Master's thesis

NTNU
Norwegian University of Science and Technology
Faculty of Information Technology and Electrical Engineering
Department of Electric Power Engineering

Emilie Birgitte Marskar

Optimizing hydrogen pathways using Norwegian energy resources dominated by offshore wind

Master's thesis in Energy and Environmental Engineering
Supervisor: Magnus Korpås
Co-supervisor: Espen Flo Bødal
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Preface

The preface of this thesis was the specialization project report, which was conducted during the autumn semester of 2023. The aim of the report was to make a theoretical basis of the aspects affecting the research questions. Additionally, it also provided some practice with the supercomputer Idun, which was utilized to solve the optimization model used in this thesis.

Parts of the chapters "Theory" and "Methodology" is extracted directly, or extracted and edited, from the specialization project report. The reused text is marked with single quotation marks and a citation. Reused tables and figures are also marked with a citation.

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Abstract

The energy system is facing several challenges simultaneously. The climate crisis is requiring immediate action to reduce the greenhouse gas emissions. The energy system is also facing a global energy crisis, which has intensified the demand for power supply to the European power system.

The objective of this thesis is to investigate and optimize the role Norwegian energy resources will constitute in future electricity and hydrogen production in the international energy system. The capacity expansion model "HEIM" was utilized to solve the optimization problem, and NTNU's supercomputer Idun was used to run the simulations. The modelled "North Sea system" geographically includes South of Norway, Denmark, Netherlands and Germany. The system encompassing both offshore and onshore Norwegian power production and a demand for hydrogen and electricity in Norway and Germany. The hydrogen production alternatives are Polymer Electrolyte Membrane Electrolysis (PEMEL) and Steam Methane Reforming (SMR) with or without Carbon Capture and Storage (CCS). The research questions include investigating how the hydrogen production pathways correlates with varying carbon prices, increased offshore power production, natural gas prices, electricity and hydrogen prices, and the importance of hydrogen storage.

The results shows without a carbon price, there are no incentives to reduce the emissions, and hydrogen is produced through SMR. However, the results shows that the carbon price contributes to phase in low-emission solutions. SMR with CCS is favorable for lower carbon prices, due to its lower capital costs, and the operational cost is not excessively penalized by emission costs. As the carbon price increases, the higher emission costs progressively phases out SMR with CCS for the benefit of PEMEL. The amount of hydrogen production is decisive for the phase-in of PEMEL, as this balances the cost savings due to zero emission costs versus the higher capital costs.

Power production itself is not dictating for the production of PEMEL. However, PEMEL production highly correlates with the electricity price. The electricity price is a result of electricity production, import and export. The findings indicate that increasing electricity supply decreases the electricity prices, and lower electricity prices is beneficial for the economic competitiveness of PEMEL. The results also shows that the electricity price increases as PEMEL is phased-in. This is because the system experiences additional electricity demand when there already is a power deficit in the system. Sufficient electricity production to keep the electricity prices at a lower level is crucial for the economic competitiveness of PEMEL. Furtherly, the findings indicate that the natural gas price is decisive phasing out fossil based hydrogen production entirely. This is due to the higher operational costs increased natural gas prices induces. Finally, the results shows that hydrogen storage was not invested in by the optimization model. This is likely due to the significant costs of it.

Sammendrag

Kraftsystemet står overfor flere utfordringer. Klimarisen krever umiddelbar handling for å redusere klimagassutslippene. Samtidig pågår det også en global energikrise, som har økt behovet for krafttilførsel i det Europeiske kraftystemet.

Objektivet i denne masteroppgaven er å undersøke og optimere rollen som norske energiressser vil utgjøre for den fremtidige strøm- og hydrogenproduksjonen i det internasjonale energisystemet. Kapasitetsutvidelsesmodellen "HEIM" ble brukt til å løse optimeringsproblemet, og NTNUs supercomputer Idun ble brukt til å kjøre simuleringene. Landene som grafisk er inkludert i "Nordsjø-case"-et er Sør-Norge, Danmark, Nederland og Tyskland. Systemet omfatter både norsk havvind og kraft produsert på land i prisområdet NO2. Videre innehaver systemet en hydrogen- og elektrisitetsetterspørsel i både Norge og Tyskland. De ulike produksjonsmetodene for hydrogen i systemet er Polymer Electrolyte Membrane Electrolysis (PEMEL) og naturagassreformering (SMR) med og uten karbonfangst og -lagring (CCS). De vitenskapelige spørsmålene som analysen skal svare på, innebærer å undersøke hvordan hydrogen produksjon korrelerer med varierende karbonpriser, økt havvindproduksjon, naturgass priser, strøm- og hydrogen priser og muligheten for hydrogenlagring.

Resultatene viser at uten en kabonpris er det ingen insentiver til å redusere utslippene, og hydrogen produseres igjennom SMR. Videre viser resultatene at karbonpriser bidrar til å fase inn lavutslippsløsninger. SMR med CCS er den mest gunstige måten å produsere hydrogen på for lavere karbonpriser. Det er fordi den har en lavere kapitalkostnad enn PEMEL, og de operasjonelle kostnadene staffes ikke for mye av utslippskostnadene. Når karbonprisen derimot øker, så vil høyere utslippskostnader gradvis fase ut SMR med CCS til fordel for PEMEL. Mengden hydrogen som produseres er også avgjørende for innfasingen av PEMEL. Dette er fordi mengden hydrogenproduksjon balanserer den høye kapitalkostanden av PEMEL opp mot

kostandsbesparelsen av å slippe og betale utslippskostnader.

Kraftproduksjon i seg selv er ikke dikterende for produksjonen av PEMEL. PEMEL produksjonen korrelerer derimot i stor grad med strømprisen, og strømprisen er et resulat av strømtilførsel, kraftimport og krafteksport. Resultatene indikerer at høyere strømtilførsel gir lavere strømpriser, og lavere strømpriser gir mer konkurransedyktig PEMEL produksjon. Vider viser resultatene at strømprisen øker når PEMEL fases inn. Dette er fordi strømkonsumet i systemet øker, og systemet har allerede knapphet på strøm fra før. Tilstrekkelig strømtilførsel for å holde strømprisene nede er derfor avgjørende for konkurransedyktigheten til PEMEL. Videre indikerer resultatene at naturgassprisen er avgjørende for å fase ut de fossil-baserte hydrogenproduksjonsmetodene helt. Dette er på grunn av de høye operasjonelle kostnadene en høyere naturgasspris fører til. Til slutt viser resultatene at hydrogenlagring ikke ble investert i av optimeringsmodellen. Dette er sannsynligvis på grunn av de høye kostnadene i forbindelse med hydrogenlagring.

Acknowledgements

I would like to express my deepest gratitude to my supervisor and co-supervisor, Magnus Korpås and Espen Flo Bødal. Thank you so much for your guidance, motivation and advice.

I would also like to thank my parents Else-Marie and Ole, my grandparents Birgit and Oddleif and my boyfriend Johan. I would like to highlight my heartfelt gratitude to Else-Marie and Johan. You have both supported me and believed in me endlessly, and I love you both very much. Mom, thank you for your unconditional love and wise guidance. I have really appreciated the endless phone-calls that we have had over my past five years here in Trondheim. Thank you for being there for me and keeping me sane. Johan, my loving boyfriend, thank you for your love and encouragement. You are the sweetest person I know. I am looking forward to our future together!

Last but not least, I would like to thank my friends, Sebastian, Ingeborg, Kirsten-Emilie, Amanda, Catharina, Ingrid and so many more. You are the best, and my time here in Trondheim would not have been the same without you. I am going to miss all of you, and will keep in touch all the way from Stavanger.

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Abbreviation

CAPEX	Capital Expenditures
CCS	Carbon Capture and Storage
CEM	Capacity Expansion Modeling
EU	The European Union
EU ETS	European Union Emissions Trading System
HVDC	High Voltage Direct Current
IEA	International Energy Agency
LCOH	The Levelized Cost of Hydrogen
LP	Linear Programming
MSR	Market Stability Reserve
NTNU	Norwegian University of Science and Technology
OPEX	Operational Expenditures
PEMEL	Polymer Electrolyte Membrane Electrolysis
PSA	Pressure Swing Absorption
RME	Norwegian Energy Regulatory Authority
SMR	Steam Methane Reforming

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TSO	Transmission System Operator
UK	United Kingdom
UTC	Coordinated Universal Time
VRE	Variable Renewable Energy
WGS	Water Gas Shift

Chapter I

Introduction

1.1 Introduction

The energy system is facing several challenges simultaneously. The climate crisis is requiring immediate action to reduce the emissions. Power generation and the transport sector together accounts for $\frac{2}{3}$ of the worlds total emissions [36]. The energy sector is therefore a key participant in combating climate change. The Paris Agreement was established in 2015 as a global response to the threat of climate change. It is an international and legally binding contract, committing its 194 signed parties to reduce their emissions [37]. The common goal is to keep the increasing global warming well beneath 2 degrees, preferably 1,5 degree, above pre-industrial levels. The Paris Agreement signifies a change towards a net zero emission society, where proactive sustainable measures are implemented and the progress of emission reduction is monitored. Norway has set targets to reach net zero emission within 2050, and reduce its emissions by 55% within 2030 [38].

The energy system is facing a global energy crisis [39]. The throttling of Russian gas supply to Europe is the core of the energy crisis, causing ripple effects through global value chains. The threat to the European security of power supply was furtherly enhanced by low hydropower outputs and outages of nuclear power plants. This lead to significantly increasing electricity prices. The European Union (EU) is addressing the energy crisis through several measures [5]. Among actions taken are boosting green energy production and establishing a common platform enabling the purchase of hydrogen and natural gas at affordable prices.

Hydrogen has the potential to be a pillar in the energy transition through reducing emissions in industries that are difficult to decarbonize [3]. However, for hydrogen to be a part of the transition to a low-carbon future the process of hydrogen production must be decarbonized itself [21, p. 8]. The most prominent production methods is predicted to be electrolysis and methane reforming with carbon capture and storage [21, p.73]. Hydrogen also provides the option of energy storage, which is useful in energy systems with high shares of intermittent renewables [40].

Norway possesses substantial sea territories. They constitute a valuable portfolio of energy resources with among others wind resources and fossil energy sources. Norway is the worlds third largest exporter of gas, after Russia and Qatar [41]. Over the last 10 years, Norway has contributed to the European energy system as a net power exporter [14]. Norwegian government has announced ambitions of distributing permissions for 30 GW of offshore wind installations within 2040 [42]. Therefore, Norway is entering an exceptional position in increased power export and facilitating the production of both low-carbon hydrogen.

1.2 Objectives and limitations

The objective of this thesis is to investigate the role Norwegian energy resources constitute in current and future hydrogen production. The focus is to specifically investigate the conditions in which low and zero emission hydrogen production alternatives are phased in. The investigation will also focus on the impact of offshore wind constitutes in decarbonizing hydrogen production. In achieving this, the research project conducts a scenario analysis centered around the North Sea. The target is to cover a pre-specified hydrogen and electricity demand with minimal total costs for varying carbon and natural gas prices. The research questions are listed as follows.

- How are the investment in and operation of hydrogen production alternatives affected by varying carbon prices?
- What is the impact of power production from Norwegian offshore wind to the investment in and operation of hydrogen production alternatives?
- How does the natural gas price affect investment in the hydrogen production alternatives?
- How is the correlation between electricity and hydrogen price within the system and the hydrogen production alternatives?
- What is the importance of hydrogen storage?

The system includes onshore power production from NO2, and offshore power production from Sørlige Nordsjø II and Utsira Nord. Additionally, the system can import and export power to the power markets in DK1 (Denmark), NL (Netherlands), DE-LU (Germany/Luxembourg) and NO2 (Norway). There is placed a hydrogen demand and electricity demand in parts of Germany and Norway.

1.3 Motivation

The motivation for performing this study was to study hydrogen systems to obtain knowledge that will provide a better decision basis for authorities and stakeholders in the energy market.

1.3.1 Hydrogen pathways 2050

This master thesis is a part of the research project "Hydrogen Pathways 2050 - Transition of the Norwegian society and value creation from export", which is to be completed in 2025 [43]. The primary targets of the project is in large terms to study how hydrogen can contribute to decarbonizing sectors in Norway and Europe. The project aims to map the interplay between green hydrogen production and renewables, such as hydro power and intermittent power sources. Additionally, establish a basis of knowledge for the role hydrogen can play as an export commodity meeting European hydrogen demand, and how this could impact the European energy transition. The research questions asked in this thesis is a part of work package 2, where offshore wind and hydrogen export is included into the scope of the research questions.

1.4 Structure of the thesis

The thesis commences by establishes a theoretical foundation for understanding the subject in chapter 2, chapter 3 and chapter 4. chapter 2 is mainly focusing on the value of Norwegian renewables and fossil energy sources. Thereby, the chapter then provides a review of power trade, interactions of the power markets and emission permit trading. chapter 3 delves into relevant aspects of hydrogen, such as production methods, current and future demand, infrastructure and the potential role of hydrogen in the energy system. chapter 4 commences by providing an introduction to general optimization theory, and thereafter narrows into capacity expansion modelling. chapter 5 provides a review of the mathematical optimization model used in this thesis. chapter 6 elaborates on the framework and inputs for the scenario analysis performed in this thesis. The results obtained in the scenario analysis are presented in chapter 7. Subsequently, chapter 8 offers an thorough discussion of the findings and the correlation between them. The conclusion of scenario analysis is presented in chapter 9. Thereafter, further work is provided in chapter 10.

References and Appendix A is subsequently provided at the end of the thesis.

Chapter II

Production and trade of Norwegian energy resources

■ This chapter gives an introduction to the role Norway has as an energy nation today and in the future, and how the power market is operated. The chapter focuses especially on the ambitions set for future power generation from offshore wind, and the potentials this entails.

2.1 The electric power nation Norway

Norway is a significant power producing nation with an abundant access to a variety of energy resources, such as fossil fuels in the North Sea and hydropower, bio energy and wind power [44]. Norway set a new record for power production in 2021, generating 157.1 TWh [45]. Hydropower makes up a majority of the Norwegian energy production, constituting 89% of the production during a typical year. An additional 10% of the power production is from wind power. The high share of renewables causes the Norwegian electricity mix to have very low emission. The carbon footprint was 11 g CO2eq/kWh for physically delivered electricity in 2021 [46]. In comparison, the European carbon footprint was 300 g CO2eq/kWh. The European electricity mix is heavily reliant of fossil fuels. Combustible fuels accounted for approximately 42% of the total electricity production in EU in 2021 [47]. Renewables contributed to one third of electricity production, accounting for 32,8%. Norway is connected to 7 other European countries through 17 connections, where 7 of them are subsea cables [48]. The largest power exchange occur between Norway and Denmark, Sweden and Germany [49]. The net export to these countries was respectively 6.4, 2.8 and 3.3 TWh in 2021. Norway has mainly contributed as a net export country to Europe every year over the last decade, as shown in Figure 2.1 [14].

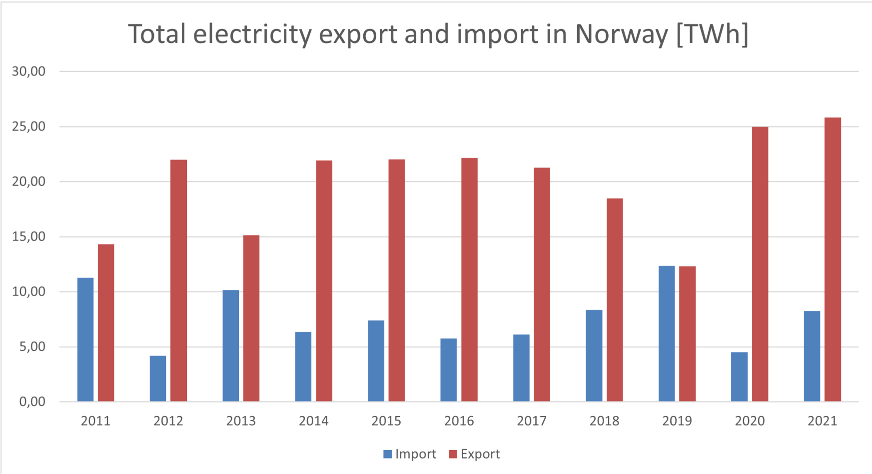

Figure 2.1: Norways total electricity export and import [GWh] during the last decade. Data is from [14].

2.1.1 Becoming an oil nation

The Norwegian energy portfolio changed drastically on the 23rd of December in 1969, when Philips Petroleum discovered the oil field Ekofisk [50]. Ekofisk is to this day one of the largest oil fields found at sea. The Norwegian oil industry expanded drastically after the finding of oil in 1969, and since then there has been produced oil and gas at more than 100 fields in the North Sea. As of the 31.12.2022, the total oil resource volume at the Norwegian continental shelf, including amount sold and delivered, equals approximately 15,8 billion SM^3 oil equivalents [51]. The overall total contribution to the gross domestic product (GDP) in net value was 15.700 billion NOK in 2020 [52]. No other industry is more important to Norway, in terms of state income, value creation and making prosperity.

The offshore infrastructure for extracting and transporting oil and gas has undergone significant development since the installation of the first gas pipes in the 1970s [29]. Today, it is a comprehensive system connecting offshore platforms to receiving terminals in both Norway and abroad. There is a total of 8800 km of natural gas pipes in the North sea, with a total transport capacity of 120 billion SM^3 dry gas each year. There are natural gas receiving terminals in Germany, Belgium, France and Great Britain. Figure A.1 in Appendix shows a map of the extensive pipeline system.

2.2 Ambitions and potential of Norwegian offshore wind

Ever since the discovery of oil beneath the Norwegian seabed, the North Sea has been a building cite for offshore infrastructure. Offshore wind installations is however a relatively new concept on the Norwegian continental shelf. There is currently only one wind park in operation, Hywind Tampen, along with several single offshore wind turbines used for research purposes [53]. This park is no less than the worlds first floating offshore wind park, and was fully operational in November 2022 [54][55]. Offshore wind turbines can be classified as either bottom-fixed or floating, depending on the depth of the sea [56]. Generally, if the depth exceeds 60-70 meters, floating turbines are preferred over bottom-fixed [56][53]. The interest and ambitions for offshore wind are great. In 2020, the Norwegian government opened up the areas Sørlige Nordsjø II and Utsira Nord for respectively 3 GW and 1,5 GW renewable energy production [57][58]. The wind park at Utsira Nord will be floating. In 2023, the Norwegian Water Resources and Energy Directorate (NVE) recommended expanding both the area and capacity of Sørlige Nordsjø II from 3 GW to 5,2 - 11,5 MW. One of the most significant events in the Norwegian offshore wind history was on May 11th, 2022, when the government announced ambitions to allocate areas for in total 30 GW of offshore wind within 2040 [59]. In comparison, the installed production capacity in Norway today is 38,74 GW, and set an all-time high production record in 2021 of 157,1 TWh [60]. The current investment in offshore wind will thus almost double the Norwegian power production capacity. Nevertheless, the total potential for offshore wind is significantly greater. An investigation performed by Multiconsult suggest there is a potential of 241-338 GW offshore wind, depending on whether the installed capacity per km^2 is 5 or 7 MW [61][62]. The offshore wind potential is approximately ten times greater than the ambitions set for 2040. The considerations used in the analysis to reduce the conflict of interest are suitability, fishing interest and environmental considerations. Power production from floating offshore wind comprises a majority of the offshore wind potential on the Norwegian continental shelf [62]. Of the total potential, the analysis estimates the share of floating offshore wind to be 65% (156-219 GW), and the potential for bottom-fixed is 35% (85-119 GW). NVE has identified 20 areas for potential installation of offshore wind, shown by Figure 2.2 [15]. These areas are the current candidates for the ambitions for 30 GW offshore wind.

Figure 2.2: An overview of the potential Norwegian offshore wind areas. Source: [15].

2.2.1 The precautionary principle

The precautionary principle was introduced at the United Nations Conference on Environment and Development (UNCED) in Rio in 1992 [63]. The aim of the principle is to mitigate damage to nature and the environment, and states that the lack of knowledge is not a basis for not making precautionary measures. The precautionary principle is incorporated the EU Environmental law, The EEA Agreement and in Norwegian legislation. Offshore wind energy has the potential to affect the natural environments negatively in several ways [64, p. 7]. Nevertheless, it is possible to install and operate offshore wind without significant damage to nature through a comprehensive planning process with sufficient mitigating measures. It is crucial to protect and preserve the environment while simultaneously transitioning towards a greener society.

2.2.2 Cost of offshore wind

Floating offshore wind is a costly project. As shown in Figure 2.3, no other energy source has currently a higher levelized cost of energy (LCOE). As a result, subsidies are necessary to make the wind farms economically feasible [53]. However, the cost curve of offshore wind is predicted to have reached an inflection point [65]. Due to a higher technological progress of offshore wind, the cost curve has been gradually reduced over the past 8 years [66][67]. This trend is predicted to continue in the coming decades [67]. An LCOE prognosis for specifically North European floating and bottom-fixed offshore wind suggests a cost reduction of approximately 45% and 35%, from a 2022 to a 2035 level [34]. This prognosis is illustrated by Figure A.3. The key drivers for cost reduction is upscaling the turbine size to 10+ MW and increase the park size [68][34].

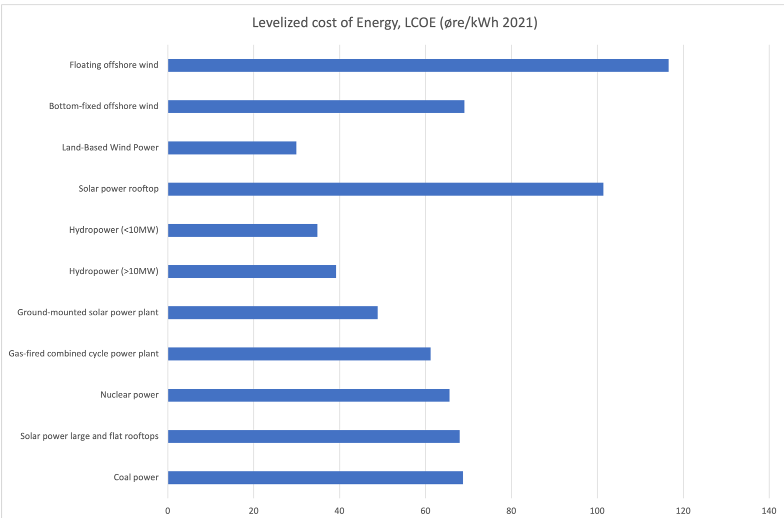

Figure 2.3: Levelized Cost of Energy (LCOE) values in [øre/kWh] from 2021. Values are collected from [16]. From [1, p. 12]

2.3 The interconnection of the European Power Market

'The power market is a dynamic market, where power can be bought and sold across borders. The power market for the Nordic countries merged into a common power market in 1990, which expanded to including the Baltic states two decades later [69].'[1, p. 17].

’The main reason for merging is increased the efficiency of the market, as a bigger power market also includes more suppliers and consumers. This minimizes curtailment as there are more opportunities to consume surplus power. It is crucial to keep a balance between power produced and power consumed [19]. There are several benefits to an interconnected and market-based power market. It provides a security of supply. A diversity of power sources ensures a higher utility value of the power units and power grid. It ensures a competition, resulting in a cost effective market price, and it strengthens the security of power supply. The Nordic countries market is a good example, as each country mainly relies on different power sources [70]. Norway produces roughly 130 TWh per year, depending on the inflow to the hydro power magazines, as 96% of the power production is from hydropower. Sweden, Finland and Denmark contribute with high shares of thermal power and wind power. This induces some differences in power flow across the boarders over the year. Norway exports during periods with beneficial hydrological conditions, for example during the autumn with considerable precipitation or during snow-melting in the spring. The large supply of hydropower pushes power prices down, resulting in a profitable trade for the consumers. This goes the other way around, for example when it is windy in Denmark. This dynamic is beneficial for all participants, and illustrates a market based and resource efficient power market. The Norwegian Energy Act, passed in 1990, ensures that sale and purchase of electricity production in Norway is market-based [71]. The law is maintained and managed by the Norwegian Energy Regulatory Authority (RME) [72]. RME is working every day to achieve this, in cooperation with the other regulation authorities in the Nordic region and in Europe. The common platform for cooperation with all energy regulators in Europe is called The Agency for the Cooperation of Energy Regulators (ACER). RME became a participant in ACER in 2019. The common goal is to regulate the market in order to achieve a competition-based effective power market in Europe’[1, pp. 17-18].

’Even though the power market is physically interconnected, it is divided into price areas. This is due to limited transmission capacity and power loss in the power grid between the areas [73]. This makes it physically impossible to transfer as the amount of power necessary to even out the power prices between the zones. As some areas will end up with a surplus of power, and others a deficit, the prices will differ. Norway is divided into 5 price areas, as shown in Figure 2.4’ [1, pp. 18-19].

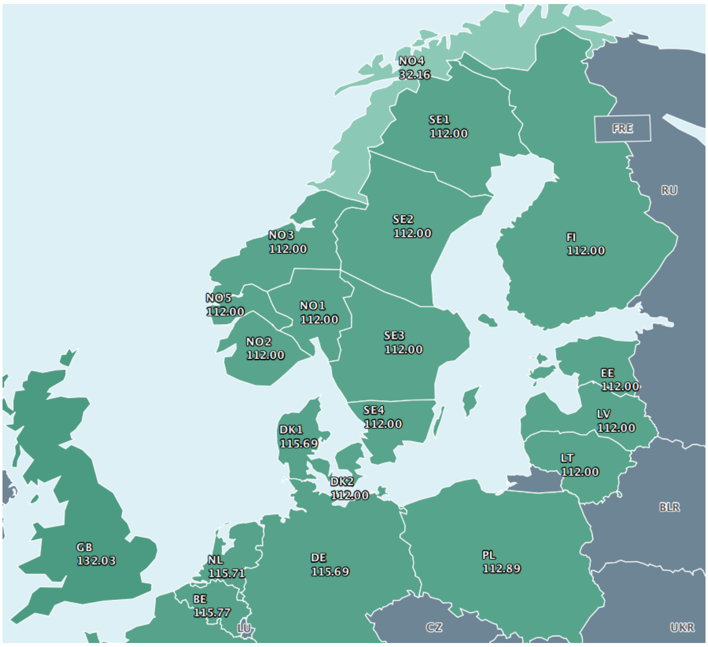

Figure 2.4: Power prices [EUR/MWh] in the European power market between 10-11am, 02.05.2023. From [17].

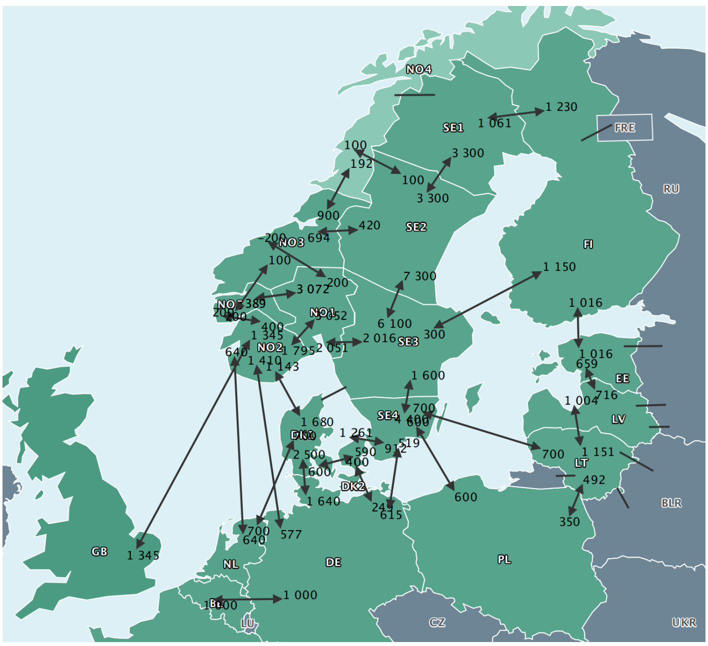

Figure 2.5: Capacities [MW] between 10-11am, 02.05.2023. From [17].

2.4 Limitations of the power grid today

The grid capacity of the domestic power grid is limited, making the connection of the offshore wind parks to mainland challenging. The government has decided that the preliminary phase Sørlige Nordsjø II of 1500 MW will be radially connected to the mainland [18]. A radial connection is a single HVDC (High Voltage Direct Current) cable connecting the wind park to the onshore grid [74]. The cables are the most expensive part of an electrical power installation connecting offshore wind to the mainland, and the cost increases with the length of the cable [74][18]. The length of the HVDC connection to shore should therefore be minimal, to keep the cost down. It is therefore rational to assume that Sørlige Nordsjø II will be connected to the Southern part of Norway. The power grid in the Southern region of Norway is shown in Figure 2.6. The central parts of the grid with the largest capacities, transferring power flow between regions in Norway, are referred to as corridors. The eastern corridor is connecting NO2 to NO1, and the western corridor connects NO2 to NO5. The middle corridor, is in the middle of the eastern and western, connecting NO2 to the middle of Norway. These corridors connect the power grid across regions as being "highways" for the power flow, enabling the consumption of power in other regions than it originates from. The export from Norway to EU through the subsea HVDC-cables are generally driven through the interconnection of power consumption, hydro power production and the weather conditions. During periods with high precipitation, the export is driven by regulated hydro power from the western part of Norway through the western corridor. The export can also be driven from power flow through the eastern corridor, mostly during the summer when consumption is low. This is furtherly reinforced in periods of high unregulated hydro power production [18, p. 5].

The power grid has a limited power flow capacity, and the part of the grid where the congestion has occurred is called a bottleneck. The conclusion drawn by Statnett, is to generally reinvest in the grid capacity between the Southern and Eastern region of Norway [18]. The potential power flow from other wind parks are also taken into account to this conclusion. As Figure 2.2 shows, a majority of the potential wind park areas are clustered in the Southern and Southwest part of the North Sea. With the same cost assessment of grid connection, these are likely to be connected to the southern grid as well. A hybrid connection, which is several HVDC cables to different consumers, would enable a better use of the energy resource [74]. A cable connecting the wind park directly to a consumer enables a better use of the grid, in addition to power trading and a more rational use of the energy resources. In total, the expected future power flow due to offshore wind induces a need for a larger capacity on the domestic and possibly at the offshore grid too. It will be a challenge to manage offshore wind power and exploit the true potential of it, without the necessary capacity on the power grid.

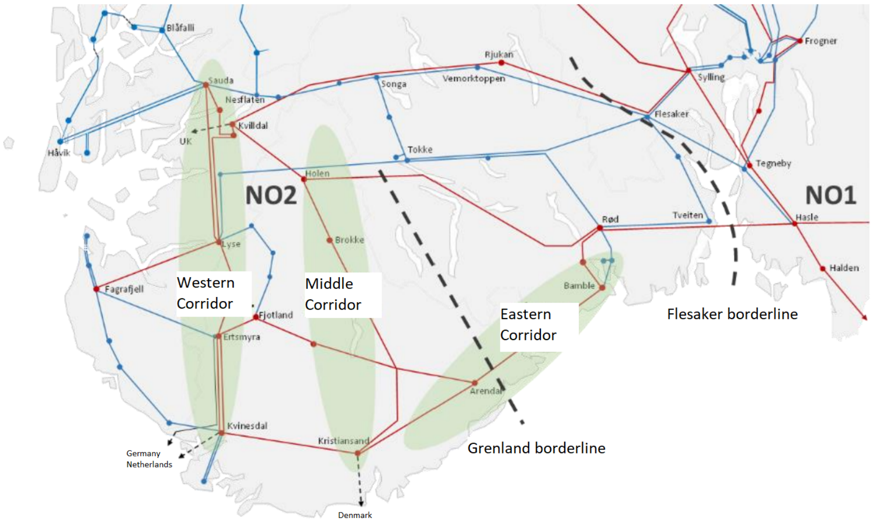

Figure 2.6: The corridors connecting power system in the South of Norway. If printed in colors; Red lines are 420 kV power lines, and blue lines are the older 300 kV power lines. Collected from [18, p. 9], edited to English translation.

2.5 Organization and trade

'The power market is the link between producers and consumers, which is shown in Figure 2.7. The power market is divided into two markets; the wholesale market and the end-user market [19]'[1, p. 19].

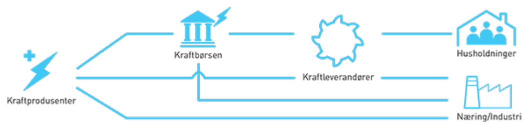

Figure 2.7: Schematic illustration of the power market. Collected from [19]. From [1, p. 19]

2.5.1 The wholesale market

'In the wholesale market, large quantities of power is traded. The negotiating parties are large power producers, power suppliers, industrial and energy-intensive customers and power brokers. The wholesale market is divided into three markets, shown in Table 2.1'[1, p. 19].

Table 2.1: Markets for power trade before delivery. Table is Source: [1, p. 19]

Type of market:	**Occurs before power delivery:**
The day-ahead market	24 hours before
The intraday market	Same day, until 1 hour before
The balancing market	Within the last hour before

'All the markets occur in chronological order before the power is to be sold. The first two markets are the day-ahead market and the intraday market exchange. These two markets happen at the Nordic power exchange, known as the Nord Pool exchange. The largest quantities of power are traded on the day-ahead market, which is the primary market for power trading. During the day-ahead market Nord Pool holds a closed auction. During the auction, producers and customers place bids and offers which contain the amount of power (MW per hour) they are willing to sell or buy for and to which price level (EUR/MWh) for each specific hour the next day [75]. A well-functioning market produces electricity to the lowest price in each hour. The offers from the producers are matched with the bids from the customers, and the equilibrium determined the theoretical market price. The market price is therefore representing both the cost of one kWh of the most expensive power source necessary to satisfy the demand, and the price the consumers are willing to pay, for the final kWh produced to cover the demand. Today, the day-ahead market at Nord Pool includes more than 21 bidding zones and over 2000 orders are placed every day [76]. Nord Pools main goal is to match the offers and the bids in order to maximize social welfare. The trading at the intraday market occurs at the same day as delivery, until one hour before [77]. The objective is to correct the amount of power supplied, in case there are unforeseen incidents that affects the energy balance [19]. The last market, the balancing market, happens at the Transmission System Operator (TSO), being Statnett in Norway [78]. The purpose is to maintain the instantaneous energy balance. The energy balance is under constant surveillance by the TSO. The energy balance occurs at 50 (49,90-50,10) Hz. If the frequency deviates from this, the TSO balances the power supply from the producers.'[1, pp. 19-20]

2.5.2 The end-user market

'About $\frac{1}{3}$ of all households, industrial customers and commercial customers purchase power at the end-user market [71]. Smaller end-users normally purchase power through a power supplier, whilst larger consumers commit an agreement directly with a power supplier or purchases directly at the wholesale market as a participant.'[1, p. 20]

2.6 Decarbonizing the power market through emission permit trading

'As a tool to cut greenhouse gas emissions in Europe, EU implemented the worlds first international system for trading emission allowances in 2005 [20]. The system is called the European Union Emissions Trading System (EU ETS), and remains the worlds largest carbon market [5]. The European countries participating in EU ETS receive a limited portion of allowances, known as carbon permits, every year based on their former emissions and are responsible for distributing allowances to facilities within their borders. The individual carbon permits are either distributed for free or auctioned [20]. The trading system includes around 11000 facilities within the energy sector, heating sector and energy-intensive industries across Europe [79]. Each allowance represents the permission to emit 1 ton of CO_2-equivalents. When a facility has emitted one ton of CO_2-eq, one allowance has to be handed back [20]. The goal is to establish a monetary worth of CO_2-eq emissions by making a trade out of the carbon permits. They incur a cost upon facilities contributing to CO_2-eq emissions, and a profit to the facilities reducing their CO_2-eq emissions. The total number of allowances is a cap on the total amount of emissions. The total emissions are reduced when the amounts of permits are reduced. The trading occurs when a facility has spare allowances due to a reduction in emission, and can thereby sell their allowances on the carbon market. For the first 15 years of the carbon markets existence, the carbon permits was close to constant and lower than intended, as shown in Figure 2.8. There were too many allowances on the market, causing the prices to stay low and weakened the incentive to reduce emissions [79]. To handle the surplus of allowances, EU started to hold back on the distribution of allowances for three years from 2014 and announced a reform called Market Stability Reserve (MSR). This reform ensures that 24% of the allowance surplus from one year is to be removed the next year. Even though the reform was applicable from 2019, the trend in Figure 2.8 illustrates the effect the announcement of MSR had on the carbon market already before this.'[1, pp. 20-21]

Figure 2.8: Development of the carbon permit price in [EUR/ton CO_2]. From [20].

Chapter III

Hydrogen production, demand and distribution

■ This chapter provides a review to the production methods for producing hydrogen, and the current and forecasted demand and areas-of-use. Additionally, the chapter will give an introduction to the necessary infrastructure for hydrogen transmission and storage, and the current and expected prices of hydrogen.

3.1 Hydrogen production methods

'Hydrogen is the most abundant element in the universe, making up $\frac{3}{4}$ of the worlds matter [80]. It is so reactive that it does not exists in its pure form, H_2, to which it needs to be produced. There are various methods for producing hydrogen, which are divided into two general groups based on whether their origins are from fossil fuels or from renewables, as illustrated in Figure A.4. On a global scale, about 90 Mt of hydrogen was produced in 2022, and almost all of it was based on fossil energy sources, as shown in Figure 3.1 [21, p. 73]. According to the prognosis, this trend is about to change. Figure 3.1 estimates that the world's hydrogen demand will increase, and it is predicted that 70% of all hydrogen produced in 2050 will be green [21, p.3]. It is also predicted that carbon capture and storage will be phased-in to a larger extent, as shown in Figure 3.1 [21, p.73].' [1, p. 5].

In the continuation of this thesis, three types of hydrogen will furtherly be focused on; grey, blue and green. Grey and blue hydrogen are produced from steam methane reforming (SMR), with and without carbon capture and storage (CCS). Green hydrogen is solely produced from renewables, through a Polymer Electrolyte Membrane Electrolysis (PEMEL) [81].

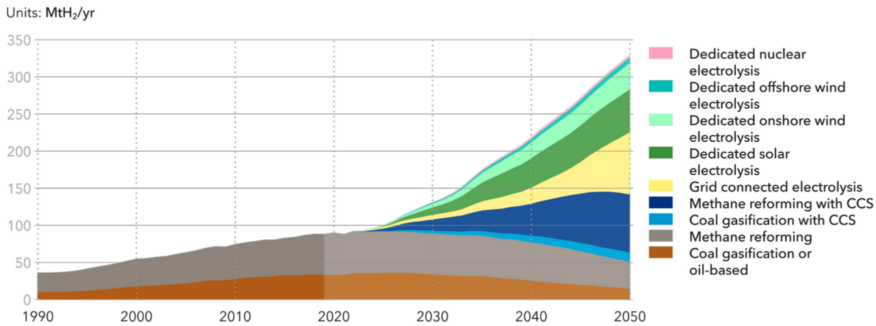

Figure 3.1: 'Historical and forecasted global production pathways for hydrogen production. Collected from [21, p.73].' Collected from [1, p. 10]

3.1.1 SMR with and without CCS

Methane reforming, which is an umbrella term comprising among others SMR, was the most common way of producing hydrogen in 2022, as shown in Figure 3.1 [82]. It is currently the most cost-efficient alternative for hydrogen-production [21, p. 74]. It also has has among the highest efficiencies for hydrogen production, ranging from approximately 74%-85% [23].

'SMR is the process where methane from natural gas reacts with steam in a heated furnace and turns into hydrogen and CO_2 [83]. The chemical process is described by Equation 3.1' [1, p. 6].

$$\begin{aligned} CH_4 + H_2O(+heat) = CO + 3H_2 \\ CO + H_2O = CO_2 + H_2(+heat) \end{aligned} \tag{3.1}$$

As shown in Figure 3.2, a modern hydrogen production process with SMR is roughly explained divided into three parts; the SMR reactor, the water gas shift (WGS) and pressure swing absorption (PSA). Firstly natural gas is fed into an SMR reactor. In this step, methane reacts with steam under pressure, making hydrogen and carbon monoxide [43]. This is the first part of Equation 3.1. In the second step, carbon monoxide and steam reacts to produce hydrogen in the WGS unit. This is the second part of Equation 3.1. Subsequently, the gas stream is fed into the PSA, which removes impurities such as CO_2, leaving pure hydrogen as the product.

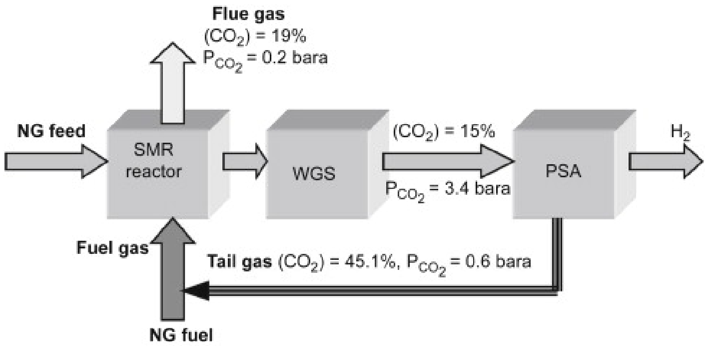

Figure 3.2: Simplified process flow chart of SMR. Collected from [22]

CCS is the process where CO_2 from a process or power plant is captured and stored, instead of emitting it to the atmosphere [84]. CCS is a climate change mitigation technology, and functions as a bridge toward a greener industry with a continued utilization of fossil fuels [84]. The overall process of CCS is comprised of the capture of CO_2 either at the production cite (point-source capture) or from the atmosphere, transport to the storage location and injection to the storage facility [85]. Figure 3.3 illustrates both where CO_2 in principle can be removed and the theoretical removal efficiency in a point-source capture process [22]. To put the removal efficiency in context, approximately 40% of the CO_2 is emitted subsequent to the process in the SMR reactor, and about 60% of the CO_2 is released after the process of WGS.

'The emission factor of 1 kg of pure hydrogen is debated, but it is estimated that the overall emissions is 9,1 kg CO_2 per kg hydrogen produced [22]. The current commercial CCS technology is able to reduce the emissions from SMR with more than 90%. The integration of CCS can therefore drastically reduce the CO_2 emissions from hydrogen production. However, SMR with CCS is more costly than without CCS [21, p. 74]. Methane reforming with CCS is not a common practice. Only 1%, translating to 0.9 Mt in 2022, of the hydrogen is produced through SMR with CCS.'[1, pp. 6-7]

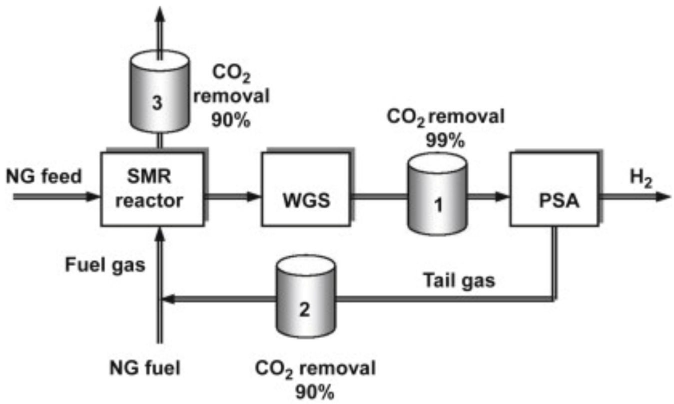

Figure 3.3: Simplified process flow chart of SMR with CCS. Collected from [22]

3.1.2 PEMEL

'In the process of PEMEL, electricity is used to split water molecules into pure oxygen and pure hydrogen. The primary components of a PEMEL is a cathode, an anode and a membrane [23]. The PEMEL operates within a water environment. As shown in Figure 3.4, the anode splits water molecules into oxygen and hydrogen. The single hydrogen atoms, being positively charged, travels through the membrane to the cathode where the pure hydrogen molecules are made. The chemical reaction is presented in Equation 3.2 and Equation 3.3. The efficiency of electrolysis is approximately 60%-80%. PEMEL is considered the most promising technique for achieving a sustainable, efficient and low-emission hydrogen production. However, only 4% of the global hydrogen production is based on PEMEL, to which there are economical reasons. As shown in figure Figure 3.5, PEMEL is more expensive than almost all of the fossil based production methods. However, PEMEL has the potential to decarbonize the hydrogen-production process, which is of interest in light of the climate crisis. Comprehensive research resources has been set in motion to furtherly develop the cost-efficiency of PEMEL.'[1, pp. 7-8]

$$H_2O \rightarrow \frac{1}{2}O_2 + 2H^+ + 2e^- \tag{3.2}$$

$$2H^+ + 2e^- \rightarrow H_2 \tag{3.3}$$

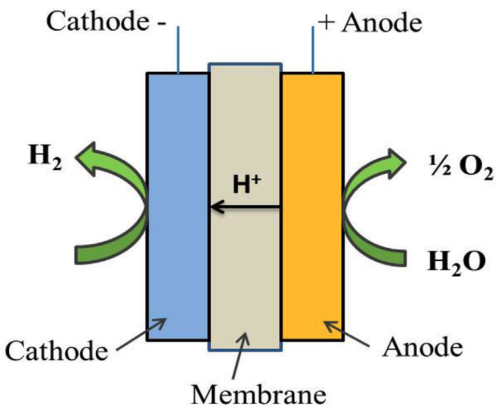

Figure 3.4: 'Illustration of PEM Electrolysis. From [23].' Collected from [1, p. 8]

3.2 Levelized Cost of hydrogen (LCOH)

'LCOH is a measure of the total price per unit of hydrogen when both capital costs and operating costs are taken into consideration [86]. There are therefore large variations in LCOH, depending on the hydrogen-production method. As figure 3.5 illustrates, it is on a general basis cheaper to produce hydrogen from fossil fuels today. This applies to both coal gasification and methane reforming with and without CCS. Figure 3.5 shows the current and forecasted hydrogen-price towards 2050. The trend predicts a change, where low-emission hydrogen becomes more affordable and the cost of fossil based hydrogen increases. The forecast in Figure 3.5 and Figure 3.1 predicts an important trend for the role of hydrogen as an energy carrier, because the basis of phasing in hydrogen is its decarbonizing contribution industries that are difficult to electrify [3].'[1, p. 9]

3.3 International and domestic hydrogen demand

'The total hydrogen consumption per year in Europe was 8 million tons [87, p. 3]. Norway produces approximately 225.000 tons of hydrogen annually, whereas a majority is consumed within the industry sector. The main area-of-use for hydrogen is as feedstock for processes such as methanol production, ammonia production, oil refining and green steel production. Most of the hydrogen-production in Norway today is from natural gas reforming, conducted by Yara and Equinor. The hydrogen is utilized in ammonia production at Herøya and methanol production at Tjeldbergodden [87, p. 5].'[1]

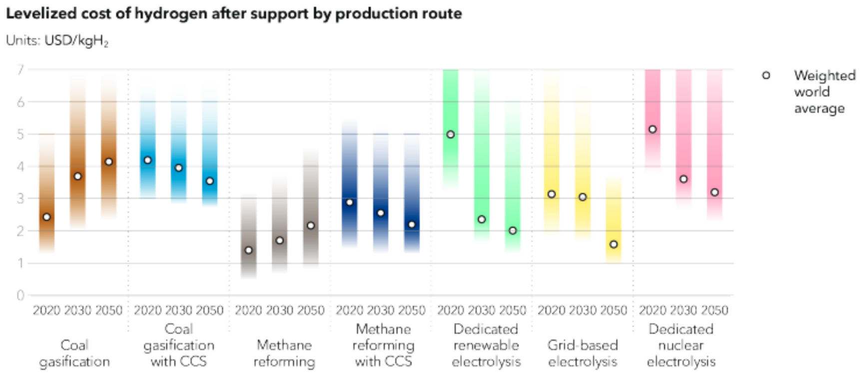

Figure 3.5: 'Forecast for LCOH from 2020-2050. Collected from [21, p. 74].' Collected from [1, p. 10]

'The demand for hydrogen is expected to increase across sectors towards 2050, illustrated by Figure 3.6 [21, p. 74]. The global hydrogen demand for producing derivatives in 2050 is predicted to be 147 Mt [21, p.79]. The demand is forecasted in figure 3.1. The most prominent sectors where hydrogen is predicted to develop a significant role, is the transport sector and the manufacturing. Within the transport sector, hydrogen is utilized in the production of ammonia and e-fuels, and directly as a fuel. In 2030, Norway's hydrogen demand is predicted to increase to 250.000 tons of hydrogen every year. Similar to the trend illustrated in figure 3.6, it is forecasted that 75% will be utilized in methanol and ammonia production [87, p. 6].'[1]

3.3.1 Utilization of hydrogen

'There is a great potential for hydrogen in the manufacturing sector, as reflected in Figure 3.6. The manufacturing sector is a collective term of all subgroups manufacturing industrial products, such as iron, cement, mining, petrochemicals and other manufactured goods. These are typical energy intensive processes, where green hydrogen can be used as feedstock to decarbonize the process. In Norway, an analysis has been conducted by Haugaland Næringspark and Sintef Energy, to investigate opportunities to utilize hydrogen in steel production [88]. The hydrogen would substitute coal, and thereby reduce the emissions from the process, if the hydrogen has a lower carbon footprint.'[1, pp. 13-14]

'The transport sector accounted for close to $\frac{1}{3}$ of Norway's emissions in 2019 [89]. To reach the goals in the Paris Agreement, the emissions within the transport sector

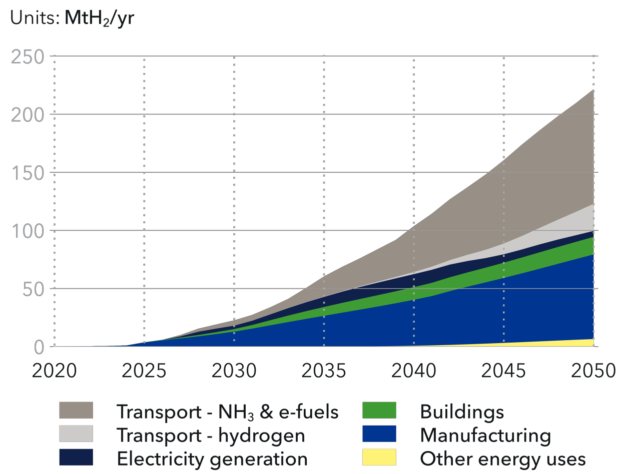

Figure 3.6: 'Forecast of hydrogen demand from 2020 to 2050. Note: All non-transport uses are pure hydrogen. Collected from [21, p. 74].' Collected from [1, p. 14]

must be reduced by 80-95% within 2050 compared to a 1990-level. It is therefore expected a massive electrification within the transport sector, which is already happening though both political and commercial incentives. The maritime transport sector is the most efficient form of transport in terms of transported goods per kilometer, and is therefore essential to decarbonize in order to reach the emission reduction goal[21, p. 85]. However, as the energy density of batteries are limited they are unsuited for long-distance shipping, unless an unforeseen break-through happens within battery technology. The electrification of the maritime transport sector is limited to on-shore electrification, for example when berthing or during short-distance shipping. The decarbonization of the maritime transport sector has to be done in another way in addition to electrification. In such cases hydrogen is particularly well suited. The International Maritime Organization announced a goal to reduce the emissions by 50 % within 2050 in the maritime transport sector [90]. This will be accomplished by an gradual transition from fossil fueled ships to low-emission fuels, instead of electrification. Pure hydrogen as fuel is considered irrelevant due its low energy density, but its derivatives are such as ammonia and methanol are prominent candidates. This is predicted to be one of the largest areas of use for hydrogen, illustrated by Figure 3.6. Norwegian hydrogen Forum have announced that there is great focus on and commitment towards hydrogen-fueled ships [91]. The total hydrogen within the transport sector in Norway is estimated to be 56.000 tons a year in 2030 [92]. An advantage with a transition towards ammonia and methanol as fuel is the possibility to use existing bunkering infrastructure. However, a disadvantage today is the higher expenses related to production of ammonia and methanol compared to the alternative fuels.'[1, pp. 14-15]

3.3.2 Hydrogen as a Norwegian commodity for export

'The increased innovation and commercial activity on the Norwegian continental shelf is hopefully the foundation for a new brand, "Made in Norway" [93]. This brand symbolizes the position Norway embraces as an important exporter of green energy. There has been predicted an opportunity for exporting blue and green hydrogen, as Norway possess the necessary resources and Europe possess a significant demand [87].The European Commission is preparing a hydrogen strategy aiming towards less dependency on Russian fossil fuels [43]. As a part of this strategy, REPowerEU plan announced an ambition in May 2022 of importing 10 billion tons of hydrogen within 2030.'[1, p. 15]

3.4 Infrastructure for energy storage

3.4.1 Hydrogen storage

'Hydrogen storage is useful for providing flexibility to VRE in the power market, and for supplying hydrogen [27, p.33]. The most common way of storing hydrogen today is in the form of gas in pressurized steel tanks. Hydrogen storage is challenging as a considerable amounts of energy is necessary to transform hydrogen into a storable form, due to its low volumetric density. The necessary amount of energy for pressurizing hydrogen constitute about 10 % of the hydrogen's energy, depending on how much the gas is pressurized. For larger quantities hydrogen is stored in its liquid form at -253 degree Celsius. The necessary energy use constitutes up to 40% of the energy content of the hydrogen.' [1, p. 9]

Salt caverns can be used for storing chemical energy carriers, such as hydrogen [24]. In fact, it is the most promising storage technology due to its ability to store larger quantities. There exists some operational salt caverns for hydrogen storage. Among others, the Clemens Dome in the United States was operational in 1983, and has a volume of 580.000 m^3 and a potential of storing 92 GWh [94]. The advantages of salt cavern storage is the low investment cost, low cushion gas requirement and the potential for high sealing [24]. Cushion gas is the volume required as permanent storage in a reservoir, to provide the necessary pressure for the gas injection or withdrawal at all times [95]. For underground hydrogen storage, an analysis suggested using methane as cushion gas, resulting in a hydrogen recovery of 89,7% [96]. Another advantage offered by salt caverns, is the tightness of the rock salt surrounding the salt cavern, as it prevents leakages of hydrogen [97, p. 51]. Figure 3.7 shows a map with potential salt caverns in Europe, from a suitability assessment for hydrogen storage [24]. These salt caverns have a depth from 500-2000 meters below ground, measured from the top of the cavern, and a salt thickness of 200 meters. Germany has the highest potential for onshore underground hydrogen storage in Europe, with an estimated capacity of 9,4 P Wh$_{H_2}$ in total.

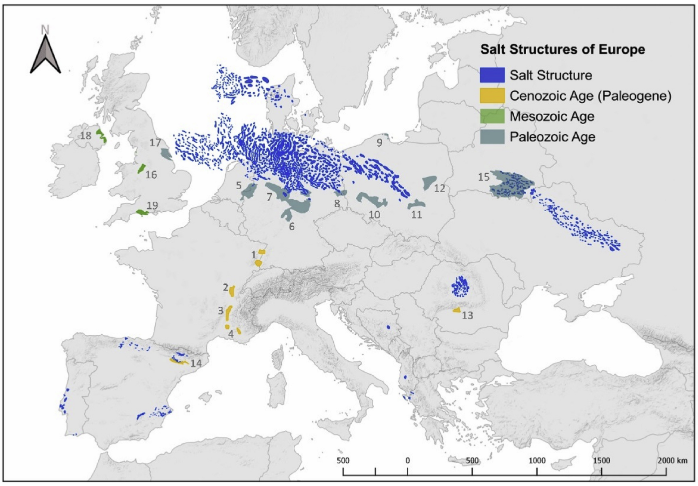

Figure 3.7: An overview of the salt caverns in Europe. Gathered from [24].

3.4.2 Fuel cell technologies

'The electrochemical energy stored in hydrogen is transformed to electrical energy through hydrogen fuel cells. A prominent fuel cell candidate is Proton Exchange Membrane Fuel Cell (PEMFC), which executes the opposite reaction as PEMEL [98, p.347]. In the fuel cell, hydrogen reacts with oxygen, providing energy and water. PEMFC has a versatile range of use, as it can be used for both small-scale power supply in the grid, car application and as portable power supply. There is an interest for its application as the main source in electric vehicles, as the material corrosion is low and it has demonstrated a long lifetime. However, as the polymer electrolyte is expensive, the fuel cell price is high. Fuel cells are also less efficient than all its competitors, both as a fuel in passenger road vehicles and in ships, and for space heating [21, p.18]. The only exception is against oil-fueled passenger road vehicles.'[1, p. 8]

3.5 Hydrogen flexibility in the power system

’In 2021, the European Commission published a revision of the "Fit for 55" package [99]. As the name indicates, the "Fit for 55"-package is a framework proposal for EU legislation in order to reduce European emissions by 55% within 2030, compared to a 1990-level [100]. The key take-away from this report in perspective of the power markets, is the necessity of substituting large shares of fossil sources in the European energy mix by variable renewable energy (VRE) and low-emission energy carriers [27, p. 36].’[1, pp. 21-22]

The energy system will change in order to accomplish emission reduction and meet the net zero towards 2050 goal [101, pp. 13-15]. The energy mix will consist of a higher share of intermittent renewables, such as wind and solar. The power production from VRE varies naturally between seasons and years. A study of the power production from offshore wind in Great Britain over a span of 25 years found large variations in the capacity factor for the same day in different years, as illustrated in Figure 3.8 [25]. The capacity factor is the relationship between actual power production and technically possible power production [102]. There are several ways to provide flexibility to a power grid, such as expanded transmission capacity, larger back-up capacity and storage options such as hydro storage with reversible pump turbines, hydrogen and batteries [24]. A prerequisite for a cost-efficient power system with high shares of VRE is the availability of long term energy storage for larger quantities [26]. The analysis also found that the total system cost was lower for hydrogen storage, including electrolyser and fuel cells, than for batteries.

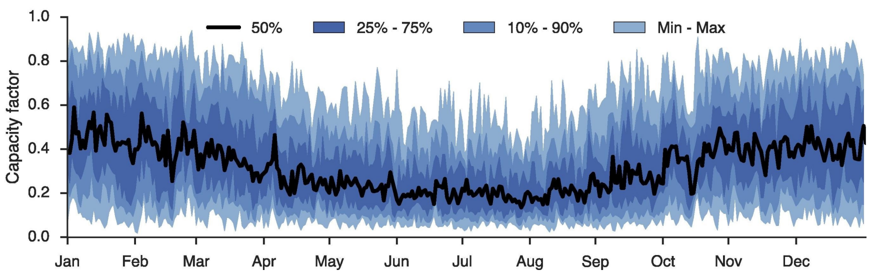

Figure 3.8: Daily mean offshore wind capacity factors from year 1990-2014. The black line is the median daily capacity factor of each day in the 25 years, and the shaded area is the capacity factor possible range. Collected from [25].

Hydrogen is suited for storing large quantities for energy, which makes it suitable for seasonal storage [26]. Batteries have a lower capacity, and is therefore more suited for intra-day storage. A joint utilization of batteries and hydrogen storage for an energy system during a year is illustrated in Figure 3.9. The option of seasonal storage through hydrogen is useful in an energy system with uncertain and seasonal dependent power production. The capacity factor for the wind profile in Figure 3.8 shows a trend with an increased power production during the winter season, and a decline over the summer season. Hydrogen offers the possibility to store excess power in surplus periods, typically the wintertime, to be used when needed, especially during the summertime. Provision of electricity from storage will therefore also have a stabilizing effect of the electricity prices [3]. A disadvantage of hydrogen compared to batteries is the low round-trip efficiency of only 30% [103]. However, if the hydrogen is storing surplus power from VRE, the remaining 30% might be considered as a supply of otherwise wasteful curtailment.

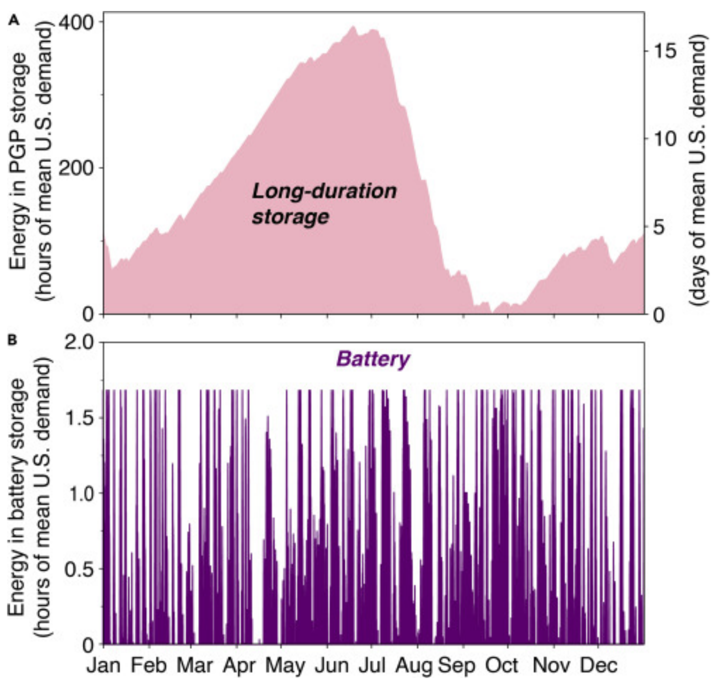

Figure 3.9: Joint hydrogen and battery storage in a power grid during the year of 2018. PGP is an abbreviation for "Power-to-Gas-to-Power", where the gas is hydrogen in this case [26]. Figure from [26].

’Another challenge following an energy system with high shares of VRE, is the grid capacity [27, p. 36]. There is a risk of congestion in the power grid when the VRE facility is generating power, and the risk increases with the quantity of VRE installed. Energy storage can postpone or remove the need for reinvestment in the grid. Hydrogen storage could therefore provide flexibility, and avoid costs regarding reinvestment in the grid. The integration of hydrogen storage opens for a new infrastructure benefiting sector coupling, where hydrogen pipelines are added to the system. This makes is possible to transfer power in shape of both hydrogen and electricity to deficit areas. This is illustrated in Figure 3.10. There are also investigations for an offshore hydrogen infrastructure, where hydrogen gas is produced offshore from natural gas and offshore wind facilities [104]. This integration of hydrogen in the power system can contribute to decarbonization across sectors. The contribution of hydrogen to flexibility is an important facilitator the integration of more than 50 % VRE [105, p. 24].'[1, pp. 21-22]

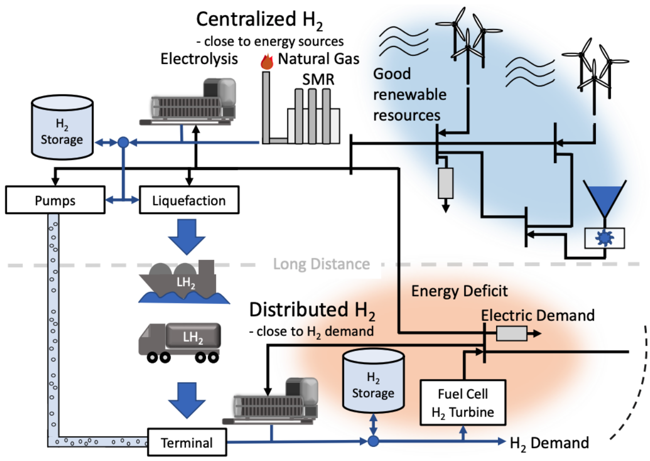

Figure 3.10: 'Schematic illustration of the integration of hydrogen infrastructure in the power system. Collected from [27, p. 39].' From [1, p. 23]

Chapter IV

Optimization Theory

■ This chapter gives an introduction to preliminary basic and more advanced optimization theory, to provide insight into the framework of optimization model used in this thesis.

4.1 Operation analysis

'Linear programming (LP) is a tool for optimizing problems of a certain character, and is widely used across disciplines, such as in mathematics, economy and for commercial purposes [106] [1]. LP problems are applied to problems of a certain character where the decision maker has an opportunity to change the value of a variable [107, p. 1]. This variable is known as a decision variable, and its value will affect the objective of the problem. The objective is the goal of the problem, and is defined as a linear objective function consisting of the problems decision variables. The decision variables are therefore optimized to achieve the best value possible for the objective function. Their values are restricted by linear constraints in the optimization problem. The best possible value of a decision variable is therefore its optimal value with respect to its restrictions. The decision variables are also restricted by non-negativity constraints, meaning that they have to be greater than or equal to zero [106]. The optimal solution occurs in the interface of restrictions, marking a vertex in the feasible region. The objective of the problem is either to minimize or maximize the objective function, depending on purpose of the problem [107, p. 1]. In summary, an optimization problem fundamentally consists of constraints, decisions variables and an objective function [108]. The structure of an minimization LP-problem on standard form can be formulated as the following [107, p. 82]' [1, p. 25-26].

$$
\begin{aligned}
\text{min z} = \quad & \sum_{j=1}^{n} c_j x_j \\
\text{subject to} \quad & \sum_{j=1}^{n} a_{ij} x_j = b_i, \; i = 1, \ldots, m \\
& x_j \geq 0, \; j = 1, \ldots, n
\end{aligned}
$$

4.1.1 The simplex method

'As there are many different kinds of optimization problems, there are also various solution methods to solve them. For LP-problems, the Simplex method is the most used solving method [107, p. 77] [1]. The simplex method is among the most efficient and well-known solving algorithms that exists today [106]. As Figure 4.1 shows, the method is iterative and is based on finding the vertexes of the feasible region, checking each one for optimality [107, p. 83]. If optimal solution is not to be found in the vertex, the adjacent vertex in the direction where the value of the objective function is improving fastest is checked [106]. A vertex is defined by some of the decision variables known as basic variables in each iteration, and the solution is called a basic solution [107, p. 85]. The rest are nonbasic variables, and are set to zero. If there are n number of variables and m number of equations, there will be n-m number of nonbasic variables and the rest are known as basic variables. The simplex method is a standard solving procedure in almost all software solving LP-problems today [106] [107, p. 77]' [1, p. 26].

4.1.2 Commercial optimization solvers

'Today, it is common to use software to solve optimization problems [1]. There are several recognized solvers, and among the leading commercial ones are Cplex and Gurobi [109]. The solvers are using standard optimization methods corresponding to the nature of the optimization problem presented to it [108]. Gurobi includes a collection of state-of-the-art solving algorithms for different kinds of optimization problems [110]. Among these algorithms are the Simplex algorithm. As the optimization model is an LP problem, Gurobi has therefore applied the Simplex algorithm to solve it.' [1, pp. 26].

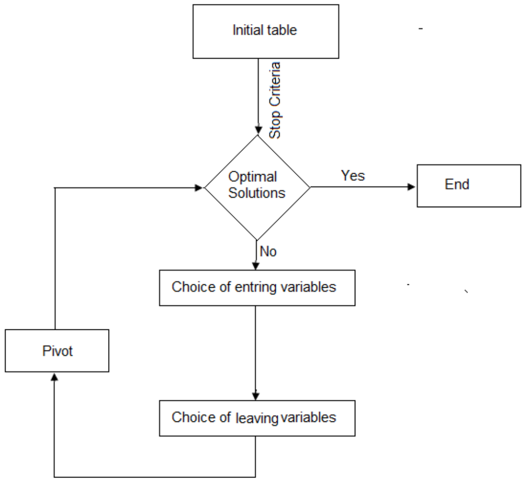

Figure 4.1: A flow chart of the Simplex algoritm. Gathered from [28].

4.2 Capacity Expansion Modeling

Capacity Expansion Modeling (CEM) is an optimization tool used for long-term and complex power sector planning [111]. A CEM embraces the complexity of the power system by including a range of factors into the model. This is, among others, the geographical location the observed power system is situated in, fixed and variable costs, technological innovation and prognosis for demand,power and fuel costs. Key parts in a capacity expansion model are listed in Table 4.1 [2], [1, p. 27]. Both the availability of data and computational resources has increased significantly the last decades, increasing the precision of the CEM [111]. As the factors varies according to geographical location and the year being viewed. This makes each capacity expansion model specific for the area and time window being modeled and simulated. As the main objective of CEM is to minimize costs, it is a useful tool for obtaining an optimal operation and development of the power system and the resources related to it. This constitutes a decision-making basis which is useful for politicians and other decision makers. However, there are limitations to CEM regarding grid planning as well. This applies to modeling grid operation and power flow on a detailed level. As the scope of CEM is to model a complex power system, it is not suited for modelling technical details. Additionally, the environmental perspective is also excluded from the scope of CEM. Therefore, several tools are necessary to obtain the full picture of power sector modeling and operation.

Table 4.1: Capacity Expansion Modeling [2]. The table is extracted from the specialization project report [1, p. 27].

Key parts in a Capacity Expansion Model
Geographical resolution
Temporal resolution
Time steps
Time horizon
Representation of generating units
Representation of transmission and associated constraints

When modeling a CEM, modeling choices regarding delimiting the models scope and granularity must be made. The model is often optimizing a power sector which interacts with a range of other sectors. This is for example the heating sector, fuel sector, transport sector, among others. As the CEM is finite, the boundaries for which sectors to include must be drawn somewhere. The goal is to only include the relevant information for the decision-making, and keeping the irrelevant outside the scope. This process should be tailored to the specific problem and research questions, as excluding sectors or geographical locations implies that the interactions and activities in the excluded parts are ignored by the model. This entails a risk of exclude relevant information. Regarding geographical resolution, a rule of thumb is to at minimum implement a geographical resolution affected by the decisions made.

4.2.1 Optimizing with a centralized or decentralized perspective

The perspective in which the model is optimizing for, is decisive for the optimal solution provided [112]. The perspective is therefore important to take into consideration when deciding the framework for the CEM. In a power system with several decision-makers, a centralized perspective will provide the most optimal solution for the system as a whole, as if the system was operated by a single decision-maker with all information and influence. A decentralized perspective will, on the other hand, give the optimal solution for the individual actor in the system. As the modern power system is intertwined in many other power systems, enabling power flow across borders, there are many decision-makers in the power system. A decentralized perspective for one of these would provide the most realistic estimate of the mode. However, the advantage of a centralized perspective is the provision of a common goal in which the power system in operated optimally.

Chapter V

Methodology

■ This chapter comprises an analytical and mathematical review of the model utilized in this thesis. It commences with an introduction to the operation of the model, as well as the reasoning behind its design. Thereafter, the chapter provides an overview of the mathematical model.

5.1 The Hydrogen and Energy system Integration Model (HEIM)

HEIM is an operation and investment capacity expansion model, and is utilized in this thesis. The objective of the model is to minimize the total cost within a specified year, while covering the hydrogen and electricity demand within the system [3]. The linear programming (LP) optimization model is written in Python, with the framework provided by Pyomo is used for optimization modelling. Gurobi was used as a solver. The model with original input data is available on Github through the following source: [113]. Each node in the system can schematically be illustrated in Figure 5.1. The node is divided into two components, as a hydrogen and an electricity node. As shown in Figure 5.1, both these components mirror each other, incorporating a generating capacity, a consumption unit, a storage unit and a transport infrastructure. The parts are interconnected through conversion technologies, facilitating the transformation of electricity into hydrogen and vice versa. The conversion technologies included in this thesis, is PEMEL, fuel cells (PEMFC) and H_2-turbines. Both the production of hydrogen and of electricity is constrained by the same set of restrictions (eq. 5.3-5.16). The nomenclature, which is the foundation of the model and explanation of the restrictions (eq. 5.3-5.16), is found in Table 5.1 and Table 5.2. Table 5.1 includes the indices, investment variables, operating variables and sets. Table 5.2 includes the parameters and costs. The optimization model operates the system on an hourly resolution, $\forall t \in T$, and for all nodes, $\forall n \in N$.

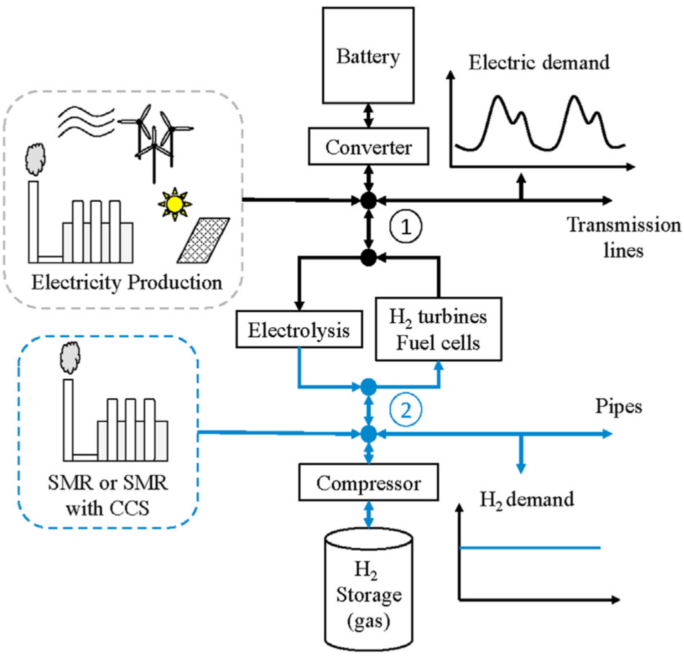

Figure 5.1: A schematic illustration of each node in the optimization model. Collected from [3]

Table 5.1: Nomenclature; Indices, Variables and Sets [3].

Indices:	
i	Plant Type
n, m	Nodes
t	Time step
Investment Variables:	
e_n^{cap}	Storage charge/discharge capacity [MW]
e_n^{cap}	Storage level capacity [MWh]
x_{in}	New plants
x_{in}^{trans}	New lines or pipes
x_{in}^{ret}	Retired capacity [MW]
Operating Variables:	
c_{tin}	Energy curtailment [MWh]
$e_{tin}^{in/out}$	Storage charge/discharge [MW]
f_{tnm}	Flow in lines or pipelines [MW]
$p_{tn}^{exp/imp}$	Export/Import [MW]
p_{tin}	Production [MW]
r_{tn}	Load curtailment [MW]
x_{tn}	Rationing power [MWh]
s_{tn}	Storage level [MWh]
u_{tin}	Number for available plants
Sets:	
L	Transmission lines and pipelines
N	All nodes
P	Plant types for electricity or H_2 production
R	VRE power plant types
S	Storage types
T	Time steps
Indexed sets:	
A_n	Plant types requiring aux. power at node n
B_n	Nodes connected to node n by transmission
C_n	Nodes connected to node n by conversion plants
F_n	Conversion plant types at node n
P_n	Plant types at node n
S_n	Storage types at node n

Table 5.2: Nomenclature; Costs and Parameters [3].

Costs:	
C_i^{energy}	Storage energy cost [€/MWh]
C^e	Emission cost [€/kg CO_2]
C_i^{fix}	Fixed cost [€/MW]
C_i^{inv}	Investment cost [€/MW]
C_i^{power}	Storage power cost [€/MW]
C_i^{rat}	Rationing cost [€/MWh]
C_i^{ret}	Retirement cost [€/MW]
C_i^{var}	Variable cost [€/MWh]
Parameters:	
η_i	Charge/discharge efficiency for storage type i
γ_i	Emission rate [kg CO_2/MWh] or [kg CO_2/GWh H_2]
A_i	Auxiliary electricity [MWh_{el}/MWh_{H_2}] or [MWh_{H_2}/MWh_{el}]
D_{tn}	Electricity or H_2 demand [MWh] or [GWh]
E_i	Cost of CO_2-emissions [€/kg CO_2]
F_i	Conversion rate [MWh/kg H_2] or [kg H_2/MWh]
P_i	Max or min plant capacity [MW]
P_{tin}	Power profile [MWh]
R_i	Maximum ramping [MW]
$T_{nm}^{init/max}$	Initial or max transmission capacity from node n to m [MW]
$X_{in}^{init/max}$	Initial or max number of power plants

5.2 Objective function

The objective function of the optimization problem is to minimize the costs over the time period, and is mathematically described in Equation 5.1. The function consists of all the costs related to investing and operating the power plants, and investing in new power lines and pipes, in the system over the given time period. The parameters C^{inv}, C^{fix}, C^{power}, C^{energy} and C^{Trans} represent capital expenditures (CAPEX) in the model. These costs refer to the expenses incurred on properties, plants and fixed assets, inter alia [114]. The operational expenditures (OPEX) are represented by C^{var} and C^{rat}. As shown in Equation 5.1, the operational costs collerate to to time, because the cost represents day-to-day operation and maintenance expenditures. Such expenses include fuel costs, salaries, and so on.

$$
\begin{aligned}
min \sum_{n \in N} [\sum_{i \in P} (C_i^{inv} x_{in} + C_i^{ret} x_i^{ret} + C_i^{fix} (X_i^{init} + x_{in} - x_{in}^{ret})) \\
+ \sum_{i \in S} (C_i^{power} e_{in}^{cap} + C_i^{energy} s_{in}^{cap}) + \sum_{n,m \in L} C_{nm}^{Trans} x_{nm}^{Trans} \\
\sum_{t \in T} (\sum_{i \in P} (C_i^{var} + \gamma_i C^e) p_{tin} + C^{rat} r_{tn})]
\end{aligned}
\tag{5.1}
$$

$$
x_{in} \leq X_{in}^{max}, \qquad \forall i \in P, \forall i \in N. \tag{5.2}
$$

5.3 Energy balance

The energy balance applies to both hydrogen production and electricity production. It ensures that the total availability of electricity or hydrogen within a node is equal to the consumption of it. Hydrogen storage provides the ability to store electricity as hydrogen, and produce electricity from hydrogen. The amount of electricity used to produce hydrogen is counted as a load in the energy balance for electricity. Similarly, the production of electricity from hydrogen is counted as a load in the energy balance for hydrogen. This is represented in the last term of eq. 5.3. Additionally, the last term also accounts for the auxiliary energy for hydrogen compression [3].

$$
\begin{aligned}
\sum_{i \in P_n} p_{tin} - p_{tn}^{exp} + p_{tn}^{imp} + \sum_{i \in S_n} (e_{tin}^{out} + e_{tin}^{in}) + r_n \\
= D_{tn} + \sum_{m \in C_n} (\sum_{i \in F_m} F_i p_{tim} + \sum_{m \in A_m} A_i e_{tim}^{in})
\end{aligned}
\tag{5.3}
$$

5.4 Storage balance

The storage balance applies to H_2-storage, hydro storage and battery storage. It ensures that the amount of energy in this time step is consistent with energy level in the last time step, in addition to any net energy changes that have occurred during this time step. The following restrictions (eq. 5.5-5.7) ensures that the storage level, discharge capacity and charge capacity are within their respective maximum limit.

$$
s_{tin} = s_{(t-1)in} + \eta^{in} e_{tin}^{in} - (\frac{1}{\eta^{out}}) e_{tin}^{out}, \qquad \forall i \in S \tag{5.4}
$$

$$s_{tin} \leq s_{in}^{cap}, \qquad \forall i \in S \tag{5.5}$$

$$e_{in}^{out} \leq e_{in}^{cap}, \qquad \forall i \in S \tag{5.6}$$

$$e_{in}^{in} \leq e_{in}^{cap}, \qquad \forall i \in S \tag{5.7}$$

5.5 Power transmission and hydrogen pipeline balance

The transmission of power and hydrogen has to be balanced, so that all of it can be accounted for. The restriction 5.8 states that the flow on a line between two nodes must equal the sum of power or hydrogen into the node must minus the sum of power or hydrogen out of it. The transfer capacity on lines and pipes can be expanded if invested in. Restriction 5.9 and 5.10 constrains the transmission of hydrogen and power between two nodes by the available transfer capacity between them.

$$p_{tn}^{exp} - p_{tn}^{imp} = \sum_{m \in B_n} f_{tnm} \tag{5.8}$$

$$f_{tnm} \leq T_{nm}^{init} + T_{nm}^{max} x_{nm}^{trans}, \qquad \forall n, m \in L \tag{5.9}$$

$$f_{tnm} \geq -(T_{nm}^{init} + T_{nm}^{max} x_{nm}^{trans}), \qquad \forall n, m \in L \tag{5.10}$$

5.6 Hydropower modelling

The inflow to the hydro power plant can either be regulated or unregulated. As the name states, unregulated inflow is inflow to the turbine where the amount of inflow cannot be adjusted. This can for example be a river. It is not possible to save the water, so water that does not go to power production is lost. Regulated inflow is on the other hand a water reservoir, where the inflow to the turbines is adjusted by the producers after demand.

$$e_{tn}^{hydro} = e_{(t-1)n}^{hydro} + F_{tn}^{reg} + F_{tn}^{unreg} - (\frac{1}{\eta^{hydro}}) f_{tn} \tag{5.11}$$

Equation 5.12 is implemented to ensure that the unregulated inflow produces power.

$$F_{tn}^{unreg} \leq f_{tn} \tag{5.12}$$

5.7 Production of power and hydrogen

The production of power and hydrogen can either happen at already existing plants, or the model can choose to furtherly invest in additional producing capacity. The power plants are permanent, meaning that they can be utilized in later time steps. The consistency of the total plants in operation in a specific time step is ensured by Equation 5.13. The number of plants in operation can never be larger than the initial number of plants and the number of plants invested in afterwards minus the retired plants. The retirement of plants means that they are out of operation. Equation 5.14 ensures that the amount of power produced from a certain plant type at a node is kept within its upper and lower bounds. The bounds for production of a certain type within a node is dependent on the amount of installed production capacity, as well as the maximum and minimum production limits of that type of plant.

$$u_{tin} \leq X_{in}^{init} + x_{in} - x_{in}^{ret}, \qquad \forall i \in P \tag{5.13}$$

$$P_i^{min} u_{tin} \leq p_{tin} \leq P_i^{max} u_{tin}, \qquad \forall i \in P \tag{5.14}$$

Rampage constraints in 5.15 ensures that the change in production between two hours is restricted. This ensures more step-wise up or down scaling of production, which is more realistic. Without rampage constraints, the production could be on for full during one hour and completely off the next.

$$-R_i u_{tin} \leq p_{tin} - p_{(t-1)in} \leq R_i u_{tin}, \qquad \forall i \in P \tag{5.15}$$

The variable renewable is a balance constraint, ensuring that the total available energy from a renewable energy source in a node is either produced or curtailed.

$$p_{tin} + c_{tin} = P_{tin}(X_{in}^{init} + x_{in}), \qquad \forall i \in R \tag{5.16}$$

Chapter VI

Scenario analysis, system boundaries and input assumptions

■ The first part of the chapter provides a review of the objective of the research project. Thereafter, the system boundaries are accounted for. Furtherly, the chapter accounts for the structure of the input data, and the assumptions made for the inputs.

6.1 Scenario analysis

The objective of this thesis is to investigate the role Norwegian energy resources constitute, with a special focus on offshore wind, in current and future hydrogen production. In light of the climate crisis, the focus is especially focuses on the conditions in which low and zero emission hydrogen production alternatives are phased in. The framework of the analysis is to investigate how the system responds to varying carbon prices and natural gas prices, in addition to increasing the offshore wind production. The research project consist of a scenario analysis comprising a total of three scenarios. Each scenario consists of 10 simulations, where the carbon price or natural gas is varying within a range of fixed steps. The differentiating factor between the scenarios are their respective hydrogen demand. Scenario 1 is the baseline scenario, and is representing the year 2019. Scenario 2 and scenario 3 represents different variants of increased hydrogen demand.

2019 represents the last year before major global events affecting the fuel, carbon and electricity prices. Such events are the COVID-19 pandemic, the war in Europe, the energy crisis and high inflation rates. In order to give scenario 1 a reference in "ordinary conditions", 2019 seemed the best year to choose. This is illustrated by

Figure A.5, showing highly unstable prices and a significant peak from 2021-2023, before it is normalized again. Also the carbon price has increased significantly the last years, shown by Figure 2.8.

6.2 System boundaries

The modelled region in the case study is illustrated in Figure 6.1. The modelled region consists of 10 geographical locations, referred to as nodes. They are classified into two nodes; dual and market. Dual nodes represent electricity producing locations, and consumers of electricity and hydrogen. There is a pre-specified power production capacity in the dual node. Some dual nodes offer the possibility to furtherly invest and operate some power generation capacities, as shown in Table 6.4. The market nodes have the capability of participating in two-way power trade with their corresponding price area. The market nodes serves as the systems boundaries, connecting it to the surrounding external power system. Table 6.1 presents av overview of the type of node corresponding city. The system boundaries is narrowed down to only include NO2 and the local area around Node 5 (Dornum) in Germany. The model is a simplification of the power system, as the scope is to examine how offshore wind in large terms affects hydrogen production and the power grid. As a result, only the price area with a direct connection to the north sea is included. This streamlined approach is why only NO2 is a part of the model, and not the other price areas in Norway.

The selection of the specific regions in EU is based on the existing energy infrastructure for power and natural gas trade connecting these areas together with Norway. As shown in Figure 6.1, Tonstand (Norway) and Wilster (Germany) are connected through the HVDC-cable "NordLink". Additionally, Dornum has reception terminals for natural gas from the North Sea [115]. The feedstock for hydrogen production in this area is available. As the hydrogen demand in Europe is larger than in Norway, this area is a suitable candidate for exploring the potentials for the Norwegian contribution to hydrogen production.

Table 6.1: Overview of the nodes in system

Node	Place (Country)		Price area
1	Kårstø (Norway)	Dual	-
2	Kårstø (Norway)	Market	NO2
3	Kristiansand/Feda (Norway)	Dual	-
4	Kristiansand/Feda (Norway)	Market	NO2
5	Dornum (Germany)	Dual	-
6	Dornum (Germany)	Market	DE-LU
7	Eemshaven (Netherlands)	Market	NL
8	Jammerbugt (Denmark)	Market	DK1
9	Sørlige Nordsjø II (Norway)	Dual	-
10	Utsira Nord (Norway)	Dual	-

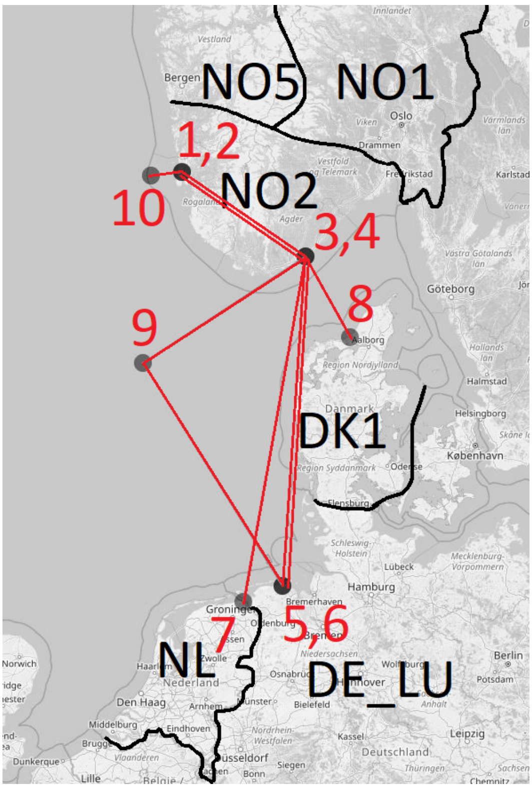

Figure 6.1: Spacial representation and distribution of nodes

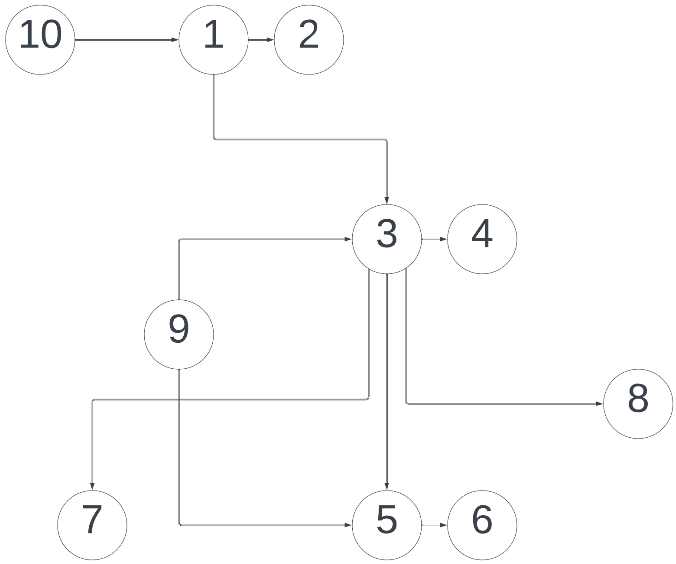

Figure 6.2: Flow chart of the defined power flow directions between the nodes in the system.

6.3 Input data and assumptions

The optimization model optimizes the system it is introduced to, which is comprised of various inputs. Figure 6.3 shows a flow chart with all the input files to the system. The files are sorted into five categories; demand, power plant, energy transmission, storage and markets. This is the foundation for the optimization problem. The assumptions made for each of these input files are accounted for in chronological order.

The systems parameters are presented in Table 6.2. All expenditures are discounted to are annualized costs in accordance with the formula for equivalent annual costs [35]. It is assumed a discount rate of 6%, as this is used in a previous analysis with a similar context [3]. Annualizing the costs is a necessity for fair comparison of the investment alternatives. It facilitates a more accurate evaluation over a specific time period, as among others the facilities have their respective technical lifetime and a cost corresponding. There are large variations in CCS-costs, and the cost is estimated to range between 4-45 (\$/ton CO_2) [4]. It is assumed a cost of 10 (\$/ton CO_2), based on its utilization in a previous study [4]. The assumed price has been unstable for last years, as shown in Figure A.5 [5]. The natural gas price in 2019 was roughly 16.5 [EUR/MWh] The forecast shown in Figure A.6 predicts an increase to approximately 50 [EUR/MWh] within April 2024. It is therefore assumed a price of 35 [EUR/MWh], but there is also performed an analysis with a lower bound of 16.5 [EUR/MWh] and an upper bound of 50 [EUR/MWh] on the natural gas price. The retirement cost is set to 0, as it seems unlikely that any of the renewable plants in the will be retired during the target year. Often are the plants being retired, which means taken out of operation, old, costly and inefficient fossil based plants [4]. There are no fossil based plants in this system, and the retirement cost is therefore negligible.

Table 6.2: The systems parameters. The CCS-cost is from [4]. Natural gas cost is from [5].

Parameter	**Value**
Discount rate	6%
CCS-cost	0,1 [€/kg CO_2]
Natural gas cost	35 [€/MWh$_{NG}$]
Rationing cost	10000 [€/MWh]
Retirement cost	0 [€/MWh]

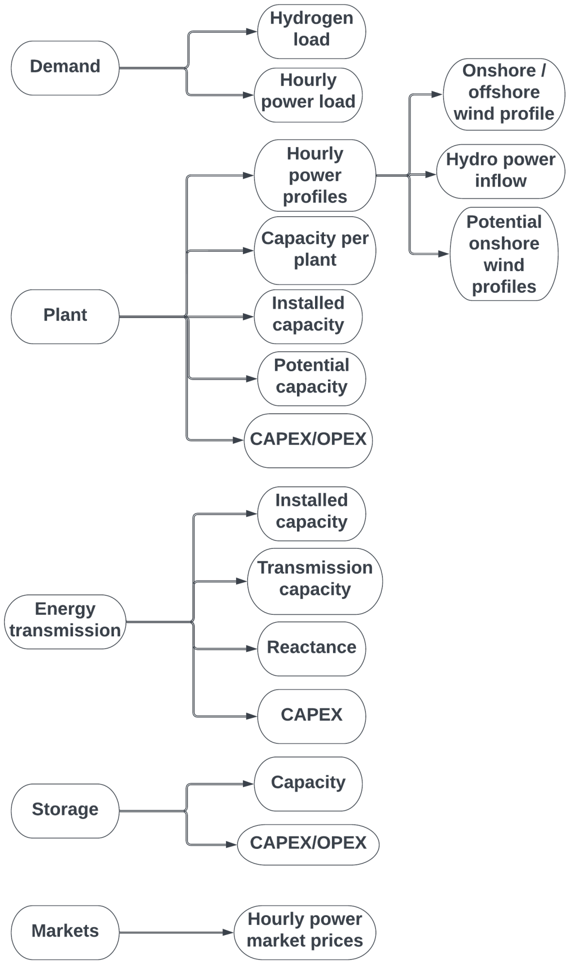

Figure 6.3: A flow chart of the input files to the system. They are containing information about the framework for power and hydrogen generation, demand and transmission, in addition to hydrogen storage and power trade.

6.3.1 Hydrogen demand

There is a hydrogen demand in Node 1 (Kårstø) and Node 5 (Dornum). During the hourly optimization, the hourly hydrogen demand in the nodes is the total annual hydrogen demand divided by the number of hours in a year (8760 hours). The following paragraphs will give a review of the chosen hydrogen demand in the three scenarios, and an overview of the hydrogen demand is presented in Table 6.3.

Table 6.3: Overview of the annual hydrogen demand [GWh] per node in each scenario.

Scenario	**Node 1** [GWh]	**Node 5** [GWh]
Baseline scenario	3746	27500
Scenario 2	4096	58996
Scenario 3	8192	117992

In Norway in 2019, the total hydrogen demand was 225000 tons [87, p. 5][116]. As one ton of hydrogen has an energy content of 33 MWh, this equals 7492 GWh [117]. To keep the system realistic, this quantity is divided by two, making the hydrogen demand equal 3746 GWh in Node 1. While it seems unlikely that all of the hydrogen demand occurs in the local area represented by Node 1, it is assumed that the region still represents a significant hydrogen demand. This assumption is necessary for conducting the analysis effectively, as this allows for a comprehensive investigation of the correlation between offshore wind and hydrogen production. The predicted Norwegian hydrogen demand in 2030 is 246000 tons, which equals 8191.8 GWh [87, p. 1]. Continuing the same procedure, the assumed hydrogen demand in Node 1 is half the quantity; 4096 GWh. In the last scenario, the hydrogen demand from the second scenario is doubled, to 8192 GWh. The increase in hydrogen demand reflects the anticipated increase in growth for hydrogen, as there is expected a sudden and large increase in hydrogen demand. However, the reports providing the prognosis is published before the offshore wind goals were announced. This may have affected the predictions, as it is assumed that hydrogen production mainly will come from electrolysis in the future [118].

In Germany in 2019, the total hydrogen demand was 55000 GWh [119, p. 6]. With the same reasoning as earlier, the total hydrogen demand in Node 5 is therefore set to 27500 GWh. The prognosis suggest a hydrogen demand within the range of 90-110 TWh in 2030 [119, p. 5]. Assuming a hydrogen demand of 100000 GWh, the total hydrogen demand in the second scenario is equal to 50000 GWh. In the third scenario, the amount from scenario 2 is doubled, to 100000 GWh.

The total hydrogen demand in scenario 2 and 3 is respectively 1.7 and 3.4 times larger than in the base case. To facilitate the comparison of the results with the inputs, the hydrogen demand in Germany is scaled up in scenario 2 and 3. The total hydrogen demand in scenario 2 and 3 is therefore 2 and 4 times larger than the base case.

6.3.2 Electricity demand

The hourly electricity demand for 2019 are gathered through the European Association for the cooperation of Transmission System Operators for Electricity (ENTSO-E) transparency platform, for the standard time reference "coordinated universal time" (UTC) [120]. There is set an electricity demand in Node 1 (Kårstø), 3 (Kr.sand/Feda) and 5 (Dornum). The electricity demand in Germany is included due to the common understanding in academia and politics that Germany will become a net importer of electricity. The net import in 2037 is estimated to be 17% of the total demand [121, p. 70]. As the parameters in this scenario analysis are based on more recent years, a pessimistic bound is set to 10%. The hourly electricity demand in Node 5 (Dornum) is therefore set to 10% of the total hourly demand in DE-LU, which it generally can cover from its own local market (Node 6). The modelled electricity demand in Node 3 (Kr.sand/Feda) therefore set to half of the real electricity demand in NO2. This is based on the fact that Node 1 both represents a geographical area with a high electricity demand. The electricity demand is set to 25% of the historical NO2 demand in Node 1.

6.3.3 Power plants and hydrogen production

There are three energy sources in the optimization model; hydro power, onshore wind and offshore wind. The hourly weather data set for wind and hydro power production is from NVE [122]. Power can be supplied to the system from hydrogen storage through fuel cells. The model initiates with an existing power system that incorporates certain power generation capacities. The model can choose to furtherly invest in more capacities, where this is possible. An overview of the installed and potential capacities of power sources in each node is provided in Table 6.4. The cost of investment is provided in Table 6.3.3.

Table 6.4: The installed and potential power generation capacity of wind and hydro power in each dual node, presented as: Installed/(potential). Hydro power is from [6], and onshore wind power is from [7].

Dual nodes	**Onshore-wind** [MW]	**Offshore-wind** [MW]	**Hydro-power** [MW]
1 (Kårstø)	621/(600)	0	3961
3 (Kr.sand/Feda)	0	0	0
5 (Dornum)	0	0	0
9 (Sørlige Nordsjø II)	0	7100/(3000)	0
10 (Utsira Nord)	0	1500/(1000)	0

Table 6.5: Technology costs in 2022. All the cost data for wind power is obtained from [8], except variable OPEX for onshore wind from 2018 [9]. Min. Gen., size. fuel unit (f.u.) and rampage rate is from [3]. The CAPEX and fixed OPEX for SMR and SMR with CCS is from [10]. CAPEX and OPEX (in 2030) for PEMEL and PEMFC is gathered from [11, pp. 153, 167]. Fuel rate for SMR and SMR with CCS is from [12, p. 5]

	CAPEX (€/MW-year)	**Fixed OPEX** (€/MW -year)	**Variable** OPEX (€/MWh)	**Fuel** (f.u. /MWh)	**Emission** ($kgCO_2$ /MWh_{H2})	**CCS rate** ($kgCO_2$ /MWh_{H2})	**Size** (MW)	**Min. Gen.** (MW)	**Ramp. rate** (%/h)	**Lifetime** (years)
Generation:										
Offshore wind	228749	223879	0	0	0	0	1500	0	1	30
Onshore wind	98730	3065	4.7	0	0	0	300	0	1	30
PEMFC	122281	3	0	1,5	0	0	50	0	1	10
H2-production:										
PEMEL	33231	1396		1,5	0	0	100	0	1	40
SMR	7060	3530		1,4	303	0	303	272,3	0,1	25
SMR w/ CCS	12667	7683		1,4	30	273	303	272,3	0,1	25

NO2 is a significant power producer area. According to [6], the maximum hydropower generation capacity is Rogaland is 3961 MW. This installed hydropower capacity is therefore included in Node 1. It is assumed that all the hydro power potential is already exploited in the area. Therefore, it is not an option to furtherly invest in hydropower. NO2 is also a supplier of onshore wind power. The power plants Ulvarudla, Moi-/Laksesvelafjellet, Brusali-Karten and Døldarheia contribute with in total 621 MW [7]. This is also added to installed capacity in Node 1. As the potential for onshore wind is large in area, it is an option to invest in an additional 600 MW onshore wind in Node 1. The modeled onshore installed power production, and thereby maximum generation capacity, in NO2 is 4582 MW.

There is assumed a total installed capacity of 7100 MW in Node 9 (Sørlige Nordsjø II) and 1500 MW in Node 10 (Utsira Nord). The capacities are assumed already installed. This is done deliberately, as they are facilitated through political incentives. It is the need for green energy that facilities the construction of the power plants. The capacity in Node 9 is generally less than the largest suggested capacity by NVE, which stands at 11.5 GW [58]. Choosing a larger installed capacity risks congestion on the onshore grid or significant curtailment. Considering that the model is already based on assumptions of facilities not yet constructed, a larger installed offshore capacity could introduce additional uncertainty into the results. However, this modelling decision is tested by offering an option of investing additional 3000 MW and 1000 MW at Node 9 (Sørlige Nordsjø II) and Node 10 (Utsira Nord).

Hydrogen can be produced either through PEMEL, SMR or SMR with CCS in the model. Just like ordinary plants, hydrogen production facilities can only exist in dual nodes. The model does not assume any already existing hydrogen production facilities, so these have to be invested in during the simulated year. When investing in a hydrogen production capacity, the production capacity is available for the rest of the simulation. Natural gas is assumed available in all dual nodes. Node 1 (Kårstø) and node 5 (Dornum) have natural gas reception facilities in reality, as shown by Figure A.1. The hydrogen demand is places in these two nodes. The costs for investing in hydrogen production plants are listed in Table 6.3.3.

6.3.4 Energy transmission

As shown in Figure 6.1, the nodes are connected through a line, representing an existing high-voltage direct current (HVDC) cable. Some of the HVDC-cables already exists, while others are are an assumption made in this research project. As illustrated in Figure 6.1, Node 1, Node 3 and Node 5 are connected with double lines. The second line represent the possibility for a hydrogen pipeline, which is an investment option in the model. Except the two hydrogen pipelines, all other cable sin Figure 6.1 are already existing. The existing ones are the ones connecting Node 3 to Node 5, 7 and 8. These subsea power cables connects the Norwegian power market to the market in Denmark (DK1), Netherlands (NL) and Germany/Luxembourg (DE-LU). The characteristics of these power cables, which are used as input to the model in terms of capacity, voltage, length and operational start year, is shown in Figure A.2. The two nodes located in the North Sea, Node 9 and 10, represents Sørlige Nordsjø II (SN2) and Utsira Nord (UN). These wind parks does not exist yet and an assumption is made regarding the connection to the onshore grid. As mentioned in section 2.4, a radial connection to the onshore grid appears to be the most likely solution. It is furtherly assumed an HVDC-cable connecting the Sørlige Nordsjø II directly to Europe. This enables selling power directly to the European market and operating the grid in a more sensible way, as this solution avoids congestion. The capacity of the line connection Node 9 (Sørlige Nordsjø II) and Node 5 (Dornum) is set to 5000 MW, as this seemed a reasonable capacity for a cable built in purpose of exploiting the significant wind resources there. From the cable connecting Node 9 (Sørlige Nordsjø II) to Node 3 (Kr.sand/Feda), is it assumed a grid capacity of 2100 MW.

The model is given the investment option of expanding the energy transmission segment between two nodes, with an upper limit of 15 GW. For the subsea HVDC-cables, the expansion cost is set to 852,87 (€/(MW-km)) [47]. The lifetime is set to 35 years [123]. This is based the grid expansion cost for a recently built 500kV cable with a transmission capacity of 1400 MW and a length of 670km between Germany and the United Kingdom (UK). The capital cost of the hydrogen pipeline is set to 266 (€/(MW-km)), and the depreciation time is 40 years [124]. It is assumed a transport capacity of 6000 MW for a hydrogen pipeline [124]. The capacity, length, type and investment cost of each line is represented in Table 6.6. The market nodes 2, 4 and 6 represent the local power market where the dual node is located, the power line has a very high capacity (5000 MW) and a low cost due to the short line (1 km). This makes a more realistic representation of connecting to the local surrounding grid.

Table 6.6: The investment alternative and corresponding cost of each segment. The distance between the nodes are measured through the following website: [13].

Nodes [From-To]	**Capacity** [MW]	**Length** [km]	**Annualized cost** [€]	**Type**
9-5	5000	411	120886886	HVDC-cable
9-3	2100	287	35454271	HVDC-cable
3-5	2100	508	62755294	HVDC-cable
3-7	1400	542	44636968	HVDC-cable
3-8	1700	135	13500506	HVDC-cable
10-1	1500	44	3882499	HVDC-cable
1-3	2100	212	26189217	HVDC-cable
5-6	5000	1	294129	HVDC-cable
3-4	5000	1	294129	HVDC-cable
1-2	5000	1	294129	HVDC-cable
Nodes [From-To]	**Capacity** [MW]	**Length** [km]	**Total cost** [€]	**Type**
1-3	6000	212	22487394	H2-pipe
3-5	6000	508	53884887	H2-pipe

6.3.5 Hydrogen storage

Hydrogen is stored in above-ground storage tanks. The costs related to storage are shown in Table 6.7. The invested energy costs is the 2030 target for "above-ground" storage, and is chosen due to the rapidly decreasing cost curve for hydrogen storage. The assumed storage size is 666 (MW) [11, p. 158].

Table 6.7: Hydrogen storage technology specifications. Inv. energy cost is gathered from [11, p. 158]. Inv. power cost and aux. power is gathered from [3].

H2-storage:	**Inv. power** [€/MW]	**Inv. energy** [€/MWh]	**Fix. power** [€/(MW-yr)]	**Fix. energy** [€/(MWh-yr)]	**Ramp. rate** [%/h]	**Eff.** [in% /out%]	**Aux. power** [MWh/ MWh]	**Size** [MW]	**Lifetime** (years)
Above ground	46666	1208	0	0	1	1	0,04	666	40

6.3.6 Power market

The market prices for price area NO2, DK1, NL and DE-LU are also extracted from the ENTSO-E transparency platform, with the standard time reference UTC: [120]. The markets surrounding the system are therefore hourly fixed prices, which the model can decide to buy from or sell to. As shown in Table 6.1, the nodes located in Denmark and Netherlands solely serve as market nodes. They are implemented in the system to investigate the system dynamics to the increased offshore power capacity, as they represent countries Norway is trading power with.

6.3.7 Computation

Each computation of the model, being one iteration in a scenario, takes about 1-4 hours to perform and about 30-50 GB of memory. The simulations are performed on NTNU's supercomputer Idun. The computational time is highly dependent on the work load of the nodes, as each iteration is simulated on a non-exclusive node. As each scenario consist of 6 iterations, and the total computational time span varies between approximately 6-15 hours. The simulations may be affected by traffic, but the overall wait time might be shorter than waiting for an exclusive node.

Chapter VII

Results

■ The results obtained from the model are presented in this chapter. The model operates on an hourly basis, but all the results are re-sampled to daily basis to be graphically presentable. The chapter begins by presenting the general results from the scenario analysis, regarding hydrogen and power production capacities and operation. Furtherly, the power and hydrogen price is presented. Thereafter, the chapter provides a presentation of a further investigation of the correlation results between PEMEL production, offshore wind and electricity price. Finally, the correlation results between PEMEL production and natural gas are presented.

7.1 Hydrogen production and impact of the carbon price

The optimization model invested in SMR, SMR with CCS and PEMEL across the scenarios. The installed capacity within the range of carbon prices in [%] for scenario 1-3 is shown in Figure 7.1, Figure 7.2 and Figure 7.3. Despite the option to investment in hydrogen storage, the optimization model does not choose to prioritize it at all.

Within each scenario, it can be observed that the carbon price affects the choice of hydrogen production method. As the carbon price increases, so does the installation of low-emission hydrogen production alternatives, such as SMR with CCS and PEMEL. Traditional SMR without CCS is entirely phased out after the first simulation across scenarios. It can be observed that the share of PEMEL compared to SMR with CCS for the same simulation is decreasing across scenarios, when comparing Figure 7.1, Figure 7.2 and Figure 7.3. However, Figure 7.4

shows that the installed capacity of PEMEL is in reality increasing for the same simulation across scenarios, but not as much as the installed capacity of SMR with CCS. This causes PEMELs share in percentage to decrease in comparison. According to Figure 7.4, the growth rate is approximately 200% and 400% for SMR with CCS, and 150% and 190% for PEMEL. The maximum generation capacity represents the hour during the year when the specific technology type has its highest production output. The trend shown in Figure 7.4 states that SMR and SMR with CCS achieved a production capacity capable of covering the entire demand alone. It can be observed that the installed capacity at its highest for each scenario corresponds to the respective hydrogen load in Table 6.3. This also confirms a hydrogen production in accordance to the hydrogen demand within the system. The hydrogen production occurs in the nodes with a hydrogen demand, being Node 5 (Dornum) and Node 1 (Kårstø). The production capacity is meeting the exact hydrogen demand within that node, making both nodes self sustained. PEMEL is predominantly incorporated in Node 5 (Dornum), and is exclusively implemented in smaller amounts in Node 1 (Kårstø) in the last iteration across the three simulations. The presented results are representing the entire system, and thereby provides an overview of the collective hydrogen production.

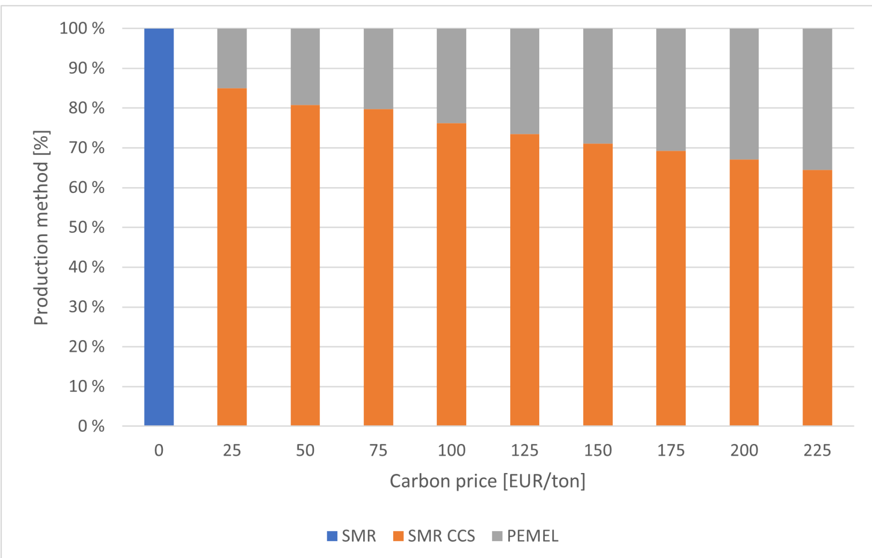

Figure 7.1: Hydrogen production sources in the Scenario 1

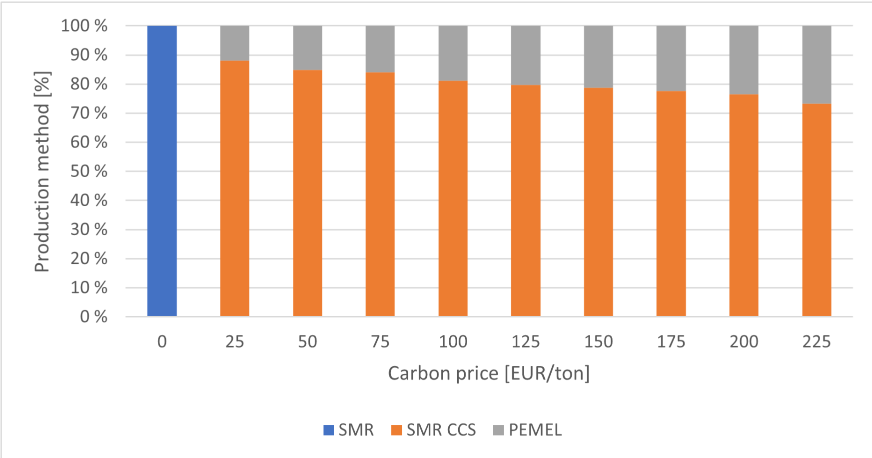

Figure 7.2: Hydrogen production sources in scenario 2

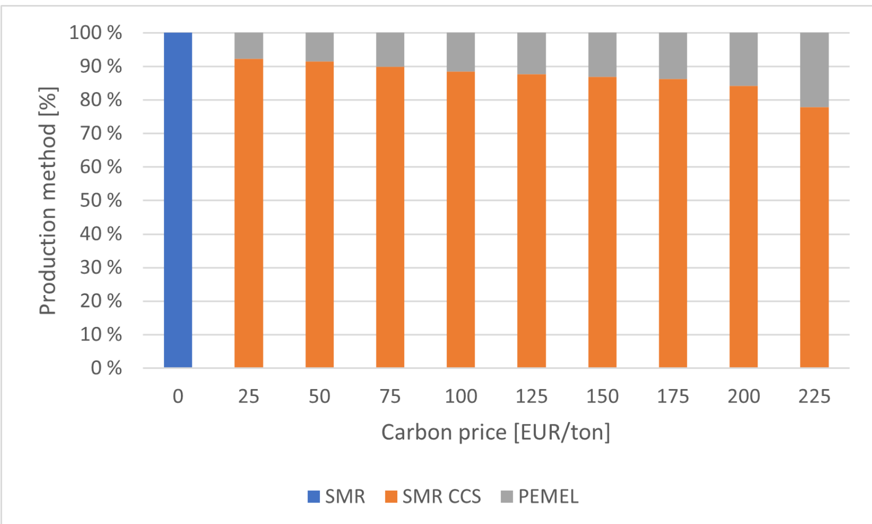

Figure 7.3: Hydrogen production sources in scenario 3

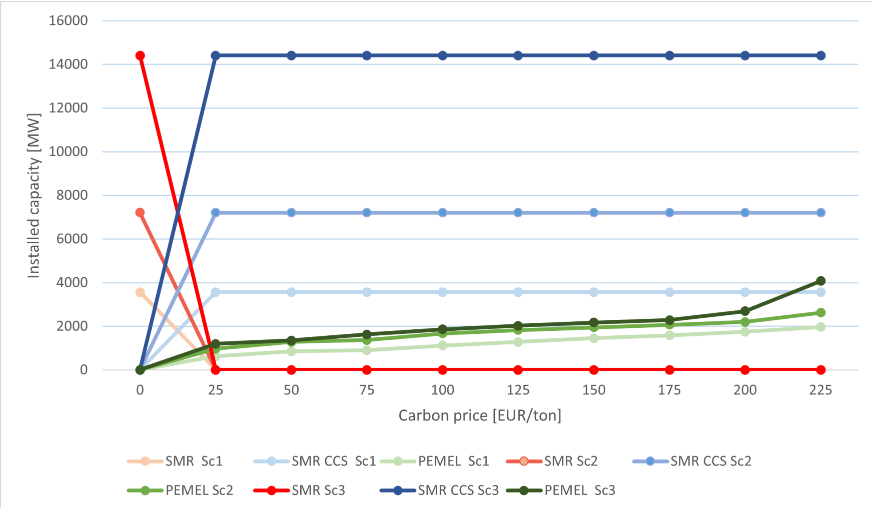

Figure 7.4: Quantities of hydrogen production from each method in each scenario, for the varying carbon prices

7.2 Power production and load

The system produces a total annual power output of 54 TWh of power across all scenarios, and of each simulation within each scenario. Furthermore, all scenarios invest in an additional 600 MW of onshore wind, as depicted in Table 6.4. No other energy sources are being invested in under any scenarios. The cumulative daily power output during a year is stacked for each energy source in Figure 7.5. This figure is based on data from scenario 3. However, there are minimal variations in average power production between the scenarios. The largest deviation in power production is observed between scenario 1 and 3, amounting to just 0,003%. Figure 7.5 illustrates that offshore wind power constitutes a majority of the electricity mix. This causes the total power production to be sensitive to the wind conditions. This can be observed in the large variations of power production over short periods of time. The typical behavior of wind production can also be observed, where production is higher during the winter than the summer [125]. The behavior of the power output from the hydro power plant stands out noticeably. It produces at a maximum capacity in the beginning of the year. Thereafter, the production is occasional and almost completely absent during the summer. Figure 7.6 illustrates the production and the load function. The total load in the system is 77 TWh. This is 23 TWh higher than the total production in the system, and makes the system reliant on power import. The load function is more stable during the year, with a lower consumption in the summer time and a higher consumption during the winter. There are weekly fluctuations, where the power consumption is at a higher level during the working week and subsequently declines on Fridays and Saturdays.

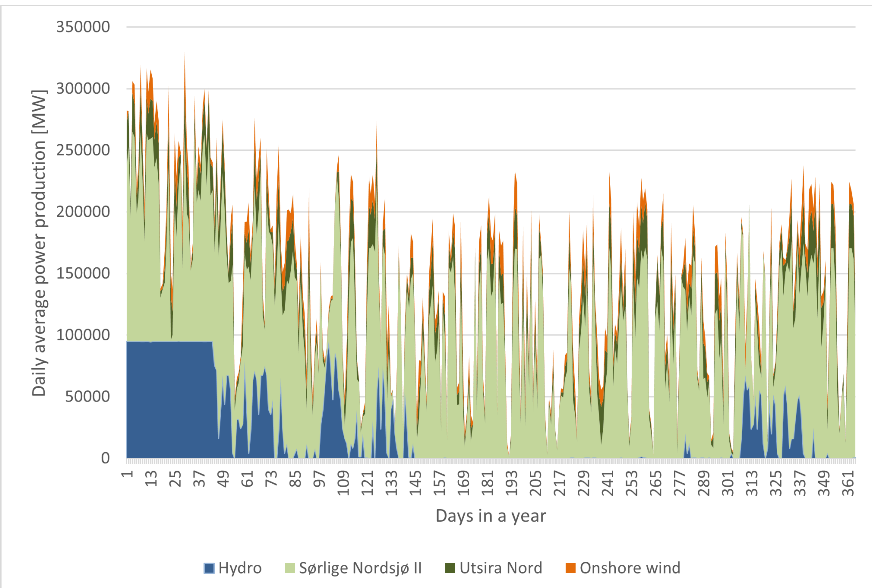

Figure 7.5: The stacked daily power production for scenario 3

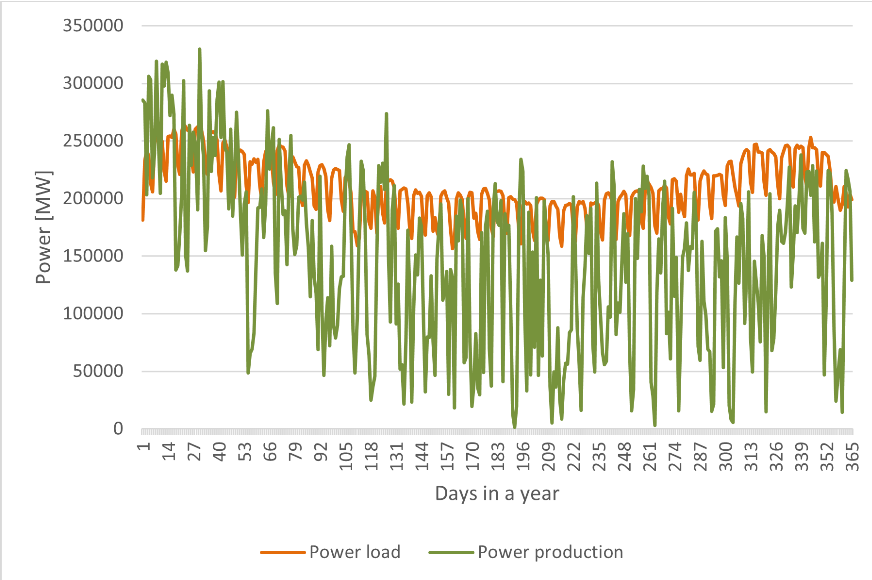

Figure 7.6: The daily load and average production through the year

7.3 Weighted electricity and hydrogen prices

The hydrogen and electricity prices from the results are obtained as the value of the dual variable of the hydrogen and electricity balance constraint in section 5.3. The weighted prices are calculated by multiplying the average annual price in each node with the corresponding average consumption encompassed by that node. Only the prices in the nodes where consumption of hydrogen and electricity occurs are included. Energy demand occurs in Node 1 (Kårstø), 3 (Kr.sand/Feda) and 5 (Dornum). Hydrogen demand occurs in Node 1 (Kårstø) and Node 5 (Dornum).

As shown in Figure 7.7, the electricity price increases for higher carbon prices and for higher hydrogen demand. The power price is the marginal cost of the system, i.e. the cost of producing one extra MWh. This can be observed mathematically in the energy balance constraint in section 5.3. The constraint consists of energy supply and energy demand variables. The energy production in the system remains constant across scenarios, as shown in Figure 7.5. The energy demand is however increasing, as the share of PEMEL increases and is electricity-driven. If the electricity import does not increase accordingly, the electricity prices will increase as a result. The annual average electricity price in NO2 and DE-LU was respectively

39,21 [EUR/MWh] and 37,66 [EUR/MWh] in 2019, according to ENTSO-E. This is generally close to the calculated weighted electricity prices, which are varying within a range from 39,6 [EUR/MWh] to 40,6 [EUR/MWh].

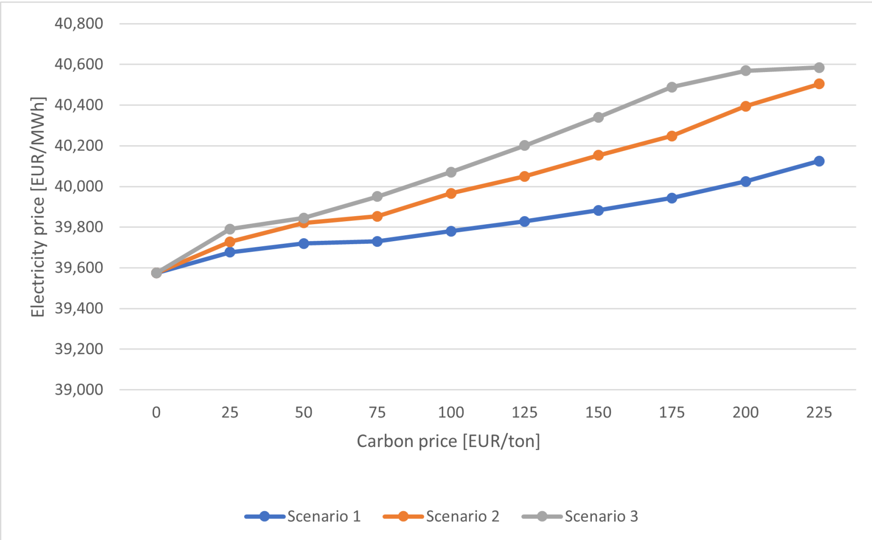

Figure 7.7: The weighted electricity price [EUR/MWh] for all the scenarios.

The weighted hydrogen price is illustrated in Figure 7.8. The development in hydrogen price is depicted across the three scenarios, and for a side-case derived from scenario 1 encompassing a double offshore wind installation. Similar to Figure 7.7, the trend in Figure 7.8 shows higher prices for increasing carbon prices, and the total price is quite similar for all scenarios. There is a significant leap in hydrogen price between the first and second simulation, demonstrating the impact of the carbon permit. For the total range of the carbon price, the hydrogen price varies from approximately 50 - 61 [EUR/MWh]. The carbon price has a significant impact to the hydrogen price. The direct consequence of a higher carbon price is the increased costs associated with SMR and SMR with CCS. Approximately 10% of the total emissions from a regular SMR facility are released from SMR with CCS, despite the CCS facility. The carbon price associated with the emissions is contributing to the increase in hydrogen price. Additionally, the electricity price in the system increases, as shown in Figure 7.7. This causes costs associated with PEMEL production to increase as well. This is also a contributing factor to the increasing hydrogen price. Figure 7.8 also shows that higher shares of power production lowers the hydrogen price. The electricity price was lower in the side-case than in scenario 1 due to the increased power production. A lower electricity price reduces the costs of PEMEL.

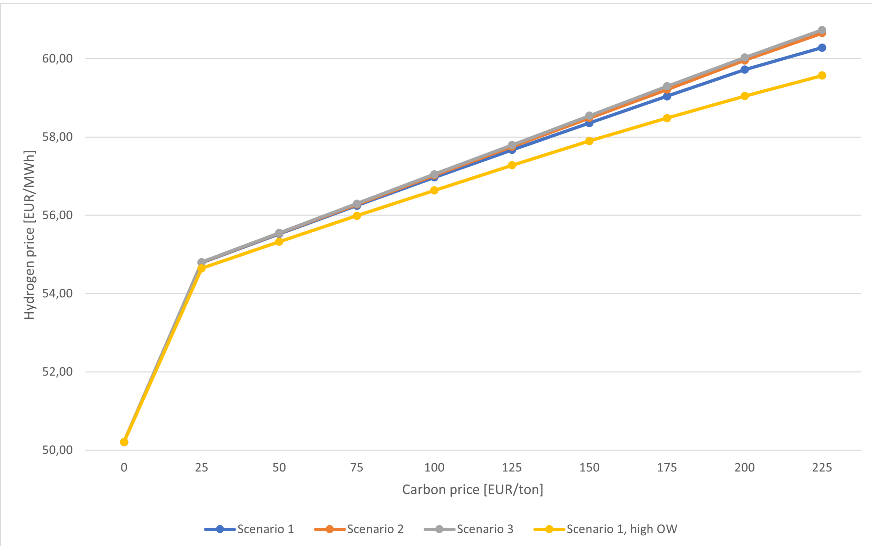

Figure 7.8: The weighted hydrogen price [EUR/MWh] for all the scenarios.

7.4 Utilization rate of installed capacity

The installed capacity of a technology is the maximum amount of production. The utilization rate is the relationship actual production and installed capacity, and is thereby somewhere in between 0 and 100%. The utilization of the installed capacity of SMR with CCS and PEMEL is shown in Figure 7.9 and Figure 7.10. The utilization rate of just SMR in the first iteration of the scenarios is not illustrated in a diagram, as the utilization rate is 100%. This makes sense, as the installation of SMR meets all of the hydrogen demand alone, and is not weather dependent. However, when the demand is covered by both SMR with CCS and PEMEL, the overall average utilization rate of the facilities decrease as they cooperate on covering the load.

The two figures shows the opposite trends, where the utilization rate of PEMEL incrementally increases whereas the utilization of SMR with CCS gradually decreases. The utilization rate shows that PEMEL is on average used between 29%-

46% for all the scenarios. In comparison, the utilization rate for SMR with CCS ranges between approximately 75%-96%. The deviation between potential and actual production of PEMEL highlights a significant underutilization of PEMEL production capacities during the year. Despite improvement of the utilization rate for higher carbon prices, substantial portions of PEMEL plants remain idle.

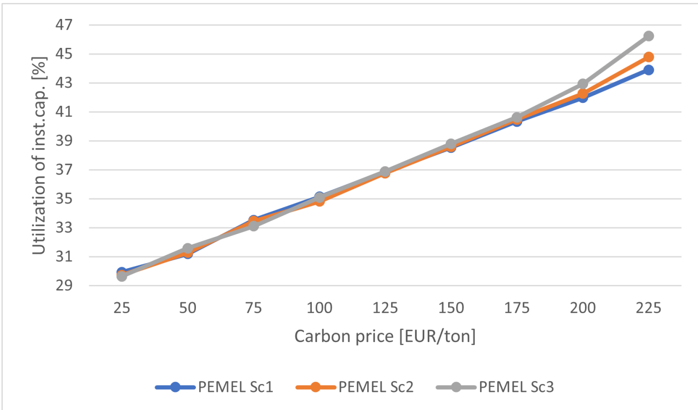

Figure 7.9: Utilization rate [%] of PEMEL for varying carbon prices

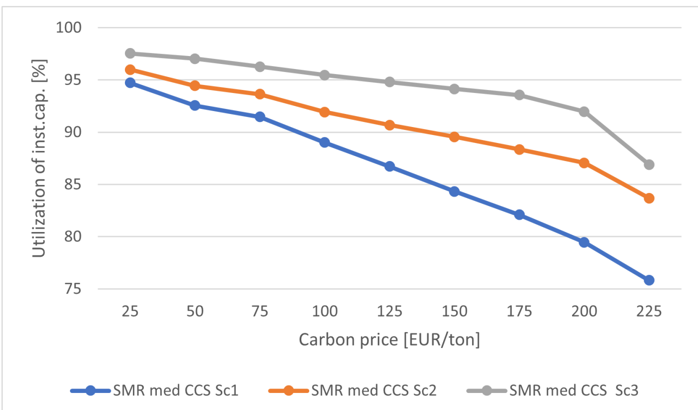

Figure 7.10: Utilization rate [%] of SMR with CCS for varying carbon prices

7.5 Correlation between PEMEL and offshore wind

In this chapter, the correlation results between PEMEL production and offshore wind are presented. As shown in section 7.1, PEMEL production is dependent on the carbon price. To capture the closest possible approximation to a realistic correlation between PEMEL and offshore wind, the carbon price was set to 100 [EUR/ton]. This carbon price falls between the range of the projected carbon price of 72 [EUR/ton] and the current trend is aiming towards 130 [EUR/ton] in 2024 [5]. Simulation 5 represents a system with a carbon price equal to 100 [EUR/ton]. Therefore, simulation 5 from the three scenarios was used in this analysis.

Figure 7.11 shows the daily average power production [MW] and the daily PEMEL production [MW] during a year from the three scenarios. The power production represents Figure 7.5 with an accuracy of 99,92%. Additionally, there is added a line showing the constant and daily hydrogen demand in each scenario. The trend illustrated in Figure 7.11 shows a higher PEMEL production with the upsurge in hydrogen demand. The hydrogen demand lines clarifies the magnitude of the total hydrogen demand compared to the production.

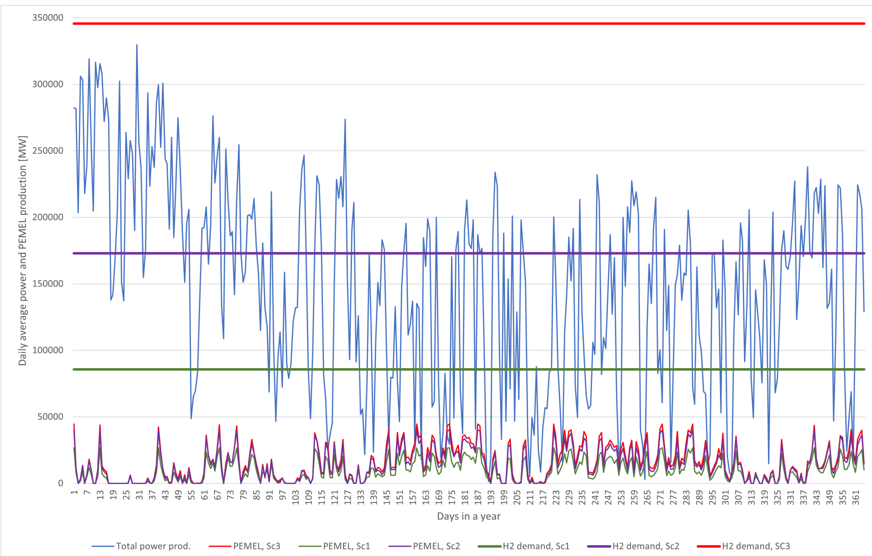

Figure 7.11: Power production [MW] and PEMEL production [MW] in each scenario

Figure 7.12 is a scatter plot showing the correlation between hydrogen production in scenario 1, and the total power production in the system. The correlation factor of the estimated trend line with the dots is just 3%. PEMEL production and the systems power production hardly correlates. A majority of the power generation originates from offshore wind, as shown in Figure 7.5. Sørlige Nordsjø II is directly connected to Node 5 (Dornum), where a majority of the PEMEL production occurs. The correlation between PEMEL production and power production from Sørlige Nordsjø II was investigated, and the result is illustrated in Figure 7.13. Although the error of the trend line improved to 11%, the correlation remains relatively low.

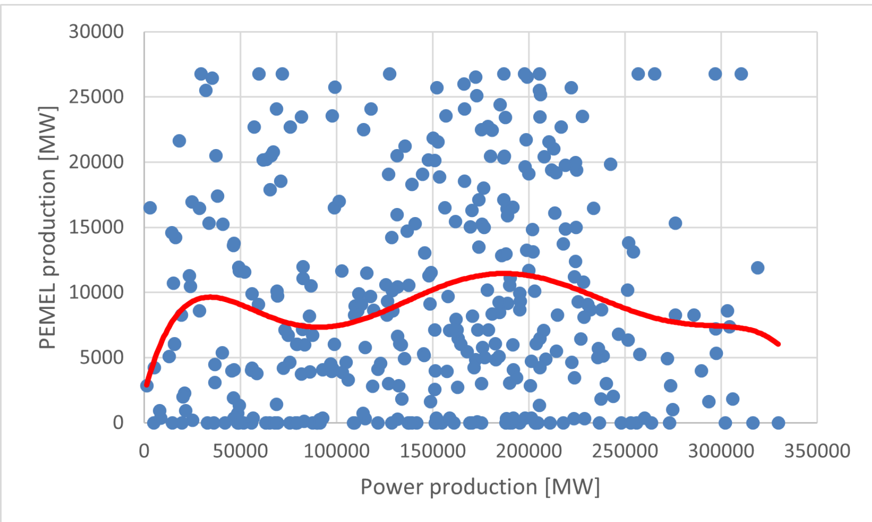

Figure 7.12: A scatter plot showing the correlation between daily average hydrogen production and total power production for simulation 5 in the scenario 1, and the respective trend line.

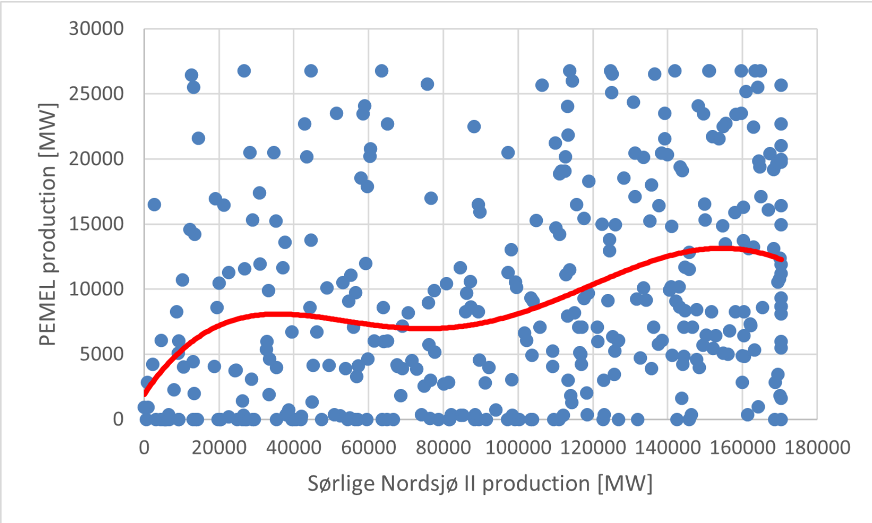

Figure 7.13: A scatter plot showing the correlation between daily average hydrogen production and power production from Sørlige Nordsjø II, and the respective trend line.

7.5.1 Increasing the share of offshore wind

Due to the significant power deficit illustrated in Figure 7.11, an investigation was performed to assess how increased power production impacts PEMEL production. A side-case was conducted, where the installed capacity of offshore wind is doubled to 14,2 GW for simulation 5 in scenario 1. Figure 7.14 presents a comparison of the power and PEMEL production in the high offshore wind case and the ordinary power and PEMEL production in simulation 5. The trend in Figure 7.14 shows that while power production increases substantially, the corresponding rise in PEMEL production is comparatively less pronounced.

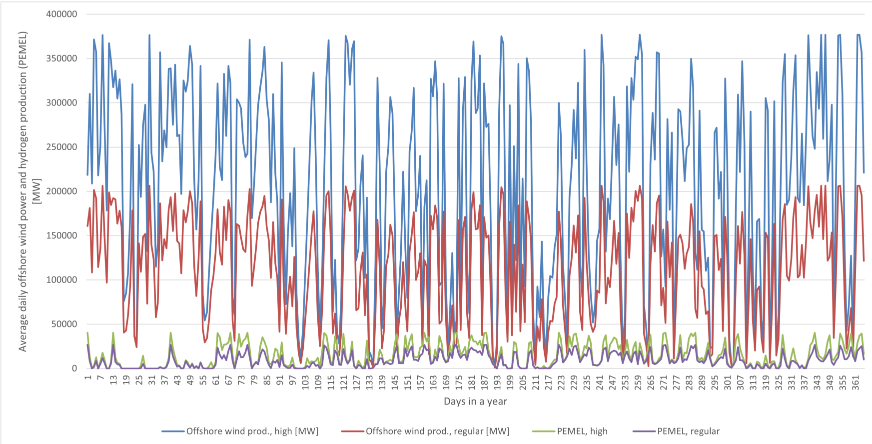

Figure 7.14: Illustration of the regular and high offshore wind production.

Figure 7.15 shows a comparison of how PEMEL and SMR with CCS covers the annual hydrogen demand in the high offshore wind case and the regular case. All parameters remains the same for both cases, including the annual hydrogen demand, except for the doubled offshore wind production capacity. Figure 7.15 demonstrated an improvement in hydrogen demand coverage by PEMEL as power supply increases, elevating it from 11% to 17,4%.

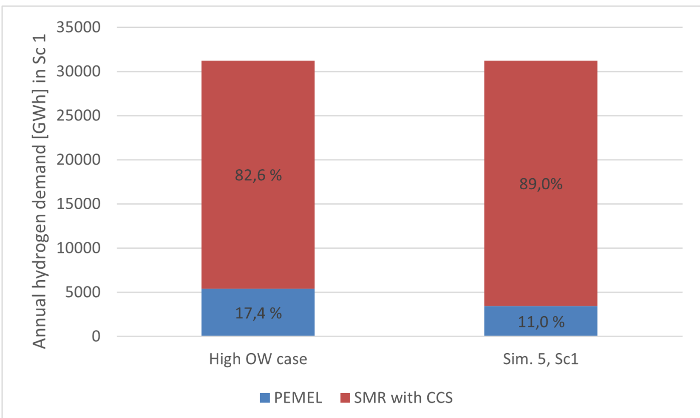

Figure 7.15: Comparative illustration of the hydrogen demand coverage in both simulation 5 from scenario 1, and in the high offshore wind case.

7.5.2 Correlation between PEMEL production and the electricity price

The correlation between PEMEL production and offshore wind is generally low, as shown in Figure 7.13. This is a system with power deficit compared to the ordinary power consumption excluding PEMEL. Additionally, Figure 7.9 shows an underutilization of PEMEL. The PEMEL facility exists from day 1, as shown in Figure 7.14. This information draws a picture; the operation of an already existing PEMEL facility depends on economically competitive operational costs compared to the operational costs of SMR with CCS. Furthermore, the operational costs of PEMEL is dependent on the electricity price. A scatter plot with PEMEL production and the average daily power price in Node 5 (Dornum), as PEMEL production is exclusively located there, for simulation 5 in scenario 1 is shown in Figure 7.16. The trend line has a correlation efficient of 84%. Trend line is to a larger extent indicating a piece wise linear function than a polynomial, but is a result of Excels interpretation of the points in Figure 7.16. Nevertheless, the presented trend line is showing the key take away of Figure 7.16, namely a high correlation between the electricity price and PEMEL production. The correlation between them predominantly occurs within the range of approximately 25-50 [EUR/MWh], as shown in Figure 7.16.

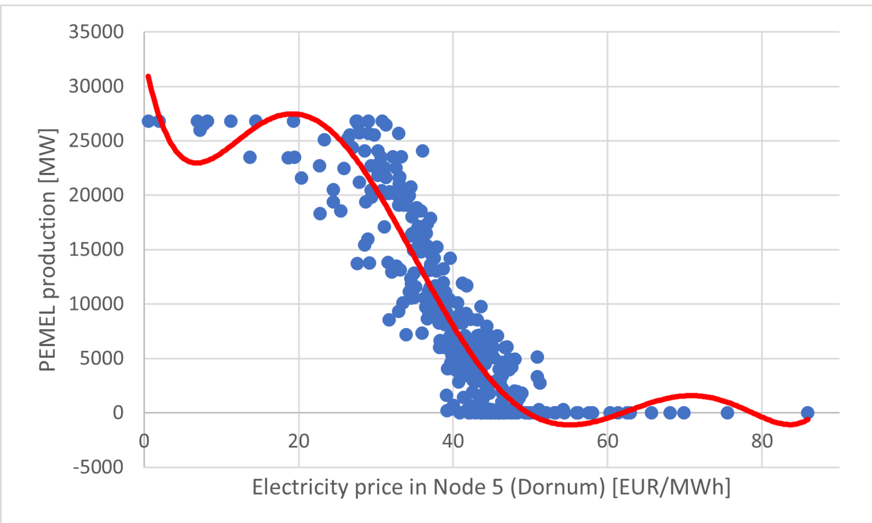

Figure 7.16: Correlation between PEMEL production and the electricity price.

Figure 7.17 shows the OPEX [EUR/MWh$_{H2}$] of producing one MWh of hydrogen for PEMEL and SMR with CCS. The cost of operating PEMEL is entirely dependent on the power price. The model accounts for power loss in the process, making it necessary to purchase 1,5 MWh$_{EL}$ per MWh$_{H2}$ produced. As shown in Figure 7.17, the OPEX is constant for SMR with CCS. It is only dependent on fixed costs; the cost of CCS, natural gas and emissions. The total OPEX for SMR with CCS is therefore constantly 55 [EUR/MWh]. Figure 7.17 shows that when the electricity price drives the OPEX of PEMEL higher than approximately 50 [EUR/MWh$_{H2}$], SMR is the most cost-efficient alternative. The production of PEMEL, illustrated by the grey graph, is respondent to this. However, it is not entirely responsive, as there is PEMEL production when the OPEX for SMR is the most cost-efficient alternative. This underlines that PEMEL is not entirely dependent on the most cost-efficient OPEX and thereby the power price. This is supported by the correlation in Figure 7.16, it is "only" 84%. It is also supported by the occasional blue dots for higher electricity prices in Figure 7.16.

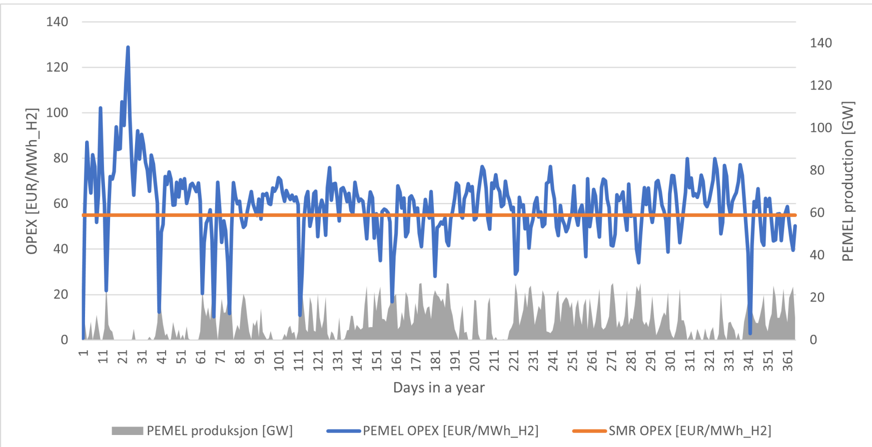

Figure 7.17: The daily OPEX of PEMEL and SMR and the production of PEMEL for a year.

7.5.3 Correlation between PEMEL production and the electricity price for a higher share of offshore wind production

The correlation of PEMEL and electricity prices is also investigated for the side-case. As mentioned earlier, the side-case is corresponds to simulation 5 in scenario 1 with a double offshore wind capacity. As shown in Figure 7.7, a higher power supply decreases the electricity price. Additionally, Figure 7.15 depicts an increased PEMEL production for higher production outputs as well. The scatter plot showing the correlation is shown in Figure 7.18. The trend line exhibits an enhanced correlation factor of 87%, marking a 3% increase compared to the correlation factor in Figure 7.16. The OPEX of PEMEL and SMR with CCS for the side-case is shown in Figure 7.19. The annual average electricity price has decreased from 39,48 to 38,87 [EUR/MWh]. The impact of the decreased electricity price is visible in Figure 7.19, as the OPEX for PEMEL has lowered compared to Figure 7.17. The OPEX for SMR with CCS is the same as before, as it is independent of the electricity price. This causes the OPEX of PEMEL to be more cost-efficient spanning over an extended duration of the year, which is reflected in the increased PEMEL production.

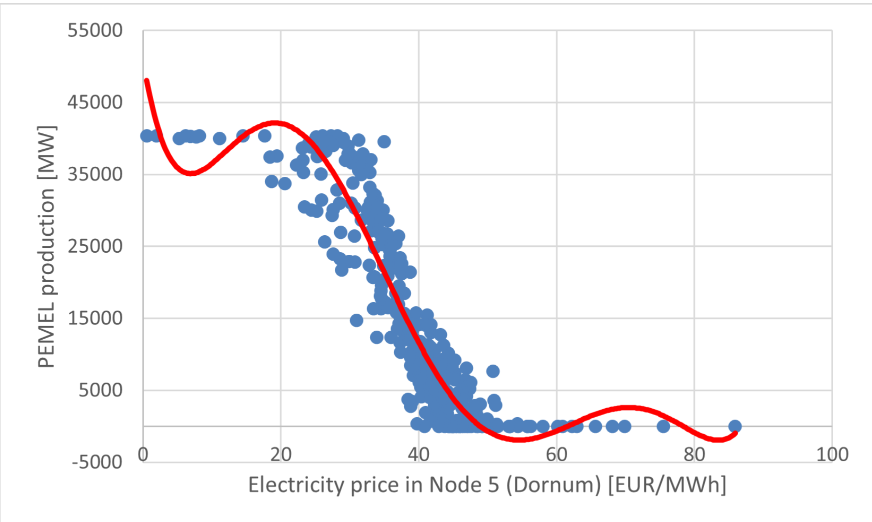

Figure 7.18: High offshore wind case; Correlation between PEMEL production and electricity price.

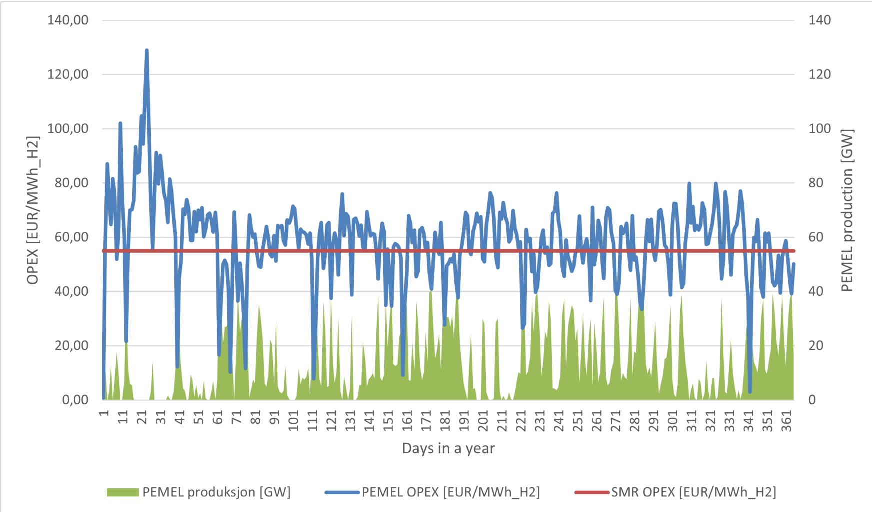

Figure 7.19: High offshore wind case; The daily OPEX of PEMEL and SMR and the production of PEMEL.

7.6 Sensitivity analysis on the natural gas prices

A sensitivity analysis on the natural gas price is conducted to assess the impact to hydrogen production and hydrogen prices. The natural gas price has experienced major fluctuations during the recent years, and has fallen to approximately 25 [EUR/MWh] [126]. The forecast suggests a natural gas price of 32,6 [EUR/MWh] within 12 months. Therefore, the range used for natural gas prices in the simulations were spanning from 10 to 45 [EUR/MWh]. As simulation 5 represents an acceptable estimate of the carbon price, it constitutes the systems framework in this sensitivity analysis.

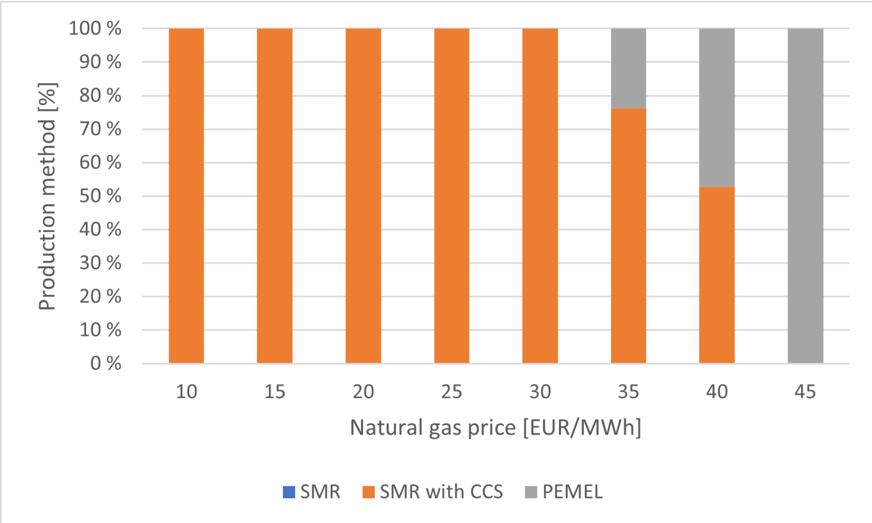

Figure 7.20: Scenario 1; development in production method for varying natural gas prices.

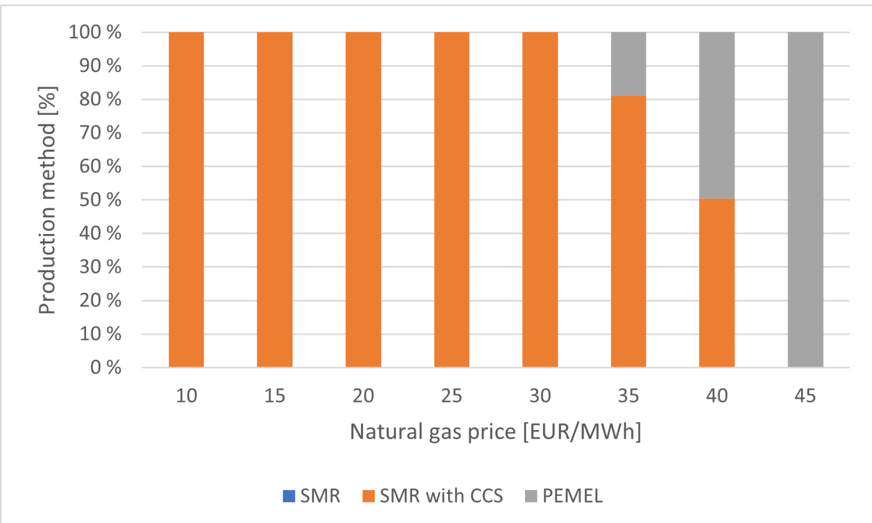

Figure 7.21: Scenario 2; development in production method for varying natural gas prices.

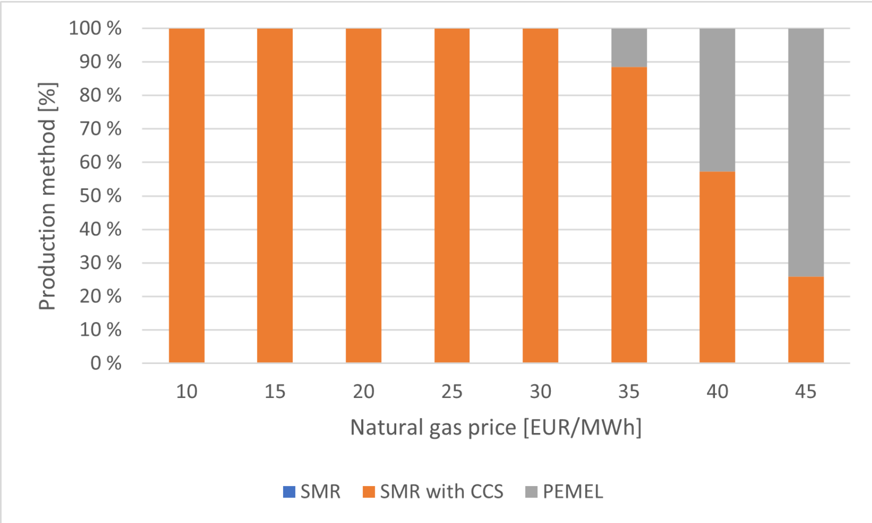

Figure 7.22: Scenario 3; development in production method for varying natural gas prices.

The weighted hydrogen price across the scenarios is shown in Figure 7.23. The hydrogen price increased for higher natural gas prices. For a natural gas price within 10-35 [EUR/MWh], the development in hydrogen price remains stable. The increase is driven by the higher operational costs of SMR, and a majority of the hydrogen is produced through SMR. For scenario 1 and 2, the hydrogen price stabilized as the natural gas price reaches 40-45 [EUR/MWh]. PEMEL is phased in, and constitutes 100% of the hydrogen production in the last simulation. As PEMEL is unaffected by an increased natural gas price, the curve stables out. As shown in Figure 7.20, PEMEL is incorporated at a slower pace compared to the other scenarios. The hydrogen price increases for higher natural gas prices when the hydrogen production is based on SMR with CCS, because natural gas is used as feedstock. For a natural gas price is 35 [EUR/MWh] in Figure 7.23, the hydrogen prices are similar across scenarios to the ones in Figure 7.8 for a carbon price of 100 [EUR/ton], as the conditions in the systems are identical. This is a positive confirmation of the reliability of the results obtained.

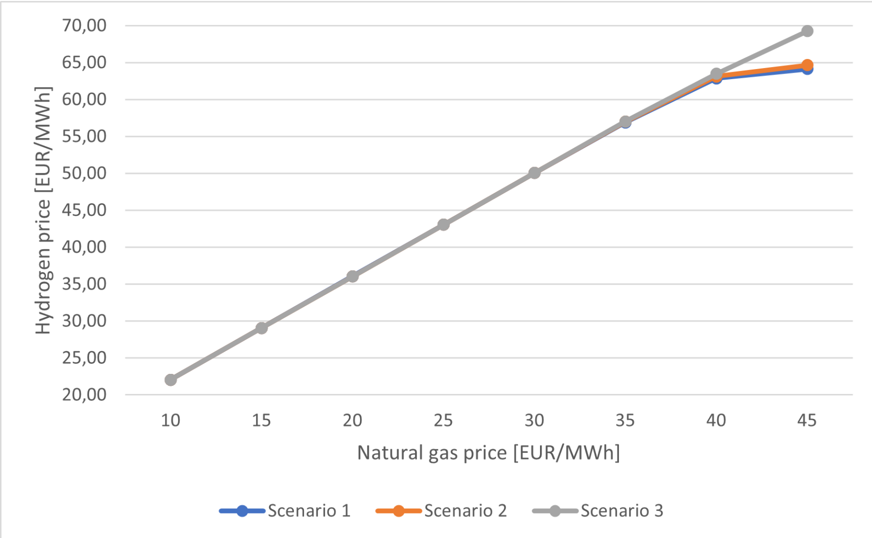

Figure 7.23: The weighted hydrogen price across scenarios for varying natural gas prices.

The weighted electricity price across scenarios is shown in Figure 7.24. The regular electricity load and the electricity used in PEMEL constitutes the total electricity demand. The electricity price remains constant through a natural gas price of 10-30 [EUR/MWh], as the only electricity demand is the regular electricity demand. In these simulations, the only electricity demand in the system comes from the regular power load shown in Figure 7.6. However, as PEMEL is phased-in and consumes power, the electricity price increases. With the increasing natural gas prices, the objective function value representing the total costs of the system increases. As the natural gas prices reach 40-45 [EUR/MWh], a change in hydrogen production technology occurs. The PEMEL production increased considerably between a natural gas prices of 40 and 45 [EUR/MWh] in scenario 1 and 2, as shown in Figure 7.21 and Figure 7.22. PEMEL went from covering approximately 50% to 100% of the load. This compelled the system to import power from the local power markets, which subsequently causing the electricity prices to marginally lower. In scenario 1, the net import to the system was 153% more in the simulation with natural gas price of 45 [EUR/MWh] compared to 40 [EUR/MWh]. 60% of the net import was imported from the local market node (Node 6) in Germany. A majority of the PEMEL facilities are located in Node 5 (Dornum). The development in electricity price for scenario 3 is rising for higher levels of natural gas price. The import conditions is likely similar for scenario 2, given the similar development in both hydrogen and electricity price. In the third scenario, the net import increased by 179% between the simulations with a natural gas price of 40 and 45 [EUR/MWh]. The electricity price still keeps on rising, as the power demand is higher than the power supply. Additionally, as mentioned in the previous paragraph, similar electricity prices to Figure 7.24 can be observed Figure 7.8 across scenarios for a carbon price of 100 [EUR/ton], as the systems conditions are similar.

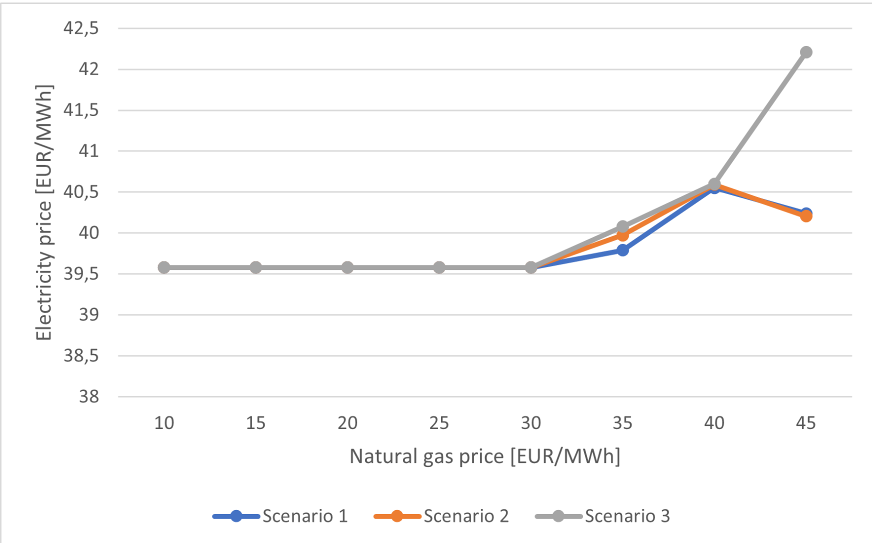

Figure 7.24: The weighted electricity price across scenarios for varying natural gas prices.

Chapter VIII

Discussion

■ In this chapter, the results obtained in the previous chapter are discussed in accordance to the research questions stated in the introduction. Finally, the system setup with a special focus on the estimate of power production is also discussed.

8.1 Phasing in low and zero emission hydrogen production

The results presented in chapter 7 shows that PEMEL is affected by an extensive portfolio of factors, and some have a higher impact than others. The results shows that carbon prices, natural gas prices, electricity prices, hydrogen production amount and supply of electricity affects the choice of hydrogen production alternative.

8.1.1 Implications of the carbon price and natural gas price

Figure 7.1, Figure 7.2 and Figure 7.3 shows an the incremental implementation of low-carbon hydrogen sources as the carbon price increases. SMR with CCS comprises a majority of the installed hydrogen production capacity across all simulations with a non-zero carbon price. However, PEMEL is present from the first iteration with a non-zero carbon price. As shown in Table 6.3.3, the CAPEX of SMR with CCS is 38% of the CAPEX of PEMEL. Table 6.3.3 shows that SMR with CCS has a 5.5 times higher fixed OPEX than PEMEL. This makes SMR with CCS favorable for lower carbon prices, where the operational cost is not excessively penalized by emission costs. As the carbon price increases, the combination of a high OPEX and a higher emission costs progressively phases out SMR with CCS for the benefit of PEMEL. The impact of the carbon price is already visible in first simulation with a carbon price above zero, namely of 25 [EUR/ton]. This trend emphasizes that the intention behind carbon permit trading is working, as an increasing carbon price facilitates low-emission hydrogen production. PEMEL prominently occurs in Node 5 (Dornum), where a significant portion of the hydrogen demand is placed. This highlights the impact of the hydrogen demand quantity to the optimal hydrogen source. PEMEL occurs to a low degree in Node 1 (Kårstø). The correlation is likely that the competitive advantage of large scale operation of PEMEL for high carbon prices does not outweigh the high CAPEX of PEMEL for low hydrogen demand quantities.

In the sensitivity analysis performed on the natural gas prices, it was anticipated a carbon price of 100 [EUR/tons]. The sensitivity analysis for varying carbon prices is based on a natural gas price of 35 [EUR/MWh]. Penalizing emissions provides incentives for phasing out SMR with CCS, as emissions are costly. Even so, the impact of the natural gas price was absent until it reached 35 [EUR/MWh]. After this point, the natural gas price was highly influential on the phase-in of PEMEL. For the next simulations, with a natural gas price of 40 and 45 [EUR/MWh], the share of installed capacity of SMR with CCS decreases rapidly. The phase-in of PEMEL is highly impacted by the natural gas price. As shown in Figure 7.20 for scenario 1, the installed capacity of PEMEL goes from 0% to 100% when the natural gas price ranges from 30-45 [EUR/MWh]. This is an aggressive phase-in of PEMEL compared to the gradual increase of PEMEL when the carbon price is varying. As shown in Figure 7.1, the installed capacity of PEMEL varies from 15% to 35% for a carbon price within a range of 25-225 [EUR/ton]. This highlight how sensitive PEMEL is to the natural gas price compared to the carbon price. As mentioned in the previous paragraph, the results shows that a non-zero carbon price is essential for phasing in low-emission solutions, and the natural gas price is decisive for phasing out fossil based hydrogen production entirely. For hydrogen to be a part of the transition to a low-carbon future, it is crucial that the process of producing hydrogen is decarbonized itself. The integration of PEMEL and SMR with CCS are imperative in this purpose.

8.1.2 Implications of power production

As electricity is the primary feedstock to PEMEL, it is indispensable for enabling the process. As shown in Figure 7.6, the modelled system experienced a power deficit, which has counteracted the process of PEMEL. The importance of power availability is evident in the form of higher electricity prices, net power import over the year and reduced PEMEL production. As shown in the scatter plot in Figure 7.12, PEMEL production is not particularly dependent on the power production itself. The correlation with total power production has an correlation factor of

3%. The response is somewhat higher to power production from Sørlige Nordsjø II in Figure 7.13, with an improved correlation factor of 11%. In comparison, the correlation factor of PEMEL and the electricity price is 84%, as shown in Figure 7.16. The findings from chapter 7 indicated that the production of power itself is not dictating for the production of PEMEL, but rather the electricity price as a result of electricity production or import. This is because the OPEX of PEMEL is dependent on the electricity price, and is therefore affecting the competitiveness towards the other production alternatives.

Among all the factors influencing PEMEL production, the electricity price has the highest correlation. The correlation factor of PEMEL and the electricity price might have been higher if the objective of the model was to produce as much hydrogen as possible. However, the correlation might be disturbed by the constant hourly hydrogen demand, which restricts the PEMEL production. As the model decided not to invest in hydrogen storage, there is no storage alternative to accommodate additional PEMEL production when the electricity price is beneficial. This might have alleviated PEMELs dependency on the current electricity price, and increased the utilization of the offshore wind resources. The trend for the timing of PEMEL production is graphically shown in Figure 7.17, where it becomes evidently clear that PEMEL is generally producing during the hours with an economically competitive OPEX. For the side-case with a doubled power output from Sørlige Nordsjø II, the electricity price decreases. This lowers the OPEX of PEMEL, and makes the PEMEL production even more competitive and active, as shown in Figure 7.19. The correlation can also be shown by the improved correlation factor of 87% in Figure 7.18. However, although he power production from Sørlige Nordsjø II was doubled, the PEMEL production did just increase by 6.4%, according to Figure 7.15 and Figure 7.14. The deviation in electricity price between these two cases was 0,61 [EUR/MWh]. This highlights two observations. Firstly, it supports the strong correlation between PEMEL and the electricity price, as a change in electricity price of 0.61 [EUR/MWh] can induce 6,4% higher PEMEL production output. Secondly, it emphasizes the severe power deficit in the system, as doubling the power output from Sørlige Nordsjø II only led to a marginal electricity price decrease by 0.61 [EUR/MWh]. These findings indicate that facilitation of PEMEL production is dependent on a sufficient electricity supply, causing electricity prices making PEMEL economically competitive. Additionally, the findings from chapter 7 indicate that the electricity price is affected by the electricity consume by PEMEL. As shown in Figure 7.7 and Figure 7.24, the electricity price increases as PEMEL is phased-in, as the system experience additional electricity consume in a system experiencing electricity shortage. This underscores the importance of sufficient electricity availability, as the competitiveness and production of PEMEL is affected by its own participation in the power market.

8.1.3 The hydrogen price

The hydrogen price is affected by the costs of operating the production source in which the hydrogen originates from, being PEMEL, SMR with CCS or SMR. A majority of the hydrogen is produced from PEMEL and SMR with CCS across varying natural gas prices and non-zero carbon prices. The operation of PEMEL and SMR with CCS increases with higher carbon prices and natural gas prices, as shown in chapter 7. This causes the hydrogen price to increase as well, as shown in Figure 7.8 and Figure 7.23. The hydrogen price itself does not directly facilitate PEMEL production. However, as shown in Figure 7.23, the hydrogen price is stabilized when PEMEL is phased in. PEMEL is defined to be unaffected by both the carbon price and natural gas price in this thesis. Therefore, high shares of PEMEL makes the hydrogen price resistant towards changes in both of these prices. Additionally, the hydrogen price in a system dominated by PEMEL can be lowered in accordance with lower electricity prices. As shown in Figure 7.1 and Figure 7.20, PEMEL is playing a predominant role in a system characterized by higher natural gas and carbon prices. Higher electricity supply decreases the electricity price. As shown in Figure 7.19, lower electricity prices decreases the OPEX of PEMEL. Therefore, in a system where hydrogen production is dominated by PEMEL, the hydrogen price will decrease with lower electricity prices. Competitive hydrogen prices through PEMEL has the potential to serve as a catalyst the expansion of PEMEL on a larger scale, and generate further development for commercial purposes.

8.2 Utilization rate of the installed hydrogen capacity without energy storage

The relationship between production and installed capacity is defined as the utilization rate. The utilization rate of SMR with CCS and PEMEL for each simulation across scenarios are shown in Figure 7.10 and Figure 7.9. As shown in Figure 7.4, the installation of PEMEL is incrementally increasing for higher carbon prices. The installed capacity of SMR with CCS is, on the other hand, large enough to cover the hourly hydrogen demand alone across all simulations in scenarios where SMR with CCS occurs. The total installed capacity of both PEMEL and SMR with CCS is therefore adding up to more production capacity than the hydrogen demand constitutes. This results in an underutilization of the facilities. As shown in Figure 7.4, SMR with CCS is covering a majority of the hydrogen load for lower carbon prices. This is reflected in Figure 7.10, where the utilization rate is centered around 96% across all scenarios. As shown in Figure 7.1, Figure 7.2 and Figure 7.3, the investment in PEMEL capacities expands incrementally along with increasing carbon prices. The utilization rate of PEMEL is increasing accordingly, as shown in Figure 7.9. The increase in utilization rate of the PEMEL facilities is therefore at the expense of SMR with CCS. However, the peak in utilization rate of PEMEL falls within a range of approximately 43-47% across the scenarios. Figure 7.9 shows that even under the most favorable conditions for PEMEL production, the facility is still idling half of the time.

The optimization model optimizes on an hourly resolution with an objective to cover the hourly hydrogen demand. The production of PEMEL is therefore restricted to cover the hydrogen demand in correspondence with an economically competitive OPEX during the target hour. The modeled system in this thesis is solely based on renewables, resulting in large fluctuations in power production over short periods of time, as shown in Figure 7.5. This causes variations in electricity prices. The electricity price and the OPEX of PEMEL are correlating through PEMELs fuel rate of 1.5 [MWh$_{El}$/MWh$_{H2}$], as shown in Table 6.3.3. The ripple effects of fluctuating electricity prices can therefore be graphically observed through the OPEX for PEMEL in Figure 7.17 and Figure 7.18. Consequently, the PEMEL production varies accordingly. During hours with high electricity prices, SMR with CCS is the most favorable option and covers 100% of the hydrogen load. This is reflected in the installed capacity of SMR with CCS being equivalent to the total hydrogen demand across all scenarios, as shown in Figure 7.4. This causes annually lower utilization rates of PEMEL.

8.2.1 Hydrogen storage

The optimization model does not invest in hydrogen storage in any of the scenarios. The decision of not investing in compressed hydrogen storage, also known as "above ground"-storage, was likely also affected by the significant costs of it, making a suboptimal objective function value. In a system where hydrogen storage did exist, it might have provided a higher utilization of the offshore wind resources, and relaxed PEMELs dependency on the electricity price for each specific hour, as mentioned in subsection 8.1.2. As mentioned in section 3.5, the increased flexibility to adapt to power production would likely also increase the utilization rate of PEMEL. On the other hand, it can be speculated whether increased PEMEL production for hydrogen storage would occur in this system due to the power deficit.

8.3 Norway's role in the future energy system

Norway is a net power exporter, contributing with low-emission energy to Europe through international grid connections, as shown in Figure 2.1. An installation of 30 GW offshore wind has the potential to double Norwegian power production, and thereby significantly increase the power export. The low-emission energy has the potential to decarbonize the European energy system by reducing the reliance on fossil energy sources. Furthermore, increased power supply can alleviate the shortage of energy in the European energy system, and thereby help counteract the energy crisis. According to ENTSO-E, the average hourly power consume in the German price area "DE-LU" in 2019 was 57379.2 MW [120]. The power export capacity from Norway to Germany in 2019 was 2100 MW. The Norwegian energy contribution during an average hour in 2019 could constitute to a maximum of approximately 3.66% of the total demand. With an offshore power cable from Sørlige Nordsjø II with a capacity of 5000 MW, the contribution increases to 12.37%. Norwegian offshore wind can contribute to the European security of power supply, contribute to decrease the electricity prices and support the independence of gas import.

The results obtained in chapter 7 shows that Node 1 (Kårstø) and Node 5 (Dornum) are self-sustained with hydrogen production in accordance with the respective demand, as mentioned in section 7.1. This is likely due to the high transmission costs of hydrogen, and the availability of power in Node 5 (Dornum) and Node 1 (Kårstø), facilitating local hydrogen production. Both section 3.1 and the results obtained in chapter 7 support the assumed significance of SMR with CCS and PEMEL in the future. Norway is a prominent contributor of both, as Norway is a large exporter of both electricity and natural gas. The commercial advantage of Norwegian electricity production should be taken into consideration when evaluating future investment in and operation of international HVDC-cables. In near future, this applies to the assessment of whether to reinvest in the HVDC-cables Skagerrak 1 and 2, connecting the Norwegian and Danish power markets together, as they are outliving their technical lifetime in 2025 [127]. However, a consequence of connecting or expanding the transmission capacity between the Norwegian power market with the European, is the impact to market price, as several electricity consumers enter the market.

8.4 Power deficit in the results

In the results obtained in chapter 7, the average hourly onshore production in NO2, was 1402.3 MW. In comparison, the actual average hourly power production in NO2 was 4860.47 MW in 2019 [120]. The modelled onshore production in NO2 therefore fails to accurately estimate the real power production. This causes a power deficit in the results, which impacts the choices performed by the model. For instance, the hydropower reservoirs are completely drained during the first approximately 40 days, as shown in Figure 7.5. This is a result of generally higher electricity prices and the high electricity demand in this period, as shown in Figure 7.6. As mentioned in section 8.2, the trend in the fluctuations of the electricity prices can be observed by examining the OPEX for PEMEL in Figure 7.17 and Figure 7.18. Both figures illustrate large fluctuations and high prices during the first 30 days, where both the peaking and the bottom point occurs. The high hydropower output might be a response in stabilizing the high electricity prices during this time period.

Chapter IX

Conclusion

The objective of this thesis is to investigate the role Norwegian energy resources, with a special focus on offshore wind, constitute in current and future hydrogen production. In light of the climate crisis, the focus is especially focuses on the conditions in which low and zero emission hydrogen production alternatives are phased in. In this thesis, low and zero emission hydrogen production encompass Polymer Electrolyte Membrane Electrolysis (PEMEL) and Steam Methane Reforming (SMR) with Carbon Capture and Storage (CCS), and are compared to traditional hydrogen production through SMR without CCS. The motivation for performing this study was to study hydrogen systems to obtain knowledge that will provide a better decision basis for authorities and participants in the energy market.

The research project encompassed a scenario analysis of a North Sea case. The objective was to cover the hydrogen and electricity demand in parts of Norway and Germany with minimal overall costs, with a specific hydrogen demand for each scenario. The system included offshore power production from Sørlige Nordsjø II and Utsira Nord, and onshore power production from NO2, with the possibility of power export and import from the power markets in DK1 (Denmark), NL (Netherlands), DE-LU (Germany) and NO2 (Norway). A capacity expansion model was utilized to solve the optimization problem, that was written in Python with the Pyomo optimization framework. Several variants of the North Sea case was simulated to investigate how the hydrogen production pathways responded to varying carbon prices, natural gas prices, hydrogen demand and increasing offshore power production. The optimal hydrogen production solution is dependent its cost-effectiveness compared to the other alternatives. Therefore, the capital expenditures (CAPEX) and operational expenditures (OPEX) of the hydrogen production alternatives lay the foundation for their respective costs, and factors affecting these provide the outcome of the optimal investment alternative.

The first research question addresses the impact of varying carbon prices to hydrogen production alternatives. The results shows that a carbon price of 0 [EUR/ton], there are no incentives to reduce the emissions, and hydrogen is produced through SMR. The results furtherly shows that for the first simulation with a non-zero carbon price, being 25 [EUR/ton], the carbon price phases out SMR entirely. Instead, the hydrogen demand is jointly covered by SMR with CCS and PEMEL. The CAPEX of SMR with CCS is 38% of the CAPEX of PEMEL. However, SMR with CCS has a 5.5 times higher fixed OPEX than PEMEL. This makes SMR with CCS favorable for lower carbon prices, where the operational cost is not excessively penalized by emission costs. As the carbon price increases, the combination of a high OPEX and a higher emission costs progressively phases out SMR with CCS for the benefit of PEMEL. However, it is likely that the competitive advantage of large scale operation of PEMEL for high carbon prices does not outweigh the high CAPEX of PEMEL for low hydrogen demand quantities. The carbon permit system was implemented by the EU to give economic incentives to phase in low-emission industrial processes. The phase-in of low-emission hydrogen production for increasing carbon prices indicates that the carbon permit trading system is working according to its intention.

The objective of the second research question was to investigate the impact of power production from Norwegian offshore wind to hydrogen production alternatives. The findings shows that the power production itself is not dictating for the production of PEMEL, but rather the electricity price. The electricity price is determined by the electricity supply and demand in the system. The findings indicate a high correlation between the OPEX of PEMEL production and the electricity price with a correlation factor approximately 84%, as shown in subsection 7.5.2. This correlation increases marginally for higher offshore wind production in the system. The electricity demand in the system is constituted by the pre-specified electricity demand and electricity use in PEMEL. The electricity price therefore increases for higher PEMEL production. This underscores the importance of sufficient electricity availability where PEMEL production occurs, as the cost-efficiency and amount of PEMEL production is affected by its own participation in the power market. As the electricity price is highly influencing the operation of PEMEL, it is also affecting the utilization rate of the hydrogen production alternatives. The results shows that during hours with high electricity prices, SMR with CCS is the most favorable option and covers 100% of the hydrogen load. This is reflected in the total installed capacity of SMR with CCS being equivalent to the total hydrogen demand across all scenarios. Additionally, it is reflected in the underutilization of installed PEMEL capacities, where the utilization rate reaches 50% at a maximum. However, the utilization of PEMEL capacities increases with rising operational cost of fossil based hydrogen production, such as increasing carbon and natural gas prices, as SMR with CCS is consequently phased out. The system is entirely based on renewables, where offshore wind constitutes a majority of the power production. Due to the stochastic nature of wind power production, the electricity prices in the system are highly fluctuating. This causes PEMEL production output to be highly varying as well. The results are also showing a power deficit in the system due to an unrealistic modelling of onshore power production as mentioned in section 8.4. This might cause unrealistic instability to the electricity price and thereby PEMEL production.

The third research question addressed the impact of varying natural gas prices to investment decisions in the hydrogen production alternatives. The findings indicate that the natural gas price is decisive phasing out fossil based hydrogen production entirely, which is SMR with CCS in this analysis. A higher natural gas price induces higher operational expenditures (OPEX) of SMR with CCS. For larger amounts of hydrogen production, the competitive advantage OPEX of PEMEL out-weighs the significant capital expenditure (CAPEX) of PEMEL. The results indicate that the natural gas price is more influential of the phase-in of PEMEL than the carbon price.

Besides the correlation between the electricity price and hydrogen production alternatives, the fourth research question also includes the correlation with the hydrogen price. The hydrogen price is affected by the costs of operating the production source in which the hydrogen originates from. It is therefore increasing for a more expensive operation of the hydrogen production alternatives, through increasing carbon and natural gas prices. The hydrogen price itself does not directly facilitate PEMEL production. However, the hydrogen price is stabilized when PEMEL is phased in. PEMEL is defined to be unaffected by both the carbon price and natural gas price in this thesis. Therefore, high shares of PEMEL makes the hydrogen price resistant towards changes in both of these prices. Additionally, the hydrogen price in a system dominated by PEMEL can be lowered in accordance with lower electricity prices.

The objective of the fifth research question was to investigate the role of hydrogen storage. However, the model decided not to invest in hydrogen storage, likely due to significant costs of it. Hydrogen storage could potentially increase PEMELs flexibility in adapting to power production, and thereby increase the utilization rate of PEMEL. As hydrogen storage was excluded from the results, it is not possible to draw any conclusions.

The overall objective of the research questions was to investigate the role Norway constitutes in future hydrogen production and as a power producer. The results shows that the hydrogen consuming nodes in Norway and Germany are self-sustained on hydrogen, where they are locally producing hydrogen in accordance to their respective demand. The largest hydrogen consumers are located in the EU, and the hydrogen demand is expected to increase towards 2050. Norway is in an exceptional position to support hydrogen production in the EU through PEMEL, SMR and SMR with CCS through export of natural gas and electricity. The role as an electricity exporter will be furtherly strengthened by the installation of an additional 30 GW of offshore wind within 2040 [42]. Additionally, increased electricity supply will have a decreasing effect on the electricity prices.

Chapter X

Further Work

While the study has provided insight to the subject, there is plenty of improvement potential to the system and the model. The results of the model is restricted to the outputs and the framework of the modelling, which excludes possible realistic solutions of interest to policy-makers and other stakeholders. Examples of improvement areas are highlighted in the following paragraphs.

The time range could have been extended to encompass several years, instead of one target year. The energy system is facing radical operational changes due to the expected higher share and dependency on VRE [101, p. 13]. This induces a necessity for performing research on the energy balance and storage options over a time range that includes the unexpected large-scale weather events, which occasionally occurs. The disadvantage of optimizing over one year, is that the chosen year might not be representative in weather conditions, illustrated by Figure 3.8. A majority of the research conducted today is generally ranging between sub-hourly and calendar years [101, p. 14]. This may lead to a knowledge gap and possible misconception of the optimal operation of storage.

The system could have been simulated with several storage alternatives. In this system, the only storage option available is "above ground"-storage. Compared to the alternative, salt cavern storage, "above ground"-storage is considerably more expensive. The capital costs of salt cavern storage is just 5% compared to "above ground"-storage [11, p. 158]. However, "above ground"-storage is the most common way of storing hydrogen today [128]. Additionally, it was difficult from a modelling perspective to restrict hydrogen storage to just Node 5 (Dornum) as salt cavern storage is located in Germany, as shown in subsection 3.4.1. This might have allowed for hydrogen storage to be a component in the system, and thereby investigate the role it constitutes in the energy system. That would have enabled an investigation of its utility value for both PEMEL production and in the energy system. According to [24], Norway is in possession of sub-sea caverns with a storage potential of 7,5 PWh$_{H2}$ in the North Sea. This is a major potential for storage. In comparison, Germany has Europe's largest onshore storage facilities in the shape of salt caverns, with a capacity of 9,4 PWh$_{H2}$. It would be interesting to look further into the potential for hydrogen production from offshore wind and storage in depleted gas fields the North Sea, with potential connections to Europe and Norway. This was excluded from the model as it was too time demanding to reprogram the code to include this.

The model does not include reversible pumped turbines (RPT) for hydro storage. This type of energy storage is highly relevant for a system with high shares of VRE. When not including it, the correlation between it and other storage options (i.e. hydrogen and battery) is not evaluated. Neglecting the value of RPT when assessing storage options cause assessment on incomplete basis.

The model would be more realistic of the cost of offshore wind was differentiated into floating and bottom-fixed. This is highly relevant for Norwegian offshore wind, which consists of a mixture of both [129].

The model only focuses on hydrogen production, but could include the production of other hydrogen derivatives, such as ammonia, as well [21, p. 6]. The area of use for ammonia is expected to increase a lot in the coming decades, especially within the heavy transport sector. Neglecting the process of ammonia production and its existing and future market share is an incomplete estimate of the total hydrogen use.

The HEIM model used in this thesis does not include hydrogen demand into the market nodes. This excludes a potential for a larger hydrogen market around the modeled region, and thereby also the potential research on this. The market nodes are somewhat functioning as drainage for the model, where surplus power is drained out of the system to maintain the energy balance. The hydrogen production works the same way, except the model has to match the hydrogen production and consumption within the system each hour. The operation of the hydrogen production plants could have been different if there was a demand outside the model as well. A hydrogen market outside the model could have represented a hydrogen demand in the surrounding system.

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Appendix - A

Appendix

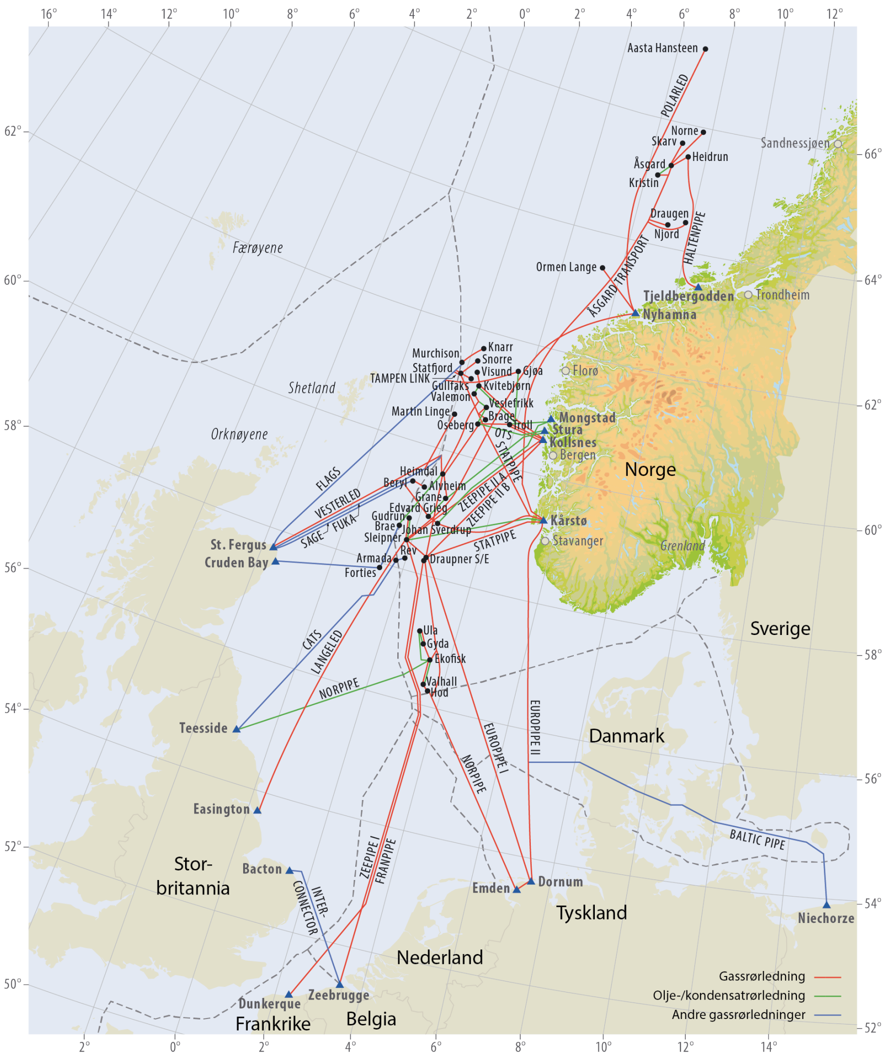

Figure A.1: Overview of the pipeline system in the North Sea. From [29].

Navn på linje	Operatør	Fra	Til	Oppstårt sår	Kapasitet (MW)	Susceptance (B)	Lengde (km)	Spenning (kV)
North Sea Link	Statnett	Suldal	Newcastle (Storbritannia)	2021	1400		720	525
NordLink	Statnett	Tonstad	Wilster (Tyskland)	2021	1400		623	525
NorNed	Statnett	Feda	Eemshaven (Nederland)	2007	700		580	450
Cross-Skagerrak	Statnett	Kristiansand	Tjele (Danmark)	1976	1700		240	350

Figure A.2: Overview of the interconnecting subsea HVDC cables and their characteristics between Norway and EU. From respectively; [30], [31], [32] and [33].

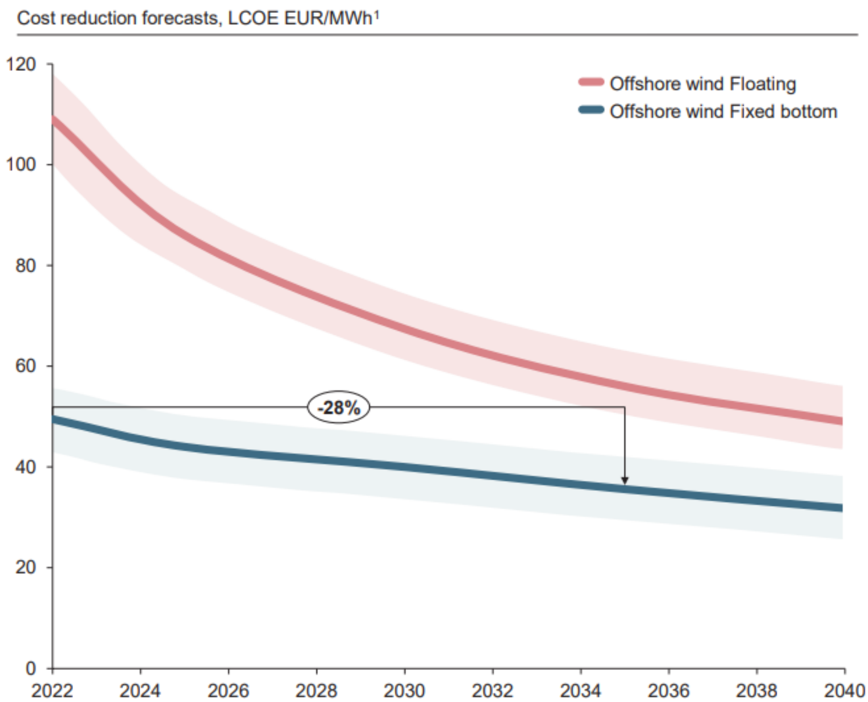

Figure A.3: A prognosis of the LCOE of North European bottom-fixed and floating offshore wind towards 2040. From [34]

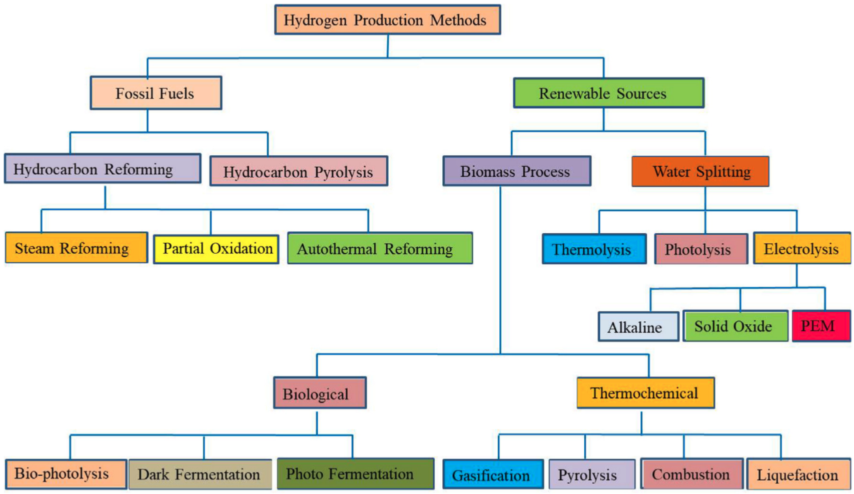

Figure A.4: Hydrogen production methods. Collected from [23].

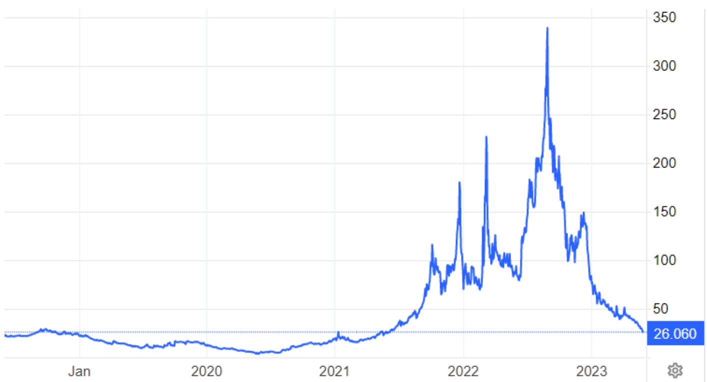

Figure A.5: Development of the natural gas price [EUR/MWh] in Europe. From [35]

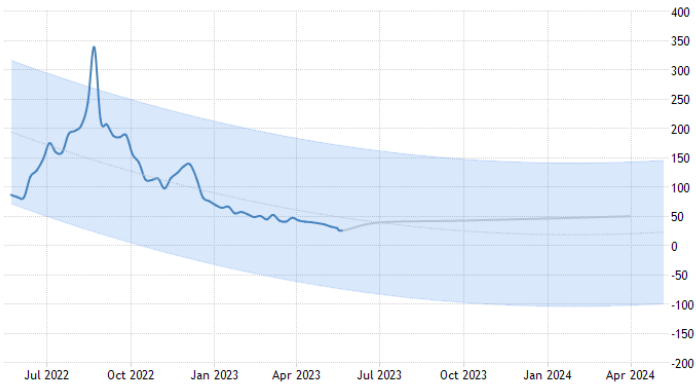

Figure A.6: Forecasted development of the natural gas price until April 2024 [EUR/MWh] in Europe. From [35]

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