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Integration of green hydrogen in the European energy systems

Technical maturity and impact assessment of hydrogen utilisation in 2050

- *Integrering av grön vätgasproduktion i de europeiska energisystemen*

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Civilingenjörsprogrammet i energisystem

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Abstract

Hydrogen has been suggested as a way to decarbonise the global energy system for decades but has yet to have a breakthrough on the European energy market. For the past decade, the efforts to reduce carbon emissions in the European energy market have increased, leading to rapid changes and a decline in costs of renewable energy. These efforts to reduce carbon emissions, combined with difficulties of decarbonising in several sectors due to few viable alternatives, surged the interest in hydrogen as a possible solution.

This thesis investigates how large scale production of hydrogen via electrolysers can be integrated into a future power system with high shares of renewable energy capacity. Based on a literature review, a scenario for the year 2050 was constructed with the aim to identify sectors with potential hydrogen demand in the future. The scenario focuses on Germany and the United Kingdom and was implemented in a power market dispatch model called Bid3 to analyse its effects on the European energy system. The hydrogen demand was estimated to 225 TWh for Germany and 157 TWh for the United Kingdom whereas the necessary storage capacity for the two countries was identified to between 20 to 24 TWh. The sectors with the largest hydrogen potential were identified as the residential and commercial heating sector as well as the heavy vehicle transportation sector. Moreover, the implementation of hydrogen managed to reduce greenhouse gas emissions by 88.8 M tonnes CO2-eq per year.

The implemented electrolysers showed great synergy with renewable energy capacity by improving the flexibility of the power system. As a result, it also reduced the severity of price crashes due to oversupply of renewable energy generation. However, even with installed electrolysers, the high share of renewable energy capacity caused several hours of wholesale power price close to zero. Hence, the scenario highlighted the difficulties of obtaining a power system with a high share of renewable capacity within the regulations of the current power market.

Sammanfattning

Den europeiska energimarknaden ändras snabbt till följd av sjunkande kostnader för förnybar energi och politisk vilja att reducera växthusutsläpp. Detta tillsammans med svårigheter att byta ut kolbaserade produkter inom en del sektorer har lett till ett ökat intresse för vätgas som en potentiell del av lösningen.

Denna uppsats analyserar hur storskalig vätgasproduktion med elektrolys kan integreras i ett framtida elsystem med stor andel förnybar energi. Ett scenario för 2050 utformades för att identifiera den potentiella efterfrågan av vätgas i flera sektorer. Scenariot fokuserade på Tyskland och Storbritannien vilket implementerades i elsystemsmodellen Bid3 för att analysera effekterna på energisystemen i Europa. Efterfrågan på vätgas uppskattades till 225 TWh för Tyskland och 157 TWh för Storbritannien, vilket täcktes av nationell produktion via elektrolys och de sektorer med störst uppskattad efterfrågan identifierades som värmesektorn samt transportsektorn. Genom produktion av vätgas som ersatte kolbaserade bränslen och produkter, kunde utsläppen reduceras med 88.8 M ton CO2-ekv per år.

Vätgasproduktion med elektrolys i förbindelse till elnätet ökade också flexibiliteten i elsystemet. Detta ledde till större motstånd vid prisras som kan uppstå vid överproduktion av förnybar energi. Dock ledde det konstruerade scenariot trots vätgasproduktion till ett stort antal timmar med låga elpriser, vilket visar på svårigheter i att integrera stora mängder förnybar energi i den nuvarande elmarknaden.

Executive summary

During the last decade, the European energy market has been changing rapidly due to declining costs of renewable energy and ambitions of reducing carbon emissions. This, together with difficulties in several sectors of decarbonising due to few viable alternatives, have resulted in a surging interest in hydrogen as a possible solution.

This thesis looks into the value chain of hydrogen to identify sectors that are more probable to have an increased demand for hydrogen in a future hydrogen market. Heavy vehicles with high utilisation rate, as well as the steel industry, were identified as sectors with a potential for increased hydrogen demand. It was also found that mixing hydrogen in the current gas infrastructure can be a way of efficiently increasing the hydrogen demand without the need for large investments in surrounding infrastructure.

Furthermore, this thesis investigates how hydrogen production by electrolysis (green hydrogen) can be integrated into the European energy systems, and how this would affect the energy markets. This was done by creating a scenario and analysing its effects. In the constructed scenario, a total hydrogen demand for Germany and the UK was estimated to 382 TWh which was covered by 99.6 to 107.9 GW electrolyser capacity. The necessary storage to balance the seasonality properties of demand, and generation from renewable energy, was calculated to 19-24 TWh. Moreover, electrolysis showed good synergy with renewable energy capacity by producing hydrogen during low price hours, acting as demand response and thus counteracting price crashes that can occur at times with high renewable energy generation. Therefore, electrolysers would enable higher penetration of renewable energy on the power grid, while at the same time produce hydrogen that can be used outside of the power sectors, where fewer alternatives for decarbonisation exist.

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Abbrevations

AEC	Alkaline Electrolysis
BEV	Battery Electric Vehicle
CCGT	Combined Cycle Gas Turbine
CCUS	Carbon Capture Utilisation and Storage
CapEx	Capital Expenditure
EU	European Union
FCEV	Fuel Cell Electric Vehicle
FES	Future Energy Scenario
GHG	Green House Gas
ICE	Internal Combustion Vehicle
IEA	International Energy Agency
LNG	Liquid Natural Gas
NGCC	Natural Gas Combined Cycle
OpEx	Operational Expenditure
PEM	Proton Exchange Membrane
SMR	Steam Methane Reforming
SOEC	Solid Oxide Electrolysis Cell
Solar PV	Solar Photovoltaics
UK	United Kingdom
VRE	Variable Renewable Energy

Nomenclature

TWh	Terra Watt Hour
GWh	Giga Watt Hour
GW	Giga Watt
MW	Mega Watt
$\mathbf{CO_2}$	Carbon Dioxide
$\mathbf{H_2}$	Hydrogen gas
$\mathbf{N_2}$	Nitrogen gas
$\mathbf{O_2}$	Oxygen
$\Delta G^{\circ}{}_d$	Gibbs Free Energy [Joule $\cdot$ mol^{-1}]
K	Kelvin
C°	degree Celsius
Nm^3	Normal cubic meter
Powerfuel	Fuel produced with electricity

1 Introduction

The energy markets are experiencing a change due to global policies and aspirations for reducing carbon emissions. Therefore, the deployment of renewable energy sources has accelerated and the increasing amount of renewable energy production comes with problems for both the power grid and energy security. At the same time, cheap and green intermittent electricity opens up new possibilities for the energy system. Hydrogen has been suggested as a way to decarbonise the global energy system for decades but has so far not seen the praised breakthrough. With an increase in deployment of renewable energy and political targets aiming to reduce carbon emissions, the interest in hydrogen has once again surged.

Today, almost all hydrogen is produced using natural gas or coal and is mostly used in refineries and chemical industry for fertilizer and methanol production. Another way of producing hydrogen is called electrolysis and is done by splitting water with electricity, emitting no direct CO_2 in the process. Hydrogen produced by electrolysis with renewable electricity is commonly known as green hydrogen and can be converted back to electricity, be used as a feedstock in different sectors, or replace conventional carbon-based fuels with synthetic fuels.

Uniper Global Commodities is a German-based energy utility company, that operates power plants as well as markets and trades energy commodities. The company's department Market Analytic works with assisting other departments with technical and fundamental analysis of how the energy markets behave and how they are expected to change in the near- and long-term future. A large-scale hydrogen market, together with a rapidly growing renewable energy sector could have large impacts on the energy markets. Therefore, it is important for Uniper to be prepared for the potential effects this has to position their business strategy accordingly.

This thesis aims to assist the department of market analytics at Uniper with analysing the effects of a large green hydrogen market in Europe. It was done by constructing a scenario, based on a literature review, which was implemented in a power dispatch model called Bid3. Furthermore, the thesis will also be used as a benchmark for the analysts at Uniper, as well as testing the implementation of hydrogen in the power market model, Bid3.

1.1 Purpose

The purpose of the thesis is to look at how a growing hydrogen market could affect and be integrated into the European energy markets. Furthermore, the current energy systems need to adapt to the current expansion of renewable power production. Therefore, this thesis will provide insights into what role a hydrogen market can have on the European energy system and how this would affect the design of this market. Integrating hydrogen in the power system could be a part of the solution to balance the intermittent property of renewable power production, as well as provide options for decarbonising other sectors.

This thesis will aim to answer:

- *How would Europe's energy markets be affected by increased usage of green hydrogen?*
- *How can electrolysis contribute to achieving the current energy policies implemented in Europe?*

1.2 Frame of the thesis

There are many different ways of producing hydrogen. The most common method today is often referred to as *grey hydrogen* and, in Europe, it is often produced through a technology called Steam Methane Reforming (SMR) that extract hydrogen from natural gas. This method can be combined with Carbon Capture, Utilization and Storage (CCUS) to capture the CO_2 and is then instead called *blue hydrogen*. Electrolysis on the other hand is a technology that extracts hydrogen from water by using electricity. This technology is referred to as *green hydrogen* and does not require any carbon based fuels. This makes it possible to produce hydrogen without any CO_2 emissions when it is combined with renewable energy sources.

Green hydrogen was the focused technology in this thesis because of its interaction with the power system and its possibility of reducing carbon emissions. Furthermore, only the most mature technologies of electrolysis was included and the constructed scenario was constrained by technologies that was assumed to be commercialised in 2050.

To avoid CO_2 emissions, the necessary electricity to produce hydrogen must come from renewable power generation. Even though it exists many different types of renewable power generation, the main focus in this thesis was Solar PV, Onshore wind, and Offshore wind since these technologies currently dominate the growth in the renewable power market.

In this thesis a scenario was created to evaluate the potential effects of green hydrogen in the European energy systems. This scenario was therefore not restricted to a certain emission reduction target. Instead, the scenario was constructed with focus on renewable energy development according to the political targets and with the assumption of a large market for green hydrogen.

Because of the interdependence of the European power system with multiple connected power markets, it is important to acknowledge that changing the energy system in one country will affect the whole European energy system. However, due to time constraints and simplifications, the implementation of hydrogen was concentrated to two countries; Germany and the United Kingdom (UK). Both these countries have high ambitions of reducing carbon emissions and including hydrogen in their energy systems. Moreover, the geographical and political conditions for power production are different for the two countries and they are both part of Uniper's core markets. This would give a broad picture of the effects of hydrogen in different power system while still being relevant markets.

Even if the constructed scenario in this thesis focus on Germany and the UK, all countries in Europe (EU 27 + 3) were simulated because the individual power systems in Europe are well connected to each other. However, due to time constraints, only data for Germany and the UK were changed to fit the scenario. For the rest of the countries, existing data from Uniper was used. This data was based on a forecast for 2035 and was the latest sufficient set of data available. Only data for the closest neighbouring countries were slightly changed since neighbouring countries with a direct interconnector to Germany and the UK affects their power system through import and export much more than countries further away. Therefore, the accuracy of the data for countries not directly connected to Germany and the UK could be kept at the predicted values for 2035 while still having a low impact on the results.

1.3 Appendices

This thesis was written at Uniper Global Commodities and used sensitive data. Therefore, this data was restricted to Appendix A, Appendix B, and Appendix C which will not be published together with the report.

Appendix A

This Appendix contains the calculations of the assumed hydrogen demand for the different sectors. Some of this data was collected from IHS Markit and some was obtained from internal data at Uniper.

Appendix B

Appendix B contains the renewable capacity forecast for 2035 for the assessed countries, including the changed capacity and the final capacity used in this thesis as input for the simulation program, Bid3. Moreover, this appendix also contains the forecasted capacity for neighbouring countries to Germany and the UK, with the added and final values used in this thesis.

Appendix C

This appendix is an excel file that includes the calculation of the renewable capacity and the electrolyser capacity added to the scenario created in this thesis. In the calculation, the capacity factor for solar PV, onshore wind, and offshore wind for the two countries was used together with the capacity and generation profile for each hour during a standardized weather year. The data was collected from the output of the power model Bid3, used by Uniper.

2 Theory: View on hydrogen today and tomorrow

Hydrogen can be used as an energy carrier which enables energy to be produced at a different time than the demand. Moreover, it can also be used as a feedstock in several processes, coupling different sectors together, e.g., energy and transport sector. This section explains how hydrogen can be produced and used in different sectors, as well as the benefits and current challenges. Figure 1 explains the value chain of hydrogen. The value chain starting at *"Carbon free energy"* in the supply division, is the focus of this paper.

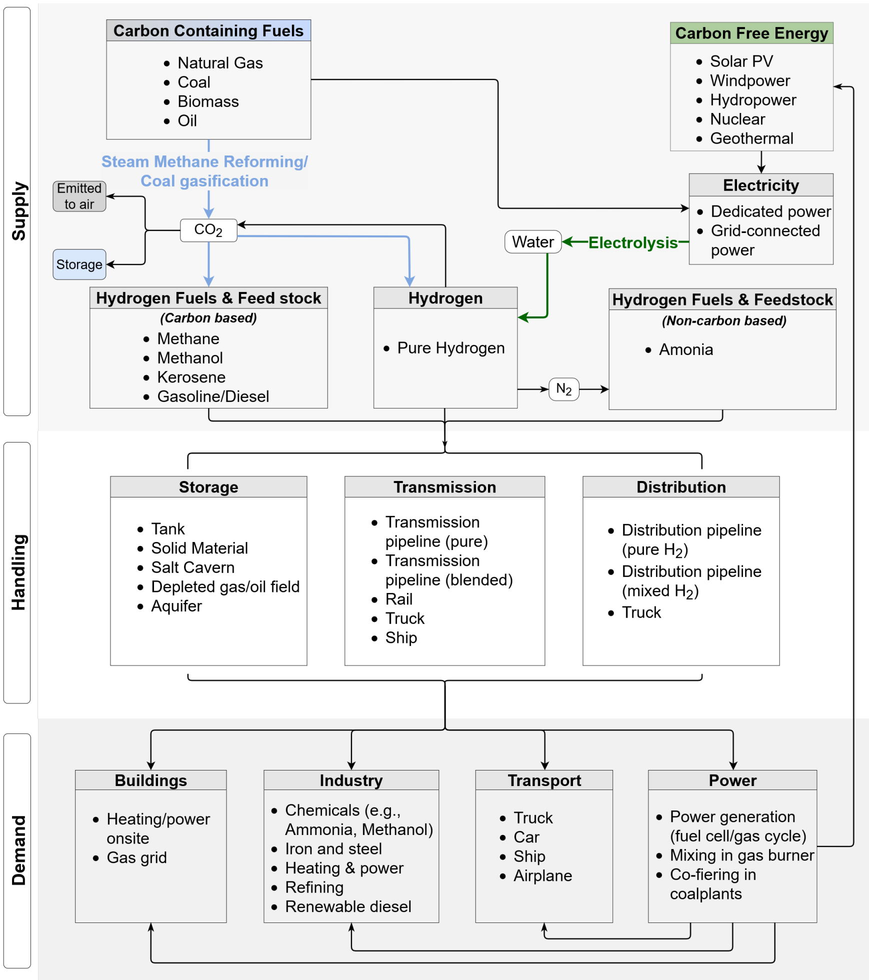

Figure 1: Value chain of hydrogen. The Figure is based on the the value chain descried in the report by IEA (2019a). Blue, grey and green color indicates the origin of fuel used to produce hydrogen.

2.1 Electrolysis

According to IEA (2019a), the most common process to extract hydrogen from today are based on natural gas and coal. With technologies such as SMR, gasification or pyrolysis, it is possible to separate the hydrogen from the coal atoms in order to obtain hydrogen gas. Another method to produce hydrogen is to extract hydrogen from water molecules with electricity. This technology is called electrolysis and several different types of electrolysis technologies exist, each with different maturity levels and advantages. Alkaline-, proton exchange membrane- and solid oxide electrolysis are the main technologies. Figure 2 shows the basic concept of electrolysis and how oxygen and hydrogen are separated by the anode and cathode.

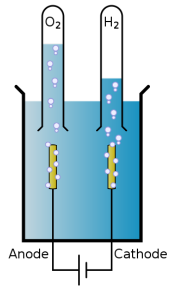

Figure 2: Basic concept of electrolysis.

The applied current flowing from the anode to the cathode forces the positive ions towards the cathode side to combine with electrons from the external circuit, while the negative ions stay at the anode. This results in a separation of gases from which hydrogen is obtained. However, this process can look slightly different depending on the technology were other electrolytes or separation methods are used.

2.1.1 Fundamentals

Electrolysis means splitting of water molecules into its elemental components. Liquid water can be separated into its basic elements as shown in Equation 1.

$$2H_2O(l) \rightarrow 2H_2(g) + O_2(g) \tag{1}$$

This reaction is endothermic for standard conditions, assuming temperature at 298 K and pressure at 1 bar. Moreover, as shown in Equation 4, adding entropy and enthalpy values given at standard conditions from Equation 2 and Equation 3, the Gibbs free energy, ΔG_d°, is positive, which means that the reaction is only spontaneous at very high temperatures. Moreover, Equation 1 together with the enthalpy change in Equation 2 shows that in ideal conditions, 1 kWh is needed to split 12.6 moles (227 g) of water which gives to 25.6 g of H_2 and 201.6 g of O_2.

The entropy change remains constant at increasing temperatures but the entropy's contribution $T \cdot \Delta S_d^\circ$ increases with higher temperature. At $T > 2500$ K is the Gibbs free energy negative and thus, the process spontaneous (see Figure 3). However, few materials can sustain such conditions (Godula-Jopek and Stolten, 2015).

$$\Delta H_d^\circ(H_2O_{(l)}) = +285.840 \quad kJ\,mol^{-1} \tag{2}$$

$$\Delta S_d^\circ(H_2O_{(l)}) = +163.15 \quad J\,mol^{-1}\,K^{-1} \tag{3}$$

$$\Delta G_d^\circ(H_2O_{(l)}) = \Delta H_d^\circ(H_2O_{(l)}) - T \cdot \Delta S_d^\circ(H_2O_{(l)}) = +237.22\,kJ\,mol^{-1} \tag{4}$$

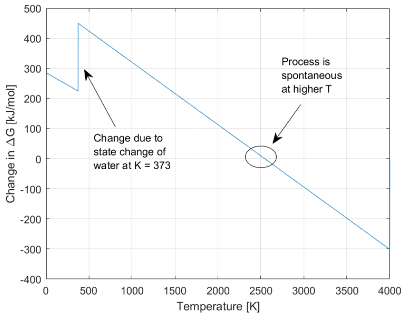

Figure 3: Change of Gibbs free energy in electrolysis for different T. High temperatures are needed for reaction to be spontaneous.

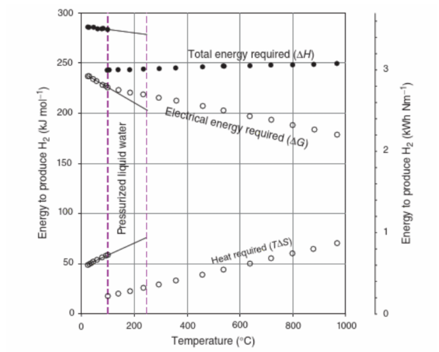

Figure 4: Electrical energy, total energy and heat energy required for the water splitting reaction at pressure $p = 1$ bar for different temperatures.

Note. Reprinted with permission from "Fundamentals of Water Electrolysis", by Millet, P., 2015, Hydrogen Production: Electrolysis, p. 34. Copyright 2015 by John Wiley and Sons.

As seen in Figure 4, the total energy required to split water remains fairly constant with increasing temperatures. However, the share of electrical energy required compared to heat energy decreases with increasing temperature. Discontinuities observed at $T = 100$°C are due to water vaporization and the solid lines represent the values for pressurized liquid water up to 250°C. Moreover, the magnitude of the enthalpy discontinuity is equal to the enthalpy of water vaporization. At room temperature (298 K), around 15% of the total energy required is coming from heat. With a temperature increase of 1000 K, the heat energy instead consists of around 30% of the total energy. This temperature dependency is an important property for reducing operational costs since heat has a lower energy quality than electricity and therefore also cheaper (Godula-Jopek and Stolten, 2015).

To make efficient use of the resources and reduce costs, it is also important to acknowledge the byproducts coming from the electrolysis process. As previously shown, more oxygen than hydrogen is produced from water electrolysis and according to Kato et al. (2005), oxygen and heat could both be utilised to improve the overall efficiency. Oxygen is already a product widely used in industries as well as in the medical sector and therefore also selling the oxygen produced could improve the revenue for the electrolysers. The retail price of oxygen bought by hospitals in Japan is estimated to around 35 US/Nm^3 and would improve the income from hydrogen production via electrolysers. However, this price would most likely decrease heavily if electrolysis is deployed on a large scale and the market is oversupplied with oxygen (Kato et al., 2005).

Its also possible to use oxygen in the energy sector where it can be combusted with methane to produce power while emitting less CO_2 than conventional gas turbines. Kato et al. (2005) propose a new concept of power generation that consists of a pure-oxygen/blown-natural-gas combined cycle (NGCC). This system would require an annual oxygen demand of 1273 M Nm^3, assuming a 400 MW NGCC with a load factor of 80%. Yearly, this would be equal to 28 GWh of energy produced and would come from by-products of around 7.63 TWh of hydrogen, assuming 70% efficiency. This way of using by-products from electrolysis would increase the total system energy efficiency from 0.71 to 0.76.

In the following sections, the most common electrolysis technologies will be explained as well as their different properties. Alkaline Electrolysis (AEC) is currently the most common and mature technology, followed by Proton Exchange Membrane (PEM) technology. These are the only two widely commercialised technologies. However, other electrolyser technologies such as Anion Exchange Membrane or high-temperature Solid Oxide Electrolysis show promising properties which could lead to wider use in the future (Vincent and Bessarabov, 2018). Figure 5, shows the total installed capacity of electrolyser technologies until year 2014.

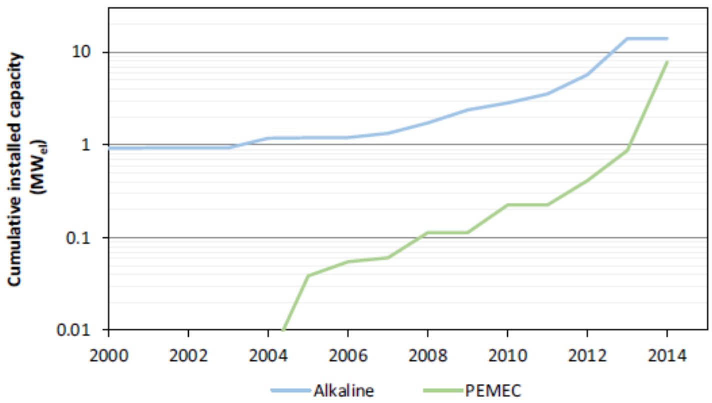

Figure 5: Cumulative installed capacity for Alkaline Electrolyser (AEC) and Proton Exchange Membrane Electrolyser (PEMEC) technologies.
Note: Reprinted with permission from "Future cost and performance of water electrolysis: An expert elicitation study", by Schmidt et al., 2017, International Journal of Hydrogen Energy Volume 42, Issue 52, p. 30483.

2.1.2 Alkaline water electrolysis

The components used for alkaline electrolysis can be made from abundant material, lowering the material costs for the technology. This technology is also the most mature electrolyser technology. The electrodes are often made of iron or nickel steel, depending on usage of the electrolyser. A liquid alkaline solution of potassium hydroxide is used as electrolyte and a membrane of porous material is placed in the electrolytic liquid, allowing the passing of hydroxide ions but not oxygen and hydrogen. This membrane separates the oxygen and hydrogen gases and ohmic losses occur from the distance of the separator to the anode and cathode (Godula-Jopek and Stolten, 2015).

Different variations of alkaline electrolysers exists, mainly unipolar and bipolar alkaline electrolysis cells. The unipolar cell uses the anode as the cell tank containing the aqueous solution, while the bipolar electrolysis cell uses bipolar plates to separate the solution on one side and the separator at the other side. The latter method requires the electrolyte to circulate but has less ohmic losses than the unipolar method (Godula-Jopek and Stolten, 2015).

Godula-Jopek and Stolten (2015) writes that most industrial alkaline electrolysers require to operate at minimum current density of 10 to 20 percent of the rated capacity because of safety reasons and because limitations in the separator allowing, according to Fick's law, a small amount of hydrogen to pass through to the oxygen side and vice versa. At lower current densities, the mix of gasses are more dominant and thus, putting a constraint on the minimum running capacity of the alkaline electrolysers. For safety reasons, the concentration of hydrogen in oxygen needs to be outside the lower and upper explosion limit between 3.9 mol% and 95.8 mol%, where the mixture is not flammable. Furthermore, sudden changes of current density while the electrodes are immersed in the electrolyte could risk the electrolyte being expelled from the compartments due to the increased pressure from the rapid production of gasses. These constraints make the alkaline water electrolysers better fit for stationary operating conditions. Moreover, alkaline electrolysis often operates with liquid water, resulting in a lower efficiency since some electrical energy is needed to vaporize the liquid.

2.1.3 Proton exchange membrane electrolysis

Another electrolysis technology called Proton Exchange Membrane, Solid Polymer Electrolysis or Polymer Electrolyte Membrane (PEM), uses a solid membrane instead of an aqueous solution as the electrolyte. This technology was first developed for use in zero-gravity applications and later for oxygen production in submarines. Because of the very thin solid membrane, the electrolyser cells remains thin and thus obtaining a higher current density, reaching efficiencies of around 70-80%. Furthermore, the PEM technology together with the alkaline technology is considered as low-temperature electrolyser technologies as they, in general, operate under 100 °C. The temperature for these technologies is partly constrained by material instability at higher temperatures (Godula-Jopek and Stolten, 2015). Moreover, the proton conductivity of the membrane in PEM technology is dependent on the water content and easily dehydrates when the stack operates with water vapour, which is why PEM technology is constrained to operate under 100 °C at ambient pressure. However, overcoming this issue to operate with vapor instead of liquid water would increase the efficiency. As shown in Figure 3, both the enthalpy for the state change reaction will be lower, as well as reduced requirement of electrical energy (Hansen, 2012).

The properties of the PEM technology makes it suitable for operations with varying power input and at different pressure, also performing more efficient at high current density. The small space of the cells is also attractive for use in situations where available space is limited. Compared with alkaline technology, PEM technology also operates safer in a pressurized environment. However, the drawbacks of the PEM technology is the low tolerance on cell dimensions for the membrane as well as the requirement of rare metals for the electrocatalysts. These requirements make the investments cost higher for this technology compared with the alkaline electrolysis technology (d'Amore-Domenech and Leo, 2019).

Another developing technology worth mentioning is the Anion Exchange Membrane (AEM) electrolysis. This technology uses low cost transition metal catalysts instead of rare metals and thus has the potential to reduce costs. Moreover, similar to PEM electrolysis, AEM electrolysis uses a non corrosive electrolyte and has a compact cell design which could also operate at higher pressures. These features shows promising potential of low cost electrolysis. However, the AEM still suffers from membrane degradation and requires further research before it can achieve commercially viable hydrogen production (Vincent and Bessarabov, 2018).

2.1.4 Solid oxide electrolysis

Solid oxide electrolysis (SOEC) is a technology that operates under high temperatures to reduce the amount of electrical energy needed for the process. This type of electrolysis cell uses a mix of hydrogen and water steam on the cathode side and oxygen on the anode side. Moreover, one advantage of SOEC technology is the potential synergy with high heat industry processes by using waste heat to decrease the cost of energy. However, the technology is less mature than Alkaline- and PEM electrolysers and requires further developments (Godula-Jopek and Stolten, 2015).

Solid oxide electrolysis is most suitable for large units, in combination with a high-temperature heat source. This makes it challenging to build and test a system at such scale and the technology also faces problems with material durability from the high operating temperature. One project of 15 kW has been build in the United States but showed significant performance degradation during the 1080 hours of operation. Furthermore, an American study analysed the economics of SOEC when coupling the production to a theoretical high-temperature nuclear reactor. This provided both a source of heat and electricity and the results showed the possibility to deliver hydrogen to a cost of 3.23 \$ kg^{-1} (Godula-Jopek and Stolten, 2015). This is comparable to the costs of hydrogen produced by natural gas of 1 to 1.7 \$ kg^{-1} or from 1.5 to 2.4 \$ kg^{-1} when produced by natural gas and CCUS, depending on the carbon and gas price (IEA, 2019a).

2.2 Distribution and storage

Nowadays hydrogen is used almost entirely in the industry sector and is often produced on-site. In a future scenario where hydrogen is produced by electrolysis, it might not always be produced at the same time of usage or located at the end-use application. Therefore, it is important to have a working infrastructure to reliably store and transport hydrogen.

2.2.1 Transportation

The two main options for transporting hydrogen are similar to those of methane. Both transport through pipelines and transport it in containers are possible options. The properties of the hydrogen also make the two options differ in effectiveness depending on circumstances. IEA (2019a), shows that transporting pure hydrogen under 1500 km costs less if transported by pipeline, compared to shipping, or by road.

Gasgrid

One opportunity of transporting hydrogen through pipelines is that existing infrastructure for natural gas can be used. Europe already has a well-developed infrastructure for natural gas, which can be adjusted to transport hydrogen. However, using existing gas infrastructure for transportation of hydrogen has some barriers. The main challenges with substituting natural gas with hydrogen are the volumetric density and the corrosiveness. Hydrogen has about a third of the energy density per volume unit compared to methane. This affects the operational properties of the gas grid e.g., pressure and flow, which in turn affects some of the current components in the infrastructure. The other difference from natural gas is the highly corrosive property of hydrogen. The European gas grid compiles of a mix of iron pipes and plastic pipelines. For the pipes to transport hydrogen, they need to be improved and treated to not corrode when transporting the gas. This could also affect components in the gas grid and appliances at the end-use of the gas (IEA, 2019a).

Instead of substituting the natural gas with pure hydrogen, it is also possible to mix the hydrogen with methane in the current gas grid. A similar method, commonly called *town gas*, was already in use in the 19th century. Town gas consisted of a mix of calorific gases, mainly hydrogen, carbon monoxide and methane, which were by-products from the coking in the coal industry. After the discovery of gas reserves in the North Sea, natural gas started to replace town gas since it requires less processing and is less toxic compared to the carbon monoxide in the town gas. Today, most European countries have regulations on how much hydrogen can be mixed in the current gas grid. In general, about 3 - 5 % volume share of the natural gas flow is allowed, with up to 10% in some places under certain conditions. Furthermore, in a test project in the Netherlands, several houses were connected to a grid with a mix of 20% vol., which showed no problems with the grid and appliances used (IEA, 2019a).

Liquid hydrogen

Another method for transporting hydrogen is changing the state of matter, just like transporting liquid natural gas (LNG). However, it is very energy-intensive to transform hydrogen into liquid state because of its low boiling point (20.28 K). Moreover, during the transport of hydrogen in liquid state it needs to be stored in cryogenic containers with a pressure of about 4 bar and temperatures between 16 K to 20 K. Since perfect isolation is difficult to achieve, the top layer of the container is probable to start boiling. For safety reasons, so that the pressure of the container doesn't increase, some of the gas is released. This released gas is called boil-off. The boil-off gases can either be released into the air or captured and re-cooled to reduce the losses from the system. Whereas boil-off of LNG causes concerns with respect to methane emissions this is not the case for hydrogen. Moreover, for long-distance transportation, the boil-off gases can also be used as fuel for the transport vessel, which could reduce the costs of transport. However, the procedure of transforming hydrogen gas to liquid state and maintaining this under a longer period of time, demands a large amount of energy which makes the process costly and not very efficient (IEA, 2019a).

2.2.2 Storage

Similar to methane, hydrogen can be stored in various ways. The storage possibilities vary depending on the desired volume, duration, and speed of discharge. Moreover, geographic availability is also something to consider when storing hydrogen.

The storage technologies can be divided into two categories; hydrogen stored in physical containers, and hydrogen stored in other materials. When storing hydrogen in containers, it is either done by compressing the gas or liquefying it. In contrast, storing hydrogen in materials involves chemical reactions with metal hydrides, sorption materials and chemical hydrides (Dagdougui et al., 2018). However, storing hydrogen in materials is a less mature technology, and is also often developed for small scale applications. Today, hydrogen is mostly stored in pressurized containers (IEA, 2019a).

For large scale and long term storage, geological storage such as salt caverns and depleted gas or oil fields are the most suitable options according to IEA (2019a). This way of storing natural gas has already been used for many years in the gas industry and salt caverns have also been used for hydrogen storage in the UK since the 1970s, which makes it the most mature technology for large hydrogen storage. The different types of geological storage have their own properties and are used for different applications. The main differences are the volume and discharge rate of the storage. Salt caverns are smaller and have a higher discharge rate and therefore they are more suitable for short term storage. This is also one of the most cost-effective options for storing a larger amount of hydrogen, according to (Lord et al., 2014). Moreover, IEA (2019a) also addresses that salt caverns often are operated as a series of smaller separate caverns, enabling them to successively be converted from natural gas storage to hydrogen, and thus minimizing the upfront costs. The disadvantage of storing hydrogen in salt caverns is the smaller volume compared to depleted gas and oil fields as well as the dependence on geographic location.

Depleted gas and oil fields are also options for storing hydrogen. Their size is often many times larger than salt caverns and will therefore operate under lower pressure, which translates to a lower discharge rate. This property makes this type of storage suitable for seasonal storage. One thing to keep in mind is the higher rate of contaminants when storing hydrogen in depleted gas and oil fields. When extracted, the gas would in many cases need to be cleaned before used (Lord et al., 2014). This is particularly a problem with hydrogen used for fuel cells, which requires high purity hydrogen for operation (IEA, 2019a). There is also research on storing hydrogen in aquifers, which would allow hydrogen to be stored in larger quantities than salt caverns, but with little contaminants. There have been a few successful attempts of storing both town gas with a high percentage of hydrogen, as well as helium, in aquifers. Since Helium is also a very light gas, it shows promising indications for also storing hydrogen in such facilities. However, technologies for large scale geological storage of hydrogen is not yet a common process and need more testing and research (Lord et al., 2014).

Storage of hydrogen in solid materials is a possibility for small scale applications. These technologies utilise the properties of different materials so that the hydrogen becomes part of the solid material through physicochemical bonding. Some materials can absorb hydrogen at certain temperatures and pressures, creating a reversible process of hydrogen storage in compounds called hydrides. Light metal hydrides are mostly used, which offers efficient storage of hydrogen with high density to volume as well as high purity. The downside of this technology is the small total storage capacity as well as the stability of performance (Dagdougui et al., 2018).

Another possibility to transport and store hydrogen is to convert it to other hydrogen-based fuels and feedstocks, e.g., ammonia which could make use of existing infrastructure. Ammonia has a much higher energy density and higher boiling point than hydrogen. Moreover, ammonia is already used as a feedstock in the chemical industry and could also be used as a fuel in the power and transport sector. However, the toxic property of ammonia needs to be considered and could potentially restrict its future usage as a hydrogen carrier (IEA, 2019a).

2.3 Applications

One of the main aspects of hydrogen is its versatility which enables sector coupling and reduction of GHG emissions across different industries. It is also important to remember that hydrogen is an energy carrier, which means that the contained energy need to be converted for usage in energy related applications. This can be done in mainly two different ways: through combustion or a fuel cell. Combusting hydrogen works in similar ways as other gas cycles and has an upper efficiency limit depending on the heating value of hydrogen. In contrast, a fuel cell works similar to a reversed electrolyser. It consists of a stack that reacts hydrogen with oxygen to generate electricity and water. This process has higher efficiency since it directly converts the chemical energy to electricity without combusting it as a middle step. Both these processes emit only water as a by-product. Depending on the application, the different options of extracting the energy is preferred, e.g., when large amount of heat is the desired energy quality, combustion of hydrogen might be a more cost-effective solution than using a fuel cell. On the other hand, when electricity in smaller amounts is the desired energy output, fuel cells might be the better option. Another big difference between the two is the purity of hydrogen. Fuel cells often need pure hydrogen of 99.97 %. This is not as important for combustion, where the purity of hydrogen can be lower and also mixed with other calorific gases (Staffell et al., 2019).

2.3.1 Transport

When looking at GHG, the transport sector is one of the most difficult to decarbonise and the emissions in the transport sector have increased during the last years (EEA, 2019). However, due to decreasing prices of Battery Electric Vehicles (BEV), battery technologies for lightweight road transport have gained in popularity. The drawbacks of BEV is the low energy density per weight as well as the limited range and the long recharging time. The refuelling options has been improved during the last years, but can still be a major downside for some applications, e.g., industrial machines with a high utilisation rate. The Hydrogen Council (2020), lifts the potential of using hydrogen in fuel cells for heavy and long-range transport. For long-distance vehicles, fuel cells could provide an alternative because of the importance to reduce the weight in order to reduce the energy usage, and thereby increase the range. In many cases, the volume is also an important factor, as the need for large space for the energy tank is not desirable. Another advantage of Fuel Cell Electric Vehicles (FCEV) is the short refueling time which becomes more crucial for vehicles with high utilisation rate. Moreover, Hydrogen Council (2020) also estimates FCEV to be more cost-efficient compared to BEV for heavy-duty trucks used for long distances as well as taxi fleets, before 2025. Large family cars and urban busses powered with hydrogen are the next two segments of vehicles to meet cost parity with BEV.

Even though large parts of the global rail network are electrified, a significant share is powered by diesel trains. This is due to low returns on investments of building electrified tracks on parts that are not frequently utilised. According to IEA (2019a), battery electric trains could be used on partially electrified lines by utilising the battery on segments with high cost of electrification, e.g., tunnels or bridges. Hydrogen fuel cell trains is also a viable alternative and are more competitive on train lines running long distances with low-frequency utilisation (common for rail freight). For example, there are already two hydrogen fuel cell trains operating in Germany that can travel 800km a day on a single refuelling. Moreover, Germany intends to expand the usage of hydrogen trains by having 14 trains operating in 2021. This is in line with several other European countries that plan to use hydrogen in the railway sector (IEA, 2019a).

The maritime sector is also facing challenges of decarbonising. The Hydrogen Council (2020), writes that The International Maritime Organization (IMO) has committed to reducing emissions by 50% by 2050. Currently, the solutions has been replacing current bunker fuels with LNG and using liquid ammonia, instead of burning conventional fuel. However, smaller ships also have the possibility to use hydrogen with fuel cells and according to IEA (2019a), hydrogen boil-offs from cryogenic storages could also power the vessels.

The whole aviation sector emits around three percent of the global carbon emissions (IEA, 2019a). Furthermore, the potential to shift from the current jet fuel, kerosene, to hydrogen or electrification is relative small compared to other sectors. Kerosene is much more ideal for jet fuel since it is has a high energy density both compared to weight and volume. Hydrogen on the other hand would require much more volume to store the fuel, and batteries would make the planes too heavy. For smaller planes over short distances, both hydrogen or battery planes could be possible. However, the major share of GHG emissions, comes from long distance flights (Hydrogen Council, 2020). According to IEA (2019a), synthetic liquid fuels produced from hydrogen is an option for aviation, but cost at the moment about six times more than the current fuel used. The Hydrogen Council (2020) also lifts that synthetic-kerosene, made from hydrogen and carbon monoxide, would be the most likely option if hydrogen is used more broadly for longer flights. They write that kerosene today costs around 0.5 USD per litre, while synthetic-kerosene costs around 2.30 USD per litre.

2.3.2 Industry

The diversity of hydrogen is that it can not only be used as an energy carrier, but also as a feedstock in several processes. The global demand for hydrogen is around 70 M tonnes per year, of which most comes from industrial uses, such as ammonia and methanol production and the refinery industry. Furthermore, the hydrogen is mostly supplied from SMR, which yearly accounts for more GHG emissions than the yearly GHG emissions of the UK. This opens for a large possibility of utilising hydrogen in industrial processes as well as low carbon energy for the industry to reduce CO_2 emissions (IEA, 2019a).

In oil refining, hydrogen is primarily used to remove impurities such as sulphur from crude oil. Hydrogen is also a main component in ammonia, which is used largely as fertilizer. Furthermore, the production of methanol also uses a large amount of hydrogen as feedstock. These markets already have a high demand for hydrogen that could potentially drive the demand for low carbon hydrogen (IEA, 2019a).

The steel industry accounts for around 7% of global CO_2-emissions. The most common way of processing iron ore to steel, is with blast furnace-basic oxygen furnace (BF-BOF), which uses coal as a reduction agent. Another method called *direct reduction with hydrogen* (H-DR) uses hydrogen as a reduction agent, and has the possibility of eliminating CO_2 emission in the primary steel production (Kushnir et al., 2020). The implementation of this technology is already taking place in Sweden in a joint project with SSAB, LKAB and Vattenfall. A pilot facility has been built with plans on building a demonstration plant to enable production of fossil-free steel for commercial use in 2026 (SSAB, 2020). Moreover, IEA (2019a) estimates that with growing steel demand and higher political targets of reducing carbon emissions, the hydrogen demand in the steel industry can grow 15 fold by 2050.

2.3.3 Commercial and residential

The global building sector accounts for 30% of the global final energy use, and has a large potential for both reducing the amount of energy used as well as shifting towards low carbon energy. Much of the energy is used for heating, which has a low energy quality and thus gives several possibilities of providing the necessary energy. Furthermore, depending on criteria, e.g., location, ownership, personal preferences, equipment costs and convenience, the energy is better supplied in various ways. IEA (2019a) therefore predict that various technologies are likely to coexist in the future with hydrogen as a possible option. Moreover, hydrogen can both be used in similar ways as natural gas is used for heating, as well as in fuel cell heat pumps.

Substituting natural gas for hydrogen in the residential and commercial heating sector is possible to do gradually by mixing hydrogen with natural gas in the current gas infrastructure. Hydrogen Council (2020) writes that blending hydrogen in the natural gas grid provides a significant potential of increasing the hydrogen demand. IEA (2019a) also mention that three to five percent of hydrogen by volume is already being blended in the natural gas grid in major heating markets, e.g. western Europe. Pure hydrogen could also be used for heating, and would be most economical for larger building complexes. However, some of the infrastructure need to be adjusted to be able to operate with high shares of hydrogen, e.g., change of gas boilers and pipes. Furthermore, better system for controlling the gas quality is needed if hydrogen is to be mixed in the conventional gas grid (IEA, 2019a).

2.3.4 Power sector

The gaseous property of hydrogen which makes it possible for storage, also opens up possibilities of using hydrogen in the power sector. For example, IEA (2019a) highlights the possibility of co-firing of ammonia, which would reduce the carbon emissions of existing coal power plants. This technology however, would still rely on coal which in the end still would emits significant GHG emissions as well as increasing NOx emission in the process (IEA, 2019a). Another option is to use hydrogen in a turbine and produce steam or heat in a similar way as natural gas is used today. This option as well as the possibility of using fuel cells, could be an alternative to provide low carbon flexible power generation. However, both these alternatives have a low round trip efficiency which makes hydrogen less competitive for power generation. Moreover, the seasonal variation of power demand in Europe makes it beneficial to store large quantities of hydrogen during longer periods. Nonetheless, the technological challenges in this area need to be solved before hydrogen can be used for seasonal storage of energy (IEA, 2019a).

Given a power system with high Variable Renewable Energy (VRE) sources, peak generation is favorable to increase the system flexibility and allowing higher utilisation of the intermittent energy sources. Peak capacity could be supplied by using hydrogen in gas turbines, Combined Cycle Gas Turbine (CCGT), or fuel cells (IEA, 2019a). However, hydrogen has higher costs than carbon-based fuels and according to IEA (2019a), the carbon price needs to be 175 USD/tonne CO_2 to be competitive with natural gas, assuming a hydrogen price of 2 USD/kg H_2 and natural gas price of 7 USD/MBtu. Apart from using hydrogen fuel for peak generation, electrolysers could also provide demand side response to help counteract the intermittency of the VRE capacity. This could efficiently be done by modulating the electrolyser operation to match the variable output of wind and solar power sources (IRENA, 2019).

2.4 Political development

Europe has a well integrated gas and electricity market with well connected energy system of several countries. Moreover, the European Union (EU), has also strengthen the integration of a common energy market and pushed for common energy policies. In 2020, EU voted for a policy package, called *The European Green Deal*. This set of policies has the overarching aim of boosting the efficient use of resources by transforming to a circular economy, restore biodiversity, as well as cut pollution with the target to reach climate neutrality in Europe by 2050 (European Comission, 2020a).

One of the strategies that is a part of the European Green Deal is the Hydrogen Strategy. This strategy focus on green hydrogen production and advocates the installation of at least 6 GW electrolyser capacity and production of up to one million tonnes of green hydrogen by 2024. Furthermore, the strategy also includes 40 GW electrolyser capacity in Europe between 2025 and 2030, with a continued growth from thereafter (European Comission, 2020b).

2.4.1 Germany

Since Germany adopted its energy strategy, *Energiewende* in 2011, it has been defining the country's energy policies. This strategy is part of a long term multiple party agreement to transform the German energy system into a more efficient system with high shares of renewable energy sources. Some of the goals of the energy policy include lowering the carbon footprint of the energy sector as well as phase out nuclear energy (Renn and Marshall, 2016).

High governmental incentives have driven the deployment of renewable energy, which have in turn diversified the German energy system. As of 2018, 78% of the total primary energy supply was represented by fossil fuels. This is down from 84% in 2000, when the total primary energy supply was 11% higher than in 2018. As seen in Figure 6, oil is the largest contributor to the total primary energy supply which is mainly due to the large car industry and the amount of cars in the country. According to Eurostat (2020), 550 cars per 1000 inhabitants was registered in 2018. Coal and natural gas are also large parts of the primary energy supply and these commodities are mainly used in the industry and power sector.

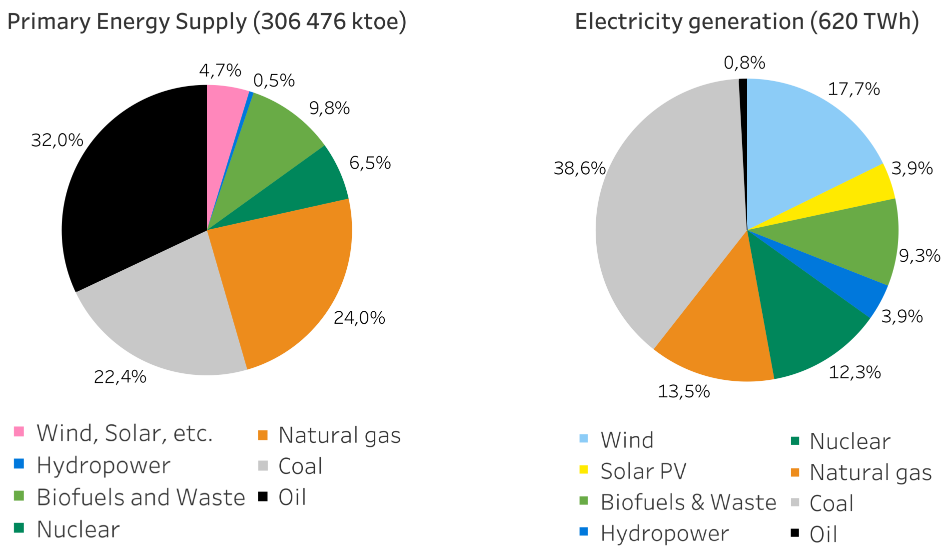

Figure 6: Primary supply (left) and electricity generation (right) by source for Germany in 2018 (IEA, 2020a)

The effects of the energy policies can be more salient in the power sector. Electricity generation from renewable sources increased from 6 % in 2000 to 38% in 2018 and the electricity generation from nuclear has declined heavily, as well as minor decline from coal generation. Furthermore, the Renewable Energy Sources Act 2017 has increased funding for more cost efficient development of renewable energies and defined near term targets for the energy transition (BMWi, 2019). In 2020, the German government adopted the *Act on the Phase-out of Coal-fired Power Plants*, which stipulates a gradual phase-out of electricity generation from hard coal and lignite until 2038 at the latest (BMWi, 2020a). This decision, together with the phase out of nuclear energy by 2022, will most likely add momentum to the country's energy transition.

The German energy transition consists of quantitative goals for the energy system and reduction of GHG emissions. The targets for energy and emission can be seen in Table 1.

Table 1: Targets for energy and GHG emissions in the German energy policy (BMWi, 2019)

	Year			
	2020	**2030**	**2040**	**2050**
Renewable energy				
Share in gross final energy consumption	18%	30%	45%	60%
Share in gross electricity consumption	30%	50%	65%	80%
Share of heat consumption	14%			
Efficiency and Consumption				
Primary energy consumption (compared with 2008)	-20%			-50%
Final energy productivity (2008-2050)	2.1% per year			
Gross electricity consumption (compared with 2008)	-10%			-25%
Primary Energy consumption in buildings (compared with 2008)				-80%
Heat consumption in buildings (compared with 2008)	-20%			
Transport				
Final energy consumption (compared with 2005)	-10%			-40%
GHG emissions				
GHG emissions (compared with 1990)	-40%	-55%	-70%	-80%

The current progression towards the different goals are varying and the Federal Ministry for Economic Affairs and Energy (BMWi) asses the probability of the goals to be met given the current progress. According to BMWi (2019), the targets for renewable energy are described as very plausible to be achieved. On the contrary, the goal for reducing energy consumption in the transport sector, is not likely to occur since it has been increasing instead of decreasing during the last years.

In June 2020, the German government announced its hydrogen strategy, where it consider hydrogen to be part of the country's energy transition and help with decarbonising certain parts of the industry sector. This strategy consists of nine billion euros and creates the potential to improve the economy from the impact of the COVID19 pandemic, along with further support of the energy transition. In the hydrogen strategy, the country expects a hydrogen demand of 90 to 110 TWh in 2030. A part of this demand will be covered by the planned installation of 5 GW electrolyser capacity by 2030 and an additional 5 GW added before 2040. However, this electrolyser capacity will only cover a small part of the total demand and Germany will therefore intensify its cooperation with the European member states to secure the supply of hydrogen (BMWi, 2020b).

2.4.2 United Kingdom

The energy market in the UK has undergone major changes during the past years. New reforms such as Electricity Market Reform, Industrial Strategy and the Clean Growth Strategy has lead the country to progress towards reducing carbon emissions and improve electrification. United Kingdom had a target of reducing GHG emissions by 80% before 2050 from 1990 levels (IEA, 2019b), but have in 2019, increased its target and made it legally binding to reach net zero carbon emissions by 2050 (BEIS, 2019a). Furthermore, the UK has made large investments in offshore wind during the last years. From 2010 to 2017, the annual wind generation increased from 0.8% to 6.2% of the total power generation and in 2019, the UK adopted the Offshore Wind Sector Deal, including a target to increase offshore wind capacity to 30 GW in 2030 (BEIS, 2019b).

There has been large focus in the energy reforms on improving the energy efficiency in buildings, as well as programs for nuclear power and CCUS. The Nuclear Sector Deal and Nuclear Sector Strategy are both policies, that will provide stronger incentives for new nuclear development. Moreover, the country has decided to phase out coal-fired power plants by 2025 as well as end sales of new conventional and diesel cars by 2040. These political agendas indicate a push to a more decarbonised and electrified energy system (IEA, 2019b).

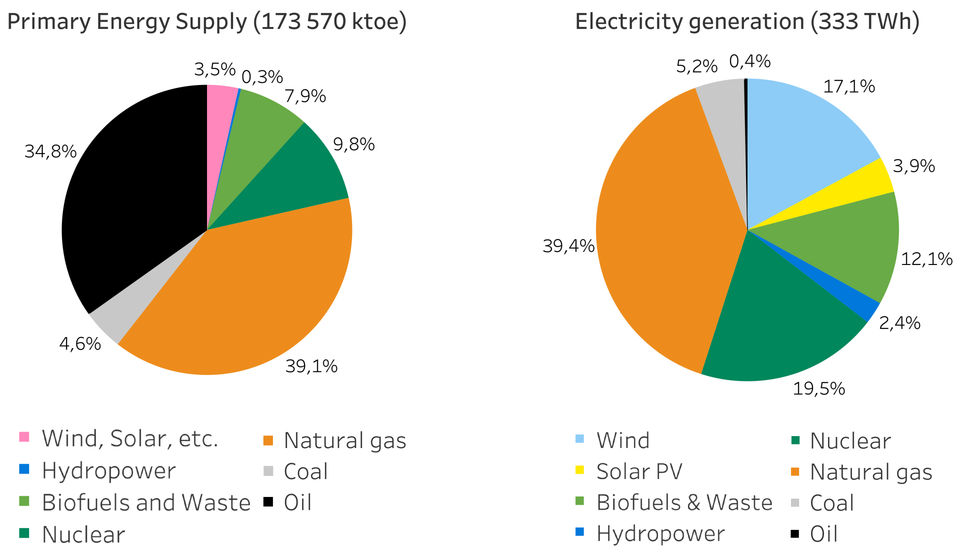

Figure 7: Primary supply (left) and electricity generation (right) by source for the United Kingdom in 2018 (IEA, 2020b)

Figure 7 shows that the power mix of United Kingdom in 2018 has a high share of natural gas generation as well as nuclear generation, with around 35% of the mix coming from renewable energy sources (including bio fuel and waste). During the latest ten years, the country has seen a large drop in coal generation as well as an increase in wind energy and bio fuel (IEA, 2020b)

So far, the United Kingdom has not implemented a specific hydrogen strategy. Nevertheless, the government has put focus on both hydrogen production as well as growing its demand. For example, the government has announced to use £90 millions to tackle GHG emissions, including funding for several hydrogen projects. Furthermore, the UK has declared to not limit the hydrogen production to one technology, but includes funding for both blue and green hydrogen production, which also is in line with the country's energy policy of investing in CCUS (BEIS, 2020).

3 Method

The thesis consists of two main parts; a literature review to determine future potential hydrogen demand, and a simulation of the power system in a constructed scenario. Below in Figure 8, is a diagram of the methodology used in this report.

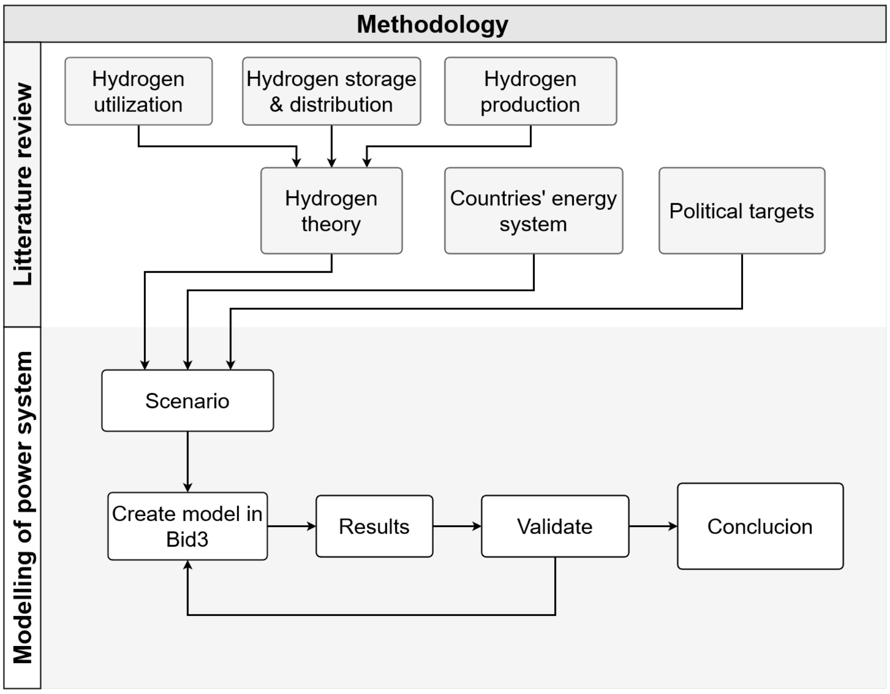

Figure 8: Overview of the methodology used in the thesis.

Based on the literature review (section 2), a scenario was constructed and derived from assumptions of how a growing hydrogen market could look like. The report "*The Future of Hydrogen*" (IEA, 2019a) was the main literature used to assess the impact of hydrogen in different sectors. This literature review laid ground for the theory and how the scenario in the second part of the thesis was constructed.

The second part consists of constructing a scenario and to simulate the power system in this scenario, using a program called Bid3. The scenario was derived from assumptions of how a large scale hydrogen market would affect the energy systems. Further explanation of the program is found in section 3.2.

3.1 Scenario

A scenario was created to analyse the effects green hydrogen production and usage have on the energy markets. The purpose of this scenario was to challenge the view on how green hydrogen could fit into the energy market but also remain plausible for how the demand and supply of hydrogen could look like in 2050.

3.1.1 How the scenario was constructed

The method of creating the scenario is illustrated in Figure 9. The first step was to determine how the energy system for the two countries, Germany and the United Kingdom, would look like without a strong focus on hydrogen. In both cases the current power system was analysed and changed to align with the policies for each country, further described in section 3.1.2 and section 3.1.3. This resulted scenario, further called the *Base Case*, was created as a reference to evaluate the effects of hydrogen production and did therefore not include any hydrogen demand from electrolysers. However, the assumptions of BEV were included in the Base Case to separate the effects of vehicle electrification from the hydrogen market. All assumptions used can be seen further down in Table 2.

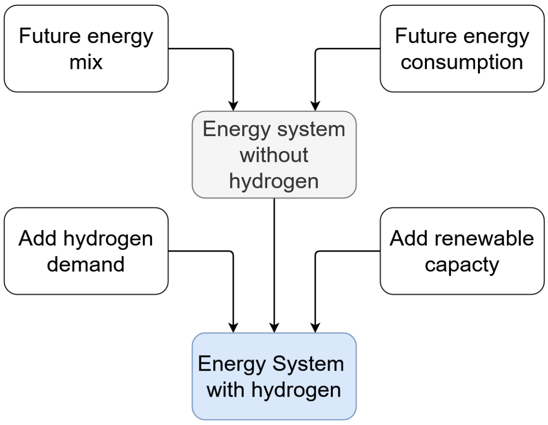

Figure 9: Flowdiagram of scenario methodology

3.1.2 Scenario for Germany

The scenario for the German power system was based on the current policies for the energy market, described in section 2.4.1. The country has determined to phase out both coal and nuclear power in the near future. Oil is also not expected to make up a large part of the future capacity, based on historical trends in utilisation of oil in the German power system. Moreover, Germany doesn't have the geographical requirements for a considerable increase in hydropower capacity. Bioenergy is also not expected to increase according to (Klaus et al., 2010) and other sectors, with difficulties of decarbonising, would have a higher demand for bioenergy which makes it less probable to be used in the power sector. This only leaves room for an increase in natural gas as carbon-based fuel, as well as renewable energy sources, i.e., on-shore wind, off-shore wind and solar PV, in the power mix in 2050. Moreover, according to the German energy strategy, the country has a target of 80% renewable energy in the generation mix for 2050 which means that the remaining 20% can only come from natural gas generation.

The annual power demand in the Base Case was assumed to the same as in 2019, not including assumptions of BEV. Klaus et al. (2010) estimate that the total electricity demand in 2050 would look similar to the demand in 2005 because the increase in energy efficiency and the increase of electrification cancel each other out. McKinsey & Company (2010) on the other hand estimate an increase of around 30% in 2050 from 2005 levels, due to more BEV used. This is also similar to what Dr. Hecking et al. (2018) suggests.

Because of the previously stated reasons, gas capacity in the Base Case was set to 20% of the total generation, based on the ratio between gas capacity and gas generation in 2019. Hydropower and bioenergy were kept at the same capacity as of 2019 and the remaining capacity was divided between offshore wind, onshore wind and solar power capacity, all with the relative share between each other from the power mix in 2019.

3.1.3 Scenario for United Kingdom

The energy policies in the UK regarding carbon-based fuels are similar to those in Germany. The main difference is the view on nuclear power in the UK, which according to the country's energy strategy will play a significant role in decarbonising their power system. However, a specific target of nuclear capacity is not determined and thus, it is more difficult to allocate the share of power sources for a future power system in the UK. Therefore, the UK's power system for the Base Case was based on the *Consumer Evolution* scenario from the FES scenario report (National Grid, 2018). This report provides several scenario forecasts and the consumer Evolution scenario was chosen because it doesn't deviate much from the current trend and does not assume a large hydrogen economy. Furthermore, the yearly power demand for the UK was, similar as for Germany, kept the same as of 2019.

3.1.4 Assumptions

The Base Case for Germany and the United Kingdom reflect a scenario with focus on decarbonising the power system, in line with the countries current policies, but without any focus on hydrogen. A hydrogen demand was then added to this Base Case to analyse its impact. Furthermore, the hydrogen demand was estimated for each sector and was derived from assumptions seen in Table 2.

Table 2: Assumptions of hydrogen demand in different sectors. The percentage is a share of the absolute value of each of the two countries (Germany and the United Kingdom).

Transport	
BEV of Passenger car fleet	50%
Trucks, Busses and Ferries as H_2	50%
Convert non electrical trains to H_2	100%
FCEV in passenger car fleet	0%
Gas grid	
Mix in the conventional gas grid (vol.%)	6%
Heating	
Residential/Commercial heating with pure H_2	6%
Industry	
Steel production from H_2	50%
Switch current H_2 production to electrolysers	50%
Power	
Share of electrolyser capacity possible for 'Back to grid'	10%
H_2 produced by dedicated offshore wind	10%
Efficiency of electrolyser	70%

The effects these assumptions had on commodities such as carbon fuels, power, and hydrogen was calculated in Appendix A and the results are shown in Table 4. The motivation behind the assumptions is further explained below in section 3.1.4.1 to section 3.1.4.3.

3.1.4.1 Assumptions of Transport sector

The low well to wheel efficiency for FCEV, in comparison to BEV, is the reason why it was assumed that FCEV will only take a small niche market segment of the passenger car fleet, making it negligible (Ramachandran and Stimming, 2015). BEV is expected to continue to win market share from Internal Combustion Engines Vehicles (ICE) and was therefore assumed to make up 50% of the passenger car fleet in 2050. As stated in section 2, the advantages of FCEV are more promising for heavy vehicles with a high utilisation rate. Because of this, much of the public transportation e.g. busses, ferries and trains were assumed to run on hydrogen. Compared to other sectors, this assumption is more easily adjusted from political policies and is likely to be one of the first segments to increase the hydrogen demand. Trucks are also an example of heavy vehicles with high utilisation rate that can benefit from the fuel-cell technology instead of batteries and were equally assumed to have a high share of FCEV. Another reason to assume a fast transition in the transport sector is the proposed ban of sales of new ICE from some European countries, thereby the UK.

3.1.4.2 Assumptions on heating and hydrogen distribution

Mixing hydrogen with natural gas in the existing gas grid is already in practice. The heating sector is also largely supplied with gas in both the UK and Germany, which gives this sector a huge potential for hydrogen demand. Adjusting the infrastructure to increase the hydrogen mix in the gas grid would be an effective way to rapidly increase the hydrogen demand. Therefore, 6% vol. of hydrogen was assumed to be mixed in the gas grid. The threshold is equal to what is currently allowed in certain parts of Germany, but still higher than the average share used today.

Creating a dedicated hydrogen grid would be beneficial for both hydrogen demand in the heating sector as well as for industries. From an economic perspective, it is most probably that dedicated hydrogen grids will concentrated around highly populated areas as well as near industries. This has the potential to significantly increase the hydrogen demand and was assumed to supply 6% of the total residential heating demand in 2050. This corresponds to half of the total heating demand in the seven largest cities in Germany.

3.1.4.3 Industry sector

Since many industries already produce and use hydrogen today, hydrogen demand already exists for these industries. With further incentives to decarbonise industries, green hydrogen could also make its entry into this market. However, it is questionable if the industries that currently produce hydrogen on-site would buy or produce hydrogen from electrolysis instead of improving their existing production facilities with CCUS technology. Since this outcome is heavily dependant on the political development, it was assumed that 50% of the current hydrogen demand, satisfied by SMR, would be supplied by green hydrogen from electrolysis in 2050.

Moreover, the steel industry is very large in Germany and currently uses coal to refine iron ore. Promising results from studies show that hydrogen can be used as a direct reductant, meaning, it would be possible to use hydrogen instead of coal in the process. Because of this improving technology as well as lack of other means to decarbonise this sector, it was assumed that half of the steel produced in the UK and Germany would be made with H-DR technology (IEA, 2019a).

The efficiency of the electrolyser was assumed to 70% based on the findings in the report from IEA (2019a) and was assumed to the lower expected future efficiency of PEM electrolysis. Furthermore, the prediction of future electrolysis efficiency differs and depends on the type of electrolyser as well as technological development. However, the efficiency of the electrolyser only translates to an increase in power demand needed to cover the hydrogen and does therefore not impact the results of this thesis substantially.

3.1.5 Allocation of power source for electrolyser

The increase of power demand, resulting from the assumptions in Table 2, needs to be met by increased power capacity. The hydrogen produced by electrolysis should also come from renewable power sources to be carbon neutral. Therefore, the extra renewable energy capacity was calculated in Appendix C.

A cost optimisation model was created in excel to determine the optimal share of added onshore wind, offshore wind, and solar, in addition to the optimal electrolyser capacity (see Appendix C). This model optimised the capacity of each technology in order to minimize the total CapEx. This means that the OpEx cost was neglected, which would be reasonable if the hydrogen is produced when the power price is close to zero and storage costs of hydrogen are not included. Moreover, properties of any storage or seasonal demand behaviour was also not considered in this optimization.

From Bid3, the hourly capacity factor for the three VRE technologies (onshore wind, offshore wind and solar PV) was collected using a generic weather year, provided by Uniper. The capacity factor was then multiplied with the unknown capacity of the corresponding technology for each hour of the year (Equation 5). If the energy produced in that hour was greater than the capacity of the electrolyser, the energy for hydrogen production was set to the capacity of the electrolyser (Equation 6).

$$\begin{aligned} E_{VRE}(h) = {} & CF_{onshore}(h) \cdot C_{onshore} \\ & + CF_{offshore}(h) \cdot C_{offshore} \\ & + CF_{solar}(h) \cdot C_{solar} \end{aligned} \tag{5}$$

$$E_{H_2}(h) = \begin{cases} E_{VRE}(h) & \text{if } E_{VRE}(h) \leq C_{electrolyser} \\ C_{electrolyser} & \text{if } E_{VRE}(h) > C_{electrolyser} \end{cases} \tag{6}$$

where:

E_{VRE}	= Energy produced from solar PV, onshore- and offshore wind power.
E_{H_2}	= Energy used for hydrogen production
$CF_{onshore}$	= Capacity factor for onshore wind power
$CF_{offshore}$	= Capacity factor for onshore wind power
CF_{solar}	= Capacity factor for solar PV
$C_{onshore}$	= Capacity for onshore wind power (output parameter)
$C_{offshore}$	= Capacity for onshore wind power (output parameter)
C_{solar}	= Capacity for solar PV (output parameter)
$C_{electrolyser}$	= Capacity for electrolysers (output parameter)

The solver in excel was then used to minimize Equation 7, with the constraints that the produced energy E_{H_2} over the whole year needed to be equal or more than the hydrogen demand for each country (Equation 8).

$$\sum_{technologies} (\text{Capacity} \cdot \text{CAPEX}) \tag{7}$$

$$\sum_{h=0}^{h=8760} E_{H_2}(h) \geq \frac{\text{Yearly hydrogen demand}}{\text{efficiency of electrolyser}} \tag{8}$$

The output was the capacity of the three VRE technologies, the electrolyser capacity and the total CapEx costs. Since the solved problem was not linear, multiple values were found as a solution, depending on the start values. After testing a set of different start values, the two most reasonable options were chosen for each country based on total CapEx cost, the likeliness of capacity growth, as well as overall load factor for the electrolyser. The resulted capacity obtained from this analysis, as well as the change in power demand based on the assumptions in Table 2, was added to the capacity and demand from the Base Case, to create two new cases for each country. The two new cases are referred to as the *Solar Case* and the *Wind Case*, based on which of the cases had more added solar or wind capacity.

3.2 Simulation of the power system in Bid3

After the demand and installed capacity for the three cases was determined, they were incorporated into a program called Bid3, in order to simulate how the power system would behave.

Bid3, version 2020.1.1.11708, is an economic power dispatch model, developed by Afry. The program is used for short term market forecast, asset evaluation and long term scenario analysis for the power markets. Bid3, simulates the dispatch of all power supply and demand in each hour for the electricity market. This is done by linear or mixed-integer programming to minimise system costs of meeting the power demand, subject to relevant constraints. System costs considered by the program are for example; production costs of individual power plants, start-up costs, bidding factors and charges associated with the use of storage (AFRY, 2020).

The main concept of Bid3 is to use multiple connected nodes. The nodes often represent a geographical area, each with inputs such as installed capacity, weather data and demand. These inputs can in turn be customized to very specific represent the desired status in each node. Moreover, the link between nodes are modelled as interconnectors with customized properties. With these inputs, the models simulates the hourly demand and generation of all power plants, taking into account fuel prices and operational constraints such as starting costs, efficiency, downtime and ambient temperature effects. The outputs from the model used in this thesis are hourly data of generation, demand, carbon emission, power price, storage level, usage of interconnectors and curtailment of VRE.

3.2.1 Implementing hydrogen

Adding the generation capacity and demand for the different cases are done with standard functions in Bid3. However, large scale hydrogen production from electrolysers have so far not been added as a function in the program. Therefore, the electrolyser was modelled as a demand with a connected storage capacity, which could be done in two ways.

One method was to create a separate node (H_2-node), which represented a virtual country. This country, or node, was then connected via an interconnector to the real country where the hydrogen production takes place. In the H_2-node, storage capacity in form of a battery was added as well as demand equal to the hydrogen demand for that country. The battery was added so that the production of hydrogen could be flexible, which is equal to the hydrogen storage. Moreover, the interconnector between the node and the real country did limit the power flow from the real country to the H_2 node and thus represented the electrolyser capacity. The model will in this case dispatch both the demand and the power generation in the H_2 node, which will only consist of the battery storage and the hydrogen demand. Therefore, the demand can only be satisfied by the energy stored in the battery, or by import from the connected country. This results in an optimisation of the power supply based on the power price in the real country and the remaining storage level, which is constrained to start and end at 50% of the storage capacity at the shift of the year. Figure 10 illustrates this way of modelling hydrogen production in Bid3.

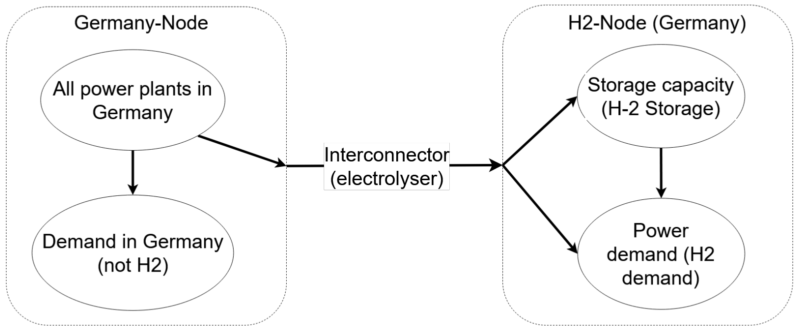

Figure 10: Method of modeling the hydrogen demand and production as a virtual node. In this case Germany is used as an example and the possible power flow is illustrated by the arrows.

Another method is to add a flexible demand with its independent storage to the node where the hydrogen is assumed to be produced, thus not adding a virtual node. This is a build-in function in Bid3, also used for modelling BEV, where the flexible demand is given a certain amount of storage capacity as well as a filling and emptying capacity. The flexible demand represents the aggregated electrolysis capacity as well as the storage capacity in that country. With this method, the hydrogen demand was placed in the same node, resulting in the program optimising when hydrogen shall be produced within the year to minimise the system costs. This contributes to hydrogen being produced, similar as for the previous method, during hours of low power prices, which often occurs at times of high VRE generation.

The two methods of modelling hydrogen in Bid3 were tested and compared to each other. This showed that the method of using a separate node was more suitable for large scale hydrogen production and was therefore used to simulate the different scenarios. The determining factor was that the method using a separate node was able to use the storage on a seasonal basis which the method using flexible demand could not. Both the power demand and the VRE production can be unevenly distributed throughout the year, which is why seasonal storage would improve the flexibility of hydrogen production and is likely to be used in a scenario with a developed hydrogen economy.

Moreover, operational or investment costs for the storage were not considered in the simulation. For the electrolysers, the investment costs were indirectly incorporated since the capacity was derived from the analysis in Excel, which in turn was based on the investment costs (see section 3.1.5). Therefore, only the wholesale power price was used as cost by Bid3 for the production of hydrogen.

The power demand for BEV in Bid3 was modelled without the possibility of reversed power flow, also called Vehicle to Grid. This is motivated by the large power demand from BEV, which would make it more difficult to distinguish its effects from the hydrogen demand. Moreover, the BEV demand was modelled as a demand storage unit, meaning that the charging of the BEV was restricted to a charging profile obtained from Fraunhofer (in order to ensure that vehicles are not charging while driving). Furthermore, the demand for the BEV was set to flexible which means that the time of use can vary depending on the current power price. This also contributed to some effects on the power system since the BEV often charged during night time when the overall demand is low, counteracting sinking power prices.

Apart from Germany and the UK, data for the rest of Europe was taken from the Uniper forecast of the power markets in 2035. In addition to this data, extra VRE capacity was also added to some of the neighbouring countries of Germany and the UK. This was done so that the two countries would not export most of the renewable generation and increase import of thermal generation during peak demand hours. The added VRE capacity to neighbouring countries is shown in Table 3. Furthermore, the capacity in Table 3 was calculated so that the share of the three different VRE technologies in a given country would be equal as the share of the technologies in the Base Case for Germany. Moreover, The capacity of offshore wind was added to the capacity of onshore wind for countries that do not have a coast.

4 Results

4.1 Base Case: A reference scenario without hydrogen

The Base Case reflects a future low carbon emission scenario for the year 2050, in line with the current political agendas in Germany and the UK. Furthermore, the Base Case was used as a reference scenario to evaluate the effects of a hydrogen market and therefore does not include the assumptions regarding hydrogen, stated in Table 2. The yearly demand and generation by power source for the Base Case are illustrated in Figure 11 below.

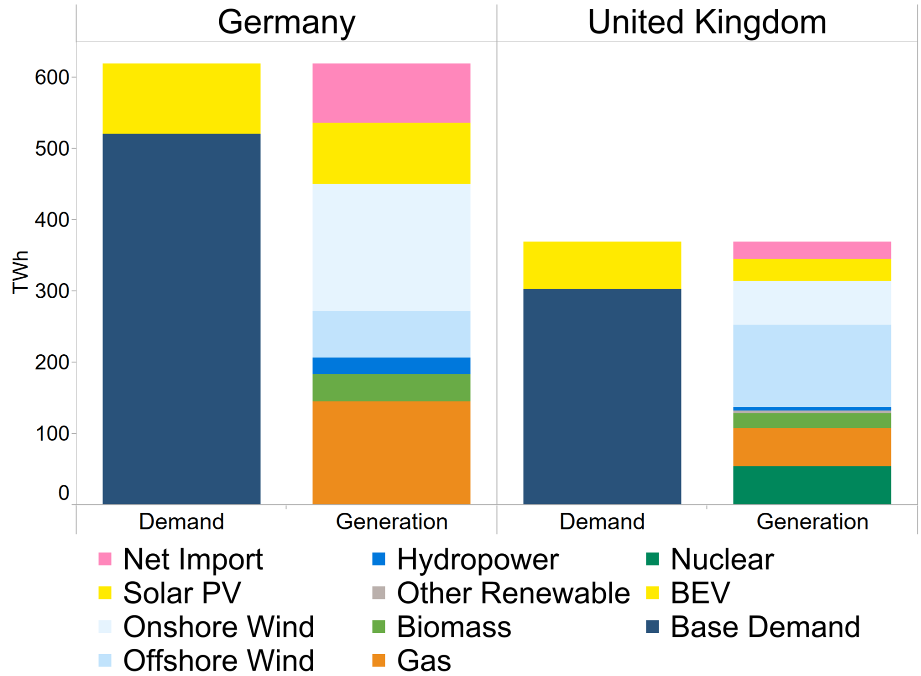

Figure 11: Yearly supply and demand in the Base Case for Germany and United Kingdom in 2050

The only assumption from Table 2 that was included in the Base Case is the demand for BEV since BEV is predicted to take large market shares, independent of the development of hydrogen. Moreover, because the BEV demand was also added to the Base Case, it was easier to distinguish the effect of the hydrogen demand from the effects of the BEV demand.

Additional VRE capacity to the neighbouring countries of Germany and the UK can be seen in Table 3. This capacity was added to the input data in Bid3.

Table 3: Added VRE capacity for neighbouring countries of Germany and the UK expressed GW. This capacity was added on top of the forecasted Uniper data for year 2035.

Country	Solar PV	Onshore Wind	Offshore Wind
Poland	26.2	2.2	2.2
France	98.4	7.6	9.8
Netherlands	17.9	1.8	0.4
Austria	12.5	4.4	-
Belgien	15.1	1.5	-0.4
Switzerland	10.7	6.7	-

Austria and Switzerland do not have any coast and the allocated additional offshore capacity was therefore added to the onshore capacity. Moreover, the forecasted offshore capacity in Belgium was larger than the allocated capacity for the country and therefore, the offshore wind capacity was reduced by 0.4 GW to be consistent with the change in the other countries.

4.2 Solar Case and Wind Case

The Solar Case and the Wind Case were created by adding hydrogen demand derived from the assumptions in Table 2. This resulted in a demand change of certain commodities that are shown in Table 4.

Table 4: Results of change in demand of the different commodities based on the assumptions in Table 2. Note that the change in power demand due to BEV is also included in the Base Case.

		Germany	UK
Change in green hydrogen demand	**TWh**	**225**	**157**
Heavy vehicle FCEV	TWh	74	61
Trains	TWh	1	6
Residential/Commercial heating	TWh	90	56
Steel industry	TWh	38	7
Switch current H_2 production to electrolysis	TWh	22	27
Change in power demand (excl. H_2)	**TWh**	**124**	**72**
Increase of BEV *	TWh	99	67
Increase usage of H_2 in steel industry	TWh	25	5
Change in other commodities			
Oil demand	ktoe	- 19 846	- 19 314
Equal to emission reduction	M tonne CO_2-eq	- 60.9	- 59.3
Gas demand	ktoe	- 9 654	- 7 157
Equal to emission reduction	M tonne CO_2-eq	- 22.6	- 16.8
Coal demand	ktoe	- 1 089	- 229
Equal to emission reduction	M tonne CO_2-eq	- 42.8	- 8.2

The demand in Table 4 was calculated in Appendix A and is divided into categories to show the specific change from each assumption. Most of the hydrogen demand comes from residential and commercial heating, as well as the transport sector. Moreover, a significant share also comes from steel production in Germany. By changing the process in the steel industry to use hydrogen, additional electricity demand is also needed. This power demand was separated from the hydrogen demand and is viewed in Table 4 under "Change in power demand".

Table 4 shows the total hydrogen demand whereas according to assumptions in Table 4, 10% of the hydrogen demand was assumed to be met by dedicated offshore wind generation, not connected to the grid. This leaves the hydrogen demand, met by grid-connected electrolysis, to be 203 TWh for Germany and 142 TWh for the UK. Moreover, given the assumed efficiency of 70% for the electrolyser, the power demand from the grid, needed to cover this hydrogen demand, is equal to 290 TWh for Germany and 203 TWh for the UK.

Apart from the added power demand from hydrogen production, the VRE capacity to cover this demand was also added to the scenario. The capacity of onshore wind, offshore wind, solar PV and electrolyser was allocated according to the method explained in section 3.1.5. Results of the two chosen options for each country are shown in Table 5 below. The one with more Solar PV capacity is referred to as the *Solar Case* and the other (with more wind capacity) is referred to as the *Wind Case*.

*This demand is also included in the Base Case

Table 5: Required renewable energy and electrolyser capacity to fulfill hydrogen demand in each country assessed.

		Germany		United Kingdom	
		Solar Case	Wind Case	Solar Case	Wind Case
Capacity					
Offshore Wind	[GW]	44.2	54.9	–	34.4
Onshore Wind	[GW]	27.3	26.7	57.3	22.9
Solar PV	[GW]	68.3	18.3	55.0	9.7
Electrolyser	[GW]	51.2	58.0	49.9	48.4
Energy generated					
Offshore Wind	[TWh]	177.5	220.1	–	134.9
Onshore Wind	[TWh]	53.0	51.9	148.0	59.3
Solar PV	[TWh]	72.7	19.5	59.5	10.5
Other data					
Yearly hydrogen demand	[TWh]	203		142	
Yearly power demand for H_2	[TWh]	290		203	
Total CapEx	[M€]	241 957	247 435	141 469	168 555
Increase of curtailment	[TWh]	13.2	2.0	4.7	1.6
Avg. electrolyser load factor	–	65%	57%	46%	48%

The capacity shown in Table 5 is the additional capacity that is added to the *Base Case*, resolving in the *Solar Case* and the *Wind Case*. The increase of curtailment is equal to the sum of energy produced by the VRE sources that can not be used by the electrolysers. When connected to the grid, this extra energy is not necessarily curtailed, since it could be used by other grid-connected demand.

The results for the Solar Case and the Wind Case are shown below, where Figure 12 illustrates the total installed capacity by source and Figure 13 shows the yearly generation by source for the three cases.

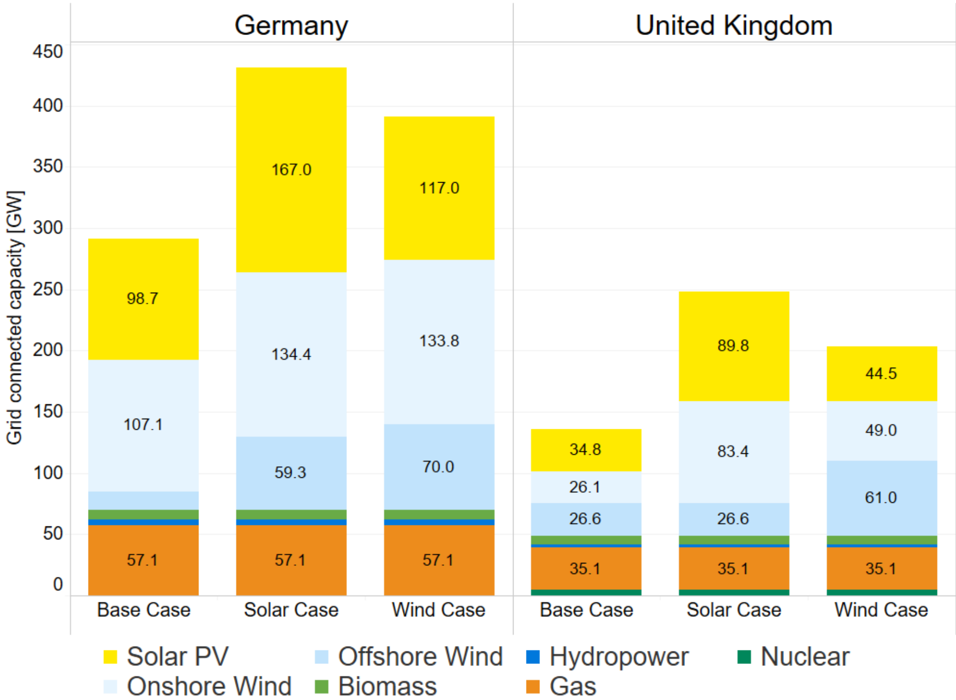

Figure 12: Total installed grid-connected capacity of the three different cases. This data was used as input for the simulation in Bid3.

The added increased share of VRE capacity in the Solar Case and the Wind Case is significant compared to the Base Case. Most dominant is the increase of offshore wind capacity in all but the Solar Case for the UK. Moreover, the displayed capacity in Figure 12 is only the grid connected capacity. Additional dedicated offshore wind capacity was also assumed to be installed in the scenario to meet 10% of the hydrogen demand that is produced without connected to the power grid (see Table 2).

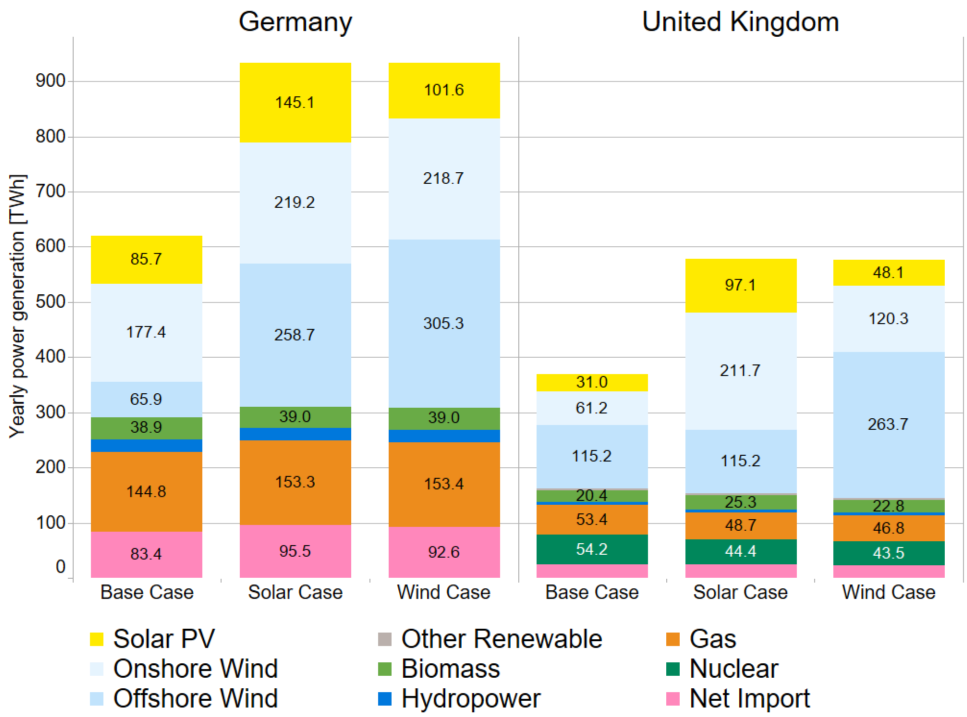

Figure 13: Yearly generation after renewable capacity and electrolysers were added to the system. Results were obtained from simulation in Bid3.

Wind generation makes up a large part of the yearly power generation in all cases. This is mainly due to the high capacity factor of the technology and the good wind resources in Germany and the UK. Moreover, the net import of power increases slightly in Germany. This could be that the added VRE capacity in the neighbouring countries is still lower than for Germany, causing it to increase import when the weather conditions are not in favour of the VRE technologies. Imports for the UK is more limited because of it being an island that is less connected to the rest of the European power grid.

4.3 Flexibility of the power system

Since the VRE capacity in the scenario was very large, the generation was also observed to be more volatile. Moreover, installed electrolysers managed to use most of this generation by increasing their demand during hours of large VRE generation. Figure 14 shows the generation and demand in Germany during two weeks in July for the Solar Case.

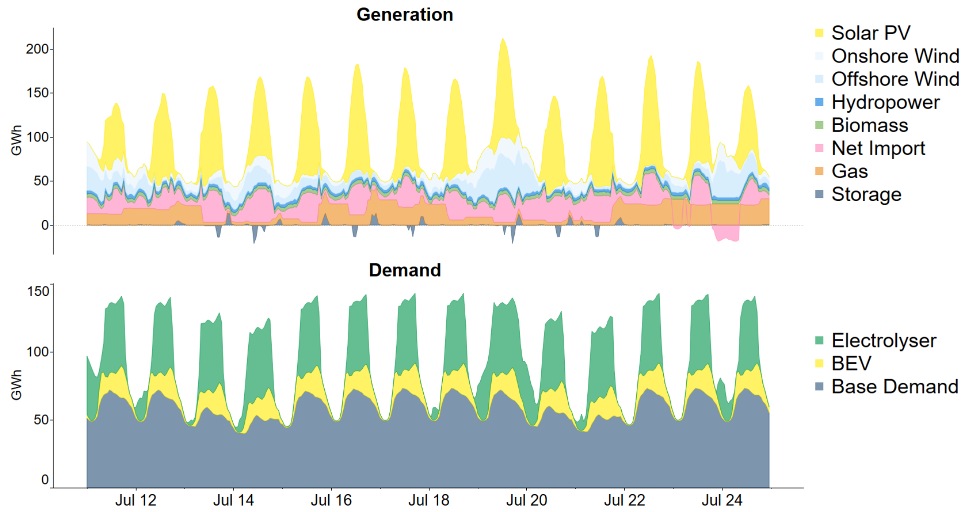

Figure 14: Generation (upper) and demand (lower) during week 29 and 30 in July for Germany in the Solar case.

The generation is displayed by source and the demand is divided into groups to show the effect of the electrolyser and BEV separately. The huge installed solar PV capacity, together with the high irradiation in July shows how the generation almost triples during the daytime. Some of this generation is taken up by BEV demand but most of the increased generation is absorbed by electrolyser activity. It is also important to note how the net import is increased during day time, which mostly comes from neighbouring countries without electrolyser capacity but high solar PV capacity.

4.4 Wholesale power price

The wholesale power price includes the cost of generating power and transmitting it over the high-voltage system. Results from the simulation showed that the connected electrolysers increase the lower wholesale prices by increasing demand during low price hours. This reduces the severity of price crashes when there is a lot of VRE generation that otherwise could not be consumed by other demand (see Figure 15). It is also important to keep in mind that this behaviour is observed even though additional VRE capacity was added to the system to cover the hydrogen demand.

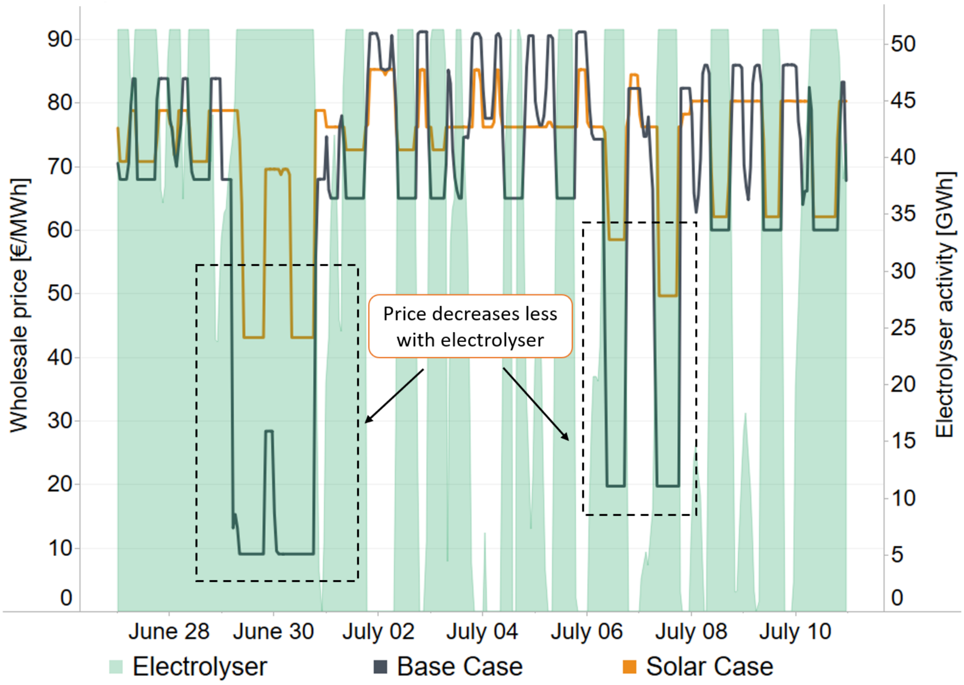

Figure 15: Wholesale price for the Base Case (grey line) and Solar Case (orange line) during week 29 and 30 in Germany. The green area shows the electrolyser activity and is displayed on the right axis.

The sudden price crashes shown in Figure 15 are due to a large amount of VRE generation. These crashes were shown to be reduced significantly in the simulations with electrolyser capacity. This behaviour contributes to increasing the low power prices up to the level where it would be beneficial to run the electrolysers. Overall, the arithmetic mean value of the power prices increased over the year, while the median value remained almost unchanged. This can be seen in Table 6.

Table 6: Arithmetic mean and median value for the wholesale power price in Euro/MWh

	Germany			United Kingdom		
	Base Case	Solar Case	Wind Case	Base Case	Solar Case	Wind Case
Arithmetic mean	60.3	65.4	65.4	58.5	64.7	63.3
Median	72.4	74.7	74.0	73.9	71.7	71.7

Table 6 shows how the power price becomes more concentrated around the median value of 72 to 74 €/MWh when more VRE and electrolyser capacity were added. This is further shown in Figure 16 and Figure 17 where the price distribution is illustrated.

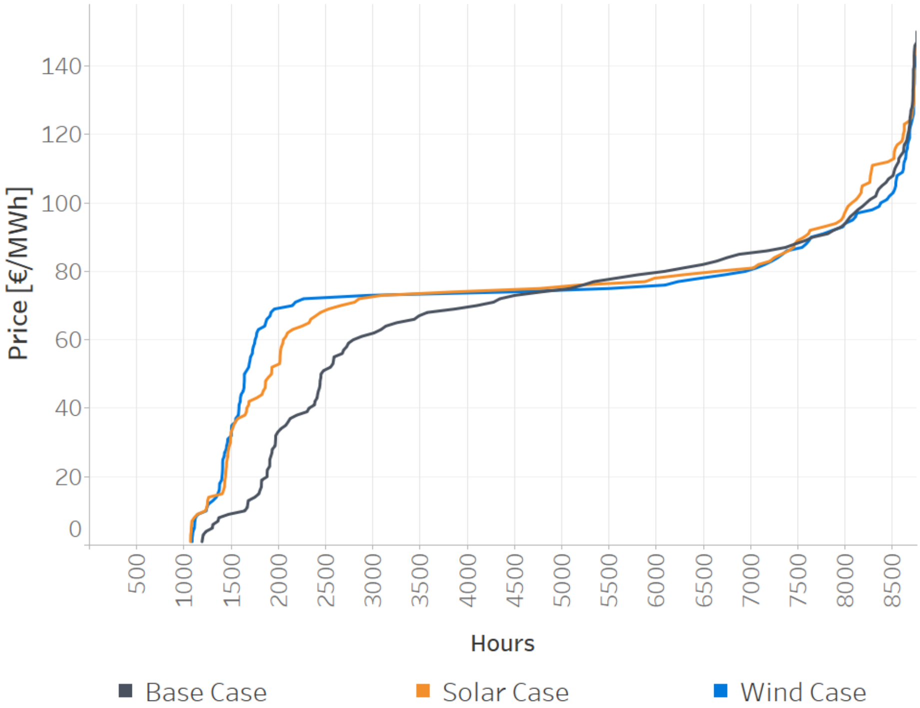

Figure 16: Graph shows how many hours the wholesale power price has been under a certain value in Germany for the different cases.

For Germany, both the Solar and Wind Case were able to reduce the number of hours with close to zero price by around 100 hours/year. This shows how the electrolysers can reduce the price crashes even with added VRE capacity. However, the results showed that there still are a significant amount of hours with a power price close to zero, which indicates that the amount of VRE capacity is too high. The hours within the price range of 70 €/MWh to 80 €/MWh increased with around 2000 to 2800 hours/year for the Solar- and Wind Case in Germany. Furthermore, the reason for the concentration of the power prices around 70 to 80 €/MWh is assumed to be because this limit is the marginal cost of the most efficient CCGT. The system also identified many of these hours to have low enough cost to run the electrolysis, resulting in the CCGT and electrolyser to run simultaneously and therefore constraint the price in this range.

Some of the higher price hours were also slightly reduced, which shows that the system avoided running some of the most expensive gas plants due to the higher amount of renewable capacity. Moreover, some increase in power prices were observed in the Solar Case for Germany. This behaviour only affected a few hours and is assumed to be a result of internal constraints in the model for how the electrolysers were simulated.

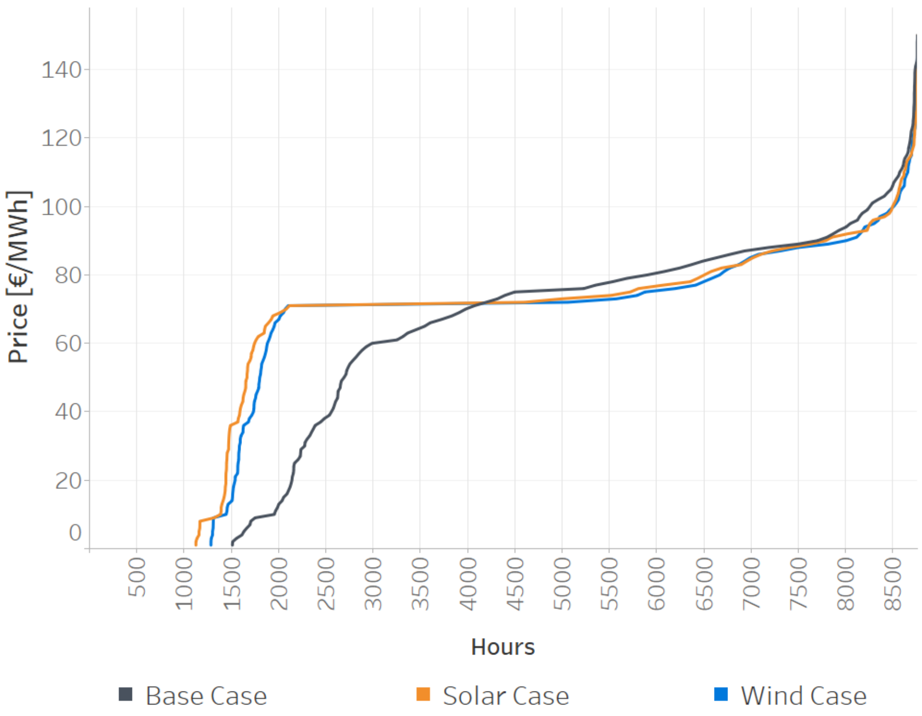

Figure 17: Graph shows how many hours the wholesale power price has been under a certain value in the United Kingdom for the different cases.

In the UK, the change in wholesale power prices was similar to the results obtained for Germany. The hours with a wholesale price between 70 to 80 €/MWh increased with around 2500 to 2600 hours/year, in the UK for the Solar and Wind Case respectively.

4.5 Color of green hydrogen

It is important to evaluate how much renewable energy is used when producing green hydrogen. This can be done by looking at the hourly generation of the grid during the hours when the electrolyser is active, to see what kind of energy source is used. In Figure 18 and Figure 19, the hourly activity of electrolysers is shown with the percentage of renewable energy being generated to the grid. In general, the electrolyser activity is more present during hours of high renewable share, which also tends to be during hours with low price. However, the renewable share on the grid is never 100%, and thus the power used for the electrolysers is also not completely renewable. This is due to the fact that there are some must-run thermal plant like Combined Heat and Power plants (CHP), which tend to always be generating on the system. It is thus almost impossible for electrolysers to operate during hours with zero thermal generation in this kind of system. This may change in the future if CHPs are converted to burn other fuels or are decommissioned. Nevertheless, the electrolyser activity is more present during hours of high renewable share, which makes the hydrogen produced mostly renewable.

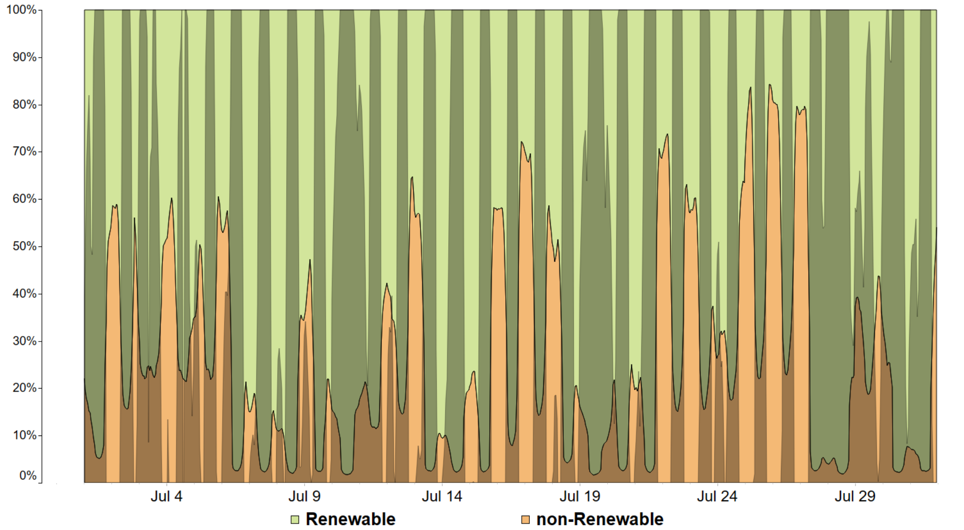

Figure 18: Share of renewable generation in July. The green area represents the amount of renewable generation in a certain hour during the month, while the orange colour represents non-renewable generation. The shaded area shows the activity of the electrolyser, expressed as a percentage of the max capacity of installed electrolysers. The current graph is from the Solar Case in Germany.

It is possible to see the flexibility of the electrolysers in Figure 18 and how they adjust the hydrogen production to hours with high renewable share, which often correspond to low power prices. This figure illustrates the Solar Case in Germany during July with high solar irradiation. Thus, the renewable generation from solar PV increases sharply the during day time and is taken up by electrolyser demand.

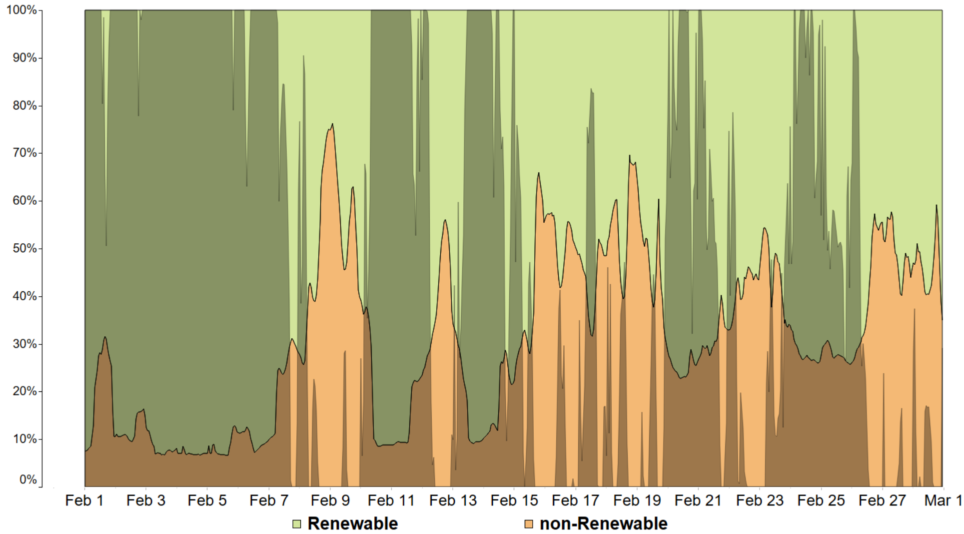

Figure 19: Share of renewable generation in February. The green area represents the amount of renewable generation in a certain hour during the month, while the orange colour represents non-renewable generation. The shaded area represents the activity of the electrolyser, shown as a percentage of the max capacity of installed electrolysers. The current graph is from the Wind Case in the UK.

Figure 19 shows the Wind Case during February in the UK where the electrolyser does not change as periodically as in Figure 18. Yet, the electrolyser activity is more concentrated to hours of high renewable generation, which in this figure, is mostly supplied by wind power. Unlike Germany, the United Kingdom also has nuclear capacity which operates as baseload. This power source does not contribute to carbon emissions but still does not count as renewable and therefore gives a higher non-renewable power mix than Germany.

Table 7: Results from simulation of the assessed cases showing yearly data of non-renewable generation, net imports of power, CO_2 emission and curtailment of VRE.

		Germany			United Kingdom		
		Base Case	Solar Case	Wind Case	Base Case	Solar Case	Wind Case
Emissions	[Mt CO_2-eq]	60	63	63	25	23	23
Gas generation	[TWh]	144,8	153,3	153,3	53,4	48,7	46,8
Net Import	[TWh]	83,4	95,5	92,6	24,4	25,2	22,2
Curtailment of VRE	[TWh]	11,1	17,3	16,7	10,0	15,9	13,5
Nuclear generation	[TWh]	-	-	-	54,2	44,4	43,5

The results of total emission from the power generation are shown in Table 7. CO_2 emissions from the German power system increased slightly for both the Solar and Wind Case compared to the Base Case. This is directly linked to the increase of gas generation, shown previously in Figure 13. For the same reasons, both gas generation and CO_2 emission decreased in the United Kingdom. However, the direct change of CO_2 emissions from the power sector was quite small, relative to the avoided emissions from the utilisation of hydrogen (see Table 4). For Germany, the total net reduction of carbon emissions was 123 M tonne CO_2-eq per year, including the avoided emissions from switching from carbon-based fuels to hydrogen. 60.9 M tonne CO_2-eq from the avoided emissions comes from decreased oil demand and is only linked to the switch from ICE to BEV. Therefore, the net reduction of emissions connected to increased use of hydrogen in Germany was 62.1 M tonne CO_2-eq per year which is equal to 9% of the total German GHG emissions in 2018. For the UK, the net emission reduction was 86.2 M tonne CO_2-eq of which 26.7 M tonne CO_2-eq comes from increase usage of hydrogen. The GHG reduction from the use of hydrogen in this scenario corresponds to 8 % of the country's GHG emissions in 2018.

4.6 Storage

The amount of available hydrogen storage was assumed to be large enough to not be a constraint in the simulation. The result of how much storage was utilised and how the storage level varied over the year is illustrated in Figure 20 for Germany and in Figure 21 for the UK.

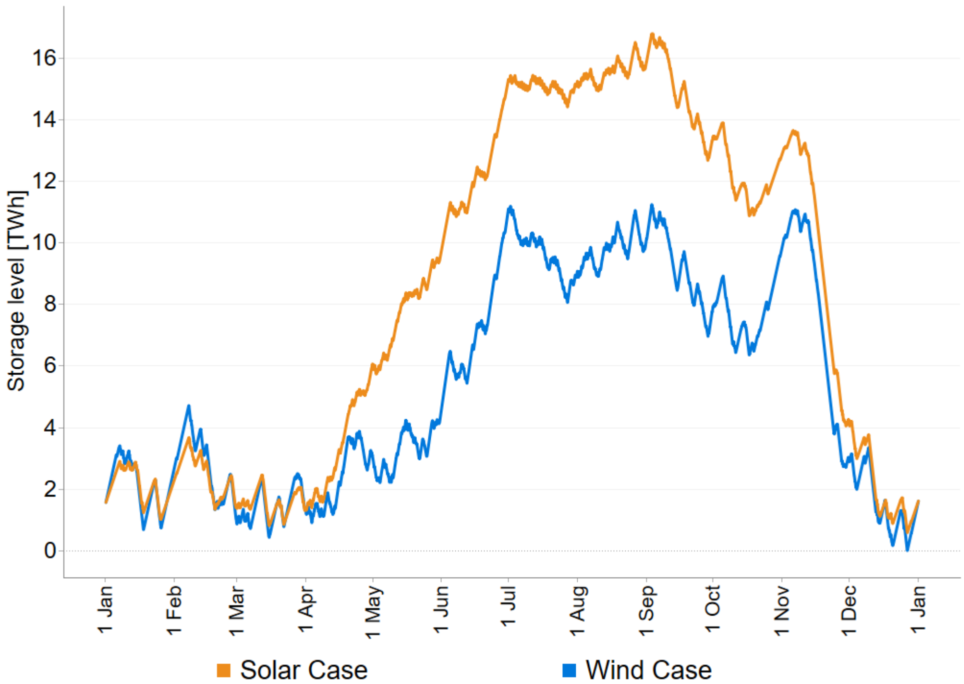

Figure 20: Storage utilisation in Germany for the two cases

For Germany, the summarized generation of solar and wind is fairly constant during the year, even if large variations can occur on an hourly or daily level. However, both the demand of power as well as the demand of hydrogen is higher during the winter and lower during the summer. Therefore, the renewable generation is exceeding the demand during the summer months, causing the electrolyser to generate more hydrogen which is stored until the winter months. This becomes even more clear in the Solar Case where the increase of solar generation during the summer amplifies this behaviour.

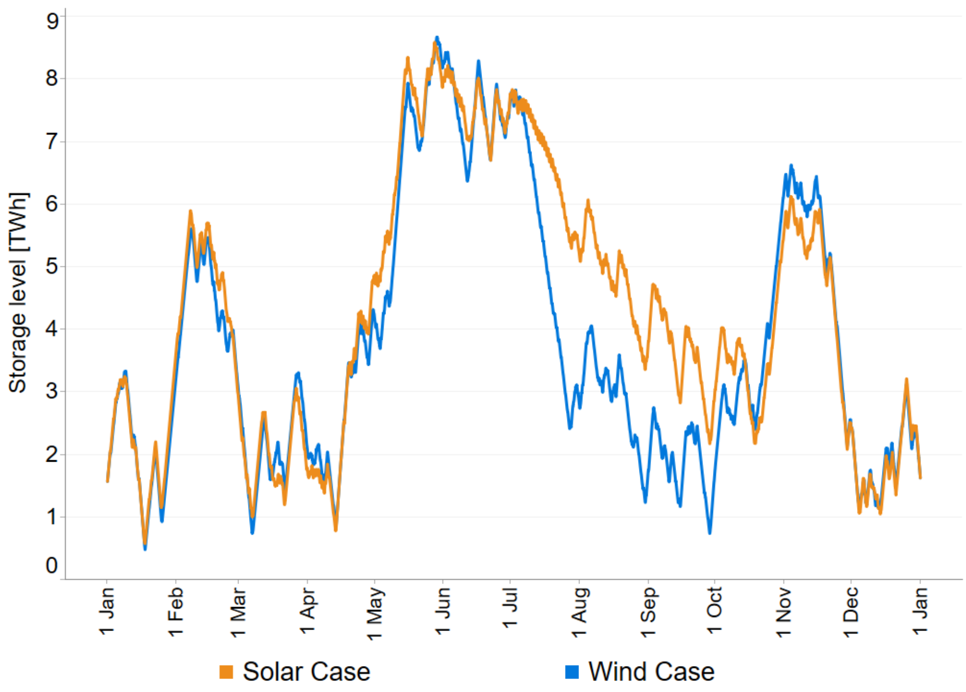

Figure 21: Storage utilisation in United Kingdom

For the United Kingdom, the storage does not follow the same seasonal shape as for Germany. Nuclear power generation, as well as the higher capacity factor for wind power, causes the seasonal off-set of generation and demand to be less distinctive than in for Germany in this scenario. Although, it is possible to see how the storage is used more during the summer in the Solar Case compared to the Winter Case.

Table 8: Maximum storage capacity in TWh required for hydrogen in the different cases assessed

	Solar Case	Wind Case
Germany	16,22	11,26
United Kingdom	8,02	8,19

The maximum storage capacity seen Table 8 was calculated by the difference between the highest and lowest storage level during the year. Clearly, the maximum storage capacity is higher for Germany compared to the UK since Germany has both a larger hydrogen demand but also less matching power generation with demand due to the high share of VRE capacity. The hydrogen storage in Germany is equal to 8% or 5.5% of the hydrogen demand in the Solar Case respectively the Wind Case. For the United Kingdom, the same value is 5.6% for the Solar Case and 5.8% for the Wind Case.

4.7 Power to X to power

The possibility of converting hydrogen back to electricity, also called "Back to grid", was implemented according to the assumptions in Table 2. As shown in Figure 22, this only occurred during 10-60 hours of the year when the prices were over average. For example, the power price changed from 108 €/MWh to 105 €/ MWh during five hours in December, for the Wind Case in the UK, due to conversion of hydrogen back to power. Mostly, the hydrogen was converted back to electricity during hours of low power prices, but high storage levels, which increased the number of hours with power prices near zero. This behaviour does not reflect the performance of a real power system and occurred due to some unknown reason of how the model is constructed. Therefore, this behaviour was later removed so that the results from the simulation was not impacted by this.

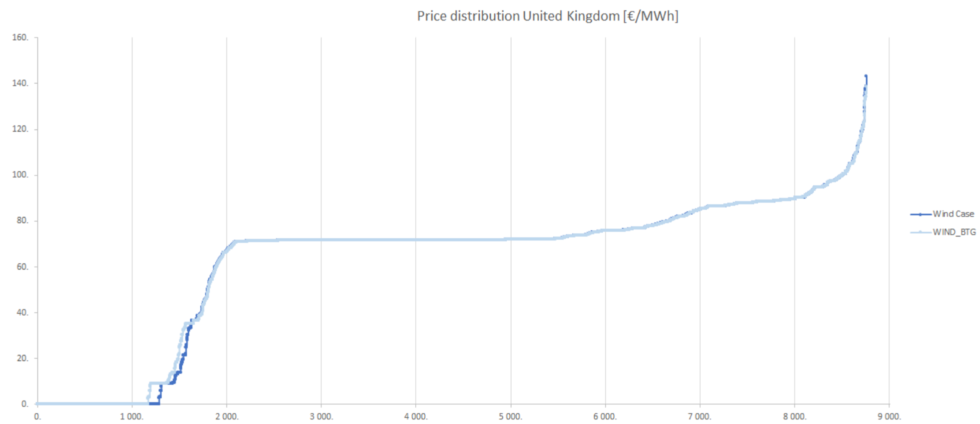

Figure 22: Comparison of the price distribution when converting hydrogen back to power on the grid

4.8 Sensitivity Analysis

The sensitivity analysis was done to understand how changing the renewable capacity would affect the emissions as well as the curtailment. The total renewable capacity was reduced and increased with 10% in both the Solar Case and the Wind Case.

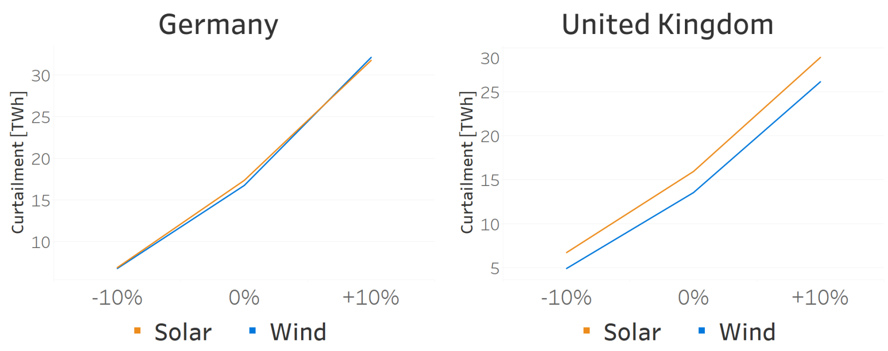

Figure 23: Sensitivity analysis of how curtailment is affected by changed VRE capacity. The blue line represent the Wind Case and the orange line the Solar Case.

The analysis showed that the curtailment changed almost linear with the change of VRE capacity. However, the emissions that are directly linked to gas generation, were not affected equally. The reduction of CO_2 emissions were similar in all cases when the VRE capacity increased, which showed a reduction of around 4 to 9 M tonne CO_2-eq for the different cases. When the VRE capacity was reduced, the CO_2 emissions from the German power system increased much more than for the UK. This is also shown in Figure 24, where the CO_2 emissions changes between 2 to 3 M tonne of CO_2-eq for the UK, while the emission increases by 28 M tonnes CO_2-eq in Germany. The German power system has a higher share of gas capacity compared to the UK, which increases the pressure on gas generation with decreasing generation from renewable sources. This is not the case of the UK, which has nuclear capacity that limits the need for gas generation.

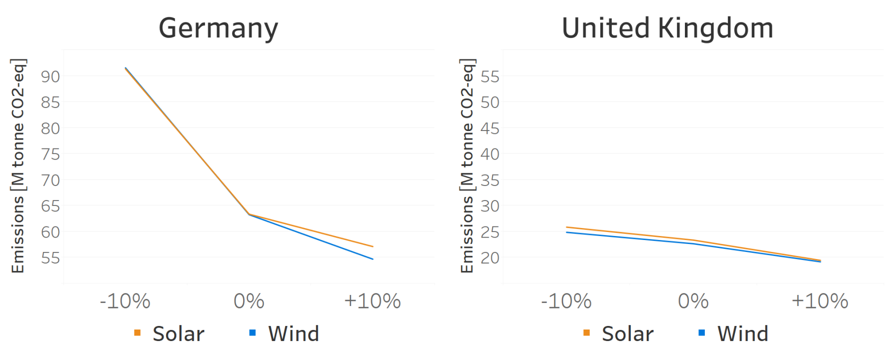

Figure 24: Sensitivity analysis of how CO_2 emissions is affected by changed VRE capacity. The blue line represent the Wind Case and the orange line the Solar Case.

5 Discussion

5.1 Carbon emission reduction

To meet the national GHG reduction target of 80% from 1990 levels, Germany needs to reduce its CO_2 emission with further 495 M tonnes per year from the current 683 M tonnes. Clearly, the emissions from the energy sector have a large impact on this but even with a completely renewable power system, the target is not certain to be met. This is due to the difficulties of decarbonising certain sectors such as the transportation and industry sector, where few viable alternatives are available. The results of this thesis showed that producing green hydrogen to be used outside the power sector can reduce the GHG emissions by around 61 M tonne for Germany and around 27 M tonne for the UK. However, it is important to mention that the shift in the passenger car segment from ICE to BEV had an equally large effect on the GHG emissions for Germany and an even bigger impact for the UK. This highlights the significant GHG emissions from the transport sector and therefore, one could argue that the switch to BEV is more important than decarbonising other sectors with hydrogen. Here it is important to remember that the emission reduction from increased shares of BEV is directly linked to the carbon intensity of the power system. Moreover, this thesis showed that the production of green hydrogen via electrolysers is beneficial for the stability of the grid and allows for higher penetration of VRE and thus should not be considered to compete with electrification in the transport sector. Also, BEV and FCEV are suitable for different segments in the transport sector which justify the lack of competition between the two technologies.

Furthermore, it is important to acknowledge the role of natural gas in the power mix, used in the constructed scenario. With no other thermal generation plants, the CO_2 emissions are heavily affected by the ratio of VRE, since gas generation covers the hours when the renewable generation is insufficient. This was shown in section 4.8 where the GHG emissions from the power system in the UK were more resilient to a decrease in VRE capacity because of the existing nuclear capacity.

5.2 Market for 100% renewable energy

The results of the constructed scenarios imply that the power system could handle a large share of VRE. However, this has a large impact on the power prices in the market, which was seen in Figure 16 and Figure 17 where a significant amount of hours have a power price close to zero. In today's power market, power prices are currently determined by the merit order and will be heavily reduced by an increasing amount of renewable energy capacity that has no associated fuel costs. Moreover, the low operational costs for VRE compared to thermal power plants contributes to its revenues by being able to capture higher power prices and when the share of VRE capacity increases, its revenues are weakened as a result of the reduction in power prices. This cannibalisation effect halts the profitability of renewable energy sources and thus also the incentives for investments. This problem is discussed by Srinivasan (2019) where the author points to studies showing how an increased penetration rate of VRE would decrease the wholesale power price. This already forces older installations of wind farms to decommission since the marginal-cost based tariffs might be insufficient to meet the operating costs. Moreover, it is argued that corporate power purchase agreements helped extend the life time of a few VRE parks, but might not be enough in an energy system dominated by VRE. López Prol et al. (2020) also argues that the cannibalisation effect jeopardises the competitiveness of VRE and might increase future policy costs for maintaining the investment incentives for VRE technologies.

The reason for the large amount of low-price hours observed for both Germany and the UK is because VRE power plants bid at prices close to zero due to the low production costs. With a large amount of VRE capacity, the power prices are then set by these bids at hours when the VRE can cover the demand. Therefore, the possibility of achieving a power system with high renewable generation could be questioned if the current market set-up is maintained. Adding electrolysers to the system can certainly help the market from heavy price drops, but the power price would anyhow be close to zero for most hours in a system where close to all capacity has no operational costs. Nowadays, Germany is already experiencing an increasing amount of hours with zero and negative prices, which are expected to increase with higher shares of VRE capacity. Winkler (2012) also lifts this problem and highlights that this will not only impair the investments incentives for VRE technologies but also for baseload, mid-merit and peaking plants were cost recovery for new plants becomes more challenging due to low wholesale power prices. Therefore it is important to keep in mind that the electricity market is likely to change if it shall accommodate high shares of renewable energy sources in order to decarbonise the power sector.

5.3 Probability of the scenarios

The scenarios in this thesis were intended to reflect a possible energy system in year the 2050. Given the far time horizon and the dependency on political actions, the uncertainties of how the energy market will look like in the future are extensive. The assumptions of the power market, as well as the hydrogen demand, are in line with the EU-green deal and the current national specific targets for 2050. However, it is arguable if hydrogen will be completely supplied by domestic production from electrolysers. The different countries in Europe have individual conditions such as geographical location and infrastructure, which provides various opportunities for hydrogen production and utilisation. Moreover, countries that have less beneficial conditions for renewable energy sources but access to natural gas, would have higher incentives to produce hydrogen in other ways than via electrolysis, i.e., blue hydrogen.

One possible bottleneck in the development of a market for green hydrogen according to the presented scenario could be the build-out rate of renewable capacity. The solar PV capacity in the scenario for Germany range from 117 GW to 167 GW in the Wind and Solar Case, and to reach this capacity, an average of 2.26 GW to 3.9 GW added capacity per year is required from the 49.2 GW installed PV capacity in Germany (2019). This might not seem so far-fetched when compared to the average addition of 2.25 GW solar PV capacity between 2015 - 2019, with a record of 7.91 GW added in 2011. However, it is also important to keep in mind the degradation of solar PV and additional capacity could be needed to replace PV installations that exceed their lifetime. Furthermore, the continued growth of the VRE market also faces the threat of reduced profits due to lower power prices which may halt the build-out rate.

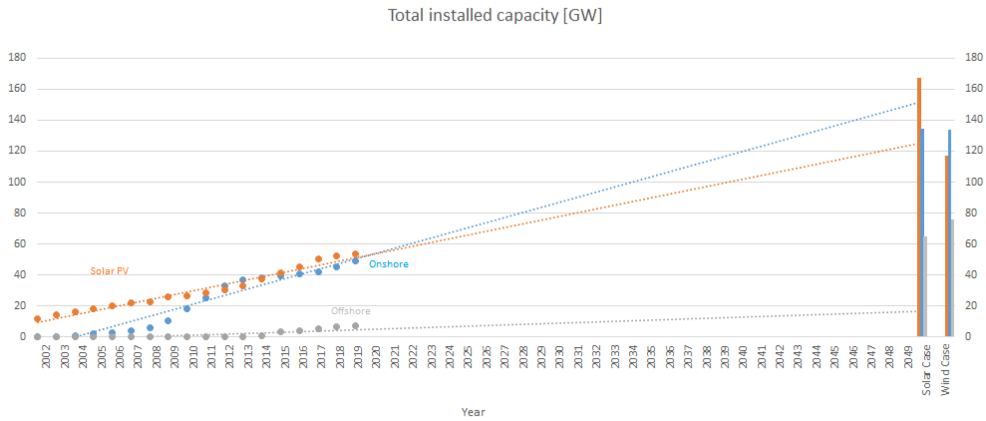

Figure 25: Historically installed capacity and installed capacity in the scenario for Germany

In Figure 25 the historical cumulative installed capacity of solar PV, onshore wind and offshore wind is showed as well as the used capacity in this thesis, projected for 2050 in Germany. If the current trend continues, it would possible to reach the suggested capacity. However, increasing renewable capacity puts more pressure on the power grid and the need for development of grid enforcement to match the VRE additions.

The supply of hydrogen in this report was estimated to 143 TWh via grid-connected electrolysis for the UK. This can be compared to the FES report that assumes a hydrogen supply between 16 and 119 TWh in 2050, depending on the scenario (National Grid, 2020). The FES scenarios *Consumer Transition* and *Leading the Way* are the most ambitious in terms of increased hydrogen supply via grid-connected electrolysis with 110 TWh respectively 119 TWh of yearly supply. The scenarios assume solar PV capacity of between 71 to 75 GW while the results in this thesis are between 45 to 90 GW, depending on the Solar or Wind Case. This shows that the estimated capacity is not too far away from the assumed capacity in the FES scenarios since the timeline also differs.

The largest difference between the FES scenarios and the results in this thesis is that the FES scenarios allocated more offshore wind in contrast to the results of the Solar and Base Case, were onshore wind and solar capacity had a larger share. The FES scenarios assumed onshore wind capacity of between 41 and 47 GW while the estimation in the Wind and Solar Case was between 49 and 83 GW. Furthermore, the offshore wind capacity in the FES scenarios is at 83 to 84 GW while the Base and Wind Case had 27 to 61 GW installed capacity. Moreover, the FES scenarios also assumed a much larger electricity storage capacity as well as three times more nuclear capacity in the Consumer Transition scenario.

Not many publicly available reports that reflect a similar scenario for Germany was found. The closest scenario to the one constructed in this thesis is the *Distributed Energy* scenario from ENTSO, (Fernandez et al., 2020). This scenario is compliant with the 1.5 °C target of the Paris Agreement and also considers the EU climate targets for 2030. Moreover, the Distributed Energy scenario only includes data for 2040 and does not show the total demand for hydrogen produced via grid-connected electrolysis but instead present 22 GW of installed electrolyser capacity. This is less than half compared to the capacity of around 50 GW estimated for Germany in this thesis for 2050. Moreover, the Distributed Energy scenario assumes 145 GW solar PV, 110 GW of onshore wind, and 43 GW offshore wind capacity. This can be compared to the results in this thesis of 117-167 GW of solar PV, 134 GW onshore wind and 59-70 GW offshore wind capacity. Clearly, the capacity for Germany in this thesis is higher than in the Distributed Energy scenario. This can, however, be from the difference in the year forecasted.

5.4 The color of hydrogen

Producing hydrogen via electrolysis can have a low carbon footprint and at the same time help the power system to reach high shares of VRE capacity. However, hydrogen produced via electrolysis is currently much more costly compared to other technologies such as SMR combined with CCUS, also called blue hydrogen. This, along with the hydrogen demand from centralised industries with already existing infrastructure for SMR facilities, advocates that it can be more cost-effective to improve the current facilities with CCUS to reduce the associated GHG emissions. Blue hydrogen also has the potential to increase the supply of low carbon hydrogen in the near future, independent of the development of the power system. This could therefore contribute to a fast-growing hydrogen market and gradually shift the supply share to green hydrogen in the long term.

The specific geographical criteria make some countries more suitable for one way of producing hydrogen than others. This is also mentioned by IEA (2019a) that highlights the importance of considering opportunities in individual countries, which likely will lead to a mix of blue and green hydrogen supply within Europe. Moreover, green hydrogen costs much more than blue hydrogen at the moment, giving much stronger incentives to invest in blue hydrogen where possible. Also, some applications are more suitable for different types of hydrogen production. Certain applications demand high purity of hydrogen, which is easier to obtain by electrolysis, and industries with already existing SMR facilities have easier to improve the existing facilities with CCUS.

The hydrogen price for the different technologies is expected to change in the future were electrolysis benefits more from economies of scale (IEA, 2019a). Furthermore, the production costs for green hydrogen is currently burdened by grid fees when produced by grid-connected electrolysers. This might change in the future to better position the green hydrogen market in line with the EU-green deal and the national hydrogen strategies. Also, when debating the benefits of different types of hydrogen production, it is important to keep in mind that blue hydrogen still emits some GHG, since not all CO_2 is captured in the process. At the same time, hydrogen from electrolysis connected to the grid is only as green as the source powering it. According to the Renewable Energy Directive (RED II) by the European Commission, green hydrogen does not have to be produced entirely from renewable energy sources to be classified as renewable powerfuel. However, given the requirements in RED II, Norway is the only country in Europe with an electricity mix that can produce hydrogen via grid-connected electrolysis as renewable powerfuel (Crone et al., 2020).

5.5 Import and export of hydrogen

In this thesis, all hydrogen for Germany and the United Kingdom was assumed to be produced domestically. However, given a large hydrogen market in Europe, it is presumable that there would be some kind of import and export, both within Europe, but also across other continents. For example, Russia, as well as the Middle East and North Africa, have all large natural gas resources and some also high potential for renewable energy production. According to a press release from the Federal Ministry for Economic Corporation and Development, Germany has together with Morocco signed a partnership to improve the framework conditions for the production and use of hydrogen, which could open up for German import of hydrogen (BMZ, 2020). Also, trade with hydrogen is likely to increase in the future, not necessarily because of countries limitations to cover the domestic production but to reduce costs and as a security of supply. The market becomes more robust and less reliant on a few actors if the hydrogen is supplied from several places.

5.6 Storage

One of the biggest advantage with hydrogen as an energy carrier is the possibility to store energy. This becomes more important when the share of intermittent energy sources in the power system increase. The energy system needs to match both peak demand and short term fluctuations in addition to the seasonal behaviour of energy supply and demand. There are several technologies capable of adjusting the short term fluctuations on the grid, such as batteries, peak generation and regulating power. Seasonal variation is more difficult to match since many storage technologies can not efficiently store a large amount of energy under a longer period. Hydropower is one of the few mature technologies that are well suited to both regulate the short term power balance and also even out seasonal variations. Unfortunately, many regions in Europe do not have the geographical prerequisites for enough hydropower capacity. Therefore, hydrogen can be a viable carbon-neutral option in places with low access to hydropower but geological storage potential of hydrogen. Nowadays, natural gas is stored in large reservoirs to meet the seasonal demand for gas. Given that the demand shifts from natural gas to hydrogen, these reservoirs could be used to store hydrogen instead. The results in this thesis suggested that the storage capacity required is between 19 and 24 TWh of hydrogen with a yearly hydrogen demand of Germany and the UK with a total yearly hydrogen demand of 344 TWh. As a comparison, the total amount of natural gas storage in Europe is currently over 1800 TWh (Statista, 2020). However, this storage would be equal to around 274 TWh of hydrogen storage since the volumetric energy density of hydrogen is lower compared to methane. Still, the maximum needed storage for a yearly production of over 300 TWh of green hydrogen would take up less than 10% of this storage capacity. Thus, the storage capacity would most likely not be a limiting constraint in a growing hydrogen market.

Furthermore, it is important to mention that the simulation of the storage might not necessarily reflect real-world behaviour. Even though different methods of simulating hydrogen storage in Bid3 was evaluated and the most promising option was chosen, some unexpected behaviours were observed. This could indicate that the results of storage usage might not be reliable since the storage level in the model never dropped significantly below the initial value, even when the model was given a very large amount of storage capacity. This could be due to some internal model constraint which was not found to be documented. Moreover, the model is forced to keep the storage level at the same level for the beginning and end of the year. This is necessary for the mean storage level to not change over a longer period. However, this does not necessarily reflect the real behaviour of storages since the levels at that date can vary between different years, even if the mean level is kept constant. This constraint seemed to force electrolysers to produce hydrogen at high power prices while avoiding lower power prices during the end of the year in order to force the storage level to the desired end value. Another possible source of error is that the model is deterministic and assumes a perfect market balance. In reality, this is not the case since the power market is based on bidding and trading on future production with human interactions, which gives rise to speculations and non-logic behaviour.

5.7 Gas to power

When allowing the model to also convert hydrogen back to power, this option was used very rarely which probably is because of the high transformation losses when converting power to gas and then back to power. IEA (2019a) propose that hydrogen could be used to regulate the intermittent power sources by producing hydrogen at times with low demand and then convert it back to power when demand is higher. However, even if this is technically possible, the results in this thesis suggest that it wouldn't be profitable most of the time. During times with insufficient renewable generation, it is often more profitable to run gas plants to meet the demand. Of course, this could change with a higher carbon price, but depending on how many hours this affects, the environmental benefits in relation to the costs might be very small. Moreover, the low round trip efficiency for power to power with hydrogen as a middle step advocates that the power sector will be one of the last usages of hydrogen and will probably grow in other sectors first. Nevertheless, even if hydrogen is not used in the power sector, producing hydrogen from the power grid still benefits the power system and its market by allowing a higher share of renewable in the system and balancing demand and supply.

5.8 Future work

The technological development of hydrogen and how it can replace carbon-based fuels and feed-stocks is rapidly changing. This thesis only covers one scenario of a green hydrogen market and leaves out other possible scenarios that could be of importance for the future. Moreover, the scenario is only based on the year 2050 and does not consider the development of the energy system up until that year. By analysing the years in between, a greater understanding of the necessary steps to reach this scenario could be obtained. Furthermore, this thesis was restricted to focus on the development in Germany and UK which could be expanded to more countries connected to the European power system, since many of them have shown interest for hydrogen and could become core players in a future hydrogen economy. Different regions are also focusing on different aspects of a hydrogen market, e.g., different types of hydrogen production as well as demand in various sectors. For example, electrolysis could look very different in Spain that has a high potential for solar PV compared to Norway with an abundance of hydropower. Therefore, these aspects can be implemented in the model to get a more detailed view of the interaction of market segments within Europe. This could also include import and export of hydrogen, which would not constraint all countries to cover their demand.

Moreover, this thesis focused on electrolysis technology and disregarded other ways of producing hydrogen. However, low carbon hydrogen produced with the help of technologies such as CCUS and pyrolysis will most likely also play a key role in a future hydrogen market. Evaluation of how low carbon hydrogen could help reduce carbon emissions in combination with electrolysis could add much needed clarity on how the market will develop in the future.

6 Conclusion

This thesis showed the possibilities of modelling hydrogen in Bid3 and concluded that the most suitable option was to use a virtual node if seasonality of hydrogen storage was to be considered. Furthermore, some unknown issues with implementing hydrogen in the model were found that caused the electrolysers to occasionally be active during high-price hours and disregarded low-price hours with curtailment of VRE. However, this only occurred during a limited amount of hours which was not seen to have had a large impact on the results.

Furthermore, electrolysis connected to a power system with high shares of VRE capacity showed great synergy by improving the flexibility of the system as well as reducing occurring price crashes. Moreover, the CO_2 emissions were reduced by replacing carbon-based fuels and feed-stock with hydrogen in various sectors. However, as mentioned in section 4.7, using hydrogen to generate power showed no promising results due to high costs caused by the low round-trip efficiency.

The constructed scenario caused over 1000 hours of wholesale power price close to zero, induced by the high share of installed VRE. Even if the electrolyser capacity was able to reduce the amount of low-price hours, the share of VRE capacity would still cause the prices on the power market to be unfavourable for businesses in the power industry. Also, the sensitivity analysis showed that reducing the amount of VRE capacity in these scenarios would significantly increase the CO_2 emissions. This was less noticeable for the UK, that had nuclear power in addition to gas power plants. These outcomes indicate that the current power market in these places will need to change to accommodate a sufficiently high share of VRE to decarbonise the power sector.

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