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Techno-economic analysis of the production of green liquid hydrogen on offshore platforms from wind energy to refuel ships

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Acknowledgments

No one knows what comes in the future. They say the only certainty, is uncertainty itself. On Friday, 14 May 2021, I couldn't expect that I have to type these words on my cellphone, due to a bicycle incident resulting in a broken shoulder. And that is what makes this acknowledgment section more meaningful for me.

The present work is a result of a long journey derived from a passion for research and being a part of a solution, however small, for a better world. This journey was by no means a solo one, and impossible without the supports provided. Therefore, I would like to express my deepest gratitude to my supervisor, Dr. Gianluca Valenti, a role model to follow, for his priceless knowledge and help in guiding me to accomplish the present work. And more importantly, his kind support during the unforeseen complexities. I would like to thank Camilla, for her help in developing the present work and sharing with me her knowledge in different steps.

I would like to thank my parents, without whom I couldn't be who and where I am today, for their unconditional support and love. To my little sister, who has always been a great friend to me as well.

I would like to thank my friends, no matter how close or far we are, who are the family that we choose. For the time that we passed together, memorable moments we share, and being there in ups and downs.

Milan, May 2021

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Much more strongly than in the past, hydrogen is considered today the best energy carrier because it can be both easily produced from green electricity, and readily exploited at the end-user, in an inherently sustainable infrastructure. The naval sector will witness an important penetration of liquid hydrogen as a ship fuel. Onboard, hydrogen has to be stored as a liquid to reach the highest possible energy density.

The present work, known as the OffLH2 project, investigates the prefeasibility of realizing offshore platforms that employ green electricity from a dedicated offshore wind farm to produce hydrogen in an electrolyzer and, subsequently, to process it in a liquefier. These platforms along with their wind farms will be located on the main ship routes to serve them efficiently and encourage the naval sector to support the penetration of liquid hydrogen. Platforms may be constructed entirely or, most likely, they may be adapted from existing oil platforms. As a starting scenario, the Mediterranean Sea is selected for the project.

The analysis of the system started with studying the main ship routes and meteorological data, then the technologies that could be suitable for the system, dividing the system into four subsystems including (1) green electricity production, (2) water treatment, (3) electrolyzer, and (4) hydrogen liquefaction and storage. After this stage, starting from, the possible location of the wind farm and plant, power production from the wind farm throughout a year, electrolysis of the water with the produced electricity, and finally, liquefaction of the produced hydrogen. After the technical assessment and obtaining the amount of liquefied hydrogen production in one year, two economical indexes are described to see how the feasibility and profitability of the OffLH2 project could be assessed. These economic indexes are the discounted payback period (DPB), and the Net Present Value (NPV).

After implementing the developed model of the present work in MATLAB, the obtained results showed that the system is profitable and viable, with a positive NPV, which is increasing with the size of the plant. The results of the NPV and DPB were in accordance together for the economic assessment. Based on the results obtained from the amount and volume of produced liquid hydrogen, it is suggested that for further development of this technology, cruise ships should be the target consumer of the produced liquid hydrogen.

Key words: *Electrolysis; Liquefied green hydrogen; Offshore wind energy; Alternative fuels*

Extended Summary

Introduction

The study of hydrogen as a new fuel for transportation is not a recent topic. But recently the interest in hydrogen as a transportation fuel has increased due to different reasons. To name a few, it could solve the problem of scarcity of fossil fuels, it is environment-friendly, it could be used even as an aircraft or rocket fuel. However, the main reason of interest into hydrogen in the recent years is due to the concerns about CO_2 emissions and usage of fossil fuels as a non-renewable source.

The largest portion of the consumption of fossil fuels is for light-duty vehicles. Consequently, they are responsible for the largest CO_2 emissions worldwide. With that being said, to tackle with the two main problems, scarcity of fossil fuels and CO_2 emissions, changing the fuel in light-duty vehicles industry seems to be the solutions. However, introduction of hydrogen in this industry, may not be the best path to follow in the long term [19].

Introducing a new fuel always comes with complexities related to changes in the social and economical system. That is why the introduction of new fuels is a slow, infrequent, rare, and difficult process. Therefore, it is very important to pay attention to how to maximize its likelihood and minimize the risks related to it.

The fuels that are used in the transportation sector, mainly derived from petroleum, dominate this sector. Firstly, because of the inherent physical properties that make them easier to use. These fuels could be easily adopted in internal combustion engines, also not complicated in transportation and storage, and high volumetric energy densities. Secondly, there is another problem with introducing a new fuel and that is investing in new vehicles and infrastructure. Therefore, introducing hydrogen at first step in heavy-duty vehicles for freight mode is beneficial in terms of spillovers of the technologies and knowledge into light-duty modes.

Today, electrolysis is a growing way of hydrogen production, which could produce hydrogen with the highest purity. This is also the technology that has been used in the present work for the production of green hydrogen from the electricity that is coming from an offshore wind farm. The wind farm is going to be located in a site with favorable wind speed profiles in the Mediterranean Sea. The site is also located in the main ship routes, since the main goal of the project is to produce liquefied hydrogen from the green electricity to refuel ships. Another important aspect of the project is to use already-existing oil and gas platforms for the production of the liquefied hydrogen.

In the end, the main objective of the present work is to assess techno-economically the production of liquid hydrogen on already-existing platforms from offshore wind energy. For this purpose, the main technologies involved in the process are studied. Then economic indexes are used to assess the pre-feasibility of the project.

Green Electricity

The process of energy conversion in the present work starts with electricity production from an offshore renewable source therefore it is necessary to study different available technologies, then choose the appropriate one for the context of the present work.

Floating solar technology is an emerging way of green electricity production. There are different motivations for the development of this technology. Two specific reasons for the development of this technology are the lack of land to install land-based solar PVs and the decrease in efficiency with an increase in the temperature of solar PVs. However, these systems are designed to be installed typically in enclosed freshwater bodies, and installation of this technology for usage in the sea is scarce and has not reached a mature and economic level.

Two other ways of production of green electricity in an offshore environment are wave energy and tidal energy. But these technologies are currently at their early stage of development and levelized cost of electricity (LCOE) from these technologies has the highest value [20].

Another way of electricity production is to harvest wind energy. Offshore wind turbines have the lowest value of LCOE among different ways of energy production and are the most common renewable source of electricity in the offshore context. Both types of offshore wind turbines, floating wind turbines and bottom-fixed wind turbines can produce electricity to a price that can make the projects viable and profitable. Depending on the location of the project, each type can have its advantages and is preferred to its counterpart. it is worth mentioning that floating wind turbines are used in sites with a water depth of more than 30-50 m. In the present work, as the exact location of the wind farm is not yet decided and at this stage, a pre-feasibility study is going on, the decision was based on the fact that the refueling point is not in very long distances from the port, consequently not too far from the shore. Therefore it is possible to benefit from the lower cost of bottom-fixed turbines.

Water Treatment

The present work is aiming at studying a plant that is located in the Mediterranean Sea, hence seawater is the water resource that is used in the OffLH2 project. Direct electrolysis of seawater is a technology that could be the future of electrolysis, but by today's technology, it is not developed enough to be used in a profitably. Already mature technologies for water electrolysis are functional with pure water. Therefore, it is necessary to study different technologies that are used for seawater treatment and choose the best option for the OffLH2 case.

The current desalination technologies could be categorized into two main classes: thermal energy driven and electricity driven processes. In today's worldwide water treatment market, three commercialized technologies are ruling the market. These technologies are seawater reverse osmosis (SWRO), multi-stage flashing (MSF), and multi-effect distillation, with accounting for 65%, 21%, and 7% of the market, respectively [21].

Considering the energy consumption of these three technologies, to have a better view of their energy consumption, it is better two divide it into electrical and thermal energy consumption. The electric energy consumption figure of SWRO is almost two times the consumption of its thermal counterparts. On the other hand, when it comes to thermal energy consumption, the energy consumption of thermal processes counteracts their superiority in electricity consumption. Therefore, in terms of energy consumption, SWRO shows a better performance [22]. However, when in terms of purity of the output water from the process, thermal processes show a better performance [10].

In conclusion, although the purity of the water that is produced from the SWRO is lower than the purity of the water from the thermal processes, the quality is high enough for the usage of the PEM electrolyzer (which is the technology that is chosen in the present work).

Electrolysis

The final product of the OffLH2 process is liquid hydrogen, which is going to be sold to the naval sector. The hydrogen is produced through an electrolysis process that is fed by the electricity coming from the wind turbine farm. Therefore, it is necessary to study different technologies that could be possibly used for the electrolysis of the water.

Different available technologies for water electrolysis include: solid oxide electrolysis (SOE), alkaline electrolysis (AE), proton exchange membrane electrolysis (PEME), and direct electrolysis of seawater (DES).

Considering the current level of development in these technologies, direct electrolysis of seawater is not feasible due to the economics of this technology, since it will cost more than 6000 $/kW which is even three times more expensive than solid oxide technology, with 2000 $/kW. PEME and AE technologies are both better choices in terms of specific cost and level of development [12]. Solid oxide electrolysis is a technology that requires very high temperatures ($700 - 800°C$) and works with superheated steam. Therefore based on the fact that the cost of this technology is higher than its low-temperature counterparts, namely PEME and AE, and it requires very high temperatures, the two choices are narrowed down to PEME and AE.

Domenech *et al.* [12] used multi-criteria decision-making method to assess which electrolysis technology is better specifically for offshore applications. In this study they considered different criteria for the basis of decision-making. These criteria include:

- investment
- maintenance
- lifetime
- resilience
- energy
- dynamics
- environment
- hazard

In the end, PEME has the best score considering these different criteria, however the difference between AE and PEME was a narrow margin, which means both these technologies have the potential to be used in offshore hydrogen production. As AE is the cheapest technology today, if the safety of this technology improves in the future and its performance becomes less risky, it could the preferred technology in the future.

Hydrogen Liquefaction

The final product of the OffLH2 project is hydrogen that is going to be used in the naval sector as a green fuel. However, a major drawback of hydrogen is its low volumetric energy density. Therefore, hydrogen must be stored and sold to the naval sector in form of liquefied hydrogen. Even though hydrogen liquefaction is an energy-intensive process, it could be a solution to reach to highest volumetric energy densities of hydrogen.

The process of liquid hydrogen production is by the cooling, expansion, and liquefaction of an expanded gaseous hydrogen feed gas from ambient conditions to a temperature of about 20 K. Two main refrigeration steps are required in built industrial hydrogen liquefaction processes. First, for the hydrogen precooling to an intermediate temperature of about 80 K, a liquid nitrogen (LN2) stream is used. Second, for the cryogenic hydrogen cooling from 80 K to a liquefaction temperature of about 20 K, only helium and hydrogen are available as pure refrigerant fluids for a cryogenic refrigeration cycle [23].

The Claude cycle is a common method to liquefy high volumes of hydrogen, as shown in Figg. 5.2a, 5.2b. The Claude cycle combines the isentropic (Brayton cycle) and isenthalpic (Linde cycle) expansions, and both the heat exchangers and mechanical expanders are used to cool the compressed and precooled hydrogen below its inversion temperature. Gases like H_2, He, show heating effect at room temperature when they go through JT expansion, because of their low inversion temperature. But if these gases are cooled to a temperature lower than the inversion temperature and then subjected to JT effect, they will experience cooling. For H_2, the maximum JT inversion temperature is at 205 K (68.15°C). Thus, hydrogen needs to be precooled to below this temperature before expansion [24]. Using the Claude closed cycle, as represented in FIg. 5.2, does not require the usage of liquid nitrogen (LN2). In OffLH2 project as the site is an offshore site and putting air separation units to produce liquid nitrogen comes with more space requirements, this need is eliminated.

Platforms

An important aspect of the OffLH2 project is reusing the oil and gas platforms that are going to be put out of usage in near future. These platforms can be refurbished and maintained to be used for the electrochemical energy conversion process. As a starting point for OffLH2 project, the data of the oil and gas platforms in the Dutch shell has been used. The reference study was carried out to analyze the adaptation of oil and gas platforms in the Dutch Shell for the production of compressed gas hydrogen and different transportation scenarios, including transportation as a mixture with CH_4, or as a pure hydrogen stream through existing gas pipelines. In the study that Jepma carried out [18], different platforms with different characteristics were studied to show how the characteristics affect the economics of future projects. The detailed information of different platforms is reported in the chapter devoted to platforms and used as a guideline for the analysis of the present work.

Comprehensive Model

This chapter brings together the technological aspect and the economics of the project to form a comprehensive analysis.

Wind Farm

The location of the OffLH2 plant is in the Mediterranean Sea. And after studying main ship routes and wind intensity in the Mediterranean Sea, between Sicily and Tunisia was chosen as a possible location for the plant. In this way, the location could be suitable for the shipping industry and they do not have to alter their way to reach the refueling point. Consequently expecting more willingness in the naval sector to use the platform, compared to a point where the ships have to change their route.

To know how much hydrogen will be produced in one year, the process starts with the wind speed profile of the site. At this stage of the analysis, the assessment is at pre-feasibility stage. Therefore, the wind profile of the site is not known. To have reasonable data as a starting point, another location with similar wind profiles are chosen. It is expected that the wind profile of Sciacca, in Sicily, will have the same patterns as that of an overseas platform between Sicily and Tunisia. The hourly wind speed of Sciacca was available for a height of 10 m above ground level. Therefore a roughness model has been used to estimate the wind speed at an altitude of 100 m above sea level. The average wind speed, however, was obtained from the satellite information and after estimating the wind speed at 100 m height, the average of the data must be equal to the annual average obtained from satellite data. The following equation was used to calculate the wind speed at an altitude of 100 m above the sea level [25]

$$\frac{u_2}{u_1} = (\frac{z_2}{z_1})^P. \tag{1}$$

In this formula, u_2 (m/s) represents the wind speed at a height of z_2 (m), and u_1 (m/s)is the known wind speed at the reference height of z_1 (m). The exponent P (-) is a function of two factors; the roughness of the underlying surface and atmospheric stability in the layer [25].

There are different approaches to model power production, starting from the wind profile. The approach that has been used in the present work requires typical parameters of a wind turbine: the cut-in wind speed, v_{ci} (m/s), rated wind speed, v_r (m/s), and cut-out wind speed, v_{co} (m/s), rated power, P_r (MW), and rotor swept area, A_r (m^2) or diameter, D_r (m) [26]. With obtaining these parameters from a turbine that fits the average wind speed of the site, the power production of the turbine can be calculated with the following function

$$f(x) = \begin{cases} 0, & \text{if } v < v_{ci}. \\ P_f(v), & \text{if } v_{ci} < v < v_r. \\ p_r, & \text{if } v_r < v < v_{co}. \\ 0, & \text{if } v_{co} < v. \end{cases} \tag{2}$$

where $P_f(v)$ (W)is calculated as followed

$$P_f(v) = 0.5 \rho A C_{tot} v^3. \tag{3}$$

The density that is used in this formula, is the air density at hub altitude and is assumed constant for all the rotor area. If N is the number of turbines in the wind farm, the total power of production of the wind farm is calculated as followed

$$P_{farm}(t) = \sum_{i=1}^{N} P(t). \tag{4}$$

Plant

Electrolysis Plant Next step is to calculate how much hydrogen could be produced from the wind farm. To calculate how much hydrogen could be produced theoretically from a given wind farm following formula is used

$$W_{LH2,theory} = \frac{P_{farm}(t)}{(E_{el} + E_w + E_{liq}) * (1 + BOP)} \tag{5}$$

in which $P_{farm}(t)$ is the energy production of the wind farm, E_{el}(MWh/kg) is the energy required for electrolysis of one kg of hydrogen, E_w (MWh/kg) is the energy required to desalinate and treat water required to produce one kg of hydrogen, and E_{liq} (MWh/kg) is the energy required to liquefy one kg of hydrogen. BOP is a factor that takes into account the other energy requirements of the plant and stands for Balance Of Plant. $E_{electrolysis}$ could be calculated from the efficiency of the electrolyzer, which is given by the manufacturer, and the energy content of a kilogram of hydrogen, in this case LHV_{H_2}. The electrolyzer that has been chosen in this analysis is SILYZER300 Siemens, which could be used for large-scale industrial applications.

Considering the dynamics of the electrolyzer, below a certain level of power input to the electrolysis plant, it is not economical to let the electrolyzers run. This limit for SILYER300 is 5% of the nominal power of the electrolyzer.

$$P_{min.load} = 0.05 P_{H_2} \tag{6}$$

What is important to note is that the practical hydrogen production is different from the theoretical hydrogen production. $W_{LH2,practical}$ is calculated from the following function

$$W_{LH2,practical} = \begin{cases} 0 & \text{,if } P_{av} < P_{min.load}. \\ \frac{P_{av}}{E_{el}} & \text{,if } P_{min.load} \le P_{av} < P_{H_2}. \\ \frac{P_{H_2}}{E_{el}} & \text{,if } P_{H_2} \le P_{av}. \end{cases} \tag{7}$$

P_{av} (MW) is the available power to the electrolysis plant at any given time. In fact, the electricity that comes from the wind farm to the plant, a fixed ratio is always injected to the electrolysis plant, and P_{av} is this available power for the electrolyzer. P_{H_2} (MW) is the rated capacity of the electrolysis plant.

The energy requirements of liquefaction plant per kilogram of hydrogen was estimated to be in the range of 5-8 kWh/kg in near future [14]. Also Cardella *et al.* [13] estimated this value to be 6.4 kWh/kg and this value was ascribed to liquefaction energy requirement in this analysis.

Regarding the energy consumption for water treatment per kilogram of hydrogen, first it must be noted that this energy differs depending on different energy resources [8]. In the present work the energy requirement of water treatment is 0.1 kWh/kg_{H_2}.

Storage Sizing

The size of the storage depends on multiple factors and needs thorough information to be designed. For example, the space limitations of the platform, or the time frame that liquid hydrogen needs to be stored, affect the storage sizing. In the present work, the size of storage has decided to be equal to the maximum daily production of the plant considering the whole year, as a preliminary sizing criterion.

Economic Modeling

In this section a model has been developed for the prefeasibility analysis of the OffLH2 project.

DPB The first economic index that has been employed in the present work is discounted payback, DPB (years). This index considers the economic resource over time by bringing the net cash flows of each period with the discount rate i to the starting time of the project, considering the different values of money over time [26]. The following formula has been derived and used for DPB calculation

$$DPB = \frac{ln\left(\dfrac{1}{1 - i\dfrac{C_0}{R_{aa}}}\right)}{ln(1+i)}. \tag{8}$$

In this formula, C_0 (M€) is the capital investment at the beginning of the project. Annual revenue, R_{aa} (M€) is assumed to be constant in different years of the lifetime of the plant and is calculated as follows

$$\begin{aligned} R_{aa} =& I_1 - OPEX_1 = I_2 - OPEX_2 = \\ & ... = I_{DPB} - OPEX_{DPB}. \end{aligned} \tag{9}$$

In the present work, it has been assumed that liquid hydrogen is the only source of income that can pay back the costs of the project. Income I_T (M€) of the project in year T is calculated with

$$I_T = \sum_{i=1}^{366*24} W_{LH2,practical} \tag{10}$$

Regarding the capital investment of the project, it is divided into five contributions

$$\begin{aligned} C_0 =& CAPEX_{windfarm} + CAPEX_{electrolyzer} + \\ & CAPEX_{liquefaction} + CAPEX_{storage} + \\ & CAPEX_{platform} \end{aligned} \tag{11}$$

NPV As a complementary index to the DPB, net present value, NPV (M€) has also been employed to account for the cash flows after the payback time of the project. NPV is calculated as follows

$$\begin{aligned} NPV =& \frac{I_1 - OPEX_1}{(1+i)} + \frac{I_2 - OPEX_2}{(1+i)^2} + \\ & ... + \frac{I_N - OPEX_N}{(1+i)^N} - C_0. \end{aligned} \tag{12}$$

Green Hydrogen Price Above all, it is important to note that in this study a sensitivity analysis has been developed to see how the DPB and NPV of the project are affected by hydrogen price. Changing the liquid hydrogen price from 5 to 7 €/kg, the mean value of this range is 6 €/kg. This value, however, is expected to be a conservative price for green hydrogen [18].

Results

In this chapter, the results of the model simulation in MATLAB, and their interpretation, have been reported.

Wind Energy to Electricity

The first phase in modeling the system's output is to link wind speed data calculated from Sciacca's wind speed data to the wind farm's power production. Fig. 8.1 depicts the power production of a single turbine in a two-week period.

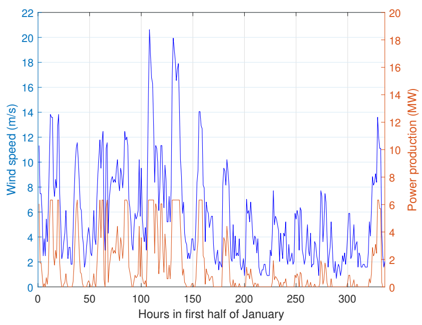


Figure 2. Hourly wind speed data and power production from a single turbine in the specified period of two weeks.

After representing the performance of a single turbine with different wind speeds, now the performance and variation in a wind farm's power production during a whole year could be represented. In the present work, an assumption regarding the performance of the wind farm is that at a specific time the wind speed for all the turbines is the same and their wake does not affect the wind speed at the inlet of adjacent turbines. The number of turbines in the wind farm, is strongly influenced by how many ships are planned to be refueled.

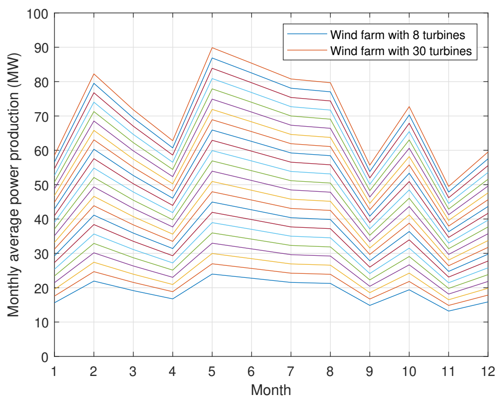


Figure 3. Monthly average power production with different number of turbines in the wind farm.

Theoretical liquid hydrogen production now can be easily assessed without considering the dynamics and limitations of the electrolyzer. In Fig. 8.4 theoretical hydrogen production is depicted for two ends of the number of turbines, 8 turbines and, 32 turbines.

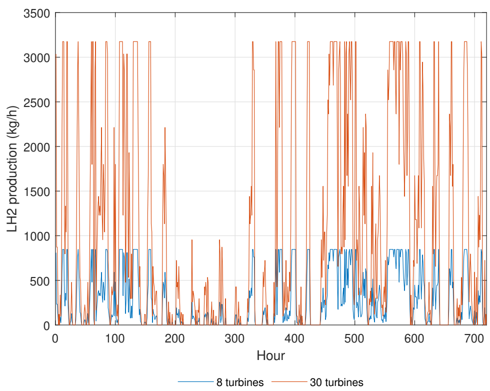


Figure 4. Theoretical liquefied hydrogen production with two different sizes of the turbine.

Optimal Sizing of The Electrolysis Plant

The energy system that is considered in the present work is a standalone system and the wind farm is not connected to the grid. Consequently, all the energy that is produced from the wind farm is fed to the electrolysis plant for liquid hydrogen production. Also, it is important to note that the electricity is not going to be bought from a wind farm that already exists, but the investor is also responsible for the CAPEX of the wind farm. This will affect the optimal sizing of the electrolyzer, compared to a case in which the electricity is bought from another farm and is accounted for in the OPEX of the economic model. Since the optimal size of the electrolysis plant, after all, is an economic balance.

Due to the intermittent nature of wind energy, the electricity that is coming from the wind farm is also intermittent. Therefore, the higher the size of the electrolyzer, the capacity of an electrolyzer that is not used in partial load will increase. This is also represented in the Fig. 8.5, along with how practical LH2 production changes with the number of turbines.

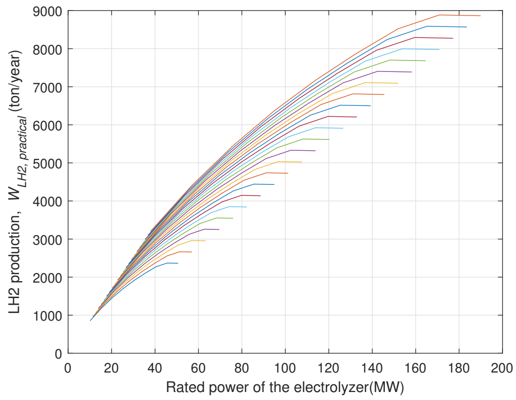
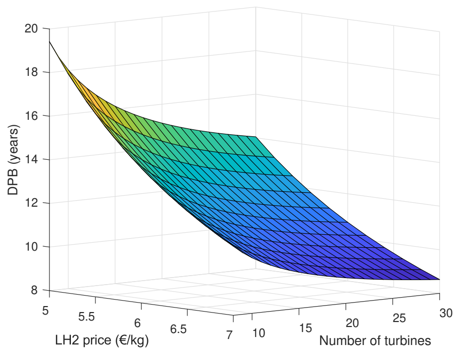


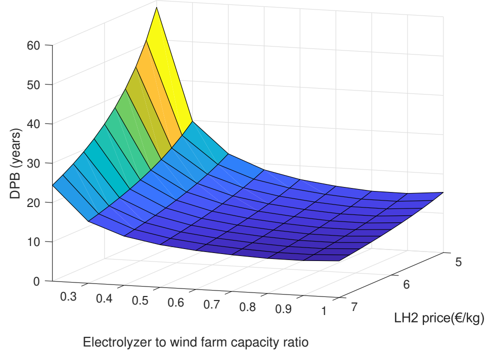
Figure 5. Variation of the practical annual LH2 production as a function of number of turbines and size of the electrolysis plant

The next step after calculating how much hydrogen could be produced practically, is to assess the economic aspect of the project, knowing that the only source of income for the project is the liquid hydrogen that is going to be sold to the naval sector. The first index that is assessed is DPB (years). Figg. 8.8 and 8.6 represent the sensitivity analysis of the DPB with changing price of liquid hydrogen, number of turbines, electrolyzer to wind farm size ratio.

NPV (M€) is another index that is used in parallel with the DPB to account for the cash flows after the payback time of the project, hence provide a better knowledge of the project. It shows how the profitability of the project is changes with number of turbines and hydrogen



(a) Variation in DPB as a function of price of the LH2 and size of the wind farm (number of turbines), with a fixed size of the electrolysis plant



(b) Variation in DPB as a function of price of the LH2 and size of the electrolysis plant, for a wind farm with 24 turbines

Figure 6. Variation in DPB

price.

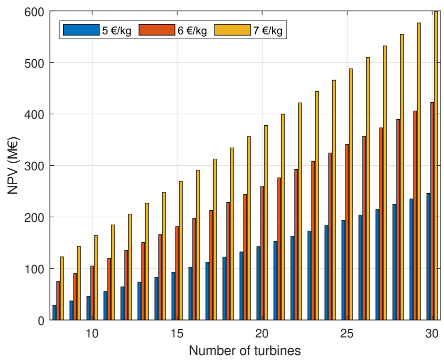


Figure 7. NPV for different number of turbines and three different prices for the liquefied hydrogen.

Liquid Hydrogen

The next step of analyzing the pre-feasibility of refueling ships with liquid hydrogen is to represent how much liquefied hydrogen can be produced and how it varies in different periods of the year. Fig. 8.13 represents the variation in daily production of liquefied hydrogen for a plant with 24 turbines and an electrolyzer to wind farm size ratio of 80%. This variation is a challenge for a continuous and secure refueling of the ships.

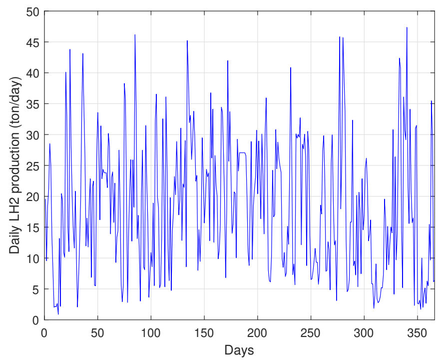


Figure 8. Daily production of the LH2 with 24 turbines and 80% electrolyzer to wind farm size ratio..

Refueling Capacity
The ultimate objective of the OffLH2 plant is to refuel the ships with the produced liquefied hydrogen from the green electricity. Hence, the last step of the analysis is the number and type of ships that could be refueled. The daily hydrogen consumption of large ships and cruise ships are about 10 and 2 ton/day, respectively [13]. Again considering a plant with 24 turbines (151.9 MW) and 80% electrolyzer to wind farm size ratio. For a plant with this size, and wind spped data that has been used in the present work, on a yearly basis, the daily average liquid hydrogen production is 18.63 ton/day, with a maximum daily production of 47 ton/day. With that being said, the target of refueling should be the cruise ships, not large ships, which tend to have larger gaps between their refueling stops.

Conclusions

The main conclusions of the present work are briefed as follows:

- As it is represented by the economic indexes used in this study, discounted payback period (DPB), and net present value (NPV), the results are satisfactory and the project could be profitable.
- The results of the comprehensive model show how increasing the size of the plant is desirable in terms of economics of the project.
- For a wind farm including 24 turbines (151.9 MW), with an electrolyzer to wind farm size ratio of 80%, only the volume of stored liquid hydrogen is 669 m^3 , excluding the volume of the process and storage equipment.
- Again considering the plant with descriptions in the previous point, the daily average liquid hydrogen production is 18.63 ton/day, yearly. With that being said, the target of refueling should be the cruise ships, not large ships.
- On a daily basis, the amount of liquid hydrogen produced varies greatly. As a result, policies governing ship refueling must take this into consideration. Transporting a portion of the produced liquefied hydrogen to the shore for land-based applications could be a possible solution.

Future Works

The present work is a pre-feasibility study of the liquid hydrogen production from offshore wind energy to refuel ships. The study of the system has considerable room for improvement. Studying the system from different engineering points of view: civil, electrical, and environmental engineering study of the work will provide an improved view over the project, rather than a purely energetic point of view.

Nomenclature

In this chapter the adopted nomenclature in the present work is depicted.

Subscripts and apexes

v_{ci} Cut-in wind speed, m/s

v_{co} Cut-out wind speed, m/s

v_r Rated wind speed, m/s

P_r Rated power, W

D_r Rotor diameter , m

Acronyms

NPV Net Present Value

DPB Discounted Payback

PEM Proton exchange membrane

$LCOE$ Levelized Cost Of Energy

$FOWF$ Floating Offshore Wind Farm

$FOWT$ Floating Offshore Wind Turbine

LCC Life Cycle Cost

$CAPEX$ Capital Expenses

$OPEX$ Operation and maintenance expenses

$DECEX$ Decommissioning Expenses

DES Direct Electrolysis of Seawater

AEL Alkaline Electrolysis

$PEME$ Proton Exchange Membrane Electrolysis

SOE Solid Oxide Electrolysis

$LH2$ Liquid hydrogen

$CGH2$ Compressed hydrogen

GHG Greenhouse gas

$SWRO$ Sea Water Reverse Osmosis

SEC Specific Energy Consumption

ADD Adsorption Desorption Desalination

MED multi-effect distillation

MSF multi-stage flashing

$CGH2$ Compressed gas Hydrogen

$LH2$ Liquid Hydrogen

$LN2$ Liquid Nitrogen

FPV Floating Photovoltaic

$FOWF$ Floating Offshore Wind Farm

TLP Tension Leg Platform

$TLWT$ Tension Leg Wind Turbine

TLB Tension Leg Buoy

GCC Gulf Cooperation Council

RO Reverse Osmosis

HPP	High Pressure Pump
ERD	Energy Recovery Device
BP	Booster Pump
PV	Photovoltaic
$MCDM$	Multi-Criteria Decision Making
CNG	Compressed Natural Gas
LNG	Compressed Natural Gas
BOP	Balance of Plant
JT	Joule-Thomson

Chapter 1

Introduction

In this chapter, the overall context and motivation of the present thesis work, known as OffLH2, are represented. The model that has been developed in the present work is a comprehensive study of the whole infrastructure of the system. First of all, the needs and reasons that encourage the study of this project are discussed. Then, an extended study of the technologies that are employed in the project are discussed. In the next step, the novelties of the OffLH2 project, which could introduce a new way of green fuel for naval transport, are discussed. Finally, the structure of the different chapters in the present thesis work are briefed in this chapter to provide a better view on the frame of the present work.

1.1 Context and Motivation

Introduction of hydrogen as a new fuel for transportation has been advocated for a long time. The support for hydrogen as a new fuel has different reasons: a solution for responding to scarcity of the non-renewable resources [27], a possible solutions for the concerns over the environmental quality [19, 27], as a high-performance aircraft and rocket fuel [19], as a means of expanding the use of nuclear energy [28], and as a response to growing climate change problems [29].

Recently, the interests into hydrogen as a fuel has strongly increased, due to the problems of CO_2 as the principal greenhouse gas, and scarcity of the fossil fuels [19]. Light duty vehicles are the dominant consumers of the fuel in the transportation sector, and consequently the main responsible for CO_2 emissions. Therefore an effective way to deal with the problems of CO_2 emission and fuel scarcity may be the changes in light duty vehicles design and usage. However, early introduction of the hydrogen-powered light duty vehicles may not be the best strategy in long term. [19].

Only focusing on the ultimate long term goals -lower emissions of CO_2 and/or petroleum independent transportation - without paying proper attention to the role of near term decisions in shaping long term technological innovation and change is a serious gap since these processes are central to the ultimate costs of meeting policy goals [30, 19].

Introducing new transportation fuels is an infrequent, rare, difficult, slow (decadal) and uncertain process, mostly because of the complexities related to major changes in the social and economic systems. Therefore, paying attention to how to maximize the likelihood of success while minimizing the costs and risks is an important step toward achieving long term goals [19, 31].

Fuels that are mainly derived from petroleum dominate the transportation sector, and the main reason is because some of their basic physical characteristics make them relatively easy (and therefore inexpensive) to use onboard vehicles. These key characteristics include the ability to be used easily with internal combustion engines and turbines (which have high power to weight ratios and simple operating characteristics suitable for vehicle use), easy to handle and store, and very high volumetric energy densities [19]. Apart from these factors that arise from the physical properties of different fuels, there is another significant problem when introducing a new fuel, and that is the problem of coordination between investments in new hydrogen vehicles and refueling infrastructure [32]. That is consumers are not willing to buy vehicles for which there are not refueling infrastructures, and investors are not willing to build infrastructures for a fuel that does not have demand [19].

A key aspect of any strategy to introduce hydrogen as a transportation fuel first in heavy duty vehicle freight modes would be the potential spillovers of technological innovation and knowledge into other modes while keeping costs low, mainly by limiting the size of the refueling infrastructure. While the marine freight mode appears to be a particularly good candidate, a more general conclusion is that freight modes are uniformly more likely to be lower-cost avenues for hydrogen fuel introduction than light duty vehicles. The cost of introducing hydrogen as a new fuel can be minimized by selecting a transportation mode that uses a small number of relatively large vehicles, which are owned by a small number of technologically sophisticated firms and operated by professional crews, and which are used intensively along a limited number of point-to-point routes or operated within a small geographic area [19]. Therefore, it is important to study how to use hydrogen as a possible fuel for the naval sector, which is the main goal of the present work.

Today, the commercial and most basic industrial process to produce purest form of hydrogen is water electrolysis, where water molecules are split to give hydrogen and oxygen by circulating electricity directly through it [33].

In the scope of the present work, hydrogen is produced through electrolysis. The electricity that is feeding the electrolyzer is coming from a renewable source of energy in the offshore environment. There are different sources of green electricity in an offshore environment, which are analyzed later in this work, so that the best candidate is chosen for this purpose.

Dedicated offshore wind farms for hydrogen production are an attractive option as these systems can be installed at any location having good wind conditions without the need for a power grid connection, and are able to produce hydrogen emission of greenhouse gases [34]. However, such systems have not been widely studied and the available literature has mainly focused on electrical aspects and development of the systems [26].

The methods currently used or being developed to store hydrogen are as followed: (1) compressing the produced hydrogen to higher pressures and store it as compressed gas, (2) storing it as cryogenic liquid hydrogen, and (3) Materials-based storage or solid-state storage [35]. Methods (1) and (3) are not of interest in the present work. As it has been reported by [36], commercial usage of the method (3) is unlikely to happen in a near future. Regarding method (1), the volumetric density of the compressed hydrogen is not favorable as a naval transport fuel. Fig. 1.1 depicts specific energy (energy per mass or gravimetric density) and energy density (energy per volume or volumetric density) of compressed hydrogen and liquefied hydrogen, and compares them with another well-known fuels.

Another important aspect of the OFFLH2 project is that it is aiming at liquid hydrogen production from existing oil and gas platforms. More specifically, the platforms that are going to be put out of oil and gas activities in near future. In this project, the location of the platform is in Mediterranean Sea, between Sicily and Tunisia.

1.2 Objectives

The main goal of the present work is the pre-feasibility study of an offshore system that could be used for production of liquid hydrogen, which is going to be consumed as a green fuel in naval sector. The following list includes main objectives of the present work.

- Analyze the main ship routes in the Mediterranean Sea.
- Identify the technologies for the electricity production, electrolyzer, water treatment, and liquefaction.
- Compute the refueling capacity as a function of the offshore wind farms size.

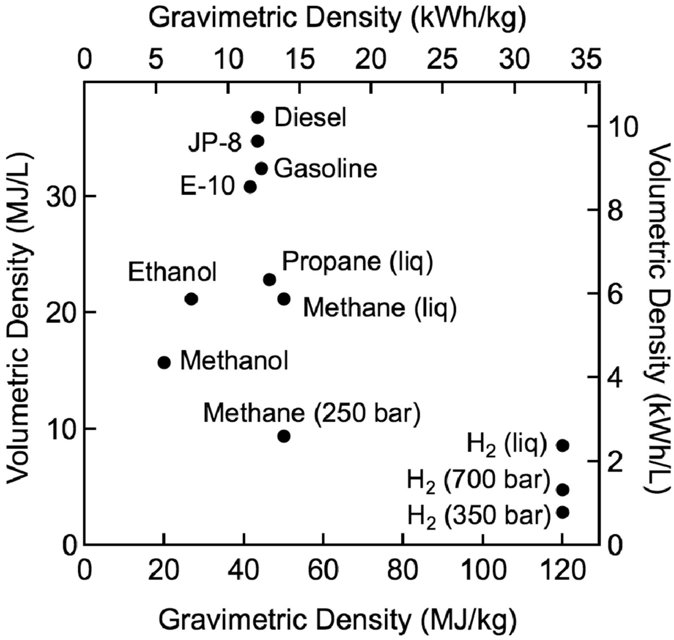


Figure 1.1. Comparison of specific energy (energy per mass or gravimetric density) and energy density (energy per volume or volumetric density) for several fuels based on lower heating values [1].

- Assess the overall cost and payback period of the project

1.3 Comprehensive model

First part of the current thesis work includes studying different technological aspects of the offshore conversion of electricity into hydrogen. This study is divided into four main parts, electricity production from renewable sources, seawater treatment, water electrolysis, and hydrogen liquefaction. Another important aspect of the project is the location of the platform and wind farm, which must be placed in a location where it is reachable for naval sector and the ships are willing to spend less time and less charging for stopping in the ports for refueling.

After studying these main four parts and choosing the best candidate, a model has been developed to calculate the power production of the wind farm. To obtain the power production of the wind farm, it is necessary to have the wind speed data of the location. Since at this stage the wind speed data of the project site are not available, the wind speed data of Sciacca in Sicily was used as a starting point. Then the wind speed data at the possible location of the wind farm is estimated, to model the power production of the wind farm. After modeling the power power production of the wind farm, liquefied hydrogen production in a yearly basis is modeled.

After the technological analysis, the project is economically assessed to check the viability of the project. The economic indexed that re used in this study are the Discounted Payback, DPB (years), and the Net Present Value, NPV (M€) of the project.

In order to have a better understanding of the OffLH2 project, a sensitivity analysis has also been performed on the parameters that affect the capacity of refueling and economics of the project. These parameters include:

- ratio of electrolyzer size to wind farm size,
- wind farm size,
- final price of the liquefied hydrogen.

1.4 Novelty

There are different studies on the conversion of green electricity to hydrogen. But by today, to the knowledge of author, main focus has been on converting power to gaseous hydrogen and liquid hydrogen is not covered in the studies. More importantly, no studies on feasibility of liquid hydrogen production for refueling the ships and usage of liquid hydrogen as a green fuel for the naval sector.

1.5 Thesis Structure

This section depicts the structure of the present thesis. The subdivision in the main chapters is as follows:

- **Chapter 2: Green Electricity.** In this chapter different possibilities of green electricity production in an offshore environment has been studied, technologically and economically. Finally, the best option for the present work is chosen.
- **Chapter 3: Water Treatment.** Different water treatment technologies have been studied in this chapter, to see which one has to be adopted for the present work.
- **Chapter 4: Electrolysis.** In this chapter different technologies for water electrolysis have been studied. After considering different criteria, the best option for present work has been opted.

- **Chapter 5: Hydrogen Liquefaction and Storage.** This chapter is devoted to assessment of hydrogen liquefaction process and its storage, both in terms of its technological and economical aspects.
- **Chapter 6: Platforms.** In this chapter a study of the platform economics has been performed. As a starting point and for the aim of economic investments related to the platform, data of the platforms in the Dutch shell has been used.
- **Chapter 7: Comprehensive Model.** The objective of this chapter is to establish a comprehensive model for the analysis of the system. Starting from wind profile estimation, to electricity production, then hydrogen production, liquefaction and storage.
- **Chapter 8: Results.** After developing the model in the previous chapter, the model has been employed in MATLAB, so that the model can be used to evaluate the performnce of the system. In this chapter the results from the model are reported and discussed.
- **Chapter 9: Conclusions.** The main conclusions and suggestions based on the obtained results of the present work are reported in the present chapter.
- **Chapter 10: Future Work.** The last chapter is dedicated to suggestions on how to develop the model further in the future works that could be based on the present work.

Chapter 2

Green Electricity

The starting point in the OffLH2 energy system, is the electricity which is going to be converted into liquefied hydrogen finally. Therefore, this chapter is devoted to analyzing different sources that could be used as the source of electricity for OffLH2 system. The candidate technologies are discussed both in terms of technology and economy. Finally, the best technology for the OffLH2 is chosen among different possible solutions.

2.1 Oliviera-Pinto *et al.*, 2020

One of the emerging technologies for green electricity production is floating solar technology. In this study [2], Oliviera-Pinto *et al.* studied this technology and their performance. There have been different motivation to develop this technology, such as lack of available land, loss of efficiency at high operating cell temperature, energy security and decarbonization targets.

Floating solar technology is an attractive solution for countries with dense population, where scarcity of land will result in an increase of its acquisition costs, impacting negatively the economic viability of ground-mounted solar projects [37]. Therefore, floating solar technology could enable to turn unused water surfaces into profitable commercial solar projects [38]. Moreover, this technology will increase the efficiency of the plant, due to the natural cooling effect, thanks to presence of the water body [39]. As it can be seen from Fig. 2.1, the floating solar technology is made up of a floating structure, where the Photovoltaic generation equipment is placed, the mooring system and the underwater cable [38].

Although there are many advantages for the floating solar technology, these systems are typically installed in enclosed freshwater bodies, like reservoirs, hydroelectric dams, or small lakes. Therefore, the applications of float-

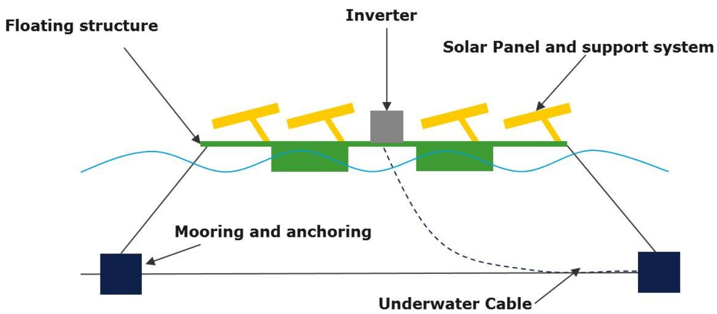


Figure 2.1. Main components of a FPV system. [2]

ing solar technology in the sea are scarce, yet installations in near shore locations are slowly emerging [2].

2.2 Dinh *et al.*, 2020

Dinh *et al.* [26] developed a viability analysis to study the Hydrogen production from offshore wind farms, as there is still lack of knowledge on these systems. They obtained relations for calculating Output of the wind power, size of the electrolysis plant, and amount of hydrogen produced from the time-varying wind speed. The method that they used to obtain the value of capital over time, adopts Net Present Value (NPV) and discounted payback period (DPB). Finally, a case study was considered with a hypothetical 101.3 MW offshore wind farm. The case study was supposed to start operation from 2030, therefore the costs were estimated using predictions already available in the literature. The type of Electrolysers was Proton Exchange Membrane (PEM) and the hydrogen produced was stored underground. They concluded that if the hydrogen price in 2030 is 5 €/kg, and compressed hydrogen is stored from 2 days to 45 days, the system will be profitable.

Dinh *et al.* broke down the analytic model into different parts:

- Wind farm power output

  In a previous work on wind turbines [40], three methods were identified to predict the power production of a wind turbine: (1) using the fundamental equations of available power in the wind, (2) presumed power functions of the wind turbine, and (3) actual power functions which are supplied by the manufacturers. Dinh *et al.* used the second approach, as the first approach is less accurate, and the third one is not available in preliminary stages of a project. The second approach needs a few typical parameters; rotor diameter, D_r (m), rated power, P_r (MW), cut-in wind speed, v_{ci} (m/s), rated wind speed, v_r (m/s), and cut-out wind speed, v_{co} (m/s).

- Hydrogen production

  First the theoretical amount of hydrogen,$W_{H_2,theory}$ (kg/hour) that can be produced from the wind farm was studied by Dinh *et al.*, which is time-dependent

$$W_{H_2,theory}(t) = \frac{P_{farm}(t) * 1hour}{\frac{E_{elec}}{\eta_{conv}} + E_{pcl}} \tag{2.1}$$

  in which, E_{pcl} (MWh/kg) is the amount of electricity needed to purify water, compress hydrogen at production pressure to the storage pressure level, and other losses. η_{conv} is the conversion efficiency. An important asset installed from the beginning of the project is the hydrogen electrolysis plant. The size of this plant (its rated capacity) is $P_{H_2-plant}$ (MW), and should be identified based on the maximum hourly production of hydrogen.

$$P_{H_2-plant} \leq \max W_{H_2,theory}(t) * E_{elec} \tag{2.2}$$

  For efficient performance of the plant, when the power input to the electrolysis plant is too low, the electrolysis must be stopped. Dinh *et al.* chose this value to be 5% of the electrolysis plant rated capacity.

- viability

  Dinh *et al.* used different methods for assessing the economical viability of the project they were studying. These methods are simple payback (SPB), Discounted Payback (DPB), and Net Present Value (NPV).

The site that Dinh *et al.* investigated was located 15 km away from the shore and water depth was between 30 and 40 m. The turbine type was chosen so that it matches the specifications of the site and the wind conditions. Which resulted in larger turbines.

As for the electrolysis plant, the electrolysers are working intermittently, due to the fact that the input power from wind farm is time-varying. As the aim of the study was to test the viability model, the smallest size of the wind farm was chosen. In that specific study such that small size did not influence the unit costs of the wind farm installation, operation and maintenance costs; because the site was within a pipeline of offshore wind projects. And as it was pointed out by [36], the minimum capacity that can produce an economically feasible hydrogen production from an offshore wind farm, is 100 MW.

Dinh *et al.* selected PEM (proton exchange membrane) electrolyser for their study, only dependent on electricity from the wind farm. The data used in their study were estimated for the year 2030, as it would take about 8 years to develop and construct the farm with that specifications.

The hydrogen price which was used in the study of Dinh et al. was considered to be 5 €/kg. This value is the minimum of the domain suggested by the *Hydrogen Roadmap for Irish Transport, 2020-2030* (5-10 €/kg) [41].

In this study, Dinh *et al.* noted that the cost of hydrogen storage significantly impacts the project CAPEX and cash flow. They considered storage systems with different storage capacities; ranging from 2 days to 60 days, capable to store 35 tons and 1020 tons of hydrogen, respectively. The result of the analysis showed that the hydrogen production from offshore wind plant is profitable in 2030 (with selected site and specified wind turbines and electrolysers) with a hydrogen price of 5 €/kg and underground storage from 2 days to 45 days. They also suggested that the shorter the storage time with the considered inputs, the plant is more economical.

2.3 Lerch *et al.*, 2018

In this study, Lerch *et al.* [3] performed a sensitivity analysis on the levelized cost of energy for floating offshore wind farms (FOWFs). The analysis was performed for three floating wind turbine concepts (namely Semi-submersible, TLP, and Spar) and three different offshore sites. Table 2.1 describes the characteristics of the sites that have been investigated in this study. Besides that, concrete as well as steel structures were also included to represent both manufacturing materials. In this study, Lerch *et al.* considered FOWTs with a rated capacity of 10 MW to represent the trend towards larger offshore wind turbines. The sensitivity analysis performed included 325 input parameters to identify the ones that most influence the LCOE. Lerch *et al.* noted that parameters related to the capital cost such as turbine, substructure and mooring system manufacturing cost, as well as power cable cost are some of the most influencing parameters besides common parameters such as the discount rate and energy losses.

"The LCOE calculation is a method used to obtain the cost of one unit of energy produced and is typically applied to compare the cost competitiveness of power generation technologies. The LCOE model sets in relation the life cycle costs (LCCs) to the electrical energy provided (Eel) as follows" [42]:

$$LCOE = \frac{LCC}{E_{el}} \tag{2.3}$$

in which LCCs include all costs occurring in the lifetime of the FOWF such as the capital expense (CAPEX), the cost during the operation and the maintenance phase (OPEX) as well as the decommissioning expense (DECEX) at the end of lifetime [43].

Table 2.1. Offshore site characteristics[3].

	Golf De Fos	Gulf of Maine	West of Barra
Country	France	USA	Scotland
Reference location	Marseille	Portland	Barra
Ocean	Mediterranean Sea	Atlantic	Atlantic
Metocean conditions	Moderate	Medium	Severe
Design water depth (m)	70	130	100
Wind speed 50 years (m/s)	37	44	50
Mean wind speed at 100 m (m/s)	10	10.18	11.26
Sign. wave height 50 years (m)	7	10.48	14.27
Transmission length (km)	38	57.8	180
Soil type	Sand/Clay	Sand/Clay	Rock/Basalt

The metocean characteristics of an offshore site have a significant influence on the design, cost and performance of FOWTs. The information about the different cites that have been studied by Lerch *et al.* could be found in table 2.1

In the study of Lerch *et al.*, a FOWF is considered with 50 offshore wind turbines and a nominal power capacity of 500 MW. The selected transmission technology is “High Voltage Alternating Current” with the collection grid voltage operating at 66 kV and the transmission voltage at 220 kV. The position of the wind turbines within the wind farm layout is the same for all concepts and, therefore, provokes the same wake losses.

Lerch *et al.* note that input data used in their study has been provided by the respective concept designer and consequently the results are affected by the accuracy and source of the data. Also, a general conclusion for FOWT concepts cannot be given since they vary widely by their technical specifications and cost composition. Moreover, the concepts compared in their paper are on different technical and commercial readiness levels, which involve a different degree of uncertainty in the data. Therefore,the authors noted that objective of their paper was not to assess the feasibility of the concepts nor the LCOE values, but rather to analyze the sensitivity of the LCOE in relation to input parameters.

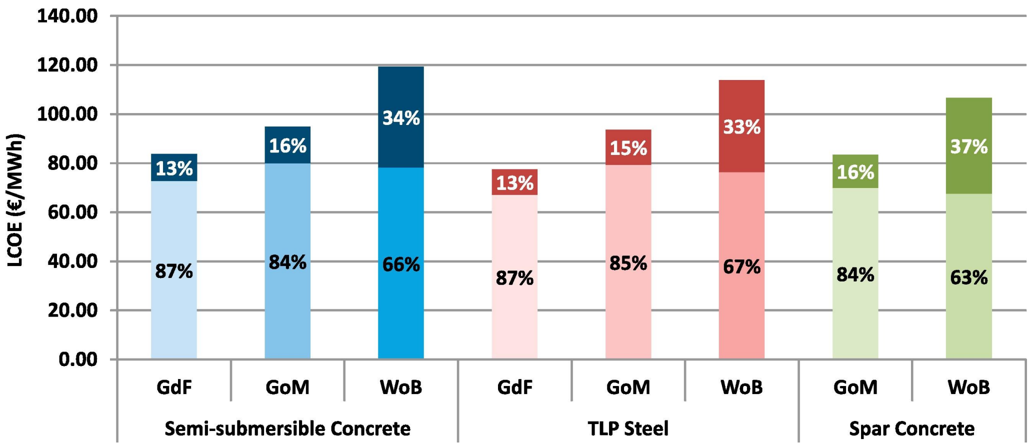


Figure 2.2. LCOE results for each concept and offshore site. The upper parts of the bars represent the portion of transmission asset costs of the LCOE. [3]

Fig. 2.2 depicts the results of the levelized cost of energy calculation for the different floating offshore wind turbine concepts and offshore sites. A significant portion of the LCOE is the cost of the offshore transmission assets, which is influenced by the different sites and highlighted in the figure. The high portion is based on the long export cable needed for the remote offshore site with respective investment costs and energy losses. Furthermore, the cost of the sub station increases with the distance due to the larger investment required for reactive power compensation in the High Voltage Alternating Current transmission.

Myhr *et al.* [4] has estimated the LCOE values for a number of different FOWT concepts and the results are taken as a reference range. It can be seen that the obtained LCOE values from the study of Lerch *et al.*,are in the lower part or even below the reference range, which demonstrates the high cost effectiveness of the studied concepts. Fig. 2.3 shows the comparison between these values that are obtained from these studies.

Moreover, Carbon Trust [5] estimated the LCOE of tidal and wave energy from 329 €/MWh to 374 €/MWh, and from 432 €/MWh to 545 €/MWh, respectively. Furthermore, the rate of cost reduction is potentially lower since ocean energy can not benefit as much as floating offshore wind from an existing supply chain [5]. To have a better view of these technologies for electricity production, Fig. 2.3 includes different technologies that have been mentioned and the LCOE of the electricity they produce.

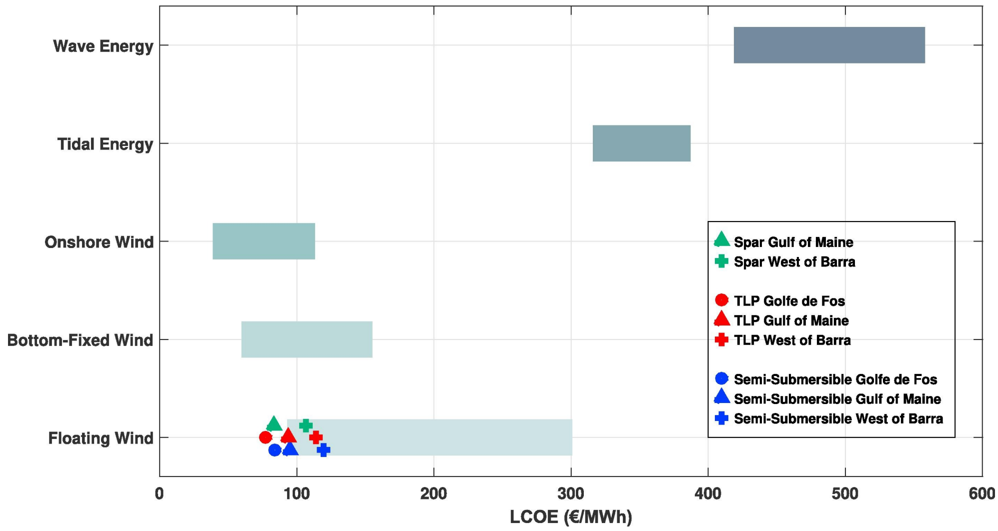


Figure 2.3. LCOE comparison between energy generation technologies. Calculated values of LCOE for a Tension Leg Platform (TLP) in red, semi-submersible in blue, and spar in green. The reference LCOE range for floating offshore wind is based on Myhr *et al.*[4]. The range for wave and tidal energy is taken from the Carbon Trust [5], for bottom-fixed offshore wind from Kausche *et al.* [6] and for onshore wind from Duan [7].

2.4 Myhr *et al.*, 2014

In this study, Myhr *et al.* [4] performed a comprehensive analysis and compared the levelised cost of energy (LCOE) for different offshore floating wind turbines. In this analysis, they considered a wind farm with 100 turbines, each with 5 MW of nominal power. The location of this study was a far offshore site.

Floating wind turbines become available in waters depths from 30 to 40 m and deeper. The bottom-fixed foundation concepts consist of a jacket, utilized at intermediate depths (30-50 m of water), and a monopile suitable for shallower water. All of the systems are illustrated in Fig. 2.4. For more information about the types of offshore wind turbines mentioned in this figure, the reference paper could be accessed.

In this study the assumption for the lifetime of the plant is that it will be functioning for 20 years, starting the operation phase from 2018. The ranges of LCOE that are depicted in Fig. 2.5 are based on the best- and worst-case scenarios. Moreover, for the reference wind farm, where bottom-fixed concepts at 30 m are compared to the floating concepts in 200 m of water, Tension-Leg-Spar (SWAY), Tension-Leg-Wind-Turbine (TLWT) and the Tension-Leg-Buoy (TLB) concepts are virtually at the same LCOE, con-

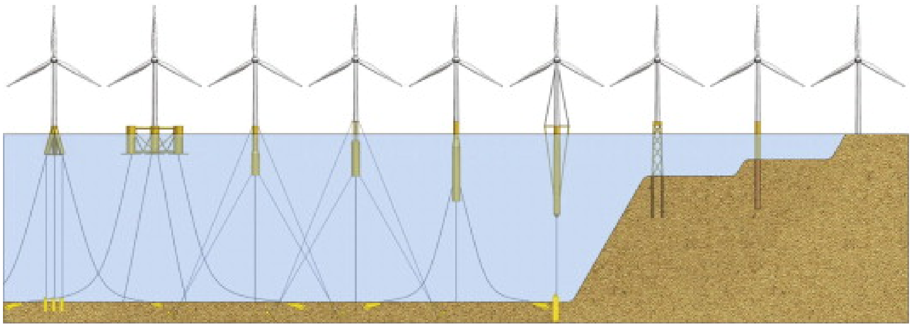


Figure 2.4. Illustration of the different concepts, from left to right; Tension-Leg-Wind-Turbine (TLWT), Semi-Submersible (WindFloat), Tension-Leg-Buoy (TLB) B, Tension-Leg-Buoy (TLB) X3, Hywind II, SWAY, Jacket, Monopile and the onshore reference. The mooring systems are not to scale in the horizontal direction. [4]

sidering the analysis accuracy. The large ranges of each high and low case result in LCOE ranges that span beyond 50% of the expected base case. Thus, the current spans are too large if one are to get a more reliable prediction to the final LCOE.

One of the parameters expected to distinguish the different floater concepts is the change in water depth and the corresponding changes of the mooring systems. Especially the Tension-Leg-Buoy (TLB) systems are sensitive to depth, as the effective stiffness at the fairleads and angle of the mooring lines have to be maintained. Fig. 2.6 shows the variation of LCOE for different types of wind turbines with changes in the water depth.

2.5 Green electricty for the present work

In this chapter different technologies that can produce green electricity in an offshore environment have been discussed. After comparing these technologies as possible candidate for OffLH2 project, wind energy has been chosen as the technology that should be used. Offshore wind energy is in a more developed stage than other options, and LCOE by wind energy is lower than the LCOE of its offshore counterparts. Also among two types of offshore wind turbines, the bottom-fixed turbine has been chosen, since it is expected to build the refueling plant not far from the shore and the expectation is that water depth will be low enough to use bottom-fixed turbines.

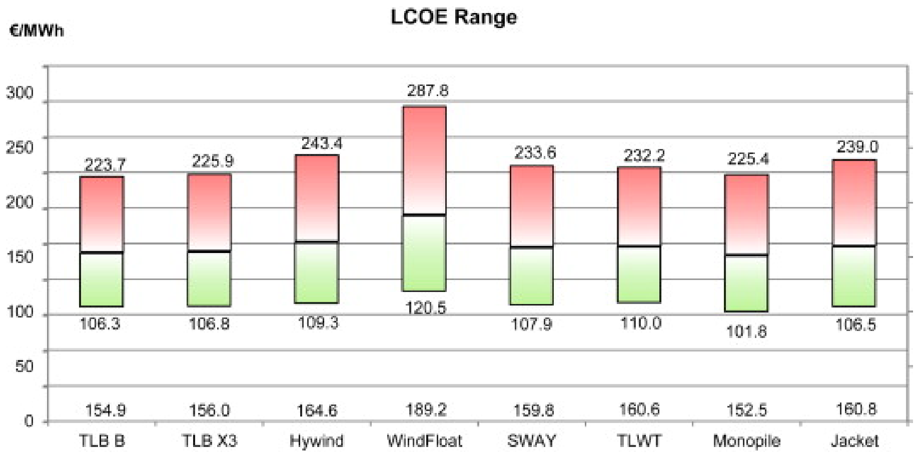


Figure 2.5. LCOE for the reference wind farm for each of the concepts with indications on both best- and worst-case scenarios. [4]

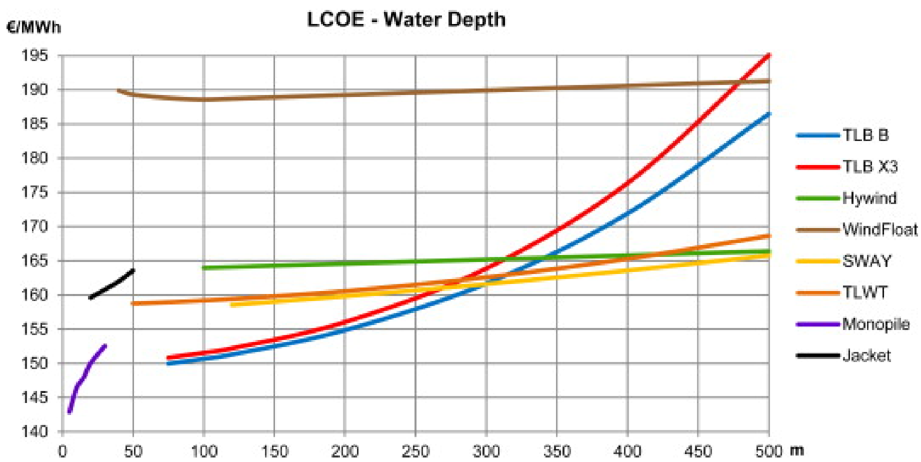


Figure 2.6. LCOE changes with depth for the reference scenario with base case values. [4]

Chapter 3

Water Treatment

Due to the fact the plant is located in the middle of the Mediterranean Sea, the seawater is used in the OffLH2 project. There are growing studies on how to electrolyze seawater directly. But this technology is not mature and not economically feasible. On the other hand, mature technologies that are discussed in the chapter specifically devoted to electrolysis, are designed to work with pure water. With that being said, in this chapter different possible solutions for seawater desalination and purification are discussed and finally the best solution is chosen among those options.

3.1 Alnajdi *et al.*, 2020

Alnajdi *et al.* [21], did a review in which, Adsorption Desorption Desalination (ADD) was reviewed and compared economically and environmentally with sea water reverse osmosis (SWRO), one of the leading commercialized desalination technologies in the world today.

As shown in 3.1, installation of SWRO technology will increase fourfold by 2030 per the Saline Water Conversion Corporation (SWCC) plan, while multi-stage flashing (MSF) will decrease, and multi-effect desalination (MED) will have a 10% share. Despite their relatively low thermal efficiency, MSF and, more recently, MED technologies still advantages in Saudi and Gulf Cooperation Council (GCC) markets due to the availability of cheap energy and the synergy of cogeneration of water and electricity.

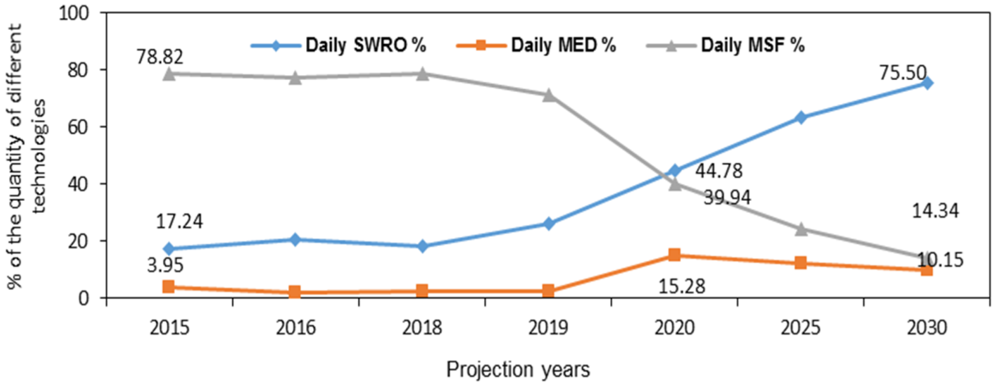


Figure 3.1. Trend of expected desalination technologies in the 2030 projection plan. MED, multi-effect desalination. MSF, multi-stage flash

The existing desalination technologies can be classified into two categories based on the form of energy used, namely **thermal energy** and **electricity driven** processes. The former includes multi-effect distillation (MED) thermal vapor compression (MED-TVC), multi-stage flash (MSF), humidification-dehumidification (HDH), adsorption desorption desalination (ADD), and membrane distillation (MD). The latter include mechanical vapor compression (MVC), reverse osmosis (RO), electro-dialysis reversal (EDR), and ion exchange (IEX) [44]. Three main commercialized desalination technologies are currently dominating worldwide, with collectively more than 90% of the total installed capacity. They are SWRO (65%), MSF (21%), and MED (7%) [45].

Table 4.1 shows a comparison of energy consumption, environmental impact in terms of quantity of CO_2 emissions, and decentralization capability for different unit capacities of various desalination technologies. It shows that SWRO has the lowest energy consumption, the lowest CO_2 emissions and the applicability of decentralization with the lowest installation cost, which explains its broad acceptance worldwide.

Table 3.1. Energy consumption and CO_2 emissions for desalination technologies. TVC, thermal vapor compression.

Item	MSF/Unit	MED-TVC/Unit	SWRO/Skid	Comments
Typical unit size (m^3/day)	$50,000 - 92,000$	$10,000 - 90,000$	$100 - 40,000$	Commercial unit size for SWCC plants
Minimum electrical energy consumption (kWh/m^3) [22]	2.5	2	$4 - 6$	Thermal plant efficiency 30% SWRO with energy recovery
Thermal energy consumption (kWh/m^3) [22]	15.83	12.2	*None*	Thermal plant efficiency 30% SWRO with energy recovery
$CO_2(kg/m^3)$ [46]	$15.6 - 25$	$7 - 17.6$	$1.7 - 2.8$	

3.2 Kim *et al.*, 2019

In this study, Kim *et al.* review and analyze SWRO plants for a comprehensive understanding of their Specific Energy Consumption (SEC). Because, the main objective of current SWRO research is to lower the SEC of SWRO plants. For this review, they used more than 70 datasets om large-scale SWRO.

It has been reported that the specific energy consumption (SEC) of seawater reverse osmosis (SWRO) process is 2.5-4.0 kWh/m^3 [47]. The SEC of a real-scale SWRO plant is even higher, approximately $3.5 - 4.5kWh/m^3$, including pre-treatment and post-treatment processes [48].

Firstly, it is necessary to describe a SWRO desalination plant. Fig. 3.2 depicts a typical process of a SWRO desalination plant. Pre-treatment units are employed to remove large-size particles and solids before the SWRO because they can cause fouling and/or scaling on the surface of the RO membrane. In SWRO, a semi-permeable membrane which allows water molecules to permeate while blocking solids molecules is employed for that separation. However, the osmotic pressure across the semi-permeable membrane becomes an obstacle to desalination. Therefore, the SWRO process requires high pressure to overcome the osmotic pressure of seawater, for which a high-pressure pump (HPP) is utilized. After the RO system, the desalted fresh water is obtained while concentrate is discharged from the RO train. In the concentrate, a considerable amount of pressure still remains. To improve the energy efficiency, the pressure in the concentrate should be recovered, for example, by energy recover devices (ERDs) [49]. The recovered pressure is utilized to increase the pressure of the feed stream. However, this pressure increase is not enough, and the feed stream pressure is supplemented by a booster pump (BP).

While most SWRO desalination plants adopt such common processes, their SEC differ depending on various factors. For example, the pre-treatment, which is mostly conducted by granular media filtration or membrane filtration, affects energy consumption. Despite its trivial effect, it can account roughly for 11% of the energy use in the plant [47]. Moreover, the characteristics of the feed water, particularly salinity and temperature, are critical because they are closely related to the minimum energy consumption for separation. Furthermore, the energy consumption of the RO system varies according to the target conditions, such as water quality and quantity. These factors are also associated with the performance of the RO membrane. Additionally, the efficiencies of the HPP, BP, and ERD significantly influence the total energy consumption, since the RO system is the most energy-intensive process in the plant (approximately 71%) [47].

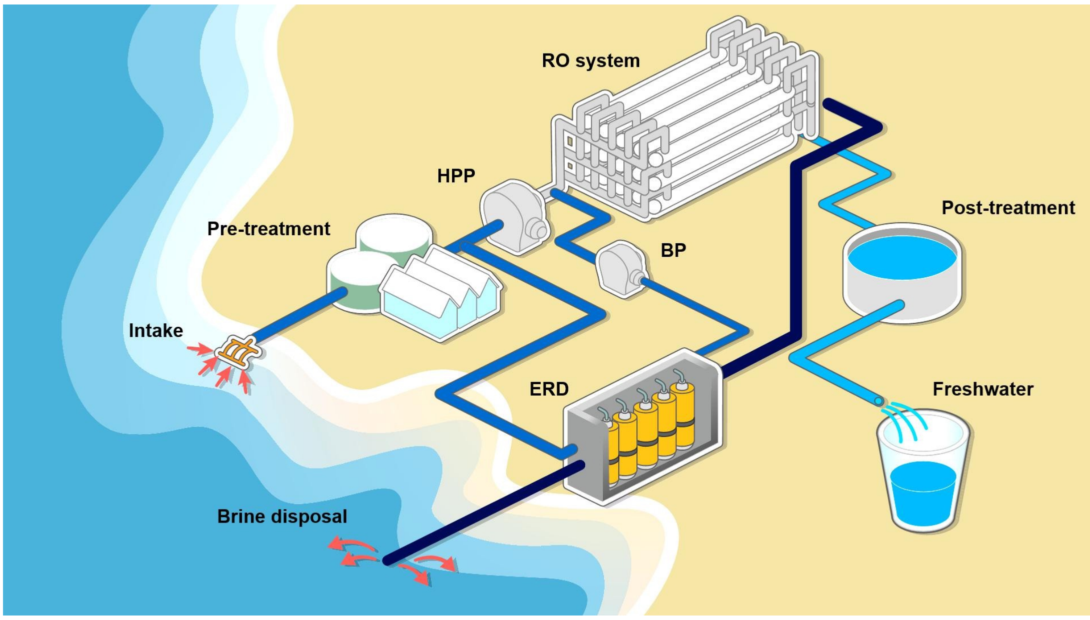


Figure 3.2. Scheme of a typical SWRO desalination process. A pre-treated feed is supplied to the RO system with pressurization by HPP and BP, and the hydraulic pressure in the concentrate is recovered by energy recovery devices (ERDs). RO: reverse osmosis. HPP: high-pressure pump. BP: booster pump. ERD: energy recovery device.

It is important to understand the factors affecting the energy consumption of the SWRO process. The RO system accounts for the majority of the energy use in a SWRO plant. Therefore, there is a dependency between the SEC of the RO system and that of the plant, as depicted in Fig. 3.3. According to the trend line, the SEC of the plant is approximately $1kWh/m^3$ higher that of the RO system. Thus, it can be inferred that the energy consumption for pre- and post-treatment is close to 1 kWh/m^3 regardless of feed conditions and other factors.

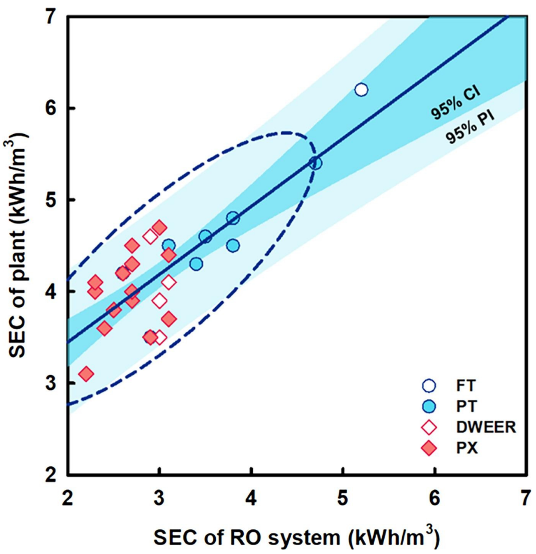


Figure 3.3. Correlation between specific energy consumption (SEC) of the reverse osmosis (RO) system and that of the plant. Reverse osmosis system is the most energy-intensive unit. Thus, the specific energy consumption (SEC) of the plant depends on that of the reverse osmosis system. FT: Francis turbine. PT: Pelton turbine. DWEER: dual work exchanger energy recovery. PX: pressure exchanger. PI: Prediction interval. CI: confidence interval.

Fig. 3.4 represents how different parameters affect the specific energy consumption (SEC) of seawater reverse osmosis .The factors that Kim *et al.* considered for the specific energy consumption (SEC) analysis of the SWRO plant are as followed:

1. Feed conditions
   - Salinity
   - Temperature
2. Equipment efficiency
   - Energy recovery device

- High-pressure and booster pump
- Retrofit and expansion

3. Target conditions

- Permeate quality
- Permeate quantity

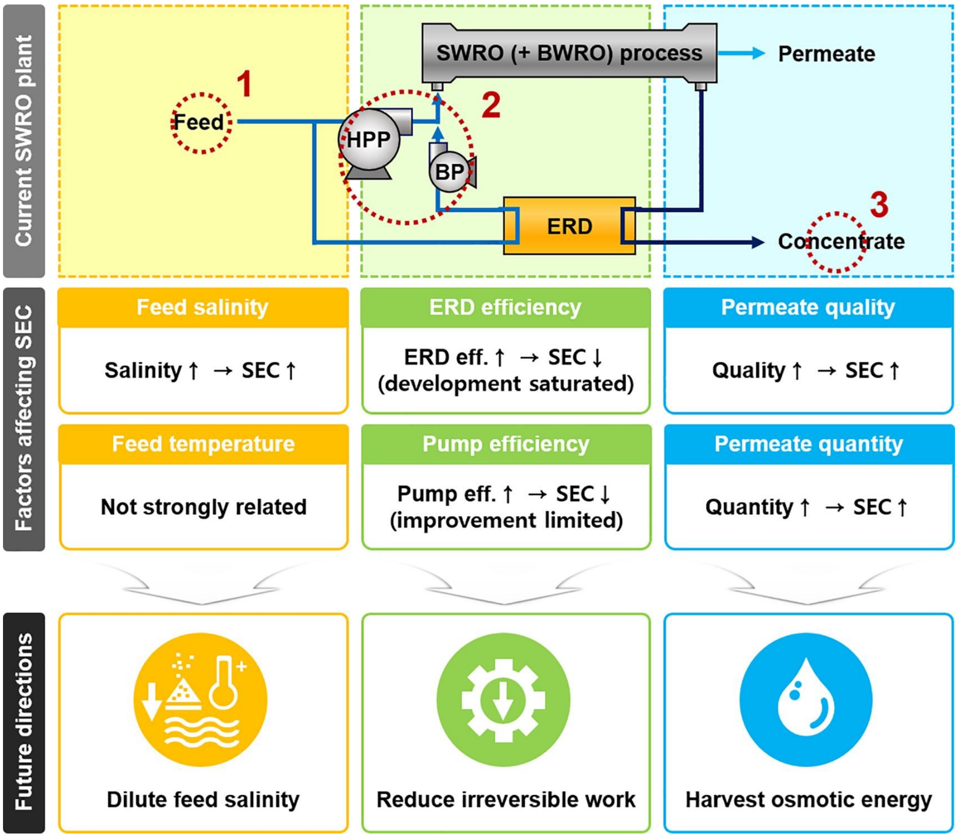
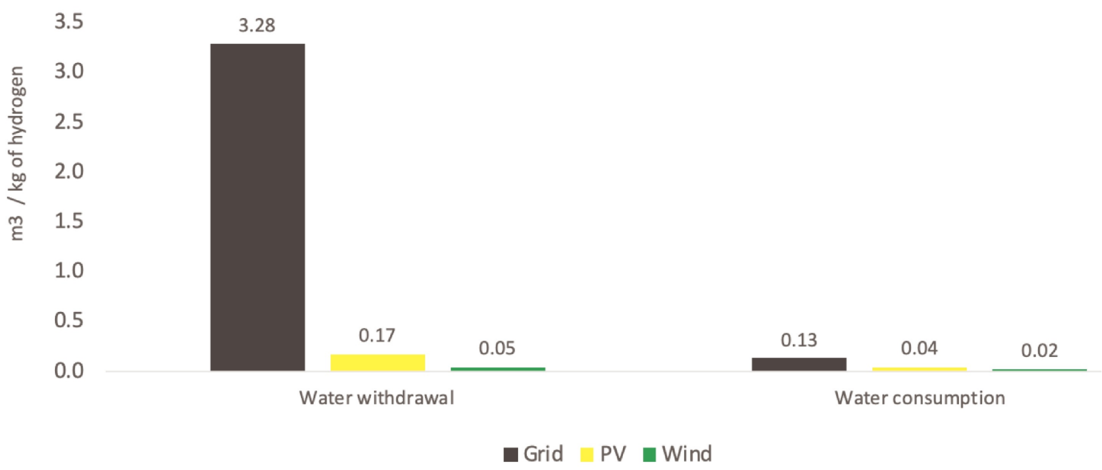


Figure 3.4. Summary of SWRO process, factors affecting SEC, and future research suggestions. SEC of SWRO plant can be lowered by diluting feed salinity, reducing irreversible work, and harvesting osmotic energy.

3.3 Shi *et al.*, 2020

Fig. 7.3 shows the life cycle water inventory of producing hydrogen in Australia from grid electricity, PV, and wind. The production of 1 kg of hydrogen in Australia consumes 0.13 m^3 of water when grid electricity is used, 0.04 m^3 of water when PV is used, and 0.02 m^3 of water when wind electricity is used.

However, the water withdrawal is much higher than the water consumption. The ratios of the three technologies are also quite different.Water withdrawal from grid electricity is 19 times that of PV, while water consumption from grid electricity is three times that of PV. The increasing gap between grid hydrogen and PV and wind is due to the significant amount of water used in the operational stage, mainly for cooling. Although a large portion of water in the operational stage will not be consumed, it has to be withdrawn first from the ecological system.



Note: kg = kilogram, m^3 = cubic meter, PV = photovoltaic.

Figure 3.5. Water withdrawal and consumption for producing 1 kg of hydrogen with grid electricity, photovoltaic (PV), and wind power in Australia. [8]

3.4 Water treatment for the present work

Different technologies that could be used for desalination and treatment of seawater have been discussed in this chapter. Regarding the OffLH2 project, although multi-stage flashing could be a promising method for water treatment in future, today the best option to treat sea water is seawater reverse osmosis (SWRO). However the limit of impurity at the outlet of SWRO is higher than that of the multi-stage flashing, but it is to an acceptable level for the usage of PEM electrolyzers and it is the technology that is used in ongoing projects today.

Chapter 4

Electrolysis

Hydrogen is the fuel that is going to be sold to the naval sector as the final product of the OffLH2 process. This hydrogen is produced through the electrolysis process. Therefore, this chapter is devoted to the electrolysis process. The reactions and details about different possibleanalyzing different technologies that are available for hydrogen production through electrolysis.

4.1 Buttler and Spliethoff, 2018

In this study [11], an overview of the current status of alkaline, PEM and solid oxide electrolysis on the way to large-scale flexible energy storage is presented. These main water electrolysis technologies were compared in terms of available capacity, nominal and part-load performance, flexibility (load range, load gradients, start-up time, stand-by losses) lifetime and investment costs.

The conversion of electricity via water electrolysis and optionally subsequent synthesis together with CO or CO_2 into a gaseous or liquid energy carrier enables a coupling of the electricity, chemical, mobility and heating sectors. This opens up enormous storage or absorption capacities for excess energy with high electricity generation from renewable energies in excess of demand. It also supports the integration of fluctuating renewables like wind and solar power in the energy system, including the provision of balancing power. The future demand for Power-to-Liquids and Power-to-Gas energy storage represents an emerging market for electrolysis systems.

The thermoneutral cell voltage gives the minimum voltage for electrolysis to take place in an ideal cell without heat integration. This means that the overall energy demand of the electrolysis reaction (including heat) is supplied electrically. The thermoneutral cell voltage is approximately $1.47 - 1.48$ V ($284 - 286$kJ/molH2) feeding liquid water below 100°C while it reduces to $1.26 - 1.29$ V ($243 - 249$kJ/molH2) in the temperature range of $100 - 1000$°C if steam is supplied (see Fig.4.1).

Thermoneutral voltage represents the standard operation mode of high temperature electrolyser. The cell is operated at constant temperature as internal heat production by irreversibilities is equalised by heat consumption of the electrolysis reaction. Low temperature electrolysers (AEL, PEMEL) are operated above the thermoneutral voltage due to high internal losses or overvoltages. This results in a heating of the electrolysis cells requiring external cooling of the module.

The dependency between cell voltage and current or current density respectively is shown exemplary in Fig.4.2. The current-voltage (I-U) relationship characterises the electrochemical behaviour of an electrolysis cell. The current density is approximately proportional to the hydrogen production rate according to Faraday's law. Grigoriev et al. [50] report a decrease of the Faraday efficiency of a PEM electrolyser from nearly 100% at pressures up to 20 bar to 90% at a pressure of 130 bar.

The efficiency of an electrolyser decreases (or the overpotentials increase respectively): (a) with rising current density, (b) with decreasing temperature (the operating temperature has a strong influence on performance but it is limited by degradation issues of the electrolysis cells and material restrictions.),(c) slightly with increasing pressure. Selection of the nominal current density of a system represents a weighting up of operating and capital costs as higher current densities result in:

- increased hydrogen production per cell area corresponding to reduced specific capital costs per Nm^3 of hydrogen production
- in a decrease in performance corresponding to an increase in operational costs
- an increase in the deactivation rate due to higher overpotentials.

Based on the nominal current density, part-load operation corresponds to a reduced current density and a higher efficiency. This means that each electrolyser can reach very high efficiencies in part-load.

When it comes to PEM electrolysis (PEMEL) (basic layout shown in Fig. 4.3), a proton exchange membrane separates the two half-cells, and the electrodes are usually directly mounted on the membrane forming the MEA (membrane electrode assembly). PEM electrolysis features a compact module design due to the solid electrolyte and high current density operation compared to Alkaline electrolysis. This supports the high-pressure operation of PEM electrolysis.

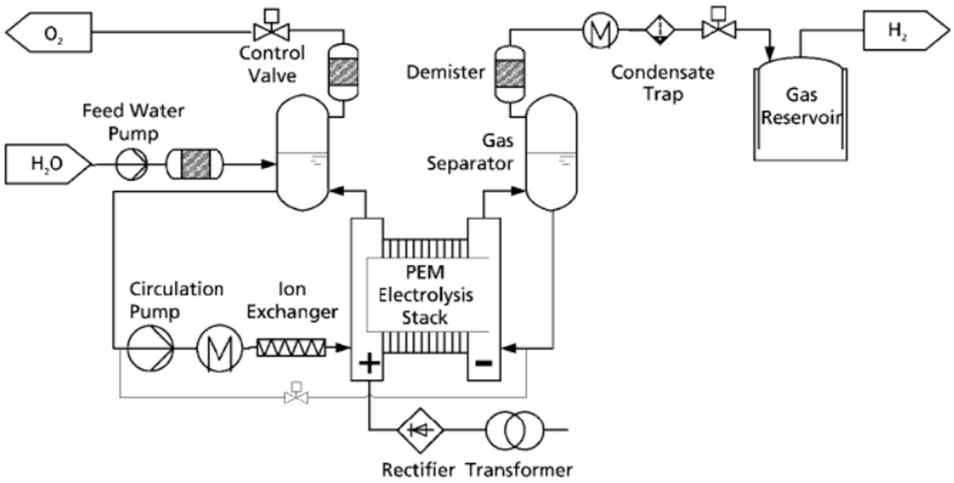


Figure 4.3. Layout of a PEM electrolysis system [9]

In this research, Bottler and Spliethoff, did a comparison of different technologies:

Nominal and part-load performance Rated efficiency and specific energy consumption of commercial electrolysis stacks are in the range of $63-71\%_{\mathrm{LHV}}$ and $4.2-4.8\mathrm{kWh/Nm^3}$ for AEL, and $60-68\%_{\mathrm{LHV}}$ and $4.4-5.0\mathrm{kWh/Nm^3}$ for PEMEL. Given specific energy consumption of electrolysis systems (including rectifier and utilities, excluding external compression) are in the range of $5.0-5.9\mathrm{kWh/Nm^3}$ ($\eta_{\mathrm{LHV}}=51-60\%$) for AEL and $5.0-6.5\mathrm{kWh/Nm^3}$ ($\eta_{\mathrm{LHV}}=46-60\%$) for PEMEL. However, the rated specific energy consumption is only meaningful in combination with the current density. Additionally, the decrease in performance over lifetime must be taken into account.

Pressurized operation Hydrogen is usually stored or utilized at high pressure. Liquid compression of water is more efficient than compression of the gaseous products [51] and pressure has only a minor impact on electrolyser performance. Ayers *et al.* [52] report that increasing the pressure from 14 bar to 165 bar results in an increase in cell voltage of less than 50 mV (approx. 0.1 $\mathrm{kWh/Nm^3}$). Based on these experiments, they calculated that electrochemical compression via PEMEL up to 70 bar followed by mechanical compression is energetically optimal for a delivery pressure of 350 bar. But, high pressure electrolyser require additional safety devices and result in higher investment costs and complexity of the electrolyser [53]. As a result, the standard pressure of commercial AEL and PEMEL is below $30-50$ bar in most cases.

Table 4.1. Summary of parameters of state-of-the-art of water electrolysis technologies.

	AEL	PEMEL
Operating parameters		
Cell temperature (°C)	60 – 90	50 – 80
Typical pressure (bar)	10 – 30	20 – 50
Current density (A/cm^2)	0.25 – 0.45	1.0 – 2.0
Flexibility		
Load flexibility (% of nominal load)	20 – 100	0 – 100
Cold start-up time	1 – 2h	5 – 10min
Warm start-up time	1 – 5min	< 10s
Efficinecy		
Nominal stack efficiency (LHV)	63 – 71%	60 – 68%
Specific energy consumption (kWh/Nm^3)	4.2 – 4.8	4.4 – 5.0
Nominal system efficiency (LHV)	51 – 60%	46 – 60%
Specific energy consumption (kWh/Nm^3)	5.0 – 5.9	5.0 – 6.5
Available capacity		
Max. nominal power per stack (MW)	6	2
H_2 production per stack ($Nm3/h$)	1400	400
Cell area (m^2)	< 3.6	< 0.13
Durability		
Life time (kh)	55 – 120	60 – 100
Efficiency degradation (% /a)	0.25 – 1.5	0.5 – 2.5
Economic parameter		
Investment costs (€/kW)	800 – 1500	1400 – 2100
Maintenance costs (% of investment costs per year)	2 – 3	3 – 5

4.2 Domenech *et al.*, 2020

In this study Domenech *et al.* [12] studied which electrolysis technology presents the best prospects of applicability in the short term by conducting a multicriteria comparison, where economic, environmental and social factors have been selected. In this study multicriteria decision-making methods were used to simplify the analysis. Because the analysis is inherently complex, due to the different nature of the involved factors. Domenech *et al.* also noted that to avoid various types of inconsistencies that may result from such methods, five different multicriteria decision-making methods have been employed. The combination of these methods enables checking the ranking consistency and its robustness, giving a higher reliability to the results.

Electrolysis technologies are often classified in the literature regarding the electrolyte they use. The following technologies are the most common ones capable of performing electrolysis at sea [54]:

- Direct Electrolysis of Seawater (DES),
- Alkaline Electrolysis (AE),
- Proton Exchange Membrane Electrolysis (PEME),
- Solid Oxide Electrolysis (SOE),

Fig. 4.4 depicts a simplified block diagram of these electrolysis technologies capable of producing hydrogen in an offshore application. The different inputs to the different electrolysis technologies are depicted, along with the expected simplified outputs.

The reactions that happen inside a PEME cell are the following:

Anode: $\mathrm{H_2O_{(l)}} \longrightarrow \frac{1}{2}\,\mathrm{O_{2(g)}} + 2\,\mathrm{H_{(aq.)}}^{+} + 2\,\mathrm{e}^{-}$

Cathode: $2\,\mathrm{H_{(aq.)}}^{+} + 2\,\mathrm{e}^{-} \longrightarrow \mathrm{H_{2(g)}}$

Overall: $\mathrm{H_2O_{(l)}} \longrightarrow \frac{1}{2}\,\mathrm{O_{2(g)}} + \mathrm{H_{2(g)}}$

The feed that is used in a PEME is liquid water. This technology features a solid polymer as an electrolyte, with a high proton conductivity [11]. It features high modularity and compactness, thanks to its zero-gap architecture. The zero-gap concept is possible thanks to the Membrane-Electrode Assembly (MEA), a single piece that unites all needed elements of a single cell in a three-layer sandwich. For this reason, PEME requires very precise machining of the bipolar plates to ensure a homogeneous contact between them and the porous electrodes. On one hand, this feature and the MEA components, make PEME more expensive than the other alternatives. On the other hand, the MEA requires no maintenance throughout the life cycle of the electrolyzer, which nowadays can go up to 100,000 h when using ultra-pure water as feed [11], but presents a slightly higher degradation rate than AE. Therefore, the efficiency that sets lifetime of PEME is lower than the one of AE. PEME can operate under pressure, typically at 30 bar, thus, offering energy savings in subsequent compression stages of the produced hydrogen. Their current densities are around 1000 mA/cm^2 for single cell voltages that range from 1.7 V to 1.8 V, at temperatures between 60°C and 80°C. PEME is the most sensitive technology to the presence of impurities. Regarding investment and maintenance costs, prediction bands for the following years set the investment cost from 600 to 1300 €/kW. Current estimations of O& M costs range between 3 and 5 % per year [11].

Table 4.2. Summary of attributes of the electrolysis technologies[12].

Criteria	Grading rule	DES	AE	PEME	SOE
Investment	Cheaper is better	> 6000 $ /kW	500-1000 $ /kW	600-1300 $ /kW	> 2000 $ /kW
Maintenance	Cheaper is better	> 240 $ /kW/y	10-60 $ /kW/y	18-60 $ /kW/y	> 65 $ /kW/y
Lifetime	Longer is better	10,000 h	100,000 h	100,000 h	10,000 h
Resilience	More is better	Acceptable	Very good	Very bad	Very good
Energy	Less is better	440 MJ/kg @350bar	170 MJ/kg @350bar	170 MJ/kg @350bar	135 MJ/kg @350bar
Dynamics	Faster is better	Fast	Fast	Very Fast	Slow
Environment	Lower risk/degree of impact is better	Very High (Chlorine and very caustic brine)	Medium (Very caustic electrolyte, small chance)	Low	Low
Hazard	Less hazardous is better	Very High (Chlorine and very caustic brine)	Medium (Very caustic electrolyte, small chance)	Very Low	Medium (Superheated steam, small chance)

The goal of this study by Domenech *et al.* was to answer the question: "What is the best electrolysis technology for producing hydrogen from seawater and marine renewable energies in a sustainable manner?". To answer that question, a list of criteria involving social, environmental, and economic factors have been considered. The economic factor involved the investment cost, the operation and maintenance cost, nominal lifetime, resistance to impurities, specific energy for hydrogen production at sea and swiftness of response to sudden power changes as criteria. The environmental and social factors involved only one criterion each, namely, the risk of environmental impact and the risk of harm or injury, respectively. All the MCDM methods agree on the ranking of all technologies, being the best option PEME, then AE, followed by SOE, thus, rendering DES as the worst possible option.

Regarding the prioritization of criteria, the factor with highest weight value after performing the priority assignment was the economic, which involved six criteria. However, the single criterion with the highest weight value corresponded equally to both the social and environmental factors.

With regard to the ranking obtained by the analysis, the AE had the best performance regarding the economic related criteria. However, it scored poorly in the social and environmental criteria, as the potential leaks of very caustic electrolyte imply a great risk for workers and the environment. Contrarily, PEM technology had the best performance in the social and environmental criteria, while scoring fairly well in the economic related criteria. It is for this reason that PEM overall presents the best score with the current state of technology.

The difference in the final score between AE and PEME, according to some of the MCDM methods used, is quite narrow, meaning that both technologies may play an important role in the production of hydrogen at sea using energy from marine renewable farms. Probably, if developments in technology improves AE safety and makes it less risky at sea, it has the potential to become the undiscussed technology for this application, since it is the cheapest option and it presents the best prospects of achieving the longest lifespan at sea, as it does not suffer irreversible damage from impurities in feed water and presents the longest nominal lifetime.

4.3 Domenech and Leo, 2019

Domenech and Leo [10] carried out a techno-economic analysis on different seawater electrolysis technologies. In this study, they reviewed all the technologies capable of performing electrolysis at sea environment. The review includes a thorough description and explanation of all known possible damages to the different electrolysis technologies caused by the impurities that may be present in water sourcing from the sea. Also, this work studies three different hypothetical plants based on the reviewed technologies, to produce hydrogen at 350 bar for its transportation in compressed state. In this study, the energetic and environmental aspects of the technologies are compared.

The authors consider the main challenges for an electrolysis plant in an offshore environment to be the high variability in energy production inherent to renewables, motion in floating platforms, and also the lack of availability of fresh water. In this context, even though there are already existing technologies capable of performing seawater electrolysis, it is yet unclear which one is the fittest for being coupled with a marine renewable farm in an offshore situation.

Hydrogen production plants at sea will not only have to produce hydrogen but also will have to increase its density for its exportation. Three possible physical transformations are possible to increase its density: compression, liquefaction, and cryo-compression. The first two options, compressed and liquid, offer the best prospects of application in the maritime sector. Depending on the application, one option will be better than the other. In this regard, equivalent studies performed on natural gas revealed that, for short distances and small quantities, compressed natural gas (CNG) shipping is cheaper than the liquefied natural gas (LNG) alternative [55] [56].

In this paper they assess the different technologies available for electrolysis. Fig. 4.5 shows these technologies.

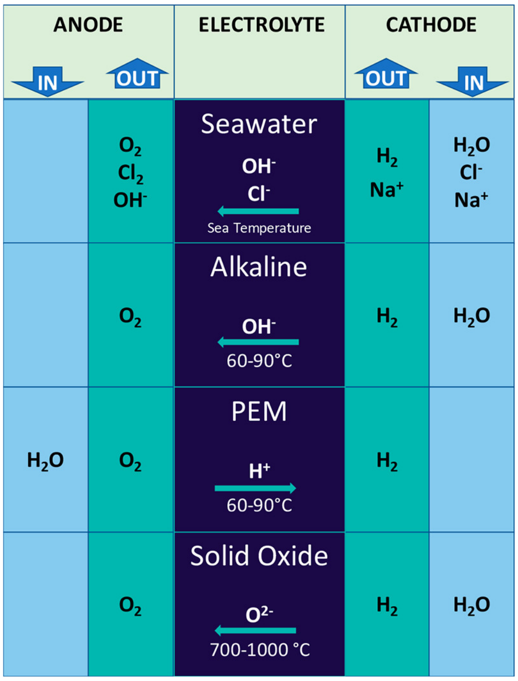


Figure 4.5. Electrolytes capable of performing the electrolysis reaction for hydrogen production at sea. [10]

Both PEM and Alkaline electrolysis are studied together as low-temperature electrolysis technologies due to their similarities. Alkaline electrolysis is one of the preferred methods of electrolysis for land-based hydrogen production. The reasons that make this technology one of the most appealing for onshore stationary applications are that there is no need for expensive catalyst and that they use relatively inexpensive materials as electrodes [57]. But above all, with the correct maintenance, their lifespan can surpass 100,000 hours.

The known problems of alkaline technology that restrain its application at sea are the risk of leakage of the corrosive electrolyte and the need for its periodic renewal [54].

PEM electrolysis technology allows a type of architecture known as zero-gap in the literature. However this technology is relatively expensive, they are very attractive since their electrolyte is maintenance-free throughout their life cycle, which nowadays can go from 25,000 h and in some cases surpass 90,000 h. PEM electrolyzers can operate under pressure, typically at 30 bar, so that energy is saved in subsequent stages of hydrogen compression.

When it comes to electrolysis, in contrast to direct electrolysis of seawater, the feed of the low-temperature electrolyzers must be pure water. In this regard, the separation of seawater into fresh water and brine is considered in the plant. Even though reverse osmosis might be more appealing than distillation from an energetic point of view, distillation methods produce water of higher purity than reverse osmosis. In addition, they do not necessarily require pre-treatment [58]. Therefore, for offshore application, distillation is preferred in plant designs. Distillation can be attained at ambient pressure and a temperature around 100°C , or at lower temperatures at partial vacuum pressures.

Ohmic heating is the simplest way to produce heating necessary for the distillation. However, vapor-recompression mechanisms are chosen, because they offer energy savings under steady-state operation of distillers. Their working principle consists in using the vapor from the distillation as the only heat source for the distillation. To achieve this, the produced vapor must be compressed to raise its condensing temperature over the one of boiling seawater. This way, if the system is correctly designed, at steady state, the only electrical consumer for the production of distilled water is the vapor compressor. Therefore, this type of mechanism is the chosen one for the operation of the plant, whereas ohmic heating is left as a backup for transient states. Figure 4 shows a simplified diagram of the low-temperature electrolysis plant that applies to PEM and alkaline technologies.

As it was discussed in the list of suitable electrolysis mechanisms, one of the advantages of the two technologies of low-temperature electrolysis, is that they are capable of working under pressure. The operating pressure of 30 bar is chosen since it is the most common pressure among commercial pressurized electrolyzers.

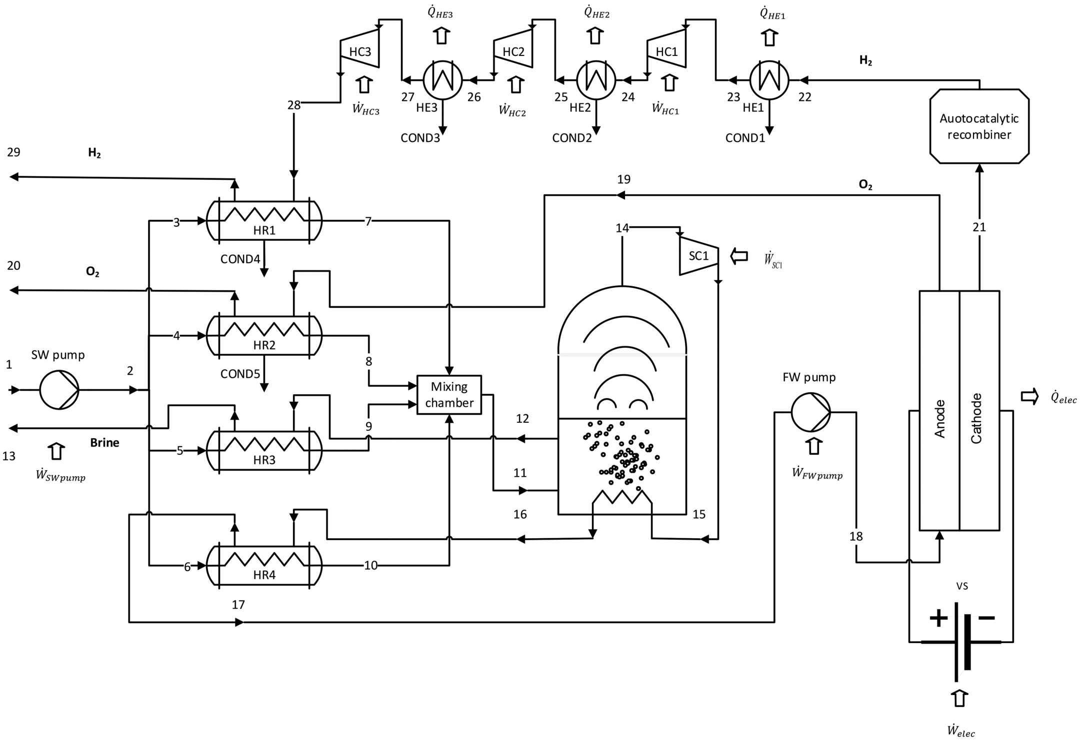


Figure 4.6. Simplified diagram of the low-temperature electrolysis plant. COND is condensate; FW is fresh water; HC is hydrogen compressor; HE is heat exchanger; HR is heat recovery; SC is steam compressor; SW is seawater; VS is voltage source. [10]

Following the diagram shown in Fig. 4.6, Fig. 4.7 summarizes the mass ratios of the cathodic stream compounds, referenced to the output of pure hydrogen. There, it can be checked that after leaving the electrolyzer at 21, the stream holds some impurities. After the purification and compression steps, in 29, the volumetric purity of hydrogen is above 99.99%, and water vapor is the only impurity.

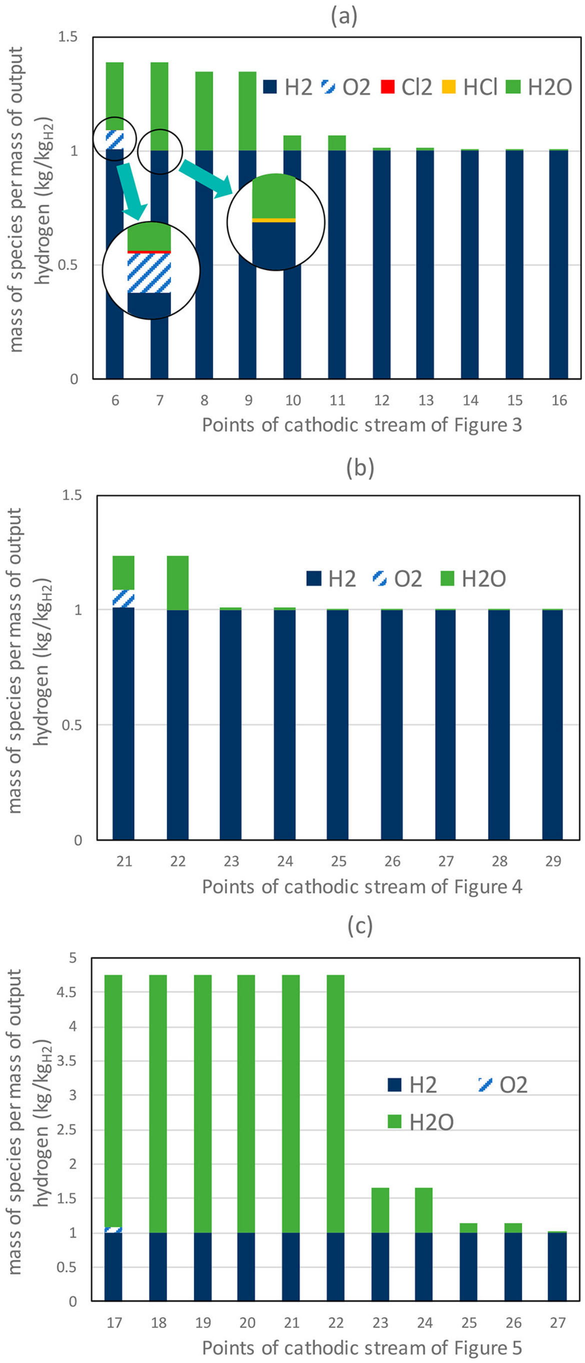


Figure 4.7. Mass ratio results of the cathodic stream of the different hypothetic plants, shown in Figures 3-5, referenced to the output of pure hydrogen. (a) Direct seawater electrolysis, (b) low-temperature electrolysis and (c) high-temperature electrolysis. [10]

Regarding the energy consumption of low-temperature technologies, part (b) of Fig. 4.8 shows the power consumption of the different consumers of the plant. There, it can be noted that almost 97% of the plant consumption accounts for the electrolyzer. In this case, the total energy for compressing the hydrogen is reduced to 4.87 MJ/kgH2. Such figure proves the benefits of having the electrolyzer operating under pressure. Under this scheme, the heat delivered by the electrolyzer is 26.5 MJ/kgH2, when operating at 76.3°C.

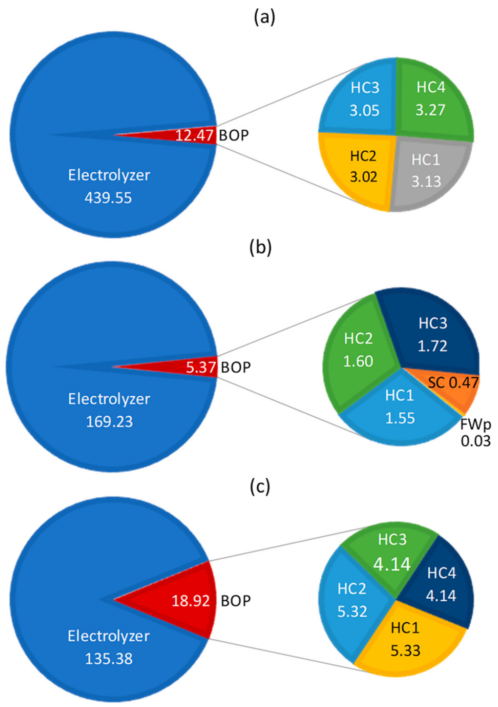


Figure 4.8. Energy balance of the different hypothetical plants. (a) Direct seawater electrolysis, (b) low-temperature electrolysis and (c) high-temperature electrolysis. All the figures are expressed in *MJ/kgH2*. BOP stands for Balance of Plant, HC for hydrogen compressor, FWp for Fresh Water Pump and SC for Steam Compressor. [10]

In this study, they also noted that even though further research is needed, low-temperature electrolysis, namely PEM or alkaline technologies, seems to be fitter for most scenarios of green hydrogen production at sea, when coupled with marine renewable energies.

4.4 Babarit *et al.*, 2018

In this study [59], Babarit *et al.* studied hydrogen as one of the most promising solutions for harvesting offshore renewables. Considering also the fact that it is challenging to store and transport hydrogen which may have a critical impact on the delivered hydrogen cost. In this paper, it is shown that there are vast areas far offshore where wind power is both characterized by high winds and limited seasonal variations. Capturing a fraction of this energy could provide enough energy to cover the forecast global energy demand for 2050. Therefore, they proposed different scenarios for the exploitation of this resource by fleets of hydrogen-producing wind energy converters sailing autonomously. The scenarios include transportation and distribution of the produced hydrogen, in a short-term view (say 2025-2030), and a longer term one (say 2035-2040). Half of the scenarios involve liquid hydrogen (LH2) whereas the other half involve compressed hydrogen (CGH2).

Although the compressed hydrogen (CGH2) scenarios have the best energy efficiency (up to 62% in the longer term), it is found that the cost estimates are close between the LH2 scenarios and the CGH2 scenarios. In the shorter term, delivered cost estimates are in the range 6.6-8.8 €/kg depending on the option and the delivery. In the longer term, the cost estimates could reduce to 3.3-5.5 €/kg. Although the cost estimates are close between the options, it is believed that the LH2 scenarios are the most promising in the longer term because of slightly smaller costs and much greater flexibility for delivery.

The produced hydrogen could be competitive on the higher price markets in the longer term (light industry, isolated consumers). For the large volume low price (oil processing, ammonia production, injection on gas grids), support mechanisms such as the carbon tax are likely to be required unless further cost reductions can be achieved. Assuming that the longer term cost estimates can be realized and without further cost reductions, a carbon tax of 200 €/kg would be required for competitiveness on these large industry high GHG emissions markets.

4.5 Electrolysis for the present work

In the present chapter different possibilities for water electrolysis have been discussed. After comparing these technologies as possible candidate for OffLH2 project and considering different factors represented in this chapter, Proton Exchange Membrane (PEM) has been chosen as the technology that should be used. However, it has to be mentioned that among different technologies available for seawater electrolysis, considering different factors involved in deciding on which technology to use, the advantage of PEM electrolyzer is its lower environmental hazard, specially in an offshore environment.

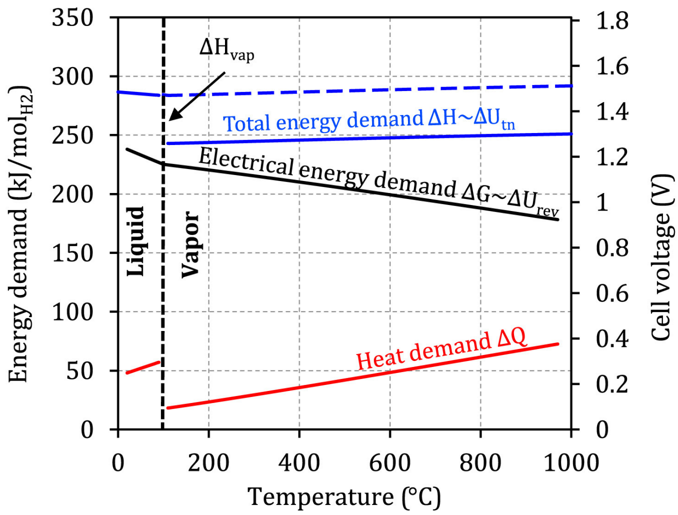


Figure 4.1. Total (ΔH), thermal (Q) and electrical (ΔG) energy demand of an ideal electrolysis process as function of the temperature [11].

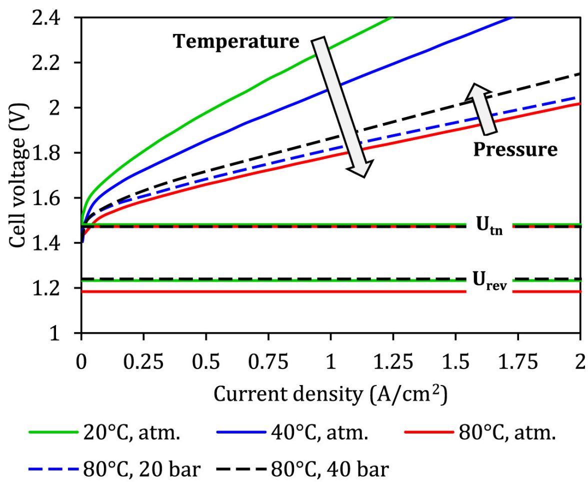


Figure 4.2. Influence of temperature and pressure on the characteristic I-U-curve of a PEM electrolysis cell [11].

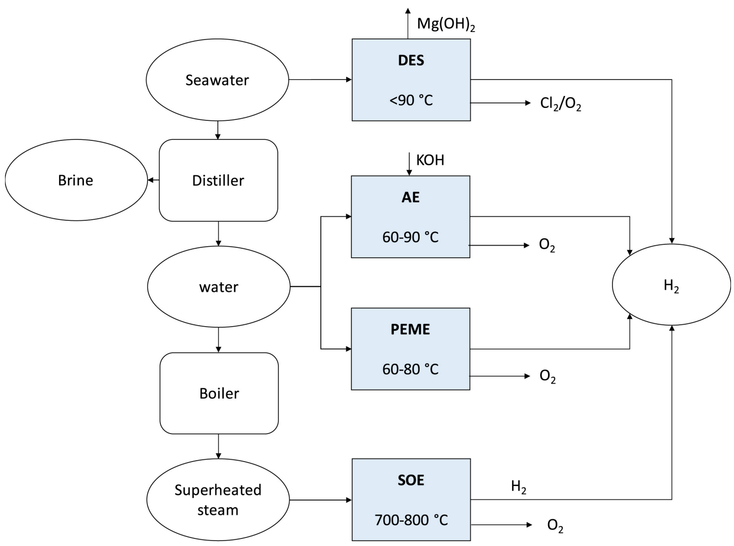


Figure 4.4. Block diagram of different electrolysis technologies applied to a marine context. DES: Direct Electrolysis of Seawater; AE: Alkaline Electrolysis; PEME: Proton Exchange Membrane Electrolysis; SOE: Solid Oxide Electrolysis. [12]

Chapter 5

Hydrogen liquefaction and storage

As it was discussed earlier, the objective of the OffLH2 project is to produce hydrogen to be used in naval sector as a green fuel. A major drawback of hydrogen is its low volumetric energy density. Therefore, hydrogen must be stored and sold to the naval sector in form of liquefied hydrogen. Although hydrogen liquefaction is an energy intensive process, it is a solution to reach to a volumetric energy density as high as possible. This chapter is devoted to assess hydrogen liquefaction and also storage of liquid hydrogen, both in terms of its technological and economical aspect.

5.1 Cardella *et al.*, 2017

In this study [13], Cardella *et al.* presented a roadmap for the scale-up of hydrogen liquefaction technology, from state-of-the-art plants to newly developed large-scale liquefaction processes. The work is aimed at reducing the specific liquefaction costs by finding an optimal trade-off between capital costs and operating costs.

Distributing and storing hydrogen as a cryogenic liquid offers several advantages compared to compressed gas H_2 (CGH_2). Because of the significantly higher volumetric density of liquid hydrogen (LH2), the transportable load per LH2 trailer is significantly higher than in a CGH2 trailer [60], bringing down transport cost and trailer frequency at the station. Compared to CGH2, the delivery of LH2 becomes increasingly cost-efficient for larger transport volumes and over longer transport distances [60], as required by hydrogen mobility. Further on, the liquid hydrogen comes in guaranteed clean condition as any impurity will be frozen out in the liquefier plant.

Liquid hydrogen is produced by the cooling, expansion and the liquefaction of an expanded gaseous hydrogen feed gas stream from ambient conditions to a temperature of about 20 K. The hydrogen cooling in built industrial hydrogen liquefaction processes is typically performed in two refrigeration steps. For the hydrogen precooling to an intermediate temperature of about 80 K, a liquid nitrogen (LN2) stream is used. For the cryogenic hydrogen cooling between 80 K and a liquefaction temperature of about 20 K, only helium and hydrogen are available as pure refrigerant fluids for a cryogenic refrigeration cycle [23]. A further challenge of industrial hydrogen liquefiers is the required catalytic ortho-to para-hydrogen conversion [23].

The relatively low exergy efficiency of installed hydrogen liquefaction plants is the main draw back of an LH2 supply infrastructure. The specific energy consumption SEC of a state-of-the-art 5 tpd LH2 hydrogen liquefier with LN2 precooling is about 10 kWh per kg LH2 [61]. The future hydrogen mobility market will ask for large-scale hydrogen liquefaction plants with a significant improvement in exergy efficiency.

The exergy efficiency of the hydrogen liquefaction process must be increased in order to decrease electricity costs, which are part of the plant variable operating costs (OPEX). The liquefier exergy efficiency is defined as the ratio between the specific work for an ideal hydrogen liquefaction process w_{ideal} and the real specific energy consumed by the process w_{real}. It is expressed as exergy efficiency in equation:

$$\eta_{ex} = \frac{w_{\text{ideal}}}{w_{\text{real}}} = \frac{(h_{Product} - h_{Feed}) - T_0 * (s_{Product} - s_{Feed})}{w_{\text{real}}} \tag{5.1}$$

The minimum required theoretical liquefaction work w_{ideal} is equal to the difference in specific exergy between the liquid product state and the inlet feed gas. It is calculated with the specific enthalpy h and the specific entropy s of the feed and the liquid product. The work required for an ideal hydrogen liquefaction process is calculated to 2.7 kWh per kg LH2 for an inlet hydrogen feed gas pressure of 25 bar, an inlet temperature of 303 K and an inlet para-hydrogen fraction of 25%. The liquid hydrogen product is assumed as saturated liquid with a pressure of 2 bar and a final para-hydrogen fraction of 98% at the outlet. In this paper, all given pressure values are absolute. The work for an ideal hydrogen liquefaction increases by over 40% to 3.8 kWh per kg LH2 if the feed is available at ambient pressure.

Built liquefiers can be categorized into processes based either on a helium Brayton cycle or a hydrogen Claude cycle, just by referring to the type of closed loop cryogenic refrigeration cycle [62]. The process is typically chosen in function of plant capacity as well as economic boundary conditions such as plant location and electricity prices. Liquid nitrogen (LN2) is often used for a precooling of the hydrogen feed gas to approximately 80 K. The benefit of LN2 precooling is the low capital expenditure compared to a closed cycle,

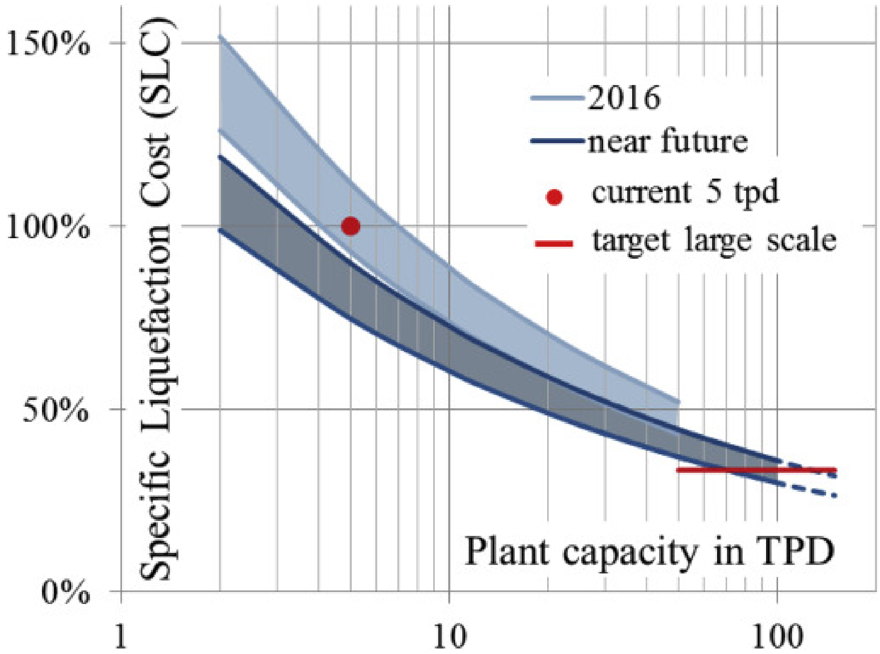


Figure 5.1. Calculated range of specific hydrogen liquefaction costs in function of plant capacity, boundary conditions and technological readiness. [13]

since no additional expander or compressor is required [62, 23]. These conventional hydrogen liquefaction processes are energy intensive. The availability of performance data of industrial liquefiers is, however, very limited. The specific energy consumption SEC of liquefier trains operated in the USA is stated to range between 12.5 and 15 kWh per kg LH2 for capacities between 5.4 and 32 tpd LH2 [63].

5.2 Moradi and Groth, 2019

Moradi and Groth [36] analyzed safety and reliability of hydrogen infrastructure in this work. They also noted in their work that ,despite the higher energy loss of hydrogen delivery in liquid state, this method is considered to be economical for high demands (above 500 kg/day) and mid range distances . Cryogenic hydrogen delivery consists of three main stages: liquifaction, storage, and transportation with cryogenic tanks to the end users. If liquid hydrogen is to become the future delivery path, to supply the future hydrogen market with the proper amounts of hydrogen, more liquefaction plants with higher production rates, less specific energy consumption (up to 40% reduction is required to meet the target value of 6 kwh/kg of liquid hydrogen), lower capital cost, and higher efficiency is required.

5.3 Zhang *et al.*, 2014

Hydrogen storage is one of the major challenges in the development of hydrogen as a fuel for widespread applications. The two traditional and well-established techniques for hydrogen storage are based on high pressure compression or low temperature liquefaction.

The energy stored in hydrogen or other fuels can be expressed either on a weight basis (mass energy density or gravimetric capacity) or on a volume basis (volumetric energy density or volumetric capacity).

When hydrogen reacts with oxygen, water (vapor or liquid) is formed and energy is released,

$$\mathrm{H_2} + \frac{1}{2}\,\mathrm{O_2} \longrightarrow \mathrm{H_2O} \tag{5.2}$$

$\Delta H = 241.826kJ/mol$ (lower heating value). Thus, if 1 mol of hydrogen is burned with 100% energy conversion efficiency, 241.826 kJ of energy should be released. Since the molar mass of hydrogen is $M = 2.02 * 10^{-3}kg/mol$, the mass energy density of pure hydrogen is

$$\rho_M^0 = \frac{\Delta H}{M} = 119.716MJ/kg. \tag{5.3}$$

At 1 atm and 298.15 K ($25°C$), the volume occupied by 1 mole of H_2 is $VM = 24.46L$, and the volumetric energy density of H_2 is

$$\rho_V = \frac{\Delta H}{V_M} = 9.89MJ/m^3. \tag{5.4}$$

In fact, hydrogen has the highest mass energy density among all the chemical fuels, but almost the lowest volumetric energy density beside wood. Taken gasoline for example, its mass energy density is $45.7MJ/kg$ and volumetric energy density is $34,600MJ/m^3$. Although gasoline has smaller mass energy density, it has the highest volumetric energy density that makes it really useful. Therefore, one critical issue in using hydrogen is to find new methods to improve the volumetric energy density of hydrogen while keeping the mass energy density high.

One of the easiest ways to increase the volumetric energy density is to compress the hydrogen or to liquefy hydrogen at low temperature. Liquid hydrogen has a mass density of $70.8\dfrac{kg}{m^3}$ (at −253°C). This gives a volumetric energy density of $8.495{*}103\dfrac{MJ}{m^3}$, which is about 860 times higher than that of hydrogen gas at ambient conditions. This storage method is based on changing the physical state of hydrogen, and usually requires extra accessories, such as robust containers, valves, regulators, piping, mounting brackets, insulation, added cooling capacity, and thermal management components.

For hydrogen storage system, the mass of the energy storage system not only includes the mass of hydrogen, but also should account for mass of containers or storage materials, m_s. Thus, the effective mass energy density ρ_M of a hydrogen storage system can be expressed as

$$\rho_M = \frac{\Delta H}{m_H + m_s} * \frac{m_H}{M} = \frac{\Delta H}{M} * \frac{m_H}{m_H + m_s} = \frac{m_H}{m_H + m_s} * \rho_M^0 \qquad (5.5)$$

Since ρ_M^0 is a constant, the effective mass energy density is proportional to the hydrogen's mass percentage ($\frac{m_H}{m_H + m_s}$(%)), in the storage system or materials, which means for a hydrogen storage system or materials, the mass energy density is only a fraction of that in pure hydrogen. Therefore, one can use the hydrogen mass percentage to describe the gravimetric capacity of hydrogen storage systems. Similarly, the effective volumetric energy density ρ_V of a hydrogen storage system or material can be expressed as,

$$\rho_V = \frac{\Delta H}{V} * \frac{m_H}{M} = \frac{m_H}{V} * \rho_M^0, \qquad (5.6)$$

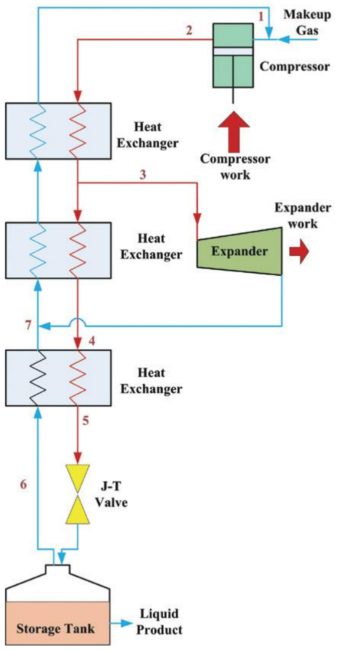
where V is the total volume of the storage system or materials. Thus, one can use the effective hydrogen density, $\rho_{V,eff}$ $(g * L^{-1})$

$$\rho_{V,eff} = \frac{m_H}{V}, \qquad (5.7)$$

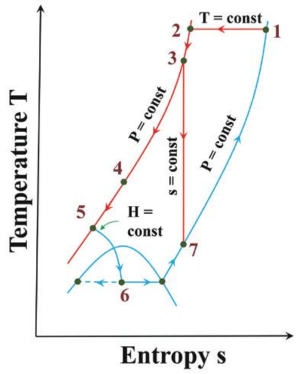
to describe the volumetric capacity of hydrogen storage systems.

Liquid hydrogen has a much higher volumetric capacity compared with gas hydrogen. However, liquid hydrogen only exists in a very narrow temperature and pressure range: between the triple point 13.8 K (at this temperature, gas, liquid, and solid phases coexist) and critical point 32.97 K (the heat of vaporization is zero at and beyond this temperature). Hydrogen has the second lowest boiling point (transition temperature from liquid to gas), 20.28 K, and melting point (transition temperature from solid to liquid), 14.01 K, of all substances, second only to helium. The boiling point is a critical parameter since it defines the temperature to be cooled in order to store and use the fuel as a liquid. Thus, liquid hydrogen requires cryogenic storage and boils around 20.28 K ($-252.87°$C).

The liquefaction process requires very clean hydrogen, several cycles of compression, liquid nitrogen or helium cooling, and expansion taking the advantage of the Joule − Thomson (JT) effect. Gases like H_2, He, whose inversion temperature is low, show heating effect at room temperature. However, if these gases are just cooled below the inversion temperature and then



(a) Schematic of a simple Claude cycle



(b) Temperature-entropy diagram of the simple Claude cycle

Figure 5.2. Claude cycle

subjected to JT effect, they will also undergo cooling. For H_2, the maximum JT inversion temperature is at 205 K (−68.15°C). Thus, hydrogen needs to be precooled to below this temperature. This can be done using cold or liquid nitrogen. Then, the gas is further expanded to cool down to the boiling point of hydrogen using a JT valve or a cryogenic turbine.

The simplest liquefaction process is the Linde cycle. But, the Claude cycle is a common method to liquefy high volume of hydrogen, as shown in Fig. 5.2. The Claude cycle combines the isentropic (Brayton cycle) and isenthalpic (Linde cycle) expansions, and both the heat exchangers and mechanical expanders are used to cool the compressed and precooled hydrogen below its inversion temperature. The gas is first compressed, and passed through the first heat exchanger. Between 60% and 80% of the gas is then deviated from the mainstream, expanded through an expander. Such an expansion process is isentropic and a much lower temperature is attained than from an isenthalpic expansion. The Claude cycle may be used without modification to liquefy hydrogen since the system does not primarily depend on the expansion valve to produce low temperatures. In addition, by using liquid nitrogen precooling with the Claude system, a figure of merit $50-70\%$ higher than that of the precooled Linde system may be obtained.

Liquid hydrogen needs to be stored in cryogenic vessels (or cryostats).

The cryostats are metallic double-walled vessels with insulation, sandwiched between the walls. In spite of the insulation, due to the unavoidable heat input, hydrogen will evaporate in the tank, which will cause the pressure rise in the vessel. Pressure build-up can be treated to be linearly proportional to storage time. Once the pressure reaches the maximum operation pressure of the tank, a blow-off valve has to be opened to release the hydrogen in order to maintain the safety of the system. The unexpected heat input could come externally or internally.

Hydrogen has two forms, the parahydrogen and orthohydrogen. These two forms of hydrogen not only have different internal energy, also have different thermal dynamic properties. The parahydrogen has lower melting and boiling points than those of the orthohydrogen. When hydrogen is cooled down, more orthohydrogen is converted to parahydrogen.

The ratio of orthohydrogen can be reduced from 75% at room temperature to 25% at 77 K, and can be further reduced to 0.2% when the hydrogen is cooled down to the boiling point (20.08 K). The conversion of orthohydrogen to parahydrogen is a heat-release process. As long as there are orthohydrogens in the cryostats, conversion of orthohydrogen to parahydrogen is inevitable, which will cause heating of the liquid hydrogen.

5.4 Asadnia-Mehrpooya, 2018

This study [14] gives a review on hydrogen liquefaction and the history behind it. Also reviews the technological advances in liquefaction of hydrogen, and economics of large scale hydrogen liquefaction.

Ortho-para conversion challenge within hydrogen liquefaction In 1912, a weird phenomenon was discovered during the experiments with hydrogen at low temperatures that knowledge of physics did not have an explanation for at that time [64]. Accordingly, while measuring heat capacities of hydrogen at cryogenic temperatures, a distinct hysteresis was observed comparing the cooling curve and the warming curve. In 1929, it was proved by experimental evidence that two spin isomers of hydrogen exist [65]. As can be seen in Fig. 5.3 , two proton nuclear spins are in the same direction in ortho-hydrogen and they are in the opposite direction in para-hydrogen. These two different directions of spins affect magnetic, optical, and thermal properties of the two isomers.

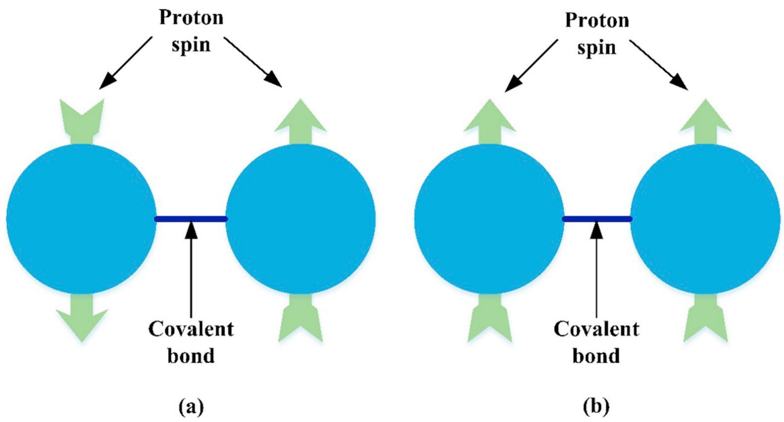


Figure 5.3. Spin isomers of molecular hydrogen. (a) para-hydrogen: anti-parallel nuclear spins with lower energy state, and (b) ortho-hydrogen: parallel nuclear spins with higher energy state. [14]

Ortho-para conversion challenge within hydrogen liquefaction Total rotational energy of the two spin isomers of molecular hydrogen are not same and the ortho-hydrogen structure is an excited state with a higher energy level than para-hydrogen [66]. Therefore, energy is released when ortho-hydrogen is converted to para-hydrogen. In addition, Fig. 5.4 depicts the equilibrium concentration of ortho and para hydrogen in the ideal gas state versus temperature. The effect of pressure on these equilibrium concentrations is considered to be negligible [67]. Para-hydrogen concentration decreases with temperature. Moreover, the equilibrium composition is almost pure para-hydrogen, near the boiling point. At the ambient temperature that is called normal hydrogen, it contains 75% orthohydrogen and 25% para-hydrogen.

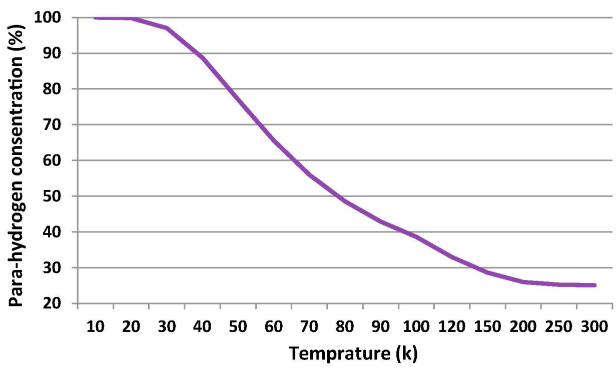


Figure 5.4. Equilibrium para-hydrogen concentration versus temperature. [15]

The necessity of o-p conversion in the hydrogen liquefaction processes Since the energy level of the ortho hydrogen is higher than para-hydrogen, spontaneous conversion of the ortho-hydrogen to para-hydrogen is always occurring to get the equilibrium concentration. However, such a fast conversion is exothermic and the generated heat is about 0.388 kcal/mol while latent heat of hydrogen evaporation is approximately 0.213 kcal/mol. Therefore, if stored liquid hydrogen contains ortho-hydrogen, some liquid hydrogen will be evaporated. This phenomenon is called "boil off" [68]. As the result, to minimize the evaporation in the storage tank of liquid hydrogen, the process of o-p conversion is essential and necessary for long time storage [69].

Simple cycles of hydrogen liquefaction Since 1895, recuperative cooling is practically employed in the gas liquefaction techniques [70]. Accordingly, it means using the liquefying fluid itself as the coolant in the system. Fig. 5.5 depicts the conceptual design of a simple Claude cycle, as a combination of the simple methodology of gas liquefaction, recuperative cooling, and expansion engine, which is the basis for all the large-scale hydrogen liquefaction plants in use, across the world, and the most other conventional liquefaction cycles [71]. In addition, Fig. 11 shows Temperature-Entropy or T-S diagram of the simple ideal Claude cycle with isothermal, isobaric, isentropic, and isenthalpic processes.

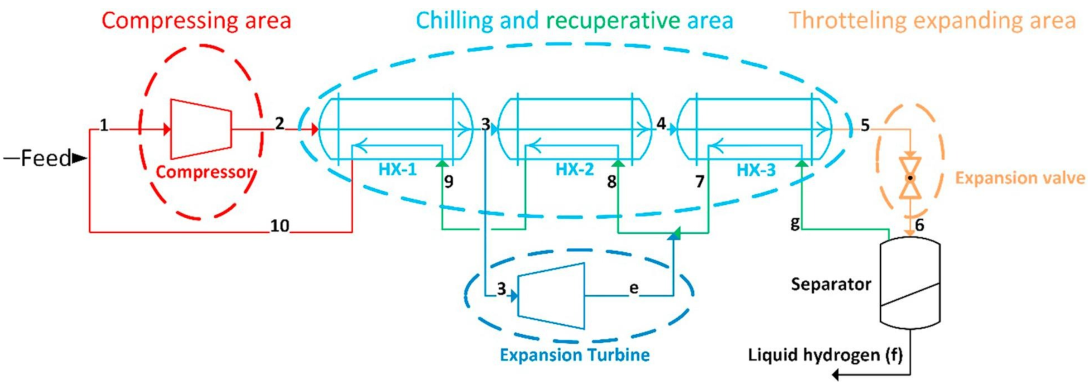


Figure 5.5. Conceptual design of the simple universal Claude cycle. [15]

In addition, Fig. 11 shows Temperature-Entropy or T-S diagram of the simple ideal Claude cycle with isothermal, isobaric, isentropic, and isenthalpic processes.

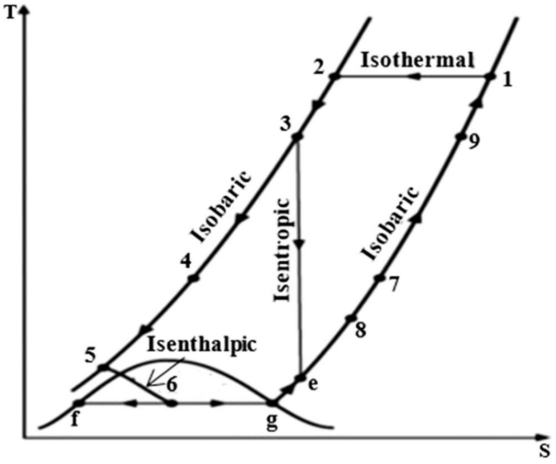


Figure 5.6. T-S diagram of the simple ideal Claude cycle.[16]

In hydrogen liquefaction plants, compressors and heat exchangers are introduced as the vital equipment. However, depending on the type of liquefaction plant, the contribution that these components have to the CAPEX will vary. Regarding the economics of the liquefaction plants, the correlation that has been reported for the CAPEX of a hydrogen liquefaction plant by Aasadnia *et. al* is as followed

$$CAPEX(€_{2000}/(kg/h)) = 828,313 * (\text{production rate})^{-0.48}. \tag{5.8}$$

5.5 Hydrogen liquefaction and storage for the present work

Hydrogen storage as compressed gas or liquefied hydrogen has been discussed in the present chapter. based on the discussions that have been represented, to increase the chances of green hydrogen to be adopted as green fuel in naval sector, it must be liquefied so that the density is increased as much as possible. Among different solutions for hydrogen liquefaction, a cycle must be adopted that does not require liquid nitrogen (LN_2)for precooling of the hydrogen flow and narrows the process down to Claude cycle for liquefaction.

Chapter 6

Platforms

This chapter is dedicated to the study of the platform. As a starting point for OffLH2 project, a study that has been performed in the Dutch shell has been used. In the study that Jepma carried out [18], following data were reported as the characteristics of the platforms which are of high importance also in the techno-economic analysis of the OffLH2, since the CAPEX related to the platform refurbishing is considerable when it compared to other contributions to the CAPEX. Also the platforms that are used in that study are adopted from oil and gas operations, too. In fact, the selected platforms are oil and gas platforms that are close to the end of their lifetime. As they are not going to be used for oil and gas extraction purposes any longer, they are going to be used for electro-chemical energy conversion. The platforms host electrolysis plants that are connected to wind farms producing electricity. Moreover, the wind farms are already in use and the electricity that is going to be used for the electrolysis of water are bought from these wind farms. In other words, the investment of the overall project does not include the CAPEX of the wind farm, but the cost of electricity is included in the OPEX of the project.

6.1 Oil and gas platforms in Dutch shell

In the selection of the platform situations to be analyzed, the aim was to consider two platforms, both on the Dutch continental shelf: one platform relatively close to shore, and another further away; one operational, and one non-operational platform; and one platform with a satellite character and one manned production platform. By this differentiation, it was hoped to get a better picture of the economics of offshore conversion, depending on the distance, operational use, and platform modalities. Also, because satellite platforms are usually smaller than manned production platforms, it was considered important to take this difference into account. For these reasons, and in close consultation with ENGIE, Jempa *et al.* the following platforms were selected.

G17d Consisting of the combination of an operational satellite platform (G17d-A) and a manned production platform (G17d-AP), not too far from the coast (85 km directly to shore, 121 km via gas pipelines to Noordgastransport near Eemshaven). G17d-A and -AP are connected via a bridge.

D18a A non-operational satellite platform, far from the coast (213 km directly to shore, 329 km via gas pipelines to Noordgastransport near Eemshaven). D18a is similar to G17d-A, but approximately 20% smaller.

6.1.1 Characteristics of platforms G17d-A and G17d-AP

- The satellite platform G17d-A is still operational (since 2005 and until mid-2020s). Moreover, the manned production platform G17d-AP will not be taken out of production until all satellites surrounding the production platform are taken out of operation. This implies that the production platform will at least be operational until 2025. An important implication is that it will not be easy to add substantial electrolyzer capacity to the platform, for reasons of space limitations.

- Both platforms are relatively near (less than 5 km) the potential wind farms Osters Bank 3 and 4 (450 MW each) and Ruyters West (260 MW). Although currently there are no concrete plans by the government for extension of the offshore wind capacity on this location, this may change in the future, also because wind conditions on this location seem to be rather favourable.

- Standard carrying weight 2,000 tonnes; the topside weight of the production platform (G17d-AP) is 2,450 tonnes. The jacket weight of the satellite (G17d-A) is 1,050 tonnes and top-sides weigh 1,310 tonnes. Water depth 38.7 m.

- Extension of the platform is possible (costs about €40/kg).

- Production platform dimensions (G17d-AP): 35 x 30 x 27 m; four levels.

- Decommissioning costs (including the jacket) are about €20 million.

- Current OPEX and maintenance per annum: €8.8 million.

6.1.2 Characteristics of platform D18a

- Wind farm (innovation park) still to be established (after 2020); max. distance from platform D18a: some 5 km.

- Unmanned satellite platform; no longer operational and for sale by 2016. This is one of the relatively young satellite platforms that consists of high-quality steel; therefore it has a relatively long remaining technical lifetime.

- Standard carrying weight: 1,000 tonnes.

- Platform dimensions: 27 x 15 x 20 m; three levels.

- In case of re-use, a new topside needs to be added, because that is a cheaper option than refurbishing the existing platform; also it allows for adapting height levels of the platform to the space requirements of the electrolysis technology and other necessary equipment.

- Current OPEX and maintenance costs per annum: €4 million.

- Decommissioning costs (including of the jacket): €6-8 million.

6.1.3 Assumptions regarding platforms

- For operational platforms, 10% of OPEX is assigned to energy conversion.

- Costs related to preparing a platform for installation of electrolysers: €10/kg

- Costs related to adding a complete new deck: €40/kg

Assumptions specifically for platform G17d

- OPEX of manned platform G17d if life is prolonged: €8,800,000/year.

- Weight of platforms G17d-A and G17d-AP: 3,200 tonnes

- Maximum electrolysis capacity to be installed: 250 MW (assuming Silyzer 300 electrolysers)

- Total costs of rebuilding platform decks, incl. design: €176,000,000

- Decommissioning costs: €20,000,000

Assumptions specifically for platform D18a

- OPEX of satellite platform D18 if life is prolonged: €4,000,000/year

- Weight of platform: 1,000 tonnes Maximum electrolysis capacity to be installed: 60 MW (assuming Silyzer 300 electrolysers)

- Total costs of rebuilding platform decks, incl. design: €40,000,000

- Decommissioning costs: €7,000,000

6.2 OffLH2 platform cost

In the end, it could be noticed that how important are the costs related to the platform. However with using an already existing platform, there will be considerable cost savings, but still it is an important portion of the investment cost in the context of the project. In OffLH2 study, since no specific platform has been selected at this stage, to be suitable for the purpose of refueling the ships, the requirement for a larger capacity is important. Therefore, a platform similar to what has been described above as platform G17-d will be a better choice.

For electricity production different scenarios are possible. The classical case is to connect the electricty of the offshore wind farm to the grid on the shore. The other option is to convert the electricity to the gas and transport it through the existing pipelines. In this case, lower costs are incurred than the classic case of all-electric power transmission. Typically hydrogen and possibly oxygen, but also syngases or methane, are the gases that are produced in this option.

In the project in the Dutch shell that Jepma *et al.* have studied, after the process of electrolysis and production of the gaseous hydrogen, the hydrogen is transported to the shore. This transportation takes place through the pipeline that already exists from the oil and gas operations to transport the CH_4 to the shore. An important difference between the application of the offshore platform in that project and OffLH2 is that the liquefied hydrogen that is produced in OffLH2 project has to be stored on the platform.

Regarding the economics of the platform, a 5% portion of the total CAPEX necessary to rebuild the G17-d platform is considered for refurbishing in the economic analysis of the OffLH2.

Chapter 7

Comprehensive model

In the previous chapters different possibilities were discussed and compared together in terms of technology and economics. Up until this chapter, the system that is going to be used in the OffLH2 has been identified. In this chapter, different steps of the techno-economic analysis of the OffLH2 are represented. Starting from, the possible location of the wind farm and plant, power production from the wind farm throughout a year, electrolysis of the water with the produced electricity, and finally, liquefaction of the produced hydrogen. After the technical assessment and obtaining the amount of liquefied hydrogen production in one year, two economical indexes are described to see how the feasibility and profitability of the OffLH2 project could be assessed. These economical indexes are the discounted payback period (DPB), and the Net Present Value (NPV).

7.1 Wind farm

OFFLH2 project is aiming at assessment of liquid hydrogen production from existing oil and gas platforms. More specifically, the platforms that are going to be put out of oil and gas activities in near future. In this project, the location of the platform is in Mediterranean Sea, between Sicily and Tunisia. This decision was based on the following. On one hand, the ship main routes in Mediterranean Sea. The location of the plant must be suitable for the ships so that they do not have to change their route to reach to the platform. In this way, also the shipping industry would be more likely to support this technology. Fig. 7.1 shows the ship routes in the Mediterranean Sea, and based on this map, it could be seen that the one of the points that sees a considerable number of ships passing through, is between Italy and Tunisia. On the other hand, the location that the platform and wind farm are going to be built, must have favorable wind intensity. Since as it was previously

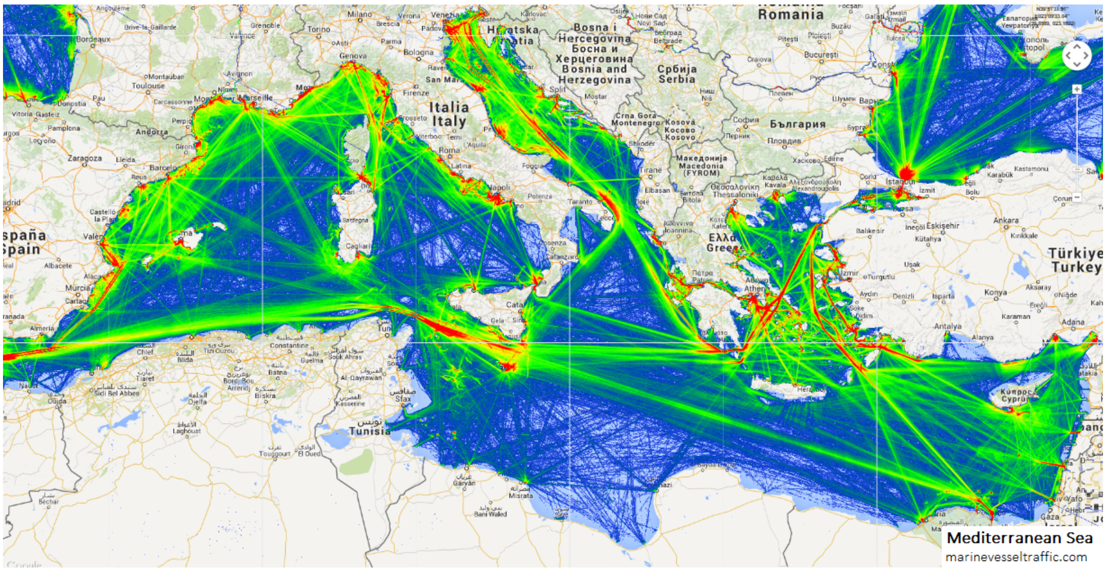


Figure 7.1. Main ship routes in Mediterranean Sea[17]

discussed, the electricity for the plant operation is coming from the offshore wind turbine farm located not far from the platform.

To calculate how much electricity could be produced from a wind farm located in an area between Sicily and Tunisia, the process starts from the wind profile of the site. As this is a prefeasibility assessment, at this stage the wind profile of the site is not known, to have a reasonable set of data as a starting point, another location with similar wind profiles to that of the OffLH2 site could be chosen.

The location that has been chosen as location with similar wind profile to that of the site location is Sciacca, Sicily. Sciacca is in the south-western shore of Sicily. The wind profile of the Sciacca for different years is accessible for public [72]. More importantly, the wind profile of Sciacca is available in an hourly level. Therefore, resulting in a higher precision in predicting the performance of the wind farm. In other words, how many hours the farm is working in its nominal condition, how many hours in its variable power part, and how many hours the wind speed is not high enough to produce power from the farm.

The hourly wind profile of the Sciacca is available at a height of 10 m above the ground level. The contours represented in the following figure, are used to have a comparison between the wind intensity at Sciacca and the platform located in the Mediterranean Sea. The assumption that is taken to obtain the hourly wind profile of the wind farm, is that the wind speed in the wind farm site, at a height of 10 m above sea level, is a 1.8 multiple of the wind speed profile of the Sciacca. With this assumption, the wind profile is available at a height of 10 m above sea level, but what is important in power production from the wind turbine, is the wind speed at turbine hub height. This is due to the fact that the assumption for calculation of the power output of the wind turbine was that the velocity profile of the wind does not change in the rotor area and the velocity at the hub could be used for power output calculation.

To obtain the wind speed at hub height, the method that is used, is to consider the effect of the sea roughness and viscous effects, which is lower in sea compared to wind profiles on the land and rural areas. With regard to Hsu *et al.* [25], the power-law exponent of 0.1 is a good choice to calculate wind profile at a higher height in an offshore site. The following formula shows how the wind profile at a higher height has been calculated

$$\frac{u_2}{u_1} = (\frac{z_2}{z_1})^P \tag{7.1}$$

in which u_2 (m/s) represents the wind speed at a height of z_2 (m), and u_1 (m/s)is the known wind speed at the reference height of z_1 (m). The exponent P (-)is a function of two factors; the roughness of the underlying surface and atmospheric stability in the layer [25].

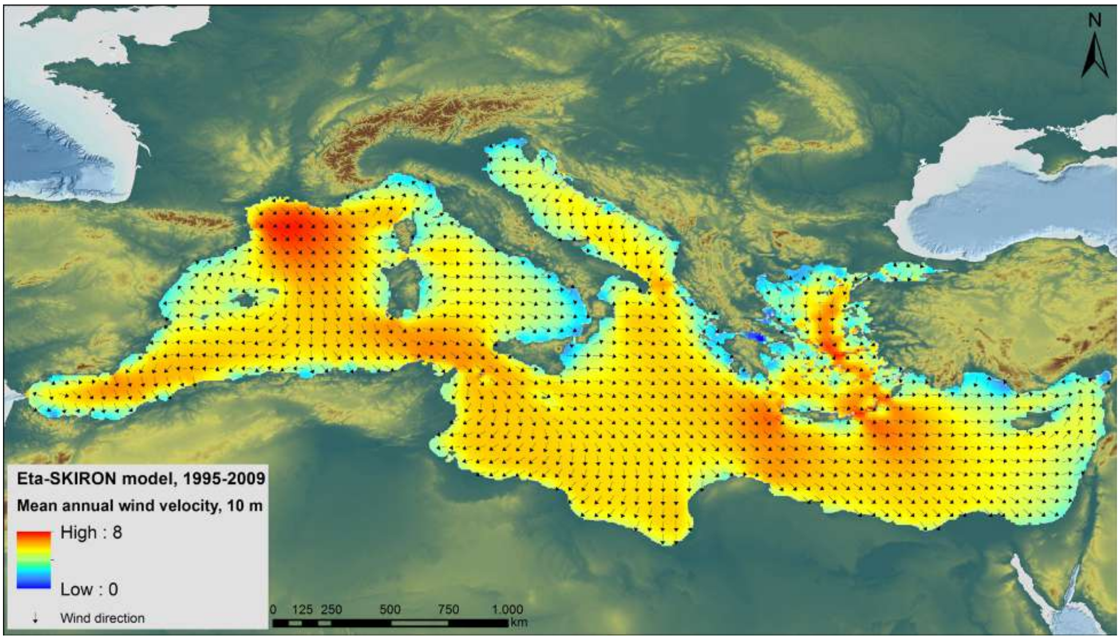


Figure 7.2. Mean annual wind speed (m/s) and direction for the Mediterranean Sea obtained from the Eta-SKIRON model (1995-2009)[18]

Using wind speed data, the power production from a wind turbine can be predicted by three approaches [40] : (i) fundamental equations of power available in the wind, (ii) presumed power curves of wind turbine, and (iii) actual power curves supplied by wind turbine manufacturers. The first approach is simply analytic but less accurate as most of the turbine physical and operational parameters are not possible to represent completely. These parameters include rotational speed, blade angle of attack and pitch angle, rated capacity, mechanical efficiency, generator efficiency, which are interdependent and also dependent on wind speed variation. The third approach is accurate for a specific wind turbine considered, however, detailed power curves would not necessarily be available at a preliminary stage or viability assessment.

The second approach is therefore what has been used in this paper, which requires few typical parameters of the wind turbine, namely the cut-in wind speed, v_{ci} (m/s), rated wind speed, v_r (m/s), and cut-out wind speed, v_{co} (m/s), rated power, P_r (MW), and rotor swept area, A_r (m^2) or diameter, D_r (m) [26]. These parameters can be adopted from a common wind turbine suitable to the wind condition at the offshore site. The power output of a wind turbine at varying wind speed v is calculated as

$$f(x) = \begin{cases} 0, & \text{if } v < v_{ci}. \\ P_f(v), & \text{if } v_{ci} < v < v_r. \\ p_r, & \text{if } v_r < v < v_{co}. \\ 0, & \text{if } v_{co} < v. \end{cases} \tag{7.2}$$

where $P_f(v)$ (W)is calculated as followed

$$P_f(v) = 0.5\rho A C_{tot} v^3 \tag{7.3}$$

In this equation, the term ρ (kg/m^3)is the air density at the hub height and C_{tot} is the overall efficiency coefficient (power coefficient) valued between 0.3 and 0.5, and varying with both wind speed and rotational speed of the turbine.

However the following assumptions are considered in this analysis:

1. Each turbine is assumed to use the same wind power curve.

2. The effects of wind shear, changes in air density, wake effects and turbulence caused by other turbines are not considered in the paper.

3. The availability of the wind farm is 95%. The availability of the wind farm indicates the proportion of time over which the wind farm can produce electrical energy, provided wind speeds are sufficient

With N being the number of turbines of the wind farm, the total power of production of the wind farm is calculated as followed

$$P_{farm}(t) = \sum_{i=1}^{N} P(t) \tag{7.4}$$

7.2 Plant

7.2.1 Electrolysis plant

To find out how much hydrogen can be produced from the plant at any given time, the ratio of the energy consumption of the electrolysis plant and the total energy consumption had been calculated. Two main consumers of the electricity on the platform are the electrolyzers and the liquefaction plant. Therefore, whenever the electricity production is high enough to run the electrolyzers, a fixed ratio of the electricity from the wind farm goes to the electrolysis plant. There are obviously other consumers in the plant, for example the energy required for seawater desalination and treatment so that it is possible to use it in the electrolyzer, but these two are the ones with highest energy consumption.

For any given size of the wind turbine, there is a specific value for the theoretical liquefied hydrogen, $W_{LH2,theory}$ (kg/h) that can be produced. Theoretical liquefied hydrogen is independent from the size of the electrolyzer and underlying assumption in its calculation is that no electricity is curtailed. The formula to calculate the theoretical hydrogen production is as follows

$$W_{LH2,theory} = \frac{P_{farm}(t)}{(E_{electrolysis} + E_{water} + E_{liquefaction}) * (1 + BOP)} \tag{7.5}$$

in which $P_{farm}(t)$ (MW) is the energy production of the wind farm, $E_{electrolysis}$(MWh/kg) is the energy required for electrolysis of one kg of hydrogen, E_{water} (MWh/kg) is the energy required to desalinate and treat water required to produce one kg of hydrogen, and $E_{liquefaction}$ (MWh/kg) is the energy required to liquefy one kg of hydrogen. BOP is a factor that takes into account the other energy requirements of the plant and stands for Balance Of Plant. In this formula, $E_{electrolysis}$ could be calculated from the efficiency of the electrolyzer, which is given by the manufacturer, and the energy content of a kilogram of hydrogen. The energy content of a kilogram of hydrogen could be stated in terms of lower heating value LHV_{H_2} or higher heating value HHV_{H_2} of hydrogen. LHV_{H_2} is the energy What is important to note in the application of the formula is that the definition of the efficiency must be consistent with the energy content that is used in the numerator of this formula. LHV_{H_2} that is used in this analysis because the efficiency that is used in this formula is based on the LHV_{H_2}.

$$E_{electrolysis} = \frac{LHV_{H_2}}{\eta_{electrolyzer}} \tag{7.6}$$

The electrolyzer that has been chosen in this analysis is SILYZER300 Siemens, which could be used for large-scale industrial applications. The technical data of the SILYZER300 are found in the appendix. These data have been used to model how much liquid hydrogen can be produced from the plant, and then stored to refuel the ships.

Regarding the performance of the electrolyzer, the dynamics of the electrolyzer must be taken into account. Below a certain level of power input, the electrolyzer has to be shut down, to make sure that the electrolyzer is working efficiently. This lower limit is given by the manufacturer of the electrolyzer. In this study, as SILYZER 300 is chosen, its lower limit from the data sheet is 5% of the nominal power of electrolyzer. Therefore, for any size of the electrolyzer in this study, 5% of the nominal size of the electrolysis plant is the lower limit for its operation. If the power production of the wind farm is below this limit, the electrolysis plant will not function.

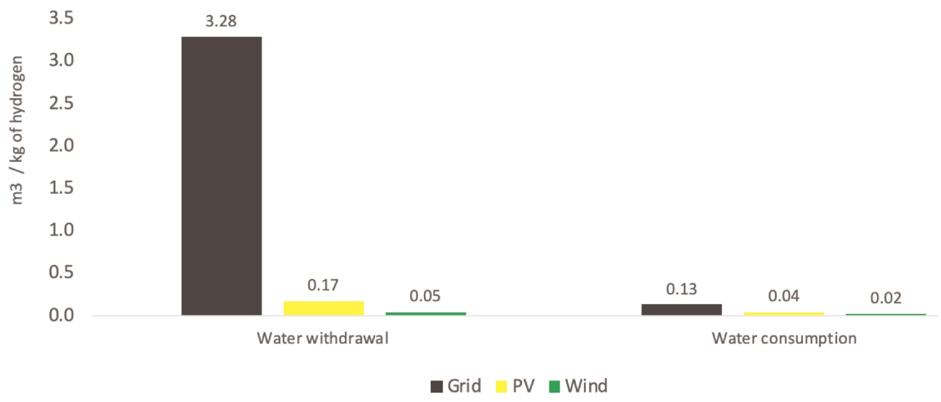
$$P_{min.load} = 0.05 P_{H_2} \tag{7.7}$$

Consequently, the practical hydrogen production $W_{LH2,practical}$ (kg/hour), from the electrlysis plant could be calculated from the following formula:

$$W_{LH2,practical} = \begin{cases} 0 & ,\text{if } P_{av} < P_{min.load}. \\ \dfrac{P_{av}}{E_{electrolysis}} & ,\text{if } P_{min.load} \leq P_{av} < P_{H_2}. \\ \dfrac{P_{H_2}}{E_{electrolysis}} & ,\text{if } P_{H_2} \leq P_{av}. \end{cases} \tag{7.8}$$

In this formula, P_{av} (MW) stands for available power to the electrolysis plant at any given time. As previously mentioned, the electricity that comes from the wind farm to the plant, a fixed ratio is always injected to the electrolysis plant. P_{H_2} (MW) is the rated capacity of the electrolysis plant.

After the production of hydrogen from the electrolysis plant, this gaseous hydrogen is sent to the liquefaction plant. From the study of Asadnia and Mehrpooya [14], the energy consumption of hydrogen liquefaction in large-scale was forecasted to be ranging from 5-8 kWh/kg in near future. In the study of Cardella *et. al* [13] 6.4kWh/kg is the value considered in upcoming future, which is in agreement with the specific energy consumption range suggested by Asadnia and Mehrpooya.



Note: kg = kilogram, m³ = cubic meter, PV = photovoltaic.

Figure 7.3. Water withdrawal and consumption for producing 1 kg of hydrogen with grid electricity, photovoltaic (PV), and wind power in Australia. [8]

Regarding the energy requirements of the water treatment, it is important to note that depending on the source of electricity the water consumption in the life cycle of hydrogen production differ from each other, as depicted in Fig. ??. If hydrogen is produced from wind electricity it shows lowest water consumption, compared with grid electricity and solar PV. Therefore, considering the specific energy requirement for water treatment, and the water consumption for hydrogen production, the value of electricity consumption for hydrogen production is obtained. Therefore, the energy consumption for water treatment per kilogram of hydrogen is 0.1 kWh/kg_{H_2}. It is also worth-mentioning that as it can be seen now, water treatment energy consumption is by orders of magnitude smaller than energy requirements of electrolysis and liquefaction process.

7.2.2 Storage sizing

The last step in the process, is the storage of the liquefied hydrogen in the tanks. The size of the storage depends on different factors, for example the space limitations of the platform that the system is going to be built, or the time frame that liquid hydrogen needs to be stored, to name a few. In this analysis, the assumption is that all the daily hydrogen produced on the platform must be stored, which results in a size of the storage equal to the maximum daily production of the plant throughout a year. Therefore, size of the storage is a function of wind farm size and electrolysis plant size.

$$\text{Storage Capacity} = maxdailyproduction \tag{7.9}$$

7.3 Economic modeling

One of the purposes of this study is to have a techno-economical analysis on the OffLH2, equally important to the technical analysis that has been shown, is the economic analysis of the system. Therefore, this section deals with economic modeling of the system and its profitability.

7.3.1 DPB

The economic index that has been employed in this study is the discounted payback period of the project, DPB (years). The DPB considers the economic resource over time by discounting the net cash flows of each period with the discount rate i before summing them up and comparing with the initial investment [26]. tarting from the definition of the DPB, in simple terms it means the time when the cashflows, when discounted to the beginning of the project, surpass the capital investment of the project, C_0 (M€).

$$\frac{(I_1 - OPEX_1)}{(1+i)^1} + \frac{(I_2 - OPEX_2)}{(1+i)^2} + ... + \frac{(I_{DPB} - OPEX_{DPB})}{(1+i)^{DPB}} \geq C_0 \quad (7.10)$$

in which I_1 (M€) is the income from selling the liquefied hydrogen in year 1, and $OPEX$ (M€) is the operation and maintenance cost in year 1, the same applied for the rest of the years.

To calculate the DPB, this form of DPB expression has not been used. Instead, the following formula, which is the analytic derivation of DPB, has been used

$$DPB = \frac{ln\left(\dfrac{R_{aa}}{R_{aa} - iC_0}\right)}{ln(1+i)} = \frac{ln\left(\dfrac{1}{1 - i\dfrac{C_0}{R_{aa}}}\right)}{ln(1+i)}. \quad (7.11)$$

In the OffLH2 analysis, the assumption for the annual revenue, R_{aa} (M€) is that it is constant in different years of the lifetime of the plant. In other words, the difference between the income from selling the liquefied hydrogen to the naval sector, and the operation and maintenance costs are constant. This assumption requires that the amount of hydrogen that is produced in different years of the plant performance are constant, the price of the liquid hydrogen sold to the naval sector remains unchanged , and the operation and maintenance costs do not vary during the lifetime of the plant. Consequently, average annual revenue can be calculated from the following formula,

$$R_{aa} = I_1 - OPEX_1 = I_2 - OPEX_2 = ... = I_{DPB} - OPEX_{DPB} \quad (7.12)$$

In OffLH2, an assumption regarding the income is that liquefied hydrogen is the only source of income that can pay back the costs of the project. Therefore, the income, I_T (M€) can be calculated from the following equation:

$$I_T = \sum_{i=1}^{366*24} W_{LH2,practical} \tag{7.13}$$

Regarding the capital investment, CAPEX (M€), it has been broken down as follows:

$$\begin{aligned} C_0 =& CAPEX_{windfarm} + CAPEX_{electrolyzer} + \\ & CAPEX_{liquefaction} + CAPEX_{storage} + \\ & CAPEX_{platform} \end{aligned} \tag{7.14}$$

The reference specific cost, is for connecting the wind farm to the shore so that the electricity is injected in the grid. The costs related to the transmission lines and other necessary equipment have to be subtracted from the wind farm capital expenditure. The lifetime of the electrolysis system is shorter than the life of the plant itself. At time T_{stack} (years), the electrolyser stack needs to be replaced and the cost incurred is C_{stack}, which is generally less than the initial investment of the electrolysis plant.

Asadnia *et. al* [14] reported that the CAPEX of a liquefaction plant, primarily depends on the system type and flow rate of the liquefied hydrogen.

$$CAPEX(€_{2000}/(kg/h)) = 828,313 * (\text{production rate})^{-0.48} \tag{7.15}$$

7.3.2 NPV

The index that has been used up until this point is DPB. However DPB is a useful tool in assessing the economics of the project, there are two main limitations attached to DPB [73, 26]. The first limitation is that it has its total focus is on how to take into account the time of the cash flows, and it is not focus on the possible cash flows after the payback time of the project. Second, it does not discount cash flows in a proper way, since in the definition of DPB, a surplus of the investments has been considered. Therefore, Net present Value, NPV (M€) is also considered together with DPB, in order to account for the cash flows after the payback period of the project. NPV is a discounted cash-flow method that calculates the expected net monetary gain or loss from a project by discounting all future cash inflows and outflows to the present point in time, using a specified rate of return. In this equation, N is the lifetime of the plant, and i represents the risk adjusted discount rate,

$$NPV = \frac{I_1 - OPEX_1}{(1+i)} + \frac{I_2 - OPEX_2}{(1+i)^2} + ... + \frac{I_N - OPEX_N}{(1+i)^N} - C_0 \tag{7.16}$$

The NPV decision rule usually implies that, as long as it is positive, the investment decision will be positive as well [18].

7.3.3 Green hydrogen price

There are different prices for hydrogen in the market, depending on the application and the source of hydrogen. The price of green hydrogen is different from the price of grey hydrogen. The grey hydrogen price as commonly used for bulk volumes by the chemical industry is assumed to be 1.56€/kg, while the grey hydrogen price as used in mobility is assumed to be 4.67€/kg [18]. Because the mass of CO_2 emissions related to the production of grey hydrogen, generated via traditional steam reforming, is about 10 times higher than the mass of the produced hydrogen, the price impact of the CO_2 footprint of the production of a kg of grey hydrogen is about 0.06€, if one would assume that hydrogen production is subject to the EU ETS, and that allowance prices are 6€/tonCO_2.

Based on average Dutch subsidy rates for green versus grey energy supply, for green hydrogen a mark-up of 30% on the price of grey hydrogen is assumed. This implies a price for green hydrogen of 2.03€/kg for the low hydrogen price cases, and 6.07€/kg for the high hydrogen price cases. To further illustrate why the assumed about 6€/kg for green hydrogen to be used in mobility could be considered to be still relatively conservative, the following reasoning could apply. The energy content of 1 kg of hydrogen is roughly sufficient to drive a modern hydrogen car (with fuel cell) about 100 km. If the same distance is covered with the help of an average car fueled by petrol or diesel, the average costs for fuels range anywhere between 8€and 10€, as ballpark figures. The assumed price of 6€/kg for green hydrogen therefore is relatively low, if a direct price comparison is made. This comparison is, however, of course complicated by the tax component of the petrol/diesel price, which is not yet included in the 6€/kg for the hydrogen. But then again, the hydrogen is a green fuel unlike the petrol/diesel, so that a less heavy tax regime would seem fair. All in all, the assumed price of 6€/kg is therefore considered an acceptable proxy level for a future high, niche market green hydrogen price [18].

Chapter 8

Results

In this chapter, the model that has been described previously in the chapter devoted to methodology, is simulated in a MATLAB code developed for the analysis of the OffLH2 project. The goal of this chapter is to visualize different parameters of the system, starting from the wind speed data and corresponding power production from the wind farm, to liquid hydrogen production. Also, the other important observation from the results is how they are affected by changing different parameters and observe the results of the sensitivity analysis. The results that have been illustrated in the present chapter include both the physical and economical parameters.

8.1 Wind energy to electricity

First step in modeling the performance of the system is to couple wind speed data that has been estimated from the wind speed data of Sciacca, to the power production of the wind farm. In this way, the model could be also tested to see if the power production of a single turbine is matching the power curve that has been used to describe the power production of a single turbine or not. Fig. 8.1 depicts the power production of a single turbine. the time domain has been cut to a shorter domain to represent the results in a better way. From this picture it can be concluded that the results of the wind turbine are matching the expectations. As it has been discussed in the previous chapter, the nominal power of the wind turbine, P_r is 6.33 MW, and the velocity that is the beginning of the nominal power production of the wind turbine, v_r, is 11.5 m/s. In this figure the blue line represents the wind speed (m/s) and the red line shows the equivalent power production from the wind turbine (MW). As it can be seen from this figure, if the wind speed goes above the rated wind speed for the specified wind turbine, the power does not exceed the rated power.

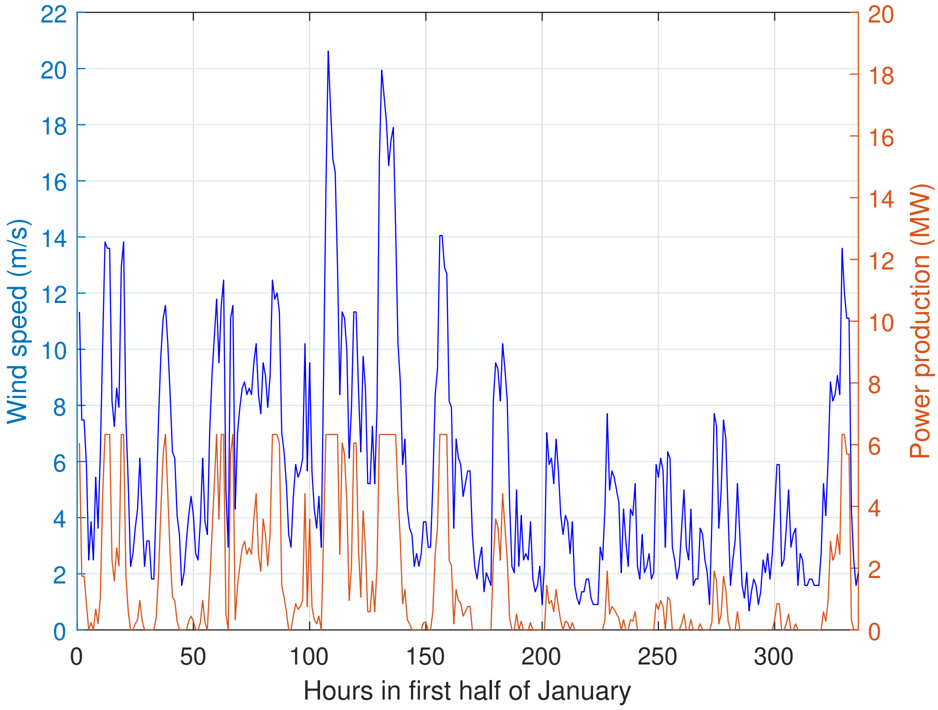


Figure 8.1. Hourly wind speed data and power production from a single turbine in the specified period of two weeks.

Another point that has to be taken into account, is the performance of the wind turbine in terms of the hours of its performance in nominal power. After choosing the type of the wind turbine, and modeling the power that could be produced from the wind speed, it is possible to analyze its performance with its histogram. Fig. 8.2 shows this distribution of power production by the turbine.

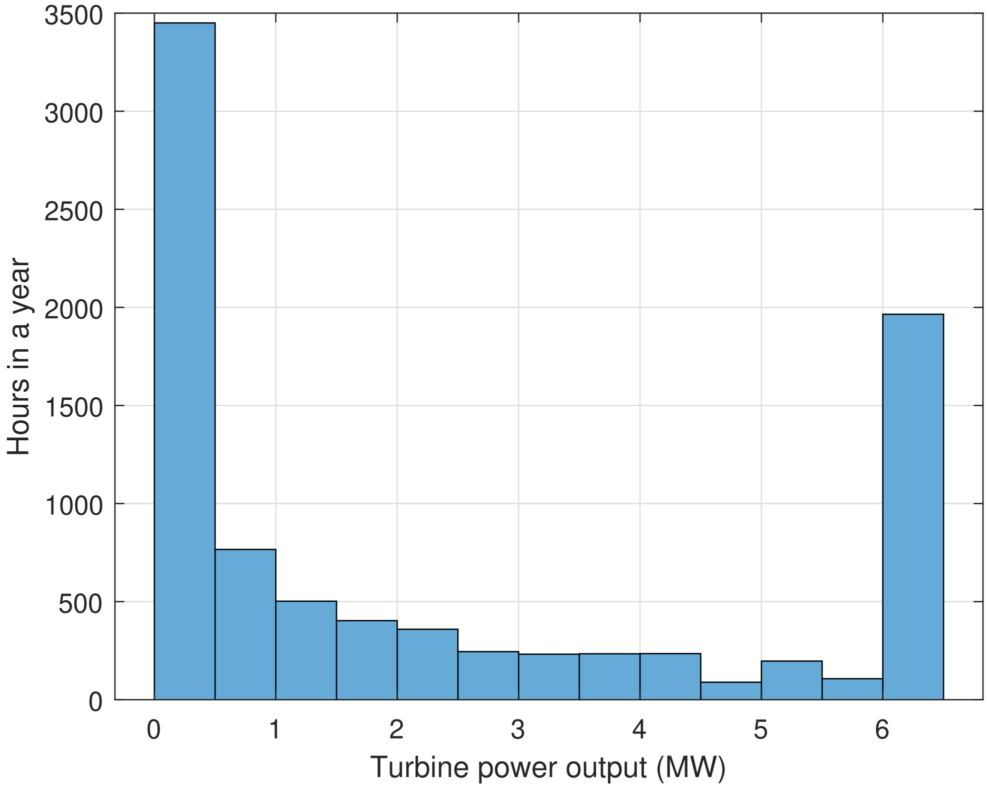


Figure 8.2. Histogram of the power production of the specified wind turbine, with $v_{ci} = 3.5$ (m/s) $v_r = 11.5$ (m/s) $v_{co} = 30$ (m/s).

In the next step, the power production of the wind farm as a complex can be assessed. As it was discussed on the previous chapter, in the present work it is assumed that the wind speed that reaches the rotor of each turbine in the wind farm is the same. In other words, the presence of a turbine and the wakes that it induces to the air flow, does not affect the wind speed that reaches other turbines. Taking into account this assumption, Fig. 8.3 represents the monthly average power production of the wind farm with different number of turbines. It can show the hydrogen production of the plant in different months of the year in a simple way and how it changes throughout the year. However the data that has been used in this study is for 2020, it is expected to have similar trends in other years. Starting from the first curve at the bottom, corresponding to 8 turbines, the number of turbines increases to 30 turbines.

Another point to note is the way that power production of the wind farm increases if the number of turbines is increased. As it can be noticed from the Fig. 8.3, the results for different number of turbines are not parallel together and that matches the expectations from the model. In other words, increasing the number of the turbines of the wind farm (assuming that the presence of one turbines does not affect the power production of the nearby turbines with its wakes), means that the maximum and minimum will be increased by the same ratio. Consequently, the difference between maximum and minimum power production in a larger wind farm is more pronounced.

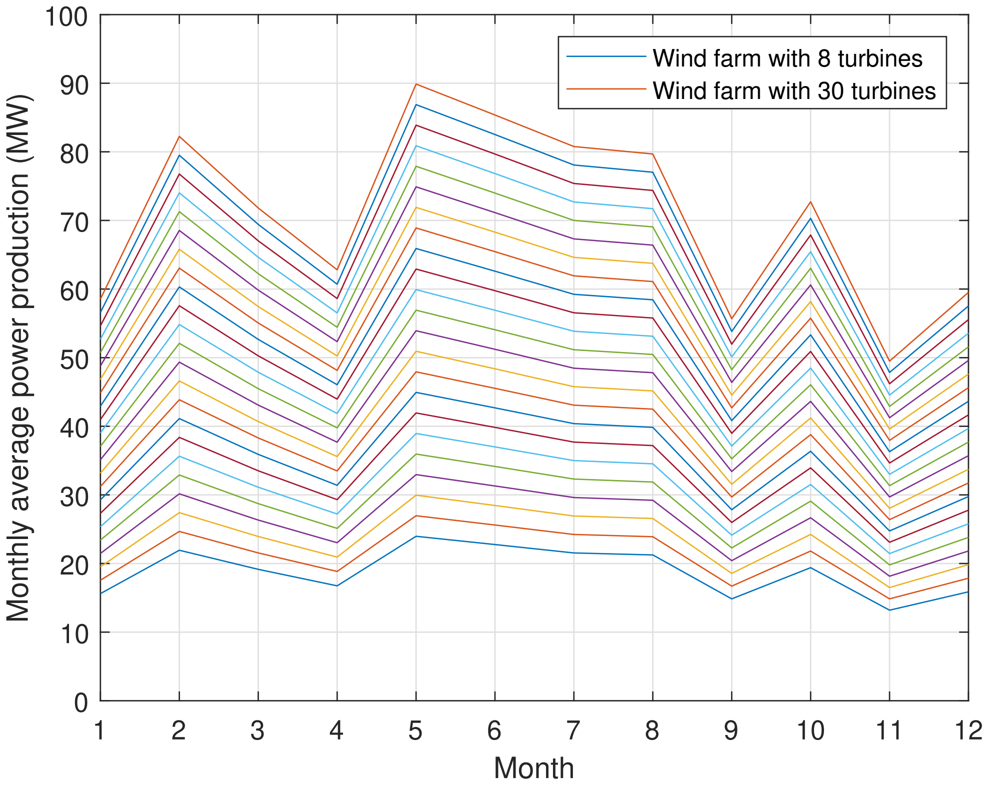


Figure 8.3. Monthly average power production with different number of turbines in the wind farm.

The number of turbines in the wind farm, is strongly influenced by how many ships the naval sector is willing to refuel. Therefore, Fig. 8.4 depicts the two ends of the domain considered for the number of turbines. It can be seen that with 30 turbines, the maximum theoretical LH2 production could reach up to about 3200 kg/hour, while with 8 turbines, this figure is well below 1000 kg/hour. However, it must be also mentioned that this graph is showing the theoretical liquefied hydrogen production, which is different from practical LH2 production. In the previous chapter, it has been discussed how theoretical hydrogen production differs from practical hydrogen production.

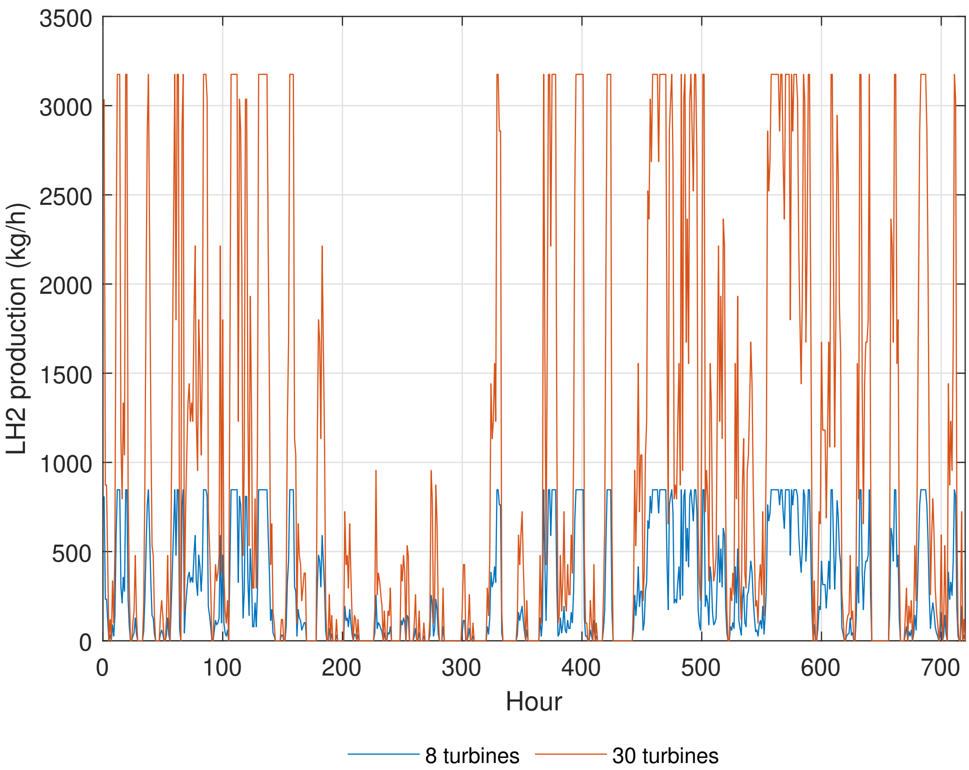


Figure 8.4. Theoretical liquefied hydrogen production with two different sizes of the turbine.

8.2 Optimal sizing of the electrolysis plant

After assessing the electricity production and theoretical liquid LH2 production, which does not take into account the dynamics of the electrolyzer, the next step to take into account the dynamics of the electrolyzer and see how much liquid hydrogen could be practically produced. Therefore, an important part of the design of the system, is the sizing of the electrolysis plant. As the energy system of OffLH2 is a standalone system, and all the electricity production of the wind farm is supposed to be consumed on the offshore platform, the sizing of the electrolysis plant is of high importance. The reason is that the electrolysis system has a considerable portion of the CAPEX after the wind farm. Therefore, the analysis to see what has to be the size of the electrolysis system with regard to the wind farm. Obviously, the electrolysis plant size could not be 100% of the size of the wind farm. Since in that case, a considerable portion of the electrolysis plant will be out of work. Because even when the wind farm is working in its nominal condition, the process that leads the final product of the process, liquefied hydrogen, needs a considerable portion of the energy from the wind farm. Therefore, in the end it is an economical decision to know what is the optimal size for the electrolysis plant.

In the OffLH2 project, the electricity that is consumed on the platform is not coming from another wind farm or the grid. In other words, the investor is also responsible for the CAPEX of the wind farm. Therefore, in the decision about what should be the size of the electrolysis plant, this must be taken into account. The question that must be answered, is what is the size of the electrolysis plant that can give the minimum discounted payback (DPB).

Increasing the size of the electrolyzer does not mean that the amount of hydrogen production will increase linearly as a result. The reason is that due to the intermittent nature of the wind energy, the electricity that is coming from the wind farm is also intermittent. Therefore, the higher the size of the electrolyzer, the capacity of electrolyzer that is not used will increase. Fig. 8.5 represents the effect of increasing the size of the electrolysis plant for different number of turbines. In this graph the horizontal axis is showing the capacity of the electrolysis plant in MW so that it can also show how the size changes with different sizes of the wind farm.

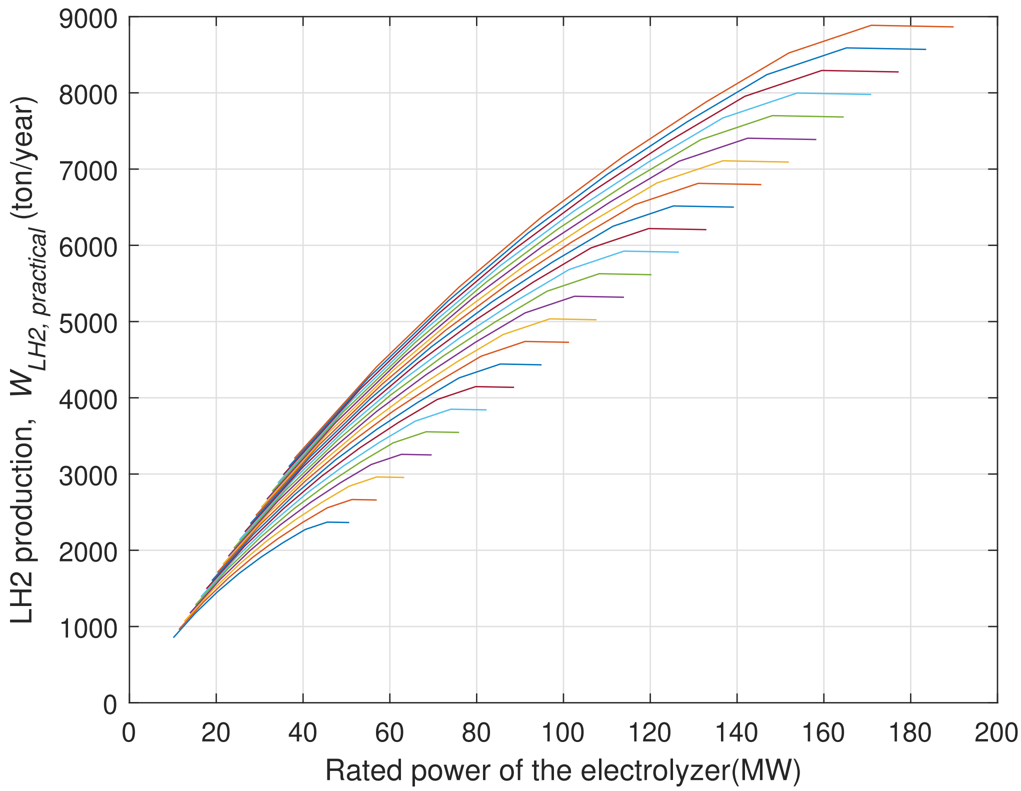


Figure 8.5. Variation of the practical annual LH2 production as a function of number of turbines and size of the electrolysis plant

After knowing how much hydrogen could be practically produced, as the only product of the project is liquid hydrogen, then the economic indexes could be assessed. As it has been discussed in the previous chapter, one of the indexes that has been used in this study to assess the viability of the OffLH2 project, is discounted payback (DPB) of the project. Fig. 8.6 shows the variation of DPB of the project with different sizes of the electrolyzer and different prices for the liquefied hydrogen, while the size of the wind farm has been fixed and it includes 24 turbines. In Fig. 8.7, the 3D graph of Fig. 8.6 is cut at a specific price of 6€/kg and with a farm with 24 turbines. It shows in a more detailed way how the DPB changes as the electrolyzer to wind farm size ratio changes and where it reaches the minimum value.

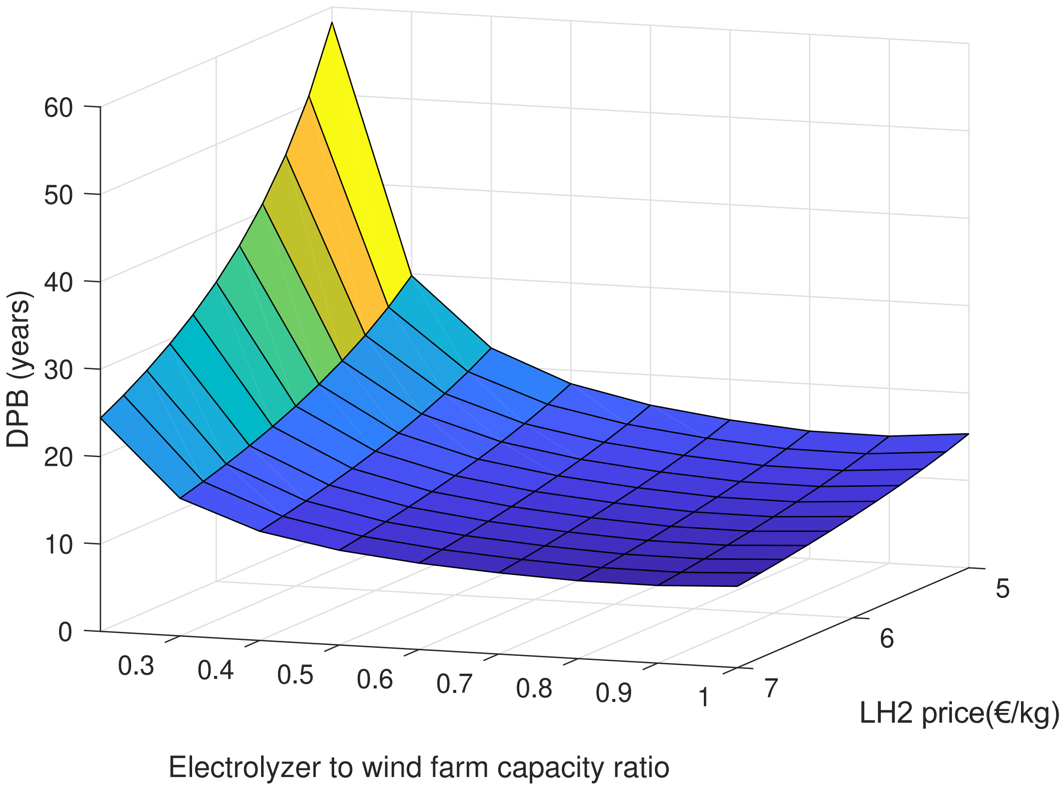


Figure 8.6. Variation in DPB as a function of price of the LH2 and size of the electrolysis plant, for a wind farm with 24 turbines

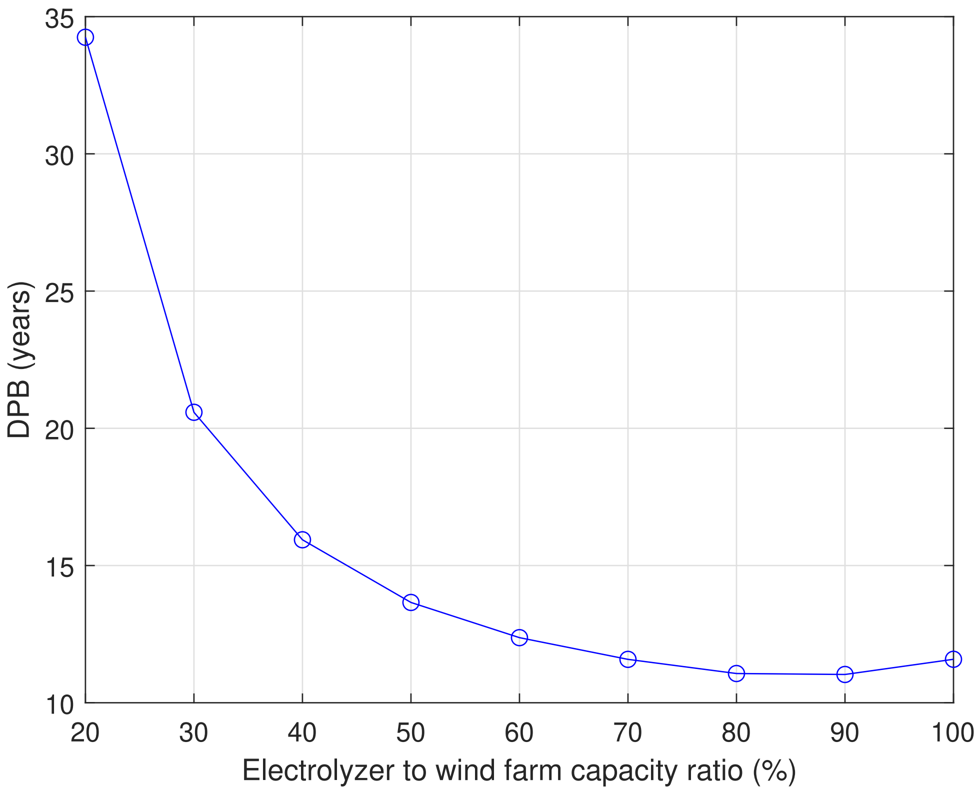


Figure 8.7. DPB in case of a plant with 24 turbines and a cost of 6€/kg for the LH2

Another practice to see how the viability of the project changes is to take the electrolyzer size to its optimal value, and chanhe the number of turbines. However, it is important to note in this case, as the investor of the project is responsible also for the CAPEX of the wind farm and it has to be payed back, therefore it is profitable to size an electrolysis plant to a level that it is acceptable even if a portion of it stays idle for a considerable time. In fact, that is the reason why the optimal value of size ratio between electrolysis plant and wind farm is between 80% and 90%. It is worth mentioning that the electrolysis energy consumption is 86% of the total power produced by the wind farm, at any given time. Fig. 8.8 takes the size ratio of electrolyzer to wind farm to be constant at 80%. This figure represents how the DPB is decreasing as the size of the plant increase. Obviously, with an increase in the price of LH2, a decrease in DPB is expected.

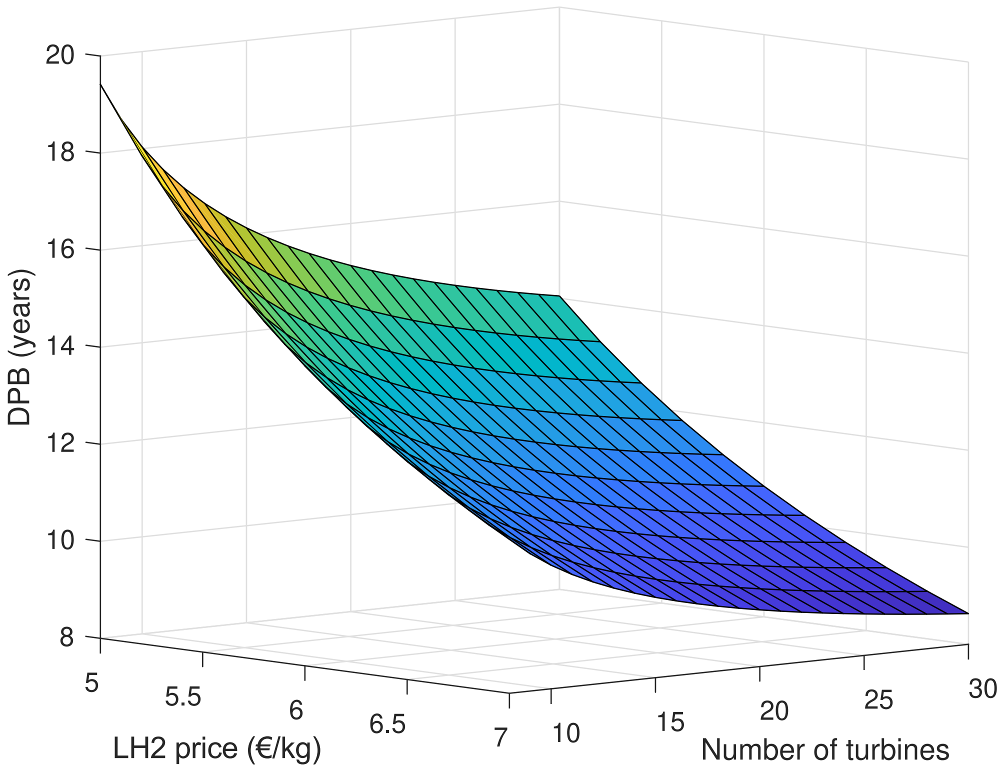


Figure 8.8. Variation in DPB as a function of price of the LH2 and size of the wind farm (number of turbines), with a fixed size of the electrolysis plant

Fig. 8.9 shows the sensitivity of the DPB to the changes of size of the wind turbine farm (and as a consequence, the size of the system), and the changes of the size of the electrolysis plant to the wind farm. It can be seen from this figure that in case of undersized electrolysis plant, the DPB is more sensitive to the size of the wind farm. On the other hand, when the plant is properly sized, the DPB is not strongly dependent on the size of the wind farm.

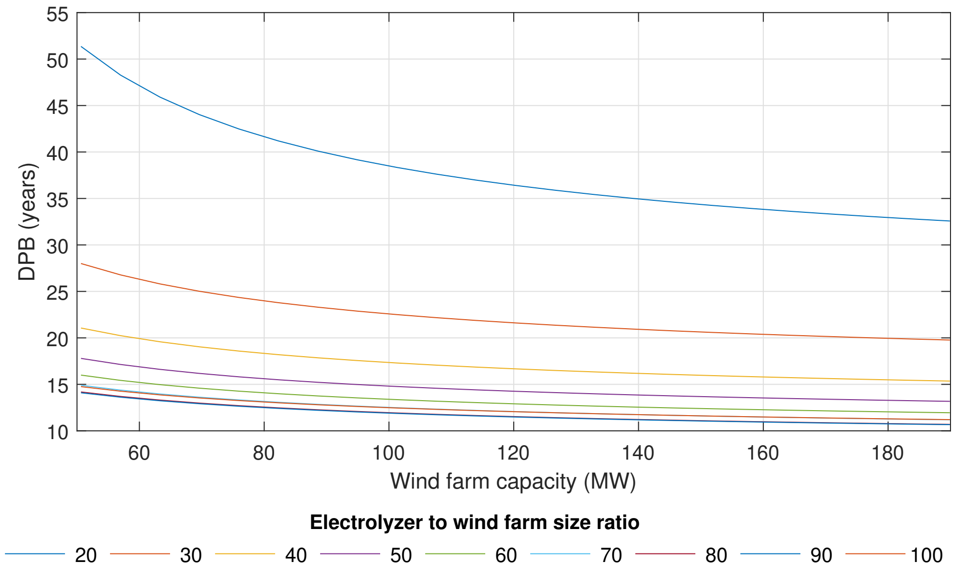


Figure 8.9. Payback time for different wind farm capacities and different electrolyzer capacities, and fixed wind power capacity and LH2 price. Different lines represent different ratios of the electrolyzer nominal capacity to the nominal capacity of the wind farm.

Fig. 8.10 depicts the dependency of the DPB of the project, on the price of the liquefied hydrogen. As discussed in the previous chapter, the liquefied hydrogen is the only source of income of the project, which has to pay back the investments and costs of the project. Moreover, 6€/kg has been considered as a conservative price for the green hydrogen.

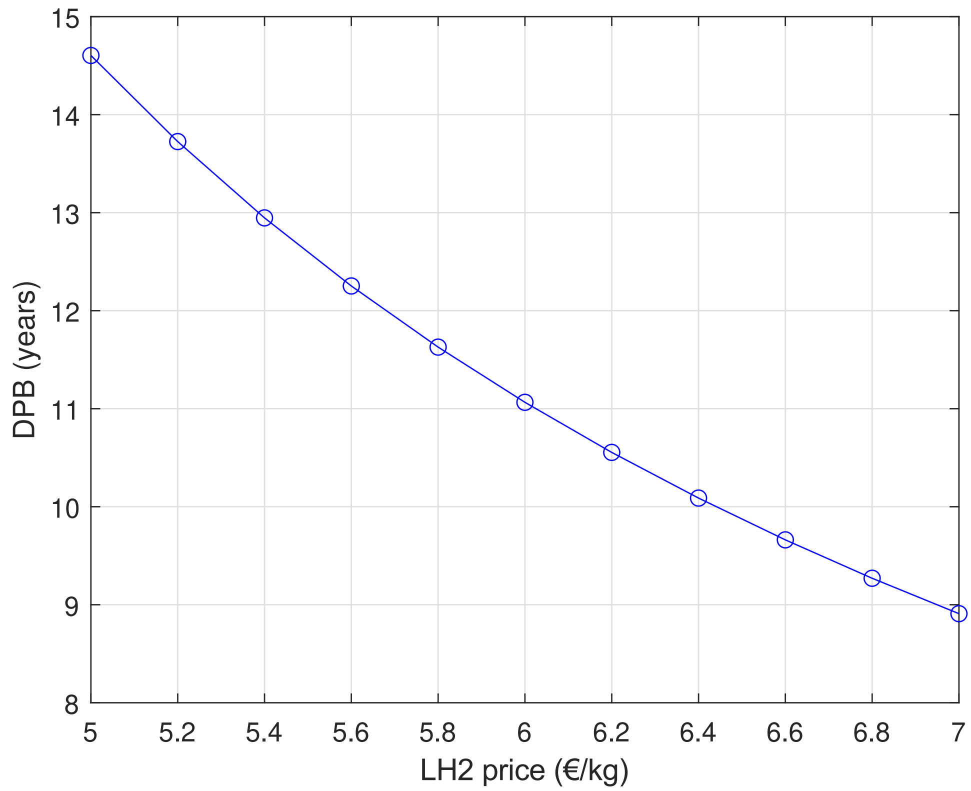


Figure 8.10. Effect of the price of LH2 on DPB, for a wind farm with 24 turbines and 80% of electrolysis size ratio.

As it was discussed in the previous chapter regarding the methodology that has been used in OffLH2, NPV is another index that is used along with the DPB to provide a better knowledge of the project. Fig. 8.11 represents the changes in the value of NPV as the number of turbines changes, while the size ratio of electrolysis plant and wind farm is fixed on 80%. In this case the selling price of the liquefied hydrogen is set to be 6 €/kg.

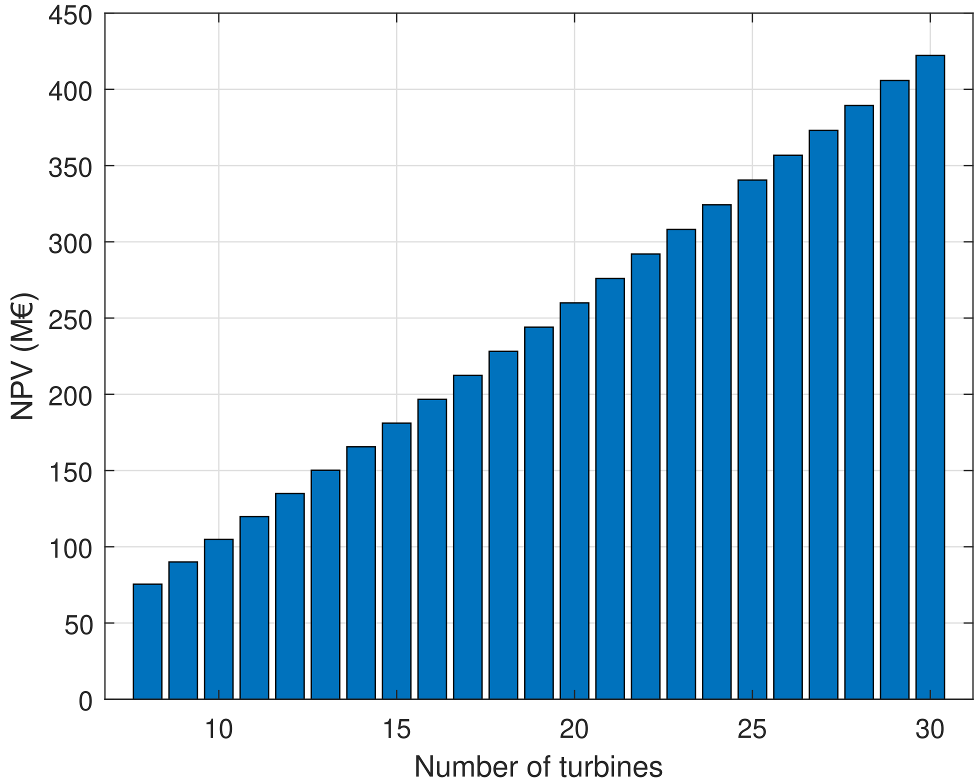


Figure 8.11. NPV for different number of turbines, with a price of 6 €/kg for the liquefied hydrogen.

In order to see how NPV changes as the price of the liquefied hydrogen changes, Fig. 8.12 includes three prices for the liquefied hydrogen in the same graph. The minimum, maximum, and mean values considered for the price of liquefied hydrogen. From this figure it could be seen how strongly the profitability of the system is affected by the hydrogen price. More importantly, how larger the difference is when the size increases.

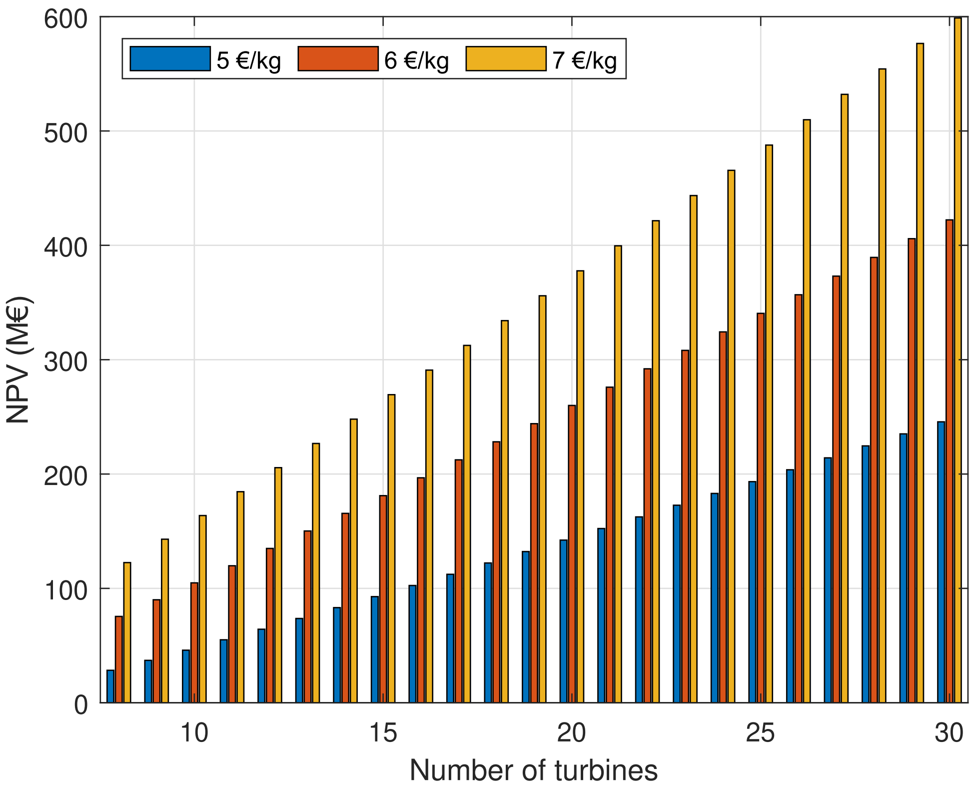


Figure 8.12. NPV for different number of turbines and different prices for the liquefied hydrogen.

8.3 Liquid hydrogen

An important piece of data for further assessment of the OffLH2 project, is how much liquefied hydrogen can be produced and how it varies in different periods of the year. Fig. 8.13 shows the results for a wind farm with 24 turbines, and an electrolysis plant of 80% size ratio. As it can be seen from this figure, the daily production of liquefied hydrogen changes in a pronounced way, matching the expectations. For this example system, the daily production can vary from around 1 ton/day, to a figure well above 45 ton/day. This variation in daily production, is a challenge for a steady refueling of the ships. To stabilize the potential of refueling, the storage is of utmost importance in proper functioning of the system, so that naval sector becomes willing to use it. Fig. 8.14 represents the daily production of hydrogen for January of 2020, to have a better view.

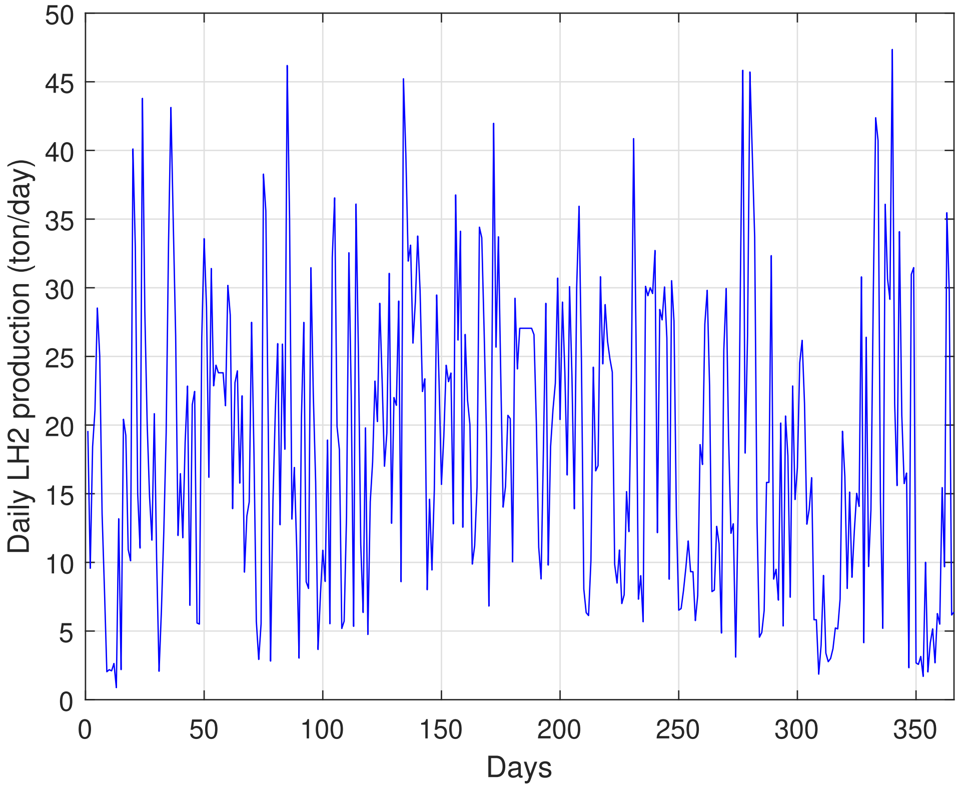


Figure 8.13. Daily production of the LH2 with 24 turbines and 80% electrolyzer to wind farm size ratio.

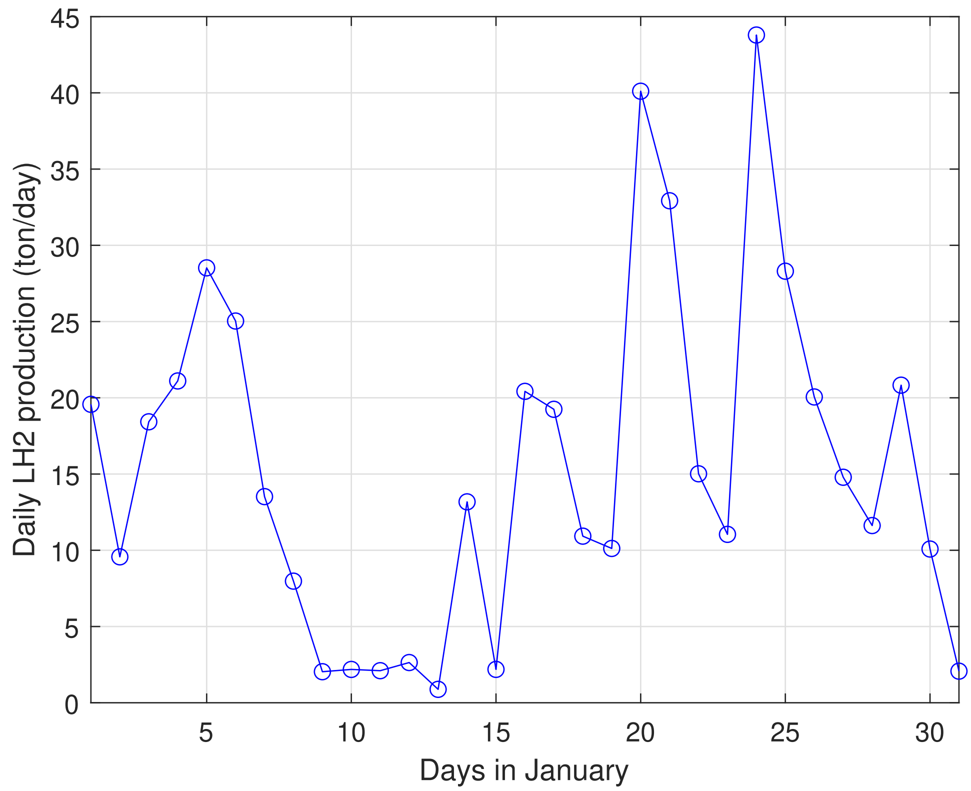


Figure 8.14. Hydrogen production in January for fixed wind and electrolyzer capacity.

Fig. 8.15 depicts the variation in the amount of liquid hydrogen, with the assumption that there is no limitation on the capacity of the hypothetical storage. The other assumption is that for all the days of the year, the platform is refueling the ships. And the amount of the liquid hydrogen that is used by the ships, is equal to the average production of liquid hydrogen in a year. Consequently, in the first half of the year, in which average production is lower than yearly average, the value goes below zero, i.e. the refueling is not sustainable.

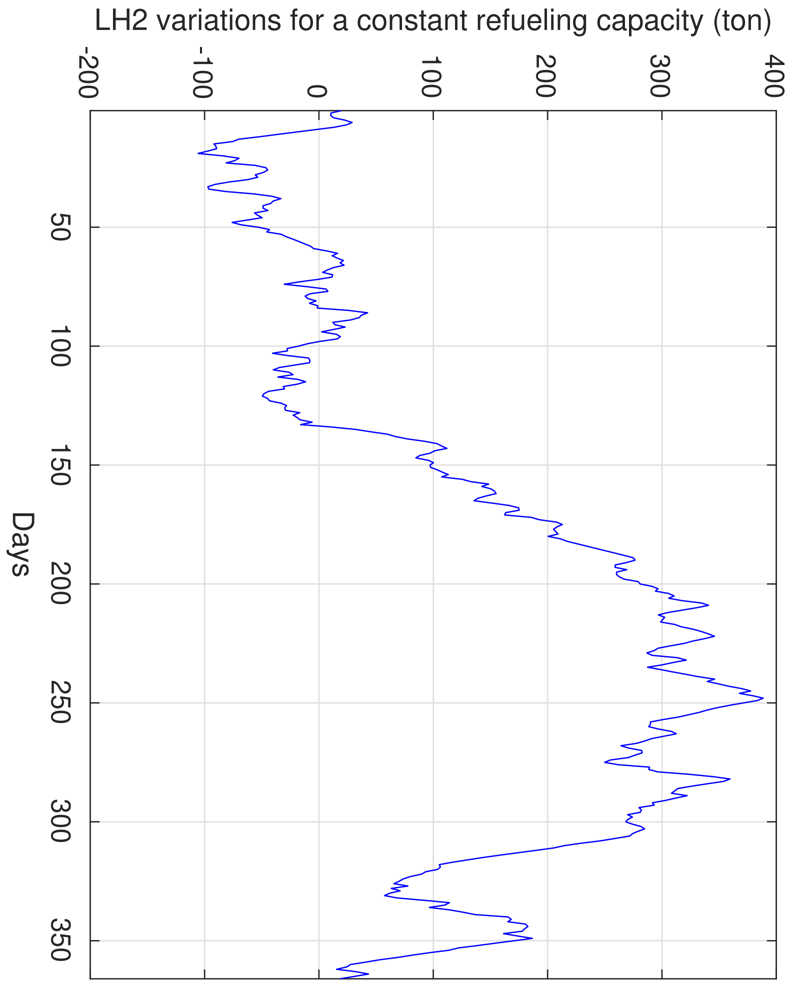


Figure 8.15. Variations in the level of LH2 stored, with everyday refueling of ships with the same amount of LH2.

The capacity of the storage strongly depends on the policies taken for the refueling and also the limitations of the offshore platform. Since at this stage of OffLH2 project these information are not available, as a starting point, the capacity of the storage is assumed to be equal to the maximum daily production of the plant in a year. Therefore, this value changes with the size of the wind farm (number of turbines), and the size ratio of the electrolysis plant. This capacity is also important in the economical analysis where the cost of the storage is a function of the amount of liquid hydrogen it can contain. Fig. 8.16 shows the capacity of the storage, considering the above mentioned assumption.

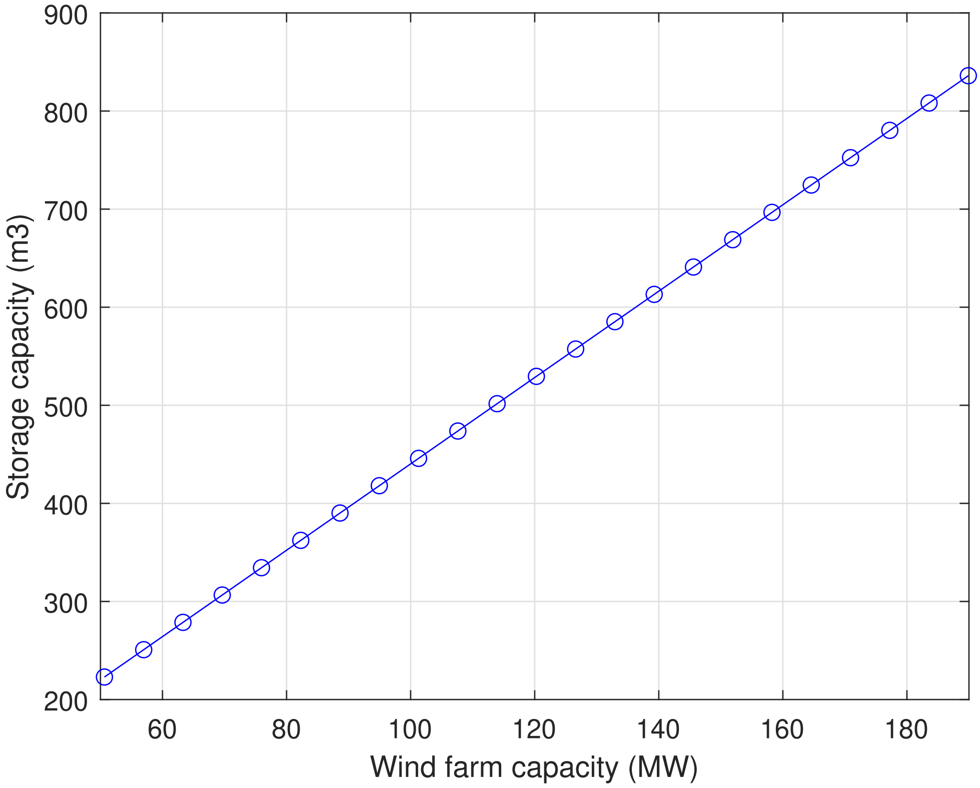


Figure 8.16. Storage capacity as a function of wind farm size.

8.4 Refueling capacity

The final objective of the OffLH2 plant is to refuel the ships with the produced liquefied hydrogen from the green electricity. Therefore, it is necessary to assess how many ships could be refueled. Table **??** shows daily consumption of coastal ships and large ships [13]. As a matter of fact, the production of liquid hydrogen varies with different number of turbines. Taking the size of the electrolyzer capacity to be its optimal value, increasing the number of turbines, the production of liquid hydrogen will increase. Consequently more ships could be refueled with a larger plant.

On the other hand what is important, is what kind of vehicles should be the target of OffLH2 project and projects of this type. As it is been mentioned in Table ??, large ships have a consumption of about 10 tons per day. This value is only a basis for the estimation of the consumption of the ships, since in reality the consumption of marine vehicles is both a function of their size and the speed of the ship.

Due to the fact that in this chapter a number of specific cases were represented for a wind farm of 24 turbines and an electrolyzer to wind farm ratio of 80%, also here it has been used for refueling representation. With the specifications that mentioned for a plant, on average 18.63 tons of liquefied hydrogen could be produced from the plant. In other words, a plant with 24 turbines, which corresponds to 151.9 MW of rated power of the wind farm, could produce 18.63 tons of liquefied hydrogen on a yearly basis. Obviously, the minimum and maximum daily production vary in a wide range, which in this case it ranges from 1 ton per day to around 47 ton/day. On the other hand, large ships could not be refueled every single day. With that being said, it is suggested that the target of OffLH2 should be on coastal ships, rather than large ships. In this case, as the plant is also located in Mediterranean Sea, there is the possibility to refuel coastal ships.

Vehicle type	Assumed H2 consumption (tpd)	Hydrogen source	
		5 tpd	50 tpd
Coastal ship	2	2.5	25
Large ship	10	0.5	5

Table 8.1. Fuel consumption of large ships and cruise ships

Chapter 9

Conclusions

The objective of the present work was to develop a pre-feasibility study of a project to produce liquefied hydrogen. This liquefied hydrogen was produced from the electricity that was coming from an offshore wind farm, located close to the plant. The plant for hydrogen production and liquefaction is was placed on an already existing offshore platform for oil and gas operations. The work included both the technological study of the system and the economical study of the whole project infrastructure as well. The objective was to provide a study, which could be used in the next step for further assessment of such a plant and its development. After developing the model of the system, the implementation of the model was performed in MATLAB to obtain the numerical results of the model.

The following conclusions are obtained from the present work:

- In the first part of the present work, the main technologies involved in the energy system of the present work were studied. Namely, electricity production, water treatment, electrolysis, and hydrogen liquefaction. With the technologies that were finally chosen as the best option by today's level of development, the economic results are satisfactory and profitable as the economic indexes, discounted payback period (DPB), and net present value (NPV), could represent.

- The results of the comprehensive model show that the system is profitable and viable and increasing the size of the plant is desirable in terms of the economics of the project. Therefore, the present model is a useful tool for performing a pre-feasibility assessment of the project. The model could to be used for different configurations and technologies involved. The MATLAB code is developed in a way that by changing the technological and economical parameters, the viability of different scenarios could be assessed.

- After estimation of the wind data, starting from the wind speed data of Sciacca, an offshore wind turbine was chosen based on the average wind speed obtained for the offshore site. As it was represented by the histogram of wind turbine power production, with working about 2000 hours in a year, with a power production of higher than 6 MW, showed satisfactory performance of the wind turbine and matching the wind profile of the site.

- A useful result for future developments of the model is the space requirements of the liquefied hydrogen to be stored on the platform. Unlike land-based applications, the cost of space requirements in an offshore project is very high and it must be taken into account at the beginning. Following the criteria that were followed for storage sizing, storing the maximum daily production, for a wind farm including 24 turbines (151.9 MW), with an electrolyzer to wind farm size ratio of 80%, only the volume of stored liquid hydrogen is 669 m^3, not considering the volume of process and storage equipment. Therefore, it has to be taken into account for further developments and utilizing the limited space of offshore platforms.

- Considering the fuel consumption in marine transportation, the daily hydrogen consumption of large ships and cruise ships are about 10 and 2 ton/day, respectively [13]. Again considering a plant with 24 turbines (151.9 MW) and 80% electrolyzer to wind farm size ratio. For a plant with this size, and wind speed data that has been used in the present work, the daily average liquid hydrogen production is 18.63 ton/day in one year. With that being said, the target of refueling should be the cruise ships, not large ships.

- Based on what has been represented in the chapter devoted to results, liquid hydrogen production varies considerably on a daily basis. For the case of 24 turbines and 80% size ratio of electrolysis plant and wind farm, this figure is changing from about 1 ton/day on low-wind days, to more than 45 ton/day on windy days. Therefore, this must be taken into account for policies regarding the refueling of the ships. A solution could be transporting a portion of the produced liquefied hydrogen to the shore for land-based applications.

Chapter 10

FutureWorks

The main goal of the present work was to develop a model for prefesibility assessment of production of liquid hydrogen from offshore green electricity, on existing oil and gas platforms to refuel ships. Certainly, for a project as important as OffLH2, a precise research and development is needed for a thorough assessment of the project. In the present work the main effort has been to develop a comprehensive, yet simple model to attain a broad view over the technical aspects and economics of the project. The following suggestions could be considered in further developing the model:

- A major improvement could be achieved by considering the specific platforms and adding the space limitations of those specific platforms to the model. In this way, the maximum hydrogen production will be improved by the limitations that are put on maximum electrolysis plant size and corresponding storage for liquefied hydrogen.
- By today, the liquefaction processes available have been land-based plants. As there is no restrictions on the volume that is occupied by the hydrogen liquefaction plant, there are not relevant data for the volume that is needed for such plant. Therefore, an improvement for the plant could be consideration of the volume of the liquefaction plant.
- As it was discussed in the chapter devoted to water treatment, today the best option for purifying the water so that it is fed to electrolyzer is seawater reverse osmosis (SWRO). However, As it was suggested by Domenech *et al.* [10] another promising way for sea water treatment could be vapor re-compression after the distillation. In this way, the heat load required by the distiller is provided by the compressed vapor in the steady state operation. During transient conditions the Ohmic heating must be used. This technology needs more research and study to see if it could be a replacement for SWRO.

- Apart from engineering aspect of the present work that needs in depth study, equally important is the environmental aspect of the project and must be included in future studies.
- To improve the power production model of the wind farm, more advanced models that consider the wake effects and energy loss of the wind farm should be adopted.
- Depending on the time and volume of the liquid hydrogen storage, the losses could vary. Specially, the losses related to ortho-para conversion in the storage and consequent boil-off of stored hydrogen. Also a precise study of the risks that may occur to the system must be studied.

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