Cost of energy modelling and reduction opportunities for offshore wind turbines

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Abstract

The cost of generating electricity from wind turbines, particularly offshore wind turbines is currently too high. To ensure offshore wind energy is truly competitive with traditional fossil fuel and nuclear energy generation, the true cost of offshore wind energy and ways of reducing that cost must be investigated. A number of wind turbine types, differentiated through their drive train configurations, currently exist. Different wind turbine manufacturers have different drive train configurations and some manufacturers have multiple configurations within their own portfolio of turbines. There is no clear evidence as to which wind turbine drive train type is best suited to offshore sites.

One way of determining which turbine drive train type is best suited to an offshore wind farm is by investigating which turbine type offers the lowest cost of energy. This thesis provides a detailed analysis of the cost of energy for different offshore wind turbine types and investigates ways in which that cost of energy can be reduced. The highest level research question amongst all of the research questions answered in this work is: "What is the overall cost of energy for different wind turbine types and how can it be reduced?"

To answer that research question the author starts off in Chapter 1 by outlining the thesis objective and describing all of the other research questions that must be answered to achieve that objective. The following chapters then provide background and contain novel analyses on the variables that are required to calculate the cost of energy. Chapter two looks at the failure rates of different wind turbine types and includes novel failure rate field analysis of on and offshore wind turbines. Chapter 3 estimates O&M costs and availabilities for 4 different wind turbine types at a number of different hypothetical offshore sites. Chapter 4 estimates the cost of energy of the four different wind turbine types for a number of hypothetical offshore sites. Chapter 5 then investigates ways of reducing the overall cost of energy from offshore wind. Lastly, Chapter 6 concludes the thesis.

Results from each chapter are novel and provide some new insight into the variables that contribute towards calculating the cost of energy. The thesis concludes that across all sites examined, the turbine type that offers the lowest cost of energy is the direct drive permanent magnet generator with a fully rated converter. The vessel strategy that offered the lowest cost of energy with this turbine type was the fix on fail strategy across all sites and further cost of energy savings could be made through the use of condition monitoring systems, performance based maintenance contracts or through the reduction in the need for heavy lift vessels through in-built lifting or large component modularity.

The results shown in this thesis will be useful for wind farm developers, operators and wind turbine manufacturers. Developers can use the results to assist in the selection of turbine types. Operators can gain an insight into what is driving their O&M costs and manufactures can see which wind turbine drive train type to develop and manufacture to satisfy one of their key customer requirements, a lower cost of energy.

Acknowledgements

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I am also very grateful to my friends from the 2012 CDT cohort, I really enjoyed our nights out in the first couple of years of this PhD and the FPL in the latter years. I would like to thank my friends outside of the CDT for taking my mind off my PhD whenever I needed it. Finally, and most importantly I would like to thank Eilidh, her family, my brothers Dan and Joe and my parents Phil and James for everything they do and have done for me.

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Nomenclature

Roman Letters

Symbol	*Description*
d	Discount rate
E_i	Expected failures in time period I
I	Number of intervals for which data are collected
K	Number of subassemblies
$n_{i,k}$	Number of failures
N_i	Number of turbines
n	Operational life
O_i	Observed failures in time period i
t	Time
T	Corporate tax rate
T_i	Total time period

Greek Letters

Symbol	*Description*
β	Shape parameter
λ	Failure rate per turbine per year
$\lambda(t)$	Failure rate as a function of time
ρ	Scale parameter

Abbreviations

Letters	*Description*
AE	Acoustic Emissions
AEP	Annual Energy Production
AM02	Asset Management 02
AOM	Active Output Management
BoP	Balance of Plant
CAPEX	Capital Expenditure
CBM	Condition Based Maintenance

CMS	Condition Monitoring Systems
CoE	Cost of Energy
CTV	Crew Transfer Vessel
DFIG	Doubly Fed Induction Generator
DFM	Design for Maintenance
EPSA	Extended Parts and Services Agreement
FCR	Fixed Charge Rate
FEED	Front End Engineering Design
FFT	Fast Fourier Transform
FINO	Forschungsplattformen in Nord- und Ostsee
FMEA	Failure Modes and Effect Analysis
FoF	Fix on Fail
FRC	Fully Rated Converter
FSA	Full Service Agreement
HLV	Heavy Lift Vessel
HPP	Homogenous Poisson Process
ICC	Initial Capital Costs
IGBT	Insulated Gate Bipolar Transistor
kWh	Kilowatt-hour
LWK	Landwirtschaftskammer
MTBF	Mean Time between Failures
MTTF	Mean Time to Failure
MTTR	Mean Time to Repair
MW	Mega-Watt
MWh	Megawatt-hour
NREL	National Renewable Energy Lab (USA)
O&M	Operations and Maintenance
OA	Oil Analysis
OEM	Original Equipment Manufacturer
OPEX	Operational Expenditure
OREDA	Offshore and Onshore Reliability Data
PBMC	Performance Based Maintenance Contract
PLP	Power Law Process
PMG	Permanent Magnet Generator

PMSG	Permanent Magnet Synchronous Generator
PRC	Partially Rated Converter
REMM	Reliability Enhancement Methodology and Modelling
SCADA	Supervisory Control and Data Acquisition
SCIG	Squirrel Cage Induction Generator
SQL	Structured Query Language
TBF	Time Between Failures
TBM	Time Based Maintenance
VA	Vibration Analysis
WSD	Wind Stats Deutschland
WRSG	Wound Rotor Synchronous Generator

Chapter 1 Introduction

1.1 Thesis overview

The cost of energy (CoE) provides a way of measuring the cost of generating electricity from an energy generation method. It is a metric used to evaluate and compare the cost of generating electricity from different sources and projects. There are different methods of calculating the CoE but generally it eventually breaks down to the sum of all costs in a time period divided by the amount of energy produced in that given time period to give a cost per kWh or MWh. The CoE is calculated based on inputs such as capital costs, operational costs, energy production and so on. A full explanation and the formula required to calculate the CoE are provided in Chapter 4.

Governments, researchers and industry are trying to reduce the Cost of Energy of offshore wind (e.g. [1]), which currently has a higher cost than onshore wind and other commercially viable power plant technologies [2]. Developers and investors are investigating the optimal balance between reduced capital investment, operating costs and risk, and increased energy conversion to maximise revenue. Choosing between competing wind turbine and wind farm enabling technologies is a key way for achieving industry-wide and project-specific cost reduction goals.

In terms of wind turbine and wind farm technology innovations, there are many technical choices that have differing effects on the capital cost, operating costs, energy capture and risks. A report by BVG on behalf of The Crown Estate investigated technical innovations and their potential for reducing Cost of Energy for offshore wind. They developed a ranking of technology innovations, illustrated in Table 1.1 [1].

Table 1.1: Technical innovations and their relative potential impacts on Cost of Energy of a typical offshore wind farm [1].

Innovation	**Relative impact of innovations on LCOE**
Increase in turbine power rating	-8.5%
Optimisation of rotor diameter, aerodynamics, design and manufacture	-3.7%
Introduction of next generation drive trains	-3.0%

Improvements in jacket foundation design and manufacturing	-2.8%
Improvements in aerodynamic control	-1.9%
Improvements in support structure installation	-1.9%
Greater level of array optimization and front end engineering design (FEED)	-1.2%
About 30 other innovations	-5.6%

The top two, to some extent, can be achieved by optimising existing designs, for example up scaling current technologies to increase the turbine power rating and optimizing rotor diameters. The biggest innovation is the selection of drive train and associated equipment (i.e. torque speed conversion, electrical machine and power conversion) which requires a choice between competing technologies. A survey of current designs of large wind turbines, Figure 1.1, reveals a variety of drive train technology choice.

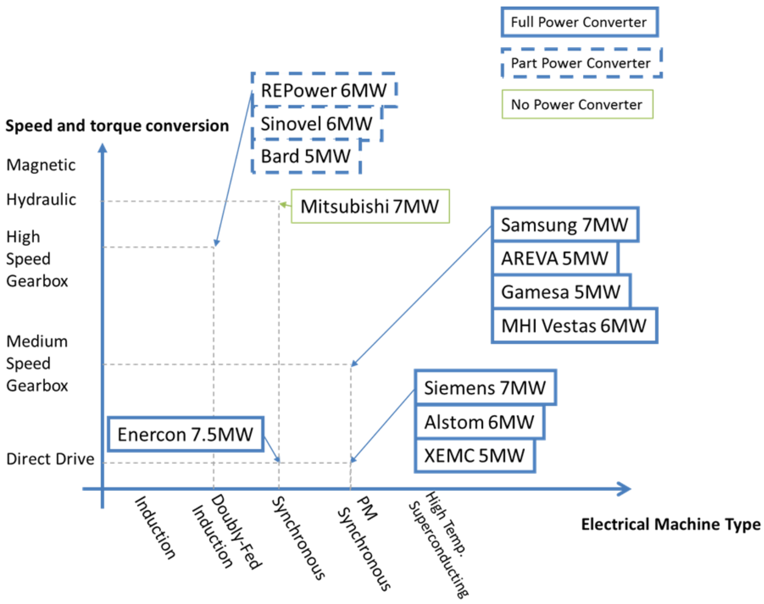


Figure 1.1: Drivetrain choice for some large wind turbines, specified by speed and torque conversion, generator type and rating of power converter [3].

With this wide and rich array of wind turbine types available it is difficult to know which to choose for offshore applications. It should be noted that, throughout this thesis when the author is discussing "turbine type" or "different turbine types" he is discussing modern variable pitch, horizontal axis wind turbines with different drive train types. One method of deciding which turbine type is most suitable is to determine which turbine type offers the lowest cost of energy (CoE). This thesis differentiates between turbine types based on their drive train because of the reasons previously mentioned and because in modern wind turbines the drive train type is the biggest differentiating factor. Currently the doubly fed induction generator (DFIG) with a partially rated converter (PRC) is the dominant drive train technology onshore. However, as turbines grow in size and move offshore there is an emerging trend for manufacturers to move towards, high speed, medium speed and low speed permanent magnet generators (PMG) with fully rated converters (FRC). The four drive train types mentioned are currently the dominant and dominant in the midterm drive train technologies; it is for that reason that they are the focus of this thesis.

Like drive train types, a large number of operation and maintenance (O&M) strategies and vessel strategies also exist, again, it is difficult to know which O&M vessel strategy is best suited to offshore applications. In this thesis a number of vessel strategies will be introduced to determine the strategy with the lowest CoE. These vessel strategies that will be introduced will include “fix on fail”, “batch”, “annual” and “purchase” heavy lift vessel strategies. Each of which is a different way of using the heavy lift vessels (HLVs) when maintaining an offshore wind farm. Further details on each vessel strategy are provided in Chapter 5. There are also different maintenance strategies for maintaining wind farms, these different strategies can result in different maintenance costs. Currently time based maintenance (TBM) strategies are the dominant maintenance strategy in both on and offshore wind. However, as the growth in offshore wind energy continues there is a greater demand for other maintenance strategies such as condition based maintenance (CBM). A comparison of the effect of both strategies on the CoE will be carried out in this thesis.

A number of different minor design changes/innovations can be made to offshore wind turbine designs, currently it is difficult to determine if these minor changes add value. In this thesis some of these minor design changes will be introduced to the CoE model created to determine if they lower the overall CoE. Currently techniques like turbine design for lean maintenance and inbuilt lifting equipment are being introduced to larger wind turbines and manufacturers are starting to explore introducing redundancy in their systems. It is these 3 small design changes/innovations that will be the focus of a section in Chapter 5 of this thesis.

All of the work outlined above will be modelled at varying distances from shore and will help answer the research question outlined in the next section.1.2 Thesis objectives, approach and structure

1.2.1 Research question

Based on the problem statement that “the cost of offshore wind energy is too high”, the objective of this thesis is to answer the following research question:

"How can the cost of offshore wind energy be reduced through turbine type selection, vessel strategy choice, maintenance strategy choice and minor turbine design changes?"

As mentioned, in the above research question, "turbine type" means standard Danish turbine design with type differentiated by drive train configuration. To answer this primary research question a number of other smaller secondary research questions must first be answered. These secondary research questions are answered throughout each chapter of this thesis. The beginning of each chapter will set out the secondary research question to be answered in that chapter. The conclusion of each chapter will answer the secondary research questions and contribute towards answering the primary research question stated above.

1.2.2 Approach taken

To answer the primary research question outlined in the previous Section 1.2.1, the following steps must be taken:

Step 1: Define the primary research question

Step 2: Determine the reliability of different wind turbine types from data obtained from industrial partners

Step 3: Model the availability and O&M costs of different wind turbine types

Step 4: Combining the results of step 2 and 3 with the other variables that determine the CoE, model and analyse the CoE for each wind turbine type

Step 5: Introduce different vessel strategies, O&M strategies and turbine design innovation/adjustments to model and analyse their effect on CoE

Step 6: Draw conclusions on the findings outlined in this thesis

Figure 1.2: Steps to complete Thesis

The above step numbers match each chapter number of this thesis. Further details on the methodology for each step can be found in each chapter.

1.2.3 Structure

Each of these chapters consist of a short introduction/background section to the work carried out in that chapter, a literature review section including a subsection highlighting the gaps in current literature to be addressed, an overview of the methodology used to obtain the results shown in that chapter and a results section. The end of each chapter will have a conclusion sub-section. The references for each chapter are provided at the end of that chapter. There will be an overall conclusion at the end of the thesis.

1.3 Novelty of research

From the initial literature review carried out for defining this work, it was determined that this research would be novel because little or no past work was carried out (or at least published on) in the following areas:

- Reliability analysis of a large population of modern multi MW on and offshore wind turbines. (Novelty compared to some of the current literature shown in table 2.2)
- O&M costs for offshore wind turbines with different drive train types at different distances from shore. Offshore wind O&M costs have been modelled for generic turbines in the past but no literature was encountered where O&M costs were modelled for different turbine types at different distances from shore based on up to date field data.
- The CoE for offshore wind turbines with different drive train types based on up to date field data.
- The effect on CoE due from vessel strategies, maintenance strategies and minor turbine design changes/innovations for different turbine types. In this thesis past work will be built on to add to the field and novel analyses will be carried out. Figure 5.0 shows the differentiation between past work and new work in this area for this thesis.

There are novel sections within each of the steps, 2-5, outlined in Figure 1.2. The novelty of each step/chapter is discussed in the following paragraphs.

- Step 2/Chapter 2:

The novelty in Step 2 was in the up to date reliability analysis carried out on a population of ~2600 modern multi MW on and offshore wind turbines. Gaining access to this type of data is very rare in the wind energy industry and it allowed for novel comparison of failure rates for different wind turbine types and comparison of onshore failure rates with offshore failure rates for the same component.

Some of the drive train types that are the focus of this thesis do not currently have reliability data available. It was for this reason that these turbine types had to have their reliability data, such as failure rates, estimated using a systematic approach. The systematic approach used was borrowed from the Management Science field and its use in estimating failure rates of new wind turbine types based on similar existing wind turbine types adds further novelty to this chapter. This systematic approach is explained further in Chapter 2. The failure rate comparisons and estimations from this work allowed for a number of different publications.

-Step 3/Chapter 3:

The novelty in Step 3 was in the use of the latest failure rate data for different wind turbine types from Step 2 to populate an offshore availability and O&M cost modelling tool. Other, previously unseen operational data such as repair time, repair cost, number of technicians required for repair were also obtained from the population of ~2600 turbines and used in the selected model to estimate offshore availabilities and O&M costs for a number of hypothetical offshore wind farms consisting of different wind turbine types. Up to date availability and O&M cost modelling for different wind turbine types had not been carried out before and allowed for a number of different publications in the area.

-Step 4/Chapter 4:

The novelty in Step 4 comes from modelling the CoE for different drivetrain types using the O&M costs from Step 3 and the other variables that make up the CoE calculation. These other variables include turbine costs, balance of plant (BoP) costs, other capital costs and energy production. The other variables came from different sources each contributing to the novelty of the CoE calculation in this work. The turbine cost data came from an industrial partner and had never before been published. The energy production for two of the different drive train types were obtained from empirical power curves. Again, the empirical power curves were provided by an industrial partner and had not been published on before. Lastly, the BoP costs and other capital cost inputs for the CoE calculation resulted from work with NREL and their BoP model, which was adjusted so it could be incorporated into the other CoE work for this thesis and populated with cost data from operating offshore wind farms. All of the work described above led to novel publications alone and with NREL.

- Step 5/Chapter 5

Providing answers to research questions relating to heavy lift vessel and mother ship vessels provided part of the novelty in Step 5. Investigating availability improvements from wind farms using condition monitoring equipment was also an analysis carried out in this section. An analysis on the change in the CoE was also carried out when inbuilt lifting mechanisms, redundancy and reduced repair times were modelled. How the combination of all of the above factors affected the O&M costs and overall cost of energy was the final novel section of this thesis and has also lead to a number of publications.

1.4 Research output

Peer Reviewed Journals published or submitted:

[1] **Carroll J**, McDonald A, McMillan D. Reliability Comparison of Wind Turbines with DFIG and PMG Drive Trains. IEEE Trans. on Energy Conversion 2015

[2] **Carroll J**, McDonald A, McMillan D. Failure Rate, Repair Time and O&M Analysis of Offshore Wind Turbines. Wiley Wind Energy Journal 2016 Vol 19, Issue 6, start page 1107

[3] **Carroll J**, McDonald A, Dinwoodie I, McMillan D, Revie M, Lazakis I. A Comparison of the Availability and Operation and Maintenance Costs of Offshore Wind Turbines with Different Drive Train Configurations. In Press with Wiley Wind Energy Journal 2016

[4] **Carroll J**, McDonald A, Dinwoodie I, McMillan D, Lazakis I. Heavy Lift Vessel Strategies and Mother Ship Analysis for Offshore Wind Turbines with Different Drive Train Types. Submitted to Wiley Wind Energy Journal July 2016

[5] Liniger J, Pedersen H, Soltani M, **Carroll J**, Sepehri N. Systematic Failure Analysis of a Fluid Power Pitch System for Wind Turbines. Submitted to Wiley Wind Energy Journal May 2016

Book Chapter:

[1] McDonald A, **Carroll J**. Design of generators for offshore wind turbines. Published in: Offshore wind farms: Technologies, design and operation. Publisher: Woodhead Publishing. Published March 2016

Peer Reviewed Conferences:

[1] **Carroll J**, McDonald A, McMillan D. 5 Steps to Reduce the Cost of Energy from Offshore Wind Farms by Over 20%. AWEA WindPower 2016, New Orleans

[2] **Carroll J**, May A, McDonald A, McMillan D. Offshore Availability with Condition Based Maintenance Strategy vs Time Based Maintenance Strategy" EWEA Offshore 2015, Copenhagen

[3] **Carroll J**, Dinwoodie I, McDonald A, McMillan D. "Quantifying O&M savings from wind turbine design for maintenance techniques. EWEA Offshore 2015, Copenhagen

[4] **Carroll J**, McDonald A, Feuchtwang J, McMillian D. Drivetrain Availability of Offshore Wind Turbines. EWEA 2014, Barcelona

[5] Hart K, McDonald A, Polinder H, Corr E, **Carroll** J. Improved Cost of Energy Comparison of Permanent Magnet Generators for Large Offshore Wind Turbines. EWEA 2014, Barcelona

[6] **Carroll J**, McDonald A, McMillan D. Reliability comparison of DFIG configurations vs PMG configuration in the first 5 years of operation. IET RPG 2014, Naples

[7] **Carroll J**, McDonald A, McMillan D. Offshore Availability for wind turbines with Hydraulic Drive Trains. IET RPG 2014, Naples

[8] **Carroll J**, McDonald A, McMillan D. Offshore Cost of Energy for DFIG PRC Turbines Vs. PMG FRC Turbines. IET RPG 2015, Beijing

[9] Kourkoulis V, **Carroll J**, Leithead W. Effect of site conditions on offshore wind turbine failures. IET RPG 2015, Beijing

[10] **Carroll J** et al. Offshore Wind Turbine Sub-Assembly Failure Rates through Time. EWEA 2015, Paris

[11] **Carroll J** et al. Cost of Energy for Offshore Wind Turbines with Different Drive Train Types. EWEA 2015, Paris

Invited Presentations:

[1] IEEE PES GM, Denver (2015) Presentation of the reliability comparison of wind turbines with DFIG and PMG drive trains

[2] Offshore CoE/O&M Workshop, University of Maryland (2015) Presentation of the CoE for different wind turbine types.

Industrial engagement and engagement with other international research institutes:

1. An onshore wind turbine manufacturer and an offshore wind turbine manufacturer were the main industrial partners for this PhD. However, they must remain anonymous for confidentiality reasons because of the sensitivity of the data within this thesis.

2. Throughout various stages of this PhD meetings to discuss research findings from this work were held with SSE; meetings were also held with Natural Power.

3. In the process of completing the research for this thesis work was carried out and papers were published with NREL, the University of Maryland and Aalborg University.

1.5 Chapter 1 references

[1] The Crown Estate. Offshore Wind Cost Reduction Pathways Study. Report 2012

[2] Department of Energy and Climate Change. Electricity Generation Costs. Report 2012

[3] McDonald A, Carroll J. Chapter, Design of generators for offshore wind turbines. Book: Offshore Wind Farms: Technologies, Design and Operation, Woodhead Publishing 2016

Chapter 2 Wind turbine reliability analysis

The reliability of wind turbines is one of the most critical drivers of the O&M costs for wind turbines. The O&M costs are one of the largest contributors to the overall cost of energy for both on and offshore wind turbines. It is for this reason that there is value in gaining a better understanding of turbine reliability. As outlined in Section 1.1, there are many different wind turbine types, consequently, it is important to try and determine the reliability of the different wind turbine types, rather than just focusing on a generic wind turbine.

2.1 Reliability analysis literature review

A literature review was carried out to determine what research was already completed in the area of onshore and offshore wind turbine reliability analysis. The purpose of this literature review was to determine what gaps existed in this area that are required for O&M and COE modelling, which could be addressed in this thesis.

2.1.1 Reliability analysis definitions

Reliability describes the ability of a wind turbine to function as it should over its design life. A turbine is reliable if it is ready (available) to produce energy whenever the wind speed is higher than the wind turbines cut in speed throughout its design life. If a wind turbine experiences a failure within its design life, the turbine reliability is reduced. The way in which a failure is defined tends to be different in many papers encountered in this literature review. [1] and [2] have stated that there is no standard format for defining failure rates or availability. It seems the definition of a failure is usually influenced by the extent of data available to the analyst. For example, some papers can include the amount of downtime in their failure definitions and some cannot, depending on whether downtime data is available to them. In [3] a failure is defined as the termination of the ability of an item to perform a required function. However the definition provided in [4] includes downtime in its definition. The authors state a failure is defined as the stoppage of a turbine for one or more hours that requires at least a manual restart to return it to operation. The fact that this definition stated that at least a manual restart was required to return it to operation meant that automatic restarts (in which the turbine is shut down and re-started remotely) were not captured as failures.

In a number of wind turbine reliability papers the failure rate is defined in a per turbine per year format [2, 5, 6, 7]. This format is provided by Equation 1:

$$\lambda = \frac{\sum_{i=1}^{I}\sum_{k=1}^{K} n_{i,k}/N_i}{\sum_{i=1}^{I} T_i/8760} \quad (1)$$

where

λ = failure rate per turbine per year

I = number of intervals for which data are collected

K = the number of subassemblies

$n_{i,k}$ = the number of failures

N_i = the number of turbines

T_i = the total time period in hours

The numerator $\sum_{i=1}^{I}\sum_{k=1}^{K} n_{i,k}/N_i$ is the sum of the number of failures in all periods per turbine. The denominator, $\sum_{i=1}^{I} T_i/8760$, is the sum of all time periods in hours divided by the number of hours in a year.

Reference [8] provides an overview of other terms used in wind turbine reliability papers. It states that $1/\lambda$ is the mean time to failure (MTTF), where λ is the failure rate. The repair rate is the transition rate from the failed to operational state and is represented by μ. $1/\mu$ is the mean time to repair (MTTR). The mean time between failures (MTBF) is the sum of the MTTR and MTTF.

2.1.2 Reliability of on and offshore wind turbines

A common theme throughout all of the wind turbine reliability analysis papers encountered in this literature review was that there was not enough data in the public domain. Reference [9] also highlighted this issue concluding that the vast majority of papers in this area highlight the lack of data as a problem when it comes to determining the reliability of wind turbines.

However, a number of reliability analyses have been carried out on the limited available data that was in the public domain and those analyses have been detailed in past publications, an overview of these reliability publications for both onshore and offshore wind turbines are seen in the following pages.

Onshore:

Reference [4] shows the results of the Reliawind analysis on 350 onshore turbines ranging from 850kW to modern MW scale turbines. In this paper an overall turbine failure rate is not given. The failure rates of the different turbines are not provided in terms of failures per turbine per year, but in percentage of overall failures, as shown in Figure 2.1. This paper can be used for comparing how much each subassembly fails in relation to the other subassemblies but without an overall failure rate these percentages alone cannot be used for availability or lost production modelling. Reference [4] is also useful because it provides a failure breakdown on a number of different levels. For example, it can be seen in Figure 2.1 that the power module is the largest contributor to the overall failure rate, the figure then provides further details on what contributes to making the power module the largest contributor e.g. frequency converter.

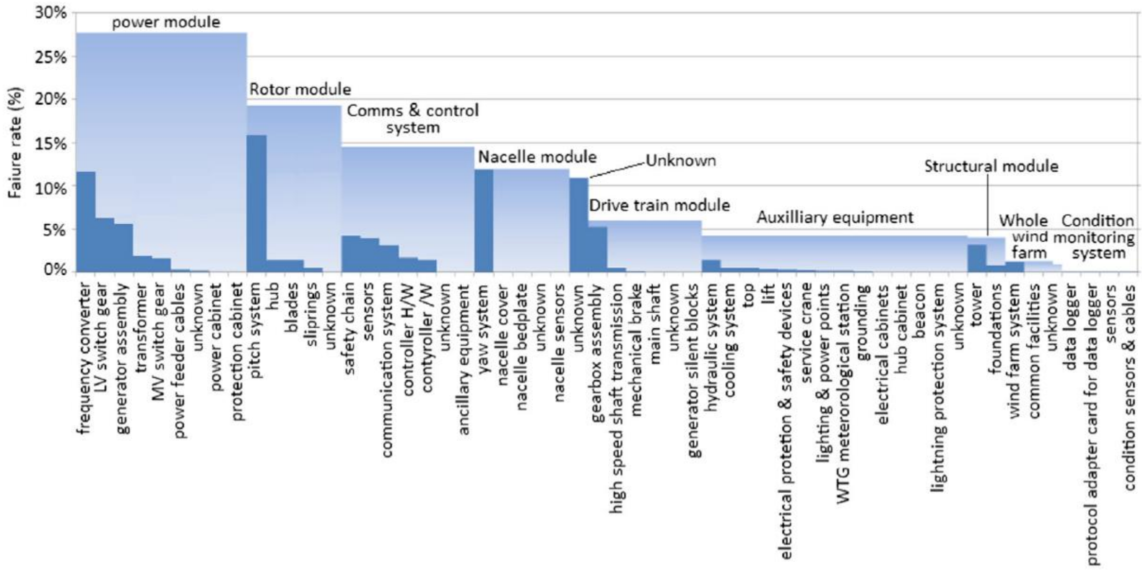


Figure 2.1: Frequency of wind turbine component failures [4]

Reference [5] is based on a larger data set than [4]. It uses the Landwirtschaftskammer (LWK) and WindStats databases from Denmark and Germany. Combined, these databases amount to over 6000 turbines. However turbines contained in these datasets are up to 20 years old and have power ratings as low as 200kW. This raises doubts about whether these failure rates are representative of modern MW scale turbines. Figure 2.2 shows the results of the failure rate analysis on each of the 3 datasets. Unlike reference [4] failures rates are given in per turbine per year format.

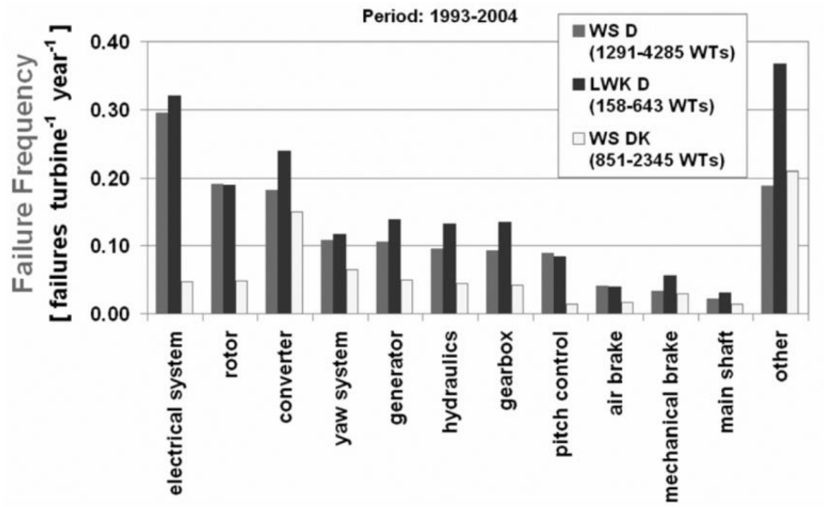


Figure 2.2: Failure rates from the databases analysed in reference [5]

It can be seen that the German populations, LWK and Wind Stats Deutschland (WSD) have a higher failure rate than the Danish populations, the reason for this could be older, smaller turbines with more mature technology in Denmark (WS DK). Even though the LWK and WSD have very different sample sizes the fact that they are so similar provides confidence in both surveys. This paper is rare in the fact that in a section of the paper it has separated its analysis into different drive train types. The paper states that even though one manufacturer tried to improve reliability through removing the gearbox it may have in fact reduced reliability in some cases due to the fact that the generator failure rates double in direct drive turbines (perhaps because of the larger number of coils, larger diameter and fact that it’s not a standard product). These direct drive results come from turbines that use wound rotor synchronous generators (WRSG) and not permanent magnet synchronous generators (PMSG). This paper does not provide any failure modes for the direct drive generator but it suggests that failure rates of direct drive machines could be reduced by using a PMSG.

Wind turbine subassembly failure rates and downtimes can also be seen in [10]. These failure rates and downtimes are obtained from analysis on 1,500 German turbines over a 15 year period, while this is a large population the majority of the population is under 1 MW. Figure 2.3 shows the failure rates and downtimes for the sub-assemblies. The product of the failure rate and the downtime give the availability of the wind turbine over a given time period. It can be seen that even though the failure rates for generators, gearboxes and drivetrains are quite low the downtime is relatively high with these 3 components having the 3 highest downtimes. Even with this lower failure rate the high down time of these drive train components lead to reduced availability. The “Drive Train” grouping in Figure 2.3 consists of everything in the drive train outside of the generator and gearbox, such as shafts and bearings.

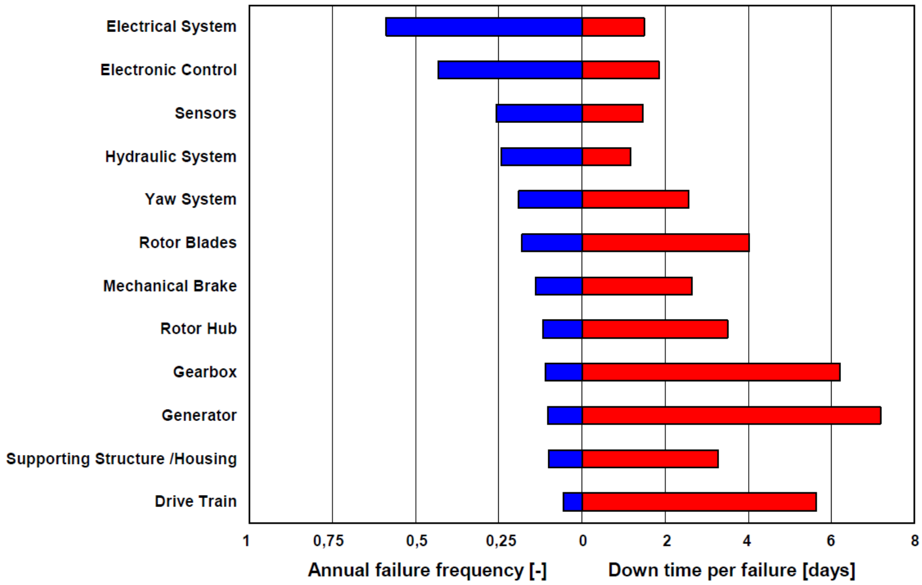


Figure 2.3: Wind turbine sub-assembly failure rates and downtimes [10]

Reference [3], compares failure rates and downtimes from analyses carried out in Sweden, Germany and Finland. The same LWK and Windstats databases used in reference [5] are also used in reference [9]. However the focus of [9] is failure rates through time. This paper also carries out an analysis on the generator failure rates. It calculates failure rates for induction and synchronous generators. The induction turbines consist of squirrel cage induction generators (SCIG) and not DFIGs. The sample size is made up of 27% synchronous generators and 73% induction generators. The paper demonstrates that induction generators have roughly half the failure rates of synchronous generators. However it must be kept in mind that in this data set the synchronous generators are direct drive Enercon machines, not modern permanent magnet synchronous generators. If direct drive machines are removed from the synchronous section, the paper shows that there is not as large a difference between induction and non-direct drive synchronous machines. An analysis on the converters in these turbines is also carried out in [9]. Converters used in direct drive machines are shown to have a higher failure rate of up to 400% between turbine types. Reference [2] corroborates the other papers that use LWK and WindStats data and finds the German populations have higher failure rates than the Danish populations. As with the analysis detailed above it finds the main driver for this is the electrical systems rather than the mechanical ones.

References [6, 7, 11], like [9] look at individual components. Reference [6] focuses on gearboxes and the failure rates of 3 stage, 2 stage and individual components of gearboxes.

These failure rates are based on an expert failure mode and effects analysis (FMEA) rather than empirical data. The results of this FMEA provide a failure rate for different gearbox types in a per turbine per year format. Reference [6] states that empirical data from operating turbines show gearbox failure rates are low in comparison to other wind turbine subsystem failure rates, however this lower failure rate doesn't transfer to higher availability because of the high downtime related to gearboxes.

Reference [11] provides the frequency of failure modes for onshore generators. The results are split for generators of rated power between 1 and 2 MW and greater than 2 MW. These results are based on an analysis of 1,200 generator repair operations. Reference [12] also looks at generator failures with a focus on condition monitoring. Reference [11] found that for generators over 2MW the bearings were the greatest contributor to the overall failure rate making up ~55% of the overall failures. This was followed by stator related issues making up ~28% of the overall failures. The remainder consisted of rotor related issues and "collector ring issues". However it is not clear if the collector ring grouping includes brush and slip ring issues. This analysis does not state whether failures are considered minor or major. Figure 2.4 shows generator failure modes and their contribution to the overall failure rate from reference [11].

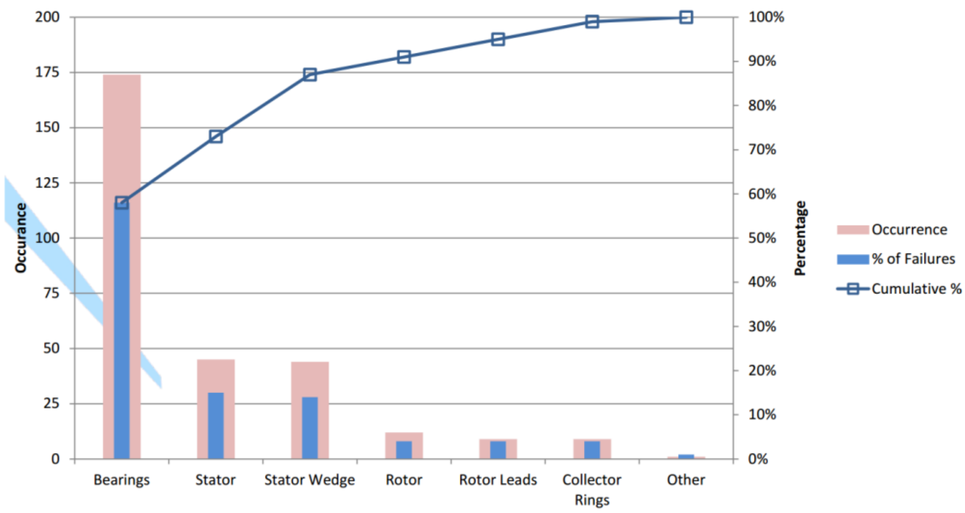


Figure 2.4: Generator failure modes and their contribution to the overall failure rate [11]

Reference [7] provides failure rates for converters based on the LWK and Reliawind databases. Other analysis on Power converters can be seen in [13] and [14]. Reference [14] is a report on converter specific failures. It also focuses on how the environmental factors influence the failures of converters, e.g. temperature, humidity, wind speed and so on. Reference [13] looks at the converter failure modes and found that the phase module is the greatest contributor to the overall failure rate. Each failure mode and its overall failure rate can be seen in Figure 2.5.

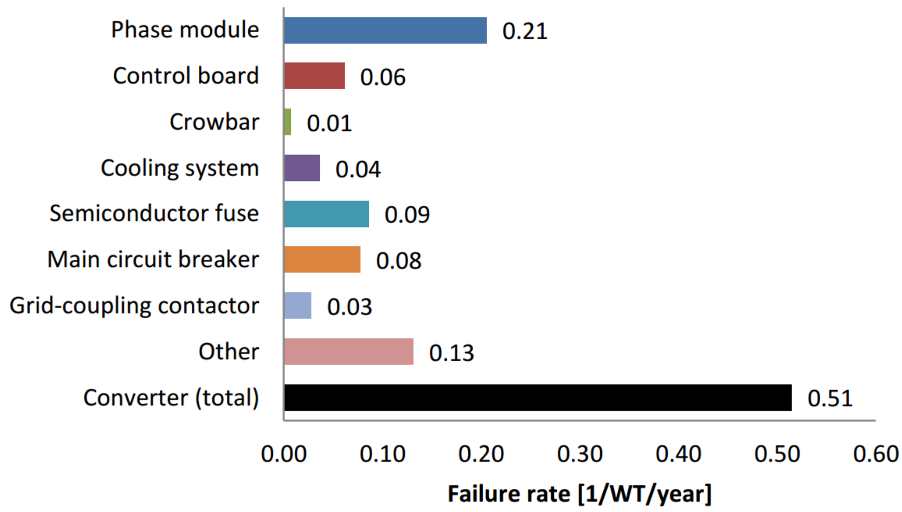


Figure 2.5: Power converter failure modes and their contribution to the overall failure rate [13]

Similar to reference [3], Reference [15] also examines turbine component failure rate with time. It describes how failure rates can be used in O&M cost modelling and the assumptions that go with it. The following paragraphs will outline the parts of [15] that are relevant for this thesis. Wind turbine and wind turbine component failure rates are a key input to any O&M modelling. Reference [15] has stated that:

- "The assumption of constant failures and the adoption of average failure intensity is only valid in the case of no reliability growth (positive or negative) (Shape parameter equal to 1)"
- "When positive reliability growth occurs the final failure intensity must be chosen as the expected value. (Shape parameter less than 1)"
- "On the other hand when negative growth occurs the initial failure intensity should be used" (Shape parameter greater than 1)

Figure 2.6 shows the failure distributions with the shape parameters mentioned above.

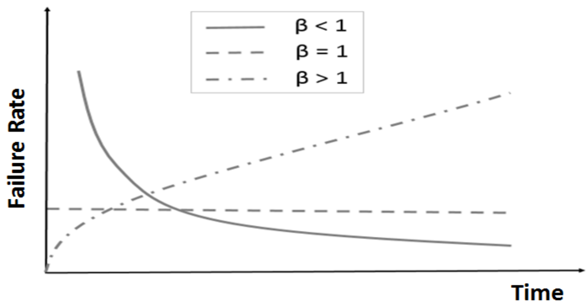


Figure 2.6: Shape parameters

It is clear from the graph that any shape parameter below 1 demonstrates a reliability improvement with time, above 1 shows a decline in reliability with time and a shape parameter of 1 shows a steady failure rate. These shape parameters are evident in the bathtub curve. The bathtub curve is shown in Figure 2.7. The first section of the bathtub curve shows rapid reliability improvements with a shape parameter of less than 1, this represents early failures in a component. The 2nd section has a constant failure rate with a shape parameter of 1 and represents intrinsic failures. The third section shows reliability decline with an increase in failure rate and a shape parameter of greater than 1. This is the component deterioration stage. The “early failures” and “deterioration” section are a special case non-homogenous Poisson process and can be represented by the power law process (PLP) [16] shown by the following equation:

$$\lambda(t) = \rho\, \beta t^{\beta-1} \quad (1)$$

where:

$\lambda(t)$ = Failure rate as a function of time

ρ = Scale Parameter

β = Shape Parameter

t = time

As mentioned, it is β that determines which stage of the bathtub curve the failure trend follows. If beta is one in this equation the process becomes a Homogenous Poisson Process (HPP) meaning that the failures are random and can be represented with an average failure rate [16].

A number of steps for determining if a set of failure data are a HPP or PLP have been outlined in [15]. Firstly the average failure rate for each operational year was plotted and a trend line was fitted. The shape parameter was estimated using the least squares estimation method.

The trend line and shape parameter then had to be tested for a 95% goodness of fit and a final test on whether the trend was following the PLP or HPP was carried out. The same process as the one carried out in [15] was used to test the goodness of fit of the trend line in which the following equation, equation (2), was used to calculate a chi square value which could then be tested off standard probability tables to determine if the null Hypothesis that "the data was governed by the assumed distribution" could be accepted or rejected.

$$\mathbf{X}^2 = \sum \frac{(observed - expected)^2}{expected} \quad (2)$$

A similar test based on equation (3) is carried out to determine whether the null hypothesis that "The failure trend follows the HPP" can be accepted or rejected.

$$\mathbf{X}^2 = \sum_{i=0}^{8} \frac{(O_i - E_i)^2}{E_i} \quad (3)$$

where:

O_i =Observed failures in time period i

E_i = Expected failures in time period i

Expected failure rates in time period i is given by the number of turbines in time period i × mean failure rate.

When the results of equations (2) and (3) are compared to the standard tables it can be determined if the goodness of fit is acceptable. As detailed in [15] once the goodness of fit is accepted, the two step procedure and Table 2.1 [15] can be used to determine if the failure trend is deteriorating, improving or remaining steady.

Table 2.1: Interpretation of HPP and PLP [15]

H_0 = HPP	Shape Parameter	Result
Rejected	$\beta < 1$	Early Failures
Rejected	$\beta > 1$	Deterioration
Accepted	$0.79 < \beta < 1.2$	Constant Failure

Section 2.3.2 of this chapter will follow the above process to determine whether the failure rates for the gearbox, generator, converter and "rest of turbine" are PLP with improving reliability, PLP with deteriorating reliability or HPP.

The bathtub curve in Figure 2.7 is for a repairable system such as a wind turbine. A repairable system can usually be returned to operation after a failure by some repair process other than complete system replacement.

Reference [15] states that in a repairable system repairs can be defined as:

- Minimal Repair (The failed unit is brought back to the condition it was in immediately before failure)
- Perfect Repair (The failed unit is brought back to the condition it was in as new and TBF (Time between Failures) are identically distributed)
- Renewal model (acts like a non-repairable system statistically).

Minimal repair is often assumed with wind turbines, returning the wind turbine back to the condition it was in before failure [15].

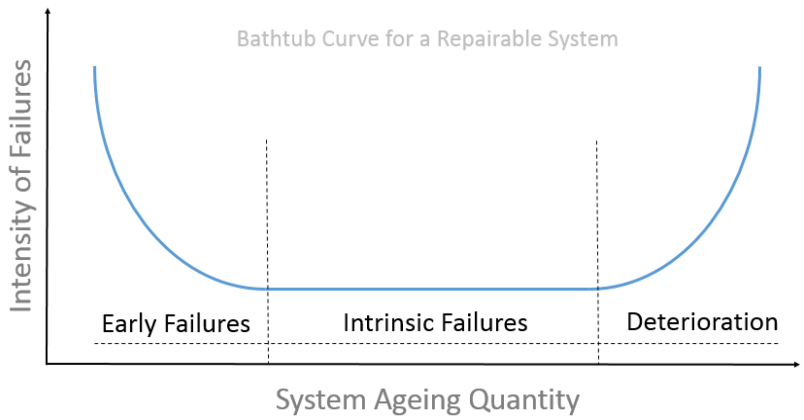


Figure 2.7: Bathtub curve for a repairable system

The bathtub curve in Figure 2.7 should not be confused with the bathtub curve of a non-repairable component. For a non-repairable system the curve shape is the same but the y-axis displays the hazard function instead of the intensity of failures and the 3 stages are called burn in, useful life and wear out rather than early failures, intrinsic failures and deterioration.

Offshore:

As limited as onshore reliability data are, even fewer papers detailing offshore wind turbine failures were encountered during the literature review for this work. While papers exist outlining the availability of a number of the UK wind farms [17] they do not provide any overall failure rate data or subassembly failure rate data. The only work encountered in the public domain that provided the failure rates of offshore wind turbines was [18]. These failure rates came from a single offshore wind farm of 36 wind turbines off the coast of the Netherlands. However the definition of a failure in these reports is very different to most other failure rate analysis. The reason for this is because remote resets are included in the definition and the analysis focuses on turbine stoppages rather than failures. As mentioned in [19], even though data from these 36 turbines for a number of operational years exist, that population is too small to be useful for tasks such as confidently modelling subsystem level failures.

Reliability data from other industries have also been used as reliability guidance for wind turbine components when no wind turbine field data could be accessed or existed. OREDA [20] publish offshore reliability data from offshore oil and gas rigs. These rigs contain many similar components to wind turbines. However, the intermittent nature of wind energy may lead to different failure patterns than the constant loading experienced on offshore oil and gas rigs.

2.1.3 Research opportunities from gaps in past reliability analyses

As highlighted in the previous sections there are a number of gaps in current on and offshore reliability publications. A lack of failure rate data in the public domain for wind turbines was repeatedly mentioned as a barrier to fully understanding the reliability of on and offshore wind turbines in the papers reviewed in Section 2.1.3. Limited data is available for onshore modern multi MW turbines, however large data sets do exist (LWK and Windstats) for older onshore wind turbines with low power ratings. The fact that these populations have turbines up to 20 years old and power ratings as low as 200kW raise the question whether they are truly representative of modern multi MW scale wind turbines.

While two of the papers encountered in the literature review [5] and [9] provide empirical failure rates for different wind turbine types, once again this is for older smaller turbine types so there is still a lack of understanding about which modern turbine type offers the lowest failure rates. Table 2.2 aims to show the gaps in current failure rate work by focusing on some of the past literature and also shows where the analysis in the following sections of this chapter contributes to this field by filling the gaps. In the colour coding of the table below green is something that is good about a database or piece of work, red means the database or piece of work would be better if it had the dimension in question and amber means the database or certain piece of work is better than red but not as good as green.

It is based on these findings that it was felt that there was an opportunity to carry out novel research through the analysis of a large enough on and offshore population of multi MW turbines with different wind turbine types to determine sub assembly failure rates. The author also came to the conclusion that it would be impossible to get empirical reliability data from all wind turbine types available, so a method of estimating reliability for new or unknown wind turbine types needed to be established.

Table 2.2 Existing failure rate analyses and contribution of the work in this chapter

	This Chapter	Reliawind [4]	LWK & Windstats work [2,5,7]	Early UK offshore Sites [17]	Egmond aan Zee [18]
Onshore	Yes	Yes	Yes	No	No
Offshore	Yes	No	No	Yes	Yes
Sub system Failure Rate	All Subsystems	All Subsystems	All Subsystems	None. Paper focuses on availability only	Number of stops given for each subsystem
Availability	Shown in chapter 3	Failure rate and downtime provided	Failure rate and downtime provided	Yes	Yes
Different drive train types	4 different drive train types. Field data and estimations	No	Direct drive and 3 stage gearbox configurations	No	No
Turbine Size/Rating	Multi MW on and offshore turbines	Multi MW Onshore turbines	Turbines rated as low as 200 kW	Multi MW Offshore turbines	Multi MW Offshore turbines
Population Size	~ 2600 onshore and offshore turbines	~ 350 onshore turbines	Builds up to ~6000 turbines	156 Offshore turbines	36 Offshore turbines
Failure Cost Categories	Split into 3 cost categories	Split into 3 cost categories	Failure rate not split by cost	No Failure rates	Failure rate not split by cost
Failure rate with time	Yes	No	Yes	No	No
Onshore to offshore comparison	Yes	No	No	No	No
Failure rate vs. Wind Speed	Yes	No	Yes	No	No

2.2 Reliability analysis introduction, background and methodology

2.2.1 Introduction

The remainder of this chapter outlines and shows results of a failure rate analysis carried out on a population of ~2600 on and offshore wind turbines. The overall population consisted of 3 sub-populations allowing for deeper analysis on turbines with different drive train types, on and offshore comparisons, failure rate vs. wind speed comparisons, failure rate vs time comparisons and so on. The novelty in this analysis is found in the large population of modern multi MW on and offshore wind turbines. As outlined in the previous sections publically available analyses of this kind are lacking in the wind energy industry.

As mentioned, currently one of the main differentiators between wind turbine types is their drive trains. Consequently this work focuses on the drive train type when talking about different wind turbine types. As there are many different kinds of drive train types and new drive trains have been and can be introduced in the wind energy industry a method of systematically estimating the reliability of those drive train types is required. Section 2.5 will also outline how that can be achieved.

2.2.2 Reliability analysis definitions, populations and drive train types.

Failure definition

In the analysis carried out in the following sections a failure is defined as a visit to a turbine, outside of a scheduled operation, in which material is consumed. A material is defined as anything that is used or replaced in the turbine; this includes everything from consumable material (such as carbon brushes) to replacement parts, such as full IGBT units and full generators. This failure definition does not cover faults that are resolved through remote, automatic or manual restarts. However, if these faults repeatedly occur, they require a visit to the turbine in which material is used and the failure is then captured in this analysis, providing the visit is outside of a scheduled service. As mentioned in Section 2.1.1 failures are defined differently in most papers encountered. In [4], a failure is defined as the stoppage of a turbine for one or more hours that requires at least a manual restart to return it to operation. Like the failure definition from this analysis, the automatic restarts are not captured. The same failure definition is not used in this analysis because the downtime data for each failure was not available.

Failure rates and failure rate categories

In this analysis the failure rates are in per turbine per year format as seen in [5, 7, 13]. The formula used to determine failure rate per turbine per year in this analysis is the same formula (1) shown in Section 2.1.1 of the literature review.

The failure types are categorized into three groups. These groups are based on the Reliawind categories from [21] in which failures are classified as a minor repair, major repair or major replacement. For the purpose of this analysis any failure with a total repair material cost of less than €1,000 is considered a minor repair, between €1,000 and €10,000 a major repair and above €10,000 a major replacement. This is similar to failure severity groupings used by Reliawind in [4] and [21]. An example of a minor repair is the changing of a pipe on the pitch hydraulic system or a seal on the gearbox, material costs to repair are below €1,000 and a crew transfer vessel (CTV) is used. An example of a major repair is the changing of an IGBT module on the converter, material costs to repair are ~£8,000 and a CTV is used. An example of a major replacement is the replacement of a generator or gearbox, material costs to repair are ~ €70,000 and ~€260,000 respectively and a HLV is used.

Populations:

The previously mentioned population of ~2600 turbines is split into three sub-populations from 2 different industrial partners. The first sub population is the offshore population, it consists of ~350 turbines from between 5-10 wind farms located throughout Europe. The years of installation for the population are shown in Figure 2.8. It can be seen that 68% of the population analysed is between three and five years old and 32% is greater than 5 years old. In total this population provides 1768 turbine years or ~15.5 million hours of turbine operation. For confidentiality reasons the exact nominal power, blade size or drive train configuration of the turbine type used in this analysis cannot be provided. However it can be stated that it is a modern multi MW scale turbine type with an identical blade size and nominal power in all turbines. As a guide to the size of the turbine type, the rotor diameter is between 80m and 120m and the nominal power is between 2 and 4MW.

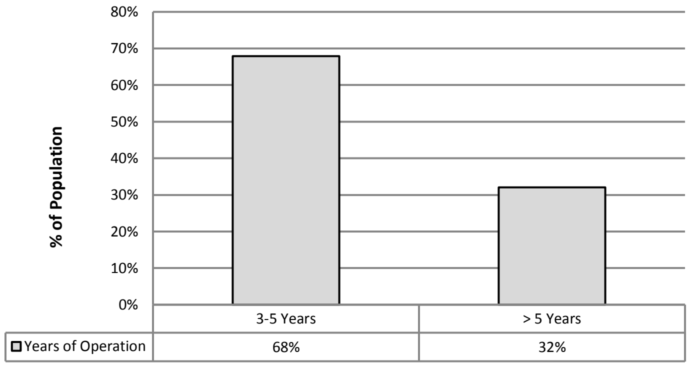


Figure 2.8: Population operational years

The turbines in the remaining two sub populations are both onshore wind turbines of the exact same type except for their drive trains. In both populations the turbine manufacturer, model, rotor size and rated power are the same but some of the turbines have DFIG PRC drive train configurations and some have PMG FRC configurations. The DFIG configuration has a sample size building up to 1,822 turbines over a five year period. This sample size provides 3,391 years or ~29.7 million hours of turbine data. The PMG FRC configuration has a sample size building up to 400 turbines over a 3 year period. This sample size provides 511 years or ~4.5 million hours of turbine data. Once again the exact nominal power and rotor size are not provided for confidentiality reasons. However it can be stated that both turbine types in the second two sub-populations are also modern multi MW scale turbines with a rotor diameter between 80m and 120m and the nominal power is between 2 and 4MW.

Drive train Types

In this research a number of different drive train and generator types were modelled. Industrial partners provided field reliability data for two of the most widespread drive train types in large onshore turbines, they are the 3 stage gearbox with a doubly fed induction generator and the 3 stage permanent magnet generator with a fully rated power converter. The DFIG configuration uses a partially rated power converter to vary the electrical frequency on the generator rotor and hence provide variable speed operation. Offshore wind turbine designers are increasingly opting for permanent magnet generator configurations [22] because of their higher efficiencies. They are also tending to choose direct drive generators (i.e. drive trains with no gearbox) or gearboxes with only 1 or 2 stages and medium speed generators. The direct drive generator will have a higher failure rate than the gear driven generators. As highlighted in [5], wound rotor direct drive generators are expected to have a failure rate up to twice that of gear driven generators. However, it is direct drive permanent magnet machines that are the focus of this analysis and [5] suggests that PMG direct drive generators may mitigate this higher failure rate through the removal of some of the failure modes related to the excitation system and rotor windings. As manufacturers are just starting to introduce direct drive and low speed generators offshore no field reliability data could be obtained. However the author wanted to include them in this analysis as they are the types of turbines that will be installed in the round 3 sites around the UK. Consequently, it was decided to systematically estimate failure rates for a direct drive PMG FRC turbine type and a 2 stage PMG turbine type. Adding them to the two 3 stage configurations, which field data was obtained for, resulted in four different wind turbine types becoming the focus of this thesis. All four drive train types can be seen in Figure 2.9.

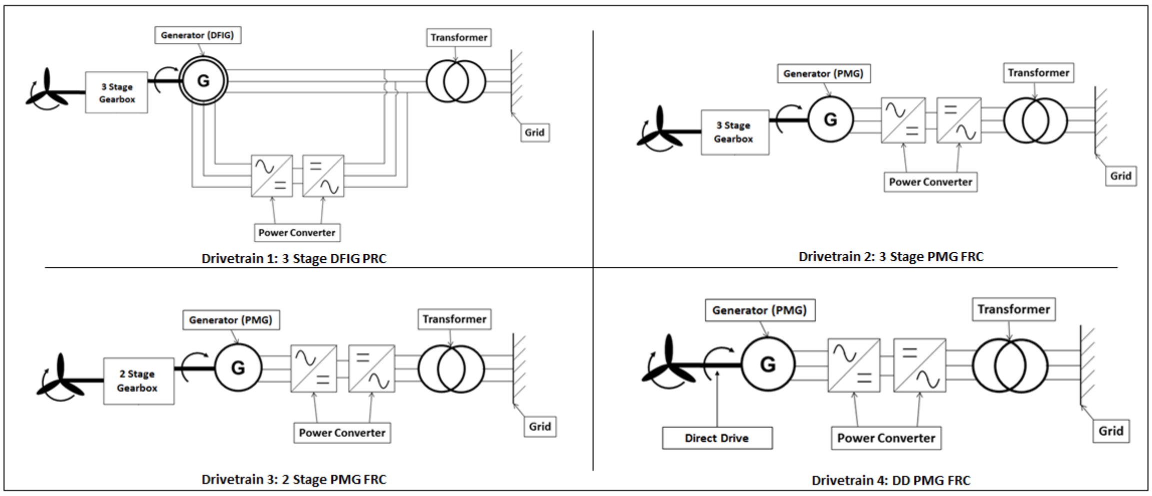


Figure 2.9: Drive train configurations in this analysis showing the different gearbox, generator and converter types used

2.2.3 Reliability analysis methodology

In order to carry out the analysis on the 3 sub populations a number of different industrial partners had to be approached and convinced to provide access to their on and offshore reliability data. Two industrial partners agreed to provide reliability data and both had similar data formats. The data bases of interest for the research in this chapter were the work order and material usage databases. The work order database is a database in which every piece of work carried out on the turbine is recorded and the material usage database is the database in which every material used on the turbine is recorded.

These two databases were connected with bespoke code created in SQL (a standard language for accessing databases) using work order numbers to match up the work carried out with the material used on the turbine. The data was also cleaned to remove any scheduled operations such as scheduled services or scheduled inspections.

Once each failure was identified, it was assigned a failure sub-assembly/component group, its total material cost was calculated and the failure was then categorized as a minor repair, major repair or major replacement as described in the previous section. Failure modes were then investigated. The failure sub-assembly/component group of each work order is determined by reading through the work order long text in which the wind turbine technician provides a brief description of the work carried out. This allowed for a failure rate per turbine per year to be calculated for each of the sub-assemblies and each of the failure cost categories. Figure 2.10 shows an example of how the subassembly/component grouping, failure categories and failure modes relate to each other in this analysis.

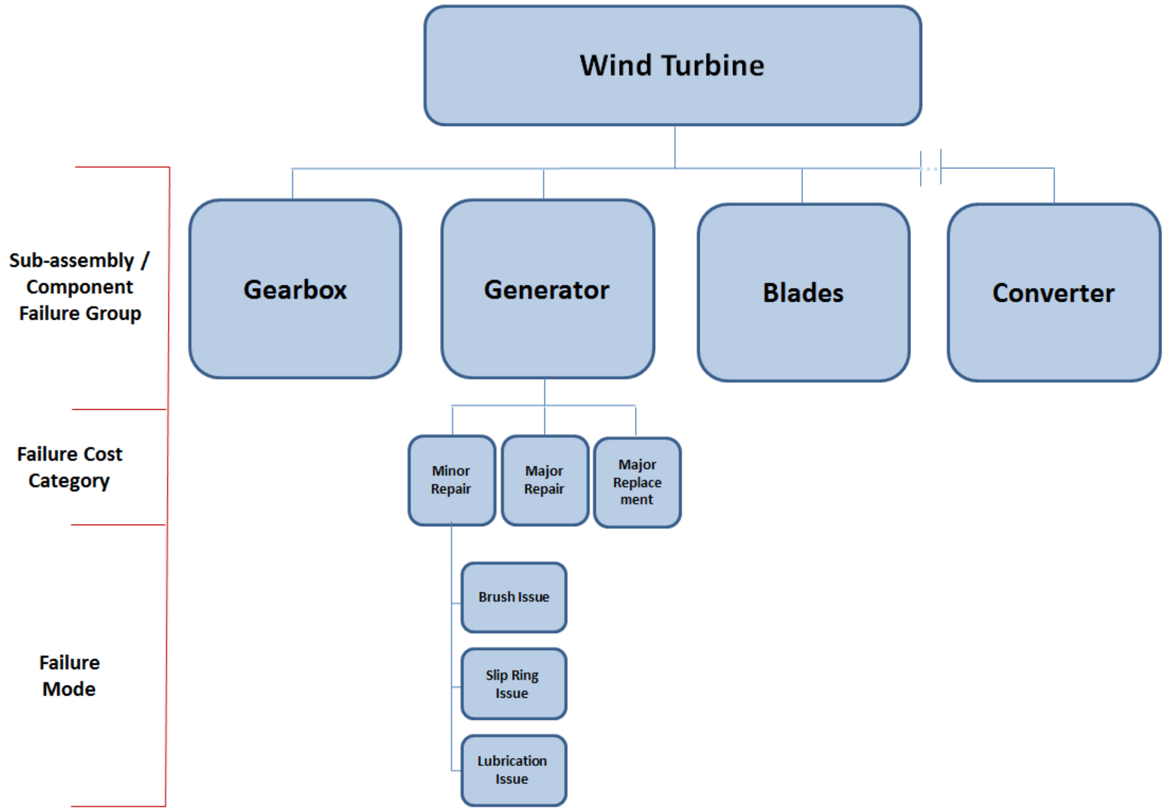


Figure 2.10: Explanation of groupings of raw data.

Further analyses then had to be carried out on the offshore population to determine how failure rates were impacted by wind speed and the number of years of operation. Onshore failure rates for generators and converters then had to be compared to offshore shore failure rates for the same components to determine the difference between onshore and offshore failure rates.

How the failure rates changed over time were also analysed for the offshore data.

A systematic approach to estimating the failure rates for the two new wind turbine types was then found. It was decided to use REMM (Reliability Enhancement Methodology and Modelling) which is detailed in Section 2.5. The process described in the previous paragraphs is shown in Figure 2.11.

Following all of the above work failure rates for the four drive train types could be determined allowing the research question of "which wind turbine type has the lowest failure rate?" to be answered.

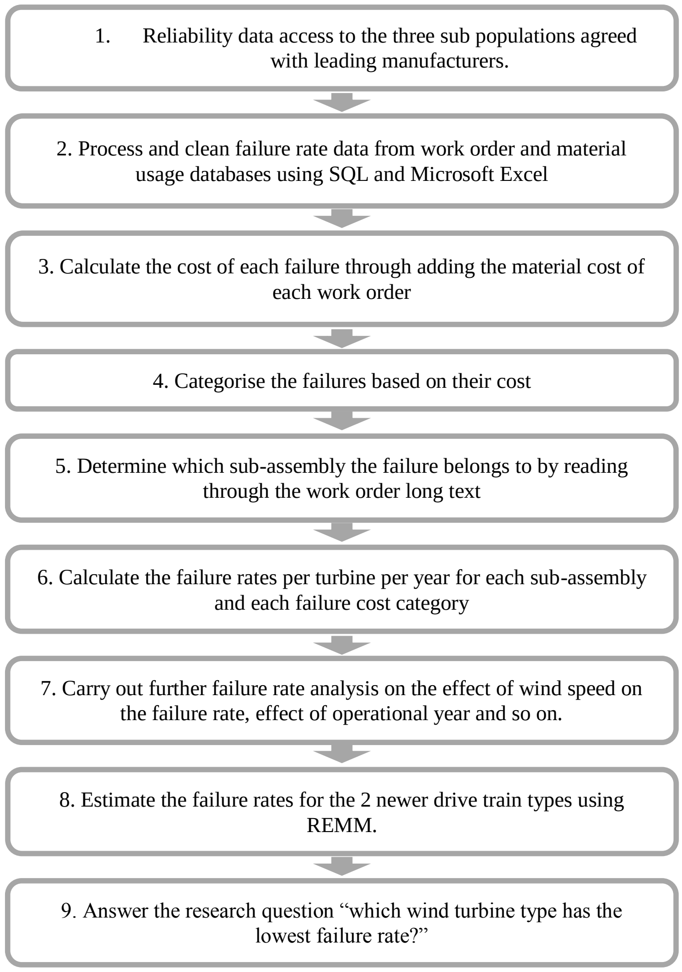


Figure 2.11: Flow chart of failure rate data analysis

2.3 Offshore reliability results

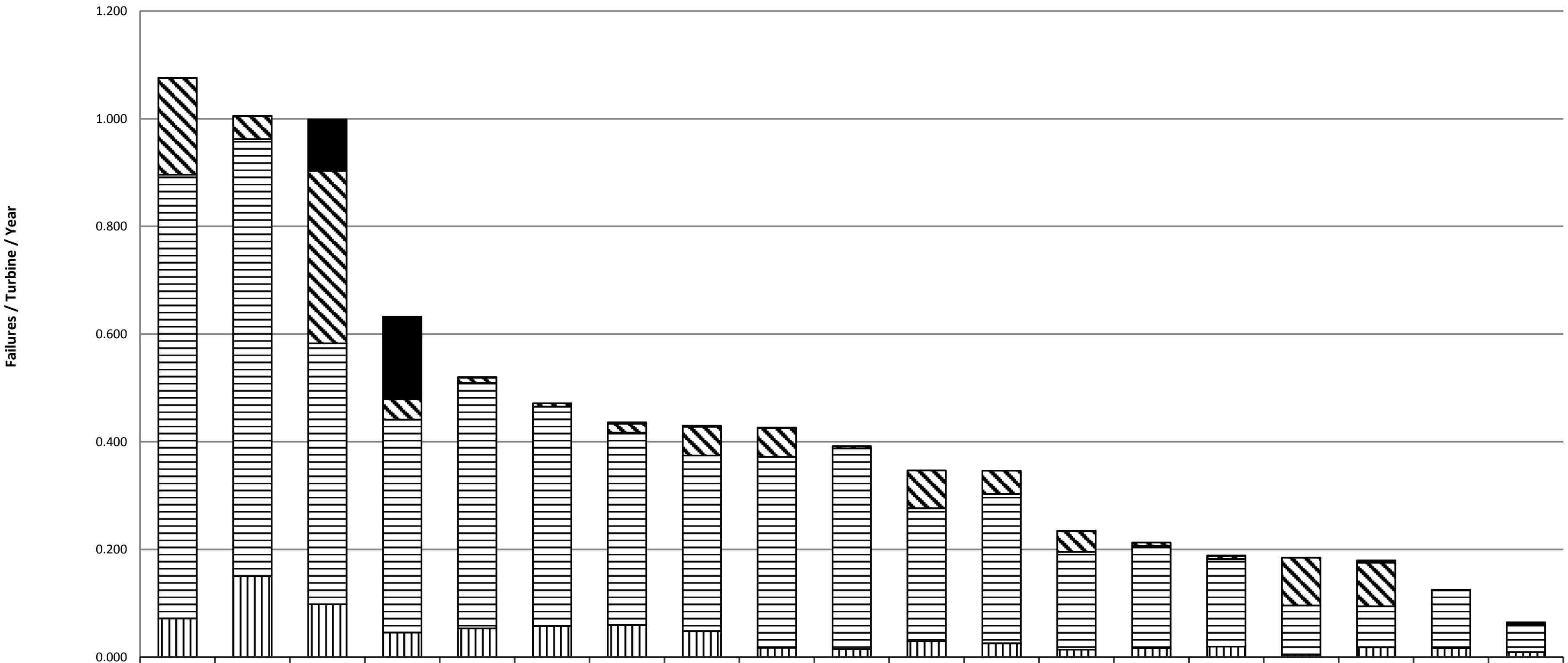
2.3.1 Overall failure rate

Based on the analysis outlined in the methodology section, the average failure rate for an offshore wind turbine from the population in this analysis is 8.3 failures per turbine per year. This consists of 6.2 minor repairs, 1.1 major repairs and 0.3 major replacements. 0.7 failures per turbine per year have no cost data so could not be categorized. The "no cost data" category must be allocated to the other categories when it comes to using this data for O&M cost modelling. The 0.7 failures per turbine per year with no cost data were spread across the other three failure categories based on their percentage contribution to the overall failure rate. For example, if minor repairs make up 70% of the overall failure rate, then the minor repair category would be allocated 70% of the failures that have no cost data and have not been otherwise categorised.

Figure 2.12 shows the breakdown of that failure rate by wind turbine subassembly/component and by failure cost category. The failure cost categories are detailed in Section 2.2.2. In the figure, the vertical hatching represents failures that have no cost data available, the horizontal hatching represents minor repairs costing less than €1,000, the diagonal hatching represents major repairs costing between €1,000 and €10,000 and the solid black sections represent major replacements costing over €10,000.

The biggest contributor to the overall failure rate for offshore wind turbines in the population analysed is the pitch and hydraulic systems. The pitch and hydraulic systems make up ~13% of the overall failure rate. “Other Components” is the second largest contributor to the overall failure rate with ~12.2% of the overall failures. The “Other Components” group consists of failures to auxiliary components which enable the other systems to function such as lifts, ladders, hatches, door seals, nacelle seals and so on. The generator, gearbox and blades are the third, fourth and fifth biggest contributors to the overall offshore failure rates with 12.1%, 7.6% and 6.2% respectively.

When minor repairs alone are considered the pitch and hydraulic systems as well as the “Other Components” group are again the largest contributors making up 26% of the failures for the minor repair category. The lack of major repairs or major replacements in the other components section is explained by the fact that the majority of the repairs are to small lower value components such as repairs to lifts, ladders, hatches and seals. The greatest contributor to the major repairs of the turbine is the generator; here 30% of the failures are in the major failure category. Looking to the third smallest contributor overall, it can be seen that the power supply/ converter has a high percentage of major repairs, this is due to IGBT issues and the cost of replacing an IGBT module being between €1,000 and €10,000. Generator and gearbox failures make up 95% of all failures in the major replacement category. The gearbox has more failures than the generator at 0.154 failures per turbine per year in comparison to 0.095 failures per turbine per year for the generator.



	Pitch / Hyd	Other Components	Generator	Gearbox	Blades	Grease / Oil / Cooling Liq.	Electrical Components	Contactor / Circuit Breaker / Relay	Controls	Safety	Sensors	Pumps/Motors	Hub	Heaters / Coolers	Yaw System	Tower / Foundation	Power Supply / Converter	Service Items	Transformer
■ Major Replacement	0.001	0.001	0.095	0.154	0.001	0.000	0.002	0.002	0.001	0.000	0.000	0.000	0.001	0.000	0.001	0.000	0.005	0.000	0.001
◪ Major Repair	0.179	0.042	0.321	0.038	0.010	0.006	0.016	0.054	0.054	0.004	0.070	0.043	0.038	0.007	0.006	0.089	0.081	0.001	0.003
⊟ Minor Repair	0.824	0.812	0.485	0.395	0.456	0.407	0.358	0.326	0.355	0.373	0.247	0.278	0.182	0.190	0.162	0.092	0.076	0.108	0.052
◫ No Cost Data	0.072	0.150	0.098	0.046	0.053	0.058	0.059	0.048	0.018	0.015	0.029	0.025	0.014	0.016	0.020	0.004	0.018	0.016	0.009

Figure 2.12: Offshore wind turbine failure rate graph for subassembly/component and cost category

2.3.2 Overall failure per year of operation

As the drive train is the focus of this thesis the gearbox, generator and converter were the focus of the failure rate vs. time analysis. The remainder of the turbine components/subsystems were combined in a grouping called “Rest of Turbine”. The method for the failure rate vs. time analysis was taken from reference [15] and is outlined in Section 2.3.2 of this chapter.

2.3.2.1 Gearbox

The failure distribution for the gearbox can be seen in Figure 2.13. The gearbox passes the goodness of fit analysis, which is outlined in the literature review in Section 2.12. The trend line has a shape parameter of 0.869. The HPP hypothesis is rejected. Based on Table 2.1 from section 2.1.2 of this chapter, all of the above means the gearbox displays slight early failure characteristics. This is not the case with the gearbox data examined in [15] in which early failures are not observed. A reason for the difference may be the lack of experience offshore.

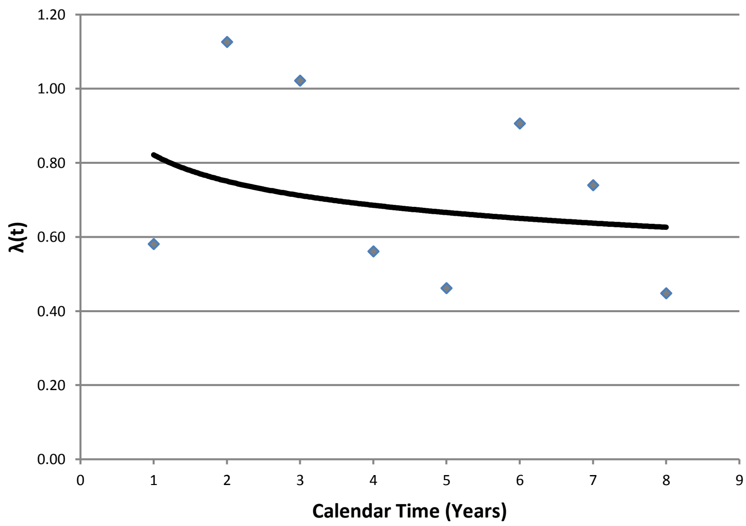
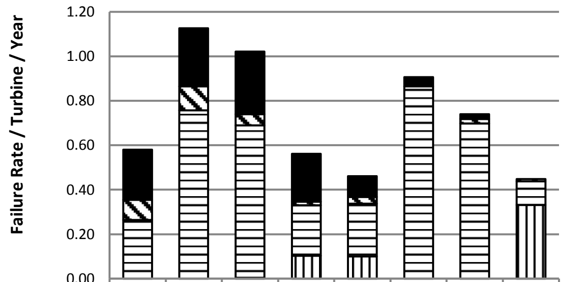


Figure 2.13: Gearbox failure rate with time. $R^2 = 0.066$

Figure 2.14 shows what the failure rate per operational year consists of. It can be seen that the gearbox shows mostly minor repair but a high percentage of major issues in comparison to the rest of turbine group seen in Figure 2.20. These major issues are seen in the earlier years of operation and reduce in the later years.



	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Major Replacement	0.23	0.26	0.28	0.21	0.09	0.04	0.02	0.00
Major Repair	0.09	0.11	0.05	0.02	0.03	0.00	0.02	0.01
Minor Repair	0.26	0.76	0.69	0.23	0.24	0.86	0.70	0.11
No Cost Data	0.00	0.00	0.00	0.10	0.10	0.00	0.00	0.33

Figure 2.14: Gearbox failure categories

2.3.2.2 Generator

The failure distribution for the generator can be seen in Figure 2.15. The generator passes the goodness of fit analysis. The trend line has a shape parameter of 1.118. The HPP hypothesis is rejected. Based on Table 2.1 from Section 2.1.2 of this chapter, all of the above mean the generator displays slight failure deterioration characteristics. This is not the case with the onshore generators data examined in [15] where the trend can often be represented by a HPP. A reason for the difference may be the harsher environment offshore leading to a slightly increasing failure rate with time. Early failures from the move to offshore may not have been seen because the type of generator used in this analysed population is a very mature and understood generator for the manufacturer.

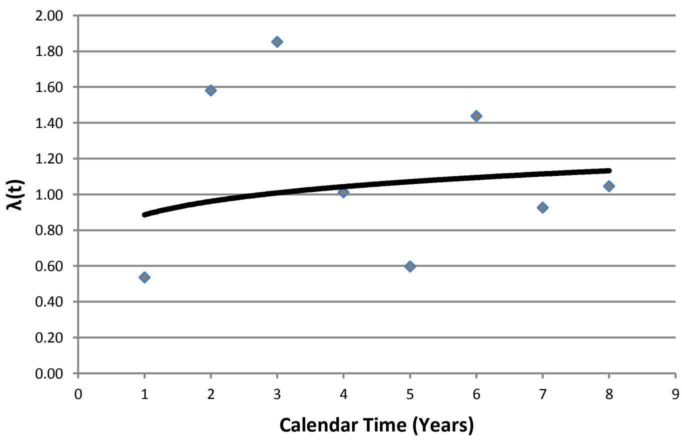
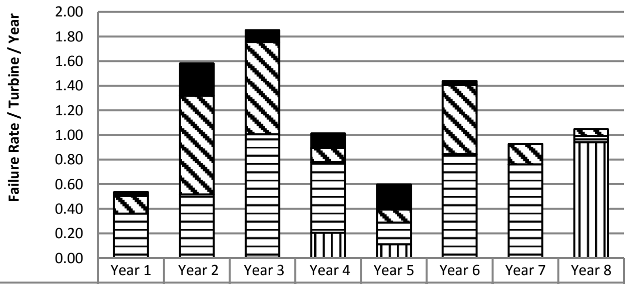


Figure 2.15: Generator failure rate with time. $R^2 = 0.035$

Figure 2.16 shows what the failure rate per operational year consists of. It can be seen that the generator experiences less minor issues than the rest of turbine group and a higher percentage of major repairs than the gearbox.



	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Major Replacement	0.03	0.26	0.10	0.12	0.20	0.03	0.00	0.00
Major Repair	0.14	0.80	0.75	0.12	0.11	0.56	0.17	0.05
Minor Repair	0.36	0.52	1.00	0.57	0.18	0.84	0.76	0.05
No Cost Data	0.00	0.00	0.00	0.21	0.11	0.00	0.00	0.94

Figure 2.16: Generator failure categories

2.3.2.3 Converter

The failure distribution for the converter can be seen in Figure 2.17. The converter passes the goodness of fit analysis. The trend line has a shape parameter of 0.561. The HPP hypothesis is rejected. Based on Table 2.1 from Section 2.1.2 of this chapter, all of the above means the converter displays early failure characteristics. This is also the case in [15] with onshore power converters.

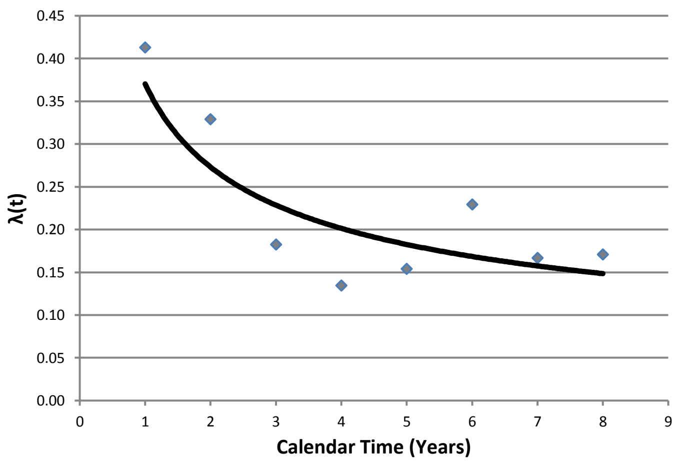
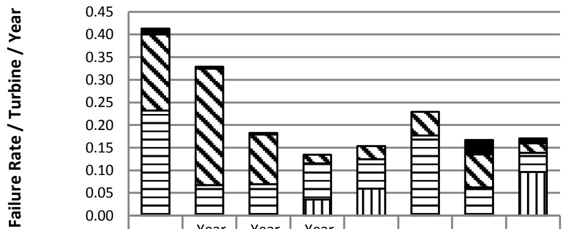


Figure 2.17: Converter failure rate with time. $R^2 = 0.622$

Figure 2.18 shows what the failure rate per operational year consists of. It can be seen that the converter shows a high percentage of major repair in the earlier years of operation. As mentioned these major repairs cost between €1,000 and €10,000 for material repairs. This is consistent with the cost of replacement IGBT modules. Similar converter repair costs for IGBT modules can be seen in Section 2.4.2 for onshore turbines.



	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Major Replacement	0.01	0.00	0.00	0.00	0.00	0.00	0.03	0.01
Major Repair	0.17	0.26	0.11	0.02	0.03	0.05	0.07	0.02
Minor Repair	0.23	0.07	0.07	0.08	0.07	0.18	0.06	0.04
No Cost Data	0.00	0.00	0.00	0.04	0.06	0.00	0.00	0.10

Figure 2.18: Converter failure categories

2.3.2.4 Rest of Turbine

The failure distribution for the "Rest of Turbine" group can be seen in Figure 2.19. The "Rest of Turbine" group passes the goodness of fit analysis. The trend line has a shape parameter of 0.944. This suggests that the trend line is close to being represented by HPP. However, the HPP hypothesis is rejected even though the shape parameter is close to 1. As the HPP hypothesis is rejected and based on Table 2.1 from Section 2.1.2 of this chapter, the "Rest of Turbine" group displays very slight early failure characteristics. Previous work [15] has shown that when turbine components and subsystems are grouped the combination of different component types produce a random failure rate over time. Even if it is the case that one of the components in the overall group shows a certain trend this trend becomes random when grouped with a number of different components. However the slight early failure trend observed in this data may be explained by the move offshore.

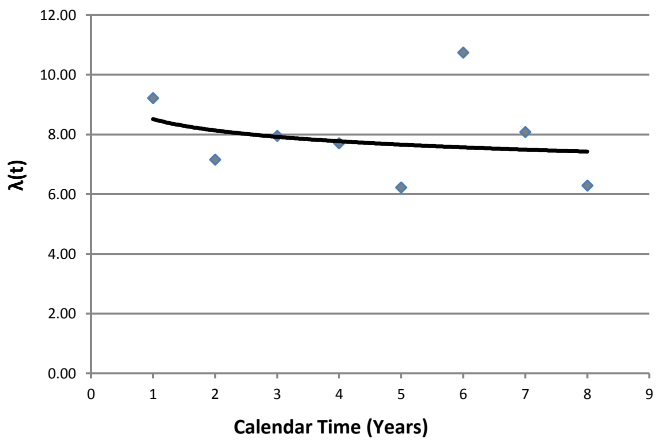
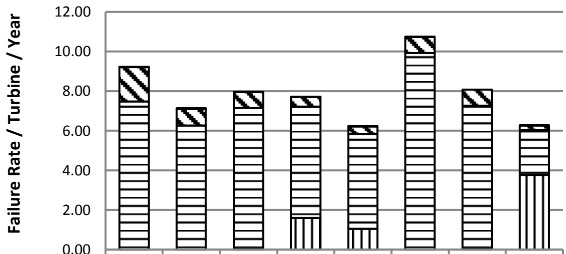


Figure 2.19: "Rest of Turbine" failure rate with time. $R^2 = 0.063$

Figure 2.20 shows what the failure rate per operational year consists of. It can be seen that the "Rest of turbine" group consists mostly of minor repairs.



	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Major Replacement	0.01	0.03	0.00	0.01	0.01	0.02	0.00	0.02
Major Repair	1.73	0.85	0.79	0.47	0.39	0.81	0.81	0.23
Minor Repair	7.48	6.26	7.13	5.62	4.76	9.92	7.24	2.25
No Cost Data	0.00	0.00	0.03	1.61	1.06	0.00	0.03	3.78

Figure 2.20: "Rest of Turbine" failure categories

The results from this failure rate with time analysis have shown that all four subsystem/groups analysed display either early failure or reliability deterioration trends. Even though shape parameters were sometimes between 0.79 and 1.2, none of the four subsystem/groups could be represented by the HPP, which past O&M modelling has assumed. Based on these results and findings from other analyses [15] that suggest average failure rates should not be used when failure trends are observed it can be concluded that past O&M cost modelling may be improved by observing failure rate trends prior to selecting the failure rate to represent the turbine subsystem.

The gearbox displayed a slight early failure trend suggesting that rather than taking the average failure rate over the 8 year period the failure rate from year 8 should be taken as an input for O&M modelling. The same can be said for the converter and "Rest of turbine failure rates". The generator displayed failure deterioration suggesting the failure rates from the first year of operation should be used as an input for O&M modelling.

In the case of this population, even though all 4 subsystems/groups passed the hypothesis test for goodness of fit, a low R^2 value and a large amount of variance from the trend lines can be seen in most graphs. The shape parameters were also in the range that can represent HPP. It is for these reasons that it is hard to have confidence that values taken from the failure trends would be significantly more representative than average failures. It is for this reason that average failure rates were used in the O&M modelling shown in Chapter 3 of this thesis.

2.3.3 Further analysis on failure modes

As seen in Figure 2.12 the top three subassemblies contributing to offshore failures are the pitch/hydraulic systems, other components and the generator. As a means of identifying the vital few failure modes from the trivial many, the following graphs show the top five failure modes in each of the three top failing subassemblies. As this thesis focuses on the drive train the top five failure modes for gearbox and converter have also been examined.

Figure 2.21 shows that oil and valve issues make up about 30% of the overall pitch/hydraulic failures with a further 20% consisting of actuator, sludge and pump repairs or replacements. Oil issues consist of failures like leaks, unscheduled oil changes and unscheduled oil top ups. Sludge issues consist of failures in sensors and leaks. The majority of valve, accumulator and pump issues are resolved through valve, accumulator and pump replacements.

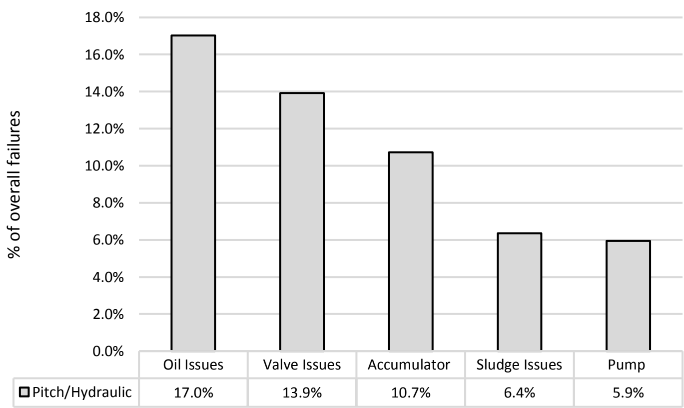


Figure 2.21: Pitch/hydraulic failure modes

Figure 2.22 shows that door hatch and skylight issues are the largest contributor to the “other components” failure group with approximately 25% of all failures in this area. The remaining 4 issues in the top 5 are covers, bolts, lighting and repairs to the lift, each of which contribute ~ 5% to the overall failure rate.

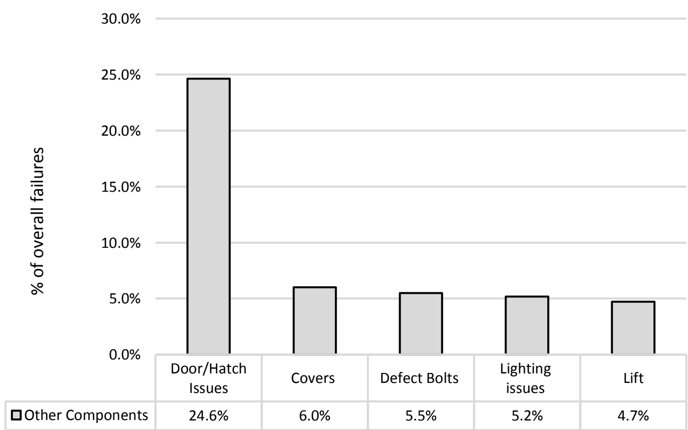


Figure 2.22: “Other Components” failure modes

Figure 2.23 shows that slip ring issues are the largest contributor to the generator failure group with approximately 31% of all failures in this area. The remaining 4 issues in the top 5 are bearing issues, problems with the generator grease pipes, issues with the rotor and fan replacements.

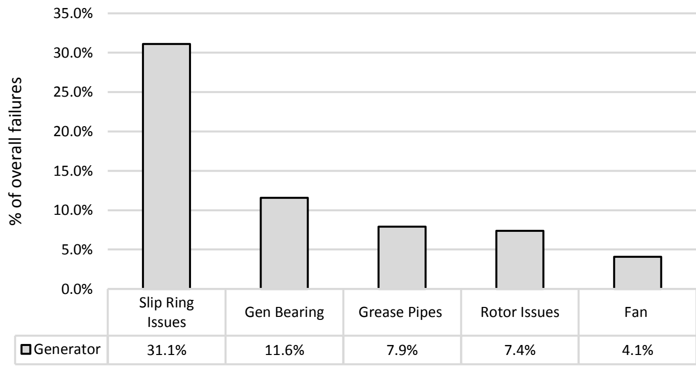


Figure 2.23: Generator failure modes

Figure 2.24 shows that for the power converter in the population analysed issues with the IGBT modules make up ~ 30% of the overall power converter failures. A further ~12% of the failures come from the encoder and the remaining three failure modes that make up the top five are the encoder, main circuit breaker and cooling issues. The majority of these repairs are minor repairs costing less than €1,000 in material costs to fix. However, the IGBT related issues also consist of major repairs costing between €1,000 and €10,000 in material costs to repair. This cost is incurred when full IGBT modules are replaced.

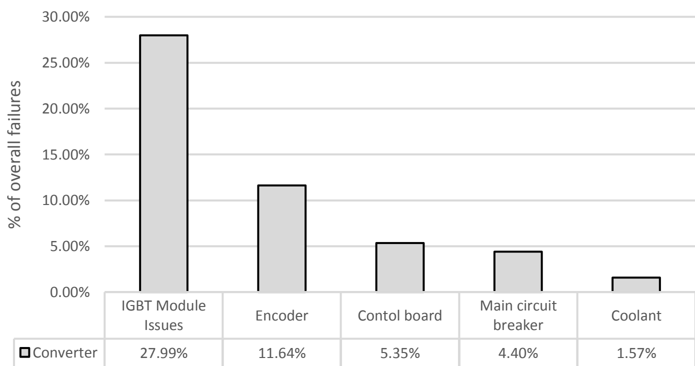


Figure 2.24: Power converter failure modes

Figure 2.25 shows that gear oil issues make up about ~29% of the overall gearbox failures with a further ~9% consisting of gearbox seal issues. Gear oil issues consist of failures like leaks, unscheduled oil changes and unscheduled oil top ups. Gear seal issues also consists of failures like leaks but are repaired through the changing of a gearbox seal. Problems with the swarf sensor are the third biggest contributor to the overall gearbox failure rate. This is followed by bearing and cooling issues.

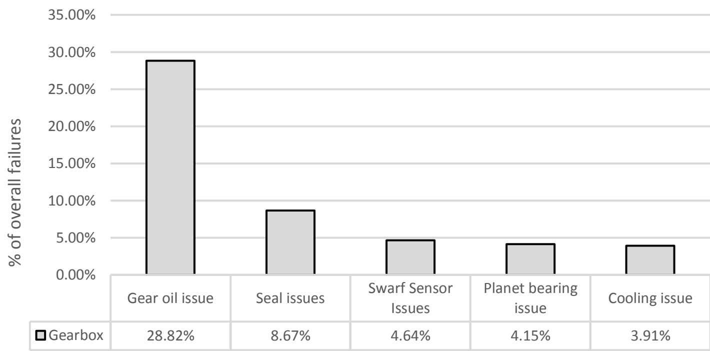


Figure 2.25: Gearbox failure modes

2.4 Onshore generator and converter reliability results

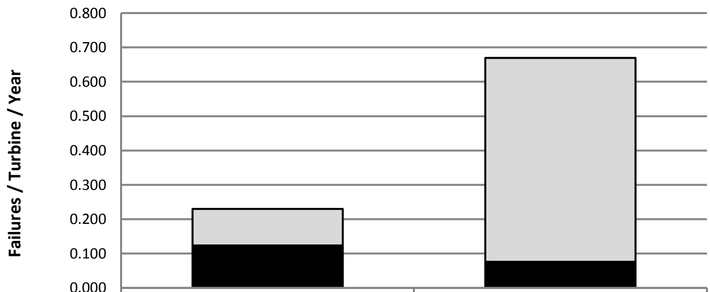
As outlined in the analysis introduction and methodology sections 2.22 and 2.23 an onshore reliability analysis was also carried out comparing the reliability of two different drive train types. The following sections show results from that analysis.

2.4.1 Generator and converter failure rate comparison

The failure rates for the permanent magnet generator (PMG) and the doubly fed induction generator (DFIG) can be seen in Figure 2.26. The failure rates of 0.123 failures per turbine per year for the DFIG and 0.076 failures per turbine per year for the PMG include the failures for the generator auxiliary systems, such as cooling and lubrication. The failure rate difference of 0.047 between both generator types is due to the fewer possible failure modes in the PMG. For example, rotor winding issues that may occur in a DFIG will not be experienced by a PMG because the PMG has a permanent magnet rotor rather than an electrically excited wound rotor. PMGs will also avoid the failures related to slip rings and brushes, which DFIGs encounter, because brushes and slip rings are not required in a PMG.

The failure rates for the PRC and the FRC can also be seen in Figure 2.26. The FRC and PRC are manufactured by the same converter manufacturer. The failure rates of 0.106 for the PRC and 0.593 for the PMG FRCs include the failures for a converter's auxiliary cooling system. A reason for the higher failure rate of the FRC can be seen in [14]. It is suggested that the converter module used in the FRC is roughly 3 times the size of the converter module in the PRC meaning there are more opportunities for failure. The FRC is approximately three times bigger than the partially rated converter because it must be rated for all of the turbines nominal power whereas the PRC is only rated to deal with approximately one third of the turbines nominal power. When the converter is rated for all of the turbines nominal power it consists of more parts which are potential failure modes e.g. more IGBT modules.

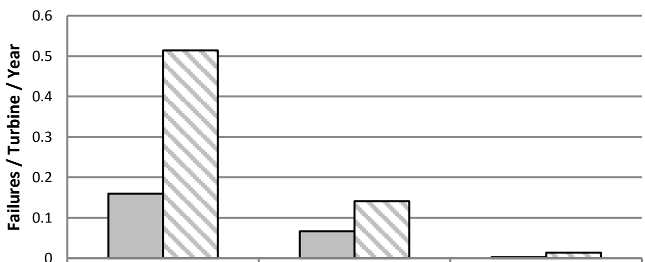
The overall PMG FRC configuration failure rate of 0.669 failures per turbine per year is nearly 3 times greater than the DFIG PRC configuration failure rate of 0.229 failures per turbine per year. The driver for this large difference is the FRC. As seen in Figure 2.26, the PMG has a lower failure rate than the DFIG but the much larger FRC failure rate means the PMG FRC configuration is higher overall.



	DFIG	PMG
Converter	0.106	0.593
Generator	0.123	0.076

Figure 2.26: Failure rates for generators and converters from both configurations

Figure 2.27 shows the cost categorization of failures for both configurations. It can be seen that the PMG FRC configuration has a failure rate over 3 times greater than the DFIG failure rate for minor failures costing below €1,000. The DFIG failure rate is ~ 50% that of the PMG FRC failure rate for major repairs costing between €1,000 and €10,000. The major repair failure rate for repairs costing over €10,000 are 0.014 failures per turbine per year for the PMG FRC configuration and 0.003 failures per turbine per year for the DFIG configuration.

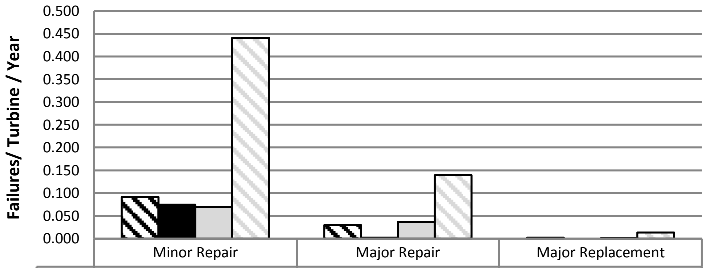


	Minor Repair	Major Repair	Major Replacment
DFIG Config.	0.16	0.067	0.003
PMG Config.	0.514	0.141	0.014

Figure. 2.27: Generator and converter failure rate per failure severity category

2.4.2 Failure modes and failure cost categories for both generators and converters

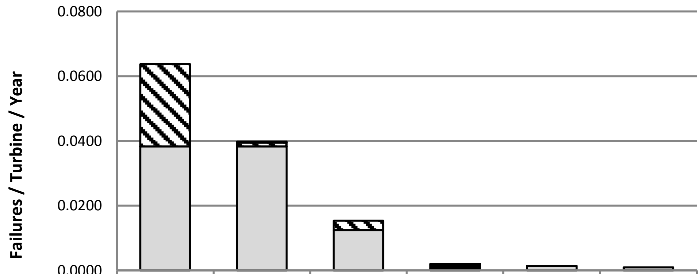
The DFIG failure rate of 0.123 failures per turbine per year is broken down into the three failure categories as described in Section 2.2.2. This break down is shown in the black hatching in Figure 2.28. The majority of the failures that occur in the DFIG are minor repairs, costing less than €1,000. Approximately 25% of failures are major repairs costing up to €10,000 and ~1.6% of the 0.123 failures / turbine / year are major replacements. In this analysis both the PMG and the DFIG are water cooled.



	Minor Repair	Major Repair	Major Replacement
DFIG	0.091	0.030	0.002
PMG	0.074	0.002	0.000
PRC	0.069	0.037	0.001
FRC	0.440	0.139	0.014

Figure 2.28: DFIG, PMG, PRC and FRC failure rate per failure severity category

Figure 2.29 shows the failure modes for the DFIG. Brush and slip ring related issues are the greatest contributor to the failure rate. The second highest contributor is generator bearing related issues; this category includes problems with the bearing itself, bearing sensor issues and problems with the generator bearing lubrication system. Issues with bearing can be caused by a number of reasons such as misalignment and unbalanced magnet pull [23]. The majority of the major replacements shown in black in Figure 2.29 are due to insulation issues; stator insulation in particular. Reference [24] suggests that insulation failures can be caused by overheating, which may have been the case here. A major replacement also occurs in the generator bearing category. When these failure modes and contributions to the overall failure rate are compared to past literature outlined in Section 2.1.2 and in particular Figure 2.4, it can be seen that there are similarities between the results in Figure 2.29 and past publications. Bearing issues were the largest contributor to the overall failure rate for a generator in [11], it can be seen that bearing issues are also one of the higher contributors in this analysis. It is worth noting that the majority of the failures related to the bearing are minor repairs, e.g. lubrication issue, and a lower failure rate in which a major replacement was required. The slip ring and brush related issues are the greatest contributor to the overall failure rate in this analysis but were not in past literature. One of the reasons for this is because of the way a failure is defined. In this analysis a failure is defined as any visit to a turbine outside of a schedule operation in which a material is used. However in other analyses changing brushes may not be considered a failure because they are a consumable item. In this analysis they are not considered a failure if they are changed during a scheduled service but are consider a failure if they are changed in a visit to the turbine outside of a scheduled service.



	Slip Ring/Brush Issue	Gen Bearing Issue	Gen Cooling System	Insulation Issue	Gen Encoder	Gen Allignment
Major Rep.	0.0000	0.0003	0.0000	0.0018	0.0000	0.0000
Major Repair	0.0254	0.0012	0.0029	0.0003	0.0000	0.0000
Minor Repair	0.0383	0.0383	0.0124	0.0000	0.0015	0.0009

Figure 2.29: DFIG failure rate per failure mode and failure severity category

As with the DFIG the PMG failure rate of 0.079 failures / turbine / year is broken down into the three failure cost categories. This break down is shown in solid black bars Figure 2.28. Even more so than the DFIG, the vast majority of the failures that occur in the PMG are minor repairs, ~ 97.4% of all the failures are minor repairs below €1,000. Approximately 2.6% of failures are major repairs costing up to €10,000 and there are no major replacements or repairs over €10,000.

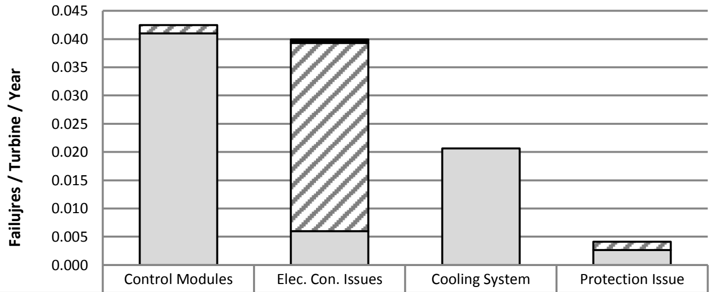
To determine which failure modes contributed to the failure rate of 0.076 failures / turbine / year, a failure mode analysis was also carried out for the PMG. The results of this analysis are seen in Figure 2.30. The majority of the failures with the PMG are related to the generators auxiliary systems, with the lubrication and cooling system making up ~89.5% of the failures. The fact that these auxiliary system repairs are generally quite cheap to repair helps explain why ~98.4% of all PMG failures are minor repairs costing below €1,000.

	Gen Lubrication System	Gen Cooling System	Gen Alignment
Major Repair	0.000	0.002	0.000
Minor Repair	0.051	0.016	0.008

Figure 2.30: PMG failure rate per failure mode and failure cost category

For the PRC failure rate of 0.106 failures per turbine per year the solid grey bars in Figure 2.31 show the failure cost categorization. Over 99% of the failures are below €10,000 with 64% of these failures costing under €1,000.

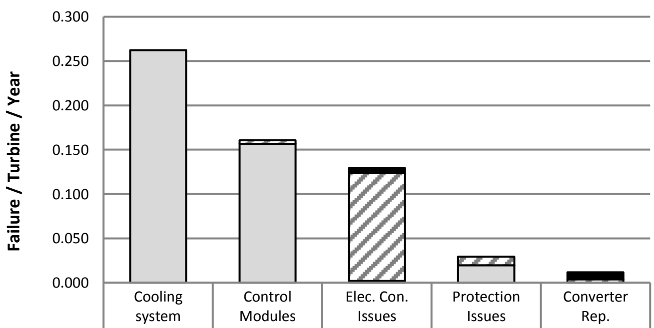
As with the DFIG and PMG, a failure mode analysis is carried out on the PRCs. The results of this analysis are seen in Figure 2.31. The biggest contributor to the failure rate is the converter control modules; they account for approximately 39% of failures, this is closely followed by electrical connection issues. In this analysis the gate-driver board and IGBT issues are included in the electrical connection issues. Other failure modes include the converters cooling system and converter protection.



	Control Modules	Elec. Con. Issues	Cooling System	Protection Issue
Major Rep.	0.000	0.001	0.000	0.000
Major Repair	0.001	0.033	0.000	0.001
Minor Repair	0.041	0.006	0.021	0.003

Figure 2.31: PRC failure rate per failure mode and failure severity category

As seen in Figure 2.26 the FRC has the highest failure rate of all parts analysed in this section. In Figure 2.32 the failure categorization is shown in grey hatched bars. It is worth noting that for the FRC the major repair failures alone are higher than all cost category failures combined for the converters used in the DFIG configuration at 0.139 and 0.106 respectively. The results of the failure mode analysis are seen in Figure 2.32. The failure modes seen in Figure 2.31 and Figure 2.32 are named and grouped in this manner on request of the manufacturer to satisfy confidentiality agreements.



	Cooling system	Control Modules	Elec. Con. Issues	Protection Issues	Converter Rep.
Major Rep.	0.000	0.000	0.006	0.000	0.008
Major Repair	0.000	0.004	0.121	0.010	0.004
Minor Repair	0.262	0.157	0.002	0.020	0.000

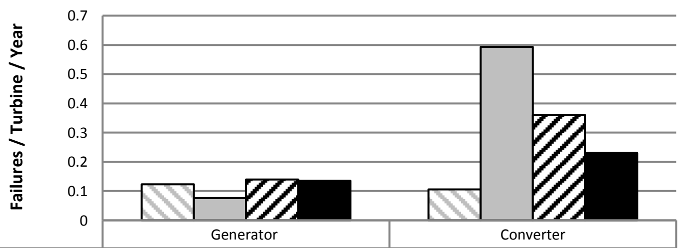
Figure 2.32: FRC failure rate per failure mode and failure severity category

Causing over 44% of the FRC failures, the converter cooling system is the largest contributor to the overall failure rate. Converter control module issues are the second most common failure mode for the FRC, followed by electrical connection issues. These electrical connection issues are one of the big contributors towards cost with all of the failures related to these issues being in the higher cost brackets. IGBT issues and gate-driver board issues are again included in the electrical connection issues section. The remainder of the failure modes relate to protection issues or the replacement of the full converter module. No details were provided on why the overall converter module had to be replaced, but these replacements fall into the highest cost bracket.

When compared to converter failure rates in the literature review, like the generator, it can be seen that there are some differences and some similarities. The differences are seen for the same reason as they occur in the generator failure mode analysis e.g. the way in which a failure is defined. The results in Figure 2.32 show that the cooling system is the greatest contributor to the overall failure rate in a converter, however this is not the case in past literature. The reason for this is because if the cooling system needs to be topped up or fixed outside of a scheduled service it is counted as a failure, whereas that may not have been the case in other studies. The similarities are in the high contributions of the control modules and electrical connection issues (which are named “phase module” and “control board” in [13]).

Comparison

As stated in the Introduction, a number of papers that look at different failure rates for onshore wind turbine systems and sub-assemblies exist. Figure 2.33 compares the failure rates presented in [4] and [5] to the failure rates presented in this analysis. In this work the generator and converter failure rates are separated for the different turbine configurations; however, this is not the case for the analyses carried out in [4] and [5], in which both populations analysed contain mixed drive train configurations.



	Generator	Converter
DFIG Config.	0.123	0.106
PMG Config.	0.076	0.593
Reliawind [4]	0.14	0.36
Spinato [5]	0.135	0.23

Figure 2.33: Generator and converter failure rate comparison with other papers

Figure 2.33 shows all four generator failure rates are relatively similar, with the greatest difference coming between the PMG failure rate from this work and the generalized generator failure rate from the Reliawind analysis. Both generator failure rates from this chapter are lower than the failure rates from the other two analyses. Spinato in [5] provides a failure rate range from 0.05 – 0.135. The range reflects different populations and ages. The lower end of the scale comes from older WindStats Denmark data for smaller turbines. The higher end of the range is from a German population that includes larger turbines and direct drive machines which are known to have a higher failure rate [5]. The Reliawind study from [4] is based on a population that is more modern than [5]; this suggests larger turbines which could explain the slightly higher failure rate. In comparison to this analysis, the slightly higher failure rate could also be related to the population including some direct drive machines, which have higher failure rates than geared driven machines [5].

When compared with the generator failure rates across all 3 analyses, the converter failure rates show a greater variance. The largest difference is seen between the PRC and the FRC from this chapter. The general converter failure rate in [4] comes from modern wind turbines all of which are at least greater than 850kW. This ensures that the nominal power difference is not as much of a factor as it is with [5] in which the turbines nominal power are smaller. The fact that the Reliawind failure rate is slightly closer to the PRC failure rate than to the PMG FRC failure rate from this chapter, may suggest that the Reliawind population consists of more DFIG configurations than FRC configurations.

2.5 Wind speed and onshore to offshore comparison

Failure rates for onshore wind turbine components may be different to failure rates for offshore wind turbine components. There are a number of reasons for these differences, such as, the difference in onshore and offshore environments, wave loading, wind speed, turbine size, O&M differences and so on. To analyse the impact of wind speed on the failure rate of the offshore population in this thesis, the average failure rate per year and average wind speed per year for each of the turbines in this population are plotted in Figure 2.34a. In the past this has been shown for onshore turbines and components [25] and [26] but not for offshore turbines. Reference [26] shows a trend for onshore turbines to have a higher failure rate in higher wind speeds. It contains a similar graph to Figure 2.34 in which the slope of the line is 0.08 showing a relatively weak correlation. It can now be seen from Figure 2.34

that offshore there is also an overall trend for turbines that are sited in areas with higher wind speeds to experience higher failure rates. The slope of the line in Figure 2.34 is 1.77 showing a stronger correlation. When compared to the slope of 0.08 from [26] it is obvious that higher wind speeds have a greater impact on failure rates offshore compared to onshore. A similar analysis was carried out for turbulence intensity and can be seen in Figure 2.34b, however no clear trend was observed.

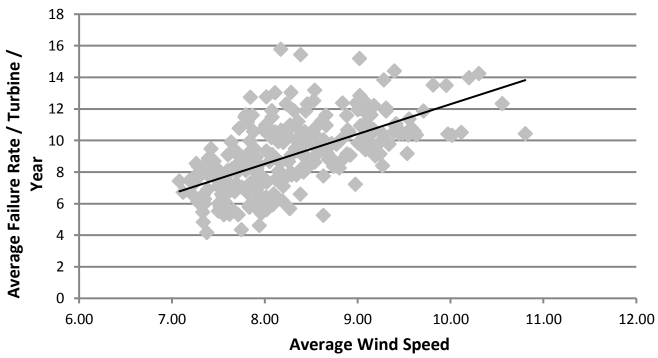


Figure 2.34a: Average wind speed vs. average wind speed

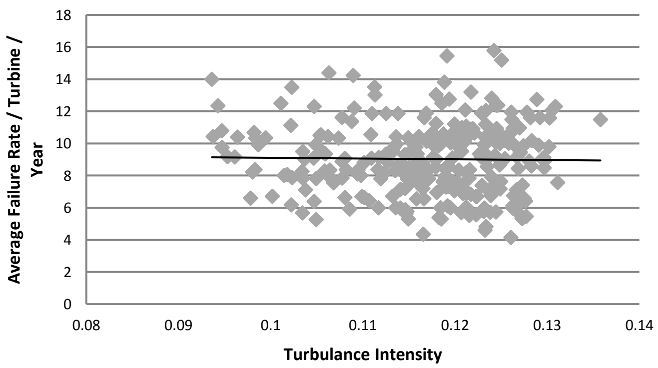
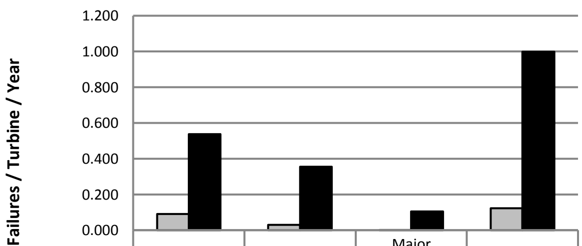


Figure 2.34b: Average turbulence intensity vs. average wind speed

The generator and converter failure rates from both the onshore and offshore analyses shown earlier in this chapter are compared in the following pages. Figures 2.35 and 2.36 use the onshore failure rates from Section 2.4.1 and the offshore failure rates for the generator and converter from Section 2.3.1 to compare the difference between onshore and offshore failure rates.

Figure 2.35 shows the onshore generator failure rates in grey and the offshore generator failure rates in black. It can be seen that overall the onshore failure rate is approximately eight times less than the offshore failure rate. This higher failure rate for offshore is evident across each of the 3 failure cost categories, minor repair, major repair and major replacement. As previously mentioned, there are a number of possible explanations for the lower onshore failure rate. One may be that offshore sites have a higher average wind speed than onshore sites and as seen in Figure 2.34 this in turn leads to a higher failure rate. The average wind speeds from all offshore sites in this paper is 8.2 m/s. The average wind speed from a similar number of onshore sites in Germany (where the majority of the onshore failure rate population in Figures 2.35 and 2.36 comes from) is 6.3m/s [27]. Based on Figure 2.34 this would see a 33% increase in onshore to offshore failure rates due to wind speeds alone. Another reason could be that onshore turbines are maintained to a better standard due to easier access which in turn reduces failures. Other reasons for the difference in Figures 2.35 and 2.36 could be down to the difference in populations analysed. Both populations have a different number of operational years and rated powers. The offshore population has a higher rated power than the turbines in the onshore populations and it is known that larger turbines have a higher failure rate [28]. Reference [20] looks at the failure rate of turbines with different rated power and concludes that for the population analysed the turbines with a higher rated power have a higher failure rate. Based on extrapolating the failure data from Figure 5 in reference [28] it was calculated that the difference in rated power, for the onshore and offshore populations compared in this chapter, would lead to a greater offshore failure rate of 27%. The difference in failure rate of turbines with different rated powers may also be dependent on turbine types. The 27% estimation is not a universal constant coefficient, it is just provided as an example of the difference in failure rate when rated powers change, based on the population from [28]. The harsher environment offshore may also contribute to the difference in failure rate from onshore to offshore. For components outside the nacelle such as blades and towers this will most likely be the case. Manufacturers have tried to mitigate the harsher environment by hermetically sealing the nacelle to protect components like the generator and converter. However, these components may be exposed when the maintenance and repairs are being carried out. Wave loading on the wind turbine may also play a part in the greater failure rate seen offshore.

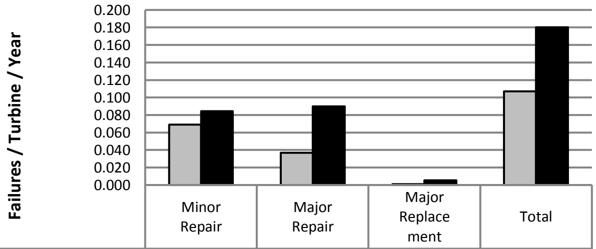


	Minor Repair	Major Repair	Major Replace ment	Total
Generator (Onshore)	0.091	0.030	0.002	0.123
Generator (Offshore)	0.538	0.356	0.105	0.999

Figure 2.35: Onshore vs. offshore generator failure rates

If it is the case that the points discussed above are the driver for the far greater failure rate for electro-mechanical components like a generator, these points do not seem to have such a high impact on purely electrical components such as the converter shown in Figure 2.36. The onshore converter is again shown in grey and the offshore converter is shown in black. It can be seen that the total difference in failure rate for the converter is less than the total difference in failure rate for the generator. Overall there are ~40% more failures for the offshore converters than there are for the onshore converters.

When combined the reasons stated in the previous paragraphs for the difference in onshore to offshore failure rates equal ~ 60%. This is 20% more than the observed difference in the converter but far less than what is observed for the difference in onshore and offshore generators. This leads the author to believe that there are certain components in a turbine that the step from onshore to offshore affects more than others. It must also be considered that other unquantified factors are driving the difference in generator failure rates when they are moved from on to offshore.



	Minor Repair	Major Repair	Major Replacement	Total
Converter (Onshore)	0.069	0.037	0.001	0.107
Converter (Offshore)	0.084	0.090	0.006	0.180

Figure 2.36: Onshore and offshore converter failure rates

2.6 Adjusting reliability data for different wind turbine types

As previously mentioned the direct drive PMG and 2 stage drive train configurations have less of an installed capacity compared to 3 stage turbines. Consequently, there is, as yet, no published failure rate data on wind turbines with these drive train configurations. Other innovative drive train configurations are also untried, so the challenge of estimating failure rate without operational data is a common and significant one. REMM is a methodology, created for the Aerospace and Defence industry, to combine engineering design concerns with historical data to estimate the reliability of a system in the design phase [29, 30, 31, 32]. The methodology then identifies different activities that can be actioned to optimize reliability improvement.

A key feature of REMM is that the method assumes that new systems are based in part on previous technologies where engineering judgement can identify, from a reliability perspective, the key differences between the new system and the previous system. Design changes between the two systems will in part remove failure modes and improve reliability. However, the design team may have concerns that new failure mechanisms have been introduced based on these design changes. For example, in the case of this chapter, new stator winding issues are encountered when going from high speed to low speed generators. These engineering concerns are elicited along with an estimate of how likely it is that these concerns will occur in-service and an estimate of the failure rate. This data is combined with historical data to create a new overall failure rate for the new component. This process applied to the historical 3 stage PMG data to estimate the direct drive PMG failure rate is explained in the following paragraphs.

Figure 2.37, taken from [32] illustrates how the reliability of a new system or component can be modelled based on experience from a similar older system or component. Figure 2.38 shows how this approach was applied to estimate the failure rate of a direct drive and 2 stage PMG based on the field experience of a 3 stage PMG.

In these cases the known offshore 3 stage PMG failure rate was adjusted to represent the offshore failure rate for the direct drive PMG and the 2 stage PMG. To estimate the offshore direct drive PMG failure rate, paper [5] was used because it describes how the onshore direct drive wound rotor generator has a failure rate twice as high as a 3 stage generator. However as the direct drive failure rate was for a wound rotor syncronous generator the doubling of the failure rate was not simply applied to the 3 stage PMG generator, it was only applied to the stator and bearing related failures leading to an offshore failure rate of 0.585 failures per turbine per year for the direct drive generator. A similar method was carried out for the two stage generator. This failure rate estimation method could be improved if the a further break down of the failure modes for a wound rotor syncrnous generator could be obtained. That would allow for a more accurate adjustment of the stator and bearing failure modes in the 3 stage PMG for which we have field data. A sensitivity analysis is carried out on the failure rates of the direct drive and 2 stage PMGs later in this chapter to try and capture the uncertainty in these estimated failure rates.

The failure rate for the two stage gearbox was obtained by reducing the 3 stage gearbox failure rate, which was based on field data, by 29.5%. This reduction is based on the FMEA published in [6]. The results of which are shown in Figure 2.39.

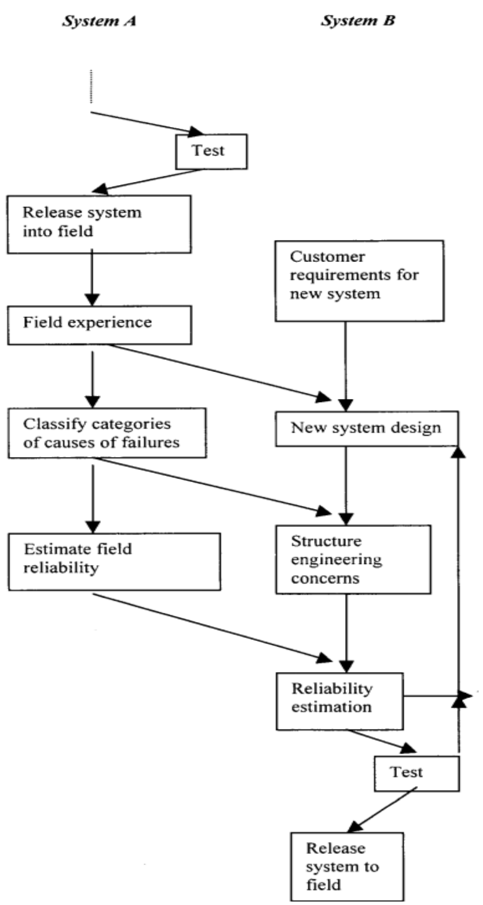


Figure 2.37: Flow chart showing reliability modelling of a new component based on a similar old component [32].

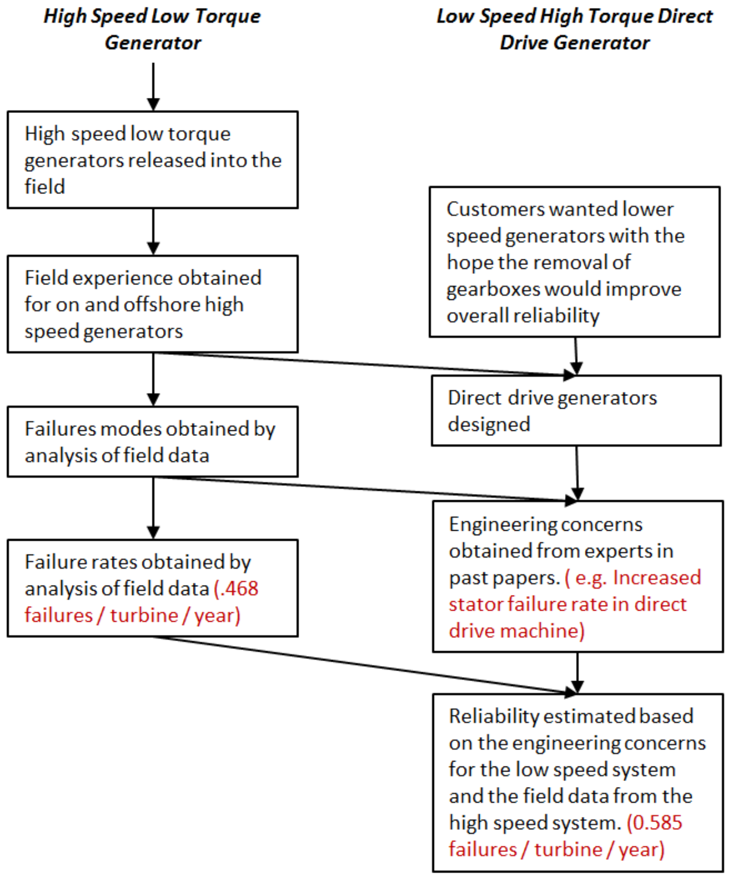


Figure 2.38: Flow chart showing the process of estimating the failure rate of the direct drive PMG based on known 3 stage PMG data.

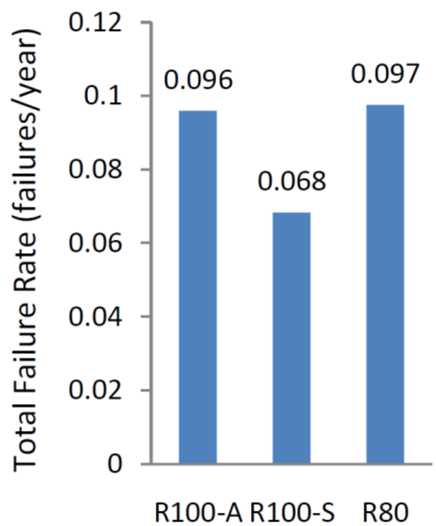
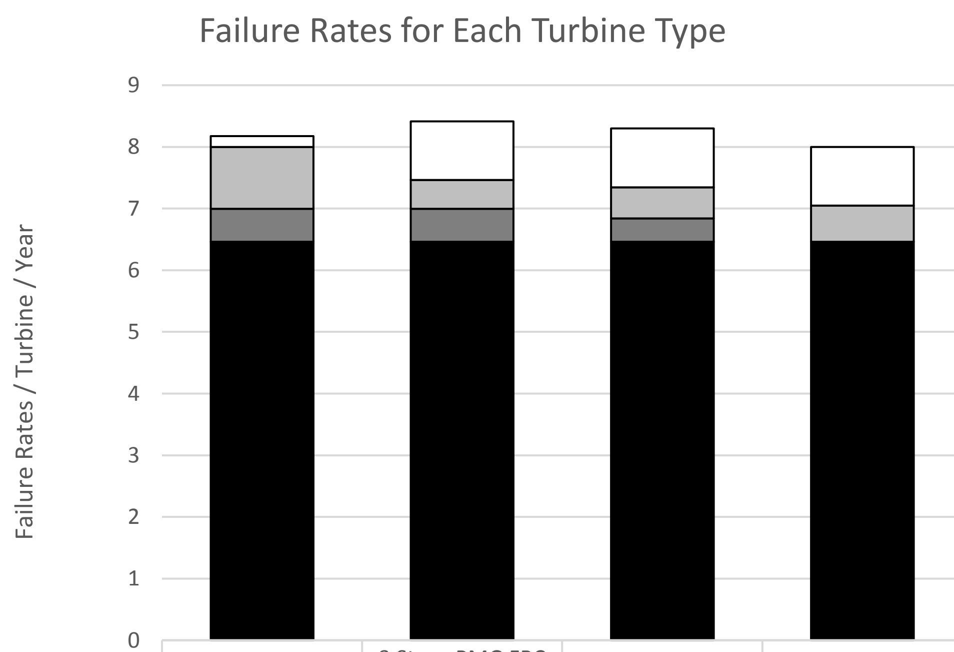


Figure 2.39: Failure rate comparison of 2 and 3 stage gearboxes showing the 29.5% difference in failure rate between the 3 stage and 2 stage configurations. [6]

Based on the analysis and adjustments detailed in the previous sections, Figure 2.40 shows the failure rates for all four of offshore wind turbine types. The failure rates are grouped by converter, generator, gearbox and "rest of turbine". The "rest of turbine" grouping is the sum of the failure rates from all of the wind turbine components outside of the gearbox, converter and generator. In reality there will be differences between the "Rest of turbine" failure rates, however due to lack of data and the fact that this thesis is only focusing on different drive train types, it was assumed failures for each turbine type were the same outside of the different drive train types. The three stage failure rates were based on the empirical offshore analysis for one of the 3 stage drive train types and the failure rates for the second 3 stage drive train type were estimated by applying the same percentage difference for each cost category from the onshore analysis in Section 2.4.1 to each cost category from the offshore data in Section 2.3.1. The 2 stage gearbox failure rate was estimated based on applying the percentage difference between a two stage and three stage gearbox from the FMEA in [6] to the offshore 3 stage gearbox in failure rates from Section 2.3.1. The medium speed PMG and the direct drive PMG were estimated using the offshore generator failure rates from Section 2.3.1 and REMM. Both 3 stage generator failure rates are assumed the same due to lack of data to differentiate them and because both have similar operational speeds, at approximately 1600 rpm. Figure 2.40 displays the resulting failure rates. Failure rates may be slightly different than the sum of the failure rates for components in Figure 2.12. The reason for this is because certain components had serial failures (e.g. failures that could be directly linked to a design fault) removed from the data for Figure

2.40 but not for Figure 2.12 because the failure rates shown in 2.40 were to be used for O&M modelling. Figure 2.40 answers the research question set out in the introduction of this chapter, it shows that the direct drive PMG FRC wind turbine type has the lowest overall failure rate followed by the 3 Stage DFIG PRC, then the 2 stage PMG FRC and lastly the 3 stage PMG FRC. As the 3 stage failure rates are based very closely on field data it is likely that they will be more accurate than the two stage and direct drive failure rate estimates. However as the systematic approach outlined earlier in this chapter was followed when estimating the 2 stage and direct drive failure rates it is expected that the failure rates shown should provide an accurate representation of the failure rates experienced by both of the newer configurations. In an ideal world, failure rate field data from operational turbines for each of the four drive train types would have been obtained from industrial partners. However, obtaining this failure rate data for each drive train type is challenging due to both confidentiality reasons and also due to two of the drive train types being relatively new, with few operational turbines.



	3 Stage DFIG PRC	3 Stage PMG FRC PRC	2 Stage PMG FRC	DD PMG FRC
Converter	0.18	0.953	0.953	0.953
Generator	1.003	0.468	0.507	0.585
Gearbox	0.533	0.533	0.377	0
Rest of Turbine	6.461	6.461	6.461	6.461

Figure 2.40: Failure rates of wind turbines with different drive train types

2.7 Conclusions

This chapter is unique in providing the overall failure rates for a number of different offshore wind turbine types differentiated by their drive train. In determining the failure rates for each turbine type a number of novel results were obtained. These novel results are concluded in the following paragraphs.

- Average failure rate, cost categories, failure modes and failure rate vs. wind speed

The average failure rate for an offshore wind turbine based on the empirical analysis in this chapter is 8.2 failures per turbine per operational year. Approximately 82% of those repairs being minor repairs (cost < €1,000 for repair), ~14.5% major repairs (€1,000 - €10,000) and ~3.5% major replacements (cost > €10,000). The subassemblies/components that fail the most in the offshore turbines analysed are the pitch/hydraulic system, the other components group and the generator. The biggest failure modes in these groups are oil issues for the pitch /hydraulic group, door/hatch issues for other components and slip ring issues for generators. As past onshore papers have shown there is a trend of rising average failure rates with rising average wind speeds. Offshore shows a stronger correlation meaning that there is a higher failure rate with higher wind speeds offshore than there is onshore.

- Onshore vs. offshore failure rate and failure rate with time

Generators and converters have a higher failure rate offshore than they do onshore. The onshore to offshore failure rate difference is greater in generators than in converters. Although increased wind speeds, age of turbines and size of turbines go some way to explain the differences there is still some differences which perhaps are due to loading or scheduled O&M.

The results from the failure rate with time analysis have shown that all four subsystem/groups analysed display either early failure or reliability deterioration trends. However low R^2 values and large amounts of variance in the data led to the conclusion that average failure rates were to be used in O&M cost modelling in Chapter 3.

- Failure rate of PMG FRC vs DFIG PRC

To compare empirical data from different wind turbine types two similar onshore populations were analysed. Those onshore analyses showed that in terms of generator alone, the PMG has a lower failure rate than the DFIG. The DFIG has ~ 40% more failures than the PMG. This difference would grow further if the generator auxiliary systems were removed from the analysis because the majority of the failures for the PMG are minor failures related to its cooling and lubrication system.

It has also been shown that the PRCs used in the DFIG configuration are more reliable than the FRCs used in a PMG configuration. The failure rate of the FRCs are over five times greater than that of the PRCs. When the generator and converter failure rates are combined for the different configurations, the gain in reliability from the PMG is completely reversed through the poorer reliability of the FRC. Onshore the PMG FRC configuration shows an overall failure rate nearly three times greater than the DFIG PRC configuration. However the difference is not as great offshore because the move to offshore has a greater effect on the generator than it does on the converter closing the failure rate gaps between the components. The DFIG failure rate consists of ~73% minor repairs, 25% major repairs and 1.6% major replacements. The PMG failure rate consists of ~97.4% minor repairs, 2.6% major repairs and there were no major replacements in the 511 years of wind turbine operational data. The PRC failure rate consists of ~64% minor repairs, 35% major repairs and less than 1% major replacements. The FRC failure rate consists of ~74% minor repairs, ~23% major repairs and ~2.5% major replacements. The greatest contributor to the onshore failure rate in terms of failure modes for the DFIG is the brush and slip ring related issues and for the PMG it is the generator auxiliary systems. The greatest contributor for the PRC is the control modules and the cooling system for the FRC.

- REMM for direct drive and 2 stage configuration

The direct drive PMG and 2 stage drive train configurations analysed in this chapter are relatively new compared to 3 stage DFIG turbines. For turbine types that are new or that no reliability data can be obtained, a structured approach for estimating reliability data based on existing similar field data has been outlined in this chapter. This approach is known as REMM. REMM is a methodology, created for the Aerospace and Defence industry, to combine engineering design concerns with historical data to estimate the reliability of a system. A key feature of REMM is that the method assumes that new systems are based in part on previous technologies where engineering judgement can identify, from a reliability perspective, the key differences between the new system and the previous system. The reliability field data from the older system is then combined with an estimated failure rate increase or decrease based on the design differences between the two systems. In this chapter this methodology was used to estimate the reliability of the direct drive generator and the 2 stage generator.

- Chapter's research question answered

Based on the field data and the estimated data calculated using REMM this chapter answers the research question "which wind turbine type has the lowest failure rate?" in Figure 2.40. This chapter concludes that the direct drive PMG FRC wind turbine has the lowest overall failure rate followed by the 3 Stage DFIG PRC, then the 2 stage PMG FRC and lastly the 3 stage PMG FRC. There is ~5% difference in failure rate between the best and worst performing turbines.

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Chapter 3 Availability and O&M costs for different offshore drive train types

3.1 Introduction, literature review and research opportunities

The availability and O&M costs of wind turbines are one of the largest contributors to the overall cost of energy for wind turbines. As wind turbines move further offshore O&M costs and availability become even more important in terms of overall costs. It is for these reasons there is value in obtaining a better understanding of availability and O&M costs for different wind turbine types.

3.1.1 Introduction

Wind turbine or wind farm availability is a time based ratio of the amount of time a wind turbine/farm is ready to operate in a given time period divided by the total time in that time period. It is defined as follows:

$$\text{Availability} = \frac{\text{Time that the turbine/farm is available and ready to operate in a given time period}}{\text{Total time in that period}} \text{ [1] } (1)$$

Figure 2.3 in Chapter two shows failure rate per turbine per year and the downtime per failure. When the product of the overall failure rate and average downtime per failure is subtracted from the total time in the given time period and then divided by the total time in the given period the availability is calculated.

Contractual availability is a similar measure in which the time the turbine is not available to operate (downtime) is allocated to either the wind turbine manufacturer/maintenance provider or the wind turbine owner based on the agreed downtime allocation procedure in the maintenance contract signed by both parties. Availability is reduced from 100% for reasons such as scheduled maintenance, unscheduled maintenance, inaccessibility, grid issues and so on. An example of downtime that is allocated to the manufacturer/service provider is unscheduled maintenance. Examples of downtime that are not allocated to the manufacturer or operator are: an agreed upon amount of scheduled maintenance or grid issues. A guarantee is often provided by the manufacturers based on contractual availability. Compensation is paid to the customer if the contracted availability guarantee is not met. Based on promotional material from manufacturers/maintenance providers typical contractual availability guarantees are 97% onshore and 95% offshore.

The O&M costs of an offshore wind farm can make up around 30% of the total levelised cost of energy of an offshore wind farm [2]. The location of newer offshore wind farms are generally further offshore than early wind farms, e.g. Robin Rigg wind farm is 11km from shore whereas the planned Hornsea wind farm is more than 100km. It is expected that the O&M cost for wind farms further offshore will rise due to longer travel time and accessibility issues leaving less time to carry out maintenance once maintenance crews can get to wind turbines.

The four turbine types outlined in the previous chapter are also the focus of the availability and O&M analysis in this chapter. This chapter describes the results of analysis determining the availability and O&M cost per MWh of wind turbines with the four different drive train types outlined in Chapter 2. Recommendations are outlined for methods of raising availability for each drive train type. O&M costs are presented detailing, transport cost, lost production cost, staff cost and repair cost. In order to obtain these results, the availabilities and downtimes for each drive train type were calculated using an offshore accessibility model. The inputs for this model were obtained from the same on and offshore populations described in Chapter 2.

The work detailed in this chapter is novel for two reasons. First, O&M costs and operational performance have never before been modelled for offshore wind turbines based on such a large and up to date offshore population. Second, no other work was encountered in the literature review in which O&M costs were modelled for different drive train types. While [3] modelled O&M costs for a generic turbine no papers were encountered in which different turbine drive train types were considered. One paper [4], modelled the cost of energy for different drive train types, but in doing so they assumed a fixed O&M cost per MWh, not one obtained by empirical analysis of a large offshore population.

The chapter is structured as follows, a short description of past literature in the area of availability and O&M costs for offshore wind turbines is outline in Section 3.1.2. This is followed by a brief outline of gaps in the research. The availability and O&M model used in this analysis and the inputs required to populate it are then detailed, followed by results, discussion and conclusions.

This chapter will answer the research question "Which wind turbine type provides the highest availability and lowest O&M cost?" Results will determine if the wind turbines with the lowest failure rates in the previous chapter will lead to higher availability and lower O&M costs.

3.1.2 Literature review

The offshore wind turbine market is dominated by a small number of Original Equipment Manufacturers (OEMs), who design and manufacture wind turbines. There are a correspondingly small number of developers and operators [5]. As a result, there is still a significant degree of commercial sensitivity surrounding operational performance and limited data in the public domain (as with the failure rates seen in the previous chapter). Additionally, offshore wind turbine designs are continuing to evolve and this means that newer turbine designs do not yet have full life operating histories. A detailed review of the issues associated with offshore wind turbine O&M is presented in [6].

There are a limited number of operational reports from early sites that received government grants in the UK and Netherlands. As mentioned in Chapter 2 the performance of UK sites is examined in [7] and performance of the Netherlands sites is reported at [8]. These reports provide limited details on wind farm availability and reliability of subsystems. However, the wider applicability of these sources of data is restricted due to a number of reasons. A common turbine model that suffered a serial defect during the reporting period was used across the reporting site in [8] and these reports do not provide detailed information of the operations and maintenance actions and resources utilised.

Due to the limited sources of data in the public domain, commercial sensitivity surrounding operations and the uncertainty associated with new technology in deeper water further from shore, in order to consider the performance of future sites it is necessary to use operational simulations. A review of developed models for offshore wind operation and maintenance is presented in [9]. The model used for this analysis in this chapter is described in detail in [10] and the relevant functionality is described in Section 3.2.2.

3.1.3 Research opportunities from past availability and O&M cost analyses

As only one paper was encountered in the literature review that provided availability figures for offshore wind farms [7] it was decided that this was an area for further research. Availability figures for a number of hypothetical wind farms and the downtime contribution of each subsystem would provide a novel input to this area as little or no work on the influence of each subsystem on offshore wind downtime was encountered in past papers. Having a better understanding of the availability of offshore wind turbines is vital for O&M and CoE planning and modelling. As with availability, O&M cost details and breakdowns for different wind turbine types based on up to date field data and operational models are provided in little or no past papers. The analysis required to determine availability figures and O&M costs will also fill a number of research gaps in the offshore wind turbine operational area, such as: field repair time, field repair costs, number of technicians required for repair and so on.

3.2 Methodology, model overview, and inputs

This chapter will determine the availability and O&M costs for the four different turbine types at hypothetical sites located at varying distances from shore. In doing so a number of analyses on downtime, transport costs, repair times, repair costs and number of technicians required for repair will also be carried out. The wind and sea state data will be assumed the same across all sites analysed.

3.2.1 Methodology

The quality of the results from the availability and O&M analysis are highly dependent on the inputs and model used in the analysis. A model with the correct functionality had to be chosen, obtained and how it functioned had to be learnt. The model chosen and used is outlined in Section 3.2.2. In order to carry out the analysis for the four turbine types the failure rates from the previous chapter were used as inputs to the model. Along with those failure rates, data on repair times, repair costs, and number of technicians required for repair were needed to populate the model. This data came from the same offshore population that was discussed in the previous chapter. As O&M cost results are provided in cost per MWh, power curves for each drive train type were also required. All of the above data were only available for one or both of the 3 stage drive train types. The remaining inputs had to be adjusted to represent the direct drive and two stage wind turbine types or assumed the same. Adjustments and assumptions are outlined in Section 3.2.3. Following the population of the availability and O&M model it had to be run providing results for comparison, discussion and conclusion. The conclusions allowed for the research question “which wind turbine drive train type offers the highest availability and lowest O&M costs” to be answered.

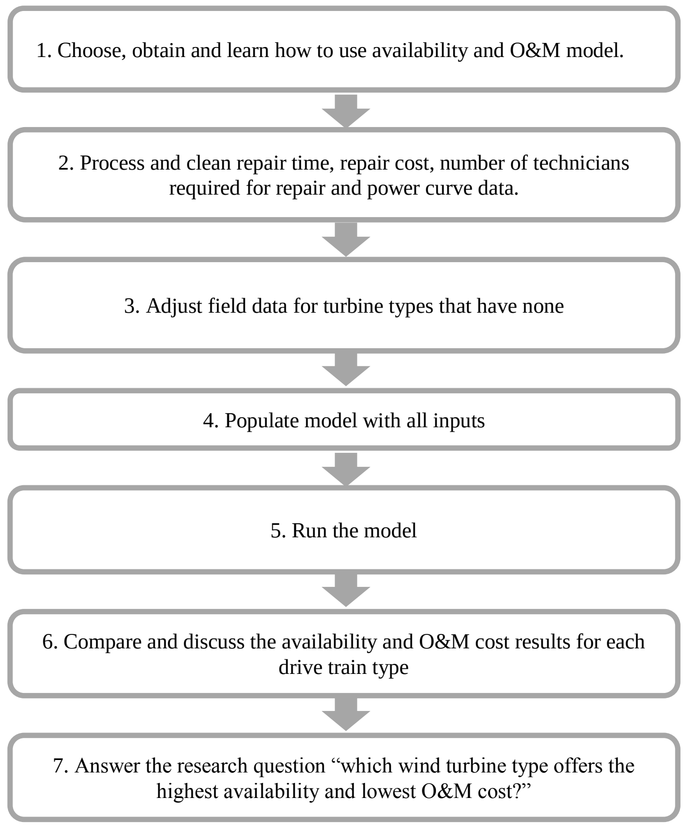


Figure 3.1: Flow chart of failure rate data analysis

Hypothetical Site Characteristics

Forty hypothetical offshore wind farms were modelled. These sites consisted of four wind farms located at 10 different distances from shore: 10km, 20km, 30km… 100km. 100km was chosen as the final distance to model because the majority of round three UK wind sites are less than 100km from shore. For the availability analysis, at each distance from shore a 100 turbine wind farm with each of the four drive train types was simulated, i.e. one of the wind farms at 10km from shore consisted of 3 stage DFIG PRC turbines, one with 3 stage PMG FRC turbines, one with direct drive PMG FRC turbines and one with 2 Stage PMG FRC turbines. For the O&M analysis 3 distances from shore were simulated 10km, 50km and 100km. Each distance had one of the four drive train types giving a total of 12 hypothetical sites for the O&M analysis.

For both the availability and O&M analyses, it was assumed that each site had the same climate characteristics. FINO climate data from an offshore research platform located 45 km off the German coast in the North Sea was used at each site to simulate the offshore environment [20]. This location corresponds to existing and future wind farms in the North Sea, and can therefore be considered representative of expected operating conditions for future developments. Different sea state data at each site could improve this analysis in further work, however it was not available when the author was carrying out this work. Throughout this chapter it is assumed that the wind speed is the same across all sites. This assumption is based on Figure 3.2, where it can be seen that 60 offshore wind farms had their distance from shore and average wind speed plotted. As no major increase was seen as wind farms moved further from shore it was decided to keep the wind speed constant for this analysis.

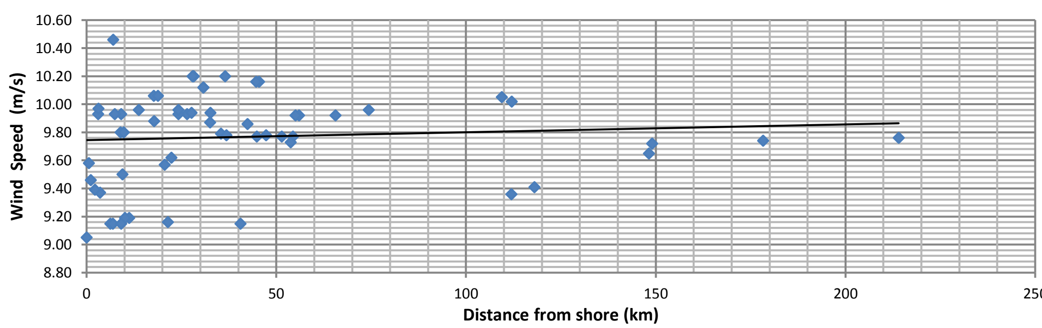


Figure 3.2: Wind farm wind speed vs. distance from shore based on 60 offshore wind farms.

The hypothetical wind farms consisted of 100 modern multi MW offshore wind turbines. The exact rated power cannot be provided for confidentiality reasons but was the same across all turbine types simulated. O&M costs are provided in £/MWh so even though exact rated power is not provided O&M cost comparisons for the different drive train types can be made.

3.2.2 StrathOW O&M model

The O&M model chosen for this analysis was the one developed by the University of Strathclyde detailed in [10]. The model is a time based simulation of the lifetime operations of an offshore wind farm. Failure behaviour is implemented using a Monte Carlo Markov Chain and maintenance and repair operations are simulated based on available resource and site conditions which are dependent on inputs. The model determines accessibility, downtime, maintenance resource utilisation, and power production of the simulated wind farms. The outputs of the model for this chapter are the availability and costs for the operations and maintenance of each of the forty hypothetical offshore wind farms. In the model availability is calculated based on inputs such as site climate and sea state data, turbine failure rate data, turbine repair time data, vessels type required for repair, vessel operating parameters and so on. Using the failure rates for each subsystem/component, provided as an input, the Markov Chain Monte Carlo algorithm in the model simulates whether the turbine subsystem/component is in a failed or operating state. If the subsystem/component is in a failed stated the model uses the repair time inputs and the sea state input data to determine when a repair window of suitable size is available to carry out the repair. The turbine remains in a failed state until that repair is carried out. All of the downtime for each subsystem/component is added to determine the total turbine downtime in a year from which the turbine availability is then calculated using Equation (1) from Section 3.1.1. The model simulates the O&M costs by considering the same inputs used to calculate availability but also considering further inputs such as, vessel costs, fuel costs, mobilisation time, number of technicians required for repair, technician costs, material cost for repair and so on. When a failure occurs the model adds total transport costs, staff costs, repair costs and lost production costs to determine the overall O&M costs. A detailed technical description of the model and its development can be seen in [11]. Reference [12] shows a comparison to other similar models. Figure 3.3 is taken from [11] and shows an overview of the model structure and its interdependencies. Inputs related to strategy choices are not used in this chapter but are used in Chapter 5. As this thesis focused on different drive train types at different distances from shore the model input parameters, shown at the top of Figure 3.3, had to be adjusted to represent each of the drive train types at each distance from shore. For example, during the work for this thesis when a simulation was carried out for the direct drive turbine type compared to the 3 stage DFIG turbine type a number of adjustments were made to the “failure rate and maintenance actions” inputs and also to the “resource and strategy choices” inputs. When the different distances from shore were considered a number of changes had to be made to the “wind farm description” inputs and when the wind speed was changed to determine its effect on O&M costs the “climate parameters” had to be adjusted.

3.2.2.1 Climate Data and Vessel Usage

Reference [13] provided the mean wind speeds, wave height and wave period data from FINO as described in Section 3.2.1. The average wind speed for that site between 2006 and 2010 was

9.88m/s, the average wave height was 1.07m and the average wave period was 5.59 seconds. The vessel operating parameters and costs were based on [10] and [14]. For the purpose of this analysis and as seen in Table 3.1, Heavy Lift Vessels (HLVs) were used for major replacements in the generators and gearboxes of the different drive train configurations and Crew Transfer Vessels (CTVs) were used for all minor and major repairs. The failure rates from Chapter 2 and the vessel type associated with that failure rate are also seen in Table 3.1. As mentioned in Chapter 2 the failure rates used for the O&M modelling will be constant. If failure rates that showed clear reliability improvement or deterioration over time, with little variance were obtained this would not be the case. However as out lined in Chapter two, due to the low R^2 values and large amount of variance, in this case constant failure rates (failure rates averaged over time period) are used to model the O&M costs.

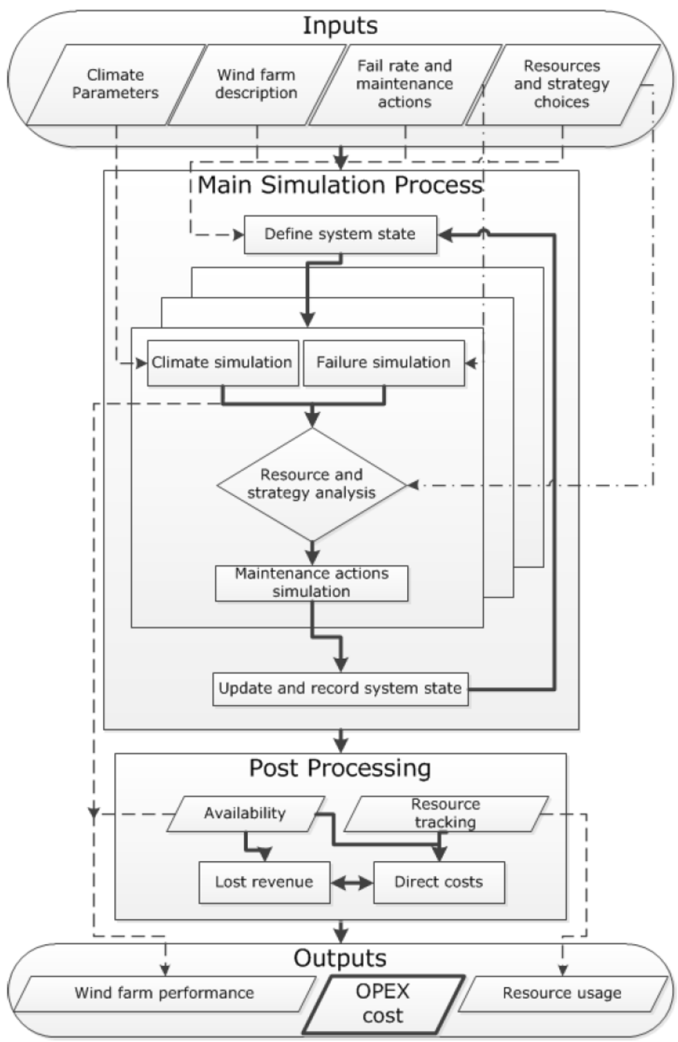


Figure 3.3: Model structural overview and interdependencies [11]

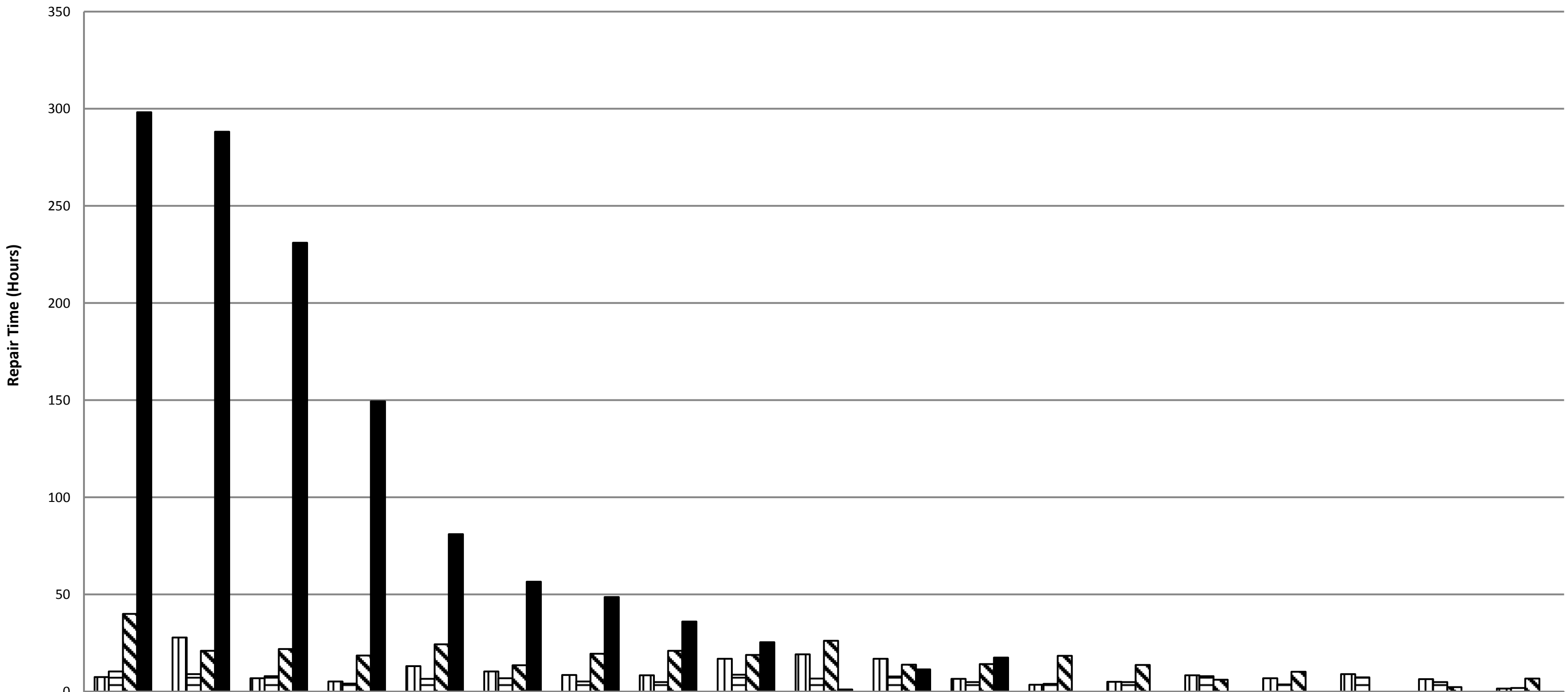
Table 3.1: Failure rates for gearbox, generator and power converter used for each drive train configuration in this analysis

Subsystem	Failure Category	Example of Failure category in each subsystem	3 stage gearbox with DFIG and PRC	3 stage gearbox with PMG and FRC	2 stage gearbox with PMG and FRC	Direct Drive PMG and FRC
Gearbox	Major Replacement	e.g. Full gearbox replacement	0.059 (HLV)	0.059 (HLV)	0.042 (HLV)	-
	Major Repair	e.g. Replace gear oil pump	0.042 (CTV)	0.042 (CTV)	0.03 (CTV)	-
	Minor Repair	e.g. Replace gearbox drain hoses	0.432 (CTV)	0.432 (CTV)	0.305 (CTV)	-
Generator	Major Replacement	e.g. Generator stator insulation failure.	0.109 (HLV)	0.007 (HLV)	0.008 (HLV)	0.009 (HLV)
	Major Repair	e.g. Replace brush and slip rings (in DFIG)	0.356 (CTV)	0.024 (CTV)	0.026 (CTV)	0.03 (CTV)
	Minor Repair	e.g. Generator lubrication issues	0.538 (CTV)	0.437 (CTV)	0.473(CTV)	0.546 (CTV)
Power Converter	Major Replacement	e.g. Full converter replacement	0.006 (CTV)	0.077 (CTV)	0.077 (CTV)	0.077 (CTV)
	Major Repair	e.g. Replace IGBT Module	0.09 (CTV)	0.338 (CTV)	0.338 (CTV)	0.338 (CTV)
	Minor Repair	e.g. Replace Encoder	0.084 (CTV)	0.538 (CTV)	0.538 (CTV)	0.538 (CTV)

3.2.2.2 Repair Time

Repair time, repair costs and number of technicians required for repair are inputs required for the availability and O&M cost modelling in this chapter. Little or no offshore wind turbine repair time, repair cost or technician data of the type required for this modelling was encountered in past papers during the literature review. Consequently a repair time, repair cost and technician requirement analysis was carried out on the population outlined in Section 2.2.2 of Chapter 2. This analysis was based on one of the three stage turbine types. The results of those analyses are seen in this and the following section.

The average offshore repair time can be seen in Figure 3.4. In this analysis the offshore repair time is defined as the amount of time the technicians spend in the turbine carrying out the repair. Unlike downtime it does not include travel time, lead time, time added on due to inaccessibility and so on. As expected it can be seen that the highest repair times occur in the major replacement category shown in black in Figure 3.4. The top three average repair times occur in the hub, blades and gearbox. It should be noted that even though the hub and blades have very high repair times for major replacement, the effect on overall availability will be quite low due to the fact that their failure rate (shown in Figure 2.12) is low. In terms of availability it is more likely that the gearbox and generator will have a greater impact due to the fact that their failure rate for major replacements and repair time for major replacements are towards the higher left sides of both graphs.



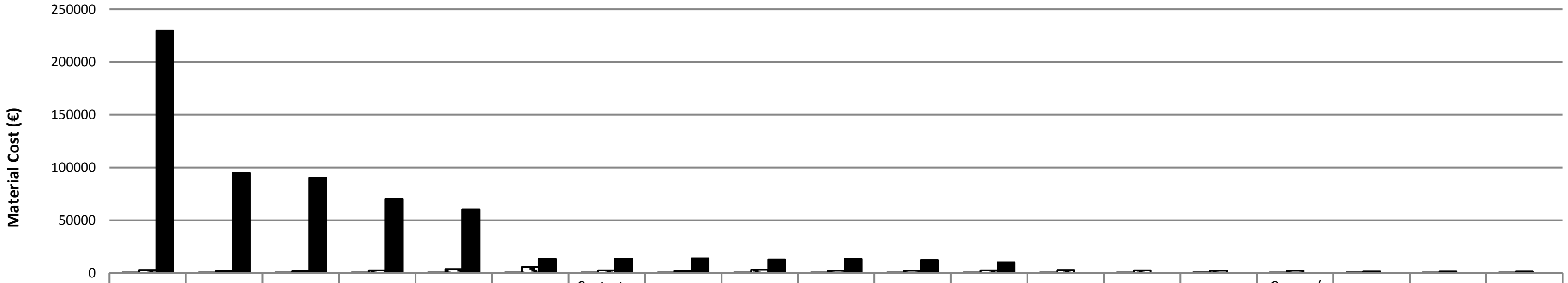
	Hub	Blades	Gearbox	Contactor / Circuit Breaker / Relay	Generator	Power Supply / Converter	Yaw System	Other Componen ts	Pitch / Hyd	Transform er	Controls	Electrical Componen ts	Grease / Oil / Cooling Liq.	Heaters / Coolers	Sensors	Pumps/Mo tors	Service Items	Tower / Foundation	Safety
No Cost Data	8	28	7	5	13	10	9	8	17	19	17	7	3	5	8	7	9	6	2
Minor Repair	10	9	8	4	7	7	5	5	9	7	8	5	4	5	8	4	7	5	2
Major Repair	40	21	22	19	24	14	20	21	19	26	14	14	18	14	6	10		2	7
Major Replacement	298	288	231	150	81	57	49	36	25	1	12	18	0	0	0	0	0	0	0

Figure 3.4: Average repair times for each sub-assembly/component

3.2.2.3 Repair Costs and average number of technicians required for repair

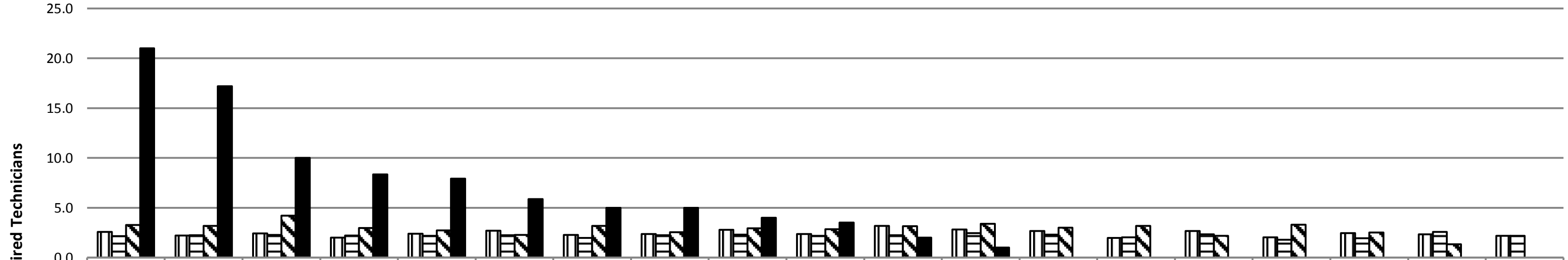
Figure 3.5 shows the average repair costs for each sub-assembly and severity category. The average costs are shown in Euros and include the cost of materials only. They do not include labour costs or compensation costs paid to the operator for downtime. It can be seen that the chart is dominated by the average costs of the major replacements. The average cost of major repairs and particularly minor repairs are far less significant in this graph because they are so small in comparison to the average cost of major replacements. The gearbox has the highest average cost per failure with a major replacement costing €230,000 on average. The fact that the gearbox has a high major replacement failure rate and repair time also suggests that it will be one of the largest contributors to the overall O&M costs for the offshore turbine. The second and third highest average costs are the hub and blades respectively. Even though these components have high average costs of repair and high repair times, the fact that their major replacement failure rate is so low means that their contribution to the overall annual O&M cost will be relatively low in comparison to the gearbox and generator.

The average number of technicians required for repair is the average of the number of technicians that recorded time working on repairing a failure to a subassembly/component in one of the three failure categories. When calculating the O&M costs for the year the average number of technicians required for repair can be used to determine the labour costs when modelling overall O&M costs. From Figure 3.6 it can be seen that the blades, gearbox and hub require the most technicians when a failure occurs. Once again it is the gearbox that will contribute more than the blades and hub to the annual labour costs due to its higher failure rate. It can be seen that up to twenty technicians are used in some of the major replacements; however this does not necessarily mean that twenty technicians are working on the repair for the full repair time. A more likely scenario is that there is a smaller core team of technicians that work throughout the repair time and there are additional technicians that register smaller amounts of time in supporting roles on the repair job. When it came to modelling the O&M costs, the number of technicians required for major replacements were provided by estimates given by our industrial partners. For example, Figure 3.6 shows that on average ~17 technicians had booked time on a gearbox exchange. However the industrial partner informed us that a gearbox replacement would require on average ~5 technicians working over the repair time period to replace the gearbox. For that reason 5 technicians were used in the O&M modelling for a major gearbox replacement instead of 17.



	Gearbox	Hub	Blades	Transformer	Generator	Power Supply / Converter	Contactor / Circuit Breaker / Relay	Pitch / Hyd	Yaw System	Controls	Electrical Components	Other Components	Sensors	Safety	Pumps/Motors	Grease / Oil / Cooling Liq.	Heaters / Coolers	Service Items	Tower / Foundation
Minor Repair	125	160	170	95	160	240	260	210	140	200	100	110	150	130	330	160	465	80	140
Major Repair	2500	1500	1500	2300	3500	5300	2300	1900	3000	2000	2000	2400	2500	2400	2000	2000	1300	1200	1100
Major Replacment	230000	95000	90000	70000	60000	13000	13500	14000	12500	13000	12000	10000	0	0	0	0	0	0	0

Figure 3.5: Average repair cost for each sub-assembly/component



	Blades	Gearbox	Hub	Contactor / Circuit Breaker / Relay	Generator	Power Supply / Converter	Other Components	Yaw System	Pitch / Hyd	Electrical Components	Controls	Transformer	Heaters / Coolers	Grease / Oil / Cooling Liq.	Sensors	Safety	Pumps/Motors	Tower / Foundation	Service Items
No Cost Data	2.6	2.2	2.4	2.0	2.4	2.7	2.3	2.4	2.8	2.4	3.2	2.8	2.7	2.0	2.7	2.0	2.5	2.3	2.2
Minor Repair	2.1	2.2	2.3	2.2	2.2	2.2	2.0	2.2	2.3	2.2	2.2	2.5	2.3	2.0	2.3	1.8	1.9	2.6	2.2
Major Repair	3.3	3.2	4.2	3.0	2.7	2.3	3.2	2.6	2.9	2.9	3.1	3.4	3.0	3.2	2.2	3.3	2.5	1.4	0.0
Major Replacement	21.0	17.2	10.0	8.3	7.9	5.9	5.0	5.0	4.0	3.5	2.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Figure 3.6: Average number of technicians required for repair for each sub-assembly/component

3.2.2.5 Repair time to down time explanation

In this analysis, repair time is defined as the amount of time the technicians spend in the turbine for a certain failure. Repair times and the number of technicians required for repair of the same failures on each of the drive train types were assumed to be the same across all wind turbine types. However, this does not mean each turbine type will have the same annual downtime (downtime includes repair time). This is because the failure rate will be different for each turbine type. Different failure rates for the three different failure categories will lead to a different requirement for the various vessels leading to different downtimes. An example of the repair time inputs and the downtime outputs for the 4 turbine types can be seen in Table 3.2 for a site located 10km from shore. If repair time and number of technicians required for repair data could be obtained for other drive train types it would further improve this analysis.

Table 3.2: Repair time input for all turbine types (h)

Grouping	Minor Repair	Major Repair	Major Replacement
Gearbox (h)	7.9	21.9	231
Generator (h)	6.5	24.3	81.1
Converter (h)	6.9	13.6	56.5
Rest of Turbine (h)	6.2	16.4	108.9

Downtime Output for all Turbine Types at 10km from shore per turbine per year (h)

Grouping	Configuration	Minor Repair	Major Repair	Major Replacement
Gearbox (h)	3s DFIG PRC	16.62	26	97.8
	3s PMG FRC	13.3	27.7	75.8
	2s PMG FRC	11.7	19.5	51.7
	DD PMG FRC	0	0	0
Generator (h)	3s DFIG PRC	19.9	38.1	88.1
	3s PMG FRC	16	2.7	5.9
	2s PMG FRC	17.2	2.8	7.5
	DD PMG FRC	19.5	3.1	12
Converter (h)	3s DFIG PRC	3.1	6	4.4
	3s PMG FRC	19.4	22.6	63.2
	2s PMG FRC	19.4	22.7	63.7
	DD PMG FRC	19.3	22.4	63.9
Rest of Turbine (h)	3s DFIG PRC	210.9	52.2	9.49
	3s PMG FRC	207	51.4	12
	2s PMG FRC	207.3	51.3	11.4
	DD PMG FRC	204.5	50.9	11.7

3.2.3 Model inputs: adjustments and assumptions

The repair costs, repair times, number of technicians and other data presented in Section 3.2.2 are only for one of the 3 stage configurations. As O&M costs and availability of the direct drive and 2 stage configurations are also modelled, these inputs must be assumed the same or estimated for the drive train types that there was no access to data for. The repair times and number of technicians required for repair of each failure category has been assumed the same across all four drive train types. The cost of the failures from Section 3.2.2.3 were adjusted to represent all drive train types and then used as inputs to the model for this analysis. As shown in Section 3.2.2.3 costs were provided by the industrial partner for the 3 stage configurations. The costs for the direct drive PMG and the 2 stage PMG were estimated by adjusting the 3 stage PMG failure costs by the same percentage difference as in [15] where costs were given for a direct drive PMG, 2 stage PMG and 3 stage PMG. The two stage gearbox cost adjustment was carried out in a similar manner based on the percentage difference in cost between the 3 stage and 2 stage gearbox in [16]. Figure 3.7 shows the difference in costs for the components of all drive train types based on data obtained from the industrial partner, [15] and [16]. The costs are normalized against the most expensive component e.g. the 3 stage DFIG is shown as a percentage of the capital cost of the most expensive direct drive PMG. For the gearbox the 100% cost is ~ £35,000/MW, for the generator the 100% cost is ~ £180,000 per MW and for the converter the 100% cost is ~£15,500/MW.

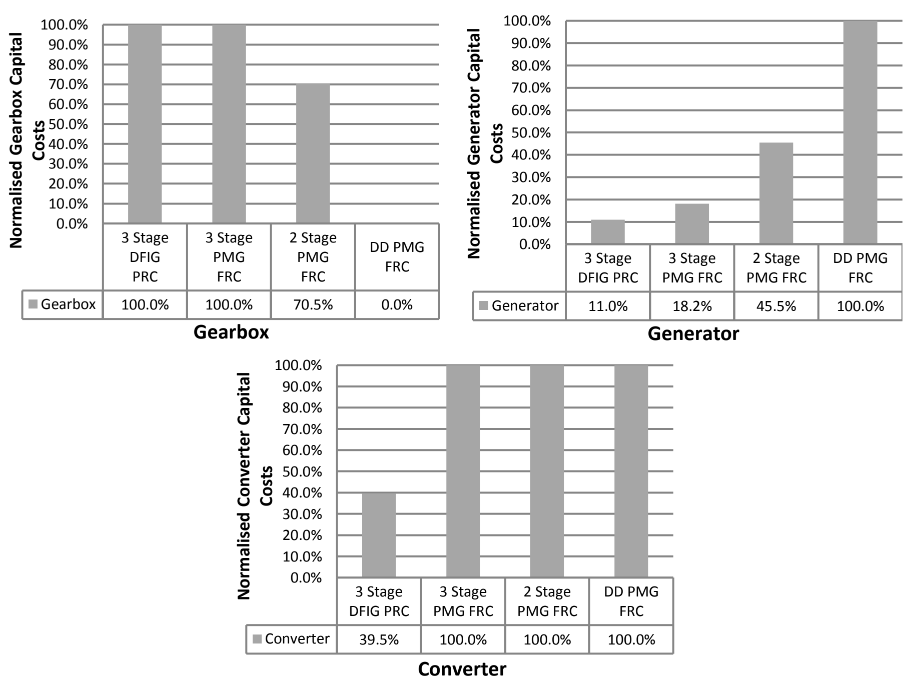


Figure 3.7: Normalised capital costs showing components from both 3 stage drive train types

The model also required power curves for all drive train types so that lost production and O&M costs per MWh could be calculated. An empirical analysis on power curves from two identical turbine types except for their drive trains was carried out for both of the 3 stage configurations. This analysis was based on the populations described in Chapter 2. The direct drive and two stage power curves were estimated based on the percentage difference in power curves in [15] in which power curves were provided for direct drive PMG, 2 stage PMG and 3 stage PMG. All power curves in this analysis had the same rated power.

3.2.4 Sensitivity analysis

As a means of determining how reliant the results are on the model inputs, a number of sensitivity analyses were carried out. The sensitivity analyses focused on inputs that were based on assumptions (e.g. failure rates for the direct drive turbine type) and also looked at varying constants used in the model (e.g. different wind farm size and increasing wind speed). The results of sensitivity analyses for the following inputs are shown in Section 3.3.4:

- Failure rates
- Repair times
- No of wind turbines in a wind farm
- Increase in average wind speed at hypothetical sites.

This work around the sensitivity of inputs is just to provide an indication of how results change when the inputs are varied. Detailed analysis on each of these areas is an area of further work. For example, optimisation for the number of wind turbines in a wind farm and optimisation for resource requirements are fields that are outside the scope of this thesis but are areas that could help in lowering O&M costs.

3.3 Results of availability and O&M cost analysis

Using the inputs and the model detailed in Section 3.2 the availability (Section 3.3.1), downtime and subsystem/component contributions to downtime (Section 3.3.2), O&M costs and contributions to O&M cost (Section 3.3.3) were modelled for the forty hypothetical wind farms described in Section 3.2. A sensitivity analysis (Section 3.3.4) was carried out on the influence of the failure rates and repair times used as inputs.

3.3.1 Availability

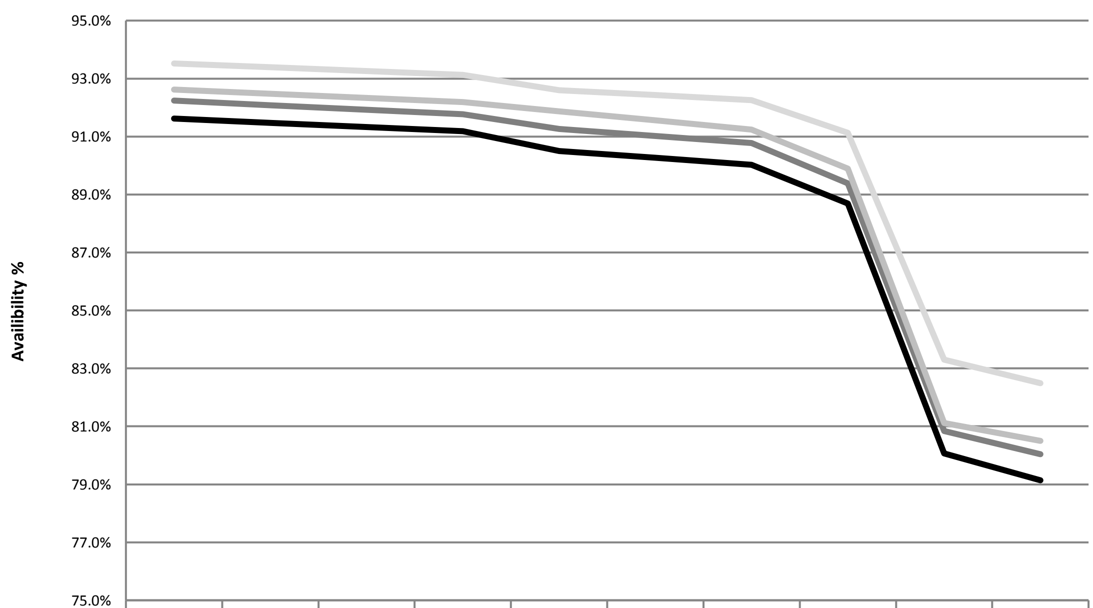
Figure 3.8 shows the modelled availability of the wind farms across all sites with the four different turbine types. Regardless of whether there was a gearbox or not, the PMG FRC turbines have a higher availability than the DFIG turbine type at all sites. The onshore failure rates from Chapter 2 found that the combined failure rate of the generator and power converter was approximately 3 times greater for the PMG configuration than for the DFIG configuration (mainly due to the failures in the power converter). The opposite outcome in availability is due to the types of failures that occur in the generator of the DFIG configuration. Failures that occur in the DFIG have a higher down time and larger vessel requirement for repair, consequently the lower failure rate of the DFIG in comparison to the converter does not mean higher turbine availability because each failure leads to greater downtime per failure.

If the converters alone were considered, the higher failure rate of the minor and major repairs for the FRC would mean the gap between the downtime of the 3 stage DFIG FRC and the direct drive PMG FRC would close as the wind farm moves further offshore. This would happen because of the higher downtime caused by the travel time required to get that further distance from shore to repair the more regularly failing FRCs. However, as the wind farm moves further offshore, both the gearbox and the generator minor and major repairs must also be considered along with the converters. The DFIG will have a higher minor repair and major repair downtime than the direct drive PMG because of the high failure rate of brush and slip ring related issues as seen in Chapter 2. As the direct drive turbine has no gearbox, the gearbox also has a higher minor and major repair failure rate than the direct drive. As the wind farms move further offshore the combination of the higher minor and major repairs to both the gearbox and the generator of the DFIG outweigh the higher downtime of the FRC meaning the gap between the 3 stage DFIG PRC and direct drive PMG FRC is maintained.

Across all sites the direct drive configuration was the best performing turbine followed by the turbines with 2 stage and 3 stage gearboxes with a PMG and a FRC, while the turbine with a DFIG had the lowest availability. It is clear from Figure 3.8 that in terms of availability the direct drive machine performed just as well at 70km as the DFIG turbine did at 10km. The main driver for this is the removal of the gearbox downtime for the direct drive wind turbines. Considering sites 40km, 80km and 100km one can see:

- Turbines with high speed PMGs have a higher availability of 0.6% (40km), 0.7% (80km) and 0.9% (100km) points compared to the turbines with DFIGs
- Reducing the speed of the generator with a 2 stage gearbox gives a higher availability compared to turbines with DFIGs of 1% (40km), 1.2% (80km) and 1.36% (100km)
- Using a direct drive turbine with PMG gives a higher availability compared to the turbines with DFIGs of 1.9% (40km), 2.4% (80km) and 3.4% (100km)

A drop in availability is noticeable in Figure 3.8 at the 90 and 100km sites. This was due to a limitation on the number of technicians and vessel capacity working on repairs. The availability could be improved at these sites by increasing the number of technicians or increasing the vessel capacity. However, like for like comparisons across all sites could not then be carried out if these sites had a different number of technicians and CTVs. Each hypothetical site could show availability improvements by optimising the number of vessels and maintenance technicians used, however this optimisation work was deemed to be out of the scope of this thesis but may be an area of further work.

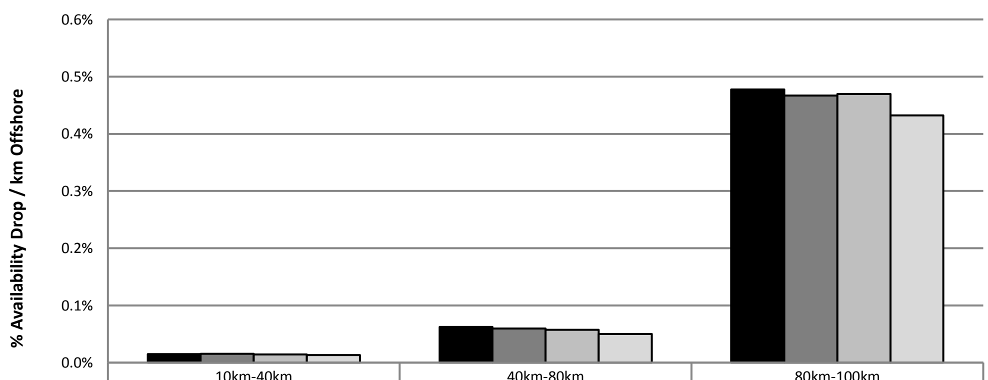


	10km	20km	30km	40km	50km	60km	70km	80km	90km	100km
DFIG PRC	91.6%	91.5%	91.3%	91.2%	90.5%	90.3%	90.0%	88.7%	80.1%	79.1%
3S PMG FRC	92.2%	92.1%	91.9%	91.8%	91.3%	91.0%	90.8%	89.4%	80.8%	80.0%
2S PMG FRC	92.6%	92.5%	92.3%	92.2%	91.9%	91.6%	91.2%	89.9%	81.1%	80.5%
DD PMG FRC	93.5%	93.4%	93.3%	93.1%	92.6%	92.4%	92.3%	91.1%	83.3%	82.5%

Figure 3.8: Availability of wind farms showing all drive train types at sites varying distances from shore

The reader should be reminded that the failure rates for wind turbines with 3 stage gearboxes (both PMG and DFIG) were based on real data whereas the inputs for the direct drive and 2 stage configuration were estimated according to the process in Chapter 2, and so there is a greater degree of uncertainty in the results for the latter two configurations. A sensitivity analysis on the failure rate inputs for each drive train type is shown later in this chapter.

Figure 3.8 illustrates that as the sites move further from shore, the availability drops for all turbines but at different rates for different configurations and the gradients vary with distance from shore. This is even clearer in Figure 3.9, in which the availability drop per km offshore increases between drive train types the further offshore the site is. Considering ranges 10-40km, 40-80km and 80-100km one can see the rate that the availability drops with distance as turbines are placed further from shore: 0.013-0.016%/km (10-40km), 0.050-0.062%/km (40-80km) and 0.43-0.48%/km (80-100km). The difference in availability between the geared drive train types and the direct drive turbines increases the further the wind farm is from shore. One reason for this is that the direct drive minor and major repair failure rates are lower than the combination of the gearbox and higher speed generator minor and major repair failure rates. This leads to less of a loading on CTV and technician resources further offshore for the direct drive configuration.



	10km-40km	40km-80km	80km-100km
DFIG PRC	0.015%	0.062%	0.478%
3S PMG FRC	0.016%	0.060%	0.467%
2S PMG FRC	0.014%	0.058%	0.470%
DD PMG FRC	0.013%	0.050%	0.432%

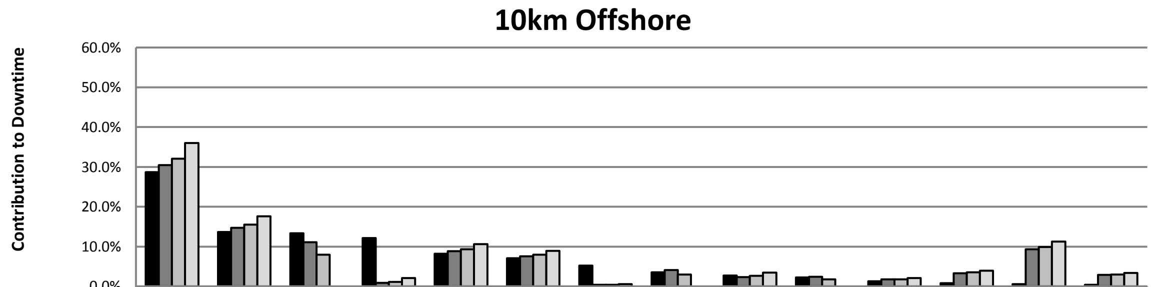
Figure 3.9: Availability drop per km for 4 drive train types as wind farms move further from shore

3.3.2 Downtime analysis

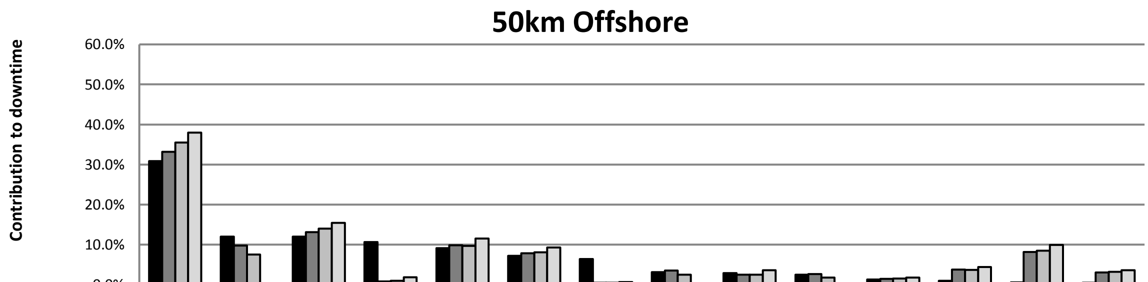
The downtime analysis was carried out across three sites rather than all ten (for the sake of brevity). The 10, 50 and 100km sites were chosen as near, medium and far shore representative sites. Figure 3.10 shows the percentage of downtime each failure group has on each wind farm; failure groups were divided by subsystems (i.e. gearbox, generator, power converter and the rest of turbine) and by failure severity (i.e. minor repair, major repair and major replacement). It can be seen that across all three wind farms the failure group called “Rest of turbine minor repairs” had the greatest influence on downtime. As predicted in [29], when wind farms moved further offshore the percentage of downtime contributed by minor failures increased.

Although the failure rate (for any turbine type) at the different distances was the same, these minor repairs became more significant due to longer travel times which in turn led to a requirement for larger travel/repair time accessibility windows. Greater travel time led to a greater downtime; hence the product of failure rate and mean time to repair for the different failure categories was closer in magnitude than for near shore sites.

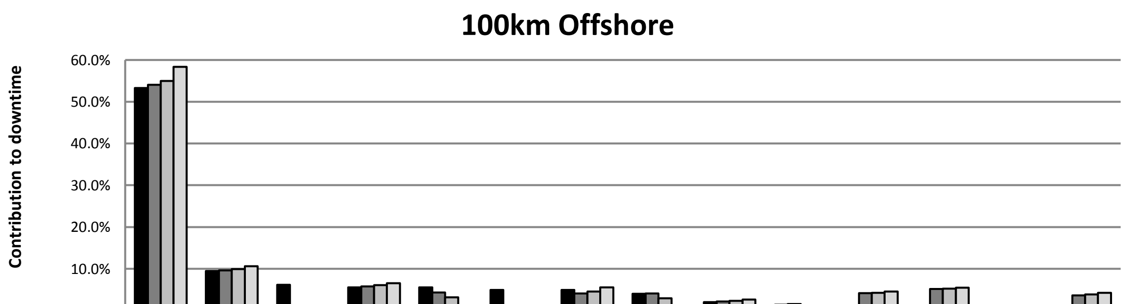
If the contributions of the three drive train components alone are considered, the generator failures are the biggest contributors to downtime for the turbines with a DFIG configuration, followed by the gearbox failures and then the converter failures. This was consistent across all three sites. If the 3 stage PMG FRC turbine drive train alone is considered it can be seen that for the 10km and 50km sites the gearbox was the biggest contributor to downtime followed by the FRC and then the generator. For the 100km site the converter becomes the largest contributor to downtime followed by the gearbox and then the generator, this switch in ranking of the gearbox and converter for the site further offshore was due to the higher failure rate of the converter and the increasing travel time. Considering the drive train alone for the 2 stage PMG FRC turbines, Figure 3.10 shows across all sites that the FRC was the biggest contributor to downtime followed by the gearbox and then the generator. When the drive train of the direct drive turbine is considered, the FRC was the biggest contributor to downtime across all sites and the generator was the second biggest. As it is a direct drive there was no gearbox to contribute failures. It should be noted that the absolute contribution from "Rest of Turbine Minor Repair" is the same across the different drive train types as they are all based on the same turbine type, however they show up different values in the graph as these are percentage contributions.



	Rest of Turbine Minor Repair	Remote Resets	Gearbox Major Replacm ent	Generato r Major Replacm ent	Schedule d Mainten ance	Rest of Turbine Major Repair	Generato r Major Repair	Gearbox Major Repair	Generato r Minor Repair	Gearbox Minor Repair	Rest of Turbine Major Replacm ent	Converte r Major Repair	Converte r Major Replacm ent	Converte r Minor Repair
3S DFIG PRC	28.7%	13.6%	13.4%	12.1%	8.2%	7.1%	5.2%	3.5%	2.7%	2.3%	1.3%	0.8%	0.6%	0.4%
3S PMG FRC	30.4%	14.7%	11.1%	0.9%	8.8%	7.6%	0.4%	4.1%	2.3%	2.4%	1.8%	3.3%	9.3%	2.9%
2S PMG FRC	32.1%	15.5%	8.0%	1.1%	9.3%	7.9%	0.4%	3.0%	2.7%	1.8%	1.8%	3.5%	9.9%	3.0%
DD PMG FRC	36.0%	17.6%	0.0%	2.1%	10.6%	9.0%	0.6%	0.0%	3.4%	0.0%	2.1%	3.9%	11.3%	3.4%



	Rest of Turbine Minor Repair	Gearbox Major Replacm ent	Remote Resets	Generato r Major Replacm ent	Rest of Turbine Major Repair	Schedule d Mainten ance	Generato r Major Repair	Gearbox Major Repair	Generato r Minor Repair	Gearbox Minor Repair	Rest of Turbine Major Replacm ent	Converte r Major Repair	Converte r Major Replacm ent	Converte r Minor Repair
3S DFIG PRC	30.9%	12.0%	12.0%	10.6%	9.1%	7.2%	6.4%	3.2%	2.9%	2.5%	1.3%	0.9%	0.5%	0.5%
3S PMG FRC	33.1%	9.7%	13.1%	0.8%	9.8%	7.8%	0.5%	3.5%	2.5%	2.6%	1.5%	3.7%	8.2%	3.1%
2S PMG FRC	35.5%	7.5%	14.0%	1.0%	9.7%	8.1%	0.5%	2.5%	2.5%	1.7%	1.5%	3.7%	8.5%	3.2%
DD PMG FRC	38.0%	0.0%	15.5%	1.8%	11.5%	9.3%	0.7%	0.0%	3.6%	0.0%	1.7%	4.4%	9.9%	3.6%



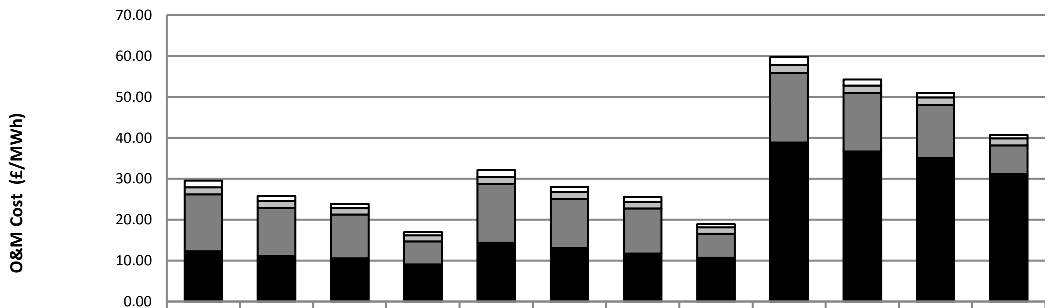
	Rest of Turbine Minor Repair	Rest of Turbine Major Repair	Generat or Major Repair	Remote Resets	Gearbox Major Replacm ent	Generat or Major Replacm ent	Generat or Minor Repair	Gearbox Minor Repair	Schedule d Mainten ance	Gearbox Major Repair	Converte r Major Repair	Converte r Minor Repair	Rest of Turbine Major Replacm ent	Converte r Major Replacm ent
3S DFIG PRC	53.3%	9.5%	6.1%	5.6%	5.5%	5.0%	4.9%	4.0%	2.0%	1.4%	1.1%	0.8%	0.6%	0.3%
3S PMG FRC	54.0%	9.6%	0.4%	5.8%	4.3%	0.3%	4.1%	4.1%	2.2%	1.6%	4.2%	5.1%	0.7%	3.6%
2S PMG FRC	54.9%	10.0%	0.5%	6.1%	3.2%	0.4%	4.5%	3.0%	2.3%	1.2%	4.2%	5.2%	0.7%	3.8%
DD PMG FRC	58.4%	10.6%	0.6%	6.6%	0.0%	0.8%	5.5%	0.0%	2.6%	0.0%	4.5%	5.5%	0.7%	4.2%

Figure 3.10: Failure group contribution to downtime showing the different turbine subsystems

3.3.3 O&M costs

Figure 3.11 shows the O&M costs per MWh for near shore, medium and far shore sites. Lost production costs are shown in black, transport costs are shown in dark grey, staff costs are shown in lighter grey and repair costs are shown in white. It can be seen that for three of the four wind turbine types up to 50km the majority of O&M costs came equally from transport and lost production costs representing ~ 45% of costs each, with repair and staff costs representing ~5% each. For the direct drive turbines the contribution of transport cost was lower because the expensive jack up vessel was not required as often due to the absence of the gearbox. At the 100km wind farm, the rise in lost production costs due to the drop in availability is clear in Figure 3.11 in which the lost production cost is seen to rise from ~45% of the overall O&M cost to ~65%, with transport costs making up ~28% and staff and repair costs each making up ~3.5% of the overall O&M cost for the DFIG turbine type.

O&M costs (expressed on an annual basis per MWh) are higher for the DFIG configuration than for the PMG configurations because the lost production costs, transport costs, staff costs and repair costs are all higher for the DFIGs in this analysis . The lost production costs are higher for the same reasons as the low DFIG availability, as discussed in Section 3.3.2. The mean annual transport costs are higher for DFIGs because the DFIG configuration requires the jack-up vessel more often (due to its higher overall major replacement failure rate) and as seen in Figure 3.12 it is the jack up vessel that contributes most to the transport costs. The staff and repair costs are higher because the major replacement failure rates for the DFIG configuration are higher than for the PMG configuration. As seen in Section 3.2.2 it is these major replacements that encounter the highest repair costs and staff requirements. The 2 stage and direct drive configurations have lower O&M costs than the 3 stage because the downsizing or removal of the gearbox reduce or eliminate the major replacement failures which are the largest contributors to the O&M costs. In terms of O&M costs, the reduction in gearbox major replacements outweighs any increase in O&M costs due to generator failures.



	10km DFIG PRC	10 km 3S PMG FRC	10 km 2S PMG FRC	10 km DD PMG FRC	50km DFIG PRC	50 km PMG FRC	50 km 2S PMG FRC	50 km DD PMG FRC	100km DFIG PRC	100 km PMG FRC	100 km 2S PMG FRC	100 km DD PMG FRC
Repair Costs (£/MWh)	1.61	1.26	0.94	0.79	1.65	1.26	1.15	0.80	1.88	1.46	1.08	0.89
Staff Costs (£/MWh)	1.71	1.63	1.6	1.49	1.74	1.65	1.65	1.5	2.01	1.9	1.85	1.71
Transport Costs (£/MWh)	13.95	11.75	10.73	5.66	14.37	12.05	11.06	5.88	17.03	14.24	13	7.02
Lost Production Costs (£/MWh)	12.26	11.16	10.53	9.04	14.37	13.03	11.68	10.72	38.81	36.63	35	31.13

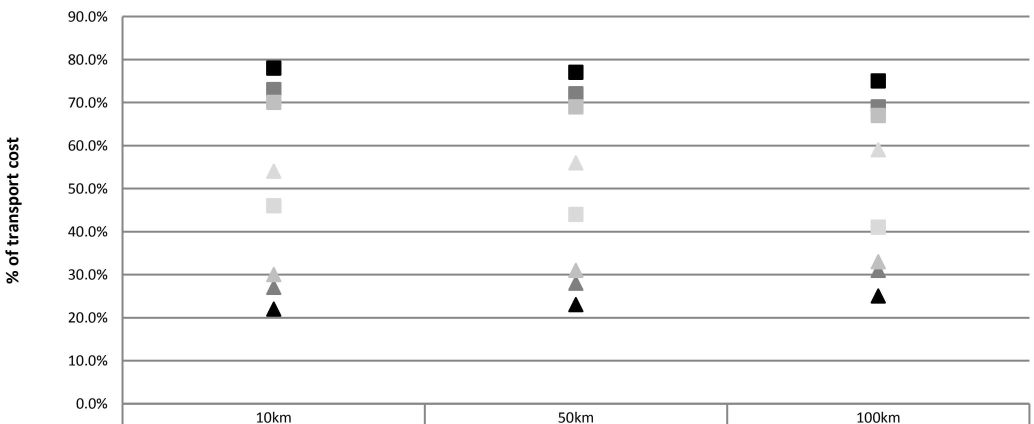
Figure 3.11: Breakdown of O&M costs showing all drive train types

The largest contributors to the O&M costs came from the lost production and transport cost, therefore further analysis has been carried out for both of these areas. Figure 3.10, which gives the percentage of downtime for each failure group, is also indicative of the percentage of lost production costs for each failure group. Consequently the earlier comments on the downtime categories hold true for the lost production contributions.

Transport costs were the second largest contributor to the overall O&M costs. Figure 3.12 shows the transport costs for 10km, 50km and 100km sites. The transport costs are made up of heavy lift vessels (HLVs) shown by the squares and crew transfer vessels (CTVs) vessels shown by the triangles. The DFIG drive train is shown in black and the PMG drive trains are shown in different shades of grey. Across all three sites the PMG turbines had a higher percentage of overall transport cost for the CTV, this was due to the higher failure rate of the converter. However the DFIG turbine had a higher percentage of its overall costs attributed to HLVs because the DFIG has a higher failure rate than the PMG. It is this higher heavy lift vessel cost that makes the 3 stage DFIG configuration have a ~16% higher overall transport cost at 50km than the turbine with a 3 stage PMG. The overall transport costs are shown for each site and turbine type in Figure 3.11.

Figure 3.12 also illustrates that in all drive train types CTVs make up more of the overall transport costs as wind farms move further offshore and HLVs make up less of the overall transport costs as the wind farms move further offshore. This was due to the travel times becoming longer as the sites move further offshore, these longer travel times have a greater effect on CTVs than on HLVs because there are more CTV trips than HLV trips.

It can also be seen that the difference in the travel cost for each vessel and turbine type remains consistent across all sites regardless of how far they are from shore. The reason for this is that the wind farms for all drive train types were the same distance from shore meaning travel times were increased by the same amount for all vessels regardless of drive train type. The direct drive turbine type (shown in the lightest shade of grey) stands out in Figure 3.12 because its percentage of transport costs for the CTV is so much higher and the HLV is so much lower than the other three drive train types. This is because the HLV is not needed as often because there is no gearbox to replace.



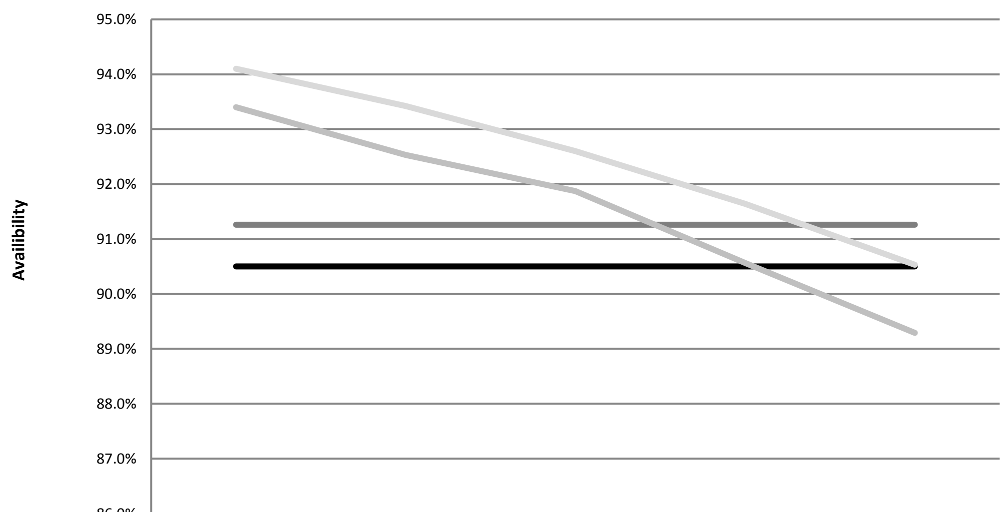
	10km	50km	100km
▲ DFIG CTV	22.0%	23.0%	25.0%
■ DFIG HLV	78.0%	77.0%	75.0%
▲ 3S PMG CTV	27.0%	28.0%	31.0%
■ 3S PMG HLV	73.0%	72.0%	69.0%
▲ 2S PMG CTV	30.0%	31.0%	33.0%
■ 2S PMG HLV	70.0%	69.0%	67.0%
▲ DD PMG CTV	54.0%	56.0%	59.0%
■ DD PMG HLV	46.0%	44.0%	41.0%

Figure 3.12: Transport cost breakdown showing vessel type and drive train type at different offshore locations

3.3.4 Sensitivity analyses

As a means of determining how reliant the results are on the model inputs, a number of sensitivity analyses were carried out. The reader should recall that the failure rate data for both of the 3 stage turbines came from empirical data, but those inputs for the turbines with PMGs with a 2 stage gearbox and direct drive generators were synthesized. All of these failure rates have uncertainty, though the uncertainty is greater for the turbines with synthesized failure rates. As the failure rates for both 3 stage drive trains came from empirical data their failure rates remained the same and were plotted as constant lines in Figure 3.13. The sensitivity analysis was carried out to determine how much the failure rate could increase in the direct drive and 2 stage drive train types before their availability was lower than the 3 stage drive train types. Figure 3.13 illustrates that if the 2 stage failure rate is increased by 10% the availability drops below both 3 stage turbine types. It also shows that the availability of the direct drive turbine type drops below both 3 stage turbines when its failure rates were increased by 20%. The failure rate was also decreased by 20% for both turbine types that used estimated failure rates to demonstrate the scale of improvement in availability when failure rates were reduced.

Figure 3.13 also shows that the 2 stage and direct drive lines diverge further at 120% than at 80% of the baseline failure rate. It is clear from this that as the failure rates increase the difference in availability between the turbine types also increases. The driver for this increase in difference is the increase in failure rates of the gearbox and 2 stage PMG repairs that require a HLV. This has a greater effect on the overall availability than the increase of failures in the direct drive PMG does as the latter does not require HLVs as frequently.



	80%	90%	100%	110%	120%
DFIG PRC (€)	90.5%	90.5%	90.5%	90.5%	90.5%
3S PMG FRC (€)	91.3%	91.3%	91.3%	91.3%	91.3%
2S PMG FRC (€)	93.4%	92.5%	91.9%	90.6%	89.3%
DD PMG FRC (€)	94.1%	93.4%	92.6%	91.6%	90.5%

Figure 3.13: Sensitivity analysis of failure rate inputs on availability outputs showing varying failure rate inputs for both drivetrain types that use estimated failure rates.

Discussions with power converter specialists from the author's industrial partner have indicated that the failure rates for the DFIG PRC configuration have reached their lowest failure rate level because it is a mature technology whereas the failure rates for the PMG FRC turbines may still fall as it is still maturing. This suggests that if the failure rates are going to change, it is most likely that they will change in favour of the PMG configurations.

As mentioned in Section 3.2.3, the technician time in turbine (repair time) for each repair type (e.g. minor generator repair, major converter repair etc.) was assumed the same across all 4 turbine types. As this is an assumption it was investigated if changes to this repair time would affect the overall conclusions of this chapter. Based on Section 5.3.3.2 of Chapter 5 it was concluded that the 3 stage DFIG would remain the drive train configuration with the highest O&M costs even if the repair times for the gearbox, generator and converter dropped by 20%. From that, it was concluded that the direct drive PMG FRC would remain the drive train configuration with the lowest O&M costs even if the repair times for the generator and converter increased by 20% . Consequently it is felt that changes to the repair times of less than 20% should not affect the overall order of the turbine type O&M costs shown in this chapter.

The number of wind turbines in a wind farm also contributes to varying availability and O&M costs. For this reason the wind farm size used in the analysis in this chapter was halved and doubled to determine the impact on availability and O&M costs. The resources (technicians, number of vessels etc.) were also halved and doubled in each case. For a wind farm located 50km from shore with direct drive PMG FRC turbines, the number of turbines in the wind farm was reduced from 100 to 50. Due to this reduction, an increase in availability from 92.6% for the 100 turbine site to 92.87% for the 50 turbine site was observed and an increase in O&M costs from £18.90/MWh (100 turbine site) to £20.50/MWh (50 turbine site) was also observed. The driver for the increased O&M costs when the wind farm reduced in size was the transport, staff costs and repair costs were higher per MWh than the 100 turbine farm, even though the availability was higher. When the number of turbines in the wind farm was doubled from 100 to 200 a decrease in availability from 92.6% to 91.96% was observed and an increase in O&M costs from £18.90/MWh to £19.22/MWh was also observed. Based on the increase in the O&M cost when the baseline wind farms size is halved it may be expected that when the baseline wind farm size is doubled the O&M costs would also decrease. However this is not the case. Even though the per MWh transport costs, staff costs and repair costs reduce due to the increased energy production of the larger wind farm, the lost production cost per MWh increased due to the lower availability of the larger wind farm. This per MWh increase in the lost production costs outweighs the decrease in the per MWh transport, staff and repair costs to provide a higher overall O&M cost.

As a means of determining the impact of wind speed on O&M costs and availability the wind speed at the 50km site was increased by 5% and 10%. For the hypothetical site of 100 turbines, used throughout this chapter, with direct drive PMG FRC turbines the availability decreased from 92.6% to 92.58% and the O&M cost decreased from £18.90/MWh to £18.24/MWh, when the wind speed was increased by 5%. When the wind speed was increased by 10% the availability decreased from 92.6% to 92.56% and the O&M costs decreased from £18.90/MWh to £17.75/MWh. In both cases the reduction in in O&M costs/MWh is because of the increased energy production from the increased wind speed. So even though absolute, lost production, repair, transport and staff cost go up slightly with the increased wind speed, so does the overall energy production which leads to a reduction in the total O&M costs per MWh when the wind speed is increased.

3.4 Discussion

The choice of different drive train types is one of the main differentiators between different offshore wind turbines. Improvements in availability and O&M costs are often cited as reasons for choosing one type over another, yet most past work concentrated on the variation in capital costs and efficiency. This chapter is unique in simulating availability and O&M cost and providing an analysis on a number of hypothetical offshore wind farms with wind turbines consisting of different drive train types. Results are based on up to date reliability and cost input data from existing modern multi-MW offshore turbines and on derived failure rates for those turbines about to enter service.

3.4.1 Turbine selection – which drivetrain is best?

Availability

This chapter found that turbines with a permanent magnet generator have a higher availability at all sites than those turbines with a DFIG. Based on onshore failure rates only, from Chapter 2, this may have been unexpected as the combined failure rates of generator and power converter were higher for the turbines with PMG and a FRC. The turbines with PMGs have a higher availability than the DFIG configuration in this chapter because the higher minor/major repair failure rate of the FRC – and the mean annual downtime related to it – is outweighed by the higher major replacement failure rates and subsequent downtimes of the DFIG. The primary cause of these higher downtimes is the increased need for heavy lift vessels. Reference [6] has suggested that the failure rate for direct drive wound rotor generators will be twice that of the geared machines. However, the direct drive generator included in this analysis is a PMG and not a wound rotor generator. In this chapter, the direct drive PMG is estimated to have around 25% more failures than a geared PMG. This is based on Chapter 2 and [17], in which the failure modes related to the excitation system and rotor windings of the wound rotor direct drive generator are removed. Out of the turbines with a permanent magnet generator, the direct drive had the highest availability, and then the turbine with a 2 stage gearbox followed by the turbine with a 3 stage gearbox. This is consistent across all the wind farms regardless of the distance to shore. Based on these results, turbines with permanent magnet generators are recommended from a point of view of maximizing availability, with a preference for lower speed generators with no gearbox.

O&M cost

DFIG PRC turbine types have a higher O&M cost/MWh than all of the PMG FRC turbine types across all wind farms in this chapter. As with availability, the direct drive turbine type with a PMG appears to be the best performing with the lowest O&M costs, followed by the PMG with a 2 stage gearbox and then a 3 stage gearbox.

Of the two three stage turbines which have failure rates based on real machines, the difference at the 50km site in:

- lost production costs are 9.5% in favour of the PMG,
- O&M transport costs are 16.5% in favour of the PMG,
- O&M staff costs are 5% in favour of the PMG,
- repair costs are 22% in favour of the PMG

Turbines with permanent magnet generators are recommended from a point of view of minimizing O&M costs, with a preference for lower speed generators with no gearbox.

3.4.2 How could the different drivetrain equipment be improved?

If the contributions of the three drive train components alone were considered, the generator failures were the biggest contributors to downtime for the DFIG turbine, followed by the gearbox failures and then the PRC failures. This is consistent across all sites. So as to improve the future performance of these turbines, efforts should be focused on reducing failure rates in the DFIG followed by reducing failures in the gearbox. To reduce failures in the DFIG the brush and slip ring related issues must be reduced as they are the failure modes that contribute most to the DFIG failure rate.

For the direct drive turbines and turbines with a 2 stage gearbox and PMG, it is the power converter that is the biggest contributor to downtime followed by the gearbox (if there is one) and then the generator. This is consistent across all sites. Reducing failure rates in the converters is important, especially for wind farms further offshore.

If the turbine with a 3 stage gearbox and PMG is considered it can be seen that for the 10km and 50km sites the gearbox is the biggest contributor to downtime followed by the converter and then the generator. For the 100km site, the converter becomes the largest contributor to downtime followed by the gearbox and then the generator. To reduce FRC failures the issues related to the cooling system and the IGBT modules must be reduced because they are the failure modes that contribute the most to the overall failure rate.

The results also suggest that significant availability improvements and O&M cost reductions can be expected from redesigning gearboxes and generators so that the most severe failures can be repaired without the use of heavy lift vessels.

3.4.3 The importance of distance to shore

This chapter has found that all turbine types here have increased downtime for wind farms much further from shore. The decline in availability is fairly constant up until about 70-80km from shore, when availability drops more sharply. At wind farms this far from shore, the percentage contribution of minor repairs becomes larger, and it is recommended that increased resources and different O&M strategies are used in order to address these issues (especially the cost of CTV use for far offshore sites).

For the O&M costs, the relative costs of the different categories changes with distance to shore. At the 10km and 50km sites in this analysis for the turbines with gearboxes the O&M costs were broken down as follows: lost production costs and transport costs each equal ~45% and the staff and repair costs each equal ~ 5% of the total O&M costs. When the wind farms moved further offshore to 100km this overall O&M cost break down changed to ~65% lost production costs, 28% transport costs, 3.5% staff costs and 3.5% repair costs. The fourth (direct drive) turbine had a lower transport cost due to the removal of the need for a jack up vessel for gearbox replacements. These changes to relative cost categories further reinforces the need to spend more on staff and transport for far offshore sites.

Based on this analysis the direct drive turbine appeared to be the best turbine, no matter what distance from shore. The location of the wind farm only influenced the relative superiority of the turbines with PMGs over the DFIG turbines and between direct drive turbines and those with gearboxes.

3.4.4 How robust are these findings?

It is important to reflect on the analysis in this chapter, its limitations and the major causes of uncertainties. The quality of the results of the analysis presented here depend on:

Failure rates and repair times for the gearbox, generator and power converters. These were based on data from a variety of sources. For one of the 3 stage gearbox configurations the failure rates and repair times were taken from offshore wind farms over a number of years and so these results have the smallest uncertainty, although it should be noted that future equipment or equipment from other manufacturers may have higher or lower failure rates. For the second 3 stage configuration, there is additional uncertainty as the failure rates for the generator and power converter were scaled from data from real onshore wind farms and repair times were assumed the same as the first 3 stage configuration. The turbines with the greatest uncertainty in failure rates are those with a 2 stage gearbox and the direct drive configuration, as failure rates for the gearbox and generator were modified using the REMM approach (outlined in Chapter 2). Repair times were once again assumed the same as the other configurations. If the assumed failure rates or repair times are significantly wrong, then one turbine type may be relatively penalised compared to another.

Failure rate and repair times for the rest of the turbine. These were based on data for an existing offshore wind turbine. Future, improved turbines or turbines from other manufacturers may have higher or lower failure rates, resource requirements and repair types. If these inputs change, the effect would be to shift up or down the availability and O&M costs, but should not affect the relative performance on the different turbine types.

Repair for failures. There is uncertainty as the model is predicated on using particular vessel types and resources for different failures. Partly based on a real wind farm data, this will be different for different wind farms, turbine manufacturers and O&M operators.

Strategies to improve availability and O&M. The same scheduled and reactive (fix on fail) HLV strategy for O&M for all wind farms have been assumed. It has been shown that condition monitoring and condition based maintenance can improve availability and may do so more for turbines with DFIGs and those with gearboxes. These issues will be examined further in Chapter 5.

The author has tried to expose the study's results to some of these uncertainties by carrying out a set of sensitivity analyses, focusing on the failure rates. If input failure rates range from 80% to 120% of the baseline failure rate, the direct drive turbine continues to have a higher availability than the other turbines. This holds true for all sites in this analysis. Repair time sensitivity analysis also showed that if the assumption of the same repair time for failure categories and types was out by up to 20% it would not change the order in which the drivetrains are ranked in terms of O&M costs.

3.5 Conclusion

- Best performing drive train type in terms of availability

As described in the results and discussion sections of this chapter, this study found that turbines with a permanent magnet generator have a higher availability at all sites analysed than those turbines with a DFIG. It has been shown (subject to the proviso of the input data and assumptions being correct) that wind turbines with permanent magnet generators are recommended from a point of view of maximizing availability, with a preference for lower speed generators with no gearbox.

- Best performing drive train type in terms of O&M costs

This chapter found that DFIG PRC turbine types have a higher O&M cost/MWh than all of the PMG FRC turbine types across all hypothetical wind farms analysed. As with availability, the direct drive turbine type with a PMG performed best with the lowest O&M costs, followed by the PMG with a 2 stage gearbox and then a 3 stage gearbox. The cost of the heavy lift vessel and its higher frequency of use in the 3 stage configuration was the main reason for the higher O&M cost.

- Influence of distance from shore

This study has found that all turbine types considered here have increased downtime for wind farms further from shore. The direct drive turbine appeared to be the best turbine, no matter what distance from shore. The location of the wind farm only influenced the relative superiority of the turbines with PMGs over the DFIG turbines and between direct drive turbines and those with gearboxes.

- Assumptions and uncertainties

It should be noted that these conclusions are based on a number of assumptions regarding failure severities, repair times and modes and costs of access, thus there are notable levels of uncertainty. Uncertainty is present in this analysis through failure rate inputs (some were based on field data from a particular model of wind turbines, whereas as a formal methodology was used to estimate failure rates for the turbines with PMGs and 2 stage gearboxes and direct drive configurations) and through assumptions made in the modelling such as the repair times for different failure severity categories. As with most models, the uncertainty of the results and conclusions can be reduced by refining the input data. Suggestions for further work include more detailed offshore failure rate analysis for direct drive turbines and 2 stage gearboxes configurations with PMGs and FRCs along with further repair time analysis for all configurations.

3.6 Chapter 3 references

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Chapter 4 Cost of energy estimations for different drive train types

4.1 Wind turbine cost of energy introduction, literature review and research opportunities

As seen in the earlier chapters of this thesis different drivetrains have different cost, performance and reliability characteristics. Whilst it is easy to compare drivetrains on single metrics, ultimately it is the CoE that provides a true indication of which wind turbine type is best suited to an offshore site. There are different ways of achieving reduced CoE, e.g. reduce capital expenditure (CAPEX), reduce O&M, improve efficiency, improve uptime and so on. This chapter will take all of these aspects into account and examine which areas contribute most to the overall CoE for each drive train type.

4.1.1 Introduction

In order to answer the research question "Which wind turbine type offers the lowest CoE for a typical offshore wind farm?" the findings from the previous two chapters must be considered along with other wind farm costs, such as Balance of Plant (BoP) costs, turbine costs and other capital costs. Previous CoE work looks at near and medium distance from shore sites, this work is novel in focusing on the CoE for those sites but also looking at sites further from shore up to 100km and considering different wind turbine types, in particular the next generation (direct drive and 2 stage) turbine configurations. These cost of energy estimations can assist developers in choosing the right turbine types for certain sites. They also allow manufacturers of a certain wind turbine type to compare costs with other wind turbine types from different manufacturers and determine which area to focus on for reduced CoE e.g. initial turbine costs, O&M costs, BoP costs.

A literature review was carried out to determine which equations past publications used to calculate the cost of energy for offshore wind. The literature review also looked for past work on each of the variables that make up the CoE. A further aim of the literature review was to determine the actual cost figures from existing CoE research. The following subsections provide an overview of CoE calculation methods and results encountered during the literature review. This is followed by the methodology section in which the steps taken to complete the CoE analysis for this chapter are outlined. The results are then shown in Section 4.4. Conclusions are drawn and the research question is answered in Section 4.5. Results show the cost of energy for the same hypothetical sites as Chapter 3 at varying distances from shore (10km, 50km and 100km). A brief sensitivity analysis is also carried out for one of the sites based on its average wind speed and the number of turbines in the wind farm.

4.1.2 Cost of energy definition and variables

The cost of energy is a metric used to evaluate and compare the cost of generating electricity from different sources and projects. There are different methods of calculating the CoE but generally it eventually breaks down to the sum of all discounted lifetime costs divided by the amount of energy produced in the lifetime of the wind turbine/wind farm to give a cost per kWh or MWh. Different discounting rates can be used to provide a life time or levelised cost of energy to allow for comparison of the costs from the life time of the project with other projects or other generating technologies. In most of the wind energy CoE calculations encountered in the literature there are generally four major inputs to the calculation [1,2,3]. Three of the four are related to the hardware required to generate the energy. The fourth is related to the total costs of financing the project. The three inputs that are related to the hardware are the installed capital cost (which are discounted and spread out to an annual basis), O&M costs and the energy production. The energy production is based on the power curve, wind resource, availability and so on. The fourth, the total cost of financing, is represented by the fixed charge rate (FCR). The fixed charge rate determines how much revenue is required to pay the return on debt, return on equity, taxes, depreciation, and borrowing insurance. These costs are also known as the carrying charges [1]. How these four inputs are combined to calculate the levelised cost of energy can be seen in equation (1). This equation or one very similar to it is used in references [1,2,3,4]. The cost of energy is defined as:

$$CoE = \frac{(ICC \times Fixed\ Charge\ Rate)+(O\&M\ Costs)}{Energy\ Production} \quad (1)[1]$$

In the above equation ICC stands for installed capital costs and O&M costs are the operation and maintenance costs. The ICCs include turbine costs, BoP costs and other capital costs. The balance of plant costs include costs for port and staging, substructure and foundation, electrical infrastructure, assembly and installation, commissioning, engineering and management costs. When considering sites at different distance from shore it is important to consider the BoP costs. As wind farms move further from shore the BoP costs will increase. This is due to the increased amount of electrical cabling required, increased complications on assembly and installation, and changes in water depth influencing the foundation and supporting structure. As the BOP results are important for answering the research questions in this thesis it was decided to work with NREL to adapt their BoP model to the sites analysed in this chapter. Other alternatives would have been to assume constant BoP costs regardless of distance from shore or to try and find BoP costs for similar sites in past literature. However it was felt that ability to model BoP for each individual site through adapting the NREL model was the best fit for this analysis. The other capital costs included in ICC are costs for construction insurance, decommissioning, finance costs and contingency. O&M costs include the staff costs, repair costs and transport costs. The Fixed Charge Rate is 10.2% as in [1] and [2], 11.6% in [4]. The fixed charge rate of 10.2% will be used in the analysis shown later in this chapter and no sea bed rent will be included in the CoE calculation. The purpose of this analysis is to compare the CoE from the different drive train types so once the FCR and seabed rent are kept constant across each of the four drive train calculations there is no requirement for further FCR or seabed rental calculations. The fixed charge rate is given by formula (2):

$$FCR(\%) = \frac{d(1+d)^n}{(1+d)^n-1} \times \frac{1-(T \times PVdep)}{(1-T)} \quad (2)[1]$$

where:

d = discount rate (%) (E.g. 6.5% in [1])

n = operational life (years) (Typically 20 years)

T = Corporate tax rate (%) (Will vary depending on where the wind farm is located. A typical rate is 38.9% [1])

PVdep = present value of depreciation (%) The present value of depreciation allows the wind farm owner to benefit from reduced tax based on the depreciation of their wind turbines. In [1] a rate of 80.7% is used.

The energy production is the amount of energy produced by the wind farm or wind turbine in the given time period, e.g. a time period representing the life time of the project is used if the analysis is to determine the life time cost of energy. In this chapter energy production is calculated using the empirical power curves, site conditions, availability and so on as outlined in Chapter 3. Based on those inputs each turbine type will have a different overall energy production.

The cost of capital is an important area of the CoE calculation for wind energy developers. It often determines whether a project is feasible or not. Generally, the higher the perceived project risk the higher the cost of capital. As this thesis focuses on the CoE for different drive train types, cost of capital analysis was considered outside the scope of this work.

4.1.3 Estimated cost of energy for offshore wind turbines

A number of past studies have been carried out to determine the cost of energy from onshore and offshore wind. The following paragraphs will show CoE figures for offshore wind estimated by NREL [5], Crown Estate [2], Siemens [6], DNV GL [7] and an academic paper [4]. The majority of the costs will be for a generic turbine type, however the academic paper focuses on the CoE for different turbine types.

Reference [5] is a study carried out by NREL in 2013 and shows an offshore CoE of $215/MWh for a hypothetical site 20km from shore. Reference [2] is a study carried out by Crown Estate in 2012 and shows an offshore CoE of £144/MWh for a site 40 km offshore. €140/MWh is the CoE provided by Siemens in [6] and DNV GL state that the CoE for offshore wind in the UK in 2015 is ~£120/MWh in [7]. For the different drive train types in [4] the CoE ranges from €110.7/MWh – €117.7/MWh.

From the previous paragraphs it can be seen that there is a range of CoE figures from ~£92/MWh [4] to £144/MWh [2] (using exchange rates from the time [4] was published for Euro to GBP). The driver for the difference in these figures is the data used to calculate them and the site location in terms of distance from shore. For example, the CoE figures from the academic paper

[4], showing different drive train types are estimated based on the weight and cost of the raw materials required to make up certain components of the wind turbine. Consequently little field cost or reliability data is used in that analysis. The figures calculated by NREL and the Crown Estate may also include some uncertainty due to the limited amount of data in the public domain that is required to calculate the CoE. As the market leader in offshore wind energy, Siemens would have the best overview of wind turbine and O&M costs however they may be missing wind farm data such as development and BoP costs.

4.1.4 Research opportunities from past cost of energy work

Based on the literature review it was determined that while CoE results exist from a number of past CoE analysis [1,2,3,5] there is a gap in the CoE research for different wind turbine types. While there has been some past CoE work carried out comparing CoE of different wind turbine types [4], that paper focuses on modelling component costs based on the mass of materials used. They do no use current operational and cost data from modern multi MW offshore wind farms. If is for this reason that the focus of this chapter will be a CoE analysis and estimation for different wind turbine types using current operational and cost data from modern multi MW offshore wind turbines.

4.2 Methodology

A number of steps were taken to complete this CoE analysis:

1. *Obtain or create the various models required to calculate the CoE for offshore wind farms.*

   The types of models required were the models to find O&M cost costs (as outlined in Chapter 3), balance of plant (BoP) costs, annual energy production (AEP) models and so on. Some of these models like the O&M cost model have been outlined in previous chapters. An overview of each of these models and inputs can be seen in Section 4.3.

2. *Source empirical offshore wind farm operational and cost data to populate these models.*

   Where possible, data from real offshore wind turbines and wind farms were used. The type of data required was BoP cost data, Turbine cost data, operational/reliability data and so on for modern multi MW turbines. The data required were obtained from a leading wind turbine consultancy, research institute, manufacturer and maintenance provider. The wind farms from where the data were obtained are reasonably representative of modern wind farms across the industry.

3. *Adjust field data to represent drive train types where no empirical data exists.*

   As the direct drive and two stage gearbox drive train types in this analysis were based on wind turbines that have only just recently been released it was impossible to obtain field cost and operational data. Consequently different methods of estimating the inputs required for both of these drive train types had to be used. As outlined in Chapter 2, REMM was used for the estimation of reliability parameters. The cost and power curve data has also been estimated for new technologies in the past using the cost of raw materials to estimate costs and through looking at efficiency of the new system [8]. Similar techniques were used in this analysis to adjust cost and energy production inputs for the two turbine types for which no field data was available.

4. *Combine the models and input data to work out the CoE for one of the drive train types at each of the three offshore locations.*

   In this analysis, as in [1,2,3,4,5], the CoE is defined as:

   $$\text{CoE} = \frac{(ICC\ x\ Fixed\ Charge\ Rates) + (O\&M\ Costs)}{Energy\ Production}\ (1)$$

   In this analysis the Fixed Charge Rate is 10.2% as in [1]. Further details on each of the variables of the above equation can be found in the literature review section of this chapter.

5. *Adjust CoE inputs to represent the 3 other drive train types and determine the effect on CoE at each of the three sites.*
6. *Carry out sensitivity analysis on average wind speed of the site and the number of turbines in the site.*
7. *Answer the research question posed in the introduction to this chapter and draw conclusions on which drive train type offers the lowest CoE at each distance from shore.*

4.3 Overview of models used in the CoE work

The results in Section 4.4 are based on a number of models that contribute towards calculating the CoE for offshore wind turbines. Each of these models require large amounts of empirical data from existing wind farms to provide accurate outputs. To see the differences in CoE due to drivetrain design, it is necessary to calculate both the inputs that are common to all the drivetrains as well as the aspects which are particular to individual drivetrains. The outputs of the models used include O&M costs for different drive train types, wind turbine costs for turbines with different drive train types, BoP costs, and energy production per turbine. To obtain these outputs the models and inputs detailed in Table 4.1 were required. The outputs of each of these models then become the inputs to the overall CoE model. Figure 4.1 shows a simple flow chart of this output/input relationship.

Table 4.1: Models and their inputs used in the analysis

Model and Output	Description	Input and source of input
O&M Cost Model. Output: O&M costs for each drive train type at each hypothetical site	The O&M cost model used in this work was the AM02 model created at the University of Strathclyde. An overview of the model is included in Chapter 3 and details are provided in [9].	Empirical failure rates, repair times, no. of technicians required for repair, repair costs and so on, from a population of ~350 offshore modern multi MW turbines from between 5-10 offshore wind farms throughout Europe. Further details on these inputs are provided in Chapter 2 and 3.
Energy Production Model. Output: Energy produced by each turbine type at each site.	The energy production model used in this work was the same AM02 model used for the O&M costs. The AM02 model simulates the energy production as well as availability and O&M costs. An overview of the model is included in Chapter 3 and details are provided in [9].	The inputs to obtain the energy production for each site were empirical or estimated power curves from wind turbines with different drive train types obtained from the populations and adjustments outlined in Chapter 3 and wind and wave data from a north sea site [10]. The wind and wave data is used for the accessibility block of the model.
BoP Model Output: BoP costs for each turbine type at each site	The balance of plant model from which results were obtained was created by NREL [11]	Inputs included costs of: ports, staging, substructure, foundation, electrical infrastructure, assembly, installation, development, engineering, management and commissioning. This input data was provided by DNV GL [11]
Other outputs:	Wind Turbine Costs for different turbine types. Component cost for different wind turbine types.	Provided by a leading wind turbine manufacturer who was the PhD industrial partner to the author. Apart from the drive train costs, turbine costs are assumed the same across all turbine types. This assumption is discussed in Section 4.4.1.

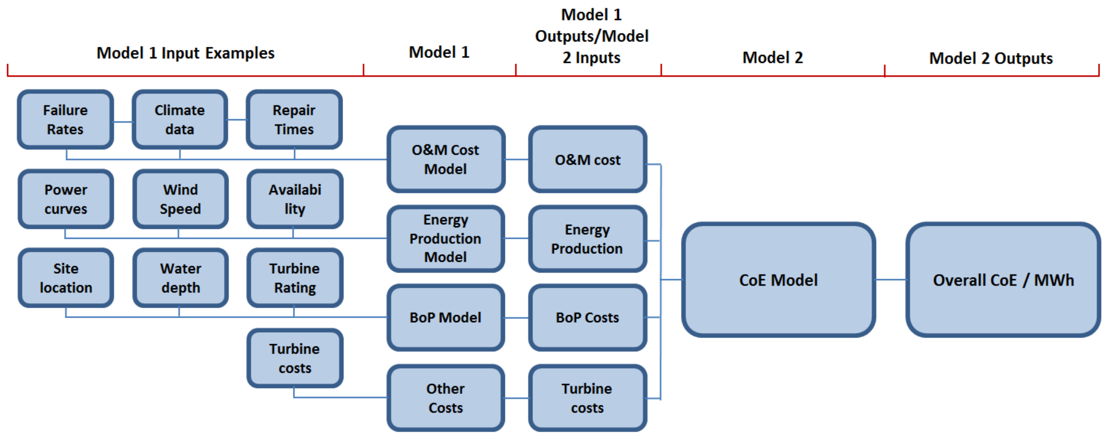


Figure 4.1: Model Inputs and outputs and how they relate to each other

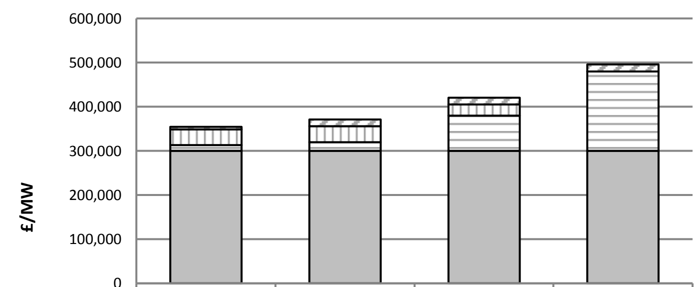
4.4 CoE results and discussion

This section provides an overview of all results obtained from the CoE analysis for each of the drive train types. Most results are shown across the 10km, 50km and 100km sites, however for the sake of brevity results for BoP Costs and Other Capital Costs will solely focus on the 50km site (Figures 4.4 and 4.6) . However the 10km and 100km sites are included in the overall CoE breakdowns. So the BoP and Other capital costs for the 10km and 50km sites can be seen in Figure 4.9. In the majority of the graphs for the remainder of this chapter, the y-axis shows the results in a per MWh format or per MW installed format. Results are shown in this way for confidentiality reasons. It allows for comparisons between wind turbine types without showing the rated power of the turbines from which the field data came from (this was requested by the industrial partner).

4.4.1 Turbine type cost

Figure 4.2 shows the cost of each turbine type used in this analysis. The graph is split into 4 groupings, rest of turbine, gearbox, generator and converter. These costs are shown per MW for a modern multi MW offshore wind turbine.

The costs were provided by an industrial partner that is major manufacturer, so it should be noted that these are what the turbines cost to manufacture not what they are sold for. This will under play the percentage contribution of turbine costs in the overall CoE calculation. Costs were provided by the manufacturer for two of the wind turbine types and the other two were estimated based on the turbine component cost estimation techniques from [4]. A profit calculation carried out in Section 4.4.6 of this chapter estimates that ~111% of the cost shown should be added to these results if profit is to be included. It can be seen that the major driver for the difference in cost between the turbine types is the generator. The lowest cost generator is the DFIG which is over ten times cheaper than the direct drive PMG. Some of this cost is cancelled out due to direct drive PMG not requiring a gearbox but this cancelation is not enough to stop the direct drive PMG FRC being the most expensive configuration. The 3 stage DFIG PRC is the lowest cost configuration due to it having the lowest cost generator and converter. It has been assumed that the "Rest of turbine" cost is the same across all drive train types. However in reality this may not be the case due to reasons such as different nacelle weights leading to different tower costs. However cost data for the "Rest of turbine" grouping was not available for all of the turbine types in this thesis. If that cost data could be obtained it would improve this analysis.



	3 Stage DFIG PRC	3 Stage PMG FRC	2 Stage PMG FRC	DD PMG FRC
Converter	6,000	15,500	15,500	15,500
Gearbox	35,000	36,000	25,000	0
Generator	13,500	20,000	80,000	180,000
Rest of Turbine	300,000	300,000	300,000	300,000

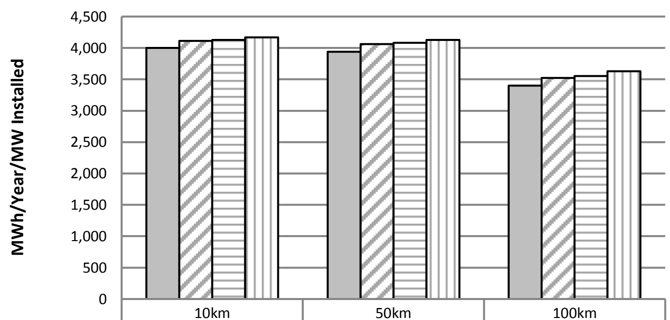
Figure 4.2: Turbine cost for the four drive train types

4.4.2 Energy production

Figure 4.3 is based on the calculated energy production for each site and each turbine type. The energy was calculated for each turbine drive train type at each site using the model detailed in Chapter 3. That model was populated with empirical power curves for both of the 3 stage drive train types in this analysis. For the direct drive and 2 stage turbines the power curves were estimated using a similar method to the power curves in [4] and [8]. Figure 4.3 shows the annual energy production per MW installed for each of the four wind turbine types across all three distances from shore. It is obvious from Figure 4.3 that as the turbines move further from shore the energy production drops. This is primarily due to accessibility issues leading to the wind turbines further offshore having a lower availability, meaning the turbines convert less energy.

Sites further from shore can sometimes overcome their lower availability and have higher energy production than sites nearer shore if the further offshore sites have a higher wind speed. However the wind speeds at all sites in this analysis were assumed to be the same and were obtained from FINO data [10] as in Chapter 3. The increase in wind speed of 5 and 10%, as seen in Chapter 3, is also carried out later in this section as a brief sensitivity analysis to determine the increase in energy production with increase in wind speed.

A difference in energy generation is also seen for each drive train type in Figure 4.3. The direct drive PMG FRC has the highest energy generation and the DFIG PRC configuration has the lowest. As seen in Chapter 3 the direct drive configuration has the highest availability and this is one of the reasons it generates more energy in a year. This higher availability in the direct drive configuration is driven by its lower failure rate for major replacements with high downtime.



	10km	50km	100km
3 Stage DFIG PRC	4,002	3,940	3,400
3 Stage PMG FRC	4,110	4,060	3,520
2 Stage PMG FRC	4,130	4,080	3,550
DD PMG FRC	4,170	4,130	3,630

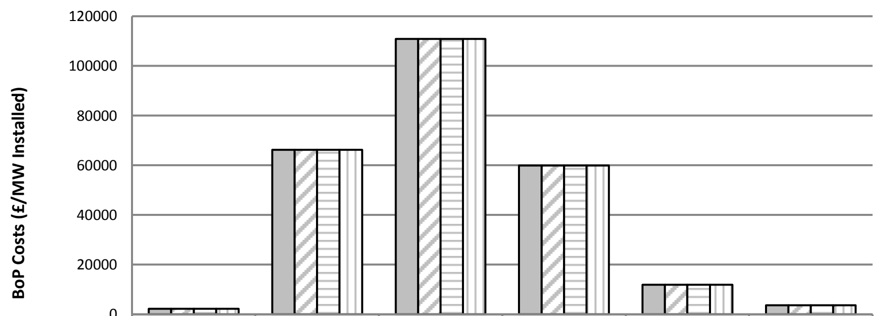
Figure 4.3: Energy production for the four drive train types

Chapter 3 outlines the reasons for assuming a constant wind speed, while carrying out a sensitivity analysis by using a wind speed that is 5% and 10% higher on the 50km site. When this 5 and 10% increase in wind speed is applied to the 50km site with the direct drive wind turbines in this section an increase in energy production of ~6% and ~11% respectively are seen. The effect this energy production increase has on the overall cost of energy can be seen in Section 4.4.7.

4.4.3 BoP costs

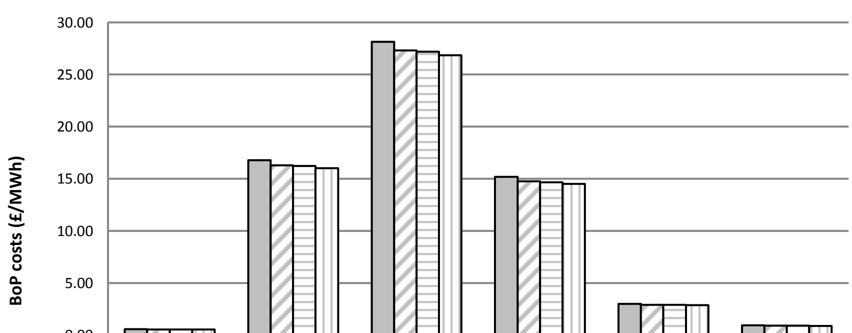
Figures 4.4 to 4.7 are based on the BoP model and inputs detailed in Table 4.1. The figures show the BoP costs for each drive train type at the site 50km from shore. Figure 4.4 shows the absolute BoP costs per MW installed and these costs are combined with the energy production in Section

4.4.2 to show the costs per MWh in Figure 4.5. It can be seen that the electrical infrastructure is the greatest contributor to the BoP costs followed by the structure and foundation. When the total BoP costs are shown for each turbine type in Figure 4.4 there is no difference between each configuration. However, Figure 4.5 shows a difference because it is in the cost/MWh format, meaning that even when total costs are constant the variation in energy production with each turbine type will cause a difference in BoP costs per MWh.   It can be seen that the DFIG configuration has the highest BoP cost per MWh generated and the direct drive configuration has the lowest. The BoP costs for the 10km and 100km sites were also calculated and included in the overall CoE shown in Figures 4.9 and 4.10.



	Port and Staging	Substructure and Foundation	Electircal Infrastructure	Assembly and Installation	Development, Engineering & Management	Commisioning
3 Stage DFIG PRC	2232	66175	110870	59886	11850	3690
3 Stage PMG FRC	2232	66175	110870	59886	11850	3690
2 Stage PMG FRC	2232	66175	110870	59886	11850	3690
DD PMG FRC	2232	66175	110870	59886	11850	3690

Figure 4.4: Total BoP costs per MW installed for the four drive train types



	Port and Staging	Substructure and Foundation	Electircal Infrastructure	Assembly and Installation	Development, Engineering & Management	Commisioning
3 Stage DFIG PRC	0.57	16.80	28.14	15.20	3.01	0.94
3 Stage PMG FRC	0.55	16.30	27.31	14.75	2.92	0.91
2 Stage PMG FRC	0.55	16.22	27.17	14.68	2.90	0.90
DD PMG FRC	0.54	16.02	26.84	14.50	2.87	0.89

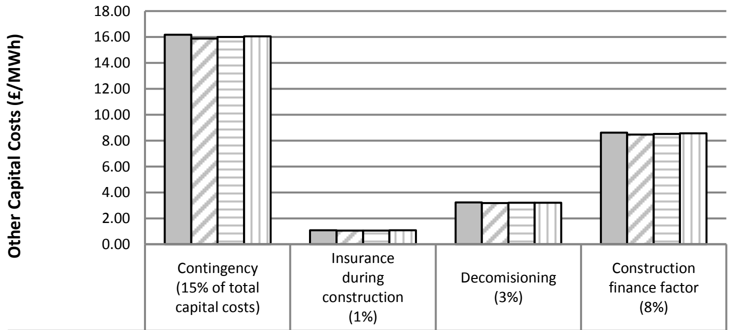
Figure 4.5: BoP costs per MWh for the four drive train types

4.4.4 Other capital costs

Figure 4.6 and 4.7 show the Other Capital Costs (capital costs outside of the turbine and balance of plant costs) for each drive train type at the site 50km from shore. The other capital costs are related to the financing of the project. Decommissioning bonds, contingency costs and insurance are all generally conditions dictated by the lender. The construction finance factor is then the cost of the capital required for constructing the project. These costs were calculated as a proportion of the total capital costs, the percentages used are seen in the graph labels. As with the BoP costs the other capital costs for the 10km and 100km sites were also calculated and are included in the overall CoE shown in Figure 4.9 but are not shown in Figure 4.6 or 4.7. Figure 4.6 shows the overall "other capital costs" per MW installed whereas Figure 4.7 combines Figure 4.6 with Figure 4.3 from Section 4.4.2 to show the "other capital costs" per MWh. It can be seen that the contingency costs are the greatest contributor to the other capital costs followed by the cost of the construction finance. It is shown in Figure 4.6 that the direct drive configuration has the highest other capital cost per MW installed and the DFIG configuration has the lowest. Figure 4.7 shows the results in the per MWh format, so the fact that the DFIG generator has lower energy generation gives it a higher "Other Capital Cost"/MWh.

	Contingency (15% of total capital costs)	Insurance during construction (1%)	Decomisioning (3%)	Construction finance factor (8%)
3 Stage DFIG PRC	64708	4314	12942	34511
3 Stage PMG FRC	66454	4430	13291	35442
2 Stage PMG FRC	66032	4402	13206	35217
DD PMG FRC	66962	4464	13392	35713

Figure 4.6: Other capital costs per MW installed for the four drive train types

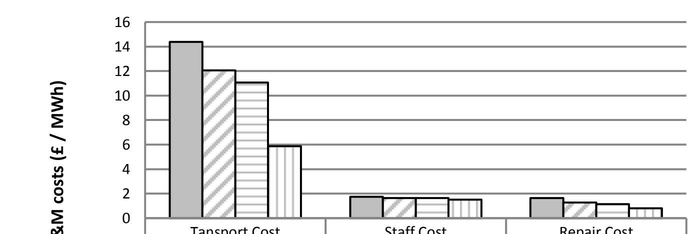


	Contingency (15% of total capital costs)	Insurance during construction (1%)	Decomisioning (3%)	Construction finance factor (8%)
3 Stage DFIG PRC	16.17	1.08	3.23	8.62
3 Stage PMG FRC	15.88	1.06	3.18	8.47
2 Stage PMG FRC	15.99	1.07	3.20	8.53
DD PMG FRC	16.06	1.07	3.21	8.56

Figure 4.7: Other capital costs per MWh for the four drive train types

4.4.5 O&M costs

The transport costs, staff costs and repair costs shown in Figure 4.8 come from work carried out in Chapter 3. Figure 4.8 shows the O&M costs for a site 50km from shore. The work is completed using the O&M model and inputs detailed in Table 4.1 and Chapter 3. Further details on this O&M model can be found in [9]. Figure 4.8 shows that the transport costs are the greatest contributor to the overall O&M cost. It can also be seen that across all three categories of staff costs, repair costs and transport costs the DFIG configuration has the highest cost whereas the direct drive configuration has the lowest. The increased major repair and replacement failure rates for the DFIG turbine leads to higher O&M costs and reduced MWh produced from the generator.

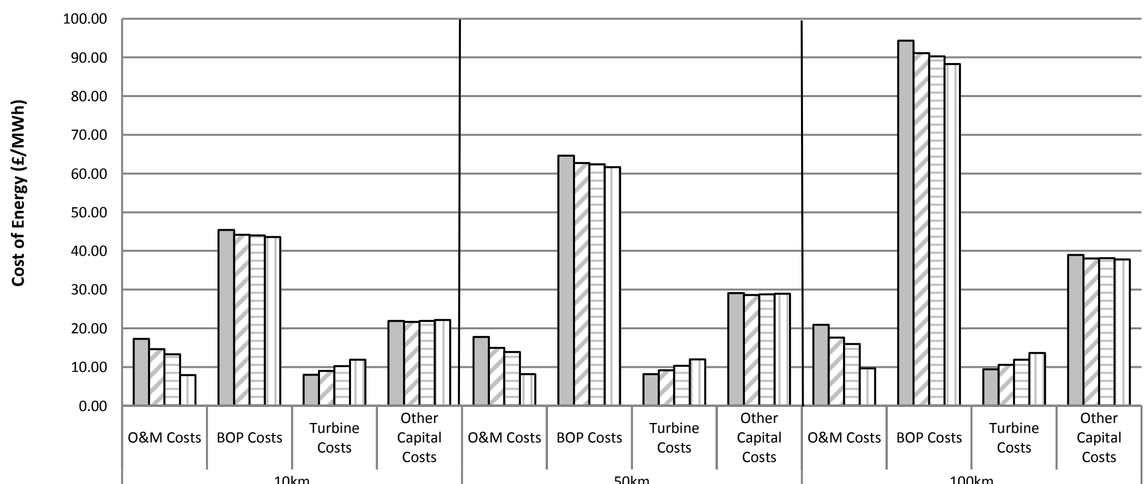


	Tansport Cost	Staff Cost	Repair Cost
3 Stage DFIG PRC	14.37	1.74	1.65
3 Stage PMG FRC	12.05	1.65	1.26
2 Stage PMG FRC	11.06	1.65	1.15
DD PMG FRC	5.88	1.5	0.80

Figure 4.8: O&M costs for the four drive train types

4.4.6 Overall CoE breakdown

Figure 4.9 shows how all of the costs discussed in the previous sections for each turbine type combine to provide an overall CoE for sites 10km, 50km and 100km offshore. The figure illustrates that when costs are shown in per MWh format all turbine cost groups are affected by distance to shore. It is obvious from the graph that the distance from shore plays a greater role in increasing the BoP and other capital costs than it does for the turbine or O&M costs. One of the reasons for this is because the turbine costs remain the same regardless of distance from shore, consequently it is the drop in energy production from the lower availability of the sites further from shore that drive up the turbine costs /MWh in the sites further from shore. The reason BoP costs increase by a greater amount than the O&M costs is primarily because of the large increase in electrical infrastructure costs as the wind farms move further from shore. The turbine costs are the same across all sites but are different in the graph below as it shows results in the per MWh format. For the direct drive turbine type at the site 50km offshore the O&M costs make up ~7.5% of the overall costs, the BoP costs make up ~55.5%, the Turbine Costs ~11% and the other capital costs ~26%. However it should be noted that the data used to simulate the O&M Costs and Turbine Costs were obtained from a manufacture and maintenance provider; these figures are the cost to manufacture the turbine and the cost for the maintenance provider to carry out the maintenance not the cost charged to the wind farm developer or owner. The BoP inputs were based on how much customers would have paid for the BoP. The consequence of this is that if all costs are looked at from a wind farm developer's point of view, the turbine and O&M costs would rise. This would mean the overall percentage cost for the BoP would drop as the overall percentage cost for the turbine cost and O&M cost rose.



	10km				50km				100km			
	O&M Costs	BOP Costs	Turbine Costs	Other Capital Costs	O&M Costs	BOP Costs	Turbine Costs	Other Capital Costs	O&M Costs	BOP Costs	Turbine Costs	Other Capital Costs
3 Stage DFIG PRC	17.27	45.40	8.01	21.90	17.76	64.65	8.13	29.10	20.92	94.31	9.43	38.97
3 Stage PMG FRC	14.64	44.21	9.03	21.66	14.96	62.73	9.14	28.58	17.60	91.10	10.54	38.03
2 Stage PMG FRC	13.27	43.99	10.23	21.89	13.86	62.43	10.35	28.78	15.93	90.33	11.90	38.10
DD PMG FRC	7.94	43.57	11.87	22.15	8.18	61.67	11.98	28.90	9.62	88.34	13.63	37.80

Figure 4.9: CoE breakdown for all turbine types and sites

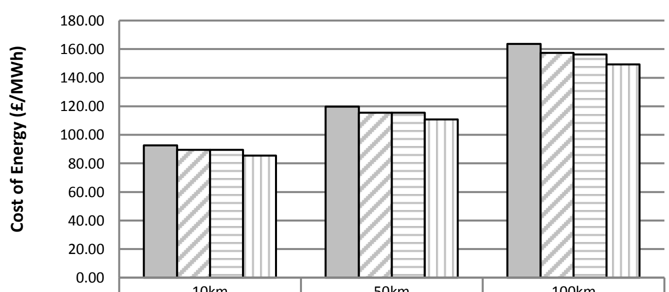
To estimate a profit margin for the O&M costs and the Turbine costs the percentage breakdown of CoE costs was used from [2]. In [2] it states that O&M costs make up ~17% of the overall costs and turbine costs make up 23% of the overall cost. Taking the example used in the previous paragraph (the direct drive turbine at 50km) and the percentage from [2] it can be estimated that the turbine costs would be 17.22/MWh when profit is included instead of 8.13/MWh with no profit. This gives a profit margin of ~111% for the turbine costs. Using the same procedure, a profit of 135% is calculated for the O&M costs.

4.4.7 Overall CoE

Figure 4.10 shows the overall CoE for each drive train type at each of the three distances from shore. This graph is based on the sum of all the costs that make up the CoE shown in Figure 4.9. Figure 4.10 illustrates that across all sites the DFIG configuration has the highest CoE whereas the direct drive configuration has the lowest. It can be seen that the two stage and three stage PMG configurations have a very similar CoE to each other.

One of the drivers for this similarity is that the higher turbine costs for the 2 stage configuration are cancelled out by its lower O&M cost. Figure 4.10 illustrates that as the drive train types move further offshore the cost of energy per MWh increases. It can also be seen that as the turbines move further offshore the business case for the direct drive PMG FRC configuration gets stronger as the difference in CoE between it and the other drive train types grows.

The higher availability of the direct drive configuration is one of the drivers for the increase in CoE difference between the drivetrain types.



	10km	50km	100km
3 Stage DFIG PRC	92.58	119.64	163.63
3 Stage PMG FRC	89.53	115.41	157.27
2 Stage PMG FRC	89.38	115.42	156.25
DD PMG FRC	85.52	110.74	149.38

Figure 4.10: CoE for all turbine types and sites

When the wind speed is increased by 5 and 10% as outlined in Section 3.3.4 of Chapter 3 and Section 4.4.2 of this chapter and is incorporated into the CoE Model a reduction in the CoE is seen due to the increased energy production from the higher wind speed. For the 50km site with the direct drive wind turbines a decrease in the CoE from £110.74/MWh to £104.17/MWh is seen with a 5% increase in average wind speed. For a 10% increase in wind speed the CoE reduces further from £110.74/MWh to £98.75/MWh. This brief sensitivity analysis demonstrates that even slight increases in the average wind speed of a site have an impact on the overall CoE for that site.

A similar brief sensitivity analysis was also carried out on the number of wind turbines in a wind farm, as in Chapter 3. As in that chapter, the hypothetical wind farm of 100 turbines was halved to 50 and doubled to 200. The number of technicians and the number of CTVs were also halved when the wind farm was reduced to 50 turbines and doubled when it was increased to 200 turbines. However, as seen in Chapter 3 this led to an increase in availability of the smaller wind farm and a decrease in availability for the larger 200 turbine wind farm. The increase and decrease in availability occurred because the optimum number of technicians and CTVs did not scale linearly with the number of turbines in the farm. For example, 30 technicians and 6 CTVs for 100 turbines provide better availability than 60 technicians and 12 CTVs for a 200 turbine wind farm. This difference in availability played an important role in the CoE analysis for the 50 turbine and 200 turbine wind farm. The CoE results from the wind farm size sensitivity analysis showed that for a 50 turbine hypothetical site with all other properties the same as the 100 turbine site (apart from the number of technicians and CTVs) the CoE decreased from £110.74/MWh to £107.30/MWh for the site 50km from shore with direct drive turbine types. The driver for this decrease was the higher energy production per installed MW for the smaller wind farm due to its higher turbine availability. The opposite occurred when the wind farm size was doubled due to the lower availability reducing the overall energy production per installed MW. The overall cost of energy per MWh was seen to rise from £110.74/MWh for the 100 turbine wind farm to £111.81 for the 200 turbine wind farm.

4.5 Conclusion

This chapter has taken a step towards answering the question posed in the introduction "How do you choose between different competing wind turbine models when planning an offshore wind farm?"

- Drive train performance ranking in terms of cost of energy

Based on modelling the CoE for four different drive train types at a number of sites at varying distances from shore this chapter found that turbine types with a direct drive, permanent magnet generator and a fully rated converter provided the lowest CoE across all sites in this analysis. This analysis found little difference between the CoE from 3 stage and 2 stage PMG FRC configurations across all sites. The 3 stage, DFIG partially rated converter configuration had the highest CoE across all sites.

- Cost of energy for hypothetical site with different turbine types

For a site 50km offshore this analysis found the DFIG configuration's CoE (~£119/MWh) was ~8% higher than the direct drive configurations (~£110/MWh). When the two stage and three stage PMG configurations are compared it can be seen that one of the reasons they are so similar across all sites is because the higher turbine cost of the of the 2 stage configuration is wiped out by its lower O&M cost providing it with a very similar CoE to the 3 stage PMG configurations. Based on field operational and cost data from modern multi MW offshore turbines and the use of newly developed O&M and BoP models this chapter concludes that the drive train that provides the lowest CoE for all sites analysed is the direct drive, permanent magnet generator with a fully rated converter.

- Influence of wind speed and wind farm size on CoE

To determine the effect of increased wind speed for a given site on the overall CoE, the site at 50km from shore with the best performing direct drive configuration had its wind speed increased by five and ten percent. This decreased the overall CoE by six and twelve percent respectively. Sensitivity analysis also showed that increasing the number of turbines in a wind farm led to a higher overall CoE. This was expected from Chapter 3 which showed the increase wind farm size led to a lower availability. However, it should be noted that the optimisation of operational resources could greatly affect this outcome; this is an area of further work. This chapter also discussed how profit margins were not included in some of the CAPEX and operational expenditure (OPEX), specifically the turbine costs and O&M costs.

- OEM Profit estimate

A simple analysis was carried out which suggested that profit margins of 111% are seen by the OEMs on the turbines and profits of 135% are seen by the O&M providers on the O&M costs.

4.6 Chapter 4 references

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Chapter 5 Cost of energy reduction through vessel strategies, maintenance strategies and turbine design

5.1 Introduction

The cost of energy (CoE) from offshore wind turbines is currently too high to make it truly competitive with traditional energy generation techniques [1]. Studies have shown that generation costs for offshore wind energy is up to 40% higher than gas turbine generation and 30% higher than onshore wind [1]. It is for this reason that industry, research institutes and academia are working towards lowering the CoE for offshore wind.

This chapter outlines ways of impacting the cost of energy through turbine operation and turbine design innovation/adjustments, it aims to answer the research question "how can the cost of energy be reduced through vessel strategies, maintenance strategies and turbine design changes/innovations?" Analyses on vessel strategy, maintenance strategy/performance based maintenance contracts and minor turbine design changes have been carried out in the following sections to determine if the cost of energy can be lowered compared to the baseline cost of energy estimates shown in Chapter 4.

The following chapter starts off by providing an overview of past literature in the areas of vessel strategies, maintenance strategies and minor turbine design changes. An overview of the gaps in the past literature for each section is then included. This is followed by a number of sections detailing the novel analysis and results that have been carried out for this thesis which contribute towards closing some of the research gaps related to vessel strategies, maintenance strategies and minor design changes to turbine design. This chapter then includes a final section which brings together all of the findings from the previous subsections to estimate their impact on the overall cost of energy. This is followed by some short discussion and conclusions.

In this chapter, for demonstrating the impact of the operational and design changes on CoE, the direct drive PMG FRC turbine type has been used for a hypothetical site located 50km from shore. The direct drive PMG FRC turbine type was used because it is the best performing turbine type in Chapter 4. 50km from shore has been chosen because it is mid-range of the sites in this thesis. However, in the following sections there are a couple of scenarios in which the impact on CoE is demonstrated, when the direct drive PMG FRC turbine type cannot be used at 50km from shore. For example, in Section 5.3.1.7 the impact of the different Vessel Strategies on the CoE are shown. In this case the use of the mother ship at 50km from shore has no positive impact on the CoE. For this reason the example is shown for a site at 100km from shore. The only time the hypothetical scenario, used to demonstrate the impact on the CoE is shown when the turbine type changes from the direct drive PMG FRC turbine type is in Section 5.3.3.3. In that section the impact on the CoE from Inbuilt lifting mechanisms, redundancy and reduced repair times are analysed. However in-built lifting mechanisms and generator redundancy may not be applicable in direct drive machines. It is for this reason the 3 stage PMG FRC has been used in the hypothetical site to demonstrate the impact on the CoE from these turbine design changes. Redundancy and in-built lifting mechanisms for HLV reduction may not be applicable in direct drive machines because of the high cost and high weight of the generator relative to high speed generators. This may mean that there is less of a business case to have a second generator sitting idly than there would be with the lower cost high speed generators. From a technical point of view the size of the direct drive generator would also lead to challenges with redundancy. A much larger nacelle and alternative torque transfer from the rotor would be required. The weight of the direct drive generator could also prove challenging for the in-built lifting mechanism unless it was a modular design.

5.2 Vessel strategies, maintenance strategies and turbine design

5.2.1 Vessel strategies introduction, background and literature review

Introduction

Past analysis has shown that O&M costs can be up to 30% of the overall CoE for some offshore wind farms [2]. In recent years wind farms and planned wind farms are moving further offshore. As wind farms move further offshore new O&M challenges emerge. New vessel operational strategies and vessel types may be required to overcome these O&M challenges and contribute towards lowering the overall cost of energy from offshore wind. O&M costs are heavily influenced by transport costs. Chapter 3 shows that for a hypothetical site at 50km from shore, transport costs make up ~45% of the overall O&M costs. Transport costs can potentially be reduced through focusing on vessel strategies. Chapter 3 has shown that different wind turbine types lead to different O&M costs, consequently it is possible that the O&M cost variance from the introduction of different vessel strategies will also be influenced by the wind turbine type. For this reason and in keeping with the rest of the thesis, Section 5.3.1 of this chapter focuses on the four drive train types outlined in the previous chapters to examine the impact of vessel strategies on O&M costs and availability for each of the four turbine types. This vessel strategy analysis focuses on how both heavy lift vessels and mother ships impact the availability and O&M costs. For the purpose of this analysis "heavy lift vessel strategy" refers to how and when the heavy lift vessel is used to fix failures. The "mother ship vessel strategy" refers to whether a mother ship is used or not.

For the HLV analysis, it is the aim of this chapter to introduce 4 different HLV strategies to hypothetical wind farms using an offshore wind farm O&M and availability model to determine which HLV strategy offers the lowest O&M cost and highest availability. The model is the same model used in [3] and populated with the offshore wind turbine field data from Chapters 2, 3 and 4. The second part of the vessel analysis will introduce a mother ship to a number of hypothetical wind farms for the CTVs to work from and in doing so will answer the research question "at what distance from shore is there a reduction in overall O&M costs from the use of a mother ship?" Section 5.3.1 of this chapter also answers another research question "for a reduction in overall O&M costs, what day rates can be paid for a mother ship at hypothetical wind farms consisting of different drive train types 70km-100km from shore?"

Heavy lift vessel strategy background and literature review

As mentioned in the previous section transport costs are the biggest contributor to the overall O&M costs. From Chapter 3 it can be seen that HLV costs are the main driver for the transport costs. It is for this reason that there is value in investigating what operating strategies are applied to HLVs. Past papers such as [4] and [5] have investigated the effect on the O&M cost using different HLV strategies. They focus on a generic wind turbine types and do not look at different wind turbine types or focus on varying distances from shore. While an example O&M estimation is provided for a certain site the majority of [5] focuses on the optimum HLV chartering period for wind farms of different sizes and provides a background on failure rates and climate data used in the analysis. Reference [4] provides an overview of the model used to determine O&M costs and again focuses on wind farms containing varying numbers of turbines. As there is uncertainty around failure rates used in [4] a section of the paper focuses on a failure rate input sensitivity analysis.

The novelty in the vessel work in this chapter is that it models the effect of the different HLV strategies on a number of different wind turbine types rather than on a single generic turbine type. While the O&M cost model is set up the same way as it was for [4, 5, 6] with some of the same inputs such as vessel day rates and climate data, for this analysis it was populated with the latest offshore reliability and cost data (as outlined in the previous chapters) which was not available to the authors of past papers and which leads to more accurate O&M cost and availability modelling. This work also focuses on O&M costs for different HLV strategies at varying distances from shore which offers a further area of novelty.

Mother ship background and literature review

As wind farms move further offshore the window of time required to access the turbine to repair it gets longer. This is due to the increase in travel time to get from shore to the wind turbine. For sites further offshore the availability is decreased by much more than the extra travel time because of the need for the increased accessibility window. The reason for this is because larger accessibility windows come around less often. So the increase in downtime is not just the extra time to travel further, rather it is this plus the fact that these longer accessibility windows are rarer and there is increased time waiting for one to occur. This results in the possibility of the wind turbine remaining shut down for longer periods, decreasing the availability because there is not an accessibility window large enough for the CTV and technicians to reach the turbine and carry out the repair. [7]

It is for this reason that O&M providers are chartering mother ships with the capability of docking CTVs, stocking spare parts and providing living quarters for wind turbine technicians. The use of mother ships increase availability as it decreases travel time to the turbines, thus reducing the required accessibility windows. Improved availability leads to less lost production costs. It is when these savings in lost production costs outweigh the mother ship day rates that it can be said there is a reduction in the overall O&M costs from the chartering of a mother ship. The results of the analysis shown in Section 5.3.1 of this chapter determine at what distance from shore there is a reduction in overall O&M costs from the use of a mother ship for each drive train type. It will also show what day rates can be paid for a mother ship at each distance from shore for each drive train while maintaining a reduction in overall O&M costs. This is important as day rates may vary with changes in the market depending on the demand for these vessels. The work may show that different drive train types require a mother ship at different distances from shore. This analysis will help O&M providers determine the maximum day rates they should pay to charter a mother ship. It is the answering of the above research questions and the use of the latest reliability and cost data that make this analysis novel and build on work from other mother ship research in [8] which shows improvements in O&M costs through the use of a mother ship at a single site for a single turbine type based on older reliability data.

5.2.2 Condition based maintenance and performance based maintenance contracts introduction and literature review

Introduction

Condition monitoring systems and performance based maintenance contracts have the potential to significantly reduce the cost of energy (CoE) for offshore wind turbines [9] and [10]. The following subsections describe the condition monitoring systems (CMS) available for offshore wind turbines. They detail how CMSs can be used in condition based maintenance (CBM) strategies and discusses the advantages and disadvantages of using CBM strategies over time based maintenance (TBM) strategies. This chapter also provides and compares the results from an empirical availability analysis of an offshore wind turbine population that has condition monitoring systems and a population that does not. Based on the comparison of these results conclusions are drawn on the value added by condition monitoring systems. Sections of this chapter also focus on performance based maintenance contracts (PBMC) and provide an overview of what performance based contracts are currently on offer and what guarantees they provide. An empirical availability analysis is carried out on a population of offshore wind turbines with performance based maintenance contracts and a population without. These results are then compared and conclusions are drawn on how much value PBMCs add.

The following sections will provide a background and detail a literature review/market analysis on the types of condition monitoring systems currently available and their advantages and disadvantages. A further subsection will provide an overview of the performance based maintenance contracts currently offered by wind turbine manufacturers. The overview describes how these maintenance contracts work, what they guarantee and their advantages and disadvantages.

CMS and CBM background and literature review

The following paragraphs outline the CMS options available, what they monitor and how they contribute to decision making and maintenance strategies. This overview is based on several review studies including the work of Garcia Marquez *et al.* [11], Takoutsing *et al.* [12], Ciang *et al.* [13] and Sinclair Knight Merz [14].

The drive train is one of the most commonly monitored systems, where the drive train includes, the main bearing, shaft, gearbox and generator. These components have been identified as critical to keeping availability high [15]. As a result, there are many technologies that have been exploited to monitor them. Vibration analysis (VA) is the most common form of monitoring for these components and is a requirement for CMS by insurer Allianz [16]. Reference [16] also describes other technologies that are well established and could be expanded into Allianz's scope for a CMS monitoring the drivetrain. These include: displacement sensors for bearings and shafts, oil analysis for the lubrication systems of bearings, electrical parameters for the generator windings and temperature measurement of the entire drive train.

There are multiple ways to analyse the data from the drive train monitoring systems to obtain useful information. First it must be collated with other operational parameters – the current operating conditions of the turbine affect how the drive train rotates and vibrates. Time (wavelets, envelope analysis), frequency (Fast Fourier Transform – FFT) domain analyses and order analysis are commonly used. Reviews of these algorithms and techniques can be found in the work of Lei *et al.* [17] and Hameed *et al.* [18].

Vibration analysis has the largest number of commercially available systems compared to other systems [19]. In the study by Crabtree, there are 14 systems mentioned based primarily on drive train vibration. The large commercial CMS manufacturers are Gram & Juhl, Brüel & Kjaer, SKF and Bently Nevada (now owned by GE).

Acoustic Emission (AE) is mentioned in several of the above studies as a possible alternative or addition to VA. Curtiss Wright [20] and Mistras Group [21] have both produced documents showing commercial offerings for wind turbines. However, not much information can be found about successful deployment of the technology.

Oil analysis (OA) has been an important tool for monitoring the condition of components for a long time. Monitoring the oil can inform the operator about the state of the lubrication system, any contamination in the system (such as moisture or water) and degradation of components. The majority of tests have taken place offline with sample collection. Hamilton and Quail give a review of online OA techniques [22]. Electromagnetic sensing, screen filtering and optical particle counting are some of the common methods of online analysis. OA can show evidence of deterioration before it is evident with VA [11]. Some of these techniques can be further applied to wind turbine hydraulic systems [15]. There have been commercial sensors available from manufacturers such as GasTOPS, Macom and Pall Corporation.

SCADA systems are commonly used to monitor the process and operating parameters. These can be used to monitor, trend and improve the performance of the wind turbines. One of the data points commonly recorded is temperature. Temperature can be used to monitor the condition of bearings, oil and generator. In rotating equipment, an increase in temperature can be an indication of increased wear or misalignment.

The CMSs described in the previous paragraphs can be used in condition based maintenance strategies. As turbines move offshore, condition based maintenance strategies or hybrid strategies (combining condition based and time based strategies) will become more common. The following paragraphs explain time and condition based maintenance strategies and how CMSs are utilised within them.

Time based maintenance (TBM), also known as calendar or schedule based maintenance, occurs at set intervals. These intervals can be determined by fixed periods of time, operating hours or cycles. This is useful where components operate with little variation in operating conditions and deteriorate in a reliable, repeatable, well understood fashion.

Condition based maintenance (CBM) uses inspections and monitoring equipment to understand the condition that the equipment is in. This allows for maintenance actions to be scheduled only when required – when it has been observed that a component or system is operating in or approaching a degraded state. This is useful for when the equipment operates in variable conditions, or deteriorates in an uncertain or unpredictable fashion [23].

Offshore wind turbines have particular attributes that separate them from other forms of power generation in terms of maintenance, including onshore wind. Onshore wind farms have most often used TBM strategies to obtain high availabilities but the availability level has dropped offshore [24]. In theory, the major advantages of utilising a CBM strategy over a TBM strategy are the reduction in maintenance actions coupled with the extraction of as much of the remaining useful life and hence value of components as possible [25]. If degradation can be detected far enough in advance, spares levels and other logistic tasks can be managed efficiently reducing overall downtime. Through the use of a CMS the lead time for the larger major replacements such as gearboxes, blades and generators could run parallel with the end of life days and weeks of the component allowing for lead time to be removed from the downtime equation. A hybrid maintenance strategy of TBM and CBM has been used for offshore wind farms with CBM being used to adjust the scheduling of TBM actions or group of actions [26].

An effective CBM strategy is dependent on having CMSs that are robust and reliable. The CMS itself is an additional system layer with extra costs and maintenance requirements. The measurement system will also have an uncertainty attached to its measurements. Every mechanical system has different parameter trends making condition thresholds difficult to set. The data needed for determining the condition level can be quite large and this needs to be communicated to the operator. False failure notifications also known as false positives can occur with condition monitoring systems. One study [9] has shown that false positives can possibly decrease the availability of wind farms when a condition based maintenance strategy is used but it also shows that overall this is usually outweighed by the benefits of using a CBM strategy. Having a good understanding of the condition of the components in operating wind turbine leads to further advantages, such as improved operating and control strategies. For example, running a turbine that contains a component that is coming towards the end of its remaining useful life at a reduced rated power to prolong its life [27] or continuing to run a turbine with a component at the end of its remaining useful life to failure because it is a high wind speed period and there is a low wind speed period coming up in which maintenance can then be carried out.

Performance Based Maintenance Contracts background and literature review

Wind turbine manufacturers that carry out maintenance claim that their PBMC increase availability or energy production. These PBMCs come with guarantees in the form of availability or production based guarantees. If performance guarantees are not met the manufacturers pay compensation and in some cases if the guarantees are exceeded the additional revenue from extra generation is shared between the wind farm owner and manufacturer. This is known as upside sharing. An overview of the types of performance based maintenance contracts that are used or could be used in the wind energy industry are seen in [10, 28, 29]. Reference [10] concludes that a wind turbine OEM that provides the PBMC is more likely to invest resources into the reliability of the wind turbine when it is under a PBMC.

Many turbine manufacturers offer PBMCs for their turbines. These vary in their level of support and guarantee. The information below outlines the offerings available from Siemens Wind Power [30], Vestas [31] and GE [32]. This list is not exhaustive but chosen for the amount of information publically available about the products. Other manufacturers have indicated that they will offer similar contracts such as Alstom Power [33] and MHI Vestas [34].

Siemens Wind Power's most basic PBMC that includes an availability clause is the SWPS-200A. This includes remote diagnostic services and servicing. The most advanced PBMC also includes individual component warranties and the inclusion of offshore logistic costs, where – in certain situations – Siemens will utilise their own fleet of helicopters and service vessels.

The AOM (Active Output Management) 5000 is the most advanced PBMC offered by Vestas. This offers an "energy-based availability guarantee that maximises output". This agreement and some of their lower level PMBCs include a 95-97% availability clause.

Finally GE's EPSA (Extended Parts and Services Agreement) and FSA (Full Service Agreement) PBMC include availability guarantees and coverage for completing manual resets. The more advanced FSA further covers unplanned maintenance actions and turbine performance review with an aim for turbine life extension.

These contracts appear to be designed to remove large amounts of perceived risk of offshore maintenance from the operator/owner at a fixed premium. Some contracts focus on the lifetime operation or extension of turbine life while others look to remove the unpredictable costs of service vehicle/vessel fleet management. The production based guarantees offered from a couple of manufacturers stand out as particularly interesting– they are of benefit to operators by forcing scheduled maintenance actions to be moved to low-wind periods, thereby maximising energy capture.

5.2.3 Turbine design innovations introduction and literature review

Offshore wind turbine manufacturers, owners, operators and researchers have investigated a number of different strategies as a means of increasing availability and reducing O&M costs. Minor turbine design changes/innovations are one of the areas where cost savings could be made through improved availability or reduced O&M costs. The following paragraphs outline three turbine design modifications/innovations that have been mentioned in past literature as a means of improving availability or reducing O&M costs.

1. Redundancy – when some of the major subsystems and components are duplicated – could be a method of improving availability of an offshore wind turbine and potentially reducing the O&M costs. References [35] and [36] suggest that as wind turbines move offshore, redundancy could contribute to reducing O&M costs. However, duplicating some subsystems, like gearboxes for example may prove unrealistic due to functionality restrictions, weight, space and capital cost restrictions [35]. Reference [37] also looks at redundancy in the drive train of offshore wind turbines. It focuses on increasing the number of generators and power converters to determine at which point the highest turbine availability is achieved. Results from that paper show that increasing the number of parallel generators and converters in a wind turbine does not necessarily lead to a higher availability. For higher availability to be achieved failure rates must be reduced or power ratings must be increased beyond P/N where *P* is the rated power and *N* is the number of parallel systems. The analysis shown later in this chapter will focus on redundancy in the generator and power converter.

2. This analysis will also look at the effect of reducing the need for heavy lift vessels (HLVs) through the design change of in-built lifting equipment in or on the turbine. Wind turbine manufacturers can build cranes into the nacelles of their turbines as detailed in the offshore turbine in [38] or provide tower cranes as seen in [39]. The aim of these in-built lifting mechanisms is to reduce the need for the hiring of HLVs which can have long waiting times and day rates of the order of £100k [40]. As an estimate of the required in built lifting capacity for major component replacements literature was reviewed to determine the mass of major component replacements. Reference [41] stated that for a modern multi MW DFIG turbine of 3MW the

generator weighed 8.5 tonnes, the transformer weighed 8 tonnes, the blades weighed approximately 7 tonnes each with the hub weighing roughly the same. The heaviest component was the gearbox at 23 tonnes. Based on [41], for a 3MW wind turbine the in-built lifting mechanism would need to be ~8 tonne to facilitate all major replacements in the wind turbine except for the gearbox which would require a capacity greater than 23 tonne to facilitate gearbox replacements.

The analysis shown later in this section will focus on the availability improvements and O&M costs savings that can be achieved if, through the use of in built lifting mechanisms, turbine manufactures can reduce the need for HLVs by 25%, 50%, 75% or 100%. These percentages were chosen because, for a 3 stage PMG FRC turbine type, an in-built lifting mechanism with a capacity of 8 tonnes can represent 25% of major replacement failures and 23 tonnes can represent 100%. However for the different drive train types this will not be the case so 50% and 75% were also included in the analysis.

3. The focus area of this section is reduced repair times, delivered through the use of design for maintenance techniques. Reference [42] provides an overview of design for maintenance techniques that could be used on wind turbines in order to reduce the repair times. These techniques aim to make repair easier and more efficient for the wind turbine technicians which in turn is hoped will allow them to carry out their repairs in a shorter period of time. The types of design for maintenance techniques discussed in [42] are: the use of fasteners where possible so the number of required tools are minimized; the provision of adequate space for maintenance around the components that need to be maintained so technicians can carry out their work unobstructed; the design of equipment in such a way that it can only be maintained in the correct way allowing for faster repair and for technicians with different expertise to complete the repair; position maintenance points close to each other; the design for the use of standard tools and the provision of visual inspection ports where possible. Optimising or creating lean processes for technicians to follow can also help reduce repair time. The analysis related to reduced repair times shown later in this chapter will quantify the improvements in availability and reductions in O&M cost and the overall CoE when repair times are reduced by 10 and 20% from the use of design for maintenance techniques similar to the techniques outlined above. It should be noted here that repair time refers to the technician time in turbine and not the overall downtime. For example minor repairs on generators, converters and gearboxes take approximately 6.5 hours,

as seen in Chapter 3. If the design for maintenance techniques and optimised maintenance procedures outlined in the previous paragraphs lead to a 10 or 20% saving in repair time this would equate to approximately 40 and 80 minutes respectively saved on the 6.5 hour repair time.

5.2.4 Research opportunities from past cost of energy work

Based on the background and literature reviewed summarised in the previous sections of this chapter a number of novel research opportunities exist in which it could be determined if the O&M costs and CoE for different wind turbine types could be reduced through adjusting vessel strategies, O&M strategies and implementing minor turbine design changes.

While past analysis has been carried out for the different vessel strategies on a generic wind turbine no past work was encountered in which vessel strategies for different wind turbine types were investigated. Consequently, a study of the impact on the CoE using different vessel strategies for a number of wind turbine types provide a novel focus area for a section of this chapter.

Section 5.2.2 showed that a number of past papers provide an overview of the different CMSs available and how they can be used in CBM. However, no past work was encountered in which an empirical availability comparison was carried out between wind turbines that had CMSs and wind turbines that did not. Little or no past papers were encountered on PBMC, leading to a further research opportunity for an empirical availability comparison of sites that had CMSs/ PBMCs and sites that did not. Further work is also carried out in this chapter to determine the impact of the availability improvements from the use of the CMS and PBMC on the overall CoE.

As outlined in 5.2.3 there is a lack of past work in the area to quantify the impact on O&M costs and the CoE from drive train redundancy, reduced HLV requirements from in built lifting mechanisms and reduced repair time from design for maintenance techniques. Consequently, a further novel research opportunity exists to carry out analysis in these areas.

Carefully selecting which drive train type to choose at a new offshore site is one of the early decisions in keeping the CoE to a minimum made at the outset of the project. A number of other steps can be taken to try and reduce the cost of energy. As previously mentioned this chapter focuses on HLV and mother ship vessel strategies, maintenance strategies, PBMCs, reducing the need for HLVs, reducing repair time and power train redundancy. These areas were chosen because they represent different areas in the O&M process where CoE savings can be achieved.

From the O&M point of view, the vessel analysis and maintenance strategy decision research carried out in this chapter will help reduce downtime by making sure lead time is kept to a minimum by having the most appropriate vessel and maintenance strategy. When a failure does occur, greater costs and downtime is incurred by the need for the use of a HLV. Consequently, this work focuses on how much downtime and costs could be reduced if the use of a HLV was reduced or removed. Actual repair time in the turbine also contributes to the overall downtime, the effect of reducing this repair time is also covered in this analysis. If a failure does occur, mitigating its consequences is also worth investigating, it is for that reason that redundancy in the generator and converter are included in this analysis.

5.3 Method and results for CoE reduction analysis

The following sections will outline the analyses carried out and show the results which determine if the CoE was reduced or increased compared to the baseline CoE shown in Chapter 4. As with the introduction section, the method and results for the vessel strategies are shown first, followed by the maintenance strategies and lastly the effects of the minor design changes.

5.3.1 HLV and mother ship analysis

5.3.1.1 Method

As in reference [4] 4 HLV strategies are modelled to determine which one offers the lowest O&M cost and in turn lowest CoE. The 4 strategies used in this analysis and the method of including them in the model are shown in the following paragraphs:

- Fix on fail (FoF) - Charter vessel when fault is predicted or observed. This is the baseline HLV strategy as used in Chapter 3. The model allocates a vessel as soon as one is required for a major replacement. It takes into account the mobilization time and other HLV inputs (such as jack up time, speed, fuel consumption and so on) that are outlined in [4] and [6].
- Batch repair - As FoF but operator does not charter a vessel until a threshold number of failures have occurred. In this case the model holds off on allocating the vessel until a certain number of failures that require a HLV have occurred. In the model the turbines that have failed and are

down, until enough turbines fail to trigger the allocation of a HLV, contribute to the availability calculation and O&M costs of the wind farm.

- Annual charter - Operator charters vessel for a number of months each year to repair all failures in charter window. Generally months with the lowest wind speed are chosen. For the purpose of this analysis June and July have been chosen in the model. The availability will not be affected by the months that are chosen but the lost production factor will be. The lost production factor is a measure of how much energy that could have been captured by the wind turbine was not. In the model all repairs that require a HLV are carried out in June and July only and turbines remain down if they fail outside of these months.
- Purchase - Purchase a vessel for the duration of the wind farm life. In this case the model spreads the cost of purchasing the vessel across the lifetime energy production of the wind farm to give an output O&M cost in the per MWh format. In the model the purchase strategy works the same as FoF because the HLV is allocated as soon as a failure occurs, however availability is increased because no mobilization time is required when the purchase strategy is used because the operator owns the HLV and has it ready to use. The model assumes the purchase cost of the vessel to be £80 million. This is based on the inputs from [4,5,6]

The first step in carrying out this HLV and mother ship analysis was to obtain field data from operational wind turbines to use in the O&M cost and availability modelling. This operational data was obtained from industrial partners as outlined in chapters 2, 3 and 4. Once all of the necessary reliability data was sourced and adjusted, the O&M model was chosen. It was decided to use the same O&M cost and availability model that was used in the earlier chapters as it allowed for the 4 HLV strategies to be simulated so O&M costs and availabilities could be obtained for 12 hypothetical wind farms using each of the 4 HLV strategies outlined in the beginning of this section. The 12 hypothetical wind farms consist of the 4 different drivetrain types described in Chapter 2 at sites 10km, 50km and 100km from shore. The O&M costs and availabilities for each of the wind farms at each distance from shore could then be compared to determine which HLV strategy offered the lowest O&M cost and highest availability for each drive train type.

Mother ship day rates were obtained from a company that charters mother ship vessels and a maintenance provider, this data was then used in the model to determine the viability of the use of a mother ship at 16 sites located at 70km, 80km, 90km and 100km from shore, each of the 4 distance had 4 wind farms each with one of the drive train types that are the focus of this thesis. The mothership is used along with the HLV in this thesis. Once again the O&M costs and availabilities for each of the wind farms at each distance from shore could then be compared to determine at what distance from shore there was a positive effect on the O&M costs from using a mother ship and what was the maximum day rate that could be paid for a mother ship at each site. When the mother ship is in use and a failure occurs the model then assumes that the technicians and CTV are traveling from the location of the mother ship to carry out the repair rather than the location of the port. The model then uses the travel time savings to determine the availability increase and takes the day rates assigned to the mother ship to determine and O&M cost/MWh.

The work outlined above builds on the work from [4,5,6,7,8] in which an O&M cost model was created that has the ability to determine O&M costs for different HLV and mothership strategies. Figure 5.0 shows what work existed and how this chapter builds on that work. In Figure 5.0 blue shows what already existed and green shows what will be done in this chapter. Other availability and O&M cost outputs from the model have been obtained in previous work such as [5] and [8]. However that work was using operational data that was not as current as the data used in this thesis and if was for a generic wind turbine type only, it did not specify availability and O&M costs for different drive train types.

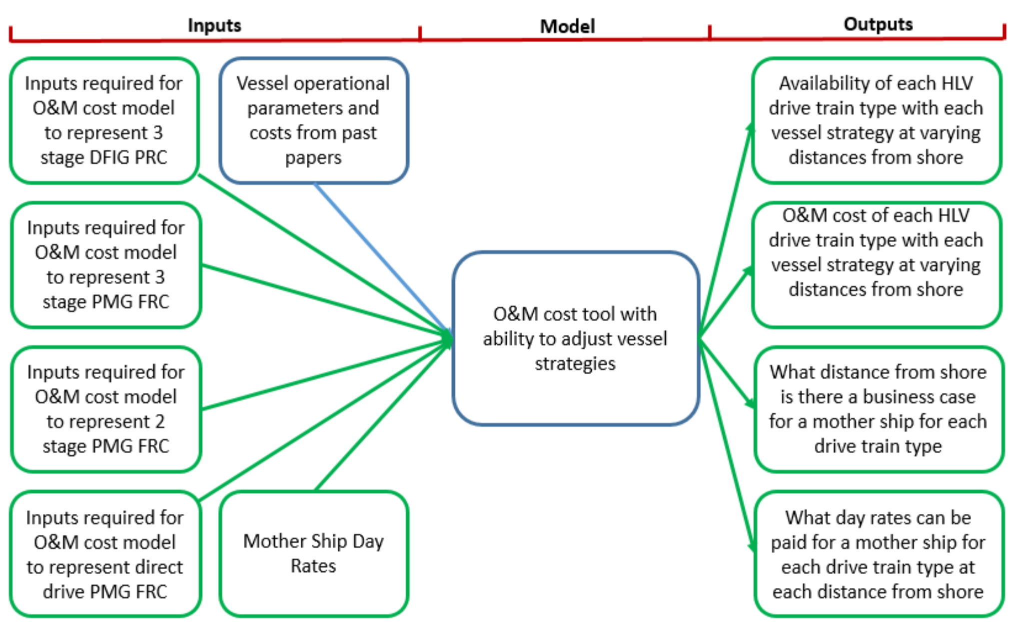


Figure 5.0: Existing vessel work (blue) and how this chapter builds on that work (green)

5.3.1.2 Hypothetical sites

For the HLV analysis 12 hypothetical offshore wind farms were modelled. These sites consisted of 4 wind farms located at 3 different distances from shore: 10km, 50km, and 100km. These distances were chosen to represent near shore sites at 10km, far shore sites at 100 km and in between at 50km. The assumption was made that each site had the same wind speed and sea state characteristic. As in the earlier chapters, and to allow for easier comparison, FINO wind and sea state data [43] gathered at a location 45 km off the German coast in the North Sea was used to model the conditions of each site. As mentioned, this FINO offshore environment data corresponds to existing and future wind farms in the North Sea, and can therefore be considered representative of expected operating conditions for future developments.

Similar to earlier chapters, the hypothetical wind farms consisted of 100 modern multi MW offshore wind turbines. The exact rated power cannot be provided for confidentiality reasons but was the same across all turbine types simulated. O&M costs are provided in £/MWh so even though exact rated power is not provided O&M cost comparisons for the different vessel strategies and drive train types can be made. At each distance from shore a 100 turbine wind farm with each of the 4 drive train types was simulated, i.e. one of the wind farms at 10km from shore consisted of 3 stage DFIG PRC turbines, one with 3 stage PMG FRC turbines, one with direct drive PMG FRC turbines and one with 2 Stage PMG FRC turbines. This was the same for the 50km and 100km sites.

For the mother ship analysis 16 hypothetical offshore wind farms were modelled. These sites consisted of 4 wind farms located at 4 different distances from shore: 70km, 80km, 90km and 100km from shore. Each distance had 4 wind farms, consisting of a different drive train type. As with the HLV analysis all sites used FINO climate data and consisted of 100 modern multi MW wind turbines.

A number of different variables relating to the hypothetical sites influence the effect of a mother ship and the different HLV strategies on overall O&M costs. These variables include the number of CTVs the wind farm has access to, the number of technicians the wind farms have access to, whether helicopters are used at the site and so on. Each of these variables requires greater analysis to determine their optimum numbers at each wind farm. However these optimisation analyses are outside the scope of this thesis but would be interesting research opportunities for further work.

5.3.1.3 HLV strategy availability results

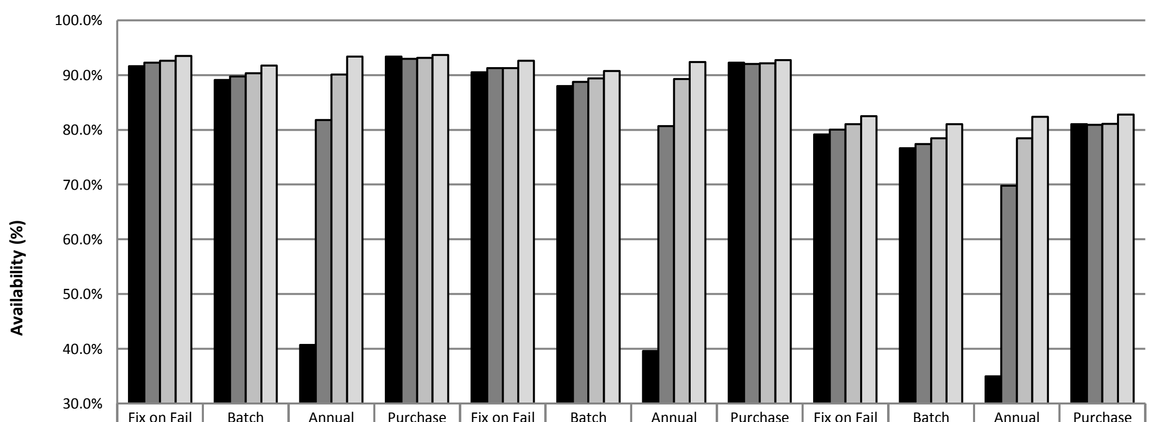
Figure 5.1 shows the availability for each drive train type at each of the 3 distances from shore when the 4 vessel strategies are used. It can be seen that the "Annual" strategy for the DFIG turbine type has the lowest availability of all the HLV strategies and turbine types. The reason for this is because there is a high requirement for a jack-up vessel with the DFIG and the fact that the vessel is only charted for 2 months of the year. With a high HLV requirement all of the turbines are not being repaired in the 2 month period so they build up for the following year. This effect is cumulative until a large number of turbines are not operating over the twenty year lifetime of the wind farm. It is for this reason that such low wind farm availabilities are seen with the annual strategy for the DFIG turbines. In reality such low availabilities would not be seen because the operator would see that all turbines are not being fixed so they would extend the chartering period of the HLV. The annual strategy starts to perform better when the gearbox or generator failure rate is reduced (as in the 2 stage gearbox or PMG turbine type) or removed (as in the direct drive turbine). The reason for this is because there is less of a requirement for HLVs meaning the turbine is less likely to be shut down for such long periods of time in the year. The HLV requirement for each drivetrain type is quite different and it is this that drives such a large difference between the drive train types in Figure 5.1. For example, if a 100 turbine wind farm is considered the HLV requirement per year for each drive train type can be seen in Table 5.1.

Table 5.1: Approximate number for HLV visits for 100 turbine wind farm per year

Drive train type	3 stage DFIG PRC	3 Stage PMG FRC	2 Stage PMG FRC	Direct Drive PMG FRC
HLV visits for 100 turbine wind farm	~ 17	~ 7	~ 5	~ 1

The purchase strategy allows for the highest availability because there is no mobilisation time and the vessel is always immediately available to carry out repairs. Consequently downtime is lower leading to a higher availability. However, higher costs will be incurred because the operator must purchase the vessel. The fix on fail (which is the strategy used in Chapter 3) and batch strategy availabilities are quite similar throughout all drive train types and distances to shore. As expected the fix on fail strategy will always have a higher availability than the batch strategy as a HLV vessel will be chartered as soon as a failure that requires a HLV occurs, whereas the batch strategy waits until failures occur in a certain number of turbines before chartering the vessel and this will lead to a higher downtime. It is expected that the batch strategy will have lower transport costs as the HLV isn't required as often. The availability of the turbines using the batch strategy is dependent on the number of turbines that must be down before a vessel is chartered as well as the number of turbines in the wind farm. Further work could be carried out to determine the optimum number of down turbines before a vessel is chartered for a wind farm of a certain size, however this is outside the scope of this thesis. For the purpose of this analysis 3 turbines out of the hundred had to be down, requiring a HLV for batch repair before one was charted.

The choice of vessel strategy changes the order of the best and worst performing turbine types. For example, the 3 stage DFIG turbine is the worst performing turbine type out of the 4 using the fix on fail strategy (as seen in Chapter 3), however it is the 2nd best performing turbine type when "purchase" strategy is used. The reason for this is because the high downtime related to the HLV for the 3 stage DFIG configuration is decreased with the purchase strategy by more than the 3 stage PMG and 2 stage PMG and. This greater reduction in downtime related to the 3 stage DFIG is because that configuration uses the HLV more often than the 3 stage PMG and 2 stage PMG and the HLV mobilization time makes up a large part of the 3 stage DFIG's downtime which is significantly reduced using the purchase strategy. As the sites move further offshore from 10km to 50km to 100km the impact of the vessel strategy also changes. However it is not enough to change the order of the turbines in terms of availability performance.



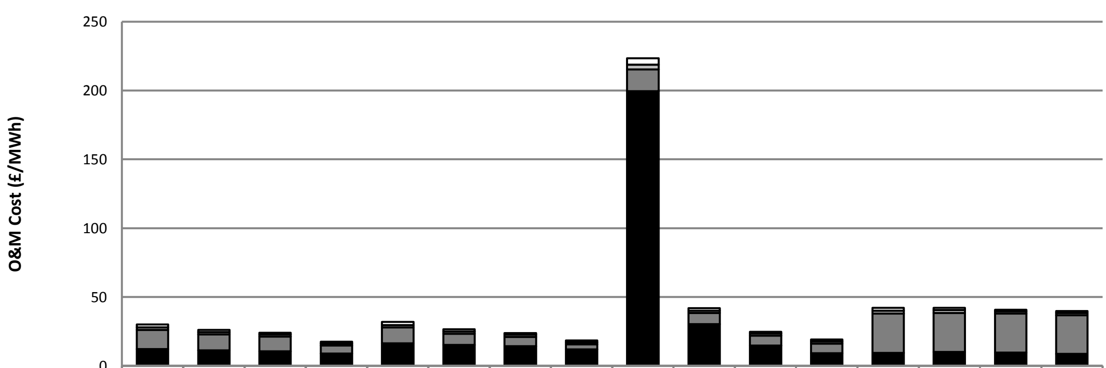
	Fix on Fail	Batch	Annual	Purchase	Fix on Fail	Batch	Annual	Purchase	Fix on Fail	Batch	Annual	Purchase
	10 km				50 km				100 km			
3 Stage DFIG	91.6%	89.1%	40.7%	93.4%	90.5%	88.0%	39.6%	92.2%	79.1%	76.6%	34.9%	81.1%
3 Stage PMG	92.2%	89.8%	81.8%	92.9%	91.3%	88.8%	80.7%	92.0%	80.0%	77.4%	69.8%	80.9%
2 Stage PMG	92.6%	90.3%	90.1%	93.1%	91.3%	89.4%	89.3%	92.2%	81.1%	78.5%	78.5%	81.1%
DD PMG	93.5%	91.7%	93.4%	93.7%	92.6%	90.8%	92.4%	92.7%	82.5%	81.0%	82.4%	82.8%

Figure 5.1: Availability of 4 drive train types using 4 different HLV strategies at 10km, 50km & 100km from shore

5.3.1.4 HLV strategy O&M cost results

Figure 5.2 shows the O&M costs per MWh for each of the vessel strategies for each drive train type at 10km from shore. The annual strategy for the 3 stage DFIG clearly has the highest O&M cost in the graph. It can be seen that the driver for this is the higher “lost revenue” costs (shown in black) which is determined by the availability. As seen in Figure 5.1 the annual vessel strategy with the 3 stage DFIG turbine has the lowest availability so it follows that this strategy with this turbine has the highest O&M cost driven by its lost production costs for the same reasons outlined in Sections 5.3.1.3.

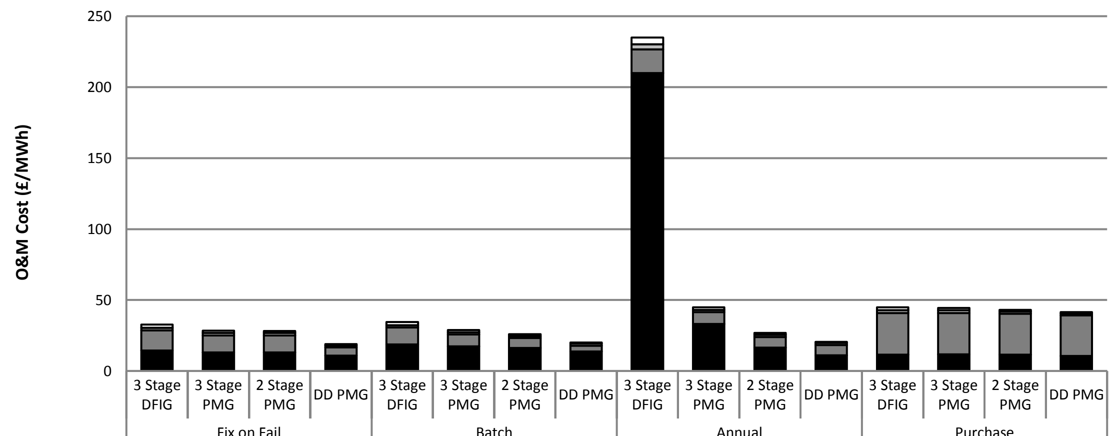
The purchase strategy offered the highest availability for each drive train type in Figure 5.1, however in Figure 5.2 at 10km from shore it can be seen that apart from the annual strategy on the 3 stage DFIG the purchase strategy for the 4 drive train types have the highest overall O&M costs. The reason for this is because of the higher transport costs shown in the darkest shade of grey. The cost of purchasing the HLV is what drives up these transport costs. At 10km the lowest O&M cost comes from a fix on fail maintenance strategy with the direct drive PMG turbine. Figure 5.1 raises the question will the lower transport costs of the batch strategy be outweighed by its lower availability (higher lost revenue costs). That question is answered in Figure 5.2, where it can be seen that the batch strategy results in a higher overall O&M cost than the fix on fail strategy because its higher lost production costs outweigh its lower transport costs.



	Fix on Fail				Batch				Annual				Purchase			
	3 Stage DFIG	3 Stage PMG	2 Stage PMG	DD PMG	3 Stage DFIG	3 Stage PMG	2 Stage PMG	DD PMG	3 Stage DFIG	3 Stage PMG	2 Stage PMG	DD PMG	3 Stage DFIG	3 Stage PMG	2 Stage PMG	DD PMG
Repair Costs	2.09	1.64	1.2	1.39	2.15	1.68	1.23	1.42	4.45	1.85	1.23	1.39	2.05	1.62	1.18	1.37
Staff Costs	1.71	1.63	1.6	1.49	1.71	1.59	1.49	1.47	3.53	1.73	1.5	1.45	1.94	1.91	1.47	1.49
Transport Costs	13.95	11.75	10.73	5.66	11.52	8.03	6.73	3.71	15.79	8.05	7.29	6.95	28.74	28.48	28.38	28.13
Lost Revenue	12.26	11.16	10.53	9.04	16.47	15.32	14.32	11.96	199.6	30.34	14.73	9.29	9.34	10.03	9.64	8.79

Figure 5.2: O&M costs for each of the 4 HLV strategies and turbine types at 10km from shore

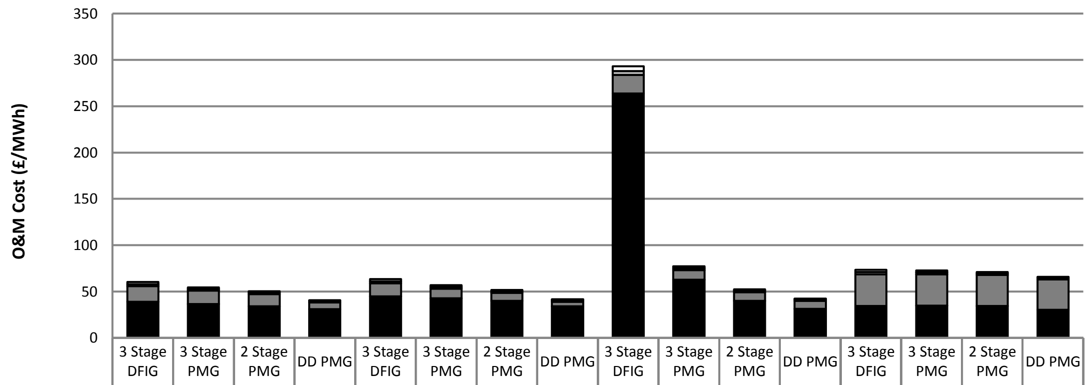
The O&M costs for each HLV strategy for each drive train type at 50km from shore is shown in Figure 5.3. Similar to results contained in Chapter 3 the overall O&M costs for each HLV strategy and each drive train type increases as the wind farms move further from shore. One difference in drive train cost order can be observed in the 50km graph when compared to the 10km graph. That difference can be seen in the 3 stage PMG turbine with the annual strategy. At 50km the annual strategy O&M cost is higher than the purchase strategy and this is not the case at 10km. The reason this change in order occurs is because of the increase in lost production costs as the turbines move further offshore. This increase in lost production cost is due to the greater decrease in availability in the 3 stage PMG with the annual strategy than the 3 stage PMG with the purchase strategy. This greater decrease in availability with the annual strategy as the wind farm moves further offshore is because the HLV is only available 2 months in the year for repairs and the number of accessibility windows that can be obtained in those 2 months are decreased as the wind farm moves further offshore. This means some wind turbines will not be repaired, leading to greater downtime.



	Fix on Fail: 3 Stage DFIG	Fix on Fail: 3 Stage PMG	Fix on Fail: 2 Stage PMG	Fix on Fail: DD PMG	Batch: 3 Stage DFIG	Batch: 3 Stage PMG	Batch: 2 Stage PMG	Batch: DD PMG	Annual: 3 Stage DFIG	Annual: 3 Stage PMG	Annual: 2 Stage PMG	Annual: DD PMG	Purchase: 3 Stage DFIG	Purchase: 3 Stage PMG	Purchase: 2 Stage PMG	Purchase: DD PMG
Repair Costs	2.14	1.64	1.47	0.8	2.18	1.69	1.24	0.82	4.57	1.82	1.24	0.8	2.08	1.63	1.2	0.79
Staff Costs	1.74	1.65	1.65	1.5	1.73	1.61	1.51	1.49	3.63	1.73	1.52	1.46	1.96	1.93	1.46	1.48
Transport Costs	14.37	12.05	12.06	5.88	11.95	8.32	6.97	3.98	16.66	8.29	7.59	7.22	29.33	29.05	28.91	28.62
Lost Revenue	14.37	13.03	13.02	10.72	18.67	17.35	16.18	13.82	210.04	33.1	16.39	11.07	11.45	11.79	11.51	10.54

Figure 5.3: O&M costs for each of the 4 HLV strategies and turbine types at 50km from shore

The O&M costs for each HLV strategy and drive train type at 100km from shore is shown in Figure 5.4. As expected the overall O&M costs for each HLV strategy and each drive train type increases as the wind farms move to 100km offshore. Apart from that overall cost increase the only difference from the 50km scenarios is that as the wind farm moves further from shore the 3 stage PMG turbine with the annual strategy further increases its higher cost over the purchase strategy, meaning as you move greater distances from shore the case for purchasing a vessel rather than chartering it annually increases. This occurs for the same reason as mentioned in the previous paragraph.



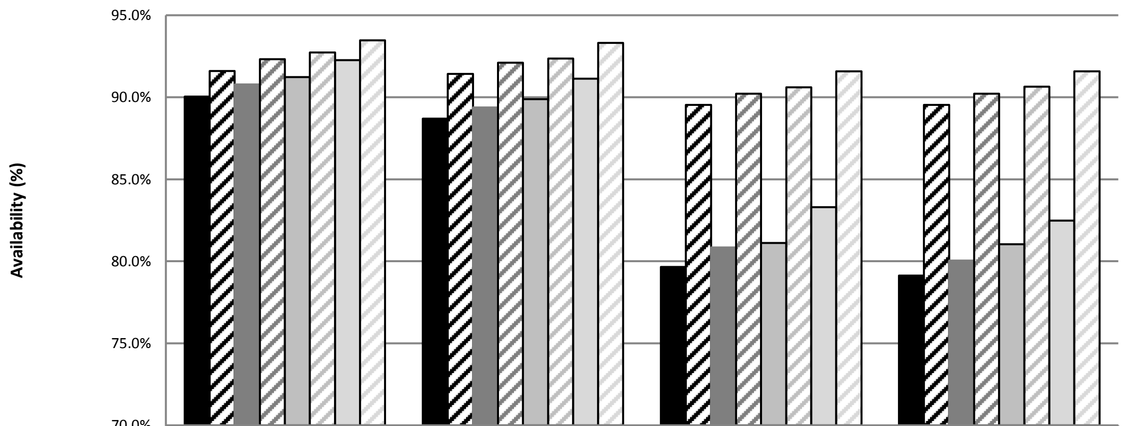
	Fix on Fail 3 Stage DFIG	Fix on Fail 3 Stage PMG	Fix on Fail 2 Stage PMG	Fix on Fail DD PMG	Batch 3 Stage DFIG	Batch 3 Stage PMG	Batch 2 Stage PMG	Batch DD PMG	Annual 3 Stage DFIG	Annual 3 Stage PMG	Annual 2 Stage PMG	Annual DD PMG	Purchase 3 Stage DFIG	Purchase 3 Stage PMG	Purchase 2 Stage PMG	Purchase DD PMG
Repair Costs	2.44	1.89	1.38	0.89	2.53	1.99	1.44	0.93	5.16	2.17	1.42	0.9	2.41	1.88	1.38	0.9
Staff Costs	2.01	1.9	1.85	1.71	2.01	1.87	1.74	1.68	4.19	2.06	1.74	1.66	2.26	2.22	1.71	1.68
Transport Costs	17.03	14.24	13	7.02	14.29	10.16	8.51	4.88	20.14	10.3	9.11	8.58	34.23	33.81	33.61	32.82
Lost Revenue	38.81	36.63	34.27	31.13	44.71	42.88	40.11	34.15	263.61	62.89	40.06	31.33	34.48	34.8	34.37	30.46

Figure 5.4: O&M costs for each of the 4 HLV strategies and turbine types at 100km from shore

5.3.1.5 Mother ship availability analysis results

Figure 5.5 shows the results of an availability analysis of 4 different turbine types at 70km, 80km, 90km and 100km from shore. The availability is displayed in the graph when a mother ship is used (shown in the hatched bars) and when no mother ship is used (shown in the solid bars). As expected, it can be seen that for the hypothetical wind farms of 100 turbines, across all 4 distances from shore and all drive train types there is an increase in availability with the use of a mother ship. At 70km from shore there is at least a 1.5% improvement in availability across all drive train types with the use of a mother ship. At 80km this shows at least a 2.2% increase in availability, 90km sees at least an 8.3% increase and at 100km there is at least 9.1% increase in availability across all 4 turbine types from the use of a mother ship.

The improvements in availability will lead to decreased lost production costs. If the decrease in lost production cost outweighs the increase in transport costs from chartering the mother ship then it can be said that there is a decrease in the overall O&M costs from the use of a mother ship, leading to a positive business case for the use of a mother ship.



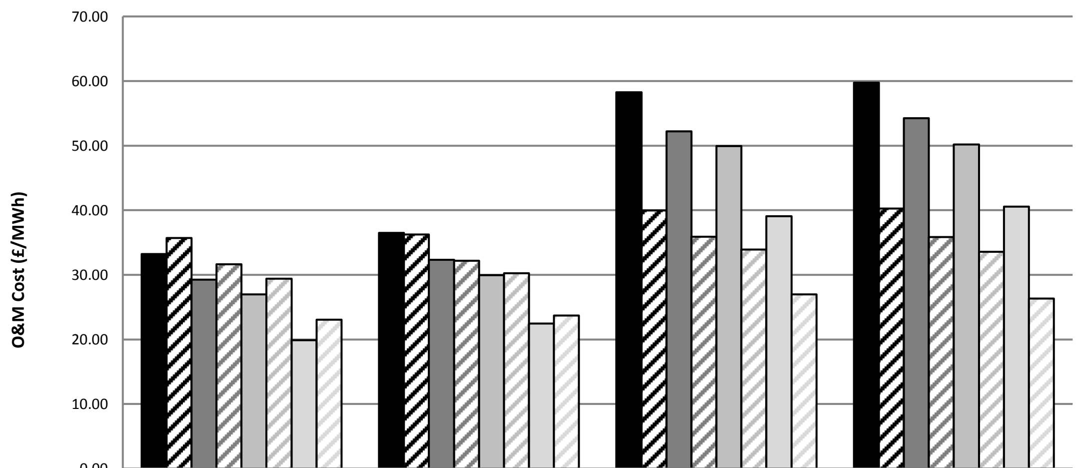
	70km	80km	90km	100km
3 Stage DFIG	90.0%	88.7%	79.7%	79.1%
3 Stage DFIG MS	91.6%	91.4%	89.5%	89.5%
3 Stage PMG	90.8%	89.4%	80.8%	80.0%
3 Stage PMG MS	92.3%	92.1%	90.2%	90.2%
2 Stage PMG	91.2%	89.9%	81.1%	81.1%
2 Stage PMG MS	92.7%	92.4%	90.6%	90.7%
DD PMG	92.3%	91.1%	83.3%	82.5%
DD PMG MS	93.5%	93.3%	91.6%	91.6%

Figure 5.5: Availability with and without a mother ship at 4 distances from shore

5.3.1.6 Mother ship O&M analysis results

As mentioned, the day rates of mother ships may vary. Figure 5.6 shows whether there is a reduction in the overall O&M costs from the use of a mother ship when the day rates are at £17,000. £17,000 is considered the lower end of the scale for day rates of a mother ship [44]. A mother ship day rate range of £17,000 to £25,000 was provided by a company that charters vessels and an offshore maintenance provider [44]. However as this range was only provided by two companies further sensitivity type analysis was also carried out to determine what was the highest day rate that could be paid for a vessel while maintaining an overall reduction in O&M costs. This further analysis is shown later in this section.

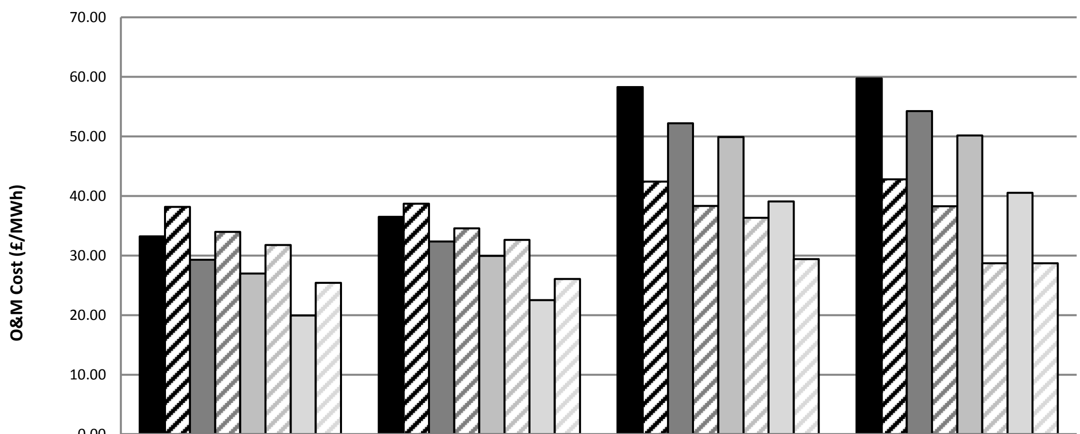
Figure 5.6 shows that at 70km there is no reduction in the overall O&M costs from the use of a mother ship with day rates of £17,000 because the O&M cost per MWh is greater across all drive train types for the hypothetical wind farms that use a mother ship in comparison to those that do not. This is because the transport cost of the mother ship outweigh the lost production cost saving from increased availability. If the reader focuses on the sites 80km from shore in Figure 5.6 it can be seen that there is reduction in the overall O&M costs for some but not all of the turbine types. The graph shows that there is a reduction in the overall O&M costs from the use of a mother ship with both of the 3 stage turbine types but not with the 2 stage and direct drive turbine types. The reason for this is that there is a larger amount of minor and major repairs that require a CTV in the 3 stage DFIG PRC and the 3 stage PMG FRC than there is in the 2 stage PMG FRC and the direct drive PMG FRC. There is also larger repair time windows required for the DFIG configuration than for the other turbines, this also increases the need for a mother ship. This greater need for a CTV in both of the 3 stage turbine types allow for a higher day rate to be paid for a mother ship while keeping the O&M costs below that of an equivalent wind farm without a mother ship for both of the 3 stage configurations. Across all drive train types there is a reduction in the overall O&M costs from the use of a mother ship at both 90km and 100km from shore. The reason for this is because as the wind farms move further from shore larger accessibility windows are required to carry out repairs. The use of a mother ship allows the accessibility windows to be shorter because not as much time is used in traveling to the turbine. This in turn leads to a lower down time reducing the lost production cost to a point that the savings from the lost production costs outweigh the mother ship charter costs.



	70km	80km	90km	100km
3 Stage DFIG	33.23	36.48	58.28	59.73
3 Stage DFIG MS	35.72	36.25	39.96	40.29
3 Stage PMG	29.27	32.36	52.21	54.23
3 Stage PMG MS	31.62	32.19	35.89	35.86
2 Stage PMG	26.99	29.95	49.91	50.18
2 Stage PMG MS	29.39	30.27	33.93	33.57
DD PMG	19.91	22.49	39.10	40.55
DD PMG MS	23.08	23.71	27.00	26.34

Figure 5.6: O&M costs with low vessel day rate (£17,000). “MS” in graph stands for mother ship.

Figure 5.7 shows whether there is a reduction in the overall O&M costs from the use of a mother ship when the day rates are at £25,000. Based on the quote from two companies, this is considered the higher end of the scale for day rates of a mother ship [44]. It can be seen that at 70km and 80km there is no reduction in the overall O&M costs from the use of a mother ship with day rates at the higher end of the range because the O&M cost per MWh is greater across all drive train types for the hypothetical wind farms that use a mother ship in comparison to those that do not. This is because the transport cost of the mother ship (cost of chartering the vessel) outweigh the lost production cost saving from increased availability. The reason some drive train types have a reduction in the overall O&M costs from the use of a mother ship at 80km in Figure 5.6 but not in Figure 5.7 is because of the higher day rate of £25,000 for the mother ship in Figure 5.7. Even with the day rates raised to £25,000 there is still a reduction in the overall O&M costs from the use of a mother ship across all drive train types at both 90km and 100km from shore. Once again the reason for this is because as the wind farms move further from shore larger accessibility windows are required to carry out repairs. The use of a mother ship allows the accessibility windows to be shorter because not as much time is used in traveling to the turbine. This in turn allows for a higher day rate to be paid for a mother ship before its costs outweigh the savings in lost production costs.



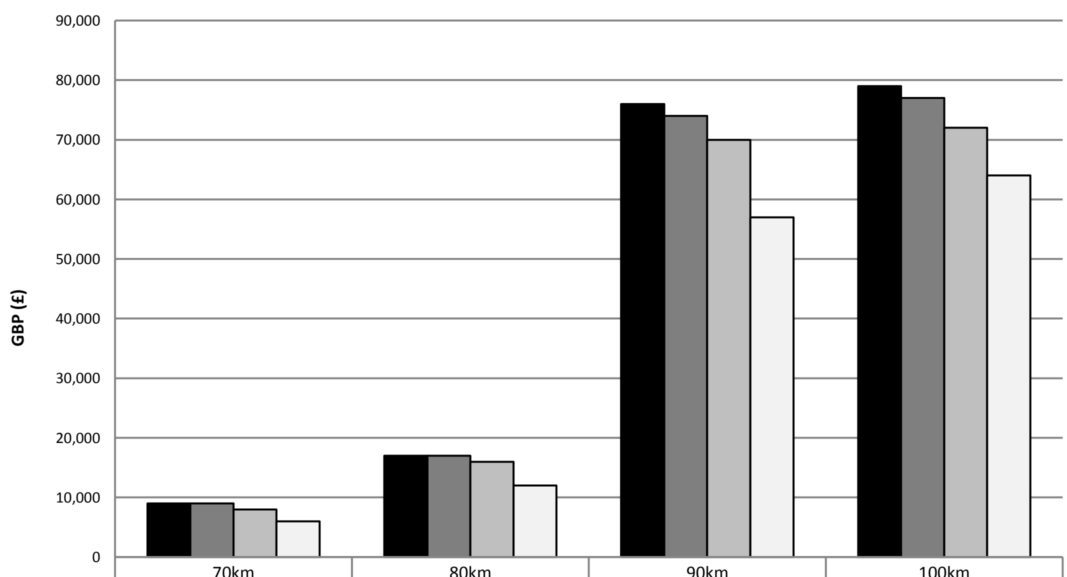
	70km	80km	90km	100km
3 Stage DFIG	33.23	36.48	58.28	59.73
3 Stage DFIG MS	38.15	38.68	42.44	42.77
3 Stage PMG	29.27	32.36	52.21	54.23
3 Stage PMG MS	33.98	34.56	38.31	38.27
2 Stage PMG	26.99	29.95	49.91	50.18
2 Stage PMG MS	31.74	32.63	36.33	28.72
DD PMG	19.91	22.49	39.10	40.55
DD PMG MS	25.40	26.05	29.38	28.72

Figure 5.7: O&M costs with high vessel day rate (£25,000). "MS" in graph stands for mother ship.

Figure 5.6 and 5.7 raise the question what is the maximum mother ship day rate that can be paid for each turbine type at each distance from shore while maintaining a reduction in overall O&M costs by keeping the mother ship costs below the savings made in lost production costs. This question also acts as a sensitivity analysis on mother ship day rates, determining what day rate can be paid at each site while maintaining an overall reduction in O&M costs.

Figure 5.8 acts as that sensitivity analysis on day rates and answers the question posed in the previous paragraph by displaying the day rates that can be paid while maintaining a reduction in overall O&M costs, for a mother ship at each distance from shore for each drivetrain type. It can be seen that at each distance from shore the 3 stage DFIG PRC turbine type can have the highest day rates for a mother ship while still reducing overall O&M costs. Across all 4 sites this is followed by the 3 stage PMG, then the 2 stage PMG FRC and lastly the direct drive PMG FRC has the lowest day rates for a mother ship while maintaining a reduction in the overall O&M costs. The reason for this is the larger amount of minor and major repairs that require a CTV in the 3 stage DFIG PRC and the 3 stage PMG FRC compared to the 2 stage PMG FRC and the direct drive PMG FRC. The day rates range from £6,000 to £79,000, demonstrating a large difference in what an operator could pay depending on turbine type and distance from shore.

The failure rate of the minor and major repair failures in the 3 stage PMG FRC turbine type are actually higher than the failure rates of the minor and major repair failures in the 3 stage DFIG PRC. However a higher day rate can be paid for the 3 stage DFIG configuration. This highlights that it is not just the failure rate that influences the amount that can be paid for a mother ship, but it is also the repair time attached to those failures.



	70km	80km	90km	100km
3 Stage DFIG	9,000	17,000	76,000	79,000
3 Stage PMG	9,000	17,000	74,000	77,000
2 Stage PMG	8,000	16,000	70,000	72,000
DD PMG	6,000	12,000	57,000	64,000

Figure 5.8: Vessel day rates below which there is an overall reduction in O&M costs

5.3.1.7 Influence of HLV and mother ship strategies on CoE

A CoE comparison was carried out for the best and worst performing HLV and CTV/mother ship vessel strategies. This analysis was based on the CoE figures from Chapter 4. For the best vessel strategy scenario the fix on fail HLV strategy was used with a mother ship (£25,000 day rates). For a hypothetical site 100km from shore with the direct drive PMG FRC turbine type the CoE per MWh was £141.31. The direct drive PMG FRC turbine type was chosen as the turbine type for this CoE vessel analysis because it was the best performing turbine type in terms of CoE in Chapter 4. The 100km site was chosen because it was the site that showed the greatest improvement in O&M costs when a mother ship was used (As mentioned earlier 50km showed no positive impact so could not be used). For the worst performing vessel strategy scenario the “Annual” HLV strategy was used with no mother ship. For the same hypothetical site 100km from shore with the same 3 stage PMG FRC turbine type the CoE was £180.46/MWh. This simple analysis based on the CoE results from Chapter 4 and the results from this section prove that the HLV strategy and CTV/mother ship strategy can have a significant influence on the overall CoE for offshore wind. This example shows a difference in CoE of ~22%

5.3.2 Condition based maintenance and performance guarantees

This section details the CBM and PBMC analysis and shows results of using CBM and PBMCs in terms of effect on availability and overall CoE.

5.3.2.1 CBM and PBMC analysis method and population analysed

Method

The first step in the CBM and PBMC analysis was to work with an industrial partner to obtain empirical offshore wind farm availability data. This data was then split into four subgroups. The subgroups were divided based on whether the windfarm used condition monitoring systems to carry out their maintenance or whether they did not and whether their maintenance was carried out under a PBMC or whether it was not. An availability analysis was then carried out on each sub group. Other factors influencing the availability of the wind turbines were also analysed, e.g. distance from shore, mean wind speed seen by the turbine, turbine age, rated power etc. Once the availability difference in failure groups were obtained an estimate of the cost of energy savings from the use of CMSs and PBMCs based on the improved availability at a hypothetical site was calculated. Conclusions were then drawn on the availability and cost improvements obtained by the use of CMSs and PBMCs. It should be noted that a wind farm may have a CMS installed but if that system never generated a work order then it was considered in the grouping that did not use CMS for maintenance activities, so would fall under the "No CMS" grouping.

Population

The population used in this availability analysis is different from the population used in the earlier sections of this chapter and the earlier chapters of this thesis. The overall population size for this analysis is between 400 – 500 offshore wind turbines. These turbines come from between 7-12 offshore wind farms located throughout Europe. The wind farms operational years range from 3 to 9 years. The turbine types are gear driven turbines with induction type generators. This overall population is made up of two different turbine types with different rated powers and rotor diameters. All turbines have a rated power between 1.5 and 4 MW and a rotor diameter of between 80 and 120 metres. Overall this population provides ~24.2 million turbine hours of operational data which is equivalent to ~2760 turbine years. Exact turbine numbers, location, types, rotor diameters and rated powers cannot be provided for confidentiality reasons.

The overall population can be categorised by two variables: (a) whether there is a CMS or not and (b) whether there is a PBMC or not. These sub-populations can be seen in Figure 5.9. The first two groups show that 86% of the overall population has CMS and 14% does not have CMS. The next two groups show that 79% of the population is subject to PBMCs and that 21% is not subject to PBMCs.

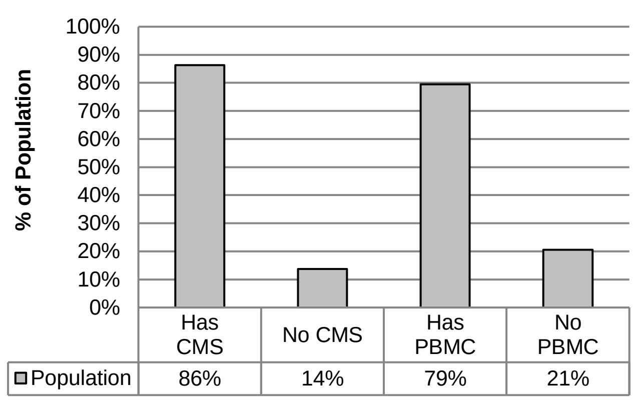


Figure 5.9: Population sub-groups. Showing the majority of the population has CMS and PBMCs

Turbines in the four groups from Figure 5.9 can overlap with each other so, for example, some of the same turbines in the "Has CMS" group are in the "Has PBMC" group. This overlap can be seen from the Venn diagram in Figure 5.10. It shows that 79% of the population has both CMS and PBMC, 14% has no CMS or PBMC and 7% have CMS but no PBMC.

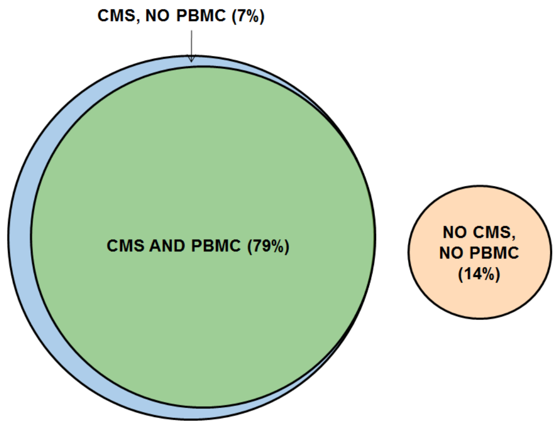


Figure 5.10: Population sub-groups. Showing the overlap of sub populations.

In the population group that has condition monitoring systems, the type of condition monitoring systems used are drivetrain vibration and temperature sensors. The population groups that have performance based maintenance contracts are a mixture of both production based and availability based guarantees.

5.3.2.2 CBM and PBMC results of analysis

The following results were obtained through an availability analysis of the population groups described in Section 5.3.2.1. Figure 5.11 shows that there is approximately a 4% difference in availability for the population analysed that had CMS and the population that had no CMS. Availability is determined by the failure rate and the downtime of the populations analysed. The failure rate and downtime can be influenced by many factors such as: distance from shore, population age, rated power of the turbines and mean wind speed. All of the factors mentioned above, except population age, were in favour of the population that had no CMS, i.e. the "No CMS" population group was closer to shore, had a lower rated power and had lower mean wind speeds. Most importantly the "No CMS" population had a slightly lower failure rate overall, indicating that the lower availability for that sub-population can only have been driven by longer mean times to repair. As the "No CMS" group is closer to the shore this higher downtime is not driven by longer travel times to the turbines. The mean wind speed is also lower, suggesting that the longer downtime is most likely also not driven by weather-related inaccessibility. Together these imply that the difference in availability is down to longer lead and repair times, both of which can be influenced by CMS. Without further data and analysis it cannot be said for certain that the reduced downtime and ~4% greater availability for the population with CMS is solely down to the CMS. However the author feels that it is fair to conclude that the CMS is one of the main reasons for the lower downtime and higher availability due to the better O&M planning that CMSs allow.

Figure 5.12 shows that there is approximately a 2.5% difference in availability for the population analysed that had PBMCs and the population that had no PBMCs. As with the “No CMS” population, the No PBMC population is closer to shore, has a lower rated power and has lower mean wind speeds. But most importantly the “No PBMC” population also had a slightly lower failure rate overall, once again indicating that the lower availability for that failure group could only have been driven by higher downtimes. As explained in the previous paragraphs, this downtime is not driven by travel times or inaccessible days so it must again be due to increased lead and/or repair times. As with the CMS, while it cannot be said for certain that the reduced downtime and ~2.5% greater availability for the population with PBMCs is solely down to the PBMC the author feels that it is fair to conclude that the PBMC is one of the main reasons for the lower downtime and higher availability due to the extra financial pressure the PBMC places on the manufacturer to reduce lead times and carry out the repair tasks as quickly as possible.

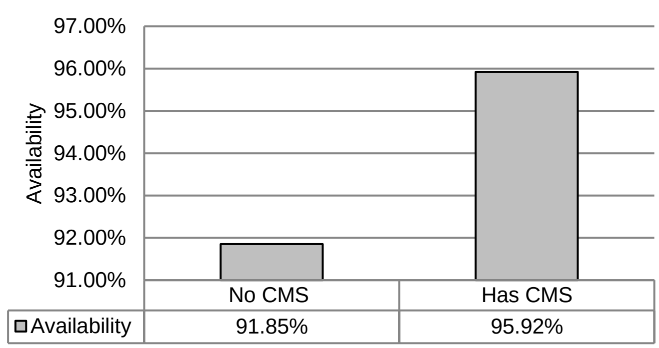


Figure 5.11: Availability of No CMS population group vs. Has CMS population group. Showing a difference of ~4%

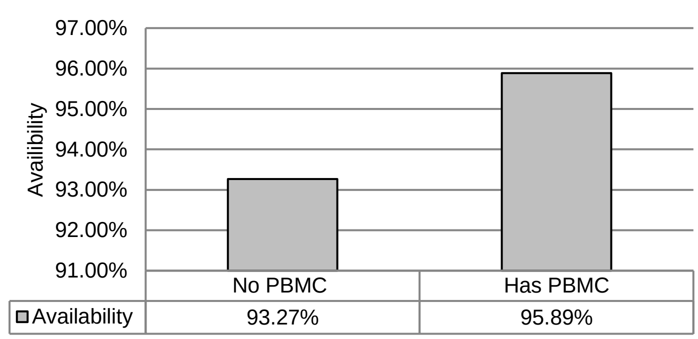


Figure 5.12: Availability of No PBMC population group vs. Has PBMC population group. Showing a difference of ~2.5%.

5.3.2.3 Impact of CBM and PBMC on overall CoE

In order to determine the impact of condition based maintenance and performance based maintenance contracts on the overall CoE an analysis was carried out on a hypothetical offshore wind farm located 50km offshore and consisting of 100 direct drive PMG FRC turbines. The CoE reductions came from the analysis outlined in the previous section, in which a ~4% improvement in availability was seen from the wind farms with CMS compared to those without, and a 2.5% availability improvement from wind farms with PBMC compared to those without.

Using the production data from the analysis in Chapter 4 and assuming revenue of £140/MWh, it was determined that a 4% improvement in availability (from the CMS) would result in a total reduction in the CoE of ~£7.80/MWh. For a site 50km from shore, consisting of 100 direct drive PMG FRC turbines, this reduces the CoE from £110.74/MWh (as seen in Chapter 4) to £102.94/MWh. However the cost of the CMS system must also be taken into account. Based on [9] and for a highest cost scenario an estimated CMS cost for each turbine was taken as £100,000 per turbine. This resulted in a cost of ~£0.40/MWh. With the cost of the CMS considered the overall CoE reduced from £110.74/MWh to ~£103.35/MWh. This resulted in approximately a 7% CoE decrease from the use of a CMS for the hypothetical site located 50km offshore consisting of direct drive PMG FRC turbines. It should be noted that this CoE estimate is based on the assumptions made in Chapter 4 and the cost assumptions outlined in this section. It should also be noted that the CMS and PBMC empirical availability comparison carried out was not carried out on direct drive turbines but is now applied to direct drive turbines in this example, this may also lead to some inaccuracies. The drive train types for which the empirical availability comparison was carried out on cannot be disclosed for confidentiality reasons. Due to the discussed reasons these CoE savings should be taken as an indication only. Even with these assumptions, it is clear that significant savings can be made from the use of CMS.

A similar analysis was carried out for the 2.5% improvement in availability from the use of PBMCs. As in the previous paragraph, using the production data from the analysis in Chapter 4 and assuming revenue of £140/MWh, it was determined that a 2.5% improvement in availability (from having a PBMC) would result in a total reduction in the CoE of ~£4.87/MWh. For a site 50km from shore, consisting of 100 direct drive PMG FRC turbines, this reduces the CoE from £110.74/MWh (as seen in Chapter 4) to £105.87/MWh. However the premium paid for the PBMC must also be taken into account. As the cost of PBMCs is a highly sensitive area it was not possible to get the PBMC costs required to determine the CoE benefit. However it can be stated for this scenario, there is a business case to have a PBMC once the premium that must be paid for it is less that £4.87/MWh. This implies that for a single direct drive PMG FRC turbine type at 50km from shore (taking an average energy production of 10,903 MWh per turbine per year) a premium of up to ~£53,000 can be paid for a performance based contract per year.

Past literature has shown savings of 20% in operation costs from the use of CMS and condition based maintenance [9]. If this is converted to CoE savings for a typical wind farm where O&M costs make up ~30% of the overall CoE [2], of which 20% savings are possible, this results in a 6% savings in the overall CoE which equates reasonably well with the 7% CoE reduction seen in this analysis. No past literature could be found detailing savings from PBMC to compare the estimated CoE savings from this analysis.

5.3.3 Cost of energy using in built lifting mechanisms, power train redundancy and reduced repair times

This section details the minor design changes/innovations (in-built lifting, redundancy, reduced repair times) analysis and shows results of these minor design changes on O&M costs and overall CoE.

5.3.3.1 Minor design changes method and model input parameters

O&M cost and availabilities were taken for four of the hypothetical sites from Chapter three. Each site represented one of the four drive train types at 50km from shore. These four hypothetical sites were then used as the base case scenarios to provide O&M costs and availability figures for this analysis. In this analysis the same population for the input data and O&M cost model from Chapter 3 are used.

The inputs from the four base case scenarios were adjusted as described in the following paragraphs to represent in-built lifting mechanisms, redundancy and reduced repair times for the four turbine types. The model was then run taking into consideration these new inputs. This provided simulated O&M cost and availability outputs for in-built lifting mechanisms, redundancy and reduced repair times for each turbine type. These new outputs for the four turbine types were then compared to the baseline O&M costs and availability figures and conclusions were drawn.

In previous chapters hypothetical sites using the four drive train types were examined at varying distance from shore. However in this chapter only four sites 50km from shore were used for the sake of brevity because each site requires 12 simulations. This is possible for four sites (48 simulations) but as simulations can take up to twelve hours it was not plausible to do this for 12 sites (144 simulations). Focusing on the sites at 50km from shore allows answers to questions regarding the impact of the minor design changes on O&M cost and CoE.

As previously mentioned the same model used in Chapter 3 was used to examine a number of scenarios for this analysis. Some of the input parameters were kept consistent for all scenarios and with Chapter 3; others were varied to describe the minor design change used in that scenario. These are the major consistent input parameters used in all of the scenarios:

- Wind data, wave height data and wave period data for the hypothetical site of 100 wind turbines 50km offshore. This was obtained from the FINO offshore research platform [43] in the North Sea, located 45km north of Borkum Island. This climate data is in the public domain and inputted to the model in hourly averages.

- Vessel cost and operational data. The inputs required for the model that relate to vessel operation and costs came from [3] and [6], as in Chapter 3. Reference [6] provides the vessel cost and operational figures based on the data and expertise of an offshore wind farm developer.

- Power curve, failure rate, repair time, required technicians and average failure cost data. This data was obtained as described in Chapter 3.

Once the O&M cost and availability were modelled for the base cases using these parameters common to all scenarios, the following adjustments were made to inputs to capture the in-built lifting mechanisms, redundancy and reduced repair times from design for maintenance techniques:

- In-built lifting mechanisms and tower cranes have been discussed in literature and advertised in wind turbine manufacturer’s promotional documents. In-built lifting mechanisms and tower cranes have the potential to reduce the need for HLVs for major replacements on the wind turbine. As a means of capturing this potential in the inputs to the model, the requirement for the use of these jack up vessels has been reduced by 25%, 50%, 75% and 100% based on the of varying degrees of capability of 4 hypothetical lifting mechanisms. This will provide O&M cost and availability outputs for both wind farms and show the effectiveness of these different lifting mechanisms (each of which have their own capital costs).

- Redundancy. The idea of including redundancy in the wind turbine power train has been encountered in other papers. This analysis will focus on the O&M cost saving by duplicating the generator and converters of the wind turbine. Later in the chapter the analysis will also consider the additional capital costs related to including the extra generator or converter. Extra costs may also be incurred in the tower and nacelle due to increased weight and space requirements; however these costs due to the extra weight and space requirements are not included in the scope of this analysis. Further work could include the costs related to the extra weight and space requirements to improve this analysis. As a means of capturing power train redundancy in this analysis, two generators and two power converters for each turbine have been included in the model. Failure rates have been split between the two converters and generators and power production has been split 50% between each generator and converter so if one of the converters or generators fail the wind turbine still produces 50% of its rated power. The split of failure rates by 50% because the rated power is halved is based on Chapter 2 for the converters and reference [45] for the generators. For the converters Chapter 2 suggests that a converter three times larger than another converter will have a failure rate ~ 3-5 times larger so the assumption is made that a converter half the size will have half the failure rate. An onshore generator roughly half the rated power of the generator used in the population shown in Chapter 2 shows a failure rate of roughly half [17] when the onshore to offshore adjustment from reference Chapter 2 is applied. The author acknowledges that this method for estimating offshore failure rates is not ideal and may not hold for all generator and converter types. Future work will aim to improve these assumptions by obtaining further offshore failure rate data for generators and converters of different power ratings. Reference [37] also looks at introducing more than two generators and converters and determining what the best overall design for redundancy is. However redundancy optimisation is outside the scope of this analysis.

- Reduced repair time due to design for maintenance techniques. It has been suggested that the design for maintenance techniques discussed in Section 5.2.3 can reduce repair times. As a means of quantifying these repair time reductions in terms of O&M cost savings and availability improvements the repair time inputs to the model were reduced by 10% and 20% for both turbine types.

5.3.3.2 Minor design changes results and discussions

This section shows the results of modelling the availability, direct O&M costs (staff costs, repair costs, transport costs) and total O&M costs (staff costs, repair costs, transport costs and lost production costs) for each turbine type in the hypothetical wind farm described in Section 5.3.3.1. In the following graphs in this section:

- The “Baseline” is the modelled results for the four turbine types
- “Redundancy Con”, “Redundancy Gen” and “Redundancy Both” are the modelled results from adjusted empirical input data to simulate redundancy in the converter, generator and both combined.
- “Repair time 10%” and “Repair time 20%” are the modelled results from adjusted empirical input data to simulate reduced repair time from design for maintenance techniques by 10 and 20%
- “HLV reduced 25%” is the modelled results from adjusted empirical input data to simulate reduced requirement for HLV by 25% due to the use of in-built lifting mechanisms. The HLV requirement is also shown when it is reduced by 50%, 75% and not required at all. When the HLV requirement is reduced by a certain percentage the CTV usage is increased by that percentage.
- “All Improvements” are the modelled results from adjusted empirical input data to simulate all of the above improvements with repair times reduced by 10% and HLV usage by 50%.

Figure 5.13 shows that for the 3 stage DFIG turbine type the greatest single improvement to the availability is achieved through the introduction of redundancy in the power train. This improves availability by ~1%. Reducing repair times by 10% through Design for Maintenance (DFM) techniques improves availability by 0.55% and reducing the need for HLVs by 50% improves availability by 0.44%.

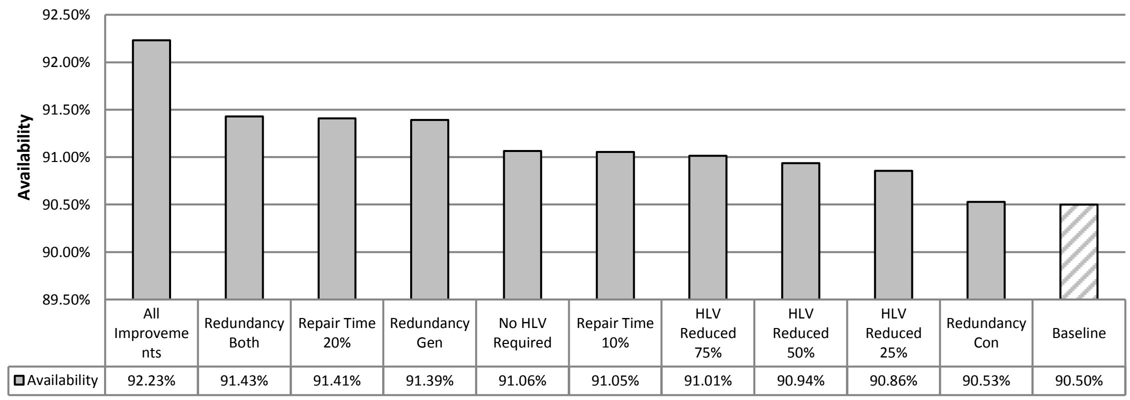


Figure 5.13: DFIG availability with simulated improvements showing "Baseline" has the lowest availability and "All Improvements" have the highest.

Figure 5.14 shows direct O&M costs for the turbines with a 3 stage DFIG PRC drive train type. These include staff costs, repair costs and transport costs. It can be seen that reducing the need for HLVs by 50% reduces O&M costs by £1.68 / MWh, reducing repair times through DFM techniques reduces O&M costs by £0.22 / MWh and redundancy in the power train reduces O&M costs by £0.16 / MWh. Redundancy does not reduce the absolute O&M costs but reduces the O&M cost per MWh because it allows the turbine to continue producing at 50% which produces more power than would be the case without redundancy meaning cost per MWh reduces even though overall O&M costs do not. In the following graphs the All Improvements group does not reduce O&M costs by the largest amounts because all improvements model HLV reduction at 50% and reduced repair times at 10%. Elimination of HLV altogether and even reducing it by 75% reduces O&M costs so much that those groups are reduced below the All Improvements group (All improvement group takes repair time at 10% and HLV reduction of 50%).

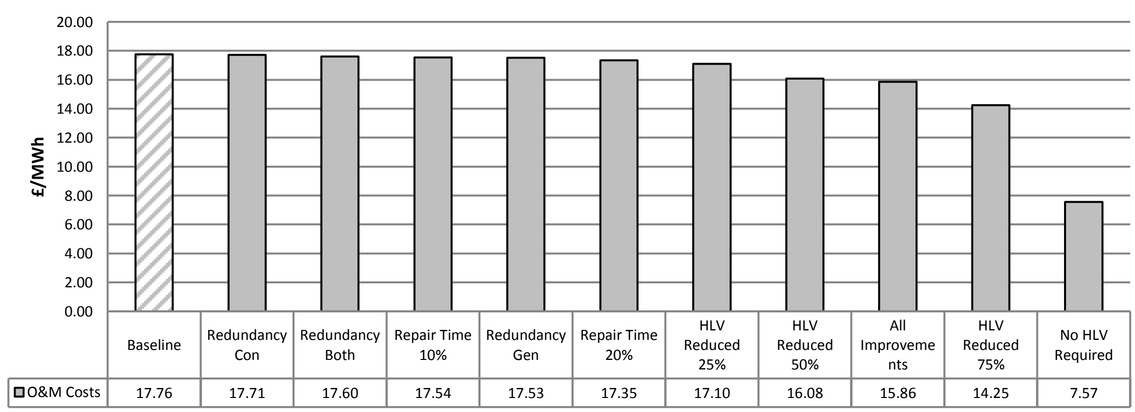


Figure 5.14: DFIG direct O&M costs with simulated improvements showing "Baseline" has the highest O&M costs and "No HLV" has the lowest.

Figure 5.15 shows total O&M costs, that is the aggregate of the cost of lost production (due to turbine downtime) and the direct O&M costs for the DFIG turbine type. It can be seen that reducing the need for HLVs by 50% reduces total O&M costs by £2.54 / MWh, redundancy in the power train leads to a reduction of £1.85 / MWh and reducing repair times through DFM techniques leads to a reduction of £1.20 / MWh.

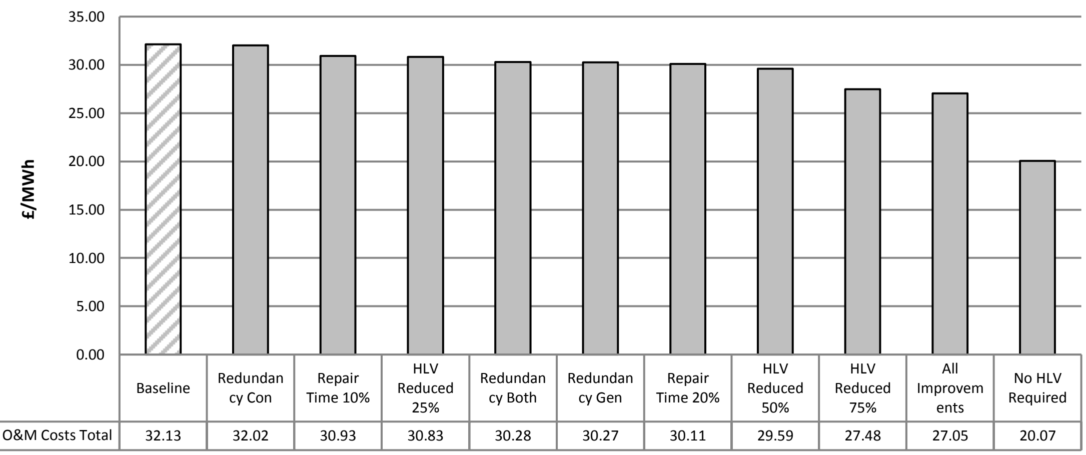


Figure 5.15: DFIG total O&M costs with simulated improvements showing "Baseline" has the highest O&M costs and "No HLV" has the lowest.

Figures 5.16-5.18 show the same analysis but for the 3 stage PMG FRC turbine type. Figure 5.16 shows that for the 3 stage PMG FRC turbine redundancy in the power train improves availability by 0.80%, reducing repair times by 10% (through DFM techniques) improves availability by 0.48%.

It can be seen that reducing the need for HLVs does not show improvements in the availability. This can be explained due to the increased dependency on CTV vessels resulting in the use of these resources becoming constrained as detailed in Section 3.3.1. However, due to crew transfer vessel usage costing significantly less than HLV usage, the benefits of the reduced HLV usage are captured in the O&M cost graphs in Figure 5.17 and 5.18. Unlike the 3 stage PMG FRC turbine, slight availability gains can be seen from the reduction in use of the HLVs for the DFIG turbines in Figure 5.13. The reason for this is there is there are more frequent failures that require a HLV for repair with the DFIG turbine than there are with the PMG turbine. As a result, the greater reduction in the need for a HLV for the DFIG shows greater impact on the DFIG availability due to the elimination of the longer mobilisation time for the HLV in comparison to the mobilisation time for the CTV. The increase in constraints on the CTV as the reduction in HLV usage goes from 25-100% and its effect on availability is cancelled out by the savings in downtime from the removal of the mobilisation time for the HLV. This results in little difference between the availability of the reduced HLV scenarios.

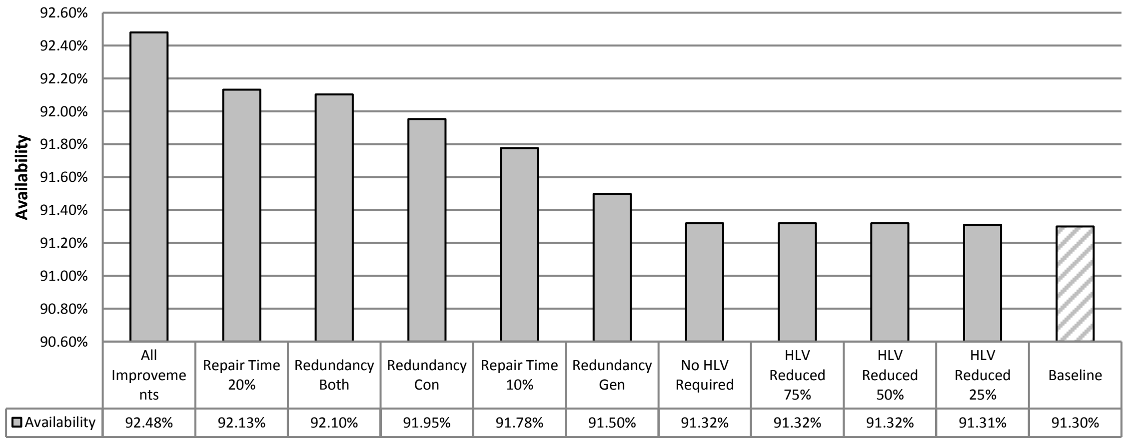


Figure 5.16: PMG FRC availability with simulated improvements showing “Baseline” has the lowest availability and “All Improvements” have the highest.

Figure 5.17 shows the direct O&M costs for the PMG FRC turbine type. It can be seen that reducing the need for HLVs by 50% reduces O&M costs by £2.01 / MWh, reducing repair times through DFM techniques reduces O&M costs by £0.39/ MWh and redundancy in the power train reduces O&M costs by £0.18 / MWh.

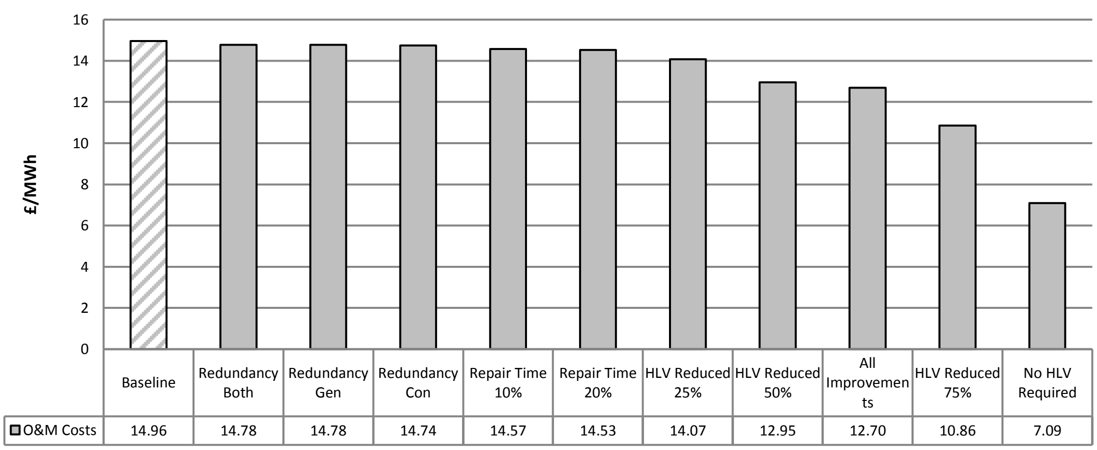


Figure 5.17: 3 Stage PMG FRC direct O&M costs with simulated improvements showing “Baseline” has the highest direct O&M costs and “No HLV” has the lowest.

The total O&M costs including lost production costs for the PMG FRC turbine can be seen in Figure 5.18. It can be seen that these are lower than the baseline for the DFIG. Figure 5.18 shows reducing the need for HLVs by 50% reduces O&M costs (including lost production costs) by £2.22

/ MWh, redundancy in the power train leads to a reduction of £1.62 / MWh and reducing repair times through DFM techniques leads to a reduction of £1.21 / MWh.

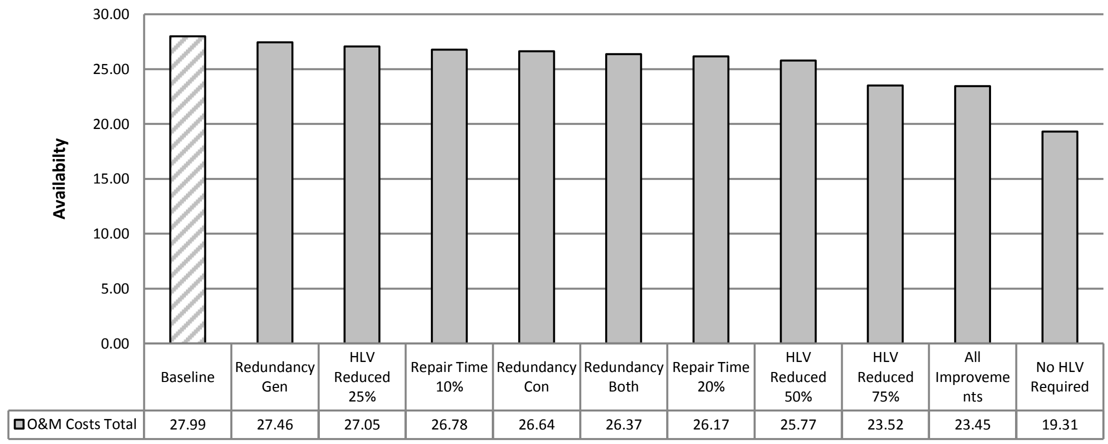


Figure 5.18: 3 Stage PMG FRC total O&M costs with simulated improvements showing “Baseline” has the highest total O&M costs and “No HLV” has the lowest.

Figures 5.19 – 5.21 show the same analysis but for the 2 stage PMG FRC turbine type. Figure 5.19 shows that for the 2 stage PMG FRC turbine, redundancy in the power train improves availability by 0.45%, reducing repair times by 10% (through DFM techniques) improves availability by 0.98%.

As in the 3 stage PMG it can be seen that reducing the need for HLVs in the 2 stage does not show improvements in the availability, in fact it reduces the availability below the baseline case. This can be explained due to the even greater dependency on CTV vessels from the increase in the two stage PMG failures that require a CTV, resulting in the use of these resources becoming constrained as detailed in Section 3.3.1. However, due to crew transfer vessel usage costing significantly less than HLV usage, the benefits of the reduced HLV usage are captured in the O&M cost graphs in figure 5.20 and 5.21. Once again the increase in constraints on the CTV as the reduction in HLV usage goes from 25-100% and its effect on availability is cancelled out by the savings in downtime from the removal of the mobilisation time for the HLV. This results in little difference between the availability of the reduced HLV scenarios. Unlike the 3 stage configurations, the “All Improvements” scenario, in which a 10% repair time improvement, redundancy and HLV reduction of 50% are combined, does not show such a high availability. The reason for this is because the reduction in the need for the HLV by 50% reduces the overall availability of the “all improvements scenario”. The reduced repair time by 20% scenario offers the greatest availability improvement of 1.34%.

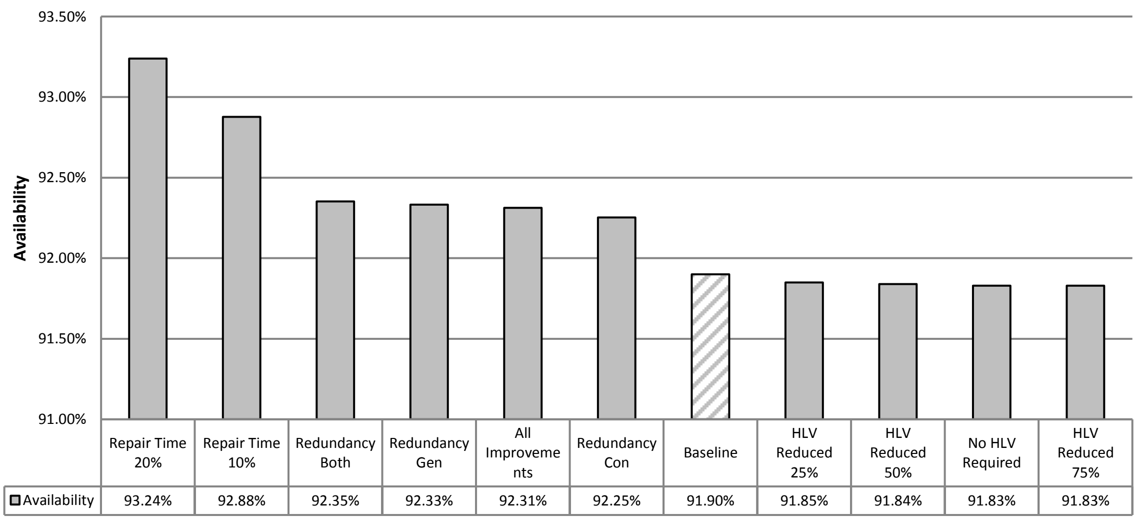


Figure 5.19: 2 stage PMG FRC availability with simulated improvements

Figure 5.20 shows the direct O&M costs for the 2 stage PMG FRC turbine type. It can be seen that reducing the need for HLVs by 50% reduces O&M costs by £2.17 / MWh, reducing repair times through DFM techniques reduces O&M costs by £1.30 / MWh and redundancy in the power train reduces O&M costs by £1.25 / MWh.

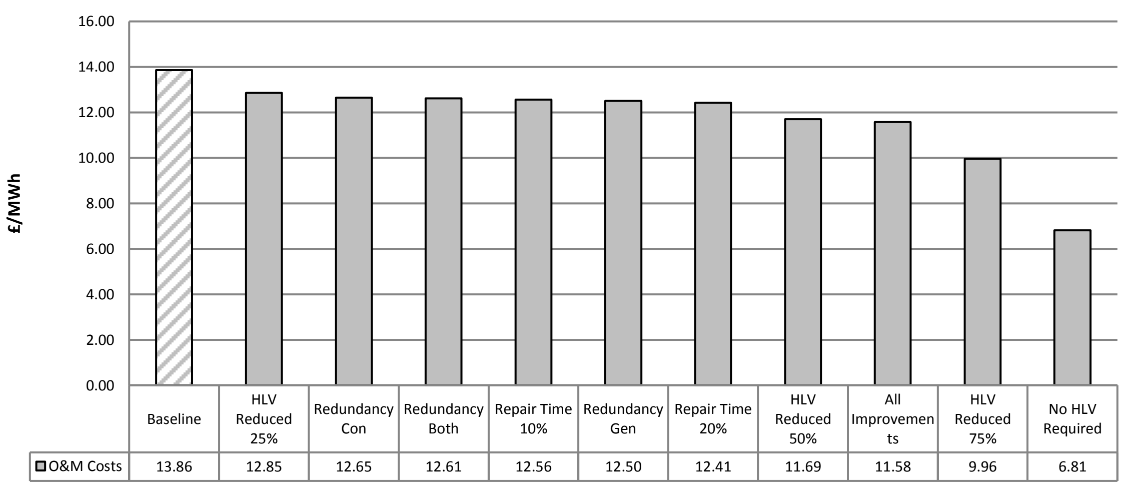
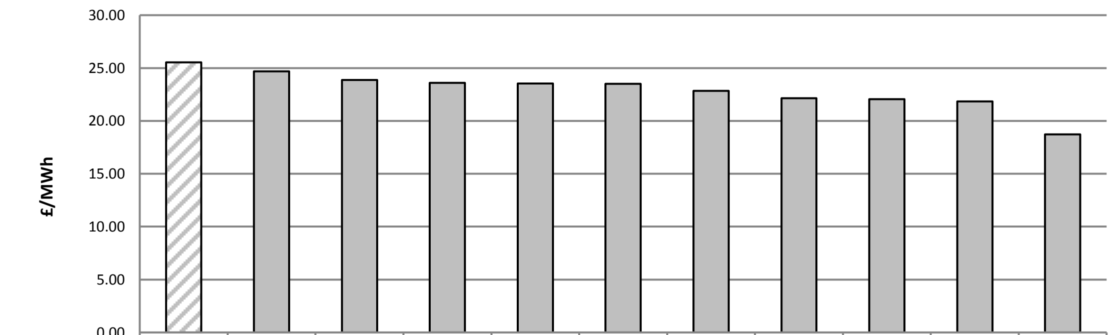


Figure 5.20: 2 stage PMG FRC direct O&M costs with simulated improvements

The total O&M costs including lost production costs for the 2 stage PMG FRC turbine can be seen in Figure 5.21. It shows reducing the need for HLVs by 50% reduces O&M costs (including lost production costs) by £2.02 / MWh, redundancy in the power train leads to a reduction of £1.99 / MWh and reducing repair times through DFM techniques leads to a reduction of £2.70 / MWh.

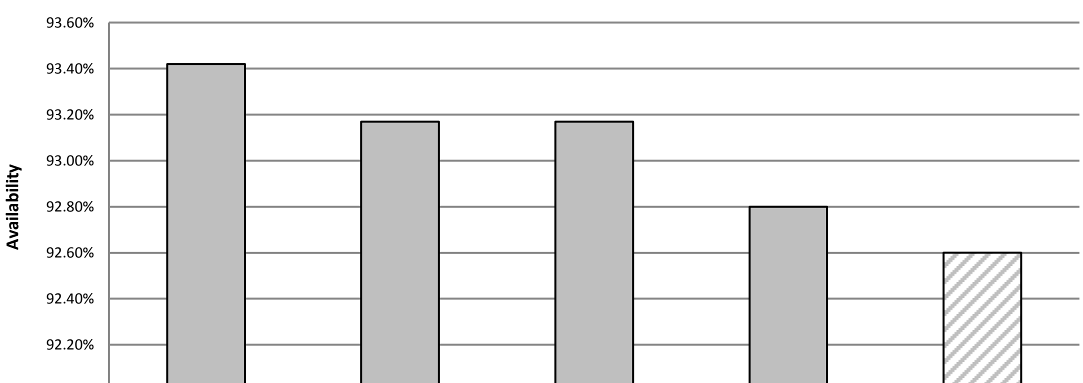


	Baseline	HLV Reduced 25%	Redundancy Con	Redundancy Gen	Redundancy Both	HLV Reduced 50%	Repair Time 10%	Repair Time 20%	All Improvements	HLV Reduced 75%	No HLV Required
O&M Costs Total	25.54	24.69	23.87	23.60	23.55	23.52	22.84	22.14	22.06	21.86	18.74

Figure 5.21: 2 stage PMG FRC total O&M costs with simulated improvements

Figures 5.22- 5.24 show the same analysis but for the Direct Drive PMG FRC turbine type. It can be seen that no redundancy in the generator or inbuilt lifting mechanisms were included in the direct drive analysis. The reason for these omissions is due to the practicalities of design. A direct drive machine is so large and expensive there would not be a business case to have an extra one included for redundancy. The size and weight of the Direct Drive machine would also make inbuilt lifting mechanisms unpractical. Figure 5.22 shows that for the direct drive PMG FRC turbine, power converter redundancy improves availability by 0.20%, reducing repair times by 10% (through DFM techniques) improves availability by 0.57%.

Unlike the other configurations, the "All Improvements" scenario only includes a 10% repair time improvement and redundancy in the power converter. The reduced repair time by 20% scenario offers the greatest availability improvement of 0.82%.



	Repair Time 20%	All Improvements	Repair Time 10%	Redundancy Con	Baseline
Availability	93.42%	93.17%	93.17%	92.80%	92.60%

Figure 5.22: Direct drive PMG FRC availability with simulated improvements

Figure 5.23 shows the direct O&M costs for the direct drive PMG FRC turbine type. It can be seen that reducing repair times through DFM techniques reduces O&M costs by £0.10/ MWh and redundancy in the power converter reduces O&M costs by £0.02 / MWh.

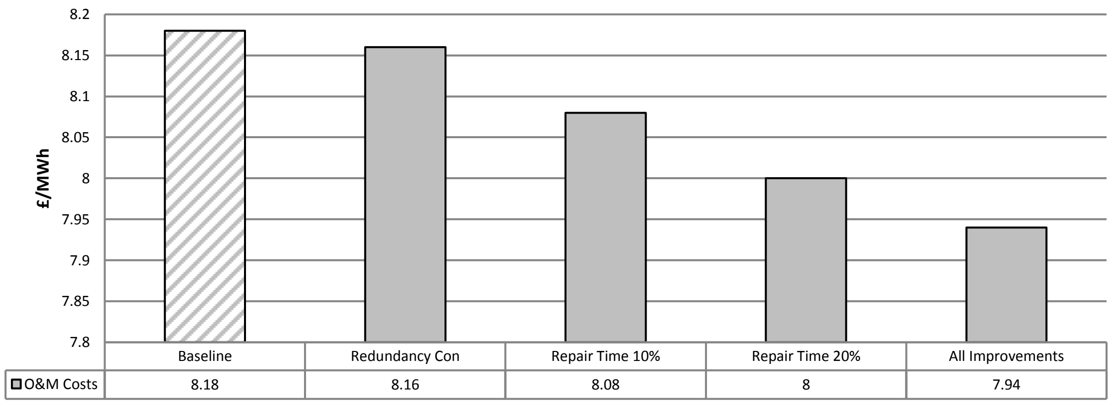


Figure 5.23: Direct drive PMG FRC direct O&M costs with simulated improvements

The total O&M costs including lost production costs for the direct drive PMG FRC turbine can be seen in Figure 5.24. Figure 5.24 shows redundancy in the power converter leads to a reduction of £0.09 / MWh and reducing repair times through DFM techniques leads to a reduction of £1.09 / MWh.

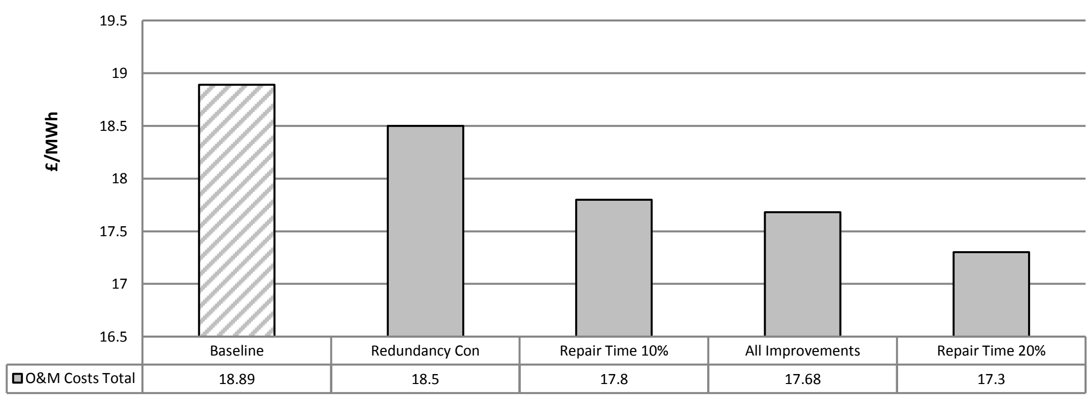


Figure 5.24: Direct Drive PMG FRC total O&M costs with simulated improvements

5.3.3.3 Impact on CoE

As previously mentioned the impact on the CoE cannot be shown for the direct drive PMG FRC for the minor turbine changes in this chapter. For this reason, this section will show the impact on CoE using the 3 stage PMG FRC turbine type at a hypothetical site 50km from shore. From Chapter 4 it can be seen that the CoE for the 50km site with the 3 stage PMG FRC turbine types is £115.41/MWh. From Figure 5.17 the O&M savings from the in-built lifting mechanisms reducing HLV vessel usage by 50%, redundancy in the power train and reduced repair times by 20% can be seen. These savings reduce the CoE to £113.39/MWh, £113.99/MWh and £113.79/MWh respectively.

However costs of the turbine modifications must also be considered during this analysis. As the purpose of this example is to provide a rough estimate of the impact on the cost of energy some assumptions on costs have been made. An opportunity for further work would be to look at the costs of the in-built lifting mechanism, redundancy and implementation of the design for maintenance techniques in more detail and include them in this analysis. The following cost assumptions have been made and it is felt represent a worst case scenario to ensure CoE savings are not over estimated. The cost of the in-built lifting mechanism was assumed to be £120,000/ turbine, ~10% of the cost for a 3MW turbine. The cost of the redundancy in the Generator was assumed to be £60,000. This estimate was based on the generator and turbine costs from Chapter 3, e.g. 3 stage PMG at £20,000/MW. The additional £60,000 is to cover the extra cost of two generators and converters, e.g. two 1.5MW generators vs. one 3MW generator. A cost assumption of £90,000 per turbine for the design for maintenance approach was made.

When these cost assumptions are included in the CoE calculations from paragraph one of this section, there is approximately a 1.6% reduction in the CoE when inbuilt lifting mechanisms can be used to reduce HLV usage by 50%. There is a reduction of ~1.1% in the CoE when there is redundancy in the generator and power converter. Lastly there is a reduction of 1.3% in the overall CoE when repair times are reduced by 20% from the use of design for maintenance techniques.

5.4 Discussion and conclusion

This section will discuss the findings from Chapter 5 and draw relevant conclusions on each of the areas included in this chapter. At the end of this section the overall impact on the CoE will be discussed and concluded.

5.4.1 Vessel analysis discussion and conclusion

- HLV Strategy Availability and explanation for why DFIG “Annual” has such a low availability

Out of the 4 heavy lift vessel strategies analysed in this chapter the “purchase strategy” offers the highest availability across all 3 distances from shore. Depending on the turbine type, availabilities ranged from 92% for the 3 stage PMG FRC configuration to 92.7% for the direct drive PMG FRC turbine type at hypothetical sites 50km from shore using the purchase HLV strategy. The reason the purchase strategy offers the highest availability is because the vessel is immediately available and no mobilisation time is needed. This leads to less overall downtime when a failure occurs, increasing availability. The “annual” strategy in which the HLV is chartered for a 2 month period every year leads to the lowest availability for the turbine types that had a higher usage rate of the HLV, i.e. the 3 stage configurations, in particular the 3 stage DFIG which shows an availability of ~40%. The annual strategy using the direct drive configuration did not show the large drops in availability due to the direct drive configuration not requiring the HLVs as often as the other turbine types so all HLV maintenance is completed every year, meaning no build-up of repairs occurs for the following year. The main driver for the low 40% availability with the DFIG turbines using the annual strategy is the fact that all maintenance requiring a HLV is not being finished in the annual 2 month chartering period so it is continuously building up for the following year. In reality the 40% availability from the annual strategy with the DFIG configuration would never occur as the operator would see a large number of its turbines were down and would not wait until the annual chartering of the HLV to repair them. In this case the operator would go to the spot market to charter the HLV in a similar way to the fix on fail strategy or increase the annual chartering length to more than two months. The fix on fail strategy had availabilities slightly less than the purchase strategy because of the time required for mobilisation of the HLV with the fix on fail strategy. Depending on the turbine type with the fix on fail strategy, availabilities ranged from 90.5% for the 3 stage PMG FRC configuration to 92.6% for the direct drive PMG PRC turbine type at hypothetical sites 50km from shore. The reason for the larger drop in availability for the DFIG turbine type from the purchase strategy to the fix on fail strategy is because of higher cumulative mobilisation time for the 3 stage DFIG over the direct drive PMG configuration when the fix on fail strategy is used.

- HLV strategy O&M Costs Discussion and Conclusion

Due to the very low availability of the 3 stage DFIG turbine using the annual strategy, the lost production costs mean this is the strategy and turbine type with the highest O&M costs across all 3 distances from shore. Apart from the 3 stage DFIG using the annual strategy, the purchase strategy has the highest overall O&M costs across all 4 drive train types. The transport costs are the cause of this and have been increased by the cost of the outright purchase of the HLV. The fix on fail vessel strategy has the lowest overall O&M cost for all drive train types across all 3 distances from shore. Fix on fail offers a slightly lower O&M cost per MWh than the batch for all drive train types because the extra transport cost of chartering a HLV every time for the fix on fail strategy is surpassed by the extra lost production costs for the batch strategy from its lower availability.

- Influence of distance to shore

Regarding the influence distance from shore has on the order of each HLV strategy in terms of overall O&M costs, this work shows that one difference can be observed when the distance from shore increases from 10km to 50 or 100km. That difference is that at 50km the 3 stage PMG turbine with the annual strategy has a higher O&M cost than the purchase strategy at 50km and this is not the case at 10km. The reason this change in order occurs is because of the greater increase in lost production costs for the 3 stage PMG with an annual HLV strategy compared to the purchase strategy. This increase in lost production cost is due to the greater decrease in availability in the 3 stage PMG with the annual strategy than the 3 stage PMG with the purchase strategy as the sites move further from shore.

- Mother Ship Analysis Discussion and Conclusion

This work shows that for 4 different turbine types across hypothetical sites at 70km, 80km, 90km and 100km from shore there is an increase in availability with the use of a mother ship. At 70km from shore there is at least a 1.5% improvement in availability across all drive train types from the use of a mother ship. At 80km, at least a 2.2% increase in availability, 90km sees at least an 8.3% increase and at 100km there is at least a 9.1% increase in availability across all 4 turbine types from the use of a mother ship. These improvements in availability lead to decreased lost production costs. If the decrease in lost production costs outweigh the increase in transport costs from chartering the mother ship then it can be said that there is a reduction in the overall O&M costs from the use of a mother ship. Mother ship day rates representing the lower end of the day rate range at £17,000 and the higher end of the range at £25,000 were modelled in this chapter to determine at what distance from shore each turbine type had a reduction in the overall O&M costs from the use of a mother ship. Results showed that when day rates are at the lower end of the range at £17,000 there is a reduction in total O&M costs for both of the 3 stage configuration turbines from 80km onwards and for the 2 stage and direct drive turbines from 90km onwards. If the higher day rates of £25,000 are taken then there is not a reduction in the overall O&M costs from the use of a mother ship until 90km offshore for each of the 4 wind turbine types. Lastly this analysis showed what day rates could be paid for a mother ship for each turbine type at 70km, 80km, 90km and 100km from shore while maintaining a reduction in overall O&M costs. Day rates ranged from £6,000 for the direct drive PMG FRC turbine type at 70km from shore to £79,000 for the 3 stage DFIG PRC turbine type at 100km from shore.

5.4.2 CBM and PBMC discussion and conclusion

- Improvement in availability from CMS and CBM

In the empirical availability analysis of two populations with and without CMS, the “No CMS” population in this chapter has a lower failure rate than the population with CMS; however the availability is also lower in the “No CMS” population. This means that downtime must be higher. As the ”No CMS” population is closer to shore the higher down time is not due to travel time, consequently it must be a result of other factors. One of the factors could be the CMS allowing for better maintenance planning which in turn leads to shorter downtimes and higher availability for turbines with CMS. This analysis showed a ~4% difference in availability between the population with CMS and the population without, in favour of the population with.

- Improvement in availability from PBMCs

Similar conclusions can also be drawn from a similar analysis with PBMCs. As the “No PBMC” population has a lower failure rate and is closer to shore the lower availability can only be explained by longer lead and repair times. These longer repair and lead times in comparison to the “Has PBMC” population could be due to the manufactures being faster at repairing the turbines that they will have to pay downtime compensation for. This analysis showed a ~2.5% difference in availability between the population with PBMC and the population without, in favour of the population with.

5.4.3 Minor turbine innovation discussion and conclusion

For a hypothetical 100 turbine site 50km offshore, significant improvements in availability and O&M costs have been simulated from adjusted input data to represent minor turbine design changes. The original input data is based on real turbine failure and operational data and the simulation is carried out using an offshore accessibility model.

- Innovation that leads to greatest improvement in availability for each drive train type

The greatest improvement in availability for the 3 stage PMG FRC turbines comes from repair times being reduced by 20% due to design for maintenance techniques. This is not the case for the DFIG turbines as the greatest improvement in availability is seen from introducing redundancy to both the generator and the converter.

- Innovation that leads to greatest improvement in O&M costs for each drive train type

In all turbine types that have a gearbox the largest reduction in O&M costs (both excluding and including lost production costs) is seen to come from the elimination of the need for heavy lifting vessels. The overall combination of each of these improvements (with HLV reduction at 50% and repair time reduction at 10%) reduces the total O&M cost by ~16% for the 3 stage DFIG and ~17% for the 3 stage PMG FRC. Eliminating the need for a HLV can reduce the direct O&M cost by ~57% and the total O&M cost by 38%(3 stage DFIG PRC). The total O&M costs for the DFIG turbine (Figure 5.15) drop below the total O&M cost for the PMG baseline turbine (Figure 5.18) if HLV usage is reduced by 75% or greater, or if power train redundancy, reduced repair time of 10% and reduced HLV usage by 50% are all applied together. Even without the removal of the requirement for the use of a HLV the direct drive PMG FRC configuration has the a lower O&M cost than all other turbines with their improvements, once the repair times are dropped by at least 10%.

5.4.4 Overall impact on the CoE

- Greatest improvement in CoE

The greatest improvement in the CoE in this chapter can be seen when the best and worst vessel strategy are compared in Section 5.3.1.7. The best and worst vessel strategies are compared for a hypothetical site at 100km from shore consisting of direct drive PMG FRC turbine types. The best vessel strategy analysed for this hypothetical site is the “Fix on Fail” HLV strategy with the use of a mother ship and the worst vessel strategy is the Annual HLV strategy without the use of a mother ship. A difference in the CoE of ~22% can be seen between both vessel strategies.

- CMS and CBM impact on CoE

The use of condition monitoring systems and performance based maintenance contracts also showed a reduction in CoE in this chapter. In an empirical analysis, an improvement in availability was shown from the use of both CMSs and PBMCs. These availability improvements were then applied to a hypothetical site consisting of direct drive PMG FRC turbine types at 50km from shore. The improvement in CoE from the use of CMS was calculated to be ~7%. It should be noted that in the empirical analyses other factors may have influenced the improvement in availability and in turn the CoE, however a number of other factors have been ruled out. This suggests that the CMS must have played an important role in this CoE decrease.

- Impact of minor design innovations on CoE

Minor adjustments to the turbine design also resulted in reductions in the CoE, however these reductions were less than the reductions encountered from the vessel strategies and the use of CMSs. For a hypothetical site consisting of 3 stage PMG FRC turbine types located at 50km from shore, the use of inbuilt lifting mechanisms to reduce the HLV usage resulted in a CoE reduction of ~1.6%. Redundancy in the power train resulted in a CoE reduction of ~1.1% and reduced repair time through design for maintenance techniques resulted in a reduction in the CoE of ~1.3%. All of the CoE savings discussed are listed in Table 5.2.

Table 5.2: Overall reduction in CoE

Step to reduce CoE	Potential Reduction in CoE
HLV strategy	~22% between best case and worst case scenario
Condition based maintenance	7%
Performance based maintenance contracts	0 - 4.5%
In built lifting mechanisms	1.6%
Reduced repair times through design for maintenance	1.3%
50% redundancy in the generator and converter	1.1%

- Difference in CoE reduction examples for different drive train types

As previously mentioned the CoE saving of 7% for the CBM and up to 4.5% for the PBMC are based on the direct drive PMG FRC turbine type at a hypothetical site 50km from shore. The inbuilt lifting mechanisms, reduced repair times and redundancy reductions of 1.6%, 1.3% and 1.1% respectively are based on the 3 stage PMG FRC. If those CoE reduction steps were considered for other drive train types, different savings would be seen. For example, compared to the 3 stage PMG FRC, the 3 stage DFIG PRC would see less savings from the power converter redundancy. The reason for this is because the 3 stage DFIG configuration has a much lower power converter failure rate than the 3 stage PMG FRC, so the redundancy in the converter would lead to a smaller reduction in CoE for the DFIG configuration. For that reason, the figures shown above are examples of CoE savings that can be achieved using different CoE reduction approaches, however the above example highlights how all savings will be turbine type specific.

5.5 Chapter 5 reference

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Chapter 6 Conclusion and Future Work

- Research Questions and overview of conclusion

Based on the problem statement that "the cost of offshore wind energy is too high", the objective of this thesis was to answer the following research question:

"How can the cost of offshore wind energy be reduced through turbine type selection, vessel strategy choice, maintenance strategy choice and minor turbine design changes?"

To answer this primary research question a number of other smaller secondary research questions were first answered. These secondary research questions were answered throughout each chapter of this thesis. This chapter provides a summary of the major concluding points from each of the previous chapters in this thesis. The main research question from each chapter and the overall research question shown above will be addressed. More detailed conclusions, discussions or answers to secondary research questions can be found at the end of each chapter. The conclusions shown in this chapter will be based on certain assumptions and will have certain levels of uncertainty around them. Details of these assumptions and uncertainty levels can be found in the chapters themselves. This chapter will conclude by providing an overview on how the work in this thesis will contribute to the offshore wind industry and by outlining future work.

6.1 Conclusion

- Key points from Chapter 2

Chapter 2 answers the research question "which wind turbine type has the lowest offshore failure rate?" In Chapter 2 the overall failure rates for a number of different offshore wind turbine types differentiated by their drive train are provided. The average failure rate for an offshore wind turbine based on the empirical analysis in Chapter 2 is 8.2 failures per turbine per operational year. Approximately 82% of those repairs being minor repairs (cost < €1,000 for repair), 14.5% major repairs (€1,000 - €10,000) and 3.5% major replacements (cost > €10,000). The subassemblies/components that fail the most in the offshore turbines analysed are the pitch/hydraulic system, the “other components” group and the generator. Generators and converters have a higher failure rate offshore than they do onshore. The onshore to offshore failure rate difference is greater in generators than in converters. The results from the failure rate with time analysis have shown that all four subsystem/groups analysed display either early failure or reliability deterioration trends. However low R^2 values for the fitted functions to the data and large amounts of variance in the data led to the conclusion that average failure rates could be used in the subsequent O&M cost modelling in Chapter 3. A second empirical analysis showed that PMGs have a lower failure rate than the DFIGs by about 40% and that FRCs have a higher failure rate than PRCs, by a factor of 5. A structured approach for estimating reliability data based on existing similar field data, known as REMM, was used to estimate the failure rates of wind turbines with a 2 stage PMG FRC drive train and the direct drive PMG FRC configuration. Based on the field data and the estimated data calculated using REMM, Chapter 2 answers the research question “which wind turbine type has the lowest failure rate?” This chapter concludes that the direct drive PMG FRC wind turbine has the lowest overall failure rate followed by the 3 Stage DFIG PRC, then the 2 stage PMG FRC and lastly the 3 stage PMG FRC. There is ~5% difference in failure rate between the best (direct drive PMG FRC, ~8 failures / turbine/ year) and worst performing turbine types (3 stage PMG FRC 8.41 failures / turbine / year).

- Key points from Chapter 3

Chapter 3 aims to answer the research question “which wind turbine type provides the highest availability and lowest O&M costs”. It found that turbines with a permanent magnet generator have a higher availability at all sites analysed (ranging from 10k to 100km offshore) than those turbines with a DFIG. If failure rates alone were considered this would not have been the case because it is the higher downtime due to the different types of failures encountered by the DFIG configuration that reduces its availability, not its failure rate. It has been shown (subject to the proviso of the input data and assumptions being correct) that wind turbines with permanent magnet generators are recommended from a point of view of maximizing availability, with a preference for lower speed generators with no gearbox. Results showed that 3 stage DFIG PRC turbine types have a higher O&M cost/MWh than all of the PMG FRC turbine types across all hypothetical wind farms analysed. As with availability, the direct drive turbine type with a PMG performed best with the lowest O&M costs, followed by the PMG with a 2 stage gearbox and then a 3 stage gearbox. The location of the wind farm, in terms of distance from shore, only influenced the relative superiority of the turbines with PMGs over the DFIG turbines and between direct drive turbines and those with gearboxes.

- Key points from Chapter 4

Chapter 4 takes a step towards answering one of the major research questions posed in the introduction "How do you choose between different competing wind turbine models when planning an offshore wind farm?" Based on field operational and cost data from modern multi MW offshore turbines and the use of newly developed O&M and BoP models Chapter 4 concludes that the drive train that provides the lowest CoE for all sites analysed is the direct drive, permanent magnet generator with a fully rated converter. The analysis found little difference between the CoE from 3 stage and 2 stage PMG FRC configurations across all sites. The 3 stage, DFIG partially rated converter configuration had the highest CoE across all sites. For a site 50km offshore this analysis found the DFIG configuration's CoE (~£119/MWh) was ~8% higher than the direct drive configurations (~£110/MWh). When the two stage and three stage PMG configurations are compared it can be seen that one of the reasons they are so similar across all sites is because the higher turbine cost of the of the 2 stage configuration is wiped out by its lower O&M cost providing it with a very similar CoE to the 3 stage PMG configurations. To determine the effect of increased wind speed for a given site on the overall CoE, the site at 50km from shore with the best performing direct drive configuration had its wind speed increased from an average wind speed of 9.88m/s by five and ten percent. This decreased the overall CoE by approximately six and twelve percent respectively. Sensitivity analysis also showed that increasing the number of turbines in a wind farm led to a higher overall CoE. Wind farm operational resources could be optimised to make wind farms with a larger number of turbines have better availability and lower overall O&M costs, however this optimisation was not in the scope of this thesis.

- Key points from Chapter 5

Chapter 5 aims to answer the research question "how can the cost of energy be reduced through vessel strategies, maintenance strategies and turbine innovations". The vessel strategies analysis looks at four different heavy lift vessel strategies and the use of a mother ship. The maintenance strategies look at time based maintenance versus condition based maintenance and the use of performance based maintenance contracts. Turbine innovation included in built lifting mechanisms, redundancy and reduced repair time from design for maintenance. Results showed that the fix on fail vessel strategy led to the lowest CoE and there was a business case for wind farms of all wind turbine types to use a mother ship beyond 80km-90km from shore. Empirical analysis showed that CoE reductions of up to 7% could be achieved by condition based maintenance and performance based maintenance contracts. CoE savings of ~1.5% each were seen from the turbine design innovations previously described.

- Summary of all CoE savings

All of the potential CoE savings analysed in this thesis can be seen in the table 6.1:

Table 6.1: All potential CoE savings analysed in this thesis

Step to reduce CoE	Potential Reduction in CoE
HLV Strategy	~22% between best case and worst case scenario
Drive Train Selection	~8%
Condition Based Maintenance	~7%
Performance Based Maintenance Contracts	~0 - 4.5% (Depending on PBMC cost)
In built lifting mechanisms	~1.6%
Reduced repair times through design for maintenance	~1.3%
50% redundancy in the generator and converter	~1.1%

- Uncertainties and assumptions

It should be noted that all of the above conclusions are based on the quality of the input data used in the models and the quality of the models themselves. If the input data has issues, such as failures or costs specific to a certain wind turbine manufacturer this may lead to conclusions that are only accurate for that manufacturer. As always with modelling, there is a level of uncertainty surrounding the results and the further work outlined in the following sections could be carried out to help reduce that uncertainty.

- Sensitivity Analyses

Sensitivity analyses were carried out on the failure rate and repair time for the CoE analysis and it was concluded that even if the failure rates and repair times used for the direct drive turbine configuration were inaccurate by up to 20% the direct drive configuration would still be the best performing turbine type.

- Answer to main research question

To answer the research question set out in Section 1.2.1 and repeated at the beginning of this chapter the author concludes that to obtain the lowest CoE a direct drive PMG FRC turbine type should be chosen and for all hypothetical sites outlined in this thesis a Fix on Fail heavy lift vessel strategy should be used with a mother ship if the wind farm is 90km or more offshore. Condition based maintenance and a performance based maintenance contract will further reduce the CoE. If a turbine type with in-built lifting mechanisms and power train redundancy can be chosen further CoE reductions will occur. Reducing the service technicians time in turbine (repair time) though design for maintenance techniques and lean processes will also decrease the CoE.

- Authors thoughts on findings compared to industry trends and future industry outlook

The findings of this thesis seem to be reflected in the product portfolios of the major wind turbine manufacturers. For example, Vestas who traditionally sold turbines that consisted of drive trains with high speed gearboxes, DFIGs and PRCs are now developing their latest turbines with PMGs and FRCs. They are also moving towards medium speed gearboxes. The same can be said for Siemens, the other major wind turbine manufacturer. They are going one step further by completely removing the gearbox and choosing the direct drive configuration, which was identified as the best performing turbine type from a CoE point of view in this thesis. For a manufacturer to switch from one turbine type to another, more than just the CoE must be considered. While the CoE is a key customer demand the manufacturer must also consider their in house expertise. Consequently, while Vestas may recognise that the direct drive configuration offers the lowest CoE, they may not be comfortable with the step change from high speed gearboxes and generators to no gearboxes and low speed generators. The medium speed compromise of their latest turbines could perhaps be a step towards building their experience and expertise in the areas of lower speed higher torque machines. Both major manufactures are also moving away from DFIGs and PRCs. While it is accepted that the FRCs have a higher failure rate than the PRCs the added control they provide and the fact that they allow for the use of more reliable generators means they are being adopted by both major manufacturers. As no converter failures require a HLV, offshore it is also more favourable to have a higher converter failure rate and a lower generator failure rate because the generator failure may require a HLV. The lower failure rate and the types of failures that occur in the PMG over the DFIG means that it has also now been adopted by most wind turbine manufacturers. While China's control of rare earth materials required for the manufacture of PMGs is a concern for manufacturers, the undoubted benefits they provide means they are replacing the DFIG in wind turbine manufacturers newly released turbines. Based on the results from this work the DFIG would need to reduce its failures that require a heavy lift vessel by ~75% (if all other factors remained as they are) for it to be competitive with the PMG on a hypothetical offshore site 50km from shore.

While some offshore maintenance providers are investigating the use of alternative HLV strategies at the moment it seems most have come to similar conclusions to this thesis and are using a fix on fail HLV strategy. In discussions with maintenance providers, they have indicated that they are also seeing business cases for the use of mother ships at 40-50 nautical miles which is consistent with the findings of this thesis. To date the minor turbine design changes discussed in this work have not been fully embraced by many wind turbine manufactures. One reason for this is that they may be focusing their efforts in areas they see as “lower hanging fruit” like drive train design. However, as the demand from customers for lower CoE gets stronger the author predicts that even though these minor design changes offer lower CoE reductions, eventually they will be adopted on a larger scale by wind turbine manufacturers.

Many offshore wind CoE targets have been set by wind turbine manufacturers and government agencies for 2020. These range from €100/MWh to £100/MWh. This work has shown that a number of steps can be taken to help reduce the CoE in comparison to the early offshore wind farms and it is for this reason that the author feels that the target of £100/MWh and perhaps even €100/MWh could indeed be reached by 2020, however these costs will be site specific. As seen in this work at some sites the £100/MWh is currently being broken. The true challenge ahead will be breaking the £100/MWh mark in the round three sites that are greater distances from shore. If that can be achieved it will be a major step towards making offshore wind energy truly cost competitive with traditional fossil fuel sources.

6.2 Contribution

- Timeliness and Importance of CoE reduction research

The Secretary of State for Energy and Climate Change, Amber Rudd, announced in late 2015 that the CoE from offshore wind must be reduced by 2020 for subsidies to remain. If subsidies were removed the offshore wind energy industry in the UK and indeed globally would encounter serious problems. It is for this reason that CoE and CoE reduction research of the kind outlined in this thesis is timely and important.

- Chapter 2 contribution

It is hoped that the failure rate work in Chapter two will help inform the industry about the reliability of offshore wind turbine components for different wind turbine types. This could lead to redesigning of some components to reduce or remove some of the problematic failure modes highlighted in this work, for example, brush and slip ring related issues in the DFIG or IGBT issues with the converters.

- Chapter 3 contribution

Chapter 3 highlights which components contribute most to the down time of different wind turbine types and actions could be taken on these results to reduce downtime and in turn reduce the CoE by focusing on improving those components.

- Chapter 4 contribution

The highlighting of the turbine type with the lowest CoE in Chapter 4 could assist wind farm developers in choosing the turbine that offers the lowest CoE in turn reducing the overall CoE.

- Contribution of Chapter 2, 3 and 4 combined

Chapters 2, 3 and 4 are the summaries of never before seen operational and cost data sets, which will improve future reliability, availability, O&M and CoE modelling. A further contribution of Chapters 2, 3 and 4 is the process that is followed to estimate the CoE for wind turbine types with no data. This is useful because new technologies and drivetrain type configurations are regularly introduced for which no past field data exists. Chapters 2-4 outline a process that could be followed to estimate the CoE for these new turbines/technologies.

- Chapter 5 contribution

Chapter 5 shows the offshore vessel strategies operators can adopt to provide the lowest CoE. It also highlights some areas wind turbine designers and manufactures can incorporate in their designs to reduce the CoE. From an academic point of view, each of the areas discussed above have led to journal and conference publications.

6.3 Future work

A number of areas have been mentioned throughout this thesis in which improvements could be made with further work. The following paragraphs will outline what further work could be carried out to improve and build on this thesis.

- Reducing Uncertainty

As with all modelling the quality of the inputs determine the quality of the outputs. Throughout this thesis models were populated with the highest quality data available and in most cases the quality of the data was so high that it warranted publication in itself. However, no field cost or operational data was obtained for the direct drive or two stage wind turbine configurations. If data of this type was obtained it would remove an element of uncertainty from this work and in turn improve the quality of this thesis. Failure rates were also estimated for the generators and converters used in the redundancy calculations in Chapter 5. To remove uncertainty in this area a field reliability analysis could be carried out to determine failure rates for smaller generators and converters. The quality of the CoE estimations in Chapter 5 could also be improved if costs could be obtained for PBMCs, in built lifting mechanisms and if a deeper analysis on the cost of implementing design for maintenance techniques could be carried out to provide better costings.

- Optimisations and Sensitivity Analyses

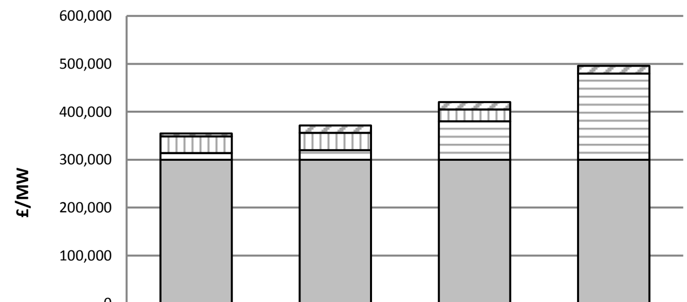
A number of optimisations and further sensitivity analyses could also be carried out for the hypothetical wind farms outlined in this thesis. While the sensitivity of the wind speed and number of turbines included in the hypothetical wind farm had a brief sensitivity analysis carried out for one wind turbine type, this could be expanded for all wind turbine types. Other sensitivity analysis could be carried out on component costs as different manufacturers may have different costs compared to the manufactures that provided the author with data. Optimisations could be carried out on a number of areas from the O&M analysis, for example, finding the optimum number of CTVs and service technicians for a certain size wind farm or investigating the use of helicopters. In the HLV vessel strategy analysis for the “batch” strategy, the optimum number of failures before a vessel is charted could also be determined. All of the above optimisations would lead to further reductions in the CoE.

- Extending this research

This research could be extended further to include different drive train types such as the 3 stage squirrel cage induction generator with a FRC or other future drive train types such as hydraulic drive trains or pseudo direct drive machines. The O&M work could be extended to check the O&M cost results using failure rates based on trended data vs. O&M cost results based on average failure rates. In this work no clear trends were observed when the failure rates were examined per operational year, however further work may look at the failure rates for each of the failure categories (minor repair, major repair and major replacement) per year of operation and determine if trends are observed.

Appendix A

Turbine costs are provided in Section 4.4.1. This appendix provides an overview of how those costs were calculated. The overall costs can be seen in Figure A1, this figure is the same as Figure 4.2.



	3 Stage DFIG PRC	3 Stage PMG FRC	2 Stage PMG FRC	DD PMG FRC
Converter	6,000	15,500	15,500	15,500
Gearbox	35,000	36,000	25,000	0
Generator	13,500	20,000	80,000	180,000
Rest of Turbine	300,000	300,000	300,000	300,000

Figure A1: Turbine cost for the four drive train types

Costs for both of the 3 stage configurations were obtained directly from an Industrial partner. Costs had to be estimated for the 2 stage gearbox and both the two stage and direct drive PMG. To estimate the 2 stage and direct drive PMG costs, the 3 stage PMG costs were adjusted based on the percentage different in costs provided in [1]. To estimate the 2 stage PMG cost in this work the same percentage cost difference between the 3 stage PMG and 2 stage from [1] were applied to the 3 stage PMG cost data that was obtained from our industrial partner. The same process was carried out for the direct drive PMG and the 2 stage gearbox also using [1].

Appendix A References

[1] Hart K, McDonald A, Polinder H, Corr E, Carroll J. Improved cost energy comparison of permanent magnet generators for large offshore wind turbines. Barcelona. EWEA 2014