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RESEARCH ARTICLE

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Analysing the cost impact of failure rates for the next generation of offshore wind turbines

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Abstract

Offshore wind turbines have rapidly scaled up in recent years, with plans to construct turbines up to 22 MW in the next decade. However, the operations and maintenance (O&M) requirements for these 'next-generation turbines' remain largely unknown. In this study, the total O&M costs are calculated, using a bench-marked O&M model, for a hypothetical 10 MW turbine scenario using two drive train configurations, based on known failure rates of smaller turbines. The O&M costs of the 10 MW turbines are compared with those of existing 3 MW turbines in two case studies: a North Sea wind farm and an East Coast US wind farm. Overall, direct drive 10 MW turbines performed better depending on the site's climate conditions. The study indicated that the two-stage drive train configuration may be more suitable for the US site than the North Sea, depending on the turbine's failure rate. The US site benefited from increased availability due to more favourable weather windows, resulting in lower lost revenue for the two-stage configuration despite high transport costs. The study found that the failure rate of 10 MW offshore wind turbines in the North Sea with a two-stage gearbox can increase by as much as 30% compared to the 3 MW failure rates without increasing direct O&M costs. These findings are crucial for the offshore wind energy industry, particularly for OEMs, developers and maintenance providers, as they provide insights into the required reliability for next generation turbines to reduce O&M costs compared to existing 3 MW turbines.

KEYWORDS
drive train configuration, failure rates, O&M modelling, turbine size

1 | INTRODUCTION

In the current economic climate, the cost of energy is a significant factor to consider when developing renewable technologies. The recent spike in energy prices means it is more critical than ever to develop affordable renewable energy alternatives.[1] Within the wind energy industry, the last 20 years has seen the development of a variety of ideas and approaches on how to maximise the economic value of an offshore wind farm. These range from novel concepts, such as floating wind, to new drive train configurations and sizes of turbines.[2,3] These advances, while promising, need to be substantiated with rigorous and pragmatic cost analyses. However, due to the lack of available data from operational turbines in the field, there is a large uncertainty surrounding the cost of energy from these new turbines. One area, that all new projects must consider, is the strategy for the operations and maintenance (O&M). O&M cover 20%–30% of an offshore wind farm's costs,[4] and, unlike capital costs, O&M can be constantly improved upon throughout the lifetime of the project to reduce costs. Recent comprehensive reviews outline the biggest challenges facing O&M for offshore wind.[5,6] The general objective of this study is to investigate the impact of a turbine's failure rates on the O&M cost for an offshore wind farm. More specifically, to look at how this impact differs depending on turbine configuration, turbine size and the location of the site. From this study, it can then be determined which scenario (considering size, type and location) produces the most economical outcome and why.

The following section outlines the motivation for the study. In order to provide results that are beneficial to the developing wind energy sector, the current trends in offshore wind energy are identified to be used as the inputs to the cost model. The rest of the paper is structured as follows. Section 2 details the methodology for the work, including the O&M model used and all of the inputs to the model with justifications. It provides an analysis of the climate data used with some key factors to consider throughout. Section 3 presents the results and discussion in the paper. This is followed by subsections that present the results that were found for the four different scenarios and then a comparative analysis with a discussion on the implications of these results. Finally, Section 4 concludes the work and offers up suggestions for further work to be carried out.

1.1 | Review of turbine design, siting and reliability

1.1.1 | Turbine configurations

There are various types of drive trains in operation for offshore wind. These configurations differ in many ways, primarily in regard to the gearbox, generator and converter. Previous turbine designs included three-stage gearboxes and doubly fed induction generators (DFIG) and partially rated power converters. Although popular with developers in the past, higher efficiencies using permanent magnet generators suggest that DFIG configurations will not be widely used in the future generation of wind turbines as long as the cost of magnets remains stable.[7]

The gearbox is one of the main components in the nacelle, which is used to convert the high torque low speed to low torque high speed from the turbine shaft to the generator. For offshore wind, environmental conditions such as waves tend to be harsher and more variable, which can be problematic for turbines. Studies have shown that gearboxes have a low reliability with faults often leading to downtime.[8-10] For an offshore site, downtime is longer than onshore sites due to the limitations with site accessibility, meaning high costs can be incurred with this component.[11] Additionally, a gearbox is often a very expensive component to replace, requiring a heavy lift vessel (HLV) for major replacements.[12] A popular alternative to the gearbox is the direct drive train configuration, which removes the gearbox completely from the nacelle. Gaining popularity offshore in recent years, this setup offers some advantages over the gearbox.[13] A direct connection from rotor to generator means issues with the gearbox are removed, but this solution comes with the requirement of heavy and expensive generators. As mentioned before, permanent magnet generators are another popular choice for generators and can be paired with a gearbox or direct drive. These utilise fully rated converters. These two configurations have been the most dominant nacelle design in the last decade.[14] Other drive train configurations have been explored and are continuing to be developed[11]; however, most of these designs are in their infancy and have not been commercially deployed at scale so are not being considered in this work. Research completed by Carroll et al[12] calculated the failure rates and reliability of smaller turbines (2–4 MW) for the two-stage gearbox with permanent magnet generator and the direct drive permanent magnet generator drive train configurations. These failure rates will be utilised in this study to provide a baseline. The two chosen drive train configurations are shown in Figure 1.

1.1.2 | Turbine size

The first offshore wind farm started operation in 1991 and had wind turbines with a power rating of 450 kW each.[15] Since then, the power rating and size of turbines has grown, with planning in place to deploy a 15 MW turbine and recently announced 22 MW turbine with a rotor diameter

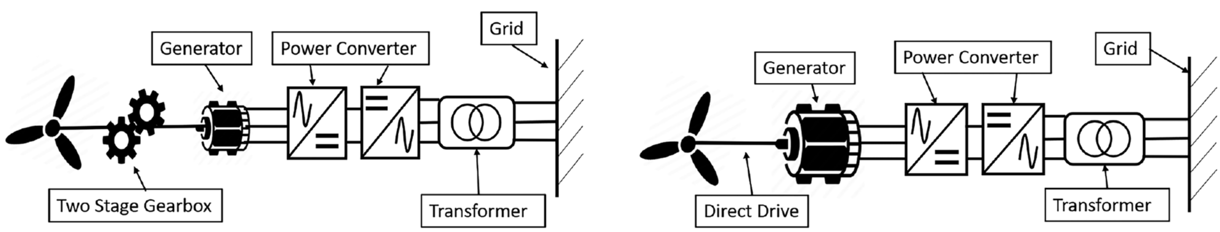


FIGURE 1 Drive train configurations for two offshore turbines. The left configuration shows a two-stage gearbox with a permanent magnet generator with a fully rated converter. The right configuration is the direct drive turbine with a permanent magnet generator and fully rated converter.

of 310 m within the next decade.[16,17] The benefit of upscaling the power rating of the wind turbines is the increase in the annual energy yield. The 15 MW turbine is predicted to increase the annual energy production by 45% compared to the previous 11 MW model.[16] In 2016, Wiser et al[18] carried out an expert elicitation survey regarding the future costs of offshore wind, considering the increase in turbine size. The survey was completed by 163 wind experts and results estimated a 9% reduction in operational expenditures (OPEX) for an 11 MW turbine fixed bottom case. The drawbacks, as mentioned by the study, is that expert elicitation can only predict the future based on opinions, but the reality may differ from these results. Developers are competitively increasing the power rating and size for the next generation of wind turbines, but the question of how O&M will change needs to be raised. With larger components, there may be issues with increased usage of larger vessels, a possible increase in technicians required, longer repair times and, importantly, larger costs incurred from downtime. Due to lack of experience with larger turbines, the problem facing the industry is the unknown, and as a result, research is focused on predicting the cost associated with wind farms at this scale. There is still doubt over this continual size increase, some research indicates that the reduction in the levelised cost of energy (LCOE) will plateau, with one study indicating no cost benefit between a 20 MW and 12 MW turbine for a given size of wind farm.[19] Furthermore, a study by Barter et al[20] comes to a similar conclusion in their work, which looks at different generator technologies for 15–25 MW turbines. Although this study holds the O&M costs at a constant, the study does indicate a plateau in the LCOE with increased turbine ratings. Hofmann and Sperstad[21] ask the question 'Will 10 MW Wind Turbines Bring Down the Operation and Maintenance Cost of Offshore Wind Farms?' and using a O&M modelling tool simulate scenarios for two 5 MW turbines versus one 10 MW turbine. They conclude that the answer to this question will be entirely dependent on the failure rates of these larger turbines and the maintenance duration for tasks. The study does not provide specific inputs for the component failure rates but does vary the 10 MW inputs through sensitivity analysis while holding a 5 MW turbine baseline scenario. The study also only looks at one location and turbine type. Figure 2 gives a schematic of the two different turbines being looked at in this study: The left is the 10 MW NREL reference turbine, and the right is the 3 MW turbine which will provide the baseline. The 10 MW turbine represents the 'next generation' of offshore wind turbines as, at the time of writing, the average rated power of current operational wind farms is below 10 MW, aside from Dogger Bank, which has recently deployed 13 MW turbines. Furthermore, Seagreen in Scotland deployed the first 10 MW offshore wind turbine in 2021. As mentioned previously, the 3 MW turbine in this study is based on the work by Carroll et al[12] and will be the baseline for the failure rates.

1.1.3 | Location

Although wind energy has been an established energy source in many European countries for the last few decades, there are countries still in their infancy when it comes to developing offshore sites. COP27 was the catalyst for nine new countries signing up to the Global Offshore Wind Alliance (GOWA), pledging to escalate and support plans for offshore wind.[22] Many of the countries in the GOWA, such as the United Kingdom, already have large commercial offshore wind farms, but others, such as the United States, do not. The growth in the size of turbines has been a natural progression for European developers, starting with smaller rated turbines, and as experience in the field has developed, the technology

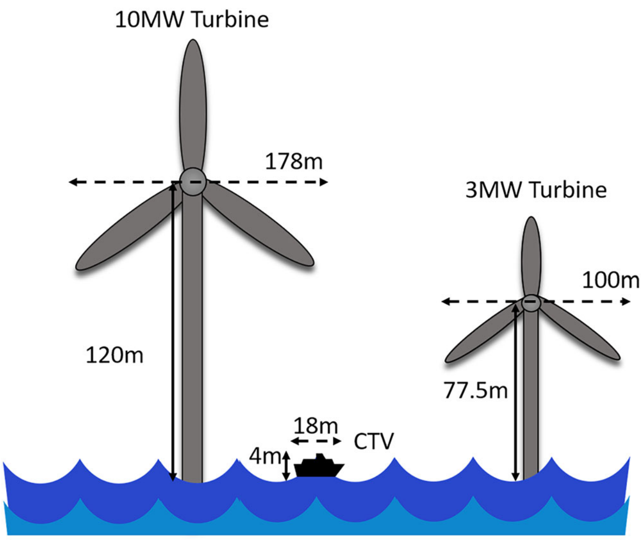


FIGURE 2 Comparison of turbine sizes between the 10 MW NREL reference turbine (left) and the 3 MW turbine (right), showing the hub heights and rotor diameters and relative to a standard catamaran crew transfer vessel that is used for maintenance in this analysis.

has advanced to a much larger scale. With the United States developing their offshore wind sector later, they have the opportunity of entering at the larger turbine stage, avoiding the smaller rated turbines, if it is profitable to do so.

A comparative review by de Castro et al[23] in 2019 looked at the development of offshore wind in Europe, China and the United States and the different challenges faced by each. It states that the United States has a well-developed onshore wind sector yet has struggled to mirror this progress in the offshore sector despite having high potential in terms of the wind resource. Economic incentives have fallen short of the mark also. There is currently no mandatory legislation regarding purchase agreements with grid operators as of 2023. A recent assessment completed by Jost et al in 2023[24] describes the current projections outlined by the Biden administration to install 30 GW of offshore wind by 2030 and the reality of trying to achieve that. The paper highlights issues with licensing and states that it currently takes 5 years to go through the process of putting a bid in for a project and receiving approval. Site locations on the Atlantic coast tend to be near major cities but this has led to issues regarding public support, leading to lengthy project times. Regardless of challenges facing the United States, there is a strong push for offshore wind to become more integral in the US energy make up. Figure 3 shows a map of offshore projects in the United States as of 2023. The planned sites in blue are the vast majority of projects on this diagram with only five projects either being approved, under construction or operational. The black circle indicates Martha's Vineyard Coastal Observatory, the location that the climate data for the US site in this study are sourced. Each offshore wind farm site has vastly different climate characteristics, with associated advantages and disadvantages. Consequently, location is a variable that will substantially impact the O&M of a wind farm and, ultimately, the overall cost. Factors to consider when evaluating a location include wind resource, sea conditions, distance from shore, grid connection, seabed foundations and many more. In this study, two different locations have been chosen. The first site is in the North Sea off the coast of Germany, where there are currently 18 operational offshore wind farms.[26] The second site is on the North East Atlantic Coast of the United States, a location where there are many projects in the early planning stages. The aim is to assess the suitability of larger rated turbines in both locations and compare O&M costs between turbine sites, types and sizes. Section 2.1.2 gives further information regarding the wind farm site selection.

1.2 | Failures and reliability

The crux of this research is turbine reliability. More specifically, the number of turbine failures per unit time, known as the failure rate. The classification of failure differs from paper to paper, but the grouping used in this research will be failures that require minor repair, major repair and major replacement. Minor and major repairs can be carried out using crew transfer vessels (CTVs), with the minor being less expensive than a major repair. A major replacement refers to a replacement of a component that involves an HLV to carry out the operation. Major replacements are the most costly out of the three classifications. Note that these classifications do not use the same cost thresholds as they were originally defined by ReliaWind in 2007 (stated in Carroll et al[27]). Turbines were much smaller in size, and components were less expensive, so classifications in terms of cost will have increased over time. The failure rates used in this research come from the paper by Carroll et al,[27] which uses this definition in their work. These are in the format of failure rates per turbine per year using the formula:

$$\lambda = \frac{\sum_{i=1}^{I} \sum_{k=1}^{K} \frac{n_{i,k}}{N_i}}{\sum_{i=1}^{I} \frac{T_i}{8760}} \tag{1}$$

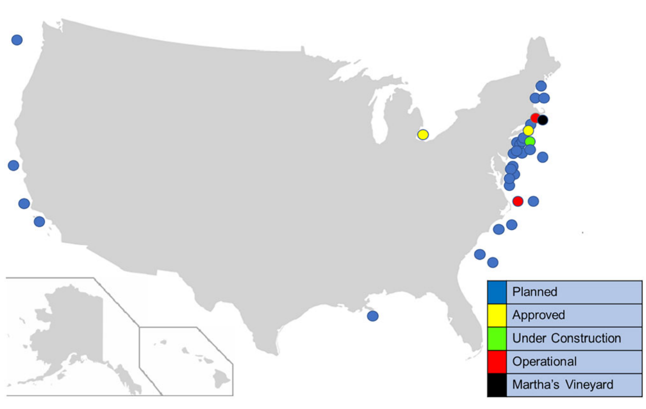


FIGURE 3 Map of offshore wind farms in the United States ranging from planning stages to fully operational. Black circle indicates Martha's Vineyard coastal observatory, the location that the climate data for the US site are sourced. Data sourced from The Wind Power,[25] up to date as of 2023.

where λ is the failure rate per turbine per year, T is the total period in hours, N is the number of turbines, n is the number of failures, and i represents the intervals for data collection and k represents the sub-assemblies. Carroll et al[27] found an average failure rate, λ, of 8.3 failures per turbine per year. One of the uncertainties regarding 10 MW turbines is their failure rates. Previous work by Jenkins et al[28] uses structured expert elicitation methods to determine major replacement rates for 15 MW turbines. Results showed that 15 MW two-stage turbines would be subject to a larger number of major replacements than direct drive. The study was limited to major replacements for 15 MW turbines and does not discuss the major repairs and minor repairs.

The aim here is not to predict what these failure rates will be but rather to input known failure rates from smaller rated turbines to see how this impacts the O&M costs. Then after looking at the baseline failure rates, adjust the baseline failure rates through sensitivity analysis to see at what failure rates do a 10 MW turbine and a 3 MW turbine have the same O&M costs in a cost unit per MWh format. It should be noted that the failure rates of the 3 MW turbines are not representative of larger 10 MW turbines. To perform the sensitivity analysis, all variables in the simulation are kept the same, apart from the failure rates. The failure rates are increased by 10%, 20%, etc. up until 100% of their original value, and these were simulated in the model. Similarly, the failure rates were decreased by 10%, 20%, etc. until a 90% decrease from their original value. Table 1 outlines the failure rates taken from Carroll et al,[27] which will be used for both the direct drive and two-stage turbines and the vessel type that is required to complete the maintenance. Note that for the gearbox failure rates the direct drive is set as blank as this component is not present in the configuration. Furthermore, the main bearing failures are encompassed in the rest of turbine failure rates.

The novelty in this work comes from the fact there has been limited investigation into the O&M costs in the United States for large offshore wind turbines and the performance of different drive train configurations in this climate. Research from Shields et al[29] investigates the impact of LCOE from upsizing turbines and plant size using a site location also along the East Coast of the United States. The paper succeeds in determining the benefit of using larger turbines and larger wind farms at the chosen site but does not go into depth regarding specific turbine configurations and how this affects the O&M costs. It highlights one of the key assumptions in the paper is to hold failure rates constant regardless of the size of the turbine. In this research, the failure rates will be adjusted for a 10 MW turbine to determine the rates in which a 10 MW will have the same O&M costs as a 3 MW turbine. As mentioned before, each site will offer different climate characteristics, but this paper will give a comparative analysis of the two locations, which contributes to the originality of this work. In summary, the novelty of this paper stems from first of a kind analysis determining:

- whether the OPEX per MWh reduces as turbines get larger, providing the reliability of the larger turbines can be as good or better than existing 3 MW turbines. It is known within the wind energy industry that CAPEX per MWh reduces as turbines get larger; this work will determine if that is also the case for OPEX.
- the required reliability of the next generation of offshore wind turbines to allow for the same or reduced O&M costs compared to existing offshore wind turbines.
- the impact of site location on the O&M costs of the next generation off offshore wind turbines.
- the impact of wind turbine/drivetrain type on the O&M costs of the next generation of offshore wind turbines.
- the impact of the combination of all of the above variables on the O&M costs of the next generation of offshore wind turbines.

TABLE 1 Outlining the baseline failure rates per turbine per year for the wind turbine components of a 3 MW two stage turbine and 3 MW direct drive turbine. Vessel types: crew transfer vessel (CTV), feeder support vessel (FSV) and jack-up vessel.

Component	Repair type	Two-stage	Direct drive	Vessel required
Generator	Minor repair	0.473	0.546	CTV
	Major repair	0.026	0.030	CTV
	Major replacement	0.008	0.009	Jack-up
Converter	Minor repair	0.538	0.538	CTV
	Major repair	0.338	0.338	CTV
	Major replacement	0.077	0.077	FSV
Gearbox	Minor repair	0.305	–	CTV
	Major repair	0.030	–	FSV
	Major replacement	0.042	–	Jack-up
Rest of turbine	Minor repair	5.76	5.76	CTV
	Major repair	0.686	0.686	CTV
	Major replacement	0.001	0.001	FSV

2 | METHODOLOGY

2.1 | Strath OW O&M model inputs

The O&M modelling tool used in this work is the industrial bench-marked Strath OW O&M model developed by Dinwoodie et al. For a more in-depth explanation of how the tool operates and its functionality, see literature.[30–32] The basic principles of the model are as follows and a schematic has been provided in Figure 4. The tool requires a number of key inputs from the user and using these inputs will model climate, turbine failures and O&M cost for the life time of a selected offshore wind farm. To model the climate, the user is required to input a minimum of 1 year's worth of hourly wind speed and significant wave height data. The model then simulates a time series of wind speed and significant wave height values over a user defined wind farm lifetime using the historical data provided while retaining any seasonality trends. A non-homogeneous Poisson process (NHPP) is used to model reliability through time. For each time step, the conditional reliability of a subsystem is compared to a hazard rate to determine if that subsystem has failed. The hazard rate is based on the failure rates input by the user. The wind turbine failure is also used when calculating availability, lost energy production and maintenance action required. When a failure occurs, repairs are carried out dependent on availability of required resources (in terms of vessels, staff and materials) and climate restraints on vessel operational usage (significant wave height and wind speed limits). Again, the resource and operational limits are user-defined. Once the shift is simulated, the model records the condition of the wind farm in terms of turbines available and resources utilised. The process is repeated for the specified lifetime of the farm, and the lifetime power production and availability are calculated and stored. The user can also define the number of simulations that are run for each scenario, and the outputs produced by the model are mean values across this number of simulations. The choice of number of simulations is to obtain a convergence of availability estimates on cross-simulation values. Cross-simulation calculations are passed to model outputs for post-processing. Outputs consist of a list of key performance indicators (availability, power production and number of failures), cost estimates (revenue, lost production costs, vessel and staff costs, costs of spare parts) and vessel specific information (CTV utilisation, number of jack-up vessel [JUV] charters).

Here, the same wind farm model is used for all scenarios considered, but adjustments have been made to the inputs. The following subsections will elaborate on these inputs and their justifications.

2.1.1 | Wind farm inputs

These are inputs regarding the wind farm that are held fixed across the four different scenarios. Table 2 outlines the important variables that were held constant throughout the models. Wind farm lifetime was chosen as 20 years; however, it has been indicated in some literature that due to advances in lifetime extension methods, this may be extended to 25–30 years. For the purpose of this research, it was only important to keep the value consistent throughout the scenarios, not the value itself, and 20 years is in agreement with some early lifetime predictions.[34] The choice of 100 simulations was to ensure convergence in the output results. When simulating 100 times, the results converge to 0.0002%. The distance

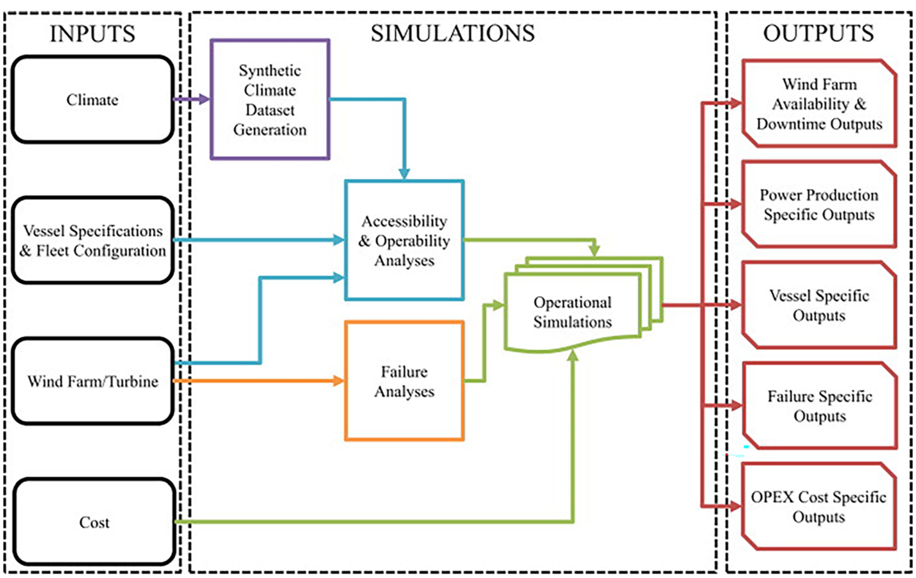


FIGURE 4 A schematic diagram depicting the Strath OW O&M tool and its basic principles of operation. Diagram from Dalgic et al.[33]

from shore was selected based on the location the climate data were observed for the North Sea and also aligns with the predicted trend that 'next generation' of turbines will be further from shore.[35] The number of turbines is a value in keeping with patterns in industry, and for comparison, the number of turbines should be kept constant for both turbine sizes, similar to Jenkins et al.[28]

2.1.2 | Climate inputs

As previously mentioned, the two climate data sets come from the North Sea and the East Coast of the United States. The North Sea data set is a 6 year span of FINO data located 45 km off the coast of Germany, which includes a complete set of hourly measurements of wind speed, wave period and significant wave height.[36] The wind speed is required for two reasons: firstly to calculate the power production of the wind turbine and secondly the wind at the sea surface to determine accessibility for different vessels. The significant wave height and wave period are also used for accessibility indicators; in particular, significant wave height limits are widely used as the main criterion to authorise maintenance vessels to travel to the wind farm. The data for the East Coast of the United States is in the same format but only contains 15 months of recorded data, which was sourced from the Martha's Vineyard Coastal Observatory[37] located in Edgartown, Massachusetts. The model requires the wind speed observation height and the hub height of the wind turbine selected. With these values, the wind speed at the theoretical height of the turbine is calculated using the log law, a simplified mathematical equation to calculate how the wind speed increases with height. The model will take these inputs and generate a simulated time series of weather over the span of the wind farm lifetime based on the data set provided.

Taking each variable separately, the wind speed, wave period and wave height for both sites can be compared. The mean and standard deviation for the wind speed, wave height and significant wave height are shown in Table 3.

The data indicate that the climate characteristics in the United States are more variable than in the North Sea. Looking at the wind speeds, the United States experiences higher peaks and lower troughs than the North Sea, and this is confirmed by the higher value for the standard deviation of wind speed also. A similar trend can be seen for both the wave period and significant wave height. The standard deviation for the data indicates that the wind speed and wave period vary from the average more than the North Sea; however, the standard deviation is lower for the significant wave height for the United States.

2.1.3 | Transport inputs

Three types of vessels were utilised in this work, the general inputs of these vessels are shown in Table 4, which is based on work by Dalgic et al.[38] The CTV used is a Catamaran, there are five of these available with the capacity to carry six technicians. The jack-up strategy is fix on fail with fixed charter and has a mobilisation cost of £1.8 million.[38]

2.1.4 | Specific turbine inputs

The outputs from the model for O&M costs are in £/MWh; therefore, the power production is required. For the model, information was required regarding the 3 MW turbines and 10 MW turbines for both the direct drive configuration and the two-stage configuration. The 10 MW NREL

TABLE 2 Inputs to model which were held constant regardless of location, drive train or turbine size.

Model input	Value chosen
Number of simulations	100
Wind farm lifetime (years)	20
Number of turbines	100
Distance from shore (km)	45

TABLE 3 The averages for the three climate variables taken from the North Sea data and US data.

Climate variables	North Sea Mean	North Sea σ	East Coast United States Mean	East Coast United States σ
Wind speed (m/s)	7.77	3.52	7.81	3.94
Wave period (s)	5.62	1.33	6.06	1.54
Significant wave height (m)	1.08	0.63	1.13	0.58

reference turbine's power curves were used, one for direct drive and the other for two stage, as well as turbine characteristics such as hub height, cut-in speed, cut-out speed, and rated speed.[39] The 3 MW turbine inputs come from the work from Carrol et al.[12] The other turbine specific input was the failure rates for the turbine depending on configuration, which can be seen listed in Table 1.

2.1.5 | Cost inputs

To estimate the repair costs for the 10 MW turbines, a report by BVG and the Crown Estate was used.[40] The report provided values for major replacement costs for turbine components. Any major or minor repair costs for the 10 MW were taken from the 3 MW case and scaled proportionally. Scaling was done by using the ratio of major replacement to major repair and minor repair costs for the 3 MW components; then, costs were scaled using these ratios to estimate the 10 MW turbine major repair and minor repair.[27] The cost inputs for the wind turbine components, based on the repair required, are listed in Table 5.

The mobilisation cost for the JUV for a 3 MW turbine is £250,000 and the 10 MW turbine is £1,800,000. The difference in mobilisation costs is based on a report by ORE Catapult that suggests that the lifting capacity of the vessel will result in higher O&M costs for larger turbines.[41] The report talks specifically about the HLV that would be used in a floating case, so using the value stated in their report is a conservative approach for this study. It is reasonable to assume that due to the lack of HLV available for charter, the prices are going to increase for these larger turbines.

The repair time and number of technicians required for repair are held the same for 10 MW as 3 MW, which can be found in Carroll et al.[27] These have been held constant based on the assumption held by experienced members of the offshore wind industry that due to lessons learnt and the modern processes in optimising maintenance through innovation, holding this constant is a conservative approach. Electricity price has been held constant across all scenarios in this study. While the electricity markets considered in this study are likely to have different prices, the focus here is to obtain a relative difference between scenarios for comparisons to be made.

TABLE 4 Transport inputs to the model which were held constant in all scenarios. Based on work by Dalgic et al.[33]

	CTV	FSV	Jack-up
Wave height limit (m)	1.5	3	4
Wind speed limit (m/s)	20	12	36[a]
Charter rate (£/day)	1980[b]	9500	360,000
Mobilisation time (days)	N/A	30	60
Fuel consumption (m^3/h)	0.24	0.3	0.55
Operational speed (knots)	12	12	11

[a]Survival speed of the jack-up vessel; the lifting limit wind speed is 8 m/s.
[b]Per CTV utilised.

TABLE 5 Outlining the cost inputs in £ for the wind turbine components of a 3 MW direct drive turbine, 3 MW two-stage turbine, 10 MW direct drive turbine and 10 MW two-stage turbine.

Component	Repair type	3 MW direct drive (£)	3 MW two-stage (£)	10 MW direct drive (£)	10 MW two-stage (£)
Generator	Minor repair	875	398	5253	2627
	Major repair	19,573	8897	117,497	58,749
	Major replacement	333,174	151,443	2,000,000	1,000,000
Converter	Minor repair	237	237	788	788
	Major repair	5280	5280	17,600	17,600
	Major replacement	12,742	12,742	42,473	42,473
Gearbox	Minor repair	–	97	–	384
	Major repair	–	2007	–	7957
	Major replacement	–	176,588	–	700,000
Rest of turbine	Minor repair	181	181	602	602
	Major repair	2234	2234	7445	7445
	Major replacement	33,427	33,427	111,422	111,422

3 | RESULTS AND DISCUSSION

The following results are split into three sections. Firstly, results are provided for the 10 MW turbines for the two locations, subsequently followed by a comparison section at the end. Before discussing the results from the 10 MW turbines, the baseline results must be modelled. For the North Sea and United States, a baseline case of 3 MW was simulated for each drive train configuration. The outputs from the model include an O&M cost overview as well as an availability and power production overview. The cost overview has two main outputs: total O&M costs and direct O&M costs. Direct O&M costs take into consideration staff costs, repair costs and transport costs, whereas total O&M costs have the additional contribution of lost revenue costs. The values for the total and direct O&M costs are listed in Table 6 and are plotted in the following sections. These results are in keeping with the findings from Carroll et al,[12] which determine that the 3 MW turbines with a direct drive (DD) configuration are lower in both total and direct O&M costs than the 3 MW turbines with a two-stage drive train configuration. This observation holds true for the 3 MW turbine in both North Sea and US sites. Looking between the two locations, the total O&M costs for a 3 MW turbine site are considerably lower in the United States than in the North Sea. The direct O&M costs are also lower in the US site; however, there is not as large a difference in this cost.

3.1 | North Sea

Figure 5 shows the total O&M costs produced for a 10 MW turbine case in the North Sea. On the left is the plot for the direct drive configuration, and on the right is for the two-stage configuration. The blue line is the 10 MW turbine as the baseline failure rates are altered over a range of −90%–100%. The black dashed line indicates the baseline 3 MW total O&M costs from Table 6, which are held constant. For direct drive configuration, the point at which 10 MW turbines have the same total O&M cost as the 3 MW turbines is when the baseline failure rates are increased by roughly 20%. For the two-stage configuration, 10 MW turbines have failure rates increased by 10% before they are equal in total O&M cost to the 3 MW turbines. The increase in failure rates required for the total O&M costs of a 3 MW and 10 MW case to be equal may be a result of the increased power production from the 10 MW turbine, which reduces total O&M costs.

Disregarding the O&M costs associated with lost revenue, Figure 6 shows the direct O&M costs for the 10 MW turbine cases in the North Sea. For the direct drive, direct O&M costs are lower for the 10 MW turbine until failure rates are increased to 70%–80% of the baseline failure rate. With a notable difference between the two configurations, direct O&M costs for two-stage reveal that the 10 MW turbine is lower cost than the 3 MW turbine until the failure rates are increased by 30% after which the 10 MW turbine will be more expensive. These results are of note for two reasons. Firstly, it confirms that the direct drive configuration is less costly than the two stage configuration regardless of the power rating increasing in this location. Secondly, it highlights that the inclusion of lost revenue has a bigger impact on the direct drive than on the two stage. Taking the % change in failure rates required to equal the 3 MW turbine O&M costs for total O&M costs and direct O&M costs, there is a larger difference for direct drive (estimated 55%) compared to the difference between the total and direct O&M costs of the two-stage (estimated 20%).

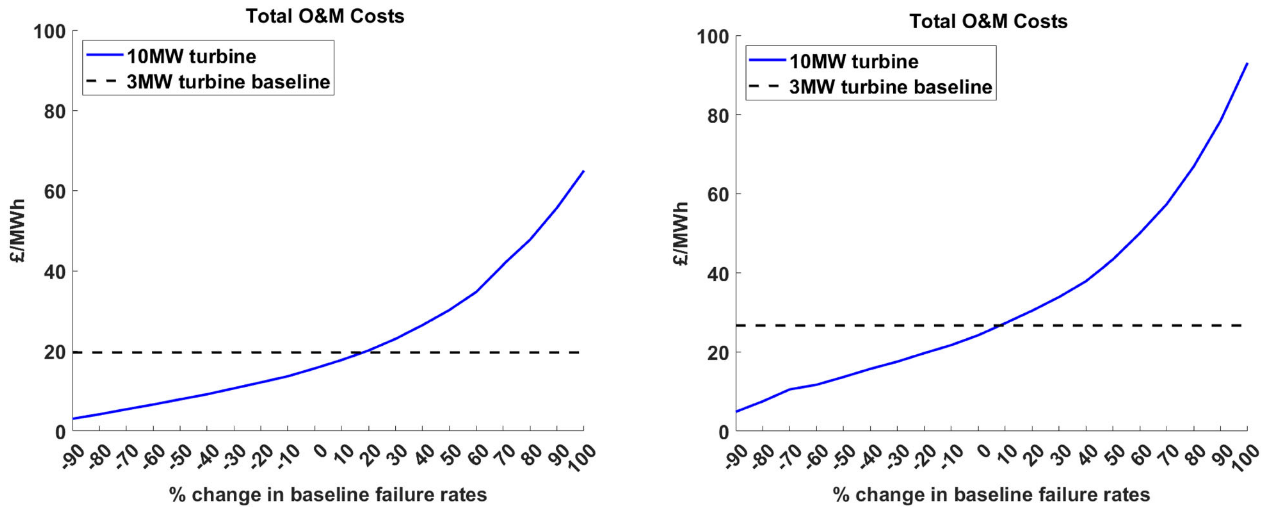
The last figure in this section, Figure 7, shows the comparison of a 10 MW turbine to a 3 MW turbine focusing on when failure ratings are the same. It includes both the direct and total O&M costs. The relative difference between 3 MW O&M costs and 10 MW O&M costs is very similar. For example, focusing on direct drive, the difference between 3 MW total O&M costs and 3 MW direct O&M costs is £12.34/MWh, and for the 10 MW case, this difference is £12.03/MWh. In the North Sea, the change in the turbine rating does not greatly impact the relative difference between the total and direct O&M costs.

3.2 | United States

Following the same method for the United States, Figure 8 shows the total O&M costs for direct drive turbine plotted against the 3 MW direct drive turbine. An increase between 20% and 30% increased baseline failure rates is the point at which total O&M costs for the 10 MW

TABLE 6 3 MW turbine results. Direct O&M costs take into consideration staff costs, repair costs and transport costs, whereas total O&M costs have the additional contribution of lost revenue costs.

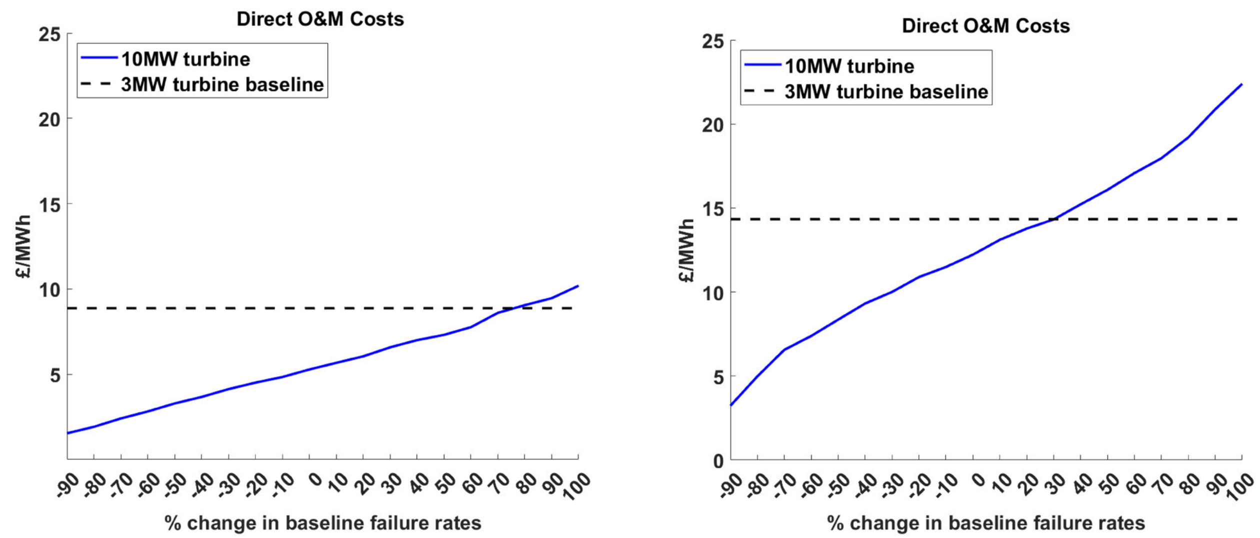
	Total O&M costs (£/MWh)	Direct O&M costs (£/MWh)
North Sea direct drive	19.66	8.88
North Sea two-stage	26.68	14.34
US direct drive	16.30	8.61
US two-stage	23.11	14.03



(A) Direct Drive Train Configuration

(B) Two Stage Drive Train Configuration

FIGURE 5 Total O&M costs in the North Sea for changing failure rates of a 10 MW turbine compared to the baseline 3 MW turbine case.



(A) Direct Drive Train Configuration

(B) Two Stage Drive Train Configuration

FIGURE 6 Direct O&M costs in the North Sea for changing failure rates of a 10 MW turbine compared to the baseline 3 MW turbine case.

direct drive turbine exceed the total O&M costs of the 3 MW direct drive turbine. When the two turbine sizes have the exact same baseline failure rates, then the 10 MW turbine is £3.42/MWh lower in total O&M cost than the 3 MW turbine, equivalent to 21% decrease in total O&M costs.

Looking at Figure 8B at the same location but changing the configuration to a two stage turbine the results differ. The 10 MW turbine is lower in total O&M cost than the 3 MW set up until its failure rates are increased between 10% and 20%, which is a smaller increase than in the direct drive case.

In terms of the direct O&M costs for the US site, as seen in Figure 9, the 3 MW has a higher £/MWh O&M cost than the 10 MW turbine for direct drive up until the failure rates are increased above 80% of the original value. From this, it could be said that the lost revenue cost has a large impact on the 10 MW turbines for direct drive; this is due to the increased power production that the 10 MW turbines can provide. Furthermore, due to this higher power production, the 10 MW turbine ends up being a lot lower in O&M cost compared to the 3 MW turbine when it comes to the direct O&M costs.

For the direct costs of the two-stage, the 10 MW case is again lower in cost at the baseline point and continues to be lower in O&M cost until the failure rates are increased to between 40% and 50% of the original values. Comparing this to the direct drive O&M costs, as seen in the North Sea, there is a significant difference between the total and direct O&M costs for the direct drive turbine in terms of the change of failure rates

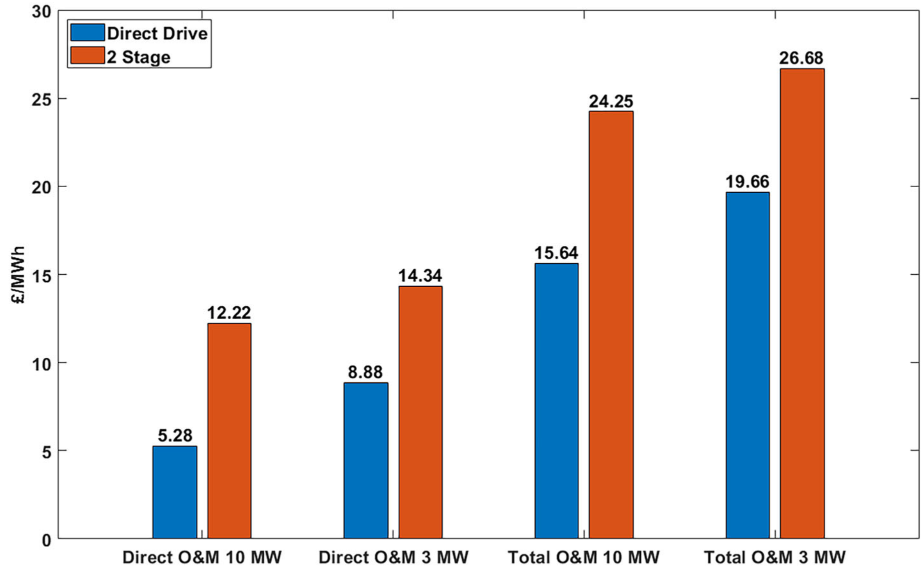


FIGURE 7 Overview of O&M costs for 3 MW and 10 MW turbines in the North Sea for direct drive and two-stage configurations.

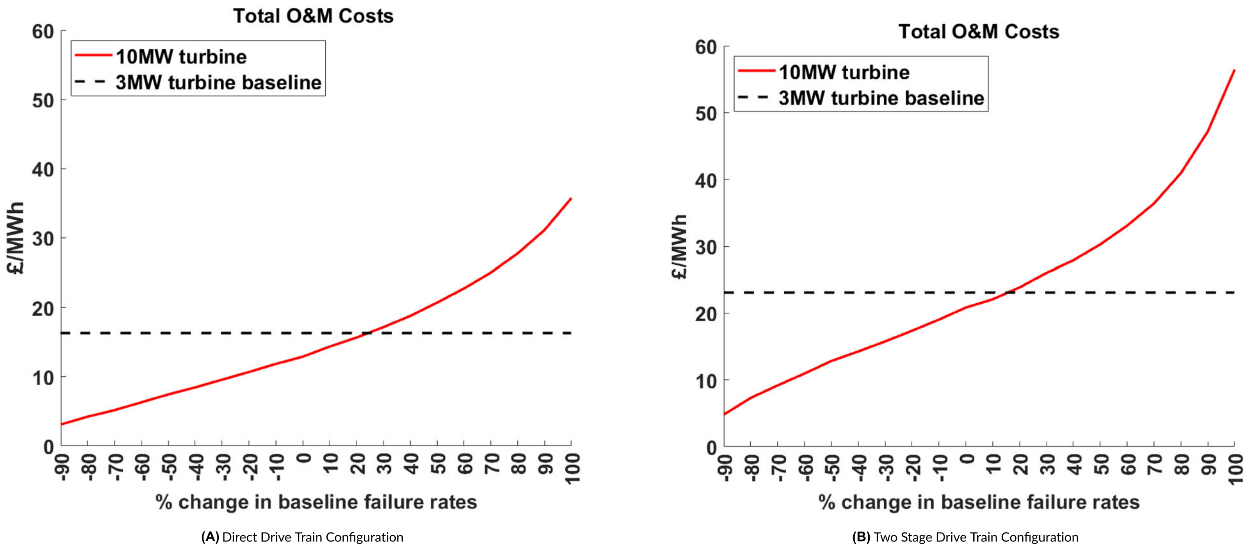


FIGURE 8 Total O&M costs in the United States for changing failure rates of a 10 MW turbine compared to the baseline 3 MW turbine case.

required before 10 MW becomes more expensive than 3 MW. This difference is much smaller in the two-stage configuration; therefore, taking account of lost revenue has a bigger impact for the direct drive configuration than for the two-stage in the US site also.

3.3 | Comparison

Figure 10 shows a comparison of the North Sea site versus the US site for the direct drive and two-stage drive train configurations for both total O&M costs and direct O&M costs of the 10 MW turbine. Comparing the difference in O&M cost between configurations for both sites shows that, when looking at the baseline failure rates as shown in Figure 10, both the North Sea and the United States have similar O&M cost differences between the two configurations both in terms of total O&M costs and direct O&M costs. However, focusing on the differences between Figure 5 and Figure 8 (or between Figure 6 and Figure 9), as the failure rates are increased, the O&M cost gap between configurations widens at a faster rate in the North Sea than in the United States. These results suggest that if a 10 MW turbine does have higher failure rates than a 3 MW turbine, the US site may be more suitable than the North Sea site for a two-stage configuration of that turbine. The transport costs associated with the two-stage drive train turbine are more expensive due to the gearbox requiring an HLV for maintenance. The US site having increased

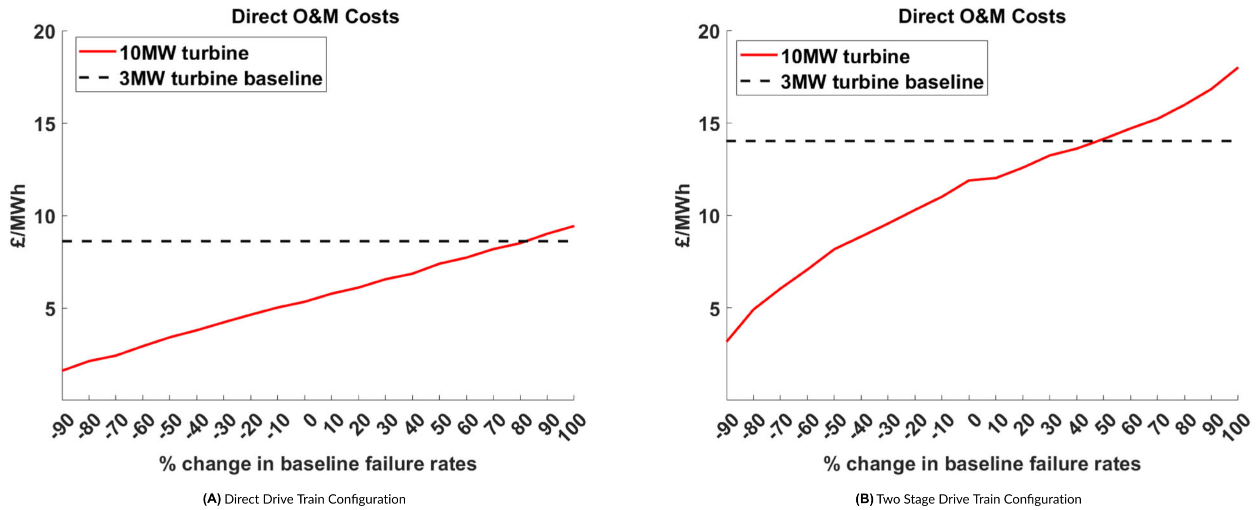


FIGURE 9 Direct O&M costs in the United States for changing failure rates of a 10 MW turbine compared to the baseline 3 MW turbine case. (A) Direct drive train configuration. (B) Two-stage drive train configuration.

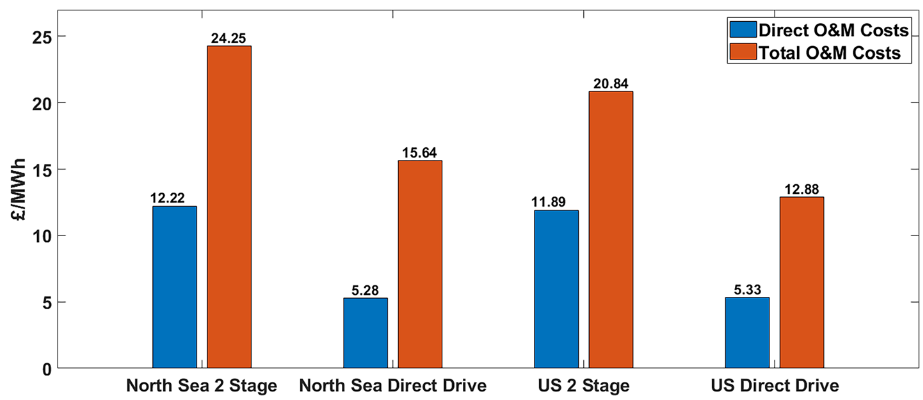


FIGURE 10 Overview of the direct and total O&M costs of the North Sea site versus the US site for the direct drive and two-stage drive train configurations of the 10 MW turbine.

accessibility and lower amounts of downtime than the North Sea may combat these expensive vessel costs better than the North Sea is able to. Increased accessibility stems from the climate conditions at the site.

Looking at Table 3, the values indicate that accessibility in the North Sea would be higher, due to the lower average wind speed, significant wave height and wave period; however, the issue is more complex than it appears. Table 3 shows the averages over the 20-year lifetime, but accessibility and crew transfer decisions are on a much smaller timescale. The decision to dispatch maintenance is on an hourly basis and requires consecutive hours where the vessel limitations are not breached; these are known as weather windows. Accessibility is higher for the US site due to the consecutive weather windows provided to allow maintenance to occur. The North Sea, despite having lower average wind speeds and wave heights, has more frequent, consistent wind speeds and wave heights that breach the limitations assigned to the vessels. Taking the percentage of significant wave height measurements that are 1.5 m or above, the North Sea breaches the limit 21% of the time, whereas the US scenario breaches the limit 18% of the time. Narrowing the data to only values during the working shift (8 AM to 8 PM), the North Sea was found to breach the limit 21.4% of the time, whereas the United States breached the limit 19.3% of the time. Though there is a smaller difference between the percentages, the trend is still the same. It was found that there were no occasions where the wind speed breached the vessel limit that did not also have a corresponding significant wave height measurement that exceeded the vessel limit, so these have not been considered here.

Figure 11 gives some examples of weather windows at both sites. The two dates have been selected as they contain the maximum value significant wave height for the North Sea (7th of December) and the United States (30th of October). The green highlighted area of the graph shows the 12-h shift from 8 AM to 8 PM. Although these are only two examples of weather windows, in both Figure 11A and Figure 11B, the North Sea significant wave height is above the wave height limitation for a CTV (marked on the graph with a black dashed line) throughout the work shift. The US significant wave height is below the CTV limit for Figure 11A, but on the 30th of October in Figure 11B, when the United States experiences the maximum wave height, the limit is breached after 11 am. These examples are to illustrate that metocean conditions can be misinterpreted if looking at the overall climate set over a long period of time. Accessibility involves dissecting the data at a smaller scale to understand dispatching decisions.

For both the two-stage and the direct drive, the total O&M costs for the 10 MW turbine are lower in the East Coast United States than in the North Sea case. This indicates that, if lost revenue is taken into account, the North Sea is a less favourable site for the 10 MW turbine than the US site in terms of total O&M costs. If lost revenue costs are not considered, there is a smaller difference between the two sites for the direct costs. In fact, in this case, the US site produces a slightly higher direct O&M cost for the direct drive configuration. Most analysis from these results point towards site location being a key factor in the cost of O&M. The climate data from Section 2.1.2 from Table 3 show that for wind speed, wave period and significant wave height, the United States had a higher overall average. This is somewhat contradictory to the Figure 12B, which illustrates that the power production for the North Sea site is greater than the US site for all failure rates.

The reason behind these results is related to the turbines that were selected for the model. They were not optimised for site conditions and the 10 MW turbines had a set rated speed at 12 m/s. The US site had a larger variability in wind speeds, but the turbine selection did not account for this; therefore, the 10 MW turbine in the North Sea site benefited from the rated speed more. When looking at the climate data at below rated speed, it was found that the United States had a lower average wind speed when considering the lower range of 0–12 m/s in comparison to the North Sea. The findings from this comparison emphasise the importance of reducing downtime in larger turbines. The reliance on higher power production to create profits means accessibility becomes a very influential factor. If climate conditions are consistently above the operational limits of the vessels, the ability to carry out maintenance to restore a turbine to full operation becomes compromised. As shown in Figure 12A, the availability of the two North Sea turbines is lower at baseline failure rates, and as failure rates increase, the availability of the turbines drops off at a quicker rate due to these conditions.

Figure 13 gives the breakdown of the total O&M costs for the four scenarios. The two-stage configuration in the United States differs from the other three scenarios as the transport costs are the largest contributor for the 10 MW turbine. The largest contributor in the other cases is lost revenue. The transport costs are expected to be higher for the two-stage as it uses the HLV more often due to the gearbox and generator. The reduction in lost revenue for the two-stage US turbine could be linked to the calmer met ocean conditions, which means turbines have reduced downtime. The biggest driver in O&M cost difference between the two types of configurations is the transport cost. The HLV is very expensive, so the increased use of this vessel for the two-stage has created this larger overall cost for direct O&M and total O&M. The direct drive configuration for the United States has similar staff, repair and transport costs as the North Sea, but the lost revenue is much larger in the North Sea compared to the United States, which, as explained previously, is due to the reduced availability of the turbine.

3.4 | Limitations and suggestions for further work

A limiting factor in the wind resource calculations is the use of the logarithmic law to calculate the wind speed at higher hub heights. The choice of the logarithmic law was for mathematical simplicity as it is widely accepted as a convenient approximation for wind speeds, but in reality, the

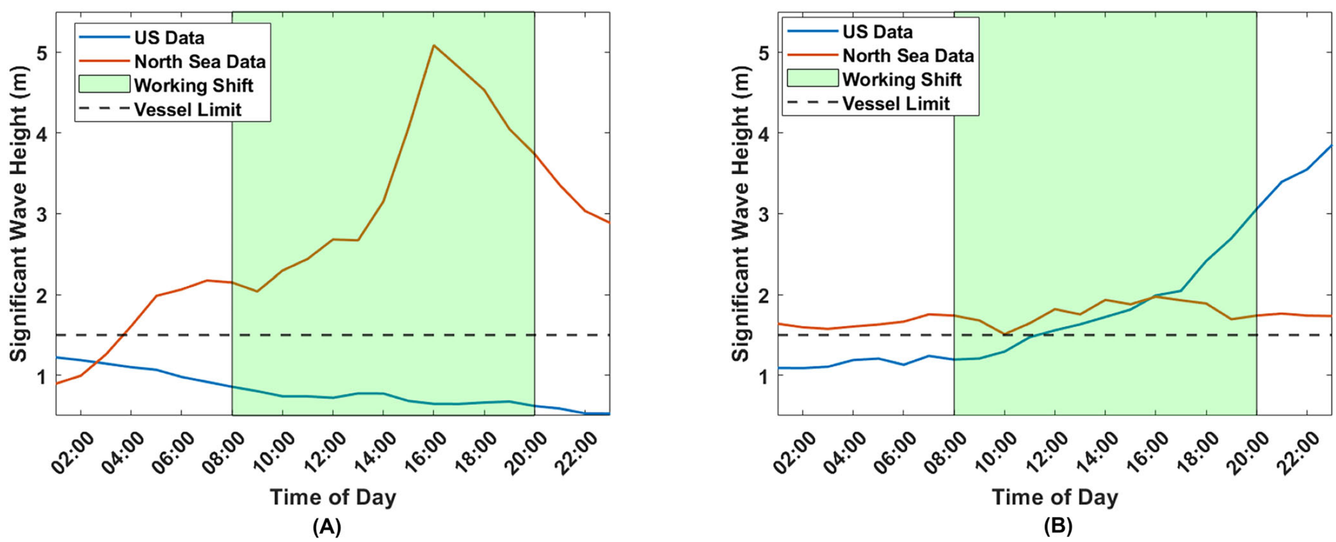


FIGURE 11 Weather window examples for the North Sea and US sites. (A) the significant wave height on the 7th of December, where the highest wave height for the North Sea is experienced, and (B) the significant wave height on the 30th of October, where the highest wave height for the US site is experienced. The green shaded area is to highlight the working shift when crew transfers occur (8 AM to 8 PM), and the black dashed line represents the wave height limit for a CTV.

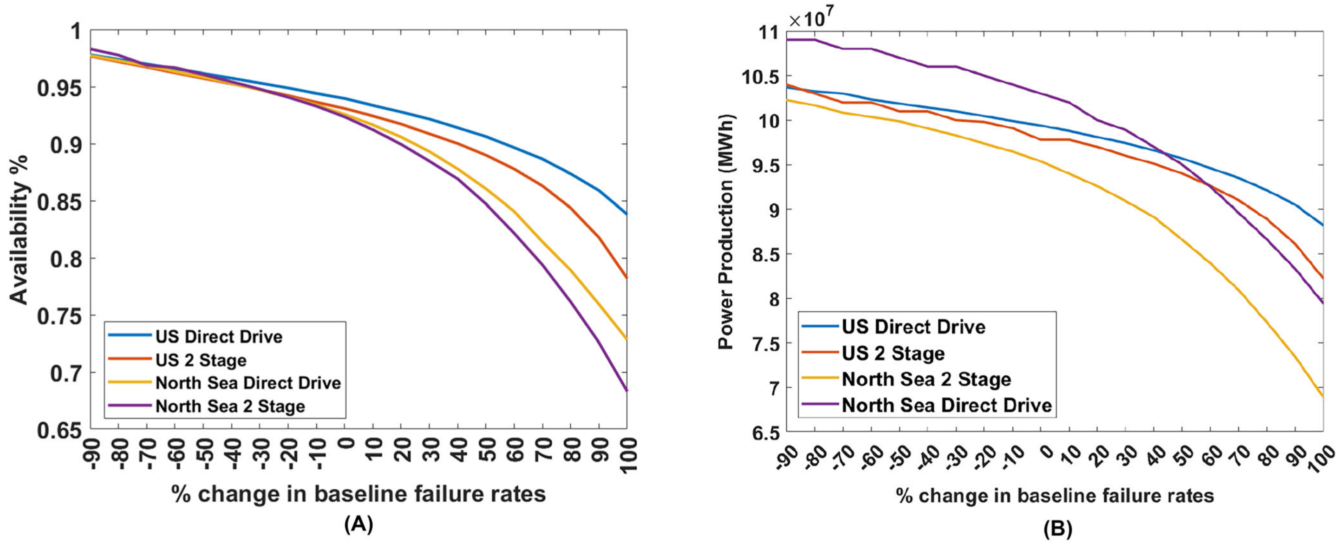


FIGURE 12 Impact of changing failure rates for the four scenarios on (A) availability and (B) power production.

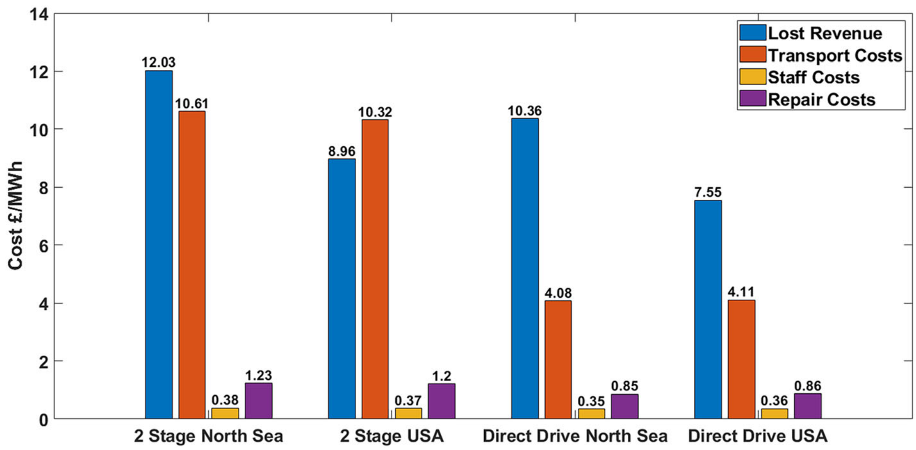


FIGURE 13 Breakdown of total O&M costs for the four scenarios.

complex nature of wind shear profiles may result in different wind speeds at the 10 MW hub heights. One limitation of the study is in regard to the variables held constant throughout the models. For example, in this work, the inter-transit time between wind turbines for maintenance trips was held constant regardless of the turbine size. In reality, the size of wind farms will undoubtedly increase from 3 to 10 MW due to the increased rotor diameters, which requires an increase in spacing between turbines to reduce the effect of wake interactions. The question of how this will impact the overall cost, if at all, remains to be seen but is a point for further work. To add to this analysis in future, the authors would like to gain a better understanding of the failure categories that contribute most to the cost deltas seen in this work. A study of specific minor repair, major repair and major replacement contributions to cost may shed further light on the areas of O&M that need addressed for these larger turbines. Another point arising from this work is the contribution from the converter to the total O&M costs. The lost revenue costs being consistently high points to the converter being a large contributor. Additionally, as mentioned, the optimisation of a turbine based on the site location is another suggestion for further work as it would potentially provide a fairer comparison between sites.

4 | CONCLUSIONS

The aim of this research was to determine if a larger 10 MW turbine would be lower in cost in terms of O&M costs than a 3 MW turbine when the failure rates were held the same. To do this, a cost model was simulated for two different drive train configurations, direct drive and two-stage drive trains, and looked at two different site locations, North Sea and East Coast United States. Based on the two sites analysed, results found that when the same baseline failure rates are used for a 3 MW turbine and a 10 MW turbine with the same location and same configuration, the 10 MW turbine will be lower in cost in terms of both direct O&M costs and total O&M costs. This was held true for both the North Sea and the East Coast United States. The paper also reaffirmed results from previous work that found direct drive turbines to have lower total O&M costs than a two-stage turbine for both 3 MW and the larger 10 MW turbine in both locations. The main driver for this difference in cost came from high transport costs from the increase usage of an HLV for the two-stage drive train.

For the North Sea, the direct drive configuration for a 10 MW turbine would have lower or equal O&M cost to a 3 MW turbine until failure rates were increased by 18%. The two-stage configuration 10 MW turbine was found to have lower or equal O&M costs to a 3 MW turbine until failure rates were increased by 8%. For the United States, the direct drive configuration for a 10 MW turbine would have lower or equal O&M cost to a 3 MW turbine until failure rates were increased by 24%. The two-stage configuration 10 MW turbine was found to have lower or equal O&M costs to a 3 MW turbine until failure rates were increased by 16%. One of the biggest drivers for the low total O&M cost in the 10 MW turbine is larger power production, so having increased periods of downtime is even more detrimental to the wind farm with larger turbines than smaller turbines. This was shown through the comparison of two sites with different climate conditions. The North Sea site produced lower total O&M costs for the direct drive 10 MW turbine in comparison to the two-stage 10 MW turbine. Despite this, the US site resulted in the least expensive total O&M costs for the direct drive 10 MW turbine. This was contributed to the fact that lost revenue costs in the North Sea were much higher as a result of higher power production but lower availability. Increasing the failure rates for the 10 MW turbine for the North Sea and the United States also highlighted the differences in the total and direct O&M costs stemming from increases in lost revenue. Based on the sites analysed, results indicated that the two-stage drive train configuration for a 10 MW turbine may be more suited to the US site than the North Sea site. Increased availability in the United States compared to the North Sea resulted in lower lost revenue costs for the two-stage configuration, which combats the high transport costs due to the requirement of HLV for the gearbox.

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CONFLICT OF INTEREST STATEMENT

The authors declare no potential conflict of interests.

PEER REVIEW

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DATA AVAILABILITY STATEMENT

The data that support the findings of this study are available from the corresponding author upon reasonable request.

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