Techno-economic analysis of offshore platforms for green hydrogen production

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Dive into system design and costs

by

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Aditya P. Ekhar
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Summary

The idea behind Power-to-Gas (P2G) is to help provide flexibility to renewable energy sources such as wind farms with intermittent nature. Additionally, hydrogen shows a great potential to help decarbonize several industries and its demand is expected to rise massively. Several studies for the technical and economic feasibility of P2G show possibilities of positive business cases far offshore. Platforms, owing to their minimal construction time and lower environmental impact provide an interesting choice of hub structure to equip electrolyser systems. However, gaps exist in the understanding of the costs of such a P2G offshore platform, driving factors, equipment involved, capacity limit and the feasible substructures to support such a facility.

When analysed based on developments by 2030, PEM electrolysers show a better fit for offshore applications owing to their compact design, higher load range, increased output pressures and lower startup times as compared to Alkaline. The balance of plant consists of liquid-gas separators, dryers, plate heat exchangers, water pumps, etc that assist the production of hydrogen. Apart from the BOP, the desalination system forms a critical part of the offshore system. In this study, the P2G platform is powered by an offshore wind farm. Hence, the need for high power transformers, grounding transformers, switchgears and AC/DC converters arises to safely distribute incoming wind power to the stacks. For offshore applications, a battery room, workshops, emergency accommodation for operators and a helideck for crew transfer are also required on the platform.

On the platform of the 1 GW P2G facility, the PEM stacks are the heaviest equipment followed by high power transformers and converters. The topsides is sized based on the equipment mass and the topsides steelwork accounts for the highest percentage of the total topsides mass. A limit of 2.5 GW of electrolyser capacity on a single jacket platform exists due to vessel installation limits for jacket mass. Jacket platforms and floating platforms like semi-submersible (SSP) are feasible substructures to support heavy P2G topsides. A crossover water depth of 50 m for 1 GW is obtained between the fixed jacket and SSP. It is also observed that SSPs become feasible at shallower water depths with an increase in topsides capacity.

With a small contribution of the structure costs to total CAPEX, the costs of the platform are found to be equipment driven rather than mass driven. A direct cost of 1,160 €/kW is obtained for an offshore P2G platform. This cost is mainly driven by the CAPEX of stacks. Economies of Scale are observed due to modular nature, however, very limited for stacks and BOP. The trend for the total cost of ownership mainly remains linear with an increase in electrolyser capacity, although some scaling advantages might exist and should be analysed further. Platform LCoH increases with an increase in electrolyser size for a fixed wind farm capacity due to reduced full load hours and the same amount of hydrogen produced. It is recommended to further take into consideration the LCoE of the wind farm and other costs for gas transport to estimate the impact on platform on the overall LCoH.

Contents

Abbreviations

AEM	Anion Exchange Membrane
ALK	Alkaline
BOP	Balance of Plant
CAPEX	Captial Expenditure
EoS	Economies of Scale
GHG	Green House Gases
ISBL	Inside Battery Limits
LCOE	Levelised Cost Of Energy
LCOH	Levelised Cost Of Hydrogen
NSWPH	North Sea Wind Power Hub
O&G	Oil and Gas
OPEX	Operational Expenditure
OWF	Offshore Wind Farm
P2G	Power to Gas
P2H2	Power to Hydrogen
PE	Power Electronics
PEM	Polymer Electrolyte Membrane
PFSA	Perfluorosulfonic Acid
PHE	Plate Heat Exchanger
PSA	Pressure Swing Absorption
R&D	Research and Development
RO	Reverse Osmosis
SMR	Steam Methane Reforming
SOEC	Solid Oxide Electrolyser Cell
SSP	Semi-Submersible Platform
STATCOM	Static Synchronous Compensator
TCO	Total Cost of Ownership
TFC	Total Fixed Capital

1
INTRODUCTION

This chapter describes the basis of this research. Section 1.1 highlights the potential of offshore wind and it's future large-scale integration possibilities to produce hydrogen. Section 1.2 details out the problem and highlights the main and sub research questions. Section 1.3 gives an overview of the approach followed in this thesis to help answer the research questions. Section 1.4 details the boundaries and scope of this research and the base case. Finally, Section 1.5 divides the report into chapters explaining briefly their content

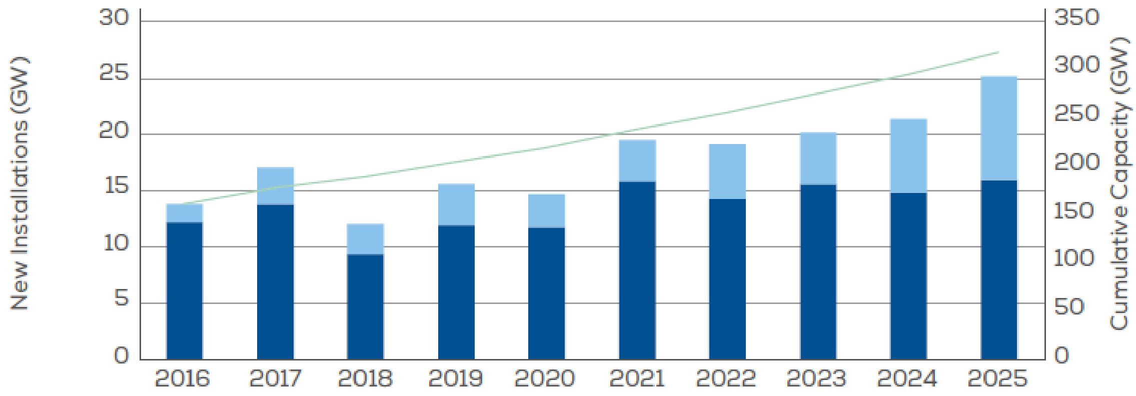
1.1. Background

The Paris Agreement came in to force in 2016 with the goal to tackle climate change. After the Netherlands signed the agreement to keep the increase of global temperatures below $2°C$, several actions and plans were taken by the Dutch government towards the energy transition. According to the Dutch Energy Agreement [54], by 2030, the Dutch government aims to reduce green house gases by almost 40% . Several energy companies, NGOs and government organisations in the Netherlands are working towards enabling this transition.

1.1.1. North Sea wind energy developments

Onshore and offshore wind turbines have seen a significant rise in installation capacities over the decade. As per a report by WindEurope [29], Europe's cumulative offshore wind capacity reached 22 GW at the end of 2019, while managing to install a record breaking capacity of 3 GW of net offshore wind power in 2019 alone. R&D programs around the world have contributed to making wind turbines stronger, larger and more powerful than ever. With this increasing trend, 2020 witnessed the emergence of the powerful 14 MW offshore wind turbine by Siemens Gamesa Renewable Energy [35]. Studies predict further rise in wind turbine capacities upto 15 MW in 2030, ready for deployment. These massive turbines are expected to have a rotor diameter as large as 250 m while standing tall at a hub height of 150 m [76]. It is logical that such turbines will also contribute to larger offshore wind farms built towards 2030.

Over the years, the North Sea has been an ideal location for exploiting wind power. Countries surrounding the North Sea have built massive wind farms to generate green electricity for their national power grids. Research and experience has helped reduce the Lev-



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Offshore	1.6	3.2	2.7	3.6	2.9	3.7	5.1	4.6	6.5	9.2
Onshore	12.3	13.9	9.4	12.0	11.8	15.9	14.1	15.6	14.9	16.0
Cumulative	162	178	190	205	220	238	256	275	295	318

Figure 1.1: New and cumulative wind installations in Europe, taken from [30]

elised Cost of Energy (LCoE) of offshore wind, making it a competitive and proven technology for electricity production in the European energy market. The North Sea countries have planned an OWF capacity of 55 GW up to 2030 and 20 GW after 2030 [58]. The Netherlands will approximately have 4.5 GW of offshore wind installed by 2030 [3], and is planned to increase up to 11.5 GW by 2050 [52]. Figure 1.1 shows the rising trends in expected installation capacities of wind energy in Europe. These solid targets pave a broader path for different integration possibilities and opportunities with offshore wind in the North Sea.

The intermittent character of offshore wind and its expected heavy deployment in the future generates a significant need of flexibility. A proposed solution to tackle this is 'Power-to-gas' (P2G). The concept of P2G is to convert renewable electricity to gaseous molecules, hydrogen (H_2) in this case. The scope of P2G reaches further than just providing flexibility. It is expected to help decarbonize various industries producing and using hydrogen. With an expected rise in hydrogen demand, P2G is an important medium that will drive us closer to a successful energy transition.

1.1.2. Hydrogen: Current status and future role

Hydrogen is the lightest and one of the most abundant gases in the universe. It has been increasingly used in industrial, transportation and mobility sectors due to one of its several advantages such as higher energy density (120 MJ/kg) and no CO_2 emissions, making it interesting for fuel use [20]. According to the FCH JU's Hydrogen Roadmap Europe, hydrogen demand in the EU in 2030 is 665 TWh or about 16.9 Mt [28]. However, currently globally around 96% of hydrogen's production is based on fossil fuels [20], producing 70 Mt of hydrogen each year for use in oil refineries and making fertilisers. To produce hydrogen, different methods exist such as coal gasification and partial oxidation but the Steam Methane Reforming (or Reformation) (SMR) remains the most used technology. SMR is the cheapest technology but produces green house emissions [20].

This means that the production and use of hydrogen globally is associated with more than 800 Mt of global CO_2 emissions today – a staggering amount that is equivalent to the emissions of the United Kingdom and Indonesia combined [2]. Thus it has become extremely important to replace hydrogen production processes that use fossil fuels, with sustainable technologies like electrolysers powered by renewable energy technologies. Electrolysers use electricity to split water into two components, oxygen on one hand and hydrogen as combustible gas on the other, without emitting any green house gases [68].

Over the last few years, an increasing number of countries have adopted hydrogen policies and strategies. The rise in such policy adoption clearly indicates the widespread recognition of the need for green hydrogen to meet the Paris agreement goals. Globally, eight jurisdictions announced hydrogen strategies until 2020 and ten more are expected by the end of 2021. The EU has the most ambitious targets of all, 40 GW by 2030, supported by national targets from France, Germany, Netherlands, Portugal and Spain. The investments of the EU for renewable hydrogen are estimated to be in order of 220 to 340 billion Euros for the renewable electricity production and 24 to 43 billion Euros for the electrolyser technology by 2030 [44]. Hydrogen is expected to play a significant role in energizing and decarbonizing several other industries that emit GHGs through the use of fossil fuels. Figure 1.2 below shows the potential of hydrogen to provide energy to power various sectors of the EU in the future.

Heating and power: One immediate opportunity for decarbonization is blending hydrogen into the current natural gas grid. The road map of Hydrogen Council, a global CEO-led initiative of leading companies for hydrogen, highlights that the blending ratio will increase up to 7 % by volume until 2030, accounting to an average estimate of 25 TWh of hydrogen blending in the natural gas grid. This could help heat around 2.5 million residential households in addition to commercial buildings. In industries, hydrogen could fulfill a demand of 8 TWh in the high grade heat segment by 2030 [13].

Transportation: Today hydrogen buses, medium-sized cars and forklifts are commercially available. Further on, medium sized and large cars, buses, trucks and trains might be introduced in the coming five years followed by other segments such as smaller cars and minibuses in the year 2030. The Hydrogen Council expects for 1 in 12 cars sold in California, Germany, Japan and South Korea to be powered from hydrogen by 2030, with sales ramping up globally. With this vision, more than 350,000 trucks, 50,000 buses and thousands of trains and passenger ships running on hydrogen would be transporting without any carbon and local emissions [18].

Industry feedstock: Today 70 % of hydrogen feedstock is produced from natural gas through reforming which is then used by companies for refining, chemicals (ammonia and methanol) and metal processing, all of this accounting to a total of approximately 325 TWh [13]. In addition, hydrogen can be used in combination with captured carbon to produce feedstock that can replace fossil fuels, and this has the potential to produce 10 to 15 Mt of chemicals by 2030 [18].

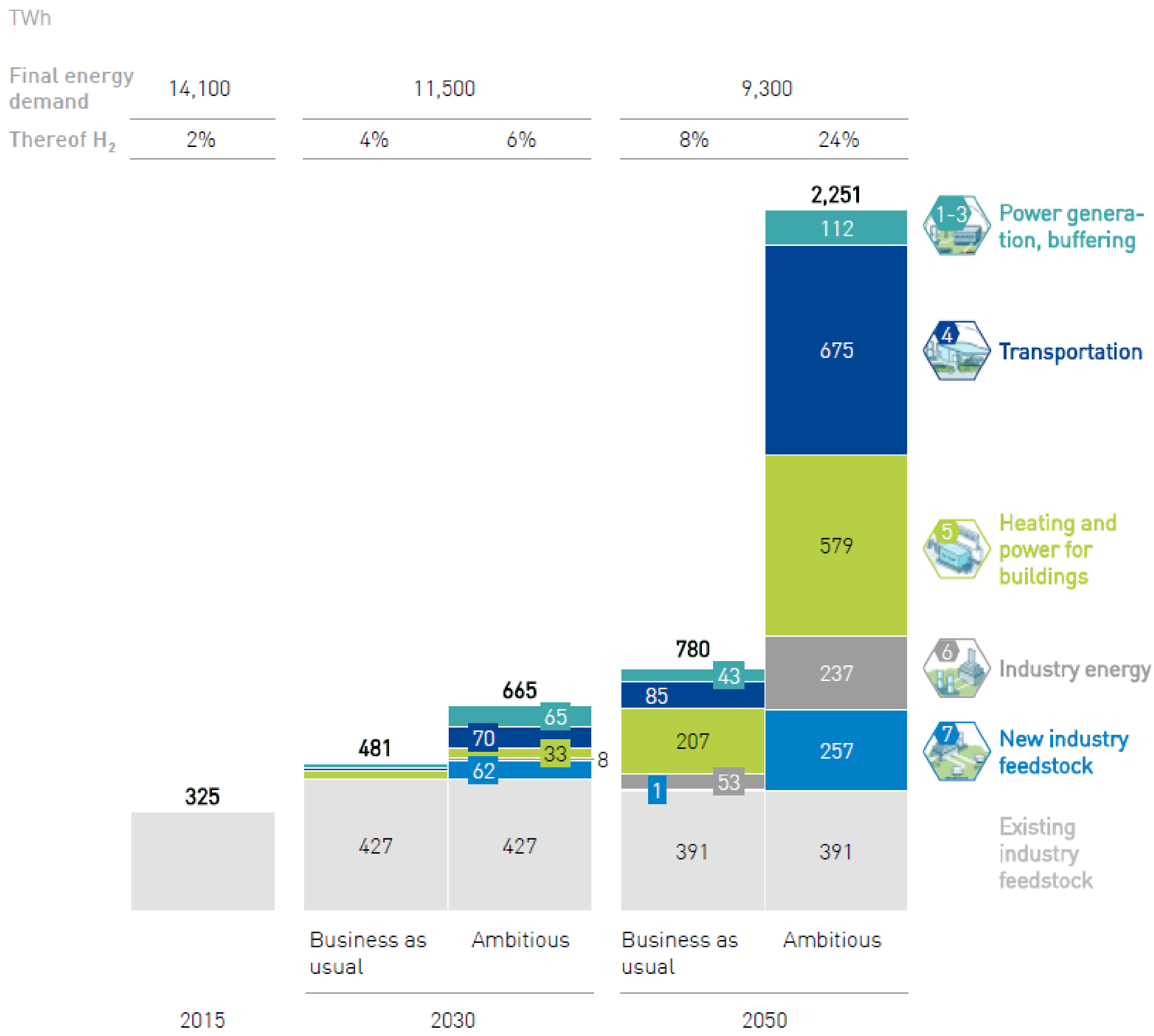


Figure 1.2: Contribution of hydrogen to energy sectors in 2030 and 2050, taken from [13]

1.1.3. Power-to-gas: Current status and future role

The idea of P2G provides solutions for renewable electricity which cannot be used directly in the grid. Renewable energy sources producing electricity can be coupled with electrolysers to produce pure hydrogen. Future possibilities for the North Sea show electrolysers supporting offshore wind. Studies highlight the production of hydrogen for storage at site. Producing hydrogen during peak hours can help reduce congestion in the transmission networks, thus increasing the flexibility of the overall system. The coupling and compatibility of electrolysers have been demonstrated using pilot projects in the industry for quite some time. By 2020, almost 320 such projects accounting up to 200 MW of electrolyser capacity were recorded [44].

Increasing interests in the North Sea have resulted into future visions that picture energy hubs and large wind power generation offshore. To support such massive wind farm capacities, installed capacities of electrolyser systems can also be expected to be of the same scale as of these wind farms. However, in order to be realistic, a balance is necessary between the immense hydrogen potential in the North Sea and cost effectiveness of such a P2G system. Gaps exist in the knowledge of system design, suitable infrastructure and costs of such systems offshore. In order to be able to to develop such systems in the future to support the energy transition, it is important that we fill these gaps with relevant studies and findings. Lately, extensive research and feasibility studies in this area have begun which promise significant potential.

The North Sea Wind Power Hub (NSWPH) is a consortium dedicated to using the hub and spoke concept to connect international power grids along with wind farms and enable sector coupling [1] with the help of power-to-hydrogen conversion. Studies are being carried out by North Sea Energy to investigate optimal location, routes and hub structures for reliable and cost effective transport of energy through offshore hydrogen conversion and or electricity. For the hub structure, platforms provide an interesting opportunity for power collection and hydrogen conversion owing to their reduced environmental impact, planning risk and construction timelines, while still having potential to equip large facilities up to 1 GW [42].

A 2018 study for the IJmuiden Ver site in the Netherlands, by DNV GL (now DNV), focused on various business cases involving different electrolyser capacities placed onshore and offshore and powered by offshore wind. The study included sizing of platforms, however with over-estimations of mass of electrolyser equipment, as later communicated by DNV. One of the conclusions derived was the possibility of offshore power-to-hydrogen (P2H2) showing a positive business case around the year 2035 [37].

Another study by North Sea Energy assessed various business cases of converting offshore wind power to hydrogen on islands, and on existing and dedicated platforms in the North Sea. The study claimed that the offshore conversion can only generate a promising business case in the next 5 to 10 years and if placed greater than around 120 km from the shore[2]. It also concluded that for 100% conversion of wind to hydrogen, installation of new platforms seem to offer good economic long-term potential and should therefore be investigated further in detail. However, this study aligned it's inputs with the previously mentioned DNV study resulting into further possible overestimation of costs [26].

Two studies by the Institute for Sustainable Process Technology (ISPT) focused on system design and costs of an onshore electrolyser facility for both PEM and Alkaline technologies. The first study depicted system layouts of such a facility and highlighted that the minimum surface requirements for PEM and Alkaline facility of 1 GW each is 8 hectares and 10 hectares respectively [32]. The second study by ISPT gave a high level estimate of the direct costs of equipment and other indirect costs involved in such a large-scale facility [33].

A study by the Energy Delta Institute focused on placing containerized electrolyser systems on exsiting platforms in the North Sea. The study analysed the resulting CAPEX for

[1] Sector coupling is the transfer of surplus renewable power using gas, to other economic sectors.
[2] Going further offshore, the electricity transmission and grid costs significantly increase, hence it can be more economical to transmit wind power in the form of hydrogen.

such a setup and its effect on hydrogen prices [46]. A report by the Offshore Wind Industry Council assessed the specific investment costs of electrolyser systems placed offshore and onshore in large capacities and highlighted the distribution of cost shares and resulting LCoH. However, the report lacked detailed insights into the sizing of structure and various equipment on the platform [19]. [31] analysed spatial distribution of costs of hydrogen production in the North Sea based upon fixed and floating platforms, in turbine and onshore configurations. However, the study did not dive into detail of various equipment needed and facility sizing. [38] focused on opportunities in the year 2050 in the North Sea, to produce cheap hydrogen offshore in combination with electricity. The design however, focused on an energy island.

1.2. Problem analysis and research questions

The current research lacks detailed insights into the equipment that would be placed on the platform(s) in order to convert wind power to hydrogen. The gap in this area also expands to the lack of information on the type of feasible and economical substructures to support the topsides at different water depths. Other indications that remain missing in present studies are the total facility costs, the driving factors that influence these costs and possible economic ways of erecting such a facility offshore.

The following main and sub research questions will guide this research and will be answered during the thesis:

1. ***How can large-scale electrolysers be equipped on offshore platforms in the North Sea?***
    - What is a typical electrolyser system layout and would this be suitable for offshore applications?
    - Which offshore platforms are technically feasible for facilitating large-scale electrolysis?
    - What electrolyser capacity can be equipped on offshore platforms in the North Sea?
    - What system layouts of the platform are possible (including electrolyser, other equipment and facilities (Helipad, living quarters, etc))?
2. ***What is the economic impact of electrolyser platforms on hydrogen production costs?***
    - What are the total ownership costs of platforms with electrolyser topsides (considering up to 3 different platforms)?
    - What is the economic optimal layout of the electrolyser platforms in terms of number of platforms and electrolyser capacities on each platform, in combination with the wind farm (taking into account platform costs, array cabling, hydrogen pipelines)?

1.3. Approach

A pragmatic approach is used to answer the research questions, combining qualitative and quantitative analysis. The former is used to define the system design for the year 2030 through researching the literature and expert opinions, and the latter is used to build a cost model to understand the real drivers for costs.

1. **Detailed review of electrolyser technologies**
   Select suitable electrolyser technology based on operational and design developments by 2030.

2. **Review types of offshore platforms in the North Sea**
   Select the most dominant platforms, both fixed and floating, in the North Sea.

3. **Size the facility**
   Calculate the total weight and size of the entire platform (topsides and substructure) through a bottom up approach.

4. **Research costs functions and estimates**
   Determine the costs for the facility with various disciplines involved, scaled to the year 2030.

5. **Model tests and determine driving factors**
   Test the model for different choices of equipment and find out the significant cost contributors and drivers.

6. **Sensitivity analysis**
   Test the validity of conclusions by performing a sensitivity analysis of selected variables.

1.4. Key assumptions

As per the current research highlighted in Section 1.1.3, offshore hydrogen production is likely to be economical in the next five to ten years. Hence this study investigates the research questions in the time horizon of 2030, where large wind developments in the North Sea can be expected and P2G starts to become a significant part of the energy sector. Due to possibilities of positive business cases far offshore, the platform is initially assumed to be installed at a hypothetical location, which is around 120 km from the shore and has an average water depth of 30 m.

This thesis will investigate the system design and costs of an offshore P2G platform dedicated for green hydrogen production. The platform will equip a large electrolyser capacity of 1 GW on the topsides as the base case in this study, where the focus remains only on the platform. To further clarify the scope of this research, the boundary conditions considered are described:

- The P2G offshore platform is assumed to be surrounded and powered by an offshore wind farm of a similar scale. The wind farm is however out of scope of this study.
- The transport pipeline network is kept out of scope.

- Hydrogen storage on the platform is out of scope and once produced, immediate transport of hydrogen is assumed.
- The onshore hydrogen grid pressure is assumed to be 50 bar in the future (as per DNV prediction)

The main goal of this thesis is to increase the knowledge of system integration of offshore wind and electrolysers, estimate the scale and size of such a platform involving stacks, balance of plant, power electronics, auxiliary systems and the substructure supporting the topsides. In line with this goal, the study details the system design and parameters, estimates costs of each of the components involved and finally builds a cost model to understand the driving factors for an economical design of such a facility offshore.

1.5. Thesis layout

The content by chapter is briefly described below.

Chapter 2 briefly discuses the suitable electrolyser technologies choice, selection criteria and the chosen equipment for hydrogen and power conversion followed by their sizing and reasoning. It concludes with the complete sizing of the platform indicating feasible substructure(s) to support the facility.

Chapter 3 details the costs estimates and functions of all disciplines scaled up to a gigawatt capacity. Expected learning curves, economies of scale and inflation are taken into account while estimating these costs for the year 2030. Finally, the chapter concludes with total cost of ownership (TCO) and the levelised cost of hydrogen (LCoH).

Chapter 4 presents gained insights in line with the research questions. Future expected changes in the system design are implemented to check their influence on total costs. A sensitivity analysis is also performed on key drivers to test the validity of results.

Chapter 5 recapitulates the most relevant findings, and links these to a larger context. Finally, it provides recommendations to improve the model and reflections.

2
ELECTROLYSER FACILITY

This chapter details the system design of the offshore P2G platform. Section 2.1 highlights the two state-of-the art electrolyser technologies and their future developments to make a facts based study choice. Section 2.2 briefly describes the various processes involved in the production of hydrogen and concludes with facility sizing. Section 2.3 assess the feasibility and highlights sizing of the offshore platforms to support the facility. Finally, Section 2.4 summarises the key equipment with their parameters and weight contributions towards the offshore facility.

2.1. Electrolyser technology selection

Electrolyser systems produce hydrogen and oxygen when powered by electricity, causing the following reaction:

$$2H_2O \longrightarrow 2H_2 + O_2 \tag{2.1}$$

The principle of water electrolysis is simple, yet technologies vary in physical, chemical and electrochemical aspects. The basic principle of a water electrolysis cell consists of two electrodes separated by an electrolyte, which is the medium responsible to transport charges from one electrode to another. While the Alkaline type of electrolysers consist of a highly concentrated electrolyte solution to transport charges, technologies like Polymer Electrolyte Membrane (PEM), Solid Oxide and Anion Exchange Membrane (AEM) do not need a liquid electrolyte solution, but rather an electron insulating solid electrolyte for separation. Alkaline and PEM are already commercial technologies. While Solid Oxide is also commercially available, significant improvements are still to be made. AEM is currently at lab scale but promises a major potential [44].

The two major electrolyser technologies PEM and Alkaline, are further described in detail. Later, various operational and design developments of the two technologies are compared and based upon that a choice is made for the present study.

2.1.1. Alkaline (ALK)

At the cell level, ALK electrolysers have a relatively simple design which is easy to manufacture. Currently the cells have an area as large as 3 m^2 . The stacks include the highly concentrate KOH as electrolyte, robust ZrO_2 based diaphragms and electrodes made of stainless steel coated with Nickel. As shown in Figure 2.1, the hydroxyl ion OH- is the ion charge carrier that passes through the porous layer. However, the KOH solution and water also permeates through the porous level causing intermixing of gases produced on both the sides, thus limiting the low power operating range and the ability to operate at higher pressures [44].

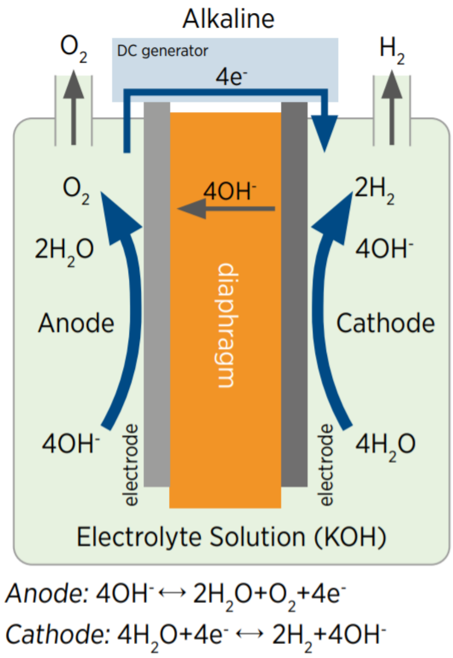


Figure 2.1: Alkaline electrolyser cell [44]

To tackle this, use of thicker diaphragms has been made at the stack level which, however, increase resistance and drastically decrease current density at given voltage. On the other hand, sturdy and reliable ALK electrolysers are known to reach a lifetime of almost 30 years [44].

2.1.2. Polymer Electrolyte Membrane (PEM)

This technology employs electrodes that are manufactured with advanced architecture thus creating lower resistance, and hence higher current density. A thinner PFSA membrane (0.2 mm) is deployed at the cell level, which is chemically and mechanically robust and which allows for higher differential pressure operation [44].

As shown in the Figure 2.2, water is supplied at the anode side and splits into oxygen and hydrogen ions. The hydrogen ions (H+) travel through the PFSA membrane combining with electrons to produce hydrogen gas on the cathode side. Due to the acidic environment created by the PFSA membrane along with the release of oxygen gas at the anode

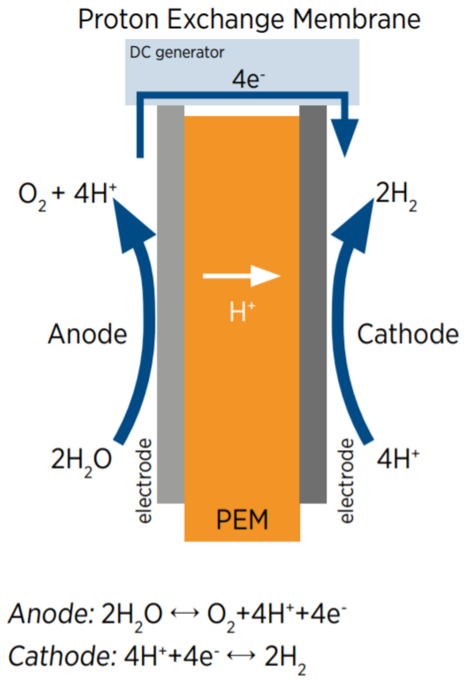


Figure 2.2: PEM electrolyser cell [44]

side, a harsh oxidative environment is generated within the cell. To withstand these conditions, the use of titanium based materials, noble metal catalysts and protective coating is necessary to increase cell lifetime and efficiency. The noble metal catalysts likely used are platinum for the cathode and iridium for the anode [40]. Factoring in these requirements have led to an increase in costs of PEM electrolysers as compared to ALK [44].

2.1.3. Selection criteria

The choice of electrolyser technology in this study depends on a lot of parameters that govern the operation and sizing of the electrolyser systems. Both ALK and PEM systems are commercial, however a choice has to be made to best suit the system design in this thesis. The driving parameters for selection are described further in detail and compared for the two technologies.

⟶ **Operating pressure**

Both ALK and PEM electrolysers have commercial units operating at high pressure ranges. While the current operating range of ALK systems is between 1-30 bar, PEM electrolysers can operate in the range of 30-80 bar [1]. The increased operating ranges of PEM might help towards reduced investments and maintenance in compression.

For the purpose of this thesis, some basic estimates for transport pressure are calculated. It is found that as per the hydrogen grid pressure of the future (50 bar), a transport pressure of 58.5 bar would be necessary to transport hydrogen over a distance of 120 km through an 18 inch pipeline for a gas velocity of 10 m/s. It can be expected that, with already existing pressure ranges further being commercial towards 2030, PEM electrolysers with operating range of 60 bar can easily replace the need for external compression to transport hydrogen [23]. Hence, with respect to operating pressures, PEM electrolyser are favoured.

⟶ Current density
PEM electrolysers have much higher current densities owing to their advanced electrodes as compared to ALK. PEM electrolysers exist with a current density of $2A/cm^2$, which is significantly larger than that of ALK, $0.45A/cm^2$ [11]. This drastically affects the size of stacks for both technologies. Owing to higher current densities, PEM electrolysers have a plant footprint of 0.048 m^2/kW, which is almost half of that of ALK [1], making PEM systems more compact in design. The current density of PEM is expected to increase up to 3 A/cm^2 by 2030, maintaining a similar sense of compactness with respect to ALK [23]. Hence, PEM electrolysers are further favoured due to their compact size.

⟶ Load range and flexibility
Electrolysers can operate under a range of loads providing flexibility necessary when coupled with renewable energy sources. A minimum load range is dedicated to avoid diffusion of gases on either side reaching close to explosive limits [11]. ALK electrolysers have a minimum load range of 10-40%, with a maximum load range close to 110% [1]. PEM electrolysers, however, do not have a minimum load (0%), due to a low gas permeability of the membrane. Such a broader load range helps to avoid frequent switching of the stacks, which has a positive effect on their lifetime [11]. In literature, PEM electrolysers have been praised to operate at much higher loads, to be as much as 160% of nominal load for a time range of 10-20 mins [69]. Thus due to a broader load range, PEM electrolysers are expected to better cope with renewable technologies.

⟶ Startup and standby
For flexible operation, PEM and ALK electrolysers are held on temperature in standby-mode due to the time required to heat up, and lower electrochemical performance in cold operation. Warm start up times are in the range of 1-5 mins for ALK electrolysers starting from heated and pressurised standby mode. Whereas for PEM, the warm startup times have been reported to be less than 10 s in MW scale [11].

Cold startups include starting of electrolysers that are completely switched off and are not heated or pressurised in the initial state. The heat-up time for electrolysers determines the time for cold startup. For large scale industrial ALK plants designed for continuous operation, necessary heat up times of 2 hrs have been reported. PEM electrolysers however, owing to their lower thermal capacity and higher current densities have much shorter cold start-up times, in the range of 5-10 mins [11].

The stand-by losses can result from purging of the gas departments after a longer shutdown (for safety reasons), applying protective current in standby (to avoid degradation of electrolysers) and while facilitating optional heating in stand-by mode (to guarantee a fast reaction time) [11]. Based on a brief literature review, it is estimated that PEM cells consume lesser power at the stack level during stand-by (2%), whereas ALK cells consume around 4% of nominal power of the stack [64].

PEM electrolysers are hence a stronger choice due to their reduced startup times and lower standby consumption.

⟶Lifetime
The lifetime of electrolyser systems can be distinguished between the stacks and BOP. The stack lifetime is defined by the decrease in efficiency with time due to degradation of the cells. It is typically defined by an acceptable efficiency drop (usually 10% efficiency loss after 60,000 hrs). A replacement or stack overhaul is necessary after the defined lifetime. Currently ALK and PEM electrolysers have a comparable stack lifetime [11], which is expected to increase through technological innovations by 2030, to a range of 60,000-90,000 hrs [1]. With a certain number of stack swaps, both ALK and PEM systems are expected to have a system lifetime of 30 years by 2030 [23]. Hence in terms of lifetime, both technologies prove to be a potential choice.

⟶Investment costs
According to various manufacturers and research institutes, the cost of an entire electrolysis system at any scale can be approximately divided into 50% stack costs (for ALK: 40-50 % and for PEM: 50-60%), further 10-20% for power electronics and lastly 30-40% for the remaining BOP [63].

The difference in costs of ALK and PEM has been significantly larger in the past. With R&D focus and increased production, the costs per kW have reduced significantly over the years. The costs are expected to decrease at a comparable level for the two technologies by the year 2030. Costs of electrolyser systems, based upon learning rates for the year 2030 are predicted to be in the range of 522-532 €/kW[1] for PEM systems, whereas 754-767 €/kW for ALK systems. The cost structure of these electrolyser systems, that is the percentage of total cost share for each of the module is expected to change with differences in learning rates of individual components [63]. With respect to specific investments costs, PEM electrolysers are preferred in the year 2030.

The expected key developments by the year 2030 for both PEM and ALK systems are listed in Table 2.1. Factoring in the expected developments of the two technologies with respect to an offshore system design, PEM electrolysers might prove to be a potential choice. Owing to high operating pressure of PEM, the need for compression might be reduced, saving space on the platform. A broad load range of PEM might prove to better cope up with itermittency of wind energy. Further on, a compact design of stacks might help save additional space on the platform. PEM excludes the need for continuous electrolyte circulation as with ALK. Lesser cold startup times and reduced switching times might save costs on maintenance of PEM systems. In general, both technologies are highly competitive, however as per this research, major advantages fall on the PEM side with respect to offshore application. Hence, **PEM electrolyser technology will form a part of this study.**

[1] For a 5 MW reference system that can be scaled within a nominal capacity of 1-100 MW [64]

Table 2.1: **2030** key developments from [60], updated with [23] [64]

	ALK electrolysis	**PEM electrolysis**
Electrolyte	Aq. potassium hydroxide (20-40 wt.% KOH)	Polymer membrane (eg. Nafion)
Cathode	Ni or Ni-plated steel	Pt and Pt-Pd, C-fibre
Anode	Ni or Co	RuO2, IrO2, Porous Ti
Current density (A/cm^2)	1.0	3.0
Operating pressure (bar)	60	100
Operating temperature ($°C$)	90	90
System lifetime (yr)	30	30
Stack lifetime (hr)	100,000	90,000
Availability (hr/yr)	8,585	8,500
Stack size (MW)	7.8	10
System size (MW)	8.6	90
Cold startup time ($mins$)	20 mins - several hours	5-15 mins
Part load operation ($\%full\ load$)	10 - 20 %	0 - 5%
Specific investments costs (€/kW)	767	532

2.2. PEM electrolyser facility design

The PEM system is relatively simpler compared to ALK system. As shown in the Figure 2.3, a typical PEM electrolyser system consists of gas seperators, dryers, heat exchangers, circulation pump and pressure control and monitoring. Usually a compressor is added on the cathode side for further gas compression. The system requires the use of circulation pumps, heat exchangers, pressure control and monitoring only on the anode side. On the cathode side, a gas separator, a deoxygenation component (typically not needed for differential pressure), gas dryer and a final compression step are required. Power electronics such as transformer and rectifier also form a part of the system to supply suitable power to the PEM stacks.

The system is available in three different design choices: atmospheric, differential and balanced thus helping to reduce costs, system complexity and maintenance. Balanced operation is the case where cathode and anode are maintained under same operational pressure. For the atmospheric operation, the pressure is less than one ATM, namely constant pressure mode. In a differential pressure operation mode, the pressure can be maintained between 30 bar and 80 bar. For this, the membrane is required to be thicker with increased mechanical stability and low gas permeability [44].

⟶Working Principle of PEM

Within the PEM system itself, the stacks operate at an average temperature of 80 - 90 °C [71]. The distilled water for conversion is supplied to the PEM stack from the anode side. Upon entering the anode side, the electrodes split the water into oxygen and hydrogen ions. The H+ ions travel through the PFSA membrane and combine with the electrons on the cathode side to form hydrogen. This hydrogen is removed from the cathode side while the oxygen is removed from the anode side of the stacks. Not all water that goes in the stacks gets converted to hydrogen and oxygen. Water comes out of the stacks at a temperature equal to that of the stack, which is recirculated back to the stack using a re-circulation pump. The pump collects the stack exit water and passes it through a heat exchanger, which cools the water down to a desired temperature for the stack. The water further passes through a de-ioniser (not shown in the Figure 2.3) to help purify the water to the quality required by the stacks. Fresh water is supplied through the same route to pitch in for the remaining water demand of the stack.

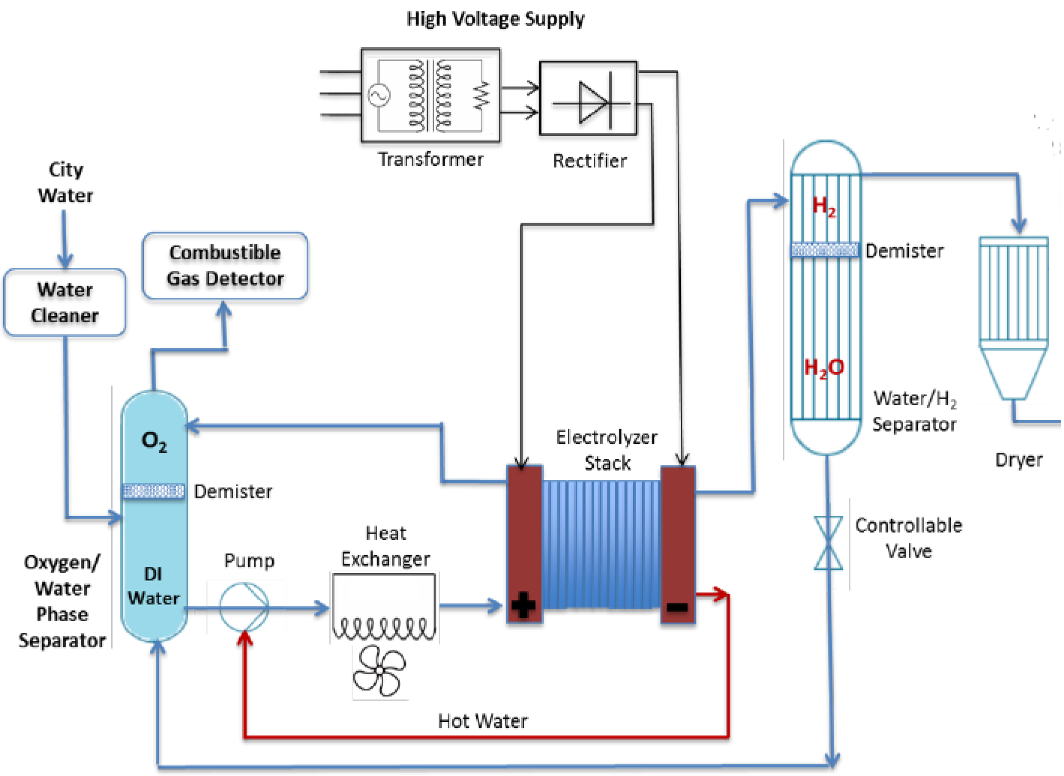


Figure 2.3: Schematic of the PEM electrolysis system showing stack and BOP parts [50]

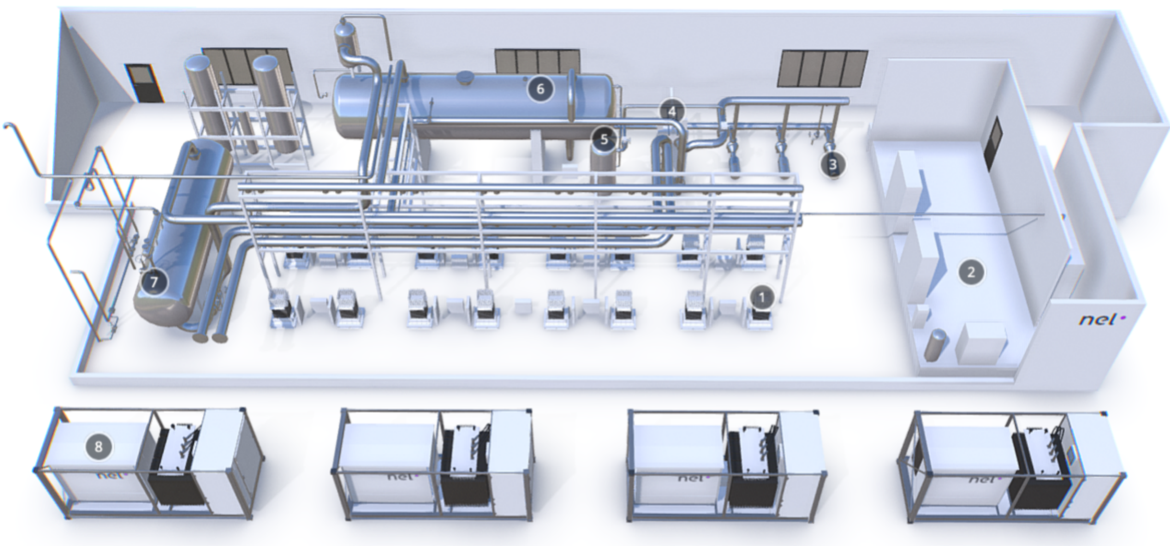


Figure 2.4: A screenshot of PEM system by nel [51]

1	Cell stacks
2	Control room
3	Circulation pump
4	Heat exchanger
5	D.I. water polishing bed
6	O2 phase separator
7	H2 phase separator
8	DC rectifer/transformer

Figure 2.4 shows a picture of PEM system by *nel* in the capacity range of 2,000-5,000 Nm^3/hr. The figure gives a good indication of how various equipment within the system could look like.

For simplicity, the total power consumption for the gigawatt platform is distributed similar to that in the ISPT study stated in Section 1.1.3, where the stacks accounted for 960 MW and the remaining BOP is rated at 40 MW, accounting to a total of 1 GW which means the BOP consumes 40 MW of power when the facility runs at full load. Next, various equipment of the PEM system including stacks, BOP and power electronics are highlighted in detail along with corresponding reasoning to support choices for the design of equipment on the platform.

2.2.1. Stacks

PEM stacks are combination of multiple cells connected in series. Stacks contain spacers (insulating material between two opposite electrodes), seals, frames (for mechanical support) and end plates (to avoid leaks and collect fluids). Figure 2.5 shows a zoomed in view of arrangement of various components within a stack.

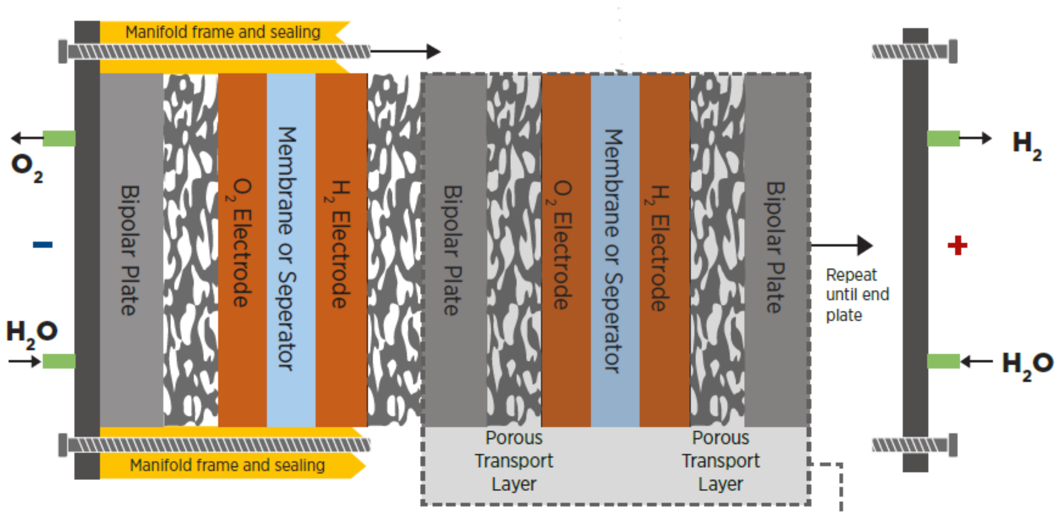


Figure 2.5: Stack level, adapted from [44]

Constant improvements in the electrolyser technologies is expected as a part of various R&D programs around the world. For PEM systems one of the major improvements are expected in the stack size, aligning with larger facilities in the future. A stack size of 10 MW is expected to be developed in the year 2030 [23], with 1-2 MW being the present stack size [44]. Hence, a total of 96 such stacks are considered for the facility to account for 960 MW. No information on weight of individual stacks is found to be available in literature. However, using data from one of the sources from DNV, the weight of a 10 MW stack is scaled to roughly around 15 tonnes. All the electrolyser stacks combined within the system design are expected to produce hydrogen at a total nominal rate of 192,000 Nm^3/hr. [2]

[2]The value is calculated as per the nominal value of hydrogen produced by a 5 MW system by Hydrogenics (now Cummins)

2.2.2. Balance of Plant (BOP)

The BOP is mainly responsible for the separation and drying of hydrogen along with cooling, recirculation and desalination of the water within the system. Various equipment used in these processes that would form a part of the offshore facility are further described in detail.

⟶Separation

Hydrogen and oxygen leave the stacks with some water content, which is necessary to separate. Gas-liquid separators thus form an important part of the BOP design. These are vertical vessels used to separate liquid and gas from their mixture. Ideally gas-liquid separation technology operates on the grounds of gravity, wherein the vertical vessel used in the process causes the liquid in the mixture to settle down at the bottom of the vessel, which is then withdrawn through a strategic outlet [61]. Oxygen and water are separated through the oxygen-water separator. Water settles down in the separator which is further recirculated back to the stack. Oxygen is further filtered through a molecular sieve to be discharged. On the cathode side, hydrogen with small amount of water enters the hydrogen-water separator. Similar to that on the oxygen side, the water molecules settle at the bottom of the hydrogen separator. The hydrogen gas then is sent further for treatment. After the water in the hydrogen separator reaches a certain liquid level, part of the water flows into the water tank [40].

Research is still being done on the number of stacks that can be connected to a single gas-liquid separator in the future. The study by ISPT estimated 99 oxygen gas-liquid separators and equal number of hydrogen gas-liquid separators for a 1 GW electrolyser facility, however, the stack size used is significantly smaller [33]. In the onshore facility design by ISPT, the report depicts one oxygen separator used for each 10 MW stack, hence, it is assumed that one oxygen and one hydrogen gas-liquid separator can be connected to each of the 10 MW stack in 2030. Finally, a total of 96 separators for oxygen and equal number for hydrogen are accounted for the offshore facility.

Both hydrogen and oxygen gas-liquid separators are sized as per the ISPT study, measuring 3.2 m in diameter and 2 m in length. The weight of the separators is estimated assuming stainless steel manufacturing [50].

⟶Drying/Purification

After hydrogen is recovered from the gas-liquid seperators, it further passes on to a set of dryers that are responsible to purify hydrogen. The drying step is responsible to filter any other contaminants and solubles within the hydrogen gas stream. Nitrogen is often used to purge electrolysers during maintenance, shut down and/or start up sequences. It has a dilution effect on the delivered hydrogen and can affect the accuracy of mass metering instruments. Additionally, small amounts of K^+ and N^+ contaminants soluble in moisture content can also be found in the hydrogen stream [47].

Pressure Swing Absorption (PSA) units are utilised in steam reforming plants and also have a potential to be integrated with electrolysers. The technology is based on physical binding of gas molecules to an absorbent material. The PSA process works at basically constant temperature and uses the effect of alternating pressure and partial pressure to perform adsorption and desorption. The process consequently allows the economical removal of large amounts of impurities [39]. A trade off can be assessed between the use of PSA units and continuous switching of the stacks. If the amount of times the maintenance and switching of the stacks is reduced, using nitrogen to purge the system also reduces. This may lead to lower amounts of nitrogen within the system and the use of a much simpler drying system. However, more research is needed to analyse this trade-off.

For complete drying of produced hydrogen, the PSA units are thus sized for a similar capacity of hydrogen as produced by electrolysers. Different capacities supplied by $XEBEC$ (manufacturer of air purification equipment) are found online. For this design the $H3100$ series with a feed flow capacity of $15,500 Nm^3/hr$ is chosen. The total number of units are calculated to be 13, where each unit weighs around 16.3 t and measures 4.7 m long and 4.3 m wide [77].

⟶Cooling

The cooling system is a complex design. It should be able to keep the stack within a desired temperature range (60 - 90 °C) under every possible operating temperature. This is to avoid generation of large temperature gradients ΔT across the cell that might result in non-homogeneous loading of the cell. This may then lead to an increase in degradation and ageing rate of the cell . The stacks can be cooled using two different methods: Excess flow of process water - where the amount of process water supplied is more than required which enables highly effective heat transfer but may also lead to corrosion. The second method is by using bipolar plates, which provide pathways for cooling water within the stack. Bipolar plates are commonly used in fuel cells, however, manufacturers are still investing a lot of effort into implementing them into electrolysers [69]. ISPT communicated in one of their webinars that future large scale stacks will probably be cooled using excess use of process water, firstly due to difficulties in implementing bipolar plates within the stacks and secondly due to increased heat rejection of larger stacks.

If the stacks are assumed to be operating at a temperature of 77 °C and the process water supplied to the stacks is required to be at a temperature of 72 °C to maintain an appropriate ΔT, it is logical that the distilled water supplied to the stacks will have to be preheated up to 72 °C. On exit side of the stack, the water coming out is generally at the operating temperature (77 °C) which will have to be cooled down to entry temperature.

A Plate Heat Exchanger (PHE) is hence used in the system design to facilitate both heating and cooling of water. Titanium based PHE help prevent corrosion in marine environments. PHE is also a preferred choice for topsides applications as compared to shell and tube type, considering the cost benefit owing to weight and footprint savings [7]. In this design, it is assumed that approximately 10% of the water that goes into the stacks is converted into hydrogen and oxygen. Hence a PHE of 270 m^3/h is used in the design to cool down the exit stack water using seawater, and further recirculate it back to the stacks. The controls to cool down the exit water to approximate entry level temperature are not looked into. Sizing data on PHE is found from an online brochure of $ArmstrongFluidTechnology$. The PHE selected has a footprint of 2.3 m^2 and weighs around 1 tonne [65]. Further, the

PHE can also be split into two different systems- one to cool down exit stack water using seawater, and another to preheat remaining entry water using exit stack water.

⟶Desalination

For offshore applications as in this case, since no other water source is available in abundance as seawater, the desalination system forms a major part of the facility design. The desalination system design is adapted from one of the studies of North Sea Energy [27].

Desalination is needed to filter the seawater to the water that can be used by the stacks. PEM electrolysers need highly distilled water (<1 $\mu S/cm$) for operation and to avoid excessive degradation of stacks. The salinity of the North Sea averages between 34-35 grams of salt per litre or a total dissolved solids (TDS) content of $35,000ppm$. In order to reach the minimum TDS content required by the PEM electrolysers, the following steps have to be followed in the desalination process.

- Pre-treatment - to remove dissolved solid content
- Seawater Reverse Osmosis (RO) - to remove salts towards 300 ppm TDS
- Low brackish water RO - to bring the TDS level down to <50pmm
- Post-treatment - De ionising and to ensure water quality reaches <1 $\mu S/cm$.

One of the main reasons to consider pre-treatment of seawater before RO is to prevent scaling or accumulation of insoluble salts in the RO membrane. In this design the LennRO-SW systems for seawater reverse osmosis by $Lenntech$ is used, with a permeate flow capacity of 100 m^3/hr each. These systems are already equipped with pre-treatment installation. In total, 3 such systems are considered to meet the distilled water requirements of the facility (300 m^3/hr), each weighing around 34 tonnes and having a footprint of 16m2, and producing water of 300 ppm. To further improve the water quality, a second desalination step is considered. LennRO-BW (low brackish) systems with a permeate flow capacity of 70 m^3/hr are chosen. Four such systems are taken into account to meet the distilled water quantity requirement of the facility, each weighing roughly 24 tonnes and covering a surface area of 7 m^2. The system is expected to bring down the TDS content to 50 ppm. For the final step of de-ionisation (ion exhange) no concrete data is found on the sizing and capacity. It is considered to be capable of reducing the TDS content upto 0.1 $\mu S/cm$ [27].

⟶ Water pumping & Re-circulation

The distilled water requirement for the electrolyser facility is calculated to be approximately 300 m^3/hr as per the requirement for current state-of-the-art PEM stacks. The capacity of re-circulation pump required to recirculate the stack exit water, in addition to the remaining water demand to the stacks, would result in same capacity as that of total water demand by the stacks. Data on circulation pumps is found from a pump supplier $CALPEDA$. The pump selected has a capacity of 300 m^3/hr and weighs around 0.64 tonnes [12].

Seawater pumps are used to pump in seawater from the ocean to the platform. Data on dimensions and weight of seawater pumps is not found online. Since the seawater pumped to the platform would be much larger than the distilled water flow on the platform, a size twice as big as that of the re-circulating pump is considered.

2.2.3. Power electronics

Power electronics consists of the electrical distribution, conversion and protection equipment responsible to integrate the wind farm with the electrolyser system on the platform. The stacks operate at a voltage level between 0.6 - 1.0 kV DC. It is assumed that the rest of the BOP also operates on the same level but mainly on AC voltage.

The inter-array cables that loop through multiple wind turbines are the connection medium between the wind farm and the central platform. The current standard voltage level for offshore wind inter-array grids is 33 kV. With ambitious offshore wind targets and increasing turbine size in the future, a higher voltage level of 66 kV is expected to be used for inter-array connections of new offshore wind projects. A higher voltage level increases the number of wind turbines that can be connected to a single inter-array cable, and consequently decreases the number of strings used (as shown in Table 2.2) and therefore, the number of J-tubes required at the offshore substation [36, 66].

However, the change in inter-array voltage level not only affects the cable design but also the system design on the platform in terms of transformer ratings, switchgear ratings, number of equipment, etc. The 66 kV inter-array grid demands higher rated equipment on the platform as compared to 33 kV .

Inter-array voltage (kV)	**Cable size** (mm^2)	**Apparent power** (MVA)	**Total cables for 1** GW
33	800	39	27
66	630	83.8	12

Table 2.2: Cable properties for 33 and 66 kV inter-array voltages

⟶Transformers (Tx)

Transformers are electrical equipment used to step down or step up voltage levels of the power supplied through them. The transformers are sized based upon the available ratings in the industry. It is preferred to use bigger transformers rather than multiple smaller ones to reduce space, as suggested by experts at DNV. Considering that all transformers in the facility are required to be protected using switchgears, the maximum flow through a transformer can be found out using the below equation:

$$S_{winding} = \sqrt{3} \times U_r \times I_r \tag{2.2}$$

where U_r is the rated (high) voltage of the transformer and I_r is the rated current of the switchgear.

For a switchgear with a voltage rating of 66 kV and a current rating of 2500 A, the maximum power flow that can be transmitted through it is calculated to be approximately 250 MVA. Hence, a total of 4 transformers of 250 MVA each are considered accounting for a total platform capacity of 1 GW. These transformers are responsible to step down the inter-array voltage of 66 kV to 33 kV. Further, an extra step is required to step down the grid voltage from 33 kV to 1 kV. Considering the power flow from a 33 kV switchgear for the same current rating, a total of 8 transformers [3] rated 125 MVA each, are further added to the facility design.

Power transformers of such high rating are built customarily, hence no precise data is found online. To scale the dimensions and weight, scaling relationships are used as per a study for the European Commission [53]:

$$Weight \longrightarrow (\frac{kVA_1}{kVA_0})^{3/4}$$

$$Length = width \longrightarrow (\frac{kVA_1}{kVA_0})^{1/4}$$

where kVA_0 and kVA_1 are the power the ratings of the base transformer and transformer under study respectively.

⟶Grounding transformers

Earthing/Auxiliary/Grounding transformers form a common part of an offshore substation [57]. In distribution systems it is common to use star-delta type winding in high power distribution transformers that step down the voltage level [24]. In that case all loads can be expected to be connected on the delta side which does not have a neutral point in itself, and then it becomes necessary to create an artificial neutral point that will help ground the main transformer during faults. For this grounding transformers are used. [8].

They are single winding transformers that are connected to each of the buses. During faults, these transformers help the fault current at any of the main transformer phases, to go through the ground and return back to source. They are generally sized 3% of rated power of main transformers to handle a fault current for 10 seconds [8]. For the 66 kV busbar a grounding transformer rating of 7.5 MVA is calculated at each bus. For the 33 kV busbar, the rating of is calculated to be 3.75 MVA at each bus. Similar to high power transformers, grounding transformers are sized using the scaling relationships.

⟶Switchgears

Switchgear is a general term covering switching devices and their combination with associated control, measuring, protective and regulating equipment. For simplicity we can assume a switchgear to be a combination of circuit breaker, disconnector and an an earthing switch, that breaks the circuit and disconnects the faulty part from the main system during faults. A switchgear bay is usually a combination of the three devices in series.

The number of switchgear bays in a facility depend on the total number of equipment to be protected [36]. Feeder bays are used for feeder cables, where as transformer bays for transformers and so on. Two large blocks of switchgear bays are estimated for the facility design. The first block consists of 24 high voltage switchgear bays (66 kV) for high voltage

[3] An even number of transformers is preferred for platform weight distribution

equipment. The second block consists of 20 medium voltage switchgear bays (33 kV) for medium voltage equipment. The distribution of switchgear bays in the facility can be observed in the single line diagram (SLD) in Appendix B.5.

⟶AC/DC Converters
Rectifiers or AC/DC converters are used to convert AC power to DC, which is further supplied to the stacks. The different type and topology of converters that can be used to integrate renewable sources, especially wind turbines with electrolysers is still under research. Various topologies are being tested for voltage fluctuations, harmonics, ripples and current control affecting the performance of the electrolyser stacks and total system response [79].

Most of the converter systems used on offshore substations to transport electricity via DC links, are immensely large with high to extra high voltage ratings. For the facility in this study, the need for low voltage converters arises due to lower level requirement of the stacks. However, no information on low voltage converters of high power ratings are found in an attempt to implement saving of platform space. Thus a 10 MW rectifier unit is used. A total of 96 such units are implemented in the design, where each unit is connected to one 10 MW PEM stack. It is assumed that the rectifiers would also be protected from faults using circuit breakers. Sizing data is obtained online from $AEGPowerSolutions$, where each unit weighs around 5 tonnes with a footprint of roughly $10m^2$ [62].

⟶Batteries for backup
The intermittent nature of wind can have major influence on the power produced by the wind farms. At some instance the power supplied to the platform can also reduce drastically due to dip in wind speeds. Also during faults, opening of circuit breakers can cause discontinuation of power supplied to the stacks. In cases like these, a backup power supply becomes important to help cope up with the fluctuations of power supplied to the electrolyser system and BOP. One of the important requirements for a backup supply is that it should not rely on any fuel sources/processes on the platform. As compared to traditional diesel generators, batteries provide a good alternative in terms of safety and explosions. Lithium ion batteries have high energy densities, hence more compact, and are becoming an increasing interest for offshore applications [43].

For the required battery capacity, backup requirements must be known. Electrolysers can be kept active on standby modes, when there is no sufficient power available to produce hydrogen. In the Hot standby mode, there is no production of hydrogen, but the stacks and BOP are kept under operating temperature and pressure. In the Cold standby mode, the electrolysers and BOP are switched off completely. In the hot standby mode, a power consumption of 2% of the nominal power by the stacks and up to 5% by the BOP is assumed [49], whereas none of it in the cold standby mode.

To enable the rapid reaction of electrolysers, we assumed the system to be on hot standby for an hour when no power is available from the wind farm. After which, the electrolysers shall switch to cold standby. For the battery to be able to supply the electrolysers facility for atleast an hour, we sized the battery as follows

$$P_{battery} = 2\% \times Stack_{ratedpower} + 5\% \times BOP_{ratedpower} \tag{2.3}$$

We calculated 22 MWh of battery capacity needed for the platform, to maintain the stacks and BOP in hot stand by mode for 1 hour. In the design, a total of 9 units of 2.5 MW each are used, found online from $SAFT$, a manufacturer of batteries.

⟶ **STATCOM**

The need for reactive power compensation arises when the power system absorbs or produces reactive power which can affect the system voltage drastically. STATCOM devices are responsible to produce and absorb reactive power as per the system requirements to maintain voltage stability. The infield cables produce reactive power calculated using the below equation [36]:

$$Q_c = 3 \times (\frac{U_r}{\sqrt{3}})^2 \times \omega \times C \quad (2.4)$$

where capacitance C is in the range of 0.2 - 03 µF/km.

For 66 kV infield cables, this accounts to 274 - 411 kVar/km. Assuming an infield cable length of 150 km within the wind farm, this could account to 65 MVAR of reactive power produced. On the contrary, transformers help absorb reactive power during full load conditions. The main high power transformers of 250 MVA are themselves capable of absorbing entire reactive power during full load. Additionally, future wind turbines are also expected to be capable of compensating for the reactive power within the wind park [67].

Hence, for simplicity it is assumed that no reactive power compensation would be needed on the platform.

2.2.4. Auxiliary equipment and systems

The various other equipment and systems that potentially form a part of offshore platforms to help operations and maintenance are highlighted further. The sizing of some of the equipment and components is referred from an expert study on offshore substation design by DNV.

Offshore workers are responsible for timely maintenance of the platform operations. As communicated by DNV, most of the electrolyser systems can be operated remotely and hence, there is no need for daily supervision. Hence in this study, an unmanned platform is assumed, however with emergency accommodation for a less frequent stay of 12 people. Accommodation becomes economically attractive when the distance to port is greater than 75 km. The need for an Helideck is not only driven by the distance to shore and travel time but also to use it for maintenance of the surrounding wind farm [22]. A helideck of roughly 150 m^2 is assumed to to form a part of the platform. The helideck is usual placed on top of the accommodation module and forms a part of the upper deck.

A fire protection room and a workshop are also added to the design. A cooling room is also included to provide cooling for different areas of the platform. For access to various decks, staircases are considered on the two opposite sides of the topsides at each deck. Assuming a 4 level platform, a total of 6 such staircases are assumed. A diesel generator is assumed as the source for final backup which can keep the minimum essential services such as lighting and communication ongoing for at least 18 hours after power failure.

2.2.5. Topsides steelwork sizing

Supported by the substructure, the topsides can be taken as the heart of an offshore platform. In case of oil and gas platforms, it holds the equipment to explore and process oil and gas, as illustrated in Figure 2.6. In case of offshore substations, the topsides equips various power electronics to collect, convert and transmit electricity. In this study case, the topsides will facilitate all equipment to collect, convert and distribute the power from the wind farm to the electrolyser system. Various equipment for hydrogen production and treatment will also be placed on the topsides. In summary, all the stacks, balance of plant, power electronics and auxiliary systems detailed in the previous sections will be placed on the topsides of the P2G platform in this study.

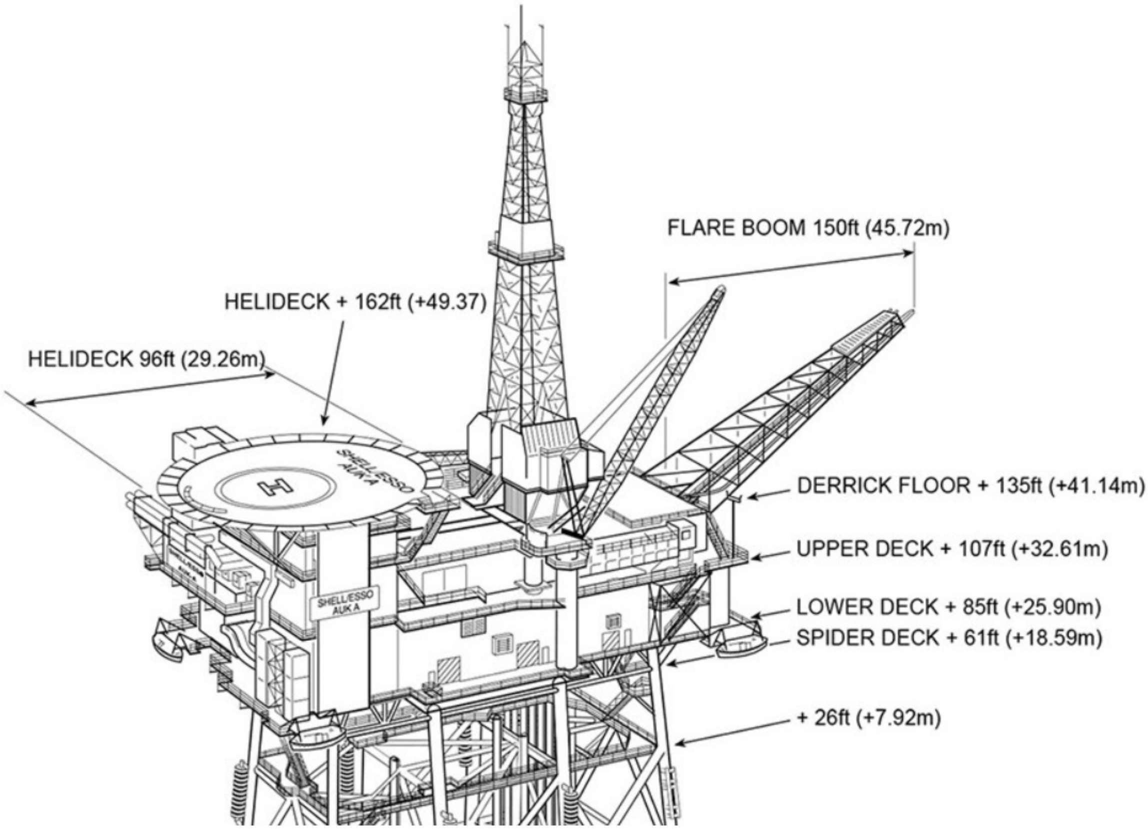


Figure 2.6: An illustration of topsides for an O&G platform, taken from [56]

The size, scale and weight of the topsides depends upon the sizing of the equipment to placed and the process flow on the platform. A detailed design of the topsides is a complex study with respect to various disciplines. For simplicity, the topsides is sized based upon equations for P2H2 platform from a study by DNV GL (now DNV) [37].

$$Topside\ volume\ (m^3) = Power\ (MW) \times 193.55 \tag{2.5}$$

$$Supporting\ steelwork\ mass\ (t) = 1.035 \times Total\ equipment\ mass \tag{2.6}$$

$$^{4}Auxiliary,\ cladding\ and\ grating\ mass\ (t) = 0.17 \times Total\ equipment\ mass \quad (2.7)$$

The total topsides mass is calculated by adding all mass estimates of the equipment, equation 2.6 and equation 2.7. The total topsides mass is estimated to be **13,492 tonnes**, a comparable estimate to that of a high level study by Offshore Wind Energy Council [19]. In this study the topsides size is driven solely by the weight of the equipment, however more research should be done to check the influence of equipment and system footprint on the topsides design.

2.2.6. Topsides layout design

The layout of the topsides is an important design aspect in order to optimally utilise the facility space, maintain an even weight distribution and reduce risks and hazards. Design of the layout is complex and is also based upon the type of application of the platform. Since no research is readily available online, especially on the layout design of an offshore hydrogen facility, some assumptions are made with respect to the expected process flow and safety considerations. The expected process flow means the flow of fluid (distilled water or hydrogen) from or towards various equipment in combined or separate manner at different stages of the process. Two dimensional layouts [5] for the facility are generated and are included in the Appendix B.

⟶Deck 1/Cable deck

This is the lowest deck of the offshore platform. It is designed to accommodate incoming feeder cables from the wind farm and hydrogen pipelines leaving the platform towards network of pipelines on the seabed. Being closest to the sea level, this deck is assumed to also support seawater pumping and desalination system including pre treatment, first stage and second stage of desalination. The deionisation is assumed to be rather on the upper decks closer to the stacks to avoid excessive higher quality piping. This deck would hence comparatively require less steelwork.

⟶Deck 2

Deck 2 is assumed to be comparatively secure than the rest of the decks for the operators. On this deck, emergency accommodation, workshop and fire protection rooms are considered to be installed. Deck 2 is also equipped with the two blocks of switchgear bays, both for HV and MV equipment. The main high power transformers are also assumed to be placed on this deck along with the grounding transformers. Finally the battery and control room also formed a part of this deck. One of the reasons behind having refuge and major electronics on one of the lower decks is to avoid contact with any hazardous leakages in hydrogen gas.

[4] The original formula is revised while discussions with DNV experts

[5] All layouts of the facility in this report are purely based on assumptions and are for illustration only

⟶Deck 3

Deck 3 equips systems for hydrogen production and treatment. The layout is designed in a way to keep the process design simple and compact. A combination of two PEM stacks powered by two individual converter units along with one hydrogen and one oxygen separator for each stack is assumed to form a module, within which they are installed close together. This is considered mainly due to the immediate need to separate water content from the produced hydrogen and oxygen and to avoid excessive DC cabling between converters and stacks. An illustration of the 20 MW module is shown in figure 2.7. A total of 24 such modules (480 MW) are installed on this deck. The module size would however vary depending on developments in the future and is presented here just for illustration.

A block for all PSA units is considered to be separately installed as the drying unit for the hydrogen produced. The re-circulation pump and PHE also form a part of this deck. In case of any emergency leakages in hydrogen and oxygen equipment, the gases would rise and flow away from the platform without posing risks to operators and power electronics on the lower deck.

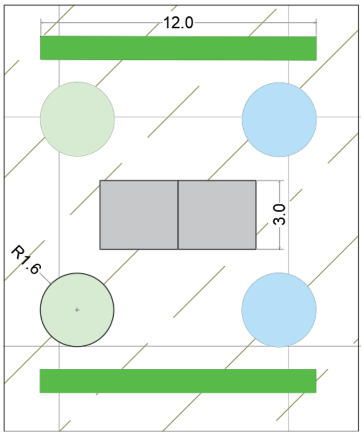


Figure 2.7: Illustration of a 20 MW module, including stacks(green), rectifiers(grey) and H2 and O2 separators (blue and green circles resp.)

⟶Deck 4

This deck forms the top most deck of the offshore platform. The remaining 24 modules for hydrogen production are equipped on this deck. Additionally, a helideck for air crew transfer and an emergency diesel generator (with diesel tank) is installed.

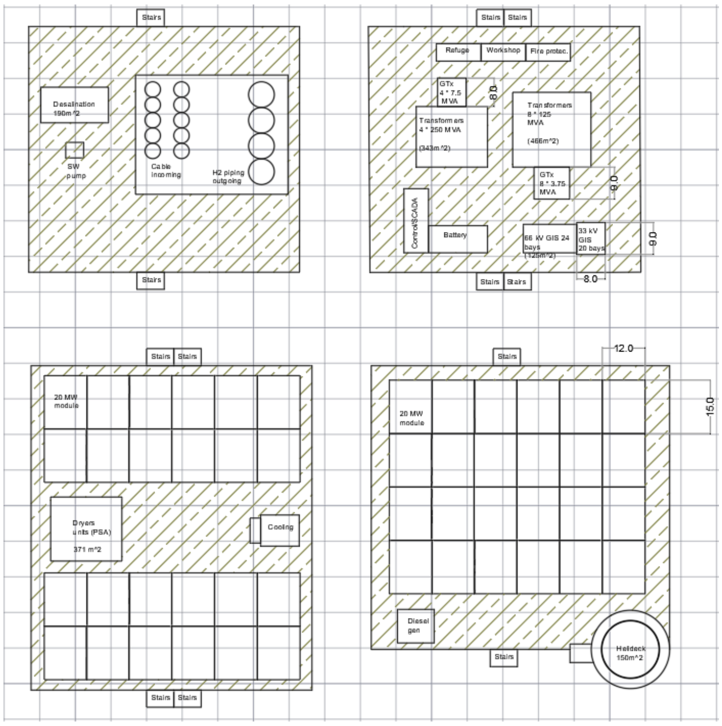


Figure 2.8: Illustration of deck layouts

2.3. Offshore substructure selection

Substructures support the topsides and keep it above the sea level. Over the years, various types of substructures both fixed and floating have supported various activities in the North Sea including Oil&Gas and wind power collection and transmission. This study also looked into the feasibility of such offshore platforms to support the designed topsides. To start with, fixed platforms are considered as a part of the base case.

A research on various fixed offshore platforms in the North Sea is done to help choose the two most dominant platforms in the North Sea - Jackets and Monotowers. The list with researched data can be found in the Appendix A.

⟶Monotowers

Substructures that support topsides using monopiles are known as 'monotowers', which are basically monopiles with a transition piece attached to support a facility without workers. Monopiles are cylindrical steel towers generally 6-7 m in diameter. Although they are easy to transport and install, they have very limited weight carrying capacities and are sensitive to fatigue from wind and wave loading [5]. Monopiles remain to be a more favorable support structure choice for wind turbines rather than platforms due to limited carrying capacities. This is also clearly visible from the researched data in Appendix A

Some rough estimates are made to check the maximum carrying capacities using state-of-the art 'XXL' monopiles, that are 8-11 m in diameter [5]. It is found that the monotowers are incapable of carrying a topsides weight of more than 2,000 tonnes. Based upon the estimated topsides mass in this study, it is concluded that almost 10 such monotowers would be needed. This is expected to be infeasible and hence montowers/monopiles did not form a part of the design further.

⟶Jackets

A jacket support structure is a fixed structure consisting of a welded tubular space frame with three or more legs. They have the benefit of being dynamically stiff, and therefore less susceptible to long term fatigue. Additionally, the open structure of the jacket significantly reduces the available area for wave loading and uses up 40% less steel than monopiles [5, 75]. Through reviewing various offshore platforms in the North Sea, it is found that jacket platforms have a history of supporting very heavy topsides, in some cases up to 30,000 t. It is fair to assume that jackets are a reliable support structure for offshore facilities. An illustration of an offshore jacket structure is shown in the figure 2.9

Figure 2.9: A 3D CAD model of an offshore jacket structure [14]

The jacket platform is generally sized based upon the topsides weight and site conditions including water depth, wave loading and so on. For simplicity, to size the jacket for the estimated topsides, equations from the DNV GL (now DNV) study are used [37].

$$Mass\ per\ unit\ water\ depth_{tonnes/m} = 0.018225 \times topsides\ mass - 15.792785 \quad (2.8)$$

$$Anode\ mass_{tonnes} = 0.0095 \times jacket\ mass + 7.5265 \quad (2.9)$$

where anodes or sacrificial anode systems are attached to the submerged un-coated portion of the jacket platform to provide cathodic protection, thus reducing corrosion rate [73]. Assuming a 4 - legged jacket structure, the pile mass is estimated from a study by NREL [48], where piles are long cylindrical hollow steel tubes hammered through the jacket legs in to the seabed.

$$Pile\ mass = 8 \times (Jacket\ mass)^{0.5574} \tag{2.10}$$

Assuming a secondary steel mass of 158 tonnes [37], the total mass of the jacket substructure to support the topsides in a 30 m water depth is estimated to be **8,238 tonnes**.

2.4. Summary

After detailing this system design and assessing the total mass of equipment and the facility, some key considerations and observations/results are detailed.

Table 2.3 summarises the key details of stacks and balance of plant for the production and treatment of hydrogen on the platform. It can be observed that the stacks are the heaviest equipment on the platform within the designed 1 GW PEM electrolyser facility.

Equipment	**Capacity**	**Total units**	**Total mass (tonnes)**
PEM stacks	10 MW, 2000 Nm^3/hr	96	**1,440**
H2-liquid separator	2000 Nm^3/hr	96	154
O2-liquid separator	1000 Nm^3/hr	96	154
PSA units (dryers)	15,500 Nm^3/hr	13	212
LennRO - seawater	100 m^3/hr	3	103
LennRO-brackish	70 m^3/hr	4	96
PHE	270 m^3/hr	1	1.0
Seawater pump	850 m^3/hr	1	1.2
Re-circulation pump	300 m^3/hr	1	0.6

Table 2.3: Summary of stacks and BOP in the system design

Table 2.4 summarises the main components and parameters for the protection, distribution and transmission of wind power to the electrolyser system on the platform. A single line diagram (SLD) of the electrical layout is included in Appendix B. High power transformers and AC/DC converters are the heaviest electrical equipment in the list for power electronics on the platform.

Equipment	**Capacity**	**Total units**	**Total mass (tonnes)**
High power transformer	250 MVA (66/33 kV)	4	**911**
High power transformer	125 MVA (33/1 kV)	8	**1084**
Grounding transformer	7.5 MVA (66 kV)	4	66
Grounding transformer	3.75 MVA (33 kV)	8	78
HV swithgear bays - block 1	66 kV	24	108
MV switchgear bays - block 2	33 kV	20	28
AC/DC converters	10 MW	96	**1200**
Battery backup	2.5 MWh	9	176

Table 2.4: Key parameters of power electronics on the platform

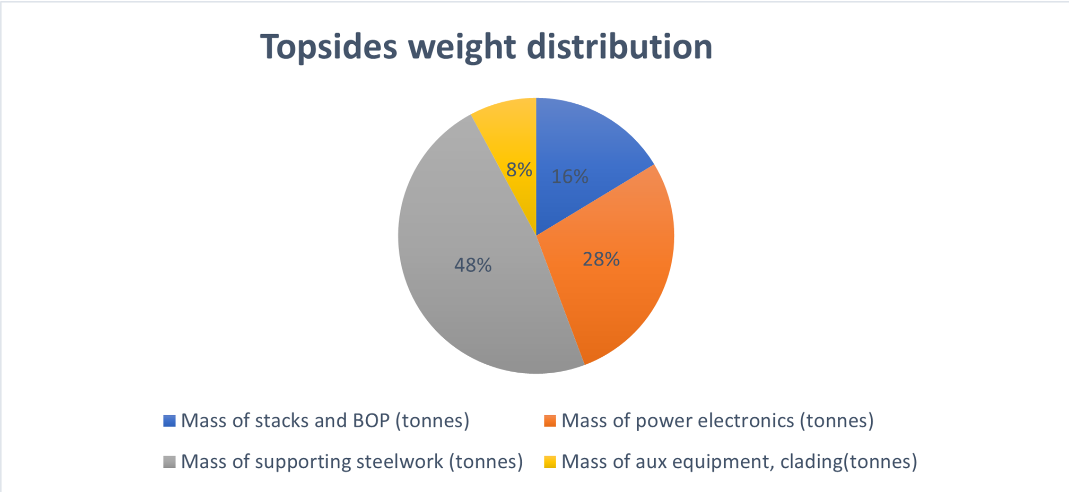


Figure 2.10: Mass distribution of the topsides

All of the equipment contribute to the total weight on the platform. The total mass of the topsides is roughly estimated to be 13,492 tonnes. From the distribution of the topsides mass in Figure 2.10, it can be observed that the steelwork carries the highest percentage of the total mass, This steelwork is responsible to support all the equipment whose combined mass is roughly close to the mass of the supporting steelwork.

To support the topsides facility, both monotower and jacket platforms are assessed and their mass requirements calculated. It is concluded that montowers are not a feasible substructure option to support such a topsides facility, due to their limited weight carrying capacities, complexity in estimating accurate weight distribution and the need for excessive amount of cabling between multiple monotowers. Jackets on the other hand are much suitable substructures due to their high weight carrying capacities and lower steel usage. The total mass of the jacket to support 1 GW P2G topsides is calculated to be 8,238 tonnes.

3
COST MODELLING

This chapter highlights the methodology, approach and expressions to calculate various costs involved in the P2G offshore platform over it's lifetime. In Section 3.1, the various effects of market growth and time on the costs along with method to calculate the additional costs are highlighted. Section 3.2 details the approach to estimate direct costs for stacks, BOP and power electronics. Section 3.3 estimates the costs for the fabrication and installation of substructure and topsides. In Section 3.4, the total fixed capital investment is highlighted along with general assumptions to help calculate the total cost of ownership. Section 3.5 details the levelised cost of hydrogen. Finally, Section 3.6 summarises the chapter with key findings in cost contributions.

3.1. Market effects and other costs

Since the developments of P2G systems and their deployment in the future depend among other things, on the profitability and thus mainly on the total investments, it becomes necessary to examine and estimate the potential of cost reductions for accurate insights in the total ownership costs. In this thesis, two important aspects: Economies of Scale(EoS) and Inflation; that affect the costs of various systems and components over time and production are analysed. Additionally, to account for costs related to installing and getting the equipment ready to use are also looked into. All of these aspects are implemented within the cost model to estimate the total cost of ownership of the P2G facility in the year 2030.

The term 'economies of scale' is often confused between the cost reductions due to doubling of cumulative production/installation volume and cost reductions due to scaling up of the units in terms of nominal power. However in this thesis, cost reductions due to up scaling of power/scale will be termed as 'economies of scale', where as the cost reductions due to cumulative doubling of production/installation volume will be termed as the 'learning rates'. The key assumptions for these factors made in the cost model are described further in detail.

The economies of scale, learning rates and inflation are implemented for various equipment cost data with respect to the source year of the data obtained. It is important to make sure that these factors are included in cost modelling either directly through a research estimate or by manual implementation.

3.1.1. Economies of Scale (EoS)

The economies of scale refers to the effect of cost reduction attained through an increase in size/scale/power via up scaling of a system. Using a logarithmic relationship is a common method for estimating costs by scaling, also known as 'six-tenth factor' or 'scale factor', according to the following equation:

$$C_b = C_a \times (\frac{S_b}{S_a})^f \tag{3.1}$$

where C_b stands for questioned costs for the system with scale S_b (size, capacity, nominal power) of the component, and C_a and S_a represents the costs and scale of the known reference component respectively. The value of f is specific to the component or can be taken as an average for a group of various equipment [64].

3.1.2. Learning rates

The formal concept of learning rates/curves describes the empirical finding that cost of an industrially manufactured product decreases by a constant percentage for every cumulative doubling of its produced volume, where the percentage is commonly referred to as the 'learning rate'. This effect can be attributed among other things, to increase in efficiency of manpower, increased utilisation of different sectors such as logistics, improvement in existing production technologies, etc. Expression for learning rate is

$$LR = 1 - PR \tag{3.2}$$

where LR is the learning rate and PR is the progress rate. If the cumulative production is doubled, then the costs would decrease to PR of the original costs [63]. For eg. an LR of 12% would mean that the original costs reduce by that percentage after doubling of cumulative capacity.

To calculate the effect of learning on the costs of various equipment it is necessary to estimate the expected cumulative production of PEM electrolyser systems by the year 2030. To start with, the scenarios developed by STORE&GO for a sustainable future are analysed which estimate the required installed capacities of electrolyser systems and other renewable energy sources in 2030 and 2050. In a moderate scenario, the study predicted 300 GW of global electrolyser production by 2030, where the share of PEM electrolyser systems in the total production would be 40% [63]. Hence in this thesis, a global cumulative production of 120 GW [1] of PEM electrolyser systems is assumed by the year 2030.

For this thesis, a linear growth in cumulative production of electrolysers globally is assumed between 1 GW of capacity production in 2014 and 120 GW in 2030 [63]. It is estimated that learning rates would decrease the costs in 7 steps with every doubling of cumulative capacity (2, 4, 8, 16 GW..) until 120 GW. For equipment with cost reference years before 2014 or much after, the learning rates are applied from then on.

[1] The scenarios in the STORE&GO report are ambitious as compared to other similar studies.

3.1.3. Inflation

Simply stated, inflation is the deterioration of the value of money over time. In other words, an equipment today will be sold at a higher rate than it would have been sold a few years ago. Between 2018 and 2021, the inflation rate in the Netherlands has fluctuated between 1 and 2% [25], hence for simplicity we consider an average inflation rate of 1.5% every year until 2030. The rate is implemented in cost model for all equipment with respect to their reference years for estimated costs.

3.1.4. Total fixed capital investment

To calculate the total investment for a P2G facility, the handbook for Chemical Engineering Design by Gavin Towler is used [70]. The fixed capital investment is the total cost of designing, constructing and installing a plant and associated modifications needed to prepare the plant site. The fixed capital investment is made up of:

- Inside battery limit (ISBL) investment - the cost of the plant itself
- Outside battery limit (OSBL) investment - modifications and improvements made to the site infrastructure.
- Engineering and construction costs
- Contingency costs

The ISBL costs, in addition to the purchase equipment costs account for various other costs such as piping, installation and erection of equipment, civil costs, insulation, etc, for which Lang Factors are commonly used. This helps to calculate ISBL costs also known as 'direct costs/installed costs', by multiplying certain factors to the purchase equipment costs. The following [2] expression is used to calculate ISBL investment

$$C = \sum_{i=1}^{i=M} C_{e,i}[(1 + f_p) + (f_{er} + f_{el} + f_i + f_c + f_s + f_l)] \tag{3.3}$$

where factors for,

Major equipment, total purchase cost	$C_{e,i}$	
Equipment erection	f_{er}	0.3
Piping	f_p	0.8
Instrumentation and control	f_i	0.3
Electrical	f_{el}	0.2
Civil	f_c	0.3
Structures and building	f_s	0.2
Lagging and painting	f_l	0.1
Offsites	OS	0.3
Design and Engineering	D&E	0.3
Contingency	X	0.1

[2] The material factor is ignored due to lesser knowledge of the construction material for various equipment

The factors are carefully selected while calculating ISBL costs of each of the equipment to avoid repetition (for eg. topsides fabrication vs structure and building). Finally, once the ISBL costs are estimated, the total fixed capital investment can be calculated using the following expression

$$Total\ Fixed\ Capital\ Investment = C(1+OS)(1+D\&E+X) \tag{3.4}$$

hence, including the engineering, contingency and other costs [70].

3.2. Plant costs

In this section, the purchase costs of the various equipment of the P2G plant are estimated and further ISBL costs are calculated for stacks, BOP and PE.

3.2.1. Stacks

The stacks consists of multiple components, all of which have different learning rates. Using this, the study by STORE&GO estimated a specific investment cost [3] for PEM electrolyser system to be [4]650 €/kW including an inflation rate of 1.5% by 2030. Hence the learning rates and inflation are not separately implemented for the stacks in cost modelling. Using the expected cost share (42%) of stacks within the PEM electrolyser system, the stacks accounted for 273 €/kW (including inflation and learning rates in 2030).

For economies of scale, the scale factor for the stack module varies with the changing cost structure due to learning effects. However, the stack does not show potential for large cost reduction via EoS because of its modular design and limited cell size. To take these effects into account, a dynamic scale factor is implemented for the electrolysis cell stack [64]

$$f = 1 - (1 - f_o) \times e^{-\frac{S}{S_o}} \tag{3.5}$$

where f_o = 0.89 is the basic scale factor, S_o = 2 MW is the average maximum stack size in 2030 and S is the questioned scale, 10 MW in this case.

The dynamic scale factor f is calculated to be 0.999, hence proving the lesser effect of EoS due to modularity of the stacks. Then using equation 3.1, the total costs are scaled to account for 960 MW of PEM stacks. In order to have all system costs on purchase level ($C_{e,i}$), already included Lang factors (in the STORE&GO study) are divided from the stack costs.

Finally, direct costs for stacks are calculated using Lang factors from Equation 3.3, that included erection, piping, electrical and civil costs. **The direct costs for PEM stacks ($ISBL_{stacks}$) are calculated to be 508 MEUR (508 €/kW) for 960 MW of stacks in the year 2030**.

[3]Specfic investment costs already include Lang factors, which can be removed to obtain purchase costs
[4]The specific investment costs are however, derived for a 5 MW reference system scalable for a nominal power range of 1-100 MW [63]

3.2.2. Balance of Plant

Firstly, costs of BOP for a 1 MW PEM system are obtained using a cost analysis study from NREL [50]. The BOP includes the liquid separators, dryers, plate heat exchangers, pumps, polishing (de ioniser), controls, valves and instrumentation. The costs can be found in Appendix C. Piping costs from the study are not considered as they are further collaborated into direct costs.

Economies of scale can be obtained when P2G systems are scaled up in power/capacity and hence the BOP size. As per research and some indications from DNV, a 100 MW module of P2G system can be expected to be commercial by the year 2030 [23]. Hence, economies of scale can be observed while scaling the obtained costs of BOP from 1 MW to a 100 MW system. Further on, the costs are multiplied by 9.6 to account for assisting 960 MW of stacks in the facility.

Investment costs for desalination units (RO) are found to be 3500 €/kW_{2020} [27]. Based upon the power rating and units used, the costs for both desalination stages are calculated. An average learning curve of 13% is implemented in the model to account for BOP and RO learning effects by 2030 [63]. An inflation correction factor of 1.16 for desalination and 1.25 for the rest of the BOP is multiplied. Finally, the direct costs of BOP are obtained using the Lang factors in Equation 3.3.

The direct costs for the BOP ($ISBL_{BOP}$) including desalination are estimated to be roughly 67 MEUR (67 €/kW) in the year 2030.

3.2.3. Power electronics

The costs for switchgears, high power transformers and grounding transformers are estimated using expressions derived for substation electrical equipment [21]. For high power transformers between 50-800 MVA, the costs are estimated using the following expression:

$$C_{TR} = 42.688 \times A_{TR}^{0.7513} \tag{3.6}$$

where A_{TR} is the rated power of the transformer in MVA and C_{TR} is the cost of the transformer in k€(2011 price) .
For grounding transformers, the following expression is used (upto 150 MVA):

$$C_{TR} = -153.05 + 131 A_{TR}^{0.4473} \tag{3.7}$$

Further, the cost of switchgears are estimated using the following expression:

$$C_{SG,MV} = 40.53 + 0.76 V_n \tag{3.8}$$

where V_n is the nominal voltage in kV and $C_{SG,MV}$ is the cost of medium voltage switchgear in k€(2011 price).

The costs of AC/DC converters are commercially sensitive and are not readily available. Through a rough indication, the costs are assumed to be 112 €/kW_{2016} [80]. For a total of 96 units of 10 MW each, this leads to a total cost of 107 MEUR. The converters turn out to be the most expensive equipment in the power electronics. The estimate is however, comparable with a similar high level study by Offshore Wind Industry Council [19]. For offshore backup systems, the cost for batteries is estimated from the same study to be 43.6 $€/kW_{2012}$ in 2030 [19].

Economies of scale are not implemented for most of the power electronics as the costs are obtained directly for the required rated capacities. A learning rate of 12% is applied and after which the costs are adjusted to inflation until 2030 with respect to reference years of the cost data obtained. Finally, using Equation 3.3, the direct costs of power electronics are obtained including erection, civil and electrical costs. **The direct costs of power electronics ($ISBL_{PE}$) are estimated to be roughly 137 MEUR (137 €/kW) in the year 2030.**

3.3. Structure costs

This section includes the approach and considerations to calculate the costs for fabrication and installation of both the jacket substructure and the topsides.

3.3.1. Fabrication

The costs to fabricate a jacket substructure and topsides are estimated as per the DNV GL (now DNV) study on P2H2 [37]. Steel is the primary material used for the fabrication of substructure and topsides, although the grades could be different. The topsides includes more than just the steelwork (estimated in Section 2.2.5) when it comes to fabrication. Coating and grating[5] also add to the total costs of the topsides. The coating and grating areas are calculated using the following expressions

$$Coating\ area\ (m^2) = 12.74 \times Steelwork\ mass + Aux.equipment\ \&\ room\ mass \tag{3.9}$$

$$Grating\ area\ (m^2) = 0.11 \times Topsides\ volume\ (m^3) \tag{3.10}$$

$$Topsides\ volume\ (m^3) = Power\ (MW) \times 193.55 \tag{3.11}$$

Similarly for the jacket substructure, apart from the mass of steel, anodes and piles (estimated in Section 2.3, coating also adds to the total costs. The coating area of the jacket is estimated using

$$Jacket\ coating\ area\ (m^2) = 1.0662 \times Jacket\ mass\ + 597.33 \tag{3.12}$$

where all the mass is in *tonnes*. Next, various rates of steel, coating and grating are used to calculate the fabrication costs of the jackets and topsides. The rates are obtained from the DNV GL (now DNV) study and are adjusted for inflation up till 2030, given in Table 3.1.

The total costs for the fabrication of topsides and jacket are calculated to be roughly 46 MEUR and 21 MEUR respectively. It can be seen that the topsides is roughly more than twice as expensive to fabricate than the jacket substructure.

[5]Made of steel and placed at the ground level on each deck for safe walkways for operators

Jacket	Rate		Topsides	Rate
Primary steel, €/$tonne$	2,400		Steel, €/$tonne$	4,184
Secondary steel, €/$tonne$	3,000		Cladding, €/$tonne$	3,586
Anodes, €/$tonne$	7,771		Grating, €/m^2	215
Coating, €/m^2	143		Coating, €/m^2	143

Table 3.1: Rates adjusted to inflation until 2030

3.3.2. Installation

Installation of offshore platforms involves several aspects and disciplines. Most importantly, various vessels are used in the installation of offshore wind turbines and platforms such as heavy lift vessels, crew transfer vessels, pile driving vessels, rock dumping vessel, etc. Vessel rates vary depending on the type of contract (short term or long term) and on the number of days used or kept on standby. Due to such variation in vessel rates and the need to formulate accurate installation requirements, a simpler but effective method is used in this thesis to obtain costs for installation of the P2G platform.

A study by Daniel Fernandes at TU Delft looked into the various vessel rates and costs with respect to the water depth and distance to shore. The study incorporated variables like average time for installation, transit time, labour rate and so on. With all this combined, the study produced a set of equations to calculate installation costs in €/kW of an offshore substation depending on the water depth and distance to shore. The study found that for fixed platforms, the fraction of installation costs associated with transit is 3.8%, whereas with depth is 28.7% [31]. The expression is given as

$$Fixed\ substation\ installation\ cost = 38.5 \times (1 - \alpha - \beta + \alpha * \frac{D_T}{D_{ref}} + \beta * \frac{t}{T_{ref}}) \tag{3.13}$$

where

α = Fraction dependant on water depth = 0.287
D_{ref} = Reference depth of 26 m
D_T = Depth at turbine location (m)
β = Fraction dependant on transit between port and site = 0.038
T_{ref} = Reference distance to port of 36km
t = Distance between configuration cluster and nearest port (km)

and the cost obtained is in €/kW.

One of the major advantages of using these equations to calculate the installation costs is to help easily analyse change in costs with respect to water depth, which is also a driving factor for the sizing of the substructure.
Using Equation 3.13, **the total costs of installation of the P2G platform with jacket and topsides, in a water depth of 30 m and at a distance of 120 km from shore are estimated to be 43 MEUR**.

The costs for both, installation and fabrication are comparable with the cost estimates of a 1 GW offshore substation by Offshore Renewable Energy Catapult [6]. For both installation and fabrication a learning curve of 10% is applied for offshore wind by 2030 [15]. No Lang factors are found for the jacket and topsides to calculate any additional costs involved.

Finally, **the total costs for both fabrication and installation of the jacket and topsides in 2030 is estimated to be 89 MEUR (89 €/kW)**.

3.4. Total Cost of Ownership (TCO)

This section highlights the general assumptions to calculate the total cost of ownership of the P2G offshore platform.

3.4.1. Total fixed capital investment

Firstly, the total direct costs (ISBL) for the P2G platform are calculated using individual ISBL costs for the stacks, PE and BOP and further adding the costs for fabrication and installation of substructure and topsides as shown below

$$ISBL_{p2g} = (ISBL_{stacks} + ISBL_{BOP} + ISBL_{PE}) * c_{capex} + C_{subst,topsides} \tag{3.14}$$

where, c_{capex} is the offshore cost factor discussed in the next subsection and $C_{subst,topsides}$ are the costs for fabrication and installation of the substructure and topsides. The total P2G CAPEX ($ISBL_{p2g}$) is estimated to be 1,150 MEUR in 2030.

Finally, using Equation 3.4, the total fixed capital (TFC) investment for the P2G facility is estimated as below

$$TFC_{p2g} = ISBL_{p2g}(1 + OS)(1 + D\&E + X) \tag{3.15}$$

The total fixed capital investment for the P2G offshore platform is estimated to be 2,111 MEUR (2,111 €/kW)in 2030.

3.4.2. General assumptions for TCO

The assumptions of various factor to calculate the total cost of ownership are highlighted further and summarised in Table 3.2.

⟶Offshore cost factor

Increasing material requirements in offshore domains and larger costs associated with bringing workforce to an offshore location for construction and maintenance purposes will likely lead to higher costs compared to conventional onshore case. In this thesis, a ballpark cost factor is used to contemplate the harsher offshore environment. The cost factor applied to CAPEX(c_{capex}) and OPEX(c_{opex}) is 1.5. Both the CAPEX and OPEX for stacks, power electronics and balance of plant are multiplied with the assumed offshore factor.

⟶Operational costs (OPEX) and project lifetime

The common OPEX figures are assumed to include the expenses that are directly related to operate the equipment including labour and maintenance. Generally, OPEX is assumed to be a small percentage of CAPEX to account for maintenance every year. In this thesis, OPEX is assumed to be 2% of CAPEX (including the offshore factor) every year of the project lifetime, which is assumed to be 20 years.

⟶Discount rate
Assuming a nominal discount rate of 8% and an inflation of 1.5% over the project lifetime, the real discount rate is estimated to be 6.4%.

⟶Full load hours
The full load hours are calculated for the Dogger bank region which is approximately 120 km away from coast of the Netherlands, using the wind speed data for the year 2019. Parameters of a 10 MW wind turbine are taken into account, including various efficiencies. A wind farm of 1200 MW is assumed initially to power the facility. This is assumed based on an optimal ratio of 80% between electrolyser and wind farm as per a study by C.J. Jepma [46]. Estimating a capacity factor of 0.54 for the wind farm, the annual full load hours for 1 GW electrolyser facility powered by 1200 MW wind farm are estimated to be roughly 6000 hrs. The estimated full load hours are on the higher side due to ample amount of wind potential in the Dogger bank region. The full load hours are assumed to be constant every year of the project lifetime.

⟶Substructure and topsides OPEX
No data is found on the maintenance of the substructure and the topsides work. Additionally, as per talks with experts from DNV, any maintenance costs would be significantly negligible as compared to other costs in the project.

⟶Decommissioning and rest value
In general, it is assumed that the terminal value of equipment and project is sufficient to balance the decommissioning costs. Hence the decommissioning phase is not considered in the cost model.

Offsore cost factor	1.5
OPEX (/yr)	2% of CAPEX
Project lifetime (yr)	20
Real discount rate	6.4%
Full load hours (hr/yr)	6,000
Stack lifetime (hr)	90,000

Table 3.2: General assumptions to calculate total cost of ownership

All of the above factors are fed into the cost model. The costs of OPEX for BOP and PE are calculated to the Net Present Value (NPV) for complete P2G lifetime. The stack replacement costs for every end of the stack lifetime are also calculated to NPV.

Finally, **the Total Cost of Ownership (TCO) for 1 GW P2G facility over it's project lifetime is estimated to 2,480 MEUR (2,480 €/kW)**.

3.5. Levelised Cost of Hydrogen (LCoH)

The levelised cost of hydrogen is a good indicator when comparing with different hydrogen production technologies in terms of their economic benefit. In general, for a scenario where the hydrogen is produced using electrolysers or other production process and powered by wind or any other source, the levelised cost also takes into consideration, in addition to P2G system, the electricity and hydrogen prices and the cost to build the wind farm, cables and transport pipelines. However in this thesis, the focus is entirely on the P2G platform and the **LCoH is calculated only using investments for the P2G offshore platform during its project lifetime**. The LCoH is estimated using the expression

$$LCoH = \frac{\sum_{t=0}^{t=T} \frac{C_I}{(1+r)^t} + \sum_{t=0}^{t=T} \frac{C_{FOM}}{(1+r)^t} + \sum_{t=0}^{t=T} \frac{C_{VOM}}{(1+r)^t}}{\sum_{t=0}^{t=T} \frac{M_{H_2}}{(1+r)^t}} \tag{3.16}$$

where C_I is the fixed capital investment in year 0 and isn't discounted, C_{FOM} is the fixed OPEX every year, C_{VOM} is the variable OPEX i.e. stack replacement costs, and M_{H_2} is the hydrogen produced every year calculated as

$$M_{H_2} = \frac{E_{ES} \times \eta_1 \times \eta_2}{LHV_{H_2}} \times t_{fullload} \tag{3.17}$$

where E_{ES} is the electrolyser size, η_1 is the P2G efficiency, η_2 is the efficiency of rest of the equipment, $t_{fullload}$ is the full load hours and LHV_{H_2} = 121 MJ/kg, is the lower heating value of hydrogen.

⟶Efficiency

The efficiency of PEM electrolyser system (η_1) is expected to increase up to 71 % by the year 2030. This includes the operation of stacks, BOP and the AC/DC converter within the P2G system [23]. For the rest of the system, an electrical efficiency (η_2) of 97 % is assumed for various transformers and switchgears that help convert and distribute wind power to the stacks and BOP.

Using Equation 3.17 , the hydrogen produced by the P2G platform is estimated to be 19.6 t/hr. Hydrogen produced annually is estimated roughly to be 118,085 t. Finally using Equation 3.16, **the LCoH for the P2G platform is estimated to be 1.89 €/kg** . If the transport pipelines are excluded, for a LCoE of 40 €/MWh from the wind farm and efficiency of 48.5 kWh/kg of PEM electrolysers in 2030 [74], the electricity costs for hydrogen production are estimated to be 1.94 €/kg. **This shows that both the platform and the wind farm contribute roughly same (50% each) to the LCoH.**, excluding the transport costs of hydrogen.

Further in the report, the focus is only on the platform LCoH.

3.6. Summary

Various market effects are implemented in the cost model such as learning rates, economies of scale and inflation to account of change in costs for larger capacities and by the year 2030. To account for additional costs of installation, piping, mounting of the equipment, in addition to purchase equipment costs, ISBL costs are calculated for stacks, BOP and PE. Stacks account for the highest in the total direct costs of the P2G plant. Within the power electronics part, the AC/DC converters are estimated to be the most expensive equipment accounting to 77% of the power electronics costs. The breakdown for direct costs of the offshore P2G facility can be seen in Figure 3.1.

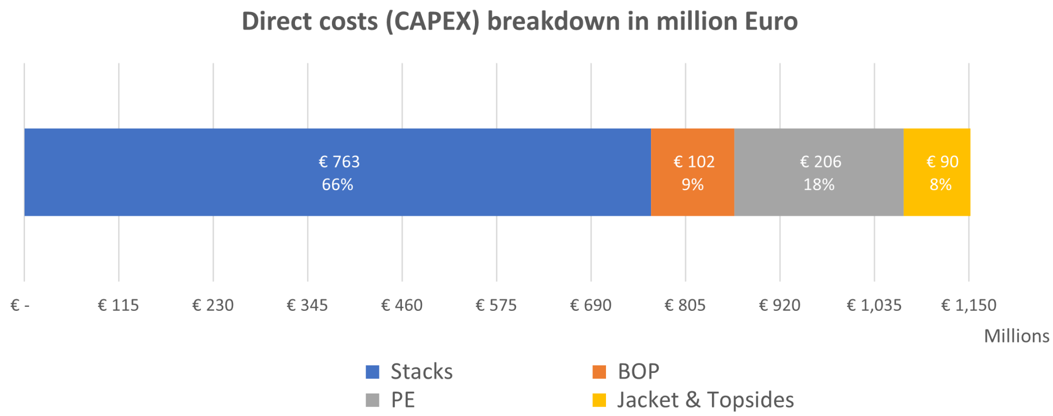


Figure 3.1: Distribution of direct costs for the offshore P2G facility

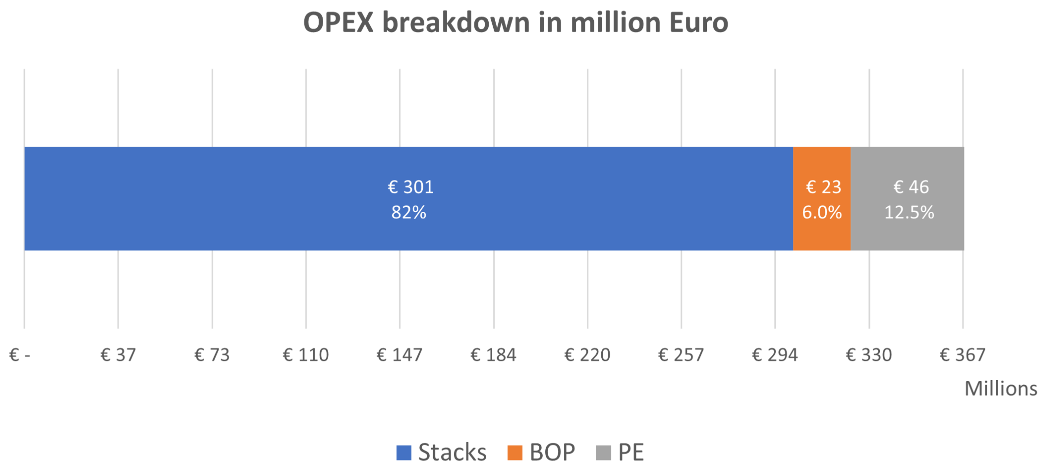


Figure 3.2: OPEX breakdown

It can be clearly seen that the costs for jacket and topsides account for less than 10% of the total CAPEX. Hence, **it is concluded that the total costs for such a facility are not driven by weight of the equipment on the platform but by the equipment itself and it's costs**, especially stack costs in this case. As an indication, the costs per kW estimated for 1 GW P2G offshore facility are summarised below.

Direct Costs (CAPEX)	Total fixed investment
1160 €/kW	2111 €/kW

Figure 3.2 shows the breakdown of the costs for operations and maintenance of the P2G facility over it's lifetime. The stacks again dominate the total OPEX in the form of variable OPEX over the lifetime of the facility. Hence it can be concluded that the stack costs are the major driving factor for the total cost of ownership and hence levelised cost of hydrogen for the platform.

4 RESULTS

This chapter highlights additional insights and reflects on the sensitivities of the inputs. Section 4.1 includes additional modelling with respect to inter-array voltage and a floating facility, provides insights into the cost trends of various disciplines in the facility and the possible capacity limit offshore. Section 4.2 explores the sensitivity of the model output for the most relevant inputs. It takes into consideration comparison between fixed and floating platforms and then, cost of stacks, offshore factor, battery size and electrolyser capacity are analysed for sensitivity. Finally, Section 4.3 summarises the various insights and sensitivity results.

4.1. Costs, limits and trends

This section dives into additional system modelling and provides insights into some general findings of the model as per the research questions.

4.1.1. Inter-array cable voltage

Currently, the traditional inter-array cable voltage used in wind farms is 33 kV. The total costs of ownership previously obtained are based upon the future 66 kV wind farms. It is observed that with changing the inter-array voltage, in addition to the change in number of cables and their design shown in Table 2.2, the amount of equipment and the rated power on the platform would also change. This would result in a change in the weight on the top of the platform, thus affecting the sizing of the topsides and substructure, and indeed, the total costs of power electronics itself.

Changing the inter-array voltage to 33 kV reduces the number of transformation steps required from two to one, hence enabling the transformation of wind power from 33 kV to 1 kV in a single step. Although 66 kV switchgears are now excluded, the number of 33 kV feeder bays increases significantly, due to the increased number of incoming cables. The second step in the original 66 kV facility remains the same in case of 33 kV, acting as the first and only step consisting of 33 kV switchgears, high power transformers and grounding transformers. The change in facility design can be clearly seen in the single line diagram in Appendix B.6.

Changing the inter-array design of the wind farm from 66 kV to 33 kV results in a difference of 47 MEUR (1.89%) in the total cost of ownership over the P2G platform lifetime, dropping the platform LCoH by roughly 1.5%. It is important to take into account this cost difference while designing future wind farms dedicated to P2G.

One of the initial motives to use 66 kV in the system design is the expected future trends of larger wind farms using higher voltage cabling to reduce transport losses and accommodate more wind turbines in each string. A study by DNV GL (now DNV) estimated a reduction of 15% in total CAPEX of a 350 MW wind farm using 66 kV inter-array voltage [36], where the cost reduction takes into account an offshore substation to collect and transmit power to shore. However, in this thesis with estimated reduction in P2G platform costs, further research is necessary for the bigger picture to assess if the reduced costs of the facility outweigh the costs for higher number of cables and transport losses within the 33 kV design.

4.1.2. Electrolyser facility limit

There must exist a limit to capacity of electrolyser facility which can be placed offshore on a single platform and at which the need for an additional platform to equip the total capacity arises due to the technical limitations of the platform design. In Section 2.3, the jacket is sized based upon various expressions, mainly dependant on the topsides weight and water depth. However, the technical design of a jacket depends on several other factors or design actions [72].

- Environmental actions - wind, waves, current.
- Permanent actions - self weight, weight of topsides, water pressure (buoyancy and hydrostatic pressure).
- Variable actions - non-permanent equipment, occupants, supplies.
- Repetitive actions - loads repeating to cause fatigue.
- Accidental actions - collisions, fire, explosions.

However, no matter which conditions and design states are considered, **it is important that the designed jacket is feasible to install in the first place**. Mainly, the jacket weight is the driving factor for installation type and limit. Installation vessels have cranes and systems that can only lift up to a certain weight within a certain range of distance from the vessel itself.

Topsides and jacket platform can be installed using either the same or different vessels and this depends on the size of the two structures. Although in some cases limit does not exist for the topsides size that can be installed using float over technique, the limitation comes into the picture with respect to the jacket that supports the topsides. A particular mass limit exists for jacket that can be installed in the North Sea. This is highlighted further in detail.

⟶Heavy Lift installation
As a common practice for offshore substations, the jackets and topsides are usually lifted by heavy lift vessels and placed on the seabed. Sleipner, a semi-submersible crane vessel by *HeeremaMarineContractors*, is the largest heavy lift vessel that exists today, shown in Figure 4.1. The vessel is equipped with two starboard heavy lift cranes with a capacity of 10,000 t each. This restricts the maximum capacity of a structure that can be installed at once to 20,000 t. Now, if the topsides heavier than this particular mass limit can be installed, say using a different vessel (float over - explained later below), the jacket limit mass is restricted to 20,000 t of installation limit. As per the model, an electrolyser capacity of 2.5 GW can be equipped for which the jacket mass is 20,000 t.

Figure 4.1: Sleipnir, Semi-Submersible Crane Vessel, taken from [16]

On another note, from 2019, owing to advanced engineering and innovation, the same company announced services of increased heavy lift activities using the two of their biggest heavy lift vessels, Thialf and Sleipnir, to heavy lift up to 30,000 t in combination, shown in Figure 4.2. This technique is used only for the topsides installation using two heavy lift vessels. Interestingly, scaling to 2.5 GW of electrolyser capacity in our model accounts to roughly 30,000 t of topsides. To support this topsides mass, a 20,000 t jacket is needed, as explained earlier. Hence, it can be fairly stated that with respect to incorporating heavy lift installation technique, a 2.5 GW of electrolyser limit exists for a single jacket platform in the North Sea.

⟶Float over installation
In addition to heavy lifting, varied methods exist for installation. Float over installation method, compared to traditional methods has no site and equipment limitation and is accompanied with simple installation and controllable risk. In float over installation method the vessel equipped with topsides passes and stabilises itself between the gap of the thick jacket legs protruding above the water surface (can also be seen in Figure 4.2). The vessel is ballasted with water which results into lowering of the vessel and hence the equipped topsides, thus mating and integrating it with the upper portion of the thick jacket legs.

Figure 4.2: Increased heavy lift ability using Thialf and Sleipnir, taken from [17]

Figure 4.3: Pioneering Spirit, largest construction vessel in the world, taken from [4]

Although no limit in total mass of topsides installation exists for the float over technique, the mass of the jacket that can be installed still acts as an obstacle to the maximum facility that can be placed offshore. The Pioneering Spirit by *Allseas* (shown in Figure 4.3), is the largest construction vessel in the world, capable of removing/installing topsides (using float over technique) up to 48,000 t and jacket platforms up to 20,000 t. The vessel installs the jacket in a different manner than the topsides. Hence, even using the largest construction vessel in the world, restricts the **facility size that can be equipped offshore to 2.5 GW on a single jacket platform**, owing again to the 20,000 t jacket limit.

As per conversation with offshore engineers at DNV, the total costs of renting and operating a heavy lift vessel and a float over vessel could be roughly the same for a given installation contract. This is due to the fact that the float over vessels need extra time for preparation and loading of the topsides at the port combined with the transportation to the site, whereas, heavy lift vessels have higher daily rates but are only needed to lift and place the topsides at the offshore site. The daily operational rate of a heavy lift vessel could be close to 0.5 MEUR, usually rented for at least three weeks. Since most of the time the vessel is in stand by mode, the daily rate for standby accounts to roughly 60% of the operational rate.

4.1.3. Facility cost trends

Figure 4.4 shows the output of the model with cost trends of NPV for stacks, BOP, power electronics, platform, fixed and variable OPEX when electrolyser capacity is changed with respect to a fixed 1200 MW wind farm.

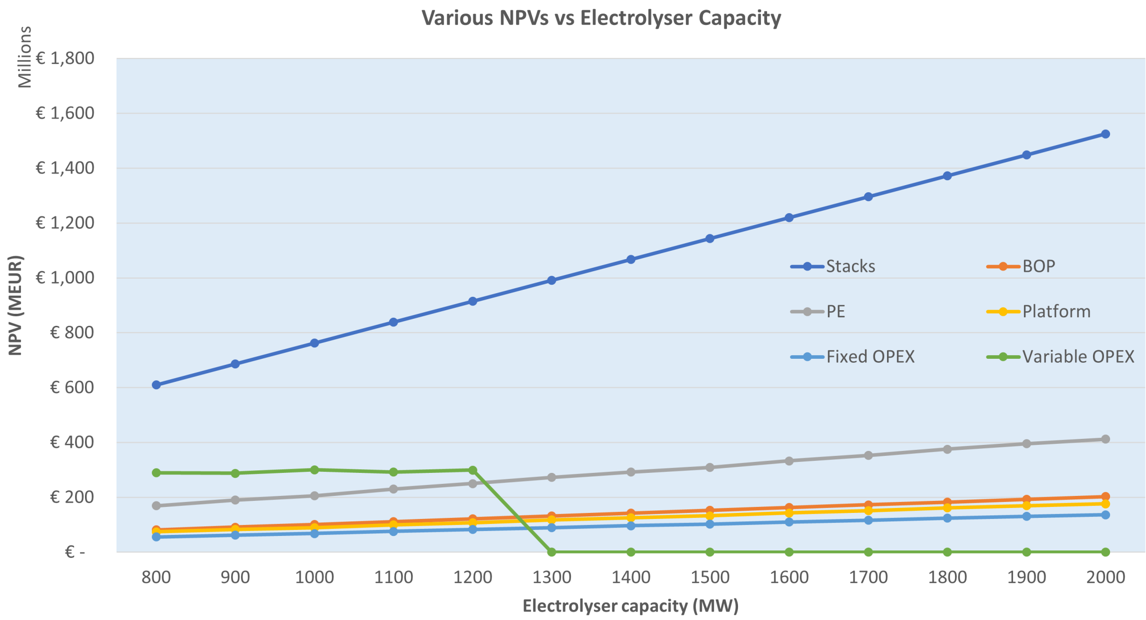


Figure 4.4: Various NPV vs electrolyser capacity with 1200 MW wind farm

The large increase in cost of the stacks is owed to its cost share of 66% in the total CAPEX, as discussed in Section 3.6. The majority of the trends are quite linear. Although economies of scale are implemented, they cannot be observed here. This is due to the fact that stacks hardly show economies of scale due to their modular nature. Similarly, the BOP shows economies of scale only up to 100 MW, again due to modular nature, explained in detail in Section 3.2. Similar to BOP, power electronics show economies of scale when, for example, the rated power of a transformer is increased from 50 MVA to 800 MVA. In our model, the base case consists of four 250 MVA and eight 125 MVA high power transformers of which, for simplicity, the number of transformers is scaled linearly and maintained even with respect to electrolyser capacity, keeping the rated power of transformer constant. Hence the trend remains linear for power electronics.

In the base case, no fixed OPEX is considered for the stacks. However, variable OPEX are the stack replacement costs that occur when the stacks complete their lifetime of operation and need to be replaced with new stacks for the remaining project life. The overall trend of the stack replacement costs can be attributed to four different factors - stack lifetime, project lifetime, full load hours and costs of stacks itself. In the base case where the project lifetime is 20 years and expected stack lifetime is 90,000 h, the fluctuating trend (green line) when increasing electrolyser capacity from 800 MW to 1200 MW, is due to the decrease in load hours and increase in stack costs which affects the time value in NPV. The decrease in load hours is due to the fixed wind farm capacity and increase in stack costs in due to increase in electrolyser capacity. After 1200 MW, the stack replacement costs drop to zero due to reduced load hours. This means that for a 1300 MW electrolyser capacity, the stacks do not reach their lifetime even towards the end of project life of 20 years.

If in case the wind farm capacity is increased, all trends except the stack replacement costs continue to follow the same fashion. An increase in wind farm capacity would mean more number of load hours for a given electrolyser size. Decreasing the electrolyser capacity also further increases the load hours. In case of a 1500 MW wind farm powering a 500 MW electrolyser, the stacks would be replaced at least three times in the project lifetime of 20 years. Hence, the ratio between electrolyser and wind farm capacity significantly affects the stack replacement costs.

As stacks seem to be the ones with largest cost share, it becomes interesting to check how sensitive the model of the output is to the inputs and assumptions made for the stacks. This analysis is carried out in Section 4.2.

4.1.4. A floating facility

Floating platforms have a history of supporting Oil&Gas activities in deeper waters offshore. Although offshore substations have not seen an increased deployment using floating platforms, floating wind turbines are already being deployed in deep waters and are a hot topic in the industry.

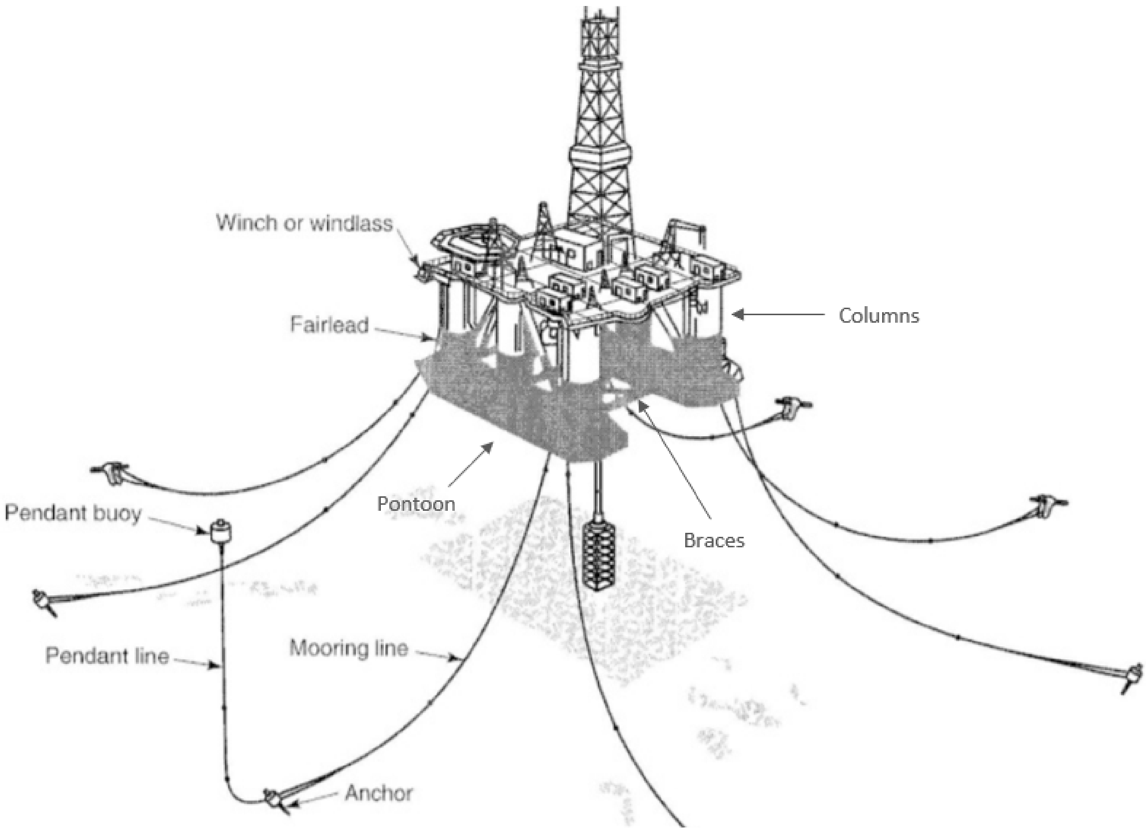


Figure 4.5: An example of semi-submersible floating platform, adapted from [55]

In order to explore the possibilities of deploying such a P2G platform in deeper waters and further offshore where ample amount of wind resource is available, an attempt is made to design a floating platform for the facility under study. Although the design of floating platform is a complex process in itself with limited amount of research publicly available, if explored, it adds an interesting aspect of cost comparison with fixed platforms at different water depths and carrying capacities.

A Semi-Submersible platform (SSP) is chosen as the floating platform type in this thesis. The choice drivers and design approach used can be found in Appendix D. Figure 4.5 shows an example of a semi-submersible floating platform with hull that includes the pontoon, braces and columns to support the topsides. The mooring lines are attached to the anchors at the seabed that hold that platform in place.

As seen in Section 3.6, the fabrication of the jacket substructure and topsides along with platform installation accounts to less than 10% of the total CAPEX for the facility. Although this is the case, it translates to roughly 89 MEUR in 2030. Hence, a comparison between fixed and floating platforms becomes interesting to analyse the increase and decreases in costs at different locations and with varied topsides capacities, to help make economical choices.

4.2. Sensitivity analysis

A sensitivity analysis is carried out to analyse the effect of various input parameters on the output of the model. The analysis is carried out in the following manner. First, the fixed and floating platforms are compared for the total structure costs. The change in costs for different water depths, electrolyser capacity and distance to shore is assessed. Next, the sensitivity of LCoH is assessed for the stack costs, offshore factor, battery size and electrolyser capacity.

Note-Total structure costs include the fabrication and installation of both the substructure and the topsides which excludes any equipment costs. Further in this section, jacket structure means the jacket platform with topsides and SSP structure means semi-submersible platform with topsides.

4.2.1. Fixed vs floating

The jacket and SSP structures are compared by varying different input parameters to assess the change in costs of the structures. The interesting parameters that affect the costs of the structures are water depth, distance to shore and topsides capacity. Met-ocean conditions can also influence the sizing and costs but are not analysed in this thesis. The sensitivity is carried out with respect to the CAPEX of the platform rather than the LCoH due to limited contribution of the structure to the later.

⟶Water depth
The water depth affects the substructure sizing and installation of the entire platform. The change in costs for the two structures as the water depth increases is shown Figure 4.6, for the base case of 1000 MW capacity and 120 km offshore. It can be observed that the the

costs for the jacket structure rise sharply with increase in water depth due to both the substructure and installation costs being dependant on it. The rise is roughly 10 MEUR for every 10 m increase in water depth, accounting to roughly 11% increase in total CAPEX. Hence it can be fairly stated that the water depth has a significant effect on CAPEX of jacket structure.

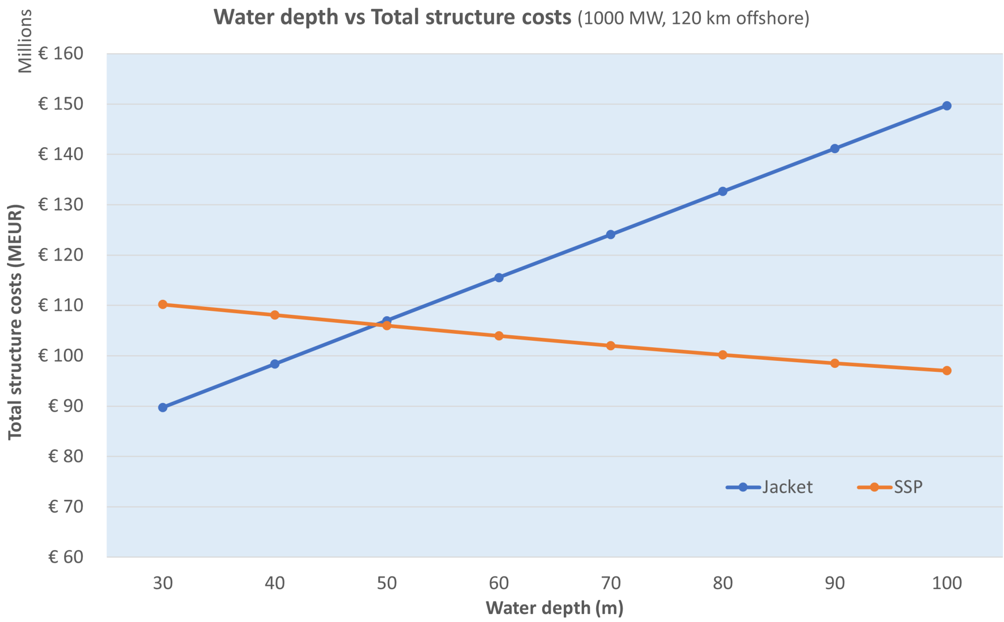


Figure 4.6: Water depth vs total structure costs for fixed and floating

On the other hand, it can be observed that the total structure costs of SSP decrease with increase in water depth, at a slower pace as per the model in this thesis. Research shows that the substructure size is unaffected by water depth. The decrease in costs can be attributed to several factors. At lower water depths the mooring lines are designed to be heavier and thicker with higher breaking loads to withstand larger fatigue. Breaking load of a mooring line is the design load at which the possibility of rupturing exists. With increase in the water depth, the breaking load requirements decrease owing to less vigorous water currents and the lines can be designed lighter with reduced diameter. Although the diameter and weight of the lines reduce at larger water depths, there is a sharp increase in length of mooring lines. This results into additional costs and the reduced slope of the SSP trend after 80 m in Figure 4.6. It can be concluded that the effect of water depth on CAPEX of SSP is moderate at shallow depths and small at larger depths. However, due to the rapid increase in length of mooring lines, the SSP costs can tend to rise rather than fall after a certain water depth. In reality, even at shallower water depths the SSP costs could rise but certainly at a very slower pace.

The cross over water depth obtained is roughly 50 m as can be seen in Figure 4.6. As per literature, floating wind could show an economical benefit when deployed at more than 50 m of water depth [10], which aligns with the cross over depth obtained using the model. Although some uncertainty revolves around this water depth due to the cost assumptions for the SSP platform (Appendix D), it gives indications that SSP platforms could be of interest for P2G facilities offshore at water depths above 50 m.

⟶Electrolyser capacity

The electrolyser capacity influences the substructure size, topsides steelwork/size and platform installation. Both jacket and SSP substructures are influenced by the amount of topsides mass they support. For the base case of 30 m water depth and 120 km offshore, the change in costs with respect to various electrolyser capacities is shown in Figure 4.7. It can be seen that for 30 m water depth, the costs for SSP continue to be higher even for increased electrolyser capacities which lead to heavier topsides. The lower slope of the SSP can be attributed to the fact that water ballasting and buoyancy play a significant role in supporting the hull and hence, the topsides. Usually the pontoon dimensions of the hull are increased to help equip heavier topsides. Also the installation costs increase with increase in topsides capacity as per installation equations used.

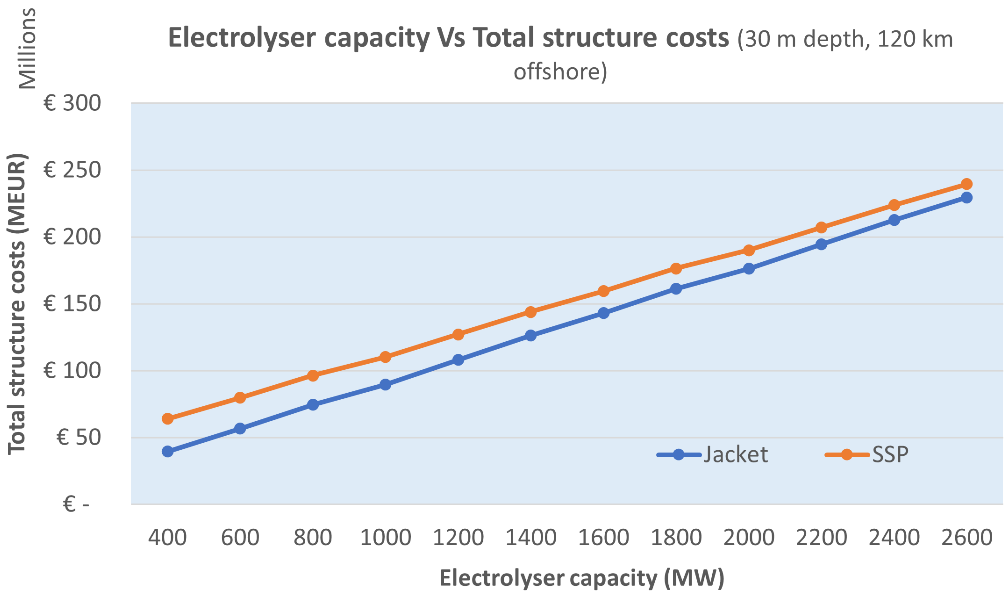


Figure 4.7: Electrolyser vs total structure costs for fixed and floating

For a 20% increase in electrolyser capacity, costs for jacket and SSP structures increase by 21% and 15% respectively, which shows that the topsides capacity significantly affects the structure CAPEX.

At higher water depths, it is observed that the costs for a jacket structure rise much more sharply than that of SSP if the electrolyser capacity is increased as shown in Figure 4.8. This is again due to the fact that SSP size is not affected by water depth but only by topsides mass. Additionally, the costs for mooring lines decrease at increasing water depths [1]. The cross over water depth between the two platforms also seem to decrease with increase in capacity as shown in Figure 4.9. This indicates that with heavier topsides/larger P2G ca-

[1]The costs of mooring lines can increase rapidly after a certain water depth due to significant increase in length.

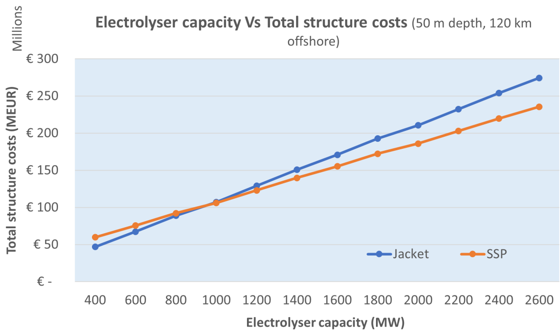


Figure 4.8: Electrolyser capacity vs total structure costs (50 m, 120 km offshore)

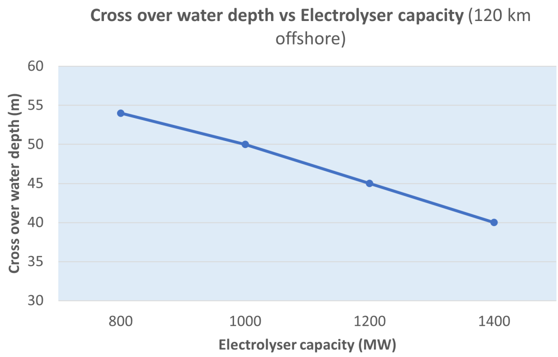


Figure 4.9: Cross over water depth vs total structure costs (120 km offshore)

pacities, the SSP could start to become economical at shallower water depths.

⟶Distance to shore

Distance to shore only influences the costs for installation. In Figure 4.10, it can be seen that the costs for SSP are hardly influenced by the distance to shore and the costs of jacket structure rise by just 2.2% by moving 40 km further away from the shore, with reference to base case. This is mainly because of only the extra fuel costs for travelling additional distances. This indicates that the distance to shore has a very small effect on the total costs for both structure types. This is only true under the assumption of constant water depth. In reality, water depth increases with distance to shore.

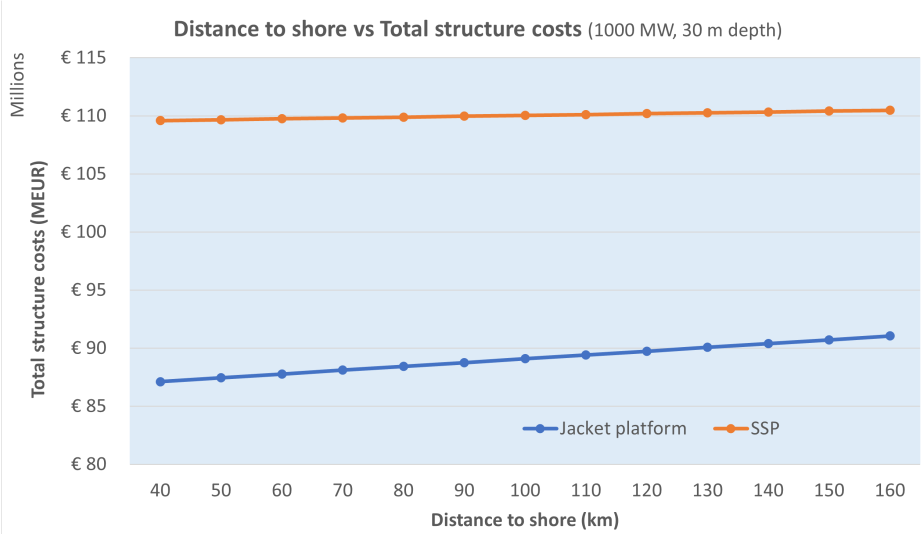


Figure 4.10: Distance to shore vs total structure costs at 30 m water depth

4.2.2. Stack costs

⟶Stack CAPEX

The specific investment cost of PEM electrolyser stacks in the base case are considered as 273 €/kW for the year 2030. A large uncertainty still revolves around the future cost of stacks and the dependency of economic feasibility of P2G projects on the same. To explore how sensitive the platform LCoH is to the cost of stacks, the costs are multiplied by 0.75 and 1.25 to see the impact of 25% higher or lower values, as shown in the Figure 4.11. This gives a bandwidth of between 1.57 to 2.21 €/kg. This means that increasing the base stack costs by 25% results in an platform LCoH increase of 17%. This indicates that the platform LCoH is very much dependant on the capital cost of stacks.

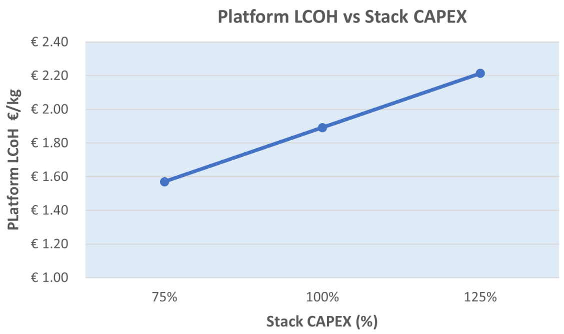


Figure 4.11: Platform LCoH sensitivity to stack CAPEX

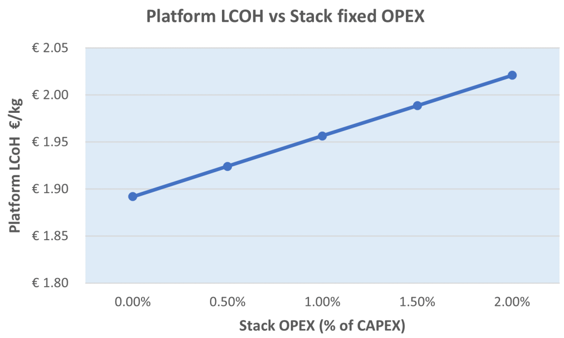


Figure 4.12: Platform LCoH sensitivity to stack fixed OPEX

⟶Stack fixed OPEX

The original cost model does not account for any fixed OPEX costs of the stack every year in the base case. The main reason being that no information was found on the operation and maintenance cost of the stacks per year. Manufacturers have indicated that some costs exist for the annual O&M of stacks which include checks on leakage, tie rods and piping maintenance. Other checks include monitoring of stack parameters like temperature, pressure, hydrogen purity and contaminants [45]. Although these checks may incur some costs, it is still unsure how they would have to be accounted for in terms of stack CAPEX. To explore the sensitivity of fixed OPEX, some calculations are done using the model developed in this thesis. The impact can be seen in Figure 4.12. When going from 0% to 2% of CAPEX for fixed OPEX of stacks, the rise in platform LCoH is estimated to be roughly 7%. This indicates that there exists a moderate amount of dependency of stack O&M costs on platform LCoH.

4.2.3. Offshore factor

The offshore factor is taken into account to include the extra costs of material and equipment to withstand marine environment combined with the additional costs that could incur when carrying out O&M activities offshore. The offshore factor is a very general factor used in high level feasibility studies, increasing significantly to the total costs. Some calculations are performed using the model to check the influence of the offshore factor on platform LCoH. With an increase of 0.5 in offshore factor, the platform LCoH rises by roughly

31%, as visible in Figure 4.13. This indicates that the dependency on offshore factor is very high and should be carefully assessed in future research.

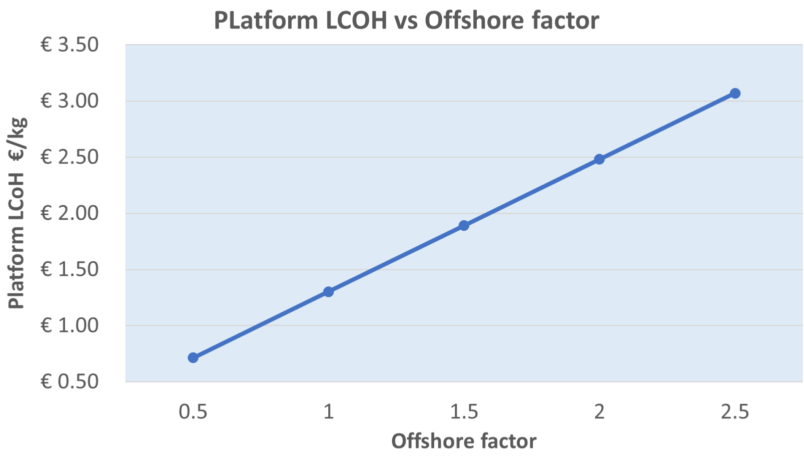


Figure 4.13: Platform LCoH sensitivity to offshore factor

4.2.4. Battery capacity

Some uncertainty revolves around the battery capacity required to support the operation of P2G facility. As such, batteries are not widely installed in offshore wind farms. However, they pose an interesting option for backup on offshore platforms. The exact sizing of the battery capacity is out of scope in this thesis. Batteries can be a significant component of the power system on offshore platforms, especially in an off grid scenario, hence it becomes important to at least get a sense of how much the battery capacity affects the platform LCoH. In a high level study, for an off grid offshore P2G facility of 1 GW, a battery capacity of 120 MWh was assumed, based on pilot wind projects [19].

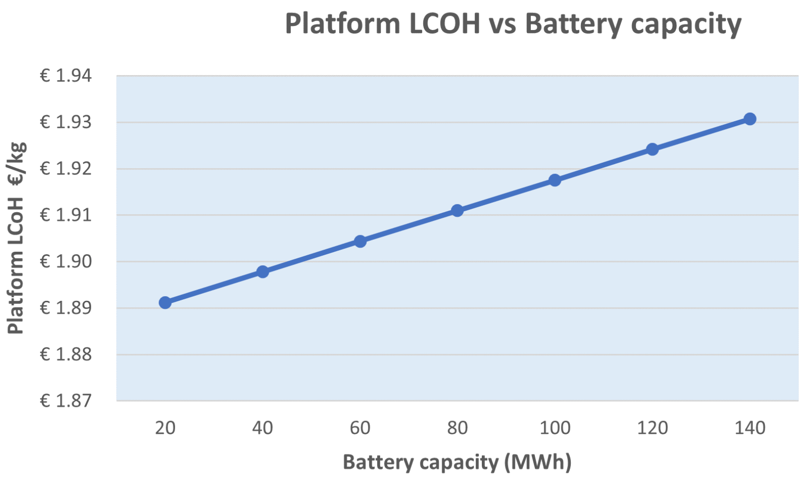


Figure 4.14: Platform LCoH sensitivity to battery capacity

Hence, to analyse the impact of increase in battery capacity from the base case, some calculations are done. As can be seen in Figure 4.14, the rise in platform LCoH is less than 2% for a five fold increase in battery size, including both the battery costs and the added weight on the platform. This indicates that the battery capacity has a very small effect on the LCoH of the P2G platform.

4.2.5. Electrolyser capacity

The ratio of the wind farm capacity to the capacity of the electrolyser facility also has an impact on the levelised cost of hydrogen. Mainly due to the increase or decrease in stacks costs and the increase or decrease in load hours. To analyse the impact, some calculations are made where the electrolyser capacity is varied with respect to a fixed reference wind farm. Figure 4.15 shows change in electrolyser capacity with respect to a fixed 1200 MW wind farm and a capacity factor of roughly 0.54 implemented in the model, which decides the number of full load hours based upon the electrolyser capacity.

The platform LCoH rises by roughly 7% for every 100 MW increase in electrolyser capacity. Several reasons can be attributed to this, the first being rise in costs of the facility. Secondly, although the capacity of electrolyser increases, the resultant load hours decrease due to fixed wind farm capacity of 1200 MW, hence hydrogen produced remains the same. The dip in platform LCoH after 1200 MW is the replacement costs going to zero as detailed in Section 4.1.3.

In reality, based upon curtailment and wind farm usage with respect to electricity costs and agreements between operators and TSO, an overall optimum LCoH can be determined, however, it is not analysed in this thesis.

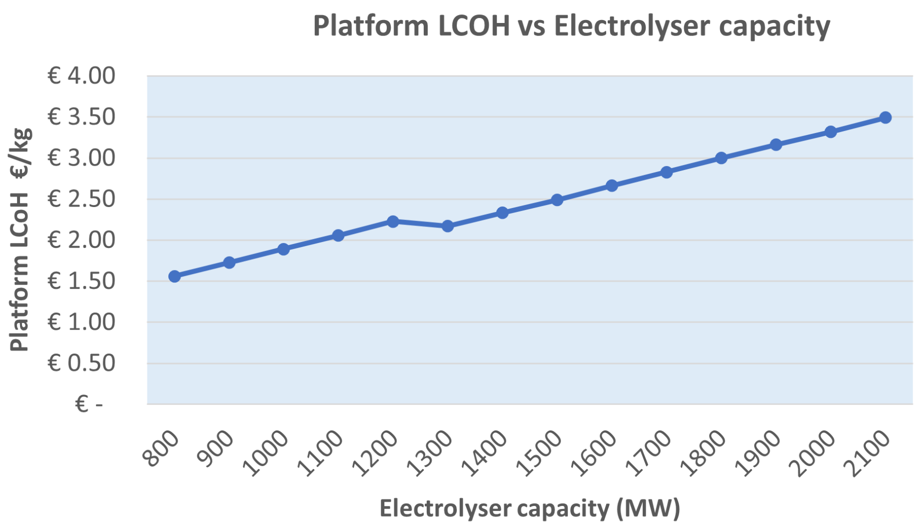


Figure 4.15: Platform LCoH sensitivity to electrolyser capacity

4.3. Summary

Change in inter-array voltage level affects other than the cable design, the number and capacities of various power electronics on the platform. Implementing 33 kV inter-array voltage instead of 66 kV, drops the LCoH of P2G platform by 1.5%. Further on, the electrolyser capacity limit than can be equipped on a single platform in the North Sea is estimated to be 2.5 GW. This is due to the installation limitations of a jacket weighing more than 20,000 t. Majority of the facility cost trends are linear due to modular nature of the stacks and BOP involved. The stack replacement costs are affected by several factors like stack lifetime, project lifetime, full load hours and the cost of stacks itself. A semi-submersible floating platform adds an interesting aspect of comparison to a fixed platform. The cross over water depth between fixed and floating platforms is found to be 50 m in the case studied here, aligning with insights from the literature. With heavier topsides, SSP platforms become economical at shallower water depths. One of the driving factors for the facility CAPEX are the stack costs. A change in stack CAPEX significantly affects the platform LCoH, whereas considering fixed OPEX of the stacks has a moderate effect. The offshore factor is a crucial and significant contributor to the LCoH and should be analysed carefully. Although the battery is an important component in an off grid scenario, its impact on platform LCoH is small. Finally, with increased electrolyser capacity, the platform LCoH rises owing to decrease in load hours and increase in total costs, showing a moderate effect.

5

CONCLUSIONS

Section 5.1 refreshes the goal of this thesis and further details relevant conclusions and answers the proposed research questions along with discussion. Section 5.2 details some suggestions for future research and model improvements for a better estimate of the results.

5.1. Summary and discussion

The main goal of this thesis is to increase system integration knowledge of offshore wind and electrolysers, estimate the scale and size of such an dedicated platform offshore involving stacks, balance of plant, power electronics, auxiliary systems and the substructure supporting the topsides. Further the thesis focuses on building a cost model to understand the driving factors of costs for such a facility. The base case considers a 1 GW electrolyser capacity equipped on a jacket platform in the North Sea, at a site with 30 m water depth and 120 km away from shore.

The conclusions derived in this thesis are specific to the following boundary conditions:

- The wind farm powering the platform is out of scope
- Hydrogen transport pipelines from platform to shore are out of scope
- Hydrogen storage on the platform is out of scope
- Onshore grid pressure for hydrogen is assumed to be 50 bar in 2030

The research questions formulated are answered with respect to conclusions derived from this thesis and are discussed further.

A. How can large scale electrolysers be equipped on offshore platforms in the North Sea?

1. What is a typical electrolyser system layout and would this be suitable for offshore applications?

⟶Technology selection

As per research in this thesis, when comparing the two commercially viable electrolyser technologies ALK and PEM, **the PEM electrolyser shows greater potential to be a better suited technology for offshore P2G applications in 2030**. No side by side comparison was made on a system basis, instead the conclusion is derived solely based on expected operational developments in the future. A summary can be found in Table 2.1. Owing to future high operating pressure range of the PEM stacks, the need for compression of hydrogen might be reduced. Further, a compact design of PEM might help saving additional space on the platform. The reduced cold startup times of the PEM system contribute to reduced switching times of PEM stacks and, hence, reduced maintenance. A much broader range of load operation of PEM stacks might help reducing wind power curtailment and required backup capacity on the platform. Finally, a higher reduction in cost per kW is expected for PEM systems by 2030, than for ALK.

⟶PEM system design

The PEM electrolyser system design implemented in this thesis is highlighted below in Figure 5.1, except for the desalination system.

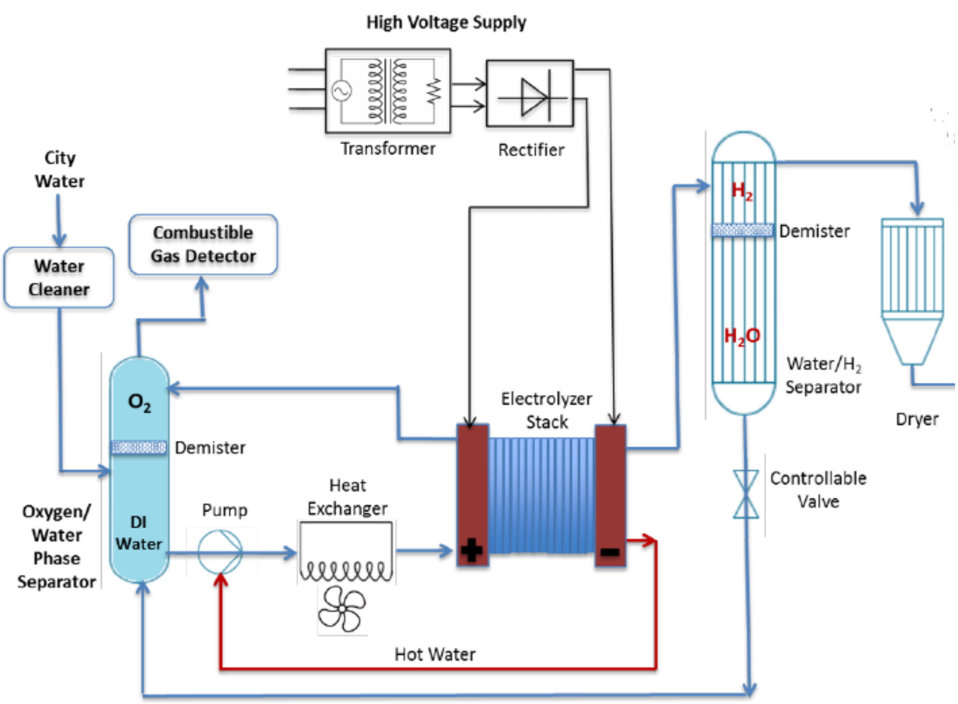


Figure 5.1: Schematic of the PEM electrolysis system showing stack and BOP parts [50]

It consists of the stacks which are powered by DC voltage, roughly between 0.6 - 1 kV, that produce hydrogen on the cathode side and oxygen on the anode side. The balance of plant that assists the production of hydrogen consists of several equipment. The liquid-gas separators for both oxygen and hydrogen are mainly vertical vessels that help separate the respective gases from the mixed water content. Further, PSA units act as hydrogen gas dryers which are used to purify hydrogen of various contaminants like nitrogen molecules, potassium ions and moisture. The use of plate heat exchangers ensures continuous cooling of the stacks that help maintain the appropriate temperature gradient across the PEM cell. Various water pumps ensure that seawater is pumped to the platform and that distilled water is recirculated via cooling equipment to the stacks. The desalination system is essential in an offshore application for the purpose of utilising the seawater, purifying it and feeding it further for hydrogen production. The system is designed in three steps that help reduce the TDS content of seawater to that required by the PEM stacks (< 1 ppm). Valves and instrumentation ensure flow and pressure control along with system monitoring.

⟶Wind power conversion and facilities
A single line diagram of the facility equipment for power collection, conversion and distribution is shown in Figure B.5 in Appendix B. On an offshore platform, the need for a large number of power electronics arises to help convert the incoming power from the wind farm to that used by the PEM electrolyser system. The number of power electronics and rated power of these equipment depends largely on the inter array voltage of the wind farm. With rise in the usage of 66 kV as the inter array voltage for newer wind farms, adds an additional transformation of stepping down the voltage level. A set of high power transformers are used in order to save space on the platform. Grounding transformers also form a part of the platform to help ground the main high power transformers during faults. Switchgears are placed at all stages of the power electronics to ensure fault protection and avoid damage. AC/DC converters ensure that DC power is supplied to the stacks. Batteries are expected to be a potential alternative to diesel generators for backup on offshore platforms, and help support the system during hot standby modes. A number of auxiliary components such as helideck, accommodation, lighting and communication also form a part of the platform.

⟶Offshore application
Producing green hydrogen offshore requires the use of more than just the electrolyser system itself. Offshore application of electrolysers requires various equipment to support the overall system. Powered by a surrounding wind farm, electrolyser systems can be equipped on a central offshore platform, as considered in this thesis. The central platform should also equip a battery backup system in cases where there is no wind power. The battery backup is essential to keep the electrolyser system in hot standby mode and for other essential services such as lighting and auxiliary. For maintenance and replacement purposes, a crew has to have emergency accommodation facilities on the platform, in cases of harsh weather or long maintenance schedules. For on boarding of the crew, the platform should have a helideck for air transfer. Workshops and fire protection rooms also form an important part of the platform. A SCADA and control system is also vital for monitoring and data sharing.

Pilot projects have been launched in the North Sea and other regions world wide to test the feasibility of electrolyser operation in marine environment. However, there is still very limited knowledge on any sort of extra material or coating needed for electrolysers to successfully operate in a saline atmosphere. Limited research available online based upon exposure of PEM cells in a controlled corrosive environment, indicates no evidence of poisoning, such as sodium and chlorine or any structure modifications. Protective casing to the cell, which the stacking provides anyways, may help mitigate any potential effects of corrosion [9]. For the rest of the BOP equipment such as separators, dryers, heat exchangers and also piping, it could be vital to manufacture the equipment with corrosive resistant materials or apply layers of coating to help survive the saline environment.

Other challenges that come with offshore electrolysis are the vibrations and motion introduced on the platform due to wind and wave loading. It becomes important to provide extra stability to the equipment on the topsides, for example using skids, bonding plates and other fittings.

All such requirements including extra material, fittings, labour and maintenance would likely results into larger costs as compared to the conventional onshore case. To take this into consideration, as offshore cost factor of 1.5 is assumed in the base case. It is a general factor used in high level studies and it takes into consideration the increased costs of material requirements in a marine environment and additional costs for bringing the workforce to an offshore location for construction and maintenance purposes. As the offshore factor in this thesis also takes into account the additional material costs for the stacks (major drivers for facility costs), it is important to carefully consider the factor in future to avoid any overestimation or underestimation of costs.

2. Which offshore platforms are technically feasible for facilitating large scale electrolyser systems?

In this thesis, the sizing of the topsides steel work is mainly driven by the weight of the equipment.

	Mass (tonnes)
Heaviest equipment	
PEM stacks	1,440
High power transformers	1,995
AC/DC converters	1,200
Other	1,483
Topsides steel work	6,333
Total topsides	13,402
Jacket	8,238

The PEM stacks, high power transformers and AC/DC converters are the heaviest equipment placed on the platform. The total steel work, cladding and grating mass on the topsides is driven by the total equipment mass. The total mass of the topsides accounts to roughly 13,402 t for 1 GW facility. Overall, the steel work carries the highest percentage of the total topsides mass.

Monopiles/monotowers and jackets are the two dominant substructures in the North Sea due to an average water depth in the range of 20 and 50 m. Monopiles are slender cylindrical structures that have limited weight carrying capacities. In this thesis, it is estimated that the largest state-of-the-art monopile can carry no more than 1,800 t, which according to our model is slightly lower than 100 MW. Hence, **monopiles become infeasible to carry the topsides mass of 13,402 t**. The jacket substructure however, is dynamically stiff owing to their reduced wave loading and long term fatigue. Hence, **jackets are suitable to support much heavier topsides**. The total mass accounts to roughly 8,238 t to support 1 GW of electrolyser facility.

Feasible platforms	**Cross over water depth for 1 GW**
Jacket	50 m
Semi-submersible	

Floating platforms also have history of supporting very heavy topsides of O&G facilities. A further step is made to analyse the implementation of floating platform, specifically Semi-Submersible Platform (SSP), being theoretically cheaper and easier to install than tension leg platforms or spar platforms. **Comparing both jacket and SSP gives a cross over water depth of 50 m**, which is in line with current deployment of floating wind as per literature. This cross over water depth is bound by a few conditions. The installation of SSP platform is assumed to be independent of water depth. Costs for coating and anode material are assumed to be same as that for jackets and a fixed cost is assumed for ballast water management. In contrary to distance to shore, **water depth and topsides mass have significant effects on the platform CAPEX. Additionally, with increase in electrolyser capacity, SSPs tend to become economical, compared to jackets at shallower water depths.**

3. What electrolyser capacity can be equipped on offshore platforms in the North Sea?

Maximum electrolyser capacity on a single jacket platform
2.5 GW

The limit to equip an offshore P2G facility on a platform in the North Sea is mainly driven by the installation limit of the jacket substructure. This is due to the fact that offshore vessels have limited lifting capacities. Heavy Lifting and Float Over are the two common installation methods. The heavy lift technique, in combination with two vessels can lift no more than 30,000 t of topsides which translates to linearly driven jacket mass of 20,000 t as per our model. The largest heavy lift vessel can lift no more than 20,000 t. Thus heavy lift technique restricts its capacity to 20,000 t of jacket mass. Hence, the maximum capacity of P2G facility that can be equipped translates to 2.5 GW (30,000 t topsides with 20,000 t jacket). No limit for topsides mass in float over installation exists. However, the largest construction vessel in the world can only install a jacket of not more than 20,000 t, using a different way as compared to float over for topsides. Hence, with respect to float over technique, again the maximum capacity that can be equipped on a single platform translates to 2.5 GW.

4. What system layouts of the platform are possible (including electrolyser, other equipment and facilities (Helipad, living quarters, etc))?

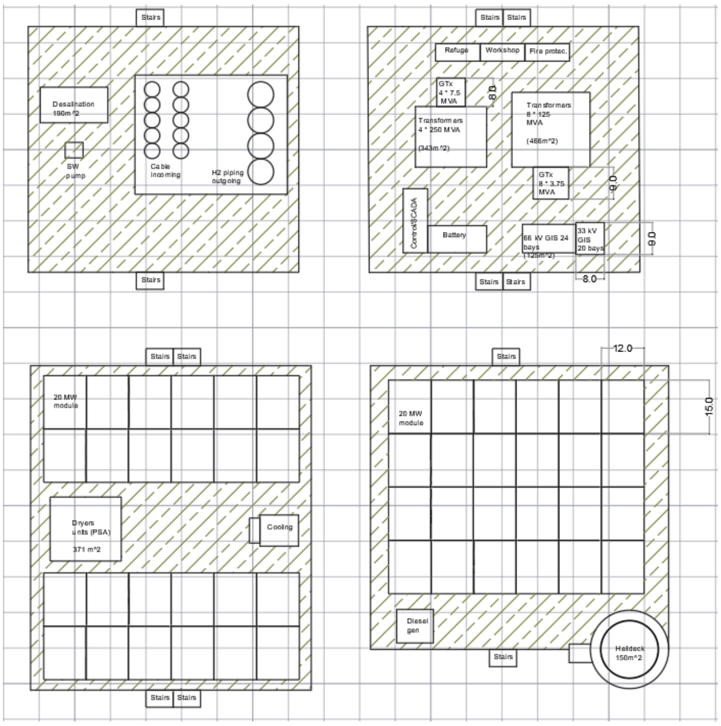


Figure 5.2: Illustration of deck layouts, zoomed in view can be found in Appendix B

The designed 2D layouts for decks of the platform can be found in Appendix B, a combined illustration of decks is shown above in Figure 5.2 above. In this thesis, the layouts are designed with respect to the expected process flow of the PEM electrolyser system and taking into considerations safety and accessibility of the operators. Important to note that the deck layouts designed are only for illustration. The lowest deck or deck 1 is close to the sea level and consists of steel work supporting feeder cables and pipeline. Additionally, it is equipped with the desalination system. Deck 2 is a comparatively secure deck for operators and consists of accommodation modules and workshops. Majority of the deck 2 area is utilised to place all of MV and HV equipment that includes the transformers, switchgears and the battery room. Deck 3 equips 24 PEM modules, where each module consists of 2 stacks, 2 separators for each stack (in total 4) and powered by 2 individual converter units for stacks. The modular nature helps reduce DC cabling and facilitates immediate separation of water content in the released gases from the stacks. PSA dryers, re-circulation pumps and PHE also form a part of this deck. The operators on the deck below are not under risk as any leakage may cause the gas to rise up and away from the platform. Deck 4 is the top most deck and consists of the remaining 24 PEM modules of the gigawatt facility along with backup diesel generator and a helideck for air crew transfer.

B. What is the economic impact of electrolyser platforms on hydrogen production costs?

5. What are the total ownership costs of platforms with electrolyser topsides (considering up to 3 different platforms)?

Monopiles/monotowers are not further assessed in terms of costs as it is concluded that they are not technically feasible to carry 1 GW P2G facility. Jackets and SSPs when compared give an economical cross over water depth of 50 m. Further the results are highlighted for the base case involving the jacket platform. The total fixed capital investment for 1 GW offshore P2G facility is estimated as 2,111 MEUR in the year 2030. Further the total cost of ownership for this facility is estimated at 2,480 MEUR. The platform LCoH only considers the life cycle costs of the offshore platform, excluding the wind farm and the gas transport infrastructure. The platform LCoH is calculated to be 1.89 €/kg for roughly 6,000 full load hours. It is expected that the platform share of overall LCoH is roughly 50%.

Total Fixed Capital Investment	2,111 MEUR
Total Cost of Ownership (TCO)	2,480 MEUR
Levelised Cost of Hydrogen (LCoH) (platform only)	1.89 €/kg
Direct costs (CAPEX)	1,160 €/kW

On a facility level, the stacks are the most expensive accounting to roughly 66% (763 MEUR) of the total facility CAPEX, as shown in Figure 5.3. Specific to the power electronics, the AC/DC converters tend to be the most expensive. The structure costs that is the costs for installation and fabrication of the jacket and topsides account to less than 10% of the total CAPEX. This **indicates that the costs of the platform facility are driven by the equipment and their costs itself, especially stacks, rather than their mass**. Finally, as an indicator of comparison with other studies, the direct costs (CAPEX) of the 1 GW offshore P2G facility is estimated to be 1160 €/kW.

Various market effects affect the total costs of such a facility. Economies of Scale and Learning Rates reduce the costs of various equipment involved, owing to increased capacity/size and increased global deployment of P2G systems, respectively. Inflation on the other hand increase the costs of equipment by deteriorating the time value of money. Apart from the purchase costs of equipment, additional costs are calculated using various Lang factors that help account for installation, piping, erection, civil costs, etc for various equipment in the facility.

The learning rates are responsible to reduce costs significantly but their effects depend on the deployment trend of the electrolyser systems in the coming future. It is important to gauge the trend carefully. Economies of scale tend to reduce costs with increase in rated ca-

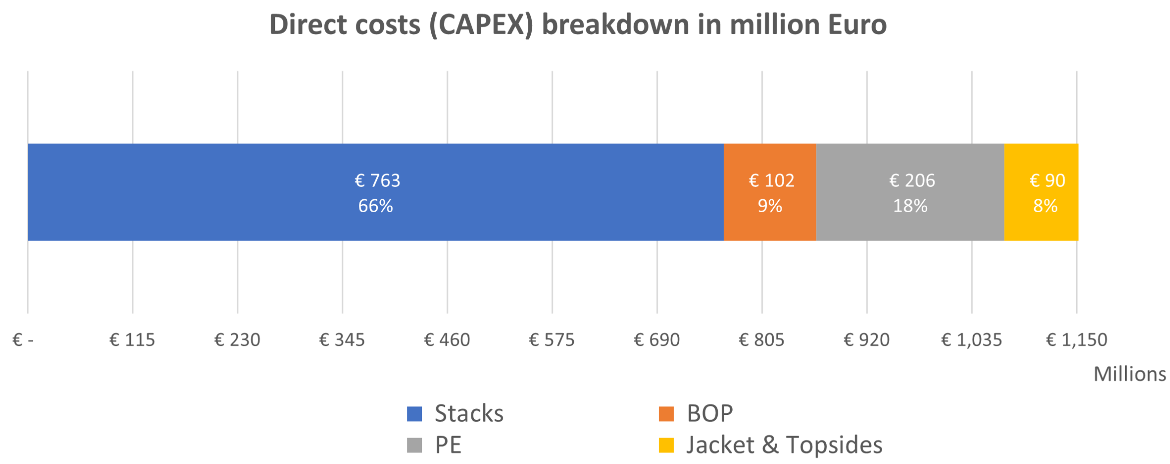


Figure 5.3: Distribution of direct costs for the offshore P2G facility

pacities of equipment. Hence, a careful consideration of the various rated power of equipment is necessary to analyse the trade off between the shelf availability of the equipment and reduced costs.

6. What is the economic optimal layout of the electrolyser platforms in terms of number of platforms and electrolyser capacities on each platform, in combination with the wind farm (taking into account platform costs, array cabling, hydrogen pipelines)?

The hydrogen pipelines and the wind farm in itself are out of scope in this thesis and the focus is only on the centralised platform. The costs of PEM stacks are the major driving factor for the total facility costs. An increase in the stack costs by 25% results in an increase of the platform LCoH by 17%, as seen in Figure 4.11. Since **the PEM stacks show very limited economies of scale due to their modular nature, the increase in stack costs with electrolyser capacity is quite linear**, shown in Figure 4.4. The BOP shows economies of scale due to it's modular nature but is limited only up to 100 MW modules, as assumed with the future developments. Hence starting from 100 MW, the overall trend of total cost of ownership (TCO) seems to be quite linear. Even though the TCO is mainly being driven by the linear stack costs, some scaling advantages should exist for example with the equipment that doesn't form a part of the modular BOP such as other piping, valves, circulating pumps, etc. Also, even though a small contribution to the total CAPEX, some scaling advantages might exist for the installation of platforms. It is important to analyse this further in the future for a better estimate of the total costs.

A reduction of 1.89% (47 MEUR) in total cost of ownership for the P2G platform is estimated when changing the inter array voltage of the wind farm from 66 kV to 33 kV. The base case considers 66 kV inter array design, in line with the future expected development of wind farms. The change in inter array voltage affects in addition to cable design and number of cables, the rated power and number of high power transformers, grounding transformers and switchgear bays. This reduction in TCO is the result of decrease in the number of equipment, their rated power and costs and also the reduced weight of the top-sides. All of this together contributes to the overall cost reduction, which however, excludes any consideration of the cable costs and transport losses. However, it would be interesting to analyse in the future if the reduced cable numbers and losses outweigh the extra costs of change in power electronics on the P2G platform.

Finally, with respect to the bigger picture an economic optimum is not assessed in this thesis as it would be an optimisation of the wind farm layout, inter array cable design and length, number of platforms to accommodate a given facility and design and number of transport pipelines.

The platform LCoH is moderately affected by the consideration of stack fixed OPEX, which is not originally considered in the model. The offshore factor significantly affects the LCoH and is to be critically analysed in the future. Size of the battery capacity has a small effect on platform LCoH including its costs and weight on the platform. For a fixed wind farm of 1200 MW, the platform LCoH increases with increase in electrolyser capacity. A rise of 7% in platform LCoH for every 100 MW increase in electrolyser capacity is seen. This is due to increase in electrolyser costs and decrease in the amount of load hours which results into same amount of hydrogen produced at every electrolyser capacity.

⟶Discussion on LCoH

In this thesis, focus is only on the platform share of LCoH. In reality, to estimate the value of a business case of such a facility some more factors need to be considered. Two scenarios revolve around offshore P2G production where the first being an off grid scenario in which all the electricity produced is converted to hydrogen. Second scenario could be an hybrid scenario where electricity is mainly transported to the grid and only converted to hydrogen when electricity prices are below a certain threshold. The NPV of any scenario is sensitive to the underlying assumption of the electricity prices. These prices affect the business case on two sides - operational expense of the P2G system and revenues from electricity sales when a hybrid system is considered. In an off grid scenario, an easy assumption can be made with respect to a flat price of electricity in terms of LCoE, since all the wind power is converted to hydrogen offshore. Hence, the reduction in LCoH produced would also depend on future offshore wind developments. In the hybrid scenario, the LCoH would rather strongly depend on price development of day ahead electricity market.

On the other hand, the market value of green hydrogen also affects the overall business case. With expected increase in the hydrogen market prices, it could become more and more beneficial for P2G operators to convert all of the wind power to hydrogen.

5.2. Recommendations

In this section, first the most important uncertainties are highlighted and recommendations are made, followed by other suggestions for improvements.

A major amount of uncertainty revolves around the offshore cost factor. It has a significant effect on the LCoH of the P2G platform. For an accurate estimation of the extra offshore costs involved and consideration of a precise offshore cost factor in future high level studies, it is important to focus further in detail on the extra operational and maintenance costs involved offshore and any extra coating or special material requirements for the equipment on the platform.

Due to limited scope of this thesis, the LCoH is only focused on the centralised platform. In reality, the costs of hydrogen produced from such a P2G platform would also depend on the costs of the wind farm generating electricity for the platform, the costs of inter array cables and the costs involved in the transportation of hydrogen to shore. Hence, in order to determine the impact of such a P2G platform on the offshore business case, further analysis and model improvements are necessary.

In this thesis, the weight of the all sorts of equipment is completely obtained via online public research and product brochures online. In addition to that, it is unsure if the weights obtained represent filled or empty equipment. This leaves room for a lot of uncertainty with respect to the platform weight and hence, it is important to have an accurate estimation of the weights of all sorts of equipment.

In this thesis, the topsides steel work or the topsides housing is sized solely with respect to the total equipment mass, while excluding any consideration of the equipment footprint. In order to have an accurate estimation of the topsides mass in the future, it is necessary to have a detailed design using footprints and clearance of various equipment on the platform, that can help estimate the length and width of the topsides and also the precise number of decks required to house all the equipment. All of this is expected to drive the topsides mass and hence, further research and model modifications are necessary.

For estimating the costs of installation, this thesis implemented cost equations based on water depth and distance to shore. These equations resulted in costs per kW for installation of the P2G platform. An accurate estimation of installation would require detailed consideration of different vessels, labour rates, weather downtime and so on. Costs would also depend on the type of installation contract. Costs would defer if the platform is solely installed within a pre-existing wind farm or if there are cost synergies while installing both the wind farm and the platform with respect to the operators, crew and vessels needed. A bigger scope would hence result further modifications in this study.

⟶Electrolyser system design

A high pressure range (up to 70 bar) of PEM stack operation is assumed in this thesis, in line with the expected developments. Although a higher output pressure of hydrogen shows potential to reduce compression requirements, it increases the complexity of the BOP. The liquid separators, dryers and piping will be expected to be designed to cope up with the higher operating pressures up to 70 bar. This can have a significant effect on the design of the equipment as well as the costs. A detailed research and industry insights are necessary to analyse this effect. It's also important to take into consideration the added equipment size and costs in the model.

Stacks with higher operating pressure can have higher costs due to thicker membranes. With further expensive BOP as explained above, the overall costs of the PEM system could rise. However, a potential way to avoid this could be to enable the use of a compressor on the platform. In this way, PEM system with average operating pressure (30 bar) could be used. Such a trade off could be an interesting aspect to explore in the future.

Further, another interesting trade off that can be analysed in the future is between the use of expensive dryers and battery capacity. The use of expensive dryers increases due to higher amounts of nitrogen within the PEM system, caused by purging of the system during cold standby modes. At times of low wind, if the electrolyser system is maintained in hot stand by mode for a longer time using larger backup battery capacity, the amount of nitrogen content within the PEM system could significantly reduce owing to less frequent purging. This could encourage the use of much simpler drying system as compared to PSA.

As per research in this thesis, the design of electrical equipment with respect to 66 kV inter-array voltage of the wind farm, the feasibility lies in having two steps of voltage transformations, 66/33 kV and 33/1 kV. This is mainly due to large scale availability of such rated transformers and also to help avoid excessive cabling (high power at low voltage). However, as per experts at DNV, transformers can be customized and built for much large differences of step voltages and it is indeed possible to have a single transformation step of 66/1 kV on the platform, reducing the total number of equipment significantly. This however, must be carefully assessed and forms a potential aspect of research in the future.

⟶Facility
Focus in this thesis is on one single centralised platform for both wind power collection and hydrogen conversion. However, an interesting point of research in the future could be to analyse the placement of a standard offshore substation within the wind farm as part of the standardised process for wind farms, and the addition of a separate hydrogen conversion platform. It would be interesting to compare the costs of such a layout with the one under study in this thesis. This is due to the fact that the a hydrogen conversion platform with no substation equipment would be technically cheaper. On the other hand, wind farm developers may save some costs on extra feasibility checks and construction for a wind farm with a traditional substation owing to their original expertise. This potential of cost saving makes this comparison an interesting aspect for future research.

⟶Costs
Learning rates play a significant role in reducing the costs of stacks, BOP and power electronics within the PEM system. As learning rates depend on the future production or installation of electrolyser systems, it is important to accurately assess the trend of this growth. The effect of learning rates occurs when the cumulative capacity of produced/installed systems double and the frequency of this occurring would depend on how the deployment

trend rises (exponential or linear). Future research should be focused on accurate estimation of the deployment trend by 2030 or 2050 and the model should be corrected for such a change in learning rate effect accordingly.

Within our original model, the fixed OPEX costs for BOP and power electronics do not change after the start year 2030. Some cost reductions in this OPEX year by year can be expected owing to continued effect of learning rates after the year 2030. This implementation within the model could help estimate better results.

The LCoH rises for increase in electrolyser capacity with respect to a fixed wind farm capacity. In future, an optimal electrolyser to wind farm ratio should be determined considering the electricity costs, curtailment costs and agreements between the wind farm operator and gas TSO.

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A

Data collection of fixed platforms in the North Sea

Platform	Topsides mass (tonnes)	Substructure mass (tonnes) with piles	Water depth (meters)
SouthWark	900	1300	30
Blythe	750	750	30
P11B	35	515	30
MONOTOWER L13-FI-1	255	360	26
A18	1110	1360	44.5
SHELL LEMAN	3570	1555	35
L5A-D	1100	950	40.3
D18a_A	1100	950	46
B13	1000	1600	44
K5CU	850	1170	35
E17A-A	1740	1440	39.5
ONOTOWERS L9-FA-1, L9-FE	200	510	24
J6A MARKHAM	1200	1650	37
K4BE	680	1230	46
L4PN	680	1220	41
K6GT	650	940	40
F3-FB	1900	1200	42
BROSELLE ALPHA & BETA	3,800	2,900	30
DOLWIN APLHA	11,000	4,000	27
HELWIN BETA HVDC	10,400	4,700	24
Sylwin	15,000	7,400	28.5
BORKUM RIFFGRUND 2	2500	2750	30
Q4C	2,400	1800	23
Jacket			
Monotower			

Figure A.1: List of parameters of researched fixed platforms in the North Sea.

B

2D deck layouts and electrical SLDs

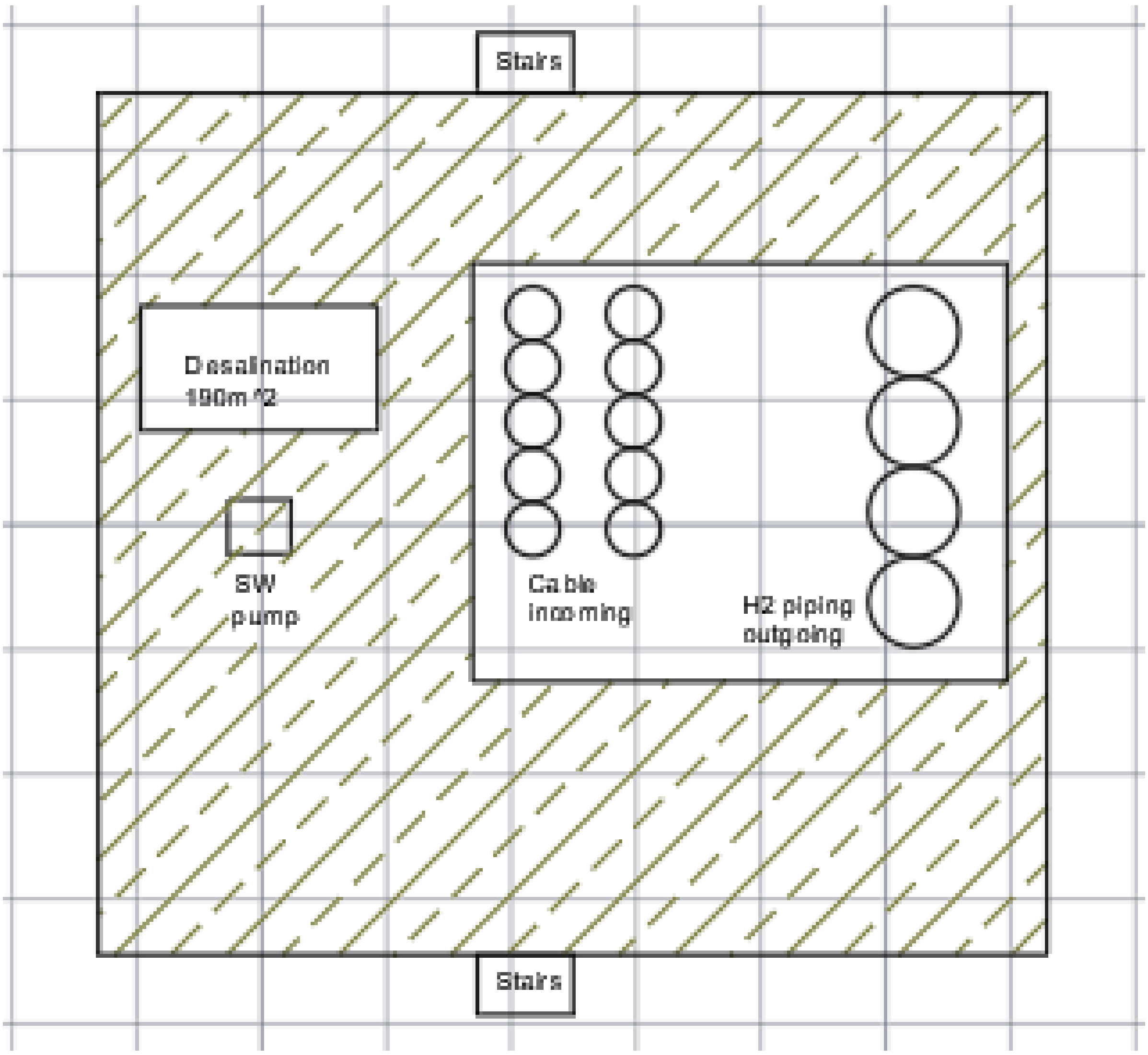

Figure B.1: Cable deck layout

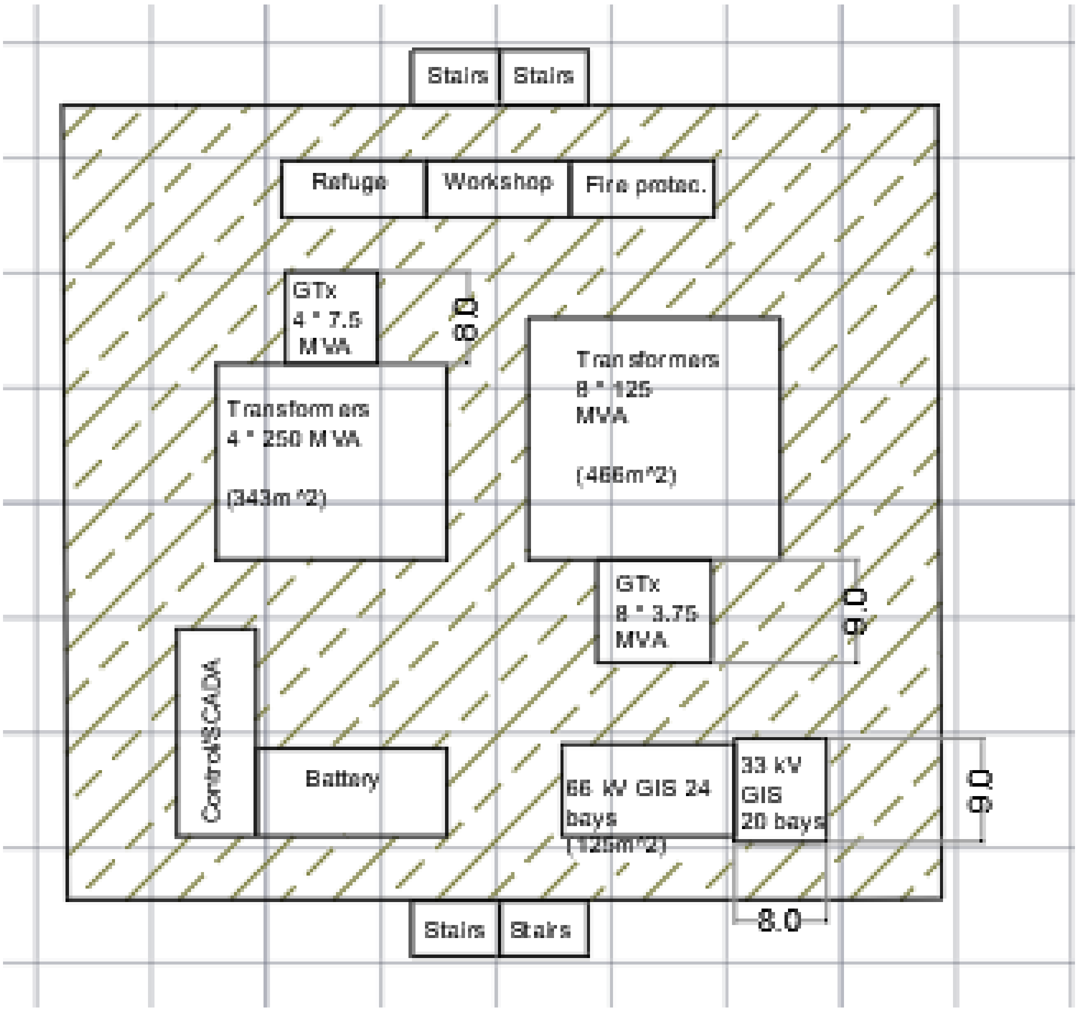

Figure B.2: Deck 2 layout

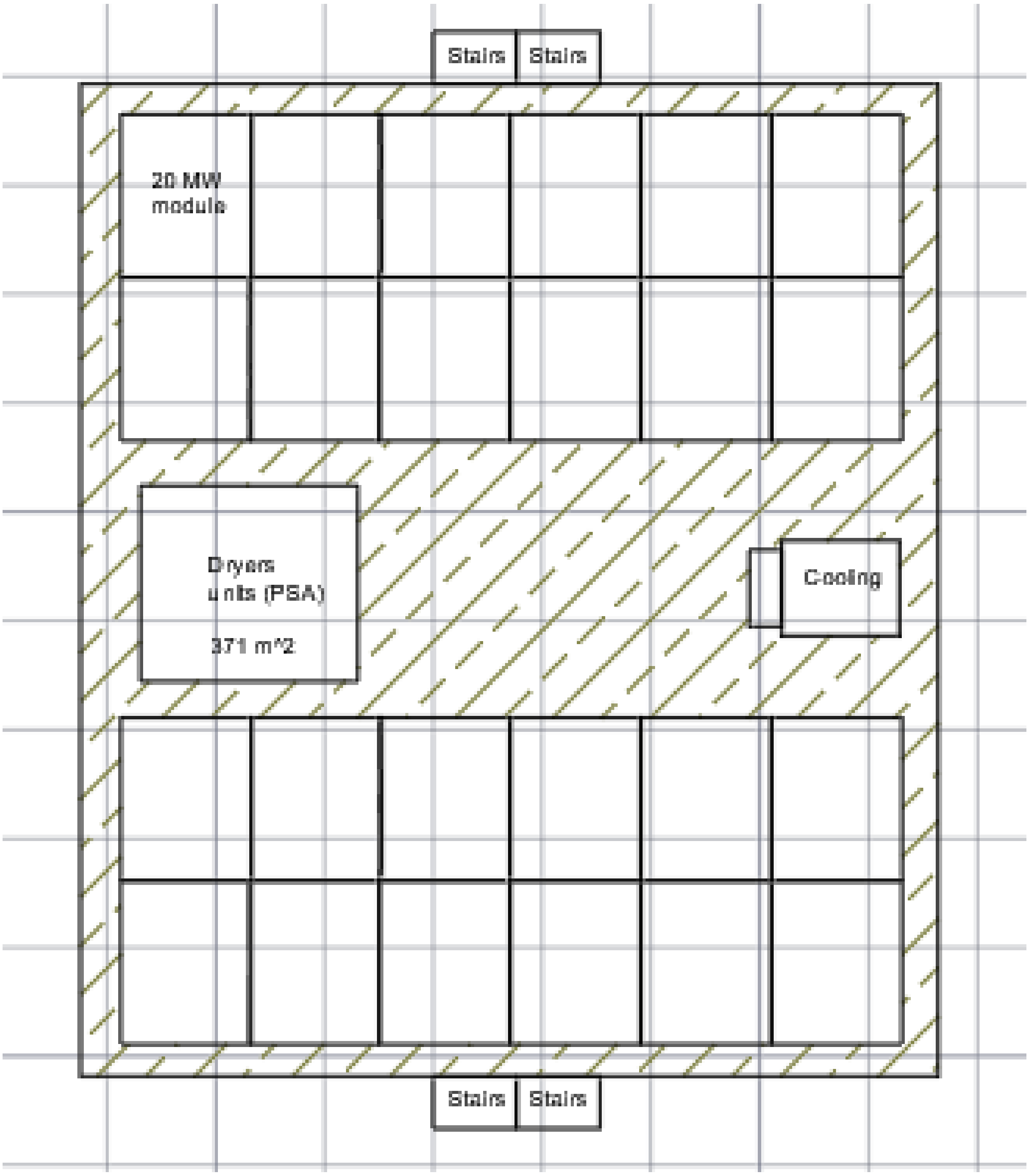

Figure B.3: Deck 3 layout

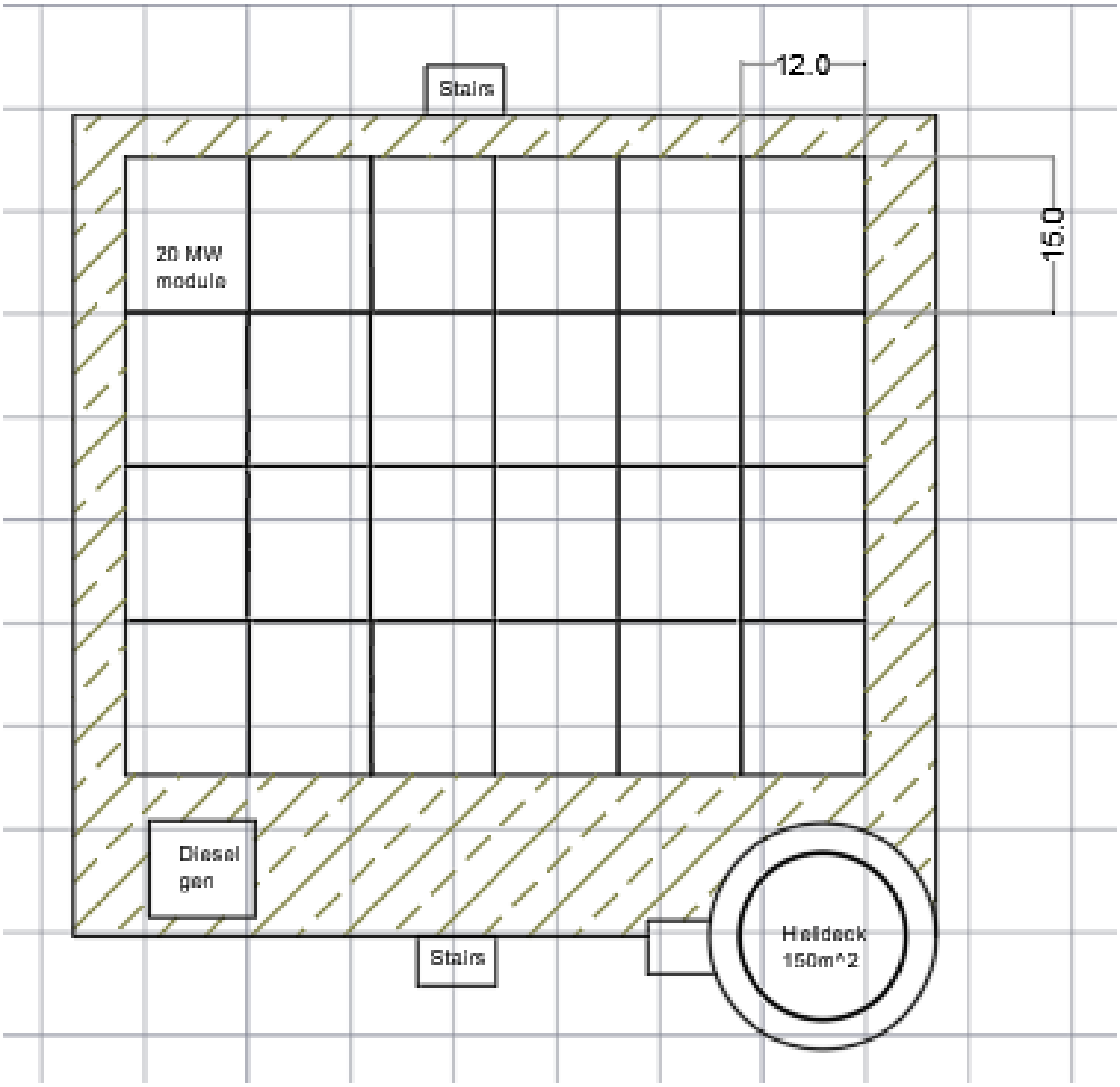

Figure B.4: Deck 4 layout

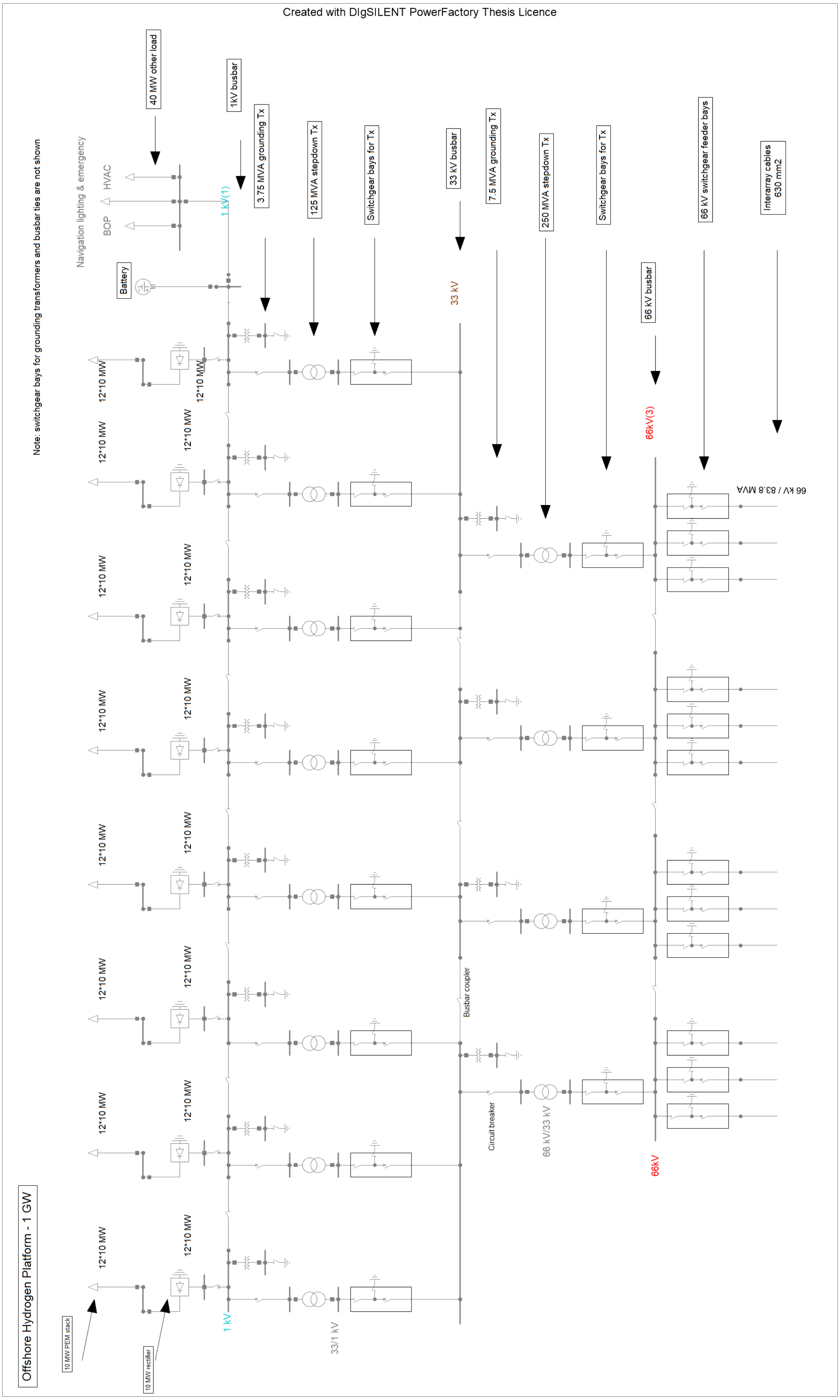

Figure B.5: Electrical SLD of P2G platform for 66 kV inter array voltage

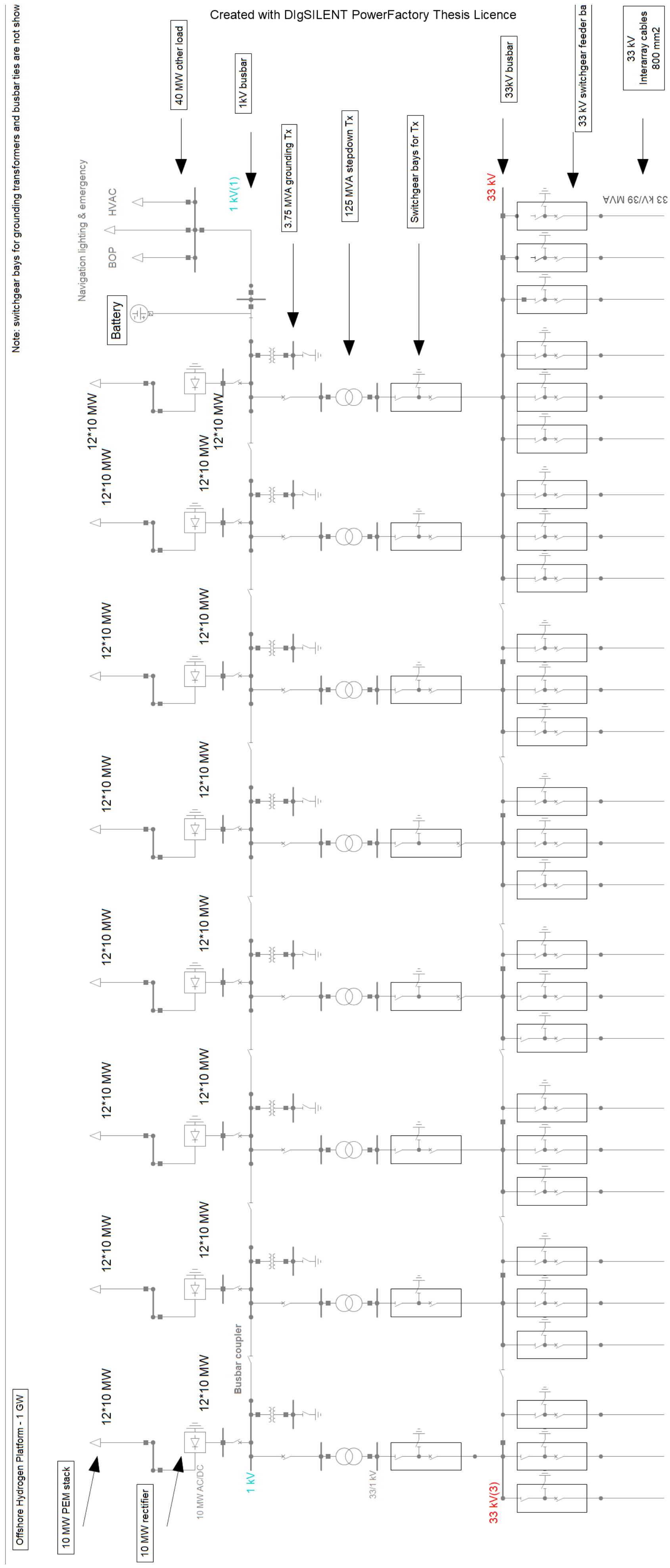

Figure B.6: Electrical SLD of P2G platform for 33 kV inter array voltage

C

BOP costs for 1 MW PEM system

System	Subsystem	200 kW	1 MW
Power Supplies	Power Supply	$44,000	$198,000
	DC Voltage Transducer	$225	$225
	DC Current Transducer	$340	$340
	Total	**$44,565**	**$198,225**
Deionized Water Circulation	Oxygen Separator Tank†	$20,000	$40,000
	Circulation Pump	$7,053	$10,962
	Polishing Pump	$2,289	$5,000
	Piping	$10,000	$15,157
	Valves and Instrumentation • Pressure, temperature, conductivity, flowmeter • A Class I, Division 2, Group B rating drives up prices.	$7,500	$11,368
	Controls	$2,000	$4,595
	Total	**$48,842**	**$87,082**
Hydrogen Processing	Dryer Bed	$13,860	$36,589
	Water/Hydrogen Separator	$10,000	$26,390
	Tubing	$5,000	$7,579
	Valves & Instrumentation • Pressure, temperature, conductivity, flowmeter	$5,000	$7,579
	Controls	$2,500	$5,743
	Total	**$36,360**	**$83,880**
Cooling	Plate heat exchanger	$9,000	$10,525
	Cooling pump	$1,500	$3,797
	Valves, instrumentation	$2,000	$4,595
	Piping	$1,000	$2,297
	Dry cooler	$4,000	$7,464
	Total	**$17,500**	**$28,679**
Miscellaneous	Valve air supply – nitrogen or compressed air	$2,000	$2,000
	Ventilation and safety requirements • Combustible gas detectors • Exhaust ventilation	 $2,000 $2,000	 $2,000 $2,000
	Total	**$6,000**	**$6,000**
	BOP Grand Total	**$153,267**	**$403,865**
	BOP Cost	**$766/kW**	**$404/kW**

Figure C.1: BOP costs for 1 MW PEM system(2015 dollars)

D

Design of a semi-submersible platform

Three main types of floating platforms namely Tension-Leg Platform (TLP), Spar-Buoy and Semi-Submersible Platform (SSP), seem to be the most promising floating technology options. SSPs are stable and cost effective. As the offshore O&G developments moved into deeper waters, the use of SSPs became increasingly popular because of their spacious deck area to accommodate large topside equipment and the ease of topside-hull integration at quayside. Although the choice for a suitable floating platform will depend on site-specific information and lowest project costs, the semi-submersible type is chosen since they are theoretically cheaper and can be easily deployed at the higher range of shallow water depths.

D.1. Fabrication

Forming a major part of the semi-submersible platform that supports the topsides known as the 'Hull', is the combination of the pontoon, columns and braces. The pontoon is the part that accommodates water ballast for stability and provides sufficient buoyancy, columns support the topsides and provide rig with sufficient air-gap between water surface and deck, and finally, bracing enhances the structural strength of the rig. The size of the hull depends on multiple factors such as static and dynamic loads on the topsides, centre of gravity (COG) of the topsides weight, draft of the hull, [1] etc [34]. Important to note that the size of the hull is not significantly affected by the water depth at which it is deployed, but mainly by the topsides weight.

A study by J. Gallala at Norwegian University of Science and Technology, looked into the design of a semi-submersible hull rig. Data points are collected from the study that displayed the effect of topsides weight on the hull mass. For simplicity, the data points used are only of the topsides, using which the following expression [2] is obtained to calculate the hull mass.

$$Hull\ mass = 0.5276 \times Topsides\ mass + 4578.38 \tag{D.1}$$

where both the masses are in tonnes.

[1] Draft is the total amount of hull part submerged in the water

[2] The trend was used ignoring any met-ocean conditions, centre of gravity of the topsides and any uncertain loads, which can possibly affect the hull size.

Similar primary steel used in fabrication of jacket is assumed for the SSP. Further, the total number of mooring lines between the platform rig and the sea bed are assumed to be 8. The number is assumed higher as compared to floating wind turbines with the motive to reduce average displacement of the platform and overall tension in the lines [59]. This means an equal number of anchors are used to help fix the mooring lines to the sea bed. The price of a single anchor is obtained to be €114,000 for a 17 ton anchor by Vryhof Anchors [78].

Chains are cost effective and usually preferred to use as mooring lines for semi-submersible platforms. The cost of mooring lines vary with water depth due to the need to meet a significant amount of breaking load. The amount of breaking load increases at shallow water depths due to increase in fatigue loads, thus requiring heavier chains with increased diameters that further increase the costs. The price of chain can be obtained using the following expression [78]

$$Cost = Length \times Weight \times Price \tag{D.2}$$

where the weight of chain can be calculated using the expression obtained from DNV standards on floating platform.

$$Weight = 0.0299d^2 \times 9.8 \tag{D.3}$$

where length is given in m, weight is given in N/m, diameter d is in mm, and price is 0.25 €/N for chain.

A per [41], the optimal length of mooring line increases linearly up to 80 meter of water depth, whereas further it increases sharply. Important to note that the optimal length of mooring lines depend on diameter, weight and the type of line used. For simplicity, the trend was derived and used in this thesis which led to the following expression

$$Length = 3.336 \times Water\ depth + 495.9 \tag{D.4}$$

where both the length and water depth are in m.

As per research, the mooring line diameter is assumed to be varying between 175 mm at 50 m water depth and 75 mm at 100 m water depth, owing to reduced breaking load requirements. Detailed breaking load requirements depending among others, on met-ocean conditions are not analysed in this thesis.

D.2. Installation

For the installation costs of SSP, a similar approach is used as in case of jacket platform in Section 3.3.2. A special Anchor Handling Vessel (AHV) is used for mooring system installation. The semi-submersible platform without the topsides is first installed at the site, with mooring lines and anchors. The following expressions are used to estimate the costs for installation of SSP

$$Floating\ platform\ and\ topsides\ installation = 35.04 \times (1 - \beta_{plat} + \beta_{plat} \times \frac{t}{T_{ref}}) \tag{D.5}$$

$$Mooring\ and\ anchoring\ installation = 2.71 \times (1 - \beta_{moor} + \beta_{moor} \times \frac{t}{T_{ref}}) \tag{D.6}$$

β_{plat} = Fraction dependant on transit between port and site = 0.02
β_{moor} = Fraction dependant on transit between port and site = 0.3
T_{ref} = Reference distance to port = 165 km
t = Distance between configuration cluster and nearest port (km)

and the cost obtained is in $€/kW$ in both equations.

Both the equations obtained from the study do not show any dependence on the water depth. In reality, costs will depend on depth and are expected to be dominated by the hydrodynamic conditions at the site which may affect the positioning of AHV during the installation process.

D.3. Other cost assumptions

Due to limited public research and knowledge, the costs for coating of the platform and anodes mass are estimated using similar expressions as in the case of jacket platforms. The cost for ballast water management system is assumed to be roughly 1 MEUR.