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Techno-economic analysis of offshore wind-powered hydrogen production

A comparison of renewable hydrogen production scenarios

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AC .... *Alternating Current*
AEC .... *Alkaline Electrolysis Cells*
CAPEX .... *Capital Expenditures*
DC .... *Direct Current*
EMODnet .... *European Marine Observation and Data Network*
HVAC .... *High Voltage Alternating Current*
HVDC .... *High Voltage Direct Current*
LCOH .... *Levelized Cost of Hydrogen*
NPV .... *Net Present Value*
OPEX .... *Operational Expenditures*
OWF .... *offshore wind farm*
PEMEC .... *Proton Exchange Membrane Electrolysis Cells*
SOEC .... *Solid Oxide Electrolysis Cells*

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1. Introduction

Hydrogen is seen as a promising opportunity for energy transition. Produced in a climate-neutral way, it can significantly reduce CO_2 emissions in the energy sectors. Hydrogen has already been used in industry for decades, such as steel or chemical industry. But there is also the possibility of using hydrogen in transportation sector by utilizing synthetic fuels or fuel cells. Furthermore, hydrogen can be used as both, energy storage medium and for heat supply. Finally, hydrogen may contribute to Germany’s independence from gas exporters. This might be a crucial factor to the security of future energy supply, as can be observed at present times of political conflicts between Russia and Ukraine.

Currently, pure hydrogen is mainly produced from natural gas emitting CO_2. In contrast, the concept of “green hydrogen” represents an alternative without emitting CO_2. Green hydrogen is produced in Power to Gas plants using electricity from renewable energy sources. The underlying principle is called electrolysis. To produce a large amount of pure hydrogen, a lot of electricity is needed. For this reason, there are already several concepts of trying to carry out electrolysis directly into the area, where renewable electricity is generated. Offshore wind farms are particularly well suited for this purpose. Following this, this paper deals with the leading question:

What production method for green hydrogen is advantageous for Germany at a specific location in the North Sea to which it is entitled?

Dealing with this, several technologies of producing green hydrogen are presented in the first place. After this, a technology selection is made for two reference scenarios. In these scenarios, various influencing factors are taken into account. Based on a cost assessment, the production costs of hydrogen are being calculated and analysed for 2030. In addition, a sensitivity analysis provides information on the extent to which the strongest influencing factors may change the result of the study.

2. Theory

This chapter presents the theoretical groundwork that will be used to answer the research question. First, chapter 2.1 provides an overview of the technological components that will be used in the scenarios presented later on. Then, in chapter 2.2, the economic parameters are presented, on the basis of which the feasibility of the scenarios will be assessed.

2.1 Technological aspects

The technologies considered include offshore wind farms, conversion technologies for producing hydrogen, installations for accommodating the components as well as the transmission infrastructure.

2.1.1 Offshore wind farm

The generation of power from an offshore wind farm (OWF) has become increasingly attractive, especially in Europe with a total installed capacity of 25 GW in 2020. Germany and the UK are the leading countries in terms of cumulative offshore wind capacity and the North Sea is the most important site for OWFs in Europe with the highest current installed capacity and the highest estimated offshore wind installations in the next decade. Decreasing costs and multiple advantages make this technology able to compete as an efficient renewable energy source bearing huge potential to accelerate the transition of the energy sector.[1] The exponential growth in offshore wind capacity from 2010 to 2020 indicates a fast-growing market and subsequently lower costs in the near future [2].

OWFs have the advantage of relatively low visual and acoustic impacts that make it hard for wind farms to expand on land with several countries reaching their limits in terms of space for installing more wind engines. Also, the ability of transporting the turbine components by barges and ships reduces logistical barriers such as narrow roads, which allows the installation of larger wind turbines and thus increasing offshore power generation. The wind flow is more constant offshore with less turbulence and variability because of the flat surface conditions which leads to a longer lifespan of the turbine components due to reduced wear of those components. Lower surface resistance also leads to higher wind speed at relatively lower heights and enables a higher energy production rate. Steadier offshore climate conditions enable higher full load hours per year. Another important advantage is that offshore wind conditions are typically better during the day due to the concept of the sea and land breezes, which leads to higher energy production when it is needed as energy demand is typically higher during the day. [3]

There are two types of OWFs: the bottom-fixed which are used for water depth up to 50 meters and floating wind farms for depths greater than 50 meters [4]. Bottom-fixed foundations are more mature than floating foundations and thus less expensive, especially in shallow waters.

There are several types for the bottom fixed technology depending on the turbines weight, water depth and dynamic load distribution. The three major types for bottom fixed foundations are: monopiles for water depths lower than 30 meters, and jackets or tripods for depths that range between 30 to 60 meters [5]. The major floating structures are tension leg platforms, spar buoy and semi-submersible platforms that are all moored and anchored to the seabed [4].

2.1.2 Conversion system for hydrogen production

There are several ways of producing hydrogen whether by using fossil fuels or renewable energy sources such as biomass or renewable electricity for water electrolysis. Nowadays, hydrogen production is still mainly based on fossil fuels emitting a significant amount of carbon dioxide, though recent progress and development of the water electrolysis and political pressure to reduce carbon dioxide emissions can turn this currently relatively expensive technology into an affordable option for producing green hydrogen. [6], [7]

Water electrolysis is an electrochemical process where water is dissociated into highly pure hydrogen and oxygen using Direct Current (DC) electricity. First, a certain substance carrying ions dissolves in a solvent, the electrolyte, and there are two conductive metallic electrodes in the dissolution: a negative charged cathode and a positive charged anode. An electric current is applied to these electrodes and the cathode attracts positive ions while the anode attracts negative ions. An electrical power source is used to keep the potential difference between the electrodes where ions absorb or emit electrons. Hydrogen is then formed at the cathode and oxygen at the anode. [6] Some advantages of water electrolysis are high cell efficiency and a high production rate of pure hydrogen [8].

An electrolyzer plant consists of one or several parallel electrolyzer stacks and the balance of plant. The stacks are generally created by a number of in series connected small electrolyzer cells that is limited by manufacturing and voltage limitations. The performance of an electrolyzer plant depends on various operating conditions such as current density, pressure and temperature. High current densities allow for smaller cell areas and thus lower investment costs but cause the increase of the cell operating voltages and thus the increase of the operating costs. Higher operating pressure levels reduce the need of a mechanical compressor but cause higher engineering complexity. High temperature levels lower cell operating voltage and improve the energy efficiency rate but robust materials are needed and material degradation becomes a big challenge at very high temperatures. All three parameters have also a direct influence on the stack lifetime and should not exceed certain limits to maintain an efficient system. [9, p. 51,52]

The three major water electrolysis technologies are: Alkaline Electrolysis Cells (AEC), Proton Exchange Membrane Electrolysis Cells (PEMEC) and Solid Oxide Electrolysis Cells (SOEC) [10]. These technologies differ in several characteristics such as degree of hydrogen purity, energy efficiency, current density, system size and design complexity, stack lifetime, temperature and pressure levels, operating dynamics, type of electrolyte and need for noble metals or expensive materials [11, p. 97,f.].

AEC is the oldest and more matured technology and has been used for industrial purposes up to the megawatt range since the 1920s [10]. It offers a high stack lifetime and produces pure hydrogen by having the two electrodes immersed in a circulating liquid alkaline electrolyte, separated by a diaphragm. The CAPEX are relatively low since this technology doesn't need noble metals, but low operating pressure and low current density due to high ohmic losses across the diaphragm and electrolyte result in less efficient system size and design [12]. The system efficiency is also negatively affected by the lack of dynamic operation ability in terms of system start-up and shutdown which makes it hard to work with intermittent renewable energy sources that require high flexibility due to varying power input such as wind energy [10]. The electrical efficiency is expected to stay between 65-71% by 2030 [13, p. 44].

The PEMEC was developed by General Electric in the 1960s in order to overcome the obstacles of the AEC and is based on the solid polymer electrolyte concept [10]. This technology reaches a high hydrogen purity, high energy efficiency and higher voltage efficiency. The operating pressure and the current densities are higher as well. Thanks to the proton exchange membrane the gas crossover rate is low while a high proton conductivity is maintained and a compact system design is deployed. [12] The capital costs are higher because of the expensive and complex system components and materials used such as platinum. Start-up and shutdown time is significantly lower allowing PEMEC to efficiently work with intermittent energy sources. [10] By 2030 the PEMEC is expected to reach electrical efficiencies between 63-68% and a stack lifetime up to 90.000 operating hours [13, p. 44].

The development of the SOEC started in the 1980s and is still mainly demonstrated on small-scale applications or at laboratory. It is also known as the high temperature electrolysis where electrical energy is converted into chemical energy [12]. A high energy efficiency rate that is expected to further increase due to the ability of using heat as an additional energy source for the electrolysis. Potentially being able to operate as a fuel cell in reverse mode or generate synthesis gas in a co-electrolysis from steam and carbon dioxide cause high attraction for this relatively young technology. Water is used in the form of steam in this process that works under ambient pressure and high temperatures up to 1000 degrees Celsius which makes it a better fit for working with nuclear power plants or geothermal heat systems to make use of the available heat instead of working with intermittent power sources such as offshore wind energy. This technology is the least mature of the three major electrolysis technologies and currently offers relatively low stack lifetime. Electrical efficiencies are expected to reach 77-84% by 2030 [13, p. 44].

In addition to the conversion unit, other technologies are required to perform electrolysis offshore using seawater. One of these is the desalination unit, which provides the electrolyzer with water of a consistent purity by removing salt from the seawater. The most commonly used technologies are membrane-based reverse osmosis and thermal-based distillation processes [14]. A relevant difference between the two is that reverse osmosis only requires electricity, whereas thermal distillation requires both electrical and thermal energy [15]. According to the electrolyzer placement, the desalination unit can be installed as either a centralized unit or decentralized in the case of in-turbine electrolysis [16].

2.1.3 Offshore and onshore installations

Depending on the concept design, different installations have to be built onshore or offshore in order to host the technical components. In case of onshore electrolysis, an offshore substation is required to integrate the Alternating Current (AC) power of individual wind turbines and allow for export via transmission cable. The functions of such a substation include the transformation of voltage and the rectification of AC when exporting through High Voltage Direct Current (HVDC) transmission lines [17, p. 33]. Furthermore, an installation housing the reception substation and electrolysis components has to be build onshore [18, p. 18].

Centralized offshore electrolysis demands a substructure that houses the components needed for electrolysis, desalination and compression. One option of installing this substructure for the power-to-hydrogen conversion is the construction of a new platform. An alternative to a newly built platform is the re-purposing of existing oil and gas platforms into hydrogen production facilities. While using existing infrastructures may be more economical, factors like the availability for re-purposing and the usage of the platforms for other system integration solutions have to be considered. [19, pp. 22–23]

In the concept of decentralized offshore electrolysis, each wind turbine houses its own desalination and electrolysis unit. Therefore, an export compression unit is the only additional offshore installation needed. A small pipeline network is used to connect the electrolyzers with the compression unit, from which the gathered hydrogen is exported to shore via a main pipeline. [16], [18]

2.1.4 Transmission infrastructure

The transmission system for offshore wind power is characterized by large installed capacities and long transmission distances to shore [20, p. 349]. The selection of the transmission system is therefore detrimental for the economic feasibility of the overall system. Depending on the location of the hydrogen production (onshore vs. offshore), the transportation of the energy carrier can either be electric via transmission cables, molecular (gaseous or liquid hydrogen) via pipeline or ship tanker, or a combination of both [21]. There are various options for the two typologies that will be reviewed in this section. First, the options for exporting electricity for onshore electrolysis will be discussed, followed by the options for the hydrogen transmission in the case of offshore electrolysis.

Electricity to shore can be transported by High Voltage Direct Current (HVDC) or High Voltage Alternating Current (HVAC) cabling. Traditionally, HVAC cabling has been used for the majority of wind farms, as its overall installation cost is lower for shorter distances compared to HVDC. However, power losses in HVAC cables become significantly higher for longer distances due to reactive power losses. Considering the lower power losses of the HVDC technology, HVDC may become the more attractive technology. The “break-even” distance to shore between both options has been calculated at around 80 km, depending on the wind farm capacity, average wind speed and discount rate. [22]

Regarding hydrogen transmission, transportation is generally performed via pipeline. The transport occurs at high pressure to ensure high technical efficiency and good economic performance. To achieve this, further compression of the hydrogen gas is needed after the electrolysis. In addition to the compressors and the pipeline itself, facilities for metering and regulation are required. One important option to be considered is the re-purposing of existing natural gas pipelines for dedicated hydrogen transport. This retrofitting of existing pipelines can reduce investment costs, since an existing infrastructure is being adjusted instead of installing a new pipeline infrastructure. The adjustments for retrofitting include upgrades in material and mechanical components, as well as more powerful compression units purposed for hydrogen. In contrast, one disadvantage of using natural gas infrastructure is the dependency on the availability at which the pipeline becomes available for dedicated hydrogen transport. The status of the pipelines and possible risks for the hydrogen compatibility should also be considered. [23]

Another method of transporting hydrogen to shore is the usage of ship tankers. These ships are equipped with vessels, which carry hydrogen in compressed or liquified form. There is also the possibility of converting hydrogen into energy carriers like ammonia or liquid organic hydrogen and then transporting it. The form of the energy carrier affects the storage capacity of the ship as well as the required amount of energy for conversion and reconversion. [24] The transportation is carried out on an offshore platform, from which the ship tanker periodically offloads volumes of hydrogen and delivers them to shore. Due to this, the transportation is less continuous compared to hydrogen pipelines and would require a short-term hydrogen storage option [25].

2.2 Economical aspects

In order to assess the feasibility of a project, an overview on the used economic parameters is given.

2.2.1 Capital Expenditures and Operational Expenditures

Capital Expenditures (CAPEX) are expenditures for long-term assets, such as machines, buildings or land. [26] These expenditures are not defined as costs, but merely the conversion of working capital to capital asset. The acquisition value of these capital assets is usually depreciated over a defined period of use to a certain final value, which represents the wear and tear.

Operational Expenditures (OPEX) are expenditures for maintaining the operations of a company. In contrast to CAPEX, they refer to short-term costs, such as staff, raw material or energy. [27] OPEX can be split into fixed costs, e. g. costs for running machines, and variable costs, e. g. due to the demand of raw material needed. Also, OPEX can be distinguished between different projects or systems of a company. In context of running an OWF, there are many expenditures to be differentiated. An overview of regarding costs is given in Table 1 - Comparision of CAPEX and OPEX in context of an OWF

.

2.2.2 Levelized Cost of Hydrogen

The Levelized Cost of Hydrogen (LCOH) is a model to understand the main factors defining the cost of green hydrogen. It is used to compare different production scenarios. The model takes all the expenses, which means CAPEX and OPEX and divides them by the amount of produced hydrogen in kg [30]. Resulting in the price the hydrogen needs to be sold at to break even. It depends for example on the electrolyzer performance and external factors like the electricity costs or installation costs [9].

$$LCOH\ \left(\frac{€}{kg}\right) = \frac{\sum_{i=1}^{n} \frac{Total\ costs\ in\ year\ i}{(1 + Discount\ rate)^{i}}}{\sum_{i=1}^{n} \frac{kg\ of\ hydrogen\ produced\ in\ year\ i}{(1 + Discount\ rate)^{i}}} \tag{1}$$

Another way of calculating the LCOH is by using the NPV like in the equation below.

$$LCOH = \frac{NPV\ CAPEX + NPV\ OPEX + NPV\ Transport}{NPV\ Hydrogen\ Production} \quad (2)$$

The net present value (NPV) is calculated to analyze the profitability of a project by taking all the future streams of payments into account. A positive NPV means the investment will be attractive [27]. The formula is a standard economic indicators to compare projects or in our case scenarios from an investing perspective [29].

3. Status Quo

The findings of the literature search on the current status of offshore hydrogen production are presented in this chapter. First, an overview of projects in the North Sea that are comparable to the subject of this study is provided. Afterwards, the LCOH of various studies are presented.

3.1 Current projects

1. PosHYdon (Offshore, North Sea)

In 2019, the world's first offshore hydrogen pilot project started in the North Sea. It is named "PosHYdon" and is located on Neptune Energy's “Q13a” oil and gas platform, about 13 km from the Dutch coast. The project is funded by the Dutch Association for Decommissioning and Reuse ("Nextstep"), the Dutch Organization for Applied Scientific Research (TNO) and various industry partners. [30]

The production of green hydrogen takes place directly on the platform. For this purpose, the surrounding seawater is first collected and then converted into demineralized water. After this step, hydrolysis takes place at a centralized PEMEC by using electrical energy produced by offshore wind turbines.[31] The oxygen is safely released to the environment, while the hydrogen is transported to the mainland by existing natural gas pipelines. In this way, there are no costs by the usage of undersea power cables. The aim of the project is to investigate the influences of offshore production on the production of green hydrogen. This includes the effects of using seawater on different electrolyzers, but also the cost of installation and operation of an offshore electrolyser unit. [32]

2. Brande Hydrogen (Onshore, Western Denmark)

In addition to offshore pilot projects, there are also onshore projects. Therefore the "Brande Hydrogen" project can serve as an example, which is being carried out by Siemens Gamesa in the west of Denmark. The project takes place in so-called “island operation”, which means that its energy supply is completely independent of the grid. There is only one wind turbine with a capacity of 3 MW, that supplies the electrolyzer with electricity, the electrolyzer itself has a capacity of 300 kW. [33, p. 9] As this project integrates an electrolyzer into a wind turbine, this project can also be referred as an example for decentralized electrolysis.

After its production, the hydrogen is stored, compressed, and then delivered to refuelling stations. In addition to the generation of hydrogen, various storage technologies, such as batteries, and their impact on grid stability are also tested. [34, p. 15] Since Siemens Gamesa uses an electrolyzer produced by Siemens Energy, it can be assumed that a PEMEC is used in this project. [35]

3. Upcoming projects: AquaSector & H2Mare (Offshore, North Sea)

The investigation and research on green hydrogen production is still evolving, not only in Europe. Currently, there are only a few projects being carried out in or around the North Sea region. However, there is enormous potential for the usage of wind energy in the North Sea. The North Sea is one of the most important locations for offshore wind energy, representing 79% of the total installed capacity in Europe. [2, p. 14]

Research on producing green hydrogen will also take place in the future. There are many different projects that are to be implemented, such as "H2Mare" or "AquaSector". These projects aim to use different types of electrolyzers, to investigate hydrogen production and storage capacities and to test different system configurations. However, these projects are still to be developed and it will take several years before results might be used for further development. [36], [37, p. 1] Until then, many feasibility studies based on theoretical concepts will need to be carried out.

3.2 Literature review on LCOH

There has already been some research carried out analyzing possible OWF scenarios. Calado & Castro provide an overview about some of them and give a summary of LCOH via an extensive literature review comparing two different approaches. The first one uses an offshore electrolyzer and transports the hydrogen via pipeline which is cheaper than a submarine cable. The second one a hybrid system with an onshore electrolyzer which has the possibility of selling the electricity or using it to produce hydrogen. [38]

McDonagh et al. analyze three scenarios for a 504 MW wind farm 15.4 km off the coast of Arklow Ireland calculating the NPV and considering curtailment. The most profitable scenario is selling just the electricity to the grid. The LCOH for converting all the power to Hydrogen is 3.77 €/kg but compared to the first scenario it would only be viable for investors if the selling price of hydrogen is greater than 4.65 €/kg. In order for a hybrid system, like in the source before, to be profitable at a hydrogen value of at least 4 €/kg is necessary. [29]

Singlitico et al. investigated how the lowest cost of green hydrogen can be achieved by combining three electrolyzer placements with three technologies and using two modes of operation. This results in a minimum LCOH of 2.4 €/kg with an offshore electrolyzer. The three technologies AEC, PEMEC and SOEC only show an insignificant difference. [16]

Dinh et al. are using a hypothetical wind farm of 101.3 MW which has a distance to shore of 12 km in the east coast of Ireland. It utilizes PEMEC and underground hydrogen storage. The system is found to be profitable in 2030 at a LCOH of 5 €/kg with storage durations between 2 to 45 days. The viability model calculates wind power output, electrolysis plant size and hydrogen production by using the time varying wind speed. [25]

Yan et al. analyze an OWF at a similar distance to shore of 10 km based on historical wind speed and system cost for five scenarios. Using pipelines for the transportation of hydrogen shows the best results with 3.4 $/kg. The viability of the project is greatly affected by the distance to shore which can increase with a higher output power or wind speed. Transporting the hydrogen via ship tanker can also be more economical for greater distances. [21]

4. Methodology

In this chapter, the model assumptions for scenarios to be investigated for hydrogen production from offshore wind are presented. The aim of the model is to determine the LCOH of both scenarios, which are calculated on the basis of the CAPEX and OPEX of individual system components. Taking into account the energy demand and energy losses of the system, the influence of individual system components can thus be analyzed.

4.1 Common assumptions for both scenarios

Both scenarios involve green hydrogen production projects with a project duration of 15 years. The difference between the two scenarios is the location of the water electrolysis. The systems include the construction of the same OWF as well as the necessary components for the production and transport of the hydrogen until it is fed into the transport network on land. In one scenario, hydrogen production takes place onshore by connecting the OWF to the conversion unit via HVDC transmission. In the other scenario, hydrogen production takes place on an offshore platform close to the OWF. From this platform, the hydrogen is transported onshore via a hydrogen pipeline. Hence, the electrolyzer and the desalination unit of the scenarios do not differ technologically but are installed differently in terms of location. The specifications of both scenarios are presented in chapter 4.2 and 4.3. The electricity demand for all system components is provided by the OWF.

The location considered for the siting of the OWF is the N-9 cluster in the German Exclusive Economic Zone of the North Sea. It is regarded in the area development plan a possible area for offshore wind energy with commission expected in the year 2029 [39]. Bathymetric data from the European Marine Observation and Data Network (EMODnet) are used to determine the water depth [40]. The data show a depth profile of up to 40 m. Therefore, jackets are assumed for the foundations of the wind turbines. The connection point to the shore is assumed to be located around the municipalities Dornum and Hagermarsch in Lower Saxony, since interconnection points in this region already exist for both gas and the electricity grid [41], [42]. Salt caverns for storing gas also exist in the selected land connection [42]. A cost calculation of hydrogen storage is not considered in the model. It is however assumed, that a salt cavern will be used as a dedicated hydrogen storage in both scenarios.

Figure 1 shows the location of the OWF as well as a simplified route of the transmission line to shore. For both reference scenarios, it is assumed that the transport infrastructure is newly built. Transmission cost reductions due to the usage of retrofitted existing gas infrastructure will be discussed in chapter 2.1.4. Hence, the existing natural gas pipelines around the location are also displayed. It should be noted that the planned HVDC transmission for the N-9 cluster, BalWin1 and BalWin3, lies approximately 60 km to the east of the reference point near the port of Wilhelmshaven [41]. However, the common reference point of Hagermarsch is chosen for better comparison of the scenarios.

Regarding the OWF, a total capacity of 120 MW consisting of 10 MW turbines arranged in a 4x3 grid is considered. The investment costs are calculated on the basis of a weighted average per MW, which includes costs for the development and installation of the turbines, their foundation as well as inter-array electrical interconnection, as specified in Table 1**Fehler! Verweisquelle konnte nicht gefunden werden.** [43, p. 97]. Losses due to the inter-array cabling of the wind turbines are assumed to be 0.55% of the transmitted electricity [16]. Influences due to the wind farm constellation e.g., wake effects are not considered in the model. A 10 MW offshore wind turbine with a rotor diameter of 193 m is used as a reference model. The power curve is obtained from publicly available manufacturer data [44]. To estimate the power yield of the wind farm for different wind speeds, a Weibull distribution is assumed. For the location under consideration, the scaling parameter of the Weibull function is set to 10.8 and the shape parameter to 2.2 [45].

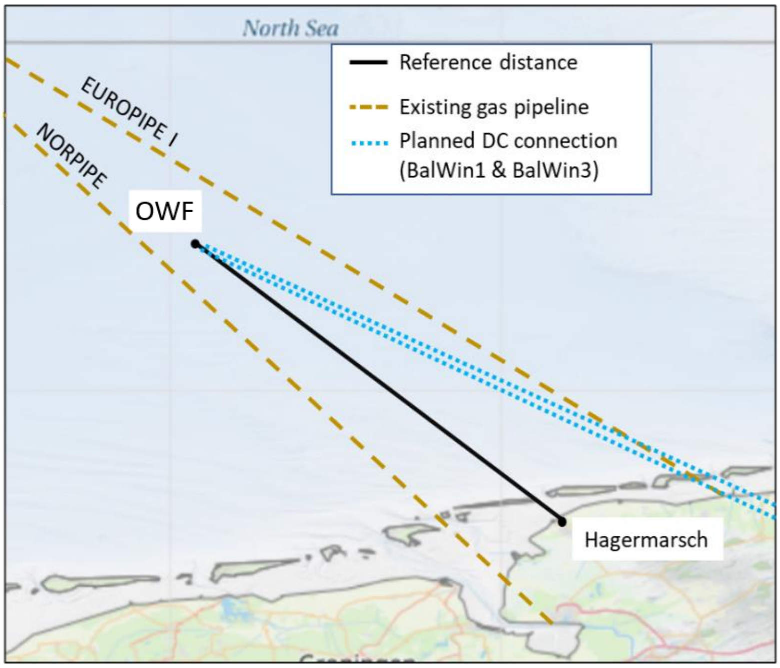

Figure 1: Sketch of wind farm location and connection to shore [40]

Regarding electrolysis technology, PEMEC has been chosen in this paper due to several advantages. For one, there are no moving parts and the electrolyte is not corrosive in the PEMEC allowing for a less complex and simple system design that is suitable for the offshore scenario. Operating at high current densities, while maintaining similar efficiency rates as AEC, enables a more compact and lighter system and in return requires a smaller offshore platform. Being able to operate under relatively higher pressure has a positive effect on the scaling of the required compressor unit [9, p. 55]. Significantly lower temperatures compared to SOEC lead to less degradation of the stacks and materials and less frequent maintenance and replacement of system components [16]. More importantly, short start-up times, fast response and dynamic operation allow PEMEC to work efficiently with intermittent renewable energy sources such as wind offshore [10]. Furthermore, significant drop in stack costs is expected in the near future which leads to PEMEC becoming the dominant technology for sustainable production of green hydrogen [46, p. 19]. The PEMEC for both reference scenarios will have the size of 100 MW.

The water required for the electrolyzer is provided by a seawater desalination unit. Although it is possible to obtain mains water in scenario A, seawater desalination is also assumed for comparative purposes. Desalination by reverse osmosis is selected as the desalination technology, because it is technically mature and, unlike other technologies discussed in 2.1.2 only requires electrical energy as input. The electrical energy consumption for desalination is considered to be 3 kWh/m^3 [47]. Assuming the PEMEC requires 10 kg of water to produce 1 kg of hydrogen [48] and is running at maximum capacity, the desalination unit would require a daily maximum of approximately 470 m^3 water with an input power of 59 kW. For the technology considered and the estimated daily capacity, the investment costs of the desalination are about €6.6 million [47]. An overview of the costs and energy considerations for the system components can be found in Table 4. To ensure the operation of an offshore production of hydrogen by wind turbines, the costs of different components of an OWF have to be considered. An overview of the costs of an OWF can be found in Table 1. However, these costs are incurred for both, offshore and onshore electrolysis.

Building a platform requires enough space and weight support for at least the electrolyzer system, seawater desalination unit, compressor and conversion and transformation units. There should also be a helicopter landing zone and accommodation. Van Shot and Jempa are studying the re-purposing of existing oil and gas platforms and concluded that 28,350 m^3 on four levels should be enough to host an electrolysis system of a 160 MW and the rest of the equipment mentioned above [19]. Since both reference scenarios need about 100 MW or less, a platform with three levels of about 21,000 m^3 is assumed. This estimated number of about 21,000 m^3 is also coherent with another study by TenneT et al. which estimates a volume of 19,355 m^3 for an OWF of 100 MW based on supplier information and engineering experience. Adding up all the costs of steelwork, pile mass and other components for the platform for a water depth of 30 m are about €14 million. [49] Estimations from Spyroudi et al. for a new 100MW platform in 2030 are 167.5 £/ kW which is €20 million [11]. Based on those studies our estimation for the costs of a new platform is € 17 million.

4.2 Assumptions for Scenario A: Onshore electrolysis

Scenario A considers the onshore production of hydrogen powered by the OWF. A schematic representation is shown in Figure 2. First, the generated electricity from the turbines is gathered on a platform, that houses the converter to transmission to shore. As argued in 2.1.4, an HVDC transmission system is chosen due to the transport distance of 140 km. The offshore substation thus comprises an AC-DC collection system, as well as a step-up DC-DC converter for transmission via a bipolar subsea HVDC cable [50]. The substation located onshore is assumed to consist of a step-down DC-DC converter, from which the electrolyzer can be operated. Additionally, an DC-AC converter is assumed in order to inject excess electricity to the grid. The total losses of the transmission system amount to 2.47% [16]. The electrolyzer and desalination unit are selected as mentioned above. Finally, a compressor is assumed for injecting the hydrogen into the grid, which represent the system boundary. The energy demand for the compressor is displayed in Table 4.

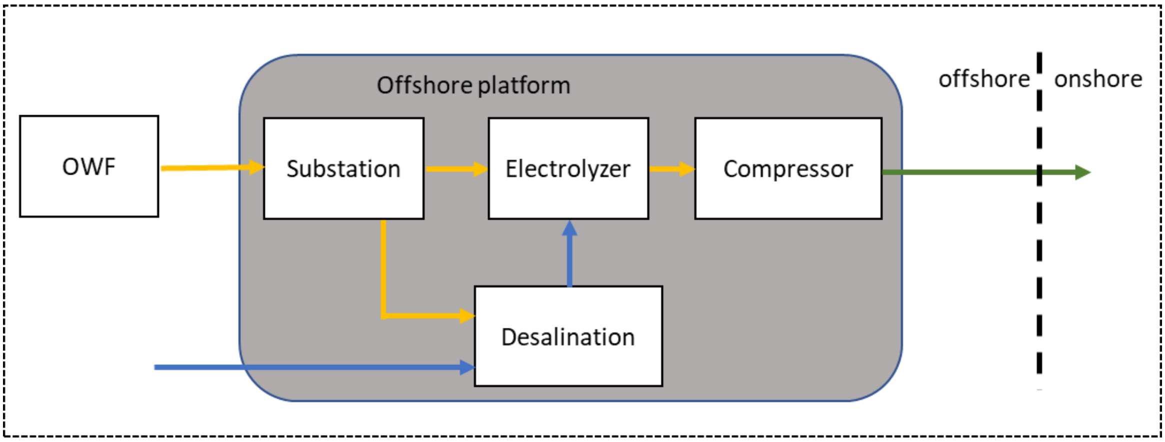

Figure 2: Schematic representation of scenario A

4.3 Assumptions for Scenario B: Offshore electrolysis

In the offshore scenario, the production of hydrogen is carried out at sea. Due to this, the entire technical infrastructure must be installed and operated offshore. This includes the desalination of the seawater, the electrolysis itself, the compression of hydrogen to transport level as well as the conversion and transformation of the incoming electricity from the OWF. For running the technological components, an offshore platform needs to be installed in the first place. Figure 3 shows a schematic representation of the scenario. During the transportation of hydrogen through the pipelines, pressure losses may occur. The resulting energy losses are taken into account by assuming a pipeline efficiency of 97%. A second compressor station is not considered inside the system, since the regarded distance is sufficiently short to be operated by only one compressor [23, p. 8].

As mentioned in chapter 2.1.3, two different design concepts exist for producing hydrogen offshore. Literature published in the context of green hydrogen generation suggests that a decentralized hydrogen production is generally associated with a higher LCOH [16, p. 8]. This is due to the higher number of electrolyzers required with comparatively low output, since the specific costs decrease with higher output. In addition, using decentralized electrolyzers requires more infrastructure, such as pipelines and storage units [16, p. 10]. For this reason, far more pilot projects and theoretical models deal with decentralized offshore production of hydrogen. Hence, this study will examine centralized electrolysis for the offshore scenario.

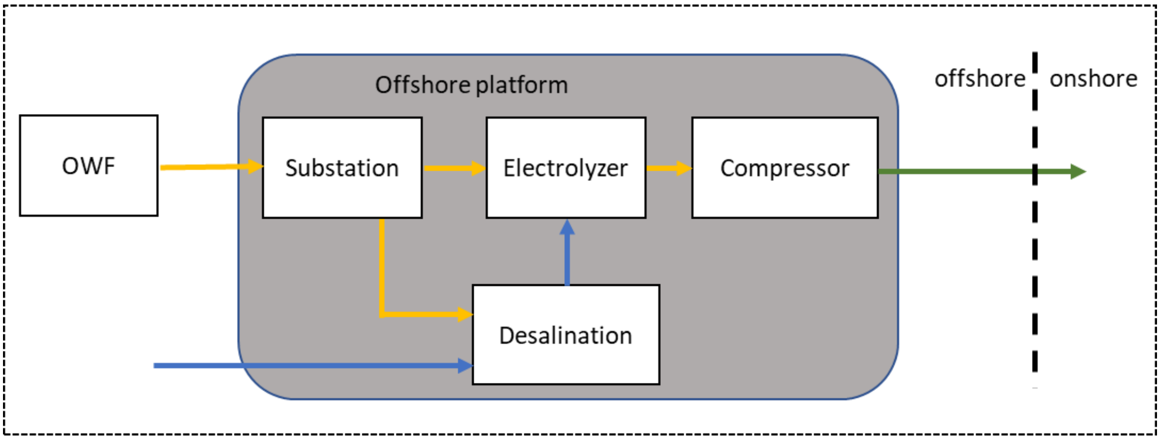

Figure 3: Schematic representation of scenario B

The transportation of hydrogen to shore can take place by using pipelines or ship tankers. Concerning ship tankers, the hydrogen needs to be liquified to make the transport feasible [51]. Whilst being under development, hydrogen transporting ships are expected to be a considerable option for distances from 3,000 km to 16,000 km [13], [52]. Other transport options of converting hydrogen into another energy carrier are also excluded for this scenario because of their expensive conversion process. For example, liquid hydrogen carriers are only feasible for distances greater than 16,000 km [52]. Consequently, this scenario will deal with hydrogen transportation by using pipelines to shore. The main components and costs required for a central offshore electrolysis platform and the other components for producing and transporting hydrogen are listed in Table 3.

5. Results and discussion

First, an overview of the results of the reference scenario is given. In general, it can be noted that the OWF of the reference scenario operates at a capacity factor of 58.8%. This value is very high compared to today's standards, but is expected to be achieved by very good OWF in the future [56, p.10]. The CAPEX and OPEX for both scenarios are shown Figure 4 in and Figure 5, respectively. Both CAPEX and OPEX of the wind farm take the largest share of costs compared to the other components. Comparing both scenarios, the respective CAPEX for the electrolyzer, desalination unit and compressor are the same, since these components are identical in design. In contrast, the respective OPEX are higher in scenario B, since it takes more effort to operate and maintain offshore components due to the distance as well as the working conditions at sea.

There are differences in CAPEX for platform, substation and transmission. The installation of the offshore platform requires higher costs than onshore since it has to provide enough space for desalination, compressor and electrolyzer units. In contrast, the CAPEX of the substation system is higher in scenario A since it is far more complex (Figure 2). However, the most significant difference between both scenarios is the CAPEX for transmission. In scenario A, the CAPEX is higher by a considerable amount. Admittedly, specific costs for HVDC transmission are lower than the specific pipeline costs, but there are two cables required to power transmission to onshore. As one consequence, the transmission costs of scenario A are about 50% higher than in scenario B. The higher costs for substation and transmission are also evident in the OPEX. However, the cumulative cost difference is not as large as for the electrolyzer and the platform in scenario B. Consequently, scenario B has the higher OPEX.

The LCOH of scenario B amount to 4.98 €/kg (14.94 ct/kWh) and are lower than the LCOH of scenario A, which total 4.41 €/kg (13.24 ct/kWh). This is due to the considerably lower CAPEX and only slightly higher OPEX of B. Yearly hydrogen production in scenario B adds up to 15,540 t, slightly exceeding the onshore production with a yearly output of 15,340 t and thus lowering the LCOH. The difference in produced hydrogen is due to the electricity losses during transmission in scenario A. In summary, the production of hydrogen in the given scenario proves to be advantageous compared to onshore production. Concrete values of the reference scenario can be found in Table 4.

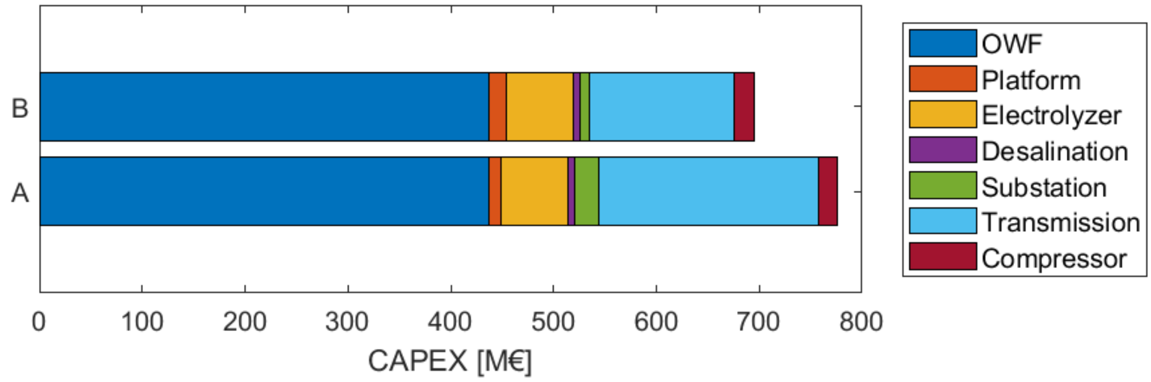

Figure 4: CAPEX of reference scenarios

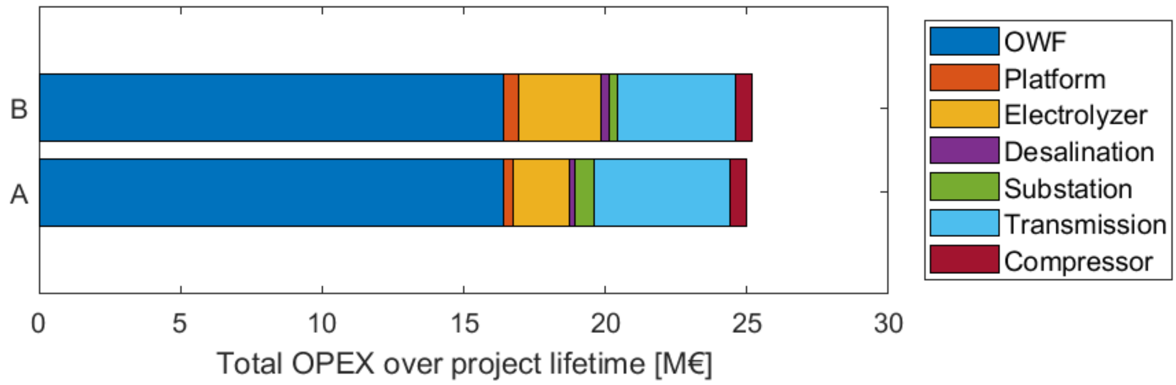

Figure 5: OPEX of reference scenarios

5.1 Analysis on varying shore distance

A key aspect in the feasibility of the scenarios is related to the distance needed to transport the energy to shore, since it has a considerable effect on the resulting LCOH for both scenarios, as is shown in Figure 6. For relatively short distances up to around 80 km, scenario A is the one to go for from an economic perspective. For distances that exceed 80 km, scenario B becomes the better option in terms of economic feasibility. At the reference distance of 140 km, the figure clearly shows a lower LCOH value for the offshore Scenario B. The distance to shore of currently operational OWFs in the North Sea region mostly varies between 40-120 km and thus the offshore scenario B that has lower LCOH values starting from a distance of 80 km can be implemented by today's typical distances to shore in the North Sea region [41].

For short distances the higher platform CAPEX and total OPEX of the electrolyzer in scenario B are the main drivers for the gap between the two scenarios, as they are relatively independent of the distance to shore. The more the distance increases the more the gap decreases until the intersection at about 80 km and then the gap increases again with the LCOH value of the onshore scenario increasing significantly higher than the offshore scenario. The transmission costs become the main driver for the increase of the LCOH value as they increase proportionally with the distance to shore. The CAPEX of the HVDC transmission system used in the onshore scenario A are higher than the distance CAPEX of the pipeline system used in the offshore scenario B. That difference leads to a higher increase of the transmission costs for scenario A and eventually to higher LCOH values at further distances.

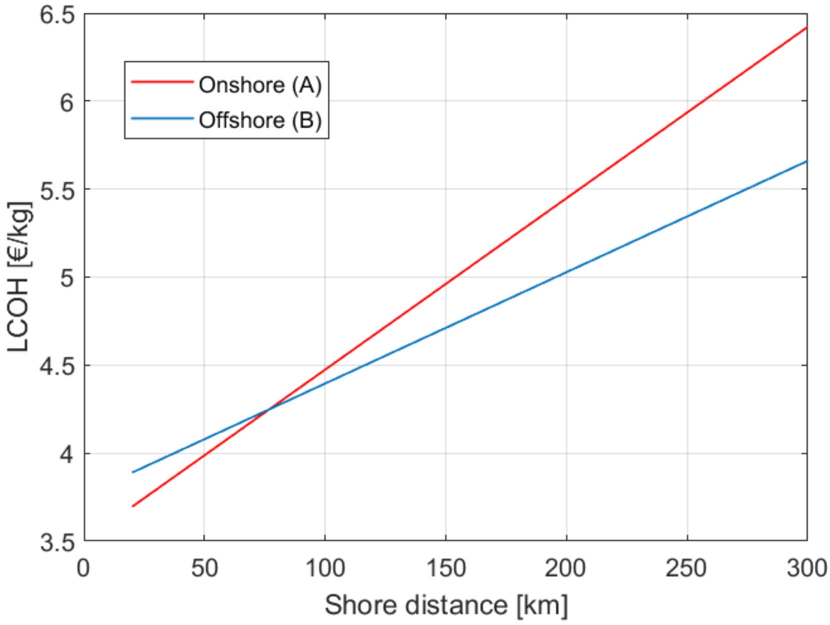

Figure 6: LCOH for varying distances to shore

5.2 Analysis on varying transmission costs

The transmission analysis shows the impact of uncertain input data regarding the CAPEX of the pipeline. The costs are an important factor for the LCOH as shown in Figure 7. Since the cost for HVDC cables are relatively stable and only vary with the distance, the distance is now kept at 140 km to look at different transmission costs for the pipeline [54]. Figure 7 shows that for costs above 1.4 M€/km, pipelines are more expensive compared to cables.

The pipeline costs depend on different factors like material, hydrogen demand, pressure, and diameter. Especially the hydrogen demand is hard to predict but has a big influence on the diameter and pressure. Higher pressure and demand mean larger and thicker pipes which are considerably more expensive [11], [19], [55]. Also, obstacles like other pipes, cables or platforms pose a challenge and result in higher costs because of crossings that need to be constructed [19].

Investments costs are therefore varying across different studies. Because there is only a small number of actual projects it is also not possible to develop a reference value with a standard statistical analysis [23]. Studies further suggest a lower CAPEX in the future [11]. By visualizing the uncertainty Figure 7 therefore emphasizes the big influence varying pipeline costs can have on the LCOH.

However, there is the potential of using existing natural gas pipelines for the transportation of hydrogen to shore, as mentioned in chapter 2.1.4, which could be the most feasible solution and lower the pipeline costs even more. As specified in Figure 1, there are two existing gas pipelines available. The conversion is possible if the pipeline meets the material and dimensional requirements. Gas infrastructure in the North Sea has been estimated to be roughly 30% suitable for hydrogen. As a consequence, it is likely that upgrading will be necessary. [56]

Even though challenges like the embrittlement of steel occur, technologies for re-purposing the existing infrastructure are tested and available. The right solution depends on the case and requires an engineering analysis [19], [57]. Studies suggest the costs of re-purposing can be significantly lower and are ranging in between 10% to 35% of a new dedicated hydrogen pipeline [23], [58]. Other studies remain within this range [23], [51], [55], [58]. Consequently, re-purposing the existing gas infrastructure could reduce the LCOH to even lower numbers than shown in Figure 7 but also the expectation of lower CAPEX in the future makes hydrogen transmission via pipeline more feasible for our scenario.

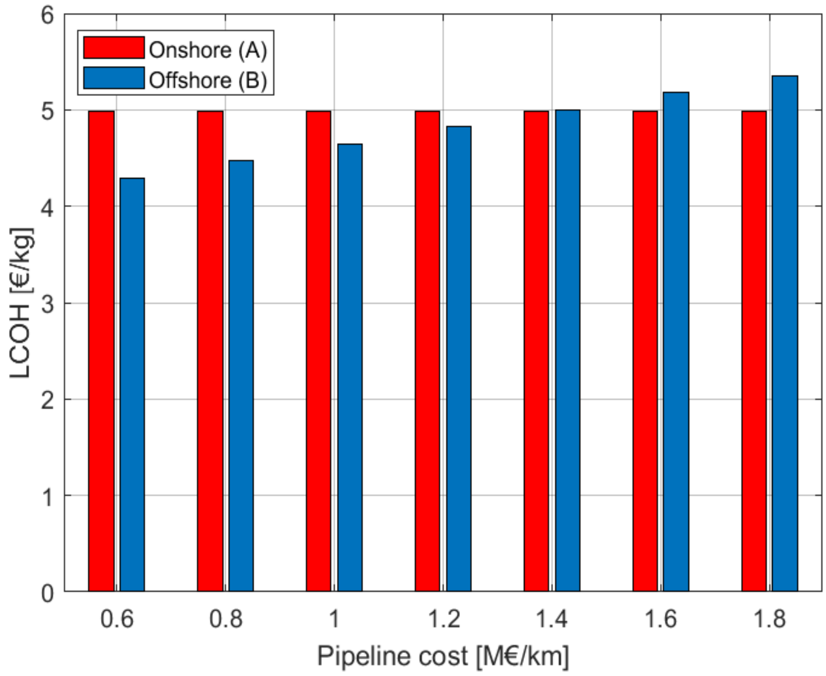

Figure 7: LCOH for varying pipeline costs

5.3 Considerations for the use of excess electricity

The net power input for the electrolyzer results from the OWF power generation, reduced by the scenario-specific losses and energy demands. Furthermore, the output capacity of the OWF depends on the occurring wind speeds, which are determined by the Weibull distribution. The electrolyzer thus operates at partial load for lower wind speeds, whereas an electricity surplus exists for greater wind speeds. In scenario A, excess electricity can be transported to shore and made profitable by being fed into the grid, thus lowering the LCOH. On the contrary, for scenario B, the surplus would lead to energy curtailment, since a cable connection to shore does not exist, leading to a capacity reduction of the OWF. This loss of energy poses one disadvantage in the offshore production of hydrogen.

One solution to overcome curtailment in scenario B is to consider a battery storage system. Accommodated on the offshore platform, it could be used to store electricity during high wind speeds and act as an additional power source during partial-load operation. In the following, some considerations for the sizing of such a battery storage system are presented. The model calculations show an excess power of 8.9 MW for wind speeds higher than 13 m/s. Together with the respective wind frequencies given by the Weibull distribution, the yearly amount of excess electricity amounts to 24.7 GWh, which equals a hydrogen production of 485 t. Taking into account both the power as well as the energy capacity, an adequate sizing of the battery could be undertaken. The limited space on the platform, as well as the additional investment costs, are the determinant factors for this solution.

6. Conclusion

In this work, the economic feasibility of future hydrogen production from offshore wind energy for a specific location the North Sea was analyzed. Two reference scenarios were developed, that compared the large-scale electrolysis with a capacity of 100 MW at sea and on land. For this purpose, a suitable technology selection and a cost evaluation for the investment costs (CAPEX) and operating expenses (OPEX) of all system components were carried out. Together with assumptions about the energy demand for the production of hydrogen, a model was developed, which calculated LCOH within the range of literature found on present and future offshore hydrogen production projects.

The option of producing hydrogen offshore and transporting it by pipeline proved to be of economic advantage, with LCOH of 4.41 €/kg compared to 4.98 €/kg for the scenario, in which the hydrogen production was operated onshore. The calculations showed, that with the increasing distance at which wind farms will be built in the future, carrying out the conversion of electricity to hydrogen offshore can represent an attractive solution. The transmission infrastructure and its costs proved to be of central importance in the feasibility of such projects, which is why these have been examined in more detail.

Because the exact cost of hydrogen infrastructures in the future is still uncertain and varies in the literature, the cost assumptions should be critically reviewed and adapted in the course of continuous development of such projects. Other aspects that could be considered in future studies based on the model are an investigation of the storage option for hydrogen, a detailed analysis on overcoming energy curtailment by considering battery storage, as well as potential cost reductions by re-purposing existing offshore platforms in the area. Since the model considers each system component individually, variations in the cost structure can be easily implemented for reassessment.

7. Literature

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Appendix

The following table provides an overview for the cost considerations of an OWF.

CAPEX	OPEX
Development and consenting • Project Management • Research on legal framework • Engineering • Environmental surveys • Contingency	**Operation and maintenance costs** • Repairs • Rents • Insurance • Project management • Supply of workers & assets
Production and acquisition • Turbine acquisition • Foundation acquisition • Electric system • Control system	
Installation and commissioning • Foundation and transition piece • Tower and turbine • Scour protection • Electric system • Personnel cost • Insurance cost during construction	
Decommissioning and disposal • Removal • Site clearance • Transportation of parts • Port preparation • Disposal of parts • Hiring vessels	

Table 1 - Comparision of CAPEX and OPEX in context of an OWF
Source: own illustration based on [25, p. 24623], [59, p. 283]

The following two tables list the cost considerations for the scenario specific components.

Component	Cost type		Notation
	CAPEX (€)	OPEX	
Platform	12.000.000	0.2% * CAPEX	Based on offshore platform; cheaper due to smaller size
Substation	193.24 per kW [50]	0.2% * CAPEX [16, p. 13]	
HVDC transmission	1,520,568 per km [54]	0.2% * CAPEX [16, p. 13]	Price for bipolar HVDC transmission cable
Electrolyzer system	650 per kW [60, Sec. 86 PEMEC 100MW]	0.2% * CAPEX [16, p. 13]	
Desalination unit	1408 per m³/d [47]	0.2% * CAPEX [16, p. 13]	
Compression unit	2802 per kW [61, p. 29]	0.2% * CAPEX [16, p. 13]	

Table 2 – Cost components of scenario A

Component	Cost type		Notation
	CAPEX (€)	OPEX	
Offshore Platform	17.000.000 [*1]	1,9% * CAPEX [*2]	Based on assumptions made in chapter 4.1
Substation	40% of substation in A	0,2% * CAPEX	Assumed to be less than half of A, because only AC-DC conversion is needed
Electrolyzer (PEMEC) $[\frac{€}{MW}]$	650.000 [60, Sec. 86 PEMEC 100MW]	0.3% * CAPEX [16, p. 13]	Argued to be slightly larger than onshore due to working conditions
Desalination unit	1408 per m³/d [47]	0.3% * CAPEX [16, p. 13]	Argued to be slightly larger than offshore due to working conditions

Compression unit	2,802 per kW [61, p. 29]	0.2% * CAPEX [16, p. 13]	
Hydrogen pipeline	1,000,000€ per km [11, p. 68]	2% * CAPEX [16, p. 13]	Transmission in North Sea

Table 3 – Cost components of scenario B

The following table lists all variables declared in the MATLAB model. The model code is provided in a separate file.

Variable	**Meaning**	**Reference scenario value**	**Unit**	**Notation**
a	parameter for cubic power curve	-	$\frac{\mathrm{MW}}{(\frac{\mathrm{m}}{s})}$	MW per $(\frac{\mathrm{m}}{\mathrm{s}})$
A	Weibull parameter for average wind speed	10.80	m per s	
avg_cost_OWF	average specific installation costs for offshore wind farm	3,645,840	€ per MW	
cap_fac	capacity factor of produced energy by wind turbines over 1 year	0.5883	-	
cap_fac_elec_A	capacity factor of onshore electrolyzer	0.5843	-	
cap_fac_elec_B	capacity factor of offshore electrolyzer	0.5915	-	
CapEx_A	total CAPEX onshore project	776,281,177	€	
CapEx_A_shore	array of onshore project CAPEX due to shore distance	*01x15 double*	€	
CapEx_A_vec	array of partial onshore project CAPEX	*01x07 double*	€	
CapEx_B	total CAPEX offshore project	713,560,307	€	
CapEx_B_pipe	array of offshore project CAPEX due to specific pipeline costs	*01x07 double*	€	
CapEx_B_shore	array of offshore project CAPEX due to shore distance	*01x15 double*	€	

CapEx_B_vec	array of partial offshore project CAPEX	*01x07 double*	€	
capf_analysis	various capacity factors of energy produced by the wind farm for analytic purposes	-	-	
comp_el	electricity consumption for compressor unit per kg hydrogen	12.47	MJ per kg	
cost_hvdc	specific costs of DC submarine cable	1,520,568	€ per km	
cost_pipe	specific costs gas pipeline	1,000,000	€ per km	
cost_pipe_analysis	array of various specific pipeline costs	*01x07 double*	€ per km	
costpMW_elec	specific costs of electrolyzer	650,000	€ per MW	
Cp_comp_A	CAPEX compressor onshore	19,071,929	€	
Cp_comp_B	CAPEX compressor offshore	19,071,929	€	
Cp_desal	CAPEX desalination unit	6,640,128	€	
Cp_elec	CAPEX electrolyzer	65,000,000	€	
Cp_hvdc	CAPEX DC submarine cable		€	
Cp_hvdc_shore	array of DC cable CAPEX due to shore distance	*01x15 double*	€	
Cp_OWF	CAPEX offshore wind farm	437,500,800	€	
Cp_pipe	CAPEX gas pipeline	140,000,000	€	
Cp_pipe_analysis	array of pipeline CAPEX due to various specific costs	*01x07 double*	€	modification of costs
Cp_pipe_shore	array of pipeline CAPEX due to various shore distances	*01x15 double*	€	modification of distance
Cp_plat_A	CAPEX onshore platform	12,000,000	€	
Cp_plat_B	CAPEX offshore platform	17,000,000	€	

Cp_sub_A	CAPEX substation onshore	23,188,800	€	
Cp_sub_B	CAPEX substation offshore	9,275,520	€	
d_shore	distance from offshore wind farm to shore	140	km	
d_shore_analysis	array for distance analysis	*01x15 double*	-	
d_tw	rotor diameter of wind turbines	193	m	
df	discount factor	0.05	-	
dsal_el	daily electricity consumption of desalination unit	3	kWh per m^3d	
E_comp_A	electricity demand compressor onshore scenario	588,085	MJ	
E_comp_B	electricity demand compressor offshore scenario	588,085	MJ	
E_curl_A	curtailed energy over 1 year onshore	*25x01 double*	MWh	
E_curl_A_year	cumulated curtailed energy over 1 year onshore	16,339	MWh	
E_curl_B	array of curtailed energy over 1 year offshore	*25x01 double*	MWh	
E_curl_B_year	cumulated curtailed energy over 1 year offshore	24,714	MWh	
E_dsal	specific electricity demand for the desalination unit	1,415	kWh per m^3	
E_elec_A	array of useful energy of onshore electrolyzer over 1 year	*25x01 double*	MWh	
E_elec_A_year	cumulated useful energy of onshore electrolyzer over 1 year	511,813	MWh	
E_elec_B	array useful energy of offshore electrolyzer over 1 year	*25x01*	MWh	
E_elec_B_year	cumulated useful energy of offshore electrolyzer over 1 year	518,139	MWh	

E_elprod	array of produced energy by wind turbines over 1 year	*25x01 double*	MWh	
E_elprod_year	cumulated produced energy of wind turbines over 1 year	618,442	MWh	
E_elprod_year_calc	cumulated produced energy of wind turbines over 1 year using various capacity factors	-	MWh	
E_h2_dmax	daily maximum of hydrogen production	1572	MWh	
E_pot_A	array of missed onshore energy potential due to less wind	*25x01*	MWh	
E_pot_A_year	cumulated missed onshore energy potential due to less wind	363,184	MWh	
E_pot_B	array of missed offshore energy potential due to less wind	*25x01*	MWh	
E_pot_B_year	cumulated missed offshore energy potential due to less wind	356,858	MWh	
eta_array	efficiency of inter array cabling collecting AC from the turbines	0.9945	-	
eta_elec	conversion ratio of electricity into hydrogen	0.6550	-	
eta_hvdc	electricity losses in the substations and HVDC transmission to shore	0.9753	-	
eta_inv	inverter efficiency	0.9700	-	
eta_pipeline	pipeline efficiency	0.9700	-	
h	array of frequency according to Weibull	*25x01 double*	-	partial appearance of various wind speeds
hours_elec_A	hours of working by onshore	76,772	h	

	electrolyzer over project duration			
hours_elec_B	hours of working by offshore electrolyzer over project duration	77,721	h	
h2_endens	gravimetric energy density of hydrogen	120	MJ per kg	
h2_rho	density of hydrogen	0.0899	g per l	
k	Weibull curve parameter	2.3000	-	
LCOH_A_kg	specific LCOH onshore project	4.9793	€ per kg	
LCOH_A_kg_shore	array of specific LCOH of onshore hydrogen due to shore distance	*01x15 double*	€ per kg	
LCOH_A_kWh	specific LCOH onshore project	0.1494	€ per kWh	
LCOH_A_kWh_shore	array of specific LCOH of onshore hydrogen due to shore distance	*01x15 double*	€ per kWh	
LCOH_B_kg	specific LCOH onshore project	4.4125	€ per kg	
LCOH_B_kg_pipe	array of specific LCOH of offshore hydrogen due to specific pipeline costs	*01x07 double*	€ per kg	
LCOH_B_kg_shore	array of specific LCOH of offshore hydrogen due to shore distance	*01x15 double*	€ per kg	
LCOH_B_kWh	specific LCOH offshore project	0.1324	€ per kWh	
LCOH_B_kWh_shore	array of specific LCOH of offshore hydrogen due to shore distance	*01x15 double*	€ per kWh	
LCOH_pipe_vector	array of specific LCOH values concerning various pipeline costs	*02x07 double*	€ per kg	
m_h2_dmax	daily maximum of hydrogen production	47,160	kg	
m_h2_year_A	mass of hydrogen produced, onshore	15,354,397	kg	
m_h2_year_B	mass of hydrogen produced, offshore	15,544,183	kg	

m_h2_ymax	yearly maximum of hydrogen production	17,213,400	kg	
N_wt	number of wind turbines	12	-	
Op_comp_A	OPEX compressor onshore	38,144	€	
Op_comp_B	OPEX compressor offshore	3.8144	€	
Op_desal_A	OPEX desalination unit onshore	13,280	€	
Op_desal_B	OPEX desalination unit offshore	19,920	€	
Op_elec_A	OPEX electrolyzer onshore	130,000	€	
Op_elec_B	OPEX electrolyzer offshore	195,000	€	
Op_hvdc	OPEX DC cable	319,319	€	
Op_hvdc_shore	array of DC cable OPEX due to shore distance	*01x15 double*	€	
Op_OWF	OPEX offshore wind farm	1,093,752	€	
Op_pipe	OPEX gas pipeline	280,000	€	
Op_pipe_analysis	array of gas pipeline OPEX due to various specific costs per km	*01x07 double*	€	modification of costs
Op_pipe_shore	array of gas pipeline OPEX due to shore distance	*01x15 double*	€	modification of distance
Op_plat_A	OPEX platform onshore	24,000	€	
Op_plat_B	OPEX platform offshore	34,000	€	
Op_sub_A	OPEX substation onshore	46,378	€	
Op_sub_B	OPEX substation offshore	18,551	€	
OpEx_A	total OPEX onshore project	1,664,873	€	
OpEx_A_shore	array of onshore project OPEX due to shore distance	*01x15 double*	€	
OpEx_A_vec	array of gathered onshore opexes	*01x07 double*	€	
OpEx_B	total OPEX offshore project	1,679,367	€	
OpEx_B_pipe	array of offshore project OPEX due to specific pipeline costs	*01x07 double*	€	

OpEx_B_shore	array of offshore project OPEX due to shore distance	*01x15 double*	€	
OpEx_B_vec	array of gathered offshore opexes	*01x07 double*	€	
P_comp_A	power capacity for the compressor	6.8065	MW	
P_comp_B	power capacity for the compressor	6.8065	MW	
P_curl_A	power curtailment onshore electrolyzer (partial power not used)	*25x01 double*	MW	
P_curl_B	power curtailment offshore electrolyzer (partial power not used)	*25x01 double*	MW	
P_dsal	power capacity of desalination unit	0.0590	MW	
P_elec_A	used power of onshore electrolyzer	*25x01 double*	MW	
P_elec_B	used power of offshore electrolyzer	*25x01 double*	MW	
P_gross	gross power of windpark	*25x01 double*	MW	
P_net_A	net power used for onshore electrolyzer	*25x01 double*	MW	
P_net_B	net power used for offshore electrolyzer	*25x01 double*	MW	
P_nom_elec	rated power of the electrolyzer	100	MW	
P_OWF	offshore wind fark capacity	120	MW	
P_OWF_avg	average wind farm power over 1 year	70.5985	MW	
P_pot_A	missed onshore power potential due to less wind	*25x01 double*	MW	
P_pot_B	missed offshore power potential due to less wind	*25x01 double*	MW	
P_wt	rated power of one wind turbine	10	MW	
pvf	pension present value factor	10.3797	-	ger. *“Renten-barwertfaktor”*
T	project duration	15	a	
totalh	hours of one year	8760	h	no leap year assumed

v	array for velocities of Weibull distribution	*25x01 double*	-	
v_in	min. cut in speed	3.5000	m per s	
v_out	max. cut in speed	25	m per s	
v_r	rated speed	14	m per s	
vol_h2o_dmax	daily water volume demand	472	m^3	assuming 10 kg water for 1 kg hydrogen & water density of 1000 $\frac{\mathrm{kg}}{m^3}$

Table 4 - Model variables