Preventing Galvanic Corrosion in Drilling Risers and Subsea Equipment

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Abstract

Equipment for drilling risers and subsea oil exploration involve use of many metals with the risk of galvanic corrosion, if not protected or maintained properly. Paint coated steel accounts for the majority of such structures, but temporary coated steel, stainless steel and hard face alloys are also applied for special components. The time for completing subsea wells typically extended over few weeks in the past, with the possibility of maintenance on the rig between the operations. As drilling technology evolves, the well completion may now last several months, which presents new challenges in respect to corrosion protection. Many of the individual parts of complex drilling equipment are usually electrically isolated by paint coating and thereby not intended for cathodic protection (CP). In some cases, wear of the coatings and the extended exposure periods have caused excessive galvanic corrosion of low alloy steel or hardface coatings coupled to stainless steel. Major efforts have been made to identify aggravating circumstances that occasionally lead to excessive corrosion. Galvanic corrosion was accelerated by the prolonged exposure periods leading to a fully developed marine biofilm on the stainless steel parts. This provides highly oxidizing conditions that are 10-100 times stronger than those observed during short-term exposure. Examples of corrosion issues are presented and mitigating actions are discussed, such as CP, partial coating, maintenance or galvanic insulation. References are made to other applications where excessive galvanic corrosion has been observed, such as ships and pump caissons. Lastly, the paper discusses recent developments with use of TSA coatings for marine drilling risers.

Keywords

Carbon steel, stainless steel, galvanic corrosion, biofilm, coatings

Introduction

Marine drilling risers are used for preparing subsea wells and subsequent servicing, often at several kilometres depth. The riser string is sequentially assembled by sections (joints) that are lowered down to the seabed from the rig. The blowout preventer (BOP) is usually the lowest section that will be left on the sea floor. The technique is not new, as it has been used for at least 30 years.

Over the recent years, the installation depths have gradually increased along with many new technological improvements of the technique that e.g. allows sequential work-over of several wells in the same riser run. As a consequence of this, the well completion time has increased from being a few weeks to several months. This implies longer exposure times of the drilling risers (i.e. wet-time) which presents new challenges in means of corrosion protection.

As opposed to permanent installations such as subsea templates and pipelines, the drilling risers are retrieved frequently allowing inspection and maintenance on the drilling rig. In addition, the joints are taken onshore at regular intervals of 1-5 years for full inspection and maintenance. The corrosion protection of drilling risers depends to some extent on such scheduled operations.

The drilling riser is mainly composed by paint coated steel line pipes, but temporary coated steel, stainless steel and hardface alloys are also applied for special components. Many of the individual parts of complex drilling equipment are usually electrically isolated by paint coating and thereby not intended for cathodic protection (CP). In some cases, wear of the coatings and the prolonged exposure periods have caused new corrosion phenomena not observed previously. An example is excessive galvanic corrosion of low alloy steel or hardface coatings unintentionally coupled to stainless steel. This has formed the basis for the present study. However, the opposite effect has also been observed, i.e. inadequate stainless steel grades that are being protected by the contact to low alloy steel.

On this basis, selected corrosion phenomena have been evaluated in order to determine the cause and propose mitigation strategies. The observed corrosion issues are not consistent, and cannot readily be correlated with equipment design, exposure history, installation depth etc. Consequently a major effort has been made to identify aggravating circumstances that occasionally lead to the excessive corrosion. This analysis has reviewed many possible factors, such as special environmental conditions, stray currents, paint coating quality, maintenance etc.

The paper reviews literature on marine corrosion in regions where deep sea drilling is performed. Examples of corrosion issues are presented and mitigating actions are discussed, such as CP, partial coating, maintenance or galvanic insulation. Lastly, the paper addresses developments within coatings itself and point at future initiatives to further enhance the longevity of the marine drilling riser.

Riser design and service conditions

In order to understand the corrosion issues, the basic design and service conditions of the risers is reviewed. Drilling risers are typically composed of riser joints each measuring 75 to 90 ft (23 to 27 m) in length. A riser connection and a cross section of a standard riser joint can be seen in Figure 1.

The main pipe and peripheral lines (P-lines; kill, choke and booster) are usually made of low alloy steel which is protected externally by a multiple-layer epoxy coating. Guide plates, brackets, clamps and other supports are made of carbon steel, also protected by epoxy coating. Hydraulic tubes may be made from duplex UNS S31803 stainless steel with or without external coating. In early projects, UNS S31603 has sometimes been used for hydraulic lines.

The surfaces and threads at the connector ends (box and pins) are protected by corrosion and wear resistant coatings. Wear parts of steel joints (pins) are typically covered by a corrosion resistant hardface applied by thermal spraying. In addition, the connectors and pins shall be treated with anti-corrosion agents or lubricants before each run of the riser.

Buoyancy modules cover most of the riser joints. A length of approximately 1 meter is freely exposed at each end that contains guide plate, box, pins, brackets and pipe end connections. The buoyancy modules are fixed to the riser by tensioner locks usually made of UNS S31600 stainless steel.

Corrosion protection of the riser system is obtained by the coating systems applied on the steel parts in combination with regular maintenance. For new risers, the parts are electrically insulated from each other by the paint coating applied. This is further aided by fiberglass bushings between parts in some projects. Secondary parts such as bolts and clamps are also insulated from each other, by the paint coating.

This corrosion protection strategy has worked for many riser systems in the past with the possibility of frequent overhauls. Thus, the risers are usually not designed for cathodic protection (CP), because that would require electrical continuity and extensive wiring between all individual components. However, CP is possible and sometimes applied in the longitudinal direction of pipes and tubings, having electrical continuity over the connections.

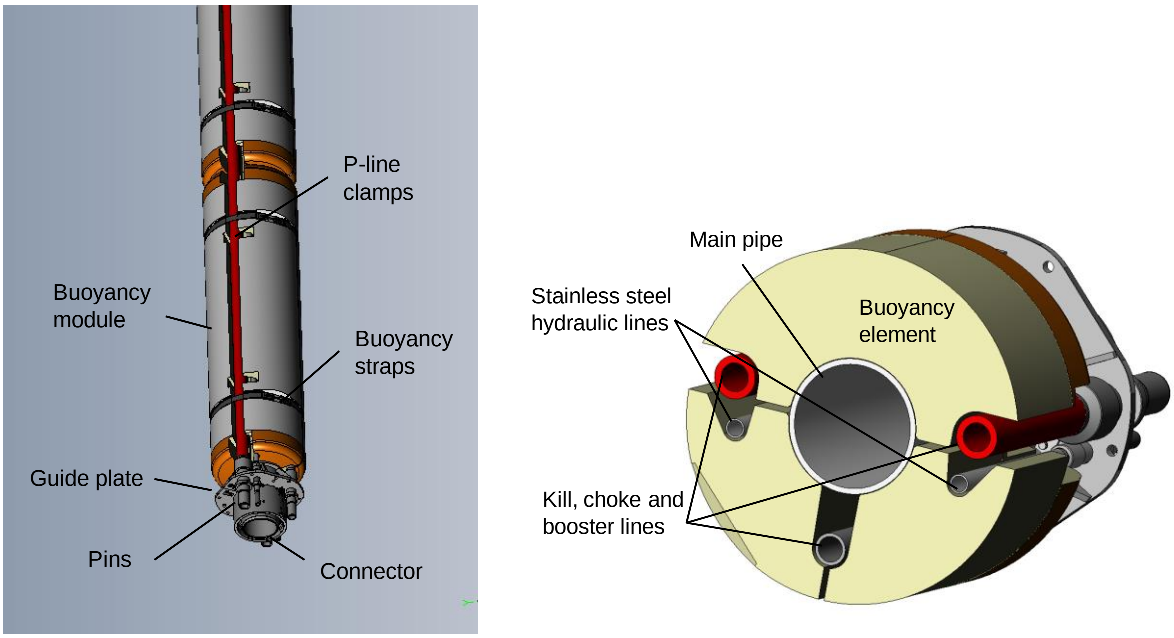


Figure 1. Example of typical marine riser design.

The above outlines the generic design of drilling risers used deep sea drilling all around the world, and supplied by several providers. The regions of application include Brazil, The Gulf of Mexico, The Mediterranean Sea, The North Sea, West Africa and West Australia among other. The ocean depth at such locations may vary from 500 to 3000 metres. At such great depths the risers experience varying conditions from top to bottom. Depending on the depth, the well completion time (or the wet-time) ranges from a few days to 6 months.

Corrosion in deep waters

Based on corrosion data from literature and CP guidelines, the conditions of the typical regions where risers are applied have been reviewed.

Carbon steel

The corrosion rate of unprotected carbon steel in deep waters mainly depends on the oxygen content[1]. Since there is continuous replacement of the seawater even at great depths, the oxygen content never reaches zero. At the concerned depths from 0 to 3000 meters, an oxygen content of 2-6 ppm in the water is usually present. The expected water temperature is from 10 °C at sea level to 2 °C at the seabed [2]. This assessment is based on the data shown in Figure 2 and Table 1. Depth profiles of several regions [3,4] have been reviewed, and they largely show the same trends although the surface temperature may be higher, up to about 25 °C.

The requirements for cathodic protection (CP) of steel partly reflect the corrosive conditions of unprotected steel. The CP design criteria differ slightly between the various regions [5], Table 2. In some cases, an increasing current demand for CP is required with increasing depth [6]. This effect is related to the difficulty in forming protective calcareous deposits at depths exceeding 300 m due to the large pressure.

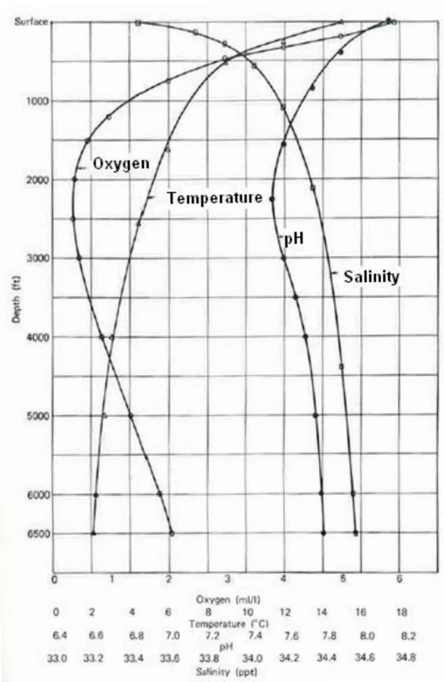


Figure 2: Variations in seawater with depth at a Pacific Ocean test site [2].

According to Table 1, subsea lateral currents and wave action (turbulence) also vary from region to region. This effect is also of importance for corrosion, since high flow rates enhance mass transport and erosion, and thereby increases the corrosion rate.

The expected corrosion rate in deep seawater has been examined in several studies, e.g. by exposure of test coupons or by inspection of old shipwrecks. Typically, the uniform corrosion rate of unprotected steel is in the range of 0.05-0.1 mm/yr. Local corrosion (pitting) may take place at a 4-5 times greater rate. The splash zone usually represents the most severe region where the uniform corrosion rate may be about 0.4 mm/yr.

Table 1.
Environmental data for deepwater (>600 m) [5].

Location	Temp. °C	Salinity %	O_2 ml/l	Mean sea current speed cm/s
Brazil	5 – 8	no data	4 – 5	15 – 17
West Africa	4 – 6	3.4 - 3.5	2 - 3	5 – 7
Gulf of Mexico	4 - 8	3.4 - 3.5	2.5 – 5	no data
Norway	-1 – 2	3.4 - 3.5	6 - 7	4 - 9

Table 2.
Typically recommended design current densities for CP in some areas and climatic zones which incorporate deepwater locations [5].

Area	Resistivity Ohm.cm (temp. °C)	Design Current density, A/m^2		
		Initial	Mean	Final
Tropical [1]	- (>20)	0.130	0.060	0.080
Subtropical [1]	- (12-20)	0.150	0.070	0.090
Temperate [1] (<70oN)	- (7-12)	0.180	0.080	0.110
Arctic [1]	- (<7)	0.220	0.080	0.130
Gulf of Mexico [2]	20 (22)	0.110	0.100	0.075
West Africa [2]	20-30 (5-21)	0.130	0.055	0.090
Brazil [2]	20 (15-20)	0.180	0.065	0.090
N.North Sea [2]	26-33 (0-12)	0.180	0.090	0.120

[1]: DNV RP B401 (1993) for depths greater than 30 m
[2]: NACE RP0176-94

Stainless steel

Corrosion of uncoated stainless steel in deep waters mainly depend on one circumstance apart from temperature, i.e. whether a marine biofilm is formed on the surface of the stainless steel. When the marine biofilm is formed, the cathode efficiency increases considerably because enzymes in the biofilm catalyse the oxygen reduction. This behaviour is often referred to as “ennoblement”.

The biofilm is fully developed after 1-2 months’ exposure in seawater. While biofilm formation is hindered in warm waters (>30 °C), it consistently occurs in cold seawater. Figure 3a shows the result of an inter-laboratory study performed in Europe [7]. It appears that the corrosion potential increases from 200 mV to 400 mV during the first 1-2 months of exposure while the biofilm is formed. At the same time the oxidizing force increases considerably by a factor in the range from 10 to 100, Figure 3b. Due to this effect, localized corrosion will usually occur within few weeks on low-alloyed stainless steel, such as UNS S31600. However, the risk becomes considerably lower when exposed for short times or at low temperature.

Data on ennoblement has not been found for all regions and depths, but it is very likely that biofilm with similar properties will form anywhere. This view is supported by the consistent occurrence of crevice corrosion on UNS S31600 stainless steel parts from the examined riser joints including at least four regions. Although corrosion was superficial and without impact on function, the occurrence of crevice corrosion has worked as an important indicator for the corrosive conditions.

It may be questioned whether possible depletion of nutrients at great depths will hinder the biofilm formation, but our observations do not suggest so. It is unlikely that UNS S31600 will develop crevice corrosion in cold seawater at 3 - 5 °C without the strong oxidizing conditions from the biofilm. Different types of stainless steel (e.g. UNS S31600, S31803 and S31254) generally show the same tendency to biofilm formation. Since the biofilm is a thin invisible layer of biological cells it cannot readily be detected by the naked eye.

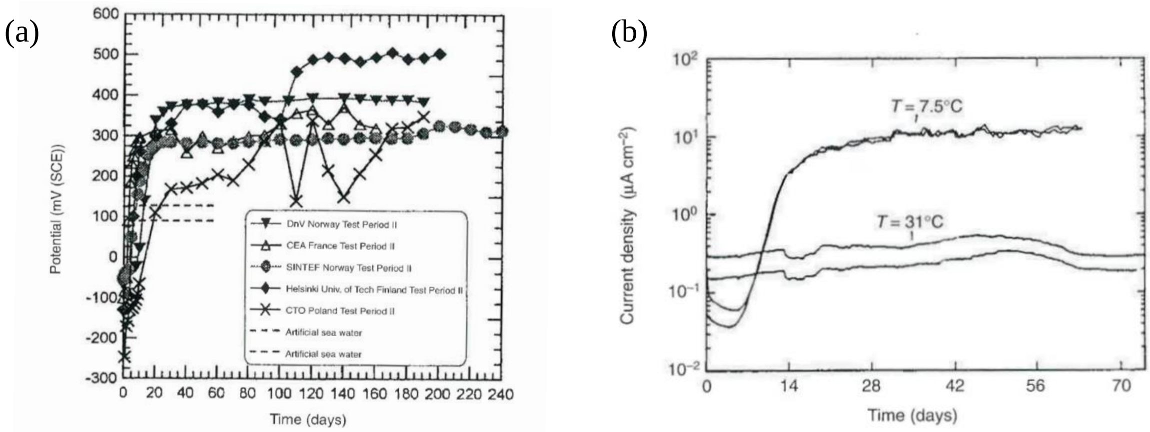


Figure 3: (a) Free corrosion potential of UNS S31254 exposed to seawater [7]. (b) Cathodic current densities vs exposure time for 6 % Mo stainless steel at 7.5 °C and 31 °C at -300 mV SCE[7].

Galvanic corrosion between stainless and carbon steel

The potential difference or voltage between biofilm-covered stainless steel and carbon steel is approximately 1 volt in seawater. This represents a high driving force for any type of corrosion. As soon as corrosion initiates, the stainless steel will depolarize slightly causing a smaller voltage, but rapid galvanic corrosion is still possible.

Galvanic corrosion also requires full electrical continuity between the two metals as well as an open space around the corrosion site to enable a current flux in the seawater.

The strong effect of biofilm formation on the corrosion rate of carbon steel is illustrated in Figure 5a. Stainless steel without biofilm (C) can provide cathodic current of 5 mA/m^2 at the potential of corroding carbon steel, i.e. -500 mV SCE. Stainless steel covered with biofilm (A) provides a much higher current of 200 mA/m^2. For closed systems, the effect of biofilm may be eliminated by adding disinfectants (biocides), such as chlorine (B), but this possibility is not an option for marine risers. The effect of ennoblement can also be shown as development in cathodic current as function of exposure time at conditions expected for a coupled system of stainless steel and carbon steel, Figure 3b. The diagram shows that the current increases by a factor 10-100 after 30 days of exposure for stainless steel that develops biofilm at low temperature (7.5 °C). At higher temperature, 31 °C, this particular biofilm is not formed.

Apart from biofilm formation, the galvanic corrosion rate is strongly influenced by the surface area ratio between the noble stainless steel and the corroding carbon steel. Figure 5b shows an example of data obtained in seawater by coupling highly alloyed stainless steel to carbon steel. A dramatic increase in corrosion rate is observed with increasing area of the stainless steel. On this basis, it is easy to understand the potential severity of galvanic corrosion in coating defects which represent a small area in respect to stainless steel.

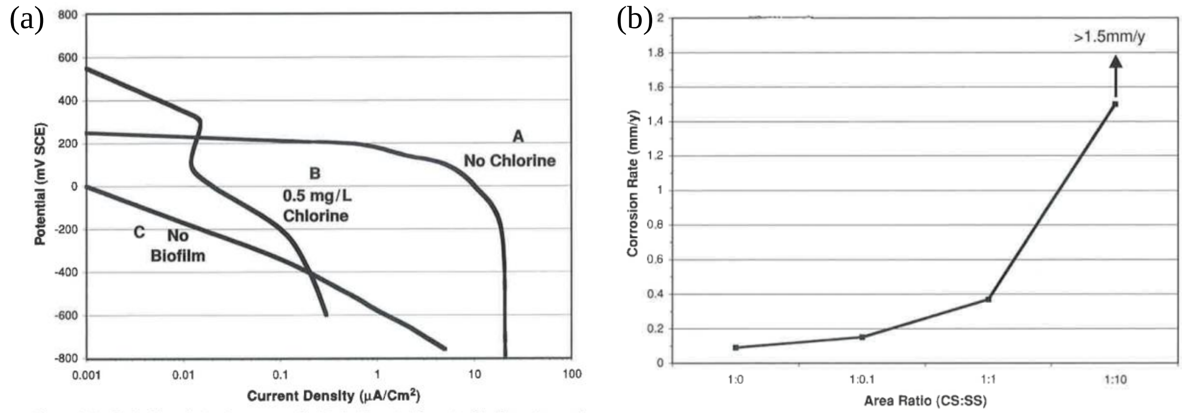


Figure 5: (a) Cathodic polarization curves for high-alloy stainless steel in three types of seawater [8]. (b) Corrosion of carbon steel coupled to 6% Mo stainless steel vs. area ratio in natural seawater [8].

The galvanic corrosion rate of a structure will also depend on resistances between the two metals, i.e. both electrical resistance in the metals and ionic resistance in the electrolyte (e.g. seawater). The galvanic effect is suppressed if there is a contact resistance between the two metals, e.g. due to rust or paint residues. Guiding calculations on galvanic corrosion show that a considerable galvanic effect is present, even at a contact resistance in the order of 500 ohms. This leads to a corrosion rate of 0.15 mm/yr instead of 0.9 mm/yr, at low contact resistance and an area ratio of 10:1.

Similar to this, the ionic resistance in the electrolyte (seawater) may suppress the galvanic interaction. Generally, the ionic resistance is negligible when the bare metal surface is freely exposed without shielding from passive elements. On the other hand, the ionic resistance may become considerable for surfaces that are shielded due to a long narrow pathway of the electrolyte separating the two metals.

Galvanic corrosion in stern tubes and pump caissons

Several cases of extensive galvanic corrosion between stainless steel and carbon steel have been observed, e.g. in stern tubes on ships or seawater pump caissons.

The galvanic corrosion in stern tubes, is facilitated by the electrical contact through the brush contact between the propeller shaft and the ship hull. This connection is part of the ship's grounding system. The propeller shaft is typically made from stainless steel or nickel-base alloy cladded steel. Flowing seawater is at the same time used for cooling and lubrication of the bearings. Thus, a small defect in the paint coated stern tube will produce very rapid and localised corrosion, as show in Figure 4a.

Extensive galvanic corrosion has also been observed in seawater pump caissons on oil rigs, both in the North Sea and the Persian Gulf. In this case, the stainless steel in the pump and riser arrangement acts as cathode, causing severe damage of the internal side of the paint coated steel caisson, Figure 4b [9]. The observed corrosion rate was 2-5 mm/yr for non-coated caissons while coated caissons showed corrosion rates up to 10 mm/yr in local coating defects.

The mentioned cases of galvanic corrosion were eliminated by installing sacrificial anodes or by applying paint coating on the noble metal, or by combining both. Mathematical modelling would usually be applied by using the SeaCorr™ software to verify the effect and lifetime of the chosen mitigation method [9].

(a) (b)

Figure 4: Examples of severe galvanic corrosion of paint coated steel due to influence from corrosion resistance alloy; (a) stern tube in ship (b) seawater pump caisson [9].

Examples of corrosion types

Inspections have been performed of approximately 150 riser joints from various projects operating in 3 different regions. The objective of the inspections was to evaluate why excessive local corrosion of low alloy steel occurred for some of the riser joints after use for short time. Since this problem was restricted to few projects, a key issue of the corrosion investigation was to identify the special circumstance(s) in the projects in question, causing rapid corrosion.

Detailed inspections were performed onshore of joints with known service history after removal of the buoyancy modules. The assessments included measurement of maximum corrosion depths, determination of anode consumption (if present) and electrical resistance measurements between parts.

(a) (b)

Figure 6: (a) Excessive corrosion on female connector and in spider contact area. (b) Excessive corrosion along edge of female connector.

<u>Paint coated carbon steel</u>

Examples of the observed corrosion on painted steel components are presented in Figures 6 to 9. The photos show extreme examples of excessive corrosion of carbon steel and should not be considered as the general condition of the inspected joints. Although corrosion appears severe and heavily localized, the integrity of the thick-walled riser components was not at risk at the time the problem was identified.

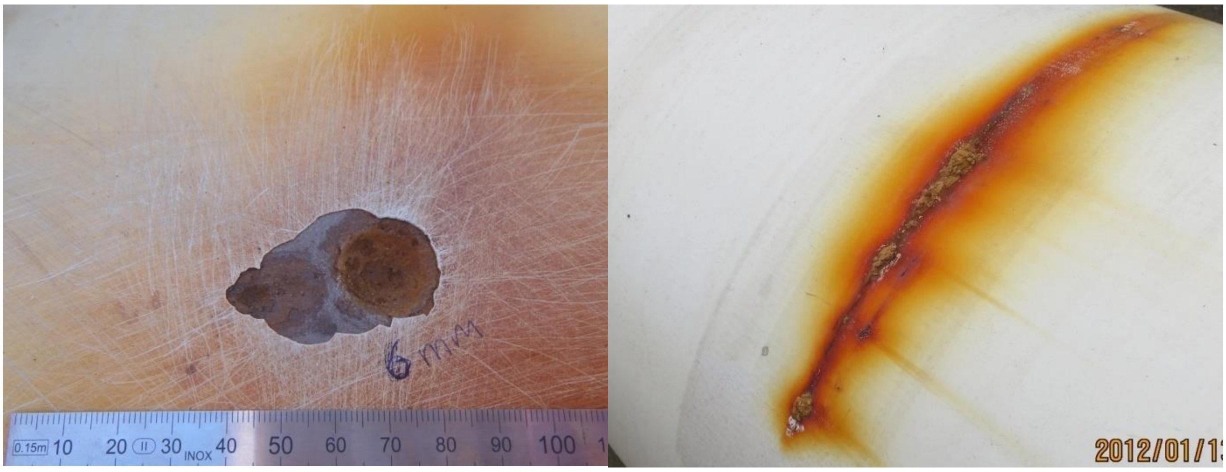
(a) (b)

Figure 6: (a) Corrosion on pin for Choke & Kill line. (b) Excessive corrosion along edge of guide plate.

In general, the corroded areas are caused by wear or damage of the protective coatings. Marine risers require frequent handling and must to some extent resist associated damage without causing severe corrosion. However, in the photos the corrosion rate exceeds the usual level (0.05-0.1 mm/yr) expected for unprotected steel in seawater. In some cases the local corrosion rate was far above 1 mm/yr and, obviously, the corrosion had been accelerated by extraordinary circumstances.

(a) (b)

Figure 7: (a) Large variation in condition of bolts for clamps. (b) Excessive corrosion at clamp.



(a) (b)

Figure 8: (a) Severe pin-hole corrosion on main pipe due to paint defect. The measured depth is 6 mm. (b) Line of coating defects on main pipe from contact with buoyancy module.

<u>Stainless steel</u>

The condition of the bare stainless hydraulic lines is generally good. Areas showing wear in contact areas with the buoyancy element is a typical feature on the hydraulic lines. The wear is superficial and does not lead to corrosion of any concern. It leaves a nicely polished spot on the surface.

Crevice corrosion was observed on UNS S31603 stainless steel tensioners for straps, fixing the buoyancy modules, Figure 9a. This type of corrosion appeared on most tensioners from projects in different regions. In some cases, crevice corrosion was also observed on clamps of UNS S31603 stainless steel. The attack was located below the rubber insert on the inward facing surface, Figure 9b.

In both cases the components were completely isolated from the structure, meaning that corrosion has been driven by the cathode reaction on the relatively small free component surface, without interaction from elsewhere.

(a) (b)

Figure 9: (a) Crevice corrosion below strap on UNS S31603 tensioner for buoyancy module. (b) Crevice corrosion inside a clamp of UNS S31603.

<u>Hardfacing</u>

In a few cases, corrosion was observed on the hardface coating of pins, connecting the hydraulic tubing. Such hardfaces are typically made from thermally sprayed Co-Cr-WC or Cr-B-C coatings. Corrosion appeared on the freely exposed part through small pin-holes in the coating, Figure 10a. This caused circular propagation along the stainless steel substrate, and finally flaking of the coating, Figure 10b.

(a) (b)

Figure 10: (a) Corrosion of freely exposed Co-Cr-WC hardfacing on pin. (b) Close-up of damage.

The applied hardface coatings provide reasonable corrosion resistance in seawater. Consequently, the observed corrosion failures were surprising. Corrosion tests were performed in the laboratory in order to simulate the failures. It was only possible to reproduce the failure mode by applying a strong anodic polarization that represents the effect typically caused by biofilm formation on stainless steel.

Galvanic anodes

Different approaches for cathodic protection had been applied by the operators on some of the examined risers in order to minimize localized corrosion of the low alloy steel parts. Figure 11a shows an example of an aluminum anode welded to the guide plate. A large spread in anode consumption was observed for most options, indicating limited efficiency that depends on “random” electrical contact from the anode to the affected parts. In line with this, no consistent or beneficial effect was observed on eliminating the corrosion types described above.

Another option involves mounting of bracelet anodes directly on the hydraulic lines, Figure 11b. The observed consumption of the anodes was in this case uniform and apparently independent of exposure depth. Initially, such anodes were made from aluminum-gallium alloy (i.e. low-voltage Al-Ga anodes) in order to exclude any possibility of Hydrogen Induced Stress Cracking (HISC) of the duplex stainless steel line11. Recent studies on stress levels and microstructure has shown that conventional aluminum or zinc anodes can be mounted on the hydraulic lines without any risk of HISC.

(a) (b)

Figure 11: (a) Aluminum anode on guide plate showing 30 % consumption after 340 days exposure. (a) Al-Ga bracelet anode mounted directly on duplex hydraulic line.

Overall assessment

The investigation shows that excessive corrosion can occur on steel parts in areas having coating defects due to mechanical impact or abrasion from relative movement. Corrosion depths of several millimeters in such local areas within a year are striking and unexpected, but the integrity of the thick-walled riser components was not at risk at the time the problem was recognized.

Galvanic corrosion between stainless steel and carbon steel appears to be the most probable factor contributing to the unusual rapid corrosion. The measured resistances indicates that wear of the epoxy coating causes full or partial electrical contact between the stainless steel tubing and the main pipe and P-lines.

Distribution of corrosion

The distribution of corrosion on the low alloy steel components was not uniform or consistent. As an example, some bolts could show extensive corrosion whereas the adjacent ones show no corrosion. Likewise, severe corrosion is observed below some fixtures, but not all. Such deviations are possibly due to marginal differences in electrical resistance between components. Furthermore, when corrosion has started in one location the likelihood of corrosion becomes smaller for adjacent areas.

Analysis of the distribution of corrosion as function of depth and service history indicated that joints exposed close to the surface were more susceptible to excessive corrosion, but exposure a greater depths has also caused excessive corrosion in some cases. Comparison of joints exposed for extended periods, indicated that the localized corrosion rate decreases with time.

Electrical continuity and anodes

Electrical resistance measurements performed onshore between the riser parts generally showed three ranges of resistances:

- Full electrical continuity (ohm range) was measured over the line connections, giving longitudinal continuity across connections of each line.
- Partial electrical continuity (kilo ohm range) was generally measured across the riser between individual parts separated by paint coating.
- No electrical continuity (mega ohm range). Resistances of this magnitude were measured between hydraulic and P-lines on new riser joints.

Presumably, full electrical continuity has been present during service at some parts, but subsequent formation of corrosion products has resulted in higher resistance when measured onshore. Consequently, short-circuiting between parts is likely while the riser is submerged and subjected to dynamic loads. Electrical contact may also be established top-sides or at the BOP, if no precautions have been taken here to isolate the individual metals. We had no possibility of examining this possibility closer during our inspections.

Galvanic anodes had been installed on the main riser structure in two projects. Large variations in anode consumption were observed, ranging from 0% to 100% after 90-340 days exposure. Again, the consumption depends on electrical continuity i.e. whether the anode has contact to the stainless steel hydraulic line. Thus, consistent protection cannot be expected, unless the anodes are installed directly stainless steel lines that causes the galvanic corrosion.

Stainless steel and biofilm

The likely formation of a marine biofilm increases the cathode efficiency of the stainless steel hydraulic line considerably. As discussed earlier, this behavior is often referred to as ennoblement. This phenomenon is usually observed after 1-2 months' exposure in seawater, and it may increase the galvanic current 10-100 times.

Crevice corrosion was observed on various UNS 31603 stainless steel parts. Since these components are electrically isolated from the riser structure, the observed corrosion is not affected by any galvanic effects with carbon steel. Corrosion was not observed consistently on all parts, but most of them. This indicates that UNS 31603 is just at the threshold for localized corrosion when used in cold, biofilm-forming seawater, which is a well-known fact. This observation strongly also suggests that oxidizing conditions due to ennoblement occur despite of region. Furthermore, this assessment is supported by the corrosion occasionally occurring in hardfacing on the hydraulic lines. It was only possible to reproduce the failure mode of such coatings by applying conditions typically caused by biofilm formation on stainless steel.

There is only limited data available in the literature on ennoblement for the specific regions where deep sea drilling is performed, so the phenomenon has not yet been fully recognized in the business. Most of the published data is focused on CP [10], and there is still an incentive for doing more studies.

Aggravating circumstances

Similar riser designs are used worldwide without corrosion of the observed magnitude as described above. On this basis, the study has tried to identify aggravating factors that can explain the high local corrosion rates. Galvanic corrosion between stainless steel and carbon steel appears to be the most probable factor contributing to rapid corrosion, but cannot solely explain the incidents. The inspections did not point to special environmental conditions or stray currents as aggravating factors. Stray currents or interference with electrical systems on the rig or other structures would otherwise have caused corrosion being more localized and severe, also including the stainless steel hydraulic lines.

On this basis, it is likely that certain aggravating circumstances have co-existed for the risers experiencing rapid corrosion. Such circumstances may involve, but not be limited to:

- Installation at greater depths in new regions with high, lateral, subsea currents. This may cause more movement of the riser, which results in increased wear between riser elements. By this, the risk of electrical contact increases.
- Longer installation time (> 1-2 months) resulting in full biofilm formation on the stainless steel, which causes stronger polarization of the carbon steel.
- No contact to the drilling rig's CP system. The riser may intentionally or unintentionally obtain cathodic protection from the drilling rig's CP system.
- Variations in coating quality and thickness, especially for areas providing isolation between stainless steel and carbon steel components.
- Short-circuiting between stainless steel tubing and carbon steel topsides or at BOP.
- New operators with limited experience involving e.g. rougher handling and lesser skilled application of lubrication systems and corrosion protection during maintenance.

Mitigation

Based on the common principles for preventing galvanic corrosion, a number of mitigating options has been established for the riser design in question. The chosen strategy depends on whether the installation takes place offshore or onshore. In general, the galvanic effect from stainless steel can be eliminated or minimized by applying one of the listed principles:

1. Apply a paint coating on the most-noble metal, i.e. the stainless steel tubing, to minimize the cathode area. Small coating defects are acceptable and insignificant since the galvanic corrosion current is proportional with the bare area of the stainless steel.

2. Install galvanic anodes on the stainless steel hydraulic lines of each joint. If the steel type is duplex stainless steel, the risk of Hydrogen Induced Stress Cracking (HISC) must be considered and avoided according to common guidelines [11].
3. Electrically insulate the stainless steel from the carbon steel parts.

Option 3 is difficult to achieve on complex structures such as drilling risers. There is always the risk of an electrical connection (grounding cable etc) either topsides or at the bottom, or in special sections inserted in the drilling riser string. Electrical currents may travel long distances in metal, so one single connection point is sufficient to jeopardize this protection strategy.

Options 1 and 2 have already been successfully applied in different configurations. As coating requires complete disassembly of the riser, this option is only possible when the risers are serviced onshore.

Installation of anodes on the stainless steel lines has been applied both offshore and onshore. The drilling risers are geometrically complex with shielded and limited spacing around the lines inside the buoyancy element. Consequently, calculations and SeaCorr 3D modeling of the cathodic protection options have been performed to define the required number of anodes and their position, Figure 12. The calculations have shown that the entire length of the hydraulic tubing can be depolarised by mounting 1 to 4 anodes on each joint, depending on design and anode types. This will eliminate the possibility of galvanic currents from the hydraulic line.

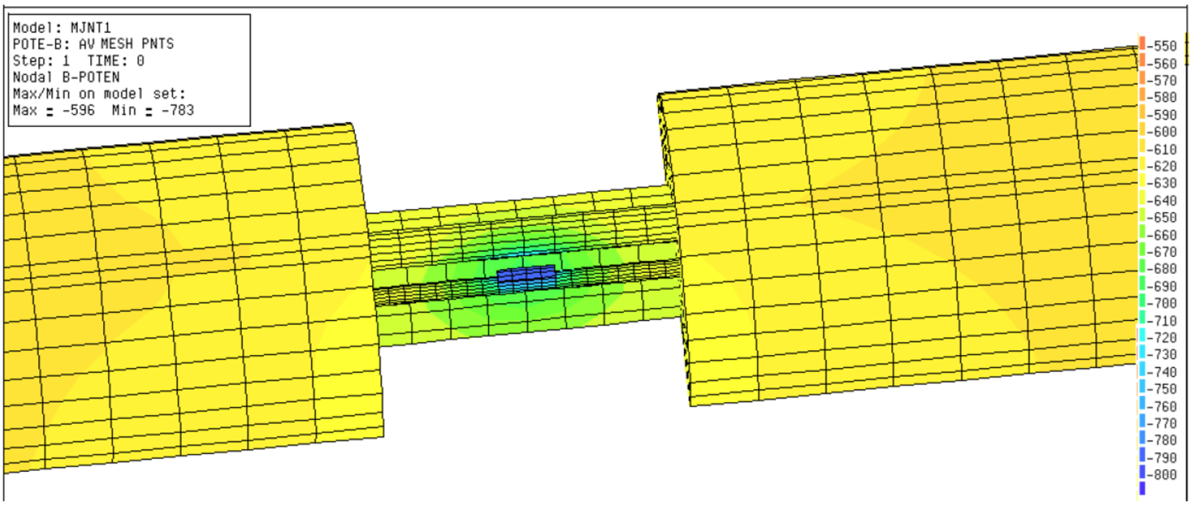


Figure 12: Example of CP modeling to calculate the required number of anodes for depolarizing the stainless steel line.

Regular maintenance of the drilling risers prior to and after each run is also of key importance to minimize corrosion. Some of the steel connector parts depend on regular application of anti-corrosion agents or lubricants. Even though the galvanic effects from stainless steel are excluded, such parts may still suffer corrosion in the order of 0.1-0.2 mm/yr if not maintained properly.

As it mentioned previously, drilling risers systems have been developed to protect from corrosion by applicable coating systems. The drilling riser pipe sections are typically in use for a few months, where they will be exposed to seawater at ambient temperature most of the time. They may carry fluids at high temperature for about a week. Between operations they may be stored on the vessel or onshore for a period of time. This storage may last from a few days to several months. The coating shall provide corrosion protection both during subsea use and onshore storage, typically in marine atmosphere in a harbor area. Subsea exposure typically last for a few months. On the other hand, the drill riser pipes are held by grabbing tools during handling onshore and offshore. This causes mechanical damages in the coating. Improved resistance against mechanical damages would be beneficial.

Based on above experiences in the projects and requirements, a coating improvement project has been started this year. The main objective of this project is evaluation of all new applicable coating systems which include epoxy coating (NORSOK M-501 system 7) [12], paint system with Zinc rich primer, Hot Dip Galvanized with powder coating on top and TSA (Thermal Spray Aluminum). Laboratory testing program as a part of the project has been done in order to identify the corrosion rate and applicability of new coating system (epoxy & TSA coating) based on riser requirements and environmental conditions. Results of laboratory testing will be presented in future papers.

Conclusions

Detailed inspections have been performed of approximately 150 marine riser joints from projects in 3 different regions. The objective of the inspections was to identify the cause of excessive local corrosion sporadically occurring on low alloy steel components after use for short time. This investigation has led to following conclusions:

- Excessive corrosion in local areas is caused by galvanic corrosion
- Biofilm formation on stainless hydraulic lines promotes corrosion in combination with random electrical contact between the components (partly due to wear of insulating paint coating)
- Longer well completion times contributes to the build-up of the biofilm that acts as a strong cathode by catalyzing oxygen reduction
- The strong effect of biofilm on galvanic corrosion is not yet fully recognized or documented within the business
- Corrosion is most excessive below fixtures and in local paint defects. In few cases excessive corrosion is observed on hardface coatings too
- The observed severity is random as it depends on the contact resistances, possibly associated with marginal differences in coating quality and wear between parts
- No obvious correlation is identified with exposure depth and service history

Mitigating actions have now successfully been applied, involving galvanic anodes or paint coating of the stainless hydraulic lines to eliminate the strong cathode effect from such lines. In parallel with this, new coating systems with higher resistance against mechanical damages are currently been evaluated.

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