Revised Manuscript with No Changes Marked

Click here to access/download;Revised Manuscript with No Changes Marked;Clean 2nd Reviewed Manuscript -

Click here to view linked References

Incorporating stochastic operation and maintenance models into the techno-economic analysis of floating offshore wind farms

Giovanni Rinaldi [1,*], Anna Garcia-Teruel [2,*], Henry Jeffrey [2], Philipp R. Thies [1] and Lars Johanning [1,3]

[1] Renewable Energy group at the University of Exeter, Penryn Campus, Treliever Road, TR109FE, Penryn, Cornwall, UK; g.rinaldi@exeter.ac.uk, p.r.thies@exeter.ac.uk, l.johanning@exeter.ac.uk
[2] School of Engineering, Institute for Energy Systems, The University of Edinburgh, Edinburgh EH9 3JG, UK; A.Garcia-Teruel@ed.ac.uk, H.Jeffrey@ed.ac.uk
[3] Harbin Engineering University, Yiman St, Nangang, Harbin, Heilongjiang, China
* Corresponding authors: Giovanni Rinaldi, g.rinaldi@exeter.ac.uk; Anna Garcia-Teruel, A.Garcia-Teruel@ed.ac.uk

Abstract

Floating offshore wind is rapidly gaining traction in deep water locations. As with all new technologies, to gain the confidence of developers and investors, the technical and economic feasibility of this technology must be proven and robust cost estimates are necessary. In this paper, the authors present a methodology to calculate the capital and operational indicators of a floating wind farm over its project lifetime. A set of computational models is used to reduce the uncertainties in the estimation of the technical and economical parameters. In particular, the effect of using detailed operation and maintenance models and strategies allows a better estimation of operational cost. The paper highlights the requirements and specific adjustments considered for floating offshore wind technology. The methodology is demonstrated for two case studies inspired by real floating wind installations in the United Kingdom, namely the Hywind and Kincardine projects. The related input data, gathered from publicly available sources, constitute a reference database for future studies in the floating offshore wind sector. Results are presented for the two case studies. These show that availability and energy production are in line with typical values for offshore wind projects, and highlight the substantial contribution of operational expenses to the cost of energy. Results are also compared against previous estimations for floating offshore wind projects, showing satisfactory agreement for the overall project costs but an underestimation of operation and maintenance costs in previous studies. This highlights the importance of using detailed operation and maintenance models to adequately capture operational expenses.

Highlights:

- Methodology for capital and operational indicators estimation is presented
- Introducing stochastic operation and maintenance modelling for uncertainty reduction
- Reference database for further works on floating wind farms provided
- Results shows agreement with observed values for offshore wind projects
- Comparison against previous work shows underestimation of operational costs

Keywords: Offshore renewable energy, floating wind, LCOE, O&M.

List of abbreviations, units and nomenclature

n = Lifetime [years]

r = Discount rate [%]

t = Expense year [-]

AEP = Annual Energy Production [MWh]

AHTS = Anchor Handling Tug Supply

CapEx = Capital Expenditures [£]

CfD = Contracts for Difference

CoE = Cost of Energy [£/MWh]

CTV = Crew Transfer Vessel

DecEx = Decommissioning Expenditures [£]

FLOW = Floating Offshore Wind

FSV = Field Support Vessel

HLV = Heavy-Lift Vessel

IRR = Internal Rate of Return [%]

KPI = Key performance indicator

LCoE = Levelised Cost of Energy [£/MWh]

NPV = Net Present Value [£]

O&M = Operation and maintenance

OpEx = Operational Expenditures [£]

ORE = Offshore renewable energy

OWT = Offshore wind turbine

PV = Present Value [£]

---

1. Introduction

Floating Offshore Wind (FLOW) is expected to provide a significant contribution to the renewable energy sector, with WindEurope envisaging EU projections of 7 GW to be installed by 2030 [1]. This technology presents numerous advantages with respect to bottom-fixed offshore wind devices [2,3]. Firstly, it unlocks the exploitation of deep-water sites (> 60m), where fixed foundations would not be economically feasible. This might also enable the use of locations with better wind resource or less usage conflicts, e.g. minor visual or social impacts. In other words, FLOW can open new markets and expand the Offshore Renewable Energy (ORE) potential. Secondly, the use of a floating platform also allows for a reduction of the operations at sea, typically characterised by higher costs and constrained by weather conditions. If suitable infrastructure is available, major installation and maintenance procedures can be carried out directly in port, which provides a safer and more controlled environment. The device can then be towed to the offshore location using less expensive vessels. Thus, the prospective opportunity provided by FLOW is noteworthy.

Nonetheless, being a novel technology, a number of economic and technical challenges exist [4]. Among the most relevant are: the creation of quick connection systems for the devices, the operation in potentially harsher conditions, the adaptation of the Offshore Wind Turbine (OWT) and related components to a more dynamic environment, and the availability of suitable port facilities. These challenges and the limited experience, in turn, lead to a significant uncertainty in regard to the Key Performance Indicators (KPIs) used for the comparison of different FLOW technologies and projects. To some extent, the KPIs are a way of quantifying the success of a project. Hence, if estimated in advance, these allow the identification of strengths and weaknesses of the proposed plan, and point towards possible areas of improvement.

A commonly used KPI to compare energy generating technologies is the Levelised Cost of Energy (LCoE). This has previously been studied for bottom-fixed offshore wind deployments [5], as well as floating offshore wind deployments [6,7], where comparisons between the two technologies have also been performed [8,9] based on this measure, as well as using other economic indicators such as the Net Present Value (NPV). The current LCoE for FLOW has been assessed to be around 176 £/MWh and a cost reduction to up to 72 to 93 £/MWh for commercial technologies is envisaged [1]. Recently, developers have been predicting cost reductions of their technologies down to 53 £/MWh by 2030 [2]. This wide range of the expected cost reductions stems from the different assumptions used in the different studies for the LCoE calculation [3]. Key factors were evaluated in a thorough sensitivity study by Lerch et al. in [7], amongst which are the annual energy production and lifetime of the systems and financial parameters such as the discount rate, but also the assumptions used to consider installation as well as operation and maintenance activities. For this reason, other, more specific KPIs that break down the different considerations and assumptions used within the calculation of the LCoE can support technology comparison. A thorough and reliable assessment of the KPIs would not only increase the confidence in the viability of a project or technology, but it would also provide valuable support in the decision-making process. This is especially relevant in regard to logistics and assets management, where very little experience exists and often oversimplified approximations are used in techno-economic assessment models. In previous techno-economic studies for ORE technologies, Operational Expenditures (OpEx) have been often considered as a percentage of the overall Capital Expenditures (CapEx) [10] or using simplified representations of the O&M operations by assuming a given number of minor and major repairs over the project life [6,7]. In previous offshore wind studies commercial models have been often used to estimate the operational expenses, such as in [8,11]. In [11] Artificial Neural Networks were used to approximate O&M model outputs by generating a range of results from the deterministic O&M model. Subsequently, it assessed the impact of the variation in total OpEx and net power production on the Net Present Value (NPV) of a bottom-fixed offshore wind project. Stochastic cost distributions have also been estimated for floating offshore wind projects, where in [12] a sensitivity study on NPV results was presented. Stochastic distributions for different parameters such as the electricity price or the cost of the offshore wind turbine were approximated by assuming triangular distributions and a 15% variation around the mean value. Although statistic distributions can be assumed around deterministic results, the use of detailed O&M models and the stochastic insights they can provide have not been fully exploited yet. These include, for example, the use of OpEx and net annual energy production distributions calculated taking into account the stochastic nature of O&M calculations accounting for weather windows and vessel availability. The aim of this study is to demonstrate the added value of using detailed O&M models that can provide stochastic foundations for important operational insights into the techno-economic assessment of floating offshore wind technologies and projects.

The gaps found in literature are addressed here, in presenting and demonstrating a methodology to obtain more accurate techno-economic assessments of FLOW farms over their project lifetime. This methodology relies on a set of computational models, previously verified with ORE projects [13–16] and now specifically adapted for FLOW, to reduce the uncertainties in the estimation of the technical and economical parameters of the project. Employing advanced O&M tools within the techno-economic model enables assessing the impact of applying different O&M strategies on the overall costs. Additionally, this allows to better understand the sources of different costs and to identify key cost drivers such as critical operation and maintenance procedures and components whose reliability characteristics should be improved within the context of minimising the overall system costs. Finally, the impact of using advanced O&M models to quantify OpEx versus employing simplified representations of OpEx on the total costs will be discussed. This, in turn, will help to understand the sensitivity of the total costs to the level of detail used in the representation of OpEx. The intention is to show not the accuracy of the models in predicting the KPIs of the case studies, nor to perform a sensitivity analysis on the input data as shown in [17] for O&M models and in [7] for LCoE models, but the use of purpose-built computational models as opposed to OpEx approximations.

The use of this methodology is demonstrated for two case studies, inspired by (but not entirely reflecting) existing FLOW projects currently under development in the United Kingdom, namely the Hywind Scotland [18] and Kincardine Phase 2 [19] farms. An extensive set of input data is required to run both models. Due to the industrial nature of both projects, part of this data is either confidential or difficult to retrieve. As a consequence, only information extracted from publicly available sources has been exploited for all subsequent modelling tasks. This has been complemented with appropriate assumptions, according to experts' elicitation and engineering judgment, when suitable sources could not be found. All the data gathered for the two case studies and related sources are reported in the dedicated sections, with additional details available upon request to the corresponding authors. Thus, a second important contribution of this work consists in the publication of a comprehensive dataset, including failure rates and cost data that can be used as a reference database for future modelling works in the FLOW sector.

The remainder of the paper is organised as follows. In section 2, the methodology employed to obtain the LCoE and OpEx estimations, in terms of the numerical models used for the calculations and their working principles, is described. Here, specific adjustments for the assessment of FLOW technology are highlighted. In section 3, input data and modelling assumptions are presented for each of the two case studies chosen to demonstrate the methodology. These are provided in terms of the numerical parameters needed to effectively define the FLOW project and to carry out the techno-economic assessment. In section 4, the outcomes of the simulations are provided regarding the expected performance of the two farms. In this regard, it must be noticed that the direct comparison between the two fictitious case studies is not one of the aims of this work. Finally, in section 5, the wider implications of using the proposed approach are discussed and conclusions are drawn in section 6.

2. Methodology

This work seeks to estimate KPIs for the techno-economic assessment of a FLOW farm. The methodology relies, on a set of numerical models to reproduce the mechanisms and constraints that simulate the lifecycle of an ORE farm. Two models are coupled to this end. The first one, hereinafter called "Cost model", is used to calculate the economic indicators of the farm taking into account the cost occurring over the whole project lifetime. The second one, hereinafter called "O&M model", is a validated tool used to simulate the operation and maintenance (O&M) activities of the farm over the operational time, and characterise the performance of the ORE farm in terms of its Reliability, Availability and Maintainability (RAM).

Within this work, outputs from the O&M model are used to reduce the number of assumptions on the inputs for the Cost model. The Annual Energy Production (AEP) and OpEx values calculated with the O&M model are used in the cost model for the calculation of LCoE and other economic indicators. More in detail, the O&M model provides both mean values and probability distributions, and the Cost model was adapted to be able to provide both single values estimates and distributions of LCoE values based on distributions of the O&M model outputs. A summary of the interactions between the Cost and O&M models is illustrated in Figure 1. For consistency the two models use the same dataset, but exploit different aspects of the input data. For example, inputs regarding the reliability of the devices or the properties of the maintenance vessels are used only in the O&M model, while inputs concerning the physical characteristics of the components are used only in the Cost model. Component cost data are exploited by both models. The detailed working principles of the two models are presented in the following two sub sections.

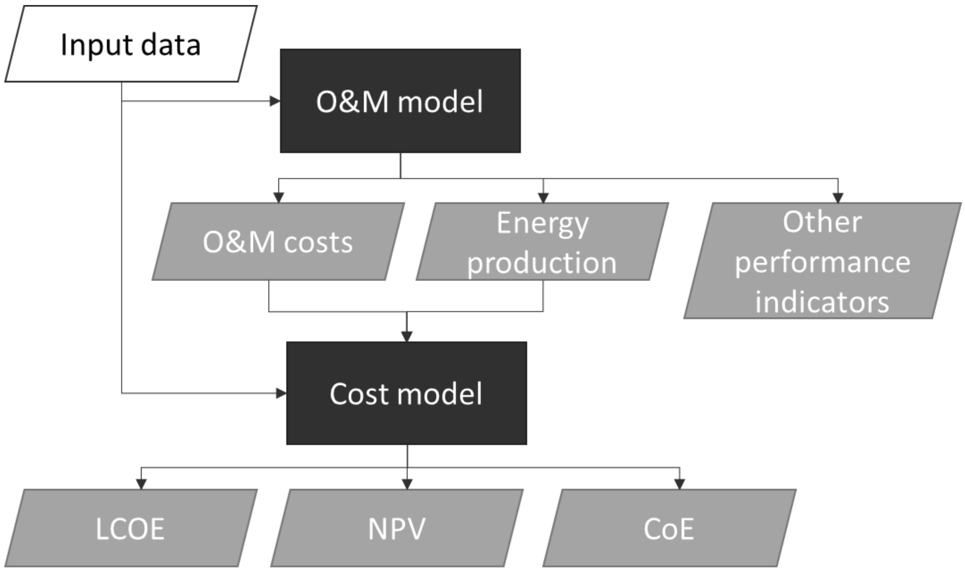


Figure 1. Overview and relationship of Input data, Cost and O&M models.

2.1. Cost model

Floating offshore wind technologies are still being developed, and often techno-economic analysis of innovative concepts aims at understanding their economic potential to find the most suitable solutions. It was suggested in [20], that different cost measures will be more suitable to compare innovative technologies with the goal of selecting the best designs, rather than to compare different possible project deployments. In that study, the Cost of Energy (CoE) was recommended for the former, whereas the Levelised Cost of Energy (LCoE) was preferred for the latter. Since the two case studies discussed here are inspired by two specific project deployments of innovative technologies, various metrics, including these two, will be calculated to provide reference values for future studies and allow comparison between techno-economic studies.

Independently of the used metric, a Life-Cycle Cost Analysis (LCCA) is performed, where the costs associated with the whole life-cycle of an offshore wind project are considered. The project life-cycle is divided into five phases: i) Development and Consenting (D&C), ii) Production and Acquisition (P&A), iii) Installation and Commissioning (I&C), iv) Operation and Maintenance (O&M) and v) Decommissioning and Disposal (D&D). The costs associated to the first three phases are categorised as Capital Expenditures (CapEx). The fourth phase is associated to the Operational Expenditures (OpEx), which here are obtained from the O&M model, and the fifth phase is associated to the Decommissioning Expenditures (DecEx). It is important to define the system boundary of the analysis. In this paper all systems up to and including the onshore substation are considered.

The cost model has been implemented in Python and three economic indicators are calculated [21]:

1. *Levelised Cost of Energy (LCoE)* is a measure commonly used to compare energy generating technologies, which represents the ratio of the costs incurred over the lifetime n of a project in relation to the cumulative Annual Energy Produced (AEP) over the operational life. The LCoE is calculated as shown in equation (1). The Present Value (PV) of the total costs and the energy production over the

lifetime of the project are taken into account. The calculation of the PV follows equation (2) where r is the discount rate, n the lifetime and t the year in which the expense occurs.

$$LCoE = \frac{PV(CapEx + OpEx + DecEx)}{PV(AEP)} \quad (1)$$

$$PV(x) = \sum_{t=0}^{n} \frac{x_t}{(1+r)^t} \quad (2)$$

2. *Net Present Value (NPV)* of all cash flows considers the sale of produced electricity at the market strike price. The NPV value represents the profitability of a project, where a positive value means the project is profitable. It is understood as the equivalent of the PV when taking into account, both, inflows, such as the revenue from selling the generated electricity, and outflows, such as all of the costs considered in the PV calculation.

$$NPV(x) = \sum_{t=0}^{n} \frac{Cash\, flows_t}{(1+r)^t}$$

3. *Cost of Energy (CoE)* is calculated as the LCoE but without accounting for any type of discounting. The discount rate and investment schedule, i.e. when each of the costs occur, are highly project dependent and have a large impact on the final cost estimates [20]. A definition of a 'risk levy' associated to different floating offshore wind technologies represented within the discount rate is also subject to large uncertainties. Including discounting might, therefore, introduce additional unnecessary uncertainty when comparing the suitability of different technologies (rather than projects).

2.2. O&M model

The second computational model used in this investigation is the UNEXE O&M tool, a performance characterisation model described in [22,23]. The validation is performed in [16] and further examples of its utilisation are presented in [24]. This model employs a time-domain approach based on the Markov Chain Monte Carlo technique [25–27], an established and widely used methodology for the simulation of O&M problems. This method permits to effectively consider all the necessary aspects that define the dynamics of a FLOW farm, including external factors, e.g. environmental conditions, logistics, spare parts and maintenance vessels.

The working principle of the O&M model is illustrated in Figure 2. Starting from the met-ocean data of the location selected for the farm deployment, the specifications of the project are added in terms of the installed devices (including details about their power performance and constituent components) and operational strategy (including corrective and preventive maintenance as well as maintenance assets). In order to achieve a high level of detail, a number of inputs is required. The details of these input data are provided through the case studies described in section 3. To obtain statistically significant outputs, according to the Monte Carlo method the same simulation is run for a sufficient number of times (according to the variance of the outputs or based on previous experiences with similar scenarios). Each of these runs simulates the operational lifetime of the ORE farm taking into account all the mechanisms and constraints defined by the user. Once the simulations are completed, a series of results describing the farm performance (i.e. KPIs) are obtained. These include energy production accounting for downtime, availability, revenue and overall O&M costs, but also more detailed information such as the number of failures per component or the hours of operation of each vessel. The results contain the full statistical distribution of each parameter, including mean value, standard deviations and confidence bounds. These results permit the identification of underlying problems in the operation of the ORE farm, and, if needed, the proposal of corrective measures. As such, this model provides support in the decision-making process required for the successful management of a project. Lastly, statistical indicators, such as exceedance probabilities and progressive average values over the simulations, can be analysed to evaluate the level of confidence on the results obtained. This allows to take into account the elements of stochasticity related to both the met-ocean environment and the reliability of the components of the device, as graphically summarised in Figure 3.

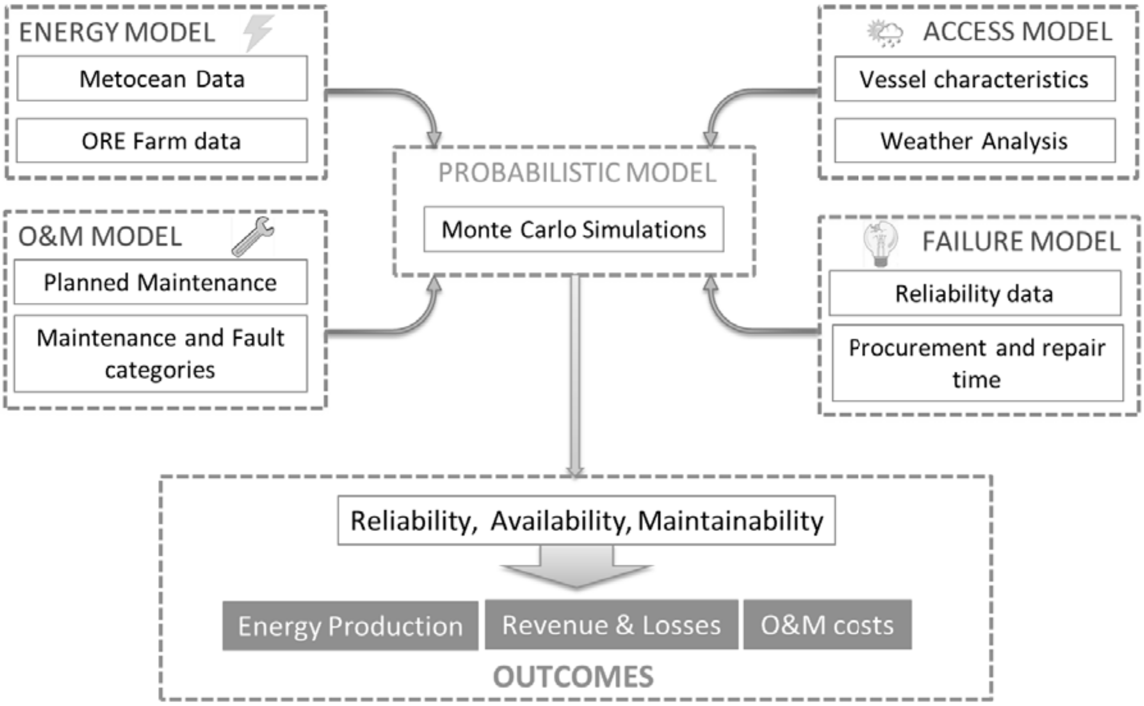


Figure 2. Working principle of the UNEXE O&M characterisation model used in this work. Adjusted from [23].

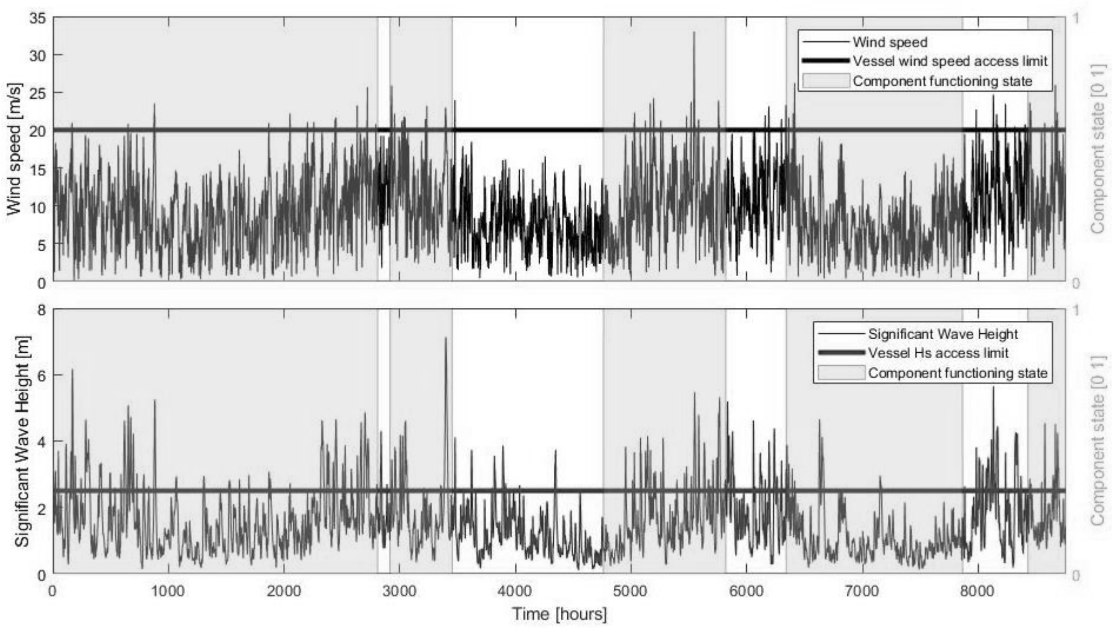


Figure 3. Visual representation of the stochastic elements taken into account by the model, including met-ocean resource and components reliability. The latter is indicated with a state of 1 (functioning component, green) or 0 (failed component, white).

3. Case studies description

In order to consider a scenario which is representative of real projects, this work is inspired by two existing ORE farms installed as demonstration clusters for FLOW technologies. These are the Hywind and Kincardine pilot parks, both being developed off the East coast of Scotland in the UK, as shown in Figure 4. Given the relatively short distance between these two parks, an offshore location located half-way between these two farms, indicated with a red dot in this figure, is selected as the hypothetical location for both cases studies. This section provides an overview of the input data and assumptions retrieved to set up the numerical models. The data specific to each case study are provided first, while general assumptions and other input data related to both case studies are provided in the following sub-sections.

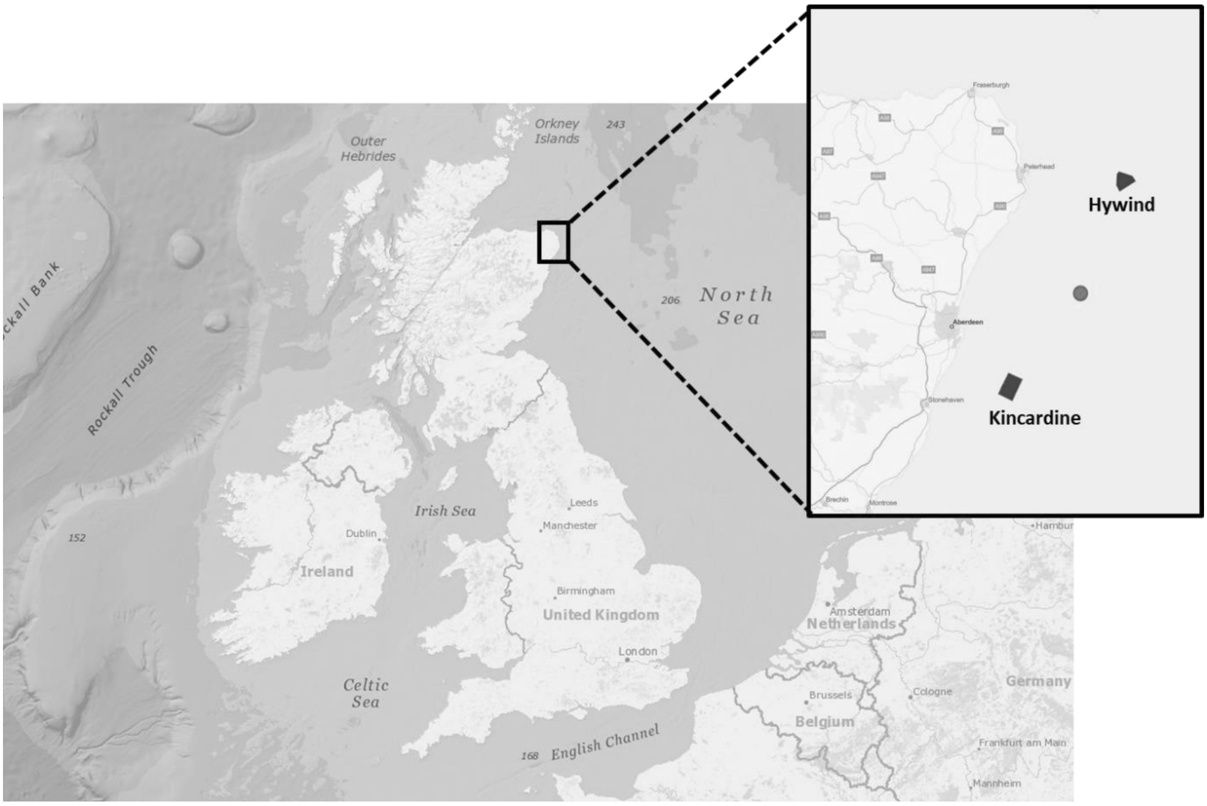


Figure 4. Location of Hywind Scotland and Kincardine floating wind pilot parks (figure produced using Google Maps [28]). The red spot refers to the offshore location selected for both case studies.

3.1. Case study 1 (Hywind inspired scenario)

Case study 1 is inspired by Hywind Scotland, which has been a demonstration project in operation since 2017 [18]. It consists of five 6 MW direct drive FLOW turbines, supported on a spar-type foundation. It is located 25 km East of Peterhead, in the UK North Sea, at a water depth ranging from 95 m to 120 m. Peterhead quay has suitable facilities and infrastructure for installation and operation of FLOW devices [29]. It was therefore chosen as the O&M port for Case Study 1 in this work. The mooring system for each turbine consists of three studless steel chains and suction bucket anchors. A 27km, 33 kV, static cable (with an additional 0.5 km dynamic section) is used to export the electricity produced to the onshore substation. Four dynamic 33kV cables are used to connect the turbines to each other. The specifications of these components are provided in Table 1, where average component costs are provided as considered in the O&M model. Further detailed information on the cost estimation approach is provided in the Appendix.

The characteristics and properties of each of these components, specific for the Hywind project, have been extracted from different sources. In this regard, the main references to define this case study have been the Hywind marine licensing application [30], the project's environmental statement [31] and the proposed decommissioning programme [32]. The component costs have been estimated based on the information provided within these documents. In the O&M tool it is possible to model both repair and replacement of a component by specifying the corresponding failure rate and intervention cost. However, for the sake of simplicity and according to the available input data, this distinction has not been made in this work, and all O&M interventions due to failure have been considered as a replacement. The only exception to this simplification has been made for the floating platform, for which 1% of the foundation capital cost is assumed as representative of a repair intervention (this may include restoration of pillar damage, corrosion, weld defects or fatigue cracks). This exception is due to the fact that a full replacement of the entire floating platform would be highly unlikely and extremely expensive, and would skew the outcomes of the simulation as a consequence. Repair and replacement times have been assumed using expert elicitations. The failure rates have been extracted from [33–35], choosing the values for those components whose structure or configuration were similar or analogous to those used in Hywind. The power curve for the wind turbine SWT-6.0-120 has been defined using the least square method [36], starting from the values of rated power of the device and corresponding cut-in (3 m/s), cut-out (25 m/s) and rated speeds (12 m/s) [37].

Table 1. Assumed taxonomy for Case study 1 specific components and related properties. Adjusted from [30,31,35,38–40].

Subsystem / Component	Repair / replacement time [hours]	Annual Failure rate [failures /turbine /year]	Cost of component [£]	Onshore Maintenance [Yes / No]
Floating platform (Spar)	12	0.0438	6,618,480*	Yes
Mooring lines	12	0.14892	570,152	No
Anchors	12	0.15768	983,180	No
Power cable (inter-array)	12	0.0000323	703,890**	No
Export cable	24	0.167	6,050,000	No

** Note that only 1% of the spar platform capital costs (£66,184) are considered as repair costs; **This includes the cost of accessories. It is expected that if an inter-array cable is replaced, the accessories will be replaced as well.*

3.2. Case study 2 (Kincardine inspired scenario)

Case study 2 is inspired by Kincardine, which is a 50MW FLOW farm currently under development South-East of Aberdeen, Scotland, at a distance of 15km from the coast, in 60m – 80m water depth. It consists of five devices of 9.5MW plus one of 2MW. This is because the Kincardine pilot park was built in two phases, where in the first phase only one 2MW turbine was installed, and in a second phase five turbines of 9.5MW with other changes in system design were introduced. Due to the different systems used within the two phases, only Phase 2 is considered in this study to facilitate the analysis of the results, i.e. only the five 9.5MW OWTs are considered. After verifying that suitable facilities (e.g. dry dock, cargo cranes, etc.) were available [41], the closest port (i.e. Aberdeen) was chosen for the O&M activities. This choice has been confirmed in the recent vessels management plan [42]. The floating platform is a semi-submersible type, and is moored with four steel chains, each anchored with a drag-embedment anchor. Two 33kV- XLPE export cables are used to transmit the electricity to shore. Thus they have been modelled in redundancy configuration. The specifications of the components and average cost modelled for Case Study 2 are provided in Table 2. As for the previous cases study, also in this case 1% of the foundation capital cost is assumed as the repair cost for the floating platform. Further information on the cost estimation is provided in the Appendix.

Several sources have been consulted to define the Case Study 2 founded on the Kincardine project. The majority of the component information has been extracted from the Marine Scotland Information web portal [43]. This includes the development specification and layout plan [44], construction programme [45] and cable plan [46]. The sources for failure rates and repair and replacement information are the same used for the other case study, i.e. [35,39,40]. The power curve of the wind turbine has also been defined through the least square method, but using different values for cut-in (3.5 m/s), cut-out (25 m/s) and rated speeds (14 m/s) and rated power (9.5 MW) based on the specification of the used turbine V164-9.5 [47].

Table 2. Assumed taxonomy for Case Study 2 specific components and related properties. Adjusted from [35,39,40,48].

Subsystem / Component	Repair / replacement time [hours]	Annual Failure rate [failures /turbine /year]	Cost of component [£]	Onshore Maintenance [Yes / No]
Floating platform (Semi-sub)	12	0.98112	10,551,200*	Yes
Mooring lines	12	0.14892	557,568	No
Anchors	12	0.15768	109,348	No
Power cable (inter-array)	12	0.0000323	828,048**	No
Export cable	24	0.167	4,522,980	No

** Note that only 1% of the Semi-sub platform capital costs (£105,512) are considered as repair costs; **This includes the cost of accessories.*

3.3. Other inputs and assumptions

Met-ocean data

The met-ocean data describing the environmental conditions of the offshore site chosen for the farm deployment, are retrieved using free-access online portals, namely the MARENDATA [49] and the Hycom [50] platforms. The first was used to obtain hindcast measures of wind (speed and direction) and wave parameters (significant wave height, peak period and direction), produced exploiting the numerical model Wavewatch III [51]. The second was used to retrieve the data related to the water current speed and direction, according to the model illustrated in [52]. More information on both platforms can be found in [53]. Due to the resolution of these hindcast models, and considering the relatively short distance between the two projects (47km), the two locations are considered close enough to assume that they experience the same weather. Hence, met-ocean data are retrieved only for one location in between the two farms (around 23km from each; latitude and longitude for this site are 57°17'N, 1°27'W) and the same set of met-ocean data has been used for both case studies. A time period of 25 years (1980-2004) is selected for the retrieved time-series (3 hour time-step). This time-series is used to calculate the energy produced by the FLOW devices, but also to establish the weather windows which govern when maintenance interventions can occur. These are established according to the vessels' limits and capabilities, i.e. the maximum wind speed, wave height and current speed they can operate in.

Reliability data

The first important step for a reliability model is the definition of the system boundaries and taxonomy. This defines what subsystems, assemblies and components are considered for the investigation, and how these are functionally arranged within the turbine. The components for the floating foundation and network infrastructure (i.e. platform, moorings and anchors, inter-array and export cables) are defined using the public information available, as detailed in the previous sections. The taxonomy and related data for the wind turbine is extracted from Carroll et al. [54]. Although this source refers to previous wind turbine models (between 2MW - 4MW capacity), it has been preferred to sources using bigger or more recent devices [55–57]. This choice has been made in agreement with [58,59]. Carroll et al. provide a complete and detailed database, based on OWTs from a single manufacturer located in Europe, with taxonomy and associated failure rates, repair times and repair costs (where by repair it is intended either a repair or replacement of the component), whereas not all of the required information is provided in more recent sources [33,57,60]. The taxonomy of the OWT considered in this work, together with its properties as adjusted from [54], is shown in Table 3. Note, that the same taxonomy, reliability and cost assumptions were used for the turbine components used in the O&M model for the two case studies unless otherwise specified.

Table 3. Taxonomy for the wind turbine and related properties. Adjusted from [54].

Subsystem / Component	Repair / replacement time [hours]	Annual Failure rate [failures /turbine /year]	Cost of repair / replacement [£]	Onshore Maintenance [Yes / No]
Pitch & Hydraulic system	89	1.076	65,910	No
Generator	67	0.999	25,973	Yes
Gearbox*	44.5	0.633	20,512	Yes
Blades	31.25	0.52	18,037	Yes
Grease, Oil, Cooling Liquids	22	0.471	5,253	No
Electrical comp	20.75	0.435	4,550	No
Contactor, Circuit breaker, relay	17.5	0.43	4,565	No
Controls	17.5	0.428	4,431	No
Safety	13.25	0.392	4,306	No
Sensors	12.75	0.346	3,995	No
Pumps, Motors	11	0.346	3,544	No
Hub	8.3	0.235	1,126	No
Heaters, Coolers	8	0.213	1,075	No
Yaw system	7.3	0.189	990	No
Tower, Foundation	7	0.05	918	No
Power supply, Converter	8	0.18	750	No
Transformer	3.6	0.065	527	No

**considered only for Case Study 2 (inspired by Kincardine) since the device used in Case Study 2 (inspired by Hywind)is direct drive (gearless).*

The overall cost of the turbine in the Cost model is calculated at 1.25 m£/MW. This value represents an average of the most recent values found in the literature. The Crown Estate reports a cost of 1 m£/MW [61] for 10MW offshore wind turbine deployments. Judge et al. assume 1.13 m£/MW for 5 MW turbines in [9]. In both these cases, the values are based on expert elicitation and offshore wind industry trends. BVG Associates suggest a value of 1.3 m£/MW [62] for small floating offshore wind pilot park deployments of 8 MW turbines based on their model estimates. Ioannou et al. work with 1.495 m£/MW for 3.6 MW turbines in [63], which is calculated based on a costs regression function developed for wind turbines between 2 and 5MW in [64].

Vessels

The other crucial consideration in the O&M planning for an ORE farm is the set of maintenance assets that are used for the planned and corrective maintenance interventions. For this work, a set of generic maintenance vessels categories for minor, medium and major maintenance activities (depending on the size and weight of the component to be repaired or replaced) have been selected, namely a Crew Transfer Vessel (CTV), a Field Support Vessels (FSV) and a Heavy-Lift Vessel (HLV). In addition, an Anchor Handling Tug Supply (AHTS) vessel to tow the device to port (and then back to the offshore location) when an onshore intervention is required, is considered. This choice is supported by the vessels management plan implemented for the Kincardine project [42]. The characteristics and limitations of these vessel categories are provided in **Error! Reference source not found.**Table 4, while a graphical example of each vessel typology is shown in Figure 5. Due to the relatively short distance from shore

(15-25km), all interventions are assumed to start from the selected O&M ports. Thus the possibility of using an offshore maintenance basis, which is a planning option for farms far offshore, has not been considered. Since the optimisation of the maintenance fleet was not one of the objectives of this investigation, limits on the maximum number of vessels available in the fleet were not imposed. For the same reason, no other constraints have been imposed on the availability of the vessels[1]. However, a delay of two hours (based on contractors' experience) has been imposed for those components requiring maintenance onshore in order to account for each platform disconnection and reconnection. These series of input parameters are needed to establish the mechanisms that determine the maintenance activities, depending on the nature of the intervention and the availability of appropriate weather windows. To this end, dependencies between components and vessels capabilities are also imposed, ensuring that for each maintenance activity the appropriate vessel is assigned. Moreover, this data is used to generate the economic outputs which will inform the vessel and technicians cost of the Cost model.

Table 4. Properties of the maintenance assets selected for this work. Adjusted from [65–68].

Name of the vessel	CTV	FSV	HLV	AHTS
Vessel speed [knots]	24	10	12.5	10
Vessel speed with device [knots]	-	-	-	4
Fuel consumption [l/h]	381	196	1,127	1,046
Fuel consumption with device [l/h]	-	-	-	1,942
Day rate [£]	1,750	9,500	150,000	18,735
Standby rate [£]	0	0	0	0
Mobilisation cost [£]	1,000	2,500	27,000	3,000
Average daily crew member cost [£]	220	220	220	220
Wave limit, H_S [m]	2.5	1.8	1.5	3
Wind limit [m/s]	30	30	25	30
Current limit [m/s]	5	5	4	4
Wave limit with device H_S [m]	-	-	-	2.1
Wind limit with device [m/s]	-	-	-	21
Current limit with device [m/s]	-	-	-	2.8

Figure 5. Examples of vessel categories constituting the fleet considered for the O&M modelling. From left to right, examples of a CTV [69], a FSV [70], a HLV [71], and a AHTS [72].

Economic parameters

To calculate the costs over the lifetime of the projects, a 25 year operational life was assumed. For LCoE and NPV calculations a discount rate needs to be defined. Discount rates of around 8-12% have

[1] If needed, restrictions on the periods one or more maintenance assets are available (e.g. only during the day or only during specific months) can be applied to the model.

been considered in the literature[2] [8]. For pilot park deployments a discount rate of 10% is assumed, due to the higher risk and uncertainty linked to these one-off deployments, whereas a lower discount rate of, for example 8% could be assumed for a commercial wind farm deployment. It is well known from previous studies that the LCoE and NPV results are highly sensitive to the discount rate assumption, for this reason, 10% is used here as baseline case, and 8% and 12% discount rates will be considered as alternative scenarios. The assumed investment timeline, i.e. when costs are assumed to occur is set out in Table 5 and was adapted based on [8]. The first operational year is assumed to be year 5, and decommissioning is assumed to occur in 1.5 years in years 30 and 31.

Table 5: Investment timeline assumed in cost model for LCoE and NPV results. Year 5 is the first year of operation.

Phase	**Year**							
	0	**1**	**2**	**3**	**4**	**5**	**6-29**	**30-31**
Development and Consenting	56%	10%	11%	11%	12%	1%	0%	0%
Production and Acquisition	0%	9%	28%	30%	34%	0%	0%	0%
Installation and Commissioning	0%	7%	25%	27%	41%	0%	0%	0%
Operation	0%	0%	0%	0%	0%	4%	96%	0%
Decommissioning	0%	0%	0%	0%	0%	0%	0%	100%

4. Results

In this section, the outcomes obtained with the combined use of the two models are presented. As already mentioned, the comparison between the two case studies is beyond the objectives of this work, since all costs values are based on estimations. However, for convenience, the results for both case studies are shown in the same table (Table 6). These represent the KPIs based on the O&M activities averaged over 100 simulations runs (as described in section 2.2) and based on the lifecycle cost analysis. They refer to the entire farm for an operational period of 25 years, imposed as the project lifecycle for both case studies, at the same location. A strike price of £57.5/MWh, in line with the Contracts for Difference (CfD) auction for offshore wind farms scheduled for commissioning in 2022/2023 [73], has been assumed to calculate the revenue generated by the sale of electricity.

[2] Different definitions of the discount rate have been used. '*Many companies calculate their Weighted Average Cost of Capital (WACC) and use it as their discount rate when budgeting for a new project.*'[95]. However, '*the discount rate usually takes into consideration a risk premium and therefore is usually higher than the cost of capital*' [95] . Since these concepts are both used in literature and not necessarily differentiated, they are considered to be equivalent here.

Table 6. Results obtained for the two case studies[3].

Quantity / Parameter	Case Study 1	Case Study 2
Average AEP [GWh]	131.9	168.7
Average annual energy lost [GWh]	8.5	13.1
Energy-based availability [%]	93.9	92.8
Net capacity factor [%]	50.2	40.5
Equivalent hours	4396	3551
Total revenue [m£$_{2019}$]	189.6	242.8
O&M costs undiscounted [m£$_{2019}$]	111.1	101.1
Normalised O&M cost per energy produced [£$_{2019}$/MWh]	33.7	24.0
CoE [£$_{2019}$/MWh]	79.3	72.4
LCoE [£$_{2019}$/MWh]	171.8	172.5
NPV [m£$_{2019}$]	-93.6	-120.1

The quantities in Table 6 are the estimated KPIs of the two simulated case studies[3]. The calculated energy delivered values are reasonable for small pilot projects with a handful of OWTs. Also availability and capacity factor are in line with typical values for offshore wind projects [74]. Although these numbers are somewhat lower than those reported for initial Hywind generation (53.8%) over the first 2.2 years of operation [75], they are higher than previously recorded in bottom-fixed offshore wind farms (38.4% in average) [76]. In both cases studied here, devices are in downtime only around 7% of the project lifetime. Nonetheless, the substantial contribution of the O&M costs can be highlighted, which significantly reduces the profitability of the case studies. However, it must be remembered that all these values depend on the economic inputs provided and more in general on the assumptions made. Thus, they do not aim at reflecting the financial viability of the two existing farms. These cost and other O&M indicators are presented and discussed in more detail in the following sections.

4.1. Overall project costs

The results obtained with the Cost model are shown in Table 7, where values found in literature are also provided for comparison. CapEx and OpEx values are undiscounted. Note, that only general values in terms of total CapEx, OpEx and LCoE for the two projects the case studies are inspired by were found in literature with no further information about how these had been estimated.

Table 7: Results from LCoE calculation for reference cases in comparison with values found in literature.

	Case study 1			Case study 2		
	Cost model	Literature[4]	% difference [%]	Cost model	Literature[4]	% difference [%]

[3] Energy-based availability expresses the ratio between the actual energy produced and the theoretical energy available without downtime. O&M costs express the sum of repair costs, crew costs and vessel costs. The Net Capacity Factor (accounting for downtime) and Equivalent hours are calculated as follows:

$$Net\ Capacity\ Factor = \frac{Average\ AEP}{8760h \times P_{rated}}$$

$$Equivalent\ Hours = \frac{Average\ AEP}{P_{rated}}$$

[4] Costs were assumed to be provided in 2019 currency values. The average conversion rate in 2019 from GBP to EUR of 1.136 was used.

LCoE [£$_{2019}$/MWh]	171.8	211.3 [77]	-20.6	172.46	220.2 [78]	-24.3
CapEx [m£$_{2019}$]	144.0	209.9 [4,77]	-37.2	236.5	324.9 [4]	-31.5
CapEx+DecEx [M£$_{2019}$]	149.5		-33.6	241.1		-29.6
OpEx [m£$_{2019}$/year]	4.4	-		4.0	-	
OpEx [m£$_{2019}$]	111.1	84 [4,77]	27.8	101.10	130.0 [4]	-25.0

The obtained LCoE values are slightly below the estimated costs reported for both pilot parks with a percentage difference of 20.6% for Case Study 1, and of 24.3% for Case Study 2. CapEx values are below previously estimated values with percentage differences between 37.2% and 31.5%. On the contrary, the OpEx results are higher than the previously estimated values for the Hywind project with a percentage difference of 27.8%, and lower for Case Study 2 with a percentage difference of -25.0%.

If assuming an 8% and a 12% discount rate, the LCoE value for Case Study 1 varies between 148.4 and 197.6 £$_{2019}$/MWh, and the LCoE value for Case Study 2 varies between 147.1 and 200.3 £$_{2019}$/MWh.

Compared previous floating offshore wind cost studies the obtained results are in the upper range of previously estimated values (62.55 £$_{2019}$/MWh [7], -179.1£$_{2019}$/MWh [79]). However, LCoE values for pilot park deployments are expected to be in the upper cost range due to the limited effects of economies of scale and volume in pilot park deployments.

The percentage contribution of the different life cycle stages to the LCoE is shown in Figure 6. The distribution of the costs agrees well with previous studies, where stage 2 of Production and Acquisition has the largest cost contribution to the LCoE (with previous results in literature ranging between 50 and 80%), followed by O&M activities (with previous results in literature ranging between 11 and 38%) [6–8,79].

The total contribution of different cost centres to the total CapEx, considering stages 1, 2, and 3 are shown in Figure 7.

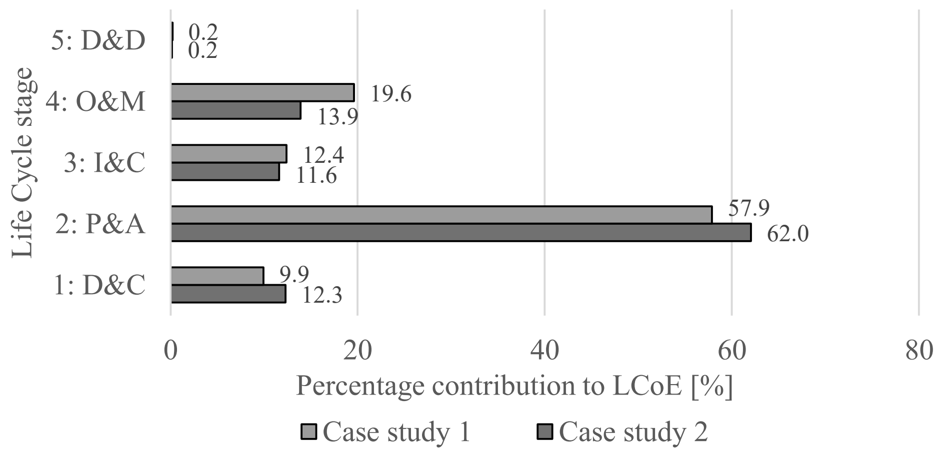


Figure 6: Percentage contribution of different life cycle stages (1-5) to the LCoE for case studies.

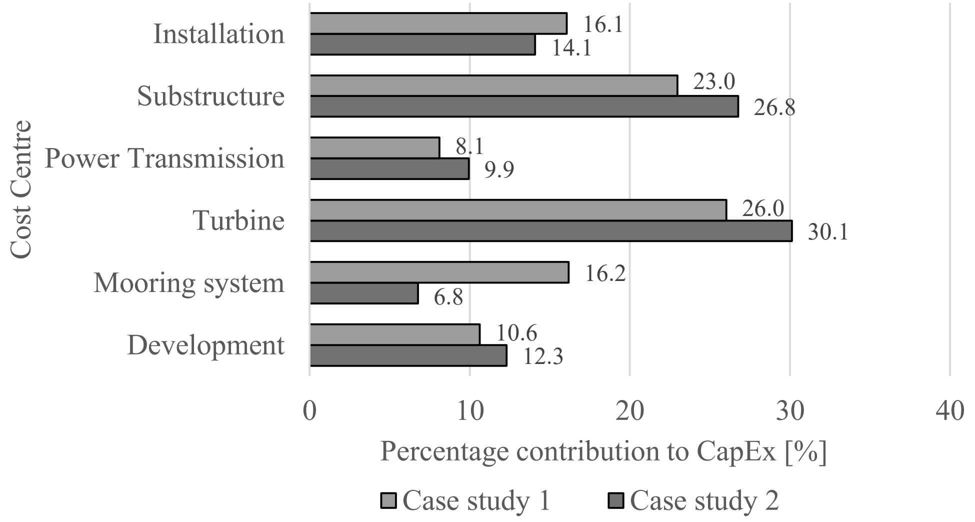


Figure 7: Contribution of different cost centres to CapEx for case studies, where total CapEx for case study 1 amounts 4801 k£$_{2019}$/MW, and for case study 2 4149 k£$_{2019}$/MW.

The turbine has the highest contribution to CapEx (26.0-30.0%), followed by the substructure (23.0-26.8%), and this by the installation (14.1-16.1%) and mooring costs (6.8-12.3). In Case Study 1, installation and mooring system costs are higher, largely due to the use of suction anchors. This is not the most commonly used anchoring technology [80]. The assumed costs for this type of anchors are significantly higher than for drag embedment anchors used in Case Study 2. In terms of the CapEx contributions, the previous studies have found the turbine to have the largest contribution to CapEx with results ranging between 29 and 50%, followed by the substructure with a contribution of between 17 and 33 %. The results agree well with previous cost distributions. Differences in the distribution ofCapEx stem from the assumptions used in terms of the cost of the turbines and the cost of a fabricated steel platform, where some of the previous studies seem to have considered the price of material only [9] or the cost of the turbine was assumed to be higher for smaller turbines [63]. Additionally, different platform designs have been considered, for example, a platform of significantly smaller weight (696 t for a 5MW turbine against 2300t reported in [77] for the 6MW turbine used in Hywind) was studied in [6]. The considered platform designs, which will be one of the main components together with the mooring system that will differentiate different FLOW technologies is expected to be associated to the most variable cost contribution to overall system costs when comparing different technologies.

4.2. Comparison of project costs when using simple O&M representations

To quantify the impact of using detailed O&M models in the cost estimations of floating offshore wind projects, the results obtained with such O&M model are compared to results obtained when approximating O&M costs as a percentage of CapEx. OpEx have been commonly approximated as percentage of CapEx for emerging offshore renewable energy technologies such as wave and tidal energy based on previous offshore wind experience, where lifetime OpEx is considered to be within a range between 22 and 40% of lifetime CapEx [10]. For floating offshore wind, the OpEx has been approximated to be 25% of the total CapEx in [81]. In the present case, undiscounted lifetime OpEx represents 77.1% of the undiscounted lifetime CapEx for Case Study 1 (inspired by Hywind) and 51.3 % for Case Study 2 (inspired by Kincardine). The economic indicators are recalculated when assuming OpEx accounting for 25% of lifetime CapEx for comparison. The obtained results are shown in Table 8.

Table 8: Economic indicators when using an approximation of OpEx as 25% of CapEx.

	Case Study 1			Case Study 2		
	With detailed O&M	**With approx. OpEx**	**% difference [%]**	**With detailed O&M**	**With approx. OpEx**	**% difference [%]**
OpEx [m£$_{2019}$]	111.1	36.0	102.1	101.1	49.3	164.7
Normalised O&M cost per energy produced [£$_{2019}$/MWh]	33.7	11.1	101.2	24.0	11.9	164.1
CoE [£$_{2019}$/MWh]	79.3	56.6	33.5	72.4	60.1	18.6
LCoE [£$_{2019}$/MWh]	171.8	149.1	14.2	172.5	160.2	7.4
NPV [m£$_{2019}$/MW]	-93.6	-74.9	22.1	-120.1	-107.3	11.3

The CoE varies the most in both cases with a 33.5 and 18.6 percentage differences from the original results using the detailed O&M model outputs for Case Study 1 and Case Study 2, respectively. The LCoE is the cost indicator the varies the least which is underestimated with a percentage difference of 14.2 and 7.4 % in case studies 1 and 2, respectively when using this OpEx approximation as a percentage of CapEx.

OpEx costs have also been commonly approximated with the normalised value per electricity generated, where values in offshore wind have been reported to be between 9.2 and 28.5 £$_{2019}$/MWh [82]. In the present case, the energy normalised OpEx ranges from 36.0£$_{2019}$/MWh for Case Study 1 to 49.3 £$_{2019}$/MWh for Case Study 2. The normalised OpEx values found in the literature are used here for comparison and the economic indicators are recalculated. The obtained results are shown in Table 9.

Table 9: Economic indicators using an approximation of OpEx as cost per MWh as provided in literature.

	Case study 1		Case study 2	
Normalised O&M cost per energy produced as provided in literature [£$_{2019}$/MWh]	**9.2**	**28.5**	**9.2**	**28.5**
OpEx [m£$_{2019}$]	30.0	92.9	38.3	118.7
CoE [£$_{2019}$/MWh]	54.7	73.8	57.5	76.6
LCoE [£$_{2019}$/MWh]	147.2	166.3	157.6	176.6
NPV [m£$_{2019}$/MW]	-73.5	-89.1	-104.6	-124.5

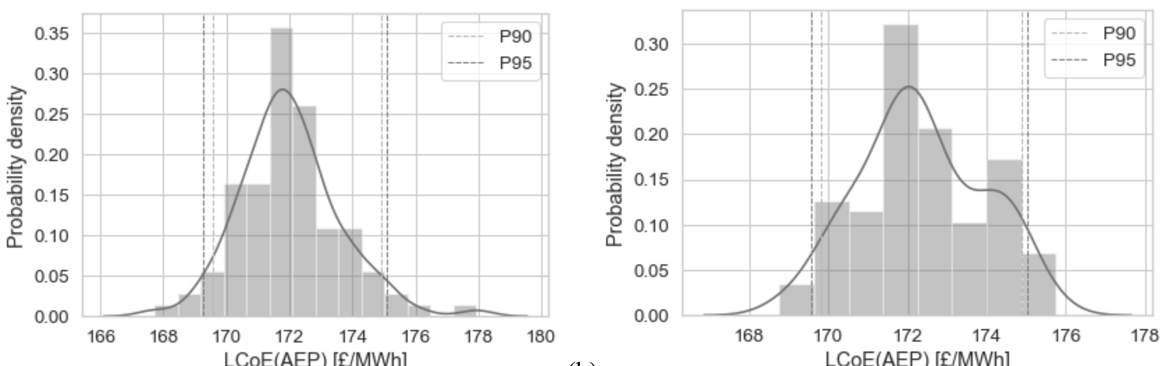
The LCoE value is underestimated with a percentage difference range of 9.0 to 15.4 % for case studies 1 and 2, respectively when using this OpEx approximation as 9.2 £$_{2019}$/MWh. With the OpEx approximation of 28.5£$_{2019}$/MWh the LCoE of Case Study 1 is underestimated with a percentage difference of 3.3%, whereas the LCoE of Case Study 2 is overestimated with a percentage difference of 2.4%.

Overall, it can be seen that significant variations in LCoE estimates result when using simplified O&M estimates versus when using a detailed O&M model. In the latter, the variation in costs due to differences in resource, weather conditions, distance to shore, or vessel availability are captured.

4.3. Analysis of the variance of case studies costs based on O&M model outputs

The use of a detailed O&M model allows analysing cost data taking into account the variability of the O&M model outputs.

For example, if considering the variability of the estimated AEP, the distribution of LCoE depending on the distribution of AEP can be examined. This is shown in Figure 8. The AEP distribution is one of the outputs of the O&M model. This, in turn, is related to the stochastic nature of the corrective interventions simulated, as well as their dependency on the availability of suitable (long enough) weather windows to decide when the operations can take place.



(a) (b)

Figure 8: LCoE distribution for AEP distribution as outputted from O&M model (a) for Case Study 1, and (b) for Case Study 2. The blue line depicted together with the histograms represents the distribution kernel. 90 and 95 percentile intervals are marked with vertical dashed lines.

Taking into account the AEP variability, the LCoE distribution is defined through a mean value of 172.0£$_{2019}$/MWh, a median value of 171.8£$_{2019}$/MWh, a 90 percentile interval of 169.6-174.9£$_{2019}$/MWh, and a 95 percentile interval of 169.2-175.1£$_{2019}$/MWh for Case Study 1. The LCoE distribution for Case Study 2 is defined through a mean value of 172.3£$_{2019}$/MWh, a median value of 172.3£$_{2019}$/MWh, a 90 percentile interval of 169.8-174.9£$_{2019}$/MWh, and a 95 percentile interval of 169.6-175.0£$_{2019}$/MWh. This cost distribution helps quantify and visualise the uncertainty associated with these cost estimates, and can therefore provide additional insights.

In the same way, the variability of the estimated OpEx can be considered, so that the LCoE distribution depending on OpEx only can be examined as shown in Figure 9. For Case Study 1, the LCoE distribution is defined through a mean value of 171.8£$_{2019}$/MWh, a median of 171.4£$_{2019}$/MWh, a 90 percentile interval of 166.1-178.7£$_{2019}$/MWh and a 95 percentile interval of 164.9-180.0£$_{2019}$/MWh. For Case Study 2, the LCoE distribution is defined through a mean value of 172.5£$_{2019}$/MWh, a median value of 172.4£$_{2019}$/MWh, a 90 percentile interval of 169.4-175.8£$_{2019}$/MWh, and a 95 percentile interval of 168.9-176.4£$_{2019}$/MWh.

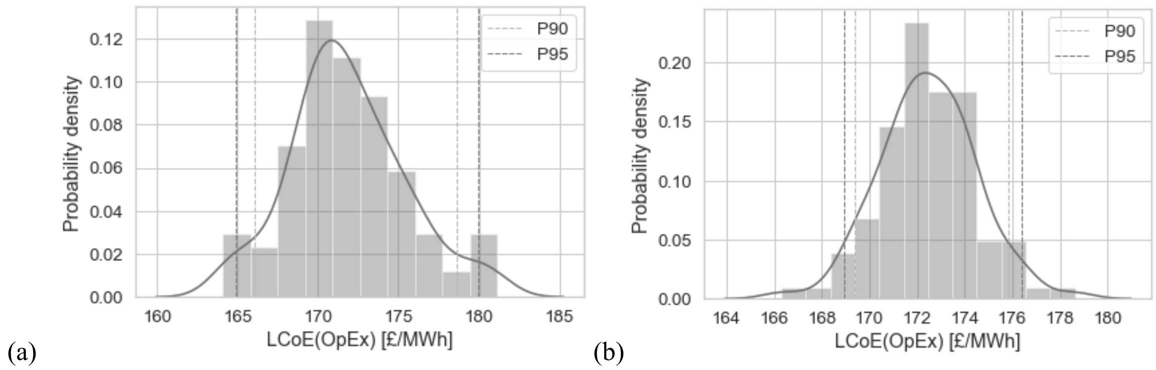


Figure 9: LCoE distribution for OpEx distribution as outputted from the O&M model (a) for Case Study 1, and (b) for Case Study 2. The blue line depicted together with the histograms represents the distribution kernel. 90 and 95 percentile intervals are marked with vertical dashed lines.

If considering both the OpEx and AEP variability resulting from the O&M model simulations, their joint impact on the LCoE can be calculated. This is for both case studies and the results are shown in Figure 10.

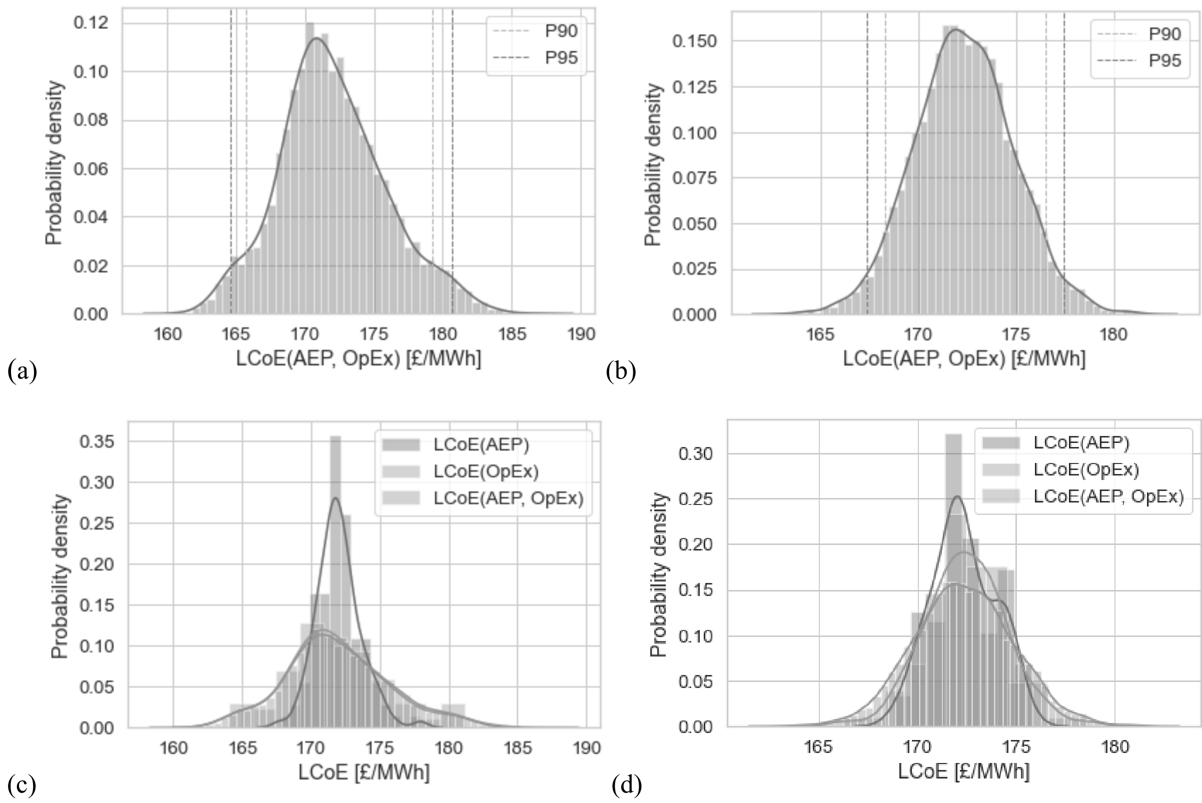


Figure 10: LCoE distribution for coupled OpEx and AEP distribution as outputted from the O&M model (a) for Case Study 1 (b) for Case Study 2; and comparison to LCoE distributions based on OpEx and AEP separately (c) for Case Study 1, (d) for Case Study 2.

It becomes apparent from Figure *10*, that the LCoE distribution due to changes in AEP is more narrow-banded than for changes in OpEx. This seems to be more clearly the case for Case Study 1 (see Figure *10* c) This shows, that OpEx costs can vary significantly depending on weather windows, vessel availability etc. and demonstrates that this can have a significant impact on the actual LCoE value. For Case Study 1, the coupled LCoE distribution is defined through a mean value of 172.0£$_{2019}$/MWh, a median of 171.7£$_{2019}$/MWh, a 90 percentile interval of 165.7-179.3£$_{2019}$/MWh and a 95 percentile interval of 164.6-180.7£$_{2019}$/MWh. For Case Study 2, the coupled LCoE distribution is defined through a mean value of 172.4£$_{2019}$/MWh, a median of 172.3£$_{2019}$/MWh, a 90 percentile interval of 168.3-

176.5£2019/MWh and a 95 percentile interval of 167.4-177.5£2019/MWh. When taking into account the combined variation of both parameters, the OpEx variation dominates the LCoE distribution results.

4.4. Other O&M-related indicators

Beyond the main technical and economical KPIs, a series of parameters can be analysed in order to explain these values and gain a further understanding of each farm's dynamics. For example, from the data in Figures Figure *11* and Figure 12, it can be seen how the elements of the floating and electrical infrastructure (i.e. floating platform, mooring system, inter-array cable and export cable) do not contribute significantly to the generated downtime, whereas the components of the wind turbine are those causing most issues in terms of failures and consequent downtime. The pitch and hydraulic system in particular is the most sensitive component, causing most of the failures but especially almost half of the total farm downtime. In this regard, the disproportion between the share of generated failures and that of generated downtime for this component is also noted. Thus, this component fails most frequently and causes the highest amount of corrective interventions and production losses.

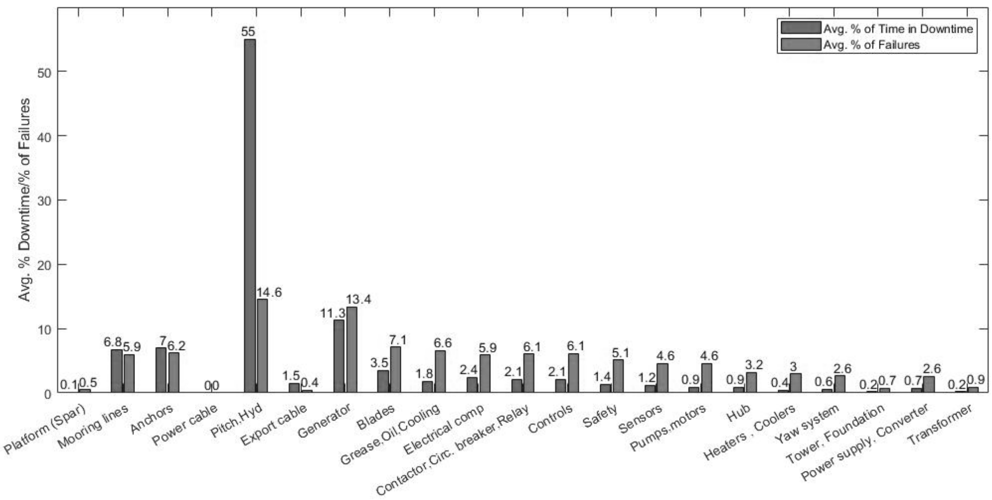


Figure 11: Contribution to total generated downtime and number of failures, per component, in the simulated Case Study 1.

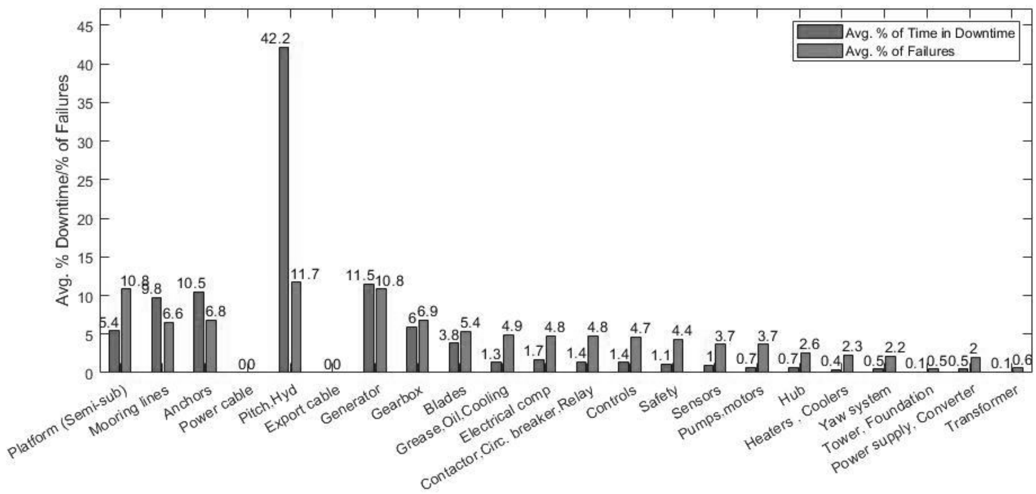


Figure 12. Contribution to total generated downtime and number of failures, per component, in the simulated Case Study 2.

When the cost of repairs and replacements are explored in more detail, Figures Figure *13* and Figure *14* show that the components of the moorings and anchoring systems are those causing the majority of expenditures. In the Case Study 1, the anchors are the most expensive components due to corrective interventions, followed by the mooring lines. In the Case Study 2 scenario instead, the interventions on the moorings are those dominating the overall costs of repair or replacement.

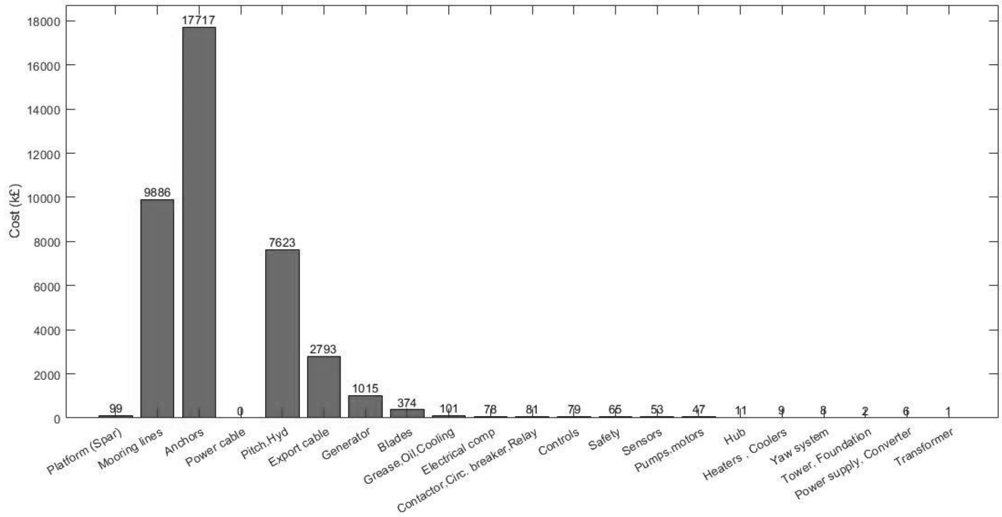


Figure 13. Total costs of repair or replacement, per component, in the simulated Case Study 1.

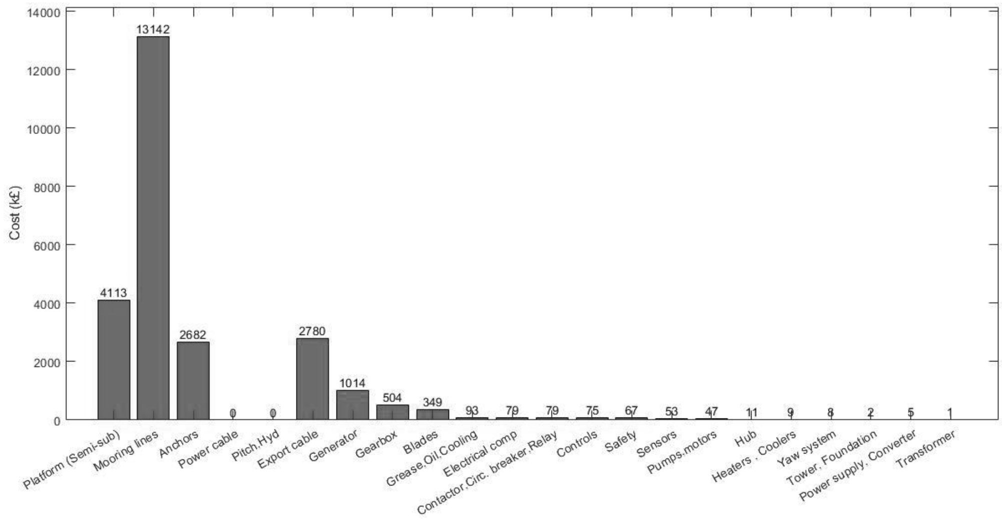


Figure 14. Total costs of repair or replacement, per component, in the simulated Case Study 2.

In order to better weigh the contribution of these and other maintenance costs on the overall economics of the project, a breakdown of the different losses is shown in Figures Figure *15* and Figure 16. In both scenarios vessels charter are the most relevant expense, followed by repairs and replacements costs. The lost production income results more relevant in Case Study 2, due to the higher turbine rating. Costs due to technicians labour and fuel are significantly less important than the others.

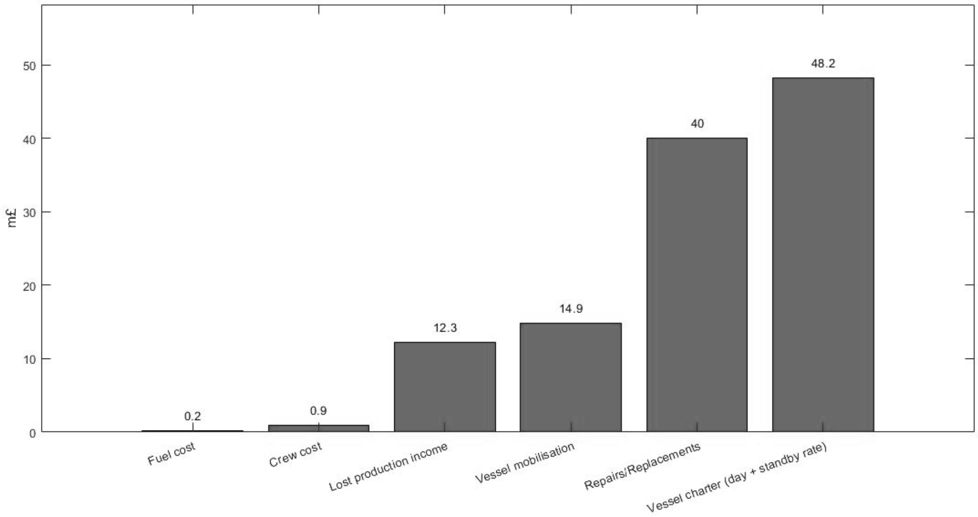


Figure 15. Breakdown of O&M related expenses in the simulated Case Study 1.

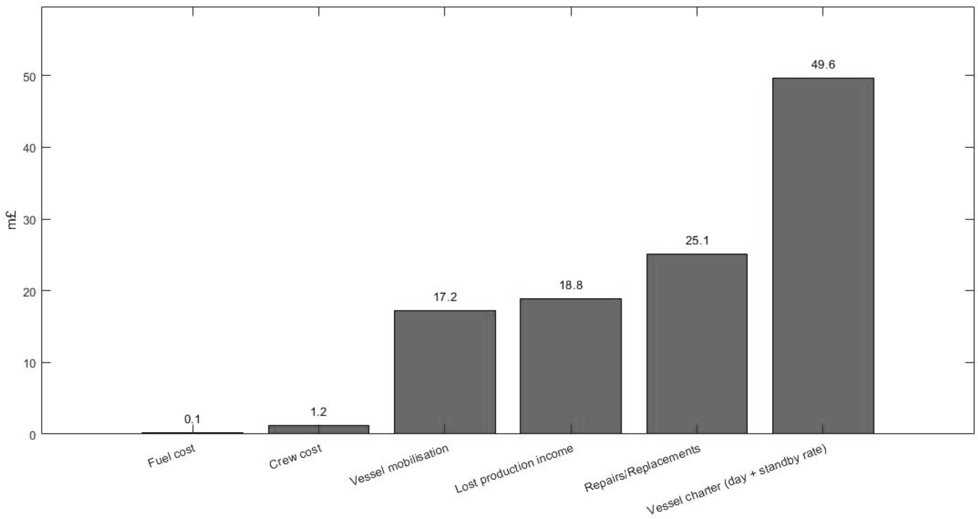


Figure 16. Breakdown of O&M related expenses in the simulated Case Study 2.

5. Discussion

Keeping in mind that the goal of this study is not to provide absolute values but to demonstrate how the use of detailed O&M models in techno-economic assessment studies can provide further insights and increase visibility of the cost assessment process, a discussion of the obtained results showing how these could be used by decision makers, as well as highlighting caveats of the method is provided here.

Within this study, a number of techno-economic KPIs were calculated, the value and the implications of which are considered in the following. The negative NPVs achieved, indicate that both case studies would not be profitable with the assumed costs and strike price of electricity. However, it is not expected for pilot park deployments of a developing technology to be competitive at current prices. Given that the case studies are inspired by pilot park developments, these deployments might have been used partly as a proof of concept, but also to test the suitability of less common components, such as suction anchors. In fact, although the strike price of electricity was used for the current analysis, an enhanced

Renewable Obligation Certificates (ROCs) scheme, created for floating wind projects in Scotland and providing 3.5 ROCs per generated MWh, was secured by both Kincardine and Hywind projects [83]. ROCs have now been discontinued and developing technologies such as floating offshore wind have to compete with more mature technologies in CfD auctions. Given the current price differences, for CfD rounds in the UK in 2022/23, one of the proposed changes is to have a separate pot for developing technologies, such as floating offshore wind, wave and tidal energy. It can be expected, that then the offered market price would be significantly higher. For example, if considering 100£/MWh instead of 57.5£/MWh, the Internal Rate of Return (IRR) increases from -4.7% to 3.0 % for Case Study 1 and from -2.6% to 3.5% for Case Study 2. The NPV becomes larger than 0, when the electricity price reaches the respective LCoE values. Considering a CfD tariff more suited to the state of development of floating offshore wind technologies would therefore make these projects more competitive. The NPV and IRR measures complement the LCoE values by providing additional insights into project profitability. The LCoE values are commonly used for project comparison and were estimated to be in the upper range of values that had previously been estimated for floating offshore wind projects. Overall, the obtained results for the case studies are considered reasonable, with the obtained costs representing the costs of the development and deployment of pilot parks today. The cost results show a sensible cost distribution that is reasonable for the represented systems. The use of O&M costs and net AEP from the O&M model, proved suitable for this purpose. Despite obtaining LCoE values that show up to 24.3% difference from previously reported costs in the literature for the pilot parks they are inspired by, the results are considered to be within the uncertainty range of LCoE calculations (see [20]). Given the large uncertainty associated with discount rate and investment time line assumptions, which can result in up to 50% variation of the LCoE value [20], the CoE is also provided here. If calculated for more technologies, the CoE can provide additional insights for technology comparison, rather than for the assessment of a project's economic viability. By avoiding the introduction of uncertain parameters such as the discount rate or the investment timeline at early stages of development, the CoE can offer a more straightforward comparison of the economic advantage of different technologies. Although, this also implies that potential risks associated to different technologies are not analysed, the authors consider it beneficial to provide the CoE to improve techno-economic assessment transparency and allow for early stage technology comparison.

However, other parameters relevant to quantify the lifecycle costs of a technology or a project remain uncertain. Given the very scarce experience in offshore operations for floating offshore wind projects, the use of a detailed and verified O&M model enables the consideration of variations in these economic indicators due to the stochastic nature of weather or component failure events. This allows build confidence in the obtained results and to facilitate technology and project comparisons. Although only some example LCoE results were provided here to demonstrate the benefit of including these considerations in economic indicators, the methodology can be equally applied to other economic indicators. Some of the cost assumptions used here have inherent uncertainties. An example is the assumed costs of the onshore substation, where cost estimates vary largely from 50k€/MW for small floating offshore wind farm deployments of 40MW or less [62] to 140k€/MW for large floating offshore wind farm deployments of 500MW [8]. For this type of cost variability, where the variation range can be approximated but not enough data is available to define a cost distribution, a stochastic approach such as suggested in [12] can be used, to assess the impact of different cost variations on the final economic indicators.

Other caveats of this model are the development costs accounting for contingencies, since these will be highly project dependent. As these projects are first, one-off deployments of their respective technologies, these costs could have been much larger than expected for similarly sized projects. In the same way, general assumptions for installation costs were used, which will vary largely depending on location, vessel availability, etc. Thus higher overall costs than approximated here could be expected for real pilot park deployments.

O&M cost proved to be a major contributor to the overall costs, as it accounted for 13.9%-19.6% of the LCoE. It is responsible for a significant reduction in the projects' generated income, and as such it is key area to be looked into. Spare parts costs and vessels charter are the main contributions to the high O&M costs. Hence, improved strategies should aim at reducing charter costs and improving the reliability of the devices. For the first goal, different charter options, including the purchase of one or more vessels, might be evaluated. For the second objective, more expensive but more reliable components might be considered, and condition monitoring instrumentation installed. Regard component reliability, it must be remembered that a relatively old design for the wind turbine taxonomy and related properties was used, instead of a modern one typical of current and future floating wind turbines. Besides, conservative failure rates have been selected for the elements of the floating platform. This has led to a more conservative scenario in which the wind turbine is still characterized by a relatively low reliability. This in turn caused an increase of the O&M costs with respect to the figures provided in [4]. The effect of new designs on reliability is uncertain. On one hand, the use of updated, modern and specific wind turbines taxonomies with related reliability data is expected to lead to a lower number of corrective interventions and consequently lower O&M costs. On the other hand, due to the use of newer components and the larger environmental loads experienced, higher capacity turbines may be associated to higher failure rates. Finally, refit measures could be considered to reduce the number of corrective interventions and extend the farm's life. However, this is not currently envisaged for floating offshore wind.

To a lesser extent, another caveat of the O&M-related estimations is that only variable operational expenses, due to maintenance activities and marine operations, were taken into account. These figures should be corrected with fixed administrative costs, due to, for example, insurance of the assets or lease of the facilities (e.g. spare parts workshop). Lastly, while accessibility due to met-ocean conditions and subsequent weather windows availability is taken into account, the workability, intended as the possibility to perform maintenance safely and efficiently considering the human response to vibrations induced by the platform motions, has not been considered. This should be assessed separately for the two case studies, by evaluating the motion response of the floating platform under those environmental conditions that were deemed feasible under accessibility constraints. In this regard, improvements like the inclusion of wake effects [84], or a proper sensitivity analysis conducted on the wind parameters [85] or by assuming slight deviations in weather conditions at the two locations, as well as the use of high-resolution met-ocean data [86], would enhance the accuracy of the obtained estimations.

6. Conclusions

In this work, a framework for the techno-economic characterisation of floating offshore wind projects exploiting the use of detailed operation and maintenance models is presented. As shown, this can be effectively employed in order to tackle some of the existing challenges for this novel technology, especially in terms of reducing the uncertainty in the estimation of the project key performance indicators. This, in turn, allows to increase the confidence in the viability of a project, and to identify possible areas of improvement to support future decisions. One of the objectives of this work was to demonstrate the added value of using an accurate and specific operation and maintenance model to reduce the number of assumptions in levelised cost of energy estimations. This is demonstrated by comparing the results obtained with the presented framework with those previously obtained in literature, as well as by analysing the variance of the project costs based on the variability of parameters such as annual energy production and operational expenses, and showing the differences that would be obtained with simpler approaches. While the accuracy of both estimations (the ones presented in this work and those found in literature) is not compared, due to the impracticalities in lack of validation against a real scenario, the advantages of considering and estimating more key performance indicators (e.g. contribution to downtime and costs of repair or replacement of individual components) is shown. The transparency of the calculations is improved, and the uncertainties inherently linked to the future operation of a given wind farm captured. In this way a better understanding of the validity and variability of the estimations is achieved, and further insights are gained with respect to design choices and assets management than a single technical or economic value with no further background can provide. Thus, the sensitivity of results to cost and performance changes is evaluated.

Another fundamental contribution of this work is the publication of a complete dataset for the characterisation of floating wind farms with different platform designs, which includes reliability, cost and vessels data. Despite the authors' best efforts, it is impractical to obtain a fully identical representation of the two existing projects the case studies were inspired by, both because of the limited information publicly available and of the limitations in the modelling work. For this reason, due to the assumptions made and the inherent uncertainty in the data gathering process, the results do not represent the financial viability of the two pilot parks, and a direct comparison between the two case studies has been avoided. Nonetheless, in agreement with the guidelines provided by IEA Wind to reduce epistemic (i.e. caused by the lack of adequate knowledge) uncertainty [87], as much detailed data as possible was retrieved, and the number of assumptions minimised, and as such a representation of the case studies useful for this and future investigations is obtained. A full sensitivity and uncertainty propagation analysis may compensate for this inherent uncertainty on part of the inputs used in this work, as well as provide further insights for future works.

Indicators depicting the performance of floating wind pilot parks represented through the case studies are estimated by means of previously validated tools. By analysing these, it is possible to get increased visibility of the techno-economic assessment process, identify key cost drives, and to better quantify and represent the uncertainty associated with the provided indicators. The proposed method which provides increased transparency in the cost assessment process could be used by decision makers, for example, to assess the different levels that are required for different offshore renewable energy technologies in future Contract for Difference allocation rounds.

Once one or more alternatives to maintenance assets and logistics are established, simulations can be repeated to evaluate their suitability and how the outcomes compare with the previous key performance indicators. Future studies could apply this method to quantitatively estimate how different operation and maintenance strategies have an impact on overall project costs.

CRediT authorship contribution statement

G. Rinaldi and A. Garcia-Teruel: Methodology, Data curation, Formal analysis, Visualization, Writing - original draft. **P.R. Thies, H. Jeffrey, L. Johanning**: Writing - review & editing, Supervision.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgments

This publication has been supported by the H2020 project FLOTANT coordinated by the Oceanic Platform of the Canary Islands (PLOCAN). The project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No. 815289.

Appendix

Table 10: Cost assumptions for Case Study 1 (inspired Hywind Scotland pilot park).

Cost centres	Weight/Length/Volume	Approximated cost	Reference for cost estimation

1. Development and Consenting			
Engineering		176 k£$_{2019}$/MW	[62]
Contingencies		334 k£$_{2019}$/MW	[62]
2. Production and Acquisition			
Floating platform (Spar)	2300 t [77]	2878 £$_{2019}$/t$_{Steel}$	Engineering assessment of cost of fabricated steel delivered to port based on [88], where a 200% of the material cost for manufacturing is assumed.
Mooring chain R4	775 m x 3 [77] 0.38 t/m [89,90]	1936 £$_{2019}$/t	Engineering assessment which aligns well with [88]
Suction anchors	100 t x 3 [91]	9020 £$_{2019}$/t	[88]
Export cable	27.5 km [91]	220 £$_{2019}$/km	Approximated based on contract price 9M£$_{2019}$ [77], with cable costs approximated based on material costs; and cost of accessories based on estimation of single components costs.
Inter-array cables	4*1.5km = 6 km [77]	238 £$_{2019}$/km	
Cable accessories (bend stiffeners, buoyancy modules…)		97.5% of inter-array cable costs 232 £$_{2019}$/km	
Cable development including margins		9 M£$_{2019}$ - cable manufacturing costs = 1.7 m£$_{2019}$	
Onshore substation		44 k£$_{2019}$/MW	[62]
3. Installation and Commissioning			
Turbine + floating platform		754 k£$_{2019}$/unit	[88]
Mooring system (mooring line + anchors)		84 k£$_{2019}$/line	[88]
Export cable		566 k£$_{2019}$/km	[88]
Inter-array cable		182 k£$_{2019}$/km	[88]
Insurance		48 k£$_{2019}$/MW	[88]
5. Decommissioning and Disposal			
Turbine + floating platform		70% of installation costs	[92]
Mooring system (mooring line + anchors)		90% of installation costs	[88]
Cables		10% of installation costs	[92]

Table 11: Cost assumptions for Case Study 2 (inspired by Kincardine phase 2 pilot park).

Cost centres	**Weight/Length/Volume**	**Approximated cost**	**Reference for cost estimation**
1. Development and Consenting			
Engineering		176 k£$_{2019}$/MW	[62]
Contingencies		334 k£$_{2019}$/MW	[62]

2. Production and Acquisition			
Floating platform (Semi-submersible)	2750 t [93]	3837 £$_{2019}$/t$_{Steel}$	Engineering assessment of cost of fabricated steel delivered to port based on [88], where a 300% of the material cost for manufacturing is assumed in this case, due to higher complexity of the structure.
Mooring chain R4	720 m x 4 [94] 0.4 t/m (approximated from Hywind)	1936 £$_{2019}$/t	Engineering assessment which aligns well with [88]
Drag embedment anchors	20 t x 4 [94]	109 k£$_{2019}$/ unit	[88]
Export cable	17.1 + 18.5 km [46]	254 £$_{2019}$/km	Same cable cross-section used for both. Assumed to be 15% more expensive than Hywind's static cable
Inter-array cables	3*1.2km+3km=6.6km [46]	254 £$_{2019}$/km	
Cable accessories (bend stiffeners, buoyancy modules…)		97.5% of inter-array cable costs 282 £$_{2019}$/km	Cost of accessories based on estimation of single components costs.
Cable development including margins		1.7 m£$_{2019}$	Assumed to be the same as Hywind
Onshore substation		44 k£$_{2019}$/MW	[62]
3. Installation and Commissioning			
Turbine + floating platform		618 k£$_{2019}$/unit	[88]
Mooring system (mooring line + anchors)		53 k£$_{2019}$/line	[88]
Export cable		566 k£$_{2019}$/km	[88]
Inter-array cable		182 k£$_{2019}$/km	[88]
Insurance		48 k£$_{2019}$/MW	[88]
5. Decommissioning and Disposal			
Turbine + floating platform		70% of installation costs	[92]
Mooring system (mooring line + anchors)		90% of installation costs	[88]
Cables		10% of installation costs	[92]

References

[1] WindEurope sees potential for 7 GW of floating wind by 2030 n.d. https://www.rivieramm.com/news-content-hub/news-content-hub/windeurope-sees-potential-for-7-gw-of-floating-wind-by-2030-60846 (accessed February 2, 2021).

[2] Wind Europe. Floating offshore wind energy generation - A policy blueprint for Europe. 2018. https://doi.org/10.33519/kwea.2019.10.4.001.

[3] Proskovics R. Floating Offshore Wind: A Situational Analysis. 2018.

[4] Hannon M, Topham E, Dixon J, Mcmillan D, Collu M, Topham E. Offshore wind, ready to float ? Global and UK trends in the floating offshore wind market. Glasgow: 2019. https://doi.org/https://doi.org/10.17868/69501.

[5] Ioannou A, Angus A, Brennan F. A lifecycle techno-economic model of offshore wind energy for different entry and exit instances. Appl Energy 2018;221:406–24. https://doi.org/https://doi.org/10.1016/j.apenergy.2018.03.143.

[6] Castro-Santos L, Martins E, Guedes Soares C. Methodology to calculate the costs of a floating offshore renewable energy farm. Energies 2016;9. https://doi.org/10.3390/en9050324.

[7] Lerch M, De-Prada-Gil M, Molins C, Benveniste G. Sensitivity analysis on the levelized cost of energy for floating offshore wind farms. Sustain Energy Technol Assessments 2018;30:77–90. https://doi.org/10.1016/j.seta.2018.09.005.

[8] Myhr A, Bjerkseter C, Ågotnes A, Nygaard TA. Levelised cost of energy for offshore floating wind turbines in a lifecycle perspective. Renew Energy 2014;66:714–28. https://doi.org/10.1016/j.renene.2014.01.017.

[9] Judge F, McAuliffe FD, Sperstad IB, Chester R, Flannery B, Lynch K, et al. A lifecycle financial analysis model for offshore wind farms. Renew Sustain Energy Rev 2019;103:370–83. https://doi.org/10.1016/j.rser.2018.12.045.

[10] Marques MI, Marques MJ, Langiano S, Lourenço T, Harvey C, Ruiz-Minguela P, et al. DTOceanPlus - Deliverable D8.2 Analysis of the European Supply Chain 2019:1–33.

[11] Ioannou A, Angus A, Brennan F. Stochastic financial appraisal of offshore wind farms. Renew Energy 2020;145:1176–91. https://doi.org/10.1016/j.renene.2019.06.111.

[12] Castro-Santos L, Diaz-Casas V. Sensitivity analysis of floating offshore wind farms. Energy Convers Manag 2015;101:271–7. https://doi.org/10.1016/j.enconman.2015.05.032.

[13] Rinaldi G, Thies PR, Walker R, Johanning L. A decision support model to optimise the operation and maintenance strategies of an offshore renewable energy farm. Ocean Eng 2017;145:250–62. https://doi.org/10.1016/j.oceaneng.2017.08.019.

[14] Rinaldi G, Thies PR, Johanning L, Walker RT. A computational tool for the pro-active management of offshore farms. 2nd Int. Conf. Offshore Renew. Energy, Glasgow, UK: ASRANet Ltd; 2016, p. 111–5.

[15] Rinaldi G, Thies PR, Walker R, Johanning L. On the Analysis of a Wave Energy Farm with Focus on Maintenance Operations. J Mar Sci Eng 2016;4. https://doi.org/10.3390/jmse4030051.

[16] Rinaldi G, Pillai AC, Thies PR, Johanning L. Verification and benchmarking methodology for O&M planning and optimization tools in the offshore renewable energy sector. Submitt. to Int. Conf. Ocean. Offshore Arct. Eng., Madrid: 2018.

[17] Martin R, Lazakis I, Barbouchi S, Johanning L. Sensitivity analysis of offshore wind farm operation and maintenance cost and availability. Renew Energy 2016;85:1226–36. https://doi.org/10.1016/j.renene.2015.07.078.

[18] Equinor. Hywind Scotland 2020.

[19] COBRA. Kincardine Offshore Floating Wind Farm 2020.

[20] Garcia-Teruel A, Jeffrey H. The economics of floating offshore wind – A comparison of different methods. Proc. 4th Int. Conf. Renew. Energies Offshore (RENEW 2020) - Adv. Renew. Energies Offshore, 2020.

[21] Duffy A, Rogers M, Ayompe L. Renewable Energy and Energy Efficiency : Assessment of Projects and Policies. John Wiley & Sons, Incorporated; 2015.

[22] Rinaldi G. An integrated operation and maintenance framework for offshore renewable energy. University of Exeter, 2018.

[23] Rinaldi G, Thies PR, Walker R, Johanning L. A decision support model to optimise the operation and maintenance strategies of an offshore renewable energy farm. Ocean Eng 2017;145:250–62. https://doi.org/10.1016/j.oceaneng.2017.08.019.

[24] Rinaldi G, Portillo JCC, Khalid F, Henriques JCC, Thies PR, Gato LMC, et al. Multivariate analysis of the reliability, availability, and maintainability characterizations of a Spar–Buoy wave energy converter farm. J Ocean Eng Mar Energy 2018;4:199–215. https://doi.org/10.1007/s40722-018-0116-z.

[25] Alexander D. Application of Monte Carlo simulation to system reliability analysis. 20th Int. pump users Symp., 2003, p. 91–4.

[26] Faghih-Roohi S, Xie M, Ng KM. Accident risk assessment in marine transportation via Markov modelling and Markov Chain Monte Carlo simulation. Ocean Eng 2014;91:363–70. https://doi.org/https://doi.org/10.1016/j.oceaneng.2014.09.029.

[27] Zhang Y, Kim C-W, Tee KF. Maintenance management of offshore structures using Markov process model with random transition probabilities. Struct Infrastruct Eng 2017;13:1068–80. https://doi.org/10.1080/15732479.2016.1236393.

[28] Google Maps n.d. https://www.google.com/maps.

[29] Peterhead Port Authority. Peterhead port n.d. https://www.peterheadport.co.uk/clients/energy/renewables (accessed July 20, 2020).

[30] marine scotland. Hywind Marine licensing application - 05515/17/0. 2017. https://doi.org/10.1017/CBO9781107415324.004.

[31] Statoil. Hywind Scotland Pilot Park Project - Environmental Statement. 2015.

[32] Austreng KR, Vold O, Eldøy S. Decommissioning Programme for Hywind Scotland Pilot Park - C178-HYS-Z-GA-00002. 2017.

[33] Zhang X, Sun L, Sun H, Guo Q, Bai X. Floating offshore wind turbine reliability analysis based on system grading and dynamic FTA. J Wind Eng Ind Aerodyn 2016;154:21–33. https://doi.org/10.1016/j.jweia.2016.04.005.

[34] Warnock J, McMillan D, Pilgrim JA, Shenton S. Review of offshore cable reliability metrics. 13th IET Int. Conf. AC DC Power Transm. (ACDC 2017), 2017. https://doi.org/10.1049/cp.2017.0071.

[35] Kang J, Sun L, Guedes Soares C. Fault Tree Analysis of floating offshore wind turbines. Renew Energy 2019;133:1455–67. https://doi.org/https://doi.org/10.1016/j.renene.2018.08.097.

[36] Kazemi M, Goudarzi A. A Novel Method for Estimating Wind Turbines Power Output Based On Least Square Approximation 2012:97–101.

[37] wind-turbine-models.com. Siemens SWT-6.0-120 datasheet n.d. https://en.wind-turbine-models.com/turbines/159-siemens-swt-6.0-120#datasheet (accessed July 20, 2020).

[38] Austreng KR, Vold O, Eldøy S. Decommissioning Programme for Hywind Scotland Pilot Park - C178-HYS-Z-GA-00002. 2017.

[39] Zhang X, Sun L, Sun H, Guo Q, Bai X. Floating offshore wind turbine reliability analysis based on system grading and dynamic FTA. J Wind Eng Ind Aerodyn 2016;154:21–33. https://doi.org/10.1016/j.jweia.2016.04.005.

[40] Warnock J, McMillan D, Pilgrim JA, Shenton S. Review of offshore cable reliability metrics. 13th IET Int. Conf. AC DC Power Transm. (ACDC 2017), 2017. https://doi.org/10.1049/cp.2017.0071.

[41] Aberdeen Harbour n.d. http://www.aberdeen-harbour.co.uk/south-harbour-development/a-home-to-energy-transition (accessed July 20, 2020).

[42] KOWL. Kincardine Offshore Windfarm Project - Vessel Management Plan. 2020.

[43] Marine Scotland. Marine Scotland Information web portal n.d. http://marine.gov.scot/ (accessed July 27, 2020).

[44] KOWL. Kincardine Offshore Windfarm Development Project - Development specification and layout plan 2015.

[45] KOWL. KINCARDINE OFFSHORE WINDFARM PROJECT - Construction Programme. 2018.

[46] KOWL. KINCARDINE OFFSHORE WINDFARM PROJECT KOWL-PL-0004-009 - Cable Plan. 2018.

[47] thewindpower.net. MHI Vestas V164-9.525 MW datasheet n.d. https://www.thewindpower.net/turbine_en_1476_mhi-vestas-offshore_v164-9500.php (accessed July 20, 2020).

[48] Marine Scotland. Marine Scotland Information web portal n.d.

[49] HIDROMOD. MARENDATA 2019. https://marendata.eu (accessed July 20, 2020).

[50] Center for Ocean-Atmospheric Prediction Studies (COAPS). HYbrid Coordinate Ocean Model (HYCOM) n.d. https://www.hycom.org/ (accessed July 20, 2020).

[51] Tolman HL, Balasubramaniyan B, Burroughs LD, Chalikow D V., Chao YY, Chen HS, et al. Development and Implementation of Wind-Generated Ocean Surface Wave Models at NCEP. Am Metereological Soc 2002:311–33. https://doi.org/10.1175/1520-0434(2002)017.

[52] Chassignet EP, Hurlburt HE, Smedstad OM, Halliwell GR, Hogan PJ, Wallcraft AJ, et al. The HYCOM (HYbrid Coordinate Ocean Model) data assimilative system. J Mar Syst 2007;65:60–83. https://doi.org/10.1016/j.jmarsys.2005.09.016.

[53] Rinaldi G, Crossley G, Mackay E, Ashton I, Campbell M, Wood T, et al. Assessment of extreme and metocean conditions in the Maldives for OTEC applications. Int J Energy Res 2019;43:7316–35. https://doi.org/10.1002/er.4762.

[54] Carroll J, Mcdonald A, Mcmillan D. Failure rate, repair time and unscheduled O&M cost analysis of offshore wind turbines. Wind Energy 2015;19:1107–1119. https://doi.org/10.1002/we.

[55] Dao CD, Kazemtabrizi B, Crabtree CJ. Modelling the effects of reliability and maintenance on levelised cost of wind energy. Proc. ASME Turbo Expo 2019 Turbomach. Tech. Conf. Expo., 2019, p. 1–8.

[56] Santos FP, Teixeira AP, Guedes Soares C. An age-based preventive maintenance for offshore wind turbines. Saf. Reliab. Methodol. Appl., 2015, p. 1147–55.

[57] Dao C, Kazemtabrizi B, Crabtree C. Wind turbine reliability data review and impacts on levelised cost of energy. Wind Energy 2019;22:1848–71. https://doi.org/10.1002/we.2404.

[58] Pfaffel S, Faulstich S, Rohrig K. Performance and Reliability of Wind Turbines: A Review. Energies 2017;10. https://doi.org/10.3390/en10111904.

[59] Kang J, Sun L, Guedes Soares C. Fault Tree Analysis of floating offshore wind turbines. Renew Energy 2019;133:1455–67. https://doi.org/https://doi.org/10.1016/j.renene.2018.08.097.

[60] Kang JC. Fault tree analysis of the failure of floating offshore wind turbines support structures and blade systems 2016:741–9.

[61] The Crown Estate, Offshore Renewable Energy Catapult. Guide to an offshore wind farm. 2019.

[62] BVG Associates. Ocean Power Innovation Network value chain study: Summary report 2019.

[63] Ioannou A, Brennan F. A preliminary techno-economic comparison between a grid-connected and non-grid connected offshore floating wind farm. Proc. Offshore Energy Storage Summit, OSES 2019, Institute of Electrical and Electronics Engineers Inc.; 2019, p. 8867350. https://doi.org/10.1109/OSES.2019.8867350.

[64] Shafiee M, Brennan F, Espinosa IA. A parametric whole life cost model for offshore wind farms. Int J Life Cycle Assess 2016;21:961–75. https://doi.org/10.1007/s11367-016-1075-z.

[65] Dalgic Y, Lazakis I, Turan O. Investigation of Optimum Crew Transfer Vessel Fleet for Offshore Wind Farm. Wind Eng 2015;39:31–52.

[66] Ship Technology. VOS Glory Field-Support Vessel (FSV) n.d. https://www.ship-technology.com/projects/vos-glory-field-support-vessel-fsv/ (accessed July 20, 2020).

[67] Fugro. Southern Ocean High Lift Vessel brochure n.d. https://www.fugro.com/docs/default-source/about-fugro-doc/Vessels/southern-ocean-brochure.pdf?sfvrsn=3fed3a1a_6 (accessed July 20, 2020).

[68] Fuel management for tugs becoming an increasing challenge n.d. http://www.professionalmariner.com/May-2008/Fuel-management-for-tugs-becoming-an-increasing-challenge/#:~:text=Modern tugs%2C with power ratings,loaded barge in ocean conditions (accessed July 20, 2020).

[69] CTV example n.d. https://www.nauticexpo.com/prod/incat-crowther/product-34070-465759.html (accessed November 25, 2020).

[70] FSV example n.d. https://www.osd-imt.com/en/news/2016/second-osd-imt958-field-support-vessel-enters-service-with-north-star-shipping (accessed November 25, 2020).

[71] HLV example n.d. http://maritime-connector.com/ship/finesse-9592850/ (accessed November 25, 2020).

[72] AHTS example n.d. http://offshore-fleet.com/data/ahts.htm (accessed November 25, 2020).

[73] CfD Round Two results 2020. https://www.4coffshore.com/news/cfd-round-two-results-are-in2c-offshore-wind-cheaper-than-gas-and-nuclear-nid6373.html (accessed March 28, 2020).

[74] IRENA. Renewable power generation costs in 2018. Abu Dhabi: International Renewable Energy Agency; 2019.

[75] Equinor and ORE Catapult collaborating to share Hywind Scotland operational data n.d. https://www.equinor.com/en/news/2019-11-28-hywind-scotland-data.html (accessed February 2, 2021).

[76] Energy numbers - UK offshore wind capacity factors 2021. https://energynumbers.info/uk-offshore-wind-capacity-factors (accessed February 2, 2021).

[77] Floating Wind Energy (FWE). Hywind Scotland | Equinor – Quest Floating Wind Energy n.d.

[78] 4C Offshore. Global Offshore Renewable Map n.d.

[79] Ebenhoch R, Matha D, Marathe S, Muñoz PC, Molins C. Comparative levelized cost of energy analysis. Proc. 12th Deep Sea Offshore Wind R&D Conf. EERA Deep., vol. 80, Elsevier B.V.; 2015, p. 108–22. https://doi.org/10.1016/j.egypro.2015.11.413.

[80] Rhodri J, Costa Ros M. Floating Offshore Wind: Market and Technology Review Important notice and disclaimer. 2015.

[81] Eik A. Statoil ' s contribution to the North East future economy. Aberdeen: 2017.

[82] Gonzalez-Rodriguez AG. Review of offshore wind farm cost components. Energy Sustain Dev 2017;37:10–9. https://doi.org/10.1016/j.esd.2016.12.001.

[83] Umoh K, Lemon M. Drivers for and Barriers to the Take up of Floating Offshore Wind Technology: A Comparison of Scotland and South Africa. Energies 2020;13. https://doi.org/10.3390/en13215618.

[84] Petković D, Pavlović NT, Ćojbašić Ž. Wind farm efficiency by adaptive neuro-fuzzy strategy. Int J Electr Power Energy Syst 2016;81:215–21. https://doi.org/https://doi.org/10.1016/j.ijepes.2016.02.020.

[85] Nikolić V, Mitić V V, Kocić L, Petković D. Wind speed parameters sensitivity analysis based on fractals and neuro-fuzzy selection technique. Knowl Inf Syst 2017;52:255–65. https://doi.org/10.1007/s10115-016-1006-0.

[86] Petković D, Nikolić V, Mitić V V, Kocić L. Estimation of fractal representation of wind speed fluctuation by artificial neural network with different training algorothms. Flow Meas Instrum 2017;54:172–6. https://doi.org/https://doi.org/10.1016/j.flowmeasinst.2017.01.007.

[87] Hahn B. IEA Wind TCP RP17 Wind farm data collection and reliability assessment fo O&M optimization. Kassel,Germany: 2017.

[88] Bjerkseter C, Ågotnes A. Levelised costs of energy for offshore floating wind turbine concepts. Norwegian University of Life Sciences, 2013.

[89] Marine Scotland. Hywind Marine licensing application - 05515/17/0. 2017.

[90] Statoil. Hywind Scotland Pilot Park Project - Environmental Statement. 2015.

[91] Austreng KR, Vold O, Eldøy S, Scotland H, Knut S, Austreng R. Decommissioning Programme for Hywind Scotland Pilot Park - C178-HYS-Z-GA-00002. 2016.

[92] BVG Associates. Offshore wind cost reduction pathways - Technology work stream. 2012.

[93] Windfloat Gen 3 | Principle Power – Quest Floating Wind Energy n.d.

[94] KOWL. KINCARDINE OFFSHORE WINDFARM PROJECT - Section 36C Variation Environmental Statement. 2017.

[95] Cost of Capital vs. Discount Rate: What's the Difference? n.d.