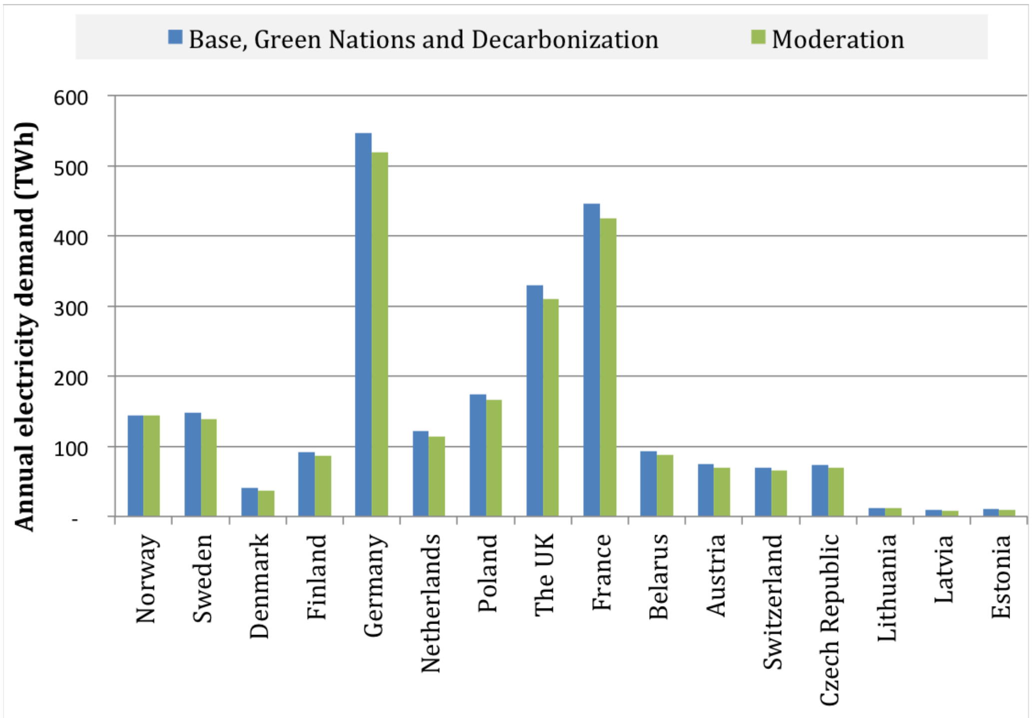

Figure 4.5: Scenario assumptions for electricity demand in 2030 by country
Source: Author's own illustration

The assumptions for the EU Member States' electricity demand in 2030 in the low demand scenario (Moderation) is based on ENTSO-E's Vision 2, while the electricity demand in the other scenarios are based on ENTSO-E's Vision 4 from the 2016 ten-year national development plan. The annual demand of 3397 TWh in ENTSO-E's Vision 4 is almost equivalent to the annual demand of 3379 TWh in the New Policies Scenario from the IEA (2016c), which supports the rational for using the demand level from ENTSO-E's Vision 4 as the basis for the majority of the scenarios in this analysis.

4.4.3 Assumptions for the installed capacity in Northwestern Europe

The assumptions for the installed capacity under the different scenarios are in general based on a combination of data from three main datasets for 2030: ENTSO-E's 2016 TYNDP, NVE's in-house dataset for the TheMA model, and THEMA's default set-up from 2013. In the 2016 TYNDP, ENTSO-E (2015) has developed two visions with moderate renewable energy development (Vision 1 and Vision 2) and two visions with high renewable energy development (Vision 3 and Vision 4). Hence, ENTSO-E's assumptions for installed capacity in Vision 1 are used as the basis for the Base and the Moderation scenarios, while Vision 4 are used as the basis for the scenarios Green Nations and Decarbonization. The datasets from TheMa and NVE supplements the dataset from ENTSO-E when necessary for modeling purposes. Appendix A.1 provides illustrations of the installed capacity of each country that is endogenously modeled in the scenario analysis.

The data from ENTSO-E (2015) has further been adjusted to reflect the scenarios in this analysis. Since the EU's climate and energy policies do not directly reflect regard the nuclear power capacity in the region, a scenario analysis of the development of nuclear power capacity is regarded out of scope for this analysis. Consequently, the assumptions for the installed capacity of nuclear power from ENTSO-E's Vision 1 and 2 are used as the basis for all scenarios in this analysis. In addition, the assumptions from ENTSO-E's visions have been adjusted to take into account recent announcements regarding the national electricity mixes in in Northwestern Europe to improve the accuracy of the scenarios for 2030. As summarized in Table 4.1, the adjustment regards the electricity mixes in Finland, Lithuania, Poland, Sweden and the UK.

Table 4.1: Updates Regarding the Installed Capacity in Europe in 2030

Country	Deviation from ENTSO-E's visions	Reason
Finland	No coal power capacity under any scenario	The Finnish government has decided to phase out coal by 2030 (Ministry of Economic Affairs and Employment of Finland, 2016)
Lithuania	No nuclear power capacity in 2030 under any scenario	The Visaginas nuclear power project is brought to a halt (Baltic Course, 2016)
Poland	No nuclear power capacity in 2030 under any scenario	Polska Grupa Energetyczna has announced that Polish nuclear capacity will not be built before 2030 (Platts, 2016)
Sweden	Higher RES-E share in all scenarios	The Swedish government will extend the electricity certificate system towards 2030 with an additional 18 TWh of RES-E (Regeringen, 2016).
The UK	Higher nuclear power capacity in all scenarios	Projections indicate that 14 GW of new nuclear capacity may be built by 2035 (The Department of Energy & Climate Change, 2016)

4.4.4 Fuel price assumptions

The prices for coal, natural gas and European Union Allowances are the most important factors for the power prices in Europe, including in the Nordic countries, as they determine the marginal costs of thermal power plants (Statnett, 2016). While the Norwegian power market is hydro-dominated, it is indirectly affected by fossil fuel prices due to its close integration with thermal-dominated power markets in Europe. Consequently, the marginal cost of thermal power generation will have implications for water values and producer behavior in Norway, and thus Norwegian electricity prices. In Norway's adjacent countries, the fuel prices have direct implications for the merit order curve and wholesale electricity prices.

As highlighted earlier in the analysis, the prices of oil, coal and gas have declined significantly since 2011 (see 2.2.3 Revision of the Target Model for Electricity). This trend has caused most analysts to reduce their long-term prognoses for fossil fuel prices, although most analysts expect the prices to increase from current levels (Statnett, 2016). While the oil price has a small direct effect on European power prices, as most oil-fueled power plants have been decommissioned, the oil price is still important due to their effect on coal and gas prices (Statnett, 2016). In the model, however, the oil price has a negligible impact on the electricity price, as the prices of coal, gas and oil are defined separately.

Table 4.2 summarizes the fuel price assumptions under the four scenarios. This analysis bases the assumptions for the coal and gas prises on Statnett's expectations in their recent power market analysis of the Nordic countries and Europe towards 2040. Statnett (2016) relies on analyses from multiple organizations that are specialized in the fossil fuel markets, including IHS, IEA, NENA and EIA, for the fossil fuel price assumptions. In the base scenario, Statnett assumes the price of gas to reach 22€/MWh by 2030, while the coal price increases to be 65$/t. These levels are applied to all scenarios of this analysis, except the gas price in the Decarbonization Scenario. For the latter, the assumptions from Statnett's low price scenario is used as the basis, in which the gas price is assumed to be 15€/MWh in 2030. Other forecasts, such as the IEA's 2016 World Energy Outlook, expect higher fossil fuel prices than these assumptions. It should therefore be noted that higher prices of coal and gas would yield a higher electricity price, which would affect the profitability of wind power projects in Norway favorably, all else being equal.

Table 4.2: Fuel Price Assumptions

Fuel	Unit	Base	Moderation	Green Nations	Decarbonization
Natural gas price	€/MWh	22	22	22	15
STMC of natural gas	€/MWh	51.4	58.4	45.4	47.3
Steam coal	USD/t	65	65	65	65
STMC of coal	€/MWh	44.1	60.3	30.5	64.5
Crude oil	€/bbl	100	100	100	100
EUA price	€/tCO_2	26	45	10	45
Carbon price UK	€/tCO_2	37	55	37	55

Notes: All prices are given in 2015-levels. MWh = Megawatt Hour, bbl = barrel; t = tonne;.

In addition to the fossil fuel prices, the carbon price has significant implications for the power market, in particular through its effect on wholesale electricity prices and the merit order curve. The long-term EUA price is however one of the most uncertain variables in a long-term power market analysis, as political decisions and future revisions of the EU ETS could change the current price trajectory significantly. Consequently, there is a wide range in the EUA price projections from different analysts.

The Base Scenario assumes that the EUA price increases to 26 €/tCO_2 by 2030, which is closely aligned with the survey published in the KfW/CO2 Barometer 2015 – Carbon Edition, where participating firms on average expected EUA prices to rise to €25.45/ tCO_2 in 2030 (KfW Bankengruppe & Centre for European Economic Research, 2015). On the lower end of the scale, Barclays estimate that the EUA price will average €5_{2019}/tCO_2 between 2020 and 2030, according to Carbon Pulse (2016b). Statnett (2016) assumes the EUA price to reach 20 €/tCO_2 in 2030 in its base scenario, while they expect the EUA price to reach 15 €/tCO_2 in their low price scenario and 40 €/t in their high price scenario. On the higher end of the scale, the IEA (2016c) projects the EUA price to range between 27€$_{2015}$/tCO_2 under the Current Policies Scenario, 33€$_{2015}$/tCO_2 under the New Policies Scenario and 90€$_{2015}$/tCO_2 under the 450 Scenario for 2030. ICIS Tschach Solutions (2015) forecasts the EUA prices to rise to €39/tCO_2 in 2030 when taking into account the MSR starting in 2019. Meanwhile Barclays estimates that a EUA price of €45/tCO_2 is required under a 2 °C target scenario, according to Parkinson (2016). Since the scenarios Moderation and

Decarbonization assume that the EU takes additional measures in order to make the EUA price aligned with its decarbonization objective, Barclay's assumption of €45/tCO_2 is applied to these scenarios. In contrast, a level of 10 €/tCO_2 is applied to the Green Nations Scenario, which is in the range between Barclay's expectation and Statnett's low price scenario for 2030.

Since the UK has introduced its own carbon price floor, the carbon price in the UK is set separately from the European carbon price in the TheMA model. For 2016, the British Government set the carbon price floor at £18 per tCO_2, while the indicative levels for 2020 were revised down from £30 to £20 due to the low EUA price (HM Revenue & Customs, 2014). Consequently, the UK carbon price is expected to follow the EUA price development, albeit at higher levels. In the scenarios where the EUA price is low and moderate in 2030, it is assumed that the British Government increases the carbon price floor to £30 (i.e., 37 $€_{2015}$/tCO_2). In the scenarios Moderation and Decarbonization, where the EUA price increases to relatively high level by 2030, it is assumed that the British government increases their carbon prices to more ambitious levels, 55€/tCO_2.

4.5 Estimating the Levelized Cost of Electricity (LCOE)

This section explains the methodology used for estimating the cost of generating electricity from onshore wind and presents the levelized cost of electricity (LCOE) formula. The LCOE has been designed as a measure that allows for comparing different energy sources on a unit cost basis over the lifetime of the project. Along with the net present value and the real option approaches, the LCOE is one of the most common approaches to evaluate the economics of energy (Narbel et al., 2014).

The main criticism of the LCOE approach is that it reflects generic technology risks and does not account for specific project risks in specific markets, such as the uncertainty in future fuel costs for instance (IEA, 2015; Narbel et al., 2014). Granted that specific technology and market risks exist, there is a gap between the LCOE and the financial costs carried by investors facing project-specific uncertainties. Consequently, the LCOE is closer to the real cost of investment in electricity generation in a regulated electricity market with regulated prices than the cost of generation in deregulated electricity markets where the spot prices fluctuate (IEA, 2015). Another criticism is that the LCOE approach does not account for elements such as intermittency and the need for back-up power (Narbel et al., 2014).

Nonetheless, the LCOE remains a consensus measure of generating costs that is widely used by investors, researchers and governments to compare various power-generating technologies.

Equation (4.3), which is provided by the IEA (2015), expresses the equivalence between the present value of the sum of discounted revenues and the present value of the sum of discounted payments.

$$\sum_t^T \left(P_{MWh} * MWh_t * (1+r)^{-t}\right) = \sum_t^T \left((Capital_t + O\&M_t + Fuel_t + CO2_t) * (1+r)^{-t}\right) \quad (4.3)$$

where the different variables indicate:

P_{MWh} = The constant lifetime remuneration to the supplier of electricity;

MWh_t = The amount of electricity produced in MWh in year t

(Load hours of the year * installed capacity);

r = Real discount rate (%);

t = Year;

T= Lifetime in years;

$(1+r)^{-t}$ = The discount factor for year t (reflecting payments to capital);

$Capital_t$ = Total capital construction costs in year t;

$O\&M_t$ = Operation and maintenance costs in year t;

$Fuel_t$ = Fuel costs in year t;

Since P_{MWh} is a constant over time, it can be brought out of the summation of revenues over the plant's lifetime. By dividing both sides on $\sum_t^T MWh_t * (1+r)^{-t}$, Equation (4.3) is transformed into Equation (4.4), where the constant, P_{MWh}, is defined as the levelized cost of electricity (LCOE).

$$LCOE = P_{MWh} = \frac{\sum_t^T (Capital_t + O\&M_t + Fuel_t + CO2_t) * (1+r)^{-t}}{\sum_t^T MWh_t * (1+r)^{-t}} \quad (4.4)$$

While Equation (4.4) might be misread as discounting the MWhs, it is rather the revenue from those MWhs that is being discounted (IEA, 2015). Hence, it is the economic value of the output that is being discounted, rather than the output itself, which is a standard procedure in cost-benefit accounting.

Since wind resources are free and generation from wind power plants does not emit CO_2, the fuel costs and carbon costs are set equal to zero. This yields equation (5.5), which is the final formula used to calculate the average lifetime levelized costs of onshore wind in this analysis.

$$\text{LCOE}= P_{MWh}=\frac{\sum_t^T (Capital_t + O\&M_t)*(1+r)^{-t}}{\sum_t^T MWh_t*(1+r)^{-t}} \tag{4.5}$$

Hence, five key variables decide the estimated unit cost of generation from onshore wind power, namely, the investment costs, the operation and maintenance costs, the annual generation (load hours * installed capacity), the discount rate and the project's lifetime. A dataset from the Norwegian Water Resources and Energy Directorate, which provides data on the investment costs, the operation and maintenance costs, the load hours and the installed capacity of wind power projects in Norway, is used as a basis for the LCOE calculation. In addition, assumptions are made regarding the cost development towards 2030, the lifetime of the wind power projects and the real discount rate. The 25 projects have a cumulative capacity of 2 170 MW and are located in five bidding zones, i.e., Southern Norway, Western Norway, Northern Norway, Mid Norway, and Oslo and the Østfold region. Based on the expected load hours for each project, the cumulative generation of the 25 projects amount to 7.04 TWh.

According to the IEA (2015), LCOE can be interpreted as the electricity tariff that would be required for an investor to precisely break even on the project after paying debt and equity investors at the required rates of return. The equivalence of electricity tariffs and LCOE is based on the assumptions that the production costs, the real discount rate and the electricity tariff are considered stable and do not change throughout the lifetime of the project (IEA, 2015).

4.6 Estimating the Market Value of Onshore Wind

This section explains the methodology used for calculating the absolute and relative market value factors of onshore wind in this analysis. In particular, it provides the mathematical formula behind the wind price and the value factor, and an explanation of the modeling approach to estimate these values through the TheMa model.

The wind price represents the market value of wind in absolute terms. Since the output from the TheMA model includes the electricity prices and the wind power generation in each bidding zone for each hour of the year, the wind price can be estimated from the results. Equation (4.6) defines the wind price as the average hourly electricity price received by wind power generators in a given time period.

$$\bar{p}_{wind} = \frac{\sum_t^T W_t * P_t}{\sum_t^T W_t} \qquad (4.6)$$

where the different variables indicate:

t = hour

T = hours of the year

W_t = Wind power generation

P_t = The equilibrium electricity price in hour t

In this analysis, the wind price is compared to the levelized cost of electricity to indicate whether a project would be profitable to develop without subsidies, i.e., whether onshore wind reaches grid parity. While the wind price is relevant for investors since it represents the revenues from wind power generation, it also has a fundamental socio-economic interpretation. Assuming perfect power markets in long-term equilibriums, the wind price corresponds to the social marginal benefit of wind power generation (Hirth, 2016). Hence, the intersection between the wind price and the levelized cost of electricity defines the cost-optimal deployment level of wind within a power system (Hirth, 2015).

When comparing the wind price across the different scenarios and iterations of this analysis, it is convenient to study the relative, rather than the absolute, market value of wind. Hirth (2015) defines the market value factor of wind (VF_{wind}) as the ratio of the wind price to the time-weighted average electricity price, which is given by Equation (4.7):

$$VF_{wind} = \frac{\bar{p}_{wind}}{\bar{p}} \qquad (4.7)$$

where the time-weighted average electricity price is:

$$\bar{p} = \frac{1}{T} \sum_t^T P_t$$

The wind value factor compares the value of actual wind power with varying generation to its value if the generation were invariant (Hirth, 2015). A value factor of wind below unity implies that wind power is less valuable as a generation technology than a constant source of electricity. This analysis estimates the relative and absolute market value of onshore wind for different bidding zones and different scenarios to analyze how wind power projects in Norway perform relative to their peers in Scandinavia and Germany.

Figure 4.6 illustrates how this analysis combines the four scenarios with different assumptions for Norway's annual wind power generation to estimate the market value factors of wind in Norway. The downward-facing arrows illustrate Norway's wind power generation under each iteration, while the horizontal arrows represent the four scenarios for the power market in Northwestern Europe. As illustrated by the downward-facing arrow to the left, the scenario analysis assumes that Norway's annual wind power generation increases to 8.6 TWh in 2030. This assumption lays the foundation for estimating the wind prices and the average hourly electricity prices in Scandinavia and Germany for each scenario, as presented in section *5.3 The Market Value for Onshore Wind in Germany and Scandinavia in 2030*. Since the assumptions for Norway's electricity demand and installed capacity remain unchanged, the results indicate how different scenarios for the power market in Northwestern Europe affect the wind market value in Norway.

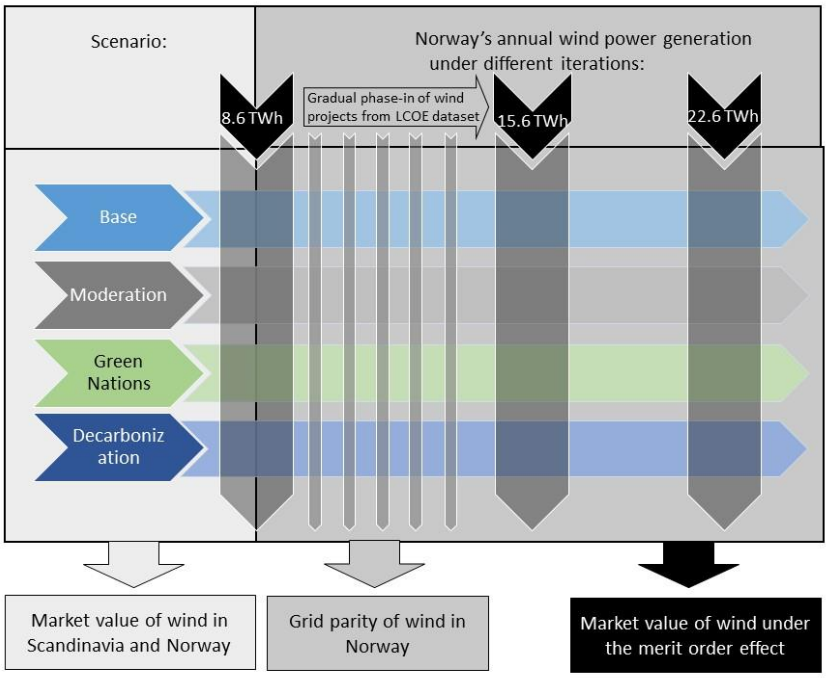

Figure 4.6: Approach for estimating the market value of onshore wind under different levels of wind power capacity in Norway
Source: Author's own illustration

In the grid parity analysis, the wind price from Section 5.4 represents the income for the first wind power project that enter the market in 2030. However, as Norway's annual wind power generation gradually increases, the wind price would inevitably decrease due to the merit order effect. Consequently, the grid parity analysis includes multiple wind prices that take into account the wind power generation from the different projects in the LCOE dataset. In particular, the installed capacity of the wind power projects with the lowest LCOE estimates in the dataset are added to their respective bidding zones in the TheMA model, until the LCOE of the marginal project equals the wind price in the bidding zone where it is located. As the wind prices vary between the four scenarios, different projects are on the margin depending on the price levels in Northwestern Europe. Subchapter 5.5 *Grid Parity for Onshore Wind Power in Norway in 2030* presents the results from this part of the analysis.

The last part of the analysis digs deeper into the effect of the merit order curve on the wind prices. In particular, it estimates the wind prices under three different levels for Norway's annual wind power generation (8.6 TWh, 15.6 Twh and 22.6 TWh) across the four scenarios. This facilitates an analysis of how the wind prices would respond to significant increases in Norway's wind share.

5. Analysis

Chapter Five presents the key analysis of how the EU's climate and energy policies affect the Norwegian electricity prices, and which implications they have for the Norwegian wind power sector. The chapter begins by analyzing the long-term cost development of the Norwegian wind sector, which is represented through estimates of the levelized cost of electricity (LCOE) for onshore wind in 2030. The LCOE estimates provide the unit costs of 25 Norwegian wind power projects over their operating lives. Against this backdrop, the chapter proceeds with presenting the long-term price development of the electricity prices in Northwestern Europe under the four scenarios for 2030. Building on the scenario analysis, the third section analyzes how the EU's climate and energy policies affect the electricity price structures in Norway. The fourth section compares the market value of onshore wind in Scandinavia and Germany, before the fifth section narrows down the scope to analyze whether onshore wind reaches grid parity in Norway in 2030. Finally, the chapter illustrates how increased wind penetration in Norway affects the Norwegian electricity prices under the four scenarios.

5.1 The Levelized Cost of Electricity for Onshore Wind in Norway in 2030

This section provides an analysis of the costs of generating electricity from onshore wind power in Norway in 2030 through estimating the levelized cost of electricity of 25 Norwegian wind power projects. These LCOE estimates further represent the costs for generating electricity from onshore wind in the grid parity analysis in section 5.5. At the same time, the LCOE can be interpreted as the electricity price that would be needed for an investor to break even on the project after paying debt and equity investors at the required rates of return (IEA, 2015).

In this analysis, the LCOE is calculated from a dataset that contains project-specific information for 25 potential wind projects in Norway. The dataset includes estimates for the load hours, the capacity and the investment costs for each project. In addition, the LCOE calculations depend on multiple assumptions that would yield significantly different results if they were altered. This section therefore explains the key assumptions behind the LCOE estimates before it presents the LCOE curve for onshore wind in 2030. For further details,

Appendix B provides sensitivity analyses of how different assumptions for the real discount rate, the cost reductions and the lifetime of wind power projects affect the LCOE curve.

The load hours of the 25 projects range from 2476 hours to 3612 hours per year, which corresponds to a capacity factor of 28 % and 41 % respectively. In other words, the wind turbines of the project with the highest load hours are expected to generate 41 % of their maximum theoretical power output throughout a year of operation. While these load hours are relatively high in comparison to onshore wind projects in other countries, they are within the range of recorded load hours for existing wind power projects in Norway. In 2015, Raggovidda wind power plant in Finnmark reached a capacity factor of 50 %, while Norwegian wind power plants had an average capacity factor of 34 % (NVE, 2016c). The high load hours for wind power plants in Norway contribute to reducing the LCOE, as the fixed capital costs of a wind power plant constitute a significantly higher share than the operation and maintenance costs.

In order to compare the costs of generating electricity between the projects, the same real discount rate is applied to all projects, even though the de-facto real discount rate may vary as they rely on multiple factors that are beyond the scope of this analysis. As a basis for this analysis, a real, pre-tax discount rate of 6 % is applied, which in this context represents the required rate of return for investors. Private investors use the weighted-average cost of capital (WACC) to discount future cash flows. This analysis assumes that the cash flows of wind power projects built in 2030 correspond to the income they receive from the spot market, as projects that start operating after December 31, 2021 are ineligible for electricity certificates. According to NVE (2016d), there has been a clear tendency of more foreign institutional investors, such as pension funds, insurance companies and investment banks, investing in renewable energy projects in Norway in recent years. These investors seek long-term investments and tend to require lower rates of return than traditional utilities (NVE, 2016d). Following discussions with wind experts in NVE, a real, pre-tax discount rate of 6 % is applied to the LCOE calculations, which is lower than the 8 % discount rate Gjølberg and Johnsen (2007) estimated for onshore wind a decade ago. Notably, the wind power industry is relatively sensitive to changes in the discount rate since it is a capital-intensive industry. If the discount rate decreases to 4 %, the LCOE of the projects in this analysis decline by 4.16 €/MWh on average, while an increase to 8 % causes the LCOE of the projects to increase by 4.49 €/MWh on average (see Appendix B.1 for an illustration of the effect on the LCOE curve).

Towards 2030, NVE (2015a) and Statnett (2016) expect the investment costs of onshore wind power plants to decline further due to the learning effect, as the installed capacity of wind power increases on a global level. In this analysis, the investment costs of onshore wind is assumed to decline by 15 % from current levels, which corresponds to the findings from a study of historical and expected learning curves conducted by NVE (2015a). In comparison, the wind experts surveyed in the IEA Wind Task 26 (2016) expect the CapEx for onshore wind to decline by 12 % from 2014 to 2030 in the median scenario for LCOE. The expected 15 % decline in investment costs causes the LCOE of the projects to decline by 4.72 €/MWh (11.2%) on average from current levels (see Appendix B.2 for an illustration of the effect on the LCOE curve).

In addition to the investment costs, wind power projects are subject to operation and maintenance costs, although they constitute a significantly smaller share of the LCOE. The operation and maintenance costs are relatively low over the lifetime of a wind power project, in comparison to other energy sources. While NVE (2015a) assumed the operation and maintenance costs of onshore wind in Norway to be 16.35 €/MWh (i.e., 15 øre/kWh) in 2015, they are expected to decline towards 2030. NVE (2015a) identifies the international price development of service agreements as a key factor for the operation and maintenance costs of wind power projects in Norway. According to NVE (2015a), there is a potential for cost reduction by optimizing the operation and maintenance strategies. Following discussions with wind experts in the Norwegian Water Resources and Energy Directorate, the operation and maintenance costs are assumed to decrease to 10.9 €/MWh (i.e., 10 øre/kWh) in 2030 for the wind power projects included in this analysis.

Since wind turbines account for the largest share of the investment costs, it is natural to use the lifetime of the wind turbines to determine the lifetime of a wind power project. This analysis expects the lifetime of the wind power plants to remain 20 years in 2030, which corresponds to the lifetime of most certified wind turbines (NVE, 2015a). However, if the lifetime increases to 25 years, which is aligned with the expectations of the IEA (2015) and IRENA (2015), the LCOE of the projects in this analysis would decline by 2.7 €/MWh on average (see Appendix B.3 for an illustration of the shift in the LCOE curve).

The abovementioned assumptions yield the LCOE curve depicted in Figure 5.1, where the LCOE ranges from 32.85 €/MWh for the cheapest project to 49.4 €/MWh for the most expensive project. Notably, the LCOE curve of wind power projects in Norway is relatively flat, with 80 % of the projects having an LCOE in the range from 33.5 €/MWh to 40.5

€/MWh. The expected annual generation of each wind power project ranges from 9 GWh (0.009 TWh) for the smallest project to 1221 GWh (1.221 TWh) for the largest project and is illustrated by the horizontal distance between each project depicted in Figure 5.1.

Figure 5.1: The levelized cost of electricity for onshore wind in Norway in 2030

Source: Author's own illustration

5.2 Scenario analysis of the Power Market in North-Western Europe in 2030

This section presents the big picture of the power market in North-Western Europe under the four different scenarios. The section has two main purposes. First, the scenario analysis illustrates how different trajectories towards achieving the EU's energy and climate objectives may affect the Norwegian power sector in 2030. Second, the section serves to make the reader familiar with the characteristics of and differences between the four scenarios, which lay the foundation for the subsequent analysis of wind power development in Norway. In particular, Norway's electricity prices in the different scenarios will be of relevance for the rest of the analysis.

The first section presents the results from the Base Scenario in detail by providing an overview of the average electricity prices and the electricity trade flows in North-Western Europe in 2030. The next sections analyze the big picture of the power markets in North-Western Europe under the three other scenarios; Moderation, Green Nations and Decarbonization. Each section presents a step-wise development from the Base Scenario to the respective scenario, which illustrates the price effects from applying different assumptions.

5.2.1 Results from the Base Scenario

In the Base Scenario for 2030, the average price of electricity in Norway is 45.4 €/MWh while the prices in North-Western Europe range between 44 €/MWh and 50 €/MWh, as illustrated in Figure 5.2. The price increase from current levels can mainly be attributed to an increase in the EUA price and increased prices of coal and gas, which outweighs the merit order effect of developing more renewable energy in Europe. In the Base Scenario, the EUA price of 26 €/tCO_2 proves insufficient to trigger a fuel switch from coal to gas on the merit order curve. While the STMC of gas power plants with 56 % efficiency increases to 51.4 €/MWh, the STMC of coal averages 44.1 €/MWh under the given fuel price assumptions. The electricity prices in North-Western Europe are thus closer to the STMC of coal, which implies that coal power plants often are the price-setter in this scenario (see Appendix C.1 for an illustration of the relationship between Norway's electricity price and the fuel prices). While the STMC of coal is lower than the electricity price in most countries, gas power plants struggle to be profitable in the Base Scenario. The issue is further enhanced by the fact that the electricity prices are relatively stable and rarely climb towards the Value of Lost Load (VoLL).

With an average electricity price of 50.5 €/MWh, the UK has the highest electricity price in North-Western Europe in the Base Scenario. Due to the high difference between the electricity prices in Norway and the UK, the UK becomes Norway's main electricity export destination in the Base Scenario. In addition, Norway is a net exporter of electricity to the Netherlands and Denmark, even though the average electricity price is 0.1 €/MWh lower in Denmark than in Norway. The transmission capacity between Norway and Germany is also utilized frequently in 2030, with Norway's exports and imports each amounting to four TWh in the Base Scenario.

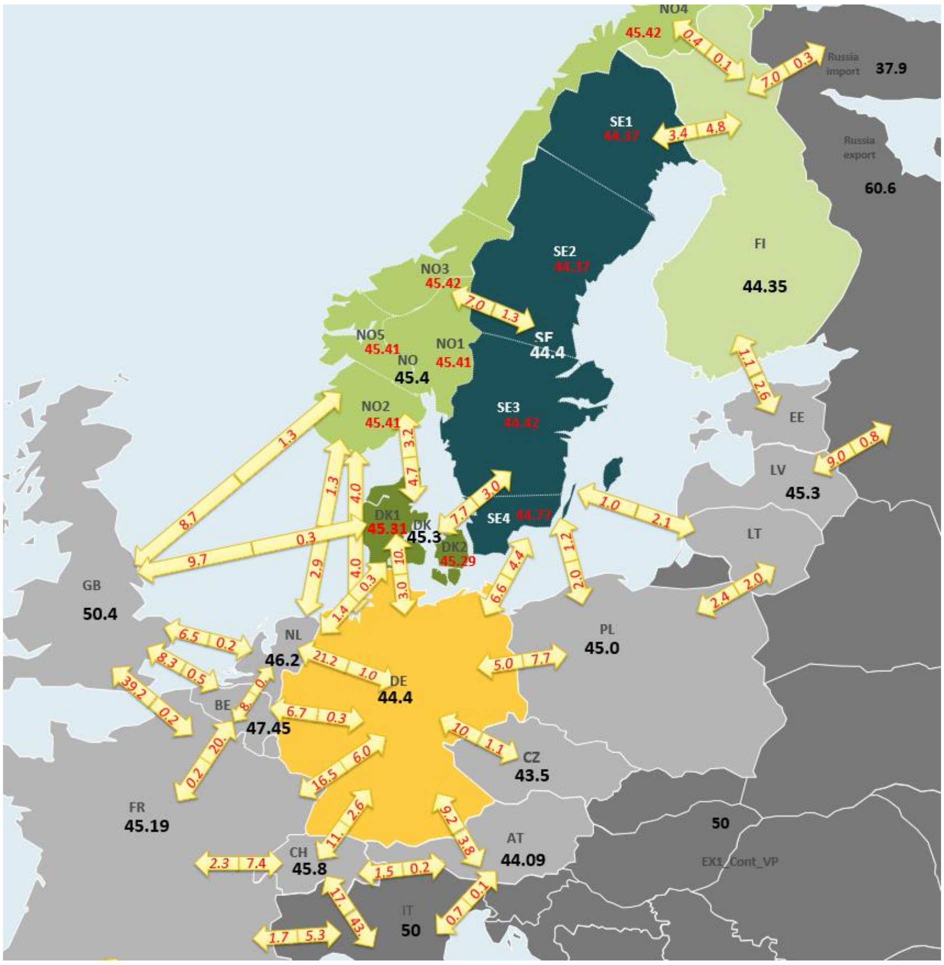

Figure 5.2: Electricity prices and trade flows in the Base Scenario for 2030
Source: Output from the The-MA model

5.2.2 Results from the Moderation Scenario

In the Moderation Scenario, the electricity prices in Europe increase relative to the Base Scenario, because of the significant increase in the EUA price. As illustrated in Figure 5.3, the electricity price in Norway increases by 10.7 €/MWh (23 %) when the EUA price increases by 73 % from 26 €/tCO2 to 45 €/tCO2, all else being equal. Hence, an increase in the EUA price of one €/tCO_2 causes Norway's electricity price to rise by 0.56 €/MWh on average under the given assumptions.

Relative to the Base Scenario, Europe's electricity demand reduction causes the price in Norway to fall by 1.2 €/MWh, all else being equal. However, when the EUA price, and thus the electricity price, increases, the effect of Europe's demand reduction on the Norwegian electricity prices is stronger. As illustrated in Figure 5.3, Norway's electricity price falls by 3.9 €/MWh because of the demand reduction, when the EUA price is 45€/tCO_2. The combined effect of the demand reduction and the EUA price increase is that the electricity price in Norway increases by seven €/MWh (26%) in Norway relative to the Base Scenario. The increase in the EUA price thus outweighs the effect of reduced electricity demand in North-Western Europe.

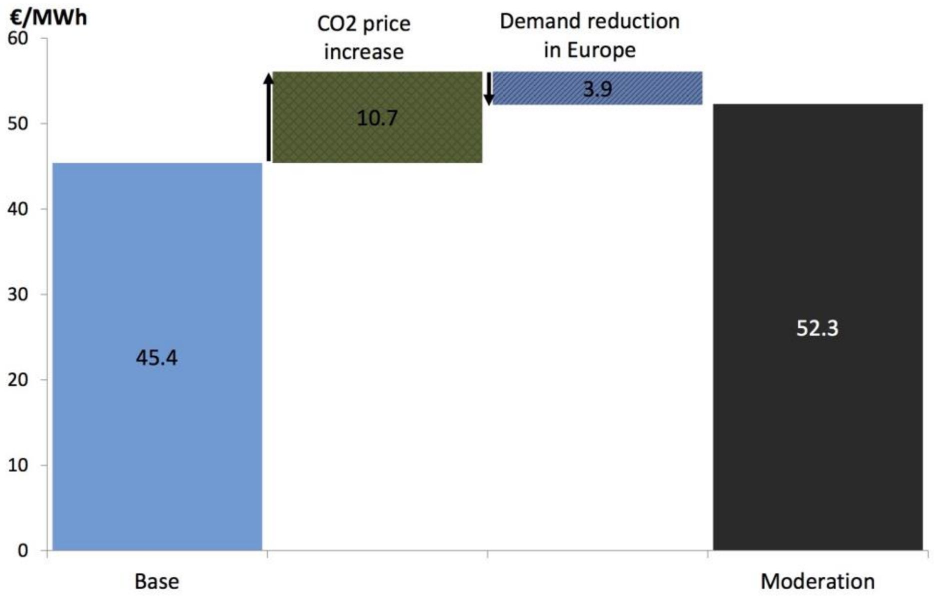

Figure 5.3: Step-wise development of Norway's average electricity price from the Base Scenario to the Moderation Scenario
Source: Author's own illustration

On average, the EUA price of 45 €/tCO_2 is high enough to trigger a fuel switch from gas to coal, as the STMC of coal increases to 60.3 €/MWh while the STMC of gas increases to 58.4 €/MWh when the gas price is 22 €/MWh and the coal price is 65 $/t. With the high EUA price, the electricity prices in North-Western Europe range between 48 €/MWh and 56 €/MWh in the Moderation Scenario for 2030 (See Appendix C.2 for an illustration of the power prices in Northwestern Europe under the Moderation Scenario).

5.2.3 Results from the Green Nations Scenario

Green Nations is the scenario with the lowest electricity prices in Europe, which above all is attributed to the low EUA price. In addition, the installed capacity of renewable energy in North-Western Europe increases significantly towards 2030 in the Green Nations Scenario, which causes Norway's electricity price to fall further due to the merit order effect in Northwestern Europe. If all assumptions from the Base Scenario are held constant except

Europe's installed capacity, Norway's average electricity price decreases by 0.6 €/MWh as the RES-E share in Northwestern Europe increases from 55 % to 62 %. Meanwhile, the electricity price in Norway decreases by 5.28 €/MWh (12%) if the EUA price decreases from 26 €/tCO_2 to 10 €/tCO_2, all else being equal. When the effects of the reduced EUA price and increased renewable energy capacity are combined, the prices fall even more than if the price reduction from the separate iterations were summarized. As illustrated in Figure 5.4, Norway's average electricity price decreases by 7.9 €/MWh relative to the Base Scenario and reaches 37.5 €/MWh in the Green Nations Scenario.

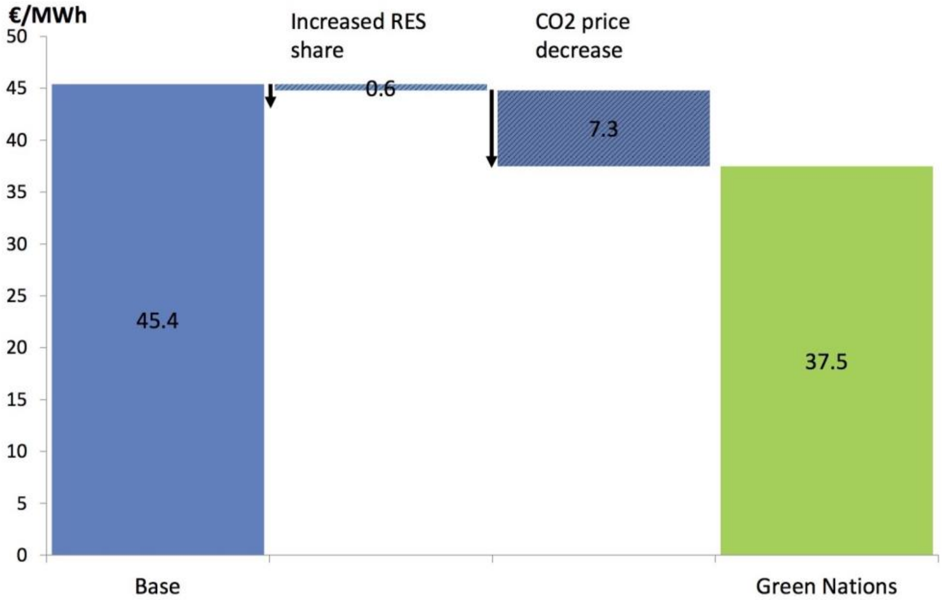

Figure 5.4: Step-wise development of Norway's average electricity price from the Base Scenario to the Green Nations Scenario

Source: Author's own illustration

With an EUA price of 10 €/tCO_2, the competitiveness of coal is enhanced relative to the Base Scenario, and gas power plants are dispatched less frequently as a result. Hence, the STMC of coal decreases by 13.6 €/MWh from the Base Scenario, to reach 30.5 €/MWh in this scenario for 2030. Meanwhile the STMC of a gas power plant with 56 % efficiency that is subject to the EU ETS reaches 45.4 €/MWh in the Green Nations Scenario, following a cost decline of 6 €/MWh relative to the Base Scenario. While coal power plants remain profitable in this scenario as the average electricity prices range between 36 €/MWh and 45 €/MWh in North-Western Europe (see Appendix C.3 for the price levels in different countries), most gas power plants struggle to remain profitable with the low price levels.

5.2.4 Results from the Decarbonization Scenario

In the Decarbonization Scenario, the average electricity prices in Europe range between 40 €/MWh and 59 €/MWh. As the EUA price increases to 45 €/MWh while the gas price falls to 15 €/MWh, the price differences within North-Western Europe increase. In most countries, the average electricity prices are lower in the Decarbonization Scenario than in the Base Scenario, as the effects of the reduced gas price and the high RES development outweigh the effect of the EUA price increase. Norway's average electricity price decreases by 3.1 €/MWh relative to the Base Scenario, which above all can be attributed to the decline in the price of gas imported to Europe. As illustrated in Figure 5.5, Norway's average electricity price increases by 10.7 €/MWh when the EUA price rises from 26 €/MWh to 45 €/MWh. When the EUA price is high, the increased renewable energy capacity in Europe causes Norway's average electricity price to fall by 2.5 €/MWh, all else being equal. In comparison to the Green Nations Scenario, the merit order effect is stronger in the Decarbonization Scenario. While Europe's increased renewable energy capacity causes Norway's average electricity price to fall by 1.3 % in the Green Nations Scenario, the price falls by 4.5 % in the Decarbonization Scenario when the EUA price is high. Even still, the strongest price effect is caused by the reduction in the gas price from 22 €/MWh in the Base Scenario to 15 €/MWh in the Decarbonization Scenario. In comparison to the Base Scenario, the reduction in the gas price causes Norway's average electricity price to fall by 7.5 €/MWh, all else being equal. However, when the EUA price is high and Europe's installed capacity of renewable energy is high as well, the reduction in the gas price causes Norway's electricity price to fall by 12.5 €/MWh.

With the high EUA price of 45 €/tCO_2 and the low gas price of €15/MWh, there is a fuel switch from gas to coal on the merit order curve in the Decarbonization Scenario. The STMC of gas decreases by 4.1 €/MWh relative to the Base Scenario, to reach 47.3€/MWh in the Decarbonization Scenario. Like in the Moderation Scenario, the price difference between the Nordic countries and the continent increases when the EUA price rises to high levels (see Appendix C.3 for further details regarding the price levels in Northwestern Europe under the Decarbonization Scenario).

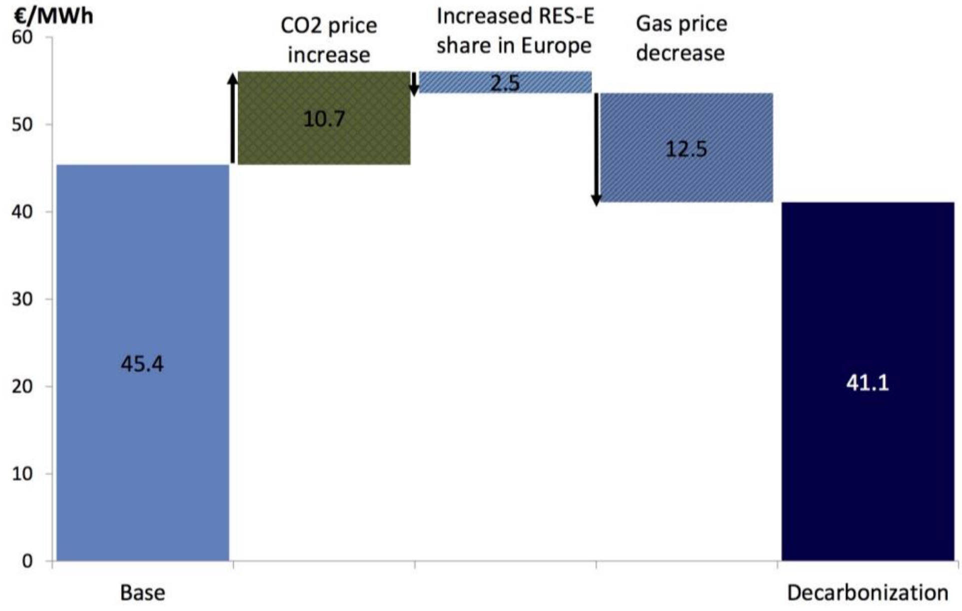

Figure 5.5: Step-wise development of Norway's average electricity price from the Base Scenario to the Decarbonization Scenario

Source: Author's own illustration

5.3 Norway's Load Duration Curves under the Four Scenarios

This section serves to give a more detailed analysis of how the development of the European power sector in the different scenarios affect the electricity prices in Norway. The installed capacity and electricity demand in Northwestern Europe have relatively strong implications for the price structures in the region, which also affect the Norwegian price structures. Figure 5.6 illustrates the duration curves for Norway's electricity prices under the four scenarios for 2030. Notably, the duration curves are steeper in the scenarios Green Nations and Decarbonization, which imply that the price volatility in Norway increases when a significant amount of Europe's thermal generation capacity is replaced by intermittent renewable energy sources. While flexible hydropower constitutes a vast share of Norway's electricity mix, this proves insufficient to prevent Norway from importing some significantly high electricity prices from adjacent countries when Europe's renewable energy share is high in 2030.

In the upper part of the duration curve, flexible demand with high willingness to pay, back-up generators, and thermal power plants with high marginal costs set the prices (Statnett, 2016). While the peak price is 146 €/MWh in the Base Scenario, the peak prices increase to 333 €/MWh and 327€ /MWh in the scenarios Green Nations and Decarbonization. In contrast, the peak price only reaches 97 €/MWh in the Moderation Scenario since the reduced electricity demand in Northwestern Europe moderates Norway's peak price. For further illustrations of the peak prices under the different scenarios, see Appendix C.5.

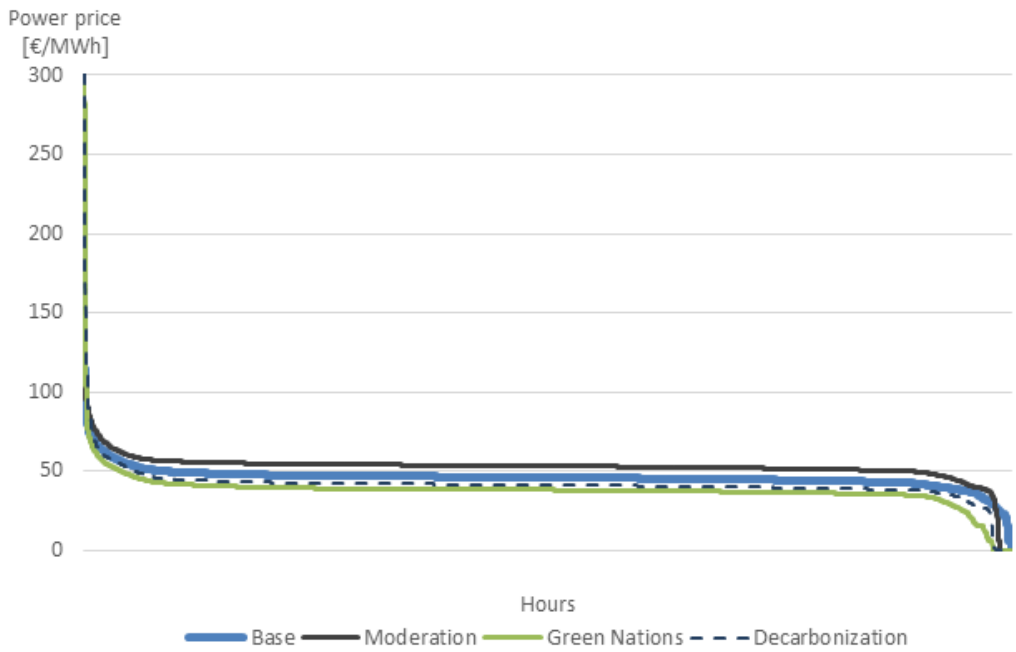

Figure 5.6: Duration curves for Norway's average electricity prices in 2030
Source: Author's own illustration

Although solar power and wind power in Northwestern Europe become a more central driver for the price fluctuations in Norway in 2030, the short term marginal costs of thermal power plants still set the price most of the hours of the year, which is illustrated by the mid-range of the duration curves in Figure 5.6.

The lower part of the duration curve illustrates the prices in the hours when the generation from power plants with low marginal costs, such as renewables and nuclear power, set the price. The steep fall in the lower part of the duration curves of all scenarios implies that the Norwegian power market is compatible with a large-scale integration of intermittent renewables in Northwestern Europe. In particular, the issue with zero and negative prices is relatively small in Norway in comparison to other power markets in Northwestern Europe, which relates to the high share of flexible hydropower in Norway's electricity mix. In the Base Scenario, the Norwegian prices plummet to zero only 61 hours (0.7%) of the year. As the RES-E share increases in Northwestern Europe while the EUA price remains low under the Green Nations Scenario, the duration curve declines earlier towards negligible levels and reach zero 180 hours (2.0 %) of the year. Yet, this figure remains low in comparison to

Denmark and Germany for instance, where zero prices occur in 458 hours (5.23 %) and 539 hours (6.2%) of the year respectively under the Green Nations Scenario.

5.4 The Market Value of Onshore Wind in Scandinavia and Germany in 2030

This section first analyzes the market value of onshore wind in Germany, Denmark and Sweden under the different scenarios for 2030. This provides the reader with an understanding of how the market conditions for the wind industry are affected as the installed capacity of wind power in each country and the region as a whole increases. In the subsequent section, the market value of onshore wind in each of Norway's bidding zones are analyzed under the four scenarios. Finally, the market values of onshore wind in all bidding zones in Norway, Sweden, Denmark and Germany under the Base Scenario are compared.

Figure 5.7 illustrates the market value factors for wind power in Germany, Western Denmark and the middle of Sweden. Notably, the market value factor is the lowest in Germany for all scenarios, ranging from 92 % in the Base Scenario to 82 % in the Green Nations Scenario. In comparison, the market value factors of wind power in Western Denmark and in the middle of Sweden range from 98 % to 93 % and 97 % to 94 % respectively.

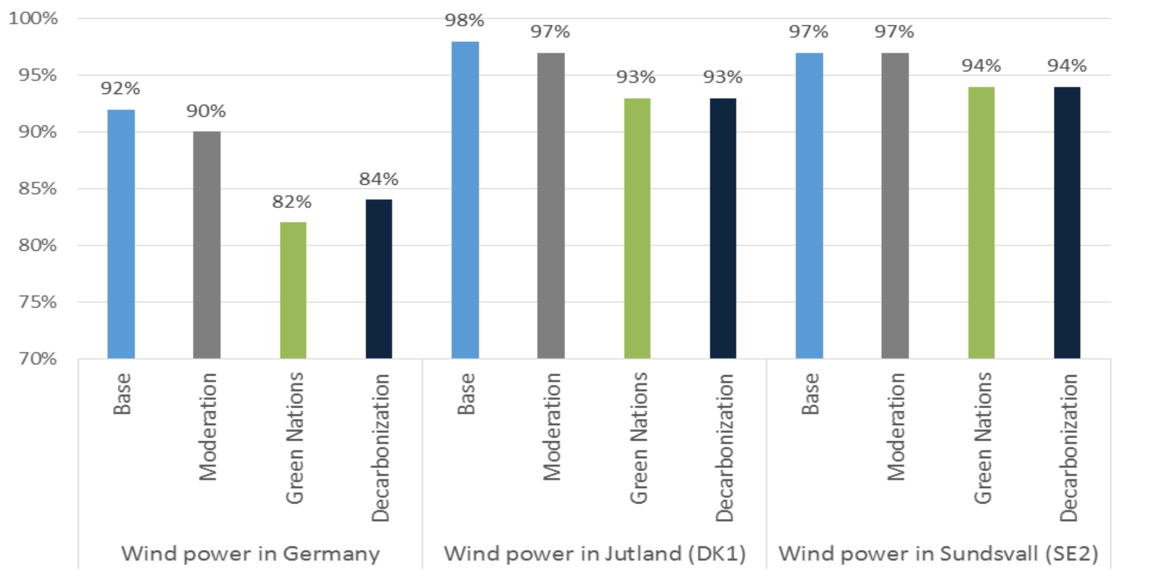

Figure 5.7: Market value factors for wind power in Germany, Western Denmark (DK1) and mid-Sweden (SE2) under the four scenarios
Source: Author's own illustration

The share of wind power generation in the electricity mix partly explains the decline in market value factors within each power system, as this share is the lowest in the Base Scenario while the market value factor is the highest. This relationship is illustrated in Figure 5.8, where the share of wind power in the electricity mix is used to explain the wind price in relation to the average electricity price in Germany. The average electricity price (blue line) and the wind price (grey line) can be read on the left axis, while the generation from wind power and non-wind sources are measured on the right axis. Notably, the gap between the average electricity price and the wind price increases from the Base Scenario to the scenarios Moderation, Green Nations and Decarbonization, as the wind share increases from 23 % to 29 %, 31 % and 35 % respectively. The price drop is particularly large in the Green Nations Scenario, where the wind price is 6.6 €/MWh below the average electricity price, which corresponds to a market value factor of 82 %. With both the wind power generation and the total generation being high, while the EUA price is low, the hourly electricity price collapses to zero or below 6 % of the year in Germany in the Green Nations Scenario for 2030. The trend depicted in the German wind power market is also present in the Swedish and Danish wind power markets, although the issue is less severe in comparison (see Appendix D.1 and D.2 for further illustrations).

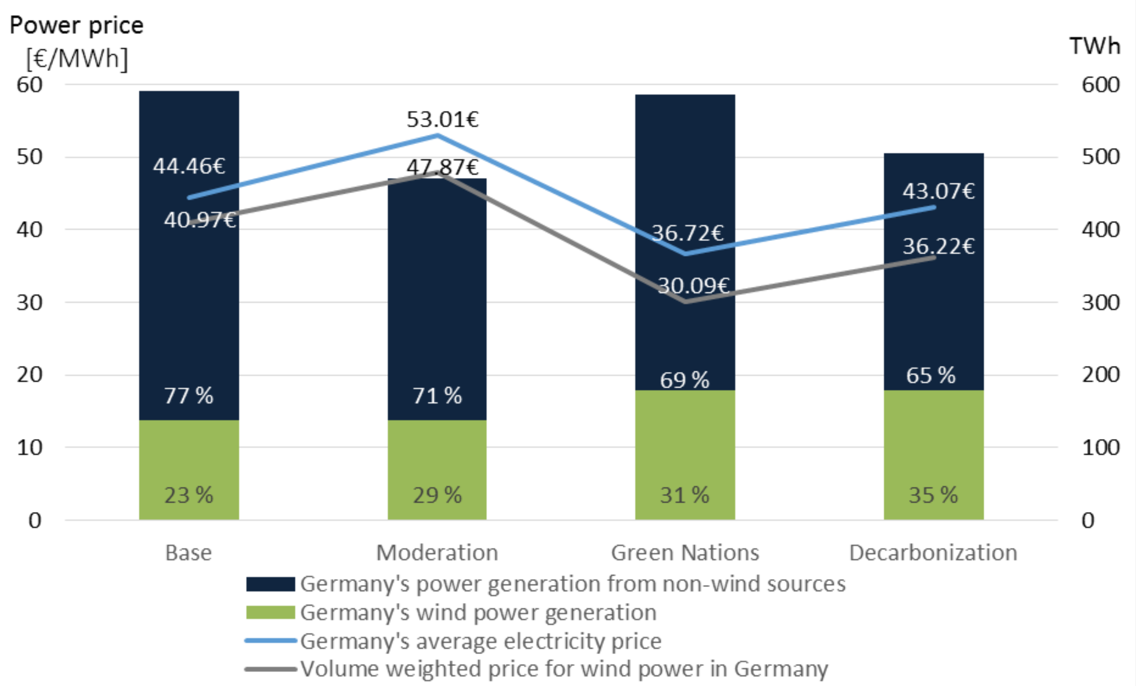

Figure 5.8: Wind prices and electricity prices (left axis) and power generation by source (right axis) in Germany under the four scenarios

Source: Author's own illustration

However, the share of wind power generation in the electricity mix does not necessarily explain the differences between the countries' market value factors, as the wind power share is significantly higher in Denmark than in Germany. The low market value factors in Germany must be viewed in relation to the overall differences between the power systems. While the Scandinavian countries have demand profiles with significant seasonal variations, Germany's electricity demand follows a flatter trend throughout the year. As the wind power generation tends to be the strongest in the winter months, it is more correlated with the demand in Scandinavia that peaks in the winter when more electricity is consumed for heating. In addition, Sweden's high share of hydropower provides more flexibility into the power system, as the hydro power plants can reduce or withhold their generation when the wind power generation is particularly strong. Although the market value factor of wind power in Sweden is reduced in the Green Nations Scenario and the Decarbonization Scenario, it remains above the market value factors in Denmark and Germany.

This section analyzes the relative and absolute market values for onshore wind in Norway's bidding zones under the four scenarios for 2030. These results also lay the foundation for the subsequent analysis of the profitability of developing wind power projects in Norway in 2030, which compares the wind prices to the levelized cost of electricity of onshore wind in Norway. This section presents the wind prices for six out of seven bidding zones in the TheMA model.[4] The results illustrate that the wind price is higher or equal to the average electricity price across all scenarios for 2030 and all bidding zones. This indicates that wind power plants in Norway will continue to receive a positive price premium if Norway's annual wind power generation increases to 8.6 TWh, regardless of the development of the EU's energy and climate policies towards 2030.

The market value factors of Norwegian onshore wind range from 100 % to 103 % across the different bidding zones and the scenarios for 2030. Like in the other Scandinavian countries, the wind power plants in Norway benefit from the seasonal correlation between generation and demand. Since Scandinavia's electricity demand increases in the winter months, the demand peaks coincide with the period when the wind conditions are the most optimal for power generation. The market value factors of wind power plants tend to be higher than the market value factors of run-of-river hydropower plants in Norway, as the latter generates

[4] The bidding zone NST, which includes Buskerud, Vestfold and Telemark, is not included in the analysis, as these counties neither have developed wind power capacity today nor are expected to develop wind power capacity by 2030.

more electricity during the summer. According to empirical studies conducted in-house by the Norwegian Water Resources and Energy Directorate, the market value factor of run-of-river hydro can be as low as 80 % in Norway.

While the market value factor of wind is 101 % in all bidding zones in the Base Scenario, the factors vary within Norway in the other scenarios. In particular, the market value factors are the lowest in Southern Norway and the highest in Northern Norway under the scenarios Green Nations and Decarbonization. This is illustrated in Figure 5.9, which compares the market value factors and the volume-weighted electricity price for wind power in Southern Norway and Northern Norway under the four scenarios for 2030.

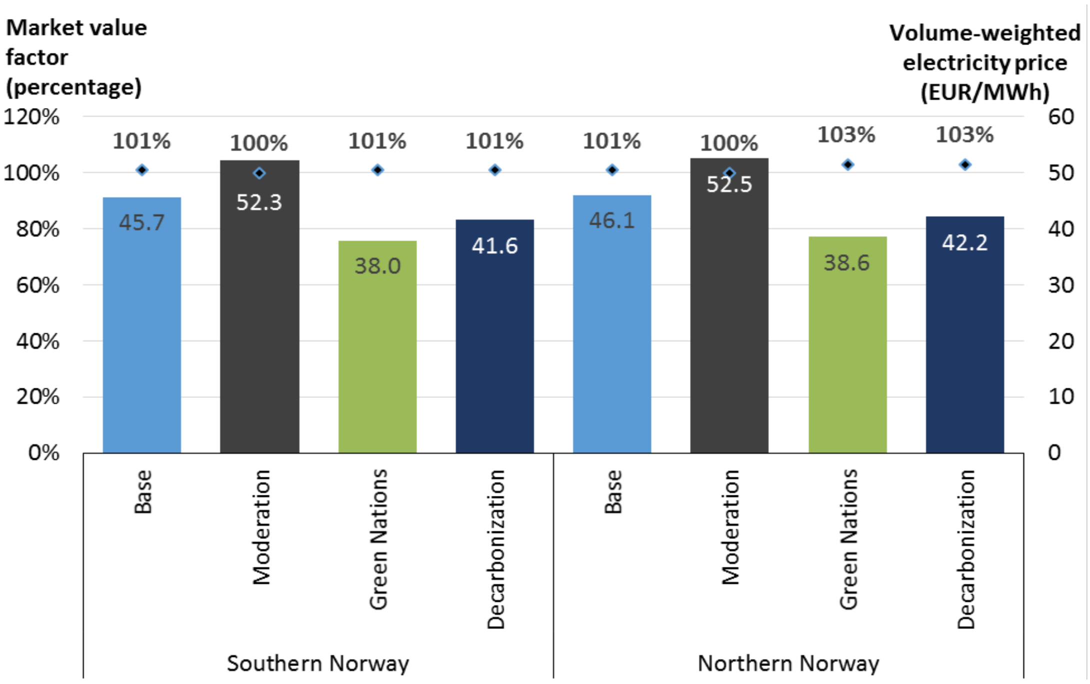

Figure 5.9: The market value factors for onshore wind (left axis) and the wind prices (right axis) in Southern Norway and Northern Norway under the four scenarios

Source: Author's own illustration.

The development in Northwestern Europe's installed capacity from the Base Scenario to the scenarios Green Nations and Decarbonization have two opposing effects on the market value factors of onshore wind in Norway. On the one hand, the high RES-E share in Northwestern Europe causes the Norwegian wind price to decrease in the hours when the wind conditions allow for high wind power generation across the region. As most of Norway's cross-border transmission capacity is located in the South, the wind power plants in Southern Norway are more affected by correlating power generation in Scandinavia and the continent than other wind power plants in Norway. At the same time, the peak prices are higher in the scenarios Green Nations and Decarbonization than in the Base Scenario, since more coal power capacity is decommissioned. The corresponding price spikes tend to correlate with the generation profiles of wind power plants, which increases the market value of onshore wind. For wind power plants located in Southern Norway, these two effects balance each other out, and the market value factors remain 101 % in the scenarios Green Nations and Decarbonization. In contrast, the market value factor of wind in Northern Norway increase to 103 % in the scenarios Green Nations and Decarbonization. The wind power projects in this area are less affected by the merit order effect in Northwestern Europe, while they also benefit from higher price spikes in the scenarios where more coal power is decommissioned than in the Base Scenario.

In the Green Nations Scenario, the geographical difference in market value factors increases the most. In particular, the market value factors of onshore wind increase to 103 % in Norway's three northernmost bidding zones, as illustrated in Figure 5.10. Meanwhile, the factors decline by one to ten percentage points from the Base Scenario in Sweden, Denmark and Germany, as the wind power capacity in these countries increases. While Germany has the largest decline in the market value factor of onshore wind relative to the Base Scenario, the adjacent bidding zones also exhibit relatively large declines in the market value factors in the Green Nations Scenario. Notably, the market value factors in Jutland, Zealand and Malmö decline by five, seven and four percentage points respectively. In contrast, the market value factors only decline by three percentage points in the other bidding zones in Sweden, even though there is a larger increase in the wind power generation in Sundsvall and Stockholm than in Malmö. Similarly, Southern Norway has the lowest market value factor in Norway in the Green Nations Scenario, even though the wind power generation is higher in mid-Norway. For further comparisons of the market value factors in the different scenarios, see Appendix D.3, which provides a map of the market value factors in Germany and the Scandinavian bidding zones in the Base Scenario.

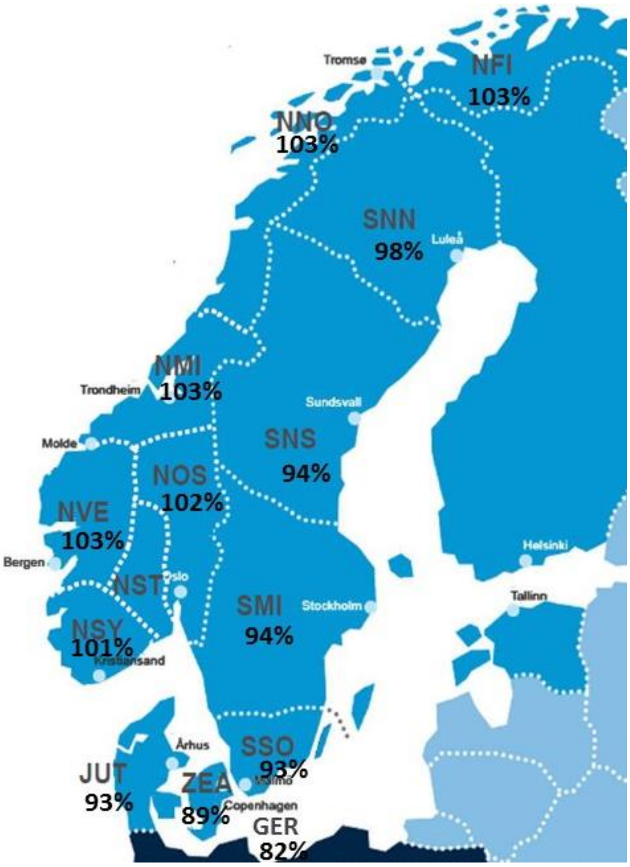

Figure 5.10: Market value factors for onshore wind in Scandinavia and Germany in the Green Nations Scenario

Source: Author's own illustration based on map of bidding zones by Thema (2014).

5.5 Grid parity for Onshore Wind Power in Norway in 2030

This subchapter compares the LCOE estimates from 25 potential wind power projects to the wind prices in Norway under the four scenarios for 2030. While the comparison is based on the simplifying assumption that these electricity prices would remain stable for the lifetime of the projects, it still provides an indication of which circumstances and price levels that would facilitate further investments in wind power in Norway.

The wind prices from the scenario analysis represent the starting point for the first wind power projects that would be developed. However, the price would inevitable be reduced as Norway's installed capacity of wind power increases due to the merit order effect. In order to take this price effect into account, the wind power projects are gradually phased in to the TheMA model by first adding the installed capacity of the cheapest projects to their respective bidding zones. Whenever the LCOE of a project is on the margin of the electricity price, it is compared to the volume-weighted electricity price of the bidding zone that the specific project is located in.

5.5.1 Grid parity in the Base Scenario

In the Base Scenario for 2030, Norway's wind prices range from 45.7 €/MWh in Southern Norway to 46.08 €/MWh in Northern Norway. Notably, this price is well above the LCOE of all projects except one. If these 24 projects were developed, the annual generation of wind power in Norway would increase by 6.94 TWh from the Base Scenario. While this development would cause the wind price in mid-Norway to fall to 44.59 €/MWh, the price remains above the LCOE of the marginal project, which is located in this bidding zone. As illustrated in Figure 5.11, it would be profitable to develop 24 of the 25 projects that have been granted licenses by the Norwegian Water Resources and Energy Directorate if the electricity tariff averaged 44.59 €/MWh over the lifetime of the projects. The results thus indicate that onshore wind will reach grid parity in Norway in 2030 under the given assumptions.

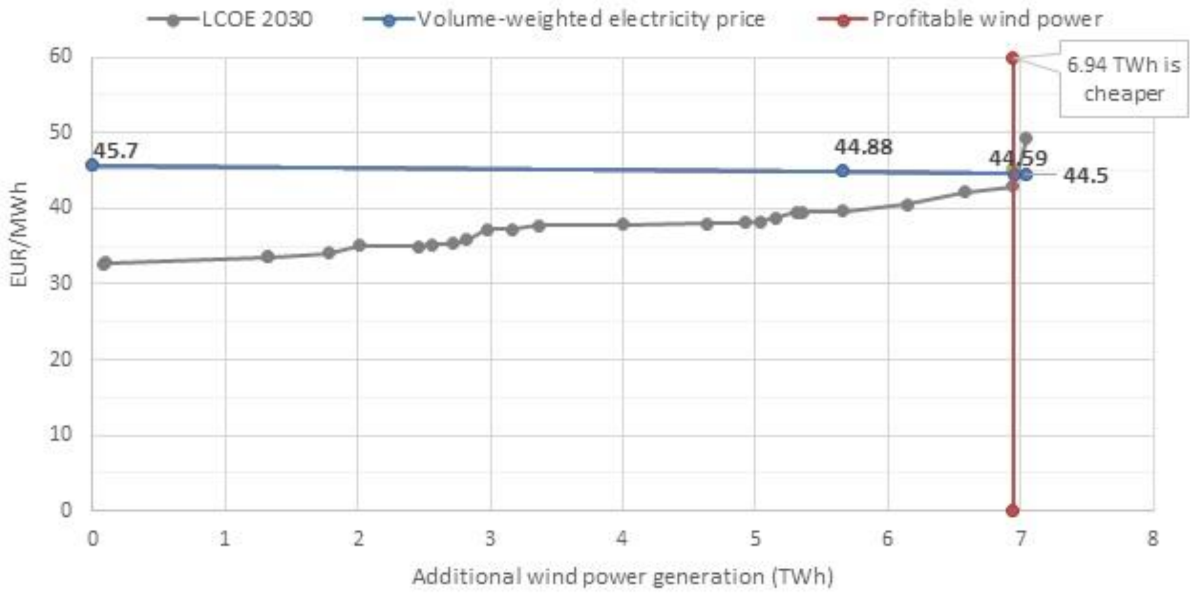

Figure 5.11: The wind price and the levelized cost of electricity for onshore wind in Norway in the Base Scenario
Source: Author's own illustration

5.5.2 Grid parity in the Moderation Scenario

In the Moderation Scenario, the wind price ranges from 52.25 €/MWh in Southern Norway to 52.69 €/MWh in Western Norway. Moderation is the scenario with the highest electricity prices in Norway, which above all is attributed to the EUA price increasing to 45 €/tCO_2. Under the price level from this scenario, all of the projects that have been granted licenses by the Norwegian Water Resources and Energy Directorate and currently await investment decisions become profitable to develop. Although the wind price decreases to 50.89 €/MWh as Norway's annual wind power generation increases by 7.04 TWh, the price remains sufficiently high for the most expensive project to be developed. As illustrated in Figure 5.12, all of the 25 projects would break even if the electricity tariff averaged 50.89 €/MWh over the lifetime of the projects.

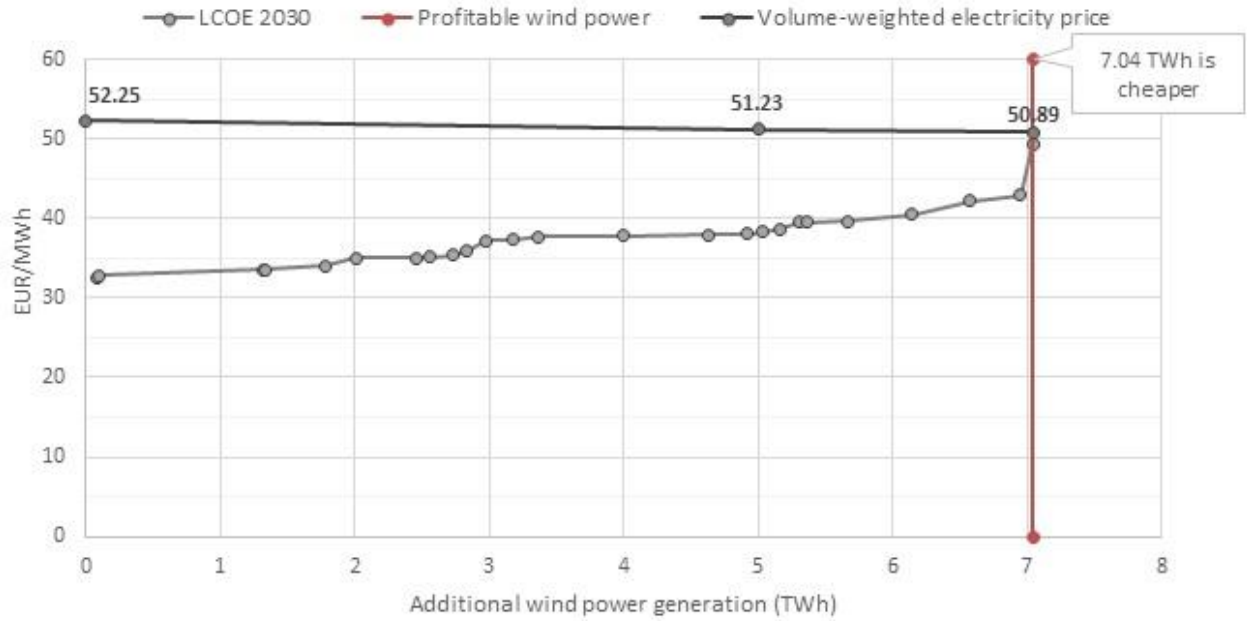

Figure 5.12: The wind price and the levelized cost of electricity for onshore wind in Norway in the Moderation Scenario
Source: Author's own illustration

Like in the Base Scenario, the wind price converges towards the average electricity price in all bidding zones, while the market value of wind decreases more in Southern Norway than in the other bidding zones. In Southern Norway, both the wind price and the average electricity price decrease by 3 % due to the merit order effect if the 25 wind power projects are developed. Still, the market value factors of onshore wind range between 100 % and 101 %, which indicates that Norwegian wind power plants will maintain an advantage over wind power plants in Sweden, Germany and Denmark even if Norway's annual wind power generation increases to a total of 15.6 TWh.

5.5.3 Grid parity in the Green Nations Scenario

In the Green Nations Scenario, the wind price ranges from 37.95 €/MWh in Southern Norway to 38.62 €/MWh in Western Norway. This is the scenario for 2030 with the lowest electricity prices, which is attributed to the low EUA price of 10 €/tCO_2 and the high development of renewable energy in North-Western Europe. While the majority of the projects appear profitable at a first glance, the merit order effect has significant implications for the projects in the mid-range of the LCOE curve. As the LCOE curve for onshore wind in Norway is relatively flat, small price changes largely affect the number of wind power projects that are profitable when the electricity price is close to the median LCOE. In addition, the merit order effect is stronger in the Green Nations Scenario, as the Norwegian electricity prices are affected by the high installed capacity of renewable energy in Europe. In particular, the wind price in Southern Norway decreases by 5 % if 7 TWh of wind power generation is added in the Green Nations Scenario, while it only decreases by 2.8% in the Base Scenario. When taking the merit order effect into account, wind power projects with a cumulative generation of 3.17 TWh become profitable to develop in Norway under the given assumptions, as illustrated in Figure 5.12.

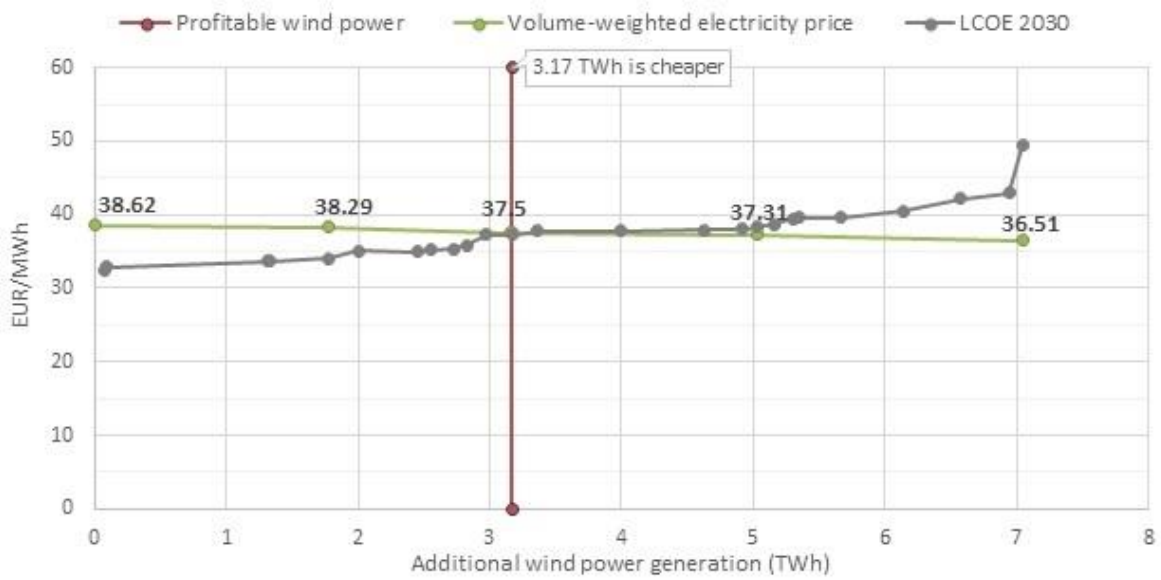

Figure 5.13: The wind price and the levelized cost of electricity for onshore wind in Norway in the Green Nations Scenario

Source: Author's own illustration

The marginal wind power project is located in Southern Norway, where the volume-weighted electricity price of wind power decreases to 37.5 €/MWh if the 12 cheapest wind power projects are developed. Hence, it is only profitable to develop 12 of the 25 wind power projects that have been granted licenses by NVE if the electricity price averages 37.5 €/MWh over the lifetime of the projects.

5.5.4 Grid parity in the Decarbonization Scenario

In the Decarbonization Scenario, the volume-weighted electricity price for onshore wind in Norway initially ranges from 41.58 €/MWh in Southern Norway to 42.25 €/MWh in Western Norway. While these prices are above the LCOE of 22 of the 25 licensed wind power projects that await investment decisions in Norway, only 21 would be profitable if they were all developed due to the price decline from the merit order effect. By developing these 21 projects, Norway's annual generation from wind power would increase by 5.7 TWh. This causes the wind price to fall slightly in all bidding zones. The wind power project that is on the margin is located in Northern Norway, where the wind price falls from 41.06 €/MWh to 39.87 €/MWh if Norway's annual generation increases by 5.7 TWh.

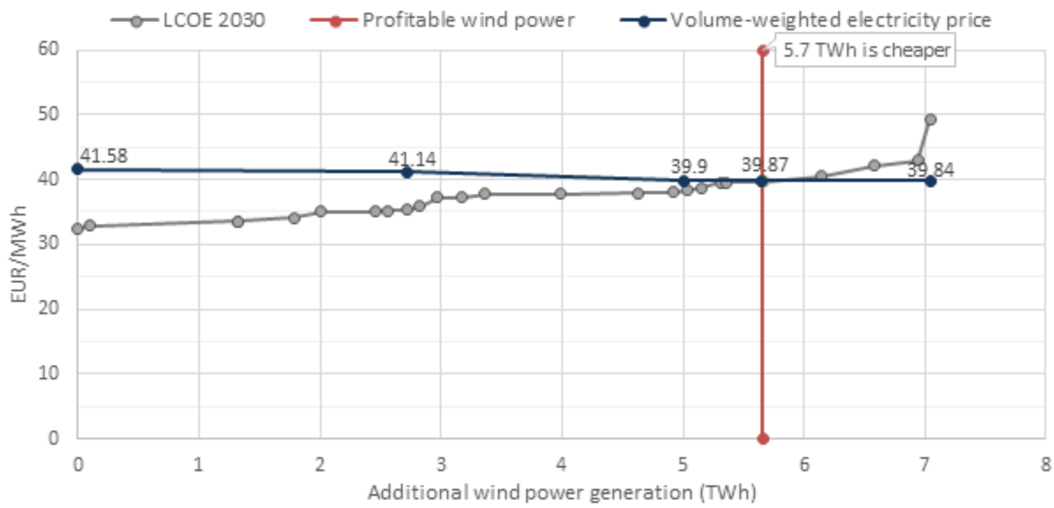

Figure 5.14: The wind price and the levelized cost of electricity for onshore wind in Norway in the Decarbonization Scenario
Source: Author's own illustration

Notably, the merit order effect is stronger in the Decarbonization Scenario than in the Base Scenario, as Europe's installed capacity of renewable energy is higher. The price reduction is strongest in Southern Norway, since this bidding zone is more integrated with the continent. In particular, the wind price in Southern Norway decreases by 4.2% if the annual generation of wind power increases by 7.04 TWh in Norway. Still, the vast share of the wind power projects remains profitable under the given assumptions. While the wind price in the bidding zone of the marginal project is only 2.37 €/MWh higher than in the Green Nations Scenario, 9 more projects become profitable to develop under the price levels from the Decarbonization Scenario. This further illustrates how small price changes will have significant implications for the wind power development in Norway if the electricity price is close to the median LCOE, due to the proximity of the LCOE for Norwegian, onshore wind power projects.

5.6 The Merit Order Effect of Increased Wind Power Generation in Norway

This subchapter takes a deeper look at how the absolute and relative market values of wind in Norway respond to increases in Norway's wind power generation. In particular, it compares the wind prices and wind value factors in Southern Norway and Northern Norway, for three different levels of annual wind power generation under the four scenarios. The lowest level (8.6 TWh) represents the cumulative generation of Norway's existing and planned wind power projects around 2030, and corresponds to a wind share of 5.8%. The medium level (15.6 TWh) takes into account the additional generation from all licensed wind power projects that await investment decisions, i.e., the projects from the LCOE dataset, which brings the wind share to 10.0 %. Finally, the highest level (22.6 TWh) represents a duplication of all the projects in the LCOE dataset and corresponds to a wind share of 16 %. The highest level serves to illustrate how the wind prices could develop beyond 2030 over the lifetime of the projects in the LCOE dataset. If Norway's electricity prices increase significantly towards 2030, such as to the levels under the Base Scenario of this analysis, many wind power projects could become profitable to develop. In the long-term, this could decrease the revenues for the projects included in the grid parity analysis due to the merit order effect. This section thus supplements the results from section *5.5 Grid Parity for onshore wind in Norway,* which only included wind prices under a cumulative wind power generation between 8.6 TWh and 15.6 TWh.

The comparison between Southern Norway and Northern Norway also highlight how the market value of wind in different Norwegian bidding zones develop depending on where the new capacity is situated. These two bidding zones are analyzed since most of the licensed wind power projects that await investment decisions are either located in Southern Norway or Northern Norway (see 4.6 *Estimating the market value of onshore wind).* However, the projects in Northern Norway are significantly larger than the projects in Southern Norway, which corresponds to a stronger merit order effect in this bidding zone.

Figure 5.15 illustrates the wind prices in Southern Norway for the three different levels of annual wind power generation under the four scenarios for 2030. Notably, the wind price falls more than the average electricity price in all scenarios, as the annual wind power generation in Norway increases.

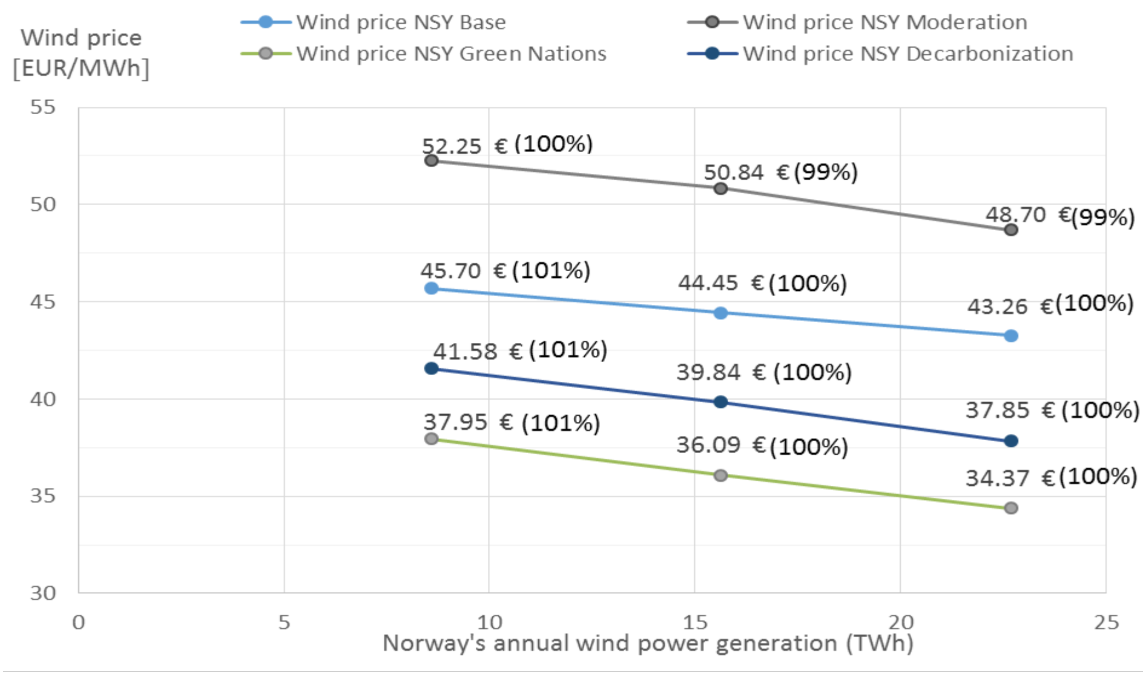

Figure 5.15: Wind prices and market value factors (in parenthesis) in Southern Norway under different levels of wind development in the four scenarios
Source: Author's own illustration

In the Base Scenario the wind price falls from 45.7 €/MWh to 44.45 €/MWh and 43.26 €/MWh in Southern Norway, as Norway's wind power generation increases from 8.6 TWh to 15.6 TWh and 22.6 TWh respectively. In comparison, the fall in the average electricity price from 45.41 €/MWh to 44.30€/MWh and 43.21 €/MWh is more modest. Although the market value of onshore wind decreases as the annual generation of wind power increases, the effect is marginal in Southern Norway. In particular, the market value factors decrease by one percentage point as the annual wind power generation increases from 8.6 TWh to 15.6 TWh and remain stable thereafter in all scenarios.

In comparison, the merit order effect is more evident in Northern Norway, where the annual wind power generation increases the most in this analysis. As illustrated in Figure 5.16, the market value factor of onshore wind in Northern Norway decreases by two to four percentage points under the different scenarios, as the annual wind power generation in Norway increases from 8.6 TWh to 22.6 TWh. Notably, the fall in the value factor is particularly strong in the scenarios Green Nations Scenario and Decarbonization, where the initial price premium for wind power plants in Northern Norway evaporates as the annual wind power generation increases.

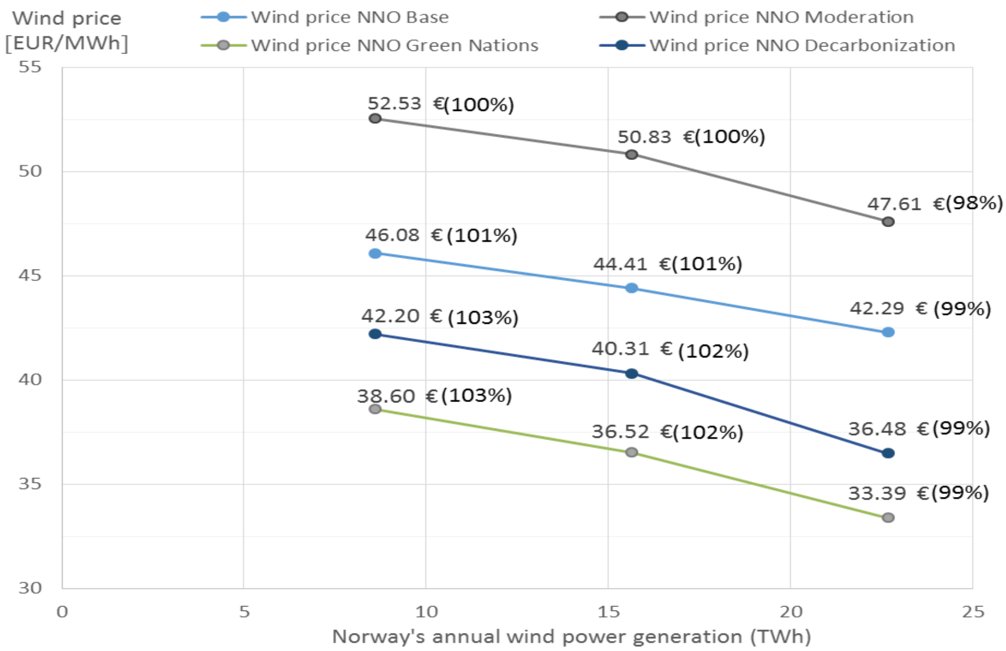

Figure 5.16: Wind prices and market value factors (in parenthesis) in Northern Norway under different levels of wind development in the four scenarios

Source: Author's own illustration

Additional wind power generation does not only affect the value factor of onshore wind, it also decreases the market price for electricity. Hence, increased wind penetration has implications for the Norwegian power market as a whole. In Southern Norway, the average electricity price decreases by 0.16 €/MWh, or 0.35 percentage points, on average for each Terawatt hour of wind power that is added to Norway's annual generation. In comparison, each additional Terawatt hour of wind power generation causes the average electricity price to decline by 0.20 €/MWh, or 0.43 percentage points, in Northern Norway where most of the new generation occurs. The price effect is even stronger in the scenarios where the RES-E share in Europe is higher. In the Green Nations Scenario, each Terawatt hour added to Norway's annual wind power generation causes the average electricity price in Southern Norway to decline by 0.24 €/MWh, or 0.58 percentage points, on average. In Northern Norway, the decline in average electricity price is as much as 0.28€/MWh, or 0.74 percentage points, in the Green Nations Scenario. This illustrates the potential merit order effect when the wind development is particularly high both within a bidding zone and in Northwestern Europe as a whole.

6. Discussion

This chapter discusses the results from the analysis and serves to analyze the thesis question in a broader perspective. Hence, the discussion chapter revolves around how the EU's climate and energy policies affect Norwegian electricity prices in 2030 and which implications they have for the wind power sector. The first section discusses the price effects of the EU's three climate and energy objectives for 2030 and the interdependency between the targets. The next section discusses the competitiveness of onshore wind in Norway based on the estimated market value factors of wind in Scandinavia and Germany. Finally, the chapter deliberates over the outlook for developing onshore wind projects in Norway without subsidies in 2030.

6.1 The EU's Energy and Climate Policies Lead to Higher and More Volatile Prices in Norway Towards 2030

The EU's energy and climate policies will lead to a significant transformation of the electricity system that has vast implications for Norway. In 2030, the Norwegian power market faces increased price levels and more short-term price fluctuations. This section begins by presenting the broad picture of the development towards 2030, before discussing how the EU's three objectives for 2030 affect the electricity price levels and price structures in Norway. The final part analyzes the interdependency between the EU's targets for 2030.

Under all scenarios for 2030, the electricity prices in Norway and Northwestern Europe increase towards 2030. While the electricity price in Southern Norway declined from 45 €/MWh in 2011 to only 20 €/MWh in 2015 (Statnett, 2016), it climbs back to 45 €/MWh in the Base Scenario for 2030. My analysis primarily attributes the price increase to a higher carbon price and an increased tendency for gas to set the prices in Northwestern Europe, as EU member states decommission parts of their coal power capacity towards 2030. In comparison, the high price levels in 2011 corresponded to particularly high coal prices, in addition to moderately high price levels for gas and EUAs. Although Europe deploys significant amounts of renewables towards 2030, thermal power plants still set the electricity prices in Northwestern Europe in most hours of the year. As the short-term marginal costs of gas tend to determine the opportunity cost for flexible hydropower plants in Norway in 2030, the price of natural gas imported to Europe becomes increasingly important for the electricity price levels in Norway.

Towards 2030, the transmission capacity from the Nordic region to the continent and the UK increases, which reflects the EU's objective of creating a pan-European electricity market to improve the efficient use of energy across Europe. The Norwegian prices converge towards the continental prices, as Norway get cross-border interconnectors to Germany and the UK, and the Nordic power market becomes more integrated with the continent. While this causes the consumer surplus to decrease, it benefits existing power producers and facilitates investments in renewable energy technologies that currently are unprofitable. With regard to existing power plants, the price increase towards 2030 coincides beneficially with a period where a great share of the hydropower plants in Norway require significant upgrades and reinvestments (Norwegian Ministry of the Petroleum and Energy, 2016). It also facilitates investments in new wind power plants, as section 6.3 explains.

The EU's climate and energy policies further increase the short-term price fluctuations in the Norwegian electricity market. This owes to a combination of the European prices both plummeting towards zero in more hours of the year due to the merit order effect and spiking towards the value of lost load more frequently due to the decommissioning of flexible thermal power generation. On top of that, a higher EUA price will increase the difference between the hours where thermal power plants set the price and the hours where carbon-free power plants, such as renewables and nuclear power, determine the price. The switch from coal to gas as the most frequent price-setter in Northwestern Europe could also exacerbate the seasonal fluctuations in the Norwegian electricity prices due to the co-variance between the gas demand in Northwestern Europe and the electricity demand in Norway. In particular, the demand for gas also tends to peak in the cold fall and winter periods, as gas is the primary source of heating in Northwestern Europe, which correlates to the electricity demand peaks in Norway. At the same time, the increased transmission capacity to the continent might moderate Norway's seasonal price fluctuations, as the price profiles in Europe are flatter than in Norway.

As the transmission capacity is still insufficient to remove all bottlenecks, Norway remains relatively resilient to zero price levels due to the high share of flexible hydropower generation in the electricity mix. However, if the cross-border border transmission capacity from Norway increases beyond the two planned cables to the UK and Germany, the issue with zero prices could become more severe in Norway. With the recent change in legislation that allows private actors to build cross-border interconnectors from Norway (Stortinget, 2016), more cross-border interconnectors might be built towards 2030. One concrete example is the project company North Connect that intends to build a 1400 MW interconnector between Norway and Scotland (Northconnect, n.d.).

In the Base Scenario for 2030, the fuel prices prove insufficient to trigger a switch from coal to gas on the merit order curve, and the short-term marginal cost of gas remain higher than the short-term marginal cost of coal. The tendency for gas to set the electricity price thus represents political rather than economic decisions to decommission coal power plants. This adds a level of uncertainty to the energy transition in Northwestern Europe, as the political priorities could change significantly over the next two decades.

6.1.1 Implications of the EU's 2030 GHG emission reduction target

The EU's emission reduction target for 2030 particularly affects Norwegian electricity prices through the EUA price. Even though Norway only generates 2 % of its production from thermal power plants in the scenarios for 2030, the EUA price strongly affects the Norwegian electricity prices through the water values of hydropower plants. Towards 2030, the EUA price is likely to increase from the 5 €/tCO2 average in 2016, due to revisions of the EU ETS including the reduction in the overall cap, the introduction of the Market Stability Reserve from 2019 and the ban on the use of Kyoto credits after 2020. The key question is whether these revisions will be sufficient to combat the oversupply of EUAs that has been increasing steadily for more than a decade (see 2.2.4 *The EU Emission Trading System* for further details). When taking into account the planned revisions of the EU ETS such as the Market Stability Reserve, analysts expect the carbon price to be in the range of 20-39 €/tCO_2 in 2030 (Statnett, 2016; IEA, 2016c; ICIS Tschach Solutions, 2015). Further revisions, such as the introduction of a carbon price floor or a tightening of the cap, could cause the EUA price to increase even more.

In my analysis, Norway's electricity price jumps by 10.7 €/MWh if the EUA price increases by 19 €/tCO_2 from the Base Scenario, which illustrates how the EU ETS have vast implications for Norwegian consumers and producers of electricity, as well as the incentives for market-based investment in new capacity. At the same time, fluctuations in the EUA price will have smaller effects on the electricity price when gas power plants with lower emission factors set the price. My analysis finds that an increase of one €/tCO_2 in the EUA price on average causes Norway's electricity price to rise by 0.33-0.56 €/MWh in 2030, which is lower than when coal power plants set the price. In comparison, an increase in the EUA price of one €/tCO_2 has historically given rise to an increase in power prices of 0.6-0.7 €/MWh (THEMA, 2015a).

6.1.2 Implications of the EU's 2030 renewable energy target

In contrast to the EU's renewable energy target for 2020, the EU's objective of increasing the share of renewable energy consumption to 27 % by 2030 is not legally binding on a national level. Consequently, Norway is so far not legally committed to increase the renewable energy share beyond the 67.5 % target for 2020. The EU-wide renewable energy target will however affect the Norwegian power market indirectly, as an increased RES-E share depresses the electricity prices and increases the short-term price fluctuations. The EU can achieve the renewable energy target through both increased renewable power production and increased renewable heat production. Hence, the target will affect Norway's price levels and price structures more the more the EU relies on renewable power production to meet its 2030 target.

My analysis estimates the price effect of increasing the RES-E share in Northwestern Europe by seven percentage points from the 55 % share applied in the Base Scenario. I find that if the RES-E share in Northwestern Europe increases from 55 % to 62 %, Norway's average electricity price decreases by 1.3 % if the EUA price is moderate (26 €/tCO_2) and by 4.5 % if the EUA price is high (45 €/tCO_2). Hence, the price decline stemming from more renewables is stronger when the EUA price, and thereby the electricity price, is higher. If the EUA price increases, the merit order curve becomes steeper (see section 3.3.2 *Effect of carbon pricing on the merit-order curve*), which corresponds to a larger price fall under the merit order effect.

However, as the renewable target for 2030 is not legally binding on a national level, and some EU Member States plan to phase out their support mechanisms, the road towards achieving the new target is less clear. Although the revisions of the EU ETS could cause the electricity market prices to increase, it is uncertain whether this mechanism alone will be sufficient to incentivize the large-scale deployment of renewables that the EU needs to meet its 2030 target. In addition, both the wholesale prices and the market value factors of renewables such as wind and solar continue to decrease as the RES-E share increases within a power system, which gradually reduces the profitability of new and existing renewable power projects. This pose a challenge for the EU to meet its 2030 target for renewable energy if the EU Member States phase out subsidies.

6.1.3 Implications of the EU's 2030 energy efficiency target

The implications for the Norwegian power market of the EU's target to increase the energy efficiency by 27 % relative to 2005 levels are more ambiguous than the other EU targets for 2030. In particular, the effect on the power market depends on whether the energy efficiency target translates into measures that cause the electricity demand in Northwestern Europe to increase or decrease. For power-intensive sectors, increased energy efficiency would cause the electricity demand in Northwestern Europe to decrease. On the other hand, the energy efficiency target could also translate into a large-scale energy substitution to electricity. In combination with the increasing RES-E share, this could be another long-term strategy for cutting greenhouse gas emissions in the EU. If EU Member States take measures to electrify non-power intensive sectors, such as the transport and heating sectors, the electricity demand would increase. This analysis expects the electricity demand in Northwestern Europe to increase significantly towards 2030 in three out of four scenarios. The level can be interpreted both as a scenario where the EU makes little progress towards the energy efficiency target, and as a scenario where reductions in the demand from power-intensive industries are combined with electrification of non-power intensive industries. In contrast, the Moderation Scenario assumes that the energy efficiency target results in a decrease in the electricity demand relative to the other scenarios.

Through iterations of the scenarios, I find that if the electricity demand in Northwestern Europe decreases by 9 % from the Base Scenario to the Moderation Scenario, the Norwegian electricity prices decline by 2.6% when the EUA price is moderate and 7 % when the EUA price is high. Furthermore, a reduced electricity demand in Northwestern Europe leads to less volatile prices because it moderates the price spikes that Norway imports from its trading partners. Unless the demand reduction is paired with a high EUA price, it would challenge the profitability of thermal peak generators that rely on these price spikes to remain profitable. In the long-term, an electricity demand reduction could therefore pose a challenge to Europe's energy security.

6.1.4 *Interdependency between the EU’s energy and climate policies*

The results presented above illustrate the interdependency between the EU’s energy and climate policies. The effects on the Norwegian power market of the EU’s objectives for increased energy efficiency and increased renewable energy share also depend on the EUA price, which reflects the EU’s final objective for 2030, namely reduced greenhouse gas emissions. The scenarios Moderation and Decarbonization presume that the EU revises the EU ETS further, which facilitates a high EUA price despite the reduced electricity demand and the increased RES-E share respectively. However, in the absence of a carbon price floor, reduced electricity demand or an increased RES-E share will have a double downward effect on the electricity prices since they also cause the EUA price, and thereby the short-term marginal costs of thermal power plants, to decrease. This conclusion draws on previous findings that reduced electricity demand or an increased RES-E share cause the EUA price to decrease (Flues et al, 2014; the Nordic Council of Ministers, 2015). Hence, these measures could bring the electricity prices below the levels observed in the Moderation and Decarbonization scenarios. For instance, the combination of a high renewable energy share and a low EUA price causes Norway’s average electricity price to decrease to 37.5 €/MWh in the Green Nations Scenario.

6.2 The Norwegian Power Market is Well Suited for Wind Power Generation

Building on the wind market values estimated under the different scenarios for the power market in 2030, this subchapter argues that the Norwegian power market is particularly well suited to the integration of intermittent wind power generation. The first section discusses how Norwegian wind power plants perform in the power market. The next section revolves around how the price structures under the different scenarios for the power market in Northwestern Europe affect the market value of onshore wind in Norway. The final section challenges the results presented in this analysis by discussing how increased cross-border transmission capacity could affect the market value of onshore wind in Norway.

The results from my analysis imply that the relative market value of onshore wind in Norway remains high under the impact of the EU’s climate and energy policies, and even sustains high RES-E shares and low electricity demand in Northwestern Europe. With wind power constituting 5.8% of the Norwegian electricity mix, the market value of wind ranges from 100 % to 103 % across all bidding zones and all scenarios. This particularly owes to the favorable correlation between the wind conditions and the electricity demand profiles in Norway, as well as the high share of flexible hydropower. In addition, Norway's wind share of 5.8% is relatively modest in comparison to Sweden, Denmark and Germany, where the wind shares in the Base Scenario are 16 %, 52% and 30 % respectively. I therefore test whether wind shares beyond this level would cannibalize the profitability of new and existing wind power projects in Norway.

My analysis finds that even if Norway's annual wind power generation were to increase ten-fold from 2014-levels, which corresponds to a wind share of 16 %, the market value of wind would remain between 99 % and 100 %. Under all scenarios, wind producers in Norway outperform their peers in Scandinavia and Germany where the wind price is significantly below the average market price for electricity. For similar domestic wind shares, the market values of onshore wind are higher in Norway than in Sweden. While the wind generation profiles and the demand profiles in Norway and Sweden are relatively similar, Norway benefits from an even higher share of flexible hydropower and a relatively smaller cross-border transmission capacity to the continent.

My analysis also finds that the different price structures under the four scenarios affect the relative market value of onshore wind in Norway. In the scenarios Green Nations and Decarbonization, where the RES-E share in Northwestern Europe is higher, there is a larger geographical difference between the market value of wind within Norway. As the wind conditions in Norway partly correlates with the wind conditions in Scandinavia and the continent, the merit order effect in Northwestern Europe causes the market value of wind in Norway to decrease. This effect is stronger for wind power plants located in Southern Norway where most of Norway's cross-border transmission capacity is situated. At the same time, higher price spikes occur in the scenarios where intermittent renewables have replaced a significant share of the thermal power capacity in Northwestern Europe. The Norwegian wind power plants thus benefit from higher peak prices in the scenarios Green Nations and Decarbonization, as they tend to generate electricity during the demand peaks in the winter. In Southern Norway, these two effects balance each other out, and the market value of wind remains 101 % in the scenarios Base, Green Nations and Decarbonization. In Northern Norway, the market value of wind actually increases to 103 % in the scenarios where the RES-E share in Northwestern Europe is high, as the hours with relatively higher price spikes correlate with their generation profiles. However, Norway’s transmission capacity must also be taken into account when evaluating the profitability of developing wind power plants in different bidding zones. As the transmission export capacity is lower in Northern Norway, and the distance to demand centers is farther, some wind power projects could be unprofitable to develop in Northern Norway when the necessary expansion of the grid is taken into account.

While my analysis takes into account all cross-border interconnectors that the Norwegian TSO Statnett plans to build before 2030, Norway’s transmission capacity might increase beyond this level. Although I find that the high market values of onshore wind are relatively sustainable, the competitive advantage of the Norwegian wind power sector could gradually decline if Norway builds more cross-border interconnectors to the UK and the continent. When taking the planned interconnectors to the UK and Germany into account, the results from the scenario analysis already imply that the Norwegian electricity prices will converge towards the prices on the continent towards 2030. Additional interconnectors would add to this effect, and leave the Norwegian power market more vulnerable to price drops in hours with high renewable power generation on the continent. While a sensitivity analysis of the market value for wind under increased transmission capacity is beyond the scope of this analysis, it is a topic for future research. However, the market values for onshore wind in Sweden serve as an indication for how the wind market values in Norway could react to more cross-border interconnectors, as Sweden has more transmission capacity to the continent. Even though Sweden’s wind share only increases by one percentage point from the Base Scenario to the scenarios Green Nations and Decarbonization, the relative market value of wind falls by three percentage points from 97 % to 94 %. Hence, the fall in Sweden’s market value reflects the high renewable power production on the continent, which strongly affects the Swedish market due to its high integration to the continent. Although the hydropower share is even higher in Norway than in Sweden, which could moderate the effect, the Swedish example still implies that increased transmission capacity to the continent could cause the market value factors in Norway to decrease.

6.3 Long Term Outlook for Wind Power Development in Norway

This section discusses the key finding from the analysis of the Norwegian wind sector, namely, that onshore wind reaches grid parity in Norway by 2030. Owing to a combination of decreased investment costs and increased electricity prices, the long-term outlook for developing wind power projects without subsidies in Norway is inevitably favorable. On top of that, the high share of flexible hydropower generation and the profound seasonal demand pattern make the value factor of onshore wind in Norway particularly high.

Under the given assumptions of this analysis, the results imply that it will be profitable to develop wind power projects without subsidies in Norway in 2030. This analysis estimates the levelized costs of electricity of 25 Norwegian wind power projects to range from 32.85 to 49.4 €/MWh in 2030. This marks a significant cost decline from current levels. In comparison, the Norwegian Water Resources and Energy Directorate (2015a) estimated the LCOE of onshore wind projects to average 56.68 €/MWh (i.e., 52 øre/KWh) in 2011-2013 when applying the same discount rate of 6 %. The cost competitiveness of Norwegian wind power projects in 2030 partly reflects long-term projections for the global wind technology development such as declining investment costs due to the learning effect. In addition, wind power projects in Scandinavia benefit from good wind conditions and relatively high load hours. Even in the sensitivity analysis where a discount rate of 8 % is applied, the best wind power projects remain profitable to develop in the scenario with the lowest electricity prices.

The wind price in the Base Scenario for 2030 is above the LCOE of all wind power projects in the sample except one. In comparison, the wind price is higher than the levelized costs of electricity for half of the projects in Green Nations, the scenario with the lowest electricity prices. At first glance, these results indicate that Norway could deploy significant amounts of wind power in 2030. As Norway remains its status as a net exporter of electricity in 2030, increased wind power generation would imply that Norway could export more electricity to the UK and the continent. However, a high wind penetration would also depress both the wind prices and the average electricity prices due to the merit order effect. This analysis finds that the average hourly electricity prices decline by 0.16-0.28 €/MWh, or 0.35-0.74 percentage points, for each Terawatt hour added to Norway's annual wind power generation. Hence, the profitability of new and existing power plants decline as more wind power projects are developed.

The cannibalization of wind power projects is particularly eminent in the Green Nations Scenario where the RES-E share in Europe is high. While 14 projects from the sample are profitable at first glance, only 12 of them would remain profitable if they all were to be developed, due to the merit order effect. This implies that there could be a race to enter the wind power market for the projects that appear profitable around 2030. It also indicates that over the course of the projects' lifetime, investors face the risk of declining wind prices if Norway's wind power generation increases further, as new projects with even lower LCOEs are developed.

In the Base Scenario, all Norwegian wind power projects with construction licenses that currently await investment-decisions reach grid parity except one. This implies that Norway could develop wind power projects with a cumulative generation of seven TWh without subsidies around 2030. Adding to the annual wind power generation of 8.6 TWh that reflects Norway's current and planned wind power capacity in 2030, this would bring Norway's wind share to 10 %. This share has a socio-economic interpretation as the cost-optimal wind share in the Base Scenario, since the intersection between the wind price and the levelized cost of electricity defines the cost-optimal deployment level (Hirth, 2015). However, the list of projects might change by 2030. Some of these projects could be developed earlier if the electricity prices increase significantly before 2030 or if investors expect a price increase in the long term. On the other hand, other projects that are currently not included might apply for construction licenses. Nonetheless, the results imply that it could be cost-optimal with a significant increase in the wind share from current levels, and that good wind power projects indeed can be profitable to develop without subsidies in Norway in 2030. Granted that Norway does not set a renewable energy target for 2030, the findings of this analysis supports the rational for phasing out subsidies for renewable energy development over the next decade.

7. Conclusion

The European energy sector is undergoing a massive transition that has vast implications for the Norwegian power market. Driven by the objectives of energy independence, competitiveness and sustainable development, the EU has embarked on a challenging and ambitious path towards a decarbonized and fully integrated power market, in which Norway serves as a net exporter of flexible, green electricity. The overarching purpose of this study was to analyze how the EU's energy and climate policies affect Norwegian electricity prices in 2030 and which implications they have for the wind power sector. My analysis models four scenarios for the power market in Northwestern Europe to study how the Norwegian electricity prices develop towards 2030 under different trajectories towards achieving the EU's energy and climate policies. The results imply that the Norwegian electricity prices will increase towards 2030 due to a range of factors. The most important ones are the increased price for European Union Allowances (the so-called carbon price) and the tendency for gas to set the electricity price in Northwestern Europe due to political, rather than economic, decisions to phase out coal. In the Base Scenario of my analysis, Norway's electricity price increases to 45.4 €/MWh in 2030, which is closely aligned with the projections from Statnett (2016) and the IEA (2016a) of 44 €/MWh and 50 €/MWh respectively.

My analysis also finds that the Norwegian electricity prices become more volatile as intermittent renewables replace thermal power capacity in Northwestern Europe. While the prices plummet towards zero more frequently under the merit order effect, they also spike to higher levels in the peak-hours due to the EUA price increase and the reduction in flexible thermal power capacity. As the Nordic power market becomes more integrated with the continent and the UK under the EU's vision of a fully integrated power market, the Norwegian price levels converge towards the levels on the continent, which average 44-50 €/MWh in the Base Scenario. However, the profound seasonal pattern of Norway's electricity prices persist, which particularly favors Norwegian wind power plants that tend to generate more electricity in the cold fall and winter periods when the demand for electricity peaks.

While both electricity demand reductions from energy efficiency measures and increases in the RES-E share in Northwestern Europe cause the Norwegian electricity price to decline, an increase in the EUA price through revisions of the EU ETS has the opposite effect. In particular, I find that an increase of one €/tCO_2 in the EUA price on average causes Norway's electricity price to rise by 0.33-0.56 €/MWh. In contrast, an increase in the EUA price of one €/tCO_2 has historically given rise to an increase in power prices of 0.6-0.7 €/MWh (THEMA, 2015a). These results imply that fluctuations in the EUA price have a smaller effect on Norwegian electricity prices in 2030 than today since gas power plants, which have lower emission factors than coal, set the electricity price in Northwestern Europe more often in 2030. The switch from coal to gas as the marginal plant in most hours of the year in the Base Scenario merely reflects the decommissioning of coal power capacity, while the EUA price of 26 €/tCO2 proves insufficient to trigger a fuel switch on the merit order curve. As the short-term marginal cost of gas remains above the short-term marginal cost of coal, the tendency for gas to set the electricity price favors the development of renewable energy, since it causes the wholesale prices to increase.

Moving on to the implications for the Norwegian wind power sector, I conclude that onshore wind reaches grid parity under all scenarios for 2030, after estimating both the volume-weighted electricity price and the levelized costs of electricity for a number of licensed onshore wind projects in Norway. My finding supports the rationale for phasing-out subsidies for renewable energy in Norway, which the Norwegian government enacted in 2016 through the decision to withdraw Norway from the joint electricity certificate market with Sweden after 2021 (Norwegian Ministry of the Petroleum and Energy, 2016). While the learning effect causes the investment costs of wind power projects to decline globally, the good wind conditions in Scandinavia and the peculiarities of the Norwegian power market make Norwegian wind power projects particularly profitable. Owing to a 15 % decline in the investment costs, high load hours for Scandinavian wind projects and a relatively low real, pre-tax discount rate of 6 %, my analysis finds that the LCOE of licensed onshore wind projects in Norway declines to a range of 32.85-49.40 €/MWh in 2030. While I apply a modest assumption of 20 years to the lifetime of wind power projects, the LCOE range would shift further downwards to 30.31-45.45 €/MWh if the average lifetime increases to 25 years by 2030.

In terms of the revenue side, my analysis finds that Norwegian wind power projects benefit from higher market value factors than their peers in Sweden, Denmark and Germany. In particular, the market value factors of Norwegian onshore wind reach 101 % in all Norwegian bidding zones in the Base Scenario when Norway's annual wind power generation increases to 8.6 TWh. This implies that Norwegian wind power is slightly more valuable as a generation technology than a constant source of electricity. In contrast, the market value factors of wind in Sweden, Denmark and Germany range from 97 %, 98 % and 92 % respectively in the Base Scenario to 94 %, 93 % and 82 % in the Green Nations Scenario. My analysis primarily attributes the high market value factors of Norwegian wind to Norway's high share of flexible hydropower generation and seasonal demand pattern that causes the electricity prices to spike in the winter when the wind power generation is highest. However, in the long term the Norwegian wind power sector is its own biggest threat as increased wind penetration causes the wholesale prices to decline due to the merit order effect. I find that for each Terawatt hour added to Norway's annual wind power generation, the average electricity price declines by 0.16-0.28 €/MWh, or 0.35-0.74 percentage points, depending on the RES-E shares within the bidding zone and in Northwestern Europe. Consequently, wind power projects face the risk of declining revenues if additional wind power projects with lower levelized costs of electricity are developed over the course of their lifetimes. Nonetheless, the outlook for developing wind power projects without subsidies in Norway is inevitably positive if the expected price increase towards 2030 materializes, as the market value factors of wind remain close to unity for wind shares up to 16 % in Norway.

To create the four scenarios for 2030, I alter the assumptions for the installed capacity and electricity demand in Northwestern Europe, the carbon prices (i.e., the EUA price and the carbon price floor in the UK), and the gas price. I also update the assumptions for the cross-border transmission capacity in Northwestern Europe in 2030 based on ENTSO-E's 2016 ten-year development plan. Finally, I base the assumptions for Norway's installed capacity and electricity demand in the scenario analysis on data from the Norwegian Water Resources and Energy Directorate. While this framework largely covers how the EU's climate and energy policies affect the Norwegian power market, future research should look at other factors that could significantly change the long-term outlook for the power market and wind sector in Norway. In particular, the effect of increased cross-border transmission capacity is a topic of current interest in the wake of the Norwegian parliament's decision from October 2016 to allow private actors to build cross-border interconnectors. To what degree this affects the Norwegian price levels and price structures should receive close review, especially with regard to the implications for the market value of onshore wind in Norway.

Another topic of interest is how the market value of onshore wind respond to the annual fluctuations in precipitation in Norway. While I estimate the market value of onshore win after running multiple iterations where I alter Norway's wind power capacity under each scenario for the power market in Northwestern Europe, I do not vary the assumptions for Norway's annual hydropower generation. Hence, my results only represent the market value of onshore wind in a normal year. My hypothesis is that the market value of onshore wind in Norway will increase in dry years, as the electricity prices spike to higher levels during the winter period, which correlates with the generation profile of Norwegian wind power plants. Future research could use historic data to estimate the market value of onshore wind under different precipitation levels in Norway. Another approach is to look at the effect of dry years and wet years under higher wind shares and closer integration to the continental market than at present. This would particularly be of relevance to the development of wind power projects after 2021 when Norway withdraws from the joint electricity certificate market with Sweden. Finally, future research could investigate the profitability of developing other renewable energy sources in Norway, such as offshore wind and small-scale hydropower, in the long term. Given my conclusion that wind power plants receive higher revenues from the wholesale market in Norway than in Germany and the rest of Scandinavia, it could be of interest to estimate the levelized cost of electricity for offshore wind in the long term and compare it to the wind prices. Although offshore wind is currently far from reaching grid parity, the learning effect is higher for offshore wind than for onshore wind, as the former is a less mature technology. Hence, a suggestion for future research is to study whether offshore wind can reach grid parity in Norway over the next decades, and which implications that would have for the Norwegian power market.

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Appendix A

A1: Assumptions for the installed capacity in Europe

Figures A.1, A.2 and A.3 illustrate the assumptions for the installed capacity of each country that is modeled endogenously in the TheMA model, and serve to give the reader an understanding of how the electricity mix in these countries develop from current levels towards 2030 under the different scenarios. Figures A.1 and A.2 illustrate the assumptions for installed capacity in the ten countries where the share of renewable energy is differentiated between the scenarios, and compares them to the model assumptions for 2016. Figure A.3 illustrates the assumptions for installed capacity in France, Belgium, Switzerland, the Czech Republic, Austria and Norway, which are kept constant throughout the scenarios.

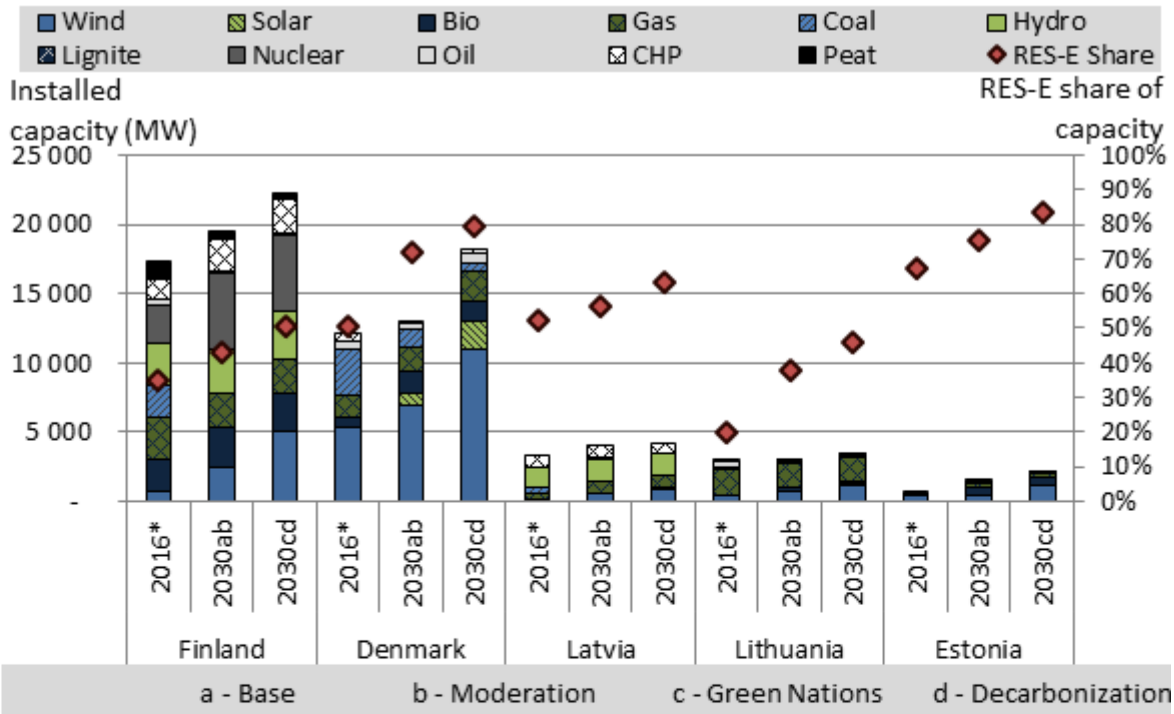

Figure A.1: Installed capacity in Finland, Denmark, Latvia, Lithuania and Estonia in 2016 and the scenarios for 2030

*Note: *The installed capacity for 2016 illustrates the data from the model's default dataset. Source: Author's own illustration*

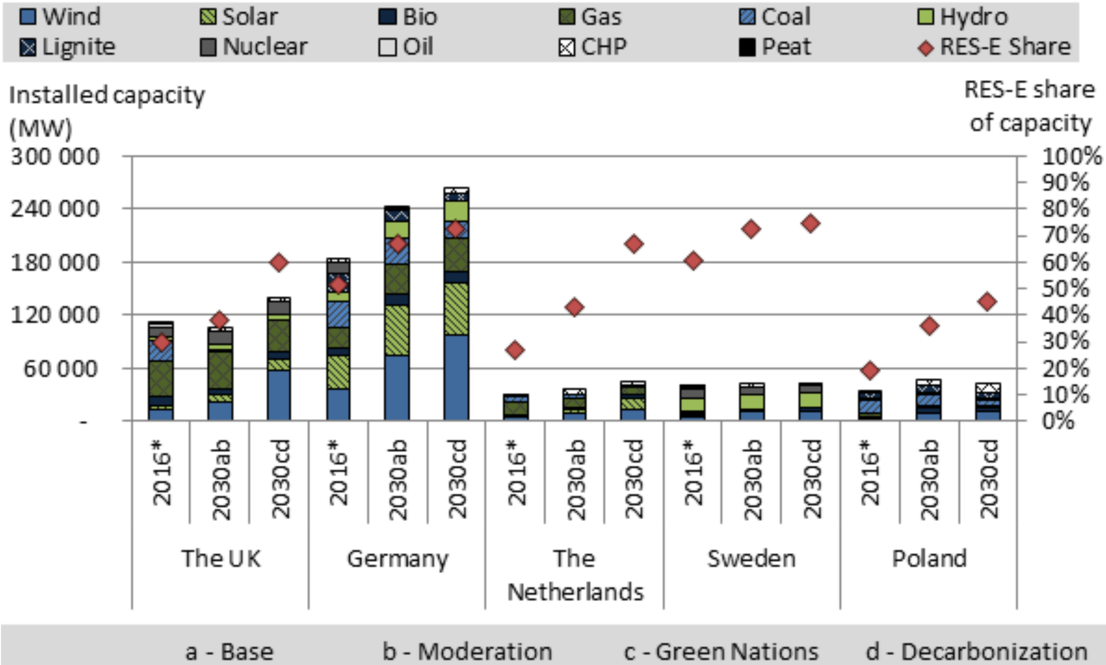

Figure A.2: Installed capacity in the UK, Germany, the Netherlands, Sweden and Poland in 2016 and 2030

*Note: *The installed capacity for 2016 illustrates the data from the model's default.*

Source: Author's own illustration

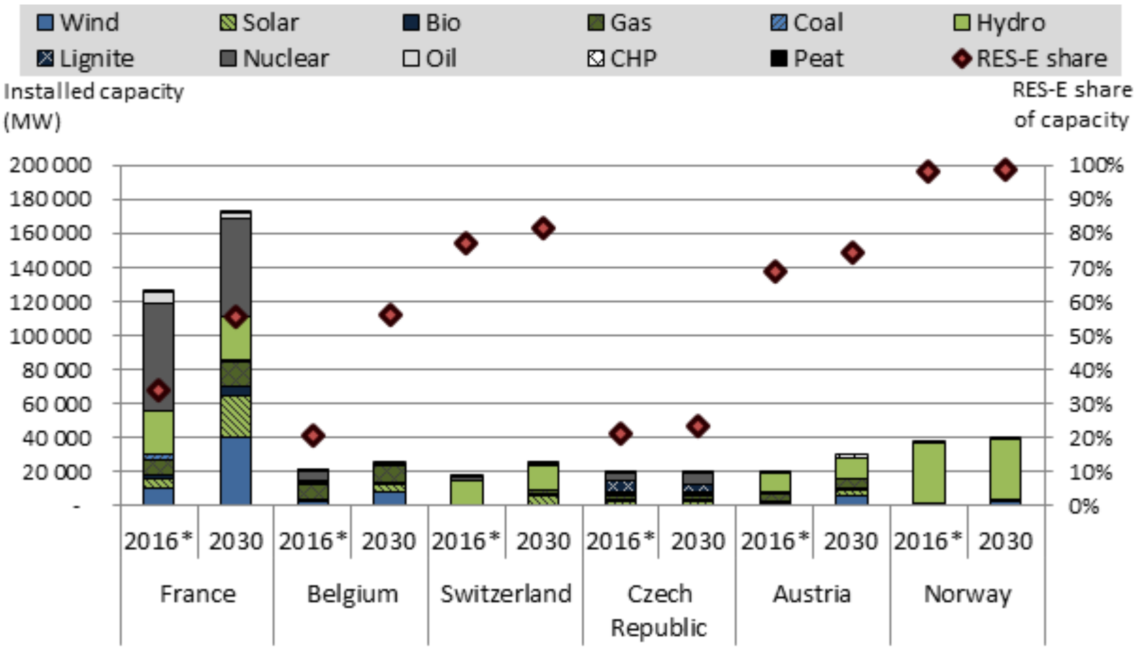

Figure A.3: Installed capacity in France, Belgium, Switzerland, the Czech Republic, Austria and Norway in 2016 and 2030

*Note: *The installed capacity for 2016 illustrates the data from the model's default.*

Source: Author's own

A2. Assumptions for the cross-border transmission capacity in Northwestern Europe in 2030

Table A.1: New Interconnectors between Countries in Northwestern Europe Towards 2030

Project	From	To	Capacity direction 1	Capacity direction 2	Year
Nemo	Belgium	UK	1000 MW	1000 MW	2018
Greenconnector	Switzerland	Italy	800 MW	800 MW	2018
ALEGRO	Belgium	Germany	1000 MW	1000 MW	2019
Italy-France	France	Italy	1200 MW	1000 MW	2019
LitPol Link Stage 2	Poland	Lithuania	1000 MW	500 MW	2020
Estonia-Latvia	Estonia	Latvia	500 MW	500 MW	2020
Austria-Germany	Austria	Germany	2900 MW	2900 MW	2020
Belgian North Border	Netherlands	Belgium	1500 MW	1500 MW	2020
IFA2	UK	France	1000 MW	1000 MW	2020
Lake Geneva West	France	Switzerland	500 MW	200 MW	2020
France-Belgium	Belgium	France	1300 MW	1300 MW	2021
GerPol Power Bridge Improvements	Poland	Germany	500 MW	1500 MW	2022
St. Peter-Pleinting	Austria	Germany	1500 MW	1500 MW	2022
Area of Lake Constance	Switzerland	Germany	1400 MW	3400 MW	2023
France-Alderney-Britain	UK	France	1400 MW	1400 MW	2022
Italy-Switzerland	Italy	Switzerland	950 MW	1000 MW	2022
Italy-Austria	Austria	Italy	1450 MW	1350 MW	2023
Lake Geneva South	France	Switzerland	1000 MW	1500 MW	2025
Dutch Ring	Netherlands	Germany	500	500	2025

Source: IEA (2016a).

Table A.2: New Interconnectors between the Nordic Region and the Continent Towards 2030

Project	From	To	Capacity direction 1	Capacity direction 2	Year
NordLink Cable	Norway Southwest	Germany	1400 MW	1400 MW	2020
West Denmark to Germany	Denmark West	Germany	860 MW	1000 MW	2019
Kriegers Flak	Denmark East	Germany	400 MW	600 MW	2019
Westcoast	Denmark West	Germany	500 MW	500 MW	2022
Hansa PowerBridge	Sweden South	Germany	700 MW	700 MW	2025
Cobra Cable	Denmark West	Netherlands	700 MW	700 MW	2019
Norway-Great Britain Cable	Norway Southwest	United Kingdom	1400 MW	1400 MW	2020
Vikinglink	Denmark	United Kingdom	1400 MW	1400 MW	2030

Source: IEA (2016a).

Appendix B

B.1 The LCOE curve under different discount rates

The effect of applying different discount rates to the LCOE of onshore wind in 2030 is illustrated in Figure B.1. A discount rate of 4 % is aligned with the risk-adjusted discount rate the Norwegian Ministry of Finance (2014) recommends for public projects with a life up to 40 years, and can also reflect investors with low requirements for the rate of return. A real discount rate of 8 % is similar to the real, pre-tax discount rate estimated by Gjørberg and Jonsen (2007), and may be more aligned with the rate of return required by traditional utilities.

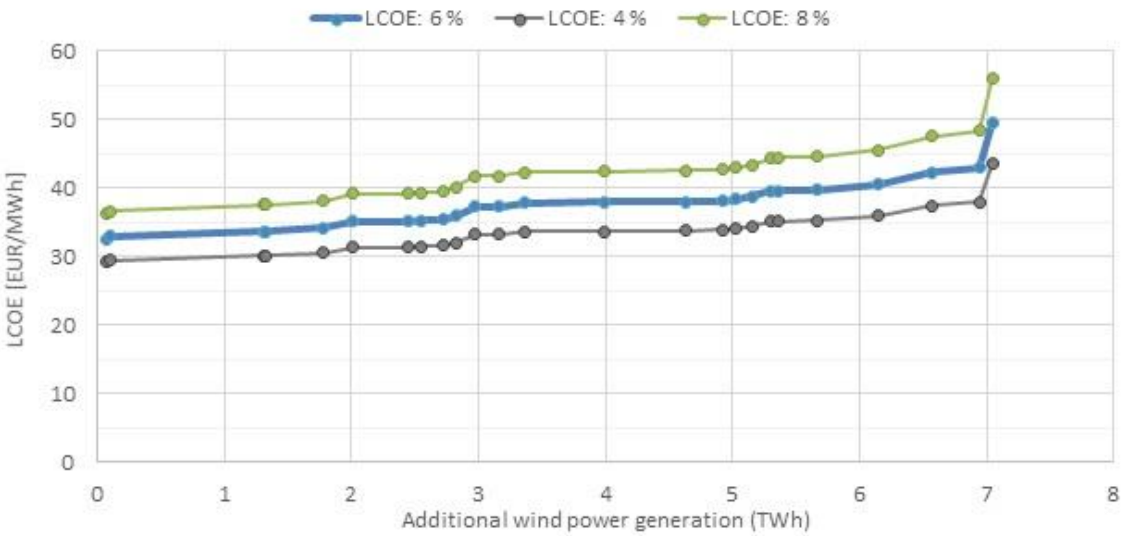

Figure B.1: LCOE curve for onshore wind in Norway in 2030 under different discount rates

Source: Author's own illustration

B.2. The LCOE curve under different investment cost levels

The expected 15 % decline in investment costs causes the LCOE of the projects to decline by 4.72 €/MWh (11.2%) on average from current levels, which is illustrated by the downward shift in the LCOE curve in Figure B.2. In the LCOE curve with cost levels from 2016, the LCOE ranges from 36.37€/MWh for the cheapest project to 56.21 €/MWh for the most expensive project. Since the investment costs constitute a large share of the LCOE for wind power, the LCOE decreases the most in absolute values for the projects with the highest LCOE. Hence, the LCOE curve for 2030 is flatter than the LCOE curve for 2016.

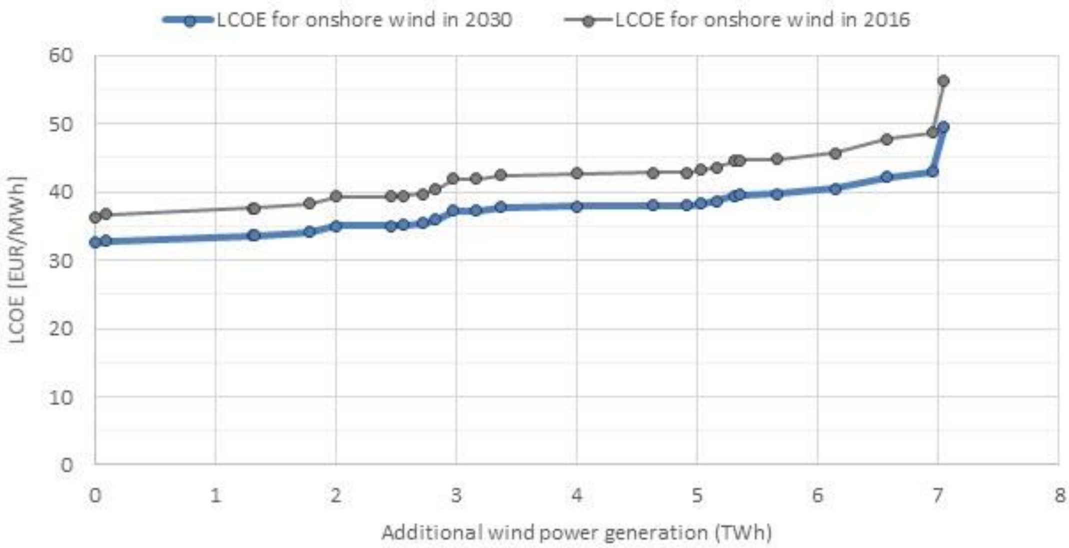

Figure B.2: LCOE curves for onshore wind in Norway in 2016 and in 2030

Note: The LCOE curve for 2030 assumes a 15 % decline in the investment costs.

Source: Author's own illustration

B3. The LCOE curve under different project lifetimes

Figure B.3 illustrates how the LCOE curve for Norwegian, onshore wind power projects in 2030 would shift downwards if the lifetime increases from 20 years to 25 years. In particular, the LCOE declines by 2.7 €/MWh on average, with the LCOE ranging from 30.31 €/MWh for the cheapest project to 45.45 €/MWh for the most expensive project.

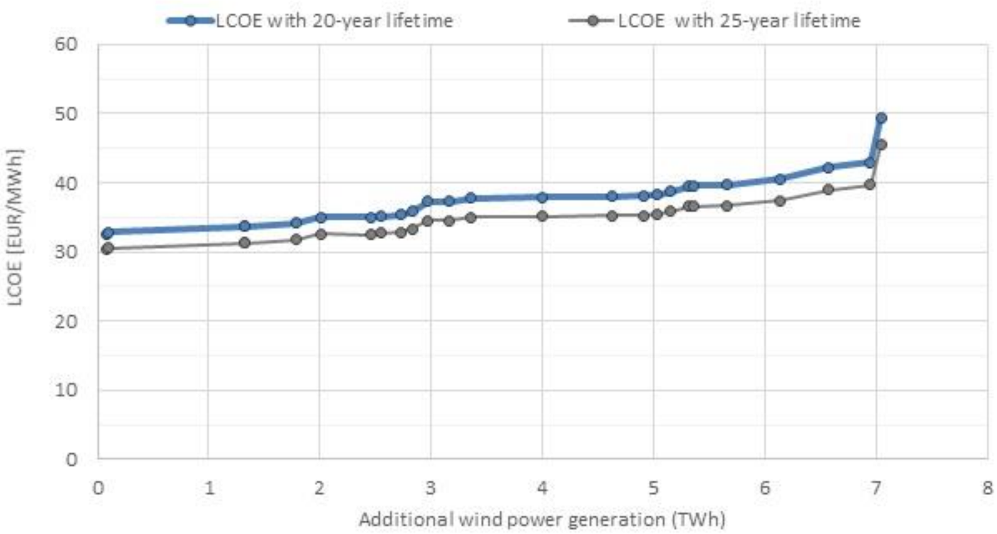

Figure B.3: The LCOE curve for onshore wind in Norway in 2030 under different lifetime assumptions

Source: Author's own illustration

Appendix C

C.1 The effect of fuel prices on Norwegian electricity prices

Figure C.1 illustrates the relationship between Norway's average electricity price, the EUA price and the short-term marginal costs of coal and gas under the four scenarios. Notably, the natural gas price is particularly important for the electricity price level in Norway. Norway's average electricity price follows the short-term marginal cost of gas in all scenarios, albeit at lower levels. The figure further illustrates that the EUA price is less correlated with the short-term marginal cost of gas than the short-term marginal cost of coal. Since gas power plants emit less CO_2 than coal power plants, the effect of changes in the EUA price is weaker.

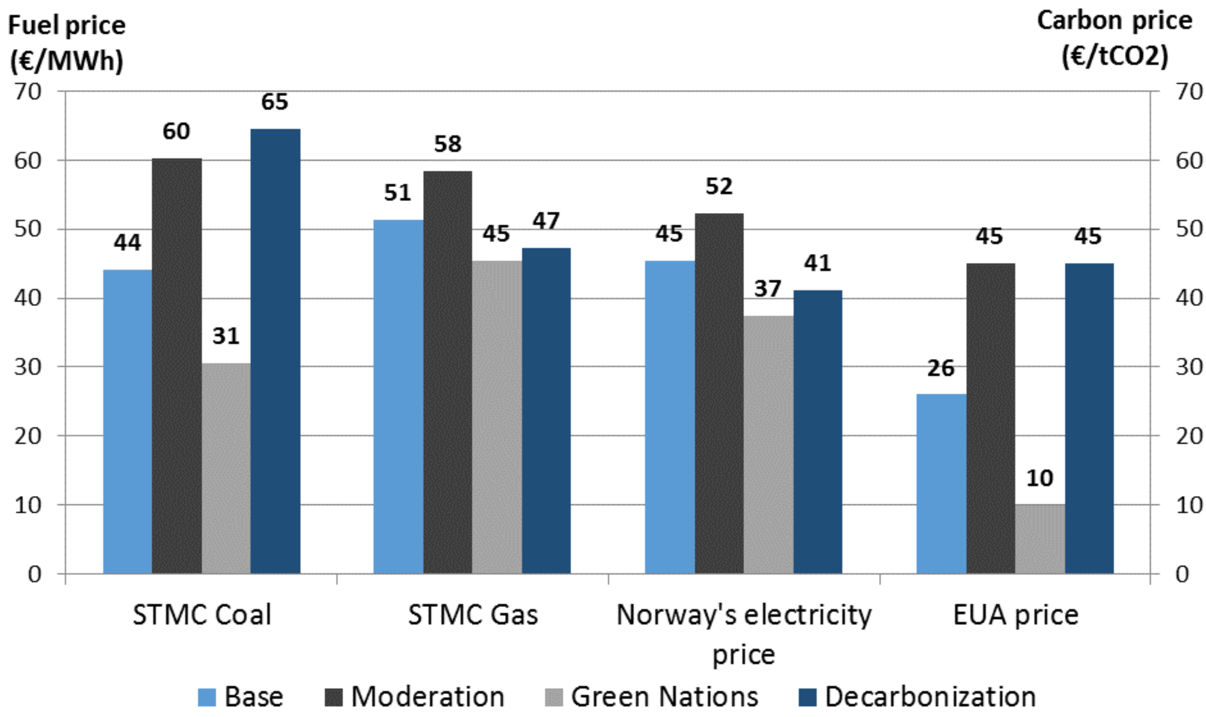

Figure C.1: Relationship between fuel prices and Norway's electricity prices in the four scenarios

Source: Author's own illustration

C.2 The power market in Northwestern Europe in the Moderation Scenario

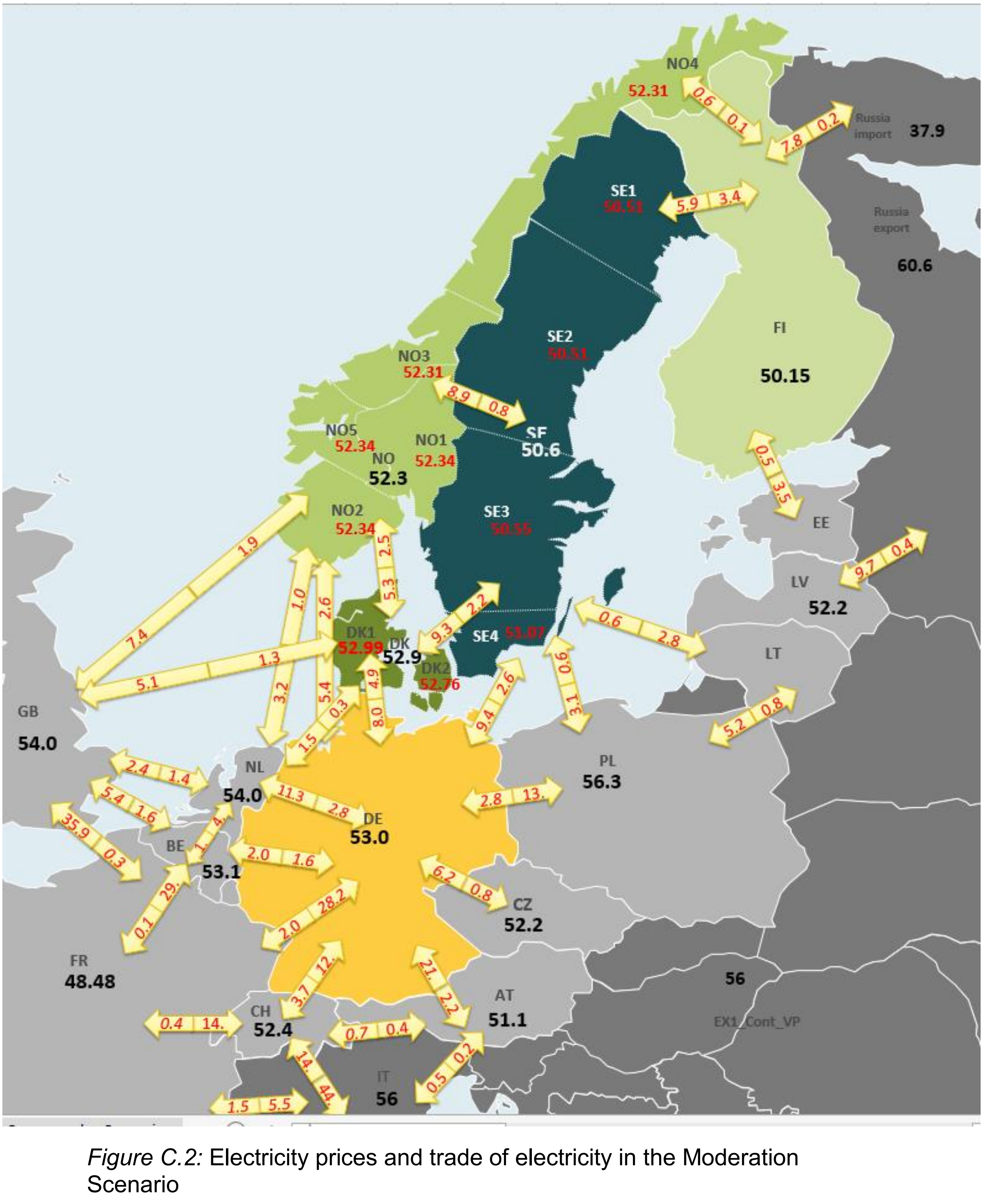

Figure C.2: Electricity prices and trade of electricity in the Moderation Scenario

Source: Output from the The-MA model

C.3 The power market in Northwestern Europe in the Green Nations Scenario

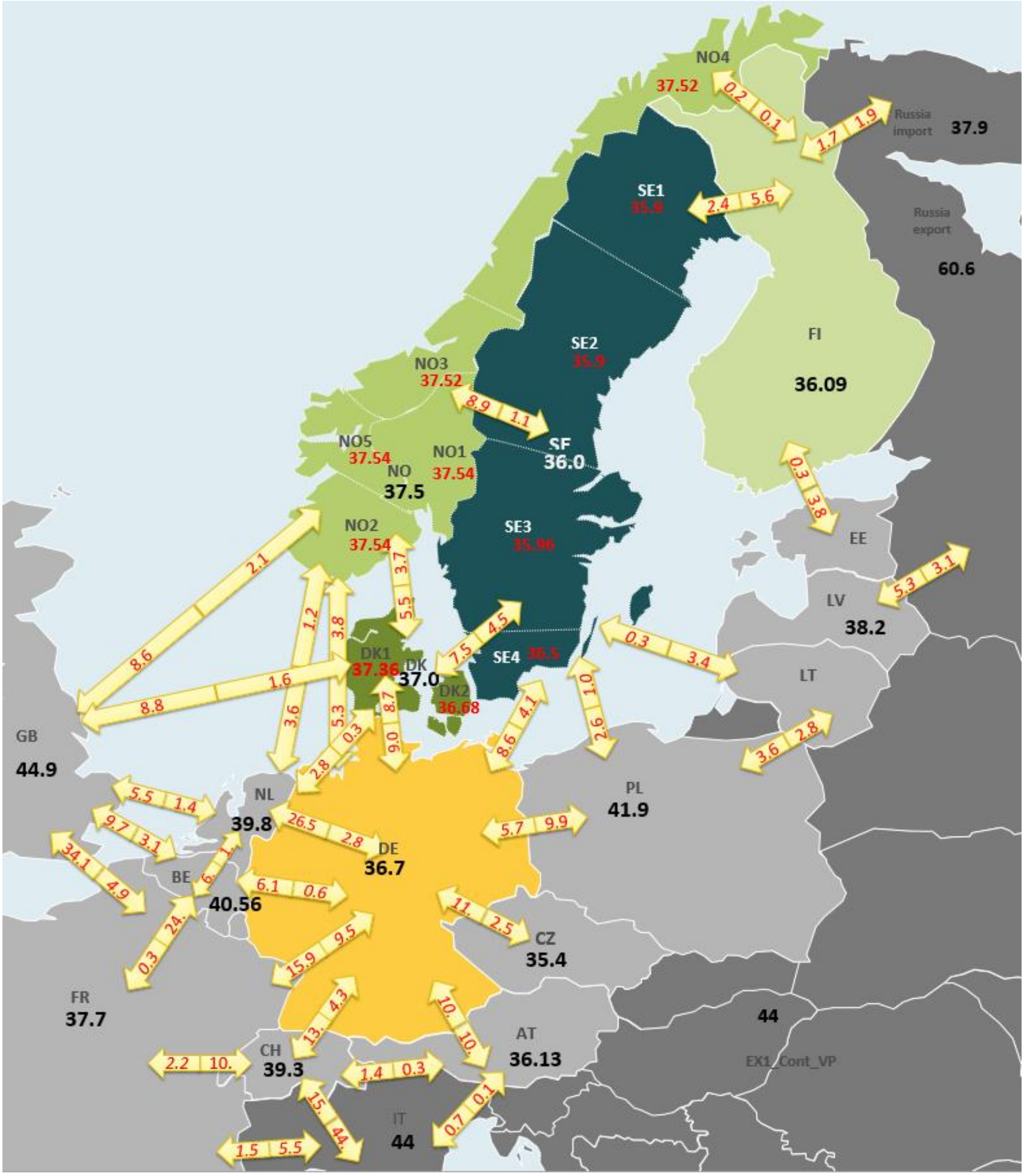

Figure C.3: Electricity prices and trade flows in the Green Nations Scenario

Source: Output from the TheMA model

C.4 The power market in Northwestern Europe in the Decarbonization Scenario

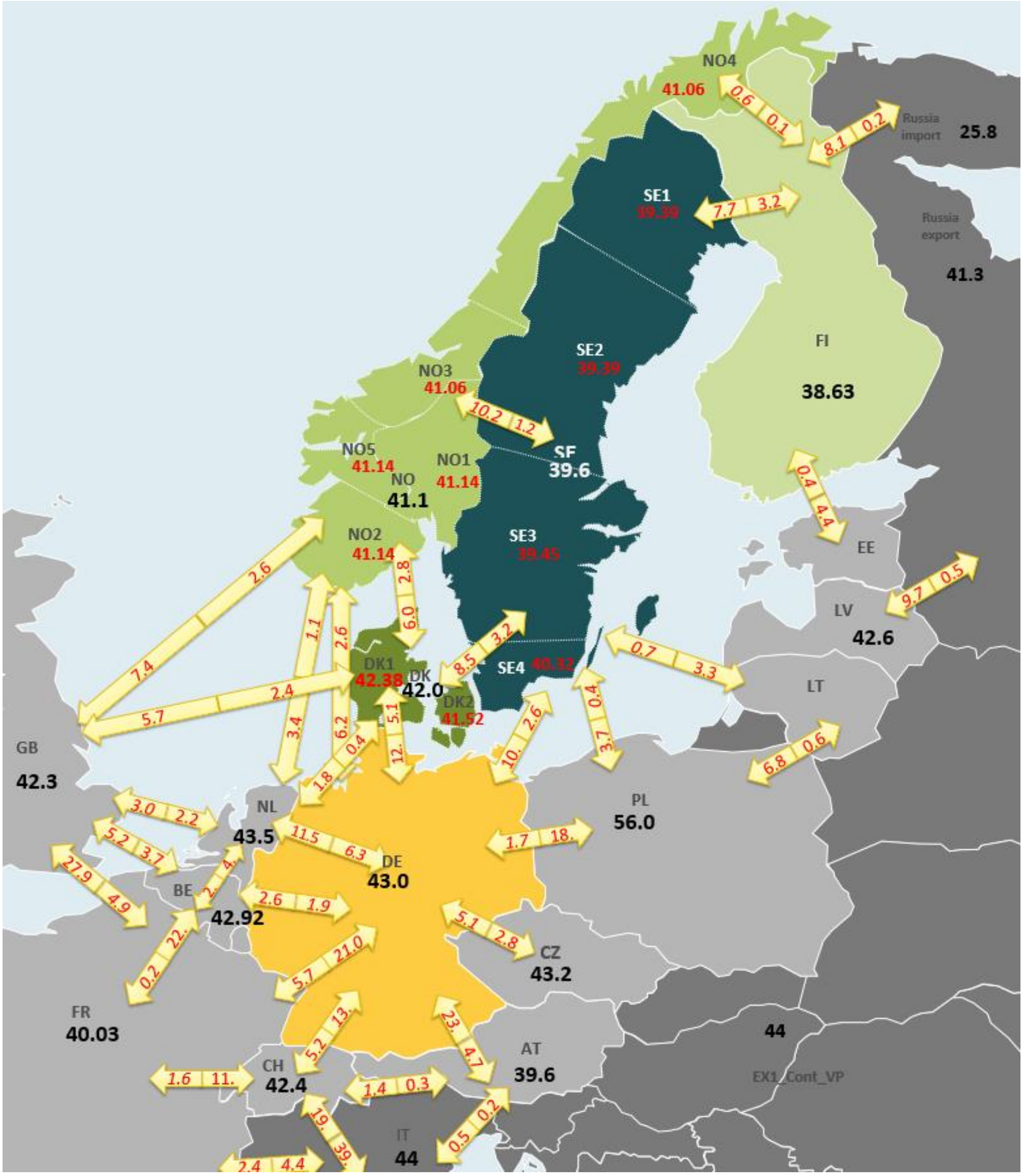

Figure C.4: Electricity prices and trade flows in the Decarbonization Scenario

Source: Output from The-MA

C.5 Hourly price fluctuations under the four scenarios

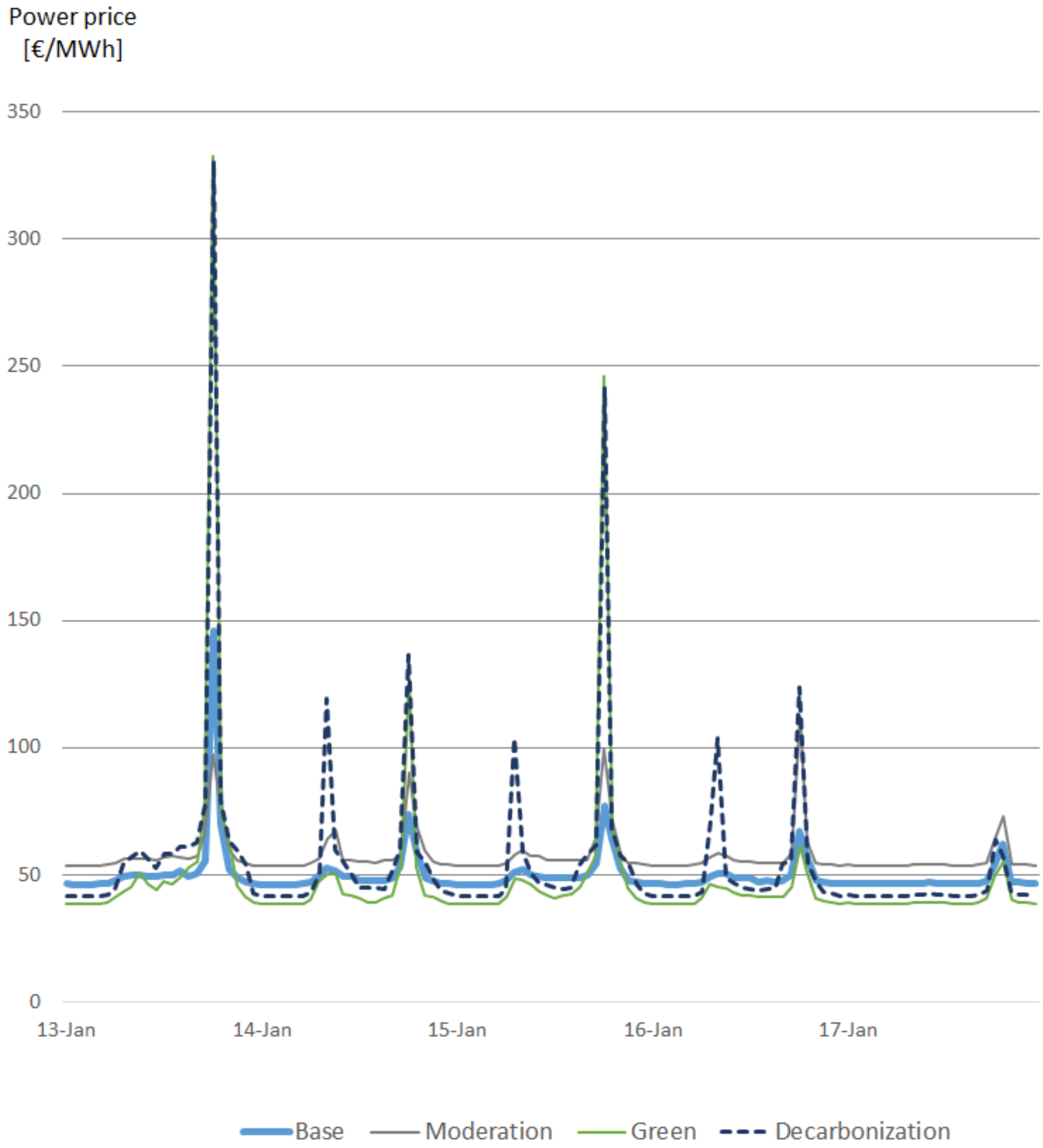

Figure C.5: Hourly price fluctuations in a week in January under the four scenarios

Source: Output from The-MA

Appendix D

D.1 Wind prices in Sweden under the four scenarios

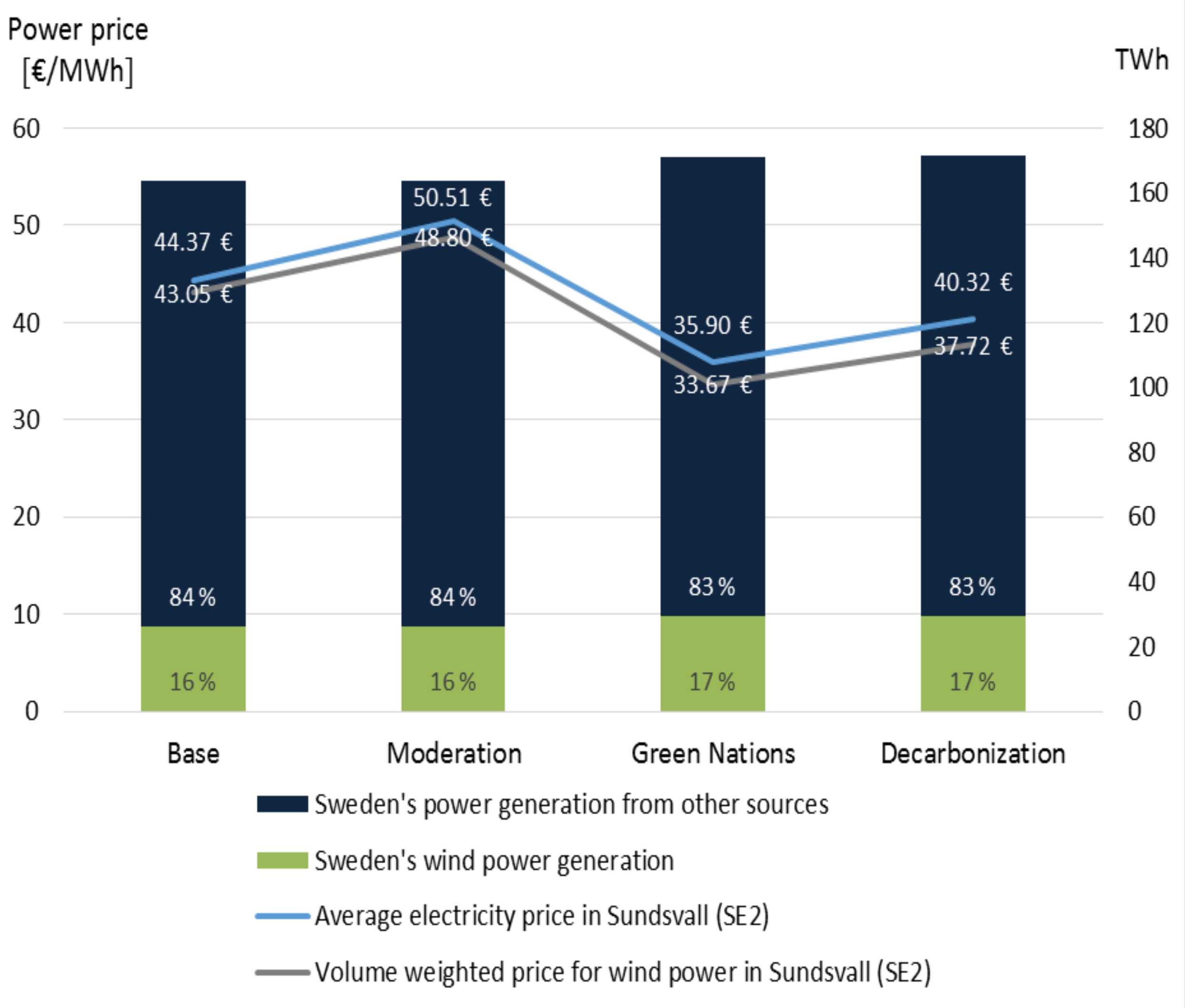

Figure D.1: Wind prices and electricity prices (left axis) and power generation by source (right axis) in mid-Sweden under the four scenarios

Source: Author's own illustration

D.2 Wind prices in Denmark under the four scenarios

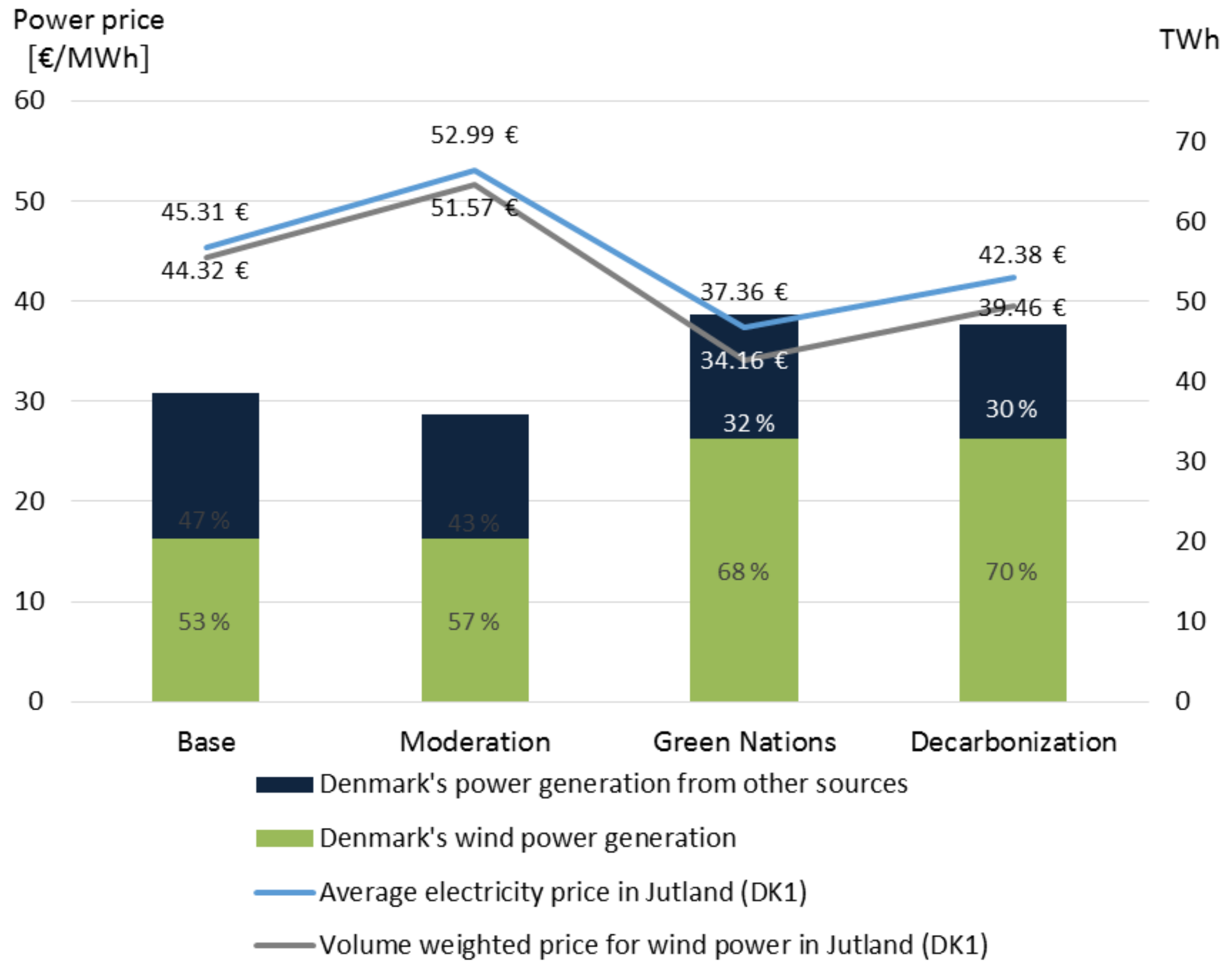

Figure D.2: Wind prices and electricity prices (left axis) and power generation by source (right axis) in West Denmark under the four scenarios

Source: Author's own illustration

D.3 Market value factors in the Base Scenario

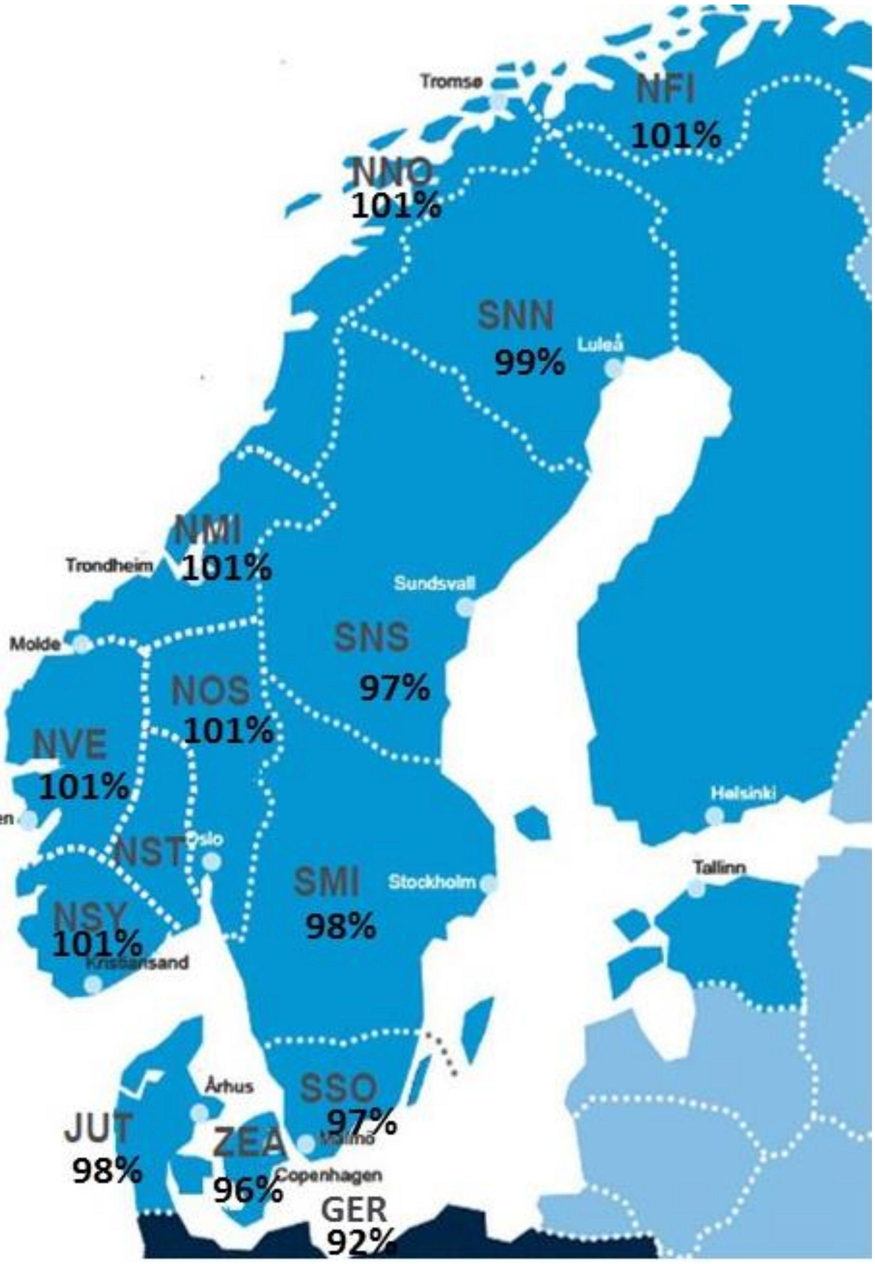

Figure D.3: Market value factors for onshore wind in Scandinavia and Germany in the Base Scenario

Source: Author's own illustration based on map by Thema (2014).