View metadata, citation and similar papers at core.ac.uk

brought to you by CORE

provided by University of Strathclyde Institutional Repository

Carroll, James and McDonald, Alasdair and McMillan, David and Stehly, Tyler and Mone, Christopher and Maples, Ben (2015) Cost of energy for offshore wind turbines with different drive train types. In: EWEA 2015 Annual Event, 2015-11-17 - 2015-11-20, Paris expo Porte de Versailles. ,

This version is available at https://strathprints.strath.ac.uk/55081/

Strathprints is designed to allow users to access the research output of the University of Strathclyde. Unless otherwise explicitly stated on the manuscript, Copyright © and Moral Rights for the papers on this site are retained by the individual authors and/or other copyright owners. Please check the manuscript for details of any other licences that may have been applied. You may not engage in further distribution of the material for any profitmaking activities or any commercial gain. You may freely distribute both the url (https://strathprints.strath.ac.uk/) and the content of this paper for research or private study, educational, or not-for-profit purposes without prior permission or charge.

Any correspondence concerning this service should be sent to the Strathprints administrator: strathprints@strath.ac.uk

The Strathprints institutional repository (https://strathprints.strath.ac.uk) is a digital archive of University of Strathclyde research outputs. It has been developed to disseminate open access research outputs, expose data about those outputs, and enable the management and persistent access to Strathclyde's intellectual output.

COST OF ENERGY FOR OFFSHORE WIND TURBINES WITH DIFFERENT DRIVE TRAIN TYPES

James Carroll
University of Strathclyde
j.carroll@strath.ac.uk

Alasdair McDonald
University of Strathclyde
alasdair.mcdonald@strath.ac.uk

David McMillan
University of Strathclyde
d.mcmillan@strath.ac.uk

Ben Maples
NREL
ben.maples@nrel.gov

Christopher Mone
NREL
Christopher.mone@nrel.gov

Abstract

Drive train configurations differ in many of the modern MW scale wind turbines available. These differences occur from manufacturer to manufacturer and even within a single manufacturer's own portfolio. The wind energy industry is aiming to reduce the cost of energy (CoE) for offshore wind turbines to make it competitive with other forms of energy generation (e.g. gas, coal, onshore wind.) This paper aims to assist with that CoE reduction by modelling four wind turbine types with different drive trains to determine which turbine type offers the lowest CoE. Results from this work show that across all three hypothetical sites the turbine type with a direct drive, permanent magnet generator and fully rated converter provides the lowest CoE out of the four drive train configurations examined in this paper.

Keyword

Drive train, Wind turbine Configurations, Offshore wind cost of energy, CoE

1. Introduction

How do you choose between different competing wind turbine models when planning an offshore wind farm? This is a deceptively simple question: simple to ask, but more challenging to answer. There are many commercial and technical differences between competing turbine models whether they are on the market or in development. Perhaps the biggest differentiator is the type of drive train, including technology choices of gearbox, generator and power converter. In this paper the authors will try and cast some light on how this technology choice can influence the cost of energy (CoE).

Three offshore sites will be analysed with one of four different drive train types. This will provide CoE results for 12 hypothetical wind farms. The wind farms will consist of 100 modern multi MW turbines located at distances of 10km, 50km and 100km from shore.

2. Drivetrain Options

The drive train is defined here as the part of the turbine that converts the rotation of the turbine's low speed shaft to energy in a form that can be accepted by the grid. For the purpose of this paper it includes the gearbox, generator and power converter.

a. Gearbox

Traditionally the gearbox has been the most popular torque/speed conversion method in on and offshore wind turbines. Gearboxes consist of different stages which convert the low speed and high torque rotation from the rotor to the high speed low torque rotation required for the generator operation. The stages in a gearbox usually consist of planetary or parallel gears. Three stage high speed gearboxes were traditionally the choice of wind turbine manufacturers; however, in recent times, lower speed two stage and single stage gearboxes have been used. Wind turbines can operate without a gearbox when they use bespoke low speed high torque generators driven directly from the wind turbine rotor.

b. Generator

Both synchronous and asynchronous generators are used in wind turbines and both will be analysed in this paper. When a synchronous machine is used in a wind turbine the generator rotor is connected to the high speed shaft from the gearbox or the shaft directly from the wind turbine rotor if it is a direct drive machine. In a wound rotor synchronous machine the rotor is excited with a DC current. In a permanent magnet machine the rotor is excited through its permanent magnet content. As the excited rotor rotates in the synchronous machine a rotating flux is created in the generator air gap which cuts the conducting stator windings, producing AC current in accordance with Faraday's law.

When an induction generator is used in a wind turbine the machine rotor is again connected to the high speed shaft of the gearbox. The rotating stator flux induces a current in the rotor windings due to a difference in rotational speed. This magnetises the rotor. A small amount of speed variation naturally occurs from the synchronous speed; to increase this speed variation the synchronous speed is effectively altered using a converter connected to the generator terminals. Manipulating speed variations can also be introduced by the frequency of the currents on the wound rotor in a doubly fed induction generator (DFIG).

c. Converter

Modern wind turbines usually have a fully rated power converter or a partially rated power converter in order to allow the turbine to operate at a variable speed. With a fully rated power converter the wind turbine is completely decoupled from the grid. This decoupling has advantages and disadvantages. The advantages include superior LVRT and the disadvantages are that the wind turbine provides no inertia for the grid. In a DFIG wind turbine a partially rated power converter is used, in which approximately one third of the power passes through the power converter. As the converter has been shown to have a high failure rate [4] some future designs have no power converter. In the designs with no power converter the input speed of the generator must be controlled. This can be achieved by hydraulic accumulators and hydraulic motors as seen in the Mitsubishi Sea Angel [1].

3. Drive train configurations used in this study

Different wind turbines have different drivetrains. The four configurations considered in this study are the:

- 3 stage doubly fed induction generator (DFIG) with a partially rated converter (PRC)
- 3 stage permanent magnet generator (PMG) with a fully rated converter (FRC),
- direct drive (DD) PMG with a FRC
- 2 stage PMG with a FRC.

All four drive train types can be seen in Figure 1.

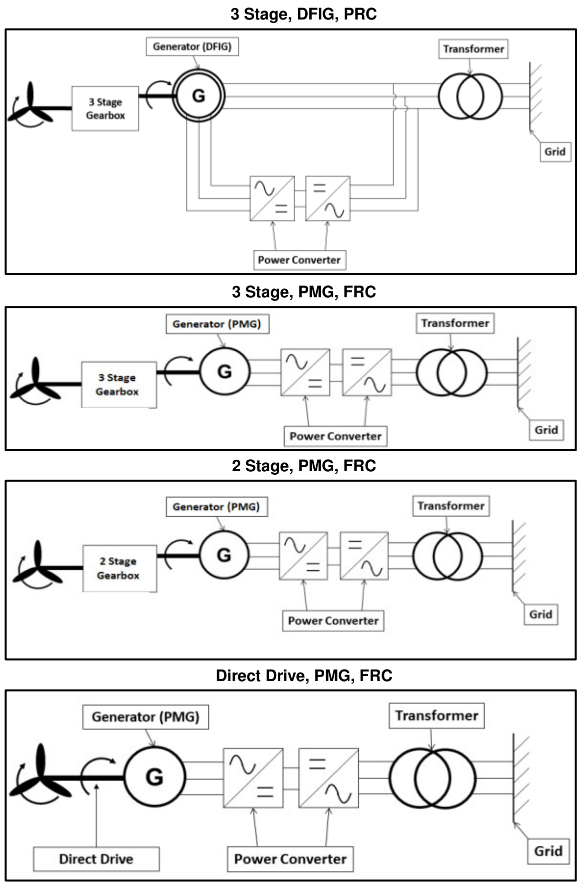


Figure 1: The four drive train types that are the focus of this paper.

4. Method and Hypothetical Sites

a. Method

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 models to find operation and maintenance (O&M) costs, balance of plant (BoP) costs, annual energy production (AEP) models and so on. Details of each of these models and inputs can be seen in Section 5

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 was used. This was up to date cost and operational data for modern multi MW turbines from a leading wind turbine manufacturer and maintenance provider. These turbines are reasonably representative of modern wind turbines across the industry.

3. Adjust empirical 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 operational and cost data. Consequently a method of estimating the inputs required for both of these drive train types had to be used. Reliability and operational data for new wind turbine types have been estimated in past publications based on similar older technologies using the reliability enhancement methodology and modelling (REMM) method [2]. This was also used in this paper. 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 [3]. Similar techniques were used in this analysis to adjust operational 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 type at each of the three offshore locations. In this analysis as in [5] the CoE is defined as:

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

   In the above equation ICC (Initial Capital costs) include turbine costs, BoP costs (port and staging, substructure and foundation, electrical infrastructure, assembly and installation, commissioning, engineering and management costs) and other capital costs (insurance during construction, decommissioning, finance costs, contingency and so on). O&M costs include the staff costs, repair costs and transport costs. In this analysis the Fixed Charge Rate is 10.1% as in [5]. The energy production is the amount of energy produced by the wind farm or wind turbine in the given time period.

5. Adjust inputs to represent the 3 other drive train types and determine the effect on CoE at each of the three sites.

6. Draw conclusions on which drive train type offers the lowest CoE at each distance from shore.

b. Hypothetical Sites

In this analysis twelve windfarms in total were analysed. Four at 10km from shore, four at 50km from shore and 4 at 100km from shore. Each wind farm contained 100 modern multi MW wind turbines of the same rated power. The four wind farms at each distance from shore will consist of one with each drive train type. For example, at 10km from shore one wind farm will have 100 turbines with a 3 stage, DFIG, PRC drive train, the second wind farm will have 100 turbines with a 3 stage, PMG FRC turbine type, the third will have 100 turbines with a 2 stage, PMG, FRC and lastly the forth will contain turbines with a direct drive, PMG, FRC. These 4 wind farm types will be repeated at the 50km distance and the 100km distance.

The wind speed and sea state data at each of the sites will be the same and simulated using the climate and sea state data from the FINO site in the North Sea [6]. As in [2], the study assumes that the climate and sea conditions at this site are representative of offshore wind farms in the North Sea. It is also assumed that water depth remains consistent across all 3 sites at 30m.

5. Models and Inputs used in analysis.

The results in Section 6 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. These outputs 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 1 were required.

The AM02 model is used to detail the O&M costs and energy production for each turbine at each site. This is a model that was created at the University of Strathclyde [7]. 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. The model determines accessibility, downtime, maintenance resource utilisation, and energy production of the simulated wind farms.

6. 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.

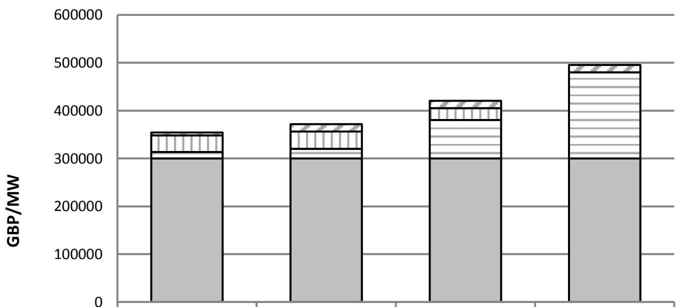
a. Turbine type cost

Figure 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.

Model and Output	Description	Input and source of input
O&M Cost Model. Output: O&M costs for each drive train type at each site	The O&M cost model used in this work was the AM02 model created at the University of Strathclyde. A brief overview of the model is included in the text of Section 5 and greater details are provided in [7].	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. [4,8]
Energy Production Model. Output: Energy produced by each turbine type at each site.	The energy production model used in this work was the AM02 model created at the University of Strathclyde. A brief overview of the model is included in the text of Section 5 and greater details are provided in [7].	Empirical power curves from wind turbines with different drive train types [2], wind and wave data from a north sea site [6]. 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 [9]	Costs of: ports, staging, substructure, foundation, electrical infrastructure, assembly, installation, development, engineering, management and commissioning. Model populated by DNV GL [9]
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.

Table 1: Models and their inputs used in the analysis

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. 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 [10]. 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 DD PMG. Some of this cost is cancelled out due to DD PMG not requiring a gearbox but this cancelation is not enough to stop the DD 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.



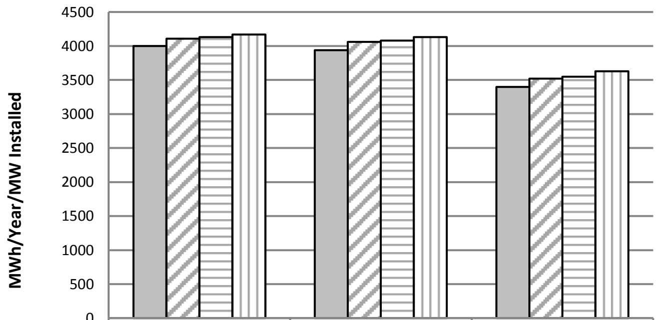
	3 Stage DFIG PRC	3 Stage PMG FRC	2 Stage PMG FRC	DD PMG FRC
Converter	6000	15500	15500	15500
Gearbox	35000	36000	25000	0
Generator	13500	20000	80000	180000
Rest of Turbine	300000	300000	300000	300000

Figure 2: Turbine cost for the four drive train types

b. Energy Production

Figure 3 is based on the calculated energy production for each site and each turbine type from [2]. In that paper the energy was calculated for each turbine type at each site using the model detailed in Section 5 [7]. That model was populated with empirical power curves for the two 3 stage drive train types in this analysis. For the DD and 2 stage turbines the power curves were estimated in a similar method to the power curves in [10]. Figure 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 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, as mentioned, the wind speeds at all sites in this analysis were assumed to be the same.

A difference in energy generation is also seen for each drive train type in Figure 3. The DD PMG FRC has the highest energy generation and the DFIG PRC configuration has the lowest. As seen in [2] the direct drive configuration has the highest availability and this is one of the reasons it generates more energy in a year.

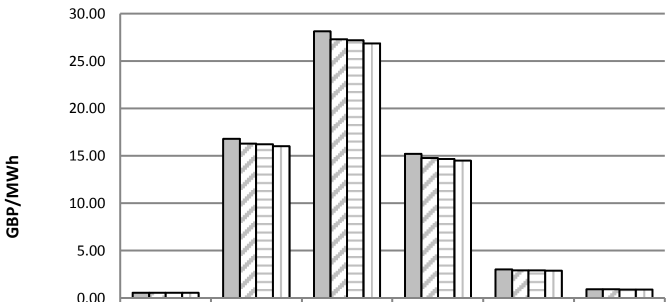


	10km	50km	100km
3 Stage DFIG PRC	4002	3940	3400
3 Stage PMG FRC	4110	4060	3520
2 Stage PMG FRC	4130	4080	3550
DD PMG FRC	4170	4130	3630

Figure 3: Energy production for the four drive train types

c. BoP Costs

Figure 4 is based on the BoP model and inputs detailed in Table 1. The figure shows the BoP costs for each drive train type at the site 50km from shore. It can be seen that the electrical infrastructure is the greatest contributor to the BoP costs followed by the structure and foundation. If total BoP costs were shown for each turbine type there would not be a difference between each configuration. However, Figure 4 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 DD configuration has the lowest. The BoP costs for the 10km and 100km sites were also calculated and included in the overall CoE shown in Figure 7.



	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: BoP costs for the four drive train types

d. Other Capital Costs

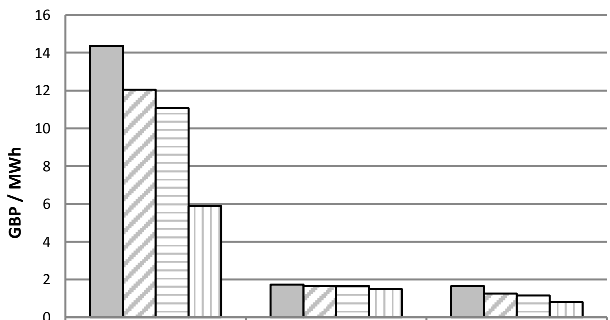
Figure 5 is based on the BoP model (which also provides other capital costs) and inputs detailed in Table 1. The figure shows the Other Capital Costs (capital costs outside of the turbine and balance of plant costs) for each drive train type at the site 50km from shore. As with the BoP costs the other capital costs for the 10km and 100km sites were also calculated and are included in the overall CoE shown in Figure 7 but are not shown in Figure 5. 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 that the DFIG configuration has the highest other capital cost per MWh generated and the DD configuration has the lowest. These costs were calculated as a proportion of the total capital costs, the percentages used are seen in the graph labels. If total other capital costs were shown for each turbine type the DD configuration would have the highest cost because it has the highest capital cost, however as the figure show results in the per MWh format the fact that the DFIG generator has lower energy generation gives it a higher cost/MWh.

	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 5: Other capital costs for the four drive train types

e. O&M Costs

The transport costs, staff costs and repair costs shown in Figure 6 come from work carried out in [2]. Reference [2] is a detailed availability and O&M cost analysis for the same four drive train types as this paper. It also covers sites ranging from 10km to 100km in 10km increments. The work is completed using the O&M model and inputs detailed in Table 1. Further details on this O&M model can be found in [7]. Figure 6 shows that the transport costs are the greatest contributor to the overall O&M cost. It can also be seen that across categories of staff costs, repair costs and transport costs the DFIG configuration has the highest cost whereas the DD 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 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

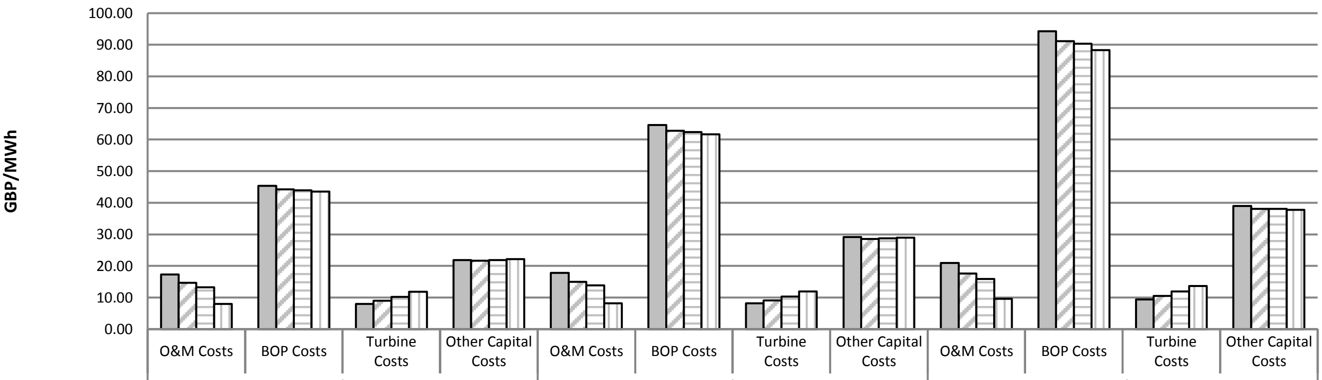
Figure 6: O&M costs for the four drive train types

f. Overall CoE Breakdown

Figure 7 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 costs than it does for the turbine or O&M costs. For the DFIG turbine type at the site 50km offshore the O&M costs make up ~15% of the overall costs, the BoP costs make up 54%, the Turbine Costs ~7% and the other capital costs ~24%. 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 % cost for the BoP would drop as the overall percentage cost for the turbine cost and O&M cost rose.

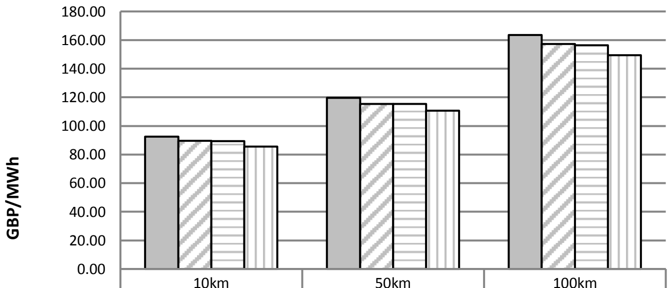
g. Overall CoE

Figure 8 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 to CoE shown in Figure 7. Figure 8 shows that across all sites the DFIG configuration has the highest CoE whereas the DD configuration has the lowest. It can be seen that the two stage and three stage PMG configurations have very similar CoE to each other.



	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 7: CoE breakdown for all turbine types and sites



	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 8: CoE for all turbine types and sites

One of the drivers for this similarity is that the higher turbine costs for the 2 stage configuration is cancelled out by its lower O&M cost. Figure 8 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 DD 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.

7. Conclusion

This paper 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?"

Based on modelling the CoE for four different drive train types at a number of sites varying distances from shore the paper 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 paper 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 the DFIG configuration's CoE (£119.64/MWh) was ~8% higher than the DD configurations (£110.74/MWh). When the two stage and three stage PMG configurations are compared it can be seen that one of the reason 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 paper concludes that the drive train that provides the lowest CoE for all sites analysed in the direct drive, permanent magnet generator with a fully rated converter. The authors plan further work of introducing different O&M vessel strategies and turbine design modifications (redundancy, in built lifting mechanisms and so on) and analysing the effects on CoE.

Acknowledgements

The authors would like to thank the industrial partners that provided operational and cost data for this work and all parties involved in creating the models referenced in this paper.

References

[1] Mitsubishi Promotional Material. Sea Angel the future of offshore wind. Accessed on 26/08/2015 Accessed at: http://www.emea.mhps.com/resources/documents/products/mpse-sea-angel-brochure.pdf

[2] Carroll J, McDonald A, Dinwoodie I, McMillan D, Revie M, Lazakis I. A Comparison of the Availability and Operation & Maintenance Costs of Offshore Wind Turbines with Different Drive Train Configurations. Submitted to Wiley Wind Energy Journal September 2015

[3] Polinder H, Van Der Pijl F, De Vilder G, Tavner P. Comparison of Direct-Drive and Geared Generator Concepts for Wind Turbines. IEEE Trans. on Energy Convers., vol. 21, no. 3, pp. 725-733, 2006.

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

[5] Moné C, Smith A, Maples B, Hand M. 2013 Cost of Wind Energy Review. NREL 2013

[6] BMU, PTJ. FINO 1 Meteorological Dataset 2004 – 2012, Accessed on: 01/12/2014. Accessed at http://fino.bsh.de

[7] Dalgic Y, Lazakis I, Dinwoodie I, McMillan D, Revie M. Advanced logistics planning for offshore wind farm operation and maintenance activities. Ocean Engineering Volume 101, 1 June 2015, Pages 211–226

[8] Carroll J. McDonald A. McMillan D. Failure Rate, Repair Time and Unscheduled O&M Cost Analysis of Offshore Wind Turbines. Wiley Wind Energy Journal, July 2015.

[9] Saur G, Maples B, Meadows B, Hand M, Musial W, Elkington C, Clayton J. Offshore Wind Plant Balance-of-Station Cost Drivers and Sensitivities.

NREL (National Renewable Energy Laboratory). 1 pg.; NREL Report No. PO-5000-56132.

[10] 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