Shipping green hydrogen, worth it?

An analysis to determine a price for green hydrogen, based on the geographical site of production.

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Summary

Meeting the global energy demand while reducing CO_2 emissions are two of the most compelling challenges of the 21st century. Therefore, many countries in Northwest Europe consider green hydrogen as a crucial part of the energy system to reduce carbon emissions. Currently, the production and consumption of hydrogen are local. The hydrogen production capacity may be limited by the space available for wind turbines and solar panels. Furthermore, weather circumstances vary across the globe and so does the suitability to produce renewable energy. The object of this study is to find insights into the levelized cost of hydrogen when it is imported.

A main research question has been formulated namely, "*Is the levelized cost of energy for the production, transportation, and import of green hydrogen able to compete with conventional fuels?"*. Four parts have been created in this thesis to be able to answer the main question. Part 1 takes a look at the levelized cost of energy for solar and wind power. The second part investigates the production methods of hydrogen together with the associated costs. Part three aims to determine the costs associated with the transportation of hydrogen. Transport by pipeline, ship, and truck are considered where the hydrogen is in a liquid or gaseous state. The final part performs scenarios to determine a price for green hydrogen per kilogram. This price is determined by a calculation model that has been designed for this thesis. This model encompasses the price for energy, efficiency, price of electrolysis, price of liquefaction, price of transport, and the transportation distance.

The results of the first three parts are set in the year 2030 and are divided over three levels. These levels are: favorable, average, and unfavorable. Part 1 gives kWh prices in these three levels based on wind speed and solar irradiance. Part 2 takes a look at the alkaline electrolyzer and the costs per kg of hydrogen for this technology. Part 3 starts with a liquefier expressed in costs per kg of hydrogen and shows the estimated costs to transport hydrogen over distance.

For hydrogen to be competitive the price should be below a certain threshold based on literature. For gaseous hydrogen, this price is estimated at €1.70 per kilogram and for liquid hydrogen at €4.25 per kilogram. The first scenario takes Morocco as producing country and exports the hydrogen to the Netherlands. Two types of transport have been calculated namely, by ship and by pipeline. These methods come to a price of €2.039/kg and €1.427/kg respectively. The second scenario estimates the price for hydrogen produced in Australia and exported to Japan by ship. This scenario calculates a price of €2.278 per kilogram of liquid hydrogen.

This thesis does not give a tailored solution, but rather a generalizable insight into the price of green hydrogen. The scenarios show that the price of electricity is one of the major factors to determine the hydrogen price. Furthermore, the most favorable prices per kWh are used in the scenarios. This means that the scenarios are in an optimistic setting.

To conclude, green hydrogen can compete with conventional fuels when it is produced in an area with high solar irradiance levels. Furthermore, transportation costs in combination with lower kWh prices are able to outweigh higher domestic production costs without transport. Although this study is based on many estimates of prices, the findings suggest that green hydrogen is competitive in the year 2030.

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List of abbreviations

ATB: Annual Technology Baseline
DIF: Diffuse Horizontal Irradiance
DNI: Direct Normal Irradiation
EHB: European Hydrogen Backbone
GHI: Global Horizontal Irradiance
IEA: International Energy Agency
IEEFA: Institute for Energy Economics and Financial Analysis
IRENA: International Renewable Energy Agency
kWh: Kilowatt hour
LCOE: Levelized Cost Of Energy
LH_2: Liquid Hydrogen
LNG: Liquid Natural Gas
NREL: National Renewable Energy Laboratory
MWh: Megawatt hour
NCA: National Climate Agreement
LCOH: Levelized Cost Of Hydrogen
PEM: Polymer Exchange Membrane
PHS: Pumped Hydro Storage
PtG: Power-to-Gas
USD: United State Dollar
WAWS: Weighted Average Wind Speed

1. Introduction

Meeting the global energy demand and reducing the corresponding environmental issues are two of the most compelling challenges of the 21st century (Dincer & Acar, 2015). While the largest share of the world's energy supply originates from fossil fuels, its consequent CO_2 emissions are seen as the main driver behind global warming. To manage the environmental challenges, almost every country in the world has signed the Paris Agreement in 2015. The goal of this agreement is to limit global warming to less than two degrees Celsius above pre-industrial levels. To follow up on the Paris Agreement, the Dutch government introduced the National Climate Agreement (NCA). The NCA gives guidance and describes the short- middle- and long-term goals on reducing carbon emissions on a national level. The Dutch government sees hydrogen as a crucial part of the energy system in the middle- to long-term objectives to reduce carbon emissions. This is also referred to as the hydrogen economy (De Rijksoverheid, 2019).

The hydrogen economy was first introduced by Prof. John Bockris in 1970. The hydrogen economy encompasses the production, storage, transportation, and distribution of hydrogen as an energy carrier (Brandon & Kurban, 2017). Hydrogen is recognized as a potential multipurpose energy carrier to provide heat, electricity, and fuel in transport (CE Delft, 2018; Certifhy, 2015; IRENA, 2018). Therefore, many Northwest-European countries describe hydrogen as an important energy source in their scenarios for energy demand management in 2050 (Hydrogen Council, 2020).

When hydrogen is produced by renewable energy sources, it is called 'green hydrogen'. Green hydrogen is seen as an outstanding candidate to overcome environmental challenges associated with the energy transition. Dincer and Acar (2015) have listed some of the advantages associated with hydrogen, namely: "(i) high energy conversion efficiencies; (ii) production from water with no emission; (iii) abundance; (iv) different forms of storage (e.g., gaseous, liquid, or in together with metal hydrides); (v) long-distance transportation; (vi) ease of conversion to other forms of energy; (vii) higher HHV (high heating value) and LHV (low heating value) than most of the conventional fossil fuels." (Dincer & Acar, 2015).

The majority of hydrogen is currently produced and consumed locally (Hydrogen Council, 2020). However, the production capacity for hydrogen may be limited, for example by the available space for wind turbines and/or solar panels. In addition, the weather circumstances in other locations than the place of consumption may be considerably more favorable in terms of solar and wind intensity hydrogen (IRENA, 2018). The costs of hydrogen depend heavily on the availability of renewable energy inputs (Hydrogen Council, 2020). As the solar and wind conditions become more favorable, the production costs of green hydrogen decrease. So, based on the weather conditions, the production of hydrogen could potentially be cheaper at a different geographical location. From an economic perspective, it would be interesting to investigate whether this decrease in production costs can outweigh the transportation costs.

In 2018, a former student of the Master program Energy and Environmental Sciences performed a study about the environmental and energy feasibility of producing hydrogen in desert areas for export to the Netherlands (Zapata, 2018). In Zapata's (2018) thesis, two geographic scenarios were studied namely, Morocco and Australia transporting hydrogen to the Netherlands and were set in the year 2030. While Zapata (2018) focused on environmental and energy feasibility, this thesis will follow up to investigate the financial aspects.

The object of this study is to obtain insights into the levelized costs of hydrogen imported over a large geographical distance. The technical-economic perspectives for hydrogen production, storage, and transportation have been analyzed extensively (Cardella et al., 2016; Götz et al., 2016). However, when the production and consumption of hydrogen occur in different countries, we find a gap of research in the combination of these factors along the supply line. Insights will be gained by creating a calculation model that enables to estimate the levelized costs of hydrogen-based on the following aspects: cost of energy based on wind and/or solar intensity at the production site, efficiency & price of electrolysis, and price of transport method over distance. This model can be used to explore opportunities rather than providing an exact calculation of costs.

2. Methodology

A couple of steps had to be taken to determine the price of green hydrogen. First, the research aim is defined. Second, a main question is formulated and a couple of sub-questions to break it up into multiple parts. The questions are followed up by the boundary settings and the research methods.

2.1 Research aim and questions

Hydrogen is seen as a multipurpose energy carrier that can fuel a CO_2-free economy. Countries with low levels of wind intensity & solar radiation and/or little room to produce renewable energy could be interested in importing hydrogen from more favorable locations. Therefore, this research aims to give insight into costs for producing hydrogen based on the geographical location from which it can be imported. The Levelized Cost Of Energy (LCOE) is used to determine and compare different electricity sources and will be further explained in the methodology. Furthermore, future prices are considered to give insight into future investments.

To achieve insights on the costs associated with producing hydrogen at different locations, the following main research question has been formulated:

"Is the levelized cost of energy for the production, transportation, and import of green hydrogen able to compete with conventional fuels?"

To be able to answer the main question, this thesis has been divided into four parts which follow the production process of hydrogen:

Part 1: Electricity

1. What is the LCOE for producing electricity with solar and wind power based on their geographical location?
2. What is the LCOE for stored electricity?

Part 2: Production

3. What method is used to produce green hydrogen from renewables?
4. What costs are associated with this method?

Part 3: Transportation

5. Which transportation methods are applicable over short distances?
6. What costs are associated with these methods?
7. Which transportation methods are applicable over long distances?
8. What costs are associated with these methods?

Part 4: Scenarios

9. Performing a couple of scenarios, are there production areas able to compete with conventional fuels?

2.2 Boundary settings

There are numerous ways to produce green hydrogen. This paper cannot provide a comprehensive review of all these options. Figure 1 shows the structure of the hydrogen resource system defined for this thesis. Once again, the aim of this study is to compare the costs for the production of green hydrogen across different geographical locations. In terms of electricity (part 1), it is most relevant to investigate energy sources that differ across various geographical areas. While hydropower has the largest share of renewable electricity generation, wind and solar PV are the most increasing sources of renewable electricity and depend directly on the amount of solar irradiance or wind power (IEA, 2020b). Thus, it has been decided that this paper limits its scope to wind and solar PV. Furthermore, due to the level of technological immaturity for electricity storage, only Pumped Hydro Storage (PHS) is considered as an option to store electricity. It is assumed that the generated electricity is fully dedicated to the production of hydrogen.

Next, in terms of production (part 2), green hydrogen can be produced in two ways, either through electrolysis or by gasification by biomass. This thesis considers only electrolysis as an option to produce green hydrogen because biomass is not an option in part 1. Furthermore, there are multiple types of electrolyzers to be considered. Mainly due to price options and technological maturity levels, only alkaline electrolyzers are considered in this thesis as will be further explained in the methodology chapter. Part 3 focusses on the transportation of hydrogen. This thesis limits itself to the transport of pure hydrogen in either liquid or gaseous state as will be explained in the methodology chapter.

Throughout the production process and transportation various losses are to be expected. Nonetheless, this thesis does not include losses into the calculations.

The values given are in either dollar or euro, these values will all be recalculated to euro for the results with an exchange rate from the year 2021 which means that USD 1 equals €0.85.

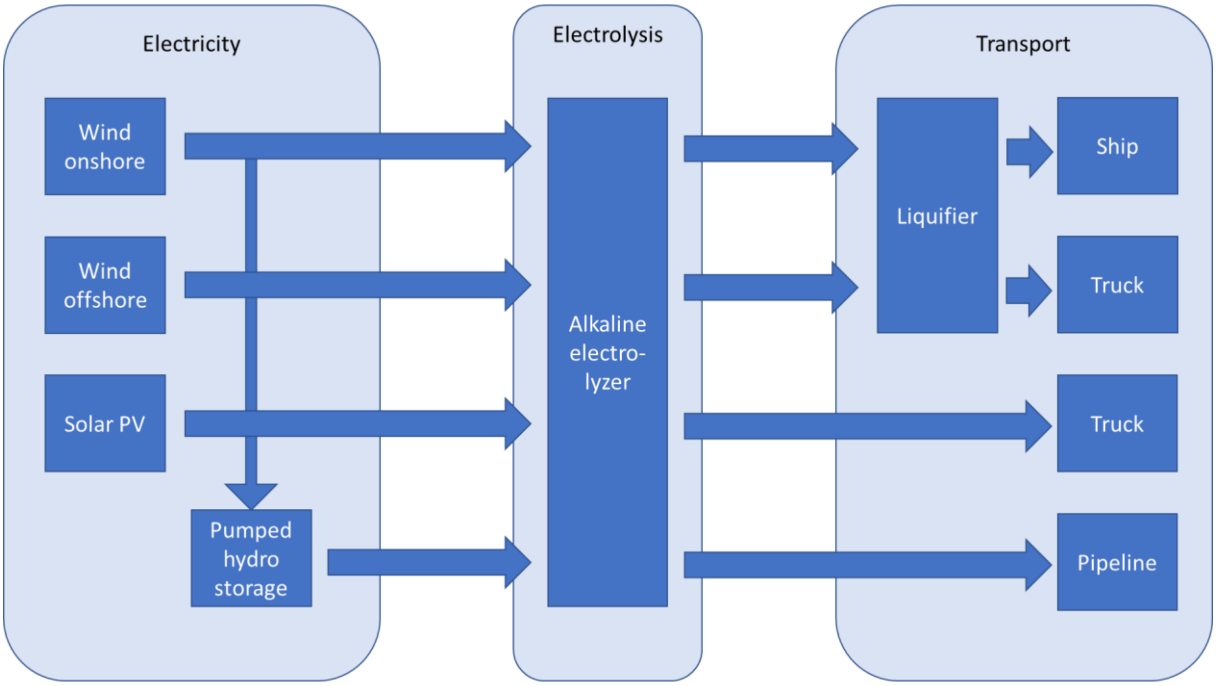

Figure 1: Structure hydrogen resource system

2.3 Research methods

To be able to achieve the aim of this research a couple of steps had to be taken. A literature research and modeling had to be carried out before a couple of scenarios could be realized. Parts 1, 2, and 3 of this research started with literature research to find valid values to calculate with. The costs for electricity generation are based on the average lifetime levelized cost of electricity generation (LCOE). This comparison of generation costs is well-established and widely used in modeling and policy-making (IEA, 2020a). This method encompasses the investments, operations and maintenance expenditures, the lifetime and uses a discount rate. The values used in this thesis originate from multiple sources to give an accurate estimate. Nonetheless, the same method is used to calculate the LCOE as shown in figure 2 below.

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

Where:
LCOE= The average lifetime levelized cost of electricity generation
I_t = Investment expenditures in the year t
M_t = Operations and maintenance expenditures in the year t
F_t = Fuel expenditures in the year t
E_t = Electricity generation in the year t
r = Discount rate
n = Life of the system

Figure 2: Levelized cost of energy

Part 2 and 3 of this study are composed by performing a literature study. The values from multiple sources are assessed to estimate production costs per kilogram of hydrogen. Figure 3 shows the calculation model that has been designed and used to perform the final scenarios in part 4 of this thesis.

$$LCOH = (En * \eta) + El + Liq + (\left(\frac{Tr}{100}\right) * Dis)$$

Where:
LCOH= Levelized Cost of Hydrogen in €/kg H_2
En = Price of energy in €/kWh
η = Efficiency of electrolyzer in kWh/kg H_2
El = Price of electrolysis in €/kg H_2
Liq = Price of liquefaction in €/kg H_2
Tr = Price of transport in €/kg H_2/100km
Dis = Distance of transport in kilometer

Figure 3: Levelized cost of hydrogen

3. Modelling the hydrogen system

Following up on the parts introduced in the previous chapter, several steps have to be taken to produce green hydrogen. Therefore, the costs for hydrogen depend on the costs for each step in the hydrogen production process. The steps are as follows: electricity generation, electricity storage, electrolysis, hydrogen storage & transport.

3.1 Hydrogen

Three types of hydrogen are to be recognized, namely grey-, blue-, and green hydrogen (CE Delft, 2018). Currently, hydrogen is mainly produced from natural gas (CH_4) through steam methane reforming. Due to the consequent CO_2 emissions, this is called grey hydrogen. When CO_2 as a byproduct is captured and stored or reused it gets the cleaner ‘blue hydrogen’ label. However, when hydrogen is produced through electrolysis of water (H_2O) powered by renewable energy sources it is called green hydrogen. While this type of hydrogen is considered carbon-free, another advantage is that it has a higher purity than grey and blue hydrogen (CE Delft, 2018). The electricity sources in this thesis are limited to renewables. Therefore, it is implied that green hydrogen is represented when hydrogen is mentioned.

3.2 Competitiveness hydrogen

Hydrogen should achieve a certain threshold price to be able to compete with conventional fuels. For gaseous hydrogen, the threshold price should be around €1.70/kg H_2 in the year 2030 according to IRENA (2020) and the Institute for Energy Economics and Financial Analysis (IEEFA, 2021). No prices for liquid hydrogen have been given due to a lack of academic validation. Nonetheless, an attempt to give a threshold price for liquid hydrogen was made. Both, natural gas and hydrogen are used as a source of energy in either liquid or gaseous state. For natural gas to become a liquid, it needs to be cooled to -162 degrees Celsius and is then called LNG (IEA, 2019a). The price factor between natural gas and LNG is used to determine a difference in price for liquid and gaseous hydrogen. Gas prices from the Netherlands will be used for calculations due to the transparency of the Dutch gas prices. The price for natural gas without taxes is €0.27/m^3 in the year 2021 (Milieucentraal, 2021). Due to the fact that one cubic meter of gas contains 0.833 kg of natural gas, the price per kg is €0.32. The LNG price is approximately between €0.77 and €0.85 per kilogram in the Netherlands (Augusteijn, 2020; Volvo, 2020). By taking a mean value for LNG and divide this by the price for natural gas, the price factor can be determined. The difference in price between natural gas and LNG is approximately a factor 2.5. This factor is used for hydrogen as well. Therefore, the threshold price for liquid hydrogen is set to €4.25 per kilogram.

3.3 Part 1: Electricity

The generation of electricity is considered the first step to produce hydrogen in this thesis. IEA (2021) states that the largest share of hydrogen production costs originates from fuel costs. Namely, between 45% and 75% account for the production costs for hydrogen (IEA, 2019b). Similarly, Ball & Weeda (2015) state that over 50% of the hydrogen price accounts for electricity costs (Ball & Weeda, 2015). Due to the fact that electricity generated with solar and wind power is affected by their environment and the local weather pattern, it is important to pick a well-suited location. Therefore, the geographical location for electricity production will have a large impact on the production price for green hydrogen. The electricity prices used in this thesis are divided over three levels namely: Favorable, Average, and Unfavorable. Furthermore, these levels have been created for the years 2019, 2030, and 2050. Information provided by two international- and one American institute have been used in order to provide an accurate estimate of electricity prices, namely the International Renewable Energy Agency (IRENA), the International Energy Agency (IEA), and the National Renewable Energy Laboratory (NREL). Both IRENA and NREL have estimates for future electricity prices from renewable sources (IRENA, 2018)(NREL, 2020). Each year, NREL presents an Excel workbook that contains detailed cost and performance data for renewable technologies. This data is presented in the Electricity Annual Technology Baseline (ATB) spreadsheet, which has been consulted for this thesis (NREL, 2020).

3.3.1 Wind energy

A wind turbine is used to harvest and transform the energy from wind into electricity with a generator. While there are several designs, the most common wind turbine uses three blades which are placed in a horizontal axis rotor. The output of a wind turbine varies with changes in wind speed. In principle, the higher the wind speed, the larger the electrical output (IEA, 2013). Wind turbines can be built on land and water. Therefore, wind energy is divided into two different parts in this thesis. The reason to divide these two is the difference in price range as the databases retrieved from IRENA and NREL show (IRENA, 2018; NREL, 2020). While turbines on sea experience more suitable wind power, their costs to build and maintain are higher too. Building on sea means more challenging working conditions and harder to reach locations (IRENA, 2018). Therefore, wind turbines on land are able to achieve a lower LCOE than the ones placed on water.

3.3.2 Wind onshore

Wind onshore encompasses wind turbines built on land. The databases retrieved from IRENA and NREL are used to estimate costs per kWh of generated electricity. IRENA distinguishes several geographical areas and large countries like China and India. Furthermore, the LCOE is presented in three different levels. A weighted average for each area or country is shown together with the 5th and 95th percentile and is expressed in USD/kWh, the table from IRENA can be seen in table 1. To estimate a price per kWh for every three levels in this thesis, the averages of the 5th and the 95th percentile are taken for the favorable and unfavorable situations and the weighted average is taken as the average level. These averages represent the 2019 values expressed in USD/kWh. Furthermore, IRENA has estimated future energy prices for the years 2030 and 2050.

Table 1: Values wind onshore IRENA

Wind onshore IRENA	**2019**		
	5th percentile	**Weighted average**	**95th percentile**
	(2019 USD/kWh)		
Africa	0,05	**0,067**	0,072
Other Asia	0,057	**0,099**	0,131
Central America and the Caribbean	0,061	**0,061**	0,061
Eurasia	0,048	**0,064**	0,093
Europe	0,037	**0,067**	0,096
North America	0,035	**0,051**	0,082
Oceania	0,043	**0,054**	0,071
Other South America	0,039	**0,057**	0,092
Brazil	0,032	**0,048**	0,056
China	0,037	**0,046**	0,064
India	0,036	**0,049**	0,07

The IEA presents data up to the year 2019 and estimates the electricity price for onshore wind up to 2025 (IEA, 2021). IEA recognizes an upper limit price of approximately 70 USD per MWh, a lower limit price of approximately 40 USD per MWh, and a global weighted average of 52.6 USD per MWh. These values have been used as the favorable, average, and unfavorable levels for the year 2019. Since IEA provides information up to the year 2025, future energy prices are not used from this database.

As has been explained, NREL presented their values in the ATB data spreadsheet which is openly accessible. This database categorized ten wind classes by their wind speed range, where class1 has the highest wind speed range and class10 the lowest. Furthermore, the Weighted Average Wind Speed (WAWS) is shown for each class, starting with a value of 5.2 m/s for class10. Therefore, a WAWS slower than 5.2 m/s is not considered in this database. An explanation for this value is the cut-in speed at which a turbine begins to operate, this cut in speed is usually around 3 to 4 m/s (Dupont et al., 2018). Therefore, a lower WAWS than class10 increases the idle time of a wind turbine due to the fact that the windspeed is regularly lower than the cut-in speed of a wind turbine. The ATB database shows the LCOE of the ten wind speed classes with annual future estimates up to the year 2050. Furthermore, the ten classes are divided over three technological advancement levels, namely Advanced, Moderate and Conservative. For this thesis, solely the Moderate values are taken into account. The mean value of the first four classes is calculated to present the Favorable level in this thesis. The mean value of class6 up to class10 is calculated to present the Unfavorable level. The mean of all ten classes is taken to present the Average level.

With the collection of data from the discussed sources and databases the following table has been created. This table will be discussed in the Results chapter.

Table 2: Summary wind onshore

Energy prices in USD/kWh		IRENA			IEA	NREL		
		2019 Energy price	2030 Energy price	2050 Energy price	2019 Energy price	2019 Energy price	2030 Energy price	2050 Energy price
100% wind Onshore	Favorable	€ 0,043	€ 0,030	€ 0,020	€ 0,040	€ 0,030	€ 0,023	€ 0,018
	Average	€ 0,053	€ 0,040	€ 0,025	€ 0,053	€ 0,050	€ 0,036	€ 0,029
	Unfavorable	€ 0,081	€ 0,050	€ 0,030	€ 0,070	€ 0,077	€ 0,053	€ 0,043

3.3.3 Wind offshore

Wind offshore encompasses wind turbines build on water, this can either be on sea or large lakes. The largest share of costs for offshore wind farms is associated with building the foundation. Therefore, most of the offshore wind farms are built near the coast because of the shallowness of the waters. Furthermore, building near the coast reduces the distance that the generated electricity has to travel which reduces costs and transmissions losses (Saur, 2008). IRENA recognizes six different areas for offshore wind farms in their database. Namely, China and Japan in Asia, and Belgium, Denmark, Germany, and the United Kingdom in Europe (IRENA, 2018). As has been explained in subsection "Wind onshore" the database retrieved from IRENA shows the weighted average, 5th, and 95th percentile and is expressed in USD/kWh as can be seen in table 3. The values from Japan, Belgium, and Denmark are filtered out due to the fact that these values are the same for the 5th, 95th percentiles, and the weighted average. Therefore, it seems that these values originate from only one location in said country. For the years 2019, 2030, and 2050, the mean value of the 5th percentile is taken as the favorable level, the mean value of the weighted average as the average level, and the mean value of the 95th percentile as the unfavorable level.

Table 3:Values wind offshore IRENA

Wind offshore IRENA	**2019**		
	5th percentile	**Weighted average**	**95th percentile**
	(2019 USD/kWh)		
Asia			
China	0,094	**0,112**	0,119
Japan	~~0,198~~	**~~0,198~~**	~~0,198~~
Europe	0,087	**0,117**	0,157
Belgium	~~0,119~~	**~~0,119~~**	~~0,119~~
Denmark	~~0,087~~	**~~0,087~~**	~~0,087~~
Germany	0,104	**0,12**	0,155
United Kingdom	0,089	**0,121**	0,142

The ATB data spreadsheet retrieved from NREL recognizes 14 classes of offshore wind. Class1 up to and including class7 describes fixed offshore wind turbines, while the remaining classes describe floating offshore wind turbines (NREL, 2020). Due to the technological immaturity of floating offshore wind turbines, this thesis takes only fixed offshore wind turbines into consideration (Collu & Borg, 2016). Similar to onshore wind turbines, the moderate values for each class are used from the ATB database. However, this database does not provide a value for the Unfavorable level, due to the fact that the lowest WAWS (for class7) is 6.78 m/s. Therefore, the mean value of the first four classes is taken as the favorable level. Furthermore, the mean value of classes 5,6 and, 7 are taken as the average level.

Combining the findings from de databases retrieved from IRENA an NREL gives the following table (IRENA, 2018; NREL, 2020).

Table 4: Summary wind offshore

Energy prices in USD/kWh		**IRENA**			**NREL**		
		2019 Energy price	**2030 Energy price**	**2050 Energy price**	**2019 Energy price**	**2030 Energy price**	**2050 Energy price**
100% wind offshore	Favorable	€ 0,094	€ 0,050	€ 0,030	€ 0,083	€ 0,050	€ 0,037
	Average	€ 0,115	€ 0,070	€ 0,050	€ 0,111	€ 0,067	€ 0,049
	Unfavorable	€ 0,143	€ 0,090	€ 0,070	x	x	x

3.3.4 Solar

The amount of solar energy generated mainly depends on the solar intensity at the involved area. The solar radiation that reaches the surface of the earth is represented in multiple ways. The Global Solar Atlas provided by the World Bank Group distinguishes three ways to measure. The Direct Normal Irradiation (DNI) recognizes the amount of solar radiation per area which is always perpendicular to straight rays coming directly from the current position of the sun. The Diffuse Horizontal Irradiance

(DIF) comprehends the radiation per area that does not follow a direct path from the sun. Therefore, the radiation scattered by molecules and aerosols for example is given by the DHI. The final way is the Global Horizontal Irradiance (GHI) which includes shortwave radiation by both DNI and DIF, the GHI is an annual average (World Bank, 2021a). Both databases retrieved from IRENA and NREL use the GHI to measure the amount of solar radiation per square meter (IRENA, 2018; NREL, 2020). Therefore, the calculated values are fit to be compared to each other. The ATB database uses a single-axis tracking PV plant as a representative for their data. Furthermore, they have calculated costs for five different locations in the US. These locations are Seattle, Chicago, Kansas City, Los Angeles, and Dagget (NREL, 2020). The GHI, provided by NREL, for these locations is in line with the GHI presented by the Global Solar Atlas (World Bank, 2021a). Seattle is the least favorable location from the ATB database and has therefore the highest LCOE for solar energy. However, Seattle has a GHI of approximately 1278 kWh/m² which is comparable to southern France (World Bank, 2021a). Therefore, NREL does not provide information for unfavorable locations.

The data provided by IRENA (IRENA, 2019) show higher LCOE's than NREL for the year 2019. However, future prices are within the same price range, especially for the favorable levels. IRENA (IRENA, 2019) expects the LCOE of solar PV to be between USD 0.08 and 0.02 per kWh in 2030 and between USD 0.05 and 0.01 in 2050 (IRENA, 2019).

Comparing the LCOE values from IRENA and NREL together with the known locations from the NREL values gives an indication of solar intensity for each level. Together with Global Solar Atlas, a level can be given to each location and vice versa. The favorable level is applicable for locations with a GHI higher than 1600 kW/m². The average level is applicable for locations with a GHI between 1600 and 1100 kWh/m². And the unfavorable level is applicable for locations with a GHI below 1100 kWh/m². Combining the findings from de databases retrieved from IRENA and NREL gives the following table (IRENA, 2018; NREL, 2020).

Table 5: Values Solar

Energy prices in USD/kWh		IRENA			NREL		
		2019 Energy price	2030 Energy price	2050 Energy price	2019 Energy price	2030 Energy price	2050 Energy price
100% Solar	Favorable	€ 0,062	€ 0,020	€ 0,010	€ 0,027	€ 0,016	€ 0,012
	Average	€ 0,068	€ 0,050	€ 0,030	€ 0,037	€ 0,022	€ 0,015
	Unfavorable	€ 0,186	€ 0,080	€ 0,050	x	x	x

3.3.5 Pumped hydro storage

When the output of renewables is to be completely utilized for hydrogen production, the peaks have to be processed as well. Without energy storage, this will result in the need for a large capacity electrolyzer. As will be explained in the upcoming chapter, electrolyzers are very costly. Therefore, Aarnes et al. (2018) propose to store electricity upfront to level out peak hours and reduce the electrolyzer's size (Aarnes et al., 2018). One of the most mature and efficient storage technology is called Pumped Hydro Storage (PHS) (Abdellatif et al., 2018). The total installed capacity of this storage technology represents 99% of the global installed storage capacity (Berrada et al., 2017). PHS uses a pump powered by (excess) electricity to pump water from a lower reservoir into an elevated basin called the upper reservoir. The upper reservoir can be emptied into the lower reservoir to power a generator in between with a roundtrip efficiency of approximately 80% (Schmidt et al., 2019).

Four different sources have been used to give a representative view of LCOE for electricity generated by PHS. Similar to previous chapters considering electricity, a division into three levels has been made. However, future costs for PHS are estimated to be similar to current costs due to the maturity of the technology (Klumpp, 2016; Schmidt et al., 2019). Therefore, no values are given for the years 2030 and 2050.

When the area of hydrogen production has naturally large differences in elevation, this area is more suitable for PHS due to the fact that water has to be pumped to an elevated basin. When these higher elevations are in place naturally, the construction costs are lower than when these elevations have to be artificially constructed (Abdellatif et al., 2018). Therefore, geographical locations with larger differences in elevation are more favorable for PHS.

Berrada et al. (2017) state that the LCOE delivered by PHS is approximately €120/MWh (Berrada et al., 2017). However, Klumpp (2016) compares LCOE for PHS under dispatch scenarios (Klumpp, 2016). Namely, short-, medium-, and long-term storage where short-term storage is considered the option with the lowest LCOE. Nonetheless, this thesis only uses the value for medium-term storage due to the fact that solar energy is used which produces electricity according to a day and night cycle. Therefore, it is assumed that PHS has one dispatch cycle per day which occurs at night with a LCOE of €89/MWh (Klumpp, 2016). Next, Abdellatif et al. (2018) calculated the LCOE of PHS for different capital investment costs at different discount rates as can be seen in figure 4.

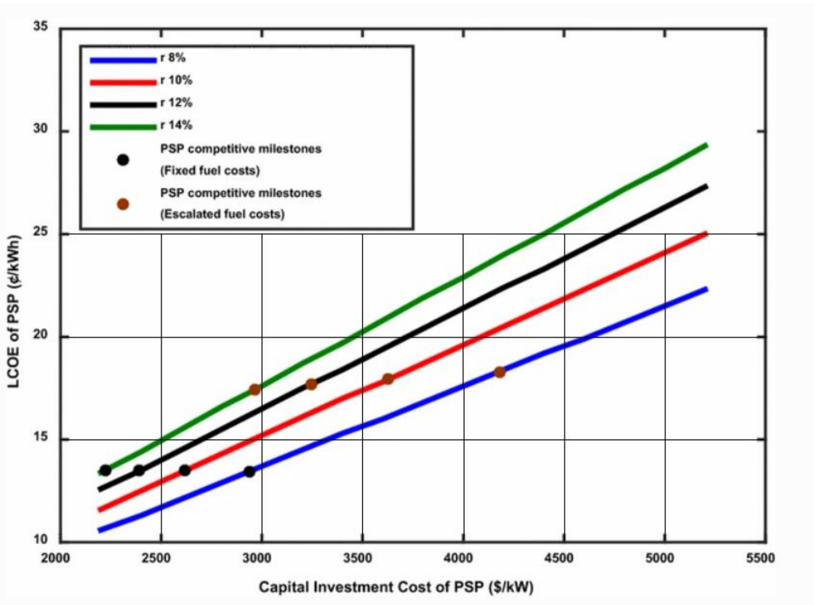

Figure 4: LCOE pumped hydro storage

The favorable locations are associated with lower capital investment costs due to natural existing elevations. Resulting in higher capital investment costs for unfavorable locations (Abdellatif et al., 2018). Therefore, the three aforementioned levels are formed by calculating the average LCOE for a capital investment cost of $2500, $3500, and $5000 per kW. The values are retrieved from figure 4 and shown in table 6.

Table 6: LCOE by capital cost

	Capital cost =		2500		Capital cost		3500		Capital cost =		5000	
r=8%	LCOE=	$	0,117	/kWh	LCOE=	$	0,158	/kWh	LCOE=	$	0,220	/kWh
r=10%	LCOE=	$	0,130	/kWh	LCOE=	$	0,174	/kWh	LCOE=	$	0,241	/kWh
r=12%	LCOE=	$	0,140	/kWh	LCOE=	$	0,191	/kWh	LCOE=	$	0,267	/kWh
r=14%	LCOE=	$	0,150	/kWh	LCOE=	$	0,204	/kWh	LCOE=	$	0,286	/kWh
Mean	LCOE=	**$**	**0,134**	/kWh	LCOE=	**$**	**0,182**	/kWh	LCOE=	**$**	**0,253**	/kWh

Schmidt et al. (2019) state that the range of LCOE from PHS is between $150-$400/MWh. However, they also state that the feed-in tariff is $50/MWh. Previous sources gave values where feed-in tariffs were set to zero. Therefore, the $50/MWh is deducted from the price range retrieved from Schmidt et al. (2019).

By combining the values from aforementioned sources the following table has been created for the three levels (Abdellatif et al., 2018; Berrada et al., 2017; Klumpp, 2016; Schmidt et al., 2019).

Table 7: Summary PHS

Energy prices in USD/kWh		**Berrada et al., 2017**	**Klumpp, 2016**	**Abdellatif et al., 2018**	**Schmidt et al., 2019**
Pumped hydro storage	Favorable	$ 0,12	$ 0,09	$ 0,13	$ 0,10
	Average	x	x	$ 0,18	x
	Unfavorable	x	x	$ 0,25	$ 0,35

3.4 Part 2: Production

A future energy system will have higher shares of renewable electricity in its energy mix. Especially wind and solar energy tend to play a significant role. These two sources of energy are fluctuating and intermittent and need to be balanced for stability on the electricity grid (Götz et al., 2016). Innovative Power-to-Gas (PtG) technologies are able to play an important role in an energy system with a high share of renewables by balancing the grid (Kopp et al., 2017). Electrolysis is a well-established PtG technology to produce hydrogen with electricity (Stojić et al., 2003). Especially water electrolysis is a well-understood technology to produce hydrogen. Electrolysis is an electrochemical conversion that splits water (H_2O) into hydrogen (H) and oxygen (O) (Shiva Kumar & Himabindu, 2019). Three types of electrolyzer technologies are to be recognized: Alkaline-, polymer exchange membrane- (PEM), and solid oxide electrolysis. Alkaline electrolysis is the most reliable and less costly technology while solid oxide electrolysis is still in the development phase. PEM is a relatively new technology when compared to Alkaline electrolysis (Götz et al., 2016). Alkaline electrolysis is more efficient when producing hydrogen steadily, while PEM electrolysis is able to handle load fluctuations (Wulf & Kaltschmitt, 2018). The Main advantage of PEM is that it can work under a lower partial load range between 0-10% (Carmo et al., 2013). Due to the intermittency of solar and wind production PEM electrolysis is better fitting for the production of green hydrogen when there is no electricity storage (Shiva Kumar & Himabindu, 2019). Nonetheless, this study chooses alkaline electrolysis to perform the calculation due to the fact that electricity storage is incorporated and is the most mature technology. Furthermore, PEM electrolyzers are approximately 50% more expensive than alkaline electrolyzers (Götz et al., 2016; IRENA, 2020).

IRENA (2020) states that there are two main issues with estimating electrolyzer costs. First of all, due to a competitive market, the availability of data is low. Second, inconsistency in boundary settings for cost estimates, which are often not even specified. Nonetheless, IRENA (2020) states that the capital costs for an alkaline electrolyzer within a system of at least 10MW are between USD 500 and 1000 per kilowatt. Recalculating these values for the aforementioned exchange rate gives the costs for an alkaline electrolyzer between €425 and €850 per kilowatt. For the year 2050, a value of a maximum of USD 200 (€170) per kilowatt is presented which is in line with the expectations of Terwel & Kerkhoven (2019) who estimate €220 per kilowatt.

Presently, most alkaline electrolyzers are on the single-digit MW scale. Nonetheless, there is one 10 MW alkaline electrolyzer located in Japan and future projects are announced for 20 MW electrolyzers (IRENA, 2020). For example, 20 MW electrolyzers are being built in Canada, Denmark, and the Netherlands (Franke, 2020; FuelCellsWorks, 2020; IRENA, 2020). FuelCellsWorks (2020) mentions that a €7.25 million contract has been signed and Franke (2020) states that €11 million in funding is secured. These values result in €362.50 and €550.00 per kilowatt respectively which is in line with the values mentioned by IRENA (2020).

Due to the fact that Terwel & Kerkhoven (2019) take a minimum of 10MW for an alkaline electrolyzer to achieve cost reductions, and looking at current projects, the size of the electrolyzer used to do calculations within this thesis is set to 20MW (Franke, 2020; FuelCellsWorks, 2020; IRENA, 2020). Terwel & Kerkhoven (2019) assume consumption of 52 kWh/kg H_2 which will be delivered at a pressure of 30 bar, which results in an efficiency of 65%. Furthermore, operating expenditures (OPEX) are estimated at 3% of capital expenditures (CAPEX) with a lifetime of 60.000 hours (IRENA, 2020; Terwel & Kerkhoven, 2019). Worth mentioning, hydrogen produced through electrolysis has a purity of 99.999% and does therefore not need any further purification. Terwel & Kerkhoven (2019) do not recognize any revenue streams other than hydrogen.

To conclude, IRENA (2020) gives a price range between €425 and €850, while Franke (2020) gives a value of €550 and FuelCellsWorks (2020) €362.50 per kilowatt for an alkaline electrolyzer. By taking the rounded-up mean value of these prices a value of €550 per kilowatt is taken to calculate the electrolyzer price for the year 2019. For the value of the year 2050, the predictions of Terwel & Kerkhoven (2019) and IRENA (2020) are taken and are set to €200 per kilowatt. Due to the fact that no values are given for the year 2030, this value has been set to €375 assuming a linear decline in price between the years 2019 and 2050.

Table 8: Summary electrolyzer

Prices in euro/kilowatt		**Price**
Alkaline electrolyz-er	2019	€ 550,00
	2030	€ 325,00
	2050	€ 200,00

3.5 Part 3: Transportation

When the hydrogen has been produced through electrolysis, the hydrogen needs to be stored and transported. This thesis addresses three different means of transporting hydrogen. The first type of transport is gaseous transport via pipeline. The second type of transport is in a liquified form via ship. The third and final type of transport is for shorter distances in either gaseous or liquid state by tube trailers.

3.5.1 Gaseous and liquified hydrogen

When hydrogen is produced by using alkaline electrolysis, the hydrogen is at a pressure of 30 bar. The European transmission pipelines used to carry natural gas from production sites to consumers operate at pressures between 16 and 100 bar (Wang et al., 2020). The pressure in the main (long-distance) natural gas pipelines is between 66 and 80 bar according to the Dutch gas network operator (KIWA, 2018). Therefore, hydrogen needs to be pressurized to be fed into the gas grid.

Hydrogen needs to be liquified before it can be transported via ship. For hydrogen, this means that it needs to be cooled down to -253 degrees Celsius (Ball & Weeda, 2015). The gaseous hydrogen is liquified by using the so-called Claude cycle, which uses liquid nitrogen for precooling (Fusaro et al., 2020). It is worth mentioning that the current global production of liquid hydrogen is around 350 tonnes per day (NCE, 2019). The current and near-future scenarios from Fusaro et al. (2020) show that the total liquefaction costs per kilogram are between €0.84 and €1.31, which is in line with research by Li et al. (2020), who estimate €0.85 per kilogram. These scenarios assume that electricity comes from renewables (Fusaro et al., 2020).

3.5.2 Pipeline

Currently, natural gas is mainly transported by pipelines. These pipelines are able to transport gaseous hydrogen with little modifications. However, modifying compressor stations may be required due to the fact that hydrogen has a density three times lower than natural gas (Wang et al., 2020). According to PWC (2021), it is more cost-effective to adjust existing natural gas grids than to build a new hydrogen transmission grid. In fact, reusing pipelines require an investment that is four times lower than building a new pipeline (PWC, 2021). Furthermore, a hydrogen pipeline network throughout Europe called the European Hydrogen Backbone (EHB) has been proposed, which mainly uses existing natural gas pipelines (Wang et al., 2020). Currently, Wang et al. (2020) estimate the levelized cost for transporting hydrogen through the EHB to be between €0.09 and €0.17 per kilogram of hydrogen per 1000 kilometers.

3.5.3 Ship

Terwel & Kerkhoven (2019) performed a study to estimate costs for transporting energy carriers by ship. It is stated that ships can be chartered or owned. However, only the costs for owned ships are explicitly worked out in the aforementioned study (Terwel & Kerkhoven, 2019). Therefore, the values calculated in this thesis are for owned ships. The costs for transporting energy carriers consist of the following costs elements: Levelized investment cost, Capital cost, Operation and Maintenance (including crew costs), fuel cost, canal fees and port costs. According to Terwel & Kerkoven (2019) ships that are able to transport liquid hydrogen are not yet existing and their values have been based on LNG tankers with special Liquid Hydrogen (LH_2) tanks. However, that report is from the year 2019. As of 2020 the first LH_2 tanker with the Suiso Frontier has been launched (Lloyd's Register, 2020).

The costs for maritime transport of hydrogen have been calculated by using the HyChain II model developed by Terwel & Kerkhoven (2019). Single trip distances have been put in the model from 1000km up to 20000km in steps of 500km. The price range is shown in figure 5.

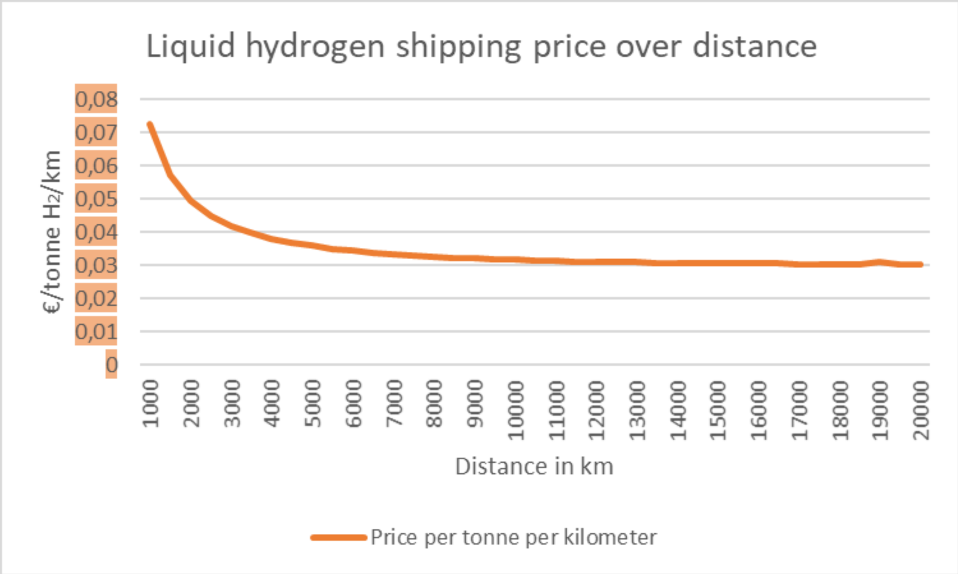

Figure 5: Price over distance maritime transport

When the transporting distance from port to port exceeds 7000 kilometers, the price per tonne H_2 per kilometer stays more or less the same around a value of €0.031/tonne H_2/km. The average price between a distance of 2000 and 7000 kilometers is €0.039/tonne H_2/km. Any maritime distances shorter than 2000 kilometers are not taken into account. Distances between ports can be estimated by using www.ports.com. When necessary, metric conversions can be applied where one nautical mile equals 1.852 kilometers.

The International Transport Forum expects an increase in the average transport costs (ITF, 2021). ITF (2021) links this increase in costs mainly to the decarbonization-inducing policies. However, in the long run, the decarbonization measures are expected to drive down the price in the long run (ITF, 2021). Due to the uncertainty, only one value of maritime transport is given in this thesis for current and future costs.

3.5.4 Tube trailers

The term tube trailer applies to a trailer on which a pressure vessel is mounted and is transported by a truck (Reddi et al., 2018). A research conducted by Li et al. (2020) used several sources to estimate transportation costs for hydrogen via truck (Reddi et al., 2018; Ruth et al., 2009). This research compared several supply chains in the United States of America and China. Both, gaseous and liquid transport were addressed (Li et al., 2020). Considerably variability in transportation costs has been found. Not only between gaseous and liquid transport but differences between these two countries were significant as well. Gas truck transport in the USA has been estimated at USD 1.5-6.5 per 200-500 km per kilogram hydrogen. Meanwhile, the same transportation in China has been estimated at USD 0.4-2.5 per 200-500 km per kilogram hydrogen. Therefore, transportation in China seems to be less expensive. Similarly, transporting liquid hydrogen has been estimated at USD 0.2-0.5 in the USA and between USD 0.02-0.1 in China. Transporting liquid hydrogen is significantly less expensive due to the fact that a larger amount of hydrogen can be transported per truck. Furthermore, the costs for liquidizing the hydrogen are not incorporated and have to be added on. The differences between the USA and China are mainly explained by the fact that capital costs and labor costs are cheaper in China (Li et al., 2020). This thesis does not select a specific country. Therefore, the values of Li et al. (2020) are divided over a low-, mid-, and high-level of cost to be able to choose from.

4. Results

This chapter will elaborate further on each step of the hydrogen production process and will give a value based on the methodology for further calculations. First, every step of the production process will be explained followed by a table with all final values. This table will then be used to perform three scenarios which will be further explained at the end of this chapter.

4.1 Hydrogen resource system Part 1: Electricity

4.1.1 Wind onshore

Prices have been estimated for three different levels of wind power. The favorable level is applicable with wind speeds over 8.1 m/s, the unfavorable level of wind speeds below 7.4, and the average level is between these two levels. Therefore, the average level ranges between wind speeds of 7.4 and 8.1 m/s. These windspeeds are the weighted average wind speeds for a certain location. Furthermore, the costs for electricity from onshore wind farms have one current price and two future prices as is shown in table 9. To connect a location to a windspeed the global wind atlas is consulted (World Bank, 2021b).

Table 9: Costs wind onshore

2030 prices in euro/kWh		Wind speed (m/s)	Costs per kWh
Wind onshore	Favorable	>8,1	€ 0,023
	Average	7,4-8,1	€ 0,032
	Unfavorable	<7,1	€ 0,044

4.1.2 Wind offshore

As has been explained in the previous subsection, prices have been estimated for three different levels of wind power. However, not the same wind speeds apply to offshore wind speeds. The favorable level is applicable with wind speeds over 8.6 m/s, the unfavorable level of wind speeds below 6.8, and the average level is between these two levels. Therefore, the average level ranges between wind speeds of 6.8 and 8.6 m/s. These wind speeds are the weighted average wind speeds for a certain location. Furthermore, the costs for electricity from onshore wind farms have one current price and two future prices as is shown in table 10.

Table 10: Costs wind offshore

2030 prices in euro/kWh		Wind speed (m/s)	Costs per kWh
Wind offshore	Favorable	>8,6	€ 0,043
	Average	6,8-8,6	€ 0,058
	Unfavorable	<6,8	€ 0,077

4.1.3 Solar

Electricity generated with PV panels is expressed in the same levels as wind onshore and offshore. However, the price range depends on GHI. Therefore, the levels are arranged as follows: favorable is applicable when GHI is higher than 1600 kWh/m², Average is applicable when GHI is between 1100 and 1600 kWh/m², Unfavorable is applicable when GHI is below 1100 kWh/m².

Table 11: Costs solar PV

2030 prices in euro/kWh		Solar GHI (kWh/m²)	Costs per kWh
Solar PV	Favorable	>1600	€ 0,015
	Average	1100-1600	€ 0,030
	Unfavorable	<1100	€ 0,068

4.1.4 Pumped hydro storage

Electricity generated by PHS is expressed in the same three levels as solar and wind. The mean values of table 12 in the methodology chapter are taken to get the following costs per kWh.

Table 12: Costs pumped hydro storage

2030 prices in euro/kWh		Costs per kWh
PHS	Favorable	€ 0,094
	Average	€ 0,155
	Unfavorable	€ 0,256

4.2 Hydrogen resource system Part 2: Production

4.2.1 Electrolysis

Costs for an alkaline electrolyzer have been estimated per kilowatt in the methodology chapter. Assuming that the 20MW electrolyzer has a lifetime of 60.000 hours and consumes 52 kWh per kilogram of hydrogen, approximately 23 million kilograms of hydrogen can be produced in its lifetime. Dividing the investment by the total production a cost per kg of hydrogen can be determined, this can be seen in table 13. Prices have been determined for the years 2019, 2030, and 2050.

Table 13: Costs alkaline electrolyzer

prices in euro/kilogram H2		Costs per kg/H2
Alkaline electro-lyzer	2019	€ 0,48
	2030	€ 0,28
	2050	€ 0,17

4.3 Hydrogen resource system Part 3: Transportation

4.3.1 Liquefier

Liquefaction is required when the transport is done by ship or by cryogenic trucks. Due to differences in values specified in the methodology chapter, three levels of costs for the liquefier have been determined. Table 14 shows values divided over three levels.

Table 14: Costs liquefier

2030 prices in euro/kilogram H2		Costs per kg/H2
Liquifier	Favorable	€ 0,84
	Average	€ 1,08
	Unfavorable	€ 1,31

4.3.2 Pipeline

Costs for transporting hydrogen through pipelines are mainly based on the EHB. Table 15 shows the values divided over the three levels. The values are in euro for each kilogram of hydrogen transported over 100 kilometers.

Table 15: Costs pipeline transport

Prices in euro/kilogram H2 /100 km		Costs per kgH2/100 km
Pipeline	Favorable	€ 0,009
	Average	€ 0,013
	Unfavorable	€ 0,017

4.3.3 Ship

Hydrogen transported by ship is in a liquid state. Only two values have been given in table 16 due to the fact that transporting distances shorter than 2000 kilometer are deemed to be too expensive.

Table 16: Costs ship transport

Prices in euro/kilogram H2 /100 km		Costs per kgH2/100 km
Ship	>7000km	€ 0,0031
	2000-7000km	€ 0,0039
	<2000km	N/A

4.3.4 Tube trailers

Transporting hydrogen by truck can be in either a liquid or gaseous state. Significant price differences can be recognized as is shown in table 17. The higher prices for liquid transportation are due to the fact that the liquefaction process has already been implemented.

Table 17: Costs truck transport

Prices in euro/kilogram H2 /100 km		Costs per kgH2/100 km
Truck (gas)	Favorable	€ 0,006
	Average	€ 0,077
	Unfavorable	€ 0,149
Truck (liquid)	Favorable	€ 0,119
	Average	€ 1,026
	Unfavorable	€ 1,934

4.4 Part 4: Scenarios

Three scenarios have been performed to give guidance to previously explained values from the results chapter. These specific scenarios are chosen to follow up on the study by Zapata (2018). Namely, producing hydrogen in Morocco and transport it to the Netherlands by pipeline or by ship. The second scenario is based on the new ship (Suiso Frontier) to transport hydrogen from Australia to Japan. Both scenarios are set in the year 2030. Recall that the threshold prices are €1.70/kg for gaseous- and €4.25/kg for liquid hydrogen and that the calculation shown in figure 6 is used.

$$LCOH = (En * \eta) + El + Liq + (\left(\frac{Tr}{100}\right) * Dis)$$

Where:
LCOH= Levelized Cost of Hydrogen in €/kg H_2
En = Price of energy in €/kWh
η = Efficiency of electrolyzer in kWh/kg H_2
El = Price of electrolysis in €/kg H_2
Liq = Price of liquefaction in €/kg H_2
Tr = Price of transport in €/kg H_2/100km
Dis = Distance of transport in kilometer

Figure 6: Levelized cost of hydrogen

4.4.1 Morocco - The Netherlands

Due to the geographical location, a high level of solar irradiation can be found in Morocco. Namely, a GHI of approximately 2000 kWh/m² while the favorable level starts at 1600 kWh/m². Therefore, 100% solar-generated electricity will be used, which comes at €0.015 per kWh for this GHI level. This scenario is set in 2030 and uses €0.28 per kg/H_2 for electrolysis. Furthermore, favorable prices are used for 'pipeline' and 'liquefier'. The distance by pipeline is approximately 2700km and by ship 3160km. Figure 7 shows that costs for electricity make up the largest share for hydrogen when transported by pipeline. However, figure 8 shows that the largest share of costs for hydrogen comes from 'transport' when ship transport is applied. With additional awareness for the share that the liquefier is accountable for. To conclude, when the same production methods apply, transporting hydrogen through pipelines is less costly when compared to transportation by ship. That is, transporting through pipelines comes to a price of €1.427/kg H_2 and by ship €2.039/kg H_2.

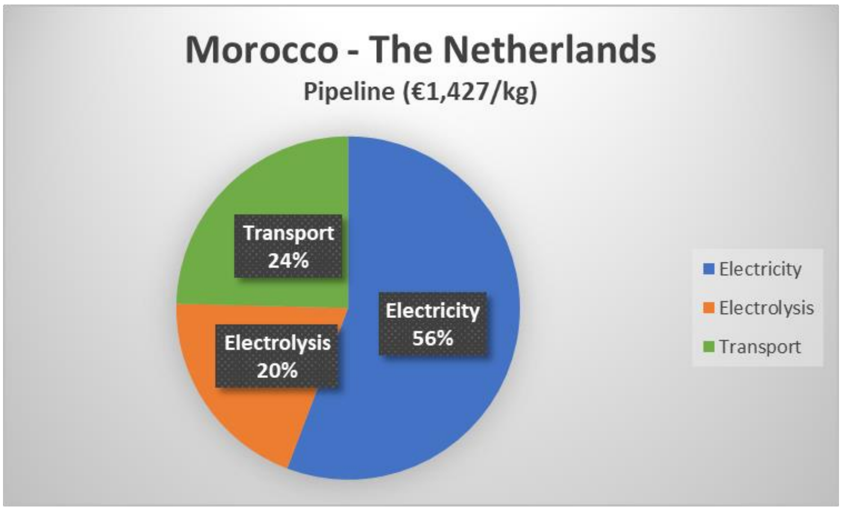

Figure 7: Pipeline transport

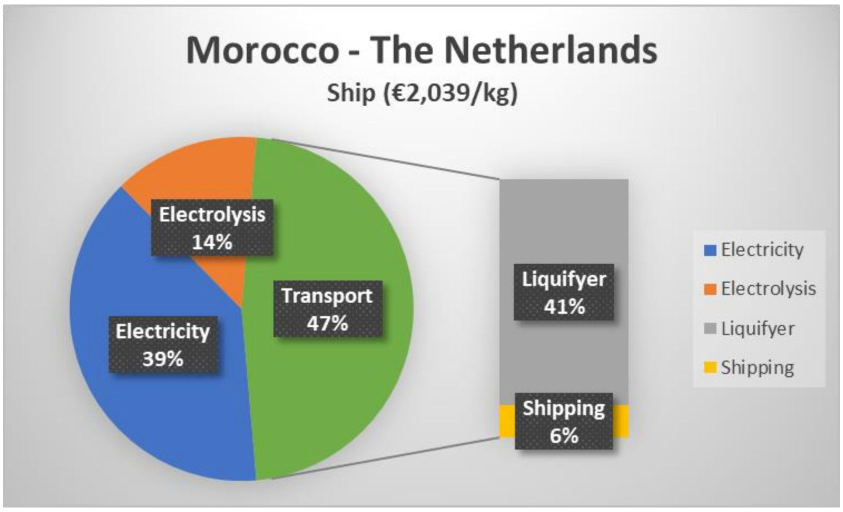

Figure 8: Ship transport

4.4.2 Australia – Japan

The first shipment of liquid hydrogen by the Suiso Frontier is to be expected within a year (Lloyd's Register, 2020). Therefore, a scenario for this ship has been performed. The largest part of Australia has a GHI above 1600 kWh/m². Therefore, 100% solar-generated electricity will be used, which comes at €0.015 per kWh for this GHI level. This scenario is set in 2030 and uses €0.28 per kg/H_2 for electrolysis. Furthermore, favorable prices are used for the 'liquefier'. The distance between Australia and Japan is approximately 11700km according to Ports.com. Figure 9 shows that the largest share of costs for hydrogen comes from 'transport' when ship transport has been applied. With additional awareness for the share that the liquefier is accountable for. To conclude, transporting liquid hydrogen from Australia to Japan by ship comes to a price of €2.278/kg H_2.

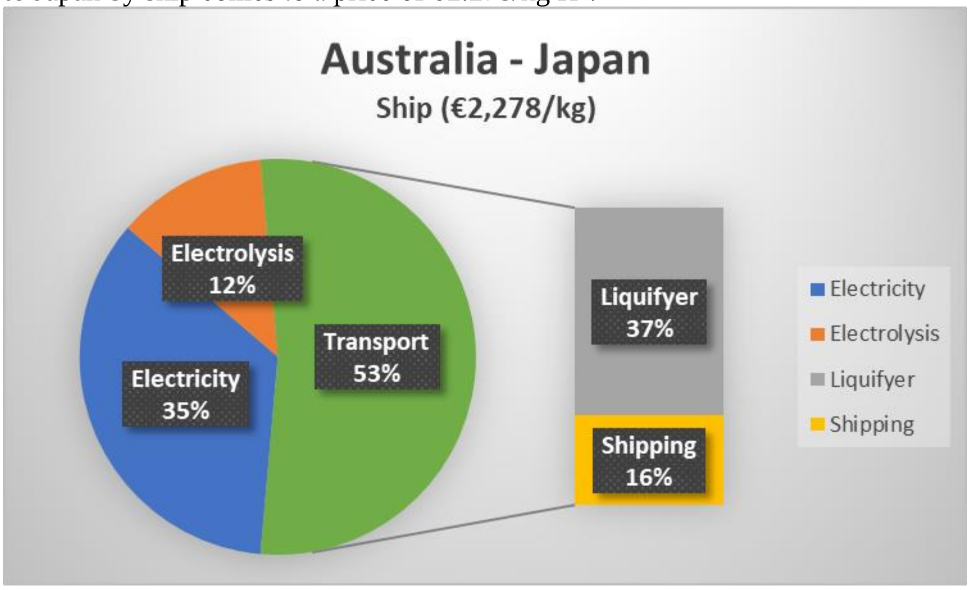

Figure 9: Ship transport

5. Discussion

This study found that some locations of production and transportation methods are able to produce hydrogen at or below the threshold price in the year 2030. Nonetheless, this thesis does not give a tailored solution, but rather a generalized insight. First of all, other renewable energy sources are available next to wind and solar. For example, electricity from biomass, hydropower, or nuclear power could be used to power an electrolyzer. Therefore, other costs per kWh could be applicable and change the outcome (IEA, 2013). Furthermore, the LCOE of both wind and solar can vary significantly over time and per location. Electricity generated by wind for example, depends on the quality of the wind resource. Furthermore, the cost of capital and the investment costs can differ per area due to different labor costs or accessibility of remote locations. The same principle goes for electricity by solar PV, lower efficiencies due to high temperatures or dust storms can influence the price per kWh, these potential losses have not been taken into account. Therefore, while being in a “favorable” location, the costs per kWh are potentially higher than indicated by this study. Therefore, the generalizability of these results is subject to the fact that the given values are based on calculated predictions.

The data suggest that an alkaline electrolyzer is the most mature technology. Nonetheless, other types of electrolyzers are either already available or still in development. Therefore, other future prices could be available for electrolyzers. Especially due to the fact that economies of scale are applicable to this technology and larger electrolyzers are being announced (De Laat, 2021). Furthermore, other energy uses and losses throughout the electrolyzer have not been taken into account. For example, the number of operating hours per year that affect the operating costs have been neglected (Jørgensen & Ropenus, 2008).

The use of pumped hydro storage has been taken out of consideration for the scenarios. To balance the amount of pumped hydro storage and the size of the electrolyzer is a study on its own. Therefore, this part is recommended for further studies.

Transportation has been divided into gaseous and liquid state transport. First of all, transport by truck is the only method to transport both over short distances. Nonetheless, this type of transportation has not been used in the scenarios. The main reason is that the price range for transport by truck has a widespread variation. For example, gaseous hydrogen transport by truck has a factor of 24.8 between a favorable and unfavorable price. Differences in infrastructure, labor costs, fuel costs, and others are too large to use the presented values in this form (Li et al., 2020). To be able to use trucks in these scenarios, a more tailored database is required.

The values given for transport by pipeline are based on (mainly) using the existing natural gas network in Europe. This network connects to North Africa and Eastern Europe as well (Wang et al., 2020). As has been mentioned in the methodology paragraph about pipeline transport, building a new gas network will result in higher costs. While North America and Europe have access to a vast natural gas network, these pipelines are not readily available in all locations on earth, and might never be due to hard accessible locations. To conclude, pipeline transport can be more expensive if existing networks cannot be used and not all countries or regions are accessible.

Due to the technological immaturity of hydrogen transport by ship, the values are mainly based on estimates and comparisons with LNG tankers. Nonetheless, the scenarios show that costs for hydrogen can be well below the threshold price. That means that there is a possibility for margin in these values. The first shipments of the Suiso Frontier will give more data in the future.

The scenarios show a larger difference between the calculated price and the threshold price for liquid hydrogen in comparison with gaseous hydrogen. Therefore, it indicates that a larger profit margin can be achieved for liquid hydrogen. In the scenario: Morocco – The Netherlands, this could mean that the hydrogen is used to liquidize rather than transported by pipeline. After all, a hydrogen vessel has access

to a world market while pipelines are restricted to the size of the hydrogen pipeline network. This development potentially boosts a worldwide competitive market for hydrogen.
While this thesis extensively addresses hydrogen as a final product, it only mentions water as a resource. Nonetheless, electrolysis requires purified water and uses approximately 9 liters of purified water per kg of hydrogen. The first issue to address is the cost of this process. Due to the low impact on the total costs of hydrogen, this factor has not been added to the calculation. Though, it is worth mentioning that the costs are below €0.01/kg of hydrogen (Harvego et al., 2012; IRENA, 2020). While this does not seem to be an issue from an economic perspective, it does impact the (fresh) water availability. According to IRENA (2020), a very large (1GW) electrolyzer corresponds to the water consumption of a small city of around 70.000 inhabitants. This does not have to pose a challenge in areas with an abundance of water. However, in water-stressed regions, this process may pose a threat to freshwater availability for consumption.

Worth mentioning is the efficiency of producing hydrogen compared to using electricity directly. While the efficiency of electrolysis is around 65%, losses throughout the rest of the process are to be recognized as well. Especially the liquefaction process is energy consuming, the energy that this process consumes equals 70% of the total energy containing in the hydrogen (Baetcke & Kaltschmitt, 2018). This means that the production of hydrogen is a very inefficient process.

While writing this study I was impressed by the rapid technological developments in the area of (green) hydrogen. For example, when I started writing this study, the largest electrolyzer was 5MW and the largest announced electrolyzer was 20 MW. Only a few months later a 100MW electrolyzer has been announced which is a factor 20 larger compared to existing electrolyzers. Next to that, the first hydrogen transportation ship got launched that did not even yet deliver its first shipment. It is fair to say that some of these developments still have to be realized. However, to me, this confirms the promising potential to realize the hydrogen economy to decarbonize the energy system.

6. Conclusions

This study was designed to examine whether the levelized cost of energy for the production and transportation of green hydrogen is able to compete with conventional fuels. In order to create a calculation model that estimates a price for hydrogen, four parts have been defined. The first part considers the price of electricity based on a geographical location. Four sources for electricity have been taken into account namely, wind onshore, wind offshore, solar PV, and pumped hydro storage. Part two involves the production of hydrogen through water electrolysis. The third part incorporates the transportation of hydrogen by ship, pipeline, or truck in either liquid or gaseous state. Finally, in the fourth part, a couple of scenarios have been performed. The values that were calculated in the previous parts have been used in these scenarios.

This study has identified that, in order to compete with conventional fuels, the price of hydrogen should be around €1.70 in gaseous- and €4.25 in liquid state per kilogram. Scenario 1 shows that the costs for production in Morocco and transport to the Netherlands by pipeline and ship are below this threshold. Based on this scenario, one could conclude that green hydrogen can be competitive in the year 2030. However, not all combinations of production sites and transport are able to achieve a competitive price. More research is necessary to determine suitable locations of production. Nevertheless, the optimistic scenarios can be a guidance for further research.

Next, the scenarios show that electricity takes up a large percentage of the total costs, namely 56%. Nonetheless, the scenarios make use of the lowest kWh price in 2030. Therefore, the electricity price seems to be one of the most important factors. As a consequence, producing hydrogen in desert areas with high levels of solar irradiation is able to compete with domestic production in northern European countries.

Additionally, this study shows an interesting perspective on the efficiency of the production of liquid hydrogen by electrolysis. It is well-known that, from an energetic point of view, this way of producing hydrogen is not an efficient process at all. However, it turns out that producing liquid hydrogen by electrolysis is efficient enough from an economic point of view. Therefore, investing in an energy system that makes use of hydrogen can be viable.

Despite its exploratory nature, this study offers some insight into the chances for hydrogen to succeed. Where many renewable energy sources were too expensive at the beginning, hydrogen is not so different. Accordingly, this study indicates that green hydrogen can be economic viable when it is produced at the right location.

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