Techno-economic analysis of vessel applications for offshore wind farm operation and maintenance

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To my eternal and beloved grandparents Maria do Carmo and Manoel Bastos.

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Resumo

A indústria eólica offshore tem testemunhado um desenvolvimento significativo na última década, entretanto ainda se encontrando em uma situação paradoxal, pois para assegurar a produção de energia limpa, ainda depende de navios à base de combustíveis fósseis. Para abordar a redução das emissões de GEE, o sector marítimo terá de considerar novas soluções para descarbonizar a frota envolvida na operação e manutenção dos parques eólicos. Várias soluções estão a ser investigadas, sendo uma delas a adopção de combustíveis alternativos como o hidrogénio verde.

Este trabalho abordou a construção de um modelo techno-econômico e a análise do impacto da introdução do hidrogénio como combustível na estratégia de O&M do parque eólico, e a comparação com o cenário atual e os cenários considerando taxas sobre emissão de carbono, identificando os principais fatores dos custos. O modelo também abordou o impacto técnico e económico, quando consideradas estações de produção e reabastecimento onshore e offshore.

O estudo mostrou que o LCOE dos parques eólicos atendidos por navios movidos a hidrogénio ainda não é competitivo e que as dificuldades para sua implementação no sector são mais evidentes quando analisando parâmetros econômicos e tecnológicos referentes à produção, armazenamento e reabastecimento, indicando que ainda não são favoráveis e maduros.

Sob uma perspectiva futura, com reduções de custos mais significativas e a implementação de medidas para desencorajar a utilização de combustíveis tradicionais, o cenário do hidrogénio começa a dar sinais de competitividade, mostrando que para construir um sistema competitivo no mercado, a barreira técnica tem de ser superada.

Palavras-chave: energia eólica offshore, descarbonização, indústria marítima, navios de serviço, hidrogénio

Abstract

The offshore wind industry has witnessed a significant development in the last decade, however still standing in a paradoxical situation, as to ensure the production of clean energy production, it still relies on fossil fuels-based vessels. To tackle the GHG emissions reduction, the maritime sector will have to consider new solutions to decarbonise the fleet involved in the operation and maintenance of the wind farms. Several solutions are being investigated, as the adoption of alternative fuels such as green hydrogen.

This work addressed the build of a techno-economic model and the analysis of the impact of the introduction of hydrogen as a fuel in the O&M strategy of the wind farm, and the comparison with the current scenario and the scenarios considering taxes on carbon emission, identifying the main factors of the costs. The model also addressed the technical and economic impact when considering onshore and offshore production and refuelling stations.

The study showed that the LCOE of wind farms served by hydrogen-powered ships is not yet competitive and that the difficulties for its implementation in the sector are more evident when analysing economic and technological parameters regarding production, storage, and refuelling, indicating that they are not yet favourable and mature.

Under a future perspective analysis, with more significant cost reductions and the implementation of measures to discourage the use of traditional fuels, the hydrogen scenario is beginning to show signs of competitiveness, showing that to build a competitive system in the market, the technical barrier must be overcome.

Keywords: offshore wind energy, decarbonisation, maritime industry, service vessels, hydrogen

Table of Contents

List of Figures

List of Tables

List of Acronyms

AC - Alternating Current

AHTS - Anchor Handling Tug Supply

AV - Autonomous Vehicles

BAU - Business as Usual

BVLOS - Beyond Visual Line of Sight

CAPEX – Capital Expenditure

CDF - Cumulative Distribution Function

CII - Carbon Intensity Indicator

CM - Corrective Maintenance

COP 21 - 21st Conference of Parties

CT - Carbon Taxes

CTV - Crew Transfer Vessels

D&C - Development and Consent

D&D - Decommissioning and Disposal

DC - Direct Current

ECAs - Emissions Control Areas

ECMWF - European Center for Medium-Range Weather Forecasts

EEDI - Energy Efficiency Design Index

ETS - Emissions Trading Scheme

EU - European Union

EVLOS - Extended Visual Line of Sight

FC - Fuel Cell

GHG - Greenhouse Gases

GT – Gross Tonnage

HB - Hydrogen-based

HFO – Heavy Fuel Oil

HVAC - High Voltage Alternating Current

HVDC - High Voltage Direct Current

I&C - Installation and Commission

IFO - Intermediate Fuel Oil

IMO - International Maritime Organization

LCOE - Levelized Cost of Energy

LCOH - Levelized Cost of Hydrogen

LH_2 – Liquid Hydrogen

LHV - Lower Heating Value

LNG - Liquefied Natural Gas

LPG - Liquid Propane Gas)

MARPOL - International Convention for the Prevention of Pollution

MCFC - Molten Carbonate Fuel Cell

MDO - Marine Diesel Oil

MFO - Marine Fuel Oil

MGO - Marine Gasoil

MRV - Monitoring, Reporting, and Verification

NPV – Net Present Value

O&G – Oil and Gas

OEM - Original Equipment Manufacturer

OPEX - Operational Expenditure

OSW – Offshore Wind

OWT - Offshore Wind Turbines

P&A - Production & Acquisition

PDF - Probability Density Function

PEMFC - Proton Exchange Membrane Fuel Cell

PM - Proactive Maintenance

R&D - Research and Development

SCADA - Supervisory Control Data Acquisition

SEEMP - Ship Energy Efficiency Management Plans

SOFC - Solid Oxide Fuel Cell

SOV - Service Operational Vessels

TEM - Techno-Economic Model

TEU - Twenty-foot Equivalent Unit

UK – United Kingdom

UN – United Nations

US – United States of America

VLOS - Visual Line of Sight

WT - Wind Turbine

1. Introduction

After the 21st Conference of Parties (COP 21) held in 2015, in Paris, and the drive for urgent actions to reduce greenhouse gases (GHG) emissions, many countries have invested heavily in energy policies, technologies, and supply chain to meet the reduction of GHG emissions and energy transition to a low carbon economy through renewable energy. The rate of electricity generation from renewable sources is continuously expanding, with a growth of 6% in 2019, and the wind sector has been playing a significant role, representing about one-third of the total growth [1] .

According to International Energy Agency (IEA) [1], an increase of 20% of the share of offshore wind in total wind additions is expected until 2025, with the diffusion into new markets, which indicates an expansion of wind farms further away from shore and to deeper waters.

The complexity of each project is influenced by the depth and shore distance, as well as the installation, and operation and maintenance (O&M) requirements, which may imply a significant rise of the Levelized Cost of Energy (LCOE) [2]. Offshore wind turbines (OWTs) are more susceptible to breakdowns than those onshore due to the rougher environment, leading to a higher rate of maintenance to ensure the OWT operation and lifespan. Besides, further travel distances, adverse sea conditions, and greater logistic challenges may lead to high variations in the cost of O&M. Estimating the expenditures of maintenance operations and predicting energy production are important factors in an offshore wind farm cost analysis.

The energy production is related to the local wind climate and the availability of the turbine, i.e., the amount of time the system is capable of running as expected. Besides the intermittency of the wind, the availability of the turbines is also impacted by the reliability and maintainability of the system. Maintenance can be split into two categories: predictive and unplanned corrective Predictive maintenance campaigns are generally planned to increase wind farm reliability and increase availability. However, due to several factors, such as assets ageing, adverse weather conditions and fatigue, failures may occur, requiring another type of action, unplanned and stochastic corrective maintenances. During turbine shutdown to await repair identification and finalization, the wind farm is losing potential revenue due to the interruption of power generation. Therefore, a consolidated maintenance strategy is required to minimize downtime.

In addition, the required resources to conduct O&M tasks play a significant role in this analysis. Vessels are capital-intensive and are crucial for the maintenance operations at offshore wind farms. To support the maintenance strategy and to reduce the cost of energy, is essential to plan and optimise an effective vessel fleet composition. However, while the wind is a clean energy source, service vessels used for offshore wind farms still rely on fossil fuels.

According to the strategy defined on the Marine Environment Protection Committee – MEPC 73 [3], the International Maritime Organization (IMO) has a long-term goal to reduce the overall GHG emissions by 50% from 2008 levels by 2050. To achieve this target, the adoption of efficiency improvements and alternative fuels vessels commercially viable by 2030 is required. However, since the IMO is a branch of United Nations (UN) and tends to stablish rules in a way that all participating countries can comply with, there is concern from countries that are more proactive from a decarbonisation perspective, such as the EU, UK and US, as to whether these rules will be sufficient to achieve climate targets.

In July 2021 the European Commission presented as part of the European Green Deal, a set of proposals to help achieve the emissions reduction goals, decreasing GHG emissions in 2030 to at least 55% compared to 1990 levels. The measures direct impact the maritime sector since they include maritime transport in the Emissions Trading Scheme (ETS), a common EU regulatory framework to increase the share of renewable and low-carbon fuels in the fuel mix of international maritime transportation, and the introduction of fossil fuel taxation for intra-EU air transport, maritime transport and fishing, through the Energy Taxation Directive (ETD) [4]. In this way, the operational and technical profile of vessels must be revised, in terms of weather route, speed optimization, efficiency, design and alternative fuels.

Considering, the framework of a larger share of greener fuels in the industry, some alternative fuels have been considered to meet the maritime decarbonization goals. LNG has been gaining attention as a transition fuel, since it is a cleaner-burning fuel, with much lower CO_2 and sulphur emissions and considered growth in the infrastructure needed to support LNG. Other fuels such as LPG (Liquid Propane Gas), methanol, ammonia, and hydrogen are also being considered for the decarbonization of the sector, although they are still struggling with key barriers including technology, cost, infrastructure, and safety.

Hydrogen is one of the promising alternative fuels for offshore vessels with potentially a low carbon footprint and high abundance. However, hydrogen use in the maritime sector still faces several challenges, such as high costs, storage, immaturity of fuel cells for marine applications, storage capability, and safety regulations [5]. To ensure reliability for hydrogen-based vessels, an infrastructure for refuelling must be considered and economically analysed, being that onshore or offshore. For a sustainable future, the maritime industry must ensure broad-based support for technological and infrastructure development, to achieve future zero-emission operations of long duration with the hydrogen-fuelled vessels. All these factors can have a significant impact on the cost of offshore wind energy, which already faces challenges to become economically viable without subsidies, although the level of technological maturity presented in recent years has provided an improvement on the LCOE.

This Master's thesis aims to develop a Techno-Economic Model (TEM) to support the analysis of O&M impacts on total costs breakdown and CO_2 emissions, as well as to evaluate the application of carbon taxes and deployment of green fuels, namely hydrogen, and respective variation in the LCOE. Three scenarios were considered in this model, namely Business as Usual (BAU) which corresponds to current scenario, Carbon Tax (CT) employing carbon tax under operations emission, and Hydrogen-based (HB) that considers fully hydrogen-based vessels. For the case study, an analysis for the Dogger Bank Wind Farm, located in the North Sea, was used for a techno-economic assessment of the scenarios listed above.

The thesis is structured as follows: In Section 2 the service vessel fleet decarbonization problem is described. Section 3 presents a literature review about offshore wind farm operation and maintenance and the decarbonization of the maritime sector through vessels electrification, use of conventional and alternative marine fuels, the introduction of carbon taxes and production of hydrogen from wind farms. The methodological approach used to develop the model is introduced in Section 4. Section 5 presents a case study and the application of the mentioned model. The results and sensitivity analysis of the case study are presented in Sections 6 and 7, respectively. Finally, in Section 8 a discussion is carried out about the main findings and some concluding remarks are hereby presented in Section 9.

2. Problem Description

The high wind resource potential and the rapid growth of offshore wind installations around the world will lead to an increase in demand for installation and O&M vessels in the next years. This, coupled with the decarbonisation policies and cost of energy are key factors that will define the imminent growth, direction, and acceleration of offshore wind O&M methods.

Maintenance activities for wind farms play an important role in the final cost of electricity produced by offshore wind, ensuring the reliability of the wind farm and thus reducing downtime, while contributing to about 20% to 30% of an offshore wind farm's total life cycle cost [6] including all personnel and material resources for the tasks, such as vessels, fuels, spare parts, among others.

Ensuring system reliability whilst minimizing the maintenance costs represent a complex problem with several uncertainties, mainly when considering a long-term perspective. Weather conditions, failure rates, interest rates, regulations and policies tendencies can all affect the performance of an offshore wind farm.

Meanwhile, the maritime sector still relies on fossil fuels. With the IMO target to cut the sector's carbon emissions in half by 2050 compared to 2008 levels, some measures have to be implemented to meet the goal. To achieve the targets, however, the sector will have to overcome the technical and economic barriers to implement new solutions.

Implementing carbon emissions tax on ships that use traditional bunker fuels is a proposed measure in the European Union (EU) to encourage the development of sector decarbonisation, by implementing technologies or operational measures for vessels. This measure, however, is likely not to be enough to reduce the emissions as required. Although the main idea is to use the revenue to develop R&D for the industry, there is a gap between quick actions as, weather routing, speed optimization and implementations require high capital investment and vessel retrofitting. Clean fuels are an alternative to replace the traditional maritime fuels in a full decarbonization framework. Among several types and sources of fuels, hydrogen is a potentially zero-carbon fuel that has been studied.

Hydrogen can be produced from a variety of sources, through conventional or renewable energy, which determines its final cost and carbon footprint. Hydrogen produced by fossil fuel sources (grey hydrogen), is still very carbon-intensive, indicating that production of green hydrogen through electrolysis of water using fully renewable energy is the most interesting approach, in terms of environmental impact.

Hydrogen produced from wind power offshore faces several challenges, including the cost differential between conventional fuels and hydrogen, the high capital cost of technologies as fuel cells and hydrogen storage, cost of vessels retrofitting or new builds, required ports and refuelling infrastructure, and lack of safety regulations. This set of barriers describes the main problem for owners and operators investment in new solutions, and consequently, it slows down the deployment of clean fuels in scale, impacting the final cost of energy.

The objective of the maintenance vessel decarbonisation problem is to analyse the impact of the introduction of clean fuel, namely hydrogen, into the wind farm O&M strategy, by considering its preventive and corrective campaigns and to compare to the business as usual and the carbon tax scenarios, identifying the main drivers of costs. To conduct the analysis an O&M model is developed considering the main inputs to which a wind farm maintenance action is exposed to such as wind farm characteristics, metocean conditions, failure rates, repair data, vessels specifications, associated costs, financial conditions, and emissions per vessel operation.

3. Literature Review

3.1. Offshore wind farms

Offshore wind power is an emerging technology that has advanced dramatically over the past years. The world installed capacity has grown from 3.4 GW in 2015 to 6.1 GW in 2019, currently the best year for the industry. Europe remains the largest offshore wind market with 75% of total global offshore wind installation in 2019, with a great contribution of the UK, followed by the rising Asian market, mainly led by China [7].

According to SPARTA [8], from April 2018 to March 2019, from the 9 major operators in the UK, there were 19 wind farms, totalizing a population of 1,256 turbines corresponding to 4,467 MW installed capacity. In this assessed period, the observed average capacity factor was 36.05%, with a total energy generation of 13,483 GWh and CO_2 offset of 4.14 Mt.

The age breakdown of the wind farms according to their commissioning date (Figure 1), shows that the oldest farms (<2010) have reached the middle of their predicted life (20 – 25 years) when the youngest farms still were in their first five years of operations, which corresponds to their initial warranty contract, where in general, the maintenance is covered by the manufactures. It is noticed also a considerable increase in the commissioning of farms in the period between 2015 and 2016.

It means that a significant number of wind farms are currently ending up their warranty period and adding O&M costs to owners' projects. With the increasing number of wind offshore projects, is expected an improvement on the learning curve, allowing costs reductions.

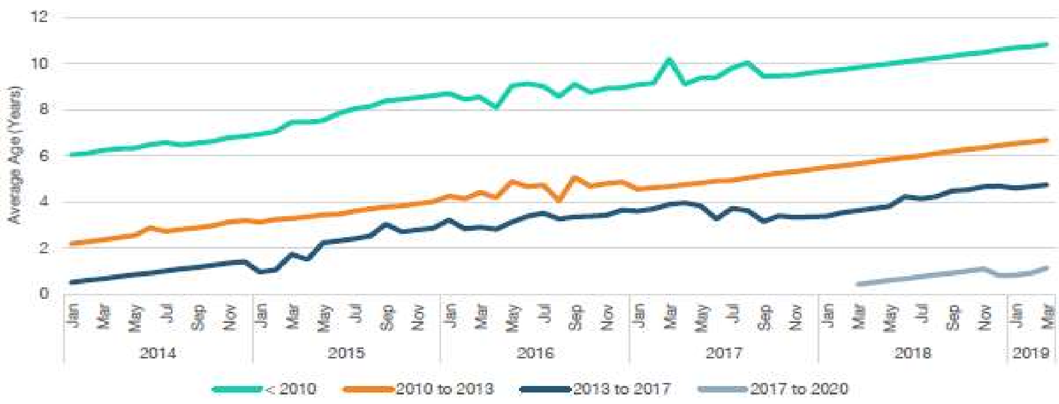

Figure 1: Average age (years) by commissioning date in the UK

[8]

The capacity factor is a measure of how much power a turbine is producing compared to its rated power generation capacity and it is strongly related to the seasonal variation since the wind speed is the main driver of this metric. To exploit the best power production, the maintenance tasks should be prioritized in the low wind speeds season, generally in summer for the northern hemisphere. To exploit the best power production, the maintenance tasks should be prioritized in the low wind speeds season, in general in summer, to be able to have the turbines fully operational in the autumn and winter periods, when the wind speed is higher, and the conditions to O&M imply harsher operational constraints. Besides the seasonality, the wind speed is also driven by distance to shore, with remote farms generally capturing higher wind speeds, and therefore increasing productivity.

The increase of the technological maturity level has allowed new installations in deeper waters providing a larger range of geographical opportunities for offshore wind and higher wind potential. However, further away from the coast, different foundations concepts may be utilised, and more complex structures must be designed to resist the severe marine environment and the waves and wind loads, increasing the technical and economic challenges to installation and maintenance tasks. [2] through a lifecycle cost model to predict the LCOE of wind farms from different concepts of foundations, concluded that the levelized cost of energy is significantly sensitive to the distance from shore, load factor and availability of the turbines.

In recent years, the offshore wind industry has witnessed meaningful cost reduction of energy production, even being planned with zero subsidies [9]. Nevertheless, is crucial to reduce the LCOE, mainly from the perspective of the increase of the distance to shore and consequently the rise of O&M costs of wind turbines.

3.1. Operation and Maintenance in wind farms

The technological development of wind farms has made wind power a more competitive source of energy. However, due to climate changes and extreme weather conditions far from land, offshore constructions are prone to critical technical issues, as corrosion, biofouling and mechanical wear, leading to a significant increase in failure rates and stoppage.

The energy production is related to the availability of the turbine, which means the percentage of time that the system is able to operate. So, the lower downtime is, the higher is the availability and the energy produced. Availability is strongly dependent on system reliability, maintainability, and logistics.

Reliability represents the ability of a wind turbine to perform under the predicted wind conditions according to its nominal power curve, withstanding the stress load, and it is measured based on the failure rate. Usually, the failure rate is high in the first year, due to manufacturing and installation defects. When most of these defects are eliminated, the turbine achieves a better phase and then start an increase of failures again due to the advance of the age of the equipment [10].On the other hand, maintainability indicates the efficiency to replace or repair the system after a failure, to prevent unexpected breakdowns or to correct the operation to maximize the production, in order to restore or maintain it to its operational state. In your turn, logistic supportability depends on the selection of vessel, crew mobilization, spare parts logistics, and equipment provision [10].

There are many critical components in OWTs, which can be sensitive to many factors such as metocean site conditions, foundation type and technological maturity, being able to cause degradation and failures. Although it is reasonable to consider the degradation of the wind farm performance over time, appropriate maintenance procedures can minimize the downtime caused by ageing. The objective of the maintenance actions is to maximize the turbine availability and minimize the probability of failures occurrence as well the energy production losses. Developing a wind turbine maintenance plan is a good strategy to minimize the likelihood of a downtime incident, taking into account the randomness of failure, repair models, vessels logistics, weather windows and waiting times that affect wind turbine performance. In general, the strategy is divided into two categories: corrective and proactive maintenance.

Corrective Maintenance (CM) is a failure-based strategy and refers to an unscheduled repair action, conducted after failures indication to get the system back to operating correctly. Generally, for offshore wind fams, it is an undesirable scenario, in terms of accessibility and costs. Since the best maintenance window occurs almost exclusively in the summer. If unexpected maintenance is required during the winter, when wind farms may be inaccessible for long periods, major downtimes and losses of energy production are expected, causing revenue loss [11].

Proactive Maintenance (PM) is a schedule of actions to be conducted before failures take place, with the objective to avoid stoppages and unsafe operations, being divided into preventive and predictive. Preventive maintenance is a time-based strategy, driven by the equipment operation and age indicators, following visual inspections and predetermined usage cycles, while predictive maintenance is a condition-based monitored by a supervisory control data acquisition (SCADA) and the most recent applications of digital-twin platforms. Besides the reduction of unplanned maintenance, the opportunity to make better use of the weather window and increasing the availability, preventive maintenance strategy provides better use of service vessels and technicians team, and avoid the excessive spare stock, optimizing maintenance tasks and reducing costs [12].

Typically, wind farm operators determine a preventive maintenance strategy to minimize failure rates and downtime but must take into consideration their maintenance plan, unexpected failures and corrective actions. For the first 5 years of the operation, the maintenance actions are conducted by the Original Equipment Manufacturer (OEM) as part of the turbines warranty. In terms of costs and reliability, it is a benefit for the operator since it is an opportunity to observe the behaviour of the wind turbine (WT) at the actual site and the response to the stochastic and unpredictable factors that were not. It is also useful and perform minor repairs that in general appear in the first year, through manufacturing and installation error. Thus, understanding the likely failure behaviour is essential to help the operator to train future technicians and to gain more confidence to conduct these tasks after the warranty period. Furthermore, it can reduce the risk of the wind farm owner, which is transferred to the service supplier.

The optimum scheduling of maintenance tasks and fleet routing must consider the type of repair, maintenance intervals, resource availability, repair time, weather conditions, operational constraints, and costs. With the increasing number of wind farms, maintenance management becomes even more complex, given the possible logistics choices, probability of failure, and weather uncertainties. As stated by [13], for 10 maintenance tasks there can be more than 3.6 million possibilities to an operational plan.

Ensuring the LCOE reduction represents a demanding management problem with several long-term uncertainties, including risks, interest rates, political tendencies, and the global market. Several works have addressed the O&M modelling and it is clear that OWT maintenance is challenging. Some authors have already stated that there is no optimization-based work reflecting a completely realistic scenario for O&M tasks. In the literature, there are no current models that accurately assess fuel types and the decarbonisation context.

It is the practice of O&M to record historical events with the aim to study and improving the reliability of wind farms. In general, the data may be presented in terms of failure rate, which corresponds to the failure frequency given by the number of failures per turbine per unit time, and downtime per failure, which corresponds to the time during which a turbine does not produce power due to a failure.

In the literature, there is still a small volume of failure data for offshore wind turbines compared to the onshore data set, mainly in terms of the number of WTs, turbine of operation, and rated capacity. Some studies summarized some information, however, due to a certain level of confidentiality in this industry, exist a considerable level of uncertainty. Besides, most of these studies report the failure rates and downtime for a mixture of WTs configurations, decreasing the reliability of the data [9]. Pfaffel et al. [14] presented a review of several initiatives which presented failures data for wind farms while Le and Andrews [15] developed a model for offshore wind turbine reliability and presented the failures rates obtained and associated with their degradation. A review of European offshore wind farm transmission failures based on public sources was presented by Warnock et al. [16]. Carrol et al. [17] and SPARTA [18] present more recent data and consider a larger number of turbines and years of operation, compared with other sources. Carrol et al. [17] presented a detailed database of failure rates categorized by severity as a minor repair, major repair and major replacement (according to cost), by different systems, from around 350 WT with capacities ranging from 2 to 4MW and ages between 3 and 10 years old were used as input.

3.2. Service Vessels

The O&M of the offshore wind farms comprises two aspects: logistics and services. While logistics focuses on managing the inventory of spares and crew allocation, services concentrate on the execution of maintenance activities on the turbines through different access vessels [19].

The service aspects can vary from scenario to scenario and the decisions of the access and operation strategy are made based on identified maintenance category, which requires a different type of technical support, number of maintenance teams, and quantity and class of vessel.

Once the failure has been identified and the maintenance plan determined, service vessels, technician team and routes can be selected to access the wind turbines and carry out the necessary tasks, taking into consideration the factors that may affect the performance of the maintenance activities like significant wave height, wind speed, type and capacity of service vessels, and failure type.

Due to the harsher weather conditions farther from shore, offshore wind farms often face issues with accessibility. Accurate information about weather conditions and forecasts are essential to building a logistic plan for transportation and transfer of the technicians and equipment required for the maintenance actions.

Typically, maintenance tasks and access to the wind turbines are performed by some specific type of vessels, including:

- Crew Transfer Vessels (CTVs): used to transport technicians between the wind farms and shore sites but are able also to take small amounts of cargo, such as components and equipment for the maintenance of the turbines, having an accessible foredeck space and smaller deck cranes. Due to the relative movement between the vessel and the turbine foundation, the transfer operation is limited to certain sea conditions, mainly the significant wave height maximum. Due to CTV operational constraints, typically it is used for minor maintenance. Therefore, the use of Service Operational Vessels (SOVs) support is becoming more common, reducing the need for CTVs. In cases where SOVs are recommended, CTVs are launched from them to be utilized during the maintenance work.

- Service Operational Vessels (SOVs) are utilized to carry out the offshore wind turbines maintenance tasks, working as a service station at sea, having required technicians, materials and daughter crafts onboard to perform smaller activities, facilitating on-time and on-demand servicing of wind turbines, increasing productivity. Besides that, SOVs are recommended when the maintenance task requires heavier equipment than the CTV’s load-carrying capacity or if the type of failure associated with the turbine is a major failure, which requires long repair time and more technicians, allowing overnight stays for the service technicians [20]. Despite the high charter costs, the vessel can stay near the wind power farms for several weeks at a time and is scheduled to always be fully manned, allowing a more quickly service and reducing the downtime of the wind farms, therefore, increasing availability and revenue. These vessels feature a dynamic positioning system, which allows them the position keeping even with the wave and current loads, roll reduction, and self-compensating gangways, affording operational safety and personal comfort, even in harsher weather. These vessels are increasingly useful for larger wind farms and further from shore, presenting more viability than for smaller farms and closer to shore.

- Jack-up and heavy lift vessels are specialized to the offshore wind farm projects and correspond to units used to transport, lift, and replace large components such as gearboxes, blades, and main bearings. Jack-ups can raise their hulls over the sea surface, providing stability for crane operations under rough sea conditions, and may have accommodation to vessels and crew. Heavy lift vessels are very flexible for unusual cargoes, having the highest capacity of lifting loads in the offshore industry since they have already a consolidated application in the oil and gas industry to install pre-assembled modules. The daily charter rates of this type of vessel are significantly high, in comparison to jack-ups. In this way, jack-up vessels have been dominating the wind offshore market, although they also present a strong variation on the availability and charter rates due to the influence of the oil industry [21].
- Anchor Handling Tug Supply (AHTS) are large vessels with considerable bollard pull capabilities, large aft deck areas to allow the carriage of several anchors and large quantities of cable. As well as Cable Laying vessels, it also can also conduct maintenance activities that refer to the removal and re-installation of cable sections. AHTS can tow either one complete turbine or two floater handle anchors or cables, if necessary, a repair is required on shore, for example.
- Autonomous Vehicles (AVs) can potentially provide the opportunity to increase the efficiency of accessibility to wind farms, especially due to the extreme conditions of the sea farther from the coast, which very often reduces the accessibility and productivity of the technicians, creating a critical working environment, which may lead to non-adequate O&M actions, increasing the costs and risks. In the last years, the sector experienced an increase in the potential of this type of vehicles application, including wind turbine blade inspection, and offshore and subsea asset inspection, reducing the need for manned vessels. As presented by Measure [22] and mentioned by Kabbabe Poleo et al. [23], a single drone per pilot operating within Visual Line of Sight (VLOS) takes around 30 minutes to perform an inspection of a wind turbine, which traditionally takes around 7 hours to be completed through human rope access. In the case of multiple vehicles operated, with technologies of Extended Visual Line of Sight (EVLOS) and Beyond Visual Line of Sight (BVLOS), the inspection time drop to 6 minutes, reducing, even more, the downtime and loss of energy due to stoppage. The application of remotely operated vehicles can reduce operating costs and improve security, although they need a mothership and an operating trained crew.

In general, for unplanned maintenance activities, short-term chartering, from 1 year or more, is the preferred practice for most wind farms operators since it ensures a quicker response to repair and lower charter rates than in the spot market. The cost of vessels decreases for longer charter periods. For sporadic repair activities which require costly vessels, mainly AHTSs and jack-ups, it is usual to look for them at the spot market.

The bareboat charter is a commonly used type of contractual arrangement in the service vessels, where the ship is hired out without crew or any operational responsibilities, as fuel, lubricants and fees. So, the more efficient the vessel the better, which encourages the owners to develop and deliver ships with a high level of performance [21].

3.3. Decarbonization of the maritime sector

Despite the incentives to the integration of wind energy in the clean energy mix of global economies, the installation and O&M services in offshore wind farms still incur a carbon footprint whether embodied in the equipment, materials and emissions produced by the vessels involved along wind farms lifespan.

According to OECD/ITF [24] it is estimated that, without action, the global share of shipping's GHG emissions may reach 17% by 2050. Besides greenhouse gases, the shipping industry is also responsible for a large amount of air pollutants emissions as NOx and SOx, corresponding respectively to around 15% and 13% of the global total [25].

While shipping was not directly included in the Paris Agreement, the maritime sector is experiencing increasing pressure to decarbonize its operations and to reduce greenhouse gases emissions. IMO still is the main forum of discussions addressing the climate impact caused by the shipping industry. The legal mandate for IMO discussion on GHG had started from the IMO's International Convention for the Prevention of Pollution from Ships (MARPOL), which originally was focused on water pollution but with MARPOL Annex VI, initialized the discussions about air contamination from ships, held in the IMO's Marine Environment Protection Committee (MEPC) [26].

In April 2018, the IMO adopted on the Marine Environment Protection Committee – MEPC 73 an ambitious strategy to reduce emissions by at least 50% total GHG emissions from shipping until 2050, with 2008 as the baseline year, while at the same time decreases the average carbon intensity (CO_2 per tonne-mile) by at least 40% by 2030, and 70% before mid-century [3]. The strategy is envisaged to be revised in 2023.

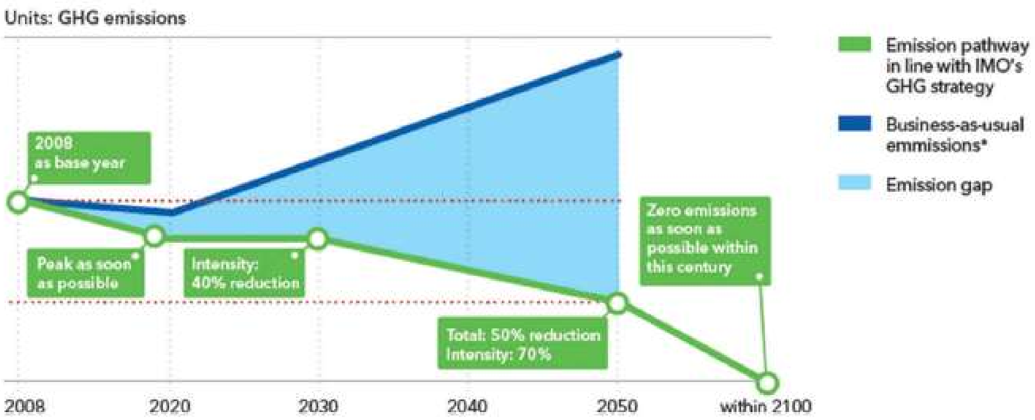

Figure 2: GHG emission gap between IMO GHG strategy and BAU emissions [27]

Additionally, in January 2020, the IMO has placed strict restrictions on the emissions of Nitrous Oxides (NOx) and Sulphur Oxides (SOx) from fuel ships, with the content below 0.1%, in all the Emissions Control Areas (ECAs), such as the North Sea [28].

Aiming at emissions reduction, the IMO has promoted technical and operational measures in the past decade, most notably through the Ship Energy Efficiency Management Plans (SEEMP) and Energy Efficiency Design Index (EEDI) [28]

SEEMP was implemented to ensure the monitoring and the improvement of several factors that can contribute to operation, while EEDI is focused on CO_2 reduction, through technological developments such as improving the design of newly built ships, whether in the hull, propeller and engine design, and adoption of new devices. However, the shipping industry is notably slow to react to changes and being a lifetime of a vessel over 20 years and considering that EEDI embraces new constructions only, the global fleet is not expected to comply with targets before 2040 [29]. With design and efficiency improvements to reduce emissions, lower fuel consumption is also expected, allowing for O&M costs decrease.

In June 2021, IMO adopted short-term measures combining technical and operational practices to improve the energy efficiency of ships as such Energy Efficiency Existing Ship Index (EEXI) calculation or all ships and establishment of annual operational carbon intensity indicator (CII) and CII rating for ships over 5,000 GT.

The different types of vessels, and their applications and operational patterns impact the decision of which emissions reduction initiative to implement. To reduce harmful emissions, the industry should focus also on other methods than ship design, as such digitalization and alternative fuels.

Brought by the Fourth Industrial Revolution, one of the major topics of the future is digitalization and automatization. Autonomous vessels, robotics, and artificial intelligence-based O&M planning are likely to play an important role in emissions and cost reduction.

In terms of fuels, the transition between traditional and alternative ones is a very disruptive way to meet the IMO goal in the intermediate term. However, there has been noticed a gradual modification at the O&M scenario with the introduction of some new hybrid (electric and conventional fuel) CTVs and SOVs. The decarbonisation of these vessels offers significant opportunities for the achievement of environmental goals, acceleration of technological maturity and cost reduction. Installation and large component repair vessels are unlikely to decarbonise fully by 2030, although new technological approaches have been also considered, as hull design improvement and different propulsion systems.

3.3.1. Electric vessels

Electric charging is proposed by many in the industry to decarbonize the sector in the near term although electric drive propulsion is broadly considered as viable only for shorter journeys given current technological and infrastructure barriers. Therefore, lower carbon combustibles, such as LNG, have been seen as a more deployable proposition for larger vessels with higher endurance requirements.

Even so, there has been a favourably and gradual change, with some operators incorporating hybrid technology (electric and conventional fuel) for new CTVs and SOVs or developing hydrogen-fuelled concepts, mainly to CTVs, although there is, yet no evidence of zero-emissions CTV or SOV having been commercially deployed in offshore wind operations.

Despite some vessels outside of the offshore wind industry using renewable and low carbon fuel sources, these tend to be limited to certain operational profiles which currently can achieve a commercial feasible basis [30].

3.3.2. Carbon taxes

Despite the IMO emissions rules, there is a concern if it will be enough to achieve the 2050 climate targets. As mentioned before, is unlikely that EEDI and SEEMP alone will be the solution to CO_2 reduction by 2050. In addition, given the expected growth of the global population and needs for energy, that technical and operational measures may not be enough to achieve the targets as expected [26].

Considering a price on carbon emissions as a market-based measure can complement the emission reduction policy tools by providing the shipping sector economic incentive to reduce GHG emissions and develop low-carbon technologies.

In the current scenario, alternative fuels face issues as the higher cost of production, transportation, and taxation, while hydrocarbon-based fuels are cheaper and widely available, with a well-established supply chain and mature technology.

With a carbon tax, based on the carbon content of the fuel, there is the opportunity to increase the competitiveness of lower carbon fuels and especially clean alternative fuels, like hydrogen besides promoting investments in research and development (R&D) for energy efficiency in ships and operational improvements [31].

Charging the carbon price on fuel suppliers, who would then pass on the cost of the levy to shipping companies, presents some barriers. Firstly, countries refrain from taxing fuels due to international tax competition, so HFO is currently not taxed. Secondly, the measure would be vulnerable to “carbon leakage” where ships would deviate from the route to bunker in ports that do not adopt the fuel tax regime. In addition, is possible to bunker at sea, in which case no port state would be responsible for charging the levy. At last, there is no precedence for MARPOL to directly take enforcement measures on fuel suppliers [26].

Some options for a downstream market-based measure for international shipping have been pondered, such as offsetting scheme, Emissions Trading Scheme (ETS) and climate levy [26].

In general, an offsetting requirement is not an effective tool to reduce emissions in the shipping sector since the main idea behind offsetting is to compensate for non-abatement or an increase of emissions in one sector with reductions in other sectors. Depending on the price of eligible offsets this could discourage the shipping industry from reducing its costs if buying offset credits is cheaper than reducing its GHG emissions [26].

An ETS sets the right to emit a certain amount of GHGs within a certain period distributed freely among participants or sold. The scarcity of available allowances creates a carbon price, where based on this price, participants can choose to either reduce their emissions, by implementing technologies or operational measures or purchase additional allowances from other shipping companies or through an auction. In comparison to an offsetting scheme, the main advantage of an ETS is that it provides greater certainty that a certain target will be achieved. The revenue could flow back to the industry, using the available budget from the Innovation Fund to bring innovative solutions to develop low carbon technologies. To avoid market manipulation, since a large amount of market power is concentrated in a few shipping companies, is required an international body to monitor it. However, demand for allowances and prices in an ETS depends on the overall demand for shipping transport services, and technological progression. In the event of a reduction in shipping trade due to an economic slowdown or the implementation of technological progress adopted by a significant number of shipping companies, the allowances demand and price would drop for other shipping companies, reducing the incentive to reduce emissions for the fleet as a whole [26].

The third option for a maritime market-based is a climate levy, which corresponds to a fee tied to the ship's GHG emissions, according to emission reporting and that could be paid directly to the IMO or integrated into the berthing fee structure that shipping companies already pay to port authorities. Unlike an ETS and offsetting scheme, a levy allows the regulator to set the price at a certain level to allow competitiveness between clean and fossil fuels. By increasing the levy periodically, the IMO could be able to react to technological changes in the shipping sector [26].

In July 2021 the European Commission presented the Fit for 55 Package [32], as part of the European Green Deal, a set of proposals to reach the emission targets of reducing GHG emissions in 2030 to at least 55% compared to 1990 levels. The measures will impact directly the maritime sector since it contemplates:

- Inclusion of maritime transport in ETS;
- A common EU regulatory framework to increase the share of renewable and low-carbon fuels in the fuel mix of international maritime transport through the FuelEU Maritime initiative proposes;
- Introduction of a minimum tax rate on certain fuels/vessels by the Energy Taxation Directive (ETD).

ETS will be extended to include emissions from all ships above a 5000 GT regardless of their flag. Shipping companies will have to purchase and return ETS emission allowances for each tonne of reported CO_2 emissions, for a portion of their emissions during an initial integration period, reaching 100% after three years.

The Commission assumes that carbon pricing in the maritime sector is likely to concentrate initially only on energy efficiency improvements, from design and operational improvements, without determining significant uptake of the alternative fuels, which requires higher technological maturity levels of production and infrastructure and are consequently costly. In this way, there is a risk cause, once energy efficiency options have been explored, could have a gap until the adoption of a new fuel mix, if the scenario is not encouraged in advance.

ETS has the role of facilitating emission reductions economically, but it is a complementary measure since it is not enough to meet the emissions target, as well ETD proposal. By integrating FuelEU Maritime to these measures, it is expected to establish the necessary conditions for the implantation of efficiency improvement and green fuels technologies to meet post-2030 climate goals.

3.3.3. Marine fuels

Traditional marine fuel can be classified according to density and sulphur content from lightest to heaviest: Marine Gasoil (MGO), Marine Diesel Oil (MDO), Intermediate Fuel Oil (IFO), Marine Fuel Oil (MFO) and Heavy Fuel Oil (HFO). The primary fuel used in the shipping sector is HFO for larger vessels, while MGO is usually used in small ones.

Vessel consumption, and consequently emissions, during the O&M phase of offshore wind farms, can vary with the farm size, distance to shore and logistical strategy adopted. The SOV fuel consumption tends to be lower than CTV when the vessel is in stand-by in the field since they often have hybrid electric power systems, however during the transit the fuel consumption increase drastically above CTV consumption, due to larger ship tonnage and consequently resistance to ship advancing.

In general, CTVs use MFO as a primary energy source, while SOVs, which very often are more modern vessels, use MGO due to the lower sulphur content [33].

Repair vessels are not explicitly considered to decarbonise within the timeframe of 2030. However, many technologies and fuels are considered that could be applicable to these vessels [30]. The designers of the hybrid system on the Viking Lady claim offshore workboats can typically achieve a 30% reduction in GHG emissions and a 25% reduction in NOx [34]

Some alternative fuels have been considered to meet the maritime decarbonization goals, not only related to CO_2 but also sulphur emissions, such as LNG (Liquefied Natural Gas), LPG (Liquid Propane Gas), methanol, ammonia, and hydrogen.

LNG has been considered as a transition fuel since its use is already well known and presents low rates of CO_2 emissions in comparison to heavy fuels. However, natural gas consists mostly of methane, which has a huge greenhouse gas warming potential if compared to CO_2 [29]. LNG has so far been utilized in large vessels that operate at moderate speeds. The gas is usually stored on deck and requires a considerable amount of space [34].

Like LNG, the use of LPG as a fuel can decrease emissions in comparison to traditional fuels, both in terms of greenhouse gas emissions and other pollutants, with lower investment costs and lower sensitivity to fuel price scenarios but also still relies on fossil fuels sources. LPG is produced mainly as a by-product of oil and gas production or a by-product of the oil refinery. It is possible to produce LPG from renewable sources, for example as a by-product of renewable diesel production

The low level of carbon, zero sulphur content, the widespread existing infrastructure, the low toxicity to marine life, and the easy storage inside the double hulls of ships are advantages of methanol over other fuel types [29]. However, methanol is currently mainly produced from natural gas, despite the possibility of being produced in the future from green hydrogen combined with CO_2 transitioning from grey, to blue to green methanol in the next years.

Ammonia is an attractive fuel due to the absence of carbon and sulphur in its composition (NH3). However, 90% of its production relies on fossil fuels such as natural gas, and the costs to produce green ammonia from renewable energy sources are not yet competitive in comparison to conventional processes [35]. Despite an existing infrastructure for transport and handling of ammonia in the fertilizer industry, the development of a bunkering infrastructure is necessary for the use as ship fuel.

Hydrogen is gaining a lot of attention as a clean fuel due to its versatility by the fact that it can be produced from a variety of primary resources. Hydrogen has an environmental perspective because when produced from renewable sources using electrolysis, the green hydrogen has no CO_2 emissions during the processes and no CO_2 particulate matter or SOx released while burning.

Pure hydrogen is a potentially attractive alternative marine fuel compared to some other proposed alternative fuels, such as LNG, methanol and ammonia. In terms of CO_2 emissions from the tank to the propeller, LNG has more than 55 g/MJ and if using methanol from CH_4, it is more than 70 g/MJ, whereas for hydrogen it is zero. In addition, as for NOx emission, hydrogen can comply with Tier III NOx limits (IMO levels of emissions control for marine engines applied based on the ship construction date) [36]. Secondly, the hydrogen energy content is 120 MJ/kg, which is about three times higher than natural gas, for example. Despite ammonia sometimes being called “the other hydrogen”, its higher liquefaction temperature (-33°C), in comparison to H_2 (-253°C), and higher energy density per unit volume simplify the storage and distribution compared to liquid hydrogen. However, ammonia presents some disadvantages as very high auto-ignition temperature, low flame speed, narrow flammability limits, and toxicity, being corrosive to copper, nickel and plastics, requiring specific designs of engines and fuel cells.

An important aspect to consider for fuel selection is the energy density, as this will determine storage space, weight requirements and fuelling time. Considering both the fuel density and the storage system, the vessel endurance range is also an important aspect and indicates how often a vessel has bunker energy. The typical bunkering interval range of LPG, LNG, methanol and liquid ammonia can be weeks, while for hydrogen, days [27].

Although LNG is the most promoted alternative fuel in shipping, hydrogen could play an important role in the future. The use of hydrogen in combination with fuel cell systems onboard ships could theoretically lower to zero the carbon intensity of shipping fleets. However, its use also brings storage and safety challenges. As LPG, ammonia, and hydrogen, are considered low flashpoint fuels according to the IMO so they must agree with the regulations in the Code of Safety for Ship Using Gases or Other Low-flashpoint Fuels. In addition, nowadays, green hydrogen presents a higher cost than hydrogen produced from natural gas reforming (grey hydrogen) or conventional fuels.

Efficiency improvements, overcoming technological barriers, economies of scale and reduction of renewable electricity cost can lead to a rapid cost reduction making green hydrogen prices comparable to MGO by 2030 [30].

3.4. Hydrogen at maritime applications

Hydrogen has stood out in recent years in the transportation sector, mainly due to the expansion of hydrogen cars and heavy vehicles. However, this market is already well established also in other sectors such as chemical and refining, and the forecast of the global demand is set to reach 50 million tons by 2025 [37].

Hydrogen as a chemical substance in nature, with the molecular formula of H_2, is not readily available to be used and it is often in the form of compounds called hydrides (H-). The fundamental difference between hydrogen and electricity is that hydrogen is a chemical energy carrier, composed of molecules and not only electrons.

There are several methods to produce hydrogen, but currently, around 96% of the production is from reforming processes of hydrocarbons, either natural gas, heavy oil, naphtha, or coal, also called grey hydrogen [29]. To minimize the reliance on conventional fuels, developments in H_2 production technologies from renewable resources, such as wind, solar and hydro, have been made, with electrolysis, an already well-consolidated method. An electrolyser operates by splitting water into its elemental components, hydrogen, and oxygen with an efficiency of around 60%.

Hydrogen is a magnificent energy carrier with a lower heating value (LHV = 33 kWh/kg), while diesel, for example, presents about 3 times less (LHV = 11.4 kWh/kg). However, hydrogen is a light gas, presenting low volumetric energy content at atmospheric conditions, making storage and transportation one of the main challenges for the adoption of hydrogen as fuel onboard ships, in terms of weight, space, technology and safety. To concentrate hydrogen and make storage more efficient, some methods are required. The most common and mature technologies of storage are compressed gaseous hydrogen (CGH) and cryogenic liquid hydrogen (LH_2) [29].

The method of compressed hydrogen storage requires just a few devices such as a compressor and a pressure tank. However, due to low storage density, the method depends on the pressure, so that can increase the capital and operating costs as the storage pressure increase [38].

Liquid hydrogen is the option most pushed by industry due to the high volumetric energy density in comparison to compressed hydrogen. When cooled, hydrogen increases its density by 775 times compared to the density of gaseous hydrogen under atmospheric conditions. The energy density of liquid hydrogen is around 5 times lower compared to the value for diesel fuels, which mean that more volume is required for LH_2 [29].

Liquefied storage corresponds to the storage of LH_2 by cooling the vapour to the cryogenic temperatures of –253 °C. It, therefore, requires expensive equipment and considerable energy for the process. The process requires a cryogenic tank where the liquid hydrogen could be stored. In addition, there are few hydrogen liquefaction plants, increasing costs to produce and transport from generation to end use [39]. The study of the first pilot project conducted by Kawasaki Heavy Industries transporting LH_2 in a tanker ship shows that it is technically and economically possible to transport and store LH_2 from Australia to Japan. However, no large-scale shipping is fully liquid hydrogen-based mainly because of the storage complexities [35]. From the previous experience of LNG deployment, where it must be carried at -160°C, a lot must to be learned and adapted for the use of liquid hydrogen.

Both gaseous and liquid are feasible to take forward, with LH_2 being a medium to a long-term solution, whereas gaseous is a short-term one.

In general, the on-board use of hydrogen can be by combustion engines and fuel cells. Fuel cells are usually the first consideration when discussing hydrogen propulsion mainly due to the higher efficiency in comparison to hydrogen combustion engine, as presented in the following paragraphs. They operate in a reverse direction as an electrolyser system, converting hydrogen and oxygen into water and power.

Several types of fuel cells exist as such the proton exchange membrane fuel cell (PEMFC), the molten carbonate fuel cell (MCFC) and the solid oxide fuel cell (SOFC). Due to higher technological maturity, the PEMFC system has been heavily considered for marine energy applications, leading to a more tolerant and feasible response to the marine environment solution, at a lower cost. The efficiency is moderate, about 50-60 % and the physical size is small, which is positive for marine use. The disadvantage is the sensibility to the hydrogen impurity and a moderate lifetime. The PEMFC creates electricity by pushing H_2 atoms through an anode, and through a chemical reaction, ionizing the now positively charged atom for applications [29].

Hydrogen combustion engines react with oxygen and move the pistons through the explosion in the same way as a petrol or diesel engine, allowing hydrogen to be combined with conventional fuels and used with little alterations to currently operational diesel engines. However, the main by-product of this process is water with some NOx and SOx. In addition, another disadvantage of combustion engines is the lower energy efficiency comparing to fuel cells (around 40%). However, the associated cost, usually, is lower them fuel cells. [29].

To overcome the barriers of space and weight required for hydrogen storage that may impact the vessel performance, some alternatives have been considered, for example, the Havyard, a liquid hydrogen fuel cell cruise ship designed to be supplemented with battery recharged by renewable electricity, allowing an emission-free vessel to longer distance. The drawbacks associated with electric vessels utilising battery power are the need for the recharging infrastructure at ports and lower energy density compared with liquid fuels, leading to larger and more expensive batteries [30].

Another important element to be considered in selecting the shipping fuel is the ease of ship recharging. In the shipping industry, the refuelling process with traditional fuels is already consolidated, being possible to refuel a vessel in a few hours in a port or by a ship-to-ship method, that is a bunkering operation between seagoing ships positioned alongside each other either while stationary or underway.

Regarding compressed hydrogen, the storage difficulty concerns space required in the deck and hold of the ship to cylinders storage, which also leads to a slow fuelling time that is inherent to transporting a low-density gas. The solution that might be considered, for smaller vessels is the use of hydrogen tanks mounted in a standard container, which can then be loaded on a ship, reducing the time of port calls. Apart van Hoecke et al. [29], from the safety concern brought by the storage of a high-pressure flammable gas on the vessel, the refuelling process has also to be in mind. Hydrogen is compressed into the storage cylinders and heat is released during such adiabatic compression. So, if bunkering is conducted without control could soften the pressure vessels, leading to catastrophic failure [39].

On the other hand, the main problem with liquid hydrogen fuelling processes is the low temperature at which the fuelling process has to be conducted, requiring cryogenic pumps, and the subsequent evaporation of liquid hydrogen. Currently, this technology is reasonably well-known from the previous experience of LNG bunkering. However, while LNG is generally transported to a port to be bunkering, a hydrogen liquefaction plant would likely be located nearby. The LNG fuelled ships can serve as a baseline for the use of liquid hydrogen ships, although the difficulties with H_2 ships should be greater due to the lower temperature and more liquid stored in comparison to LNG. Besides that, the liquid hydrogen evaporation will create partially filled hydrogen tanks, impacting the stability of the vessels because of the free surface effect [29]. The solution to minimizing this effect might be to use smaller tanks or install transversal web frames to reduce their size.

That been said, the transition towards low carbon fuels still presents many challenges to the industry, such as the ability to deliver energy and power densities comparable to traditional propulsion systems, current lower efficiency of hydrogen fuel cells, cost of storage, fire risk with battery systems and higher capital costs. Shipowners, ports and regulatory institutions like the IMO, will have to make strategic choices on the methods of hydrogen storage for shipping.

3.4.1. Hydrogen production from wind farms

It would be beneficial to use power generated by wind farms to charge the vessels that service them. With declining costs for renewable electricity, there is growing interest in electrolytic hydrogen, especially if better use of the excess wind power is considered. Hydrogen can be used to store wind power, helping to lower grid balancing costs and the electrolysers could act as an ancillary service, taking excess power from the grid to produce hydrogen.

With the offshore wind farm producing electricity, the electrolyser is responsible for hydrogen production, also requiring a hydrogen storage system.

Besides the cost associated with the turbine and electrolyser platform, bottom fixed or floating, bring electricity to shore has also a significant cost, due to converters, grid connections and underwater cables, which costs increase linearly with the distance to shore. Transmission losses also must be considered and may vary from 1% to 5% if considering a High Voltage Alternating Current (HVAC), and from 2% to 4%, for High Voltage Direct Current (HVDC). However, hydrogen transport through pipelines presents lower losses, under 0.1% [40].

In this way, some configurations of hydrogen production from offshore wind farms can be considered. The first one consists of an offshore wind farm producing electricity, that travels to an offshore transformer, and is transmitted to shore by a cable to an onshore electrolyser or the electricity grid. The flexibility of this hybrid system allows the operator to manage the electricity, that can be sold directly to the grid or used to produce hydrogen. This configuration presents a lower level of complexity of installation and better conditions for maintenance, enabling costs reductions [40].

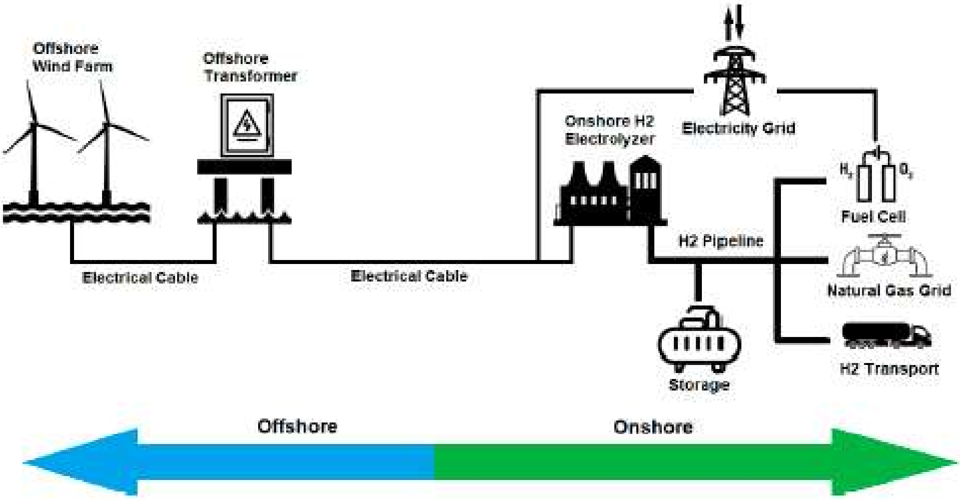

Figure 3 - Onshore electrolyser system
[40]

The second one consists of an offshore wind farm, offshore electrolyser, and onshore hydrogen storage, where the electricity produced by the wind farms travels a short distance until the electrolyser station, reducing losses. At this point, the hydrogen is produced and transported to shore through a pipeline [40].

Multiple electrolyser layouts are possible: a single centralized electrolyser fed by the whole wind farm, where power produced by each turbine is transmitted to a central platform through regular underwater cables, an individual electrolyser, one per wind turbine, or a multi-centralized configuration, where there are several electrolysers, each being fed by a number of turbines in the farm. However, for the individual electrolysers layout, some significant modifications are required on the platform to accommodate the additional weight of the electrolyser system, from the structural and stability point of view. A more cost-effective approach is to slightly undersize the electrolyser, since the wind farm is not all the time at nominal power, and so the nominal power of the electrolyser does not need to match the wind farm's one. In this case, the revenue lost when the wind farm is at nominal power could be lower than the additional cost of a more powerful electrolyser [40].

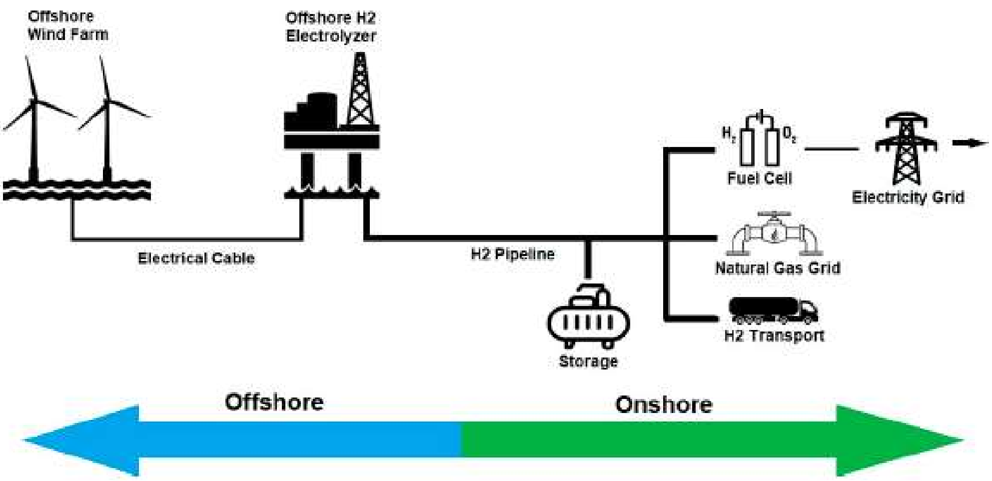

Figure 4- Offshore electrolyser system
[40]

However, for this configuration, the offshore H_2 electrolyser platform is bound to face more severe conditions for installation and maintenance, increasing CAPEX and OPEX, impacting the Levelized Cost of Hydrogen (LCOH). Meanwhile, for O&M tasks in farms farther from shore, an offshore H_2 electrolyser platform working as a refuelling station at the site can be effective for service vessels, increasing its endurance, allowing vessels availability, reducing their overall transportation time and port traffic, while reducing time response to turbine failures and repair campaigns, and increasing wind turbine availability.

4. Methodological approach

This section outlines the methodological approach comprised in the presented work.

The proposed workflow with its inputs and outputs is shown in Figure 5. The framework includes a set of seven types of inputs, as the wind farm characteristics, which are weather conditions, failure rates, time to repair, vessels specifications, costs and emissions, that are processed through a mathematical model.

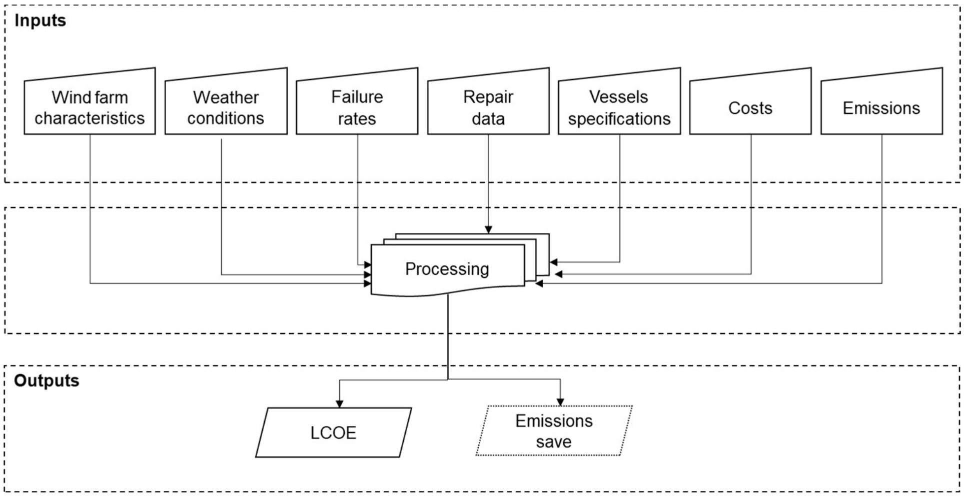

Figure 5 - Proposed workflow

The main objective of this model is to estimate the levelized cost of energy produced by a wind farm, considering an O&M strategy, and comparing different scenarios. The scenarios were divided into:

- Scenario 1: Business as usual (BAU) comprises fossil fuel-based vessels as in the current scenario;
- Scenario 2: Carbon taxes (CT) scenario comprises fossil fuel-based vessels, however considering the application of carbon taxes according to vessels emissions in O&M. Embodied carbon is not considered in this case;
- Scenario 3: Hydrogen-based (HB) scenario considers fully hydrogen-based service. Furthermore, for this case, two analyses are proposed: offshore and onshore hydrogen refuelling stations.

Table 1 - Summary of scenarios

	Business as usual (BAU)	Carbon tax (CT)	Hydrogen-based (HB)
Fuel	Fossil fuel	Fossil fuel	Hydrogen fuel
Emissions fee	No	Yes	No
Refuelling	Onshore	Onshore	Onshore and offshore

The wind farm of the case study mentioned in Section 5 is assumed, with the defined number of turbines and specifications of operation, requiring a preventive maintenance action, defined in the annual campaign, and corrective repair, due to a failure occurrence.

The O&M strategy is determined by the type of maintenance, the type and number of vessels required for each required inspection or repair and their operational specifications.

The common parameters between preventive and corrective maintenance are the number of turbines, the distances from shore and port, the turbines capacity, the vessels' specifications, the work shift hours per day, the cost of personnel, the wind profile, the project lifetime, and the discount rate.

The LCOE model considers the costs throughout the whole lifetime of the asset so that the initial capital investment and energy production must also be estimated.

CAPEX comprises the cost of the turbines, including the foundations, infrastructure, installation, and other investments for wind farm development, deployment, and commissioning, while energy production takes into account the local wind profile, WT technical specifications, losses due to stoppage and electricity demanded by hydrogen refuelling station.

The overall OPEX relies on the failure rates of each subsystem, duration of repair tasks, sources consumption (spare parts, technicians, and fuel), vessel charter, and, in case of scenario 2, emissions cost. The methodology also considers the weather downtime and consequently cost impact due to stoppage.

In event of the decarbonisation scenario, it is possible to also analyse the CO_2 emissions savings in comparison to the fossil fuels framework.

A detailed mathematical model was developed, based on several sources, assumptions and simplifications, and solved in Excel. Due to the inclusion of variations in the seasons of the year in which the failure may occur, these O&M simulations can be categorised as stochastic as they contain inherent randomness providing a higher level of detail.

The quantitative coefficients were determined based on historical data and project experiences. There is a lack of availability of reliable data on the key offshore wind components and maintenance actions given that, in general, there is confidential conduct to protect companies' knowledge and data. This lack of information leads to a disparity of data presented by different authors. An average of failure rates across these multiple sources was considered, as is further detailed in Section 5.4.

The tool developed does not focus on more complex modelling of operations, such as fleet or route optimisation, concentrating on developing a tool to compare the impact of decarbonisation of the O&M fleet, and to analyse the most significant drivers of the cost components.

With the LCOE calculated from the model, and considering its random characteristic, a set of Monte Carlo simulations was conducted, considering 100 simulations, to estimate the average costs of electricity and its standard deviation.

In the following sections, the different components of this techno-economic model are presented.

5. Case study

To illustrate the developed model, a case study of an O&M strategy for the Dogger Bank Wind Farm is created and its respective LCOE and cost impacts for each scenario are presented in the following sections.

5.1. Wind farm characteristics

Dogger Bank is an isolated sandbank within the central to southern North Sea spanning UK, German, Danish and Dutch waters, located between 130km and 190km from the North East coast of England at their nearest points, and water depths range from 18m to 63m. The Dogger Bank Wind Farm is being developed in three phases – Dogger Bank A, B and C, with a combined installed generation capacity of up to 3.6GW (1.2GW each phase). Each project counts with 95 monopile turbines with 12 MW direct-drive turbines each [41].

Both, Dogger Bank A and B, are located around 131km from shore at their closest point and will connect to the existing Creyke Beck substation, while Dogger Bank C is 196km from shore and the connection will be at the existing Lackenby Substation at Teesside [41].

The monopile foundations will be amongst the largest ever used for offshore wind, and their installation is expected to begin in 2022, with this first project expected to be operational in 2023.

For this specific case study, the analysis focused on Dogger Bank A, although being possible to be applied for any site.

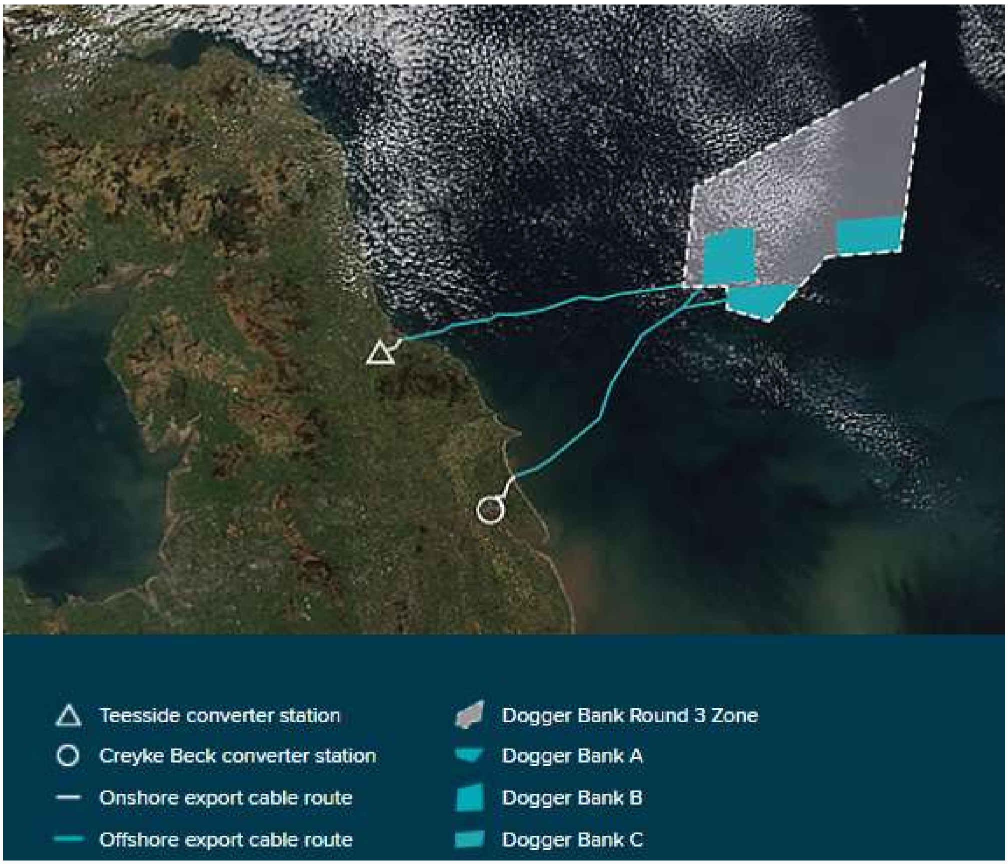

Figure 6 - Wind farm location - Dogger Bank A, B and C

[41]

The Port of Tyne was announced as the long-term operational base of Dogger Bank, and it will contain the infrastructure required for the installation and maintenance of offshore wind farms and service the supply chain. It is located at a minimum of 96 nautical miles (178 km) of the Dogger Bank, closer than any other port to seven of the world's biggest offshore wind farms.

Besides the easy access, the design of the port includes the development of deep-water quays, equipped with heavy lift cranes, suitable for service vessels operations, as well to assemble, store, load and offload giant turbines, blades and towers, mature logistics infrastructure and capacity to bunkering, storage, supply, crew change and other activities [42].

Recently launched, Tyne 2050 strategy, aligned to the UK Governments Maritime 2050 plan, aims to drive further transformation in the ports and maritime sector, creating an all-electric port and looking to port technology focused on the future [43].

For this study was considered that all required port infrastructure and technology for the service vessels are already available.

The main characteristics of the wind farm are summarised in Table 2.

Table 2 - Wind farm main characteristics
[41]

Wind farm characteristics	
Wind farm	Dogger Bank A
Wind turbine capacity	12 MW
Number of turbines	95
Foundation	Monopile (Fixed)
Water depth	36 m
Distance to shore	131 km
Operational base port	Port of Tyne
Distance to port	178 km
Generator type	Direct drive
Turbine	12-MW Haliade-X
Hub height	150 m
Rotor diameter	220 m

5.2. Maintenance planning

Preventive maintenance will include activities like routine inspections and checks of particular components while corrective actions are designated according to failures occurrence. If there is a need to perform more complex work on a wind turbine or replacement of equipment, it means that a turbine could be shut down.

To simplify the operational planning problem, the model considers independent repair actions for each turbine yearly as the failure occurs and replicate it for the total WT of the wind farm.

The failure rates were categorized by level of repair for each group of the subassembly of subsystems.

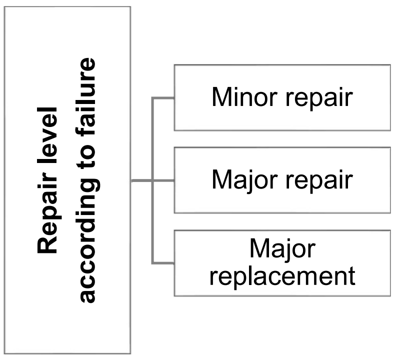

Figure 7 – Repair levels of failures

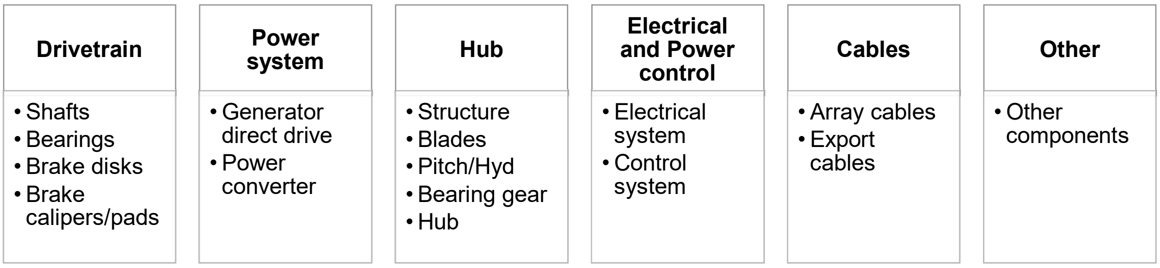

Figure 8 – WT's subsystems and subassemblies
adapted from [17]

CTVs were designated for minor repairs, while SOVs were for major repairs. Jack-ups are indicated to the most of major replacements, due to payload capacity, equipment and available deck area while AHTS was chosen to conduct tasks with cables and to tow the turbine or equipment, if necessary, due to its capacity to handle anchors and cables, plus high bollard pull characteristics [2].

As soon as a failure is identified and categorized according to repair level, a vessel is set. Since SOV and CTV are dedicated vessels and stand-by near the site, it is considered that they are already available to move to the site, with adequate equipment to conduct the action. For jack-ups and AHTS, as soon a major replacement is identified, the mobilisation time to the vessel be hired and to transit to the site is considered. This model does not comprise the impact of the jack-ups availability variation on the spot market, and consequently the downtime and hire costs. These vessel types are in high demand by both the offshore wind industry and the oil and gas sector worldwide, impacting their availability.

The initial time of failure identification is considered the time zero of a weather window.

For minor and major repairs, the action starts with the respective vessel leaving the stand-by location in the direction of the WT. The spot where the set of SOV+CTV is located is shown in Figure 9, based on the Dogger Bank layout presented by Schepers et al. [44].

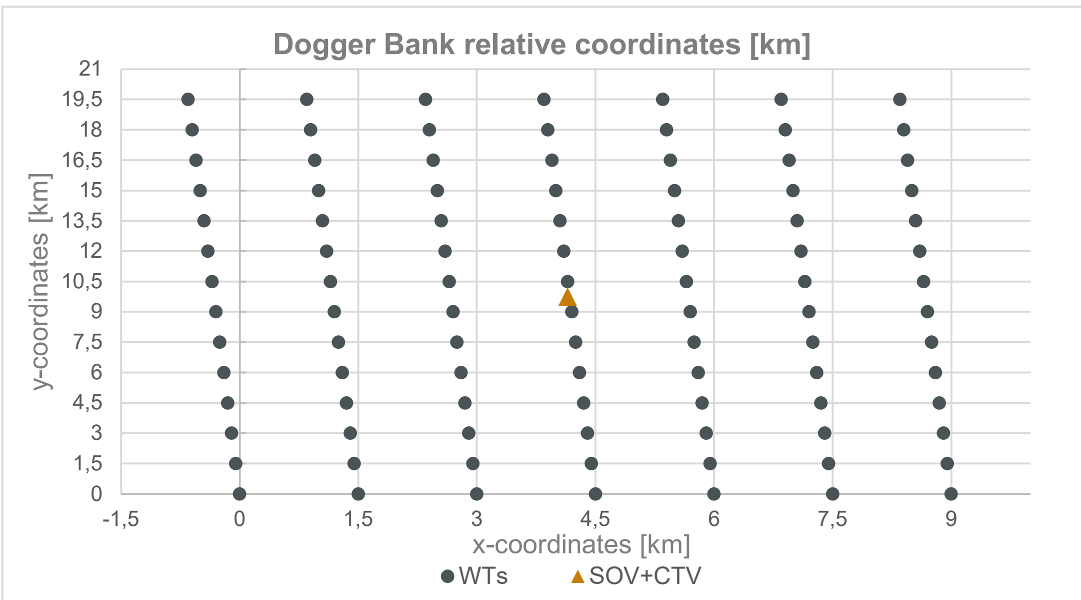

Figure 9 - Dogger Bank layout - relative coordinates
adapted from [44]

The distance between WTs can be considered as 7 times the rotor diameter [45], then the distance travelled by the vessels is considered as the average between the closer and the farther wind turbine and is considered to 5.3 km.

The action is considered complete when the repair is finalized, and the vessels return to the spot.

Table 3 - Distance from SOV base point and between turbines

Distance$_{SOV+CTV}$	**5.3 km**
Distance$_{WTs}$	1.5 km

5.3. Weather conditions

The weather conditions are crucial for the O&M of wind turbines as it defines if the site is accessible at a required moment and if tasks are possible or not to be conducted. A vessel is considered available in a window where there is a possibility to transit to the wind farm, to manage the required repairs and to transit back to the base.

This work took into consideration the most critical weather parameters for the addressed vessels, namely the significant wave height (H_s) and the wind speed at hub height (W_s), especially for jack-ups due to crane operations.

The metocean data correspondent to Dogger Bank A's significant wave height and wind speed at hub height were obtained from ESOX [46] which uses the ERA5 reanalysis data produced by the European Center for Medium-Range Weather Forecasts (ECMWF) on behalf of the European Union's Copernicus Climate Change Service (C3S).

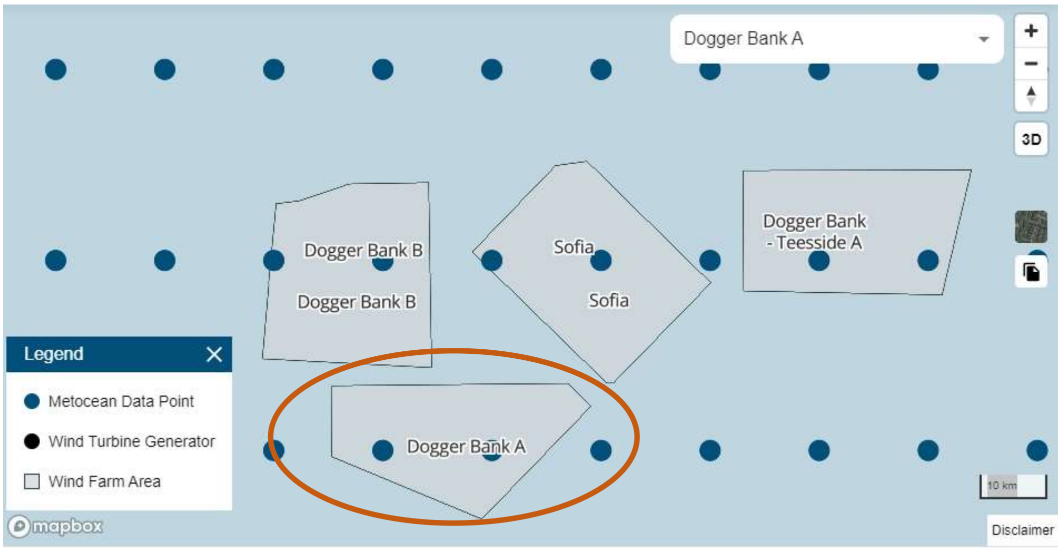

Figure 10 -Dogger Bank Metocean Data Point
[46]

A wind speed and wave height distribution created by measured data is a good way to show the frequency of occurrence of the variation of these parameters in a particular location.

The Weibull distribution is a three-parameter function expressed by the probability density function, depending mainly on the shape factor k (dimensionless) and scale parameter b (dimensional). The third parameter is the location parameter (X_0), which shifts the distribution along the x-axis. It is only altered to provide a better fit of the function but by default it is defined as zero, i.e., considers that the distribution starts at the origin [47].

Hence, Weibull is more general than, for instance, the Rayleigh distribution, which has k=2, and more practical to be implemented in a model than to the more general bi-variate normal distribution, which requires five parameters for representation, namely the mean values of variables x and y, their respective standard deviation and the coefficient correspondent to the correlation between x and y [48].

As seen from literature, the Weibull distribution is frequently used to model weather data due to its flexibility and capability to mimic various distributions, providing a reasonable accurate representation of the observed normal distribution.

Muraleedharan et al. [49] presented a study that shows a deviation of only 0.33% between the observed mean maximum wave height and the estimated by Weibull distribution. The wind speed frequency distribution can also be approximated by a Weibull distribution, as shown by Parajuli [50], being a well-established approach.

The probability density function (PDF) is given by the equation 1 as function of the wind speed (U) [m//s]:

$$f(U) = \frac{k}{b}\left(\frac{U}{b}\right)^{k-1} exp\left[-\left(\frac{U}{b}\right)^{k}\right] \tag{1}$$

To assess the weather operational conditions at a site, a numerical modelling approach was used, considering the vessels constraints and tasks duration. The analysis was conducted seasonally, through a random season generation, divided into winter, spring, summer and autumn. By re-arranging the cumulative distribution function (CDF) of the Weibull and doing a regression, it was possible to find the shape (k) and scale parameters (b) for each season data set. The average of the distribution ($\overline{M}$) is obtained by:

$$\overline{M}=b\Gamma\left(1+\frac{1}{k}\right)+X_0 \tag{2}$$

Where Γ represents the gama function. The location parameter (X_0) was considered zero since no adaptation along of x-axis was necessary. Table 4 and Table 5 indicate the values found.

Table 4 - Weibull wind speed (Ws) parameters

Ws parameters	Winter	Spring	Summer	Autumn
Average (Ws) [m/s]	9.54	7.49	6.45	8.61
Shape factor (k) [-]	2.40	2.32	2.31	2.39
Scale factor (b) [m/s]	10.76	8.45	7.28	9.71

Table 5 - Weibull wave height (Hs) parameters

Hs parameters	Winter	Spring	Summer	Autumn
Average (Hs) [m]	2.09	1.42	1.06	1.76
Shape factor (k) [-]	2.40	2.42	2.49	2.42
Scale factor (b) [m]	2.35	1.60	1.19	1.98

With time-varying parameter data, the Weibull Persistence Method was chosen to calculate the probability of an operational threshold being exceeded and consequently the associated waiting time for the next weather window, as conducted by McDowell et al. [47] and Walker et al. [51]. This approach is seen to be well suited for this application and holds relative computational simplicity to be applied even for large time series.

Having identified the Weibull Parameters, the Weibull Probability of Exceedance (P_w) can then be calculated:

$$P_w(M>M_{ac})=e^{\left(-\left(\frac{M_{ac}-X_0}{b}\right)^k\right)} \quad (3)$$

Where M represents the parameter (Ws or Hs) and M_{ac} is the threshold operational limit for that parameter.

The average window length (T_{ac}) was calculated using the following equations:

$$T_{ac}[h]=\frac{\frac{1-P_w(M>M_{ac})}{P_w(M>M_{ac})}\times A}{[-\ln P_w(M>M_{ac})]^{\beta}} \quad (4)$$

$$A=\frac{35}{\sqrt{\gamma}} \quad (5)$$

$$\beta=0.6\gamma^{0.287} \quad (6)$$

$$\gamma=k+\frac{1.8X_0}{\overline{M}-X_0} \quad (7)$$

The required weather window length (X_{ac}) is given by the sum of repair duration, connection time, disconnection time and transit time.

$$X_{ac}[h]=Transit_{time}[h]+Disconnect_{time}[h]+Repair_{time}[h]+Connect_{time}[h] \quad (8)$$

The probability that the access conditions persist for a normalised duration (X_i) is calculated, as shown in (9).

$$P(X_i>X_{ac})=e^{\left(-C_{ac}(X_{ac})\right)^{\alpha_{ac}}} \tag{9}$$

Where C_{ac} is the occurrence of accessible conditions and α_{ac} is the relationship between the mean value ($\overline{M}$) and the threshold operation value (M_{ac}), assuming a linear correlation characteristic, with γ calculated by (7.

$$C_{ac}=\left[\Gamma\left(1+\frac{1}{\alpha_{ac}}\right)\right]^{\alpha_{ac}} \tag{10}$$

$$\alpha_{ac}=0.267\gamma\left(\frac{M_{ac}}{\overline{M}}\right)^{-0.4} \tag{11}$$

The probability of occurrence of a weather window with a specified environmental threshold and duration is obtained from (12), as follows:

$$P(T>T_{ac})=P(X_i>X_{ac})*P_w(H>H_{ac}) \tag{12}$$

Calculating N_{ac} and N_{wa} it is possible to evaluate the number of access days in a given duration that such windows will occur for ((13), and how long it is likely that an operation will have to wait if the repair does not occur or is completed within this window ((14), respectively.

$$N_{ac}=D \times P(T>T_{ac}) \tag{13}$$

$$N_{wa}=\begin{cases}\frac{\left(D-(N_{ac}-T_{ac})\right)}{N_{ac}};N_{wa}\leq D\\ D;N_{wa>D}\end{cases} \tag{14}$$

Where D is the duration of the time frame, considered 90 days for each season in this case.

The portion of downtime caused by the weather window is given by:

$$\begin{cases}Time_{waiting}=0\ ;\ X_{ac}\leq T_{ac}\\ Time_{waiting}=N_{wa}\ ;\ X_{ac}>T_{ac}\end{cases} \tag{15}$$

5.4. Failure rates

The failure rates considered in this work were obtained from a combination of some available sources ([15], [16], [17],[52] , [53], [54] and [55]) due to high variability in published figures and categorized by level of repair for each subassembly. These data were extracted from different WTs, with several installed capacities, and at different sites and conditions. Then, due to variance of the information and level of uncertainty, an average of these values was considered. The yearly failure rate (F) per turbine according to category and subassembly is presented in Figure 11.

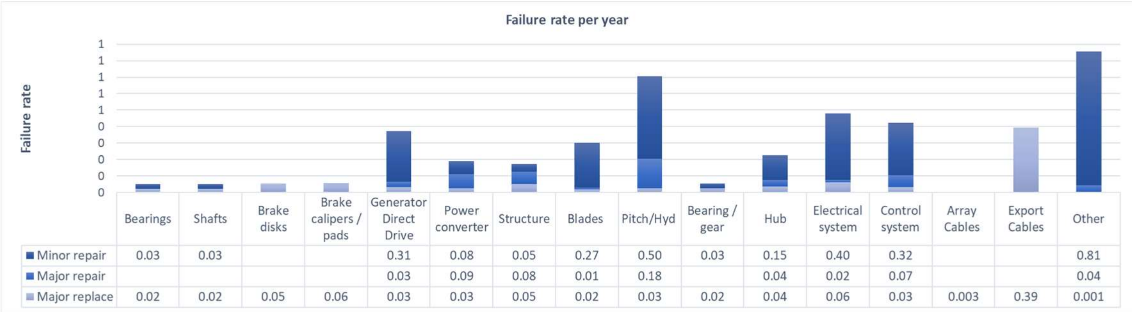

Figure 11 – Yearly failure rate per turbine

adapted from [15], [16], [17], [52], [53], [54] *and* [55]

The total annual failure rate (F_{total}) for each subassembly is given by the product of the expected number of failures per turbine per year (F) by the number of turbines ($N_{turbines}$) of the wind farm.

$$F_{total} = F \times N_{turbines} \quad (16)$$

5.5. Repair data

Similarly, the repair time at the site (Figure 12) and the number of required technicians per failure (Figure 13) for each turbine were determined for each subassembly and type of repair, as reported by Carrol et al. [17] and Elusakin et al. [54].

The repair time ($Time_{repair}$) [h] comprises the hours to conduct the repair per se, not including mobilisation ($Time_{mob}$), transit ($Time_{transit}$) or waiting time ($Time_{waiting}$).

Durations of downtimes ($Downtime$) [h] due to failures were estimated taking into account the mobilization, waiting on weather, transit, disconnect, repair and connect time.

$$Downtime = Time_{mob} + Time_{waiting} + Time_{transit} + Time_{disconnect} + Time_{repair} + Time_{connect} \quad (17)$$

Where for WT shutdown event, disconnect and connect time were considered a conservative period of 2 hours and 4 hours respectively, and 0 hours if it is not necessary to turn off the turbine.

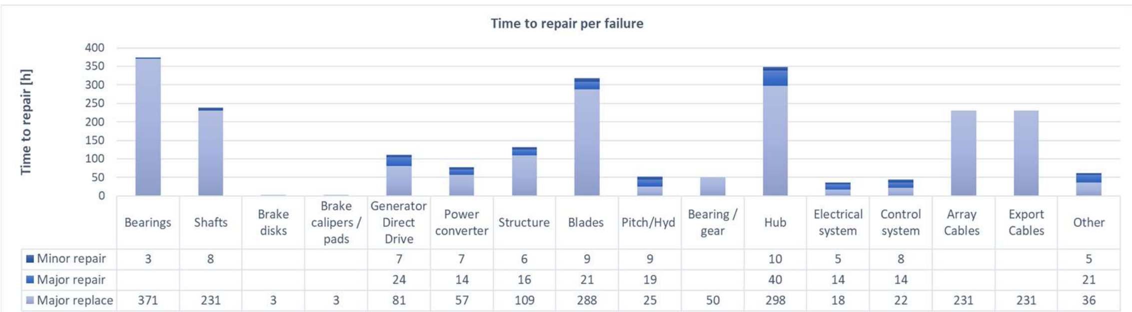

Figure 12 – Time to repair per failure
[17] *and* [54]

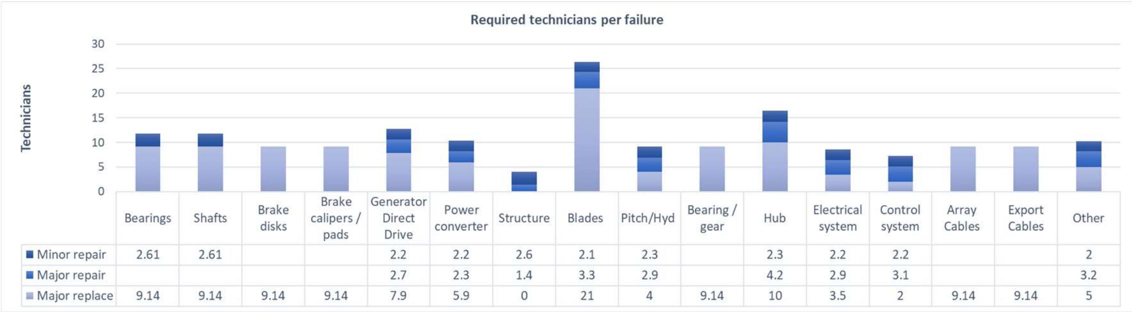

Figure 13 - Required technicians per failure
[17] *and* [54]

5.6. Vessels' specifications

Vessel data cover the key characteristics of vessels chartered for carrying out the O&M tasks.

In this current study, it is considered the set of mother and daughter vessels, namely SOV and CTV, for major and minor repairs, respectively. Due to the long distance from the port, the set SOV+CTV is hired in the leasing mode (360 days) and planned to be placed in stand-by near the site in a work regime of 15 days, to minimize the downtime caused by the mobilisation time. A scenario with only CTVs travelling daily to and from the site does not present feasible in terms of time spent to transit, being commonly not applied to wind farms farther from shore.

Jack-ups are considered for major replacements, where higher load capacity and cranes are necessary. AHTS are addressed to conduct cables repairs and to tow the turbine or equipment if necessary. Nevertheless, since these types of repairs historically are less frequent and longer jack-ups and AHTS contracts are costly, these types of vessels are hired at the spot market as needed, implying, however, longer downtime due to the associated mobilisation time.

The mobilisation activities comprise the time and cost allocated to hiring, planning and preparing the vessel for the operation.

As the SOV+CTVs are dedicated to O&M activities and situated near the wind farm, the mobilisation cost and time are considered zero, since this model considers that the vessels are available to start the action at the time of failure occurrence.

Regarding the operational consumption, it comprises the fuel used during the transit and in operations on the site, as stand by and machinery operation. Some vessels, as SOVs usually use different fuels for transit and site operations (primary and secondary fuel).

In the case of on-site actions, the model considers only 1 vessel for the repair, otherwise, 2 vessels are considered. Conventional vessels are considered in scenarios 1 and 2, while hydrogen-based vessels are contemplated in scenario 3.

The main operational specifications of the vessels are shown in Table 6 and are based on many sources ([19], [33], [53], [56], [57], [58], and [59]). For hydrogen-based vessels were considered the same operational conditions, adjusting the fuel consumption.

Table 6 - Vessels main operational specifications
based on [19] [33], [53], [56], [57], [58] *and* [59]

	CTV	SOV	Jack-up	AHTS	CTV H_2	SOV H_2	Jack-up H_2	AHTS H_2
Type of contract	Lease	Lease	Spot market	Spot market	Lease	Lease	Spot market	Spot market
Offshore periods	1 day	15 days	30 days	30 days	1 day	15 days	3 days	3 days
Transit speed	26 knots	11 knots	10 knots	14 knots	26 knots	11 knots	10 knots	14 knots
Personnel	12 techn	60 techn	60 techn	40 techn	12 techn	60 techn	60 techn	40 techn
Hs	1.5 m	3 m	2 m	2 m	1.5 m	3 m	2 m	2 m
Ws	12 m/s	17 m/s	10 m/s	17 m/s	12 m/s	17 m/s	10 m/s	17 m/s
Primary fuel	MFO	MGO	MDO	MGO	H_2	H_2	H_2	H_2
Secondary fuel	-	MDO	-	-	-	-	-	
Consumption in transit	320 l/h	1000 l/h	2180 l/h	700 l/h	208 l/h	667 l/h	1082 l/h	340 l/h
Consumption in field	130 l/h	120 l/h	484 l/h	120 l/h	71 kg/h	60 kg/h	244 kg/h	50 kg/h
Mobilisation time	-	-	720 h	360 h	-	-	720 h	360 h

5.7. Costs

To analyse the cost breakdown of a studied wind farm the main expenditures of the project must be estimated. The total cost of the project comprises CAPEX and OPEX of the wind farm and, additionally, for the hydrogen-based scenario, the capital and operation and maintenance expenditures of the integration of a refuelling station must be included in the evaluation. These costs will be presented in detail in the next sections.

For the cost analysis the currency exchanges were considered as follows:

Table 7 - Currency exchange

Currency Exchange		
£	1.16 €	31/05/2021
$	0.85 €	31/05/2021

5.8. Wind farm CAPEX

Wind farm CAPEX includes full lifecycle costs during the Development and Consenting (D&C), Production & Acquisition (P&A), Installation and Commission (I&C) and Decommissioning and Disposal (D&D) phases of the wind farm.

Development and consenting costs consist of the expenditures of contract negotiation, project management, environmental, impacts evaluation, legal authorisation, front-end engineering, design and contingency costs [59]. The Crown Estate [61] indicates a total of £120million for a 1GW wind farm, which was the relation assumed.

Production and acquisition costs, in general, are divided into a wind turbine, turbine foundation, transmission system and operations base.

The wind turbine cost is estimated at £1 million per MW, including installation and commissioning. Turbine foundation cost is strongly dependent on the type of foundation, while it is defined mainly according to the water depth and the seabed characteristics. An estimative of £280 million for a 1GW wind farm for monopiles indicated by was considered [61].

The transmission system consists of collecting the generated power using array cables, integrating the power through an offshore substation, transmitting the electricity from the offshore substation to shore through the export cables. Offshore export cables transmit the electricity from the offshore substation to the onshore substation and the onshore export cable transport the power to the grid connection point [59].

Offshore substations are used to reduce electrical losses before exporting power to shore, which, in general, is considered for projects located at a distance of 20 km offshore [59]. This is done by increasing the voltage, and in some cases converting from alternating current (AC) to direct current (DC). The total offshore substation cost was referenced as £120million for a 1GW wind farm. In its turn, the onshore substation transforms power to grid voltage. A cost of £30 million for a 1GW wind farm, is assumed [61].

In case a new grid connection is needed to meet the demand of this wind farm, the cost of $167million per GW must be considered [62].

The cables deliver the power output from the WTs to the grid. The array cables create loops or individual strings connecting all turbines to the offshore substation. Assuming the array cable length associated with each wind turbine is around 7 times the rotor diameter, and rated at 66kV, allowing more capacity to be connected on a single string and reducing the length of cable.

Export cables connect the onshore and offshore substations and for long-distance transmission (over 100 km), HVDC should be used instead of HVAC because the full capacity of the cable system can be used for transferring active power. A 320 kV export cable was dimensioned to support the load transmission. Cables costs were defined as the model presented by Lundberg [63].

The operations base supports the operation, maintenance and service of the wind farm. The estimated cost is about £3 million for a 1GW offshore wind farm [61].

The installation and commission phase refers to all activities for transportation and installation of turbines and balance of plant on site and commissioning of these to a fully operational state. The I&C cost estimated to be about £650 million for a 1GW wind farm and consists of the balance of plant and turbines, with related offshore logistics, developer's insurance, construction project management and spent contingency [61].

Finally, decommissioning activities consists of the removal of the wind turbine as well as substation and cables, the clearance of the area, transportation, and disposal of the structures. The decommissioning of a 1GW offshore wind farm will cost around £330 million, not including any resale value of equipment removed [61].

A summary of $CAPEX_{OSW}$ is shown in Table 8.

Table 8 – Wind farm CAPEX summary

Wind farm CAPEX	
Development and Consent	**158.60 M€**
Production and Acquisition	**2102.92 M€**
Wind turbine	1322.40 M€
Turbine foundation	370.27 M€
Transmission system	406.28 M€
Offshore substation	158.69 M€
Onshore substation	39.67 M€
Grid connection	158.02 M€
Array Cables	29.59 M€
Export Cables	20.32 M€
Operations base	3.97 M€
Installation and Commission	**859.56 M€**
Decommissioning and Disposal	**436.39 M€**
Total expenditure	**3557.56M€**

5.9. Wind farm OPEX

Wind farm's operational and maintenance expenditures ($\mathrm{OPEX_{OSW}}$) comprises all the costs to maintain the turbines operating correctly, for scheduled and unscheduled maintenance, and includes spare parts, vessels charters and other day-to-day operating costs. The variable O&M expenditures consist of the variable costs that rely on maintenance strategies applied to the turbine and failures occurrence, being possible also split the variable expenditures into preventive maintenance ($\mathrm{C_{PM}}$) cost, which corresponds to scheduled maintenance and corrective maintenance cost (C_{CM}), which represents the costs associated with unplanned maintenance when failures occur [9].

$$OPEX_{osw} = C_{PM} + C_{CM} \quad (18)$$

Besides the wind farm and vessels characteristics, some other parameters are common between preventive and corrective actions:

Table 9 - Maintenance common inputs

Maintenance common inputs		
Personnel cost	500 €/day	[23]
Work shift	12 hours	[56]
Quayside fee	174 €/per port operation	[52]
Fuel price	0.34 €/l MFO	[64]
	0.44 €/l MGO	[65]
	0.35 €/l MDO	
Emission tax	48 €/t CO_2 (2020)	[4]

After wind farm installation, in general, is supposed a warranty period provided by the manufacturer to cover required initial maintenances or replacements. However, warranty terms may vary from different manufactures and types of costs and conditions covered by procurements. To simplify the model, all O&M expenses over the total lifetime of the turbines have been assumed to be attributed to the operator.

5.9.1. Preventive maintenance cost

The preventive maintenances are supposed to occur annually in the summer, due to better weather conditions.

In general, CTVs are the vessels considered to conduct inspections and repairs in the preventive campaign. It was considered that CTV hired for corrective maintenance is shared with the preventive maintenance campaign, representing a single annual expense for hire. The impact on the preventive maintenance schedule was not considered in this model in case corrective maintenance is needed during the preventive campaign.

Nowadays, using drones for structure inspection, as such blades and towers, is becoming common, driven by the reduction of risk and costs. This study considered a drone-based inspection with multiple drones and EVLOS technology [23], already based on hydrogen.

Preventive maintenance inputs are presented in Table 10:

Table 10 - Preventive maintenance inputs

Preventive maintenance inputs		
Vehicles	CTV	Drone
Number of vehicles	1	4
Campaign occurrence	Summer	Summer
Charter	Included at C_{CM}	1883 €/day/set
Technicians per work	3	2/drone
Turbines per vehicle	4	1
Repair time per turbine per year	53 h	0.1 h
Disconnect time	2 h	-
Connect time	4 h	-
Parts cost	21,000 **€**	-

Each CTV travels to 4 turbines each day to perform maintenance operations. The vessel transit time per operation ($\mathrm{Transit}_{\mathrm{time}_{\mathrm{PM}}}$) [h] is defined by:

$$\mathrm{Time}_{\mathrm{transit}_{\mathrm{PM}}}=2\mathrm{x}\left[\left(\frac{\mathrm{Distance}_{\mathrm{SOV}}}{\mathrm{Vessel}_{\mathrm{speed}}}\right)+\left(\frac{3*\mathrm{Distance}_{\mathrm{turbine}}}{\mathrm{Vessel}_{\mathrm{speed}}}\right)\right] \quad (19)$$

As presented by (15) and (17) is possible to calculate the waiting time and total downtime due to the stoppage of turbines during maintenance. The total yearly cost for preventive maintenance (C_{PM}) [€] is estimated by:

$$\mathrm{C}_{\mathrm{PM}}=\mathrm{N}_{\mathrm{turbines}}\mathrm{x}\left(\mathrm{Cost}_{\mathrm{parts}}+\mathrm{Technicians}\times\mathrm{Cost}_{\mathrm{personnel}}\times\mathrm{Days}+\frac{\mathrm{Cost}_{\mathrm{fuel}}}{\mathrm{Turbines}_{\mathrm{per\ vehicle}}}\right)+\mathrm{Cost}_{\mathrm{emissions}} \quad (20)$$

Where ($Days$) indicates the number of required days to conclude the maintenance.

5.9.2. Corrective maintenance cost

The corrective maintenance cost (C_{CM}) [€] can be estimated by the product of the failure rates ($\mathrm{F}_{\mathrm{total}}$) presented in Section 5.4, and the overall cost of the failure, dependent on expected downtime, labour rate, spare parts cost, vessels charter rates, port charges, fuel consumption and all the repair costs associated.

As already mentioned, the information regarding costs is not yet readily and easily publicly available. Carroll et al. [17] also presented repair costs, based on minor repair, major repair and major replacement of spare parts of turbines from a range of 2 to 4 MW of installed capacity. However, considering the

12MW wind turbines under study, it is possible to state that, considering a concept of economies of scale, the costs of equipment will increase as the WT capacity also increase.

Due to the lack of data concerning larger turbines to support the study, for minor and major repair, was considered the same costs as presented by Carrol et al. [17], while for major replacements, which represents a more significant cost, a relation between turbines with 3, 5, 10 and 20 MW was considered using the data presented by Carrol et al. [17] and Ashuri et al. [66] for equipment replacement cost estimation. Estimated spare parts costs ($\mathrm{Cost_{parts}}$) [€] per failure are shown in Figure 14.

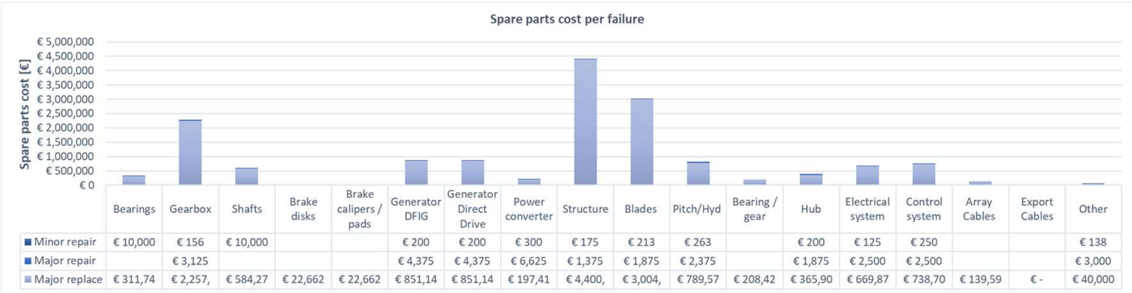

Figure 14 - Spare parts cost per failure
adapted from [17] *and* [66]

The cost of repair ($\mathrm{Cost_{repair}}$) [€] at site per failure can be estimated by:

$$\mathrm{Cost_{repair}} = \mathrm{Cost_{parts}} + \left(\mathrm{Technicians} \times \mathrm{Cost_{personnel}} \times \mathrm{Days}\right) \qquad (21)$$

The estimative of conventional charter rates were based on several sources, as presented in Table 11.

Table 11 - Conventional vessels charter rate

Conventional vessels charter rate			
CTV	500,000 €/year	Annual fee	[33]
SOV	12,000,000 €/year	Annual fee	[56]
Jack-up	333,384 €/day	Day hire	[60]
AHTS	19,040 €/day	Day hire	[33]

However, given that the hydrogen-powered ships industry is not yet consolidated, the lack of information on the charter rates for a hydrogen-based vessel is still a limitation. In this way, was conducted an estimative of the vessel break-even cost, which corresponds to the value at which the vessel must be hired to cover the total cost of the ship including all capital and operational expenses for a new build.

To simplify this estimative, it was considered, the same build cost for a conventional service vessel, deducted the costs of the main fossil fuel-based system and added the cost to own and install a liquid hydrogen-based system with PEM fuel cells, using the following approach:

$$NPV=\frac{\sum_{t=1}^{n} CashFlow}{(1+i)^{t}} - Initial\ Investment \quad (22)$$

$$Cash\ Flow= - \ Capital\ expenses \ - (O\&M_{PEMFC} - O\&M_{Conventional}) + Revenue \quad (23)$$

$$Initial\ Investment= \ - (Initial\ Investment_{PEMFC} - Initial\ Investment_{Conventional}) \quad (24)$$

Where the discount rate (i) was considered as 8%, the lifetime (t) as 25 years, and capital expenses contemplate required equipment replacement along the project lifetime. The summary of CAPEX, OPEX and Cost Deductions can be checked in Appendix 1.

Considering the vessels with the same specifications, the initial investment is assumed to be constituted mainly of the major devices, as such fuel cells, electric motor, power conditioning equipment, as well fuel storage system and installation. On the other hand, the costs of the conventional system comprise equipment like engine, gearbox, generator, and their respectively O&M costs.

Many studies have looked into the estimates of the capital cost of fuel cells in several applications. Is recognized that the capital cost tends to decrease with increasing production rate. Raucci [67] presented a projected fuel cell cost over the years.

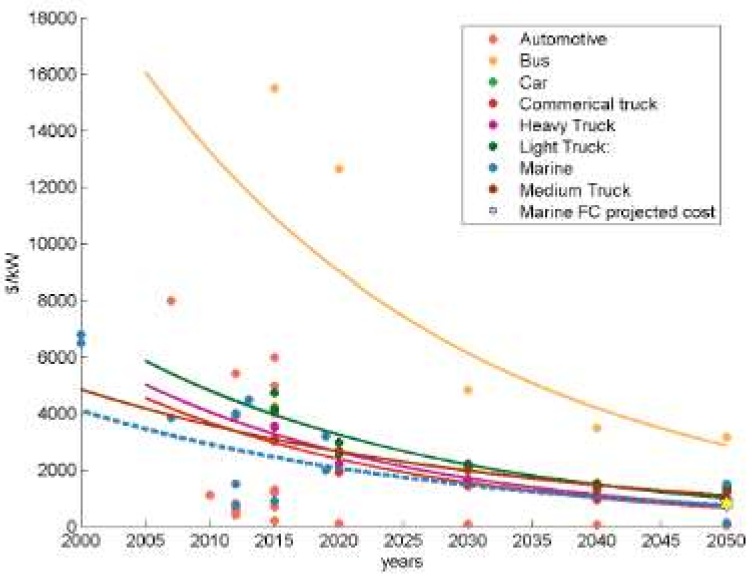

Figure 15 - Fuel cell projected cost function
[67]

For the capital cost analysis, the following considerations were taken:

- PEM FC initial acquisition cost and replacement cost follows the projected cost function, presented in Figure 15.
- PEM FC system would require an electric motor to convert the electricity produced in mechanical work for propulsion.

- A power conditioning system is required, comprising equipment to turn AC to DC as converter and inverter.
- The cost of H_2 storage technologies depends mainly on the type of storage technology chosen and storage capacity. A cost estimative of hydrogen storage technologies of large dimensions onboard ships is still difficult to define, presenting a wide range. According to International Energy Agency (IEA) [68] liquid storage costs may vary from 800 to 10,000 $/MWh. A reference cost was considered based on Raucci [67].
- Being the LH_2 storage tank installation is not yet well consolidated, its installation cost can be estimated the same as the LNG tanks. Taking some references, Saito [36] assumed the cost of 300 $/kW for LNG tank installation on a container ship of 2,500 TEU, while Inland [69] estimated a cost of 327 $/kW for a motor vessel of 110m and 169 $/kW for a push boat with four barges, both for newly built.
- To size the LH_2 tank, an energy balance was estimated, to determine the total amount of energy required for each operational profile, endurance and transit speed of vessels. Naturally, it is not expected that the operational speed is achieved all the time. A maximum allowable transit speed is set to each sea condition to maintain the accelerations comfortable for the crew and technicians. So that, to estimate the capacity of hydrogen tanks, the operational speed was considered lower than the maximum for each vessel.
- For the O&M cost of PEM FC system, was considered a growth rate of 1% per year, considering the system degradation.
- It is known that the additional weight on the vessel caused by the onboarding of fuel cells and LH_2 will impact its performance due to the increase of the resistance to advance and may impact the fuel consumption. However, to analyse this modification is necessary a further hydrodynamic and hull study, which was not considered in this work.
- The costs associated with SOx scrubbers, used to remove harmful elements from exhaust gases in fossil fuel-based vessels, was not considered as it cannot be guaranteed that the vessels under analysis are equipped with this component.

The expenditures for the considered PEM fuel cell system were based on the data presented in Table 12 and Table 13.

Table 12 - PEM fuel cell system CAPEX

PEM FC CAPEX		
PEM FC Initial Cost	1,630 €/kW	[67]
PEM FC Installation	209 €/kW	[36]
PEM FC Lifetime	47,500 hours	[67]
PEM FC Replacement Cost	836 €/kW	[67]
PEM FC Efficiency	60%	[67]
Electric Motor	95 €/kW	[67]

Power Conditioning System	49 €/kW	[70]
H_2 Tank	58 €/kg	[67]
H_2 Tank Installation	139 €/kW	[69]

Table 13 - PEM fuel cell system OPEX

PEM FC OPEX		
PEM FC O&M	41 €/kW/year	[67]

Recycle and Residual Value are considered components of life cycle stages. PEM fuel cells consist of platinum that holds a significant cost than other metals included in the fuel cell [36]. The vessel´s residual value is considered at the end of its economic life, and it is determined based on the weight of the hull and the expected price of aluminium [71]. The structural weight of a catamaran can be estimated by 30% of the vessel displacement [72].

Table 14 - Residual value (fuel cell and vessel)

Residual Value		
Platinum Price	841 €/oz	[67]
Platinum Weight	0.2 g/kW	[67]
Aluminium Price	2,066 €/ton	[73]

CTV hydrogen-based vessel

For the operational profile of a work shift of 12 hours, the endurance of 1 day and minimum electrical power requirement at the port, a fuel cell replacement should occur in 18 years.

Considering the CTV a small vessel was assumed a similar complexity to tank installation as the push boat, as well as its cost.

To size the LH_2 tank, an energy balance was estimated, to determine the total amount of energy required. For this case, it is estimated a regular speed of 15 knots. The energy balance can be checked in detail in Appendix 2.

Considering a new build, the cost of a conventional propulsion system must be deducted from the original investment, as well as its O&M costs from OPEX.

Table 15 - Cost deductions for conventional system (CTV)

Conventional System Cost Deductions		
Engine	680 €/kW	[74]
Generator	0.017 €/kW	[74]
Gearbox	0.6 M€	[74]

With these data and computing for the NPV equal to zero is possible to notice a charter rate increase by around 46% in comparison to conventional CTV.

Table 16 - H_2 CTV Charter Rate

Charter Rate		
Conventional CTV	**Additional charter H_2 CTV**	**Total charter H_2 CTV**
500,000 €/year	227,478 €/year	727,478 €/year

SOV hydrogen-based vessel

The same approach as for H_2 CTV was considered to estimate the fully hydrogen-based SOV charter rate. The conventional SOV is planned for 15 days offshore. However, it would not be feasible to guarantee 15 days of endurance for a vessel based on liquid hydrogen due to technical limitations of weight and space on the vessel. For this reason, a refuelling on average every 3 days was considered necessary.

For the operational profile of a work shift of 12 hours, an endurance of 3 days and the minimum electrical power requirement at the port, a fuel cell replacement should occur in 6 years.

To size the LH_2 tank, it is estimated a regular speed of 10 knots. The energy balance is presented in Appendix 2.

Conventional system cost deductions were estimated as shown in Table 17

Table 17 - Cost deductions for conventional system (SOV)

Conventional System Cost Deductions		
Engine	120 €/kW	[75]
Genset	350 €/kW	[74]
Installation	0.03 M€	[75]

With the additional cost for H_2 SOV calculated, as shown in Table 18, the estimated increase in the charter rate is 13%.

Table 18 - H_2 SOV Charter Rate

Charter Rate		
Conventional SOV	**Additional charter H_2 SOV**	**Total charter H_2 SOV**
12,000,000 €/year	1,593,695 €/year	13, 593,695 €/year

Jack-up hydrogen-based vessel

As for SOV, the endurance for H_2 jack-ups was considered as 3 days. Then, for this operational profile and considering that the vessel operates all the days of the year when the weather conditions are favourable, is estimated that the fuel cells must be replaced every 9 years of operation.

To size the LH_2 tank, it is estimated a regular speed of 10 knots. The energy balance can be checked in detail in Appendix 2.

Conventional system costs were considered as the same range of SOV, considering that the difference between MGO and MDO systems are not so significant.

A similar jack-up is estimated to cost at 1-year leasing of 46,854,720 €/year [60]. The estimated increase in the yearly charter rate is about 10%, as can be observed in Table 19.

Table 19 - H_2 Jack-up Charter Rate

Charter Rate		
Conventional Jack-up	**Additional charter H_2 Jack-up (1-year leasing)**	**Total charter H_2 Jack-up (1-year leasing)**
46,854,720 €/year	4,779,181 €/year	51,633,901 €/year

In this way, the charter rate on the spot market was considered 10% higher than the cost presented in Table 11, corresponding to 367,389 €/day.

AHTS hydrogen-based vessel

Similarly to jack-up, the endurance was considered as 3 days and for AHTS operational profile the fuel cells the replacement of fuel cells is estimated to occur also every 9 years of operation.

To size the LH_2 tank, it is estimated a regular speed of 12 knots. The energy balance can be checked in detail in Appendix 2.

Since, in general, the spot hire rate of AHTS is around 1.75 times the long-term charter rate [76], the charter rate at a leasing regime of 1 year for a similar AHTS was estimated as 2,303,325 €/year. The estimated increase in the yearly charter rate is about 88%, as can be observed in Table 20

Table 20 - H_2 AHTS Charter Rate

Charter Rate		
Conventional AHTS	**Additional charter H_2 AHTS (1-year leasing)**	**Total charter H_2 AHTS (1-year leasing)**
2,303,325 €/year	2,018,866 €/year	4,322,191 €/year

In this way, the charter rate on the spot market is considered 88% higher than the cost presented in Table 11, corresponding to 35,729 €/day.

As is possible to notice, hydrogen-fuelled vessels have considerably larger costs in terms of investment over their lifetime than traditional ships. Despite the amount of the additional cost of SOV and jack-up be much higher than for CTV and AHTS, proportionally, the initial cost of the vessel these variations are less significant. This means that for vessels less costly this investment could be less profitable, due to the high initial investment. The switch to hydrogen can affect the shipowners' margins and revenues, who in turn pass this cost on to wind farm operators, which impacts the final cost of energy.

Costs associated with fuel consumption per operation ($\mathrm{Cost_{fuel}}$) [€] corresponds to a parcel equal to consumption during transit and another which corresponds to operations at the site.

The portion which corresponds to transit costs ($\mathrm{Cost_{fuel_{transit}}}$) [€] reflects the expenditure during transit to and from the site to attend the turbines and, specifically for SOVs in the BAU and Carbon taxes scenarios, the cost related to transit to and from the port every 15 days, as for the hydrogen-based scenario, the cost associated with refuelling trip.

The second amount ($\mathrm{Cost_{fuel_{op}}}$) [€] represents the costs related to fuel expended during the operations and, for SOVs, the consumption of fuel during vessel loitering at the site in DP along the year ($\mathrm{Time_{loitering}}$).

It was considered that due to operational constraints SOV is available on site 90% [77] of the leasing period (360 days).

$$\begin{aligned}\mathrm{Cost_{fuel_{transit}}} = {} & \mathrm{Cons_{transit}} \times \mathrm{Time_{transit}} \times Price_{\mathrm{fuel}} \\ & + 360 \times 24 \times 0.9 \times \left[\mathrm{Cons_{transit}} \times \mathrm{Time_{transit_{port}}} \times Price_{\mathrm{fuel}}\right]_{\mathrm{SOV_{BAU_{CT}}}} \\ & + \left[\mathrm{Cons_{transit}} \times \mathrm{Time_{transit_{station}}} \times Price_{\mathrm{fuel}}\right]_{\mathrm{SOV_{HB}}}\end{aligned} \tag{25}$$

$$\begin{aligned}\mathrm{Cost_{fuel_{op}}} = {} & \mathrm{Cons_{op}} \times \left(\mathrm{Time}_{disconnect} + Time_{repair} + \mathrm{Time}_{connect} + \mathrm{Time}_{waiting}\right) \times Price_{\mathrm{fuel}} \\ & + \left[\mathrm{Cons_{op}} \times Time_{loitering} \times Price_{\mathrm{fuel}}\right]_{\mathrm{SOV}}\end{aligned} \tag{26}$$

$$\mathrm{Cost_{fuel}} = \mathrm{Cost_{fuel_{transit}}} + \mathrm{Cost_{fuel_{op}}} \tag{27}$$

Where $\mathrm{Cons_{transit}}$ and $\mathrm{Cons_{op}}$ represent the consumption during transit and operation.

Although, the discussions about mandatory contributions by vessels for each tonne of carbon emitted does not yet involve ships with gross tonnage below 5,000GT, for the CT scenario, was considered the cost associated with CO_2 emissions for all vessels in order to analyse the impact of this tax.

According to European Commission [4], prices for ETS for the sector is in the range of 32 to 65 €/tCO_2 to cut GHG emissions by at least 55% by 2030. For this model was considered the average price of 48 €/tCO_2 ($\mathrm{Price_{ETS}}$).

Carbon emissions per operation ($\mathrm{Emissions}$) [t] were estimated according to the operational profile of each vessel type and the fuel used.

$$\text{Emission}_{\text{fuel}_{\text{transit}}}=\text{Cons}_{\text{transit}}\times\text{Time}_{\text{transit}}\times\text{Emission}_{\text{fuel}} + 360\times24\text{x}0.9\times\left[\text{Cons}_{\text{transit}}\times\text{Time}_{\text{transit}_{\text{port}}}\times\text{Emission}_{\text{fuel}}\right]_{\text{SOV}_{\text{BAU}_{\text{CT}}}} \quad (28)$$

$$\text{Emission}_{\text{fuel}_{\text{op}}}=\text{Cons}_{\text{op}}\times\left(\text{Time}_{\text{disconnect}}+\text{Time}_{repair}+\text{Time}_{connect}+\text{Time}_{\text{waiting}}\right)\times\text{Emission}_{\text{fuel}} + \left[\text{Cons}_{\text{op}}\times\text{Time}_{\text{loitering}}\times\text{Emission}_{\text{fuel}}\right]_{\text{SOV}} \quad (29)$$

$$\text{Emissions}=\text{Emission}_{\text{fuel}_{\text{transit}}}+\text{Emission}_{\text{fuel}_{\text{op}}} \quad (30)$$

The costs associated with emissions per operation ($\text{Cost}_{\text{emissions}}$) [€] can be estimated as:

$$\text{Cost}_{\text{emissions}}=\text{Emissions}\times\text{Price}_{\text{ETS}} \quad (31)$$

Other costs associated with O&M activities were included as such quayside cost ($\text{Cost}_{\text{quayside}}$) for vessels operations at port and mobilisation cost (Cost_{mob}).

The quayside fee is presented in Table 9 and represents the cost per ship operation in port.

As mentioned in 5.6, for the vessels hired in a leasing mode there is no mobilisation cost associated. However, for the vessels under the spot market hiring, this cost may vary according to the availability and usage of the vessels, as is the case with jack-up and AHTS. The availability of vessels on the market depends on the number of vessels of this type in the region and the demand of the industry, not only wind but also the oil and gas sector.

Vessel's mobilisation fee may vary according to vessel reaction time which includes contract negotiation, operational planning, sea transit and other tasks so that the vessel is ready to work on the repair. It may also be impacted by the number of repair events. In general, mobilisation costs can be higher for a single turbine repair. However, this model includes a simplified approach, adopting a fixed value for mobilisation cost.

Table 21 - Mobilisation cost

Mobilisation cost		
Jack-up	350,000 €/operation	[56]
AHTS	116,000 €/operation	[53]

5.10. Refuelling station

For the hydrogen-based scenario, the associated infrastructure for refuelling, including electrolysers, compressors and pipelines, must also be in place. Hence, two different types of green H_2 projects were considered: onshore on-grid which is feed by electricity produced by the wind farm and produces hydrogen onshore by grid-connected electrolysers and, and offshore off-grid centralised with hydrogen being produced offshore at centralised facilities.

A simple techno-economic analysis was conducted to estimate the impact of station costs on overall LCOE, i.e., capital and O&M expenses, and loss of energy due to electricity demanded to produce hydrogen to refuel the vessels. The model considered the main station drivers of CAPEX and OPEX. To simplify the estimative, the liquid hydrogen infrastructure, neither onshore nor offshore were considered.

The electric capacity of the electrolyser ($\mathrm{Elec}_{\mathrm{cap}}$) was dimensioned to be 80% of the wind farm nominal capacity [78].

Lifetime operation and stack replacement costs were considered the same as in Table 12.

An overview of the $CAPEX_{H2}$ and $OPEX_{H2}$ for both scenarios, are presented in Table 22 and Table 23.

Table 22 - Hydrogen CAPEX

Hydrogen CAPEX			
	Offshore station	**Onshore station**	
Electrolyser	522 €/kW	522 €/kW	[78]
Compressor	3.83 €/kW	3.83 €/kW	[78]
Stand-by Power/Battery	55.91 €/kW	22.39 €/kW	[78]
AC cable to platform	2.78 €/kW	-	[78]
AC/DC converter	169.13 €/kW	-	[78]
Water desalination	0.93 €/kW	-	[78]
Central electrolyser	230.14 €/kW	-	[78]
System replacement	10.87 €/kW	4.35 €/kW	[78]
Hydrogen pipeline	67.16 €/kW	-	[78]
Total	1050.00 M€	545.94 M€	[78]

Table 23 - Hydrogen OPEX

Hydrogen OPEX			
	Offshore station	**Onshore station**	
Electrolyser	13.05 €/kW	13.05 €/kW	[78]
Compressor	0.12 €/kW	0.12 €/kW	[78]
Stand-by	1.39 €/kW	1.39 €/kW	[78]
AC cable to platform	0.08 €/kW	-	[78]
AC/DC converter	5.08 €/kW	-	[78]
Water desalination	0.05 €/kW	-	[78]

Hydrogen pipeline	2.02 €/kW	-	[78]
Total	21.52 M€	14.38 M€	[78]

CAPEX and OPEX of offshore refuelling stations are significantly higher than for the onshore scenario, as shown in Figure 16 and Figure 17.

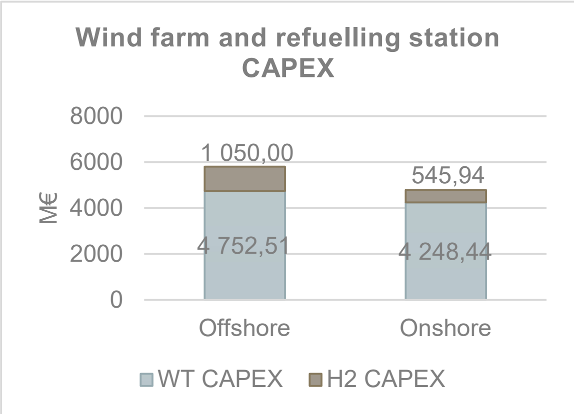

Figure 16 - CAPEX: Wind farm and refuelling station

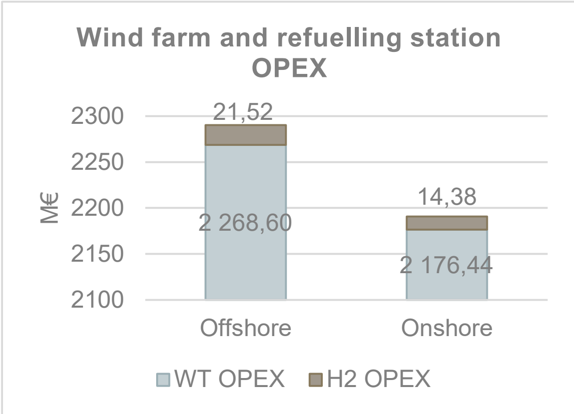

Figure 17 - OPEX: Wind farm and refuelling station

5.11. Energy production

Although CAPEX is an important parameter for the LCOE calculation, OPEX and annual energy production (AEP) are key drivers for this model since both vary depending on the availability and maintenance of the turbines.

The estimation of the AEP is done by using the available wind data and wind turbine power curve, to predict the output power of the turbine for various wind speeds.

The cumulative distribution function of the Weibull distribution is given by:

$$F(U)=1-e^{-\left(\frac{U}{b}\right)^k} \tag{32}$$

Where $F(U)$ represents the CDF of the wind speed, k is the shape parameter and b is the scale parameter. By analogy, the power generated by a wind turbine P in function of the wind speed can be expressed as:

$$P(U)=P_{max} \times \left(1-e^{-\left(\frac{U}{b}\right)^k}\right) \tag{33}$$

Where P_{max} is the maximum power of the turbine.

The amount of electricity generated varies accordingly to weather conditions. Given the hourly wind speed at hub height, the annual power production of each turbine over the year (n=8760 hours) is given by ($\mathrm{Power_{turbine}}$) [MWh], according to the turbine power curve and considered related losses. The total power produced by the wind farm corresponds to ($\mathrm{Total\ Power_{ele}}$) [MWh].

$$\mathrm{Power_{turbine}} = \sum_{t=1}^{n} P(U_t) \times \left[(1\text{-}\mathrm{Loss_{ele}})+\mathrm{Loss_{wake}}+\mathrm{Loss_{blockage}}\right] \quad (34)$$

$$\mathrm{Total\ Power_{ele}}=\mathrm{N_{turbines}}\times \mathrm{Power_{turbine}} \quad (35)$$

The electric loss ($\mathrm{Loss_{ele}}$) is related to the transmission losses in the grid and is considered 1.5%, while the wake effect, which indicates the wind speed reduction due to the influence of near turbines, representing a loss of 10% ($\mathrm{Loss_{wake}}$). The blockage loss ($\mathrm{Loss_{blockage}}$), is caused by the induction of a reduction of the upstream wind speed during the energy extraction, but in this TEM it was not considered.

The net annual power is in function of wind speed, losses, and turbine availability, related to failure rates during the year.

For the hydrogen-based case, the model assumes a hybrid system where electricity will be addressed to the electrolyser to produce hydrogen. The energy directed to hydrogen production ($\mathrm{Power_{H2}}$) [MWh], depends on electricity price ($\mathrm{Price_{ele}}$) [€/MWh] given by the forecasted hourly spot market electricity, as well hydrogen market price ($\mathrm{Price_{H2}}$) [€/MWh] ((37), assuming the minimum between the electrolyser production capacity ($\mathrm{Elec_{cap}}$) and the wind farm production ($\mathrm{WF_{production}}$), while the remaining electricity ($\mathrm{Power_{ele}}$) [MWh] is directed to the grid (38).

$$\mathrm{Price_{H2}} = \frac{Price_{H2_{retail}} \times Efficiency_{H2}}{Density_{H2}} \quad (36)$$

$$\begin{cases} \mathrm{Power_{H2}}=\mathrm{Min}\left(\mathrm{Elec_{cap}};\mathrm{WF_{production}}\right) & ;\ \mathrm{Price_{ele}}\leq\mathrm{Price_{H2}} \\ \mathrm{Power_{H2}}=0 & ;\ \mathrm{Price_{ele}}>\mathrm{Price_{H2}} \end{cases} \quad (37)$$

$$\mathrm{Power_{ele}}=\mathrm{Total\ Power_{ele}} - \mathrm{Power_{H2}} \quad (38)$$

The cost of hydrogen production, storage and delivery are not already cost-competitive with the fossil fuel traditionally used in shipping. Green hydrogen produced by offshore bottom-fixed wind farms can be sold for a retail price ($Price_{H2_{reta}}$) of 5.42 £/kg (offshore centralised PEM system) and 5.24 £/kg (onshore PEM system) [78].

The efficiency of the electrolyser technology ($Efficiency_{H2}$) was estimated as 64% and the hydrogen density is 0.033 MWh/kg [78].

Considering lifetime (t) equal to 25 years and the discount rate (i) to 8% the LCOH calculated for both scenarios by ((39), considering a hybrid system, is indicated in Table 24

$$LCOH=\frac{\sum_{t=1}^{n}\frac{CAPEX_{station_t}+OPEX_{station_t}}{(1+i)^t}}{\sum_{t=1}^{n}\frac{E_{H2_t}}{(1+i)^t}} \quad (39)$$

Table 24 - Levelized cost of hydrogen for offshore and onshore systems

Levelized cost of hydrogen		
	Offshore station	**Onshore station**
LCOH	5.1 €/kg	4.7 €/kg

5.12. Levelized cost of energy

LCOE of a wind farm represents the present cost to produce electricity over wind turbines lifetime based on the expected power generated, including the life-cycle costs of the turbine divided into CAPEX and operation and maintenance expenditure OPEX.

Analysing the hydrogen-based scenario, $CAPEX_{station}$ and $OPEX_{station}$ of the refuelling station must also be contemplated in the total wind farm expenditures. Additionally, the reduction in the final amount of electricity to be transmitted to the grid due to energy addressed to power vessels at the stations also impacts the LCOE.

The project's financing terms reflect its specific risk profile. Based on industry practice and a literature review the range of discount rates for OSW may vary between 5%-7% [62] [59].

For the BAU and Carbon taxes scenarios, the nominal discount rate (i) was considered 6% [79] while for the Hydrogen-based as 8% [78]. This difference represents a riskier scenario when considering ships powered by hydrogen produced by the very farm they serve. Tax and inflation were not modelled.

Project lifetime (t) was considered 25 years.

LCOE can be calculated by:

$$LCOE=\frac{\sum_{t=1}^{n}\frac{CAPEX_{total_t}+OPEX_{total_t}}{(1+i)^t}}{\sum_{t=1}^{n}\frac{E_{final_t}}{(1+i)^t}} \quad (40)$$

$$CAPEX_{total}=CAPEX_{osw}+CAPEX_{station}\ ;\ \ CAPEX_{station}=0 \text{ if scenario} \neq HB \quad (41)$$

$$OPEX_{total}=OPEX_{osw}+OPEX_{station}\ ;\ \ OPEX_{station}=0 \text{ if scenario} \neq HB \quad (42)$$

The loss of energy available to the grid due to stoppage during maintenance actions and to electricity demand to produce hydrogen to power service vessels, the latter in the case of scenario 3, must be considered.

6. Results

In this section, an overview of the results obtained from the developed model, contemplating the referred case study is presented.

Before presenting the achievements, some considerations about the model:

- The presented model was not built to optimize the routes for the maintenance activities;
- Neither the changes in failure rates due to different sites weather conditions nor the rate increase along the lifetime of the turbine due to ageing were not considered;
- Technical constraints by adding a hydrogen system onboard, such as additional weight, stability and hydrodynamics performance were not evaluated, since it requires a further design and hydrodynamic study;
- Failures of refuelling station were not considered;
- The model considers that the required infrastructure and supply chain to own the refuelling station are available;
- The hydrogen produced by the refuelling stations is assumed to be sold to an unlimited H_2 network;
- The carbon emissions considered are only related to fuels in O&M, not contemplating the embodied carbon along the life cycle of the vessels.

Due to the stochastic characteristic of the model and consequently variation of the results, given the randomness associated with the season in which the failure occurs, Monte Carlo simulations were carried out to verify the mean and standard deviation of the parameters under analysis. A set of 100 simulations for each analysis was conducted. Figure 18 and Figure 19 present a summary of the main results obtained.

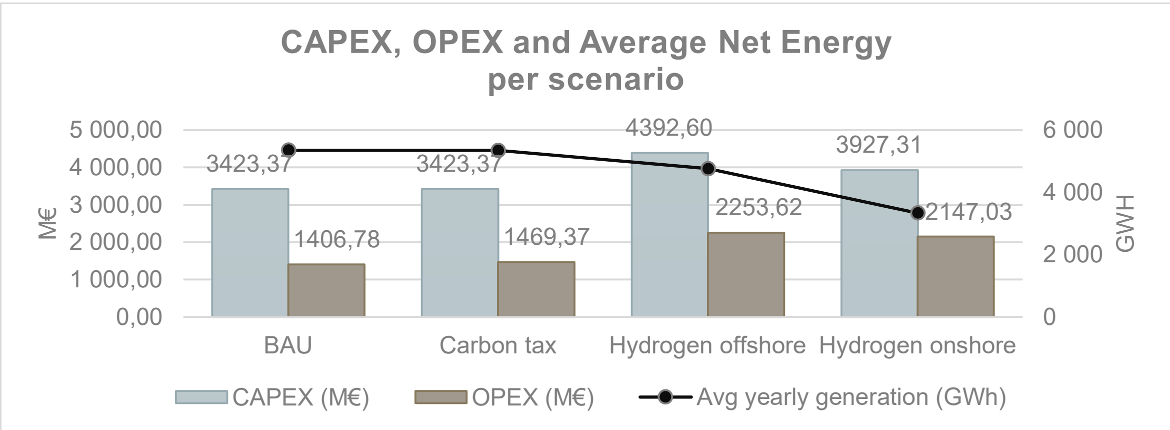

Figure 18 - Summary of results (CAPEX, OPEX and average net energy produced)

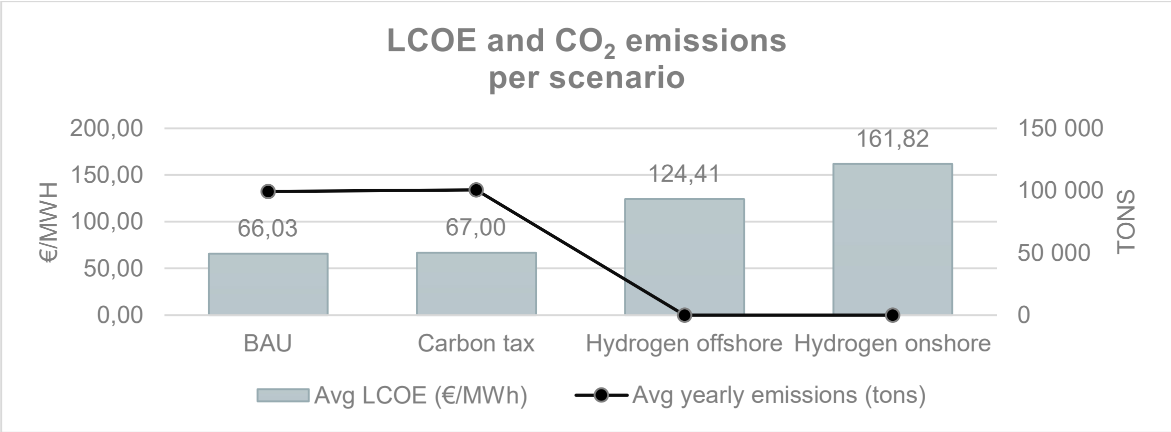

Figure 19 - LCOE and CO_2 emissions per scenario

The annual OPEX obtained for the BAU scenario is around 89 €/kW, which is approximately 2% higher than the reference presented by The Crown Estate [61] for a bottom-fixed turbine (87 €/kW). Therefore, is possible to consider that the model was well structured, showing reasonable values in comparison to reference, despite the assumptions and uncertainties of inputs.

Another finding in this work is the carbon tax applied under emissions shows that it is not yet sufficient to make the hydrogen-based scenario economically viable. However, the hydrogen scenario brings emissions to zero, showing be an alternative to achieve the IMO objectives.

A framework with fully hydrogen-powered vessels still faces challenges, in terms of technology and costs. The required volume of LH_2 to power vessels is driven by fuel cells efficiency and limited by the technics and operational constraints of ships, especially the smaller ones, reducing the endurance. With that, the frequency of bunkering requirements increases, leading to a rise in downtime. This issue is even more pronounced by the onshore station, given the higher distance to travel.

Figure 20, Figure 21, Figure 22 and Figure 23 indicates the cost breakdown of each scenario, respectively BAU, Carbon taxes, Hydrogen-based (offshore and onshore).

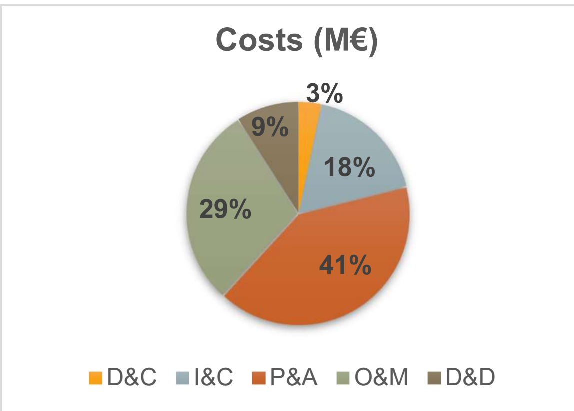

Figure 20 - Cost breakdown - BAU scenario

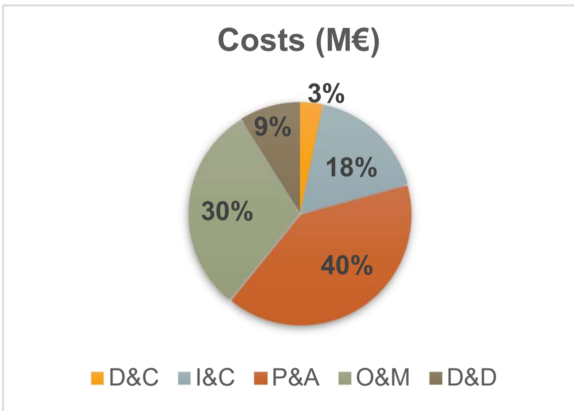

Figure 21 - Cost breakdown - Carbon tax scenario

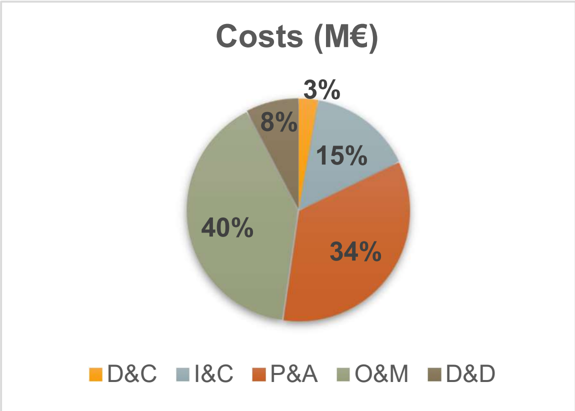

Figure 22 - Cost breakdown - Hydrogen- based scenario (Offshore)

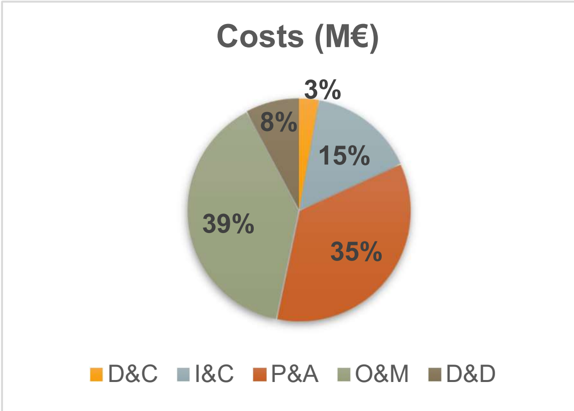

Figure 23 - Cost breakdown - Hydrogen- based scenario (Onshore)

The slight increase of O&M share for the carbon tax scenario, in comparison to BAU, is mainly due to the inclusion of the fee applied for, being it the only difference between both.

The hydrogen-based scenarios own an additional significant cost for the station refuelling CAPEX, being higher for the offshore station. On the other hand, the share of OPEX is impacted by, also the added cost associated with the refuelling station, and high hydrogen cost and the increased number of trips to refuel along the year, causing more fuel consumption and downtime.

From Figure 18 and Figure 19 it is noticeable the decreasing trend on net energy since for the hydrogen-based scenarios, a portion of the electricity generated is addressed to produce H_2 to power the vessels, being the onshore case a larger consumer of fuel due to endurance limitations and required frequency on which have to travel to and from to onshore refuelling station. Moreover, the time taken to transit coming and going brings rise on the downtime and decrease in energy production.

These factors lead to a significant increase in LCOE, as shown in Figure 19. The annual emissions are reduced to zero when moving to the hydrogen scenario, considering the vessels operations.

7. Sensitivity analysis

A set of sensitivity analyses was conducted considering the wind farm general specifications with the variation of some parameters independently, namely distance to shore, fuel cells cost, electrolyser efficiency and vessels operational constraints. The change of each analysis set was chosen according to its characteristics, to represent a feasible variation and to evaluate more meaningful results.

7.1. Distance to shore

By analysing the variation of the distance to shore, which also impacts the distance to port and wind speed at the site it is possible to observe the variation on CAPEX, OPEX, energy production, and consequently on LCOE and CO_2 emissions. This analysis did not consider the variation of water depth with the distance to shore, remaining it, the same as the base case.

A variation of 15%, 30% and 45% on the distance to shore was considered. As shown in Figure 24 [80], this distance change does not significantly impact the mean wind speed in Dogger Bank site, implying on average a variation of 1%, 2% and 3%, respectively to each referred distance to shore. The variation of each of these parameters is shown in Table 25.

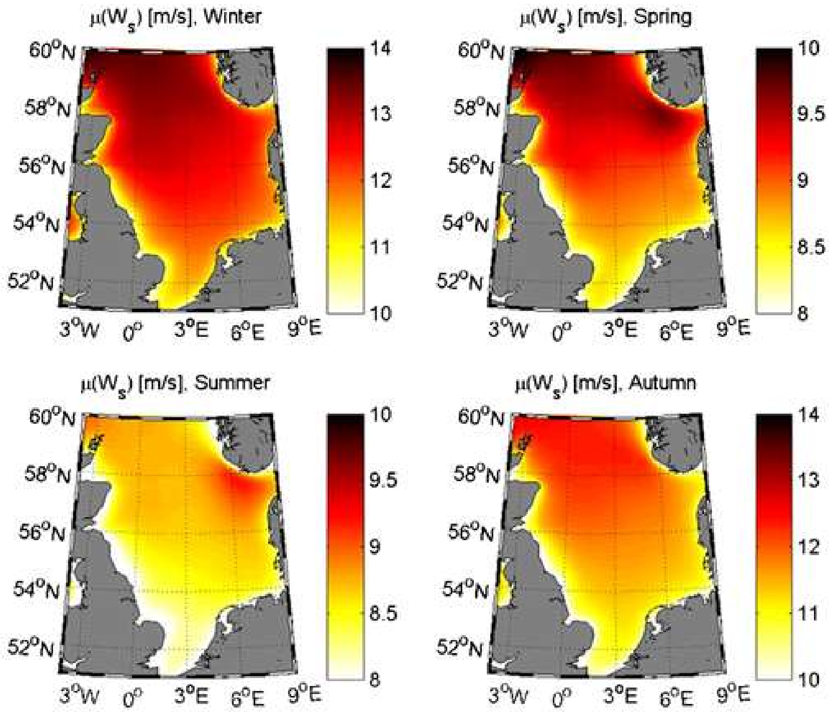

Figure 24 - Mean wind speed in Dogger Bank [80]

Table 25 - Variations of parameters distance to shore, distance to port and wind speed

Distance to shore change [%]	Distance to port change [%]	Wind speed change [%]
45%	33%	3%
30%	22%	2%
15%	11%	1%
0%	0%	0%
-15%	-11%	-1%
-30%	-22%	-2%
-45%	-33%	-3%

The results of this sensitivity analysis are illustrated in Figure 25, Figure 26, Figure 27, Figure 28 and Figure 29. The graphs represent the variation of each parameter, under the baseline shown in the previous section, with distance to shore, distance to the port and mean wind speed changes.

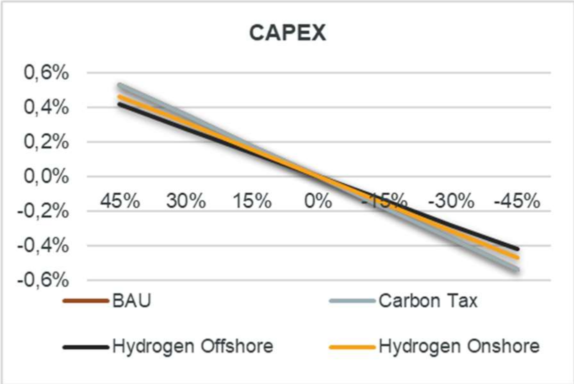

Figure 25 - CAPEX from sensibility analysis (distance to shore)

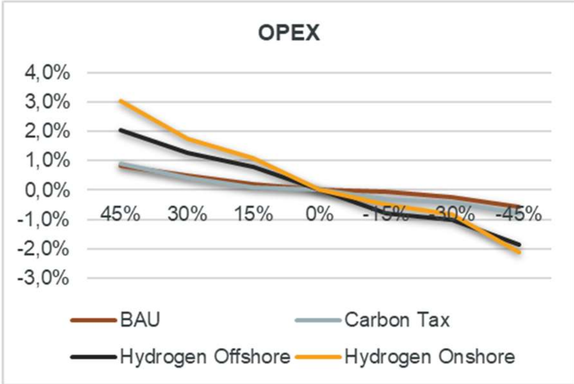

Figure 26 - OPEX from sensibility analysis (distance to shore)

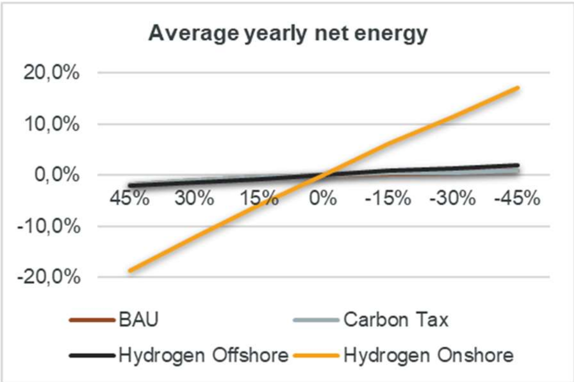

Figure 27 - Annual net energy from sensibility analysis (distance to shore)

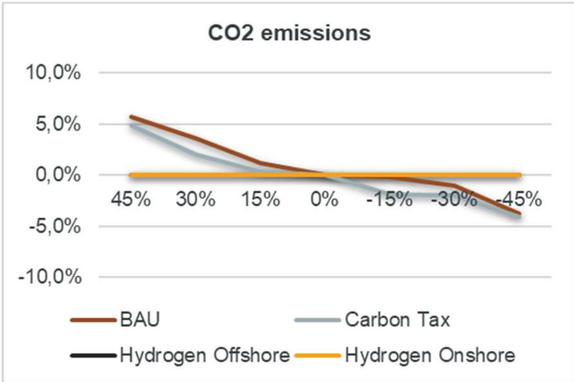

Figure 28 - CO_2 emissions from sensibility analysis (distance to shore)

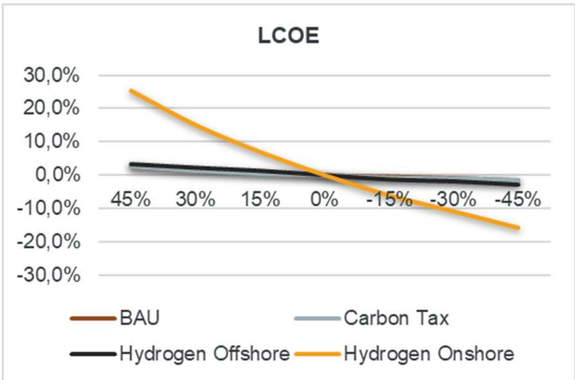

Figure 29 - LCOE from sensibility analysis (distance to shore)

By the analysis is visible a similar behaviour for CAPEX in all scenarios, since in this case, the main driver of the variations in the length of cables.

The OPEX variation relies mainly on fuel consumption and the costs associated with downtime. By increasing the distance to the port, the waiting time can also increase. The total time to repair, which includes also transit time, may not fit into the expected weather window, increasing the waiting time and leading to a higher downtime. With that, the fuel consumption also increases, which also explain the largest growth of CO_2 emissions when the distance is increased, as shown in Figure 28.

For the onshore hydrogen-based scenario, the variations are more meaningful since it considers the round-trip time for refuelling every 3 days on average.

By Figure 27, it is possible to notice that, despite the slight variation in the mean wind speed on-site due to change on the distance to shore, the net energy produced by the wind farm varies inversely to distance to shore variation. It means that as the distance to shore decreases, although mean wind speed decrease, the drop of downtime leads to higher energy production. The onshore hydrogen-based case has a significant variation since it contemplates, in addition to the demand of energy to refuel vessels, the higher downtime due to refuelling trips. As the distance decrease, the demand for energy to produce hydrogen for the vessels also decreases as does the time dispended in transit along the year, resulting in more electricity delivered to the grid.

The offshore hydrogen-based case, on the other hand, has less prominent variations, since refuelling is done on-site, reducing the need for the ship to transit to and from port as frequently, being this scenario the most suitable for fleet decarbonisation perspective, considering the increase of wind farms further from shore, even with higher expenses of refuelling station.

By this analysis, is possible to notice that LCOE is highly impacted by the downtime, which impacts OPEX and, mainly, the energy available from the turbines. The Hydrogen onshore case has shown more sensitivity to these factors than other scenarios.

7.2. Cost of fuel cell

CAPEX of vessels is a key determinant to define the charter rate. Within the necessity to invest in new technological solutions in the sector, charter rates should increase significantly with this cost repass from the ownerships. By the developed model, annual costs related to vessels represent around 25% on average of the total OPEX.

Despite fuel cells market availability progress, PEM cells are still considered highly expensive, sharing a large percentage of the initial investment of a new hydrogen system installation. In order to become hydrogen a feasible alternative for energy solutions, including ships, several barriers must be overcome. An important one is the ability to produce fuel cells in mass, to achieve cost reductions. On the other hand, if the market is not prepared to supply the future demand for fuel cells, it could lead to an increase in costs at the first moment due to the necessity to develop and invest in infrastructure for production.

The set of fuel cells own the biggest share of the estimated initial cost, due to the elevated cost per kW, as presented in Table 12.

Taking into account a more conservative scenario and the trend of the curve shown in Figure 15, variations of 10%, 20% and 30% were considered. The impact of each vessel charter rate is shown in Table 26.

Table 26 - Variations of parameters fuel cell cost and charter rate

FC cost change [%]	CTV charter change [%]	SOV charter change [%]	Jack-up charter change [%]	AHTS charter change [%]
30%	10.2%	1.2%	2.5%	11.0%
20%	6.8%	0.8%	1.6%	7.3%
10%	3.4%	0.4%	0.8%	3.7%
0%	0.0%	0.0%	0.0%	0.0%
-10%	-3.4%	-0.4%	-0.8%	-3.7%
-20%	-6.8%	-0.8%	-1.6%	-7.3%
-30%	-10.2%	-1.2%	-2.5%	-11.0%

From Table 26 is possible to notice that proportionally, the change in fuel cell cost is more meaningful for the less costly vessel (CTV and AHTS), which means that the hydrogen system has a higher share of their initial investment.

On the other hand, for the vessels hired on the spot market (jack-up and AHTS), this cost change may have a higher impact on total O&M cost, according to the frequency in which they are requested.

Given the analysis presented in the previous section and knowing that the onshore hydrogen case is strongly dependent on the downtime, the analysis of the fuel cell cost was conducted to the offshore scenario, to obtain a better response of the sensitivity in relation to the parameter change. Figure 30 and Figure 31 illustrates the results obtained.

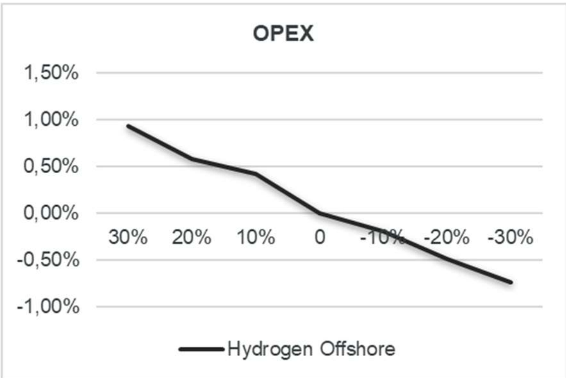

Figure 30 - OPEX from sensibility analysis (fuel cell cost)

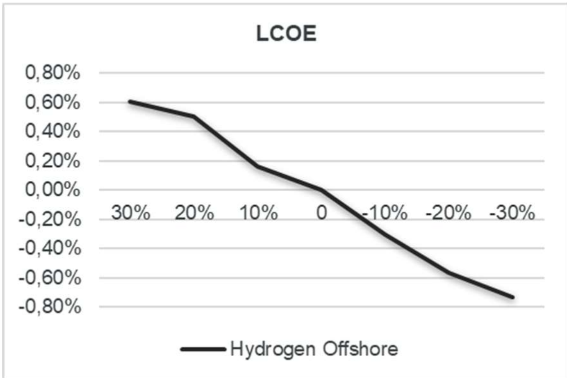

Figure 31 - LCOE from sensibility analysis (fuel cell cost)

With the analysis is possible to notice a slight variation on OPEX with charter rates change, by the range of 0.93% to -0.73%, leading to a change of 0.61% to -0.73% of the LCOE.

The LCOE also depends on the energy production, which varies according to the availability of wind turbines, which, however, has no relation to the costs of the vessel. It is notable, however, that technological development of the system as a whole to the level where costs can be reduced on a large scale, can reduce, albeit very slightly, the final cost of energy.

7.3. Efficiency of electrolysers

Supplying green hydrogen from large-scale electrolysis with cheaper wind electricity might be the ideal long-term solution for the decarbonization challenge. Hydrogen, however, is not yet cost-competitive to fossil fuels, increasing largely the OPEX of hydrogen-based service vessels and consequently the

LCOE. Developing the hydrogen industry is crucial to tackling this barrier, as, increasing the efficiency of electrolysers.

In this section was performed an analysis of change on refuelling station electrolysers efficiency, responsible to produce the required hydrogen to power the vessels to understand how much it contributes to hydrogen cost reduction and consequently OPEX and LCOE.

It is known that efficiency improvements are challenging and costly. For this analysis, however, the parameter was adjusted to an increase of 3%, 5% and 10%, without system cost changes. With the increase of electrolyser efficiency, the trend is to have a drop in hydrogen cost, as shown in Table 27.

Table 27 - Variations of parameters electrolyser efficiency and hydrogen cost

	Offshore	Onshore
Efficiency change [%]	**Hydrogen cost change [%]**	**Hydrogen cost change [%]**
▲ 10%	▼ -18%	▼ -19%
▲ 5%	▼ -12%	▼ -13%
▲ 3%	▼ -6%	▼ -9%
▬ 0%	▬ 0%	▬ 0%

The analysis shows that the reduction in the cost of hydrogen due to increased efficiency led to a significant change in the OPEX, varying in the range of around 3.4% to 13%, in both cases, as illustrated in Figure 32. LCOE also presented a meaningful drop, however, smaller as shown in Figure 33, since it relies on energy production from wind turbines. These variations show a potential improvement on the hydrogen system since this efficiency gain is likely to be possible for future electrolysers.

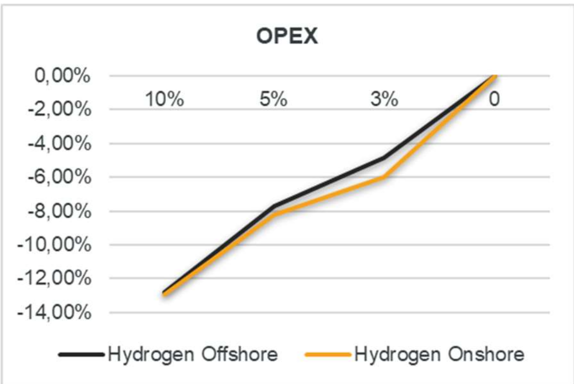

Figure 32 - OPEX from sensibility analysis (electrolyser efficiency)

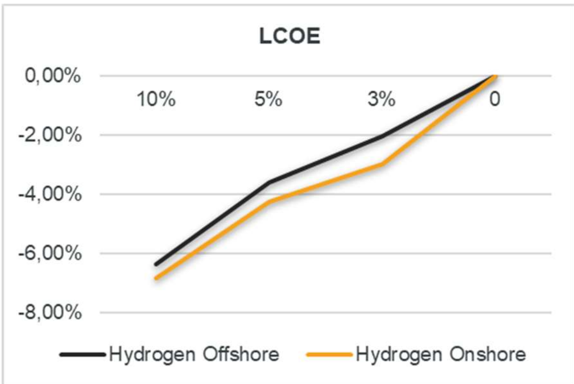

Figure 33 - LCOE from sensibility analysis (electrolyser efficiency)

The slight difference between offshore and onshore may be explained by the fact of the cost of hydrogen is also considered in the portion that concerns consumption during the transit to and from shore for refuelling, in the former case, which implies more fuel cost savings.

In the same direction, improving electrolyser efficiency leads to a reduction in the amount of electricity required to produce one unit of hydrogen and consequently lowers electricity costs. The onshore scenario requires more energy to refuel the ship, so by enhancing the efficiency of hydrogen production, more energy will be available to the grid, explaining the higher LCOE variability for this case.

7.4. Operational constraints

Operational constraints, especially, wave height and wind speed are fundamental to offshore access and maintenance tasks since they will affect the downtime. Increasing the operational range of the vessels may lead to a drop in stoppage time and O&M costs.

In meantime, allowing vessel operations with upper limits of restrictions requires design and equipment changes. The roll movement in waves is considerably critical to operational limits, so if wave-induced vessel motions can be minimized, the workability and comfort can be improved. It can be done by adding a damping system, as such anti-rolling tanks and moving weight systems (passive or active systems) or new hull designs.

For the wind effects, it can be more costly, since the dynamic position system must be improved. Moreover, for crane operations there are safety restrictions regarding wind speed, not allowing substantial increases.

For this reason, in this section, the analysis considered only the change on wave height constraints, varying by 0.5m, 1.0 m and 1.5m. This analysis has not considered possible additional costs in the charter rate with the referred vessels improvements.

Wave height change [m]	CTV change [%]	SOV change [%]	Jack-up change [%]	AHTS change [%]
1.50	100%	50%	75%	75%
1.00	67%	33%	50%	50%
0.50	33%	17%	25%	25%

Figure 34 - Variations of parameter wave height

Figure 35, Figure 36 and Figure 37 illustrate the results obtained from this analysis for offshore and onshore scenarios.

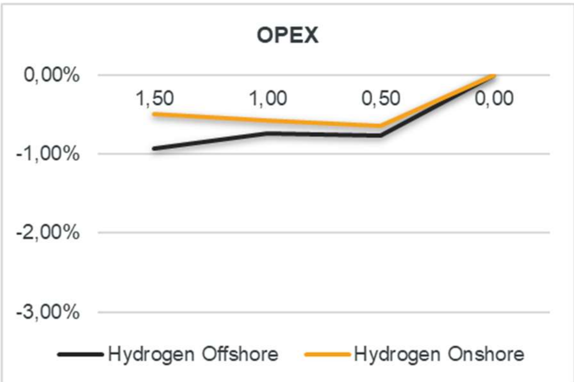

Figure 35 - OPEX from sensibility analysis (operational constraints)

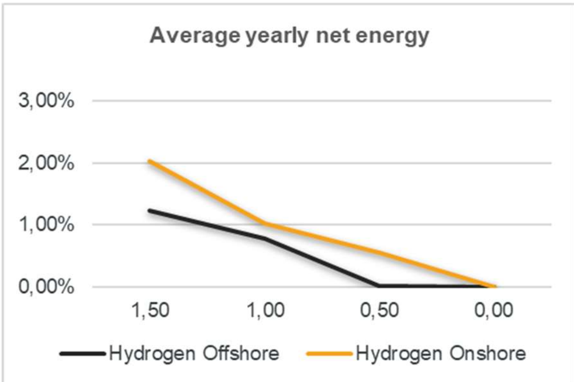

Figure 36 - Annual net energy from sensibility analysis (operational constraint)

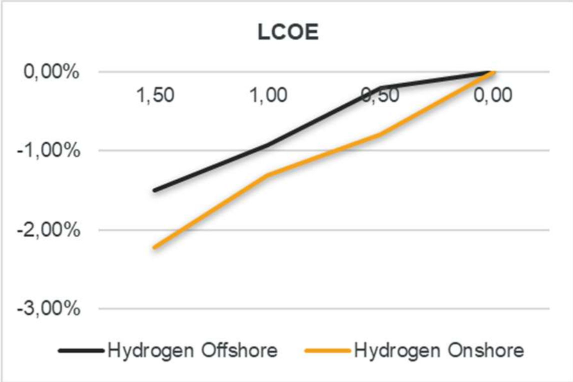

Figure 37 - LCOE from sensibility analysis (operational constraints)

The sensitivity analysis has shown a similar trend for both scenarios, in terms of OPEX, net energy and LCOE, with a slightly higher reduction for offshore OPEX, since it is not impacted by the transit to and from shore for bunkering, as in the onshore case. With the increase of weather window, given the larger range of operation, the downtime decreases for both scenarios, increasing the net energy produced, reflecting on the LCOE, as well.

8. Discussion

The analysis presented in this work indicates that O&M shares are highly dependent on the downtime, given by the transit time, weather conditions and consequently to time to repair.

The model has revealed that under an economic analysis, the proposed carbon tax will not be enough to make hydrogen attractive indicating an LCOE 85.7% and 141.5% lower from the offshore and onshore scenarios, respectively.

Looking to the hydrogen framework, a significant increase of the LCOE is severely driven by the operational expenses rise due to the high cost of hydrogen and additional expenses of the refuelling station. The offshore case presented 60.2% and 53.4% higher than BAU and carbon scenario respectively, while the onshore 52.6% and 46.1% higher costs

Despite the higher CAPEX and OPEX, as shown in Figure 16 and Figure 17, the H_2 offshore station indicates a more feasible scenario than the onshore, as it has a faster response time to supply vessels on-site, increasing the net energy produced. The onshore LCOE represents around 29% higher than when considering an offshore station.

Therefore, the hydrogen production cost is still very high in both cases and not competitive with fossil fuels, thus making its introduction as a fuel in the maritime industry unfeasible, unless there are significant changes in policies and mechanisms to discourage fossil fuel use, and technological development of hydrogen system to allow dramatically drops of LCOH.

By examining the reduction of the LCOE, the major impact from the sensitivity analysis is indicated by the parameter “electrolyser efficiency”, which impacts the cost of hydrogen and indicates a reduction by 6.4%, followed by the “distance to shore” (2.8%), “operational constraints” (1.5%) and “fuel cell costs” (0.7%) in comparison to the base case modelled.

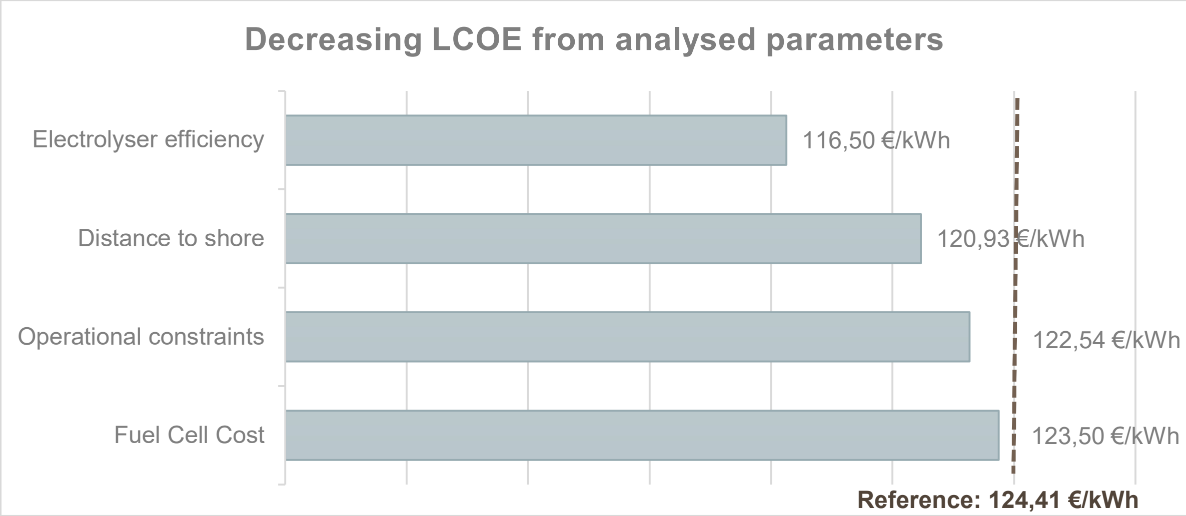

Figure 38 - Decrease of LCOE through sensitivity analysis parameters

From the results presented it is clear that difficulties to implement hydrogen as an alternative fuel arise when parameters as hydrogen price, investments cost, and technological barriers are not favourable. In addition, the financial conditions for a riskier project reduce the viability of the business.

Hydrogen would not be competitive without further cost reductions or support mechanisms. With regulations implementing carbon and fossil fuel taxation, the technological maturation of hydrogen systems, and more attractive discount rates, hydrogen-based vessels may reach more economically feasible levels. Technology acceleration is essential for reducing electrolysis and storage systems costs. The LCOH projection for PEM electrolyser in bottom-fixed structures for 2050 is 1.65 £/kg, representing 57% decrease. It can be achieved by reducing CAPEX and OPEX of the offshore hydrogen production system, as predicted by Spyroudi et al. [78], in around 54% and 29% respectively.

Table 28 - Hydrogen CAPEX forecast to 2050

Hydrogen Offshore station - CAPEX (2050)		
Electrolyser	232 €/kW	[78]
Compressor	1.97 €/kW	[78]
Stand-by Power/Battery	22.39 €/kW	[78]
AC cable to platform	1.97 €/kW	[78]
AC/DC converter	77.60 €/kW	[78]
Water desalination	0.23 €/kW	[78]
Central electrolyser platform	129.34 €/kW	[78]
System replacement	11.39 €/kW	[78]
Hydrogen pipeline	52.78 €/kW	[78]
Total	483.07 M€	[78]

Table 29 - Hydrogen OPEX forecast to 2050

Hydrogen Offshore station - OPEX (2050)		
Electrolyser	5.80 €/kW	[78]
Compressor	0.03 €/kW	[78]
Stand-by Power/Battery	0.56 €/kW	[78]
AC cable to platform	0.05 €/kW	[78]
AC/DC converter	2.32 €/kW	[78]
Water desalination	0.01 €/kW	[78]
Hydrogen pipeline	1.58 €/kW	[78]
Total	9.44 M€	[78]

Assume that, in the future, fuel cells and storage methods can achieve technological improvements to allow competitive charter rates of hydrogen-based service vessels, at the same level as traditional ships, and a discount rate similar to that practised for business-as-usual scenarios (6%) are also key to reducing the levelized cost of energy.

With these set of cost reductions, it is noticing the signs of meaningful LCOE reduction for a hydrogen offshore scenario, reaching around 88 €/MWh in a future scenario and representing a decrease by 29% in comparison to the cost calculated initially by the model.

Table 30 - Inputs for hydrogen offshore scenario in a future perspective

Hydrogen offshore scenario	
Hydrogen cost	2.2 €/kg
Station CAPEX	483.07 M€
Station OPEX	9.44 M€
Vessels charter	Same as assumed for BAU scenario
Discount rate	6%

The ETS and ETD should ensure emission reductions in the sector. Meanwhile, as mentioned by the European Commission [4], to start to make alternative fuels attractive to the maritime sector, each ton of CO_2 must cost at least 200 €.

The revision of the ETD proposes that conventional fossil fuels may be subject to the reference rate of 10.75 €/GJ when used as a motor fuel [32].

Table 31 - Inputs for carbon tax scenario in a future perspective

Carbon tax scenario	
Emissions tax	200 €/tCO_2
Fossil fuel tax	10.75 €/GJ
Discount rate	6%

Then, assuming this scenario change, the LCOE for carbon for a fossil fuel-based scenario should achieve around 73 €/MWh, an increase of almost 9%.

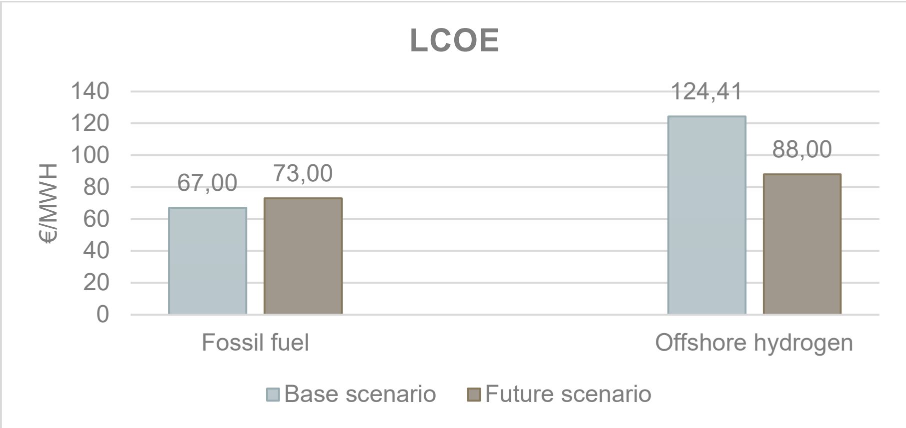

Figure 39 - Comparison between LCOE of fossil fuel and hydrogen offshore in base and future scenarios

From this perspective, it is clear that the LCOE of wind farms served by hydrogen-powered ships with offshore fuelling stations can start to become competitive if costs are reduced and measures to discourage the use of fossil fuels are implemented cost-effectively.

9. Conclusion and future work

Given the deployment of offshore wind power and the rise of the numbers of projects planned for construction over the coming years will boost the needs of the fleet increase and more efficient service vessels will be required.

O&M is expected to account for nearly one-third of offshore wind levelized cost of energy for business as usual scenario. Consequently, there is a large potential for reducing LCOE through maintenance strategies, by reducing downtime through the introduction of higher performance vessels and autonomous vehicles, increasing reliability, and minimizing costs. There is an increasing pressure on market competitiveness to decarbonise the sector, to deliver more green-fuelled, efficient, and less costly vessels to the operators.

Therefore, it represents a complex issue, mainly when considering the long-term uncertainties, as weather forecast, failure rates, energy market fluctuation, financial and political tendencies.

The offshore wind industry is in a rather paradoxical situation since to guarantee the production of renewable wind energy they still depend on ships based on fossil fuels. The maritime sector generally tends to be conservative but to tackle the targets, the industry will have to implement new solutions to deep decarbonisation of the fleet involved in O&M tasks for offshore wind farms.

Alternative fuels are being evaluated to be implemented in the maritime industry. However, given the technological maturity level and current infrastructure and supply chain, many barriers still have to be overcome to make hydrogen feasible as a fuel for the maritime sector.

The purpose of this study was to evaluate the economic potential in hydrogen-based vessels addressed to wind farm O&M tasks. To this end, this study has seen an O&M simulation tool for an analysis of a wind farm allowing for the assessment of the levelized cost of energy from different perspectives, namely the business as usual, a scenario considering carbon tax applications and fully hydrogen-powered vessels framework, with onshore and offshore refuelling stations.

Access to operation and maintenance data is not as broad in the literature given the confidentiality from owners and operators, leading this type of tool to some assumptions, approximations and consequently a certain level of uncertainty. Comparing the OPEX of the developed model with the operational costs of a reference bottom-fixed platform, it can be considered that well modelled, since it presented a difference of 2% of the reference case, being considered within the limits of the uncertainties of the input data and assumptions made.

In general, the variation in LCOE is strongly related to the availability of the wind turbine, leading to a loss of energy production due to downtime, very noticeable in more severe weather conditions such as winter or in an onshore bunkering perspective, where higher energy amount is requested to fulfil the ship operational requirements. When considering hydrogen as fuel, the LCOE is severely driven by the H_2 cost, which is still far from competitiveness with fossil fuel, being 88.4% and 145.1% higher for the offshore and onshore hydrogen cases, respectively, in comparison to BAU.

From the sensitivity analysis, the model had indicated higher sensitivity to the costs associated with the technological maturity of the electrolysis system, varying the LCOE by around 6 %.

In addition to higher costs, the hydrogen-based project presents more risks when considering ships powered by hydrogen produced by the very farm they serve. In this way, the financial conditions are not favourable as for a traditional project, being the discount rate in general 2% above, making energy even more expensive.

Difficulties to implement hydrogen as an alternative fuel arise when technological and economic parameters still are a challenge. Due to the high hydrogen price and investment costs of hydrogen related to technologies, the study case for hydrogen-powered ships was not competitive.

To effectively build a market competitive system, the technical barrier must be overcome to provide business leverage and allow a clean, feasible and affordable shipping industry. Additionally, the infrastructure and supply chain must be well structured to enable lower costs and to minimize the losses of energy production.

Analysing the estimated cost reductions of electrolysis system by 2050 and considering similar vessels charter rates and discount rate as BAU, it is noticeable a decrease by around 31% of hydrogen offshore LCOE.

In comparison to the increase of the mechanisms to discourage the use of fossil fuels, namely higher emissions cost and implementation of fossil fuel taxation, the LCOE revealed an increase by 15% for the conventional fuels' scenario.

In this perspective of technological advance and consequent cost reduction, hydrogen can start to show economic viability improvement, even though it seems slightly above the fossil fuels scenario. Meanwhile, this scenario is capable of reducing to zero carbon emissions during maintenance operations, proving to be effective in achieving IMO's objectives.

The key to achieving the reduction of emission is developing, maturing, and scaling up solutions, as well supplement the sector by regulations, policy measures and incentives to drive technology development and cost-effective emission reductions, while at the same time ensuring the shipping activity is not restricted, as well as wind power generation. These measures should be implemented in conjunction so that combined they can represent more significant impacts on final costs and enable the introduction of hydrogen as a clean fuel in the marine industry.

In order to obtain more realistic results, a future model should assess more adequate data on turbine failures with power and operating characteristics closer to the wind farm under study, as well as more updated ship charter rates and other cost inputs. The failures occurrence in the refuelling station should be also considered.

In respect of vessels' operational performance, further design and hydrodynamic studies should be recommended to evaluate the vessels' stability and hydrodynamics impacts by adding a hydrogen system onboard and technical feasibility.

For a more refined analysis of the introduction of hydrogen in the maritime sector, an optimisation of the main hydrogen production system parameters is suggested to reach the break-even point to allow hydrogen to be competitive with fossil fuels.

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Appendix 1

Vessels' initial investment and cost deductions

CTV H_2 - Initial Investment	**M€**
PEM FC	-2.3
FC System Installation	-0.3
Hydrogen Tank	-0.1
Hydrogen Tank Installation	-0.6
Electric motor	-0.1
Power Conditioning	-0.1
Convencional System Cost Deductions	1.6
Total	-1.9

SOV H_2 - Initial Investment	**M€**
PEM FC	-5.7
FC System Installation	-0.7
Hydrogen Tank	-1.0
Hydrogen Tank Installation	-3.7
Electric motor	-0.3
Power Conditioning	-0.2
Convencional System Cost Deductions	0.5
Total	-11.2

Jack-up H_2 - Initial Investment	**M€**
PEM FC	-30.5
FC System Installation	-2.1
Hydrogen Tank	-2.2
Hydrogen Tank Installation	-1.9
Electric motor	-1.8
Power Conditioning	-0.9
Convencional System Cost Deductions	5.2
Total	-34.2

AHTS H_2 - Initial Investment	**M€**
PEM FC	-11.4
FC System Installation	-1.5
Hydrogen Tank	-0.8
Hydrogen Tank Installation	-1.2
Electric motor	-0.7
Power Conditioning	-0.3
Convencional System Cost Deductions	0.9
Total	-15.0

Appendix 2

Vessels'energy balance

Energy balance CTV (rough sea state, speed=15 knots)						
Operation	**Duration (h)**	**Power (kW)**	**Energy (MJ)**	**FC Efficiency (%)**	**H2 LHV needed (MJ)**	
Transit to/from site	0.38	936	1,286	60%	2,143	[72]
Crew transfering	0.37	864	1,148	60%	1,914	[72]
Transit between WT	0.18	864	546	60%	910	[72]
Stand by in DP	11.07	864	34,413	60%	57,356	[81]
Accommodation (HVCA)	12.00	38	1,619	60%	2,698	[82]
Lighting	12.00	12	522	60%	871	[81]
Pumps	12.00	22	950	60%	1,583	[81]
Crane	1.80	19	121	60%	202	[83]
Various equipment	12.00	7	322	60%	536	[81]
Emergency	25.00	432	38,849	60%	64,748	[72]
Total (per day)		4,058			132,961	
Margin 5% (day)		4,261			139,609	

Energy Balance SOV (rough sea state, speed=10 knots) - Period: 3 days						
Operation	**Duration (h)**	**Power (kW)**	**Energy (MJ)**	**FC Efficiency (%)**	**H2 LHV needed (MJ)**	
Transit to/from port	9.62	2,800	96,908	60%	161,514	[72]
Crew transfering	1.11	2,100	8,372	60%	13,954	[72]
Transit to site and between WT	4.43	2,100	33,430	60%	55,716	[72]
Transit to refuel station	0.57	2,100	4,328	60%	7,214	[72]
Stand by in DP	54.8	2,100	414,150	60%	690,251	[81]
Accommodation (HVCA)	72	188	48,561	60%	80,935	[82]
Lighting	72	24	6,268	60%	10,446	[81]
Pumps	72	44	11,396	60%	18,993	[81]
Crane	5.4	75	1,457	60%	2,428	[83]
Various equipment	72	15	3,859	60%	6,432	[81]
Emergency	75	1,050	283,273	60%	472,122	[72]
CTV H2 refuel		12,782			418,826	
Total (3 days)		25,378			1,938,831	
Margin 5% (day)		26,647			2,035,773	

Energy Balance Jack-up (rough sea state, speed=10 knots)						
Operation	**Duration (h)**	**Power (kW)**	**Energy (MJ)**	**FC Efficiency (%)**	**H2 LHV needed (MJ)**	
Transit to/from port	19.24	6,500	449,932	60%	749,887	[72]
Crew transfering	0.70	5,213	13,126	60%	21876	[72]
Stand by in DP	52.1	5,213	976,120	60%	1,626,867	[81]
Accommodation (HVCA)	72	187.5	4,8561	60%	80,935	[82]
Lighting	72	24.2	6,268	60%	10,446	[81]
Pumps	72	44.0	11,396	60%	18,993	[81]
Crane	27	746.0	72,453	60%	120,755	[83]
Various equipment	72	14.9	3,859	60%	6,432	[81]
Emergency	75	5,606.4	1,512,518	60%	2,520,863	[72]
Total		13,123			4,385,292	
Margin 5% (day)		13,779			4,604,556	

Energy Balance AHTS (rough sea state, speed=12 knots)						
Operation	**Duration (h)**	**Power (kW)**	**Energy (MJ)**	**FC Efficiency (%)**	**H2 LHV needed (MJ)**	
Transit to/from port	16.04	4,550	262,460	60%	437,434	[72]
Crew transfering	0.70	990	2,493	60%	4,155	[72]
Stand by in DP	55.3	990	196,803	60%	328,006	[81]
Accommodation (HVCA)	72	125	32,374	60%	53,957	[82]
Lighting	72	24	6,268	60%	10,446	[81]
Pumps	72	44	11,396	60%	18,993	[81]
Handling	18	1,000	64,748	60%	107,914	[81]
Towing	7.2	445	11,525	60%	19,209	[81]
Various equipment	72	15	3,859	60%	6,432	[81]
Emergency	75	2,100	566,547	60%	944,245	[72]
Total		8,303			1,598,628	
Margin 5% (day)		8,718			1,678,559	

Appendix 3

Results: Average LCOE, Yearly Emissions, CAPEX, OPEX and Yearly Generation and respective standard deviation, per scenario.

	Avg LCOE (€/MWh)	Avg yearly emissions (tons)	Avg CAPEX (M€)	Avg OPEX (M€)	Avg yearly generation (GWh)
BAU	66.03	99,268	3,423	1,407	5,355
St. dev.	0.83	5,600	0	9	61
Carbon tax	67.00	100,605	3,423	1,469	5,351
St. dev.	0.91	4,750	0	11	65
Hydrogen offshore	124.41	0	4,393	2,254	4,762
St. dev.	3.17	0	0	54	87
Hydrogen onshore	161.82	0	3,927	2,147	3,340
St. dev.	5.81	0	0	55	93