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Master's Thesis – Master Energy Science

Hydrogen production on offshore platforms

A techno-economic analysis

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Preface

This thesis research was conducted as part of the master's programme Energy Science at the University of Utrecht. The thesis was written in combination with an internship at the Dutch Marine Energy Centre (DMEC). DMEC is one of the leading organizations in the marine energy sector in Europe. As a service provider in the marine energy sector, it accelerates technology, innovation and commercialization of marine energy solutions. Aim of this research is to provide an overview of the current status of the oil and gas industry and its platforms in the Dutch sector of the North Sea (the Dutch continental shelf) and to assess whether hydrogen production on these platforms can be technological and economical viable in the future.

Abstract

It is essential for the world to reassess its energy production technologies, because of the ever-growing energy demand and the developing climate awareness. One of the energy production technologies that is reaching the end of its lifetime is the oil and gas production on the Dutch Continental Shelf (DCS). As of 2019, around 150 installations are operative in this DCS. In the coming ten years, 100 of the 150 installations will be decommissioned. Approximately 10% of these 150 platforms can be re-used for future activities such as carbon capture and storage and hydrogen production. Hydrogen can play an important role in the energy transition. Green hydrogen, produced using renewable energy sources, is seen as a promising technology that might enable an energy system using renewable energy on a large scale. Advantages of green hydrogen are its ability of decoupling supply and demand for energy due to its storage capacity and its ability to be transported and stored in large quantities.

This research presents a techno-economic analysis of the costs of producing hydrogen on decommissioned offshore platforms using offshore renewable energy sources. Aim of this analysis is to compare these production costs with projected costs of producing green hydrogen using other renewable and conventional energy sources. The analysis resulted in a levelized cost of hydrogen ranging from 4.90 €/kg in the most positive scenario, where electrolyzer costs are low and hydrogen is transported to shore using existing pipelines, to 10.81 €/kg in the high cost scenarios. This is significantly higher than expected production costs of 3 €/kg of green hydrogen in 2030 as presented in existing literature. Based on the outcomes of the analysis, and using the assumptions made in this research, a competitive price cannot be reached. Future research must show whether a combination of a decreasing electricity price and an increase in capacity factor can improve the economic feasibility of offshore hydrogen production. Due to the decommissioning of offshore infrastructure and the increasing urge to find energy storage options for the growing share of intermittent renewable energy in the energy mix, offshore hydrogen production is seen as a concept with potential. This research shows however, that significant cost reduction is necessary to make offshore hydrogen production on existing platforms economically viable.

1. Introduction

With increasing energy demand and even more increasing climate awareness, it is essential for the world to reassess its energy production technologies. Today's energy markets are defined by growing uncertainties, caused by unstable oil markets, geopolitical tensions and climate targets (IEA, 2019). While the connection between energy use and global warming has been known for decades, the problems of energy use and production have finally arrived at the centre of public attention (Quaschning, 2019). The transition from the current fossil fuel based system towards a system based on renewable energy sources can be seen as one of the biggest challenges of this generation (van der Weer et al., 2018). In order to gain insight in the different possible futures, the International Energy Agency (IEA) presented three different scenarios in their World Energy Outlook (IEA, 2019). The *current policy scenario* presents a pathway that shows how global energy markets will evolve if governments make no changes in existing energy policies. In this scenario energy demand will increase 1.3% each year, up to 2040. In spite of the fact that this increase is lower than the 2.3% growth in energy demand in 2018, this scenario would result in a persistent growth of energy-related emissions, with additional environmental consequences (IEA, 2019). The second scenario IEA presented is the *stated policies scenario*, which does incorporate today's policies and measures. This scenario takes 1% increase of energy demand in account. This growth is supplied by renewable energy sources, mainly solar PV, and by fossil fuels, mainly natural gas. The demand for oil decreases and flattens out near 2040 (IEA, 2019). Thirdly, there is the *sustainable development scenario*. This scenario does not imply simple solutions but demands a thorough change across all parts of the global energy system (IEA, 2019). This scenario is based on the Paris Agreement, drawn up by the United Nations (McCollum et al., 2018). The aim of this agreement is to keep global warming below 2 degrees Celsius and pursue efforts to limit it to 1.5 degrees Celsius (Rogelj et al., 2016). Besides this Paris agreement on global level, there is an agreement on European level as well. This so-called European Green Deal aims for Europe to become the first net carbon neutral continent by 2050 (Lechtenböhmer et al., 2020). In the nearby future, the EU aims for a decrease in greenhouse gas emissions of 50-55% by 2030. Using this Green Deal, the European commission focusses on relying less on fossil fuels and a swift transition towards renewable energy production (Claeys et al., 2019). According to the UN and EU agreements, the Dutch government aims to realize a decrease in CO_2 emission, compared to 1995, of 95% by 2050 (Hekkenberg et al., 2019). In 2017, the energy use of the Netherlands was around 3,000 PJ. The share from renewable energy was 169 PJ (CBS, 2018). This 6% share of renewables is far from the goals set by the agreements above, so substantial measures are needed for the Netherlands to meet these goals (van der Weer et al., 2018). When looking at the energy mix used in the Netherlands, oil accounted for 1167 PJ and natural gas for 1273 PJ (CBS, 2019). Of this oil and gas, 25% is produced in the North Sea region (CBS, n.d.). The remainder is imported (CBS, 2012). As of 2019, a total of around 184 oil and gas production platforms are operative in the North Sea, which makes it the region with the highest number of platforms, followed by the Gulf of Mexico, which accounts for 175 active platforms (Statista, 2019). Active drilling and production in the North sea began in 1964, after the UK Continental Shelf act came into force (Nakhle, 2004). 6 years before, the exclusive economic zones on the North Sea continental shelf were ratified. Five countries are involved in the North sea oil and gas production: the United Kingdom, Norway, Denmark, Germany and the Netherlands (Freestone, 1993). In 2017, 20 billion barrels of oil were produced in the North Sea. Due to depletion of oil and gas fields, lower oil and gas prices and increasing costs of operation and maintenance, the production in the North Sea will decrease (Steketee, 2017). Figure 1 shows the historical and forecasted gas production in the Dutch North Sea area, as presented by Energy Beheer Nederland (EBN).

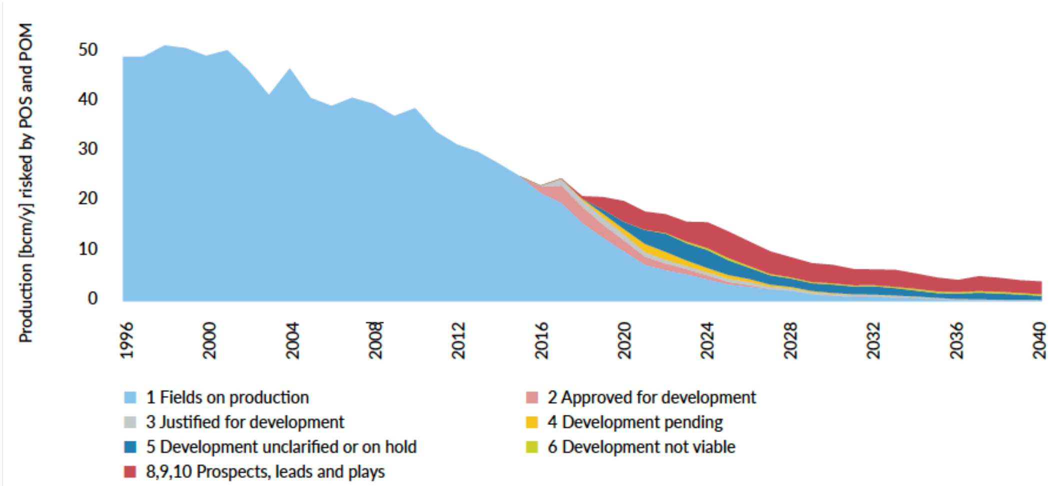

Figure 1. Historical and forecasted gas production in the Dutch North Sea sector (EBN, 2016).

TNO (van der Weer et al., 2018) confirms this predicted decrease of production. Figure 2 shows the amount of offshore North Sea gas installations that reaches their cessation of Production (COP). As stated before, the rate of dismantling relies on the gas price. Figure 2 shows the best- and worst-case scenarios regarding this gas price.

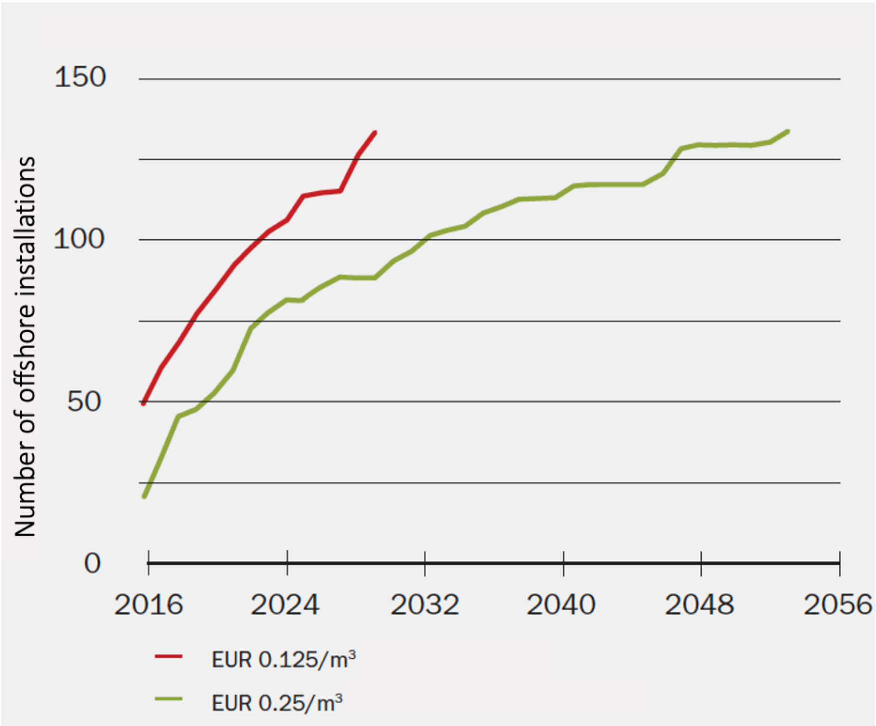

Figure 2. Number of offshore installations that reach their Cessation of Production (CoP), based on a lower and upper limit of the development of the natural gas price (van der Weer et al., 2018)

Besides the fact that 90% of the carbon emissions caused by fossil fuels are due to combustion, the emissions from the production processes are significant as well. 20% of the domestic emissions of oil and gas producing countries like Canada and Russia is caused by oil and gas production and transmission (IEA, 2020). For Norway, who mainly extracts its oil and gas in the North Sea area, this percentage is even higher, up to 27% in 2013 (Gavenas et al., 2015). Most of the carbon emissions from the Norwegian petroleum production comes from the use of gas turbines that generate electricity. These are located on the offshore platforms, and are much less efficient than modern large-scale gas power plants onshore (Marvik et al., 2013). Figure 3 shows Norway's greenhouse gas emission per industry sector. It is clear to see that the oil and gas industry accounts for a significant share of the country's total emissions. Note that 70% of these 'oil and gas' emissions are from the use of natural gas to power offshore turbines on platforms. These turbines supply the power necessary to run the platforms, including drilling and pumping.

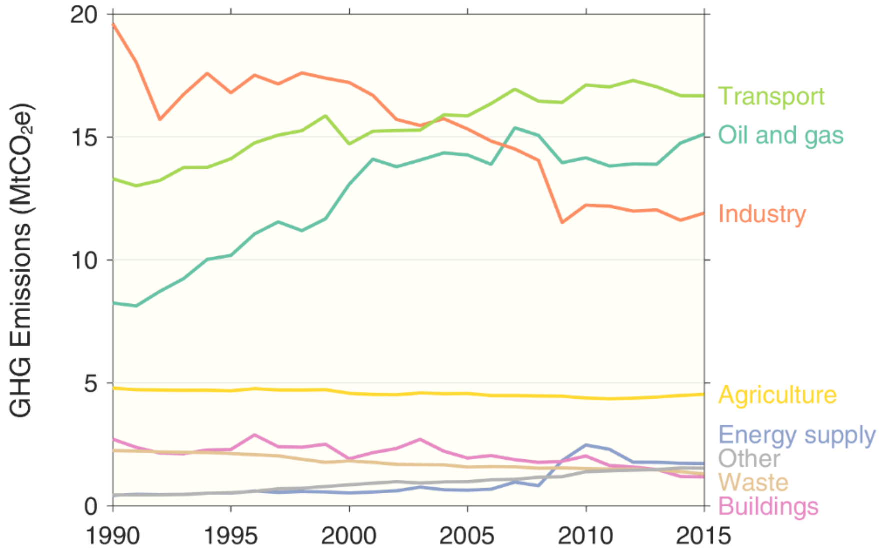

Figure 3: Norwegian emissions of greenhouse gases between 1990 and 2015. Oil and gas production account for 15 Mt CO_2 equivalent, which results in the second highest source of greenhouse gas emissions (Norwegian Statistics Agency, SSB, 2015)

As stated above, the oil and gas production sector in the North Sea region is highly climate intensive and is expected to undergo significant changes in the coming decades. In order to gain insight in the more precise lifetime expectation of these platforms, this research starts with answering the question: *What is the lifetime of oil and gas platforms and installations in the North Sea region?* The answer of this question will shape the rest of this research, because it can provide insight into the options of finding a new purpose for these installations. Broadly, there are two options.

The first option is the possibility of electrification of current oil production processes. Electrification of oil and gas platforms can result in one of the best tools to mitigate climate change (KIVI, 2020). When looking at the oil and gas industry of a country as Norway, electrification of installations is the most effective way of meeting national and international climate targets (Davies 2018). Electrification of these platforms implies that the gas turbines that are currently used will be replaced by electricity from an external source (Kerlogue, 2020). There are two options for the electrifications of platforms. The first option is to connect the platforms with an onshore electricity grid using submerged electricity cables. An example of this application is Equinor's Johan Sverdrup field in the Central North Sea which opened October 2019 and currently is producing 350,000 barrels per day. By powering the field almost entirely by hydroelectric power from shore, they decrease emissions to 0.67 kg per barrel produced. With a world's average of 17 kg per barrel, this is a decrease of 96% (Equinor, 2020). This means the field will avoid emissions of more than 620,000 tonnes of CO_2 every single year. The second electrification option is to power the platforms using offshore renewable energy production applications, such as offshore wind energy farms, offshore PV farms, and marine energy technologies such as tidal and wave energy. Electricity will be transported from a transformer station inside the wind farm to the petroleum platform (van der Weer et al., 2018). If these platforms rely on one type of renewable energy, backup electricity from shore is needed. For bigger platforms which are located further from shore, an offshore network of renewable energy technologies is needed, including possibilities to store excess energy which can be used during periods of low energy production. Whether electrification of the existing platforms on the North Sea is economically viable, depends on the lifetime of the oil and gas production. The results section provides answers to this question.

The second option is to find a new purpose for the platforms, as well for the coming decades as for the period after the oil and gas fields are decommissioned. The option that will be studied in this research, is the possibility of the production of green hydrogen gas on the platforms. Instead of grey and blue hydrogen, which is hydrogen produced using fossil fuels, the production of green hydrogen is a process where electricity is used to convert water to hydrogen gas and oxygen. Hydrogen can play an important role in the energy transition, because green hydrogen is seen as one of the most promising technologies that will enable an energy system using wind and solar energy on a large scale (Demirbas, 2017). Advantages of green hydrogen are its ability of decoupling supply and demand for energy, due to its storage capacity, reducing of congestion problems and it can be transported and stored in large quantities (Haghi, 2018). Furthermore, it can be used in sectors that cannot be electrified completely (KIVI, 2019). Also, green hydrogen can be used to produce synthetic fuels (e.g. methane), ammonia and other fertilizers, as well as other chemicals, but most importantly, can be used directly as fuel (Dincer, 2012). The current market in the Netherlands for hydrogen is 800 kilotons annually, from which half is used in the fuel refineries of the Port of Rotterdam (van der Weer et al., 2018). This hydrogen is almost entirely produced using natural gas and is therefore characterized as 'grey' hydrogen. In the results section of this research, different types of hydrogen are discussed, as well as the outlook on market price and production development. Where current focus mainly is on the production of hydrogen onshore, which has the advantage of lower maintenance costs, transportation costs, platform modification costs and lower electricity costs, this research aims on the possibilities for offshore hydrogen production. In order to provide insight in the processes of offshore hydrogen production using offshore renewable energy, this research presents a techno-economic model which shows the production price of offshore green hydrogen in the North Sea region. Doing so, the second question that is answered in this research is: *What are the costs of producing hydrogen on offshore platforms on the Dutch Continental Shelf?* After answering this question, the results have been compared to the projected costs of hydrogen production using other technologies and locations. Doing so, the last sub question that is answered is: *Are the production costs of offshore produced hydrogen competitive with alternative ways of hydrogen production in the future?*

Answering the sub questions mentioned above, ultimately leads to answering the main research question of this thesis:

What can be the role of hydrogen production in the re-use/repurpose of oil and gas platforms in the North Sea region?

The following sub questions have been answered:

1. *What is the economic and technical lifetime of oil and gas platforms and installations in the North Sea region?*
2. *What are the costs of producing hydrogen on offshore platforms on the Dutch Continental Shelf?*
3. *Are the production costs of offshore produced hydrogen competitive with alternative ways of hydrogen production in the future?*

This research consists of two phases. In the first phase, articles, reports and experts' opinions are used to get insight in the current projects and prospective regarding re-use and repurposing of the current oil and gas industry in the North Sea. The second phase consists of a techno-economic analysis of three different platform configurations in the Dutch North Sea to gain insight which quantitative parameters influence the viability of future business cases in offshore hydrogen production on the Dutch continental Shelf (DCS). Before the results are presented, an organized plan on how the analysis has been carried out is presented in the methodology section. In this section, the selection of platforms, scenarios and input parameters and the assumptions used is explained. In the discussion section, future research is analysed, and the limitations of the techno-economic analysis and its assumptions are justified.

2. Methodology

This thesis consists of a qualitative research and a quantitative analysis. A combination of analyses has been chosen to assess the current status of oil and gas production on the Dutch Continental Shelf (DCS) and to gain insight in the possible economic feasibility of offshore hydrogen production. In this section, firstly the chosen methodology for the qualitative part is explained. After that, the input parameters and scenarios for the techno-economic analysis are displayed. The geographical focus of the research is on the North Sea region. This area has been selected because it proved to be the area with the most innovative mindset in terms of electrification, the presence of projects regarding the subject, and the interest of the internship company. However, certain outcomes of the research questions can be relevant for other oil and gas producing regions as well. In the first phase of the research, in which the current status of the industry is analysed, gas as well as oil platforms are mentioned. In the techno-economic analysis however, only gas platforms are used because the production technology and infrastructure of natural gas installations is similar to the technology needed for hydrogen production, compression and transportation.

2.1 Qualitative research

As stated in the introduction, this research consists of two phases. In the phase 1, first the history, current use and future of the oil and gas industry on the Dutch continental shelf has been analysed. During initial research, some opposing predictions and expectations came forward, especially when comparing governmental papers and papers/interviews with oil and gas companies. It is important to distinguish technical from economic lifetime. The economic lifetime relies heavily on the gas and oil price. The literature research consists of scientific primary literature, found on Scopus or Google Scholar, grey literature, such as reports from research institutions or reports from petroleum companies that operate in the North Sea region (e.g. BP & Shell), and reports from governmental organizations which have interest in the region are searched via Google. Articles have been be retrieved from newspaper websites. If comments or references from these meetings, and written contacts are used they are referred to as *personal communication, including name and date*.

After the analysis of current oil and gas production the research continues with the production of hydrogen on existing platforms. During the proposal phase it came forward that there are not sufficient publications on the subject yet. The aim of the more in-depth literature research is to ensure that all existing literature on platform electrification is analysed.

2.2 Quantitative research – Input parameters

In this section, the methodology of the techno-economic model is described. The main objective of the model is to present quantified data in order to gain insight which economical and technical parameters influence the performance of a potential offshore integrated energy system the most. In the subsections below, the different aspects of the model, together with their input values, are described. In the results section, the outcomes of the model are presented. Different cost and performance scenarios are discussed. Because of the assumptions and simplifications used, these different scenarios are important to get a certain bandwidth of outcomes. In the discussion section, further investigation based on these outcomes is discussed. The technical and economic assumptions are based on expected values in 2025. This year has been chosen due to the expected development of possible large-scale hydrogen production, with viable business cases expected from 2025 onwards (North Sea energy, 2020). Table 1 below presents a first overview of the different cost components of the analysis, followed by the revenue components, which consists of green hydrogen. Section 2.2.1 below presents the different scenarios which have been used. The input data used for this model is presented in the sections further in this methodology section.

Table 1: Different cost components of techno-economic model

Component	Unit
Platforms	Cost of modification of platform for hydrogen production
	Cost of operating and maintenance of platform while producing hydrogen
Renewable energy source	Cost per MWh delivered to the platform
Electrolysis	Cost of electrolyzers on platform
	Cost of desalination unit
Hydrogen transportation	Costs of transporting produced hydrogen to shore

2.2.1 Scenarios

As stated above, two scenarios have been chosen in order to keep the model from reaching out of the scope of this research. Before looking at the input parameters, the different scenarios that have been considered are presented. These different scenarios are displayed in Figure 4 and Table 2 below. The three different types of platforms used in this scenario are explained in section 2.2.2. The magnitude and form of renewable energy used in the scenarios is explained in section 2.2.3.

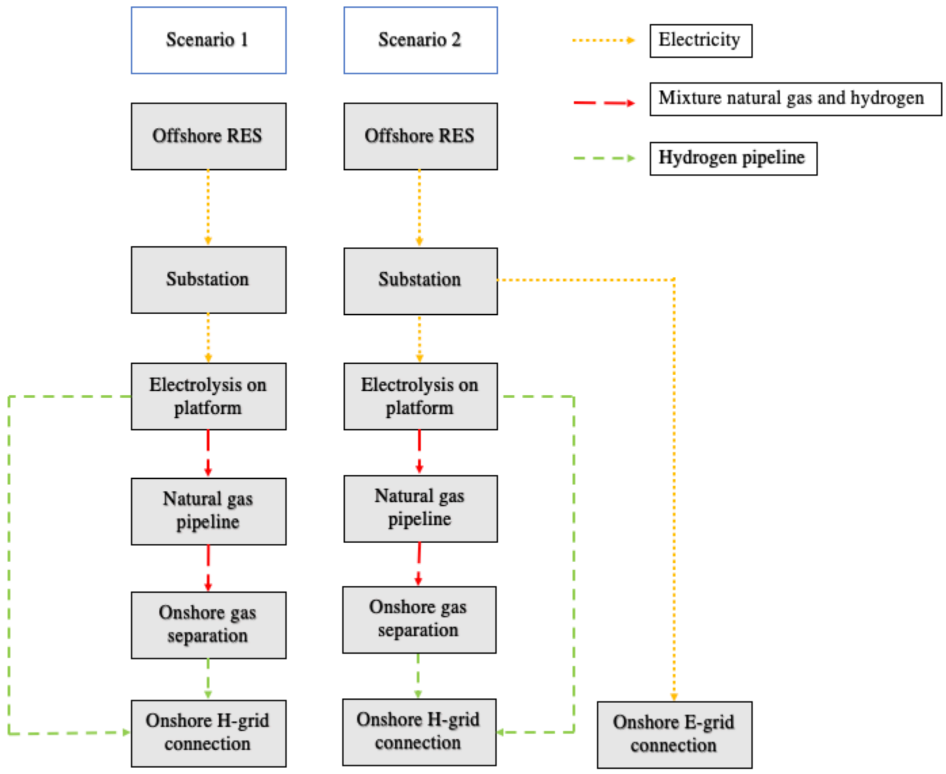

Figure 4: Schematic view of different scenarios considered

Table 2: Different scenarios which have been analysed in the techno-economic model

Scenario	**Explanation**
Scenario 1: Only gas scenario	Use of offshore renewable energy technologies to produce green hydrogen. The produced electricity is converted to hydrogen completely. No additional electricity connection to shore is needed. This scenario entails curtailment of renewable energy when the supply of this energy exceeds the capacity factor of the electrolyzers on the platform. Costs for this curtailment is incorporated in the model.
Scenario 2: Partly gas scenario	Use of offshore renewable energy technologies to produce green hydrogen. The produced electricity is partly converted to hydrogen and used for electrification of compression technology, so additional electricity transportation to shore is needed. No curtailment of produced offshore energy is needed, and the capacity factor of the electrolyzers is expected to increase. In the most optimal case, hydrogen is produced when the electricity price is lower than the sum of the hydrogen selling price and the production costs of hydrogen.

2.2.2 Types of platforms

In this research, different types of platforms are considered. The considered platforms are named Type A, Type B and Type C. Because the aim of this model is to provide an inside in the magnitude of costs for the proposed scenarios, which entails assumptions, literature is used to come up with the platform characteristics.

Platform type A is based on the combination of a production platform and a nearby satellite platform. This platform combination is located 85 km directly from shore. In the model, this combination is referred to as one platform. Platform type B is based on a smaller satellite platform, located 213 km from shore. Characteristics that have been used for both platforms are from Jepma and van Schot (2017).

Platform C is based on the Neptune Q13a platform from the PosHYdon project. This PosHYdon project is further mentioned in the results section. It is important to distinguish the characteristics and outcomes of type A and B with the outcomes of type C due to the fact that A and B are projections of full business cases and C a projection of a small-scale pilot.

Table 3, 5 and 6 below present the relevant assumptions that were used in the model. In this model, it is assumed that all platforms will be out of operation by the time hydrogen production starts. The platforms are located near existing wind farms, so the assumption is that sufficient nearby produced renewable electricity is available. More on this power supply in section 2.3.3. The assumed characteristics of platform type A are displayed in Table 4.

Table 3: Characteristics platform Type A (Jepma and van Schot, 2017)

Type A: Combination of operational satellite platform and manned production platform (G17d)		
Parameter	**Unit**	
Distance directly to shore	km	85
Distance to wind farm	km	5
Carrying weight	tonnes	2000
Total capex of rebuilding platform decks	M€	176
Operations and maintenance platform	M€/yr	8.8
Available platform area m^2	m^2	2273
Electrolyser capacity (sylizer 300)*	nr./elec.	25
Cost of using existing gas grid	€/Nm^3	0.0165

* More on electrolyzer selection in section 2.3.4

Platform type B is based on a smaller satellite platform located further offshore, on 213 kilometer out of the coast. This platform is also assumed to be out of operation when large scale hydrogen production will begin. Table 4 displays the assumed characteristics of platform type B.

Table 4: Characteristics platform Type B (Jepma and van Schot, 2017)

Type B: Non operational satellite platform (D18a)		
Parameter	**Unit**	
Distance directly to shore	km	213
Distance to wind farm	km	5
Carrying weight	tonnes	1000
Total costs of rebuilding platform decks	M€	40
Operations and maintenance platform	M€/yr	4
Available platform area	m^3	639
Electrolyser capacity (sylizer 300)*	nr./elec.	6
Maintenance cost gas grid	M€/year	2
Ratio of electrolyzer capacity related to wind energy production		78%

* More on electrolyzer selection in section 2.2.4

Besides these two full scale business cases, a more pilot-scale platform is also considered in the model. The platform that is used is based on the Q13a pilot platform. The idea of including this platform in the model is to see to what extend a pilot configuration differs from a full-scale business case, mainly economically. Table 5 displays the used characteristics for this pilot platform Type C. The characteristics are retrieved from Neptune's *PosHydon Offshore green hydrogen (2019)*.

Table 5: Characteristics platform Type C (Neptune, 2019)

Type C: Neptune Q13a Pilot platform		
Operational, 'green' electricity delivered from shore		
Parameter	**Unit**	
Distance to shore (Scheveningen)	km	13,4
Carrying weight	tonnes	672
Available platform area (main deck)	m^3	400
Total costs of rebuilding platform decks	M€	4.5
Electrolyzer capacity (1 MW elec.)	nr./elec.	1, 5 and 10
Electricity and hydrogen connection	M€	0.75

2.2.3 Power supply

In order to power the electrolysers on the platform to produce 'green' hydrogen, supply of renewable energy is needed. The model uses different renewable energy capacities for each of the scenarios. Below, the different configurations are displayed. The base technology to deliver electricity to the platforms is wind energy. Due to the relatively low price and high level of technological development of wind parks, this technology is seen as the most realistic option for powering the business case size projects of platform types A and B in de model. Due to the intermittent character of wind energy the capacity factor is relatively low, around 50% (Lensink and Pisca, 2019). Therefore, in the discussion section, an additional option on the load factor of combined renewable energy sources is mentioned, and the economic effect this has on the production costs of hydrogen in the most positive scenarios. In other words, how much extra costs can be made in adding other renewable energy options, such as solar energy, in order to compensate for the extra revenue in terms of electrolyzer capacity factor?

In scenario 1, all energy from de renewable energy source is used on the platform. Jepma and Schopma (2017) state in their article that the most optimal ratio between wind park capacity and electrolyser capacity is 78%. This entails that platform type A with 250 MW installed electrolyzer capacity needs 321 MW renewable energy capacity. It is assumed that for 500 hours, when the wind farm runs at full capacity, 22% of the energy has to be curtailed. For another 1000 hours, an average of 11% has to be curtailed. This results in a total curtailment of 110 GWh per year. Assuming 4800 full load hours (see Table 3), this is 7.14% of the annual production of the wind farm. This is incorporated in the cost model. Platform type B with its 60 MW electrolyzer would need 77 MW renewable energy capacity. Using the same assumptions as for type A, 17,8 GWh needs to be curtailed. In scenario 2 no curtailment is incorporated in the model. The assumptions about the size of the windfarms are the same as in scenario 1.

The cost of the electricity used is different for each scenario. Due to the fact that in scenario 1 no grid connection between the renewable energy source and shore is needed, a lower cost price of the produced electricity is used. Table 6 below presents a summary of a wind energy cost assessment conducted by the Netherlands Environmental Assessment Agency (Lensink and Pisca, 2019)

Table 6: Summary of a wind energy cost assessment conducted by the Netherlands Environmental Assessment Agency (Lensink and Pisca, 2019).

Wind farm	**CAPEX (€/kW)**	**OPEX (€/kW/yr)**	**Base LCOE (€/MWh)**	**Connection costs (€/MWh)**	**Full load hours (hr/year)**	**Total (€/MWh)**
Dutch coast (West)	1750	44	47	19.5	4,500	66
Dutch coast (North)	1700	41	46	17	4,400	63
IJmuiden (Far offshore)	1850	56	50	28	4,600	78
North of Wadden islands	1900	64	50	21	4,800	71

Based on Table 6 and the locations of platform type A and B, a base amount of 0.050 €/MWh is considered for as well platform A (north of Wadden islands), as platform B (far offshore). These are the costs that have been used in scenario 1. For platform type C, electricity prices of *Dutch coast (West)*, have been used, so 66 €/MWh.

2.2.4 Electrolysis

For the production of ‘green’ hydrogen, electrolysis needs to take place. Electrolysis is considered the least climate intensive way to produce hydrogen using renewable energy sources (Briguglio, 2016). Other technologies, such as steam reforming of natural gas, can be more cost effective, but due to the urge of decreasing carbon emissions, hydrogen from electrolysis is used in this research, as explained in the introduction section. More on these different types of hydrogen in the results section.

During the electrolysis, water is reformed to hydrogen and oxygen (see process below):

$$2H_2O + electricity \rightarrow O_2 + 2H_2$$

There are different electrolysis technologies to produce hydrogen out of water and electricity. Electrolysis using renewable energy needs to cope with the intermittent character of this renewable energy, so has to operate more dynamically than hydrogen production using natural gas.

The four main technologies currently available are: alkaline technology, polymer electrolyte membrane (PEM) technology, Anion Exchange Membrane (AEM) technology and the Solid Electrolyser Cell (SOE) technology (TKI systeemintegratiestudie, 2018). For this research, PEM water electrolysis is chosen as the most promising electrolysis technology. The reason for this choice is the promising developments in the industry to increase the stack capacity of this type of electrolyser, its low footprint and the relatively low use of space, which is important for the implementation on platforms with limited deck space. Another advantage of the PEM electrolysis over the other technologies is the greater safety and reliability, which together with the environmental impact makes it the most favourable option for green hydrogen production (Briguglio, 2016; Kumar, 2019).

Jepma and van Schot (2017) presented 3 types of PEM electrolysers. The characteristics of one of these electrolysers are displayed in Table 7. The most important technical characteristics that have been used in the model of this research are the stack capacity, the efficiency and the hydrogen production per energy input. Furthermore, the dimensions of the structure are important, since they have to be placed on platform deck. The economical characteristics that have been used in the model consists of the OPEX and CAPEX of the electrolysers. For platform type A and B, characteristics of the Siemens Silyzer 300 have been used. For the CAPEX of the electrolyser, which forms a significant percentage of the total investment costs, a range from 250 to 1270 €/kW is used. This due to the fact that estimations of the costs per kW installed capacity show a large bandwidth (Gigler, 2018). Three different price scenarios are used, respectively 250, 760 and 1270 kW/€. These scenarios are referred to as Low, Base and High, respectively. For the modelling of the pilot platform (type C), a configuration of 1, 5 and 10 container sized 1 MW electrolyzers are used. Characteristics of this electrolyser are displayed in Table 8. For both electrolyzers an efficiency of 75% is assumed.

Table 7: Assumptions silyzer electrolyser (Jepma and van Schot, 2017, (Siemens AG, 2019))

Electrolyser: Siemens silyzer 300 PEM		
Technical specifications		
Technical assumptions		
	Unit	
Stack capacity	MW	10
Fresh water infeed	l/Nm^3	1.5
Hydrogen produced under nominal load	Nm^3/h	1800
Hydrogen produced under nominal load	kg/h	162
Oxygen produced under nominal load	Nm^3/h	900
Density of hydrogen	kg/m3	0.08988
hydrogen production per unit of power	kg/kWh	0.0212766
Power needed per kg hydrogen produced	kWh/kg	47
Skid dimensions	m2	70
Weights	tonnes	102
Outlet pressure	Bar	35
Purity levels	h2 %	100%
Lifetime	years	9,1
Efficiency	%	75%
Depreciation period of electrolyser	Years	10
Economic assumptions		
Capex	€/kW	250 – 760 - 1270*
Capex desalination unit (2000L/h)	€/unit	61,200
	€/kg H_2 produced	0,02
Opex (2,5% of Capex)	€/kW/year	19
	€/year	1530
	€/kg produced	0.0005

*(Gigler, 2018).

For the Type C pilot platform, 3 different configurations are considered. Neptune (2019) described a 1 MW electrolyzer with a power input op 1 MW, which fits inside a basic 40 ft container. In the model, configurations with 1, 2 and 10 containers are considered. Specifications of 1 container unit are displayed in Table 8 below.

Table 8: Assumptions electrolyzer platform Type C (Neptune, 2019)

Electrolyser Q-13		
Technical specifications		
Stack capacity	MW	1
Input power	MW	1
Water consumption	l/h	300
Hydrogen flow	Nm^3/h	200
Hydrogen purity	%	100%
Outlet pressure	bar	30
Footprint	ft container	40
Weight	tonnes	20

2.2.5 Hydrogen transportation

The model incorporates 2 scenarios of transporting gas to shore. In scenario G1, newly build hydrogen pipelines are used. The costs for these pipelines are assumed to be 700,000 €/km. This is a rough estimation, based on examples presented in Mulder et al. (2019) and Jepma and Van Schot (2017). Scenario G2 is based on using existing pipelines, with adjustments, to transport pure hydrogen. This obviously is the cheaper option. In their report they use a cost for transportation and compression using existing natural gas pipelines, which is one of the assumptions used in the model for this research, of € 16,50 per 1000 Nm^3 (Jepma and van Schot, 2017). However, the analysis assumes the platforms to be out of operation during future hydrogen production processes. This means that the hydrogen cannot be admixed with the natural gas flow. The limitations of this methodology are discussed in the discussion section.

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2.3 Quantitative research – Output parameters

The output parameter that is used to analyse the different scenarios is the *levelized cost of hydrogen (*$LCOH_2$). This is a measure of the average net present value cost of hydrogen production for a production platform over its lifetime. The $LCOH_2$ is calculated as the ratio between all the costs over the lifetime of the platform divided by the discounted sum of the actual hydrogen delivered. Input includes the investments costs and annual costs presented in the methodology section. The formula used for calculating the $LCOH_2$ is displayed below.

$$LCOH_2 = \frac{total\ CAPEX\ (€) * CRF + total\ OPEX\ (€)}{Hydrogen\ production\ (\frac{kg}{yr})}$$

Here, the **capital recovery factor** is a ratio used to calculate the present value of an annuity (a series of equal annual cash flows). Using this, the initial investment costs can be corrected over the lifespan of the project. The CRF is calculated using the formula below:

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

Where:

r = discount rate
n = years of operation

The lifetime of the electrolyser is 10 years. The discount rate is set on 5%.

3. Results

In this section, the results of the research conducted as described in the methodology section are displayed and analysed. Following the methodology, first the expectations on current and future oil and gas operations on the Dutch Continental Shelf are briefly described. After that, current hydrogen production is discussed, including an outlook on future hydrogen pricing. After this the more extensive results of the techno-economic analysis are presented. In the discussion section, the production costs of hydrogen are compared with the forecasted hydrogen costs as presented in literature.

3.1 Historical, current and future oil and gas production on the Dutch Continental Shelf

In the Dutch North Sea region there has been oil and gas production and exploration since the five countries with interest in this region signed and ratified the convention of the continental shelf in 1958 (Glennie, 1997). The treaty was put into use in 1964. The relevant countries for oil and gas exploration in the North Sea region were Denmark, Germany, Norway, the United Kingdom and the Netherlands (Kent, 1967). After the start in the 60's, the production of oil and gas started to grow in numbers, reaching over 100 installations in 1985. For over 50 years, this region became the epicentre of one of the world's most productive energy industries.
The Netherlands started with exploration of the North Sea bedding in 1959, Followed by the first exploration drillings in 1963 (NAM, n.d.). In 1975, the Nederlandse Aardgas Maatschappij (NAM) got its first license to start production. When this production started, oil and gas production took place the same way as it did on land. After the first years, other installations were put to use. They switched to the bigger platforms with smaller, unmanned satellite platforms. The difference between these different types of platforms is explained later in this results section. After these first innovations on different types of platforms, the mass production of oil started. The 1973 energy crises showed that the Netherlands were to dependable of foreign oil. The urge for energy from own domestic sources became greater. Because of the closing of the coal mines in Limburg (NL), a new source of energy was needed: Natural gas. After findings of the big gas fields, the Netherlands became one of the biggest natural gas producer of the European union (NAM, n.d.). Up until 2014, natural gas revenues were 10 to 15 billion euro per year. To this day, the Dutch oil and gas industry is providing 16,500 jobs, which includes people on platforms, researchers, engineers and downstream jobs.

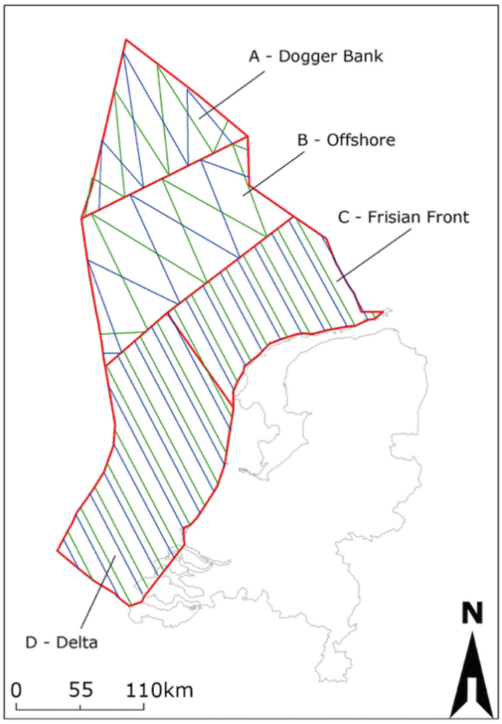


Figure 5. Dutch Continental Shelf (DCS) (Geelhoed & Scheidat, 2018)

The part of the North Sea which has been looked at during this research is the Dutch continental Shelf (DCS). Figure 5 shows the DCS as part of the North Sea.
At this moment, around 200 production platforms are situated in the DCS. Most of them are situated in the central part of the DCS. The gas platforms can be divided into two categories (Landmeer, *personal communication*, 2020):

1. Main production platforms, which have a relatively long lifetime. Production platforms stay on its location during its lifetime, which usually is 20 to 30 years. In shallow waters, the most common type of production platform is the fixed piled structure, also known as *jackets*. These platforms are fixed to the seafloor (Chakrabart, 2005). Production platforms are connected to one or more satellite platforms where the actual gas is being produced, processed, and then pumped into the main pipelines which then go to shore. Production platforms have a power consumption carrying from 8 MW to 20 MW (Landsmeer, personal communication, 2020)
2. Satellite platforms are platforms where on its deck multiple pumps can be mounted which can be connected to subsea pumps. The gas is transported to the production platform, where it is further processed. Depending on the processing abilities of the platform itself, its capacity lies around 50 kW to 2 MW (Landsmeer, personal communication, 2020).

These approximately 150 platforms produced in the DCS around 11 billion m^3 of gas in 2018, which is 27% of the Dutch natural gas consumption (North Sea energy, 2020). It is difficult to determine the end-of-lifetime of platforms. Nexstep, the Dutch national platform for re-use and decommissioning, has presented two reports on the subject, in 2019 and 2020. These reports indicate when the oil and gas infrastructure on the DCS is being decommissioned. Both of these reports state that, due to decreasing revenues, the Dutch oil and gas production sector loses its economic value. Of the 150 installations which are currently deployed, 100 will be decommissioned in the coming 10 years (Nexstep, 2020). This is also showed in Figure 6 below. Nexstep states that approximately 10% of these decommissioned platforms can be re used for activities like offshore hydrogen production (Nexstep, 2019). The technical lifetime of these platforms is considered to surpass the potential economic lifetime (Personal communication R. Schulte, April 2020). Schulte also mentioned that the rapid decommissioning which is currently being carried out can be a disadvantage for the opportunities for hydrogen production. This because the costs of maintaining the platforms while out of use are too high. It is therefore important that the moment of decommissioning needs to match the availability of hydrogen production business cases in the future.

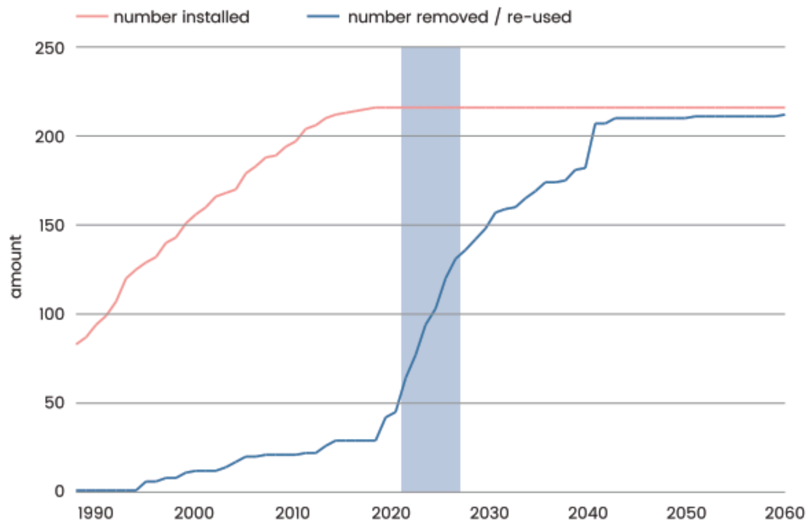


Figure 6:Number of installed and removed platform on the DCS (Nexstep, 2019)

Nexstep further states in their most recent re-use and decommissioning report, which was issued in 2020, that only a limited part of the infrastructure can be re-used or repurposed. They name carbon capture, utilization and storage (CCUS), and offshore hydrogen production as two of the most promising options for this repurposing. In the discussion section, CCUS is discussed as an alternative option for repurposing, but as mentioned before, this research is mainly focusing on that last second possibility, the production of offshore hydrogen.

After looking at the different ways to produce hydrogen, and the possible future of green hydrogen production, the focus of this section is on one of the possible ways of producing hydrogen, namely hydrogen production on offshore platforms using renewable energy.
The Netherlands are frontrunner in hydrogen production at sea (North Sea Energy, 2020). The PosHYdon project is an initiative of the Dutch association for decommissioning and re-use, and TNO, the Netherland organization for applied scientific research. Aim of the project is to gain experience in the operations of offshore hydrogen production. To do so, a 1 MW electrolyzer is installed at an offshore production platform, out of the coast of Den Haag. This is planned to form a starting point for scaling up green hydrogen projects, with the ultimate goal of a large-scale business case in 2030. Platform Type C of the techno-economic model of this research is based on this platform.

3.2 Hydrogen production and pricing

Hydrogen, which is the most abundant molecule in our universe, is a gas which can be converted into electricity, without carbon emission into the atmosphere. Hydrogen can be used for heating homes, can serve as basis ingredient in the chemical industry and has a promising future as clean fuel (Hosseini, 2016). The most important advantage of hydrogen gas is that it can be stored in industrial hydrogen tanks, as well as in underground oil and gas fields and empty salt caverns (Gigler, 2018). This makes it suitable to serve as solution for the intermittency problems that arise when the share of renewable energy sources in the energy mix increases. There are three different methods to produce hydrogen.

First of all, 'grey' hydrogen production is the process in which fossil fuels, mainly natural gas, are used to produce hydrogen. Natural gas reacts with steam (H_2O) forming hydrogen and CO_2. This process is also known as Steam-Methane Reforming (SMR). Due to the emission of carbon into the atmosphere, this process does not contribute to a less climate intensive energy production. In 2016, 50% of the global hydrogen was produced using this process (Hosseini, 2016). On average, 9 tonnes of CO_2 are being emitted per tonne hydrogen produced (Mulder et al., 2019). Currently, hydrogen is mainly used in the chemical, refining industry and metal industry (Mulder et al., 2019). The price of grey hydrogen is sensitive to the cost of natural gas. Currently, the costs of producing grey hydrogen vary between 1 and 1.50€/kg (emission taxation is excluded in this price (IEA, 2020)). This cost may increase towards 2030 to 1.7 €/kg assuming a natural gas price of 31,7 €/MWh (Hers et al., 2018). When assuming a carbon price of 30 – 40 €/ton in 2030, this price can increase towards 2€/kg (IEA, 2020).
Because hydrogen transportation is relatively expensive, there is an alternative to this large-scale industrial hydrogen plants. This alternative contains the use of small-scale steam methane reforming units which typically produce 300 to 600 kg hydrogen a day (Gigler, 2020). This is comparable to configuration 1 of platform Type C of the techno-economic analysis, where a 1MW electrolyzer is placed on an offshore platform. Expectations are that the prices of this small-scale production can decrease to 4-5€/kg in the short-term, towards 3-4€/kg towards 2030 (Gigler, 2018). This is an interesting trend which is taken into consideration when comparing small scale green hydrogen production further in the results section.
As mentioned before, blue hydrogen is the option where part of the produced CO_2, around 55% (Mulder et al., 2019), is captured and stored (CCS). Current estimates put the price of CCS in the range of 50 to 70 €/tonne of CO_2 (IEA, 2020). Because this price is higher than the carbon price of 30-40 €/tonne mentioned before, the current expected price of blue hydrogen in Europe is higher than the price of grey hydrogen. This gap may decrease when carbon prices will rise, or when the price of CCS decreases, which is expected to happen when looking at the early stage of development of this technology (Dagash, 2019).
As mentioned in the methodology section about electrolysis, this type of hydrogen production is seen as the most viable option for low carbon hydrogen production. This requires renewable energy as

electricity source for the process. When looking at onshore production of hydrogen using these PEM-electrolysers, and electricity costs of 70-80 €/MWh, current costs are estimated at 6-6.5 €/kg (Gigler, 2020). Towards 2030, costs of large-scale onshore electrolysis are estimated to be around 3€/kg, with lowest estimations of even 2 €/kg in case of decreasing electrolyser CAPEX and increasing electrolyze efficiency (Gigler, 2020). An estimated price of 2 €/kg hydrogen, in the most positive estimation, is interesting because this would imply that green hydrogen can be competitive with grey hydrogen prices in 10 years. Where grey hydrogen prices are heavily influenced by the natural gas price, the price of green hydrogen depends on the electricity price. In the report of Mulder et al. (2019), analysis shows that the required hydrogen price of electrolysis plants is a linear function of the electricity price. The reports show a required hydrogen price of little over 3€/kg when the electricity price is 50 €/MWh, which is the expected price of wind energy in the techno-economic analysis, for platform Type A and B.

3.3 Techno-economic analysis

In this part of the results section, the outcomes of the techno-economic model are displayed. As mentioned in the methodology, the analysis incorporates different scenarios regarding cost components and technical parameters. Firstly, it is important to gain insight on the cost division of the different scenarios and platform types. A breakdown of the investment costs in case of wind energy as renewable energy is displayed in the section 2.3.1.

3.3.1 Initial investment costs

The figures below present the investment costs per platform Type, both in million euro per component and as percentage of the total investment costs per type. The total investment costs are significantly influenced by the different electrolyser CAPEX scenarios. When looking at Figure 8, 44% and 52% of the total investment costs, for transport scenario G1 and G2 respectively, are due to the electrolyser CAPEX. On the other hand, when taking the LOW CAPEX G2 scenario, 73% of the costs are made by the platform modifications. In this scenario, it is arguable whether these electrolysers can better be placed onshore, but this can better be concluded after seeing the hydrogen production price in section 3.3.4. As expected, the desalination unit has a negligible influence on the total cost. In contrary, the use of newly build hydrogen pipelines has significant influence on the total investment costs. The OPEX of this newly, purpose build pipelines, however, is expected to be lower, as analysed in the next sections. The costs breakdown of platform Type B is even more influenced by the G1 scenario, due to its location further offshore, and the other investment costs are lower due to its size. Both platforms have a similar precentage of electrolyser cost, which implies similar modification costs per kw electrolyser, which is discusses further in this section.

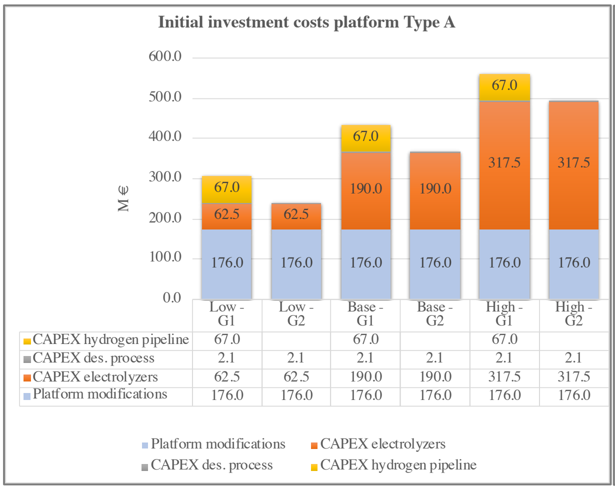


Figure 7:Initial investment cost breakdown platform A in M€

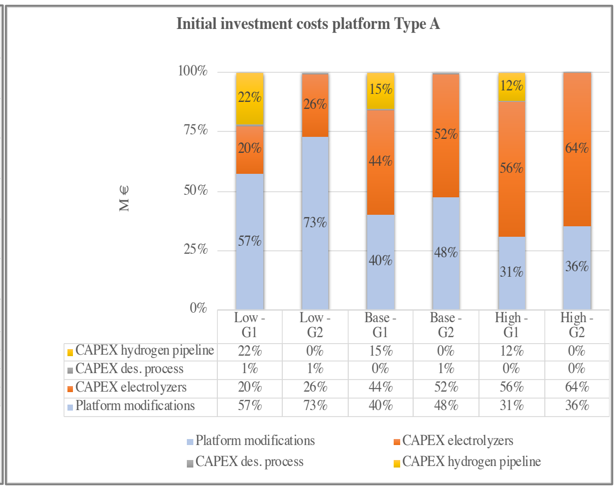
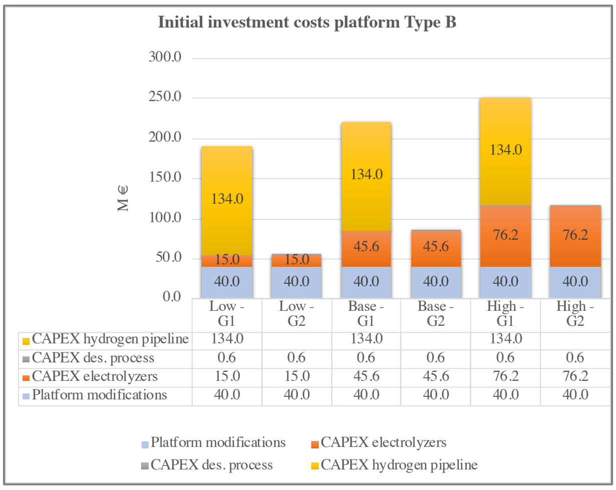
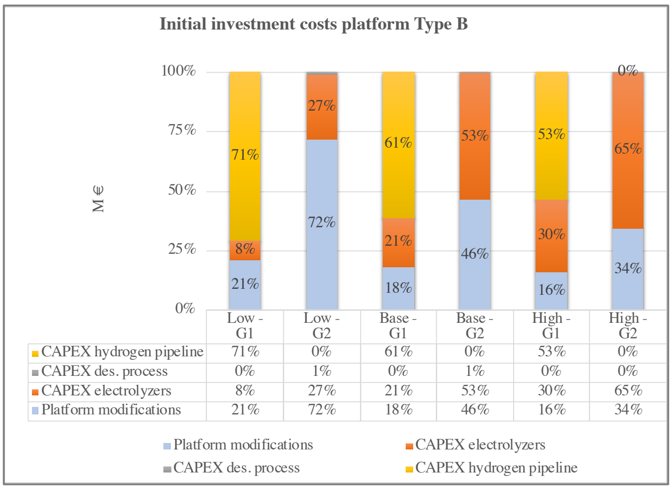


Figure 8: Initial investment cost breakdown platform A in %



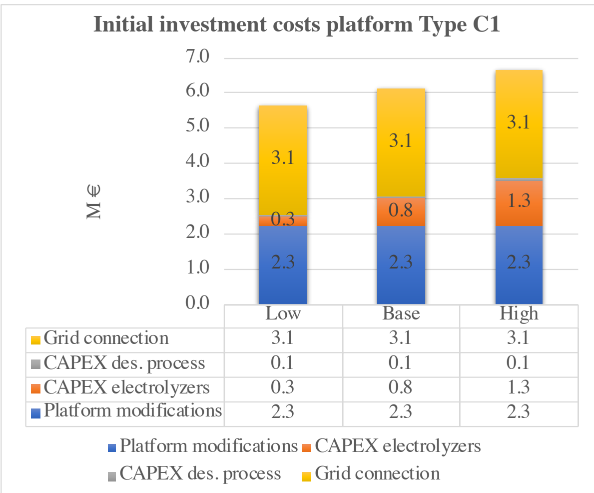
	Low - G1	Low - G2	Base - G1	Base - G2	High - G1	High - G2
CAPEX hydrogen pipeline	134.0		134.0		134.0	
CAPEX des. process	0.6	0.6	0.6	0.6	0.6	0.6
CAPEX electrolyzers	15.0	15.0	45.6	45.6	76.2	76.2
Platform modifications	40.0	40.0	40.0	40.0	40.0	40.0



	Low - G1	Low - G2	Base - G1	Base - G2	High - G1	High - G2
CAPEX hydrogen pipeline	71%	0%	61%	0%	53%	0%
CAPEX des. process	0%	1%	0%	1%	0%	0%
CAPEX electrolyzers	8%	27%	21%	53%	30%	65%
Platform modifications	21%	72%	18%	46%	16%	34%

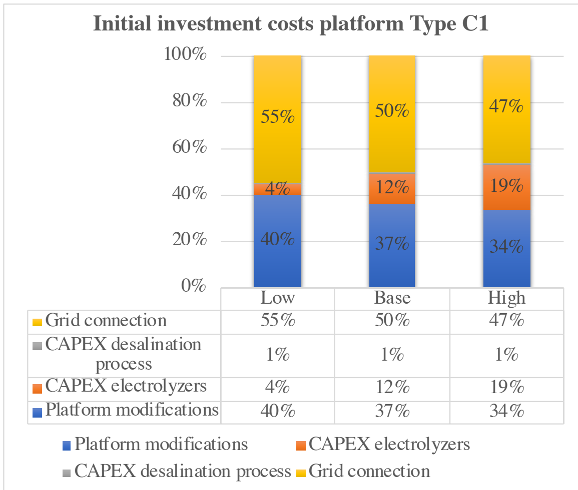
Figure 9: Initial investment cost breakdown platform B in M€. Figure 10: Initial investment cost breakdown platform B in %

When looking at platform type C, the relatively high grid connection costs stand out. The desalination unit again has little influence on the total investment costs. The percentage of the electrolyser costs as part of the total investment costs increases more in the high scenario, due to the fact that the costs remain the same.



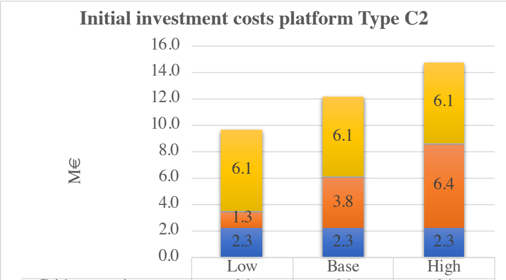
	Low	Base	High
Grid connection	3.1	3.1	3.1
CAPEX des. process	0.1	0.1	0.1
CAPEX electrolyzers	0.3	0.8	1.3
Platform modifications	2.3	2.3	2.3

Figure 12: Initial investment cost breakdown platform C1 (pilot platform with 1 MW electrolyzer) in M€



	Low	Base	High
Grid connection	55%	50%	47%
CAPEX desalination process	1%	1%	1%
CAPEX electrolyzers	4%	12%	19%
Platform modifications	40%	37%	34%

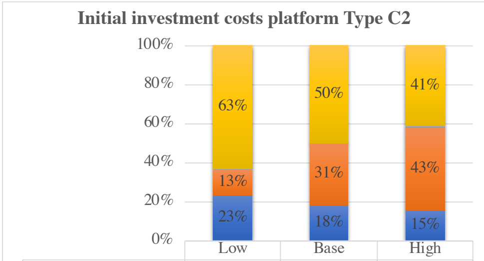
Figure 11: Initial investment cost breakdown platform C1 ((pilot platform with 1 MW electrolyzer) in %



	Low	Base	High
Grid connection	6.1	6.1	6.1
CAPEX des. process	0.1	0.1	0.1
CAPEX electrolyzers	1.3	3.8	6.4
Platform modifications	2.3	2.3	2.3

Platform modifications, CAPEX electrolyzers, CAPEX des. process, Grid connection

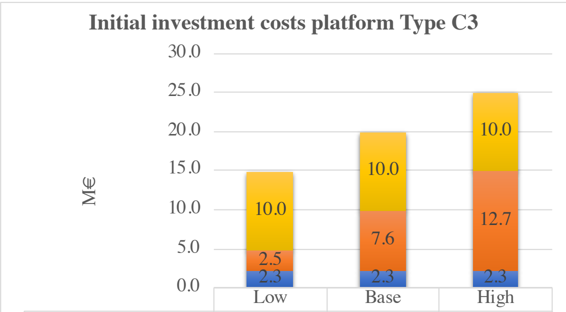
Figure 14: Initial investment cost breakdown platform C2 (pilot platform with 5 MW electrolyzer) in M€



	Low	Base	High
Grid connection	63%	50%	41%
CAPEX desalination process	1%	1%	0%
CAPEX electrolyzers	13%	31%	43%
Platform modifications	23%	18%	15%

Platform modifications, CAPEX electrolyzers, CAPEX desalination process, Grid connection

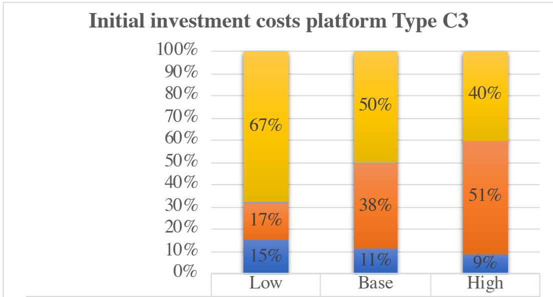
Figure 13: Initial investment cost breakdown platform C2 (pilot platform with 5 MW electrolyzer) in %



	Low	Base	High
Grid connection	10.0	10.0	10.0
CAPEX des. process	0.1	0.1	0.1
CAPEX electrolyzers	2.5	7.6	12.7
Platform modifications	2.3	2.3	2.3

Platform modifications, CAPEX electrolyzers, CAPEX des. process, Grid connection

Figure 16: Initial investment cost breakdown platform C3 (pilot platform with 10 MW electrolyzer) in M€

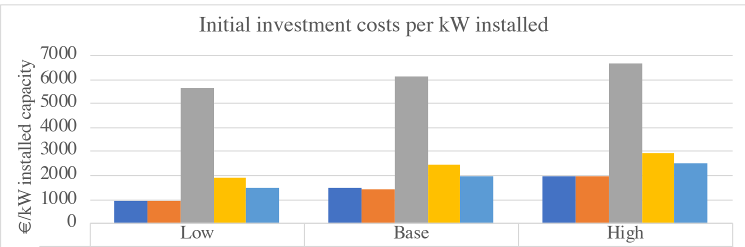


	Low	Base	High
Grid connection	67%	50%	40%
CAPEX desalination process	1%	1%	0%
CAPEX electrolyzers	17%	38%	51%
Platform modifications	15%	11%	9%

Platform modifications, CAPEX electrolyzers, CAPEX desalination process, Grid connection

Figure 16: Initial investment cost breakdown platform C3 (Pilot platform with 10 MW electrolyzer) in %

Figure 18 displays the initial investment costs per kW installed electrolyser capacity. Costs per kW installed are the highest at the pilot platform, not surprisingly due to relatively high costs for very low yield. The costs per kW for type A and B are similar. Apparently, platform investment costs are proportional with the installed capacity.



	Low	Base	High
1A	962	1472	1982
1B	926	1436	1946
1C1	5631	6141	6651
1C2	1934	2444	2954
1C3	1484	1994	2504

Figure 18: Initial investment costs per kW installed

3.3.2 Annual costs breakdown

The expected dominant component of the annual cost breakdown is the cost of electricity. The calculations relating this energy supplied are displayed in Table 15 and Table 16. The assumed electricity prices are derived from Table 7. Explanation about the percentage of curtailment can also be found in the methodology section.

Table 9: Costs of electricity supply for scenario 1 (assuming offshore wind energy)

	Type A	**Type B**	**Type C v1**	**Type C v2**	**Type C v3**
Electricity generated by RES (GWh/yr)	1540.8	354.2	8.76	43.8	86.7
Electricity curtailed (GWh/yr)	74.6	17.9			
Electricity consumption on platform (GWh/yr)	1466.2	336.3	8.76	43.8	86.7
Electricity price (€/MWh)*	50	50	66	66	66
Cost curtailed energy (M€)	3.7	0.9			
Cost electricity used on platform (M€)	77	16.8	0.6	2.9	5.7
Total (€/MWh)	80.7	17.7	0.6	2.9	5.7

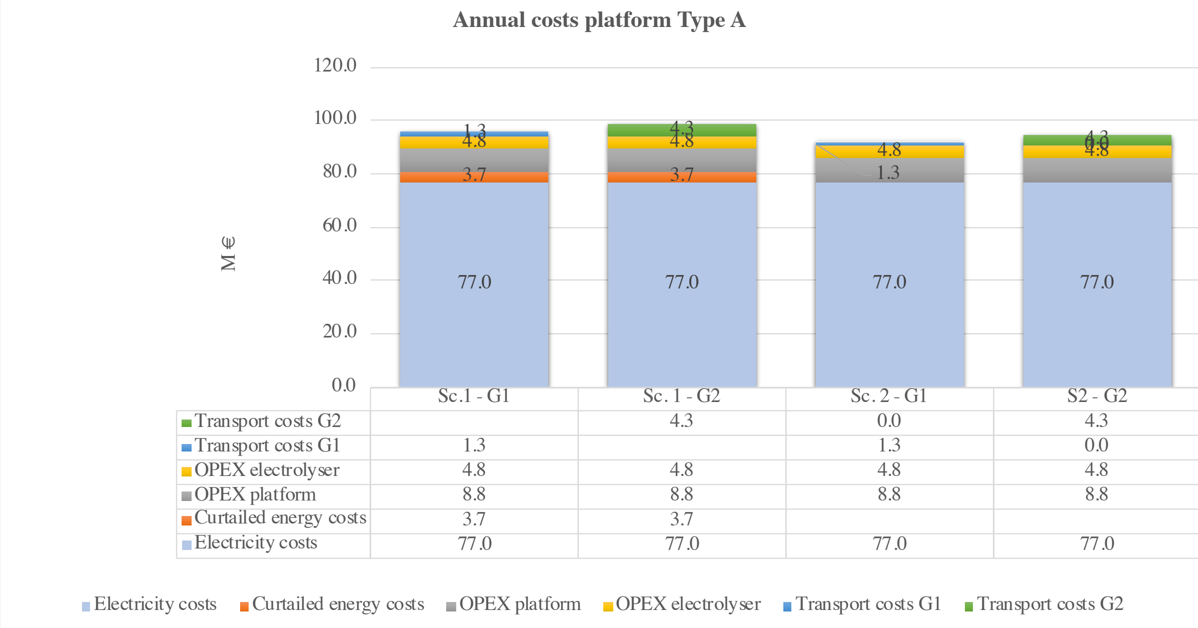
* See Table 6

Table 10: Costs of electricity supply for scenario 2 (assuming offshore wind energy)

	Type A	**Type B**
Electricity generated by RES (GWh/yr)	1540.8	354.2
Electricity curtailed (GWh/yr)	0	0
Electricity consumption on platform (GWh/yr)	1466.2	336.3
Electricity price (€/MWh)*	50	50
Cost curtailed energy (M€)	0	0
Cost electricity used on platform (M€)	77	16.8
Total	77	16.8

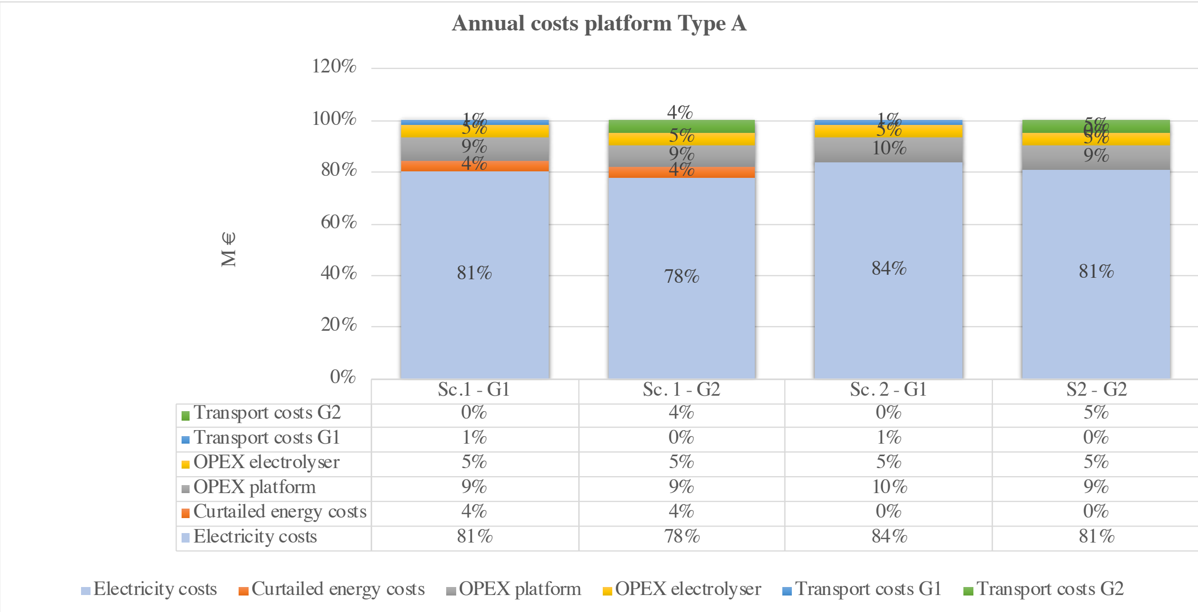
* See Table 6

As mentioned in the methodology section, is the amount of energy lost due to curtailment assigned to the cost of the hydrogen production process of scenario 1. In the cost breakdown below, this curtailment costs, together with the other cost components, are presented. In contrast to the initial investment costs breakdown, the annual cost breakdown of Figure 18 is not divided into three electrolyser scenarios. This is because OPEX of electrolyser is assumed to be 2.5% of the CAPEX, so cost differences between the three electrolyser scenarios, as share of the total annual costs, are small. However, in the eventual analysis, these OPEX differences are taken into account. The two different pipeline transportation scenarios are mentioned. Again, the G1 scenario assumes a newly build pipeline dedicated for hydrogen transportation, where the G2 scenario uses the assumption that hydrogen can be transported using existing pipelines with minor modifications. In contrast to the CAPEX of these pipelines, is the OPEX of scenario G2 more expensive, namely 4% of the total annual costs, instead of 1% in scenario G2. This is due to the higher maintenance costs of the older pipelines when compared to the newly build pipelines. The electricity costs form, as expected, the main share of the annual costs, accounting for roughly 80% of the total annual costs. In the discussion section an additional scenario where two renewable energy sources are combined is introduced.



	Sc.1 - G1	Sc. 1 - G2	Sc. 2 - G1	S2 - G2
Transport costs G2		4.3	0.0	4.3
Transport costs G1	1.3		1.3	0.0
OPEX electrolyser	4.8	4.8	4.8	4.8
OPEX platform	8.8	8.8	8.8	8.8
Curtailed energy costs	3.7	3.7		
Electricity costs	77.0	77.0	77.0	77.0

Figure 19: Annual costs per scenario and platform. in million euros



	Sc.1 - G1	Sc. 1 - G2	Sc. 2 - G1	S2 - G2
Transport costs G2	0%	4%	0%	5%
Transport costs G1	1%	0%	1%	0%
OPEX electrolyser	5%	5%	5%	5%
OPEX platform	9%	9%	10%	9%
Curtailed energy costs	4%	4%	0%	0%
Electricity costs	81%	78%	84%	81%

Figure 20: Annual costs per scenario and platform. As percentage of total annual costs

3.3.3 Hydrogen production

The revenues in this model consist of the produced amount of hydrogen. The amount of hydrogen produced is calculated using the following formula:

$$\frac{Energy\ supplied\ to\ platform\ \left(\frac{MWh}{yr}\right) * effiency\ electrolysis\ process}{Specific\ energy\ hdyrogen\ \left(\frac{MWh}{kg}\right)} = annual\ hydrogen\ production\ (kg)$$

The energy supplied to the platform per scenario is displayed in Table 9 .The specific energy of hydrogen is 0.04 MWh/kg. The electrolysis process is assumed to have a total efficiency of 75%.

This results in the following hydrogen production quantities:

Table 11: Hydrogen production per platform

Platform type	Hydrogen produced (tonnes/yr)
Type A	27,684
Type B	6,351
Type C v1	165
Type C v2	827
Type C v3	1637

Table 17 shows the amount of hydrogen produced per year. To put these numbers into perspective, the industry in the Netherlands currently produces 800,000 tonnes of 'grey' hydrogen per year (TNO, 2020). The global hydrogen production using electrolysis was 280,000 tonnes in 2017 (IRENA, 2018). Table 17 shows the potential of producing industrial amounts of hydrogen on offshore platforms. As explained in section 3.2, the price of hydrogen is subject to many forecasted changes. It is therefore more interesting to see what these tonnes of hydrogen cost to produce.

3.3.4 Levelized cost of hydrogen

In the figures below the levelized cost of producing hydrogen ($LCOH_2$) is presented. As explained in the methodology section, this levelized cost of hydrogen is calculated using a discount factor of 5% and a lifespan of 10 years. Figure 21 shows a relatively small $LCOH_2$ difference for the different hydrogen transportation scenarios. The G1 scenario, where newly build hydrogen pipelines are used, shows a 5% higher price, this is due to the relatively short distance to shore. The difference between scenario 1, where all the energy from a renewable energy source is used to produce hydrogen, and scenario 2, where no curtailment costs need to be made, is more significant, with an average price increase of 10%. The difference between the electrolyzer CAPEX is visible, but with 10% difference between the base scenario and the low and high scenario the influence is lower than expected when seeing the initial investment cost breakdown in Figure 6. Logically, this difference decreases further when the lifetime of the system is prolonged. When this lifetime is set on 15 years, hydrogen prices decrease on average by 7%.

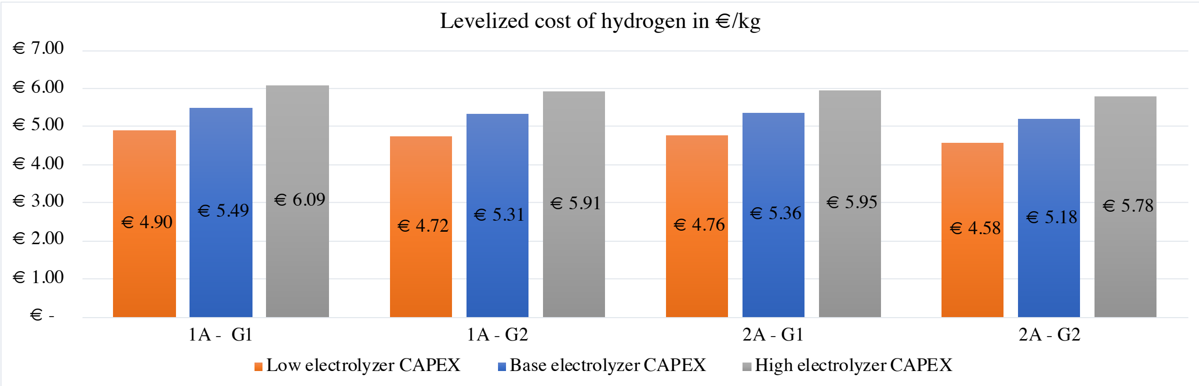


Figure 21: LCOH₂ per scenario for platform type A

When looking at $LCOH_2$ of platform type B, differences between the scenarios are more substantial. This is due to the greater distance to shore, which makes the G1 scenario much more expensive. Roughly, the costs for a new hydrogen pipeline are 600.000€/km. If the platform would be commissioned at closer distance to shore, for example 100km instead of 200, the 1B-G1-Base hydrogen price would decrease to €8.15. When comparing platforms A and B, and thereby assuming both of them operate from the same location, with the same distance to shore, platform B still proves to be more expensive than platform A, in every single scenario. As *Figure 18: Initial investment costs per kW installed* shows a comparable initial investment costs per kW, this difference must come from the average annual costs. Especially differences in annual platform OPEX are disproportionate with the installed electrolyzer capacity.

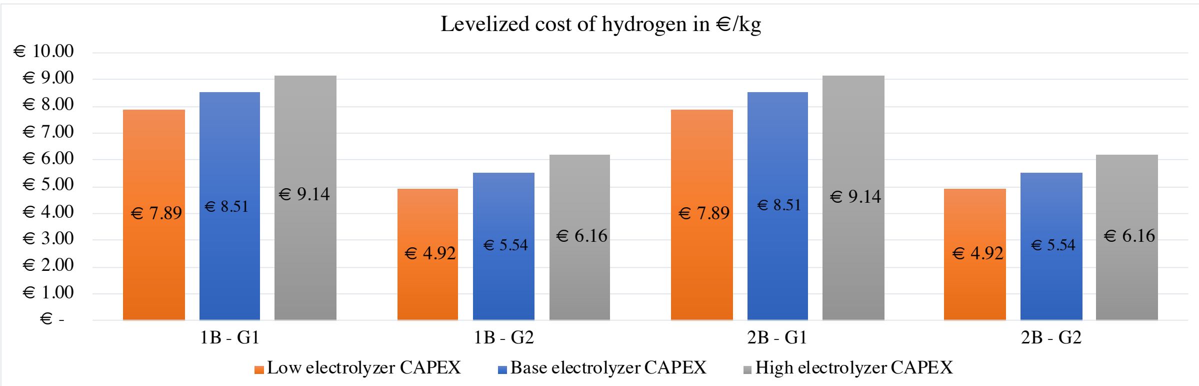


Figure 22: $LCOH_2$ per scenario for platform type B

For pilot platform C, the hydrogen costs are the lowest of the three different platforms. Presumably, the input data for this platform type, which is derived from factsheets of Neptune energy, is a low estimate, assuming many of the costs are covered by subsidies or current production processes on the platform. Nonetheless, it is interesting to see the differences between the three platform configurations. A capacity of 1MW will be useful to test offshore electrolysis condition, but hydrogen prices drop significantly when installing 5 or 10 MW capacity.

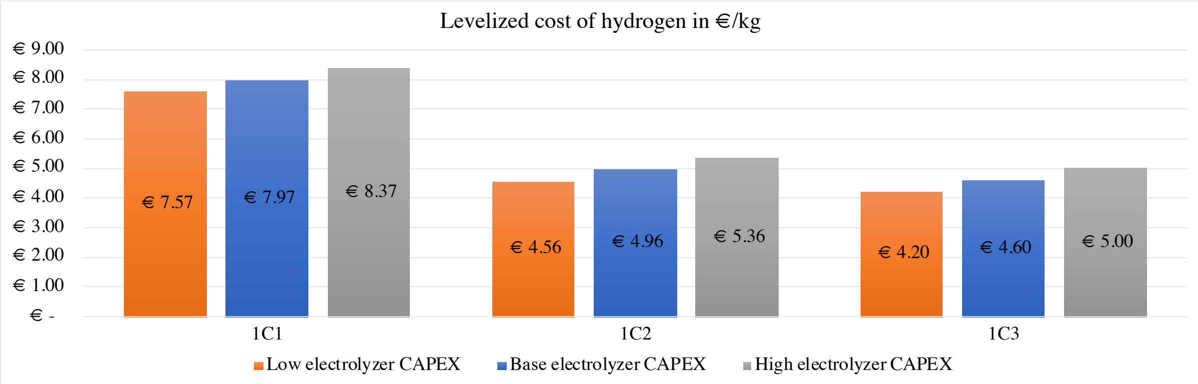


Figure 23: LCOH$_2$ per scenario for platform type C

In the next section the different LCOH$_2$ as presented above are discussed and compared to projected costs found in literature.

4. Discussion

This section follows the order of results as presented in the research. Firstly, the current and future research on the decommissioning of the oil industry on the Dutch continental shelf (DCS) is discussed. Secondly, the limitations of the techno-economic model are addressed, together with expectations on what innovations on costs components can decrease the levelized price of hydrogen. Lastly, another possibility is considered; a combined renewable energy supplied using offshore solar energy together with the aforementioned offshore wind parks.

4.1 Lifetime oil and gas industry

The research started with the question what the economic and technical lifetime of the oil and gas platforms and installations on the DCS is. Due to decreasing revenues, the Dutch oil and gas production sector loses its economic value. Of the 150 installations as displayed in Figure 24 which are currently deployed, 100 will be decommissioned in the coming 10 years (Nexstep, 2020 Nexstep, the Dutch national platform for re-use and decommissioning, has presented two reports on the subject, in 2019 and 2020. In these reports, they state that a limited part of the oil and gas infrastructure can be used for hydrogen production. They estimate that approximately 10% is suitable for re-use. Logically, current reports focus mainly on the other 90%, the actual decommissioning.

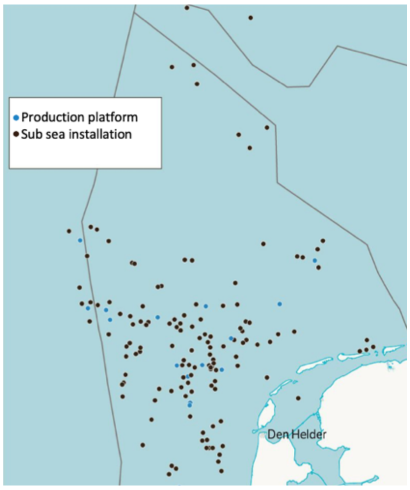


Figure 24: Current oil and gas infrastructure in DCS (Noordzeeloket, n.d.)

This research however is focussing on the re-use possibilities, the production of hydrogen on decommissioned platforms. In the other possibilities for platforms that qualify for re-use are discussed as well. But first, it is explained why this research has not touched upon the electrification of current gas and oil production. The reason for this is that due to the fast decommissioning of the platforms on the Dutch Continental Shelf is going very rapidly. Also, the aim of the research was to look at innovative and sustainable energy transition opportunities In the North Sea area, while electrification the existing oil and gas production mainly has the objective to increase license to operate, regardless of carbon emission restrictions. On the other hand, electrification of oil and gas production can work as a catalyst for offshore system integration, ultimately leading to offshore hydrogen production (KIVI, 2019). The Q13A-A platform, type C from the techno-economic model, is currently the only electrified gas production platform, saving approximately 14,000 tons of CO_2 per year. The largest electrification project currently planned in the Netherlands is the electrification of the K-14 platform. This project aims to replace two gas driven compressor engines with 30MW electrical motors (KIVI, 2019). Platform electrification is expected to work as a steppingstone for hydrogen production, but besides this possibility, can create opportunities for Carbon Capture and Storage (CCS) as well. In order for this research to stay inside the scope of the time and resources, this CCS has not been included in the techno-economic analysis. However, the existing gas infrastructure in the North Sea, together with the empty gas reservoir that will become available after depletion, can be used for carbon storage (Dobbs et al., 2018). Three of the Europe's largest ports, the ports of Rotterdam, Antwerp and Gent, are planning to capture and store 10 million tonnes of CO_2 in gas reservoirs under the North Sea. In 2009, the European commission granted 1 billion euros to finance six pilot projects. Because of increasing costs, not one of the projects was developed. Currently, the world's largest initiative is the Petra Nova project in Texas, which was launched in 2017 and is attached to a coal-fired power station (Boffey, 2019). It has an annual capture capacity of 1.4M tonnes of CO_2 (Mantripragada, 2019). The pipeline planned for the European ports would have the capacity of 5 million tonnes of CO_2 a year. To put this number into perspective, in 2019 the Netherlands emitted an amount of 161 million tonnes of CO_2 (CBS, 2019). In the recent report on *unlocking potential*

of the North Sea (North Sea Energy, 2020), CCS is also mentioned as one of the key elements of low-carbon energy solutions in the North Sea. They see CCS as an important example of system integration because the existing gas infrastructure can be partially used for transport and storage of CO_2. They also mention the importance of platform electrification because it is environmental beneficial for compression and monitoring of the CO_2. CCS is also needed for producing blue hydrogen, which is seen as a possible intermediate step towards green hydrogen.
Green hydrogen forms the most important offshore energy integration option of this research. This option, power-to-hydrogen, entails the conversion from renewable electricity to hydrogen gas. This research focussed on re-use of existing platforms. Another possibly is are new platforms or newly build energy islands (North Sea Energy, 2020). In their report, North Sea Energy mentioned different advantages of the power-to-hydrogen option. The most important advantages are the use of already available gas infrastructure and thus lower costs of transport. This can also lead to shorter onshore power infrastructure extensions. Also, the delay of decommissioning expenditures is mentioned. In the techno-economic analysis these avoided expenditures are not taken into account, due to the fact that these costs are only delayed, instead of cancelled at all. They also mention that hydrogen can be produced at competitive cost offshore (North Sea energy, 2020).

4.2 Techno-economic analysis

4.2.1 Limitations

The first limitation, which applies to the entire techno-economic analysis, is the use of a simplified model. Where there are several extensive reports which incorporates many more cost components, this research, with its limited scope, is based on simplified scenarios and cost components. Because one of the most mentioned advantages of power-to-gas in the North Sea is the use of existing infrastructure, existing platforms were used as locations for the hydrogen production. Scenario 1 involved a situation where all power is converted to hydrogen, so no power connection to shore was needed. This was seen to be interesting due to the more remote locations of future wind farms that are planned, and the high costs of electricity transportation. Due to the absence of power cables to transport electricity to shore during peak load hours, curtailed energy was incorporated in the model. Scenario 2 involved power connection to shore, so no curtailment costs were taken into account.

The characteristics of the platforms were selected from the platforms used in the article *on the economics of offshore energy conversion: smart combinations* by Jepma and van Schot (2017). Where in this article a distinction was made whether the platforms were operational or not, the assumption in this research was made that the platforms were decommissioned by the time they were put to use, based on the expected limited lifetime of the industry in the North Sea. Recent literature does not provide many examples of large scale electrolysers which are compact enough to be installed on offshore platforms, so a simplified version of the Siemens Silyzer 300 PEM was used in the model, with the parameters based on Jepma and van Schot (2017), Siemens AG (2019) and Gigler (2019). This last report presented an analysis of a bandwidth of electrolyser CAPEX which was used to create three cases (Low, Base and High scenario). For the Type C platform, which is based on the already mentioned electrified Q13A-A platform, costs assumptions were more difficult to make. Because no objective literature is available, data was used provided by Neptune in their factsheet. These platform characteristics can be seen as a significant limitation to the relevance of the outcomes of the analysis of hydrogen production prices of this pilot. However, because it is a pilot instead of a full-scale business model, technical implications of the principle of offshore hydrogen production are the main objective of the pilot, instead of producing hydrogen at a competitive price. For the transportation of hydrogen to shore, two scenarios were used. In the G1 scenario, a newly build hydrogen pipeline was used. This pipeline created a significant share, up to 22%, of the initial investment costs of platforms A and B. In the G2 scenario, existing pipelines were used. However, an important limitation in this scenario is the assumption that the hydrogen is transported without being admixed to the natural gas flow. This, since the assumed inactivity of the platforms at the time the hydrogen production process starts. In order to produce hydrogen in existing pipelines, different aspects have to been taken into account, e.g. the lower partial pressure, lower temperatures, and the porosity of the pipeline materials, since hydrogen molecules are smaller than carbon hydro molecules (Haeseldonkx et al., 2007). Future research will have to show whether it will be possible to modify existing pipelines for the transportation of pure hydrogen.

4.2.2 Price of hydrogen

In this section the $LCOH_2$ is compared to typical hydrogen production prices based on existing literature. Figure 25 shows the low-cost and base scenarios for producing hydrogen using renewable energy and for producing blue hydrogen using fossil fuels, so including carbon capture and storage (CCS). The figure shows that hydrogen produced from renewable energy can have the same low price as hydrogen produced using fossil fuels, but only in the best case scenario. The best-case wind scenario in the figure, in which hydrogen is produced for 1.25 €/kg, electricity is supplied for 20€/MWh, and electrolyzer CAPEX is 170€/kW[1]. When applying these prices for platform scenario 2A-G1, which is the best-case scenario from the analysis that uses newly build pipelines for hydrogen transportation and no curtailment costs are made due to power lines to shore, the LCOH drops from 4.76 to 2.82 €/kg, which is still significantly higher than the 1.25 presented in the Table below. When using the parameters that were used at the other scenarios in the IRENA research, $LCOH_2$ of scenario 1A-G1 is 5.31€/kg. This is around 1 euro per kg more expensive than the average cost wind scenario and around the same production price as the average-cost solar PV scenario, which is displayed on the far left side of Figure 24.

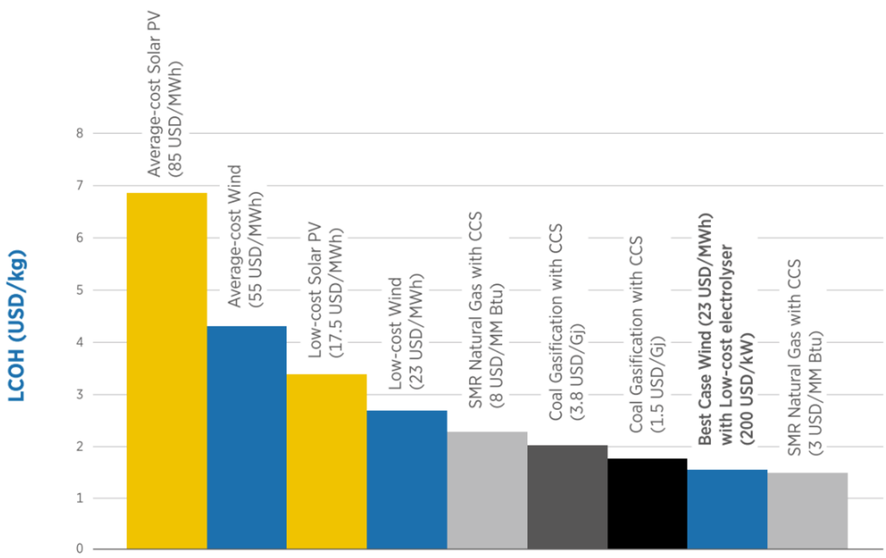


Figure 25: Costs of producing hydrogen from renewables and fossil fuels today (IRENA, 2019)

When looking at the $LCOH_2$ of the other scenarios, it is clear that those costs per kilogram produced are higher than the outlook prices as presented in section 3.2 and Figure 25. The most positive business case is the of platform Type A, using existing gas infrastructure with no curtailment. However, it is important to note that the costs of curtailment are relatively low, so the benefits from an electricity grid connection is not significant.

[1] (Exchange rate used: 0.85€/$, June 30th, 2020).

When looking at the breakdown of total investment costs of the platforms of transportation scenario G1, where a purpose build hydrogen pipeline has to be installed, costing 700,000 €/km, the percentage of this hydrogen transportation as part of the total investment costs are significant. Figure X shows how this percentage relates to the distance a pipeline has to cover to shore, in case of platform type B. The percentages, ranging from 20% to nearly 70%, are significantly higher than typical 15 to 30% grid connection cost of the percentage of total CAPEX of offshore wind farms (Douglas- Westwood, 2010).

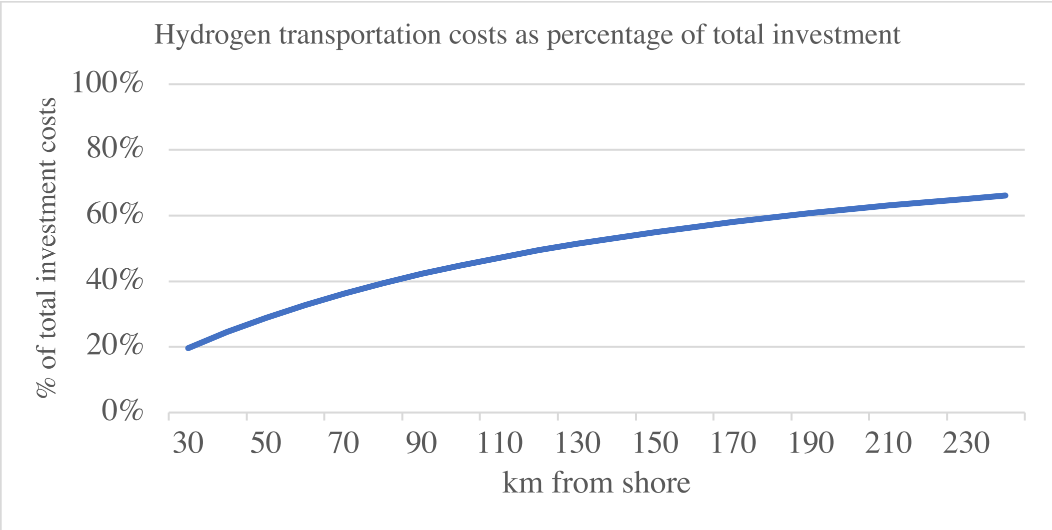


Figure 26: Hydrogen transportation costs as % of total investment costs for platform type B

While the focus of this research so far has been on wind energy as renewable energy, a combination of renewable energy sources is analysed as well. As showed in Figure 13, electricity input forms the most important costs component for all different platform types. This section shows the influence of energy supply on the $LCOH_2$. Not only the price of renewable energy is taken into account, but mainly the consequences of combining renewable energy sources on the capacity factor of the electrolysers. The ideal situation for hydrogen production is a combination of a low electricity price combined with a high capacity factor (IRENA, 2019). With the wind farm capacities and load hours presented in Table 7, the capacity factors of the electrolyzers on platform type A and B are respectively 67% and 64%. The reason this capacity is not optimal is the simple reason that the renewable energy source, wind in this case, does not provide the needed 60 or 250 MW al day round. In the case of scenario 1, where all energy is converted to hydrogen, an average of 6% of the produced energy has to be curtailed. This is happening when the wind farm produces more energy than the 60 or 250 MW.

Because the $LCOH_2$ is above the expected market price, the most positive scenario is chosen in this analysis, in order to see if a positive business case is possible in the future. The characteristics of the platform for this analysis are based on platform type A, which has 250 MW of installed electrolyzer capacity. The electrolyzer CAPEX scenario used is the low-cost scenario. The reason for this combination of scenarios is to see whether a more optimal location with a higher capacity factor can result in a competitive 'green' hydrogen price. Newly purpose build hydrogen pipelines are used for transporting the hydrogen to shore, due to the assumption that the platform is out of use by the time large scale offshore solar energy is available. As can be seen in Figure 10, the foreseen $LCOH_2$ for this scenario is €5.79/kg. As is mentioned in the section about hydrogen production and pricing, the hydrogen price has to drop to at least €5/kg. This number is used in this analysis as aiming price and is in figure below displayed as the red horizontal line.

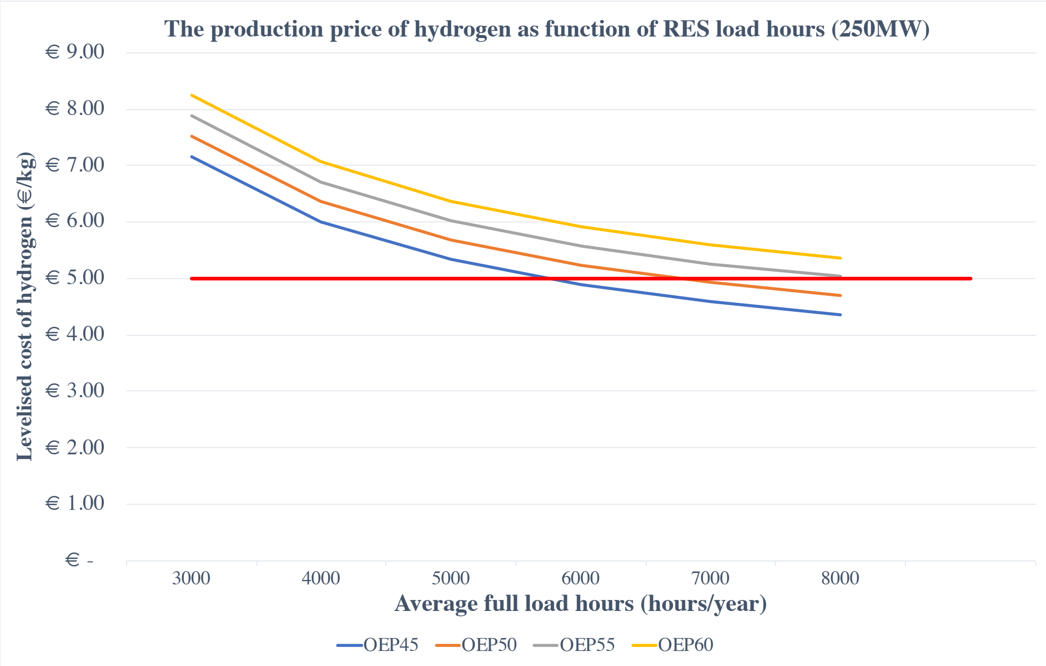


Figure 27: Production price of hydrogen as function of the average total amount of full load hours of a combination of renewable energy source for 4 different offshore energy prices (OEP<€/MWh>)

For the analysis, four different offshore energy prices (OEP) were used. The number after OEP displays the costs of energy in €/MWh. OEP50 is based on the current electricity production prices of Dutch offshore wind farms on the selected locations, as displayed in Table 6. OEP45 is incorporated due to predicted decrease in offshore energy prices, which are expected to decrease to even lower values after 2030 (Ruijgrok et al., 2019). OEP55 and OEP60 are based on a higher energy price than the current outlook prices. This is based on the assumptions that the wind energy will be combined with one or more other renewable energy sources. To see whether this combination may be viable, it is relevant to look at the load factors necessary to achieve a production price of 5 €/kg hydrogen. When looking at Figure 27, it is clear that a relatively high amount of full load hours is needed to achieve this production cost. For the OEP60 and OEP55 scenarios, with current input parameters and scenario assumptions, the figure does not show a realistic amount of full load hours. The OEP60 scenario does not provide a number of hours at all, while OEP55 requires an amount of over 8000 full load hours. In the OEP50 scenario, 5700 hours of full load capacity, which corresponds with a capacity factor of 65%, is needed. With the current capacity of 4800, as displayed in Table 7, this means that another 900 full load hours are needed. This can be achieved using different technological options. When these electrolysis processes are carried out onshore, with less space restrictions, storage of energy is the best option. Available space is limited on the platforms, and the space that is available is used for electrolysis. Another way to increase the capacity of the renewable energy source is combining the wind energy with solar energy, using a joint distribution of wind speeds and solar irradiance. Irradiance is somewhat anticorrelated with wind speed throughout the year, e.g. on cloudy days wind speed is higher (Bett et al., 2016). Figure 28 visualizes this concept. In order to get an idea of the economic feasibility of this combination, two different offshore renewably energy farms are

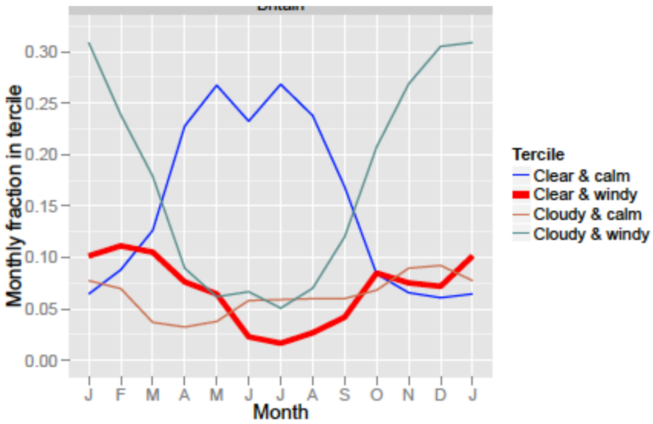


Figure 28: Anticorrelation between windy and clear days ((Bett et al., 2016)

assumed. One of them is the already mentioned 271MW wind farms with a full load capacity if 4800 hours per year. The other is a hypothetical offshore solar farm of 271 MW per year. The average annual capacities of typical PV farms vary between 10% and 21%, which results in an average of 1370 full load hours per year. When looking at a typical load duration curve of offshore wind energy used in this research, an amount of 1600 hours per year the energy production exceeds the 250MW, and consequently has to be curtailed in scenario 1. This also implies that during 7160 hours per year, the electrolyzers do not produce at their rated power. Based on the assumptions of Bett et al., one can cautiously presume that at least 900 hours, which are needed for the OEP50 scenario, of the 1370 full load hours will fall outside these 1600 'windy' hours. The other 470 full load hours of the solar farm has to be curtailed as well. In this case, which entails many assumptions due to the fact that no large scale combined offshore farms exists at the moment, the two large-scale farms, have the combined capacity of 5700 full load hours. On a yearly base, 1300 GWh is produced by the wind farm, from which 1225 is supplied to the 250 MW platform and 75 GWh is curtailed. The 271 MW solar farm produces 370 GWh, from which 243 GWh is supplied to the platform as addition to the wind energy and an assumed 128 GWh needs to be curtailed. This system will increase the capacity factor of the electrolyzer on platform A in scenario 1 from 67% to a 95%.
The low-cost offshore wind electricity price outlook of Ruijgrok et al (2019) foresees the cost of wind energy to decrease towards 40€/MWh. Assuming a combined offshore electricity price of 50 €/MWh, and an energy supply ratio of 1300 GWh and 370 GWh for respectively the wind farm and the solar farm, the costs for the solar energy has to get to 85€/MWh. Future research and the feasibility of large scale solar farms on the North sea is needed to assess whether a large scale solar farm in this region is possible, and what the accompanying LCOE's will be, but if solar energy is expected to meet the price of offshore wind energy (Kost et al., 2019), so this 85 €/MWh is expected to be possible in the future decades. As an alternative to solar farms, wave energy can be used as additional renewable energy source next to solar. Wave energy converters capture the energy in ocean waves and use that energy to generate electricity. Due to limited commercial experience, the estimates of the production costs of this type of renewable energy in 2030 is in the range from 85 to 121 €/MWh (IRENA, 2014). However, due to its expected capacity factor of 35 to 42%, wave energy converters may be more suitable than solar farms for increasing the total load of the combined energy sources in the future. However, compared to solar energy, wave energy has the disadvantage that its energy production over a certain period of time is more in phase with wind energy, and therefore less suitable as complementary renewable energy source.

5. Conclusion

This research contains a techno-economic analysis of offshore hydrogen production as one of the alternatives for decommissioning the existing oil and gas infrastructure. Before addressing this techno-economic analysis, this research focussed on the economic and technical lifetime of the oil and gas infrastructure on the Dutch Continental Shelf. As of 2020, 150 platforms on the Dutch Continental shelf produce 11 billion m^3 of gas per year. However, due to decreasing revenues, the Dutch oil and gas production sector is losing its economic value. Of the 150 installations which are currently deployed, 100 will be decommissioned in the coming ten years. Carbon capture and storage (CCS) and offshore hydrogen production are seen as two of the most promising options for the repurposing of these decommissioned platforms. Approximately 10% of the 150 platforms can be used for such activities.
Hydrogen is seen as a promising solution for the intermittency problems that arise when the share of renewable energy sources in the energy mix increases. Because the largest part of the renewable sources in the Netherlands is located offshore, the research addresses the opportunity of hydrogen production on the decommissioned platforms. The aim of this part of the research was to analyse the production cost per kg hydrogen on the offshore platforms. In the techno-economic analysis, two scenarios were distinguished. In the first scenario, the produced renewable electricity is completely converted to hydrogen on the platforms. No additional electricity connection to shore is needed. This scenario entails curtailment of renewable energy when the supply of this energy exceeds the capacity factor of the electrolyzers on the platform. Costs for this curtailment were incorporated in the model. In the second scenario, the produced electricity is partly converted to hydrogen and partly transported to shore as electricity, so additional electricity transportation to shore is needed. The advantage of this scenario is that no curtailment costs have to be made. Three different platforms sizes are distinguished, with different electrolyzer capacities, ranging from 250 MW on the largest platform to 1 MW on the small pilot platform.
The analysis resulted in a levelized cost of hydrogen ranging from 4.90 €/kg in the most positive scenario, where electrolyzer costs are low and hydrogen is transported to shore using existing pipelines, to 10.81 €/kg in the high cost scenario. This is significantly higher than expected production costs of 3 €/kg of green hydrogen in 2030, with even lower estimates of 2 €/kg in case of a significant decrease in electrolyser CAPEX and an increase in electrolyze efficiency. Based on the outcomes of the analysis, and using the assumptions made in this research, no competitive price can be reached. It must be noted that many assumptions for the input parameters were used in this research, due to the fact that no test results exist, because no pilot or large-scale offshore hydrogen production is deployed at this moment. The PosHYdon initiative aims for a small-scale pilot starting in 2021. Test results from this pilot must prove whether a large-scale business case can be viable in the future. The ideal situation for hydrogen production is a combination of a low electricity price combined with a high capacity factor. This high capacity factor may be reached by combining different renewable energy sources. Adding a large-scale solar farm to a wind farm can increase the capacity factor of the electrolyser from 67% to 95%. Wave energy converters may be an even better option, due to their higher load factor. However, compared to solar energy, wave energy has the disadvantage that its energy production over a certain period of time is more in phase with wind energy, and therefore less suitable as complementary renewable energy source. Aside from this, currently no large-scale wave and solar energy farms are deployed offshore. Future research must show whether the combination of renewable energy sources is a realistic option.
In conclusion, the best-case renewable hydrogen production options in the North Sea are currently not competitive with grey hydrogen prices, produced using natural gas, or onshore produced green hydrogen, which has the advantage of lower CAPEX, transportation costs, platform modification costs and lower electricity costs. However, due to the decommissioning of offshore infrastructure and the increasing urge to find energy storage options for the growing share of intermittent renewable energy in the energy mix, it seen as a concept with potential. This research shows that significant cost reduction is necessary to make offshore hydrogen production on existing platforms economically viable.

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