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

Paula Cristina de Sousa Bastos

paulabastos@tecnico.ulisboa.pt

Instituto Superior Técnico, Universidade de Lisboa, Portugal

December 2021

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

1- Introduction

Estimating the expenditures of operation and maintenance (O&M) and predicting energy production are important factors in an offshore wind farm cost analysis. The resources to conduct O&M tasks play a significant role in this evaluation. Vessels require capital-intensive and they are crucial to support the maintenance strategy. However, while the wind is a clean energy source, service vessels used to support the offshore wind farms still rely on fossil fuels.

According to the strategy defined on the Marine Environment Protection Committee – MEPC 73 [1], the International Maritime Organization (IMO) has a long-term goal to reduce the overall GHG emissions by 50% from 2008 levels by 2050. 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 directly impact the maritime sector since they contemplate the inclusion of maritime transport in the Emissions Trading Scheme (ETS), and the introduction of fossil fuel taxation for intra-EU maritime transport, through the Energy Taxation Directive (ETD) [2]. To achieve this target, the adoption of efficiency improvement and alternative fuels vessels commercially viable by 2030 is required.

Considering, the framework of clean fuels shares in the industry, hydrogen is one of the promising alternative fuels for offshore vessels with potentially a low carbon footprint. However, hydrogen use in the maritime sector still faces several challenges, such as high costs, storage, transportation, maturity of fuel cells for marine applications, bunkering infrastructure, and safety regulations, making its use in shipping unfeasible for the time being, since it impacts strongly the levelized cost of energy (LCOE).

2- Problem description

The objective of this maintenance vessels decarbonisation problem is to analyse the impact of the introduction of clean fuel, namely hydrogen, in the wind farm O&M strategy, by considering its preventive and corrective campaigns, by the construction of a hydrogen-based scenario (HB), and to compare to Business as Usual (BAU) which corresponds to current scenario, and Carbon Tax (CT) employing carbon tax under operations emission, and 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 O&M

In recent years, the offshore wind industry has witnessed meaningful cost reduction of energy production, even being planned with zero subsidies. Nevertheless, is crucial to reduce the LCOE, mainly from the perspective of the rise of O&M costs of wind turbines farther from shore. O&M is expected to account for nearly one-third of offshore wind levelized cost of energy. of an offshore wind farm's total life cycle cost [3].

Developing a wind turbine maintenance plan is a strategy to minimize the likelihood of a downtime incident. In general, the strategy is divided into two categories: corrective (CM) and proactive maintenance (PM), where the former is a strategy based on unscheduled repair actions conducted after failure indication, while the latter refers to a schedule of actions to be conducted before failures take place, to avoid stoppages and unsafe operations.

The decisions of the access and operation strategy are made based on identified maintenance category. Typically, maintenance tasks and access to the wind turbines are performed by some specific type of vessels, including Crew Transfer Vessels (CTVs), Service Operational Vessels (SOVs), Jack-ups, Anchor Handling Tug Supply (AHTS), and Autonomous Vehicles (AVs) as drones with Extended Visual Line of Sight (EVLOS) technology.

3.2. Decarbonization of the maritime sector

Since the launch of the IMO GHG Strategy[1], the maritime sector is experiencing increasing pressure to decarbonize its operations and to reduce greenhouse gases emissions.

In July 2021 the European Commission presented a set of proposals, the Fit for 55 Package, to help the achievement of the emission targets of reducing GHG emissions in 2030 to at least 55% compared to 1990 levels [2], contemplating some direct impacts to the maritime sector as the inclusion of maritime transport in Emissions Trading Scheme (ETS), a common EU regulatory framework (FuelEU) to increase the share of renewable and low-carbon fuels in the fuel mix of international maritime transport, and the introduction of a minimum tax rate by the Energy Taxation Directive (ETD).

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.

In this way, some alternative fuels have been considered to meet the maritime decarbonization goals. It is in this framework that green hydrogen arises as an option since when produced from renewable sources using electrolysis, it has no CO_2 footprint neither during the processes nor while reacting. The use of hydrogen in combination with fuel cell systems onboard ships could lower to zero the carbon intensity of shipping fleets. However, its use brings also technological and economical challenges. The most critical bottlenecks with hydrogen as a fuel are likely the production and storage cost. To deal with the low volume energy content of hydrogen at atmospheric conditions, further technological processes have to be considered to concentrate hydrogen and allow storage, which can be by compression or liquefaction. It restricts the operation and endurance of vessels, in terms of space, weight and safety.

In reference to hydrogen production, 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 when better use of the excess wind power is considered. With the offshore wind farm producing electricity, some configurations of hydrogen production from offshore wind farms can be considered.

The first configuration 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, presenting a lower level of complexity of installation and better conditions for maintenance, enabling costs reductions [4]. The second one consists of an offshore wind farm and an electrolyser, 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 [4] or can be used to bunker ships on the site.

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.

4- Methodological approach

The model developed includes a set of seven types of inputs, as the wind farm characteristics, weather conditions, failure rates, time to repair, vessels specifications, costs and emissions, that are processed through a mathematical model in Excel.

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.

It is assumed a wind farm 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 weather 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 must also be estimated. CAPEX comprises the cost of the all 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 the loss of energy production due to stoppage.

A detailed mathematical model was developed, based on several sources, assumptions, and simplifications. 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. Apart from data restrictions and uncertainties, the tool developed does not focus on more complex modelling of operations, such as optimising the use of the vessel on a given day. However, to compare the impact of decarbonisation of the O&M fleet, the model demonstrates an effective tool, to analyse the more significant drivers of 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.

5- Case study

To illustrate the developed model, a case study is created and presented based on an O&M strategy for the Dogger Bank Wind Farm.

Wind farm characteristics

Dogger Bank is an isolated sandbank within the central to the southern North Sea, being developed in three phases – Dogger Bank A, B and C[5], being the former the site under study in this work.

Table 1 - Wind farm characteristics (Dogger Bank A)

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

Maintenance planning

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. Based on [6], the failure rates were categorized by level of repair (minor repair, major repair, and major replacement) for each group of the subassembly of subsystems.

In this current study, it is considered the set of SOV and CTV, for major and minor repairs, respectively. Jack-ups are indicated to the most of major replacements, due to associated 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.

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.

The set of SOV+CTV is planned to be placed on stand-by near the site in a work regime of 15 days, to minimize the downtime caused by the mobilisation time. The stand-by spot is located is considered in the middle of the wind farm, based on the Dogger Bank layout presented by [7]. The distance between WTs (1.5 km) can be considered as 7 times the rotor diameter [8] then the distance travelled by the vessels is considered as the average between the closer and the farther wind turbine and is equal to 5.3 km.

The initial time of failure identification is considered the time zero of a weather window. The action is considered complete when the repair is finalized, and the vessels return to the spot. For minor and major repairs, the action starts with the respective vessel leaving the stand-by location in the direction of the WT.

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 [9].

The Weibull approach was used to mimic the wind speed and wave height distribution created by measured data since it is being a well-established approach. 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 Weibull Persistence Method conducted by [10] was chosen to calculate the probability of an operational threshold being exceeded and consequently the associated waiting time. This approach is seen to be well suited for this application and holds relative computational simplicity to be applied even for large time series. With this method, it is possible to calculate the waiting time for the next weather window, given the required time to repair, if the current window is not enough to finalize the task.

Failure rates and repair data

The failure rates considered in this work were obtained from a combination of some available sources, namely [6], [11], [12], [13], [14], [15] and [16], 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. 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.

Similarly, the repair time at the site and the number of required technicians per failure for each turbine were determined for each subassembly and type of repair, as reported by [6] and [13].

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

Vessels' specifications

The main operational specifications of the vessels are shown in Table 2 and are based on [17], [12], [18], [19], [20], [21]and [22]. For hydrogen-based vessels were considered the same operational conditions, adjusting the fuel consumption. In general, CTV uses Marine Fuel Oil (MFO), SOV uses Marine Gasoil (MGO) as primary fuel and Marine Diesel Oil (MDO) as secondary, jack-up burns MDO, while AHTS the MGO.

Table 2 - Vessels' specifications

	CTV	SOV	Jack-up	AHTS
Type of contract	Lease	Lease	Spot	Spot
Offshore period (days)	1	15	30	30
Transit speed (knots)	26	11	10	14
Personnel (pax)	12	60	60	40
Hs (m)	1.5	3	2	2
Ws (m/s)	12	17	10	17
Mobilisation time (h)	-	-	720	360
Fossil fuel transit (l/h)	320	1000	2180	700
H2 transit (kg/h)	176	493	1099	345
Fossil fuel field (l/h)	130	120	484	120
H2 field (kg/h)	71	60	244	59

Costs

Wind farm CAPEX ($CAPEX_{OSW}$) includes costs during the Development and Consent (D&C), Production & Acquisition (P&A), Installation and Commission (I&C) and Decommissioning and Disposal (D&D) phases of the wind farm. Reference costs were obtained from [23], [22], [24] and [25], and presents a total initial expenditures of offshore wind farm of 3557.56M€.

Wind farm's operational and maintenance expenditures ($OPEX_{OSW}$) comprises all the costs to maintain the turbines operating correctly, whether scheduled and unscheduled maintenance, such as spare parts, vessels charters and other day-to-day operating costs, being possible also split the variable expenditures into preventive maintenance (C_{PM}) cost and corrective maintenance cost (C_{CM}).

There are some common cost inputs between C_{PM} and C_{CM}, as personnel cost [26], quayside fee [11], fuel price [27] [28] and emission tax [2].

Preventive maintenance costs

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. Nowadays, introducing drones for structure inspection, as such blades and towers, is becoming common, driven by the reduction of risk and costs. Hence, this study added a drone-based inspection with multiple drones and EVLOS technology [26], already based on hydrogen.

Each CTV travels to 4 turbines each day to perform preventive maintenance operations. The vessel transit time per operation ($Transit_{time_{PM}}$) [h] is in function of distance travelled by the SOV to and from the stand -by spot ($Distance_{SOV}$), distance between the turbines ($Distance_{turbines}$) and vessel speed ($Vessel_{speed}$), defined by:

$$Time_{transit_{PM}}=2x\left[\left(\frac{Distance_{SOV}}{Vessel_{speed}}\right)+\left(\frac{3*Distance_{turbine}}{Vessel_{speed}}\right)\right] \quad (1)$$

The total yearly cost for preventive maintenance (C_{PM}) [€] is estimated by:

$$C_{PM}=N_{turbines}x(Cost_{parts}+Technicians \times Cost_{personnel} \times Days+\frac{Cost_{fuel}}{Turbines_{per\ vehicle}})+Cost_{emissions} \quad (2)$$

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

Corrective maintenance costs

The corrective maintenance cost (C_{CM}) [€] can be estimated by the product of the failure rates (F_{total}) 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.

Due to the lack of data concerning larger turbines to support the study, for minor and major repair, was considered the same spare parts costs ($Cost_{parts}$)as presented by [6], 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 [6] and [29] for equipment replacement cost estimation. The cost of repair ($Cost_{repair}$) [€] at site per failure can be estimated by:

$$Cost_{repair}=Cost_{parts}+(Technicians \times Cost_{personnel} \times Days) \quad (3)$$

The estimative of conventional charter rates were based on [17], [18] and [30]. 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.

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.

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. [31]presents a projected fuel cell cost over the years.

To size the liquid hydrogen (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. 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.

The expenditures for the considered PEM fuel cell system, considering the stacks, Electric Motor, Power Conditioning System, H_2 Tank, recpective installation, lifetime and efficiency, as well as maintenance, were based on several sources as [31], [32], [33] and [34].

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 [32]. 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 [34].

With that, an increase on charter rate by 46%, 13%, 10% and 88% in comparison to conventional CTV, SOV, jack-up and AHTS, respectively, was estimated.

Fuel costs

Costs associated with fuel consumption per operation (Total $\mathrm{cost_{fuel}}$) [€] 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 t and from the site to attend the turbines and, specifically for SOVs, for 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.

It was considered that due to operational constraints SOV is available on site 90% [35] of the leasing period (360 days).

$$\begin{aligned}\mathrm{Cost_{fuel_{transit}}} &= \mathrm{Cons_{transit}} \times \mathrm{Time_{transit}} \times Price_{\mathrm{fuel}} \\ &+ 360\times24\times0.9\times\left[\mathrm{Cons_{transit}}\times\mathrm{Time_{transit_{port}}}\times Price_{\mathrm{fuel}}\right]_{\mathrm{SOV_{BAU_{CT}}}} \\ &+ \left[\mathrm{Cons_{transit}}\times\mathrm{Time_{transit_{station}}}\times Price_{\mathrm{fuel}}\right]_{\mathrm{SOV_{HB}}}\end{aligned} \tag{4}$$

$$\begin{aligned}\mathrm{Cost_{fuel_{op}}} &= \mathrm{Cons_{op}}\times\big(\mathrm{Time}_{disconnect}+\mathrm{Time}_{repair}+\mathrm{Time}_{connect} \\ &+ \mathrm{Time}_{waiting}\big)\times Price_{\mathrm{fuel}} \\ &+ \left[\mathrm{Cons_{op}}\times\mathrm{Time}_{loitering}\times Price_{\mathrm{fuel}}\right]_{\mathrm{SOV}}\end{aligned} \tag{5}$$

$$\mathrm{Cost_{fuel}} = \mathrm{Cost_{fuel_{transit}}} + \mathrm{Cost_{fuel_{op}}} \tag{6}$$

According to [2], 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 (Emissions) [t] were estimated according to the operational profile of each vessel type and the fuel used.

$$\begin{aligned}\mathrm{Emission_{fuel_{transit}}} &= \mathrm{Cons_{transit}}\times\mathrm{Time_{transit}}\times\mathrm{Emission_{fuel}} \\ &+ 360\times24\mathrm{x}0.9\times\left[\mathrm{Cons_{transit}}\times\mathrm{Time_{transit_{port}}}\times\mathrm{Emission_{fuel}}\right]_{\mathrm{SOV_{BAU_{CT}}}}\end{aligned} \tag{7}$$

$$\begin{aligned}\mathrm{Emission_{fuel_{op}}} &= \mathrm{Cons_{op}}\times\big(Time_{disconnect}+\mathrm{Time}_{repair}+\mathrm{Time}_{connect} \\ &+ Time_{waiting}\big)\times\mathrm{Emission_{fuel}} \\ &+ \left[\mathrm{Cons_{op}}\times\mathrm{Time}_{loitering}\times\mathrm{Emission_{fuel}}\right]_{\mathrm{SOV}}\end{aligned} \tag{8}$$

$$\mathrm{Emissions} = \mathrm{Emission_{fuel_{transit}}} + \mathrm{Emission_{fuel_{op}}} \tag{9}$$

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

$$\mathrm{Cost_{emissions}} = \mathrm{Emissions}\times\mathrm{Price_{ETS}} \tag{10}$$

Mobilisation costs

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. To simply this model adopted a fixed value for mobilisation cost for jack-up and AHTS, based on [18] and [17]

Refuelling station costs

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 maintenance expenses, and loss of energy due to electricity demanded to produced hydrogen to refuel the vessels. The model considered the main station drivers of CAPEX and OPEX, namely electrolyser, compressor, battery, AC cable to platform, AC/DC converter, water desalination, central electrolyser platform, system replacement and hydrogen pipeline, which costs were based on [36].

The electric capacity of the electrolyser ($Elec_{cap}$) was dimensioned to be 80% of the wind farm nominal capacity [36].

CAPEX and OPEX of offshore refuelling stations are significantly higher than for the onshore scenario, representing a difference of 48% and 33%, respectively, between offshore and onshore station, as shown in Table 3.

Table 3 - CAPEX and OPEX of Hydrogen Offshore and Onshore refuelling station

	Offshore	Onshore
$\mathbf{CAPEX_{station}}$	1050.00 M€	545.94 M€
$\mathbf{OPEX_{station}}$	21.52 M€	14.38 M€

Energy production

The estimation of the annual energy production (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.

By analogy of the cumulative distribution function (CDF) of a Weibull distribution, with the shape parameter (k) and the scale parameter (b) the power generated by a wind turbine P in function of the wind speed (U) [m/s] can be expressed as:

$$P(U)=P_{max} \times \left(1-e^{-\left(\frac{U}{b}\right)^{k}}\right) \qquad (11)$$

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 ($Power_{turbine}$)[MWh], according to the turbine power curve and considered related losses. The total power produced by the wind farm corresponds to Total $Power_{ele}$.

$$Power_{turbine} = \sum_{t=1}^{n} P(U_t) \times \left[(1\text{-}Loss_{ele})+Loss_{wake}+Loss_{blockage}\right] \qquad (12)$$

$$\text{Total } Power_{ele}=N_{turbines}\times Power_{turbine} \qquad (13)$$

The electric loss ($Loss_{ele}$) 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% ($Loss_{wake}$). The blockage loss ($Loss_{blockage}$), is caused by the induction of a reduction of the upstream wind speed during the energy extraction, but in this model was not considered (0%).

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 ($Power_{H2}$) [MWh], depends on electricity price ($Price_{ele}$) [€/MWh] given by the forecasted hourly spot market electricity, as well hydrogen market price ($Price_{H2}$) [€/MWh] (15), assuming the minimum between the electrolyser production capacity ($Elec_{cap}$) and the wind farm production ($WF_{production}$), while the remaining electricity ($Power_{ele}$) [MWh] is directed to the grid (16).

$$Price_{H2} = \frac{Price_{H2retail} \times Efficiency_{H2}}{Density_{H2}} \qquad (14)$$

$$\begin{cases} Power_{H2}=\mathrm{Min}\left(Elec_{cap};WF_{production}\right); & Price_{ele}\leq Price_{H2} \\ Power_{H2}=0 & ; \; Price_{ele}>Price_{H2} \end{cases} \qquad (15)$$

$$Power_{ele}=\text{Total } Power_{ele} - Power_{H2} \qquad (16)$$

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 of 5.42 £/kg (offshore centralised PEM system) and 5.24 £/kg (onshore PEM system) [36]. The efficiency of the electrolyser technology was estimated as 64% [36] .

Considering lifetime (t) equal to 25 years and the discount rate (i) to 8%, and calculating the LCOH using similar approach as to LCOE, the hydrogen production cost is 5.1 €/kg and 4.7 €/kg for offshore and onshore scenarios, respectively.

Levelized cost of energy

Analysing the hydrogen-based scenario, $CAPEX_{station}$ and $OPEX_{station}$ of the refuelling station must be contemplated either 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% [24] [22]or the BAU and Carbon taxes scenarios, the nominal discount rate (i) was considered 6% [23] while for the Hydrogen-based as 8% [36]. 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:

$$LCOE=\frac{\sum_{t=1}^{n}\frac{CAPEX_{total_t}+OPEX_{total_t}}{(1+i)^t}}{\sum_{t=1}^{n}\frac{E_{final_t}}{(1+i)^t}} \qquad (17)$$

$$CAPEX_{total}=CAPEX_{osw}+CAPEX_{station}\ ; \quad CAPEX_{station}=0 \text{ if scenario} \neq HB \qquad (18)$$

$$OPEX_{total}=OPEX_{osw}+OPEX_{station}\ ; \quad OPEX_{station}=0 \text{ if scenario} \neq HB \qquad (19)$$

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

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 1 and Figure 2 present a summary of the main results obtained.

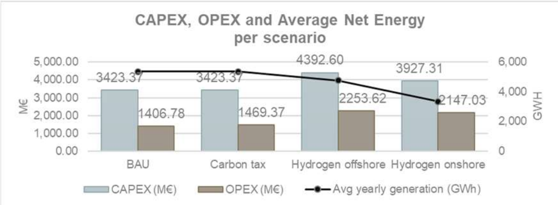

Figure 1 - CAPEX, OPEX and Average net energy per scenario

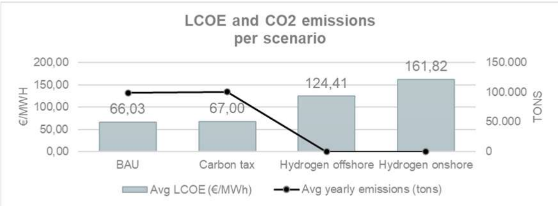

Figure 2 - LCOE and COs emissions per scenario

The annual OPEX obtained for the BAU scenario is around 89 €/kW, which is approximately 2% higher than the reference presented by [23] 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.

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 H2 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 2. Meanwhile, the annual emissions are reduced to zero when moving to the hydrogen scenario, considering the vessels operations.

The share of OPEX shown by the model is 29%, 30%, 40% and 39% for BAU, Carbon tax, Hydrogen Offshore and Hydrogen Onshore scenarios, respectively. 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 total 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.

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.

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 by [37], 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.

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. 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.

Despite the slight variation in the mean wind speed on-site, 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. By this analysis, is possible to notice that LCOE is highly impacted by the waiting time and 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.

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. The production of fuel cells in mass, should help 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. Considering a more conservative scenario and the trend of cost reduction presented by [31], variations of 10%, 20% and 30% were considered.

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.

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.

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 challenger 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. 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 4% to 13%, in both cases, leading also to a meaningful LCOE drop, by around 2% to 6.8%.

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 lowering 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.

Operational constraints

Operational constraints, especially, wave height and wind speed are fundamental to offshore access and maintenance tasks since they will affect the waiting time. 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 system (passive or active systems). 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.

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 and conclusion

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 total 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 a LCOE 85.7% and 141.5% lower comparing to the offshore and onshore scenario, 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 OPEX 60.2% and 53.4% higher than BAU and carbon scenario respectively, while the onshore operational costs are 52.6% and 46.1% higher.

Despite the higher CAPEX and OPEX, the 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.

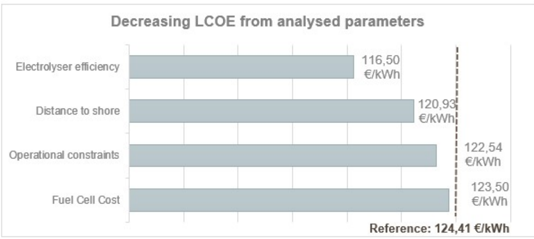

Figure 3 - Decrease of LCOE through sensitivity analysis parameters

Hydrogen would not be competitive without further set of 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 [36], in around 54% and 29% respectively.

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.

The ETS and ETD should ensure emission reductions in the sector. Meanwhile, as mentioned by the [2], 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 [38].

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

From the presented study is clear that 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. 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.

To obtain more realistic results, a future model should assess more updated and adequate data on turbine failures with power, operating characteristics vessel 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.

9- References

[1] International Maritime Organization (IMO), “Adoption of the Initial IMO Strategy on Reduction of GHG Emissions From Ships and Existing Imo Activity Related To Reducing Ghg Emissions in the Shipping Sector,” *Mepc 72*. p. 27, 2018. Accessed: Mar. 26, 2021. [Online]. Available: https://unfccc.int/sites/default/files/resource/250_IMO submission_Talanoa Dialogue_April 2018.pdf

[2] European Commission, “Regulation of the European Parliament and of the Council on the use of renewable and low-carbon fuels in maritime transport and amending Directive 2009/16/EC,” vol. 0210. p. 247, 2021. Accessed: Oct. 05, 2021. [Online]. Available: https://ec.europa.eu/info/sites/default/files/fueleu_maritime_-_green_european_maritime_space.pdf

[3] A. Gray, “What are operations and maintenance simulation tools? An explanation of O&M models in the offshore renewable energy sector,” no. August, pp. 1–11, 2020, [Online]. Available: https://ore.catapult.org.uk/analysisinsight/what-are-operations-and-maintenance-simulation-tools/

[4] G. Calado and R. Castro, “Hydrogen Production from Offshore Wind Parks: Current Situation and Future Perspectives,” *Applied Sciences*, vol. 11, no. 12, p. 5561, 2021, doi: 10.3390/app11125561.

[5] Dogger Bank, “Dogger Bank Wind Farm.” https://doggerbank.com/about/ (accessed Jun. 21, 2021).

[6] J. Carroll, A. Mcdonald, and D. Mcmillan, “Failure rate, repair time and unscheduled O&M cost analysis of offshore wind

turbines," *Wind Energy*, vol. 19, pp. 1107–1119, 2015, doi: 10.1002/we.1887.

[7] G. Schepers, A. Pena, A. Ely, and A. Palomares, "EERA DTOC calculation of scenarios," no. June, pp. 1–130, 2015.

[8] D. Clayton, "Wind Turbine Spacing: How Far Apart Should They Be?," *Energy Follower*, 2021. https://energyfollower.com/wind-turbine-spacing/ (accessed Aug. 20, 2021).

[9] LAUTEC, "ESOX Metocean Data." https://esox.lautec.com/map/ (accessed Aug. 04, 2021).

[10] R. T. Walker, J. van Nieuwkoop-Mccall, L. Johanning, and R. J. Parkinson, "Calculating weather windows: Application to transit, installation and the implications on deployment success," *Ocean Engineering*, vol. 68, pp. 88–101, 2013, doi: 10.1016/j.oceaneng.2013.04.015.

[11] A. Gray, B. Dickens, T. Bruce, I. Ashton, and L. Johanning, "Reliability and O&M sensitivity analysis as a consequence of site specific characteristics for wave energy converters," Elsevier Ltd, 2017. doi: 10.1016/j.oceaneng.2017.06.043.

[12] A. Gray, H. MacDonald, and N. Avanessova, "Periscope Network," 2021. [Online]. Available: https://periscope-network.eu/sites/default/files/2021-03/Periscope O%26M case study.pdf

[13] T. Elusakin, M. Shafiee, T. Adedipe, and F. Dinmohammadi, "A Stochastic Petri Net Model for O&M Planning of Floating Offshore Wind Turbines," *Energies*, vol. 14, no. 1134, 2021, doi: https://doi.org/10.3390/en14041134.

[14] S. Faulstich, B. Hahn, and P. J. Tavner, "Wind turbine downtime and its importance for offshore deployment," *Wind Energy*, vol. 14, no. 3, pp. 327–337, 2011, doi: 10.1002/we.421.

[15] B. Le and J. Andrews, "Modelling wind turbine degradation and maintenance," *Wind Energy*, vol. 19, pp. 571–591, 2016, [Online]. Available: https://onlinelibrary.wiley.com/doi/epdf/10.1002/we.1851

[16] J. Warnock, D. McMillan, J. Pilgrim, and S. Shenton, "Failure rates of offshore wind transmission systems," *Energies*, vol. 12, no. 14, pp. 1–12, 2019, doi: 10.3390/en12142682.

[17] A. Gray, "Setting a Benchmark for Decarbonising O&M Vessels of Offshore Wind Farms," 2021. Accessed: Apr. 06, 2021. [Online]. Available: https://ore.catapult.org.uk/analysisinsight/setting-benchmark-decarbonising-om-vessels-offshore-wind-farms/?utm_campaign=Analysis %26 Insight&utm_content=155090544&utm_medium=social&utm_source=linkedin&hss_channel=lcp-3318975

[18] A. Dewan and M. Asgarpour, "Reference O&M Concepts for Near and Far Offshore Wind Farms," *Ecn-E-16-055*, no. December. p. 49, 2016.

[19] ORE Catapult, "Service Operating Vessel Logistics at Dudgeon Offshore Wind Farm Owner-led selection, setup, and early experience in use," no. May, pp. 1–12, 2017.

[20] Y. Dalgic, I. Lazakis, and O. Turan, "Investigation of optimum crew transfer vessel fleet for offshore wind farm maintenance operations," *Wind Engineering*, vol. 39, no. 1, pp. 31–52, 2015, doi: 10.1260/0309-524X.39.1.31.

[21] A. Dewan, "Logistic & Service Optimization for O&M of Offshore Wind Farms," 2013. [Online]. Available: https://repository.tudelft.nl/islandora/object/uuid:cd8d6a48-e469-4fc2-becc-c5c1153f6522/datastream/OBJ/download

[22] A. Ioannou, A. Angus, and F. Brennan, "A lifecycle techno-economic model of offshore wind energy for different entry and exit instances," *Applied Energy*, vol. 221, no. November 2017, pp. 406–424, 2018, doi: 10.1016/j.apenergy.2018.03.143.

[23] The Crown Estate, "A Guide to an Offshore Wind Farm," *Power*, no. April, pp. 1–70, 2010, [Online]. Available: http://www.thecrownestate.co.uk/guide_to_offshore_windfarm.pdf

[24] T. Stehly, P. Beiter, and P. Duffy, "2019 Cost of Wind Energy Review," 2020. [Online]. Available: https://www.nrel.gov/docs/fy21osti/78471.pdf

[25] S. Lundberg, "Performance comparison of wind park configurations," 2003. [Online]. Available: https://core.ac.uk/download/pdf/70559221.pdf

[26] K. Kabbabe Poleo, W. J. Crowther, and M. Barnes, "Estimating the impact of drone-based inspection on the Levelised Cost of electricity for offshore wind farms," *Results in Engineering*, vol. 9, p. 100201, 2021, doi: 10.1016/j.rineng.2021.100201.

[27] Ship & Bunker, "World Bunker Prices." https://shipandbunker.com/prices#MGO (accessed Aug. 17, 2021).

[28] IEA Bioenergy, "Biofuels for the marine shipping sector: An overview and analysis of sector infrastructure, fuel technologies and regulations," 2017. [Online]. Available: https://www.ieabioenergy.com/wp-content/uploads/2018/02/Marine-biofuel-report-final-Oct-2017.pdf

[29] T. Ashuri, M. B. Zaaijer, J. R. R. A. Martins, and J. Zhang, "Multidisciplinary design optimization of large wind turbines - Technical, economic, and design challenges," *Energy Conversion and Management*, vol. 123, no. June, pp. 56–70, 2016, doi: 10.1016/j.enconman.2016.06.004.

[30] Y. Dalgic, I. Lazakis, and O. Turan, "Vessel charter rate estimation for offshore wind O&M activities," 2013. doi: 10.1201/b15813-113.

[31] C. Raucci, "The potential of hydrogen to fuel international shipping," 2017. [Online]. Available: https://discovery.ucl.ac.uk/id/eprint/1539941/

[32] N. Saito, "The economic analysis of commercial ships with hydrogen fuel cell through case studies," *The Maritime Commons : Digital Repository of the World Maritime*, 2018.

[33] D. Papadias, R. K. Ahluwalia, E. Connelly, and P. Devlin, "Total Cost of Ownership (TCO) Analysis for Hydrogen Fuel Cells in Maritime Applications," *Argonne National Laboratory*, 2019.

[34] KPMG, "Valuing ships the LTAV approach," 2020. [Online]. Available: https://assets.kpmg/content/dam/kpmg/qa/pdf/2020/1/valuing_ships_the _ltav_approach_kpmg_qatar.pdf

[35] Power and Energy Solutions, "Small vessels for large waves. The daughter craft for wind farms far from shore." [Online]. Available: https://cdn.pes.eu.com/v/20180916/wp-content/uploads/2020/10/PES-W-2-20-ESNA-1.pdf

[36] A. Spyroudi, D. Wallace, G. Smart, K. Stefaniak, S. Mann, and Z. Kurban, "Offshore Wind and Hydrogen: Solving the Integration Challenge," 2020. [Online]. Available: https://ore.catapult.org.uk/wp-content/uploads/2020/09/Solving-the-Integration-Challenge-ORE-Catapultr.pdf

[37] M. Martini, R. Guanche, I. J. Losada, and C. Vidal, "Accessibility assessment for operation and maintenance of offshore wind farms in the North Sea," *Wind Energy*, vol. 20, no. 4, pp. 637–656, Apr. 2017, doi: 10.1002/we.2028.

[38] European Comission, "Council directive restructuring the Union framework for the taxation of energy products and electricity (recast)," 2021.