Master Thesis

Global Techno-Economic Feasibility of Far Offshore Green Hydrogen Production towards 2050

T. Melles

MARIN TU Delft

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Global Techno-Economic Feasibility of Far Offshore Green Hydrogen Production towards 2050

by

Tycho Melles

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Company supervisor	
Responsible supervisor:	Ir. J.J. de Wilde
Email:	J.deWilde@marin.nl
Thesis exam committee:	
Chair/ Responsible professor:	Dr. ir. J.F.J. Pruyn
Staff member:	Ir. J.L. Gelling
Staff member:	Dr. J.M. Vleugel
Staff member:	Ir. M.B. Duinkerken
Company member:	Ir. J.J. de Wilde
Author details:	
Student number:	4868099
Contact email:	tycho.melles@gmail.com

Preface

Before you lies my graduation thesis. To write this thesis, I have decided to embark on a journey into a new, relatively unexplored field of research: far offshore green hydrogen production. In the rest of this report, it will become clear what was already known and what knowledge was still missing regarding the potential of far offshore green hydrogen production, how the available knowledge was utilized and extended in this research, and what the worldwide potential of far offshore green hydrogen production is expected to be towards 2050. Also, it will be discussed how this research could be used as a base from which to further explore the exciting research field of far offshore green hydrogen production.

My gratitude goes to my supervisors Jeroen Pruyn, Jaap Gelling and Jaap de Wilde for their guidance, advice and continuous feedback throughout the writing of this thesis. With their help, I was able to deliver an impactful, insightful and useful result which will help to further advance the knowledge base regarding the far offshore production of green hydrogen and its derivatives.

Tycho Melles
Delft, 17-01-2024

Abstract

As the world attempts to slow down and eventually stop climate change, sustainability becomes increasingly important. To reach net-zero emissions, hydrogen produced through water electrolysis with renewable energy, also known as green hydrogen, is expected to be necessary. Space restrictions onshore, strong offshore renewable resources, and growing demand for green hydrogen and renewable energy in general indicate a potential for floating green hydrogen production (far) offshore. However, the technological and economic feasibility of far offshore green hydrogen production towards 2050 remains relatively unclear. Therefore, this research aims to answer the following main research question:

Which role is far offshore green hydrogen able to play in the path towards a worldwide net-zero economy in 2050, how is this influenced by various factors, and which technologies are expected to be integrated in its supply chains, looking at both the technological and economic feasibility?

In an extensive literature review, the primary gap in literature was identified, which was found to be an evaluation of the worldwide potential of far offshore green hydrogen production over time using local comparisons with specific scenarios. In addition, the literature review identified suitable methods for the research. The focus of the analysis and therefore the model was put on the optimization of far offshore green hydrogen supply chains (instead of higher level supply/demand interaction), which was expected to lead to the most reliable and relevant insights at this point in time. Furthermore, it was decided to use optimization with mixed integer quadratically constraint programming (MIQCP) for the model and implement it in Python with the Gurobi optimization solver. Finally, it was decided which technologies to include in the rest of the research. Energy generation with floating wind and solar, and electrolysis with PEM electrolyzers and desalination equipment on a floating production, storage and offloading unit (FPSO) were included. Transport over sea in ships as liquid hydrogen or ammonia, and transport over land in pipelines as gaseous hydrogen are also considered. Furthermore, suitable estimations were found for hydrogen demand and alternative green hydrogen costs.

Six worldwide scenarios in which far offshore green hydrogen was expected to have the highest potential were defined. These scenarios were then analyzed with the model in the period between 2020 and 2050 to assess the potential of far offshore green hydrogen production and the technologies involved. From the results of these analyses, it may be concluded that far offshore green hydrogen costs will be in the same order of magnitude as its alternatives, especially as we get closer to 2050. In some scenarios, its costs are closer to its alternatives than in others, but none of the scenarios show a clear economic preference for far offshore green hydrogen. As these are already the scenarios with a high potential for far offshore green hydrogen, this means the role this hydrogen is able to play in the path towards a worldwide net-zero economy in 2050 is expected to be relatively small from a purely techno-economic perspective. In practice however, geopolitical and societal factors may increase its potential.

From the results, it can also be seen that combining wind and solar energy generation is beneficial when producing green hydrogen far offshore in certain scenarios. Furthermore, ammonia is expected to be the preferred transport medium until at least 2050. In addition, the cost distributions and performed sensitivity analysis give interesting insights as to what influences the costs per kilogram of far offshore green hydrogen.

Limitations to this research are found in possible inaccuracies of the results due to uncertainties of the input data and model simplifications. Many possibilities for follow-up research exist, which include (1) using the developed model to gain more insights, (2) expanding the model to improve the accuracy of its results even further and (3) building additional models to explore the topic. In addition, a lot of related research is still needed as well, such as in-depth technical studies.

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Chapter 1

Introduction

1.1 Background and problem definition

As the world attempts to slow down and eventually stop climate change, sustainability becomes increasingly important. Many agreements have been made and goals have been set to reduce greenhouse gas emissions. Over 70 countries, responsible for 76% of emissions and including China, the USA and the European countries, have set net-zero targets. However, the 193 parties participating in the Paris agreement taken together are on track to increase their emissions by 11% in 2030 with respect to 2010, instead of the 45% reduction needed to keep global warming within 1.5 degrees. This means drastic steps must be made to reach the set goals. (United Nations, n.d.) Recently, agreements were made to accelerate the transition away from fossil fuels at the COP28 UN Climate Change Conference in Dubai (NOS, 2023).

1.1.1 The last mile of decarbonization: green hydrogen

In order to reduce emissions, the European Union has drawn up a long-term strategy aiming for net-zero emissions in 2050 (European Commission, n.d.). According to Lapides et al. (2020), around 80% of the economy is relatively easy to decarbonize by electrification, with costs being reasonable and technologies already (widely) available. This part of the economy concerns general power generation (with renewable energy), passenger vehicles (electric vehicles), heating of buildings (heat pumps and energy saving measures) and manufacturing processes that do not include high temperatures. The other 20% consists of peak power generation (the peaks when the generated renewable energy does not cover the demand), heavy duty transport (buses, trucks and ships) and industrial processes requiring combustion of a fuel to create high temperatures. For this last 20%, also referred to as the 'last mile' of decarbonization, hydrogen may play a key role in the path towards sustainability, as visualized in Figure 1.1. (Lapides et al., 2020)

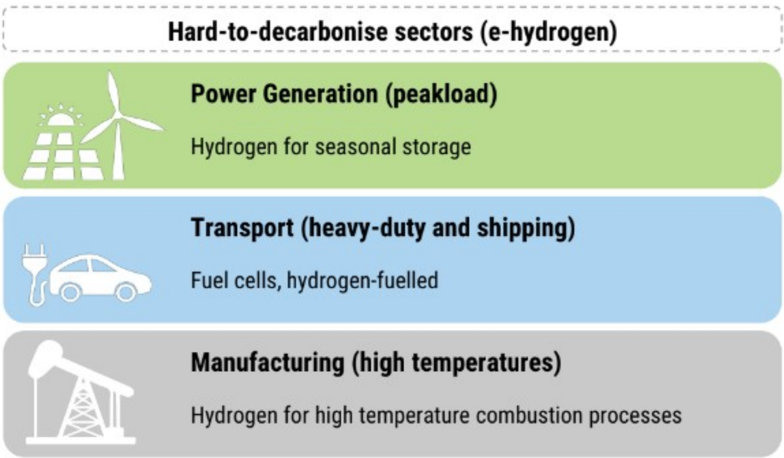


Figure 1.1: Parts of the economy where hydrogen may play a major role in decarbonization (Lapides et al., 2020)

Hydrogen may be seen as an alternative fuel, being able to replace for example diesel oil or natural gas. However, since hydrogen requires natural gas or electricity to be produced (in a process where losses occur), it is generally seen as less energy efficient and more expensive. (Lapides et al., 2020) However, with a net-zero emission economy in mind, sustainable hydrogen may still play an important role, as explained above. Hydrogen may be produced in several ways, resulting in so-called grey, blue or green hydrogen. Grey hydrogen is the most common form at this moment and is produced in a process called steam methane reforming (SMR), where high-temperature steam reacts with a methane source (for example natural gas) to produce hydrogen, CO and CO2. Since emissions occur during the production of this hydrogen, it is not seen as sustainable and not suitable to be used to reach net-zero goals. The production of hydrogen using coals, also called brown hydrogen, causes CO2 emissions as well and can be put in the same category. (Hague, 2021)

The process for the production of blue hydrogen is similar to the one for grey hydrogen. However, this time carbon capture and storage (CCS) is applied, meaning a large part of the produced CO2 is captured and stored, often underground. In the short term, it is expected that blue hydrogen will be necessary to make the transition to green hydrogen as part of the path towards a net-zero economy. If this would not done, it would result in a ‘bow wave’ of CO2 emissions, resource usage and investment costs, leading to higher societal costs and a slower decrease of CO2 emissions (Von Döllen et al., 2021). Blue hydrogen can be seen as an intermediate step in the transition from grey to green hydrogen, since it is relatively easy to implement with the current grey hydrogen production facilities as a basis, but does not lead to zero emissions and can therefore not be part of the eventual net-zero emission economy. (Hague, 2021)

Finally, green hydrogen production occurs in a process called electrolysis, where electricity and water are used to produce hydrogen and oxygen. When renewable energy is used in this process, the hydrogen can be regarded as zero-emission or green. In Figure 1.2, the CO2 emissions of different hydrogen production techniques are shown. As can be seen, indeed only electrolysis using renewable energy leads to zero-emission (green) hydrogen. Since the production of green hydrogen will require large amounts of energy, a lot of additional renewable energy is also expected to be needed. (Hague, 2021) When considering hydrogen production with electrolysis, it should be noted that electrolysis using non-renewable energy leads to very high CO2 emissions (see also Figure 1.2) and should therefore not be seen as sustainable. One kilogram of hydrogen contains 33 kWh of energy (Agriculture and Horticulture Development Board, 2023). To put the numbers in Figure 1.2 into perspective: the CO2 emission of heavy fuel oil (HFO) is 0.27 kg CO2/kWh (The Engineering ToolBox, 2009), which means 33 kWh of energy equals an emission of 8.91 kg CO2.

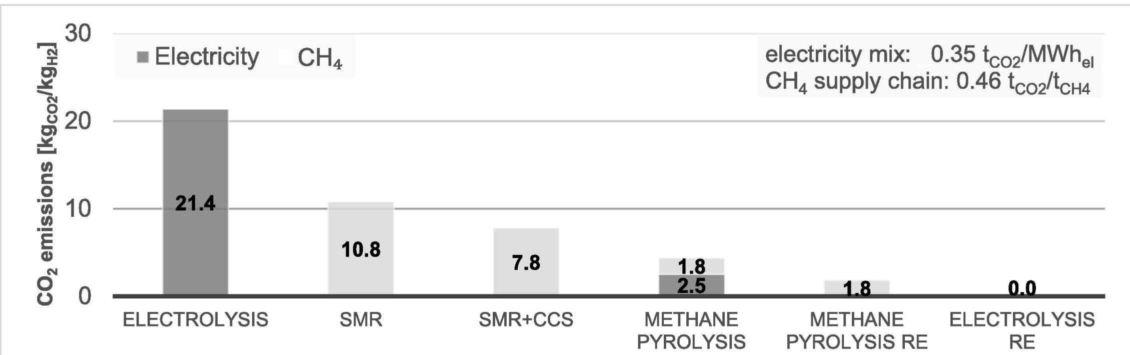


Figure 1.2: CO2 emissions of several hydrogen production techniques (Dermühl & Riedel, 2023)

1.1.2 Rising demand for renewable energy

At the moment, 98% of the produced hydrogen is grey (Hague, 2021), meaning a significant increase in sustainable hydrogen production is needed to make hydrogen part of the net-zero future. This is especially the case when taking into account the expected rise of demand for hydrogen; Lapides et al. (2020) predict hydrogen’s share in the EU’s primary energy mix to rise from 2% in 2019 to 15% in 2050. This expectation can be linked to the EU’s hydrogen strategy, where the potential of hydrogen is utilized to bridge the last mile to a net-zero economy as explained before.

This strategy consists of several steps. Starting from an electrolyzer capacity of 0.06 GW in 2020, the first step aims to increase the capacity to 6 GW in 2024, which would mean the current hydrogen use would be decarbonized and the need for grey hydrogen would be eliminated. In the next step, the capacity is increased to 40 GW by 2030, where hydrogen starts to play a major role in industrial processes, transport (trucks, trains and ships) and in balancing the renewable energy system (covering peak loads). In the final step, the electrolyzer capacity is increased to 500 GW, which is aimed to be reached in 2050. At that point, hydrogen technology is expected to have developed to maturity and hydrogen is applied in many different parts of the economy. (Lapides et al., 2020)

Given the energy losses in hydrogen production, Lapides et al. (2020) estimate a renewable energy need of 1100-1300 GW for an electrolyzer capacity of 500 GW, roughly doubling the EU's current energy need. In addition, the current energy need will also be decarbonized greatly, meaning a lot of new renewable energy sources will be needed. Hague (2021) also mentions that each year for the next 30 years, more offshore wind capacity will have to be installed than in the previous 20 years combined.

Next to the EU, the demand for hydrogen is expected to rise strongly in many parts of the world (The Hydrogen Council & McKinsey & Company, 2021), meaning the potential for green hydrogen production can be assessed on a global level. In general, the expected rise of demand for (green) hydrogen is very significant and should be considered when looking at the potential of green hydrogen production options.

1.1.3 Offshore green hydrogen production

As may be concluded from the above, a lot of new renewable energy generation will be needed. For Northwestern Europe, offshore wind energy (OWE) is seen as one of the most suitable renewable energy sources and the European Union aims to develop 300 GW of offshore wind capacity by 2050 (De Vries et al., 2021). This makes sense, given the scarcity of land in this part of the world (De Wilde, 2022). In addition, other offshore renewable energy generation devices are being developed and should be taken into account, such as offshore solar platforms (Jan De Nul, 2023) and wave energy converters (SBM Offshore, n.d.).

When hydrogen production is required and renewable energy is generated offshore, the consideration must be made whether to produce the hydrogen onshore or right at the energy source offshore (and then transport the hydrogen to shore). For sufficient volumes, the latter is expected to be preferred, given the lower costs, less complex rollout, improved reliability and possibilities for offshore hydrogen storage. It would also decrease the environmental impact, since a pipeline transports significantly more energy than a cable and existing natural gas pipelines could be used. (De Vries et al., 2021) In Figure 1.3, the costs for offshore and onshore hydrogen production using energy from offshore wind are compared for various sizes of wind farms. This figure is indicative and other factors such as the distance to shore of the wind farm are also expected to have an influence, but it may be seen from this figure that with bigger wind farms, offshore hydrogen production may become highly beneficial.

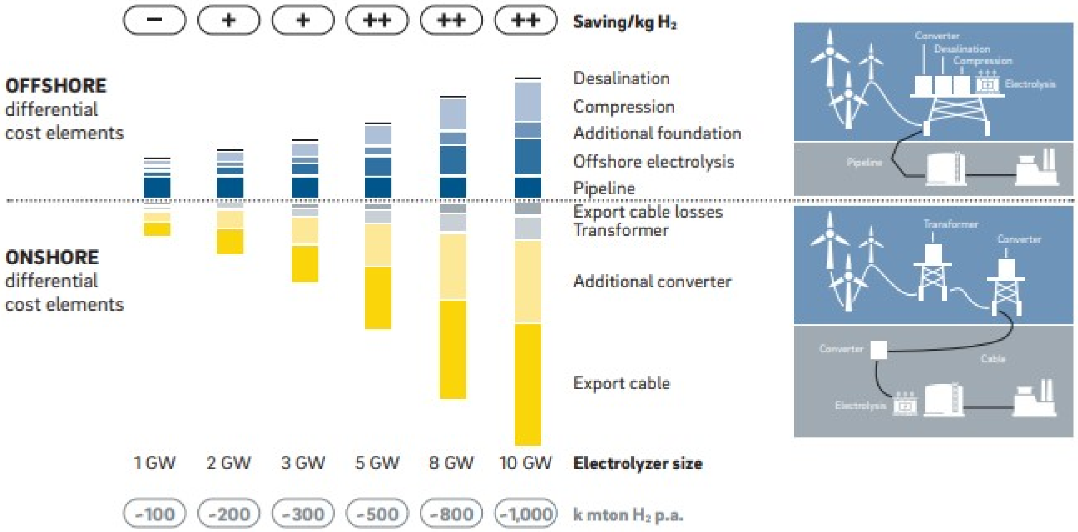


Figure 1.3: Indicative comparison of costs for onshore and offshore hydrogen production using energy from offshore wind parks of various sizes (De Vries et al., 2021)

1.1.4 Floating production

When the hydrogen is produced offshore, one of the limitations for offshore energy generation becomes much less stringent; the generated energy does not have to be transported to shore by electrical cables, meaning the distance to shore has a smaller influence. The flexibility regarding the distance to shore means many promising offshore wind locations could be utilized, such as the seas off the southern coast of Greenland, which have some of the strongest and most constant winds on earth, causing a wind energy capacity that is 3.5 times higher than in the North Sea. This could further reduce the costs of offshore hydrogen. However, since many of these waters are too deep for bottom-founded structures, floating energy production such as floating wind is the last crucial factor in this mix. Many industry parties are already working on this; SBM offshore for example has a floating wind turbine design that can be anchored in water with a depth up to 2000 meters. From about 50 m of water depth, bottom-founded structures for wind turbines are economically not possible anymore and floating wind energy production becomes necessary (Arapogianni & Genachte, 2013). In this research, all areas with water depths over 50 m will be considered 'far offshore', which is the focus area of this research. In these areas, the hydrogen production itself would have to be done on an FPSO, which is used in the offshore oil and gas sector as well.

Babarit et al. (2018) mention that with bottom-fixed offshore wind turbines (in waters less than 50 m deep), the maximum amount of energy that can be generated in Europe in 2030 is 3500 TWh, which is only 16% of the expected energy demand, showing the necessity to go further offshore with floating wind. Floating offshore wind (FOW) turbines are getting closer to commercial viability and the first commercial floating offshore wind farm, the Hywind Scotland farm, was constructed in 2017 and consists of five 6 MW turbines. Since then, several other FOW farms have become operational or have started construction with sizes ranging from 1 MW (the SeaTwirl S2 farm in Sweden) to 400 MW (the Yangjiang Guangdong farm in China). (Rehman et al., 2022)

To achieve high capacity factors, winds that are both strong and stable year-round are necessary. Therefore, Babarit et al. (2018) identify the areas with class I winds (average above 8.5 m/s) in both summer and winter, which are shown in Figure 1.4. The dashed line in this figure indicates a distance of approximately 1000 km from shore, equal to 1.5 days sailing at 15 knots. This shows that a significant part of the high potential areas are located in deep waters, but still relatively close to shore. In general, it can be seen that very large areas are available offshore for wind energy production with high capacity factors.

Figure 1.4: Offshore areas with class I winds year-round (shaded) (Babarit et al., 2018)

To install wind turbines in deep water (far) offshore, floating foundations are used. The basic concept of floating foundations has been used for a long time in the oil and gas sector and has already proved its functionality and durability in the harsh operating environments encountered offshore. The dynamics caused by installing a wind turbine on such a platform is however a new consideration. In Appendix H, a short discussion has been added of the different platforms commonly used for FOW.

At the moment, the pre-commercial floating wind projects produce electricity for about 180-200 euros/MWh. However, it is predicted that these costs will drop to 80-100 euros/MWh by 2025 and 40-60 euros/MWh by 2030, given that volumes and industrialization develop as envisioned (De Vries et al., 2021). This is already a good future perspective, given the fact that for the Dutch (bottom founded) offshore wind farms in the North Sea the costs are around 60-80 euros/MWh (Lensink & Pisca, 2019). However, the costs for floating wind may decrease even further, given the possibilities for standardization of floating foundations, the possibility to assemble a floating turbine in port and tow it to its location, the possibility to tow floating turbines to a port for maintenance, and improvements of design for floating wind turbines specifically. (De Vries et al., 2021) For green hydrogen production, the electricity accounts for almost 65% of the costs, meaning the decreasing energy prices have a big influence on the costs per kg of this hydrogen (Lapides et al., 2020).

It may be clear that the combination of demand for green hydrogen, available FPSO technology and developments in floating offshore wind (and other floating sources of renewable energy) could present a promising opportunity to further bring down green hydrogen costs and tap into vast energy sources that are left unused until now. Other parties have already identified the opportunity of far offshore green hydrogen production, as is for example shown in the report by De Vries et al. (2021) which was referred to before. However, it remains relatively unclear what exactly is already technologically possible at this moment, which technological developments different parties are working on and the progress they expect to make over time, how the total costs for far offshore green hydrogen in different locations are expected to develop in the future and how this is influenced by various factors, and how far offshore green hydrogen compares to other sources of green hydrogen. In short, the technological and economic feasibility of far offshore green hydrogen production over time must be researched further. This leads us to the objective of this research.

1.2 Objective

The main objective of this research is to create a first idea of the worldwide technological and economic feasibility of far offshore green hydrogen production over time, identifying the technologies to be used in its supply chains, comparing it to its alternatives, exploring what influences its costs, and showing the role it may play in a net-zero economy in and towards 2050. The technological feasibility will be mostly explored through the literature review, identifying technologies that are (expected to be) feasible and should be taken into account in the further analysis of far offshore green hydrogen supply chains. Using the literature review as a base, the rest of the thesis will mainly focus on the economic feasibility, while also taking an additional look at some of the technical considerations.

To reach the objective formulated in the previous paragraph, far offshore green hydrogen supply chains will have to be analyzed. Many factors can influence the far offshore green hydrogen supply chain and therefore the costs of far offshore green hydrogen. Among other things, the right combination of different energy generation devices, electrolyzers, conversion devices, storage size, FPSO size and hydrogen carrier must be determined in every scenario. In order to find the optimal far offshore green hydrogen supply chains leading to the lowest far offshore green hydrogen costs, an optimization model is needed. The focus of the literature review will be how this model should be set up, including the modelling methods, the focus of the model, and what technologies to consider in the model.

1.3 Research questions

To come to the intended conclusions, a main research question and several sub-questions were formulated. The main research question to be answered in this thesis is:

Which role is far offshore green hydrogen able to play in the path towards a worldwide net-zero economy in 2050, how is this influenced by various factors, and which technologies are expected to be integrated in its supply chains, looking at both the technological and economic feasibility?

In order to answer this main research question, several sub-questions have been formulated. The following sub-questions will be answered in this research:

1. How can the model for this research be set up such that it allows for the collection of insights leading to the most complete and reliable answer to the main research question?
2. Which scenarios should be analysed in order to obtain an as complete as possible overview of the potential of far offshore green hydrogen and the relevant technologies around the world and over time?
3. What are the values of the relevant techno-economic parameters of the considered technologies and the other needed input data?
4. In what locations and under which circumstances could far offshore green hydrogen production already be feasible from a techno-economic perspective at this moment?
5. In what other locations or scenarios could far offshore green hydrogen production become feasible from a techno-economic perspective, and when is this expected?
6. What is the influence of various aspects of the far offshore green hydrogen supply chain on the eventual far offshore green hydrogen costs?
7. Which (combinations of) technologies are most promising in the far offshore green hydrogen supply chain and under what circumstances?

The first sub-question will be mostly answered in the literature review. In the following chapters, all other sub-questions will be answered as well in order to eventually be able to answer the main research question.

Chapter 2

Literature review

In this chapter, an overview of the retrieved literature and its contents will be given. Based on this literature, conclusions will be drawn regarding the existing gaps in literature to be filled (partly) by this thesis and suitable methods to do this. In Section 2.1, the methodology and execution of the literature review will be described. Next, Section 2.2 will describe the primary gap in literature that this research will attempt to fill. Section 2.3 will then identify suitable methods to fill this identified gap in the literature. Finally, Section 2.4 will discuss which technologies to include in this research.

2.1 Methodology literature review

In this section, the methodology for the literature retrieval will be discussed, in order to make sure the performed literature research is repeatable. For the retrieval of literature, mainly SCOPUS has been used, as this can be seen as one of the main, very complete databases of scientific papers. In this section, the used search terms and associated sources found will be given, making clear which literature has been found where and how. Each of the search terms mentioned has been searched twice until no relevant references were found anymore, once with the results sorted based on relevance and once with the results sorted based on year of publication. This has been done to find both the highly relevant papers and the papers describing the most recent development. This was deemed necessary because a lot of research is being done into the topics reviewed at the moment, meaning the developments go quickly and it is important to have a good overview of the most recent findings. 83 % of the literature eventually included was published in the last three years.

After all the search terms identified as relevant had been searched, a systematic overview of the retrieved literature was made in order to understand what is already known. This overview including accompanying explanation has been added in Appendix A, B and C.

In total, eight combinations of search terms were used, most of which were meant to get a complete overview of all relevant topics. These topics were the hydrogen production (offshore renewable energy production and green hydrogen production), the hydrogen usage, the hydrogen transport, and the modelling methods. Some of the search terms had a more exploratory nature (the last two in Table 2.1) and were meant to figure out which research has already been done regarding far offshore energy and hydrogen production specifically. In Table 2.1, the used search terms are shown and it is explained why they were included.

Table 2.1: Explanation search terms

Search terms	**Explanation**
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	This combination was included to find general information on offshore renewable energy and hydrogen production techniques. During preparatory exploration, it was concluded that mainly wind, solar and wave energy showed potential for offshore energy generation towards 2050, which is why these received the focus of this literature research and were included here. The term 'cost' was added because without it too many irrelevant results showed up and it was found that when the technological feasibility of the technologies of interest was discussed, almost always the costs were discussed (shortly) as well. In addition, the economic feasibility plays a central role in this research.
(wind OR solar OR wave OR hydrogen) AND offshore AND econom*	Since 'cost' is rather specific, a similar combination of search terms as the previous one was included but now with 'econom*' as the last term. This made sure no relevant references were missed.
green AND hydrogen	This combination was included to find references discussing the production of green hydrogen in general.
hydrogen AND demand AND countries	This combination was included to find references looking at the present and future demand for hydrogen in various parts of the world, also reviewing the price level based on alternative green hydrogen supply options.
hydrogen AND transport AND (pipeline OR ship)	This combination was included to find references discussing the transport of hydrogen, with a focus on transport over sea.
solar AND offshore	Since the first two search terms in this table gave a relatively small amount of references that discussed offshore solar energy production, this search term was included to fill this gap.
far AND offshore AND hydrogen	This combination was included to see what references were available that discussed production, transport and/or usage of hydrogen far offshore specifically.
far AND offshore AND renewable	This combination was included to see what references were available that discussed renewable energy production far offshore specifically.

As mentioned before, each of the combinations shown in Table 2.1 was searched on Scopus. A title scan and subsequently a quick abstract scan were performed which resulted in a list of possibly interesting references. Next, the selected references were analysed further by doing an extensive abstract scan and a quick scan of the rest of the paper. This lead to a further selection and structuring of the papers. In Figure 2.1, the literature retrieval process is shown visually and the amount of references is indicated for each part of the process. As can be seen, the initial scan resulted in a total of 247 references, which was brought down to 180 after the second scan. Eventually, a total of 57 references were identified as most relevant (categories A and C, see also Appendix A for a more detailed explanation of the different categories). The literature review has been written primarily based on these references. In all of the reviewed literature, only one reference was found describing a solution approach with a similar scope, which will be discussed in more detail in Section 2.2.

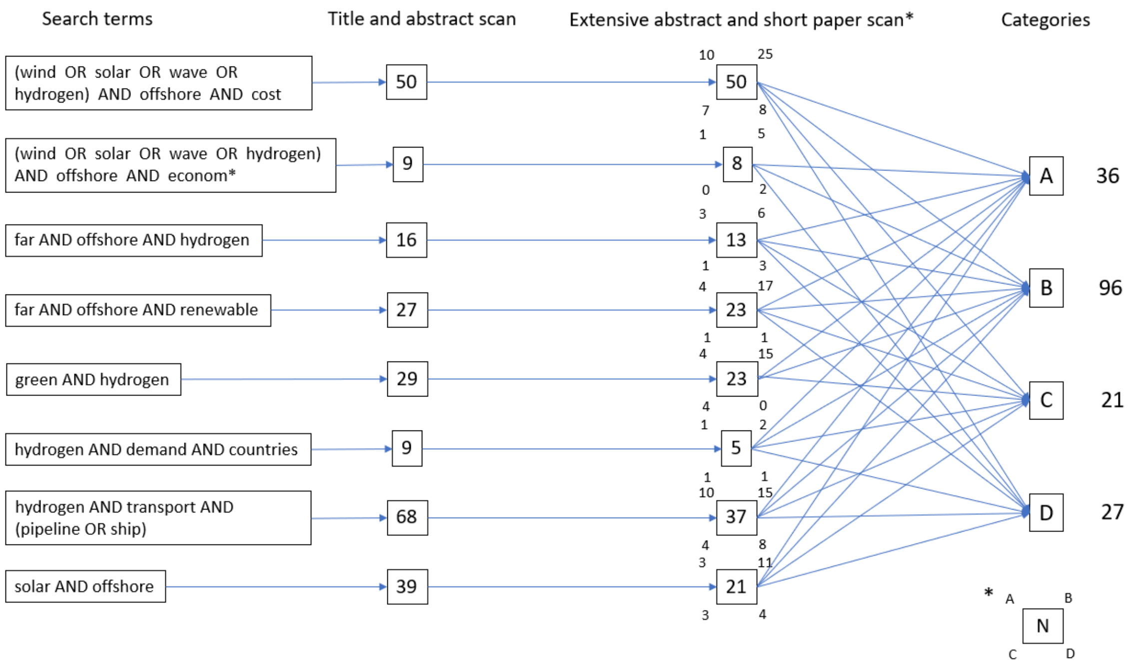


Figure 2.1: Flow chart literature retrieval (please note that the small numbers in the third column indicate how many references were placed into each category, as shown in the legend in the bottom right corner of the figure)

2.2 Primary gap in literature

This section will explain the primary gap in literature identified while reviewing the retrieved literature. During the reviewing, only one reference describing a solution approach with a similar scope to this research has been found. In this paper, Salmon and Bañares-Alcántara (2022) from the University of Oxford look at the feasibility of (far) offshore green ammonia production, taking into account the fact that land scarcity poses a major limit to onshore production and considering the options of combining wind and solar energy generation.

In Figure 2.2, the modelling approach used by Salmon and Bañares-Alcántara (2022) is shown. To implement this approach, they set up a mixed integer linear programming (MILP) optimization model. As a solver, they used the Gurobi optimization solver. When analyzing their approach, several limitations were identified. Below, these limitations are discussed and adjustments to the modelling approach used by Salmon and Bañares-Alcántara (2022) are proposed to find a baseline for the model to be developed in this research.

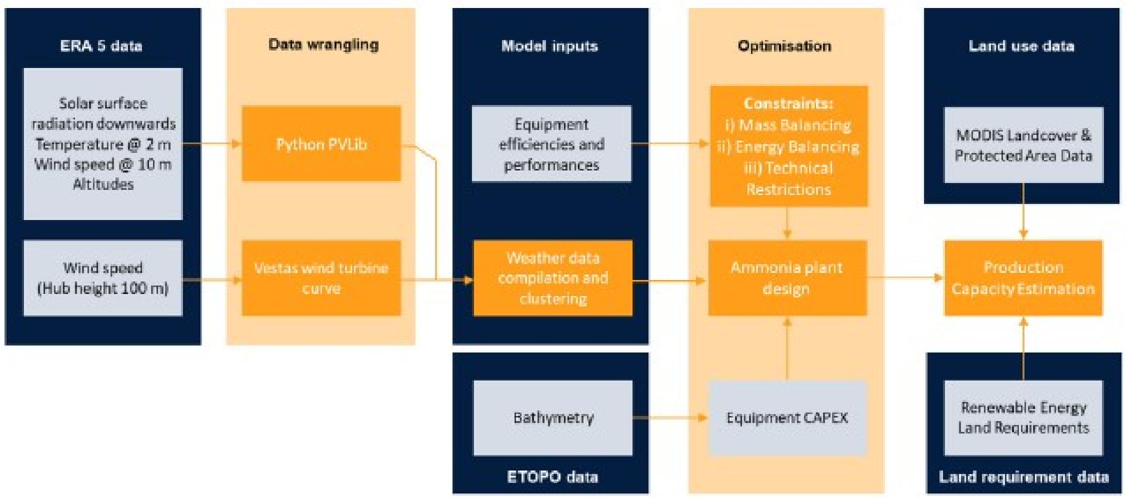
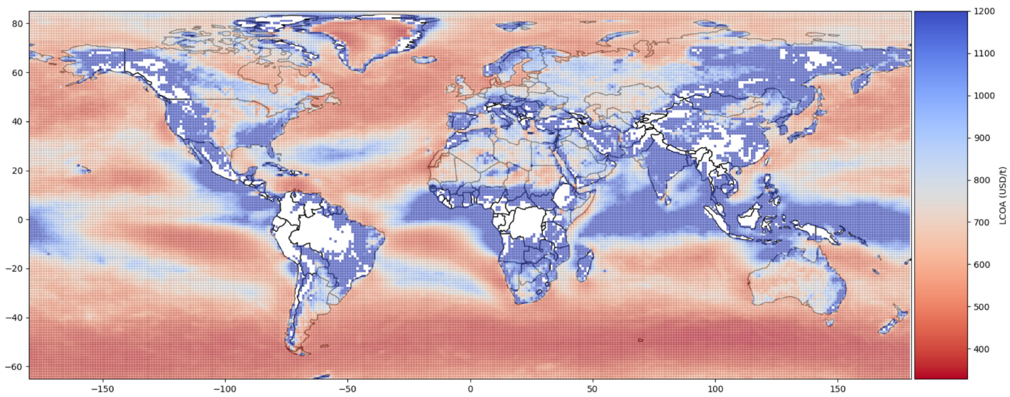


Figure 2.2: Modelling approach as applied by Salmon and Bañares-Alcántara (2022)

Salmon and Bañares-Alcántara (2022) show the massive potential of wind resources available on the ocean, but also show that the significantly higher costs for offshore wind and the potential of onshore solar decrease the benefits of offshore ammonia production, as shown in Figure 2.3. With this figure it must however be noted that it does not give a completely accurate visualization of the potential for green ammonia production, since certain areas indicated as high potential are in reality not very suitable.

An example of the latter is Greenland, which is indicated as being able to produce ammonia onshore at a very low price based on the available wind and solar resources, while it would in reality be very difficult to have large-scale chemical process there due to the temperature and other environmental condition (Salmon & Bañares-Alcántara, 2022). The model made by Salmon and Bañares-Alcántara (2022) takes into account technological constraints, but since it would theoretically be possible to produce in Greenland it is not excluded and since the model takes into account different onshore costs for large regions, but not for individual countries, the model sees it as a suitable location. The fact that onshore production costs are not differentiated per country shows a limitation to the research. Including an estimation of local green hydrogen production costs per country such as for example given by Brändle et al. (2021) could lead to more accurate results.

(a) - Wind only, onshore and offshore costs equal



(b) - Wind and solar, true onshore and offshore costs

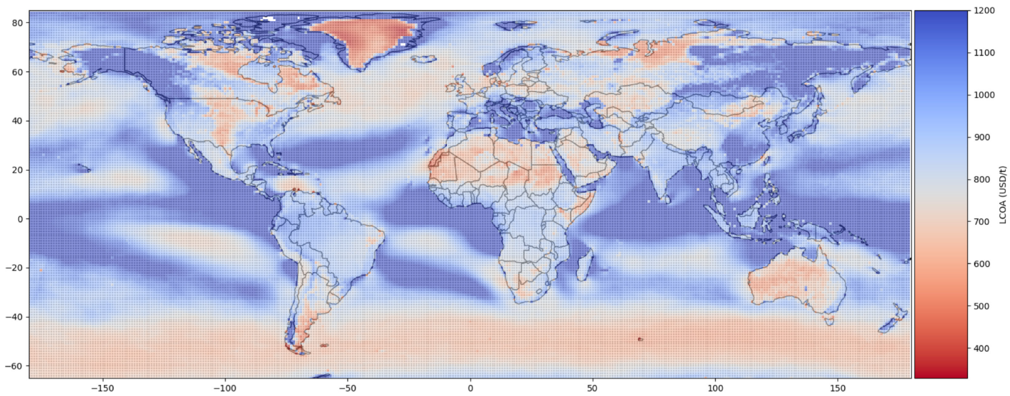


Figure 2.3: Levelized cost of ammonia production worldwide in 2030 when only using wind with the same costs on- and offshore (a) and when taking into account the higher cost of offshore wind and using both wind and solar onshore (b) (Salmon & Bañares-Alcántara, 2022)

Salmon and Bañares-Alcántara (2022) conclude that the best locations for green ammonia production remain to be onshore. However, once a certain amount of demand is passed and the best onshore locations have been exploited, offshore green ammonia production would become a feasible solution when land scarcity is taken into account. This is especially the case if the costs for solar panels and electrolyzers further decline. How much they should decline and by when this is expected is however not further discussed. Since the expected ammonia production costs are only reviewed in 2030, a further outlook on the future potential of (far) offshore ammonia production (for example towards 2050) is not given, which is another limitation. Extending the analysis further into the future as for example done by Brändle et al. (2021), which assess the potential of (onshore) low-carbon hydrogen production options until 2050, could lead to important additional insights.

Furthermore, the comparisons between on- and offshore production are made on a global level, while it would be more beneficial to do this on a country/region level. The fact that the best offshore green ammonia production sites cannot compete with the best onshore sites does not mean that in some regions (with high local hydrogen production costs or high import costs) it could not already be beneficial to produce offshore. For this reason, comparing green hydrogen production costs on a global level directly as done by Salmon and Bañares-Alcántara (2022) in their main analysis does not lead to a realistic comparison and fails to show the full potential of far offshore green hydrogen production. Therefore, the global potential of far offshore green hydrogen should be assessed 'bottom-up', where a representative set of specific scenarios is analyzed, from which conclusions are drawn about the global potential of far offshore green hydrogen. The fact that Salmon and Bañares-Alcántara (2022) did not do a local comparison of delivered ammonia costs worldwide to assess the actual potential of (far) offshore production shows a major limitation to their scope.

In the global comparisons mentioned in the previous paragraph, the transport costs are not yet taken into account and these are only considered for two specific cases later (Hamburg and Yokohama), which can be seen as another limitation. When looking at the specific cases, it is concluded that for Hamburg far offshore green ammonia production would not be beneficial, while for Yokohoma it would. (Salmon & Bañares-Alcántara, 2022) This shows the importance of evaluating the potential for different locations and/or situations separately (and including transport) as argued in the previous paragraph.

Furthermore, only green ammonia is considered by Salmon and Bañares-Alcántara (2022). This ignores the potential of other hydrogen carriers, while several other options exist (International Renewable Energy Agency, 2022a).

Finally, it does not become clear whether the needed demand to make offshore green ammonia production feasible will be reached. Only the current ammonia demand from the fertilizer industry is considered and no predictions are made about the demand development, although some new applications of ammonia such as maritime fuel are mentioned. It is expected that including demand estimations such as those made by The Hydrogen Council and McKinsey & Company (2021) in the analysis would lead to important additional insights.

All in all, it seems clear that the approach taken by Salmon and Bañares-Alcántara (2022) shows several limitations because of the absence of demand estimations in the analysis, the absence of predictions further into the future, the fact that the costs for transport were not taken into account in the main analysis and the limited consideration of local green hydrogen production costs. Furthermore, by only looking at the potential of far offshore ammonia production, other applications of hydrogen and therefore its full potential for far offshore production are not taken into account. The main limitation however is found in the global instead of local comparison of far offshore production with its onshore alternatives. The main gap in literature is therefore concluded to be an evaluation of the global potential of far offshore green hydrogen over time using local comparisons with a representative set of specific scenarios.

Having presented the limitations identified in the research by Salmon and Bañares-Alcántara (2022), adjustments to their modelling approach (as already shown in Figure 2.2) can be proposed to create a base for the model to be developed in this research. Figure 2.4 shows the adjustments to be made (in green). As can be seen, the transport of the produced hydrogen or its derivatives and the local demand are taken into account, also leading to additional constraints regarding the logistics and the demand/supply balancing. Furthermore, the optimization leading to the most optimal plant design will not only consider ammonia, but also other hydrogen carriers, as various options exist (Cebolla et al., 2022; International Renewable Energy Agency, 2022a). In addition, the period until 2050 is considered, instead only the year 2030. Based on the plant design, costs and amount to be produced, the costs per kilogram of the produced hydrogen (carrier) can be determined, which can then be compared to local alternatives, mainly green hydrogen (derivatives) produced locally or imported. The fact that the local demand, transport and local alternatives are taken into account show that the modelling approach assesses the global potential of far offshore green hydrogen through local comparisons. With these adjustments, all limitations discussed in the previous paragraph have been addressed. In Section 2.4, it will be decided what exactly to include in the intended model for the different aspects shown in Figure 2.4 (which hydrogen carriers, which energy generation devices, what kind of electrolyzers, how the transport will be set up, etcetera).

As can be seen in Figure 2.4, the right column, which represented the estimation of the production capacity, has been taken out. As the amount to be produced will now depend on the specified demand, this part is not needed anymore. Taking the production capacity estimation out also reduces the complexity, leading to a lower development and computational time, which partly compensates for the added parts..

Lastly, it can be seen from Figure 2.4 that it is expected that the left three columns can remain (almost) the same. Similar wind and solar data from ERA5 can be used in the intended model, which is done by several other references as well (Burdack et al., 2022; Diaconita et al., 2022; Soukissian et al., 2021). The solar data can be processed using PVLib. For the wind data, a wind turbine curve can be used, but WindPowerLib is also suitable (Burdack et al., 2022). When considering the weather data, taking a so-called representative day approach, where a small number of daily profiles represent a full year, does not lead to satisfactory estimates (Salmon & Bañares-Alcántara, 2022). This means a longer period must be simulated to make proper estimations. Finally, it is expected that bathymetry data can be collected in a similar way to be included in the scenarios and that similar techno-economic data will be put into the model, although the technologies to be included still have to be determined in Section 2.4, as mentioned before.

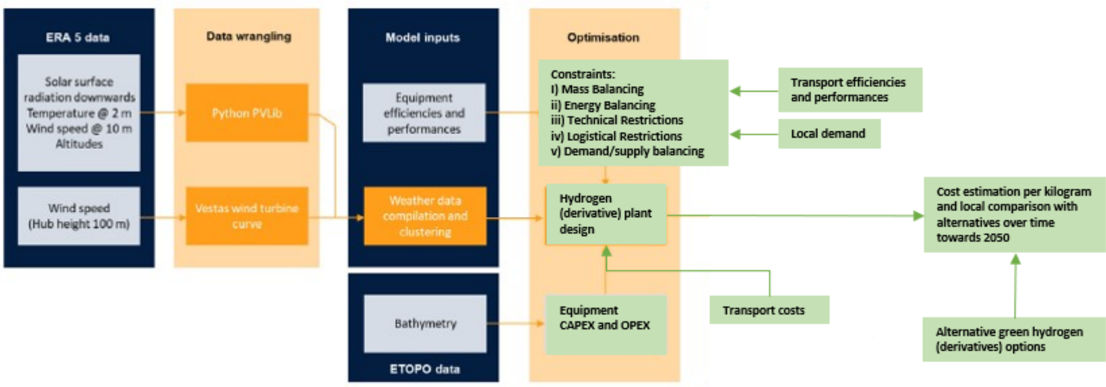


Figure 2.4: Adjustments to the modelling approach by Salmon and Bañares-Alcántara (2022) as to be applied in the intended research (the green boxes)

By reviewing various representative scenarios with the intended model, insight into the potential of far offshore green hydrogen production around the world and over time can be created. In the research to be performed, the described model will be set up and, using this, the identified primary gap in the literature will be filled. In Section 2.3, the method will be looked into in more detail, discussing the focus of the model, the methods to be used and the implementation. The foundation for this was already laid in this section. In Section 2.4, each part of the far offshore green hydrogen supply chain will be looked into separately to learn more about what is known regarding the technological and economic feasibility of the relevant technologies and their expected development. Based on this, it will be decided what technologies to include in the model.

2.3 Suitable methods

In this section, the most suitable methods to be used for the model to be developed will be identified, using the baseline found in Section 2.2 and shown in Figure 2.4. First of all, the focus of the model will be discussed in Subsection 2.3.1. Next, Subsection 2.3.2 will discuss the general method to be applied, after which Subsection 2.3.3 will discuss the implementation of the model. Finally, Subsection 2.3.4 will give a short conclusion.

2.3.1 Focus of the model to be developed

In this subsection, the focus of the model to be developed will be discussed. Given the limited amount of available development and computational time, choices will have to be made regarding simplifications to be implemented. These simplifications can either be made (1) in the level of detail on which the far offshore hydrogen production process is modelled and optimized, or (2) in the extend to which the interaction of supply and demand is represented in the model and optimized. Salmon and Bañares-Alcántara (2022) chose the second option and focused on the optimization of the production process. It must be decided if this part of their approach will be followed in this research or not. Both options will be elaborated upon below, and the advantages and disadvantages of both options as taken into account in the final choice are summarized in Table 2.2.

Optimizations to be made
When optimizing the supply and demand interaction, a network of demand and production nodes may be used. For every demand node, a suitable far green offshore hydrogen supply chain would have to be set up, with production in a certain production node. To do this, several production nodes (which would depend on the set constraints) would have to be evaluated and the one leading to the lowest delivered costs of hydrogen would have to be chosen. In order to do this, the demand and supply interaction would have to be optimized for every combination, since the size of the demand influences the price of the supply, but the price of the supply also influences the demand. This means several optimization steps would be necessary for each production node to find the final outcome. Also, several demand nodes may want to retrieve their hydrogen from the same production nodes and vice versa, which will again influence the balances. This means the demand from all demand nodes and the supply from all production nodes would have to be optimized simultaneously. As may be concluded, this would already lead to a complex optimization problem even when simple demand and supply curves are used.

When optimizing the far offshore green hydrogen production process in detail, many parts and the interactions between them will have to be taken into account. The configuration and combination of the different renewable energy generators together with the electrolyzers, desalination equipment, conversion equipment, storage and transport options will have to be optimized based on the demand and renewable resource availability. This in itself presents a complex optimization problem as well, even if the demand and production node to be reviewed are already known.

Possible simplifications
Ideally, no part of the model would be simplified, since both optimizations explained above fill a part of the existing knowledge gap. However, when this would be done, the needed development and computational time would become too large. In that case, every iteration in the optimization of the supply and demand interaction would require a full optimization of the production and transport processes. It is strongly expected that running such a model would not be realistic, especially when wanting to also consider the development of the potential over time. In addition, it was expected that developing such an elaborate model would not be possible in the available timeframe. Therefore, either the optimization of the supply and demand interaction, or the optimization of the production process had to be taken out of the model and replaced by a simplified alternative.

When simplifying the side of the production process, the optimization of this process should be replaced by a function for the far offshore green hydrogen production and transport costs based on the produced amount. When every production node has such a function, the possible hydrogen price from that node given a demand from a demand node can be determined very quickly. This way, the computational time can be spend on optimizing the demand and supply interactions. Because of this simplification however, the found hydrogen production prices are less accurate. In addition, this simplification makes it harder to evaluate the potential of new concepts and review the applicability of (combinations of) certain technologies in the hydrogen supply chain. This means this option may give some idea of the potential of far offshore green hydrogen production around the world and over time, but does not show which technologies (and their combinations) have the highest potential and which new concepts could be beneficial. Also, it is expected to be very difficult to find suitable input data for such a model, as this is already difficult when looking into far offshore green hydrogen anyway, let alone on a higher level.

When simplifying the side of the supply and demand interaction, the balance between supply and demand cannot be optimized anymore. This means a global system of supply an demand nodes and their interaction cannot be taken into account to the same extent as in the previous option. The main part of this model would be an optimization of the far offshore green hydrogen supply chain (production and transport), given a demand and production node and the size of the demand. In this optimization, all parts of the far offshore green hydrogen supply chain identified as technologically feasible in Section 2.4 would be taken into account. This way, the most optimal production and transport configuration for the specific situation can be found. By doing this, a tool that is able to assess the potential of specific concepts in specific scenarios could be made. Several case studies with this tool could be done to assess the potential of far offshore green hydrogen in various situations. This option would lead to a more detailed assessment of the potential of far offshore green hydrogen and the technologies involved. On the other hand, it may give a less complete image of this potential around the world and over time, since a limited amount of scenarios can be identified. By choosing the right combination of representative scenarios however, it could be attempted to acquire an as complete as possible overview. The produced tool could have a great practical use as well.

Choice of simplification
To assess which simplification would lead to the most insightful results at this point in time and to the most complete answer to the main research question as stated in Section 1.3, the final results and the available input data and its reliability should be considered. First of all however, it should be determined what results or insights are most important to obtain in order to be able to answer the main research question.

At this point in time, it is expected that detailed and reliable results will be more relevant than complete results. Since so much is still unknown, reliable results are crucial to fill part of the existing knowledge gaps and lay a proper foundation for further research. If it is attempted to fill a possibly larger amount of knowledge gaps, but with less reliable results, this could potentially only increase the uncertainties for follow-up research instead of taking them away.

In addition, the information gained from detailed results is highly relevant at this point in time and to answer the main research question. As mentioned in Chapter 1, it has already been concluded that offshore areas could present great potential for energy and hydrogen production in general, and that several technologies exist to make this possible in the future. However, more detailed insight is necessary into which (combinations of) technologies are fit for which scenarios and what far offshore green hydrogen supply chains look like first. With this insight, it will be possible to further identify the exact potential of far offshore green hydrogen production in specific locations and scenarios around the world (the first part of the main research question), assess which factors mainly influence this potential (second part of the main research question) and determine which technologies have a high potential and should therefore be developed further (the third part of the main research question). Once this insight has been created and more data is available on some other topics such as the local hydrogen demand, follow-up research could make estimations on a higher level (for example looking at worldwide supply/demand interactions) with less uncertainty.

Finally, it would be valuable for follow-up research if the model/tool to be drafted in the intended research can easily be used to evaluate additional scenarios and concepts to be able to quickly expand the knowledge base around far offshore green hydrogen production. Below, the insights to be created and reliability of the results when implementing both of the simplifications will be described and it will be concluded which match the insights needed to answer the main research question best. An overview of these considerations is given in Table 2.2

Table 2.2: Comparison between possible simplifications

	Focus on far offshore green hydrogen supply chain	**Focus on green hydrogen supply/demand interaction**
Expected availability of data	+	-
Expected reliability of results	+	-
Insight into global development of far offshore green hydrogen towards 2050	+	++
Insight into demand and supply interaction of green hydrogen and competition between different sources of green hydrogen	0	++
Insight into potential of (combinations of) certain technologies in the far offshore green hydrogen supply chain	++	-
Insight into what far offshore green hydrogen supply chains may look like	++	–
Provides a reliable and complete answer to all parts of the main research question	++	0
Possibility to evaluate new concepts with drafted model/tool (in further research)	++	-
Possibility to evaluate specific scenario's with the drafted model/tool (in further research)	++	0

As mentioned before, when simplifying the production process and focusing on the interaction of supply and demand, the results will give a very high-level idea of the potential of far offshore green hydrogen production, not showing the potential of different technologies. Insight into the supply/demand interactions and competition between different green hydrogen sources will be created, but it is expected to be very difficult to acquire the relevant input data. The uncertainties of the results with this option are expected to be caused by the drafting of the mentioned production and transport cost curves, the demand estimations, and the uncertainties of input data regarding the technologies to be used. The latter are expected to be manageable. The drafting of the production and transport cost curves for a production node is expected to be difficult, given the limited knowledge on what far offshore green hydrogen supply chains look like. The uncertainty of the results caused by the local demand estimations are also expected to be significant given the limited availability of data.

As also mentioned before, when simplifying the interaction of supply and demand, and focusing the model on the optimization of the far offshore green hydrogen supply chain, it can be used to gain more detailed knowledge on the potential of different technologies and concepts in the far offshore green hydrogen supply chain. In addition, insight into what far offshore green hydrogen supply chains may look like will be created. Furthermore, when choosing the right scenarios to analyse with this model, it is expected that insight into the potential of far offshore green hydrogen in various situations can be created as well. Although this insight can of course never be as complete as with the other option, it is expected to be more detailed and reliable. The uncertainties in the results with this option are mainly introduced by the data regarding the technologies to be used. As mentioned above, these uncertainties are expected to be manageable. The uncertainties regarding the demand estimations discussed above can be mitigated with this option by choosing scenarios where sufficient demand data is available or can be derived.

Lastly, when focusing on optimizing the far offshore green hydrogen supply chain, a model will be drafted that could easily be used by follow-up research to evaluate other scenarios and/or concepts. This may eventually lead to a more rapid development of the knowledge regarding the worldwide potential of far offshore green hydrogen production.

From the considerations presented above, which have been summarized in Table 2.2, it may be concluded that both options for the simplification of the model could lead to insightful results. Focusing on optimizing the supply and demand interaction will lead to a (slightly) more complete insight into the global potential of far offshore green hydrogen, and especially to more insight regarding the supply/demand interaction and competition between different green hydrogen sources. However, focusing on optimizing the far offshore green hydrogen supply chain is expected to lead to a more detailed and reliable insight into far offshore green hydrogen supply chains and its technologies. Although both could be very useful, it is expected that the latter may have a more direct practical relevance for the choices to be made in the development of far offshore green hydrogen production at this moment in time, and that it will result in a more complete and reliable answer to the main research question. Furthermore, when focusing on the optimization of the supply and demand interaction, (too) significant uncertainties are expected to be introduced caused by uncertainties in the demand estimations and other input data. Lastly, the model drafted when focusing on the hydrogen supply chain optimization could be used relatively easily in possible follow-up research to evaluate additional concepts and/or scenarios. In short, it is expected that at this point in time, focusing on the optimization of the far offshore green hydrogen supply chain will lead to more relevant results, lead to a more reliable answer to the main research question and lay a stronger basis for follow-up research. Because of this, the focus of the model will be on the optimization of far offshore green hydrogen supply chains, which means the approach of Salmon and Bañares-Alcántara (2022) will be followed in this respect. In Subsection 2.3.2, the method to be applied to set up the model will be discussed, using among other things the focus chosen in this subsection.

2.3.2 General method

In this subsection, the choice of the general method to be used for the analysis of far offshore green hydrogen supply chains will be discussed. First, it will be explained why the general method applied by Salmon and Bañares-Alcántara (2022) (mixed integer linear programming (MILP)) is not expected to be suitable for the intended model and mixed integer quadratically constrained programming (MIQCP) is needed instead. Next, the choice for MIQCP and the choice for using optimization instead of simulation will be elaborated upon to substantiate them further.

As explained in Section 2.2, the primary gap in literature to be filled by the intended research is an evaluation of the worldwide potential of far offshore green hydrogen production using local comparisons with specific scenarios. Next to this, several other shortcomings of the research by Salmon and Bañares-Alcántara (2022) were identified, leading to aspects to be added to the model and other changes to be made as depicted in Figure 2.4. In Subsection 2.3.1, it was decided the focus of the model should be on the optimization of the far offshore green hydrogen supply chain, following the example of Salmon and Bañares-Alcántara (2022) in that respect. This means many different aspects must be optimized simultaneously, such as the amount of electrolyzers, different energy generation devices and the transport medium to be used. This was also discussed in Section 1.2.

As mentioned before, Salmon and Bañares-Alcántara (2022) use MILP for their optimization. To be able to use this in the intended model as well, the objective functions and all constraints would have to remain linear. As shown in Figure 2.4, two kinds of constraints have been added; logistical constraints and demand/supply balancing. Several references used (mixed integer) linear programming for supply chain optimization while including transport and demand, formulating linear constraints for both the transport (Ibrahim & Al-Mohannadi, 2022; M. Kim & Kim, 2016; Parolin et al., 2022) and demand (M. Kim & Kim, 2016; Martínez-Gordón et al., 2022). Based on this, it would be expected that the logistical constraints and demand/supply balancing in the intended model could be linear.

However, the choice between different transport mediums will also be included in the optimization, which could cause non-linear, quadratic constraints and objective terms. The reason for this is that the value of certain variables will depend on which hydrogen carrier is used, which will be defined in the model through a constraint. When those variables are then used in other constraints, quadratic constraints could arise. For the same reason, quadratic objective terms could also arise. This means the intended model would have to use mixed integer quadratically constraint programming (MIQCP) instead of MILP. To be able to accommodate this, a solver must be chosen that is also suitable for MIQCP.

Next to MILP and MIQCP, several alternatives exist, mainly integer programming, linear programming and genetic algorithms. As some variables in the model will be integers, while others will be continuous, both integer and linear programming are not suitable. When looking at genetic algorithms, very little literature was found comparing MIQCP to genetic algorithms. However, this comparison is expected to be similar to the comparison between MILP and genetic algorithms, which is discussed more in literature. Genetic algorithms are found to be faster (Foster et al., 2014). However, MILP will guarantee the optimality of its solution (EMD

International, 2020), which is not the case for genetic algorithms (Zurada, 2010). As finding the most optimal solution is very important in this case to properly assess the potential of far offshore green hydrogen production, mixed integer programming seems to have the preference. MILP is often used for system analysis and optimization due to its flexibility and its applicability for solving large, complex problems (Kantor et al., 2020). In the literature of the considered research field, it can be seen that genetic algorithms seem to often be used for wind park lay-out optimizations (Bin Ali et al., 2022; Kaya & Oğuz, 2022), while MILP is often applied when supply chains are optimized (Ibrahim & Al-Mohannadi, 2022; M. Kim & Kim, 2016; Parolin et al., 2022; Salmon & Bañares-Alcántara, 2022), as will be done in this research. From this, it may become clear that genetic algorithms do not have the preference for this research and mixed integer programming is expected to be more suitable.

Finally, the choice for optimization over simulation will be discussed. With optimization, an optimal solution is found to achieve an objective while satisfying all the set constraints, which represent limitations on for example the available resources. Optimizations are often used for the maximization or minimization of a cost or revenue function. Optimization can be applied for various purposes and gives the best solution possible, but does become less effective when more uncertainties are introduced into the model. (T. Lee, n.d.) In order for optimizations to work well, it is important to be able to set proper constraints and define mathematical relationships without variability. An optimization generally requires more assumptions than a simulation or more computing power to deal with many variables. When making assumptions, oversimplifying the problem should be prevented. (MOSIMTEC, n.d.)

With simulation, a (large) number of pre-defined scenarios is evaluated. This means it does not give the best solution, but only allows for a comparison of selected scenarios, meaning the user must have sufficient knowledge to decide which scenarios to simulate and compare. When a problem cannot be accurately described in a set of mathematical expressions or when there are many parameters with a high uncertainty, simulation is preferred. (T. Lee, n.d.) Simulations allow for the integration of randomness, for example by expressing the speed of a task as a normal distribution. They also allow for easy sensitivity analysis by adjusting the initial conditions and show an actual simulation of reality. Finally, simulations require less assumptions and are therefore generally easier to model. (MOSIMTEC, n.d.)

When looking at the information presented in the previous paragraphs, it can be concluded that using optimization would best serve the needs of the intended model. Most importantly, optimization leads to the most optimal solution (T. Lee, n.d.), which is crucial to obtain when wanting to compare far offshore green hydrogen to its alternatives and assess its true potential. If the optimal solution would have to be obtained with simulation, sufficient knowledge would be needed to identify a set of possibly optimal configurations for every scenario (T. Lee, n.d.), which is not (yet) available. Furthermore, it is expected that it will be possible to describe the far offshore green hydrogen supply chain as a set of mathematical expressions, to set constraints and to define a clear objective (as also done by for example Salmon and Bañares-Alcántara (2022) as explained before), which makes the problem suitable for optimization. The uncertainties present in the input data should be managed well, since dealing with uncertainties can be more challenging when using optimization (T. Lee, n.d.). A sensitivity analysis of the developed model could help in managing the existing uncertainties.

From the information presented in this subsection, it may be concluded that an optimization with MIQCP is expected to be the most suitable method for the intended model, which means the example of Salmon and Bañares-Alcántara (2022) will be followed only partly in this respect. It should be noted however that MILP can require a lot of computational time and that the difficulty of a MILP problem is hard to predict in advance (Purdue University, n.d.), which is expected to be even more so for MIQCP. Therefore, choosing the right solver to limit computational time is important. This will be discussed in the next subsection.

2.3.3 Modelling language and optimization solver

In this subsection, the modelling language and optimization solver to be used for the model developed in this research will be discussed. Several options are possible, but some have the preference over others given the expected characteristics of the model. The programming language to be used must be able to handle complex optimization problems and it must also be suitable for including other parts of the model next to the optimization. In addition, the solver to be used must be able to solve a MIQCP problem.

One option for making (optimization) models is Microsoft Excel. This program can be suitable for doing optimizations using Excel solver add-ins, which is relatively easy to do. On the other hand, it can be difficult to define complex problems in Microsoft Excel, spreadsheet models are challenging to scale and errors go unnoticed easily (River Logic, n.d.). Therefore, it may be concluded that it is not suitable for large and complex optimization problems.

Furthermore, there are many third and fourth generation programming languages, of which Python is an example. Python is very suitable for making highly complex optimization models and many optimization solvers have Python interfaces as well (River Logic, n.d.). An example of such a solver is Gurobi, which is available through a free academic license, is able to handle MIQCP problems and is for example used by Salmon and Bañares-Alcántara (2022).

Finally, fifth-generation programming languages are being developed and some are already available. Making a model with such a language could be significantly easier, since no actual (mathematical) coding has to be done (River Logic, n.d.). These languages are based on constrained based problem solving, eliminating the need for a programmer to write an algorithm. It should be noted however that with larger programs, fifth generation languages may have issues defining (efficient) algorithms, since this remains a highly challenging task. (Rouse, 2011) Furthermore, it is expected that using such a language could mean the operations of the model are understood less thoroughly, leading to complications when errors occur and possibly lower reliability.

From the information above, it may be concluded that at this point, a third or fourth generation programming language such as Python is expected to be very suitable for the (complex) optimization part of the intended model, in combination with an optimization solver such as Gurobi. An important additional advantage of using Python for solving an optimization problem is that (almost) all other parts of the model or tool you want to build can be made directly in Python as well, instead of having to script to other tools. Also, Python can be easily integrated with many databases. (Gurobi, n.d.) Another advantage of Python is that a lot of open-source libraries are already available that could be of use while drafting the optimization code, but also the other parts of the intended model. Furthermore, Python has a large community of users, and a lot of information and help is available ("Julia Vs. Python", 2020). Finally, Python is freely available, which would make the code to be drafted more accessible for potential follow-up research. All of this has lead to the decision to focus on Python in combination with Gurobi's optimization solver to draft the intended model.

2.3.4 Conclusion: methods to be used

In the previous subsections, a suitable method to fill the identified primary gap in literature has been found. The adjustments to be made to the modelling approach by Salmon and Bañares-Alcántara (2022) to create a baseline for the model to be developed in this research had already been identified in Section 2.2 and visualized in Figure 2.4. It was decided to put the focus of the model on the optimization of the far offshore green hydrogen supply chain. It is expected that by focusing on the optimization of the far offshore green hydrogen supply chain instead of the optimization of the global supply/demand interactions, less uncertainties will be introduced into the model, results that are more relevant at this point in time will be obtained, and a more complete and reliable answer to the main research question can be formulated. The choice for this simplification may lead to a less complete, but more detailed and reliable insight into the global potential of far offshore green hydrogen over time. In addition, detailed insight into which technologies are expected to be suitable for far offshore green hydrogen supply chains will be obtained.

Next, it was discussed why some constraints and objective terms could become quadratic when making the proposed adjustments to the modelling approach of Salmon and Bañares-Alcántara (2022), which means MIQCP should be used in the model to be developed in this research. The choice for optimization over simulation and MIQCP over genetic algorithms has also been discussed further. It was concluded that optimization with MIQCP is indeed expected to be the most suitable method.

To set up the model, Python will be used. This programming language is widely spread and very suitable for complex optimization problems, next to several other advantages over its alternatives. For the optimization, Gurobi's optimization solver will be used, which has a Python interface and is available through a free academic license.

2.4 Available Technology

In this section, it will become clear which knowledge is already available regarding the technological and economic feasibility of the technologies of interest in this thesis. Based on this knowledge, it will be decided what technologies to include in this research, which is the main goal of this section. The information from this section and Section 2.3 will be used to work out the baseline created for the model in Section 2.2 to the actual model to be used in this research, which will be presented in Chapter 3.

In Subsection 2.4.1, the production of (green) hydrogen will be discussed, including the production of the renewable energy needed for this. Next, Subsection 2.4.2 will discuss the transport and storage of hydrogen. Finally, Subsection 2.4.3 will conclude on which technologies and further information to include in this research.

2.4.1 Hydrogen production

This subsection will discuss the production of green hydrogen, including the energy needed to produce it. First, a general overview of green hydrogen production technologies will be given in Subsection 2.4.1.1. Next, hydrogen production in an offshore environment specifically will be discussed in Subsection 2.4.1.2. Finally, Subsection 2.4.1.3 will discuss offshore renewable energy generation (needed for the hydrogen production).

2.4.1.1 Green hydrogen production

In this subsection, green hydrogen production and the equipment needed for this will be discussed. As explained in Chapter 1, green hydrogen is made through electrolysis with renewable energy. In the electrolysis process, water is split into hydrogen and oxygen, for which energy is needed (285.83 kJ/mol). Three different kinds of water electrolysis mainly receive attention: alkaline electrolysis (AEL), polymer electrolyte membrane electrolysis (PEMEL or PEM electrolysis), and high-temperature electrolysis (HTEL, also known as SOEC). These mostly differ in the electrolyte used. (Dermühl & Riedel, 2023) Figure 2.5 shows the main advantages and disadvantages of these technologies. Because of its high dynamics, PEMEL shows especially good potential applicability for green hydrogen production using fluctuating renewable energy sources. In addition, it has a relatively high current density. AEL and HTEL also have several advantages over PEMEL, but given their longer start-up times, they are more suitable for stationary operation in industrial applications. The technology readiness level (TRL) is also shown in Figure 2.5. As can be seen, none of the technologies have thus far reached a TRL of 10 (full rate production), meaning all of them still need to be developed further. (Dermühl & Riedel, 2023)

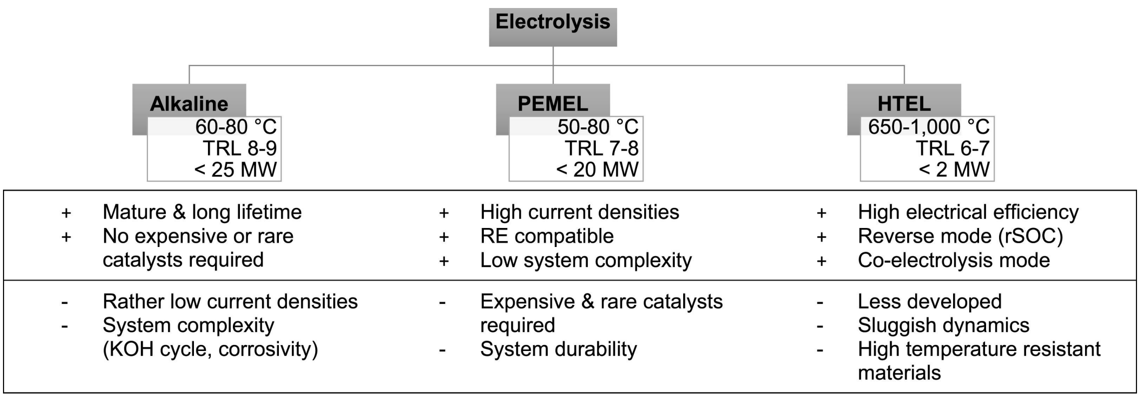


Figure 2.5: Advantages and disadvantages of electrolysis technologies (Dermühl & Riedel, 2023)

Next to the TRL, the scalability of the technology is highly important, given the enormous amounts of hydrogen that will have to be produced. Several electrolysis stacks can be connected (modularity), leading to easy scalability. Over the past decade, the electrolysis capacity has increased rapidly and several large projects are being realised. (Dermühl & Riedel, 2023) An example of this is the Holland Hydrogen 1, a 200 MW electrolysis plant in the Port of Rotterdam. This plant is to be completed in 2025 and will be powered by offshore wind (NS Energy, n.d.). Finally, the ecological impact of electrolysis caused by its water usage (at least 8.9 kgH2O/kgH2) should be taken into consideration (Dermühl & Riedel, 2023).

With future technological developments, the costs of electrolyzers are expected to decrease significantly. In the short term, a decrease of 40% is predicted, while in the long term this could be as high as 80 %. (International Renewable Energy Agency, 2020) The costs of electrolyzers and their development as used in this research will be discussed in Chapter 5.

2.4.1.2 Far offshore green hydrogen production

In this subsection, green hydrogen production in a far offshore environment will be discussed. The enormous potential of offshore renewable energy resources, specifically wind resources, has already been discussed several times before. Subsection 2.4.1.1 looked at the production of green hydrogen in general. Given the significantly different environment far offshore however, the specifics of far offshore green hydrogen production will be discussed separately here.

As mentioned before, hydrogen production using electrolysis requires water. This poses both an advantage and disadvantage for offshore hydrogen production: limitations in water availability seen onshore do not exist when producing offshore, but regular electrolyzers cannot use seawater directly. Seawater direct electrolysis, AEL and PEMEL are seen as candidates for offshore hydrogen production. Seawater direct electrolysis does not need any desalination of the water, but produces chlorate, which can cause environmental pollution. (Jang et al., 2022) For AEL and PEMEL, a desalination plant would have to be included to filter the water before it is used. During desalination, brine is produced, which can have negative effects on the environment as well due to its high salinity and must therefore be disposed off in a proper manner to prevent environmental impacts (Panagopoulos et al., 2019). This is however not expected to be a major concern in the case of far offshore green hydrogen production, as most onshore desalination facilities also dispose the produced brine into the sea (Omerspahic et al., 2022). Since the desalination capacity installed on an FPSO will be a factor 50 smaller than the capacity of most onshore desalination plants (A. Kim et al., 2023) and the disposal of brine will most likely be done in much deeper waters, its effect is expected to be limited in far offshore green hydrogen production. In addition, new technologies are being developed to limit the production of brine during desalination (Omerspahic et al., 2022).

Two other major differences when looking at far offshore hydrogen production are (1) the fact that the production location is generally far away from civilization and (2) the strong limitations regarding the size and weight of the electrolyzers. The first may make operations and maintenance more challenging, and may even require personnel to stay offshore for longer periods of time, which could influence the operational expenses. Although they use inexpensive materials, have a long lifetime and are advantageous for large-scale applications, alkaline electrolyzers are more difficult to manage from a distance due to their highly corrosive electrolytes. Furthermore, PEM electrolyzers have a higher current density and better applicability in the case of renewable energy, as mentioned before as well. Finally, the membrane electrode assembly of PEM electrolyzers allows for compact stacking. Looking at these considerations, PEM electrolyzers are expected to be most suitable for offshore hydrogen production. (Jang et al., 2022) Decentralized offshore hydrogen production might be slightly more economic than centralized offshore production in certain situations (Jang et al., 2022). In this research however, the focus will be on centralized hydrogen production in an FPSO.

Since a far offshore hydrogen production location is not connected to the grid, excess energy cannot be offloaded and energy from the grid cannot be used to keep the production running at a low level when no renewable energy is available. Therefore, a proper balancing between the renewable energy and hydrogen production capacities is crucial to minimize the costs, considering both lost power at peak power generation and idle electrolyzer capacity when less energy is produced. This optimization will be included in the model to be developed later in this research.

To help in this balance, it could be considered to add batteries to the FPSO to temporarily store energy (Woznicki et al., 2020). The latter will however not be included in this research for simplification purposes.

Finally, as already mentioned before, the hydrogen production in a far offshore environment will be done on a floating production, storage and offloading (FPSO) unit. This concept has been used for a long time in the oil and gas industry, but is in the early development stage for the production of hydrogen and its derivatives. Lee et al (2023) have made a concept design for a liquid hydrogen producing FPSO, also designing the production process and optimizing its hull dimensions. Furthermore, they estimated the total steel weight and mentioned estimates for the weights and dimensions of the electrolyzers, which are highly relevant for far offshore production as discussed before. Some companies are also developing FPSO's to produce green hydrogen or its derivatives. SwitcH2 is for example working on FPSO's producing hydrogen (SwitcH2, 2022b) as well as ammonia (Saskia Kunst, personal communication, April 4, 2023), which will have an electrolyzer capacity of 100 MW and use a former Very Large Crude Carrier (VLCC) as a base (see Figure 2.6). They expect to have the first FPSO operational in 2028 (SwitcH2, 2022a).

Figure 2.6: SwitcH2's concept design for a hydrogen producing FPSO (SwitcH2, 2022b)

Finally, another crucial aspect when wanting to produce hydrogen and/or its derivatives at sea using an FPSO is the technological feasibility of the production process in an offshore environment. The idea of an ammonia producing FPSO has been proposed before, considering ammonia's high volumetric density, low storage and transportation costs, possible use in (marine) combustion engines and industrial generators, and the fact that infrastructure for its transportation and distribution already exists in many countries (Sun et al., 2022). The main technological challenges faced with LNG and hydrogen liquefication, mostly caused by the needed temperatures, do not apply to ammonia as much. Ammonia needs to be cooled to -35 degrees Celsius to become liquid with respect to -253 degrees Celsius for liquid hydrogen and -162 degrees Celsius for LNG, making it relatively easy to handle and a high potential hydrogen carrier. (Sun et al., 2022)

Since an ammonia producing FPSO will be located far offshore, movements caused by waves may have an influence on the production facilities. Sun et al. (2022) built an experimental setup to assess the influence of motions of the FPSO and therefore sloshing on the ammonia production process. It is eventually concluded that the influence of sloshing on the flow and heat transfer characteristics of non-azeotropic refrigerants in the temperature zone of liquid ammonia, and therefore the impact of sloshing on ammonia production far offshore, is limited and the proposed production process shows good adaptability to a far offshore environment. A liquid hydrogen FPSO is also expected to be technologically feasible, as for example J. Lee et al. (2023) already made quite a detailed concept design for a liquid hydrogen FPSO. The considerations in this paragraph imply that the production process of both ammonia and liquid hydrogen should not pose a significant limit to the technological feasibility of far offshore green hydrogen production.

2.4.1.3 Far offshore renewable energy production

In order to produce green hydrogen far offshore, the energy production must also be done in a far offshore environment. In fact, the main reasons to produce hydrogen far offshore are the resource potential and space availability for the needed energy production, next to the water availability for electrolysis, as mentioned before. Therefore, this subsection will look at the techno-economic feasibility of far offshore energy production and its expected development in order to decide which technologies to include in this research. In the following, the focus will be on far offshore wind, solar and wave energy production. Given the limited amount of time, other developing technologies will be left outside of the scope of this research.

Far offshore wind energy production
To start, the far offshore production of wind energy will be discussed, which is the energy generation technology that has been developed the furthest for far offshore applications. At the moment, European companies seem to be taking the lead in the development and testing of floating offshore wind (FOW) (Rehman et al., 2022). Since they are already being deployed, the first barrier for the technological feasibility of FOW turbines seems to have been overcome. However, the technology still needs strong further development to increase the efficiency, reliability and performance of the turbines and decrease the costs per kWh of produced energy. Rehman et al. (2022) mention that based on the ongoing FOW projects (with small capacities), the current costs can be estimated at 220-245 USD/MWh. With increasing capacity and technological developments, they expect this to decrease to 100-125 USD/MWh in the short term and 50-75 USD/MWh once the technology reaches maturity. This in line with the expectations presented by (De Vries et al., 2021) mentioned in the introduction, which expect the FOW technology to reach maturity around 2030.

Other sources also mention the advantages and possibilities of floating offshore wind (Barooni et al., 2022; Zhou et al., 2023). All in all, there seems to be a consensus in literature regarding the potential of FOW and its expected cost reductions. The timeline of these developments is however not often specified, except for by De Vries et al (2021) as mentioned before. A clear timeline for the cost reduction of floating offshore wind will be determined when presenting the input data in Chapter 5.

When looking at FOW turbines, the mooring systems that can be used to make sure the floating wind turbines stay in place must be considered as well. Three standard mooring systems could be suitable for FOW, which find their origin in the oil and gas sector: catenary mooring systems (A), tension-leg mooring systems (B), and semi-taut mooring systems (C) (see Figure 2.7)(Barooni et al., 2022).

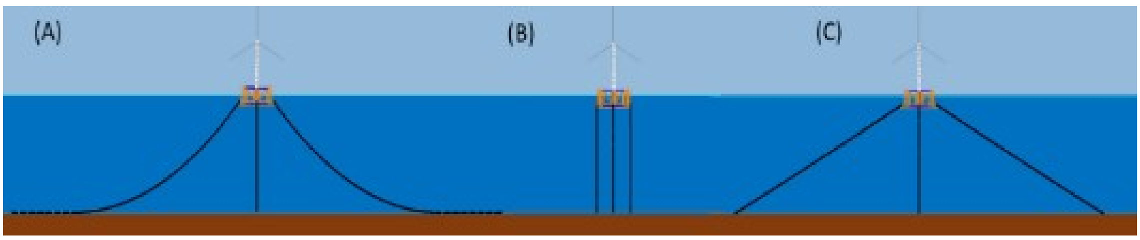


Figure 2.7: FOW mooring options (Barooni et al., 2022)

More relevant for this research however are the technological limits regarding the water depths and the costs of the mooring. Not many references discuss this, although some put the limit for the water depth at 1000 m (Energy Sector Management Assistance Program, 2022). As mentioned before, SBM offshore claims to have a floating wind turbine design that can be anchored at depths up to 2000 m (De Vries et al., 2021). From a cost perspective however, mooring in waters over 200 m deep is not desirable (Connolly & Crawford, 2022). A floating wind farm will need many mooring systems (one of the systems shown in Figure 2.7 for each wind turbine), which is a significant cost contributor for FOW and is often underestimated (Ma et al., 2021). Given the amount of mooring systems needed and the significance of its costs, it is expected that high mooring costs will have a relatively big influence for FOW compared to for example floating structures in the oil and gas sector. These costs must therefore be included in the model to be developed in this research as well.

Although some cost-saving strategies are being developed to try to decrease the costs, such as shared mooring and shared anchors, unmoored floating wind energy generation could be an interesting alternative (Connolly & Crawford, 2022). The latter could include floating offshore wind turbines held in place by propellers (Connolly & Crawford, 2022; Raisanen et al., 2022) and wind energy converter ships (Babarit et al., 2018). Even if mooring in up to 2000 m of water depth is possible, many offshore areas would be out of range due to their water depths without unmoored concepts, unless mooring systems would see large technological developments and cost reductions. In this research however, unmoored structures will not be considered given the early state of their technological development and uncertainty about how this will evolve in the coming decades. If more about their technological feasibility and costs is known in the future, it should however be included in follow-up research.

Far offshore solar energy production
To optimize the space usage, hydrogen production running time and redundancy of the far offshore green hydrogen production, it could be beneficial to combine several renewable energy sources. One of the options for offshore energy generation is solar energy. As mentioned in the scope, offshore solar concepts such as SEAVOLT (Figure 2.8) are being developed and show great potential to be combined with offshore wind energy.

Another company developing offshore solar platforms is SolarDuck (Figure 2.9). As can be seen, both platforms are raised above the water, which is done to prevent salt deposits on the panels, micro-cracks in the panels due to water impact, and electrical cable fatigue and corrosion. Furthermore, it can be seen that the solar panels are tilted, which is done to allow for self-cleaning. According to SolarDuck, their platform has a lifetime of 30 years and can withstand hurricanes with wind speeds over 30 m/s. Furthermore, they state it can withstand significant wave heights of over 5 m, making it suitable for many offshore locations, although possibly not all of them. Lastly, they have attempted to minimize the maintenance costs and during installation, their platform can be towed towards its final location, as with certain floating wind turbines. (SolarDuck, n.d.-b)

Figure 2.8: SEAVOLT offshore solar platform (Jan De Nul, 2023)

Figure 2.9: SolarDuck offshore solar platform (SolarDuck, n.d.-b)

The produced energy per unit area of a combined offshore wind and solar farm may be seven times higher than that of a stand-alone wind farm, showing the the potential of combining offshore wind and solar. However, since there are only two offshore solar farms worldwide (in the Netherlands and Taiwan) some uncertainties remain, mainly regarding the structural safety and power performance in high winds and waves of offshore solar platforms. (Bi & Law, 2022) SolarDuck claims to have solved the issues around structural safety with their structure of flexibly connected triangles (SolarDuck, n.d.-b).

To assess the uncertainties around the power performance of solar energy in offshore conditions (caused by the temperature, wind, waves, humidity and varying solar irradiation), Bi and Law (2022) set up a simulation model. From their simulations, they conclude that the changes in solar power output are relatively small, even in high wind and wave conditions, meaning the power output of offshore solar energy platforms would remain stable. Therefore, they conclude combining solar and wind offshore would be feasible.

Other sources have also identified the potential of combining offshore wind and solar in various situations, concluding that it increases the total renewable energy source and decreases its variability significantly (Bahadori & Ghassemi, 2021; Costoya et al., 2022). The variability of the energy output is decreased because when combined, wind and solar energy generation can act as a back-up for each other. It should be noted that the main advantage of producing further offshore for wind energy, namely the increase in resource capacity, does not exist for solar energy (Kasiulis et al., 2022). However, the increased performance of a far offshore wind farm and the possible onshore or near shore constraints for solar energy generation could still make far offshore solar energy production beneficial when integrated in a wind farm. Given that the main benefit for going far offshore is experienced from the wind energy production however, the wind resource should be leading in the location selection, and the integration of solar energy should be considered afterwards.

All in all, it may be concluded that combining wind and solar energy offshore is expected to be beneficial. Also, offshore solar energy generation seems to already be technologically feasible, although the technological limits, for example regarding the maximum significant wave height, should be kept in mind. The costs of floating offshore solar are not yet widely available in literature, but will be determined later in this research and presented with the input data to be used in this research in Chapter 5.

Far offshore wave energy production

The last way to produce renewable energy far offshore included in the scope of this literature review is wave energy. Figure 2.10 shows the global mean wave power. Comparing this figure to Figures 1.4 and 2.3 shows that the high-potential areas for wind and wave energy largely overlap, indicating an added advantage for the combination of wind and wave energy.

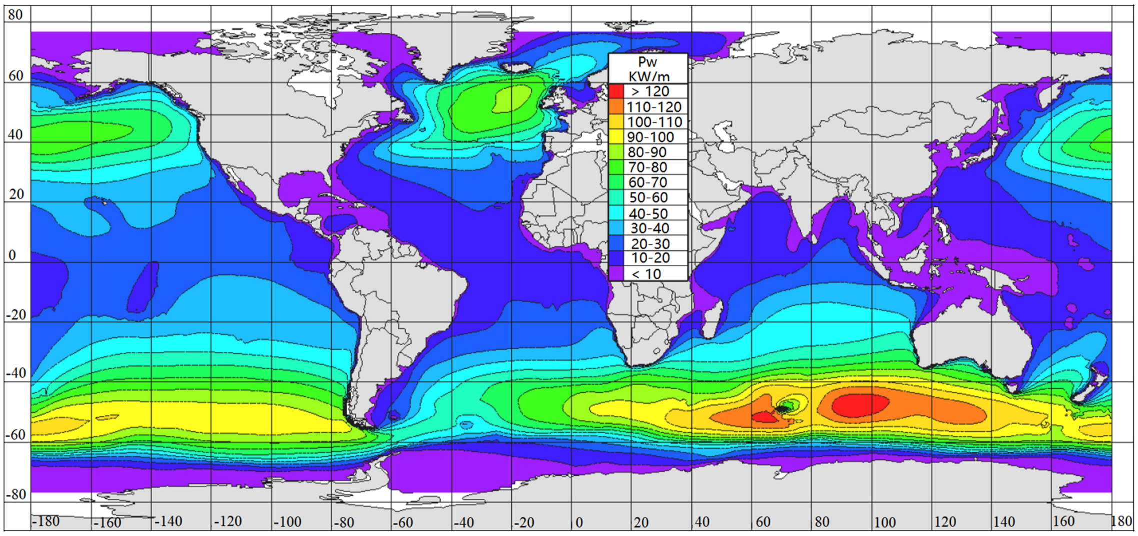


Figure 2.10: Global mean wave power over a 10-year period (Rehman et al., 2022)

Combining offshore wind and wave energy generation presents several advantages, mainly an increased power output, less variability and reduced operations and maintenance costs (Kasiulis et al., 2022). As can be seen, these advantages are similar to those of combining wind and solar energy generation. Usually, wind and wave energy show low correlation, and wave peaks follow the wind peaks, leading to the two being a potentially good combination in many locations. Furthermore, wave energy converters can shield the wind farms from waves. (Kasiulis et al., 2022)

Several wave energy converter techniques exist. However, these different techniques are in a very early stage of development, it is not clear which wave energy converter technology will become dominant and no working prototype combining wind and wave energy has been built yet. (Kasiulis et al., 2022; Rehman et al., 2022) Given the early development stage of the technology and its components, making estimations regarding the technological feasibility and costs of wave energy converters towards 2050 would introduce large uncertainties into the model, where many other (more manageable) uncertainties already exist. Therefore, it has been decided not to include wave energy converters as an option for renewable energy production far offshore in the intended model, despite its future potential. When the technology has been developed further and more is clear regarding its technological feasibility and the development of its costs, it could be included in the model in follow-up research. For the intended research to be performed now, the focus regarding renewable energy production will be on wind and solar energy, and the combination of the two.

2.4.2 Hydrogen transport and storage

In this subsection, the transport and storage of hydrogen will be discussed. Both of these are crucial parts of the hydrogen supply chain and their techno-economic feasibility is therefore highly relevant when discussing the feasibility of far offshore green hydrogen production. In Subsection 2.4.2.1, the transport of hydrogen will be discussed, after which Subsection 2.4.2.2 will discuss the storage.

2.4.2.1 Hydrogen transport

This subsection will discuss the transport of hydrogen. Energy transport in the form of hydrogen will be compared with electrical cables and several hydrogen transport mediums will be discussed, namely gaseous hydrogen, compressed hydrogen, liquid hydrogen, liquid organic hydrogen carriers (LOHC), ammonia and methanol. Various transport modes will be talked about as well: ships and pipelines for overseas transport, and pipelines, trains and trucks for transport over land.

When comparing energy transport through electrical cables and hydrogen, the specific situation is important in determining which will be most economic. The potential of hydrogen increases with the amount of energy to be transported (see also Figure 1.3), the distance to be transported over and a decrease of the electricity price (d'Amore-Domenech et al., 2021). Since the transport of energy produced far offshore is expected to be over large distances and in large quantities, it is highly likely that hydrogen transport will be more economic. This is strengthened by the fact that several references identified the potential of energy transport through hydrogen already for (relatively) near offshore energy production (A. Kim et al., 2023; Maynard & Abdulla, 2023). Therefore, this research will not consider energy transport through electrical cables and only focus on transport as hydrogen or its derivatives.

When hydrogen is transported through pipelines, this is normally done as gaseous hydrogen. When it is transported by ship, this can be done in its pure form as compressed or liquefied hydrogen, or in the form of a hydrogen carrier such as ammonia or methanol. These hydrogen carriers can introduce additional losses, but are generally more easy to handle, as already shortly discussed in Subsection 2.4.1.2 for ammonia. This means they could still be more economic for the transport of hydrogen, especially when they are directly used instead of converted back to hydrogen again. (Cebolla et al., 2022; International Renewable Energy Agency, 2022a)

Naturally, the costs of transport and the ideal transport medium and mode for hydrogen also greatly depend on many factors, among which the quantity to be transported, the distance to be bridged and the environmental conditions. Therefore, different studies find different results for the optimum transport configuration depending on the analysed scenarios. Babarit et al. (2019) for example concluded that methanol would be most suitable for their wind energy converter ships, while H. Lee and Lee (2022) decide on ammonia for the transport of green hydrogen from Australia to South Korea and Brändle et al. (2021) claim liquid hydrogen will become the most beneficial over time.

When looking at transport through pipelines, it can be seen that for many offshore areas, pipelines are not economically feasible due to the water depths. For example, hydrogen pipelines to South Korea and Japan would face depths of a few kilometers, which may in some cases be technologically feasible, but leads to excessive costs. Overseas transport through pipelines can be beneficial for larger quantities, especially with refurbished pipelines, although it depends on the material of the existing pipelines whether they can be reused or not. However, of the potential large-scale hydrogen importers, pipeline transport is mostly applicable to Europe, which may have a pipeline connection with North Africa. (International Renewable Energy Agency, 2022a) In Figure 2.11, the global sea areas with depths over 1000 m are shown (the dark blue areas). As can be seen, it may be expected that in most areas where far offshore hydrogen production could be located, the depths would be too large for pipelines to be economically feasible. Therefore, the intended research should not include overseas transport of hydrogen through pipelines and focus on transport with ships.

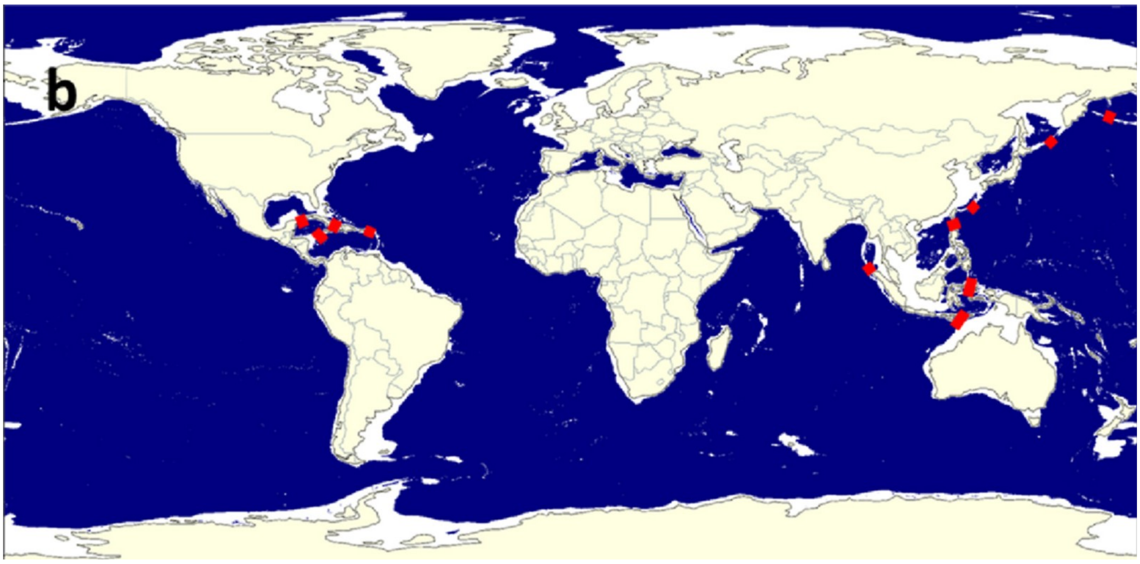


Figure 2.11: Sea areas with depth over 1000 m (dark blue areas) (Hunt et al., 2022)

When comparing hydrogen transport by ship as compressed hydrogen or liquid hydrogen, it can be seen that although compressed hydrogen may be technologically feasible sooner, it is not attractive from an economic perspective (d'Amore-Domenech et al., 2021). For small distances and quantities, compressed hydrogen may be more economic. However, as the quantity increases, the costs for liquid hydrogen decrease. Also, for larger distances the costs of compressed hydrogen transport increase significantly, as the 'conversion' costs for compressed hydrogen are relatively low, but the transport costs per kilometer are high. (d'Amore-Domenech et al., 2023) Given the large distances and quantities expected with far offshore hydrogen production, it may be concluded that compressed hydrogen will be less suitable than liquid hydrogen and should therefore not be considered in the intended research.

Another possibility for hydrogen transport is LOHC. However, the carriers used are (at the moment) oil derivatives and the losses while recycling the carrier could lead to carbon emissions. This means this transport method does not fit into a net-zero economy. In addition, several additional challenges exist for LOHC, such as the limited (current) availability of LOHC and its relatively low hydrogen density, leading to large transport volumes. (International Renewable Energy Agency, 2022a) For these reasons, it has been decided to not include this transport medium in the intended research either.

Finally, hydrogen transport in the form of methanol could be an option. However, transport in the form of methanol is expected to be significantly more expensive than in the form of ammonia or liquid hydrogen for distances up to at least 25000 km due to the relatively high conversion costs (Cebolla et al., 2022). Therefore, it is assumed that methanol will not turn out to be the more economic option in any situation and it should not be considered in the intended research. This may also be the reason why it was not included in the study by International Renewable Energy Agency (2022a). Some studies consider methanol one of the more economic transport options (Johnston et al., 2022). However, when looking at the assumptions made by Johnston et al. (2022), it can be seen that they have not taken into account the conversion and reconversion processes, which is expected to be the cause for this conclusion. This is confirmed by the fact that Cebolla et al. (2022) also show that transport as methanol is relatively insensitive to the distance to be transported over, but has relatively high costs for short distances, indicating high conversion costs. This means that when taking the entire transport chain into account, methanol indeed does not seem to be an economically viable option for hydrogen transport.

The considerations presented above mean that for the overseas transport, the intended research will consider hydrogen transport with ships in the form of liquid hydrogen and ammonia. Techno-economic estimates for the conversion, shipping and reconversion of ammonia and liquid hydrogen for 2030, 2040 and 2050 are for example given by International Renewable Energy Agency (2022a). To get a first feeling of the comparison between ammonia and liquid hydrogen, Figure 2.12 shows which is expected to be more economic for various combinations of distance and quantity. As can be seen, liquid hydrogen may be more beneficial for relatively short distances and high quantities, but only under optimistic cost assumptions. This figure should however not be taken as input directly, since these considerations strongly depend on assumptions and the situation considered. To illustrate this, the tipping point where ammonia transport becomes more economic than liquid hydrogen is at 15000 km according to the results obtained by Cebolla et al. (2022), while Figure 2.12 shows this to be at 4000 km (for a sufficiently large project size). The figure is therefore only added here to illustrate the comparison between ammonia and liquid hydrogen.

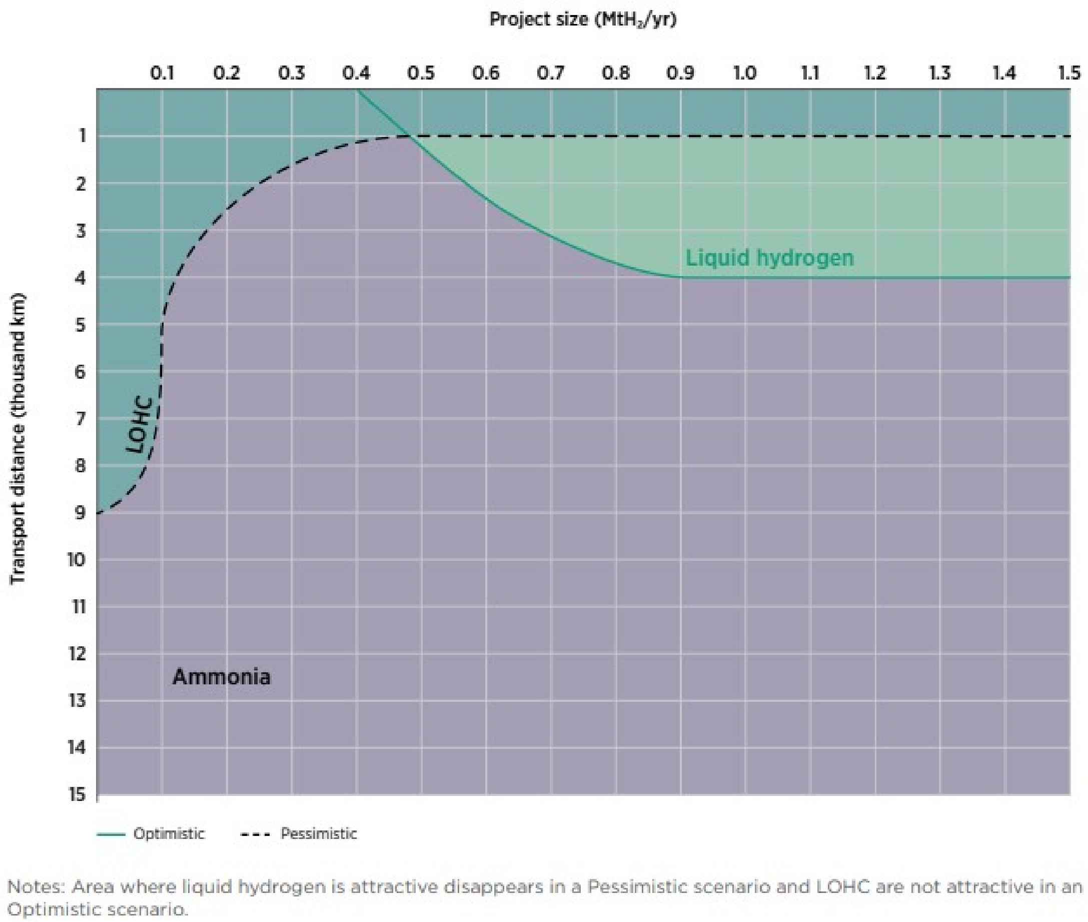


Figure 2.12: Comparison between hydrogen transport through ammonia and liquid hydrogen for various combinations of distance and quantity (International Renewable Energy Agency, 2022a)

When looking at transport over land, the ammonia and liquid hydrogen could be reconverted to gaseous hydrogen and transported through pipelines. The Port of Rotterdam is for example working on plans for a hydrogen pipeline to North Rhine-Westphalia at the moment of writing (Port of Rotterdam, n.d.). The costs of these pipelines per quantity transported over a certain distance depend mainly on whether existing pipelines can be reused and on the diameter of the pipeline (and therefore the quantity transported)(International Renewable Energy Agency, 2022a). These have to be considered for each situation separately. Alternatively, the ammonia or liquid hydrogen could be transported further. For ammonia, the infrastructure is very well established, and data is expected to be available on the various transport options, namely ships, trains and trucks. For larger distances, ammonia may also be transported through pipelines. (Cebolla et al., 2022)

Liquid hydrogen can be transported in trucks or trains, although no commercial railway transport options are currently available. The low temperatures needed for liquid hydrogen make its transport more difficult. (Cebolla et al., 2022) It is expected that the data on liquid hydrogen transport over land will show more uncertainties. For simplification purposes, it has been decided to assume in this research that all transport over land is done through pipelines with gaseous hydrogen, since the comparison to be made eventually is between far offshore green hydrogen and its alternative green hydrogen options anyway, meaning reconversion to hydrogen is always done in this research.

2.4.2.2 Hydrogen storage

In this subsection, the storage of hydrogen and its derivatives will be discussed. As explained in detail in Subsection 2.4.2.1, the intended research will focus on transport in the form of liquid hydrogen, ammonia and gaseous hydrogen (over land). Therefore, these will also be considered while discussing hydrogen storage below. Long term storage does not lie within the scope of the intended research, so underground storage such as in salt caverns will not be discussed here, although they could be beneficial as part of the hydrogen ecosystem. Also, it is assumed that hydrogen delivered to a port can be transported further by pipeline (almost) immediately after conversion, which is the more economic option (d'Amore-Domenech et al., 2023). In the intended research, hydrogen storage in the FPSO is therefore most relevant.

For (compressed) gaseous hydrogen, above-ground storage can be done in pipelines or vessels, which must be made of materials that can withstand the pressure and the other conditions of the stored hydrogen. This is however an order of magnitude more expensive than underground storage and should only be done when underground storage is not available or for smaller storage needs. (Cebolla et al., 2022) This could be applicable for short term storage in an FPSO. However, as the transport over sea is done as liquid hydrogen or ammonia anyway, it is expected that it is more economic to store the produced hydrogen directly in those forms in the FPSO, as their storage is significantly cheaper (Cebolla et al., 2022). It may be concluded that storing hydrogen in gaseous form above-ground is not ideal and should be minimized. It will therefore be assumed no compressed hydrogen storage will be done on the FPSO.

Liquid hydrogen storage is done in double-walled, insulated tanks. An important issue is boil-off, which is the evaporation of part of the liquid hydrogen caused by heat transfer from the surroundings. The boil-off causes pressure to build up, causing the need for safety valves. The boil-off rate depends on the outside temperature, the material of the tank and its shape, which is why these tanks are often spherical. (Cebolla et al., 2022) Boil-off may also introduce losses, although there are solutions for this. Some for example propose using the boil-off as fuel for the propulsion system in liquid hydrogen carrying ships (Alkhaledi et al., 2021), but it can also be reliquefied (International Renewable Energy Agency, 2022a).

Storage of ammonia is significantly easier, since the storage temperatures can be higher, as discussed in Subsection 2.4.1.2 as well. In addition, the technologies involved are relatively mature given the fact that an ammonia industry already exists and there are several references giving detailed techno-economic information regarding ammonia storage (Cebolla et al., 2022). Of the three options considered, ammonia is deemed the most beneficial when (slightly) longer storage is needed. SwitcH2 also uses an ammonia producing FPSO when they are not able to connect to a pipeline and therefore need storage onboard (Saskia Kunst, personal communication, April 4, 2023), which may be for this reason.

From the considerations presented above, it may be concluded that for far offshore green hydrogen production, either ammonia or liquid hydrogen should be used to store the produced hydrogen on the FPSO. Offshore storage of gaseous hydrogen will not be considered in this research.

2.4.3 Conclusion: technologies to be included in this research

From the previous subsections, it may be concluded that quite a lot is already known about (the techno-economic feasibility of) the various aspects of the far offshore green hydrogen supply chain. Based on the findings presented in this section, it was decided which technologies to include in this research, which will be summarized below. Based on these findings, the baseline modelling approach set up in Section 2.2 and the methods chosen in Section 2.3, the model will be formulated in Section 3.1.

With regards to the hydrogen production, it was found that several electrolyzers are already available in prototype form or even used commercially onshore, and that PEM electrolyzers are expected to be most suitable for far offshore green hydrogen production. Technological developments are however still needed and strong cost reductions are expected. Furthermore, hydrogen production far offshore with PEM electrolyzers will require a desalination plant.

In a far offshore environment, centralized hydrogen production can be done on an FPSO. Decentralized hydrogen production will not be considered in this research. The offshore adaptability of the production process is expected to be good and FPSO technology is available from the oil and gas sector.

For the far offshore renewable energy generation, moored floating wind and solar energy seem already technologically feasible, although they require further development to increase their performance and economic feasibility. Also, certain technological limits regarding wind speeds and wave heights are present. The technological and especially cost development of wave energy converters is deemed too uncertain and therefore, wave energy is left outside of the scope of the intended research. For floating wind, cost estimates exist and they do not seem to deviate too much looking at the eventual costs, although it would be good to confirm the timeline of the cost development. Cost estimates for floating solar may be harder to obtain.

With regards to the transport of hydrogen produced far offshore, the transport over sea seems technologically and economically feasible if it is done by ship in the form of ammonia or liquid hydrogen. Whether ammonia or liquid hydrogen is more beneficial depends on the distance to be travelled and the quantity of hydrogen to be transported. Both options will therefore be included in the model to be developed in this research. Transport over land will be done with pipelines as gaseous hydrogen. Long term storage onshore will not be included in the model, but storage in the FPSO will. This storage may be done as ammonia or liquid hydrogen, depending on which medium is used for transport.

2.5 Conclusion literature review

In this section, some concluding remarks for the literature review will be given. A short recap of the main findings will be presented in Subsection 2.5.1. Following these findings, the scope for the rest of the research will be formulated in Subsection 2.5.2.

2.5.1 Findings

In this subsection, a recap of the findings in this literature review will be given. These findings will form the basis for the rest of the research. The conclusion and discussion of the findings in Sections 2.3 and 2.4 have already been given more elaborately in Subsections 2.3.4 and 2.4.3 respectively. Therefore, only a short recap will be given here.

The primary gap in literature identified is an evaluation of the global potential of far offshore green hydrogen over time using local comparisons with specific scenarios. In addition, several other shortcomings of previous research with a similar scope were identified and it was indicated how their modelling approach must be adjusted to take these into account. A local comparison with specific scenarios is important because the applicability of far offshore green hydrogen production is highly dependent on the situation and comparing onshore and offshore hydrogen production costs on a global level directly does not show its potential accurately. Only when comparing green hydrogen alternatives on a local level and/or in a specific context, useful conclusions can be drawn. When this local comparison is made for a sufficient amount of representative locations/scenarios, conclusions about the global potential can be drawn as well.

The available literature has been reviewed extensively and systematically, finding a suitable method to fill the identified primary gap in literature: optimization with MIQCP. To limit the needed development and computational time, it was decided to simplify the supply and demand interaction and focus on the optimization of the far offshore green hydrogen supply chain. This leads to less complete, but more detailed and reliable results, which is expected to lead to the insights that are most relevant at this point in time and to the most complete answer to the main research question. The general set up of the model was discussed, and it was decided to focus on Python as a programming language and use the Gurobi optimization solver.

Finally, an overview was made of the available knowledge regarding the technological and economic feasibility of the relevant technologies at this point in time and in the future. All aspects of a far offshore green hydrogen supply chain, including production, transport and storage, have been reviewed. Based on this, it was decided which technologies to include in the model to be developed.

2.5.2 Scope of the research

In this subsection, the scope for the rest of the research will be formulated, based on the information gathered in this literature review. This will assist in eventually finding an answer to the main research question.

Looking at the geographical scope, the entire world will be included in the literature review, since the goal is to asses the worldwide potential of far offshore green hydrogen. In a later part of the research, a representative set of specific scenarios will be defined, considering various parts of the world. Certain areas are expected to be of higher interest. For the production side, this would be the areas of the oceans with strong and constant winds. For the usage side, it would be the areas of the world with less potential for other kinds of green hydrogen production.

The time period of interest for this research will be the period from 2020 until 2050. In 2050, the net-zero targets should be accomplished. Therefore, the main interest will be what role far offshore green hydrogen production can play by that time. If by then it will still not be feasible from a technical or economic perspective, investments for green hydrogen production will have to go elsewhere, and once other green hydrogen production options have been invested in and built, the role far offshore green hydrogen production can still play is expected to be minimal. Therefore, this research will focus on assessing the techno-economic feasibility of far offshore green hydrogen production between 2020 and 2050.

With regards to the modelling approach, an optimization of global supply and demand interaction will be left out of the scope, since it has been decided to put the focus on the optimization of the far offshore green hydrogen supply chain. Also, the choices for Python as the modelling language, optimization with MIQCP as the method and Gurobi as the optimization solver have been made, meaning these will have the focus in this research.

For the hydrogen production, centralized green hydrogen production on an FPSO using PEM electrolyzers with desalination equipment will be considered, as discussed in Subsection 2.4.1.2. For the renewable energy generation, only moored, floating wind and solar energy will be taken into account, as discussed in Subsection 2.4.1.3. When looking at the transport over sea, transport with ships in the form of ammonia and liquid hydrogen will be taken into account. For transport over land, transport as gaseous hydrogen through pipelines is considered. This has been discussed previously in Subsection 2.4.2. All technologies not mentioned in this paragraph will be left out of the scope of the intended research based on the findings of this literature review.

In general, detailed engineering such as hydrodynamic analysis will be outside of the scope of this research. For the configurations of the renewable energy production, each energy producing unit will be seen as a black box, which will produce energy over time based on the determined environmental conditions for the identified location and the technical features of the unit. More detailed technical analysis, for example aerodynamic analysis for wind turbines, will be outside the scope of this research.

For the hydrogen production, the electrolyzers will also be seen as (individual) black boxes, producing hydrogen based on the amount of energy used from the renewable energy sources and the technical features of the electrolyzers. The same will apply to possible other equipment included in the FPSO (for example for desalination). Based on the equipment needed in the FPSO (resulting from the optimizations done by the model), an estimation of the FPSO's size and (related to that) costs will be made. A more detailed design of the layout of the FPSO will however not be included in the scope of this research.

For the transport, the model will determine the costs based on the amount to be transported, the distance to be transported over and the transport medium. More detailed considerations of for example the flow through a pipeline or of individual ships sailing will be outside the scope of this research. For possible conversions to other energy carriers, the device performing this conversion will also be seen as a black box, producing the other molecule based on the amount of hydrogen and energy inserted, and the technical features of the device.

Chapter 3

Methodology and implementation

In this chapter, the methodology and its implementation for the analysis of the worldwide potential of far offshore green hydrogen production will be explained. First, Section 3.1 will discuss the model itself and shortly dive into its implementation as well. Next, Section 3.2 will explain how the necessary data will be inserted in the model used in this research and shortly discuss the quality of the available data. Finally, Section 3.3 will define the set of representative scenarios to be analyzed using the model to be able to give a first sense of the worldwide potential of far offshore green hydrogen production towards 2050.

3.1 Model

In this section, the model set up to analyze various scenarios for the production and usage of far offshore green hydrogen will be discussed in more detail. This model will be used in this research to analyze the identified set of representative scenarios, but is also meant to be used in follow up research to further advance the knowledge base regarding far offshore green hydrogen production when more accurate data is available. In addition, it is meant to be used by industry parties in the future to be able to assess the feasibility of a considered far offshore green hydrogen supply chain. The model was set up based on the findings in the literature review, as explained before. Before explaining the model itself, the main optimization challenges solved by the model will be discussed.

3.1.1 Main optimization challenges

In this subsection, the main optimization challenges to be solved by the model will be discussed. These challenges are (1) the optimization of the amount of wind turbines, solar platforms and electrolyzers and (2) the choice between using ammonia or liquid hydrogen as transport and storage medium for the produced hydrogen. Below, these two main challenges are discussed separately.

Optimization of the amount of wind turbines, solar platforms and electrolyzers
As already mentioned in Section 2.4. combining wind and solar power generation is expected to be beneficial. One of the main reasons for this is the variability of both wind and solar power production and the possibility for the two to complement each other to create a steadier power production. Next to combining wind and solar with each other, the combination with the right amount of electrolyzers is also important. Finding the right combination of wind turbines, solar platforms and electrolyzers is one of the main challenges solved by the model when optimizing the far offshore green hydrogen supply chain for a specific scenario. How this is done by the model will be explained in more detail in the next subsections. In Figures 3.1 to 3.5, a strongly simplified visualization is shown to illustrate this optimization. The values on the axes of these figures are purely meant for illustrative purposes.

In Figure 3.1, a simplified example of the variable power production of a set of wind turbines is shown, with an accompanying electrolyzer capacity. As can be seen in Figure 3.1, the electrolyzers are not running at their maximum capacity for a relatively large amount of time due to the variability of the wind power production. Furthermore, some power is lost if more power is generated than the capacity of the electrolyzers. In Figure 3.1, these are the peaks of the wind power graph that are above the line representing the electrolyzer capacity.

In Figure 3.2, the wind power production, the solar power production and the sum of those two is shown. In this simplified example, the peaks of the solar power production coincide exactly with the lows of the wind power production. In reality, this is not necessarily the case. As shown in the simplified visualization in Figure 3.2, the wind and solar power generation complement each other in this case, leading to a more steady power production. In reality, the complementarity of wind and solar in a specific scenario will largely influence to what extend the two will be combined.

When finding the optimal far offshore green hydrogen supply chain, the model will vary the electrolyzer capacity, the total energy generation capacity, and the ratio between the wind turbines and solar platforms (changing the shape of the generated power graph). Examples of these variations are shown in Figures 3.3, 3.4 and 3.5 respectively. The first is done by changing the amount of electrolyzers, while the second and third are done by changing the amount of wind turbines and/or solar platforms. The most optimal combination of wind turbines, solar platforms and electrolyzers for each scenario is the combination with the lowest total costs while still producing enough hydrogen. The calculations and constraints used to implement this optimization in the model will be discussed in more detail in the following subsections. The results of this optimization (as eventually implemented in the model) will be discussed separately in Subsection 6.7.1 when analyzing the results.

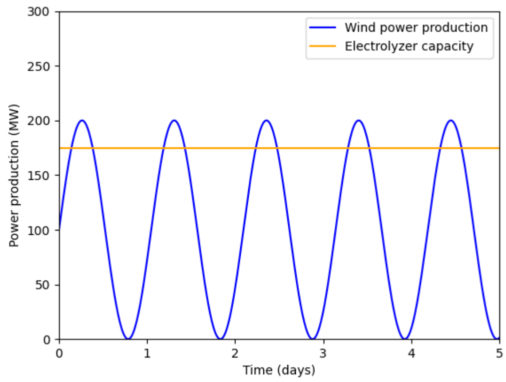


Figure 3.1: Simplified example wind power production with electrolyzer capacity

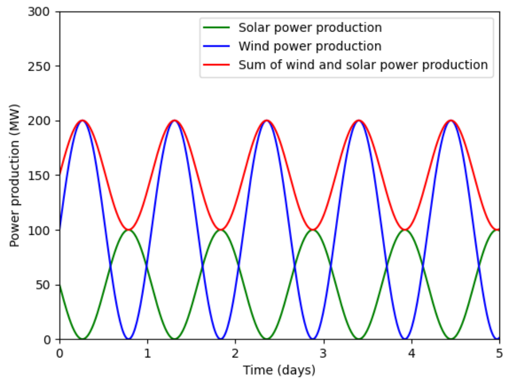


Figure 3.2: Simplified illustration of combining wind and solar power production

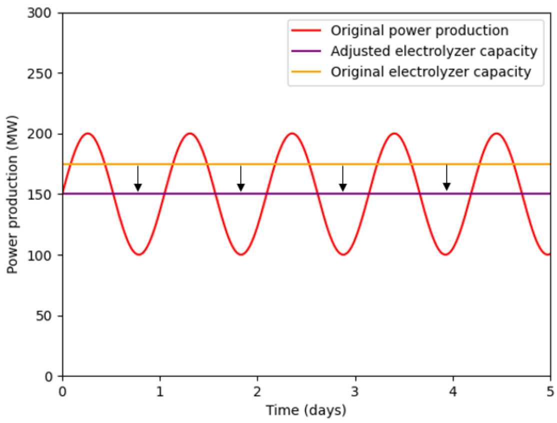


Figure 3.3: Simplified illustration of reducing electrolyzer capacity

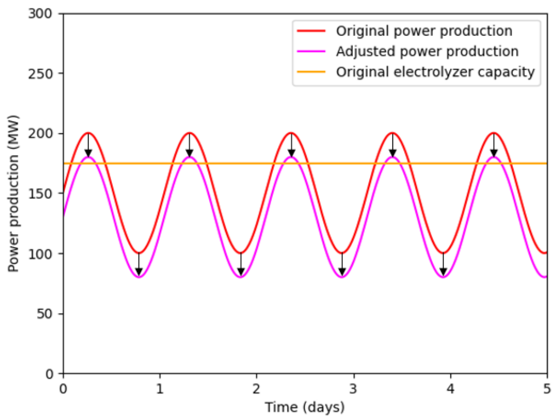


Figure 3.4: Simplified illustration of reducing total power generation capacity

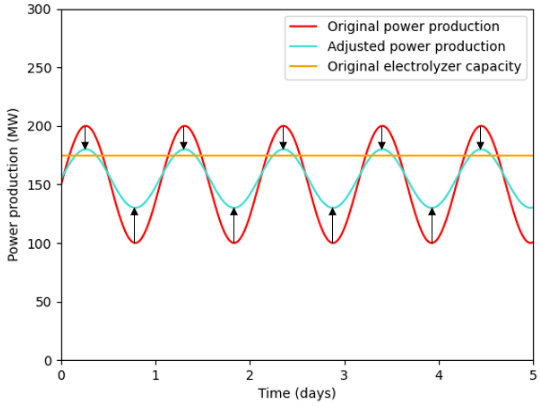


Figure 3.5: Simplified illustration of adjusting power generation graph shape by changing ratio between wind and solar power production

Choosing between ammonia and liquid hydrogen

The second main optimization challenge to be solved by the model is the choice between using ammonia or liquid hydrogen as transport and storage medium. This influences (the costs of) many different factors of the far offshore green hydrogen supply chain, namely the percentage of the energy coming into the FPSO that is available for the electrolyzers, the needed size of the storage tank on the FPSO (and therefore the needed size of the FPSO), the costs of transport, the costs of the storage tank, the (re)conversion costs and the (re)conversion efficiency. In the following subsections, this will be explained further and it will be shown how exactly the choice between ammonia and liquid hydrogen has been incorporated in the model.

In Table 3.1, an overview of the strong and weak points of ammonia and liquid hydrogen is given. As the costs of liquid hydrogen decrease over the years, it is expected to eventually become more attractive (Brändle et al., 2021). The scenario analyses will show if and/or when it may become more attractive than ammonia in the scenarios to be analyzed in this research.

Table 3.1: Strengths of ammonia and liquid hydrogen

	Ammonia	Liquid hydrogen
Storage costs per m^3	+	-
Storage tank size (also influences FPSO costs)	+	-
Transport costs	+	-
Power usage on FPSO for conversion and storage	+	-
(Re)conversion costs	-	+
(Re)conversion efficiency	-	+

3.1.2 Model overview and objective function

A schematic overview of the calculations belonging to an optimization of a far offshore green hydrogen supply chain, which forms the core of the developed model, is shown in Figures 3.6 and 3.7, where the second is a continuation of the first. It should be noted that only one optimization is visualized here, while a normal run of the model will include several optimizations for the chosen scenario in different years. When looking at the input data for these optimizations belonging to different years, only the cost data will change, which are represented by the cell in the bottom right of Figure 3.7. This could lead to a different optimal far offshore green hydrogen supply chain for every considered year.

Next to the time domain included in the model by simulating several years, a second time domain is included within each optimization. From ERA5, hourly weather data is imported for a reference period of 10 months, which enters the model at the very left of Figure 3.6. From this hourly weather data, the hourly power production, the hourly power available for and used by the electrolyzers, and the hourly hydrogen production are determined over the reference period. Using these hourly production figures, the supply chain is optimized for production over a longer period of time, leading to more realistic results. The details of this optimization will be explained later in this section.

In Figures 3.6 and 3.7, the cells with yellow filling are 'normal', numeric input data or based on calculations with solely numeric data. The cells with red filling are variables, which are to be varied directly by the used optimization solver when finding the optimum. The cells with blue filling are based on calculations including other variables, meaning their value also changes while the optimization runs. For a further explanation of the used variables, please refer to Table 3.2. Furthermore, the black arrows connecting cells represent 'regular' calculations, whereas the orange arrows represent constraints. Finally, the meaning of the colours of the outlines of the cells will be discussed later. In the rest of this section, the model will be explained piece by piece.

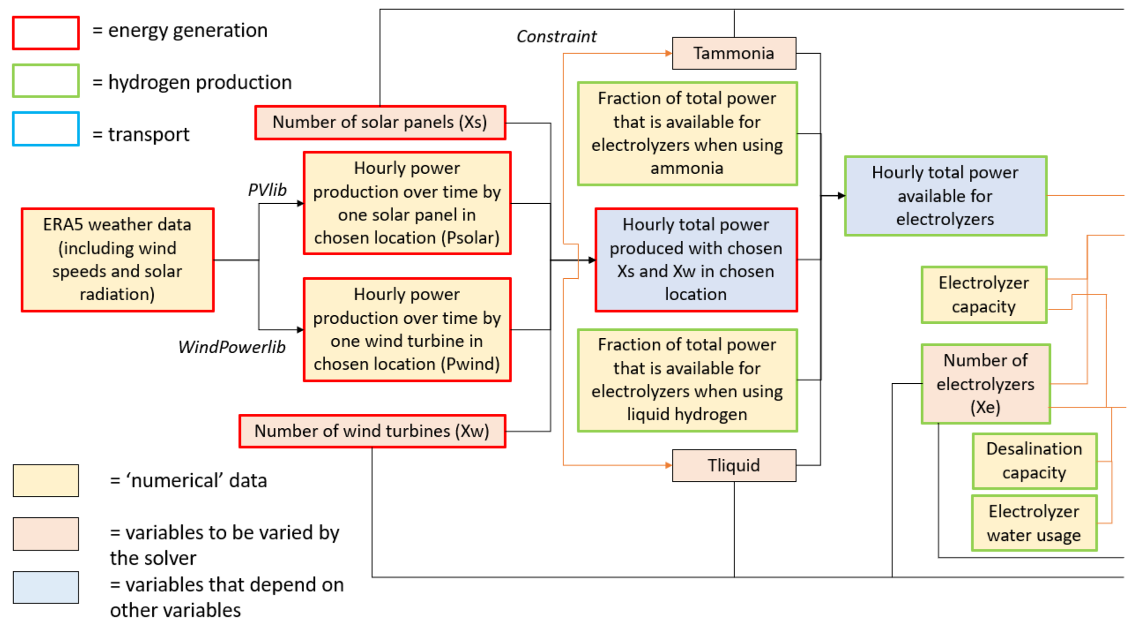


Figure 3.6: Model visualization 1/2

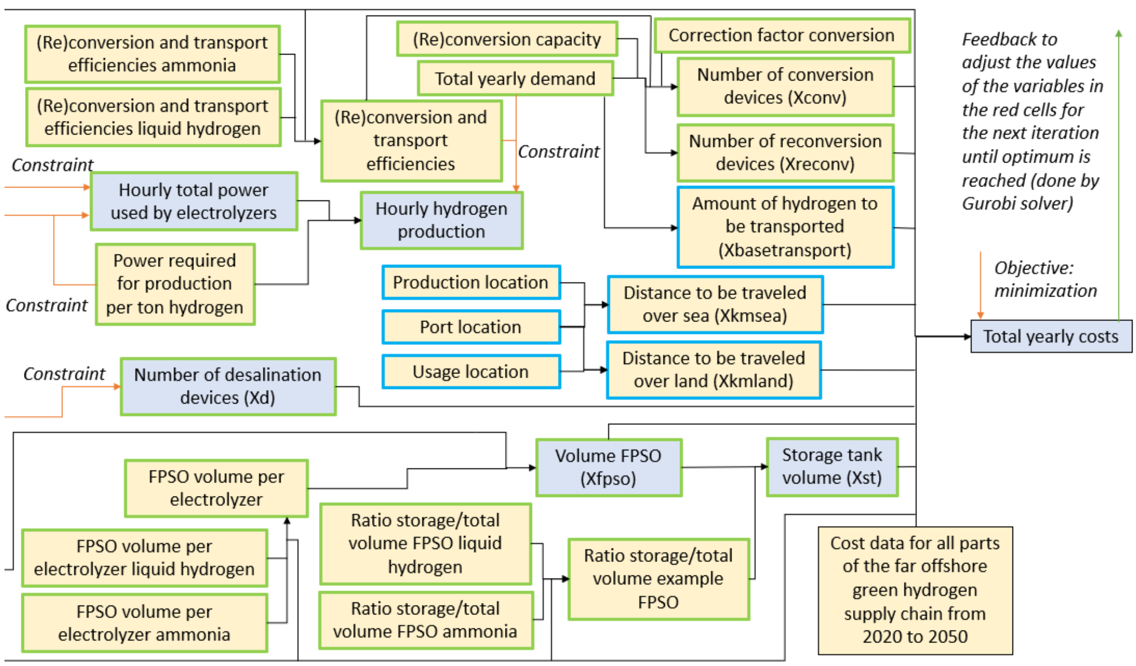


Figure 3.7: Model visualization 2/2

As can be seen in the figures, most calculations in the model eventually lead back to the calculation of the total yearly costs. As the yearly hydrogen production is given as a (constant) input to the optimization, these total yearly costs are directly related to the costs per kg of hydrogen. This means minimizing the total yearly costs is equal to minimizing the costs per kg of hydrogen for the analyzed supply chain. Therefore, the objective function to be minimized in the model is formulated as shown in Equation (3.1), where ‘i’ indicates the components of vectors x and C. Vectors x and C represent the number of units and the cost per unit respectively.

$$MIN(\sum_i x[i] * C[i]) \tag{3.1}$$

This means the sum that is minimized in the objective function is equal to the total costs for the far offshore green hydrogen supply chain in the defined scenario in the selected year. The elements of vectors x and C can be split up into three different groups: energy generation (X_{energy} and C_{energy}), hydrogen production ($X_{\text{production}}$ and $C_{\text{production}}$) and transport ($X_{\text{transport}}$ and $C_{\text{transport}}$). This gives the split shown in Equation (3.2). In Figures 3.6 and 3.7, it has been indicated which part of the model belongs to each group through the colour of the outlines of the cells. The meaning of these colours is given in the legend. The cells with T_{ammonia}, T_{liquid} and the cost data do not have a coloured outline, because the calculations in which they are used belong to multiple groups.

$$x * C = X_{\text{energy}} * C_{\text{energy}} + X_{\text{production}} * C_{\text{production}} + X_{\text{transport}} * C_{\text{transport}} \tag{3.2}$$

The three categories shown in Equation (3.2) can each be split up further, as shown in Equations (3.3) to (3.5). In Table 3.2, the variables used in these equations are explained. As indicated in the table, most of the equipment types are restricted to integer values.

$$X_{\text{energy}} * C_{\text{energy}} = X_{\text{w}} * C_{\text{w}} + X_{\text{s}} * C_{\text{s}} \tag{3.3}$$

$$\begin{aligned} X_{\text{production}} * C_{\text{production}} &= X_{\text{e}} * C_{\text{e}} + X_{\text{d}} * C_{\text{d}} + X_{\text{st}} * C_{\text{st}} + X_{\text{fpso}} * C_{\text{fpso}} \\ &+ T_{\text{ammonia}} * X_{\text{convammonia}} * C_{\text{convammonia}} + T_{\text{liquid}} * X_{\text{convliquid}} * C_{\text{convliquid}} \\ &+ T_{\text{ammonia}} * X_{\text{reconvammonia}} * C_{\text{reconvammonia}} + T_{\text{liquid}} * X_{\text{reconvliquid}} * C_{\text{reconvliquid}} \end{aligned} \tag{3.4}$$

$$X_{\text{transport}} * C_{\text{transport}} = X_{\text{basetransport}} * C_{\text{basetransport}} + X_{\text{kmsea}} * C_{\text{kmsea}} + X_{\text{kmland}} * C_{\text{kmland}} \tag{3.5}$$

Table 3.2: Meaning variables

Component	**Meaning**	**Unit**
X_{w}	Number of wind turbines (integer)	dmnl
X_{s}	Number of solar platforms (integer)	dmnl
X_{e}	Number of electrolyzers (integer)	dmnl
X_{d}	Number of desalination devices (integer)	dmnl
X_{st}	Volume of the storage tank on the FPSO	m^3
X_{fpso}	Volume of the FPSO	m^3
X_{kmsea}	Distance to be traveled over sea	km
$X_{\text{basetransport}}$	Amount of hydrogen to be transported	tons
X_{kmland}	Distance to be traveled over land	km
$X_{\text{convammonia}}$	Amount of conversion devices in case of transport as ammonia (integer)	dmnl
$X_{\text{convliquid}}$	Amount of conversion devices in case of transport as liquid hydrogen (integer)	dmnl
$X_{\text{reconvammonia}}$	Amount of reconversion devices in case of transport as ammonia (integer)	dmnl
$X_{\text{reconvliquid}}$	Amount of reconversion devices in case of transport as liquid hydrogen (integer)	dmnl
T_{ammonia}	Binary variable that indicates transport is done with ammonia when equal to 1	dmnl
T_{liquid}	Binary variable that indicates transport is done with liquid hydrogen when equal to 1	dmnl
C_{w}	Yearly costs of one wind turbine	euros/year/unit
C_{s}	Yearly costs of one solar platform	euros/year/unit
C_{e}	Yearly costs of one electrolyzer	euros/year/unit
C_{d}	Yearly costs of one desalination device	euros/year/unit
C_{st}	Yearly costs of one m^3 of storage tank	euros/year/$m3$
C_{fpso}	Yearly costs of one m^3 of FPSO	euros/year/$m3$
C_{kmsea}	Costs of ammonia or liquid hydrogen transport over sea for one tonkm hydrogen	euros/ton of hydrogen/km
$C_{\text{basetransport}}$	Base sea transport costs of ammonia or liquid hydrogen for one ton of hydrogen	euros/ton of hydrogen
C_{kmland}	Costs of gaseous hydrogen transport over land through pipelines per tonkm hydrogen	euros/ton of hydrogen/km
$C_{\text{convammonia}}$	Yearly costs of one ammonia conversion device	euros/year/unit
$C_{\text{convliquid}}$	Yearly costs of one liquid hydrogen conversion device	euros/year/unit
$C_{\text{reconvammonia}}$	Yearly costs of one ammonia reconversion device	euros/year/unit
$C_{\text{reconvliquid}}$	Yearly costs of one liquid hydrogen reconversion device	euros/year/unit

In the following subsections, the calculations done by the model every iteration, as also shown in Figures 3.6 and 3.7, are discussed per category. In some of these calculations, $T_{ammonia}$ and T_{liquid} are used, which are also mentioned in Table 3.2. $T_{ammonia}$ and T_{liquid} are binary variables used to include the choice between transporting with ammonia or liquid hydrogen in the optimization. To force the optimization solver to choose between the two, the constraint in Equation (3.6) has been implemented, which is also shown in Figure 3.6.

$$T_{\text{ammonia}} + T_{\text{liquid}} = 1 \tag{3.6}$$

Having mentioned this general constraint, the calculations done in the model can be looked at in more detail. How the model operates will be explained by going through the three categories, discussing both regular calculations (black arrows in Figures 3.6 and 3.7) and constraints (orange arrows in those same figures). As both the regular calculations and constraints are incorporated in the same 'flow', they are discussed simultaneously. It will however be indicated clearly with an equation when it regards a constraint and this is also shown in Figures 3.6 and 3.7. Although a distinction is made in the model description between regular calculations and constraints, most of the regular calculations were also incorporated as constraints in the implementation of the model in Python. This was needed to make sure all of the variable values in the calculations that needed to be updated every iteration were actually updated.

With every part of the model discussed in the rest of this section, an additional figure with the relevant part of the model taken from Figures 3.6 and 3.7 will be added to make clear which part of the model is being discussed. In these additional figures, it is also indicated which equations correspond with the connections in the model visualization. In the previous, the objective has been discussed first, since this is the most important part of the model. As visualized in Figures 3.6 and 3.7, and shown in Equations (3.1) to (3.5), the cost data in combination with many different variables and values are included in the objective function. As these variables and values are included in all parts of the model as well, there is not one single, clear 'flow' going from the objective function back to the beginning of the model. Instead, the objective function is connected to the model in many different points. Therefore, it makes more sense to discuss the model from the beginning to the end. This will be done in the following, starting at the left of Figure 3.6. In the figures, it will be indicated which variables and values connect to the objective function.

3.1.3 Energy generation

To start, the calculations belonging to the energy generation part of the model will be discussed (with red outline in Figure 3.6). This part of the model is shown in Figure 3.8, where the connection representing Equation (3.7) is also indicated.

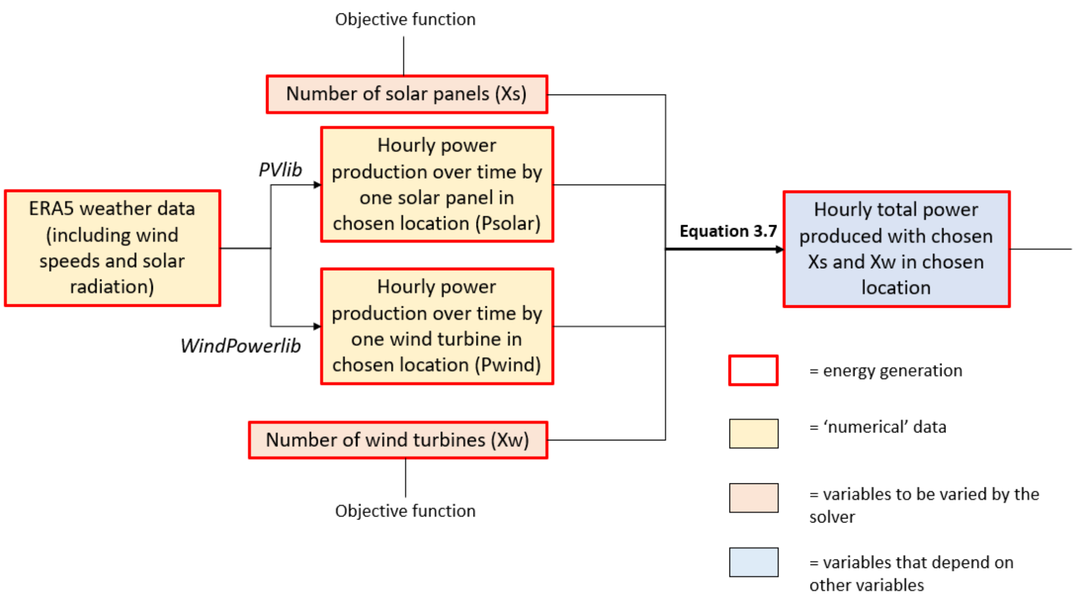


Figure 3.8: Model visualization power generation

As shown in Figure 3.8, weather data from the ERA5 database is used, which is retrieved using the first script added in Appendix E. Based on the inserted coordinates and dates, the script will send a download request to Climate Data Store, from which the relevant data is then downloaded automatically. In this research, weather data for a 10 month reference period has been used from the 1st of January 2020 to the 31st of October 2020. The hourly weather data retrieved from the ERA5 database is loaded into the model developed in this research and used to determine the hourly power output over the chosen reference period of one reference solar panel and one reference wind turbine in the chosen production location with PVlib and WindPowerlib respectively. Based on the size of the wind turbine and solar platform chosen in the input data, the hourly power output over time determined with PVLib and WindPowerlib is scaled to represent the chosen wind turbine (P_{wind}) and solar platform (P_{solar}). Next, P_{wind} and P_{solar} are used to determine the total hourly power output over time, as shown in Equation (3.7).

$$Power = P_{solar} * X_s + P_{wind} * X_w \tag{3.7}$$

In Equation (3.7), Power is the total hourly power generated over the reference period by solar and wind together in W, P_{solar} is the hourly power generated over the reference period by one solar platform in the specified coordinates in W, P_{wind} is the hourly power generated over the reference period by one wind turbine in the specified coordinates in W, X_s is the amount of solar platforms and X_w is the amount of wind turbines. This equation defines the total power production, based on the amount of wind turbines and solar platforms, which are varied in the optimization process as shown in Figures 3.6 and 3.8.

3.1.4 Hydrogen production

After having calculated the total hourly power production over the reference period, the model will continue with the calculations belonging to the hydrogen production part of the model (with green outline in Figures 3.6 and 3.7). The first part of these calculations is shown in Figure 3.9, where the connections representing Equations (3.6), (3.8) and (3.9) are also indicated.

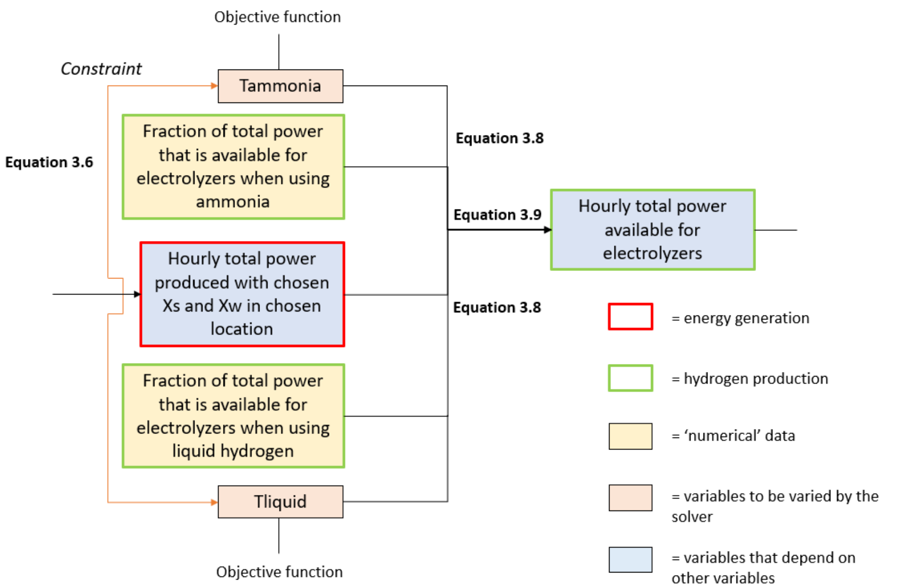


Figure 3.9: Model visualization power available for electrolyzers

With the total hourly power production, the fraction of total power that is available for electrolysis when using ammonia or liquid hydrogen, and the binary variables indicating the use of either ammonia or liquid hydrogen, the hourly power available for the electrolyzers is determined. In Equations (3.8) and (3.9), the determination of the fraction of the total hourly power available for electrolysis based on which transport medium is used, and the subsequent determination of the hourly power available for electrolysis are shown respectively.

$$fracpowerelectrolyzer = T_{\text{ammonia}} * fracpowerelectrolyzerammonia + T_{\text{liquid}} * fracpowerelectrolyzerliquid \quad (3.8)$$

$$Powerelectrolyzer = Power * fracpowerelectrolyzer \quad (3.9)$$

In Equation (3.8), fracpowerelectrolyzer represents the fraction of the total hourly power coming into the FPSO that is directly available for the electrolyzers to produce hydrogen. This equation determines if the fraction corresponding to ammonia or liquid hydrogen is used, based on which of these is used in the rest of the supply chain. Since liquid hydrogen requires a relatively large amount of power for conversion and storage, this could have a significant influence.

In Equation (3.9), Powerelectrolyzer is the hourly power over the reference period that is available for the electrolyzers in W. This is determined from the total available hourly power and the fraction of this power that is available for the electrolyzers.

The next part of the calculations is shown in Figure 3.10. In this figure, the connections corresponding to Equations (3.10) and (3.11) are indicated as well.

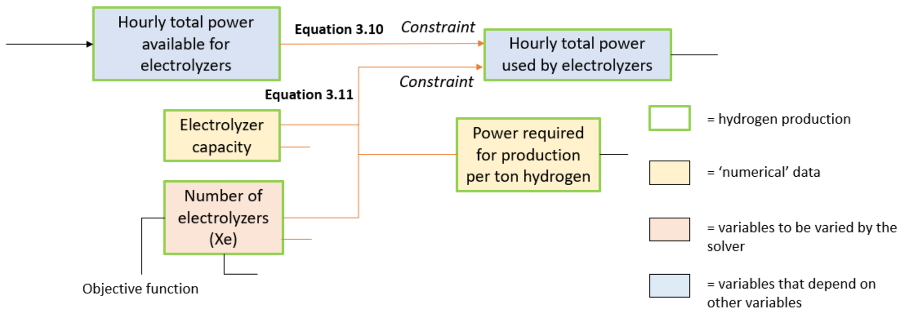


Figure 3.10: Model visualization power used by electrolyzers

The hourly power over the reference period available for the electrolyzers as determined before is used as a base for a constraint to limit the hourly power that is actually used by the electrolyzers. In addition, another constraint is added to limit the actual hourly power used by the electrolyzers as well. These constraints are shown in Equations (3.10) and (3.11) respectively.

$$Powerusedelectrolyzer \leq Powerelectrolyzer \quad (3.10)$$

$$Powerusedelectrolyzer \leq capelectrolyzer * X_{\text{e}} * electrolyzer\_power \quad (3.11)$$

In Equations (3.10) and (3.11), Powerusedelectrolyzer is the hourly power over the reference period used by the electrolyzers in W, capelectrolyzer is the hourly capacity of one electrolyzer in tons of hydrogen/h, X_e is the amount of electrolyzers and electrolyzer_power is the power in Wh required to produce one ton of hydrogen. These two constraints put an upper limit on the hourly power used by the electrolyzers and therefore on the hourly hydrogen production from these electrolyzers. This limit is twofold; (1) the power used in a certain hour cannot be higher than the power available in that hour and (2) the power used cannot be higher than the power that would be used at the maximum electrolyzer capacity. This means that in order to increase the hydrogen production, the available power (so X_s and/or X_w) or the total electrolyzer capacity (so X_e) can be increased. The balance between increasing X_s, X_w and/or X_e to increase the hydrogen production, while minimizing the total costs and taking into account the very dynamic behaviour of the sustainable energy production over time, forms one of the main parts of the optimization done by the model. This was also explained in Subsection 3.1.1.

The next part of the calculations is visualized in Figure 3.11. In this figure, it has also been indicated which connections correspond to Equations (3.12) to (3.15).

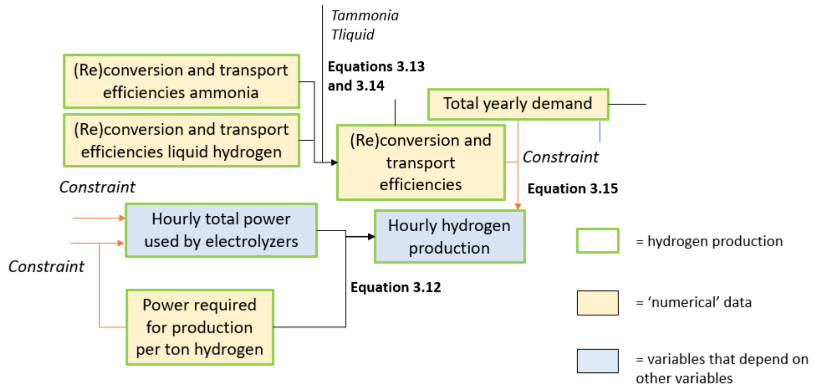


Figure 3.11: Model visualization hydrogen production

From the total hourly power used by the electrolyzers and the power required to produce hydrogen, the hourly hydrogen production is determined. This is shown in Equation (3.12).

$$Y_{\text{hydrogen}} = \frac{Powerusedelectrolyzer}{electrolyzer\_power} \tag{3.12}$$

In Equation (3.12), $\mathrm{Y}_{\text{hydrogen}}$ is the hourly hydrogen production (or yield) over time in tons of hydrogen/h. The sum of $\mathrm{Y}_{\text{hydrogen}}$ over the reference period gives the total amount of hydrogen produced over the reference period ($\mathrm{Y}_{\text{hydrogentot}}$), which will be used for another constraint. First however, the efficiencies indicating the hydrogen losses during conversion, reconversion and transport must be determined. It is assumed that during transport with both transport mediums, boil-off will be reliquefied, meaning no hydrogen is lost during transport. The hydrogen losses during conversion and reconversion depend on the transport medium used and are therefore determined as shown in Equations (3.13) and (3.14) respectively.

$$\eta_{conv} = T_{\text{ammonia}} * \eta_{convammonia} + T_{\text{liquid}} * \eta_{convliquid} \tag{3.13}$$

$$\eta_{reconv} = T_{\text{ammonia}} * \eta_{reconvammonia} + T_{\text{liquid}} * \eta_{reconvliquid} \tag{3.14}$$

In Equations (3.13) and (3.14), η_{conv} is the conversion efficiency and η_{reconv} is the reconversion efficiency. They both depend on which transport medium is used. When saying efficiency here, what is referred to is the amount of hydrogen that remains after the (re)conversion process. For example, if 2% of the hydrogen is lost in the conversion process to ammonia, η_{conv} for ammonia would be 0.98.

With the conversion and reconversion efficiencies, the next constraint can now be formulated. For this, $\mathrm{Y}_{\text{hydrogentot}}$ is used, which is determined from $\mathrm{Y}_{\text{hydrogen}}$, as explained before. This constraint is meant to make sure enough hydrogen is produced to fulfill the demand and is shown in Equation (3.15).

$$Y_{\text{hydrogentot}} \geq \frac{D}{(\eta_{conv} * \eta_{transport} * \eta_{reconv})} \tag{3.15}$$

In Equation (3.15), $\mathrm{Y}_{\text{hydrogentot}}$ is the total hydrogen production (or yield) over the reference period in tons of hydrogen as determined by the model and D is the demand in that same reference period in tons of hydrogen as defined in the scenario. Furthermore, $\eta_{transport}$ is the transport efficiency, which is assumed to always be equal to 1 in this research, as explained before. The lower limit set for $\mathrm{Y}_{\text{hydrogentot}}$ in Equation (3.15) translates into a lower limit for the area under the graph of $\mathrm{Y}_{\text{hydrogen}}$ over the reference period and therefore also for the area under the graph of Powerusedelectrolyzer over the reference period. This forces the optimization solver to increase X_{e}, X_{s} and/or X_{w} to accommodate the constraints in Equations (3.10) and (3.11). The constraint in Equation (3.15) is one of the most important constraints, as it is the one giving 'push-back' to the objective; if this would not be there, the minimization of total costs would simply lead to a production of zero tons of hydrogen, since without a minimal production, the cheapest far offshore green hydrogen supply chain is the one that does not exist.

Next to the constraint in Equation (3.15), the total yearly demand is also used to determine the number of conversion and reconversion devices. This is shown in Figure 3.12, and in Equations (3.16) and (3.17) respectively.

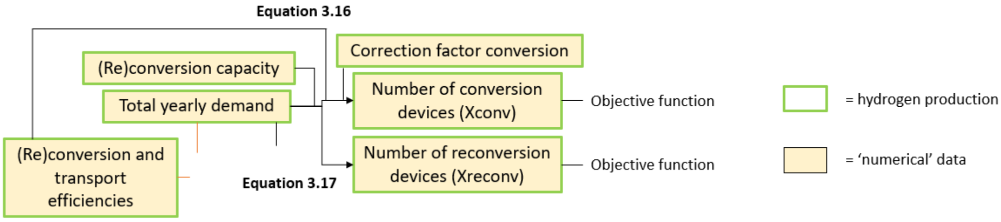


Figure 3.12: Model visualization (re)conversion

$$X_{\mathrm{conv}} = k * \frac{D}{\eta_{reconv} * \eta_{transport} * capconversion} \tag{3.16}$$

$$X_{\mathrm{reconv}} = \frac{D}{capreconversion} \tag{3.17}$$

In Equations (3.16) and (3.17), X_{conv} is the number of conversion devices, k is the correction factor to account for fluctuating hydrogen production, capconversion is the yearly capacity of a conversion device in tons of hydrogen/year, X_{reconv} is the number of reconversion devices and capreconversion is the yearly capacity of a reconversion device in tons of hydrogen/year. The value of k to be used in this research will be discussed in Chapter 5. X_{conv} and X_{reconv} are determined for both ammonia and liquid hydrogen, and the values corresponding to the chosen transport medium are used in the further calculations. Furthermore, X_{conv} and X_{reconv} are both integer values and the result of the calculation is rounded up to the next integer.

Within the category hydrogen production, another chain of calculations is included in the model, which starts from the amount of electrolyzers used. This chain of calculations determines the amount of desalination devices used and the sizing of the FPSO and storage tank. The first is shown in Figure 3.13 and the second in Figure 3.14. The amount of electrolyzers was also used in the calculations shown in Figure 3.10 already.

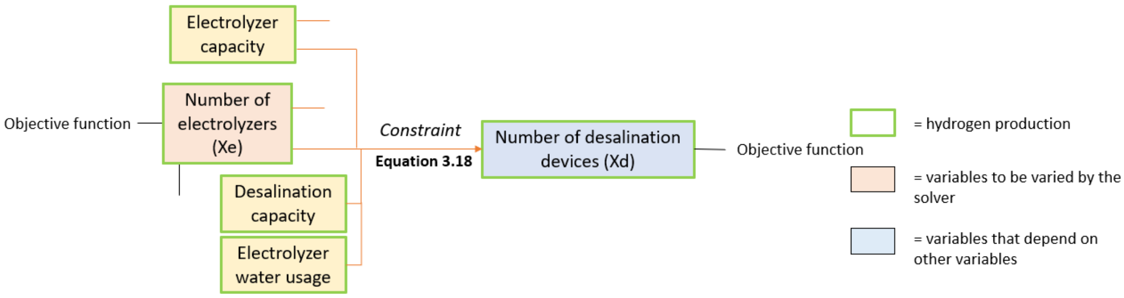


Figure 3.13: Model visualization desalination devices

To determine the amount of desalination devices, the constraint shown in Equation (3.18) has been implemented. The corresponding connection is shown in Figure 3.13.

$$X_{\mathrm{d}} \geq \frac{X_{\mathrm{e}} * capelectrolyzer * electrolyzer\_water}{capdesalination} \tag{3.18}$$

In Equation (3.18), X_d is the amount of desalination devices, electrolyzer_water is the water needed to produce one ton of hydrogen in m^3 and capdesalination is the hourly capacity of a desalination device in m^3 of water. This constraint makes sure the desalination capacity matches the electrolyzer capacity.

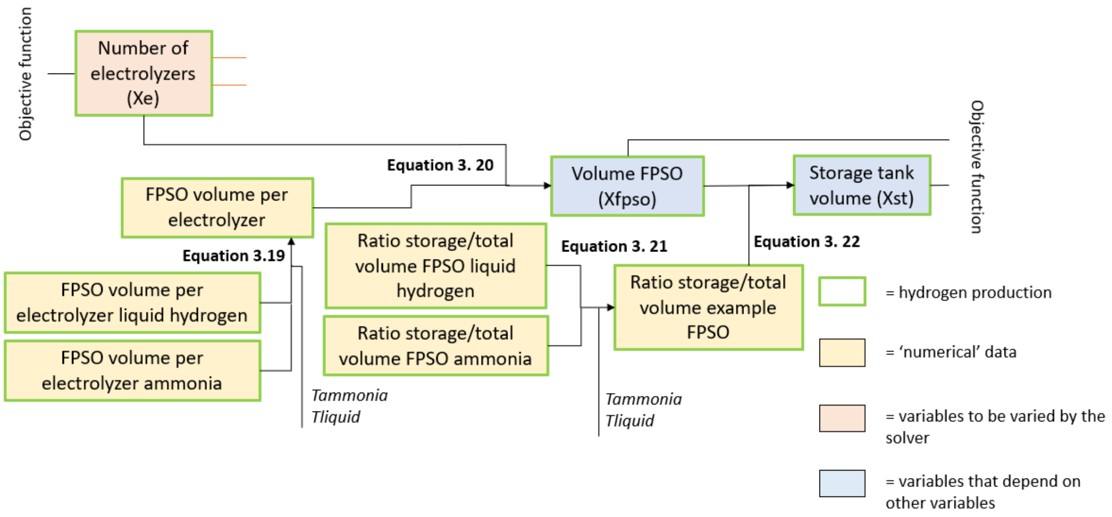


Figure 3.14: Model visualization FPSO and storage size

To estimate the needed size of the FPSO for hydrogen production and therefore its costs, the dimensions and layout of the liquid hydrogen FPSO concept as presented by J. Lee et al. (2023) have been used. The assumption is made that ammonia production equipment will require a similar amount of space as liquid hydrogen production equipment. A distinction is however made in the size of the needed storage tank, since ammonia has a higher hydrogen density per cubic meter than liquid hydrogen. This is taken into account through the value of $\mathrm{R}_{\mathrm{storagefpso}}$, which will be shown in Equations (3.21) and (3.22). It is also taken into account in the FPSO volume per electrolyzer used in Equations (3.19) and (3.20).

$$X_{\mathrm{FPSOelectrolyzer}} = T_{\mathrm{ammonia}} * X_{\mathrm{FPSOelectrolyzerammonia}} + T_{\mathrm{liquid}} * X_{\mathrm{FPSOelectrolyzerliquid}} \tag{3.19}$$

$$X_{\mathrm{fpso}} = X_{\mathrm{e}} * X_{\mathrm{FPSOelectrolyzer}} \tag{3.20}$$

In Equations (3.19) and (3.20), $\mathrm{X}_{\mathrm{FPSOelectrolyzer}}$ is the FPSO volume per installed electrolyzer in m^3 and $\mathrm{X}_{\mathrm{fpso}}$ is the total volume of the FPSO in m^3. The FPSO volume per installed electrolyzer is determined based on the concept FPSO of J. Lee et al. (2023) as discussed above (with an adjustment for ammonia). The total volume of the FPSO determines its costs. Based on the FPSO volume, the storage volume can be determined both in case of ammonia and liquid hydrogen usage, as shown in Equations (3.21) and (3.22).

$$R_{\mathrm{storagefpso}} = T_{\mathrm{ammonia}} * R_{\mathrm{storagefpsoammonia}} + T_{\mathrm{liquid}} * R_{\mathrm{storagefpsoliquid}} \tag{3.21}$$

$$X_{\mathrm{st}} = X_{\mathrm{fpso}} * R_{\mathrm{storagefpso}} \tag{3.22}$$

In Equations (3.21) and (3.22), $\mathrm{R}_{\mathrm{storagefpso}}$ is the ratio between the storage volume and total volume of the FPSO, which is based on the concept FPSO of J. Lee et al. (2023) (with an adjustment for ammonia). This equation determines the size of the storage tank on the FPSO, based on which its costs are determined.

3.1.5 Transport

Having discussed all the calculations included in the energy generation and hydrogen production categories, the focus can now be put on the final part of the model. This part considers the hydrogen transport from the production to the usage location (with blue outline in Figure 3.7). This part is visualized in Figure 3.15.

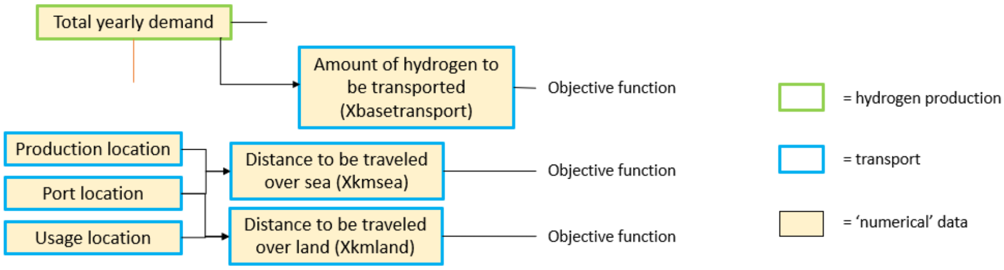


Figure 3.15: Model visualization transport

From the yearly demand as defined in the scenario, the amount to be transported ($X_{basetransport}$) is determined. It is assumed in this research that the amount to be transported is equal to the demand, as the hydrogen losses in the process are assumed to be small and it was convenient for programming reasons.

The other part of the calculations in the transport category is meant to determine the distance to be traveled over sea and over land to bring the produced hydrogen to its usage location. The geodesic function of Geopy is used to determine the distance between the production location, transfer port and usage location for the given scenario. With this method, the distance is calculated 'as the crow flies', but the roundness of the earth's surface is taken into account using an ellipsoidal model (GeoPy Contributors, 2018). In some scenarios, the transport over sea cannot be done 'as the crow flies', because the ships have to go around a land area. For these scenarios, a correction factor has been implemented to adjust the distance to be traveled over sea accordingly. In Chapter 6, the value used for this factor will be indicated for each scenario. From the distances to be traveled, the transportation costs are determined.

It was considered to include the transportation chain in the optimization, optimizing the storage in the FPSO against the amount of ships transporting hydrogen. However, as opposed to FPSO's in the oil and gas sector, hydrogen FPSO's will most likely have a much more variable production output, also showing seasonality. Therefore, optimizing the amount of ships for one specific supply chain will not give a realistic result, since the peak production will have a significant influence. In reality, ships transporting hydrogen would have to be switched between projects in different parts of the world based on the production in different seasons. The optimization of this worldwide transport network including many hydrogen production locations should be researched separately. Therefore, when looking at one specific scenario in this research, the costs of transport are only based on the amount of tonkm of hydrogen to be transported and not optimized. It is assumed transport is always available when needed.

By minimizing the total costs while adhering to the constraints stated in this section and using the discussed calculations, the minimal costs for far offshore green hydrogen in the defined scenario will be found by the model. When this is done for a representative set of scenarios, this research will be able to draw the first conclusions on the worldwide potential of far offshore green hydrogen over time. The scenarios to be analyzed will be defined in Section 3.3.

In this research, the model described in this section has been implemented in Python, as already discussed in Subsection 2.3.3. The Python code has been added in Appendix E, where it has also been indicated which version has been used of any modules implemented in the model. Furthermore, as will be explained in Section 3.2, the data input is handled through a dedicated Excel file. When the model runs, all of this data is loaded into Python to be used in the optimization. The optimization itself is done with the Gurobi optimization solver.

3.2 Data input

In this section, it will be described how the needed input data can be inserted into the model and how this data is then managed. In Chapter 5, the actual values and sources of the input data used in this research will be given. To make the model easily usable and as transparent as possible, the input data can be inserted through a dedicated Excel file.

Next to inserting the initial input data, the Excel file is meant to allow for some data pre-processing. This pre-processing is visualized in Figure 3.16. As can be seen in the figure, some of the initial input data is directly imported to Python to be used by the model, but most of it is used in the Excel file first to determine the cost data of all the aspects of the far offshore green hydrogen supply chain considered on a yearly basis from 2020-2050. From this cost data, the Excel selects the data for the years that are to be included in the defined scenario so only the data for the relevant years is loaded into Python. Because this option is included in the Excel and Python models, the same scenario can be analyzed for several years at once, allowing for an easier assessment of the development over time. The cost data for a certain year used in the model regard the yearly costs to be encountered over the lifetime of the installed equipment if installed in that year, including depreciation, financing costs and operational expenses. This cost is determined as shown in Equations (3.23) and (3.24).

$$C_{yearly} = a * CAPEX + OPEX \tag{3.23}$$

$$a = \frac{r * (1+r)^l}{(1+r)^l - 1} \tag{3.24}$$

In Equations (3.23) and (3.24), C_{yearly} is the yearly cost of the equipment in euros, a is the amortization factor, CAPEX is the capital expenditure in euros, OPEX is the operational expedenditure in euros/year, r is the interest rate (as a decimal) and l is the expected lifetime of the equipment in years.

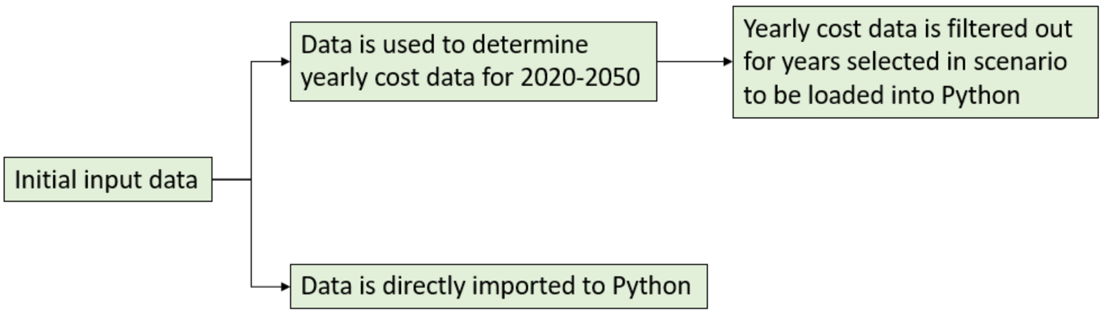


Figure 3.16: Data pre-processing in Excel

A large amount of input data is needed for the optimization to run. The Excel file is divided per topic into ten sheets: general, wind, solar, electrolyzer, desalination, ammonia, liquid hydrogen, land transport, storage and FPSO. The first sheet ('General') is meant for the input that defines the scenario to be simulated. The other sheets are meant for the input regarding the technical specifications and costs of the various technologies to be considered by the model. Based on the scenario defined on the first sheet ('General') and the data inserted on the other sheets, the input data Excel file will automatically prepare the data to be inserted to the Python model in the correct format. When this Python model is run, it will automatically import the needed data from Excel.

With the input data to be used in this research, it must be noted that due to the relatively early stage of development of floating energy and hydrogen production, data availability for this topic is still limited. Therefore, the sort of data inserted can differ per sheet and the sources will vary as well, even though most of this data is used to eventually determine the same sort of input data for the model in Python: yearly costs for the various aspects of the far offshore green hydrogen supply chain. In addition, uncertainties are expected to exist in the data and the level of these uncertainties may often not be known. Although the found data will allow us to give a first outlook on the potential of far offshore green hydrogen production, this research should be continued in the future with growing certainty of the input data.

3.3 Scenario definition

In this section, the scenarios to be simulated will be defined. As explained elaborately before, one of the main goals of this research is to get a first idea of the worldwide potential of far offshore green hydrogen production towards 2050. As opposed to some of the previous research, it was decided to take a bottom-up approach, which was discussed in detail when identifying the primary gap in literature in Section 2.2. In short, the bottom-up approach taken means knowledge on the worldwide potential of far offshore green hydrogen will be obtained by analyzing a representative set of specific, local scenarios, instead of directly comparing green hydrogen alternatives on a global level. This approach will make it possible to show the potential of far offshore green hydrogen in a more realistic way.

To identify the full potential of far offshore green hydrogen production, scenarios with a high expected potential should be analyzed. These are the scenarios with production in relatively cheap locations, and usage in locations with limited alternatives and significant population levels. As it is still unknown whether far offshore green hydrogen production will become feasible at all, the highest potential scenarios will be looked at first; if it is not feasible there, it will not be feasible anywhere. If far offshore green hydrogen turns out to be feasible in the most optimal scenarios, follow-up research can further explore its feasibility.

To identify the far offshore production locations with the highest potential, ocean bathymetry (Hunt et al., 2022; Molina, n.d.) and worldwide wind potential ((Salmon & Bañares-Alcántara, 2022), see also Figure 3.17) were analyzed to find locations with depths of around 200 m and high wind potential. As explained in Subsection 2.4.1.3, the wind resource (and not the solar resource) should be leading in the production location selection, because going further offshore is mostly beneficial for the wind energy production and not for the solar energy production. The high potential usage locations were identified by analyzing the worldwide onshore green hydrogen production costs ((De Vries et al., 2021), see also Figure 3.18). In figures 3.17 and 3.18, the high potential production and usage locations are shown respectively.

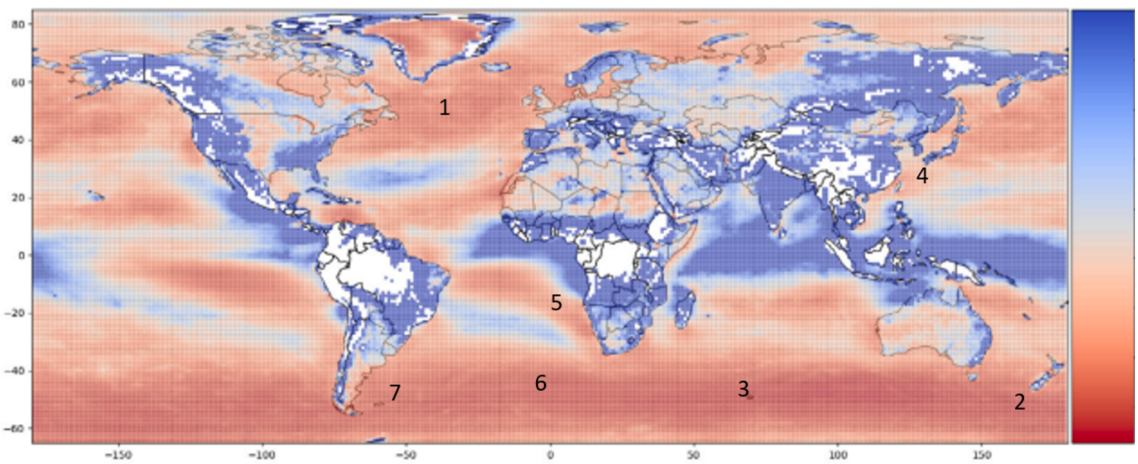


Figure 3.17: High potential far offshore production locations 1 to 7 (modified from (Salmon & Bañares-Alcántara, 2022)). Dark red areas are the areas with the strongest wind resources, while dark blue areas are the areas with the weakest wind resources

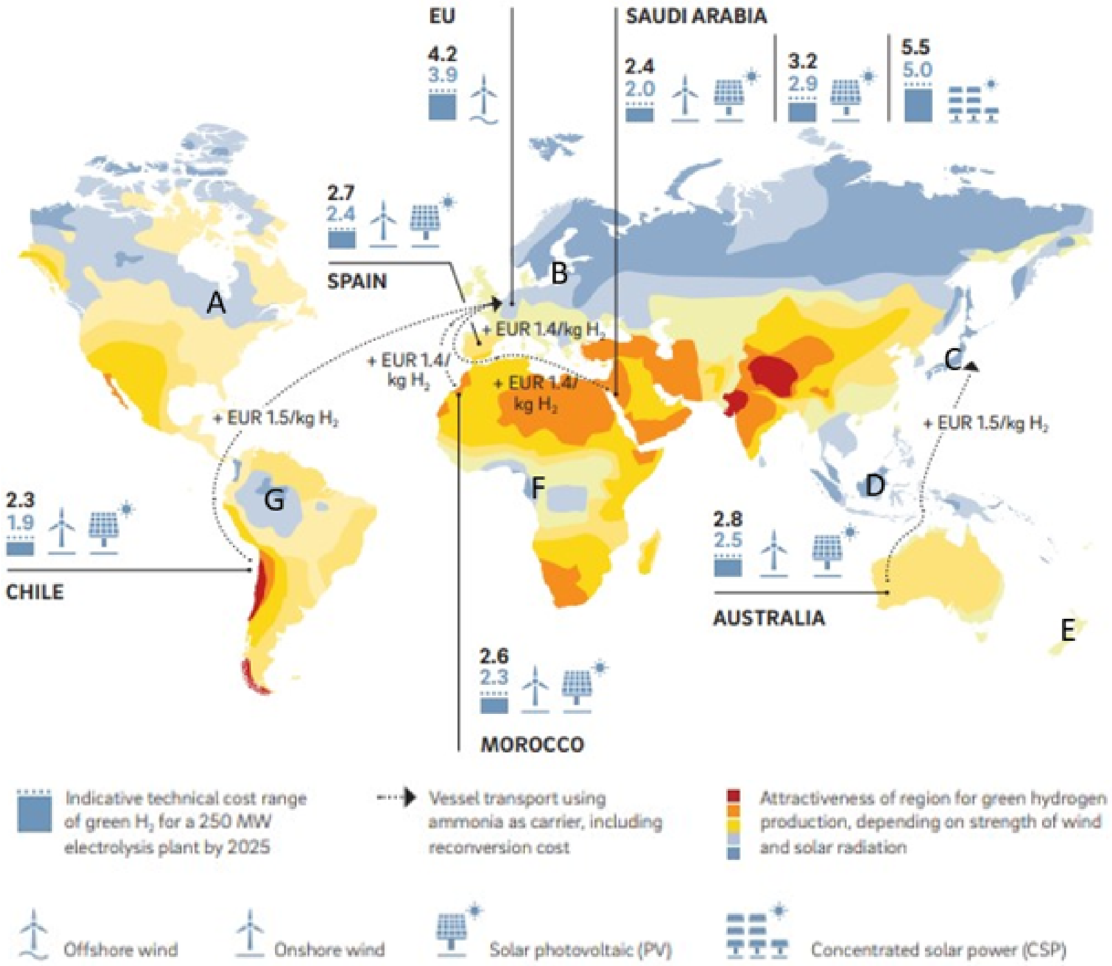


Figure 3.18: High potential far offshore green hydrogen usage locations A to G (modified from (De Vries et al., 2021)). The colours on the map indicate the potential of local, onshore green hydrogen production, with red areas being the highest potential onshore production locations and blue areas being the lowest potential onshore production locations. Low potential onshore production locations with significant population levels (and therefore hydrogen demand) are regarded as high potential usage locations for far offshore green hydrogen due to the limited alternatives.

When looking closer at the identified usage locations, location F was excluded. This was done because the demand for green hydrogen in central Africa is expected to be limited, especially since The Hydrogen Council and McKinsey & Company (2021) do not mention Africa at all when discussing worldwide future green hydrogen demand. Location G was excluded as well, as it has relatively strong onshore renewable resources close by, particularly in Chili. The other potential usage locations were combined with the closest production location to create the scenarios to be analyzed. For usage location D, this could have been production locations 2, 3 or 4. In this case, location 2 was chosen due to the strong renewable resource potential and relatively large area with limited water depth. The selection described here lead to the scenarios shown in Table 3.3, which will be analyzed in this research.

Table 3.3: High potential far offshore green hydrogen scenarios to be analyzed further in this research

	Production location	**Usage location**
Scenario 1	4	C (Japan)
Scenario 2	4	C (South Korea)
Scenario 3	1	B
Scenario 4	1	A
Scenario 5	2	D
Scenario 6	2	E

For each of the scenarios identified, the delivered costs of far offshore green hydrogen will be determined from 2020 to 2050 with a a time step of 3 years using the model created in this research. In addition, the local green hydrogen production costs and the delivered costs of green hydrogen when importing from onshore production in other countries will be found from 2020 to 2050. This will be done using the model created by Brändle et al. (2021). The delivered costs of far offshore green hydrogen will be compared to the costs of local production and import in every scenario to assess the feasibility of far offshore green hydrogen over time. As mentioned before, by doing this for a representative set of worldwide high potential scenarios, a first grasp on the worldwide potential of far offshore green hydrogen towards 2050 will be created.

Chapter 4

Model verification

In this chapter, the verification of the model created and used in this research will be discussed. This is crucial to assess whether the results given by the model can be considered reliable. Since no real life cases exist yet to validate the model with, this could not be done at this point in time. Therefore, an extensive verification has been done to assess the reliability of the model. When possible in the future, validation could be done in follow-up research as well.

In Sections 4.1 and 4.2, it will be discussed how the model results were checked with hand calculations. Next, Section 4.3 shows the tests that were performed to confirm that the model is working as expected. Lastly, Section 4.4 will discuss whether the results are in the right order of magnitude.

4.1 Cost calculations

To verify the model, the cost calculations have been checked for all six scenarios in the years 2020, 2035 and 2050. Of these checks through hand calculations, one example will be discussed here.

In Table 4.1, the model output of the selected case is shown. As can be seen, it concerns the scenario with hydrogen production in the East Chinese Sea and usage in Tokyo (Japan) in 2050. To check the output given by the model, the total costs and costs per kg of hydrogen have been calculated by hand, as shown in Table 4.2, and compared to the model output. The first column of Table 4.2 shows the amounts of equipment, kilometers to be traveled, and storage and FPSO volume. The second column shows all the costs per unit for the considered year, which are retrieved manually from the input data Excel. The last column shows the multiplication of the two previous columns, which is equal to the total costs per year for that element of the supply chain.

At the bottom of the table, all the costs in the third column are added together to find the total yearly costs of the far offshore green hydrogen supply chain, which are equal to 214,480,197 euros. As can be seen in Table 4.1, this is equal to the total yearly costs determined by the model. The numbers in this section are not rounded to the correct amount of significant numbers, since they are not meant as a result, but purely to compare the model results with hand calculations. Table 4.2 also shows the costs per kg of hydrogen, which are determined manually as well and are equal to 4.29 euros/kg. This coincides with the costs per kg of hydrogen found by the model, as shown in Table 4.1. From these results, it may be concluded that (this part of) the model appears to be working properly, which was also the case for all the other cases where the cost calculations were verified with hand calculations.

Table 4.1: Model output verification scenario

	2050
Demand (tons of hydrogen/year)	50,000
Usage location	Tokyo
Year	2050
Production location	East Chinese Sea
Transfer port	Tokyo
Total costs per year (euros)	214,480,197
Costs per kg hydrogen (euros)	4.29
Wind turbines	63
Solar platforms	5
Electrolyzers	26
Desalination equipment	25
Storage volume (m^3)	46,143
Conversion devices	9
Reconversion devices	5
Transport medium	Ammonia
FPSO volume (m^3)	468,414
Distance over sea (km)	1566
Distance over land (km)	0

Table 4.2: Hand calculations verification scenario

	Amount	Costs/unit (euros/unit)	Total costs (euros)
Wind turbines	63	956852	60,281,681
Solar platforms	5	36514	182,571
Electrolyzers	26	1,072,953	27,896,789
Desalination devices	25	12,347	308,684
Storage volume (m^3)	46,143	37.2	1,718,737
FPSO volume (m^3)	468,414	90.6	42,445,663
Sea transport (tonkm hydrogen)	78292087	0.0104	817,717
Sea transport base (ton hydrogen)	50,000	156.7	7,833,333
Land transport (tonkm hydrogen)	0	0.203	0
Conversion devices	9	7,374,000	66,365,998
Reconversion devices	5	1,325,805	6,629,024
Total			214,480,197
Total/kg hydrogen			4.29

4.2 Technical calculations

Next to the cost calculations, the technical results were also checked through hand calculations. For this, the results of the case with hydrogen usage in Tokyo (scenario 1) in 2050 were used, which is the same case as discussed in Section 4.1. The results of this case have already been shown in Table 4.1.

As can be seen, 63 wind turbines and 5 solar platforms are included in the design produced by the model. With a used wind turbine capacity of 12 MW and solar platform capacity of 0.524 MW (see also Chapter 5), this leads to a maximum energy production capacity of 759 MW. In Figure 4.1, the energy available for the electrolyzers over the 10 month reference period in this scenario is shown. It may be seen that the peaks of this available energy go up to approximately 700 MW. The difference between the installed energy generation capacity and the peaks of the available energy may be mostly explained by the fact that not all energy on the FPSO is used for the electrolyzers, as also explained in Section 3.1. In the analyzed scenario, ammonia is used (see also Table 4.1), which means 92% of the energy on the FPSO is available for the electrolyzers (see also Chapter 5). This leads to a maximum energy availability for the electrolyzers of 707 MW, which is in line with the peaks as visible in Figure 4.1.

As described in Section 3.1, the energy used by the electrolyzers is maximized at the capacity of the installed electrolyzers. With 26 electrolyzers of 20 MW (see also Table 4.1 and Chapter 5 respectively), the maximum capacity of the electrolyzers is 520 MW. In Figure 4.2, it can indeed be seen that the energy used by the electrolyzers does not exceed 520 MW. With an energy usage of 50.5 MW/ton hydrogen (see also Chapter 5), this coincides with a maximum hydrogen production of 10.3 ton/hour. In Figure 4.3, it can be seen that indeed the hydrogen production does not exceed 10.3 ton/hour. This also coincides (taking into account rounding errors) with an electrolyzer capacity of 0.4 tons/hour, as assumed in this research (see also Chapter 5). It is assumed that the electrolyzers can follow the dynamic pattern of the renewable power input and no power is lost due to ramp-up time of the electrolyzers. This assumption can be made because PEM electrolyzers are used in this research, which can ramp up or down in seconds (International Renewable Energy Agency, 2022b).

The total power available for the electrolyzers in the 10 month reference period for this scenario is 2.45E6 MWh, which is equal to 2.94E6 MWh when converted to a full year. With an installed power generation capacity (available for the electrolyzers) of 707 MW, the maximum total yearly power production would be 6.19E6 MWh. This means the capacity factor of the power generation in the considered case is 47.4%. Given that onshore wind capacity factors generally range from 20% to 40%, but can be over 40% (Brändle et al., 2021), this seems to be in the right order of magnitude (this case uses mostly wind energy). Since one of the main reasons for far offshore green hydrogen production is the stronger offshore wind resource, 47.4% may seem to be on the low side. However, out of the production locations considered in this research, the one used in scenario 1 (as considered here) has the weakest wind resources. The location with the strongest wind resources considered in this research is the one used for scenarios 5 and 6, which is located in the southern pacific ocean below New Zealand. In that location, the capacity factor found with the model is over 85%.

The total hydrogen produced in this scenario (converted to a year) is 51709 tons. This is a little bit higher than the demand of 50.000 tons. This can be explained by the fact that ammonia is used for transport in the considered case and the model takes into account some hydrogen losses for ammonia conversion and reconversion. Taking into account an hourly hydrogen production capacity of 10.3 tons/hour as mentioned before, the total yearly hydrogen production capacity is 90.228 tons. This leads to a electrolyzer utilisation factor of 57.3%. This is also in the expected order of magnitude (Jaap de Wilde, personal communication, November 15, 2023).

In short, all the (intermediate) technical results discussed in this section are consistent and align with each other and the expectations. This means that next to the final cost calculations discussed in Section 4.1, the technical calculations preceding them also seem to be performed correctly by the model. This leads to a further verification.

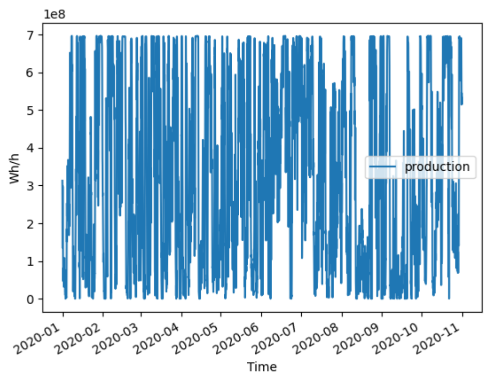


Figure 4.1: Energy available for the electrolyzers over 10 month reference period in verification scenario

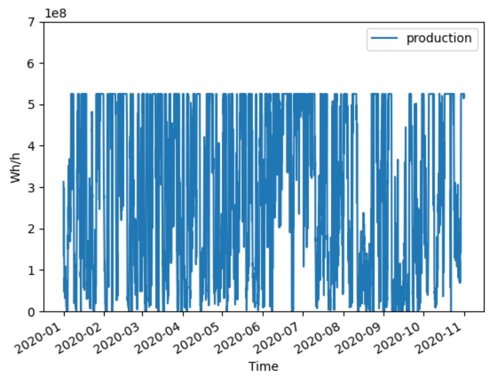


Figure 4.2: Energy used by the electrolyzers over 10 month reference period in verification scenario

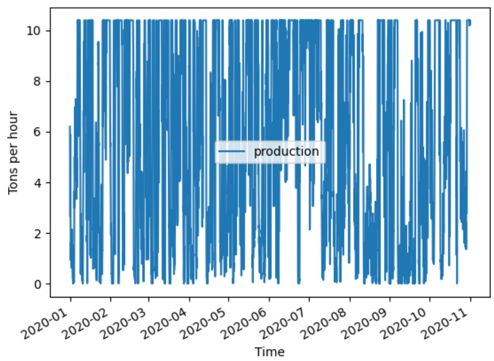


Figure 4.3: Hydrogen produced by the electrolyzers over 10 month reference period in verification scenario

4.3 Model tests

To verify the model even further, a set of tests has been done to see whether it performs as expected. Table 4.3 describes these tests and indicates whether the model passed the test or not. As can be seen, the model showed results in line with expectations for all the performed tests, giving a further verification of the model.

Table 4.3: Verification tests

Test	**Confirmation**
If the wind turbine costs are increased, the amount of used wind turbines should decrease and the amount of solar platforms and/or electrolyzers should increase	✓
If the desalination costs are increased, the amount of desalination devices and electrolyzers should go down. Therefore, the amount of wind turbines and/or solar platforms should go up	✓
If the electrolyzer costs are increased, the amount of desalination devices and electrolyzers should go down. Therefore, the amount of wind turbines and/or solar platforms should go up	✓
If the FPSO costs are increased, the amount of desalination devices and electrolyzers should go down. Therefore, the amount of wind turbines and/or solar platforms should go up	✓
If the ammonia transport costs are increased significantly, the model should switch to liquid hydrogen (if it took ammonia originally)	✓
If the costs of ammonia storage are increased significantly, the model should switch to liquid hydrogen (if it took ammonia originally)	✓
If the fraction of power available for the electrolyzers is decreased in case of ammonia, the model should switch to liquid hydrogen (if it took ammonia originally)	✓
If the power produced by one wind turbine is decreased (and the costs stay the same), the model should switch to using (more) solar platforms	✓
If the hydrogen losses in the conversion process to ammonia are increased significantly, the model should switch to liquid hydrogen (if it took ammonia originally)	✓
If the constraint enforcing that the hydrogen production over the whole year meets the demand is removed, the production and with it the amounts of electrolyzers, desalination devices, wind turbines and solar platforms should become zero. The costs will not become zero because the transport and (re)conversion costs are not part of the optimization and therefore they remain.	✓
If the port and usage location are the same, the distance to be traveled over land should be zero	✓
If the space used by an electrolyzer is decreased, the FPSO volume should go down, the amount of electrolyzers should go up, and the amount of wind turbines and/or solar platforms should go down	✓

4.4 Order of magnitude

As a last verification, it may be checked whether the results are in the expected order of magnitude and if they behave in correspondence with expectations. In Chapter 6, the results will be discussed in more detail. However, when looking at the results overall, the delivered costs of far offshore green hydrogen range between 3 and 12 euros/kg, depending on the year and location. These numbers are in the same order of magnitude as the delivered costs for green hydrogen produced onshore, contributing to their perceived reliability.

In addition, it can be seen in the results that the costs per kg of far offshore green hydrogen are higher than those of locally produced or imported green hydrogen for most countries in the years following 2020. Between 2020 and 2035, far offshore green hydrogen catches up most of the difference. In some cases, far offshore green hydrogen becomes one of the more economic options, while in other cases it remains one of the more expensive ones. The fact that the far offshore hydrogen costs are relatively high in the beginning is in line with expectations, as the relevant technology is still in development and expected to mature over the coming decade(s), while onshore technologies are already developed further. In addition, the fact that far offshore hydrogen is a viable option in some but not all situations is also in line with expectations, as some locations worldwide have better potential for local onshore green hydrogen production and/or are closer to possibly big green hydrogen export countries than others. Also, some far offshore green hydrogen production locations have more potential than others.

To conclude, although the model cannot be validated with real world data, the results are in the right order of magnitude and show behaviour that is in line with expectations. In addition, the model passed all the performed tests and it was checked with hand calculations. Based on this, it is expected that the model is performing correctly.

Chapter 5

Input data

In this chapter, the input data for this research is discussed. In Section 5.1, an overview of the data to be inserted in the model developed in this research is given with accompanying explanation, sources and values where applicable. Next, Section 5.2 will discuss how the alternative green hydrogen costs will be found (local production and import) to which far offshore green hydrogen costs will be compared. Finally, Section 5.3 will discuss which green hydrogen demand estimations will be used in the analysis of the scenarios.

5.1 Model input data

In this section, an overview of the data to be inserted in the model developed in this research is given with accompanying explanation, sources and values where applicable. In Tables 5.1 to 5.10, the data to be inserted is discussed per topic. The sources of the data and the actual values used for the data where the value stays the same across the scenarios are included in the tables as well. Some of the input data differs per scenario and will be given with the scenario in the respective sections in Chapter 6. Each table in this section will be accompanied by a short discussion highlighting the key points.

In Table 5.1, the 'general' input data is shown, which is the input data not belonging to one of the other topics. Most of this input data is meant to define the scenario and is therefore scenario specific. In this table, the reconversion factor can also be found, which indicates whether reconversion to hydrogen is done after transport. It is equal to 1 for all scenarios reviewed in this research. In addition, the correction factor for the distance over sea is shown, which is used to correct the distance to be traveled over sea when the ships cannot sail in a straight line from the production location to the transfer port in a specific scenario. Furthermore, the correction factor for the conversion capacity is shown, which increases the conversion capacity with respect to constant production over the year to account for fluctuations. This factor was determined based on the hourly capacities of the used electrolyzers and conversion devices, and the results of several initial optimizations. Lastly, the interest rate is shown, which is the same as the interest rate in the model by Brändle et al. (2021) that was used to determine the alternative green hydrogen costs, as will be explained in Section 5.2.

Table 5.1: Input data 'General'

Data	Source	Value	Unit
Starting year	Chosen when defining scenario		dmnl
Total period	Chosen when defining scenario		years
Time step	Chosen when defining scenario		years
Production location coordinates	Chosen when defining scenario		dmnl
Port location coordinates	Chosen when defining scenario		dmnl
Usage location coordinates	Chosen when defining scenario		dmnl
Demand size	Chosen when defining scenario		ton hydrogen /year
Reconversion	Chosen when defining scenario. This determines whether the hydrogen is reconverted to gaseous hydrogen when it arrives in the port. When it is equal to 1, reconversion is done. When it is equal to 0, no reconversion is done.		dmnl
Factor distance over sea	Chosen when defining scenario. The distance over sea to be traveled as calculated with GeoPy ('as the crow flies') is multiplied with this factor to get a more accurate approximation of the distance when ships cannot sail to their destination in a straight line.		dmnl
Conversion capacity factor	This factor is used to increase the conversion capacity (to liquid hydrogen or ammonia) with respect to the capacity needed for constant production over the year. It has been determined based on the hourly production of the electrolyzers and conversion equipment, and the results of several initial optimizations.	1.6	dmnl
Interest rate	The interest rate (as a decimal) used to determine the financing costs (Brändle et al., 2021)	0.08	dmnl

In Table 5.2, the relevant data for the wind turbines used in the optimizations is shown. It should be noted that for the period from 2035 to 2050, no clear learning rate was found in literature. Therefore, an assumption had to be made. It was decided to decrease the learning rate with respect to 2025 to 2035 significantly, since De Vries et al. (2021) mention that floating offshore wind technology is already expected to start reaching maturity around 2030 and BVG Associates (2023) also show that the future cost reductions gradually slow down over the years towards 2035. The water depth is also included in this table, which is taken into account through the mooring line costs for the wind turbines. This is done specifically for the wind turbines, since a floating wind farm will require many mooring systems (for each wind turbine) and these are a significant cost contributor (Ma et al., 2021). Since the entire FPSO requires only one mooring system, these costs are less significant there. For the solar platforms, these costs are also not included separately, as it is expected that they will be moored in between the wind turbines and not separately to the sea bottom.

Table 5.2: Input data 'Wind'

Data	Source	Value	Unit
CAPEX floating wind turbine 2020	Based on the cost analysis done by BVG Associates (2023) for a water depth of 100 m, using a semi-submersible platform. To be adjusted based on water depths.	3,953,700	euros/MW
OPEX floating wind turbine 2020	Based on the cost analysis done by BVG Associates (2023), using a semi-submersible platform.	81,650	euros/MW/year
Wind turbine capacity	Value to be used for this research	12	MW
Lifetime wind turbine	(Bills, 2021)	25	years
Learning rate wind turbine costs	2025-2035 is based on cost development graph from BVG Associates (2023). 2035-2050 is an assumption	2025-2035: 0.35 2035-2050: 0.5	dmnl
Water depth	Chosen when defining scenario (Molina, n.d.)		m
Mooring line costs	(BVG Associates, 2023)	1265	euros/m/MW

In Table 5.3, the input data regarding the used solar platforms is shown. Since no clear cost data could be found for offshore solar, cost data for onshore solar from 2020 to 2050 were taken from Brändle et al. (2021) and this was corrected with a conversion factor taken from Salmon and Bañares-Alcántara (2022). For the solar platform size, the Merganser pilot platform from Solar Duck (in cooperation with TU Delft, TNO, MARIN and Deltares) was used (SolarDuck, n.d.-a).

Table 5.3: Input data 'Solar'

Data	Source	Value	Unit
CAPEX onshore solar	Average of the baseline solar costs from 2020-2050 of all countries considered by Brändle et al. (2021)	See Appendix F	euros/kW
OPEX onshore solar as fraction of CAPEX	(Brändle et al., 2021)	0.02	dmnl
Solar platform capacity	(SolarDuck, n.d.-a)	524	kWp
Lifetime solar	(Brändle et al., 2021)	25	years
Conversion factor onshore to offshore solar costs	(Salmon & Bañares-Alcántara, 2022)	2	dmnl

In Table 5.4, the techno-economic data for the electrolyzers as used in this research is shown. One thing to note is the fraction of the total power available for the electrolyzers, which differs greatly when using ammonia and liquid hydrogen. This is due to the large energy consumption of liquid hydrogen conversion and storage. Furthermore, it should be noted that the electrolyzer costs used here are not corrected for offshore usage. The fact that they are used offshore is however taken into account through the fact that they take up space in the FPSO (leading to costs), the fact that desalination equipment is needed offshore to provide water and the fact that the electricity input they receive comes from offshore production.

Table 5.4: Input data 'Electrolyzer'

Data	Source	Value	Unit
Water requirement	(TNO, 2022)	10	m^3 water/ton hydrogen
Energy requirement	(TNO, 2022)	50500	kWh/ton hydrogen
Hourly output capacity PEM electrolyzer	(TNO, 2022)	0.4	ton hydrogen/hour
Fraction of total power available for electrolyzers in the case of liquid hydrogen	Based on the energy required for electrolysis, desalination (A. Kim et al., 2023; TNO, 2022), liquid hydrogen conversion (Lloyd's Register and University Maritime Advisory Services, 2020) and liquid hydrogen storage (TNO, 2022)	0.82	dmnl
Fraction of total power available for electrolyzers in the case of ammonia	Based on the energy required for electrolysis, desalination (A. Kim et al., 2023;TNO, 2022), ammonia conversion (Lloyd's Register and University Maritime Advisory Services, 2020) and ammonia storage (Nayak-Luke et al., 2021;Lloyd's Register and University Maritime Advisory Services, 2020)	0.92	dmnl
Capacity PEM electrolyzer	(TNO, 2022)	20	MW
CAPEX PEM electrolyzer in 2020	(TNO, 2022)	20,000,000	euros
CAPEX PEM electrolyzer in 2030	(TNO, 2022)	13,000,000	euros
CAPEX PEM electrolyzer in 2040	(TNO, 2022)	9,600,000	euros
OPEX PEM electrolyzer in 2020	(TNO, 2022)	500,000	euros
OPEX PEM electrolyzer in 2030	(TNO, 2022)	300,000	euros
OPEX PEM electrolyzer in 2040	(TNO, 2022)	200,000	euros
Lifetime PEM electrolyzer	("Proton exchange membrane electrolysis", 2023)	15	years

In Table 5.5, the input data for the desalination equipment is shown. The capacity of desalination equipment on an FPSO is expected to be relatively small compared to desalination plants onshore. In literature however, no sufficient techno-economic data for smaller desalination installations was found. Therefore, data from a big plant was taken from A. Kim et al. (2023) and this was scaled to the biggest size offered by Hatenboer-Water (2023), which supply desalination equipment for offshore vessels and structures.

Table 5.5: Input data 'Desalination'

Data	Source	Value	Unit
Energy requirement	(A. Kim et al., 2023)	3.5	kWh/m^3 of water
Hourly capacity	Data from big plant taken (A. Kim et al., 2023) and scaled to biggest size offered by Hatenboer-Water (2023)	4.17	m^3 of water/hour
CAPEX	Data from big plant taken (A. Kim et al., 2023) and scaled to biggest size offered by Hatenboer-Water (2023)	113,458	euros
OPEX as fraction of CAPEX	Assumption	0.02	dmnl
Lifetime	(A. Kim et al., 2023)	30	years

In Table 5.6, the data related to ammonia conversion, reconversion and transport is shown. Something that should be noted is that it is assumed in this research that no cost reductions will be seen in ammonia (re)conversion and transport costs, since this is already a mature technology. Next, it should be noted that a transport rate for 10.000 and 20.000 kilometers have been included. Based on these, a transport rate per kilometer and a 'starting rate' are determined. This makes the transport costs more realistic, since it gives sufficient weight to the loading and unloading costs. Finally, it is assumed that all boil-off can be reliquefied, leading to no hydrogen losses in the transport process.

Table 5.6: Input data 'Ammonia'

Data	Source	Value	Unit
CAPEX reconversion equipment	Scaled from larger reconversion device (TNO, 2022)	2,157,534	euros
OPEX reconversion equipment	Scaled from larger reconversion device (TNO, 2022)	36,530	euros/year
Capacity reconversion equipment	Assumption	10,000	ton of hydrogen/year
Cost factor from reconversion to conversion costs	Based on sizes and costs of conversion and reconversion equipment as presented in TNO (2022)	5.56	dmnl
Capacity conversion equipment	Must be the same as for a reconversion device as the costs of conversion are determined based on the ratio shown in the row above	10,000	ton hydrogen/year
Hydrogen density in ammonia	(Black & Veatch, 2022)	0.18	ton hydrogen/ton ammonia
Ammonia sea transport costs 10000 km	(International Energy Agency, 2022)	47	euros/ton ammonia
Ammonia sea transport costs 20000 km	(International Energy Agency, 2022)	65.8	euros/ton ammonia
(Re)conversion 'efficiency' (hydrogen losses during conversion and reconversion)	Hydrogen losses during conversion and reconversion are put at 2 %, based on calculations with data from (TNO, 2022) and (Black & Veatch, 2022)	0.98	dmnl
Transport 'efficiency' (hydrogen losses during transport)	Boil-off can be reliquefied to prevent ammonia losses (International Renewable Energy Agency, 2022a), which is assumed to be the case here	1	dmnl

In Table 5.7, the input data regarding liquid hydrogen conversion, reconversion and transport is shown. Like with ammonia, the transport costs are included for two distances to be able to determine a rate per kilometer and a starting rate. Also, it has been assumed here that all boil-off can be reliquefied. Finally, since hydrogen is not converted to become liquid hydrogen, but only liquefied, the hydrogen losses are assumed to be zero there as well.

Table 5.7: Input data 'Liquid hydrogen'

Data	Source	Value	Unit
CAPEX conversion equipment	Values from 2020-2050 from Brändle et al. (2021)	See Appendix F	euros/(ton hydrogen/year)
OPEX conversion equipment	Values from 2020-2050 from Brändle et al. (2021)	See Appendix F	euros/(ton hydrogen/year)/year
Yearly production of one conversion device	Assumption	10000	ton hydrogen/year
Cost factor from conversion to reconversion costs	Based on the figure showing hydrogen liquefication and regasification costs in Vos et al. (2020)	0.2	dmnl
Yearly production of one reconversion device	Must be the same as for a conversion device as the costs of reconversion are determined based on the ratio shown in the row above	10000	ton hydrogen/year
Liquid hydrogen sea transport costs 10000 km	(International Energy Agency, 2022)	1109.20	euros/ton hydrogen
Liquid hydrogen sea transport costs 20000 km	(International Energy Agency, 2022)	1438.20	euros/ton hydrogen
Learning rate transport costs	Assuming same learning rate as for liquid hydrogen storage	2020-2030: 0.9 2030-2050: 0.5	dmnl
(Re)conversion 'efficiency' (hydrogen losses during conversion and reconversion)	The hydrogen is not converted, but only liquefied and regasified, so it is assumed no hydrogen is lost	1	dmnl
Transport 'efficiency' (hydrogen losses during transport)	Boil-off can be reliquefied to prevent hydrogen losses (International Renewable Energy Agency, 2022a), which is assumed to be the case here	1	dmnl

In Table 5.8, the data regarding the transport over land is shown. As mentioned before, it is assumed this is done as gaseous hydrogen in pipelines. Brändle et al. (2021) give costs for refurbished pipelines, low cost new pipelines and high cost new pipelines. To avoid being on one of the extremes, it was decided to use the costs associated with low cost new pipelines. In addition, not every location is expected to have the option of reusing existing pipelines, which means this option cannot be assumed.

Table 5.8: Input data 'Land transport'

Data	Source	Value	Unit
CAPEX of gaseous hydrogen pipeline	Considering new but low cost pipelines for gaseous hydrogen from Brändle et al. (2021)	1.671	euros/(ton hydrogen/year)/km
OPEX of gaseous hydrogen pipeline	Considering new but low cost pipelines for gaseous hydrogen from Brändle et al. (2021)	0.0627	euros/(ton hydrogen/year)/km /year
Lifetime of gaseous hydrogen pipeline	Considering new but low cost pipelines for gaseous hydrogen from Brändle et al. (2021)	40	years

In Table 5.9, the input data regarding the storage of ammonia and liquid hydrogen is shown. Based on the capacities and costs of the tanks shown here, the CAPEX and OPEX per m^3 of storage tank are determined for ammonia and liquid hydrogen. As can be seen, there is a big difference in density between the two. Even though every ton ammonia contains only 0.18 ton of hydrogen (see Table 5.6), the amount of hydrogen is still higher per m^3 of storage tank for ammonia, as already mentioned before as well.

Table 5.9: Input data 'Storage'

Data	Source	Value	Unit
Liquid hydrogen tank capacity	(Brändle et al., 2021)	3190	ton hydrogen
CAPEX liquid hydrogen tank	(Brändle et al., 2021)	272,600,000	euros
OPEX liquid hydrogen tank as fraction of CAPEX	(Brändle et al., 2021)	0.04	dmnl
Density liquid hydrogen	(Demaco, 2023)	71	kg/m^3
Learning rate liquid hydrogen storage costs	(Brändle et al., 2021)	2020-2030: 0.9 2030-2050: 0.5	dmnl
Lifetime liquid hydrogen tank	(Brändle et al., 2021)	30	years
Ammonia tank capacity	(Nayak-Luke et al., 2021)	25000	ton ammonia
CAPEX ammonia tank	(Nayak-Luke et al., 2021)	24,534,000	euros
OPEX ammonia tank as fraction of CAPEX	(Nayak-Luke et al., 2021)	0.03	dmnl
Density ammonia	(Air Liquide, 2023)	681.97	kg/m^3
Learning rate ammonia storage costs	Assumed to be the same as liquid hydrogen storage costs learning rate	2020-2030: 0.9 2030-2050: 0.5	dmnl
Lifetime ammonia tank	(Nayak-Luke et al., 2021)	25	years

Lastly, Table 5.10 shows the input data regarding the FPSO itself (without equipment). A cost estimation for the FPSO per kg was obtained from Clemens van der Nat at Bluewater Energy Services. However, since a cost estimation per m^3 was needed, the mass per m^3 of an FPSO without equipment was approximated based on data from J. Lee et al. (2023). With this and the costs per kg, the costs per m^3 could be determined, which are used by the model to determine the costs of the FPSO. The costs of the FPSO are assumed to stay constant towards 2050. Furthermore, in order to size the FPSO based on the equipment needed for the hydrogen production process (as determined by the model), the concept FPSO designed by (J. Lee et al., 2023) was used as an example. With this, the size and therefore the costs of the FPSO and its storage can be determined. This has already been explained in more detail in Section 3.1. The ratio to determine the size of the storage tank from the FPSO volume is different for ammonia and liquid hydrogen, since ammonia requires a smaller storage tank, as explained before. For this same reason, the FPSO volume per installed electrolyzer differs between ammonia and liquid hydrogen.

Table 5.10: Input data 'FPSO'

Data	Source	Value	Unit
Mass per m^3 FPSO (without equipment)	Based on estimates given by J. Lee et al. (2023) for the FPSO volume and the mass of its hull structure, turret, additional machinery, additional hull systems and accommodation	106	kg/m^3
FPSO CAPEX (only the ship itself)	Based on C. van der Nat (personal communication, September 6, 2023)	7.52	euros/kg
Lifetime	Based on C. van der Nat (personal communication, September 6, 2023)	25	years
FPSO OPEX as fraction of CAPEX	Assumption	0.02	dmnl
FPSO volume per installed electrolyzer capacity liquid hydrogen	Based on the concept layout of a liquid hydrogen FPSO from J. Lee et al. (2023)	1109	m^3/MW
FPSO volume per installed electrolyzer capacity ammonia	Based on the concept layout of a liquid hydrogen FPSO from J. Lee et al. (2023) with adjustments for ammonia	900.8	m^3/MW
Ratio storage volume/total volume in case of liquid hydrogen FPSO	Based on the concept layout of a liquid hydrogen FPSO from J. Lee et al. (2023)	0.138	dmnl
Ratio storage volume/total volume in case of ammonia FPSO	Based on the concept layout of a liquid hydrogen FPSO from J. Lee et al. (2023) with adjustments for ammonia	0.0985	dmnl

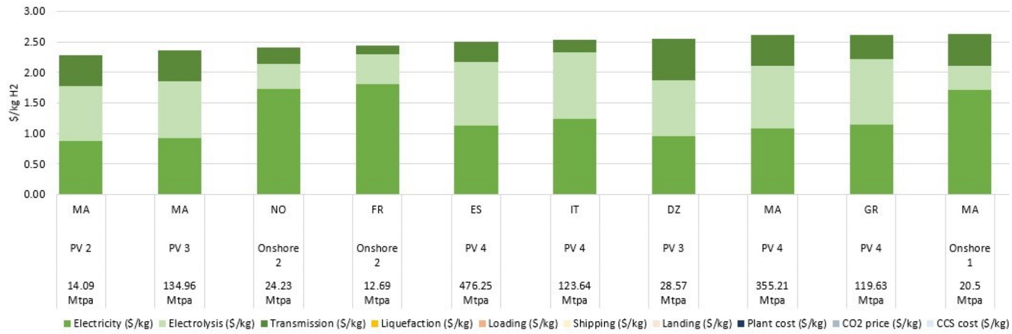
5.2 Alternative green hydrogen supply

To assess the potential of far offshore green hydrogen production, it must be clear which alternatives it will have to compete with. As explained in Chapter 1, this research focuses solely on green hydrogen production. Therefore, this section will discuss the alternatives for green hydrogen production and which data will be used in this research to determine the costs and availability of these alternatives.

The technologies to produce renewable energy onshore and near offshore (with bottom founded wind turbines) are developed significantly further than those for far offshore environments and have been deployed commercially on a large scale for a significant amount of time. As mentioned before, the production of hydrogen using electrolysis onshore has also been increasing and some big hydrogen production facilities will be built in the near future. Therefore, it is expected that the costs and feasibility of these technologies can be assessed significantly more easily and reliably.

To assess the competition for far offshore green hydrogen production, the worldwide alternative green hydrogen production costs must be known. A study from the Institute of Energy

Economics at the University of Cologne has looked at the worldwide potential of green and blue hydrogen production, evaluating onshore green hydrogen production costs in 94 different countries using energy from onshore solar, onshore wind and bottom-founded offshore wind in waters up to 55 m deep (Brändle et al., 2021). These energy resource classes have also been split up further into categories based on the capacity factors of the available resources to more clearly map the available potential and the availability of green hydrogen at different price levels. In addition, transport by pipeline and/or ship (in the form of liquid hydrogen) has been taken into account to be able to find the minimal delivered costs of green hydrogen in China, France, Germany, Italy, Japan, Korea, the Netherlands, Spain, the UK and the US. As an example of the model's output, Figure 5.1 shows the ten most cost-optimal supply routes of green hydrogen to Germany in 2050 under certain conditions. In this figure, the origin country and resource class (with its capacity) are also indicated for each hydrogen supply chain.



	Morocco PV 2	Morocco PV 3	Norway Onshore 2	France Onshore 2	Spain PV 4	Italy PV 4	Algeria PV 3	Morocco PV 4	Greece PV 4	Morocco Onshore 1
H2 Potential (Mtpa)	14.09	134.96	24.23	12.69	476.25	123.64	28.57	355.21	119.63	20.5
Total supply cost ($/kg)	**2.29**	**2.37**	**2.40**	**2.44**	**2.50**	**2.54**	**2.55**	**2.62**	**2.62**	**2.62**
Electricity ($/kg)	0.88	0.93	1.72	1.80	1.12	1.24	0.95	1.08	1.14	1.71
Electrolysis ($/kg)	0.89	0.93	0.41	0.49	1.04	1.09	0.91	1.02	1.07	0.40
Transmission ($/kg)	0.51	0.51	0.26	0.14	0.33	0.21	0.68	0.51	0.40	0.51

Figure 5.1: Top ten most cost-optimal green hydrogen supply routes to Germany in 2050 as determined with the model made by Brändle et al. (2021)

The entire, very extensive Excel model made by Brändle et al. (2021) is available with the paper and contains much of the data and assumptions, including intermediate results. For example, the expected costs of green hydrogen production from the different resource classes mentioned above for each of the 94 countries considered are given per year between 2020 and 2050 (as long as the total capacity of a resource class in a country is at least 1 GW), showing significant expected reductions in costs.

These local production costs could be compared directly to the delivered costs of far offshore green hydrogen to these countries as a first assessment of its potential. Even better would be to compare the delivered costs of far offshore green hydrogen production to the alternative delivered costs of green hydrogen (from import) as well, which could at least be done for the destination countries included in the model as mentioned above. For countries not included in those destination countries, some extra calculations will have to be done, which will be discussed in Chapter 6 when discussing the relevant scenarios. Both for local production and import, the limit on the production capacity should be taken into account, since the limited availability of onshore and near offshore resources may increase the attractiveness of far offshore hydrogen production, as mentioned by Salmon and Bañares-Alcántara (2022) as well. The data in the Excel model also contains the estimated capacity of all (onshore and near offshore) resource classes for the considered countries, which can be used for this purpose. Where possible, the model made by Brändle et al. (2021) will be used to determine the alternative green hydrogen costs in this research. For the cases where this model cannot be used, alternative sources will be sought, which will be mentioned when discussing the scenarios in question.

When using the model made by Brändle et al. (2021) to determine alternative green hydrogen costs, the baseline cost assumptions with low temperature electrolyzers and low cost new pipelines will be selected in this research. When using data from Brändle et al. (2021) as input for the model developed in this research (see also Section 5.1), the same assumptions are used.

5.3 Global current and future demand

In this section, it will be discussed which green hydrogen demand estimations will be used in this research. This is relevant for the assessment of the potential of far offshore green hydrogen production, because a demand for hydrogen should not only be present when a usage location is reviewed, but its size should also be known. This way, it can be assessed which local or imported resources far offshore production will have to compete with.

By 2030, 28% of the hydrogen is expected to be green, which is then expected to increase to 60% in 2050 (with the other 40 % being blue hydrogen). (Yakubson, 2022) The latter is expected to not be 100% because not all countries have net-zero goals for 2050 or before. For this research however, a global net-zero economy is assumed in 2050, which means only green hydrogen is considered and it is assumed this will fill the total demand in 2050. For the years before, it will be looked at if far offshore hydrogen production would become beneficial at the expected hydrogen demand levels in those years, considering the limited availability of high quality local renewable resources.

Several studies make very different projections for the development of the global hydrogen demand, as can be seen in Figure 5.2. The light blue line showing a demand of 660 Mt in 2050 represents a study by McKinsey & Company and the Hydrogen Council, which consists of many industry parties. This study assumes a global net-zero economy in 2050, which could be a reason why their estimates are on the high end, but this is in line with the timeline assumed in this research. The predictions they make are labeled ambitious but realistic and they mention 93 countries have already adopted net-zero targets and 39 countries have adopted hydrogen strategies. In their demand predictions, they assessed the cost competitiveness of hydrogen in each simulated region with respect to both decarbonized options (such as batteries and carbon capture and storage) and conventional alternatives (such as diesel and natural gas). The feasibility of hydrogen application and the hydrogen supply chain were also taken into account. (The Hydrogen Council & McKinsey & Company, 2021)

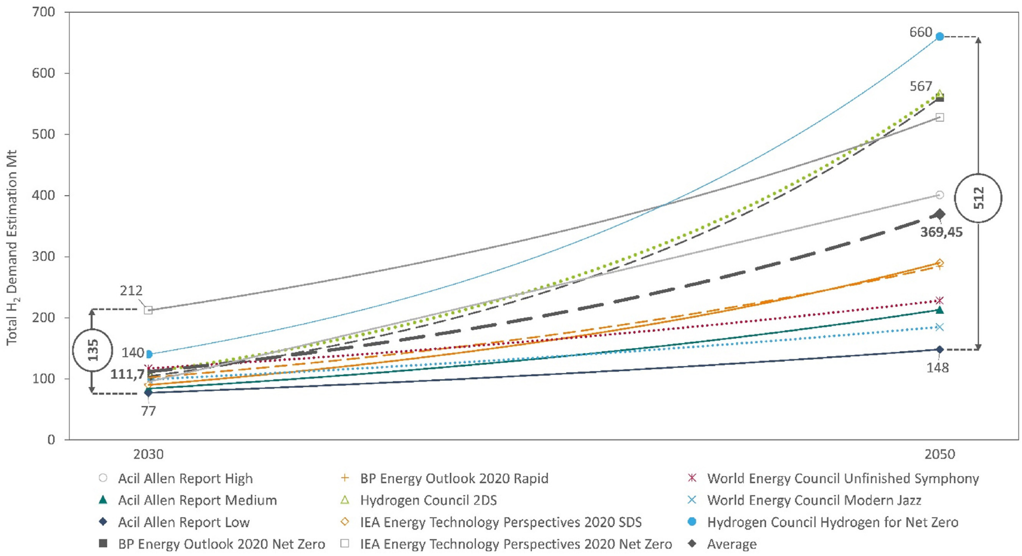


Figure 5.2: Expected development of the global hydrogen demand as predicted by various studies (Wappler et al., 2022)

North America, Europe and China are expected to have the highest demands for hydrogen, as shown in Figure 5.3. However, as can be seen in the figure, the demand in the rest of the world is also expected to rise very strongly towards 2050. Another striking finding can be seen in Figure 5.4, depicting the announced hydrogen production capacity towards 2030 in 2021. In this same figure, the projections made in 2019 and 2020 are shown as well. As can be seen, the projections for the roll out of hydrogen grow rapidly from year to year, indicating how strong the interest in hydrogen has become over the past few years. When looking at the hydrogen strategies of different countries, it can be seen that some are planning to become self-sufficient with respect to hydrogen, while others are planning to import or even export blue or green hydrogen (Wappler et al., 2022).

The growing popularity of hydrogen on the one hand and still existing disagreements about its potential on the other introduce some uncertainties in the estimation of future hydrogen demand. However, since the report by The Hydrogen Council and McKinsey & Company (2021) has very similar assumptions regarding the timeline of the transition to a net-zero economy as those taken in this research, it is expected that their demand predictions can be seen as representative for the analysis to be made in the intended research. In 2020, the global hydrogen demand was 90 Mt, which is expected to rise to 140 Mt and 385 Mt in 2030 and 2040 respectively. With a total yearly hydrogen production of 660 Mt in 2050, the hydrogen usage will account for 22% of the expected global energy mix. (The Hydrogen Council & McKinsey & Company, 2021)

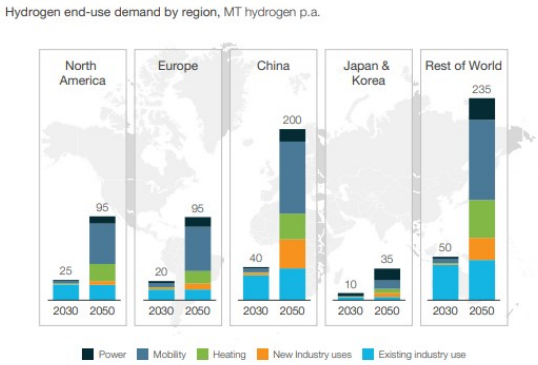


Figure 5.3: Expected hydrogen demand per region in 2030 and 2050 (The Hydrogen Council & McKinsey & Company, 2021)

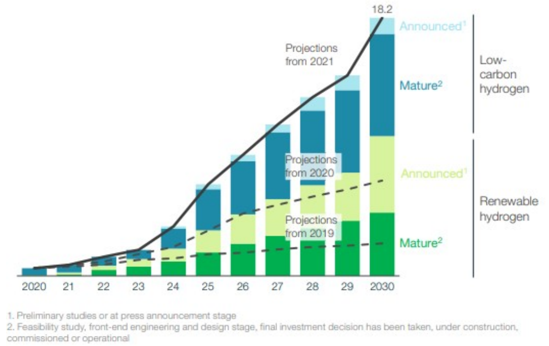


Figure 5.4: Announced hydrogen production volume towards 2030 in 2021 (The Hydrogen Council & McKinsey & Company, 2021)

Chapter 6

Scenario analysis

In this chapter, the analysis of the selected set of representative scenarios is discussed to provide a first grasp on the worldwide potential of far offshore green hydrogen production towards 2050. In addition, some further analysis of the results is done to gain a more comprehensive inside and a sensitivity analysis is performed to understand the influence of several input parameters on the final results. Sections 6.1 to 6.6 will discuss each of the selected scenarios separately. After this, Section 6.7 will highlight some general results that stand out across the scenarios in more detail and discuss the sensitivity analysis.

6.1 Scenario 1: Tokyo

In this section, the analysis of the first scenario is discussed, in which the competitiveness of far offshore green hydrogen in the Japanese market is analyzed. In Table 6.1, the scenario-specific input data is shown. In Figure 6.1, the production location and usage location are shown on the map. As can be seen, a production location is considered in the East Chinese Sea within the exclusive economic zone of Japan and with a water depth of approximately 200 m. The produced hydrogen is transported by ship to Tokyo and used there as well.

Table 6.1: Scenario-specific input parameters scenario 1

Parameter	**Value**	**Unit**
Starting year	2020	
Total period	30	years
Time step	3	years
Production location	East Chinese Sea Latitude: 26.81 Longitude: 126.94	degrees
Port location	Tokyo Latitude: 35.64 Longitude: 139.8	degrees
Usage location	Tokyo Latitude: 35.64 Longitude: 139.8	degrees
Water depth	200	m
Factor distance over sea	1	

Figure 6.1: Production location (purple marker) and usage location (red dot) for scenario 1

In Figure 6.2, the most important economic results of the analysis are shown. More detailed results regarding the far offshore green hydrogen supply chain designed by the model for the different years considered in this scenario are shown in Table 6.2. In Appendix D, similar tables have been added for every considered scenario. Some interesting findings and trends visible in these tables will be discussed in Section 6.7. As indicated in the legend of Figure 6.2, the grey graph represents the delivered costs of far offshore green hydrogen, which have been found with the model created in this research, using the input data as presented in Chapter 5. The orange and dark blue graphs represent the highest and lowest local green hydrogen production costs in Japan respectively, which were found using the model made by Brändle et al. (2021). The yellow graph shows the lowest delivered costs of imported green hydrogen. However, there may exist competition for these low cost hydrogen imports. To take this into account, the delivered costs for the most expensive import option needed when wanting to import the expected total worldwide hydrogen demand in the relevant year (as presented in Section 5.3) are given as well. This is seen as the guaranteed maximum import rate and shown with the light blue graph. Both the yellow and light blue graphs have been generated using the model made by Brändle et al. (2021) as well.

For the guaranteed maximum import rate, it is assumed that the hydrogen production can take up all of the available renewable energy capacity in all countries, as is also done by Brändle et al. (2021). In reality, this will not be the case, as countries will use part of their renewable energy capacity for local energy production, leading to a higher guaranteed delivered cost of imported green hydrogen due to reduced availability in the low cost countries. On the other hand, it is highly unlikely that all countries worldwide will compete for the same green hydrogen import resources as assumed when determining the guaranteed import rate, which would in turn lead to lower guaranteed import costs. Next to the fact that these two points counteract each other's effects, the differences between the green hydrogen import options' costs are generally relatively small. For these reasons, it is expected that neglecting the competition of green hydrogen production in exporting countries with their local renewable energy needs will not have a major influence on the results.

When analyzing the potential of far offshore green hydrogen, it must be compared to both local green hydrogen production and green hydrogen import options. The total local production capacity in Japan is expected to be equal to 11.45 Mt per year in 2050 (Brändle et al., 2021). As this production capacity also has to compete with the renewable energy demand and the total demand for only hydrogen is expected to be equal to 35 Mt per year in 2050 for Japan and South

Korea together (see Figure 5.3), it is expected that local production will not be able to fulfill Japan's hydrogen demand. This means that without green hydrogen import, far offshore green hydrogen production is expected to not only be competitive, but necessary for Japan.

Next, the far offshore green hydrogen delivered costs should be compared to the costs of importing green hydrogen from abroad. It can be seen that although the costs of far offshore green hydrogen are in the same order of magnitude as its alternatives, importing green hydrogen is still expected to be significantly cheaper. The difference is the smallest and stable between 2035 and 2050. Between 2020 and 2035, the difference is larger and still decreasing, which is expected to be mostly due to the fast cost reductions of floating offshore wind in this period. From a purely economic perspective, far offshore green hydrogen usage does not make economic sense in Japan under the current assumptions taken in this research and the research by Brändle et al. (2021). With this conclusion however, it should be noted that the main green hydrogen import candidates for Japan include China, Russia, Iran, Saudi Arabia and Oman. As some of these countries may be more controversial than others, this means the (geo)political aspect will also play a big role in the potential of far offshore green hydrogen in Japan. Far offshore green hydrogen is expected to be mostly relevant when Japan decides to keep its energy generation in its own hands. As mentioned before, far offshore green hydrogen would be necessary in that case, as Japan does not have sufficient onshore renewable energy generation capacity to fulfill its own demand and the considered far offshore production location in this scenario is located in Japan's exclusive economic zone.

In short, it may be concluded that from a purely economic perspective, far offshore green hydrogen delivered costs cannot beat the costs of imported green hydrogen in Japan under the current assumptions, especially between 2020 and 2035. However, as the costs of far offshore green hydrogen are in the same order of magnitude as its alternatives and the considered production location is located in Japan's exclusive economic zone, (geo)political factors could work in favour of far offshore green hydrogen in Japan.

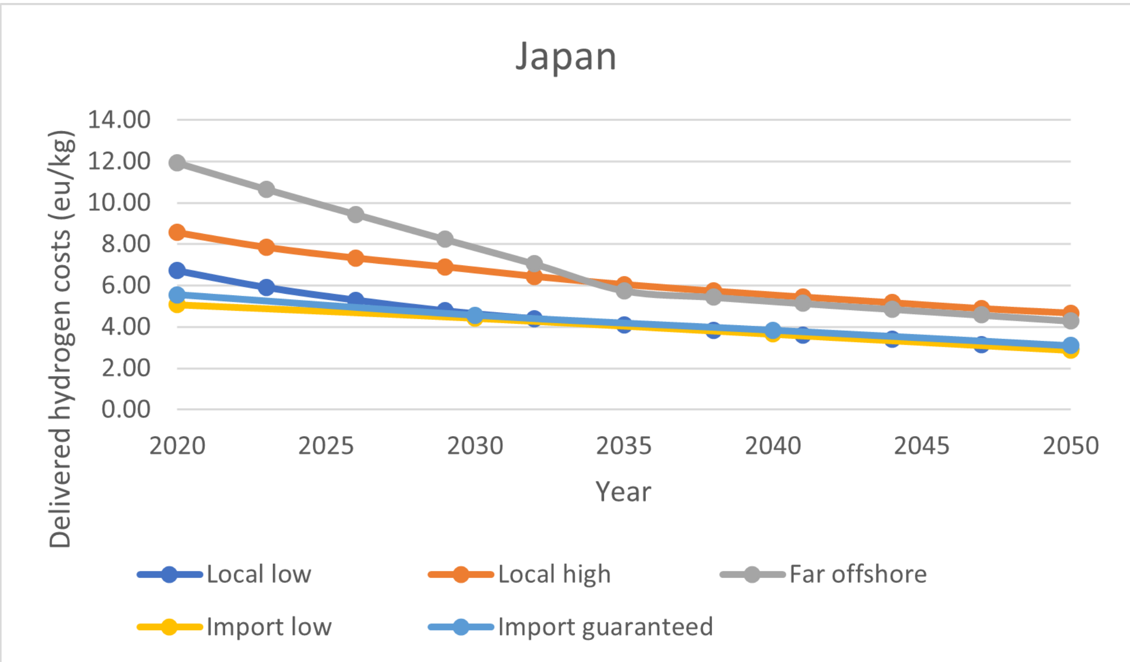


Figure 6.2: Comparison of delivered costs of green hydrogen to Tokyo from 2020 to 2050 (produced far offshore, produced locally and imported)

Table 6.2: Results scenario 1 far offshore green hydrogen

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Total costs per year (euros)	5.96E+08	5.33E+08	4.72E+08	4.12E+08	3.52E+08	2.88E+08	2.72E+08	2.57E+08	2.43E+08	2.29E+08	2.14E+08
Costs per kg hydrogen (euros)	11.93	10.65	9.44	8.23	7.04	5.76	5.44	5.14	4.86	4.57	4.29
Wind turbines	39	41	44	46	49	59	60	60	60	63	63
Solar platforms	1464	1328	1111	939	663	0	30	30	30	5	5
Electrolyzers	27	26	25	25	26	28	27	27	27	26	26
Desalination equipment	26	25	24	24	25	27	26	26	26	25	25
Storage volume (m3)	4.79E+04	4.61E+04	4.44E+04	4.44E+04	4.61E+04	4.97E+04	4.79E+04	4.79E+04	4.79E+04	4.61E+04	4.61E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	4.86E+05	4.68E+05	4.50E+05	4.50E+05	4.68E+05	5.04E+05	4.86E+05	4.86E+05	4.86E+05	4.68E+05	4.68E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

In order to get a grasp on what the size of the far offshore green hydrogen production location designed by the model is for this scenario (with a demand of 50 kiloton of hydrogen per year), the size of the design for 2050 has been visualized in Figures 6.3 and 6.4. Figure 6.4 shows a close-up view of the area marked with the red circle in Figure 6.3. The size of the wind farm was estimated based on a spacing between wind turbines of 7.7 times their rotor diameter (Pryor et al., 2021) and a rotor diameter of 220 meters for a 12 MW wind turbine (GE Renewable Energy, n.d.). As shown in Table 6.2, 63 wind turbines are used in 2050, which can be placed in a grid of 9x7 wind turbines. This leads to a used area of 13.8x10.2 kilometers. As it is assumed that the solar platforms are placed between the wind turbines, no extra space is allocated to them. The FPSO will be placed next to the energy farm. The total FPSO volume is 468,000 m^3, which could coincide with an FPSO with a length of approximately 265 m, a breadth of approximately 50 m and a depth of approximately 35 m.

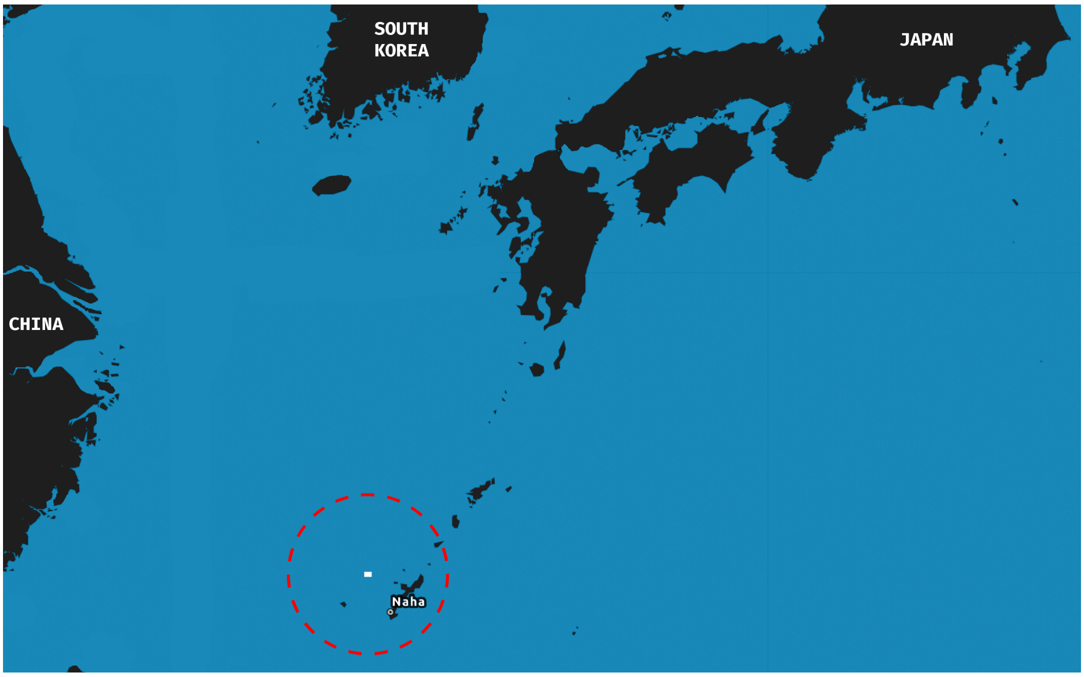


Figure 6.3: Size of far offshore green hydrogen production location for scenario 1

Figure 6.4: Size of far offshore green hydrogen production location for scenario 1 zoomed in

6.2 Scenario 2: Seoul

In this section, the analysis of the second scenario is discussed, in which the competitiveness of far offshore green hydrogen in the South Korean market is analyzed. In Table 6.3, the scenario-specific input data is shown. In Figure 6.5, the production location, transfer port and usage location are shown on the map. As can be seen, a production location is considered in the East Chinese Sea within the exclusive economic zone of Japan and with a water depth of approximately 200 m. This is the same location as used in scenario 1. The produced hydrogen is transported by ship to the port of Incheon and from there by pipeline to Seoul.

Table 6.3: Scenario-specific input parameters scenario 2

Parameter	**Value**	**Unit**
Starting year	2020	
Total period	30	years
Time step	3	years
Production location	East Chinese Sea Latitude: 26.81 Longitude: 126.94	degrees
Port location	Incheon Latitude: 37.45 Longitude: 126.6	degrees
Usage location	Seoul Latitude: 37.55 Longitude: 127	degrees
Water depth	200	m
Factor distance over sea	1	

Figure 6.5: Production location (purple marker), transfer port (orange dot) and usage location (red dot) for scenario 2

In Figure 6.6, the most important results of the analysis are shown. The colours of the graphs in this figure correspond to those in Figure 6.2, which have been explained in Section 6.1. More detailed results can be found in Appendix D.

When looking at the local green hydrogen production capacity with the model made by Brändle et al. (2021), it can be seen that South Korea is expected to be able to produce 27.38 Mt per year in 2050. This means the local production capacity of South Korea is significantly higher than that of Japan and could provide in South Korea's share of the expected hydrogen demand of 35 Mt per year for South Korea and Japan together (see Figure 5.3). However, when considering these resources have to be shared with local renewable energy production, it is expected that the capacity will be insufficient to fulfill South Korea's local demand, meaning import of green hydrogen will be necessary.

When comparing the delivered costs of far offshore green hydrogen to imported green hydrogen, it can again be seen that the latter would be significantly cheaper. Like in the previous scenario, this is especially the case between 2020 and 2035. This means that from a purely economic standpoint, far offshore green hydrogen usage would also not be feasible for South Korea. However, the countries from which green hydrogen can be imported cheaply to South Korea are similar to those used for Japan in scenario 1. Therefore, (geo)political considerations might still affect the feasibility in practice in this scenario as well.

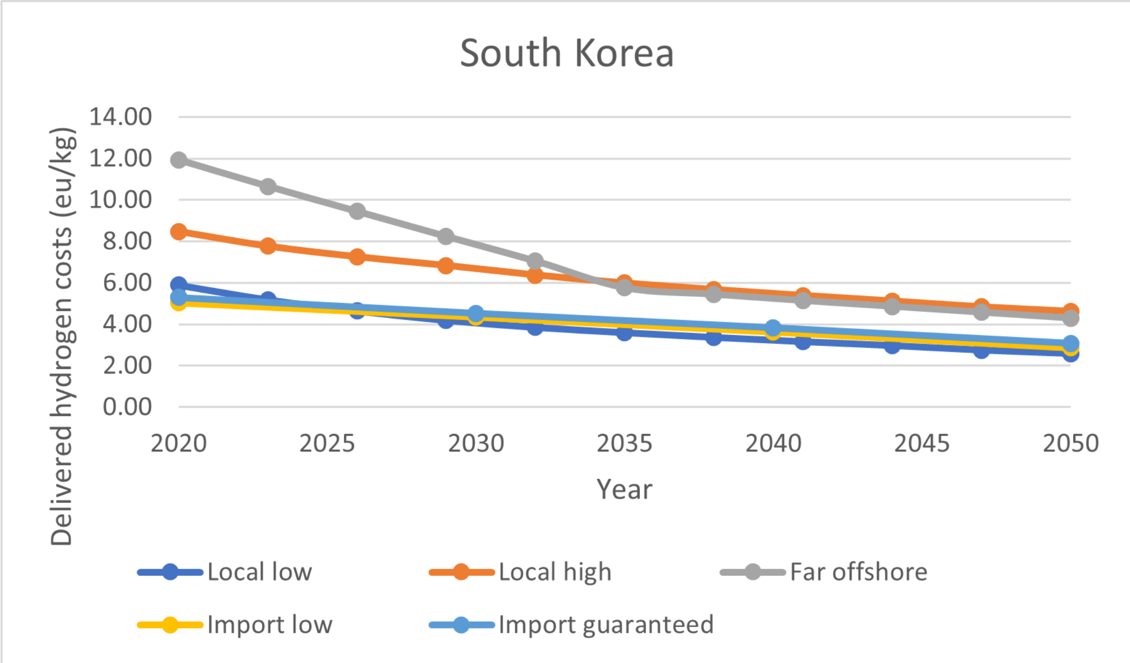


Figure 6.6: Comparison of delivered costs of green hydrogen to Seoul from 2020 to 2050 (produced far offshore, produced locally and imported)

6.3 Scenario 3: Cologne

In this section, the analysis of the third scenario is discussed, in which the competitiveness of far offshore green hydrogen in the German market is analyzed. In Table 6.4, the scenario-specific input data is shown. In Figure 6.7, the production location, transfer port and usage location are shown on the map. As can be seen, a production location is considered in the Celtic Seas and with a water depth of approximately 200 m. The produced hydrogen is transported by ship to the port of Rotterdam and from there by pipeline to Cologne. The feasibility of a pipeline from Rotterdam to North-Rhine Westphalia (where Cologne is located) for the transport of various product streams including hydrogen is being considered by the Port of Rotterdam already (Port of Rotterdam, n.d.).

Table 6.4: Scenario-specific input parameters scenario 3

Parameter	**Value**	**Unit**
Starting year	2020	
Total period	30	years
Time step	3	years
Production location	Celtic Seas Latitude: 57.58 Longitude: -15.56	degrees
Port location	Rotterdam Latitude: 51.92 Longitude: 4.48	degrees
Usage location	Cologne Latitude: 50.94 Longitude: 6.96	degrees
Water depth	200	m
Factor distance over sea	1.7	

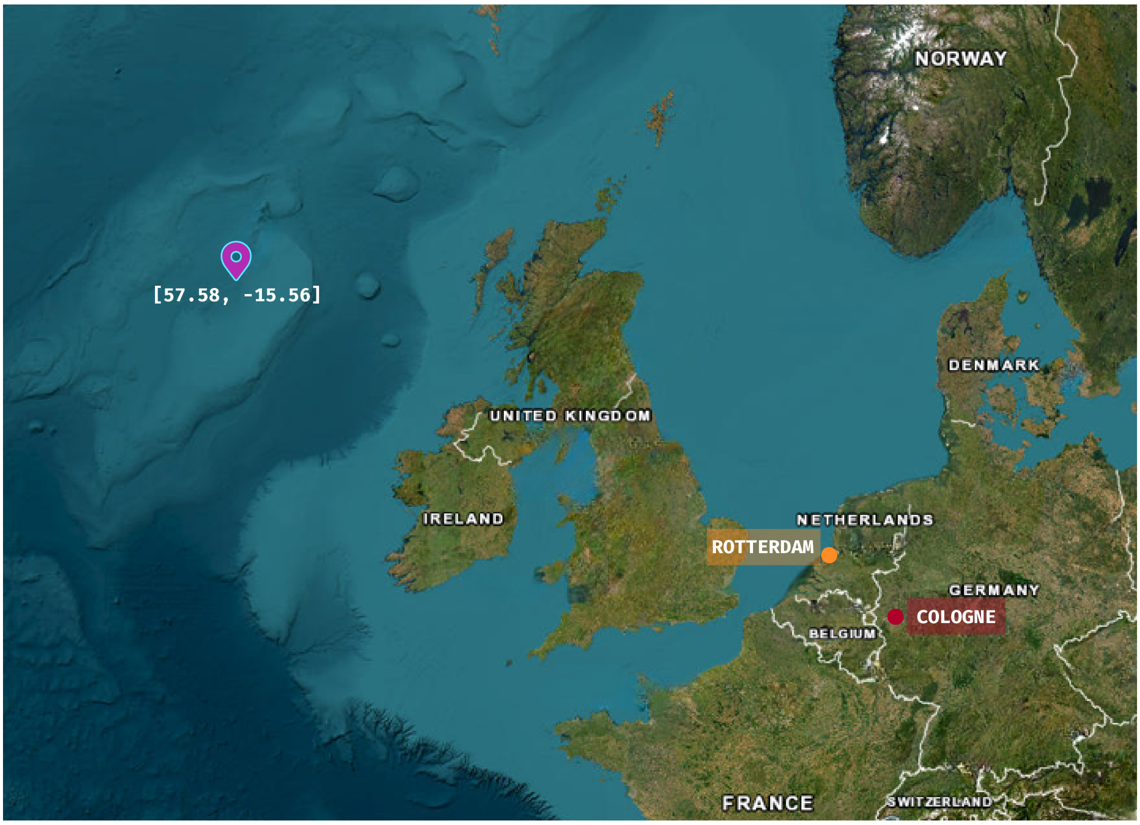


Figure 6.7: Production location (purple marker), transfer port (orange dot) and usage location (red dot) for scenario 3

In Figure 6.8, the most important results of the analysis are shown. The colours of the graphs in this figure correspond to those in Figure 6.2, which have been explained in Section 6.1. More detailed results can be found in Appendix D.

In scenarios 1 and 2, the costs of far offshore green hydrogen were similar to the highest local production costs between 2035 and 2050. In this scenario however, although they are still in the same order of magnitude, the far offshore green hydrogen costs are clearly higher than all its alternatives, even in 2050. The local green hydrogen production capacity in Germany is expected to be equal to 30.04 Mt per year in 2050 (Brändle et al., 2021). With a total hydrogen demand of 95 Mt per year in 2050 for all of Europe (see Figure 5.3), this capacity could be sufficient to supply Germany's local demand if necessary. Competition with renewable energy production might still cause the need to import green hydrogen however, as was the case in scenario 2 as well.

When looking at the green hydrogen import opportunities for Germany, it can be seen that they are expected to remain significantly cheaper than far offshore green hydrogen and very close to the cheapest local production. As discussed in Sections 6.1 and 6.2, (geo)political considerations regarding the green hydrogen import options could have a notable influence on the feasibility of far offshore green hydrogen in scenarios 1 and 2. In this scenario, these considerations are expected to play a smaller role, since the main import options for Germany appear to be Norway, Morocco, France, Spain, Italy and Algeria (Brändle et al., 2021).

Green hydrogen produced from solar energy (PV) in Morocco and transported by pipeline appears to become the cheapest import option for Germany in the long term. It is however closely followed by import from Norway (onshore wind), Spain (PV), France (onshore wind) and Italy (PV). Just the 'cheapest' resources from these four (European) countries, which are shown by the model made by Brändle et al. (2021) as import options for Germany, are already expected to have a combined green hydrogen production capacity of 636.81 Mt per year in 2050 (Brändle et al., 2021). This could easily fulfill the yearly hydrogen demand of Europe itself (95 Mt). Given the fact that yearly hydrogen demand estimations correspond to hydrogen accounting for 22% of the expected global energy mix (see also Section 5.3), it is expected that the available capacity of these four resources will already leave sufficient capacity for local renewable energy production as well, let alone the other available renewable energy resources across Europe.

In short, far offshore green hydrogen usage is expected to not be feasible for Germany from a purely economic perspective, mostly because of the cheap and reliable import options. Import from Morocco is expected to be the cheapest option, but if (geo)political factors would require production within Europe, sufficient capacity at an attractive price level is available. In that case, Spain could play a big role, as their potential production capacity for low cost green hydrogen is relatively large.

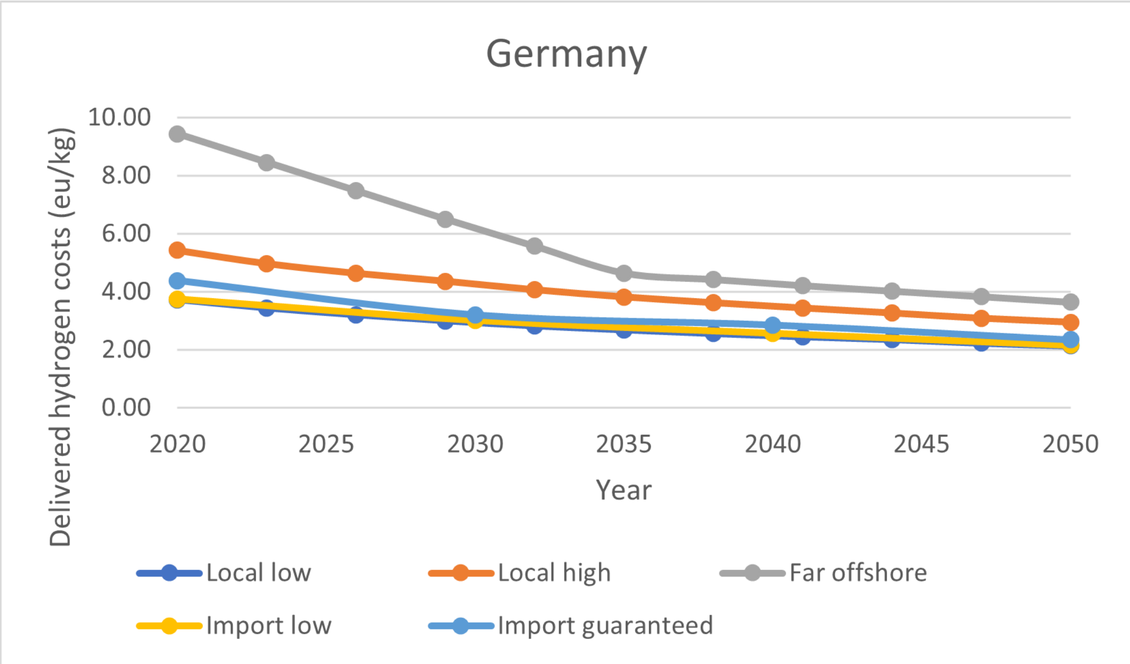


Figure 6.8: Comparison of delivered costs of green hydrogen to Cologne from 2020 to 2050 (produced far offshore, produced locally and imported)

6.4 Scenario 4: New York

In this section, the analysis of the fourth scenario is discussed, in which the competitiveness of far offshore green hydrogen in the USA market is analyzed. In Table 6.5, the scenario-specific input data is shown. In Figure 6.9, the production location and usage location are shown on the map. As can be seen, a production location is considered in the North Atlantic Ocean off the coast of Canada and with a water depth of approximately 200 m. The produced hydrogen is transported by ship to New York, where it is used as well.

Table 6.5: Scenario-specific input parameters scenario 4

Parameter	**Value**	**Unit**
Starting year	2020	
Total period	30	years
Time step	3	years
Production location	North Atlantic Ocean Latitude: 47.71 Longitude: -47.79	degrees
Port location	New York City Latitude: 40.70 Longitude: -74.00	degrees
Usage location	New York City Latitude: 40.70 Longitude: -74.00	degrees
Water depth	200	m
Factor distance over sea	1	

Figure 6.9: Production location (purple marker) and usage location (red dot) for scenario 4

In Figure 6.10, the most important results of the analysis are shown. The colours of the graphs in this figure correspond to those in Figure 6.2, which have been explained in Section 6.1. More detailed results can be found in Appendix D.

As can be seen in Figure 6.10, far offshore green hydrogen costs are lower than the highest local production costs in the United States (US) between 2032 and 2050. However, the green hydrogen production capacity of the US is very large; the expected total production capacity in 2050 is equal to 7421.3 Mt per year (Brändle et al., 2021). This is equal to more than 11 times the worldwide demand. A large part of this local production potential has a price lower than the lowest price of imported green hydrogen to the US. This means the US will most likely not require any green hydrogen import and therefore also no far offshore green hydrogen, as this is even more expensive.

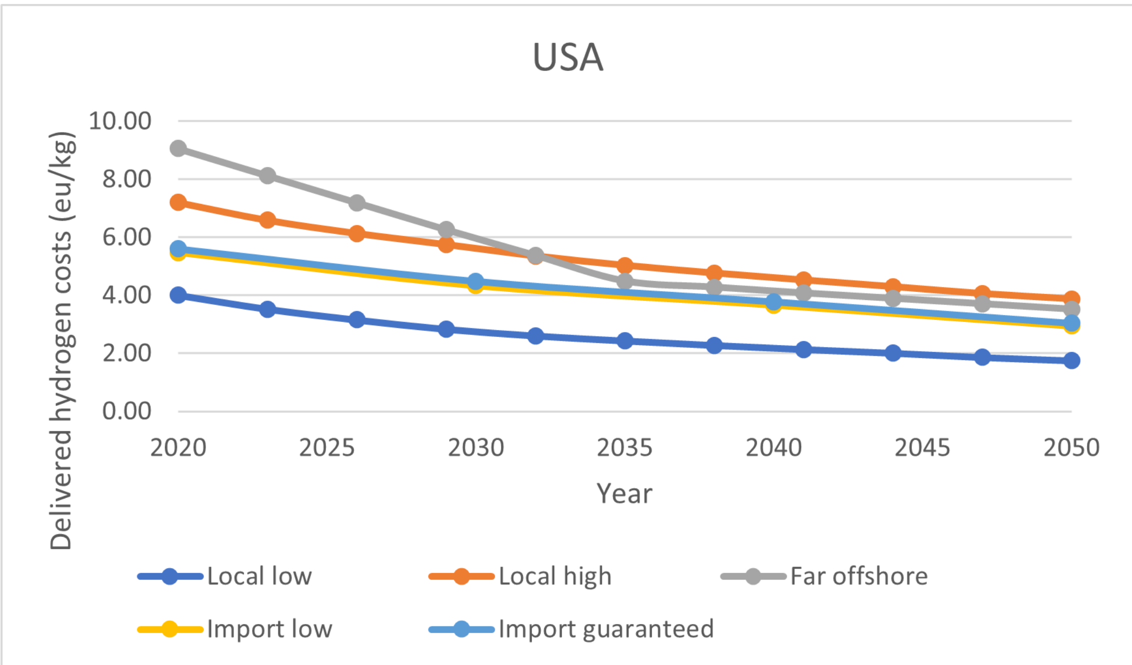


Figure 6.10: Comparison of delivered costs of green hydrogen to New York from 2020 to 2050 (produced far offshore, produced locally and imported)

6.5 Scenario 5: Singapore

In this section, the analysis of the fifth scenario is discussed, in which the competitiveness of far offshore green hydrogen in the Singaporean market is analyzed. In Table 6.6, the scenario-specific input data is shown. In Figure 6.11, the production location and usage location are shown on the map. As can be seen, a production location is considered in the Southern Pacific Ocean in New Zealand's exclusive economic zone and with a water depth of approximately 200 m. The produced hydrogen is transported by ship to Singapore, where it is used as well.

Table 6.6: Scenario-specific input parameters scenario 5

Parameter	**Value**	**Unit**
Starting year	2020	
Total period	30	years
Time step	3	years
Production location	Southern Pacific Ocean Latitude: -52.99 Longitude: 166.92	degrees
Port location	Singapore Latitude: 1.28 Longitude: 103.85	degrees
Usage location	Singapore Latitude: 1.28 Longitude: 103.85	degrees
Water depth	200	m
Factor distance over sea	2	

Figure 6.11: Production location (purple marker) and usage location (red dot) for scenario 5

In Figure 6.12, the most important results of the analysis are shown. More detailed results can be found in Appendix D. The colours of the graphs in Figure 6.12 correspond largely to those in Figure 6.2, which have been explained in Section 6.1. However, only one graph (instead of two) is included for the local green hydrogen production costs (the dark blue graph). The reason for this is the fact that the model made by Brändle et al. (2021) shows only one local green hydrogen resource in Singapore, which is also very small (0.01 Mt per year). This makes sense, since Singapore has very little land area compared to other countries.

In addition, the model by Brändle et al. (2021) does not include the option to determine the import costs of green hydrogen to Singapore. Therefore, these were determined manually based on the production costs in surrounding countries found from Brändle et al. (2021), the distances to be transported over land and sea, and the costs of this transport including conversion to liquid hydrogen (International Energy Agency, 2022). The lowest import costs regard import from Malaysia and the guaranteed import costs consider import from China. The considered resource in Malaysia is relatively small (3.78 Mt per year) and therefore not expected to be large enough to supply both Malaysia and Singapore with the needed hydrogen and renewable energy.

For Singapore, local green hydrogen production does not seem to be an attractive option, due to the low capacity and relatively high price. Therefore, Singapore will depend on import if it wants to use green hydrogen. As can be seen in Figure 6.12, the difference in costs between far offshore green hydrogen and green hydrogen import alternatives is very small, especially between 2035 and 2050. As the resource in Malaysia is relatively small and not expected to be sufficient to fulfill the demand, the guaranteed import rate and far offshore costs may be compared. As they appear to be very similar between 2035 and 2050, no clear economic preference can be stated for that period. In this case, it would be a purely political decision to choose between import of onshore green hydrogen from China or far offshore green hydrogen from New Zealand. Alternatively, both of these options could share the Singaporean market. Between 2020 and 2035, far offshore green hydrogen is slightly more expensive, although the difference is relatively small and becoming smaller towards 2035.

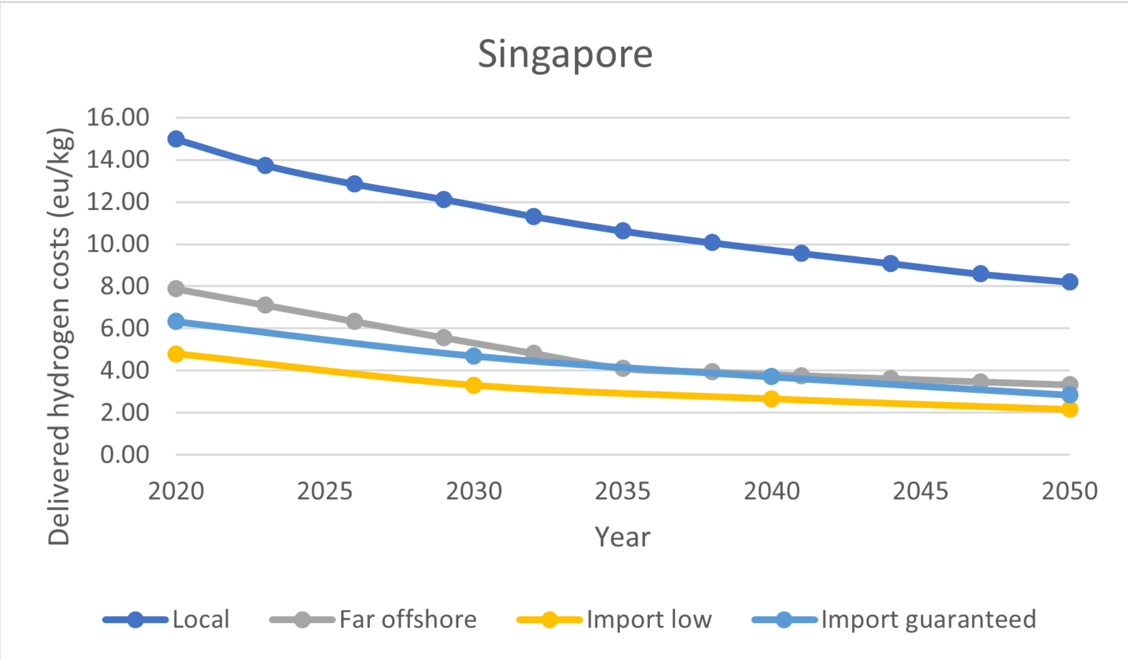


Figure 6.12: Comparison of delivered costs of green hydrogen to Singapore from 2020 to 2050 (produced far offshore, produced locally and imported)

6.6 Scenario 6: Christchurch

In this section, the analysis of the sixth scenario is discussed, in which the competitiveness of far offshore green hydrogen in the New Zealand market is analyzed. In Table 6.7, the scenario-specific input data is shown. In Figure 6.11, the production location and usage location are shown on the map. As can be seen, a production location is considered in the Southern Pacific Ocean in New Zealand's exclusive economic zone and with a water depth of approximately 200 m. The produced hydrogen is transported by ship to Christchurch, where it is used as well.

Table 6.7: Scenario-specific input parameters scenario 6

Parameter	**Value**	**Unit**
Starting year	2020	
Total period	30	years
Time step	3	years
Production location	Southern Pacific Ocean Latitude: -52.99 Longitude: 166.92	degrees
Port location	Christchurch Latitude: -43.54 Longitude:172.72	degrees
Usage location	Christchurch Latitude: -43.54 Longitude:172.72	degrees
Water depth	200	m
Factor distance over sea	1.1	

Figure 6.13: Production location (purple marker) and usage location (red dot) for scenario 6

In Figure 6.14, the most important results of the analysis are shown. More detailed results can be found in Appendix D. The colours of the graphs in Figure 6.14 correspond largely to those in Figure 6.2, which have been explained in Section 6.1. Unfortunately, New Zealand has not been included in the model made by Brändle et al. (2021). Therefore, the local production and import costs had to be determined manually. The local green hydrogen production costs in 2020 for New Zealand are 4.89 euros/kg (Concept Consulting Group, 2019). To determine the local production costs towards 2050 from this, the learning rate from year to year of onshore wind in Australia from the model made by Brändle et al. (2021) was used. This results in the dark blue graph.

The import costs were also determined manually, based on the production costs in the considered countries found from Brändle et al. (2021), the distances to be transported over land and sea, and the costs of this transport including conversion to liquid hydrogen (International Energy Agency, 2022). Import from China and Australia was compared and it was determined that import from China is significantly more economic. The yellow and light blue graphs show the lowest and guaranteed import rates to New Zealand respectively.

As can be seen in Figure 6.14, local green hydrogen production is expected to be the most economic for the coming decades, although in 2050 the costs of all options seem to become very similar. From 2032 to 2050, the costs of far offshore green hydrogen production and import from China are relatively similar. Whether the local production in New Zealand at the given price point will be able to fulfill its local demand for green hydrogen and renewable energy is not clear, although Concept Consulting Group (2019) mention that if a lot of hydrogen will be needed, additional renewable energy capacity could be necessary, which would lead to higher prices. If local production is sufficient, it is the most attractive option from a techno-economic perspective. If local production is not sufficient, the choice between far offshore production and import from China will be a political decision, as again no clear preference emerges based solely on the economic analysis. In addition, New Zealand could consider to become a green hydrogen exporting country, using its far offshore resources. This potential is shown when looking at the results of scenario 5, where it turns out far offshore green hydrogen from New Zealand's exclusive economic zone might be an option for Singapore.

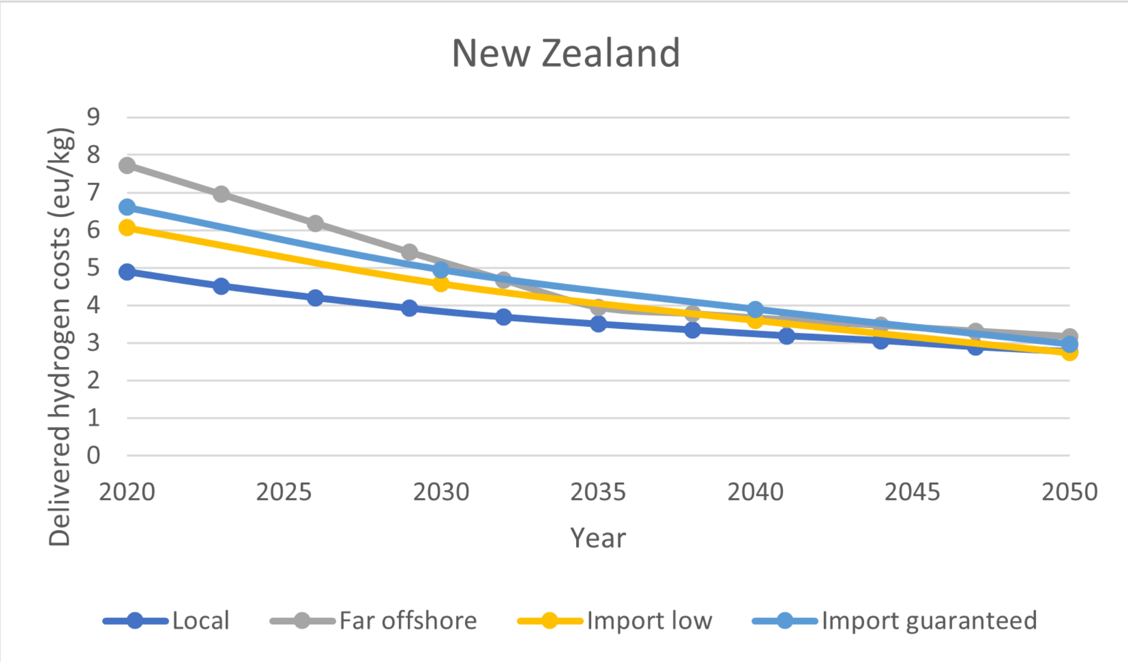


Figure 6.14: Comparison of delivered costs of green hydrogen to Christchurch from 2020 to 2050 (produced far offshore, produced locally and imported)

6.7 Further analysis

In the previous sections, only the final results of the optimizations done with the model developed in this research have been used to compare far offshore green hydrogen to its alternatives from an economic perspective. In this section, the results of the model will be looked at in more detail, in order to gain a further understanding of the techno-economics of far offshore green hydrogen supply chains. These results can be found in Appendix D. Also, a sensitivity analysis will be done in order to understand the influence of certain input parameters on the results.

Subsection 6.7.1 looks into the results regarding the combination of wind turbines, solar platforms and electrolyzers. Next, Subsection 6.7.2 takes a closer look at the cost distribution of far offshore green hydrogen production, and the differences to be seen between scenarios and over time. After this, Subsection 6.7.3 describes the performed sensitivity analysis. Finally, Subsection 6.7.4 discusses the choice between ammonia and liquid hydrogen.

6.7.1 Combining wind turbines, solar platforms and electrolyzers

In this subsection, finding the optimal combination of wind turbines, solar platforms and electrolyzers is discussed in more detail. As explained in Chapter 2, wind and solar energy are included in the model. In the optimization, the optimal amount of wind turbines and solar platforms is determined and the model can also combine the two. In Subsection 3.1.1, the optimization between wind turbines, solar platforms and electrolyzers was already explained. This subsection will give a short overview of how this was incorporated in the model using the model results and discuss the results of this optimization in the analyzed scenarios.

As mentioned in Subsection 2.4.1.3, far offshore energy production is mostly beneficial for wind energy and not as much for solar. However, previous research had already concluded that adding solar energy generation to a (far) offshore wind farm used for hydrogen production would be beneficial anyway, due to the more stable energy production and the decreased usage of space, leading to shorter electrical cables. The influence of shorter electrical cables is not taken into account in the model developed in this research due to the implemented simplifications. The benefits of combining wind and solar far offshore can however be seen, because the hydrogen and energy production are looked at over a reference period of 10 months, as also described in Section 3.1. Over this period of time, the wind and solar resources will vary in strength, and the optimizer will find the optimal amount of wind turbines, solar platforms and electrolyzers for this entire period, instead of only for one time instance. This is one of the main strengths of the model, giving a significantly more realistic and useful outcome than a model that would not use this method. Even though either wind or solar energy might be more expensive in a certain scenario when viewed out of its context, the steadier energy output achieved by combining the two of them will lead to a lower amount of electrolyzers needed, which could lead to lower costs in the end.

To visualize the optimization between the amount of wind turbines, solar platforms and electrolyzers over the considered 10 month time period in the results of the model, Figures 6.15 to 6.17 have been added. Figure 6.15 shows the energy available for the electrolyzers in this example scenario over the 10 month reference period. This is based on the energy generated by one wind turbine or solar platform, the amount of wind turbines and solar platforms, and the fraction of the total energy coming into the FPSO that is available for electrolysis, which was explained elaborately in Section 3.1. Figure 6.16 shows the energy that is used by the electrolyzers, which depends on the available energy and the installed electrolyzer capacity, as explained in Section 3.1 (see also Equations (3.10) and (3.11)). When comparing the two figures, the electrolyzer capacity setting a maximum for the used energy at 520 MW can be observed clearly in Figure 6.16.

The energy used by the electrolyzers is translated directly to the produced hydrogen, as shown in Figure 6.17. As this figure shows the hourly hydrogen production over the reference period, the area under this graph is the total hydrogen production over this period. A minimum is set for this area by the constraint shown in Equation (3.15), which enforces that the total hydrogen production must fulfill the demand. Within the limits of this constraint, the model will find the most economic combination of wind turbines, solar platforms and electrolyzers. Changing the amount of electrolyzers will influence the installed electrolyzer capacity, and therefore the 'cut-off' seen when comparing Figures 6.15 and 6.16. Changing the amount of energy generation devices will change the amount of energy generated and therefore the height of the graphs. Lastly, changing the ratio between wind turbines and solar platforms will change the shape of the graph, possibly leading to a more steady energy input. All of this influences the area under the graph and therefore the total hydrogen production. These variations have also been explained and visualized using a simplified example in Subsection 3.1.1.

If a lot of energy generation capacity is installed with too little electrolyzers, more energy is lost. If too little energy generation capacity is installed with many electrolyzers, the electrolyzers will have more downtime. The result of this optimization done by the model depends completely on the weather data associated with the considered production location, and the costs and specifications of the equipment. Therefore, the model generally gives a different result for every scenario and even for every year considered within a scenario, since the costs of the equipment change from year to year at a different pace.

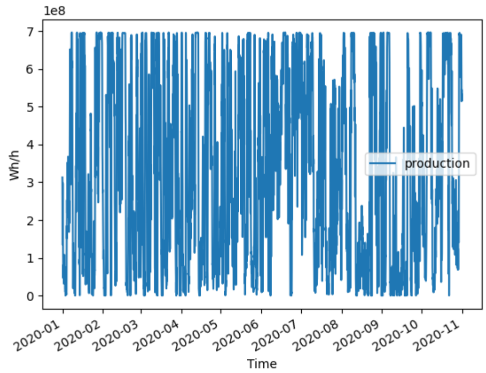


Figure 6.15: Energy available for the electrolyzers over the reference period (scenario 1, 2050)

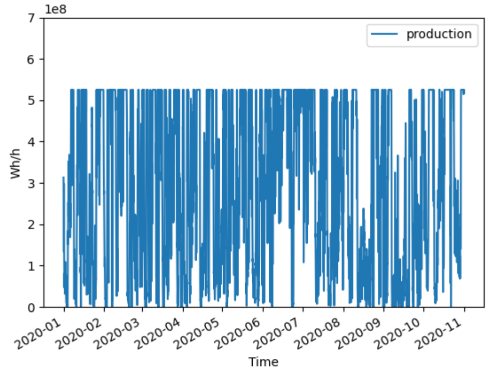


Figure 6.16: Energy used by the electrolyzers over the reference period (scenario 1, 2050)

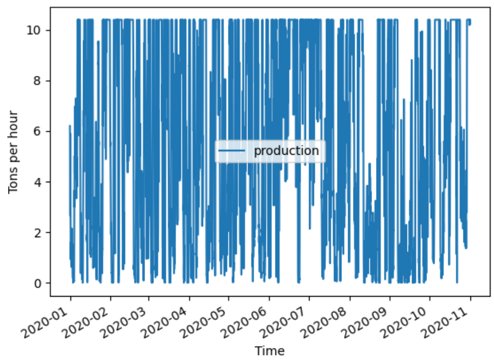


Figure 6.17: Hydrogen produced over the reference period (scenario 1, 2050)

The results as shown in Appendix D display the amount of wind turbines, solar platforms and electrolyzers to be incorporated in the supply chains designed by the model for every scenario. To illustrate the installed wind and solar capacity in the supply chains designed by the model over the years, Figures 6.18 to 6.23 have been added. In scenarios 1 to 4, the model is combining wind turbines and solar platforms for its energy generation for most of the years considered. The installed solar capacity is however small compared to the installed wind capacity, except for the years between 2020 and 2035 in the first two scenarios. This indicates a relatively weak wind resource in the production location used in those scenarios. The fact that the total installed power generation capacity in those scenarios is relatively large also indicates that the renewable resources are relatively weak. Over the years, the amount of solar capacity used decreases in the first two scenarios too, which is in line with expectations, as the wind turbine costs decrease faster than the solar platform costs. However, in scenarios 1 to 4, at least some solar platforms are used in almost all the years considered.

When looking at scenarios 5 and 6, it can be seen that the model chooses to use only wind turbines and no solar platforms. This indicates a very strong and steady wind resource in the production location of these scenarios. This is in line with expectations, as this production location is located in a zone also called the ‘furious fifties’, which is known for its strong winds. These last two scenarios also have relatively little electrolyzers, again indicating a strong and steady energy supply. The model includes the fact that wind turbines will stop operation if the winds get too strong (in this case at wind speeds above 25 m/s). From the results, it can be seen that this does not happen too often, because that would mean the production of the wind turbines would not be steady anymore.

In short, the results reconfirm the potential of combining wind and solar energy generation for certain locations, but also show that it is not beneficial in every scenario. Furthermore, the results show that although combining wind and solar is found to be beneficial, the solar platform capacity will be small compared to the wind turbine capacity in most cases. In addition, the results clearly highlight the high potential of the wind resources in the production location used for scenarios 5 and 6. Finally, the results show that the optimization of the amount of wind turbines, solar platforms and electrolyzers generally yields a different result for every production location and every year considered.

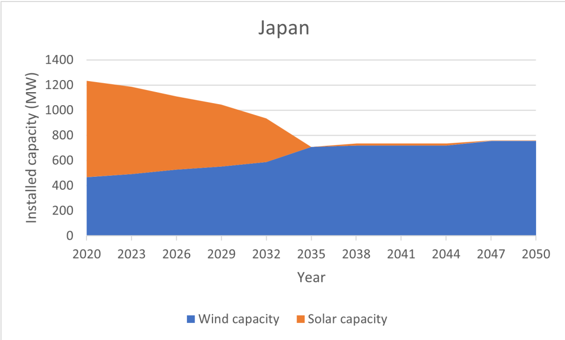


Figure 6.18: Total installed wind and solar power generation capacity from 2020 to 2050 in supply chains as optimized by the model for scenario 1

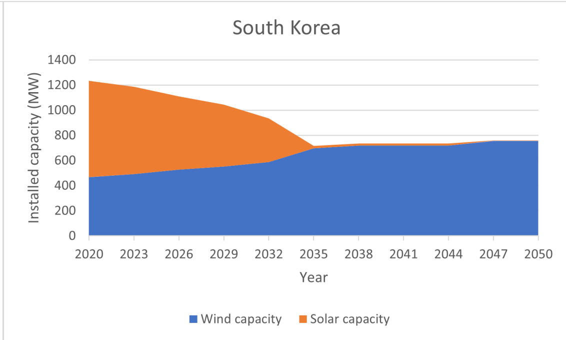


Figure 6.19: Total installed wind and solar power generation capacity from 2020 to 2050 in supply chains as optimized by the model for scenario 2

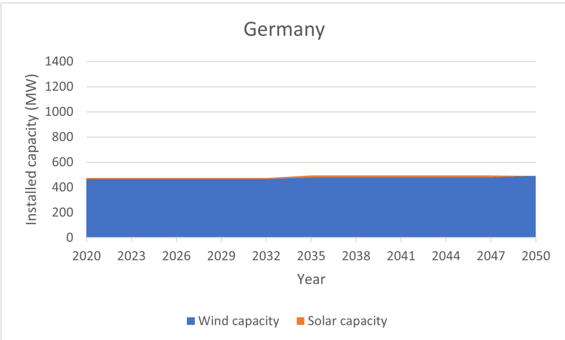


Figure 6.20: Total installed wind and solar power generation capacity from 2020 to 2050 in supply chains as optimized by the model for scenario 3

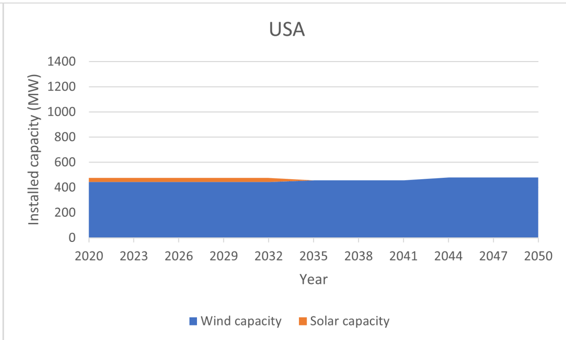


Figure 6.21: Total installed wind and solar power generation capacity from 2020 to 2050 in supply chains as optimized by the model for scenario 4

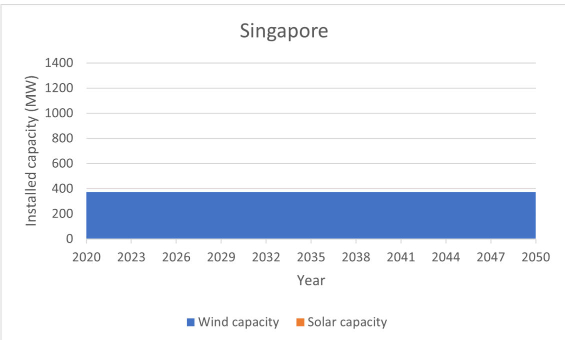


Figure 6.22: Total installed wind and solar power generation capacity from 2020 to 2050 in supply chains as optimized by the model for scenario 5

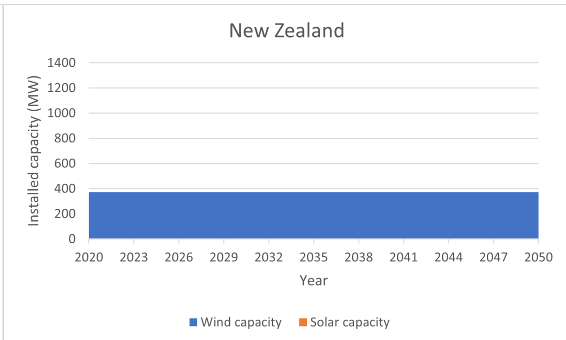


Figure 6.23: Total installed wind and solar power generation capacity from 2020 to 2050 in supply chains as optimized by the model for scenario 6

6.7.2 Cost distribution

In this subsection, the results regarding the cost distribution of green hydrogen produced far offshore and its development over time will be discussed. In Appendix D, the cost distribution for all six scenarios has been included for 2020, 2035 and 2050. In this subsection, the cost distributions for scenario 1 are taken as an example. Figure 6.24 shows the cost distribution in 2020, 2035 and 2050, also showing the total costs in each year, which decrease over time. In Figures 6.25 to 6.27, the cost distributions of scenario 1 are shown in more detail for each year separately.

When looking at the cost distributions in 2020, it can be seen that the category 'Energy generation' accounts for the biggest share of the costs, followed at a distance by 'Electrolysis', 'Conversion/reconversion' and 'FPSO'. For the energy generation, technologies in a relatively early stage of development are being considered (also when compared to the other considered technologies), which leads their costs to be relatively high. The costs for transport and storage are relatively low for all considered years, which is in line with expectations, since ammonia is used. The desalination devices also represent only a small part of the costs.

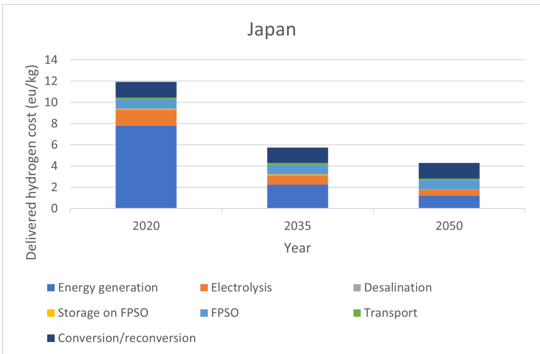


Figure 6.24: Cost distributions scenario 1 in 2020, 2035 and 2050

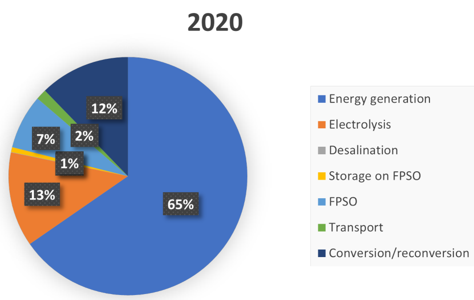


Figure 6.25: Cost distribution scenario 1 2020

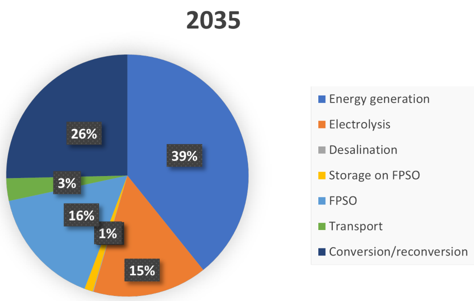


Figure 6.26: Cost distribution scenario 1 2035

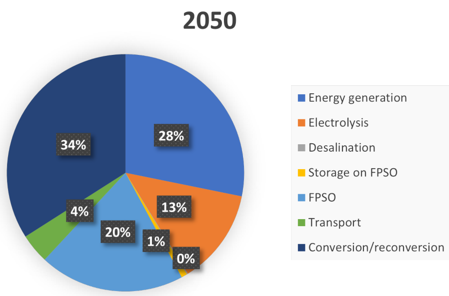


Figure 6.27: Cost distribution scenario 1 2050

When comparing the cost distributions in 2020 and 2035, a rise can be seen in the percentage taken up by 'Conversion/reconversion' and 'FPSO'. This can be explained by the fact that the costs of most other equipment decrease over time (see also Figure 6.24), whereas the costs of the FPSO and (re)conversion equipment remain constant (as also mentioned in Chapter 5). The latter therefore start to represent a bigger portion of the costs. The same can be observed for the transport costs. The percentage of the costs represented by energy generation decreases significantly, which is in line with expectations, since the costs of especially floating wind turbines are expected to decrease very rapidly between 2020 and 2035. The percentage taken up by electrolysis rises slightly, while its costs do decrease over time. However, under the assumptions taken in this research, energy generation costs are decreasing faster than electrolysis costs, which causes this rise.

Similar trends can be observed when comparing the cost distributions in 2035 and 2050. The energy generation costs decrease further and with FPSO, (re)conversion and transport costs staying constant, their percentages keep increasing. The decrease of electrolysis costs catches up slightly and its percentage of the total decreases. Under the current assumptions, liquid hydrogen does not become the more economic option in any scenario before 2050. Eventually however, it will become more economic if the ammonia (re)conversion and transport costs stay the same and those of liquid hydrogen keep decreasing.

6.7.3 Sensitivity analysis

In order to better understand the influence of different factors on the costs of far offshore green hydrogen and to assess how sensitive these costs are to changes in the input data, a sensitivity analysis was performed. This analysis will be shown and discussed in this section. For this analysis, the first scenario was used as a baseline, which was discussed in Section 6.1. Each of the input variables analyzed in this sensitivity analysis has been increased and decreased by 50%. The effect this has on the final costs per kilogram of hydrogen is looked at over the full time period considered in this research (2020-2050). More extensive results of all the optimizations run for the sensitivity analysis can be found in Appendix G. All graphs included in this subsection show normalized results of the baseline scenario (equal to 1) and the scenarios with the variable in question increased or decreased.

Demand
The first input variable that was varied is the demand. In reality, it would be expected that the demand will influence the eventual costs per kilogram of hydrogen, because bigger production facilities may enjoy economies of scale. In Table 6.8 and Figure 6.28, the results of this sensitivity analysis are shown. As can be seen, the demand seems to hardly influence the costs per kilogram of hydrogen. This is in line with expectations, because economies of scale are not included in the developed model. This is one of its limitations and something that could be developed in follow-up research.

When looking closer, it can be seen that the demand seems to have some influence on the results. This can be attributed to the fact that much of the equipment that is part of the far offshore green hydrogen supply chain comes in integer numbers. This can lead to small deviations in the costs per kilogram of hydrogen. For the decrease of demand by 50%, a deviation that grows over time can be seen. This specific deviation is expected to be caused by the conversion and reconversion devices. For a yearly demand of 50,000 tons of hydrogen (the baseline scenario), nine conversion devices and five reconversion devices are needed. For half the demand (25,000 tons), five conversion devices and three reconversion devices are needed, leading to a slight rise in the costs per kilogram. As shown in Subsection 6.7.2, the percentage of the total costs taken up by the conversion and reconversion rises over time. Therefore, this specific deviation also increases over time.

Table 6.8: Results sensitivity analysis: normalized comparison for change of demand

	2020	**2023**	**2026**	**2029**	**2032**	**2035**	**2038**	**2041**	**2044**	**2047**	**2050**
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.00	1.00	1.00	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
-50%	1.01	1.02	1.02	1.02	1.02	1.03	1.03	1.04	1.04	1.04	1.04

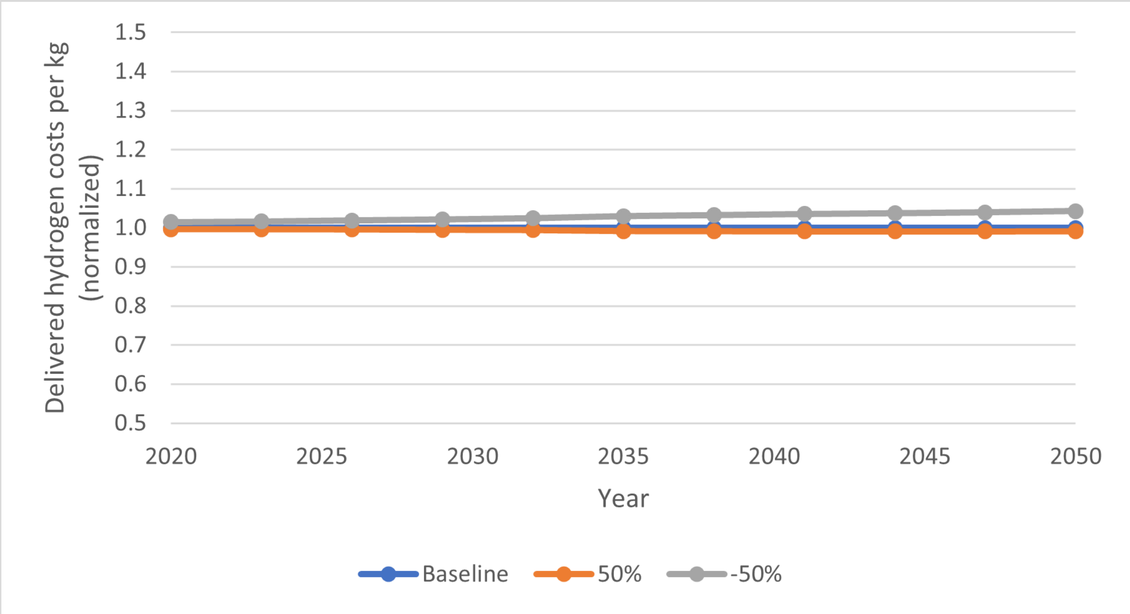


Figure 6.28: Results sensitivity analysis: normalized comparison for change of demand

Distance to shore

Next, the distance to shore was varied. The effect of this is shown in Table 6.9 and Figure 6.29. In reality, the costs would increase with an increasing distance to shore due to a longer transport distance, higher OPEX and (most likely) increased water depth. The influence of the second is expected to be limited once the offshore farm is managed with personnel and ships staying offshore for longer periods of time. The influence of distance to shore on the OPEX is therefore not taken into account in the model, although this could be done in follow-up research. Furthermore, in this analysis, the increased water depth was not taken into account, as this is considered separately later in this sensitivity analysis.

This means only the effect of the larger transport distance can be seen in the results presented here. Since in this scenario the transport is done as ammonia, the transport costs per kilometer are very low and minimal influence can be seen.

Table 6.9: Results sensitivity analysis: normalized comparison for change of the distance to shore

	2020	**2023**	**2026**	**2029**	**2032**	**2035**	**2038**	**2041**	**2044**	**2047**	**2050**
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
-50%	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

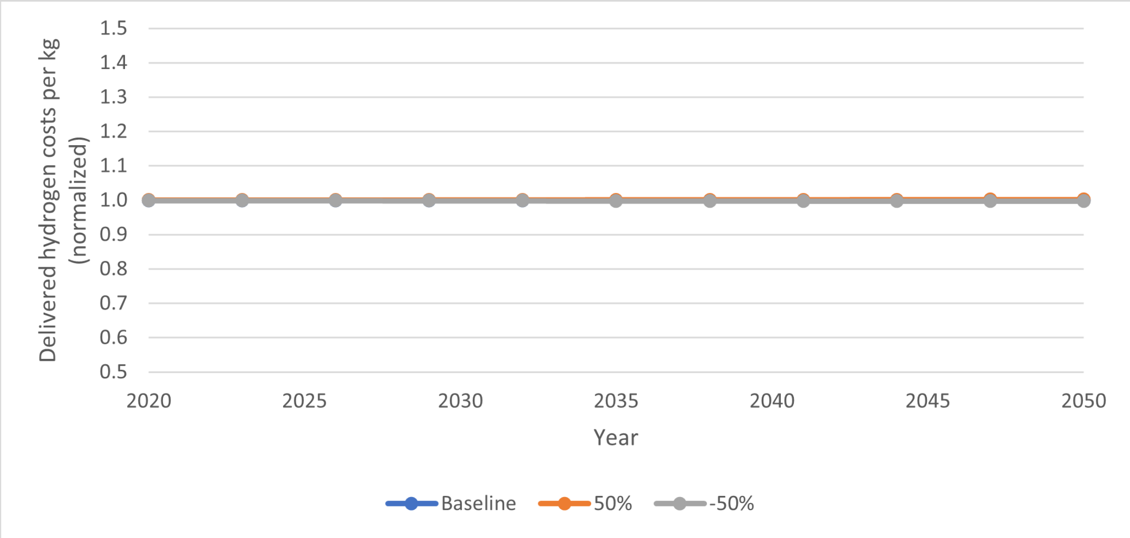


Figure 6.29: Results sensitivity analysis: normalized comparison for change of the distance to shore

Ammonia (re)conversion costs

In Table 6.10 and Figure 6.30, the effect of varying the ammonia conversion and reconversion costs is shown. As can be seen in the presented results, changing the ammonia conversion and reconversion costs has the same influence in both directions initially, since the effect is not dampened in either direction by ammonia being replaced with alternatives. Over time, the effect of the change in ammonia conversion and reconversion costs on the costs per kilogram of hydrogen grows. This can be explained by the fact that the percentage of the total costs represented by ammonia (re)conversion grows over the years, as shown in Subsection 6.7.2.

At the right of Figure 6.30 (in 2047 and 2050), a deviation can be seen in the graph showing the effect of a 50% increase of the ammonia (re)conversion costs. The effect of this increase suddenly starts to become less strong, which does not happen for the decrease. This can be explained by the fact that in 2047 and 2050, the model decides to switch to transport and storage as liquid hydrogen in the scenario with increased ammonia (re)conversion costs. With the risen costs of ammonia (re)conversion, liquid hydrogen now becomes the cheaper option once its costs have declined sufficiently. The fact that the model switches to liquid hydrogen here shows that the difference in costs of liquid hydrogen and ammonia transport is limited, especially close to 2050.

Table 6.10: Results sensitivity analysis: normalized comparison for change of ammonia (re)conversion costs

	2020	**2023**	**2026**	**2029**	**2032**	**2035**	**2038**	**2041**	**2044**	**2047**	**2050**
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.06	1.07	1.08	1.09	1.10	1.13	1.13	1.14	1.15	1.13	1.10
-50%	0.94	0.93	0.92	0.91	0.90	0.87	0.87	0.86	0.85	0.84	0.83

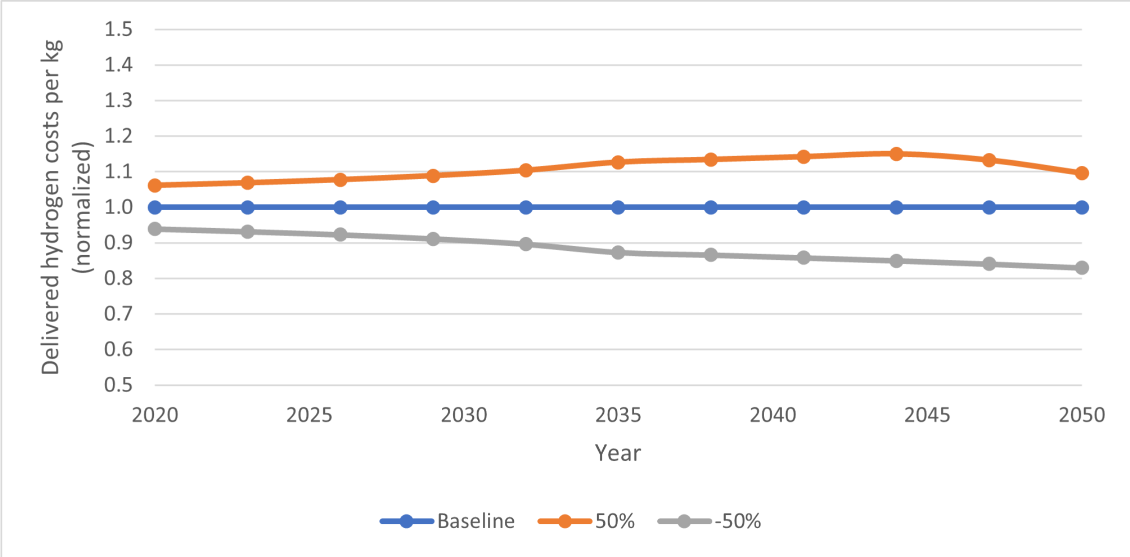


Figure 6.30: Results sensitivity analysis: normalized comparison for change of ammonia (re)conversion costs

Floating offshore wind costs

Next, the effect of changing the floating offshore wind costs may be discussed, which is shown in Table 6.11 and Figure 6.31. This time, a clear difference can be seen in the effect of increasing and decreasing the costs. This can be explained by the fact that the model has alternatives for the wind turbines, namely increasing the amount of solar platforms and/or electrolyzers. How the optimization between wind turbines, solar platforms and electrolyzers works has already been explained in Subsections 3.1.1 and 6.7.1.

When increasing the wind turbine costs, the model switches to using more solar platforms and electrolyzers. This significantly dampens the effect of the increase in wind turbine costs. However, since the costs of wind turbines decrease faster over the years than the costs of solar platforms and electrolyzers, more wind turbines are used again in later years and the effect of the cost increase becomes larger.

When decreasing the wind turbine costs, the effect is enhanced for the same reason it is dampened when increasing the costs. When decreasing the wind turbine costs, more wind turbines and less solar platforms are used.

Over time, the effect becomes smaller in both cases. This in line with expectations, because the part of total costs represented by energy generation decreases over time, as also shown in Subsection 6.7.2.

Table 6.11: Results sensitivity analysis: normalized comparison for change of floating offshore wind costs

	2020	**2023**	**2026**	**2029**	**2032**	**2035**	**2038**	**2041**	**2044**	**2047**	**2050**
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.09	1.12	1.17	1.21	1.20	1.18	1.18	1.17	1.16	1.15	1.14
-50%	0.71	0.72	0.73	0.74	0.76	0.79	0.80	0.81	0.82	0.84	0.85

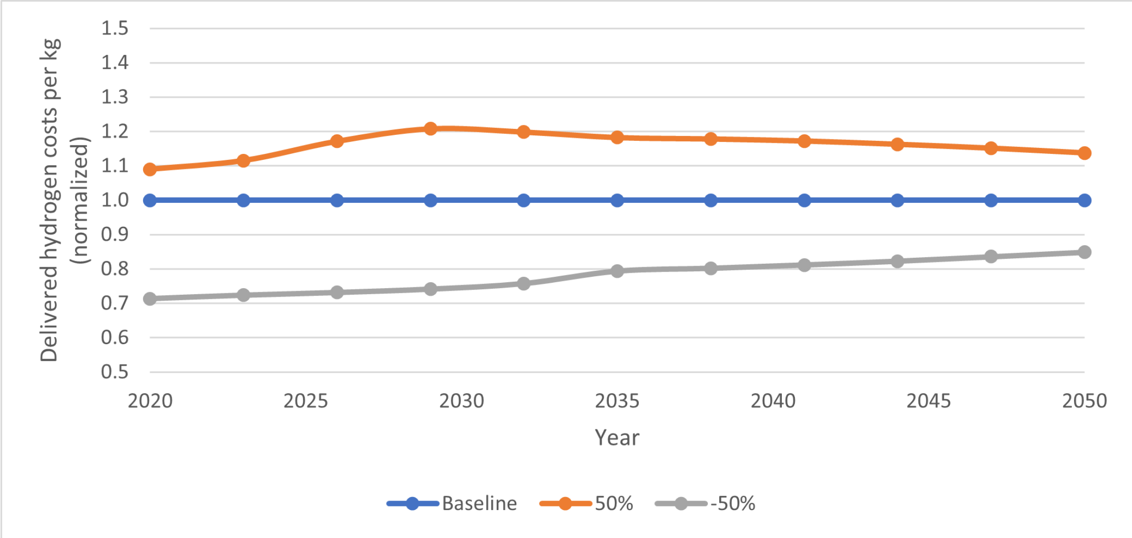


Figure 6.31: Results sensitivity analysis: normalized comparison for change of floating offshore wind costs

Floating solar costs

In Table 6.12 and Figure 6.32, the effect of changing the costs of the solar platforms is shown. The dampening and enhancing effect of having alternatives in the model as described above when discussing the floating offshore wind costs can be seen very clearly here as well.

A decrease in offshore solar costs will lead to a significant effect because more solar platforms will be used, causing the effect to be enhanced. This effect becomes smaller over the years because wind turbine costs will still decrease faster than solar platform costs, causing the solar platforms to be replaced by wind turbines again.

An increase in solar platform costs does not have major effect, because the model compensates by using more wind turbines. The 'bump' seen when increasing floating offshore wind costs is not seen here, because the dampening effect stays, as the wind turbine cost decrease faster than the solar platform cost.

Table 6.12: Results sensitivity analysis: normalized comparison for change of floating offshore solar costs

	2020	**2023**	**2026**	**2029**	**2032**	**2035**	**2038**	**2041**	**2044**	**2047**	**2050**
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.05	1.05	1.04	1.03	1.01	1.00	1.00	1.00	1.00	1.00	1.00
-50%	0.81	0.84	0.89	0.92	0.93	0.95	0.96	0.96	0.97	0.98	0.98

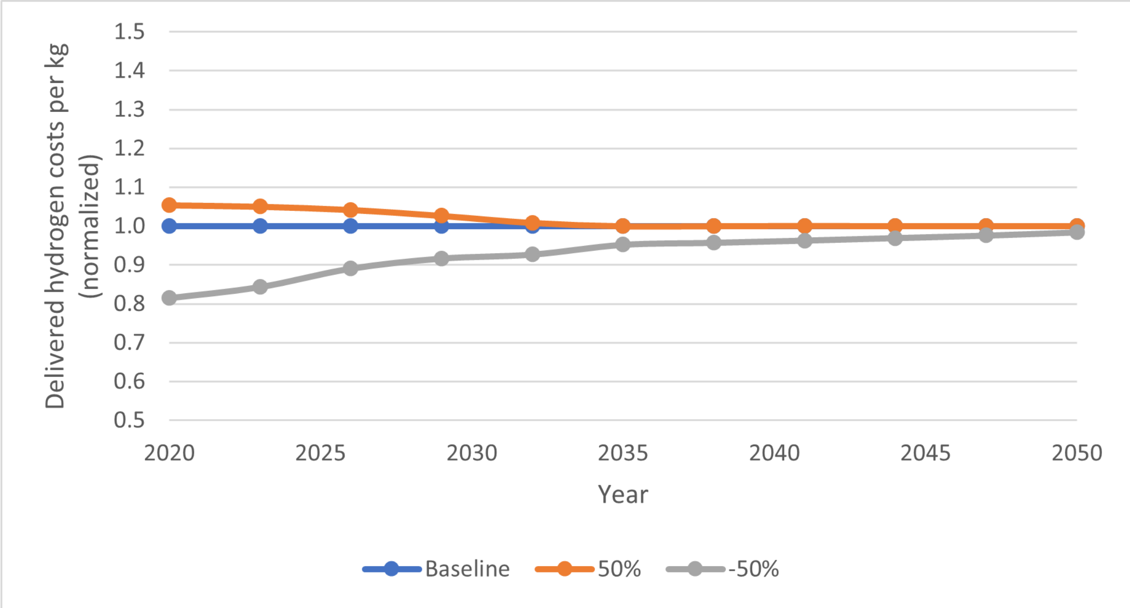


Figure 6.32: Results sensitivity analysis: normalized comparison for change of floating offshore solar costs

Electrolyzer costs
Next, Table 6.13 and Figure 6.33 show the effect of varying the electrolyzer costs. Like with the floating wind and solar costs, a difference can be seen between the effect of increasing and decreasing the electrolyzer costs. The effect is however less clear here.

The effect of changing the electrolyzer costs seems relatively stable over the considered time period. A small 'bump' may be observed around 2035. This is in line with the analysis of the cost distributions in Section 6.7.2, where it was found that the percentage of the total costs represented by the electrolyzers costs increases slightly from 2020 to 2035 and then decreases again towards 2050.

Table 6.13: Results sensitivity analysis: normalized comparison for change of electrolyzer costs

	2020	**2023**	**2026**	**2029**	**2032**	**2035**	**2038**	**2041**	**2044**	**2047**	**2050**
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.06	1.06	1.06	1.06	1.06	1.07	1.07	1.07	1.07	1.07	1.06
-50%	0.93	0.93	0.94	0.94	0.93	0.92	0.93	0.93	0.93	0.93	0.93

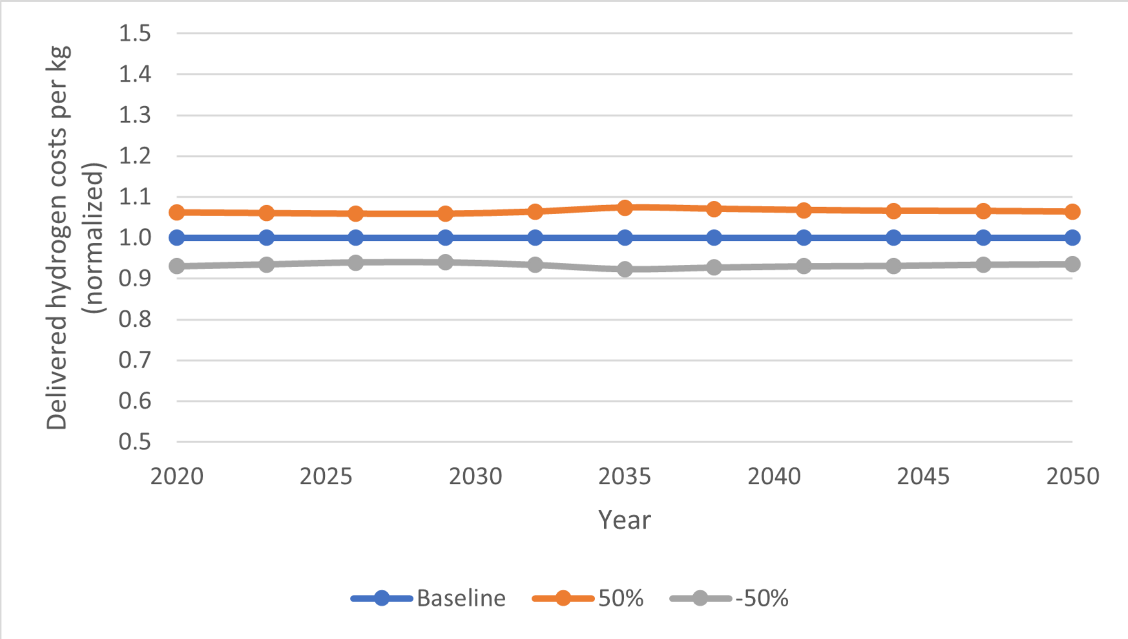


Figure 6.33: Results sensitivity analysis: normalized comparison for change of electrolyzer costs

Water depth

In Table 6.14 and Figure 6.34, the effect of a changing water depth is shown. As can be seen, the found effect is very small. In Chapter 5, it was already explained that the water depth is only taken into account in the costs of the wind turbines and not in the costs of the FPSO. This may lead to a small underestimation of the effect of the water depth on the total costs.

The main reason why only a small effect is seen here however is expected to be the fact that the baseline water depth is 200 m. This means the variation done here regards a 100 m difference in water depth, which is relatively small. In reality, water depth increases could be significantly higher, as many areas in the ocean have water depths of several kilometers. If a 100 m depth increase already has a visible effect on the total costs (about 1%), a depth increase of several kilometers is expected to have a significant effect. This is also the reason why for the analyzed (high potential) scenarios, areas with a limited water depth of around 200 m were chosen.

Table 6.14: Results sensitivity analysis: normalized comparison for change of water depth

	2020	**2023**	**2026**	**2029**	**2032**	**2035**	**2038**	**2041**	**2044**	**2047**	**2050**
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01
-50%	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99

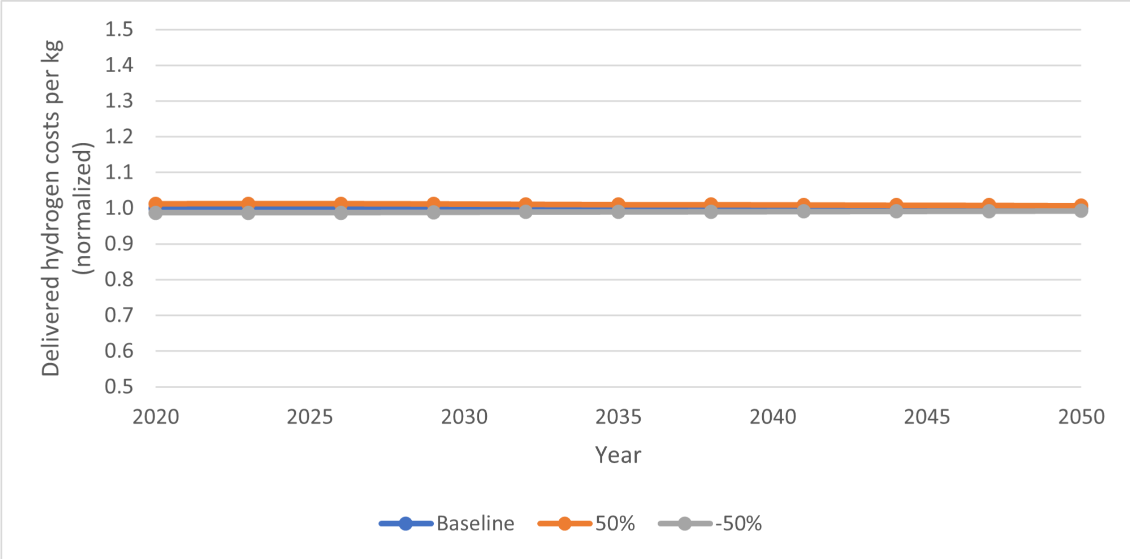


Figure 6.34: Results sensitivity analysis: normalized comparison for change of water depth

FPSO costs

In Table 6.15 and Figure 6.35, the effect of varying the FPSO costs is shown. As can be seen, the effect of the change in FPSO costs on the costs per kilogram of hydrogen grows over the years. This can be explained by the fact that the percentage of the total costs represented by the FPSO grows over the years, as shown in Subsection 6.7.2.

Table 6.15: Results sensitivity analysis: normalized comparison for change of FPSO costs

	2020	**2023**	**2026**	**2029**	**2032**	**2035**	**2038**	**2041**	**2044**	**2047**	**2050**
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.04	1.04	1.04	1.05	1.06	1.08	1.08	1.08	1.09	1.09	1.10
-50%	0.96	0.96	0.96	0.95	0.94	0.92	0.92	0.91	0.91	0.90	0.90

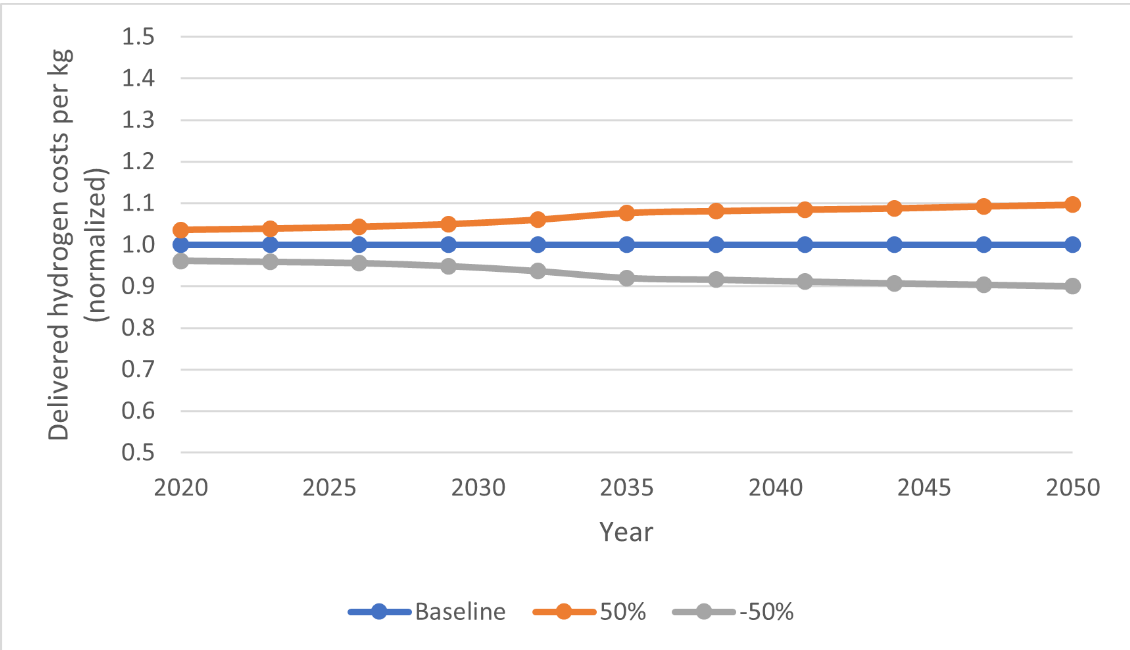


Figure 6.35: Results sensitivity analysis: normalized comparison for change of FPSO costs

Desalination costs

Next, Table 6.16 and Figure 6.36 show the effect of varying the desalination costs. As can be seen, the effect is minimal. This is in line with the findings in Subsection 6.7.2, where an analysis of the cost distribution of far offshore green hydrogen showed desalination accounted for a very small part of the costs.

Table 6.16: Results sensitivity analysis: normalized comparison for change of desalination costs

	2020	**2023**	**2026**	**2029**	**2032**	**2035**	**2038**	**2041**	**2044**	**2047**	**2050**
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
-50%	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

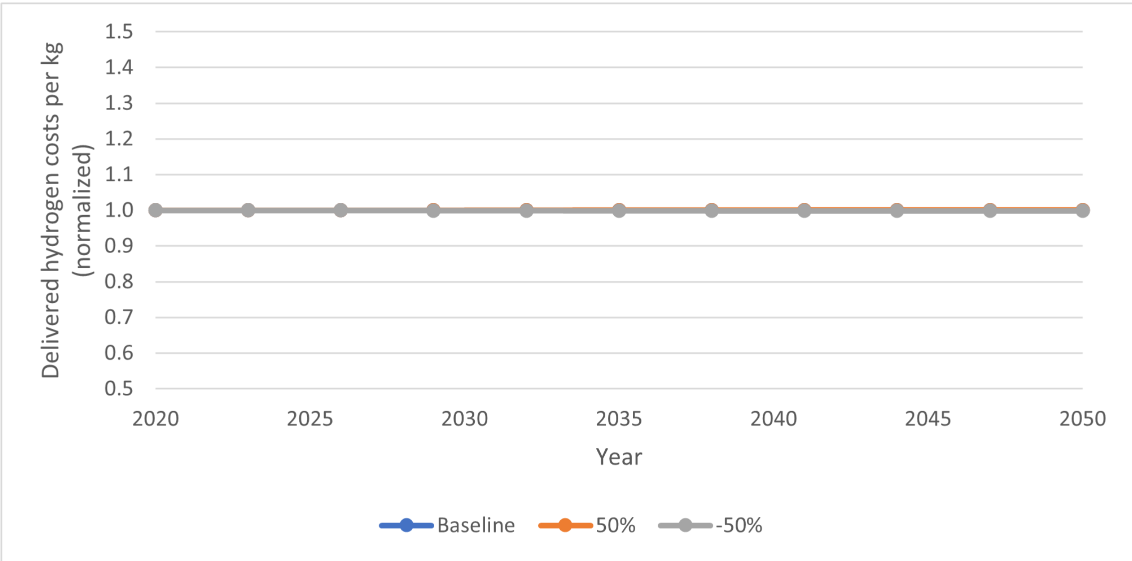


Figure 6.36: Results sensitivity analysis: normalized comparison for change of desalination costs

Ammonia transport costs

In Table 6.17 and Figure 6.37, the effect of varying the ammonia transport costs is shown. As can be seen, the effect is relatively small, which can be explained by the fact that ammonia transport costs themselves are relatively small, which was also shown in Subsection 6.7.2. Over the years, the effect becomes bigger, which is again in line with Subsection 6.7.2, where it was shown that the percentage of the total costs represented by transport increases over the years.

Table 6.17: Results sensitivity analysis: normalized comparison for change of ammonia transport costs

	2020	**2023**	**2026**	**2029**	**2032**	**2035**	**2038**	**2041**	**2044**	**2047**	**2050**
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.01	1.01	1.01	1.01	1.01	1.02	1.02	1.02	1.02	1.02	1.02
-50%	0.99	0.99	0.99	0.99	0.99	0.98	0.98	0.98	0.98	0.98	0.98

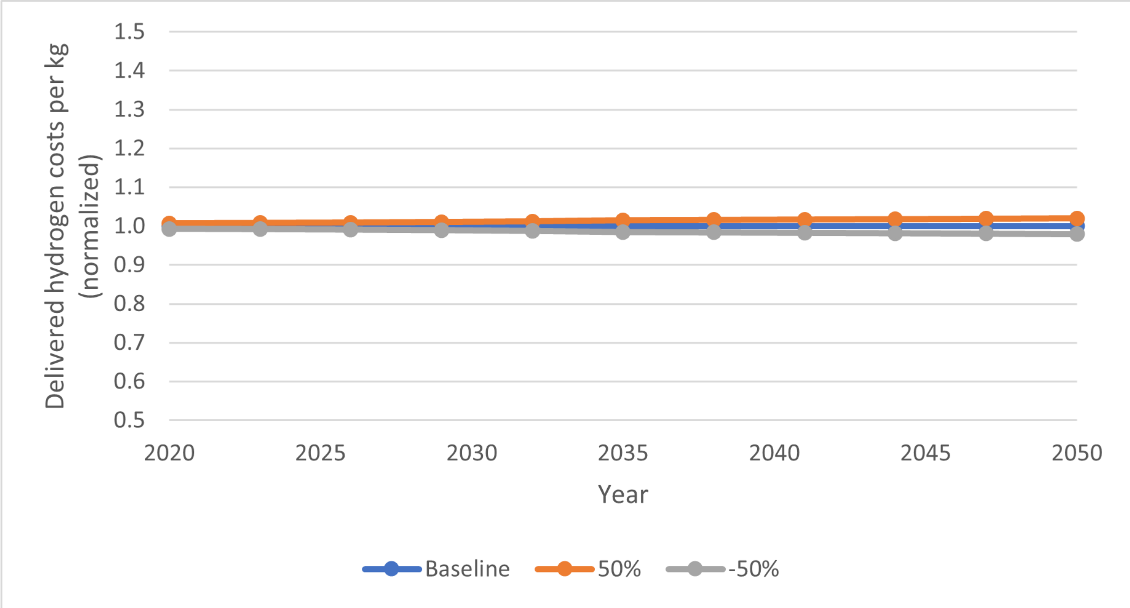


Figure 6.37: Results sensitivity analysis: normalized comparison for change of ammonia transport costs

Liquid hydrogen transport costs

Next, Table 6.18 and Figure 6.38 show the effect of varying the liquid hydrogen transport costs. As can be seen, no effect is found. This means a 50% decrease of the liquid hydrogen transport costs does not make liquid hydrogen more economic than ammonia over the considered period, since the model would have otherwise switched, showing an effect on the total costs.

Table 6.18: Results sensitivity analysis: normalized comparison for change of liquid hydrogen transport costs

	2020	**2023**	**2026**	**2029**	**2032**	**2035**	**2038**	**2041**	**2044**	**2047**	**2050**
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
-50%	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

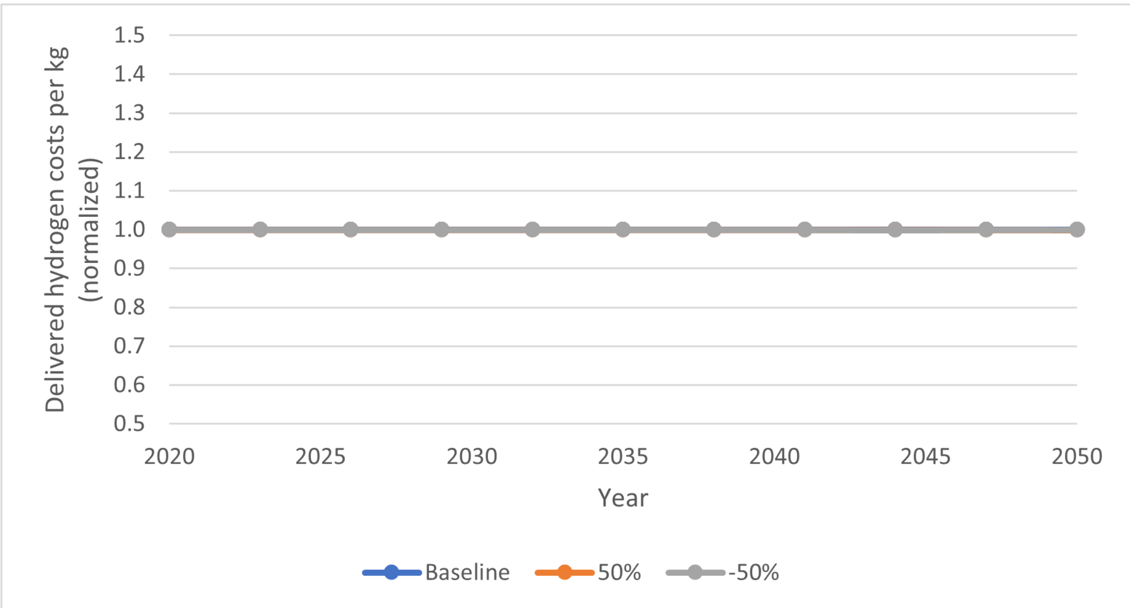


Figure 6.38: Results sensitivity analysis: normalized comparison for change of liquid hydrogen transport costs

Interest rate
Finally, Table 6.19 and Figure 6.39 show the effect of varying the interest rate. In this research, an interest rate of 8% was used, since this was also done in the model by Brändle et al. (2021), which was used to determine local and imported green hydrogen production costs. As can be seen in the results of this sensitivity analysis however, the used interest rate can have a big effect on the final costs per kilogram of far offshore green hydrogen.

When changing the interest rate, the design of the supply chain also changes slightly. This can be explained by the fact that not all costs are affected in the same way by a changing interest rate, since the lifetime and the ratio between OPEX and CAPEX differ between equipment types.

Furthermore, the increase of the costs is bigger than the decrease, while the percentual change in interest rate is the same in both directions. This can be explained by the fact that the interest rate is taken into account through the amortisation factor (see also Equation (3.24)). In this amortisation factor, compound interest is also taken into account, meaning the effect of increasing the interest rate is enhanced.

Table 6.19: Results sensitivity analysis: normalized comparison for change of the interest rate

	2020	**2023**	**2026**	**2029**	**2032**	**2035**	**2038**	**2041**	**2044**	**2047**	**2050**
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28
-50%	0.75	0.75	0.75	0.75	0.75	0.76	0.76	0.76	0.76	0.76	0.76

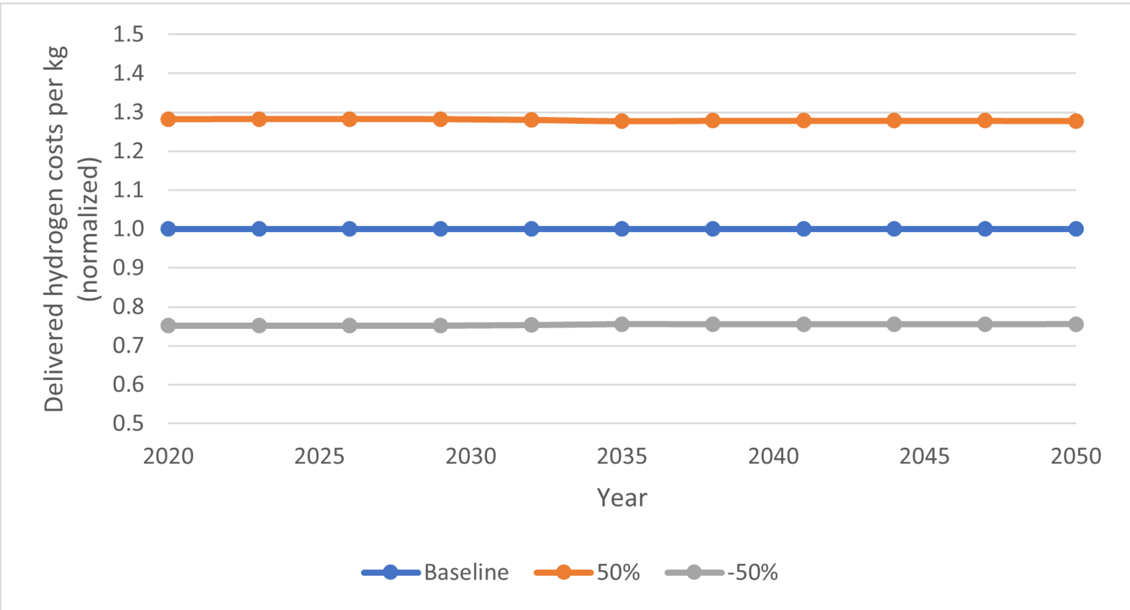


Figure 6.39: Results sensitivity analysis: normalized comparison for change of the interest rate

6.7.4 Ammonia versus liquid hydrogen

In this subsection, the transport medium for the produced hydrogen will be discussed. Ammonia and liquid hydrogen have been identified as suitable candidates for this in the literature review, and the choice between them has been incorporated in the optimization to be done by the developed model. In Subsection 3.1.1, the choice between ammonia and liquid hydrogen was already identified as one of the main optimization challenges to be solved by the model.

For ammonia, the conversion and reconversion are and remain relatively expensive, but the transport and storage costs are relatively low. In addition, ammonia has a higher hydrogen density per cubic meter, meaning the storage tank and therefore the FPSO can be smaller, also saving costs. Liquid hydrogen on the other hand is expected to be relatively cheap to convert once its technology has developed further, but comes with significantly higher transport and storage costs. In addition, the liquid hydrogen technology is still in development and not all parts of it are already commercially available. The costs associated with liquid hydrogen are expected to decrease over the years. Ammonia is already widely used as a fertilizer, meaning the related technology is much more developed. Because of this, it has been assumed that its costs will not decrease significantly over the coming decades, as also explained in Chapter 5.

When looking at the results, it can be seen that in all scenarios, the model chooses ammonia for the entire period between 2020 and 2050 under the current assumptions. This can be explained by the higher transport costs, higher storage costs (and space requirements in the FPSO), and higher energy usage for conversion and storage associated with liquid hydrogen. This means that a low distance to be transported over, a steady energy resource and low cost energy will work in favor of liquid hydrogen. The last two will be explained below.

As explained before in section 3.1, the model analyzes the hydrogen production over a reference period of 10 months. If the energy production over this period is steady, less electrolyzers are needed and the hydrogen production is more steady as well. This leads to a lower storage need, which especially favours liquid hydrogen.

Next to a steady energy source and short transport distances, strong renewable energy resources also work in favour of liquid hydrogen due to the lower costs of energy generation. When transport is done with liquid hydrogen, significantly more energy is needed on the FPSO because more energy is used for conversion and storage. This can be seen in the ratios between the energy used for electrolysis and the total energy used on the FPSO as included in Table 5.4.

In the production location considered in scenarios 5 and 6, it can be seen that relatively little wind turbines and electrolyzers are needed, and that no solar platforms are added by the model. All of this indicates a strong and steady wind resource, which is indeed the case in this location, as already mentioned in Subsection 6.7.1. As explained above, this would be beneficial for liquid hydrogen. Out of the considered locations, liquid hydrogen is therefore expected to become feasible in this production location first. As already discussed in Subsection 6.7.3, liquid hydrogen is not preferred over ammonia towards 2050 under the current assumptions, but an increase in ammonia (re)conversion costs would make liquid hydrogen the more economic option close to 2050 in scenario 1. Based on the explanation given in this section it may be expected that this would be the case even earlier for scenarios 5 and 6.

To further illustrate the choice between ammonia and liquid hydrogen, Figure 6.40 has been added. This figure shows at which distance to be traveled over sea and/or storage volume required on the FPSO ammonia or liquid hydrogen is more beneficial under the current assumptions in 2050 for scenario 1. In this figure, it can be seen clearly that lower transport distances and lower storage volumes favor liquid hydrogen, as explained before as well. In this same scenario in 2020 and 2035, ammonia is the preferred transport medium for all distances and storage volumes. The storage volume actually used in this scenario is around 46.000 m^3, meaning ammonia is still clearly the preferred choice in 2050 as well under the current assumptions. As liquid hydrogen costs decrease and ammonia costs stay constant, the dividing line in Figure 6.40 will move further right and upward.

In Figure 6.40, it is also shown where the dividing line would be if the liquid hydrogen transport, storage and (re)conversion costs would be decreased by 10%. As can be seen in the figure, this has a significant effect, although ammonia would still be preferred at a storage volume of 46.000 m^3 for all transport distances. It should be noted that this visualization slightly favours liquid hydrogen, since the storage volumes of liquid hydrogen and ammonia are compared directly, while the hydrogen density of liquid hydrogen is lower, as already mentioned before.

Finally, it should be noted that the slope of the two dividing lines is not exactly the same. This (small) difference is in line with expectations. For both the storage and transport costs, the liquid hydrogen costs decrease by 10% and the ammonia costs stay the same. However, the influence this has on the difference between the liquid hydrogen and ammonia costs (with the liquid hydrogen transport and storage costs being higher than those of ammonia) depends on how big this difference is compared to the liquid hydrogen costs. If the difference between the liquid hydrogen and ammonia costs is relatively small, the effect of a reduction of the liquid hydrogen costs will be bigger. The change of the cost difference is most important, as this cost difference determines how fast the ‘tipping point’ (where ammonia becomes more beneficial than liquid hydrogen) is reached. In this case, the difference in transport costs is reduced by 34%, while the difference in storage costs is only reduced by 11%. This is why the 10% transport cost reduction has a relatively stronger effect than the 10% storage cost reduction, leading to a steeper slope of the dividing line.

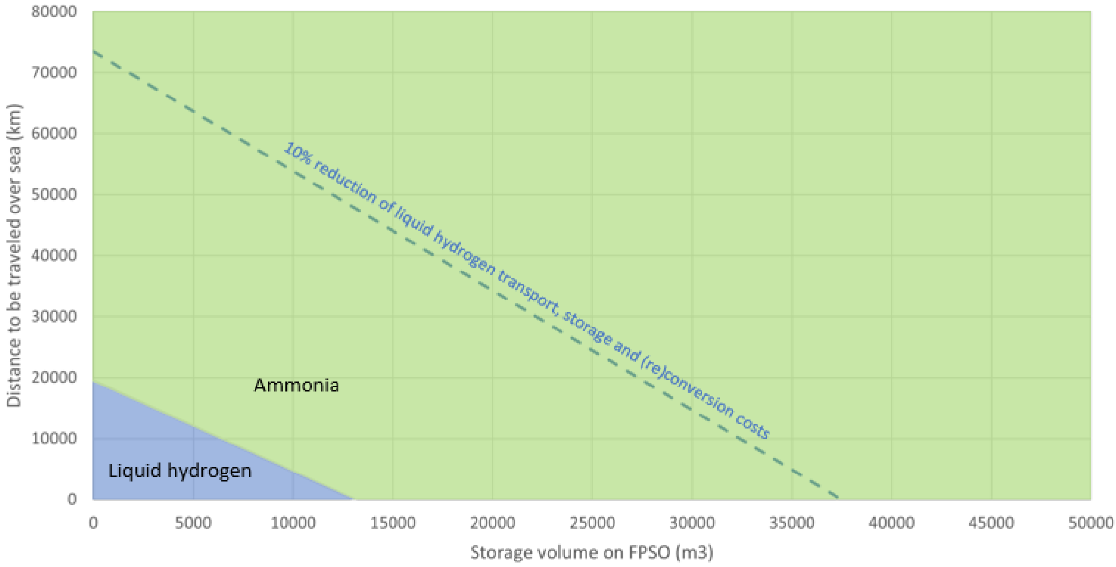


Figure 6.40: Visualization of preference for liquid hydrogen or ammonia based on distance to be traveled over sea and storage volume on the FPSO for scenario 1 in 2050

Chapter 7

Discussion

In this Chapter, the findings of this research will be discussed further, answering the seven sub-questions as formulated in Section 1.3. Based on the discussion in this chapter, the main research question will be answered in Chapter 8. Below, the answer to each sub-question will be discussed separately.

1. *How can the model for this research be set up such that it allows for the collection of insights leading to the most complete and reliable answer to the main research question?*

This sub-question was answered by the literature review in Chapter 2. In this literature review, the primary gap in literature was identified and the most suitable modelling method and model focus to fill this gap were found. It was also discussed how to best implement the model and which technologies to include. In Chapter 3, the actual model was drafted based on the findings of the literature review.

For the modelling method, mixed integer quadratically constrained programming (MIQCP) was chosen, since it was expected that quadratic constraints and objective terms could arise in the model due to the choice between ammonia and liquid hydrogen. This indeed turned out to be the case when setting up the model. Furthermore, the MIQCP model was able to converge within reasonable time limits, while giving the optimal solutions. This means MIQCP turned out to be a suitable choice for this research.

The focus of the model was put on the optimization of the far offshore green hydrogen supply chain. An overview of the reasons for this choice was given in Table 2.2. The main reasons for choosing this focus were the availability of data, the insights to be created with this focus and the usability of the model to be developed in further research. Although it was still challenging to find the needed data, all necessary data was eventually found. Furthermore, the insights created matched those indicated in Table 2.2 and these insights were pivotal in answering the main research question. Finally, the model drafted in this research can indeed be used relatively easily by follow-up research to analyze additional scenarios and/or new technologies. Therefore, it may be concluded that the focus of the model chosen in this research was satisfactory.

Next, it was decided to implement the model in Python, handle the input data in Excel and use the Gurobi optimization solver. Python provided all the necessary functions for the model and allowed for the usage of libraries such as PVlib and WindPowerlib, which were crucial for the functioning of the model. Handling the input data in Excel made adjusting this data quick and convenient during the analysis of many different scenarios. The Gurobi optimization solver was able to solve the model relatively quickly, which was necessary since many optimizations had to be run and the developed model can take some effort to solve, as it contains both quadratic constraints and several integer variables.

Based on the findings in the literature review, the model was set up. It was attempted to make this model as realistic as possible and the most important factors were included. As described in Chapter 4, the model has been verified extensively. It is therefore considered probable that the model is functioning as intended, although validation would still be desirable once real life cases are available. Several simplifications were however implemented in the model. For example, the model could be made more accurate by including limitations on offshore space usage, as for example done for onshore space by Salmon and Bañares-Alcántara (2022). Furthermore, the effects of economies of scale could be considered, as the scale influences the costs, with large-scale deployment leading to lower costs (International Energy Agency, 2020). In addition, the costs of longer electricity cables for bigger wind parks could be taken into account, since the electrical infrastructure of offshore wind farms contributes significantly to the capital expenses (Taylor et al., 2023). Also, differences in OPEX worldwide could be taken into consideration, as they can be significant (C. van der Nat, personal communication, September 6, 2023). Furthermore, a more accurate estimation of the distance to be traveled over sea could be made, using for example shipping routes from the AIS database as done by Salmon and Bañares-Alcántara (2022). Next, a more accurate estimation of the amount of conversion devices needed could be an important improvement to the model, as these represent a significant part of the costs when using ammonia and these are now determined directly based on the yearly production, their production capacity and a correction factor. In addition, a more accurate estimation of the size of an ammonia FPSO could be made, as this was now based solely on the size of a liquid hydrogen FPSO (J. Lee et al., 2023) and some additional assumptions. Finally, it could be considered to add the option of using batteries for temporary energy storage on the FPSO to the model. This could decrease electrolyzer downtime and losses of surplus energy production, but would also add additional costs. (Woznicki et al., 2020) Although the model may be functioning as intended, the implemented simplifications will still lead to inaccuracies. These simplifications present opportunities for follow-up research to extend the model and make it even more accurate.

In addition to expanding the current model, follow-up research may also find opportunities in setting up additional models to analyze the far offshore green hydrogen supply chain from a different perspective. Follow-up research could for example develop a model to look into the optimization between storage volume in green hydrogen FPSO's and the amount of transport ships in a worldwide network of several production locations, as described in Subsection 3.1.5 as well. Next to this, follow-up research could expand the model developed in this research to pick its production or usage location as a variable of the optimization once the other has been chosen (somewhat similar to how this is done by Brändle et al. (2021)), which would lead to even more optimized far offshore green hydrogen supply chains than those found with the current model if the rest of the current modelling approach is retained. In addition, follow-up research could conduct a more high-level analysis of the worldwide potential of far offshore green hydrogen, automatically analysing many different scenarios and the interaction with green hydrogen alternatives to create a complete overview, which was described in more detail in Subsection 2.3.1. This would however require very significant computing power and development time. Finally, unmoored floating production (Connolly & Crawford, 2022; Raisanen et al., 2022) and wave energy converters (Kasiulis et al., 2022) could be considered in follow-up research once sufficient input data is available.

2. *Which scenarios should be analysed in order to obtain an as complete as possible overview of the potential of far offshore green hydrogen and the relevant technologies around the world and over time?*

In Section 3.3, the scenarios to be analyzed to create a first idea of the worldwide potential of far offshore green hydrogen production over time were defined. In Figures 3.17 and 3.18, the potential production and usage locations identified as high potential were shown respectively. These production and usage locations were combined to create six high potential scenarios to be used to assess the worldwide potential of far offshore green hydrogen production, as shown in Table 3.3.

Naturally, as the high potential scenarios had to be identified qualitatively, it cannot be guaranteed that they are the highest potential scenarios worldwide. However, it is expected that they are among the highest potential scenarios, which is strengthened by the fact that the found costs of far offshore green hydrogen production are close to the costs of alternatives. It is therefore expected that with these scenarios, it was possible to give a good first overview of the worldwide potential of far offshore green hydrogen.

Furthermore, not all usage locations are covered as only six scenarios were looked at. Therefore, the competitiveness of far offshore green hydrogen production in other (lower potential) scenarios was not shown by this research. However, as it was found that far offshore green hydrogen production is already not the clearly preferred choice from a techno-economic perspective in the analyzed high potential scenarios, it is expected that its potential will be relatively low from an economic perspective in scenarios with very good alternative green hydrogen supply options. However, to further explore this, follow-up research could use the developed model to simulate a more diverse range of scenarios to increase the insight into the worldwide potential of far offshore green hydrogen and especially the cost difference with alternative green hydrogen options in scenarios which are less favourable for far offshore green hydrogen.

3. *What are the values of the relevant techno-economic parameters of the considered technologies and the other needed input data?*

In Chapter 5, most of the input data for the model developed in this research was shown. In Chapter 6, some additional scenario-specific input data was shown for each scenario as well. The weather data over the 10 month reference period needed as input for the model was retrieved from the ERA5 weather database, and translated to wind turbine and solar platform power output using PVlib and WindPowerlib.

When gathering the input data, it has been attempted to create an as complete and reliable set of input data as possible. However, for some parameters, assumptions had to be made, which has been indicated in the tables in Chapter 5. The current set of input data has allowed the creation of a first look into the future potential of far offshore green hydrogen production. However, if follow-up research uses the developed model again, the input data should be reconsidered based on the research available at that point in time, as a lot of progress is being made in the hydrogen knowledge base at the moment and this is expected to continue in the foreseeable future. In addition, once sufficient data is available, it could be attempted to take into account the uncertainty in the input data to determine the uncertainty of the output, as for example done by Brändle et al. (2021). The current set of input data is subject to uncertainties and the exact extent of these uncertainties is not yet known. Finally, many in-depth technical studies are still needed to increase data availability and reliability. An example of this is the liquid hydrogen FPSO concept design made by J. Lee et al. (2023), which served as a valuable input data source for this research.

In order to assess the potential of far offshore green hydrogen, its costs were compared to its alternatives. To find the costs of green hydrogen produced locally and imported green hydrogen, this research has relied heavily on the model made by Brändle et al. (2021), which also has several limitations. Brändle et al. (2021) do not consider interaction between hydrogen production and the regular power system, which is usually the case in reality for onshore green hydrogen production. Also, they do not take into account the competition for renewable energy resources between green hydrogen and regular renewable energy. This limitation has been taken into account in this research when analyzing the scenario's, as mentioned in Chapter 6. Next, their model does not consider in-country transportation costs, leading to an underestimation of import costs, especially from larger countries such as China. Lastly, they only consider transport as gaseous or liquid hydrogen and not for example as ammonia, possibly leading to an overestimation of the costs.

Finally, the hydrogen demand estimations used in this research were taken from The Hydrogen Council and McKinsey & Company (2021). This study used similar assumptions with regards to the timeline to a net-zero economy as those taken in this research (net-zero in 2050), which made their demand estimations suitable to be used in this research, although they may be considered ambitious.

4. *In what locations and under which circumstances could far offshore green hydrogen production already be feasible from a techno-economic perspective at this moment?*

After the first three sub-questions focused on the model to be set up, the scenarios to be defined and the input data to be gathered, the remaining sub-questions could focus on the insights to be gained from the results. In Chapter 6, the results were presented. When looking at the results of the scenario analyses, it can be seen clearly that between 2020 and 2035, the costs of far offshore green hydrogen production are decreasing strongly, but are still significantly higher than the costs of its alternatives across all scenarios. This means that at this point in time, far offshore green hydrogen production is not feasible from a techno-economic perspective in any location, unless very strong external factors such as space shortage onshore would have an influence in specific scenarios. The reason the costs are still this high in the earlier years is the fact that many of the technologies included in far offshore green hydrogen supply chains are still in development, such as floating wind, floating solar and PEM electrolyzers. Because of this, their costs are still decreasing significantly, which is especially the case until 2035, but will also continue after that.

5. *In what other locations or scenarios could far offshore green hydrogen production become feasible from a techno-economic perspective, and when is this expected?*

As mentioned before, the scenario results were discussed in Chapter 6. When analysing the scenarios, significant differences could be seen between them. In the scenarios with hydrogen usage in Cologne (Germany) and New York (USA), alternatives to far offshore green hydrogen were clearly more economic over the entire period considered under the current assumptions, although the costs were in the same order of magnitude, especially from 2035 to 2050. These alternative green hydrogen options also did not seem to be geopolitically sensitive, as they consisted of local production for the USA and (mostly) production within Europe for Germany. The potential of far offshore green hydrogen could however be increased in the case of Germany and the USA by societal factors, such as resistance against onshore production by local residents in potential onshore green hydrogen production locations.

For Japan and South Korea, alternatives to far offshore green hydrogen were also more attractive from a purely economic standpoint (especially between 2020 and 2035). Geopolitical considerations could however play a role, since Japan has a possible far offshore green hydrogen production location in its exclusive economic zone. For Singapore, far offshore green hydrogen seemed to be approximately as attractive as importing green hydrogen from China from an economic perspective between 2035 and 2050 under the current assumptions. This means both could share the market or the Singaporean government could choose between the two. Lastly, New Zealand has cheap local production possibilities. However, if these turn out not to be sufficient to fulfill demand, far offshore production could be attractive. New Zealand has a very high potential far offshore production location within its exclusive economic zone, leading to far offshore green hydrogen costs at par or even below the costs of importing green hydrogen from China between 2032 and 2050.

Looking at the results of the scenarios, it may be concluded that far offshore green hydrogen costs will be in the same order of magnitude as its alternatives, especially as we get closer to 2050. In some of the analyzed scenarios, far offshore green hydrogen was the slightly less economic option under the current assumptions (especially between 2020 and 2035), while in other scenarios it was very close to or at par with its alternatives. Far offshore green hydrogen production was however not the clear choice from a purely economic perspective in any of the analyzed scenarios, which were already high potential scenarios for far offshore green hydrogen. Therefore, it is expected that far offshore green hydrogen will not have a strong preference over alternative green hydrogen options in any scenario worldwide towards 2050 from an economic perspective, although it will be at par with its alternatives in certain scenarios after 2032 or 2035.

Next to the (techno-)economic perspective however, a lot of other, less tangible factors may play a role in the potential of far offshore green hydrogen. The geopolitical side has already been discussed per scenario in Chapter 6. In addition, societal factors could play a big role. Low cost hydrogen production countries could decide not to produce hydrogen (at their maximum capacity), for example because they want to put their investments elsewhere or because they want to preserve their landscape. The latter presents a major benefit of far offshore green hydrogen production and forms a main argument for its feasibility for some. Taking into account these considerations and the fact that far offshore green hydrogen costs seem to be in the same order of magnitude as its alternatives from 2035 onwards in all scenarios, it may be concluded that the potential of far offshore green hydrogen has been shown and further research is expected to be worthwhile. Follow-up research should take a closer look at the exact influence of geopolitical and societal factors on the potential of far offshore green hydrogen.

Furthermore, this research has compared the delivered costs of pure green hydrogen produced far offshore to green hydrogen alternatives to make sure a clear and fair comparison could be made. However, because of this, opportunities to for example deliver ammonia produced far offshore directly (instead of converting it back to hydrogen) have not been taken into account. The direct usage of ammonia produced far offshore could present opportunities that have been missed in this research and those possibilities should therefore be looked at further, especially now this research has shown that green hydrogen produced far offshore can be delivered at a cost in the same order of magnitude as its alternatives.

Finally, where possible, the same (cost) assumptions have been used in the model developed in this research as those used in the model made by Brändle et al. (2021), which was used to determine the costs of green hydrogen alternatives. For example, the same interest rate has been used. In addition, the scope is very similar; both models include production and transport, and both assume delivery as pure hydrogen. Differences in assumptions can be seen in the fact that the model made by Brändle et al. (2021) only considers liquid hydrogen as transport medium (as mentioned before), whereas the model developed in this research also considers ammonia. In addition, the model made by Brändle et al. (2021) does not consider inland transport of hydrogen to/from a specific production or usage location within a country, as mentioned before. The model developed in this research does consider this inland transport (from a transfer port to the final usage location) as this makes the result more realistic, but the additional costs caused by this are relatively small. Lastly, the model developed in this research assumes that the produced green hydrogen is delivered directly and not stored at the import terminal, whereas the model developed by Brändle et al. (2021) does take this into account. The expected effect of adding storage at the import terminal on the found far offshore green hydrogen costs in this research is however expected to be small, as ammonia is used as transport medium in all the considered scenarios and ammonia storage is relatively inexpensive.

6. *What is the influence of various aspects of the far offshore green hydrogen supply chain on the eventual far offshore green hydrogen costs?*

To better understand the results discussed when answering sub-questions 4 and 5, this sub-question was included. By answering this question, insight is gained into how the found results may change when certain input parameters change. Subsections 6.7.2 and 6.7.3 looked at the distribution of the total far offshore green hydrogen costs and the sensitivity of these total costs to changes of various input data respectively. Subsection 6.7.2 showed that the high costs in 2020 are mostly caused by high energy generation costs and that these energy generation costs decrease strongly over the years, not only in absolute value, but also relative to the other cost components. Furthermore, it showed that the electrolysis costs decrease approximately at the same rate as the total costs. Lastly, it was found that certain cost components, among which the FPSO costs and ammonia (re)conversion costs, do not decrease and therefore start to]represent a bigger percentage of the total costs over the years. The exact cost distribution and its development depend on the scenario and it may be influenced by uncertainty in the input data. The main trends identified are however seen in all scenarios.

The sensitivity analysis in Subsection 6.7.3 showed that the interest rate, floating wind costs, floating solar costs, ammonia (re)conversion costs, FPSO costs and large changes in water depth can have a significant influence on the costs per kilogram of hydrogen. In addition, it was found that dampening and enhancing effects can be seen when changing the costs of floating wind, floating solar and the electrolyzers, since they are able to replace each other. The influence of changing the desalination costs, liquid hydrogen and ammonia transport costs, electrolyzer costs and distance to shore was found to be limited. The same was found for changing the size of the hydrogen demand, although this was attributed to modelling simplifications. This means that because of modelling simplifications, some effects that are there in reality cannot be seen in the model results, such as the effect of economies of scale. Because the input data and scenarios were chosen with these limitations of the model in mind, it is however expected that their effect on the results is limited.

7. *Which (combinations of) technologies are most promising in the far offshore green hydrogen supply chain and under what circumstances?*

In Chapter 2, it was decided which technologies to include in the model based on their current and expected techno-economic feasibility as presented in literature. This already partly answered this sub-question. It was decided to use PEM electrolyzers with desalination and focus on centralized hydrogen production on an FPSO. In addition, it was decided to consider moored floating wind and floating solar for the energy generation, and to include ammonia and liquid hydrogen as transport medium options. Although the scope of possible technologies was narrowed through the literature review, the results of the optimizations have given a lot of additional information on this topic.

In the results of the optimizations, the potential of combining wind and solar energy generation to achieve a more steady energy production in order to reduce the total costs could be seen clearly. It should however be noted that it was not found to be beneficial in every scenario and that the installed solar capacity was small compared to the installed wind capacity in most cases. Furthermore, it could be seen that the specific scenario and the costs of the different kinds equipment (which each change at their own rate from year to year) greatly influence the most optimal combination of wind turbines, solar platforms and electrolyzers. As there are uncertainties in this input data, this may influence the most optimal combination of these different equipment types in the scenarios analysed in this research. However, this is not expected to change the fact that combining wind and solar creates a more steady energy production in most scenarios, which often has a positive effect on the total costs of the produced hydrogen.

Next, the results also showed a preference for ammonia as the transport and storage medium across all scenarios until 2050. The sensitivity analysis in Subsection 6.7.3 did however show that in the years close to 2050, the liquid hydrogen costs are quite close to the ammonia costs. The choice between ammonia and liquid hydrogen is strongly influenced by the development of their transport, storage and conversion costs, especially those of liquid hydrogen, as they are expected to decrease much more than those of ammonia. Uncertainty in this input data may influence the choice between ammonia and liquid hydrogen. In addition, the scenario is important for this choice, since the distance to be transported over, the storage volume needed on the FPSO and the costs of power generation have an influence. In Figure 6.40, the influence of the distance to be transported over and the storage volume on the FPSO was shown, also considering the effect of a reduction in liquid hydrogen costs.

Having answered all sub-questions, the main research question can now be answered, which will be done in Chapter 8. Despite the possible uncertainties in this research mentioned in this chapter when discussing the answers to the sub-questions, valuable first insights were created in the potential of far offshore green hydrogen production. It was shown when and in which scenarios far offshore green hydrogen may become feasible, creating direct insight into its 'theoretical' techno-economic feasibility and discussing the extension to its practical feasibility as well. Furthermore, overarching analyses were also done, creating additional insight into the potential of different technologies and their combinations, and the aspects of the far offshore green hydrogen supply chain that will contribute to its costs most over the years. Finally, it was shown how sensitive the far offshore green hydrogen costs are to different aspects. With all of this, valuable insight into the potential future of far offshore green hydrogen has been created and a foundation has been laid for further research into this topic.

Chapter 8

Conclusion

Based on the discussion of all sub-questions in Chapter 7, the main research question as formulated in Section 1.3 may now be answered.

Which role is far offshore green hydrogen able to play in the path towards a worldwide net-zero economy in 2050, how is this influenced by various factors, and which technologies are expected to be integrated in its supply chains, looking at both the technological and economic feasibility?

The answer to the first part of the main research question is twofold: from a purely techno-economic perspective, the role far offshore green hydrogen production is able to play in the path towards a worldwide net-zero economy in 2050 is relatively small and limited to a few specific scenarios in the period after 2032. In practice however, it may play a bigger role, as its costs are in the same order of magnitude as its alternatives and it has several additional, less tangible benefits that may cause decision makers to opt for far offshore green hydrogen after all.

The second part of the main research question was answered through the analysis of the cost distributions and the sensitivity analysis. It was found that the interest rate, floating wind costs, floating solar costs, ammonia (re)conversion costs, FPSO costs and large changes in water depth have a relatively large influence on the costs per kilogram of hydrogen. Dampening and enhancing effects were also observed when changing the floating wind, floating solar and electrolyzer costs, as they are able to substitute each other. Furthermore, it was found that the desalination costs, liquid hydrogen and ammonia transport costs, electrolyzer costs, distance to shore and size of the hydrogen demand have a relatively small influence. The small influence of the last one was however attributed to model simplifications. Finally, it was found that the cost distribution of far offshore green hydrogen will develop strongly over the years. In 2050, the optimizations predict the ammonia (re)conversion costs to account for the biggest part of the total costs, closely followed by the energy generation.

The third and last part of the main research question had already been answered partly in the literature review, as mentioned before. There it was for example already concluded that PEM electrolyzers (with desalination) would be most suitable for far offshore green hydrogen production and that the research would focus on centralized hydrogen production on an FPSO. Looking at the results of the optimizations performed in this research, as was done in Section 6.7, has given further insights. It was confirmed that combining wind and solar energy generation in far offshore hydrogen production can be beneficial, but it was also found that this not the case in every scenario. In addition, it was concluded that the optimal combination of wind turbines, solar platforms and electrolyzers strongly depends on the production location and the year considered. Furthermore, it was found that until at least 2050, ammonia is expected to be the most suitable transport medium for green hydrogen produced far offshore under the current assumptions.

Having answered all three parts of the main research question, a tangible outlook on the worldwide potential of far offshore green hydrogen towards 2050 has been created. This outlook, together with the developed model and gathered input data, will form a base from which future research will be able to explore this new and exciting research field in various directions. This way, the current research may be one of the first bricks in the wall for the development of a future where far offshore green hydrogen is a part of our energy mix.

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Appendix A

In this appendix, the method applied during the literature retrieval will be explained. Three tables were drafted. The first table is mainly meant to increase the repeatability of the research and contains the search terms used and the title, year of publication, authors and DOI of each reference. Also, each reference has been assigned a unique identification code in this table, which is used in the other two tables to identify the paper and indicates its relevance. The identification codes can start with an A, B, C or D. References deemed (mainly) relevant for assessing the available knowledge and the gaps in the literature have been put in categories A and B, while references containing relevant information regarding the methods to be used have been put in categories C and D. Papers that could be placed in category A or B, but also contain relevant information regarding possible methods, have been placed in category A or B, but with an indication that their method is also relevant. Categories A and C contain the papers that are most relevant for this research. Categories B and D contain papers that also have some relevance for the intended research (for example a specific result, part of a method or the data used), but are not relevant in their entirety.

The second and third table are meant to allow readers to quickly understand the contents of the reviewed sources, showing which topics are discussed in each paper and giving a one-sentence summary of each reference. This will allow for a rapid identification of the existing gaps in the literature, but also to easily find papers on a certain topic. The tables are included in the appendix of this research, but have originally been drafted in Microsoft Excel. Using the table function in this program, the references regarding a certain topic (included as a column in the table) can be filtered out easily, leading to large time savings when searching for specific topics in the retrieved literature. Table 2 includes the references in categories A and B, and Table 3 those in categories C and D. Once the tables were drafted, they were used right away to quickly find the relevant papers and identify gaps in literature during the writing of the rest of this literature review. The first table is included in this appendix, the second table in Appendix B and the third table in Appendix C.

Search terms	Title	Year	Authors	DOI	Paper ID
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	A review of energy extraction from wind and ocean: Technologies, merits, efficiencies, and cost	2022	Shafiqur Rehman a , Luai M. Alhems, Md. Mahbub Alam, Longjun Wang, Zakria Toor	https://doi.org/10.1016/j.oceaneng.2022.113192	A001
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Feasibility of offshore wind turbines for linkage with onshore green hydrogen demands: A comparative economic analysis	2023	Ayeon Kim, Heehyang Kim, Changgwon Choe, Hankwon Lim	https://doi.org/10.1016/j.enconman.2023.116662	A002
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	International competitiveness of low-carbon hydrogen supply to the Northwest European market	2022	Peter Perey, Machiel Mulder	https://doi.org/10.1016/j.ijhydene.2022.10.011	A003
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Review of Key Technologies for Offshore Floating Wind Power Generation	2023	Bowen Zhou, Zhibo Zhang, Guangdi Li, Dongsheng Yang, Matilde Santos	https://doi.org/10.3390/en16020710	A004
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Techno-economic assessment of offshore wind-to-hydrogen scenarios: A UK case study	2023	Alessandro Giampieri , Janie Ling-Chin, Anthony Paul Roskilly	https://doi.org/10.1016/j.ijhydene.2023.01.346	A005
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Assessment of offloading pathways for wind-powered offshore hydrogen production: Energy and economic analysis	2021	Brais Armino Franco, Patrícia Baptista , Rui Costa Neto, Sofia Ganilha	https://doi.org/10.1016/j.apenergy.2021.116553	A006
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Estimating long-term global supply costs for low-carbon hydrogen	2021	Gregor Brändle, Max Schönfisch , Simon Schulte	https://doi.org/10.1016/j.apenergy.2021.117481	A007
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Hydrogen Production from Offshore Wind Parks: Current Situation and Future Perspectives	2021	Gonçalo Calado, Rui Castro	https://doi.org/10.3390/app11125561	A008
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Techno-economic analysis and Monte Carlo simulation for green hydrogen production using offshore wind power plant	2022	Dohyung Jang, Kilwon Kim, Kyong-Hwan Kim, Sanggyu Kang	https://doi.org/10.1016/j.enconman.2022.115695	A009
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Techno-economic feasibility of fleets of far offshore hydrogen-producing wind energy converters	2018	Aurelien Babarit, Jean-Christophe Gilloteaux, Ga€el Clodic, Maxime Duchet, Alexandre Simoneau, Max F. Platzer	https://doi.org/10.1016/j.ijhydene.2018.02.144	A010
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	A technical evaluation to analyse of potential repurposing of submarine pipelines for hydrogen and CCS using survival analysis	2022	Ramy Magdy A. Mahmoud, Paul E. Dodds	https://doi.org/10.1016/j.oceaneng.2022.112893	B001
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Assessing benefits and costs of expanded green hydrogen production to facilitate fossil fuel exit in a net-zero transition	2022	Ian Maynard, Ahmed Abdulla	https://doi.org/10.1016/j.ref.2022.12.002	B002
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Co-located offshore wind–wave energy systems: Can motion suppression and reliable power generation be achieved simultaneously?	2022	Fantai Meng, Nataliia Sergiienko, Boyin Ding, Binzhen Zhou, Leandro Souza Pinheiro Da Silva, Benjamin Cazzolato, Ye Li	https://doi.org/10.1016/j.apenergy.2022.120373	B003
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Compressed air seesaw energy storage: A solution for long-term electricity storage	2023	Julian David Hunt, Behnam Zakeri, Andreas Nascimento, Jonas Rafael Gazoli, Fabio Tales Bindemann, Yoshihide Wada, Bas van Ruijven, Keywan Riahi	https://doi.org/10.1016/j.est.2023.106638	B004
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Floating offshore wind and the real options to relocat	2022	Jostein Tvedt	https://doi.org/10.1016/j.eneco.2022.106392	B005
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Green development strategy of offshore wind farm in China guided by life cycle assessment	2022	Jingjing Chen, Bingjing Mao, Yufeng Wu, Dongya Zhang, Yiqun Wei, Ang Yu, Lihong Peng	https://doi.org/10.1016/j.resconrec.2022.106652	B006
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Impact of accessibility on O&M of floating offshore wind turbines: Sensitivity of the deployment site	2022	M. Centeno-Telleria, J.I. Aizpurua, M. Penalba	https://doi.org/10.1201/9781003360773-94	B007
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Operation and maintenance optimization of offshore wind farms based on digital twin: A review	2022	Jiajun Xia, Guang Zou	https://doi.org/10.1016/j.oceaneng.2022.113322	B008
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Powering Europe with North Sea offshore wind: The impact of hydrogen investments on grid infrastructure and power prices	2022	Goran Durakovic, Pedro Crespo del Granado, Asgeir Tomasgard	https://doi.org/10.1016/j.energy.2022.125654	B009

(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Sensitivity study of the economics of a floating offshore wind farm. The case study of the SATH® concrete platform in the Atlantic waters of Europe	2023	Almudena Filgueira-Vizoso, David Cordal-Iglesias, Félix Puime-Guillén, Isabel Lamas-Galdo, Araceli Martínez-Rubio, Irati Larrinaga-Calderón, Laura Castro-Santos	https://doi.org/10.1016/j.egyr.2023.01.091	B010
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Technology Assessment of offshore wind turbines: Floating platforms – Validated by case study	2022	Ammar Alkhalidi, Hazem Kaylani, Noureddine Alawawdeh	https://doi.org/10.1016/j.rineng.2022.100831	B011
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	The power balancing benefits of wave energy converters in offshore wind-wave farms with energy storage	2022	Jocelyn M. Kluger, Maha N. Haji, Alexander H. Slocum	https://doi.org/10.1016/j.apenergy.2022.120389	B012
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Towards 100% renewable energy systems: The role of hydrogen and batteries	2022	Paolo Marocco, Riccardo Novo, Andrea Lanzini, Giuliana Mattiazzo, Massimo Santarelli	https://doi.org/10.1016/j.est.2022.106306	B013
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	An analytical cost model for co-located floating wind-wave energy arrays	2018	Caitlyn E. Clark, Annalise Miller, Bryony DuPont	https://doi.org/10.1016/j.renene.2018.08.043	B014
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Country-specific cost projections for renewable hydrogen production through off-grid electricity systems	2021	Jacob L.L.C.C. Janssen, Marcel Weeda, Remko J. Detz, Bob van der Zwaan	https://doi.org/10.1016/j.apenergy.2021.118398	B015
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Ecological and economic cost-benefit analysis of offshore wind energy	2008	Brian Snyder, Mark J. Kaiser	https://doi.org/10.1016/j.renene.2008.11.015	B016
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Life cycle cost-benefit analysis of offshore wind energy under the climatic conditions in Southeast Asia – Setting the bottom-line for deployment	2018	Victor Nian, Yang Liu, Sheng Zhong	https://doi.org/10.1016/j.apenergy.2018.10.042	B017
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	MINIMIZING COST IN A 100% RENEWABLE ELECTRICITY GRID: A CASE STUDY OF WAVE ENERGY IN CALIFORNIA	2022	Ryan G. Coe, George Lavidas, Giorgio Bacelli, Peter H. Kobos, Vincent S. Neary	http://dx.doi.org/10.1115/OMAE2022-80731	B018
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Optimum Turbine Design for Hydrogen Production from Offshore Wind	2022	Mihir Mehta, Michiel Zaaijer, Dominic von Terzi	https://doi.org/10.1088/1742-6596/2265/4/042061	B019
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	PERFORMANCE ANALYSIS OF OFFSHORE MONO-PILE WIND TURBINE CO-LOCATED WITH FLOATING PHOTOVOLTAIC SYSTEMS IN SHARK BAY, AUSTRALIA	2021	Morteza Bahadori, Hassan Ghassemi	http://dx.doi.org/10.1115/OMAE2021-63852	B020
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Pooling the cable: A techno-economic feasibility study of integrating offshore floating photovoltaic solar technology within an offshore wind park	2020	S.Z.M. Golroodbari, D.F. Vaartjes, J.B.L. Meit, A.P. van Hoeken, M. Eberveld, H. Jonker, W.G.J.H.M. van Sark	https://doi.org/10.1016/j.solener.2020.12.062	B021
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Renewable Energy from Oceans	2019	K. Narula	https://doi.org/10.1007/978-981-13-1589-3_8	B022
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Review of Hybrid Offshore Wind and Wave Energy Systems	2016	Kaylie L. McTiernan, Krish Thiagarajan Sharman	https://doi.org/10.1088/1742-6596/1452/1/012016	B023
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Techno-economic analysis of offshore wind PEM water electrolysis for H2 production	2022	Hugo Groenemans, Genevieve Saur, Cortney Mittelsteadt, Judith Lattimer, Hui Xu	https://doi.org/10.1016/j.coche.2022.100828	B024
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Techno-Economic Analysis of Low Carbon Hydrogen Production from Offshore Wind Using Battolyser Technology	2022	Brian Jenkins, David Squires , John Barton, Dani Strickland, K. G. U. Wijayantha, James Carroll , Jonathan Wilson, Matthew Brenton, Murray Thomson	https://doi.org/10.3390/en15165796	B025
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	A geospatial method for estimating the levelised cost of hydrogen production from offshore wind	2023	Quang Vu Dinh, Van Nguyen Dinh, Hadi Mosadeghi, Pedro H. Todesco Pereira, Paul G. Leahy	https://doi.org/10.1016/j.ijhydene.2023.01.016	C001
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	A multi-criteria methodology for wind energy resource assessment and development at an intercontinental level: Facing low-carbon energy transitio	2022	Jiawei Wu, Jinyu Xiao, Jinming Hou, Wei Sun, Peng Li, Xunyan Lyu	https://doi.org/10.1049/rpg2.12590	C002

(wind OR solar OR wave OR hydrogen) AND offshore AND cost	An overview of the offshore wind energy potential for twelve significant geographical locations across the globe	2022	Alexandra Ionelia Diaconita, Gabriel Andrei, Liliana Rusu	https://doi.org/10.1016/j.egyr.2022.10.193	C003
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Scenario generation and risk-averse stochastic portfolio optimization applied to offshore renewable energy technologies	2023	Victor A.D. Faria, Anderson Rodrigo de Queiroz, Joseph F. DeCarolis	https://doi.org/10.1016/j.energy.2023.126946	C004
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	An integrated decision support model for design and operation of a wind-based hydrogen supply system	2016	Minsoo Kim, Jiyong Kim	http://dx.doi.org/10.1016/j.ijhydene.2016.10.129	C005
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Capital expenditure and levelized cost of electricity of photovoltaic plants and wind turbines e Development by 2050	2021	Lucas Sens, Ulf Neuling , Martin Kaltschmitt	https://doi.org/10.1016/j.renene.2021.12.042	C006
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Development of a viability assessment model for hydrogen production from dedicated offshore wind farms	2020	Van Nguyen Dinh, Paul Leahy, Eamon McKeogh, Jimmy Murphy, Val Cummins	https://doi.org/10.1016/j.ijhydene.2020.04.232	C007
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	A Case Study: Layout Optimization of Three Gorges Wind Farm Pakistan, Using Genetic Algorithm	2022	Muhammad Bin Ali, Zeshan Ahmad, Saad Alshahrani, Muhammad Rizwan Younis, Irsa Talib, Muhammad Imran	https://doi.org/10.3390/su142416960	D001
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	A Hierarchical Met-Ocean Data Selection Model for Fast O&M Simulation in Offshore Renewable Energy Systems	2023	Hailun Xie, Lars Johanning	https://doi.org/10.3390/en16031471	D002
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Investigation of layout optimization for offshore wind farms and a case study for a region in Turkey	2022	Baran Kaya, Elif Oguz	https://doi.org/10.1016/j.oceaneng.2022.112807	D003
(wind OR solar OR wave OR hydrogen) AND offshore AND cost		2022	Basem Elshafei, Alfredo Pena, Atanas Popov, Donald Giddings, Jie Ren, Dong Xu, Xuerui Mao	https://doi.org/10.1016/j.renene.2022.12.006	D004
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Wind farm array cable layout optimisation for complex offshore sites—A decomposition based heuristic approach	2022	Peter Taylor, Hong Yue, David Campos-Gaona, Olimpo Anaya-Lara, Chunjiang Jia	https://doi.org/ 10.1049/rpg2.12593	D005
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	A Software for Calculating the Economic Aspects of Floating Offshore Renewable Energies	2019	Laura Castro-Santos, Almudena Filgueira-Vizoso	http://dx.doi.org/10.3390/ijerph17010218	D006
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Electrolysis plant size optimization and benefit analysis of a far offshore wind-hydrogen system based on information gap decision theory and chance constraints programming	2021	Yuewen Jiang, Weijie Huang, Guoming Yang	https://doi.org/10.1016/j.ijhydene.2021.11.211	D007
(wind OR solar OR wave OR hydrogen) AND offshore AND cost	Methodology to Calculate the Costs of a Floating Offshore Renewable Energy Farm	2016	Laura Castro-Santos, Elson Martins, C. Guedes Soares	https://doi.org/10.3390/en9050324	D008
(wind OR solar OR wave OR hydrogen) AND offshore AND econom*	Sensitivity study of the economics of a floating offshore wind farm. The case study of the SATH® concrete platform in the Atlantic waters of Europe	2023	Almudena Filgueira-Vizoso, David Cordal-Iglesias, Félix Puime-Guillén, Isabel Lamas-Galdo, Araceli Martínez-Rubio, Irati Larrinaga-Calderón, Laura Castro-Santos	https://doi.org/10.1016/j.egyr.2023.01.091	A036
(wind OR solar OR wave OR hydrogen) AND offshore AND econom*	Design and Techno-Economic Analysis of a Novel Hybrid Offshore Wind and Wave Energy System	2022	Ermando Petracca, Emilio Faraggiana, Alberto Ghigo, Massimo Sirigu, Giovanni Bracco, Giuliana Mattiazzo	https://doi.org/10.3390/en15082739	B092
(wind OR solar OR wave OR hydrogen) AND offshore AND econom*	Developing large-scale offshore wind power programs: A choice experiment analysis in France	2022	Olivier Joalland, Pierre-Alexandre Mahieu	https://doi.org/10.1016/j.ecolecon.2022.107683	B093
(wind OR solar OR wave OR hydrogen) AND offshore AND econom*	Europe's onshore and offshore wind energy potential An assessment of environmental and economic constraints	2009	European Environment Agency	https://doi.org/10.2800/11373	B094
(wind OR solar OR wave OR hydrogen) AND offshore AND econom*	Evolution of offshore wind resources in Northern Europe under climate change	2023	A. Martinez, L. Murphy, G. Iglesias	https://doi.org/10.1016/j.energy.2023.126655	B095

(wind OR solar OR wave OR hydrogen) AND offshore AND econom*	Techno-economic analysis of offshore wind PEM water electrolysis for H2 production	2022	Hugo Groenemans, Genevieve Saur, Cortney Mittelsteadt, Judith Lattimer, Hui Xu	https://doi.org/10.1016/j.coche.2022.100828	B096
(wind OR solar OR wave OR hydrogen) AND offshore AND econom*	A Hierarchical Met-Ocean Data Selection Model for Fast O&M Simulation in Offshore Renewable Energy Systems	2023	Hailun Xie, Lars Johanning	https://doi.org/10.3390/en16031471	D026
(wind OR solar OR wave OR hydrogen) AND offshore AND econom*	The collocation feasibility index e A method for selecting sites for co-located wave and wind farms	2016	S. Astariz, G. Iglesias	http://dx.doi.org/10.1016/j.renene.2016.11.014	D027
far AND offshore AND hydrogen	Case study on the benefits and risks of green hydrogen production co-location at offshore wind farms	2022	Wei He, Yi Zheng, Shi You, Goran Strbac, Kasper T. Therkildsen, Gudmund P. Olsen, Aaron Howie, Eirik Byklum, Kamran T. Sharifabadi	https://doi.org/10.1088/1742-6596/2265/4/042035	A011
far AND offshore AND hydrogen	Far off-shore wind energy-based hydrogen production: Technological assessment and market valuation designs	2020	M Woznicki, G Le Solliec, R Loisel	https://doi.org/10.1088/1742-6596/1669/1/012004	A012
far AND offshore AND hydrogen	Energy and economic performance of the FARWIND energy system for sustainable fuel production from the far-offshore wind energy resource	2019	Aurélien Babarit, Jean-Christophe Gilloteaux, Edwin Body, Jean-François Hetet	https://doi.org/10.1109/EVER.2019.8813563	A013
far AND offshore AND hydrogen	Dedicated large-scale floating offshore wind to hydrogen: Assessing design variables in proposed typologies	2022	Omar S. Ibrahim, Alessandro Singlitico, Roberts Proskovics, Shane McDonagh, Cian Desmond, Jerry D. Murphy	https://doi.org/10.1016/j.rser.2022.112310	B026
far AND offshore AND hydrogen	Experimental validation of the energy ship concept for far-offshore wind energy conversion	2021	A. Babarit, N. Abdul Ghani, E. Brouillette, S. Delvoye, M. Weber, A. Merrien, M. Michou, J.-C. Gilloteaux	https://doi.org/10.1016/j.oceaneng.2021.109830	B027
far AND offshore AND hydrogen	Modelling a highly decarbonised North Sea energy system in 2050: A multinational approach	2021	Rafael Martínez-Gordóna, Manuel Sánchez-Diéguez, Amirhossein Fattahi, Germán Morales-España, Jos Sijm, André Faaij	https://doi.org/10.1016/j.adapen.2021.100080	B028
far AND offshore AND hydrogen	Optimizing hybrid offshore wind farms for cost competitive hydrogen production in Germany	2021	Michele Scolaro, Noah Kittner	https://doi.org/10.1016/j.ijhydene.2021.12.062	B029
far AND offshore AND hydrogen	Synergy of green hydrogen sector with offshore industries: Opportunities and challenges for a safe and sustainable hydrogen economy	2022	Sumit Kumar, Til Baalisampang, Ehsan Arzaghi, Vikram Garaniya, Rouzbeh Abbassi, Fatemeh Salehi	https://doi.org/10.1016/j.jclepro.2022.135545	B030
far AND offshore AND hydrogen	Wind Turbine Technology Trends	2022	Mladen Bošnjakovi, Marko Katini, Robert Santa, Dejan Mari	https://doi.org/10.3390/app12178653	B031
far AND offshore AND hydrogen	Offshore CO2 Capture and Utilization Using Floating Wind/PV Systems: Site Assessment and Efficiency Analysis in the Mediterranean	2022	Douglas Keller, Jr., Vishal Somanna, Philippe Drobinski, Cédric Tard	https://doi.org/10.3390/en15238873	C008
far AND offshore AND hydrogen	Developing a novel risk-based methodology for multi-criteria decision making in marine renewable energy applications	2016	Mohammad Mahdi Abaei, Ehsan Arzaghi, Rouzbeh Abbassi, Vikram Garaniya, Irene Penesis	http://dx.doi.org/10.1016/j.renene.2016.10.054	D009
far AND offshore AND hydrogen	Estimating hydrogen usage of a Crew Transport Vessel fleet for Offshore Windfarm maintenance	2023	Habbo Cramer, Annika Fitz, Arto Niemi, Bartosz Skobiej, Frank Sill Torres	https://doi.org/10.1007/s13437-023-00300-x	D010
far AND offshore AND hydrogen	Optimal strategies of deployment of far offshore co-located wind-wave energy farms	2021	Aitor Saenz-Aguirre, Jon Saenz, Alain Ulazia, Gabriel Ibarra-Berastegui	https://doi.org/10.1016/j.enconman.2021.114914	D011
far AND offshore AND renewable	An integrated conceptual model to characterize the effects of offshore wind farms on ecosystem services	2023	Yoann Baulaz, Maud Mouchet, Nathalie Niquil, Frida Ben Rais Lasram	https://doi.org/10.1016/j.ecoser.2023.101513	A014
far AND offshore AND renewable	Deriving Current Cost Requirements from Future Targets: Case Studies for Emerging Offshore Renewable Energy Technologies	2022	Shona Pennock, Anna Garcia-Teruel, Donald R. Noble, Owain Roberts, Adrian de Andres, Charlotte Cochrane, Henry Jeffrey	https://doi.org/10.3390/en15051732	A015

far AND offshore AND renewable	Floating Offshore Wind Turbines: Current Status and Future Prospects	2022	Mohammad Barooni, Turaj Ashuri, Deniz Velioglu Sogut, Stephen Wood, Shiva Ghaderpour Taleghani	https://doi.org/10.3390/en16010002	A016
far AND offshore AND renewable	Comparison of the capacity factor of stationary wind turbines and weather-routed energy ships in the far-offshore	2019	Roshamida ABD Jamil, Alisée Chaigneau, Jean-Christophe Gilloteaux, Philippe Lelong. AuréLien Babarit	https://doi.org/10.1088/1742-6596/1356/1/012001	A017
far AND offshore AND renewable	Analytical modelling of power production from Un-moored Floating Offshore Wind Turbines	2022	Patrick Connolly, Curran Crawford	https://doi.org/10.1016/j.oceaneng.2022.111794	B032
far AND offshore AND renewable	Analyzing Europe's Biggest Offshore Wind Farms: A Data Set with 40 Years of Hourly Wind Speeds and Electricity Production	2022	Oliver Grothe, Fabian Kächele, Mira Watermeyer	https://doi.org/10.3390/en15051700	B033
far AND offshore AND renewable	A Review of Offshore Renewable Energy in South America: Current Status and Future Perspectives	2023	Milad Shadman, Mateo Roldan-Carvajal, Fabian G. Pierart, Pablo Alejandro Haim, Rodrigo Alonso, Corbiniano Silva, Andrés F. Osorio, Nathalie Almonacid, Griselda Carreras, Mojtaba Maali Amiri, Santiago Arango-Aramburo, Miguel Angel Rosas, Mario Pelissero, Roberto Tula, Segen F. Estefen, Marcos Lafoz Pastor, Osvaldo Ronald Saavedra	https://doi.org/10.3390/su15021740	B034
far AND offshore AND renewable	Conceptualization and dynamic response of an integrated system with a semi-submersible floating wind turbine and two types of wave energy converters	2022	Hongjian Zhang, Ningchuan Zhang, Xinyu Cao	https://doi.org/10.1016/j.oceaneng.2022.113517	B035
far AND offshore AND renewable	Feasibility of Replacing Nuclear and Fossil Fuel Energy with Offshore Wind Energy: A Case for Taiwan	2022	Cheng-Dar Yue, I-Chun Wang, Jhou-Sheng Huang	https://doi.org/10.3390/en15072385	B036
far AND offshore AND renewable	Floating wind power in deep-sea area: Life cycle assessment of environmental impacts	2023	Weiyu Yuana, Jing-Chun Fenga, Si Zhang, Liwei Suna, Yanpeng Cai, Zhifeng Yanga, Songwei Sheng	https://doi.org/10.1016/j.adapen.2023.100122	B037
far AND offshore AND renewable	Floating offshore wind turbine – Heavy construction requirements	2022	Alan Crowle, Philipp R Thies	http://dx.doi.org/10.1201/9781003360773-72	B038
far AND offshore AND renewable	Integration of multitrophic aquaculture approach with marine energy projects for management and restoration of coastal ecosystems of India	2022	Kapilkumar Nivrutti Ingle, Mark Polikovsky, Mulugeta Chanie Fenta, Akash Sopan Ingle, Alexander Golberg	https://doi.org/10.1016/j.ecoleng.2021.106525	B039
far AND offshore AND renewable	More than a feeling: Analyzing community cognitive and affective perceptions of the Block Island offshore wind project	2022	Aaron Russell, Jeremy Firestone	https://doi.org/10.1016/j.renene.2022.05.032	B040
far AND offshore AND renewable	Pathways to low carbon energy transition through multi criteria assessment of offshore wind energy barriers	2022	Kannan Govindan	https://doi.org/10.1016/j.techfore.2022.122131	B041
far AND offshore AND renewable	Reconciling climate action with the need for biodiversity protection, restoration and rehabilitation	2022	Courtney E. Gorman, Andrew Torsney, Aoibheann Gaughran, Caroline M. McKeon, Catherine A. Farrell, Cian White, Ian Donohue, Jane C. Stout, Yvonne M. Buckley	http://dx.doi.org/10.1016/j.scitotenv.2022.159316	B042
far AND offshore AND renewable	Review of integrated installation technologies for offshore wind turbines: Current progress and future development trends	2022	Yaohua Guo, Haijun Wang, Jijian Lian	https://doi.org/10.1016/j.enconman.2022.115319	B043

far AND offshore AND renewable	UK perspective research landscape for offshore renewable energy and its role in delivering Net Zero	2022	Deborah Greaves, Siya Jin, Puiwah Wong, Dave White, Henry Jeffrey, Beth Scott, Ross Wigg	https://doi.org/10.1088/2516-1083/ac8c19	B044
far AND offshore AND renewable	Assessment of entanglement risk to marine megafauna due to offshore renewable energy mooring systems	2015	Violette Harnois, Helen C.M. Smith , Steven Benjamins, Lars Johanning	http://dx.doi.org/10.1016/j.ijome.2015.04.001	B045
far AND offshore AND renewable	Benthic effects of offshore renewables: identification of knowledge gaps and urgently needed research	2019	Jennifer Dannheim, Lena Bergström, Silvana N R Birchenough, Radosław Brzana, Arjen R Boon, Joop W P Coolen, Jean-Claude Dauvin, Ilse De Mesel, Jozefien Derweduwen, Andrew B Gill, Zoë L Hutchison, Angus C Jackson, Urszula Janas, Georg Martin, Aurore Raoux, Jan Reubens, Liis Rostin, Jan Vanaverbeke, Thomas A Wilding, Dan Wilhelmsson, Steven Degraer	http://dx.doi.org/10.1093/icesjms/fsz018	B046
far AND offshore AND renewable	Health and climate benefits of offshore wind facilities in the Mid-Atlantic United States	2016	Jonathan J Buonocore, Patrick Luckow, Jeremy Fisher, Willett Kempton, Jonathan I Levy	http://dx.doi.org/10.1088/1748-9326/11/7/074019	B047
far AND offshore AND renewable	The role of floating offshore wind in a renewable focused electricity system for Great Britain in 2050	2018	Andy Moore, James Price, Marianne Zeyringer	https://doi.org/10.1016/j.esr.2018.10.002	B048
far AND offshore AND renewable	Site selection of floating offshore wind through the levelised cost of energy: A case study in Ireland	2022	A. Martinez, G. Iglesias	https://doi.org/10.1016/j.enconman.2022.115802	C009
far AND offshore AND renewable	A novel metric for assessing wind and solar power complementarity based on three different fluctuation states and corresponding fluctuation amplitudes	2023	Guorui Ren, Wei Wang, Jie Wan, Feng Hong, Ke Yang	https://doi.org/10.1016/j.enconman.2023.116721	D012
FPSO AND hydrogen OR ammonia	Multi-objective optimization of liquid hydrogen FPSO at the conceptual design stage	2023	Jonghun Lee, Byeongwon Park, Kyoung-Hwan Kim, Won-Sun Ruy	https://doi.org/10.1016/j.ijnaoe.2022.100511	A040
green AND hydrogen	A comparison of the most promising low-carbon hydrogen production technologies	2023	Sandra Dermühl, Uwe Riedel	https://doi.org/10.1016/j.fuel.2023.127478	A018
green AND hydrogen	Building the green hydrogen market e Current state and outlook on green hydrogen demand and electrolyzer manufacturing	2022	Mona Wappler, Dilek Unguder, Xing Lu, Hendrik Ohlmeyer, Hannah Teschke, Wiebke Lueke	https://doi.org/10.1016/j.ijhydene.2022.07.253	A019
green AND hydrogen	Estimating global production and supply costs for green hydrogen and hydrogen-based green energy commodities	2022	Michael Moritz, Max Schonfisch, Simon Schulte	https://doi.org/10.1016/j.ijhydene.2022.12.046	A020
green AND hydrogen	On the bulk transport of green hydrogen at sea: Comparison between submarine pipeline and compressed and liquefied transport by ship	2023	Rafael d'Amore-Domenech, Vladimir L. Meca, Bruno G. Pollet, Teresa J. Leo	https://doi.org/10.1016/j.energy.2023.126621	A021
green AND hydrogen	Advancement of fuel cells and electrolyzers technologies and their applications to renewable-rich power grids	2023	Md. Biplob Hossain, Md. Rabiul Islam, Kashem M. Muttaqi, Danny Sutanto, Ashish P. Agalgaonkar	https://doi.org/10.1016/j.est.2023.106842	B049

green AND hydrogen	Carbon net zero transition: A case study of hydrogen storage in offshore salt cavern	2023	Julia Franco Abreu, Alvaro M. Costa, Pedro V.M. Costa, Antonio C.O. Miranda, Zhuoyuan Zheng, Pingfeng Wang, Nelson F.F. Ebecken, Renato S. de Carvalho, Pedro L.P. dos Santos, Normando Lins, Paulo R.C. de Melo, Mariana B.R. Goularti, Andre Bergsten, Carlos H. Bittencourt, Gustavo Assi, Julio R. Meneghini, Kazuo Nishimoto	https://doi.org/10.1016/j.est.2023.106818	B050
green AND hydrogen	Waste-Derived Catalysts for Water Electrolysis: Circular Economy-Driven Sustainable Green Hydrogen Energy	2022	Zhijie Chen, Sining Yun, Lan Wu, Jiaqi Zhang, Xingdong Shi, Wei Wei, Yiwen Liu, Renji Zheng, Ning Han, Bing-Jie Ni	https://doi.org/10.1007/s40820-022-00974-7	B051
green AND hydrogen	An overview of water electrolysis technologies for green hydrogen production	2022	S. Shiva Kumar, Hankwon Lim	https://doi.org/10.1016/j.egyr.2022.10.127	B052
green AND hydrogen	Catching the hydrogen train: economics-driven green hydrogen adoption potential in the United Arab Emirates	2022	Krishiv Gandhi, Harry Apostoleris, Sgouris Sgouridis	https://doi.org/10.1016/j.ijhydene.2022.05.055	B053
green AND hydrogen	Chile and its Potential Role Among the Most Affordable Green Hydrogen Producers in the World	2022	Kevin Acosta, Iván Salazar, Manuel Saldaña, Jahir Ramos, Alessandro Navarra, Norman Toro	https://doi.org/10.3389/fenvs.2022.890104	B054
green AND hydrogen	Critical assessment of the production scale required for fossil parity of green electrolytic hydrogen	2020	Joris Proost	https://doi.org/10.1016/j.ijhydene.2020.04.259	B055
green AND hydrogen	Exporting sunshine: Planning South America's electricity transition with green hydrogen	2022	Antonio Galvan, Jannik Haas, Simon Moreno-Leiva, Juan Carlos Osorio-Aravena, Wolfgang Nowak, Rodrigo Palma-Benke, Christian Breyer	https://doi.org/10.1016/j.apenergy.2022.119569	B056
green AND hydrogen	Green hydrogen as an alternative fuel for the shipping industry	2021	Selma Atilhan, Sunhwa Park, Mahmoud M El-Halwagi, Mert Atilhan, Margaux Moore, Rasmus B Nielsen	https://doi.org/10.1016/j.coche.2020.100668	B057
green AND hydrogen	Political Economy of Green Hydrogen Rollout: A Global Perspective	2021	Elkhan Richard Sadik-Zada	https://doi.org/10.3390/su132313464	B058
green AND hydrogen	Power to Hydrogen: The Prospects of Green Hydrogen Production Potential in Africa	2022	Nour Abou Seada, Tarek M. Hatem	https://doi.org/10.1007/978-3-030-92559-8_16	B059
green AND hydrogen	Prospect of Green Hydrogen Generation from Hybrid Renewable Energy Sources: A Review	2023	Asim Kumar Sarker, Abul Kalam Azad, Mohammad G. Rasul, Arun Teja Doppalapudi	https://doi.org/10.3390/en16031556	B060
green AND hydrogen	Prospects for the production of green hydrogen: Review of countries with high potential	2022	V.A. Panchenko, Yu.V. Daus, A.A. Kovalev, I.V. Yudaev, Yu.V. Litti	https://doi.org/10.1016/j.ijhydene.2022.10.084	B061
green AND hydrogen	The Future Is Colorful—An Analysis of the CO2 Bow Wave and Why Green Hydrogen Cannot Do It Alone	2021	Andreas von Döllen, YoungSeok Hwang, Stephan Schlüter	https://doi.org/10.3390/en14185720	B062
green AND hydrogen	A green hydrogen credit framework for international green hydrogen trading towards a carbon neutral future	2021	Zhao Yang Dong, Jiajia Yang, Li Yu, Rahman Daiyan, Rose Amal	https://doi.org/10.1016/j.ijhydene.2021.10.084	B063
green AND hydrogen	Techno-economic feasibility of hybrid PV/wind/battery/thermal storage trigeneration system: Toward 100% energy independency and green hydrogen production	2022	Loiy Al-Ghussain, Adnan Darwish Ahmad, Ahmad M. Abubaker, Külli Hovi, Muhammed A. Hassan, Andres Annuk	https://doi.org/10.1016/j.egyr.2022.12.034	C010
green AND hydrogen	An integrated framework of open-source tools for designing and evaluating green hydrogen production opportunities	2022	Muhammad Haider Ali Khan, Phoebe Heywood, Aaron Kuswara, Rahman Daiyan, Iain MacGill, Rose Amal	https://doi.org/10.1038/s43247-022-00640-1	C011

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green AND hydrogen	Suitable Site Selection for Solar-Based Green Hydrogen in Southern Thailand Using GIS-MCDM Approach	2022	Fida Ali, Adul Bennui, Shahariar Chowdhury, Kuaanan Techato	https://doi.org/10.3390/su14116597	C013
hydrogen AND demand and countries	A global energy system perspective on hydrogen Trade: A framework for the market color and the size analysis	2021	Svetlana A. Ikonnikova, Bridget R. Scanlon, Sofia A. Berdysheva	https://doi.org/10.1016/j.apenergy.2022.120267	A022
hydrogen AND demand and countries	An Extensive Review of Liquid Hydrogen in Transportation with Focus on the Maritime Sector	2022	Federico Ustolin, Alessandro Campari, Rodolfo Taccani	https://doi.org/10.3390/jmse10091222	B064
hydrogen AND demand and countries	Hydrogen economy for sustainable development in GCC countries: A SWOT analysis considering current situation, challenges, and prospects	2022	Muhammad Imran Khan, Sami G. Al-Ghamdi	https://doi.org/10.1016/j.ijhydene.2022.12.033	B065
hydrogen AND demand and countries	The development of an assessment framework to determine the technical hydrogen production potential from wind and solar energy	2022	Ayodeji Okunlola, Matthew Davis, Amit Kumar	https://doi.org/10.1016/j.rser.2022.112610	C014
hydrogen AND demand and countries	Comparative analysis of multi-criteria decision-making approaches for evaluation hydrogen projects development from wind energy	2022	Seyyed Jalaladdin Hosseini Dehshiri, Seyed Mahmoud Zanjirchi	http://dx.doi.org/10.1002/er.8044	D013
hydrogen AND transport AND (pipeline OR ship)	Assessment of Hydrogen Delivery Options	2022	Ortiz Cebolla, R. Dolci, F. Weidner, E.	https://doi.org/10.2760/869085	A023
hydrogen AND transport AND (pipeline OR ship)	Assessment of Hydrogen Production Costs from Electrolysis: United States and Europe	2020	Adam Christensen		A024
hydrogen AND transport AND (pipeline OR ship)	End-to-end value chain analysis of isolated renewable energy using hydrogen and ammonia energy carrier	2022	Jinwoo Kim, Cheol Huh, Youngkyun Seo	https://doi.org/10.1016/j.enconman.2022.115247	A025
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hydrogen AND transport AND (pipeline OR ship)	Large-scale overseas transportation of hydrogen: Comparative techno-economic and environmental investigation	2022	Ju-Sung Lee, Ali Cherif, Ha-Jun Yoon, Seung-Kwon Seo, Ju-Eon Bae, Ho-Jin Shin, Chulgu Lee, Hweeung Kwon, Chul-Jin Lee	https://doi.org/10.1016/j.rser.2022.112556	A027
hydrogen AND transport AND (pipeline OR ship)	Moving toward the low-carbon hydrogen economy: Experiences and key learnings from national case studies	2022	Gunhild A. Reigstada, Simon Roussanaly, Julian Straus, Rahul Anantharaman, Robert de Kler, Maxine Akhurst, Nixon Sunny, Ward Goldthorpee, Lionel Avignon, Jonathan Pearce, Stefan Flamme, Gianfranco Guidati, Evangelos Panosi, Christian Bauer	https://doi.org/10.1016/j.adapen.2022.100108	A028
hydrogen AND transport AND (pipeline OR ship)	Prospects for Using Hydrogen in Various Branches of the World Economy as One of the Directions of Its Decarbonization	2022	K. I. Yakubson	https://doi.org/10.1134/S1070427222030016	A029
hydrogen AND transport AND (pipeline OR ship)	Unmoored: a free-floating wind turbine invention and autonomous open-ocean wind farm concept	2022	Jack H Raisanen, Stig Sundman, Troy Raisanen	https://doi.org/10.1088/1742-6596/2362/1/012032	A030
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hydrogen AND transport AND (pipeline OR ship)	A hydrogen fuelled LH2 tanker ship design	2021	Abdullah NFNR Alkhaledi, Suresh Sampath, Pericles Pilidis	https://doi.org/10.1080/17445302.2021.1935626	A032
hydrogen AND transport AND (pipeline OR ship)	A review on ports' readiness to facilitate international hydrogen trade	2023	Peggy Shu-Ling Chen, Hongjun Fan, Hossein Enshaei, Wei Zhang, Wenming Shi, Nagi Abdussamie, Takashi Miwa, Zhuohua Qu, Zaili Yang	https://doi.org/10.1016/j.ijhydene.2023.01.220	B066

hydrogen AND transport AND (pipeline OR ship)	Cost minimized hydrogen from solar and wind – Production and supply in the European catchment area	2022	Lucas Sens, Yannick Piguel, Ulf Neuling, Sebastian Timmerberg, Karsten Wilbrand, Martin Kaltschmitt	https://doi.org/10.1016/j.enconman.2022.115742	B067
hydrogen AND transport AND (pipeline OR ship)	Design concepts of hydrogen supply chain to bring consumers offshore green hydrogen	2023	Youngkyun Seo, Hyunjun Park, Sanghyuk Lee, Junyoung Kim, Seongjong Han	https://doi.org/10.1016/j.ijhydene.2023.01.030	B068
hydrogen AND transport AND (pipeline OR ship)	Hydrogen liquefaction and storage: Recent progress and perspectives	2023	Tongtong Zhang, Joao Uratani, Yixuan Huang, Lejin Xu, Steve Griffiths, Yulong Ding	https://doi.org/10.1016/j.rser.2023.113204	B069
hydrogen AND transport AND (pipeline OR ship)	Large-scale long-distance land-based hydrogen transportation systems: A comparative techno-economic and greenhouse gas emission assessment	2022	G. Di Lullo, T. Giwa, A. Okunlola, M. Davis, T. Mehedi, A.O. Oni, A. Kumar	https://doi.org/10.1016/j.ijhydene.2022.08.131	B070
hydrogen AND transport AND (pipeline OR ship)	Large-scale maritime transport of hydrogen: economic comparison of liquid hydrogen and methanol	2022	Vladimir L. Meca, Rafael d’Amore-Domenech, Antonio Crucelaegui, Teresa J. Leo	https://doi.org/10.1021/acssuschemeng.2c00694	B071
hydrogen AND transport AND (pipeline OR ship)	Perspective on the hydrogen economy as a pathway to reach net-zero CO2 emissions in Europe	2022	Mijndert van der Spek, Catherine Banet, Christian Bauer, Paolo Gabrielli, Ward Goldthorpe, Marco Mazzotti, Svend T. Munkejord, Nils A. Røkke, Nilay Shah, Nixon Sunny, Daniel Sutter, J. Martin Trusler, Matteo Gazzani	https://doi.org/10.1039/d1ee02118d	B072
hydrogen AND transport AND (pipeline OR ship)	Preliminary evaluation of hydrogen blending into high-pressure natural gas pipelines through hydraulic analysis	2023	Bonchan Koo, Youngcheol Ha, Hweeung Kwon	https://doi.org/10.1016/j.energy.2023.126639	B073
hydrogen AND transport AND (pipeline OR ship)	Prospects for the Implementation of Underground Hydrogen Storage in the EU	2022	Barbara Uliasz-Misiak, Joanna Lewandowska-Smierzchalska, Rafał Matuła, Radosław Tarkowski	https://doi.org/10.3390/en15249535	B074
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hydrogen AND transport AND (pipeline OR ship)	Renewable hydrogen imports for the German energy transition – A comparative life cycle assessment	2022	Sebastian Kolb, Jakob Müller, Natalia Luna-Jaspe, Jürgen Karl	https://doi.org/10.1016/j.jclepro.2022.133289	B076
hydrogen AND transport AND (pipeline OR ship)	Research and development of hydrogen carrier based solutions for hydrogen compression and storage	2022	Martin Dornheim, Lars Baetcke, Etsuo Akiba, Jose-Ramón Ares, Tom Autrey, Jussara Barale, Marcello Baricco, Kriston Brooks, Nikolaos Chalkiadakis, Véronique Charbonnier, Steven Christensen, José Bellosta von Colbe, Mattia Costamagna, Erika Dematteis, Jose-Francisco Fernández, Thomas Gennett, David Grant, Tae Wook Heo, Michael Hirscher, Katherine Hurst, Mykhaylo Lototskyy, Oliver Metz, Paola Rizzi, Kouji Sakaki, Sabrina Sartori, Emmanuel Stamatakis, Alastair Stuart, Athanasios Stubos, Gavin Walker, Colin J Webb, Brandon Wood, Volodymyr Yartys, Emmanuel Zoulias	https://doi.org/10.1088/2516-1083/ac7cb7	B077
hydrogen AND transport AND (pipeline OR ship)	Techno-economic evaluation of two hydrogen supply options to southern Germany: On-site production and import from Portugal	2022	Florentin Eckl, Ludger Eltrop, Ana Moita, Rui Costa Neto	https://doi.org/10.1016/j.ijhydene.2022.05.266	B078

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hydrogen AND transport AND (pipeline OR ship)	Options of natural gas pipeline reassignment for hydrogen: Cost assessment for a Germany case study	2020	Simonas Cerniauskas, Antonio Jose Chavez Junco, Thomas Grube, Martin Robinius, Detlef Stolten	https://doi.org/10.1016/j.ijhydene.2020.02.121	B080
hydrogen AND transport AND (pipeline OR ship)	Development of a multi-modality hydrogen delivery infrastructure: An optimization model for design and operation	2022	Federico Parolin, Paolo Colbertaldo, Stefano Campanari	https://doi.org/10.1016/j.enconman.2022.115650	C015
hydrogen AND transport AND (pipeline OR ship)	Point-to-point transportation: The economics of hydrogen export	2022	Tory Borsboom-Hanson, Shashank Reddy Patlolla, Omar E. Herrera, Walter Merida	https://doi.org/10.1016/j.ijhydene.2022.07.093	C016
hydrogen AND transport AND (pipeline OR ship)	Shipping the sunshine: An open-source model for costing renewable hydrogen transport from Australia	2022	Charles Johnston, Muhammad Haider Ali Khan, Rose Amal, Rahman Daiyan, Iain MacGill	https://doi.org/10.1016/j.ijhydene.2022.04.156	C017
hydrogen AND transport AND (pipeline OR ship)	Techno-economic calculation of green hydrogen production and export from Colombia	2022	Arne Burdack, Luis Duarte-Herrera, Gabriel Lopez-Jimenez, Thomas Polklas, Oscar Vasco-Echeverri	https://doi.org/10.1016/j.ijhydene.2022.10.064	C018
hydrogen AND transport AND (pipeline OR ship)	Benefits of the multi-modality formulation in hydrogen supply chain modelling	2022	Federico Parolin, Paolo Colbertaldo, Stefano Campanari	https://doi.org/10.1051/e3sconf/202233402003	D014
hydrogen AND transport AND (pipeline OR ship)	Economic Analysis on Hydrogen Pipeline Infrastructure Establishment Scenarios: Case Study of South Korea	2022	Heeyeon Lee, Sanghun Lee	https://doi.org/10.3390/en15186824	D015
hydrogen AND transport AND (pipeline OR ship)	Evaluation of levelized cost of hydrogen produced by wind electrolysis: Argentine and Italian production scenarios	2021	G. Correa, F. Volpe, P. Marocco, P. Munoz, T. Falagüerra, M. Santarelli	https://doi.org/10.1016/j.est.2022.105014	D016
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hydrogen AND transport AND (pipeline OR ship)	Optimization of low-carbon hydrogen supply chain networks in industrial clusters	2022	Yasir Ibrahim, Dhabia M. Al-Mohannadi	https://doi.org/10.1016/j.ijhydene.2022.12.090	D018
hydrogen AND transport AND (pipeline OR ship)	Techno-economic assessment of green hydrogen and ammonia production from wind and solar energy in Iran	2022	Ali Kakavand, Saeed Sayadi, George Tsatsaronis, Ali Behbahaninia	https://doi.org/10.1016/j.ijhydene.2022.12.285	D019
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mooring AND offshore AND cost	MOORING DESIGNS FOR FLOATING OFFSHORE WIND TURBINES LEVERAGING EXPERIENCE FROM THE OIL & GAS INDUSTRY	2021	Kai-tung Ma, Yongyan Wu, Simen Fodstad Stolen, Leopoldo Bello, Menno van der Horst, Yong Luo	https://doi.org/10.1115/OMAE2021-60739	B098
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solar AND offshore	A global, spatially granular techno-economic analysis of offshore green ammonia production	2022	Nicholas Salmon, René Bañares-Alcántara	https://doi.org/10.1016/j.jclepro.2022.133045	A033
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solar AND offshore	Modelling and analysis of offshore energy hubs	2022	Hongyu Zhang, Asgeir Tomasgard, Brage Rugstad Knudsen, Harald G. Svendsen, Steffen J. Bakker, Ignacio E. Grossmann	https://doi.org/10.1016/j.energy.2022.125219	B086
solar AND offshore	OFFSHORE ENERGY HUBS IN THE DECARBONISATION OF THE NORWEGIAN CONTINENTAL SHELF	2022	Hongyu Zhang, Asgeir Tomasgard, Brage Rugstad Knudsen, Ignacio E. Grossmann	https://doi.org/10.1115/OMAE2022-78551	B087
solar AND offshore	The co-benefits of California offshore wind electricity	2022	Adam Rose, Dan Wei, Adam Einbinder	https://doi.org/10.1016/j.tej.2022.107167	B088
solar AND offshore	Use of Marine Renewable Energy in Ports of Middle East: A Step Toward Sustainable Ports	2022	Dilba Rayaru Kandiyil	https://doi.org/10.1007/978-3-030-76081-6_42	B089

solar AND offshore	Assessment of the potential of combining wave and solar energy resources to power supply worldwide offshore oil and gas platforms	2020	Sara Oliveira-Pinto, Paulo Rosa-Santos, Francisco Taveira-Pinto	https://doi.org/10.1016/j.enconman.2020.113299	B090
solar AND offshore	Large-scale integration of optimal combinations of PV, wind and wave power into the electricity supply	2006	H. Lund	https://doi.org/10.1016/j.renene.2005.04.008	B091
solar AND offshore	Site Selection of Offshore Solar Farm Deployment in the Aegean Sea, Greece	2022	Dimitra G. Vagiona, George Tzekakis, Eva Loukogeorgaki, Nikolaos Karanikolas	https://doi.org/10.3390/jmse10020224	C019
solar AND offshore	Exploiting offshore wind and solar resources in the Mediterranean using ERA5 reanalysis data	2021	Takvor H. Soukissian, Flora E. Karathanasi, Dimitrios K. Zaragkas	https://doi.org/10.1016/j.enconman.2021.114092	C020
solar AND offshore	Two-level planning approach to analyze techno-economic feasibility of hybrid offshore wind-solar pv power plants	2021	Syed Raahat Ara, Santanu Paul, Zakir Hussain Rather	https://doi.org/10.1016/j.seta.2021.101509	C021
solar AND offshore	Capital expenditure and levelized cost of electricity of photovoltaic plants and wind turbines e Development by 2050	2021	Lucas Sens, Ulf Neuling, Martin Kaltschmitt	https://doi.org/10.1016/j.renene.2021.12.042	D022
solar AND offshore	Green hydrogen production potential for Turkey with solar energy	2021	G. Kubilay Karayel, Nader Javani, Ibrahim Dincer	https://doi.org/10.1016/j.ijhydene.2021.10.240	D023
solar AND offshore	Offshore wind and solar complementarity in Brazil: A theoretical and technical potential assessment	2022	Marcolino Matheus de Souza Nascimento, Milad Shadman, Corbiniano Silva, Luiz Paulo de Freitas Assad, Segen F. Estefen, Luiz Landau	https://doi.org/10.1016/j.enconman.2022.116194	D024
solar AND offshore	Scaling the production of renewable ammonia: A techno-economic optimization applied in regions with high insolation	2020	Ola Osman, Sgouris Sgouridis, Andrei Sleptchenko	https://doi.org/10.1016/j.jclepro.2020.121627	D025

Appendix B

Paper ID	Far offshore	Wind	Solar	Wave	Hydrogen production process	Hydrogen transport	Production location	Hydrogen usage	Energy storage	Environmental impact	Operations & maintenance	Technological feasibility	Economic feasibility	Method also	Additional remarks
A001		x		x								x			Reviews wind and ocean energy potential; also other renewable offshore energy sources than indicated are reviewed
A002		x			x	x							x		Comparative economic analysis of hydrogen production using OWE
A003		x			x	x	x						x		Identifying most competitive sources of low-carbon hydrogen for Northwest Europe, looking at different production locations and methods, and different transport options
A004		x										x			Review of research progress and critical technical issues of FOW, and future research directions for this
A005		x			x	x	x		x		x	x	x		In this study, data were collected, technologies were chosen, systems were designed, and simulation models were developed to determine technical requirements and levelised costs of hydrogen produced and transported through different pathways for the case of the UK.
A006					x	x						x	x		Techno-economic analysis of competitiveness of different pathways of exporting hydrogen from offshore production plants, with special focus on the offloading to export hydrogen (pure hydrogen or hydrogen carriers) to land and also doing a sensitivity analysis of different factors on the cost of hydrogen. In addition, it is found that the commercialization of produced oxygen greatly improves the viability of the
A007		x	x		x	x	x	x					x	x	A comprehensive approach for estimating the development of global production and supply costs of low-carbon hydrogen from renewable energy sources (onshore wind, offshore wind and solar photovoltaics) and natural gas (natural gas reforming with carbon capture and storage and natural gas pyrolysis) until 2050, taking into account production and transport
A008		x			x	x		x	x			x			Literature review providing a summary of the technologies involved in hydrogen production along with an analysis of two possible hydrogen producing systems from offshore wind energy and also looking at storage and usage of the produced hydrogen
A009		x			x	x						x	x	x	Techno-economic analysis reviewing onshore, centralized offshore and decentralized offshore hydrogen production from OSW, conluding the latter is most economic, and using among other things a monte carlo simulation
A010	x	x			x	x	x	x	x			x	x		Techno-economic analysis of far offshore green hydrogen production with fleets of hydrogen producing wind energy converters sailing autonomously to see if it would be competitive now and in the future, also looking at suitable locations, and transport and distribution of the produced hydrogen
A011		x			x	x		x				x	x		Techno-economic feasibility of near offshore hydrogen production using energy from OSW
A012		x			x	x			x			x	x	x	Techno-economic analysis of OSW coupled with green hydrogen production with MHyWind, leading to rules of thumb for system configuration and sizing to minimize LCOH and concluding off-grid hydrogen production leads to the lowest costs
A013	x	x				x			x			x	x		Determination of the most suitable molecular energy carrier for renewable energy produced with mobile wind energy converters (energy ships)(same main author as paper A010)
A014		x								x				x	A conceptual model is proposed for studying the ecological and social impacts on the environment caused by offshore wind in coastal areas
A015		x		x									x	x	Development of a model for potential cost reduction trajectories of emerging renewable energy technologies, which is applied to floating offshore wind, tidal stream and wave energy production

A016		x										x			Review of the most recent state-of-the-art developments in the (floating) offshore wind turbine technology, and the design concepts and numerical models used to simulate them
A017	x	x					x					x			Review of capacity factor for weather routed wind energy ships and stationary offshore wind turbines in the North Atlantic, showing both can achieve capcaity factors over 80% (main author of A010 and A013
A018					x					x		x	x		Comparison of low-carbon hydrogen production technologies based on technology readiness level, scalability, levelized cost of hydrogen, the impact of by-products and their carbon footprint
A019					x			x					x		Previous studies, hydrogen country roadmaps and the electrolyzer market are analysed to identify the expected demand and potential market ramp-up scenarios, and to evaluate if green hydrogen demand forecasts can be filled
A020					x	x	x						x	x	Reviews the production cost and potentials of hydrogen and hydrogen-based energy commodities ammonia, methane, methanol, gasoline, diesel and kerosene in 113 countries and the supply costs of hydrogen to Germany from those countries, conluding that production costs dominate the supply cost composition for liquid or easily liquefiable commodities, while transport costs dominate for gaseous
A021	x					x						x	x		Compares transport of hydrogen in different transport mediums, by pipeline or ship, and over different distances, concluding on the best alternatives for the considered distances (100, 2500 and 5000 kilometers)
A022					x	x	x	x							Simulation of the worldwide hydrogen market, looking at both the production and demand side and identifying which countries are likely to become exporters and importers of (green) hyrdogen
A023						x						x	x		Extensive assessment of hydrogen transport mediums and modes
A024		x	x		x								x		Examines the expected price development of green hydrogen production from wind and solar energy in the USA and Europe towards 2050, taking into account the entire system instead of solely electricity and electrolyzer costs, and using realistic energy prices
A025						x						x			Analysis of a long-distance end-to-end value chain of ammonia as an energy carrier and how to improve the efficiency of the entire process, involving transport by ship from an offshore production location
A026	x					x			x			x	x		Analysis of the possibilities for the creation of ' hydrogen ocean links', using the high pressure in deep sea to cheaply transport and store pressurized hydrogen, allowing for more economic storage of hydrogen and transport between continents (and from far offshore)
A027	x					x							x		The long-distance overseas transport of hydrogen by ships is assessed from an economic and environmental perspective
A028					x	x		x	x	x		x	x		Based on national case studies, this paper presents reflections on estimates of future hydrogen demand, optimization of infrastructure for hydrogen production, transport and storage, development of viable business cases, and environmental impact evaluations using life cycle assessments
A029								x							Prospects for hydrogen usage in different applications, also in the future
A030	x	x			x							x			Free floating wind farm concept for the open ocean, where turbines are kept in place by propellers and the energy is used to produce fuels such as hydrogen and ammonia in a separate unit, which are then transported by ship
A031	x					x						x	x		Assessment of different options for overseas energy transport over distances up to 3000 km: by electrical cable, liquid hydrogen (pipeline and ship) and compressed hydrogen (pipeline and ship)
A032						x		x				x			Design of a large-scale liquid hydrogen carrier that uses the boil-off as fuel for propulsion and onboard power demand
A033	x	x	x		x	x	x					x	x	x	Review of worldwide potential for far offshore ammonia production from floating wind and solar energy in 2030, conluding the best offshore locations cannot yet compete with the best onshore locations due to higher energy generation costs, but there is significant potential when land scarcity plays a role
A034		x	x	x								x			Review of complementarity and applicability of renewable energy sources in the marine environment
A035	x				x				x			x			An experiment is performed to assess the effect of complex sloshing on the production of ammonia in a floating facility far offshore, conluding the effect is small and the process system shows strong marine adapatability

A036		x											x		Assessment of the influence of different parameters of a floating offshore wind farm such as number of offshore wind turbines, the energy produced by one wind turbine, the interest rate, the capital cost and the electric tariff influence its economic feasibility
A037					x	x	x	x				x	x		
A038					x	x						x	x		Report on potential of hydrogen
A039					x	x						x	x		Report on potential of hydrogen
A040	x				x							x			Concept design and optimization of liquid hydrogen FPSO
A041								x							Reviews the potential of hydrogen and expected demand development (for different regions and applications) towards 2050
A042						x									Study looking at different transport mediums for hydrogen
B001						x					x	x	x		Looks at the possibilities for using existing pipelines for hydrogen and CCS
B002		x			x	x		x				x	x		Potential of hydrogen production from near offshore wind in Canada
B003		x		x								x			Framework for combining floating wind and wave energy to minimize motions while still having stable power production
B004	x								x			x			Compressed air seesaw energy storage in deep sea as alternative to hydrogen
B005		x											x		Possibilities for and economic attractiveness of relocation of floating wind turbines during lifetime
B006		x								x					Life cycle assessment (LCA) to evaluate the potential environmental impact of China's first high-power prototype windfarm
B007		x									x		x		Influence of accesibility of FOWTs on operation and maintenance activities and its costs
B008		x									x	x			Reviews digital twin technology for O&M of OWFs
B009		x			x			x					x		Influence of green hydrogen on grid development, analysis of North Sea offshore wind projects, an offshore energy hub and influence of hydrogen on power prices
B010		x													A sensitivity analysis to determine the most essential parameters that affects to the economic feasibility of a marine wind farm composed by platforms built in concrete material
B011		x										x	x		Analysis of different platform options for FOWTs
B012		x		x					x			x	x		It is investigated how incorporating wave power into an offshore wind farm affects farm power predictability, smoothness, required energy storage capacity, and cost.
B013		x	x		x			x	x			x			The aim of this work is to investigate the role of batteries and hydrogen storage in achieving a 100% renewable energy system.
B014		x		x									x		A cost model is made and used to assess the potential of co-location of wind and wave energy production, leading to th conclusion that it is beneficial
B015		x	x		x	x	x		x				x		Estimation of hydrogen production costs from solar, onshore wind and offshore wind towards 2050, and overview of dependencies of green hydrogen production costs, showing LCOE is much lower with solar, but LCOH is lower with offshore wind
B016		x								x					Discussion of costs and benefits (ecological and economic) of offshore wind relative to onshore wind and conventional electricity production
B017		x					x						x		Review of economic of offshore wind in Southeast Asia
B018				x									x		Shows that in the case of California wave-energy is cost competitive even when the cost of installation and maintenance are twice that of solar and wind because they produce a lot in the winter months when wind and solar energy do not
B019		x			x							x			Explores the possibilties of designing a wind turbine specifically for hydrogen production in order to minimize LCOH instead of LCOE
B020		x	x												Shows the benefits of combining offshore wind and solar PV for the case of Shark Bay (Australia)
B021		x	x									x	x	x	Assessment of techno-economics of adding solar to an offshore wind farm with spare cable capacity and the development of a model for general techno-economic analysis of combined solar and wind is
B022		x	x	x								x			Discusses the technology, existing plants and their oper ation, estimated resource potential, future developments, advantages and challenges of different marine renewable energy technologies

B023		x		x								x			Discusses hybrid wind-wave energy and their potential with a focus on floating offshore wind
B024		x			x	x					x		x	x	Develops a model and shows that for the reviewed location, offshore hydrogen production is more beneficial than electricity transmission to shore
B025		x			x								x		Techno-economic assessment of battolyser (battery and electrolyzer in one, which is less expensive but also less efficient) usage for hydrogen production from wind energy, concluding that it makes economic sense to use it for the curtailed wind energy
B026		x			x	x						x	x		Looks at centralised onshore, decentralised offshore and centralised offshore hydrogen production with energy from FOW. Also looks at electrolyser technology, floating wind platform and energy transmission vector.
B027	x								x			x			Experimental validation of wind-propelled ship with water turbines attached to generate electricity from wind far offshore, showing a full scale ship could deliver high levels of power production (same main author as paper A010 and A013)
B028		x			x	x		x					x	x	Development of integrated energy system model written as a linear problem to optimize the long-term investment planning and short-term operation of seven North Sea region countries, allowing for evaluation of the influence of several factors and showing large usage of hydrogen when international transport emissions are considered
B029		x			x								x		Strategies are developed for optimal bidding into ancillary service markets for offshore wind farms that build hydrogen production facilities and for optimal sizing of Power-to Hydrogen (PtH) facilities at wind
B030								x				x	x		Discusses the possibilities for using offshore green hydrogen in offshore industries (such as acquaculture, shipping, ports and oil/gas) to make them more sustainable
B031		x									x	x	x		Reviews the expectations for the developments of wind turbines, also looking at offshore floating wind turbines and green hydrogen production from offshore wind
B032		x										x			Modelling of un-moored floating offshore wind turbines in order to assess their technological feasibility, showing a large amount of power would have to go to the thrusters
B033		x													This paper provides a dataset of hourly wind data in European offshore wind farms covering 40 years from 1980 to 2019 and additional data on the wind farms, such as wind turbine power curves
B034		x													This paper adresses the current and future situation of offshore renewable energy production in South America, concluding there is a lot of potential, but it is not being explored commercially yet and more investments are needed
B035		x		x								x			A novel concept for a floating wind-wave combined power generation system is proposed and analyzed
B036		x										x			Review of potential of offshore wind to replace nuclear and fossil energy sources in Taiwan
B037		x								x					Assessment of the environmental impact of floating offshore wind, looking at emissions and not yet investigating the effect on marine ecology in depth
B038		x										x			This paper gives an overview of what will be needed to be able to design, build and install floating offshore wind turbines
B039										x		x	x		Review of possibilities for using acuaculture projects (IMTAs) to compensate for the encironmental impacts of marine energy projects in India
B040										x					Study of local perceptions of the Block Island Offshore Wind Project (United States) by evaluating both cognitive (rational) and affective (emotional) responses with the goal of learning about how each relates to project support and opposition and how a nearby island population differs from that of the coastal residents farther away
B041		x										x		x	Identifies the main barriers for the implementation of offshore wind energy through a multi-criteria decision making approach with a focus on India
B042		x	x							x					This paper discusses the impact of climate action measures on biodiversity and identifies possible synergies between the two, looking at Ireland as a case and identifying offshore wind as a win-win situation
B043		x										x	x		Looks at the installation of (floating) offshore wind turbines, its costs, its technological challenges and how this will develop in the future

B044		x										x	x		Overview of challenges for the offshore renewable energy sector in the UK
B045										x					Development of methodology to assess risk of entanglement of marine megafauna in offshore renewable energy mooring configurations (which can also be used for arrays and power cables) and review of six different configurations, finding low risk of entanglement in general
B046										x					Overview of knowledge regarding the effect of offshore renewables on marine ecology and identification of knowledge gaps to be researched further regarding this topic
B047		x								x					Assessment of climate and health benefits of the deployment of two offshore wind farms in the USA
B048		x													Use of a high spatial and temporal resolution power system optimisation model to explore the conditions that lead to the deployment of floating offshore wind and the effect this has on the rest of the electricity system for Great Britain in 2050, showing a strong competition between floating and conventional offshore
B049					x			x				x			Review of electrolyzer and fuel cell technologies, specifically focused on using green hydrogen to connect renewable energy systems to use excess energy and cover possible shortages
B050									x			x			Feasibility study of hydrogen storage in salt caverns created by leaching in the Gulf of Mexico, including a conceptual design of wells for leaching the caverns and hydrogen injection and withdrawal cycles
B051					x					x		x			Evaluation of potential of waste-derived catalysts for water electrolyzers in order to make green hydrogen production more sustainable
B052					x							x	x		Various water electrolysis technologies and their techno-commercial prospects including hydrogen production cost, along with recent developments in electrode materials, and their challenges are
B053					x								x		Review of potential of green hydrogen for United Arab Emirates for domestic use and export
B054					x								x		Review of potential of green hydrogen for Chile for export, given its highly advantageous position for green hydrogen production (estimated at 1.5 USD/kg in 2030)
B055					x							x	x		Shows at which scale green hydrogen should be produced in order to be cost competitive with grey hydrogen already today, which is concluded to be a few MW
B056		x	x		x								x		Looks at potential of renewable energy and green hydrogen production in South America, showing renewable energy is expected to become the most cost effective option as well
B057								x				x	x		This paper provides a critical assessment of the potential usage of green hydrogen in the shipping industry with an evaluation of production routes, techno-economic performance, storage, and safety
B058										x					Discusses the societal effects of a green hydrogen rollout, specifically for developing countries
B059					x								x		Review of potential of green hydrogen for Africa
B060		x	x		x							x			Reviews the possibilities and challengse of hydrogen production from solar, wind and a combination of the
B061					x	x	x						x		Looks at the potential of different countries for hydrogen production, the transport of the produced hydrogen to other countries and the associated costs
B062										x					Argues that alternatives like blue hydrogen are necessary to avoid a ' bow wave' of CO_2 emissions caused by the building up of production capacity for green hydrogen
B063								x					x		A hydrogen credit framework is proposed to facilitate international trade of hydrogen from a financial perspective for a global hydrogen economy
B064								x				x			Review of the implementation of liquid hydrogen in the transportation sector including aerospace and aviation industries, automotive, and railways is provided, after which the application in the maritime industry is explored in more detail
B065					x	x			x			x	x		Extensive SWOT analusis of the developing hydrogen economy in general and specifically the Gulf countries' position in it
B066								x							Analysis of ports in an international hydrogen trade system and their readiness to facilitate hydrogen trade, also identifying countries/ports that are expected to be the first to facilitate the importing/exporting of hydrogen
B067		x	x		x	x	x		x			x	x		Review of hydrogen supply possibilities and costs to Germany from Europe, North Africa and the Middle East towards 2050, also looking at the possibilities of hydrogen storage in salt caverns
B068						x						x	x		Analysis of different options for hydrogen/energy transport from offshore wind in South Korea

B069						x						x	x		Reviews the current state of technology development related to the liquid hydrogen supply chain in order to assess its potential for hydrogen transport
B070						x						x	x		Assessment of the unit costs and emission footprints (direct and indirect) of 32 systems for hydrogen transportation, namely pure hydrogen (hydrogen pipeline and truck transport of gaseous and liquified hydrogen), hydrogen-natural gas blends (pipeline), ammonia (pipeline), and liquid organic hydrogen carriers (pipeline and rail
B071					x	x	x						x		Comparison of local geen hydrogen production and importing from overseas, also considering different transport options and their break-even points
B072					x	x		x	x			x	x		Extensive analysis of (i) hydrogen end-use technologies and applications, (ii) hydrogen production methods, (iii) hydrogen transport and storage networks, (iv) legal and regulatory aspects, and (v) business models
B073						x						x			Reviews feasibility of blending hydrogen in existing pipelines for natural gas, showing that a volumetric fraction of hydrogen below 20% would require no modifications in infrastructure or operations
B074									x						Review of possibilities for hydrogen storage in natural geological structures underground in Europe
B075								x				x	x		Review of alternative fuels for the aviation industry, among which hydrogen, ammonia and methanol, concluding hydrogen could be one of the suitable options if a hydrogen fueled aircraft is brought to the market successfully
B076						x				x					Life cycle assessment of green hydrogen import to Germany from Chile, Canada and Morocco in order to determine the associated emissions and compare them to the emissions of domestic green hydrogen production, concluding that in some cases importing hydrogen results in lower emissions
B077						x						x			This paper summarizes the newest developments of hydrogen carriers for storage and compression and in addition, give an overview of the different research activities in this field
B078			x		x	x	x						x		Comparison of hydrogen costs for usage in Stuttgart when produced locally or in Portugal
B079						x							x		Comparison of costs of energy transport through electrical cables and hydrogen towards 2050
B080						x							x		Cost assessment of the recycling of natural gas pipelines for hydrogen transport in Germany
B081		x		x								x			Review of wind-wave co-generation technologies and identification of the best combinations
B082		x	x									x			Assessment of influence of strong waves and winds on offshore floating solar performance (several rows of panels on a rigid platform), concluding the influence is minimal and offshore solar and wind energy may be very well combined
B083		x	x									x			Review of potential of combining offshore wind and solar power to improve energy stability using the performance classification method Delphi for the case of Iberia, concluding it leads to significant impovements, especially near offshore
B084								x				x			Estimation of future demand between 2020 and 2050 for electricity and hydrogen for transport in the UK (car, bus and train) to assess how much land area would be necessary to produce the required energy
B085		x		x								x			Discusses the control problems for different kinds of marine rewable energy sources, among which wind and wave energy
B086					x				x			x			Modelling and analysis of offshore energy hubs and what their effect would be when used in the energy system in Norway
B087		x			x				x			x	x		Analysis of offshore energy system on the Norwegian continental shelf, mainly looking at the role of on- and offshore energy hubs (with hydrogen production) in this system
B088		x								x					Review of the (additional) benefits of offshore wind energy production for California
B089								x							Discusses the potential for making ports in the middle east more sustainable by using renewable energy
B090			x	x								x	x		Reviews the possibilities for combination of offshore solar and wave energy for the offshore industry, showing that it could be benificial
B091		x	x	x								x			Analysis of the combination of wind, wave and solar energy in the Danish energy system, identifying the percentual combinations leading to the lowest amounts of excess energy for a renewable energy share between 0 and 100% of the total amount of energy used

B092		x		x								x	x		This paper focuses on the development of an integrated wind and wave platform and the creation of a numerical model to evaluate the system performance for the Belmullet site
B093		x								x					Analysis of the factors impacting the social acceptance of offshore wind in Europe
B094		x										x	x		Potential for on- and offshore wind energy generation in Europe
B095		x										x			Analysis of effect of emissions on wind resource potential in Europe, concluding the potential is expected to decline overall because of emissions, and it will decline less if the emissions are limited
B096		x			x	x						x	x		Techno-economic analysis comparing on- and offshore hydrogen production using energy from offshore
B097					x							x			Discusses disposal and treatment methods for brine, which is produced as a by-product when desalinating water
B098		x									x	x	x		Discusses mooring systems for floating offshore wind based on experience from the oil and gas sector

Appendix C

Paper ID	General	Energy production	Hydrogen production	Hydrogen transport	Hydrogen demand	Energy farm layout	Location selection	Operations & Maintenance	Future prediction	Methods used	Additional remarks
C001	x	x	x	x			x		x	Geospatial model and learning rates	Economic viability of offshore hydrogen production; LCOH in Irish waters
C002		x					x				Global onshore wind resource assessment
C003		x									Evaluation of wind energy production for 12 specific locations based on ERA5 data and a Siemens wind turbine
C004		x				x	x			Artificial neural networks and risk-averse stochastic programming	A model is developed to be used for site-selection and portfolio optimization for energy production with with wind, wave and ocean current technologies
C005	x	x	x	x		x				Mixed-integer linear programming	Development of an optimization tool to design and analyze a wind-powered hydrogen supply system, looking at the energy production and transport, and their costs
C006		x							x	Experience curve theory	This paper aims to project the capital expenditures (CAPEX) of photovoltaic plants, onshore and offshore wind turbines for 2030 and 2050 by using the experience curve theory, also concluding the LCOE of renewable energies may become significantly lower than the LCOE fossil fuel based energy
C007	x	x	x	x					x		Model developed to rapidly assess economic feasility of hydrogen production with OSW in 2030, taking into account electricity/hydrogen from time-varying wind speed, electrolysis plant size and hydrogen storage
C008							x			Pyseafuel	Optimal locations in het Mediterranean were identified for a methanol production island using a purpose built python package and wind, solar, wave and water temperature data
C009		x					x				Potential areas for the development of a FOW farm in Ireland were identified and the most attractive locations were selected based on LCOE and using a site-specific approach taking into acccount the distance to the coast and to adequate port facilities, water depth and wind climate, also showing which have the biggest influence
C010	x	x	x				x		x	Genetic Optimizer	Using Estonia as a case, optimal locations for energy/hydrogen production are identified and it is determined whether to use wind, solar or a combination of the two, looking at the amounts of hydrogen produced and its costs

C011			x				x			Several open source Python tools	A comprehensive four-tier framework for hydrogen production is proposed based on specially designed open-source tools that build upon existing knowledge by providing (i) zoning filters to identify potential green hydrogen hubs, (ii) Multi-Criteria Analysis to compare and rank the selected sites, (iii) a production cost tool that allows analysis of 24 different electrolyzer – powerplant design scenarios and (iv) a python based algorithm that establishes the capacity mixes of electrolyzer, powerplant and battery energy storage system required to achieve cost or operational capacity factor targets
C012		x	x	x					x		This paper assesses the energy efficiency and the cost of a green hydrogen supply from well to tank exemplified for fuel cell heavy-duty vehicles in Germany related to the years 2030 and 2050, considering different transport medium, and local production in Germany and import from Tunisia and Argentina
C013							x			Multi-criteria decision making	Through the consolidation of a geographic information system (GIS) and the analytical hierarchy process (AHP) technique of multicriteria decision making (MCDM), the potential of green hydrogen in southern Thailand is assessed, through the selection of suitable sites for solar-based green hydrogen production
C014		x	x				x				This study proposes a framework for assessing country-level hydrogen technical potential from wind and solar energy, looking at wind and solar resources, but also taking into account seven setback factors which decrease the potential for hydrogen production
C015	x		x	x	x					Mixed-integer linear programming and multi-modality formulation	Optimization of hydrogen production, transport and demand, allowing multi-modality and the choice between different alternatives for each part of the supply chain, and applied for the case of Sicily (seems to be the successor of paper D014)
C016				x							Development of a model and framework to assess the costs of different hydrogen transportation options (gaseous or liquid, and truck, train, ship or pipeline) in order to choose the most optimal combination for the given distances
C017				x						Open-source model	Development of an open source model to assist in assessing the costs of shipping various forms of hydrogen over different routes, which is applied to the Rotterdam-Australia route but can be adapted globally
C018	x	x	x	x			x		x	Several open-source Python tools, such as WindPowerLIB, PVLIB, ERA5 weather data, and the Hydrogen-2-Central model	Techno-econmic assessment of Colombia's and Chile's potential for hydrogen production and export, resulting in the production costs and the costs including transport to Europe and Asia
C019							x			Geographic information systems and multi-criteria decision making models	Identification of suitable locations for offshore solar energy production in Greece and ranking of the different locations based on several criteria
C020		x					x				Analysis of wind and solar potential in the Mediterranean sea using ERA5 and assessment of complementarity of wind and solar energy production using correlation and variation coefficients, concluding which locations would be most suitable

C021		x				x					Two-level planning approach for offshore wind-solar parks, where first the optimal layout is determined for maximum energy generation and then the economics are analysed, both from a perspective where the optimal combination between solar and wind for a given capacity is sought and a perspective where the optimal amount of solar is determined for an existing wind park, after which the two are compared and the most optimal solution is chosen
C022	x									Mixed integer linear programming	This research looked at the potential of drop-in biofuels in the maritime sector, using optimizations with Mixed Integer Linear Programming
D001						x				Genetic Algorithm	Method developed for optimization of wind farm in Pakistan
D002		x							x	Met-ocean data selection model	Data selection model to reduce computing time for evaluation of Operation and Maintenance for offshore renewable energy systems
D003						x				Genetic Algorithm	Methods developed for cost minimization and power maximization of wind farm by optimizing the lay-out
D004		x					x				Development of new method for more accurate assessment of offshore wind in the pre-construction phase of wind farms
D005	x					x				Ant colony optimization with decomposition, ant colony optimization and mixed-integer linear programming	Development of a more efficient method giving almost optimal solutions for wind farm cable lay-out optimizaiton using ant colony optimisation with decomposition
D006		x									Development of a software to calculate the economic parameters so as to determine the feasibility of a floating offshore renewable farm in a selected location, also combined with wave energy
D007			x		x					Chance constrained programming, information gap decision theory and particle swarm optimization	A CCP model is used for electrolyzer size optimization leading to a maximum NPV for the wind-hydrogen project, an IGDT model is used to determine acceptable hydrogen price ranges and and particle swarm optimization is used to to solve the CCP-IGDT model
D008		x									Gives a method to calculate the main life-cycle cost and LCOE of a floating offshore renewable energy farm with wind or wave energy
D009		x					x			Bayesian network	This paper presents a novel risk-based methodology for selecting sites for WEC installation to minimize the overall economic risk, which allows evaluating influencing parameters for potential site locations
D010					x						Development of generic model to estimate hydrogen consumption of ships, applied to crew transport vessels for OSW maintenance in Germany
D011		x	x			x	x				Identification of best locations for wind and wave energy based hydrogen production in the Atlantic ocean and assessment of wave energy converter size with BEM-simulations, showing a significant improve in efficiency of an offshore wind farm when adding wave energy converters

D012		x				x				Complementarity metric	A novel complementarity index to assess complementarity of different energy sources is proposed (since using a correlation coefficient can lead to misestimations), which can also be used to optimize the ratio between the energy sources and is applied for the case of wind and solar complementarity in China
D013							x			Multi-criteria decision making	An approach is developed to find suitable locations for hydrogen production from wind energy and applied to a case in Iran
D014				x						Multi-modality formulation	Adoptation of an optimization model for hydrogen transport design, considering pipelines, compressed hydrogen trucks and liquid hydrogen trucks, and allowing multi-model transport during optimization
D015				x							Development of a cost estimation model for hydrogen pipeline construction for the case of South Korea, and comparison between newbuild or existing natural gas pipeline modification
D016	x	x	x	x							Comparison of costs for green hydrogen production in Italy and Argentina for usage in Italy, including the entire supply chain, also considering different alternatives for the transport medium
D017		x	x		x				x		Adresses the potential of low-carbon and renewable hydrogen in decarbonizing the European energy system and (among other things) gives an elaborate estimation of hydrogen demand in Europe as a result from the used model
D018		x	x	x						Mixed integer linear programming	Development of optimization model for the design of a hydrogen supply chain network, looking at costs and emsisions, and also comparing different long-distance hydrogen transport options, concluding ammonia would be most cost efficient
D019	x	x	x	x			x			HOMER Pro simulation platform	Techno-economic assessment of hydrogen/ammonia production from wind and solar energy using seawater in Iran, including transportation to the port for export
D020					x		x				Analysis of most optimal hydrogen production sites towards 2050 in California based on hydrogen demand (estimated) and site suitability
D021				x							Presents a mathematical model for a multi-period hydrogen supply chain design problem, looking at production, storage and transport with pipelines and trucks, also finding the number of needed transport units and the optimal piping routes based on google maps data
D022		x							x	Experience curve theory	Estimation of capital expenditures for solar, onshore wind and offshore wind energy in 2030 and 2050
D023		x	x				x				Evaluation of green hydrogen production potential from solar energy in the different regions of Turkey, also looking at different kinds of electrolysers
D024		x									Assessment of complementarity of offshore wind and solar energy production in Brazil
D025		x	x			x				Aspen Plus and linear optimization	Assessment of potential for green ammonia production in the UAE for energy export, showing the potential to reach similar prices as conventional ammonia
D026								x		Hierarchical met-ocean data selection model	Development of a model to reduce the computational cost in stochastic simulation of operation and maintenance (O&M) and enable rapid evaluation of offshore renewable energy systems (97.65% reduction in computing time) by producing a met-ocean reference year comprising twelve representative historical months as the input for O&M stochastic simulation

D027		x					x				Identification of suitable sites for wind-wave combined energy production in the North Sea
D028	x									Mixed integer linear programming	This research presents a mathematical formulation for optimizing integration of complex industrial systems from the level of unit operations to processes, entire plants, and finally to considering industrial symbiosis opportunities between plants

Appendix D

Results scenario 1

Table 8.1: Results scenario 1 far offshore green hydrogen

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	5.96E+08	5.33E+08	4.72E+08	4.12E+08	3.52E+08	2.88E+08	2.72E+08	2.57E+08	2.43E+08	2.29E+08	2.14E+08
Costs per kg hydrogen (euros)	11.93	10.65	9.44	8.23	7.04	5.76	5.44	5.14	4.86	4.57	4.29
Wind turbines	39	41	44	46	49	59	60	60	60	63	63
Solar platforms	1464	1328	1111	939	663	0	30	30	30	5	5
Electrolyzers	27	26	25	25	26	28	27	27	27	26	26
Desalination equipment	26	25	24	24	25	27	26	26	26	25	25
Storage volume (m3)	4.79E+04	4.61E+04	4.44E+04	4.44E+04	4.61E+04	4.97E+04	4.79E+04	4.79E+04	4.79E+04	4.61E+04	4.61E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	4.86E+05	4.68E+05	4.50E+05	4.50E+05	4.68E+05	5.04E+05	4.86E+05	4.86E+05	4.86E+05	4.68E+05	4.68E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.2: Results scenario 1 local production (Brändle et al., 2021)

	PV 1	PV 2	PV 3	PV 4	Onshore 1	Onshore 2	Onshore 3	Offshore 1	Offshore 2
Production capacities (Mt/year)									
2020				4.98			1.2	0.83	
2023				5.02			1.21	0.83	
2026				5.07			1.23	0.84	
2029				5.12			1.24	0.85	
2032				5.18			1.26	0.86	
2035				5.26			1.28	0.87	
2038				5.33			1.3	0.89	
2041				5.4			1.32	0.9	
2044				5.48			1.35	0.91	
2047				5.57			1.37	0.93	
2050				5.65			1.39	0.94	
Costs (euros/kg)									
2020				6.73			6.55	7.15	
2023				5.91			6.05	6.54	
2026				5.30			5.64	6.10	
2029				4.78			5.28	5.72	
2032				4.39			4.98	5.34	
2035				4.10			4.73	5.01	
2038				3.84			4.51	4.75	
2041				3.60			4.32	4.51	
2044				3.39			4.15	4.28	
2047				3.14			3.93	4.04	
2050				2.95			3.76	3.86	

Table 8.3: Results scenario 1 import (Brändle et al., 2021)

Year	Total worldwide demand (Mt/year)	Cheapest (euros/kg)	Guaranteed (euros/kg)
2020	90	5.08	5.55
2030	140	4.43	4.56
2040	385	3.66	3.84
2050	660	2.88	3.10

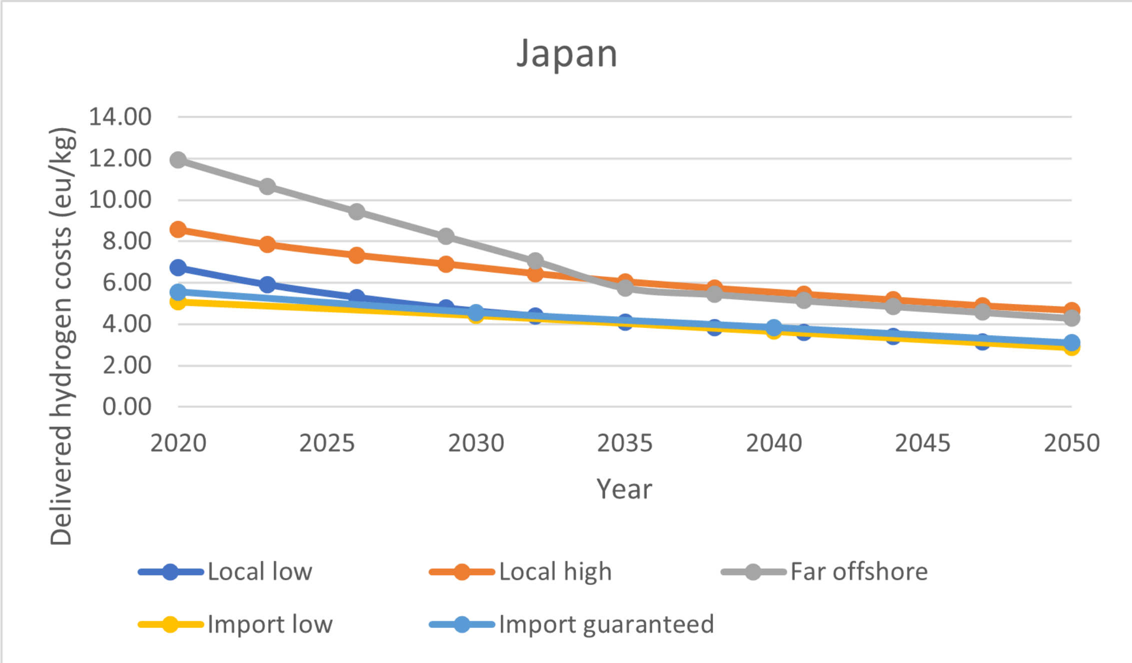

Figure 8.1: Comparison of delivered costs of green hydrogen to Tokio from 2020 to 2050 (produced far offshore, produced locally and imported)

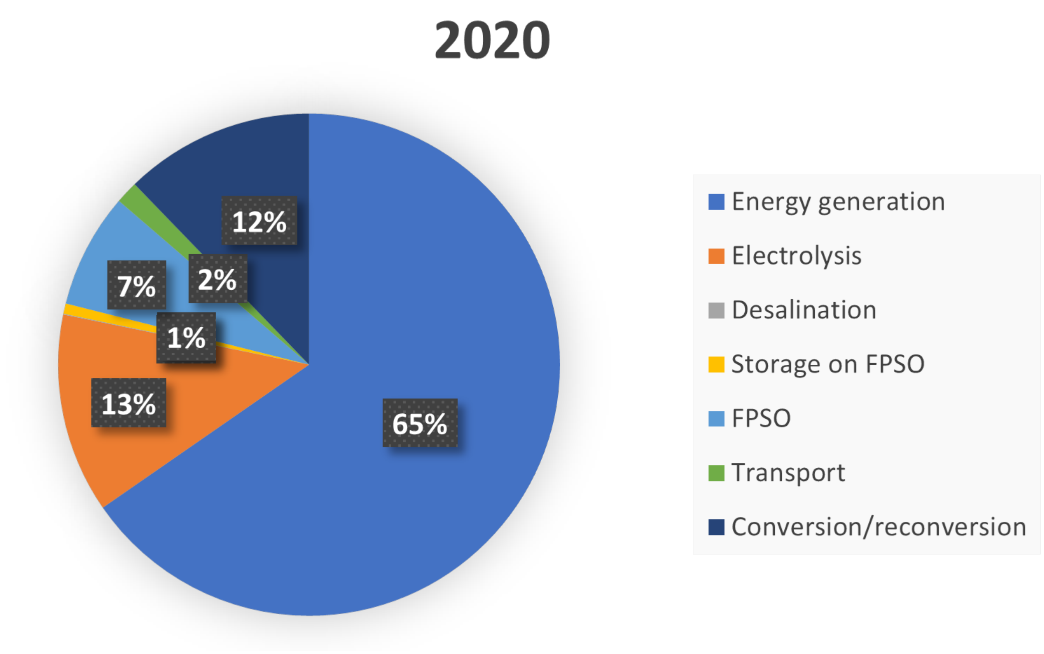

Figure 8.2: Cost distribution of far offshore green hydrogen delivered costs in 2020 in scenario 1

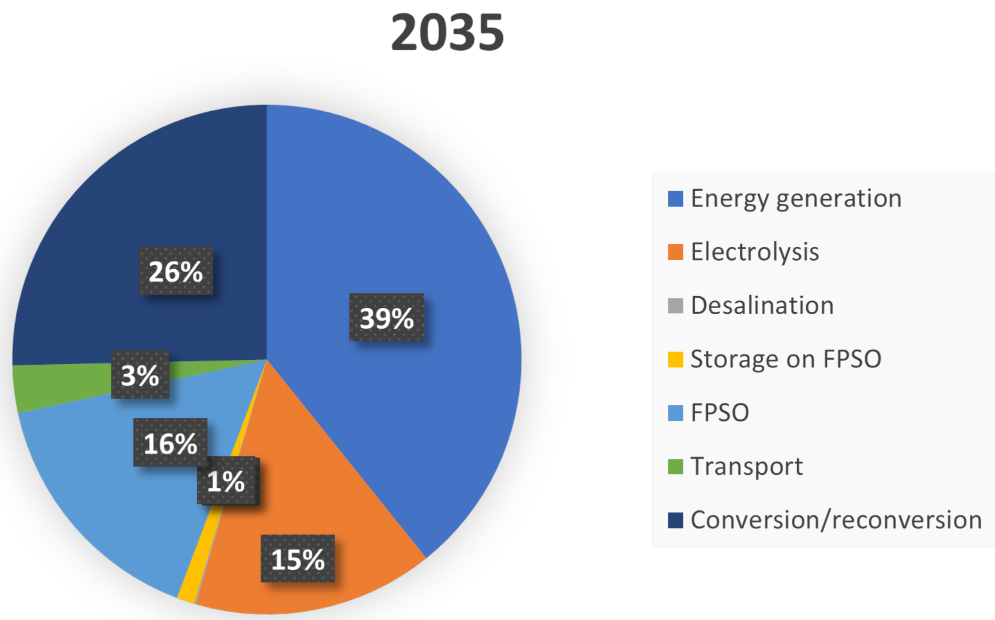

Figure 8.3: Cost distribution of far offshore green hydrogen delivered costs in 2035 in scenario 1

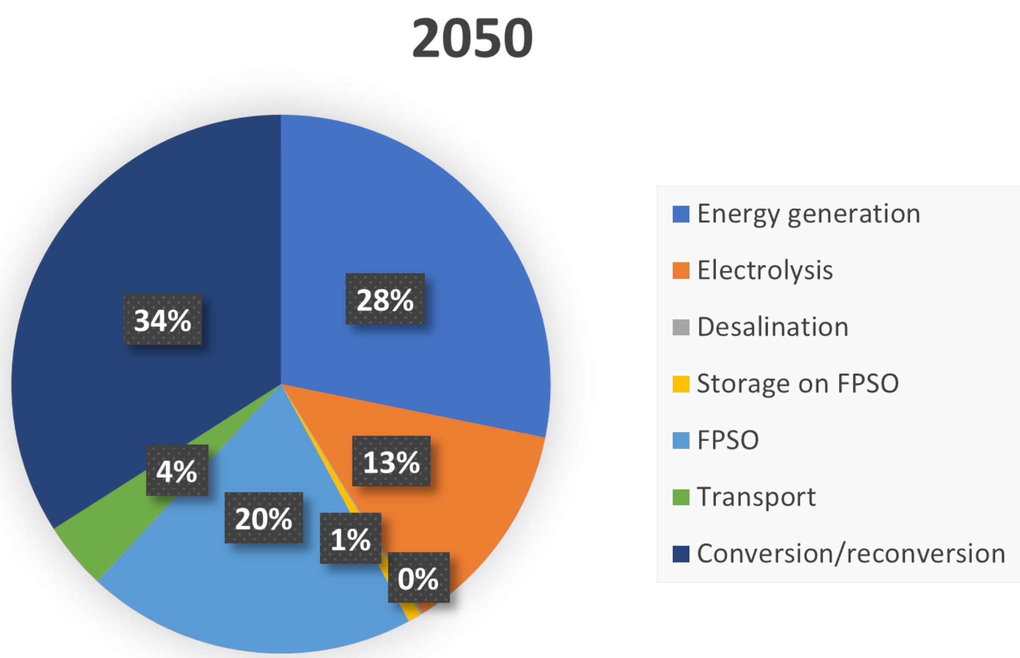

Figure 8.4: Cost distribution of far offshore green hydrogen delivered costs in 2050 in scenario 1

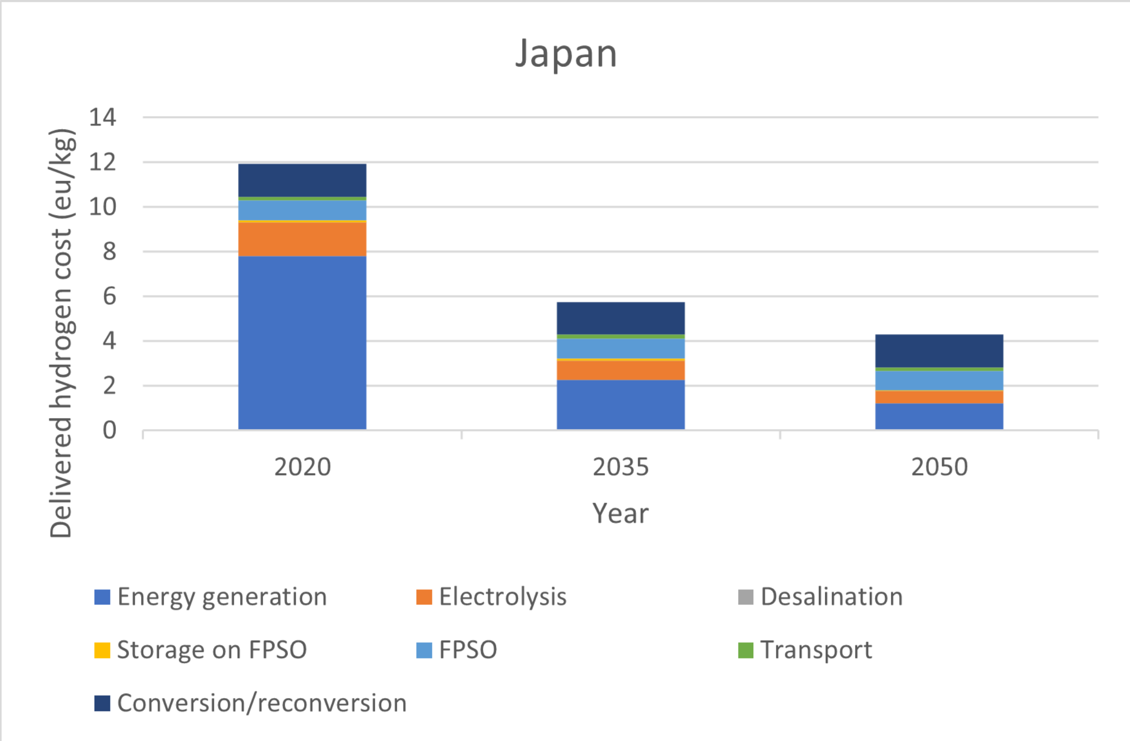

Figure 8.5: Cost distribution of far offshore green hydrogen delivered costs in 2020, 2035 and 2050 in scenario 1

Results scenario 2

Table 8.4: Results scenario 2 far offshore green hydrogen

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Seoul	Seoul	Seoul	Seoul	Seoul	Seoul	Seoul	Seoul	Seoul	Seoul	Seoul
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Incheon	Incheon	Incheon	Incheon	Incheon	Incheon	Incheon	Incheon	Incheon	Incheon	Incheon
Total costs per year (euros)	5.97E+08	5.33E+08	4.72E+08	4.12E+08	3.52E+08	2.88E+08	2.72E+08	2.57E+08	2.43E+08	2.29E+08	2.15E+08
Costs per kg hydrogen (euros)	11.93	10.66	9.45	8.24	7.05	5.76	5.44	5.14	4.86	4.58	4.29
Wind turbines	39	41	44	46	49	58	60	60	60	63	63
Solar platforms	1464	1328	1111	939	663	40	30	30	30	5	5
Electrolyzers	27	26	25	25	26	28	27	27	27	26	26
Desalination equipment	26	25	24	24	25	27	26	26	26	25	25
Storage volume	4.79E+04	4.61E+04	4.44E+04	4.44E+04	4.61E+04	4.97E+04	4.79E+04	4.79E+04	4.79E+04	4.61E+04	4.61E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume	4.86E+05	4.68E+05	4.50E+05	4.50E+05	4.68E+05	5.04E+05	4.86E+05	4.86E+05	4.86E+05	4.68E+05	4.68E+05
Distance sea	1180	1180	1180	1180	1180	1180	1180	1180	1180	1180	1180
Distance land	37	37	37	37	37	37	37	37	37	37	37

Table 8.5: Results scenario 2 local production (Brändle et al., 2021)

	PV 1	PV 2	PV 3	PV 4	Onshore 1	Onshore 2	Onshore 3	Offshore 1	Offshore 2
Production capacities (Mt/year)									
2020				14.86			0.11	2.78	6.31
2023				15			0.12	2.8	6.36
2026				15.14			0.12	2.82	6.4
2029				15.28			0.12	2.85	6.45
2032				15.48			0.12	2.89	6.54
2035				15.7			0.12	2.93	6.64
2038				15.92			0.12	2.97	6.74
2041				16.15			0.13	3.02	6.84
2044				16.39			0.13	3.06	6.94
2047				16.62			0.13	3.11	7.04
2050				16.86			0.13	3.15	7.14
Costs (euros/kg)									
2020				5.90			6.84	7.56	8.47
2023				5.19			6.32	6.92	7.76
2026				4.65			5.90	6.45	7.25
2029				4.19			5.52	6.05	6.83
2032				3.85			5.20	5.64	6.37
2035				3.59			4.95	5.30	5.99
2038				3.37			4.72	5.02	5.67
2041				3.16			4.51	4.76	5.39
2044				2.97			4.34	4.52	5.12
2047				2.75			4.11	4.27	4.84
2050				2.58			3.93	4.08	4.62

Table 8.6: Results scenario 2 import (Brändle et al., 2021)

Year	Total worldwide demand (Mt/year)	Cheapest (euros/kg)	Guaranteed (euros/kg)
2020	90	5.04	5.29
2030	140	4.35	4.53
2040	385	3.63	3.84
2050	660	2.86	3.08

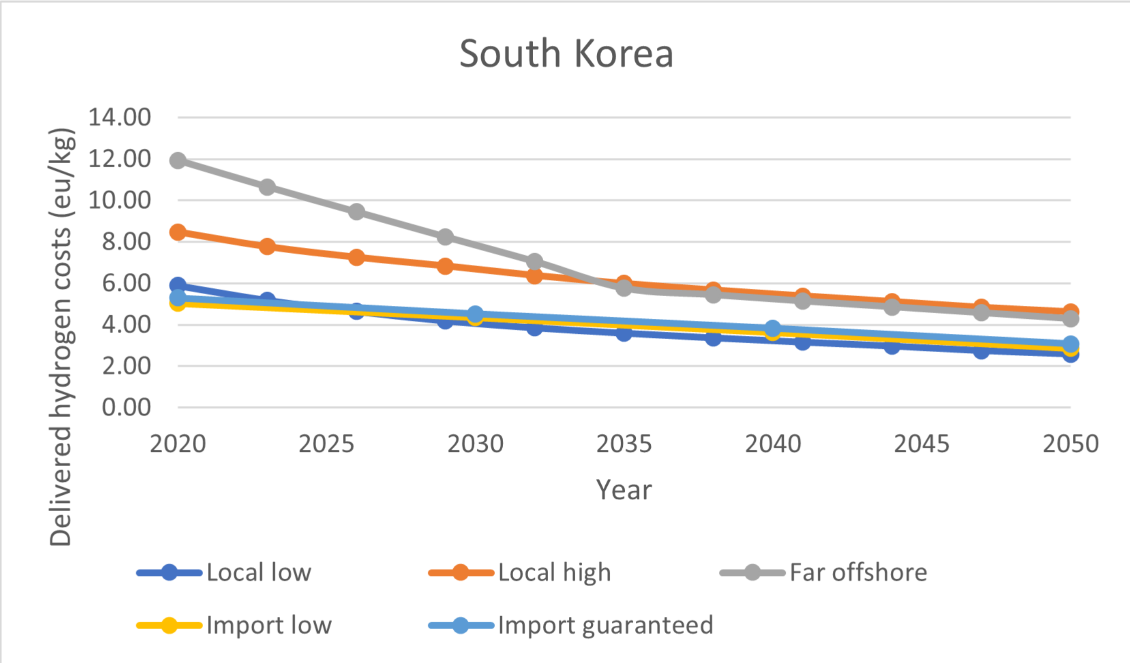

Figure 8.6: Comparison of delivered costs of green hydrogen to Seoul from 2020 to 2050 (produced far offshore, produced locally and imported)

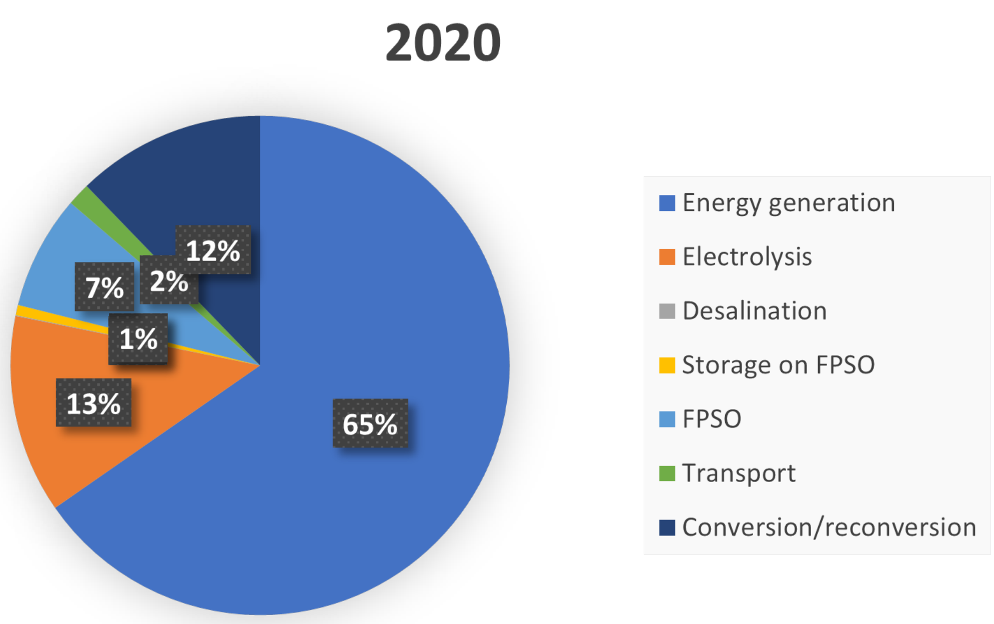

Figure 8.7: Cost distribution of far offshore green hydrogen delivered costs in 2020 in scenario 2

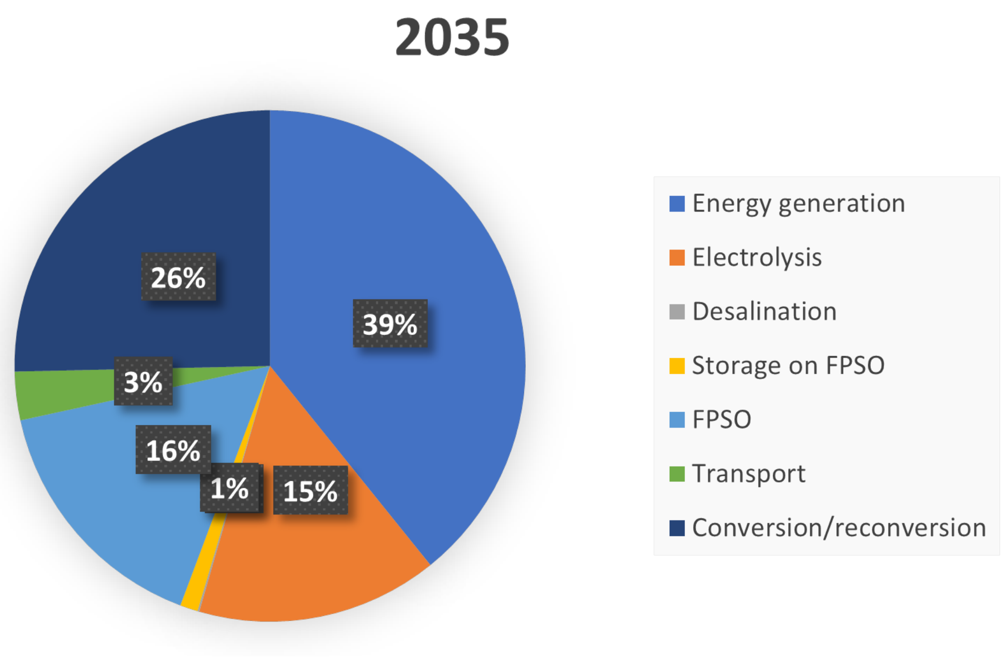

Figure 8.8: Cost distribution of far offshore green hydrogen delivered costs in 2035 in scenario 2

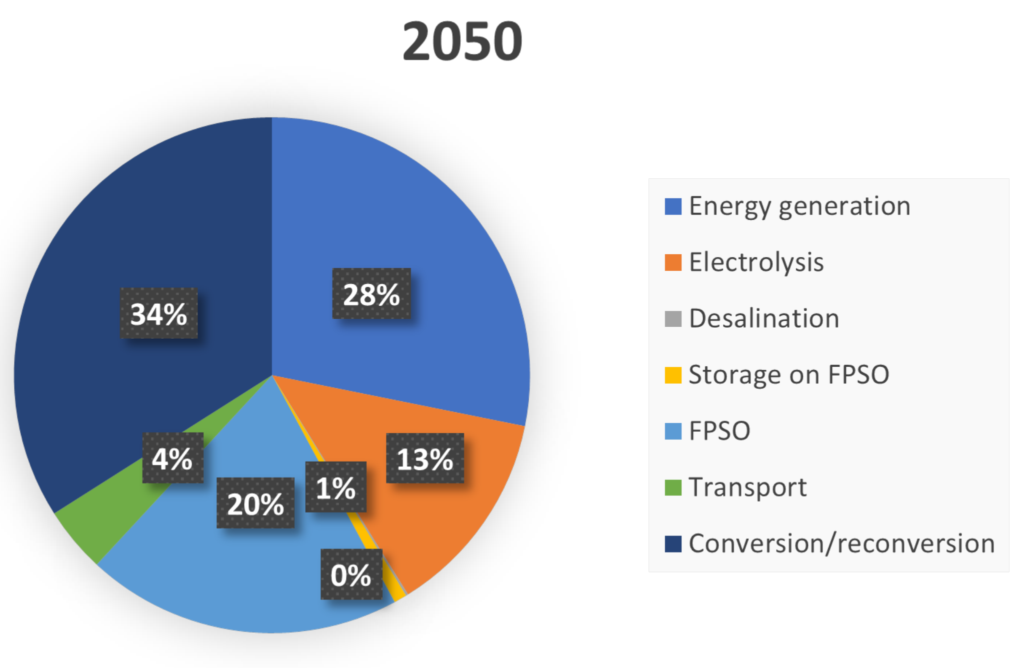

Figure 8.9: Cost distribution of far offshore green hydrogen delivered costs in 2050 in scenario 2

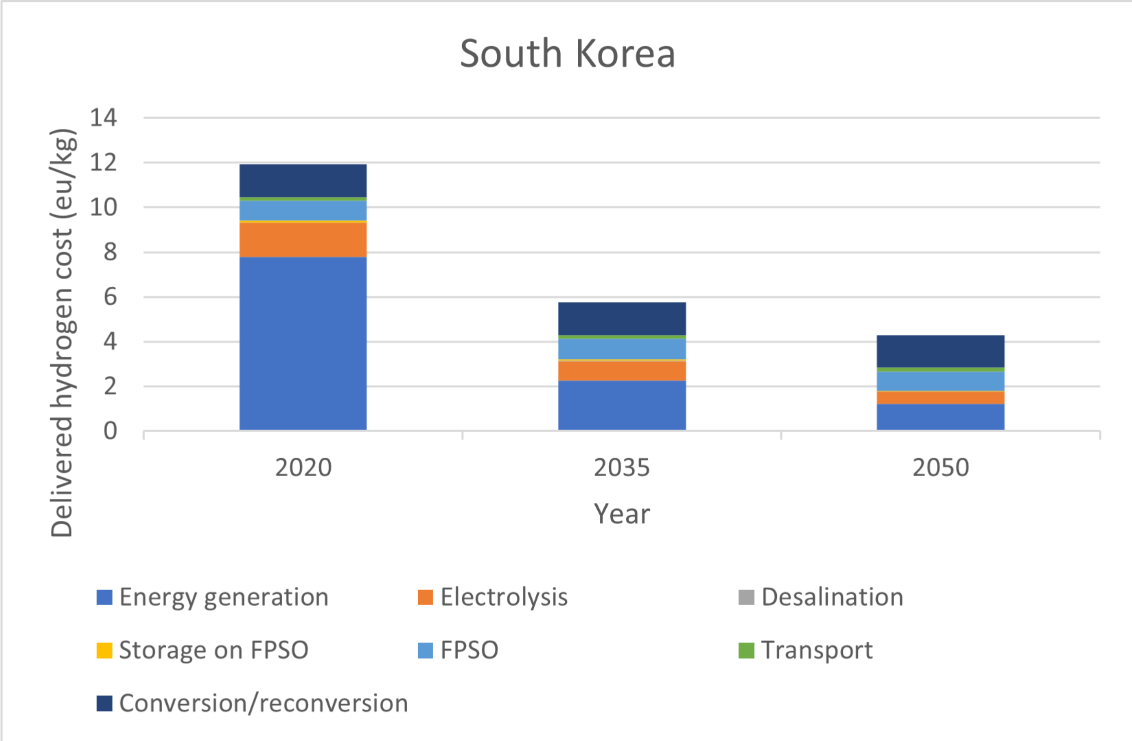

Figure 8.10: Cost distribution of far offshore green hydrogen delivered costs in 2020, 2035 and 2050 in scenario 2

Results scenario 3

Table 8.7: Results scenario 3 far offshore green hydrogen

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Cologne	Cologne	Cologne	Cologne	Cologne	Cologne	Cologne	Cologne	Cologne	Cologne	Cologne
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	Celtic Seas	Celtic Seas	Celtic Seas	Celtic Seas	Celtic Seas	Celtic Seas	Celtic Seas	Celtic Seas	Celtic Seas	Celtic Seas	Celtic Seas
Transfer port	Rotterdam	Rotterdam	Rotterdam	Rotterdam	Rotterdam	Rotterdam	Rotterdam	Rotterdam	Rotterdam	Rotterdam	Rotterdam
Total costs per year (euros)	4.72E+08	4.23E+08	3.74E+08	3.25E+08	2.78E+08	2.32E+08	2.21E+08	2.10E+08	2.01E+08	1.91E+08	1.82E+08
Costs per kg hydrogen (euros)	9.43	8.45	7.48	6.50	5.57	4.64	4.42	4.21	4.02	3.83	3.64
Wind turbines	39	39	39	39	39	40	40	40	40	40	41
Solar platforms	16	16	16	16	16	30	30	30	30	30	0
Electrolyzers	22	22	22	22	22	21	21	21	21	21	21
Desalination equipment	22	22	22	22	22	21	21	21	21	21	21
Storage volume (m3)	3.90E+04	3.90E+04	3.90E+04	3.90E+04	3.90E+04	3.73E+04	3.73E+04	3.73E+04	3.73E+04	3.73E+04	3.73E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	3.96E+05	3.96E+05	3.96E+05	3.96E+05	3.96E+05	3.78E+05	3.78E+05	3.78E+05	3.78E+05	3.78E+05	3.78E+05
Distance sea (km)	2429	2429	2429	2429	2429	2429	2429	2429	2429	2429	2429
Distance land (km)	204	204	204	204	204	204	204	204	204	204	204

Table 8.8: Results scenario 3 local production (Brändle et al., 2021)

	PV 1	PV 2	PV 3	PV 4	Onshore 1	Onshore 2	Onshore 3	Offshore 1	Offshore 2
Production capacities (Mt/year)									
2020				8.36		0.47	10.64	1.24	5.57
2023				8.46		0.48	10.76	1.25	5.61
2026				8.56		0.48	10.88	1.26	5.66
2029				8.67		0.49	11	1.27	5.7
2032				8.78		0.49	11.16	1.28	5.78
2035				8.89		0.5	11.34	1.3	5.86
2038				9		0.51	11.52	1.32	5.95
2041				9.12		0.52	11.7	1.34	6.04
2044				9.25		0.53	11.89	1.36	6.13
2047				9.39		0.53	12.07	1.38	6.22
2050				9.53		0.54	12.26	1.4	6.31
Costs (euros/kg)									
2020				5.99		3.72	5.13	4.68	5.42
2023				5.27		3.44	4.75	4.28	4.97
2026				4.71		3.20	4.43	3.98	4.64
2029				4.23		3.00	4.16	3.73	4.36
2032				3.89		2.82	3.92	3.48	4.07
2035				3.63		2.69	3.73	3.27	3.82
2038				3.40		2.56	3.56	3.09	3.62
2041				3.19		2.45	3.40	2.94	3.44
2044				3.00		2.35	3.27	2.79	3.26
2047				2.78		2.23	3.10	2.63	3.08
2050				2.61		2.14	2.97	2.51	2.95

Table 8.9: Results scenario 3 import (Brändle et al., 2021)

Year	Total worldwide demand (Mt/year)	Cheapest (euros/kg)	Guaranteed (euros/kg)
2020	90	3.74	4.38
2030	140	3.01	3.21
2040	385	2.57	2.86
2050	660	2.15	2.35

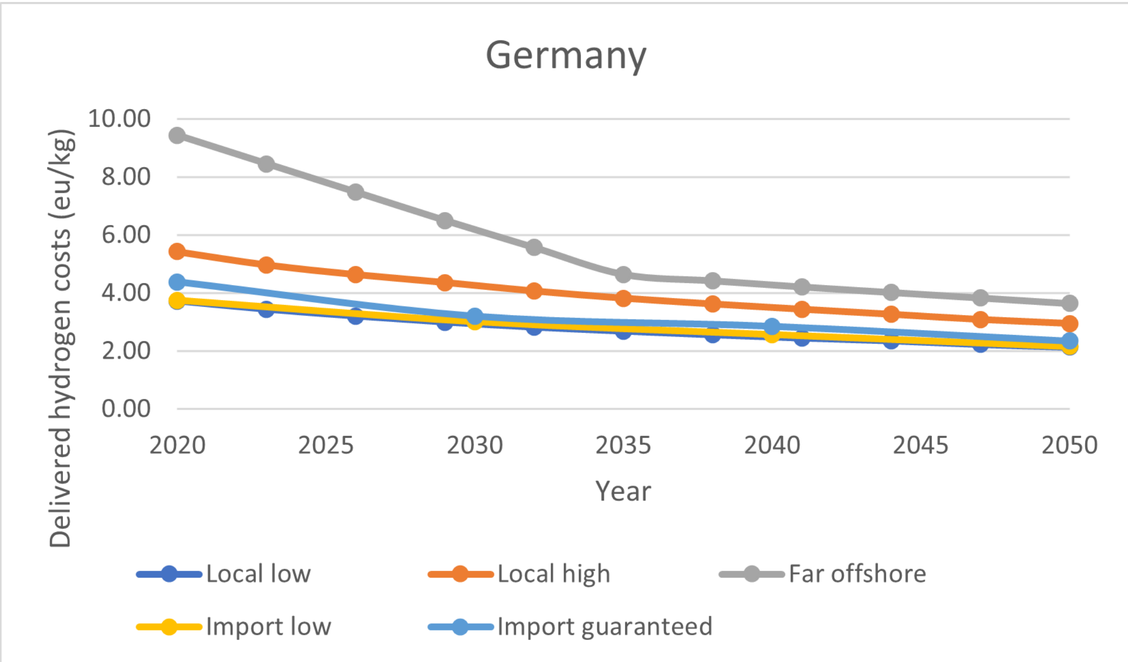

Figure 8.11: Comparison of delivered costs of green hydrogen to Cologne from 2020 to 2050 (produced far offshore, produced locally and imported)

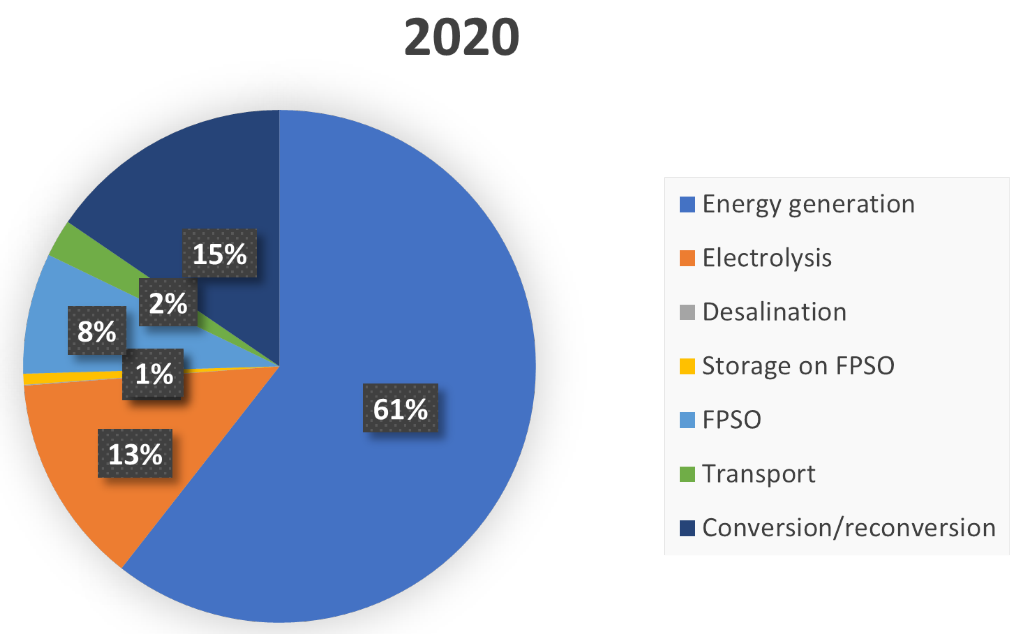

Figure 8.12: Cost distribution of far offshore green hydrogen delivered costs in 2020 in scenario 3

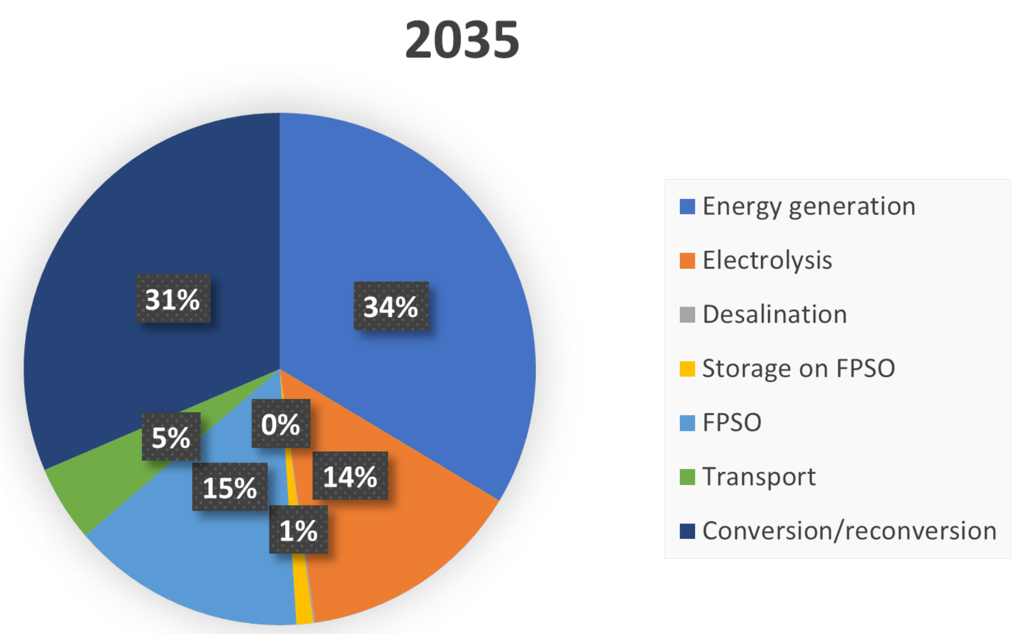

Figure 8.13: Cost distribution of far offshore green hydrogen delivered costs in 2035 in scenario 3

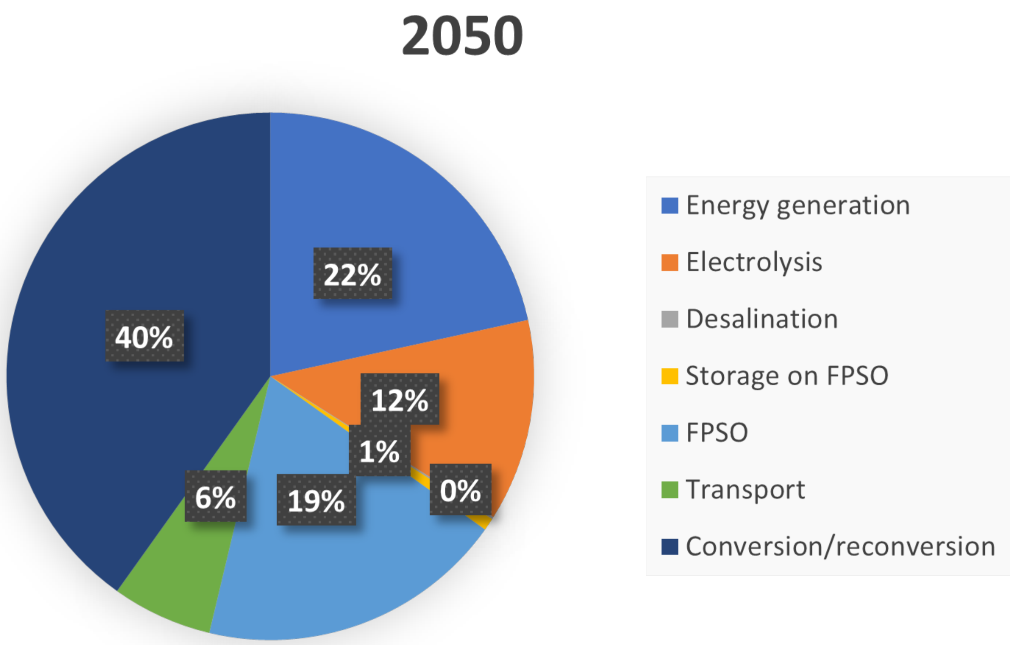

Figure 8.14: Cost distribution of far offshore green hydrogen delivered costs in 2050 in scenario 3

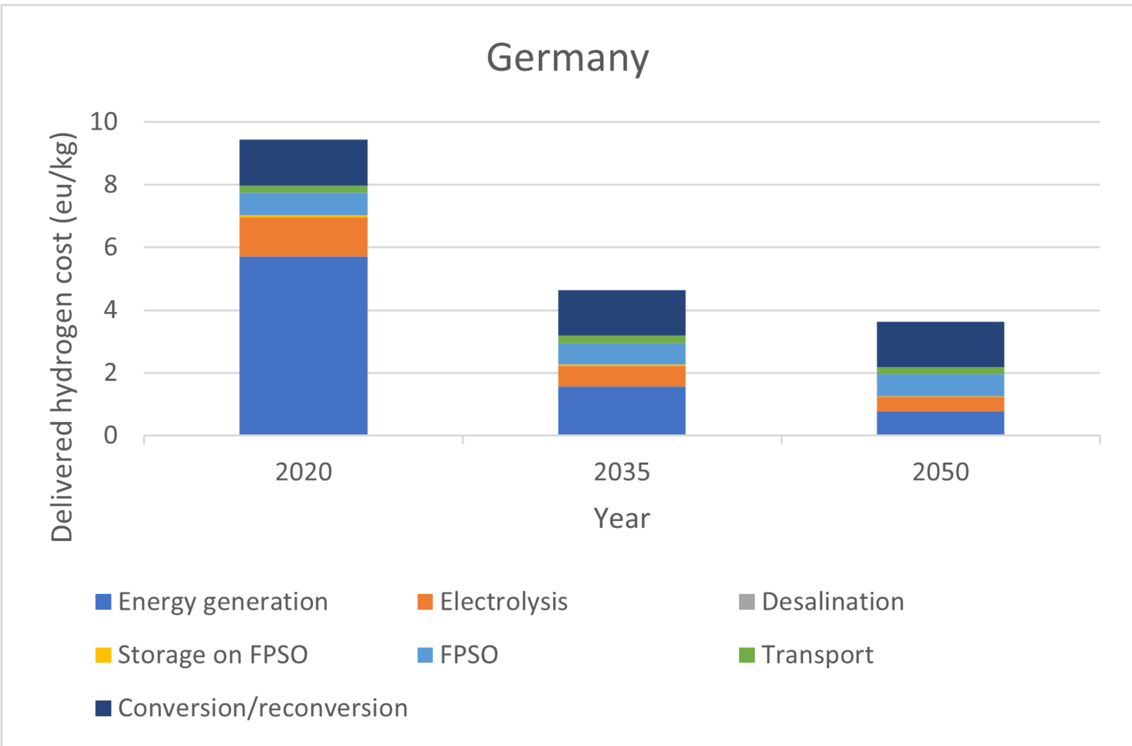

Figure 8.15: Cost distribution of far offshore green hydrogen delivered costs in 2020, 2035 and 2050 in scenario 3

Results scenario 4

Table 8.10: Results scenario 4 far offshore green hydrogen

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	New York City	New York City	New York City	New York City	New York City	New York City	New York City	New York City	New York City	New York City	New York City
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	North Atlantic Ocean	North Atlantic Ocean	North Atlantic Ocean	North Atlantic Ocean	North Atlantic Ocean	North Atlantic Ocean	North Atlantic Ocean	North Atlantic Ocean	North Atlantic Ocean	North Atlantic Ocean	North Atlantic Ocean
Transfer port	New York City	New York City	New York City	New York City	New York City	New York City	New York City	New York City	New York City	New York City	New York City
Total costs per year (euros)	4.53E+08	4.07E+08	3.60E+08	3.13E+08	2.69E+08	2.25E+08	2.14E+08	2.04E+08	1.95E+08	1.85E+08	1.76E+08
Costs per kg hydrogen (euros)	9.07	8.13	7.20	6.27	5.38	4.49	4.28	4.08	3.89	3.71	3.52
Wind turbines	37	37	37	37	37	38	38	38	40	40	40
Solar platforms	59	59	59	59	59	0	0	0	-9.86295E-14	5.78147E-14	0
Electrolyzers	21	21	21	21	21	21	21	21	20	20	20
Desalination equipment	21	21	21	21	21	21	21	21	20	20	20
Storage volume	3.73E+04	3.73E+04	3.73E+04	3.73E+04	3.73E+04	3.73E+04	3.73E+04	3.73E+04	3.55E+04	3.55E+04	3.55E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume	3.78E+05	3.78E+05	3.78E+05	3.78E+05	3.78E+05	3.78E+05	3.78E+05	3.78E+05	3.60E+05	3.60E+05	3.60E+05
Distance sea	2222	2222	2222	2222	2222	2222	2222	2222	2222	2222	2222
Distance land	0	0	0	0	0	0	0	0	0	0	0

Table 8.11: Results scenario 4 local production (Brändle et al., 2021)

	PV 1	PV 2	PV 3	PV 4	Onshore 1	Onshore 2	Onshore 3	Offshore 1	Offshore 2
Production capacities (Mt/year)									
2020	1.86	136.21	787.87	5428.88		10.93	124.58	17.4	32.89
2023	1.88	137.58	795.41	5478.55		11.06	126.11	17.54	33.19
2026	1.9	138.96	803.01	5528.55		11.18	127.68	17.7	33.5
2029	1.92	140.35	810.67	5578.88		11.31	129.3	17.85	33.8
2032	1.94	142.16	821.14	5650.38		11.48	131.26	18.08	34.25
2035	1.97	144.15	832.99	5732.26		11.67	133.38	18.36	34.78
2038	1.99	146.15	844.82	5814.03		11.85	135.5	18.64	35.3
2041	2.02	148.21	856.86	5897.2		12.04	137.66	18.92	35.83
2044	2.05	150.4	869.39	5983.38		12.23	139.89	19.2	36.37
2047	2.08	152.6	881.91	6069.56		12.42	142.13	19.48	36.92
2050	2.11	154.8	894.43	6155.74		12.61	144.38	19.77	37.46
Costs (euros/kg)									
2020	4.01	4.21	4.40	5.30		4.01	5.24	7.20	4.68
2023	3.53	3.71	3.87	4.66		3.69	4.83	6.59	4.28
2026	3.16	3.32	3.46	4.17		3.43	4.49	6.13	3.98
2029	2.84	2.98	3.11	3.76		3.20	4.19	5.75	3.74
2032	2.61	2.74	2.86	3.45		3.00	3.94	5.36	3.49
2035	2.43	2.56	2.67	3.23		2.86	3.75	5.03	3.27
2038	2.28	2.40	2.50	3.02		2.72	3.57	4.77	3.10
2041	2.14	2.25	2.35	2.84		2.60	3.41	4.53	2.94
2044	2.01	2.12	2.21	2.67		2.49	3.28	4.30	2.79
2047	1.86	1.96	2.05	2.47		2.36	3.10	4.06	2.64
2050	1.75	1.84	1.92	2.32		2.26	2.97	3.87	2.52

Table 8.12: Results scenario 4 import (Brändle et al., 2021)

Year	Total worldwide demand (Mt/year)	Cheapest (euros/kg)	Guaranteed (euros/kg)
2020	90	5.48	5.60
2030	140	4.33	4.48
2040	385	3.67	3.78
2050	660	2.94	3.04

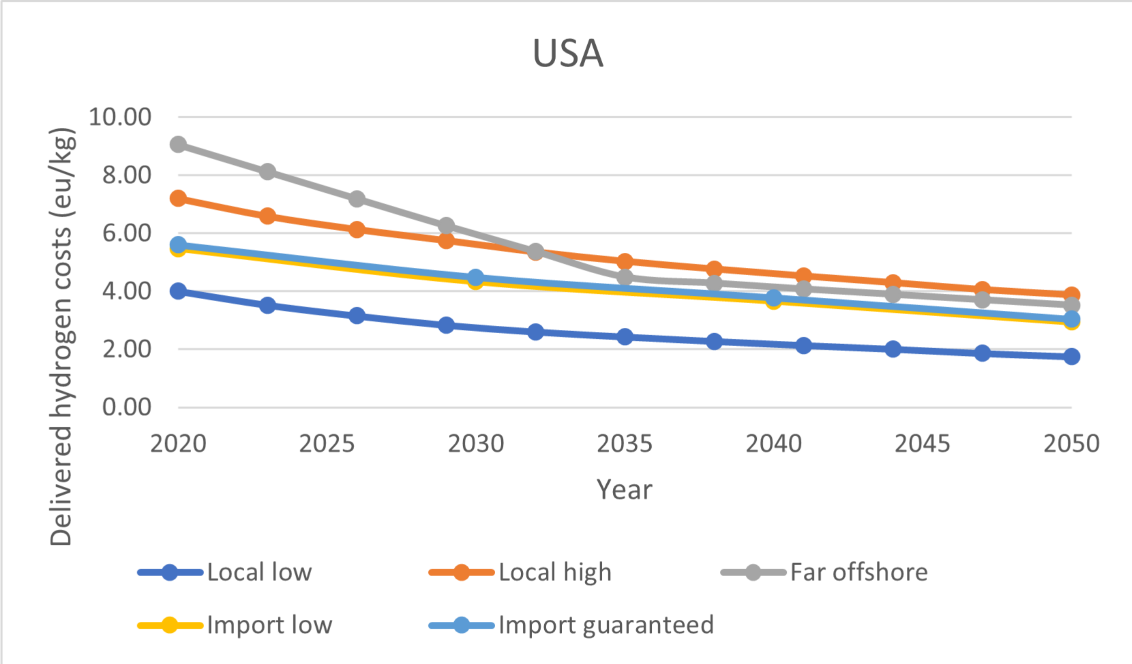

Figure 8.16: Comparison of delivered costs of green hydrogen to New York from 2020 to 2050 (produced far offshore, produced locally and imported)

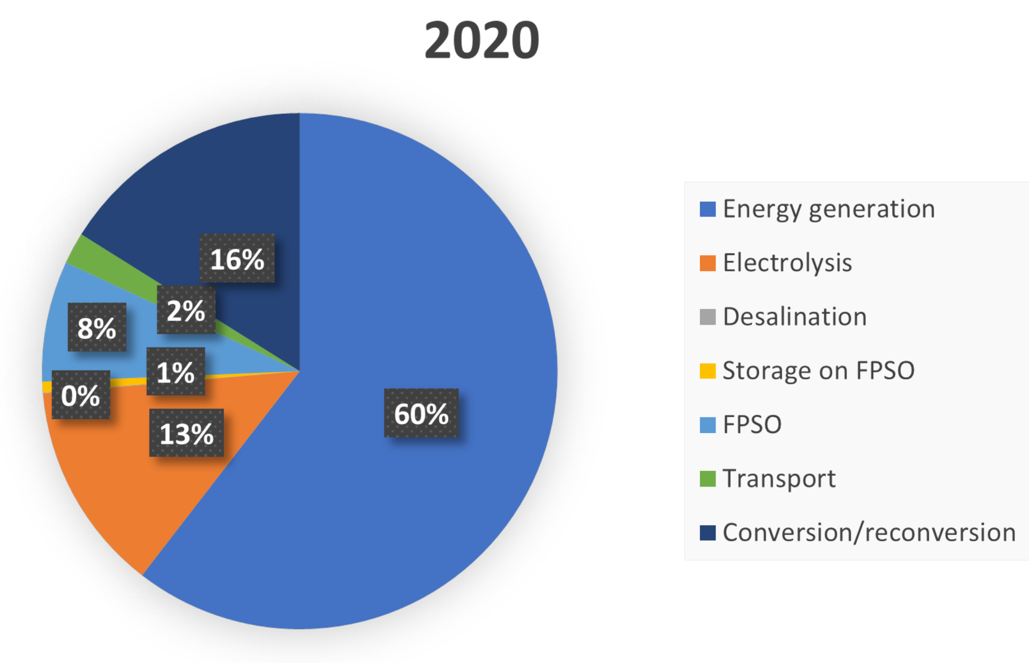

Figure 8.17: Cost distribution of far offshore green hydrogen delivered costs in 2020 in scenario 4

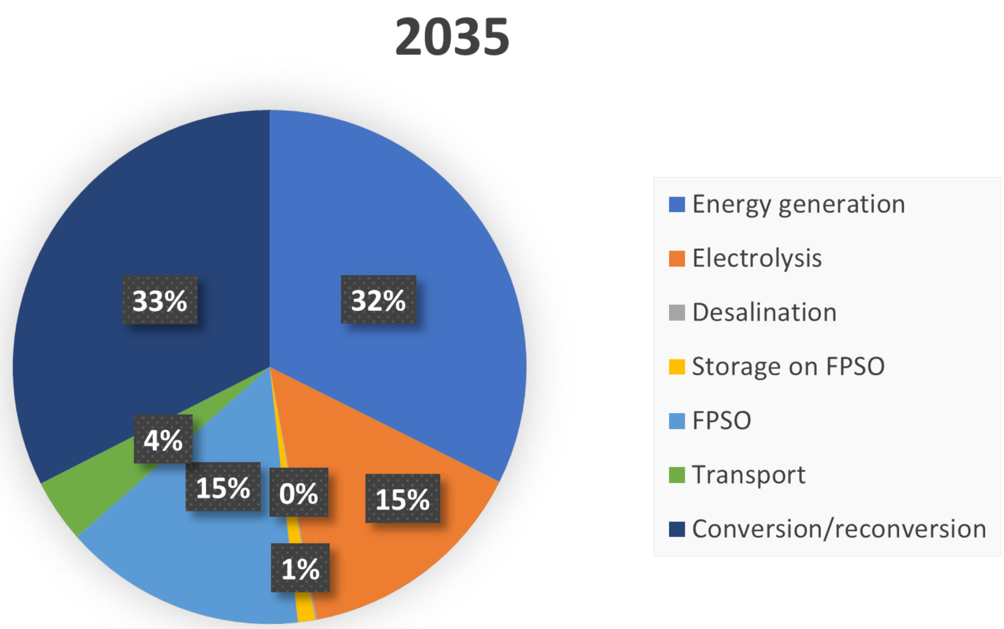

Figure 8.18: Cost distribution of far offshore green hydrogen delivered costs in 2035 in scenario 4

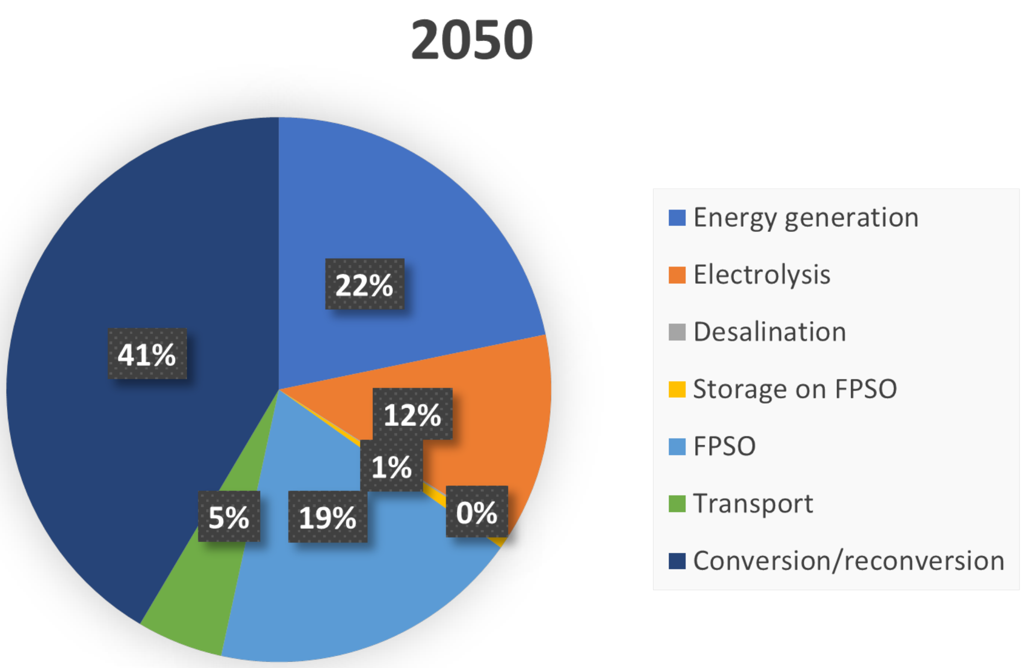

Figure 8.19: Cost distribution of far offshore green hydrogen delivered costs in 2050 in scenario 4

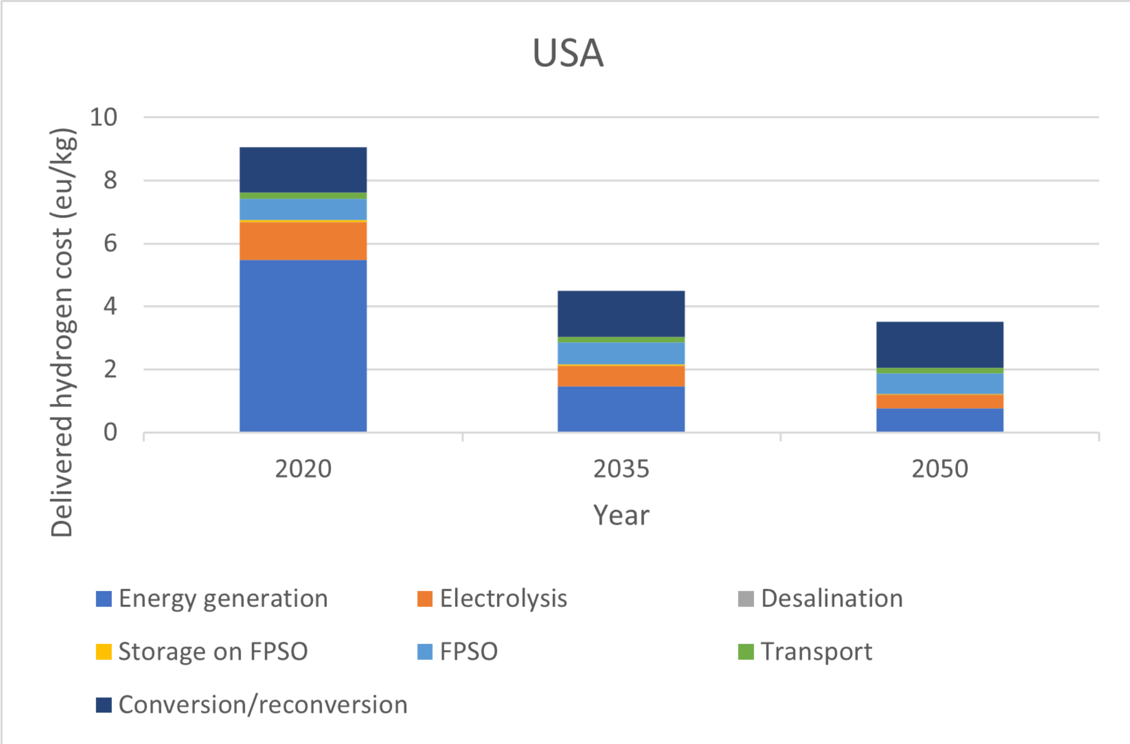

Figure 8.20: Cost distribution of far offshore green hydrogen delivered costs in 2020, 2035 and 2050 in scenario 4

Results scenario 5

Table 8.13: Results scenario 5 far offshore green hydrogen

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Singapore	Singapore	Singapore	Singapore	Singapore	Singapore	Singapore	Singapore	Singapore	Singapore	Singapore
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	Southern pacific ocean	Southern pacific ocean	Southern pacific ocean	Southern pacific ocean	Southern pacific ocean	Southern pacific ocean	Southern pacific ocean	Southern pacific ocean	Southern pacific ocean	Southern pacific ocean	Southern pacific ocean
Transfer port	Singapore	Singapore	Singapore	Singapore	Singapore	Singapore	Singapore	Singapore	Singapore	Singapore	Singapore
Total costs per year (euros)	3.94E+08	3.56E+08	3.17E+08	2.79E+08	2.42E+08	2.06E+08	1.97E+08	1.89E+08	1.81E+08	1.74E+08	1.67E+08
Costs per kg hydrogen (euros)	7.89	7.12	6.34	5.57	4.83	4.11	3.94	3.77	3.63	3.48	3.33
Wind turbines	31	31	31	31	31	31	31	31	31	31	31
Solar platforms	0	0	0	0	0	0	0	0	0	0	0
Electrolyzers	17	17	17	17	17	17	17	17	17	17	17
Desalination equipment	17	17	17	17	17	17	17	17	17	17	17
Storage volume	3.02E+04	3.02E+04	3.02E+04	3.02E+04	3.02E+04	3.02E+04	3.02E+04	3.02E+04	3.02E+04	3.02E+04	3.02E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume	3.06E+05	3.06E+05	3.06E+05	3.06E+05	3.06E+05	3.06E+05	3.06E+05	3.06E+05	3.06E+05	3.06E+05	3.06E+05
Distance sea	16719	16719	16719	16719	16719	16719	16719	16719	16719	16719	16719
Distance land	0	0	0	0	0	0	0	0	0	0	0

Table 8.14: Results scenario 5 local production (Brändle et al., 2021)

	PV 1	PV 2	PV 3	PV 4	Onshore 1	Onshore 2	Onshore 3	Offshore 1	Offshore 2
Production capacities (Mt/year)									
2020								0.01	
2023								0.01	
2026								0.01	
2029								0.01	
2032								0.01	
2035								0.01	
2038								0.01	
2041								0.01	
2044								0.01	
2047								0.01	
2050								0.01	
Costs (euros/kg)									
2020								14.98	
2023								13.74	
2026								12.85	
2029								12.13	
2032								11.32	
2035								10.63	
2038								10.07	
2041								9.57	
2044								9.09	
2047								8.59	
2050								8.21	

Table 8.15: Results scenario 5 import (Brändle et al., 2021;International Energy Agency, 2022)

Year	Total worldwide demand (Mt/year)	Cheapest (euros/kg)	Guaranteed (euros/kg)
2020	90	4.79	6.33
2030	140	3.31	4.70
2040	385	2.67	3.72
2050	660	2.17	2.85

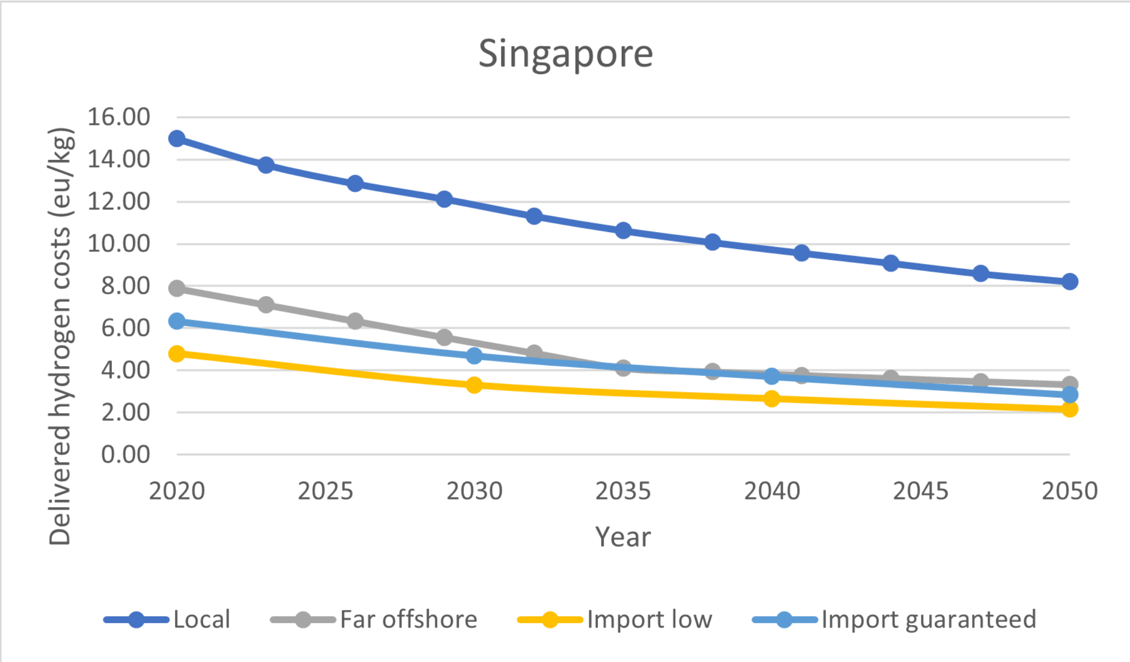

Figure 8.21: Comparison of delivered costs of green hydrogen to Singapore from 2020 to 2050 (produced far offshore, produced locally and imported)

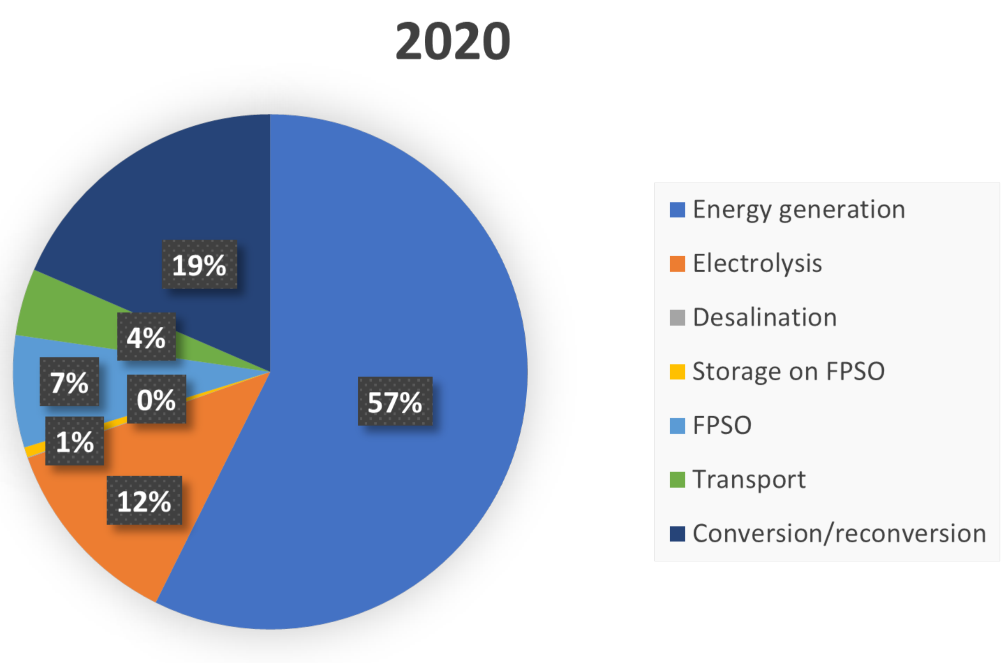

Figure 8.22: Cost distribution of far offshore green hydrogen delivered costs in 2020 in scenario 5

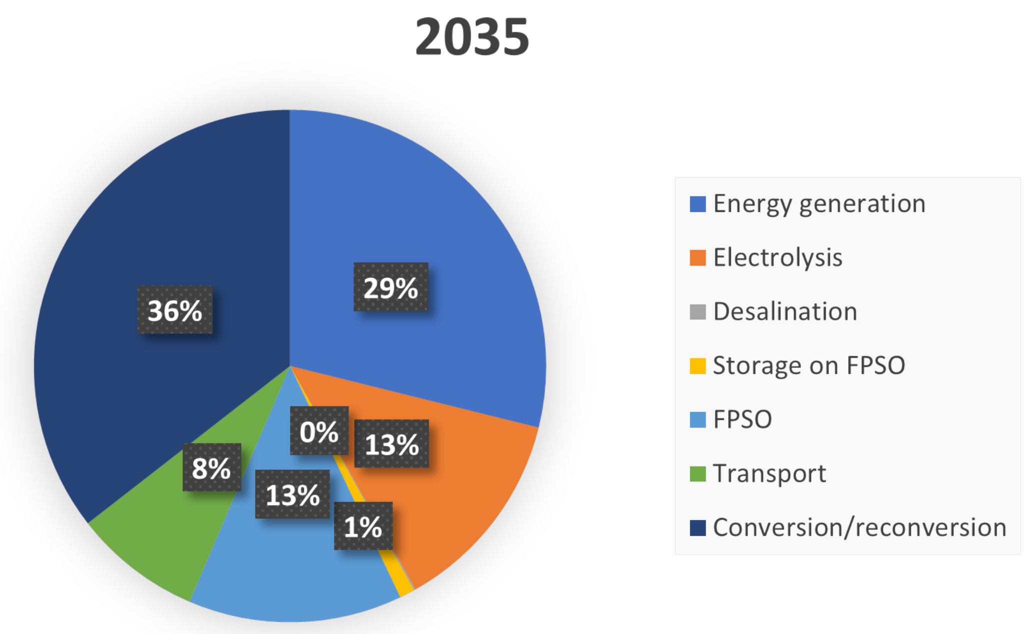

Figure 8.23: Cost distribution of far offshore green hydrogen delivered costs in 2035 in scenario 5

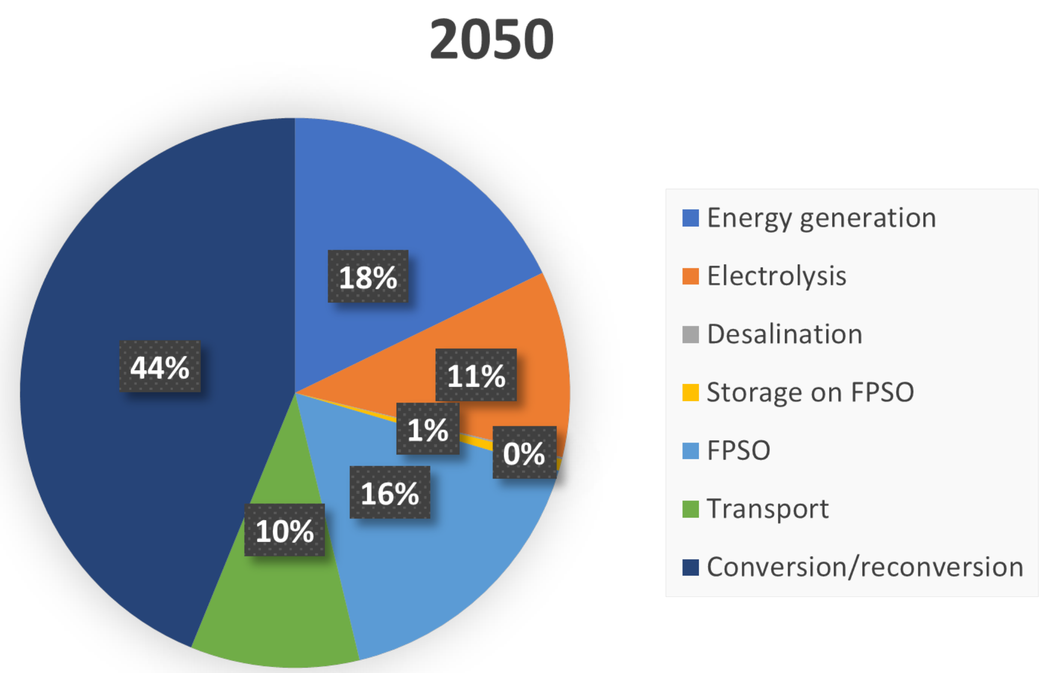

Figure 8.24: Cost distribution of far offshore green hydrogen delivered costs in 2050 in scenario 5

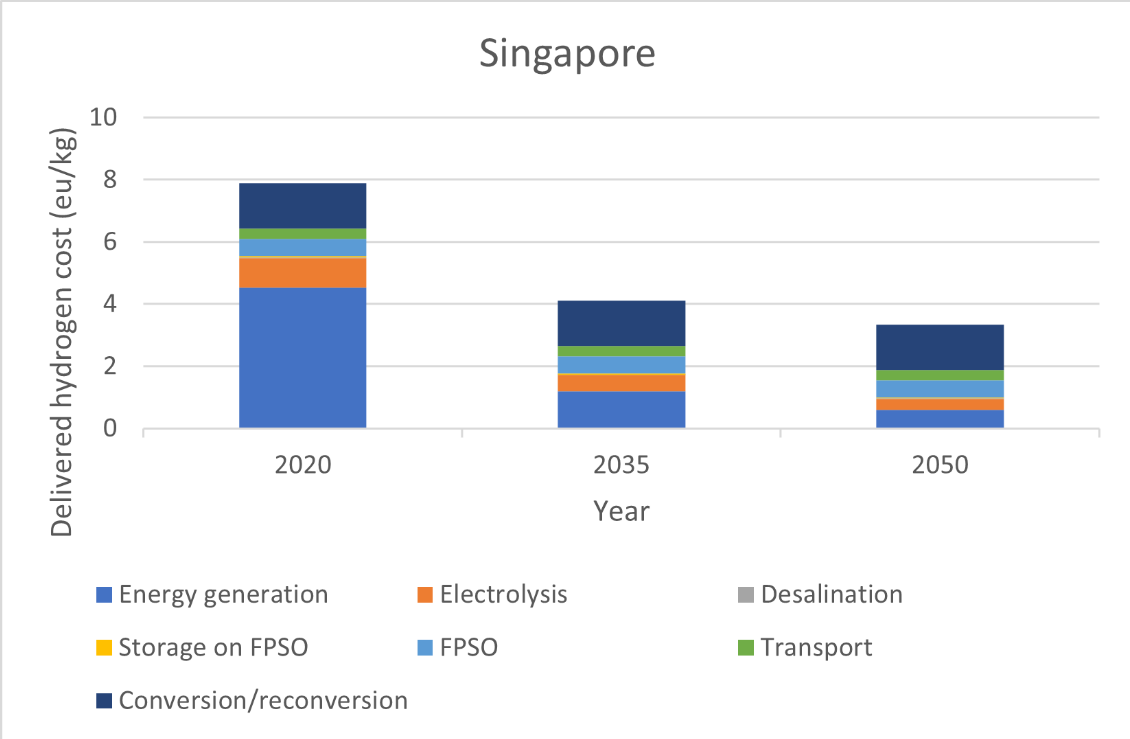

Figure 8.25: Cost distribution of far offshore green hydrogen delivered costs in 2020, 2035 and 2050 in scenario 5

Results scenario 6

Table 8.16: Results scenario 6 far offshore green hydrogen

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Christchurch	Christchurch	Christchurch	Christchurch	Christchurch	Christchurch	Christchurch	Christchurch	Christchurch	Christchurch	Christchurch
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	Southern pacific ocean	Southern pacific ocean	Southern pacific ocean	Southern pacific ocean	Southern pacific ocean	Southern pacific ocean	Southern pacific ocean	Southern pacific ocean	Southern pacific ocean	Southern pacific ocean	Southern pacific ocean
Transfer port	Christchurch	Christchurch	Christchurch	Christchurch	Christchurch	Christchurch	Christchurch	Christchurch	Christchurch	Christchurch	Christchurch
Total costs per year (euros)	3.86E+08	3.48E+08	3.09E+08	2.70E+08	2.34E+08	1.97E+08	1.89E+08	1.81E+08	1.73E+08	1.66E+08	1.58E+08
Costs per kg hydrogen (euros)	7.73	6.95	6.18	5.41	4.67	3.95	3.78	3.61	3.46	3.32	3.17
Wind turbines	31	31	31	31	31	31	31	31	31	31	31
Solar platforms	0	0	0	0	0	0	0	0	0	0	0
Electrolyzers	17	17	17	17	17	17	17	17	17	17	17
Desalination equipment	17	17	17	17	17	17	17	17	17	17	17
Storage volume	3.02E+04	3.02E+04	3.02E+04	3.02E+04	3.02E+04	3.02E+04	3.02E+04	3.02E+04	3.02E+04	3.02E+04	3.02E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume	3.06E+05	3.06E+05	3.06E+05	3.06E+05	3.06E+05	3.06E+05	3.06E+05	3.06E+05	3.06E+05	3.06E+05	3.06E+05
Distance sea	1248	1248	1248	1248	1248	1248	1248	1248	1248	1248	1248
Distance land	0	0	0	0	0	0	0	0	0	0	0

Table 8.17: Results scenario 6 local production (Concept Consulting Group, 2019;Brändle et al., 2021)

Year	Costs (euros/kg)
2020	4.89
2023	4.51
2026	4.20
2029	3.92
2032	3.68
2035	3.50
2038	3.34
2041	3.19
2044	3.06
2047	2.90
2050	2.77

Table 8.18: Results scenario 6 import (Brändle et al., 2021;International Energy Agency, 2022)

Year	Total worldwide demand (Mt/year)	Cheapest (euros/kg)	Guaranteed (euros/kg)
2020	90	6.07	6.61
2030	140	4.58	4.95
2040	385	3.60	3.90
2050	660	2.74	2.97

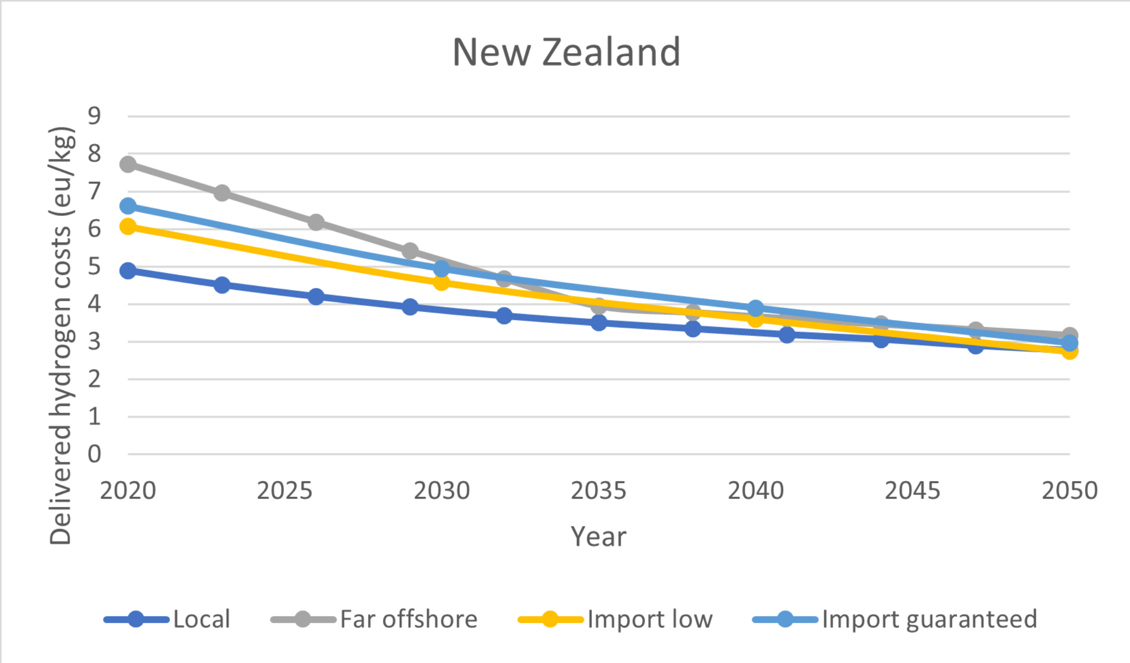

Figure 8.26: Comparison of delivered costs of green hydrogen to Christchurch from 2020 to 2050 (produced far offshore, produced locally and imported)

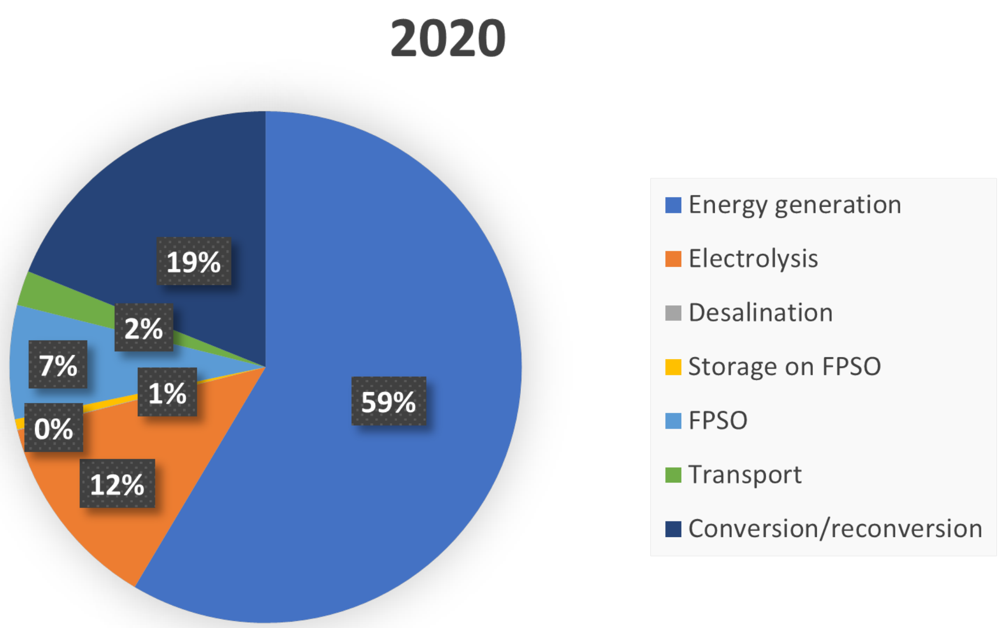

Figure 8.27: Cost distribution of far offshore green hydrogen delivered costs in 2020 in scenario 6

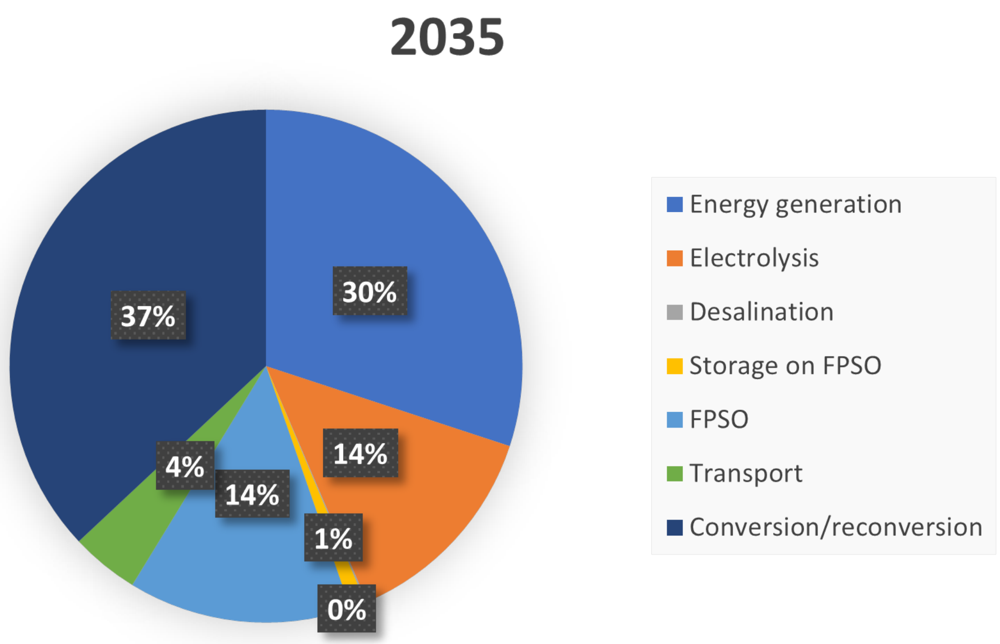

Figure 8.28: Cost distribution of far offshore green hydrogen delivered costs in 2035 in scenario 6

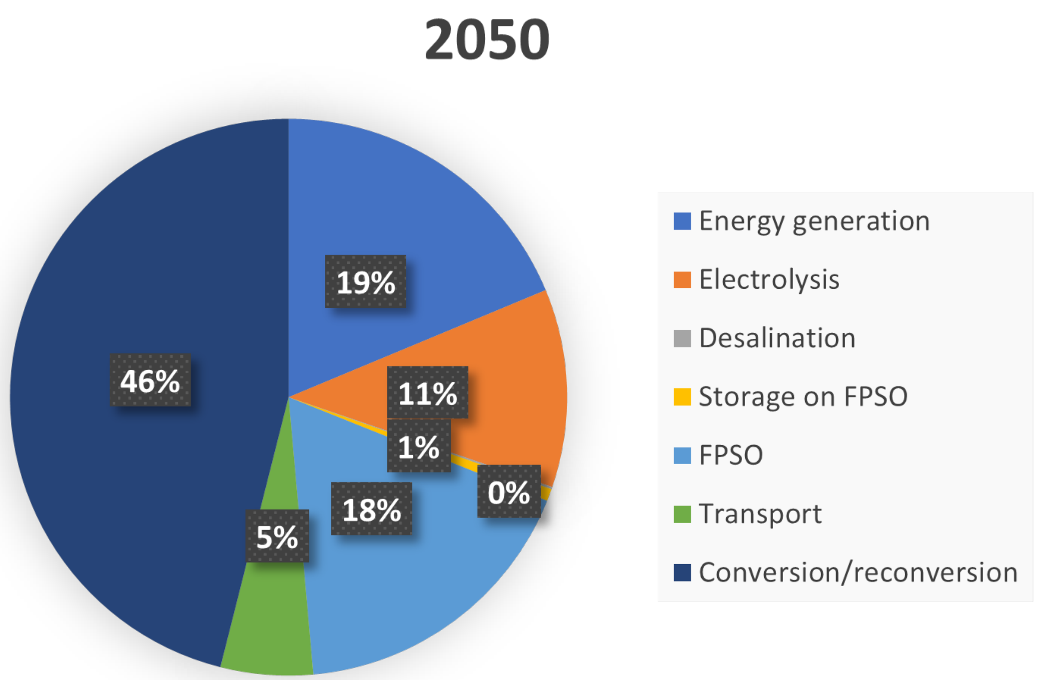

Figure 8.29: Cost distribution of far offshore green hydrogen delivered costs in 2050 in scenario 6

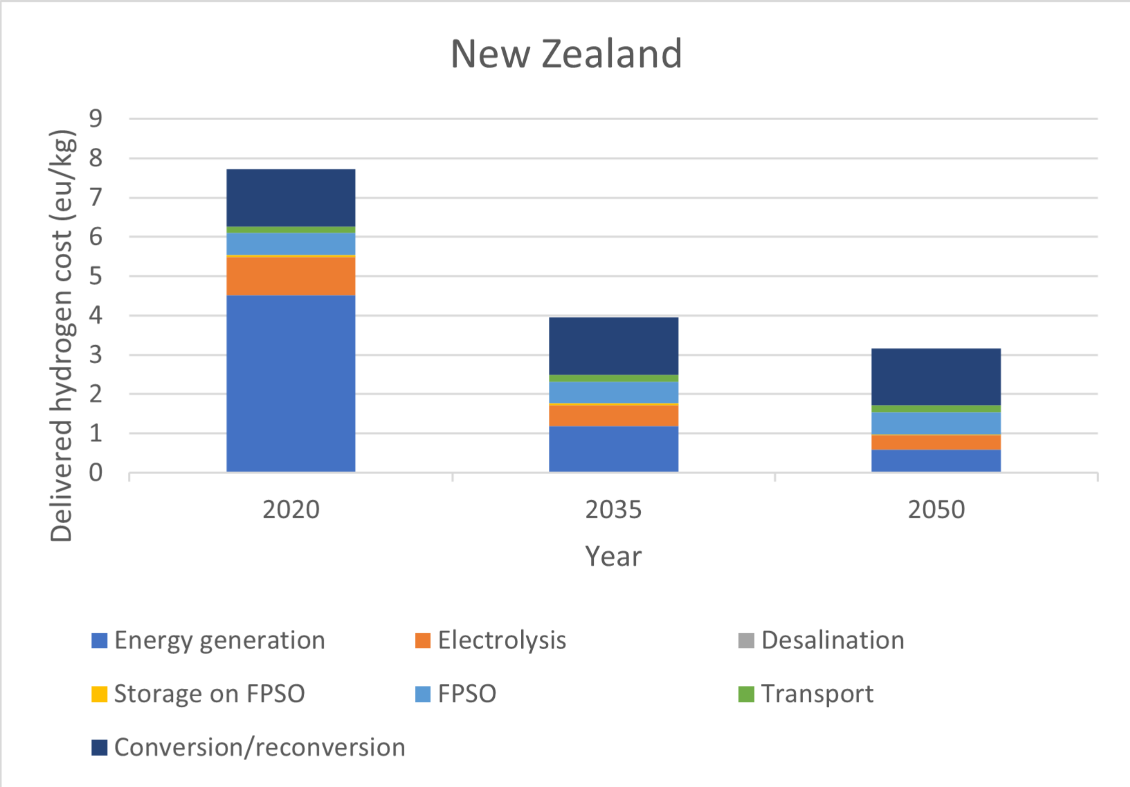

Figure 8.30: Cost distribution of far offshore green hydrogen delivered costs in 2020, 2035 and 2050 in scenario 6

Appendix E

When running the Python codes added in this appendix, the following versions of the relevant programs and modules were used:

- Python: version 3.8.10
- Spyder: version 5.4.3
- PVlib: version 0.9.5
- WindPowerlib: version 0.2.1
- Feedinlib: version 0.1.0rc4
- Geopy: version 2.3.0
- Gurobi Optimizer: version 10.0.3 build v10.0.3rc0 (win64)

```

from feedinlib import era5

#set the location coordinates
latitude =  #to be inserted per scenario
longitude =  #to be inserted per scenario

#set the start and end date
start_date, end_date = '2020-01-01', '2020-10-31'

# set variable set to download
variable = "feedinlib"

#name of file to be created with downloaded data
target_file = 'ERA5_weather_data.nc'

#download data
ds = era5.get_era5_data_from_datespan_and_position(
    variable=variable,
    start_date=start_date, end_date=end_date,
    latitude=latitude, longitude=longitude,
    target_file=target_file)
```

Listing 8.1: Python script for ERA5 weather data retrieval from Climate Data Store

```

import numpy as np
import pandas as pd
import matplotlib.pyplot as plt
import geopy.distance
import math
from openpyxl import load_workbook
from feedinlib import era5
import pvlib
from feedinlib import Photovoltaic
from feedinlib import get_power_plant_data
from windpowerlib.modelchain import ModelChain
from windpowerlib.wind_turbine import WindTurbine
from windpowerlib import get_turbine_types
from datetime import timedelta
import gurobipy as gp

#loading excel to later retrieve input data using openpyxl
```

```
data_file = 'C:/Users/tmell/Documents/TU Delft/Master/Afstuderen/Model/Inputdata.
    xlsx' #importing data from input data excel
wb = load_workbook(data_file,data_only=True) # creating workbook

general = wb['General'] #selecting data from sheet called general
wind = wb['Wind'] #selecting data from sheet called wind
solar = wb['Solar'] #selecting data from sheet called solar
electrolyzer = wb['Electrolyzer'] #selecting data from sheet called electrolyzer
desalination = wb['Desalination'] #selecting data from sheet called desalination
ammonia = wb['Ammonia'] #selecting data from sheet called ammonia
liquidhydrogen = wb['Liquid hydrogen'] #selecting data from sheet called liquid
    hydrogen
landtransport = wb['Land transport'] #selecting data from sheet called
    landtransport
storage = wb['Storage'] #selecting data from sheet called storage
fpso = wb['FPSO'] #selecting data from sheet called fpso

#creating the model
m = gp.Model()

#time period data
Startyear = general.cell(row=9, column=2).value #first year to be reviewed
timeperiod = general.cell(row=10, column=2).value #total time period to be reviewed
     in years
timestep = general.cell(row=11, column=2).value #time step between years to be
    reviewed over time period in years
Nsteps = int(timeperiod/timestep+1) #number of time steps (important for data
    selection from excel and loop at the end)

#scenario data
demand = 10/12*general.cell(row=21, column=2).value #demand in tons of hydrogen per
     year
demandlocation = general.cell(row=17, column=2).value #location where hydrogen is
    asked
transferport = general.cell(row=16, column=2).value #port where hydrogen is
    transferred from sea to land transport
productionlocation = general.cell(row=15, column=2).value #location where hydrogen
    is produced
reconversion = general.cell(row=23, column=2).value #equal to 1 if reconversion has
     to be done for delivery and to 0 when it does not

#capacity data
capconvammonia = 10/12*ammonia.cell(row=10, column=2).value #yearly output capacity
     in tons of hydrogen per year after conversion of one conversion installation
    for ammonia
capconvliquid = 10/12*liquidhydrogen.cell(row=25, column=2).value  #yearly output
    capacity in tons of hydrogen per year after conversion of one conversion
    installation for liquid hydrogen
capreconvammonia = 10/12*ammonia.cell(row=75, column=2).value #yearly output
    capacity in tons of hydrogen per year after reconversion of one reconversion
    installation for ammonia
capreconvliquid = 10/12*liquidhydrogen.cell(row=25, column=2).value  #yearly output
     capacity in tons of hydrogen per year after reconversion of one reconversion
    installation for liquid hydrogen
capdesalinationhour = desalination.cell(row=14, column=2).value #hourly output
    capacity of one desalination device in m3 of water per hour
capelectrolyzerhour = electrolyzer.cell(row=9, column=2).value #hourly output
    capacity of one electrolyzer in tons of hydrogen per hour


#efficiency data
fracpowerelectrolyzerliquid = electrolyzer.cell(row=11, column=2).value #fraction
    of energy used in FPSO that is used by electrolyzers when using liquid hydrogen
fracpowerelectrolyzerammonia = electrolyzer.cell(row=12, column=2).value #fraction
    of energy used on FPSO that is used by elecyrolyzers when using ammonia
fracpowerelectrolyzer = m.addVar(vtype=gp.GRB.CONTINUOUS, name='
    fracpowerelectrolyzer')  #fraction of energy used by elecyrolyzers
eta_conversionammonia = ammonia.cell(row=13, column=2).value #please not that these
     are actually equal to 1/eta for programming purposes. Conversion efficiency
    ratio between amount of hydrogen going into the ammonia conversion process and
    the amount of hydrogen coming out
eta_conversionliquid =  liquidhydrogen.cell(row=16, column=2).value #please not
    that these are actually equal to 1/eta for programming purposes. Conversion
    efficiency ratio between amount of hydrogen going into the liquid hydrogen
    conversion process and the amount of hydrogen coming out
eta_reconversionammonia = eta_conversionammonia #please not that these are actually
```

```
equal to 1/eta for programming purposes. Conversion efficiency ratio between amount of hydrogen going into the ammonia reconversion process and the amount of hydrogen coming out
eta_reconversionliquid = eta_conversionliquid #please not that these are actually equal to 1/eta for programming purposes. Conversion efficiency ratio between amount of hydrogen going into the liquid hydrogen reconversion process and the amount of hydrogen coming out
eta_transportammonia = 1 #transport efficiency (to take into account hydrogen losses during transport). Boil-off is reliquified so no losses
eta_transportliquid = 1 #transport efficiency (to take into account hydrogen losses during transport). Boil-off is reliquified so no losses
electrolyzer_water = electrolyzer.cell(row=6, column=2).value #water requirement of electrolyzer in m3 of water per ton of hydrogen
electrolyzer_energy = 1000*electrolyzer.cell(row=7, column=2).value #power requirement of electrolyzer in Wh per ton of hydrogen

eta_conversion = m.addVar(vtype=gp.GRB.CONTINUOUS, name='eta_conversion') #conversion efficiency of chosen transport medium (eta_conversionammonia or eta_conversionliquid)
eta_reconversion = m.addVar(vtype=gp.GRB.CONTINUOUS, name='eta_reconversion') #reconversion efficiency of chosen transport medium (eta_reconversionammonia or eta_reconversionliquid)

#distance calculation ('as the crow flies') and distance variables
coords_production = (general.cell(row=15, column=4).value, general.cell(row=15, column=5).value) #coordinates (latitude and longitude) of production location
coords_port = (general.cell(row=16, column=4).value, general.cell(row=16, column=5).value) #coordinates (latitude and longitude) of port
coords_demand = (general.cell(row=17, column=4).value, general.cell(row=17, column=5).value)  #coordinates (latitude and longitude) of demand location

distanceseafactor = general.cell(row=25, column=2).value #correction factor for the distance to be traveled over sea in case it is not possible to sail in a straight line
distancesea = distanceseafactor*geopy.distance.geodesic(coords_production, coords_port).km #distance to be traveled over sea from production location to transfer port in km
distanceland = geopy.distance.geodesic(coords_port, coords_demand).km #distance to be traveled over land from transfer port to demand location in km

Xtransport = demand #amount to be transported by ship in tons of hydrogen, assumed to be equal to demand for programming purposes, which is acceptable as hydrogen losses are almost zero
Xkmsea = Xtransport*distancesea #yearly amount of tonkm to be transported over sea
Xkmland = demand*distanceland #yealy amount of tonkm to be transported over land

#two binary variables to decide the transport mode over sea
Tammonia = m.addVar(vtype=gp.GRB.BINARY, name='Tammonia') #if equal to 1, overseas transport is done with ammonia
Tliquid = m.addVar(vtype=gp.GRB.BINARY, name='Tliquid') #if equal to 1, overseas transport is done with liquid hydrogen


#wind
Ntypewind = 1 #number of wind turbine types included in the analysis. For now always equal to 1, but option exists to include several wind turbine types


Xw1 = m.addVar(vtype=gp.GRB.INTEGER, name='Xwind1') #number of wind turbines of type 1
Xw2 = m.addVar(vtype=gp.GRB.INTEGER, name='Xwind2') #number of wind turbines of type 2
Xw3 = m.addVar(vtype=gp.GRB.INTEGER, name='Xwind3') #number of wind turbines of type 3
Xw4 = m.addVar(vtype=gp.GRB.INTEGER, name='Xwind4') #number of wind turbines of type 4
Xw5 = m.addVar(vtype=gp.GRB.INTEGER, name='Xwind5') #number of wind turbines of type 5

Cw1 = 10/12*np.array([float(cell.value) for cell in wind[48][2:2+Nsteps]]) #cost per year (depreciation+OPEX) of a type 1 floating wind turbine in euros over several years
#Cw2 = 10/12*np.array([float(cell.value) for cell in wind[52][2:2+Nsteps]]) #cost per year (depreciation+OPEX) of a type 2 floating wind turbine in euros over several years
#Cw3 = 10/12*np.array([float(cell.value) for cell in wind[56][2:2+Nsteps]]) #cost
```

```
per year (depreciation+OPEX) of a type 3 floating wind turbine in euros over several years
#Cw4 = 10/12*np.array([float(cell.value) for cell in wind[60][2:2+Nsteps]]) #cost per year (depreciation+OPEX) of a type 4 floating wind turbine in euros over several years
#Cw5 = 10/12*np.array([float(cell.value) for cell in wind[64][2:2+Nsteps]]) #cost per year (depreciation+OPEX) of a type 5 floating wind turbine in euros over several years


if Ntypewind == 1: #including variables and cost vectors for the amount of the wind turbines
    x = np.array([Xw1])
    C = np.array([Cw1])
elif Ntypewind == 2:
    x = np.array([Xw1,Xw2])
    C = np.array([Cw1,Cw2])
elif Ntypewind == 3:
    x = np.array([Xw1,Xw2,Xw3])
    C = np.array([Cw1,Cw2,Cw3])
elif Ntypewind == 4:
    x = np.array([Xw1,Xw2,Xw3,Xw4])
    C = np.array([Cw1,Cw2,Cw3,Cw4])
elif Ntypewind == 5:
    x = np.array([Xw1,Xw2,Xw3,Xw4,Xw5])
    C = np.array([Cw1,Cw2,Cw3,Cw4,Cw5])

#solar
Ntypesolar = 1 #number of solar platform types included in the analysis. For now always equal to 1, but option exists to include several solar platform types

Xs1 = m.addVar(vtype=gp.GRB.INTEGER, name='Xsolar1') #number of solar panel platforms of type 1
Xs2 = m.addVar(vtype=gp.GRB.INTEGER, name='Xsolar2') #number of solar panel platforms of type 2
Xs3 = m.addVar(vtype=gp.GRB.INTEGER, name='Xsolar3') #number of solar panel platforms of type 3
Xs4 = m.addVar(vtype=gp.GRB.INTEGER, name='Xsolar4') #number of solar panel platforms of type 4
Xs5 = m.addVar(vtype=gp.GRB.INTEGER, name='Xsolar5') #number of solar panel platforms of type 5

Cs1 = 10/12*np.array([float(cell.value) for cell in solar[51][2:2+Nsteps]]) #cost per year (depreciation+OPEX) of a type 1 floating solar platform in euros over several years
# Cs2 = 10/12*np.array([float(cell.value) for cell in solar[60][2:2+Nsteps]]) #cost per year (depreciation+OPEX) of a type 2 floating solar platform in euros over several years
# Cs3 = 10/12*np.array([float(cell.value) for cell in solar[64][2:2+Nsteps]]) #cost per year (depreciation+OPEX) of a type 3 floating solar platform in euros over several years
# Cs4 = 10/12*np.array([float(cell.value) for cell in solar[68][2:2+Nsteps]]) #cost per year (depreciation+OPEX) of a type 4 floating solar platform in euros over several years
# Cs5 = 10/12*np.array([float(cell.value) for cell in solar[72][2:2+Nsteps]]) #cost per year (depreciation+OPEX) of a type 5 floating solar platform in euros over several years

if Ntypesolar == 1: #including variables and cost vectors of the solar platforms
    x = np.append(x,[Xs1])
    C = np.vstack([C,Cs1])
elif Ntypesolar == 2:
    x = np.append(x,[Xs1,Xs2])
    C = np.vstack([C,Cs1,Cs2])
elif Ntypesolar == 3:
    x = np.append(x,[Xs1,Xs2,Xs3])
    C = np.vstack([C,Cs1,Cs2,Cs3])
elif Ntypesolar == 4:
    x = np.append(x,[Xs1,Xs2,Xs3,Xs4])
    C = np.vstack([C,Cs1,Cs2,Cs3,Cs4])
elif Ntypesolar == 5:
    x = np.append(x,[Xs1,Xs2,Xs3,Xs4,Xs5])
    C = np.vstack([C,Cs1,Cs2,Cs3,Cs4,Cs5])
```

```
#production equipment
convcapfactor = general.cell(row=27, column=2).value #conversion capacity factor; used to increase the conversion capacity with respect to the capacity needed for constant production over the year. Determined based on hourly production of electrolyzers and conversion equipment, and the results of some initial simulations.

Xe =  m.addVar(vtype=gp.GRB.INTEGER, name='Xelectrolyzers') #number of electrolyzers
Xd =  m.addVar(vtype=gp.GRB.INTEGER, name='Xdesalination') #number of desalination devices
Xconvammonia = math.ceil(convcapfactor*(demand*(eta_reconversionammonia*eta_transportammonia))/capconvammonia) #number of conversion devices to ammonia.
Xconvliquid = math.ceil(convcapfactor*(demand*(eta_reconversionliquid*eta_transportliquid))/capconvliquid) #number of conversion devices to liquid hydrogen
Xreconvammonia = math.ceil(reconversion*demand/capreconvammonia) #number of conversion devices for ammonia
Xreconvliquid = math.ceil(reconversion*demand/capreconvliquid) #number of conversion devices for liquid hydrogen

#fpso dimension ratios and electrolyzer area (to determine fpso size), and fpso and storage variables
ratiostoragefpsoliquid = fpso.cell(row=18, column=2).value #ratio storage tanks in m3/fpso volume in m3
ratiostoragefpsoammonia = fpso.cell(row=19, column=2).value #ratio storage tanks in m3/fpso volume in m3
volumefpsoliquid = electrolyzer.cell(row=15, column=2).value #FPSO volume per electrolyzer liquid hydrogen
volumefpsoammonia = electrolyzer.cell(row=16, column=2).value #FPSO volume per electrolyzer ammonia


Xst =  m.addVar(vtype=gp.GRB.CONTINUOUS, name='Xstorage') #storage capacity in m3
Xfpso = m.addVar(name='Xfpso', vtype=gp.GRB.CONTINUOUS, lb=0) #volume of FPSO in m3

ratiostoragefpso =  m.addVar(vtype=gp.GRB.CONTINUOUS, name='ratiostoragefpso')
volumefpso =  m.addVar(vtype=gp.GRB.CONTINUOUS, name='volumefpso')

#creating the variable vector with quantities
x = np.append(x,[Xe,Xd,Xst,Xfpso,Xkmsea,Xtransport,Xkmland,Tammonia*Xconvammonia,Tliquid*Xconvliquid,Tammonia*Xreconvammonia,Tliquid*Xreconvliquid])

#
#costs input data
#

#equipment costs
Ce = 10/12*np.array([float(cell.value) for cell in electrolyzer[50][2:2+Nsteps]]) #cost per year (depreciation+OPEX) of an electrolyzer in euros over several years
Cd = 10/12*np.array([float(cell.value) for cell in desalination[49][2:2+Nsteps]]) #cost per year (depreciation+OPEX) of a desalination installation in euros over several years
Cconvammonia = 10/12*np.array([float(cell.value) for cell in ammonia[48][2:2+Nsteps]]) #cost per year (depreciation+OPEX) of an ammonia conversion installation in euros over several years
Cconvliquid =10/12*np.array([float(cell.value) for cell in liquidhydrogen[61][2:2+Nsteps]]) #cost per year (depreciation+OPEX) of a liquid hydrogen conversion installation in euros over several years
Creconvammonia = 10/12*np.array([float(cell.value) for cell in ammonia[111][2:2+Nsteps]]) #cost per year (depreciation+OPEX) of an ammonia reconversion installation in euros over several years
Creconvliquid = 10/12*np.array([float(cell.value) for cell in liquidhydrogen[125][2:2+Nsteps]]) #cost per year (depreciation+OPEX) of a liquid hydrogen reconversion installation in euros over several years

#transport and storage costs (including fpso)
Cstliquid =  10/12*np.array([float(cell.value) for cell in storage[25][2:2+Nsteps]]) #cost per year (depreciation+OPEX) of storage per m3 in euros over several years liquid hydrogen
Cstammonia =  10/12*np.array([float(cell.value) for cell in storage[54][2:2+Nsteps]]) #cost per year (depreciation+OPEX) of storage per m3 in euros over several years ammonia
Cfpso = 10/12* np.array([float(cell.value) for cell in fpso[53][2:2+Nsteps]]) #cost
```

```
per year (depreciation+OPEX) of FPSO per m3 in euros over several years
Ckmammonia = np.array([float(cell.value) for cell in ammonia[158][2:2+Nsteps]]) #variable costs per km of overseas transport of 1 ton of hydrogen as ammonia in euros over several years
Cbasetransportammonia = np.array([float(cell.value) for cell in ammonia[159][2:2+Nsteps]]) #base costs of overseas transport of 1 ton of hydrogen as ammonia in euros over several years
Ckmliquid = np.array([float(cell.value) for cell in liquidhydrogen[168][2:2+Nsteps]]) #variable costs per km of overseas transport of 1 ton of hydrogen as liquid hydrogen in euros over several years
Cbasetransportliquid =  np.array([float(cell.value) for cell in liquidhydrogen[169][2:2+Nsteps]]) #base costs of overseas transport of 1 ton of hydrogen as liquid hydrogen in euros over several years
Ckmland = np.array([float(cell.value) for cell in landtransport[33][2:2+Nsteps]]) #costs per year per km of overland pipeline for 1 ton of hydrogen in euros over several years

Cst = Tammonia * Cstammonia + Tliquid * Cstliquid #cost of storage per m3, depending on whether ammonia or liquid hydrogen is chosen

Ckmsea = Ckmammonia * Tammonia + Ckmliquid * Tliquid #costs per km of overseas transport, depending on whether ammonia or liquid hydrogen is chosen
Cbasetransport = Cbasetransportammonia * Tammonia + Cbasetransportliquid * Tliquid #baserate of the transport per ton hydrogen, depending on whether ammonia or liquid hydrogen is chosen

#creating costs matrix with the costs of every aspect over the years
C = np.vstack([C,Ce,Cd,Cst,Cfpso,Ckmsea,Cbasetransport,Ckmland,Cconvammonia,Cconvliquid,Creconvammonia,Creconvliquid])

#
#wind and solar energy generation calculations based on ERA5 weather data, pvlib, windpowerlib and feedinlib
#

#
#general
#

#this script works with version 0.1.0rc4 of feedinlib, version 0.9.5 of pvlib and version 0.2.1 of windpowerlib

#coordinates production location
latitude =  general.cell(row=15, column=4).value
longitude = general.cell(row=15, column=5).value


# set start and end date
start_date, end_date = '2020-01-01', '2020-10-01'
# set variable set
variable = 'feedinlib'

era5_netcdf_filename = 'ERA5_weather_data_location2.nc' #referring to file with weather data downloaded from ERA5

area = [longitude, latitude] #location of production

#
#PV
#

# get modules
module_df = get_power_plant_data(dataset='SandiaMod') #retrieving dataset for PV modules

# get inverter data
inverter_df = get_power_plant_data(dataset='cecinverter') #retrieving dataset for inverters

temp_params = pvlib.temperature.TEMPERATURE_MODEL_PARAMETERS['sapm']['open_rack_glass_polymer'] #defining temperature model parameters (leaving at default causes errors)

#PV system definition
system_data = {
    'module_name': 'Advent_Solar_Ventura_210___2008_',  # module name as in
```

```
    database
    'inverter_name': 'ABB__MICRO_0_25_I_OUTD_US_208__208V_',  # inverter name as in database
    'azimuth': 180, #angle of sun position with north in horizontal plane
    'tilt': 30, #angle of solar panels with horizontal
    'albedo': 0.075, #albedo (fraction of sun light reflected) of ocean water (https://geoengineering.global/ocean-albedo-modification/)
    'temperature_model_parameters': temp_params,
}


pv_system = Photovoltaic(**system_data)


#getting the needed weather data for PV calculations from the file as downloaded with a seperate script from ERA5
pvlib_df = era5.weather_df_from_era5(
    era5_netcdf_filename='ERA5_weather_data_location2.nc',
    lib='pvlib', area=area)

#determining the zenith angle (angle of sun position with vertical in vertical plane) in the specified locations for the time instances downloaded from ERA5
zenithcalc = pvlib.solarposition.get_solarposition(time=pvlib_df.index,latitude=latitude, longitude=longitude, altitude=None, pressure=None, method='nrel_numpy', temperature=pvlib_df['temp_air'])

#determining DNI from GHI, DHI and zenith angle for the time instances downloaded from ERA5
dni = pvlib.irradiance.dni(pvlib_df['ghi'],pvlib_df['dhi'], zenith=zenithcalc['zenith'], clearsky_dni=None, clearsky_tolerance=1.1, zenith_threshold_for_zero_dni=88.0, zenith_threshold_for_clearsky_limit=80.0)

#adding DNI to dataframe with PV weather data
pvlib_df['dni'] = dni

#replacing 'NAN' in DNI column with 0 to prevent 'holes' in graphs (NANs are caused by the zenith angle being larger than the 'zenith threshold for zero dni' angle set with GHI and DHI not yet being zero. The DNI should be 0 in that case)
pvlib_df['dni'] = pvlib_df['dni'].fillna(0)

#plotting dhi and ghi
plt.figure
pvlib_df.loc[:, ['dhi', 'ghi']].plot(title='Irradiance')
plt.xlabel('Time')
plt.ylabel('Irradiance in $W/m^2$');

#determining PV power generation
feedin = pv_system.feedin(
    weather=pvlib_df,
    location=(latitude, longitude))


#plotting PV power generation
plt.figure()
feedin.plot(title='PV feed-in')
plt.xlabel('Time')
plt.ylabel('Power in W');

#calculating total PV power generated in selected period
PVpower = pd.Series.sum(feedin) #power produced over time period in Wh

print('One panel with the chosen input parameters in location', latitude,',', longitude, 'will produce',PVpower,'Wh of electricity between', start_date, 'and', end_date )

#
#Wind
#


# set print_out=True to see the list of all available wind turbines
df = get_turbine_types(print_out=False)

#defining the wind turbine system
turbine_data= {
```

```
    "turbine_type": "E-101/3050",  # turbine type as in register
    "hub_height": 130,  # in m
}
my_turbine = WindTurbine(**turbine_data)

#getting the needed weather data for PV calculations from the file as downloaded with a seperate script from ERA5
windpowerlib_df = era5.weather_df_from_era5(
    era5_netcdf_filename='ERA5_weather_data_location2.nc',
    lib='windpowerlib', area=area)

#increasing the time indices by half an hour because then they match the pvlib time indices so the produced energy can be added later
#assumed wind speeds half an hour later are similar and this will not affect the results significantly
windpowerlib_df.index = windpowerlib_df.index + timedelta(minutes=30)

# power output calculation for e126

# own specifications for ModelChain setup
modelchain_data = {
    'wind_speed_model': 'logarithmic',
    'density_model': 'ideal_gas',
    'temperature_model': 'linear_gradient',
    'power_output_model': 'power_curve',
    'density_correction': True,
    'obstacle_height': 0,
    'hellman_exp': None}

# initializing ModelChain with own specifications and calculating power output
mc_my_turbine = ModelChain(my_turbine, **modelchain_data).run_model(windpowerlib_df)
# write power output time series to WindTurbine object
my_turbine.power_output = mc_my_turbine.power_output


# plot turbine power output
plt.figure()
my_turbine.power_output.plot(title='Wind turbine power production')
plt.xlabel('Time')
plt.ylabel('Power in W')
plt.show()

#
#Total power and hydrogen production
#

multsolar = solar.cell(row=16, column=2).value*1000/206.7989 #scaling factor from reference solar panel in PVlib to solar platform used in input data
multwind = wind.cell(row=7, column=2).value/3 #scaling factor from reference wind turbine in WindPowerlib to wind turbine in input data

feedinarray = multsolar*feedin.values #hourly power production over the reference period of 1 solar platform of the specified kind (in input data) in the specified location in Wh/h
feedinarray[feedinarray<0]=0 #correcting some elements with very small negative power production to zero
my_turbinearray = multwind*my_turbine.power_output.values #hourly power production over the reference period of 1 wind turbine of the specified kind (in input data) in the specified location in Wh/h

powerovertime = m.addVars(len(feedinarray),vtype=gp.GRB.CONTINUOUS,name='powerovertime') #hourly power production from all wind turbines and solar platforms combined in Wh/h
powerovertimeelectrolyzer = m.addVars(len(feedinarray),vtype=gp.GRB.CONTINUOUS,name='powerovertimeelectrolyzer') #hourly power available for the elctrolyzers in Wh/h
electricityusedelectrolyzer = m.addVars(len(feedinarray),vtype=gp.GRB.CONTINUOUS,name='electricityudeselectrolyzer') #hourly power actually used by the electrolyzers in Wh/h (limited by their capacity and the energy availability)
hydrogenproduced = m.addVars(len(feedinarray),vtype=gp.GRB.CONTINUOUS,name='hydrogenproduced') #hourly hydrogen production in tons/h

#
#Constraints
#
```

```
m.params.NonConvex = 2
m.Params.NumericFocus = 1

print('Optimalisatie start')

#the transport over sea is done completely with either ammonia or liquid hydrogen
m.addConstr(Tammonia + Tliquid == 1)


for i in range(len(electricityusedelectrolyzer)):
    #produced power depends on the amounts of wind turbines and solar platforms and
     the production per unit
    m.addConstr(powerovertime[i] == feedinarray[i]*Xs1 + my_turbinearray[i]*Xw1)
    #fraction of the power used by the electrolyzers depends on whether ammonia or
    liquid hydrogen is used for storage and transport
    m.addConstr(fracpowerelectrolyzer == Tammonia*fracpowerelectrolyzerammonia +
    Tliquid*fracpowerelectrolyzerliquid)
    #then the power available for the electrolyzers can be determined
    m.addConstr(powerovertimeelectrolyzer[i] == powerovertime[i]*
    fracpowerelectrolyzer)
    #the power actually used by the electrolyzers must be lower than or equal to
    the available power for the electrolyzers
    m.addConstr(electricityusedelectrolyzer[i] <= powerovertimeelectrolyzer[i])
    #the power actually used by the electrolyzers must also be lower than or equal
    to the capacity of the electrolyzers
    m.addConstr(electricityusedelectrolyzer[i] <= capelectrolyzerhour*Xe*
    electrolyzer_energy)
    #from the power actually used by the electrolyzers, the produced hydrogen can
    be determined
    m.addConstr(hydrogenproduced[i] == electricityusedelectrolyzer[i]/
    electrolyzer_energy)

#the hydrogen losses during conversion belonging to the chosen transport medium are
     determined
m.addConstr(eta_conversion==Tammonia*eta_conversionammonia+Tliquid*
    eta_conversionliquid)

#the hydrogen losses during reconversion belonging to the chosen transport medium
    are determined
m.addConstr(eta_reconversion==Tammonia*eta_reconversionammonia+Tliquid*
    eta_reconversionliquid)


#the hydrogen produced in the whole period should be bigger than or equal to the
    demand (with correction for conversion, transport and reconversion efficiencies
    . The transport efficiency is always 1)
m.addConstr(hydrogenproduced.sum() >= demand*(eta_conversion*eta_conversion))

#the capacity of the desalination equipment should match the capacity of the
    electrolyzers to be able to produce sufficient water
m.addConstr(Xd >=  Xe*capelectrolyzerhour*electrolyzer_water/capdesalinationhour)

#determining FPSO volume per installed electrolyzer based on liquid hydrogen or
    ammonia fpso
m.addConstr(volumefpso == Tammonia*volumefpsoammonia + Tliquid*volumefpsoliquid)


#with the amount of electrolyzers and FPSO volume per electrolyzer, the total FPSO
    volume is determined
m.addConstr(Xfpso == Xe*volumefpso)

#determining storage as ratio of fpso volume based on liquid hydrogen or ammonia
    fpso (ammonia requires smaller tank to store same amount of hydrogen)
m.addConstr(ratiostoragefpso == Tammonia*ratiostoragefpsoammonia + Tliquid*
    ratiostoragefpsoliquid)

#based on the volume of the FPSO and the example FPSO design we can determine the
    storage capacity
m.addConstr(Xst == Xfpso*ratiostoragefpso)

powerovertimeelectrolyzerdata = pd.DataFrame(index=feedin.index) #for plotting the
    available electrolyzer power
electricityusedelectrolyzerdata = pd.DataFrame(index=feedin.index) #for plotting
    the used electrolyzer power
hydrogenproduceddata = pd.DataFrame(index=feedin.index) #for plotting the hydrogen
```

```
    production
exceldf = pd.DataFrame(index=['Demand (tons of hydrogen)', 'Usage location', 'Year'
    ,'Production location','Transfer port','Total costs per year (euros)','Costs
    per kg hydrogen (euros)','Wind turbines', 'Solar platforms','Electrolyzers','
    Desalination equipment', 'Storage volume','Conversion devices','Reconversion
    devices','Transport medium', 'FPSO volume']) #for exporting results to excel


#objective
for k in range(Nsteps): #for loop allows to evaluate several years in one run
    m.reset() #optional, makes sure the model does not use the results of the
    previous optimization as starting point for the next one. If this is done, it
    can make the optimization quicker, but it can also cause it to get stuck.
    m.setObjective(sum(x[i]*C[i][k] for i in range(len(x))),gp.GRB.MINIMIZE) #
    minimization of the total costs with the given demand (aka minimization of the
    costs/ton hydrogen, aka optimization of the hydrogen supply chain in the given
    scenario)
    m.optimize()
    #determine fuel chosen for printing to output data information
    if Tammonia.x>0 :
        Transportmedium ="AMMONIA"
    else:
        Transportmedium = "LIQUID HYDROGEN"
    print("Optimal solution found!")
    #printing output data to python console
    print("For a demand of", demand*12/10 ,"tons of hydrogen per year in",
    demandlocation ,"in year", timestep*k+Startyear, "with production in",
    productionlocation ,"and transfer in the port of", transferport, "the yearly
    costs are equal to", m.ObjVal*12/10,"euros in total.\n This is equal to a cost
    of", m.ObjVal/demand, "euros per ton of hydrogen.\n In this configuration, we
    will use:\n",Xw1.X, "wind turbines of type 1\n",Xw2.X, "wind turbines of type
    2\n",Xw3.X, "wind turbines of type 3\n",Xw4.X, "wind turbines of type 4\n",Xw5.
    X, "wind turbines of type 5\n", Xs1.X, "solar platforms of type 1\n", Xs2.X, "
    solar platforms of type 2\n", Xs3.X, "solar platforms of type 3\n", Xs4.X, "
    solar platforms of type 4\n", Xs5.X, "solar platforms of type 5\n", Xe.X, "
    electrolyzers\n", Xd.x , "desalination installations\n", Xst.X, "m3 of storage
    capacity \n ",Tammonia.X*Xconvammonia + Tliquid.X*Xconvliquid , "conversion and
    ", Tammonia.X*Xreconvammonia + Tliquid.X*Xreconvliquid , "reconversion
    installations for", Transportmedium ,"\n in an FPSO of", Xfpso.X, "m3") #prints
     the values of all variables in the optimized solution
    #saving output data for exporting to excel
    exceldf[timestep*k+Startyear] = [demand*12/10,demandlocation,timestep*k+
    Startyear, productionlocation, transferport, m.ObjVal*12/10, m.ObjVal/demand
    /1000,Xw1.X, Xs1.X, Xe.X, Xd.x , Xst.X, Tammonia.X*Xconvammonia + Tliquid.X*
    Xconvliquid, Tammonia.X*Xreconvammonia + Tliquid.X*Xreconvliquid ,
    Transportmedium , Xfpso.X]

    #plot power available for electrolyzers
    powerovertimeelectrolyzervalues = np.empty(len(powerovertimeelectrolyzer),
    dtype=object)
    for i in range(len(powerovertimeelectrolyzer)):
        powerovertimeelectrolyzervalues[i] = powerovertimeelectrolyzer[i].x
    powerovertimeelectrolyzerdata['production'] = powerovertimeelectrolyzervalues.
    tolist()
    powerovertimeelectrolyzerdata.plot(title='power available for electrolyzers')
    plt.xlabel('Time')
    plt.ylabel('Wh/h')

    #plot power used by electrolyzers
    electricityusedelectrolyzervalues = np.empty(len(electricityusedelectrolyzer),
    dtype=object)
    for i in range(len(electricityusedelectrolyzer)):
        electricityusedelectrolyzervalues[i] = electricityusedelectrolyzer[i].x
    electricityusedelectrolyzerdata['production'] =
    electricityusedelectrolyzervalues.tolist()
    electricityusedelectrolyzerdata.plot(title='power used by electrolyzers')
    plt.xlabel('Time')
    plt.ylabel('Wh/h')

    #plot produced hydrogen
    hydrogenproducedvalues = np.empty(len(hydrogenproduced), dtype=object)
    for i in range(len(hydrogenproduced)):
        hydrogenproducedvalues[i] = hydrogenproduced[i].x
    hydrogenproduceddata['production'] = hydrogenproducedvalues.tolist()
    hydrogenproduceddata.plot(title='produced')
    plt.xlabel('Time')
```

```python
    plt.ylabel('Tons per hour')

#exporting output data to excel
exceldf.to_excel('Simulation_results.xlsx', sheet_name='Results')
```

Listing 8.2: Python script of model developed in this research

Appendix F

Table 8.19: CAPEX onshore solar (Brändle et al., 2021)

	CAPEX euros/kW
2020	603.5581801
2021	573.8539
2022	549.5981
2023	529.2398
2024	511.7922
2025	496.5917
2026	483.1721
2027	471.1947
2028	460.4061
2029	450.6123
2030	441.6617
2031	431.0166
2032	421.5213
2033	412.7647
2034	404.6841
2035	397.0101
2036	389.5779
2037	382.7595
2038	376.3008
2039	370.2546
2040	364.4097
2041	358.2935
2042	352.2463
2043	346.6093
2044	342.6516
2045	330.8734
2046	325.3125
2047	320.1351
2048	315.2969
2049	310.7604
2050	306.4938

Table 8.20: Liquid hydrogen conversion device CAPEX and OPEX 2020-2050 (Brändle et al., 2021)

Year	CAPEX (euros/ton hydrogen/year)	OPEX (euros/ton hydrogen/year)
2020	5623.93	224.96
2021	5567.69	222.71
2022	5511.45	220.46
2023	5455.21	218.21
2024	5398.97	215.96
2025	5342.74	213.71
2026	5286.50	211.46
2027	5230.26	209.21
2028	5174.02	206.96
2029	5117.78	204.71
2030	5061.54	202.46
2031	5010.92	200.44
2032	4960.31	198.41
2033	4909.69	196.39
2034	4859.08	194.36
2035	4808.46	192.34
2036	4757.85	190.31
2037	4707.23	188.29
2038	4656.62	186.26
2039	4606.00	184.24
2040	4555.38	182.22
2041	4504.77	180.19
2042	4454.15	178.17
2043	4403.54	176.14
2044	4352.92	174.12
2045	4302.31	172.09
2046	4251.69	170.07
2047	4201.08	168.04
2048	4150.46	166.02
2049	4099.85	163.99
2050	4049.23	161.97

Appendix G

Table 8.21: Results scenario 1: baseline for sensitivity analysis

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	5.96E+08	5.33E+08	4.72E+08	4.12E+08	3.52E+08	2.88E+08	2.72E+08	2.57E+08	2.43E+08	2.29E+08	2.14E+08
Costs per kg hydrogen (euros)	11.93	10.65	9.44	8.23	7.04	5.76	5.44	5.14	4.86	4.57	4.29
Wind turbines	39	41	44	46	49	59	60	60	60	63	63
Solar platforms	1464	1328	1111	939	663	0	30	30	30	5	5
Electrolyzers	27	26	25	25	26	28	27	27	27	26	26
Desalination equipment	26	25	24	24	25	27	26	26	26	25	25
Storage volume (m3)	4.79E+04	4.61E+04	4.44E+04	4.44E+04	4.61E+04	4.97E+04	4.79E+04	4.79E+04	4.79E+04	4.61E+04	4.61E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	4.86E+05	4.68E+05	4.50E+05	4.50E+05	4.68E+05	5.04E+05	4.86E+05	4.86E+05	4.86E+05	4.68E+05	4.68E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Demand

Table 8.22: Results sensitivity analysis: 50% increase of demand

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000	75000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	8.91E+08	7.96E+08	7.05E+08	6.14E+08	5.25E+08	4.28E+08	4.04E+08	3.82E+08	3.61E+08	3.40E+08	3.19E+08
Costs per kg hydrogen (euros)	11.89	10.61	9.40	8.19	7.00	5.71	5.39	5.09	4.81	4.53	4.25
Wind turbines	60	62	67	70	75	90	90	90	90	92	95
Solar platforms	2074	1942	1612	1295	835	0	0	0	0	6	0
Electrolyzers	40	39	37	38	40	41	41	41	41	40	39
Desalination equipment	39	38	36	37	39	40	40	40	40	39	38
Storage volume (m3)	7.10E+04	6.92E+04	6.57E+04	6.74E+04	7.10E+04	7.28E+04	7.28E+04	7.28E+04	7.28E+04	7.10E+04	6.92E+04
Conversion devices	13	13	13	13	13	13	13	13	13	13	13
Reconversion devices	8	8	8	8	8	8	8	8	8	8	8
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	7.21E+05	7.03E+05	6.67E+05	6.85E+05	7.21E+05	7.39E+05	7.39E+05	7.39E+05	7.39E+05	7.21E+05	7.03E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.23: Results sensitivity analysis: 50% decrease of demand

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000	25000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	3.03E+08	2.71E+08	2.41E+08	2.10E+08	1.80E+08	1.48E+08	1.40E+08	1.33E+08	1.26E+08	1.19E+08	1.12E+08
Costs per kg hydrogen (euros)	12.10	10.83	9.62	8.41	7.22	5.93	5.62	5.32	5.04	4.76	4.47
Wind turbines	19	21	22	24	24	29	29	29	31	31	31
Solar platforms	751	615	524	362	362	20	20	20	23	23	23
Electrolyzers	14	13	13	13	13	14	14	14	13	13	13
Desalination equipment	14	13	13	13	13	14	14	14	13	13	13
Storage volume (m3)	2.48E+04	2.31E+04	2.31E+04	2.31E+04	2.31E+04	2.48E+04	2.48E+04	2.48E+04	2.31E+04	2.31E+04	2.31E+04
Conversion devices	5	5	5	5	5	5	5	5	5	5	5
Reconversion devices	3	3	3	3	3	3	3	3	3	3	3
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	2.52E+05	2.34E+05	2.34E+05	2.34E+05	2.34E+05	2.52E+05	2.52E+05	2.52E+05	2.34E+05	2.34E+05	2.34E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.24: Results sensitivity analysis: normalized comparison for change of demand

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.00	1.00	1.00	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
-50%	1.01	1.02	1.02	1.02	1.02	1.03	1.03	1.04	1.04	1.04	1.04

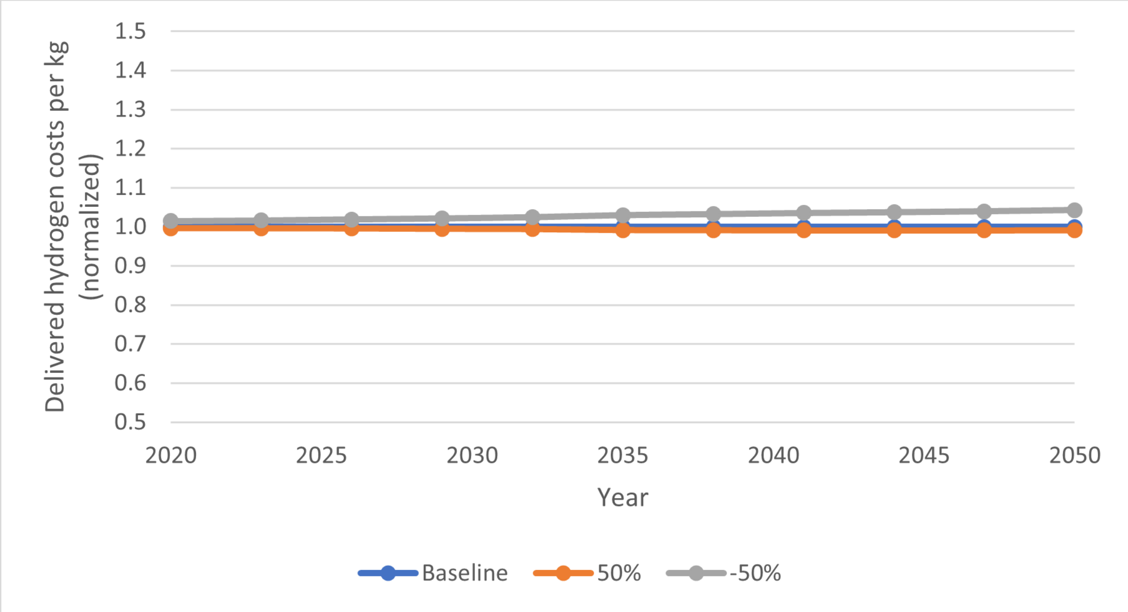

Figure 8.31: Results sensitivity analysis: normalized comparison for change of demand

Distance to shore

Table 8.25: Results sensitivity analysis: 50% increase of the distance to shore

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	5.97E+08	5.33E+08	4.73E+08	4.12E+08	3.53E+08	2.88E+08	2.72E+08	2.57E+08	2.43E+08	2.29E+08	2.15E+08
Costs per kg hydrogen (euros)	11.94	10.66	9.45	8.24	7.05	5.76	5.45	5.14	4.87	4.58	4.30
Wind turbines	39	41	44	46	49	59	60	60	60	63	63
Solar platforms	1464	1328	1111	939	663	0	30	30	30	5	5
Electrolyzers	27	26	25	25	26	28	27	27	27	26	26
Desalination equipment	26	25	24	24	25	27	26	26	26	25	25
Storage volume (m3)	4.79E+04	4.61E+04	4.44E+04	4.44E+04	4.61E+04	4.97E+04	4.79E+04	4.79E+04	4.79E+04	4.61E+04	4.61E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	4.86E+05	4.68E+05	4.50E+05	4.50E+05	4.68E+05	5.04E+05	4.86E+05	4.86E+05	4.86E+05	4.68E+05	4.68E+05
Distance sea (km)	2349	2349	2349	2349	2349	2349	2349	2349	2349	2349	2349
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.26: Results sensitivity analysis: 50% decrease of the distance to shore

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	5.96E+08	5.32E+08	4.72E+08	4.11E+08	3.52E+08	2.87E+08	2.72E+08	2.56E+08	2.43E+08	2.28E+08	2.14E+08
Costs per kg hydrogen (euros)	11.92	10.64	9.43	8.22	7.04	5.75	5.43	5.13	4.85	4.57	4.28
Wind turbines	39	41	44	46	49	58	60	60	60	63	63
Solar platforms	1464	1328	1111	939	663	40	30	30	30	5	5
Electrolyzers	27	26	25	25	26	28	27	27	27	26	26
Desalination equipment	26	25	24	24	25	27	26	26	26	25	25
Storage volume (m3)	4.79E+04	4.61E+04	4.44E+04	4.44E+04	4.61E+04	4.97E+04	4.79E+04	4.79E+04	4.79E+04	4.61E+04	4.61E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	4.86E+05	4.68E+05	4.50E+05	4.50E+05	4.68E+05	5.04E+05	4.86E+05	4.86E+05	4.86E+05	4.68E+05	4.68E+05
Distance sea (km)	783	783	783	783	783	783	783	783	783	783	783
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.27: Results sensitivity analysis: normalized comparison for change of the distance to shore

	2020	**2023**	**2026**	**2029**	**2032**	**2035**	**2038**	**2041**	**2044**	**2047**	**2050**
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
-50%	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

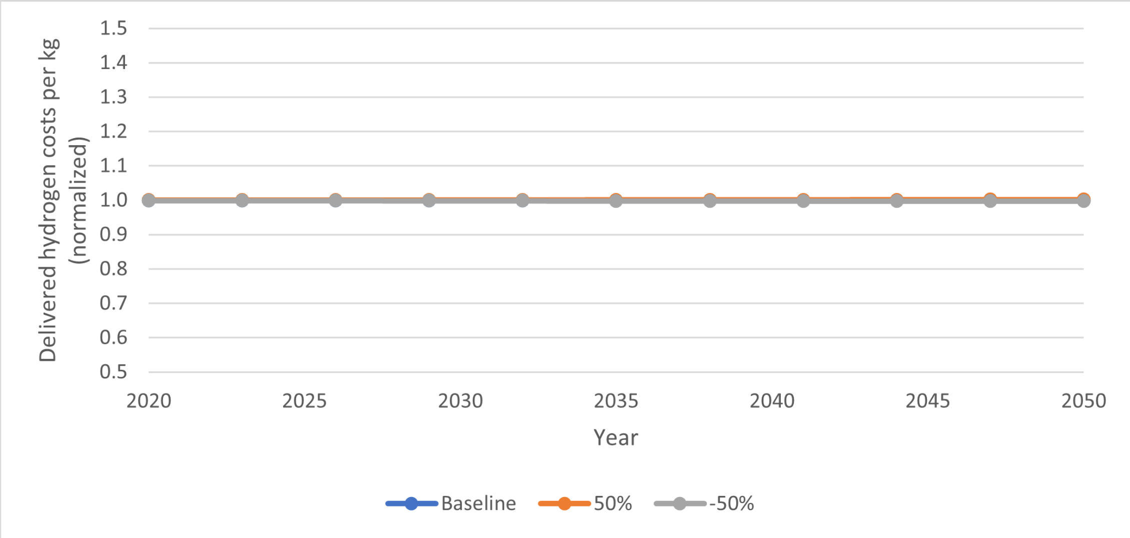

Figure 8.32: Results sensitivity analysis: normalized comparison for change of the distance to shore

Ammonia (re)conversion costs

Table 8.28: Results sensitivity analysis: 50% increase of ammonia (re)conversion costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	6.33E+08	5.69E+08	5.09E+08	4.48E+08	3.89E+08	3.24E+08	3.08E+08	2.93E+08	2.79E+08	2.59E+08	2.35E+08
Costs per kg hydrogen (euros)	12.66	11.38	10.17	8.96	7.77	6.49	6.17	5.87	5.59	5.18	4.70
Wind turbines	39	41	44	46	49	58	60	60	60	72	72
Solar platforms	1464	1328	1111	939	663	40	30	30	30	8	8
Electrolyzers	27	26	25	25	26	28	27	27	27	24	24
Desalination equipment	26	25	24	24	25	27	26	26	26	24	24
Storage volume (m3)	4.79E+04	4.61E+04	4.44E+04	4.44E+04	4.61E+04	4.97E+04	4.79E+04	4.79E+04	4.79E+04	7.35E+04	7.35E+04
Conversion devices	9	9	9	9	9	9	9	9	9	8	8
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	LIQUID HYDROGEN	LIQUID HYDROGEN
FPSO volume (m3)	4.86E+05	4.68E+05	4.50E+05	4.50E+05	4.68E+05	5.04E+05	4.86E+05	4.86E+05	4.86E+05	5.33E+05	5.33E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.29: Results sensitivity analysis: 50% decrease of ammonia (re)conversion costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	5.60E+08	4.96E+08	4.36E+08	3.75E+08	3.16E+08	2.51E+08	2.35E+08	2.20E+08	2.06E+08	1.92E+08	1.78E+08
Costs per kg hydrogen (euros)	11.20	9.92	8.71	7.50	6.31	5.03	4.71	4.41	4.13	3.84	3.56
Wind turbines	39	41	44	46	49	58	60	60	60	63	63
Solar platforms	1464	1328	1111	939	663	40	30	30	30	5	5
Electrolyzers	27	26	25	25	26	28	27	27	27	26	26
Desalination equipment	26	25	24	24	25	27	26	26	26	25	25
Storage volume (m3)	4.79E+04	4.61E+04	4.44E+04	4.44E+04	4.61E+04	4.97E+04	4.79E+04	4.79E+04	4.79E+04	4.61E+04	4.61E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	4.86E+05	4.68E+05	4.50E+05	4.50E+05	4.68E+05	5.04E+05	4.86E+05	4.86E+05	4.86E+05	4.68E+05	4.68E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.30: Results sensitivity analysis: normalized comparison for change of ammonia (re)conversion costs

	2020	**2023**	**2026**	**2029**	**2032**	**2035**	**2038**	**2041**	**2044**	**2047**	**2050**
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.06	1.07	1.08	1.09	1.10	1.13	1.13	1.14	1.15	1.13	1.10
-50%	0.94	0.93	0.92	0.91	0.90	0.87	0.87	0.86	0.85	0.84	0.83

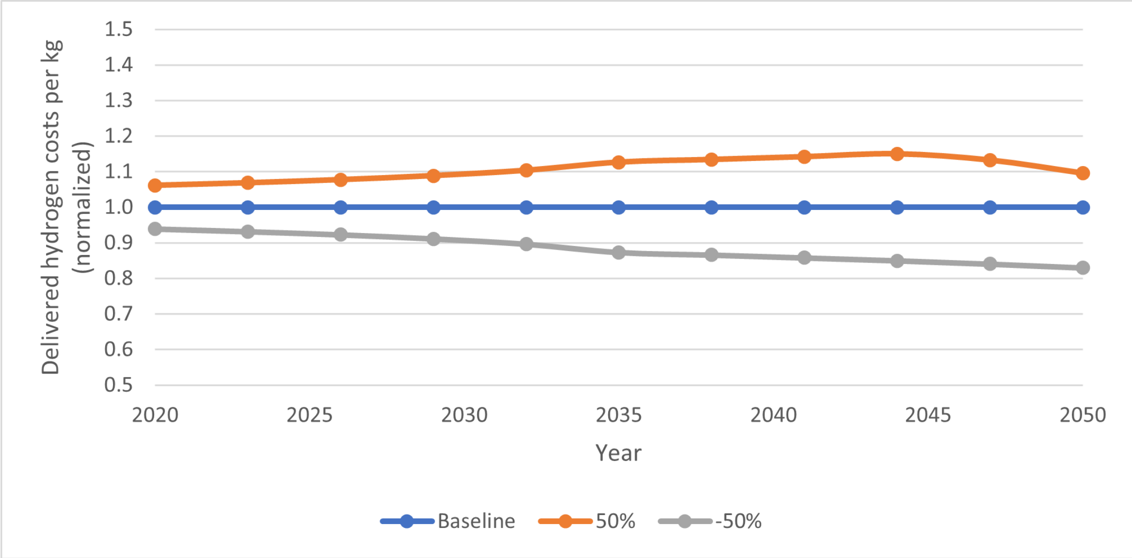

Figure 8.33: Results sensitivity analysis: normalized comparison for change of ammonia (re)conversion costs

Floating offshore wind costs

Table 8.31: Results sensitivity analysis: 50% increase of floating offshore wind costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	6.50E+08	5.94E+08	5.53E+08	4.97E+08	4.22E+08	3.40E+08	3.20E+08	3.01E+08	2.82E+08	2.63E+08	2.44E+08
Costs per kg hydrogen (euros)	13.00	11.88	11.06	9.94	8.44	6.80	6.41	6.02	5.65	5.27	4.88
Wind turbines	0	0	0	35	44	49	49	53	58	58	60
Solar platforms	4428	4428	4428	1764	1111	663	663	367	40	40	30
Electrolyzers	54	54	54	29	25	26	26	27	28	28	27
Desalination equipment	52	52	52	28	24	25	25	26	27	27	26
Storage volume (m3)	9.58E+04	9.58E+04	9.58E+04	5.15E+04	4.44E+04	4.61E+04	4.61E+04	4.79E+04	4.97E+04	4.97E+04	4.79E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	9.73E+05	9.73E+05	9.73E+05	5.22E+05	4.50E+05	4.68E+05	4.68E+05	4.86E+05	5.04E+05	5.04E+05	4.86E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.32: Results sensitivity analysis: 50% decrease of floating offshore wind costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	4.26E+08	3.85E+08	3.45E+08	3.05E+08	2.67E+08	2.28E+08	2.18E+08	2.08E+08	2.00E+08	1.91E+08	1.82E+08
Costs per kg hydrogen (euros)	8.51	7.71	6.91	6.10	5.34	4.57	4.36	4.17	4.00	3.82	3.64
Wind turbines	56	58	58	60	63	66	66	66	70	70	76
Solar platforms	140	40	40	30	5	9	9	9	13	13	0
Electrolyzers	28	28	28	27	26	25	25	25	24	24	23
Desalination equipment	27	27	27	26	25	24	24	24	24	24	23
Storage volume (m3)	4.97E+04	4.97E+04	4.97E+04	4.79E+04	4.61E+04	4.44E+04	4.44E+04	4.44E+04	4.26E+04	4.26E+04	4.08E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	5.04E+05	5.04E+05	5.04E+05	4.86E+05	4.68E+05	4.50E+05	4.50E+05	4.50E+05	4.32E+05	4.32E+05	4.14E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.33: Results sensitivity analysis: normalized comparison for change of floating offshore wind costs

	2020	**2023**	**2026**	**2029**	**2032**	**2035**	**2038**	**2041**	**2044**	**2047**	**2050**
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.09	1.12	1.17	1.21	1.20	1.18	1.18	1.17	1.16	1.15	1.14
-50%	0.71	0.72	0.73	0.74	0.76	0.79	0.80	0.81	0.82	0.84	0.85

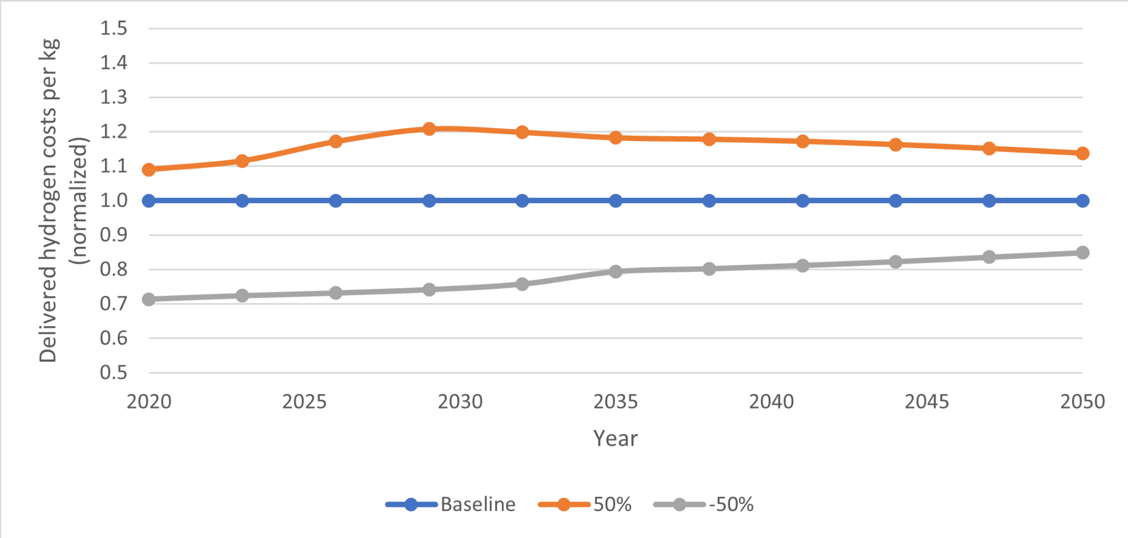

Figure 8.34: Results sensitivity analysis: normalized comparison for change of floating offshore wind costs

Floating offshore solar costs

Table 8.34: Results sensitivity analysis: 50% increase of floating offshore solar costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	6.29E+08	5.60E+08	4.92E+08	4.23E+08	3.55E+08	2.88E+08	2.72E+08	2.57E+08	2.43E+08	2.29E+08	2.15E+08
Costs per kg hydrogen (euros)	12.57	11.19	9.84	8.45	7.10	5.76	5.44	5.14	4.86	4.58	4.29
Wind turbines	51	51	54	56	57	59	59	59	61	63	63
Solar platforms	421	421	190	29	26	0	1.03E-13	0	0	5	5
Electrolyzers	28	28	29	30	29	28	28	28	27	26	26
Desalination equipment	27	27	28	29	28	27	27	27	26	25	25
Storage volume (m3)	4.97E+04	4.97E+04	5.15E+04	5.32E+04	5.15E+04	4.97E+04	4.97E+04	4.97E+04	4.79E+04	4.61E+04	4.61E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	5.04E+05	5.04E+05	5.22E+05	5.40E+05	5.22E+05	5.04E+05	5.04E+05	5.04E+05	4.86E+05	4.68E+05	4.68E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.35: Results sensitivity analysis: 50% decrease of floating offshore solar costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	4.86E+08	4.49E+08	4.20E+08	3.77E+08	3.26E+08	2.74E+08	2.60E+08	2.47E+08	2.36E+08	2.23E+08	2.11E+08
Costs per kg hydrogen (euros)	9.72	8.98	8.41	7.55	6.53	5.48	5.21	4.95	4.71	4.47	4.22
Wind turbines	0	0	0	36	42	44	45	45	46	48	51
Solar platforms	4809	4809	4809	1841	1414	1196	1119	1119	1050	1076	911
Electrolyzers	50	50	50	27	24	24	24	24	24	23	23
Desalination equipment	48	48	48	26	24	24	24	24	24	23	23
Storage volume (m3)	8.87E+04	8.87E+04	8.87E+04	4.79E+04	4.26E+04	4.26E+04	4.26E+04	4.26E+04	4.26E+04	4.08E+04	4.08E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	9.01E+05	9.01E+05	9.01E+05	4.86E+05	4.32E+05	4.32E+05	4.32E+05	4.32E+05	4.32E+05	4.14E+05	4.14E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.36: Results sensitivity analysis: normalized comparison for change of floating offshore solar costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.05	1.05	1.04	1.03	1.01	1.00	1.00	1.00	1.00	1.00	1.00
-50%	0.81	0.84	0.89	0.92	0.93	0.95	0.96	0.96	0.97	0.98	0.98

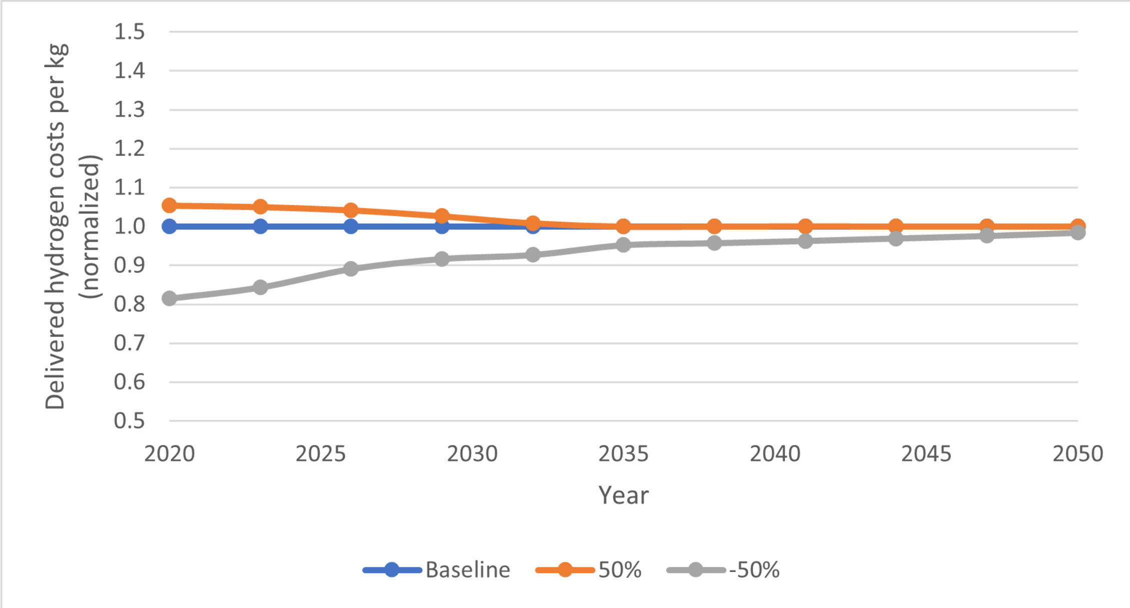

Figure 8.35: Results sensitivity analysis: normalized comparison for change of floating offshore solar costs

Electrolyzer costs

Table 8.37: Results sensitivity analysis: 50% increase of electrolyzer costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	6.33E+08	5.65E+08	5.00E+08	4.36E+08	3.75E+08	3.09E+08	2.91E+08	2.74E+08	2.59E+08	2.44E+08	2.28E+08
Costs per kg hydrogen (euros)	12.66	11.29	9.99	8.71	7.49	6.18	5.82	5.48	5.18	4.87	4.56
Wind turbines	42	43	44	46	49	60	60	63	63	63	66
Solar platforms	1305	1204	1196	939	663	30	30	5	5	5	9
Electrolyzers	25	25	24	25	26	27	27	26	26	26	25
Desalination equipment	24	24	24	24	25	26	26	25	25	25	24
Storage volume (m3)	4.44E+04	4.44E+04	4.26E+04	4.44E+04	4.61E+04	4.79E+04	4.79E+04	4.61E+04	4.61E+04	4.61E+04	4.44E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	4.50E+05	4.50E+05	4.32E+05	4.50E+05	4.68E+05	4.86E+05	4.86E+05	4.68E+05	4.68E+05	4.68E+05	4.50E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.38: Results sensitivity analysis: 50% decrease of electrolyzer costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	5.55E+08	4.98E+08	4.44E+08	3.87E+08	3.29E+08	2.66E+08	2.52E+08	2.39E+08	2.26E+08	2.14E+08	2.01E+08
Costs per kg hydrogen (euros)	11.10	9.96	8.87	7.74	6.57	5.32	5.04	4.78	4.52	4.27	4.01
Wind turbines	32	36	42	47	52	57	59	59	59	60	63
Solar platforms	1860	1597	1176	797	358	26	0	0	0	30	5
Electrolyzers	33	30	27	26	28	29	28	28	28	27	26
Desalination equipment	32	29	26	25	27	28	27	27	27	26	25
Storage volume (m3)	5.86E+04	5.32E+04	4.79E+04	4.61E+04	4.97E+04	5.15E+04	4.97E+04	4.97E+04	4.97E+04	4.79E+04	4.61E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	5.95E+05	5.40E+05	4.86E+05	4.68E+05	5.04E+05	5.22E+05	5.04E+05	5.04E+05	5.04E+05	4.86E+05	4.68E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.39: Results sensitivity analysis: normalized comparison for change of electrolyzer costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.06	1.06	1.06	1.06	1.06	1.07	1.07	1.07	1.07	1.07	1.06
-50%	0.93	0.93	0.94	0.94	0.93	0.92	0.93	0.93	0.93	0.93	0.93

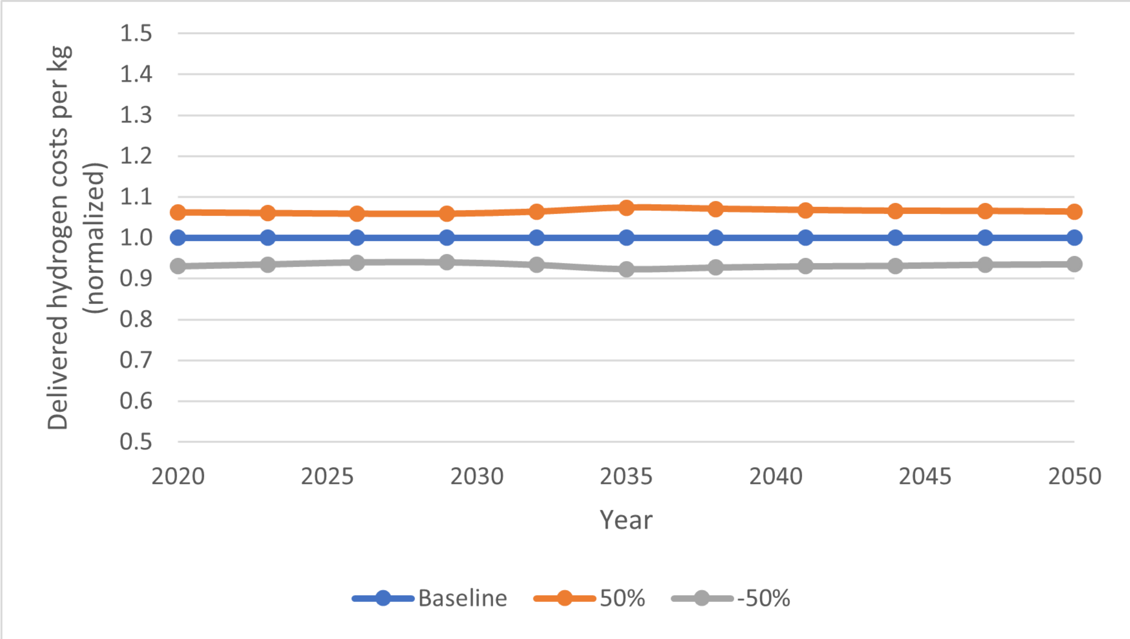

Figure 8.36: Results sensitivity analysis: normalized comparison for change of electrolyzer costs

Water depth

Table 8.40: Results sensitivity analysis: 50% increase of water depth

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	6.04E+08	5.39E+08	4.78E+08	4.16E+08	3.56E+08	2.91E+08	2.75E+08	2.59E+08	2.45E+08	2.31E+08	2.16E+08
Costs per kg hydrogen (euros)	12.07	10.78	9.56	8.33	7.12	5.81	5.49	5.18	4.90	4.61	4.32
Wind turbines	38	41	44	46	48	58	60	60	60	63	63
Solar platforms	1502	1328	1111	939	724	40	30	30	30	5	5
Electrolyzers	28	26	25	25	26	28	27	27	27	26	26
Desalination equipment	27	25	24	24	25	27	26	26	26	25	25
Storage volume (m3)	4.97E+04	4.61E+04	4.44E+04	4.44E+04	4.61E+04	4.97E+04	4.79E+04	4.79E+04	4.79E+04	4.61E+04	4.61E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	5.04E+05	4.68E+05	4.50E+05	4.50E+05	4.68E+05	5.04E+05	4.86E+05	4.86E+05	4.86E+05	4.68E+05	4.68E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.41: Results sensitivity analysis: 50% decrease of water depth

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	5.89E+08	5.26E+08	4.66E+08	4.07E+08	3.48E+08	2.85E+08	2.69E+08	2.54E+08	2.41E+08	2.27E+08	2.13E+08
Costs per kg hydrogen (euros)	11.78	10.52	9.32	8.14	6.97	5.70	5.39	5.09	4.82	4.54	4.26
Wind turbines	41	42	45	46	50	60	60	60	63	63	63
Solar platforms	1328	1230	1022	939	535	30	30	30	5	5	5
Electrolyzers	26	26	25	25	27	27	27	27	26	26	26
Desalination equipment	25	25	24	24	26	26	26	26	25	25	25
Storage volume (m3)	4.61E+04	4.61E+04	4.44E+04	4.44E+04	4.79E+04	4.79E+04	4.79E+04	4.79E+04	4.61E+04	4.61E+04	4.61E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	4.68E+05	4.68E+05	4.50E+05	4.50E+05	4.86E+05	4.86E+05	4.86E+05	4.86E+05	4.68E+05	4.68E+05	4.68E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.42: Results sensitivity analysis: normalized comparison for change of water depth

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01
-50%	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99

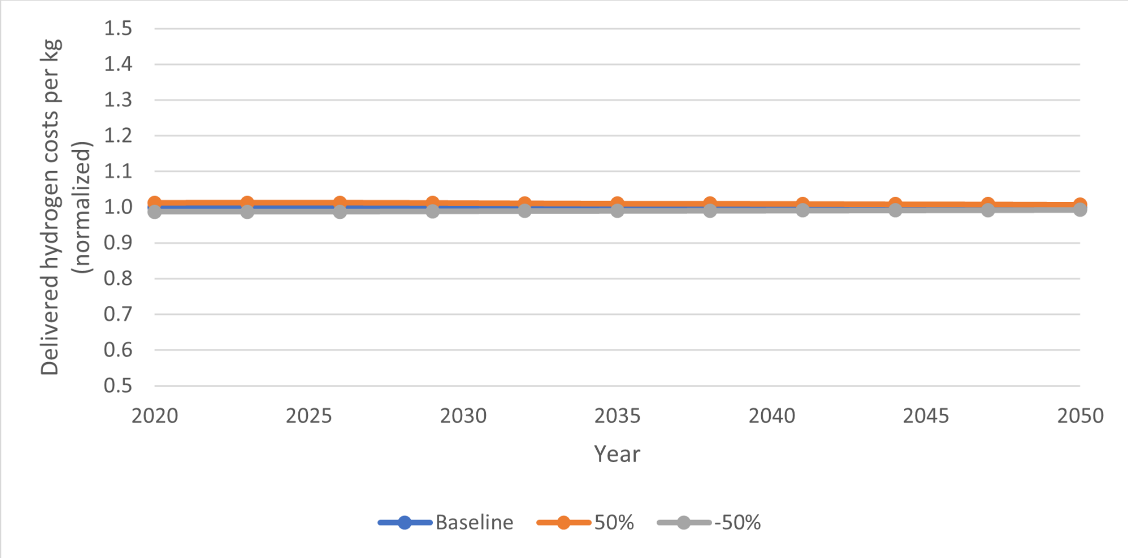

Figure 8.37: Results sensitivity analysis: normalized comparison for change of water depth

FPSO costs

Table 8.43: Results sensitivity analysis: 50% increase of FPSO costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	6.18E+08	5.53E+08	4.93E+08	4.32E+08	3.73E+08	3.10E+08	2.94E+08	2.78E+08	2.64E+08	2.50E+08	2.35E+08
Costs per kg hydrogen (euros)	12.36	11.07	9.85	8.64	7.47	6.20	5.88	5.57	5.28	5.00	4.70
Wind turbines	41	43	44	46	49	60	60	63	63	66	66
Solar platforms	1328	1204	1111	939	663	30	30	5	5	9	9
Electrolyzers	26	25	25	25	26	27	27	26	26	25	25
Desalination equipment	25	24	24	24	25	26	26	25	25	24	24
Storage volume (m3)	4.61E+04	4.44E+04	4.44E+04	4.44E+04	4.61E+04	4.79E+04	4.79E+04	4.61E+04	4.61E+04	4.44E+04	4.44E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	4.68E+05	4.50E+05	4.50E+05	4.50E+05	4.68E+05	4.86E+05	4.86E+05	4.68E+05	4.68E+05	4.50E+05	4.50E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.44: Results sensitivity analysis: 50% decrease of FPSO costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	5.73E+08	5.11E+08	4.51E+08	3.91E+08	3.30E+08	2.65E+08	2.49E+08	2.34E+08	2.20E+08	2.07E+08	1.93E+08
Costs per kg hydrogen (euros)	11.47	10.21	9.03	7.81	6.60	5.30	4.98	4.68	4.41	4.14	3.86
Wind turbines	37	38	44	47	52	57	59	59	59	59	61
Solar platforms	1548	1502	1048	797	358	26	0	0	0	-4.9E-14	0
Electrolyzers	29	28	26	26	28	29	28	28	28	28	27
Desalination equipment	28	27	25	25	27	28	27	27	27	27	26
Storage volume (m3)	5.15E+04	4.97E+04	4.61E+04	4.61E+04	4.97E+04	5.15E+04	4.97E+04	4.97E+04	4.97E+04	4.97E+04	4.79E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	5.22E+05	5.04E+05	4.68E+05	4.68E+05	5.04E+05	5.22E+05	5.04E+05	5.04E+05	5.04E+05	5.04E+05	4.86E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.45: Results sensitivity analysis: normalized comparison for change of FPSO costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.04	1.04	1.04	1.05	1.06	1.08	1.08	1.08	1.09	1.09	1.10
-50%	0.96	0.96	0.96	0.95	0.94	0.92	0.92	0.91	0.91	0.90	0.90

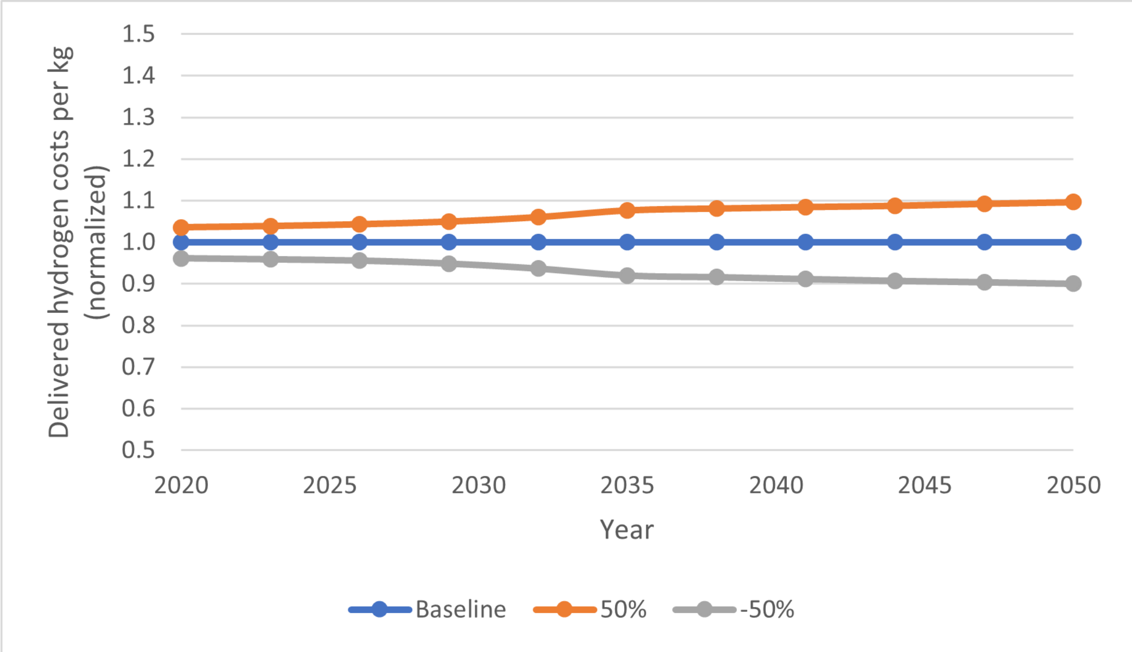

Figure 8.38: Results sensitivity analysis: normalized comparison for change of FPSO costs

Desalination costs

Table 8.46: Results sensitivity analysis: 50% increase of desalination costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	5.97E+08	5.33E+08	4.72E+08	4.12E+08	3.52E+08	2.88E+08	2.72E+08	2.57E+08	2.43E+08	2.29E+08	2.15E+08
Costs per kg hydrogen (euros)	11.93	10.66	9.45	8.23	7.05	5.76	5.44	5.14	4.86	4.58	4.29
Wind turbines	39	41	44	46	49	60	60	60	60	63	63
Solar platforms	1464	1328	1111	939	663	30	30	30	30	5	5
Electrolyzers	27	26	25	25	26	27	27	27	27	26	26
Desalination equipment	26	25	24	24	25	26	26	26	26	25	25
Storage volume (m3)	4.79E+04	4.61E+04	4.44E+04	4.44E+04	4.61E+04	4.79E+04	4.79E+04	4.79E+04	4.79E+04	4.61E+04	4.61E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	4.86E+05	4.68E+05	4.50E+05	4.50E+05	4.68E+05	4.86E+05	4.86E+05	4.86E+05	4.86E+05	4.68E+05	4.68E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.47: Results sensitivity analysis: 50% decrease of desalination costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	5.96E+08	5.32E+08	4.72E+08	4.11E+08	3.52E+08	2.88E+08	2.72E+08	2.57E+08	2.43E+08	2.29E+08	2.14E+08
Costs per kg hydrogen (euros)	11.93	10.65	9.44	8.23	7.04	5.75	5.44	5.13	4.86	4.57	4.29
Wind turbines	39	41	44	46	49	59	60	60	60	63	63
Solar platforms	1464	1328	1111	939	663	0	30	30	30	5	5
Electrolyzers	27	26	25	25	26	28	27	27	27	26	26
Desalination equipment	26	25	24	24	25	27	26	26	26	25	25
Storage volume (m3)	4.79E+04	4.61E+04	4.44E+04	4.44E+04	4.61E+04	4.97E+04	4.79E+04	4.79E+04	4.79E+04	4.61E+04	4.61E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	4.86E+05	4.68E+05	4.50E+05	4.50E+05	4.68E+05	5.04E+05	4.86E+05	4.86E+05	4.86E+05	4.68E+05	4.68E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.48: Results sensitivity analysis: normalized comparison for change of desalination costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
-50%	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

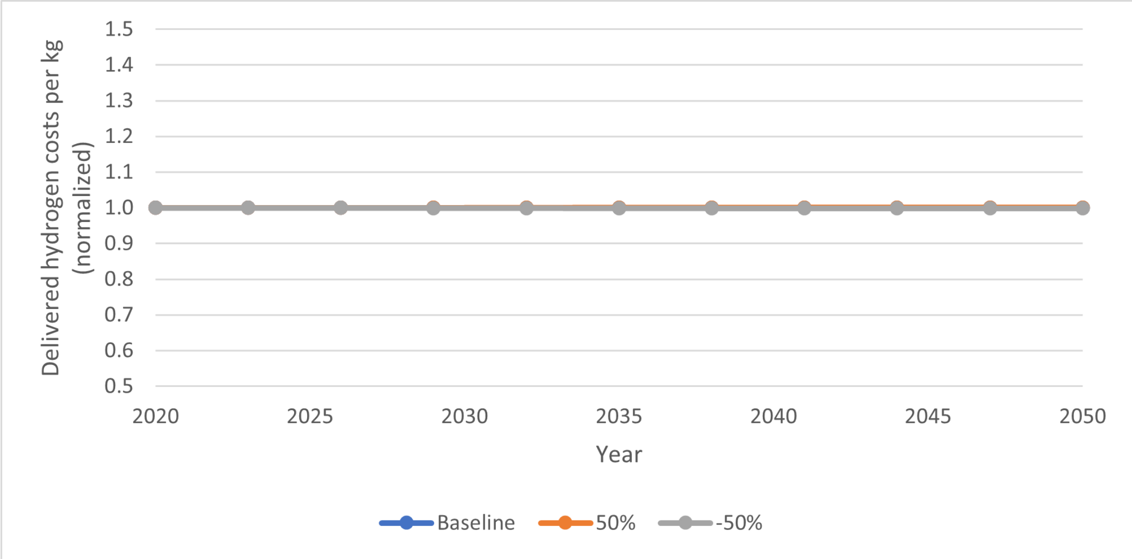

Figure 8.39: Results sensitivity analysis: normalized comparison for change of desalination costs

Ammonia transport costs

Table 8.49: Results sensitivity analysis: 50% increase of ammonia transport costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	6.01E+08	5.37E+08	4.76E+08	4.16E+08	3.57E+08	2.92E+08	2.76E+08	2.61E+08	2.47E+08	2.33E+08	2.19E+08
Costs per kg hydrogen (euros)	12.01	10.74	9.53	8.32	7.13	5.84	5.53	5.22	4.95	4.66	4.38
Wind turbines	39	41	44	46	49	59	60	60	60	63	63
Solar platforms	1464	1328	1111	939	663	3.21E-13	30	30	30	5	5
Electrolyzers	27	26	25	25	26	28	27	27	27	26	26
Desalination equipment	26	25	24	24	25	27	26	26	26	25	25
Storage volume (m3)	4.79E+04	4.61E+04	4.44E+04	4.44E+04	4.61E+04	4.97E+04	4.79E+04	4.79E+04	4.79E+04	4.61E+04	4.61E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	4.86E+05	4.68E+05	4.50E+05	4.50E+05	4.68E+05	5.04E+05	4.86E+05	4.86E+05	4.86E+05	4.68E+05	4.68E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.50: Results sensitivity analysis: 50% decrease of ammonia transport costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	5.92E+08	5.28E+08	4.68E+08	4.07E+08	3.48E+08	2.83E+08	2.68E+08	2.52E+08	2.39E+08	2.24E+08	2.10E+08
Costs per kg hydrogen (euros)	11.84	10.57	9.36	8.15	6.96	5.67	5.35	5.05	4.77	4.49	4.20
Wind turbines	39	41	44	46	49	59	60	60	60	63	63
Solar platforms	1464	1328	1111	939	663	0	30	30	30	5	5
Electrolyzers	27	26	25	25	26	28	27	27	27	26	26
Desalination equipment	26	25	24	24	25	27	26	26	26	25	25
Storage volume (m3)	4.79E+04	4.61E+04	4.44E+04	4.44E+04	4.61E+04	4.97E+04	4.79E+04	4.79E+04	4.79E+04	4.61E+04	4.61E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	4.86E+05	4.68E+05	4.50E+05	4.50E+05	4.68E+05	5.04E+05	4.86E+05	4.86E+05	4.86E+05	4.68E+05	4.68E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.51: Results sensitivity analysis: normalized comparison for change of ammonia transport costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.01	1.01	1.01	1.01	1.01	1.02	1.02	1.02	1.02	1.02	1.02
-50%	0.99	0.99	0.99	0.99	0.99	0.98	0.98	0.98	0.98	0.98	0.98

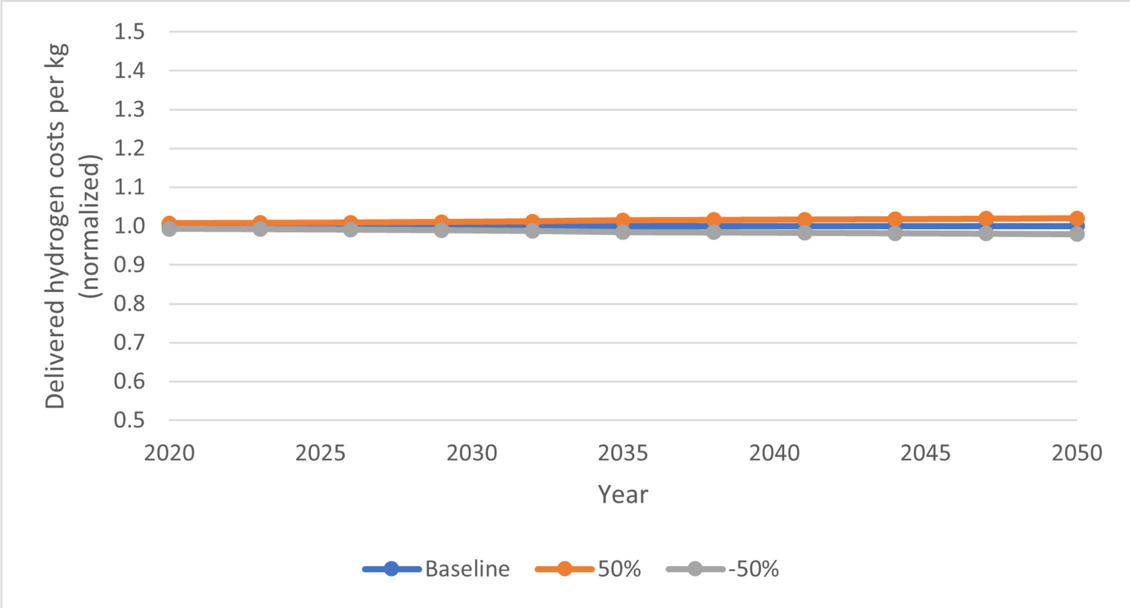

Figure 8.40: Results sensitivity analysis: normalized comparison for change of ammonia transport costs

Liquid hydrogen transport costs

Table 8.52: Results sensitivity analysis: 50% increase of liquid hydrogen transport costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	5.96E+08	5.33E+08	4.72E+08	4.12E+08	3.52E+08	2.88E+08	2.72E+08	2.57E+08	2.43E+08	2.29E+08	2.14E+08
Costs per kg hydrogen (euros)	11.93	10.65	9.44	8.23	7.04	5.76	5.44	5.14	4.86	4.57	4.29
Wind turbines	39	41	44	46	49	59	60	60	60	63	63
Solar platforms	1464	1328	1111	939	663	0	30	30	30	5	5
Electrolyzers	27	26	25	25	26	28	27	27	27	26	26
Desalination equipment	26	25	24	24	25	27	26	26	26	25	25
Storage volume (m3)	4.79E+04	4.61E+04	4.44E+04	4.44E+04	4.61E+04	4.97E+04	4.79E+04	4.79E+04	4.79E+04	4.61E+04	4.61E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	4.86E+05	4.68E+05	4.50E+05	4.50E+05	4.68E+05	5.04E+05	4.86E+05	4.86E+05	4.86E+05	4.68E+05	4.68E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.53: Results sensitivity analysis: 50% decrease of liquid hydrogen transport costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	5.96E+08	5.33E+08	4.72E+08	4.12E+08	3.52E+08	2.88E+08	2.72E+08	2.57E+08	2.43E+08	2.29E+08	2.14E+08
Costs per kg hydrogen (euros)	11.93	10.65	9.44	8.23	7.04	5.76	5.44	5.14	4.86	4.57	4.29
Wind turbines	39	41	44	46	49	59	60	60	60	63	63
Solar platforms	1464	1328	1111	939	663	0	30	30	30	5	5
Electrolyzers	27	26	25	25	26	28	27	27	27	26	26
Desalination equipment	26	25	24	24	25	27	26	26	26	25	25
Storage volume (m3)	4.79E+04	4.61E+04	4.44E+04	4.44E+04	4.61E+04	4.97E+04	4.79E+04	4.79E+04	4.79E+04	4.61E+04	4.61E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	4.86E+05	4.68E+05	4.50E+05	4.50E+05	4.68E+05	5.04E+05	4.86E+05	4.86E+05	4.86E+05	4.68E+05	4.68E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.54: Results sensitivity analysis: normalized comparison for change of liquid hydrogen transport costs

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
-50%	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

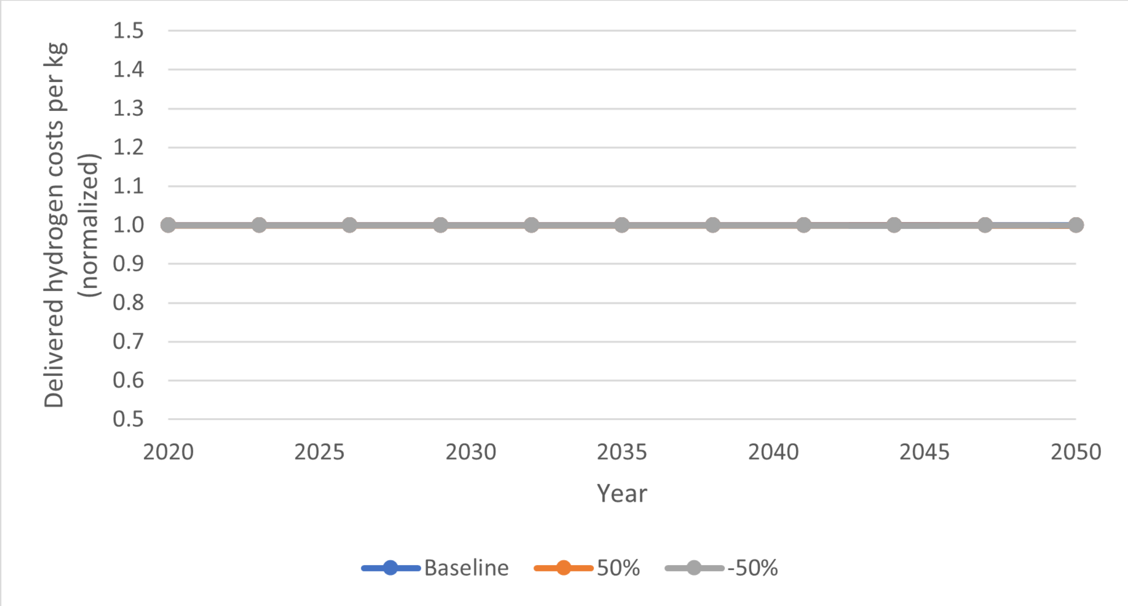

Figure 8.41: Results sensitivity analysis: normalized comparison for change of liquid hydrogen transport costs

Financing costs (interest rate)

Table 8.55: Results sensitivity analysis: 50% increase of the interest rate

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	7.65E+08	6.83E+08	6.06E+08	5.28E+08	4.51E+08	3.68E+08	3.48E+08	3.28E+08	3.11E+08	2.92E+08	2.74E+08
Costs per kg hydrogen (euros)	15.30	13.67	12.11	10.56	9.02	7.35	6.95	6.57	6.21	5.85	5.48
Wind turbines	38	41	44	46	50	58	59	60	60	63	63
Solar platforms	1502	1328	1111	939	535	40	0	30	30	5	5
Electrolyzers	28	26	25	25	27	28	28	27	27	26	26
Desalination equipment	27	25	24	24	26	27	27	26	26	25	25
Storage volume (m3)	4.97E+04	4.61E+04	4.44E+04	4.44E+04	4.79E+04	4.97E+04	4.97E+04	4.79E+04	4.79E+04	4.61E+04	4.61E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	5.04E+05	4.68E+05	4.50E+05	4.50E+05	4.86E+05	5.04E+05	5.04E+05	4.86E+05	4.86E+05	4.68E+05	4.68E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.56: Results sensitivity analysis: 50% decrease of the interest rate

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Demand (tons of hydrogen)	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000	50000
Usage location	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Year	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Production location	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea	East Chinese Sea
Transfer port	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo	Tokyo
Total costs per year (euros)	4.48E+08	4.00E+08	3.55E+08	3.09E+08	2.65E+08	2.17E+08	2.05E+08	1.94E+08	1.83E+08	1.73E+08	1.62E+08
Costs per kg hydrogen (euros)	8.96	8.01	7.09	6.19	5.30	4.35	4.11	3.88	3.67	3.46	3.24
Wind turbines	41	41	44	46	49	60	60	60	63	63	63
Solar platforms	1328	1328	1111	939	663	30	30	30	5	5	5
Electrolyzers	26	26	25	25	26	27	27	27	26	26	26
Desalination equipment	25	25	24	24	25	26	26	26	25	25	25
Storage volume (m3)	4.61E+04	4.61E+04	4.44E+04	4.44E+04	4.61E+04	4.79E+04	4.79E+04	4.79E+04	4.61E+04	4.61E+04	4.61E+04
Conversion devices	9	9	9	9	9	9	9	9	9	9	9
Reconversion devices	5	5	5	5	5	5	5	5	5	5	5
Transport medium	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA	AMMONIA
FPSO volume (m3)	4.68E+05	4.68E+05	4.50E+05	4.50E+05	4.68E+05	4.86E+05	4.86E+05	4.86E+05	4.68E+05	4.68E+05	4.68E+05
Distance sea (km)	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566	1566
Distance land (km)	0	0	0	0	0	0	0	0	0	0	0

Table 8.57: Results sensitivity analysis: normalized comparison for change of the interest rate

	2020	2023	2026	2029	2032	2035	2038	2041	2044	2047	2050
Baseline	1	1	1	1	1	1	1	1	1	1	1
50%	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28
-50%	0.75	0.75	0.75	0.75	0.75	0.76	0.76	0.76	0.76	0.76	0.76

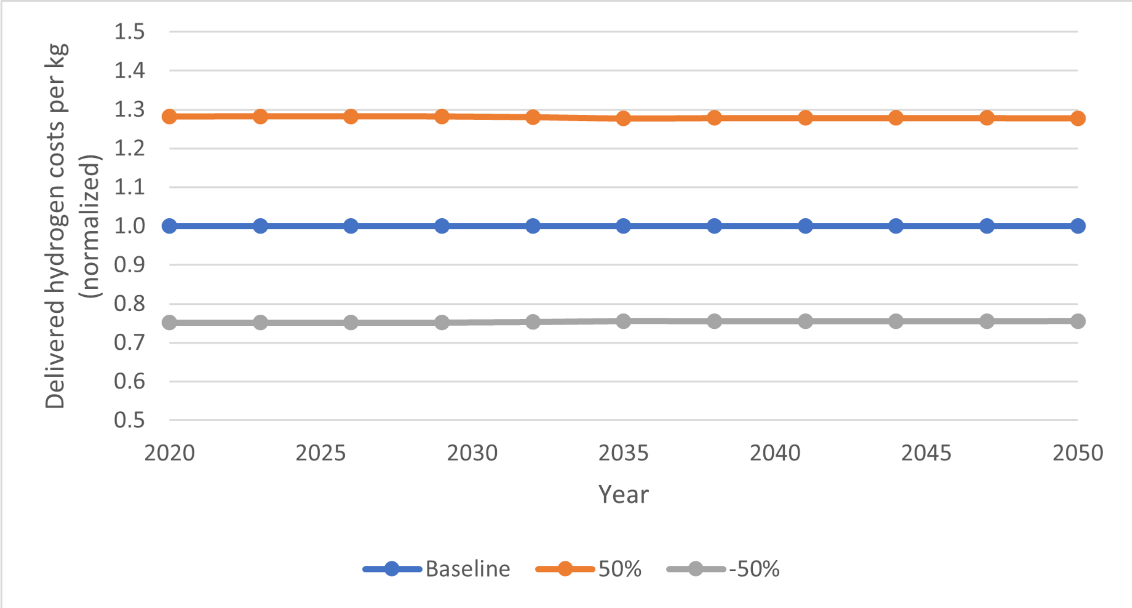

Figure 8.42: Results sensitivity analysis: normalized comparison for change of the interest rate

Appendix H

In this appendix, the platform options for floating offshore wind (FOW) are discussed shortly. The four main kinds of floating platforms for FOW turbines are the barge, semi-submersible, spar-buoy and tension leg platforms (see also Figure 8.43). The barge foundation is wide and shallow, and has moonpool in the middle. The mooring lines provide station keeping and restoring moment to prevent the turbine from tipping over. This configuration is mainly suitable for water depths of 50-100 m and is relatively economical and easy to construct. (Rehman et al., 2022) The limited water depth poses a major limitation for far offshore application, since it is expected that the water depths will often exceed 100 m in far offshore environments.

The semi-submersible foundation consists of columns with tubular connections between them. These connections can be partially filled with water to provide the needed ballast. The turbine can be placed on top of one of the columns or in the center of the entire foundation. When a FOW turbine has this foundation, it can be constructed onshore and towed to its destination once it is completely finished. (Rehman et al., 2022)

The spar foundation consists of a cylinder made of steel and/or concrete. To make sure the center of gravity is sufficiently low to provide the needed stability to the turbine, this cylinder is filled with gravel and water. Finally, the tension-leg platform foundation consists of several floaters. This foundation is kept in position by vertical mooring configurations, which also make sure the turbine has sufficient stability. (Rehman et al., 2022) When presenting the input data to be used in this research, it has been indicated which platform configuration is assumed.

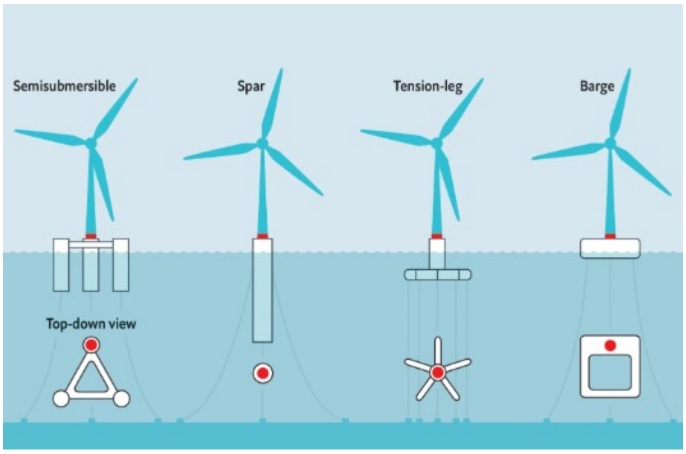

Figure 8.43: Side and top views of FOW main turbine platform options (Barooni et al., 2022)