# O&M cost modelling of large component major replacement in next-generation offshore wind turbines with uncertain failure rates

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This thesis is the result of the author's original research. It has been composed by the author and has not been previously submitted for examination which has led to the award of a degree.



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Date: January 2023

# Abstract

The costs associated with the maintenance of next-generation offshore wind turbines are a source of uncertainty to developers, in particular due to the unknown replacement rate of large components. This is particularly true for floating turbines, with accessibility impacted by wave-induced turbine and vessel motion. This thesis addresses the impact that the currently unknown major replacement rate of turbine components may have on the maintenance cost of large, offshore wind farms and how this varies between fixed and floating wind farms when using 15MW direct-drive or medium-speed wind turbines.

Application of the Classical Model of structured expert elicitation with six wind energy experts found that the expected overall rate of major replacement tasks for 15MW next-generation offshore turbines is lower than those reported for first-generation turbines. Medium-speed turbines are expected to have higher overall major replacement rates than direct-drive turbines. Floating configurations are expected to have higher overall major replacement rates than fixed-foundation turbines, ranging from 7.9% to 112.5% higher depending on the scenario and weighting method applied.

Cost modelling of 18 fixed and 18 floating wind farm scenarios using the StrathclydeOW O&M model amended for floating wind scenarios found a wide range of lifetime costs associated with major replacement tasks over the estimated uncertainty ranges of major replacement rates. Fixed-foundation medium-speed turbines achieved lower lifetime major replacement costs than direct-drive turbines. Combined mean repair and vessel costs ranged from £5.6k-£33.4k/MW.yr compared to £6.5k-£34.5k/MW.yr. The cost of major component replacement for floating turbines increased due to higher replacement rates and additional wave limits. Combined mean repair and vessel costs ranged from £14.0k-£69.6k/MW.yr for medium-speed turbines and £17.6k-£88.0k/MW.yr for direct-drive turbines.

These findings can inform future wind farm costing and suggest that floating wind farms are likely to have higher and more variable maintenance costs than fixed wind farms.

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# Abbreviations

| | |
|---|---|
| CDF | Cumulative distribution function |
| CfD | Contracts for difference |
| CTV | Crew transfer vessel |
| DD | Direct-drive |
| DFIG | Doubly-fed induction generator |
| DM | Decision maker |
| DOF | Degree of freedom |
| EFSA | European food safety authority |
| EW | Equal weighting |
| FF | Fixed-foundation |
| FL | Floating-foundation |
| GW | Global weighting |
| $H_s$ | Significant wave height |
| JIP | Joint industry project |
| LCOE | Levelised cost of energy |
| MS | Medium-speed |
| NPV | Net present value |
| O&M | Operations and maintenance |
| PMG | Permanent magnet synchronous generator |
| RAO | Response amplitude operator |
| RMS | Root mean square |
| SOV | Service operation vessel |
| $T_p$ | Peak wave period |
| ws | Wind speed |

# Chapter 1: Introduction

## 1.1 Background summary

After a record year for offshore wind installations, the total installed global capacity of offshore wind reached 57.2GW by the end of 2021 and another 90GW of offshore wind is expected to be installed from 2022-2026 [1]. The construction of offshore wind farms is supported by governments setting ambitious climate change targets, with offshore wind often at the centre of these [2], [3]. One of the key factors driving this focus towards offshore wind has been the ability of the industry to continually drive down the cost of energy produced from offshore wind farms, even to levels beyond the expectations of many experts in the area [4]. Markets such as the UK have seen successful Contract for Difference (CfD) bids as low as £40/MWh, from values greater than £100/MWh in only 2015 [5].

A major factor in this impressive price reduction has been the rapid development and scaling of offshore wind turbine technology [6]. Early offshore wind farms generally consisted of wind turbines of 2MW – 3MW rated power and rotor diameters of around 80m – 90m [7]–[9]. However, the past decade has seen the rated power and physical size of offshore wind turbines increase and turbines with rated power of 11MW [10] are beginning to be installed offshore. These developments are expected to continue, as turbines with rotor diameters of greater than 230m and rated power of 15MW are expected by the middle of the decade [11]. Along with increasing size and rated power, the drive-train configuration of offshore wind turbines has also developed over the years since the early first-generation turbines were installed. Direct-drive and medium-speed gearbox configurations with permanent magnet synchronous generator are now the dominant technology for current offshore wind developments [12]. Another big development in offshore wind technology is the introduction of floating turbine foundations. Floating wind farms are currently operational at pilot scale, however, large commercial-scale floating offshore wind farms are expected within the next decade [13].

These developments in turbine technology present further opportunities for reducing the cost of energy generated from offshore wind and accessing wind resource offshore that was previously considered inaccessible. However, this rapid development also brings uncertainties as novel technologies go into operation and new operational strategies may be required. One area of uncertainty surrounding large, next-generation offshore wind turbines is the operations and maintenance (O&M) phase of wind farm projects. The operations and maintenance of offshore wind turbines has been shown to account for around 20% – 30% of the levelised cost of energy (LCOE) from an offshore wind farm [14]–[16] and therefore can have a large impact of the overall cost of energy of an offshore wind energy development. A particularly uncertain area for next-generation turbines is the replacement of large wind turbine components (such as the generator, gearbox and blades) when a failure occurs. While historically making up only a small proportion of the overall number of maintenance tasks required on an offshore wind turbine [17], major replacement tasks have consistently been shown to be one of the largest contributors to overall O&M cost and O&M cost variability in offshore wind farms [18]–[21].

When considering next-generation turbine technology in fixed-foundation wind farms, the rate of major replacement tasks required in these turbines is currently unknown. It has been previously demonstrated that LCOE can be a function of failure rate [22] and previous studies have highlighted failure rate as one of the parameters with the largest impact on operational cost [16]. This presents an area of risk in offshore wind farm developments as uncertainty in the failure rate value has the potential to impact overall O&M cost and therefore cost of energy. This risk is magnified further when considering the use of 15MW turbines. The number of offshore lifting vessels in operation which are able to replace large components at the hub height required for these turbines is very limited [23]. When considering next-generation turbine technology in floating-foundation wind farms, further uncertainty is added by the deep-water locations in which these wind farms are sited. The operational depth of jack-up vessels, which are currently used for replacing large components in offshore wind turbines, is limited by the length of their legs to around 60m – 65m [24], [25] and floating turbines are moving to water depths beyond this [26]. Therefore, alternative strategies for replacing large components in floating turbines are being investigated – this includes the tow-to-port strategy, or the floating-to-floating heavy lift strategy [27], [28]. The tow-to-port approach will have challenges around disconnection and reconnection of the turbines and limitations around port availability to complete repairs, whereas the floating-to-floating heavy lift strategy will require expensive floating heavy lift vessels and accessibility to complete repairs will be limited by the wave-induced motion of both the floating turbine and the floating lifting vessel.

In light of these uncertainties surrounding large component major replacement tasks in next-generation offshore wind turbines (both fixed and floating) and the impact this could have on wind farm O&M costs and overall cost of energy, major component replacement is considered an important area for investigation. The remainder of this chapter will detail the key research question of this PhD thesis, outline the overall approach taken and outline the structure of the thesis. The novelty of the research that is presented within this thesis will then be highlighted and the additional research output from this work in the form of journal papers and conference papers will be summarised.

## 1.2 Motivation and research question

The motivation for this research is centred around the idea that offshore wind turbines and offshore wind farms are developing and the size of both are increasing. Up until now, this development has resulted in decreasing cost of energy due to economies of scale and learning through experience as more turbines have been installed and operated. However, as large wind farms transition to next-generation turbines, there are risks around the replacement of large components. New approaches to replacing large components will be required, particularly in floating offshore wind farms, and the differences between these approaches and conventional methods, and the impact this could have on O&M cost has to be understood. As turbines increase in size, the cost of replacing large components (component cost, vessel cost and lost electricity revenue) will continue to increase and therefore the impact of the currently unknown major replacement rate of these turbines on O&M cost and how this is impacted by turbine drive-train configuration is also an area in which further understanding is required.

Therefore, the primary research question forming the basis of this PhD thesis is as follows:

*"What impact can the currently unknown major replacement rate have on the cost of major replacement tasks in next-generation offshore wind turbines and how does this vary between different next-generation offshore wind turbine configurations?"*

The idea of the 'next-generation offshore wind turbine' within the context of this research and the different turbine configurations considered in this work will be further explored and defined in Chapter 2, however, for now this can be summarised as 15MW turbines with either direct-drive or medium-speed drive-train configurations and permanent magnet synchronous generators with either a fixed-foundation or a semi-submersible floating foundation. To answer this primary research question, each of the main chapters forming this thesis will address a secondary research question. The research questions will be clearly outlined at the start of each chapter and are briefly summarised in Figure 1.1.

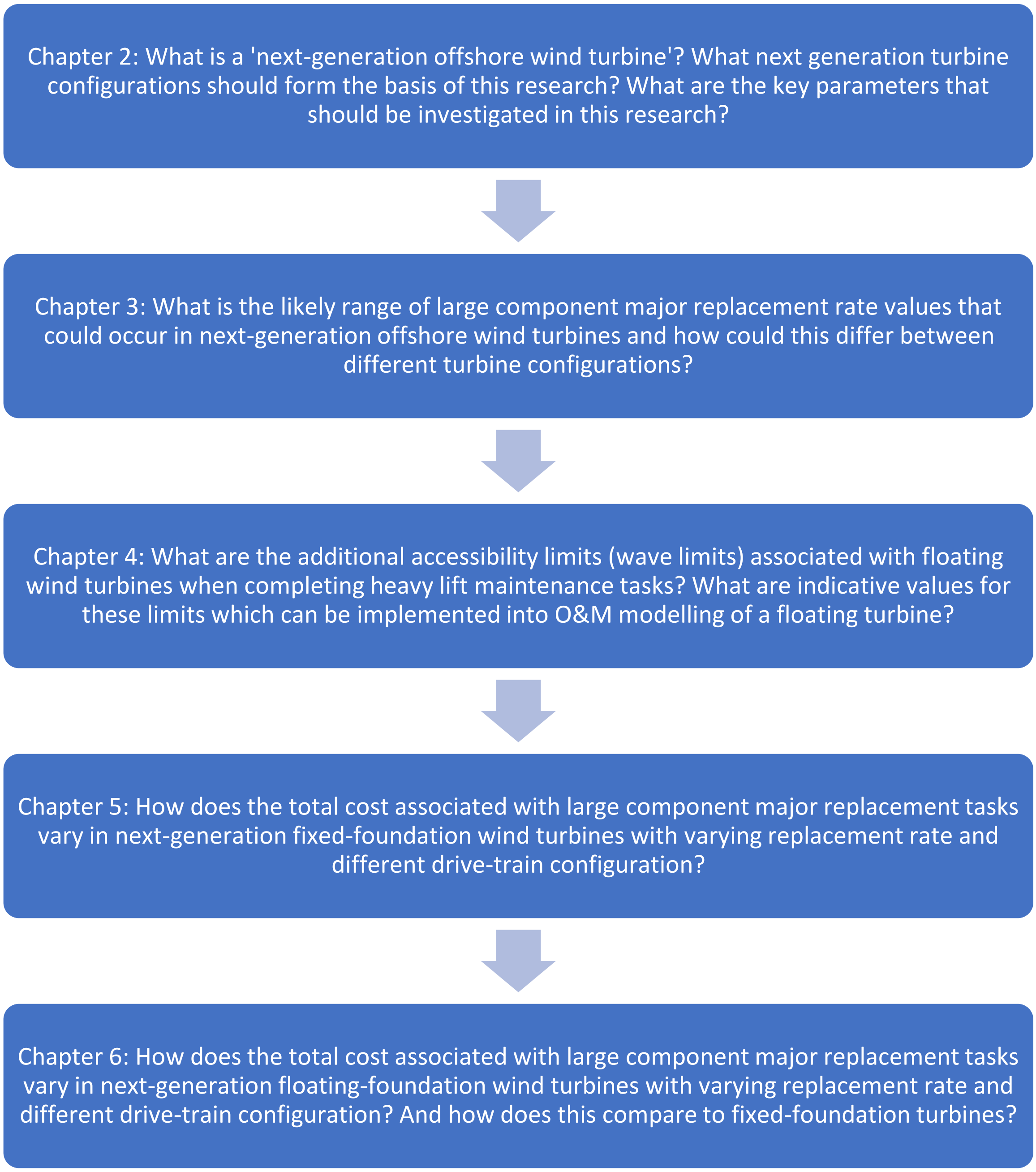


*Figure 1.1.* Summary of research questions to be addressed in each of the main thesis chapters.

## 1.3 Thesis structure

This thesis consists of seven chapters, including this introduction chapter. There are four main analysis chapters (Chapters 3 – 6) and each of these main chapters aim to answer a secondary research question (as outlined in Figure 1.1). The final chapter (Chapter 7) then brings together the findings from each of these secondary research questions to answer the primary research question that has been previously defined. Chapter 7 also highlights the novel contribution of each chapter and suggests future work to expand on this area of research.

Chapter 2 describes the development of offshore wind turbine technology over time and presents a summary of the key background information and literature in defining the focus and scope of this project. Within Chapter 3, the major replacement rate values of large components in four 15MW next-generation offshore wind turbine configurations are estimated using the Classical Model of structured expert elicitation. In Chapter 4, additional wave accessibility limits for maintenance tasks on floating turbines are estimated based on the frequency-domain modelling of wave-induced rigid-body motion of a 15MW floating reference turbine. In Chapter 5, the estimated major replacement rate values for next-generation fixed-foundation turbines are implemented into an existing offshore wind O&M model. This model is used to investigate the impact of major replacement rate and turbine drive-train configuration on O&M major replacement costs. And in Chapter 6, the estimated replacement rate values for floating turbine configurations are implemented into the O&M model, along with additional wave limit values. The results are then used to investigate the impact of major replacement rate and drive-train configuration on O&M major replacement costs for floating-foundation wind farms. The flow of information between thesis chapters is summarised in Figure 1.2.

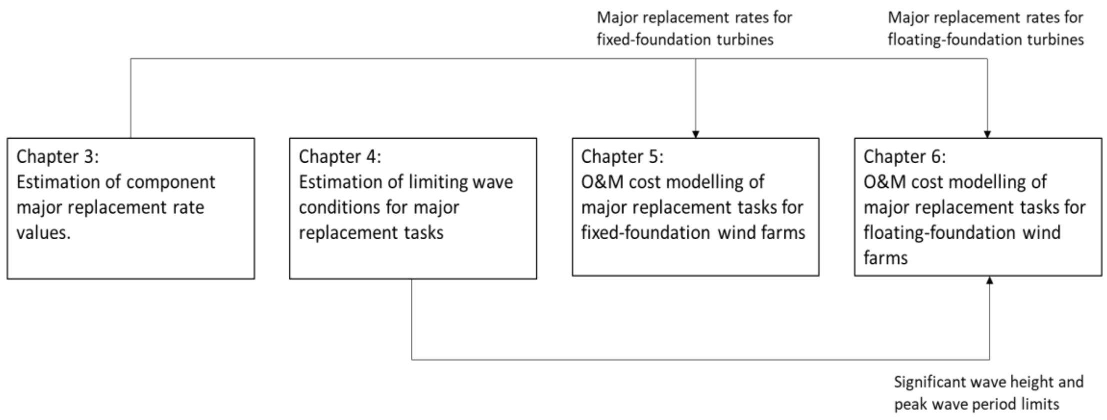


*Figure 1.2. Flow of information between thesis chapters.*

## 1.4 Novel contribution of research

Based on the review of the existing literature that was completed as part of this PhD project, several novel contributions of the work presented in this PhD thesis are highlighted below.

Chapter 3 contributes a series of major replacement rate values for selected large components in four 15MW next-generation offshore wind turbine configurations. These values have been systematically estimated using a recognised framework for capturing, representing and validating subject matter expert knowledge and uncertainty. All key steps within this process have been described as transparently and in as much detail as appropriate to allow for the full understanding of this approach when applying these results, or if attempting to apply this approach to another area. These replacement rate values can be used by both industry and academia in areas such as operations and maintenance and cost modelling, as well as spare parts and inventory planning.

Chapter 4 contributes indicative wave limit values for floating-to-floating major replacement tasks for a 15MW floating turbine which can be easily estimated and used in an O&M modelling tool. Since this work was completed, there has been further research published in this area which address a number of the limitations of the work presented in this chapter. However, as floating wind turbine accessibility is still a relatively new area of research, the key conclusions and recommendations from this chapter are still considered to be useful contributions to support the existing literature. This includes highlighting the importance of wave period conditions, as well as wave height, when determining maintenance accessibility for floating turbines and highlighting that technician workability is not expected to be as limiting as other accessibility parameters for large, floating turbines.

Chapter 5 contributes a range of estimated costs associated with major replacement tasks over the lifetime of large fixed-foundation offshore wind farms, based on a range of replacement rate scenarios systematically estimated specifically for 15MW fixed-foundation offshore wind turbines. Therefore, providing an understanding of how uncertainty in turbine reliability can translate through to O&M cost in next-generation offshore wind farms and how this can differ between wind farms using direct-drive or medium-speed machines. The key drivers for cost differences between scenarios are also highlighted and discussed. The sources and assumptions around all other key values input into the model are fully described in detail, allowing the approach to be fully understood if applying the results and conclusions presented, or if a similar piece of modelling work was attempted. The findings from this chapter can be used by both industry and academia in further understanding the O&M costs of next-generation offshore wind farms.

Chapter 6 contributes a range of estimated costs associated with major replacement tasks over the lifetime of large floating offshore wind farms, based on a range of replacement rate scenarios systematically estimated specifically for 15MW floating offshore wind turbines. Therefore, providing an understanding of how uncertainty in turbine reliability can translate through to O&M cost in commercial-scale floating wind farms and how this can differ between wind farms using direct-drive or medium-speed machines. How these costs differ between floating and fixed-foundation wind farm scenarios are also investigated and the key drivers for cost differences between scenarios are highlighted and discussed. The sources and assumptions around all other key values input into the model are fully described in detail, allowing the approach to be fully understood if applying the results and conclusions presented, or if a similar piece of modelling work was attempted. The findings from this chapter can be used by both industry and academia in further understanding and de-risking the operations and maintenance of commercial-scale floating wind farms.

## 1.5 Research output

The following papers have been produced based on the work presented within the following chapters of this thesis.

**Published:**

**Chapter 3:**

1. Jenkins B, Belton I, Carroll J and McMillan D. 2022. Estimating the major replacement rates in next generation offshore wind turbines using structured expert elicitation. *Journal of Physics: Conference Series* **2362.**

**Chapter 4:**

2. Jenkins B, Prothero A, Collu M, Carroll J, McMillan D and McDonald A. 2021. Limiting Wave Conditions for the Safe Maintenance of Floating Wind Turbine. *Journal of Physics: Conference Series* **2018.**

**Accepted:**

**Chapter 5:**

1. Jenkins B, Carroll J and McMillan D. O&M Cost Modelling of Major Replacements in Next-Generation Offshore Wind Turbines. Submitted to IET Renewable Power Generation 2022 conference in May 2022, accepted in July 2022.

**Drafted:**

At the time of writing, the following papers have been drafted and will be submitted to journals for review.

**Chapter 3:**

1. Jenkins B, Belton I, Carroll J and McMillan D. Estimating the Major Replacement Rate of Large Components in Next-Generation Fixed and Floating Offshore Wind Turbines using the Classical Model of Structured Expert Elicitation.

**Chapter 5 and Chapter 6:**

2. Jenkins B, Carroll J and McMillan D. O&M Cost Modelling of Large Component Major Replacements in Next-generation Floating Offshore Wind Turbines.

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# Chapter 2: Background

## 2.1 Chapter overview and research question

This chapter will summarise some of the key background information and literature in determining the scope of this PhD project. Firstly, the development of offshore wind turbines from the early first-generation of offshore wind turbines, to the future next-generation offshore turbines will be presented. Secondly, a review of the key existing literature around the operations and maintenance cost modelling of offshore wind turbines related to the focus area of this PhD project will be summarised. The aim of this chapter is to provide an answer to the secondary research questions below:

*What is a 'next-generation offshore wind turbine'? What next-generation offshore wind turbines configurations should form the basis of this research? What are the key parameters that should be investigated in this research?*

## 2.2 The development of offshore wind turbines

The first operational offshore wind farms in the UK, which begun operation from 2004 to 2006, were North Hoyle, Scroby Sands, Kentish Flats and Barrow [1]. These early offshore wind farms consisted of 2-3MW wind turbines with 80-90m rotor diameters and a drive-train configuration consisting of a 3-stage, high-speed gearbox and induction generator [2]–[4]. However, since the installation of these first offshore wind farms, there have been key changes to offshore wind turbines. This section will focus on the changes that have been seen from this first generation of offshore turbines to the current and next generations. It should be noted that similar development trends, for example increasing turbine size and rated power, and the use of direct-drive generators, have also been observed in onshore turbines [5] and are therefore not unique to offshore turbines. These changes will be considered under the following key areas.

a) Turbine size
b) Turbine drive-train configuration
c) The introduction of floating foundations

### 2.2.1 Turbine size

Over time, offshore wind turbines have increased both in rated power and in physical size. Using data from a combination of three online databases [2], [6], [7], the trend of increasing turbine size is illustrated in the following Figures.

Figure 2.1 shows how the rated power of turbines in offshore wind farms greater than 100MW in the UK has developed over time. The turbines in early offshore wind farms were around 2MW – 4MW rated power. However, around the middle of the last decade, rated power began to increase, with turbines of around 6 MW – 8MW having been installed and turbines of around 8MW – 10MW currently being installed in offshore wind farms in the UK. Figure 2.2 shows how the rotor diameter of these turbines have also developed over this time. This trend of increasing turbine size is expected to continue. Table 2.1 shows the rated power of the wind turbines planned for large offshore wind farms currently consented in the UK. The rated power of offshore wind turbines will continue to increase up to 15 MW. Similar trends of increasing turbine rated power and physical size are expected to continue across Europe and globally [8], [9].

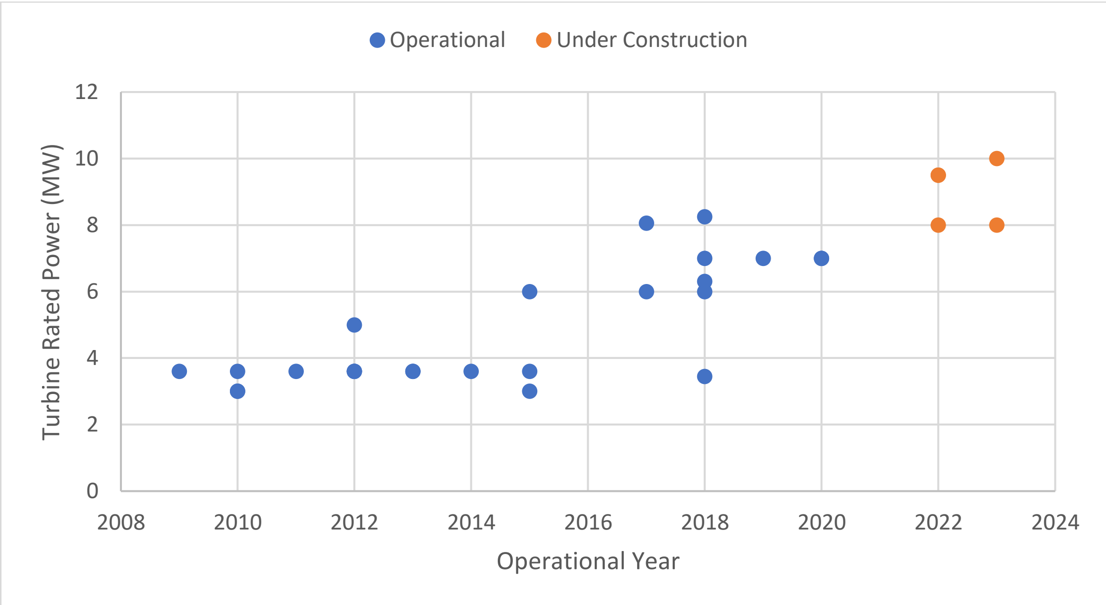


*Figure 2.1. Plot of the rated power of wind turbines in UK offshore wind farms greater than 100MW against the year they became / will become fully operational* [2].

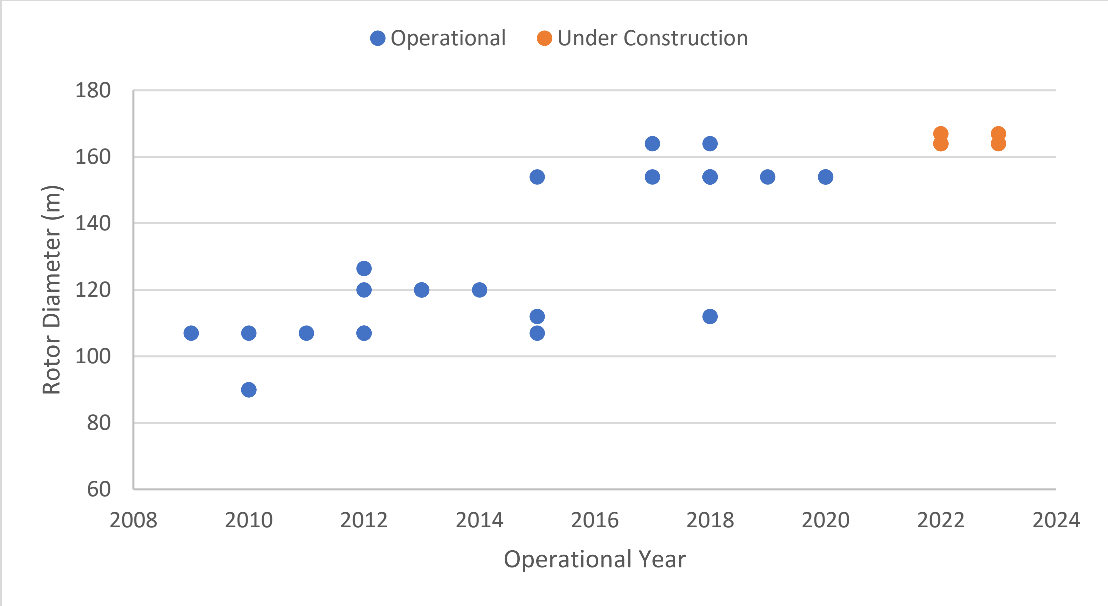


*Figure 2.2. Plot of the rotor diameter of wind turbines in UK offshore wind farms greater than 100MW against the year they became / will become fully operational* [6], [7].

*Table 2.1. Rated power of turbines currently planned for consented future offshore UK wind farms* [2].

| Wind farm | Turbine rated power (MW) |
|---|---|
| Hornsea Project Three | 10 |
| East Anglia Three | 14 |
| Sofia | 14 |
| Dogger Bank A & B | 13 |
| Dogger Bank C | 14 |
| Inch Cape | 14 |
| Norfolk Boreas | 15 |
| Norfolk Vanguard | 15 |

### 2.2.2 Turbine drive-train configuration

As well as increasing turbine size and power, changes have also been seen in the drive-train configuration of offshore wind turbines since the early-generation turbines. Figure 2.3 shows the number of different turbine drive train configurations in UK offshore wind farms, greater than 100MW, prior to 2015. Whereas Figure 2.4 shows the number of different drive-train configurations in UK offshore wind farms, greater than 100MW, from 2015 onwards. When comparing these Figures, a clear change can be seen. Early offshore wind farms extensively used turbines with high-speed gearboxes and induction generators. However, since 2015, only one large UK wind farm has used this turbine configuration, with all other wind farms using permanent magnet synchronous generator (PMG) machines. Since 2015, the majority of large wind farms in the UK have selected direct-drive turbines, with medium-speed turbines also chosen for several projects. Again, this trend towards permanent magnet synchronous generators and lower speed or no gearbox is expected to continue with the big offshore wind turbine manufacturers developing either direct-drive or medium-speed machines.

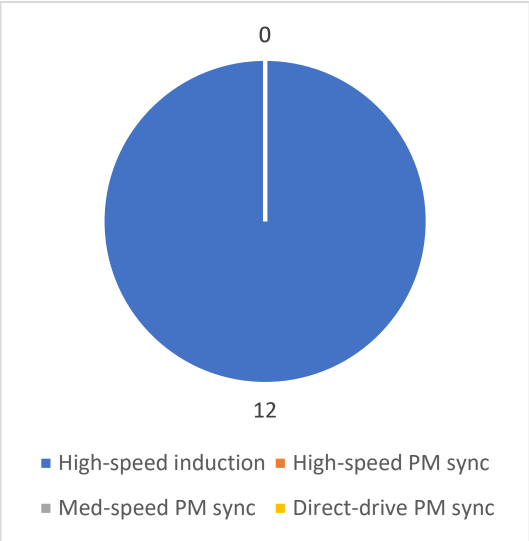


*Figure 2.3. Split of drive-train configurations in offshore wind turbines installed in UK offshore wind farms before 2015 [2], [6], [7].*

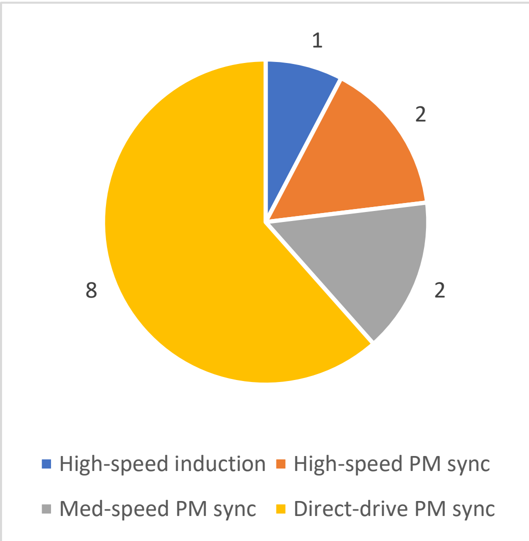


*Figure 2.4. Split of drive-train configurations in offshore wind turbines installed in UK offshore wind farms after 2015 [2], [6], [7].*

### 2.2.3 Floating foundations

Floating-foundation offshore wind turbines currently only make up a small proportion of the overall installed offshore wind capacity. For example, as of the end of 2021, there was only 113 MW of floating wind capacity in Europe [9]. However, the installed capacity of floating wind is expected to increase in the time period up to 2030 and onwards. Around 80% of Europe's offshore wind resource is located in water depths greater than 60m, which is considered not suitable for fixed-foundation wind turbines [10]. Therefore, floating wind can provide access to areas previously considered inaccessible, with generally higher wind speeds and the option for greater turbine spacing to reduce wake effects caused by nearby turbines [10].

A number of market analysis studies have been published, highlighting the future potential of floating offshore wind projects. It was estimated by Hannon et al. that 4.3GW of floating offshore wind projects could be installed by 2030 [11]. Within this analysis, planned future projects were separated into more developed projects which have applied for consent and less developed concept/early planning projects. Including less developed projects, there was 5.9GW of floating wind capacity at a concept or early planning stage. It was estimated by the Carbon Trust that there is potential for 10.7GW of floating wind capacity by 2030 and up to 70GW by 2040 [12]. An economic analysis published in 2018 by Crown Estate Scotland and ORE Catapult identified 10.5GW of floating wind projects in the early stage of planning [13]. This picture is rapidly changing as offshore leasing processes begin and progress. In France, the tendering process has recently been launched for three 250 MW floating offshore wind farms [14], [15] and in the UK, the Scotwind leasing round has seen option agreements offered to around 15GW of commercial scale floating wind, including a 3GW floating wind farm [16].

The study by Hannon et al. [11] also identifies the floating foundation type that is used or planned for use in these projects and this is summarised in Table 2.2. These numbers show that the semi-submersible foundation type is expected to be the dominant floating-foundation type for future floating wind projects.

*Table 2.2. Current and future expected installed capacity of floating wind foundation types taken from* [11].

| Time Period | Spar Capacity (MW) | Semi-submersible Capacity (MW) | Tension Leg Platform Capacity (MW) |
|---|---|---|---|
| 2018 | 39 | 17 | 0 |
| 2022 | 64 | 174 | 27 |
| Future (early planning) | 111 | 5,749 | 2 |

### 2.2.4 Summary of offshore wind turbine development

Based on the development trends outlined in this chapter, the concept of 'first', 'current' and 'next' generation offshore wind turbines are defined for the purposes of this PhD thesis. First generation offshore wind turbines are considered to be within the 2MW – 4MW rated power range with 100m – 120m rotor diameters, high-speed, three-stage gearboxes and induction generators. Current generation turbines are considered to be the turbines which are currently being installed in offshore wind farms. These are in the 6MW – 10MW rated power range with 150m – 170m rotor diameters, direct-drive or medium-speed gearboxes and permanent magnet synchronous generators. And finally, next-generation offshore wind turbines are considered to be those which will be installed in offshore wind farms around the middle of the decade. These turbines are in the 12MW – 15MW rated power range with rotor diameters greater than 200m and direct-drive or medium-speed configurations with permanent magnet synchronous generators. A large number of these next-generation offshore turbines may use floating foundation types, with the expectation these will be mainly semi-submersible. This idea of turbine grouping is summarised in Figure 2.5.

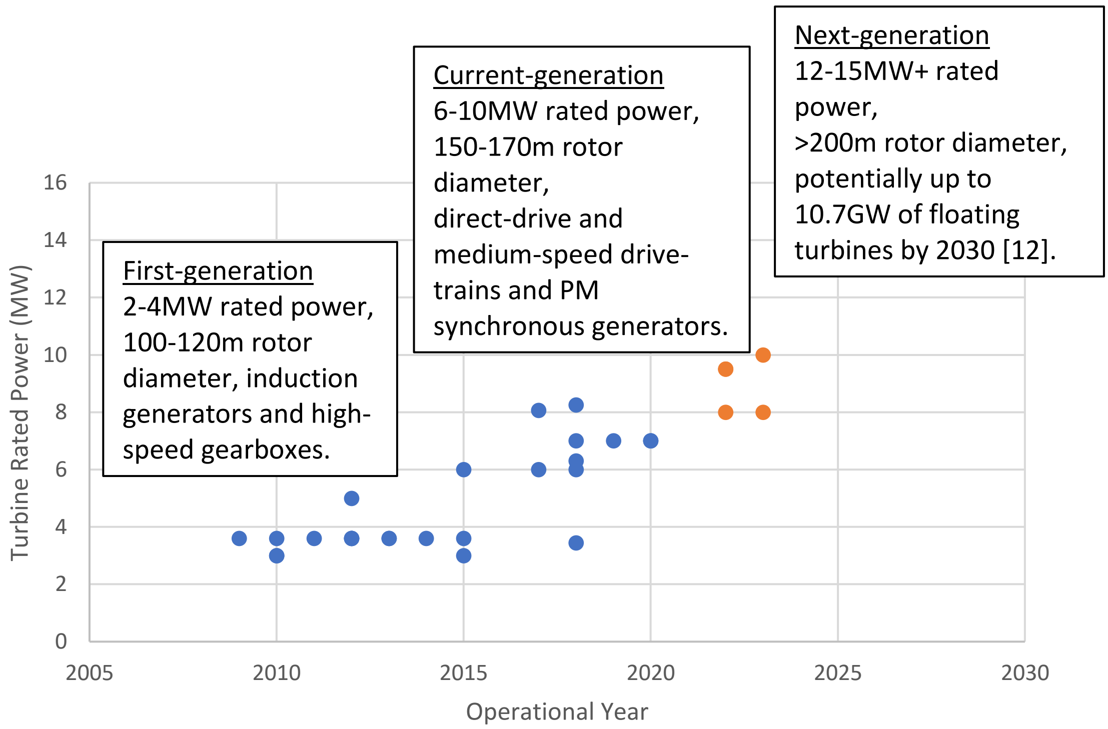


*Figure 2.5. Summary of offshore wind turbine development over time, separated into first, current and next-generation turbines.*

Based on this analysis, four next-generation offshore wind turbine configurations have been selected for focus as part of this research. These are as follows:

- 15MW fixed-foundation direct-drive turbine,
- 15MW fixed-foundation medium-speed turbine,
- 15MW semi-submersible floating-foundation direct-drive turbine, and
- 15MW semi-submersible floating-foundation medium-speed turbine.

Commercial-scale wind farms using each of these turbine configurations are expected to be operational by around 2030. Therefore, the general scenarios considered throughout this thesis are large, commercial-scale wind farms consisting of these turbines around the year 2030.

## 2.3 Offshore wind operations and maintenance cost modelling

### 2.3.1 Overview of offshore wind O&M cost models

The operations and maintenance phase of an offshore wind farm is a large contributor to the overall cost of energy and therefore it is important to understand the magnitude of these costs and the impact that decisions taken and choices made during the design and the O&M phase can have on this. One approach to this is through the use of offshore wind O&M modelling tools. These tools generally focus on the modelling of maintenance activities and the costs associated with these.

One approach to estimating O&M cost is to develop and use deterministic cost models with parameters estimated from previous data. Parametric O&M cost modelling typically defines a cost per failure or maintenance activity and determines the overall cost using the failure rate [17], [18]. This approach provides an efficient and computationally simple way to estimate cost and cost sensitivity to certain variables. However, one of the key limitations of deterministic models is that they cannot account for uncertainty in the problem being modelled [19]. When considering the operations and maintenance phase of an offshore wind farm, there are a number of uncertain aspects associated with the problem. This includes wind speed and wave height, the occurrence of failures, electricity prices, repair times, personnel, spare parts, and vessel-hiring costs [20]. Therefore, a large number of offshore wind operations and maintenance modelling tools which have been developed are stochastic, time-domain models. Stochastic models are able to account for randomness in component failures and variability in weather conditions, activity duration and associated costs. The use of stochastic O&M models in offshore wind are discussed in more detail in the remainder of this section.

The StrathclydeOW O&M model, which has been used to complete the O&M cost modelling work presented in Chapters 5 and 6 of this thesis, is a stochastic time-domain model based on a Markov Chain Monte Carlo simulation [21]. It was selected for use due to its ability to account for the uncertainties mentioned in the previous paragraph and will be described in more detail in Chapter 5 of this thesis.

A comprehensive review of existing offshore wind operation and maintenance models and the key parameters within these has been recently published by Seyr and Muskulus [20] and a summary of offshore wind O&M models is also provided as part of the ROMEO project [22]. The key inputs and outputs for these models, as well as the constraints applied within these are also summarised by Rinaldi et al. [23]. Therefore, a detailed review of offshore wind O&M models will not be repeated here, however their use in the existing literature will be summarised and some of the key features of these models highlighted.

O&M modelling tools are generally based on the stochastic, time-domain modelling of wind turbine component failures, and the subsequent scheduling of their repairs based on weather and resource limitations (for example vessel and crew availability) [22]. Based on their comprehensive review of the existing literature, Seyr and Muskulus highlight the key parameters within these models as 'the occurrence of failures, availability of maintenance crew, spare parts and vessels, weather and external factors, the chosen maintenance strategy, and economical parameters such as the electricity price and subsidies' [20]. The outputs of these models are often parameters such as wind farm availability, O&M costs and information on resource utilisation.

Through the use of operations and maintenance cost modelling tools, the O&M costs (either on their own, or as part of LCOE estimation) and the impact of some of the key input parameters and constraints on these costs have been investigated in the existing literature. Dalgic et al. used a time-domain Monte Carlo based model to investigate the impacts that vessel fleet selection and charter strategy can have on O&M costs [24]–[26]. Vessel fleet selection was also investigated by Sperstad et al. using several O&M modelling tools [27]. The StrathclydeOW O&M model was developed by Dinwoodie and used to investigate the sensitivity of wind farm O&M cost to uncertain parameters such as component failure rate, number of maintenance vessels, distance to port and external factors such as electricity price and vessel cost [21]. The StrathclydeOW O&M model was also used by Carroll et al. to investigate the impact of offshore wind turbine drive-train configuration on O&M cost [28]. Martin et al. used the ECUME O&M model to analyse the sensitivity of wind farm O&M costs to a large number of parameters such as failure rate, component cost and repair duration [29]. In the ECUME model, time-varying weather conditions are simulated using a Hidden Markov approach and failure rate is modelled using a Weibull distribution with failure events based on a Monte Carlo simulation [30]. Shields et al. used the Shoreline O&M model to calculate the O&M costs when investigating the impact of turbine size on the cost of energy [31]. Shoreline is a commercial software in which project parameters, weather time-series, vessel characteristics, failure probabilities and maintenance strategies are defined. It is an agent-based model where scheduled and unscheduled maintenance activities are simulated throughout the project lifetime [31]. Ioannou et al. used the ECN tool to calculate O&M costs and investigate the sensitivity of wind farm net present value (NPV) to various parameters such as turbine mean time to failure, workboat wave height limits, workboat day rate, etc. [32]. The ECN tool is a time-domain Monte Carlo based simulation program where failures are modelled as a Poisson process, with accessibility and wind farm production based on historical weather data [33]. The NOWIcob model is a discrete-event Monte Carlo simulation model where weather conditions are modelled using a Markov Chain and failures are based on a Homogeneous Poisson Process and was used by Judge et al. in developing a financial model for offshore wind farms [34]. In recent times these offshore wind O&M models have also been applied to floating wind farms. Rinaldi et al. used the UNEXE O&M tool when analysing the cost of energy from two case study floating offshore wind farms [35]. This is a probabilistic, time-domain Monte Carlo simulation model which considers met-ocean data, project specifications and operational strategy. Avanessova et al. used the COMPASS model, another time-domain based Monte Carlo simulation model with failures randomly generated based on component reliability, to investigate alternative vessel strategies for floating offshore wind farms [36].

### 2.3.2 O&M modelling of large component major replacements

The failure of a wind turbine component is often classified by severity and commonly as either a minor repair, major repair or a major replacement. These categories, which were defined as part of the Reliawind project and based on the cost of repair materials, are also used by Carroll et al. when reporting the observed failure rates in offshore wind turbines [37].

At this time, the cost of a major replacement (>€10,000) coincided with the type of repair which would require the use of a heavy lift vessel and although, due to increasing turbine size and cost, these cost categories no longer represent what they once did, the term ‘major replacement’ is still used to represent a failure which requires a heavy lift vessel to carry out the replacement of a component.

Major replacement tasks have consistently been found to be one of the largest contributors to operations and maintenance costs or cost variability of an offshore wind farm. Dalgic et al. concluded that the cost associated with maintenance tasks requiring the use of a jack-up vessel was higher than those associated with any other maintenance vessel type and that these costs were highly uncertain and dependant on charter strategy [24], [26]. It was also concluded by Dinwoodie et al., when modelling a range of scenarios using four different O&M modelling tools, that major replacement tasks which require the use of heavy lift vessels account for the majority of direct O&M costs, whilst only having a small impact on wind farm availability [38]. When investigating the sensitivity of offshore wind farm O&M costs to different parameters, Martin et al. highlighted gearbox major replacement as having a large impact on OPEX cost [29] and Judge et al. found that the highest cost variability in the O&M phase is associated with major replacement tasks [34].

Due to some of the particular challenges related to floating turbines, for example their wave-induced motion and need to use alternatives to conventional jack-up vessels, the major replacement of large components in floating offshore wind turbines is of particular interest to industry at the moment, with the Carbon Trust, ORE Catapult and World Forum Offshore Wind all currently investigating this area [39]–[41].

### 2.3.3 Key parameters influencing O&M cost

There are a large number of factors that can influence the O&M cost of an offshore wind farm to varying degrees. As previously discussed, the majority of O&M modelling tools are based on the simulation of turbine failures based on user-input failure rates and the repair of these failures through the use of various repair vessels which are influenced by their user-input operational limits, the weather conditions, and resource availability. Hence, numerous studies have found that wind turbine component failure rate and vessel weather operability limits are two of the most influential factors in these models, as described below.

Ioannou et al. identified mean time to failure (MTTF) and the work boat wave height limit as the two OPEX parameters which have the largest impact on wind farm NPV [32]. MTTF is the mean of the failure-free times of a number of items and, if a constant failure rate is assumed with failure-free times being independent random exponentially distributed variables, is the inverse of failure rate [42]. A 20% decrease in the work boat wave height limit decreased NPV by 16% [32]. Martini et al. also found that increasing significant wave height limits for completing maintenance from 1.5m to 2.5m can reduce the mean waiting time by up to 53% [43]. Martin et al. found that there are a number of factors that impact O&M cost and concluded that access and repair costs and turbine failure rates were the main influencing factors. Repairs of the gearbox requiring a heavy lift vessel is highlighted as a particular area of importance [29]. Dao et al. highlighted the importance of reducing wind turbine failure rate through determining LCOE as a function of failure rate [44] and also found that uncertainties in failure rate and failure cost can cause variations greater than 10% in LCOE [45]. Dinwoodie also found that wind farm O&M cost has a high sensitivity to failure rate, particularly to major replacement rate of large components requiring a heavy lift vessel [21].

### 2.3.4 Summary of offshore wind O&M cost modelling

Based on the reviewed literature relating to offshore wind operations and maintenance cost modelling it is found that O&M cost modelling tools have been used extensively within the existing literature to investigate a number of uncertain areas related to offshore wind operations and maintenance and their impact of cost. Within the reviewed literature, it is often concluded that the cost associated with the major replacements of large wind turbine components are one of the largest contributors to O&M costs. Previous work also identifies wind turbine component failure rates and vessel accessibility limits as having a large influence on the operations and maintenance costs of an offshore wind farm.

It is these trends found within the existing literature, as well as discussions with contacts in industry and academia throughout the course of this PhD project, that have led the focus of this PhD to centre on the following areas:

- Major replacement rates of large components in next-generation offshore wind turbines
- Wave limits for carrying out a floating-to-floating heavy lift maintenance tasks on floating wind turbines

- The cost associated with major replacement tasks requiring a heavy lift vessel in next-generation offshore fixed and floating offshore wind turbines.

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# Chapter 3: Estimating major replacement rates using structured expert elicitation

## 3.1 Chapter overview and research question

It has previously been highlighted that the failure rate of wind turbine components has a large impact on the O&M costs of an offshore wind farm, particularly the more severe failures which require the major replacement of a large component such as the generator, gearbox or a blade using a heavy lift vessel. It has also been stated that the rate at which these major replacement operations will be required in next-generation offshore wind turbines is unknown. This chapter will further expand on these points and address this knowledge gap.

The chapter will begin by summarising the existing literature on publicly available wind turbine failure rate data and how failure rate has been found to vary with wind turbine design, for example turbine size and drive-train configuration. The chapter will then go on to introduce the concept of structured expert elicitation and in particular an approach known as the Classical Model. The Classical Model of structured expert elicitation will then be applied in estimating major replacement rate values for large wind turbine components (generator, gearbox, and rotor) of four 15MW next-generation offshore wind turbine configurations using the knowledge of six wind energy experts. The methodology of how the Classical Model was applied will be presented and explained in detail within this chapter and the results presented and discussed. Finally, conclusions will be drawn based on these results and discussion and wind turbine major replacement rate values which will be applied in the O&M cost modelling in Chapter 5 and Chapter 6 will be determined.

The aim of this chapter is to answer the secondary research question outlined in Chapter 1 and shown below:

*What is the likely range of large component major replacement rate values that could occur in next-generation offshore wind turbines and how could this differ between different turbine configurations?*

The main deliverable of this chapter, in the context of this overall thesis, is a range of major replacement rate scenarios, representing the range of values expected to be possible in various next-generation offshore wind turbine configurations, which can be used as an input into the O&M cost modelling in Chapter 5 and Chapter 6.

The novel contribution of the work presented in this chapter is the systematic estimation of the currently unknown major replacement rate values for large components in four different 15MW next-generation offshore wind turbine configurations. The replacement rate values have been estimated using a recognised framework for capturing, representing and validating subject matter expert knowledge and uncertainty. All key steps within this process have been described as transparently and in as much detail as appropriate to allow for the full understanding of this approach when applying these results, or if attempting to apply this approach to another area.

## 3.2 Wind turbine failure rate data

Reliability of a system can be defined as the ability of a system or component to perform its required functions under stated conditions for a specified period of time, or mathematically defined as the probability that a random variable time to failure is greater or equal to mission time [1]. Two different approaches to reliability analysis are generally considered – the physical and the actuarial approach. An example of the physical approach would be to model the strength of a structure and the load on the structure as random variables, with the reliability of the structure being the probability that the load does not exceed the strength. Whereas for the actuarial approach, the physical quantities are not explicitly modelled, but often determined from field or test data [2].

The reliability of wind turbines, or individual wind turbine components, is often characterised using failure rate. Failure rate, λ, is expressed as the number of failures per turbine per year [3], [4] and can be calculated using Equation 3.1. In Equation 3.1, $N_i$ is the number of turbines, $T_i$ is the number of hours of the measurement interval, $n_i$ is the total number of failures in this interval, i represents the number of time intervals, and k represents the number of subassemblies [3], [4].

$$\lambda = \frac{\sum_{i=1}^{I}\sum_{k=1}^{K}\frac{n_{i,k}}{N_i}}{\sum_{i=1}^{I}\frac{T_i}{8760}} \tag{3.1}$$

Wind turbine failure rate data is highlighted in this thesis as being of particular importance to wind energy O&M modelling. However, publicly available historical failure rate data for operational wind farms is very limited. In recent years a number of review papers summarising the available data in this area have been published. The most recent of these was published by Cevasco et al. and reviews 24 wind turbine reliability databases [5]. Other summaries of available wind turbine failure rate data have been published by Pfaffel et al. [6] and Artigao et al. [7]. Seyr and Muskulus also provided a brief overview of currently available failure rate data when reviewing offshore wind operations and maintenance models [8], and there have also been several publications from Dao et al. which summarise currently available wind turbine failure rate data [9], [10]. Across these studies the amount of publicly available failure rate data for onshore wind farms is limited compared to the overall number of operational wind farms and is generally based on older wind turbine technology, for example some datasets include stall-regulated turbines. There is often limited detail provided on the turbine population, for example the age of turbines, and detail on the severity of failures is rarely provided. Limitations of failure rate datasets used in previous studies are highlighted throughout the review in the remainder of this section. For offshore wind farms the available data is extremely limited and based mainly only on early, first-generation offshore wind turbines. Across these datasets, various trends of changing failure rate with varying turbine size and configuration have also been found.

The following sub-sections will summarise the available failure rate literature in more detail, firstly describing the existing wind turbine failure rate data (both onshore and offshore) and then summarising the findings within the literature regarding the impact that turbine size and configuration can have on failure rate.

### 3.2.1 Onshore wind turbine failure rate data

The majority of the published reliability studies are focussed on onshore wind turbines, with most of these being for onshore wind turbines operating from the early-to-mid 1990's up until the mid-2000's in Europe. These studies generally contain a statistically significant number of turbines, however, include a large number of smaller and older technologies.

The Windstats dataset from Germany and Denmark [3], [11], [12] consists of failure rate data for up to 4,500 onshore turbines in Germany and up to 2,500 onshore turbines in Denmark over the period from 1994-2004. The turbine population includes a wide and time-varying range of turbine configurations, including a large number of older configurations such as stall-regulated turbines. The rated power ranged from 100kW to 2.5MW, with the average turbine size at the end of the survey period in 2004 at just under 1MW for the German turbines and around 650kW for the Danish turbines. From these studies there is data available for component failure rates, however there is no classification of the severity of these failures.

Other notable German onshore datasets are the WMEP and the LWK datasets. The WMEP dataset [13]–[16] consists of data from around 1,500 onshore wind turbines from 1989-2006. The turbine population varies from 30kW to 1.8MW in rated power [9] and the published data includes the failure rates for the turbine components as well as the downtimes. Throughout the various studies that have been carried out on this data, the failure rates have been analysed for different turbine sizes, different turbine configurations and also classed by severity of failure (greater or less than 1 day to repair). The LWK dataset [11],[17],[18] consisted of up to 650 onshore turbines of varying size and configurations running over a similar time-period as the Windstats datasets (1993-2006) and contains turbines ranging from 225kW up to 1.8MW [9]. For this dataset, component failure rates have been published for various turbine models with differing sizes and configurations. However, there is no distinction between the severities of the component failures.

There is also similar onshore failure rate data available for turbines in Sweden and Finland [19], which is summarised by Ribrant [20]. This provides data on average turbine component failure rates and average downtimes for a changing turbine population of, on average 625 Swedish turbines and 71 Finish turbines from 2000-2004. Again, these turbines varied in configuration and size, from 55kW to 3MW [9].

Slightly more recent data from European onshore turbines, including Spain and the UK, can also be found. The CIRCE dataset [21] consists of failure rate and repair time data over a 3-year period for around 4,300 onshore wind turbines in Spain from around 2013 [9]. This dataset again consists of a mixed population of turbines with rated power between 300kW and 3MW, however, in contrast to the other datasets, contains a large number of turbines greater than 1MW in rated power (2,270 on average per year), and a large number of direct drive turbines (215 turbines). Turbines are grouped into geared turbines less than 1MW, geared turbines greater than 1MW, and direct-drive turbines (600kW – 2MW) and there are average component failure rates and downtimes given for each group. The CIRCE failure rate data is also further presented in more detail for some specific turbine models of various sizes and configurations. However, once again there is no classification of failure severity across this dataset. Wilson & McMillan presented failure rate data for 2.3MW onshore turbines over 382 wind turbine operational years for two UK wind farms [22]. Carroll et al. presented and analysed generator and power convertor failure rates for a sample of 2,222 onshore wind turbines with a rated power somewhere between 1.5MW – 2.5MW [23]. More specifically, the turbine population includes up to 1,822 DFIG turbines over a five-year period and up to 400 turbines with permanent magnet synchronous generators over a three-year period. Based on cost, the paper also separates the failures into groups based on severity – minor failures, major failures and major replacements.

In recent years there has also been an increasing amount of reliability data coming from onshore wind farms in China [24]–[26]. However, the available data from these studies is not as detailed as some of the larger European studies previously mentioned.

### 3.2.2 Offshore wind turbine failure rate data

In comparison to onshore wind farms, the published reliability data for offshore wind turbines is much more limited. Within the previously mentioned review papers, only a few offshore reliability studies were highlighted and no others found through additional searching. Two of these, one reporting on performance of the Round 1 UK offshore wind farms [27] and the SPARTA study [28], which reports performance on UK offshore wind farms, do not contain any failure rate information. These studies report other performance parameters such as wind farm availability or capacity factor. The NoordZee Wind study, reporting on the first three operational years of a Dutch offshore wind farm, reports the number of stops per component which is not equivalent to a failure of that component [29]–[31].

However, the latest edition of the SPARTA report, published in June 2022, did report some failure rate data from UK offshore wind farms [32]. These failure rate values are based on operational data from April 2020 – March 2021, with over 60% of UK offshore wind farms providing data into the study. Average values for turbine forced outages were included, along with data on the number of major repairs required within the dataset of the SPARTA study. Within this report, a major repair is defined as "a repair requiring mobilization efforts far and above those normally seen during routine wind farm operations, such as using jack-up barges". Average monthly turbine failure rate requiring major repairs for different large components are presented. Values of around 0.005 major repairs per turbine per month for a blade, between 0.0012 and 0.0013 for the gearbox and between 0.0004 and 0.0005 for the generator, are very approximately estimated from Figure 20 included in the report.

At the time of completing the work presented in this thesis, the only publicly available wind turbine component failure rate data for offshore turbines was reported by Carroll et al. [4]. This paper presents the average failure rate, repair time and repair cost for around 350 fixed-foundation offshore wind turbines of the same model over a five-year period. It is stated that these turbines are geared, induction machines and have a rated power between 2MW – 4MW. However, the exact details of the turbines are not given for confidentiality reasons. Importantly, the data is grouped by severity category – minor failures, major failures and major replacements, based on the cost of repair. The failure rate values for the major replacement of selected components (gearbox, generator and blades) taken from this publication are shown in Table 3.1.

*Table 3.1. Summary of failure rate for major replacements of selected wind turbine components taken from Carrol et al.* [4].

| Component | Gearbox | Generator | Blades |
|---|---|---|---|
| **Major replacement rate (failures/turbine.yr)** | 0.154 | 0.095 | 0.001 |

### 3.2.3 Impact of turbine size on failure rate

One of the onshore data sets where the failure rates have been extensively studied is the WMEP data set. Hahn et al. [33] showed that, within the range of turbine sizes in the dataset, that the larger turbines had a higher failure rate than the smaller turbines. Further studies based on the same data set observe an increase in turbine failure rate across the majority of components with increasing turbine complexity [13]. This trend is further supported by studies which show an increase in turbine failure rates when moving from constant-speed to variable speed-turbines [14] and an increase in failure rates when moving from stall-control to pitch-control [15]. It should be noted that increasing complexity generally occurs with increasing wind turbine size and therefore difficult to separate. These studies also highlight a reduction in failure rate over time.

The trend of increasing failure rates with turbine size and complexity has also been observed within the analysis of other onshore wind turbine failure rate datasets. When comparing the Windstats Germany dataset with the Windstats Denmark dataset, Tavner et al. found that the turbines within the Windstats Germany dataset, consisting generally of newer, larger and more complex turbines had higher failure rates [3]. However, it was also acknowledged that these would likely have been at an earlier stage in their ‘bathtub curve’ and that failure rates were decreasing with time. It should also be noted that the average size of turbines within these datasets were below 1MW. Analysis of the LWK dataset also shows an overall increase in failure rates within the population of larger wind turbines [12]. Analysis of the more recent CIRCE dataset, from Spanish onshore turbines from around 2013 also shows that the observed failure rate was higher in the larger wind turbines (geared turbines greater than 1MW) compared to the smaller turbines (geared turbines smaller than 1MW) [21].

### 3.2.4 Impact of turbine configuration on failure rate

Carroll et al. compared the failure rates of the generator and convertor in two different onshore wind turbine configurations – DFIG and permanent magnet synchronous generator (PMG) turbines [23]. Based on over 1,000 DFIG turbines and 400 permanent magnet synchronous generator machines with rated power between 1.5MW – 2.5MW, it was found that the PMG configuration had a higher combined failure rate. However, the permanent magnet synchronous generator on its own had a lower failure rate by around 40% compared to the DFIG generator.

Comparisons have also been done between direct drive configurations using wound rotor synchronous generators and other geared configurations. Using the WMEP database, it was found that direct-drive turbines had a higher overall failure rate compared to turbines with high-speed induction or synchronous generators [15]. However, the differences in failure rate when comparing the direct-drive synchronous generator to the high-speed synchronous generator is less clear. Suggesting that this increased failure rate seen in the direct-drive turbines may come from the impact that the direct-drive configuration has on the other components, and not necessarily from the generator itself. Data presented by Ozturk et al.

for 500kW turbines, also showed a higher failure rate in direct-drive generators in comparison to high-speed induction generators [16].

Perez et al. [17] compared the component failures between a 600kW onshore turbine with high-speed induction generator and 600kW direct-drive turbine with wound rotor synchronous generator. This comparison also showed the direct-drive configuration to have a higher number of overall failures, but it was noted that a large amount of these were electrical failures. When comparing specific component failure rates, it was found that the direct-drive turbine had a higher generator failure rate and a higher blade failure rate. Spinato et al. [12] also showed direct-drive turbines having a generally higher failure than geared turbines.

Reder et al. [21] compared the failure rates between onshore geared and direct-drive turbines and found direct-drive turbines to have a lower failure rate than geared turbines over the whole dataset. One of the limitations of this data is that it does not separate the turbines into age groups, and therefore the relative ages of the turbines are unknown. However, this is a large dataset and contains a higher number of more modern turbines, greater than 1MW, in comparison to the majority of other onshore turbine datasets.

### 3.2.5 Summary of wind turbine failure rate data

This review of the available wind turbine reliability literature shows that the amount of publicly available data is extremely limited, especially for offshore wind turbines. The majority of available failure data is for onshore wind turbines, which has been shown to be different to offshore turbines [4], [9]. Excluding that, these data sets are mainly made up of turbines below 1MW in size and contain a large proportion of very old turbine concepts, such as stall regulated turbines. For offshore wind turbines, there was only one publicly available dataset that contains failure information at the time of carrying out this work. This dataset is therefore representative of offshore wind turbines and presents the failure information grouped into minor failures, major failures and major replacements. However, this dataset is formed from the first generation of offshore turbines and, as shown in Chapter 2, these are different from current and next generation of offshore wind turbines and therefore may not be representative of these new turbines. The recent SPARTA publication provides failure rate data, including data on major replacement tasks, based on the last year of operation of a large volume of UK offshore wind turbines. The SPARTA data is therefore likely to include more modern turbine configurations and will be extremely useful to offshore wind researchers and developers. However, this dataset will also include a large number of first-generation turbines and will include nothing defined as ‘next-generation’ within the scope of the PhD project.

It has also been shown that the historical development of onshore wind turbines has had an impact on failure rate. There have been a number of onshore reliability studies that suggest increasing failure rate with increasing turbine size. However, these datasets are also influenced by developments in configuration, for example the change from stall-regulated to pitch-regulated turbines and from constant-speed to variable-speed turbines, that are now long established in modern wind turbines. Differences in drive-train configuration has also been shown to impact turbine reliability historically, with older studies (WMEP and LWK) concluding higher failure rates in direct-drive turbines. However, more recent studies (CIRCE and Carroll) show lower failure rates in the direct-drive configurations.

Therefore, although there has been some analysis in the past of how wind turbine development can impact failure rates, these are based on old, onshore turbine technologies that do not represent the current and future generation of offshore wind turbines. And although some trends do emerge regarding the impacts of these technological developments, they are certainly not conclusive in a way that can be applied to current offshore wind turbines. This review shows that past analysis cannot be used entirely to predict the failure rates of modern offshore turbines and that more work is required to understand the impacts of current turbine development on their reliability.

## 3.3 Structured expert elicitation

When trying to make complex decisions about future scenarios, the information required to inform the decision-making process can often be uncertain or unknown. In some cases, existing, similar information can be used directly, or adjusted based on existing relationships and heuristics. However, sometimes there is not enough data available or it is judged not to sufficiently represent the scenario being investigated. In these situations, the knowledge of subject matter experts is often used as an alternative.

Within the previous chapters it has been highlighted that the major replacement rate of large wind turbine components is a critical input into O&M cost modelling tools. It has also been highlighted that, despite the availability of some limited publicly available failure rate data, this data is not representative of the next-generation of offshore wind turbines and that turbine size and configuration has been shown to historically impact wind turbine reliability. Therefore, the lack of failure rate data will be addressed using structured expert elicitation.

Other approaches to estimating turbine failure rate values were considered. This included the scaling of historical turbine failure rate data based on parameters which could influence failure rate, for example turbine rated power. This approach was not progressed as there are a large number of factors which could impact turbine reliability and the impact of each of these parameters are not easily identifiable from existing failure rate databases. As discussed previously, historical increases in turbine rated power also coincided with developments in turbine technology, changes in turbine design and increased operational experience. Within failure rate datasets, larger turbines are also likely to be earlier in their reliability 'bathtub curve' than smaller turbines. Therefore, scaling of turbine failure rates based on parameters like rated power was not considered a suitable approach. Another approach which was considered was to carry out physics-based modelling of different component failure modes and use this to estimate the failure rate of different components. However, this is a very time and resource intensive approach and does not capture the impact of factors like increased operational learning and experience. Therefore, this approach was also not considered suitable within the scope and requirements of this project.

The following sub-sections will briefly introduce the area of structured expert elicitation, before going on to explain the Classical Model of structured expert elicitation in detail.

### 3.3.1 Introduction to structured expert elicitation

Expertise can be defined in many ways, however an expert is generally considered to be someone who has "superior knowledge" in a subject area, as well as "experience of the practical use of knowledge" [34]. Structured expert elicitation methods provide a structured framework to capture this knowledge and represent the uncertainty. When applying structured elicitation approaches, it is accepted that there will be uncertainty within the values estimated by experts and that there are a number of cognitive and motivational biases which may impact the results. However, the aim of these methods is to capture and quantify the uncertainty of the expert in what these unknown values may be and to minimise the impacts of the various biases and heuristics [35], [36]. Uncertainty is captured as a probability distribution representing the expert's distribution of uncertainty in what the true value of an unknown parameter could be. The expert defines this distribution by providing values for various percentiles. There are also various steps within these approaches to minimise the impacts of cognitive biases and heuristics on the results. Some of the most impactful of these which have to be considered are overconfidence, anchoring, and availability.

*Overconfidence* - A commonly seen bias in expert elicitation is overconfidence. When asked to estimate the certainty in a given value an expert will often overestimate their certainty of their given outcome [37]. In the case of eliciting a probability distribution from the $5^{th}$ to $95^{th}$ percentile confidence range, it would be expected that the true value should fall within this range 90% of the time. However, due to the overconfidence bias, it is likely that the range of this distribution will be too narrow [38], and therefore capture the true value less than 90% of the time.

*Anchoring* - Another bias, which is often seen is known as anchoring. Typically, when estimating values, a person will start with an initial value and then adjust this value in their head to give their final estimate. However, it has been consistently shown that these adjustments from the initial value are not big enough – the estimate is still "anchored" to the initial value [39]. In the case of estimating a probability distribution, this again, will likely lead to a distribution that is too narrow to represent the actual uncertainty in the value being estimated.

*Availability* - Availability is another heuristic that should be considered in expert elicitation methods. Tverksy & Kahnemann showed that when people assess the likelihood of an event occurring, they place more emphasis similar events that they can bring to their mind more easily, for example something that happened recently [39], [40]. Therefore, they are likely to overestimate the likelihood of these events. It is therefore likely that experts may overestimate the probability of events that they have been exposed to in recent times, whilst underestimating the probability of other events.

Further details on these and other cognitive and motivational biases which should be considered within expert elicitation methods are well summarised by Montibeller and von Winderfeldt [41], [42].

Structured expert elicitation techniques have been applied across a wide range of areas, including limited use within wind energy within the existing literature. Wiser et al. used expert elicitation to estimate the future cost of offshore wind energy in 2030 and 2050 [43], [44]. Zitrou et al. used expert elicitation to identify wind turbine subassemblies with the largest uncertainty in their reliability estimates and provide reliability profiles for these subassemblies when exposed to certain "triggers" [45]. Within the area of wind energy O&M modelling, expert elicitation or expert knowledge is often mentioned when estimating unknown input values [46]–[50], however, details on how this has been done is very rarely provided.

Three of the most commonly used methods of structured expert elicitation are the Classical Model, The Sheffield Method and the Delphi Method [36]. These approaches vary mainly based on the number of stages used to elicit information from the experts, the style of interview (group or individual), the level of interaction allowed between experts, and how the responses provided by experts are weighted and aggregated (behavioural or mathematical). The Classical Model is characterised by the individual interviewing of experts with no interaction between them, performance weighting of experts (using seed or calibration questions) and the mathematical aggregation of expert responses [51], [52]. The Sheffield Method is a two-stage process where experts first provide their own individual estimates, and then discuss and agree on a final set of values as a group (behavioural aggregation) [53], [54]. Finally, the Delphi method is a multi-stage method where experts provide values individually, before being allowed to share information and interact anonymously before then providing final individual values [55], [56]. These are then mathematically aggregated with no performance weighting. The main features of these three elicitation approaches are summarised in Table 3.2.

*Table 3.2. Summary of some of the key features of three of the main methods of structured expert elicitation.*

| Elicitation Method | Number of Stages | Interview Style | Interaction Between Experts | Performance Measurement | Aggregation Method |
|---|---|---|---|---|---|
| **Classical** | 1 stage | Individual | No interaction | Performance measurement and weighting through seed questions | Mathematical aggregation |
| **Sheffield** | 2 stages | Individual + group session | Full interaction during the group session | No performance measurement | Behavioural aggregation |
| **Delphi** | Multiple stages | Individual | Controlled interaction, anonymity between experts maintained | No performance measurement | Mathematical aggregation |

The method applied in this work is the Classical Model, this was selected for three reasons. Firstly, the individual interview sessions and the lack of interaction between experts eliminated the need to manage the impact of various group biases (such as false consensus, groupthink, and group overconfidence [42]) from impacting the results. This was judged to outweigh the potential benefits of information and idea sharing between experts. Secondly, the performance weighting used in the Classical Model provides a framework for identifying and validating the optimum weighting of expert responses, and mathematical aggregation of these responses is also judged to give clarity and transparency to how the final results have been found. Finally, the single-stage of individual interview sessions was also determined to be the most applicable approach from a logistical and resource perspective.

### 3.3.2 The Classical Model

Within the existing literature the Classical Model has been applied extensively across a large range of subject matter areas [57]. As previously mentioned, this approach is characterised by no interaction between experts, performance weighing of responses using seed questions, and the mathematical aggregation of the values provided by experts. The number of experts interviewed, and number of questions vary from study to study (this will be discussed in more detail in Chapter 3.4), however the number of experts are typically within the range of 5-20 and the number of uncertain items being assessed around 20-30 [51]. Firstly, experts are asked to provide estimates for a range of seed variables. This is generally done by providing values for the 5$^{th}$, 50$^{th}$, and 95$^{th}$ percentile of their theoretical probability distribution of uncertainty in what the true value could be [51]. However, the true values of these seed variables are known to the elicitation team and therefore the values provided by the experts can be used to measure the statistical properties of their responses. These statistical properties, explained below, are then used to assign weighting to the values provided by experts on the unknown variables of interest, for which experts also provide a range of percentile values, when carrying out the final aggregation of these values. Using this weighting, the values provided for the variables of interest are mathematically aggregated to form an overall, combined distribution of uncertainty across the group of experts. The aggregated value of the group is often referred to as the Decision Maker (DM). There are multiple weighting methods which can be applied within the Classical Model and descriptions of these can be found in various sources [51], [58]–[60]. The global-weighting approach has been applied within the work presented within this thesis and this is therefore described in detail below.

#### 3.3.2.1 Global weighting

Within the global weighting approach, weighting is based on the measures of calibration and information across the entire range of seed questions used in the elicitation [57]. The calibration score is a measure of the statistical accuracy of the values provided to the seed questions. When providing a range of percentile values (5$^{th}$, 50$^{th}$ and 95$^{th}$), it would be expected that, across a number of seed questions, the true value would fall below the 5$^{th}$ percentile 5% of the time, between the 5$^{th}$ and 50$^{th}$ percentile 45% of the time, and so on. Divergence from the expected distribution is calculated using the Kullback-Leibler divergence measure, D(s,p), (Equation 3.2) where $s_i$ is the number of values that fall within each percentile range given by the expert, $p_i$ is the expected number of true values within each percentile range, and n is the number of percentile ranges [51].

$$D(s,p) = \sum_{i=1}^{n} s_i \ln\left(\frac{s_i}{p_i}\right) \tag{3.2}$$

If a sufficient number of seed questions are used, the probability distribution of the divergence measure tends to a chi-square distribution ($\chi^2$) [51]. This is shown in Equation 3.3, where q is the number of seed questions and $\chi^2_{n-1}$is the cumulative distribution function (CDF) for the $\chi^2$ distribution with n-1 degrees of freedom. The $\chi^2$ distribution gives the likelihood that the calculated divergence measure will be exceeded. This value taken from the chi-square CDF is used to determine the expert's calibration score (C = 1-value).

$$Pr\{2qD(s,p) \le x\} \rightarrow \chi^2_{n-1}(x) \tag{3.3}$$

The information score can generally be considered as a measure of how wide the uncertainty ranges provided for the seed questions are. This score is found by determining the divergence of the distributions provided by experts from an uninformative distribution, generally considered as a uniform distribution over the intrinsic range of values provided across the entire group of experts on each question [51]. As experts have only provided a range from the 5th to the 95th percentile, the intrinsic range, including minimum ($q_L$) and maximum values ($q_H$), is found using the "k% overshoot rule" [52]. The values of $q_L$ and $q_H$ can then be found from Equations 3.4 and 3.5, where $q_5$ is the lowest 5th percentile value across the group of experts and $q_{95}$ the highest 95th percentile value across the group [51]. A k value of 10 is a typically accepted value [51], [52].

$$q_L = q_5 - k.\frac{(q_{95} - q_5)}{100} \tag{3.4}$$

$$q_H = q_{95} + k.\frac{(q_{95} - q_5)}{100} \tag{3.5}$$

Once the intrinsic range of this uninformative, uniform distribution is specified, the divergence between the distribution given by the expert and the uninformative distribution can be found using Equation 3.6 [51].

$$I_i(e) = 0.05 \ln\left(\frac{0.05}{\frac{(q_{ei5}-q_{iL})}{(q_{iH}-q_{iL})}}\right) + 0.45 \ln\left(\frac{0.45}{\frac{(q_{ei50}-q_{ei5})}{(q_{iH}-q_{iL})}}\right) + 0.45 \ln\left(\frac{0.45}{\frac{(q_{ei95}-q_{ei50})}{(q_{iH}-q_{iL})}}\right) + 0.05 \ln\left(\frac{0.05}{\frac{(q_{eiH}-q_{ei95})}{(q_{iH}-q_{iL})}}\right) \tag{3.6}$$

Using the global-weighting approach, each of the experts are weighted based on the calibration score and an average information score across the complete set of seed questions, as shown in Equation 3.7 [51]. $C(e_i)$ is the calibration score, $I(e_i)$ is the average information score across all seed questions. $Z(C(e_i))$ is given a value of either 0 or 1 and is dependent on receiving a minimum calibration score value, α. The value of α is not fixed, but is chosen through optimisation to be the value which maximises the weight of the aggregated Decision Maker on the seed questions [52]. Therefore, experts with a calibration score above this value are given a value of 1, and those with a calibration score below this value are given a value of 0 and therefore receive zero weight in the final aggregating when using the global-weighting approach. The calculated weights are then normalised to equal 1 across the experts.

When the Classical Model is used, it is common for the majority of experts to receive a calibration score below values typically chosen for α, therefore receiving a Z value and a final weighting value of zero. This will be discussed more in the following section (Chapter 3.3.2.2). However, the values provided by these experts still impact the overall aggregation and optimisation through the calculation of the information scores. Therefore, the global-weighting approach should not be viewed as a way to exclude the values provided by some experts, but rather as an optimisation problem, where the aim is to combine expert responses in a way that maximises the weight of the Decision Maker on the seed questions - therefore providing a level of validation to the chosen weighting and aggregation.

$$w_{ri} = C(e_i) \times I(e_i) \times Z\big(C(e_i)\big) \tag{3.7}$$

The values provided by the group of experts for each percentile and each variable of interest are then mathematically aggregated across the group using a linear pooling approach. The aggregated percentile value can be calculated using Equation 3.8, where $p_i(\theta)$ is the percentile value given by each expert, i, and $p(\theta)$ is the aggregated percentile value [61].

$$p(\theta) = \sum_{i=1}^{n} w_i p_i(\theta) \tag{3.8}$$

#### 3.3.2.2 Equal weighting

Another approach that can be used when aggregating the values provided by a group of experts is equal weighting, where the weight given to the values provided by each expert in Equation 3.8 is simply 1/n (where n is the number of experts). This is a simpler alternative to the performance weighting of the Classical Model and ensures that the values provided by all experts are fully incorporated into the final aggregation process. The relative merits of equal weighting and performance weighting is an area of active discussion within the published literature. An equally-weighted aggregation of results can potentially average out values that are too high or too low across a group of experts, can help to reduce the impacts of overconfidence on the final aggregated values, and in some instances has been found to perform as well as performance weighting methods, like the Classical Model [62].

However, performance weighting ensures that the final results are weighted and aggregated in the way which optimises the performance of the combined DM on the seed questions, providing validation of the aggregation approach used. As previously mentioned, this can lead to a large number of experts receiving a weight of zero in the final aggregation when performance weighting is used. A review of calibration scores of over 300 experts over a range of elicitations carried out prior to 2006 shows that 73% of experts would have received zero weight, if a minimum calibration score of 0.05 was applied [60]. Other potential challenges when using performance weighting have also been highlighted within the existing literature, with Bolger and Rowe arguing that performance weighting struggles to appropriately measure substantive expertise [63]. Hemming et al. have also highlighted the difficulties in developing good seed questions for performance-weighting approaches, recommending equal-weighting as an alternative in these situations [64].

However, a large number of comprehensive comparison studies have found that, in most cases, performance weighting of expert responses outperforms equal weighting. Eggstaff et al. carried out a cross-validation study on a large number of datasets and found that the Classical Model's performance-weighting approach outperformed the equal-weighting approach in the majority of cases [61]. Colson and Cooke also compared the Classical Model against equal weighting across 33 expert elicitation studies and found superior performance of the Classical Model [65]. Although, it should be noted that these studies assess performance within the confines of the Classical Model approach – measuring calibration and information – and are based on performance of the seed questions, as the outcome to the variables of interest are rarely known [36], [66].

## 3.4 Methodology

This section will now outline the methodology used in this work when applying the Classical Model to estimate major replacement rate values in next-generation offshore wind turbines. The overall approach applied in this work is based on the Classical Model of structured expert elicitation as outlined in the previous section (Chapter 3.3.2), with steps taken based on guidance produced by the European Food Safety Authority (EFSA) on practically applying expert knowledge elicitation methods [54]. Based on the EFSA guidance, the elicitation lifecycle was approached in four stages - the initiation stage, the pre-elicitation stage, the elicitation stage and the post elicitation stage – and the steps applied in each of these stages summarised in Figure 3.1.

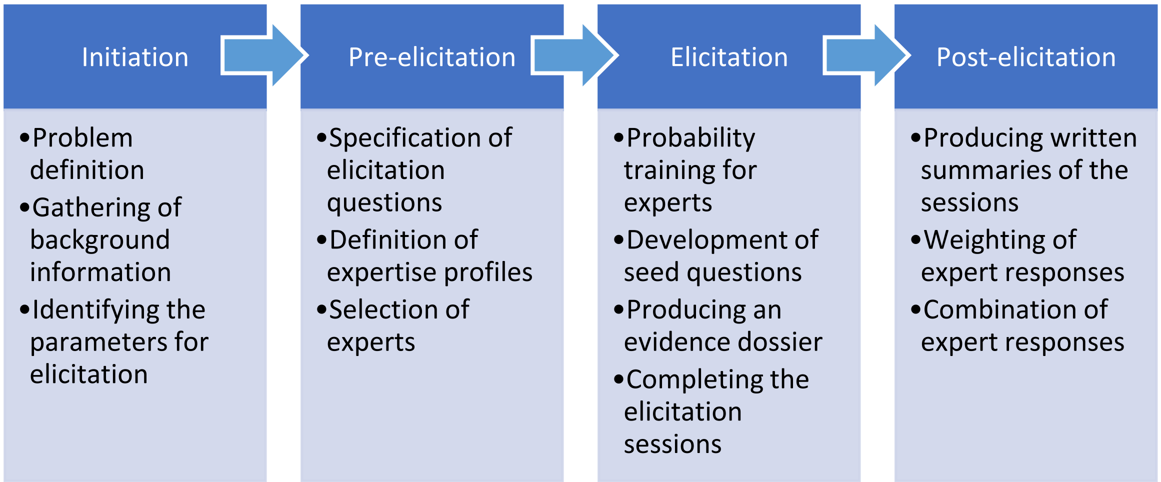


*Figure 3.1. Overview of each of the stages of the elicitation lifecycle and the key activities in each stage.*

The problem definition, gathering of background information and the identification of elicitation parameters have already been addressed throughout the literature review portion of this chapter, therefore this Methodology section will focus on the latter three stages (pre-elicitation, elicitation and post-elicitation) and will address the following areas explicitly and in detail:

- Specification of the elicitation questions (variables of interest and seed questions),
- Definition of expertise profiles and selection of experts,
- How the elicitation sessions were structured and carried out, and finally,
- How the scoring, weighting, and aggregation of the experts' responses were carried out.

### 3.4.1 Specification of the elicitation questions

#### 3.4.1.1 Variables of interest

The way in which the elicitation questions are asked and the order that information is elicited can have a large impact on the results [54], therefore care has to be taken to ensure that the questions are understandable to the experts presented in a way that reduces cognitive biases.

For each question where the experts were asked to estimate percentile values for a variable of interest, the publicly available major replacement rate data for that component for first-generation offshore wind turbines was provided as part of the question [4]. Experts were then asked to estimate by what percentage they expected this value to differ when considering the next-generation of offshore wind turbines. It was considered important that experts were able to provide responses in a manner they were comfortable with, and therefore they were also able to provide replacement rate values directly, if preferred. Experts were asked to provide three percentile values (5$^{th}$, 95$^{th}$, and 50$^{th}$ percentiles) that represent their distribution of uncertainty for 10 variables of interest. The 5$^{th}$ and 95$^{th}$ percentile values represented the values they thought it was very unlikely that the true value would be below or above, and the 50$^{th}$ percentile represented the value they thought it equally likely the true value could be below or above. One of the ways in which the impacts of cognitive biases can be reduced when using the Classical Model is by asking experts to provide their percentile values in an appropriate order. For example, if the experts were first asked to provide their 50$^{th}$ percentile value, they could then become 'anchored' to this value, thus leading to their distribution becoming too narrow and not capturing the full uncertainty in the problem [51]. Therefore, when structuring the questions, the experts were asked to specify their 5$^{th}$ percentile value, followed by their 95$^{th}$ and 50$^{th}$ percentiles. The variables of interest were the major replacement rates of large components in four different next-generation offshore wind turbine configurations, and these configurations and components are given in Table 3.3. Other components which may lead to major replacement tasks on a floating turbine, for example the moorings and cables, were not considered as part of the scope of this PhD.

*Table 3.3. Turbine configurations and components which were considered within the variables of interest.*

| Turbine Configuration | Components |
|---|---|
| 15MW fixed-foundation direct-drive turbine | generator and rotor (defined as any of the blades or the hub) |
| 15MW fixed-foundation medium-speed turbine | generator, gearbox, and rotor |
| 15MW semi-submersible floating-foundation direct-drive turbine | generator and rotor |
| 15MW semi-submersible floating-foundation medium-speed turbine | generator, gearbox, and rotor |

An example of one of these questions on the variables of interest is shown in Figure 3.2 and the full set of questions is given in Appendix I. By providing known replacement rate values for first-generation turbines as part of these questions, an opportunity for the anchoring bias to occur is created. However, as part of the interview session, the various cognitive biases and heuristics considered most relevant to the elicitation, including anchoring, are explained to the expert. During the course of the interview session, answers are also discussed with the expert to ensure that they are providing values representative of their true thoughts and beliefs as best as possible. In this case, it was concluded that the benefit of having an initial, known value as a basis for discussion, and to understand why the values provided by the expert are different to these published values, outweighed the potential risks of cognitive biases such as anchoring occurring.

Based on offshore data, the average number of major replacements for a generator in a fixed bottom, 2-4MW turbine with high-speed gearbox and induction generator over the first 8 years is estimated to be around *0.095 replacements/ turbine.yr.*

By what percentage do you think the average number of major replacements for a generator will change for a fixed bottom, 15MW, direct-drive turbine with a permanent magnet synchronous generator over the same time period?

| | | |
|---|---|---|
| 5$^{th}$ percentile | 95$^{th}$ percentile | 50$^{th}$ percentile |
| Reasons for answer: | | |

*Figure 3.2. Example of one of the elicitation questions for the variables of interest.*

#### 3.4.1.2 Seed questions

Various types of data can be used to generate seed questions and these are well summarised by Quigley et al [51]. Sources of data can be separated into predictions, where the true value is not known at the time of the elicitation but becomes known after. Or retrodictions, where the true values are known at the time to the elicitation team, but not to the experts. Data sources can also be separated into domain variables which are within the same area as the expert's expertise, or adjacent variables which are in a related area of expertise which can still be estimated by the expert. The preferred type of data for seed questions are domain predictions, however these are often very difficult to find.

There is no clear conclusion on the number of seed questions that should be used when using the Classical Model, however when reviewing the performance validation work that has been done on the Classical Model, Cooke [67] advises the use of 10 seed questions, as opposed to a smaller question set, to give improved performance of performance weighting against equal weighting of experts. Analysis of 33 elicitations using the Classical Model, from 2007-2015, by Colson & Cooke [66] found that the number of seed questions across the range of elicitation reviewed ranged from seven to 17, however the majority of these used 10 seed questions. Based on this, 10 seed questions were used in this work.

As was outlined previously in this chapter (Chapter 3.2), available failure rate data for wind turbines is very limited – this is particularly true for offshore wind turbines. Therefore, seed questions were based on published failure rate data for onshore wind turbines taken from the following publications [17], [21], [23]. These are retrodictions rather than the more preferable predictions, however due to the limited data available, this was judged to be the most appropriate data to use. Where possible, values from data-sets were combined rather than being taken directly from the publications. Seed questions based on onshore wind turbine failure rates can potentially be considered as either domain or adjacent variables depending on how the domain of the variables of interest are considered – wind turbine reliability and failure rates (domain) or offshore wind (adjacent). Regardless, what is considered important is that seed variables trigger the same judgement heuristics in experts as the target variables [51] and this is the case here (impact of increasing turbines size, turbine configuration, etc. on failure rate). An example of one of these seed questions is given in Figure 3.3 and the full set of questions is given in Appendix II. It should also be noted that the seed questions are based on total number of failures, regardless of severity, rather than only major replacement operations. As the total number of failures is higher than the number of major replacements, these differences present another opportunity for anchoring to have an effect on the values provided when moving between these questions.

| | | |
|---|---|---|
| Based on onshore data, the average failure rate for geared turbines with rated power between 300kW and 1 MW was found to be 0.46 failures/turbine.yr.<br><br>1. By what percentage do you think the average failure rate will change for geared turbines with rated power between 1MW and 3MW? | | |
| | | |
| $5^{th}$ percentile | $95^{th}$ percentile | $50^{th}$ percentile |
| Reasons for answer: | | |

*Figure 3.3. Example of one of the seed questions from the elicitation.*

### 3.4.2 Definition of expertise profiles and selection of experts

There is no clear definition of the number of experts required for expert elicitation when using the Classical Model and therefore this number can vary across different studies. Quigley et al. [51] gives a range of 5-20 experts for elicitation using the Classical Model, other sources suggest that between five and ten experts are optimum, or that best performance is found with between three and sixteen experts [34]. In a review of 45 expert elicitations using the Classical Model up until 2006 by Cooke and Goossens, it can be seen the number of experts ranged from four to 77 [57]. Another analysis of 33 Classical Model elicitations from 2007-2015 carried out by Colson and Cooke, showed expert numbers ranging from four to 21 [66]. As part of the work carried out in this PhD project, six experts were interviewed. Six experts is within the range typically seen in the existing literature and consideration was given to the required knowledge and expertise for the elicitation.

As part of the expert selection process, the expertise required for the elicitation was defined. This is an important step in ensuring that the required knowledge and experience is represented across the final group of experts interviewed as part of the elicitation process. A practical approach to specifying the necessary expertise is through the creation of a profile matrix [34], [54] in which the expertise required for the elicitation is defined. A profile matrix was created outlining the areas of knowledge that the PhD team considered should be represented across the group. These areas of knowledge are shown in Table 3.4. It is accepted that all experts may not have expertise in all areas, but what is considered important is to have coverage across all areas within the group and this is achieved in this work.

Firstly, a long-list of potential experts to be considered for the elicitation was created. This was done primarily through the familiarity of the PhD team with the areas which were defined in the profile matrix. When potential experts were contacted, some provided names of additional potential experts and these were also added to the long-list, however, no explicit 'snowballing' technique [34] was used. A smaller short-list of potential experts was then chosen by comparing the known expertise of the names in the long-list to the areas previously defined in the profile matrix. At this stage, known expertise was judged based on the review of publications, job history available online, for example on LinkedIn, or through the knowledge of the PhD team.

Potential experts from this smaller group were then contacted and individual interview sessions were completed with six experts. Prior to the interview sessions, experts were sent a questionnaire in which they were asked to summarise their experience and identify the areas outlined within the profile matrix which they thought they had a good understanding of. The number of experts self-identifying as having a good knowledge of each of these areas are also given in Table 3.4. Across the group of experts there was a combined experience of 85 years within the area wind energy (an average of 14 years per expert), plus a combined 33 years of experience in other, related areas. The list of expert names can be found in Appendix III.

*Table 3.4. Areas of knowledge that were identified as required across the expert group, along with the number of experts who identified themselves as having good knowledge in that area.*

| Required areas of knowledge | Number of experts with good knowledge of area |
|---|---|
| Wind turbine technology | 5/6 |
| Offshore Wind | 6/6 |
| Wind turbine reliability and maintenance | 5/6 |
| Floating wind | 5/6 |
| Wind turbine drive-train (gearbox and generator) | 5/6 |
| Wind turbine rotor (blades and hub) | 4/6 |
| Mathematical probability | 5/6 |

### 3.4.3 Structure of the elicitation sessions

The interview sessions were completed from April – June 2021, and therefore, due to restrictions in place due to Covid-19, were completed remotely using either Zoom (five sessions), or Microsoft Teams (one session). All experts were sent an evidence dossier one week prior to their elicitation session. The evidence dossier is a document which contained a summary of the main existing wind turbine reliability and failure rate literature judged to be relevant to the elicitation area. An evidence dossier is often used as a way of ensuring that experts have access to the literature relevant to the elicitation and to reduce the impacts of the availability bias within the elicitation [36].

The interview sessions themselves consisted of two main parts. The first part was an introduction to expert elicitation and the Classical Model, including details on how experts should provide answers to the questions and an overview of some of the main cognitive biases and heuristics that may impact the results. It is expected that experts would generally have very limited experience in specifying percentiles as required in the elicitation process, and therefore a key part of the session is to provide training on probability and specifying percentiles [53], [54]. The second part of the interview session was the questions, including the ten seed questions and ten questions on the variables of interest.

The experts were asked to provide their three percentile values (5th, 95th and 50th percentile) for the seed questions and the variables of interest and provide reasoning for the values provided. The questions were presented both visually on the screen to the experts, and verbally. Experts were able to ask questions regarding the method and how to provide their values during these sessions. In the majority of the interview sessions (four out of six), all twenty questions were completed during the session. In the remaining two sessions, all ten seed questions and six of the ten questions on the variables on interest were completed during the session. The remaining four questions were sent to the experts via email and they responded with their values and reasoning. In both cases, these questions were for the variables of interest regarding rotor major replacements.

### 3.4.4 Weighting and aggregation of responses

Weighting and aggregation of the values provided by experts for the variables of interest was then completed using the two approaches previously discussed – the Classical Model's global-weighting approach and equal weighting. When applying equal weighting, the weight given to each expert's responses is simply 1/n, where n is the number of experts [61]. When using global weighting, the weight each expert's response is given is based on the values given to the seed questions, as outlined in Chapter 3.3.2.1.

Using the Excalibur software [68], the relative weighting for each of the experts based on their responses to the ten seed questions was then calculated, and is shown in Table 3.5. The weighting was based on global weighting with DM optimisation and a 10% k-overshoot value. The optimised value of $\alpha$ was found to be $2.8\text{x}10^{-4}$, which is lower than the value of 0.05 typically referred to in classical hypothesis testing and often applied in the Classical Model [60]. However, it was found that this lower value of $\alpha$ improved the performance of the Decision Maker on the seed questions. This can be seen in Table 3.6, which compares the DM calibration, information and overall weighting scores when these different values are used. Some experts receive a relative weighting value of zero. This has already been highlighted as a common occurrence when the Classical Model is used, however, the values provided by these experts still influence the overall results through their impact on the calculated information scores. As was explained in Chapter 3.3.2.1, the weighting of the values provided by experts during aggregation is not intended as a way to exclude values, but rather to optimise the performance of the aggregated DM on the seed questions. Therefore, the values given in Table 3.5 are those which lead to the highest weighting of the DM on the seed questions – hence providing a level of validation to the aggregation of expert values for the variables of interest.

Relative weightings for both the global-weighting and equal-weighting approaches were then used in Equation 3.8 with the values provided by each expert on the variables of interest to produce overall aggregated values for the group.

*Table 3.5. Relative weighting given to each expert's set of responses using global weighting with optimised DM and α=2.8x10$^{-4}$.*

| Expert | Relative Weighting from Excalibur |
|---|---|
| A | 0.177 |
| B | 0.011 |
| C | 0 |
| D | 0.812 |
| E | 0 |
| F | 0 |

*Table 3.6. Comparison of DM properties with α=2.8x10-4 and α=0.05.*

| Value of α | DM Calibration Score | DM Information Score | DM Weight |
|---|---|---|---|
| 2.8x10$^{-4}$ | 0.244 | 0.256 | 0.063 |
| 0.05 | 0.061 | 0.406 | 0.025 |

## 3.5 Results

Within this section, the estimated major replacement rate values for large components in the four next-generation offshore wind turbine configurations using both global weighting and equal weighting are presented. Firstly, the results for the 15MW fixed-foundation turbines (both direct-drive and medium-speed) are shown on a modified box-plot in Figure 3.4, this includes the results produced using both the global and equal weighting approaches, labelled as GW and EW on the Figure. The range shown for each component represents the aggregated percentiles and uncertainty range of the Decision Maker, with the outer lines representing the 5$^{th}$ and 95$^{th}$ percentiles and the inner line representing the 50$^{th}$ percentile. These values for the fixed-foundation turbine configurations are also presented numerically in Table 3.7. The estimated replacement rate values for the 15MW semi-submersible floating turbines are then shown in Figure 3.5, with the values given in Table 3.8.

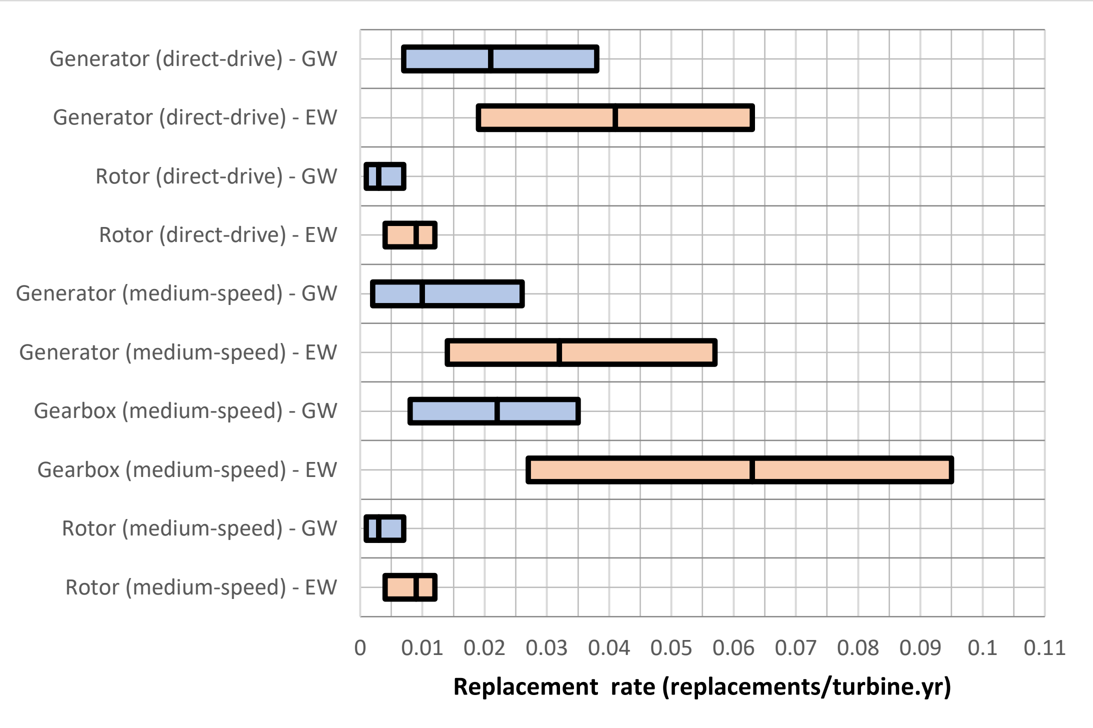


*Figure 3.4. Uncertainty range and 5th, 50th, and 95th percentile values of both the globally weighted (GW) and equally weighted (EW) decision makers for the 15MW fixed-foundation turbine components. The outer lines represent the 5th and 95th percentiles and the inner line the 50$^{th}$ percentile values.*

*Table 3.7. Percentile values of both the globally weighted (GW) and equally weighted (EW) decision makers for the 15MW fixed-foundation turbine components.*

| **Component (configuration) – weighting method** | **5th Percentile (replacements / turbine.yr)** | **50th Percentile (replacements / turbine.yr)** | **95th Percentile (replacements / turbine.yr)** |
|---|---|---|---|
| Generator (direct-drive) - GW | 0.007 | 0.021 | 0.038 |
| Generator (direct-drive) - EW | 0.019 | 0.041 | 0.063 |
| Rotor (direct-drive) – GW | 0.001 | 0.003 | 0.007 |
| Rotor (direct-drive) – EW | 0.004 | 0.009 | 0.012 |
| Generator (medium-speed) – GW | 0.002 | 0.01 | 0.026 |
| Generator (medium-speed) – EW | 0.014 | 0.032 | 0.057 |
| Gearbox (medium-speed) - GW | 0.008 | 0.022 | 0.035 |
| Gearbox (medium-speed) - EW | 0.027 | 0.063 | 0.095 |
| Rotor (medium-speed) - GW | 0.001 | 0.003 | 0.007 |
| Rotor (medium-speed) - EW | 0.004 | 0.009 | 0.012 |

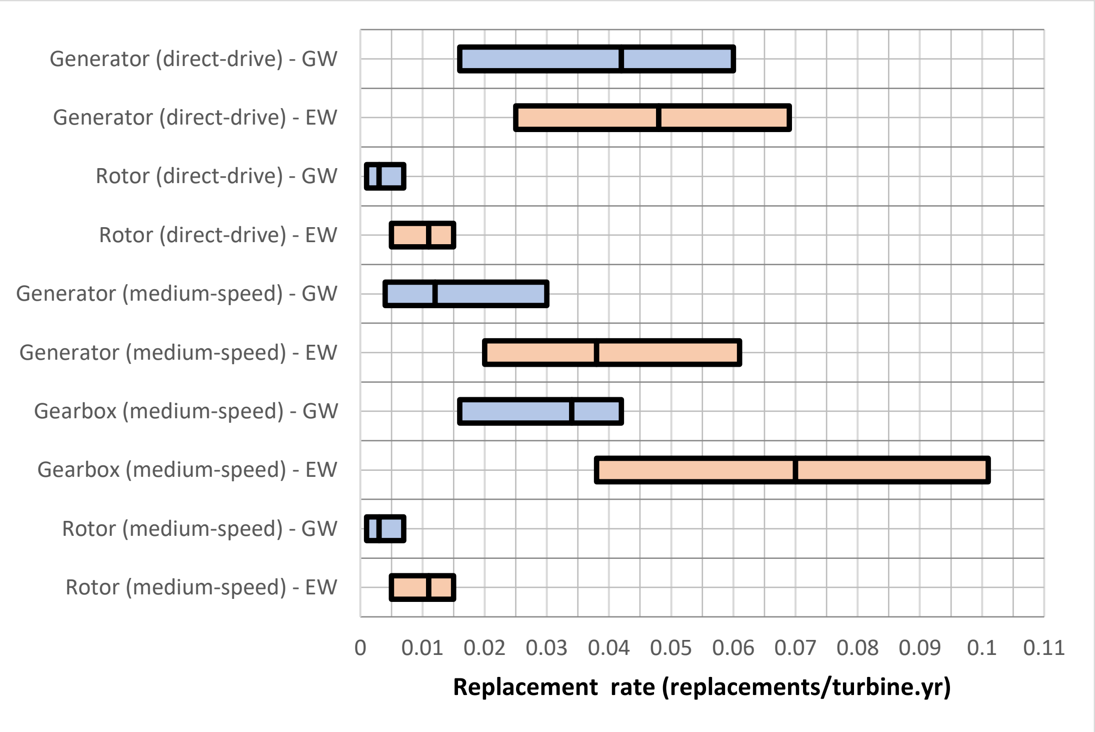


*Figure 3.5. Uncertainty range and 5th, 50th, and 95th percentile values of both the globally weighted (GW) and equally weighted (EW) decision makers for the 15MW semi-submersible floating turbine components. The outer lines represent the 5th and 95th percentiles and the inner line the 50th percentile values.*

*Table 3.8. Percentile values of both the globally weighted (GW) and equally weighted (EW) decision makers for the 15MW semi-submersible floating turbine components.*

| Component (configuration) – weighting method | 5th Percentile (replacements / turbine.yr) | 50th Percentile (replacements / turbine.yr) | 95th Percentile (replacements / turbine.yr) |
|---|---|---|---|
| Generator (direct-drive) - GW | 0.016 | 0.042 | 0.06 |
| Generator (direct-drive) - EW | 0.025 | 0.048 | 0.069 |
| Rotor (direct-drive) – GW | 0.001 | 0.003 | 0.007 |
| Rotor (direct-drive) – EW | 0.005 | 0.011 | 0.015 |
| Generator (medium-speed) – GW | 0.004 | 0.012 | 0.03 |
| Generator (medium-speed) – EW | 0.02 | 0.038 | 0.061 |
| Gearbox (medium-speed) - GW | 0.016 | 0.034 | 0.042 |
| Gearbox (medium-speed) - EW | 0.038 | 0.07 | 0.101 |
| Rotor (medium-speed) - GW | 0.001 | 0.003 | 0.007 |
| Rotor (medium-speed) - EW | 0.005 | 0.011 | 0.015 |

### 3.5.1 Global Weighting Aggregation of Responses

When reviewing the replacement rate values for fixed-foundation turbines produced using the global-weighting aggregation approach, labelled as GW in Figure 3.4 and Table 3.7, it can be observed that the range of replacement rate values estimated for the generator and gearbox are lower than the published values for first-generation offshore wind turbines. Even the 95th percentile values for these components in both the direct-drive and medium-speed configurations are lower than the values shown in Table 3.1 for the 2MW – 4MW turbines. It can also be seen that in the medium-speed configuration, the replacement rate of the gearbox is expected to be higher than the replacement rate of the medium-speed generator. The medium-speed gearbox also has a higher 50th percentile value than the direct-drive generator, but a lower 95th percentile when global weighting is used. It should be noted that the replacement rate values provided to experts within each question also had a higher replacement rate value for the gearbox. Therefore, there is also the possibility that if anchoring bias or the availability heuristic did occur, this could have contributed to predicted higher values for the gearbox compared to the generator.

It is also clear that there is still a large range of uncertainty in these values, as well as some overlap in the ranges across different components. The largest uncertainty range, when global weighting is used, is seen in the direct-drive generator, therefore suggesting that there is the most uncertainty in the replacement rate of this component. The overlap between the estimated replacement rate ranges of different components also highlights that, although some components are considered more likely to have a higher or lower replacement rate value, the opposite could also be observed – however, this is much less likely.

When reviewing the replacement rate values for the rotor also presented in Figure 3.4, unlike the drive-train components, this value is expected to be higher than that published for first-generation offshore wind turbines. However, these values are still much lower than those estimated for the generator and gearbox and have a much smaller uncertainty range than the drive-train components. It is possible that these values could be influenced by the anchoring bias and the availability heuristic as the values provided to experts for first-generation offshore wind turbines also had a much lower replacement rate value for the blades and hub compared to the generator and gearbox. This could also help explain why the uncertainty range is also narrower, as experts' relative changes in this low anchor value would also translate to small absolute values in this range. It can also be seen that the values in Figure 3.4 for the rotor in the direct-drive and medium-speed turbines are identical.

When reviewing the replacement rates of the major components in the 15MW turbine configurations with a semi-submersible, floating foundation using the global-weighting approach, shown in Figure 3.5 and Table 3.8, the general trends in these values are similar to those previously highlighted for the fixed-foundation turbines. A key difference however, is that the percentile values across all components are slightly higher in the floating turbine configurations compared to the values estimated for the fixed-foundation turbines. This shows that higher replacement rates of these components are expected to be more likely in floating turbines than in the fixed-foundation configurations. The 50$^{th}$ percentile value for the direct-drive generator is also higher than that for the medium-speed gearbox when considering the floating turbine configurations.

### 3.5.2 Equal Weighting Aggregation of Responses

When comparing the estimated replacement rates of major components in the fixed-foundation turbines using the equal-weighting method (labelled as EW in Figure 3.4 and Table 3.7), to the values for the global weighted decision maker, these are generally higher. The uncertainty range for each component is also generally wider when the equal-weighting aggregation is applied. This difference can be expected due to the nature of the two approaches. The equal-weighting approach is a combination of the values given by all six experts, therefore a larger range of values are considered than with the global-weighting method which, in this case, only considers the values provided by three experts in the final aggregation. Another difference that can be observed between the equal weighting and global weighting results is that, when equal weighting is used, the gearbox has a higher 95$^{th}$ percentile value than the direct-drive generator.

When comparing the estimated replacement rates of major components in the next-generation semi-submersible floating turbines using the equal-weighting approach to the values found for the fixed-foundation turbines, the same differences can be seen as were observed using global weighting. The uncertainty ranges are wider for the floating turbines and the predicted replacement rates are also higher than for the fixed-foundation turbines.

### 3.5.3 Replacement rate inputs for O&M cost modelling

Using the results presented in Table 3.7 and Table 3.8, a possible range of major replacement rate scenarios that could be used in the O&M modelling work in Chapter 5 and Chapter 6 of this thesis were defined. For each turbine configuration, the 5$^{th}$ percentile values for each of the components within that configuration were summed together to give the 'low' replacement rate scenario for each configuration. For example, the 5$^{th}$ percentile values for the fixed-foundation direct-drive generator and rotor were summed together to give the low replacement rate scenario for the fixed-foundation direct-drive turbine configuration. The same was done using the 50$^{th}$ and 95$^{th}$ percentile values to define a 'medium' and a 'high' replacement rate scenario for each turbine configuration. The values for each of these scenarios using global weighting are given in Table 3.9 and using equal weighting are given in Table 3.10.

The trends seen at component level are also reflected within these summed values for each turbine configuration. The medium-speed turbine configurations have higher major replacement rates than the direct-drive turbines in each of the three replacement rate scenarios and the floating turbine configurations have higher replacement rate values than the equivalent fixed-foundation turbines in the three scenarios. Detailed discussion of the results produced using the global and equal weighting approaches is included in the following section.

*Table 3.9. Low, medium and high major replacement rate scenarios for each turbine configuration based on global weighting results.*

| Turbine configuration | Low replacement rate scenario (rep/turbine.yr) | Med. replacement rate scenario (rep/turbine.yr) | High replacement rate scenario (rep/turbine.yr) |
|---|---|---|---|
| **Fixed-foundation, direct-drive** | 0.008 | 0.024 | 0.045 |
| **Fixed-foundation, medium-speed** | 0.011 | 0.035 | 0.068 |
| **Semi-sub foundation, direct-drive** | 0.017 | 0.045 | 0.067 |
| **Semi-sub foundation, medium-speed** | 0.021 | 0.049 | 0.079 |

*Table 3.10. Low, medium and high major replacement rate scenarios for each turbine configuration based on equal weighting results.*

| Turbine configuration | Low replacement rate scenario (rep/turbine.yr) | Med. replacement rate scenario (rep/turbine.yr) | High replacement rate scenario (rep/turbine.yr) |
|---|---|---|---|
| **Fixed-foundation, direct-drive** | 0.023 | 0.05 | 0.075 |
| **Fixed-foundation, medium-speed** | 0.045 | 0.104 | 0.164 |
| **Semi-sub foundation, direct-drive** | 0.03 | 0.059 | 0.084 |
| **Semi-sub foundation, medium-speed** | 0.063 | 0.119 | 0.177 |

## 3.6 Discussion of results

This section will discuss some of the aspects considered most interesting within the results presented in the previous section. This will include a discussion of how major replacement rate is expected to improve in next-generation turbines at component level and how the major replacement rate values are expected to differ across different 15MW next-generation offshore wind turbine configurations. This section will then conclude with a critical discussion and comparison of the results produced using both the global weighting and equal weighting approaches, before concluding which results are considered the most applicable for use in the O&M modelling work in Chapter 5 and Chapter 6 of this thesis.

### 3.6.1 Reliability of major components

When comparing the major replacement rate values of the components estimated within this study to those observed in first-generation offshore turbines published by Carroll et al. [4] and summarised in Table 3.1, several differences are found. Firstly, the replacement rate values of the generator and the gearbox are expected to decrease in next-generation turbines. This occurs when both the equal-weighting and the global-weighting aggregation approaches are used. A key reason given by experts for this improvement in reliability was the experience and learning gained as the offshore wind sector has developed, including referring to the number of major replacement tasks in current-generation offshore turbines which is lower than the number required in early offshore turbines. Another reason for the reduction in replacement rate values for these components was the negative impact on economics and the business case for major offshore wind projects if the large replacement rate values seen in early offshore turbines were observed in next-generation turbines. Technological developments were also mentioned as ways of improving turbine reliability and reducing the major replacement rate, for example the move to permanent magnet generators, and to medium-speed gearboxes.

However, when comparing the estimated replacement rate values for the rotor, defined as a replacement of any of the blades or the hub, both weighting methods found that this value is expected to increase in comparison to the published value for first-generation turbines. The main factors highlighted by experts for this increase were the increased risk of defects and weather-related damage due to the increased size of the rotor blades. There are other factors which may have influenced this result. The combination of the comparatively low replacement rates for the rotor in the first-generation turbines presented to experts and the anchoring effect of considering the larger replacement rates of the generator and gearbox, discussed by experts on previous questions, could have led to experts predicting higher replacement rate values for the rotor. However, the reasoning provided by the experts when discussing these values were consistent with the expectation that the number of major replacements related to the rotor is expected to be higher in large, next-generation turbines. This could potentially highlight some different challenges with larger, next-generation offshore wind turbines.

In the early, first generation of offshore wind turbines the biggest issues relating to major replacement tasks were due to the gearbox and generator. However, it is the view of the experts overall that these risk areas have therefore been recognised and reliability has been improved and will continue to be improved. In contrast to this, the expected replacement rates of the rotor blades, although still lower than the generator and gearbox, are expected to increase. The increasing likelihood of issues with turbine blades and reduced likelihood of issue with large drive-train components could change the risk profile associated with next-generation turbines compared to previous generations.

### 3.6.2 Differences in major replacement rate across different next-generation configurations

When comparing the different replacement rate scenarios shown in Table 3.9 and Table 3.10 for the direct-drive and medium-speed configurations, it can also be seen that a higher number of major replacements are expected to occur in the medium-speed turbines. The main cause of this higher replacement rate is the gearbox in the medium-speed configuration, which in most cases is expected to have the highest replacement rate value compared to the other components considered. The historical reliability issues encountered with gearboxes in offshore wind turbines and the limited experience of designing and operating gearboxes at the scale required for a 15MW turbine were highlighted by experts. However, there is overlap between the uncertainty range for the direct-drive and medium-speed turbine configurations shown in Table 3.9 and Table 3.10. Therefore, it is considered possible that the medium-speed configuration may have a lower rate of major replacements, but it is considered to be less likely.

When comparing the estimated major replacement rate values between the fixed and floating foundation configurations, it can be seen in Table 3.9 and Table 3.10 that each of the three percentile values for the floating turbine configurations are slightly higher than of the equivalent fixed-foundation turbine. Thus, highlighting that a larger number of large component major replacement tasks are expected in floating turbines. There were several reasons given by experts for this expected increase. The additional degree of motion and potentially higher nacelle acceleration values in floating turbines could lead to increased loading on turbine components. The expected lower accessibility of floating turbines will increase the difficulty in completing maintenance tasks on these turbines also potentially increasing the number of component failures and major replacements required. It was also mentioned that, if floating turbines can be towed to shore to carry out major replacement tasks, replacing large components may in fact be easier compared to fixed-foundation turbines, therefore reducing to need to minimise major replacement tasks to a lower level than fixed-foundation turbines.

However, it should be noted that although the aggregated values using both weighting methods found a higher replacement rate value in floating turbines, this agreement was not seen across all individual experts, with some expecting lower values in floating turbines. One of the reasons given for this included knowledge of existing research suggesting that, for some configurations, the loading on the drive-train is not largely impacted by the floating turbine wave-induced motion. Another reason given was that there will be large drivers to improve the reliability of floating turbines compared to fixed-foundation turbines as the replacement of large components is expected to be more challenging.

Again, there is a large overlap between the range of aggregated values in Table 3.9 and Table 3.10 for the fixed and floating turbine configurations, suggesting that a higher rate of major replacements in floating turbines is considered the more likely outcome, however the alternative is possible.

### 3.6.3 Comparison between Classical Model global weighting and equal weighting results

It has been highlighted earlier in this chapter (Chapter 3.3.2.2) that there is discussion within the academic literature regarding the relative merits of performance weighting and equal weighting when aggregating the values provided by experts. It is not the aim of the work presented within this thesis to add further to this discussion, but rather to apply both of these approaches, present the results and highlight the potential benefits and limitations of each in the context of this work. A decision on whether to use the values produced using either global weighting or equal weighting within the context of this thesis is then arrived at.

When the equal-weighting approach is applied, the values provided by all six experts are considered equally within the final aggregation step, whereas global weighting only considers the values provided by three experts, with different weights applied, in the final aggregation process. All six of the experts interviewed as part of this work are considered by the PhD team to be subject matter experts in the key areas concluded to be important for this elicitation study. Therefore, a potential advantage of applying the equal-weighting aggregation approach is that the values provided by all six subject matter experts are considered equally within the final aggregation of results. However, when considering the Classical Model's global-weighting aggregation, the aggregation of values across the expert group is done in a way which optimises the performance of the combined Decision Maker on the seed questions.

Using global weighting therefore provides a level of validation to how the individual judgements are aggregated across the group – this is the best combination with regards to capturing the true values in the seed questions. The weight of the DM when using global weighting was found to be 0.063, compared to a weight of 0.02 when equal weighting is used. Therefore, a key consideration is whether the seed questions are considered as representative of the variables of interest. If so then the global-weighting approach, validated against these questions should be considered as a better representation of the possible true values of replacement rate values for the next generation of offshore turbines than the equal-weighting approach.

As described previously within this chapter, the seed questions used within this work were based on published historical failure rate data for onshore wind turbines. It is therefore possible to consider these as either adjacent or domain variables, depending on how the domain of the elicitation is defined. Regardless, it is concluded that there is sufficient correlation between the impacts of changing turbine size, rated power, and drive-train configuration on the reliability of onshore turbines, and the impacts of these changes on offshore turbine reliability, for this data to be representative of the variables of interest and suitable for use as seed questions.

However, there are several well-known issues with historical onshore wind turbine failure rate datasets, which would likely have made it challenging for experts to capture the true values expected for the seed questions during this elicitation. Within the academic literature on wind turbine reliability, it is often highlighted that there are inconsistencies in how failures are defined and classified across different wind turbine reliability studies [5], [6], [9] This can lead to different failure rate values across different studies and can lead to differing interpretations on what may or may not represent a failure. Another well-known feature of historical onshore wind failure rate datasets is that they generally contain a range of turbine configurations, sizes and ages and the exact composition of these turbines are often unknown. This again, can lead to challenges when attempting to capture the true value on the seed questions. Some reliability datasets are broken down into more defined turbine populations, however this leads to small sample sizes subject to large variations. The limitations of historical failure rate data were also mentioned by several of the experts during the elicitation sessions where it was highlighted that the true values will be dependent on how failures are categorised and that a failure is often interpreted differently between industry and academia. Experts also highlighted that turbine manufacturer, site conditions, maintenance regime, time period and sample size can all influence the expected true value when considering small, onshore wind turbines.

Therefore, although onshore wind failure rates are considered a suitable domain on which to weight the assessments given by experts on offshore wind failure rates in this context, there are clear challenges for experts when it comes to maximising their weighting on these questions when using the Classical Model. Therefore, the equal-weighting aggregation approach should not be discounted without careful consideration of what properties are most desirable from the elicitation process - consideration of a wider range of subject matter experts' values in the final aggregation, or validation against historical onshore wind failure rate data.

When determining the range of replacement rate scenarios to be applied within the O&M modelling work in Chapter 5 and Chapter 6, it was decided that the values shown in Table 3.9 found using global weighting would be used. Despite the limitations highlighted with using historical onshore wind turbine failure rate data for seed questions, it is concluded that this is outweighed by the benefits of validating the optimal aggregation of expert responses using the seed questions. If sufficient weighting can be achieved, despite the uncertainties around these values, this is considered to add further credibility to this aggregation approach.

### 3.6.4 Comparison of results to recent SPARTA data

In June 2022, the SPARTA study reported monthly major replacement rate values based on a large number of UK offshore wind turbines from March 2020 – April 2021. The publishing of this data coincided with the completion of this thesis report and therefore a detailed comparison of the reported values against the values estimated within this chapters was not completed, however some initial comparisons are discussed here. It should be remembered that the data reported in the SPARTA report is based on current operational turbines and are therefore not directly comparable to those estimated here for next-generation 15MW turbines. However, as this is the first operational failure rate data for offshore wind turbines published since 2016 [4], a high-level comparison is considered to be a useful exercise.

From Figure 20 in the SPARTA report [32], the annual major replacement rate values are very approximately estimated to be around 0.06 replacements/turbine.yr for a blade and around 0.015 and 0.005 for the gearbox and generator. Comparing these values to those estimated within this chapter, the major replacement rates from the SPARTA study for the generator and gearbox are within the ranges estimated for medium-speed turbines using global weighting, but lower than those estimated using equal weighting. However, the SPARTA values are much higher than those estimated for the turbine rotor/blades. It is highlighted within the SPARTA report that the majority of blade replacements are likely done as part of planned campaigns, rather than a result of failure. The combined value of the major replacement rates estimated from the SPARTA report for these three components is around 0.08 replacements/turbine.yr. This value is higher than the range of combined values estimated using the global-weighting approach (Table 3.9), but within the range of the medium-speed turbines found using equal weighting (Table 3.10).

Several of the key trends identified within the expert elicitation work are also represented in the SPARTA data, including a reduction in gearbox and generator major replacement rate from data published for early, first-generation offshore turbines and an increase in the major replacement rate of blades compared to the first-generation data.

## 3.7 Conclusion to chapter

In the context of this PhD thesis, the aim of this chapter was to answer the following secondary research question:

*What is the likely range of large component major replacement rate values that could occur in next-generation offshore wind turbines and how could this differ between different turbine configurations?*

The main deliverable from this chapter was defined as a range of major replacement rate scenarios, representing the possible range of values expected in various next-generation offshore wind turbine configurations, which can be used as an input into the O&M cost modelling in Chapter 5 and Chapter 6.

This has been comprehensively addressed within this chapter. Firstly, the existing literature on wind turbine reliability and failure rate studies were summarised. This review highlighted the lack of publicly available failure rate data for wind turbines, particularly offshore wind turbines. It was also highlighted that developments in turbine technology has been historically shown to impact turbine reliability and failure rates, showing the limited applicability of the available failure rate data from onshore turbines and first-generation offshore wind turbines to the next-generation of offshore turbines. This chapter then addresses this knowledge gap and the secondary research question posed by estimating the major replacement rate values of three large wind turbine components (generator, gearbox, and rotor) in four next-generation offshore wind turbine configurations, given below.

- 15MW fixed-foundation direct-drive turbine,
- 15MW fixed-foundation medium-speed turbine,
- 15MW semi-submersible floating-foundation direct-drive turbine, and
- 15MW semi-submersible floating-foundation medium-speed turbine.

This has been done by using a recognised, and widely applied, method of structured expert elicitation known as the Classical Model and applying its global-weighting approach, as well as an equal-weighting approach.

The concept of structured expert elicitation is introduced and the Classical Model with global weighting is explained in detail. The methodology of the specifying the elicitation questions (both seed and variables of interest), selecting the six experts, carrying out the interview sessions and the weighting and aggregation of expert responses are then explained in detail. The aggregated major replacement rates of the four 15MW next-generation offshore wind turbines using both global and equal weighting are then presented and discussed at component level. These are then aggregated to form three major replacement rate scenarios (low, medium and high) that can be used in the O&M cost modelling presented later in this thesis.

The results highlight an expected reduction in major replacement rate in next-generation offshore wind turbines compared to the early, first-generation offshore turbines. They also highlight the turbine configurations and components where the most uncertainty in reliability may lie in these next-generation turbines. Based on the results, these appear to be the medium-speed gearbox and the direct-drive generator, however a potential increase in major replacements of part of the rotor is also expected in comparison to first-generation offshore turbines. The results also highlight that a larger number of major replacement operations are expected in next-generation medium-speed turbines compared to direct-drive turbines and in floating turbines compared to the fixed-foundation equivalent.

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# Chapter 4: The impact of wave-induced motion on the wave limits for floating turbine major replacement tasks

## 4.1 Chapter overview and research question

It has previously been highlighted within this thesis that the environmental limits (for example wave height and wind speed limits) in which maintenance vessels can operate in can have a large impact on wind turbine accessibility for maintenance. It has also been stated that new approaches for replacing large components in floating wind turbines will be required, with one of these approaches potentially being a floating-to-floating heavy lift replacement strategy. However, the wave limits at which these replacement tasks can be completed on a floating wind turbine using a floating heavy lift vessel are not widely known in the existing literature. This chapter will address this knowledge gap.

The chapter will begin by summarising the currently available literature on the environmental limits which have historically been applied in fixed-foundation offshore wind O&M modelling, before highlighting why these limits may not be applicable for use for floating offshore wind turbines. The available literature where wave limits for offshore wind lifting operations have been estimated will also be summarised. The chapter will then go on to introduce the approach of frequency-domain modelling of the wave-induced motion of a floating, rigid-body structure. This approach will then be applied to estimate the wave-induced motion of a 15MW floating reference turbine across a range of wave conditions and then combined with floating crane motion values taken from literature to estimate relative motion values between the two structures. Operational wave limits are then found through applying maximum motion limits for technician working on the turbine and maximum relative motion limits between the turbine and the crane. The methodology applied in this chapter will be presented and explained in detail and the results presented. These results will then be discussed and critically compared to other literature within this area which has been published after this work was completed. Finally, conclusions will be drawn based on these results and conclusions, and wave limit values which can be applied in the O&M cost modelling in Chapter 6 will be determined.

The aim of this chapter is to answer the secondary research question outlined in Chapter 1 and shown below:

*'What are the additional accessibility limits (wave limits) associated with floating wind turbines when completing heavy lift maintenance tasks? What are indicative values for these limits which can be implemented into O&M modelling of a floating turbine?'*

The main deliverable of this chapter, in the context of this overall thesis, is a range of wave limit values representative of a floating-to-floating major replacement task which can be used as an input into the O&M cost modelling in Chapter 6.

At the time of completing this work, the novel contribution of this chapter was considered to be the estimation of indicative wave limits for floating-to-floating major replacement tasks on large floating wind turbines which could be easily implemented into an offshore wind O&M model. This was an area which had not been investigated in the existing literature and wave limit values for these tasks were not known at the time. However, since the work presented in this chapter was completed, there has been a recently published analysis which addresses this knowledge gap [1], without some of the limitations of the work presented here - this will be discussed in detail at the end of this chapter. However, the conclusions and recommendations from the work within this chapter are still considered to be a useful contribution to support the existing literature.

## 4.2 Wave limits for offshore wind heavy lift maintenance tasks

The wave limits at which large component major replacement tasks can be completed is highlighted within this thesis as being an important input for offshore wind O&M cost modelling. Accessibility values are well understood for fixed-foundation offshore wind turbines when using a jack-up vessel. However, when considering floating offshore wind turbines where a floating heavy lift vessel is required, wave limits are not widely known in the existing literature. The following sub-sections firstly summarise the use of environmental accessibility limits in fixed-foundation offshore wind O&M modelling work, before going on to discuss why additional limits may be required when modelling floating offshore wind turbines due to the additional wave-induced motion of the floating structures. The existing literature on estimating wave limits for offshore wind lifting operations will then be summarised.

### 4.2.1 Environmental accessibility limits for fixed-foundation offshore wind O&M modelling

Generally, throughout the offshore wind O&M modelling literature, only a wind speed limit at the hub height of the wind turbine is applied as a limiting condition when completing a major replacement task on a fixed-foundation offshore wind turbine. Within some of the literature an additional significant wave height limit is applied during the jacking-up process prior to the lifting operation, but generally not during the replacement operation itself. Dinwoodie et al. applied a wind speed limit of 10m/s during lifting and a jacking-up wave limit of 2m [2]. These are the same values used in Ioannou et al.[3]. Smart et al. proposes values of 11m/s for the lifting operation and 2m for jacking-up [4]. Shields et al. applied a wind speed limit of 15m/s and a wave height limit of 2m [5] and Dalgic et al. uses values of 15.3m/s and 2.8m [6].

When considering major replacement tasks, it is generally assumed that the wave conditions at the site do not impact the maintenance task when a jack-up vessel is used due to the fixed nature of both the turbine and the jack-up vessel. This same assumption will be applied in this thesis when in Chapter 5 when modelling fixed-foundation wind turbines, however this may not be an appropriate assumption when considering floating wind turbines due to a) the wave-induced motion of the turbine and b) the wave-induced motion of the floating lifting vessel.

### 4.2.2 Impact of floating turbine wave-induced motion on offshore wind O&M

It has already been highlighted in Chapter 3 that the wave-induced motion of floating offshore wind turbines may impact the operations and maintenance phase of these turbines due to increasing the number of failures in these turbines. However, this motion can also impact the turbine accessibility to carry out maintenance tasks and this is a current concern within the industry and is receiving increasing focus within academia.

The first phase of the CoreWind project highlighted the relative motion between floating turbines and crew transfer vessels as a challenge due to the motion of the floating turbine substructure [7]. This report also highlights the relative motion between the floating turbine and lifting vessel as a challenge when considering large component exchange and also that the low-frequency motions of the floating turbines are within the range likely to impact technician workability due to motion sickness. The second phase of the CoreWind project then investigated these areas in detail, with areas such as floating-to-floating heavy lift wave limits, technician workability limits and crew transfer vessel (CTV) wave limits all being investigated [1]. Through time-domain modelling of the relative motion between turbine and crane vessel using two different 15MW floating turbine concepts and two floating crane vessel concepts, significant wave height limits for a floating-to-floating large component exchange were estimated over a range of peak wave period and wave direction values. These significant wave height limits can be seen to vary with peak wave period – from values of 3m at low wave period values, to less than 0.5m at high wave period conditions. When assessing technician workability for two floating turbine concepts, the second phase of the Corewind project also found that this is also impacted by the peak wave period of the sea state. However, it was concluded that the wave conditions at which workability limits were exceeded were always higher than vessel accessibility limits and therefore this is not likely to be a limiting factor in O&M tasks for large floating turbines.

Phase 1 of the Joint Industry Project (JIP) led by the Carbon Trust also stated that the relative motion between the lifting vessel and the floating turbine substructure as something that will put high demands on vessel dynamic position systems and lead to more restrictive met-ocean limits [8]. Phase 2 of this project highlighted that semi-submersible floating turbine motion can always be expected at long wave period conditions and that all floating crane vessel types are impacted by long wave period conditions, stating that this is a more important factor than significant wave height when determining feasibility [9]. The Phase 3 summary report again states that, compared to fixed-foundation wind farms, O&M is expected to be more challenging due to the motion of the floating turbine and maintenance vessel and that the relative motion between the lifting vessel and floating turbine will be a challenge for heavy lift tasks [10]. The report also includes the reduction of relative motion between the crane hook and turbine nacelle as a key technical challenge for floating-to-floating heavy lift tasks. A review of floating wind technology and operations by ORE Catapult have also highlighted the relative motion between the floating platform and vessel when considering offshore component exchange [11].

Guanche et al. modelled the motion of a 5MW semi-submersible floating platform with both a crew transfer vessel (CTV) and a service operations vessel (SOV) in the frequency-domain to determine wave limit values for accessibility using these vessels [12]. The results show that accessibility using these smaller vessels is also highly variable depending on wave period and wave direction. Scheu et al. found that accessibility to complete maintenance on a floating turbine could be reduced by up to 5% when applying acceleration limits for technician working on the turbine [13].

The importance of wave conditions during major replacement tasks in floating wind turbines are beginning to be seen within the area of operations and maintenance modelling. When modelling and comparing the cost of major replacement tasks in floating turbines using both a floating-to-floating heavy lift and a tow-to-shore strategy, ORE catapult implemented a significant wave height limit of 1.5m in the floating-to-floating scenario [14]. Rinaldi et al. also applied a significant wave height limit of 1.5m for the heavy lift vessel when modelling two floating wind farm scenarios [15] and Shields et al. applied a significant wave height limit of 2m for a heavy lift vessel, albeit for offshore substation installation rather than floating turbine O&M [5].

### 4.2.3 Estimating wave limits for offshore wind lifting operations.

There have been a number of publications which have investigated the wave limits for offshore lifting operations related to offshore wind turbines. However, the majority of these publications have focussed on either the installation of wind turbine foundations, or on the installation of wind turbine blades onto a fixed-foundation offshore wind turbine. Therefore, these studies do not generally give consideration to wave-induced turbine motion during the analysis. The exception to this being the CoreWind publication discussed previously and again at the end of this chapter [1].

A methodology for determining the operational limits for marine operations was developed and described in detail by Acero et al. [16], and the majority of the research published in this area has used this framework, or a similar approach. Zhu et al. estimated the limiting sea states for the lifting of a tripod foundation during installation, using both a floating heavy lift vessel and a jack-up vessel, through frequency-domain and then time domain modelling [17]. Li et al. assessed the allowable sea states for the lowering and installation of a wind turbine monopile using a floating heavy lift vessel [18], [19], and the operational limits and limiting sea states for the installation of a turbine monopile and transition piece were also estimated by Acero et al. [16]. Acero et al. also modelled vessel response and limiting sea states for the installation of a full turbine structure onto an offshore foundation using a novel installation method [20]. Zhao et al. have investigated the installation of a blade for a fixed-foundation, DTU 10MW reference turbine, through modelling vessel, crane, and blade motion for both a jack-up vessel and floating vessels [21], [22]. The limiting environmental parameters for blade installation based on the DTU 10MW turbine using a jack-up vessel were also investigated by Verma et al. [23]. The relative motion between the turbine hub and blade during installation of a 5MW fixed-foundation turbine blade using a jack-up vessel was modelled by Jiang et al. [24], and Acero at al. investigated the limiting environmental conditions for a wind turbine blade replacement in a fixed-foundation turbine using a novel tower climbing concept [25]. One study into offshore wind lifting operations which also gives consideration to floating turbine motion was in investigating the probability of failure for rotor installation on a Hywind turbine [26], however, this does not present details of the turbine motion or wave limits.

### 4.2.4 Summary of literature on wave limits in offshore wind heavy lift maintenance modelling

The review of the literature within this area has highlighted several key points. Within the majority of offshore wind O&M modelling which considers fixed-foundation wind turbines and jack-up vessels, only a wind speed limit is applied to major replacement tasks. These limits have been determined from industry experience of completing a large number of component exchanges on fixed-foundation turbines offshore. However, when considering major replacement tasks on floating wind turbines using floating heavy lift vessels, consideration must also be given to the wave conditions during the replacement task in addition to wind speed. It is regularly highlighted that the wave-induced relative motion between the two floating structures can impact the ability to complete these component exchanges and previous studies have shown turbine motion to have an impact on accessibility using smaller maintenance vessels and on technician workability. Significant wave height limits have begun to be implemented into O&M modelling work when floating turbines or floating heavy lift vessels have been considered. However, the existing literature also shows that these wave height limits can also vary with wave period.

At the time of completing the work presented within this chapter, there were no publications which investigated or presented wave period varying wave height limits for floating-to-floating major replacement tasks in floating offshore wind turbines which could be implemented into an O&M model. There were also no publications which investigated and presented wave period dependent wave height limits for technician working on a floating wind turbine which could be implemented into an O&M model. There were existing studies which estimated these limits for various offshore wind lifting operations, but these were limited to the installation of turbine foundations, or blades on fixed-foundation wind turbines. Therefore, this was highlighted as an area required for further investigation and these limits were required to be estimated within this PhD project for use in the O&M modelling of floating turbines in Chapter 6.

However, since this work was completed, the CoreWind project have released a report which extensively investigates these areas and presents wave period dependant wave height limits which can be used in O&M modelling work [1]. Therefore, the work completed within this PhD project will be presented within this chapter, before being critically compared to the analysis presented within the CoreWind publication and the optimal results selected from the two for use in Chapter 6.

## 4.3 Frequency-domain modelling of floating rigid-body structures

The linear, rigid-body response of a floating structure to irregular waves can be estimated using wave energy spectra and the response amplitude operators (RAO) of the structure in different degrees of freedom. This is a widely applied approach within ocean engineering and is described in detail in a number of sources [27]–[29]. This section will briefly describe this approach, before its specific use is explained within the Method section. Firstly, the statistical analysis of irregular, unidirectional ocean waves is introduced. This is then expanded to the statistical frequency-domain analysis of the linear, rigid-body response of a floating structure to these waves.

### 4.3.1 Analysis of irregular waves

Realistic wave conditions can be represented as an irregular, or random, sea consisting of a large number of superimposed, regular waves with different amplitude, $a_n$, frequency, $\omega_n$, and random phase, $\epsilon_n$ [27]–[32]. Therefore, at a fixed point, the water surface elevation, $\varsigma(t)$, can be found using Equation 4.1.

$$\varsigma(t) = \sum_{n=1}^{n} \mathrm{a}_n \sin(\omega_n t - \epsilon_n) \tag{4.1}$$

Unlike a regular wave, irregular waves cannot be characterised by single amplitude and frequency values, as these values vary from one wave to the next. Therefore, irregular waves are characterised by a wave energy spectrum which shows the wave amplitude and how the energy is distributed at the different regular component wave frequencies, for example Figure 4.1. The energy of a regular wave is dependent on the square of the wave amplitude [27], [29] and the summation of energy of the regular component waves at each frequency gives the total energy of the irregular wave.

The variance of the water surface elevation time series value, $\varsigma(t)$, is equal to the area under the wave energy spectrum [27], [28] and therefore can be easily found. The standard deviation or root mean square (RMS) value, $\varsigma_{RMS}$, is then the square root of this variance value. This is shown in Equation 4.2, where $S_{w,i}$ is the spectral density value at wave frequency $\omega_i$.

$$\varsigma_{RMS} = \sqrt{\int_0^{\infty} S_{w,i}(\omega_i).\, d\omega} \tag{4.2}$$

From the differentiation of the surface elevation equation of the regular waves making up the surface elevation of an irregular sea, the energy spectrum of velocity and acceleration can also be found using Equation 4.3 and Equation 4.4 [28].

$$S_{w,vel,i}(\omega_i) = \omega_i^2 S_{w,i}(\omega_i) \tag{4.3}$$

$$S_{w,acc,i}(\omega_i) = \omega_i^4 S_{w,i}(\omega_i) \tag{4.4}$$

Similar to the example of water surface elevation, the area under the velocity and acceleration spectrum is equal to variance of the velocity and acceleration of the time series measurements of these values.

While water surface elevation typically follows a Gaussian distribution, the wave amplitude value (the maximum of each wave) follows a Rayleigh distribution [27]–[29] assuming that the wave energy spectrum is narrow-banded (ie. the energy is distributed over a narrow range of wave frequencies). Using the standard deviation, or root mean square, value for water surface elevation, the probability of a certain reference amplitude value being exceeded can be found [29]. This can be done using the cumulative density function of the Rayleigh distribution by applying Equation 4.5 [27]. Of course, this approach can also be used with a probability of exceedance value to find a corresponding wave amplitude value.

$$P(\varsigma_a > \varsigma_{a,ref}) = e^{-\frac{1}{2}\left(\frac{\eta_{a,ref}}{\sigma_\eta}\right)^2} \tag{4.5}$$

Wave energy spectra can be determined based on measured surface elevation time series data using a Fourier analysis, or through using various standard spectral formulae [27], [28]. The JONSWAP spectrum was developed based on North Sea wave measurements [33] and is commonly used to represent fetch-limited seas. A JONSWAP wave energy spectrum can be produced from two parameters – the significant wave height, $H_s$ and the peak wave period, $T_p$, using Equation 4.6 [27]. Where ϒ is the peak factor and is equal to 3.3 and A is calculated as shown in Equation 4.7 [27]. $\omega_p$ is the angular frequency at the peak wave period ($T_p$) and σ is equal to 0.07 when $\omega < \omega_p$ and 0.09 when $\omega > \omega_p$.

$$S_w(\omega) = \frac{320.H_s^2}{T_p^4}.\omega^{-5}.exp\left\{\frac{-1950}{T_p^4}.\omega^{-4}\right\}.\gamma^A \tag{4.6}$$

$$A = exp\left\{-\left(\frac{\frac{\omega}{\omega_p}-1}{\sigma\sqrt{2}}\right)^2\right\} \tag{4.7}$$

Another wave energy spectrum which is often used to describe fully developed seas, for example the North Atlantic, is the Bretschneider spectrum. This can be found using Equation 4.8, where $T_1 = 0.772.T_p$ [27]. Figure 4.1 shows an example of a JONSWAP and Bretschneider wave energy spectrum at wave conditions of $H_s$ = 2m and $T_p$ = 8s.

$$S_w(\omega) = \frac{173.H_s^2}{T_1^4}.\omega^{-5}.exp\left\{\frac{-692}{T_1^4}.\omega^{-4}\right\} \tag{4.8}$$

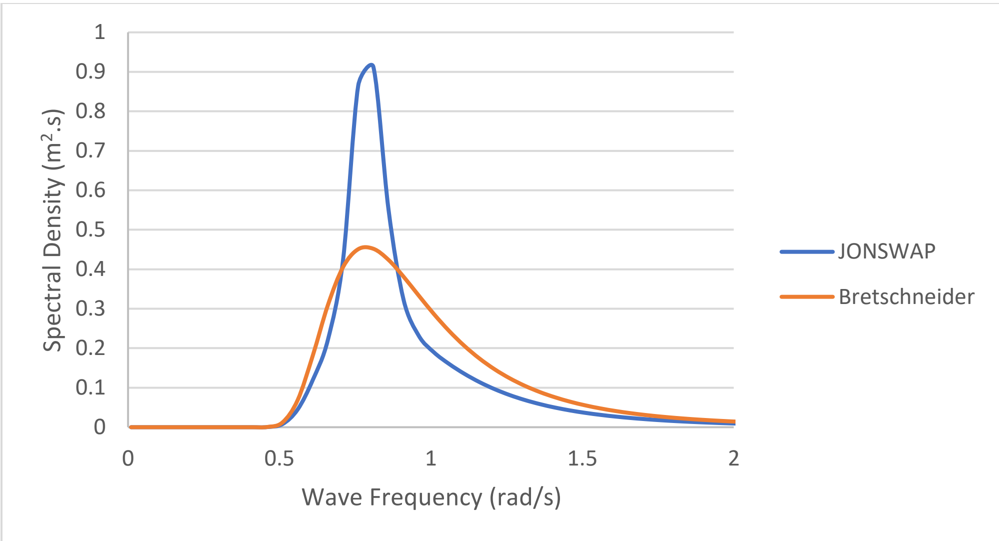


*Figure 4.1. Example of a JONSWAP wave energy spectrum and a Bretschneider spectrum at wave conditions of Hs = 2m and Tp = 8s.*

### 4.3.2 Linear response of a floating structure to irregular waves

When analysing the motion of a floating structure in the frequency-domain, a frequency-dependent transfer function can be used to characterise the structure's motion response to varying wave frequencies, with the assumption that the response is linearly proportional to the amplitude of the wave [28], [34]. This transfer function, for the 6 degree of freedom (DOF) rigid body displacements (surge, sway, heave, roll, pitch, yaw), is called the displacement response amplitude operator (RAO) and is dependent on the structural and hydrodynamic properties of the structure [32], [34]. Using this approach, the oscillatory motion of a floating structure can also be assumed to be made up of a series of superimposed regular waves [27], [28], [32] and can be statistically analysed using the approach discussed previously for waves. By multiplying the values from the wave energy spectrum by the square of the magnitude of the RAO for a particular degree of freedom, the response spectrum of the structure in that DOF can be found as shown in Equation 4.9 [27], [28], [32].

$$S_R(\omega_i) = |RAO(\omega_i)|^2 * S_w(\omega_i) \tag{4.9}$$

As this approach assumes a linear relationship between the wave amplitude and the structure's response to the waves, the variance in the structure's displacement, and therefore the RMS value of the floating structure's displacement can be found by calculating the area under the response spectrum similar to the wave amplitude discussed previously [28] using Equation 4.10.

$$Displacement_{RMS} = \sqrt{\int_0^\infty S_{R,i}(\omega_i).\,d\omega} \tag{4.10}$$

This approach discussed previously for waves can also be used to calculate the variance values for the velocity and the acceleration of the structure, for example using Equation 4.11 and Equation 4.12 to calculate RMS acceleration values. The cumulative density function of the Rayleigh distribution can then be used to calculate the likelihood of certain values being exceeded [28].

$$S_{R,acc,i}(\omega_i) = \omega_i^4 S_{R,i}(\omega_i) \quad (4.11)$$

$$Acceleration_{RMS} = \sqrt{\int_0^{\infty} \omega_i^4 S_{R,i}(\omega_i).\, d\omega} \quad (4.12)$$

## 4.4 Methodology

This section will present the methodology that has been applied within this work to estimate the wave-induced motion of a 15MW floating reference turbine using the frequency-domain analysis outlined in the previous section, along with using this to estimate wave limit values (significant wave height and peak wave period) for large component major replacement tasks based on motion limits for offshore technician working and for the lifting operation. This approach was selected due to its simplicity and computational efficiency compared to other potential analysis methods, for example a full time-domain analysis. The aim of this work was to be able to quickly and efficiently estimate indicative wave limits across a wide range of wave conditions which could be used in an O&M model, with the potential for this step to be incorporated into the model itself.

The wave-induced rigid body motion of a floating wind turbine concept was found using a statistical frequency-domain analysis over a range of wave conditions (significant wave height values from 0.1m to 5m and a range of peak wave period values from 4.75s to 15.75s). Crane vessel motion was estimated based on values taken from literature and the motion values were then compared to the acceptable motion limits identified. The wave conditions at which these motion limits are exceeded are taken as the wave limits for this heavy lift maintenance operation. The details of this approach are given throughout this section.

This approach does not consider the impact of the wind aerodynamic forces on the wind turbine and platform when modelling the motion response. The scope of this work is limited to determining the motion of the floating turbine during a major maintenance task. It is therefore assumed that this would be done during low wind speed conditions and the wind turbine will be non-operational, leading to much reduced aerodynamic loading compared to that seen during operational conditions. This is the approach that has been taken within the existing literature when modelling the motion of floating wind turbines during maintenance operations [1], [12], [35].

### 4.4.1 Floating reference turbine and response amplitude operators

When analysing the motion of a floating structure in the frequency-domain, a frequency-dependent transfer function can be used to characterise the structure's motion response to varying wave frequencies, with the assumption that the response is linearly proportional to the amplitude of the wave [34]. This transfer function, for the 6 DOF rigid body displacements (surge, sway, heave, roll, pitch, yaw), is called the displacement response amplitude operator (RAO).

RAOs were not calculated as part of the scope of this work, but taken from data published in the reference documents for an existing floating reference turbine. The turbine used in this analysis was the IEA 15MW offshore reference turbine supported by the UMaine VolturnUS-S semi-submersible reference platform [36], [37]. This floating turbine concept was selected as it is considered to be representative of the turbine size and rated power of the next generation of floating wind turbines.

This reference turbine system consists of a steel floating semi-submersible platform, a three-line chain catenary mooring system, and the IEA 15MW reference turbine [36] with modified tower and controller [37]. Various hydrodynamic properties of the system are presented within the reference document for the turbine, including the rigid body wave-induced displacement response amplitude operators of the platform in the surge, heave and pitch DOFs at still water level and the turbine nacelle in the fore-aft DOF at hub height, all at zero degrees wave heading. It is described that these were evaluated through time-domain regular wave simulations using the OpenFAST software with the hydrodynamic properties of the system, including the platform viscous drag effects, represented within the software's HydroDyn module [37]. The rigid body natural frequencies of the system in each degree of freedom are also given within the reference document and these are summarised in Table 4.1.

*Table 4.1. Rigid body natural frequency values of the floating turbine system taken from [37].*

| Degree of freedom | Natural frequency – 15MW turbine (s) |
|---|---|
| **Surge** | 142.9 |
| **Heave** | 20.4 |
| **Pitch** | 27.8 |

The response amplitude operators at zero degrees wave heading for this turbine were extracted from the figures given in the reference document using the Enguage Digitizer software [38]. This was done for the platform surge, pitch and heave degrees of freedom, as well as the nacelle fore-aft degree of freedom. The extracted values for these RAOs are shown in Figure 4.2 - Figure 4.5.

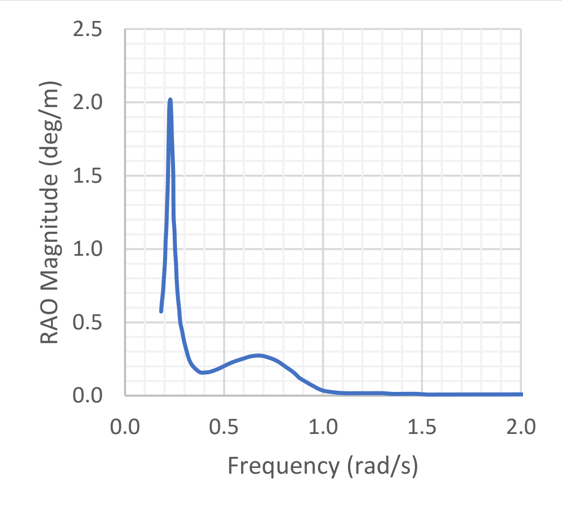


*Figure 4.2. Platform pitch RAO magnitude for the 15MW reference turbine extracted from [37].*

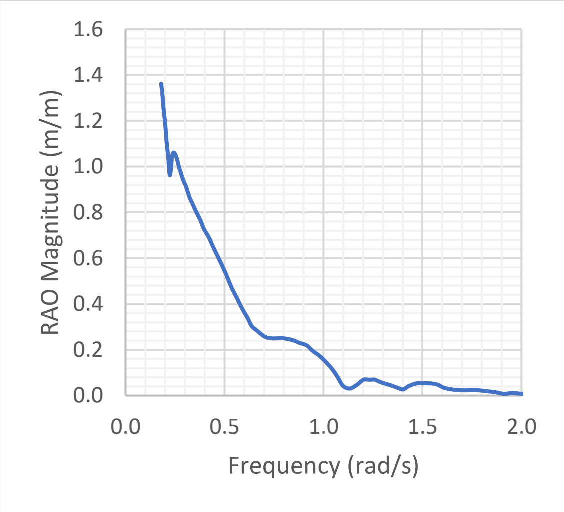


*Figure 4.3. Platform surge RAO magnitude for the 15MW reference turbine extracted from [37].*

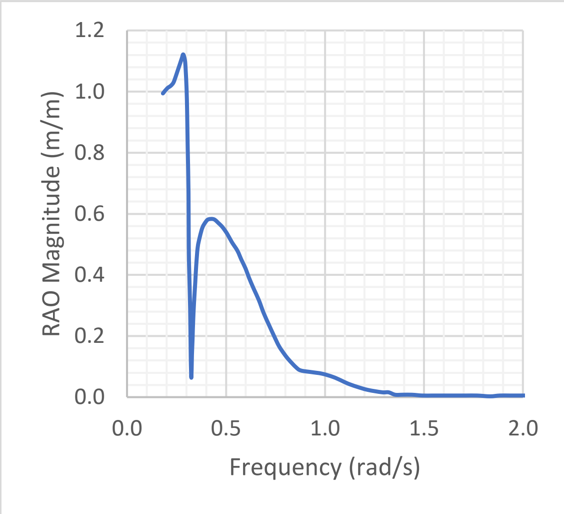

*Figure 4.4. Platform heave RAO magnitude for the 15MW reference turbine extracted from [37].*

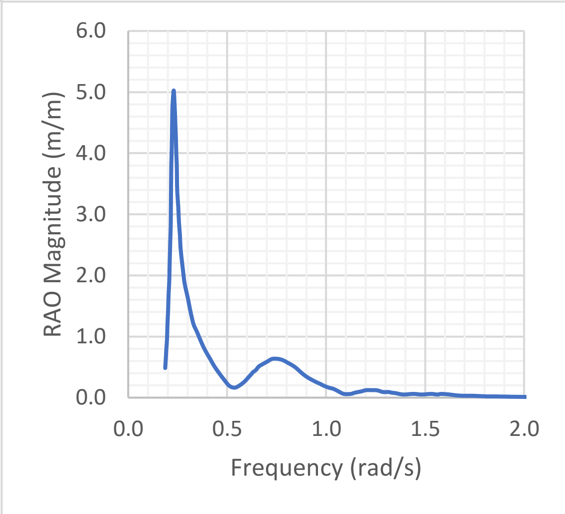

*Figure 4.5. Nacelle fore-aft RAO magnitude for the 15MW reference turbine extracted from [37]*

### 4.4.2 Calculating the turbine motion response values

Using these response amplitude operators and JONSWAP wave energy spectra, response spectra for the platform were found over a range of peak wave period and significant wave height conditions using Equation 4.6 and Equation 4.9. Using Equation 4.10 and Equation 4.12 the root mean square values of platform or turbine displacement and acceleration in the various degrees of freedom were then found. It should be noted that this approach is only applied at zero degrees wave heading and therefore does not consider the impacts of wave direction or wave spreading on turbine motion. This was done over a range of significant wave height values from 0.1m to 5m and a range of peak wave period values from 4.75s to 15.75s using the JONSWAP wave energy spectrum. This range was chosen to capture a likely range of significant wave height values in which turbine maintenance tasks would be considered due to vessel accessibility, and to capture the majority of peak wave period conditions expected at a typical floating wind site.

It is assumed that the magnitude of the pitch and heave motion at the nacelle is equal to the pitch and heave motion of the platform. This can be done by assuming that the tower is a rigid structure and therefore does not capture the impact the flexibility of the tower will have on these displacement and acceleration values.

A cumulative Rayleigh distribution (Equation 4.5) was then used to estimate the maximum likely wave-induced displacement values for the floating turbine nacelle motion using a $10^{-4}$ probability of exceedance. This limit is often applied for offshore operations [19], [39], [40].

### 4.4.3 Estimation of turbine and crane relative motion

A high-level approach was taken to estimate an approximate value representative of the crane tip motion, and thus the maximum likely relative motion between the turbine nacelle and crane tip for a typical heavy lift vessel, based on crane tip displacement values taken from literature. The dynamic motion response of a floating crane vessel during blade installation on a 10MW fixed-foundation turbine using a fully coupled time domain simulation was published by Zhao et al. [22]. The standard deviation values for the crane tip displacement for a semi-submersible crane vessel at three combinations of significant wave height and peak wave period were estimated from this publication, shown in Table 4.2, and compared to the calculated displacement amplitude for the 15MW turbine nacelle at similar wave conditions. A ratio between these values was then calculated, these are shown in Table 4.2. To estimate the relative displacement between the turbine nacelle and crane tip over the range of wave conditions in this analysis, the turbine nacelle displacement at each combination of $H_s$ and $T_p$ was multiplied by this ratio and this was added to the nacelle displacement of the turbine at these wave conditions to estimate the relative motion. The addition of the turbine nacelle displacement and the estimated crane tip displacement values provides the highest possible relative displacement value, not accounting for any phase difference in the motions that may cancel each other out, and is therefore likely to overestimate the relative motion between them, making this a conservative approach.

*Table 4.2. Crane tip displacement standard deviation values estimated from [22], and the calculated ratio between this and the displacement amplitude of the 15MW reference turbine nacelle at similar wave conditions.*

| Hs (m) | Tp (s) | Crane tip displacement (fore-aft) | Crane tip displacement (heave) | Crane tip / nacelle displacement ratio (fore-aft) | Crane tip / nacelle displacement ratio (heave) |
|---|---|---|---|---|---|
| **1** | 7.3 | 0.108 | 0.043 | 1.17 | 1.52 |
| **1.5** | 7.7 | 0.185 | 0.077 | 1.14 | 1.42 |
| **0.5** | 6.8 | 0.045 | 0.017 | 1.24 | 1.58 |

This approach to estimating the relative motion between the turbine nacelle and the crane tip will not account for the complexities of the dynamics of the suspended load, nor does it consider any interaction between the two floating structures. It is also recognised that the motion of floating structures can vary with wave period and that, although the ratio crane tip to nacelle motion is fairly constant over the range of wave conditions shown in Table 4.2, this may not be the case for higher wave period values. The hook height above water level of the crane considered here is also only around 140m [22], and the required hook height of around 160m required for a 15MW turbine, based on the 150m hub height [37] with an additional 10m clearance. If the impacts of this were considered, the crane motion would likely differ to the values used here. However, the aim of this approach is not to accurately model a specific case study of a specific scenario, but rather to estimate approximate displacement values representative of a floating crane vessel that can then be combined with the turbine displacement values to estimate an approximate relative motion value. However, to assess the impact of these uncertainties, a sensitivity analysis was also carried out to investigate the impacts of varying crane tip motion on the results. Within this sensitivity analysis, the crane tip displacement was varied by -20% and +20%.

### 4.4.4 Determining the wave limits

The calculated motion values were then compared to maximum motion limits based on two sets of criteria. The first set of motion limits are for safe and effective technician working within the turbine nacelle. The applied limits are based on the Nordforsk guidance for offshore working, discussed by Scheu et al [13]. These limits are applied to the RMS values of nacelle fore-aft acceleration, heave acceleration, and pitch displacement amplitude, and are shown in Table 4.3. The wave limits for the lifting operation, based on safe and effective technician working, are considered as the wave conditions at which these motion limits are exceeded.

*Table 4.3. Motion limits for offshore technician working proposed by Scheu et al. [13] (based on Nordforsk guidance).*

| **Limiting criteria** | **RMS heave acceleration** | **RMS fore-aft acceleration** | **RMS pitch displacement** |
|---|---|---|---|
| **Limiting value** | 0.05g (0.49m/s$^2$) | 0.04g (0.39m/s$^2$) | 2.5° |

The second set of criteria are the motion limits for the safe and accurate lifting of the wind turbine components out of, and into, the turbine nacelle, and this is based on a maximum allowable relative displacement between the turbine nacelle and the crane tip. In the absence of specific guidance for floating wind turbines, these limits are based on industry guidance for offshore installation using a bumper and guide system [41]. These systems are expected to be used for the exchange of components within the wind turbine nacelle [10], and the applied motion limits are shown in Table 4.4. Again, the wave limits based on these criteria are taken as when these values are exceeded.

*Table 4.4. Relative motion limits for a module being installed offshore using a bumper and guide system based on GL Noble Denton guidance [41].*

| **Limiting criteria** | **Relative heave displacement (m)** | **Relative fore-aft displacement (m)** |
|---|---|---|
| Limiting value | 0.75 | 1.5 |

# 4.5 Results

## 4.5.1 Wave limits for technician working

Using the approach outlined in the previous section, values for RMS heave acceleration, RMS fore-aft acceleration and RMS pitch displacement were found and compared to the limits for offshore technician working shown in Table 4.3.

Figure 4.6 shows the calculated value of the RMS acceleration in the heave degree of freedom across the range of significant wave height and peak wave period conditions. These values increase with increasing significant wave height as expected and also that the acceleration value varies with peak wave period. However, the acceleration values found are all well within the applied limit of $0.49 m/s^2$. Figure 4.7 shows the calculated RMS acceleration value of the nacelle in the fore-aft degree of freedom across the range of wave conditions assessed. Again, the acceleration of the turbine nacelle increases with significant wave height and varies with peak period of the wave energy spectrum, with the largest fore-aft acceleration values seen at peak wave period values around 8.25s. However, it can again be seen that, across the range of wave conditions analysed, that the acceleration limit applied to the motion in this degree of freedom was not exceeded. Finally, the calculated RMS pitch displacement values are shown in Figure 4.8. These values show similar trends to the acceleration values – increasing with significant wave height and varying with peak wave period. These values are also below the applied limit of 2.5°.

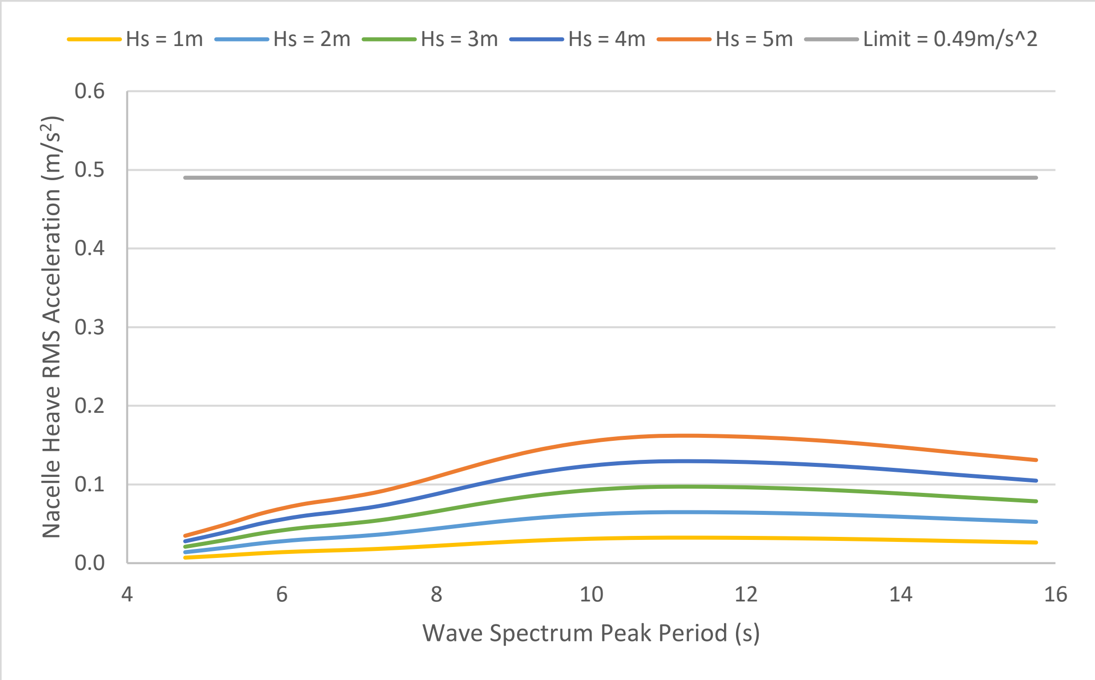


*Figure 4.6. Nacelle heave RMS acceleration for the 15MW reference turbine with varying wave conditions.*

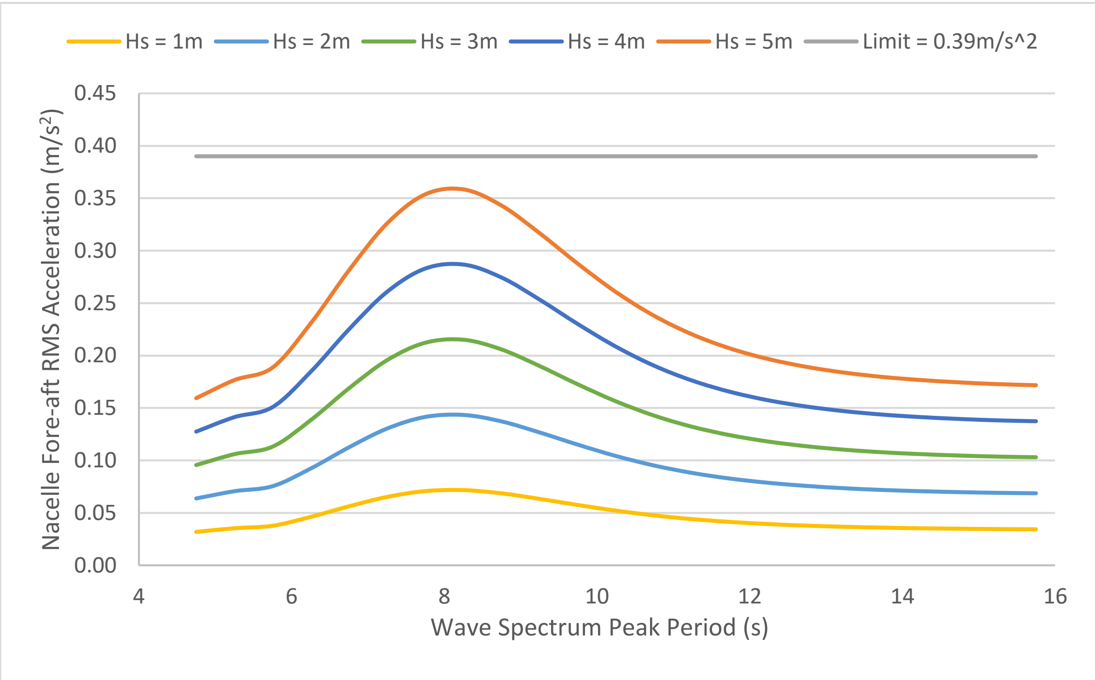


*Figure 4.7. Nacelle fore-aft RMS acceleration for the 15MW reference turbine with varying wave conditions.*

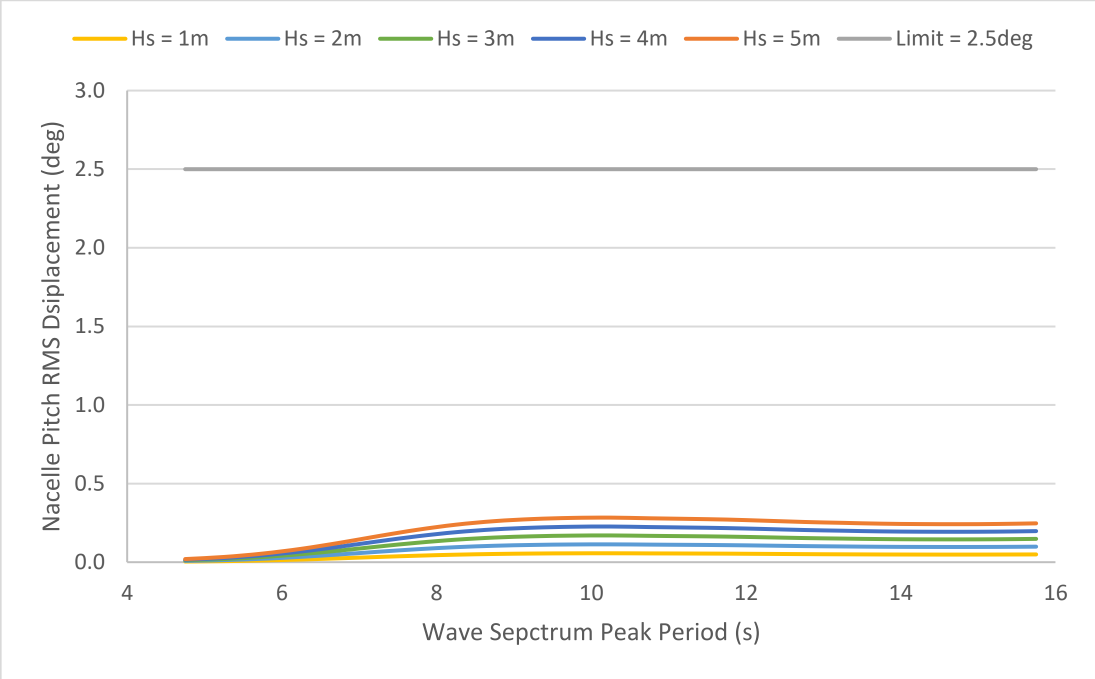


*Figure 4.8. Nacelle pitch RMS displacement amplitude for the 15MW reference turbine with varying wave conditions.*

### 4.5.2 Wave limits for heavy lift maintenance tasks

Using the cumulative density function of the Rayleigh distribution with a probability of exceedance of $10^{-4}$, the maximum likely displacement values of the turbine nacelle in the fore-aft and the heave degrees of freedom were found. These are shown in Figure 4.9 and Figure 4.10. It can be seen again that both the displacement in the fore-aft and heave degrees of freedom increase with increasing significant wave height values and vary with the peak period of the wave energy spectrum. However, there is a general trend of increasing displacement with increasing peak wave period in both degrees of freedom over the range of values analysed. The range of peak period conditions analysed, 4.75s – 15.75s, coincides with frequency values of approximately 0.4rad/s to 1.3rad/s, therefore it is this area of the RAOs shown in Figure 4.4 and Figure 4.5 which influence these motion values.

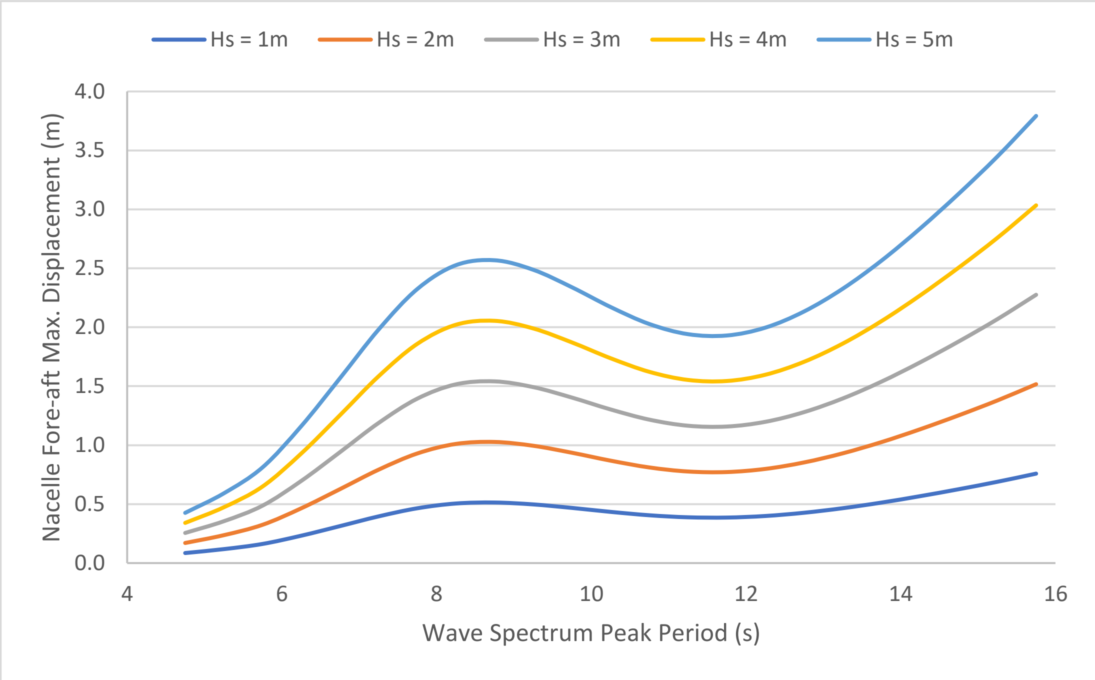


*Figure 4.9. Nacelle fore-aft displacement amplitude for the 15MW reference turbine estimated from a Rayleigh distribution with $10^{-4}$ probability of exceedance with varying wave conditions.*

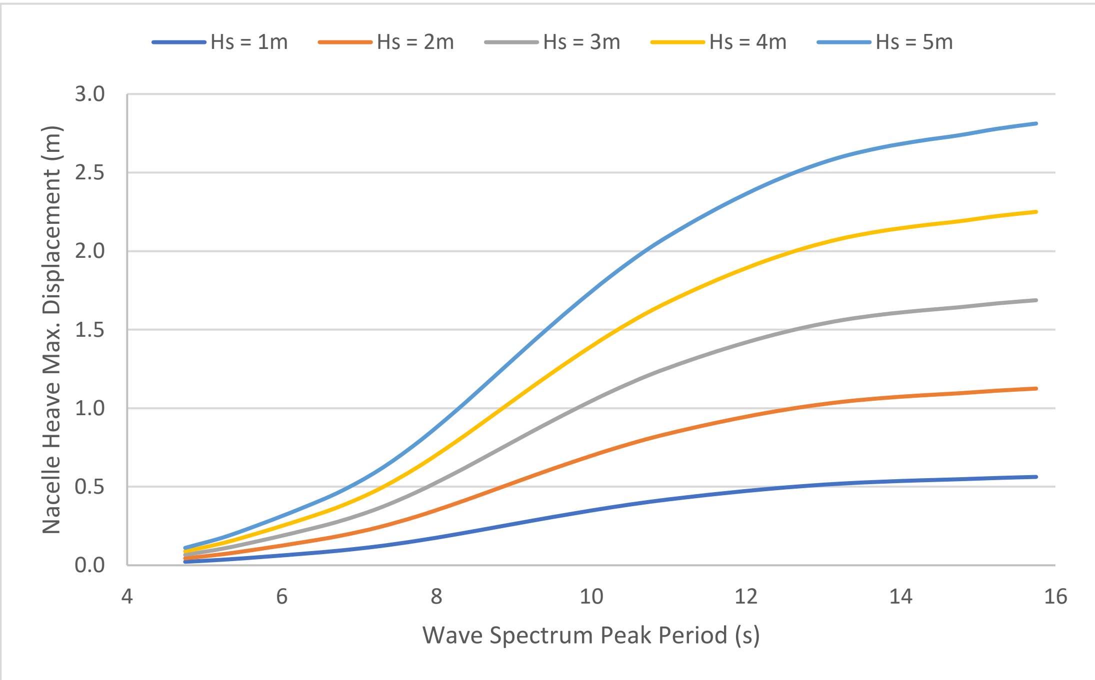


*Figure 4.10. Nacelle heave displacement amplitude for the 15MW reference turbine estimated from a Rayleigh distribution with $10^{-4}$ probability of exceedance with varying wave conditions.*

By applying a ratio of crane tip displacement to turbine nacelle displacement and summing these values together, as explained in Chapter 4.4.3, the maximum likely relative motion between the turbine nacelle and crane tip was estimated over the range of wave conditions. These values were then compared to the relative displacement limits as shown in Table 4.4 and the wave conditions at which these motion limits were exceeded found. The value of the crane tip displacement was then varied by -20% and +20% and used to estimate the wave limits. The significant wave height value at which this relative displacement value was exceeded at different peak wave period values are shown in Figure 4.11. As the peak wave period of the wave energy spectrum is increased, the significant wave height value at which the motion limits are exceeded decreases. This decrease is large, going from 5m at low wave period conditions, to below 1m at higher wave periods. It should however be noted that some of these wave conditions will not be seen in reality, for example due to maximum limiting wave steepness. Figure 4.12 shows the percentage of the time that each combination of significant wave height and peak wave period is observed at the North Sea co-ordinates 58N, 1.6W based on ten years of hindcast data taken from the EU Copernicus Marine Environment Monitoring Service online database [42].

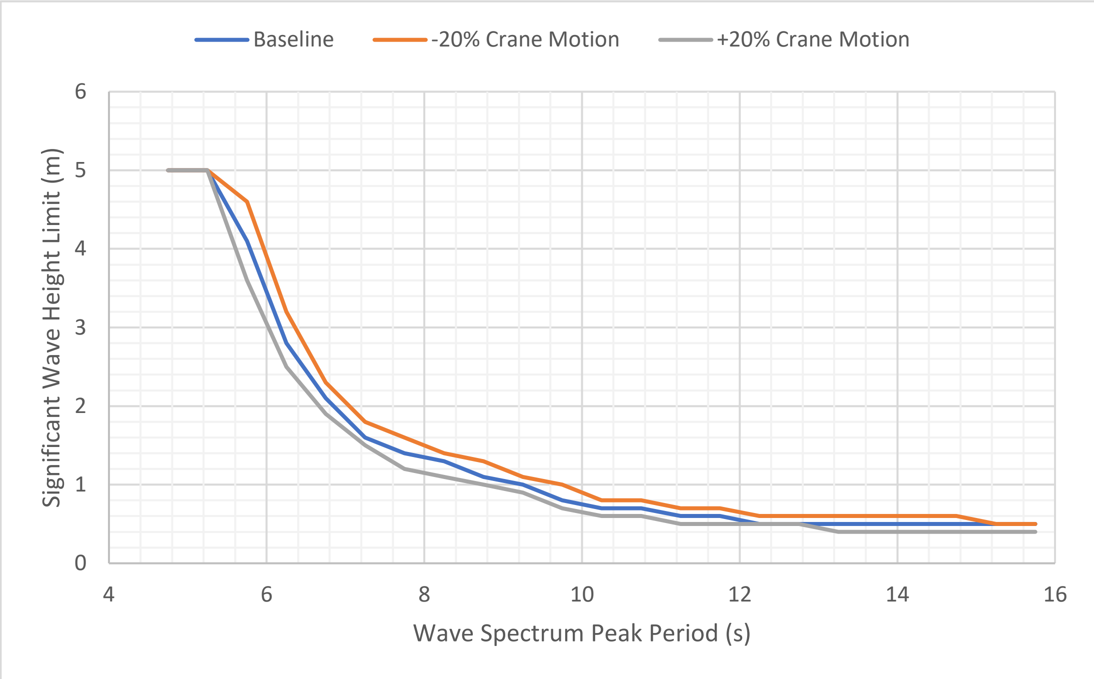


*Figure 4.11. Estimated significant wave height limits with varying wave energy spectrum peak period values using baseline, -20% and +20% crane tip motion values.*

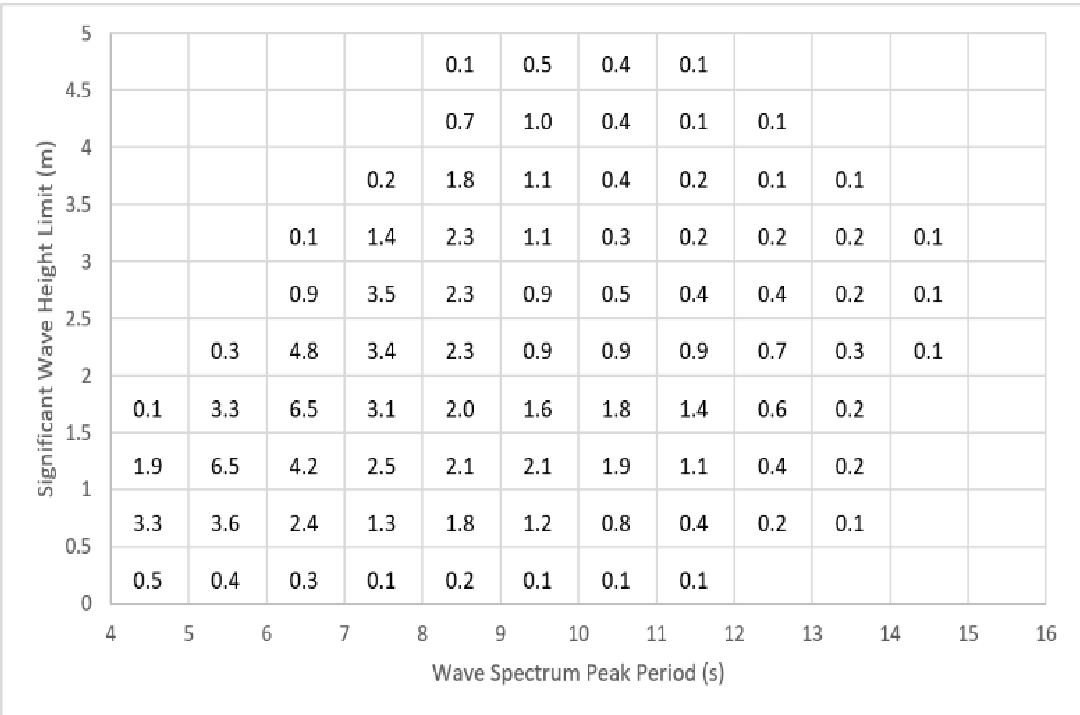


*Figure 4.12. Wave scatter diagram showing percentage of time at each combination of $H_s$ and $T_p$ based on ten years of hindcast data at co-ordinates 58N, 1.6W.*

## 4.6 Discussion of Results

### 4.6.1 The large impact of wave period on maximum wave height limits

When reviewing the results presented, it is clear that the peak wave period of the wave energy spectrum has a large impact on the wave-induced motion response, and thus the identified wave limits, for the floating turbine concept analysed. This is consistent with the existing literature investigating the potential impacts of floating turbine wave-induced motion on O&M activities. In general, due to the high natural period of the floating turbine, as the peak wave period of the wave energy spectrum is increased closer to these natural period values, the magnitude of the motion response is increased and the significant wave height limit at which lifting operations can be completed is reduced. This is clearly seen in Figure 4.11, where the significant wave height limit is reduced from 5m to below 1m as peak wave period is increased from 4.75 to 15.75s.

These results are dependent on the particular floating platform design, however, within the context of analysing maintenance strategies for floating offshore wind turbines, this highlights the importance of considering wave period, as well as wave height, when determining accessibility for maintenance tasks on a floating turbine. As has been highlighted within this chapter, current maintenance models for fixed-foundation offshore wind turbines generally use only significant wave height for jacking-up of the vessel and wind speed during the replacement operation to determine whether a maintenance task involving a heavy lift vessel can take place. O&M analysis of floating turbines have begun to implement significant wave height limits but, with the exception of the CoreWind project [1], these wave height limits are constant and do not vary with wave period. It is therefore suggested that the inclusion of a wave period dependant significant wave height limit should be included in floating wind O&M modelling tools when analysing large component major replacements involving a heavy lift vessel. This suggestion will be implemented in Chapter 6 of this thesis.

### 4.6.2 The limited impact of floating turbine motion on technician working when considering major replacement tasks

When comparing the wave-induced nacelle motion to the maximum motion limits for safe and effective technician working, it was found that the impacts of applying this motion limit is not likely to be large in this particular example. The applied motion limits were not exceeded during the analysis of this 15MW reference turbine in significant wave height values up to 5m. When comparing this to typical turbine accessibility limits using smaller vessels, for example a crew transfer vessel (CTV) with limits of 1.5m significant wave height, or a service operations vessel (SOV) with potentially up to a 4.5m significant wave height limit if a motion compensation access system is in operation [43], it can be seen that wave-induced turbine motion is unlikely to be a limiting factor compared to other accessibility limits. This is consistent with the findings reported by the CoreWind project [1]. This can also be seen when comparing this to the estimated limits based on the relative displacement between the turbine nacelle and crane tip shown in Figure 4.11.

It is therefore considered that, while maintenance tasks may be limited by the wind turbine technician's ability to work on the floating turbine under some wave conditions, this impact is likely to be limited over the majority of wave conditions when considered in the context of vessel accessibility, or in comparison to the motion limits for the lifting operation itself. However, again, this is very much dependent on platform design.

### 4.6.3 The large impact of floating turbine and crane motion on major replacement tasks

However, when reviewing the limiting wave conditions for the lifting operation based on the nacelle and crane tip relative displacement, it was found that the impact of applying these limits to accessibility is more important. This can reduce the significant wave height limit to below 1m at higher wave period conditions in the example presented and could potentially lead to much reduced accessibility limits compared to fixed-foundation wind turbines and jack-up vessels. Although, it should be noted that the wave height limits found during this analysis are generally higher than the limits applied for vessel jacking-up at low wave periods. When reviewing the impact that varying the crane tip motion has on the significant wave height limits, it was found that varying this motion has a large impact on the significant wave height limit for the lifting operation, highlighting the effects of heavy lift vessel design as well as turbine design on accessibility. However, it should again be noted that this is a conservative approach where the turbine and vessel motions are summed together, while in reality the phase difference between the motion of the two structures could lead to these motions partially cancelling each other out in the time domain. This approach is also based on a very simplified approach to estimating the motion of the crane vessel and only considers a single wave direction when estimating the turbine motion.

Therefore, it is expected that the main limiting wave-induced motion during heavy lift maintenance operations in floating wind turbines will be the relative displacement between the turbine nacelle and the heavy lift vessel crane tip. Based on this conservative approach, it was found that this could lead to low maximum significant wave height limit for completing this operation under higher wave period conditions. However, this is again highly dependent on both floating turbine and heavy lift vessel design.

### 4.6.4 Comparison of results to recent literature and wave limits for O&M modelling work

It has already been highlighted within this chapter that since completing this analysis, new literature has been published which addresses this area of wave limits for floating-to-floating heavy lift maintenance tasks on floating turbines. This was published as part of the CoreWind project and estimated with wave limits for two different 15MW floating turbine concepts with two different floating crane vessel concepts [1]. Within this publication, significant wave height limits were estimated at different peak wave period values through modelling of the relative motion between the floating turbine and crane vessel in the time-domain using the Orcaflex software. The relative motion is then compared to maximum relative vertical velocity values for a motion compensation system to find the wave height limits across the range of peak wave period values. Some of the key conclusions from this CoreWind study are similar to those reported within this thesis chapter, for example the significant wave height limit varies with the peak wave period value, reducing with increasing wave period. And also, that the impact of turbine motion on technician working is unlikely to be the limiting factor compared to other accessibility limits. However, the approach applied within the CoreWind project addresses a number of the limitations highlighted with the approach presented within this PhD thesis chapter.

Firstly, within the work presented within this chapter, a very simplistic approach is taken to estimate displacement values representative of what may be seen in a floating crane vessel over a range of wave conditions using a ratio based on limited data taken from literature for a crane vessel replacing a blade on a 10MW turbine. Within the CoreWind analysis, the response amplitude operators of a floating crane vessel capable of replacing components on a 15MW turbine are found and the wave-induced motion response of this vessel modelled over a range of wave conditions. The CoreWind analysis also models the relative motion of the floating turbine and the crane vessel in the time-domain and is therefore able to capture the phase difference between the motion of the two floating structures, whereas the analysis applied within this chapter assumes a conservative, worst-case scenario where the estimated displacement values of both structures are summed together to find the relative motion. Finally, the CoreWind analysis modelled the relative motion between the floating structures at a number of different wave direction values and the estimated wave limits are based on the worst case across the range of scenarios, whereas the approach presented within this chapter only accounts for a single wave direction of zero degrees.

It is therefore concluded that when applying wave limits within the O&M cost modelling of the floating turbine scenarios in Chapter 6 of this thesis, that the wave limits estimated and published from the CoreWind project will be applied, rather than those estimated within this chapter. At the time that the work presented within this chapter was completed, there were no published literature which investigated the wave limits for a major replacement task on a floating wind turbine based on its wave-induced motion and no literature which presented wave limits based on motion limits for technician working. Therefore, this approach was considered to be an appropriate method to estimating indicative values for these and understanding the impact that these could have on the O&M modelling of major replacement tasks on floating turbines within the time and resource available for this part of this PhD project. However, the limitations of this approach lead to large uncertainty around the motion of the floating crane vessel, and also the impact that different wave directions may have on these estimated wave limits. These areas are addressed within the analysis published by the CoreWind project and therefore these values are applied within the O&M modelling of floating wind turbines presented in Chapter 6 of this thesis.

## 4.7 Conclusion to chapter

In the context of this PhD thesis, the aim of this chapter was to answer the following secondary research question:

*'What are the additional accessibility limits (wave limits) associated with floating wind turbines when completing heavy lift maintenance tasks? What are indicative values for these limits which can be implemented into O&M modelling of a floating turbine?'*

The main deliverable from this chapter was defined as is a range of wave limit values representative of a floating-to-floating major replacement task which can be used as an input into the O&M cost modelling of floating turbines in Chapter 6.

This has been addressed within this chapter. Firstly, the literature on wave limits within offshore wind heavy lift maintenance tasks was summarised. This highlighted that wave height limits are generally not applied to large component major replacement tasks in O&M modelling work, however this assumption may not be applicable in floating turbines due to the wave-induced motion of both the turbine and the floating heavy lift vessel. However, at the time this work was completed, wave limits for floating-to-floating heavy lift tasks that could be used in O&M modelling were not available within the existing literature. This chapter then addresses this knowledge gap and secondary research question by estimating the wave-induced motion of a 15MW floating reference turbine using a statistical frequency-domain approach. These values are then combined with crane vessel motion values estimated from existing literature. The acceleration of the turbine nacelle across a range of wave conditions was then compared to acceleration limits for offshore technician working, and estimated relative displacement between the turbine nacelle and crane tip compared to relative displacement limits for offshore lifting operations.

The concept of frequency-domain modelling of the wave-induced motion of a floating, rigid-body is explained. The methodology of how this approach was applied to estimate wind turbine nacelle motion and how the wave limits were then determined are then explained in detail. The estimated wave limits are then presented within the results section with a sensitivity analysis applied to the estimated crane tip motion values.

The results from this analysis highlight that the wave-induced motion of the large floating turbine analysed is highly dependent on the peak period of the wave energy spectrum and therefore so are the estimated wave limits. These limits are driven by the relative motion limit between the turbine and crane and the acceleration limit applied for offshore technician working was not exceeded within this analysis. However, when comparing the analysis presented within this chapter to existing literature published after this work was completed, it was concluded that there are a number of limitations to the approach applied within this chapter which has since been addressed within this literature, for example the simple approach to estimating crane tip motion. It was therefore concluded that wave limit values presented as part of the published outputs from the CoreWind project would be used in the O&M modelling work in Chapter 6, rather than the analysis presented within this chapter.

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# Chapter 5: O&M cost modelling of major replacements in next-generation fixed-foundation turbines

## 5.1 Chapter overview and research question

It has previously been highlighted within this thesis that failure rate is one of the parameters which has been shown to have a large impact on the O&M cost of an offshore wind farm and that major replacement tasks are a large contributor to the overall O&M cost. It has also been highlighted that the failure rate of large components which require a major replacement is not known in next-generation 15MW turbines. Therefore, the O&M cost associated with these tasks is highly uncertain in commercial scale wind farms using these turbines. 15MW offshore wind turbines with both direct-drive and medium-speed drive-train configurations are currently being developed. Direct-drive turbines are able to eliminate the need for a gearbox, at the expense of having a larger and more expensive direct-drive generator and were estimated in Chapter 3 to have lower major replacement rates than medium-speed turbines. How this difference in major replacement rate translates into O&M cost is not known. This chapter will address these knowledge gaps.

The chapter will begin by describing the O&M modelling tool which has been used in this analysis along with the minor edits which were made to carry out this analysis. Three offshore wind farm case study locations will then be defined and the key input data into the model will be discussed. This will include a range of three major replacement rate scenarios (estimated and defined in Chapter 3) for each of the two turbine configurations – direct-drive and medium-speed. The wind farm time-based availability and O&M cost associated with major replacement tasks (consisting of vessel, repair and lost electricity costs) output from the model are then presented and compared across the different scenarios. The differences across the range of replacement rate values and the different turbine configurations are then discussed and conclusions drawn. Unlike the previous two chapters, this chapter will not begin with a general literature review of the area. The relevant key literature relating to offshore wind O&M modelling tools, O&M modelling of major replacement tasks and the key factors influencing O&M costs have already been summarised within Chapter 2 and therefore will not be repeated here. However, there will be a comprehensive literature review of the key inputs used within offshore wind O&M modelling presented within this chapter.

The aim of this chapter is to answer the secondary research question outlined in Chapter 1 and shown below:

*How does the total cost associated with large component major replacement tasks vary in next-generation fixed-foundation wind turbines with varying replacement rate and different drive-train configuration?*

The main deliverable of this chapter, in the overall context of this thesis, is a range of cost values associated with major replacement tasks for three different case study offshore wind farm locations using two different 15MW next-generation turbine types (direct-drive and medium-speed) and three different major replacement rate scenarios (low, medium and high – as defined in Chapter 3). The results presented within this chapter and the conclusions drawn will then be used in Chapter 7 in answering the primary research question addressed in this PhD project, as defined in Chapter 1 and given again below.

*"What impact can the currently unknown major replacement rate have on the cost of major replacement tasks in next-generation offshore wind turbines and how does this vary between different next-generation offshore wind turbine configurations?"*

The novel contribution of Chapter 5 is the estimation of cost values associated with major replacement tasks in large offshore wind farms, based on a number of major replacement rate scenarios systematically estimated specifically for 15MW offshore wind turbines. Thus, providing an understanding of how uncertainty in turbine reliability can translate through to O&M cost and how this can differ between large direct-drive and medium-speed turbines. The sources and assumptions around all other key values input into the model are fully described in detail, allowing the approach to be fully understood if applying the results and conclusions presented, or if a similar piece of modelling work was attempted.

## 5.2 Strathclyde offshore wind O&M model and input data

This section will begin by introducing and describing the offshore wind operations and maintenance modelling tool which was used to carry out this analysis. This is a Matlab-based model which was previously developed at the University of Strathclyde as part of another PhD project [1] and is used in both the work presented within this thesis chapter and in Chapter 6 with some minor adjustments. This section will then go on to describe three case study locations which have been used to represent three fixed-foundation offshore wind farm scenarios around the Scottish coast. Finally, a detailed review of the key inputs used within recent offshore wind O&M modelling literature will be presented and the key inputs which have been used within the modelling work presented in this chapter are defined.

### 5.2.1 StrathclydeOW O&M Model

The StrathclydeOW O&M model is a time-domain offshore wind operations and modelling tool which was previously developed at the University of Strathclyde by Dr Iain Dinwoodie as part of his PhD project [1], [2]. The original version of this model was benchmarked against three other offshore wind modelling tools across a number of different reference scenarios as part of its verification by Dinwoodie et al. [3]. Some of the key aspects of the model are described here, but a full, detailed description of the underlying theory and the structure of the model can be found in [1].

There are three main parts within this model – climate modelling, turbine failure modelling, and resource and cost modelling. Based on sample data input by the user, the model can simulate a time-series of wind speed and significant wave height values over the user-defined wind farm lifetime using a multivariate autoregressive model. Wind speed and wave height values are used in calculating parameters such as energy produced and lost by the wind farm and in determining whether the wind turbine is accessible to carry out maintenance tasks when required. Failures of wind turbine components are generated throughout the time-series using a Markov Chain Monte Carlo simulation, where a random number is generated and compared to the hazard rate at each time step to determine whether the transition to a failed state has occurred. The hazard rate is based on a user-defined failure rate and different failure severities can be represented. Wind turbine failures are used to determine whether a maintenance action is required and also in calculating wind farm availability, lost energy production, etc. Depending on the maintenance strategy selected, a repair task may then be initiated when a failure occurs. The model checks whether the required resources are available to complete the repair, for example the required vessel, and whether the weather conditions are within the user-defined operational limits for the required weather window duration. Maintenance costs are then estimated based on aspects such as cost and duration of vessel hire, repair costs, lost revenue due to turbine downtime, etc.

The user can also define the number of simulations which are run for each scenario and the outputs produced by the model are mean values across this number of simulations. Outputs from the model include wind farm availability, wind farm energy production and losses, vessel costs, staff costs and overall O&M cost. Key inputs which are required into the model include:

- Wind speed and significant wave height time-series data
- Wind turbine power curve
- Electricity cost
- Wind turbine failure rates
- Repair costs
- Repair time / required weather window
- Vessel costs
- Vessel operational limits (wind speed, significant wave height)

These inputs will be described in more detail later in this chapter. A simple flow diagram showing the overall structure of the model is shown in Figure 5.1.

Within the analysis presented in this thesis chapter, some of the features within this model have not been utilised. The climate model, used to generate a synthetic time-series of wind speed and significant wave height values, was disabled to allow historical climate data for the case study locations to be input directly into the model. As the scope of this work is to investigate and compare major replacement tasks across different scenarios, other maintenance tasks, for example minor repairs and scheduled maintenance, have been set to zero within the model.

The key adaptation made to the model within this chapter was to adapt the code to by-pass the existing climate model to allow historical climate data to be directly used within the model, whilst ensuring no other parts of the model were impacted. The key contribution made to the model in this chapter was the researching and updating of key input values within the model such as repair costs, repair times, and vessel costs. This is described in more detail in Chapter 5.2.3.

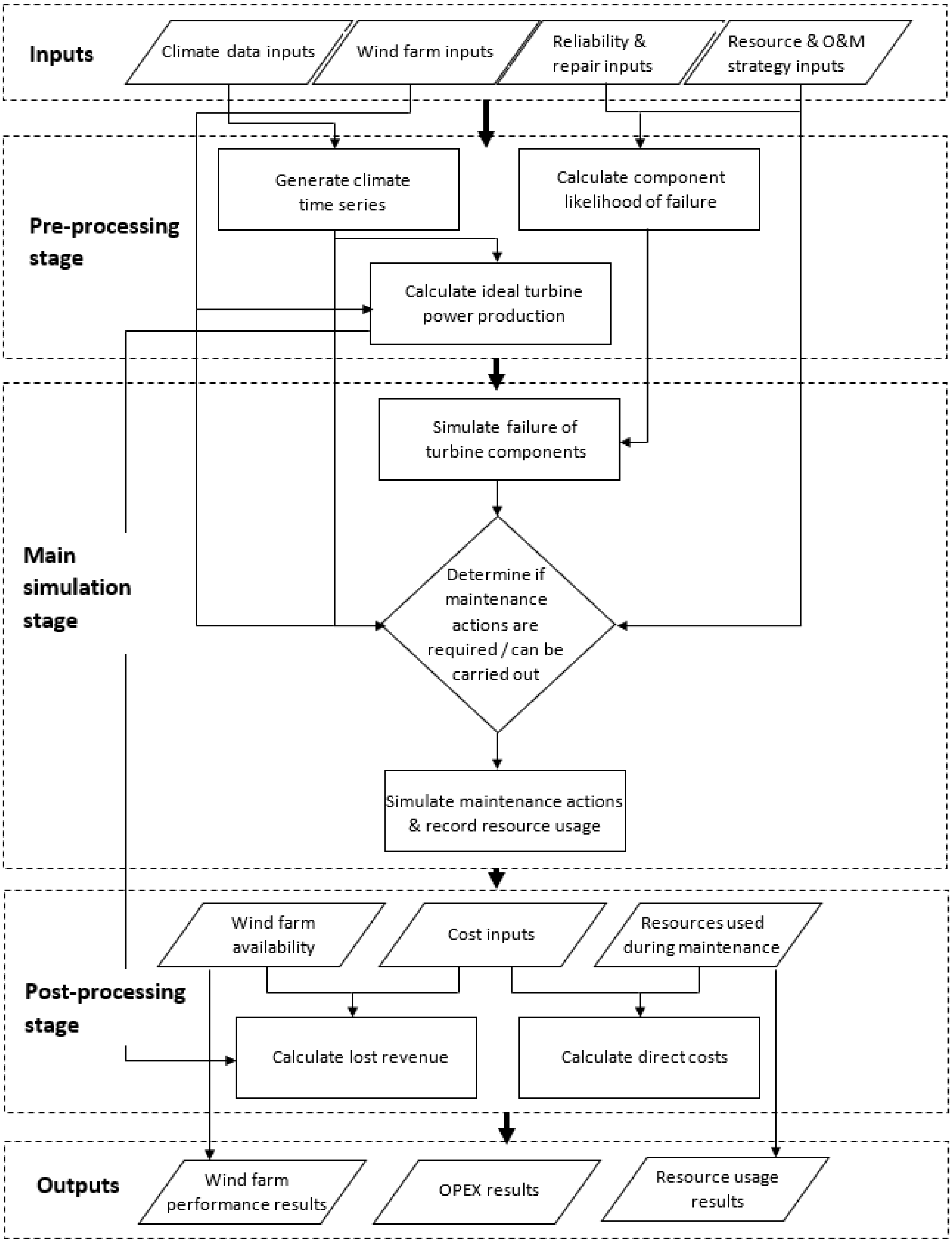



*Figure 5.1. Simple flow diagram of O&M model used, based on Figure 3.19 in [1]*

### 5.2.2 Fixed-foundation wind farm case study locations

To compare the impact of turbine configuration and major replacement rate on O&M cost in different environments, three fixed-foundation offshore wind farm case study locations were selected around the coast of Scotland. These three locations were selected to coincide with areas included within the Scotwind offshore leasing process [4], [5] and are therefore thought likely to be developed over the next decade with next-generation offshore wind turbines. The co-ordinates of these three case study locations, as well as the co-ordinates of the assumed maintenance port and the estimated travel time between the two locations, are summarised in Table 5.1. The port locations have been assumed based on being identified as suitable for marshalling/assembly for offshore wind projects by Crown Estate Scotland in their analysis of ports in Scotland [6] and their proximity to the case study locations. The travel time has been estimated based on the distance between the two sets of co-ordinates and assuming a travel speed of 19km/h [7]. The locations of the three case study sites are also shown on Figure 5.2.

*Table 5.1. Co-ordinates of the three fixed-foundation case study locations and assumed port locations, along with the travel distance and time between the locations.*

| Site | Site co-ordinates | Maintenance port | Port co-ordinates | Travel distance (km) | Travel time (hr) |
|---|---|---|---|---|---|
| FF1 | 56° 45’ 0” N<br>1° 0’ 0” W | Aberdeen | 57° 8’ 32” N<br>2° 4’ 45” W | 79 | 5 |
| FF2 | 58° 15’ 0” N<br>2° 30’ 0” W | Nigg | 57° 41’ 44” N<br>4° 1’ 49” W | 110 | 6 |
| FF3 | 59° 0’ 0” N<br>4° 15’ 0” W | Scrabster | 58° 36’ 0” N<br>3° 32’ 0” W | 61 | 4 |


*Figure 5.2. Location of the three fixed-foundation (FF) case study locations plotted using Google Maps.*

For each of the three case study locations, ERA5 reanalysis climate data [8] was used to input a time-series of wind speed and significant wave height values into the O&M model. Wind speed values at 100m height and significant wave height values were downloaded from the online ESOX tool developed by Lautec [9] at each of the three sets of site co-ordinates given in Table 5.1. This was 25-years of reanalysis data at 1-hour frequency from 1995 – 2019. As the available wind speed data was at a height of 100m and the hub height of a 15MW turbine is 150m [10], wind speed values at 150m were estimated using the log law, as shown in Equation 5.1 [11]. Where u(z) is the wind speed at height z, u($z_r$) is the wind speed at the reference height, $z_r$, and $z_0$ is the surface roughness length, taken here to be the mid-point between the values for a calm open sea and a blown sea, given in [11]. The average wind speed values at 150m and significant wave height values from the data input into the model at each of the three case study locations are given in Table 5.2.

$$u(z) = u(z_r) * \frac{\ln\left(\frac{z}{z_0}\right)}{\ln\left(\frac{z_r}{z_0}\right)} \tag{5.1}$$

*Table 5.2. Average wind speed and significant wave height values for each fixed-foundation case study location based on the ERA5 reanalysis data [8] downloaded from the ESOX tool [9] with the log law at 150m applied at each of the site co-ordinates given in Table 5.1.*

| Site | Average ws (m/s) | Average $H_s$ (m) |
|---|---|---|
| FF1 | 10.36 | 1.66 |
| FF2 | 10.14 | 1.43 |
| FF3 | 10.77 | 2.46 |

### 5.2.3 O&M model inputs for fixed-foundation scenarios

Within this section, the key inputs used within the O&M model are discussed. This includes key input parameters related to the wind farm, turbine reliability and repair, and the maintenance vessels.

#### 5.2.3.1 Wind farm specification

Within the O&M model, the wind farm size and operational lifetime must be defined, along with a power curve for the wind turbines used and the electricity price at which electricity can be sold. Within this analysis, a 1.5GW wind farm consisting of 100 x 15MW wind turbines was chosen as representative of a commercial-scale offshore wind farm using large, next-generation turbines. The operational lifetime of the wind farm is selected as 25 years and the turbine power curve is based on the IEA 15MW offshore reference turbine [10]. An electricity price of £40.7/MWh was assumed. This was based on LCOE values estimated from a survey of 140 wind energy experts published by Wiser et al. in 2021 [12]. An average of the estimated median values in 2025 and 2035 was used. These wind farm inputs are summarised in Table 5.3.

*Table 5.3. Wind farm related inputs for the fixed-foundation case studies.*

| | |
|---|---|
| **Wind farm size (GW)** | 1.5 |
| **Number of turbines** | 100 |
| **Turbine rated power (MW)** | 15 |
| **Wind farm lifetime (yrs)** | 25 |
| **Electricity cost fixed-bottom wind (£/MWh)** | 40.7 |

### 5.2.3.2 Turbine reliability and repair inputs

Failure rate data is required as in input into the O&M model and the severity of the failure, and therefore the vessel required to complete the repair, can also be defined. As previously stated, in this analysis only the most severe major replacement tasks which require the use of the heavy lift vessel are modelled. Therefore, the failure rate inputs for all other failure severities and scheduled maintenance tasks are set to zero.

Major replacement rate values of large components (generator, gearbox and rotor) in 15MW direct-drive and medium-speed fixed-foundation offshore wind turbines have previously been estimated in Chapter 3 and a set of major replacement rate values for input into the O&M model defined (Table 3.9). This includes low, medium and high replacement rate scenarios. These values are shown again in Table 5.4 for ease of review.

*Table 5.4. Low, medium and high major replacement rate inputs for 15MW direct-drive and medium-speed fixed-foundation turbines based on the analysis presented within Chapter 3.*

| Turbine configuration | Low replacement rate scenario (rep/turbine.yr) | Med. replacement rate scenario (rep/turbine.yr) | High replacement rate scenario (rep/turbine.yr) |
|---|---|---|---|
| **Fixed-foundation, direct-drive** | 0.008 | 0.024 | 0.045 |
| **Fixed-foundation, medium-speed** | 0.011 | 0.035 | 0.068 |

Another input required into the O&M model is the repair cost of a major replacement task. Repair cost is based on the cost of materials required to complete the repair and therefore, when considering the replacement of a large component, such a generator, gearbox or blade, will consist mainly of the component cost. Component costs are highly uncertain in next-generation offshore wind turbines as they are not currently in operation in commercial wind farms and the cost of large components are subject to changes in the market price of raw materials [13]. Therefore, the costs must be estimated using the best currently available information. The cost of a major replacement task is based on the estimated component cost. A recent report published by BVG Associates on the behalf of the Crown Estate and the

Offshore Renewable Energy Catapult provides cost estimates for a 1GW offshore wind farm consisting of 100 x 10MW wind turbines [14]. Within this report, estimated capital cost values of £2,000,000 for a direct-drive generator, £1,000,000 for a medium-speed generator, £700,000 for a medium-speed gearbox and £1,300,000 for a set of wind turbine blades are given. Starting with the direct-drive turbine components, these cost values were then scaled to the estimated cost for 15MW turbine components with the assumption that the cost of the component scales proportionally with the component's mass. The mass of a blade and the generator for the IEA 15MW offshore reference turbine (65t and 371t) [10] were compared to the mass of a blade and a direct-drive generator design for the DTU 10MW offshore reference turbine (41t and 231t) [15], [16] and mass ratios between these different sized components found. A ratio of approximately 1.6 was found for both components and the component costs for the 10MW turbine were multiplied by this ratio to estimate costs for a 15MW direct-drive generator and blade. The estimated cost of these components was then used along with the average relative contribution of each component to the overall major replacement rate value to estimate an average cost representative of a major replacement task. Using the same component cost scaling ratio of 1.6, the component costs in a 15MW medium-speed turbine were then estimated. These costs were again used with the relative contribution of each component to the overall major replacement rate (in this case generator, gearbox and blades) to estimate an average cost representative of a major replacement task in this configuration. The major replacement cost estimated for the medium-speed turbine is therefore lower than that estimated for the direct-drive turbine due to the majority of major replacements consisting of the cheaper medium-speed generator and gearbox. The repair costs input into the model for the fixed-foundation direct-drive and medium-speed turbines are shown in Table 5.5.

The time required to complete the repair is another input which is required in the model and is used to determine the weather window for which the turbine must be accessible for a repair to be completed. Repair time values have been estimated based on previous values used in recent offshore wind operations and modelling literature. A repair time of 24 hours for major replacement tasks was used by Dalgic et al. [17], whereas Smart et al. and Shields et al. both used values of 34 hours [18], [19]. ORE catapult used a repair time of 47 hours when modelling major replacement tasks in floating turbines [7] and a value of 52 hours was used in the reference cases defined by Dinwoodie et al. [3]. When estimating the cost of energy from floating wind farms using advanced O&M modelling, Rinaldi et al. used repair times of 67 hours for a generator replacement, 44.5 hours for a gearbox replacement and 31.25 hours for a blade replacement [20]. It can be seen that there is large variation in these values typically applied. There is also further uncertainty when considering next-generation turbines as difficulties may emerge when replacing components in turbines of this scale or replacement techniques may develop and improve. Therefore, in this analysis, a worst-case scenario is assumed and the largest values within the existing literature are used – these are the repair times used by Rinaldi et al. [20]. In a similar manner to estimating an average representative repair cost for each turbine configuration, an average repair time representative of a major replacement task was estimated based on these component repair times and the relative contribution of each component to the overall major replacement rate for each turbine configuration. This leads to a shorter repair time for the medium-speed turbine in comparison to the direct-drive turbine due to the large contribution of the gearbox, with a shorter repair time, to the overall major replacement rate. The estimated repair times input into the model are also given in Table 5.5.

*Table 5.5. Estimated repair cost and repair times for a major replacement task in fixed-foundation direct-drive and medium-speed turbines used as inputs in the O&M model.*

| | |
|---|---|
| **Direct-drive (fixed) repair cost (£)** | 2,861,136 |
| **Medium-speed (fixed) repair cost (£)** | 1,216,221 |
| **Direct-drive (fixed) repair time (hrs)** | 62 |
| **Medium-speed (fixed) repair time (hrs)** | 50 |

#### 5.2.3.3 Maintenance vessel inputs

A number of vessel related inputs are also required within the O&M model, this includes vessel mobilisation time and cost, charter time and cost, and vessel accessibility limits. It should be noted that time and cost values related to heavy lift vessel mobilisation and charter are highly variable and dependent on the market conditions [18]. It should also be highlighted that currently there are no heavy lift vessels available which are able to replace large components in 15MW offshore wind turbines [21], [22]. Therefore, these values are subject to a high level of uncertainty. However, these have been estimated using what is considered to be the currently best available data information and are kept consistent across the different scenarios to allow for a consistent comparison. It is assumed that a jack-up vessel will be used for major replacement tasks in these fixed-foundation wind farm scenarios.

Within the existing literature, a mobilisation time of 60 days or two months is often used when hiring a jack-up vessel to carry out major replacement tasks [3], [17], [18], [23]. Therefore, this value of 60 days is also used within this analysis. The mobilisation cost associated with heavy lift vessels required to replace large components in offshore wind turbines is large. The values applied within previous O&M modelling studies also vary throughout the published literature in this area. For example, Ioannou et al. used a mobilisation cost of £405,000 for a jack-up vessel [24] and Judge at al. used a cost of €500,000 [23]. Dinwoodie et al. applied a jack-up mobilisation cost of £500,000 [3] and a value of £800,000 was used by Dalgic et al. [17]. There are also examples of mobilisation costs for floating heavy lift vessels within the existing literature and these are subject to even more variation than jack-up vessels. A value of £27,000 is used by Rinaldi et al. [20], €325,000 is used by CoreWind [21] and the largest value of £1,800,000 used by ORE Catapult [7]. As there is large variation across these values and next-generation vessels required for 15MW turbines are expected to have higher costs than current generation vessels, the worst-case scenario from the existing literature has been assumed. Therefore, a mobilisation cost of £1,800,000 has been used in this analysis. It is also assumed that this value has been informed through knowledge of the market due to the author's (ORE Catapult) industry connections. Although this mobilisation cost is based on that of a floating heavy lift vessel in the analysis by ORE Catapult, it is assumed that, due to the lack of vessels capable of replacing components in 15MW turbines, next-generation jack-up vessels could command fees similar to those for next-generation floating vessels.

Within the case study scenarios presented in this chapter, a fix on fail strategy is used when chartering a jack-up vessel to carry out a maintenance task. Therefore, a vessel is mobilised once a failure occurs and a repair is required and becomes available after the mobilisation time. The vessel is then available until any outstanding repairs are completed, after which the charter period is ended and the vessel must be mobilised again if required. A vessel daily hire cost is also required as an input into the model and, similar to the mobilisation cost, these values are highly market dependent and vary throughout the existing literature in this area. A jack-up vessel daily hire cost of £110,000/d was used by Dalgic et al. [17] and £112,600/d used by Ioannou et al. [24]. Whereas values of €140,000/d and £150,000/d were used by Smart et al. [18] and Dinwoodie et al. [3]. Examples of daily hire costs for floating heavy lift vessels include £150,000/d [20], €290,000/d [21], and £360,000/d [7]. There are also examples where floating vessel hire costs are given without considering a mobilisation cost. For example, a value of $500,000/d was applied by Shields et al. [19] and a value of €811,900/d applied by Maienza et al. [25]. Again, the worst-case scenario has been assumed and the highest daily hire value, which also assumes a mobilisation cost, of £360,000/d is used within this analysis. This value has been selected for the same reasons previously outlined when assuming the mobilisation cost from the same publication. The jack-up vessel mobilisation time and cost and daily hire cost applied in this analysis are summarised in Table 5.6.

*Table 5.6. Estimated jack-up vessel mobilisation and hire values input into the O&M model.*

| | |
|---|---|
| **Vessel mobilisation time (d)** | 60 |
| **Vessel mobilisation cost (£)** | 1,800,000 |
| **Vessel daily hire cost (£/d)** | 360,000 |

Finally, another important input into the O&M model are the environmental accessibility limits of the vessels when completing repairs. When considering a jack-up vessel, a significant wave height limit is generally applied during the duration of the jacking-up operation and a wind speed limit applied during the maintenance task itself. A significant wave height limit of 2m [3], [18], [19], [24] and a wind speed limit ranging somewhere from 10m/s – 15m/s [3], [17]–[19], [24] is typically applied within the existing literature. Consistent with these values, a significant wave height limit of 2m was applied during the jacking-up stage and a wind speed limit of 10m/s applied during the repair itself in this analysis.

## 5.3 Results

Within this section, some of the key results from the simulations will be presented and described – this will include the mean wind farm availability and the mean cost associated with major replacement tasks (consisting of vessel, repair and lost electricity costs) over the wind farm lifetime. Firstly, the results for the scenarios using direct-drive turbines will be presented, followed by the results for the medium-speed turbine scenarios. Finally, the results from the simulations using both turbines will be compared.

All results presented within this section are the mean values based on 100 simulations of each scenario.

### 5.3.1 Direct-drive turbine scenarios

Figure 5.3 shows the mean wind farm time-based availability for each of the three offshore wind farm case study locations (FF1, FF2 and FF3) in each of the three major replacement rate scenarios (low, medium and high). It should be clear that this is not the overall availability of the wind farm, but an availability based only on the downtime due to major replacement tasks. All other maintenance tasks, such as minor repairs or planned maintenance have been set to zero within these simulations. Therefore, these values are higher than would be expected when considering overall wind farm availability, but are considered to be consistent with the values reported by Dinwoodie et al. when comparing major replacement only scenarios across four different O&M modelling tools [3].

It can be seen from Figure 5.3, that as the major replacement rate is increased, the wind farm availability decreases. This is unsurprising as a higher number of failures will lead to more turbine downtime, thus lowering the wind farm availability. However, it can also be seen that this decrease in availability is not as large as might be expected when considering the difference between the different major replacement rate values. For example, the high replacement rate value is more than five-times greater than the low replacement rate scenario, yet the decrease in wind farm availability is only 0.61% in location FF1 (and of similar magnitude in the other locations). This can be explained by the combination of the large number of wind turbines within the case study wind farm and the relatively small major replacement rate values. As the large majority of turbines are normally operational, large amounts of downtime would be required from the non-operational turbines to decrease overall wind farm availability by a large amount. This finding is similar to the conclusions drawn by Dinwoodie et al. that major replacement tasks only have a moderate impact on wind farm availability but a large impact on O&M cost compared to minor repair tasks which happen at a much higher rate [3].

In general, the time-based availability is high in all scenarios and does not drop below 99% in any of the nine scenarios modelled with the direct-drive turbines. Minor variations can be seen across the three case study locations, with location FF3 (which has the highest average wind speed and is therefore likely less accessible) achieving lower availability values than the other two locations.

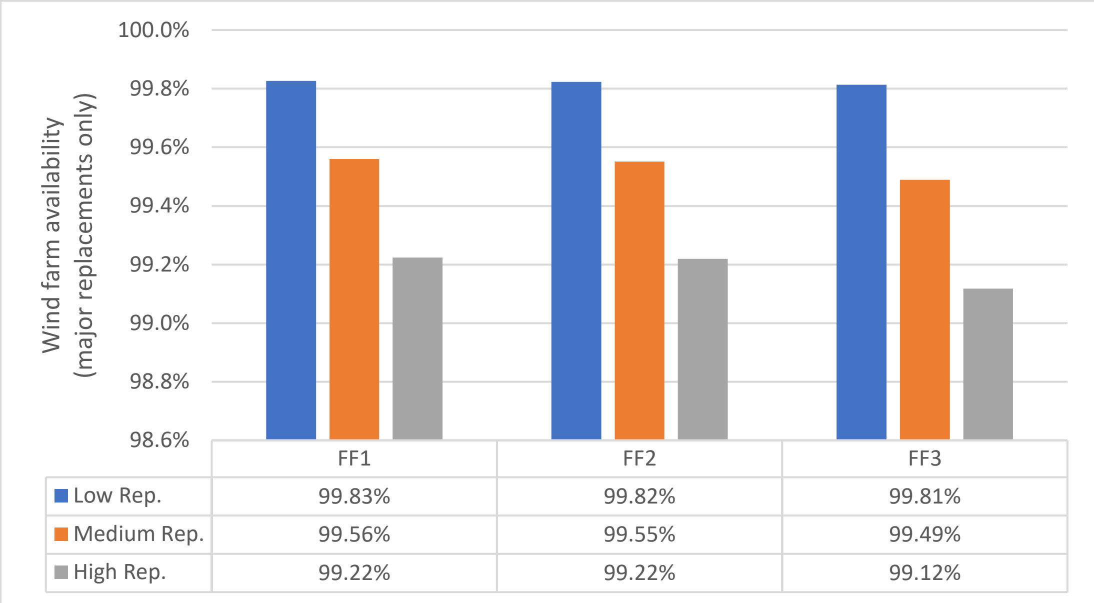
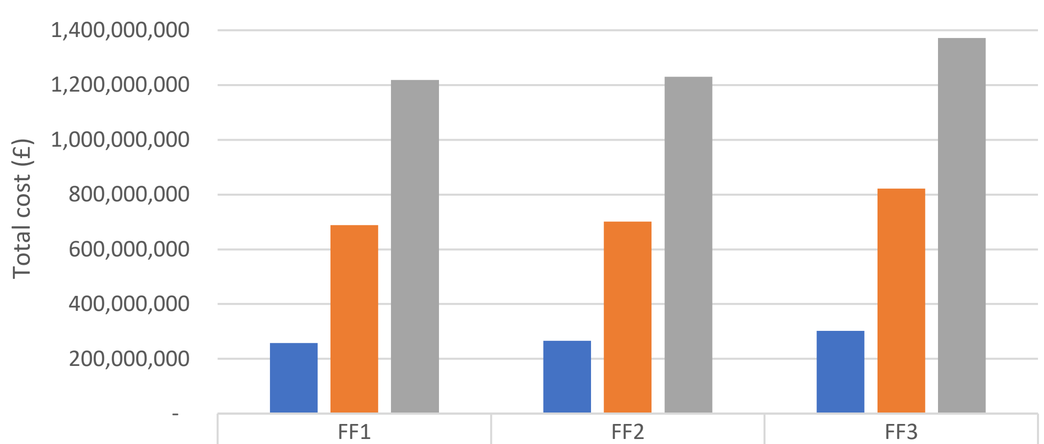


*Figure 5.3. Mean wind farm time-based availability for the three fixed-foundation case study locations and three replacement rate scenarios using direct-drive turbines.*

Figure 5.4 shows the total cost associated with major replacement tasks over the wind farm lifetime in each of the direct-drive turbine scenarios. The total cost value consists of the jack-up vessel cost (mobilisation cost and daily charter cost), repair cost and lost electricity cost (the energy lost due to turbine downtime multiplied by the electricity cost per unit).

The first observation from these results are that the cost associated with major replacement tasks over the wind farm lifetime is large and that this cost, unlike wind farm availability shown previously, varies by a large amount across the different major replacement rate scenarios. Despite the relatively low major replacement rate values, each one of these tasks will have a large cost associated with it – almost £3-million per replacement (Table 5.5) and a jack-up mobilisation cost of £1.8-million and a daily hire cost of £360k (Table 5.6). Again, these values are uncertain, but they have been applied consistently across these scenarios to allow for comparison. In all three case study locations, the cost difference between the low and high replacement rate scenarios range from £960-million to £1.07-billion – representing a cost ratio between 4.54 to 4.72 times the cost.

In general, it can also be seen that, in comparison to the differences caused by major replacement rate, the cost differences between the different locations are not large. However, location FF3 has the highest cost across each of the replacement rate scenarios.




| | FF1 | FF2 | FF3 |
|---|---|---|---|
| Low Rep. | 258,310,134 | 265,702,585 | 302,033,541 |
| Medium Rep. | 688,527,859 | 701,689,081 | 822,140,145 |
| High Rep. | 1,218,531,061 | 1,230,472,250 | 1,372,271,997 |

*Figure 5.4. Mean total cost (vessel + repair + lost electricity) of major replacements for the three fixed-foundation case study locations and three replacement scenarios using direct-drive turbines.*

As mentioned previously, the overall cost value is composed of the repair cost, jack-up vessel cost and the lost electricity revenue cost due to turbine downtime. Staff costs are not explicitly included, but the vessel crew cost is assumed to be included in the vessel hire cost [7]. Figure 5.5 shows the percentage breakdown of this total cost into each of these three categories for the medium replacement rate scenario at case study location FF1. The majority of the cost (69%) is from the cost of the jack-up vessel, with 25% of the overall cost due to the component repair and 6% due to lost revenue.

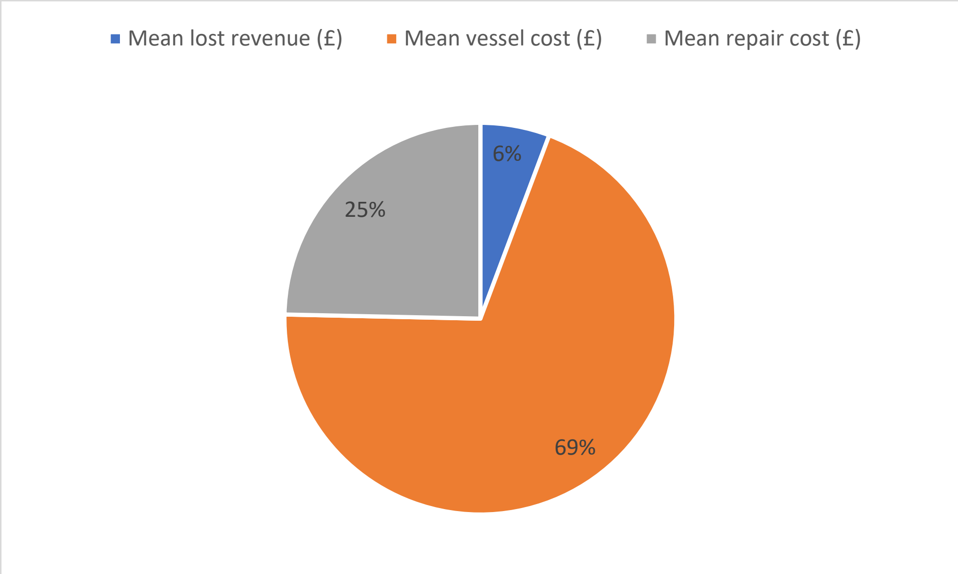
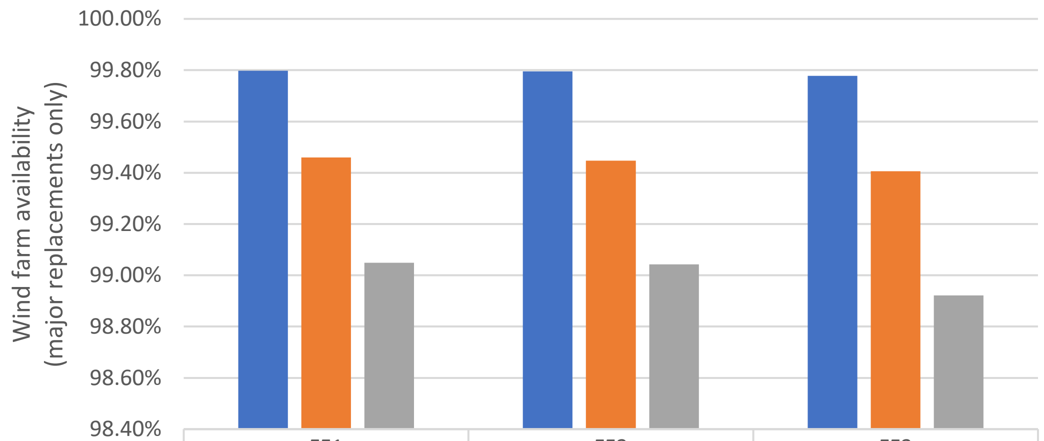



*Figure 5.5. Major replacement cost breakdown of the FF1 case study location simulation with medium replacement rate and direct-drive turbines.*

### 5.3.2 Medium-speed turbine scenarios

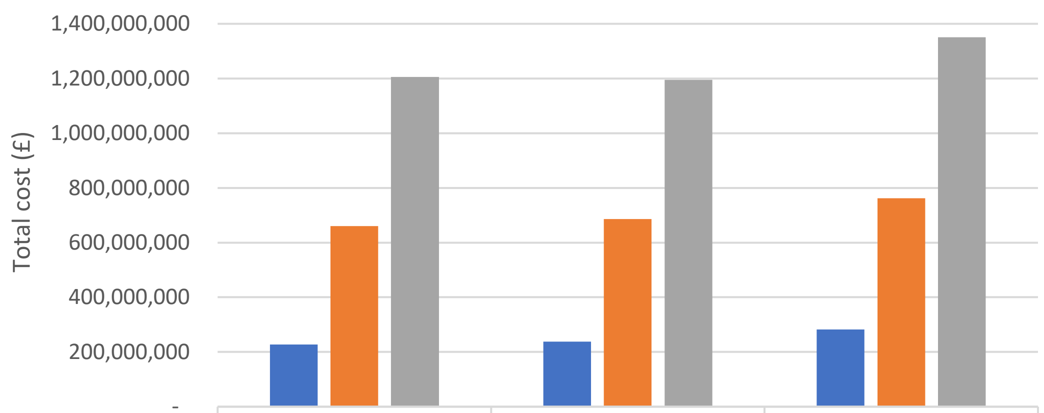
Figure 5.6 shows the mean wind farm time-based availability for each of the three offshore wind farm case study locations in each of the three major replacement rate scenarios when the medium-speed turbines are used. Again, it should be remembered that this is not the overall availability of the wind farm, but an availability based only on the downtime due to major replacement tasks. Similar trends in these availability values can be seen with the medium-speed scenarios as those described previously for the direct-drive turbine scenarios. As the major replacement rate value is increased across the different scenarios, the wind farm availability value is decreased. However, the availability values are still high and vary by less than 1% between the low and high major replacement rate scenarios across all three case study locations.

Figure 5.7 shows the total cost associated with major replacement tasks over the wind farm lifetime in each of the medium-speed turbine scenarios. As a reminder, this total cost value consists of the jack-up vessel cost, repair cost and lost electricity cost. The cost values also vary across the different major replacement rate scenarios, with cost differences ranging from £957-million to £1.07-billion between the low and high replacement rate scenarios across the case study locations (4.79 to 5.29 times the cost). Figure 5.8 shows the cost breakdown for the medium replacement rate scenario at location FF1. It can again be seen that the vessel cost makes up the majority of the overall costs associated with major replacement tasks over the project lifetime (77%).




| | FF1 | FF2 | FF3 |
|---|---|---|---|
| Low Rep. | 99.80% | 99.80% | 99.78% |
| Medium Rep. | 99.46% | 99.45% | 99.41% |
| High Rep. | 99.05% | 99.04% | 98.92% |

*Figure 5.6. Mean wind farm time-based availability for the three fixed-foundation case study locations and three replacement rate scenarios using medium-speed turbines.*




| | FF1 | FF2 | FF3 |
|---|---|---|---|
| Low Rep. | 227,881,265 | 237,903,393 | 281,919,160 |
| Medium Rep. | 660,352,656 | 686,575,106 | 762,653,381 |
| High Rep. | 1,205,253,115 | 1,195,097,983 | 1,350,742,348 |

*Figure 5.7. Mean total cost (vessel + repair + lost electricity) of major replacements for the three fixed-foundation case study locations and three replacement scenarios using medium-speed turbines.*

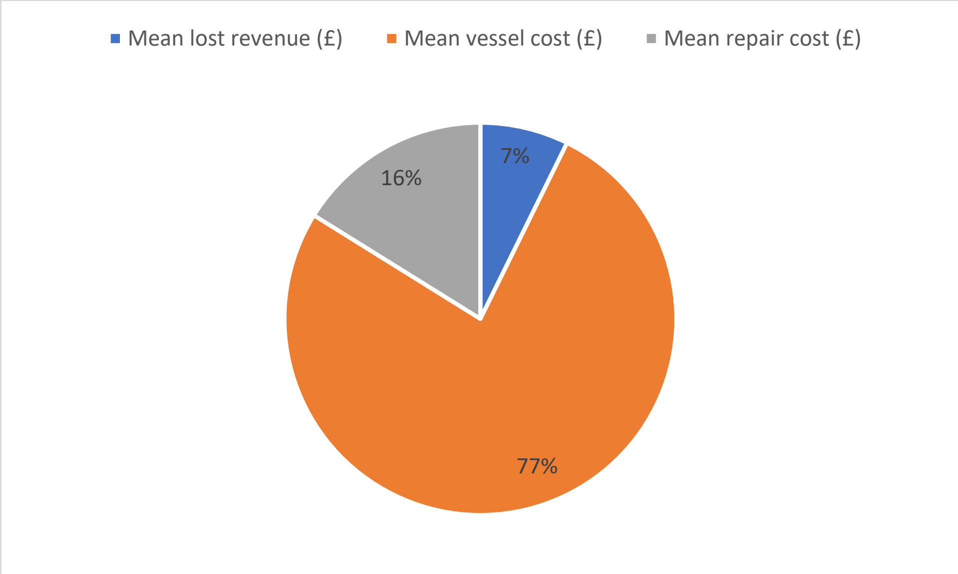
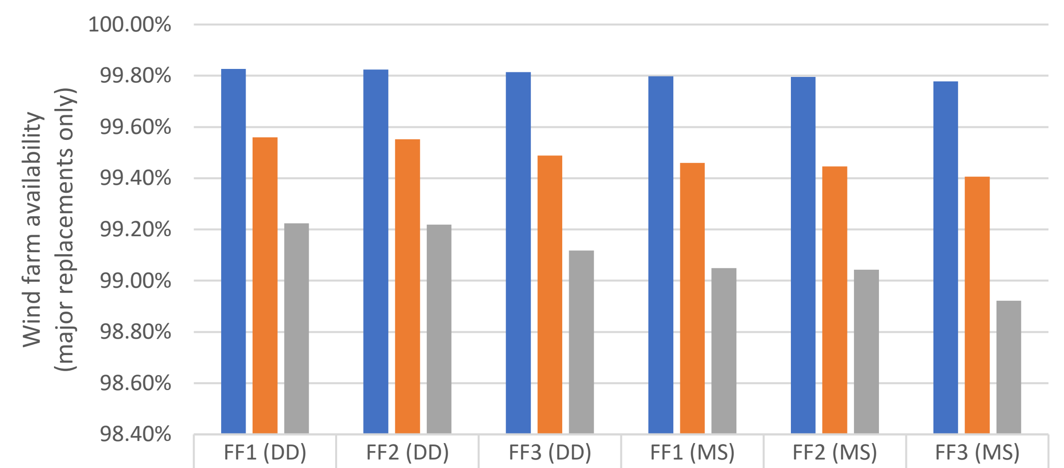



*Figure 5.8. Major replacement cost breakdown of the FF1 case study location simulation with medium replacement rate and medium-speed turbines.*

### 5.3.3 Comparison between the direct-drive and medium-speed scenarios

When comparing the results between the direct-drive and medium-speed turbine scenarios, several differences can be observed in both the wind farm time-based availability values and in the total cost associated with major replacement tasks over the wind farm lifetime.

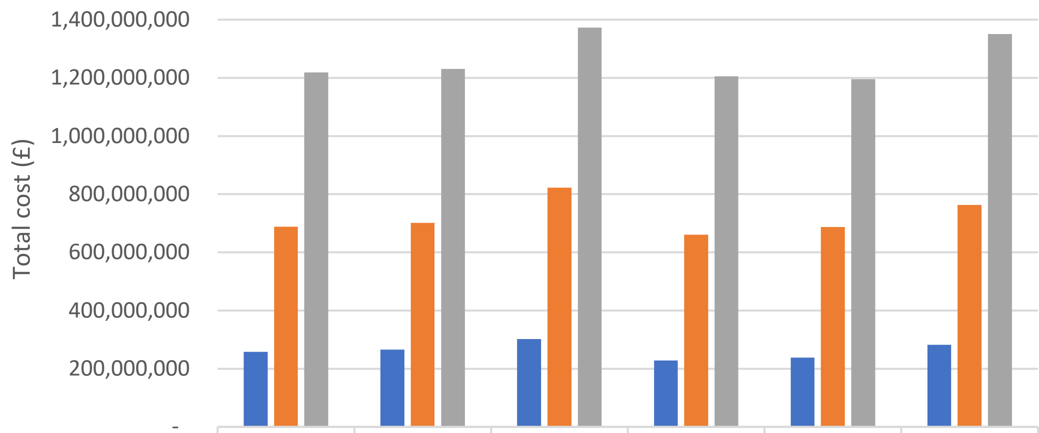
The wind farm availability values for all scenarios, previously shown in Figure 5.3 for the direct-drive turbines and in Figure 5.6 for the medium-speed turbines, are shown together in Figure 5.9 for ease of comparison. When comparing availability values between the direct-drive and medium-speed turbines in each location and replacement rate scenario, the scenarios using direct-drive turbines achieve a higher wind farm availability in all location and replacement rate scenarios. These differences in availability between the wind farms using the different turbine configurations are driven by the different major replacement rates of the turbine configurations. As shown in Table 5.4, the medium-speed turbine configurations have higher replacement rate values than the direct-drive turbines in all three replacement rate scenarios (low, medium and high). Therefore, the medium-speed turbines have more downtime over the lifetime of the wind farm, and therefore a lower time-based availability value is achieved.




| | FF1 (DD) | FF2 (DD) | FF3 (DD) | FF1 (MS) | FF2 (MS) | FF3 (MS) |
|---|---|---|---|---|---|---|
| Low Rep. | 99.83% | 99.82% | 99.81% | 99.80% | 99.80% | 99.78% |
| Medium Rep. | 99.56% | 99.55% | 99.49% | 99.46% | 99.45% | 99.41% |
| High Rep. | 99.22% | 99.22% | 99.12% | 99.05% | 99.04% | 98.92% |

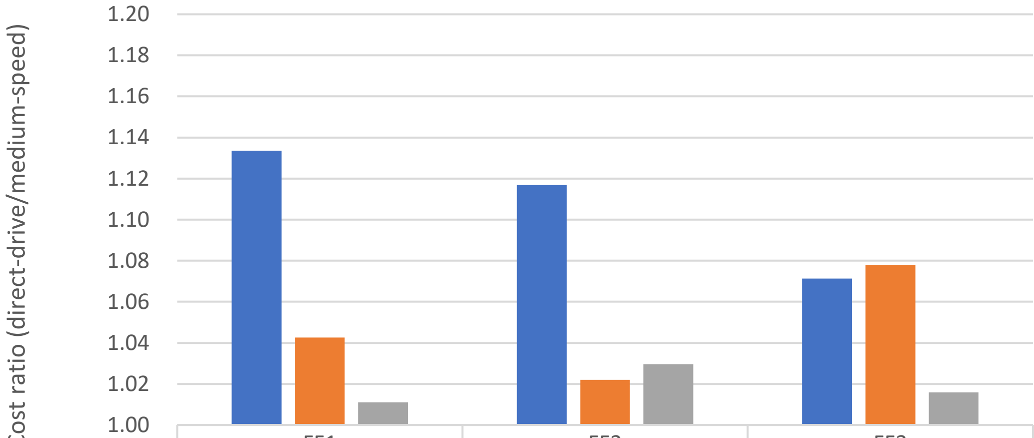
*Figure 5.9. Mean wind farm time-based availability for the three fixed-foundation case study locations and three replacement rate scenarios using both direct-drive (DD) and medium-speed (MS) turbines.*

Figure 5.10 shows the total cost associated with major replacement tasks for the direct-drive and medium-speed turbine scenarios already presented in Figure 5.4 and Figure 5.7 together for ease of comparison. When comparing cost values, the scenarios using the medium-speed turbines achieve lower overall costs than the direct-drive turbine scenarios. The lower cost is achieved despite the medium-speed configuration having higher major replacement rate and lower availability values in all scenarios. This cost difference is highlighted more clearly in Figure 5.11, which shows the ratio of total cost between the direct-drive and medium-speed scenarios. In general, the relative cost difference between the direct-drive and medium-speed turbine scenarios is greatest in the low replacement rate scenario and this difference is reduced in the higher replacement rate scenarios.




| | FF1 (DD) | FF2 (DD) | FF3 (DD) | FF1 (MS) | FF2 (MS) | FF3 (MS) |
|---|---|---|---|---|---|---|
| Low Rep. | 258,310,134 | 265,702,585 | 302,033,541 | 227,881,265 | 237,903,393 | 281,919,160 |
| Medium Rep. | 688,527,859 | 701,689,081 | 822,140,145 | 660,352,656 | 686,575,106 | 762,653,381 |
| High Rep. | 1,218,531,061 | 1,230,472,250 | 1,372,271,997 | 1,205,253,115 | 1,195,097,983 | 1,350,742,348 |

*Figure 5.10. Mean total cost (vessel + repair + lost electricity) of major replacements for the three fixed-foundation case study locations and three replacement scenarios using both direct-drive (DD) and medium-speed (MS) turbines.*




| | FF1 | FF2 | FF3 |
|---|---|---|---|
| Low Rep. | 1.13 | 1.12 | 1.07 |
| Medium Rep. | 1.04 | 1.02 | 1.08 |
| High Rep. | 1.01 | 1.03 | 1.02 |

*Figure 5.11. Ratio of major replacement cost (vessel + repair + lost electricity revenue) of each fixed-foundation case study location at each replacement rate scenario when direct-drive turbines are used against the scenarios when medium-speed turbines are used.*

Within the context of these simulations, there are a number of factors driving this cost difference between the two turbine types. Firstly, in all scenarios the lost electricity revenue is lower when the direct-drive turbines are used. This can be expected due to the higher wind farm availability when these turbines are used – as previously shown. Secondly, the scenarios using direct-drive turbines also have generally lower vessel costs (with the exception of FF1 and FF2 with low replacement rate). Again, this is due to the higher major replacement rate value of the medium-speed turbines in each of the three major replacement rate scenarios, leading to more vessel charters. Therefore, the main factor driving the lower total cost of major replacements in the medium-speed scenarios is the much lower repair cost of this turbine configuration (Table 5.5). Across all scenarios, the repair cost is much lower when the medium-speed turbines are used, despite more repair tasks being required when these turbines are used. The lower repair cost outweighs the higher vessel and lost electricity costs.

## 5.4 Discussion of results

### 5.4.1 Impact of major replacement rate on wind farm availability and O&M cost

When discussing the impact of major replacement rate of wind farm availability and major replacement cost, a few things should be kept in mind. Firstly, there are currently no 15MW offshore wind turbines currently operational in an offshore wind farm. Therefore, the true values of major replacement rate for the next-generation offshore wind turbines considered in this analysis are unknown. Secondly, the values applied within this analysis have been estimated using a recognised and systematic method where the lower and upper percentiles estimated for each component are the values which the true value is thought very unlikely to be either below or above. Therefore, the range of major replacement rate values applied are considered to represent the range of values that may be possible in these next-generation offshore wind turbines. Thus, the range of availability and cost values produced are also considered to represent the range of values that may be possible when these turbines are used, within the limitations and assumptions of this analysis.

Firstly, when considering the impact of major replacement rate on wind farm availability, as the replacement rate is increased, the wind farm availability is decreased. However, this reduction is not large with the largest reduction in availability being 0.86% between low and high replacement rate scenarios. However, although these differences appear small, when considering large, multi-gigawatt offshore wind farms, the lost electricity revenue from these differences can be significant.

When considering the impact of major replacement rate on the total cost associated with major replacement tasks, the cost is much more sensitive to the replacement rate value. Therefore, uncertainty in the reliability of next-generation turbines leads to a large amount of uncertainty in what the operations and maintenance cost associated with future wind farms may be. Across all case study locations and all turbine types, total cost associated with major replacement tasks differed by a factor somewhere between 4.54 and 5.29 when comparing the lower end of the range of replacement rate values considered possible against the upper end. Of course, there is uncertainty in a number of the other, currently unknown, values used as inputs into this analysis (this will be discussed in more detail later in this section), however, when comparing the impact of major replacement rate, all other input values remain constant. The sensitivity of O&M cost to major replacement rate and the wide range of cost values considered possible from this analysis, highlights the importance of high levels of reliability and limiting the number of major failures in next-generation offshore wind farms.

### 5.4.2 Comparison between direct-drive and medium-speed fixed-foundation turbines

The results also highlight differences when either the direct-drive or the medium-speed turbines are used within the case study wind farm. Within Chapter 3, it was found that higher major replacement rates of large components are expected in 15MW medium-speed turbines compared to 15MW direct-drive turbines due to the inclusion of the gearbox. The higher expected number of replacements translates through to lower availability values seen in the medium-speed scenarios compared to the direct-drive scenarios and leads to higher lost electricity costs. In the majority of scenarios, the higher replacement rate also leads to higher vessel costs in the medium-speed scenarios as a higher number of expensive vessel charters are required. However, despite this, across all scenarios, the total cost associated with major replacement tasks is lower when the medium-speed turbines are used. This lower cost is driven by the lower repair cost estimated for the medium-speed wind turbines based mainly on the cheaper medium-speed gearbox and generator compared to the more expensive direct-drive generator.

The difference between different turbine configurations highlights several areas for discussion. Firstly, the results suggest that using medium-speed turbines in next-generation offshore wind farms may lead to lower costs associated with major replacement activities. However, unlike comparing the difference caused by varying major replacement rate where all other input values were constant, there are a number of uncertain inputs which differ between the different turbine scenarios – for example, repair cost, which is the key driver in the lower cost of the medium-speed turbine scenarios. Although it is considered very likely that components such as the medium-speed gearbox and medium-speed generator will have a lower capital cost than a direct-drive generator, the magnitude of this difference is not currently certain, especially if developments such as modular direct-drive generators do reach the market within this generation of offshore turbines. Regardless of these uncertainties, what is clear from the comparison between the two configurations is that there is likely to be a trade-off required when selecting a turbine type in next-generation offshore wind farms and that there are a number of factors which have to be considered.

Again, it should be remembered that this analysis is focussed only on modelling major replacement tasks based on two or three large components, as per the scope of this PhD project. To achieve a more holistic understanding of how the O&M costs may compare between these different turbine types, further analysis with all other failure types and maintenance tasks included would be required.

### 5.4.3 Limitations and further areas of investigation

Within this analysis there are a number of assumptions and limitations, some of which have been mentioned throughout this chapter. Here, some of the key limitations will be discussed and potential areas for further investigation highlighted.

One of the main limitations, which is applicable to modelling any uncertain, future scenario, is the uncertainty in the input values into the O&M model. As this work is focussed on wind turbine technology and supporting infrastructure that does not currently exist, there is no ‘real-world data’ that can be used. Yet this area still has to be modelled and understood. Jack-up vessel costs and mobilisation times are considered to be the inputs with the largest uncertainty. The hire cost and mobilisation times of the current generation of these vessels are highly dependent on market conditions and those required to replace large components in 15MW turbines are currently not in operation. It is expected that there will be a high demand for these next-generation vessels as large amounts to next-generation turbines begin to be installed and maintained. However, these values have been estimated using what is considered to be the currently best available information and are consistent with discussions with industry contacts. For the purpose of comparing the impact of different replacement rate scenarios and different turbine configurations, the vessel related values are consistent across the different scenarios. Therefore, although uncertainty in vessel inputs may lead to uncertainty in the absolute cost values found, these values still provide a consistent baseline for comparing the relative performance of different turbine scenarios.

Other areas of uncertainty are the repair cost and repair time of major replacement tasks. The repair cost values have been based on the scaling of an indicative cost for 10MW components and may therefore differ in reality when considering 15MW turbines. However, this true value is currently unknown and, regardless, is also dependent on market conditions and raw material costs. The repair times are based on those in the current literature, however it is also accepted that these times may differ when considering next-generation 15MW turbines. There may be additional, new challenges when replacing large components at this scale which can increase replacement times, or there may be developments in lifting technology and methods, or in turbine technology which can reduce these times. As of now, this is another unknown for next-generation offshore wind turbines.

One approach to reducing the uncertainty in all these variables discussed above could be to apply structured expert elicitation to these areas. This is the approach that has been applied to the uncertain area of major replacement rate within this PhD thesis and has also been used to estimate the future LCOE from offshore wind by Wiser et al. [12]. Structured elicitation methods allow the range of uncertainty in what these values could be to be captured from subject matter expert knowledge and, in the absence of available data, provides a starting point for understanding the potential range of values that these unknown parameters may take. It should be noted however, that these methods are time and resource intensive.

Another area of further development in this work could be to apply different vessel charter strategies beyond the fix on fail strategy applied within the modelling work presented here. When the fix on fail approach is used, the mobilisation of a jack-up vessel begins once a failure occurs, unless mobilisation is already in progress or a vessel is currently available for another repair. Once the vessel is mobilised, it is available to complete all outstanding repairs and remains available until the repairs are completed. This approach is commonly applied within offshore wind O&M modelling work, however may not be representative of the approach taken in reality. In an offshore wind farm, it is likely that jack-up vessels would be selectively hired in the summer months when the required weather windows are more likely to be available to carry out repair tasks. Replacement tasks may also be grouped into batches, rather than an expensive jack-up vessel being mobilised and chartered only to carry out a single replacement. It is also likely that vessels would only be available for a limited time on site to complete repairs.

Applying different charter strategies may reduce the vessel costs within these scenarios, however this would likely come at the expensive of increased turbine downtime and lost electricity costs. Therefore, the optimisation of vessel charter could be another area for future investigation.

Finally, as has been highlighted throughout this chapter, this analysis is limited to major replacement tasks only (based on two or three large components) and does not consider other maintenance activities such as minor repairs or scheduled, proactive maintenance of turbines. Major replacement tasks are the focus of this PhD project as they are regularly highlighted as the most significant contributor to overall O&M costs and this is an area of high uncertainty and focus in industry at the moment. However, to further expand on the O&M cost analysis of next-generation turbines beyond the work presented within this PhD thesis, other failure types and maintenance tasks could be included within the model. This would allow for a more complete understanding of the overall O&M cost associated with next-generation turbines and allow for a more holistic comparison between the different next-generation turbine configurations. However, it should again be noted that the reliability of other components and the number of minor repairs needed in the generator, gearbox and blades in these next-generation turbines are also currently unknown.

## 5.5 Conclusion to chapter

In the context of this PhD thesis, the aim of this chapter was to answer the following secondary research question:

*How does the total cost associated with large component major replacement tasks vary in next-generation fixed-foundation wind turbines with varying replacement rate and different drive-train configuration?*

The main deliverable of this chapter was defined as a range of cost values associated with major replacement tasks for three different case study offshore wind farm locations using two different 15MW next-generation turbine types (direct-drive and medium-speed) and three different major replacement rate scenarios (low, medium and high). With the aim of using the results and the conclusions drawn in Chapter 7 when answering the primary research question addressed in this PhD project.

The above research question has been comprehensively addressed within this chapter in combination with Chapter 2 of this thesis. Within Chapter 2 it was highlighted that major replacement tasks are a large contributor to overall O&M cost and cost variation in an offshore wind farm and that failure rate has a large impact on O&M cost. As the rate of major replacements in 15MW next-generation offshore wind turbines is currently not known, it is concluded that there is therefore a large amount of uncertainty in the O&M cost associated with these tasks in next-generation offshore wind farms. This chapter addresses this knowledge gap and the secondary research question posed by estimating the total cost associated with major replacement tasks across a range of case study offshore wind farm locations with different major replacement rate scenarios (low, medium and high) and different turbine configuration scenarios (direct-drive and medium-speed).

The knowledge gap and secondary research question has been addressed using a previously developed and benchmarked offshore wind operations and maintenance model and implementing the major replacement rate values previously estimated in Chapter 3. Other required inputs are estimated based on the currently best available information.

The offshore wind operations and maintenance model used in this analysis was described along with the range of inputs used. The relevant background information and literature used in estimating and selecting the inputs used in the model was also described in detail. The wind farm time-based availability values (based on major replacements only) and the total cost associated with major replacement tasks over the wind farm lifetime (consisting of vessel, repair and lost electricity costs) were then presented and compared across the different replacement rate and turbine configuration scenarios.

The results highlight that the O&M cost associated with major replacement tasks is highly sensitive to major replacement rate in next-generation offshore wind farms and varies by a large amount across the range of replacement rate values considered possible in 15MW next-generation fixed-foundation offshore wind turbines. With cost increasing by a factor of up to 5.29 between low and high replacement rate scenarios. Within the scope of this analysis, it was also found that the wind farm scenarios using medium-speed turbines achieved lower major replacement costs than the scenarios using direct-drive turbines, despite requiring a larger number of major replacement tasks. However, the uncertain nature of the inputs required in this analysis should be considered and this is also discussed within this chapter.

## 5.6 Chapter 5 references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# Chapter 6: O&M cost modelling of major replacements in next-generation floating-foundation turbines

## 6.1 Chapter overview and research question

Based on the findings in the previous chapter for fixed-foundation offshore wind turbines, along with the existing literature, it can be assumed that the O&M cost of floating offshore wind farms using next-generation floating offshore wind turbines is also uncertain due to the unknown major replacement rate of large components for these turbines. How the cost is impacted by the choice of either direct-drive or medium-speed floating turbines and how it compares to fixed-foundation turbines is also uncertain. This chapter will address these knowledge gaps.

The O&M modelling tool which has been used to complete this analysis has already been described in Chapter 5.2.1, therefore this will not be repeated in this chapter. However, there are several key changes made to the model to allow for the improved modelling of floating wind turbine scenarios. The chapter will begin by describing the changes and why they are required. Three offshore wind farm case study locations, suitable for floating wind turbines, will then be defined and the key inputs into the model presented and discussed. Again, this will include a range of three major replacement rate scenarios, unique to the floating turbine configurations, for both direct-drive and medium-speed turbine scenarios. The background literature relating to the key inputs required in the O&M model has already been discussed in Chapter 5, therefore a comprehensive literature review of these areas is not included within this chapter. However, when there is considered to be key differences between the areas already covered for fixed-foundation turbines and floating turbines, for example environmental accessibility limits, these will be discussed. The wind farm time-based availability and O&M cost associated with major replacement tasks (consisting of vessel, repair and lost electricity costs) are then presented and compared across the different floating wind farm scenarios. The results and conclusions drawn are then compared to those previously analysed for the fixed-foundation scenarios in Chapter 5 and key differences between the fixed and floating turbine scenarios are highlighted.

The aim of this chapter is to answer the secondary research question outlined in Chapter 1 and shown below:

*How does the total cost associated with large component major replacement tasks vary in next-generation floating-foundation wind turbines with varying replacement rate and different drive-train configuration? And how does this compare to fixed-foundation turbines?*

The main deliverable of this chapter, in the overall context of this thesis, is a range of cost values associated with major replacement tasks for three different case study floating offshore wind farm locations using two different 15MW next-generation floating turbine types (direct-drive and medium-speed) and three different major replacement rate scenarios unique to these floating turbine configurations (low, medium and high – as defined in Chapter 3). The results presented within this chapter and the conclusions drawn will then be used in Chapter 7 in answering the primary research question addressed in this PhD project, as defined in Chapter 1 and given again below.

*"What impact can the currently unknown major replacement rate have on the cost of major replacement tasks in next-generation offshore wind turbines and how does this vary between different next-generation offshore wind turbine configurations?"*

The novel contribution of Chapter 6 is the estimation of cost values associated with major replacement tasks in large floating offshore wind farms. This is based on a number of major replacement rate scenarios systematically estimated specifically for 15MW floating offshore wind turbines, with additional wave limits included to account for the wave-induced motion of the floating turbine and vessel. Therefore, providing an understanding of how uncertainty in floating turbine reliability can translate through to O&M cost and how this can differ between floating direct-drive and medium-speed turbines. A particularly important part of this contribution is thought to be the highlighting of how costs can differ from fixed-foundation offshore wind farms and a discussion of the key drivers causing these differences.

## 6.2 Strathclyde offshore wind O&M model and input data

The StrathclydeOW O&M model, which has been used in this analysis has already been described in Chapter 5 of this thesis. However, the model was originally developed based on fixed-foundation offshore wind turbines and therefore changes were required when extending this to the analysis of floating turbines. This section will begin by describing the changes made to the O&M model and why these were required. Three case study locations around the Scottish coast considered suitable for floating offshore wind turbines will then be defined. Finally, the key inputs into the O&M model will be presented and discussed, particularly when these inputs differ to those used in the fixed-foundation case study scenarios in Chapter 5.

### 6.2.1 O&M model changes for floating wind modelling

Once again, the climate model was disabled to allow for historical wind and wave data to be input directly into the model. Less severe maintenance tasks and scheduled maintenance were also set to zero so that the impact of major replacement tasks could be investigated across the scenarios.

Within Chapter 4 it was highlighted that floating wind turbine and vessel wave-induced motion is an area of concern for the maintenance of floating offshore wind turbines (Chapter 4.2.2). The analysis completed in Chapter 4 found that floating turbine motion, and therefore the wave limits at which major replacement tasks can be completed, is dependent on the wave period conditions at the site. These findings are supported by the results published from the CoreWind project when estimating limiting wave conditions for floating to floating major replacement tasks [1] and also by Guanche et al. when investigating the wave limits for CTV and SOV access of floating turbines [2]. Therefore, one of the conclusions from Chapter 4 was that a wave period dependant significant wave height limit should be implemented into O&M modelling of floating offshore wind turbines. This has been done for the modelling work presented within this chapter.

Peak wave period values were entered into the model alongside wind speed and significant wave height values. The model was then edited so that accessibility to carry out a major replacement task was also dependant on significant wave height and peak wave period, rather than only wind speed, as before. A series of IF statements were used to check if the peak wave period and significant wave height values were within the defined limits at each time step during the simulation, with the significant wave height limit varying with differing peak wave period conditions. Care was taken to ensure that no other areas of the model were impacted by this change.

Therefore, there were two key adaptations made to the model within this chapter. Firstly, the input weather parameters within the model were expanded to accommodate peak wave period as an input in addition to significant wave height and wind speed. Secondly, the code was updated to include peak wave period as an additional limiting parameter, in addition to significant wave height and wind speed, when determining whether the turbine was accessible to carry out a maintenance task. These adaptations are the key contributions to the model within this chapter, along with the researching and updating of key input values specifically for floating wind farm scenarios. By presenting the analysis of floating wind farm scenarios as a separate chapter to the previous analysis of fixed-foundation wind farms, the impact of the changes to the model and input values can be more clearly seen.

### 6.2.2 Floating-foundation wind farm case study locations

To compare the major replacement cost of floating-foundation wind farms in different scenarios, three new case study locations were chosen. These locations are different to those defined previously in Chapter 5. Again, the locations were selected based on the areas included in the Scotwind offshore leasing process, with the three areas selected being considered suitable for floating turbines during the application process [3], [4]. The co-ordinates of the three floating wind farm case study locations, along with the assumed port location and estimated travel time are given in Table 6.1. The port locations have been selected using the same criteria described in Chapter 5.2.2 for the fixed-foundation wind farm scenarios – identification as suitable for marshalling/assembly [5] and proximity to the case study site location. The locations of these three floating case study locations (FL) are also shown in Figure 6.1, alongside the previous three fixed-foundation case study locations (FF) for ease of comparison. An attempt has been made to select locations within the same areas, however the areas identified as suitable for floating wind turbines in the Scotwind application process [3], [4] are generally further from shore to coincide with deeper water conditions, preferable for floating turbines.

*Table 6.1. Co-ordinates of the three floating-foundation case study locations and assumed port locations, along with the travel distance and time between the locations.*

| Site | Site co-ordinates | Maintenance port | Port co-ordinates | Travel distance (km) | Travel time (hr) |
|---|---|---|---|---|---|
| FL1 | 56° 45′ 0″ N<br>0° 15′ 0″ E | Aberdeen | 57° 8′ 32″ N<br>2° 4′ 45″ W | 148 | 8 |
| FL2 | 58° 30′ 0″ N<br>1° 15′ 0″ W | Nigg | 57° 41′ 44″ N<br>4° 1′ 49″ W | 187 | 10 |
| FL3 | 58° 45′ 0″ N<br>5° 45′ 0″ W | Scrabster | 58° 36′ 0″ N<br>3° 32′ 0″ W | 130 | 7 |

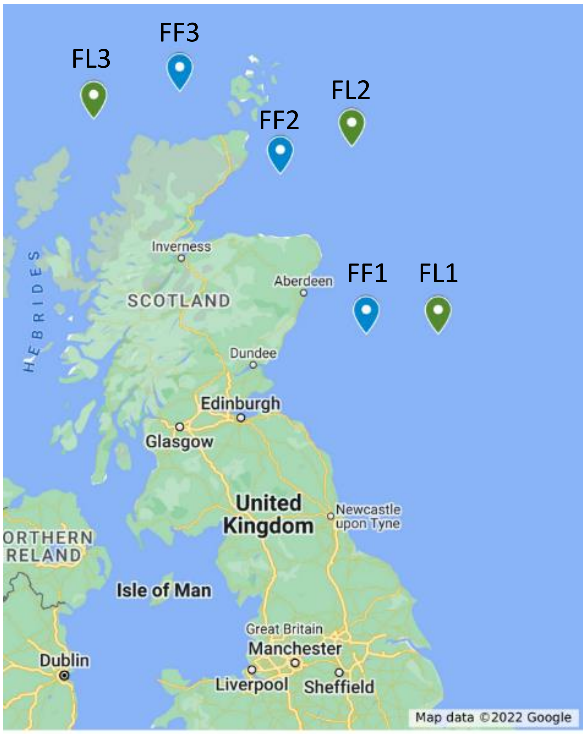



*Figure 6.1 Location of the three floating-foundation (FL) case study locations shown with the three fixed-foundation (FF) plotted using Google Maps.*

Wind speed, significant wave height and peak wave period values were again downloaded from the online ESOX tool [6] for each of the three case study locations given in Table 6.1 and the wind speed values at a height of 150m estimated using the log law (Equation 5.1). The average wind speed values at 150m, average significant wave height values and average peak wave period values of the data input into the model for each of the three case study locations are shown in Table 6.2.

*Table 6.2. Average wind speed and significant wave height values for each floating-foundation case study location based on the ERA5 reanalysis data* [7] *downloaded from the ESOX tool* [6] *with the log law at 150m applied at each of the site co-ordinates given in Table 6.1.*

| Site | Average ws (m/s) | Average $H_s$ (m) | Average $T_p$ (s) |
|---|---|---|---|
| FL1 | 10.35 | 1.85 | 7.64 |
| FL2 | 10.56 | 1.89 | 7.81 |
| FL3 | 10.76 | 2.37 | 10.57 |

### 6.2.3 O&M model inputs for floating-foundation scenarios

This section will define the key inputs used in the O&M model for the floating-foundation case study scenarios. It will be made clear whether these inputs are the same as those used in the fixed-foundation scenarios, or whether different values have been used. The existing literature on each area will not be presented, as this has already been done in Chapter 5.

#### 6.2.3.1 Wind farm specification

The majority of the wind farm parameters have been kept the same as those used in the fixed-foundation wind farm scenarios. A 1.5GW wind farm with 100 x 15MW wind turbines with a 25-year lifetime and power curve based on the IEA 15MW reference turbine [8] is used.

However, a difference between these scenarios is the cost of electricity produced from the wind farm. The cost of energy produced from floating wind turbines is currently much higher than the LCOE from fixed-foundation turbines, however this cost is expected to decrease as this technology develops to a commercial scale [9]. Therefore, the electricity cost from a commercial scale floating offshore wind farm is currently uncertain and, in this analysis, is based on the work published by Wiser et al. estimating future wind energy costs using expert knowledge [10]. A medium LCOE value from floating wind in 2025 was estimated to be \$96.3/MWh (£72.2/MWh) and \$63.6/MWh (£47.7/MWh) by 2035. An average of these two values, £60/MWh, was found and used as the electricity cost in this analysis. This is based on the assumption that the first commercial-scale floating wind farms are expected around 2030.

The wind farm input parameters for the floating-foundation wind farm case study scenarios are shown in Table 6.3.

*Table 6.3. Wind farm related inputs for the floating-foundation case studies.*

| | |
|---|---|
| **Wind farm size (GW)** | 1.5 |
| **Number of turbines** | 100 |
| **Turbine rated power (MW)** | 15 |
| **Wind farm lifetime (yrs)** | 25 |
| **Electricity cost floating wind (£/MWh)** | 60 |

#### 6.2.3.2 Turbine reliability and repair inputs

The main reliability and repair inputs required for the model are major replacement rate, repair cost and repair time. All three of these parameters differ from the values used previously in the fixed-foundation wind farm case study scenarios.

Firstly, the major replacement rate values of the two floating turbine configurations (direct-drive and medium-speed) are given in Table 6.4. These values were estimated and defined in Chapter 3 (Table 3.9), but are shown again here for ease of review. As was highlighted in Chapter 3, the replacement rate values for the floating turbines are higher than those estimated for the equivalent fixed-foundation turbine configurations.

*Table 6.4. Low, medium and high major replacement rate inputs for 15MW direct-drive and medium-speed floating-foundation turbines based on the analysis presented within Chapter 3.*

| | **Low major replacement scenario (rep/turbine.yr)** | **Medium major replacement scenario (rep/turbine.yr)** | **High major replacement scenario (rep/turbine/yr)** |
|---|---|---|---|
| **Direct-drive (floating)** | 0.017 | 0.045 | 0.067 |
| **Medium-speed (floating)** | 0.021 | 0.049 | 0.079 |

The repair cost of a major replacement task in the two floating turbine configurations were estimated using the same indicative cost data and approach used for the fixed-foundation turbines, described in Chapter 5.2.3.2. Indicative component cost values for 10MW turbines were taken [11] and scaled to 15MW size based on component mass. The cost values were then used with the relative contribution of each component to the overall major replacement rate to estimate an average cost representative of a major replacement task for each turbine in exactly the same way as was done for the fixed-foundation turbines. However, it can be seen from Table 3.7 and Table 3.8 in Chapter 3, that the relative contribution of each component to the overall major replacement rate differs between the fixed and floating foundation turbine types. Therefore, while the component costs used to estimate the repair cost is the same for both the floating and fixed-foundation turbines, the calculated major replacement cost may differ. For example, the floating direct-drive configuration has a higher repair cost than the fixed-foundation direct-drive turbine as a higher proportion of the overall major replacement rate consists of the more expensive generator. The repair cost of the floating medium-speed turbine is also slightly higher than the fixed-foundation equivalent. The repair cost values used in the model are given in Table 6.5.

The repair time for a major replacement task on the floating turbine configurations is also estimated using the same information and approach as was used for the fixed-foundation turbines. Therefore, this value again may differ between the fixed and floating configurations due to the different relative contribution of each component to the overall major replacement rate, as was discussed in the previous paragraph for repair cost. The repair time for the floating direct-drive turbine is slightly longer than the fixed-foundation equivalent, whereas the medium-speed configurations are the same. The repair time values input into the model for the floating-foundation turbine scenarios are also given in Table 6.5.

*Table 6.5. Estimated repair cost and repair times for a major replacement task in floating-foundation direct-drive and medium-speed turbines used as inputs in the O&M model.*

| | |
|---|---|
| **Direct-drive (floating) repair cost (£)** | 3,007,849 |
| **Medium-speed (floating) repair cost (£)** | 1,222,337 |
| **Direct-drive (floating) repair time (hrs)** | 64 |
| **Medium-speed (floating) repair time (hrs)** | 50 |

### 6.2.3.3 Maintenance vessel inputs

When considering major replacement tasks on a floating offshore wind turbine, it is assumed that a floating heavy lift vessel will be required due to the water depth at the site. Within this analysis, the mobilisation and cost values estimated for a floating heavy lift vessel are the same as those used for the jack-up vessel when modelling the fixed-foundation offshore wind turbine scenarios in Chapter 5. A fix on fail vessel charter strategy is used and a mobilisation time and cost of 60 days and £1,800,000 are assumed. A daily hire cost of £360,000/d is also used, with all values based on the information and discussion in Chapter 5.2.3.3. As was highlighted in Chapter 5, heavy lift vessel input values are highly uncertain. However, it is assumed that next-generation heavy lift vessels (regardless of floating or jack-up) can command similarly high indicative costs due to the market demand for these. These values are summarised in Table 6.6.

*Table 6.6. Estimated jack-up vessel mobilisation and hire values input into the O&M model.*

| | |
|---|---|
| **Vessel mobilisation time (d)** | 60 |
| **Vessel mobilisation cost (£)** | 1,800,000 |
| **Vessel daily hire cost (£/d)** | 360,000 |

The biggest difference between the model inputs for the floating and fixed-foundation scenarios (aside from replacement rate values) are the environmental accessibility limits. A wind speed limits of 10m/s is again implemented in the floating turbine scenarios. However significant wave height and peak wave period limits are also implemented into the floating turbine scenarios to account for the wave-induced relative motion between the floating turbine and heavy lift vessel during the replacement operation. As was concluded in Chapter 4, these wave limit values are determined by the relative motion between the floating turbine and lifting vessel, and are based on analysis published by the CoreWind project [1]. The specific values used from this publication are those for the semi-submersible WindFloat turbine concept with a generic semi-submersible crane vessel in the low motion limit scenario. The maximum relative displacement values found in the medium and high scenarios are considered to be high for an offshore lifting operation. It is considered unlikely that a floating-to-floating replacement task would be carried out in higher wave height conditions than those using a jack-up vessel. Therefore, the significant wave height values taken from the CoreWind publication were limited to 2m (the jacking-up limit applied to the jack-up vessel scenarios), when values greater than this were given. The limiting significant wave height value applied at each range of peak wave period conditions are given in Table 6.7.

*Table 6.7. Wave limit inputs for floating-foundation wind farm major replacement tasks based on* [1].

| Peak wave period range (s) | Significant wave height limit (m) |
|---|---|
| <10s | 2 |
| 10 – 12s | 1 |
| 12 – 16s | 0.5 |

## 6.3 Results

This Results section will consist of four main parts. Firstly, the mean time-based wind farm availability values (based on major replacements only) and the total cost associated with major replacement tasks (consisting of vessel, repair and lost electricity costs) will be presented for the floating-foundation direct-drive turbine scenarios. This will be followed by the availability and cost results for the medium-speed turbine scenarios. Both sets of results will then be compared. Finally, the results of the floating-foundation wind turbine scenarios will be compared to the results found in Chapter 5 for the fixed-foundation wind turbine scenarios.

All results presented within this section are the mean values based on 100 simulations of each scenario.

### 6.3.1 Direct-drive turbine scenarios

Figure 6.2 shows the wind farm time-based availability values, based only on downtime from major replacement tasks, for the three floating wind farm case study locations (FL1, FL2 and FL3) at the three major replacement rate scenarios when direct-drive turbines are used. Similar to the fixed-foundation scenarios, the higher replacement rate scenarios have lower time-based availability values. As the number of maintenance tasks is increased, the amount of turbine downtime is increased and the availability decreases. From Figure 6.2, it is clear that the largest impact of high replacement rate on availability is seen at case study location FL3, which has the highest average wind speed, significant wave height and peak wave period values of the three locations (Table 6.2). In general, all case study locations achieve time-based availability values greater than 99% in the low replacement rate scenarios, however, in the high replacement rate scenarios, these values drop to as low as 94.9% at location FL3. This highlights the negative impact that the combination of high major replacement rate and harsh weather conditions can have on floating wind farm downtime related to major replacement tasks. The accessibility of location FL3 in particular is negatively impacted by the applied wave limits as the average peak wave period at the site is greater than 10s – coinciding with a large decrease in the applied wave height limit (Table 6.7).

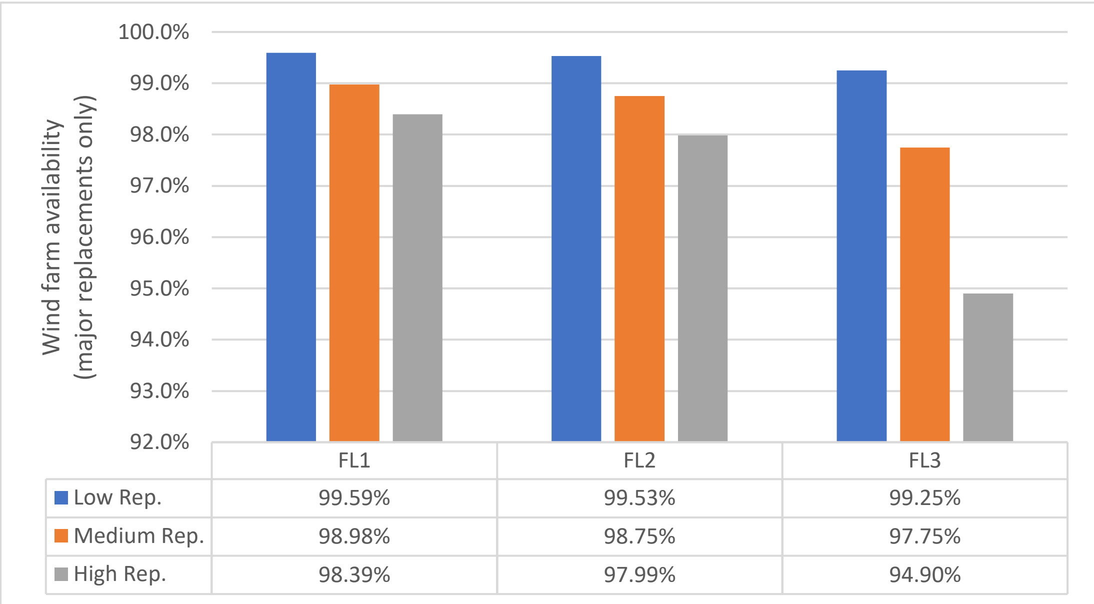
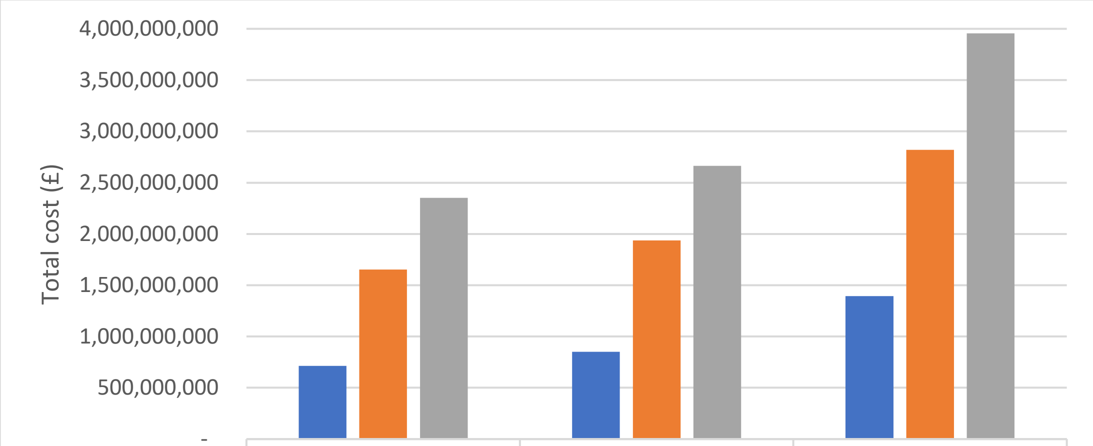



*Figure 6.2. Mean wind farm time-based availability for the three floating-foundation case study locations and three replacement rate scenarios using direct-drive turbines.*

Figure 6.3 shows the lifetime cost associated with major replacement tasks in each of the three case study locations with different major replacement rate values using the direct-drive turbines. Similar trends to that observed in the results for the fixed-foundation scenarios can be observed. The overall cost associated with major replacement tasks over the wind farm lifetime is large and varies greatly across the major replacement rate scenarios. Across all case study locations, the cost difference between the low and high replacement rate scenarios range from around £1.64-billion (FL1 – with the lowest mean climate conditions) to £2.56-billion (FL3 – with the highest mean climate conditions) – representing a ratio of around 2.84 (FL3) to 3.29 (FL1) times the cost. Additionally, there is a large cost variation across the three case study locations – in particular when comparing location FL3 to the other two locations. A cost difference of over £680-million is seen between locations FL1 and FL3 in the low replacement rate scenario and a difference of over £1.6-billion seen in the high scenario. This highlights the negative impact that the combination of high major replacement and harsh site conditions can have on the overall cost of major replacement tasks in next-generation floating-foundation wind farms.




| | FL1 | FL2 | FL3 |
|---|---|---|---|
| Low Rep. | 714,710,894 | 849,552,761 | 1,394,767,665 |
| Medium Rep. | 1,654,253,304 | 1,937,445,464 | 2,818,656,821 |
| High Rep. | 2,353,201,953 | 2,663,970,417 | 3,954,238,780 |

*Figure 6.3. Mean total cost (vessel + repair + lost electricity) of major replacements for the three floating-foundation case study locations and three replacement scenarios using direct-drive turbines.*

Figure 6.4 shows the breakdown of the total cost associated with major replacement tasks for case study location FL1 with medium replacement rate into the three contributing parts – vessel cost, repair cost and lost electricity cost. The vessel cost is again the largest contributor to the overall cost.

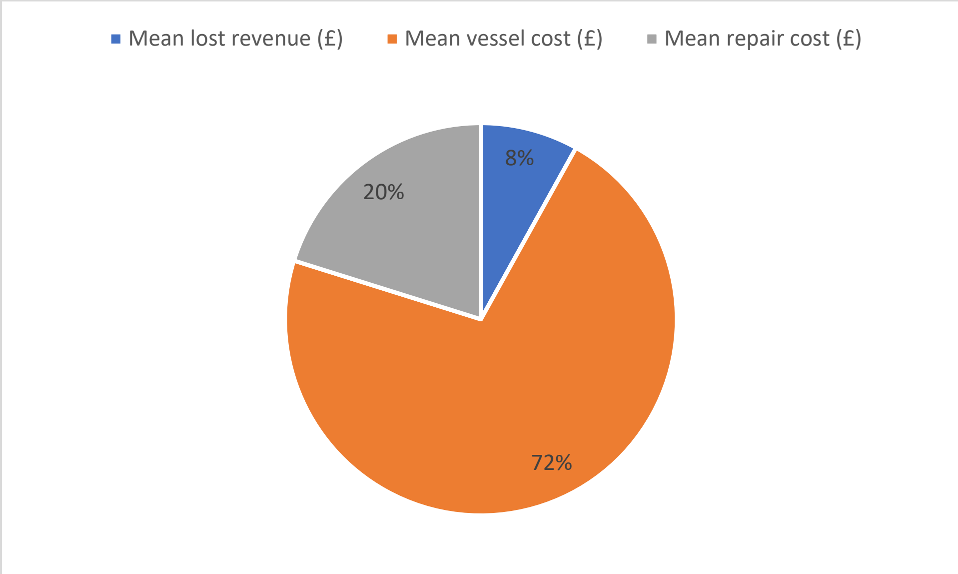



*Figure 6.4. Major replacement cost breakdown of the FL1 case study location simulation with medium replacement rate and direct-drive turbines.*

### 6.3.2 Medium-speed turbine scenarios

Figure 6.5 and Figure 6.6 show the wind farm time-based availability and total cost of major replacement values for the three floating wind farm case study locations and replacement rate scenarios when the medium-speed turbines are used. Similar trends to those reported for the floating direct-drive scenarios are observed. The wind farm availability is generally high, only dropping below 98% in the high replacement rate scenarios at location FL3. Whereas the cost values again vary by a large amount across the major replacement rate scenarios, with cost differences between the low and high replacement rate scenarios ranging from around £1.2-billion to £1.72-billion (2.32 to 3.09 times the cost) across the case study locations. Much higher cost values can again be seen at location FL3, compared to the other two locations. The breakdown of total cost of major replacement tasks for case study location FL1 with medium replacement rate is shown in Figure 6.7.

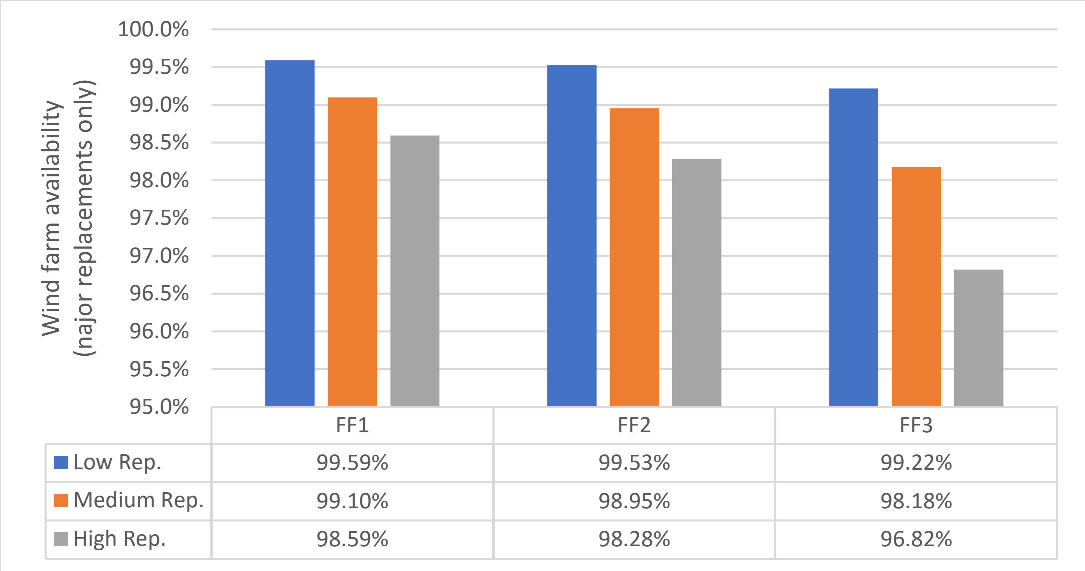



*Figure 6.5. Mean wind farm time-based availability for the three floating-foundation case study locations and three replacement rate scenarios using medium-speed turbines.*

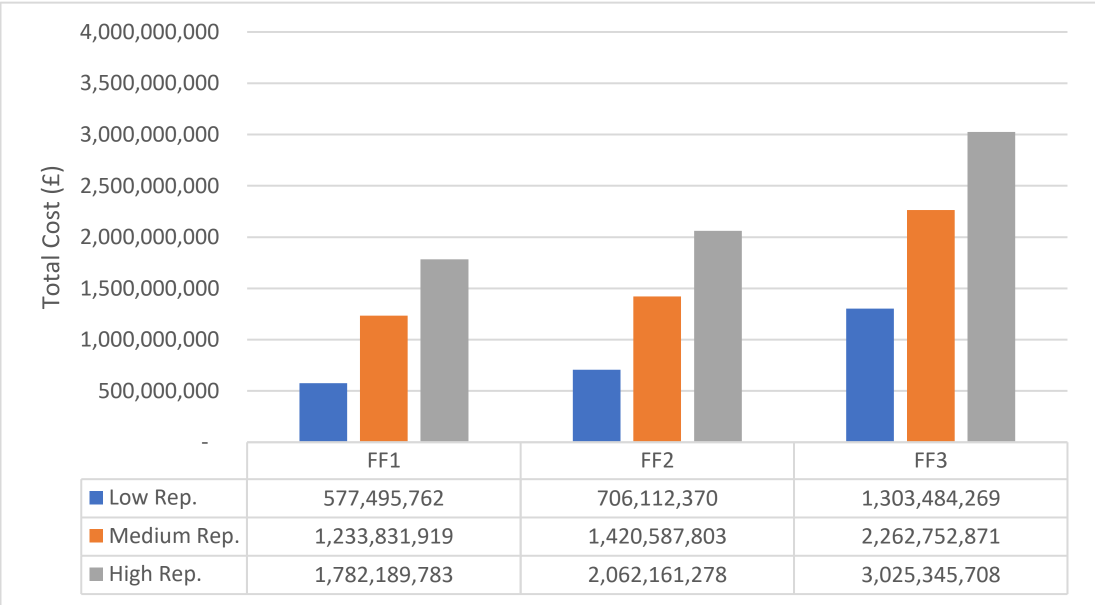



*Figure 6.6. Mean total cost (vessel + repair + lost electricity) of major replacements for the three floating-foundation case study locations and three replacement scenarios using medium-speed turbines.*

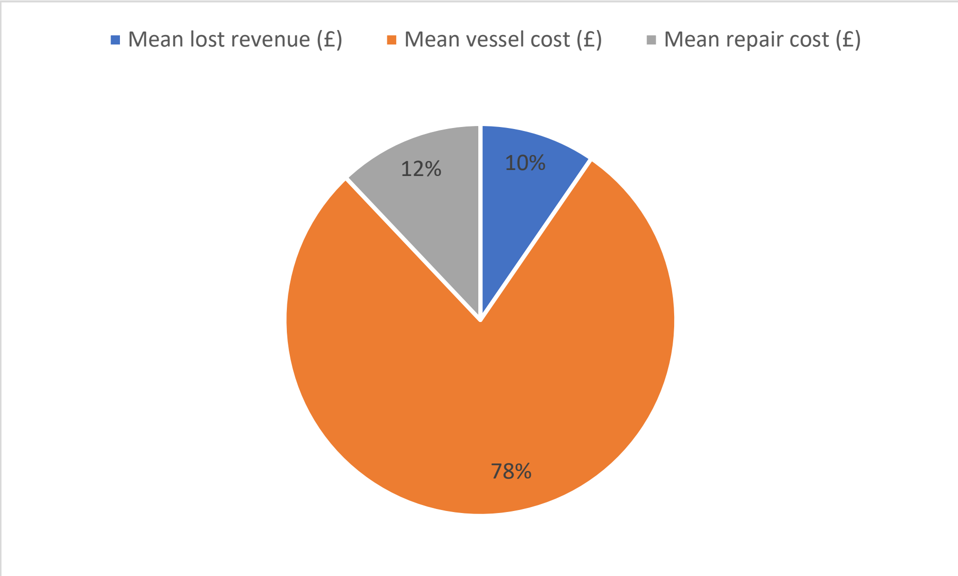
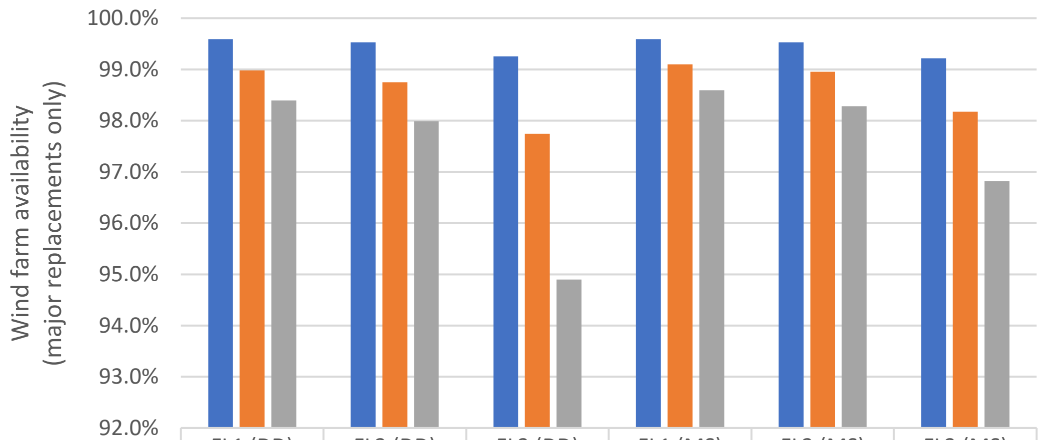



*Figure 6.7. Major replacement cost breakdown of the FL1 case study location simulation with medium replacement rate and medium-speed turbines.*

### 6.3.3 Comparison between the direct-drive and medium-speed scenarios

When comparing the results shown in the previous two sub-sections, differences can be observed between the scenarios using the direct-drive and the medium-speed turbine configurations.

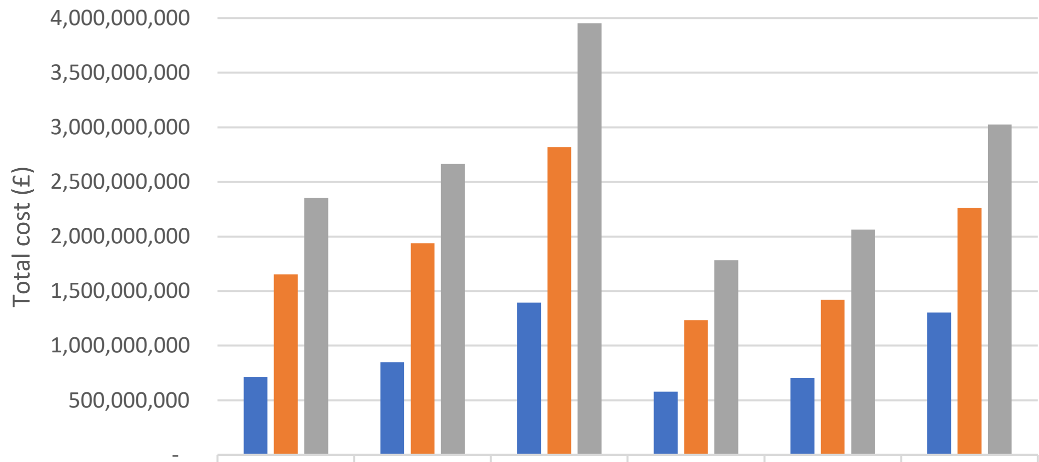
For ease of comparison, the wind farm time-based availability values from all floating-foundation simulations (already shown in Figure 6.2 and Figure 6.5) are shown together on Figure 6.8. When comparing availability values, with the exception of site FL3 with high replacement rates, there are not large differences between the values when either direct-drive or medium-speed turbines are used. However, in general, the medium-speed turbine scenarios do achieve availability values higher than, or equal to, the availability values achieved when direct-drive turbines are used. This higher availability is achieved despite the medium-speed turbines having higher major replacement rates, shown in Table 6.4. This difference in availability across the different scenarios is driven by the shorter repair time of the medium-speed turbines compared to the direct-drive turbines, as shown in Table 6.5. This shorter repair time means that a smaller weather window is required to complete the replacement task and therefore, it is less likely to be disrupted due to excessive wind and wave conditions at the site. In these scenarios, it can therefore be concluded that the increased opportunity to find suitable weather windows, due to a shorter repair time, outweighs the higher replacement rate value of the medium-speed turbine compared to the direct-drive turbines. It would therefore be expected that the impact of turbine selection on availability would be largest in the high replacement rate scenarios at location FL3, which has the harshest weather conditions, and therefore less opportunities to achieve the required weather window. Indeed, this is the case, with a difference of almost 2% between the medium-speed and direct-drive turbine scenarios.




| | FL1 (DD) | FL2 (DD) | FL3 (DD) | FL1 (MS) | FL2 (MS) | FL3 (MS) |
|---|---|---|---|---|---|---|
| Low Rep. | 99.59% | 99.53% | 99.25% | 99.59% | 99.53% | 99.22% |
| Medium Rep. | 98.98% | 98.75% | 97.75% | 99.10% | 98.95% | 98.18% |
| High Rep. | 98.39% | 97.99% | 94.90% | 98.59% | 98.28% | 96.82% |

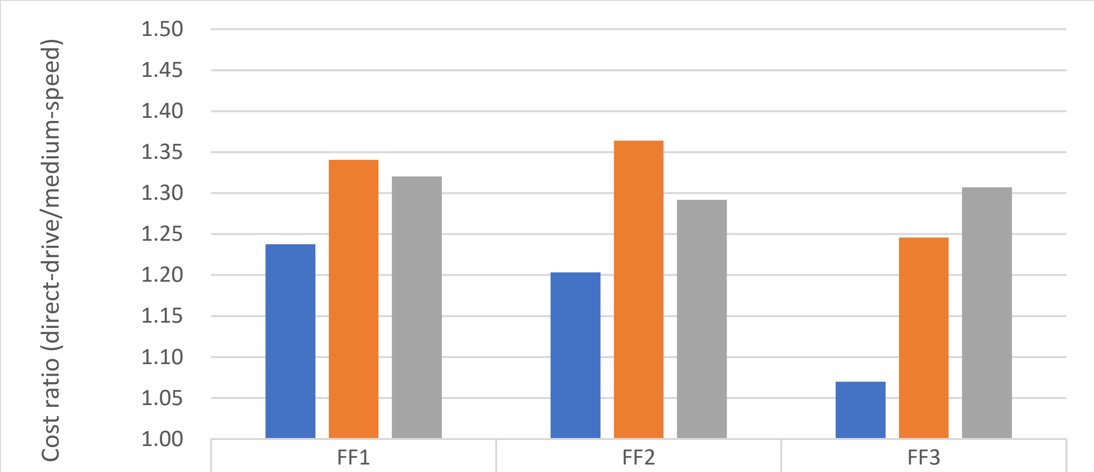
*Figure 6.8. Mean wind farm time-based availability for the three floating-foundation case study locations and three replacement rate scenarios using both direct-drive (DD) and medium-speed (MS) turbines.*

Figure 6.9 shows the total cost associated with major replacement tasks for both the floating-foundation direct-drive and medium-speed turbine scenarios already shown in Figure 6.3 and Figure 6.6. When comparing the cost values, the medium-speed turbine scenarios achieve lower lifetime costs associated with major replacement tasks across all case study locations and major replacement rate scenarios. This difference is shown more clearly in Figure 6.10, which shows the ratio of the direct-drive scenario costs against the medium-speed scenario costs. Here the costs of the direct-drive scenarios are much greater (at least 20% higher in all except one scenario) than the medium-speed scenarios. The lower cost of the medium-speed turbine scenarios is driven by two factors. Firstly, the lower repair time of the medium-speed turbines means that repairs are carried out faster and are less likely to be disrupted by unfavourable weather conditions compared to the direct-drive turbines with a longer repair time. Therefore, the lost electricity costs are generally lower in the medium-speed case studies (with the exception of the low replacement rate scenarios) and the vessel costs are lower across all scenarios, despite more vessel charters being required over the wind farm lifetime. The lifetime repair costs of the medium-speed turbine scenarios are also lower. This is due to the lower cost per repair of this configuration, despite the higher number required. The differences are shown in Figure 6.11, which compares the vessel cost, repair cost and lost electricity cost for location FL1 with medium replacement rate when both the direct-drive and medium-speed turbines are used.




| | FL1 (DD) | FL2 (DD) | FL3 (DD) | FL1 (MS) | FL2 (MS) | FL3 (MS) |
|---|---|---|---|---|---|---|
| Low Rep. | 714,710,894 | 849,552,761 | 1,394,767,665 | 577,495,762 | 706,112,370 | 1,303,484,269 |
| Medium Rep. | 1,654,253,304 | 1,937,445,464 | 2,818,656,821 | 1,233,831,919 | 1,420,587,803 | 2,262,752,871 |
| High Rep. | 2,353,201,953 | 2,663,970,417 | 3,954,238,780 | 1,782,189,783 | 2,062,161,278 | 3,025,345,708 |

*Figure 6.9. Mean total cost (vessel + repair + lost electricity) of major replacements for the three floating-foundation case study locations and three replacement scenarios using both direct-drive (DD) and medium-speed (MS) turbines.*




| | FF1 | FF2 | FF3 |
|---|---|---|---|
| Low Rep. | 1.24 | 1.20 | 1.07 |
| Medium Rep. | 1.34 | 1.36 | 1.25 |
| High Rep. | 1.32 | 1.29 | 1.31 |

*Figure 6.10. Ratio of major replacement cost (vessel + repair + lost electricity revenue) of each floating-foundation case study location at each replacement rate scenario when direct-drive turbines are used against the scenarios when medium-speed turbines are used.*

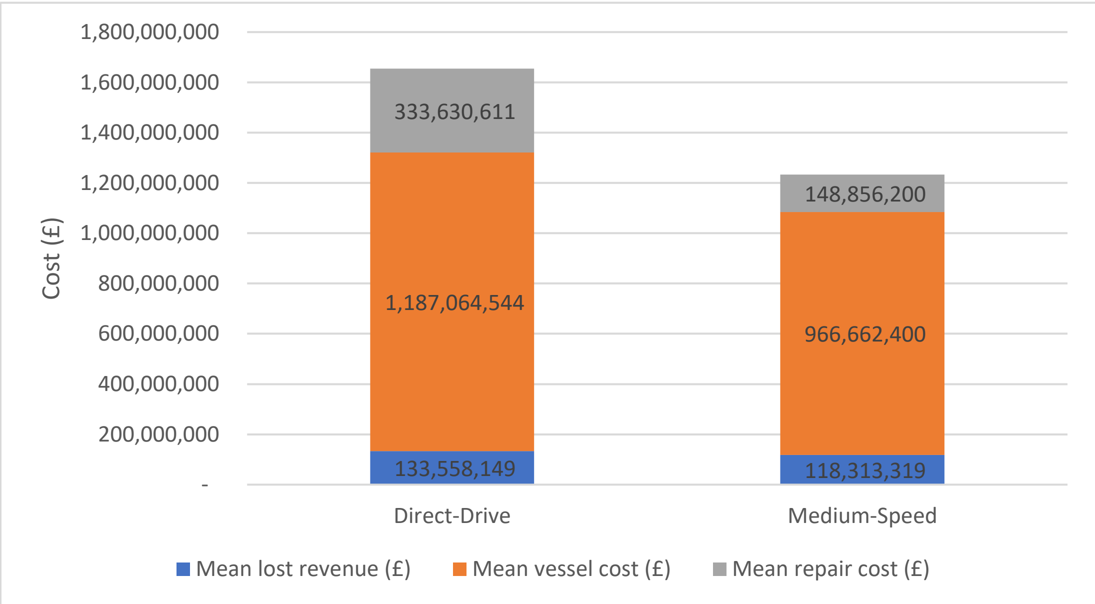
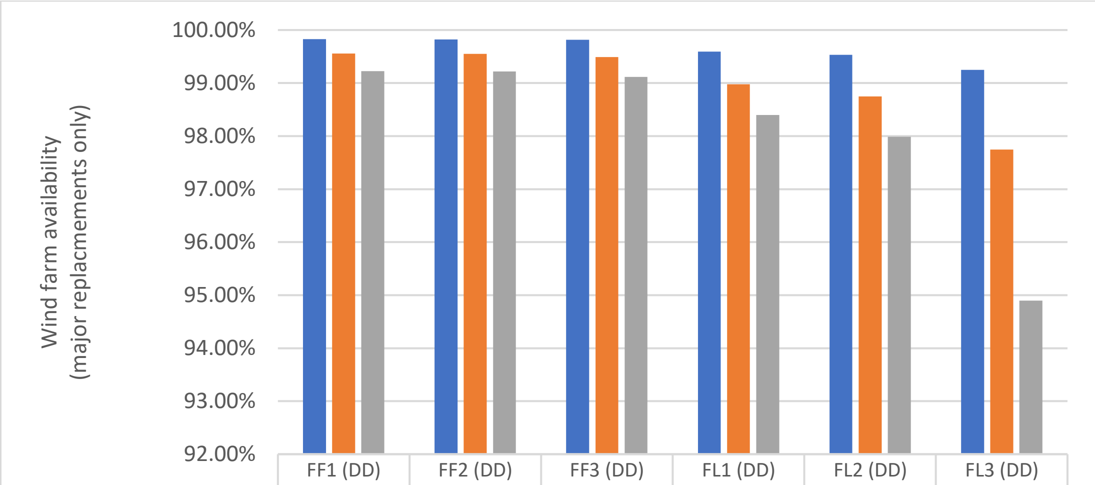



*Figure 6.11. Cost breakdown of the total lifetime cost associated with major replacement tasks at case study location FL1 in the medium replacement rate scenarios when direct-drive and medium-speed turbines are used.*

### 6.3.4 Comparison between floating-foundation and fixed-foundation turbine scenarios

When comparing these results for floating-foundation offshore wind farms to those for the fixed-foundation wind farm scenarios in Chapter 5, several differences can be seen. The differences are highlighted in this section mainly through comparison of the results for the fixed and floating foundation turbine scenarios using direct-drive turbines.

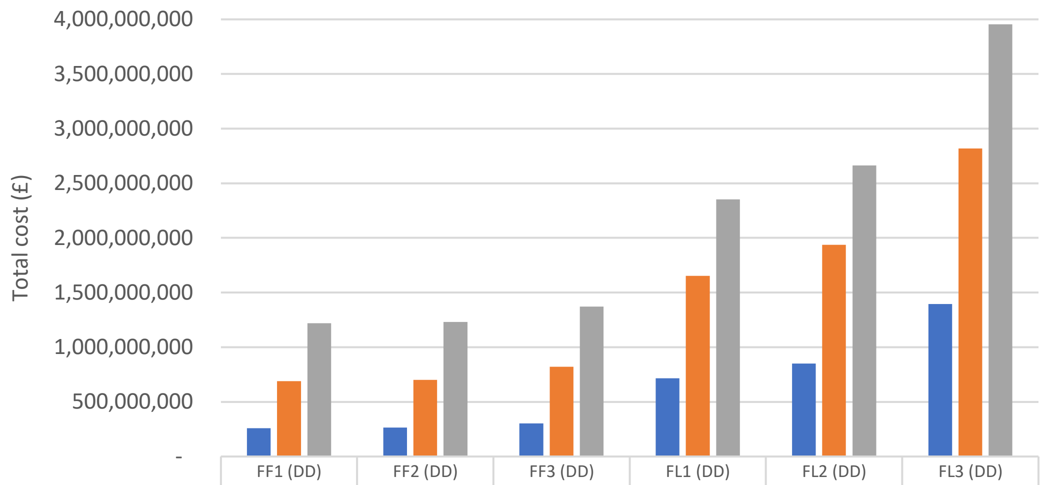
Firstly, the mean wind farm time-based availability values for the fixed and floating offshore wind farm scenarios using direct-drive turbines, already shown in Figure 5.3 and Figure 6.2, are shown together on Figure 6.12 for ease of comparison. Of course, the locations and climate conditions of the fixed and floating case study locations are different and therefore, cannot be directly compared. However, an understanding of the general trends across the different scenarios is considered to be valuable in identifying differences that may be seen when moving to commercial-scale floating wind farms and what factors may contribute to these. From Figure 6.12, the availability values of the fixed-foundation wind farm scenarios are higher and vary less across the range of replacement rate scenarios estimated for these specific turbine configurations. For example, in all nine fixed-foundation scenarios, the wind farm availability value does not fall below 99%, whereas only in the low major replacement rate scenarios are values above 99% achieved in the floating-foundation case study wind farms. The largest difference in availability between the low and high replacement rate scenarios seen in any of the fixed-foundation case study locations is 0.69%, whereas differences of up to 4.35% are seen in the floating-foundation scenarios. Within the limits of these simulations there are two main factors driving this difference. Firstly, in all scenarios, the major replacement rate of the floating turbine configurations is higher than that of the equivalent fixed-foundation turbine. This leads to a larger number of failures and more downtime associated with the floating turbines than the fixed-foundation turbines. Secondly, accessibility to complete a repair on the floating turbines is limited by three parameters – wind speed, significant wave height and peak wave period – whereas accessibility to complete a repair on the fixed turbines is based only on wind speed. The additional accessibility limitations on the floating turbines reduce the chance of achieving the required weather window, therefore leading to more downtime and lower availability. This highlights the particular impact that a combination of a high number of major replacement tasks and harsh climate conditions can have on floating offshore wind farms, compared to fixed-foundation wind farms.




| | FF1 (DD) | FF2 (DD) | FF3 (DD) | FL1 (DD) | FL2 (DD) | FL3 (DD) |
|---|---|---|---|---|---|---|
| Low Replacements | 99.83% | 99.82% | 99.81% | 99.59% | 99.53% | 99.25% |
| Medium Replacements | 99.56% | 99.55% | 99.49% | 98.98% | 98.75% | 97.75% |
| High Replacements | 99.22% | 99.22% | 99.12% | 98.39% | 97.99% | 94.90% |

*Figure 6.12. Mean wind farm time-based availability values (based on major replacements only) for three fixed-foundation wind farm case study locations (FF1, FF2 and FF3) and three floating wind farm case study locations (FL1, FL2 and FL3) with three different replacement rate scenarios (low, medium and high) using direct-drive (DD) turbines.*

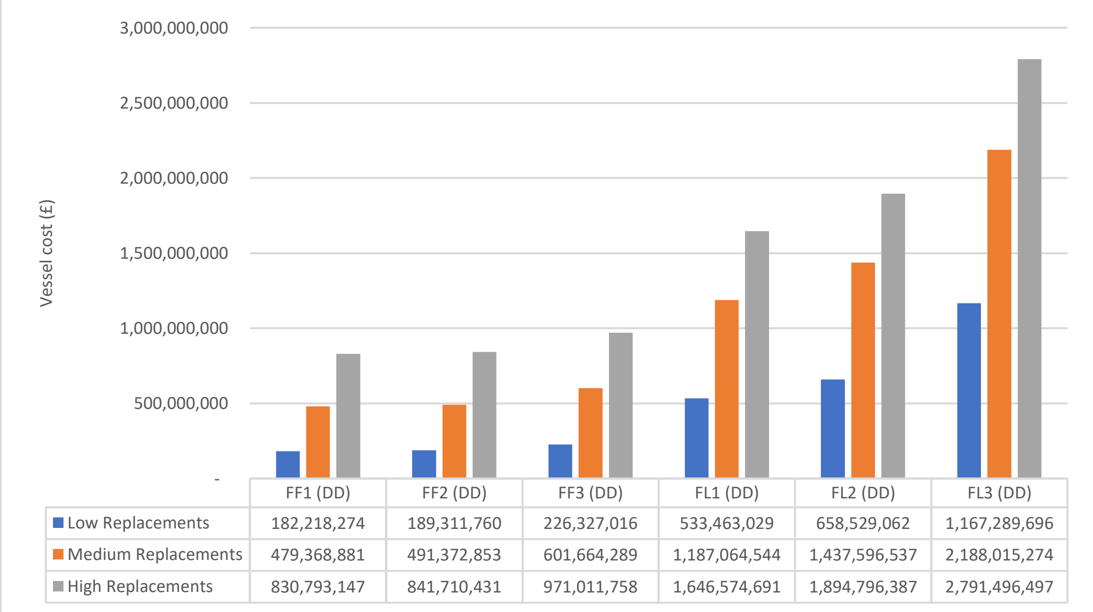
Figure 6.13 presents the total cost associated with major replacement tasks for the fixed and floating foundation scenarios where direct-drive turbines are used, already shown in Figure 5.4 and Figure 6.3. Here the costs of major replacement tasks are much lower for the fixed-foundation turbines and these costs vary much less across the range of replacement rate and site location scenarios, compared to the costs found for the floating turbine scenarios. None of the fixed-foundation scenarios exceed a cost of £1.5-billion, whereas this value is exceeded in all floating case studies, except from the low replacement rate scenarios. When comparing the cost of the low and high replacement rate scenarios for the fixed-foundation wind farm case study locations, the cost difference ranges from £960-million to £1.07-billion, whereas the differences seen in the floating scenarios range from £1.64-billion to £2.56-billion. When comparing cost values across different case study locations, for example, in the medium replacement rate scenarios, a difference of £134-million is seen between location FF1 and FF3, whereas a difference of £1.16-billion is seen between location FL1 and FL3. Again, it must be highlighted that there are a number of differing factors between these scenarios and therefore direct comparison is not a suitable approach. However, across the range of scenarios within this analysis, it is clear that the floating scenarios have higher costs associated with major replacement tasks than the fixed-foundation scenarios and that these costs vary much more with site location and across the applied range of major replacement rate values. This highlights the particular impact that poor turbine reliability, harsh climate conditions, or the combination of both, can have on the O&M cost of major replacement tasks in floating offshore wind farms compared to wind farms with fixed-foundation turbines.




| | FF1 (DD) | FF2 (DD) | FF3 (DD) | FL1 (DD) | FL2 (DD) | FL3 (DD) |
|---|---|---|---|---|---|---|
| Low Replacements | 258,310,134 | 265,702,585 | 302,033,541 | 714,710,894 | 849,552,761 | 1,394,767,665 |
| Medium Replacements | 688,527,859 | 701,689,081 | 822,140,145 | 1,654,253,304 | 1,937,445,464 | 2,818,656,821 |
| High Replacements | 1,218,531,061 | 1,230,472,250 | 1,372,271,997 | 2,353,201,953 | 2,663,970,417 | 3,954,238,780 |

*Figure 6.13. Mean total costs associated with major replacements (vessel + repair + lost electricity revenue) for three fixed-foundation wind farm case study locations (FF1, FF2 and FF3) and three floating wind farm case study locations (FL1, FL2 and FL3) with three different replacement rate scenarios (low, medium and high) using direct-drive (DD) turbines.*

The differences between the fixed and floating wind farms are driven mainly by the factors already discussed previously in the context of wind farm availability – higher replacement rate values and additional accessibility limits in the floating turbine scenarios. The floating-foundation scenarios also have slightly higher repair costs and repair times in this analysis. This combination of factors leads to higher costs across all areas for the floating turbine scenarios – vessel cost, repair cost and lost electricity cost. The vessel cost in particular is a large driver to the overall cost difference and Figure 6.14 highlights this by showing only the vessel cost in each of the direct-drive turbine scenarios (both fixed and floating). Due to the large cost associated with using the heavy lift vessels required for large component major replacements (which are assumed to be the same for both the jack-up and floating heavy lift vessel), the higher number of vessel charters in the floating case studies, along with more limited accessibility and longer waiting times, leads to much higher costs in the floating turbine scenarios.




| | FF1 (DD) | FF2 (DD) | FF3 (DD) | FL1 (DD) | FL2 (DD) | FL3 (DD) |
|---|---|---|---|---|---|---|
| Low Replacements | 182,218,274 | 189,311,760 | 226,327,016 | 533,463,029 | 658,529,062 | 1,167,289,696 |
| Medium Replacements | 479,368,881 | 491,372,853 | 601,664,289 | 1,187,064,544 | 1,437,596,537 | 2,188,015,274 |
| High Replacements | 830,793,147 | 841,710,431 | 971,011,758 | 1,646,574,691 | 1,894,796,387 | 2,791,496,497 |

*Figure 6.14. Mean vessel costs for three fixed-foundation wind farm case study locations (FF1, FF2 and FF3) and three floating wind farm case study locations (FL1, FL2 and FL3) with three different replacement rate scenarios (low, medium and high) using direct-drive (DD) turbines.*

When comparing some of the other trends identified and discussed in Chapters 5 and 6, it can also be seen that, in the fixed-foundation turbine scenarios, the direct-drive turbines achieved higher availability values, whereas higher availability was generally achieved using the medium-speed configurations in the floating wind farm scenarios. There are two main factors contributing to this difference. Firstly, the difference between the major replacement rate values of the two configurations is generally smaller in the floating-foundation scenarios and secondly, due to the additional wave limits in the floating scenarios, the shorter repair time of the medium-speed turbines contribute more benefit here than in the fixed-foundation scenarios. When comparing the cost ratio of the direct-drive against medium-speed scenarios in Figure 5.11 and Figure 6.10, it can also be seen that the relative difference between the direct-drive and medium speed scenarios is higher in the floating scenarios compared to the fixed foundation ones. This cost difference is, similar to availability, driven by the smaller difference in replacement rate values between the two floating turbine configurations and the shorter repair time of the medium-speed turbine. This shorter repair time means that the required weather window is more likely to be achieved and less waiting time, with associated expensive vessel hire cost, is required.

## 6.4 Discussion of results

Within this section, some of the key findings and results will be discussed. This includes the impact of major replacement rate and site location on major replacement cost, the impact of wind turbine drive-train configuration on major replacement cost, and discussion of how these costs differ to those for the fixed-foundation wind farm scenarios. Some of the key limitations of this analysis and areas for further investigation are also discussed.

### 6.4.1 Improved turbine reliability is important in reducing floating wind LCOE

One area of continued focus for the development of commercial-scale floating offshore wind is LCOE reduction. From the results presented in the previous section, it can be concluded that an area of importance in reducing the LCOE from floating wind is the reliability of next-generation offshore wind turbines and reducing the number of large component major replacement tasks required on floating turbines. From the existing literature it was found that the operations and maintenance phase of an offshore wind farm contributes around 20-30% of the overall LCOE and that the overall O&M cost is heavily impacted by major replacement maintenance tasks.

Within the results shown and discussed in the previous section, it was found that, within the assumptions and limitations of this analysis, the total cost associated with major replacement tasks varied by a large amount across the range of major replacement rate scenarios in all floating wind farm case study locations, with costs more than trebling in some cases between the low and high replacement rate scenarios. Large differences in major replacement costs across the range of replacement rate scenarios were also found in the fixed-foundation turbine scenarios – therefore this challenge is not unique only to floating turbines. However, the magnitude of the cost differences across the range of replacement rate scenarios is higher for the floating wind farm scenarios and the need to reduce the LCOE from floating wind farms is considered to be currently more pressing than with fixed-foundation turbines.

### 6.4.2 Site conditions can significantly impact floating wind major replacement costs

The results previously presented also show the impact of site location and weather conditions on the cost of major replacement tasks in floating offshore wind farms. Large differences in the cost values were found between the different locations, especially when comparing case study location FL3, on the North coast of Scotland and exposed to the high wave height and long wave period conditions of the Atlantic, against locations FL1 and FL2 on the east coast with the shorter wave period conditions of the North Sea. This highlights the impact that weather conditions and in particular wave conditions may have on floating wind operations and maintenance.

When comparing these differences to those found across the different fixed-foundation case study locations, also with a site (FF3) on the North coast, it was found that the major replacement costs for the fixed-foundation scenarios are much less impacted by location, with much smaller differences observed. The results highlight a potential new risk when moving from commercial-scale fixed-foundation wind farms to commercial-scale floating-foundation wind farms. Due to the impacts of wave-induced motion on the accessibility to complete major replacement tasks on floating turbines, the wave conditions at the site location will have a greater impact on the costs associated with these tasks when compared to fixed-foundation turbines. This should therefore be given consideration when selecting locations for floating wind farms and when completing cost estimates for floating offshore wind farms. More advanced vessels and replacement techniques may be required in locations with harsher wave conditions and new or updated cost models may be required than those used for fixed-foundation offshore wind farms.

### 6.4.3 Comparison between direct-drive and medium-speed floating-foundation turbines

When comparing the floating wind farm scenarios using direct-drive turbine to those using medium-speed turbines, it was found that the medium-speed turbines achieved equal or higher time-based availability values in most scenarios and lower major replacement costs in all scenarios. The differences between the different configurations are driven mainly by the lower repair time and lower repair cost for the medium-speed turbines defined within this study. The shorter repair time is of particular benefit in the floating wind farm scenarios due to the additional accessibility wave limits. Required weather windows are less likely to be encountered compared to fixed-foundation turbines which are only subject to wind speed limits during the repair task. This is seen in the generally higher availability values for the medium-speed turbines in the floating scenarios, compared to the higher availability for the direct-drive scenarios in the fixed-foundation case studies, and by the larger relative cost differences between the two configurations in the floating wind farms compared to the fixed-foundation wind farms.

These findings highlight that lower major replacement costs may be achieved by using medium-speed turbines in next-generation floating wind farms. However, the results are subject to some of the same uncertainties discussed for the comparison of direct-drive and medium-speed fixed-foundation turbines in Chapter 5.4.2. The differences are caused mainly by the cheaper repair cost and shorter repair time of the medium-speed components. Although differences are expected between the medium-speed and direct-drive configurations, and the input values have been estimated using what is considered to be the currently best available information, the true magnitude of the differences between these values is uncertain.

It should again be noted that this comparison between both turbine configurations is based only on major replacement tasks, as per the scope of this PhD project. To achieve a more holistic understanding of how the O&M costs may compare between these different turbine types, further analysis with all other failure types and maintenance tasks included would be required.

### 6.4.4 Limitations and further areas of investigation

The assumptions, limitations and suggested further areas of investigation already discussed in Chapter 5.4.3 for the O&M cost modelling of the fixed-foundation wind farm scenarios are all fully applicable to the analysis presented within this chapter.

The inputs used to model the scenarios within this chapter are subject to high levels of uncertainty, like those discussed in Chapter 5. Commercial-scale floating wind farms using large, 15MW turbines are not currently in operation and therefore no ‘real-world data’ is available for these scenarios. However, input values are estimated using what is considered to be the currently best available data, with all assumptions detailed within Chapter 5 and 6 of this thesis. As was suggested when discussing input uncertainty for the fixed-foundation turbine scenarios, approaches like structured expert elicitation can be applied to these uncertain areas to help quantify this uncertainty within a recognised framework.

The vessel charter strategy, again, may have a large impact on the results, particularly due to additional accessibility limits of the floating turbine scenarios. With less opportunity for the required weather windows to be achieved, it is possible that floating wind farms may benefit more from a selective vessel charter strategy than fixed-foundation wind farms. Therefore, the investigation of different vessel charter strategies for floating wind farm scenarios may be a very interesting area of future investigation.

Other maintenance activities, in addition to the major replacement of the selected large components, could also be included within future O&M modelling analysis to achieve a more holistic understanding of the O&M costs associated with next-generation floating offshore wind farms. It has been highlighted within this chapter that there are differences between fixed and floating foundation wind farms when considering major replacement tasks. An interesting area of future investigation would be how the key differences between fixed and floating wind farms impact less severe maintenance tasks and the costs associated with these. Although it should again be highlighted that the repair rates of these less severe tasks are currently unknown in next-generation floating wind turbines.

## 6.5 Conclusion to chapter

In the context of this PhD thesis, the aim of this chapter was to answer the following secondary research question:

*How does the total cost associated with large component major replacement tasks vary in next-generation floating-foundation wind turbines with varying replacement rate and different drive-train configuration? And how does this compare to fixed-foundation turbines?*

The main deliverable of this chapter was defined as a range of cost values associated with major replacement tasks for three different case study floating offshore wind farm locations using two different 15MW next-generation floating turbine types (direct-drive and medium-speed) and three different major replacement rate scenarios unique to these floating turbine configurations (low, medium and high). With the aim of using the results and the conclusions drawn in Chapter 7 when answering the primary research question addressed in this PhD project.

This has been comprehensively addressed within this chapter, in combination with the work previously presented in Chapter 5. It has already been found that the total lifetime cost associated with major replacement tasks varies by a large amount across the identified range of potential replacement rate values when considering large, next-generation fixed-foundation offshore wind farms. It was also found that the choice of wind turbine drive-train configurations also leads to differences in these costs for fixed-foundation wind farms. However, how the estimated range of replacement rate values for next-generation floating turbines translates through to major replacement costs and how this differs between direct-drive and medium-speed floating turbines was not known. It was also not fully understood how the cost associated with major replacement tasks may differ in floating-foundation offshore wind farms, compared to their fixed-foundation equivalents. This chapter has addressed this knowledge gap and the secondary research question posed by estimating the total cost associated with major replacement tasks across a range of case study floating offshore wind farm locations with different major replacement rate scenarios (low, medium and high) and different turbine configuration scenarios (direct-drive and medium-speed). The results are then compared against those found previously for fixed-foundation wind farms and trends identified.

This was done using the offshore wind operations and modelling tool previously described in Chapter 5, updated to include a wave period dependant significant wave height limits to account for floating turbine and vessel wave-induced motion. Major replacement rate values previously estimated within Chapter 3, specifically for 15MW floating turbine configurations, are used and other inputs are estimated based on what is considered to be the currently best available information.

This chapter started by describing the changes made to the offshore wind O&M model to include additional wave limits, before presenting the three floating wind farm case study locations used in the analysis. The key inputs to the model were then given and it was highlighted where these differ from those used in the previous fixed-foundation wind farm scenarios. The wind farm time-based availability values (based on major replacements only) and the total cost associated with major replacement tasks over the wind farm lifetime (consisting of vessel, repair and lost electricity costs) were then presented and compared across the different replacement rate and turbine configuration scenarios. The results were then compared to the results for the fixed-foundation turbine scenarios and key trends identified and discussed.

The results highlight that the O&M cost associated with major replacement tasks is highly sensitive to major replacement rate and site conditions and varies by a large amount across the range of major replacement rate values estimated for 15MW next-generation floating wind turbines. Larger cost differences were found across the range of replacement rate values and site locations, compared to the fixed-foundation wind farm scenarios, highlighting the increased importance of turbine reliability and site conditions when considering floating wind turbines. It was also found that, within the limits of this analysis, the medium-speed turbine scenarios achieved lower major replacement costs across all scenarios and that the differences found between the medium-speed and direct-drive turbines were greater than those found in the fixed-foundation wind farm scenarios. However, the uncertain nature of the inputs required in this analysis should be considered and this is also discussed within this chapter.

## 6.6 Chapter 6 references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# Chapter 7: Overall conclusions and future work

The overall research motivation for this PhD project can be summarised in the following statement:

Offshore wind turbine technology is rapidly developing. Unfortunately, as turbine technology has developed, the reporting of operational reliability data has not. Publicly available failure rate data for offshore wind turbines is extremely limited and, even if this data was reported, it may still not be representative of the next-generation of offshore wind turbines. Operations and maintenance costs contribute around 20-30% of the overall cost of energy from an offshore wind farm and this cost has been found to a) be highly dependent on failure rate values, and b) highly dependent on major replacement tasks requiring the use of a heavy lift vessel. Therefore, it can be hypothesised that there is currently a large amount of uncertainty in the future cost of energy from next-generation offshore wind farms due to the uncertain rate at which large component major replacement tasks will be required. This uncertainty is further magnified for floating offshore wind farms, where the impact of wave-induced turbine and vessel motion must be considered for these replacement tasks.

Therefore, the primary research question of this PhD project was as follows:

*"What impact can the currently unknown major replacement rate have on the cost of major replacement tasks in next-generation offshore wind turbines and how does this vary between different next-generation offshore wind turbine configurations?"*

Each chapter presented throughout this thesis has defined a secondary research question and produced certain key deliverables required in answering this primary research question. Each of these chapters have also, in their own right, provided a novel contribution to the existing literature within this field with opportunity for application in future projects and areas of research. However, at the same time, it is also recognised that the analysis presented within this report does contain a number of limitations and can be developed further across a number of interesting and highly useful areas. These areas are discussed in detail in each chapter and will not be repeated here. This concluding chapter will provide some overall conclusions from this research in addressing the overall primary research question of this PhD thesis, highlight and discuss potential areas where the results and findings from this research could be applied, and also suggest ways in which limitations could be addressed and this work could be developed further.

## 7.1 Overall conclusions

When addressing the first half of this primary research question posed by this PhD project, it is concluded that major replacement rate indeed has a large impact on the lifetime maintenance cost for next-generation offshore wind farms. This conclusion is supported by the results presented in Chapter 5 for fixed-foundation turbines and Chapter 6 for floating-foundation turbines. This is not a new or unique finding, the relationship between failure rate and O&M cost is a recurring finding throughout offshore wind O&M modelling literature. What is new and unique within this analysis, however, is that the major replacement cost associated with next-generation offshore wind farms was found to vary by a large amount across the range of replacement rate scenarios defined using the knowledge of six wind energy experts elicited using a recognised framework known as the Classical Model of structured expert elicitation. Lifetime major replacement costs were found to increase by a factor of up to 5.29 for fixed-foundation scenarios and a factor of up to 3.29 for floating-foundation turbines when comparing high and low replacement rate scenarios. The sources and assumptions around all other key values input into the model are fully described in detail, allowing the approach to be fully understood if applying the results and conclusions presented, or if a similar piece of modelling work was attempted.

Major replacement rate values for 15MW offshore wind turbines are not currently known from operational data, therefore the application of a structured framework to capture and represent expert uncertainty in this area is considered to be the first step in understanding the range that these values could take. Replacement rate values were systematically estimated and all key steps of this process, from the structuring of the questions and the selection of the experts to the aggregation of responses, have been described as transparently and in as much detail as is considered appropriate. This allows the approach to be fully understood if applying the results, or if attempting to replicate a similar study. The conclusion that there is still a large amount of uncertainty among experts in what these major replacement rate values could be and that this uncertainty translates through to a very large range of potential costs in next-generation wind farms using these turbines, highlights the potential risk and need to continuously understand and improve reliability of next-generation offshore wind turbines.

In answering the second part of this primary research question, it can be concluded that different next-generation turbine configurations can have a large impact on major replacement cost. This is again supported by the findings from Chapter 5 and Chapter 6. Due to the additional accessibility limits placed on major replacement tasks to account for wave-induced motion found to be applicable in Chapter 4, major replacement costs for floating wind farms are more likely to be negatively impacted by high replacement rates and harsh site conditions than their fixed-foundation equivalents. Chapter 6 concluded that larger lifetime cost variations are found in the floating scenarios as replacement rate and the value of weather parameters at the site are increased compared to fixed-foundation scenarios.

When comparing direct-drive and medium-speed drive train configurations, the medium-speed fixed-foundation turbines were found to achieve lower major replacement costs than fixed-foundation direct-drive turbines due largely to the lower repair costs associated with the medium-speed generator and gearbox, compared to the large and expensive direct-drive generator. Floating medium-speed turbines were also found to achieve lower major replacement costs than the floating direct-drive turbines due to lower repair cost and the lower repair time which, in combination with the additional accessibility limits placed on floating turbines, has an increased benefit in the floating wind farm scenarios. Lifetime major replacement costs of direct drive turbines were found to be up to 13% higher in some fixed-foundation scenarios and up to 36% higher in some floating scenarios.

However, there are limitations to this work. These comparisons are based only on major replacement tasks alone, and there is a large amount of uncertainty in a number of the inputs required in the O&M model. However, what is clear is that there are a number of factors to be considered when selecting a turbine type for large, next-generation offshore wind farms and that, depending on the nature of the project and site, some of these factors may be more important than others. For example, turbine configurations with higher replacement rates, but lower repair times may be preferable in sites with harsh weather conditions or with restrictive accessibility limits as shorter weather windows may be more achievable.

## 7.2 Application of results and areas for development

There are a range of findings from this PhD project which can be used and applied in future work and two of these – major replacement rate and major replacement cost – will be discussed in detail within this section.

### 7.2.1 Major replacement rate for floating wind turbines

There are a number of areas in offshore wind projects where reliability data is required. The main application of the estimated major replacement rate values is thought to be as follows:

- Offshore wind cost and risk modelling as part of wind farm development
- Research on floating wind major component replacement strategies
- Vessel demand forecasting

The major replacement rate values for different turbine configurations given in Chapter 3 can be used as inputs into the cost and risk modelling of offshore wind farms as part of the development process. Wind farm developers carry out a range of cost modelling activities when planning an offshore wind farm, for example calculating project LCOE or when doing wind farm design activities such as turbine selection. The major replacement rate values provided within this thesis can be used as inputs into these models. These values can also provide an understanding of the level of risk associated with offshore wind projects, in particular floating wind farm projects. There is currently no operational data available to show the impact that the move to floating foundations has on turbine reliability. Therefore, this work could also be used in helping wind farm developers begin to understand the comparative level of risk when developing floating wind farm projects compared to fixed-foundation projects. Table 7.1 shows the percentage difference between the major replacement rate values for the floating-foundation wind turbine configurations across the low, medium, and high replacement rate scenarios compared to the fixed-foundation equivalent with both the equal-weighting and global-weighting aggregation approaches applied in this work. These values could be used as initial metrics when trying to understand the comparative level of risk associated with floating wind farm developments.

*Table 7.1. Percentage difference between the estimated overall major replacement rate values for floating and fixed turbine configurations.*

| | Comparison to fixed-foundation equivalent | | |
|---|---|---|---|
| **Turbine configuration** | **Low replacement rate (%)** | **Medium replacement rate (%)** | **High replacement rate (%)** |
| **Floating-foundation direct-drive (GW)** | + 112.5 | + 87.5 | + 48.9 |
| **Floating-foundation medium-speed (GW)** | + 90.9 | + 40.0 | + 16.2 |
| **Floating-foundation direct-drive (EW)** | + 30.4 | + 18.0 | + 12.0 |
| **Floating-foundation medium-speed (EW)** | + 40.0 | + 14.4 | + 7.9 |

Another application of the major replacement rate values estimated in Chapter 3 is in further research comparing different approaches to major component replacement for floating wind turbines. The work presented within this thesis has focussed on the replacement of large components with a floating heavy lift vessel, however, currently floating wind major component replacement is done by towing the turbine to port and completing the repair at port [1]. There is still uncertainty around which approach will be most applicable on a commercial scale and this is an active area of research [2]. As part of a comparative analysis of different major replacement strategies, major replacement rate values will be required and the values presented within this thesis could be used as an input to these studies.

Furthermore, an area of risk for floating offshore wind at a commercial scale is the availability of heavy lift vessels or port capacity to complete the required number of major replacements of large components which may be required. It has already been highlighted that there are currently no vessels available on the market with the capability to replace large components on a 15MW floating turbine [3]. There are also concerns about available port capacity for the floating wind in general – assembly of floating turbines, as well as operations and maintenance [4]. To understand the future need for vessel and port availability, a forecasting of demand based on the required replacement rate of large components would be a worthwhile activity. These major replacement rate values could a be input into such analysis.

There are also a number of ways in which the estimation of next-generation offshore wind turbine reliability could be expanded. A valuable area of further development could be to expand the use of structured expert elicitation to minor and major repair activities for different wind turbine components in addition to the major replacement activities estimated within this work. The rates of these repair activities are required inputs for O&M models when estimating the total wind farm OPEX cost and are also currently uncertain for next-generation turbines, particularly floating turbines.

Expanding the scope of the expert elicitation work completed during this PhD project to include these less substantial repair activities was considered. However, this would have led to a much larger number of questions for the experts to consider – increasing the interview time and the cognitive load on the experts. However, this could be an area of focus for future elicitation studies. Due to the large number of different turbine components, an approach like the Classical Model may be too resource intensive to apply across a number of different turbine configurations. However, an elicitation activity based around online surveys, similar to that applied by Wiser et al. [5] or Moverley Smith et al. [6] could be a way to do this in a less resource intensive way. Alternatively, an approach like the Classical Model could be applied to the variable of, for example, minor repair activities at turbine level rather than at individual component level. This would reduce the number of variables of interest and make the scope of the elicitation more manageable.

### 7.2.2 Major replacement cost of floating wind farms

The lifetime cost of major replacement activities for different next-generation wind farm scenarios found through this research can also be used by developers in building up a profile of lifetime project cost and project risk for future offshore wind farms and in general offshore wind cost modelling activities.

One way in which these cost values from Chapter 5 and Chapter 6 can be easily applied in future analysis is by converting these lifetime cost values for the entire wind farm into a cost per MW per year. These values can then be used in simple, parametric cost models to quickly estimate the cost associated with different wind farm scenarios. The lifetime major replacement cost values (repair cost + vessel cost) from the different scenarios modelled in Chapter 5 and Chapter 6 have been converted to a cost per MW per year and are given in Table 7.2. The range of cost values are based on the different replacement rate scenarios modelled. The cost values in Table 7.2 can be used to quickly estimate the cost of major replacement tasks across wind farms with different turbine configurations and locations and can be extrapolated to estimate different wind farm sizes.

*Table 7.2. Range of major replacement cost values per MW per year (repair + vessel cost) for the different wind farm scenarios modelled in Chapters 5 and 6.*

| Scenario | Range of major replacement costs per MW per year (£k/MW.yr) |
|---|---|
| **FF1 (DD)** | 6.5 – 30.6 |
| **FF2 (DD)** | 6.7 – 31.0 |
| **FF3 (DD)** | 7.6 – 34.5 |
| **FF1 (MS)** | 5.6 – 29.9 |
| **FF2 (MS)** | 5.9 – 29.6 |
| **FF3 (MS)** | 7.0 – 33.4 |
| **FL1 (DD)** | 17.6 – 57.2 |
| **FL2 (DD)** | 21.0 – 64.0 |
| **FL3 (DD)** | 34.6 – 88.0 |
| **FL1 (MS)** | 14.0 – 42.6 |
| **FL2 (MS)** | 17.1 – 48.8 |
| **FL3 (MS)** | 32.0 – 69.6 |

When comparing the values shown in Table 7.2, the cost of major replacement tasks for floating wind farms are higher than the costs found for the fixed-foundation wind farm scenarios. As has already been discussed in Chapter 6, this difference is driven by the higher replacement rate values and the additional wave limits applied to the floating wind turbine scenarios. This raises some interesting discussion points for the development of floating wind farm projects.

It has already been highlighted throughout this thesis that the cost of major replacement tasks is a large contributor to overall O&M cost and wind farm LCOE. Therefore, the difference in major replacement cost between fixed-foundation and floating-foundation wind farms suggests that it will be challenging for large floating wind farms to reach similar LCOE values to those expected for next-generation fixed-foundation wind farms, assuming replacements using a floating heavy lift vessel. Given the current focus on reducing the cost of floating wind to similar levels as fixed wind, it should be kept in mind that there are additional challenges associated with operating and maintaining floating wind farms. This may make it challenging for floating wind farms to directly compete against fixed wind farms in financing auctions.

However, it has already been stated that the two key drivers for the cost difference in this analysis was the higher replacement rate values for floating turbines and the additional wave limits placed on the tasks in the O&M model. Therefore, a potential area of focus for reducing the cost difference associated with major replacement tasks between floating and fixed-foundation wind farms could be to improve the reliability of floating wind turbines. This could potentially be done through developing floating-specific turbine designs, or through increased monitoring and minor repair activities for floating turbines. Another potential future area of focus could be to have less restrictive wave limits for floating to floating heavy lift operations through advanced vessel design with motion compensation or designing the floating turbine system in a way which focusses on minimising nacelle motion or allows for quick component exchange.

As the largest contributor to the lifetime cost of major replacement tasks was found to be the vessel cost, another approach to reducing this cost for a floating wind farm could be the use of alternative major component replacement strategies which do not require expensive floating heavy lift vessels. The tow to shore strategy is currently being utilised when a major component replacement is required on floating turbines. However, it is still not clear if this is the most suitable strategy on a commercial scale. Other approaches, for example a turbine-mounted crane is another option that is currently being investigated for floating wind major component replacement [2]. These alternative approaches may have the potential to reduce major component replacement costs if found to be effective.

There are also a number of ways in which the O&M cost modelling analysis presented within this PhD thesis could be developed and expanded.  An area that has been highlighted throughout this thesis is the uncertainty around inputs required for modelling of different scenarios. This is a common challenge when modelling any uncertain future scenario, particularly in an area developing as rapidly as offshore wind. An attempt has been made within this PhD project to reduce the uncertainty in some of these values, for example the estimation of major replacement rate values and the estimation of wave limit values. However, other areas such as repair times are uncertain as turbines increase beyond the of existing jack-up vessels, floating-to-floating heavy lift tasks are required and lifting technologies and techniques develop and improve. Repair costs for large turbine components are also uncertain and influenced market conditions for raw materials in the supply chain and vessel costs and mobilisation times are highly uncertain as new next-generation vessels are required with high demand likely to influence costs. Attempts have been made to estimate these values based on what is considered to be the currently best available information, with any assumptions fully explained. As the industry continues to develop, more information on these areas should become available, but for now, any research into further understanding what these values could be would be valuable to reducing the uncertainty in these scenarios.

The final area highlighted for future investigation here is the impact of different vessel charter strategies on major replacement costs. Within the work presented in Chapter 5 and Chapter 6, a fix on fail strategy was assumed with the vessel remaining on site until outstanding repairs are completed. However, in practice, it is likely that heavy lift vessels would be selectively hired at certain times of year for defined periods of time. It would be of interest to discover the impact that placing some of these limitations on vessel hire would have on the major replacement cost values produced across the range of replacement rate and turbine configuration scenarios, and whether any of the trends identified would differ from those highlighted within this report.

## 7.3 Chapter 7 references


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[2] Carbon Trust, “Floating Wind Joint Industry Project: Phase III summary report,” 2021.

[3] M. A. Schwarzkopf *et al.*, “Corewind D4.2 Floating Wind O&M Strategies Assessment,” 2021.

[4] Crown Estate Scotland, "Ports for offshore wind," 2020.

[5] R. Wiser *et al.*, "Expert elicitation survey predicts 37% to 49% declines in wind energy costs by 2050," *Nat. Energy*, vol. 6, pp. 555–565, 2021.

[6] B. Moverley Smith, R. Clayton, A. H. van der Weijde, and P. R. Thies, "Evaluating technical and financial factors for commercialising floating offshore wind: A stakeholder analysis," *Wind Energy*, vol. 25, pp. 1959–1972, 2022.

# Appendices

## Appendix I: Full set of questions on variables of interest

Based on offshore data, the average number of major replacements for a generator in a fixed bottom, 2-4MW turbine with high-speed gearbox and induction generator over the first 8 years is estimated to be around *0.095 replacements/ turbine.yr.*

1. By what percentage do you think the average number of major replacements for a generator will change for a fixed bottom, 15MW, direct-drive turbine with a permanent magnet synchronous generator over the same time period?

| | | |
|---|---|---|
| | | |
| 5$^{th}$ percentile | 95$^{th}$ percentile | 50$^{th}$ percentile |

Reasons for answer:

Based on offshore data, the average number of major replacements for a generator for a fixed bottom, 2-4MW turbine with high-speed gearbox and induction generator over the first 8 years is estimated to be around *0.095 replacements/ turbine.yr.*

2. By what percentage do you think the average number of major replacements for a generator will change for a semi-submersible floating, 15MW, direct-drive turbine with a permanent magnet synchronous generator over the same time period?

| | | |
|---|---|---|
| | | |
| 5$^{th}$ percentile | 95$^{th}$ percentile | 50$^{th}$ percentile |

Reasons for answer:

Based on offshore data, the average number of major replacements for part of the rotor (blade or hub) for a fixed bottom, 2-4MW turbine with high-speed gearbox and induction generator over the first 8 years is estimated to be around *0.002 replacements/ turbine.yr.*

3. By what percentage do you think the average number of major replacements for part of the rotor (blade or hub) will change for a fixed bottom, 15MW, direct-drive turbine with a permanent magnet synchronous generator over the same time period?

| | | |
|---|---|---|
| | | |
| 5th percentile | 95th percentile | 50th percentile |
| Reasons for answer: | | |

Based on offshore data, the average number of major replacements for part of the rotor (blade or hub) for a fixed bottom, 2-4MW turbine with high-speed gearbox and induction generator over the first 8 years is estimated to be around *0.002 replacements/ turbine.yr.*

4. By what percentage do you think the average number of major replacements for part of the rotor (blade or hub) will change for a semi-submersible floating, 15MW, direct-drive turbine with a permanent magnet synchronous generator over the same time period?

| | | |
|---|---|---|
| | | |
| 5th percentile | 95th percentile | 50th percentile |
| Reasons for answer: | | |

Based on offshore data, the average number of major replacements for a generator for a fixed bottom, 2-4MW turbine with high-speed gearbox and induction generator over the first 8 years is estimated to be around *0.095 replacements/ turbine.yr.*

5. By what percentage do you think the average number of major replacements for a generator will change for a fixed bottom, 15MW turbine with medium-speed gearbox and permanent magnet synchronous generator over the same time period?

| | | |
|---|---|---|
| | | |
| $5^{th}$ percentile | $95^{th}$ percentile | $50^{th}$ percentile |
| Reasons for answer: | | |

Based on offshore data, the average number of major replacements for a generator for a fixed bottom, 2-4MW turbine with high-speed gearbox and induction generator over the first 8 years is estimated to be around *0.095 replacements/ turbine.yr.*

6. By what percentage do you think the average number of major replacements for a generator will change for a semi-submersible floating, 15MW turbine with medium-speed gearbox and permanent magnet synchronous generator over the same time period?

| | | |
|---|---|---|
| | | |
| $5^{th}$ percentile | $95^{th}$ percentile | $50^{th}$ percentile |
| Reasons for answer: | | |

Based on offshore data, the number of major replacements for a gearbox for a fixed bottom, 2-4MW turbine with high-speed gearbox and induction generator over the first 8 years is estimated to be around *0.154 replacements/ turbine.yr.*

7. By what percentage do you think the average number of major replacements for a gearbox will change for a fixed bottom, 15MW turbine with medium-speed gearbox and permanent magnet synchronous generator over the same time period?

| | | |
|---|---|---|
| | | |
| 5th percentile | 95th percentile | 50th percentile |

Reasons for answer:

Based on offshore data, the number of major replacements for a gearbox for a fixed bottom, 2-4MW turbine with high-speed gearbox and induction generator over the first 8 years is estimated to be around *0.154 replacements/ turbine.yr.*

8. By what percentage do you think the average number of major replacements for a gearbox will change for a semi-submersible floating, 15MW turbine with medium-speed gearbox and permanent magnet synchronous generator over the same time period?

| | | |
|---|---|---|
| | | |
| 5th percentile | 95th percentile | 50th percentile |

Reasons for answer:

Based on offshore data, the average number of major replacements for part of the rotor (blade or hub) for a fixed bottom, 2-4MW turbine with high-speed gearbox and induction generator over the first 8 years is estimated to be around 0.002 *replacements/ turbine.yr.*

9. By what percentage do you think the average number of major replacements for part of the rotor (blade or hub) will change for a fixed bottom, 15MW turbine with medium-speed gearbox and permanent magnet synchronous generator over the same time period?

| | | |
|---|---|---|
| | | |
| 5$^{th}$ percentile | 95$^{th}$ percentile | 50$^{th}$ percentile |

Reasons for answer:

Based on offshore data, the average number of major replacements for part of the rotor (blade or hub) for a fixed bottom, 2-4MW turbine with high-speed gearbox and induction generator over the first 8 years is estimated to be around 0.002 *replacements/ turbine.yr.*

10. By what percentage do you think the average number of major replacements for part of the rotor (blade or hub) will change for a semi-submersible floating, 15MW turbine with medium-speed gearbox and permanent magnet synchronous generator over the same time period?

| | | |
|---|---|---|
| | | |
| 5$^{th}$ percentile | 95$^{th}$ percentile | 50$^{th}$ percentile |

Reasons for answer:

## Appendix II: Full set of seed questions

| Based on onshore data, the average failure rate for geared turbines with rated power between 300kW and 1 MW was found to be 0.46 failures/turbine.yr.<br><br>1. By what percentage do you think the average failure rate will change for geared turbines with rated power between 1MW and 3MW? | | |
|---|---|---|
| | | |
| 5th percentile | 95th percentile | 50th percentile |
| Reasons for answer: | | |

| Based on onshore data, the average failure rate for geared, DFIG turbines with rated power between 850kW and 1.5MW was found to be 0.53 failures/turbine.yr.<br><br>2. By what percentage do you think the average failure rate will change for geared, DFIG turbines with rated power between 1.8MW and 2MW? | | |
|---|---|---|
| | | |
| 5th percentile | 95th percentile | 50th percentile |
| Reasons for answer: | | |

| Based on different onshore data, the average failure rate for geared, induction generator turbines with rated power of 600kW was found to be 1.86 failures/turbine.yr.<br><br>3. By what percentage do you think the average failure rate will change for direct-drive, synchronous generator turbines with the same rated power? | | |
|---|---|---|
| | | |
| 5th percentile | 95th percentile | 50th percentile |
| Reasons for answer: | | |

| |
|---|
| Based on onshore data, the average failure rate of the generator for geared, induction generator turbines with rated power of 600kW was found to be 0.09 failures/turbine.yr.<br><br>4. By what percentage do you think the average failure rate of the generator will change for direct-drive, synchronous generator turbines with the same rated power? |

| | | |
|---|---|---|
| | | |
| 5th percentile | 95th percentile | 50th percentile |
| Reasons for answer: | | |

| |
|---|
| Based on onshore data, the average failure rate of a blade for geared, induction generator turbines with rated power of 600kW was found to be 0.17 failures/turbine.yr.<br><br>5. By what percentage do you think the average failure rate of a blade will change for direct-drive, synchronous generator turbines with the same rated power? |

| | | |
|---|---|---|
| | | |
| 5th percentile | 95th percentile | 50th percentile |
| Reasons for answer: | | |

| |
|---|
| Based on different onshore data, the average failure rate of the generator for geared, DFIG turbines with rated power between 1.5 MW and 2.5MW was found to be 0.12 failures/turbine.yr.<br><br>6. By what percentage do you think the average failure rate of the generator will change for geared, permanent magnet synchronous generator turbines with the same rated power? |

| | | |
|---|---|---|
| | | |
| 5th percentile | 95th percentile | 50th percentile |
| Reasons for answer: | | |

| |
|---|
| Based on onshore data, the average failure rate for geared, DFIG turbines with rated power of 1.5MW was found to be 0.24 failures/turbine.yr.<br><br>7. By what percentage do you think the average failure rate will change for geared, DFIG turbines with rated power of 2MW? |

| | | |
|---|---|---|
| | | |
| 5th percentile | 95th percentile | 50th percentile |
| Reasons for answer: | | |

| |
|---|
| Based on onshore data, the average failure rate of the generator for geared, DFIG turbines with rated power of 1.5MW was found to be 0.03 failures/turbine.yr.<br><br>8. By what percentage do you think the average failure rate of the generator will change for geared, DFIG turbines with rated power of 2MW? |

| | | |
|---|---|---|
| | | |
| 5th percentile | 95th percentile | 50th percentile |
| Reasons for answer: | | |

| |
|---|
| Based on onshore data, the average failure rate of the gearbox for geared, DFIG turbines with rated power of 1.5MW was found to be 0.01 failures/turbine.yr.<br><br>9. By what percentage do you think the average failure rate of the gearbox will change for geared, DFIG turbines with rated power of 2MW? |

| | | |
|---|---|---|
| | | |
| 5th percentile | 95th percentile | 50th percentile |
| Reasons for answer: | | |

| |
|---|
| Based on onshore data, the average failure rate of a blade for geared, DFIG turbines with rated power of 1.5MW was found to be 0.05 failures/turbine.yr.<br><br>10. By what percentage do you think the average failure rate of a blade will change for geared, DFIG turbines with rated power of 2MW? |

| | | |
|---|---|---|
| | | |
| $5^{th}$ percentile | $95^{th}$ percentile | $50^{th}$ percentile |
| Reasons for answer: | | |

# Appendix III: Expert list

The names of the experts who were interviewed as part of this work are given below.

Any opinions given by experts as part of this work are those of the experts themselves at the time of, and in the context of, the interview sessions and may not be representative of the opinions of their respective companies or institutions.

It should also be noted that the results presented are aggregated results of the group, and therefore may not be representative of the opinions of the individual experts making up the group.

- Dr Iain Dinwoodie
- Prof. Alasdair McDonald
- Dr Amir Nejad
- Dr Roberts Proskovics
- Dr Peter Tavner, Eur Ing, FIET, Emeritus Professor
- Dr Graeme Wilson