Corrosion protection of offshore wind foundations

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ABSTRACT

This paper presents a review of the current standards and guidelines on corrosion protection of offshore wind foundations. It also gives a review of the experiences reported within the industry over the last decade, during which time offshore wind has gone from a marginal industry to a major governmentally supported renewable energy source within Northern Europe in particular. Today many reported experiences concerning both the external and internal corrosion protection systems of offshore wind foundation structures have highlighted the need for updated and further documentation within the standards and guidelines. The concerns include the special challenges with external cathodic protection (CP) of tall steel structures in shallow waters under often extreme tidal loads as well as possible interactions between the sulfide rich mud zone and either freely corroding steel or steel under CP in the stagnant water inside the foundation. Other concerns are related to controlling the maintenance costs of the structures that in contrast to most oil/gas offshore structures are unmanned. In summary this paper provides a GAP analysis between the experiences reported versus the recommendations given by the current guidelines and standards. The analysis is related to the work in NACE TG 476 and aims at sharing the recent European experiences within the industry. The need for further material testing, review of the CP design basis as well as corrosion monitoring options is discussed.

Key words: Offshore Wind, Marine Corrosion, Corrosion Monitoring, Cathodic Protection, Potential Criterion, Mud zone Corrosion, Protective Coatings.

INTRODUCTION

Support structures and foundations are vital parts for offshore wind turbines. During the last decade an increasing number of structures has been installed particularly in Northern Europe, especially in the form of monopile structures, however also lattice (jacket) structures see increasing installations. Monopiles are currently the most commonly used foundations in the offshore wind industry because of their ease of installation in shallow to medium water depths. This type of structure is suitable for water depths ranging from 0-30 m and a sketch of the structure is seen in figure 1. The three or four-legged jacket (lattice) structures are considered suitable for water depths ranging from 20-50 m. Further tripod, gravity, tripile and floating structures may be installed as support structures for offshore wind. This paper will mainly focus on the corrosion protection of monopile foundation structures.

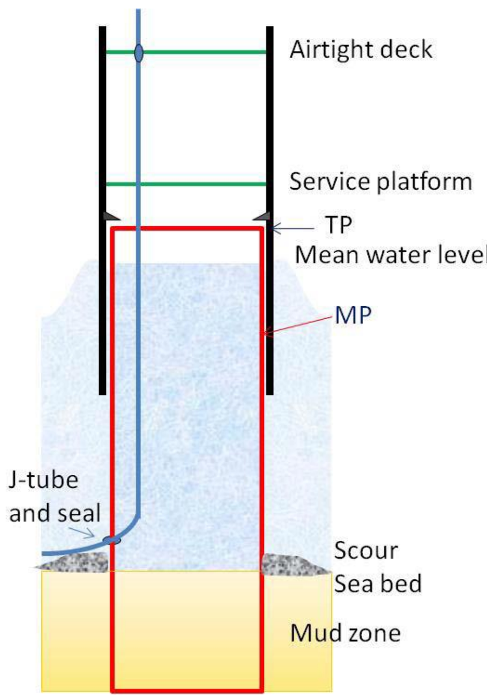

Figure 1: Overview sketch of monopile (MP) foundation design with transition piece (TP) (system with internal J-tube)[1].

The general design of a monopile foundation is that a steel pile, the MP, is driven into the seabed leaving 1-2 m above the sea level. The TP is installed on top of and outside the MP with an overlap of typically 6 meters. In this process a number of brackets on the inside of the TP aid adjusting the position of the TP. The gap between the two elements is filled with high strength grout intended to cement the two pipes together.

In recent years unexpected corrosion related issues have emerged especially as regards monopile structures. Externally the corrosion in general is well understood and rather similar compared to the challenges observed across multiple offshore industries. Internally in the closed compartments the guidelines and standards however are inadequate but data from inspections and surveys are becoming available. Issues such as fatigue life, internal (and external) CP design and internal CP and corrosion monitoring have become unexpected and costly challenges, since working offshore in confined spaces provides large logistical as well as safety challenges.

Design basis

The design basis and the corrosion protection of offshore foundations is well described in current guidelines such as DNV[2] and previously Germanischer Lloyd, GL[3] and is to a wide extent based on the experiences from the oil&gas industry.

Externally in the atmospheric and splash zones the use of coating is mandatory, whereas use of coating in the submerged zone is optional and primarily intended to reduce the required CP capacity. External surfaces of the submerged zone shall have CP. In the splash zone, CP may be assumed to be fully protective below MWL (Mean Water Level). In most projects CP is performed by galvanic anodes placed solely on the TP, but impressed current CP systems are also applicable in an increasing number of projects.

At present no precise guidelines are provided for the internal corrosion protection. However DNV[2] describes that for the atmospheric zone corrosion allowance may replace coating. Similarly, the use of coating is optional for the splash zone, whereas the submerged surfaces may be protected by either CP or corrosion allowance, with or without coating in combination. Hence, at the moment, the corrosion protection strategy for the internal surfaces is not well-defined and up to the individual owners or designers.

In early projects no corrosion protection (except corrosion allowance) was included for the internal surfaces, since the structures were assumed completely water- and airtight. However, experience shows that in practice it is difficult to obtain compartments that will be completely sealed and airtight[1]. Also large differences in tide may result in variations of the internal water level[2]. On this basis recent projects have included coatings and/or CP as part of the internal corrosion protection.

Corrosive conditions

Internal corrosion rates

The design for corrosion inside a monopile foundation anticipates low, uniform corrosion rates in a closed compartment. However as reported by Hilbert et al.[1] seawater and thus oxygen ingress have been detected in 2-10 year old foundations (2011), increasing corrosion rates and localizing attacks. The unexpected changes to the design assumption was determined during inspections and surveys related to grout failures, which in a large number of northern European wind farms caused setting of the transition piece (TP) in relation to the monopile (MP). In several cases this has reduced the gap between the brackets and the MP top from approximately 20 mm to zero in some cases entailing that the brackets are exposed to unintended structural stresses. It causes concern that such changed load pattern might increase the risk of fatigue[1].

The corrosion conditions in sea water in a completely airtight structure or a structure partly or fully open to the surroundings is discussed in further detail by Hilbert et.al[1].

In a completely airtight structure the dissolved oxygen in seawater is quickly consumed by uniform corrosion of the entire steel surface. As the media turns anaerobic corrosion rates will decrease.

If the airtight platform is not properly sealed direct ingress of air is possible. The corrosion rate in the atmospheric zone may initially be high, but the rate will decrease in time. Below the water-line, corrosion is facilitated by differential aeration between the upper water layer and the active steel surfaces below. If the water level is completely stagnant, corrosion will be highly localized. The corrosion element will however have limited coverage, so no considerable effect on corrosion at greater depths in the foundation or for the parts buried in sediment is expected.

The oxygen content in the foundation may also change due to slow seawater ingress e.g. through minor leaks at the J-tube seal, degraded grout connections or small J-tube openings/perforations. In this case seawater with dissolved oxygen enters the system, increasing corrosion over the entire surface. However, in the air-depleted mud-zone there is a higher risk of accelerated corrosion, mainly due to the differential aeration. Moreover the renewal of sea water will affect the microbiological and chemical processes inside the compartment.

If the ingress of seawater is substantial, e.g. if the J-tube seal has fully failed, tidal variations may occur directly inside the foundation and the water level may change daily or at extreme events such as spring tide. In this case the inside foundation resembles almost the conditions for a sea port with fairly stagnant water and tidal effects, or a ballast tank, where the access of air is also restricted. In this type of system accelerated low water corrosion (ALWC) up to 0.5 mm/year localized has been determined. In comparison DNV[2] states that any corrosion allowance for primary structural parts with more or less free replenishment of seawater, or if air is present above the seawater surface, shall be determined based on a corrosion rate of minimum 0.10 mm/year for submerged internal surfaces. For the splash zone the design corrosion rates shall be minimum 0.15 mm/year in temperate climates and 0.20 mm/year in subtropical/tropical climates.

In a closed foundation there is a risk of microbiologically influenced corrosion (MIC) on the submerged surfaces and in the MP parts buried in the upper part of the sediment as described by L. R. Hilbert[4]. In a closed foundation it is expectable that sulfate reducing bacteria (SRB) are present, and if growth conditions should become favorable, then sulfide production will start. Alternating aerobic and anaerobic conditions may also favor growth. The risk of MIC also depends on other species present and how homogenous the final conditions are, but it is most likely that localized corrosion attacks will occur on the submerged and midline covered surfaces.

Installation and monitoring of internal CP

On the above basis several wind farm owners have decided to retrofit old existing monopile structures with internal CP by galvanic anodes. Furthermore, new projects may include internal CP as part of the design basis. In order to assess the actual corrosion conditions and thus decide on appropriate corrosion prevention several wind farm owners, including DONG Energy[5] have additionally installed monitoring systems within offshore monopile foundations in order to increase the level of understanding and provide data on the corrosive conditions. The offshore conditions vary, hence the corrosion rates change in time. In order to detect changes or check the effect of mitigation efforts continuous monitoring is highly relevant. Monitoring critical parameters and/or corrosion rates may be carried out by accumulated techniques (coupons) or real time techniques (probes). Measured parameters could include dissolved oxygen, temperature, salinity, pH-values and potentials, measured manually and by an automated system.

Although internal CP is currently being installed in many wind farms, it is widely recognized that there may be some challenges with such systems, including passivation of aluminum anodes, reduction in pH values, hindering of calcareous scale formation, stray current effects and excessive formation of hydrogen gas or accumulation of hydrogen sulfide[5]. Further internal CP retrofit is costly and difficult since work must be carried out offshore in confined spaces and the strategy most likely must be determined on a case by case basis, since designs and conditions differ between various wind farms.

Furthermore, especially the risk of high localized corrosion rates in the mud zone due to differential aeration or microbiologically influenced corrosion may be a concern, since the mud zone area is not accessible for inspection or NDT. In 2013 a basic device design concept has been designed for wind foundations comprising a full length cylindrical corrosion probe covering the height from the service platform to 0.5 m deep in the mud zone[6]. The probe thus simulates the localized corrosion observed on the vertical MP wall, focusing on the risk of mud line corrosion. For long term documentation of the selected corrosion control an on-line monitoring device may be developed for the mud zone, described further by L.R. Hilbert[6].

Structural risks

The influence of localized corrosion on the structural integrity need be investigated further. According to DNV-OS-J101, section 6[2] the grade of steel to be used shall in general be selected so that there will be no risk of pitting damage. Since literature data and reported experiences show that the common construction steel used for offshore structures is prone to pitting corrosion in seawater and marine environment this statement from DNV cannot be fulfilled, and using construction materials not prone to pitting corrosion such as high alloyed stainless steels is not economically feasible.

Since pits may act as stress raisers and initiate fatigue cracks, it should be determined which degree of pitting corrosion (and in which positions/concentrations) will be tolerated on wind farm structures in order to not compromise the structural integrity.

Furthermore the risk of localized corrosion need be investigated further for the mud zone, since mudline corrosion may be significant for structures with long service lives.

Further fatigue life and the risk of to HISC (hydrogen-induced stress cracking) may be issues to consider when implementing internal CP. According to DNV-OS-J101, section 6[2] the susceptibility of the steel to HISC shall be especially considered when used for critical applications. The use of steel types with a specified minimum yield stress greater than 550 N/mm^2 shall be subject to special consideration for applications where anaerobic environmental conditions such as stagnant water, organically active mud (bacteria) and hydrogen sulfide may predominate.

The resistance against fatigue is usually given in terms of an S-N curve. S-N curves for most frequently used structural details are given in DNV-OS-J101, section 7[2], and classification of structural details and their corresponding S-N curves in air, in seawater with adequate CP and in free corrosion conditions can be taken from DNV-RP-C203. Actual stresses in hot spots/critically loaded areas can be measured by means of strain gauges, potentially by extrapolating from stresses measured outside notch zones as described in DNV J101, section 7, J307[2].

By comparison with stresses in e.g. the TP wall the stress concentration factor valid for a specific detail may be determined. With sufficient data measured under various wind loads, a credible prediction of future behavior may be modeled[1].

The fact that the water level in some foundations is located above the service platform and fully or partly submerges the stoppers entails that the stoppers are exposed in oxygenated seawater. Hence, if the stoppers are subjected to mechanical stress, this structural detail should be considered exposed to free corrosion when conducting fatigue calculations (S/N curves). This significantly lowers the fatigue life compared to if the stoppers were exposed in air.
Hence the aspect of fatigue and corrosion fatigue is a serious structural risk. In the case of freely corroding steel in seawater in principle the models give no fatigue life, leaving no other option for a loaded structure than to either ensure sufficient CP or ensure that corrosion rates are indeed very low[4]. The situation of fairly slowly progressing uniform or localized corrosion is not taken into account in the available curves and more research is needed in this field.

Presently several wind farm owners have chosen the very conservative solution for the inside corrosion protection of new foundations including protective coatings, corrosion allowance and CP as corrosion control options on new projects since documentation of the actual corrosive conditions is limited. A more differentiated view on solutions is therefore needed in order to optimize the cost for new projects.

<u>External CP</u>

Cathodic protection of offshore structures by galvanic anodes (GACP) is well established. DNV-RP-B401 gives requirements and guidelines for cathodic protection design, anode manufacturing, and installation of galvanic anodes[2]. Further the design of an Impressed Current CP (ICCP) system is described in DNV-OS-J101, section 11, subsections D300-308. Guidance for the design of ICCP systems for offshore structures is given in NACE RP0176 and EN 12495.

Today cathodic protection is commonly estimated based on tabulated standard values, but the interactions between the structure and environmental parameters (seawater, depth and currents) are not fully understood and actual data seldom available. Generation of data on actual cathodic protection current demand on site to use as basis for updating of design standards is needed.

Early detection of protection failure is crucial. If protection failure is not determined in time and unacceptable corrosion is detected, the original design assumptions may be compromised and free corrosion must instead be assumed when calculating S/N curves. However the limit for acceptable corrosion is not well defined and at the moment one must rely on conservative indirect measurements such as initial CP surveys and detailed inspections.

CP surveys are performed in many ways, hence direct comparison is difficult. Therefore there is a need for formalizing inspection and survey procedures in order to obtain a better basis for comparison.

Inspection and monitoring of external CP systems may include:

- A drop cell survey providing valuable information about the potential drop along the MP length from sea level to sea bed. The survey may be conducted by lowering a reference electrode from the external platform into the water and measuring the potential as close as possible to the steel surface. If necessary diver support may be needed.

- Visual assessment of the anode consumption by divers, including measurements of the anode dimensions.

According to experience obtained by Denmark and Norway[7], experiences obtained from CP drop cell surveys among others include:

- CP drop cell surveys on monopiles show variations from -650 mV to -990 mV (Ag/AgCl) in critical areas within the same site and design.
- The measured potential depends on the monopile length, seabed condition and marine fouling.
- It is not unusual that 30 % of foundations lack protection since all fail to comply with DNV RP-B401 specifications.
- Robustness/conservatism in DNV RP-B401 together with beneficial effects from marine fouling save many foundations.
- Many sites are probably under-protected without the owners being aware of it.
- In case of under-protection the life expectancy is affected and fatigue evaluations must be revised.
- Anode material need be checked before installation, since the chemical composition may not always comply with the specification

Osvoll[8] has reviewed the essential factors influencing cathodic protection not covered by standards and recommended practices for both offshore and onshore structures.

From the evaluation, several general issues are found not to be well covered or documented in the various design rules and recommendations, including the following issues relevant for offshore monopile structures:

- Anode interference not accounted for
- Drain to internal tubing (piles) can be further optimized
- Consequence of shadow effects, shielding and narrow space (e.g. large metal area compared to seawater volume) not well covered, i.e. the cathodic potential drop is not included in standard calculations
- Consequence of uneven anode distribution not covered

As regards retrofits, inspections and studies over the past years have revealed a large number of offshore structures that will have to be retrofitted with CP, which in many cases can only be solved by remote anode sleds or subsea installation of additional anode cages. These activities involve very costly underwater operations with Remotely Operated Vehicles (ROV) with additional supply vessels and crew. The practical weather window for such operations restricts available time slots for inspections as well as the actual retrofit operations. The costs for such operations may be at the level of Millions of Euro per field.

Coatings

Specified systems

External steel surfaces: Steel surfaces in the atmospheric zone shall be protected by coating. In the splash zone the use of coating is mandatory on primary structures. Use of coating in the submerged zone is optional and is primarily intended to reduce the required CP capacity[2].

Internal steel surfaces: Corrosion allowance may replace coating in the atmospheric zone. In the splash zone the use of coating is optional, and in the submerged zone, the steel surfaces shall be protected by either CP or corrosion allowance, with or without coating in combination[2]. Hence internally the use of coating systems is optional.

For structural parts in each corrosion zone, the selection of coating systems shall be specified, as well as requirements for the qualification of manufacturer specific coating materials and of personnel to carry out the work. The specification shall further contain general requirements for the quality control of coating work and for the coating applicator´s documentation[2].

General recommendations for coating systems to be used offshore are given in international standards such as EN ISO 12944, ISO 20340 and NORSOK M-501. The standards prescribe that systems to be used offshore should be qualified by external testing according to:

EN ISO 12944-6, corrosive categories C5-M and Im2 (both durability high, >15 years).

ISO 20340, C5-M, Im2, tidal and splash zone and NORSOK M-501, coating systems 1 and 7.

Hot dip zinc coating is applicable to certain secondary structural parts in the atmospheric and splash zones as described in DNV-OS-J101, section 11, subsection E104[2].

Testing includes cyclical ageing test according to ISO 20340, cathodic disbonding according to ISO 15711 as well as adhesion test according to ISO 4624.

The paints and painting systems used for wind farm corrosion protection have developed during the last decades through – for instance - valuable experience gained from the offshore oil and gas industry. A combination of 2-3 epoxy coats and a polyurethane topcoat is often used; however the systems may vary depending on the exposure (atmospheric, immersed) and location. Typical coating systems are described by Mühlberg[9].

In general, the inside surfaces of most monopile foundation structures have been left uncoated, based on the assumption that the corrosion rates would be negligible. However since ingress of seawater and air may occur in the foundations resulting in more corrosion than expected on the internal surfaces, more focus has been put on protecting the internal areas of the foundations. In some cases, 3-4 meters of the internal surface of the TP is coated in the area where the predominant water level is expected located (due to financial considerations as well as limited production time available)[11]. Inside the foundation structures, the areas that are not airtight and closed may be coated by epoxy coating (2x 200-250 µm). Also systems based on epoxy zinc dust primers may be applicable.

Quality control

The qualification of the systems far from guarantees successful corrosion protection, since many other factors are decisive for the durability of the systems. Most defects, but not all, actually occur due to faulty processing or erroneous application and not from incorrect specifications. Damage analyses in Germany have, reported by Mühlberg[9], shown that faulty processing and/or erroneous application have caused between 43 % and 68 % premature failures of the corrosion protection in the paint industry.

Consequently, it is essential to ensure that the surfaces to be protected are optimally prepared for coating application, including that the surfaces are accessible, meaning that the design considerations stated in EN ISO 12944-3 are complied with. Furthermore, the recommendations of ISO 8501-3 regarding preparation of welds and edges should be considered.

However, most importantly, it must be ensured that the application work is carried out in accordance with the international as well as the owner's specific standards, following the guidelines described in the paint's technical data sheet.

Optimal protection may furthermore be ensured by review of the painting facilities and procedure specifications for fabrication and control, scrutiny of the relevant quality documentation as well as control of procedures before, during and after paint application. In particular, checks of surface preparation, paint application and finish are crucial. If the paints have not been applied correctly, and coating breakdown during service occurs, limited possibilities are available in order to repair the coating offshore - possibilities which are comprehensive and costly[10].

According to GL[3] the application of the coating system shall be supervised by qualified personal, i.e. FROSIO-, NACE-, DIN-certified paint inspectors (or equivalent), which is in good agreement with the requirements specified in e.g. NORSOK M-501.

Coating repair

In general root causes for coating failures occurring on offshore wind foundations include:

- Mechanical damages occurring before, during and after installation
- Areas not coated before transportation offshore, often occurring due to delays in production
- Environmental breakdown over prolonged exposure

Known failure cases occurring after offshore installation include three cases described by A.R. Black[10]. Furthermore, Momber[11] has performed a review of inspection results on offshore wind power structures in the North Sea and the Baltic Sea and described several damage types observed, including under rusting, flaking, mechanical damage, wear, transportation damages, bi-metal corrosion and more.

Painting the outside of installed TPs is a challenge due to tidal surroundings and the above-mentioned weather conditions. Hence roping or scaffolding appear feasible as methods of repair. However weather downtime may be significant.

Due to the recent discoveries of more than expected corrosion inside the foundations, coating of areas internally has become an applicable solution. The work inside the foundations however requires compliance with working in confined spaces and entails large logistical challenges.

Hence offshore coating repairs entail huge costs, which is why optimization of coating repair procedures may provide significant project cost reductions.

On this background the durability of coating repairs on offshore structures under ambient offshore application conditions have been investigated by A. R. Black[12]. The factors surface preparation, coating thickness (number of coating layers) and quality of the coating (coating type) have been selected as test variables in order to investigate the impact of each factor on the durability of coating repairs through laboratory performance test methods.

The conducted tests show that it may be possible to reduce the requirements for offshore coating repairs without compromising the durability of the coating systems significantly. Good durability may be obtained by coating systems from all tested manufactures on abrasive blasted substrates with increased soluble salt concentrations, even with systems with a total dry film thickness (DFT) of 326-571 µm. Further the study has shown that a reduced pre-treatment quality may provide good results depending on coating type. Especially one manufacture shows remarkably good results on power tool cleaned substrates with results comparable to abrasive blasted substrates.

CONCLUSIONS

This paper has highlighted areas in which the most frequently used standards and guidelines for corrosion protection of offshore wind structures are in need of updates and more detail. Further areas where more work is needed in order to provide more documentation on actual conditions or project cost reductions have been discussed.

The major challenges connected to the corrosion protection of offshore monopile wind foundations are summarized below:

(a) Localized corrosion

DNV-OS-J101 states that the grade of steel to be used shall in general be selected so that there will be no risk of pitting damage, which is not in agreement with current experiences. Since pits may act as stress raisers and initiate fatigue cracks if localized at a critical position, it should be investigated which degree of pitting corrosion can be tolerated on wind farm structures in order to not compromise the structural integrity.

Especially the risk of high localized corrosion rates in the mud zone may be a concern, since the mud zone area is not accessible for inspection or NDT. For long term documentation of the selected corrosion control an on-line monitoring device may be developed for the mud zone. However especially localized corrosion may be difficult to measure with existing techniques which is why new approaches may be needed.

(b) Fatigue and HISC in the mud zone internally

For the mud zone, the risk of fatigue and hydrogen induced stress cracking (HISC) should be investigated further. In case of no corrosion protection, mudline corrosion may be significant affecting the long term fatigue properties. Since no corrosion rates are available from the mud zone, monitoring and inspection options need be developed in order to quantify the risk.

If cathodic protection is applied to the internal surfaces, the risk of HISC in the mud zone should be investigated further. Since the environment inside offshore wind foundations is different from known reference structures from e.g. the oil&gas industry, specific HISC tests need be developed for offshore wind in order to quantify the risk. For presently used construction steel the risk of HISC may not be high but if more high strength steel types are used in the future, the risk of HISC may increase.

(c) Clarifying the CP design, externally and internally

In general there is a need for calculating the current drain to the mud zone. Furthermore better input parameters for CP modeling need be determined. The design guidelines need to be updated with industry experiences and include more detail on internal CP design.

(d) Monitoring of internal CP

Monitoring the impact of installed CP is an area of further investigation, since the various guidelines presented in the standards do not give a precise description or method for designing a CP system for the internals of a MP and TP. Installing internal CP may affect parameters such as corrosion potentials, gas concentrations, pH levels and more. Especially resent observations have shown that documentation of pH and H_2S levels is needed and the impact on corrosion rates and structural integrity and safety need be evaluated.

(e) Offshore coating repairs

Coating damages have been observed on structures on several offshore wind farms. The root cause for the damages may be numerous, but the repair procedures are universal. Since offshore coating repairs are very costly optimization of coating repair procedures may provide significant project cost reductions.

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