D4.1 Identification of floating-wind-specific O&M requirements and monitoring technologies

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1 ABBREVIATIONS

Abbreviation	Description
AUV	Autonomous Underwater Vehicle
ADCP	Acoustic Doppler Current Profilers
CBM	Condition Based Maintenance
CM	Condition Monitoring
CTV	Crew Transfer Vessel
DCI	Decompression Illness
FOWF	Floating Offshore Wind Farm
FOWT	Floating Offshore Wind Turbine
HSE	Health, Safety and Environment
JUV	Jack-Up Vessel
LCE	Large Component Exchange
LWC	Light weight crane
O&M	Operations and Maintenance
OSV	Offshore Service (or Support) Vessel
OSS	Offshore Substation
PPE	Personal Protective Equipment
RNA	Rotor-Nacelle-Assembly
ROV	Remotely Operated Vehicle
SHM	Structural Health Monitoring
SOV	Service Operation Vessel
SRB	Spherical Roller Bearing
TBM	Time Based Maintenance
TDO	Two-row Double-Outer Race
USV	Unmanned Surface Vessel
W2W	Walk-to-Work
WTG	Wind Turbine Generator

2 EXECUTIVE SUMMARY

This document identifies floating-wind-specific requirements as well as state-of-the-art techniques and monitoring technologies in order to enable economic O&M operations for future commercial floating wind farms. The deliverable concludes with recommendations for advanced O&M strategies which will feed into the simulations foreseen in deliverable D4.2.

The floating wind requirements have primarily been identified through interviews with relevant stakeholders from the offshore industry and an internal workshop with the COREWIND project partners. The shared experiences and trends from the interviews were combined with a thorough literature research and compiled into this comprehensive report. The chapters treat the principal topics in floating offshore wind O&M. The report starts with a classification of maintenance activities. Hereby, the benefits of applying condition-based maintenance are pointed out and structural health monitoring, as well as condition monitoring are defined as the base for an economical strategy. It follows a summary of the characteristics of FOWTs and the critical components to inspect such as the floating substructure, the station keeping system as well as the dynamic cable. For each component regulatory requirements regarding maintenance are reviewed, commonly occurring faults are examined and typical inspection and monitoring methods are presented. The following chapter treats remotely operating vehicle (ROV) technologies and provides a classification of the different existing ROV types and their fields of application. It further addresses their advantages and limitations during maintenance operations. The chapter concludes with recommendations for an Inspection Protocol using ROVs and gives first-hand information gained in an interview with Equinor about ROVs used in the Hywind Park.

The report then addresses the topic of accessibility and the challenge arising from the relative motions between the crew-carrying vessel or helicopter and the floater. Three options are discussed including the Bow Transfer, Walk-to-Work-Systems as well as the access via helicopter. To conclude this chapter and to gain valuable input for D4.2 a preliminary accessibility study has been conducted in order to gain insight in how the access is affected in the three reference wind farm sites form the COREWIND project. As expected, the harsh environment in West of Barra allows the smallest access probability of all three sites. The report then turns to the subject of human comfort on the assets. The effect of low frequency motions of FOWTs on motion sickness and its influence on the workability is explained. Existing standards and guidelines are presented and evaluated in their applicability to floating wind. Vibration threshold values are provided for different types of work. The chapter closes with a pre-study of the frequency response of the COREWIND floaters, showing peak responses of the nacelle acceleration in the relevant frequency range for motion sickness.

In a last chapter the deliverable addresses the large component exchange on FOWTs. The two options to perform the exchange offshore or to tow the floater into harbor are discussed. The state-of-the-art and current developments of both alternatives are presented. The report then identifies the requirements for the floater disconnection at-site and the towing process. For the option of conducting a large component exchange offshore the major challenge to overcome are the relative motions during the hoisting and spare part installation due to the open water conditions. To overcome those challenges new technologies and procedures currently under development are presented. It becomes apparent that no clear trend can yet be identified among the possible solutions. It depends on the market development and the investments that will be made for future commercial wind farms. The report concludes with the main recommendations to O&M strategies which could be identified for the different topics.

3   INTRODUCTION

Operational expenditures (OPEX) account for about one third of the total levelized cost of energy (LCOE) of an offshore wind farm. In the annual wind energy cost review by NREL from 2018 the OPEX share on the LCOE was calculated to 31.3 % for floating and to 34.0 % for fixed-bottom offshore wind, [1]. Workpackage 4 of the COREWIND project intends to investigate, in the prospect of future floating offshore wind parks, the influence of different O&M strategies and new requirements on the OPEX. The O&M phase being a major cost driver motivates the assessment of new strategic opportunities and developments to reduce the O&M costs.

80% of Europe's wind resources is located in deeper water, not suitable for fixed bottom wind turbines, [2]. Floating wind turbines open the possibility to exploit these regions and to drastically increasing the areas on our planet suitable for generating renewable clean wind energy. Larger areas with much better wind conditions can be used which do not compete with aviation and shipping lanes. Expertise with floating structures developed in the deep-sea oil and gas sector can be applied with similar technologies to floating wind turbines.

Moving further offshore also brings along rougher sea states and stronger winds which pose a challenge to the structure design and wind farm logistics. The aim of the operation phase is a high availability of the plants to ensure a good electricity production. To achieve this, high component reliability is essential, besides which the maintenance strategy and logistics play the main role.

This deliverable intends to provide a comprehensive overview of the state-of-the-art inspection and maintenance strategies and monitoring techniques for floating offshore wind farms. In the course of this deliverable one workshop with all project partners as well as ten interviews with relevant stakeholders throughout the industry have been performed. Interviews have been conducted with the following stakeholders:

- The O&M manager of the Hywind floating wind farm from **EQUINOR**,
- The Inter-Array Cable fabricator for offshore wind, wave and tidal energy projects, **JDR**,
- The mooring line fabricator **Bridon-Bekaert**,
- The motion compensated gangway supplier **Ampelmann**,
- A helicopter pilot from **Windpark Heliflight Consulting GmbH**,
- The marine contractor **HEEREMA** operating a fleet of installation vessels for the offshore industry, commanding the entire supply chain of offshore construction, from design to completion,
- The marine contractor **DEME** operating a fleet of vessels for offshore wind farm development, usually acting as EPCI contractor in offshore wind farm projects,
- **Principle Power**, the innovative technology and services provider for the deep-water wind energy market and designer of the WindFloat floating wind turbine foundation,
- The self-hoisting crane supplier **Liftra**, developing, producing, delivering and operating customized solutions for special lifting and transport tasks in the wind industry,
- and an offshore wind turbine original equipment manufacturer, offering offshore wind turbines, components, and spare parts, as well as providing repair and maintenance services.

The experience and opinion of the interviewed experts were incorporated into this report. Their assessments of the new challenges that will arise with commercial floating wind farms, as well as current trends and developments they shared, have become part of this report. Due to the wide range of stakeholders it was possible to reflect a comprehensive picture of the current state of the industry and to make recommendations for advanced O&M strategies.

4 MAINTENANCE CLASSIFICATION

The frequency of planned inspections considers several aspects, as for example, the requirements of the authority and the operator, the probability and consequences of failure, and the results of previous inspections as well as changes in the operational conditions. Hence, critical sections of the FOWT system that are prone to damage or that undergo major changes in their service lives should be at least inspected at adequate periods of time [3].

Maintenance can be distinguished into three different types which each differ from the trigger of the maintenance work. In following figure, the different types and their classification are illustrated while their effects on the condition of the object to be inspected can be seen.
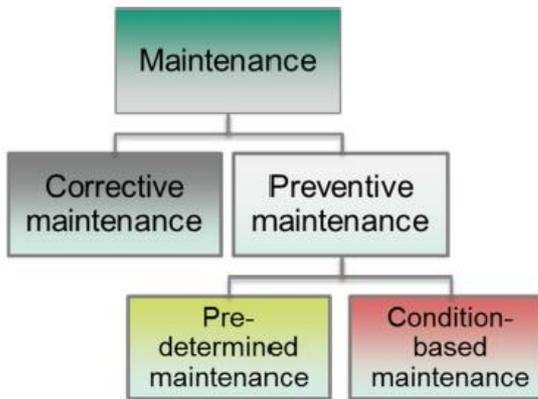

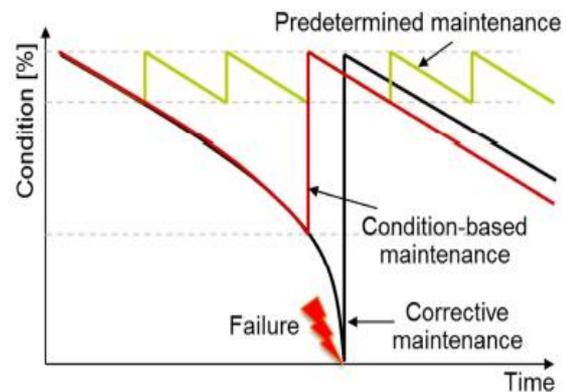Figure 1: Classification and types of Maintenance, [source: [4]].

Figure 2: Effects of maintenance types on inspected object`s condition, [source: [4]].

4.1 Corrective Maintenance

Corrective Maintenance is a non-planned repair or replacement work after failure has already occurred. This kind of maintenance is especially expensive because locating the fault, organizing the external survey, getting access to the required equipment and personal and undertaking the actual repair work must take place as soon as possible and on a spontaneous basis [5], [6]. Related downtimes depend strongly on the prevailing weather conditions.

4.2 Predetermined Maintenance

Also known as "Time Based Maintenance" (TBM), predetermined maintenance performs preventive maintenance based on a specified time schedule. This kind of maintenance is often the basis and is carried out as offshore surveys. As the observed condition is steady and no significant changes over several inspections can be seen the period between inspections can be increased. In the case of condition worsening the TBM may result in the next maintenance type [5].

4.3 Condition Based Maintenance

The Condition Based Maintenance (CBM) is performed upon the condition of the FOWT and not with a fixed time interval. This allows pre-emptive repairs to minimize lost generations and allows the inspector to take advantage of predictable future surveys. Due to the larger distances from shore which floating offshore wind farms (FOWF) make accessible since they are easier to install in deep waters, travel time will increase significantly. Hence, a high-quality Operations & Maintenance plan and a decreasing number of visits is important in order to work economically [7]. The challenge here is to predict the remaining life time of the

system concerned and to follow the evolution of the FOWT system and to plan appropriate maintenance activities [5].

Good starting points are the observations during TBM activities but especially important in order to conduct condition-based maintenance is the ability to monitor the status of the system of interest.

4.4 Structural Health Monitoring, Condition Monitoring and Population Monitoring

Structural Health Monitoring (SHM) and Condition Monitoring (CM) have significantly increased their relevance for offshore wind turbines in the last years because of their significance for a predictive maintenance strategy. Further, a third monitoring type, known as population or fleet monitoring (PM) defines the comparative monitoring of a large number of assets. Multiple definitions have arisen in the literature, but commonly accepted are:

- SHM, defined as the process of implementing a damage identification strategy for aerospace, civil, and mechanical engineering infrastructure, [8]. It serves as remote diagnosis of (civil) infrastructure by evaluating recorded sensor signals.
- CM, as the procedure of monitoring the state of different parameters in electrical and rotating machinery (vibration, temperature, noise, etc.) in order to identify discrepancies between the actual and the nominal state and to identify changes which indicate a development of faults and inefficiencies.
- PM, as the procedure to monitor the asset in comparison to the other wind turbines in the wind farm. Purpose is to maintain the nominal condition of the population (wind farm) and get information about deviations from this state by comparing the individual assets, [9].

In practice the terms SHM and CM are often used synonymously causing confusion and misunderstanding. The German Standards ISO 17359:2018 [10] and ISO 13372:2012 [11] treat SHM as subset of CM, whereas no international SHM rule exists yet. The paper [9] published by Wölfel Engineering makes a good contribution to clarifying the terms, their field of application, and explaining the similarities and differences. Both terms are defined hereafter, but in summary the difference can be pointed out as SHM being implicated with the overall load-bearing structure of the wind turbine asset, while CM is concerned with the machinery parts and mainly moving components such as gears and bearings.

SHM assesses the integrity of in-service structures through a continuous monitoring in real-time. Making suitable decisions and recommendations is done by comparing the measurements at the same location at different predefined moments in time on the structure while it is in operating condition. Features commonly considered essential for SHM are [12]:

- Real-time monitoring
- Operating structures
- Use of an array of network of sensors
- Collection of data changes in the condition of a structure over time
- Data communication over a network
- Use of data processing algorithms
- Residual life prediction

Some literature considers SHM as a way to estimate the state of the structure avoiding destructive testing, even though this consideration falls short because SHM includes sensing, communication, post-processing, and computational resources. In addition, this continuous monitoring allows to detect damage trigger by accidental events, environmental effects, aging or random phenomena. The state of the materials and the whole structure is under operation conditions whenever measurements remain in the domain specified in the design. Currently

sensors not only are considered from the beginning of the design, but also the sensoring system is incorporated during the manufacturing process. Another relevant advantage provided by SHM is the chance to include a communication system able to collect and store the data. This database allows to have the historical information throughout the life span of the structure enabling to estimate residual life and fatigue cycles as well as preventive maintenance actions avoiding catastrophic failures.

Regarding economic aspects, SHM is reducing the life-cycle cost in civil, aerospace and energy structures flattening maintenance cost throughout the whole service life. This process of monitoring, computation, signal processing, communication and non-destructive evaluation can bring further cost reductions through:

- Predictive and preventive maintenance strategies allowing to schedule inspections and maintenance actions.
- Increased safety, reliability and durability.
- Design improvements thanks to post-processing of the data saving materials (weight and thickness) as well as manufacturing time (shape and replicability).
- Minimizing downtimes and dismounting parts without defects/damages.

On the other hand, CM approaches monitoring of mobile pieces. In fact, it is commonly used in rotational equipment to detect degradation, changes in the operation conditions, vibrations and/or failures. This is a key technique for predictive maintenance since the comparison of current and nominal values allows to detect early failure developments.

Main CM techniques have been listed according to SemioticLabs' "The condition monitoring comparison guide" [13]:

- Vibration analysis and diagnostics: vibration analysis is generally considered the first technology that could monitor machine health to provide advance warning of failure. Sensors are installed directly on the component to be monitored, and can warn in case of upcoming failure if they detect vibration patterns that fall outside the range exhibited by a normally functioning piece of equipment
- Lubricant analysis: this technique uses spectrograph to detect individual chemical elements such as iron and copper
- Infrared thermography: infrared imagers map the heat emitted by an object; changes from the usual pattern can signal a developing problem
- Acoustic emission: sensors placed on the asset detect transient elastic waves generated by the processes associated with wear and tear, such as friction, crushing and cracking. Though these processes may produce audible sounds, the acoustic emission method usually measures frequencies above the range of normal human hearing (a.k.a. ultrasonic)
- Motor condition monitoring and motor current signature analysis (MCSA): this technique is based on the observation that the current drawn by a motor contains information about the state of the machine the motor is driving. Sensors are placed at a point between the power supply and the motor, rather than on the asset being monitored. MCSA + voltage adds voltage measurements to the basic technique, which enhances the system's sensitivity (by enabling it to correctly identify power-supply fluctuations) and makes it possible to analyze energy consumption and process efficiency in addition to asset health

CM has been standardized by ISO and ASTM. Based on ISO17359 [10], CM can be included in different degrees according criticality of machines under monitoring taking into account the machine`s purpose, redundancy, cost of repair, downtime impact, Health, Safety and Environment (HSE) issues, etc.. The three categories defined in ISO are enumerated in the order of their criticality: critical machinery, essential machinery and general purpose or balance of plant machines.

Table 1: CM criticality categories according to ISO17359, [source: [10]].

Type of machine/equipment	In case of failure	Requirements	Measurements
Critical	The process cannot continue working	Fully online Performance data Prediction and diagnosis of failures Historical data	Loads, pressures, temperatures, casing vibration and displacement, shaft axial and radial displacement, speed, lubricant conditions and differential expansion.
Essential	The process continues	Redundancy Alternative plans	
General / Balance of plant	Process continues without restrictions	Periodical monitoring Handheld data collector	

These monitoring methods employ nominal or previous measurements to foresee failure modes, i.e., comparing the real conditions of machinery, structures or equipment allowing to establish an appropriate O&M strategy. Even though sensors are a key part of CM and SHM, since they provide electrical signals and data acquisition a storage system is required to control and monitor the conditions. Moreover, communication systems should guarantee the proper connection between the different components. The last stage computes the signals and offers inputs to O&M specialists. Most commonly used monitoring sensors are listed in Table 2:

Table 2: Monitoring methods.

Monitoring	Techniques
Lubricant	Dielectric constant Optical characteristics Magnetics fields X-ray emissions
Vibration	Piezoelectric accelerometers (frequency and amplitude)
Acoustic	Microphones
Motor condition signature analysis	Model-based voltage and current systems (MBVI): shunt (AC current), voltage sensors and induced current sensors
Thermography	Thermal cameras
Thickness, shape and degradation	Ultrasound sensor

5   INSPECTION AND MONITORING

The advancing floating offshore wind technology has already established itself as a sustainable way of generating green energy in the future. With the deployment of first prototypes and commercially working wind farms with FOWT the question of how to maintain these systems is rising up fast. The maintenance strategies play an important role for the economic operation of future floating wind farms. Major issue is the trade-off between the production losses when a system fails and the costs of the offshore maintenance action as well as the basis on which the maintenance is conducted (see chapter 4). If maintenance e.g. is conducted on minor failures, which are non-critical for the functionality of the system, an immediate corrective maintenance can be questioned and preferably be postponed to a later scheduled maintenance, to save extra costs. On the other hand, if the system fails due to not undertaken maintenance, the related costs will be much higher because of a sudden stand-still of the system and longer production losses. Therefore, maintenance activities have to depend on the criticality of the components concerned and be based on as much data as available to allow a funded decision. This data can be collected through well-documented inspection histories and monitoring data.

The next subchapters will address the characteristics of FOWTs and the main differences to fixed-bottom turbines. They will discuss the critical components (floater, station keeping system and dynamic cable) of an FOWT system, which shall be subject to inspection. Hereby, the terms "Inspection" as well as "Monitoring" are used frequently. To avoid any confusion each term is defined in the following:

Inspection is when human action (offshore or onshore) is required and executed to obtain condition data from site. The frequency of data collection is not the indicator for differentiation between inspection and monitoring. However, monitoring data is usually measured continuously or in short-term steps (minutes, seconds), whereas inspections can be performed after longer time periods (weeks, months, years) or unscheduled on demand, [14].

Monitoring is defined as an automated inspection being a subset of inspection. A monitoring system collects and stores data automatically and continuously in a predefined time-step (usually short-term) or if a predefined threshold value is reached. It continuously measures conditions without the need of offshore human operation. Usually, the monitored data is transferred directly to onshore servers for storage and further usage, therefore we speak about online measurements, [14].

The following Table 3 summarizes the main components which are subject to planned periodic inspections. It should be noted that a risk-based inspection plan can be established for the wind farm under certain conditions, according to DNV-GL 0126 [15], which will change the inspection intervals. The indicated intervals are recommendations from the different indicated sources and will most likely differ during the warranty period, where they are subject to the requirements from the component supplier/fabricator and OEM.

Table 3: Scheduled inspection intervals of main components of floating offshore wind turbine.

Component	Sub-component	Inspection	Interval	Source
Wind Turbine	drive train inspection	Structural integrity, coating, corrosion, leakage, vibration diagnostics, oil level, function control, noise, etc.	1Y	Bundesverband WindEnergie e.V., [16].

Wind Turbine	Condition control of the rotor blades	Structural integrity, grease and oil condition, function of pitch, etc.	2Y	Bundesverband WindEnergie e.V. [16].
Floater Hull	Compart-ments	Structural Integrity	5Y	DNVGL-ST-0119 [17], in consideration of DNVGL-ST-0126 [15]
Floater Hull	Outer Hull	Marine Growth	5Y	DNVGL-ST-0119 [17], in consideration of DNVGL-ST-0126 [15]
Mooring Line	-	Structural Integrity	5Y	Bureau Veritas - NR 493 DT R03 E [18]
Dynamic Cables	-	Structural Integrity	Within 1Y from start of operation (damage inspection). Additional inspections to be determined if significant changes found after this first inspection.	DNVGL-RP-0360 [19]

5.1 Relevant Characteristics of Floating Offshore Wind Turbines

Floating foundations allow access to deep-water sites. In waters deeper than 50 meters, they offer access to large areas with a strong wind resource and proximity to population centers. In addition, floating foundations generally offer environmental benefits compared with fixed-bottom designs due to less-invasive activity on the seabed during installation. [20]

Although the floating wind industry is still in a premature stage, with just two demonstration wind farms deployed around the world, there is a lot of interest in this new field, since it is expected to play a major role in the future of offshore wind. Existing design concepts of floating foundations, station keeping systems and electrical cabling for FOWTs are mostly developed based on experience from the offshore oil and gas industry. However, platform designs for offshore wind require adaptation to accommodate different dynamic characteristics and a distinct loading pattern due to the presence of wind turbines, making designers to follow a very different design approach: strong interactions among the wind turbine rotor, turbine control systems, floating support structure and station keeping system also pose a great challenge to the design of FOWTs. The

main difference between bottom-fixed and floating wind turbine systems is the maximum inclination angle: while FOWT systems can experience relatively large inclination angles (in roll and/or pitch), fixed-bottom offshore wind turbines do not experience such angles and there is very little experience in estimating the performance of wind turbines at large inclination angles. [21]

In the following subchapters, the main subsystems of FOWTs are addressed while different inspection and monitoring options are pointed out in order to ensure an efficient O&M.

5.2 Floating Substructure

5.2.1 Regulatory Requirements

DNVGL-ST-0119 [17], states that the provisions for inspection, maintenance and monitoring during operation set out in DNVGL-ST-0126 [15], apply. The time interval for periodic inspections shall be at most five years, if the Design Fatigue Factor (DFF) is applied as specified in Section 7 of [17]. The interval for periodic inspections can be increased if the DFF is modified according to DNV requirements.

DNVGL-ST-0119 [17] further states that for corroded steel structures measurements of plate thicknesses by ultrasonic testing shall be included in the inspection program, in order to document the degradation.

DNV GL-ST-0126 [15] allows for risk-based inspections in case of large numbers of turbines in a wind farm. It needs to be noted that the standard accounts for offshore wind turbines in general and is not specifically developed for floating substructures. Non-inspectable items need to be designed with sufficient durability for the entire operation lifetime. For critical items of the substructure, DNVGL recommends inspection intervals of less than one year, [15].

5.2.2 Critical Failure Modes

The principal failure mechanisms that FOWT foundation might undergo are corrosion especially in and near the splash zone and due to the high salinity of the surrounding air as well as fatigue due to combined wind and wave loadings. This fatigue is produced by the enhancement of stresses due to resonance, which takes place when natural frequencies are found to be similar to the rotor's frequency. [14] Under the water line, the components are additionally exposed to marine growth resulting in additional weight and stress for the material. For concrete-based structures an underestimation of the dynamic loading can lead to cracks in the outer hull. If these cracks propagate through the wall and lie under water or within the splash zone, then they constitute a risk to the watertightness.

5.2.3 Inspection Methods

The aim of the maintenance free design is to ensure a long component lifetime and to avoid corrective maintenance. However scheduled inspection campaigns are organized to mitigate the risk of corrosion or cracks through visual inspections of the outer hull and, if accessible, the inner side of the buoyancy compartments. These inspections can be performed with ROVs (for underwater inspections) and by technicians inside of the compartments. The water level inside the compartment shall also be measured on regular basis as well as the functioning of the bilge pump system. These measures help to ensure the structural integrity of the hull, its watertightness and thus the buoyancy capacity.

The vast majority of the scheduled inspections of the platform during the project are governed by class rules with regulations based on O&G. For a larger farm this may change and a statistical methodology can be a solution

to optimize the efficiency. The solution would be to move away from a planned maintenance towards a risk-based inspection methodology.

During the interview with the floating substructure designer, Principle Power, it was explained that a lot of value is seen in predictive maintenance and digitalization (e.g. digital twin for continuous structural health monitoring) to enable more cost-efficient O&M. There is the trend towards more automation offshore to reduce the human interaction on the platform or inside the compartments and replace it as far as possible by using robots. For this the structure needs to accommodate the autonomous tools, such as docking stations. Principle Power is part of the European funded H2020 ATLANTIS Project, [22], developing autonomous underwater vehicle (AUV) applications for offshore wind farms. They state that the future lies in using AUVs but that the industry is still far from a practical scenario.

An opportunity also lies in active ballast systems. They can be adapted dynamically during the lifetime in contrast to passive systems. The active systems pumps water in and out to reduce the imbalance caused by the thrust. The underlying regulation can be adjusted during the 25 years of operation if the system itself changes, e.g. if marine growth increases, raising the dead weight of the substructure. It would also allow to further lower the platform for a large component exchange. It is a learning system, a smart platform, which uses fleet wide data analysis to improve the performance during the course of the project.

5.3   Station Keeping Systems

This subchapter provides a baseline of current state-of-the-art inspection and monitoring techniques for mooring systems of floating offshore wind turbines. Note that the content discussed here is similar to the content in D2.1 [23].

Developers of foundations and mooring systems strive to design their products maintenance free. Even in case maintenance free design might be possible, it can be expected that this design will not be economically feasible. Hence, O&M activities will be required for future projects to ensure reliable operation throughout the lifetime. After a first evaluation on this topic following risks and challenges for operation, maintenance and monitoring are being identified:

- Routing of cables needs to be considered in mooring system design and anchor placement, particularly where shared anchorage is being considered or where large platform excursions are expected.
- Calculation or determination of all mooring line tension loads is essential to guarantee optimized mooring system behavior.
- Excessive corrosion and wear
- Pre-emptive maintenance activities
- A concept for removal of mooring lines for inspection or maintenance purpose needs to be developed.
- Lack of system knowledge and inadequate training for operators
- Dropping lines / re-tensioning of lines
- Reusing mooring components: Suction anchors are not re-usable so if the floater is required at another location, new anchors need to be installed.
- Lack of proper monitoring systems
- There is a demand for the real-time monitoring of mooring systems both in their deployment and to track their condition. A lack of monitoring and tracking can lead to mooring line replacement or failure.
- Effective monitoring and data management – ideally without the need for costly maintenance or subsea sensors—is necessary to detect mooring line failure and ensure continued mooring systems integrity for the lifetime of the asset.
- Assessment of new technologies such as Advanced Distance and Positioning System (ADAPS) and Device Tracking and Control Systems (DTAC) – supports monitoring real-time drag anchor positioning and potentially eliminates the need for ROV work during prelay operations.

- Synthetic fibres shall not get into contact with the seabed at any time during operation.
- Quality and efficiency of offshore inspections if required
- Deferral of inspections if required

5.3.1 Regulatory Requirements specifically for Mooring Systems

5.3.1.1 Class NK

Class NK [24] requires the following components of a mooring system to be inspected in intermediate and special surveys:

Intermediate surveys

- Mooring line stoppers
- Tensioning equipment
- Measurement of mooring line departure angles to check if the line tensions remain within the permitted limits. Other verification methods may also be applied.
- Mooring line above water to identify wear and tear
- Mooring components above water to identify wear and tear
- Turret mooring system bearings if applicable (including the lubricating system)
- Check of abnormalities in the operation of the mooring equipment (winches, windlasses etc.)

Special surveys

- Connecting points to the platform and the anchor (remove marine growth in advance)
- Mooring lines and tendons in their complete length including all connections
- Detailed inspection of areas where high corrosion and wear is to be expected (seabed, splash zone)
- NDT (see section 5.3.3.3) of chain and chain stoppers above sea level (remove marine growth before testing)
- Examination of turrets and related equipment and measurement of thickness due to corrosion
- MEP (see section 5.3.3.4) at representative locations in the mooring line
- Check of abnormalities in the operation of the mooring equipment

Occasional inspections have to be executed in case of loads acting on the structure exceeding the design assumptions and the results have to be reported to the classification society. If essential parts of the substructure are damaged, the operator needs to apply for an occasional survey.

5.3.1.2 DNVGL

In general, the time interval for periodic inspections will be five years, if the Design Fatigue Factor (DFF) is applied as specified in Section 7 of [17]. The interval for periodic inspections can be increased if the DFF is modified according to DNV requirements.

DNV GL [15] allows for inspection programs based on a risk-based approach in case of large numbers of turbines in a wind farm. It needs to be noted that the standard accounts for offshore wind turbines in general and is not specifically developed for floating substructures. Non-inspectable items need to be designed with sufficient durability for the entire operation lifetime.

For critical items of the substructure, DNVGL recommends inspection intervals of less than one year, [15].

5.3.1.3 Bureau Veritas

Bureau Veritas (BV) [18] requires the determination of inspection intervals on a case-to-case basis. However, it is recommending a 5-year inspection interval. The items to be accounted for, the methods chosen, the sampling rate, the inspection intervals and the personnel requirements of all inspections must be listed in an inspection and test plan which needs to be approved by BV. The inspection plan is continuously updated to address new experiences from R&D and other floating foundations. Revisions are to be approved by BV.

5.3.2 As-built Inspection

To verify that the completed installation work meets the specific requirements and to identify the first mooring conditions an as-built survey should be performed. The survey is primarily conducted to confirm that the anchor legs are connected as designed, to check for damages that occurred during installation, and to ensure that the twist in the anchor legs is within the design margins. Most as-built surveys are conducted by visual inspections from anchor to fairlead (mostly by video-capable ROVs). Those recordings should be saved with comments made by the inspector. In general, every damage and any discrepancy between the actual as-built-status and the nominal planned state should be addressed with enough detail and documented in a report in order to facilitate future inspections. Additionally, a detailed list of all components can be attached including manufacturer, serial number and/or other identification [25].

5.3.3 Inspection Methods

Inspections are understood as the determination of the status and/or condition of a mooring system or a mooring component at a specific point in time. The identified status and/or condition of the mooring system or component is compared to the status/condition according to design prediction. In case the predicted values are exceeded, more detailed investigations or corrective measures/replacement are to be initiated. Usually, inspections are carried out by skilled personnel often under use of inspection equipment. Inspection intervals are set in the design phase but can also be adjusted based on findings of previous inspections. The inspections need to be executed by a company certified by the classification society, [24] and utilized survey robots also need to be approved. For underwater inspections remotely operated vehicles with mounted camera are suggested; diver operations shall be omitted whenever possible. The required scope of inspection can vary significantly from one individual component to the other.

A detailed definition of the term "inspection" is given in the introduction to chapter 5.

5.3.3.1 General Visual Inspection

General visual inspection (GVI) is the most common inspection method for mooring lines by carrying out a continuous slow ROV flight or a diver swim (hardly ever, due to high HSE risk and matured ROV technology (see chapter 6)) along the mooring line in order to evaluate and assess the structural integrity and completeness of the mooring line and components. It is obvious that a GVI can only assess the overall condition of the mooring lines and give indication for areas which should be inspected in more detail. Although time consuming, removal of marine growth might be necessary for specific areas. A GVI can be executed according to e.g. DIN EN 13018, [26]. The viewing distance shall be selected appropriately for the inspection.

The scope of a general visual inspection is to assess:

- Damage to the structure and components such as dents and deformation(s)
- General wear on the chain links
- Presence of corrosion and or pitting
- Missing or loose parts
- Distorted elements

Necessary tools for the inspections:

- Digital camera with flash (for those accessible components above water)
- Video camera with permanent illumination from ROV
- Tape measure (for those accessible components above water)
- Writing instrument
- Voice recording during video footage
- ROV (for those components underwater)
- Chain survey robots (for those components underwater)

The GVI of a mooring line can be performed by use of support equipment as ROVs or chain survey robots according to DNVGL, [15]. These support tools check the whole mooring system for its integrity.

According to Ma et al., [27], the most critical areas to be inspected are the following:

- Top chain at fairleads and chain stoppers
- Rope terminations
- Connectors
- Seabed touchdown area

The quality of this inspection depends highly on the knowledge of the inspector and on the prevailing water clarity and the access to the item. Therefore, it should be free of marine growth. To film and stream the item being inspected (whether by a ROV or diver) an adequate camera resolution is required. To allow a complete real-time record of the inspection process it is of advantage if the device used is capable of videotaping which allows to rewind when in doubt. [25]

To determine whether a ROV or a diver is best fitted to undertake this survey the item inspected must be considered. In shallow waters, diving could be successful but with a considerable safety risk to personnel even though all precautionary measures are taken. Especially, when it comes to a close-up visual inspection where a particular component is the subject, diver inspections are not the favored option simply due to the required close proximity. Due to the highly dynamic environment constant movement and unexpected motion (from the floater and/or the mooring line) are a great risk for divers nearby. Although not all ROVs can fly sufficiently close to a component, it is considered more safely. Additionally, by using ROVs the depth limitations are far greater. [25]

Stakeholders suggest that the integrity of the mooring system could be checked according to a risk-based 5-year schedule, instead of a scheduled maintenance inspection in predetermined time intervals. The scope and periodicity of the inspection is based on previous findings and potential incidents since the last survey. By inspecting a representative percentage of the assets, it may be possible to extrapolate the findings to the other assets and to make the engineering assumption, that the other mooring lines will be in a comparable condition. But it should be pointed out, that external threats (e.g. subsea operations, other vessels, fishing gear, seabed inspection) are the largest risks for mooring lines (other stakeholders are therefore skeptical about the possibility of extrapolation).

5.3.3.2   Detailed Visual Inspection

Detailed inspections of critical areas underwater can be done with e.g. scanning methods. A DVI can be executed according to e.g. DIN EN 13018, [26]. A DVI is required for a more precise investigation whenever needed. The viewing distance and angles are defined in standards like [26]. Mirrors may be used to improve the angle of vision, and aids such as a magnifying lens, endoscope and fibre optic may be used to assist testing. Marine growth often makes it difficult to perform a detailed inspection and preparatory work might be required.

The scope of a detailed visual inspection is to assess:

- Material degradation
- Condition of issues from previous periodical inspections
- Connectors, anchors and chain stoppers
- Corrosion
- Pitting
- Cracks
- Indication for weld defect

Necessary tools for the inspections:

- Digital camera with flash
- Tape measure
- Writing instrument
- Mirror tool or endoscopic camera
- Diver

According to DNVGL-0126 [15], diver operation could be required in order to carry out a DVI.

Since an inspection with ROVs, vessels and the necessary topside equipment and personnel is quite costly and considering the fact, that the wind turbine operation needs to be stopped during examination a detailed inspection is mostly conducted after the appearance of concrete external threats including natural incidents like storms. The amount of the production loss is generally less than the rent for the survey vessel, with increasing turbine sizes however, there will be a tipping point.

The inspection itself poses a threat for the mooring system. Especially, after considering the amount of mooring lines which would have to be checked for a large wind farm each by a relatively close fly-by of an ROV. Thus, a slight inattention could cause a navigational fault and eventually could damage one of the many lines.

5.3.3.3 Non-destructive Examination Techniques (NDT)

Due to findings by the GVI or the DVI or other requirements a more detailed inspection might be needed. Multiple NDT methods are available. The NDT method that has to be chosen depends on multiple factors (e.g. type of damage to be investigated, part and accessibility, operational aspects) and shall be chosen by the NDT person of the executing company.

Surface preparation is required in most cases. Manual (brush, scraper) or high-pressure cleaning of the investigated area might be necessary in addition.

Necessary tools for the inspections depend on the following parameters:

- Inspection method
- Type of defect
- Material which shall be inspected

An NDT is in general possible for those elements above the water surface, but difficult for the submerged components. It might be required for high wear and tear areas in the platform chain or for mooring equipment as the chain stoppers and winches. In case an NDT inspection for submerged components is initiated, the results should be treated carefully (defects are often further below the surface and may not be detected, critical areas are often inaccessible etc.).

Non-destructive testing may be one of the following (the NDT methods described below are based on [28] and have been partly adapted to fit into the floating wind specific context):

Mooring Line Dimension Measurement

Certain measurements of mooring components may be required during periodic inspection. Mooring chain measurement systems that have been used include simple diver-deployed manual calipers, a prototype stand-alone robotic system, and ROV-deployed systems. Some dimensional checks, particularly those that involve measurement over multiple chain links, become difficult or impossible to perform underwater. But some ROV-deployed systems include both mechanical caliper and optical caliper systems that appear to be practical and effective.

Magnetic Particle Inspection (MPI)

MPI is commonly used during manufacture and installation, including most of the chain surface if equipment is supplied allowing good access to the chain intrados. MPI is normally used to detect surface breaking or near surface breaking crack indications but it should be noted that the rough surface of most chain links may create false indications. In-service inspection could include MPI but noting that moving components around to allow thorough inspection is generally not feasible. For most chain, MPI of the flash butt welded area would be possible, but only for surface breaking or near surface breaking cracks.

Ultrasonic Testing (UT)

UT is often used to examine the flash butt weld area of chain. The great advantage that UT has is that it can detect both surface breaking and subsurface defects. This is particularly important in the flash butt weld area where incomplete fusion can result in subsurface defects. The technique is straightforward to use above water and underwater with divers. For ROV applications, it may be necessary to develop a special tool to hold the probe(s).

Electro Magnetic Detection (EMD)

EMD is an old technology that has been used for many years for the inspection of wire ropes. The method can detect surface breaking defects through non-conductive coatings. One of the biggest problems with the technology is that it is not good at detecting defects close to the wire rope termination, probably the area of greatest interest in mooring wires. For many years there has been discussion about moving the existing, relatively mature, technology underwater, but so far little progress has been made.

Dye Penetrant Testing (PT)

PT can be used on metallic and non-metallic materials. Only surface breaking defects can be detected. PT requires the surfaces and possible surface-open discontinuities to be clean. It is only applicable above water.

Radiography Testing (RT)

RT for mooring chain and wire rope produces a picture of mainly volumetric discontinuities, provided these are favorably oriented with respect to the direction of the applied X- or gamma radiation. Two-dimensional flaws can be difficult to reveal and the defect height, which often is the most critical parameter, is normally impossible to assess by radiography. The radiation hazard can limit the applicability of the method.

5.3.3.4   Measurement of electrochemical potential (MEP)

Measuring the electrochemical potential of the steel surfaces can be required in order to ensure that sufficient cathodic protection has been achieved.

Its scope is to assess:

- The polarization of steel surfaces (protective potential)

Necessary tools for the inspections:

- Reference electrode (vs. Ag/AgCl)
- Voltmeter
- Cables for electrical connection
- ROV

5.3.3.5   Inspection of Scour Protection

The method of survey, (e.g. sonar, Acoustic Doppler Current Profilers (ADCP) or ROV) is up to the operator's choice, most likely depending on cost and availability. Though, it is important to obtain survey data with sufficient accuracy to identify changes of the prescribed dimensions.

The scope of the inspection is:

- To assess dimensions of eventually occurring cross sectional changes
- To serve as a basis for efficient rectification measures (if required).

Measurement errors and tolerances must be considered. In general, scour will only occur around suction piles, driven pile anchors and drilled pile anchors.

5.3.3.6   Marine Growth Measurement (MGM)

The continuous monitoring of marine growth aims at ensuring that the marine growth build up is not more than what has been accommodated in the design assumptions, because the growth varies from region to region. Especially on emerging floating wind farms the measurements have the important benefit that they bring an understanding of the marine growth accumulation, which can be used for cost and risk reduction in future projects in similar regions. Measuring the marine growth thickness is carried out in order to ensure that the operational limits as considered in the design are not exceeded.

Its scope is to assess:

- Thickness of marine growth

Necessary tools for the inspections:

- Measuring probe or folding ruler

Corrective measures are to be taken in case the maximum allowable marine growth thickness is exceeded. In Figure 3 marine growth on a mooring chain in Equinor's Hywind Scotland Park is shown exemplary.

Figure 3: Marine growth on mooring chain in Hywind Scotland Park, [source: courtesy of Equinor].

5.3.4 Failure Mechanisms of Mooring Systems and how to detect them

After introducing diverse inspection methods which can be used to determine the state of the mooring system, this chapter will explain common failures and their locations on mooring components. It is required to be considered in order to successfully inspect the mooring system.

Table 4 extracted from [28], briefly highlights the areas that need to be inspected, what is being looked for, and some of the difficulties of inspecting those areas.

Table 4: Outline of mooring components for inspection, [source: [28]].

What to **Inspect**	Where to **Inspect**	Difficulties with **Inspection**
Chain		
General inspection	All over chain	Need to clean chain and access difficulties at and below mudline
Tension-tension fatigue	Half-crown intrados (most common location)	Very difficult to see or get any access to the area as it obstructed by the adjacent link
	Crown extrados (another relatively common location)	Reasonable access, particularly in stud less chain when the adjacent link is not as obstructive
	Flash butt weld (occasional location for fatigue)	Good access to outside, but more difficult on intrados.

Out-of-plane Bending Fatigue	Chain link at the bell-mouth	Access impaired by bell-mouth in most cases. Can be either in-air or under water, depending on the design.
General corrosion	All over chain, especially top chain	Visual gives some information. Measurements can be taken if needed.
Pitting corrosion	All over chain	Good from visual
Interlink wear	Contact point between links	Need to measure the double diameter of the two links at the contact point. Need baseline dimensions. Chain bar stock ovalizes during fabrication.
Dimensional anomalies	Length over a number of several adjacent links	Need baseline for results to be meaningful. Can be difficult to measure relatively large distances with sufficient accuracy
Mechanical or installation damage	All over chain	No significant problems if there is sufficient visibility
Twist in chain	All over chain	Need reasonable visibility to be able see twist over number of links
Synthetic		
Mechanical damage	Splice	Generally good visual, but access to termination limited
	Body of rope	No significant problems if there is sufficient visibility
Internal damage		Not possible with available technology
Wire rope		
Fatigue of wire rope	All over – sheathed rope	Not currently technology, but possible in the future
	All over – un-sheathed rope	Visual of surface only
Corrosion	All over	Visual, but can be difficult to interpret. Measurements of diameter feasible if wire not sheathed

Fatigue of rope termination	Body of termination	Similar access problems as with chain
Connectors		
Misalignment	Between connector and connected components	Visual normally adequate (see also discussion below this table)
Corrosion	All over	Similar to chain (see also discussion below this table)
Inter-component wear		Similar to chain interlink wear
Loose pins, lost retainers, etc.	Visual	Inspectors need to know what the component should look like (in order to see defective condition)

Critical areas for which more detailed inspections may be beneficial are the fairlead region, the splash zone, the seabed touchdown area, the connectors and the rope terminations. Another area where failures are likely are parts of the mooring line where weight discontinuities occur leading to additional bending and wear. The following are some of the reasons that connectors are of special interest during inspections of existing installations, based on [28]:

- Tolerances: Connectors are designed and fabricated within specified tolerance limits to help ensure that the components being connected will fit into the connector. However, if the connector tolerances are, for example, at their maximum, and the components being connected are at their minimum, then there can be appreciable play in the system, potentially leading to out of alignment loading. This issue is being considered for inclusion in a new draft API document, but there are currently no industry-based guidelines.
- Materials: Another issue that has been discussed at some length by the group developing the draft connector guideline is that of material compatibility: different types of steel have resulted in increased corrosion rates.
- Design Details: Missing retaining pins, nuts, etc. has been a problem on connectors, often due to failure of design details.

Figure 4 has been included to help to explain the tension-tension fatigue crack locations on a common (stud link) chain. The locations are similar on a stud less link.
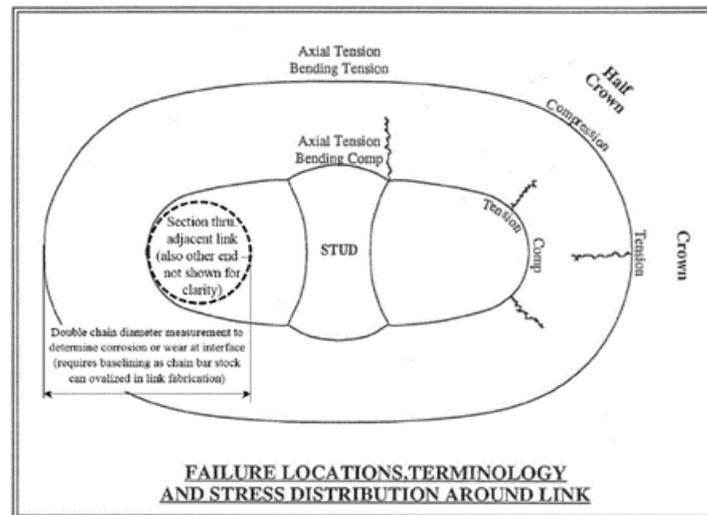
Figure 4: Terminology and Tension-Tension Fatigue Crack Locations on Common (stud link) Chain, [source: [28]].

5.3.5   Monitoring of Mooring Systems

For reducing O&M cost and implementing advanced O&M strategies, monitoring systems are a key enabling technology. (Continuous) monitoring systems indicate mooring line failures in real time or at least on short term, whereas inspections will only detect mooring line failures on pre-set inspection intervals or after major events. A detailed definition of the term is given in the introduction of chapter 5.

Since FOWT mooring systems are and will be designed with lower level of redundancy and safety than the mooring systems of O&G substructures, detection of mooring line failure should be possible within a short time window. Thus, it is likely that the significance of monitoring will be higher than the significance of inspections of FOWT mooring systems in order to allow early mooring line failure detection.

The purpose of monitoring can be to identify mooring line loss, to validate design assumptions or to gain information on possible structural optimization and hence reduce cost of future projects. It is possible to use monitoring in order to collect data on fatigue damage (and remaining structural lifetime), extreme loads as well as on specific issues like chain bending characteristics around fairleads and chain stoppers. Monitoring of mooring lines improves reliability and optimizing operation and maintenance of floating support structures leading to reduced costs. State-of-the art sensor devices are able to monitor chain bending characteristics in chain stoppers and fairleads. An analysis of the monitoring data can indicate whether chain wear at these hot spots has developed and also chain failure. Wear is often present at fairleads in the splash zone. Inspection might be possible by de-ballasting the foundation and monitoring may support the decision-making process for such inspections.

5.3.5.1   Equipment for Monitoring

In the following an overview about current technologies for monitoring is presented based on [28] with partial adaptions to fit into the floating wind specific context.

Simple Sonar Probe

A simple sonar probe system has been applied under offshore conditions. Horizontal scanning single beam or multi beam sonars are typically deployed from center of the turret or moonpool or over the vessel side. The

sonar head is usually submerged down to approximately 15 to 20 meters below the hull. The sonar reflections are processed in real time to detect if a line is missing or has moved outside its maximum allowable design envelope, the system can automatically trigger an alarm notifying the operator. The illustrated system is simple and easy to repair if something does go wrong with it. But if a line breaks in the mud, still having some tension/catenary, the signals from the sonar probe may not be sufficient enough to indicate that a line has failed. This technology has limited application and long-term field performance data will help assess its reliability and accuracy.

Table 5: Sonar Probe, [source: [28]].

Maturity	Has been used in a limited number of applications (O&G)
Intent	Detect failed mooring line only – no tensions. If not permanently deployed, then no real time feedback on a failure
Application	All types of facility, but easiest on a turret moored system
Deployment	New and existing units (O&G)
Advantages	Can be retrofitted; low technology; probes easily repaired if damaged
Disadvantages	Only failed line detection when system deployed. Possible problems detecting failure on seabed if it does not result in significant mooring line angle change at turret. No mooring line tension data gathering

Inclinometer

A simple inclinometer could measure mooring line departure angles. Using analysis tools, the current mooring line tensions can be estimated. In calm weather, if any of the mooring line angles have changed to a significant extent, there is a possibility of a line failure. Such inclinometers could be checked using "football" sized ROVs, which can be deployed directly from the deck of the vessel itself. Installation is easy and the technology is relatively cheap and robust. Simple inclinometers overcome the difficulties sometimes encountered with damage to power and signal distribution cables on more complex systems as inclinometers installed under water usually come with an acoustic signal link. A challenge is the limited battery lifetime. Measurement accuracy is not optimal, and a continuous error might be present due to calibration errors. The readings are not continuously monitored. Inclinometers have been applied in several O&G projects under offshore conditions.

Table 6: Inclinometer, [source: [28]].

Maturity	Has been used in a limited number of applications (O&G)
Intent	To measure mooring line angles for the use of detecting line failure or as input to the mooring line load assessment
Application	All types of mooring systems
Deployment	New and existing units (O&G)
Advantages	Direct measurement of line angle and not affected by other parameters. Relatively simple system with low cost
Disadvantages	No continuous monitoring. Line angle for each mooring line may be recorded at different times and could cause inaccurate line load assessment

Load Cell

In theory, mooring line load monitoring is the most straightforward way to detect mooring line failures. Direct in-line load cells have been used widely under offshore conditions and this method is a proven technology in order to determine line tensions, [29]. There are systems that use fixed chain stoppers, which have been outfitted with load cells underneath their base. Next figure illustrates a load cell at chain stopper. There are also load cells installed in mooring lines (e.g. between the bar stocks of stud less chain elements) with the limitation that data transfer is only possible by hardwired cables leading to increased need of repair or replacement, [29]. Long term application of these strain gauges can be questioned due to decreasing signal quality evoked by loose connections due to corrosion. Figure 6 shows an instrumented load pin. A third option is to determine the natural frequencies of chain segments in order to calculate the load acting on it. However, experience in O&G application has indicated that the accuracy, reliability and robustness are major issues using load monitoring systems, especially for underwater where access to the mooring line and instrument is very difficult if not possible. The power and signal transmission cables are areas of particular weakness for systems exposed to long term offshore loading conditions. Acoustic data transmission overcomes these weaknesses but seems to be a complex solution as well. A new development in recent years is the use of in-line load cells housed in a protective casing, making it better suited for offshore installation. Data transfer is conducted via an acoustic transmitter. See ref. [28] for further information.
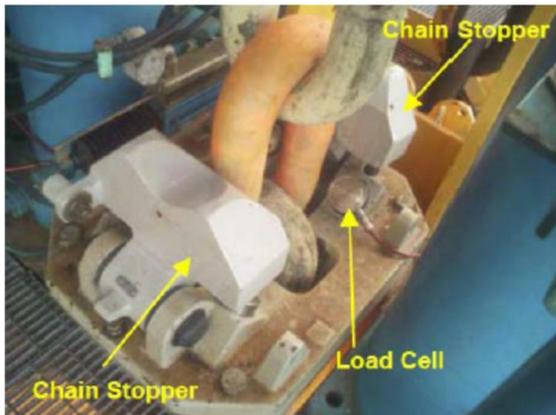
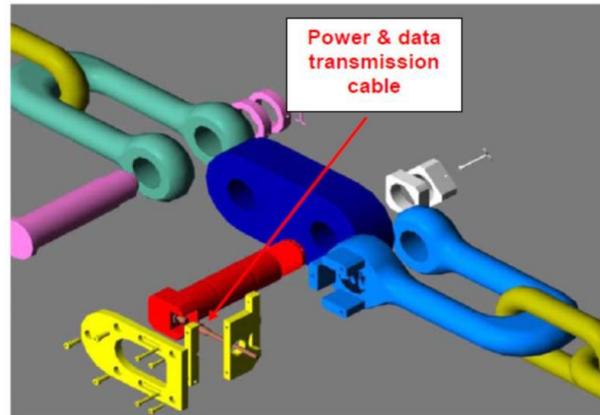Figure 5: Instrumented Load Cell at Chainstopper (courtesy of FPS mooring integrity JIP), [source: [28]].

Figure 6 Instrumented Load Pin (courtesy of BMT/SMS) ,[source: [28]].

Load cells have been found to be unreliable when used in mooring system monitoring being sensitive to weather and lightening. Part of the problem is that they are required to be operational for extended periods of time with little opportunity for recalibration or suitable replacement (especially for the load pin option). Signal drift can be detected up to a point; however, it is not always possible to determine what is due to instrument drift versus what is a slow change in the real mooring line load. Another problem can be the system losses between the chain stopper, where the load cell is installed, and the mooring line tension away from the facility. Not only is it difficult to ascertain the frictional losses, but they may not be fixed over time. Again, this can introduce an unexplained signal drift.

Table 7: Load Cell, [source: [28]].

Maturity	Has been used in number of applications (O&G)
Intent	Monitor mooring line load for the detection of line failure, over loading, or fatigue assessment
Application	All type mooring systems; difficulty for submerged turret mooring system
Deployment	New and existing systems (O&G). For inline load cell; retrofit is difficult
Advantages	Long time, very well used method for load measurement. Relatively simple system, low cost.
Disadvantages	Measurement is not reliable especially when the mooring line load is not very high. Many other factors affect the output of the measurement, such as frictions, temperature, signal drafting, recalibration, durability of transmission cables, etc

Global Positioning System (GPS) and Gyro

Table 8 illustrates a global positioning system. Theoretically, the abnormal changes of the offset of a floating substructure should be able to indicate the failure of a mooring line. Some O&G units have installed GPS/ Differential Global Positioning System (DGPS) for position monitoring which makes this system a proven offshore technology. However, the effectiveness of using offset monitoring to detect mooring line failure depends upon many factors, such as the characteristics of the mooring system, water depth, monitoring of environmental conditions, and reliability of GPS and Gyro. But in general, overall offset monitoring and recording using GPS and

Gyro is cheap. The offset information combined with knowledge of environment and mooring system behavior could, at least, provide indications for further inspection.

Table 8: Global positioning System (GPS) and Gyro, [source: [28]].

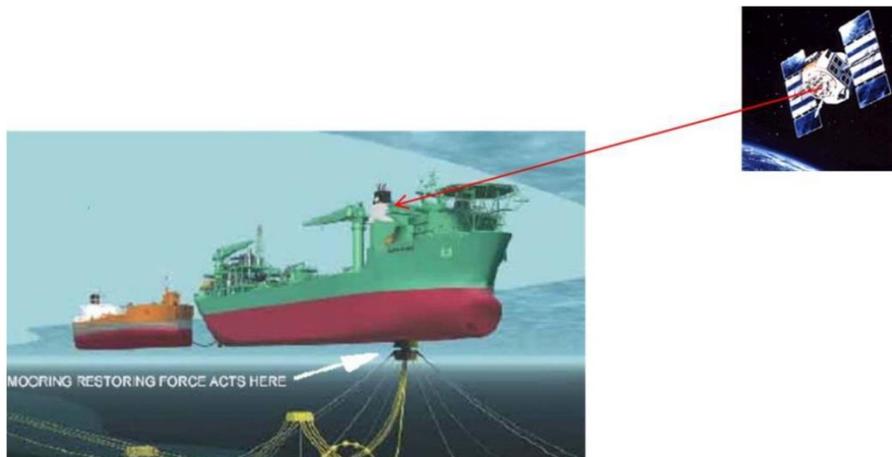| Maturity	Has been used in a number of applications (O&G)
Intent	To monitor and measure vessel locations and hence to derive the mooring line load
Application	All types of mooring systems
Deployment	New and existing systems (O&G)
Advantages	Easy to install and relatively low cost. Equipment on board the vessel and easy to maintain
Disadvantages	The relationship between vessel's position and mooring line load needs to be carefully studied to have a clear understanding between the measured positions and mooring line load. Environment measurement (wind, wave, and current) may be necessary

Figure 7: Global Positioning System (FPS mooring integrity JIP), [source: [28]].

Indirect in-line tension monitoring (moorASSURE)

The moorASSURE monitoring system monitors the mean angle of mooring lines and vessel's position. On each mooring line, an inclinometer is attached to measure its mean angle. The measured angle is periodically transmitted to vessel mounted acoustic receivers using hydro-acoustic data link. The acoustic inclinometer is placed in a holder to allow its retrieval and installation by ROV or diver. The logger holders can be attached to chain links or on the chain follower below the chain table. A number of hull-mounted acoustic receivers are connected using electrical cables to an industrial rack mounted data acquisition system located on the topside (see Figure 8).

The measured mooring line angles are collected by a topside data acquisition system. The mean mooring line tension is derived using the measured mooring line angles and vessel's position data. The calculated mooring line tension is displayed and compared with predefined thresholds. Where measurements exceed the threshold,

alarms are raised by the software. The system has already been installed under offshore conditions in O&G industry.

Table 9: Indirect in-line tension monitoring (moorASSURE), [source: [28]].

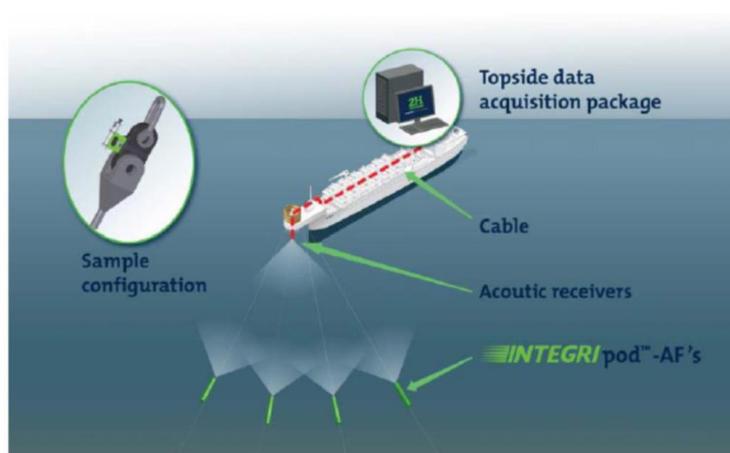| Maturity	Used in limited number of applications (O&G)
Intent	Continues monitoring and measuring mooring lines angles and predicts mooring line load based on line angles or detects mooring line failures
Application	All types of mooring systems
Deployment	New and existing units (O&G)
Advantages	Real time monitoring, acoustic transmission, less maintenance
Disadvantages	Need careful calibration for the model of mooring line angles and mooring line load. Data management and alarm setting criteria

Figure 8: Indirect Line Tension Monitoring System of 2H, [source: [28]].

Integrated Monitoring and Advisory System

Integrated Monitoring and Advisory Systems (IMAS) have been installed in O&G industry in the past. It includes monitoring system, forecast system and data acquisition system. The monitoring system monitors wind, wave and current conditions, vessel motions and mooring load. The forecast system includes the prediction of vessel motions and mooring line load. It also provides advisory on optimum loading conditions. The hardware used includes DGPS, Inertial Measurement Unit (IMU), Acoustic Doppler Current Profilers (ADCP), inclinometers, accelerometers, Fiber Bragg Gratings (FBG) sensors.

Table 10: Integrated Monitoring and Advisory System, [source: [28]].

Maturity	Has been used in a limited number of applications (O&G)
Intent	Monitor and detect mooring line overloading, failure, and provide operation advisory
Application	All types of mooring systems

Deployment	New and existing units; could be difficult for existing units (O&G)
Advantages	Comprehensive system for real time monitoring and provide advisory for operations
Disadvantages	Relatively expensive with the measurements systems. The system is relatively new and the effectiveness of the advisory system is not yet known.

AUV based mooring monitoring

For the monitoring of mooring lines, the use of crawler devices that are attached to the mooring lines may be a valuable option. But due to a chain's asymmetric geometry the use of such crawlers is rather complicated but could be an alternative inspection method for steel rope and fibre rope. For the latter mentioned no tests have been conducted yet and the advantage compared to ROVs are not yet clear.

5.3.5.2   Post-processing
Since a huge amount of data is generated by all monitoring sensors in a wind farm (considering that sensors are not only installed in the mooring lines, but also in the wind turbine, on the turbine substructure and on the substation), data storage and transmission is a huge challenge.

The data is collected in the onshore SCADA center and needs to be evaluated and assessed which requires skilled personnel. The evaluation software and the personnel need to be able to identify a mooring line failure from a false alarm within a short time frame since repair or replacement measures should be initiated shortly. It is necessary not only to track and assess the real time data, but also to identify any trends comparing actual data with historic data in order to e.g. identify slow changes in mooring line tensions. Data storage is also a challenge since the large number of sensors will generate a huge amount of data that needs to be stored. This also indicates the need to clearly define the purpose and the number of sensors that are needed to gain the target parameters. Even though the cost of the sensors itself may decrease in the future, server space for storage of large data may be the critical parameter.

5.3.6   Repair Methods and Procedures

5.3.6.1   Mooring Line Replacement Procedures
In the design phase of the substructure and the mooring system, a mooring line replacement concept shall already be worked out, since experience from Ramboll in the O&G sector showed that mooring line failures during operation are quite probable. Close collaboration to the installation contractor is beneficial since line failures can be installation induced. In general, redundancy or safety levels applied in the design should keep the probability of a mooring line failure as low as economically possible. However, if one mooring line breaks, it should be ensured by design (consideration of damaged and transient conditions in the mooring analysis) that the remaining mooring lines and anchors are not overloaded and that the structure will not break free completely. After a mooring line failure, it might be reasonable to not tow back the substructure into the port but replace the mooring line at site. A procedure for mooring line replacement using an AHV in O&G industry is given in [29] and is described below:

The replacement of an in-service mooring line presents some unique challenges. Failed mooring lines could be replaced either by derrick barge or by large Anchor Handling Vessels (AHV). Mooring line replacement feasibility using AHVs was evaluated with an objective to develop an effective and economic line replacement option. Original installation in O&G typically uses large derrick barges as a part of a more comprehensive installation scope. However, using a derrick barge for a limited mooring replacement campaign is not practical as they are difficult to obtain a lease on short order and are much more expensive.

AHVs may require modifications to be able to perform the job of construction vessels. Depending on the scope of mooring component replacement, special installation aids such as a Subsea Chain Table may be required to make subsea cutting and joining of mooring line. Further requirements on the AHV capabilities regarding the equipment and procedures to apply can be found in [29]. This includes step-by-step procedures, and requirements for suction pile installation, rope installation and amount of AHVs needed.

5.3.6.2   Tow-In for Major Repair Work

The Tow-in and the required procedures for handling of the mooring system is discussed in chapter 9.2.

5.4   Dynamic Cables

Analysis of insurance pay-outs have shown that 70-80% of all pay-outs on offshore wind projects have been spent on cable system damages [6], [30]. This chapter is intended to cover methods of inspections as well as monitoring techniques of dynamic power cable systems which help to maintain these components economically. Note, that the content discussed here is similar to the content in D3.1 [31].

First an overview of regulatory requirements regarding the maintenance of dynamic cables is given, followed by the explanation of common failure mechanisms during the service life. After that, different inspection methods, both of visual as well as electrical nature are presented. For reducing O&M cost and implementing advanced O&M strategies, monitoring systems for dynamic cables are a key enabling technology and will be discussed later on.

5.4.1   Regulatory Requirements for Cable Inspections and Monitoring

5.4.1.1   DNVGL

DNVGL-ST-0359, "Subsea power cables for wind power plants" [3], specifies several requirements for the inspection and monitoring of submarine power cables. Those requirements which were deemed applicable for maintaining dynamic cables have been reviewed within this document.

Where testing activities are specified to be carried out during the operational phase, the activities shall be planned, executed, reviewed and documented. A detailed external inspection plan including specifications for the inspections shall be prepared for each survey. The detailed inspection plan should be updated based on findings of previous inspections as required.

External inspection shall be carried out to ensure that the design requirements remain fulfilled and that no damage has occurred. The inspection program shall, as a minimum, contain following inspection under water:

- free spans including mapping of length, height and end-support conditions
- condition of artificial supports installed to reduce free span
- local seabed scour, settlement, subsidence or instability affecting the cable integrity
- mega ripple / sand wave movements affecting the cable integrity
- cable settlement in case of exposed sections
- the integrity of cable protection covers (e.g. protection sleeves)
- mechanical damage to cable
- major debris on, or close to, the cable or cable components that may cause damage to the cable.

The sections at the offshore units shall be part of the long-term external inspection program for the cable system including:

- functionality of supports and guides and integrity issues (e.g. cracks in welds)
- damage or displacement, e.g. due to vessel impact or foundation settlement
- corrosion, e.g. of J- or I-tubes
- damage to coating
- extent of marine growth

The frequency of future external inspections shall be determined based upon an assessment of:

- authority and cable operator requirements
- degradation mechanisms and failure modes
- probability and consequences of failure
- seabed dynamics, e.g. mega ripples or sand waves
- results from previous inspections
- changes in the operational parameters
- requalification activity and results
- repair and modifications
- subsequent cable laying operation in the area.

Critical sections of the cable system vulnerable to damage or subject to major changes in the seabed conditions should be inspected at suitable intervals.

Additionally, monitoring can be used to detect changes in the operating conditions and to take mitigation actions. Conditions of the cable which are monitored may include:

- electrical - voltage, current, power
- thermal - temperature
- mechanical - tension, bending, vibration

5.4.1.2   CIGRÉ

The Cigré Technical Brochure 610 [5] distinguishes maintenance work as described in chapter 4.

Therefore, time-based maintenance activities shall include following subjects:

- Controlling of external conditions (e.g. marine activities, profile and stability of the seabed)
- Cable route survey
- Transition joint inspection
- Scour protection in vicinity of cable touchdown point
- Inspection on platform (connection points)
- Inspection of complementary hardware (e.g. buoyancy modules)
- Inspection of Spare parts
- Electrical Measurements (discussed in 5.4.4.2)

These TBM activities may trigger condition-based maintenance work with the purpose to follow the evolution of the cable system. Next to the above-mentioned inspections, there are also monitoring techniques which shall be used in order to estimate the remaining lifetime of the asset and to plan offshore interventions in more detail. These techniques are reviewed subchapter 5.4.5.

5.4.2 As-laid inspections

Like explained in subchapter 5.3.2 regarding the station keeping system a survey after the completed installation helps to understand the first condition of the asset of interest. This may also be useful to apply at dynamic subsea power cables in order to plan future inspections. Due to the previous installation, space at the test location may be limited what may lead to reduced safe working distances. Additionally, it can be a challenge to get the test equipment offshore. Therefore, testing may have to be applied through adjacent components, e.g. testing all consecutive cables or all cables in a branch with one test or performing tests that require smaller equipment such as partial discharge measurements or VLF testing (see 5.4.4.2) [5]. Besides electrical tests, visual inspections can be performed (mostly by video-capable ROVs). Note here, that the handling of the data and facts found should be the same as described in chapter 5.3.2.

To evaluate the need for an as-built survey its benefit must be compared with the costs and risks of testing [5], but analysis of cable failures due to mechanical damage had shown that damage that occurred during installation is often the direct cause of failure in service [32].

5.4.3 Failure Mechanisms of Dynamic Cable Components

Dynamic cables on floating offshore wind platforms experience great levels of mechanical stress due to their dynamic environment [33]. The cables are continuously subject to external forces like bending and twisting caused by floater movement and tidal current which can be seen in the following figure. Tensile forces normally do not apply on dynamic cables, since the mooring lines limit the floaters horizontal drift before the dynamic cable can reach its maximum stretch. The cable should be configured as such that this possibility does not exist during normal operation.
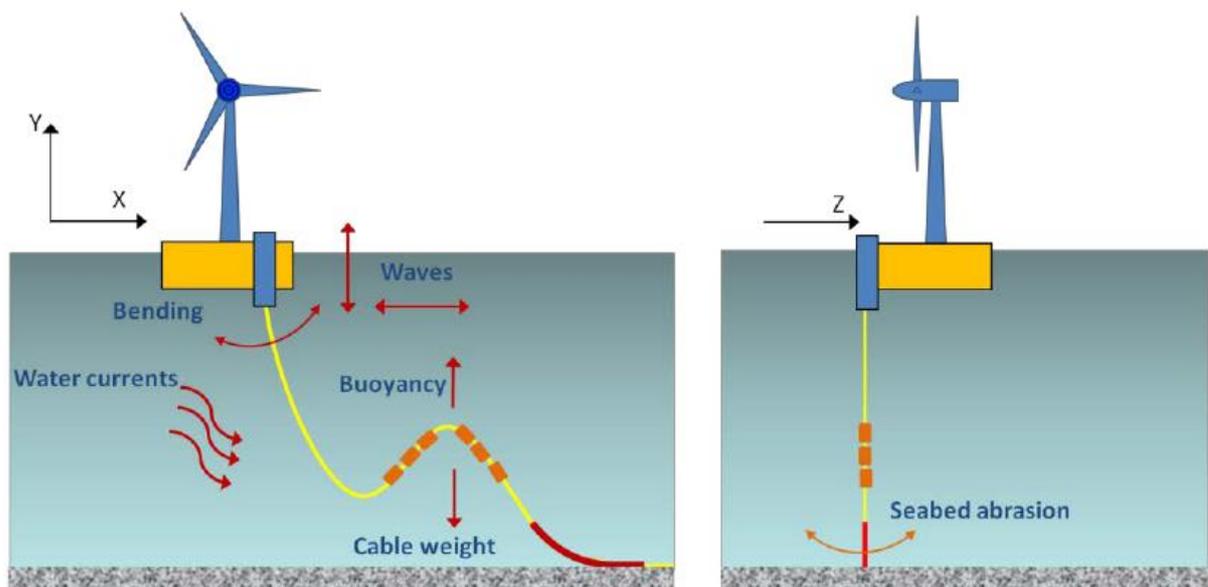

Figure 9: External Forces on Dynamic Cables, [source: [34]].

Hence, dynamic cables are likely to suffer damage in various sections during their operational time [35] but not only natural damages may occur as Table 11 illustrates.

Table 11: Overview of submarine power cable damages applied to dynamic power cable, [source: [7]].

Damage category:	Kind of damage:	Applicable:
Installation	Loss of Dynamic Positioning	yes
	Anchoring damages	yes
	Kink	less likely
	Loading / re-loading	less likely
	Trenching	no
	Small bending radius	yes
	Emergency cut	less likely
Human Activities	Fishing equipment	less likely
	Anchors	no
	Jack up	less likely
Operational	Free span	yes
	Joint failure	yes
	Geo-hazards	yes
	Internal defects	yes

A focus of the cable inspection should be laid on the wear of the outer sheath of the power cable inside the J-tubes. Longitudinal and vertical movements are possible inside the J-tube causing abrasion on the cable coating. Relative movements inside the J-tube are a critical cause for this failure mode in the O&G industry and are considered in particular relevant also for floating wind. There are not yet conventional inspections methods available for power cable wear inside J-tubes by ROVs and USVs. This remains a challenge that still requires further efforts.

Amongst damages that happen during the operational lifetime, damages in the installation and/ or maintenance process are also possible. As already pointed out in D3.1, damages that occur during installation are often the direct cause of failure in service since the damage exacerbates due the natural forces described in previous figure. Damages caused by human activities, on the contrary, are less likely to happen due to a 500m-2000m safety zone recommendation for FOWF. This cannot be applied on static cables, especially export cables, which may cross existing shipping routes and are exposed to human activities.

After pointing out possible damage sources and explaining natural external forces acting on the cable this chapter will treat typical damages that should be considered while inspecting the different cable components. It can be said that areas that are subject to constant movement like the top end at the floater interface and the touchdown point at the seabed deserve special attention during an inspection.

5.4.3.1 Cable

As discussed in D3.1, due to the dynamic environment the integrity of cable protection is in danger and mechanical damage like cut and abrasion can occur. This damage is often caused during installation when the cable is in contact with sharp edges during deployment and retrieval but can also be caused by falling objects. In the case of wet-storage the dragging on a hard seafloor can cause abrasion marks [25]. Once the insulation is

damaged and show tiny pores soil and water can invade. Those pores do not have to be visible to the naked eye. Consequently, water trees in the cable insulation occur and weaken its integrity and enable electrical failure to occur. Water trees (can be seen in next figure below) take time to grow and propagate but are responsible for unexpected failures after an otherwise healthy cable´s lifetime [33].
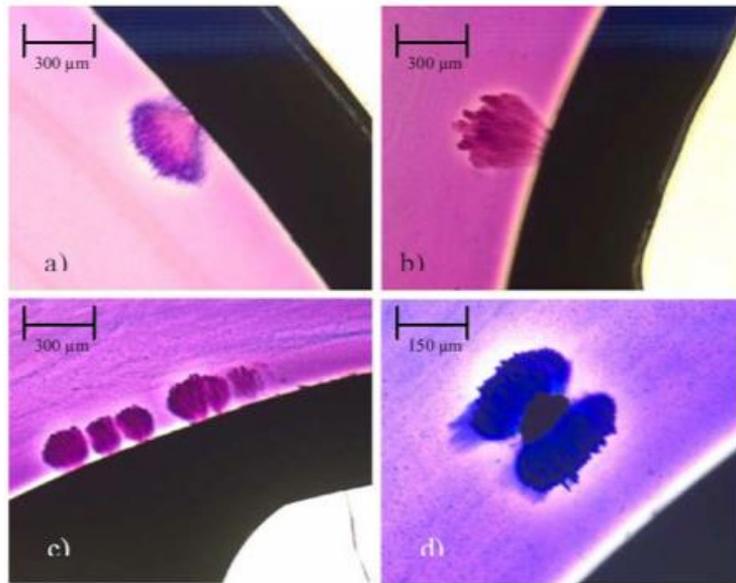

Figure 10: Differing types of water trees within cable insulation layers, [source: [33]].

Once the protection is no longer in-tact the mechanical forces accelerate mechanical fatigue as one form of damage may lead to another [32].

The spacing between the integrated fibre optics and the HV power core of the cable can lead to potential overheating of the fibre optics. In the latest design, cable modifications were done to prevent such problems.

During operational time it can be expected that the buoyancy modules that keep the lower part of the dynamic cable from dragging on the seafloor are losing 10% of their buoyancy [7]. While inspecting it should be verified that the modules did not lose more buoyancy than expected and that the lower cable part is not rubbing on the seafloor. To reduce the weight of the cable and to protect the insulation from growing marine life the marine growth could be removed periodically (according to cables design basis). A realistic marine growth assumption is used for the dynamic analysis in the design of the cable configuration, to accommodate loss of buoyancy and marine growth build up over windfarm lifetime. Figure 11 illustrates that a variety of life forms can use the cables surface as a habitat.
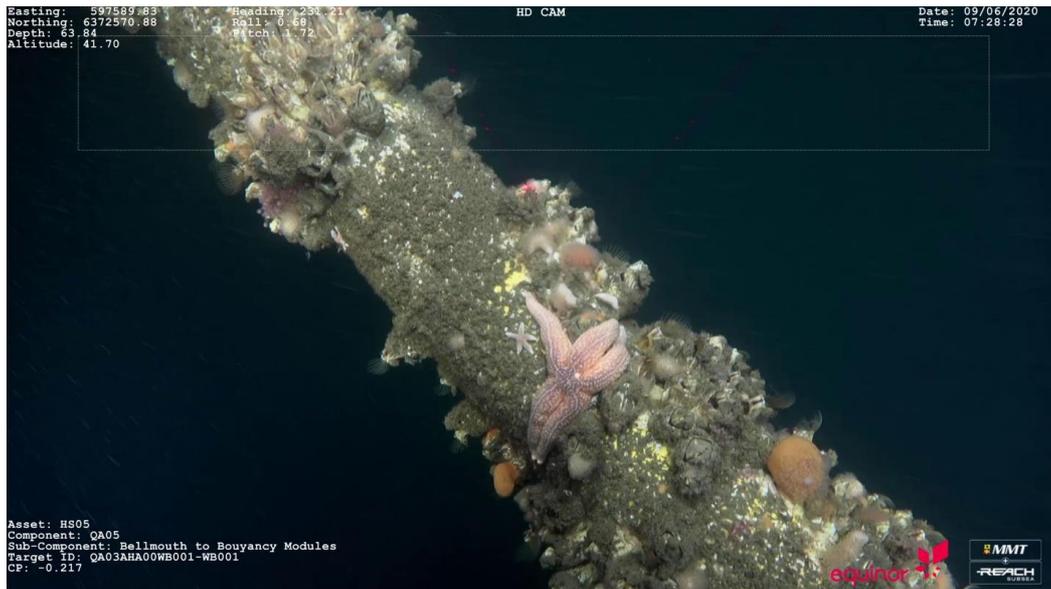
Figure 11: Marine growth on a dynamic cable in Equinor`s Hywind Scotland Park, [source: courtesy of Equinor].

5.4.3.2 Protection Sleeves

The touchdown point of the dynamic cable represents a critical area that should be inspected closely. The interaction between the dynamic cable and the seabed should be carefully assessed. Driven by the cable movement abrasion will trigger premature damage of the outer protection layer which can be followed by water penetration, corrosion and mass loss. Therefore, the specially designed protection sleeves around the cable's touchdown point need to be checked on a continuous basis, while considering the surface quality of the prevailing ocean floor [5]. Considering the depth, a visual inspection by using a ROV is most likely. The inclusion of a tether can also reduce or remove the tendency for touchdown point abrasion.

5.4.3.3 Transition Joint

The transition from the static to the dynamic cable often contains extra equipment such as metallic screen disconnections or connection knots of fibre optic cables so that it makes sense to check it on a regular basis. Due to the deep location of the transition joint visual inspections can be made by using ROVs. To ensure the transition joint does not suffer thermal anomalies infra-red cameras can be used to detect local hotspots. Although the transition joint is placed on the seabed it is not exempted from movement. Moving sand dunes underwater or seismic activities can dislocate and bury the transition joint. Especially after seismic activities a re-survey should be undertaken [5]. In case of major debris on or around the cable joint the disturbance should be removed to prevent future damages that may occur [3]. Due to the transition from a dynamic to a static behavior the cable is subject to high degradation so that abrasion and wear marks can present themselves.

5.4.3.4 Substructure Connection

The top part of the dynamic cable which is attached directly to the floater experiences the most movement due to nearby floater motions. Nevertheless, in many cases it is the accessory attached to support the link between cable and floater that initiates the failure and not the cable. By movements or a simply poorly installed interface the accessory gets damaged which eventually will damage the cable [32]. Typical failure location at the platform are the hang-off point, the fixing clamps of the cable on the platform, the bending restrictors as well as damages to the coating which may lead to corrosion e.g. at the J-tube. Due to these damages the cable itself could get damaged and therefore needs to be inspected too (see 5.4.3.1). Those external damages are not the only

potential failure occurrences. As well, the termination of the dynamic cable inside the floater needs to be inspected on a regular basis if not equipped with monitoring techniques [5].

5.4.3.5 Spare Parts

Dynamic subsea cables are mainly specialized products that are mostly tailor made for their purposes. This indicates that the delivery time in the case of cable failure might be long and that the concerned wind turbine is incapable of transport electricity. To make sure the spare parts remain in a good and operational condition they should be inspected on a regular basis. A visual survey is mostly enough to locate possible damages. Some products in the accessory kits have an expiring date and need to be replaced before. If possible, the management of the spare parts including undertaking inspections may be outsourced to the cable supplier [5].

5.4.4 Inspection Methods

After several failure mechanisms have been pointed out in the upper section different inspection methods of dynamic cables are now introduced. As discussed in D3.1 an as-laid inspection is the first step to verify that the completed installation work meets the specific requirements and to identify the first cable condition. Every damage and any discrepancy between the actual as-built-status and the nominal planned state should be addressed with enough detail and documented in a report in order to facilitate future inspections. Additionally, a detailed list of all components can be attached including manufacturer, serial number and/or other identification [25]. To evaluate the need for an as-built survey its benefit must be compared with the costs and risks of testing [5], but analysis of cable failures due to mechanical damage had shown that damage that occurred during installation is often the direct cause of failure in service [32].

5.4.4.1 Visual Inspection

General visual inspection is the most common method that is carried out on a regular basis by a continuous slow ROV flight or diver swim past the item being inspected. Throughout the discovery of external damage possible internal cable damages may be deduced. Due to the environmental similarity of dynamic cables and mooring lines this inspection method is kept rather short and a reference is made to the previous chapters 5.3.3.1 and 5.3.3.2. If a more accurate modelling of the cable, seabed conditions, marine growth etc. is possible, the inspection intervals can be increased, moving towards a risk-based inspection strategy.

In contrast to the mooring lines, the two ends of the cable are exposed which can lead to potential problems. Especially the high voltage connectors at those ends are delicate and may be subject to poor workmanship. The connectors need to be inspected on a regular basis for sign of exposure to high temperatures or discoloration. Therefore, it is very important to ensure that high-voltage specialised technicians are well trained for the core connection and fitting.

5.4.4.2 Offline Measurements

In addition to the above-mentioned maintenance activities offline measurements can also be performed in order to examine the cables internal condition and to find damages that may cannot be seen by visual inspections [5]. Unlike online measurements where the subject tested is powered by the grid during the tests, offline measurements are performed while an external voltage source is attached [36]. Those measurements are performed manually and therefore rely upon the skill of the inspecting personnel.

Time-Domain Reflectometry

Main concepts of offline measurements are based on reflectometry. One measurement method is the Time-Domain Reflectometry (TDR). It is used to locate low resistive faults and cable interruptions. Also, the exact location of joints along the cable and the total cable length can be analyzed. A low voltage pulse is sent into the cable and at any impedance change within the cable a reflection will be seen. The time between release and

return of the pulse from any reflection is measured and with the propagation velocity of the pulse, the distance to the reflection can be calculated. This can help to identify the type of impedance change and/or detect possible failure that could be present in the cable [37].

Optical Time-Domain Reflectometry

The Optical Time-Domain Reflectometry (OTDR) is only applicable if there is an additional optical fibre cable in the interstices of the dynamic cable. This can be considered standard nowadays. The method works similar to the above-mentioned TDR but sends light pulses through the optical fibre. The
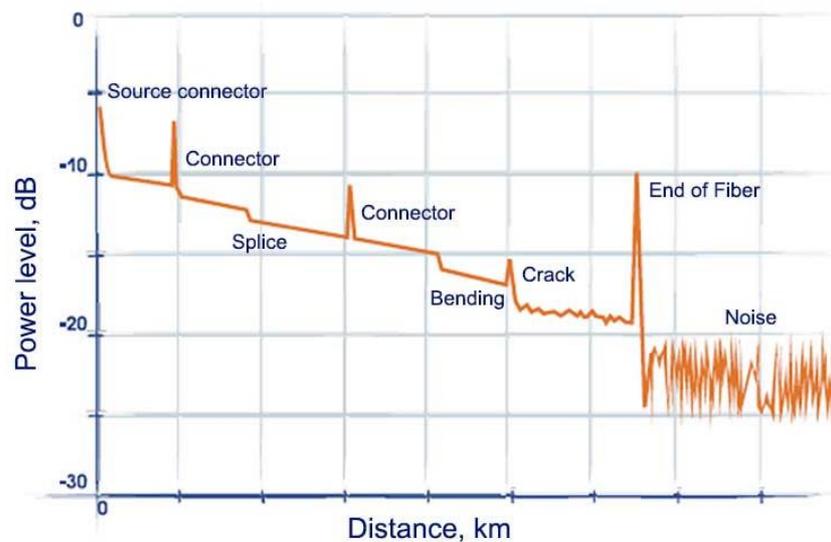

Figure 12: Typical OTDR trace and its interpretation, [source: [33]].

scattered or reflected light pulse is used to characterize the optical fibre in order to find possible anomalies in the cable or its surface, (see Figure 12). The strength of the returning pulse is measured and integrated as a function of time and plotted as a function of fibre length [38].

This technique of monitoring the cables condition is currently used during lay-up, load-out and as a post installation test to monitor strains on the fibre which may indicate damages on the rest of the cable [39].

Partial Discharge Measurements

Partial Discharge (PD) is a failure of part of the insulation system to withstand the electrical field applied to it. PD can be a result of poor design, poor workmanship, defective materials, contamination or aging which results in a high frequency discharge along with a current that flows through and on the insulation. The discharge sparks erode the insulation from the inside through heat and ionization till the discharge occurs on the cables surface. The most likely consequence then is the development of water trees (see 5.4.3.1). To measure PD the cable should be disconnected from external equipment and connected to a high-quality voltage source. The test equipment itself should be free of discharge due to danger of results invalidation [40]. There are currently two methods of measuring PD which differ in the strength of the test voltage. When measuring PD with the normal supply voltage, warning signals (if any) are very small. If discharge is of such significance to be observed damage may be too big and it may be too late to guarantee a remaining lifetime. To see even minor defects on the cable before failure in service can occur the test voltage has to be increased. In this case an appropriate maintenance can be planned [32]. It shall be noted that PD testing puts the cable under high loading and the testing itself can

have an adverse effect on the cable lifetime or its future performance. Before this method can be recommended as in-field monitoring / diagnostic tool further data is needed. In the following illustration a typical installation of PD measuring can be seen:
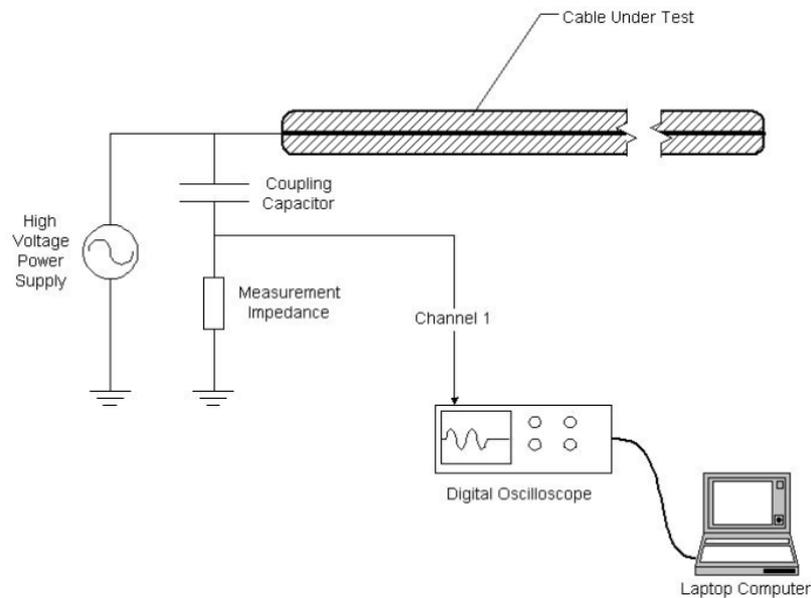

Figure 13: Typical installation of an offline PD testing, [source: [41]].

Very Low Frequency testing

Very Low frequency testing for medium and high voltage cables is a method for testing the integrity of the cable insulation. VLF testing is a resistance test that is typically performed at a frequency between 0.1 Hz and 0.01 Hz instead of 50/60 Hz. [42]

VLF systems have the advantage of being small and lightweight, which makes them useful - especially for field tests where transport and space can be a problem like offshore applications. Since the inherent capacitance of a power cable needs to be charged when it is for testing, system frequency power sources are much larger, heavier and more expensive than their low frequency alternatives.

5.4.5   Monitoring Techniques

Offshore interventions are very expensive and therefore need to be planned very well [5]. With improving technology, it is possible to monitor an entire subsea cable grit while providing alerts as soon any faults crop up [5]. A detailed definition of the term "monitoring" is given in the introduction of chapter 5.

Monitoring can give useful input for the upcoming maintenance activities. The objectives for continuous online monitoring can be summarized in [3]:

- Record status of cable system
- Verify and detect changes in operating conditions
- Provide input for the assessment of cable integrity
- To take mitigation actions

To accomplish those goals three general steps are necessary [32]:

- Collection of raw data from sensors installed on the cable
- Data processing and diagnosis to detect where defect or damage takes place and/or starts developing
- Prediction of remaining lifetime of component

As an important part of the asset integrity management online monitoring should be enforced as a viable means to address the condition of the dynamic cable system in conjunction with inspection programs so that the collected data can be fed into the maintenance plan [25], [7]. The more data collected the more comprehensive is the picture of the condition of the cable. Therefore, it is recommended to integrate different monitoring techniques and to synchronize the different information to get an overall view [5]. It should be noted that monitoring systems in general are helpful in order to assess the condition of the cable and are therefore recommended if applying a risk-based O&M strategy. However, they are not essential since the high voltage cables are designed maintenance free and also pose a big cost driver for the cable O&M. In general monitoring systems which allow a continuous monitoring of the cable condition are highly valuable to the young industry of floating wind and allow an early detection of issues and provide data for potential lifetime extension.

5.4.5.1   Distributed Temperature Measurement System and RTTR

The transportation of electricity over cables creates heat. Even tough submarine dynamic cable pass through relatively cold water, wear can occur which might end in other unanticipated problems [6]. To monitor a cable's temperature during operation, the cable needs to be equipped with an optical fibre in the interstices [39]. The Distributed Temperature Measurement System (DTS) is a well-established technology which uses the change in behavior of optical signal to determine the temperature of the fibre optic. A laser pulse is travelling down the optical fibre in the cable and the reflected signals are measured. The position of each measurement point is determined by its travel time from laser sending while the back-scatter intensity is depending on the fibre optics temperature. To detect the very small changes in the optical signal, complex electro-optical devices are needed [32]. For a more detailed view on this procedure please refer to [32]. From the temperature of the optical fibre the temperature of the nearby conductors can be calculated. This monitoring method is especially useful where the cable is not rated for the full output on a continuous basis but instead a dynamic rating. The DTS allows sampling every two meters in a total fibre length of up to 30 km and due to their immunity against EMC interferences the sensors used for DTS have a significant advantage and can be used in hazardous areas [32]. In following Figure 14 the result of a DTS-Measurement can be seen. It is a function of calculated temperature over the cable length.
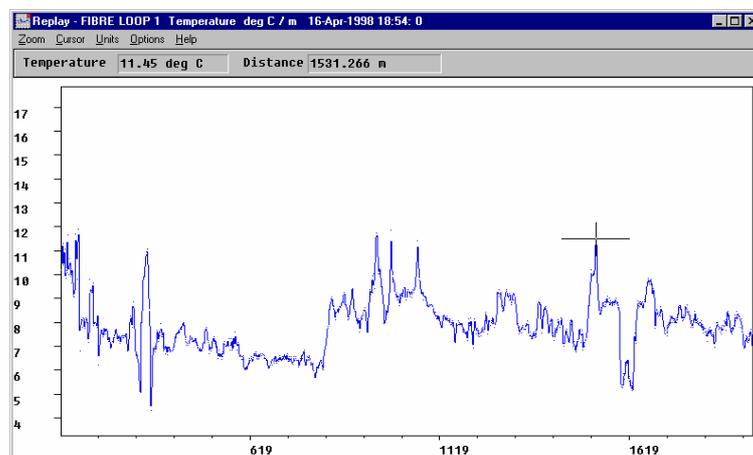

Figure 14: Resulting temperature profile over cable length, [source: [32]].

Additionally, the DTS can be equipped with a Real Time Thermal Rating (RTTR). By taking the current load, historic loads, thermal conditions and other factors into account, the RTTR continuously calculates the conductor´s temperature and at the same time predicts the maximum permissible load considering the current condition and emergency situations [43].

The most accurate technology for DTS is bragg grating, which however does not give the precision needed over distances required in a typical windfarm. The Raman technique and Brillouin scattering are better suited, though both have advantages and disadvantages. The Raman technique often shows dead spots at the connections in areas of interest. The challenge with the Brillouin backscatter is to isolate the fibre from strain to get accurate temperature information, [44].

5.4.5.2   Distributed Acoustic Sensing

The Distributed Acoustic Sensing (DAS) works like the above mentioned DTS method. An optical fibre conducts a laser pulse while the inside scattering sites cause the fibre to act as a distributed interferometer. It detects the acoustic signals that may be caused by a fault or disturbances nearby the cable. If any acoustic disturbances occur, the oscillations cause microscopic elongations and compressions (like micro-strains) on the fibre. This leads to a change in the phase relation and/or amplitude of the laser pulse. Vibrations caused by cable failures are typically located in the low-frequency range and therefore can be identified [45]. The DAS is currently used at the fixed-bottom wind farm Horn Rev. 3 in Denmark. The system used is configured to monitor the power cables in real time, visualize the acoustic energy over time and distance and store the measured data for later analysis. Additionally, it is equipped with alarms in the case of fault events [46].

5.4.5.3   Outlook into Future Monitoring

With advancing information technology, like the Internet of Things (IoT), pervasive networked sensors are becoming more common in manufacturing operation. This will likely happen in the offshore wind sector as well. Real time monitoring and data recording becomes more accurate, data software will help to detect subtle changes in parameters, so that repair work can be even more accurately scheduled [6]. In section 5.4.4.2, Partial Discharge Measurement was presented as an offline inspection method. Due to the required high voltage to identify minor damages it is not yet used for continuous monitoring on dynamic cables. But research is aiming for an online PD measurement in the future. Next to PD monitoring, online OTDR monitoring and the related DSS (Distributed Strain Sensing) are promising techniques to monitor the cables condition in the future. For a more detailed view into DSS please check [47]. All these monitoring techniques are being developed or are already in use to measure fatigue on the cable, which is crucial for dynamic power cables.

5.4.6   Repair Methods and Procedures

5.4.6.1   Preparation

During the operational lifetime of dynamic cables certain damages discussed in the section above can occur. Some may result in a damaged but usable accessory; others will cause a total loss of the submarine dynamic cable. After a failure has been noted it has to be considered whether the damage is too significant to postpone the inspection and repair work or if the projected remaining lifetime is in an acceptable range. Anyway, to plan and actually undertake the offshore inspection the type and location of the failure must be found. Then, after the requirements are clear, the mobilisation of the repair vessel can start, and the cable repair crew can be contacted [5]. It should be noted, that especially for the handling of the grid connection via dynamic cable, large and specialized vessels are required [48]. When the crew and vessel are ready to operate and the detailed procedures are established based on the previous analyses, the location has to be free of obstructions. Additionally, the level of uncertainty in the weather forecast must be taken into account [3].

5.4.6.2 Repair

When the repair work finally takes place, which can take weeks or even month, critical parameters should be monitored continuously and the repairs should be inspected and electrically tested, comparable to an As-laid Inspection discussed in 5.4.2. It should be noted, that if a dynamic cable is seriously damaged and the remaining life time is no longer acceptable, it is most likely to replace it in its entirety to prevent subsequent faults [39]. This is done, because the dynamic cable is relatively short and to cut and replace the damaged part would not be worthwhile. The repair work should be documented to capture the current status of the structure and to simplify future surveys [3]. It is generally valid that the better prepared the procedures for repair work, the shorter is the repair time expected to be and therefore the disconnection time from the grid [5].

5.4.6.3 Disconnection for Tow-In Operations

The Tow-in as well as the disconnection procedure is closely discussed in 9.2.

6 ROV TECHNOLOGY FOR UNDERWATER INSPECTIONS

A remotely operated vehicle (ROV) is a cable-guided underwater vehicle for scientific, industrial and military applications. This underwater robot is connected to, and operated from, the water's surface. Operations undertaken by ROVs in the offshore wind sector can be divided into five categories: pre-construction, construction, routine inspection, unplanned maintenance and decommissioning. [49]

A ROV, in its simplest configuration, consists of the main body of the vehicle, thrusters (propellers), lights and associated video and stills cameras. They can be fitted to carry additional equipment, such as suction samplers and grabbers for example. The ROV is connected to the surface by a tether (or umbilical) that transmits electrical power and command and control signals to the vehicle and sends a return video stream and telemetry (data signals) back to the surface operator(s).

6.1 Classification of ROVs and Characteristics

The term remotely operated vehicle (ROV) covers a wide range of equipment. ROVs are considered to be unmanned vehicles with individual capacities of tasks. No ROV can be described as "typical" especially with numerous modifications that are possible. Depending on its modifications one single ROV can carry out different tasks, even though the most common used in offshore wind farms is for visual inspections. ROVs can work from 100 meters depth up to several hundred (around 1000 meters) finding different in size, weight and power.

ROV equipment can be deployed from a wide range of vessels and static platforms (offshore infrastructure/coastal structures). However, independently of the vessels and platforms used, there are a number of operational requirements that need consideration when defining the ROV Inspection Protocol, and are defined in the IMCA R018 report, [50]:

- Sea conditions
- Load path and deck loading
- Regulation and classification

Sea Conditions
According to [50], the sea state is generally described by the two parameters of the significant wave height (Hs) in meters and the corresponding wave period (Tp) in seconds. In addition to the sea state, the safe deployment and recovery of an ROV will also depend on several other interrelated factors, given in [50], including but not limited to:

- vessel heading;
- wind speed;
- wave direction and interaction;
- surface currents;
- visibility;
- general weather forecast.

The assessment of the weather conditions and the associated factors lies within the responsibility of the ROV supervisor to make the decision whether or not to conduct the ROV inspections.

Regulation and Classification
IMCA R018, [50], indicates that the structural and engineering design of an ROV needs to be in accordance with recognized rules, regulations, codes and standards, regardless of its final location for deployment. If it is specified by the wind farm owner that the ROV system should be in compliance with the rules, regulations, codes and standards of a given classification society, then these rules have priority. It is further indicated by IMCA R018,

[50], that ROV systems are not normally built under conditions of class. The following classification society documents can however be useful when designing ROV systems:

- Lloyd's Register; Code for Lifting Appliances in a Marine Environment;
- Lloyd's Register of Shipping; Rules for Diving Systems;
- DNV Offshore Standard for Diving Systems (DNV-Os-E402);
- DNV Standard for Certification No 2.22 – Lifting Appliances.

The following provide a brief classification of ROV Systems, based on IMCA R004, [51]:

6.1.1 Class I – Observation ROVs

ROVs of this class are generally small and compact vehicles which are fitted with cameras, lights and sonars only. Their purpose is the pure observation although they may be able to carry additional sensors (e.g. for testing cathodic protection as well as additional video or stills cameras. Given their small size ROVs of class I can be easily hand deployed or can even be deployed from a ROV 'mothership' [52].

Figure 15: Class I ROV: VideoRay Pro 4 by VideoRay, [source: [53]].

6.1.2 Class II – Observation ROVs with Payload Option

These vehicles are standardly equipped with two simultaneously viewable cameras/sonars and additionally are capable of handling several sensors. In some cases, they also have a basic manipulative capability. In general, they should be able to operate without loss of the original function while carrying the additional sensors/manipulators.

Figure 16: Mojave class II ROV by Rovco during free-swimming launch, [source: [54]].

6.1.3 Class III – Work-Class ROVs

Class III ROV Systems are generally larger and more powerful than the ROVs of classes I and II. They can take up the volume of a small room and weigh up to two tons. Those vehicles commonly have a multiplexing capability that allows additional sensors and tools to operate without being 'hard-wired' through the umbilical cable.

The larger equipment normally comes with a commensurate increase in topside support requirements, as well as wide variations in capability, power and maximum depth. A solution including a large work-class ROV is therefore significantly more expensive [55].

Figure 17: Class III ROV: XLX 150HP by Triton on a semi-submersible drilling rig, [source: [56]].

Due to their generally larger dimensions ROVs of class III are usually deployed using a tether management system (TMS, see 6.2) [52].

6.1.4 Class IV – Towed and Bottom-Crawling Vehicles

Towed vehicles are pulled through the water by a surface craft or winch. Although they do not necessarily have propulsive power, they may be capable of limited maneuverability. Bottom-crawling vehicles use a wheel or track system to move across the seafloor, although some may be able to 'swim' limited distances in free-flying mode. These vehicles are typically large and heavy, and will require significant topside support requirements, and are often designed for one specific task, such as cable or flowline burial.

6.1.5 Class V – Prototype or Development Vehicles

This class includes all vehicles which are still being developed and those regarded as prototypes. Additionally, special-purpose vehicles that do not fit into one of the other classes are also included in class V.

6.1.6 Class VI – Autonomous Underwater Vehicles

While ROVs are connected to a surface vessel with a cable connection (umbilical) for energy and information transfer, Autonomous Underwater Vehicles (AUVs) can do so without such a cable connection while carry their energy supply in accumulators. They navigate via predetermined and preprogrammed sets of coordinates [57]. Researchers drop an AUV in the ocean and it will conduct its survey mission without operator intervention. When the mission is complete, the AUV will return to a pre-programmed location where the AUV can be picked up and the collected data can be downloaded and processed [58]. With present technology, AUVs are best suited for surveys that can be pre-simulated and therefore programmed ahead and which can be accomplished without supervision. Whereas ROVs are better suited for complex manipulations and the collection of samples [59].

The following Table 12 summarizes the different ROV classes, their fields of application and the required equipment:

Table 12: ROV classes, application and required tools.

ROV Class	ROV tasks	ROV tools
Class I – Observation ROVs	Observation	Video Cameras & Variable lighting
Class II – Observation ROVs with payload option	Observation Survey Inspection	Video Cameras & Variable lighting Non-Destructive Testing (NDT) Acoustic and Tracking Sensors
Class III – Work-Class vehicles	Survey Inspection Construction	Video Cameras & Variable lighting Non-Destructive Testing (NDT) Acoustic and Tracking Sensors Cleaning Devices to clean offshore structures Work Tools
Class IV – Towed and bottom-crawling vehicles	Survey Intervention Burial and trenching	Tools for a specific task

Class V – Prototype or development vehicles	Multipurpose and special purpose vehicles	Work Tools and multi-mode tools
Class VI – Autonomous underwater vehicles		

6.2 Management, Launch and Recovery Systems

6.2.1 Tether Management System (TMS)

ROVs can either be free-floating, which the supply cable of the surface winch is directly connected to the vehicle (mostly for smaller ROVs) and deployed via a Tether Management System (TMS). ROVs deployed via a TMS where the supply cable of the surface winch is directly connected to a cage or clump weight through the umbilical cable allowing excursions up to certain drag. Being strict, TMS is only the tether handling machinery, i.e., an additional underwater winch with tether cable r connected to the ROV, [60]. Figure 18 visualizes this connection.
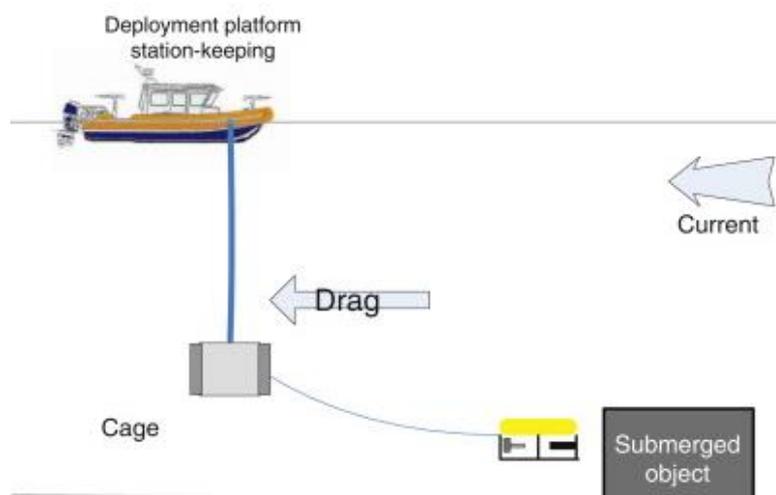

Figure 18: Visualization of the TMS, [source: [61]].

The two main types commonly used are with side entry (cage) or the "top hat" TMS. Typically, both solutions are mostly used in larger ROVs of class III since it is used like an additional protection during launch and recovery. Moreover, the cage can transport additional tools and equipment.

Figure 19: ROV being recoverd with its cage/garage TMS, [source: [112]].

Figure 20: ROV being deployed with "top tat"-TMS, [source: [113]].

6.2.2   Launch and Recovery Systems (LARS)

Given the fact that the launch and particularly the recovery of ROVs are amongst the most challenging aspects of their operation, a specialized system called Launch and Recovery System (LARS) is used to ensure a safe and stable deployment for the ROV, the ship and the personnel. The IMCA R018 report, [50], informs that launching and recovering the ROV through the splash zone puts dynamic loads on thee ROV itself, the umbilical, the handling system and the winch. Loads can also be transferred through sea fastenings to the deck and structure of the deployment vessel. Every part of the load path needs to be designed such that it can handle the highest likely dynamic loads.

A close cooperation between the vessel naval architects and the ROV system supplier is necessary to establish a complete picture of the dynamic loadings, which can be calculated with a selection of parameters for any specific vessel. These calculations should comply with any rules or criteria from certifying authorities which apply to the ROV installation.

LARS can feature different systems to handling ROVs from deck or ship to sea level.

- One side of the ship: A-frames and crane LARS
- Opening the hull: Moonpool

A-Frames are commonly used to lower and lift the ROV with its TMS into and out of the water, whereas moonpool can be used to ensure a safer launch operation from a more stable location on the ship, allowing launch and recovery operations in higher sea states. In order to eliminate the risk of excessive ROV motions during the transition close supervision is typically required since it allows to extend lifetime and minimize operational downtimes.

Figure 21: A-Frame preparing for launch, [source: [62]].

Figure 22: ROV being launched through moonpool; [source: [50]].

6.3   Advantages and Limitations

The ERDC TR-07-4 report from the CRRE Laboratory, [63], provides a good overview of the benefits of using ROVs for underwater inspections. They explain that the simple, cost-effective, and expedient way in which ROVs conduct underwater inspections decrease the need for divers for potentially hazardous inspections. With ROV's, underwater inspections can be carried out more efficiently and in a safer environment, keeping the divers out of danger, not matter how highly trained they are.

The benefits of using ROVs instead of divers are multiple, [63]:

- There is minimal risk of injury for the ROV pilot compared to a significantly higher risk related to diving activities.
- The ROV tool can help to improve the overall asset management by increasing inspection rates, geotagging the visited locations and monitoring the efficacy of the repairs. These activities can help to reduce expensive, unplanned maintenance.
- ROVs are not restricted like divers to the physical limitations of the human body which come along with increasing water depths. This is especially interesting for floating wind, as the potential sites show greater water depths and harsher environments. After a maximum depth of 50 meters nitrogen narcosis becomes a significant concern for divers. ROVs can submerge to depths of 200-300 meters, some types can be deployed in several thousands of meters. [63]
- According to ERDC TR-07-4 [63], ROVs have a better benefit/cost ratio compared to diver inspection operations. This is due to the fact that at depths of 30m or more, the divers need special equipment, which makes the operation more expensive than with ROVs.
- The ROVs have a longer operation time than divers. For divers the time spend at operational level decreases with water depth, because the ascent takes longer, due to the necessary safety stops to avoid decompression sickness. Divers are only able to remain underwater for 1-2 hours before having to resurface to replace the breathing tanks. ROVs operation time only depends on the availability of the ROV pilot and the weather conditions which need to be favorable. [63]

The following Table 13, published by [64], shows maximum time limits which should be incorporated for diver operations to reduce the incidence of decompression illness (DCI).

Table 13: Maximum bottom time limitations for surface decompression (SD), in water decompression and transfer under pressure (TUP) decompression diving, [source: [64]].

Depth (m)	Bottom time limits (minutes)	
	TUP	SD and in water
0 - 12	240	240
15	240	180
18	180	120
21	180	90
24	180	70
27	130	60
30	110	50
33	95	40
36	85	35
39	75	30
42	65	30
45	60	25
48	55	25
51	50	20

However, there are other factors limiting the work possibilities of the ROVs in offshore environments, which have been elaborated by Rémouit et al. in [65]:

- As with divers, difficulties might occur when working in severe weather conditions: below sea level the ROV is not affected by high waves and strong winds, but the crew on the boat piloting the ROV are highly affected by harsh weather conditions.
- Due to the ROV's limited thrust, it is usually difficult to work in an environment where current speeds are high. The limited thruster power also affects the ROV's ability to perform tasks that require large forces, such as carrying, pushing and dragging.
- Since the ROV's pilot has to rely on the lights and cameras on the ROV, certain depths and muddy waters can also cause problems.
- Whilst reasonable efforts are usually made to design out diving operations from offshore projects by using the ROVs, there may still be works that will require the services of expert divers:
  o Assisting with vessel problems below the waterline
  o Recovery of dropped objects
  o Repairing and cleaning operations
  o Assisting with installations below low water
  o Other ad hoc duties.

6.4   HSE Specifications and Risks

According to [51], the health and safety plan for ROV operations should account for safe operating conditions, timing of inspections in relation to currents, weather, season and visibility. Clear environmental limits are defined by the ROV contractors for operating the ROV that they supply. Inspections shall be planned for times of the year that are likely to be less stormy. Visibility will be poorer in near-shore environments following storms with high-levels of rainfall as increased sediments are washed. An inspection plan should incorporate a 'poor weather contingency' buffer to allow extra time for the inspection in cases where the inspection vessel may not be able to carry out operations.

Qualifications and Competence of vessel crew

The IMCA R004 report, [51], provides information on what is required of the personnel responsible for the ROVs. The team must have the capability to maintain and repair electrical, electronic, fibre optic, hydraulic and mechanical systems of the ROV, as well as having the operational knowledge to safely operate and maintain the equipment. All ROV personnel should be competent to carry out the tasks required of them. The competences should be demonstrated by the possession of suitable qualifications or experience or a combination of both. The vessel crew needs to be trained and experienced to carry out the operations and maintenance and it lies within the responsibility of the contractor to provide a well-balanced, competent team of sufficient numbers to ensure safety at all times, [51]. Any communication between the ROV operating crew and any other relevant personnel (such as the support vessel crew) is essential.

IMCA R004 informs further, that the ROV contractors is responsible for the safety and technical training of his personnel in line with any relevant legislation or specific contractual conditions or requirements. ROV personnel should attend technical training courses, in order to gain a sound knowledge of the operation and maintenance of ROVs and associated equipment. In addition to this technical training, also safety training should be provided, including:

- courses on survival, first aid and firefighting;
- installation- or vessel-specific safety induction covering possible hazards at work and while responding to emergencies;
- task-specific safety outlining the hazards associated with tasks such as working overside;
- refresher training at regular intervals.

Personal Protective Equipment (PPE)

Protective equipment shall be provided to the personnel for the operational tasks. Life jackets should be provided by the vessel for all crew members and the inspection team should have Personal Protective Equipment (PPE) such as safety helmets, safety boots with reinforced steel toecaps, eye protection, safety harnesses with double lanyard and immersion suit. The supply of correct PPE, its good maintenance, routine inspection, necessary replacements and the usage of this equipment at all relevant times as indicated by risk assessments and work instructions lies within the responsibility of the ROV contractor. The risk assessment for the job must indicate if any additional PPE is required.

Diving operations

When diving operations are required, the works will be carried out by competent diving contractors, registered with the H&SE and fully compliant with the requirements of the diving regulations applying to the specific project itself.

According to [66] , the main responsibility lies with the diving companies to ensure that a safe diving project is carried out in compliance with the diving regulations. The diving project is broken down into individual diving operations. For each operation a supervisor must be appointed. The diving companies have responsibility to ensure that all parts of a diving project are managed in such a way as to ensure the safety of the involved people. They further manage the proper coordination of parallel diving operations. [66] further specifies that a diving project plan based on a health and safety risk assessment shall be developed and shall identify:

- All known items below and above water, which may cause a hazard to the dive team (ship propellers or equipment which can start operating automatically, etc.) to be taken into account by the diving company;
- All other activities in the proximity which can affect the safety of the diving project (i.e. pile installation will prevent diving activities unless a specific assessment is completed, focusing on aural and cavity damage to diver, loading or unloading of vessels, lifts, etc.)
- Details of any possible substance likely to be encountered by the dive team that would be a hazard to their health (i.e. explosives) in sufficient time to allow them to take appropriate action.

The diving companies must be able to demonstrate that an injured diver can be recovered and transported to a recompression chamber within the prescribed time limits. If compliance cannot be demonstrated then recompression facilities will be required. Individual diving specialists, contractors and all other person supervising diving activities must ensure that recompression facilities and means of transport there to are readily available before any diving operation starts.

6.5   Recommendations to ROV Inspection Protocol

Operation contracts of offshore wind farms usually include long term inspection programs detailing the components to be monitored, the frequency required for the inspections and the procedures to be followed in these inspections being, most of them, visual underwater inspections that can be carried out using ROVs and divers. Because of diving activities require a detailed and specific HSE plan, contractors tend to replace their activities by ROVs considering the inspections by divers only whenever there is not another option.

Depending on the total capacity of the offshore wind farm and the number of WT structures, the frequency of the inspections may vary from strict annual inspection programs in small wind farms to more flexible ones in those wind farms where a large number of WT structures are installed and carrying out inspections on a few representative structures each year should provide the operator confident information regarding the status of each of the components included in the inspection program. As a general rule and according to [67], certification bodies, recommend continuous inspections applied annually to a minimum of 20% of the Offshore Wind Substructure Installations in the Wind Farm.

There are several guidelines from different certifications bodies for these inspections. In the following table, the main recommendation from DNV/GL are highlighted:

Table 14: Collected recommendation for underwater inspections according to DNV/GL, [sources: [68], [69] and [70]].

	DNV Guidelines	
Reference Documents	DNV OS J101, [68]	DNVGL-SE-0190, [69] DNVGL-SE-0441, [70]
Components to be inspected	Structures below water and submerged power cables.	Support structure (tower, substructure, and foundation), including seabed level, splash zone and underwater components.
Recommended methodology	General visual underwater inspections using ROV and close visual underwater inspections performed by divers. Inspections should include tests, inspections on site and an assessment of the findings in order to identify random failures and systematic failures.	General visual inspections for the splash zone and underwater inspections performed by divers.
Periodicity	Long-term inspection plan: • for critical items, inspection intervals should be shorter than one year • for lower critical items, longer intervals can be considered The entire wind farm should be inspected at least once during a five-year period.	The intervals between inspections should be defined in the inspection plan developed by the operator and agreed with the Certification Authority.
Expected final results of the inspections	Technical assessment that structures or structural components continue to comply with design assumptions stated in the Certificate of Compliance issued by the Certifying Authority	Measurements of corrosion, corrosion protection (including cathodic protection), marine growth, any damage, deformation, or spalling of the support structure, cracks and abrasions.

6.5.1 Recommendations to ROV Inspections by EQUINOR

Within the scope of the COREWIND project, several interviews have been performed with strategic stakeholders to gather updated information and recommendations for O&M strategies. In this section, the most relevant content of the interview with the O&M manager in EQUINOR is summarized.

In general, the subsea inspections have 2 purposes:

1. To verify the technical equipment (integrity): An inspection strategy is prepared for the wind farm and not every turbine is inspected every year but alternatively.
2. To fulfil the marine license

Usually, underwater inspections of mooring chains, floating substructures, in-field cables and export cables are carried out by ROVs. EQUINOR states that ROVs are able to carry out almost every offshore operation, making it possible to replace all diver operations relevant for the inspection campaigns. The high HSE risk associated with diving campaigns would thus be removed.

Currently, the deployed USVs are limited to perform operations up to 30m depth while floating on the water surface. The surveys are controlled from an onshore operation control center and the USVs are launched from the beach which eliminates the need of a service vessel. It is used to survey the export cable using a sonar and multi-beam echo.

Figure 23: USV used to survey the export cable of Hywind Scotland Park, [source: courtesy of Equinor].

However, for deeper waters tethered work-class ROVs (see subchapter 6.1.3) are required. For a safe operation weather restriction, such as limiting significant wave heights Hs for the support vessels must be considered, as well as the technological limitations regarding the current speeds for the deployed ROV/USV. Common issues with the navigation of ROVs have been reported to be caused by currents and by the cylindrical substructures, which cause a classic fluid flow problem, inducing eddy currents in close proximity to the substructure. This can make ROV operations in close proximity to the structure challenging.

Regarding AUVs, EQUINOR foresees a future where AUVs will be widely used, even though they are not still employed in its offshore wind farms. However, the experience gained in oil and gas installations bring a strong knowledge to include AUVs in the inspection plan. EQUINOR considers that it can help to reduce the downtime especially whenever offshore wind farms are far from shore.

7 ACCESSIBILITY

The waiting time for a suitable weather window in which the maintenance vessel or helicopter can reach the wind turbine and perform the transfer of the maintenance personnel has an essential impact on the plant availability. The sea state and wind conditions must be in a range that does not exceed the limits of the service vessels or the helicopter nor any restrictions for lifting or hoisting operations. The vessel access primarily depends on the maximum wave height on site. If the sea state is too severe and the wind is too strong, higher waves can be expected and exceed the limit values for access of the crew transfer vessel (CTV) or service operation vessel (SOV). For helicopter the accessibility depends on the wind conditions (velocity and turbulences) at the height of the hoisting or landing platform.

Floating wind turbines can open up new regions further out to sea. This brings along stronger winds and larger wave heights, which apply additional dynamic loads on the structures. The wind waves in the closed North Sea are shorter, whereas the swell waves prevail in the wave field of the Atlantic Ocean. Due to the long fetch of the Atlantic the swell waves can become quite long compared to typical vessel lengths. Significant wave height limits of vessels for the access to fixed-bottom wind turbines have been developed according to the wave conditions in the north and Baltic Sea. When moving to the Atlantic or Pacific Ocean these significant wave height limits need to be revaluated.

7.1 Relative Body Motion

The relative motion between two bodies describes the discrepancy between their individual movements; it is zero if both bodies move exactly at the same velocity, into the same direction. For floating wind, the relative motions of the floater hull or the nacelle in comparison to the motions of the crew transfer vessel (CTV) or the helicopter constitute a challenge, because different than for fixed-bottom wind turbines, the wind turbine substructure is now moving too. Due to its higher inertia the floater will react differently to the wave excitation than the vessel, such that both bodies do not necessarily move in the same direction or at the same velocity, when exposed to the same wave field. This can lead to excessive motions. To accomplish the safe transfer of technicians to the floating platform these relative motions need to be compensated.

7.2 Access Systems

Three categories of access system have been identified: a) Bow Transfer Method, b) Walk-to-Work System, c) Helicopter Access. They can be distinguished based on their point of access and are explained in the following section.

7.2.1 Bow Transfer Method

The most common access method is the bow transfer method, where the vessel connects with the boat landing attached to the transition piece of the tower for fixed bottom or to the floater hull on FOWTs. With its fender-protected bow the vessel pushes against the boat landing using the thrust force to create sufficient friction at the point of contact. This friction needs to be strong enough to compensate the heave, sway and roll motions induced by the waves. The time for the transfer of the personnel is often short because the boat can, on occasion, lose its position due too large waves or current, [71].
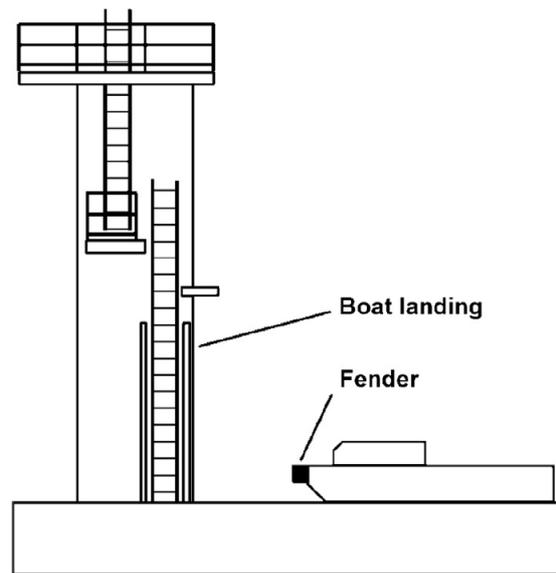
Figure 24: Access by Bow Transfer Method, [source: [72], adapted by [73]].

The operational decision, if the weather window is suitable for the maintenance campaign, is taken by the site marine coordinator depending on the weather conditions. CTVs can operate up to a significant wave height of around 1.5 m. Access however is also depended on the wave frequency and length as well as on the sea current. This makes the decision more complex, [71]. The access from a moving vessel to a ladder attached to a fixed-bottom wind turbine is challenging because the vessels motions need to be compensated in order to ensure a save passing of the personnel to the boat landing.

It exists a vast variety of specialized CTVs with the function to provide a fast access to offshore wind structures. CTVs are used to carry technicians and small cargo which can be lifted from the deck to the platform by the davit crane of the wind turbine generator (WTG) or platform. The CTVs can be categorized according to their hull shape which include: Monohull, Catamaran, Trimaran, Small Waterplane Area Twin Hull (SWATH) and the Surface Effect Ship (SES), which is similar to the catamaran but where the vessel's weight is lifted by an air cushion, [74].

A published report by TNO, [74], provides general characteristics and accessibility limits for all five vessel categories presented in Table 15.

Table 15: Characteristics of CTV types, [source: TNO Offshore Wind Access Report 2019, [74]].

	Monohull	Catamaran	Trimaran	SWATH	SES
Length [m]	12-25	15-27	19-27	20-34	26-28
Top Transit Speed [knots]	15-25	18-27	18-22	18-23	35-39
Passengers [No°]	12	12	12	12/24	12/24
Cargo [mt]	5-10	10-15	1-5	2-10	3-5
Hs (limit) [m]	1-1.2	1.2-1.5	1.5-1.7	1.7-2	1.8-2.2

7.2.2   Walk-to-Work System

The walk-to-work system (W2W) uses a motion compensated gangway with an extendable bridge which is provided by various providers independent of the ship. The connection is made by the bridge docking onto the external platform of the tower. A hydraulic system is carried by a service operation vessel (SOV) and compensates the vessel motions. It should be noted, that SOVs are typically fixed integrated systems and other gangways (mostly rental) are installed on Offshore Service Vessels (OSVs) for shorter term. The hydraulic compensation is assisted by a dynamic positioning (DP) system of the SOV. The DP-system is a computer-controlled GPS system which can automatically adjust and maintain the exact ship position with the help of propellers and thrusters. The maintenance crew is able to walk to work on a stationary bridge and can access the turbine at higher sea states in which a bow transfer would not be feasible anymore, see Figure 25. This allows for an increase in availability which becomes important for bigger wind farms far offshore where postponing a maintenance activity has a large impact on the productivity of the entire farm. Far from shore, transit times on CTVs are increased. This means that personnel are exposed to seasickness and other ergonomic issues. In contrary to a CTV, a SOV provides a base that is not depending on daily port calls and therefore limits transfer-time (more hands-on-tools-time) and also limits the exposure of personnel to rough CTV rides.
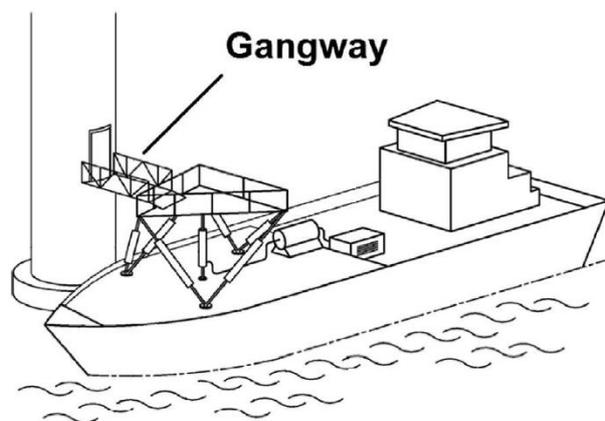

Figure 25: Access by a Motion Compensated Gangway, [source: [75], adapted by [73]].

During the conducted interview with a W2W system provider, experiences from the WindFloat project could be shared, according to which the floater has moved vertically up to 1.5 m and no pitch and roll motions have been apparent. In addition to the vertical floater motions, the ship moved horizontally and in pitch angles of max. 3 to 5 degrees. Another problem were the waves which were hitting the back of the ship (following sea). Due to the "hits" the DP system had difficulties to correct the position. The DP system reacted better in head sea, when the waves were hitting the bow. Multiple landing points on the floater substructure are helpful to be able to adapt to the wave direction. The operator of the gangway must take into account the various ship movements and the movements of the floater to land the gangway safely at a predefined landing point.

Commonly a H-profile beam serves as landing point on the floating structure which the operator needs to hit with the extendable bridge. This is proving difficult when confronted with relative motions as described above. In the O&G industry V-shaped landing zones, see Figure 26, are used which act like a funnel and ease the landing of the gangway for the operator. The funnels are difficult to retrofit and should be pre-installed as part of a maintenance friendly floater design.

Figure 26: V-shaped landing zone for the motion compensated gangway, [source: [76] with permission by Ampelmann].

The motion compensator of the gangway can equalize translations in x- and y- and z-direction, but manual control will result in a slight delay. Therefore a "follow-target mode" is currently being worked on. There are two types of follow target modes:

1. The **follow-target of the vessel**, which can follow the motions of the floater in surge-sway and rotatory motion with the help of a laser system and communicate to the DP2 or DP3 system of the vessel to better adjust the vessel's position with regard to the floater. For this purpose, light reflector strips would have to be attached to the turbine tower (Floater hull is not suited in order to prevent interaction with motion of the reflective PPE on the floater or obstruction by equipment on the vessel. The receiver is always placed on bridge-lever or mast, therefore the higher the reflector is the better.)
2. The **follow-target-assistance of the gangway**, which recognizes the landing zone on the floating structure and assists the operator to land safely. For this, an optical recognition is currently being developed by Ampelmann. The easiest solution would be a QR-code for which an industry standard still needs to be developed. The QR-code is then mounted on the floater at a standardized X-Y-Z-distance to the landing point. It will be scanned by a 3D-camera attached to the gangway, such that the landing will be assisted by the camera following this target.

With floating wind moving into deeper ocean regions, the prevailing swell waves challenge the Hs limits of the gangway systems developed for the North and Baltic Sea. The swell waves have longer periods which lie closer to the eigenfrequency of the SOV, such that motions build-up quicker and the Hs-access-limit is reduced. Bigger SOV types (110 m - 120 m length) are necessary for these regions to offer a calmer motion behaviour. It is recommended to use a reference vessel to determine the vessel utilisation rate in the Atlantic Ocean for different types of gangways. This would allow a realistic comparison and evaluation of the various systems.

7.2.3 Helicopter Access

An alternative option from accessing the floating structure by boat is to transfer the maintenance worker by helicopter to the wind farm. To decide if this option is the most economical solution and if it can be preferred towards a CTV or W2W access two factors have to be taken into account:

- The distance to shore
- The environmental conditions

7.2.3.1 Distance to Shore

The further away the wind farm is, the more likely helicopters are used. A CTV can take serval hours to reach the wind farm if it is located far offshore. An example is Global Tech 1 which is located about 93 kilometers northwest of the island of Juist. A CTV will take up to 4 hours to reach the wind farm. Assuming that an offshore shift lasts 12 hours, this transit time reduces the working time on site to 4 hours. The helicopter can be used to increase the available time for the inspection and maintenance work. The technicians are lowered onto the platform on the nacelle and the helicopter lands on the helideck of the offshore substation (OSS) to wait or flies back to serve in another mission. Helicopters are also employed to perform the crew change on manned platforms in less time than it would have been possible by boat.

When time is an important factor the helicopter becomes a valuable asset. In the case where a turbine stops working and immediate corrective maintenance is required to reduce the production losses, the helicopter is not dependent on the sea state to bring the technicians to the platform. If a helicopter is reserved for the wind farm (by contract or other agreement), a flight can be offered within one hour. The machine and the weather must be checked and fuel samples need to be taken. Flight performance calculation (passengers, fuel quantities) can be done in 15-30 minutes. Two crew members will be on board: the pilot and one who operates the winch. Their maximum flight service time is 10h.

7.2.3.2 Environmental Conditions

For CTV, the sea state is decisive, and can easily reduce the weather windows in which the access can be accomplished. The limits of 1.5 m significant wave height for common CTV vessels have now increased to rather 3 m - 4 m for an SOV with a motion compensated gangway, [77], or to approximately 2 m significant wave height with a SWATH vessel [78]. The helicopter, however, is independent from the wave height. Nevertheless, it needs to be taken into account as the helicopter pilot has to be able to handle the floater motions induced by the sea state.

The wind speed is more decisive for the use of the helicopter. For operations on an offshore location the legal limit, given by the EASA HOFO (**E**uropean **U**nion **A**viation **S**afety **A**gency **H**elicopter **O**ffshore **O**perations) [79], is a maximum wind speed of 60 knots on the helideck. Especially at higher wind speeds the turbulences are decisive for successful landing or hoisting operation and must be taken into account during the approach. The legal limits can be lowered by the wind farm operator. The wind direction is not a very limiting factor for the helicopter pilot. In daytime operation there is a 150° sector around the wind turbine available for the approach.

Other environmental conditions, however, put a limit to the use of the helicopter. It is not possible to fly during a thunderstorm and certain foggy conditions or heavy snowfall do not allow a take-off due to insufficient visibility. A minimum visibility of 2.0 km during daytime and 5.0 km during the night is required when two helicopter pilots are present during the flight. For a short time a visibility of 800 m in daytime and 1500 m in the night is accepted, provided the destination or an intermediate structure is continuously visible, [79]. The cloud base must be at least at a height of 600 feet (approx. 183 m), [79]. Large wind turbines would then already have the rotor tip in the cloud cover.

Another risk which occurs rarely but which can have severe consequences relates to airframe icing. In this case the aerodynamics of the rotor blades are no longer given. Very large helicopters have a blade de-icing system but smaller service helicopters such as those used for transport in OFW are not equipped accordingly.

7.2.3.3 Hoisting Operation

During the hoisting or winching operation, the technician is attached to a rope and lowered to the hoisting platform. The pilot holds the position reported by the hoist operator. As a reference the distance to the turbine and to the landing platform is used. For this, a good visibility is indispensable.

It is not uncommon that during winch-off operations on fixed-bottom wind turbines the nacelle can move between 1 to 3 meters, due to the flexibility of the tower. If the area under the helicopter moves so much that the movement cannot be compensated by the pilot, it is not possible to approach. The wind limits given by the OEM for the technicians' stay inside the nacelle also need to be respected. They vary between 18 m/s and 25 m/s average wind speed at hub height, depending on the wind turbine manufacturer. Even the helicopter can theoretically approach the wind turbine, the technicians may not be allowed to enter the nacelle.

The hoisting of technicians on the floater platform is technically possible and advantageous if technicians do not have to go into the nacelle, but work on the substructure or in the TP. For this purpose, a hoisting area must be clearly marked at a sufficient distance from the tower.

The winching area platform must be a clear, square or rectangular area containing a circle with a minimum diameter of 4 m and have a safety zone next to it to accommodate helicopter hoist operations passengers at a secure distance, [80]. The distance between the rear rotor of the helicopter and the turbine must be 5m, [80], (see Figure 27). Recommended is half the rotor diameter of the helicopter, which is about 5.5 m. This requirement can however not be maintained by larger machines which can have a diameter of 16 m - 18 m.
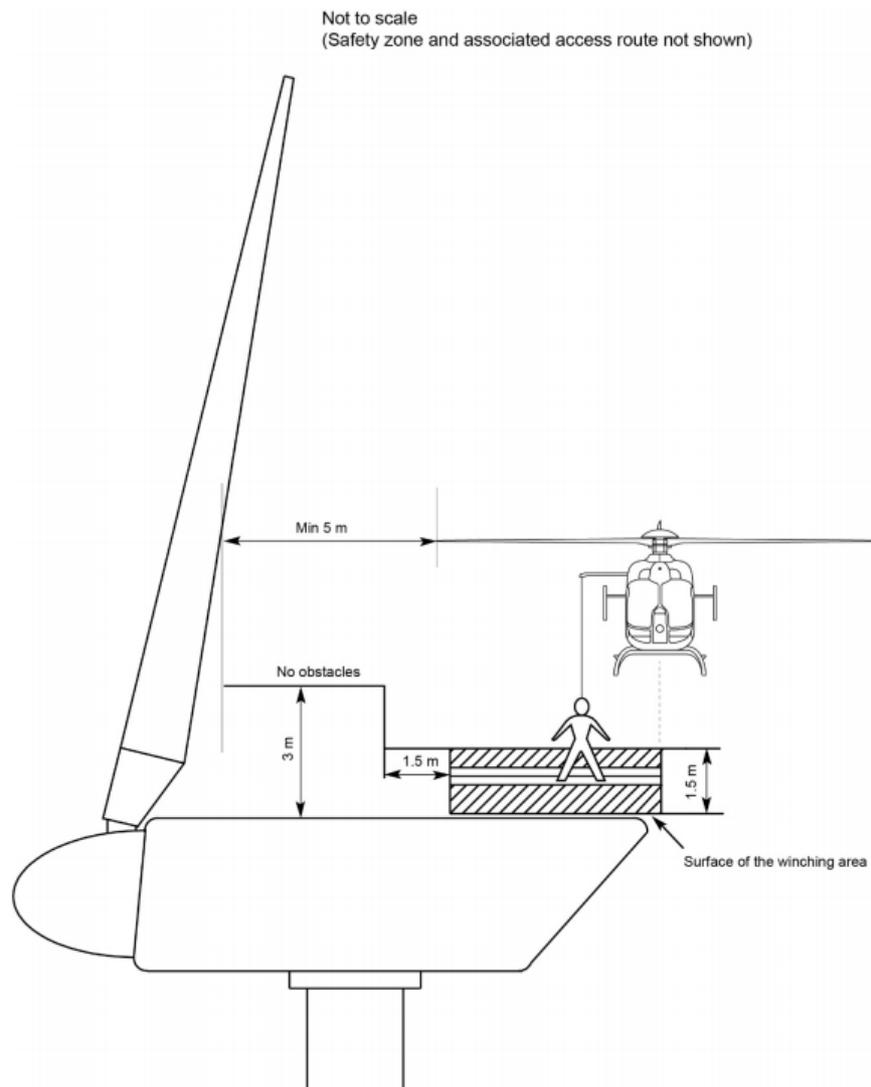
Figure 27: General arrangement of the winching platform on the nacelle, showing the safety clearance zone to the wind turbine rotor. [source: CAP 437, [80]].

7.2.3.4 Landing Operation

Landing on a FOWT would be comparable to landing on a mobile unit or vessel for which the landing procedure is well tested and proven. However, the FOWT motions would most likely be less critical than the vessel motions, due to the higher inertia of the floater and a resulting slower motion response. The operational limitations for landing on mobile assets (roll angle, etc.) are determined by the helicopter operator and follow legal recommendations (see Table 16). They are valid at the moment of touchdown and are based on proven procedures. These limitations should address the movement of the helideck in pitch, roll, helideck inclination, significant heave rate (SHR) and vessel heading and be incorporated in the Operations Manual of the operator. The pilot himself decides whether to break off if there is too much lateral movement (e.g. for a helideck on nacelle). Normally, in the case of an abort, the whole maintenance operation would be postponed.

Table 16: Recommended Limitation Values for Helicopter Access on Helidecks in Motion, [source: [81]]

Limiting condition of Helideck	Limiting value during good visibility	Limiting value at night/darkness
Roll	± 3 degrees	± 2 degrees
Pitch	± 3 degrees	± 2 degrees
Average Heave Rate	1,0 m/s	0,5 m/s

During the landing all motions play an equal role. Holding the position can become a challenge when the nacelle moves a lot. It is very difficult to follow these motions with the helicopter as it can be compared to following the motion of a blade of grass in the wind. In the military, extreme landing maneuvers are trained but not in the civilian sector. The minimum distance of 5 m to the blades must always be maintained, [80]. The UK CAA Paper 2008/03, [82], gives guidance on the helideck location and how the motions influence the operability of the helicopter. If a helideck is considered for the floating substructure it shall be included into the design at the earliest possible stage of the design process, [80]. On the ActiveFloat platform, for example a helideck could be considered on one of the external columns. With a 29 m distance from the column center to the tower and a vertical clearance of 6 m between the column surface and the lowest position of the rotor tip, there is enough space for the landing operation of a helicopter, [83]. On the Windcrete spar floater a helideck would have to be installed on the landing platform in form of a cantilever to ensure a minimum distance to the tower and the rotor tip in its lowest position. The increasing size of the substructures, as for the 15 MW WTG, will favor the installation of helidecks on the floating platform in the future.

7.3 Accessibility Study

Accessibility assessments have been carried out for the three different sites presented in [84]. The accessibility limits were defined following [83] for different CTV vessels allowable significant wave height. The maximum significant wave height in this study is 2m. The maximum wind speed allowed during maintenance is 7 m/s to 8 m/s, which drops to 4 m/s to 5 m/s for maintenance work on the top of the nacelle. The wind speed values are different for different turbine operators. For the accessibility assessment in this section the maximum allowable wind speed is 8 m/s.

The data for wind-wave scatter presented in [84] was used to calculate the access probability per year for every site. The probability of occurrence for wind-wave cases is multiplied by one if the wind speed is less than 8m/s, and the significant wave height is less than 2m. Otherwise, the wind-wave probability of occurrence is multiplied by zero. A zero probability is also marked for wind/wave combinations which do not occur on the specific site.

7.3.1 Site A: West of Barra

The accessibility probability for West of Barra is shown in Table 17. The accessibility probability per year is 29.08 %.

Table 17: Accessibility probability for West of Barra.

Significant Wave Height [Hs]	Wind speed (1 hour) at 10 m [m/s]					
	0.0 - 0.3	0.3 - 1.6	1.6 - 3.4	3.4 - 5.5	5.5 - 8.0	8.0 - 10.8
0.0 - 0.5	0	0	0	0	0	0
0.5 - 0.1	0	0.006342	1.336834	2.937483	1.137704	0
1.0 - 1.5	0	0.017757	1.345712	5.143133	7.230826	0
1.5 - 2.0	0	0.001268	0.801593	2.625471	6.501528	0
2.0 - 2.5	0	0	0	0	0	0

7.3.2 Site B: Gran Canaria Island

The accessibility probability for Gran Canaria Island is shown in Table 18. The accessibility probability per year is 77.49 %.

Table 18: Accessibility probability for Gran Canaria Island.

Significant Wave Height [Hs]	Wind speed (1 hour) at 10 m [m/s]				
	0.0 – 2.0	2.0 – 4.0	4.0 – 6.0	6.0 – 8.0	8.0 – 10.0
0.0 - 1.0	2.083	8.396	12.354	8.754	0
1.0 - 2.0	3.012	12.063	18.533	12.298	0
2.0 - 3.0	0	0	0	0	0
3.0 - 4.0	0	0	0	0	0

7.3.3 Site C: Morro Bay

The accessibility probability for Morro Bay is shown in Table 19. The accessibility probability per year is 31.98 %.

Table 19: Accessibility probability for Morro Bay.

Significant Wave Height [Hs]	Wind speed (1 hour) at 10 m [m/s]				
	0.0 – 2.0	2.0 – 4.0	4.0 – 6.0	6.0 – 8.0	8.0 – 10.0
0.0 - 1.0	0.084	0.27	0.28	0.084	0
1.0 - 2.0	3.103	9.247	10.896	8.021	0
2.0 - 3.0	0	0	0	0	0

It is clear that the site which is most accessible is site B - Gran Canaria, while the least accessible is site A - West of Barra. As the accessibility of the site decreases, the maintenance periods are more dependent on the environmental conditions and not just on the maintenance strategy. This requires a more robust and reliable system to be able to function for longer periods of time without the need for regular maintenance and inspection. Therefore, it is a necessity for the offshore wind turbine fault prediction to avoid long downtimes and production losses.

8 MAINTAINABILITY

The reliable functioning of the wind turbine under the given operating conditions is ensured by proper maintenance during the operating phase. The maintainability of an asset indicates to which extend these works can be carried out. This depends on many factors like for example the availability of vessels or helicopters, the accessibility of the asset, the available equipment, the training and the well-being of technical personnel performing the works. The latter is also known under the expression of human comfort. The ability of the technicians to perform the expected work highly depends on the human comfort criteria and is understood under the expression of workability. This aspect is assessed closer within this chapter aiming to provide an overview of standards and guidelines, requirements and limit criteria and numerical assessment methodologies in order to quantify its effect on the operation and maintenance phase.

8.1 Human Response to Vibration

To better understand the effects of vibrations on the human body this chapter provides a short introduction to the resulting health issues and the human response to vibrations.

Mansfield [85] introduces a classification of vibrations by contact site, effect and frequency. He distinguishes three categories into which the vibration a human is exposed to can be classified: Hand-transmitted vibration, whole-body vibration and motion sickness. Figure 28 shows the frequency ranges and magnitudes of interest to which the categories apply. While hand-transmitted or hand-arm vibrations (HTV or HAV) only cause vibrations in certain parts of the body, usually hands and arms (e.g. use of a pneumatic hammer, abrasive works), the whole body vibration (WBV) refers to motions which affect the entire body and are transferred over the ground or seat and backrest surface.

HAV mostly occur at very high frequencies between 10-1000 Hz. A prolonged exposure can lead to a hand arm vibration syndrome (HAVS) which irrevocably damages blood vessels, muscles, tendons and nerves in hand, finger and wrists, [86] [85]. WBV are commonly induced during transport. Mansfield [85] describes the sources as mechanical disturbances and impacts which occur while traveling. He states that the frequency range within which people are most perceptive of WBV lies between 1 Hz and 20 Hz. In his Handbook of Human Vibration [87], Griffin describes five effects of WBV as degraded comfort, interference with activities, impaired health, perception of low-magnitude vibration, and the occurrence of motion sickness. All effects can lead to various consequences like the interference with task execution or concentration which then leads to injury.

While Griffin includes motion sickness into the category of WBV, Mansfield introduces this phenomenon as a separate class. Because even though the whole body is affected by the respective motions, the frequency range and the effects on the person are very different from those which are characteristic for WBV, [85]. Motion sickness is induced by low frequent motions in a range below 1 Hz.

Studies performed by Schwarzkopf [88] showed that the motion response of floating offshore wind turbines is typically located in the low frequency range, below 1 Hz. Slightly higher frequency responses can be expected from the stiffer fixed bottom wind turbine structures, [89] and [88]. This study concentrates on motions of the entire structure induced by waves or wind. As in the maintenance case the wind turbine is switched off for safety reasons mechanical vibrations are not assessed in this study and therefore higher frequencies are not relevant for the human comfort of technical personnel. It follows that this chapter concentrates on WBV and motion sickness.
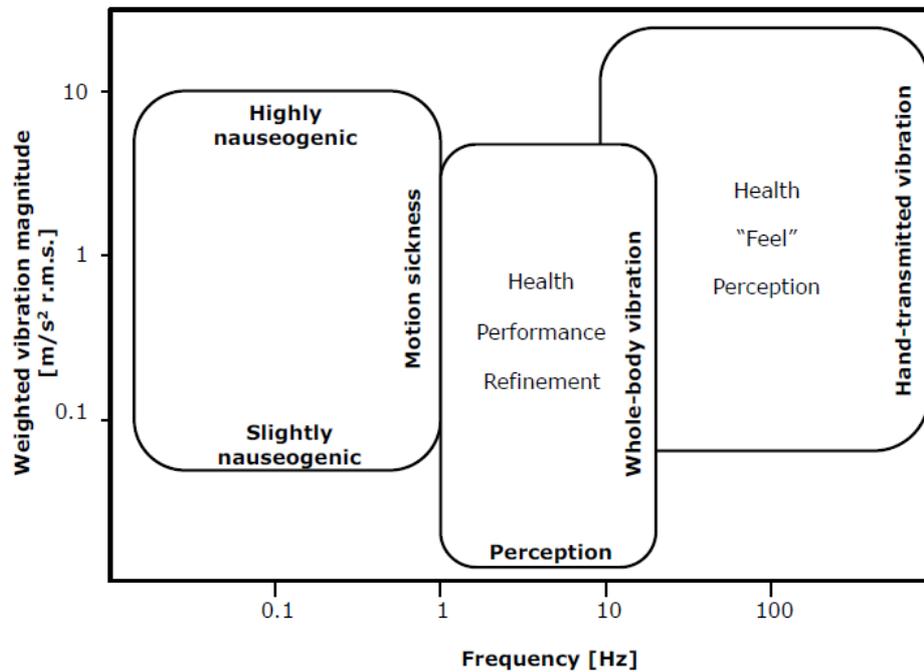
Figure 28: Motion characteristics classification according to Mansfield, [source: [85]].

8.2   The Concept of Workability

The complex motion behavior of FOWTs shows a motion response in all translational and rotational directions of all six degrees of freedom. The motion occurs in a combination of surge, sway, heave and rotatory oscillations, which lie in the low frequency range. The exposure to low frequent oscillations, like they are known to occur on ships or on very high buildings, can provoke a feeling of uneasiness, which is known as the phenomenon of motion sickness.

Widely discussed in the past for marine or railway transfer, human comfort is a fairly new topic in the wind industry. As the market becomes more competitive the reduction of the operational expenditures during the lifetime becomes more and more important. Maintenance campaigns are cost intensive especially for wind farms far away from shore, where the working time is limited due to longer travel times. The success of these campaigns is crucial to keep the availability high. Seasickness is directly related to the safety of the worker and can be decisive for the success or failure of a maintenance operation. The aim is therefore to include a workability assessment already in the design process of the structure. As the motion response varies greatly from one floater to another the workability needs to be assessed for each case individually.

8.3   Standards and Motion Limit Criteria

This chapter introduces the standards and guidelines which offer the most promising evaluation methodologies and motion criteria for the assessment of low frequency motions of floating offshore wind structures. This also includes literature from the railway industry, where human comfort has been assessed to a much larger extent due to its day-to-day application and the resulting public interest. For a thorough evaluation of these and further standards on their applicability to floating wind and the potential adverse effect of the motions on human comfort, it is referred to Schwarzkopf et al. in [90]. This gap analysis proved a deficiency in guiding literature to this topic for the offshore industry.

The most relevant standard is ISO 2631–1, referred to [91] and the ISO 6897, referred to in [92]. ISO 2631–1 provides general guidance on assessing motions of all frequency ranges. Motion limit criteria are, however, only given for a frequency range higher than 1 Hz. In ISO 6897 the motion assessment is described in line with ISO 2631-1, but it provides more guidance on treating low frequency motion in the lower range of 0.063 Hz–1 Hz. To make motion quantifiable, root-mean-square (r.m.s.) values are calculated with the following formula with x_i representing the acceleration magnitude over n time steps:

$$\mathrm{r.m.s.} = \sqrt{\frac{1}{n}\sum_{i=1}^{n} x_i{}^2} \tag{1}$$

Research ([93], [94]) has shown that depending on the frequency at which they occur, vibrations are perceived varyingly strong and with different nausogenic properties. To take into account the relation of the physical scale of vibration measurement to the probability and severity of the annoyance, the standards require to postprocess the signal with band-limiting low and high pass frequency filters (e.g. Butterworth filter), as well as acceleration-velocity transition and upward step formulations. Weighted means that frequencies which are not relevant for the assessment of motion sickness are reduced. Accelerations occurring during other, more relevant, frequencies are amplified. For detailed description of these postprocessing steps please refer to ISO2631-1:1997, [91]. For the assessment of motion sickness, the standard suggests the calculation of a *Motion Sickness Dose Value (MSDV)* or *Vibration Dose Value (VDV)* which respects the exposure time to the vibration and only applies to vertical oscillations. The same assessment is proposed by VDI 2057 – Part1, [95], with the following formula, where a_w is the frequency weighted acceleration for the measurement duration T_M:

$$\mathrm{VDV} = k\left(\int_0^{T_M} a_w{}^4(t)\, dt\right)^{\frac{1}{4}} \tag{2}$$

A correction factor k is applied and described further in [95]. For vertical motions $k = 1$. VDI 2057 gives different correction factors for x and y motions but explicitly states that those are only applicable for higher frequencies. This poses a problem, as a vertical motion dose value insufficiently reflects the complex motion combining lateral, vertical and rotatory motions of FOWTs. The standard acknowledges that the acceptable values of vibration magnitude for human comfort change for different applications and are subject to different influencing factors. Therefore, only indicative values, presented in, Table 20, are given by ISO 2631-1, which describe the reaction to different vibration magnitudes in public transport.

Table 20: Reactions to different vibration magnitudes for public transport, [source: [91]].

Vibration Magnitude [m/s²]	Perception
< 0.315	Not uncomfortable
0.315 - 0.63	A little uncomfortable
0.5 - 1	Fairly uncomfortable
0.8 - 1.6	Uncomfortable
1.25 – 2.5	Very uncomfortable
> 2.0	Extremely uncomfortable

An interesting approach can be found in BS EN 12299:2009 which presents the method of vibration analysis for train rides. The railway industry suggests displaying the variation of the root-mean-square value over the time length of the signal. The simulated or measured time signal is divided into multiple small-time windows, for each window one weighted r.m.s. value is calculated. The calculated value is then compared to a motion limit criterion. The time segment in which a threshold value is exceeded belongs to a certain railway section and can indicate irregularities in the corresponding railway line. This can then motivate an inspection campaign of this railway segment.

This approach is also applicable for the offshore industry where a parallel can be drawn for the motion assessment of the nacelle during a maintenance task. One offshore shift counts 12 hours, of which often 8-10 hours are effectively spend on the asset and 2 to 4 hours are spend on the boat transfer, [90]. With changing sea states and weather conditions during these time windows, peak values of high response amplitudes can occur and initiate motion sickness. The calculation of an overall r.m.s. value, as suggested by ISO 2631-1, would neglect the information at which moment during the time signal the peaks occurred and to which sea state combination they can be associated to. Orienting the assessment on the evaluation methodology of the DIN EN 12299 allows to display the variation of the r.m.s. value over the duration of vibration exposure, [88], [96]. This helps to identify how frequently the r.m.s. value exceeds a certain set motion criterion.

Those threshold limits suggest limitations on the motion exposure of personnel, such as a maximum average acceleration over time. An evaluation of existing threshold values has been made by Schwarzkopf et al. in [90]. The paper concludes that most standards suggest limit criteria only for frequencies above 1 Hz and that the guidance of standards on acceleration thresholds for low frequency responses is very limited. Those are not applicable to motions in floating wind as this is outside the expectable frequency range of the structures assessed in COREWIND. A frequency analysis of the floater accelerations of the ActiveFloat semisubmersible and Windcrete spar are presented in chapter 8.4.

Apart from the standard literature, the "Assessment of ship performance in a seaway" published by the Nordic research collaboration Nordforsk (1987), [97], provides relevant motion limit criteria for ship motions. The work is practically oriented and aims to develop criteria and methods for the verification of the seakeeping performance of vessels. Nordforsk addresses the decrease in performance due to deck wetness or motion sickness and provides threshold values of the vibration magnitude for different kinds of works on vessels. These limit criteria, presented in Table 21, are suggested for the evaluation of floating offshore wind turbine motions by [90].

Table 21: Limit criteria for r.m.s. accelerations and roll motions on vessels for different types of activities, [source: [97], adapted by [90]].

Root Mean Square Criterion			Description
Vertical accel. [m/s²]	Lateral accel. [m/s²]	Roll [deg]	
1.962	0.981	6.0	Light manual work
1.472	0.687	4.0	Heavy manual work
0.981	0.491	3.0	Intellectual work
0.491	0.392	2.5	Transit passengers
0.196	0.294	2.0	Cruise liner, older people

8.4 Frequency Analysis of the COREWIND Floaters

In this section simulations were carried out with the highest allowable environmental condition for the floating turbines' accessibility level introduced in section 7.3. Hence the parameters used for the simulations were as follows, maximum wind speed of 8m/s and maximum significant wave height of 2 m. The peak wave period is 6 s, this value was used from [84] which is the most probable wave period for our significant wave height. Site B - Gran Canaria from [84] is used for the frequency analysis throughout this section. The simulations also investigated the response of the turbine in both idling and parked conditions. The simulation frequency analysis was done by a FAST simulation for 5400 s then the first 1800 s were cut off to get rid of any transient effects.

8.4.1 Windcrete Frequency Response

Windcrete frequency response is shown in Figure 29. The frequency response for nacelle acceleration in surge, heave and pitch directions have the highest frequency response around 0.16 Hz, which matches the wave natural frequency. This lies within the critical frequency levels for motion sickness which is between 0.16 Hz and 0.2 Hz according to [94]. For the sway, roll and yaw motion the frequencies lie in the lower frequency range, coinciding with the natural frequency of each DOF. The higher frequency response around 0.5 Hz coincides with the tower's natural frequency. Looking at Figure 29, the idling simulation gives lower responses for the motion sickness frequency ranges, but higher frequency response at lower and higher frequencies.
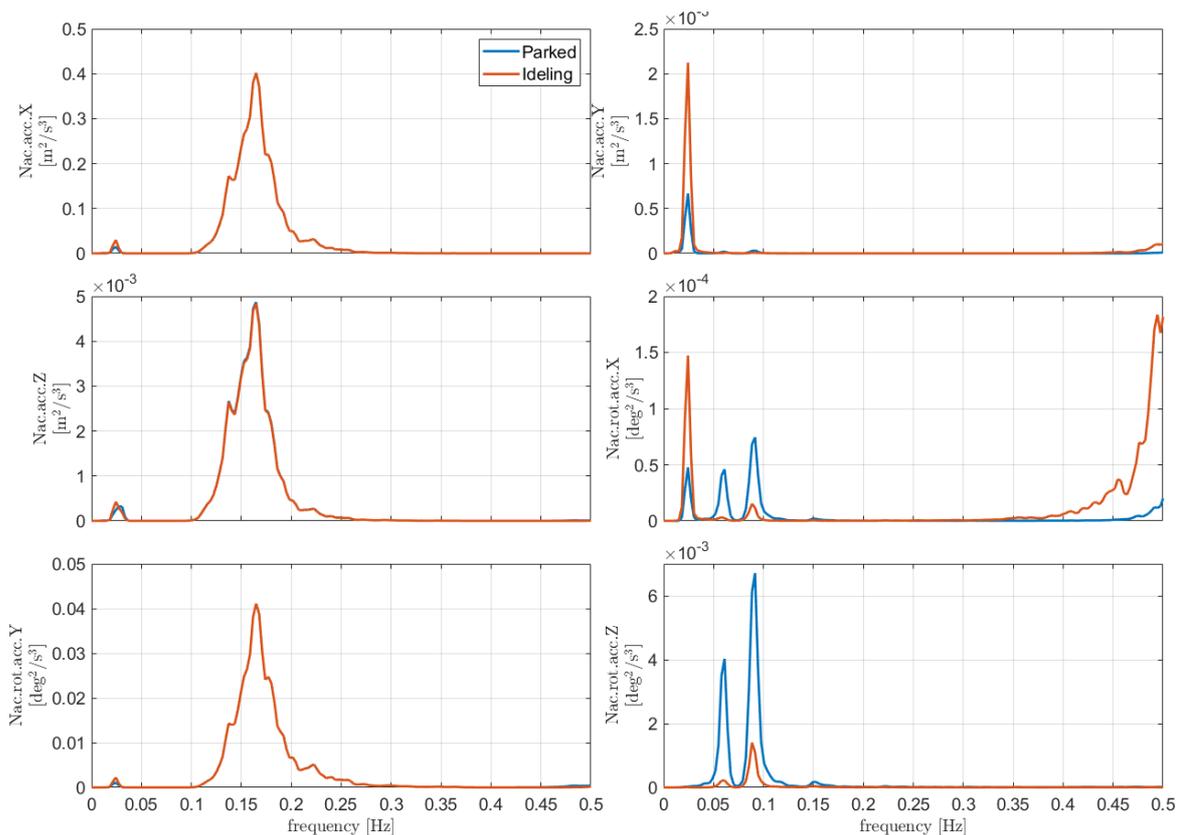

Figure 29: Frequency response for Windcrete parked and idling.

8.4.2   ActiveFloat Frequency response

ActiveFloat frequency response is shown in Figure 30. The frequency response for nacelle acceleration in surge, heave and pitch directions have the highest frequency response around 0.16 Hz, which matches the wave natural frequency. This lies within the critical frequency levels for motion sickness which is between 0.16 Hz and 0.2 Hz according [94]. For the sway, roll and yaw motion the frequencies lie in the lower frequency range, coinciding with the natural frequency of each DOF. The higher frequency response around 0.42 Hz coincides with the tower's natural frequency.
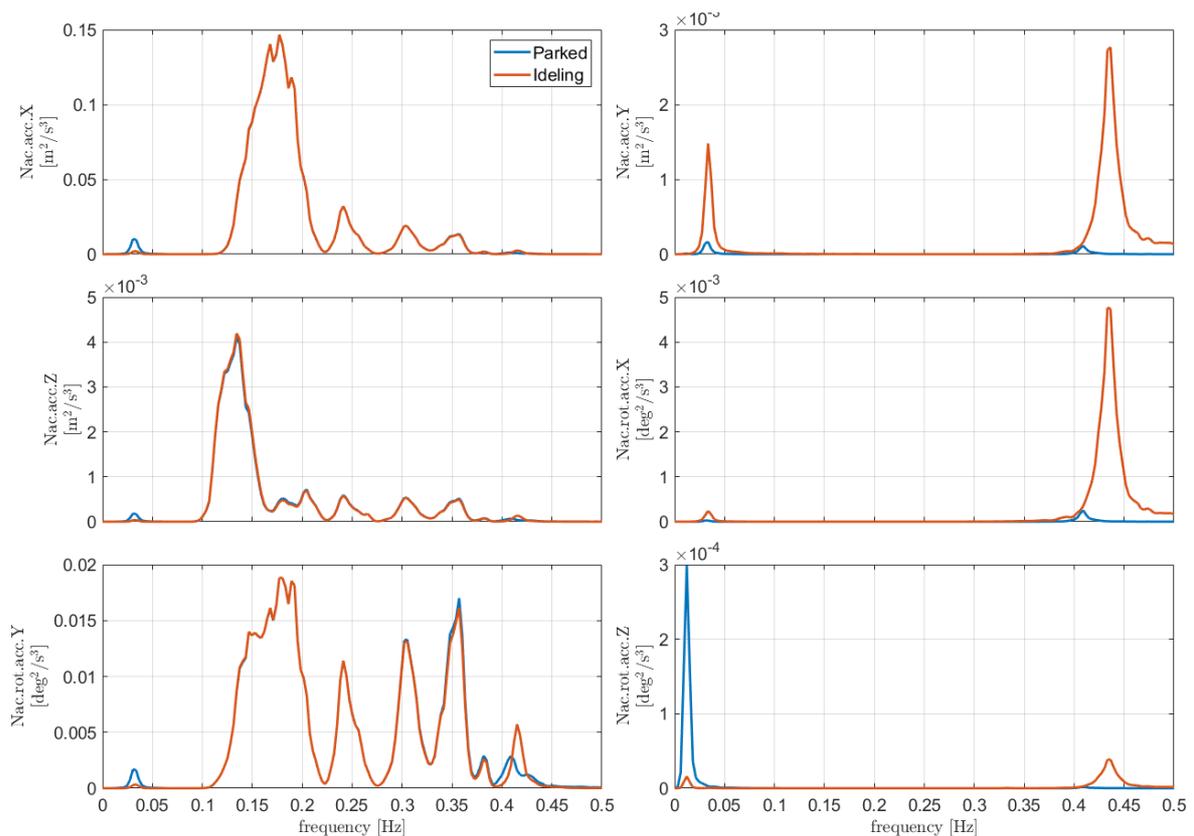

Figure 30: Frequency response for ActiveFloat parked and idling.

The frequency peaks between 0.2 Hz and 0.42 Hz in surge, heave and pitch is from the wave excitation frequencies shown in Figure 31. These frequency peaks coincide with peaks in the wave excitation forces, and hence affecting the nacelle's accelerations.
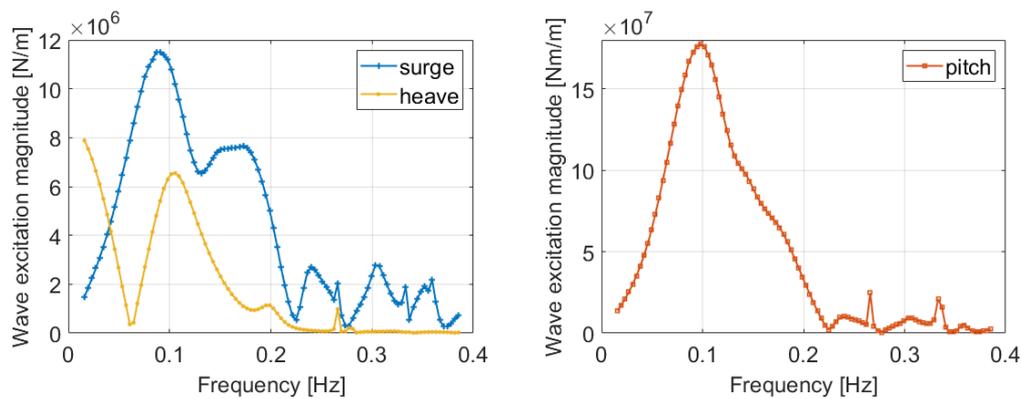
Figure 31: Wave excitation forces at ActiveFloat.

After looking at the frequency response for both floaters, we can see that the wave peak period plays a leading role in the nacelle's acceleration frequency peaks. This can be avoided by introducing a new accessibility limitation which includes the peak wave periods. This would suggest avoiding wave periods between 4.5 s and 7 s, to avoid intersection with the seasickness motion frequencies.

The amplitude of the frequency responses cannot be compared to the limit criteria in subchapter 8.3, because for this the root mean square acceleration needs to be calculated and weighting factors as well as filters need to be applied on the time signal. A more comprehensive study performing a workability analysis of the two floaters will be performed in the subsequent deliverable D4.2 of workpackage 4.

9 LARGE COMPONENT EXCHANGE

The advancing floating offshore wind technology has already established itself as a sustainable way of generating green energy in the future. With the deployment of first prototypes and commercially working wind farms with FOWT the question of how to conduct a major component exchange is rising up. It will play a big role for the economic operation of future wind farms. Since Jack-up vessels, which are generally used for the exchange of large components of fixed-bottom turbines, may not be a solution, given that floating offshore wind farms are typically located in deeper offshore areas, new solutions have to be found. Currently, there are two mainly discussed options: The disconnection and tow-in of the whole FOWT to a service port or shallow waters (discussed in 9.2) as well as the component exchange on-site (see 9.3).

9.1 List of Large Components

Large components of wind turbines can be identified by two main parameters. The dimensions and the weight of the component need to be taken into consideration, when planning and conducting a large component exchange (short: LCE). Normally, those components are the blades, blade bearings, hub, bearing of main shaft, generator, gearbox (if applied), high voltage transformer, switch gear, and in general everything that requires external equipment and cannot be handled on the turbine, e.g. reached or lifted with the internal crane (normal capacity of 3t).

Following the trend of growing wind turbines, 15MW turbines are the next generation for offshore wind applications. Exemplary the main components of the IEA 15MW Reference Wind Turbine are listed in Table 22 below. Figure 32 shows the turbine's principle structure. The IEA turbine works with a direct drive system and is therefore not equipped with a gearbox. Due to the susceptibility to failures of gearboxes it is assumed that future offshore wind turbines are mainly equipped with a direct drive system to lower the need of cost intensive offshore maintenance.
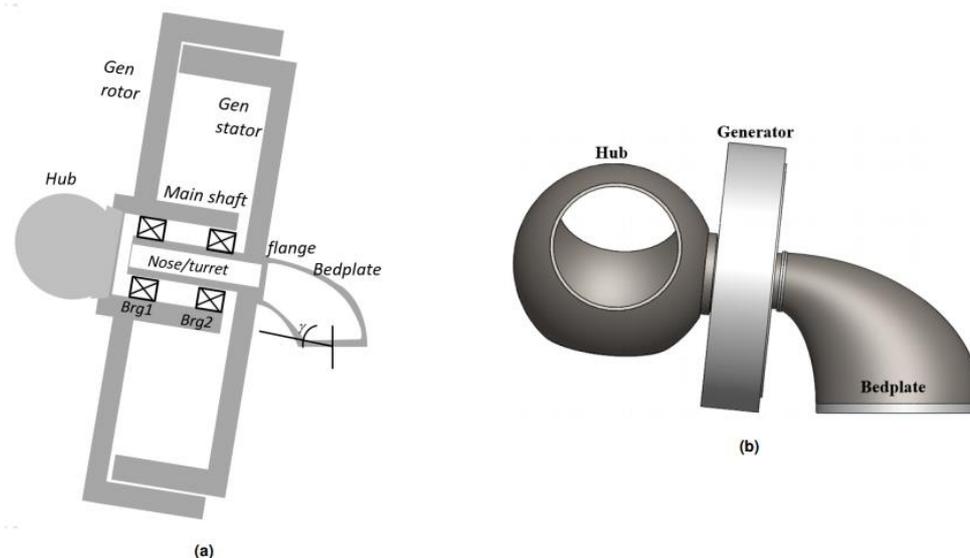

Figure 32: a) Sketch and b) CAD model of the nacelle layout of the IEA 15MW WT (Not to scale and some structural details omitted), [source: [98]].

Table 22: Main Components of the IEA 15MW Wind Turbine, [source: [98]].

Component name	Mass for IEA Wind 15 MW Wind Turbine [t]	Dimensions [m]	
Inner Generator Stator	226.629	Air gap radius	5.08
Outer Generator Rotor	114.963	Outer radius	5.15
		Core length	2.17
Shaft	15.734	Length	2.20
		Inner radius	2.80
		Outer radius	3.00
Hub	190.000	Base diameter	7.94
		Approx. length	11.00
Bedplate	70.329	Lower diameter	6.50
		Approx. total height	6.75
Turret Nose	11.394	Length	2.20
		Inner radius	2.00
		Outer radius	2.20
Yaw System	100.000	Diameter	6.50
Blade	65.250	Length	117.00
		Root diameter	5.20
Flange	3.946		
TDO Shaft Bearing (Two-row Double-Outer Race)	2.230		
SRB Shaft Bearing (Spherical Roller Bearing)	5.664		
Misc. Equipment in Nacelle	50.000		

9.2 Tow-In Strategy

The disconnection procedure for either the decommissioning or major repair works, which are planned to be done inshore, is in many terms similar to the installation procedure. This applies especially for the towing procedure. For the disconnection step of both dynamic cable and mooring system from the floater, all explained installation steps are conducted in opposite order. After all operating systems are shut down and the operational ballast system is emptied in order to reduce the draft. Hereinafter, first the cable system and then the mooring system are disconnected. The following towing process terminates the disconnection process, [48].

9.2.1 State-of-the-Art

Disconnection and reconnection for major maintenance is not yet a proven procedure for commercially working floating offshore wind farms. While detailed analysis of the benefits and disadvantages of such maintenance schemes was not performed in this study, because it is very site and design dependent, some statements can be made: The pre-tension in the moorings, dynamic cables and the mooring connectors should not be too high in order to use smaller equipment which gives an advantage on vessel requirements. Furthermore, the use of special mooring connectors and innovative solutions for the cable disconnection which are explained in more detail in the following subchapter 9.2.2 can save valuable time offshore. With the correct preparation the disconnection can be done in 2-3 days. Both disconnection and tow operations will have restrictive weather conditions for their execution. Typically, these operations are aimed to be seasonal and planned for the spring/ summer moths with the goal of decreasing the associated downtime and thereafter increasing availability. It is important to highlight the importance of the selection of the most efficient port, considering quay side/ dry dock availability, crane availability and capacity and supply chain availability. Depending on the nature of the require maintenance activity it is assumed that the in-port maintenance takes 1-2 weeks, excluding transportation time. To overcome this and reduce transport distance, a tow-in to sheltered areas and the use of a traditional jack-up barges for the repairs might be a viable option – however feasibility of this option is site dependent. In the future it is an open question how much investment in ports there will be to support installation and O&M activities for floating wind.

9.2.2 FOWT Requirements and Required Marine Operations

For the concept of disconnection and tow-in for major repair work several requirements for the FOWT system and also for the maintenance location onshore can be established. For latter mentioned general statements were already given in the previous subchapter 9.2.1. Note that, each location, design and operation need to be evaluated individually.

In the following, the requirements for the towing procedure as well as the main components of the FOWT are presented.

9.2.2.1 Towing Process

The towing process of floating offshore wind turbines demands several requirements to be fulfilled. Firstly, a suited weather window for the towing process has to be identified. As it can be derived from the presented examples in 9.2.3 a reasonable limiting significant wave height H_s can be set at 2m and the towing speed over ground varies between 2 and 3 knots. For the towing connection of the FOWT to the towing vessel additional tugs are needed. The towing process itself can be conducted by a single ship. As the convoy is very large and speed is rather slow, it is reasonable to avoid long stays in the navigation channel. Sailing out of the channel will prevent any risk of interference with regular navigation. When approximating the maintenance harbor or any pass-through where space is limited it is recommended to use a towing configuration with higher motion control like it can be seen in 9.2.3.2. Since the tow-in of a single FOWT from a commercially operating wind farm with more units has never been conducted, it might be a viable option to also make use of this high motion control towing configuration when leaving and returning to the wind farm in order to avoid interferences with the other units. For substructures with relatively small drafts like semi-submersible and barges the tow-in to a maintenance port should not experience any trouble. For substructures which gain their stability by a large draft like spars and TLPs the tow-in solution is more complicated due to the very high requirements of water depth. Therefore, it might be a better solution to tow the structure into sheltered waters and conduct the exchange using floating vessels.

However, the towing procedure shall be compliant with the international standards regarding navigational lights and shapes, various equipment and authorization (the following is taken from [99] and partly adapted for reasons of generality):

Navigational Lights and Shapes:

- Lights required by the International Regulations for Preventing Collisions at Sea, 1972 amended 1996, and local regulations (especially aeronautical regulation) shall be carried
- Lights shall be independently operated (e.g. from gas containers or from independent electric power sources). Spare mantles / bulbs should be carried, and fuel and power sources should be adequate for the maximum anticipated duration of the towage plus a reserve. It is desirable that a duplicate system of lights be provided
- The object being towed shall exhibit (towed object is considered as an inconspicuous, partly submerged vessel or object):
    — two additional all-round white lights at or near the extremities of its breadth
    — a stern light
    — a diamond shape at or near the aftermost extremity of the last vessel of object being towed and if the length of the tow exceeds 200 meters an additional diamond shape where it can best be seen and located as far forwards as is practicable.

Various Equipment:

International regulation will command the FOWT owners to operate the tow with the following equipment:

- A system of portable pumps such that any one tank can be emptied within a specified time
- A generator with sufficient capacity to operate the bilge pumping system, the navigation aids (lights and AIS) and the WTG simultaneously. Additional fuel tank should be installed to provide enough fuel for a specified minimum amount of time of continuous pumping.
- A boarding party should be appropriately equipped with survival suits, lifejackets and communication equipment.
- An AIS transceiver should be operating during the whole time of operation for an easy follow up of the convoy from the shore

Authorization

The following administrative procedures have to be taken prior to the tow:

- Airfield license: project must meet the requirements of the civil and military Agencies for safety during transport to offshore site.
- Maritime Transport License: the project must meet the requirements of the Maritime & Coastguard Agency and other regulatory requirements for navigational safety during transport to site.
- Prevention Plan: This document must be agreed and signed prior to the deployment.
- Coast Guards: Notice to Coast Guards shall be done with sufficient delay
- Port Pilotage: Pilotage shall be cleared, if not part of towing procedure
- Insurance: Insurance scheme with tow Contractor for the FOWT must be finalized
- Towing procedure will need to be approved by local authorities.
- Responsible authorities shall be warned with sufficient notice and will issue a special information (notice to mariners).
- Project insurance will provide a green light in relation with a favorable weather window for operation.

9.2.2.2 Mooring System

Regarding the mooring design, the top connector design is most relevant for the disconnection. Quick connectors (e.g. ball-taper bearings used by Principle Power) make this process easier. These types of connectors are typically lighter than other solutions, making them cost competitive. Their robustness over the whole lifetime can be a challenge, i.e. ensuring that the mechanism still works after a 20-year lifetime and accumulated corrosion and marine growth. Other, simpler connector systems using e.g. only links, could still be disconnected, but then likely involve either more complex marine operations and larger vessels, or if the links are simply cut, result in the additional cost, both for the component and the re-installation of the connector. During the temporary absence of the floater wet-storage on the seabed is most likely for chains. Regarding steel or fibre rope which might be part of the mooring system the wet-storage is rather problematic since dynamic seabed contact triggers abrasion. The rope material itself is not as expensive compared to the costs associated to the retrieval operations and re-installation. Additionally, the buoys which are needed to keep the lines off the seabed are expensive. To increase the robustness of the deployed fibre and hence decrease the cost of line handling, the use of a hybrid mooring line type, consisting of a combination of steel and fibre ropes, might be a valuable option.

9.2.2.3 Cable Disconnection

For cables it is very important to distinguish between an emergency disconnection and a controlled disconnection. In case of an emergency it is not the focus to maintain the accessories and the integrity of the cable structure: It must be ensured that the turbine can float freely and is not dragged down by the cable. A weak link system can help to not adding forces. The weak link ensures the main hang off assembly and shearing off electrical connectors during an emergency (i.e. at increased loading). Its inspection is therefore vital after installment and regularly during its life to ensure it still maintains condition.

 After the emergency the cable needs to be recovered and cut back to clear any damage and water ingress. Only as little as necessary must be cut back from the cable. The water penetration mitigation of the cable design for the time until the cable recovery happens needs to be taken into account. For a scheduled disconnection, due to maintenance purposes, procedures have been developed for WindFloat and Hywind, using dry-mate connectors in the form of T-connectors. The T-connectors are the main electrical termination connection of the core to the structure and are fitted during installation. During a disconnection, the T-boots are removed but some sections of the connector may remain. It is critical, that the core end is sealed to prevent water ingress. The pull-in head then is fitted over this end to enable disconnection. J-tube fit must be designed to consider the pull in head fitment over the product end during disconnection. Wet-connectors, which have been addressed in [31], are currently under development and have not yet been designed for high voltage applications.

Currently, there are two main designs of the cable exit point for FOWTs. The first is the traditional exit point in the transition piece at the centre section (e.g. Ideol, Hywind), where the cable enters and is hung-off inside. A J- or I-tube is attached to the substructure to guide the cable into the water. Once the connectors are fitted pulling heads need to be attached at the end of the cable to pull it back into the J-/I-tube. To prevent the cost intensive procedure of picking up the cable from the seabed, additional buoyancy modules can be attached, and the cable can be easily recommissioned at a later time. In this scenario, the end of the cable would have to be secured in order to keep it relatively localized and avoid collision risks. The alternative, which is currently in the market was designed primary for the WindFloat project by Principle Power. Hereby, the cable exit point is located on a separate spar which is attached to the floating substructure (see Figure 33). It can be unmounted in its entirety and float on the water surface as spar buoy. During the absence of the floater the buoy serves as a floating grid connection for the other operational FOWTs while the broken unit is being maintained. This solution decreases the transmission lost revenue due to floater disconnections.

The O&M strategy for the removal of turbines for routine maintenance should consider minimizing the loss of transmission and thus of revenue. This may be achieved by one turbine performing as substation, if this is cost

effective, or by linking of two cable ends together. The cable design and joint needs to be designed to allow this and the time to install and position the joint also needs to be considered.

Figure 33: WindFloat Atlantic with additional spar attached to the floating substructure, [source: [100]].

It should be noted that the connector hereby is fully exposed to the elements. Therefore, shelters and canopies might be necessary to protect the termination work. Due to the much smaller additional spar buoy oscillations are bigger and risk levels for onboard technicians are increased.

The electric disconnection procedure can take up to two 12h shifts. Therefore, timing of this operation is essential as the external environment is playing a bigger part with increasing distance from shore. The reconnection after floater re-arrival is expected to take the same time as disconnection. Nevertheless, testing is required after the re-connection, similar to the commissioning to guarantee the correct functioning of the cables (see 5.4.4.2). This is estimated to take up to two days.

For the disconnection operators need to have a good understanding of the loading on the cables and the weather limits of the vessel handling the cable. This may include personnel disembarking onto the floating platform. For O&M exclusively large W2W vessels and large SOVs can be used due to the remote distance and higher sea states. A CTV cannot be operated that far out the open ocean. The limits of the installation of the cable (pre-lay) are more vessel related whereas the connection and disconnection are more personnel related. Analysis need to be done to determine where the vessel limits are.

9.2.3   Examples

As described above the procedure of disconnecting the FOWT, its tow-in, the conducting of repair work and the following tow-out and recommissioning is a not yet proven procedure and has never been undertaken for maintenance reasons. Due to the lack of information to this overall process the following examples shall give an overview over the different steps. Furthermore, it is assumed that for the disconnection process the installation steps are undone in reverse order.

9.2.3.1 Principle Power WindFloat1 Prototype - Tow-In

After 5 years of successful operation off the coast of Portugal the Principle Power WindFloat1 Prototype was decommissioned in 2016. Objectives of the decommissioning procedures were the testing of a simple and cost-effective disconnection and towing of the platform as well as the removal of anchoring and cables systems. The latter mentioned would not be conducted for a tow-in for repair work. During the temporary absence of the FOWT it is most likely that wet-storage of the electrical cable and the mooring system is applied in order to assure an easier re-hook-up. For the cable there is also the possibility to use a separate buoy like seen above.

The decommissioning for the Principle Power WindFloat1 prototype had three distinct phases which can also be applied in a modified form to the tow-in for a large corrective event. Firstly, a planning and engineering phase was conducted followed by the offshore phase where the platform was disconnected from its mooring and cable and towed approx. 400 km to the deep water port in Sines, South Portugal (see Figure 34). During the installation in 2011, the offshore work to be done was dependent on favorable weather conditions which was indicated by a significant wave height of $H_s < 2m$. Due to the similarity of the required steps it can be assumed, that the offshore work during disconnection was also limited by this value.

Figure 34: WindFloat1 prototype decommissioning map, [source: [101]].

The main cost driver regarding the towing procedure is the used vessel. For cost saving purposes, from Viana do Castelo to Sines, a 30 m long 455 gross ton tug with an 80-ton bollard pull was used to tow the FOWT to its destination. The towing speed was limited to three knots to assure a save travel. The overall offshore operation lasted for three consecutive days. In the third phase, the onshore phase, the turbine was decommissioned at quay side and the platform was inspected and prepared for winter storage (see Figure 35).

Figure 35: WindFloat at Sines quay side, while the turbine is being decommissioned, [source: [101]].

The docking maneuvers were done in a few hours before the disassemble could start. The fact that the platform was floating caused no issues to the crane operators. [101]

9.2.3.2 Ideol Floatgen – Initial Tow-Out

The tow-out for Ideol's Floatgen structure was divided into two different phases. The harbor tow out of the port of Saint-Nazaire, France and the seagoing tow. Due to limited space in the harbor water a rigid convoy configuration was chosen which enables a higher motion control where the tugs are in contact with the FOWT. Two tractor tugs (each with a 40-ton bollard pull) in the FOWT bow and one Azimuth Stern Drive vessel (60-ton bollard pull) in the FOWT aft were moored to the floating structure. The following Figure 36 illustrates the constellation.
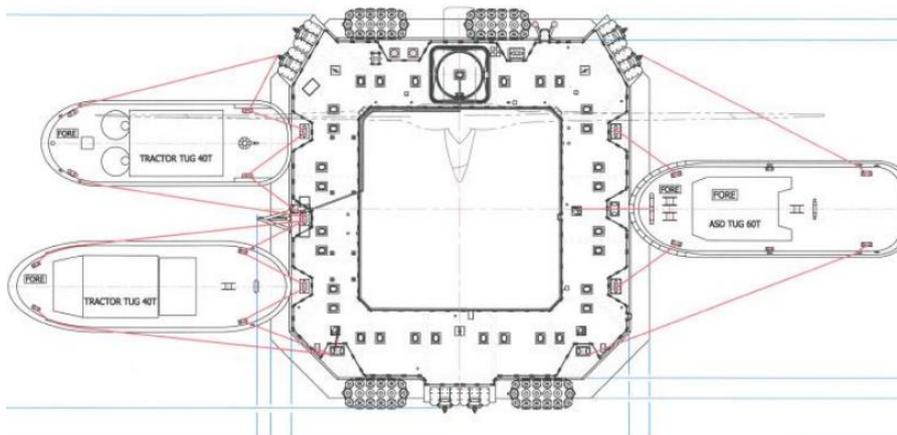

Figure 36: Port towing arrangement with local tugs for Ideol's Floatgen, [source: [99]].

As the convoy reached the coast the sea towing commenced. Therefore, a more classical towing configuration was chosen and two solutions were provided, depending on vessel availability. Towing analysis has confirmed the use of a single tugboat (90-ton bollard pull) on the bow or two tugboats in parallel tow (60-ton pollard pull) as illustrated in Figure 37.
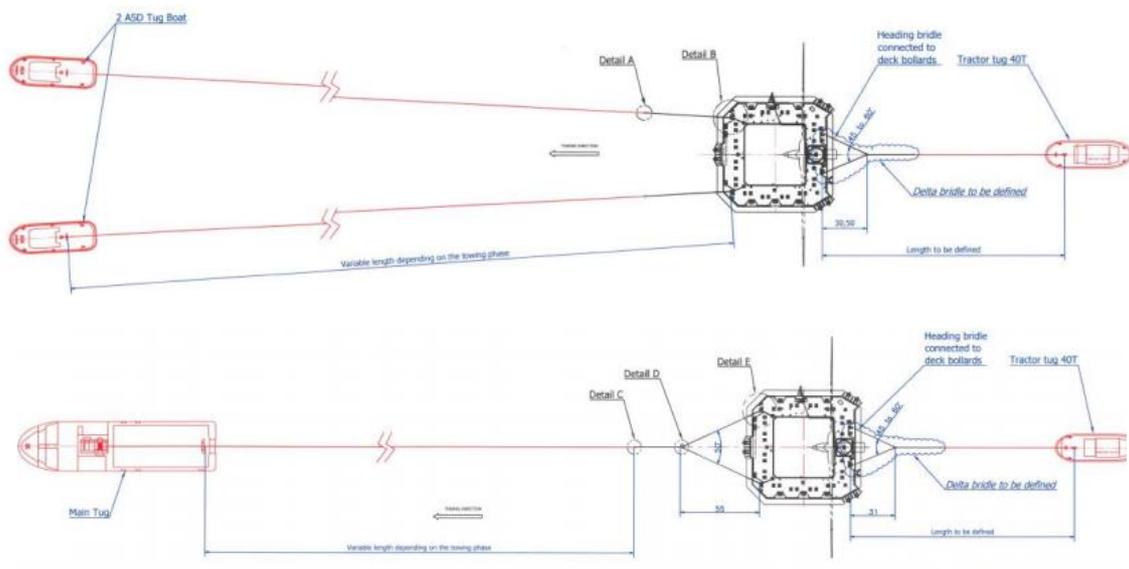
Figure 37: Configuration options for sea going tow for Ideols Floatgen, [source: [99]].

For the towing procedure environmental conditions have to be taken into account. For the sea going tow a towing force has been computed for calm and normal conditions with 2 and 3 knots towing speed over ground and a limiting significant wave height H_s of 2m. As the convoy is very large and speed is rather slow, it is intended to avoid long stays in the navigation channel. Sailing out of the channel will avoid any risk of interference with regular navigation. The planned route is 29nm (15hours at 2kn) or following the navigation channel 40nm (20hours at 2kn). [99]

9.2.3.3 Hywind Scotland – Initial Tow-Out

All five spar structures and turbines were mated in Stord, Norway and had to be towed individually across the North Sea into Scottish waters off the coast of Peterhead in mid-July of 2017. Estimated duration for the towing process were 4-5 days. This leads to an approximate towing speed of 2-3 knots over ground (approx. distance 495km (measured by Google Maps)). The turbines were towed standing, with a submerged depth of 80m using Solstad Shipping's anchor handling tug supply vessels Normand Rangerand and Normand Drott. [102] For the hook-up to the towing vessel additional tugs were needed as it can be seen in Figure 38.

Figure 38: Preparations being made for the first turbine to be towed to Scotland, [source: [103]].

Figure 39: Turbine being towed to open waters, [source: [104]].

For a large component exchange it was stated in [105] that, the units can be disconnected and towed to shore to allow more efficient working in sheltered waters if offshore lifts are hindered by waiting on weather. Offshore lifts would require a crane vessel, while the tow-in solution would likely require tugboat(s), anchor handling vessel(s) and a crane vessel/barge. The Pilot Park would continue operation in the situation where a WTG Unit had been removed.

9.3   Component Exchange Offshore

Next to the tow-in operation for maintenance reasons it is discussed to perform large component exchanges of wind turbines directly on site. Major challenge for this kind of operation is the dynamic environment and therefore the relative motion between the two floating bodies (operation vessel and FOWT). Due to the unreachable seabed in deeper waters Jack-up vessels drop out as an option. Since there is only a limited number of installed floating turbines, experience with the challenges of accessing floating offshore wind turbines is limited. The floating structures of the O&G industry should and can be used as a reference. It should be noted that floating O&G structures are much larger and therefore behave differently. However, having both systems (floating structure and vessel) synchronized is not 100% possible.

One further criterion to consider is the weather window on site. Due to the open water conditions weather windows for complex operations are even more important to consider than for maintenance activities inshore where the swell can mostly be neglected. Motions of the structure at open sea depend also very much on the

type of the platform. While TLPs may be more stable during the operation spars, barges and semi-submersible substructure show a higher level of dynamic motions.

However, research and development has already been conducted including the development of tower-climbing and self-hoisting cranes, new positioning systems for vessels to compensate relative motions as well as adapted RNA designs by OEMs. But the hurdle to overcome are the costs. Offshore large component exchange needs to be cheaper than the exchange onshore at the harbor. Therefore, new technologies are needed. Bigger companies dealing with O&M operations are trying to finance their ideas or are already testing them in less harsh conditions like onshore applications. For floating offshore wind there are many things to consider also concerning safety and compliance. Financing of these developments will take some time, since yet there is no pull by the market side. This will change as soon as first commercial floating wind farms exist.

For now it seems that the tow-in operation is the winning solution (at least for the next 5 to 10 years according to a stakeholder) but in the long run and with the development of new technologies, it is likely that most repairs to the extent possible will be performed offshore. This would eliminate the need to disconnect and reconnect moorings and cables and to find a suited maintenance harbor.

To evaluate the cost of future offshore component exchanges the following points need to be considered:

- Local regulations (assets/local content-manpower)
- Location of FOWT
- Mobilization and availability of marshalling site
- Number of WTGs to be maintained
- Additional services which are required (e.g. installation of necessary equipment)
- Offshore working environment and consequently the motion behavior of the floating foundation
- Complexity of the work to be done
- Insurance costs

9.3.1   Current Developments

9.3.1.1   Offshore O&M Hub

In order to facilitate the O&M process for wind farms far from shore (mostly floating) and therefore to lower the costs of transport and maintenance the idea to establish an O&M hub at site is a valuable option and was mentioned several times by various stakeholders. This possible O&M hub could be a strategic spare at the OSS of main equipment which is beneficial for fast maintenance such as transformers which are standardized across the sites. The spare part is connected while the other part is repaired on land. This can be beneficial for commercial scale floating wind farms as well for the routine maintenance activities. Standardization across a wind farm would generally lead to reduced complexity and a better availability of spares.

Other stakeholders can imagine a big offshore dry dock which could be useful for the whole industry. One would be less exposed to weather factors but is also restricted because the hub would only be at one place. Increased towing distances to such an offshore hub with available cranes may be costlier than other solutions.

9.3.1.2   Adaptions of Designs by OEMs

The industry is trying to keep the movement of the nacelle in a certain range to make the process of large component exchange easier. Therefore, turbine manufactures are trying to make improvements in their turbines, such that small movements are tolerable. Turbine manufacturers are also starting to move to more manageable and maintainable designs, e.g. by exchanging bolted connections with fast connectors.

According to stakeholders, the connection method called "slip joint connection" could speed up the installation and therefore also the exchange process of components. This "slip joint connection" is a relatively new method which was firstly adapted in the fixed-bottom wind market. Hereby, the connection between turbine mast and foundation mast is not formed by a bolted flange, nor by a sheath of grout, but consists of two conical shells that fall on top of each other (for more detailed information please see [106]). This kind of connection might also be used in future application for the tower-nacelle- as well as the nacelle-blade-connection in order to simplify the exchange process.

General statements that could be drawn from the interviews are that designers should keep the number of components to a minimum in order to reduce costs because the exchange of those components will be difficult (considering insurance and feasibility). Current large component exchange campaigns are related to older turbine models, which are more prone to failures. The focus of OEMs shall be a design in which large component exchanges are not necessary but if needed, can be easily conducted. Therefore, the reliability of the system shall be monitored closer in the future to avoid expensive exchange campaigns and the WTG shall host more lifting tools and devices to realize a fast exchange. Wind turbines are often equipped with an internal lifting system, e.g. davit crane. Its lifting capacity reaches a maximum at around 3 tons and allows for quick lifting of smaller spare parts and equipment which is more cost efficient than with external lifting devices. If the internal crane reaches the limit of its lifting capacity, external equipment is necessary to perform the lifting operation. This changes the circumstances and brings the operation cost- and effortwise to a new level. But with bigger turbines, higher crane capacities above these limits would be valuable for the future. As it was pointed out by a stakeholder, it is a large and complex task to install an internal crane system on a turbine while also complying with all regulations including the increasing HSE. To get the best result regarding maintainability it is vital that WTG suppliers maintain a close dialogue with the offshore contractors who actually perform the offshore work.

9.3.1.3   Self-Hoisting Cranes

The major challenge to overcome are the relative motions between the operation vessel and the FOWT so that lifting operations based on the vessel are quite complex. But if the cranes are installed on the floating structure itself, stakeholders do not expect any issues with the movement. Self-hoisting cranes are installed by using wires attached to the nacelle. They have the ability to crawl via those wires from the base station on the ground (or vessels for offshore applications) up to the nacelle and conduct lifting operations of large components lowering the impact of motion restrictions and wind speeds.

One stakeholder interview was led with Liftra, a self-hoisting crane developer from the onshore wind industry, who is currently developing this technique for offshore application. The biggest developed crane has a maximum lifting capacity of 72t in a very short lifting arm and would have a purchase price of around 6 M€. The capacity depends on the reach of the crane, the higher the leaver arm, the less it can carry. The application lies in the onshore market where every large component can be exchanged and it is not expected to be different in similar conditions offshore. The peak wind limit for lifting up the crane and the spare parts is 18 m/s but more jobs need to be done offshore to assess the limits of the wave height.

For the installation of the crane several steps need to be conducted:

1. The container which contains the crane system including the wires is brought to the turbine by a truck in the onshore case (see Figure 40) and by a barge for offshore use. A CTV would bring the people on/off the platform. For the smaller crane types the container is also smaller and can be carried by the CTV. This would not be the normal case as the bigger crane would normally be deployed offshore. It should be noted that the container has a weight of 30 t on a length of 12.2 m with the crane. Therefore, the barge must have sufficient space and carrying capacity for the container and the component(s) to be replaced.

2. The nacelle top cover is opened by a pre-installed crane on the nacelle to allow installation of the interface (called base plate) for the self-hoisting crane.

3. Then the base plate and the wires are lifted up by the pre-installed light-weight crane and installed on top of the nacelle. The base plate is individual for every turbine model and designed in coordination with the turbine supplier.

4. The self-hoisting crane then crawls up on his own wires and is fixed to the base plate.

5. Spare parts are lifted by self-hoisting-crane and installed on the turbine (see Figure 41).

Figure 40: Self-hoisting crane climbing its own lifting wire from its container to the nacelle, [source: [107]].

Figure 41: Self-hoisting crane changing gearboxes in a Nordex 2.5MW turbine, [source: [107]].

The spare part exchange is facilitated with the crane mounted on the nacelle of the turbine. This enables that the crane moves together with the turbine which allows a safer operation than when a big crane is positioned parallel to the turbine but not fixed to it. This applies to fixed-to-fixed lifting but also fixed-to-floating, floating-to-fixed or floating-to-floating. A freely floating solution will be more sensitive to the weather window resulting in time restrictions. When the suspension wires are installed, these wires will help the crane to crawl up. They are managed by electrical drives, which are adjustable in speed and torque, see Figure 42. A heave compensation of the movement of the deck of the vessel is directly included in this solution. This control is managed over the winches which are located on the vessel and future improvements will include that the winches act dynamically according to the vessel motion, see Figure 43. They are compensated in such a way that they do not bring any oscillations to the crane so that the tension of the wires needs to be kept constant.
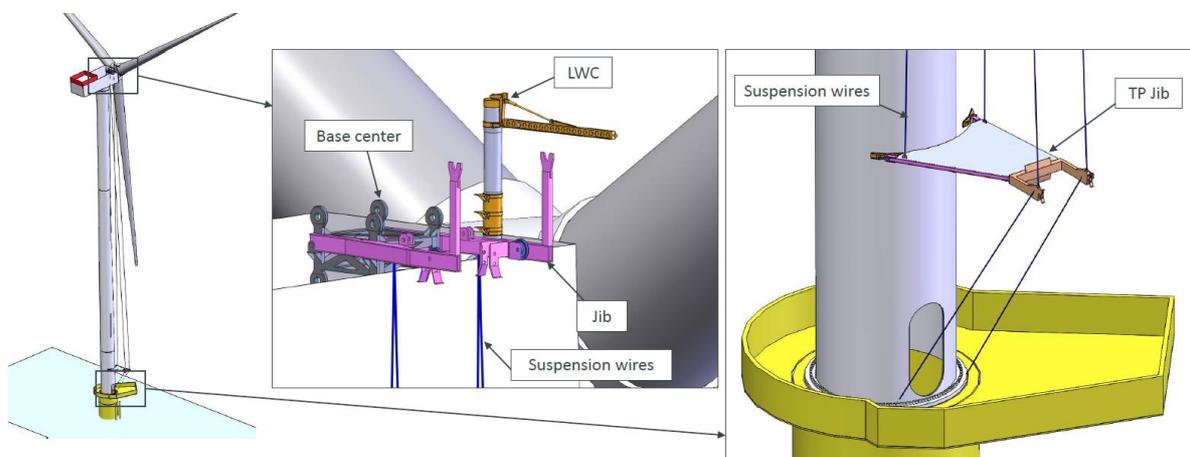

Figure 42: Preparation process: Base parts, nacelle jib and TP jib are installed using the lightweight crane (LWC) or nacelle crane, [source: with courtesy from Liftra]

Depending on the floating substructure one could avoid the need of a separate barge to host the crane base. If the substructure offers enough space (mostly applying to semi-submersibles and barges) the container and the spare parts could be lifted on the floating platform by a small crane system. Then the crane would be located on the same reference system as the turbine. This would solve the problem of the relative motions during the LCE. Deeper waters change the dynamics of the waves and this makes it necessary to change the setup to keep it safe and sound. For this operation it is necessary to provide sufficient space on board of the platform to perform the job. The container has a size of 12.2m and a weight of 30 t. This can be positioned where the helideck or hoisting area is foreseen on the platform or any other free space that allows enough distance to the turbine to hoist up the crane, auxiliary components and the component to be replaced.
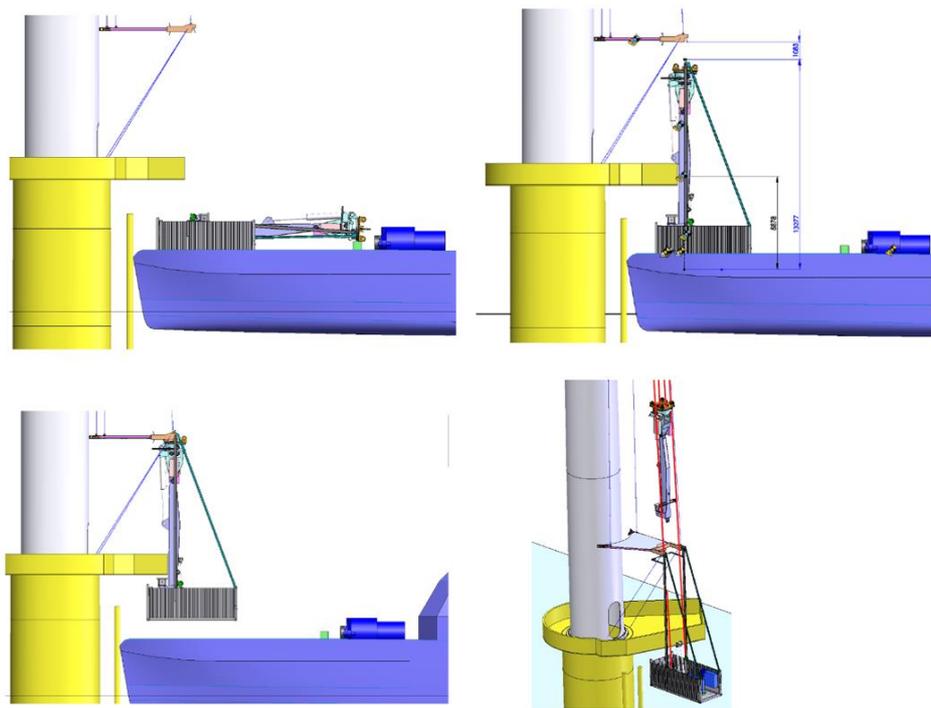

Figure 43: Installation process: Lifting the crane to the nacelle, [source: with courtesy from Liftra]

For a large component exchange (Note here: onshore LCE, since offshore has not been conducted yet) it is possible to perform the complete operation within 48 hours if the team works round the clock. Under good conditions it would be possible within up to 36 hours. But normally it will take more days as no shift operation will be established and weather conditions will not be perfect. It should be noted that weather windows are a major influence for the offshore application and times can vary significantly. Also transport and vessel availability plays an important role. Another critical point for offshore but as well for onshore is the installation of the plate base which is strongly dependent on the internal crane of the nacelle which is individual for each turbine type. In general, the efficiency of the process depends on the quality of the O&M equipment onsite.

For an LCE conducted by the self-hoisting crane approximately four people from the supplier team are necessary. Two at the bottom and two on the top of the nacelle (50% at the bottom and 50% at the top). This is for onshore but offshore can be similar. Some more people from the OEM will be there, stakeholders checking the installation quality, and HSE people. OEMs can operate the crane by themselves if they followed the Liftra's certified training program. With technicians on top of the nacelle while cranes are operating in close proximity, some stakeholders see HSE issues e.g. if technicians need to exit in case of an emergency.

For next generation wind turbines (>15MW) Liftra states that new solutions will need to be designed to comply with bigger components. This process takes approximately one year and requires close collaboration with OEMs.

9.3.1.4 Climbing Cranes

Similar to the above described self-hoisting cranes, climbing cranes make use of the same reference system as the floating wind turbine and thus mitigating relative motions. Climbing cranes are currently under development and have only been tested onshore. But they have potential to facilitate the installation process as well as the LCE.

Climbing cranes are able (after being adapted to the tubular steel tower) to climb the tower up to the nacelle. From there the lifting operation of large components (like blades) from the ground or barges can commence, enabling a smooth assembly.

Figure 44: The Lagerwey climbing crane luffs its boom hydraulically, [source: [108]]

Figure 45. Blade installation at nacelle using the Lagerway climbing crane, [source: [109]]

The Lagerwey climbing crane LCC140 can hoist a maximum capacity of 140t while it has a net weight of 240 tons. It can be assembled and disassembled each in one day and requires approximately 500m² for its construction. [109]

9.3.1.5 GREP System

Parkwind, Heerema Marine Contractors and MHI Vestas Offshore Wind announced a revolutionary construction methodology for Arcadis Ost 1 located in the German Baltic Sea. Due to challenging soil conditions at site the classic method for bottom-fixed turbines using a JUV could not be used. Hence, they developed a floating solution called the GREP System. A floating vessel carries all turbine components necessary on its deck including a dummy tower (red-white in Figure 47), which will be used for pre-assembly of the RNA. After the nacelle has been assembled it is lifted on to the dummy tower where the blades are attached. For this the blade is grabbed by the roots and moved it into position (GREP System, guided root end positioning). The complete RNA will then be lifted and installed onto the actual preinstalled tower. [110]

Figure 46: GREP Tool, [source: with courtesy of HEEREMA]

Figure 47: Visualization of RNA Assembly Process [source: with courtesy of HEEREMA, [111]]

It has to be noted, that this procedure was developed especially for bottom fixed turbines and therefore cannot be easily applied for floating to floating solutions. Nevertheless, this technique is a big step forward for the offshore wind industry and can lead to more floating wind specific solutions also applying for LCEs like blades or even whole RNAs since the relative motion for the RNA assembly can be neglected.

9.3.2 Floating Wind Requirements

The components of the wind turbines of the future of 15 MW and more will be heavier and bigger in size. Also, the equipment (partially described above) which will be necessary to conduct a large component exchange offshore will one way or the other require a certain space and capacity for transport and installation. The ships, barges and crane capacities need to fulfill these requirements in order to handle the equipment and components offshore. It was pointed out by a stakeholder that some existing vessels could conduct this kind of operation but it would increase the costs significantly (e.g. deep-water construction vessel "Thialf" by HEEREMA). The availability of these highly specialized vessels will also become an important factor to be considered in the cost estimation of these operations. Other stakeholders do not foresee the use of offshore installation vessels and point out, that new vessels with heave compensators will be necessary, which will be different in design than currently available vessels. Bigger companies dealing with O&M operations are trying to finance the development of semi-submersible vessels which can adapt to the new tasks and turbine sizes, such that they are flexible in the operation tasks to perform. Those systems exist in lower scale, but upscaled versions are not in sight because the market is not following suit. For now, costs of these newly developed vessels cannot be easily extrapolated. However, if a floating to floating solution for the LCE is applied, the use of a dynamic positioning system is vital to mitigate motions between the structure and the vessel. Due to the thrusters working on the continuous positioning of the vessel additional fuel is burned which needs to be taken into consideration.

If a component shall be delivered to the FOWT via helicopter it should be taken into account that most winch-off areas can only carry about 100kg and that most winches are allowed to carry a mass up to 300kg. This results in a limit of transportable goods. By attaching a harness underneath the helicopter an external load transport is possible. This harness can carry up to 1000 or 2000 kg, which compared to the masses of Table 22 is still relatively small and is roughly equivalent to common internal crane capacities.

Due to the complex operation of an LCE for FOWT, time is limited to suited weather windows. Weather windows vary on the time of the year and therefore, offshore component exchange is likely to happen during the summertime if planned or non-foreseen in order to lower the risk. In any case, a thorough pre-investigation is required. For the installation process with floating vessels a common wind speed limit is 25knots. Not only the wind can influence the available weather window but also the swell. During the installation of WindFloat Atlantic very different conditions were observed, from challenging 0.5-0.8 m to limiting swell of 1.5 m. Hence, the swell can limit the suitable weather windows significantly or make the operation challenging in some locations. Anyhow, the installation is always performed within the limits given by the OEM. New limits for floating installations are to be defined in consultation with the vessel developers, the floater designers and the OEMs.

For an offshore large component exchange specialised people from different organizations are necessary to perform the operation. The following is only a rough estimation since every operation needs to be planned individually and is also depending on the required time.

- 8-10 turbine technicians send by the OEM, max. 6 in nacelle
- 20-25 technicians to handle offshore equipment
- Operating team of vessel (captain, DP operator, etc.)

Required operation times were approximated by an OEM as the following: 24 hours are needed for the exchange of a blade and 48h for a gearbox exchange. Blade bearings are more time consuming since the blade has to be taken of in a first step in order to reach the bearing. Required times for transformer and switch gear exchange depend as the cables have to be detached first. Here, approximately 6-8 hours for the exchange are reasonable. In the future, the OEM could imagine that a tow-in will only be required for blade exchange (since a large space is required to put down the plates) while all other components can be replaced offshore.

10 CONCLUSIONS AND RECOMMENDATIONS TO ADVANCED O&M STRATEGIES

This deliverable gives a comprehensive overview over the main topics of the operation and maintenance of floating offshore wind farms, presenting related challenges and opportunities. The included information has been based on thorough literature research, one internal workshop with all COREWIND project partners and ten interviews with relevant stakeholders throughout the offshore wind industry. The compiled report provides the official requirements from standards and guidelines for offshore inspections of floaters, cables and mooring lines and the state-of-the-art inspection methods and/or monitoring techniques. For the dynamic cables and station keeping system repair methods and procedures are described. ROV types, their characteristics, environmental requirements, launching and recovery systems are outlined in a separate chapter. The chapter has a focus on ROV operation but also puts it in relation to diving operation. In this context the limitations of ROV inspections are discusses and the report provides a detailed description of the HSE risks and requirements for diving and ROV operations. The chapter concludes with the recommendations for underwater inspections from DNVGL and states that diver inspections are almost fully replaced by ROV inspections to remove the related HSE risks. It is further stated that, in order to reduce the inspection effort and to reduce the OPEX, the trend goes toward risk-based inspections of representative assets, instead of scheduled campaigns of all assets in pre-defined intervals.

As floating wind farms are likely to be located further offshore in deeper waters, rougher sea states and harsher environmental conditions need to be respected during the operation phase. The accessibility of the plant therefore constitutes an important topic. Three access methods bow transfer method, walk-to-work and helicopter access are discussed within this publication. The environmental conditions, the type of transport vehicle, and access method, as well as the geometric shape of the floating substructure are main influencing factors for the accessibility. A small study has been performed to assess the access probability of the three reference wind farm sites with the result that the site which is most accessible is site B - Gran Canaria with 77.49% access probability, while the least accessible is site A - West of Barra with 29.08%. These results fit the expectation of the medium and harsh environment of these sites. The floater motions do not only influence the accessibility, but also the feasibility of maintenance work and the performance of the technicians working on the assets. The effects of human exposure to these motions is described and the applicability of existing standards and guidelines including their vibration limit criteria are discussed. The chapter closes with a pre-study of the frequency response of the ActiveFloat and Windcrete floating substructures. It shows peak responses for surge, heave and pitch accelerations of the nacelle of both floaters in the relevant frequency range for motion sickness. It further showed that the wave peak period plays a leading role in the nacelle's acceleration frequency peaks. These results provide the motivation to perform a comprehensive workability assessment in the subsequent deliverable D4.2 of workpackage 4 and to assess if the peak wave period should be considered an access limiting parameter.

In a last chapter this report discusses the topic of tow-in to harbor for repair and large component replacements and the alternative to perform these operations offshore. The tow-in solution depends on the distance to a suitable harbor facility, the capacities in the harbor, the de-and reconnection technology of the cable and mooring lines and the weather conditions. The alternative is presented as a floating-to-floating solution, where the exchange is performed with a floating installation vessel. With a two-lift operation the exchange can be performed on the same reference system as the crane, reducing relative motions to a minimum. A third, very promising solution is an offshore component exchange with the help of a self-hoisting crane. This solution from onshore, is just starting to be applied in the offshore industry. From the stakeholder interviews it becomes apparent that different points of view exist on the future trend of the solution for large component exchange on FOWTs. It will clearly depend on the market development and the investments that will be made for future commercial wind farms.

The thorough assessment of the opportunities and challenges in the operation and maintenance of future floating wind farms has led to the following list of findings and recommendations:

- The workability and performance capacity of the technicians on the asset shall be verified for different sea states.
- The alternatives of an offshore large component exchange and a floater tow-in for repair shall be assessed in a case study respecting the influence of distance to shore, vessel availability and costs, harbor facilities and weather implications.
- The walk-to-work system is the most promising technique to overcome the relative motions between floater and vessel and to accomplish a save access.
- New follow-target mode developments make this option more competitive and better suited for sea states in the Atlantic Ocean.
- Prevailing swell waves in Atlantic Ocean challenge Hs-limits of the gangway systems developed for the North and Baltic Sea.
- Recommendation to use a "vessel utilisation rate" for a reference vessel with different types of gangways in the Atlantic Ocean to allow a realistic comparison and evaluation of the various systems.
- Helicopter access important to raise availability for wind farms far offshore.
- Winch-off areas on floater platform and nacelle allow for easier access than by CTV or SOV.
- Trend towards risk-based inspections and the extrapolation of findings of representative wind turbine to the entire wind turbine cluster.
- Incidences on cables and mooring lines through fishing industry not detectable with risk-based inspection.
- Establishment of a "good neighborhood" communication is essential for reducing conflicts during the operation phase with other stakeholders (e.g. fishing industry)
- Trend towards reduction of maintenance activities offshore involving human interaction to reduce maintenance costs.
- Trend towards more automation using robots on platform and sensors supporting failure finding and assessment.
- Use of ROVs instead of divers to reduce HSE risk for operation phase.
- Promising development of resident ROVs with subsea charging station which do not require a deployment vessel and therefore are less limited by weather windows.

To reflect the comprehensive picture of the current state of the industry the following scenarios would be of interest for a more detailed analysis in D4.2. The list is a suggestion, the possibility of implementation must be examined in T4.2.

- Influence of the floater motions on the workability of the technicians and thus on the accessibility of the plant.
- Large component exchange offshore versus tow-in scenario to perform operation inshore
  - Sensitivity of influencing factors like the distance to shore, time for de-and reconnection of cables and moorings, weather conditions, and availability of vessels and harbor facilities.
- Feasibility of access to the floaters with motion compensated gangway versus CTV vessel.
- Influence on the plant availability of a helicopter for transfer of personnel to the assets.
- Evaluation if risk-based inspection and subsea-resident ROV inspections can be integrated into the assessments of D4.2.

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