Floating Offshore Wind: Installation, Operation & Maintenance Challenges

Author: J. Harrison
Date: 29th July 2020
Reference: BF008-001-RE
Version: A
Pages: 53

Approval / Revision History

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Changes</th>
<th>Author</th>
<th>Checked</th>
<th>Approved</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>29/07/2020</td>
<td>First Release</td>
<td>J Harrison</td>
<td>A Garrad T Warren</td>
<td>I Smallwood</td>
</tr>
</tbody>
</table>
Contents

Executive Summary ........................................................................................................... 5
Disclaimer.............................................................................................................................. 6
Abbreviations......................................................................................................................... 7

1  Introduction ..................................................................................................................... 8
   1.1  Background ................................................................................................................. 8
   1.2  Aims of this Study ..................................................................................................... 10
   1.3  Market Growth ......................................................................................................... 10

2  Types of Floating Offshore Wind Foundations ............................................................... 13
   2.1  Spar-buoy .................................................................................................................. 14
       2.1.1  Overview ........................................................................................................... 14
       2.1.2  Examples ........................................................................................................... 15
   2.2  Semi-submersible ..................................................................................................... 16
       2.2.1  Overview ........................................................................................................... 16
       2.2.2  Examples ........................................................................................................... 17
   2.3  Tension Leg Platforms ............................................................................................. 18
       2.3.1  Overview ........................................................................................................... 18
       2.3.2  Examples ........................................................................................................... 19
   2.4  Combined Structures ............................................................................................... 20
       2.4.1  Overview ........................................................................................................... 20
       2.4.2  Examples ........................................................................................................... 21
   2.5  Foundation Motion in Operation ............................................................................. 23

3  Installation Requirements ............................................................................................... 27
   3.1  Environmental Conditions ....................................................................................... 29
   3.2  Outline Installation Procedure .................................................................................. 30
   3.3  Spar-buoy .................................................................................................................. 30
   3.4  Semi-sub .................................................................................................................... 31
   3.5  TLP ............................................................................................................................. 31
   3.6  Specific Mooring Installation Challenges ................................................................. 32
3.7 Specific Electrical Connection Challenges ................................................................. 33

4 Improvements & Cost Reduction ..................................................................................... 35
   4.1 LCOE Context ........................................................................................................ 35
   4.2 Electrical Connection .............................................................................................. 39
   4.3 Mooring Systems .................................................................................................... 39
   4.4 Other Limitations and Risks .................................................................................. 40
   4.5 Decommissioning Strategy & Sustainability ......................................................... 42

5 Recommendations ......................................................................................................... 45

References ......................................................................................................................... 47

Appendix A – TRL Level Definition .................................................................................. 49
Appendix B – About Blackfish ......................................................................................... 50
Executive Summary

Floating offshore wind is an expanding sector within renewable power generation. The floating nature of the foundations permits turbine placement in previously unattainable (or prohibitively costly) sites. As this sector of the industry has been growing, various foundation concepts have been developed. However, to date much of the focus has been on proving the stability of the platforms and the compatibility with large offshore wind turbines. Whilst this was a valuable starting point for the industry, it is now entering a new phase where the operations and maintenance procedures surrounding these foundations assumes a more critical role both in the running of a farm and in the reduction of the levelised cost of energy (LCOE) for floating offshore wind. This report investigates the installation challenges for the various foundation types and suggests priority areas for future development to help reduce the LCOE for floating offshore wind.

Design for installation and O&M activities are seen as priority areas for the cost reduction of floating offshore wind projects. Studies and future developments should focus on the following:

- Expanding the weather window in which these foundations can be towed/transported to and from site
- Making mooring and electrical connection operations more weather tolerant
- Simplification of installation methodology to reduce time spent offshore
- Reduce risks to personnel working offshore during installation and maintenance
- Technologies to allow return to port maintenance to become a feasible maintenance strategy. This would encapsulate:
  - Maintaining electrical continuity throughout an array
  - Efficiency of mooring and electrical connection and disconnection
  - Ease of towing
- In addition to facilitating return to port maintenance, technologies should be developed to allow for a greater range of maintenance activities at sea, including heavy lift and installation of key components, blade repair and replacement and safe crew transfer for maintenance, whilst reducing the use of expensive vessels.
- Integrated wind turbine and floating foundation solution. This should simplify the certification process and improve investor confidence.
- Advanced structural health monitoring to evaluate fatigue damage.
Disclaimer

This report has been prepared by Blackfish Engineering Design Limited (Blackfish) solely as a research piece.

The report should only be read as a whole, taking full cognizance of the assumptions and risks as set out in the report. In producing this report, Blackfish has relied upon information provided by others. The completeness or accuracy of this information is not guaranteed by Blackfish.

No representation or warranty, express or implied, is given by or on behalf of Blackfish, its directors, officers or employees or any other person as to the accuracy or completeness of the information or opinions contained in this document and no liability whatsoever is accepted by Blackfish or any of its members, directors, officers or employees nor any other person for any loss howsoever arising, directly or indirectly, from any use of such information or opinions or otherwise arising in connection therewith.

By accepting receipt of this report, you agree to be bound by this disclaimer. The disclaimer and any claims or disputes arising in connection with it shall be governed by the laws of England and Wales and shall be subject to the exclusive jurisdiction of the courts of England and Wales to which you irrevocably submit.
Abbreviations

CAPEX – Capital Expenditure
CfD – Contracts for Difference
ERDF – European Regional Development Fund
ESME – Energy Systems Modelling Environment
ETI – Energy Technologies Institute
FOW – Floating Offshore Wind
FMECA – Failure Mode Effect and Critical Analysis
GEBCO - General Bathymetric Chart of the Oceans
IEA – International Energy Agency
IRENA – International Renewable Energy Agency
LCOE – Levelised Cost of Energy
OPEX – Operational Expenditure
ROCs – Renewable Obligation Certificates
ROVs – Remotely Operated Vehicles
SPF – Single Point Failures
TLP – Tension Leg Platform
TRL – Technology Readiness Level (see Appendix A – TRL Level Definition)
WES – Wave Energy Scotland
1 Introduction

1.1 Background

The offshore wind industry has seen great growth in and around Europe, China and particularly around the waters of the UK, in recent years. The offshore wind farms around the UK now contribute ~10% of the UK’s electricity demand on average (1). In order to continue down the path of decarbonising the UK’s energy supply more offshore wind farms are being considered. Using ETI’s ESME modelling tool it is estimated that 18-56GW of offshore wind power could be required by 2050 (2). However, the shallow sites with agreeable seabed conditions have now been largely consumed and a move further offshore and/or to deeper water is inevitable for future offshore wind installations. The move to deeper water necessitates the use of floating foundations in order to be fully exploited.

In these increased water depths, a fixed monopile / jacket foundation ceases to become a viable, cost-effective solution due to the loads imparted on the structure and the incurred sizes and costs required to counteract these. For these sites of water depth deeper than ~60m a floating wind solution is considered more economically viable. For several years developers have been investigating the potential of floating offshore wind installations – starting with the first UK floating offshore wind farm Hywind Scotland in 2017.

![Operational Water Depth for Floating Foundation Types](image)

*Figure 1: Feasible water depths for floating foundations overlaid with UK water depth occurrence distribution (RH scale) (GEBCO 2019 data)*
For example, in the UK, the deepest water for a fixed foundation offshore wind farm is currently found at the Beatrice Wind Farm off the north-east of Scotland, where the water depth is ~45m. By comparison, the Hywind Scotland site (also north-east Scotland) is located in water depths of up to 120m.

It should be noted that it is not only in deep water where these foundations can be used. There are shallower sites where the seabed conditions prohibit the use of fixed wind that may be exploitable using floating wind. However, in the main, water depths of around 80m-100m (~25% of UK waters and ~80% of global offshore wind resource (3) – as shown in Figure 1) are best suited to floating offshore wind due to the wave loading at these depths, the length and mass of the moorings and the suitability of the foundations compared to a fixed solution. In that respect, for the June 2020 Scotwind leasing round ~50% of the sites have potential to utilise floating wind solutions.

IRENA cites the development of floating foundations as highly important in the development of offshore wind energy (Figure 2) and these foundations are expected to reach commercialisation in the next few years. With the need to move to deeper waters and further offshore, we would concur with the importance of this development for the sustained growth of offshore wind, both in the UK and globally. Also given the bathymetry around the European coastline, floating offshore wind will be necessary to achieve the EU target of 450GW of offshore wind by 2030.

![Figure 2: Development expectations for offshore wind (Reproduced from IRENA (4))](image)

At present floating wind CAPEX is expected to be ~15% greater than that of fixed foundations (5). However, this comparison is only valid for sites where both fixed and floating wind would
be an option (~45m-60m water depth). The higher CAPEX is largely due to slightly elevated turbine costs, the additional cost of moorings and anchors, and the knock-on effects to the balance of plant equipment which will also require dynamic electrical cables. These costs outweigh the benefits in reduced foundation, installation and decommissioning costs. It should be noted that once water depths increase beyond ~60m floating wind becomes the more commercially sound solution.

1.2 Aims of this Study

This study aims to review the present floating offshore wind technologies with a focus on some of the key remaining challenges around installation:

- Installation and connection of moorings (as applicable)
- Electrical connection

With an understanding of the challenges facing each technology, potential improvements and cost reduction ideas will be suggested.

1.3 Market Growth

Cumulative Global Deployment of Floating Offshore Wind

![Cumulative Global Deployment of Floating Offshore Wind](image)

*Figure 3: Growth of floating offshore wind deployed capacity in the last decade*
Cumulative deployment of floating offshore wind has been expanding rapidly in the last decade (Figure 3). We have included the first of the WindFloat Atlantic turbines (Portugal) in the 2019 figures as it was installed in late 2019 as part of a major project and started coming online in the first few days of 2020 to show that significant progress was still being made last year. There are now two further (8.4MW each) turbines installed at the WindFloat Atlantic site to contribute to continued growth in 2020.

The UK is in a strong position to lead the way with floating offshore wind. Currently 56% of the global floating offshore wind capacity is based in the UK (6). Japan is the other dominant floating offshore wind market, with 33% of the installed capacity; this is due to the depth of water around the islands of Japan necessitating that offshore wind installations are floating. Japan has a heightened interest in offshore wind due to the complex onshore terrain which renders onshore wind installations challenging.

Whilst the growth is impressive the 65.4MW is only a small fraction (0.24%) of the globally installed ~27GW of offshore wind capacity (7). However this is estimated to rise to between 5%-15% (50-150GW) by 2050, if the remaining technological challenges can be overcome and a competitive cost of energy can be demonstrated (8).

Another factor essential to sustaining growth is policy support for floating wind development, test sites and pre-commercial arrays. Where we have seen floating wind deployments policy has been favourable (Norway, Portugal and Scotland) whereas some planned/proposed projects never saw the light of day in the face of unfavourable policy (in Spain, for example – HiPRWIND BIMEP site in the Bay of Biscay).

Focusing on the UK a little more closely, there are a number of suitable sites around Scotland and the south-west that could also benefit from bringing together established UK industries and supply chains in oil & gas and offshore wind turbines. The involvement and creation of UK jobs provides significant political incentive. Up to September 2018 the floating offshore wind projects deployed in Scotland have benefitted from ROCs, and more recently floating offshore wind has been angling for its own division within the UK’s CfD auctions such that it is not competing directly with established technologies like fixed foundation offshore wind. A restructuring of the CfD auction is underway and it seems likely that floating offshore wind will emerge in a better position for future projects.

The support that floating offshore wind is likely to receive through CfD auction restructuring will be essential to its sustained growth in the UK. The support and target setting of governments helps establish a pipeline of projects, boosting investor confidence. Similarly, the support for these early projects enables deployment of floating wind and starts the cost reduction process through stimulation of volume production and feedback of lessons learnt. Finally, these early projects help develop the technology and refine the innovations whilst simultaneously de-risking and developing supply chains.
With these support mechanisms we are likely to see continued rapid growth in this area matching that seen in fixed offshore wind in the first decade of this millennium. There are a number of projects at an advanced stage of development/consenting and we could see as much as 4GW of global floating offshore wind capacity installed in the coming 10-15 years (6).
2 Types of Floating Offshore Wind Foundations

There are many different floating foundation concepts, however they can be grouped broadly into three primary forms that have been tested to date. These are spar buoys, semi-submersibles and tension leg platforms (TLPs).

![Figure 4: Offshore wind floating foundation technologies (Reproduced from National Renewable Energy Laboratory [Joshua Bauer]) (9)](image)

The distribution of technologies between these three options are shown in Figure 5. We have grouped barge style foundations with semi-submersibles as they achieve their stability in the same way, i.e. displaced buoyancy. Spar concepts achieve stability through a mass-based righting moment and TLPs through the tension in the lines.

There are also multiple examples in recent years of floating wind platform concepts being developed with multiple turbines or in combination with various wave energy devices to form a floating offshore energy unit, or “hybrid” systems. More recently wave energy developers have been keen to integrate their technology with floating offshore wind, so that is an area of development to watch as funded projects get underway.
2.1 Spar-buoy

2.1.1 Overview

Spar buoys utilise a large ballasted buoy beneath the turbine to provide the buoyancy force and stability (courtesy of a large distance between the centres of mass and buoyancy) to the turbine. These buoys are made of steel or concrete and ballasted using water or solid ballast (concrete) to keep the centre of mass low in the structure. Typically, these foundations are moored in place using 3 to 6 mooring lines (typically catenary moorings). The concept is an adaptation of the spar buoys used in oil and gas platforms in water depths of up to 2000m. The dry weight of this type of foundation is around 1500t and this rises to approximately 8000t once ballasted (5).

Due to the draft of the submerged buoy, the technology is suited to sites with a water depth greater than 100m (~25% of UK waters). These foundations are typically suited to moderate wave loads and progressive turbine response to gusts – severely wavy sites would present a real challenge that may prohibit the use of this type of foundation.
2.1.2 Examples
The most notable UK example of a spar buoy foundation is seen in the Statoil Hywind project. The first significant scale (2.3MW) demonstration (TRL6) of this technology came in 2009 in a project off the coast of Norway and has since progressed in to a 30MW array (TRL8) in the North Sea using five Siemens SWT6.0-154 6MW turbines. These turbines sit upon buoys with approximately 80m draft and use a three-line catenary mooring system. The hull of the buoy is ballasted with stone to resist the loads from the 6MW turbines. Throughout the first two years of operation at this site a capacity factor of over 55% has been achieved and almost 300GWh of energy exported to the grid (10).

Figure 6: Hywind Scotland site information (10)
The Stiesdal TetraSpar (Figure 7) is an interesting solution that brings together attributes from all three major foundation types. The concept features a buoyant tetrahedral structure, much like many semi-sub foundations. However, once this foundation is towed to site a central keel can be lowered and ballasted to give stability in the same way as a spar buoy. This is the configuration where the TetraSpar is most applicable to UK projects; where it uses the ballasted keel to act as a spar, however other configurations for shallower sites are possible. A unit with a 3.6MW Siemens turbine is due to be deployed in 2020. It will be situated near Stavanger, Norway, in water with a depth of 200m.

![Stiesdal TetraSpar installation process](image)

**Figure 7: Stiesdal TetraSpar installation process (11)**

### 2.2 Semi-submersible

#### 2.2.1 Overview

These structures use distributed buoys situated on the water plane to provide both buoyancy and stability to the structure. The overturning moment form the turbine is counteracted by the changing buoyancy force from each of the buoys as the turbine pitches. To keep the foundations on station a system of mooring lines is typically used (3 to 6 lines). The area enclosed by the foundation intrinsically takes up a large amount of space, restricting access and limiting the number of ports where these foundations can be fabricated and launched. The draft requirements are the lowest of the three types examined here, making transit to site easier as direct routes can be taken. The design permits operational water depths of 30m to 300m (~85% of UK waters). The distributed nature of the buoyancy typically leads to increased wave loading and lively dynamic performance of the structure, particularly if towed prior to
ballast installation. The dry weight of these foundations is around 2000t and this rises to around 6000t once ballasted. (S)

2.2.2 Examples
The Principle Power WindFloat foundation (Figure 8) uses three ballasted tanks to form the main structure of the foundation. Each one can be filled with sea water to submerge approximately two thirds of the structure once located on site – using a shallower draft for tow out. At the base of each column is a set of plates that are used to entrain water and make use of added mass effects and viscous damping to minimise rigid body motions. The system is moored using three to four mooring lines and typically drag embedment anchors (where seabed conditions allow). This foundation has been used in a pilot project off the coast of Portugal where one 2MW turbine was installed in 2011 (TRL6) and more recently (late 2019 / early 2020) in the WindFloat Atlantic project, where three 8.4MW turbines will be deployed to give a total capacity of 25MW (TRL8).
The IDEOL platform (Figure 9) is a square concrete hull (barge) with a moonpool (an enclosed body of water) in the centre, which acts as a “damping pool”. The damping pool uses the entrapped water to minimise the motion of the foundation. This foundation has been used in the first French offshore wind turbine: a 2MW Vestas V80 installed in 2018 (TRL6). There is also a 3MW turbine installed in Kitakuyshu, Japan. Currently there are plans in place for a 24MW array (4 turbines), again off the coast of France, with construction starting this year (2020).

2.3 Tension Leg Platforms

2.3.1 Overview

A TLP is a positively buoyant structure that is held in place by vertical and/or angled members in tension. These members can be solid rods, cables, or tendon pipes. When these members are positioned on an angle, the increased tension in the downwind leg resists the turbine thrust-induced overturning moment. There is some concern over the fatigue life of these tendons, which is yet to be fully understood in relation to turbine loading (5) – wave loading is understood to some degree by applications in the oil and gas sector.

The draft requirements are less onerous than for a spar-buoy, with TLPs able to be deployed in operational water depths of 40m to 350m (~75% of UK waters). These foundations can withstand significant wave environments without the turbine experiencing great motion. The
dry weight of these foundations is around 1000t and no additional ballast is used, making for a comparatively low-mass structure. (5)

2.3.2 Examples
The Glosten PelaStar (Figure 10) is a solution focused on using less steel weight in the foundation. In the absence of the mass of steelwork, tensile legs attach to the platform to keep it in place and react the loads introduced by the operation of the wind turbine. To date the FEED studies performed by Glosten (12) have focused on a design with five arms, each attached to a synthetic fibre tendon. Scale tank testing took place in 2013 (TRL4). This foundation was scheduled for use at the WaveHub site in Cornwall; however, delays in planning and consenting caused the project to be shelved.

Figure 10: Glosten PelaStar
GICON-SOF have also developed a tension leg platform concept (Figure 11) which uses a gravity base between the seabed and the floater, which can be floated out with the rest of the structure. The structure is comprised largely of prestressed concrete in an effort to reduce fabrication time. The integration of a gravity anchor gives the GICON-SOF TLP stability during tow out that might not be normally afforded to other TLPs until they are secured by their moorings. Scale testing of the concept took place in 2018 (TRL4) and a planned demonstration deployment offshore near Germany is approved to use a 2.3MW turbine (TRL6) and in the future could feature a turbine as large as 8MW (TRL7).

![Figure 11: GICON-SOF TLP platform installation process](image)

2.4 Combined Structures

2.4.1 Overview
There are also several examples of floating wind platforms being designed for use with multiple turbines or with the integration of wave energy devices. The aim with these solutions is to maximise the power extracted from each foundation. Due to the additional requirements of the foundation, the dry weight of these foundations is around 2500t and this rises to approximately 9000t once ballasted (5).
2.4.2 Examples

Marine Power Systems have developed the DualSub concept (Figure 12) from their original WaveSub wave energy device. The concept uses a tension leg platform as a base (similar to their original WaveSub device), and now features their floater concept for extracting power from the orbital motions of the waves. This concept has undergone scale testing (TRL4) and has secured ERDF funding to continue the development of the device to a point where sea-based testing can be carried out. The testing at sea is to be carried out in 2021 using a wind turbine of approximately 100kW and a structure representing ~¼ scale in geometry.

Figure 12: Marine Power Systems DualSub Concept
EnBW and Aerodyne has developed a semi-submersible foundation (Figure 13) that supports two turbines per foundation. The aim here is to reduce the area and cable length required for an offshore wind farm as well as enabling access to deeper water sites. This is a development of the original “Nezzy” design that was demonstrated with a single turbine in the sea off Japan in 2018 at 1/10th scale. The multi device platform has since been tested in a wave tank in Ireland at a smaller scale (1:36) and on a lake near Bremerhaven in Germany at 1/10th scale. This means the project is approximately TRL5 and is supported by companies and personnel with a long history in the wind industry.

Figure 13: EnBW and Aerodyne’s multiple turbine foundation
2.5 Foundation Motion in Operation

Information and data regarding the stability of these various platform types is not typically widely shared. However, data has been made available to us from the Hywind Scotland project – see Figure 15 and Figure 16 below.

![Diagram of wind turbine with motion markers](image)

*Figure 14: Definition of co-ordinate system referred to in this section*

To date foundation design has focused largely on the stability of the platform to aid operation of the turbine. As a result, turbine selection and integration has been an iterative process between foundation designers and turbine suppliers. It can be seen in Figure 15 that in operation (in the region of rated power) the foundation adopts a nacelle pitch angle (pitch defined in Figure 14) due to the thrust load from the rotor. Motion about this angle results from the turbulence of the incoming wind and the response of the foundation to the waves. Analysis of the data shows that the standard deviation of this motion is approximately 0.5°. Similar behaviour is seen in the nacelle roll angle due to the torque produced. This sees a smaller angular offset and tighter spacing about the mean with a standard deviation close to 0.25°.

This pitch and roll behaviour will be different for different foundation types. Semi-submersibles are likely to see the same pattern of behaviour as that seen on spar buoys; however, the magnitude of any offset may be smaller due to the distribution of buoyancy, and without specific damping features the distributed buoyancy could make the variability greater. For TLPs
the tensile legs will restrict turbine motion to a much smaller range of angles and a smaller offset when operating.

There is generally 4 to 6 degrees of tilt angle on a conventional wind turbine rotor axis. This is typically used to avoid the tip of the blade colliding with the tower during extreme wind gusts, and the phenomenon is often called tower closest approach. There are other benefits to have a tilt angle on a wind turbine, one being that the wind shear effect is reduced with an increase in tilt angle (13). By using the same turbine that would be used on a fixed foundation on a floating foundation, the additional increase in rotor angle induced by the foundation motion may cause some unwanted results. There could be an opportunity here to design a specific turbine for floating wind that mitigates the effects (such as a downstream rotor), or benefits in some way from this phenomenon (rotor load balancing or alleviation).

Figure 15: Pitch and roll at the nacelle for the Hywind Scotland spar buoy installation

The surface excursion of a foundation is an important factor for farm layout and particularly the dynamic electrical cable. As the magnitude of these excursions increase, the demands on the dynamic cable to accommodate this range of motion is greater. This data showed ~10m excursion from the nominal centre point during typical operation. This in-itself is not a big concern as most sites will have a prevailing wind direction and will spend most of the time centred around a position owing to the wind direction. Prevailing wind behaviour is highly site specific, in the UK, for example, only 35% of the time does the wind originate from the southwest and onshore wind sites in Texas have no observed prevailing direction (omni-directional). Whilst there will be changes in wind direction the low cycle fatigue of the moorings and
dynamic electrical cables is less of a concern than the high frequency motion around the nominal operating position. In that regard, the standard deviation of the surface planar motion is ~1.5m.

This deviation behaviour is likely to be similar for semi-submersible structures moored in the same manner as the spar buoys used in Hywind Scotland (catenary moorings), with both similar initial offsets based on wind and wave direction and similar deviation about a mean. TLPs will have initial offsets of the order of 1m and much smaller deviations due to the restrictive nature of the mooring systems.

Figure 16: Foundation excursions for the Hywind Scotland spar buoy installation
The displacement in isolation is of interest to several components as discussed; however of more importance to the operation of the turbine is the rate of change of these motions (i.e. the variations in perceived wind speed at the rotor due to the dynamic motion). Using the data from the previous two figures Blackfish were able to produce Figure 17 that shows the speed distribution of the nacelle due to pitch and surface translation. It can be seen that the nacelle remains very still during normal operation, with only ~1% of the time where the apparent rotor speed is varying by more than 0.5m/s due to foundation motion. It should be noted that this motion will be exaggerated further for a blade at the top of a rotation as the distance from the point of rotation is even greater; this point (~60% of the turbine radius) is also where the aerodynamic loads are at their peak. It is these changes in speed that will drive the loads that will be the primary driver in the turbine design, rather than accelerations or displacements.

![Change in Apparent Wind Speed at the Rotor Due to Foundation Motion](image)

**Figure 17:** Nacelle speeds in a typical operational state for the Hywind Scotland spar buoy installation (figure showing a range of conditions available on request)

Whilst early foundations have shown to be very stable in order to placate turbine suppliers, there is an important piece if work to find out the limits and influence of the angular deflection. It is thought that these limits may be greater than presently advised and/or turbine design changes could be implemented specifically for floating foundations. Further to this, the fact that the tower is situated on a floating structure will introduce different dynamic behaviour due to the compliance in the foundation. This may give rise to the first natural frequency of the tower, when connected to the foundation structure, approaching that of the 3P frequency of the rotor and necessitating tower design changes.
3 Installation Requirements

The installation process for a floating wind turbine varies with foundation type; however, there are some overarching benefits relative to fixed wind that are seen in almost all cases. Generally, the installation cost for floating wind is lower than that of fixed wind turbines. Intrinsically the installation of mooring lines and anchors is fundamentally easier to achieve than a large monopile/jacket structure and the tolerance in position is larger.

Floating systems can simplify the overall installation work since turbine assembly and commissioning can take place at the at quayside, with the whole turbine foundation unit being towed to site and hooked-up. Obviously, this is not applicable in all cases, for example spar buoys in shallower water will require specialist vessels to first orientate the buoy on site and then install the turbine. However, in most cases floating wind allows more operations to be conducted onshore/port-side than with fixed wind. Fewer offshore operations results in fewer weather-constrained operations, reducing the requirement for expensive offshore vessels. Additionally, key assembly steps can be performed onshore in safer, more controlled environments.

Given that the turbine is coupled with the foundation, there is potential for operations and maintenance in larger sea states and therefore larger weather windows than for fixed foundations, where this is often limited to ~1.5m Hs (14). Similar Hs constraints exist around access to fixed wind foundations, and so the option to retrieve the turbine and foundation in larger sea states than this and complete works in a safer, inshore environment is also an attractive benefit of floating wind. It should be noted that to date, floating wind towing and installation operations have faced similar (sometimes even more) restrictive weather limits than the use of jack-up barges for fixed wind foundations.

The environmental impact of installing anchors and moorings is much lower compared to piling of the seabed, with far less seabed penetration and a lower impact upon marine life. It has also been noted that installation of wind farms further offshore, in deeper water, has a lower impact upon sea birds (15).

As can be seen in Figure 18 there are certain operations that simply must happen offshore (electrical connection, anchor installation and mooring connection). It is these areas where the challenges for floating offshore wind remain. The connection of the turbine to the structure should be done in port wherever possible; as soon as this operation is attempted offshore the risks and costs are much greater.

With all operations occurring offshore there is a reliance upon good weather monitoring and forecasting to enable accurate installation planning. The availability of this information in enough detail (wind and wave in particular) is somewhat restricted and it is likely that site-specific measurement campaigns will be required. Given the influence of the environmental
variables on yield (wind) and operations (wind and wave) demonstration of the environment will be required to secure finance too.

### Split of Operations for Floating Wind Installation

![Graph](image1)

*Figure 18: Breakdown of floating wind installation operations by where they occur (reproduced from (5))*

Figure 19 presents the average vessel usage in the installation of the various foundation types (data sourced from (5)). There are some variations between foundation types, with spar-buoys requiring, on average, 1.5 more vessels than semi-submersibles. It is likely that the requirement for a bespoke vessel has limited the development of some foundation types, i.e. the development of a bespoke vessel for a one-off demonstrator or a pilot project is likely cost prohibitive. It should be noted that this is still at an early development stage and that the marine operations, equipment and vessels will be refined as the sector grows – as we have seen in fixed offshore wind.

The aim of this report is not to say that one foundation type is the frontrunner. We agree with past studies, that have suggested that all of the three/four major foundation types will continue to be developed and deployed, each suited to their own environmental conditions, the local supply chain and the available infrastructure.
3.1 Environmental Conditions

It is considered that optimal environmental conditions for floating offshore wind are water depths between 80m and 150m with as benign a wave environment as possible. The feasible water depth is dependent on several factors, such as the turbine used, the environmental conditions, the seabed conditions, the port infrastructure available, and the operations and maintenance strategy.

It was seen through the study done by Glosten (12) that the project CAPEX is sensitive to the extreme wave conditions for which the foundation must be designed, hence, this is an important driving parameter. The water depth range (80m to 150m) represents the range in which the mooring lines can contribute most effectively to load handling, reducing the requirements on the anchors. As the depth increases beyond this, the overall mooring system mass starts to add significant cost both in terms of hardware and marine operations. Another concern with increased depth is the need for deep water robotic vehicles (ROVs) which are not widely available at present.

The seabed geotechnical conditions are important for deriving the anchoring system that can be used. The ideal conditions will vary with each foundation type, however, as a generalisation, cohesive soils that allow penetration of the seabed offer flexibility for various anchor types. With the installation of drag embedment anchors, a large tug with bollard pull of a specific

<table>
<thead>
<tr>
<th>Vessel Type</th>
<th>Image</th>
<th>Typical Day Rate</th>
<th>Average Number of Vessels Required</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Spur</td>
</tr>
<tr>
<td>Tug</td>
<td><img src="image1.png" alt="Image" /></td>
<td>£20,000-£50,000</td>
<td>1.8</td>
</tr>
<tr>
<td>Anchor Handler</td>
<td><img src="image2.png" alt="Image" /></td>
<td>£20,000-£50,000</td>
<td>1</td>
</tr>
<tr>
<td>Cable Lay Vessel</td>
<td><img src="image3.png" alt="Image" /></td>
<td>£70,000-£110,000</td>
<td>1</td>
</tr>
<tr>
<td>Barge</td>
<td><img src="image4.png" alt="Image" /></td>
<td>£80,000-£180,000</td>
<td>1</td>
</tr>
<tr>
<td>DP Vessel</td>
<td><img src="image5.png" alt="Image" /></td>
<td>£50,000-£200,000</td>
<td>0.6</td>
</tr>
<tr>
<td>Bespoke Vessel</td>
<td><img src="image6.png" alt="Image" /></td>
<td>~£200,000</td>
<td>0.2</td>
</tr>
<tr>
<td>Other</td>
<td><img src="image7.png" alt="Image" /></td>
<td>Vessel dependent – likely within the ranges above</td>
<td>0</td>
</tr>
</tbody>
</table>

Figure 19: Typical floating offshore wind vessel requirements for installation (vessel requirement data from (5))
tension is required to correctly seat the anchor and test the moorings. Anchoring in more challenging conditions is highly site specific and represents a technical risk to each new site. However, floating wind foundations can be installed in hard rocky seabed conditions where fixed offshore wind monopile or jacket structures could not be economically installed.

3.2 Outline Installation Procedure

This is a high-level procedure that varies somewhat for each foundation type, the strategy chosen by the developer, and the availability of vessel and port facilities.

1. Load-out of the floating foundation from the port. Typically, by either flooding the dry dock, using a slipway, or using a heavy lift vessel to transition the foundation to the water.
2. Installing the turbine assembly onto the foundation using onshore cranes (not the case for spar-buoys, see next section for this)
3. At site, the anchors and moorings are pre-installed by an anchor handling vessel and a working class ROV. It is typically required at this stage to test the moorings to 100% load to prove the structural integrity.
4. The electrical cables are preinstalled at the site using a cable laying vessel, prior to the arrival of the foundations.
5. The foundations are towed to site using tugs/barge as required by the specific foundation type. Spar buoys will be towed to a sheltered area to be ballasted and have the turbine installed onto the foundation (using a crane vessel), before final transit to site.
6. Connection of mooring lines to the foundation.
7. Electrical connection to the turbine is made.
8. Ballast added to further stabilise the foundation (if required).
9. Mooring lines tensioned as required.
10. Final commissioning of turbine and foundation systems.

3.3 Spar-buoy

The installation challenges specific to spar-buoy configurations are focused on the large draft of the buoy. This necessitates, in almost all cases, that the foundation is towed horizontally to a sheltered site, ballasted, and then the turbine installed via a specialised heavy lift vessel (assuming that it has not been constructed in a deep-water port with a deep-water tow path). This process not only adds some steps and complexity to the installation but adds time. It should be noted that the process of installing a turbine onto a foundation is not trivial, with ~100-200 ≥M48 bolts needing to be installed and tensioned. Although a significant proportion of the assembly (~70%) happens offshore, the weather windows are still larger than that for fixed offshore wind.
From the sheltered location the assembled turbine and foundation can be towed to site and connected to the pre-laid moorings and electrical cable. The additional processes result in an overall installation time of ~50h (20 to 24h targeted for commercial deployment) and dictate that there is a tighter weather window when compared to other floating foundations. If the buoy can be towed in a ballasted state, then this opens-up the weather window considerably as the structure is very stable.

Of the three main foundation types, the spar buoy has the greatest installation cost on average (5) – driven by the vessel requirements and the sheltered/calm conditions required for turbine assembly. Hywind cite a considerable amount (~30%) of their targeted cost reduction coming from operations and installation (16).

The catenary mooring used by most spar-buoy configurations are more expensive than those used in TLPs, typically due to their length and mass. These moorings allow for ~5 to 6m of lateral movement on site and a tower pitch angle of ~4° in operation\(^1\). These motions are passed through to the dynamic electrical cable, adding additional risk.

### 3.4 Semi-sub

Typically, semi-sub foundations have been the simplest to install and are based upon a large amount of learning form the oil & gas sector. The majority (~60%) of the assembly happens on/near-shore and the reasonably shallow drafts allow for the turbine-foundation assembly to be towed to site using simple tugs, for connection to the pre-laid moorings and the electrical cable. The total installation time is ~60h (again, 20 to 24h targeted for commercial deployment) and can be carried out in up to 2m H\(_s\). The relative simplicity of the installation process makes this the cheapest format of floating foundation to install and therefore very easy to deploy demonstration turbines and pilot arrays as the technology progresses through the various TRL levels.

These foundations typically use catenary mooring systems of similar cost to spar-buoys although present applications have seen a few additional mooring lines (typically 3 to 6). The nature of this foundation and its moorings lead to lateral movement of the turbine of up to 50m (5), which presents a challenge for the export cable.

### 3.5 TLP

The installation challenges for tension leg platforms are different from the other foundation types as they are usually unstable until connected to the mooring system. This lack of buoyant stability can reduce the weather window for the installation of these foundations to below ~1.5m H\(_s\). TLPs also often rely upon a bespoke barge for installation that has features specific

---

\(^1\) Determined using Hywind data shared by ORE Catapult POD
to that foundation type for transport and positioning – however, drafts of these barges and platforms are usually very low.

The use of tensile lines to hold the platform in place, puts a greater requirement on the anchor system and, as such, these are typically more expensive than conventional mooring for other floating foundations. However, the combined mooring system itself tends to be cheaper, leading to a system that is marginally cheaper overall (5). TLPs tend to have only a small amount of offshore assembly work (~35% although this is highly concept dependent), but an installation time of ~65h (~40h targeted for commercial deployment). When this long installation time is coupled with the calm weather requirement, it leads to a relatively high cost of installation somewhere between spar-buoys and semi-sub.

It should be noted that some TLP concepts that use gravity anchors like GICON-SOF are able to do full mooring tension-up prior to leaving port and install everything in one go, by lowering the base to the seabed once on site. This means only the electrical connection needs to be made offshore. On the other hand, no significant deployment of TLP foundations has taken place yet and it would be illuminating to see these concepts put to the test. As stated previously, a barrier to the installation of these devices at scale is the requirement for bespoke barges which do not make sense commercially for small deployments.

The tensile mooring systems only allow for a few metres of excursion and virtually no pitch or roll; this reduces the requirements and fatigue concerns for the dynamic export cable, as well as providing more stable loading on the turbine itself.

3.6 Specific Mooring Installation Challenges

Mooring lines and anchoring systems are defined by factors such as the environmental and seabed conditions, the floating foundation motion and forces, the loading from the turbine (mostly thrust loading) and the materials chosen for the mooring lines.

Typically, mooring anchors – and in the case of catenary moorings, the mooring lines – are pre-installed and left on the seabed for when the foundation arrives on site. Then once the foundation is on site, an ROV will be used to either pick up the individual pre-laid lines or connect the lines to the anchors. Then these lines need to be connected to the foundation – the top connection. To date, top connections have borrowed cumbersome, costly designs from oil & gas, and this has had a significant influence on the initial connection and any disconnection procedures used in through-life maintenance. Moreover, connecting lines one by one adds time to the offshore operations and requires certain sea conditions (<1.5m Hs). It is considered possible to develop a more focused, lower cost solution for floating foundations (17).

It has been noted that in some installations to date the mooring lines have been fitted with temporary buoyancy modules that need to be removed once the turbine is installed. The
removal of these modules again adds time, and can be particularly challenging. There are two key components that make this operation challenging; the first is operating an ROV just below the waterline where it can be significantly influenced by the waves. Secondly, the ROV is cutting free the buoyancy module and care needs to be taken not to damage the mooring line during this operation, hence a limited sea state to enable accurate cutting.

There is also the issue of the potential failure rate of mooring lines. Information from oil and gas shows failure rates above industry target levels, with 22% of these failures due to installation damage or issues (17). Simplifying installation to eliminate these issues would greatly increase the confidence in moored floating wind solutions.

It is worth noting that the applicability of oil & gas mooring systems to floating offshore wind and the different fatigue duty cycles is another area for improvement. However, the focus of this report is on the installation challenges.

### 3.7 Specific Electrical Connection Challenges

The Carbon Trust note that the electrical system integration is often overlooked and a cost effective means of transmitting energy back to shore needs to be determined (5).

Dynamic cables – lazy wave and catenary configurations – were assessed by the Carbon Trust (17) with a focus on the fatigue of these cables being an important factor. For example, based on the operational data, and if the electrical cable is ~20m below the waterline, the operational motion has a typical range of 1.5m to 2m – add to this the motion on the moorings relative to the wind direction and the range of motion is ~7.5m. This motion over a 20+ year lifetime is a significant driver of fatigue design life, in terms of connections and their protection as well as the cable bend restrictors. The anticipated fatigue loading is likely to exceed the capability of current polyurethane designs, so further development is required (17).

Marine growth can dramatically influence the response of the dynamic cable, altering its mass and buoyancy and in turn affecting the distribution of fatigue loads (in a clean, non-fouled state the load ranges are greatest nearest the turbine). Whilst design with due consideration for marine growth is relatively commonplace in marine renewables, it is still an important factor to bear in mind, particularly in warm sites and/or where the cable may be near the surface (warm oxygenated water).

At the end of the dynamic cable there is a connector. This is typically a dry mate connector, examples of which are commercially available up to 72.5kV. However, connection and disconnection will still need to be proven over a 20+ year lifetime, particularly with the influence of marine growth, corrosion, and fatigue loading. There is also the need for the electrical connection to be maintained when a turbine is removed for maintenance (often cited as a major benefit of floating wind) but there is no convergence on a solution for this yet, nor is there a demonstration at sea. Hannon et al. cite the installation and mating of cable
connections to floating foundations as a core challenge facing the development of floating offshore wind (6).

Regarding the export voltage, connectors and cables exist in the 22kV-66kV range; however, they are neither highly established nor widely used technologies. Furthermore, with sites being further and further offshore with larger turbines (and therefore larger array spacing) there is a need for HV cables (130-250kV) to minimise losses. By means of quantifying the impact of this, using only a 10kV system results in 7% electrical losses for a typical site. Development of a HV dynamic cable is challenging due to the design requirements for fatigue, sealing, and cable sizes.
4 Improvements & Cost Reduction

The major benefits of floating offshore wind are the ability to access deep water sites and the potential for more cost-effective foundation installation and O&M activities. To help realise these benefits for the industry the offshore operations are key to success. To quote the Carbon Trust’s Joint Industry Project (17) “There is a need to develop cost effective methods and technologies for ‘plug-and-play’ functionality of floating offshore wind turbines”.

Wave Energy Scotland is funding the development of quick mechanical and electrical connection systems for wave energy converters\(^2\). Within this competitive funding environment applicability to other industries is being encouraged, so these projects should be monitored for potential technology crossover. However, this is just one potential solution to a myriad of challenges facing the installation and maintenance operations of commercial floating offshore wind arrays.

4.1 LCOE Context

\[
LCOE = \frac{\text{CAPEX} + \sum_{t=1}^{n} \frac{\text{OPEX}}{(1+r)^t}}{\sum_{t=1}^{n} \frac{\text{Yield}}{(1+r)^t}}
\]  
(Equation 1)

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>LCOE</td>
<td>Levelised cost of energy (£/MWh)</td>
</tr>
<tr>
<td>CAPEX</td>
<td>Capital cost of generation equipment (£)</td>
</tr>
<tr>
<td>OPEX</td>
<td>Operational cost of generation per year (£)</td>
</tr>
<tr>
<td>Yield</td>
<td>Annual energy yield (MWh)</td>
</tr>
<tr>
<td>r</td>
<td>Discount rate</td>
</tr>
<tr>
<td>n</td>
<td>System lifetime</td>
</tr>
</tbody>
</table>

Table 1: Definition of terms in Equation 1

With respect to Equation 1, improvements in mooring and electrical connections result in an enhanced ability to install foundations and will benefit both CAPEX and OPEX. CAPEX will be lowered by reducing initial one-off installation costs (13% of CAPEX). Whilst OPEX reductions will be realised through the ability to efficiently remove, return to port and reinstall a turbine that requires any major maintenance activity through its lifetime. The potential for repeated installation operations contributing to OPEX makes the relative contribution to OPEX greater than for CAPEX.

\[^2\] For more information, see Wave Energy Scotland’s website
In terms of commercial projects, all foundation types are targeting almost identical CAPEX/MW of ~£2.6m to £2.7m. To date prototypes and pre-commercial arrays have been in the region of £4m to £5.5m, so there is some margin for improvement. It can be seen in Figure 20 that installation accounts for ~13% CAPEX costs (~£0.6m/MW) at present. In order to achieve a LCOE competitive with fixed wind, this will need to reduce to approximately half this value. Of course, there will need to be improvements in other areas, but it is estimated that 10% of the commercial cost reduction will be realised through improved installation methods (5).

**Figure 20: CAPEX composition based on average of three major foundation types (reproduced from (5))**
Referring to the topics covered already, the most important cost drivers for installation are time and vessel requirements. Reviewing the expected costs of the installation of the different typologies (5) shows that semi-submersibles are expected to offer the most cost competitive installation solution by c. £1m CAPEX (Figure 21). This is not because they claim the shortest installation time, but because they make use of simple vessels throughout the installation process.

This doesn't mean that spar-buoys and TLPs are unfeasible concepts; they make their cost savings elsewhere (lower grade steel and simple construction for spar-buoys and reduced steel weight and lower mooring costs for TLPs) to come out with very similar LCOE values. What this does highlight is the different installation challenges with each foundation type. Some solutions that will benefit semi-submersible foundations, will not have the same value to spar-buoys, due to the different installation challenges, for example.

Breaking down the pie chart in Figure 20 a little further and the installation cost can be viewed as being comprised of labour and vessel costs broken down as in Figure 22 the size of the pie (or the size of the segment in the overall CAPEX pie chart) is determined by the time taken for the installation operation (i.e. greater vessel and labour costs due to the increased duration of operations).
Reductions in installation CAPEX of the order of £0.3m/MW are being targeted by the industry. This is going to be achieved through simpler and faster installation methods that will reduce the cost contributors (vessels, labour and duration) shown in Figure 22. Improvements of this magnitude will only be achieved by opening up weather windows, using simpler, cheaper vessels and reducing installation time. No one factor alone can achieve these ambitious goals.

Modelling the current state of the art\(^3\) puts the LCOE of floating offshore wind at around £144/MWh on average (using Equation 1), however this is still highly site dependent. It is worth noting that a significant proportion of overall expense is OPEX (\(~25\%)\). Similar reductions of \(~50\%\) are targeted in OPEX when moving from prototypes to commercial arrays. A significant proportion of the OPEX savings, particularly when compared with fixed foundations, is the potential for return to port maintenance activities (gearbox change etc.).

---

\(^3\) Current state of the art defined as a pilot array of 3x 8.4MW turbine, average wind speed of 10.75m/s, Weibull distribution, 25-30km offshore in 100m water depth. Wave and weather data taken from a north Scotland site.
4.2 Electrical Connection

Current electrical installations are completed by personnel on the turbine itself. The cable is laid beforehand and then winched up into the foundation, where it is clamped, and the electrical connection completed by personnel on board. This requirement for personnel on board not only requires skilled electrically qualified personnel, but also a crew transfer vessel and access to the floating foundation. Access to floating foundations is not that well understood at present and the Carbon Trust has launched a study into the area in recent months. If this requirement could be completely removed from the installation process, not only would the installation be safer, the weather window would be greater and the cost of installation lower.

With almost all floating foundations the ability to tow the turbine back to port for major maintenance is cited as a major benefit. However, to date no-one has proven this concept and the implementation on pilot farms presents a challenge. Since the turbines in an array are typically connected together in a chain, removal of one turbine would lead to the entire farm being down. The alternatives are lifting the cables and connecting a temporary piece of cable to maintain the continuous chain or installing temporary equipment to provide electrical continuity, or allowing for the possibility of turbine retrieval in the cable topology. The act of breaking and making the electrical connection, as well as installing temporary equipment to allow the array to keep running is, once again, a costly process requiring specific vessels, personnel and limited by access weather windows.

For a typical north Scotland site, if the sea state restricting operations could be raised from ~1.5m Hs to ~2.5m Hs then the weather window availability increases by ~55%. This, in turn, means that operations can be completed more frequently leading to less downtime and increased availability across the array improving yield and ultimately improving the LCOE.

The cost of any hardware to maintain electrical continuity should not be overlooked and will need to scale with the turbine sizes and export voltages over coming years. This equipment will have a cost associated with it and therefore, if by utilising this equipment, the window for operations can be expanded, the cost of the equipment can be offset.

4.3 Mooring Systems

The installation of the mooring system anchors will likely be the most expensive part of the mooring install; however, this is dependent on the site geotechnics and cannot be significantly reduced across all seabed conditions with a single solution. However, there is also a significant amount of time (and therefore cost) attributed to connecting up to the mooring arrangement once a floating offshore wind system is on site. If this connection time could be reduced the costs associated with vessels and labour (the size of the pie in Figure 22) could be reduced.
Currently, (as mentioned earlier) for spar-buoys and semi-submersibles, the moorings are pre-installed and laid on the seabed. Once the foundation arrives on site these are lifted from the seabed – either by ROV, or ROV fitted leader line – for connection to the foundation. The time, equipment and skill required for this operation highlights an area that could be simplified to help reduce costs.

Again, referring to a North Scotland offshore site, the mooring line hook-up faces challenges in terms of operational time⁴. A shorter operation time offers an increased weather window in line with that mentioned for electrical connections above. In the case of mooring lines there is also the vessel requirement for something akin to anchor handlers and ROVs (and skilled pilots). If these factors could be reduced the installation costs would start to tumble. For example, if the requirement for any anchor handlers or DP vessels was removed, and the operation time halved, savings in vessel costs of ~40% could be achieved, which amounts to a LCOE reduction of ~4%, which is significant.

Improvements to installation methods do not solely arise through cost reduction, safety of operations is another area where aspects could be improved. Operations that do not involve personnel accessing floating platforms in an offshore environment are intrinsically safer and lower risk than those that do. Personnel safety in the operation and maintenance of floating offshore wind farms is a top priority. It should also be recognised that reducing offshore risks makes an offshore wind farm a more attractive investment prospect, thus helping to inject finance into the developing industry.

Furthermore, increasing the service intervals is something turbine manufacturers are looking into. This is something that has been looked at in detail for tidal turbines, where access to the turbines generally involves turbine retrieval, which is generally a very expensive process⁵. Generally speaking, when increasing the service interval, an enhanced condition monitoring system needs to be in place, in order to prevent malfunction, monitor the condition remotely and detect failures before it is too late. Adding this complexity into the system needs careful consideration and usually a full FMECA to design a system that is the most cost effective.

### 4.4 Other Limitations and Risks

Another significant limitation affecting installation and maintenance activities is the ability to tow these foundations to and from site. The large structural fabrications involved in floating wind platforms are inherently massive and have significant drag making towing difficult. Additional complexity comes from lively semi-sub foundations with their distributed buoyancy and the inherently unstable tension leg platforms. At present, towing operations have been

---

⁴ Mooring connection time for Hywind Scotland ranged between 48 and 24 hours

⁵ With the exception of Orbital 2’s surface based tidal turbine, which can be accessed without turbine retrieval.
limited to ~1m Hs. For future commercial sites this level of restriction could be harmful to the deployment of projects and cause a blockage in the supply chain with foundations in port awaiting deployment.

The towing limitation has further ramifications for any return to port maintenance strategies; perhaps the reason why we have not seen this concept executed in practice as yet. If the wait time to tow a turbine back to port for significant maintenance is of the order of months (as in our example site in Scotland) this is seriously damaging to LCOE for a farm of turbines.

For example, if we look at our sample site with an operations (mooring and electrical connection/disconnection) limit of 1.5m Hs and a towing limit of 1m Hs then the average wait time for a weather window long enough to disconnect a turbine and tow 25km (at an assumed speed of 3 knots (18)) is in excess of 100 days. Understandably there is significant seasonal variation in this value with <10 days possible during the summer and some significantly long periods over winter months. The loss of energy generation potential from those 100+ days is approaching 11GWh and thus has a significant impact upon the lifetime LCOE that could be as much as £10/MWh.

Another limitation that exists for the operation and maintenance activities for floating wind is the safe transfer of equipment to the turbine/foundation, such as transformers or generators, using cranes from either a fixed platform (such as a jack-up) or two moving platforms (more commonly seen in deeper water). The risk here is considerable as there are many factors that affect the safety of the workers, such as relative motion of vessel/platform. This can result in uncontrolled dynamic effects, and the user unable to lift off or put down the equipment safely. Furthermore, the use of cranes (on the sparsely available heavy lift vessels with sufficient hook height) is impractical as a crane hook will be swinging relative to the vessel and the foundation further complicating lifts offshore.

If we were to compare a wind turbine to a tidal turbine once again, one area where a tidal turbine is possibly more advanced is the number of redundancies that are included in the turbine. On a tidal turbine, generally speaking, single point failures (SPF) are kept to a minimum, and there are usually back-up systems in place to enable maximum availability and minimum downtime after an initial fault. Although continuous operation may not be possible, in most cases secondary components would be activated to replace the faulty component, and the faulty component could then be replaced during routine service maintenance. This ideology could easily be adopted for wind turbine manufacturers.

Present demonstration sites in the UK have consisted of a turbine that has been initially designed for operation on a fixed foundation with refinements made to the control system. When a ~120m tall tower and nacelle is now placed on a floating unit at sea, it will see additional loading that will be slightly different to that of a fixed foundation – due to the motion demonstrated in Figure 17. One risk is therefore that the fatigue life is not fully
accounted for as invariably there will be sites with a spectrum of different wave height, periods and direction compared to the prevailing wind direction. When designing a wind turbine, there is a very fine balance between weight reduction and strength. Too much weight reduction may cause strength/fatigue cracking issues, but excessive mass will cause other challenges such as lifting restrictions and pricing yourself out of the market. Here lies another opportunity which would assist certification bodies, and technology developers, which relates to structural health monitoring. Every turbine could feature instrumentation to monitor live fatigue damage so that the condition is known, inspections can be planned and failures foreseen.

4.5 Decommissioning Strategy & Sustainability

Often overlooked, the type of foundation has a considerable effect on the decommissioning cost. A semi-submersible would be towed to shore and cut up either in shallow water or taken completely out of the water depending on the location and available facilities. A tension leg platform has to be released from the seabed in a controlled manner and towed back in a similar way. However, a spar-buoy would need to be partly decommissioned in deep water before getting towed to shore. This additional step will increase the cost of decommissioning. With all cases the moorings and anchoring systems would also need to be retrieved.

Decommissioning is an area Blackfish have direct experience of in the FoDTEC project where a tidal turbine foundation was removed after nearly a decade subsea – see Figure 23. A factor to consider in all the decommissioning activities will be the level of biofouling on the foundation and its connections. This will add considerable weight to the structure and may cause issues in the disconnection of mooring lines or electrical cables.
Since no farm has been decommissioned yet at a large scale the full cost is not fully understood; estimates range from zero cost (operational cost balanced out by the scrap steel value) (12) to £80k/MW (5). ORE Catapult estimate decommissioning cost for fixed wind at about £45k/MW (20). Given that floating wind has the potential to use less material and does not require removal of large structures embedded in the seabed, we would expect the decommissioning cost to be slightly below this. Blackfish has undertaken its own estimates based on our experience and we expect this range be between £20k/MW and £40k/MW. This does not account for the reduction in cost due to technology improvements. The range presented is largely due to the difference in design fundamentals between the three main foundation types and the variability in future steel prices.

The emphasis on sustainability is becoming increasingly important. The effect of waste such as plastics in the ocean is being seen more and more in the news these days, as it has been proven to cause such a serious issue for marine ecosystems (21). Therefore, if a structure is in the water for a period of 25 years, it has to be completely decommissioned safely and restore the site to its previous condition. Steel is relatively easy to recycle as it can be melted and used again, and concrete – another common material increasingly used for foundation designs – is

---

6 Assuming 1000t – 1500t of scrap steel at a conservative nett price of £50/t to cover transport. Added costs of tugs for towing and an anchor handler for operations and mooring retrieval, plus labour to begin to break down and clean the foundation.
usually recycled as aggregate and can be used for sub-base and fill (22) although carrying this out on a used reinforced concrete FOW foundation has not been done before.

Needless to say, having a smaller initial mass has the best chance of reducing the total lifecycle cost.
5 Recommendations

Looking at the LCOE equation (Equation 1) it is fundamentally built of three components: CAPEX, OPEX and Yield. These neatly fit on to a tri-floater foundation graphic in Figure 24 and illustrate the challenges facing floating offshore wind (note that install-ability is included in OPEX owing to the potential for return to port maintenance). The focus of this report has been largely on the OPEX sector of this triple challenge as that is where we see the expertise of Blackfish having the biggest impact upon the sector as it develops. Obviously all the factors in Figure 24 need to be addressed to make floating wind a commercial success, yet to date we feel that the OPEX sector has been largely neglected in order to get early devices in the water at as low a cost as possible. Prototype devices are essential to raise awareness of the industry and to stimulate interest and growth, and in most cases the turbine is essentially the same for fixed based turbine (albeit with some control modifications) but inevitably there will be a “second phase” of devices that take a more holistic approach and are thus better equipped to make an economic success of floating offshore wind.

From this review it is apparent that floating offshore wind has as significant role to play in the continued implementation of renewable energy technologies as nations strive to meet 2030 and 2050 emissions targets. However, we have highlighted several installation and maintenance challenges that need to be overcome in order to see effective commercial, global integration of floating offshore wind. Undoubtedly there are advances to be made in other
aspects of the turbine technology and performance, but this is generally done in-house by the (now small number of) large manufacturers.

In terms of the installation challenges we believe that some innovation is required in this area and the thought process should not be constrained by current technologies and means of doing things for fixed offshore wind. In 10-20 years’ time the infrastructure for installing and maintaining floating offshore wind turbines and foundations could be radically different to today, as we have seen with the development of technology suited to the installation of fixed offshore wind foundations. This open mindset should be focused on overcoming the installation and maintenance challenges for implementation of floating wind both on a pilot project and commercial scale.

Studies and future developments should focus on the following:

- Expanding the weather window in which these foundations can be towed/transported to and from site
- Making mooring and electrical connection operations more weather tolerant
- Simplification of installation methodology to reduce time spent offshore
- Reduce risks to personnel working offshore during installation and maintenance
- Technologies to allow return to port maintenance to become a feasible maintenance strategy. This would encapsulate:
  - Maintaining electrical continuity throughout an array
  - Efficiency of mooring and electrical connection and disconnection
  - Ease of towing
- In addition to facilitating return to port maintenance, technologies should be developed to allow for a greater range of maintenance activities at sea, including heavy lift and installation of key components, blade repair and replacement and safe crew transfer for maintenance, whilst reducing the use of expensive vessels.
- Integrated wind turbine and floating foundation solution. This should simplify the certification process and improve investor confidence.
- Advanced structural health monitoring to evaluate fatigue damage.

Blackfish have developed a number of ideas that aid operations and maintenance activities for fixed offshore wind, and we are in the process of developing specific tooling and methodologies to take floating offshore wind to the next level. Throughout this process we have been aware of the rapid development seen in fixed offshore wind maintenance vessels in a short space of time. A comparable pace of development and implementation could be achieved in floating offshore wind as commercialisation and more widespread installation occurs.
References


Appendix A – TRL Level Definition

TRL levels seen in this report are defined as in the table below (17):

<table>
<thead>
<tr>
<th>TRL Level</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Initial concept</td>
</tr>
<tr>
<td>2</td>
<td>Proof of concept</td>
</tr>
<tr>
<td>3</td>
<td>Numerical Modelling</td>
</tr>
<tr>
<td>4</td>
<td>Tank Testing</td>
</tr>
<tr>
<td>5</td>
<td>Scale Testing (&lt;1MW)</td>
</tr>
<tr>
<td>6</td>
<td>1-5MW Demonstration</td>
</tr>
<tr>
<td>7</td>
<td>&gt;5MW Demonstration</td>
</tr>
<tr>
<td>8</td>
<td>Pilot Array (20-50MW)</td>
</tr>
<tr>
<td>9</td>
<td>Commercial Project (&gt;50MW)</td>
</tr>
</tbody>
</table>
Appendix B – About Blackfish

At Blackfish we provide innovative engineering designs for a sustainable future; offering bespoke solutions for complex problems. We are a renewable energy engineering consultancy serving marine energy and wind clients to bring our specific engineering knowledge and expertise to this rapidly developing sector. We consider ourselves experts in our field, covering many aspects of renewable energy development with offices in England, Scotland and Wales.

- Rotor dynamics
- Blade profile design
- Systems engineering
- Structural design
- Structural loads analysis
- Testing and validation
- Manufacturing
- Commissioning
- Test rig design
- Sealing technologies
- Biofouling and corrosion
- Composites
- Pitch systems
- Drivetrain design
- Subsea clamping
- Electrical connections
- Instrumentation
- Hydraulic systems

All of our team members have a background working in large engineering OEMs (Rolls-Royce, Alstom, GE, Siemens, Vestas), which allows us to couple the flexibility of a SME with extensive, large OEM experience. This results in a high-quality, professional approach from a personable engineering team.

With our headquarters in Bristol, UK, our engineering team is fully equipped to work remotely using the latest web-based collaboration software and cloud-based servers. Our early adoption of the remote working technology and culture has enabled us to support remote projects in throughout the UK, Europe, and the Americas.

Blackfish Engineering Design Limited was established in 2016 by a team of engineers who had worked together at Tidal Generation Limited (TGL). The Blackfish senior engineering team includes seven engineers formerly of TGL, bringing a wealth of tidal stream turbine knowledge and expertise to our commercial offering.
Whilst at TGL, our engineers were instrumental in successfully designing, manufacturing, commissioning, and deploying two tidal stream turbines. A half-scale 500kW prototype was developed first, followed by a pre-production 1MW device. Both turbines were successfully tested at the world-leading European Marine Energy Centre in Orkney, UK, supplying over 1.2
GWh of electricity to the grid. Following the successful deployment of the 1MW device, TGL was acquired by Alstom and the team set about designing a 1.4MW production turbine.

Members of Blackfish were involved in the design of all three turbines as well as the assembly and testing of both prototypes. Between them they covered all aspects of mechanical design.

- Blades
- Hub
- Pitch systems
- Main shaft
- Main bearings
- Shaft sealing
- Shaft brakes
- Yaw system
- PTO
- Hydraulics
- Instrumentation
- Structural nacelle

In addition, Blackfish engineers were also involved in blade and turbine performance modelling and loads assessment as well as overseeing assembly, commissioning, deployed operations, and maintenance. Deployment methods with the 1MW turbine were streamlined and reduced to 40mins from ROV on deck to ROV retrieval following a fully installed turbine.
In 2016 Alstom Power was acquired by GE, and in the restructuring that followed the tidal business was disbanded. Recognising the value in their experience and knowledge from a combined 25+ years of marine renewables development, Blackfish Engineering Design Limited was formed by its four founding directors in the summer of 2016.

Four years later we are proud to be one of the foremost marine renewable consultancies in the business, having worked with many of the leading wind, tidal and wave developers from around the world.

For more information on our team, projects and services see blackfishengineering.com