Techno-economic analysis of offshore wind-based hydrogen production in western Finland

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Master's thesis

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ABSTRACT

Finland has one of the most ambitious climate targets in the world, to reduce greenhouse gas emissions by 70% and become climate neutral by 2035. The rising average global temperature contributes to this determined goal and the possibility of limiting global warming by 1.5 °C. To meet these goals, the share of renewable energy must increase. Offshore wind production is previously undiscovered in Finland, but research and development within the area are increasing. Energy storage is required to balance the intermittency of wind energy, and hydrogen production could be a solution. Paring the offshore wind farm with a hydrogen production system and storing the electricity in the form of hydrogen when the electricity demand is low.

This thesis aims to provide a comprehensive overview of the feasibility, cost, and potential profitability of using offshore wind energy to produce hydrogen. The thesis includes an analysis of offshore wind-based hydrogen production in western Finland for two scenarios. The first scenario is offshore-based hydrogen production, and the second is onshore-based hydrogen production connected to an offshore wind farm. The information and results of this thesis can indicate these technologies' technical potential and competitiveness.

The feasibility and economic potential of an onshore and offshore hydrogen system were studied. The levelized cost of energy (LCOE) and levelized cost of hydrogen (LCOH) were calculated to indicate how the system's competitive cost compared to the current LCOE and LCOH levels. The calculations included current data from existing cases and studies, including capital-, and operational costs of the system components and an estimation of the yearly electricity production. The planned offshore wind farm, Laine, intended to be built in the exclusive economic zone outside the coast of Pietarsaari in 2029, is used as a case study.

The result showed that an electricity price competitive with market prices is only possible with an offshore wind farm connected to an onshore hydrogen production unit. The offshore hydrogen system includes too many losses to be efficient for electricity production and does not have a competitive electricity price. The price of hydrogen was competitive with green hydrogen (produced renewably) in base, best, and worst-case scenarios for both offshore and onshore hydrogen production.

Keywords: Techno-economic analysis, offshore wind power, hydrogen production, LCOE, LCOH

ABSTRAKT

Finland har som mål att minska mängden utsläpp med 70 procent samt att bli klimatneutralt före år 2035 och då även bli en av de första koldioxidneutrala länderna i världen. Orsaken till detta mål är den stigande medeltemperaturen på jorden. För att kunna uppnå dessa mål och uppnå koldioxidneutralitet krävs nya lösningar. Havsbaserad vindkraft har potential att producera stora mängder elektricitet. Men hittills har havsbaserad vindkraft varit relativt outforskat i Finland. Detta håller dock på att ändras och Finland planerar flera havsbaserade vindkraftsparker utanför sin västra kust. Användning av vätgas som en energibärare kunde vara en ytterligare möjlighet att möjliggöra energiomställningen i samhället. Genom att producera vätgas i samband med den havsbaserade vindkraftsparken kan man lagra elektriciteten i form av vätgas då behovet för elektrictet är lågt.

Syftet med detta examensarbete var att undersöka möjligheterna och den ekonomiska genomförbarheten för vindbaserad vätgasproduktion till havs i västra Finland. Detta genom två scenarion varav det första scenariot är vätgasproduktion på land och det andra scenariot med vätgasproduktion till havs. Syftet med examensarbetet var även att sammanställa kunskapen kring liknande projekt och tillämpa denna kunskap på det projekt som valts som fallstudie vilket är en planerad offshore vindkraftspark. Detta projekt planeras i den ekonomiska zonen utanför Jakobstad med produktionsstart 2029.

Metoden innefattar delvis en insamling av kapital-, och driftskostnader för komponenterna i systemet samt en uppskattning av den årliga produktionen av elektricitet och vätgas. Denna data användes för att beräkna ett uppskattat värde för el-, samt vätgasproduktionskostnaderna (LCOE och LCOH). Datan som användes som grund för beräkningarna är baserad på resultat från studier av liknande projekt inom Europa.

Resultatet visade att ett elpris som konkurrerar med marknadspriserna endast är möjligt med en havsbaserad vindkraftpark ansluten till en vätgasproduktionsenhet på land. Det havsbaserade vätgassystemet innehåller för många förluster för att vara effektivt för elproduktion och hade inget konkurrenskraftigt elpris. Priset på vätgas var konkurrenskraftigt med grön vätgas (producerad förnybart) i bas-, bästa och sämsta tänkbara scenarier för vätgasproduktion både till havs och på land.

Nyckelord: Tekno-ekonomisk analys, havs-baserad vindkraft, vätgasproduktion, LCOH, LCOE

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ACKNOWLEDGEMENTS

Working full time alongside my studies, I dedicated my own time to research and analyse the feasibility of offshore wind-based hydrogen production in western Finland. With the guidance of my supervisors, Margareta Björklund-Sänkiaho and Jessica Tuuf, I conducted an analysis of two scenarios, aiming to provide insights into the techno-economic feasibility of offshore wind-based hydrogen production.

The journey towards completing this thesis has been both challenging and rewarding. I started with a deep dive into the relevant literature and data sources, followed by the development of a methodology to analyse the feasibility of the two scenarios. Finally, I presented the results and discussed their potential implications.

This thesis is intended to contribute to the ongoing discussion of sustainable energy production in Finland, and I hope it will serve as a valuable source of information for further research and for other stakeholders interested in offshore wind-based hydrogen production. The chosen wind farm case-study "Laine" in this thesis was only used as a reference and the company OX2 has not been involved in the thesis process.

I am grateful for the support of my supervisors and family, and I hope that this thesis will inspire others to explore the potential of sustainable energy production in Finland and beyond.

Vaasa, Finland

16th of May

Ida Kålax

LIST OF ABBREVIATIONS

Abbreviation	Definition
AEL	Alkaline electrolyser
AEMEL	Anion exchange membrane electrolyser
CAPEX	Capital expenditure
CRF	Capital recovery factor
EIA	Environmental impact assessment
EU	European Union
GHG	Greenhouse gas
HVAC	High voltage alternating current
HVDC	High voltage direct current
IEA	International Energy Agency
LCOE	Levelized cost of electricity
LCOH	Levelized cost of hydrogen
LHV	Lower heating value
LNG	Liquified natural gas
OPEX	Operational expenditure
PEMEL	Polymer electrolyte membrane electrolyser
SOEL	Solid oxide electrolyser

1 INTRODUCTION

In a world where energy demand and carbon emissions are rising, natural resources like crude oil and petroleum products are slowly becoming less abundant (Eurostat, 2022a). To be able to limit the 1.5 °C rise in global temperature, sustainable technologies and actions towards a net zero society need to be taken. According to the International Energy Agency (2021), the number of countries pledging to comply with climate neutrality is increasing. However, global greenhouse gas emissions are also increasing. The most significant contributing sector of total emissions is power generation and transport. Around 40% of the European Unions' (EU) electricity originates from fossil-fuelled power stations, 35% of the electricity consumed comes from renewable energy sources, and the remaining share comes from nuclear power plants. However, the production methods vary between the member states, with smaller and larger percentages of electricity produced from fossil fuels (Eurostat, 2022b).

In Finland, the phasing out of fossil energy sourced from Russia, continuously rising energy prices, and determined climate goals have further increased the need for green energy solutions. Hydrogen is seen as an essential player in future energy systems as a green alternative. The European Commission released 2022 the REPowerEU Plan, which aims to terminate the dependency on Russian fossil fuels within the EU (European Comission 2022b). The measures in the plan include, firstly, energy savings as the quickest measure to address the ongoing energy crisis, secondly, diversifying the energy supply, and thirdly, accelerating the roll-out of renewable energy sources. As part of accelerating the renewables, green hydrogen production and infrastructure is being introduced (European Commission, 2022a).

As Finland is committed to reaching carbon neutrality by 2035, intensive measures are needed within all parts of society. The electricity in Finland is primarily produced renewably through hydro-, wind-, biomass-, and solar power. As referred to in Statistics Finland in 2021, the number of renewable energy sources used in Finland was, for the first time in 2020 since the statistics were compiled, higher than the use of fossil fuels combined with peat. In the same year, wind power production increased by 30%. As of 2022, several offshore wind farms in Finland are planned in state-owned sea areas. This is a substantial development of the Finnish renewable energy grid and a way of increasing the production of offshore-based wind power (Finnish government, 2022).

Wind energy may, in many aspects, be an ideal renewable energy source, but it still has constraints such as curtailment, limited intercontinental electricity connections, policy or regulatory barriers, and intermittency. Curtailment in wind farms is standard practice, according to Giampieri, Ling-Chin, and Roskilly (2023). The wind turbines can be shut down due to technical problems, unfavourable wind conditions (wind speeds under or over the speed range). As offshore and onshore wind power capacity is anticipated to rise, the level of curtailment will also rise, this would result in a significant amount of energy that is not utilised. Hydrogen could be produced using electricity from the wind farm as an alternative to primarily selling the energy in form of electricity to the grid. Hydrogen could be produced through electrolysis and sold directly or stored until the price of electricity is favourable again, then reconverted into electricity. Hydrogen is also needed in the production of ammonia and methanol which are two of the potential future fuels also (Laurikko et al., 2020).

Hydrogen is primarily used today in Finland for oil refining to lower the amount of sulphur in the fuel. Other areas of use also currently include the chemical industry and ore refining. Hydrogen could be an option for preventing climate change. This is due to its potential to cope with the variability in output from renewable electricity sources like solar photovoltaics and wind, by converting the excess energy into hydrogen and storing it for shorter and longer periods (Laurikko et al., 2020).

Singlitico, Østergaard and Chatzivasileiadis (2021) state that the offshore wind power capacity is expected to increase within the EU from 12 GW to 300 GW by 2030. Challenges with this include the intermittency of wind power, the needs of reinforcing the power grid to meet the requirements, and difficulties in entering areas and industries that traditionally have been difficult to amend. It was also shown in the same study that, the interest in using green hydrogen (hydrogen produced renewably) produced with offshore power has increased during the last few years. A contributing factor to the previous low interest is the previously high costs of this type of system compared to other renewable energy sources, as the costs are expected to come down the interest has risen.

This type of wind-based hydrogen production does not yet exist in Finland. However, the topic is being discussed as an offshore wind park is planned outside of Kokkola, Pietarsaari and Nykarleby in Finland. The wind speeds in Finland are good both offshore and onshore, which is essential for enabling sustainably sourced hydrogen. The electricity transmission system in

Finland is also very robust and evolving (Laurikko et al., 2020). Offshore wind energy has not yet been profitable in Finland. As the profitability is anticipated to improve, several offshore wind projects have received exploration permits in 2022 in Finland. Finland is planning on leasing 2-4 areas of the west coast for offshore wind energy (Finnish government, 2023). The increase in offshore wind will also enable green hydrogen production.

1.1 Aim and methods

The purpose of this thesis is to provide investigate the feasibility of a possible offshore wind-based hydrogen production system in the western parts of Finland, and provide further knowledge within the area through a literature review of hydrogen production from the planned Laine offshore wind power farm, comparing the economic difference between onshore or offshore hydrogen production in the system and investigating the possible competitiveness of two system configurations. Furthermore, in line with the gap in research identified through the literature review, a research question was defined: What would be the most cost-effective method for producing hydrogen from offshore wind electricity? Onshore or offshore hydrogen production?

The possibility of paring the offshore windfarm Laine with some type of hydrogen production was also discussed in the environmental assessment program made by AFRY Finland Oy (2022). This is however, still speculations but this thesis aims to investigate this alternative and go into further details on the technical and economic aspects of producing hydrogen in connection to an offshore wind farm.

To research the feasibility of the system, the calculated levelized cost of electricity and hydrogen (LCOE and LCOH) in two separate scenarios are compared in a sensitivity analysis. The two scenarios are one offshore and one onshore hydrogen production in connection to the offshore wind farm.

1.2 Limitations

This thesis is based on data from similar research and the expected electricity production of the Laine offshore wind farm and hydrogen production. The thesis is limited to investigating only the production of hydrogen or electricity and does not go further into detail on the potential storage or distribution methods. The thesis is also limited so that the two scenarios only consider producing either one or the other of electricity and hydrogen and not both simultaneously, balancing the production of hydrogen is possible but not included in this thesis. Some of the information on costs, efficiencies or fuel needs have been sparse, and in these cases, assumptions have been made according to previous studies. Costs found in other currency than the euro have been converted into euro currency according to the latest currency rate.

2 LITERATURE REVIEW

Greenhouse gas (GHG) emission regulations and targets exist globally as well as on a national level. The European climate change law passed in 2019 by the European Union states a short-term goal of reducing GHG emissions by 55% by 2030 compared to 1990 levels. The long-term goal is to achieve climate neutrality within the EU by 2050, meaning there will be net zero GHG emissions through investment in green technology and environmental protection (European Commission, 2022). Carbon neutrality can be defined as the amount of carbon being emitted, balanced by carbon absorption by so-called carbon sinks. These sinks can consist of naturally occurring forests and oceans, as well as artificial methods of removing CO_2 from the surrounding atmosphere. However, these methods are not sufficient enough to help fight global warming (European Parliament, 2019).

As stated by the authors Jenkins, Malho, and Hyytiäinen (2022), Finland is one of the leading countries in Europe on renewable energy production within the EU. As a sparsely populated country, wind power has this far been placed on land, coastal areas, or hill tops. Wind power has gained momentum during the last ten years in Finland, and at the end of 2022, Finland had 1393 installed wind turbine generators with a total capacity of 5677 MW onshore (Finnish wind power association, 2023a). The interest in offshore wind has increased due to the rising demand of electricity and strict climate goals, however, the rise of this new technology does not come without obstacles. Public acceptance and political support are critical drivers for the successful development of offshore wind farms.

2.1 The Finnish energy system

The Finnish energy system plays a significant role in supporting wind farms' function on land and at sea, ensuring sufficient electricity grid development to support the constantly growing grid. According to Statistics Finland (2022), the total electricity consumption of Finland in 2022 was approximately 82 TWh, of which 45% is consumed by the industry, 27% by households, 21% by services and public sectors, and the last seven percent is listed as others. According to the Ministry of Economic Affairs and Employment (2022), a weakness of the Finnish energy system is the lack of electricity production capacity when electricity consumption is at its highest during the cold winter months. A fifth of the annual electricity supply has originated from imports. The gap between peak consumption and production will become narrower as the new Olkiluoto 3 nuclear power plant becomes fully operational. However, ongoing electrification is a crucial element within all sectors. Energy consumption is predicted to reach 92 TWh in 2030, and 96 TWh in 2040, with nuclear and wind power assumed to cover the growing electricity demand (The Ministry of Economic Affairs and Employment, 2022). There is even a possibility that Finland could become an electricity exporter in the future.

The Finnish transmission system is operated by Fingrid Oyj, owned by the Finnish state and pension insurance companies, ensuring the secure delivery of electricity from the production facility to the electricity companies. Fingrid is also responsible for maintaining the balance between the consumption and production of electricity around the clock (Fingrid, 2017). The transmission system in Finland consists of the main, high voltage, and distribution grid. To minimise transmission losses, the voltage of the main grid is 400 kV, 220 kV or 110 kV. The electricity from the main grid is transported further through the high voltage distribution grid that distributes the electricity to certain areas. The distribution grid operates at 20,10.1 or 0.4 kV. The transmission system consists of several power stations and distribution transformers. The power stations can be found in places where powerlines with different voltages meet. The power can be distributed, terminated or transformed in these power stations (Energiateollisuus, 2022).

AFRY (2020) stated that the upcoming decarbonisation of the Finnish industries will increase the electricity demand by 2035 and even more drastically by 2050. However, substantial investments are required for electricity generation and transmission network strengthening. Fingrid (2022) states that an investment of EUR 3 billion will be put on the main grid over the next ten years to improve the north and south transmission and add new cross-border connections to Estonia and Sweden.

2.2 Offshore wind power

As the energy demand is expected to increase and the energy mix is being shifted from fossil-based resources to renewable electricity, action plans need to be well-defined and in place to enable electrification. Regarding offshore wind power production, the Finnish innovation fund Sitra (2021) suggests ensuring building permits to secure the upcoming building of the needed wind power capacity. The total expected need for wind power by 2030 is 6.3 GW, and 4 GW of the capacity should come from offshore wind (Granskog et al., 2018). By implementing offshore wind energy, Europe is one step closer to achieving climate neutrality by 2050. To attain a net zero carbon society within the EU, Paolo et al. (2020) state that greenhouse gas emissions must be reduced faster than anticipated to meet 2030 climate targets.

As different sectors switch to renewable energy sources, the power demand will increase, requiring rapid capacity upscaling. An estimation of the technical potential for offshore wind in Finland in MW is shown in **Figure 1** including both fixed and floating application. Based on the potential wind speeds shown in the figure, the conclusion is that there is potential for offshore wind power also in Finland.

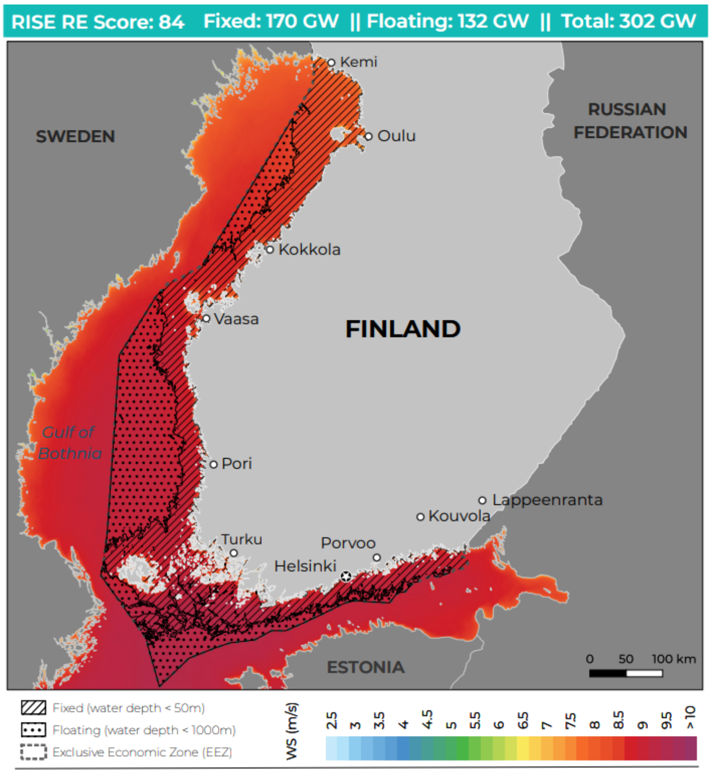

Figure 1 - Offshore wind technical potential in Finland (Global Wind Energy Council, 2021)

In situations where the water depth is greater than 50-90 m, bottom-fixed offshore wind foundations become non-profitable. This means that floating foundations are the alternative if the wind farm is planned in greater water depths than 90 m. **Figure 2** explains the current most developed foundation types available. Which are the gravity-type, monopile, jacket and floating foundations.

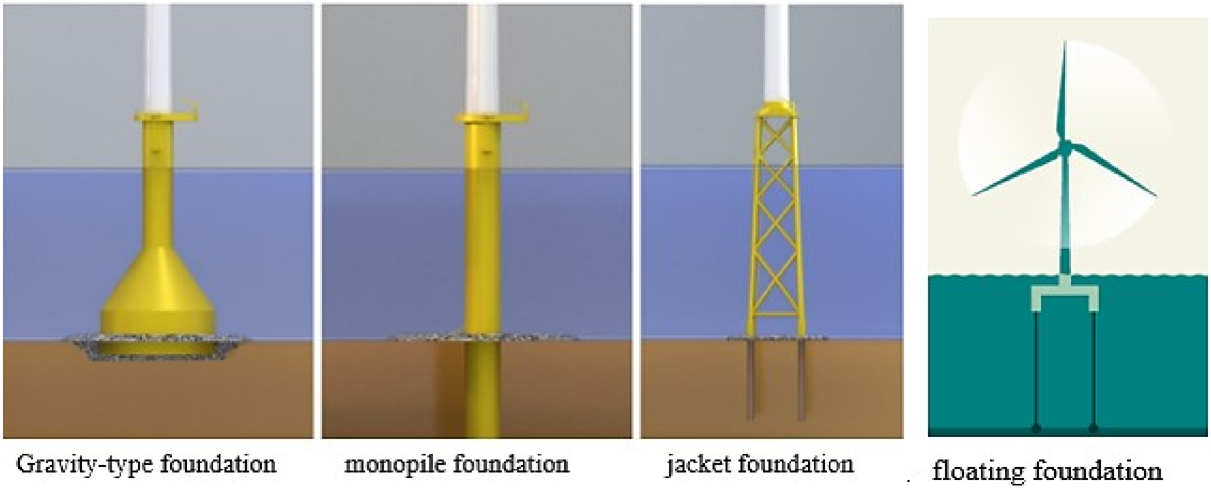

Figure 2 - Offshore wind energy tower foundations (AFRY Finland Oy, 2022)

According to The Ministry of Economic Affairs and Employment (2022), the target is that Finland will have the first offshore wind farm in operation in 2030. This will result in job opportunities and improve the expertise of the wind power companies specialising in offshore wind operations in arctic conditions, creating added value and improving export opportunities. According to the same report, financial aid is necessary for the demonstration. The goal is that the project will receive aid primarily through the Finnish Sustainable Growth Programme. **Figure 3** shows that several projects are in the early planning phase in the Gulf of Bothnia and the current situation of offshore wind power projects in northern Europe.

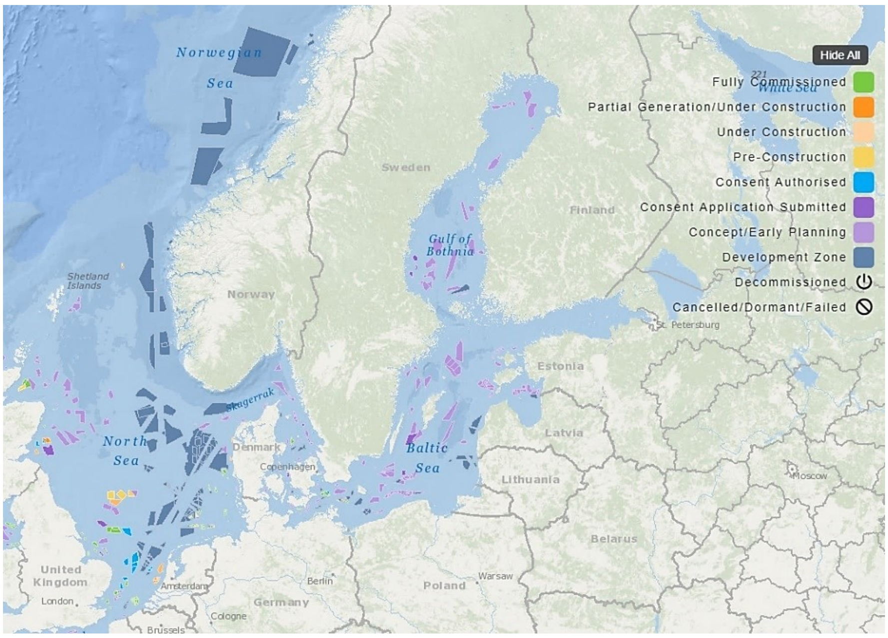

Figure 3 - Offshore wind projects in Europe (4C Offshore, 2023)

An offshore wind park consists of five significant segments: the wind turbines, the foundation and substructure of the wind turbines, the grid which collects the electricity produced, the substations and the transmission continuing from the substations to shore (Tande et al., 2018). The wind turbines found offshore usually have a greater output than land-based turbines. During the last decade, an increase in the rated capacity of offshore wind turbines has been a fact. When comparing turbine capacities of 2010 and 2018, there has been a growth of over 200%. In 2018 the largest offshore wind turbines were 8.8 MW, and nowadays, there are already 14 MW commercial offshore turbines available, as shown in **Figure 4**. The wind turbines keep getting bigger because increasing height and blade length will generate more electricity.

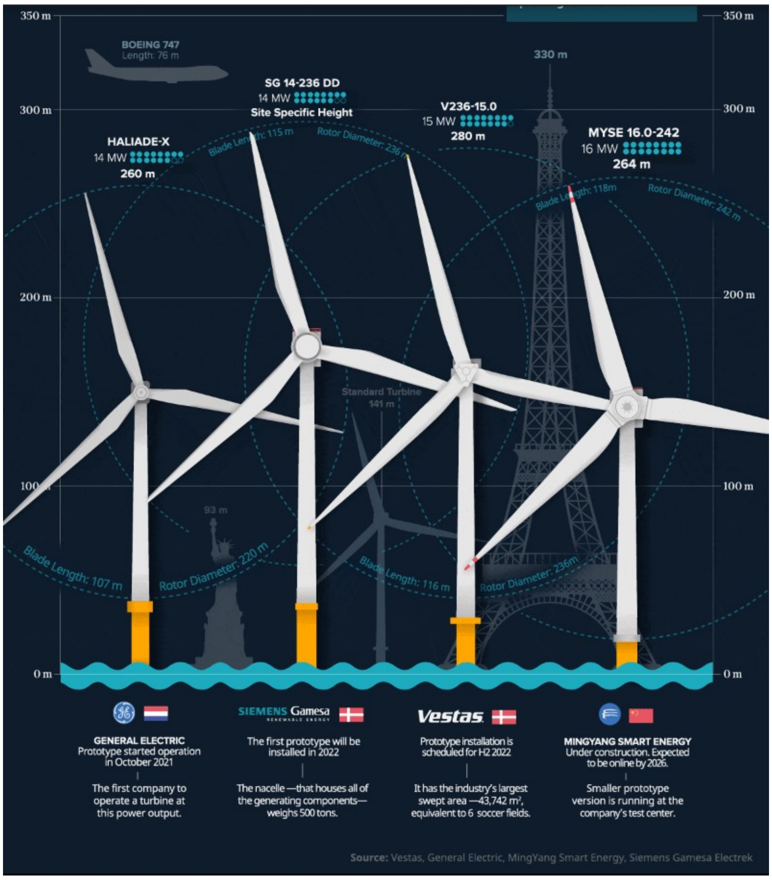

Figure 4 - The largest wind turbines of the world (Venditti, 2022)

The internal grid most often operates with alternating current (AC) at around 33 kV and up to as high as 66 kV is anticipated soon. The internal grid also includes one or several offshore substations that include transformers that increase the voltage to the preferred transmission level (Tande et al., 2018).

The two transmission methods from offshore wind power plants are through high voltage alternating current (HVAC) and high voltage direct current (HVDC) as illustrated in **Figure 5**. According to Fernández-Guillamón, Das and Cutululis (2019), HVAC has been the most popular method for offshore wind power transmission for shorter distances and lower capacities due to certain limitations. However, HVDC transmission is the most suitable solution for parks situated further away from land. It is suggested that the so-called breakeven distance for HVDC is economically feasible for distances above 50-70 kilometres (Legorburu, Johnson, and Kerr , 2018). This entails less loss of electricity. It is also suggested by Tande et al. (2018) that HVDC is preferred for a rated wind farm power exceeding 200 MW.

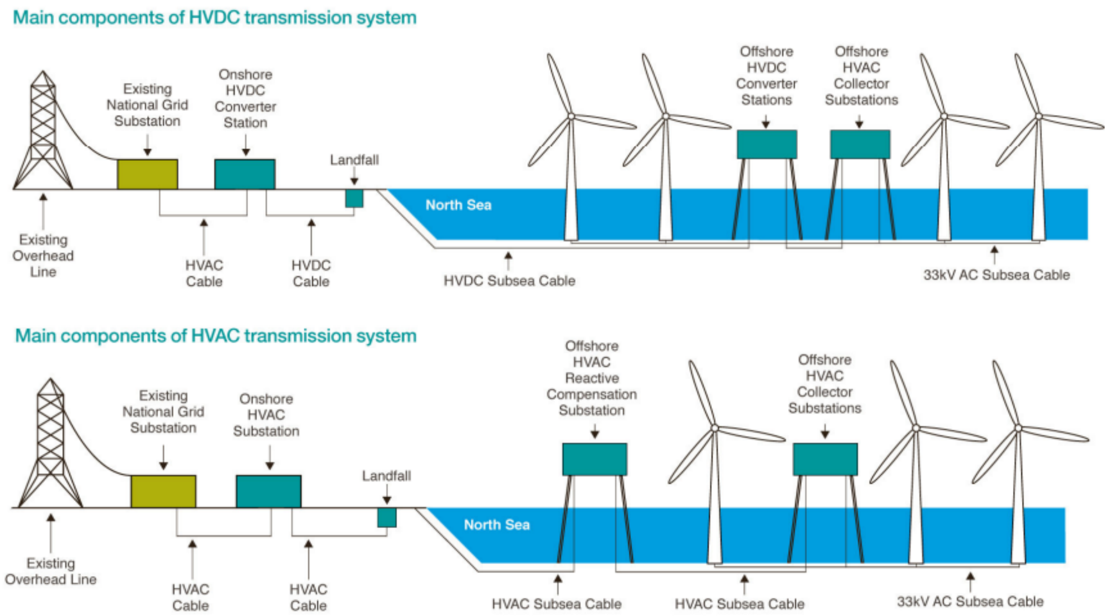

Figure 5 - Main components of a high-voltage DC and high-voltage AC transmission system (RPS, 2012)

2.2.1 Offshore wind-related costs

The Finnish innovation fund Sitra (2021) suggest that the LCOE for offshore wind could be as low as 30-35 €/MWh by 2030. The coastal regions in Finland have significant advantages due to the shallow waters and high wind speeds. According to assumptions in the report made by Freeman et al. (2019), the sea area in the western parts of Finland is grouped as mostly low LCOE but medium LCOE closest to shore. Low LCOE, in this case, refers to a cost of between 50€/MWh and 65€/MWh and medium as 65€/MWh and 80€/MWh in 2030. Current projects planned in the Gulf of Bothnia focus on shallow sea areas (depth <15m) in a close perimeter of the coast.

According to BVG associates (2018), an increase in energy production, reduced costs and changes in project financing can result in a lowered LCOE. These changes can come from technological advances of the used technology and improving the operational process to reduce losses in energy. It is also stated that the key driver of the cost is the site conditions. Deeper waters result in higher installation costs and more expensive foundation types. The distance to shore also impacts the transmission and service operation costs and construction costs. However, the increase in turbine rating has a positive impact on the capital expenditure (CAPEX) of the wind farm with the increased electricity production.

The guide by BVG associates (2018) was created on behalf of the Offshore Renewable Energy Catapult, an innovation and research centre for offshore renewable energy in the United Kingdom. It was created to lead companies in the right direction of creating a better understanding of the involved processes and components in developing an offshore wind farm. The configuration chosen as a base case in the guide was 100 pieces of 1 GW turbines located 60 km from the shore at a water depth of 30 meters, which would be in operation in 2022 (BVG associates, 2018).

BVG associates (2018) suggest a total CAPEX of 2.6 M€/MW (values are converted from GBP to € with an exchange rate of 1.12 GBP = 1 € as of 2023). An annual average OPEX of 84 k€/MW over a lifetime of 27 years and an average energy production of 4471 MWh/year/MW. In that case, the total average electricity production per year would be 4.47 MWh if divided by the total wind farm rating of 1000 MW. As seen in **Figure 6**, the highest costs outside of maintenance and service are the turbines and the foundation, together with cables. **Table 1** summarises the costs included to connect the offshore wind farm to the grid.

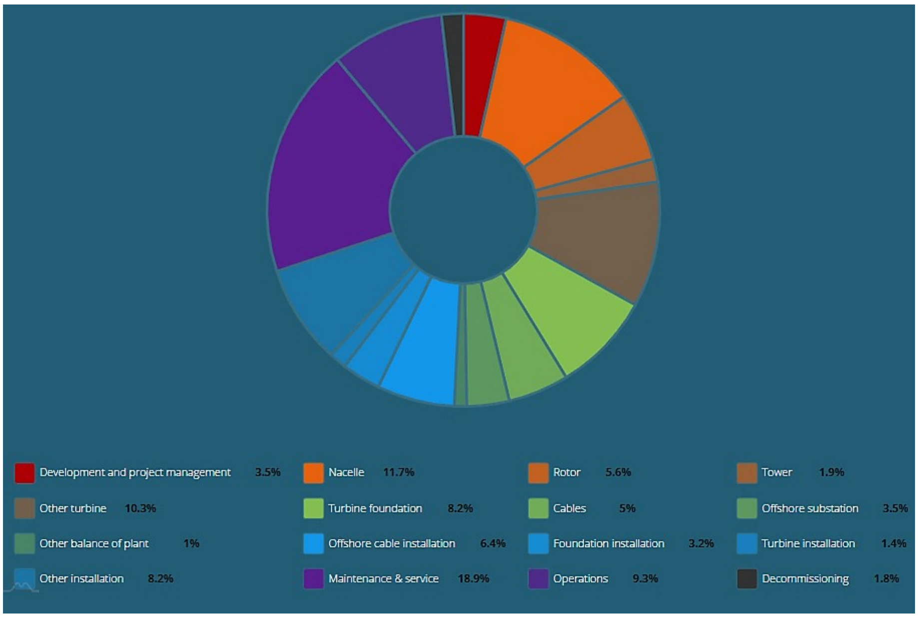

Figure 6 - Pie chart showing cost contributions of an offshore wind farm (BVG associates, 2018)

Table 1 - Costs for offshore wind when connected to the grid based on parameters in BVG associates, 2018 (exchange rate of 1.12 GBP = 1 € as of 2023)

Parameter	**Rounded cost €/MW**
Export cable	116,071
Array cable	31,250
Turbine foundation	250,000
Offshore substation	107,143
Onshore substation	26,786

2.3 Hydrogen

Hydrogen, the most abundant element in the Universe, has no colour, odour, or taste and is the simplest chemical element consisting of two protons and two electrons. Hydrogen has primarily been used in ammonia manufacturing, with approximately two-thirds of the total hydrogen production in the world going to the Haber-Bosch process creating ammonia. Other products also created using hydrogen include methanol and petroleum products (Jolly, 2022). The IEA and the scientific community have recognised the role of hydrogen in the energy transition from a fossil-fuelled society. As a unique path towards decarbonisation, including zero CO_2 emissions of energy storage, hydrogen has the potential to become the building block towards a carbon-neutral society (Kovač, Paranos, and Marciuš, 2021).

The European Commission (2020) state that hydrogen could help to close the gap of decarbonising energy consumption of the EU. Being an alternative to fossil fuels, an alternative to battery storage, ensuring a stable electricity production during seasonal variations and also connecting remote locations with energy production. The share of hydrogen in the European energy mix is expected to grow from the current 2% to 13-14% by 2050. Furthermore, fossil fuels can be replaced by hydrogen in energy intensive industries such as the steel or chemical sector by lowering the GHG emissions.

The energy density (lower Heating Value) of hydrogen by volume is around 9.9 MJ/m^3, which is low compared to fossil fuels. This means that the storage vessels for hydrogen need to be more significant. Roughly speaking, the same amount of energy in the form of LNG (Liquified natural gas) compared to compressed hydrogen requires two and a half times less storage volume with a LHV of 20.8 MJ/m^3. Another aspect to be aware of is that hydrogen is highly flammable with high flame speeds meaning that great attention is needed on storing and operating the fuel (Inal, Zincir, and Deniz, 2022).

Hydrogen can be produced using different production methods, and to distinguish which method has been used to produce the hydrogen, a variety of colours are used. The emissions and costs related to the production process vary depending on the primary energy source used. As stated by Ajanovic, Sayer and Haas (2022), the colours used are grey, blue, turquoise, green, purple and yellow. Also, brown, and black hydrogen exist for hydrogen produced using brown or black coal during gasification. However, the interpretation of some colours can vary between studies. A suggestion of the colour codes and a short description of their meaning are depicted in **Figure** *7*. Green Hydrogen is often expressed as a low-carbon alternative to the other hydrogen categories since it is produced from water and with energy from renewable sources (Ajanovic et al., 2022).

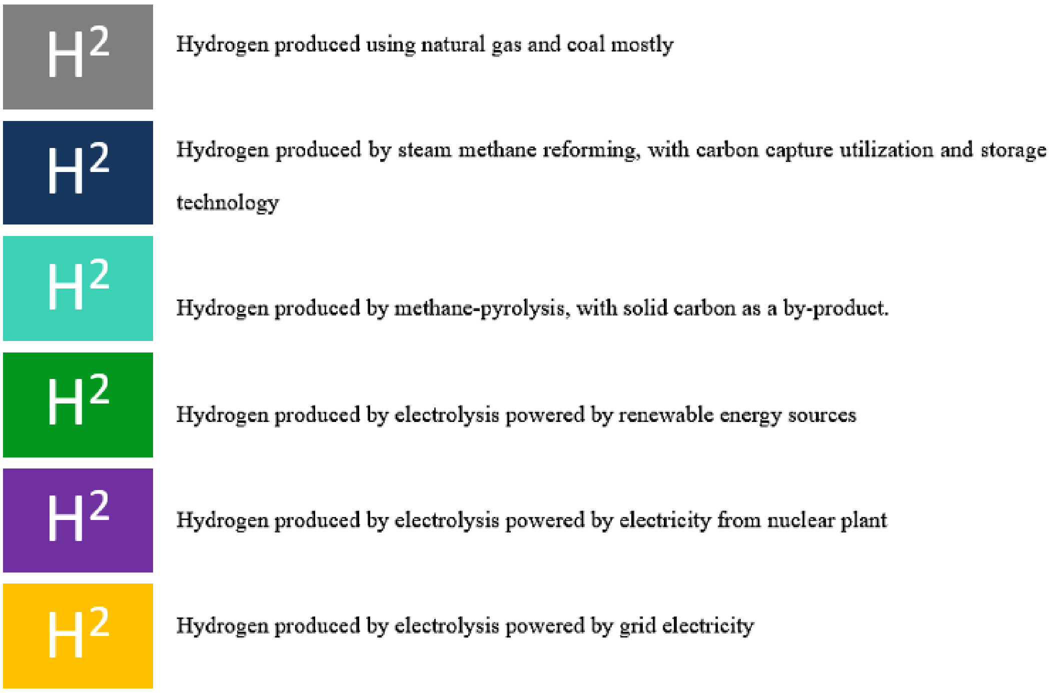

Figure 7 - Hydrogen colour codes (Ajanovic et al., 2022)

According to Ibrahim et al. (2022), green hydrogen has, on average, a two to three times higher price than so-called blue hydrogen, produced by fossil fuels with carbon capture. The central part of the production cost is related to the electricity need of the electrolyser, which means that the price of green hydrogen depends on the cost of the energy supplied. The LCOE (levelized cost of energy) of bottom-fixed offshore wind is anticipated to drop from around 75 €/MWh to approximately 35€/MWh from 2022 to 2030. The LCOE was in 2020, according to Offshore Renewable Energy Catapult (2020) for floating wind double the price of bottom-fixed wind but is anticipated to have comparable costs in 2040 due to a higher capacity factor (a percentage of the nameplate turbine capacity based on the energy delivered to the grid).

2.3.1 The hydrogen strategy

The roadmap for hydrogen within the European Union is to produce hydrogen renewably with solar and wind energy because these methods are most in line with climate neutrality and net zero carbon goals. By choosing renewable hydrogen as one path towards climate neutrality, the EU supports the development of new jobs and economic growth within the energy sector. However, the EU acknowledges the need for other colours of hydrogen as the costs decrease and technology becomes mature. During the first phase from 2020 to 2024 the goal is to have installed 6 GW of hydrogen electrolysers within EU. Enabling the production of one million tonnes of green hydrogen. During the second phase from 2025 to 2030 it is expected that 40 GW of electrolyser capacity will be installed by 2030, producing 10 million tonnes of hydrogen. During the last phase which is from 2030 onwards, electrolyser technology should have matured and could be possibly deployed at a large scale (European Commission, 2020).

The European Commission (2020) state that to be able to reach the target, additional renewable electricity in the form of wind, amongst others, needs to be produced. According to the Ministry of Economic Affairs and Employment (2022), hydrogen projects will receive €150 million from the Sustainable Growth Programme for Finland. This funding comes from the EU recovery package "Next Generation EU".

The European Hydrogen Backbone initiative was founded in 2020, which is a group of 31 different energy infrastructure operators with a shared vision of enabling a sustainable society through the development of the hydrogen network in Europe (European Hydrogen Backbone, 2022). **Figure 8** shows the plans for the future hydrogen transportation infrastructure via pipelines. The yellow lines in the figure are the planned onshore pipelines, whereas the blue dotted lines are the planned subsea offshore pipelines for hydrogen transportation. With this being mentioned, there are plans to strengthen the position of hydrogen as a future fuel by enabling it through infrastructure development.

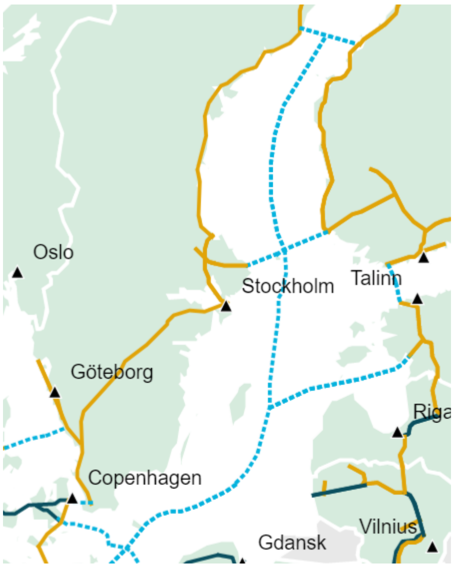

Figure 8 - Plans for the European hydrogen network (European Hydrogen Backbone, 2022)

2.3.2 Hydrogen production

An electrolyser is needed to produce green hydrogen; the input is water and electricity. When fed an electrical current, the water molecules are split into hydrogen and oxygen (IRENA, 2020). There are four types of commercially available electrolysers: Alkaline, polymer electrolyte membrane (PEM), anion exchange membrane (AEM) and solid oxide, which are presented in **Table 2**. SOEL is still under development. Having a higher efficiency and higher stack lifetime than the other methods but requires a much higher operating temperature. This makes SOEL not suitable for operations such as offshore connections due to the long start-up time.

Table 2 - Technical and economic comparison of electrolyser technologies (IRENA, 2020)

		PEM	**Alkaline**	**AEM**	**Solid oxide**
Operating temperature	[°C]	50-80	70-90	40-60	40-60
Cold start (to nominal load)	[min]	< 20	< 50	< 20	> 600
Voltage efficiency (LHV)	[%]	50-70	50-68	52-67	75-85
Lifetime (stack)	[h]	50,000-80,000	60,000	>5000	20,000
CAPEX of the system	[USD/kW]	700-1400	500-1000	Unknown	Unknown

The most suitable electrolyser for a wind-connected application is PEM and Alkaline. In these cases, the limiting factors are the compressors and not the stacks themselves (IRENA, 2020). The PEM electrolyser (PEMEL) also offers a relatively compact design, which is beneficial if placed offshore. To be able to follow the fluctuations if connected to a wind turbine, a fast response is necessary. PEMEL can respond within one second to five minutes and Alkaline electrolyser (AEL) within one to ten minutes, making them the most promising technologies for this application (Ibrahim et al., 2022).

The electrolysis process requires a high purity of the water used with a maximum of 0.5 ppm of total dissolved units (Ibrahim et al., 2022). Beswick, Oliveira, and Yan (2021) also state that producing 1 kg of hydrogen requires 9 kg of fresh water from the electrolysis process. The water supply can be secured from the water main in an onshore application. However, in an offshore application, a desalination unit driven by the electricity output of the turbines is needed since seawater cannot be used directly due to the dissolved mineral salt content that would result in component erosion. According to (Scolaro & Kittner, 2022a), a CAPEX of 0.7 m€/MW can be expected for a PEMEL with an OPEX of 2%CAPEX per year and a stack lifetime of 50,000

– 80,000 hours for the PEMEL.

Fuel cell technology is needed to reconvert hydrogen back to the form of electricity. Hydrogen in gaseous form together with gaseous oxygen are combined in a catalytic reaction, producing electricity, water and heat. According to Scolaro & Kittner, (2022), a CAPEX of 2 m€/MW , OPEX of 4 %CAPEX/y and stack replacement cost of 50 %CAPEX can be expected. The lifetime of the system is expected to be 20 years or 15,000 hours with the efficiency rate of 50%.

2.3.3 Wind hydrogen systems

The majority of installed wind power in the world is situated onshore, this is also true for Finland. However, offshore installations can provide more consistent and higher wind speeds providing more stability compared to onshore wind power production. With a growing demand for green hydrogen, offshore wind-based hydrogen production systems could be a solution (Calado and Castro, 2021). As stated by Scolaro and Kittner (2022), the electricity produced by the wind farm can power the splitting of water in the electrolyser, resulting in hydrogen and oxygen. It is possible to store hydrogen in a storage system or be directly utilised by industrial processes or as fuel in transportation.

According to Scolaro and Kittner (2022), the system mainly consists of a wind farm, an electrolyser, a fuel cell, and a way of storing the hydrogen produced. These systems can be divided into two configurations: The first system shown in **Figure 9** consists of the offshore wind farm with the electrolyser located offshore, whereas the second system in **Figure 10** uses an onshore located electrolyser. If there is a need for load matching or balancing, a fuel cell can be added to both systems to provide electricity (Calado and Castro, 2021). A clear advantage of the system is that negligible curtailment can be expected since hydrogen can be produced if the electricity demand of the grid drops (Offshore Renewable Energy Catapult, 2020).

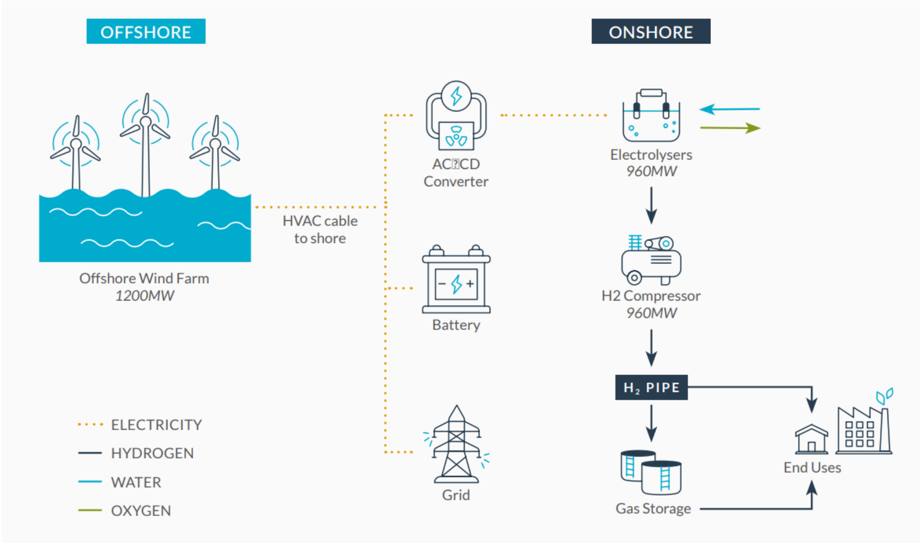

Figure 9 - System description of offshore wind with onshore electrolysis (Offshore Renewable Energy Catapult, 2020)

In the system where electricity is transported through high voltage alternating current (HVAC) cables to shore, there will be losses in the system. The more recent transfer method, high voltage direct current (HVDC), has fewer losses but is related to higher costs due to the need for additional converter stations (Calado and Castro, 2021). By producing the hydrogen offshore, it is possible to utilise gas pipelines instead that offer smaller losses (<0.1%).

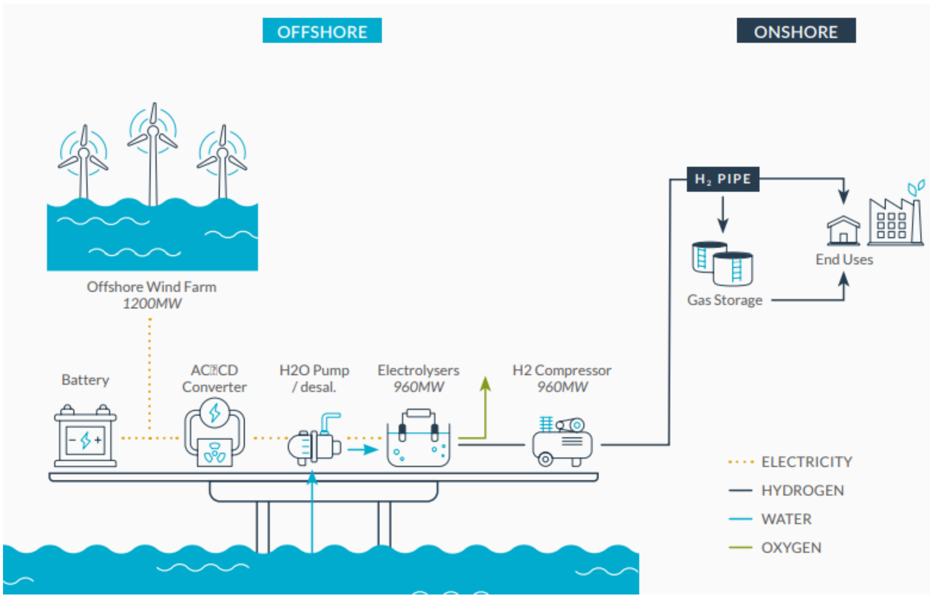

Figure 10 - System description of offshore wind with offshore electrolysis (Offshore Renewable Energy Catapult, 2020)

Miao, Giordano, and Chan (2021) concluded in their study that for the base cases, hydrogen transmitted through the pipeline was cheaper, at least for longer distances, if observing the whole picture. However, the cost per unit length is cheaper for an offshore cable from an economic perspective (Calado and Castro, 2021).

2.3.4 Transportation and storage

Storing and transporting the fuel is a critical element of the total energy system. A robust infrastructure for transporting and storing hydrogen is vital to utilise it fully. Moradi and Groth (2019) state that storage methods can be divided into stationary and mobile applications. For the need for on-site storage, stationary applications are used, and in the case of mobile applications, the hydrogen is either transported to another storage place or used as vehicle fuel. Hydrogen can be stored physically or integrated into a chemical structure of another material or in porous materials. The physical storage technology includes compression, cryo-compression, and liquid storage. The most mature processes of hydrogen storage use compression or cryo-compression; however, the latter has low energy efficiency and for compression, the storage requirement is a problem for the low-density hydrogen.

Moradi and Groth (2019) state that the method chosen to deliver hydrogen will be determined according to population, consumer characteristics, and geography. The pathway of hydrogen includes the transmission from the production facility and the distribution to the end user and is a crucial part of the cost build-up. The way of transporting the hydrogen is primarily dependent on the storage method. The three main ways of transport are, in gaseous form, in liquid form or in material-based form.

As described in the report by IRENA (2022), the form of hydrogen to be used for transportation depends on the transportation distance and the production facility size. Hydrogen transported in its liquid form include high costs and equipment requirements since hydrogen is in gaseous form in ambient conditions and requires the temperature to be kept at -253 °C for liquefaction. This makes the transportation of hydrogen in the liquid form more suitable for shorter distances. IRENA say in the same report that for hydrogen to be transported, it must be transformed into a higher energy density form, preferably in a process that requires the least energy. The volumetric energy density of different fuels is shown in **Figure 11**. This means that to bunker the same amount of energy as liquid natural gas in the form of liquid hydrogen, the tank would need to be 2.5 times larger.

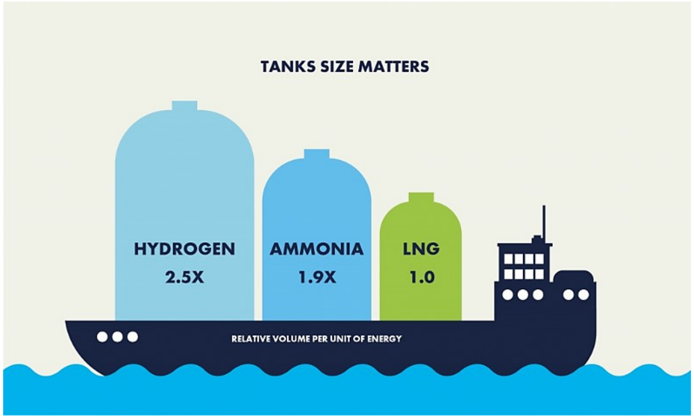

Figure 11 - Visual representation of energy density of future fuels (SEA-LNG, 2021)

If hydrogen is to be stored or transported in compressed form, there is a need for a compressor that can pressurise the hydrogen due to its low volumetric energy density. According to Sdanghi et al. (2019), compression is the most widespread storage method for hydrogen. The average pressure in commercial vessels is around 200 to 250 bar. However, composite pressure tanks can withstand up to 700 bars of pressure, increasing the volumetric energy density of hydrogen in the tank. Sdanghi et al. (2019) state that the cost of a compressor, when compressing hydrogen from 100 bar to 875 bar with a flow rate of 100 kg hydrogen per hour would be 259,201 € (values are converted from USD to € with an exchange rate of 0.94 USD = 1 € as of 2023). This includes an annual maintenance cost of 4%, where 90% of the maintenance cost consist of piston rings, packings, and valve maintenance.

2.4 Levelized cost of electricity and hydrogen

In their report from 2021, the Finnish innovation fund Sitra estimated an LCOE of 62 €/y/MWh in 2025 and 59.3 €/y/MWh in 2035 for offshore wind. According to Sharma (2022), an LCOH of 2.93-6.61 €/kgH_2 for green hydrogen is expected in the Vaasa region. LCOH has to be around 3.45 €/kgH_2 to compete with blue hydrogen and 1.75 €/kgH_2 to compete with grey Hydrogen (Calado and Castro, 2021).

Scolaro and Kittner (2022) concluded in their techno-economic study on the cost competitiveness of an offshore wind-based hydrogen system in northern Germany that the minimum required subsidy was 2.4€/kgH_2 to reach competitiveness compared to fossil fuel-based hydrogen. According to the study by Thommessen et al. (2021), the total cost of hydrogen produced in the North Sea region is expected to range between 7.58-8.11€/kgH_2. Other studies covering the same topic show the same trend, a considerably higher price tag for green hydrogen compared to hydrogen produced from fossil fuels impacting competitiveness negatively. For green hydrogen to compete with blue hydrogen (Steam Methane Reform with carbon capture), LCOH must be around 2.51-3.45 €/kgH_2 (Calado and Castro, 2021). The same study states that LCOH for offshore wind with a PEM electrolyser is expected to be around 3.77-11.75 €/kgH_2. **Table 3** summarises the key finding of previous studies with similar research question.

Table 3 Key findings of previous studies with similar scope

Authors	Scope	Method	Conclusions
Scolaro and Kittner (2022)	Hydrogen production from an Offshore wind farm (Northern Germany)	LCOH, NPV	Competitive with an LCOH of 4.9 €/kg$_{H2}$
Giampieri, Ling-Chin, and Roskilly (2023)	Which pathway would be more technically strategic and cost-effective: offshore wind farms implement hybrid production of electricity and hydrogen/hydrogen carriers/LOHC	LCOH	An LCOH of 8.45 €/kg$_{H2}$ (onshore hydrogen production) and 12.33 €/kg$_{H2}$ (offshore hydrogen production)
Singlitico et al. (2021)	Hydrogen production from an offshore wind-integrated hybrid system	LCOH, NPV	An LCOH of 2.4 €/kg$_{H2}$ could be achieved in the North Sea
Lucas et al. (2022)	Hydrogen and oxygen production from the WindFloat Atlantic offshore wind farm	LCOH, NPV, Total cost	LCOH ranging from 4.25-8.25 €/kg$_{H2}$, dependant on the offshore wind farm capacity
Dinh et al. (2021)	Compressed Hydrogen production from a hypothetical offshore wind farm	LCOH, NPV	Competitive with an LCOH of 5 €/kg$_{H2}$
Hansson (2022)	Hydrogen production from offshore wind in southern Sweden for different subsidy scenarios	LCOH, LCOE	LCOH for onshore hydrogen was 3.85 €/kg$_{H2}$ (without subsidy) LCOH for offshore hydrogen was 3.47 €/kg$_{H2}$ (without subsidy)

As seen in **Figure 12** the electrolyser has the most significant impact on the total cost according to Giampieri, Ling-Chin, and Roskilly (2023), with the CAPEX significantly increased if a larger amount of hydrogen was produced from the offshore wind electricity. A reduction in CAPEX was observed in the same study with increased efficiency from 64% to 70.5%, reduced cost of replacing the stack, and lower specific cost of the electrolysers (CAPEX/kW).

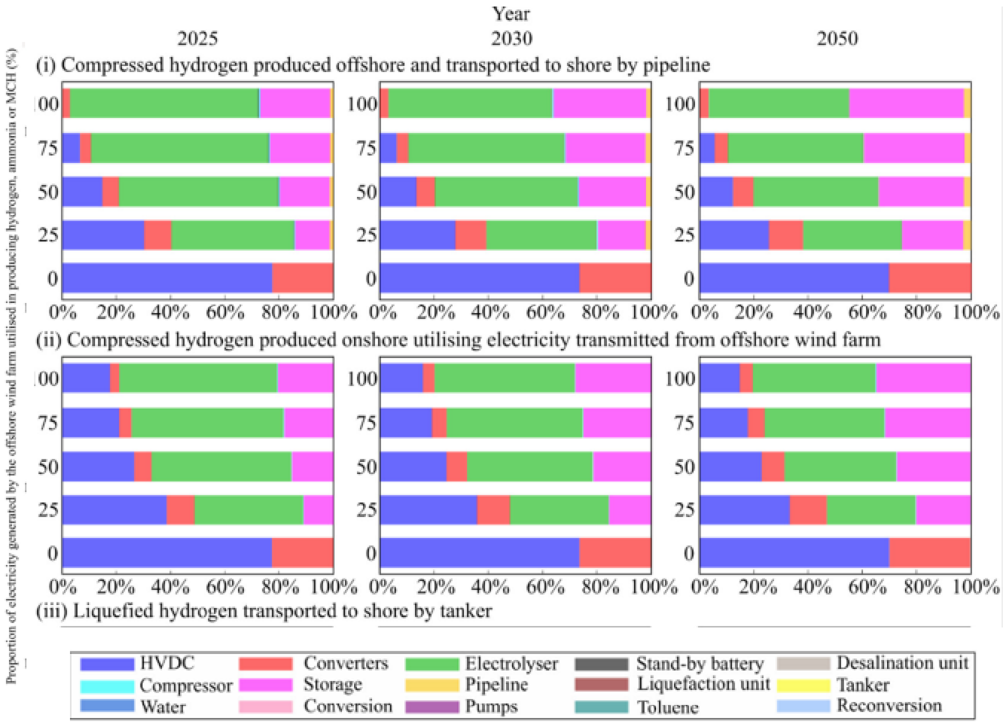

Figure 12 - Cost breakdown of each system and their components (Giampieri et al. 2023)

The factor influencing LCOH most is the LCOE, meaning that projects with the lowest LCOE are best suited for being the electricity source in green hydrogen production. According to Calado and Castro (2021), the lowest LCOH was found to be in the desert of Chile using solar photovoltaics. Furthermore, onshore wind in Patagonia, with an enormous wind potential, resulted in an LCOH of 2.16 €/kgH_2 at the electrolyser output (Heuser et al., 2019).

3 MATERIAL AND METHODS

The Laine offshore wind farm planned to be built was used as a case study. The Finnish government has granted the exploration permit to three wind energy companies, which are OX2, Skyborn Renewables and Ilmatar. Furthermore, the companies each have their working name for the project (YLE, 2022). The name used in this thesis is the one used by OX2, Laine. Laine was chosen in this case because the environmental assessment plan published by OX2 contained more information than the competitors at this stage.

The two scenarios investigated in this thesis are based on two separate system configurations and these are summarised in **Table 4**. The LCOE and LCOH are examined for both systems based on offshore wind-based hydrogen production. The chosen electrolyser technology in both scenarios is PEMEL.

Table 4 - Laine Offshore wind farm and hydrogen system options

Scenario 1 **Offshore windfarm - offshore hydrogen production**	**Scenario 2** **Offshore windfarm - onshore hydrogen production**
– Windfarm and internal grid	– Windfarm and internal grid
– H_2 platform	– Fresh water
– Desalination unit	– PEM Electrolyser
– PEM electrolyser	– Compressor
– Compressor	– Hydrogen pipeline onshore
– Hydrogen pipeline offshore	– Fuel cell
– Hydrogen pipeline onshore	
– Fuel cell	

To allow a fair comparison of the LCOH in this thesis, it is assumed that the total amount of offshore-produced electricity is used for hydrogen production. In reality, this is not the case, where the hydrogen production and electricity output to the grid is estimated based on detailed wind assessments and power demand. The electrolysers are then, in reality, sized and optimised according to these parameters. According to Donkers (2020), the efficiency of the electrolyser is 70% of the rated wind farm capacity.

In **scenario one**, the hydrogen production unit is positioned offshore as seen in **Figure 13**. The

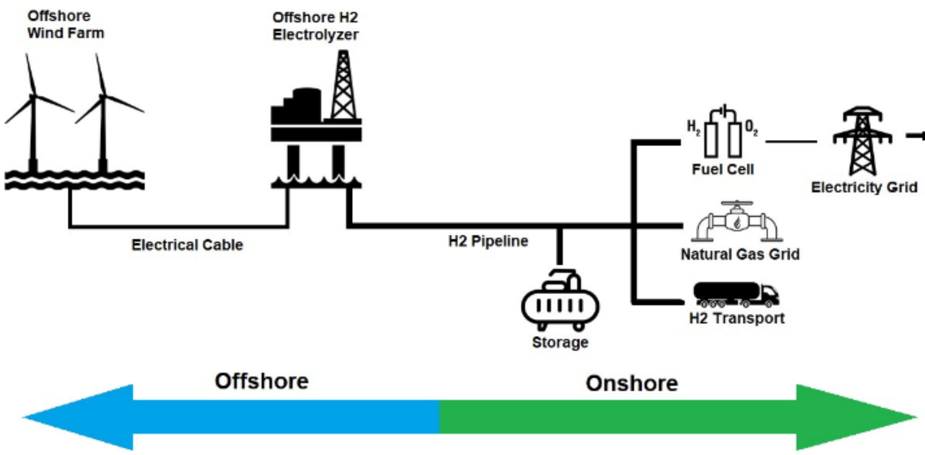

Figure 13 - Offshore electrolysis system (Calado and Castro, 2021)

hydrogen that will be produced can either be stored or reconverted into electricity using a fuel cell system. In this scenario, the HVDC/AC connection lines to shore are replaced by the offshore hydrogen electrolysis platform, including the electrolyser itself, desalination unit, compressors, and the hydrogen export pipeline, which means the complete electricity production will go to the electrolysis. The steps include transforming the hydrogen back to electricity using a fuel cell to be able to compare the LCOE between the two scenarios.

In **scenario two**, the hydrogen production unit is positioned onshore and is depicted in **Figure 14**.

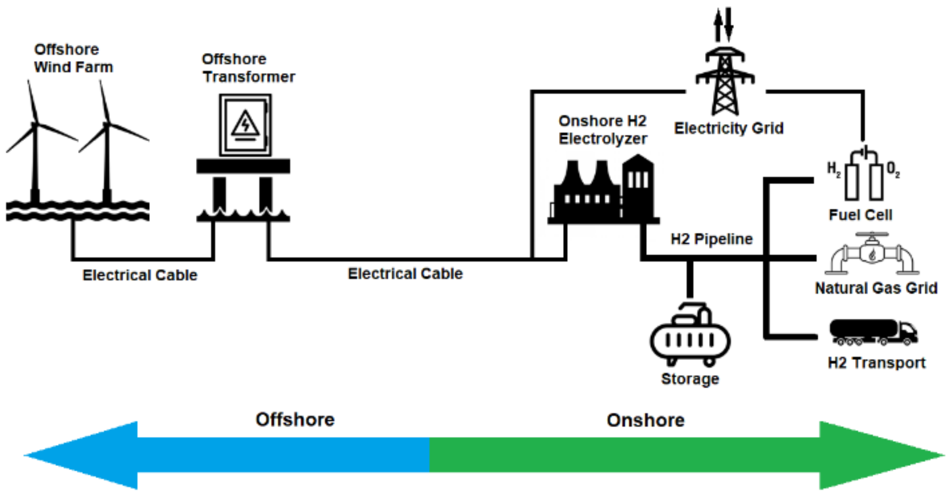

Figure 14 – Onshore electrolysis system (Calado and Castro, 2021)

This system includes a main water connection, PEMEL, compressor and gas pipe, storage vessels or fuel cell and is connected to the offshore wind farm through an HVDC/AC connection line. It is also in this scenario considered that the hydrogen produced onshore, is fed to the fuel cell that reconverts the hydrogen to electricity. This is done to be able to compare the electricity cost of the systems. Another possibility would be to include an additional electricity connection line from the offshore hydrogen production scenario in order to make a fair comparison. In this thesis the fuel cell was simply added to the scenario two system configuration.

3.1 Case study: Laine offshore wind farm

The chosen case study for this thesis is the planned offshore wind park named Laine in the Finnish exclusive economic zone, 35 kilometres from Pietarsaari. In 2022, the Finnish government granted the building of three offshore-based wind projects in the EEZ, and OX2 Finland Oy was one of the companies granted the research permit for the Pietarsaari region (Ministry of Economic Affairs and Employment, 2022). The environmental impact assessment (EIA) program, made by the company AFRY Finland Oy was released in October 2022. The EIA material made by AFRY Finland Oy 2022) will be used as input data for the calculations in this thesis.

The Laine offshore wind park is currently in a pre-planning phase, where the EIA was handed over during the autumn of 2022, and the EIA process will be finalised with the government's final statement within a year in the autumn of 2023. The preliminary timetable of the wind park would be at the earliest to start building in 2028 and have a running production earliest by 2030 (AFRY Finland Oy, 2022).

The proposed position of the Laine offshore wind park can be seen in **Figure 15,** where the dotted line is the EEZ border, and the red line is the territorial border of Finland and Sweden.

AFRY Finland Oy (2022) states in the EIA program that the wind park would cover

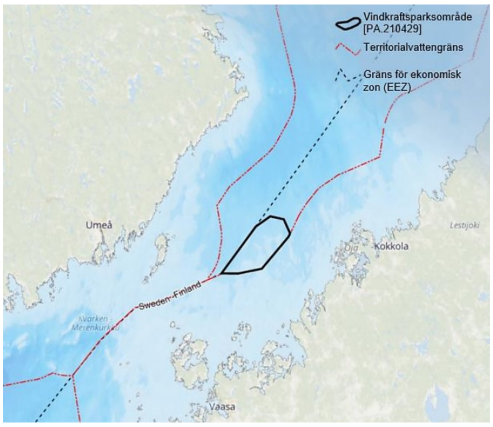

Figure 15 - Suggested position of the Laine offshore wind park (AFRY Finland Oy 2022)

approximately 450 km^2 with a maximum of 150 wind turbines. The cable network of the wind farm with two offshore transformer stations is shown in **Figure 16**. The approximated yearly production of the park is 11 TWh. The system configuration is not yet decided, meaning the number of turbines, height, and rated power. This is since the wind park is in such an early phase. The cost estimations done in this thesis have been done based on the parameters in **Table 5**. The fuel cell is sized to 75% of the electrolyser capacity according to (Donkers, 2020).

Table 5 - Suggested system parameters of the Laine offshore wind farm (AFRY Finland Oy, 2022)

p	Scenario 1 (Offshore)	Scenario 2 (Onshore)	Unit
Turbine capacity	15	15	MW
Wind farm capacity	2250	2250	MW
Number of turbines	150	150	
Distance from the shore	29	29	km
Project design life	30	30	years
Fresh water supply	Desalination	Water mains	
Transport type	Pipeline	Export cable	
Discount rate	5	5	%
Electrolyser size	1800	1800	MW
Fuel cell size	1350	1350	MW

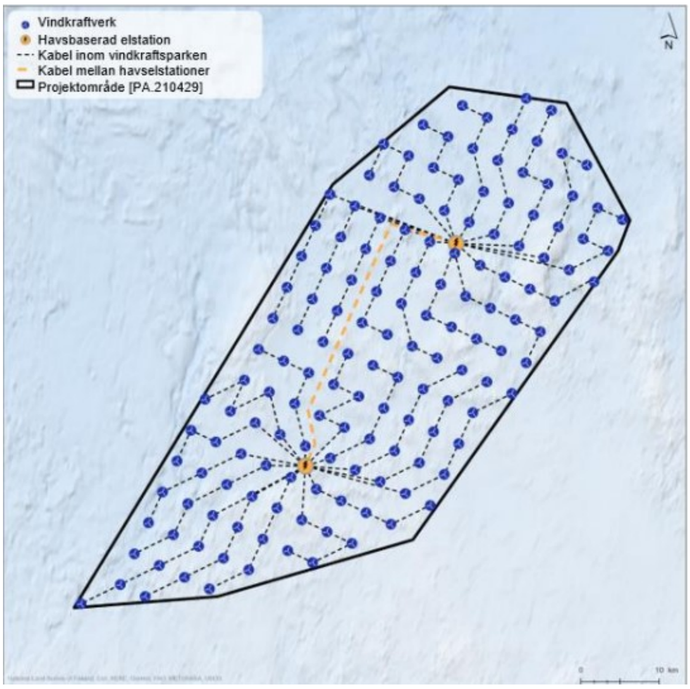

Figure 16 - An example of the possible placement of the 150 windmills including the internal cable array network (AFRY Finland Oy, 2022)

The two previously mentioned scenarios are applied to the chosen case study of the planned wind farm Laine on the western coast of Finland. The information about the planned project mentioned in the environmental assessment plan created by AFRY Finland Oy (2022) is used to estimate the size of the production and related costs. Then finding, data from similar projects in Europe and the size of the production and cost according to the case study.

3.2 Electricity and hydrogen production

To estimate the actual amount of electricity produced by the Laine offshore wind farm, the capacity factor will be used. **Equation (1)** is used to estimate the capacity factor, which is used as a method of determining the actual amount of delivered power during a specific period (Bakhshi and Sandborn, 2017) by dividing the average amount of electricity produced by the actual rated turbine power multiplied by in this case the number of hours in a year.

$$Capacity\ factor\ (CF) = \frac{E_p}{P_r t} \tag{1}$$

E_p = Energy production on average
P_r = Rated turbine power
t = time including downtime

The average capacity factor is calculated based on literature findings of possible future offshore wind capacity factors. The average of 36%, and 58% is 47%. The different efficiencies and losses mentioned in **table 6** of the different systems have been applied when calculating a year's actual electricity and hydrogen production.

The Laine offshore wind park is planned to be built in 2029 (OX2, 2022), and as described in Chapter 2, the capacity factor in 2030 is expected to range between 36% and 58% (IRENA, 2019). An average of these capacity factors was used to calculate and estimate electricity production for the Laine Offshore wind park. The actual capacity of the wind park is not yet available since the technology is rapidly developing. However, the rated power used in this case is the 15 MW rating per wind turbine and 150 turbines. **Equations (2)** and **(3)** shows how the rated production and yearly production in MWh is approximated.

$$\textbf{Electricity production} = \text{total rated wind farm power} * \text{CF} \tag{2}$$

$$\textbf{Electricity production}\ [\text{MWh}] = (\text{total rated wind farm power} * \text{hours in a year}) * \text{CF} \tag{3}$$

The 9 263 700 MWh result was compared to previous studies with similar scenarios. Compared to the value found in the thesis by Hansson (2022), 9.2 TWh is optimistic but possible in 2029. The following table shows the total electricity or Hydrogen production from the two different systems, including the fuel need, losses, and efficiencies.

Table 6 - Efficiencies and losses of the systems

Component	Efficiency	Loss	Fuel need	Source
PEMEL, Electrolyser	70%		47 kWh/kgH_2 10 l/kg$_{H2}$	*Donker, K.M (2020)*
PEMFC, Fuel cell	50%		16.5 kWh/kgH_2	*Calado, Castro (2021)*
Desalination unit	50%		3.5 kWh/kgH_2 18 L/kg$_{H2}$	*Shahzad, Burhan et.al (2019)*
Freshwater			9 kg/kg$_{H2}$	*Beswick et al. (2021)*
Compressor	45%		0.33 kWh/kgH_2	*Roy et al., (2006), Sdanghi et al., (2019)*
HVAC/HVDC Cable		2.50%		*Calado, Castro (2021)*
H2 pipeline		0.10%		*Calado, Castro (2021)*

For the scenario with onshore hydrogen production, the losses of the high-voltage cables and electrolyser are applied. The losses of compressing and transferring the hydrogen through a pipeline are subtracted. The losses subtracted in the offshore hydrogen system include the electrolyser, desalination unit, compressor, and hydrogen pipeline. The efficiency rate of the fuel cell is subtracted when reconverting hydrogen to electricity with a fuel cell, and the losses of the high-voltage cables to the grid.

The estimated maximum production of hydrogen and electricity, shown in **Table 7**, was calculated for both scenarios. For the onshore hydrogen production scenario, this was done using the estimated electricity production calculated using **equation (2)**, subtracting the fuel needs and losses mentioned in **Table 6.** The amount of hydrogen possible to produce was then calculated by dividing the amount of electricity produced by the fuel need of the PEMEL. Further details of the calculations can be seen in **Appendix A**.

Table 7 - Maximum production of electricity or hydrogen per scenario

Production	Electricity [MWh]	H2 [kg_{H2}]
Windfarm with offshore H_2 system	2 995 677	181 737 900
Windfarm with onshore H_2 system	9 032 108	191 590 159

3.3 Levelized cost of hydrogen and electricity

Levelized cost of electricity (LCOE) can be defined according to (Papapetrou and Kosmadakis, 2022) as the price of what the generated electricity should be sold for to cover the costs and break even at the end of its lifetime. More and less detailed versions of the formula are used to calculate the LCOE. This thesis uses **equation (5)** specified by NREL (2022). The capital recovery factor (CRF) must be calculated before attaining the LCOE. To explain, the CRF measures the present value of a series of annual cash flows of the same size. A correction of the initial investment cost over the total lifetime of the project (Donkers, 2020). The *n* in **equation 4** is the annuity or the lifetime, and *i* is the discount rate.

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1} \tag{4}$$

As seen in **equation (5),** the current value of the capital expenditures (CAPEX) is attained by multiplying it with the CRF and adding the operational costs (OPEX). These values are then divided by the annual production to attain the LCOE. The system lifetime is 25 years, and the discount rate is 5%, according to AFRY Finland Oy (2022) and the Scottish government (2020).

$$LCOE = \frac{\text{CAPEX} * \text{CRF} + \text{OPEX}}{\text{annual production}} \tag{5}$$

The **equation (6)** used to calculate the levelized cost of Hydrogen (LCOH) is similar to the one used to calculate LCOE. Except for an added annual energy cost, consisting of the electricity needed to produce one kilogram of hydrogen.

$$LCOH = \frac{\text{CAPEX } * \text{CRF} + \text{OPEX} + annual\ energy\ cost}{average \text{ annual hydrogen production}} \tag{6}$$

The attained values for LCOE and LCOH are then compared to average prices from nearby regions to assess the feasibility of the systems. In their report (2021), the Finnish innovation fund Sitra estimated an LCOE of 62 €/y/MWh in 2025 and 59.3 €/y/MWh in 2035. According to Sharma (2022), an LCOH of 2.93-6.61 €/kgH2 for green hydrogen is expected in the Vaasa region. LCOH has to be around 3.45 €/kgH2 to compete with blue hydrogen and 1.75 €/kgH2 to compete with grey Hydrogen (Calado and Castro, 2021).

The LCOE and LCOH are marked in the result with different colours depending on how competitive they are compared to LCOE and LCOH market prices. For the results the LCOE is either red or green if competitive with market prices or not. As seen in **Table 8**, the LCOH is marked green if competitive with green, blue, and grey hydrogen. An LCOH competitive with blue and green hydrogen is blue and lastly, an LCOH that is only competitive with green hydrogen is yellow.

Table 8 Colour chart on how to interpret the result of this thesis

	LCOE (€/MWh)	**LCOH (€/kg H_2)**
Market price of electricity	59-62	
	>>62	
Grey, blue, and green hydrogen		<1.75
Blue and green hydrogen		>2.7
Green hydrogen		2.7 - 6.6
		>>6.6

4 RESULTS

The estimated electricity production was calculated using **equations 1** and **2**, and the result was the following.

$$\text{Electricity production} = (2250\ \text{MW} * 47\%) = 1058\ \text{MW}$$

$$\text{Electricity production}\ [\text{MWh}] = (2250\ \text{MW} * 8760\ \text{h}) * 47\% = 9\ 263\ 700\ \text{MWh}$$

4.1 Wind farm costs

The capital and operational expenses are estimations since the exact system configuration of the studies case is not yet confirmed. As construction is planned to start in 2029, a further cost reduction compared to current levels is expected. The CAPEX and OPEX used in this thesis are according to similar cases. A valuable source used as a reference is a report from 2020 on the initial assessment of Scotland's opportunity to produce green hydrogen from offshore wind, which is a techno-economic assessment of the influences on the LCOH (Scottish Government, 2020). Also, the guide to offshore wind farm costs in the United Kingdom provided data on the costs associated with an offshore wind project (BVG Associates 2018). **Table 9** depicts the system costs for the electricity production part.

Table 9 - Laine offshore Wind Farm costs

Variable	**Unit**	**Cost per unit**
The Offshore wind farm & internal grid	€/MW	CAPEX: 2 697 995 OPEX: 86 527
Export cable	€/MW	CAPEX: 148 033
Offshore substation	€/MW	CAPEX: 136 620
Onshore substation	€/MW	CAPEX: 34 159
Hydrogen pipeline to shore	€/m	CAPEX: 740

4.2 Hydrogen system costs

The capital and operational costs are depicted in **Table 10** and **Table 11**, including both hydrogen system scenarios. The costs are only applied to the system scenario where the component is present.

Table 10 - Capital costs of the system components

Parameter	Scenario 1 (Offshore)	Scenario 2 (Onshore)
Windfarm & Internal grid	*6 085 412 865 €*	*6 085 412 865 €*
Fresh water		237 526 €
Offshore H2 platform	10 889 775 €	
Desalination unit	61 200 €	
PEM electrolyser	1 260 000 000 €	1 260 000 000 €
PEM fuel cell	2 700 000 000 €	2 700 000 000 €
Compressor	259 201 €	259 201 €
H2 pipeline offshore (á 29km)	21 465 220 €	
Total cost	**10 078 088 261 €**	**10 045 909 592 €**

Table 11 - Operational costs of the systems

Variable	Scenario 1 (Offshore)	Scenario 2 (Onshore)
Windfarm & Internal grid	*84 417 590 €*	*84 417 590 €*
Offshore H2 platform	10 889 775 €	
Fresh water		33 254 €
Desalination unit	1 224 €	
PEM electrolyser	25 200 000 €	25 200 000 €
PEM fuel cell	108 000 000 €	108 000 000 €
Stack replacement$_{electrolyser}$	218 802 600 €	218 802 600 €
Compressor	15 552 €	15 552 €
H2 pipeline offshore	159 760 €	
Total cost	**447 486 501 €**	**436 468 996 €**

4.3 Levelized cost of electricity and hydrogen

The LCOE and LCOH of this thesis were calculated for two scenarios. The first scenario includes offshore hydrogen production, and the second onshore hydrogen production. The calculations are explained in detail in **Chapter 3**. The results in this chapter are then compared to the current LCOE and LCOH values.

Table 12 - LCOE and LCOH in each scenario

	LCOE €/MWh	LCOH €/kg H2
Scenario 1: Offshore Hydrogen system	388	3.56
Scenario 2: Onshore Hydrogen system	57.2	6.06

The result shows that achieving a competitive system with onshore hydrogen production could be possible. In this case, the LCOH would be competitive with Green Hydrogen, and the LCOE would be competitive compared to the Finnish levels.

4.3.1 Sensitivity analysis

The sensitivity analysis was calculated as a best-case and a worst-case scenario. The parameters chosen for the best-case scenario are a production increase of 10%, 10% fewer costs, and an interest rate of 3%. The best-case scenario shown in **Table 13** did not result in a significant change compared to the base case. However, the LCOH for an onshore Hydrogen system was lower and closer to competing with the LCOH of blue Hydrogen than the base case.

Table 13 - 10% more production, 10% fewer costs, and 3% interest rate (best-case scenario)

	LCOE €/MWh	LCOH €/kg H2
Scenario 1: Offshore Hydrogen system	251	3.05
Scenario 2: Onshore Hydrogen system	42.8	5.02

The parameters chosen for the worst-case scenario are a 10% decrease in production of 10%, an increase of costs by 10%, and an interest rate of 7%. The worst-case scenario in **Table 14** did not result in a competitive LCOE in either system.

Table 14 - 10% less production, 10% more cost, and 7% interest rate (worst-case scenario)

	LCOE €/MWh	LCOH €/kg H2
Scenario 1: Offshore Hydrogen system	333 €	7.39 €
Scenario 2: Onshore Hydrogen system	75.7 €	€

None of the scenarios resulted in an LCOH competitive with grey hydrogen.

5 DISCUSSION

This thesis studied and compared two scenarios of hydrogen production from offshore wind. The analysis of LCOE and LCOH showed that only the onshore hydrogen production scenario was feasible for electricity production. Electricity being reconverted from hydrogen in the offshore scenario was highly unprofitable. The LCOE was nowhere near competitive levels. This can be related to significant losses and additional fuel cell system costs. It was also concluded that the CAPEX and OPEX were considerably higher in the offshore scenario. However, it would increase with an increased distance to shore. The result for Hydrogen production showed that producing hydrogen onshore or offshore with electricity from an Offshore wind farm could be feasible but only competitive with green hydrogen costs, as seen in **Table 1**. The conclusion was that hydrogen would be competitive with hydrogen in both scenarios.

The sensitivity analysis with a best- and worst-case scenario did not drastically change the results. Where the parameters changed were production, investment costs, and discount rates. The LCOH was still only primarily competitive with green hydrogen, and the onshore Hydrogen system was the only scenario close to having a feasible LCOE. The worst-case scenario showed no profitability of any price except the LCOH, which was still within the range of green hydrogen.

The LCOH corresponds to the values found in previous studies in **Table 3**. The calculated LCOH of this thesis ranges between 3.67 - 9.82 €/kg_{H2} and the results of the below studies range between 3.47 – 12.33 €/kg_{H2}, depending on the system scenario. The conditions of the previous studies have not been the same for all cases, such as distance to shore, the total power output of the wind farm, anticipated construction year, lifetime etc. This impacts the possibility of reliably comparing the results of the studies with the result of this thesis. The information of the chosen case-study was also spare since the project is in the planning phase. Other factors that affected the possible uncertainty of the input data were unknown future situations, round-off errors due to limited access to data, development of the technology.

The offshore system has a lower efficiency compared to the onshore system. The desalination unit and compression are extra steps needing further electricity. The electrolysis process also produces a significant amount of heat energy that cannot be utilised efficiently if the hydrogen production unit is placed offshore. The need for reconversion from hydrogen to electricity makes this system scenario unfavourable. These factors have an impact on both the technical and economic feasibility of the systems.

The anticipated high production in this case study may be a factor possibly making the LCOE of the onshore scenario competitive. The possibility of producing both hydrogen and electricity could further improve the economy of this type of system. So that in situations where the electricity price is low, hydrogen can be produced, and when the electricity price increase, no Hydrogen will be produced. Converting electricity into hydrogen and reconverting it back is only feasible in cases where the electricity price is very high, during high demand for electricity and low production.

Finland does not have a subsidy program for offshore wind power. However, the rapidly decreasing prices and rapidly developing technology could enable offshore wind without state subsidies during the 2030s (Finnish wind power association, 2023b). Sweden is one example where the state covers the grid connection costs of projects that have completed the tendering process. The result of this thesis indicates that it is currently not possible to achieve a price of hydrogen that would be competitive with grey or blue hydrogen. Hansson (2022) concluded in a similar study in southern Sweden that even with total subsidies of the high-voltage lines, the price of the produced hydrogen was not competitive with grey or blue hydrogen. However, in a best-case scenario where the production was increased by 10%, costs were reduced by 10% and an interest rate of 5%. With total power line subsidies, onshore hydrogen production achieved an LCOH, competitive with blue hydrogen prices in that study and a competitive LCOH was achieved even without subsidies for the offshore hydrogen system scenario.

6 CONCLUSIONS AND RECOMMENDATIONS

The ongoing energy transition in society is driving technological development. As future fuels and energy carriers are becoming an increasingly hot topic, hydrogen has become a subject for discussion. There are many possible applications of hydrogen, with energy storage and grid balancing capabilities being the most interesting ones. Hydrogen has previously been associated with carbon emissions due to the production methods and has not been seen as a viable option for limiting GHG emissions. However, with the rise of green hydrogen produced through electrolysis and competitive green hydrogen prices rising. Green hydrogen is expected to be competitive with its fossil-based counterparts in the coming future.

Building wind farms offshore has advantages, with higher and more consistent wind speeds offshore than onshore. The previously high costs and technical challenges associated with offshore wind production have been the main limiting factor. Due to higher capacity factors and more significant electricity production, a decrease in LCOE has been experienced.

The hydrogen system scenarios studied in this thesis are based on offshore wind energy. The two scenarios studies are offshore hydrogen production and onshore hydrogen production. The first system would produce hydrogen offshore, compress it and transport it onshore through a pipeline and then either store it or feed it to a fuel cell. The main advantage of this system is that the need for high-voltage lines is removed and that the gas pipeline has lower transmission losses than high-voltage lines. In the second system, the electricity from the offshore wind farm would be transported through sub-sea high-voltage lines onshore, where hydrogen could then be produced. The advantage of this system is that the electricity can be sold directly to the grid when the electricity price is favourable, and the electrolyser can be utilised to produce hydrogen when curtailment is needed, or the price is not favourable.

This thesis concluded that from the LCOE perspective, only onshore hydrogen production would be feasible, since the offshore scenario only included gas pipelines from the hydrogen platform. However, the LCOH was within the range of green hydrogen for both scenarios. The LCOH was not able to compete with either grey or blue hydrogen. The most significant contributing factor to the LCOH was the price of electricity.

A suggestion for further research could be to study the feasibility of a similar system where it is possible to produce both hydrogen and electricity offshore. The different scenarios could be to investigate the difference between centralised hydrogen production on a platform or separate small-scale production units at the base of the windmill. Further suggestions would be to study a system that does not have a shore connection, meaning that the hydrogen is stored entirely in the form of hydrogen in sub-sea compressed storage. This system could be feasible if the offshore wind farm is far from shore. Another suggestion for further studies could be to go deeper into the actual efficiencies of these systems and how they could be improved. If the Hydrogen production is placed on shore, the waste heat could be distributed in the district heating system, for example.

SVENSK SAMMANFATTNING

Teknoekonomisk analys av vätgasproduktion med havsbaserad vindkraft i västra Finland

För att Finland skall kunna uppnå sitt klimatmål att bli kolneutralt redan år 2035 krävs stora ansträngningar och investeringar. I och med kriget i Ukraina och de efterföljande sanktionerna mot Ryssland har många länder i Europa vilka tidigare varit beroende av ryska fossila bränslen blivit tvungna att tänka om. Europeiska unionen presenterade år 2022 en plan på hur EU skall gå tillväga för att bli energisjälvförsörjande. Denna plan inkluderar bland annat utvecklingen av den gröna vätgasekonomin samt förnybara energikällor.

Energibehovet i samhället fortsätter att öka, samtidigt som mängden växthusgasutsläpp måste begränsas allt mer. Detta betyder att behovet av klimatneutrala lösningar är större än någonsin. Användningen av förnybara energikällor har dock sina egna utmaningar. Det måste alltid finnas en balans mellan produktion och förbrukning inom elnätet. Problemet grundar sig i att man inte kan anpassa elförbrukningen till när det blåser eller solen skiner. Det behövs alltså reglerkraft för att kunna balansera dessa toppar och dalar i förbrukning och produktion. Detta skapar möjligheten att ta tillvara elektriciteten då den behövs som minst och sedan använda den när den behövs som mest. Det finns förstås många olika typer av teknologier inom detta område, men den teknologi som undersökts i denna studie är vätgasproduktion med havsbaserad vindkraft.

Vätgas producerad genom användningen av förnybara energikällor kallas grön vätgas. Vindkraft är en energiresurs som kan användas för att genom elektrolys av vatten skapa vätgas och syrgas, och i detta arbete studeras havsbaserad vindkraft. Havsvindkraften är i dagsläget ett relativt outforskat ämne i Finland. Ämnet diskuteras dock livligt och det finnas planer på flera havsvindkraftsparker längs med Finlands kust. Ett av dessa projekt som drivs och planeras av företaget OX2 och går under projektnamnet Laine har valts som fallstudie i denna undersökning.

Genom att placera vätgasproduktionen till havs kan man transportera vätgasen genom gasledningar istället för elektricitet genom högspänningsledningar på havsbotten. Överföring av elektricitet kräver transformatorstationer både till havs och på land. Högspänningsledningar är även förknippade med större förluster, de är upp till 5% större jämfört med gasledningar som har en förlust på kring 0,1%. Man bör dock utvärdera de olika systemalternativen ur ett större perspektiv för att avgöra vilket alternativ som är mer ändamålsenligt.

Detta diplomarbete har ingen extern uppdragsgivare. Det undersökta ämnet valdes för att utveckla kunskapen inom ett relativt nytt forskningsområde i Finland. Syftet med denna studie var att jämföra lönsamheten hos två scenarion genom att beräkna medelkostnaden för el- samt vätgasproduktionen. I studien beräknades den genomsnittliga kostnaden per producerad enhet energi, och *levelized cost of electricity* (LCOE) och *levelized cost of hydrogen* (LCOE) jämfördes. Dessa värden är mått på den genomsnittliga kostnaden per producerad enhet energi över hela livslängden för en energikälla eller en produktionsanläggning, inklusive investerings- och driftskostnader. Resultatet av beräkningarna kunde sedan jämföras med prisnivåerna på marknaden. Lönsamheten kan sedan utvärderas utifrån om de beräknade värdena är högre eller lägre än marknadspriset. Ifall priset är högre kan slutsatsen dras att det inte är lönsamt.

De två scenarier som har undersökts i samband med havsvindkraftsparken Laine är följande: vätgasproduktion till havs eller vätgasproduktion på land. Den planerade havsvindkraftparken med arbetsnamnet Laine har använts som fallstudie, och informationen om projektet har tagits från miljökonsekvensbedömningsplanen. Det planerade antalet vindkraftverk och deras märkeffekt har använts för att uppskatta den årliga elproduktionen, en uppskattad effekt på elektrolysanläggningen har också hämtats från samma källa.

Kostnaderna för de olika systemen samt vindkraftsparken har samlats in från liknande projekt i Europa och sammanställts i tabellform för att sedan användas i beräkningarna. Mängden data inom detta område är väldigt begränsad vilket gjorde det svårt att hitta exakta data för alla parametrar. I dessa fall har antaganden gjorts eller ett medeltal använts med stöd av det material som funnits tillgängligt.

Resultatet visar att priset för vätgas producerad till havs är 3,56 €/kgH_2 och att vätgas producerad på land är 6,06 €/kgH_2. Priset på elektriciteten för havsbaserade scenariot var 388 €/MWh och 57,2 €/MWh för landbaserade scenariot.. Priset för vätgas är alltså konkurrenskraftig med grön vätgas (producerad med förnybara energikällor) i båda fallen.Priset på den gröna vätgasen skulle behöva vara under 3,45 €/kgH_2 för att vara konkurrenskraftigt med blå vätgas (vätgas producerad med fossila bränslen, där koldioxidutsläppen reducerats genom koldioxid-fångst samt lagring). En känslighetsanalys gjordes även på resultatet där produktionen ökades med 10% och kostnaderna minskades med 10%. I det fallet kunde ett konkurrenskraftigt LCOE uppnås men LCOH var ännu inte konkurrenskraftigt jämfört med blå eller grå vätgas (vätgas producerad med fossila bränslen). Känslighetsanalysen ga vi detta fall inget riktgivande resultat, eftersom att det inte resulterade i att någon metod skulle varit med konkurrenskraftig,

Resultatet i studien överensstämmer med tidigare empiri och tidigare utförda studier. Slutsatsen av studien är att det i nuläget varken är lönsamt att producera vätgas till havs eller på land genom att använda havsbaserad vindkraft, utan subventionering. Det finns en rad olika faktorer som inverkar på resultatet, varav systemkostnaden samt den årliga produktionen har störst inverkan. De höga komponentkostanderna resulterar i ett vätgaspris för dessa system som är högre än det nuvarande marknadspriset för respektive sätt att producera vätgas.. Det bör dock observeras att de parametrar som är relaterade till vindkraftsparken i nuläget endast är spekulationer som kan komma att justeras.

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APPENDICES

Appendix A: An overview of the electricity and hydrogen production calculations

Turbines	pc	150	150	pc	Turbines
Individual wind turbine power	MW	15	15	MW	Individual wind turbine power
Windfarm power	MW	2 250	2 250	MW	Windfarm power
Capacity factor	%	47	47	%	Capacity factor
available average power	MW	1 058	1 058	MW	available average power
Available amount of electricity	MWh/year	**9 263 700**	**9 263 700**	MWh/year	Available amount of electricity
			2.5	%	cable losses
			9 032 108	MWh/year	Electricity to shore
Electrolysis efficiency	%	70	70	%	Electrolysis efficiency
Hydrogen energy content	kWh/kg_{H2}	33	33	kWh/kgH2	Hydrogen energy content
Electrolysis energy need	kWh/kg_{H2}	47.1	47.1	kWh/kgH2	Electrolysis energy need
Electricity used by the processes					
Desalination	kWh_{el}/kg_{H2}	3.5			
Compressor	kWh_{el}/kg_{H2}	0.33			
Total electricity need$_{offshore}$	**kWh_{el}/kg_{H2}**	**51.0**			
Actual hydrogen production$_{offshore}$	$kg_{hydrogen}/year$	181 737 900			
Actual hydrogen production$_{onshore}$	$kg_{hydrogen}/year$	**191 590 159**			
Transmission losses	%	0.1			
Hydrogen on shore	$kg_{hydrogen}/year$	**181 556 162**			
Fuel cell efficiency	%	50			
Hydrogen energy content	kWh/kg_{H2}	33			
Back to electricity	MWh	**2 995 677**			

Appendix B: Base scenario: levelized cost of electricity and levelized cost of hydrogen for scenario one and two.

Base scenario		
Scenario 1 - Windfarm with offshore hydrogen production		
Rated power [MW]	2 250	
Rated power$_{electrolyzer}$ [MW]	1 800	
Annual production [MWh]	8 051 067	
Annual production after reconversion [MWh]	2 995 677	*(16,5 kWh/kgH2 and cable loss 2,5%)*
Annual H_2 production [kg]	181 737 900	
CAPEX$_{electricity}$	6 085 412 865	
OPEX$_{electricity}$	84 417 590	
CAPEX$_{H2}$	3 992 675 396	
OPEX$_{H2}$	363 068 911	
i	0.05	
n	25.00	
CRF	0.07	
Fuel cost *(Fuel need * cost)*	646 359 042 €	
LCOE €/MWh	388 €	
LCOH €/kgH$_2$	3.56 €	

Scenario 2 - Windfarm with onshore hydrogen production		
Rated power$_{windfarm}$ [MW]	2 250	
Rated power$_{electrolyzer}$ [MW]	1 800	
Annual production [MWh]	9 032 108	
Annual H_2 production [kg]	191 590 159	
Electricity needed for H2 production[MWh] *47 kWh/kgH2*Annual H2 production*	9 004 737	
CAPEX$_{electricity}$	6 085 412 865	
OPEX$_{electricity}$	84 417 590	
CAPEX$_{H2}$	3 992 675 396	
OPEX$_{H2}$	363 068 911	
i	0.05	
n	25	
CRF	0.07	
Fuel cost *Electricity for H2 * LCOE*	514 628 367	
LCOE €/MWh	57.2 €	
LCOH €/kgH$_2$	6.06 €	

Appendix C: Best case scenario: levelized cost of electricity and levelized cost of hydrogen for scenario one and two.

Best Case scenario		
10% more **production**, 10% less **costs** and 3% interest rate		
Scenario 1 - Windfarm with offshore hydrogen production		
Rated power [MW]	2 250	
Rated power$_{electrolyzer}$ [MW]	1 800	
Annual production [MWh]	8 051 067	
Annual production after reconversion [MWh]	2 995 677	*(16,5 kWh/kgH2 and cable loss 2,5%)*
Annual H_2 production [kg]	181 737 900	
CAPEX$_{electricity}$	6 085 412 865	
OPEX$_{electricity}$	84 417 590	
CAPEX$_{H2}$	3 992 675 396	
OPEX$_{H2}$	363 068 911	
i	0.03	
n	25.00	
CRF	0.07	
Fuel cost *(Fuel need * cost)*	346 787 406.896 €	
LCOE €/MWh	251 €	
LCOH €/kgH_2	3.05 €	

10% more **production**, 10% less **costs** and 3% interest rate		
Scenario 2 - Windfarm with onshore hydrogen production		
Rated power$_{windfarm}$ [MW]	2 250	
Rated power$_{electrolyzer}$ [MW]	1 800	
Annual production [MWh]	9 032 108	
Annual H_2 production [kg]	191 590 159	
Electricity needed for H2 production[MWh] *47 kWh/kgH2*Annual H2 production*	9 004 737	
CAPEX$_{electricity}$	6 085 412 865	
OPEX$_{electricity}$	84 417 590	
CAPEX$_{H2}$	3 992 675 396	
OPEX$_{H2}$	363 068 911	
i	0.03	
n	25	
CRF	0.06	
Fuel cost *Electricity for H2 * LCOE*	516 192 587	
LCOE €/MWh	42.8 €	
LCOH €/kgH_2	5.02 €	

Appendix D: Worst scenario: levelized cost of electricity and levelized cost of hydrogen for scenario one and two.

Worst case scenario		
10% less **production**, 10% more **costs** and 7% interest rate		
Scenario 1 - Windfarm with offshore hydrogen production		
Rated power [MW]	2 250	
Rated power$_{electrolyzer}$ [MW]	1 800	
Annual production [MWh]	8 051 067	
Annual production after reconversion [MWh	2 995 677	*(16,5 kWh/kgH2 and cable loss 2,5%)*
Annual H_2 production [kg]	181 737 900	
CAPEX$_{electricity}$	6 085 412 865	
OPEX$_{electricity}$	84 417 590	
CAPEX$_{H2}$	3 992 675 396	
OPEX$_{H2}$	363 068 911	
i	0.07	
n	25.00	
CRF	0.07	
Fuel cost *(Fuel need * cost)*	346 787 407 €	
LCOE €/MWh	333 €	
LCOH €/kgH$_2$	4.17 €	

10% less **production**, 10% more **costs** and 7% interest rate		
Scenario 2 - Windfarm with onshore hydrogen production		
Rated power$_{windfarm}$ [MW]	2 250	
Rated power$_{electrolyzer}$ [MW]	1 800	
Annual production [MWh]	9 032 108	
Annual H_2 production [kg]	191 590 159	
Electricity needed for H2 production[MWh] *47 kWh/kgH2*Annual H2 production*	9 004 737	
CAPEX$_{electricity}$	6 085 412 865	
OPEX$_{electricity}$	84 417 590	
CAPEX$_{H2}$	3 992 675 396	
OPEX$_{H2}$	363 068 911	
i	0.07	
n	25	
CRF	0.09	
Fuel cost *Electricity for H2 * LCOE*	516 192 587	
LCOE €/MWh	75.7 €	
LCOH €/kgH$_2$	7.39 €	